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Division of Reactor Inspection and Safeguards

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Inspection at: Fort St. Vrain Nuclear Generating Station
Plattsville, Colorado 80651

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1.0 INSPECTION SCOPE

The primary focus of the inspection was to assess the safe operation of the Fort St. Vrain Nuclear Generating Station (FSV). The inspection effort was concentrated on control room operations and activities that related to operations and supported the safe operation of the plant. As a part of the operations performance evaluation, the team observed approximately 120 hours of shift operations, including backshift and weekend inspections. In addition to observing operations, the team inspected the areas of maintenance, surveillance testing, management oversight, safety review, and quality programs.

2.0 DETAILED INSPECTION FINDINGS

2.1 Plant Operations

2.1.1 Observation of Operations Activities

In this portion of the inspection the team assessed the overall adequacy of the licensee's operational management controls program implementation by observing plant activities continuously and in depth. A team of three inspectors evaluated these activities and programs by combining around-the-clock on-shift inspections with routine day-shift inspections. The inspection emphasized direct observation of the licensee's activities, rather than review of the program content.

Control room and in-plant activities were observed around-the-clock for approximately 120 hours. The inspectors observed key corrective maintenance, surveillance testing, and operations activities occurring during routine shifts.

The team evaluated the licensee's operational activities from the cold shutdown mode to criticality. The inspectors observed the following activities:

(1) operations shift personnel performing their duties (personnel observed included the shift supervisor, senior reactor operator, control room operators, equipment operators, and auxiliary tenders.)

(2) conduct of control room operations

(3) plant system alignments and plant startup activities

(4) placing and removing of system clearances

(5) in-process surveillance testing

(6) attendance at station management's post-trip review committee meeting

(7) plant tours to observe work in-progress and housekeeping

(8) management's direct involvement in operational activities

(9) all-discipline support of plant operations.

Plant programs and procedures reviewed by the team included:

(1) remote shutdown procedure

(2) emergency operating procedures (EPs)

(3) standard operating procedures (SOPs)

(4) Independent Verification (IV) Program

(5) controlled drawings

(6) Temporary Configuration Program controls

(7) overtime controls for operations, mechanical, and electrical maintenance groups

(8) equipment clearance and operation deviation reports

(9) equipment tagging and labeling program.

2.1.2 Control Room Activities

The team observed the conduct of operations in the control room.

Access to the controls area was restricted as is required by procedures and NUREG-0737, Item I.C.4. A professional atmosphere was observed in the control room, and distractions such as music and non-job-related reading materials were excluded.

Operating procedures and references, including the latest revisions and indices, were readily available. Drawings in the control room were current approved revisions. An expanded sampling of about 170 drawings were reviewed to assess clarity and quality of information provided. Of the 170 drawings reviewed, 7 had portions where information was either missing or very difficult to read. The drawings reviewed were Piping and Instrument Drawings PI-1 through PI-45-8 inclusive. The following problems were noted:

PI-21-7 Valves and instruments added because of plant modifications were very faintly indicated and equipment numbers were difficult to discern.

PI-21-8 Valves and instruments added because of plant modifications were very faintly indicated and equipment numbers were difficult to discern.

PI-11-1 Areas of the drawing were obscured and fuzzy. Some setpoint values and instrument numbers were incomplete and unreadable.

PI-31-3 Information on portions of the drawing was crowded and small text could only be read with the use of a magnifying glass.

PI-33-1 Some valve and line numbers were unreadable.

PI-42-2 Gray background that resulted from poor reproduction quality made information unreadable.

Approximately 25 EL series electrical drawings were also evaluated for readability; no readability problems were identified.

The licensee advised the inspectors that this problem had been previously identified and that actions were being taken to eventually convert the plant drawing system to a computer-aided drafting system.

The operators were observed to adhere to procedures and routinely referred to procedures during the conduct of control room operations. The inspectors also noted during observations and interviews that the operators were very knowledgeable and strived for good plant operations.

The communications between shift personnel were effective and included good shift turnover briefings, start-of-shift briefings by the shift supervisor, and information briefings before major plant operations. The plant manager and operations superintendent were frequently observed in the control room checking the plant status and communicating with shift personnel. The team considered this a strength.

A review of the shift logs revealed the following weaknesses:

(1) Entries were too brief.

(2) Operations performed were not entered in some logs. However all significant operations performed could be retrieved by reviewing the shift supervisor, senior reactor operator, and reactor operator logs. More attention needs to be paid to log entries for all shift logs including the equipment operator and equipment tender logs.

Too many control board annunciators had nuisance alarms (not actual alarm condition) for the existing plant operating mode. The licensee was working toward the goal of a dark annunciator board.

2.1.3 Plant Tours and Inspections

During the team inspection, several tours of the plant were made to observe plant housekeeping conditions, equipment conditions, and compliance with procedure and program requirements. During the early portion of the inspection, the plant was in a shutdown condition and maintenance was ongoing in several areas of the reactor building. Toward the end of the inspection period, the plant was in a startup condition.

The general condition of the plant from a housekeeping perspective was very good. Cleanliness controls were evident and containers for contaminated clothing and for waste were not overly full. In areas in which maintenance was not being performed, materials were not allowed to accumulate to unmanageable levels. The team observed maintenance personnel moving through the reactor building cleaning oil accumulations from components and equipment and removing debris.

Several areas of concern and weaknesses noted during the tours were brought to the licensee's attention. The licensee addressed all of these and either initiated or completed corrective action before the team left the site. These areas are detailed below:

(1) In several instances, equipment used in servicing, surveillance, or maintenance activities was lying loose on the metal grating on several levels or was stored on top of installed equipment. Examples are: pipes used to support the moisture monitor closure flange were lying loose on the deck or on top of one of the prestressed concrete reactor vessel (PCRV) penetrations, valve wrenches were placed atop valve operators, scaffolding materials that were not in use were not secured to the deck, and ladders were not rehung on racks or fixed in place. If left unsecured, these items could cause damage to safety-related equipment during plant operation.

(2) On level 4 of the reactor building in the cubicle containing the gas blowers, several supports on a line in the vicinity of valves V-63117 and V-63118 were broken loose from the baseplates mounted in the floor.

(3) On level 7 of the reactor building, fire hose rack RH7J2 was noted as not having all hose loops properly pinned in the rack. Upon closer inspection, it was noted that the hose nozzle had a piece broken off the diffuser portion, which would change the spray pattern of the nozzle from its design.

(4) On level 5 of the reactor building, the wooden deck of a four wheel cart had not been painted with fire-retardant paint, as is required by Administrative Procedure SOAP-8, "Plant Signage and Labeling Programs," Issue 1.

(5) The licensee had located two Scott Air-Pak bottles in clamp-type holders on the wall next to the elevator on level 1 of the reactor building to provide backup breathing air capability in the event of a fire or radiological incident. The team questioned if the restraining device for the bottles could keep them from becoming a missile hazard if the bottles should fall and rupture during seismic activity. The licensee could not document the adequacy of the installation, but informed the team that the problem would be investigated and resolved.

During a tour with one of the equipment operators, a valve was noted to be leaking around the packing. The operator informed the team that a procedure was in place to adjust minor packing leaks without requiring a station service request and thus expedite leak reduction efforts. The procedure for control of this program was MAP-6, "Valve Packing Adjustment," Issue 2. The team reviewed this procedure and noted that the effect of packing adjustments on stroke times for valves with operators was not addressed. It was possible that packing adjustments could affect the stroke time of valves required to close or open within certain times as defined in Technical Specifications and potentially render them inoperable. However, the team found no examples in which stroke time was affected. The licensee responded that it would investigate this area; if stroke-time-sensitive valves could be affected by this procedure, the program would be revised to ensure that the valves remain operable.

During walkdowns with operations personnel, the team observed a sound level of knowledge and familiarity with the location and operation of plant equipment. This gave the team confidence in the operators' ability to perform their job functions and to respond to abnormal occurrences.

2.1.4 Management Controls

The licensee's overtime controls for the operations, mechanical, and electrical groups were reviewed. The review period covered approximately two months. Only one minor deviation from Technical Specification guidelines was found. This shows a strong commitment to adhere to the Technical Specification guidelines.

The inspectors attended the licensee's post-trip-review committee meeting on May 12, 1988. The purpose of this meeting was to establish the causes of the events associated with the reactor trip on May 6, 1988. This review was conducted in accordance with procedure SMAP-7, "Post Trip Reviews," Issue 6.

This procedure required that a documented review be performed to determine the feasibility of a reactor restart after an unscheduled reactor trip.

The inspectors observed representatives from all licensee departments at the meeting, exceeding the requirements for a quorum; personnel actively participated in discussions until a consensus was reached. The meeting scope far exceeded the post-trip-review requirements. This broadly based management involvement was considered a strength.

2.1.5 Procedure Reviews

2.1.5.1 Emergency Operating Procedures

The licensee's emergency operating procedures (EPs) were reviewed and emphasis was placed on the planned revision to the emergency procedures to achieve compliance with NUREG-0737, "Clarification of TMI Action Plan Requirements," and with Supplement 1 to NUREG-0737, subtitled "Requirements for Emergency Response Capability."

The current emergency procedures (EPs) were event oriented, and contained a number of events which could be reclassified as abnormal events. Procedures EP A, "Moisture In-Leakage," Issue 54, and EP B-1, "Reactor Scram," Issue 54, were reviewed as samples. The procedures consisted of a symptom/action matrix, which correlated immediate actions and followup actions for the turbine (west) side and the reactor (east) side control room operators with symptoms obtained from annunciators or control board meters. The procedures contained several immediate action steps which the operators were required to memorize. This, in combination with the large number (more than 20) of EPs, required a high degree of operator knowledge to link the symptoms to the action steps and then identify the event accurately in order to determine the followup actions. Considering operator stress as a factor during off-normal events, the procedures may be difficult to apply efficiently and accurately. The licensee acknowledged that the current procedures need to be improved and that a significant improvement should be realized once the revised EPs are implemented.

The program for improving the EPs was described in the licensee's letter of April 10, 1987, as including the Procedures Generation Package, a proposed Writer's Guide, and a Program Plan for the Integrated Validation of NUREG-0737 initiatives. NRR was then reviewing the program. The utility expected final review and approval of the program within the next several months so that the new procedures might be implemented by the end of the fourth refueling outage, or approximately mid-1989.

The licensee intended to utilize a flowpath approach for controlling the events arising from an upset condition as opposed to the symptom/action matrix. The flowpaths will be symptom oriented, and will be applied to the control of transient events following a reactor scram as well as the restoration of critical safety functions. The critical safety function parameters will be monitored by the safety parameter display system and will address five areas of control: reactor flux, primary system, secondary system, prestressed concrete reactor vessel (PCRV) integrity, and radiation. The team reviewed the planned safety parameter display system inputs as well as draft flowpaths for critical safety function restoration and found that the methods being employed appeared to be appropriate and were consistent with the approaches being taken by other utilities. The licensee indicated that the bulk of the current EPs would be redefined as abnormal operating procedures and that the safe shutdown cooling procedure set would be incorporated as part of the EP set.

The licensee dedicated two individuals to the EP development program, one of whom was an experienced shift supervisor. The schedule for flowpath procedure development, review, verification/validation, training and implementation was very aggressive. Even though the program appeared strong because of the high quality of the individuals assigned to the project and the availability of other plant personnel who had much operational experience, additional resources may be required during the development phase to enable implementation of a quality product by the commitment date. It was also observed that the shift supervisor involved in the project had been occasionally diverted from the EP project to handle other procedural problems, such as those arising from the recent emergency plan team inspection; such diversion could weaken the effort. The adequacy of the resources assigned to the upgrading of the EPs was considered a potential weakness if management does not maintain its priorities.

As part of the emergency operating procedure reviews, the team reviewed the safe shutdown cooling procedures to assess the capability of auxiliary tenders or equipment operators to perform as operators. These procedures were not part of the EPs, but were contained in a separate volume of the plant operating manual. However, the licensee intended to incorporate these procedures into the upgraded EPs. The following procedures were reviewed:

° SSC-01, "Restoration of Power to Essential 480 Volt Busses," Revision 1

° SSC-02, "Steam Line Rupture Detection and Isolation System (SLRDIS) Reset Procedure," Revision 1

° SSC-03, "Recovering From a Noncongested Cable Area Fire Resulting in an Interruption of Forced Circulation," Revision 1

° SSC-04, "Recovery From SLRDIS," Revision 1

° SSC-05, "Design Basis Earthquake/Maximum Tornado Recovery," Revision 1.

Attachment 1 to SSC-01 was a checklist for lineup of alternate cooling method backfeed to essential buses which was to be performed by the auxiliary tender. During a walkthrough of the checklist by the team and a qualified auxiliary tender, a weakness was observed. The procedure step to position or verify position of the four switches inside the 277-V lighting panel could not be simulated because with the breaker in the closed position (as required by the previous step) the panel could not be opened. The licensee stated that this problem had been previously identified, but the procedure had not yet been corrected. It was observed that equipment required to accomplish the checklist was available in the dedicated cabinet in the alternate cooling methods cubicle (e.g., a screwdriver and rubber safety gloves). A copy of the procedure was also located in the alternate cooling method cubicle for use by the operator. The team noted that procedures and system drawings were strategically located throughout the plant, which was a strength.

Attachment ? to SSC-03 provided instructions for the auxiliary tender to set the circulator's brake and seal from the helium storage area, a remote manual activity. During the walkthrough of this attachment for circulator 1A, a weakness was observed because the steps to set the brake and seal require opening a locked cabinet door to gain access to the valves. The door of the cabinet was hinged on top, and had to be lifted to a position just past vertical. The possibility existed that the door could have fallen closed and injured the operator during the activity required by the procedure, thus disabling him from completing further required actions. The licensee indicated that it would investigate altering the hinging of the doors to the cabinets in question. The operator was observed to have the necessary key to open the cabinet, and a copy of Attachment 2 to SSC-03 was available to help the operator in the immediate area of the valves that required manipulation.

Attachment 7 to SSC-03 provided an operator aid for the equipment operator to read thermocouple temperatures from the temperature transmitter located in the auxiliary electrical room. During the walkthrough of this attachment, two minor weaknesses were observed: (1) The Fluke thermocouple reader was not located in the shift supervisor's office as referenced in the attachment but was located in the control room and (2) the standard screwdriver required to connect the thermocouple reader to the temperature transmitter was not dedicated to that specific use and was not located with the Fluke instrument. The licensee stated that the Fluke instrument had been relocated to the control room to provide a more secure area for control of the instrument, but the procedure had not been revised to reflect this change. The screwdriver was supposed to be taped to the handle of the Fluke meter, but someone had used it and placed it in a desk drawer in the control room.

Attachment 5 to SSC-04 provided instructions for installing a through flange between the firewater system and the emergency feedwater header. During a walkthrough of this attachment with an equipment operator, two weaknesses were observed: (1) Drain valve V-45947 did not have a tag and could not be verified as the correct valve and (2) the mechanical spreader referenced in steps 7 and 10 of the procedure could not be found in the sealed toolbox dedicated to performing this procedure. It was observed that the platform and toolbox required to perform this procedure were located near at hand and had been sealed against unauthorized use.

Attachment 1 to SSC-03 provided a table for defeating interlocks associated with valves, controllers, or other plant equipment which may become disabled as a result of fire or other situations arising from plant transients. The required actions included pulling fuses or confirming the integrity of fuses, installing jumpers at terminal blocks, or removing a grill cover and actuating relays located behind the grill. During a walkthrough of the attachment with a senior reactor operator, three weaknesses were observed: (1) For SV-2106, the attachment required the operator to pull fuses F-254 and F-134 at I-05; however, fuse F-254 did not exist and (2) a dedicated supply of fuses for replacing blown-out fuses had not been provided; (3) the grill at the bottom of panel I-10, Bay 800 could not be removed by use of a screwdriver since one of the screws had been replaced by a hex head bolt. The licensee replaced this bolt and other similar bolts in grill covers with screws, and will investigate the other areas identified.

It was observed that the operations personnel assisting the team in the walkthrough were knowledgeable of the procedures, the actions required, and the locations of the referenced equipment.

An overall weakness was failure to periodically walk through the procedures and attachments to ensure that all required equipment was in place and ready for use. Licensee action to correct the above procedure and material deficiencies is an unresolved item pending further review by NRC Region IV (267/88200-01).

2.1.5.2 Standard Operating Procedures

The team reviewed selected standard operating procedures (SOPs). These procedures, as many of the other plant procedures, were undergoing major revision as part of the licensee's procedure upgrade programs. The procedures reviewed were:

° SOP 21-01, "Helium Circulators," Revision 20
° SOP 21-02, "Helium Circulator Auxiliary Systems," Revision 72
° SOP 22-01, "Steam Generators," Revision 45
° SOP 31, "Feedwater and Condensate Systems," Revision 43
° SOP 32-01, "Secondary Coolant System - Feedwater Heaters," Revision 3.

The review determined that several of the procedures, in particular SOP 21-01, SOP 22-02, and SOP 32-01, contained a number of valve lineup changes and complex activities without an associated checklist. The lack of a prepared checklist for these manipulations means that they must be copied from the procedure in the field, possibly introducing error. Additionally, there was no sign-off by the operator to indicate completion of the actions nor was independent verification of safety-related valve manipulations required. This was considered a weakness in an otherwise satisfactory program for controlling and verifying equipment position. The licensee stated that the provision of checklists would be investigated. Confirmation of licensee action in this regard is an unresolved item pending further NRC Region IV review (267/88200-02).

2.1.6 Independent Verification

The licensee's independent verification program was reviewed with regard to implementation in the equipment clearance program, repositioning or reterminating equipment following surveillance testing, and positioning of valves and other plant equipment following outages or major work on systems. The licensee's independent verification program has been previously inspected and found to be acceptable with respect to the requirements of NUREG-0737, Item I.C.6 (NRC Inspection Report 82-27). The team found that the surveillance tests reviewed contained required steps for independent verification of critical equipment returned to normal status if the procedure had been revised as part of the procedure revision program. For those tests that have not yet been revised, independent verification steps have been added by procedure change when the test is performed or will be added the next time the test was performed.

The licensee has independently verified each valve contained in the system valve list (SVL) for all plant systems. The SLV contained manual valves such as isolation valves, and vent and drain valves. This was a strength because all critical and noncritical valves would be independently verified anytime a system lineup was conducted. Valves with operators were considered "instruments" as well as being considered operational valves (controlled by operating procedures) and were not included in the SVLs. The licensee indicated that a system lineup would not necessarily be conducted on a system unless major work was performed during an outage; this implies that valves could be manipulated during normal operation over an extended period without being independently verified. However, there was some indication that the licensee was considering conducting system walkdowns including independent verification on a more regular basis. Confirmation of licensee action in this regard is part of unresolved item 267/88200-02, Section 2.1.5 of this report.

SMAP-19, "Processing Equipment Clearances and Operation Deviations," Issue 7, controlled equipment removed from and returned to service. The procedure required independent verification that all clearance cards and auxiliary tags were placed properly and were removed when the work was completed; that the equipment, annunciator, or instrument had been properly isolated before work on it began and properly returned to normal before testing or returning to service, and that all sealed and critical valves would be independently verified for proper resealing and correct positioning before the equipment, annunciator, or instrument was returned to service. This program was considered acceptable and appeared to satisfy the requirements of NUREG-0737.

2.1.7 Equipment Clearances

The team reviewed the active clearance book during preparation for plant startup and identified two weaknesses associated with the proper administration of the independent verification requirements of SMAP-19, "Processing Equipment Clearances and Operation Deviations." On May 12, 1988, Clearance No. 21136 was completed to place helium circulator C-2101 out of service without independent verification of two valve positions. The valves were isolation and bypass valves on the non-safety-related auxiliary portion of the system, and were subsequently confirmed to be in their required position. On May 15, 1988, Clearance No. 21155 was completed to place the reactor building sump filters out of service without independent verification of the sump pump hand switch positions. The switches were not safety related and the hand switches were subsequently confirmed to be in their required position. In both cases, the independent verification blocks on the clearance form had not been initialed as required, indicating that independent verification had not been performed for this equipment.

2.1.8 Valve Mispositioning

Both the Institute of Nuclear Power Operations (INPO) and NRC had identified concerns related to valve mispositioning incidents. The team reviewed procedure P-1, "Plant Operations," Step 4.6.4.c.1, which directed the operator in the correct method of checking manual valve position. The team questioned Training Department personnel about operator training on valve positioning for different classes of valves, such as gate, globe, or butterfly; considerations related to valve backseating; how to determine positions of locked or sealed valves and ensure locks and seals are properly applied; and other considerations which have been the subject of INPO Safety Evaluation Reports and INPO Significant Operating Event Reports. After the team reviewed auxiliary tender and equipment operator training program materials, the licensee reported that the subject was not currently addressed in their training program. Training deficiency report (TDR) No. 051388-1 was issued on May 13, 1988, to develop a lesson plan for auxiliary tender trainees on the subject of valve operations. NRC review of the training deficiency report's resolution is an unresolved item pending further NRC Region IV review (267/88200-03).

2.1.9 Equipment Tagging and Labeling Program

The team reviewed the licensee's equipment tagging and labeling program. The program was controlled by plant procedure SOAP-8, "Plant Signage and Labeling Policy," Issue 1, which controlled the identification of components, pipes, rooms or equipment for the improvement of maintenance, operation, and performance. The procedure was specific in defining label or sign sizes, colors, method of attachment, and standards for descriptions used on the signs. NUREG-0700 and INPO OP-208 were used as guidance documents in developing the program. Independent verification was employed to ensure signs and labels were applied correctly.

The program had been under way for approximately six months, and progress was evident. Problems had been identified with existing plant labels and steps had been taken to correct them through the implementation of this program. The operations group had worked an average of 40 to 50 hours of overtime per week to identify and apply signs and labels. The emphasis had been placed on consistently identifying major safety-related valves and electrical components such as motor control centers, as well as other equipment, components and piping. The licensee anticipated full plant compliance with Procedure SOAP-8 by the end of 1988.

This program was considered a strength because the licensee was acting aggressively to implement this program. Personnel who had extensive plant experience, including a retired shift supervisor, were involved in administration of the program and ensuring its compliance with procedures. It appeared that plant personnel in general were highly supportive of the program and recognized its importance to operation, maintenance, and surveillance activities.

2.1.10 Temporary Configuration Report Reviews

The team reviewed the Temporary Configuration Report (TCR) Log for completeness in accordance with procedure SMAP-18, "Processing of Temporary Configuration Reports," Issue 4, dated November 19, 1987. This procedure described the controls and steps for processing temporary changes to plant equipment. During this review, the inspectors found that three active TCRs, 88-03-05, 88-04-01, and 88-05-03, had not been entered in the TCR index. Procedure SMAP-18, step 4.1.1, required the index to be updated when a new TCR was initiated. The significance of an incomplete index was that lifted leads, jumpers, and other temporary equipment changes were tracked only by TCRs. Missed TCRs could result in inoperable safety significant equipment.

Open TCRs dating back to 1985 were found, but none of these dated TCRs were safety significant, and a major effort to close these out was in progress. Licensee action to ensure correctness of the TCR log and reduce the lacklog of old open TCRs is an unresolved item pending further NRC Region IV review (267/88200-04).

2.1.11 Remote Plant Shutdown

The team reviewed the procedure for remote shutdown outside of the control room. This procedure review and walkdown identified the following weaknesses:

(1) Only the licensed operators were trained on remote shutdown every two years. The team was concerned about the frequency of training and the lack of training for unlicensed operators who must be used for remote plant shutdown.

(2) Training every two years consisted of walkdown of the procedures and did not simulate the event by a coordinated team drill. An additional weakness was that instructor involvement in the procedure walkdown was too small to evaluate the weaknesses and provide input to retraining.

This training deficiency became even more significant if a fire was the cause for control room evacuation, since three operations personnel were assigned to the fire brigade and may not be available to help with the remote shutdown.

Additionally, no remote shutdown test has ever been performed. This raised significant concerns about the ability to integrate operation of equipment, which has been independently tested, but not tested on an integrated basis.

Licensee attention to these weaknesses appears warranted: Inadequate training, minimum operations staff required for remote shutdown concurrent with a fire, and whether an integrated test of remote shutdown capability should be performed are an unresolved item pending further NRC Region IV review (267/88200-05).

2.2 Maintenance

The maintenance inspection consisted of observations made (1) during the licensee's performance of four corrective maintenance activities, (2) reviewing approximately 30 station service requests (SSRs), (3) and reviewing selected maintenance procedures. On the basis of these inspection activities, the team reached two general conclusions. First, the team was concerned about the licensee's control of maintenance activities and the adequacy of work instructions. Second, the team was impressed with the level of knowledge and skill demonstrated by the craftsmen. The team noted an apparent relationship between poor quality work instructions and work being performed without written procedures.

After reviewing work activities and interviewing craftsmen and supervisors, the inspection team concluded that the first-line supervisors were well aware of inadequacies in maintenance procedures and documentation of maintenance activities. The team further determined that these procedure and documentation problems had apparently not been communicated to management, nor had any corrective action been initiated.

On the basis of discussions with region-based personnel, recent inspection reports, the latest systematic assessment of licensee performance (SALP) report, and licensee program changes in progress, it appeared that significant improvements have been recently effected to bring the maintenance program into agreement with industry standards. These improvements, on a relative scale, were considerable; however, on an absolute scale, the licensee's maintenance program lagged behind the industry by a considerable margin. For example, the licensee was in the process of reestablishing the basis for the Preventive Maintenance Program. Vendor maintenance recommendations, equipment operating history, and regulatory requirements were being reviewed as part of this effort. In addition, the Maintenance Superintendent stated that sophisticated maintenance programs, such as predictive maintenance utilizing thermography and vibration analysis, were planned for the future. However, the development of the planned maintenance had to be complete before the improved maintenance programs could be instituted.

The team noted a positive attitude on the part of most maintenance personnel contacted during this inspection. In general, maintenance technicians realized that the past practice of conducting maintenance without administrative controls was unacceptable. Additionally, the technicians seemed to have a feel for the relative safety importance of the equipment they were working on. They stated that they relied on the SSR classification to determine the equipment's safety-related classification.

2.2.1 Maintenance Organization

While the team was on site, the licensee reorganized the Nuclear Production Division to produce a more streamlined division. Before the reorganization, the instrumentation and controls (I&C), mechanical, and electrical maintenance disciplines were under two separate superintendents. The I&C technicians were under the control of the Nuclear Betterment Engineering Superintendent; the mechanical and electrical technicians were under the control of the Maintenance Superintendent. The reorganization placed all three maintenance disciplines under the control of the Maintenance Department Manager.

2.2.2 Station Service Requests

Work was authorized, controlled, and documented for plant maintenance using the SSR and its associated work package as described in procedure P-7, "Station Service Request Processing," Issue 13. The SSR for any individual maintenance task consisted of a control document and attachments, referred to as an SSR work package. Documents that accompanied an SSR included: procedures, such as controlled work procedures (CWPs) and corrective maintenance procedures; special instructions, including supervisor's instructions; excerpts from approved documentation; drawings; supporting documentation, such as nonconformance reports (NCRs), design changes (DCs), and other documents that expanded on the work plan.

Plant instrumentation and equipment that were required by the Fort St. Vrain (FSV) Quality Assurance Program to be maintained at the highest level of quality attainable were classified as safety-related/enhanced quality SSRs. As required by Procedure P-7, these SSRs received enhanced material control, maintenance, and documentation considerations per 10 CFR 50 Appendix B, the FSV Station License, Final Safety Analysis Report (FSAR), and other regulatory documents. Procedure P-7 further stated that equipment classified as safety-related/enhanced quality required quality control (QC) services and other activity as a consequence, and completion of reviews on the SSR form otherwise not required. The equipment classification was determined by the Scheduling and Planning Department with assistance from the Operations Department. Procedure P-7 also defined special processes (e.g., welding, heat treating, nondestructive examination) as requiring QA/QC.

In the performance of a complicated task, a "chained" SSR could result. A chained SSR was defined as being supplementary to an existing SSR and was used to direct a support activity to a primary job task. A chained SSR was denoted by a numerical suffix attached to the primary SSR number. As an illustration, a primary job task SSR would be numbered 8800500-00; a chained SSR to this task would be numbered 8800500-01.

Plant Procedure P-7 allowed the maintenance supervisor or planner at the job site to make pen-and-ink changes to the SSR, if the scope of the work statement was not changed. The computerized version of the SSR did not have to be updated. The team noted that the potential for losing the content of the pen-and-ink changes was considerable should the original SSR (which was also the field copy) be lost. Several of the SSRs reviewed by the team contained numerous pen-and-ink changes. If an SSR with significant pen-and-ink changes was lost or destroyed, it would be difficult or impossible to recover the information. Additionally, the potential existed for adding work requirements that would not be appropriately reviewed by site engineering and quality assurance personnel.

2.2.3 Maintenance Activities Observed

The inspection team observed portions of four maintenance activities focusing on work planning, performance, documentation, post-maintenance testing, and quality control effectiveness. The team reviewed the controlling administrative procedures for these programmatic areas to verify correct implementation during performance of the actual work. The team's observations noted for each observed maintenance activity are discussed in the material that follows.

2.2.3.1 Cold Reheat Steam Thermocouple Repairs

Station Service Requests (SSR) 88502797, 88502827, and 88502823 were issued to remove damaged thermocouples TE 2256-1, TE 2255-5, and TE 2255-3, respectively. Thermocouples TE 2255-5 and TE 2256-1 were stuck in their thermowells and TE 2255-3 had damaged conduit. The inspection team followed the work on the removal of the damaged thermocouples over the course of the onsite inspection period. At the time the team initially began to follow the work, thermocouple TE 2256-1 had been electrically disconnected and the electrical leads on the thermocouple had been removed. The work authorized to be performed under primary job task SSR 88502797 is summarized in the table that follows:

Suffix	Approval Date	Work Description
00	May 7, 1988	Troubleshoot current loops per drawings referenced on attached. Note any disconnections and/or reconnections during troubleshooting. Contact I&C Department to originate SSRs against any bad instrument.
01	May 7, 1988	Remove/reinstall insulation as required in support of Results Engineering work.
02	May 8, 1988	Heat up thermowell in accordance with MAP-15 in order to remove thermocouple. Thermowell is safety-related pressure boundary only.

Suffix	Approval Date	Work Description
03	May 11, 1988	Drill out broken thermocouple as required. NOTE: Thermowell TW-2256-1 is safety-related. Contact I&C Department when work completed.

The team began its observation on May 11, 1988, inspecting the work described in suffix 03 and following the work through completion. It is important to note that the thermocouple was classified as not safety-related and that the thermowell itself was classified as safety-related. The following observations were made concerning this maintenance activity:

(1) The SSR work plan stated, "Remove seized section of thermocouple as appropriate." Maintenance technicians were observed drilling into the safety-related thermowell without having appropriate drawings of the thermowell; the SSR work description did not provide any information on the depth, diameter, or tolerances of the thermowell, nor did the attached QC inspection sheet contain any of this information. The SSRs should be more specific leaving less latitude and placing less reliance on the "skill of the craft."

(2) Special drill bits consisting of a regular bit welded to an extension shaft had to be manufactured to drill out the thermowells. Apparently, the manufacture of the extended drill shaft was not controlled under an SSR, and the material compatibility of the drill bits and thermowell material was not considered.

(3) No procedure was provided for conducting the post-maintenance test, which was a hydrostatic test of the thermowell (see Section 2.2.4 of this report for a discussion of hydrostatic testing).

(4) A welding rod was placed down inside the thermowell and was momentarily energized using a foot switch to remove two broken drill bits from the thermowell. This technique was referred to as using a "stinger." Application of this special process pursuant to 10 CFR 50, Appendix B, Criterion IX was not controlled. Apparently, an engineering review was not conducted and the SSR work instructions did not address the use of a welding "stinger." The SSR did not reference site welding procedures; the requirements of P-7, Section 3.1.3f (QA/QC involvement during the use of special processes) apparently were not observed; and the requirements of P-12, "Plant Maintenance," Issue 5, dated January 19, 1988, were not observed. Section 3.9.3 of P-12 required that procedures for special processes shall be reviewed and approved to ensure that the work was performed in accordance with the required specifications. Failure to control the welding special process used for the above activities is an unresolved item pending further NRC Region IV review (267/88200-06).

(5) Insufficient detail was recorded for maintenance history. The work done portion of the SSR did not contain all information about the job - in particular, that the "stinger" was used to remove portions of the two broken drill bits.

(6) Two virtually identical maintenance activities were inconsistently classified. The work in both cases involved separating by drilling a stuck non-safety-related thermocouple from a safety-related thermowell. SSR 88502797 was classified as non-safety-related; SSR 88502827 was classified as safety-related. This was significant because involvement of the Quality Control Department was contingent on the safety-related classification of the SSR, as defined in P-7, Section 3.1.3.

(7) Inconsistent post-maintenance test requirements between these SSRs was noted because the SSR classified as safety-related required a hydrostatic test but the non-safety-related SSR did not require post-maintenance testing.

(8) SSR 8850287 was amended by a pen-and-ink change in the field to include a hydrostatic test of the thermowell. Since the original scope of the SSR was to drill out the broken thermocouple, a suffix to the SSR should have been prepared and formally reviewed.

In addition to unresolved item 267/88200-06, above, licensee actions to correct the other maintenance program and implementation weaknesses in paragraphs 2.2.3.1(1), (2), (3), (5), (6), (7), and (8) are an unresolved item pending further NRC Region IV review (267/88200-07).

2.2.3.2 Steam Generator B-2-6 Trim Valve (TV-2228-6) Repairs

SSR 88502035 was issued to repair a body-to-bonnet leak on the valve in question. The scope of the repair included a weld buildup and remachining of the body-to-bonnet mating surface. The function of this valve was to regulate feedwater flow to steam generator module B-2-6. Each steam generator module had an associated trim valve (TV-2227-1 through TV-2227-6 and TV-2228-1 through TV-2228-6). By design, each trim valve was set so that, with the valve fully shut, it would pass a minimum of 20-percent full-rated feedwater flow. To satisfy this requirement, each trim valve was set 1-inch off the shut seat when the valve operator was in the fully shut position.

The inspection team observed portions of the valve reassembly. The team was particularly interested in how the valve was set 1-inch off the shut seat to ensure the minimum flow requirement was satisfied. The team noted the following discrepancies in the performance of this maintenance task:

(1) Maintenance technicians were observed disassembling the valve stem coupler without written procedures controlling the valve disassembly. The maintenance technicians had been instructed to verify the alignment of the valve stem and the valve operator stem. This was the setting that ensured steam generator module B-2-6 had adequate flow when the valve positioner was in the fully shut position.

(2) Neither the work instructions nor the valve calibration data sheet specified that the valve disc was required to be set 1-inch off the shut seat with the valve operator fully shut.

(3) Nuclear engineering personnel were unable to justify the correlation between the "1-inch off the shut valve seat" design requirement and scribe marks on the valve stem and operator stem that maintenance technicians used to set up the valve. The scribe marks had been made some time in the

past and were routinely used by the maintenance technicians in setting the valves. Maintenance technicians did not directly measure the "1-inch off the shut seat" requirement. Rather, the scribe marks on the valve stem and the operator stem were set at 5 1/2-inches apart. The date and circumstances when the scribe marks were made could not be determined, yet the maintenance technicians relied solely on the scribe marks to ensure that the minimum flow requirements were satisfied. Failure to maintain 20-percent flow could result in heat damage to the steam generator module.

(4) The maintenance technicians partially disassembled the valve when checking the distance between the scribe marks, despite the absence of written procedures and in the presence of a quality control inspector. The QC inspector did not realize that the maintenance technicians were working outside of calibration procedure, RP-90D. When the NRC inspector questioned the maintenance technicians about the procedure they were using to set up the valve and the basis for the 5 1/2-inch measurement, the QC inspector stated that he had similar concerns.

10 CFR 50, Appendix B, Criterion V requires that procedures shall be "of a type appropriate to the circumstances and shall be accomplished in accordance with these...procedures.... Instructions shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished." It appeared to the team that these requirements had not been satisfied in the performance of this maintenance task because the requirement to set the valve 1-inch off the shut seat was not specified, the use of the scribe marks was uncontrolled and apparently without any technical justification, and the disassembly of the valve stem coupler was also uncontrolled. Failure to provide acceptable instructions for setting the stem on TV-2228-6 is an unresolved item pending further NRC Region IV review (267/88200-08).

2.2.3.3 HV-21243, Loop 1 Turbine Water Header Isolation Valve Repairs

SSR 88502490 was issued to repair seat leakage and body-to-bonnet leakage on valve HV-21243. The SSR was issued as a tracking SSR mechanism for nonconformance report (NCR) 88-0088. Repairing the valve involved weld buildup and machining affected portions of the main seat and the body-to-bonnet mating surface. This valve had a history of body-to-bonnet leakage, and temporary repairs had been made before the outage by injecting sealant into the affected area of the mating surface. The inspection team followed portions of the valve machining and reassembly. The team noted that, in conjunction with repairs made to valve TV 2228-6, the licensee was for the first time using FSV craftsmen to do the machining. In the past, the licensee had contract machinists perform this type of repair work. The team also noted considerable involvement by the Nuclear Engineering Department in evaluating the as-found condition of the valve internals while performing the root cause determination.

During observations of this maintenance activity the team noted poor housekeeping practices at the job site. Debris from lagging removal was not cleaned up until several days after the lagging had been removed and with the system open to the environment. Maintenance Administrative Procedure (MAP) MAP-8, "System and Component Cleanliness Requirements During Performance of Maintenance Activities," Issue 3, required that the work area be cleaned after each operation that generates potential contaminants. Additionally, the valve internals were left unprotected and untagged on the floor. MAP-7, "Parts

Identification and Control," Issue 1, dated April 28, 1986, required that maintenance personnel performing the work shall ensure that component and parts were packaged and identified as they were removed. MAP-7 also required that removed components and parts receive the required degree of protection while they were removed from the system. Failure to implement procedures for cleanliness control and material control is an unresolved item pending further NRC Region IV review (267/88200-09).

2.2.3.4 Bypass Flash Tank Drain Valve Repair

During preparations for plant startup on May 17, 1988, control room licensed operators experienced problems with LCV-32-17-1, the bypass flash tank drain valve. The valve responded slowly to the demand signal and would not close past the 40-percent open position. SSR 88502982 was issued to troubleshoot the valve and, calibrate it if necessary, and required that the SSR be replanned if any other problems were detected. While troubleshooting, the maintenance technicians found that the valve's instrument air pressure reducer had a ruptured diaphragm. The SSR was returned for replanning, the pressure reducer was replaced, and post-maintenance testing (stroking the valve from the control room) was completed satisfactorily. While observing this maintenance activity the inspection team noted no discrepancies.

2.2.4 Engineering/Maintenance Interface

The inspection team noted that the maintenance staff did not request engineering involvement in non-routine or unusual maintenance activities that could potentially compromise a safety-related system or function. For example, before drilling out the thermowell to remove the stuck thermocouple the maintenance staff should have consulted with the engineering staff, since the thermowell was part of the safety-related pressure boundary. Also, since no hydrostatic test procedure exists at Fort St. Vrain, engineering personnel should have been asked by maintenance personnel to specify the test rig configuration to assure that (1) it included a relief valve to prevent overpressurization of the thermowell and that (2) the pressure gauge was installed in such a manner as to preclude its being isolated and potentially giving an erroneous reading. Engineering personnel did specify the hydrostatic test pressure and the duration of the test.

The team reviewed three non-conformance reports (NCRs) associated with maintenance activities related to the removal and replacement of thermocouples stuck in thermowells. NCR 88-127 addressed the cutting and rewelding of thermowell TW 2256-1 to retrieve pieces of a drill bit that had broken in the thermowell during the attempt to remove the stuck thermocouple. NCR 88-131 addressed the replacement of the original 1/4-inch-diameter thermocouple with a 3/16-inch-diameter thermocouple because the 1/4-inch thermocouple could not be fully inserted into the thermowell after the stuck thermocouple had been drilled out. Both NCRs 88-127 and 88-131 appeared acceptable in that the dispositions adequately addressed the technical aspects of these NCRs. NCR 88-122 contained an evaluation of the thermowells to establish an appropriate hydrostatic test pressure to verify that the drilling process did not compromise the integrity of the pressure boundary. Although the evaluation demonstrated that the hydrostatic test pressure of 3000 psig would produce stress five times greater than stresses seen in normal service with a large margin before the thermowells were overstressed, the team noted that the evaluation referenced versions of ANSI Standard B31.1 and ASME Boiler and

Pressure Vessel Code Section VIII that were not committed to in the FSAR. Since the thermowell design margins were so large, this did not raise a concern of technical adequacy. However, the team cautioned the licensee that careless or inappropriate use of codes and standards not committed to in the FSAR can lead to future concerns regarding failure to meet licensing commitments.

2.3 Surveillance Testing

The inspection team reviewed the licensee's program for observing the testing requirements imposed by the Technical Specifications (TS). The review included assessments of the responsible organizations; adequacy of procedures; acceptability of test results and resolution of problems found during testing; administration and scheduling of tests; and observation of test performance.

2.3.1 Organization and Scheduling

Program Controls

The team reviewed the contents and implementation of administrative procedures applied to the Surveillance Program. The principal controls were provided by SMAP-1, "Technical Specifications Surveillance Testing Program," Issue 7; SMAP-5, "Scheduling Program for Surveillances Governed by FSV Technical Specifications," Issue 5; and NPAP-4, "Surveillance Procedure Preparation," Issue 3.

Each line department (e.g., Operations, Results, Maintenance, etc.) was made responsible for preparing and implementing surveillance tests applicable to their areas of expertise via several TS procedure matrices. These matrices identified individual TS line item requirements, the corresponding implementing procedure, procedure issue status, departmental responsibility, etc. and provided an effective management tool for assuring satisfaction of each TS surveillance requirement. The team found these administrative procedures, matrices, and related working documentation acceptably implemented except as noted below.

Scheduling

Surveillance test schedules were administered by the Planning and Scheduling Group and a Surveillance Scheduling Technician was dedicated to the task. Computer-generated schedules were prepared weekly and the applicable test procedures issued by the scheduling group bore a "scheduled date" and a "late date" on the cover sheet of each procedure. The scheduled date was developed from the last actual performance date and the late date represented the actual TS due date without application of TS allowed schedule tolerance (25-percent of the surveillance interval). The technician checked on test completion daily and collected completed tests from performing departments. The technician also reviewed and signed the procedures documenting completion, and entered the performance data in the computer. Postponed and failed tests were similarly tracked but were specially identified to indicate their status. These activities were checked very closely and the intensity of the approach appeared to be very effective in controlling the status of testing and assuring that tests were completed within the intervals required by the TS. No examples of overdue testing were identified. All examples of failed or delayed tests found by the team were identified and were being controlled by the licensee's system. The surveillance scheduling and accountability program was considered a strength.

Although the mechanics of the surveillance scheduling and administration processes appeared to be functioning satisfactorily, one discrepancy involving definition of the TS surveillance intervals was identified. SMAP-5, "Scheduling Program for Surveillances Governed by FSV Technical Specifications," Issue 5, generally provided amplification of TS definitions and scheduling requirements. TS 2.15 defined "refueling cycle" surveillance interval as that (non-quantified) interval between refuelings of greater than one-tenth of the core. No specific interval in calendar time was provided. Similarly, SMAP-5 was silent with regard to defining or discussing refueling cycle intervals. Subsequent discussion with the Manager, Nuclear Production determined that the licensee does, however, apply the 18-month + 25-percent definition of standardized technical specifications to the interval. The Manager, Nuclear Production stated that the procedures would be revised to insure adequate procedure coverage.

Procedure SR 5.4.1.1.8.c-R, "Reheat Steam Temperature Scram Calibration," Issue 24, performed March 1987, was a refueling interval surveillance per TS. The team noted that the entire instrument had been calibrated during March 1987, except for the thermocouples that originated the process variable signal. Discussions with plant managers revealed that new environmentally qualified thermocouples had been bench calibrated upon receipt from their vendor in December 1985 and held in storage until they were installed in late 1986 or early 1987. Although TS 5.4.1.1.1.8.c specified a "refueling cycle" frequency, PSC Action Request No. 1875 had been issued to justify deferral of thermocouple recalibration for 18 months from the date the thermocouples were first exposed to elevated operating temperature (about April 1, 1987). The justification was based upon information from the equipment vendor, the Instrument Society of America, and PSC Engineering which indicated that the thermocouple charateristics were affected only by exposure to operating temperatures and would not be expected to drift at ambient storage or cold shutdown conditions. The team discussed the propriety and technical basis for this deferral with the licensee and the NRC:NRR staff. In the absence of a TS or other regulatory requirement more quantitatively defining the refueling cycle interval and on the basis of the licensee's technical justification, the deferral was considered acceptable.

2.3.2 Procedures

The team reviewed approximately 35 completed surveillance tests. These procedures were reviewed for conformance to TS functional requirements, frequency/test intervals, acceptability of results, and adequacy of licensee disposition of test deficiencies. The procedures included the general areas of plant protection system testing, fluid system testing, fire protection, air and gas system testing, electrical and diesel generator testing, and others. Except as noted below, no discrepancies were identified.

The team noted that the FSV "custom TS," dating from initial plant licensing, frequently provided only very general requirements for functional testing of major systems. The licensee was in the process of rewriting surveillance procedures to meet current industry guidelines and had effectively interpreted the TS to broadly apply the generalized TS requirements to not only the major systems but also to system auxiliaries and support equipment which contributed to the operability of the major systems. For example, the SR 5.2.20 series of surveillance tests for the alternate cooling method (ACM) diesel generator included testing of the batteries and auxiliaries implicit in the TS requirements but not explicitly listed. Similarly, Procedure SR-RE-80-X included calibration of ACM instruments not explicitly required by TS. The vintage of the TS had resulted in some limiting conditions for operation (LCOs) not having corresponding surveillance requirements. The licensee appeared to have extensively evaluated the TS for such omissions and had issued surveillance procedures for verification of conformance with these LCOs not having discrete surveillance requirements. This application of operability concepts was considered a strength.

The licensee was also working with the NRC staff to develop new TSs in the standardized TS format and expected to issue proof and review draft TSs for NRC review shortly after this inspection. This effort was expected result in another major surveillance procedure rewrite effort (expected sometime in 1989). The licensee appeared to have the processes in place to effectively make the transition from custom to standardized TS.

2.3.3 Inservice Testing of Pumps and Valves

The facility's Inservice Test (IST) Program was under development at the time of this inspection. As a high-temperature gas-cooled reactor (HTGR), FSV's systems fall under Division 2, Section XI of the American Society of Mechanical Engineers (ASME) Code instead of Division 1, Section XI (applicable to light water reactors (LWRs)). Division 2, Section XI had not been approved/endorsed by NRC and FSV had not yet implemented a full-scope IST Program.

Individual interim inservice testing requirements had been included in certain Technical Specifications, e.g., TS 5.3.4, "Safe Shutdown Cooling Valves Surveillance." Typically, these TS requirements did not specifically invoke the ASME XI provisions but merely required "operability" or "functional" testing of components. Although the licensee was committed to use the provisions of ASME XI as guidance, no overall program description or component test matrix had been developed. Individual test requirements were addressed only in the individual implementing procedures. Similarly, no program for collation and trending of equipment performance data typically required of IST programs had been implemented. Such a program was under development at the time of inspection. As a result of the above ambiguities in the IST Program development, several discrepancies were identified in implementation of the existing TS IST requirements during review of Procedure SR 5.3.4b1-A, "Loop I Safe Shutdown Cooling Power Operated Valve Tests," Issue 5, performed on April 16, 1987. TS 5.3.4 required an annual "full functional test" of the system valves and provided progressive implementation requirements for various valve types through the cycle 5 refueling. Table II in this procedure listed seven sets of valves which were identified as exempt from testing with the justifying annotation "normally operates." The same was true for the Loop II procedure SR 5.3.4.b2-A. None of the valves exempted by the licensee appeared to fall under the delayed implementation requirements of the TS nor the exemption or deferral provisions of the NRC safety evaluation reports of the applicable TS Amendments Nos. 33 and 51.

On May 17, 1988, the licensee provided the team with a list of procedures which coincidentally exercised all the valves for Loops I and II except for valves HV-2153 -1 and -2, bearing water filter isolation valves. Although these procedures did not perform preplanned testing of the valves, the licensee considered that the coincidental operation met the requirements of their program, processed Procedure Deviation Reports to incorporate the tests into

SR 5.3.4.b1-A and SR 5.3.4.b2-A, and documented the test performances. The HV-2153 valves were subsequently tested on May 12, 1988 because equivalent, existing data was not available.

The team also requested the licensee to identify any other procedures that may contain similar inappropriate exceptions. On May 18, 1988, the licensee advised that Procedure SR 5.2.7.a1-A, "Loop I/II Valves and Circulator Drive Tests," Issue 3, included an exemption for valve V-22371, emergency feedwater (EFW) header check valves. At the end of the inspection, the licensee was evaluating the availability of existing, coincidental test data and the applicability of forward/reverse flow testing requirements for this valve. NRC review of the results of the above licensee actions to ensure all valves subject to IST are not improperly exempted is an unresolved item pending further NRC Region IV review (267/88200-10).

The team considered the absence of an overall program control document to be a major detractor from effective definition and management of the program in that essentially no guidance had been provided to either procedure writers or test conductors.

2.3.4 Measuring and Test Equipment Inaccuracies

As part of the licensee's post-trip review of a reactor scram occurring on May 6, 1988, control problems were identified with the reheat steam temperature control circuits. Troubleshooting from May 6 through May 14 identified several circuit and equipment problems. The conduct of licensee post-trip review and problems regarding thermocouple removal, repair, and reinstallation are discussed in Section 2.1.4 and 2.2.3.1, respectively, of this report.

The team also reviewed the calibration-related problems with the reheat steam temperature controls. This control loop was considered not to be safety-related and was not subject to TS. Accordingly, it had been routinely calibrated on a modular basis; no complete loop checks were performed which would test the circuit from input (thermocouple output) to control output (reactor flux control/rod movement). The circuit apparently had been operating with about a 35°F offset in actual reheat temperature vs. the demand control signal. The licensee subsequently determined that the offset was caused by a suspected loose lead in one of the circuit's averaging sub-loops; the licensee had completed a full-loop circuit check and was planning to incorporate the full loop check into future calibrations.

During this troubleshooting, the licensee encountered difficulties in obtaining stable module calibrations between bench and field calibrations. Initially, early in the week of May 9, 1988, the digital multimeters used for testing were suspected to have drifted out of the manufacturer's calibration tolerances. The loop was subsequently recalibrated using test meters known to be good.

On about May 16, the licensee determined that meter test leads were improperly connected to the meter for sc r all of the reheat steam temperature control troubleshooting and recalibration. The meters had two positive and two negative female test lead jacks for measurement of voltage, resistance, or current. Except for current measurements, selection of any positive and negative jack combinations was apparently acceptable and resulted in accurate measurements.

However, for current (milliamp) measurements such as used for this activity, only one combination of jack installation was acceptable and incorrect combinations can and did result in significant meter errors.

Procedure RP-A-04, "Requirements Governing the Control and Calibration of Test Equipment and Standards," Issue 6, Section 4.5, "Out of Tolerance Conditions," provided requirements for evaluation of prior use of out-of-calibration equipment to ensure that installed instruments were recalibrated if defective test equipment may have been used on them. When the team inquired late on May 16, 1988 about the identification and operability status of safety-related instruments potentially calibrated with the affected meters, the responsible instrument and control supervisor advised that the evaluation had not been started, even though plant restart had initially been scheduled for May 15, 1988 had been delayed, and was then scheduled for the night of May 16-17, 1988. The team considered this failure to recognize the need to establish the operability and calibration status of potentially affected safety-related instruments as a weakness in the area of licensee management controls and attention.

Apparently as a result of the team's inquiry, the evaluation was conducted from the evening of May 16 through May 17, 1988 and approximately 100 uses of five meters were evaluated. Eleven cases of safety-related uses requiring calibration rechecks were identified; of these eleven, two were found to be out of tolerance and were recalibrated. Another 11 cases of non-safety-related uses of the meter were considered to require rechecks, and rechecks were scheduled for the week following plant restart. The team reviewed the detailed records used for the licensee's evaluation and found the evaluation acceptable.

2.3.5 Surveillance Activities Witnessed

Surveillance test performance was observed to determine that the procedures were properly performed and satisfied the referenced TS requirements, that coordination between plant operators and test performers was adequate, that measurement and test equipment was properly calibrated and applied, that test results were properly acquired and evaluated, and that problems were properly handled. The team witnessed part or all of the following surveillance tests:

- SR 4.1.1.d-X, "Full Stroke Scram Test," Issue 3, May 12, 1988
- SR 5.4.1.1.4.b-P, "Wide Range Power Channel Test," Issue 26, May 16, 1988
- SR 5.4.9-A2, "Process Beta Monitors Calibration," Issue 26, Section 5.5, RT 31193, "SJAE Process Flow," May 16, 1988
- SR 4.1.1.1.14.a-M, "Plant 480 Volt Power Loss Test," May 17, 1988.

All observed testing was considered satisfactory by the team except for SR 5.4.1.1.4.b-P as further discussed below.

As previously discussed, the licensee was completing a major rewrite of TS surveillance tests to meet current industry format and content standards.

Procedure SR 5.4.1.1.4.b-P, "Wide Range Power Channel Test," functionally tested the logarithmic nuclear instrument channel interlocks, rod withdrawal prohibits, and scrams. The procedure had been initially reissued as Issue 25 in the new format.

During its first performance, the licensee found that the new procedure, prepared using the vendor's Operations and Maintenance Manual (O&M) No. 93-I-1-335, included testing of an interlock circuit which would generate a single channel scram when the "Wide Range Channel Level Calibrate Switch" was removed from the "Operate" position. This circuit feature was not actually installed in the plant equipment. Nonconformance Report No. 88-030 identifying the above discrepancy was issued on February 18, 1988 and was resolved to "use as is" pending long-term investigation and evaluation by the licensee. The team reviewed the licensee's NCR disposition finding that, although appearing contradictory with respect to the controlled vendor information, the absence of the circuit appeared to have negligible safety significance. The log level portion of the channels did not have any normal scram or rod-withdrawal-prohibit outputs; only the unaffected startup rate portion of the channels generated either a scram or rod withdrawal prohibit signal. Further, the Updated Safety Analysis Report (USAR) took no credit for any log channel scrams in the various accident analysis scenarios of USAR, Section 14. The licensee had not been able to determine when or why the circuit was deleted from the equipment and was following up the problem with the nuclear steam supply system (NSSS) vendor.

At the time of discovery in February, the procedure was temporarily changed via a Procedure Deviation Report (PDR) to delete the inapplicable tests and reconfigure the procedure for performance. On May 4-6, 1988 the procedure was reissued as Issue 26, incorporating some administrative changes in procedure completion and signoff forms, but inadvertently reinstating the erroneous procedure steps addressing the nonexistent scram signal. Although the procedure went through the routine review and approval steps, the licensee did not identify the error.

On the 0000-0800 shift of May 16, 1988 initial attempts to perform Issue 26 of the procedure were unsuccessful when the procedure was found to have inadequate instructions for establishing the necessary initial conditions and clearing existing scram signals (plant shutdown). The inapplicable level switch scram steps had been marked "N/A" but had been left in the procedure. During the 0800-1600 shift on the same day, the team observed a second attempt to perform the procedure following approval of a PDR to reset the shutdown scrams. This attempt was initially unsuccessful because the PDR was incomplete. Following issuance of a second PDR to set initial conditions, the inspector witnessed another unsuccessful attempt to calibrate the "A" channel of the wide range power nuclear instrument. The procedure, as written, including the inapplicable steps, did not provide a smooth, sequenced instruction and resulted in the technician having extreme difficulty placekeeping and maintaining the functional sequence of the test. For example, bistable alarms and indicating lights from previous steps were not always reset, preventing the technicians from determining whether the lights had merely remained on from prior steps or had reflashed as a result of the current step. Similarly, the actual system responses did not match the procedure's expected responses with the scram interlock circuit missing. Additionally, the procedure had been partially signed off by the previous shift which caused some confusion for the subsequent shift continuing the procedure at the proper step. In response to the difficulties encountered, the licensee issued PDR No. 88-340 during the evening shift of May 16, 1988, deleting the inapplicable steps and correcting the remaining steps. The poor quality of the initial and revised procedure had the potential for an inoperable reactor protection channel to go undetected by the testing.

During review of other completed tests and operating procedures discussed elsewhere, the team had also noted that several of the procedures had required one or more PDRs to correct the originally issued versions to permit performance. The licensee routinely issued full-page changes when a procedure was modified by PDR, thereby reducing the chances for error inherent in issuing piecemeal changes. However, the need to issue multiple changes to a recently reviewed and approved procedure indicated weaknesses in the process for maintaining accurate and current procedures.

As a result of the apparent frequency of PDR use and the performance-based observations, the adequacy of the licensee's procedure review, validation, and approval practices was identified as a concern to PSC management. The PSC Systems Engineering Manager, Results Supervisor, and others on the licensee's staff discussed plans for creating a Plant Operations Review Committee procedures subcommittee which was in the planning stage and which was intended to improve the procedure publication process. These plans included a procedure verification and validation process.

The team further reviewed the last two years' data for PDR usage, noting that for the approximately 3690 total procedures, more than 1300 PDRs had been issued during calendar year 1987. In contrast, about 340 PDRs had been issued for 1988, or roughly one-half the number issued in 1987. Although the trend appeared to indicate a declining use of PDRs as the new format procedures have matured, the team remained concerned that the overall procedure approval process was weak.

2.4 Management Oversight and Safety Review

The general functions of committee activities and safety assessment were reviewed and included the staffing, the onsite review committee, the offsite review committees, the operating information assessment group, and the post-trip review activity. The review included selected procedures and records and personnel interviews regarding the implementation of the activities. The plant staffing appeared to be adequate and the May 12, 1988 reorganization appeared to be a positive step toward improving the operations and support of the facility. The overall impact of the reorganization was not assessed during the inspection. The plant operations onsite review committee (PORC) activities appeared to be adequately implemented. The inspection revealed that the review function could have been more effective with regard to the use of telephone poll (voting) reviews and the content of the PORC charter, including adequate specific guidance for all activities.

The Nuclear Facility Safety Committee (NFSC) activities appeared to be a strong function. Strengths included the specific use of NFSC members as technical auditors in the areas of expertise and the provision of the NFSC meeting minutes to all NFSC members and alternates for review and comment, as appropriate. Three noteworthy observations were made regarding the NFSC activities: (1) The NFSC planned to meet more frequently than once each six months, (2) almost all meetings were conducted onsite at the visitor's center, where the plant staff could easily attend; and (3) it was apparent from review of the minutes and through discussions, that the NFSC was aggressive regarding reviews.

The operating information assessment group (OIAG) activities (FSV, industry, and NRC operating experience) appeared to be acceptable. However, the distribution of reports of items reviewed by the OIAG and the OIAG program status reports was, limited and did not include all the facility managers nor the Vice President, Nuclear Operations NFSC chairman. The review of the NRC Information Notice No. 87-25 appeared to be limited and could have been more comprehensive (See Section 2.4.4 of this report). Finally, even though the intent of the OIAG function may have been addressed, the OIAG activities were not being fully implemented in accordance with the procedure requirements.

The post-trip review activities appeared to be adequately implemented. The practice of utilizing a formal multidiscipline post-trip review of all reactor trips and the established post-trip review committee for reviewing all reactor trips routinely and condition III reactor trips (complicated) prior to plant restart was considered a good system. Procedure SMAP-7, "Post Trip Reviews," Issue 6, did not require all plant transients to be reviewed. The other transients were generally being reviewed, however, at the option of the Station Manager.

2.4.1 Staffing

The facility appeared to be adequately staffed. The licensee management was sensitive to the potential staffing problems that could arise because the nuclear plant had an uncertain future. The nuclear production department was hiring additional personnel, operators were being trained in order to obtain an NRC operator license, and work on a limited plant simulator was progressing. Further, a reorganization of the Nuclear Operations Department was effective May 12, 1988. The reorganization addressed the consolidation of engineering activities, elevation of the training department to a division level, the focusing of planning and scheduling activities, and the streamlining of the nuclear production (plant) division. The Quality Assurance Division continued to report directly to the Vice President, Nuclear Operations, as noted in the Fort St. Vrain license. The licensee was working actively with the NRC, making the organization changes required in the license.

2.4.2 Plant Operations Review Committee

The PORC function was specified by Procedure NPAP-2, "Charter for Plant Operations Review Committee for Fort St. Vrain Nuclear Generating Station," Issue 2, which implemented the requirements of Technical Specification AC 7.1.2, "Plant Operations Review Committee (PORC), Administrative Controls." The minutes of five PORC meetings (Nos. 763-767) were reviewed. Selected personnel were interviewed regarding the PORC activities. A team member attended a PORC training/seminar conducted on May 11, 1988 and observed the PORC meeting (No. 777) conducted on May 12, 1988.

The PORC conducted meetings routinely at weekly intervals, generally on Tuesday afternoon. The PORC reconvened during the week, as necessary, to review other items requiring prompt attention. It was noted that although Quality Assurance Department (QAD) personnel attended the scheduled PORC meeting; they did not attend the reconvened meetings. Interviews revealed that the items reviewed by the PORC during the reconvened meetings were reviewed by QAD as part of the routine QA activities.

It was also noted that the PORC review, conducted on February 20, 1988, at 4:00 pm (Saturday), a reconvening of Meeting No. 765, took place by telephone and included the Chairman, three members, and two alternates - no QAD representative. The review included a change notice (CN 2763), a controlled work procedure (CWP 88-0036), and a functional test (2763) associated with the D-circulator speed/cable repair and/or replacement activity. Review of the PORC minutes and interviews revealed that telephone reviews did not usually take place. However, the practice of performing telephone reviews may not meet the full intent of the TS, in that the PORC (quorum in session) meets and recommends to the Manager, Nuclear Production approval or disapproval (in writing) of items and rendered determinations in writing with regard to whether or not the item constituted an unreviewed safety question. Section 3.3.3 of NPAP-2, regarding the conduct of business, item (a), allowed the use of "telephone polls" as situations dictated.

The review of reportable events was addressed in Section 4.6 of procedure NPAP-2; however, the procedure requirements were not inclusive of internally generated 10 CFR Part 21 reports. These may not be reportable under 10 CFR 50.72/50.73 which were reviewed routinely by the PORC. Section 4.7 of procedure NPAP-2 addressed the forwarding of other matters to the PORC for review, including 10 CFR Part 21 reports, as part of the review of facility operations to detect potential nuclear safety hazards. The review of procedure G-8, "Compliance With 10 CFR 21 Requirements," revealed that the procedure did not specifically address the PORC review of the 10 CFR Part 21 reports. Interviews indicated that 10 CFR Part 21 reports were reviewed routinely by the PORC.

The review of the PORC meeting minutes revealed that the documentation of the matters discussed could be more comprehensive in order to provide a better independent review of the PORC activities by other PORC members and alternates, NFSC members and NFSC alternates, and QAD auditors. Furthermore, it appeared that the number of questions documented in the NFSC minutes regarding the subject matter documented in the PORC minutes, could have been reduced by improving the content of the PORC minutes.

The review of PORC minutes and interviews with license personnel revealed that the PORC was reviewing plant procedures as required by Technical Specifications utilizing a memorandum from the associated department; however, the PORC charter, NPAP-2, Section 4.1, noted that the "existing procedures...reviewed by PORC in accordance with SMAP-11." Procedure SMAP-11 was deleted on December 1, 1986.

The review of PORC minutes and discussions revealed that the PORC minutes were not provided routinely to all members and alternate members of the PORC for their review and comment. The minutes were only provided to those persons who attended the specific PORC meeting.

2.4.3 Nuclear Facility Safety Committee

The NFSC function was specified by the "Charter for the Nuclear Facility Safety Committee for Fort St. Vrain Nuclear Generating Station", Issue 5, implementing the requirements of Technical Specification AC 7.1.3, "Nuclear Facility Safety Committee (NFSC), Administrative Controls." The minutes of six NFSC meetings (Nos. 108-113) were reviewed. Selected personnel were interviewed regarding the NFSC activities.

The NFSC charter addressed the requirements of the Technical Specification and contained liberal of guidance to assist in the performance of the NFSC activities. The review of the NFSC charter and the NFSC minutes revealed that the NFSC charter appeared to have recently been substantially improved. The charter addressed two specific subcommittees formed to assist in the area of licensed activities: Special Test Review Subcommittee and the Startup Test Review Subcommittee. Also an NFSC QA Subcommittee was established to perform the required NFSC audits in concert with the QAD. The performance of the required audits under the cognizance of the NFSC routinely included NFSC members as part of the audit team. The practice of using NFSC members as auditors was considered a strength as the technical content of the audits appeared to be good and NFSC members were more closely involved in the independent overview of facility departments.

The NFSC charter, Section 10.0, addressed the meeting frequency requirements of at least once each six months; however, reviews and discussions revealed that the meetings were scheduled and conducted more frequently than required. Additionally, the NFSC meetings were held on site at the visitor's center in most cases, providing access to the meetings by the plant staff. Document review and discussions revealed that the minutes were routinely provided to all the NFSC members and alternates for review and comment, even if the persons had not attended the scheduled meeting.

Review of the NFSC minutes and discussions indicated that the NFSC appeared to be a strong independent review group. At times, NFSC personnel asked many questions; answering these questions apparently required substantial effort. The questions, at times, were asked because the PORC minutes provided to the NFSC did not include complete information. As noted previously, this area could possibly be improved to obtain more effective, efficient, and timely NFSC reviews. Overall, the NFSC appeared to be an aggressive review group.

The NFSC conducted telephone polls (voting) on a limited basis. Section 4.2.8 of the NFSC charter allowed voting by telephone, when "it is desirable to expedite the voting action." The item or document in question was identified in the minutes of the next NFSC meeting. The review of minutes and discussions confirmed the practice.

The review of reportable events (LERs) and Part 10 CFR 21 reports was required by Section 43 of the NFSC charter. The review of procedure G-8, "Compliance With 10 CFR 21 Requirements," revealed that the procedure did not specifically address NFSC review of the 10 CFR Part 21 reports. Interviews and review of the NFSC minutes revealed that 10 CFR Part 21 reports were routinely reviewed by the NFSC.

2.4.4 Operation Information Assessment Group

The OIAG function was specified by procedure NPAP-1, "Fort St. Vrain Nuclear Generating Station Operation Information Assessment Group Charter," Issue 4, implementing NUREG-0737, Item I.C.5, "Feedback of Operating Experience." The inspection revealed that the licensee had addressed the independent safety engineering group in correspondence to the NRC in 1980, and the licensee was not required to implement a safety engineering group, as addressed by NUREG-0737, Item I.B.1.2. Accordingly the licensee had not implemented an independent safety engineering group and the review of in-house and outside operating experience was provided by the OIAG within the technical services engineering group. The details of the receipt, logging, review, independent review, results reporting, and periodic OIAG program review were provided in procedure TSP-28, "Conduct of Technical Services Reviews for the Operating Information Assessment Group (OIAG)" Issue 3.

The designated OIAG Chairperson, the OIAG Coordinator, and the OIAG Senior Engineering group provided the initial logging, screening, reviews, and distribution of information for review and consideration for action. Document reviews and discussions revealed that, with exceptions, the OIAG program appeared to be functioning.

Following the initial screening of incoming information (SOER, SERs, IENs, etc.) by the OIAG, the information was forwarded to the training department for reproduction and transmittal to the designated groups, as appropriate.

The OIAG reviewed the FSV events for applicability, both in-house and external (industry), which were considered by the group routinely. The source of the FSV operating experience reports (OERs) included licensee event reports (LERs), procedure changes, transient analysis reports, change notices, control work procedures, and facility license changes. Additionally, the OIAG had generated a number of FSV OERs, Attachment NPAP-1c, as a result of other operating events, including the circulating water pit flooding June 12, 1986 and Loop II restart/cooldown May 4, 1987. The OERs were generated in order to fully assess the events and provide appropriate feedback to the plant programs, procedures, and personnel.

During the inspection period on May 12, 1988, a reorganization of the Nuclear Production Division was announced. The OIAG function was planned to be transferred to the Nuclear Licensing Department. The plan was to maintain the OIAG function to ensure effective and timely review and actions regarding in-house and industry experience. Licensee actions to improve and ensure the OIAG's continuing effectiveness is an unresolved item pending further NRC Region IV review (267/88200-11).

The review of the OIAG meeting minutes and other general OIAG correspondence revealed that the OIAG reports were given a limited distribution. All appropriate managers and the Vice President, Nuclear Production/NFSC Chairman were not included.

The team reviewed the OIAG processing of NRC Information Notice No. 87-25, "Potentially Significant Problems Resulting From Human Error Involving Wrong Unit, Wrong Train, or Wrong Component Events." The NRC information notice was noted to be received on June 18, 1987, and was assigned a number, G-87198, for review and tracking purposes. On July 21, 1987, the OIAG coordinator noted on the OIAG review sheet (TSP-28A) that immediate attention was not required. An independent review was noted as applicable and on July 24, 1987, the independent reviewer noted that the actions regarding the notice was to "route to operations FYI only." The OIAG Chairman concurrence with the above actions "route ops" was noted on July 27, 1987. The team did not note evidence of a detailed review of the references in the notice, including NUREG-1192," An Investigation of Contributors to Wrong Unit or Wrong Train Events" (labeling); IE Information Notice 84-51, "Independent Verification"; IE Information Notice 84-58, "Inadvertent Defeat of Safety Function Caused by Human Error Involving Wrong Unit, Wrong Train, or Wrong System"; and numerous NRC AEOD reports and four supplemental reports specifically addressing the subject of the notice. The review of the overall OIAG activity revealed that, even though the reviews were being performed, the OIAG was not being fully implemented in accordance with the OIAG Charter, NPAP-1, Issue 4.

Monthly meetings to review the operation of the program and ensure proper functioning were not being conducted per NPAP-1, Section 2.0. Therefore, the screening process was not being "reviewed in the regular meetings by the members" per NPAP-1, Section 3.6.1.5.

Routine internal audits had not been performed "to assure that the OIAG program was functioning effectively," per NPAP 1, Section 3.6.1.7. These audits were to have been reviewed during the regular meetings. Reviews and discussions revealed that a program review had been performed on December 29, 1987, at the request of the OIAG chairperson; and a QAD audit of the OIAG function was scheduled later in 1988.

Interviews revealed that the OIAG chairperson felt that the intent of the OIAG function was being met because discussions were being held routinely at the daily (morning) superintendent meeting, although the discussions were not well documented.

The failure to fully implement the OIAG function per the approved charter, procedure NPAP-1 was considered a weakness. This weakness was discussed with licensee management for their consideration.

2.4.5 Post-Trip Reviews

The post-trip review function was specified by procedure SMAP-7, "Post-Trip Reviews" Issue 6. The program/procedure provided a "consistent, comprehensive and systematic method to diagnose the causes of and conditions associated with unscheduled reactor trips." The reviews provided the basis for making a determination about safe reactor restart. At the Station Manager's option, the procedure was used for transients other than reactor trips.

The review of controlling procedure SMAP-7, and selected transient review packages revealed the activity to be quite comprehensive. The transient review function consisted of multiple-discipline reviews, including the shift operating personnel, results engineer, technical advisor, and other plant personnel, as appropriate. A transient review committee (TRC) review was required before restart for a Condition II reactor trip (complicated) as was written permission from the Station Manager. The TRC reviewed all reactor trips during regularly scheduled meetings including Condition I and II reactor trips (uncomplicated) although this was not required.

The establishment of the post-trip review function appeared to be a good method for reviewing trips and provided a multi-disciplined review with some amount of independence and determination of immediate or short-term corrective actions. The ultimate responsibility for plant restart rested in all cases with the Station Manager/Manager, Nuclear Production. However, the post-trip review procedure was not fully inclusive of all plant transients but was applied at the Station Manager's option for transients other than reactor trips. The inspection revealed that some of the transients had been reviewed by the TRC; however, the review of all required transients (complicated) was not a requirement in procedure SMAP-7. This observation was discussed with licensee management for their consideration.

2.4.6 Management Overview and Safety Review Weaknesses

The inspection team concluded that the apparent primary contributors to the weaknesses described in paragraph 2.2 above were poor licensee management overview controls and inadequate communications between first-line supervisors and higher levels of management. This conclusion was based on interviews of personnel, observations of maintenance and surveillance testing activities in progress, and the noted weak procedural guidance available.

2.5 Corrective Action Programs

The team reviewed the implementation of the FSV quality assurance program relative to corrective actions taken in the following areas:

- discrepant report tag (DRT)

- ongoing activities related to maintenance and repair initiation and disposition of nonconformance reports (NCRs) internal audit findings

- operating events.

The review included discussions with knowledge personnel performing the work, review of records in document control, and attendance at post-trip reviews and outage scheduling meetings.

2.5.1 Discrepant Report Tags - Initiation and Disposition

The licensee uses DRTs to identify equipment and component problems requiring corrective action or repair. The most recent NRC Systematic Assessment of Licensee Performance (SALP) 50-267/87-06 discussed prior problems with the licensee's inadequate and slow corrective actions. The team reviewed the following DRTs to determine the effectiveness and timeliness of the corrective action applied.

(1) DRT 11853 was affixed to the low-pressure separator pump motor, that separated helium and water. The relevant SSR 88502740 was initiated on May 4, 1988 to identify that the pump motor was running roughly. Corrective action isolated the pump, replaced the motor bearings, and set the flow per procedure SR 5.4.9-A1. This equipment was a non-safety-related item (NRI).

(2) DRT 005604 was affixed to an NRI pressure differential transmitter used to monitor the moisture level in the helium cooling medium. SSR 87507903

was initiated on August 6, 1987 to replace the existing flexible hose connecting the condulet and the instrument with a longer hose.

(3) Internal leakage from the bottom of the prestressed concrete reactor vessel (PCRV) pipe cavity air handling unit resulted in DRT 005610. SSR 87508684 was initiated August 18, 1987 to open the unit, investigate the leak, and repair was required. This was an NRI.

(4) The inboard and outboard mechanical seal of the safety-related cooling water pump 1C, Loop 11 leaked in excess of 30 drops per minute. DRT 002182, dated May 11, 1988 was affixed to this equipment. SSR 87508759 identified this as a safety-related component and included corrective action to replace both mechanical seals. The technical specifications required that at least one cooling water pump must be operating in each of the two PCRV cooling water loops during the reactor at power level (LCO 4.2.13). The SSR required post-maintenance testing per procedure SR RE-55-X.

Review of the above DRTs and SSRs, and subsequent discussions with the cognizant planning and scheduling personnel indicated that in these instances, the delay in implementing the corrective action was justifiable.

2.5.2 Ongoing Activities Related to Maintenance and Repair

The team observed maintenance activities in progress for two thermowell repairs and maintenance on feedwater trim valves. As discussed in Section 2.2.3.1 of this report, the procedures and practices applied to these activities were considered unacceptable by the team.

Although some of the activities were subject to QC inspection, no action had been taken by QC inspection personnel to question or stop obviously noncomforming activities. These matters were ultimately brought to the attention of the Plant Manager who promptly stopped the work. The team subsequently interviewed a QC inspector involved with the work to evaluate the awareness and effectiveness of "stop work" practices and implementation in the current context. The QC inspector referred the team to the requirements regarding "stop work" in paragraph 4.4 of procedure P-12, "Plant Maintenance," Issue 5. The QC Manager referred the team to another procedure, MPRM-13, "Stop Work," Issue 2. The team determined from review of these procedures that they did not provide adequate guidance or the necessary authority to enable on-site QC inspectors and supervisors to exercise "stop work" actions when field conditions warranted. The FSV QA manager concurred with the team that the existing procedures could not be effectively implemented and agreed to develop a procedure to implement "stop work" and to train the FSV staff in its implementation. Completion of these actions is an unresolved item pending further NRC Region IV review (267/88200-12).

2.5.3 Initiation and Disposition of Nonconformance Reports

Nonconformance Reports (NCRs) were initiated to document nonconforming conditions and to specify and document actions to restore conformance. The team reviewed the NCR file in the document room to determine any trend in the repair of safety-related thermowells and bearing water WYE strainers. The team determined that NCRs 85-042 and 85-043 were initiated in 1985 to extract thermocouple remnants from thermowells. NCRs87-607, 88-002, and 88-003 dealt with the repair of bearing water WYE strainer baskets. The NCR form did not contain provisions to evaluate and document root cause analyses and corrective action to preclude repetition. Administrative Procedure Q-15, "Nonconformance Reports," Issue 7, which addressed nonconformances did not require these provisions for the resolution of NCRs. Administrative Procedure Q-16, "Corrective Action System," Issue 8, which addressed corrective action, however, provided for these elements in the resolution of Quality Deficiency Reports, (QDRs) Corrective Action Requests (CARs) and Corrective Action Request Programs (CARP) but not for NCRs.

NCRs 85-867, 86-608, and 85-998 which dealt with discrepancies in procurement and installation of thermocouples were reviewed and determined to be adequately resolved. The QA manager stated that Administrative Procedures Q-15 and Q-16 would be revised to include provisions to document root cause analysis and actions taken to prevent recurrence. Completeness of these licensee actions is an unresolved item pending further NRC Region IV review (267/88200-13).

An elaborate computerized NCR status keeping system was in place to track and trend future NCRs. However, key words or other similar provisions were not established to code the NCRs prior to entry to facilitate the retrieval and trend analysis of NCRs on the same subject.

2.5.4 Internal Audit Findings

The team reviewed a sample of QA audit reports (below) finding that the audits were well planned, checklists were used where applicable, and adverse audit findings were adequately documented in the form of QDRs, CARs, and CARPs. Licensee followup and corrective actions were considered acceptable. The team performed detailed reviews of the following:

(1) Audit-QAC-87-1209 had been performed during September/October 1987 for activities related to preventive maintenance (PM), training and qualifications, adequacy of maintenance procedures, and associated action to correct previously identified noncompliance with regulatory requirements. As a result of this audit, one CAR, seven QDRs and twenty improvements items (IIs) were initiated. The audits and licensee corrective actions were considered acceptable.

(2) Audit QAC-86-1862 was performed during July through September 1986 of activities related to independent reviews of analyses, record keeping, clarification of surveillance intervals, an apparent reactivity anomaly, validity of input data, and inconsistencies in surveillance procedures. Thirteen CARs were issued for the audit findings identified during this audit. The dispositions of CARS 148, 150, 159, 160, 161, and 167 were reviewed during this inspection. The licensee actions taken to correct the conditions identified were considered acceptable.

(3) Review of Corrective Action Program (CARP-88-01) Audit Report

This audit was performed in March, 1988 to evaluate and reasses the overall quality assurance program for corrective action. The audit identified one CAR and three IIs. The CAR identified the need for programmatic controls for the adequate resolution of externally generated 10 CFR Part 21 reports. The IIs related to programmatic changes to improve the efficiency of the 10 CFR Part 21 review process so that they can be resolved in a timely manner. The audit also reviewed the actions taken on CARP-87-02 performed in October 1987. Review of the results of the audit indicated that a conscientious effort was being made to resolve items that degrade quality.

2.5.5 Corrective Action for Operating Events

The team reviewed the licensee analyses of two operating events that occurred on April 7 and May 6, 1988 and and the actions taken to preclude recurrence. The team members attended one Transient Review Committee briefing and discussed the analyses with knowledgeable system engineers. The results of the review indicated that the analyses identified the probable causes of the events and corrective action was completed in most of the cases before startup.

(1) Operating Event - Unplanned Release

On April 4, 1988 with the reactor operating at approximately 74-percent full power, a disturbance of the offsite electrical power grid actuated a power/load unbalance (PLU) circuit which resulted in a turbine trip. The licensee identified that the turbine control system was unable to respond to the upset condition because of a manufacturing deficiency in the PLU circuit. During a July 1988 outage, the licensee plans to correct errors in the PLU circuit. During the cooldown, a relief valve (V6389) in the core support floor (CSF) vent line lifted, permitting unpurified helium to enter the reactor plant ventilation exhaust system causing an unplanned release of radioactive gas. The licensee concluded that the relief valve setpoint was too low and reset the valve from 5 to 10 psig lift pressure. CSF components were cleaned and the system restored to service.

In an unrelated incident, a neoprene expansion joint in one of the circulating water lines failed and flooded both circulating water pumps. The failed neoprene expansion joint was replaced with one from a different manufacturer and other questionable expansion joints in the circulating water system were inspected and replaced.

(2) May 6, 1988 Transient

On May 6, 1988, the event discussed below occurred at the plant. The parts of the event were independent of each other. The corrective action taken on each part of the event is also discussed.

a. The B Circulator tripped at 12:32 pm and subsequently the A circulator transferred to backup bearing water from normal bearing water supply. All the instruments associated with the B circulator trip, including level controller LC-2135 and emergency high drain valve LV-21245, were cleaned, tested, and recalibrated where necessary. All the relays which would cause the transfer of the cooling water to the A circulator from normal to backup bearing water, were tested and non were observed inoperable.

b. A reactor scram caused by two inaccurate temperature modifiers in the reheat system occurred. Subsequent to this transient, both individual components including thermocouples and the entire loop were calibrated and the loop was tested and verified to be operating properly. The calibrations of the thermocouples is discussed in paragraph 2.3.

c. The radiological aspects of the transient included a purified helium compressor trip. The loop 2 buffer helium and bearing water systems were contaminated by the tripping of the purified helium compressor and the failure of the loop 2 buffer helium makeup water to transfer to the helium supply tank because the transfer switch, HS-2366, was in the "normal" position instead of the "auto" position. The radioactivity in the low-pressure bottles and the bulk of unplanned release was attributed to operator error. In his haste to reduce the prestressed concrete reactor vessel (PCRV) helium inventory as fast as reasonably achievable, an operator exceeded the capabilities of the operating purification train. Most of the activity went to the the helium storage tank (LP bottles). This area was posted as a high radiation area and access to this area was restricted.

d. Water that entered via circulator A became visible at 12:51 pm. It was postulated that water in the buffer-mid-buffer and main drain transmitter sense lines caused the main drain control system to erroneously raise the back pressure in the circulator bearing cartridge and forced bearing water into the PCRV. The licensee was unable to determine the cause of this part of the event.

This information indicated that the licensee determined three of the four causes of this transient and took adequate corrective actions.

3.0 DRAFT INFORMATION RELEASED to the LICENSEE

During this inspection, one of the team members gave a member of the licensee's staff a copy of some handwritten observations. Attachment B is a copy of the document that was released to the licensee.

4.0 EXIT MEETING

The operational safety team and other NRC representatives met with licensee personnel on May 20, 1988 to discuss the scope and findings of the inspection. Attendees at the exit meeting are identified in Attachment A. During the inspection, the team also contacted other members of the licensee's staff not identified in Attachment A to discuss issues and ongoing activities.

ATTACHMENT A

ATTENDANCE SHEET

EXIT MEETING - May 20, 1988

NAME	ORGANIZATION	POSITION TITLE
J. E. Cummins	USNRC	OSTI Team Leader
E. V. Imbro	USNRC	OSTI Assistant Team Leader
C. J. Haughney	USNRC	Chief, Special Inspection Branch, NRR
J. D. Smith	USNRC	Operations Engineer
D. R. Hunter	USNRC-RIV	Senior Reactor Inspector
D. A. Beckman	USNRC	Consultant
D. B. Waters	USNRC	Consultant
J. M. Sharkey	USNRC	Operations Engineer (Mechanical)
K. Naidu	USNRC	Reactor Inspector
T. F. Westerman	USNRC-RIV	Chief, Projects Section B
P. F. Tomlinson	PSC	Manager, QA
J. Eggebroten	PSC	Technical Projects Manager
M. H. Holmes	PSC	Nuclear Licensing Manager
D. Goss	PSC	Nuclear Regulatory Affairs Manager
P. Michavo	USNRC	Resident Inspector
L. J. Callan	USNRC	Director, Div. of Reactor Proj., RIV
H. O'Hagan	PSC	Outage Manager
R. Crown	PSC	Nuclear Engineering Manager
K. L. Heitner	USNRC	NRR Project Manager
M. E. Deniston	PSC	Shift Supervisor - Audit Coordinator
R. W. Williams, Jr.	PSC	V.P. Nuclear Operations
C. H. Fuller	PSC	Manager, Nuclear Production
M. Coppello	PSC	Central Planning & Sched. Manager
L. D. Scott	PSC	QA Services Manager
M. J. Ferris	PSC	QA Operations Manager
F. J. Borst	PSC	Nuclear Training Manager
N. Snyder	PSC	Maintenance Department Manager
H. L. Brey	PSC	Mgr., Nuclear Licen. & Resource Mgmt.
M. Block	PSC	Manager, System Engineering
D. W. Evans	PSC	Operations Manager
F. J. Novachek	PSC	Nuclear Support Manager
D. Rodgers	PSC	Nuclear Computer Service Manager
S. Piepenbrink	PSC	Management QC Supervisor
M. Leht	PSC	QA Engineering Supervisor
R. Sargent	PSC	Asst. to V.P. Nuclear Operations
A. L. Kitzman	PSC	Nuclear Documents Supervisor
D. L. Weber	PSC	Asst. to Station Manager
J. Gramling	PSC	Supervisor, Nuclear Licensing - Ops.
W. M. Dender, Jr.	PSC	Nuclear Licensing, Coordinator
L. W. Cogdill	PSC	Planner
R. W. Moler	PSC	Scheduling Engineer
D. Warrenbourg	PSC	Manager Nuclear Engineering

A. concerns on loose equipment in reactor building

RB Level 5½

1. next to valve HV-46231 - scaffolding pipe wired off to conduit
2. underneath HV 46243 - various pipes on deck - not tied down
3. penetration C-3 - pipes laying on top of penetration
4. underneath T-2506 Dewar - pipes not tied down
5. above penetration D-1 - cover plates for penetration and valve boxes stored

Level 4

6. spool piece for FE-6375 - stored leaning in corner of wall

Level 2

7. loose valve cheater on top of HV-2187

Level 1

8. Cheater on top of EG SB1349

General

9. ladder securing program

B. what is policy on emptying oily waste cans - per label? (cans empty nightly)

C. RB level 5½ near V-22125 (NW corner) - locker contains paper towels & miscellaneous "stuff" - not fireproof

D. Level 4 - supports on line containing V63117, V63118 have broken loose from base plates

E. Level 2, next to HV 21260 - extension/drop cord - open socket next to walkway with no bulb in it

F. Level 1 - justification for Scott air pack bottles on wall inside Rx Building

G. Level 2, opposite wall #33 - no visible tag/designation for valve coming off vertical pipe at ~8' above floor level - seemingly related to fire protection?

H. Level 7, Hose Rack RH7J2 - Fire hose not properly placed in rack, hose nozzle has broken piece in diffuser and needs replaced

ATTACHMENT C

ABBREVIATIONS AND ACRONYMS

ACM	alternate cooling method
ANSI	American National Standards Institute
AEOD	Analysis and Evaluation of Operational Data
ASME	American Society of Mechanical Engineers
CAR	corrective action request
CWP	controlled work procedure
DRT	discrepant report tag
EFW	emergency feedwater
EP	emergency procedure
FSAR	final safety analysis report
FSV	Fort St. Vrain
HTGR	high temperature gas-cooled reactor
I&C	instrumentation and controls
IEN	inspection and enforcement notice
INPO	Institute of Nuclear Power Operations
IST	inservice test
IV	independent verification
LCO	limiting condition for operation
LWR	light water reactors
MAP	maintenance administrative procedure
M&TE	measuring and test equipment
NCR	nonconformance report
NFSC	nuclear facility safety committee
NRI	nonsafety-related item
NSSS	nuclear steam supply system
OER	operating experience report
OIAG	operating information assessment group
PCRV	prestressed concrete reactor vessel
PDR	procedure deviation report
PM	preventive maintenance
PORC	plant operations review committee
PSC	Public Service of Colorado
QA	quality assurance
QAD	quality assurance department
QC	quality control
SALP	systematic assessment of licensees performance
SER	safety evaluation report
SOAP	station operators administrative procedure
SOER	standard operating expeience report
SOP	standard operating procedure
SR	surveillance procedure requirement
SSR	station service request
SVL	system valve list
TCR	temporary configuration report
TS	technical specifications