



UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

January 31, 1994

Docket Nos. 50-334
and 50-412

Mr. J. D. Sieber, Senior Vice President
and Chief Nuclear Officer
Nuclear Power Division
Duquesne Light Company
Post Office Box 4
Shippingport, Pennsylvania 15077-0004

Dear Mr. Sieber:

SUBJECT: SPECIAL AUDIT OF CONTROL PROCESSES FOR COMMITMENTS THAT AFFECT THE
CURRENT LICENSING BASIS, BEAVER VALLEY POWER STATION
(TAC NO. M86422)

This letter provides the results of the commitment management audit conducted by the Office of Nuclear Reactor Regulation at the Beaver Valley Power Station June 7 through 11, 1993. As you are aware, the staff is conducting audits at a cross-section of reactor plants to assess the processes used by licensees for controlling commitments that affect the plant's current licensing basis. The staff will use the information gathered during the audits to evaluate the regulatory process in this area. Beaver Valley was the sixth site visited by the staff, and our audit report is enclosed.

The audit team focused on three principal areas: (1) management of commitments made to the U.S. Nuclear Regulatory Commission (NRC), (2) reporting of changes to commitments made to the NRC, and (3) maintaining and updating the final safety analysis report (FSAR). In addition to reviewing the governing programs for these areas, the team reviewed the status of commitments made to the NRC in response to specific issues (selected generic letters, bulletins, licensee event reports, and notices of violation) in order to examine the programs in actual practice.

Overall, the team found that commitments affecting the plant's licensing basis were being implemented and maintained. The team did not identify any examples in which a commitment was not implemented, or any examples in which a commitment was inadvertently altered or deleted after implementation. However, the team did identify a number of programmatic weaknesses with regard to commitment management at Beaver Valley and found that site management relied greatly on the memory and experience of the plant staff to ensure commitments were not altered or deleted after implementation. The team noted that just prior to its arrival onsite, the resident inspector found that commitments for functional testing of certain Unit 2 anticipated transient without scram mitigation scram actuation circuitry (AMSAC) time delays and setpoints had not been conducted since the original AMSAC installation in 1989. Although the safety significance of this oversight was partially mitigated by the satisfactory performance of the regularly scheduled Unit 2 AMSAC end-to-end testing, the NRC issued a Notice of Deviation to the Duquesne Light Company in regard to this issue on July 2, 1993.

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Mr. J. D. Sieber

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January 31, 1994

The team found that changes to commitments were evaluated on a case-by-case basis by the licensing and compliance group managers to determine if NRC notification was necessary. The team also found that the commitments it reviewed that affected the plant Updated Final Safety Analysis Report (UFSAR) were captured by the UFSAR update process, with the exception that the Unit 2 UFSAR had not been updated to include the AMSAC. The Unit 1 UFSAR had been updated to include the AMSAC in accordance with the plant's administrative controls. The team did not identify any items of significance in its review of commitments made in response to the specific issues.

We thank your staff for their candor in our discussions and your cooperation in providing the team the information necessary to conduct an efficient audit.

Sincerely,

Original signed by:
Gordon E. Edison, Senior Project Manager
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Office of Nuclear Reactor Regulation

Enclosure:
Audit Report

cc w/enclosure:
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We thank your staff for their candor in our discussions and your cooperation in providing the team the information necessary to conduct an efficient audit.

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Gordon E. Edison, Senior Project Manager
Division of Reactor Projects - I/II
Project Directorate I-3
Office of Nuclear Reactor Regulation

Enclosure:
Audit Report

cc w/enclosure:
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Duquesne Light Company

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COMMITMENT MANAGEMENT AUDIT OF THE
BEAVER VALLEY POWER STATION
JUNE 7-11, 1993

I. Scope and Participants

The purpose of the audit conducted at Beaver Valley was to assess the effectiveness of the licensee's programs for identifying and controlling commitments that affect the facility's current licensing basis. The audit focused on three principal areas: (1) management of commitments made to the U.S. Nuclear Regulatory Commission (NRC), (2) reporting of changes to commitments made to the NRC, and (3) maintaining and updating the final safety analysis report (FSAR). The team reviewed the licensee's administrative procedures involving commitment management; reporting; action tracking; control of design, configuration, test and experiments; and others. To examine the programs in actual practice, the team reviewed the status of commitments made by the licensee to the NRC in response to specific issues. Five of these issues, generic in nature, were the following:

10 CFR 50.62	Anticipated Transient Without Scram (ATWS)
Generic Letter 89-13	Service Water System Problems Affecting Safety-Related Equipment
Generic Letter 88-14	Instrument Air System Problems Affecting Safety-Related Equipment
Bulletin 85-01	Steam Binding of Auxiliary Feedwater Pumps
NUREG-0737, I.C.5	Procedures for Feedback of Operating Experience to Plant Staff

The remaining issues were specific to Beaver Valley, including licensee commitments made in licensee event reports (LERs) and responses to notices of violation (NOVs). The team also reviewed the licensee's design basis document program to determine how a commitment from the program would be captured in the commitment management process.

The team relied on standard NRC inspection practices in conducting the review of specific commitments. In conducting the audit, the team performed system walkdowns, reviewed applicable documentation (including design change packages, training records, and procedures), and interviewed plant staff. A detailed review for each issue specified above is contained in the appendix to this report.

The following NRC personnel participated in this audit:

James E. Beall, Team Leader
Steven A. Reynolds
Anthony J. D'Angelo
Deborah A. Jackson

II. Findings and Conclusions

The following are the team's findings and conclusions for the three major areas of focus: (1) commitment management, (2) reporting changes to commitments made to the NRC, and (3) maintaining and updating the FSAR.

Commitment Management: Overall, the team found that commitments affecting the plant's current licensing basis were being implemented and maintained. The team did not identify any examples in which a commitment was not implemented, or any examples in which a commitment was inadvertently altered or deleted after implementation. The team noted, however, that the licensee had no overall program for the management of commitments. Rather, it had several different systems, procedures, or programs, and each system handled one specific type of commitment. Not all commitments were captured by the licensee's systems. For example, commitments implemented before the licensee formally responded to the NRC were not entered into any system because no immediate, additional actions were necessary. This practice resulted in some commitments not being entered into any tracking system; therefore, future actions might result in the inadvertent modification or deletion of the commitments. The licensee relied greatly on the memory and experience of its technical staff to ensure commitments were not altered or deleted after they were implemented.

The team noted that just prior to its arrival on site, the resident inspector staff found that commitments for functional testing of certain Unit 2 ATWS mitigation scram actuation circuitry (AMSAC) time delays and setpoints had not been conducted since the original AMSAC installation in 1989. Although the safety significance of this oversight was partially mitigated by the satisfactory performance of the regularly scheduled Unit 2 AMSAC end-to-end testing, the NRC issued a Notice of Deviation to the Duquesne Light Company in regard to this issue on July 2, 1993. This item is discussed in more detail in the appendix to this report.

Reporting Changes to Commitments Made to the NRC: The team found that the licensee did not include in its procedures specific guidance for reporting changes to commitments to the NRC but rather relied on the judgment of its licensing and compliance managers for making such decisions. The team did not identify any instances in which it questioned the judgment of the licensee in the area of reporting changes to commitments made to the NRC. In general, the licensee did not modify commitments, and licensee senior managers stated that they felt obligated to notify the NRC of any change to a commitment. The team did not find any examples of commitments that were changed after implementation. The team reviewed several examples of licensee notifications of changes to commitments that were volunteered by the licensee at the request of the team, and found no deficiencies or problems.

Maintaining and Updating the Updated Final Safety Analysis Report (UFSAR): The commitments reviewed by the team that affected the plant UFSAR were captured by the UFSAR update process, with the notable exception that the Unit 2 UFSAR had not been updated to include the AMSAC. The Unit 1 UFSAR included a thorough description of the AMSAC. The licensee had administrative controls in place for making design changes and for updating the UFSAR. The procedure for the implementation and control of design changes directed the responsible engineer to perform a UFSAR review and to forward the necessary information to the UFSAR coordinator to implement a UFSAR change if needed. However, no procedural guidance delineated what constituted a UFSAR change or the level of detail that should be placed in the UFSAR when a new system was installed or an existing system was modified. The team reviewed plant modifications

involving the AMSAC, service water system, instrument air system, and other plant systems. With the exception of the Unit 2 AMSAC, the commitments that affected the UFSAR were captured in the UFSAR update process.

III. Discussion

A. Commitment Management

The licensee's controlling procedure for commitment management allowed each plant organization to independently manage the commitments that it was responsible for implementing. The licensing group maintained a computerized commitment tracking system (CTS) that tracked commitments documented in docketed, licensee-generated letters to the NRC. However, the CTS contained only entries that involved actions that were not complete at the time of entry. Commitments that had been completed before a letter or other response had been sent would not be entered into the CTS. Similarly, responses in which the licensee took credit for existing actions, procedures, and so forth, also would not be placed in the CTS. For example, if an NRC bulletin required that a quarterly action be performed, the licensee entered the action into the CTS if the item was not implemented before the licensee's response. The action would not be entered into the CTS if either the existing program already included the required action or the change had been implemented before the response letter was transmitted.

The CTS was not the only system used by the licensee's organizations to track commitments. The operations group used the open item resolution system to track items associated with LERs. However, not all LER items were entered into that system. An individual at Beaver Valley, who had been associated with LERs for many years was able to retrieve the information necessary for the team to perform the audit of LER-related commitments. The team found other examples of commitments tracked in different systems. Commitments associated with Generic Letter 89-13 were tracked as part of the licensee's heat exchanger semi-annual status report. Commitments identified as part of the licensee's Unit 1 design basis document program were tracked as open items under that same program. The plant staff may use additional tracking systems for other particular groups of commitments, but the preceding systems were those identified by the team. The team concluded that the licensee did not have an overall program for managing commitments. Instead, many licensee groups used their own systems to manage those commitments that were each group's responsibility and that were not yet complete.

The team found that the licensee seldom changed its commitments. The licensee had only recently (in the past year) instituted a systematic process to ensure that implemented procedural commitments would not be modified or deleted. There was no defined process for design modifications requiring the review of previous commitments. The team did not identify any examples in which a committed modification was inadvertently altered by a subsequent modification and attributed this to the experience level of the engineering organization and the multiple levels of review and approval required by the design change process.

The team did not identify any examples of missed, deleted, or modified commitments. The team considered this to be indicative of the experience and general conservatism of the licensee staff and management. Despite what

appeared to the team as potential weaknesses in the systems used at Beaver Valley for managing commitments, the team found that personnel at the site were able to identify the status of the commitments the licensee had made to the NRC. The team concluded that the systems in place relied greatly on the corporate memory and experience of licensee personnel in the management of commitments made to the NRC.

B. Reporting Changes to Commitments Made to the NRC

The team found that the licensee relied on the judgment of its managers for making the decision whether a change to a commitment should be reported to the NRC. The licensee did not include in its procedures specific guidance for reporting changes to commitments. It indicated that meeting commitment dates was very important and, therefore, the NRC would be formally notified of changes to commitment schedules via docketed correspondence. In general, the licensee did not modify commitments and licensee senior managers stated that they felt obligated to notify the NRC of any change to a commitment. The licensee relied on the expertise of its licensing and compliance managers to decide those issues that might be questionable regarding a commitment's intent.

If the decision was made to cancel a design change, the licensee's process contained a mechanism that alerted the licensing group that the design change was cancelled. This mechanism allowed the licensing group to formally report the change to the NRC. The team concluded that the licensee's program would result in notification to the NRC the change in the commitment once the licensee completed its processing of the cancelled design change.

The licensee provided the team with several examples where it notified the NRC of changes to previous commitments. The examples included (1) technical changes to heat exchanger testing methodology and (2) schedule changes for completing commitments. These examples indicated to the team that the licensee adequately managed and reported changes to identified and tracked commitments.

C. Changes Made to the Final Safety Analysis Report

The team found that the licensee had administrative controls for making design changes and updating the UFSAR. The UFSAR updates were controlled by Administrative Procedure 7.3, "Annual Final Safety Analysis Report Update," which defined the responsibilities and requirements for the preparation, review, approval, compilation, processing, and distribution of the changes to the UFSAR. The procedure gave instructions for revising the UFSAR section affected by a design change and for completing the associated forms in the administrative procedure to ensure the change was incorporated in the next revision of the UFSAR.

In addition to Administrative Procedure 7.3, UFSAR updates were addressed in Design Change Control Procedure NEAP 2.2, which established the responsibilities, requirements, and guidelines for implementing and controlling design changes at Beaver Valley. This procedure directed the engineer performing a design change to review the UFSAR and to forward the documentation needed to implement a UFSAR change, if needed, to the UFSAR

coordinator. However, no procedural guidance delineated what constituted a UFSAR change or the level of detail that should be placed in the UFSAR when a new system was installed or an existing system was modified.

The Unit 2 UFSAR did not contain a description of the AMSAC as installed. The Unit 1 UFSAR included a thorough system description of the AMSAC. The design change packages for installing the AMSAC at Unit 1 had indicated that an update to the UFSAR was necessary and provided the necessary information for the revision. The design change packages for the Unit 2 AMSAC did not indicate that a UFSAR update was necessary. However, the AMSAC was represented in the Unit 2 UFSAR in a figure showing the auxiliary feedwater start logic (modified to show AMSAC start circuitry) and a reference to Westinghouse WCAP-8330 (the accident analysis chapter for ATWS). No section had been added to the Unit 2 UFSAR describing the AMSAC.

It should be noted that Units 1 and 2 have separate UFSARs because of the significant differences between the two units. There was an approximately 11-year difference between issuance of operating licenses for the two units.

The team reviewed plant modifications involving the AMSAC, service water system, instrument air system, and other plant systems. With the exception of the Unit 2 AMSAC, the team found that the commitments that affected the UFSAR were captured in the UFSAR update process.

APPENDIX - SPECIFIC ISSUES REVIEWED AT BEAVER VALLEY

To examine the implementation of the licensee's programs, the team reviewed the licensee's response to the following specific issues:

10 CFR 50.62	Anticipated Transient Without Scram
Generic Letter 89-13	Service Water System Problems Affecting Safety-Related Equipment
Generic Letter 88-14	Instrument Air System Problems Affecting Safety-Related Equipment
Bulletin 85-01	Steam Binding of Auxiliary Feedwater Pumps
NUREG-0737, I.C.5	Procedures for Feedback of Operating Experience to Plant Staff
Notices of Violation	50-334/87-08, 88-21, 87-02, and 88-02
Inspection Report	50-334/89-80
Licensee Event Reports	50-334/87-01, 87-07, 87-21, 88-06, 88-09, 88-13, 89-02, 89-11, 89-13, and 50-412/89-13
Design Basis Document Program	

10 CFR 50.62 - Anticipated Transient Without Scram (ATWS)

The licensee defined the design and testing requirements for the ATWS mitigation scram actuation circuitry (AMSAC) in its submittals of February 27, 1987, and December 2, 1987, to the NRC. The licensee installed the AMSAC system at Unit 1 in 1988 and Unit 2 in 1989. The AMSAC approved by the NRC required the installation of the control circuitry to trip the main turbine generator and start the auxiliary feedwater pumps on the basis of specified set points. The commitments made by the licensee concerning the design and periodic testing of the AMSAC were documented in an NRC safety evaluation report.

The week before the audit team arrived on site, the resident inspector found that periodic testing of the AMSAC had been established and performed at Unit 1 in accordance with the licensee's commitments. However, the resident inspector found that no similar procedure for testing the AMSAC set points for main feedwater flow, main turbine power, and time delay for system actuation had been prepared or implemented for Unit 2. Startup testing of the Unit 2 AMSAC set points had been performed as part of postmodification testing in 1989, but had not been performed since then. The licensee's submittal of December 2, 1987, had established commitments to perform periodic testing of these specific AMSAC time delays and set points. An 18-month testing frequency was planned, but had not been conducted. However, the Unit 2 AMSAC end-to-end testing was being performed as the licensee had committed, and was last satisfactorily performed on April 15, 1992. Although the safety significance of the missed testing of the time delays and setpoints was partially mitigated by the satisfactory performance of the regularly scheduled Unit 2 AMSAC end-to-end testing, the NRC issued a Notice of Deviation to the Duquesne Light Company in regard to this issue on July 2, 1993.

The team found that the Unit 2 updated final safety analysis report (UFSAR) did not contain a description of the AMSAC as installed. The Unit 1 UFSAR included a thorough description of the AMSAC. The design change packages for installing the AMSAC for Unit 1 had indicated that an update to the UFSAR was necessary and provided the necessary information for the revision. The design change packages for the Unit 2 AMSAC did not indicate that a UFSAR update was necessary. However, the AMSAC was represented in the Unit 2 UFSAR in a figure showing the auxiliary feedwater start logic (modified to show AMSAC start circuitry) and a reference to Westinghouse WCAP-8330 (the accident analysis chapter for ATWS). No section had been added to the Unit 2 UFSAR describing the AMSAC.

Except for the testing commitments as described above, all other commitments made by the licensee and reviewed by the team concerning ATWS implementation had been met. With respect to the periodic testing of the Unit 2 AMSAC, the team concluded that the possible cause for the absence of a periodic test procedure was the irregular updating of plant documents used by plant personnel to keep track of system-design basis information. The failure to update the various plant documents consistently, such as using the same system number for the AMSAC in the operating manual, the master equipment list, and the periodic test procedure, made finding all applicable documents related to the system time consuming and difficult. This difficulty, combined with the lack of a database or list that contained all commitments associated with the AMSAC, may have contributed to the failures to develop a test procedure and update the UFSAR.

Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment"

All the commitments related to Generic Letter (GL) 89-13 were initially implemented and were being maintained, including hardware modifications, testing, surveillances, and procedures. Several of the commitments contained in the response to the GL were tracked on the commitment tracking system (CTS). Most implementing documents, including the associated design change packages, affected procedures, and associated engineering memoranda, clearly referenced the GL. However, the preventive maintenance procedures (PMPs) reviewed did not reference the GL, for example, 1PMP-44VS-E-14A-B-1M, "Control Room Air Cooling Coils River Water Side Tube Cleaning," which was generated expressly to implement the GL commitments. These items were tracked as part of the licensee's heat exchanger semiannual status report.

Generic Letter 88-14, "Instrument Air System Problems Affecting Safety-Related Equipment"

The licensee responded to GL 88-14 by letter dated February 17, 1989. In the letter, the licensee submitted a plan and schedule for completing the required design and verification of the safety-related portions of the instrument air system. The design and verification of operation did not identify any components of the instrument air system that would not perform their intended safety function.

The team interviewed the system engineer for the instrument air system and found the individual to be cognizant of all the commitments made by the licensee in response to GL 88-14. All of the commitments were tracked and verified through the CTS.

The licensee committed to make modifications to the plant instrument air, control room instrument air, and intake structure instrument air systems. The team verified the design change packages (DCPs) for these modifications. It performed a system walkdown to verify the installation of the components and equipment stated in each of the DCPs.

The team found that the licensee's program was adequate for ensuring that the commitments were tracked, controlled and implemented. No problems were identified.

Bulletin 85-01, "Steam Binding of Auxiliary Feedwater Pumps"

The licensee was not required to respond to Bulletin 85-01 for Beaver Valley Unit 1 because the unit was in compliance with the bulletin requirements before the bulletin was issued. The licensee docketed the bulletin commitments for Unit 2 as part of the licensing process, but the team could not find the items in any licensee tracking system. The licensee implemented very similar steps at both units to detect and mitigate elevated temperatures in the auxiliary feedwater (AFW) system. These steps included periodic monitoring for temperatures above ambient and the creation of procedures in each unit operating manual to restore the AFW system should high temperatures be discovered.

The team confirmed the adequacy of the procedures through walkdowns with the cognizant system engineer. The procedures contained differences that were confirmed to be consistent with design differences between the Beaver Valley units. Specifically, the Unit 2 procedures addressed separately the steps to be taken should temperatures be determined to be in excess of 200° F in downstream piping, but the Unit 1 procedures did not contain the additional steps. The reason for the extra Unit 2 procedural steps was that the AFW piping has dedicated containment penetrations with associated temperature limits, but the Unit 1 AFW lines join with the large main feedwater lines before penetrating the containment. The team noted that Unit 2 had experienced some AFW backleakage and elevated temperatures. The affected piping did not extend all the way to the AFW pumps, but the events were properly reported in LERs. The licensee used the appropriate procedures to restore normal AFW system temperatures.

The team did not identify any deficiencies or weaknesses with respect to the licensee's implementation of commitments associated with Bulletin 85-01.

NUREG-0737, I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff"

The NRC review of the actions taken by the licensee in response to NUREG-0737, I.C.5, was documented in Inspection Reports 81-08 for Unit 1 and 87-18 for Unit 2. No correspondence initiated by the licensee contained any specific commitments as to how the licensee would meet the applicable requirements. The team confirmed that the licensee's actions identified in the NRC inspection reports were still in effect. These items included all the attributes identified in NUREG-0737, I.C.5, including periodic internal audits. The team selected one issue, the one discussed in NRC Information Notice 92-36, "Intersystem LOCA Outside Containment," to examine the licensee's implementation of its operating experience feedback program. The

licensing group, which consisted of engineers and a previously licensed supervisor, reviewed the information notice and decided that the notice did not need further review at the working level. An internal position paper was drafted and reviewed by several managers, including those with cognizance of engineering, training, and operations. The team reviewed the position paper and did not identify any deficiencies in the licensee's actions.

Design Basis Document (DBD) Program

The licensee initiated safety system functional evaluations (SSFES) of Unit 1 key safety systems in 1987 with the intent to reconstitute the system design bases. The licensee subsequently created DBDs for many Unit 1 systems, including those not yet subjected to an SSFE. The Unit 2 systems have not received a similar review because the licensee considered the design bases for the recently licensed (1987) unit to be well understood and documented. The team reviewed the Unit 1 SSFE/DBD program and noted that the licensee had procedures in place that controlled the evaluation of open items for operability and reportability. The process also appeared to have been effective in identifying previously unrecognized commitments. The process had its own open item system and was not part of the CTS.

NOV 50-334/87-08

The NRC found the operator licensing examiner requalification training program to be unsatisfactory during the 1987 review. The licensee committed to three corrective actions to improve the training program in response to the unsatisfactory rating.

The team verified that all corrective actions had been implemented through discussions with the Director of Operations Training and a review of followup correspondence. Each subsequent NRC requalification examination at Beaver Valley has obtained a program evaluation of satisfactory.

NOV 50-334/88-21

Section 50.49(f) of Title 10 of the Code of Federal Regulations (10 CFR) requires that the qualification of each component be based on testing or experience with identical equipment or with similar equipment with a supporting analysis to show that the equipment to be qualified is acceptable. This NOV was issued because the licensee did not have sufficient documentation in the equipment qualification file to establish the qualification of Ideal Model wirenuts used in the motor starter wiring circuit of a motor-operated valve.

The licensee committed to a training review of environmental qualification (EQ) maintenance requirements for electrical maintenance personnel and an EQ seminar for quality control inspectors and supervisors. The objective of the training was to provide a better understanding and heightened awareness to maintain the environmental qualification of the equipment.

The team verified that personnel had been trained through discussions with the Director of Maintenance Training and a review of maintenance training records.

NOV 50-334/87-02

Technical Specification 4.3.1.1.1 and Table 4.3-1, "Reactor Trip System Instrument Surveillance Requirements," specified that the neutron flux power range monitor low setpoint channel functional test be performed for each startup (if not performed in the previous 7 days). This NOV was issued because the test was not performed during the reactor startup on January 11, 1987, and had not been performed within the previous 7 days.

The licensee committed to revise a startup procedure and a startup checklist which are both in the plant operations manual. The commitments were tracked in the CTS. Two operating manual change notices were generated to revise both documents.

The team verified implementation of the commitments by reviewing the revised procedure and checklist. Both correctly referenced the commitment.

NOV 50-334/88-02

In GL 82-33, the NRC staff gave basic requirements for upgrading licensee emergency response capabilities. The licensee responded to the letter by committing to use an NRC-approved procedures generation package (PGP) for upgrading its emergency operating procedures (EOPs). This NOV was issued because many of the licensee's EOPs did not adhere to the guidelines in the PGP. Numerous inconsistencies with the PGP were identified in the procedural steps of the EOPs.

The licensee's corrective actions, with a completion schedule, were submitted to the NRC in formal, docketed correspondence. The actions were to review the Unit 1 PGP and EOPs to determine the actions necessary to resolve and to eliminate the deficiencies. The commitments were listed and tracked on the CTS.

The audit team reviewed the EOPs and identified no problems or deficiencies.

Inspection Report 50-334/89-80

This inspection report documented a special maintenance team inspection that was part of NRC's industry-wide effort to evaluate the effectiveness of maintenance activities at licensed power reactors. No violations or unresolved items were identified during this inspection; however, six weaknesses were identified. The licensee committed to corrective actions for each of the six weaknesses. The team confirmed that each commitment was closed in the CTS.

Also, as part of the corrective actions, the licensee committed to the implementation of a nuclear group administrative manual which would replace the nuclear group directives and site administrative procedures and would indicate the site organization and responsibilities of each group. The audit team verified the implementation of this corrective action.

Licensee Event Reports (LERs)

The audit team reviewed the commitments associated with the corrective actions contained in the following 10 LERs:

- 50-334/87-01 Reactor Trip/Turbine Trip During the Performance of Turbine Pedestal Checks and Failure To Perform Startup Surveillance
- 50-334/87-07 Inadvertent Main Filter Bank Actuation During Radiation Monitor Recorder Maintenance
- 50-334/87-21 Inoperable Charcoal Filter Bank Sprinkler Nozzles
- 50-334/88-06 ESF (Engineered Safety Features) Actuation Due to the Inadvertent Energization of Slave Relay K643B
- 50-334/88-09 Reactor Trip and Feedwater Isolation
- 50-334/88-13 Exceeding Technical Specification Surveillance Requirement
- 50-334/89-02 Reactor Trip Due to Feedwater Regulating Valve Malfunction
- 50-334/89-11 Pressurizer Surge Line Rupture Restraints Outside the Design Basis
- 50-334/89-13 Diesel Generator Auto Start of Bus Undervoltage
- 50-412/88-13 Overpower Delta-T Reactor Trip Due to Faulty Lead/Lag Circuit Card

The LERs contained commitments to a wide variety of corrective actions including hardware modifications, technical specification and FSAR changes, procedure revisions, and technical studies. The team did not identify any safety-significant deficiencies with respect to the licensee implementing and maintaining commitments made in the LERs.

The team reviewed the LERs to determine if the commitments (corrective actions) in the LERs had been implemented and were being tracked. It also reviewed the licensee's implementing documents to determine if the commitments were clearly identified or referenced. Additionally, it reviewed implementing documents to determine, if the document had been changed, revised, or superseded, if the commitments were still in effect. Lastly, the team reviewed applicable administrative procedures concerning commitments to see if the procedures were followed correctly.

The team determined that all the commitments (corrective actions) in the LERs appeared to have been initially implemented or were scheduled to be implemented. However, none of the commitments were tracked on the licensee's CTS, and very few of the commitments were tracked on the open item resolution (OIR) system. The documents that implemented the commitments, including design change packages, 10 CFR 50.59 reviews, standing night orders, operating manual (OM) procedures, corrective maintenance procedures, engineering memoranda, and special operating orders, did not reference the commitments, nor were the commitments annotated in any manner.

In one instance, the commitment (made in LER 89-11) was initially implemented by several OM procedures, such as OM 1.50.4A, OM 1.50.4B, OM 1.51.4C, OM 1.51.4D, OM 1.6.4.F, OM 1.6.2, and OM 1.7.4.I, but the commitments were not referenced or annotated in the procedures. The commitments were to place administrative operational limits to limit the temperature differential between the pressurizer surge line and the reactor coolant system (RCS) hot leg to less than 200 degrees Fahrenheit during formation or collapse of the pressurizer steam bubble.

These procedures were later changed and the commitments were deleted. It was not apparent that the licensee personnel involved with the procedure changes were aware that commitments were being deleted. The modification itself, however, was implemented only after formal NRC approval. The issue had resulted in the issuance of an NRC bulletin and the corrective actions were handled accordingly. Discussions with NRC and licensee personnel indicated that the administrative limits were considered to be an interim measure until the permanent plant modification (DCP #1431) could be approved and completed. The team concluded that the commitments had been properly implemented and deleted, but that the process had not been well documented in the commitment files associated with the later revision of the procedures.

The team reviewed Operations Assessment Procedure OAG 4.0, "Preparation of Licensee Event Report (LER)," Revisions 7 through 11. Revisions 7 and 8 were in effect at the time Unit 1 LERs 89-02, 89-11, and 89-13 and Unit 2 LER 88-13 were written. These revisions required the shift technical advisor to ensure that all corrective actions (commitments) stated in the issued LER were entered in the CTS. However, there was no evidence that any of the corrective actions in the above LERS were entered in the CTS. Additionally, the licensee indicated that the corrective actions should also be tracked in the OIR system, even though this was not required during the timeframe of the LERs reviewed by the audit team. However, as stated previously, few of the commitments were tracked in the OIR system.