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Monticello Nuclear Generating Plant
Docket No. 50-263
License No. DPR-22

Response to NRC Requests for Additional Information Regarding License Amendment Request Supporting 24-Month Fuel Cycles (TAC No. MC3692)

Reference 1) Letter from NMC to NRC, "License Amendment Request to Support 24-Month Fuel Cycles," dated June 30, 2004

Reference 2) Letter from NRC to NMC, "Monticello Nuclear Generating Plant - Request For Additional Information Related To Technical Specifications Change Request to Implement a 24-Month Fuel Cycle (TAC No. MC 3692)," dated January 26, 2005

Reference 3) Letter from NRC to NMC, "Monticello Nuclear Generating Plant - Second Request for Additional Information Related To Technical Specifications Change Request to Implement a 24-Month Fuel Cycle (TAC No. MC 3692)," dated January 31, 2005

Pursuant to and in accordance with the requirements of 10 CFR Part 50, Section 50.90, Nuclear Management Company, LLC (NMC) herein provides its response to the NRCs request's for additional information regarding the License Amendment Request (LAR) supporting 24-month fuel cycles for Monticello Nuclear Generating Plant (MNGP).

Reference 1 proposed Technical Specifications changes to Appendix A of Operating License DPR-22, for the MNGP. The purpose of the LAR was to revise the MNGP Technical Specifications (TS) to support 24-month fuel cycles.

References 2 and 3 requested NMC to provide additional information in support of the LAR submitted by Reference 1.

Enclosure 1 provides the NMC response to the NRC's request for additional information (RAI) (Reference 2) and supplemental information for the previously submitted LAR in support of 24-month fuel cycles at MNGP.

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Enclosure 2 provides the NMC response to the NRC's second RAI (Reference 3) for the previously submitted LAR in support of 24-month fuel cycles at MNGP.

Enclosure 3 provides marked-up TS pages, provided as a supplement to the original LAR dated June 30, 2004. NMC has determined that this supplemental submittal is administrative and editorial in nature and has no technical impact on pages or justifications previously submitted. Therefore, the Determination of No Significant Hazards Consideration and Environmental Assessment submitted by the original letter dated June 30, 2004, are also applicable to this supplemental submittal.

Enclosure 4 provides additional marked-up TS Bases pages that are also provided to supplement the original LAR dated June 30, 2004. These pages are provided for information only.

Enclosure 5 provides the retyped MNGP TS pages.

This letter makes no new commitments or changes any existing commitments.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on 3/3/2005.

Thomas J. Palmisano
Site Vice President, Monticello Nuclear Generating Plant
Nuclear Management Company, LLC

Enclosures (5)

cc: Regional Administrator-III, NRC
NRR Project Manager, NRC
Sr. Resident Inspector, NRC
Minnesota Department of Commerce

ENCLOSURE 1

LICENSE AMENDMENT REQUEST TO SUPPORT 24-MONTH FUEL CYCLES RESPONSE TO FIRST REQUEST FOR ADDITIONAL INFORMATION

Pursuant to the requirements of 10 CFR Part 50, Section 50.90, Nuclear Management Company, LLC (NMC) submitted a License Amendment Request (LAR) for the Monticello Nuclear Generating Plant (MNGP) by letter dated June 30, 2004. This LAR was submitted to request revisions to the MNGP Technical Specification (TS) in support of 24-Month Fuel Cycles.

The NRC provided NMC with a Request For Additional Information (RAI) dated January 26, 2005, (TAC No. MC 3692), regarding the above LAR. Listed below are the NRC's requests for additional information in italics followed by the NMC response.

NRC Request #1:

The following statement appears in your Technical Specifications (TS) Bases on page 69a, "Although the operator will set the setpoints within the trip settings specified in Tables 3.2.1 through 3.2.9, the actual values of the various set points can differ appreciably from the value the operator is attempting to set. . . . Therefore, these deviations have been accounted for in the various transient analyses." These statements are then followed by a table of values.

Explain how this table is currently being used. In your current license amendment you are changing setpoints. However, the amount of deviation in your tables remains the same. Explain why you are not changing these values.

Licensee Event Reports 2002-02 and 2002-07 address corrective actions associated with the use of this table. Provide the status of these corrective actions.

NMC Response:

At a public meeting between NMC and the NRC on October 12, 2004, to discuss the above LAR, NMC provided information regarding a TS Bases Table 3.2 that previously allowed deviations from the setpoints listed in the MNGP TS. NMC stated that this Table is no longer being used by plant personnel performing TS required surveillances at MNGP.

In response to the NRC RAI and upon further review by NMC of TS Bases Table 3.2, it has been determined that this table should be deleted from the MNGP TS Bases. MNGP confirms that the current licensing amendment requested changes to several TS setpoint values. These changes were not reflected in the TS Bases Deviation Table because this table was only used as a historical reference. Therefore, since the instruments are no longer allowed to deviate by the values stated in the Deviation Table there is no need to maintain the table in the MNGP TS Bases.

This revision to the previously submitted LAR will eliminate any potential confusion as to the use of this deviation table in the MNGP TS Bases.

NMC has determined that this revision does not impact the Determination of No Significant Hazards Consideration and Environmental Assessment submitted by the original letter dated June 30, 2004, and that it can be implemented during the implementation of this License Amendment by following the guidance of MNGP TS 6.8.K, "Technical Specifications (TS) Bases Control Program." The revised marked-up TS Bases pages included in Enclosure 4 of this submittal are provided for information only.

The NRC also requested NMC to provide the status of the corrective actions associated with MNGP License Event Reports (LERs) 2002-002 and 2002-007. Currently, the corrective actions, associated with LERs 2002-002 and 2002-007, are closed except for one that will be closed upon submittal of the MNGP Improved Standard Technical Specifications.

NRC Request #2

Provide a statement confirming that your proposed setpoints are within analytical safety limits for the following:

- *TS Table 3.2.2, Function A.1.b.ii, "Reactor Low Pressure Permissive Bypass Timer"*
- *TS Table 3.2.6, Function 2, "Loss of Voltage Protection"*
- *TS Table 3.2.7, "Reactor Coolant System Pressure for Opening/Closing"*
- *TS Table 3.2.7, "Discharge Pipe Pressure Inhibit and Position Indication"*
- *TS Table 3.2.7, "Inhibit Timers"*

NMC Response:

As stated by NMC in Enclosure 1 of the initial LAR, dated June 30, 2003:

> *"NMC uses the setpoint methodology provided in GE NEDC-31336, "General Electric Setpoint Methodology." Setpoint assessments were performed for Monticello in which the calculated 30-month drift values replaced the vendor, or assumed, drift values from each setpoint calculation. The Nominal Trip Setpoints (NTSPs) were assessed, considering the 30-month drift.... Plant setpoints have been revised or will be revised prior to exceeding 22.5 months of operation (18 months + 25%) where the NTSP is less conservative than the plant setpoints. An evaluation was performed with any needed NTSP changes identified and included in this License Amendment Request.... There was sufficient margin within the existing safety analysis to accommodate the revision in the NTSPs without revising the safety analysis in each of these cases. ...In no case was it necessary to change the existing analytical limit or safety analysis to accommodate a larger instrument drift error."*

Therefore, NMC can confirm that the proposed MNGP TS setpoints are within analytical safety limits as demonstrated below:

TS	Analytical Limit	Current TS Limit	Proposed TS Limit
(1) Table 3.2.2 Function A.1.b.ii	10 to 24 minutes	20 ± 1 minutes	20 ± 2 minutes
(2) Table 3.2.6 Function 2	1400 to 3200 volts	2625 ± 175 volts	2625 ± 280 volts (2345 to 2905 volts)
(3) Table 3.2.7	1095 / 1015 psig 1085 / 1005 psig 1075 / 995 psig	1072 ± 3 / 992 ± 3 psig 1062 ± 3 / 982 ± 3 psig 1052 ± 3 / 972 ± 3 psig	1072 ± 14 / 992 ± 14 psig 1062 ± 14 / 982 ± 14 psig 1052 ± 14 / 972 ± 14 psig
(4) Table 3.2.7	≥ 20 psid ≤ 40 psid	30 ± 1 psid	30 ± 3 psid
(5) Table 3.2.7	5.75 to 14 sec	10 ± 1 sec	10 ± 2 sec

(1) Reactor Low Pressure Permissive Bypass Timer
(2) Loss of Voltage Protection
(3) Reactor Coolant System Pressure for Opening/Closing (Low-Low set and inhibit logic is provided for three non-Automatic Pressure Relief System Valves. The three valves have staggered setpoints as indicated).
(4) Discharge Pipe Pressure Inhibit and Position Indication (Differential pressure with respect to drywell atmosphere).
(5) Inhibit Timers

NRC Question #3

In your proposed TS changes, you propose to change the language in Surveillance Requirement 4.5 on Page 102, and again on page 105, from "low" reactor water level to "Low Low" reactor water level. In discussing this change you state that "this is an administrative change required for clarification and to maintain consistency with actual plant practice and other Monticello TS specifically TS Table 3.2.2, Function B.2." Provide the plant procedures for performing the affected surveillances which demonstrate that this is merely an administrative change.

At the public meeting between NMC and NRC on October 12, 2004, you stated that "low" (lowercase "l") is not a defined level and that "Low" and "Low-Low" (uppercase "L") are defined levels. Provide the administrative documentation that describes this convention.

In your TS Bases on page 64, you have the following two statements: "The low reactor water level instrumentation is set to trip when reactor water level is >7" on the instrument," and "The low low reactor water level instrumentation is set to trip when reactor water level is ≥ -48." Neither of these statements reflect your *uppercase/lowercase convention as noted previously. The inconsistency is confusing. Describe how you will assure that your plant personnel are aware of the appropriate level ("Low" or "Low Low") despite the lack of total consistency throughout your documentation.*

NMC Response:

As stated by NMC in Enclosure 5 of the initial LAR, dated June 30, 2004:

> *"This is an administrative change required for clarification and to maintain consistency with actual plant practice and other Monticello TS..."*

This is a change in the wording used within the TS and does not reflect a physical plant modification or setpoint change.

In response to the NRC RAI and upon further review by NMC it has been determined that additional TS and TS Bases pages should have been submitted with the original TS amendment request to provide consistency and eliminate the potential for confusion.

The following additional revisions to the previously submitted LAR will eliminate potential confusion:

- Clarify Note 2 to TS Table 4.1.1 on page 33 of the MNGP TS by replacing "low" with "Low," and

- Revise TS Bases Section 3.2 by correcting the Low reactor water level trip setpoint which is actually $\geq$ 7" instead of > 7" that MNGP TS Bases page 64 currently states as the Low reactor water level trip setpoint.

These TS administrative changes are necessary to remove an ambiguity in the existing MNGP TSs 4.5.A.4 and 4.5.D.2, and make the TS terminology consistent with MNGP TS Tables 3.2.1 and 3.2.2. Site procedures and the operator training program clearly differentiates between the "Low Reactor Water Level Setpoint ($\geq$ 7"), and the Low Low Reactor Water Level Septpoint ($\geq$ -48")." This change will provide the same consistent terminology for MNGP TS, as currently provided in plant procedures. Due to the large number of affected procedures, and since no MNGP procedure supersedes the MNGP TS, NMC is not providing plant procedures that demonstrate that this is an administrative change.

NMC has determined that the Determination of No Significant Hazards Consideration and Environmental Assessment submitted by the original letter dated June 30, 2004, are also applicable to this supplemental submittal. A revised marked-up TS page is included in Enclosure 3 of this submittal and the retyped page is included in Enclosure 5. NMC has determined that the TS Bases changes can be implemented during the implementation of this License Amendment by following the guidance of MNGP TS 6.8.K, "Technical Specifications (TS) Bases Control Program." Therefore, the revised marked-up TS Bases pages included in Enclosure 4 of this submittal are provided for information only.

NRC Question #4

In Enclosure 5, pages 41 and 42, for Standby Liquid Control System SR 4.4.A.2.a and SR 4.4.A.2.b, in discussing the basis for which you conclude that the "proposed change on system availability is minimal" you state this "based upon the inherent system and component reliability." Provide the basis from which you determined this inherent reliability. Provide specific examples of test data that supports this conclusion.

NMC Response:

The Standby Liquid Control System (SBLC) at MNGP is located in the Reactor Building. It consists of an unpressurized tank for low temperature sodium pentaborate solution storage, two full capacity positive displacement pumps, two explosive actuated shear plug valves, heaters, piping, valves, and instrumentation. Two independent level indication systems are provided on the tank. A separate power supply is provided for each level indication system. Low or high temperature at either the piping or the tank causes an alarm in the control room.

Each SBLC subsystem contains a 100% capacity injection pump and an explosive squib valve in independent loops. The subsystems have independent power supplies for pump motors and squib valve controls.

The explosive valves are double squib actuated shear plug valves that are the explosive type to provide a high assurance of opening when actuated and to ensure that no boron leaks into the reactor when the injection pump is being tested. A low current electrical monitoring system gives visible (pilot light) indication of circuit continuity through both firing squibs in each valve. Loss of continuity through the squibs also causes an alarm in the control room. One of the two primer assemblies (squib valves) is replaced each operating cycle. The longest a primer assembly will be in service, with two-year operating cycles, will be four years. The explosive squibs are considered to have a usable lifetime of 5 years.

The process portions of SBLC system are classified as safety-related in accordance with the MNGP Quality Assurance Plan. The SBLC system has been designated safety-related since MNGP first developed a quality plan to demonstrate compliance with 10 CFR 50 Appendix B, ANSI N18.7 and the various N45.2 daughter standards in 1976.

One of the two SBLC systems is manually initiated once each operating cycle during performance of TS 4.4.A.2.a required surveillance testing. This test checks explosion of the charge associated with the tested system. TS 4.4.A.2.b verifies proper operation of the valves, pump capacity and flow path by pumping demineralized water into the reactor vessel. The same surveillance test satisfies the requirements of both of the TS Surveillance Requirements (SR) discussed above. Review of the last 8 performances determined that there were no failures of the surveillance test, as demonstrated below:

- 05/05/03 - Successful completion. Once per cycle.
- 12/02/01 - Successful completion. Once per cycle.

- 02/16/00 - Successful completion. Once per cycle.
- 04/09/98 - Successful completion. Once per cycle.
- 05/09/96 - Successful completion. Once per cycle.
- 10/13/94 - Successful completion. Once per cycle.
- 02/28/93 - Successful completion. Once per cycle.
- 05/12/91 - Successful completion. Once per cycle.

Two major considerations form the basis for the conclusion that the SBLC system and components are inherently reliable:

- Classification of the system as safety-related, and
- The single-failure proof design of the active SBLC components, as demonstrated by the independence and redundancy of these components.

The surveillance history of the SBLC system, as described above, supports this conclusion.

NRC Question #5

Refer to Enclosure 5, page 42 for Standby Liquid Control System SR 4.4.B.1. The staff finds your justification for extending this surveillance from 18 months to 24 months incomplete as you do not specifically address verifying boron enrichment (i.e. amount of Boron-10). Provide justification as to why the boron enrichment would not be adversely affected as a result of extending this surveillance interval from 18 to 24 months.

NMC Response:

MNGP TS Bases 3.4/4.4 states:

> *"Boron Enrichment will not vary unless more Boron is added. No deterioration of the Boron-10 enrichment level should occur during system standby operation."*

Two mechanisms have the potential to affect the B-10 enrichment in the SBLC Tank:

- Absorption of thermal neutrons by the B-10 in the tank solution, and
- Alteration of the average B-10 enrichment resulting from addition of Boron to the SBLC Tank.

NMC receipt inspection of the Sodium Pentaborate material includes isotopic and impurities analyses of a sample. Approved vendors, who have been audited/surveyed and qualified for the applicable analyses as part of this process, perform confirmatory chemical analyses.

The location of the SBLC system at MNGP is such that the SBLC Tank is not subjected to a thermal neutron flux. Thus, no deterioration of the B-10 enrichment level would be expected due to neutron absorption.

MNGP TS 4.4.B.1 requires that at least once per operating cycle a sample of the SBLC tank is taken to determine the Boron enrichment. The SBLC tank sample is sent offsite to be analyzed by an approved vendor who has been audited/surveyed and is qualified to perform this type of analysis. NMC performs the same vendor analysis when boron is added to the SBLC Tank. The results of this analysis will ensure that the Boron-10 enrichment is greater than or equal to 55-atom% for the MNGP SBLC.

The extension of the operating cycle to 24-months will not introduce any new mechanisms by which the B-10 enrichment could be adversely affected. Sampling of the SBLC tank will continue to be performed consistent with the TS requirements and current operational practices. Thus, it can be concluded that the Boron-10 enrichment of the MNGP SBLC system would not be adversely affected as a result of extending this surveillance interval from 18 to 24 months.

NRC Question #6

Refer to Enclosure 5, pages 44 and 45, for ECCS Systems SR 4.5.A.4.a and SR 4.5.A.4.b of your submittal. Provide the details of your evaluation that describe the basis upon which you conclude that "Operating experience shows these components routinely pass the SR when performed at the 18-month interval." Also, explain how you conclude that extending the surveillance interval from 18 to 24 months causes a minimal change in system availability. Provide the details from your review of the surveillance history that leads you to this conclusion. Provide specific examples of test data that supports this conclusion.

NMC Response:

NMC personnel, following the guidance provided in NRC Generic Letter 91-04, reviewed the historical performance of the MNGP procedures that are performed to satisfy the requirements of the TS surveillances to determine if there had been previous time related failures of this equipment.

NMC verifies the operability of the three Safety Relief Valves (SRVs) that comprise the Automatic Depressurization System (ADS) by performing the testing required by TS 4.5.A.4. In this test, valve operability is verified by cycling the valve and observing a compensating change in turbine bypass or control valve position. Eight previous performances of this test, going back to the 1991 Refueling Outage, as tabulated below, were reviewed with no time related failures being identified:

- 05/24/03 - Successful completion
- 12/14/01 - Successful completion
- 02/28/00 - Successful completion
- 04/24/98 - Successful completion
- 05/20/96 - Successful completion
- 10/22/94 - Successful completion

- 03/22/93 - Successful completion
- 05/30/91 - Successful completion

NMC tests the circuitry of the ADS Inhibit Switch and its ability to inhibit ADS actuation by performing the testing required by TS 4.5.A.4. Eight previous performances of this test, going back to the 1991 Refueling Outage, as tabulated below, were reviewed with no time related failures being identified:

- 05/20/03 - Successful completion
- 12/08/01 - Successful completion
- 02/11/00 - Successful completion
- 04/15/98 - Successful completion
- 05/12/96 - Successful completion
- 10/19/94 - Successful completion
- 03/16/93 - Successful completion
- 05/25/91 - Successful completion

The last 8 historical performances of the two tests discussed above did not identify any time related failures, therefore this previous test data confirms that MNGP operating experience shows that these components routinely pass the SR when performed at the 18-month interval.

To provide a satisfactory back-up function for the HPCI system, the ADS system must be capable of discharging 1.6×10^6 pounds of steam per hour at 1125 psig. Two SRVs would be capable of discharging more than the required amount of steam. In order to provide redundancy, three SRVs are used in the automatic circuitry.

To assure that the ADS SRVs are able to operate, provisions are made to power each SRV independently from alternate power sources. Each SRV normally draws power from a predetermined 125 VDC system. Upon loss of voltage from the predetermined source a relay transfers that valve to the other 125 VDC power source.

Additional component testing performed on the ADS SRVs provides assurance of the mechanical integrity of the valve and its functionality beyond the valve operability test required by TS 4.5.A.4.a. The ADS SRVs are tested prior to installation by overpressure hydrostatic strength tests, leakage tests and steam tests to test the set point and specified response times. The valve setpoint is checked with a bench test in accordance with the MNGP In-service Inspection (ISI) and Testing (IST) Program[1]. After installation, the ADS circuitry is the only portion of the system that can easily be tested.

The ADS inhibit switch operability test evaluates the circuitry of the switch and its ability to inhibit ADS actuation.

[1] This testing is also performed to satisfy the requirements of MNGP TS 4.6.E.1.

Extending the TS surveillance interval from 18 to 24 months causes a minimal change in system availability because the instrumentation, including the actuation logic, is designed to be single failure proof and, therefore, is highly reliable. Furthermore, as stated by the NRC in its Safety Evaluation dated August 2, 1993, relating to the extension of Peach Bottom Atomic Power Station, Units 2 and 3, surveillance interval extension from 18 to 24 months:

> *"Industry reliability studies for boiling water reactors (BWRs), prepared by the BWR Owners Group (NEDC-30936P) show that the overall safety systems' reliabilities are not dominated by the reliabilities of the logic system, but by that of the mechanical components, (e.g., pumps and valves), which are consequently tested on a more frequent basis.... Since the probability of a relay or contact failure is small relative to the probability of mechanical failure, increasing the logic system functional test interval represents no significant change in the overall safety system unavailability."*

NMC's review of the surveillance history demonstrates the reliable past performance of these components. The utilization of additional component testing (beyond the surveillance requirements being evaluated), combined with the highly reliable single failure proof design of the systems, support the continued reliable operation of these components. Based on these considerations, it can be concluded that extending the surveillance interval from 18 to 24 months results in only a minimal change in system availability.

NRC Question #7

The 1995 edition, 1996 addenda, of the ASME O&M Code applies to Monticello's IST Program Plan. Do you have any restrictions or relief requests that will be affected as a result of going from an 18 to a 24 month fuel cycle? Explain in detail how you address the affected surveillances.

NMC Response:

NMC personnel have reviewed the MNGP IST Program Plan, including relief requests and restrictions, and have not identified any surveillance that would be impacted as a result of going from an 18-month to a 24-month fuel cycle.

ENCLOSURE 2

LICENSE AMENDMENT REQUEST TO SUPPORT 24-MONTH FUEL CYCLES RESPONSE TO SECOND REQUEST FOR ADDITIONAL INFORMATION

Pursuant to the requirements of 10 CFR Part 50, Section 50.90, Nuclear Management Company, LLC (NMC) submitted a License Amendment Request (LAR) for the Monticello Nuclear Generating Plant (MNGP) by letter dated June 30, 2004. This LAR was submitted to request revisions to the MNGP Technical Specification (TS) in support of 24-Month Fuel Cycles.

The NRC provided NMC with a Request For Additional Information (RAI) dated January 31, 2005 (TAC No. MC3692), regarding the above LAR. Listed below are the NRC's requests for additional information followed by the NMC response.

NRC Question #1

Enclosure 1 to Nuclear Management Company's (NMC's) November 5, 2004, submittal contains sample calculation CA-97-241 where the allowable value (AV) is derived from the analytical limit (AL). This is similar to Instrumentation, Systems, and Automation (ISA) Society ANSI/ISA-S67.04-2000, "Setpoints for Nuclear Safety-Related Instrumentation," Method 2, but the uncertainty components are not defined in the calculation. Please confirm that the setpoint methodology used at Monticello is equivalent to ISA Method 2.

NMC Response:

NMC uses the methodology contained in NEDC-31336P-A, General Electric (GE) Instrument Setpoint Methodology, to determine the allowable value (AV). While the method used to calculate the AV is similar to Instrumentation, Systems, and Automation (ISA) Society ANSI/ISA-S67.04-2000, Method 2 in that the AV is derived from the analytical limit (AL), it is not equivalent since the GE methodology includes additional error terms not included in ISA Method 2. With the inclusion of the additional error terms, the resulting AV is more conservative from the perspective of protecting the AL.

In the GE setpoint methodology, the AV is established so that there is at least a 95% probability of providing the trip action before the process variable reaches the AL when the maximum allowable drift has occurred. The methodology used to determine the AV includes all known error terms (excluding drift) for a particular instrument application under trip conditions. Specifically, the following terms are included in the determination of the AV:

- Loop Accuracy under Trip Conditions. This term is the combination of all the individual error contributions for all devices in the loop and is identified as A_N in the sample calculation. The individual error contributions considered in the determination of A_N are listed in Section 6.2.1.3.

- Loop Calibration Error. This term accounts for inaccuracies due to measurement and test equipment effects and calibration methods. This term is identified as C_L in the sample calculation with the individual contributions determined in Section 6.2.1.6.

- Primary Element Accuracy (PEA). PEA is the accuracy of the device (exclusive of the sensor) used as a primary element to obtain a given process measurement. No PEA was identified for the sample calculation.

- Process Measurement Accuracy (PMA). PMA accounts for the variation in actual process conditions that influence the measurement. No PMA was identified for the sample calculation.

- Other error terms. Other error terms are included when applicable to incorporate all reasonably expected error terms that may exist. These terms include, but are not limited to; Indicator Readability/Operator Reading Error (ORE), Degradation of Insulation Resistance (IRE), Software Errors, and errors due to resistors, multiplexers, etc. No other error terms were identified for the sample calculation.

- Bias terms associated with the above terms would also be included when applicable. Bias is taken into account linearly. No bias terms were identified for the sample calculation.

The nominal trip setpoint (NTSP) is established as the limiting value of the sensed process variable at which a trip action may be set to operate at time of calibration so there is at least a 95% probability of providing the trip action before the process variable reaches the AL. The NTSP is determined using the above terms plus the loop drift (D_L).

The GE methodology includes two additional evaluations, summarized below, that may affect the relationship between the AV and the NTSP. While the results of these evaluations may change the calculated NTSP, the calculated value between the AL and the AV would not be reduced.

- Licensee Event Report (LER) Avoidance Test. The LER Avoidance Test is performed to assure that there is sufficient margin between the AV and the NTSP to reasonably avoid violations of the AV. The LER Avoidance Test determines the error that may be present during surveillance testing and adjusts the NTSP to provide added margin to the AV if necessary. The following terms are considered in the LER Avoidance Test; Loop Accuracy under Normal (Calibration) Conditions, Loop Calibration Error, and Loop Drift.

- Spurious Trip Avoidance Evaluation. A spurious trip avoidance test is performed, when applicable, to evaluate the impact of the NTSP on plant availability. If an acceptable probability of avoiding a spurious trip is not shown, the selected NTSP or as-left tolerances should be optimized to achieve the best practical balance between the design constraints. The following terms are considered in the Spurious Trip Avoidance Evaluation; Loop Accuracy under Normal Conditions, Loop Calibration Error, Loop Drift, PMA, and PEA.

The NRC has previously reviewed and approved the GE methodology as documented in a letter to the Boiling Water Reactor (BWR) Owners Group dated November 6, 1995, "Revision to Safety Evaluation Report on NEDC-31366, Instrument Setpoint Methodology (NEDC-31336P)."

NRC Question #2

In sample calculation CA-97-241, Section 6.5 indicates that many analyses assume a trip value of 200°F, and then NMC uses an analytical limit (AL) of 212°F. If the analyses simply indicate that the value will only reach 200°F, but corrective action is based upon something else, then this is stated unclearly. If the analyses presume corrective action at 200°F, then the AL must be 200°F. Is NMC claiming that the temperature will always rise to 212°F in a "negligible" amount of time whenever it hits 200°F, or does this not matter because the device in question is only a "backup" device? Please more explicitly justify these points. In particular, it seems that the analyses either presume action based upon this switch or they do not. It is not clear in this context what it means to say that this is a "backup" device or function.

NMC Response

An AL of ≤ 212°F is correct for this function. The temperature switches provide the primary means of detecting a small break (approximately five to ten gallons per minute) of the main steam lines. The evaluation in EDS Nuclear, Inc. Report No. 01-0910-1151, Revision 2, "Main Steamline Tunnel Temperature Switches Technical Specification Modification", provides the basis for the AL of ≤ 212°F. This evaluation is listed as Input 4.8 to calculation CA-97-241 and was previously transmitted to the NRC as Exhibit C to the LAR Dated September 24, 1982, "Miscellaneous Technical Specification Changes". The NRC approved this portion of the LAR as Amendment No. 18 to Facility Operating License No. DPR-22 by letter dated November 28, 1983.

The analyses listed in calculation CA-97-241, Section 6.5 were performed for the limiting Main Steam Line Break (MSLB) analysis. The limiting MSLB analysis is performed consistent with the assumptions in the MNGP Updated Safety Analysis Report (USAR) Section 14.7.3. The postulated accident involves a guillotine break of one of the four main steam lines outside of the containment. Analytically, closure of the main steam line isolation valves is initiated by the increase in differential pressure across the main steam line flow restrictors (steam line high flow). Consistent with the USAR, an event time of 10.5 seconds is assumed from break initiation to final valve closure. This includes a maximum valve closing time of 9.9 seconds (USAR Table 5.2-3b) with 0.6 seconds allowed for break detection.

For the limiting MSLB, the steam line high flow instruments are credited in the safety analysis as detecting and mitigating the event. This high steam flow function is selected since it results in the slower response time and maximizes the mass release from the break. The temperature switches will react to the MSLB; analyzed cases show that the steam tunnel temperatures will exceed 212°F within 0.22 seconds. However, the temperature switches are not explicitly modeled in the MSLB analysis since the flow response is the most limiting. Since the temperature switches are not credited in the MSLB analysis, this information is not required in calculation CA-97-241 and was included only to show that the steam tunnel temperature quickly exceeds the current TS trip setting (as left limit) of 200°F.

NRC Question #3

NMC's June 30, 2004, submittal proposes allowing a significant increase in the amount of drift for each component, and extends the time available for random failures to occur. Since the amount of setpoint drift could increase, it would be appropriate to make most setpoints and AVs more conservative. NMC has proposed changing very few setpoints and AVs. Is NMC maintaining that experience shows that drift is far less than assumed in the existing technical specifications (TS), and that the existing TS are overconservative and bound the increased drift? If so, then demonstrate that existing data show that present TS surveillance requirements are usually met. Explain how NMC has extrapolated the 18-month data to justify a 24-month interval considering both random failures and calibration drift. Please provide additional documentation to demonstrate the results of your evaluation that the projected 30-month drift value for these instruments does not exceed the drift allowance provided in the setpoint calculation for these instruments. Please show that the change in channel availability (in regard to equipment failures) is acceptable.

NMC Response

NMC used the methodology contained in NEDC-31336P-A, GE Instrument Setpoint Methodology, to evaluate the impact of predicted 30-month drift values on TS setpoints affected by cycle length extension. In some cases, existing margin was sufficient to accommodate the increased 30-month drift without adjusting existing ALs, AVs, or TS trip settings. NMC has proposed changing the TS trip settings only where the available margin between the plant setpoint and the TS trip setting was determined to be insufficient to bound the increased drift. The NRC has previously reviewed and approved the GE methodology as documented in a letter to the BWR Owners Group dated November 6, 1995, "Revision to Safety Evaluation Report on NEDC-31366, Instrument Setpoint Methodology (NEDC-31336P)."

As discussed in Enclosure 1 of the initial LAR, dated June 30, 2004, NMC followed the guidance provided in Generic Letter 91-04. The plant specific drift analysis procedure used to extrapolate the 18-month drift data was provided as Enclosure 4 to the LAR. As a result of the drift analysis, the following actions were taken where necessary:

1. Setpoint calculations were performed that include the calculated 30-month drift value. No TS trip setting changes were required.

These calculations show that the existing margin between the plant setpoint and the TS trip setting is adequate to accommodate the 30-month drift values without adjustment of the TS trip setting. Tolerances for As Found setpoints were adjusted where required to ensure the As Found values do not exceed the TS trip settings. Where applicable, a Spurious Trip Avoidance Evaluation was performed to ensure adequate margin between the operational limit and the plant setpoint.

2. The existing setpoint calculation uses a drift allowance that is greater than the calculated 30-month drift value.

   The drift allowance in these calculations exceeded the calculated 30-month drift values. These calculations were not revised.

3. A setpoint calculation was performed that includes the calculated 30-month drift value. The setpoint calculation resulted in the proposed TS trip setting change as described in the LAR.

   These calculations show that the existing margin between the plant setpoint and the TS trip setting is not adequate to accommodate the 30-month drift values without adjustment of the TS trip setting. New TS trip settings (AVs) were calculated for these instruments using the plant setpoint methodology. In no case was it necessary to change the existing AL or safety analysis.

A summary of the result of each drift analysis listed in Enclosure 1 of the LAR is provided below:

Drift Evaluation Calculation No.	Technical Specification Table Item or LCO	Drift Evaluation Results
CA-03-019	3.1.1-7 3.2.1-1.a 3.2.1-2.a 3.2.1-3.b 3.2.2-A.1.a 3.2.2-B.2 3.2.2-C.1 3.2.2-D.2 3.2.4-1 3.2.8-A.1 3.2.8-B.1	Setpoint calculations were performed that include the calculated 30-month drift value. *No TS trip setting changes were required.*
	3.2.1-3.d	*The existing setpoint calculation uses a drift allowance that is greater than the calculated 30-month drift value.*

Drift Evaluation Calculation No.	Technical Specification Table Item or LCO	Drift Evaluation Results
CA-03-054	3.2.2-A.1.b.ii	A setpoint calculation was performed that includes the calculated 30-month drift value. *The setpoint calculation resulted in the proposed TS trip setting change as described in the LAR.*
	3.2.2-C.2	A setpoint calculation was performed that includes the calculated 30-month drift value. *No TS trip setting changes were required.*
CA-03-055	3.1.1-10 3.1.1-12	These switches provide a bypass function for the listed TS Table item. There is no applicable AV. *Existing setpoint calculations use a drift allowance that is greater than the calculated 30-month drift.*
CA-03-057	3.2.1-1.c	A setpoint calculation was performed that includes the calculated 30-month drift value. *The setpoint calculation resulted in the proposed TS trip setting change as described in the LAR.*
CA-03-058	3.2.6-2	A setpoint calculation was performed that includes the calculated 30-month drift value. *The setpoint calculation resulted in the proposed TS trip setting change as described in the LAR.*
CA-03-061	4.1.C.2	A setpoint calculation was performed that includes the calculated 30-month drift value. *No TS trip setting changes required.*
CA-03-065	3.2.6-2	A setpoint calculation was performed that includes the calculated 30-month drift value. *The setpoint calculation resulted in the proposed TS trip setting change as described in the LAR.*
CA-03-068	3.2.5-2	A setpoint calculation was performed that includes the calculated 30-month drift value. *No TS trip setting changes were required.*
CA-03-069	3.2.5-1	The existing setpoint calculation uses a drift allowance that is greater than the calculated 30-month drift value. *No TS trip setting changes were required.*

Drift Evaluation Calculation No.	Technical Specification Table Item or LCO	Drift Evaluation Results
CA-03-072	3.2.7-4	A setpoint calculation was performed that includes the calculated 30-month drift value. *The setpoint calculation resulted in the proposed TS trip setting change as described in the LAR.*
CA-03-073	3.2.7-4	A setpoint calculation was performed that includes the calculated 30-month drift value. *The setpoint calculation resulted in the proposed TS trip setting change as described in the LAR.*
CA-03-074	3.2.7-2 3.2.7-3	A setpoint calculation was performed that includes the calculated 30-month drift value. *The setpoint calculation resulted in the proposed TS trip setting change as described in the LAR.*
CA-97-110	3.2.1-3.c	As discussed in the LAR, only a limited number of calibrations have been performed on these instruments. Evaluation of the available drift data shows that the drift as determined from the as-found/as-left calibration data has been well within the vendor specified drift values. The setpoint calculation was performed using the vendor specified drift values. *No TS trip setting changes were required.*

The effect on safety of the change in instrument surveillance intervals to accommodate a 24-month fuel cycle was evaluated following the guidance provided in Generic Letter 91-04. This evaluation was performed in the same manner as described in Part A of Enclosure 1 of the initial LAR dated June 30, 2004. The results of this review, with regard to instrument channel availability, are summarized below:

> *"...licensees should evaluate the effect on safety of the change in surveillance intervals to accommodate a 24-month fuel cycle. This evaluation should support a conclusion that the effect on safety is small."*

Justifications for extending the Instrument Functional Tests are provided based upon more frequent testing of system components and/or the high reliability of system design. The more frequent testing may include the performance of Sensor Checks that verify that the instrument loop (i.e., transmitter and indication) is functional, and the system parameters (e.g., pump flow, system pressure, etc.) are within expected values. More frequent testing also includes Channel Functional Tests that verify the operation of circuits associated with alarms, interlocks, displays, trip functions, time delays and channel failure trips. Where a Sensor Check or Channel Functional Test is not required, normally the circuit is simple and these checks will not provide any additional assurances that the components are functional.

Additionally, as stated by the NRC in the Safety Evaluation (SE) issued for the Peach Bottom Atomic Power Station Units 2 and 3 surveillance interval extension from 18 to 24 months (NRC SE for Peach Bottom Atomic Power Station Units 2 and 3 License Amendments 179 and 182, respectively, Operating License DPR-44 and DPR-56, Dockets D50-277 and D50-278, dated August 2, 1993), industry reliability studies for BWRs, prepared by the BWR Owners Group (NEDC-30936), show that overall safety system reliability is not dominated by logic system reliability, but by mechanical component reliability (e.g., pumps and valves) that are consequently tested on a more frequent basis, usually by the Inservice Testing Program. Since the probability of a relay or contact failure is small relative to the probability of mechanical component failure, increasing the Instrument Functional Test interval represents no significant change in overall safety system unavailability.

> *"...licensees should confirm that historical maintenance and surveillance data do not invalidate this conclusion."*

The surveillance test history of the affected TS SRs was evaluated. This evaluation consisted of a review of surveillance test results and associated maintenance records. Only SR test failures were evaluated because failures detected by other plant activities, such as preventive maintenance tasks or surveillance tests performed at shorter intervals than 24 months were assumed to continue to detect failures. This review of surveillance test history validated the conclusion that the impact, if any, on system availability will be small as a result of the change to a 24-month testing frequency.

NRC Question #4

Pages 102 and 105 in Enclosure 6 of NMC's June 30, 2004, submittal contain marked-up changes from "Low" reactor water level to "Low-Low" reactor water level. Justify these changes and also provide references to related Updated Safety Analysis Report sections.

NMC Response

Additional discussion of the changes to TS 4.5.A.4 and TS 4.5.D.2 is provided in the response to Question 3 in Enclosure 1.

The change from "low" to "Low-Low" in TS 4.5.A.4 and TS 4.5.D.2 is a change in the wording used within the TS and does not reflect a physical plant modification or setpoint change.

Operation of the High Pressure Coolant Injection (HPCI) System is discussed in MNGP Updated Safety Analysis Report (USAR) section 6.2.4. As stated in subsection 6.2.4.2.5:

"Automatic trip of the HPCI turbine occurs on ... high reactor water level... The high reactor water level trip seals in until either a manual restart is initiated or a low-low reactor water level signal is received."

Operation of the Reactor Core Isolation Cooling (RCIC) System is discussed in MNGP USAR section 10.2.5. As stated in subsection 10.2.5.2:

"Upon reaching a pre-determined low-low level, the RCIC System is initiated as the steam admission valve automatically opens. The RCIC System supplies makeup water until a high level point is reached at which time the steam admission valve automatically closes to prevent turbine water induction. The auto restart of the turbine on low-low water level following a high water level trip satisfies NUREG-0737 ..., Item II.K.3.13."

No TS trip settings have been changed. The Safety Analysis Safety Limits and the Analytical Limits are also unchanged.

NRC Question #5

In the first paragraph on page 9 of 17 in Enclosure 1 of NMC's June 30, 2004, submittal, NMC states "NTSPs [nominal trip setpoints] were changed where it was not possible to accommodate the projected drift by adjusting plant settings . . . ." What plant settings other than setpoint change is NMC referring to?

NMC Response

As noted in the response to Question 3, tolerances for As Found setpoints were adjusted as required to assure the As Found values do not exceed the TS trip settings.

ENCLOSURE 3

PROPOSED TECHNICAL SPECIFICATION CHANGES (MARK-UP)

This enclosure consists of current Technical Specification pages marked up with the proposed changes. The pages included in this exhibit are as listed below:

<u>Pages</u>
33

1 page follows

TABLE 4.1.1 (Continued)

Note 1: Deleted.

Note 2: A sensor check shall be performed on ~~low~~ **[Low]** reactor water level once per day.

Note 3: Perform functional test prior to every startup, and demonstrate that the IRM and APRM channels overlap at least 1/2 decade prior to every normal shutdown.

Note 4: Functional tests are not required when the systems are not required to be operable or are tripped. If tests are missed, they shall be performed prior to returning the systems to an operable status.

Note 5: A functional test of this instrument means the injection of a simulated signal into the instrument (not primary sensor) to verify the proper instrument channel response, alarm, and/or initiating action.

ENCLOSURE 4

PROPOSED TECHNICAL SPECIFICATION BASES CHANGES (MARK-UP)

This enclosure consists of current Technical Specification Bases pages marked up with the proposed changes. The pages included in this exhibit are as listed below:

<u>Pages</u>
38
64
65
66
69
69a
70
71
71a
111

10 pages follow

6. High Drywell Pressure Scram
Instrumentation (pressure switches) in the drywell are provided to detect a loss of coolant accident and initiate the emergency core cooling equipment. This instrumentation is a backup to the water level instrumentation which is discussed in Specification 3.2.

7. Reactor Low Water Level Scram
The ~~low~~ **[Low]** reactor water level instrumentation is set to trip when reactor water level is > 7" on the instrument. This corresponds to a lower water level inside the shroud at 100% power due to the pressure drop across the dryer/separator. This has been accounted for in the affected safety analyses. All Technical Specification reactor water level setpoints are specified as inches measured in the reactor annulus and referenced to instrument "zero." Instrument "zero" is a point 477.5" above the inner clad surface on the bottom of the reactor vessel.

8. Scram Discharge Volume Scram
The control rod drive scram system is designed so that all of the water which is discharged from the reactor by the scram can be accommodated in the discharge piping. Part of this piping consists of two instrument volumes which accommodate in excess of 56 gallons of water each and is the low point in the piping. During normal operation the discharge volumes are empty; however, should they fill with water, the water discharge to the piping from the reactor could not be accommodated which would result in slow scram times or partial or no control rod insertion. To preclude this occurrence, level switches have been provided in the instrument volumes which alarm and scram the reactor when the volume of water in either of the discharge volume receiver tanks reaches 56 gallons. At this point there is sufficient volume in the piping to accommodate the scram without impairment of the scram times or amount of insertion of the control rods. This function shuts the reactor down while sufficient volume remains to accommodate the discharged water and precludes the situation in which a scram would be required but not be able to perform its function adequately.

9. Turbine Condenser Low Vacuum
Loss of condenser vacuum occurs when the condenser can no longer handle the heat input. Loss of condenser vacuum initiates a closure of the turbine stop valves and turbine bypass valves which eliminates the heat input to the condenser. Closure of the turbine stop and bypass valves causes a pressure transient, neutron flux rise, and an increase in surface heat flux. The condenser low vacuum scram is a back-up to the stop valve closure scram and causes a scram before the stop valves are closed and thus the resulting transient is less severe. Scram occurs at 22" Hg vacuum, stop valve closure occurs at 20" Hg vacuum, and bypass closure at 7" Hg vacuum.

Bases 3.2:

In addition to reactor protection instrumentation which initiates a reactor scram, protective instrumentation has been provided which initiates action to mitigate the consequences of accidents which are beyond the operators ability to control, or terminate a single operator error before it results in serious consequences. This set of specifications provides the limiting conditions of operation for the primary system isolation function, initiation of the emergency core cooling system, and other safety related functions. The objectives of the Specifications are (i) to assure the effectiveness of the protective instrumentation when required, and (ii) to prescribe the trip settings required to assure adequate performance. This set of Specifications also provides the limiting conditions of operation for the control rod block system.

Isolation valves are installed in those lines that penetrate the primary containment and must be isolated during a loss of coolant accident so that the radiation dose limits are not exceeded during an accident condition. Actuation of these valves is initiated by protective instrumentation shown in Table 3.2.1 which senses the conditions for which isolation is required. Such instrumentation must be available whenever primary containment integrity is required. The objective is to isolate the primary containment so that the guidelines of 10 CFR 100 are not exceeded during an accident.

The instrumentation which initiates primary system isolation is connected in a dual bus arrangement. Thus, the discussion given in the bases for Specification 3.1 is applicable here.

The ~~low~~ **[Low]** reactor water level instrumentation is set to trip when reactor water level is > 7" on the instrument. This corresponds to a lower water level inside the shroud at 100% power due to the pressure drop across the dryer/separator. This has been accounted for in the affected transient analysis. This trip initiates closure of Group 2 primary containment isolation valves. Reference Section 7.7.2.2 FSAR. The trip setting provides assurance that the valves will be closed before perforation of the clad occurs even for the maximum break in that line and therefore the setting is adequate. The head cooling valves no longer function to provide head cooling, but continue to provide containment isolation for penetration X-17.

The ~~low-low~~ **[Low Low]** reactor water level instrumentation is set to trip when reactor water level is ≥ -48". This trip initiates closure of the Group 1 and Group 3 Primary containment isolation valves, Reference Section 7.7.2.2 USAR, and also activates the ECC systems and starts the emergency diesel generators.

Bases 3. 2 (Continued):

This trip setting level was chosen to be low enough to prevent spurious operation but high enough to initiate ECCS operation and primary system isolation so that no melting of the fuel cladding will occur and so that post accident cooling can be accomplished and the guidelines of 10 CFR 100 will not be violated. For the complete circumferential break of a 28-inch recirculation line and with the trip setting given above, ECCS initiation and primary system isolation are initiated in time to meet the above criteria. Reference Section 6.2.7 and 14.6.3 FSAR. The instrumentation also covers the full range or spectrum of breaks and meets the above criteria. Reference Section 6.2.7 FSAR.

The high drywell pressure instrumentation is a back-up to the water level instrumentation and in addition to initiating ECCS it causes isolation of Group 2 and Group 3 isolation valves. For the complete circumferential break discussed above, this instrumentation will initiate ECCS operation at about the same time as the ~~low-low~~ **[Low Low]** water level instrumentation; thus the results given above are applicable here also. Group 2 and Group 3 isolation valves include the drywell vent, purge, sump isolation, RWCU, and recirc sample valves.

Two pressure switches are provided on the discharge of each of the two core spray pumps and each of the four RHR pumps. Two trip systems are provided in the control logic such that either trip system can permit automatic depressurization. Each trip system consists of two trip logic channels such that both trip logic channels are required to permit a system trip.

Division I core spray and RHR pump discharge pressure permissives will interlock one trip system and Division II permissives will interlock the other trip system. One pressure switch on each pump will interlock one of the trip channels and the other pressure switch will interlock the other trip channel within their respective trip system.

The pump pressure permissive control logic is designed such that no single failure (short or open circuit) will prevent auto-blowdown or allow auto-blowdown when not required. The trip setting for the low pressure ECCS pump permissive for ADS is set such that it is less than the pump discharge pressure when a pump is operating in a full flow condition and also high enough to avoid any condition that results in a discharge pressure permissive when the pumps are not operating.

Venturis are provided in the main steamlines as a means of measuring steam flow and also limiting the loss of mass inventory from the vessel during a steamline break accident. In addition to monitoring steam flow, instrumentation is provided which causes a trip of Group 1 isolation valves. The primary function of the instrumentation is to detect a break in the main steamline, thus only Group 1 valves are closed. For the worst case accident, main steamline break outside the drywell, this trip setting of 140% of rated steam flow in conjunction with the flow limiters and main steamline valve closure, limit the mass inventory loss such that fuel is not uncovered, fuel clad temperatures remain less than 1000°F and release of radioactivity to the environs is well below 10 CFR 100 guidelines. Reference Sections 14.6.5 FSAR.

Temperature monitoring instrumentation is provided in the main steamline tunnel to detect leaks in this area. Trips are provided on this instrumentation and when exceeded cause closure of Group 1 isolation valves. Its setting of 200°F is low enough to detect leaks of the order of 5 to 10 gpm; thus, it is capable of covering the entire spectrum of breaks. For large breaks, it is a back-up to high steam flow instrumentation discussed above, and for small breaks with the resultant small release of radioactivity, gives isolation before the guidelines of 10 CFR 100 are exceeded.

Low MSL pressure indicates that there may be a problem with the turbine pressure regulation, which could result in a ~~low~~ **[Low]** reactor vessel water level condition and the RPV cooling down more than 100°F/hr if the pressure loss is allowed to continue. The Main Steam Line Pressure - Low Function is directly assumed in the analysis of the pressure regulator failure (USAR Section 7.6.3.2.4-4). For this event, the closure of the MSIVs ensures that the RPV temperature change limit (100°F/hr) is not reached. In addition, this Function supports actions to ensure that Safety Limit 2.1.A is not exceeded. (This Function closes the MSIVs prior to pressure decreasing below 785 psig, which results in a scram due to MSIV closure, thus reducing power to < 25% RTP.)

The MSL low pressure signals are initiated from four transmitters that are connected to the MSL header. The transmitters are arranged such that, even though physically separated from each other, each transmitter is able to detection low MSL pressure. Four channels of Main Steam Line Pressure - Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was selected to be high enough to prevent excessive RPV depressurization.

The Main Steam Line Pressure - Low Function is only required to be OPERABLE during power operation since this is when the assumed transient can occur (USAR Section 7.6.3.2.4-4).

This Function isolates the Group 1 valves.

The RWCU high flow and temperature instrumentation is provided to detect a break in the RWCU piping. Tripping of this instrumentation results in actuation of the RWCU isolation valves, i.e., Group 3 valves. The trip settings have been established so that the radiological consequences of a high energy line break in this system are bounded by a break in the main steam system. The recirc sample isolation valves, which receive a Group 1 isolation signal, also receive a redundant Group 3 isolation signal.

Bases 3.2 (Continued):

The ATWS high reactor pressure and ~~low-low~~ **[Low Low]** water level logic also initiates the Alternate Rod Injection System. Two solenoid valves are installed in the scram air header upstream of the hydraulic control units. Each of the two trip systems energizes a valve to vent the header and causes rod insertion. This greatly reduces the long term consequences of an ATWS event.

Voltage sensing relays are provided on the safeguards bus to transfer the bus to an alternate source when a loss of voltage condition or a degraded voltage condition is sensed. On loss of voltage, the voltage sensing relays trip immediately and energize auxiliary relays that control the bus transfer sequence. The transfer on degraded voltage has a time delay to prevent transfer during the starting of large loads. The degraded voltage setpoint corresponds to the minimum acceptable safeguards bus voltage for a steady state LOCA load that maintains adequate voltage at the 480V essential MCCS. An allowance for relay tolerance is included.

Safety/relief valve low-low set logic is provided to prevent any safety/relief valve from opening when there is an elevated water leg in the respective discharge line. A high water leg is formed immediately following valve closure due to the vacuum formed when steam condenses in the line. If the valve reopens before the discharge line vacuum breakers act to return water level to normal, water clearing thrust loads on the discharge line may exceed their design limit. The logic reduces the opening setpoint and increases the blowdown range of three non-APRS valves following a scram. A 15-second interval between subsequent valve actuations is provided assuming one valve fails to open and instrumentation drift has caused the nominal 80-psi blowdown range to be reduced to 60 psi. Maximum water leg clearing time has been calculated to be less than 6 seconds for the Monticello design. Inhibit timers are provided for each valve to prevent the valve from being manually opened less than 10 seconds following valve closure. Valve opening is sensed by pressure switches in the valve discharge line. Each valve is provided with two trip, or actuation, systems. Each system is provided with two channels of instrumentation for each of the above described functions. A two-out-of-two-once logic scheme ensures that no single failure will defeat the low-low set function and no single failure will cause spurious operation of a safety/relief valve. Allowable deviations are provided for each specified instrument setpoint. Valve operation within the specified allowable deviations provide assurance that subsequent safety/relief valve actuations are sufficiently spaced to allow for discharge line water leg clearing.

Bases 3.2 (Continued):

Control room habitability protection instrumentation assures that the control room operators will be adequately protected against the effects of accidental releases of radioactive leakage which may bypass secondary containment following a loss of coolant accident or radioactive releases from a steam line break accident, thus assuring that the Monticello Nuclear Generating Plant can be operated or shutdown safely.

Although the operator will set the setpoints within the trip settings specified in Tables 3.2.1 through 3.2.9, the actual values of the various set points can differ appreciably from the value the operator is attempting to set. The deviations could be caused by inherent instrument error, operator setting error, drift of the set point, etc. Therefore, these deviations have been accounted for in the various transient analyses.

 [Deleted]

	~~Trip Function~~	~~Deviation~~
~~Reactor Building Ventilation Isolation and Standby Gas Treatment System Initiation Specification 3.2.E.3 and Table 3.2.4~~	~~Reactor Building Vent Plenum Monitors~~	~~+5 mR/hr~~
	~~Refueling Floor Radiation Monitors~~	~~+5 mR/hr~~
	~~* Low Low Reactor Water Level High Drywell Pressure~~	~~-3 inches~~ ~~+1 psi~~
~~Primary Containment Isolation Functions Table 3.2.1~~	~~* Low Low Water Level~~	~~-3 inches~~
	~~High Flow in Main Steam Line~~	~~+2%~~
	~~High Temp. in Main Steam Line Tunnel~~	~~+10°F~~
	~~Low Pressure in Main Steam Line~~	~~-10 psi~~
	~~High Drywell Pressure~~	~~+1 psi~~
	~~* Low Reactor Water Level~~	~~-6 inches~~
	~~HPCI High Steam Flow~~	~~+7,500 lb/hr~~
	~~HPCI Steam Line Area High Temp.~~	~~+2°F~~
	~~HPCI Steam Line Pressure~~	~~-5 psi~~
	~~RCIC High Steam Flow~~	~~+2250 lb/hr~~
	~~RCIC Steam Line Area High Temp.~~	~~+2°F~~
	~~RCIC Steam Line Pressure~~	~~-5 psi~~
	~~Shutdown Cooling Supply ISO~~	~~+7 psi~~

~~Bases 3.2 (Continued):~~ [Deleted]

	~~Trip Function~~	~~Deviation~~
~~Instrumentation That Initiates Emergency Core Cooling Systems~~ ~~Table 3.2.2~~	~~*Low-Low Reactor Water Level~~ ~~Reactor Low Pressure (Pump Start) Permissive~~ ~~Reactor Low Pressure (Pump Start) Permissive Bypass Timer~~ ~~High Drywell Pressure~~ ~~Low Reactor Pressure (Valve Permissive)~~	~~-3 Inches~~ ~~-10 psi~~ ~~>10 min~~ ~~<24 min~~ ~~+1 psi~~ ~~-10 psi~~
~~Instrumentation That Initiates Rod Block~~ ~~Table 3.2.3~~	~~IRM Downscale~~ ~~IRM Upscale~~ ~~APRM Downscale~~ ~~APRM Upscale~~ ~~RBM Downscale~~ ~~RBM Upscale~~ ~~Scram Discharge Volume High Level~~	~~-2/125 of Scale~~ ~~+2/125 of Scale~~ ~~-2/125 of Scale~~ ~~See Basis 3.2~~ ~~-2/125 of Scale~~ ~~+2/125 of Scale~~ ~~+ 1 gallon~~
~~Instrumentation That Initiates Recirculation Pump Trip~~	~~High Reactor Pressure~~ ~~* Low Reactor Water Level~~	~~+12 psi~~ ~~-3 Inches~~
~~Instrumentation for Safeguards Bus Protection~~	~~Degraded Voltage~~ ~~Loss of Voltage~~	~~≥3897 volts (trip)~~ ~~≤3975 volts (reset)~~ ~~≥5 sec ≤10 sec (delay)~~ ~~<3000 volts >2000 volts~~

~~Bases 3.2 (Continued):~~ **[Deleted]**

	~~Trip Function~~	~~Deviation~~
~~Instrumentation for Safety/Relief Valve Low-Low Set Logic~~	~~Reactor Coolant System Pressure for Opening/Closing~~ ~~Opening - Closing Pressure~~ ~~Discharge Pipe Pressure Inhibit~~ ~~Timer Inhibit~~	~~± 20 psig~~ ~~≥ 60 psi~~ ~~± 10 psid~~ ~~-3 sec~~ ~~+10 sec~~
~~Other Instrumentation~~	~~*High Reactor Water Level~~ ~~*Low-Low Reactor Water Level~~	~~+6 inches~~ ~~-3 inches~~

~~* This indication is reactor coolant temperature sensitive. The calibration is thus made for rated conditions. The level error at low pressures and temperatures is bounded by the safety analysis which reflects the weight of coolant above the lower tap, and not the indicated level.~~

Bases 3.5/4.5 (Continued):

The surveillance requirements provide adequate assurance that the LPCI system will be operable when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage to piping and to start cooling at the earliest moment.

The high pressure coolant injection (HPCI) system is provided to assure that the reactor core is adequately cooled to limit fuel clad temperature in the event of a small break in the reactor coolant system and loss of coolant which does not result in rapid depressurization of the reactor vessel. The HPCI system permits the reactor to be shut down while maintaining sufficient reactor vessel water level inventory until the vessel is depressurized. The HPCI system continues to operate until reactor vessel pressure is below the pressure at which Core Spray system operation or LPCI mode of the RHR system operation maintains core cooling.

The flow tests for the HPCI System are performed at two different pressure ranges such that the system capability to provide rated flow is tested at both the higher and lower operating ranges of the system. Additionally, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the HPCI System diverts steam flow. Reactor steam pressure must be ≥ 950 psig to perform SR 4.5.A.3.a and ≤ 165 psig to perform SR 4.5.A.3.b. Adequate steam flow is represented by at least 0.8 turbine bypass valves open. Reactor startup, and pressure increase to ≤ 165 psig, is allowed prior to performing the low pressure surveillance test because the reactor pressure is low and the time allowed to satisfactorily perform the surveillance test is short. Therefore, pressure may be raised above 150 psig, but ≤ 165 psig to perform this surveillance without entering an LCO for the HPCI System. The reactor pressure is allowed to be increased to normal operating pressure once the low pressure test has been satisfactorily completed since there would be no indication or reason to believe that HPCI is inoperable.

Sufficient time is needed after adequate pressure and flow are achieved to perform these tests. Therefore, SR 4.5.A.3.a and SR 4.5.A.3.b are modified by a note which states that the surveillances are not required to be performed until 12 hours after the reactor steam pressure and flow are adequate to perform the test.

With the HPCI system inoperable, adequate core cooling is assured by the operability of the redundant and diversified automatic depressurization system and both the Core Spray and LPCI systems. In addition, the reactor core isolation cooling (RCIC) system, a system for which no credit is taken in the safety analysis, will automatically provide makeup at reactor operating pressures on a reactor ~~low~~ **[Low]** water level condition. The HPCI out-of-service period of 14 days is based on the verified operability of the RCIC system and the redundant and diversified low pressure core cooling systems. Verification of RCIC operability may be performed as an administrative check by examining logs or other information to determine if RCIC is out of service for maintenance or other reasons. It does not mean to perform the surveillance needed to demonstrate the operability of the RCIC system.

ENCLOSURE 5

PROPOSED TECHNICAL SPECIFICATION CHANGES (RETYPED)

This enclosure consists of revised Technical Specification pages that incorporate the proposed changes. The pages included in this exhibit are as listed below:

<u>Pages</u>
33

1 page follows

TABLE 4.1.1 (Continued)

Note 1: Deleted.

Note 2: A sensor check shall be performed on Low reactor water level once per day.

Note 3: Perform functional test prior to every startup, and demonstrate that the IRM and APRM channels overlap at least 1/2 decade prior to every normal shutdown.

Note 4: Functional tests are not required when the systems are not required to be operable or are tripped. If tests are missed, they shall be performed prior to returning the systems to an operable status.

Note 5: A functional test of this instrument means the injection of a simulated signal into the instrument (not primary sensor) to verify the proper instrument channel response, alarm, and/or initiating action.