UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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ARLINGTON, TEXAS 76011-4005

April 13, 2006

George A. Williams, Site Vice President
Grand Gulf Nuclear Station
Entergy Operations, Inc.
P.O. Box 756
Port Gibson, MS 39150

SUBJECT: Grand Gulf Nuclear Station - NRC INSPECTION REPORT 05000416/2006-008

Dear Mr. Williams:

On February 13 through March 10, 2006, the US Nuclear Regulatory Commission (NRC) conducted an inspection at your Grand Gulf Nuclear Station. The enclosed report documents the inspection findings which were discussed on March 27, 2006, with Mr. D. Wiles, Director, Engineering, and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed cognizant plant personnel.

Based on the results of this inspection, the NRC has identified two issues that were evaluated under the risk significance determination process as having very low safety significance (Green). The NRC has also determined that violations are associated with these issues which are being treated as noncited violations, consistent with Section VI.A.1 of the Enforcement Policy. These noncited violations are described in the subject inspection report. If you contest the violation or significance of these noncited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Grand Gulf Nuclear Station facility.

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Sincerely,

/RA/

Jeffrey A. Clark, PE, Chief
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Division of Reactor Safety

Docket: 50-416
License: NPF-29

Enclosure:
Inspection Report 05000416/2006-008
w/Attachment: Supplemental Information

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket:	50-416
License:	NPF-29
Report No.:	05000416/2006-008
Licensee:	Entergy Operations, Inc.
Facility:	Grand Gulf Nuclear Station
Location:	Waterloo Road Port Gibson, Mississippi
Dates:	February 13 through March 10, 2006
Team Leader:	C. Paulk, Senior Reactor Inspector Engineering Branch 1
Inspectors:	P. Gage, Senior Operations Engineer G. George, Reactor Inspector J. Nadel, Reactor Inspector E. Owen, Reactor Inspector J. Reynoso, Reactor Inspector W. Sifre, Senior Reactor Inspector
Contractors:	F. Baxter, Electrical, Beckman and Associates M. Yeminy, Mechanical, Beckman and Associates
Approved By:	J. Clark, PE, Chief Engineering Branch 1

SUMMARY OF FINDINGS

IR 05000416/2006-008; January 30 through March 10, 2006; Grand Gulf Nuclear Station: baseline inspection, NRC Inspection Procedure 71111.21, *Component Design Basis Inspection*.

The report covers an announced inspection by a team of seven regional inspectors and two contractors. Two findings of very low safety significance were identified. The significance of most findings is indicated by its color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, *Significance Determination Process (SDP)*. Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, *Reactor Oversight Process*, Revision 3, dated July 2000.

A. NRC-Identified and Self Revealing Findings

Cornerstone: Mitigating Systems

- Green. The team identified a finding of very low safety significance involving a noncited violation of 10 CFR Part 50, Appendix B, Criterion XI, *Test Control*, for the failure to implement a testing program to demonstrate the ability of standby service water-cooled heat exchangers to perform their design basis functions under all conditions.

  The finding is greater than minor because, if left uncorrected, it would lead to a more significant issue, namely a heat exchanger would become unable to fulfill its safety function due to excessive fouling accumulating during the time between testing. This finding has cross-cutting aspects because it is more than minor, it represents current performance, and the cause is directly associated with the problem identification and resolution attribute of evaluation of test data

  Using the NRC Inspection Manual Chapter 0609, *Significance Determination Process*, Phase 1 Screening Worksheet, the team determined this finding to be of very low safety significance (Green) since it was associated with the equipment performance attribute of the mitigating systems cornerstone and was a design or qualification deficiency that did not result in a loss of function in accordance with NRC Inspection Manual Part 9900, *Operable/Operability: Ensuring the Functional Capability of a System or Component*, (formerly Generic Letter 91-18, *Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability*).

  Because the finding is of very low safety significance (Green) and has been entered into the licensee personnel's corrective action program as Condition Reports 2006-00834, 2006-00852, 2006-00864, 2006-00952, 2006-00959, and 2006-00960, this violation is being treated as a noncited violation, consistent with Section VI.A.1 of the Enforcement Policy: NCV 05000382/2006008-01, *Inadequate Test Control Program for Standby Service Water-Cooled Heat Exchangers*. (Section 1R21b.1.)

- <u>Green</u>. The team identified a finding of very low safety significance for a noncited violation of 10 CFR Part 50, Appendix B, Criterion III, *Design Control*, for the failure to translate all design basis information into specifications and procedures were not adequate to assure that instrument uncertainties were correctly accounted for in the development of Technical Specification values or in the surveillance test acceptance criteria.

  The team determined this finding to be greater than minor because, similar to an example in MC 0612, *Power Reactor Inspection Reports*, Appendix E, *Examples of Minor Issues*, the failure of licensee personnel to demonstrate where, and how, instrument uncertainties were translated into either Technical Specification values or the surveillance test acceptance criteria could result in systems and/or components not being capable of performing design basis functions. This finding has cross-cutting aspects because it is more than minor, the failure to correct a previously identified adverse condition is an ongoing performance deficiency, and the cause (i.e., not understanding how to address instrument uncertainties) is directly associated with the problem identification and resolution attribute of corrective actions.

  The finding affected the procedure quality attribute of the mitigating systems cornerstone. Using the Manual Chapter 0609 Phase 1 Worksheet, the team determined that this finding had very low safety significance (Green) because there was no loss of operability or safety function and it did not involve an external event.

  Because the finding is of very low safety significance (Green) and has been entered into the licensee's corrective action program as Condition Report 2006-01191, this violation is being treated as a noncited violation, consistent with Section VI.A.1 of the Enforcement Policy: NCV 05000382/2006008-02, *Failure to Translate Design Basis Information into Specifications and Procedures*. (Section 1R21b.2.)

REPORT DETAILS

1 REACTOR SAFETY

Inspection of component design bases verifies the initial design and subsequent modifications and provides monitoring of the capability of the selected components and operator actions to perform their design bases functions. As plants age, their design bases may be difficult to determine and an important design feature may be altered or disabled during a modification. The plant risk assessment model assumes the capability of safety systems and components to perform their intended safety function successfully. This inspectable area verifies aspects of the Initiating Events, Mitigating Systems and Barrier Integrity cornerstones for which there are no indicators to measure performance.

1R21 Component Design Bases Inspection (71111.21)

The team selected risk-significant components and operator actions for review using information contained in the licensee's probabilistic risk assessment. In general this included components and operator actions that had a risk achievement worth factor greater than two or Birnbaum value greater than 1E-6.

a. Inspection Scope

To verify that the selected components would function as required, the team reviewed design basis assumptions, calculations, and procedures. In some instances, the team performed independent calculations to verify the appropriateness of the licensee engineers' analysis methods. The team also verified that the condition of the components was consistent with the design bases and that the tested capabilities met the required criteria.

The team reviewed maintenance work records, corrective action documents, and industry operating experience information to verify that licensee personnel considered degraded conditions and their impact on the components. For the review of operator actions, the team observed operators during simulator scenarios associated with the selected components, as well as observing simulated actions in the plant.

The team performed a margin assessment and detailed review of the selected risk-significant components to verify that the design bases have been correctly implemented and maintained. This design margin assessment considered original design issues, margin reductions due to modification, or margin reductions identified as a result of material condition issues. Equipment reliability issues were also considered in the selection of components for detailed review. These included items such as failed performance test results; significant corrective actions; repeated maintenance; 10 CFR 50.65(a)1 status; operable, but degraded, conditions; NRC resident inspector input of problem equipment; system health reports; industry operating experience; and licensee problem equipment lists. Consideration was also given to the uniqueness and complexity of the design, operating experience, and the available defense in depth margins.

The inspection procedure requires a review of 15-20 risk-significant and low design margin components, three to five relatively high-risk operator actions, and four to six operating experience issues. The sample selection for this inspection was 17 components, five operator actions, and six operating experience items.

The components selected for review were:

- Automatic depressurization system safety-relief valve
- Condensate storage tank level indication
- Division 1 125Vdc battery
- Division 1 emergency diesel generator load capability
- Division 1 emergency load sequencer
- Division 3 emergency diesel generator ventilation fan/cooler
- Emergency diesel generator jacket water temperature controller
- Emergency diesel generator lubricating oil filter
- High pressure core spray pump room cooler
- High pressure core spray pump
- Low pressure core spray pump
- Reactor core isolation cooling pump
- Residual heat removal/low pressure core injection pump
- Standby liquid control system relief valve
- Standby service water cooling tower siphon pipe
- Secondary Containment Isolation Valve M41-F037
- Instrument Air Secondary Containment Isolation Valve P53-F026B

The selected operator actions were:

- Alternate boration for the Standby Liquid Control system
- Cross-tie of the Division 3 electrical bus with the Division 1 electrical bus
- Reset of the reactor core isolation cooling trip/throttle valve
- Restoration of the instrument air system
- Restoration of the standby service water system

The operating experience issues were:

- Alternate boration during an anticipated transient without a scram

- Component cooling water butterfly valves

- Demonstration of accountability for uncertainties in the establishment of acceptance criteria

- Double acting air operated valves, as identified in a Grand Gulf Nuclear Generating Station operator workaround condition

- Reactor core isolation cooling trip throttle valve

- Reactor recirculation system optical isolators

b. <u>Findings</u>

b.1. <u>Inadequate Test Control Program for Standby Service Water-Cooled Heat Exchangers</u>

Introduction. A violation of very low safety significance (Green) was identified for failure to properly demonstrate the Division I, II, and III emergency diesel generators' jacket water heat exchangers, and the high pressure core spray pump room cooler were able to remove their design heat loads under all conditions.

Description. In their response to Generic Letter 89-13, *Service Water System Problems Affecting Safety-Related Equipment*, licensee personnel committed to a testing and trending program for their standby service water-cooled heat exchangers. Specifically, they responded that an 18-month testing frequency would be established for at least three cycles and any extensions of the testing frequency would be based on an appropriate trend in the data.

The team noted that testing of the standby service water-cooled heat exchangers began in 1990. The team looked specifically at five of these heat exchangers, namely the Division I and Division II diesel generator jacket water cooling heat exchangers, both of the Division III jacket water cooling heat exchangers, and the high pressure core spray room cooler. The Division I and II jacket water heat exchangers are identical. The Division III diesel generator has two identical jacket water cooling heat exchangers that are much smaller than their Division I and II counterparts. The Division III diesel generator serves only the high pressure core spray system loads and has a smaller load rating and thus a smaller jacket water cooling requirement than Divisions I and II. The high pressure core spray system room cooler is an air-to-water heat exchanger that ensures the high pressure core spray pump will fulfill its safety function by keeping the room temperature below design limits.

The Division I, II, and III jacket water heat exchangers were tested about every 18 months, using the same methodology, from 1990 until 2000. In 2000, a new testing methodology was adopted using more accurate temperature instruments to improve the test data.

In 2002, licensee engineers extended the testing frequency for these heat exchangers to 4 years from their previous 18-month cycle. The team concluded that, although the initial testing frequency remained in place for 12 years before it was extended, licensee personnel were unable to establish an adequate trend in that time. This conclusion was based, in part, on the use of an average of the calculated heat removal capacity from the previous tests (including invalid data) and also on the fact that the data scatter was too large to establish a meaningful trend (see Tables 1, 2, 3, and 4).

The team learned that the licensee engineers based their decision to extend the time period between tests on the average being greater than 100 percent for each heat exchanger. The team found the use of the average heat removal capacity values was not supported by good engineering judgement. The team found no attempt by licensee engineers to trend the data at any time during their testing of these heat exchangers.

The team noted that the first test of the Division I jacket water heat exchanger should have been classified as a failure (Table 1) and corrective actions should have been taken. However, licensee engineers did not consider the test a failure and took no corrective actions. Even though there were no corrective actions, the fouling factor improved from 1993 to 1997. Without a cleaning performed on the heat exchanger the team did not expect such an improvement in heat removal capacity. Results showed a relatively stable heat removal capacity of around 110 percent for tests from 1998 to 2000. In 2004 the capacity decreased to 102 percent.

The team performed independent analysis on the data in Table 1 and concluded that the heat removal capacity would decrease below the 100 percent value anywhere from January 2005 to February 2006. The Division I heat exchanger has never been cleaned. A cleaning is currently planned in May 2006.

Table 1

Division I Jacket Water Heat Exchanger
Performance Testing Results
(Data taken from ER-GG-2002-0058, Revision 0)

Test Date	Fouling Factor	Projected Heat Transfer Rate (BTU/hr)	Design Required Heat Transfer Rate (BTU/hr)	Percent Design Capacity
09/25/1992	0.000258	1.086E+07	1.930E+07	56.27%
10/18/1993	0.000840	2.620E+07	1.930E+07	135.75%
04/17/1995	0.001900	2.807E+07	1.930E+07	145.43%
03/12/1997	0.000852	2.919E+07	1.930E+07	151.24%
10/20/1998	0.002400	2.142E+07	1.930E+07	110.98%
05/2/2000	0.002500	2.151E+07	1.930E+07	111.45%
			Average =	118.52%
02/16/2004	0.002980	1.969E+07	1.930E+07	102.0%

The team noted that the results for the Division II jacket water heat exchanger test data also showed a failure in 1993 without any corrective actions taken by licensee personnel. From 1995 through 2001, the team saw that there was a steady decline in the heat removal capacity with a relatively constant fouling factor. The last test, performed in 2001, indicated the heat exchanger at 110 percent of design heat removal capacity. The team observed that the licensee personnel did not test the Division II jacket water heat exchanger within the 4-year period established in 2002.

As a result of fouling discovered in Division III (Table 4, 6/5/2005), the Division II heat exchanger was cleaned in February 2006; no test data was taken before the cleaning. This eliminated all trend information since the 2001 test. The heat exchanger was tested immediately after the cleaning as a re-baseline. However, licensee personnel were not successful in measuring accurate temperatures; which resulted in an invalid test. A combination of a freshly cleaned heat exchanger, a temperature sensitive three-way jacket water valve, and low standby service water temperature due to outside ambient air temperatures in February, resulted in insufficient jacket water flow through the heat exchanger. Low jacket water flow resulted in low heat transfer due to a laminar flow regime and inaccurate temperature readings which led to the invalidated test.

The last successful test of Division II was the 2001 test. A new test is planned for May 2006.

Table 2

Division II Jacket Water Heat Exchanger
Performance Testing Results
(Data taken from ER-GG-2002-0058, Revision 0)

Test Date	Fouling Factor	Projected Heat Transfer Rate (BTU/hr)	Design Required Heat Transfer Rate (BTU/hr)	Percent Design Capacity
04/14/1993	0.002970	2.333E+07	1.930E+07	120.88%
11/11/1993	0.002630	1.074E+07	1.930E+07	55.65%
04/15/1995	0.002460	2.547E+07	1.930E+07	131.99%
01/8/1997	0.002830	2.404E+07	1.930E+07	124.54%
08/18/1998	0.002550	2.287E+07	1.930E+07	118.50%
07/17/2001	0.002430	2.136E+07	1.930E+07	110.67%
			Average =	110.37%
02/24/2006	Invalid	Invalid	Invalid	Invalid

The team noted that the Division III ‘A’ and ‘B’ jacket water heat exchangers have exhibited the most service water side fouling. This was expected because of the smaller size of the heat exchangers.

In June of 2005, licensee personnel tested the ‘A’ heat exchanger (Table 3). The team noted that the fouling factor was greater than design and that the calculated heat removal capacity was just 100.8 percent of design. At the same time, the ‘B’ heat exchanger (Table 4) was tested. It also showed greater than design fouling with only an 83.5 percent calculated heat removal capacity.

Licensee personnel performed an operability analysis to determine the status of the Division III emergency diesel generator. The licensee personnel concluded that the component was “operable but degraded.” On that basis, licensee management deferred cleaning until December 2005. The team found no issues with the operability analysis.

As a result of the fouling removed from the Division III jacket water heat exchangers in December 2005, licensee management scheduled cleaning and inspection of the other divisions during their next scheduled outage.

Table 3

Division III ‘A’ Jacket Water Heat Exchanger
Performance Testing Results
(Data taken from ER-GG-2002-0058, Revision 0)

Test Date	Fouling Factor	Projected Heat Transfer Rate (BTU/hr)	Design Required Heat Transfer Rate (BTU/hr)	Percent Design Capacity
08/30/1991	0.00098	N/A	5.120E+06	N/A
09/25/1992	0.00097	5.060E+06	5.120E+06	98.83%
04/14/1993	0.00042	8.280E+06	5.120E+06	161.72%
04/24/1995	0.00134	6.522E+06	5.120E+06	127.37%
11/3/1996	0.00108	6.611E+06	5.120E+06	129.12%
03/21/1997	0.00146	6.402E+06	5.120E+06	125.05%
05/2/1998	0.0013	6.562E+06	5.120E+06	128.17%
01/18/2001	0.0017	5.690E+06	5.120E+06	111.13%
			Average =	125.97%

Table 3

Division III ‘A’ Jacket Water Heat Exchanger
Performance Testing Results
(Data taken from ER-GG-2002-0058, Revision 0)

Test Date	Fouling Factor	Projected Heat Transfer Rate (BTU/hr)	Design Required Heat Transfer Rate (BTU/hr)	Percent Design Capacity
06/3/2005	0.00218	5.160E+06	5.120E+06	100.8%
12/16/2005	0.00134	6.093E+06	5.120E+06	119.0%

Table 4

Division III ‘B’ Jacket Water Heat Exchanger
Performance Testing Results
(Data taken from ER-GG-2002-0058, Revision 0)

Test Date	Fouling Factor	Projected Heat Transfer Rate (BTU/hr)	Design Required Heat Transfer Rate (BTU/hr)	Percent Design Capacity
8/30/1991	0.00138	N/A	5.120E+06	N/A
4/24/1995	0.00173	5.763E+06	5.120E+06	112.56%
3/21/1997	0.00196	5.530E+06	5.120E+06	108.01%
5/2/1998	0.00160	5.942E+06	5.120E+06	116.05%
1/18/2001	0.00170	6.640E+06	5.120E+06	110.16%
			Average =	111.69%
6/3/2005	0.00277	4.275E+06	5.120E+06	**83.5%***
12/16/2005	0.00139	5.998E+06	5.120E+06	117.1%

*Identified as a test failure

The team noted that, in response to Generic Letter 89-13, *Service Water System Problems Affecting Safety-Related Equipment*, licensee personnel committed to calculate the air flow rate through their high pressure core spray room cooler. This was to be done by measuring various inlet and outlet temperatures and fluid flow rates. The team observed that licensee engineers met this commitment for the testing performed prior to January 2004. In January 2004, during a test of the high pressure core spray room cooler, licensee personnel measured air flow and used the measurement to calculate the standby service water inlet temperature. This was a change in the commitment provided to the NRC.

Licensee personnel extended the period between tests for the high pressure core spray room cooler to 4 years in 2002 despite the fact that the test performed in 2000 showed a fouling factor greater than the design allowable and no cleaning had been performed.

As with the jacket water heat exchangers, the team found that licensee engineers did not question improved heat removal capacities with an increased fouling factor. Neither did the licensee engineers question improved fouling factors without having performed any cleaning of the heat exchangers.

Analysis. The team determined that the failure to properly control heat exchanger testing constituted a performance deficiency. Generic letter responses constitute a commitment to the NRC and the failure to comply with that commitment usually results in a deviation. In this case; however, Generic Letter 89-13 described a program acceptable to the NRC that would properly ensure 10 CFR Part 50, Appendix A, General Design Criteria 44, 45, and 46 are being met. The program may either be the one outlined in Enclosure 1 of Generic Letter 89-13, or an equally acceptable alternative.

Licensee engineers chose the program outlined in Enclosure 1, of Generic Letter 89-13, that required testing and trending of the performance of these heat exchangers. The engineers failed to adequately demonstrate that these heat exchangers remained operable between tests because the testing data was never trended. Without trend information, the team found that the licensee engineers had no ability to predict when performance would drop below design basis requirements. This was, in fact, what happened when the Division III diesel generator ‘B’ jacket water heat exchanger failed its performance testing in June 2005.

The team determined this finding to be greater than minor because if left uncorrected it would lead to a more significant issue, namely a heat exchanger that becomes unable to fulfill its safety function due to excessive fouling accumulating in the time between testing. This finding has cross-cutting aspects because it is more than minor, it represents current performance, and the cause is directly associated with the problem identification and resolution attribute of evaluation of test data.

Using the NRC Inspection Manual Chapter 0609, *Significance Determination Process*, Phase 1 Screening Worksheet, the team determined this finding to be of very low safety significance (Green) since it was associated with the equipment performance attribute of the mitigating systems cornerstone and was a design or qualification deficiency that did not result in a loss of function in accordance with NRC Inspection Manual Part 9900, *Operable/Operability: Ensuring the Functional Capability of a System or Component* (formerly Generic Letter 91-18, *Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability*).

Enforcement. 10 CFR Part 50, Appendix B, Criterion XI, *Test Control*, states, in part, that a test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed.

Contrary to the above, as of March 10, 2006, the program established to test the standby service water-cooled heat exchangers failed to demonstrate the capability of the heat exchangers to perform their design functions under all conditions. Specifically, the program did not include any requirements for evaluating inconsistent data (i.e., improved performance without cleaning, data scatter, etc.). The program also did not address trending and assessing the performance to support the testing period and predict when corrective actions would be necessary to ensure continued capability of the heat exchangers to perform their design functions.

Because the finding is of very low safety significance (Green) and has been entered into the licensee's corrective action program as Condition Reports 2006-00834, 2006-00852, 2006-00864, 2006-00952, 2006-00959, and 2006-00960, this violation is being treated as a noncited violation, consistent with Section VI.A.1 of the Enforcement Policy: NCV 05000382/2006008-01, *Inadequate Test Control Program for Standby Service Water-Cooled Heat Exchangers*.

b.2. Failure to Translate Design Basis Information into Specifications and Procedures

Introduction. A violation of very low safety significance (Green) was identified for the failure to demonstrate that the acceptance criteria for surveillance tests had appropriately accounted for uncertainties.

Description. During review of Calculation MC-Q1111-84016, *ECCS Pump Surveillance Criteria*, Revision 3, the team noted that licensee engineers had not accounted for all uncertainties associated with the high pressure core spray pump. Additionally, the team noted that the engineer had incorrectly included a biased value when calculating the square root of the sum of the squares for those uncertainties that were accounted for. The team also found that uncertainties were not included in the acceptance criterion for the reactor core isolation cooling pump flow surveillance test.

For the high pressure core spray pump criterion, the team found that, while not accurately included in the calculation, the Technical Specification required flow included sufficient margin to implicitly account for uncertainties. Therefore, Calculation MC-Q1111-84016 was not required to support an indicated value greater than that in the surveillance requirement. However, the team found that neither the criterion provided in the Technical Specification nor the surveillance test for the reactor core isolation cooling pump accounted for any uncertainties.

The issue of accounting for uncertainties was first addressed with Entergy Operations, Inc. (Entergy), during an architect engineering inspection documented in NRC Inspection Report 50-382/98-201 as Unresolved Item 50-382/98201-18. This item was specifically related to the accounting of uncertainties for instruments used to perform in-service testing of pumps and was closed in NRC Inspection Report 50-382/99-06. However, another unresolved item (50-382/9906-04) was opened to evaluate the accounting for total loop uncertainties when demonstrating the operability of safety-related pumps. This unresolved item was subsequently closed in NRC Inspection Report 50-382/00-01 (ADAMS Accession ML003697828) on the basis of the Waterford engineer's ability to demonstrated adequate margin for the affected components.

A meeting was held on December 2, 1999, with representatives of Entergy to discuss how the organization accounted for uncertainties (ADAMS Accession ML003694170). During the meeting, Entergy officials agreed that the uncertainties must be addressed in either the technical specification value or the surveillance test acceptance criteria. The manner of how the uncertainties were addressed was discussed in detail.

As a result of the meeting, the NRC found Entergy's methodology of a graded approach to be acceptable. This approach allowed for the use of "implicit" and "explicit" methods, as well as a range of detail in the documentation of the accounting for the margins. Explicit methods require the use of calculations and formal evaluation to demonstrate that there is sufficient margin in either the Technical Specification value or the surveillance test procedure acceptance criteria. This method is most straight forward.

Implicit methods utilize more judgement than detailed analyses. For example, at Grand Gulf, the Technical Specification for high pressure core spray flow is 7115 gpm, and the accident analysis uses 6300 gpm to evaluate the accident response. This provides an implied margin of 815 gpm in the Technical Specification value. Using the implicit method would allow a surveillance test acceptance criteria of 7115 gpm without further consideration of uncertainties.

Conversely, if the Technical Specification value did not have any uncertainties built into it, the surveillance test would then need them accounted for in the acceptance criteria. For example, the Technical Specification for the reactor core isolation cooling pump flow is 800 gpm. There was no consideration of uncertainties in the establishment of this value. Therefore, the surveillance test acceptance criteria would need to include the uncertainties in order to assure that the Technical Specification was satisfied and demonstrate that the pump was operable. The team noted that the actual values attained during the surveillance tests were approximately 830 gpm, which was greater than the estimated uncertainties.

The team noted that engineering personnel at Grand Gulf began a program to address the issue of accounting for uncertainties, but abandoned it before completion. While the work was still in draft form, the team reviewed the effort for the reactor core isolation cooling pump flow and found that the engineers did not understand the issue. The engineers incorrectly concluded that, while there was no explicit demonstration that uncertainties were included in the establishment of the Technical Specification limit, there was no need to include uncertainties in the surveillance test acceptance criteria. This demonstrated a misunderstanding of the application of uncertainties to assure the demonstration of operability.

<u>Analysis</u>. The team found that the failure to translate design information (i.e., instrument uncertainties) into specifications and procedures was a performance deficiency.

The team determined this finding to be greater than minor because, similar to an example in MC 0612, *Power Reactor Inspection Reports*, Appendix E, *Examples of Minor Issues*, the failure of licensee personnel to demonstrate where, and how, instrument uncertainties were translated into either Technical Specification values or the surveillance test acceptance criteria could result in systems and/or components not being capable of performing its design basis functions. This finding has cross-cutting aspects because it is more than minor, the failure to correct a previously identified adverse condition is an ongoing performance deficiency, and the cause (i.e., not understanding how to address instrument uncertainties) is directly associated with the problem identification and resolution attribute of corrective actions.

The finding affected the procedure quality attribute of the mitigating systems cornerstone. Using the Manual Chapter 0609 Phase 1 Worksheet, the team determined that this finding had very low safety significance (Green) because there was no loss of operability or safety function and it did not involve an external event.

<u>Enforcement</u>. 10 CFR Part 50, Appendix B, Criterion III, *Design Control*, states, in part, that measures shall be established to assure that design basis are correctly translated into specifications and procedures.

Contrary to the above, the measures established by licensee personnel to translate design basis information into specifications and procedures were not adequate, as of March 10, 2006, to assure that instrument uncertainties were correctly accounted for in the development of Technical Specification values or in the surveillance test acceptance criteria. Specifically, licensee engineers did not include instrument uncertainties in the development of the Technical Specification for the reactor core isolation cooling pump flow (800 gpm) and established an acceptance criteria of 800 gpm for the demonstration of operability.

Because the finding is of very low safety significance (Green) and has been entered into the licensee's corrective action program as Condition Report 2006-01191, this violation is being treated as a noncited violation, consistent with Section VI.A.1 of the Enforcement Policy: NCV 05000382/2006008-02, *Failure to Translate Design Basis Information into Specifications and Procedures*.

4. OTHER ACTIVITIES

4OA6 <u>Meetings, Including Exit</u>

On March 27, 2006, the team leader presented the inspection results, via telephone, to Mr. D. Wiles, Director, Engineering, and other members of the Grand Gulf Nuclear Station's staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during this inspection

ATTACHMENT

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

D. Franklin, Engineering Supervisor, Programs and Components
D. Wilson, Engineering Supervisor, Design Engineering
W. White, Manager, Programs and Components
D. Wiles, Director, Engineering
C. Bottemiller, Manager, Licensing
D. Coulter, Senior Licensing Specialist, Licensing
E. Harris, Manager, Nuclear Safety Assurance Corrective Action and Assessment
W. Brian, General Manager, Plant Operations
M. Krupa, Director, Nuclear Safety Assurance Corrective Action and Assessment
T. Thornton, Manager (Acting), Design Engineering

NRC personnel

A. Barrett, Resident Inspector, Grand Gulf
R. Bywater, Senior Reactor Analyst, Region IV
G. Miller, Senior Resident Inspector, Grand Gulf
G. Replogle, Senior Reactor Inspector, Engineering Branch 1

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

05000382/2006008-01	NCV	Inadequate Test Control Program for Standby Service Water-Cooled Heat Exchangers (Section 1R21b.1.).
05000382/2006008-02	NCV	Failure to Translate Design Basis Information into Specifications and Procedures (Section 1R21b.2.).

LIST OF DOCUMENTS REVIEWED

Calculations:

NUMBER	TITLE	REVISION
1.1.5-3-Q	ECCS Pumps NPSH, supplement 1	0

Calculations:

NUMBER	TITLE	REVISION
1X77PT01	X77 Diesel Generator Building Ventilation	January 28, 1982
21A9520AB	Fuel Pool Cooling and Cleanup System, Purchase Specification Data Sheet, Heat Exchanger	7
22A2747	System Design Criteria, Fuel Pool Cooling & Cleanup and FPCCU, SDC-G41/G46	1
22A7419	System Design Criteria SDC-C41-4010 Standby Liquid Control System Criteria	3
3.8.35	HPCS D.G. Room-Heating and Ventilating	0
CC-Q1M24-97019	ECCS Suction Piping Load Determination	0
DCA No. NPE-4-112	ECCS Pumps NPSH Calculation	0
DRN 04-571	Design of Pipe Support Q1P41G010R03	0
E-DCP82/5020-1	Transient Loading on DG During Load Sequencing	A
EC-Q1111-90028	AC Electrical Power System Calculation	0
EC-Q1E12-87015	Water Infiltration into Valve Motor on E12 F009	0
EC-Q1L21-90026	125 V DC Div. I & II Batteries Short Circuit Evaluation	2
EC-Q1L21-90032	Sizing of 125 V Div. I Battery & Chargers	2
EC-Q1L21-91016	Division I 125 V DC Class 1E Coordination Study	3
EC-Q1L21-91033	Div. I 125 V DC Class 1E Voltage Drop Study	3
EC-Q1L21-91034	Voltage Drop Calc. for MNCR 251-90	0
EE 00018619	Procurement Engineering Evaluation, 1/4 amp 600V fast action fuse.	July 21, 2005

Calculations:

NUMBER	TITLE	REVISION
ER-GG-2001-0158	Standby Liquid Control Pump Discharge Pulsation Dampener Change.	0
ER-GG-2002-0467-000	Rib Replacement/ Rework and Torque Switch Modification to RHR Heat Exchanger Outlet Valve, E12F0003A/B	0
ERT-GG-2002-0467	RHR B Heat Exchanger Outlet Valve 1E12F003B Retest.	2
GEB-80/0223	RHR Valve Throttling Requirements.	August 4, 1980
GGNS-E-100.0	Environmental Specification Data Sheet, Accident Environment	5
GGNS98-0037	Spent Fuel Pool Decay Heat Removal Licensing Bases	1
GTC 2003-00053	RHR E12F0003A Retrofit	September 12, 2003
JC-Q1E22-N656-2	Instrument Loop Uncertainty and Setpoint Determination for the HPCS Pump Min Flow Bypass Valve Low Flow Interlock	1
JC-Q1E22-N654-1	Instrument Loop Uncertainty and Setpoint Determination for Loops 1E22-N654C&G HPCS Pump Suction Transfer on Low CST Level (TS 3.3.5.1)	2
JC-Q1E51-N635-1	Instrument Loop Uncertainty and Setpoint Determination for Loops 1E51-N635A&E RCIC Pump Suction Transfer on Low CST Level	0
JC-Q1E51-N654-1	Instrument Loop Uncertainty and Setpoint Determination for Loops 1E22-N654C&G HPCS Pump Suction Transfer on Low CST Level	2
M3.9.8	Standby Gas Treatment System Drawdown Time Calculation	3
MC-Q1111-84016	ECCS Pump Surveillance Criteria	3

Calculations:

NUMBER	TITLE	REVISION
MC-Q1P81-90188	Diesel Fuel Storage Requirements for the Division 3 Diesel Generator	2
MC-Q1P81-97034	Division 3 Engine Heat Rejection Rate	0
MC-Q1111-04003, App 680	Erosion/Corrosion Inspection Stage 1 Calc, 12" E12-020A	March 7, 2004
MC-Q1111-04003, App 681	Erosion/Corrosion Inspection Stage 1 Calc, 4" E12011C	February 19, 2004
MC-Q1111-05005, Sht 2	Erosion/Corrosion Inspection Program Stage I Evaluation of Q1E21-F011-A	0
MC-Q1111-84016	ECCS Pump Surveillance Criteria	3
MC-Q1E12-91149	RHR Design Pressure and Temperature	2
MC-Q1E22-00010	HPCS and RCIC System Performance with Regards to CST and Suppression Pool Suction for Level Transmitters E22N054C&G and E51N035A&E	0
MC-Q1M24-97016	Suppression Pool Heat Capacity Change Due to Installation of New ECCS Strainer.	0
MC-Q1M24-97017	RHP Heat Exchanger Thermal Effectiveness	0
MC-Q1P41-86007	Basin Volume Calculations	0
MC-Q1P41-90186	Determination of the Thermal Performance of Standby Service Water System Heat Exchanger.	0
MC-Q1P41-97036	Determination of Fuel Pool Cooling & Cleanup Heat Exchanger Capability	0
MC-Q1P75-90190	Diesel Fuel Storage Req. for Div. 1 and 2 Diesel Generators	2
MC–Q1M24-97014	ECCS Suppression Pool Suction Strainer Head Loss Evaluation	0

Calculations:

NUMBER	TITLE	REVISION
MS-39.0	Mechanical Standard	3
NSP41G014C05	Evaluation of Pipe Support NSP41G014C05	0
PC-Q1P53-02202	Calculation of the Maximum Expected Differential Pressure for Air Operated Valve 1P53F026B for the GGNS AOV Program	0
Q 1.1.1	Available NPSH for each RHR pump to see if the GE requirement are met.	E
XC-Q1111-98013	Suppression Pool pH Analysis.	3
XC-Q1G41-97007	Design Basis Spent Fuel Pool Decay Heat Load	3

Condition Reports:

1998-00733	2003-00765	2004-01020	2004-04042
1998-01442	2003-03692	2004-01061	2004-04306
1998-01473	2004-00074	2004-01062	2004-04373
1998-01474	2004-00163	2004-01110	2004-04419
1999-00024	2004-00198	2004-01304	2004-04468
1999-00249	2004-00284	2004-02092	2004-04484
1999-00433	2004-00293	2004-02218	2005-00073
1999-00481	2004-00404	2004-02344	2005-00138
1999-00567	2004-00458	2004-02387	2005-00260
2001-00158	2004-00508	2004-02435	2005-00263
2001-00407	2004-00606	2004-02523	2005-00554
2001-01103	2004-00626	2004-02642	2005-01270
2001-01260	2004-00633	2004-03047	2005-01568
2001-01752	2004-00647	2004-03085	2005-01832
2001-01933	2004-00649	2004-03104	2005-01854
2002-00112	2004-00668	2004-03151	2005-02208
2002-00285	2004-00675	2004-03162	2005-02449
2002-01108	2004-00679	2004-03163	2005-02843
2002-01385	2004-00699	2004-03167	2005-02848
2002-01920	2004-00700	2004-03168	2005-03207
2002-02041	2004-00750	2004-03350	2005-03289
2002-02059	2004-00777	2004-03454	2005-03406
2002-02083	2004-00786	2004-03497	2005-03552
2002-02277	2004-00879	2004-03906	2005-03975
2003-00253	2004-01003	2004-04033	2005-04095

2005-04185	2006-00140	2006-00852	2006-00946
2005-04274	2006-00188	2006-00864	2006-00959
2005-04663	2006-00255	2006-00895	2006-00963
2005-05062	2006-00712	2006-00897	2006-00969
2005-05405	2006-00796	2006-00908	2006-01191
2006-00088	2006-00834	2006-00921	

Drawings:

NUMBER	TITLE	REVISION
167A1970	Fuse (13/32 x 11/2, 600V) Standards	3
762E445	High Pressure Core Spray	7
768E584	Purchase Part – Safety Relief Valve, Nuclear Boiler System	3
865E292-002	Electrical Device List and Parts List	6
9645-M-102.0-Q 1P75A-A-1.1-1	Diesel Generator Fuel Oil Storage Tank	4
9645 M-242.0-1.2-61	Globe Valve, E12 F037A	3
9645 M-242.0-1.2-80	Gate Valve, E12 F018B	2
B209A6176	GE Meter Relay	4
E-0001	Main One Line Diagram	38
E-0300	Fuse Tabulation	25
E-1008	One Line Meter & Relay Dgm. 4.16 kV ESF System, 15AA & 16AB	20
E-1009	One Line Meter & Relay Dgm. 4.16 kV ESF System, 17AC Bus17	9
E-1017	One Line Meter & Relay Dgm. 480 V Bus 15BA1, 15BA2, 15BA3, 15BA4	11

Drawings:

NUMBER	TITLE	REVISION
E-1018	One Line Meter & Relay Dgm. 480 V Bus 16BB1, 16BB2, 16BB3, 16BB4	11
E-1019	One line Meter & Relay Dgm. 480 V Bus 15BA5, and 16BB5	9
E-1020	One Line Meter & Relay Dgm. 480 V Buses 15BA6 and 16BB6	7
E-1023	One Line Meter & Relay Dgm. 125 V Buses 11DA, 11DB & 11DC	33
E-1053	Jacket Water Cooler	15
E-1057-001	MCC Tabulation 480 V ESF MCC 15B41 Aux. Bldg.	27
E-1057-002	MCC Tabulation 480 V ESF MCC 15B41 Aux. Bldg.	20
E-1081-001	MCC Tabulation 480 V ESF MCC 15B11 Aux. Bldg.	36
E-1081-002	MCC Tabulation 480 V ESF MCC 15B11 Aux. Bldg.	35
E-1081-003	MCC Tabulation 480 V ESF MCC 15B11 Aux. Bldg.	10
E-1082-001	MCC Tabulation 480 V ESF MCC 15B31 Aux. Bldg.	42
E-1082-002	MCC Tabulation 480 V ESF MCC 15B31 Aux. Bldg.	34
E-1083-001	MCC Tabulation 480 V ESF MCC 15B21 Aux. Bldg.	36
E-1083-002	MCC Tabulation 480 V ESF MCC 15B21 Aux. Bldg.	37
E-1099-001	MCC Tabulation 480 V ESF MCC 15B42 Aux. Bldg.	31
E-1099-002	MCC Tabulation 480 V ESF MCC 15B11 Aux. Bldg.	16
E-1109-020	4.16 kV ESF System Diesel Generator Breaker 152-1508	15

Drawings:

NUMBER	TITLE	REVISION
E-1110-012	P75 Standby Diesel Generator System Div. I Train “A” Start & Stop Circuit	16
E-1169-012	C41 Standby Liquid Control System Power Distribution and Pressure Indicator Annunciator.	15
E-1169-014 Sh1, Sh2	C41 Standby Liquid Control System Pumps and Valves	8, 9
M-0007	General Arrangement Section A-A, Unit 1& 2.	7
M-1061A	P&I Diagram Standby Service Water Unit 1	60
M-1061B	P&I Diagram Standby Service Water Unit 1	47
M-1061C	P&I Diagram Standby Service Water Unit 1	36
M-1061D	P&I Diagram Standby Service Water Unit 1	38
M-1070B	Standby Diesel Generator System	34
M-1070D	Standby Diesel Generator System	15
M-1077E	P&I Diagram Nuclear Boiler System	2
M-1082	P&I Diagram Standby Liquid Control System, Unit 1	27
M-1085A, -B, -C, -D	P&I Diagram Residual Heat Removal System	67, 60, 16, 3
M-1086	P&I Diagram High Pressure Core Spray System	30
M-1348A	RHR “A” Pump Suction & Discharge Piping Isometric	23
M-1358P	Standby Service Water Siphon Line Isometric	1
M-1370	Standby Service Water Basin A Valve Room	3
M-242.0	Standard Spec. To Nuclear Service Valves 2-1/2 Inches & Larger, Safety Related	57

Drawings:

NUMBER	TITLE	REVISION
M-KA1318	Standby Service Water Basin “A” Pumphouse	A
PL 195B9851	GE Meter Relay Panel (195B9851)	March 2, 1987
SFD-1082	System Flow Diagram Standby Liquid Control System, Unit 1.	2
SFD-1085-001	System Flow Diagram Residual Heat Removal System.	4
T36620	Byron Jackson Pump Test data	2
VPF-3636-120-001	Schematic Diagram Jacket water System W/Heat Exchanger	6

Miscellaneous:

NUMBER	TITLE	REVISION / DATE
	Trend of Worst case Fouling of HPCS Pump Cooler 1T51B001	
05-0014	Double Acting Air-actuator Isolation Valves	October 14, 2005
07-S-07-211	General Maintenance Instruction – Service Level I Coatings Condition Assessment – Safety Related	0
07-S-14-421	General Maintenance Instruction – Main Steam Relief Valve Testing – Safety Related	1
2088-377	Jacket water Cooler Heat Exchanger Specification Sheet	May 30, 1974
21A9538	Purchase Specification – Safety Relief Valve	4
22A3131	HPCS System Design Spec	5
22A3131AC	High Pressure Core Spray System	11

Miscellaneous:

NUMBER	TITLE	REVISION / DATE
9645-M-611.0	HPCS Room Cooler (sheet 5)	6
9645-M-619.0	HPCS Diesel Generator Room Outside Air Fan (sheet 2) Data Sheet (sheet 2)	6
9645-E-019.1	125 V DC Batteries	6
9645-E-019.2	125 V DC Battery Chargers	9
9645-E-092.0	Load Shedding & Sequencing Panels	5
DRN-04-1215	Revision of SDC-P41, Standby Service Water	2
EAR MC-99-016	No Title	September 10, 1999
ER-GG-2002-005 8-000	Generic Letter 89-13 Thermal Performance Program Review	0
ER 97/0285-01	No Title	0
ER 97/0588-00	No Title	April 29, 1998
ER 97/0285-00	No Title	0
ER 1999-0311-00	No Title	April 13, 2000
FR-X-77-0018	Field Report for Testing Diesel Generator HVAC	April 27, 1982
GGNS-2000-0004	50.59 Evaluation (Appendix J, Type C Testing for Containment Isolation Valves)	0
GGNS-93-0002	Grand Gulf Nuclear Station Engineering Report for Evaluation of IN 91-56	0
GGNS-MS-39.0	Mechanical Standard for Thermal Performance Testing of safety Related Standby Service Water Heat Exchangers	4

Miscellaneous:

NUMBER	TITLE	REVISION / DATE
GL 97-04	Assurance of Sufficient Net Positive Suction Head for ECCS and Heat Removal Pumps	October 7, 1997
IN 01-06	Centrifugal Charging Pump Thrust Bearing damage not detected due to inadequate assessment of oil analysis results	May 11, 2001
IN 01-09	Main Feed water System Degradation in Safety Related ASME Code Class 2 Piping	June 12, 2001
IN 87-10	Potential for Water Hammer during Restart of Residual Heat Removal Pumps.	May 15, 1997
IN 89-01	Valve Body Erosion	January 4, 1989
LER 2005-003-00	Mode Change Contrary to Tech. Spec. LCO 3.0.4	December 19, 2005
Letter: Dale J. Kempainen (GE) to F. W. Titus (GG)	Transmittal of Selected Responses to Design Basis Questions of DCA-NPE-89-223 SGEJ 90/047	March 19, 1990
Letter W. T. Cottle to USNRC	Docket No. 50-416, License No. NPF-29, Response to Generic Letter 89-13; Service water System Problems Affecting Safety Related Equipment	January 29, 1990
LO-OPX-2003-00031	(IN 01-13) Response, RHR Relief Valve Pressure Setting	August 10, 2001
MAI 284107	Governor	October 5, 2000
NEDO-20566	General Electric Company Analytical Model for Loss of Coolant Analysis in accordance with 10CFR50 Appendix K – Volumes I and II	January 1976
SDC-E22	High Pressure Core Spray System	2

Miscellaneous:

NUMBER	TITLE	REVISION / DATE
SDC-P81	HPCS Diesel Generator System	1
SDC-X77	Update Tech Spec References with Corrected Improved Tech Spec Numbers and TRM Sections	0
SDC-T51	Update Tech Spec References with Corrected Improved Tech Spec Numbers and TRM Sections	0
SR-0667	Report of Minimum Flow Calculations for Unit No. 1 HPCS, RHR, and LPCS Pumps	December 22, 1989
Test No. 0591-1	Stationary Battery Short Circuit Test	June 13, 1991

Modifications:

NUMBER	TITLE	REVISION
DCP 84/5006	Design Change of Standby Service Water Siphon Line	1
DCP 91/0112	Replacement of Div. I (1A3) and II (1B3) Batteries	0
DCP 93/0050	Add Cell to Div. I (1A3) and II (1B3) Batteries	1
ER-GG-1999-0217-000	CST Level Transmitter Replacement	0
ER-GG-2003-0035-000	Carbon Steel Pipe Replacement for LPCS Pump Room Cooler	0
ER-GG-2003-0061-000	RF13 Contingency Modification-Replace piping associated with FAC Item 662-LPCS Min. Flow Line	0
ER-GG-2003-0138-000	Standby Service Water Pipe Repairs	0
ER-GG-2004-0116-000	RF14 Replacement of FAC Items 679 and 750	0
ER-GGN-2003-0131-000	Welded Plugs in Standby Service Water Piping Through-Pits	0

Modifications:

NUMBER	TITLE	REVISION
MCP 95/1049	Install Filter Assembly for Class 1E Battery Chargers	0
SCN-01/0002	Technical Specification for Replacement Standby Service Water Pumps	0
SCN-02/002	Mechanical Standard for Piping Class Sheets Change Notice	1
SCN-96-0001	Butterfly Valves 20" & Smaller – Nuclear Service Change Notice	28
TCN 01-S-02-3	Change to Main Steam Safety/Relief Valve Operability Test	111

Procedures:

NUMBER	TITLE	REVISION / DATE
	Grand Gulf Nuclear Station Strategic Plan for Open Loops	2
01-S-06-49	Control of Engineering Documents	6
01-S-06-51	Document Revision Notice (DRN)	2
01-S-06-52	Plant Operations Manual, Engineering Reviews	0
01-S-06-54	Plant Data Management System (PDMS)	0
04-1-01E12-1	System Operating Instruction RHR	127
04-1-01-E22-1	High Pressure Core Spray System	108
04-1-01-E51-1	Reactor Core Isolation Cooling	123
04-1-01-P41-1	Standby Service Water	123
04-1-01-P42-1	Component Cooling Water	44

Procedures:

NUMBER	TITLE	REVISION / DATE
04-1-01-P51-1	Plant Air	4
04-1-01-P53-1	Instrument Air	63
04-1-01-P81-1	High Pressure Core Spray Diesel Generator	59
04-1-02-1H13-P870-2A-F1	LPCS Pump Room Flooded	33
04-1-02-1H22-P400-1A-C9	Alarm Response Instructions	107
04-1-02-1H22-P401-1A-C9	Alarm Response Instructions	110
04-1-03-E12-1	Equipment Performance Instr, RHR Shutdown Cooling Mode, LPCI line A&B	4
05-S-01-EP-2	RPV Control	36
05-S-01-EP-3	Containment Control	26
05-S-01-EP-4	Auxiliary Building Control	25
05-1-02-I-4	Loss of AC Power	32
05-1-02-I-5	Automatic Isolations	38
05-1-02-V-9	Loss of Instrument Air	32
05-1-02-V-1	Loss of Component Cooling Water	18
05-1-02-1-4	Off Normal Event Procedure	32
05-1-02-V-11	Loss of Plant Service Water	26
06-CH-1000-V-0038, Attachment 1	Surveillance Procedure data Package – Diesel Fuel Oil Receipt Analysis	102
06-OP-1E22-C-0003	HPCS Testable Check Valve Test (Attachment II)	105

Procedures:

NUMBER	TITLE	REVISION / DATE
06-OP-1E22-Q-0005	HPCS Quarterly Functional Tests (from April 2, 2004 to November 8, 2005)	112
06-EL-1L11-R-0003-01	Battery 1A3 Service. Discharge Test	104
06-EL-1L21-0-0001-01	Battery 1A3 Performance Discharge Test	100, 102
06-ME-1E12-R-0001	Surveillance Procedure, Verification of RHR Pump Mini-flow Check Valves by NIT or Internal Inspection.	102
06-OP-1B21-Q-0011	MSIV Accumulator Check Valve Test	100
06-OP-1E12 Q-0023	Surveillance Procedure LPCI / RHR Subsystem A, Quarterly Function Test Safety Related	11
06-OP-1E21-Q-0001	LPCS Monthly Functional Test	100
06-OP-1P75-M-0001-01	Div. 1 Standby DG 11 Functional Test	122, 124, 125, 126
06-OP-1P75-M-0001-02	Div. 1 Standby DG 11 Functional Test	122, 124, 125, 126
06-OP-1P75-M-0001-03	Div. 1 Standby DG 11 Functional Test	122, 123, 124, 125
06-OP-1P75-M-0003-01	Div. 1 Standby DG 11 Functional Test	105
06-OP-1P75-M-0003-04	Div. 1 Standby DG 11 Functional Test	107
06-OP-1P75-M-0003-05	Div. 1 Standby DG 11 Functional Test	105
06-OP-1P75-R-0003	SDG 11 18 Month Functional Test	107
06-OP-1P75-R-0003-01	Div. 1 Standby DG 11 Functional Test	107
06-OP-1P75-R-0003-02	Div. 1 Standby DG 11 Functional Test	110
06-OP-1P75-R-0003-03	Div. 1 Standby DG 11 Functional Test	107

Procedures:

NUMBER	TITLE	REVISION / DATE
06-OP-1P75-R-0003-04	Div. 1 Standby DG 11 Functional Test	107, 110
06-S-01-SAP-1	Severe Accident Procedure	4
07-S-12-127	General Maintenance Instruction, Installation and Operation of VOTES Diagnostic Test Equipment	6
08-S-03-10	Chemistry Procedure – Chemistry Sampling Program – Safety Related	42
08-S-03-120	Chemistry Instruction – Chemistry Evolutions at Standby Service Water – Safety Related	11
17-S-03-16	Safety Related MOV Program	8
17-S-03-29, Attachment III	SSW "C" Thermal Performance Test (with test results and analysis dated January 24, 2006)	0
17-S-05-E22	System Pressure Test – HPCS System	4
17-S-05-15	Performance and System Engineering Instruction, Inservice Inspection.	4
21A9514	Purchase Specification, Pump RHR for BWR	August 5, 1976
272A8638	GE Isolator Application	3
EN-WM-100	Work Request (WR) Generation, Screening and Classification	0
EN-WM-101	On-line Work Management Process	0
ENS-DC-112	Engineering Request and Project Initiation Process	4
ENS-DC-315	Flow Accelerated Corrosion Program	1
ENS-LI-101	10CFR 50.59 Review Program	7

Procedures:

NUMBER	TITLE	REVISION / DATE
GE 22A3759AE	Ge Standard Specification	1
GEK-73506A	Isolator Card Description of Operation	January 1, 1984
GEK-73514A	High Level Output Isolation Card (204BF6188AAG1)	January 1, 1984
GEK-73687B	Standby Liquid Control System Operation and Maintenance Manual	B
GGNS-JS-09	Methodology for the Generation of Instrument Loop Uncertainty & Setpoint Calculations	1
GGNS M 489.1	Program Section for ASME Section XI, Div 1 Inservice Inspection Program.	13
GGNS- M 927.0	Technical Specification for ECCS Suction Strainer	3
GGNS-MS-39.0	General Procedure for Room Cooler Thermal Performance Evaluations	1
GGNS-MS-41	Program Plan for Monitoring Internal Erosion / Corrosion of Piping Components.	8
NPEAP 330	Nuclear Plant Engineering Applicability Review Requirements No. 330	15

Work Orders:

NUMBER	TITLE	DATE
00033928 01	52-15505 Circuit Bkr. Test	September 28, 2004
00033929 01	52-15506 Circuit Bkr. Test	September 30, 2004

Work Orders:

NUMBER	TITLE	DATE
00038745 01	52-15105 Test Closing Coil	September 7, 2004
00039242 01	152-1509 Test Charging Motor	November 24, 2004
00042928 01	Standby Service Water Siphon Functionality	38,097
00044309 01	Safety/Relief Valve Refurbishment	38,154
00044330 01	Safety/Relief Valve Recertification	38,410
00062613 01	Standby Service Water Pipe Vent Siphon Piping	38,425
00076678 01	Standby Service Water Pipe Vent Siphon Piping	38,665
00204152	52-15505 Circuit Bkr. Test	September 15, 1998
204,153	52-15506 Circuit Bkr. Test	March 28, 1998
3,927,901	152-1508 Ckt. Bkr. Test Closing Coil	November 24, 2004
50324861 01	152-1508 Ckt. Bkr. Test Closing Coil	July 8, 2003
50336965 01	Main Steam Safety Relief Valve Operability Test	January 7, 2004
50338600 01	1E51P013 Test Minimum Voltage	August 2, 2004
50983201 01	Automatic Depressurization System Safety Relief Valve Activities	38,295
MAI 253749	RHR Pump Motor 1E12C002A Ckt. Bkr. Test	May 5, 1999
MAI 271145	52-15505 Circuit Bkr. Test	January 11, 2000
MAI 271324	52-15506 Circuit Bkr. Test	June 15, 2000

Work Orders:

NUMBER	TITLE	DATE
MAI 274954	RCIC Inj. Shut Off MOV Ckt. Bkr. Test	April 4, 2000
MAI 275135	Q1E61C001A-A Circuit Breaker Test	March 22, 2000
MAI 275408	Div. I Gen. Set Bus 15AA Fdr. Bkr. Test	April 25, 2000
MAI 299591	52-15506 Circuit Bkr. Test	January 10, 2002
MAI 304882	52-15505 Circuit Bkr. Test	January 8, 2002
MAI 305688	RCIC Inj. Shut Off MOV Ckt. Bkr. Test	November 27, 2001
MAI 308482	Div. I Gen. Set Bus 15AA Fdr. Bkr. Test	July 23, 2002
MAI 311478	Removal and Replacement of Main Steam Safety Relief Valves	37,508
MAI 315294	Q1E61C001A-A Circuit Breaker Test	July 11, 2002
MAI 316476	RHR Pump Motor 1E12C002A Ckt. Bkr. Test	July 8, 2002
MAI 322780	52-15505 Circuit Bkr. Test	May 13, 2003
MAI 328341	RCIC Inj. Shut Off MOV Ckt. Bkr. Test	April 14, 2003
MAI 328523	Ultrasonic Thickness Examination Report	38,484
MAI 330064	52-15506 Circuit Bkr. Test	May 15, 2003
MAI 331132	Q1E61C001A-A Circuit Breaker Test	June 11, 2003
MAI 331133	Q1E61C001A-A Circuit Breaker Test	May 1, 2003