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L-2008-245
10 CFR 50.59

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D. C. 20555-00001

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

In accordance with 10 CFR 50.59 requirements, attached is the summary report of changes, tests and experiments made without prior commission approval for the period covering December 9, 2006 through May 11, 2008. The report also contains a summary of Technical Specification Bases changes and reload safety evaluation summaries for Unit 3 Cycle 23 and Unit 4 Cycle 24. The updated Technical Specification Bases are provided in Attachment 2.

Should there be any questions, please contact Mr. Robert J. Tomonto, Licensing Manager, at 305-246-7327.

Very truly yours,

William Jefferson, Jr.
Vice President
Turkey Point Nuclear Plant

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

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

IE47
NRR

L-2008-245

ATTACHMENT 1

UNIT 4 CYCLE 23

10 CFR 50.59 SUMMARY REPORT

CHANGES, TESTS, AND EXPERIMENTS

ALLOWED BY 10 CFR 50.59

FOR THE PERIOD COVERING

DECEMBER 9, 2006 THROUGH MAY 11, 2008

FLORIDA POWER & LIGHT COMPANY

TURKEY POINT UNITS 3 & 4

DOCKET NUMBERS 50-250 AND 50-251

INTRODUCTION

This report is divided into four (4) sections. Section 1 summarizes changes made to the facility as described in the Updated Final Safety Analysis Report (UFSAR) resulting from Plant Changes/Modifications (PC/Ms), and developed and processed as Engineering Packages. Section 2 summarizes changes made to the facility or procedures as described in the UFSAR which were performed by a 10 CFR 50.59 evaluation not performed as part of a PC/M, and any tests and experiments not described in the UFSAR which were performed during this reporting period. Section 3 provides a summary of the Unit 3 and Unit 4 fuel reload evaluations. Section 4 provides a summary of the Technical Specification Bases changes made since the previous update.

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SECTION 1

PLANT CHANGES / MODIFICATIONS

PLANT CHANGE / MODIFICATION 02-092

Revision 4

UNIT: 3 & 4

TURNOVER DATE: 01/17/2007

SPENT FUEL POOL CASK AREA RACK PROJECT – REA 02-032

Summary:

This Plant Change/Modification (PC/M) package installed a freestanding, self-supporting, and removable spent fuel storage rack in the cask loading area of each Turkey Point Unit 3 and 4 Spent Fuel Pool (SFP) to allow continued full core offload capability with increased SFP loading. The cask area rack was designed as a Region I storage rack utilizing water flux traps and Boral panels for neutron absorption. The new rack was configured as a 11 x 12 array of storage cells, providing storage for 131 additional fuel assemblies. With one cell designated for storage of the fuel handling tool, the licensed storage capacity was increased from 1404 to 1535 fuel assemblies only during refueling operations. The cask area rack would remain empty during normal plant operation so it could be removed from the pool when needed to load a cask for dry storage, or transfer of fuel to another site storage location. The storage of fuel in the new cask area rack has been evaluated under 10 CFR 50.59 and found to require a change to the technical specification limiting the capacity of fuel stored in the SFP.

Revision 1 of this PC/M provided several administrative changes and updates to the package and included proposed changes to the Updated Final Safety Analysis Report (UFSAR) as an attachment to the PC/M. Revision 2 provided a 10 CFR 50.59 evaluation to permit installation of the cask area rack in the SFP pool; however, the storage of fuel in the rack cells was prohibited pending issuance of the license amendment. Revision 3 revised both the Licensing and Design Basis Requirements Section of the PC/M and the 10 CFR 50.59 screening to elaborate on the administrative restriction that prohibited placing fuel in the cask area rack until the technical specifications were amended. Revision 4 of this PC/M provided several administrative changes and updates to the package, incorporated commitments made to the NRC in Requests for Additional Information, and revised the UFSAR change package to reflect the final license amendment submittal.

10 CFR 50.59 Evaluation:

The 10 CFR 50.59 evaluation was limited to the activity of installing the cask area rack in the SFP (but not loading fuel in the rack). The evaluation considered the effects of (1) installing (and removing) the rack using the Auxiliary Building Cask Crane, considering the potential consequences of a rack drop on systems and structures, radiological releases, and criticality (neutronics), and (2) once the rack was installed, other accidents and effects such as a misloaded fuel assembly, a dropped fuel assembly, and the ability of the SFP cooling system to cool the spent fuel elsewhere in the pool. Since the evaluated accidents, malfunctions, and associated consequences remained bounded the UFSAR, and no new or different accidents or malfunctions were created, the proposed activity did not require a change to the plant technical specifications, or require prior NRC approval for implementation.

PLANT CHANGE / MODIFICATION 03-109

Revision 0

UNIT: 4

TURNOVER DATE: 10/10/2007

QUALIFIED SAFETY PARAMETER DISPLAY SYSTEM REPLACEMENT

Summary:

This Plant Change/Modification (PC/M) package replaced the obsolete electronics of the existing Unit 4 Qualified Safety Parameter Display System (QSPDS) with current technology devices. The QSPDS primarily provides control room indication of process instruments and parameters required by Regulatory Guide 1.97. The system also provides power to the heated junction thermocouples used to determine reactor vessel water level during accident conditions. The scope of the modification included replacement of all cabinet mounted electronics, control room displays, and operator interfaces. The replacement system uses a Triconex Tricon triple modular redundant processor for increased reliability and Westinghouse touch-sensitive flat panel display (FPD) screens. Both of these components have been approved by the NRC for safety related applications. The human-machine interface (HMI) provided by the FPDs was human factored engineered to provide information efficiently. The navigation between the different screens displaying data such as reactor vessel water level, reactor core subcooled margin, and core exit temperature was also improved over the existing design. Color coding was provided to ensure that parameters requiring immediate concern are highly visible. Internally, the application software provided with the new system performs the same monitoring and calculation functions as the existing QSPDS processors (and associated firmware). Additionally, all existing inputs and system parameters are retained by the new system.

The new equipment was shown to be compatible with the temperature, humidity, electromagnetic, and radio frequency conditions in which they were to be installed.

10 CFR 50.59 Evaluation:

The existing QSPDS electronics and HMI were upgraded in this design package to improve reliability, accuracy, and fault tolerance of the display system. The activity was considered to be a design enhancement since the new system was functionally similar to the existing QSPDS, relying on redundant channels that are electrically and physically separated to provide indication of, and the approach to, inadequate core cooling. No new failure modes were created as a result of the component upgrades. Additionally, common cause failures related to software failure (same software running on both independent channels) were not considered to be probable due to the vendor software quality assurance program, extensive factory acceptance testing, and post-installation testing. Since no functional changes were made, and the components were previously approved by the NRC for safety related applications, this modification did not require prior NRC approval for implementation.

PLANT CHANGE / MODIFICATION 06-004

Revisions 0 - 3

UNIT: 3 & 4

TURNOVER DATE: 04/25/2007

ADDITION OF UNIT 5 TO THE TURKEY POINT SITE

Summary:

This Plant Change/Modification (PC/M) package evaluated the impact on Turkey Point Units 3 and 4 of a new combined cycle power plant built at the Turkey Point site. The new unit (designated Unit 5) consists of 4 gas turbine-generators and a heat recovery steam generator producing approximately 1200 MWe. Revision 0 of the PC/M evaluated the electrical impacts associated with backfeeding Unit 5 through the modified Turkey Point switchyard to support final construction and startup of the plant support systems. Revision 1 of the PC/M evaluated the electrical impacts of Unit 5 supplying power to the switchyard plus many of the non-electrical impacts associated with Unit 5 operation. These non-electrical impacts on Units 3 and 4 included access and egress to the site during the construction phase, post-accident dose and release assumptions, potable water usage, connection to the site natural gas main, heat addition to the cooling canal system, cooling tower plume, operability of the Units 3 and 4 emergency diesel generators in the event of a release of distillate fuel oil or natural gas, and other hazards (e.g., missile generation, flooding, explosions). Revision 2 of the PC/M evaluated the impacts on Units 3 and 4 of the two 40,000 gallon tanks of 19% aqueous ammonia used to reduce nitrous oxide releases from Unit 5. This included the impacts of a postulated release of aqueous ammonia on Units 3 and 4 control room habitability, security personnel habitability, and habitability of plant support staff due to a rupture of one of the 40,000 gallon tanks of 19% aqueous ammonia. This revision included the results of a detailed ammonia release calculation and supported the installation of Seimens E-balls™ to the ammonia storage tank impoundment basin to reduce the evaporation rate of any spilled ammonia, and to minimize the air borne concentration of any released ammonia vapor. Revision 3 of the PC/M substantiates that the postulated release of ammonia from the Unit 5 storage tanks does not represent a new accident for Units 3 and 4 based on a review of the plant licensing basis.

10 CFR 50.59 Evaluation:

The impacts on Units 3 and 4 due to construction and operation of Unit 5 were evaluated and determined to not adversely affect the probability of occurrence or consequences of any accident or the malfunction of any equipment important to safety previously evaluated in the UFSAR. Similarly, the changes did not alter the function of any safety related structures, systems, or components, or introduce any new failure modes. Therefore, the modifications did not create the possibility of an accident or malfunction of equipment important to safety of a different type than any previously evaluated in the UFSAR. Since no functional changes were made to any safety related structures, systems or components, the addition of Unit 5 to the Turkey Point site did not reduce the margin of safety as defined in the bases for any technical specification. As these modifications did not adversely affect safe operation of Units 3 and 4, or require a change to the plant technical specifications, prior NRC approval was not required for implementation.

PLANT CHANGE / MODIFICATION 06-094

Revisions 0 & 1

UNIT: 4

TURNOVER DATE: 01/03/2007

CORE EXIT THERMOCOUPLE REPLACEMENT VIA IN-CORE SYSTEM FLUX THIMBLES AT LOCATION M3

Summary:

This Plant Change/Modification (PC/M) package was provided for the installation of a new Core Exit Thermocouple (CET) assembly at core location M-3 to replace the assembly damaged during the Unit 4 Cycle 23 refueling outage. The damaged CET was originally installed by PC/M 02-004 to compensate for the CETs lost during the Unit 4 Cycle 17 refueling outage when CET support column 53 was damaged. This PC/M modified the original design by installing a new CET assembly into the same thimble tube as the damaged assembly. This was accomplished by inserting the new CET cables alongside the non-functional CET assembly, which was abandoned in place within the available free space of the M-3 thimble tube.

The CETs are part of the reactor in-core instrumentation which serves the Inadequate Core Cooling System (ICCS). CETs are strategically positioned within the reactor core to measure fuel assembly coolant outlet temperature, and are required to be monitored under post-accident conditions by Regulatory Guide 1.97. The replacement CET sensor was positioned just above the active fuel as required to meet the described NUREG-0737 core exit location and provide an equivalent temperature reading at the M-3 core location. The replacement CET assembly used the same type of mineral insulated, inconel sheathed thermocouple cable as the original (damaged) assembly to meet the safety related and R.G. 1.97 environmental qualification requirements. The M-3 thimble tube was evaluated to ensure the added cables would not result in tube failure due to unacceptable seismic loading or tube wall wear/fretting caused by flow induced vibratory motion of the adjacent cables.

Revision 1 updated the analysis of thimble tube service life based on eddy current test results from the 2005 and 2006 refueling outages.

10 CFR 50.59 Evaluation:

This PC/M restored CET operation at core location M-3 by installing a replacement CET assembly in the same thimble tube in parallel with the damaged assembly. It was identified that the new CET configuration could potentially cause thimble tube failure resulting from unacceptable seismic loading and tube wall wear/fretting. However, based on evaluation, it was concluded that the potential for occurrence of these failure modes was negligible. As such, no new accidents are created by this modification and there is no increase in the frequency of occurrence of any accidents previously evaluated. This modification did not physically alter equipment, system performance, or operator actions in a manner that adversely impacts the safety analyses. Furthermore, there is no impact on the technical specifications since the number of available thimble tubes per core quadrant was maintained. It was, therefore, concluded that this PC/M did not impact safe operation of the plant or require a change to the plant technical specifications. Accordingly, prior NRC approval was not required for implementation.

PLANT CHANGE/MODIFICATION TSA 07-015

Revision 0

UNIT: 3 & 4

IMPLEMENTATION DATE: 08/31/2007

3P212B AND 4P212A MOTORS - SPENT FUEL POOL COOLING SYSTEM

Summary:

This Temporary System Alteration (TSA) reconfigured the power supplies for the Unit 3 and 4 Spent Fuel Pool (SFP) Cooling Pumps to minimize the risk of a loss of SFP cooling on Unit 3 during the Cycle 23 refueling outage, and permit continued SFP cooling during performance of the Engineered Safeguards Integrated Test. The Unit 3 SFP Cooling System is normally electrically and mechanically separate and independent from the Unit 4 SFP Cooling System. Each system consists of two 100% capacity cooling pumps, and a 50% capacity emergency cooling pump. The two 100% capacity SFP Cooling Pumps are powered from a single 480 volt breaker powered from the associated unit's electrical distribution system. A manual transfer switch at the breaker cubicle allows power to be switched between the two cooling pumps. Only one 100% capacity pump can be operated at a time. To reduce the risk of a loss of SFP cooling when the decay heat load is highest, the 480 volt power feed to one of the Unit 4 100% capacity pumps was connected to a power cable that was routed to one of the 100% capacity pumps on Unit 3. This arrangement provided each 100% capacity pump on Unit 3 with an independent power source. On Unit 4, power was only available to one 100% capacity pump. When the Unit 4 alternate power supply was aligned to the Unit 3 SFP cooling pump, cooling for the Unit 4 SFP would be limited to that provided by the emergency pump. The TSA evaluated the ability of the 50% capacity emergency pump to successfully remove the decay heat load in the Unit 4 SFP, the ability to restore power back to the spare 100% capacity SFP on Unit 4, and the human-machine interface impacts associated with the temporary configuration change. Electrical characteristics such as cable ampacity, breaker settings, voltage drop, and Emergency Diesel Generator Loading were also considered along with routing a power cable across multiple fire zones.

10 CFR 50.59 Evaluation:

The configuration change was considered to be a temporary system alteration in support of maintenance on Unit 3. The impact on Unit 4 was considered to adversely affect Updated Final Safety Analysis Report (UFSAR) described design functions since the change temporarily decreased the reliability of the Unit 4 SFP Cooling System below that assumed in the UFSAR, and temporarily exposed operation of the 4C Load Center (LC) to events or conditions on Unit 3. The evaluation demonstrated that adequate time was available to restore power to a Unit 4 SFP Cooling Pump due to the low pool heat-up rate, and that the manual restoration actions for the Unit 4 SFP Cooling System were similar to those normally required to operate the system. Furthermore, it was concluded that powering a Unit 3 SFP Cooling Pump from a Unit 4 LC did not increase the frequency of a Unit 4 bus failure since adequate electrical protection was maintained under the proposed activity. Since the probability of a loss of SFP cooling leading to bulk boiling was not increased by the temporary change, prior NRC approval for implementation of the actions or changes identified within the TSA was not required.

PLANT CHANGE / MODIFICATION TSA 08-02

Revision 0

UNIT: 3

IMPLEMENTATION DATE: 01/19/2008

INSTALLATION OF EQUIVALENT ROD POSITION INDICATION

Summary:

This Temporary System Alteration (TSA) installed an alternate display of Rod Control Cluster Assembly (RCCA) position to allow continued compliance with Technical Specification 3.1.3.2 during maintenance on the existing Analog Rod Position Indication (RPI) System. The existing Analog RPI System displayed the position of each RCCA in the control room (on console 3C01) on an analog meter in units of steps, with Step 0 representing the bottom of the core and Step 228 representing the top of the core. During the maintenance activity, RPI would continuously be available in the control room via the alternate indication system. The alternate indication system utilized the same analog output signals from the RPI system rack to display RCCA position on a microprocessor based Yokogawa recorder. The Yokogawa recorder was programmed to display RCCA position for a bank of RCCAs in similar step units and was installed in vertical panel 3C04, in front of control room console 3C02. The evaluation addressed the potential for both electrical and seismic interactions with other safety systems. The following characteristics of the Yokogawa recorder were also considered: a) susceptibility to electromagnetic and radio frequency interference, recorder scan rate, display graphics, location of the recorder relative to the analog RPI displays, signal conditioner loading, and loss of power to the recorder. The evaluation concluded that the temporary installation would not introduce any new failure modes for the RPI and would not prevent an operator from observing a RCCA deviation—alarm or indicated position—then taking appropriate recovery actions. Installation of the alternate RPI display was limited to a specific period in time after which it was removed under the requirements of the evaluation.

10 CFR 50.59 Evaluation:

The evaluation concluded that the installation of the temporary RPI display recorder would have no adverse impact on plant safety or operation, and would not compromised the licensing basis for Unit 3. The graphical display provided by the Yokogawa recorder was shown to be similar to existing displays used in the control room such that ability of an operator to observe a RCCA deviation and take appropriate recovery actions would not be impeded. Moreover, the location of the alternate RPI display in the control room would not subject the operator to additional physical barriers or environmental hazards that would prevent determining individual RCCA positions when required. Since the RPI does not cause, initiate, or detect any of the postulated RCCA drive system accidents evaluated in the Updated Final Safety Analysis Report, the installation of the temporary display, as discussed in this TSA, did not require prior NRC approval for installation and use of the temporary monitoring recorder.

PLANT CHANGE/MODIFICATION TSA 08-004

Revision 0

UNIT: 3 & 4

IMPLEMENTATION DATE: 03/28/2008

INDEPENDENT POWER SOURCE FOR 4B SFP COOLING PUMP

Summary:

This Temporary System Alteration (TSA) reconfigured the power supplies for the Unit 3 and 4 Spent Fuel Pool (SFP) Cooling Pumps to minimize the risk of a loss of SFP cooling on Unit 4 during the Cycle 24 refueling outage. The Unit 4 SFP Cooling System is normally electrically and mechanically separate and independent from the Unit 3 SFP Cooling System. Each system consists of two 100% capacity cooling pumps, and a 50% capacity emergency cooling pump. The two 100% capacity SFP Cooling Pumps are powered from a single 480 volt breaker powered from the associated unit's electrical distribution system. A manual transfer switch at the breaker cubicle allows power to be switched between the two cooling pumps. Only one 100% capacity pump can be operated at a time. To reduce the risk of a loss of SFP cooling when the decay heat load is highest, the 480 volt power feed to one of the Unit 3 100% capacity pumps was connected to a power cable that was routed to one of the 100% capacity pumps on Unit 4. This arrangement provided each 100% capacity pump on Unit 4 with an independent power source. On Unit 3, power was only available to one 100% capacity pump. When the Unit 3 alternate power supply was aligned to the Unit 4 SFP cooling pump, cooling for the Unit 3 SFP would be limited to that provided by the emergency pump. The TSA evaluated the ability of the 50% capacity emergency pump to successfully remove the decay heat load in the Unit 3 SFP, the ability to restore power back to the spare 100% capacity SFP on Unit 3, the flow limits on the Unit 4 SFP Heat Exchanger, and the human-machine interface impacts associated with the temporary configuration change. Electrical characteristics such as cable ampacity, breaker settings, voltage drop, and Emergency Diesel Generator loading were also considered along with routing a power cable across multiple fire zones.

10 CFR 50.59 Evaluation:

The configuration change was considered to be a temporary system alteration in support of maintenance on Unit 4. The impact on Unit 3 was considered to adversely affect Updated Final Safety Analysis Report (UFSAR) described design functions since the change temporarily decreased the reliability of the Unit 3 SFP cooling system below that assumed in the UFSAR, and temporarily exposed operation of the 3C Load Center (LC) to events or conditions on Unit 4. The evaluation demonstrated that adequate time was available to restore power to a Unit 3 SFP cooling pump due to the low pool heat-up rate, and that the manual restoration actions for the Unit 3 SFP cooling system were similar to those normally required to operate the system. Furthermore, it was concluded that powering a Unit 4 SFP cooling pump from a Unit 3 LC did not increase the frequency of a Unit 3 bus failure since adequate electrical protection was maintained under the proposed activity. Since the probability of a loss of SFP cooling leading to bulk boiling was not increased by the temporary change, prior NRC approval for implementation of the actions or changes identified within the TSA was not required.

SECTION 2

10 CFR 50.59 EVALUATIONS

10 CFR 50.59 EVALUATION JPN-PTN-SEEJ-89-085

Revisions 19 - 21

UNIT: 3

APPROVAL DATE: 09/16/2007

DE-ENERGIZATION OF UNIT 3 4160 VOLT SAFETY RELATED BUSSES

Summary:

This 10 CFR 50.59 evaluation establishes the requirements and restrictions placed on the operation of Units 3 and 4 and their equipment when a Unit 3 4160 volt bus is de-energized and Train "A" and "B" load centers are cross-connected. Also examined are 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 3 4160 volt bus de-energization. The de-energization of a Unit 3 4160 volt safety related bus, with Unit 3 in cold or refueling shutdown (Modes 5 and 6) or defueled and Unit 4 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 causes de-energization of the 480 volt load centers and motor control centers (MCCs) 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 is alleviated by closing the tie-breakers between opposite train 480 volt load centers, while one 4160 volt bus is de-energized or by ensuring that alternate equipment is available. Revision 19 of this evaluation analyzed the affected bus and transformer loading in support of the Containment Spray (CS) System design flow tests of CS pumps 3A and 3B. The existing evaluation assumed both CS pumps 3A and 3B were de-energized. The revised evaluation analyzed the worst case loading with both CS pumps 3A and 3B connected to the same energized 4160 volt bus (3A or 3B) while any one 4160 volt bus (3A or 3B) is de-energized and 480 volt load centers trains A and B are cross-connected. Although analyzed for both CS pumps connected, restrictions have been added to require the breaker for the CS pump not being tested to be open. In addition, wiring changes are implemented to ensure that the CS pump in test will trip on an undervoltage condition on the opposite train and not load onto the operating EDG. Revisions 20 and 21 evaluated the additional loading associated with either the 3A motor-generator or the 3A Emergency Diesel Generator air compressor and vent fan.

10 CFR 50.59 Evaluation:

This evaluation addressed the technical and licensing requirements for the de-energization of each Unit 3 4160 volt bus and concluded that the altered plant configuration and mode of operation are bounded by the technical specifications and do not change the accident analyses addressed in the plant safety analyses or the results and conclusions of any previous safety evaluations. The load changes reflected in these revisions of the evaluation were evaluated for their effects on the 4160 volt bus analysis and were determined to be acceptable. Therefore, since the conditions, actions, and precautions identified and evaluated in this evaluation did not have any adverse effect on plant safety or operations and did not require changes to plant technical specifications, prior NRC approval was not required for implementation.

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

Revision 9

UNIT: 3

APPROVAL DATE: 03/31/2008

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

Summary:

This 10 CFR 50.59 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 9 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-SEMS-96-003

Revision 8

UNIT: 4

APPROVAL DATE: 03/12/2007

UNIT 4 STEAM GENERATORS' SECONDARY SIDE FOREIGN OBJECTS

Summary:

Foreign objects have previously been identified within the secondary side of all of the Unit 4 Steam Generators (S/Gs). Foreign objects identified in this evaluation were not retrievable (or have not been retrieved) and potentially remain within the S/Gs. Previous evaluations and earlier revisions of this evaluation have addressed the acceptability of continued Unit 4 operation with the identified foreign objects remaining in the S/Gs and associated systems. The purpose of this evaluation revision is to: (1) assess the analysis results, requirements, restrictions, and effects of each incident of Unit 4 S/G foreign objects while applying the most recent industry standards, regulations, and clarifications; (2) present the methodology for determining the required interval between the performance of S/G eddy current testing (ECT) as affected by the estimated minimum wall wear times created by the presence of S/G secondary side foreign objects; and (3) provide a single Unit 4 evaluation to assess and document estimated wear times to tube minimum wall thickness for all Unit 4 S/G foreign objects, as adjusted by updated SG ECT data and SG secondary side Foreign Object Search and Retrievals (FOSAR) results.

Revision 8 of this evaluation incorporated results from the Unit 4 Cycle 23 (Fall 2006) refueling outage FOSAR inspections. The FOSAR inspections identified and removed a total of seven foreign objects from the Unit 4 S/Gs. Three new items were also observed in the 4A S/G but were not retrievable. Several small sludge-like fragments were found in the 4B and 4C S/Gs. ECT was performed on 100% of the active S/G tubes. A total of six S/G tubes were conservatively plugged as a result of these inspections. Based on foreign object wear time calculations, the most restrictive requirement for future ECT inspections is January 2013.

10 CFR 50.59 Evaluation:

The impact of continued operation of Unit 4 with S/G secondary side foreign objects is bounded by existing detection and plugging limits as defined in the technical specifications and assessed using conservative analytical techniques. Operation with secondary side foreign objects does not increase the potential for a Steam Generator Tube Rupture (SGTR), or any other accident, nor does it affect any actions described or assumed in the accident analyses. Furthermore, sufficient barriers are in place to prevent loose foreign object interactions which could increase the consequences of an accident or malfunction resulting from such operation. Thus, the consequences of an accident or malfunction will remain bounded by the SGTR accident analyses. Therefore, based on the prescribed inspections and analyses, continued operation of Unit 4 with the currently identified foreign objects within the secondary side of the S/Gs did not adversely affect the safety or design functions of the S/Gs and did not require a change to the technical specifications. Accordingly, prior NRC approval was not required for continued plant operation in accordance with this evaluation.

10 CFR 50.59 EVALUATION JPN-PTN-SEMS-96-038

Revision 8

UNIT: 3

APPROVAL DATE: 01/30/2008

STEAM GENERATORS' SECONDARY SIDE FOREIGN OBJECTS

Summary:

This 10 CFR 50.59 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 (ECT) 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 ECT data and S/G Foreign Object Search and Retrievals (FOSAR) results.

Revision 8 of this evaluation incorporated results from the Unit 3 Cycle 23 (Fall 2007) refueling outage FOSAR inspections. The FOSAR inspections identified and removed a total of four foreign objects from the Unit 3 S/Gs. Three new items (one in each S/G) were also observed but were not retrievable. ECT was performed on 100% of the active S/G tubes. One S/G tube was plugged as a result of these inspections due to an indication on the outside diameter of the tube below the tubesheet. Due to the location of the defect, it was not related to foreign objects in the S/G. Based on foreign object wear time calculations, the most restrictive requirement for future ECT inspections is January 2014.

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-SEMS-06-001

Revision 1

UNIT: 3

APPROVAL DATE: 09/20/2007

USE OF A FREEZE SEAL IN SUPPORT OF MAINTENANCE ON RELIEF VALVES

Summary:

This 10 CFR 50.59 evaluation assessed the use of freeze seals as a Component Cooling Water (CCW) System isolation boundary to support scheduled testing and possible repair/replacement of relief valves RV-3-747A, RV-3-791C, RV-3-791D, and RV-3-791E during the Unit 3 refueling outage. Valve RV-3-747A is the CCW thermal relief valve on the outlet side of the 3A Residual Heat Removal (RHR) Heat Exchanger. Valve RV-3-791C is the CCW thermal relief valve on the outlet side of the Chemical and Volume Control System (CVCS) Non-Regenerative Heat Exchanger. Valve RV-3-791D is the CCW thermal relief valve on the inlet side of the Reactor Coolant System (RCS) Sample Coolers. Valve RV-3-791E is the CCW thermal relief valve on the outlet side of the CVCS Seal Water Heat Exchanger. Application of freeze seals on the discharge side of these relief valves is necessary to prevent isolating their respective CCW headers and to maintain existing CCW inventory to support Spent Fuel Pool (SFP) cooling and containment cooling as required. To maintain safe plant operation, only one freeze seal was allowed to be installed at a time and specific operating modes were identified for each freeze seal application.

Revision 1 of this evaluation added the application of a freeze seal on the upstream (inlet) side of valve RV-3-747A, for housekeeping purposes, to eliminate leakage past the upstream manual isolation valve.

10 CFR 50.59 Evaluation:

The freeze seals were relied on to perform a CCW system boundary function during the short relief valve testing/repair duration. The strict controls imposed on the freeze seal process, the contingency measures, relatively low pressure of the contained fluid, and small size of the piping opening ensured that all CCW safety functions would remain unimpaired while the freeze seals were installed. Based on the precautions identified in this 10 CFR 50.59 evaluation, it was concluded that the freeze seals could be performed in the manner described, and that the activity did not result in unacceptable plant risk 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-SEFJ-07-012

Revision 0

UNIT: 3 & 4

APPROVAL DATE: 01/17/2008

REVISION OF THE TURKEY POINT LOCA CONTAINMENT INTEGRITY DESIGN BASIS ANALYSES

Summary:

Westinghouse notified FPL that non-conservative assumptions had been used in the two Loss-of-Coolant Accident (LOCA) Containment Integrity Design Basis Analyses: the Double-Ended Pump Suction (DEPS) Guillotine Break and the Double-Ended Hot Leg (DEHL) Guillotine Break. The errors were all related to input or modeling assumptions and did not involve changes in methodology. The applicable errors affecting Turkey Point Units 3 and 4 were as follows:

- Downcomer flow area in the REFLOOD Code was underestimated which under predicted the time required for the Emergency Core Cooling System (ECCS) water to completely refill the downcomer.
- Upper plenum flow area in the FROTH Code was over predicted which resulted in the amount of liquid entrainment and post-reflood mass and energy releases being under predicted.
- Two of the models used to calculate LOCA Mass & Energey (M&E) releases in Westinghouse WCAP-10325-P-A were found to be used inconsistently with the original WCAP and corresponding SER.
- The assumption regarding main feedwater (MFW) isolation was not conservative for the DEPS LOCA.
- The volume of hot MFW that remains in the feedwater piping between the Auxiliary Feedwater (AFW) injection point and the SG was not considered LOCA M&E releases.

The consequence of these input and modeling assumption errors was slightly higher peak containment pressure and temperature values for the DEPS LOCA analysis, and slightly lower peak containment pressure and temperature values for the DEHL LOCA analysis. In both cases, the peak containment pressure remained below the 49.9 psig assumed in the containment leakage rate testing program for an initial containment pressure of 0.3 psig. Additionally, the peak containment pressure remained below the design pressure value of 55 psig for the both the DEPS and DEHL analyses when the initial containment pressure was assumed to be at the technical specification limit.

Changes to the Updated Final Safety Analysis Report (UFSAR) and Design Basis Documents were included as an attachment to this 10 CFR 50.59 evaluation.

10 CFR 50.59 Evaluation:

This 10 CFR 50.59 evaluation demonstrated that adequate margin to the licensing basis limits on peak containment pressure were maintained following correction of the identified errors. The environmental qualification of safety related equipment inside containment was also shown to be bounded by the results of the updated analyses. Since correction of the identified errors did not involve a change in evaluation methodology for Turkey Point, the changes to the accident analysis results reported in the UFSAR change package for the DEPS and DEHL did not require prior NRC approval for implementation.

10 CFR 50.59 EVALUATION PTN-ENG-SEFJ-07-025

Revision 0

UNIT: 3 & 4

APPROVAL DATE: 02/06/2008

UFSAR AND DBD CHANGE PACKAGES FOR THE FUEL HANDLING ACCIDENT REANALYSIS

Summary:

The current Fuel Handling Analysis of record for Turkey Point Units 3 and 4 utilizes the Alternate Source Term (AST) per Regulatory Guide (RG) 1.183. The analysis assumes the non Loss-of-Coolant Accident (LOCA) fuel cladding gap release fraction given by Table 3 of RG 1.183 to determine the fraction of the fission product inventory activity in the gap available for release. A footnote to this table limits the use of these gap fractions to fuel rods that do not exceed a peak average fuel rod power of 6.3 kw/ft for burnups of greater than 54 GWT/MTU. A burnup analysis predicted that six fuel rods in each of four symmetric fuel assemblies in the Turkey Point Unit 4 Cycle 23 core would exceed this restriction. As a result, the FHA event was reanalyzed for radiological consequences using increased gap release fractions given within RG 1.25, as endorsed by NUREG/CR-5009, which are approximately twice that of RG 1.183, Table 3. This methodology was previously utilized by other licensees to address fuel rods that exceed the applicability limitations of RG 1.183, Table 3. The control room unfiltered inleakage value was also reduced from 1000 cfm to 500 cfm to ensure adequate results would be maintained by the reanalysis. The dose consequence results of the reanalysis remained significantly less than the applicable regulatory limits.

Changes to the Updated Final Safety Analysis Report (UFSAR) and Design Basis Documents were included as an attachment to this 10 CFR 50.59 evaluation.

10 CFR 50.59 Evaluation:

This 10 CFR 50.59 evaluation demonstrated that adequate margin to the regulatory limits were maintained following reanalysis of the FHA. The results were obtained using a methodology that was previously reviewed and approved by the NRC for other licensees to address fuel rods that exceeded the applicability limitations of RG 1.183, Table 3. Additionally, to offset the increased gap fractions, the results were based on a reduced control room unfiltered inleakage value that remained conservative based on the control room unfiltered inleakage value used in the LOCA analysis. Since an approved methodology was used in the reanalysis, and the dose consequences remained within 10% of the difference between the existing dose analysis and the regulatory limits, the changes to the accident analysis results reported in the UFSAR change package for the FHA did not require prior NRC approval for implementation.

10 CFR 50.59 EVALUATION PTN-ENG-SENS-07-032

Revision 0

UNIT: 3 & 4

APPROVAL DATE: 12/06/2007

RHR SYSTEM OPERATION WITH THE REACTOR CAVITY FILLED AND THE VESSEL UPPER INTERNALS IN PLACE

Summary:

This 10 CFR 50.59 evaluation provided the technical justification to permit only one train of the Residual Heat Removal (RHR) System to be operable and in operation with the refueling cavity flooded to greater than or equal to 23 feet, without regard to whether the reactor vessel upper internals assembly was in place or removed. Existing plant administrative and operating procedures required two trains of RHR to be operable and one train in operation in Mode 6 (Refueling) with the reactor cavity flooded to greater than or equal to 23 feet above the reactor vessel flange and the reactor vessel upper internals assembly in place. The requirement to have two trains (loops) of RHR operable (one train in operation) with the vessel upper internals in place was more conservative than the Limiting Condition for Operation (LCO) for Technical Specification (TS) 3.9.8.1. That LCO only requires one loop of RHR to be operable and in operation in Mode 6, without regard to whether the vessel upper internals assembly is in place or removed. The additional administrative controls placed on the RHR system were considered necessary pending plant-specific resolution of a concern identified in NUREG/CR-5820 and discussed in the draft version of NUREG-1449 and a draft Regulatory Guide for shutdown operations. Computer models were constructed using the GOTHIC Code and plant specific information relative to the available area for flow to compare and assess the resulting effects of a loss of RHR event with the reactor vessel upper internals assembly in place versus removed. The analysis results indicated that stable natural circulation patterns would occur both for the case where the reactor vessel upper internals assembly is in place and the case where the internals assembly is removed. Furthermore, with the water level in the refueling cavity at about 11 feet above the vessel flange, the analysis demonstrated adequate heat removal for at least 30 hours for both cases.

10 CFR 50.59 Evaluation:

Although some steam voiding in the core volume occurs in both cases, the voiding is more prevalent in the internals in case. However, the heat flux is far below the Critical Heat Flux (CHF) in each case. Hence, there is no discernable difference between having the reactor vessel upper internals assembly installed or having it removed with respect to fuel damage following a loss of RHR since there will be no increase in the incidence of fuel damage in either case. Given that the impact of the evaluated change is only applicable for a short period, any discernable increase in the likelihood of occurrence of a malfunction of the RHR system (causing a loss of RHR shutdown cooling) would be small, and would be more than offset by the programmatic controls in place to maximize the reliability of safety-related equipment and minimize the potential for operator error and inadvertent closure of the RHR suction valves when shutdown cooling is required. Based on the analysis presented in this 10 CFR 50.59 evaluation, it was concluded that the activity did not result in unacceptable plant risk 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-SEMS-07-041

Revision 1

UNIT: 3

APPROVAL DATE: 09/28/2007

CONTROL ROD GUIDE TUBE K-6 FLOW RESTRICTOR ANOMALY

Summary:

This 10 CFR 50.59 evaluation provide justification for allowing the Control Rod Guide Tube (CRGT) flow restrictor at core location K-6 to remain in the "as-is" condition for one fuel cycle of operation. Flow restrictors were installed as part of Reactor Vessel Closure Head (RVCH) replacement to provide flow resistance equivalent to the part-length control rod drive mechanism lead screws that were eliminated by the new RVCH design. The lower end of the lead screws, which protruded into the upper rod control cluster assembly shroud, added resistance to flow coming up the CRGT and into the upper region of the head. This "as-is" condition deviates from the design condition in that the nut for the flow restrictor at core location K-6 has not been fully torqued to the specified value to assure the seating of the sealing surfaces. In the absence of this preload, the seating of the sealing surfaces is achieved by the component weight. The evaluation addressed the potential for flow bypass around the flow restrictor as well as the potential for flow-induced vibration, wear particles, and foreign materials (loose parts) on operability of the reactor coolant system components.

Revision 1 was issued to address a comment from the Plant Nuclear Safety Committee regarding the impact of reactor vessel internals vibration on movement of the K-6 flow restrictor, and the possible increase in component wear during the fuel cycle. The evaluation concluded that:

- The flow restrictor is not expected to break apart and become loose parts in the reactor coolant system during the fuel cycle.
- The fractional increase in wear products released to the reactor coolant will not adversely affect the operation or performance of any plant structure, system or component.
- The flow restrictor can be expected to continue to perform as designed to limit the flow into/out of the reactor vessel upper head region consistent with the Unit 3 original configuration equipment.

10 CFR 50.59 Evaluation:

The 10 CFR 50.59 evaluation demonstrated that allowing the CRGT flow restrictor at core location K-6 to remain in the "as-is" condition for one fuel cycle of operation was acceptable and would have no adverse impact on plant operation. Since there would be no adverse effects on core flow, core bypass flow, reactor vessel upper head flow patterns, or reactor vessel upper head fluid temperatures, none of the safety evaluations that use RVCH temperature were affected. The current as-is condition was determined to be bounded by the structural analysis of record such that the likelihood of failure during the operating cycle was not increased. It was concluded that the activity did not result in unacceptable plant risk 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 10 CFR 50.59 EVALUATIONS

PLANT CHANGE/MODIFICATION 07-019

Revision 0

UNIT: 3

TURNOVER DATE: 01/25/2008

TURKEY POINT UNIT 3 CYCLE 23 RELOAD DESIGN

Summary:

This Plant Change/Modification (PC/M) Package provided the core design for the Turkey Point Unit 3 Cycle 23 reload. The design change for Cycle 23 primarily involved the replacement of 53 burned fuel assemblies with 52 fresh assemblies, plus one fuel assembly previously discharged in Cycle 21. The maximum enrichment for the Cycle 23 fuel, including a 0.05 weight percent fabrication uncertainty, was less than or equal to 4.45 w/o and was bounded by the technical specifications limit of 4.50 w/o. All of the Cycle 22 fuel assemblies were Debris Resistant Fuel Assemblies (DRFAs) and all contained a nominal 6-inch axial blanket of natural UO_2 annular pellets at both the top and bottom of the fuel stack. Hafnium vessel flux depression absorbers were used on the core flats. No Wet Annular Burnable Absorbers (WABA) were used in this reload consistent with the current core design practice.

There are no mechanical design changes to the fresh fuel assemblies loaded in Cycle 23 relative to the fuel loaded in Cycle 22.

Cross core fuel bundle shuffles were utilized in the Cycle 23 loading pattern to minimize potential power asymmetries. The fuel was arranged in a low leakage pattern with no significant differences between the Cycle 22 and Cycle 23 patterns.

10 CFR 50.59 Evaluation:

The Unit 3 Cycle 23 reload core design was evaluated by Florida Power & Light Company and by the fuel supplier, Westinghouse Electric Corporation. The Cycle 23 reload core design met all applicable design criteria, appropriate licensing bases, and the requirements of the plant technical specifications. It was, therefore, concluded that the Cycle 23 core reload did not have any adverse effect on plant safety or plant operations or require changes to the technical specifications. Accordingly, prior NRC approval was not required for implementation.

PLANT CHANGE/MODIFICATION 07-093

Revision 0

UNIT: 4

TURNOVER DATE: 07/08/2008

TURKEY POINT UNIT 4 CYCLE 24 RELOAD DESIGN

Summary:

This Plant Change/Modification (PC/M) Package provided the core design for the Turkey Point Unit 4 Cycle 24 reload. The design change for Cycle 24 primarily involved the replacement of 56 burned fuel assemblies with 56 fresh assemblies. The maximum enrichment for the Cycle 24 fuel, including a 0.05 weight percent fabrication uncertainty, was less than or equal to 4.45 w/o and was bounded by the technical specification limit of 4.50 w/o. All of the fuel assemblies were Debris Resistant Fuel Assemblies (DRFAs) and all contain a nominal 6-inch axial blanket of natural UO_2 annular pellets at both the top and bottom of the fuel stack. Hafnium vessel flux depression absorbers were used on the core flats. No Wet Annular Burnable Absorbers (WABA) were used in this reload consistent with the current core design practice.

There were no mechanical design changes to the fresh fuel assemblies loaded in Cycle 24 relative to the fuel loaded in Cycle 23.

Cross core fuel bundle shuffles were utilized in the Cycle 24 loading pattern to minimize potential power asymmetries. The fuel was arranged in a low leakage pattern with no significant differences between the Cycle 23 and Cycle 24 patterns.

10 CFR 50.59 Evaluation:

The Unit 4 Cycle 24 reload core design was evaluated by Florida Power & Light Company and by the fuel supplier, Westinghouse Electric Corporation. The Cycle 24 reload core design met all applicable design criteria, appropriate licensing bases, and the requirements of the plant Technical Specifications. It was, therefore, concluded that the Cycle 24 core reload did not have any adverse effect on plant safety or plant operations or require changes to the technical specifications. Accordingly, prior NRC approval was not required for implementation.

SECTION 4

TECHNICAL SPECIFICATION BASES CHANGES

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 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 of this letter. A summary of Technical Specification Bases changes made since the previous update are as follows:

0-ADM-536 Procedure Changes:

RTS No. 07-0536

RTS No. 07-0536 incorporates changes to Sections 3/4.4.5, 3/4.4.6.2 and 3/4.4.8 as a result of revisions to Units 3 and 4 Technical Specification (TS) by License Amendments 233 and 228, respectively. The amendments revised the Turkey Point requirements related to steam generator tube integrity, and RCS leakage consistent with NRC-approved Revision 4 to Technical Specification Task Force (TSTF) Standard Technical Specification Change Traveler, TSTF – 449, "Steam Generator Tube Integrity."

RTS No. 07-0806P

RTS No. 07-806P added Section 3.0.6 as a result of revisions to Units 3 and 4 TS by License Amendments 235 and 230, respectively. The amendments added a new Limiting Condition for Operation (LCO) 3.0.6 establishing the allowance for restoring equipment to service under administrative controls when equipment has been removed from service or declared inoperable to comply with TS Action Statements requirements.

RTS 07-1082

RTS No. 07-1082 incorporated clarification to Sections 3/4.3.1 and 3/4.3.2 regarding the use of gammametric instrumentation in place of the source range monitors only when the reactor trip breakers are open (TS 3.3.1, Table 3.3-1, Items 4b and 4c). In addition Section 3/4.6.3 was revised to reflect the changes made by PC/M 04-123, which changed the Emergency Containment Filter System dousing valve flow switches from de-energized-to-open to energize-to-open.

L-2008-245

ATTACHMENT 2

TURKEY POINT NUCLEAR PLANT

PROCEDURE 0-ADM-536

TECHNICAL SPECIFICATION BASES CONTROL PROGRAM

Florida Power & Light Company

Turkey Point Nuclear Plant

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

0-ADM-536

Title:

Technical Specification Bases Control Program

(Information Use)

Responsible Department:	Licensing
Revision Approval Date:	7/23/08

PCRs *08-3002*
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, 04-0818P, 04-1062P, 05-0138, 05-0148, 06-0844, 06-0904P, 06-0660P, 07-0536, 07-0806P, 07-1082*
PC/Ms *06-049, 04-123*

W2003:DPS/cls/ln/ln

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15	10/10/07	47	10/10/07	79	10/10/07	111	10/10/07
16	10/10/07	48	10/10/07	80	10/10/07	112	10/10/07
17	10/10/07	49	10/10/07	81	10/10/07	113	10/10/07
18	10/10/07	50	10/10/07	82	10/10/07	114	10/10/07
19	10/10/07	51	10/10/07	83	10/10/07	115	10/10/07
20	10/10/07	52	10/10/07	84	10/10/07	116	10/10/07
21	10/10/07	53	10/10/07	85	10/10/07	117	10/10/07
22	10/10/07	54	10/10/07	86	10/10/07	118	10/10/07
23	10/10/07	55	10/10/07	87	10/10/07	119	10/10/07
24	10/10/07	56	10/10/07	88	12/12/07	120	10/10/07
25	10/10/07	57	10/10/07	89	12/12/07		
26	10/10/07	58	10/10/07	90	10/10/07		
27	10/10/07	59	10/10/07	91	10/10/07		
28	10/10/07	60	10/10/07	92	10/10/07		
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1.0 PURPOSE

1.1 This procedure provides instructions for the preparation, review, approval, distribution and revision of Technical Specification Bases as required by Technical Specification 6.8.4.i, Technical Specifications (TS) Bases Control Program.

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. Proposed TS Bases changes that meet the criteria of Section 1.3 below shall be reviewed and approved by the NRC prior to implementation. [TS 6.8.4.i.d]

1.3 Licensees may make changes to the Bases without prior NRC approval provided the changes do not require either of the following [TS 6.8.4.i.b]:

1.3.1 Change in the TS incorporated in the license, or [TS 6.8.4.i.b.1]

1.3.2 A change to the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59 [TS 6.8.4.i.b.2].

2.0 REFERENCES/RECORDS REQUIRED/COMMITMENT DOCUMENTS

2.1 References

2.1.1 Technical Specifications

1. 6.8, Procedures and Programs

2.1.2 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. PI-AA-204, Condition Identification and Screening Process
5. PI-AA-205, Condition Evaluation and Corrective Action Process

2.1.3 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

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

1. CR-98-0382
2. CR 2005-1152
3. CR 2006-31637
4. ENG-QI 2.0, Engineering Evaluation
5. ENG-QI 2.1, 10 CFR 50.59 Applicability/Screening/Evaluation
6. Engineering Evaluation PTN-ENG-SEMS-06-0035, Ultra Low Sulfur Diesel Fuel Oil in the Emergency Diesel Generators
7. 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
8. NRC Letter and SER dated 1/6/05, Turkey Point Units 3 and 4 – Issuance of Amendments Regarding Accident Monitoring Instrumentation Outage Times
9. NRC Letter and SER dated July 22, 2004, Turkey Point Units 3 and 4 - Issuance of Amendments Regarding Revision to Technical Surveillance Requirement 4.0.5
10. NRC letter and SER dated September 5, 2007, Issuance of Amendments Regarding Addition of a New Technical Specification 3.0.6. Amendments 235/230
11. PC/M 04-123, Flow Switch Modification for the Emergency Containment Filter System
12. PC/M 06-049, Interim Containment Recirculation Sump Debris GSI-191 Resolution
13. PTN-ENG-SEFJ-02-016, Rev. 0
14. PTN-ENG-SENS-03-0046, Rev. 0

2.2 Records Required

2.2.1 Completed copies of the below listed items 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

2.3.2 Amendment Nos 233/228, NRC Letter dated, April 27, 2007

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 [TS 6.8.4.i.a].

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 Screening.

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 [TS 6.8.4.i.a].

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 [TS 6.8.4.i.c].

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 [TS 6.8.4.i.d].

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.

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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.

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; 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 location 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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2.1.1 (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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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 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>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.

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2.2.1 (Cont'd)

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 105 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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2.2.1 (Cont'd)

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, and (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.

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.

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2.2.1 (Cont'd)

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 x 106 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.

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.

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2.2.1 (Cont'd)

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.

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.

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2.2.1 (Cont'd)

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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3/4 Limiting Conditions For Operation And Surveillance Requirements

3/4.0 Applicability

Specification 3.0.1 through 3.0.6 establishes 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 systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

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.

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3/4.0 (Cont'd)

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.

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.

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3/4.0 (Cont'd)

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.

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.

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3/4.0 (Cont'd)

Specification 3.0.6 establishes the allowance for restoring equipment to service under administrative controls when equipment has been removed from service or declared inoperable to comply with Technical Specification ACTION requirements. The sole purpose of this specification is to provide an exception to TS 3.0.1 and 3.0.2 (i.e., to not comply with the applicable required actions to allow the performance of required testing to demonstrate either:

- The OPERABILITY of the equipment being returned to service; or
- The OPERABILITY of other equipment.

Administrative Controls, such as test procedures, ensure the time the equipment is returned to service in conflict with the ACTION requirements is limited to the time absolutely necessary to perform the required testing to demonstrate OPERABILITY. LCO 3.0.6 does not provide time to perform any other preventive or corrective maintenance.

An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a containment isolation valve that was closed to comply with TS action requirements. The valve must be reopened to perform the testing required to demonstrate OPERABILITY.

An example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of required testing on another channel in the other trip system.

A similar example of demonstrating OPERABILITY of the other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of required testing on another channel in the same trip system.

Temporarily returning inoperable equipment to service fro the purpose of confirming OPERABILITY, places the plant in a condition which has been previously evaluated in the development of the current Technical Specifications and determined to be acceptable for short periods as prescribed by allowed outage times in ACTION requirements. Performance of the surveillance/testing is considered to be a confirmatory check of that capability which demonstrates that the equipment is indeed operable in most cases. For those times when equipment, which may be temporarily returned to service under administrative controls per LCO 3.0.6, is subsequently determined to remain inoperable, the Technical Specification ACTION requirements continue to apply until the equipment is determined OPERABLE.

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3/4.0 (Cont'd)

Specification 4.0.1 through 4.0.5 establishes 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.

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.

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3/4.0 (Cont'd)

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 ACTIONs 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.

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 ACTIONs.

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3/4.0 (Cont'd)

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 ACTIONs 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 ACTIONs 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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3/4.0 (Cont'd)

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.

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.

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3/4.0 (Cont'd)

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 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. Inservice testing of ASME Code Class 1, 2 and 3 pumps and valves shall be performed in accordance with the ASME Code of Operation and Maintenance of Nuclear Power Plants (ASME OM Code) and applicable 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 or the ASME OM 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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3/4.1 Reactivity Control Systems

3/4.1.1 Boration Control

3/4.1.1.1 &
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 x 10-4 Δk/k/°F. The MTC value of -3.0 x 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 x 10-4 Δk/k/°F.

TECHNICAL SPECIFICATION BASES

3/4.1.1.3 (Cont'd)

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 components 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.

TECHNICAL SPECIFICATION BASES

3/4.1.2 (Cont'd)

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 the ASME OM 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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3/4.1.2 (Cont'd)

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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3/4.1.3 (Cont'd)

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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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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3/4.2.1 (Cont'd)

At power level below PT, 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 PT 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 FQ(Z) less than its limiting value. Therefore, PT is calculated to be less than 100%. To allow operation at the maximum permissible value above PT 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 PT 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) PT (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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3/4.2.2 &
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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3/4.2.2 and 3/4.2.3 (Cont'd)

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}.

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

In the specified limit of $F_{\Delta H}^{N}$, there is an 8 percent allowance for uncertainties which means that normal operation of the core is expected to result in $F_{\Delta H}^{N} \leq F_{\Delta H}^{RTP}/1.08$, where $F_{\Delta H}^{RTP}$ is the $F_{\Delta H}^{N}$ 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 $F_{\Delta H}^{N}$ 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 $F_{\Delta H}^{N}$ 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 $F_{\Delta H}^{N}$ is less readily available. When a measurement of $F_{\Delta H}^{N}$ 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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3/4.2.2 and 3/4.2.3 (Cont'd)

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:

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

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

$F_{xy}(Z)_{\text{measured}}$ = 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 FZ(Z) is calculated from the following relationship:

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

TECHNICAL SPECIFICATION BASES

3/4.2.2 and 3/4.2.3 (Cont'd)

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 required 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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3/4.2.2 and 3/4.2.3 (Cont'd)

e) Rj, 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 PT.

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

where

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

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) σj 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.

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

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

h) The factors (1+ σj) and 1.07 represent the margin between (Fj(Z)]L limit and the MIDS alarm setpoint [Fj(Z)]s. Since (1 +σj) 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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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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3/4.2.5 (Cont'd)

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.

3/4.3 Instrumentation

3/4.3.1 &
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 Protection and Control 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.

TECHNICAL SPECIFICATION BASES

3/4.3.1 and 3/4.3.2 (Cont'd)

If the reactor trip breakers (RTB) are closed and the Rod Control System is capable of withdrawing the control rods, then source range instrumentation is required to support Technical Specification 3.3.1, Table 3.3-1, Item 4c. This is specified by the single asterisk note and the requirement in the table for the trip function. Otherwise, Item 4b of Table 3.3-1 applies. The double asterisk note of Item 4b allows the use of the Gammametrics only if the RTBs are open. If the RTBs are closed but the Rod Control System is not capable of withdrawing rods, then Item 4b does not allow Gammametrics to take the place of source range instruments. Item 4b does not require the trip function to be operable.

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 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 ≥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.

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3/4.3.1 and 3/4.3.2 (Cont'd)

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 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:

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

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).

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,

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3/4.3.1 and 3/4.3.2 (Cont'd)

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 has 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 Tavg. The permissive is generated when two out of three Low Tavg 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 Tavg channels rise above their setpoints. The permissive may be manually defeated when two out of three Low Tavg channels are below their setpoints and the manual SI Block/Unblock switch is momentarily placed in the unblock position.

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.

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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.

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.

Action c states that separate Action entry is allowed for each Instrument. This Action has been added for clarification. The Actions of this Specification may be entered independently for each Instrument listed on Table 3.3-5. Allowable outage times of the inoperable channels of an Instrument will be tracked separately for each Instrument starting from the time the Action was entered for that Instrument.

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3/4.3.3.3 (Cont'd)

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 30 days or submit a Special Report in the next 14 days).

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, 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 30 days one must be fixed or a Special Report submitted within the next 14 days.

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.

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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 x 10-6 μCi/ml are measurable.

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.

TECHNICAL SPECIFICATION BASES

3/4.4.1 (Cont'd)

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.

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.

TECHNICAL SPECIFICATION BASES

3/4.4.1 (Cont'd)

Demonstration of the safety valves lift settings will occur only during shutdown and will be performed in accordance with the provisions of the ASME OM 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.

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 valves, consistent with the required function of the valves.

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

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3/4.4.4 (Cont'd)

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 valves 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 valves 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 valves closed with power maintained to the block valves 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.

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 valves 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 valves 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.

ACTION statements b. and c. include removal of power from a closed block valve as additional

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3/4.4.4 (Cont'd)

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.

3/4.4.5 Steam Generator - (SG) Tube Integrity

Background

Steam generator (SG) tubes are small diameter, thin walled tubes that carry primary coolant through the primary to secondary heat exchangers. The SG tubes have a number of important safety functions. SG tubes are an integral part of the reactor coolant pressure boundary (RCPB) and, as such, are relied on to maintain the primary system's pressure and inventory. The SG tubes isolate the radioactive fission products in the primary coolant from the secondary system. In addition, as part of the RCPB, the SG tubes are unique in that they act as the heat transfer surface between the primary and secondary systems to remove heat from the primary system. This Specification addresses only the RCPB integrity function of the SG. The SG heat removal function is addressed by LCO 3.4.1.1, Reactor Coolant Loops and Coolant Circulation - Startup and Power Operation, LCO 3.4.1.2, Hot Standby, LCO 3.4.1.3, Hot Shutdown, LCO 3.4.1.4.1, Cold Shutdown - Loops Filled, and LCO 3.4.1.4.2, Cold Shutdown - Loops Not Filled.

SG tube integrity means that the tubes are capable of performing their intended RCPB safety function consistent with the licensing basis, including applicable regulatory requirements.

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3/4.4.5 (Cont'd)

SG tubing is subject to a variety of degradation mechanisms. SG tubes may experience tube degradation related to corrosion phenomena, such as wastage, pitting, intergranular attack, and stress corrosion cracking, along with other mechanically induced phenomena such as denting and wear. These degradation mechanisms can impair tube integrity if they are not managed effectively. The SG performance criteria are used to manage SG tube degradation.

Specification 6.8.4.j, Steam Generator (SG) Program, requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 6.8.4.j, tube integrity is maintained when the SG performance criteria are met. There are three SG performance criteria: structural integrity, accident induced leakage, and operational leakage. The SG performance criteria are described in Specification 6.8.4.j. Meeting the SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions.

The processes used to meet the SG performance criteria are defined by the Steam Generator Program Guidelines (Ref. 1).

Applicable Safety Analysis

The steam generator tube rupture (SGTR) accident is the limiting design basis event for SG tubes and avoiding a SGTR is the basis for this Specification. The analysis of a SGTR event assumes a bounding primary-to-secondary leakage rate equal to 500 gpd for each of the two intact SGs plus the leakage rate associated with a double-ended rupture of a single tube in the third (ruptured) SG. The accident analysis for a SGTR assumes the contaminated secondary fluid is released to the atmosphere via safety valves or atmospheric dump valves. No credit for iodine removal is taken for any steam released to the condenser prior to reactor trip and concurrent loss of offsite power.

The analysis for design basis accidents and transients other than a SGTR assume the SG tubes retain their structural integrity (i.e., they are assumed not to rupture). In the dose consequence analysis for these events the activity level in the steam discharged to the atmosphere is based on a primary-to-secondary leakage rate of 1 gpm total through all SGs and 500 gallons per day through any one SG at accident conditions, or is assumed to increase to these levels as a result of accident induced conditions. For accidents that do not involve fuel damage, the primary coolant activity level of DOSE EQUIVALENT I-131 is assumed to be equal to the LCO 3.4.8, Reactor Coolant System Specific Activity, limits. For accidents that assume fuel damage, the primary coolant activity is a function of the amount of activity released from the damaged fuel. The dose consequences of these events are within the limits of GDC 19 (Ref. 2), 10 CFR 100 (Ref. 3), 10 CFR 50.67 (Ref. 7) or the NRC approved licensing basis.

Steam generator tube integrity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

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3/4.4.5 (Cont'd)

Limiting Condition for Operation (LCO)

The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the repair criteria be plugged in accordance with the Steam Generator Program.

During a SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is removed from service by plugging. If a tube was determined to satisfy the repair criteria but was not plugged, the tube may still have tube integrity.

In the context of this Specification, a SG tube is defined as the entire length of the tube, including the tube wall between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet. The tube-to-tubesheet weld is not considered part of the tube.

A SG tube has integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 6.8.4.j and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

There are three SG performance criteria: structural integrity, accident induced leakage, and operational leakage. Failure to meet any one of these criteria is considered failure to meet the LCO.

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as, the gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation. Tube collapse is defined as, for the load displacement curve for a given structure, collapse occurs at the top of the load verses displacement curve where the slope of the curve becomes zero. The structural integrity performance criterion provides guidance on assessing loads that have a significant effect on burst or collapse. In that context, the term significant is defined as an accident loading condition other than differential pressure is considered significant when the addition of such loads in the assessment of the structural integrity performance criterion could cause a lower structural limit or limiting burst/collapse to be established. For tube integrity evaluations, except for circumferential degradation, axial thermal loads are classified as secondary loads. For circumferential degradation, the classification of axial thermal loads as primary or secondary loads will be evaluated on a case-by-case basis. The division between primary and secondary classifications will be based on detailed analysis and/or testing.

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3/4.4.5 (Cont'd)

Structural integrity requires that the primary membrane stress intensity in a tube not exceed the yield strength for all ASME Code, Section III, Service Level A (normal operating conditions) and Service Level B (upset or abnormal conditions) transients included in the design specification. This includes safety factors and applicable design basis loads based on ASME Code, Section III, Subsection NB (Ref. 4) and Draft Regulatory Guide 1.121 (Ref. 5).

The accident induced leakage performance criterion ensures that the primary-to-secondary leakage caused by a design basis accident, other than a SGTR, is within the accident analysis assumptions. The accident analyses assume that accident leakage does not exceed 1 gpm total through all SGs and 500 gallons per day through any one of the three SGs at accident conditions. The accident induced leakage rate includes any primary to secondary leakage existing prior to the accident in addition to primary to secondary leakage induced during the accident.

The operational leakage performance criterion provides an observable indication of SG tube conditions during plant operation. The limit on operational leakage is contained in LOC 3.4.6.2 and limits primary-to-secondary leakage through any one SG to 150 gpd at room temperature. This limit is based on the assumption that a single crack leaking this amount would not propagate to a SGTR under the stress conditions of a LOCA or a main steam line break. If this amount of leakage is due to more than one crack, the cracks are very small, and the above assumption is conservative.

Applicability

SG tube integrity is challenged when the pressure differential across the tubes is large. Large differential pressures across SG tubes can only be experienced in MODE 1, 2, 3, or 4.

Reactor Coolant System conditions are far less challenging in MODES 5 and 6 than during MODES 1, 2, 3, and 4. In MODES 5 and 6, primary-to-secondary differential pressure is low, resulting in lower stresses and reduced potential for leakage.

Actions

The ACTIONS are modified by a Note clarifying that the ACTIONS may be entered independently for each SG tube. This is acceptable because the ACTIONS provide appropriate compensatory actions for each affected SG tube. Complying with the ACTIONS may allow for continued operation, and subsequent affected SG tubes are governed by subsequent ACTION entry and application.

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TECHNICAL SPECIFICATION BASES

3/4.4.5 (Cont'd)

a.1 &
a.2 ACTIONS a.1 and a.2 apply if it is discovered that one or more SG tubes examined in an inservice inspection satisfy the tube repair criteria but were not plugged in accordance with the Steam Generator Program as required by Surveillance Requirement (SR) 4.4.5.2. An evaluation of SG tube integrity of the affected tubes must be made. SG tube integrity is based on meeting the SG performance criteria described in the Steam Generator Program. The SG repair criteria limits on SG tube degradation that allow for flaw growth between inspections while still providing assurance that the SG performance criteria will continue to be met. In order to determine if a SG tube that should have been plugged has tube integrity, an evaluation must be completed that demonstrates that the SG performance criteria will continue to be met until the next refueling outage or SG tube inspection. The tube integrity determination is based on the estimated condition of the tube at the time the situation is discovered and the estimated growth of the degradation prior to the next SG tube inspection. If it is determined that tube integrity is not being maintained, ACTION b applies.

An allowable outage time of seven days is sufficient to complete the evaluation while minimizing the risk of plant operation with a SG tube that may not have tube integrity.

If the evaluation determines that the affected tubes have tube integrity, ACTION a.2 allows plant operation to continue until the next refueling outage or SG inspection provided the inspection interval continues to be supported by an operational assessment that reflects the affected tubes. However, the affected tubes must be plugged prior to entering MODE 4 following the next refueling outage or SG inspection. This allowable outage time is acceptable since operation until the next inspection is supported by the operational assessment.

b. If the requirements and associated allowable outage time of ACTION a are not met or if SG tube integrity is not being maintained, the reactor must be brought to HOT STANDBY within 6 hours and COLD SHUTDOWN within the following 30 hours. The allowable outage times are reasonable, based on operating experience, to reach the desired plant conditions from full power conditions in an orderly manner and without challenging plant systems.

Surveillance Requirements

SR 4.4.5.1

During shutdown periods the SGs are inspected as required by this SR and the Steam Generator Program. NEI 97-06, Steam Generator Guidelines (Ref. 1), and its referenced EPRI Guidelines, establish the content of the Steam Generator Program. Use of the Steam Generator Program ensures that the inspection is appropriate and consistent with accepted industry practices.

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3/4.4.5 (Cont'd)

During SG inspections a condition monitoring assessment of the SG tubes is performed. The condition monitoring assessment determines the as found condition of the SG tubes. The purpose of the condition monitoring assessment is to ensure that the SG performance criteria have been met for the previous operating period.

The Steam Generator Program determines the scope of the inspection and the methods used to determine whether the tubes contain flaws satisfying the tube repair criteria. Inspection scope (i.e., which tubes or areas of tubing within the SG are to be inspected) is a function of existing and potential degradation locations. The Steam Generator Program also specifies the inspection methods to be used to find potential degradation. Inspection methods are a function of degradation morphology, non-destructive examination (NDE) technique capabilities, and inspection locations.

The Steam Generator Program defines the frequency of SR 4.4.5.1. The frequency is determined by the operational assessment and other limits in the SG examination guidelines (Ref. 6). The Steam Generator Program uses information on existing degradations and growth rates to determine an inspection frequency that provides reasonable assurance that the tubing will meet the SG performance criteria at the next scheduled inspection. In addition, Specification 6.8.4.j contains prescriptive requirements concerning inspection intervals to provide added assurance that the SG performance criteria will be met between scheduled inspections.

SR 4.4.5.2

During a SG inspection any inspected tube that satisfies the Steam Generator Program repair criteria is removed from service by plugging. The tube repair criteria delineated in Specification 6.8.4.j are intended to ensure that tubes accepted for continued service satisfy the SG performance criteria with allowance for error in the flaw size measurement for future flaw growth. In addition, the tube repair criteria, in conjunction with other elements of the Steam Generator Program, ensure that the SG performance criteria will continue to be met until the next inspection of the subject tubes. Reference 1 provides guidance for performing operational assessments to verify that the tubes remaining in service will continue to meet the SG performance criteria.

The frequency of prior to entering HOT SHUTDOWN following a SG inspection ensures that the Surveillance has been completed and all tubes meeting the repair criteria are plugged prior to subjecting the SG tubes to significant primary-to-secondary pressure differential.

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3/4.4.5 (Cont'd)

References

1. NEI 97-06, Steam Generator Program Guidelines
2. 10 CFR 50 Appendix A, GDC 19
3. 10 CRF 100
4. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB
5. Draft Regulatory Guide 1.121, Bases for Plugging Degraded PWR Steam Generator Tubes, August 1976
6. EPRI Pressurized Water Reactor Steam Generator Examination Guidelines
7. 10 CFR 50.67, Accident source term

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).

Background

Components that contain or transport the coolant to or from the reactor core make up the Reactor Coolant System (RCS). Component joints are made by welding, bolting, rolling, or pressure loading, and valves isolate connecting systems from the RCS.

During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant Leakage, through either normal operational wear or mechanical deterioration. The purpose of the RCS Operational Leakage LCO is to limit system operation in the presence of Leakage from these sources to amounts that do not compromise safety. This LCO specifies the types and amounts of leakage.

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3/4.4.6.2 Operational Leakage

10 CFR 50, Appendix A, GDC (Ref. 1), requires means for detecting and, to the extent practical, identifying the source of reactor coolant leakage. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting leakage detection systems.

The safety significance of RCS leakage varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring reactor coolant leakage into the containment area is necessary. Quickly separating the IDENTIFIED LEAKAGE from the UNIDENTIFIED LEAKAGE is necessary to provide quantitative information to the operators, allowing them to take corrective action should a leak occur that is detrimental to the safety of the facility and the public.

A limited amount of leakage inside containment is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected, located, and isolated from the containment atmosphere, if possible, to not interfere with RCS leakage detection.

This LCO deals with protection of the RCPB from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident (LOCA).

Applicable Safety Analyses

The primary-to-secondary leakage safety analysis assumption for individual events varies. The assumption varies depending on whether the primary-to-secondary leakage from a single steam generator (SG) can adversely affect the dose consequences for the event. In which case, the affected SG is assumed to have the maximum allowable leakage (500 gallons per day). Collectively, however, the safety analyses for events resulting in steam discharge to the atmosphere assume that primary-to-secondary leakage from all steam generators (SGs) is 1 gpm total and 500 gallons per day through any one SG accident conditions or increases to these levels as a result of accident conditions. The LCO requirement to limit primary-to-secondary leakage through any one SG to less than or equal to 150 gpd at room temperature is significantly less than the conditions assumed in the safety analysis.

Primary-to-secondary leakage is a factor in the dose releases outside containment resulting from a locked rotor accident. To a lesser extent, other accidents or transients involve secondary steam release to the atmosphere, such as a SG tube rupture (SGTR). The leakage contaminates the secondary fluid.

The UFSAR (Ref. 3) analysis for SGTR assumes the contaminated secondary fluid is released to the atmosphere via the atmospheric dump valves and/or main steam safety valves for a limited period of time. Operator action is taken to isolate the affected SG within the time period. The 500 gallons per day primary-to-secondary leakage in each of the two intact SGs at accident conditions in the safety analysis assumption is relatively inconsequential.

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3/4.4.6.2 (Cont'd)

Accidents for which the radiation dose release path is primary-to-secondary leakage, the locked rotor accident is more limiting for site radiation dose releases. The safety analysis for the locked rotor accident assumes that primary-to-secondary leakage from all SGs is 1 gpm total. The dose consequences resulting from the locked rotor accident are well within the limits defined in 10 CFR 100 or the NRC approved licensing basis (i.e., a small fraction of these limits).

The RCS operational leakage satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

Limiting Condition for Operation (LCO)

RCS operational leakage shall be limited to:

a. Pressure Boundary Leakage

No PRESSURE BOUNDARY LEAKAGE is allowed, being indicative of material deterioration. Leakage of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher leakage. Violation of this LCO could result in continued degradation of the RCPB. Leakage past seals and gaskets is not PRESSURE BOUNDARY LEAKAGE.

b. Unidentified Leakage

One gallon per minute (gpm) of UNIDENTIFIED LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring and containment sump level monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB, if the leakage is from the pressure boundary.

c. Identified Leakage

Up to 10 gpm of IDENTIFIED LEAKAGE is considered allowable because leakage is from known sources that do not interfere with detection of UNIDENTIFIED LEAKAGE and is well within the capability of the RCS Makeup System. IDENTIFIED LEAKAGE includes leakage to the containment from specifically known and located sources, but does not include PRESSURE BOUNDARY LEAKAGE or controlled reactor coolant pump seal leak-off (a normal function not considered leakage). Violation of this LCO could result in continued degradation of a component or system.

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3/4.4.6.2 (Cont'd)

d. Primary-to-Secondary Leakage Through Any One SG

The limit of 150 gpd per SG at room temperature is based on the operational leakage performance criterion in NEI 97-06, Steam Generator Program Guidelines (Ref. 4). The Steam Generator Program operational leakage performance criterion in NEI 97-06 states, The RCS operational primary-to-secondary leakage through any one SG shall be limited to 150 gallons per day. The limit is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The operational leakage rate criterion in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of SG tube ruptures.

e. RCS Pressure Isolation Valve Leakage

RCS pressure isolation valve leakage is IDENTIFIED LEAKAGE into closed systems connected to the RCS. Isolation valve leakage is usually on the order of drops per minute. Leakage that increases significantly suggests that something is operationally wrong and corrective action must be taken.

The specified leakage limits for the RCS pressure isolation valves are sufficiently low to ensure early detection of possible in-series check valve failure.

Applicability

In MODES 1, 2, 3, and 4, the potential for reactor coolant PRESSURE BOUNDARY LEAKAGE is greatest when the RCS is pressurized.

In MODES 5 and 6, leakage limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for leakage.

ACTIONS

a. If any PRESSURE BOUNDARY LEAKAGE exists, or primary-to-secondary leakage is not within limit, the reactor must be brought to lower pressure conditions to reduce the severity of the leakage and its potential consequences. It should be noted that Leakage past seals and gaskets is not PRESSURE BOUNDARY LEAKAGE. The reactor must be brought to HOT STANDBY within 6 hours and COLD SHUTDOWN within the following 30 hours. This ACTION reduces the leakage and also reduces the factors that tend to degrade the pressure boundary.

b. UNIDENTIFIED LEAKAGE or IDENTIFIED LEAKAGE in excess of the LCO limits must be reduced to within the limits within 4 hours. This allowable outage time allows time to verify leakage rates and either identify UNIDENTIFIED LEAKAGE or reduce leakage to within limits before the reactor must be shut down. This ACTION is necessary to prevent further deterioration of the RCPB.

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3/4.4.6.2 (Cont'd)

c. 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. With one or more RCS Pressure Isolation Valves with leakage greater than that allowed by Specification 3.4.6.2.e, within 4 hours, at least two valves in each high pressure line having a non-functional valve must be closed and remain closed to isolate the affected lines. In addition, the ACTION statement for the affected system must be followed and the leakage from the remaining Pressure Isolation Valves in each high pressure line having a valve not meeting the criteria of Table 3.4-1 shall be recorded daily. If these requirements are not met, the reactor must be brought to at least HOT STANDBY within 6 hours and COLD SHUTDOWN within the following 30 hours.

d. With one or more RCS Pressure Isolation Valves with leakage greater than 5 gpm, the leakage must be reduced to below 5 gpm within 1 hour or the reactor must be brought to at least HOT STANDBY within 6 hours and COLD SHUTDOWN within the following 30 hours.

The allowable outage times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODE 5, the pressure stresses acting on the RCPB are much lower, and further deterioration is much less likely.

Surveillance Requirements

SR 4.4.6.2.1

Verifying Reactor Coolant System leakage to be within the LCO limits ensures the integrity of the Reactor Coolant Pressure Boundary is maintained. PRESSURE BOUNDARY LEAKAGE would at first appear as UNIDENTIFIED LEAKAGE and can only be positively identified by inspection. It should be noted that leakage past seals and gaskets is not PRESSURE BOUNDARY LEAKAGE. UNIDENTIFIED LEAKAGE and IDENTIFIED LEAKAGE are determined by performance of a Reactor Coolant System water inventory balance.

a.&
b. These SRs demonstrate that the RCS operational leakage is within the LCO limits by monitoring the containment atmosphere gaseous or particulate radioactivity monitor and the containment sump level at least once per 12 hours.

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3/4.4.6.2 (Cont'd)

c. The RCS water inventory balance must be performed with the reactor at steady state operating conditions and near operating pressure. The Surveillance is modified by two notes. Note *** states that this SR is not required to be performed until 12 hours after establishment of steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

Steady state operations is required to perform a proper inventory balance since calculations during maneuvering are not useful. For RCS operational leakage determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and Reactor Coolant Pump seal injection and return flows.

An early warning of PRESSURE BOUNDARY LEAKAGE or UNIDENTIFIED LEAKAGE is provided by the automatic systems that monitor containment atmosphere radioactivity, containment normal sump inventory and discharge, and reactor head flange leak-off. It should be noted that leakage past seals and gaskets is not PRESSURE BOUNDARY LEAKAGE. These leakage detection systems are specified in LCO 3.4.6.1, Reactor Coolant System Leakage Detection Systems.

Note ** states that this SR is not applicable to primary-to-secondary leakage because leakage of 150 gallons per day cannot be measured accurately by an RCS water inventory balance.

The 72 hour frequency is a reasonable interval to trend leakage and recognizes the importance of early leakage detection in the prevention of accidents.

d. This SR demonstrates that the RCS operational leakage is within the LCO limits by monitoring the Reactor Head Flange Leak-off System at least once per 24 hours.

e. This SR verifies that primary-to-secondary leakage is less than or equal to 150 gpd through any one SG. Satisfying the primary-to-secondary leakage limit ensure that the operational leakage performance criterion in the Steam Generator Program is met. If this SR is not met, compliance with LCO 3.4.5, Steam Generator (SG) Tube Integrity, should be evaluated. The 150-gpd limit is measured at room temperature as described in Reference 5. The operational leakage rate limit applies to leakage through any one SG. If it is not practical to assign the leakage to an individual SG, all the primary-to-secondary leakage should be conservatively assumed to be from one SG.

TECHNICAL SPECIFICATION BASES

3/4.4.6.2 (Cont'd)

The SR is modified by Note ***, which states that the Surveillance is not required to be performed until 12 hours after establishment of steady state operation. For RCS primary-to-secondary leakage determination, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and reactor coolant pump seal injection and return flows.

The surveillance frequency of 72 hours is a reasonable interval to trend primary-to-secondary leakage and recognizes the importance of early leakage detection in the prevention of accidents. The primary-to-secondary leakage is determined using continuous process radiation monitors or radiochemical grab sampling in accordance with the EPRI guidelines (Ref. 5).

SR 4.4.6.2.2

It is apparent that when pressure isolation is provided by two in-series check 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 that bypasses containment, these valves should be tested periodically to ensure low probability of gross failure.

This SR verifies RCS Pressure Isolation 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.

References

1. 10 CFR 50, Appendix A, GDC 30
2. Regulatory Guide 1.45, May 1973
3. UFSAR, Section 14.2.4.1
4. NEI 97-06, Steam Generator Program Guidelines
5. EPRI PWR Primary-to-Secondary Leak Guidelines

TECHNICAL SPECIFICATION BASES

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.

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 primary-to-secondary steam generator leakage rate of 500 gpd through each of the two intact steam generators. 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.

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3/4.4.8 (Cont'd)

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.

Reducing Tavg 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 Pressure/Temperature Limits

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.

TECHNICAL SPECIFICATION BASES

3/4.4.9 (Cont'd)

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:

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.

TECHNICAL SPECIFICATION BASES

3/4.4.9 (Cont'd)

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.

Heatup and cooldown limit curves are calculated using the most limiting value of the nil-ductility reference temperature, RTNDT, 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 RTNDT, at the 1/4T location in the core region is greater than the RTNDT, of the limiting unirradiated material. The selection of such a limiting RTNDT 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 RTNDT; 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 RTNDT. 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 RTNDT at the end of the applicable service period.

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3/4.4.9 (Cont'd)

The actual shifts in RTNDT, 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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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)		RT_{NDT} (°F)	Minimum Upper Shelf (ft lb)	
						Long	Trans		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)	-2[illegible]	>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

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TECHNICAL SPECIFICATION BASES

3/4.4.9 (Cont'd)

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, RTNDT, is used and this includes the radiation-induced shift, ΔRTNDT, 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, KI, for the combined thermal and pressure stresses at any time during heatup or cooldown cannot be greater than the reference stress intensity factor, KIR, for the metal temperature at that time. KIR is obtained from the reference fracture toughness curve, defined in Appendix G to the ASME Code. The KIR curve is given by the equation:

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

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

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

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.

TECHNICAL SPECIFICATION BASES

3/4.4.9 (Cont'd)

At any time during the heatup or cooldown transient, KIR is determined by the metal temperature at the tip of the postulated flaw, the appropriate value for RTNDT, 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, KIT, 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 KIR at the 1/4T location for finite cooldown rates than for steady-state operation. Furthermore, if conditions exist such that the increase in KIR exceeds KIT, the calculated allowable pressure during cooldown will be greater than the steady-state value.

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.

TECHNICAL SPECIFICATION BASES

3/4.4.9 (Cont'd)

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 KIR for the 1/4T crack during heatup is lower than the KIR 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 KIR'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.

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 RTNDT for these regions when the pressure exceeds 20 percent of the pre-service hydrostatic test pressure (621 psig). Since the limiting RTNDT 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.

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TECHNICAL SPECIFICATION BASES

3/4.4.9 (Cont'd)

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.

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.)

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3/4.4.9 (Cont'd)

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.

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.

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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.

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.

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.

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3/4.5.1 (Cont'd)

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.

3/4.5.2 &
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.

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TECHNICAL SPECIFICATION BASES

3/4.5.2 and 3/4.5.3 (Cont'd)

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.

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.

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TECHNICAL SPECIFICATION BASES

3/4.5.2 and 3/4.5.3 (Cont'd)

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.

Technical Specifications Surveillance Requirement 4.5.2.e.3 requires that each ECCS component and flow path be demonstrated OPERABLE every 18 months by visual inspection which verifies that the sump components (trash racks, screens, etc.) show no evidence of structural distress or abnormal corrosion. The strainer modules are rigid enough to provide both functions as trash racks and screens without losing their structural integrity and particle efficiency. Therefore, the strainer modules are functionally equivalent to trash racks and screens. Accordingly, the categorical description, sump components, is broad enough to require inspection of the strainer modules.

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.

ATTACHMENT 1

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 do not fall under Technical Specification 3.6.1.1. For example Penetration 38 is an electrical penetration only, closed by virtue of its seals, 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 do not 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, Pa. The measured as–found overall integrated leakage rate is limited to less than or equal to 1.0 La 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 La 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.

TECHNICAL SPECIFICATION BASES

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

3/4.6.1.4 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.

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.

TECHNICAL SPECIFICATION BASES

3/4.6.1.6 (Cont'd)

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 La 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.

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).

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TECHNICAL SPECIFICATION BASES

3/4.6.2.1 (Cont'd)

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.

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.

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TECHNICAL SPECIFICATION BASES

3/4.6.3 (Cont'd)

The Technical Specification does not require that both independent trains of ECF dousing components be OPERABLE to support the ECFs. Disabling one train of ECF dousing components does not render the associated ECF inoperable.

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.

TECHNICAL SPECIFICATION BASES

3/4.6.3 (Cont'd)

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 solenoid 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 solenoid operated valve is energized and opened upon a loss of airflow as detected by its associated flow switch, which 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 will fail the solenoid-operated valves in the closed position because the flow switch design is to energize to actuate. The fail-closed position of the solenoid-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.

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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).

3/4.7.1.1 Safety Valves

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:

$Hi\Phi$ = 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

TECHNICAL SPECIFICATION BASES

3/4.7.1.1 (Cont'd)

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.

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.

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TECHNICAL SPECIFICATION BASES

3/4.7.1.2 (Cont'd)

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 units shall be placed in at least HOT STANDBY within 6 hours and HOT SHUTDOWN within the following 6 hours.

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 units 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.

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TECHNICAL SPECIFICATION BASES

3/4.7.1.3 (Cont'd)

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.

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 = 3.47×10^{-4} m^3/sec.

X/Q= atmospheric dispersion parameter = 1.54×10^{-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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3/4.7.1.5 (Cont'd)

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.

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.

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3/4.7.1.6 (Cont'd)

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.

3/4.7.1.6 Standby Steam Generator Feedwater System

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 FPLs 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.

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.

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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.

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TECHNICAL SPECIFICATION BASES

3/4.7.5 (Cont'd)

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.

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.

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TECHNICAL SPECIFICATION BASES

3/4.7.6 (Cont'd)

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.

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.

TECHNICAL SPECIFICATION BASES

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.

3/4.8 Electrical Power Systems

3/4.8.1, 3/4.8.2, & 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 systems, subsystems, trains, components or devices does not result in the systems, subsystems, trains, components or devices 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 systems, subsystems, trains, components, and devices that depend on the remaining OPERABLE diesel generators as a source emergency power to meet all applicable LCOs 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 LCOs as needed.

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TECHNICAL SPECIFICATION BASES

3/4.8.1, 3/4.8.2, and 3/4.8.3 (Cont'd)

More specifically, LCOs 3.5.2 and 3.8.2.1 require that associated EDGs 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 LCOs 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 LCOs of the shared systems (3.5.2 and 3.8.2.1). It is important to note that in these particular LCOs, 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.

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. EDGs 3A and 3B provide Unit 3 A-train, and B-train emergency power, respectively. EDGs 4A and 4B provide Unit 4 A-train and B-train emergency power, respectively.

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TECHNICAL SPECIFICATION BASES

3/4.8.1, 3/4.8.2, and 3/4.8.3 (Cont'd)

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 components 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 components 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.

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 transformers 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.

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TECHNICAL SPECIFICATION BASES

3/4.8.1, 3/4.8.2, and 3/4.8.3 (Cont'd)

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 systems, subsystems, trains, components, and devices that depend on the remaining required OPERABLE diesel generators as a source of emergency power to meet all applicable LCOs, 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 systems, subsystems, trains, components, or devices being considered inoperable provided: (1) Its corresponding normal power source is OPERABLE, and (2) Its redundant systems, subsystems, trains, components, and devices that depend on the remaining required OPERABLE diesel generators as a source of emergency power to meet all applicable LCOs, are OPERABLE.

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 EDGs associated with the applicable unit.

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TECHNICAL SPECIFICATION BASES

3/4.8.1, 3/4.8.2, and 3/4.8.3 (Cont'd)

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 units 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.

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.

TECHNICAL SPECIFICATION BASES

3/4.8.1, 3/4.8.2, and 3/4.8.3 (Cont'd)

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 components 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 components 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).

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.

TECHNICAL SPECIFICATION BASES

3/4.8.1, 3/4.8.2, and 3/4.8.3 (Cont'd)

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.

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.

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.

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.

Diesel Fuel Oil Testing Program

The fuel supply specified for the Unit 3 EDGs 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 EDGs 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.

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TECHNICAL SPECIFICATION BASES

3/4.8.1, 3/4.8.2, and 3/4.8.3 (Cont'd)

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.

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, and ASTM-D1500-82.

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

3/4.8.1, 3/4.8.2, and 3/4.8.3 (Cont'd)

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.

Lubricity Specification for Ultra Low Sulfur Diesel Fuel Oil

To ensure that Ultra Low Sulfur Diesel fuel (15 pm sulfur, S15) is acceptable for use in the Emergency Diesel Generators, a test is added in the Diesel Fuel Oil Testing Program that validates, satisfactory lubricity (Reference: Engineering Evaluation PTN-ENG-SEMS-06-0035).

The test for lubricity is based on ASTM D975-06, testing per ASTM D6079, using the High Frequency Reciprocating Rig (HFRR) test at 60 degrees C and the acceptance criterion requires a wear scar no larger than 520 microns.

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.

TECHNICAL SPECIFICATION BASES

3/4.8.1, 3/4.8.2, and 3/4.8.3 (Cont'd)

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 LCOs of the opposite unit are considered.

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 generators OPERABLE. This requires both EDGs 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.

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TECHNICAL SPECIFICATION BASES

3/4.8.1, 3/4.8.2, and 3/4.8.3 (Cont'd)

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 generators.

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.

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TECHNICAL SPECIFICATION BASES

3/4.8.1, 3/4.8.2, and 3/4.8.3 (Cont'd)

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 MCCs 3A, 3K, 4J and 4K) is applied to the associated unit. Since MCCs 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 re-energization 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 re-energization 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.

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

TECHNICAL SPECIFICATION BASES

3/4.8.1, 3/4.8.2, and 3/4.8.3 (Cont'd)

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 Units 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 Units 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.

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

TECHNICAL SPECIFICATION BASES

3/4.8.1, 3/4.8.2, and 3/4.8.3 (Cont'd)

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.

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.

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3/4.8.1, 3/4.8.2, and 3/4.8.3 (Cont'd)

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).

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.

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.

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3/4.9.2 Instrumentation

T.S. surveillance requirement 4.9.2.b and c states:

Each required Source Range Neutron Flux Monitor shall be demonstrated OPERABLE by performance of:

b. An ANALOG CHANNEL OPERATIONAL TEST within 8 hours prior to the initial start of CORE ALTERATIONS, and

c. An ANALOG CHANNEL OPERATIONAL TEST at least once per 7 days.

A normal refueling consists of 2 core alteration sequences: unloading the core, and reloading the core, typically with a suspension of core alterations in between. The core unload sequence begins with control rod unlatching, followed by removal of upper internals, followed by unloading fuel assemblies to the SFP. The core reload sequence consists of reloading fuel assemblies from the SFP, followed by upper internals installation, followed by latching control rods. Therefore, if T.S. 4.9.2.c is complied with following the ANALOG CHANNEL OPERATIONAL TEST performed within 8 hours prior to start of control rod unlatching, then the ANALOG CHANNEL OPERATIONAL TEST need not be performed within 8 hours prior to the start of core reload. Otherwise, comply with T.S.4.9.2.b within 8 hours prior to the start of core reload.

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.

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.

TECHNICAL SPECIFICATION BASES

3/4.9.4 Containment Building Penetrations

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).

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.

3/4.9.4 Containment Building Penetrations

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.

TECHNICAL SPECIFICATION BASES

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.

T.S. surveillance requirements 4.9.6.1 & 4.9.6.2 are as follows:

4.9.6.1 At least once each refueling, each manipulator crane used for movement of fuel assemblies within the reactor vessel shall be demonstrated OPERABLE within 100 hours prior to the start of such operations by performing a load test of at least 2750 pounds and demonstrating an automatic load cutoff when the crane load exceeds 2700 pounds.

4.9.6.2 At least once each refueling, each auxiliary hoist and associated load indicator used for movement of drive rods within the reactor vessel shall be demonstrated OPERABLE within 100 hours prior to the start of such operations by performing a load test of at least 610 pounds.

A normal refueling consists of 2 core alteration sequences: unloading the core, and reloading the core, typically with a suspension of core alterations in between. The core unload sequence begins with control rod unlatching, followed by removal of upper internals, followed by unloading fuel assemblies to the SFP. The core reload sequence consists of reloading fuel assemblies from the SFP, followed by upper internals installation, followed by latching control rods. The surveillance requirements call for the specified testing to be performed at least once each refueling, and do not specify additional testing at any particular frequency. Therefore, the manipulator crane testing need only be performed within 100 hours prior to the start of unloading fuel assemblies to the SFP, and likewise, the auxiliary hoist testing need only be performed within 100 hours prior to the start of control rod unlatching.

TECHNICAL SPECIFICATION BASES

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.

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.

T.S. surveillance requirement 4.9.9 states:

4.9.9 The Containment Ventilation Isolation System shall be demonstrated OPERABLE within 100 hours prior to the start of and at least once per 7 days during CORE ALTERATIONS by verifying that Containment Ventilation Isolation occurs on a High Radiation test signal from each of the containment radiation monitoring instrumentation channels.

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3/4.9.9 (Cont'd)

A normal refueling consists of 2 core alteration sequences: unloading the core, and reloading the core, typically with a suspension of core alterations in between. The core unload sequence begins with control rod unlatching, followed by removal of upper internals, followed by unloading fuel assemblies to the SFP. The core reload sequence consists of reloading fuel assemblies from the SFP, followed by upper internals installation, followed by latching control rods. Therefore, if the Containment Ventilation Isolation System is demonstrated OPERABLE at least once per 7 days following the specified testing within 100 hours prior to the start of control rod unlatching, then Containment Ventilation Isolation System operability need not be demonstrated within 100 hours prior to the start of core reload. Otherwise, the specified testing is required to be performed within 100 hours prior to the start of core reload.

3/4.9.10 &
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.

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.

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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) Keff ≤ 0.95 with a minimum soluble boron concentration of 650 ppm present, and b) Keff <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 (B10) 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.

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.

TECHNICAL SPECIFICATION BASES

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 Tavg 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 Tavg 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.

FINAL PAGE