U.S. NUCLEAR REGULATORY COMMISSION

REGION V

Report No: 50-397/85-19

Docket No: 50-397

Licensee: Washington Public Power Supply System
P. O. Box 968
Richland, WA. 99352

Facility Name: Washington Nuclear Project No. 2 (WNP-2)

Inspection at: WNP-2 Site near Richland, Washington

Inspection Conducted: May 4-31, 1985

Inspectors: for A. D. Toth, Senior Resident Inspector — Date Signed: 6/24/85

for R. S. Waite, Resident Inspector — Date Signed: 6/24/85

Approved by: P. H. Johnson, Chief, Reactor Projects Section 3 — Date Signed: 6/24/85

Summary:

Inspection on May 4-31, 1985 (50-397/85-19)

Areas Inspected: Routine, unannounced inspection by the resident inspectors of control room operations, engineered safety feature (ESF) status, surveillance program, maintenance program, licensee event reports, special inspection topics, and licensee action on previous inspection findings.

This inspection involved 240 inspection-hours on site by two resident inspectors, including 31 hours during backshift work activities.

Results: No violations or deviations were identified.

DETAILS

1. Persons Contacted

D. Mazur, Managing Director
*J. Martin, Assistant Managing Director for Operations
*C. Powers, Plant Manager
*J. Baker, Assistant Plant Manager
*R. Corcoran, Operations Manager
R. Beardsley, Assistant Operations Manager
*K. Cowan, Technical Manager
*J. Landon, Maintenance Manager
*R. Graybeal, Health Physics and Chemistry Manager
*D. Feldman, Plant Quality Assurance Manager
*R. Partrick, Administrative Supervisor, Plant Support
J. Peters, Administrative Manager
N. Porter, Manager, Electrical/I&C Systems Engineering
P. Powell, Licensing Manager
M. Wuesterfeld, Reactor Engineering Supervisor

*Personnel in attendance at exit meeting

The inspectors also interviewed various control room operators, shift supervisors and shift managers, engineering, quality assurance, and management personnel relative to activities in progress and records.

2. General

The Senior Resident Inspector and/or the Resident Inspector were on site May 6-10, 13-17, 20-24 and 28-31. Backshift inspections were conducted on various days.

Several regional office inspectors visited the site this month for routine inspection activities. These activities were documented in separate inspection reports.

The WNP-2 Project Inspector (P. Qualls) was on site May 6-10.

A Safeguards Inspector (L. Norderhaug) was on site May 6-10.

A Reactor Inspector (C. Clark) was on site May 6-9, accompanied by consultant (B. Compton) who was on site May 6-10.

The Acting Chief, Reactor Safety Branch (R. Pate) was on site May 28-30 for the operator and senior operator licensing examinations scheduled for May 29 and 30.

The Chief, Radiological Protection Section (G. Yuhas), and Radiation Specialist (C. Sherman) were on site May 28-31.

3. Plant Status

The plant was shut down on May 6 for a 60 day outage to perform inspection and maintenance work. No refueling will take place since the core of nuclear fuel had received less exposure than originally planned at this time, due to delays in the power ascension test program. The reactor vessel head will not be removed. Work planned includes repair of the "B" recirculation pump, which had limited power to about 55% since mid-April.

4. Operations Verifications

The resident inspectors reviewed the control room operator and shift manager log books on a daily basis for this report period. Reviews were also made of the Jumper/Lifted Lead Log and Nonconformance Report Log to verify that there were no conflicts with Technical Specifications and that the licensee was actively pursuing corrections to conditions listed in either log. Events involving unusual conditions of equipment were discussed with the control room personnel available at the time of the review and evaluated for potential safety significance. The licensee's adherence to Limiting Conditions for Operation (LCO's), particularly those dealing with ESFs and ESF electrical alignment, were observed. The inspectors routinely took note of activated annunciators on the control panels and ascertained that the control room licensed personnel on duty at the time were familiar with the reason for each annunciator and its significance. The inspectors observed access control, control room manning, operability of nuclear instruments, and availability of on site and offsite electrical power. The inspectors also made regular tours of accessible areas of the facility to assess equipment conditions, radiological controls, security, safety and adherence to regulatory requirements.

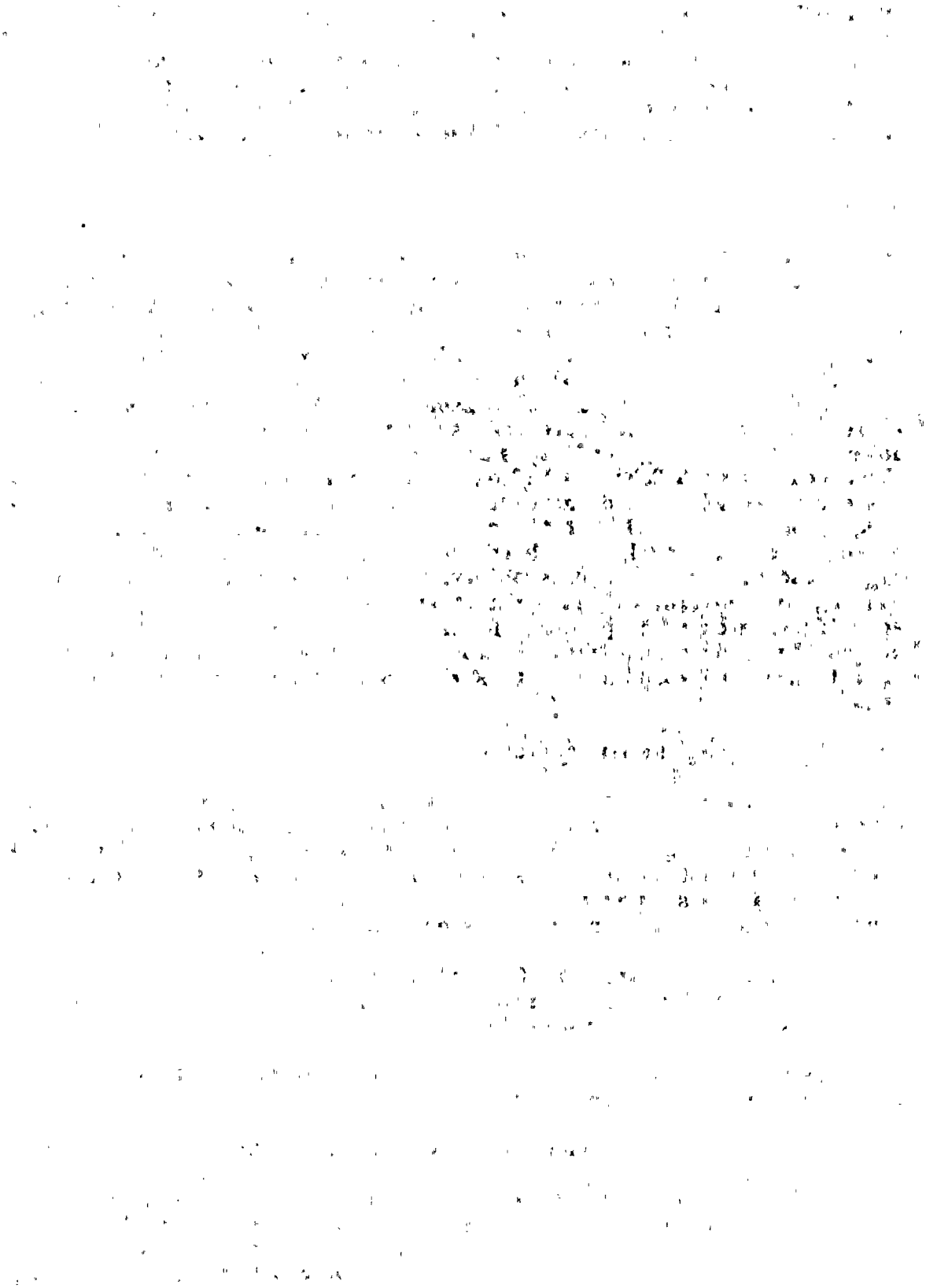
5. Surveillance Program Implementation

The inspectors ascertained that surveillance of safety-related systems or components was being conducted in accordance with license requirements. In addition to observing and occasionally witnessing and verifying daily control panel instrument checks, the inspectors observed portions of several detailed surveillance tests by operators and instrument and control technicians. Typical tests observed included:

a. Technical Specifications Surveillance (T.S.S) 4.8.4.2.a.1.a - Channel calibration of protective relay for 6.9 KV switchgear for recirculation system pump 1A.

b. T.S.S 4.6.1.2.h - Type C leak testing of an RCIC vent line containment isolation valve.

c. T.S.S. 4.4.3.3.2 - Type C leak testing of reactor coolant system pressure isolation valves. The inspector verified that the applicable hydraulic testing procedure (PPM-7.4.4.3.2.2) included each of the valves listed in Technical Specification Table 3.4.3.2-1, plus associated vents, drains and test connection isolation valves. The WPPSS assigned coordinator for leak testing



demonstrated by in-process records and interview that she had reviewed the provisions of the Technical Specification, FSAR and ASME Section XI Testing Test Plan to assure that all identified valves were included in the valve lists of the applicable pneumatic testing procedures. The records showed identification of applicable maintenance work requests for repair of valves which failed the leak rate testing. The compilation of individual containment leak rates was evident and formatted to identify the as-found and as-left leakage values.

d. T.S.S 4.7.4.d - Snubber inspection. The licensee performed transient event inspections of five snubbers associated with the recirculation system pump which had experienced excessive vibration during April. An additional 5 snubbers on connected piping were also inspected. This testing included visual inspection and stroking of each snubber to assure freedom of motion. No evidence of damage or inoperability was found.

e. T.S.S. 4.8.1.1.2.e - The inspector performed a detailed review of the licensee's surveillance procedures for the Emergency Diesel Generators which were intended to comply with the 18 month T.S.S. 4.8.1.1.2.e, the regulatory guides, and the FSAR. The inspector found several editorial errors and two instances where, if the procedure were performed as written, the procedure would not have satisfied the requirements of the T.S.S.(see example below). The inspector presented these findings to the licensee and the procedures were corrected prior to initial use. In addition, the system engineer performed a review of the related surveillance procedures for the HPCS Diesel Generator and corrected similar editorial errors in those procedures.

T.S.S. 4.8.1.1.2.e.2 requires verification of the diesel generator capability to reject a load of greater than or equal to 1377 kw for DG-1 and DG-2. The licensee's procedure required the standby service water pump (the largest load on the bus with a nameplate rating of 1305 kw) to be rejected. The inspector presented this finding to the licensee and the licensee's procedure was revised to reject a load of 1500 kw. During a review of this licensee procedure the inspector identified apparent errors in tables 8.1.1 and 8.1.2 of the FSAR. These tables describe the principal engineered safety features (ESF) subsystem loads requiring electric power to perform safety functions along with specific power supply requirements. This review showed that the kilowatt loading for many of the ESF subsystem components listed in these tables (by nameplate horsepower rating and converted to kilowatts) was incorrect, including the standby service water pump mentioned above. These errors were presented to the manager of Electrical/I&C Systems Engineering and a commitment was obtained to perform a review of Tables 8.1.1, 8.1.2, and 8.1.3 of the FSAR and correct them as necessary. This item is open (85-19-01).

f. T.S.S. 4.3.1.1.4 - Reactor Water Level Low - Division II

The inspector also reviewed the current status of all 18-month cycle surveillances prescribed by the Technical Specifications and ascertained that each had been completed or was scheduled for the ongoing major maintenance outage (planned 60-day cold shutdown).

No violations or deviations were identified.

6. Monthly Maintenance Observation

Portions of selected safety-related systems maintenance activities were observed. By direct observation and review of records the inspector determined whether these activities were consistent with LCOs; that the proper administrative controls and tag-out procedures were followed; and that equipment was properly tested before return to service. The inspector also reviewed the outstanding job orders to determine if the licensee was giving priority to safety related maintenance and verify that backlogs which might affect system performance were not developing.

No violations or deviations were identified.

7. ESF Verification

The inspector verified the operability of the Standby Gas Treatment System by performing a walkdown of the accessible portions of the system. The inspector confirmed that the licensee's system lineup procedures matched plant drawings and the as-built configuration, and verified that valves were in the proper position, had power available, and were locked as appropriate. The licensee's procedures were verified to be in accordance with the Technical Specifications and the FSAR.

In a review of licensee system lineup procedure 2.3.5 the inspector found several editorial errors in addition to several errors concerning hardware/procedure discrepancies. These items were presented to the licensee and a commitment was obtained from the assistant plant manager to ensure that operations staff is made aware of the necessity of correcting procedures when errors are discovered during performance of a procedure. A commitment was also obtained to perform a review of volume 2 procedures for hardware/procedure discrepancies by performing system walkdowns, and procedural content in accordance with a new guidance document for the operations staff use which will be issued by June 30. This review will consist of the assignment of one procedure per crew to be reviewed within a 6 week shift rotation period. The initial systems selected for review will be the ECCS, Standby Service Water and Reactor Core Isolation Cooling systems, with other ESF systems to be assigned as these are completed. In addition, a guidance document will be prepared for use by the technical staff to assist in their review of volume 2 procedures. These actions will be reviewed as followup inspection to a previous Open item (84-22-02).

No violations or deviations were identified.

8. Plant Events

During routine daily activities the inspectors observed and inquired into circumstances of various plant events, including the following:

a. Reactor Vessel Water Inventory Loss and Reactor Scram

On May 7 a reactor operator terminated the A-loop shutdown cooling mode and aligned the loop to ECCS Low Pressure Injection Mode. In doing so he failed to assure that the suction valve (RHR-V-6A) to the reactor vessel was fully closed before opening the suction valve (RHR-V-4A) to the containment suppression pool, in spite of a Caution Tag on the Valve 4A switch. While both valves were in their transient positions, water from the reactor vessel drained to the suppression pool. Although the reactor was already shutdown and in the shutdown cooling mode, the reduction of water level resulted in a discharge of the scram accumulators and related events which the licensee plans to discuss in a Licensee Event Report (LER). The licensee's initial response to inspector questions focused on simple operator error.

The inspector interviewed the responsible operator, operations manager, system engineer, training supervisor, and Nuclear Safety Assurance Group (NSAG) manager and examined relevant records and procedures. The NSAG had issued a Monthly Operating Experience Bulletin (MOB) in January 1984, which addressed experiences of this same type at other sites. Training records showed that operators were instructed relative to this MOB in February 1984. However, changes to the permanent training material and lecture content were not instituted relative to this matter, such that the February - March 1985 training cycle did not address related precautions. Also, the plant staff's November 1983 action on the NSAG recommendations on this matter (July 1, 1983) committed to revision of the operating procedure (PPM-2.4.2) "... to include steps to prevent inadvertent draining of RPV to Suppression pool." However, although parts of the current revision of PPM-2.4.2 included precautions regarding verifying closure of valve RHR-V-6 prior to opening RHR-V-4, these were not included in the portion of the procedure being performed at the time (shutdown of the shutdown cooling mode of operation), nor in the general precautions and limitations section of the procedure. Such a precaution also was not noted in the abnormal condition procedure for control room evacuation (PPM-4.12.1.1), which requires manipulation of the RHR valves from the remote shutdown panel. In the main control room, the valves RHR-V-4A and 4B each had a Caution Tag attached; such caution was not on the remote shutdown panel.

The licensee's continued review of this matter resulted in a May 16 commitment to revise the procedures PPM-2.4.2 and 4.12.1.1 to include precaution statements at appropriate points within the procedure. This matter was another example of ineffectiveness of licensee procedure reviews conducted in the late 1983 time period, previously identified as NRC followup item 84-22-02.

During the event on May 7, the scram discharge volume (SDV) drain and vent valves did not close. The valves are spring loaded, air to open, with air supply controlled by one pair of normally open and energized air pilot valves, and the normally open and de-energized backup scram valves. The principal scram relay (K14 designation) responds to various process variables to open the circuit to the backup air valves (CRD-V-110A and 110B). While the reactor was shutdown, the operations staff approved removal of fuses powering the relays of both backup air supply valves. Removal of the fuses left the backup scram valves in their normally de-energized and open positions, providing instrument air pressure to the vent and drain valve air operators. The logic for the normal pilot valves (CRD-V-9 and 182) which control the SDV vent and drain valves was designed to initiate via energization of the backup logic circuit, which was disabled as described above. Therefore, the normally energized air pilot valves could not be de-energized. As a result, the vent and drain valves remained open when the scram signal was received, and had to be manually operated. During normal conditions, the arrangement of the various relay contacts would assure that the air header is exhausted if only one of the backup scram circuits were out of service (e.g. a fuse removed). Although not included in documented operating policies, plant management and shift managers stated that it is their practice to not approve concurrent surveillances or other work on redundant safety channels, as a matter of good practice. The practice was not applied in the above situation, since Technical Specifications do not require the control rod drive system to be operable when the plant is shutdown.

Because the SDV vent and drain valves did not close, an unexpected condition of slow drainage of the reactor vessel inventory occurred, which required the operators to manually close the vent and drain valves at their location in the reactor building. This was due to normal leakage of water past the CRD hydraulic pistons, which is normally compensated by 40-60 gpm of control rod cooling flow from the control rod drive pumps. However, the pumps had tripped off due to low suction pressure; this developed from high pressure drop across the suction filters during the high flow condition occurring when the control rod accumulators discharged upon the scram signal. A design change is scheduled during the maintenance outage to install additional parallel filters to avoid such high pressure drop conditions.

No violations or deviations were identified.

b. Open Main Steam Drain Valves

The FSAR, Table 6.2, identified normal operation with main steam drain valves open, and technical specifications 3.6.3 establish minimum automatic isolation time requirements. At the time the architect engineer performed the missile analysis, the engineer noted that a small steamline break in the steam tunnel could damage the power cables to the isolation valves; he dismissed this as irrelevant since the plant procedure at that time included a requirement that the valves would be closed at greater than 5%

power. Subsequently the procedure was revised to be consistent with the FSAR. The responsible engineer later became an employee of the licensee, and became aware of the provisions of the current revision of the procedure which undermined the basis for his original disposition of the steam break issue. The inspector interviewed this individual, who produced records of the original missile analysis, and who was able to demonstrate and attest that this was the only item which had been dispositioned on the basis of planned methods of operation (i.e. provisions of a plant operating procedure). The inspector confirmed that the valves were closed by operations staff as soon as this issue was brought to their attention. Engineering evaluation of options is in progress to establish conditions to permit operation with the valves open.

c. Reactor Recirculation Pump Vibration

The licensee's investigation into the cause of vibration is still in progress.

9. Licensee Event Reports

The inspector performed an in-office review of the following Licensee Event Reports (LERs) relative to timeliness, adequacy of description, generic implications, planned corrective actions, and adequacy of coding.

The resident inspectors reviewed selected reports and supporting information on site to verify that licensee management had reviewed the events, corrective action had been taken, no unreviewed safety questions were involved, and violations of regulations or Technical Specification conditions had been identified.

LER-85-021 Containment Isolation Valve Closure (Closed)

The inspector interviewed the reactor operator and the responsible system engineer, and examined the logic diagram for the controls of the isolation valves for the recirculation system flow control valve hydraulic lines. It appeared that the isolation valve closure was not due to actuation of engineered safety feature logic, in view of the lack of simultaneous actions of other devices governed by this logic system.

A similar event again occurred in April, but in this case the licensee decided that this type event was not reportable, in view of the absence of ESF logic actuation.

LER-85-24 Reactor Scram Initiated By DEH Failure (Closed)

This March 22 event was monitored by the inspectors as described in NRC Inspection Report 85-12. Corrective actions were implemented as described in the LER. The inspector particularly interviewed plant operating staff relative to the delay in reset of RCIC. The operators were waiting for reactor water level to fall to the normal operating range, at which time they planned to restart the RCIC system to maintain the level at the normal value. The RCIC system tripped upon the attempt to start it. During the reset, the control valve actuator did not relatch, such that

when the valve control actuator was activated the valve position did not change. During the time required to again reset the valve control, the water level continued to decrease until the +13 inch reactor protection system (scram) actuation point was reached. The licensee could not determine whether the failure to reset was due to the operator not waiting long enough for the valve operator to relatch, or due to mechanical problems.

No violations or deviations were identified.

10. Licensee Actions On Previous NRC Inspection Findings

The inspectors reviewed records, interviewed personnel, and inspected plant conditions relative to licensee actions on previously identified inspection findings:

a. (Closed) (85-11-06) An April 26, 1985 NRC team inspection identified a weakness in program instructions regarding inclusion of acceptance criteria, prerequisites, precautions and limitations in test procedures. In response to the NRC observation, the licensee promptly (May 14, 1985) revised the instructions (PPM-1.2.2) for preparation of procedures to require that test procedures include appropriate aspects identified above.

b. (Closed) (85-11-07) An April 26, 1985 NRC team inspection identified a weakness in licensee quality control organization priorities in selection of inspection points. The quality assurance management has implemented actions specific to evaluation and correction of this item, including: (1) Establishing a system of identification and tracking of hold points; (2) Quality control supervisor review of maintenance work requests (MWRs) and hold points selected by the quality control staff; (3) Specific efforts to alert the quality control staff to most current significant safety related activities, via Quality Control Supervisor's attendance at daily maintenance planning sessions, and the Quality Assurance Manager's attendance at daily plant status meetings and his participation at Plant Operations Committee meetings. The inspector noted that special topics identified during such sessions have been incorporated into the Quality Control Supervisor's review of the MWRs. These efforts appeared consistent with the licensee's stated goal of making management expectations more clearly known to the plant staff.

11. Special Inspection Topics

a. Independent Verification Program

The inspector reviewed the current status of independent verification measures for electrical, instrumentation and control, and mechanical surveillance procedures, jumpers and lifted leads. Resolution of prior specific NRC questions on this subject was discussed in NRC inspection report 85-15.

The maintenance work request Procedure 1.3.7 (Revision 6), prescribes a Work Package Planning Checklist. It includes a specific

checkpoint to determine if a temporary modification, bypass or jumper would be required, and references the appropriate governing procedures (PPM-1.3.9 and 1.4.1) which prescribe handling of such independent verifications. For the mechanical area, only the supervisors and four maintenance engineers prepare the maintenance instructions and they appeared to be aware that mechanical devices are included in the scope of these instructions. Also, the MWRs which affect permanent plant equipment are routed through the Shift Manager, who controls the issuance of electrical and mechanical jumpers. For devices which would be installed when specifically prescribed by an operating procedure step, the Operations Manager stated that the controls of Procedure PPM-1.3.9 would be applied. Except where specifically mandated by Technical Specifications, independent verification is not provided for control room controls manipulated by licensed operators in accordance with the approved operating procedures (which do not contain checklists).

Some 18-month surveillance procedures, such as those for local leak rate testing of containment penetrations, include positioning of valves at test connections without specific independent verification of restoration prescribed in the test procedures. Where the valves are normally locked closed, the independent verification is provided via the locked valve control program, in addition to the planned execution of the containment isolation valve verification procedures (7.4.6.1.1 and 7.4.6.1.2) prior to startup. For future cases of repair work on valves which may require local leak rate testing following repairs, simply invoking the existing local leak rate testing procedure would not necessarily result in independent verification. However, such individual cases would be coordinated through the control room, relying upon the shift manager's familiarity with PPM-1.3.9 requirements to specify independent verification.

This inspection showed that the licensee had incorporated effective independent verification provisions into the control of surveillance testing and jumpers/lifted leads.

No violations or deviations were identified.

b. Plant Procedures Upgrade

The licensee revised instructions for use of plant procedures (PPM-1.2.3 Revision 9) to reduce the burden to user personnel relating to multiple temporary changes to the procedures. The new procedure requires that only one Procedure Deviation may be issued against an approved procedure, that subsequent Deviations shall encompass any prior changes, all Deviations shall be in the form of marked-up pages of the approved procedure, and Deviations shall not be issued for items involving technical specification deviation, unreviewed safety or environmental questions, or which nullify previous regulatory commitments.

The licensee revised the instructions for procedure approval (PPM-1.2.4 Revision 7) to require flagging individual line items

which involve prior commitments to NRC, and allow use of such flags for commitments relating to INPO, Quality Assurance, or WPPSS management requirements. The instructions provide a review sheet for procedure revisions, which will be available to the Plant Operations Committee and reviewers, with a specific item alerting reviewers if a proposed change to prior commitments is included in the revision.

These revisions reflect increasing management attention to plant configuration control and long term commitment control.

No violations or deviations were identified.

c. Licensee Response to Selected Safety Issues - Mispositioned Control Rods

The inspector verified that the licensee had received NRC information Notice 83-75 and associated INPO operating experience reports 84-02, 83-75, 83-84, 83-85, 83-86, and 84-11 and service information letter SIL-407. These were evaluated by the licensee's Nuclear Safety Assurance Group (NSAG) for applicability on November 29, 1984. It was determined that plant actions were not required, with exception of minor upgrade of the control rod sequence record sheets. The record generation procedure was subsequently revised to improve documentation of rod movement activities.

The WNP-2 plant does not include control rod timing control panels in the control room, unlike the facilities described in the operating experience reports. The plant includes a rod worth minimizer (RWM), rod sequence control system (RSCS) and a control rod drive control system (RDCS) which include features to prevent out of sequence or continuous rod movement actions. Technical Specification prohibit movement of control rods if the RSCS is inoperable. Procedures reference Technical Specification limits regarding bypassing the RWM system. Procedures call for involvement of the Shift Technical Advisor in all control rod maneuvers and startups, as directed by the Plant Nuclear Engineer. The procedures also provide detailed guidance for generation of control rod withdrawal and insertion sequence sheets, and a fast shutdown rod sequence.

The licensee's review and conclusions appeared adequate. No violations or deviations were identified.

12. Management Meeting

An exit meeting was held May 31 to discuss the results of inspection activities this report period. Personnel attending this meeting are identified in paragraph 1. In addition, the inspector met with the plant manager approximately weekly during this period, to discuss inspection findings.