Nebraska Public Power District

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NLS940001
July 28, 1994

Mr. L. J. Callan
Regional Administrator
NRC Region IV
611 Ryan Plaza Drive
Suite 400
Arlington, Texas 76011

Subject: Response to Confirmatory Action Letter
Cooper Nuclear Station
NRC Docket No. 50-298

References: (1) Confirmatory Action Letter (Revision 0) Dated May 27, 1994, to Guy R. Horn - Nebraska Public Power District (CAL 4-94-06).

(2) Confirmatory Action Letter (Revision 1) Dated June 16, 1994, to Guy R. Horn - Nebraska Public Power District (CAL 4-94-06A).

(3) Confirmatory Action Letter (Revision 2) Dated July 1, 1994, to Guy R. Horn - Nebraska Public Power District (CAL 4-94-06B).

Dear Mr. Callan:

References (1), (2), and (3) confirmed Nebraska Public Power District's (the District's) commitment to address four items prior to restart of the Cooper Nuclear Station (CNS). Several technical meetings already have been held which addressed NRC concerns described in the Confirmatory Action Letter (CAL) Items 1, 2, 3, and 4. These items involved: 1) as-found testing of 4160- and 480-volt undervoltage devices; 2) the design basis for surveillance acceptance criteria for the Control Room and Turbine Building Ventilation Systems; 3) primary containment penetration discrepancies; and, 4) electrical distribution surveillance testing and inservice inspection of penetration welds. An additional meeting will be held in NRC Headquarters office to review: 1) the conclusions discussed during the four technical meetings noted above; 2) actions taken to resolve the noted issues; and, 3) the basis for District management's conclusion that CNS is ready for restart. That meeting has been scheduled for July 29, 1994, at 9:00 a.m.

CAL Item 5 required the District, prior to plant restart, to provide the NRC Region IV office with a letter discussing eight areas of NRC interest. The attached discussion responds to this NRC request. However, limiting this response to just answering NRC questions would not fully capture the extensive efforts that the District has expended to address not only NRC issues, but also issues that CNS management has determined must be resolved prior to plant startup. During this shutdown, CNS has assessed several areas of Technical Specification interpretation, system design basis requirements, maintenance practices, and management oversight. Additionally, several CNS efforts resulted in extension of the shutdown period because District management took a careful and conservative approach to resolving these emerging issues. Region IV management has been kept apprised of the District's actions.

The District's findings, while having a negative connotation regarding compliance, also have a positive side. Recent findings are in great part a result of management efforts to improve the questioning attitude of personnel and management's commitment to resolving emerging issues. CNS culture improvement initiatives to identify and fix problems correctly the first time are working. New management has brought to CNS fresh ideas and higher standards for problem identification and resolution. Issues are being raised and resolved which, in past years, may have been placed at a lower priority. District management firmly believes that these initiatives will result in sustained improvement for the long term. The District will continue to monitor the effectiveness of performance improvement efforts to ensure that desired results are being achieved. The NRC will be kept informed of the progress of performance improvement efforts.

If there are any questions about the information presented in the attachment, or on other matters, please call.

Sincerely,

Guy Horn

G. R. Horn
Vice-President, Nuclear

/nr

Attachment

cc: U.S. Nuclear Regulatory Commission
Attention: Document Control Desk

NRC Resident Inspector Office
Cooper Nuclear Station

NPG Distribution

Introduction

CAL 4-94-06B, Item 5, required that prior to restart, the District provide Region IV with a letter that discusses the following:

(a) the root cause(s) for defeating the undervoltage trip function in the Motor Control Center N supply breaker;

(b) the actions taken to confirm the design basis for the Control Room and Turbine Building Ventilation Systems;

(c) the results of all testing that was performed for the issues discussed in Items 1, 2, and 3 of the CAL;

(d) the safety significance of all off-normal or discrepant conditions in Items 1, 2, 3, and 4 of the CAL;

(e) the corrective actions that will be taken to prevent recurrence of the installation of devices (i.e., cable ties, jumpers, blocks, etc.) that will prevent the actuation of safety system functions and to ensure that the design basis surveillance testing criteria are established and maintained for the facility;

(f) the lessons learned by CNS staff in response to the incident involving the undervoltage trip function in the motor control center supply breakers, including the lack of prompt recognition of the potential safety significance;

(g) the basis for the District's determination that the testing programs for Electrical Distribution System surveillance testing and inservice inspection of penetration welds are technically adequate and complete; and,

(h) the basis for the District's assurance that the testing programs for other licensed activities are adequately implemented.

Each of these CAL issues are addressed in this attachment. Where appropriate, the District also has addressed previously ongoing activities that are responsive to NRC concerns and additional issues that have emerged as a result of initial problem investigations.

CAL 4-94-06b
Item 5 (a) :

"Discuss the root cause(s) for defeating the undervoltage trip function in the Motor Control Center N supply breaker."

NPPD Response

On May 16, 1994, a cable tie was found installed on the undervoltage trip device for the 480-volt feeder breaker to MCC-N. Its installation defeated this undervoltage trip device which was installed to isolate (shed) its load in the event of Loss of Off Site Power.

The root cause of the event is the failure of management to ensure that requirements for configuration control were not adequately implemented into the maintenance procedure. Maintenance procedures must have appropriate configuration control elements. Management's expectations must be clearly communicated and effected through the procedure review and approval process. While procedure content guidance existed regarding this issue, it was not well expressed. Strong, clear management expectations regarding its inclusion in maintenance procedures was not provided.

The immediate cause of the loss of configuration control was found to be an inadequate maintenance procedure. The procedure allowed installation of a cable tie, but did not provide specific guidance to remove, or verify removal, of the cable tie. While not the root cause, post-maintenance testing and surveillance tests both failed to identify that the cable tie was still installed and that the breaker could not perform its intended safety function. Human error also was involved. However, it was only a symptom and not the root cause.

CAL 4-94-06b
Item 5 (b) :

"Discuss the actions taken to confirm the design basis for the Control Room and Turbine Building Ventilation Systems."

NPPD Response

The District has reviewed several hundred documents to verify the design basis for the Control Room and Turbine Building Ventilation Systems. These documents span nearly 30 years, beginning with pre-construction in the mid 1960's, through the present. The documents reviewed included General Electric plant design criteria; Burns and Roe calculations, system descriptions and correspondence; pre-operational test procedures and test results; the FSAR and related amendments, questions and answers; the SER; the USAR; correspondence with the NRC; internal NPPD correspondence; test procedures, design changes and supporting calculations.

The results of our review are as follows:

Control Room Ventilation System Design Basis

The Control Room Ventilation System design basis is:

a) Provide temperature and humidity control and air movement for personnel comfort and optimum equipment performance.

b) Provide sufficient filtered fresh air supply for personnel.

c) Minimize the possibility of exhaust air recirculation into the air intake.

d) Provide for operator protection in the event of a Design Basis Accident by providing filtered air and maintaining the Control Room Envelope at a positive pressure with respect to adjacent areas. This function is performed by the Control Room Emergency Filter System. Dose calculations assume a positive pressure in the Control Room Envelope; however, no specific value of pressure is assumed for use in the calculations. Dose calculations assume 10 CFM of unfiltered inleakage in accordance with guidance furnished by Murphy and Campe in a paper titled, "Nuclear Power Plant Control Room Ventilation System Design for Meeting General Criterion 19."

The Control Room Ventilation System is not designed to automatically respond to toxic gas events; rather, operators don Self Contained Breathing Apparatus (SCBA) and manually secure the outside air supply to the Control Room.

The administrative, operability, and surveillance requirements for the Control Room Emergency Filter System were discussed during a meeting between NPPD and NRC on July 7, 1994, and confirmed in a letter to the NRC from G. R. Horn, dated July 20, 1994.

Turbine Building Ventilation System Design Basis

The Turbine Building Ventilation System design basis is:

a) Provide temperature control and air movement for personnel comfort and optimum equipment performance.

b) Provide sufficient filtered fresh air supply for personnel.

c) Provide for air movement from lesser to progressively greater areas of radioactive contamination potential prior to final exhaust.

d) Minimize the possibility of exhaust air recirculation into the air intake.

e) Accommodate effluent monitoring capability.

CAL 4-94-06b
Item 5 (c)1:

"Discuss the results of all testing that was performed for the issue discussed in Item 1 of the CAL:

4160-volt undervoltage relay logic and 480-volt undervoltage devices (as-found)."

NPPD Response

4160-Volt Testing

As-found testing of the 4160-volt undervoltage devices for electrical loads supplied directly from the two emergency busses 1F and 1G was performed. Two discrepancies were identified. The discrepancies consisted of one relay that exceeded the allowable time delay setting and one relay contact that had marginally high resistance. Retests following resetting of the relay timing and cleaning of the contacts were satisfactory.

480-Volt Testing

Out of a total of 12 breakers that were as-found tested, two breakers failed to trip and two breakers failed to trip within the time delay acceptance criteria. Subsequent testing of the undervoltage trip assemblies (UVTAs) identified a fifth breaker which previously passed its acceptance testing but failed due to slow actuation timing. The unreliable and inconsistent performance of these UVTAs was either caused by mechanical binding in the latching mechanism or a defect in the time delay attachment. As a result, the UVTAs for these twelve breakers were replaced with a shunt trip device that is activated by the loss of voltage logic for the 4160-volt breakers. Successful testing of this shunt trip network for the 480-volt bus loads was completed on July 4, 1994.

CAL 4-94-06b
Item 5 (c)2:

"Discuss the results of all testing that was performed for the issue discussed in Item 2 of the CAL:

Control Room and Turbine Building Ventilation Systems."

NPPD Response

Control Room Envelope

On April 11, 1994 the Control Room Emergency Bypass Filter System failed post-maintenance testing which was being performed following maintenance on a door that formed part of the Control Room pressurization boundary. (See LER 94-006, dated May 11, 1994) Several leak pathways were sealed and the Control Room Envelope was successfully tested on April 28, 1994.

On June 24, 1994 another test of the Control Room Envelope was conducted to verify that the new administrative limit (≥ +0.04" wg) could be satisfied. The test failed. Another search for new or degrading leak paths was conducted. Several small leaks were identified and sealed.

Recent testing confirms that the Control Room Emergency Bypass Filter System can satisfy its design basis of providing a positive pressure to the Control Room envelope. The administrative limit of ≥ +0.04" wg has been consistently achieved during numerous tests of Control Room Envelope integrity conducted since July 9, 1994, with the exception of a test conducted on July 22, 1994, which failed due to a flow balancing deficiency. The balancing deficiency has been corrected and appropriate Control Room Envelope testing was satisfactorily performed on July 27, 1994.

The effects of wind speed have also been considered during recent testing and will be considered during future testing. Investigation into system design improvements to increase system performance margins is continuing. These improvements will be implemented prior to startup from the spring 1995 refueling outage.

Turbine Building

Actions taken recently to correct operational deficiencies in the Turbine Building Ventilation System discovered following the unsatisfactory Control Room Emergency Bypass Filter System test conducted on April 11, 1994, include the following:

a) Repaired exhaust fan vortex and outlet dampers and controls.

b) Cleaned and lubricated the vortex dampers for the exhaust fan.

c) Repaired damaged ductwork.

d) Verified sensing line integrity.

e) Cleaned and balanced the system to obtain -0.25" wg in the Steam Jet Air Ejector (SJAE) Room at design flow.

f) Updated the system operating procedure to require operation at -0.25" wg with respect to the environment in the SJAE Room. This parameter is also routinely logged in the Control Room Data log in the Control Room.

As a result of the above actions, satisfactory system operation at the -0.25" wg differential pressure margin in the SJAE Room has been demonstrated. Preventive measures will be implemented through the ongoing Preventive Maintenance Program to ensure that performance of the Turbine Building ventilation system will remain satisfactory.

CAL 4-94-06b
Item 5 (c)3:

"Discuss the results of all testing that was performed for the issue discussed in Item 3 of the CAL:

Primary Containment Penetrations."

NPPD Response

Walkdowns of primary containment penetrations for Design Basis Reconstitution purposes were performed from May 18 through June 5, 1994. As a result of identified discrepancies, eleven design changes were developed and implemented. These actions included the addition of test connections, installation of welded caps on spare penetrations, complete redesign of several containment isolation barriers, and installation of caps on vents, drain lines and test connections.

As-found testing was performed for penetrations which had not previously been Type A, B, or C tested and for which as-found testing was determined to be practicable. The total as-found leak rate due to these additional tests was approximately 26 SCFH, not including drywell pneumatic supply check valve IA-CV-65CV. Leak rate testing for this check valve revealed that it could not be pressurized. The safety significance of this leak rate is discussed in the response to Issue 5(d)3. Following modifications and repairs, the total Primary Containment as-left leak rate, including IA-CV-65CV, was less than the 0.6 La (189 SCFH) limit specified in CNS Technical Specifications.

Penetrations classified as IIIN, IVP, or indeterminate, were identified for which appropriate NDE records could not be found to ensure that the piping welds were of equivalent quality level to the containment. A design change was completed on forty-seven penetrations during this outage to upgrade the design and installation of this piping to a quality that is equivalent to the primary containment. The District will update the CNS ASME Section XI Inservice Inspection Program prior to the 1995 outage to include these piping segments. This action will ensure that the quality level of these piping segments will be maintained in the future. Thirty-five related butt welds were radiographed. Of that total, five rejectable indications were found. Two of the five rejected welds were removed by shortening a piping run and the remaining three welds were repaired. In addition, a total of 262 socket welds were subjected to liquid penetrant examination. There were no rejectable indications.

Based on the as-left leak rate, the repair of rejectable NDE indications on butt welds, and no rejectable indications for socket welds, the District concludes that containment integrity satisfies regulatory requirements. This issue was discussed with the NRC on June 27, 1994.

CAL 4-94-06b
Item 5 (d)1:

"Discuss the safety significance of all off-normal or discrepant conditions found in Item 1 of the CAL:

4160-volt undervoltage relay logic and 480-volt undervoltage devices (as found)."

NPPD Response

4160-Volt Undervoltage Relay Logic

The safety significance of the 4160-volt undervoltage relay discrepancies discovered during performance of Special Procedure 94-208 is as follows:

a) EE-REL-27X3/1G timed out at 14.63 seconds, which is 3.63 seconds longer than allowed by acceptance criteria (10 seconds ± 10%). This relay provides a close interlock in the DG breaker EG2 close circuit to prevent breaker closure until the 480-volt switchgear breakers feeding non-essential loads have adequate time to trip. The design basis for the DGs specify that the output breaker of tne DGs must be closed within sixteen seconds from the time of DG actuation to meet the 10CFR, Part 50, Appendix K Analysis. The 14.63 second timing of EE-REL-27X3/1G would not have prevented DG2 from meeting this requirement. Concurrent with relay timing, DG2 would start, reach required speed, and bus load shedding would occur. Since DG2 would have started within the sixteen second limit and relay EE-REL-27X2/1G would have closed within the sixteen second limit, Bus 1G also would have been powered within the required sixteen seconds and the intended safety function would have been satisfied.

b) The resistance of contacts 11-12 of EE-REL-27X/1GB was found to be higher than the acceptance criteria limits. These contacts provide a trip signal to breaker 1GB during a loss of voltage. The trip of breaker 1GB separates Bus 1G from the off-site power supply and allows transfer to the Emergency Transformer, if available. The acceptance criteria is <1 ohm and the resistance of these contacts was measured at 3.1 ohms. The 1 ohm acceptance criteria was chosen as a screening point for contacts requiring further evaluation. Subsequent review determined that this contact would have been able to perform as designed under all design basis conditions. Based on the above, the as-found contact resistance had minimal safety significance.

c) On June 16, during performance of testing associated with Special Procedure (SP) 94-208, a malfunction associated with the 52/IN contact, the breaker position switch, for breaker 1GS occurred after the breaker had been racked to the test position to support testing and then racked in. The breaker malfunction was due to mis-adjustment of its guide wheels which resulted in it becoming misaligned as it was racked into its cubicle. The misalignment led to an over-travel in the position switch as the breaker was electrically cycled, which resulted in the breaker malfunction.

To ensure that we thoroughly understood the cause of failure, a vendor representative was utilized to assist in evaluating the condition and correcting it. All other safety related breakers of this type have been inspected and no similar conditions were found.

The inoperable status of the breaker did not have an adverse impact on plant safety during the special procedure. Bus 1G had already been declared inoperable and the plant was in Cold Shutdown. The redundant division was available during performance of the special procedure and during repair of the breaker.

During normal operations, breaker 1GS is normally open, and would automatically close upon loss of power from the Normal and Startup Transformers, powering the 1G bus, providing that power is available from the Emergency Transformer. Had this malfunction occurred while at power, the effect would have been that the breaker would not have tripped upon loss of power from the Emergency Transformer.

To assess the operability of the breaker during the past operating cycle, a review of the operating history of the breaker was performed. It was determined that in each case where the breaker was racked in and cycled once successfully, the breaker would then operate properly in each subsequent demand. All failures of the breaker to operate properly have occurred on the first cycle of the breaker after it has been racked in.

On July 18, 1993, the 1GS breaker was racked in and was successfully cycled during the transfer to the emergency transformer and back to the startup transformer. No indication of a breaker problem was indicated between the July 18 cycling and the performance of STP 94-208.

In the misaligned condition, the ability of the breaker to perform its function during a seismic event is being evaluated. In the event that the seismic qualification was not affected by the misalignment, this condition would have had no safety significance. Should the breaker not be found seismically qualified, the safety significance would have been minimal based upon the following discussion.

The sequence of events that would have resulted in an accident scenario of concern is as follows:

a) loss of a portion of the transmission system and normal off-site power (emergency transformer power source remains available);

b) closure of the 1GS breaker, transferring the Division II emergency bus to the emergency transformer;

c) loss of the 1GS breaker trip function due to the effects of a seismic event;

d) loss of the emergency transformer, de-energizing both 4160-volt busses; and,

e) failure of Diesel Generator 1.

Given this sequence, HPCI and RCIC would have been operated in accordance with plant procedures to stabilize the plant. Operator action would be necessary to locally trip the 1GS breaker, permitting breaker EG2 to close, allowing the DG to assume the necessary loads.

<u>480-Volt Undervoltage Devices</u>

Due to test failures and demonstrated unreliability of the 480-volt undervoltage trip devices (UVTA) discussed in Item 5(c)1 above, Nuclear Engineering Design Calculations (NEDC) 94-110, "Operability of DG1 With Additional Loads," and NEDC 94-114, "Steady State Operability of DG and ET With Additional Loads," were prepared to assess whether the EDG units would satisfy their intended safety function, even if the UVTAs did not function as intended. As a result of these calculations, the District concluded that: 1) the EDGs would not have stalled; 2) EDG capacity would not have been exceeded to the degree that performance would have been adversely impacted; 3) EDG tie breakers would not have tripped; 4) the fuel supply would have been adequate; and, 5) all electric motors supplied by the EDGs would have successfully accelerated to operating speed. In summary, the EDG units would have been able to perform their intended safety function, even if all twelve of the UVTAs failed.

CAL 4-94-06b
<u>Item 5 (d)2:</u>

"Discuss the safety significance of all off-normal or discrepant conditions found in Item 2 of the CAL:

Surveillance testing acceptance criteria for the control room and turbine building ventilation systems."

<u>NPPD Response</u>

As previously discussed, the design basis Control Room operator dose calculation assumes 10 CFM of unfiltered inleakage based on positive pressure in the Control Room envelope. Therefore, the safety significance of the failure to achieve a positive pressure was evaluated by calculating the dose consequences of up to 2000 CFM of unfiltered inleakage. The basis for this assumption and the detailed results of the calculation has been provided to the NRC by separate letter from G. R. Horn, dated July 20, 1994. In summary, the resulting dose would be within GDC 19 and Standard Review Plan (SRP), Section 6.4 limits.

Based on the results of the calculations summarized in the referenced correspondence, the District concludes that the as-found condition of the Control Room envelope had minimal safety significance.

CAL 4-94-06b
Item 5 (d)3:

"Discuss the safety significance of all off-normal or discrepant conditions found in Item 3 of the CAL:

Containment penetrations."

NPPD Response

The majority of the containment penetrations that did not comply with design requirements had been successfully tested at design pressure during the primary containment ILRT last performed in 1991. As-found testing was performed for penetrations which had not previously been subjected to ILRT or LLRT test pressure, and for which as-found testing was determined to be practicable. Testing demonstrated that the leak rates were within Technical Specification limits with the exception of the Drywell Pneumatic Supply Check Valve, IA-CV-65CV, in penetration X-22. Type C LLRT testing revealed this penetration could not be pressurized.

Potential off-site and on-site radiological dose consequences due to leakage from penetration X-22 during the 30 days following the accident were evaluated per calculation NEDC 94-154, "Off-site and On-Site Dose Consequences For LLRT Failure of IA-CV-65CV." The results of this calculation are summarized in the following chart.

Scenario:	Whole Body Dose (Rem)	Thyroid Dose (Rem)	Whole Body Dose Limits (Rem)	Thyroid Dose Limits (Rem)
1) Current Off-site LOCA Dose (USAR XIV-6.3)	7.4×10^{-3}	9.0×10^{-4}	25	300
2) Off-site LOCA Dose With Additional Leakage from Penetration X-22	4.2×10^{-2}	5.2×10^{-3}		
3) Current Design Basis Control Room LOCA Dose	1.74	11.39	5	30
4) Control Room Design Basis LOCA Dose With Additional Leakage from Penetration X-22	4.42	58.51		
5) Control Room LOCA Dose With Additional Leakage from Penetration X-22 and and no SGTS Actuation Delay	4.42	10.85		

Off-site doses, considering the additional leakage in Scenario 2, are far below the 10CFR100 limits of 25 Rem whole body and 300 Rem thyroid. For Scenario 4 the Control Room doses exceed the SRP 6.4 limit of 30 Rem thyroid, but are below 10CFR Part 100 limits. However, this scenario reflects conservatisms which go beyond those required by the relevant guidance documents for dose calculations of this type. The more accurate analysis is discussed below.

Scenario 5, which addresses additional leakage with no Standby Gas Treatment System (SGTS) delay, is more accurate in depicting the Control Room dose. This case does not consider 90 seconds of unfiltered release from secondary containment prior to SGTS actuation, which is assessed in design basis calculations based upon worst case secondary containment valve closure time. The basis for removing this assumption comes from draft NUREG 1465, "Accident Source Term for Light Water Nuclear Power Plants," which indicates that it would take over one hour for fission product radionuclides to begin to exit containment. Therefore, it is a more realistic case to assume that all flow from secondary containment containing fission products would be filtered through the Standby Gas Treatment System within this time. Since Control Room dose for the more realistic Scenario, No. 5, is within GDC 19 and SRP 6.4 limits and the off-site dose would be within 10 CFR Part 100 limits, the safety significance of the inoperable X-22 penetration is minimal.

Additionally, barriers that should realistically mitigate the effects of the assigned leak rate include two other valves outboard of IA-CV-65CV and the Instrument Air and Nitrogen Systems. However, since these barriers are non-safety related, they were not taken credit for in the analysis described above. The design pressure/temperature for the associated piping is 125 psi/200°F and the piping system operating pressure for both systems is above 100 psi, well in excess of containment design pressure. These conservatisms provide further assurance that the Control Room operator thyroid dose would be within regulatory limits.

Creation of the postulated release pathway from primary containment requires a failure in the instrument air system piping, both inside and outside containment, concurrent with a DBA LOCA. A Probabilistic Safety Analysis (PSA) was used to estimate the frequency. It was postulated that under accident conditions (large break LOCA resulting in core damage, probability of occurrence 5.54E-08/yr.), the line could become a pathway for radionuclides to reach the environment. The probability of a line break outside of containment was assumed to be bounded by the probability of a loss of the Instrument Air System. This probability, including pipe breaks, is conservatively assumed to be 2.58E-04.

Therefore, the frequency of occurrence of this scenario resulting in a release of radionuclides outside of containment through this penetration to the environment is 1.43E-11/yr. This value is well below the regulatory concern value of 1.0E-07/yr used in Probabilistic Safety Assessments for containment bypass events. Based on the above considerations, containment penetration leak pathways had minimal safety significance.

CAL 4-94-06b
Item 5 (d)4.a:

"Discuss the safety significance of all off-normal or discrepant conditions found in Item 4 of the CAL:

Electrical distribution system surveillance."

NPPD Response

A review of the Electrical Distribution System was conducted to verify testing was performed as specified in the Technical Specifications, USAR, and Design Basis. This review identified two discrepancies with potential safety concerns which are discussed below:

a) Relays 27/1F-1 and 27/1G-1 were not being tested properly per the definition of the instrument functional test. The monthly functional test visually verified contact closure; however, the Technical Specification definition required the associated auxiliary relay to be energized. The past method of functionally testing the relay was not a safety concern because:

   1) Relays 27/1F-1 and 27/1G-1 are calibration tested once per cycle and functionally tested once per cycle by surveillance Procedure 6.3.4.3.

   2) The subject relays are protective relays which have contact mechanisms in which the relay contact position is visible in the both the open and close conditions. In the test mode, the relay contact will not be in the intermediate position.

   3) The monthly functional check did prove the induction disk rotated when the input voltage was removed, indicating a loss of voltage had been detected by the relay mechanism.

   The monthly surveillance procedure has since been revised to correct this discrepancy and the relays have been satisfactorily tested.

b) Two installed Diesel Generator Starting Air pressure indicators for which qualification was in question were discovered. An engineering evaluation was performed which verified that the instruments were qualifiable and capable of performing their safety function. Documentation of their qualification has now been developed. Therefore, the safety significance of this discrepancy was minimal.

CAL 4-94-06b
Item 5 (d)4.b:

"Discuss the safety significance of all off-normal or discrepant conditions found in Item 4 of the CAL:

Inservice inspection of penetration welds."

NPPD Response

Twelve Class 2 welds were found to have been excluded from the ISI Program. However, even with the addition of the twelve welds to the total Class 2 weld population, the required weld examination percentages are still satisfied. For the current ten year interval, one outage remains to complete inspection interval examination requirements. CNS is confident that the welds are mechanically sound based on NDE verification at original construction. As such, the District has concluded that the safety significance of excluding the 12 Class 2 welds from the ISI Program is minimal. Further information related to this issue is provided in the response to CAL Item 5(g).

CAL 4-94-06b
Item 5 (d)4c:

"Discuss the safety significance of all off-normal or discrepant conditions found in Item 4 of the CAL:

Testing programs implemented in other areas of licensed activities."

NPPD Response

The safety significance associated with ongoing testing programs implemented in other areas of licensed activities is addressed in the response to Item 5(h).

CAL 4-94-06b
Item 5 (e)1:

"Discuss the corrective actions that will be taken to:

Prevent recurrence of the installation of devices (i.e., tie wraps, jumpers, blocks, etc.) that will prevent the actuation of safety-system functions."

NPPD Response

The following corrective actions have been or will be taken:

a) A walkdown was conducted to verify that no similar cable tie installations were in place. None were found.

b) A review was performed of station mechanical and electrical maintenance procedures; surveillance procedures in the chemistry, operations, and instrument and control areas, as well as the

14.x series instrument and control procedures, to identify similar procedural deficiencies. Three mechanical procedures were identified as deficient. Changes have been initiated to correct them. Fifteen electrical procedural deficiencies were identified. Changes have been initiated to correct them. Three minor discrepancies were identified and corrected in the operations and instrument and control procedures. The noted procedure discrepancies will be corrected and approved prior to next use. No discrepancies were identified in the chemistry procedures. Field walkdowns were performed for similar deficiencies that could have been created during past use of the deficient procedures. No equipment configuration discrepancies were found.

c) A revision has been made to Maintenance Work Practice (MWP) 5.0.4 to add guidance to further ensure that any impairments, changes, or blocking devices installed during performance of maintenance have been removed prior to completion of the procedure.

d) In response to management deficiencies, maintenance supervision has held meetings with their personnel to emphasize the need for procedure compliance and immediate correction of problems and incomplete understanding of procedure requirements. Considerable effort is also being expended by Maintenance Management to ensure that expectations are clear regarding procedure compliance, procedure adequacy, and control of maintenance activities.

CAL 4-94-06b
Item 5 (e)2:

"Discuss the corrective actions that will be taken to ensure that the design basis surveillance testing criteria are established and maintained for the facility."

NPPD Response

The testing requirements specified in Technical Specifications and the USAR for the major components of six critical systems have been reviewed against existing surveillance procedures. The systems reviewed included:

High Pressure Coolant Injection
Reactor Core Isolation Cooling
Residual Heat Removal (Low Pressure Coolant Injection mode)
Core Spray
Automatic Depressurization
Emergency Diesel Generators

The review was performed as follows:

a) An existing cross reference between Technical Specifications and surveillance procedures, which is maintained by the Surveillance Coordinator, was independently reviewed for correctness.

b) The Technical Specification surveillance requirements were reviewed against the respective surveillance procedures to determine if the requirements were being met.

c) USAR sections describing the six systems were reviewed to determine if the USAR requirements were being met by the surveillance.

The results of this review are summarized in the response to Item 5(h).

Also, the District will verify that operating and surveillance test procedure content and surveillance test acceptance criteria are consistent with the design basis. Verification of surveillance testing program adequacy will be accomplished for future system-related Design Criteria Documents (DCDs) as part of the Design Basis Reconstitution Project. Based upon a risk assessment, management has selected those systems that will be completed on an expeditious basis.

An in-depth systematic review of the surveillance test program was initiated on July, 11 1994. This review addresses testing requirements specified in the Technical Specifications, the USAR, and those completed DCDs to ensure that the surveillance test procedures, including those specifically developed for ASME IST purposes, adequately incorporate pertinent requirements. This review is scheduled to be completed by March 1995. The systems included in the scope of this review are those for which Technical Specification testing requirements are specified.

Organizational and programmatic changes will be made to enhance configuration control consistency between design input and design output documents to ensure that: 1) procedure modifications are reviewed for impact on design input documents; 2) design output documents are revised when affected by changes to calculations; and, 3) changes to CNS engineering program documents (e.g., LLRT) are reviewed for impact on design input documents. Additionally, the District will perform a review to identify additional design input and output documents that require enhanced configuration maintenance provisions.

CAL 4-94-06b
<u>Item 5 (f) :</u>

"Discuss the lessons learned by the Cooper Nuclear Station staff in response to the incident involving the undervoltage trip function in the motor control center supply breaker, including the lack of prompt recognition of the potential safety significance of some issues."

<u>NPPD Response</u>

An assessment was performed of CNS performance related to the noted incident. The District found that the initial response was narrow, compliance-based, and poorly directed by management. Management and staff exhibited narrow-focused and compliance-based values. Although the District has been striving to provide the tools and management oversight to overcome those behaviors, it is clear that efforts have not yet been successful.

Management performance issues are being addressed in great part by changes in management staff, communicating management expectations, and requiring an increased level of accountability. The District's immediate goal is to acquire new talent with higher performance standards, to deepen management resources, and to allow reassignment of some incumbent managers to other areas of need, while bringing fresh industry perspective to Cooper Nuclear Station's central management structure. A new Site Manager and Licensing Manager, both from plants which recently improved their performance, assumed their duties on July 11. The Maintenance Manager has been replaced from within. A new senior manager with many years in the Navy Nuclear Program has been hired. A new Corrective Action Program Manager has been assigned, Condition Resolution Team mentor support has been provided, and five full-time, rotational Condition Resolution Team Leader positions are being established. Additional planning is underway for replacement or reassignment of the other key senior and middle manager positions, as appropriate.

Weaknesses in Quality Assurance staff performance during recent events are being addressed by: 1) the establishment of stronger guidance for dealing with emerging issues and interaction with the line organization; 2) increased oversight and supervision of QA field activities by QA Division and Department Managers, 3) training to improve safety and assessment skills (underway and to be completed by August 1994); and, 4) publication of senior management expectations for quality assessment activities.

Management oversight of Condition Review Group (CRG) activities has been increased by having a senior manager oversee the CRG's evaluation and decision making activities in the role of a protagonist to ensure adequate rigor and urgency. Condition Reports are being more thoroughly screened for significance by the Technical Staff prior to submittal to the CRG.

To improve safety attitudes and performance, training in safety principles and performance-based evaluation techniques will be provided to appropriate segments of the NPG staff starting in September 1994. Advanced root cause analysis and investigation training will also be provided.

Other programs were found to be ineffective during recent events. For example, the Operating Experience Review (OER) program should have addressed the inadequate diesel load shed testing and logic system functional testing problems. To ensure that this deficiency is not pervasive, a comprehensive review of past operating experience documents has begun.

The absence of design basis information adversely affected the District's efficiency in responding to potential safety issues. As a result, the reconstitution schedule has been accelerated. Efforts to review and upgrade the CNS surveillance and other testing programs are discussed elsewhere in this letter.

In summary, the District has taken, and will continue to take actions responsive to technical, programmatic, and managerial problems as they are identified.

CAL 4-94-06b
Item 5 (g) :

"Discuss the basis for your determination that the testing programs for electrical distribution system surveillance testing and inservice inspection of penetration welds are technically adequate and complete."

NPPD Response

Electrical Distribution

The District is confident that the surveillance testing of the Electrical Distribution System (EDS) for Cooper Nuclear Station is adequate. This confidence is based on the number and scope of actions that have been taken. The following summarizes some of the more significant activities and improvements that have been made during the current outage.

a) compared the General Electric ECCS input assumptions against the Emergency Diesel Generator (EDG) load calculation;

b) upgraded the 480-volt undervoltage design;

c) reviewed the 4160-volt first and second level undervoltage logic and conducted additional testing via special procedures, temporary procedure changes, or new surveillance procedures;

d) revised the EDG sequential loading test procedure and performed the revised test on both divisions to ensure appropriate load shedding;

e) reviewed maintenance practices regarding installation and removal of devices such as cable ties, jumpers and contact boots and initiated procedure changes where necessary;

f) reviewed operating procedures for proper operation of the Electrical Distribution System;

g) reviewed the battery load study and compared it with battery load testing procedures;

h) reviewed Design Criteria Documents (DCDs) for AC, DC, and EDGs at the component level, including support systems (e.g., Fuel Oil Transfer, HVAC, etc., that support the EDGs) to ensure proper testing/functionality could be demonstrated; and,

i) reviewed the above DCD listings for Licensing commitments and open items identify items of potential safety significance.

Future actions planned by the District are addressed in response to Items 5(e)1 and 5(e)2.

With regard to preconditioning, CNS will neither test nor repair components, systems, or structures for the purpose of satisfying as-found acceptance criteria in surveillance tests. As-found testing will be performed prior to maintenance requiring adjustment of setpoints or re-calibration per the surveillance program. For example, prior to performance of Technical Specification instrument surveillance calibrations and setpoint adjustments as-found data will be recorded. Similarly, prior to performance of maintenance on essential electrical breakers, as-found data will be recorded.

Inservice Inspection of Penetration Welds

As discussed during the July 8, 1994, meeting with the NRC, examples of incorrect classification of primary containment penetration piping welds were identified. As a result, a commitment was made to assess the ISI Program, to submit an addendum to add the excluded welds, component supports, and pressure test boundaries to the ISI Program, and to submit relief requests if required prior to the 1995 refueling outage to ensure ASME Section XI requirements are implemented. Upon completion of these activities, the District will consider the ISI Program to be technically adequate and complete.

CAL 4-94-06b
Item 5 (h) :

"Discuss the basis for your assurance that the testing programs for other licensed activities are adequately implemented."

NPPD Response

As discussed in Item 5(e), the surveillance testing for the major components of six critical plant systems has been reviewed to ensure conformance to the USAR and Technical Specification testing requirements. These reviews were performed on systems with substantial safety significance: High Pressure Coolant Injection, Reactor Core Isolation Cooling, Residual Heat Removal Low Pressure Coolant Injection Mode, Core Spray, Automatic Depressurization, and Emergency Diesel Generator Systems. The review found several discrepancies between CNS tests and the USAR. The discrepancies were corrected by USAR revisions or were incorporated into surveillance test procedures.

As a result of the investigation of the undervoltage trip assembly problems, the District also reviewed its program for logic system functional testing (LSFT). This review included the following systems:

High Pressure Coolant Injection	Standby Gas Treatment
Reactor Core Isolation Cooling	Reactor Building HVAC
Reactor Protection	Diesel Generator HVAC
Control Room HVAC	Reactor Equipment Cooling
Residual Heat Removal	Core Spray
Alternate Rod Insertion	Fire Protection
Service Water	Low-Low Set
Automatic Depressurization	Diesel Generator Lube Oil
Standby Liquid Control	Diesel Generator Auto Start
Diesel Generator Fuel Oil	Primary Containment Isolation (Gr 1-7)
Diesel Generator Starting Air	Anticipated Transient w/o Scram

Each contact in the above listed systems was evaluated to determine if it performed an essential safety function and to determine whether a procedure existed which confirmed each contact's operability. Where testing was not being performed, either appropriate procedures were revised or special test procedures were issued to perform the testing. Completion of this testing has confirmed the design and functionality of the logic systems. From all of the testing performed, one minor, non-safety significant discrepancy associated with relay timing was noted. Time delay relay REC-REL-1FR was found outside of its allowable range (27 to 33 seconds), but within procedural limits (15 to 60 seconds). Actual relay time delay was 33.27 seconds. The relay was calibrated and retested satisfactorily.

Furthermore, the District has implemented several programs and activities to critically evaluate and improve CNS operation. As part of these longer range programs, a series of self-evaluations of key programs continues to be performed, including those involving licensed testing activities. Examples include: fire protection, MOV program, Appendix J, ISI, IST, and instrument setpoint. "Health Reports" are also being generated for each program. These reports consider a number of program performance factors including currency of the program with industry practice, currency with regulatory issues and commitments, and establishment of adequate program controls. The health reports for activities involving testing programs include the surveillance testing program, the calibration program, inservice testing program, containment leak rate testing program, relief valve setpoints, instrument setpoints, relay setpoints, and the MOV program.

While no significant deficiencies were identified, a health report for the Protective Relay Setpoint Program identified concerns related to overall program management. Previously, control of the setpoints included in this program was considered one of many elements of the electrical maintenance program, not a unique setpoint program. Currently, program responsibility has been assigned to the design engineering group.

In addition, inservice testing and inspection, containment leak rate testing (program upgrades in progress), and the Check Valve and Vendor Manual Programs were all found to have health ratings that require further in-depth assessment and program improvements. The most significant concerns have been related to program ownership and support (i.e., management), not technical concerns. No technical deficiencies that would impact safe plant operation have been identified. Management concerns previously noted will be addressed. Any safety significant technical deficiencies discovered during in-depth program reviews will be evaluated for impact on safe plant operation and aggressively resolved.

While some activities remain to be completed, the District has concluded that testing programs for other licensed activities are adequately implemented.

Nebraska Public Power District

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NLS9400026
August 8, 1994

Mr. L. J. Callan
Regional Administrator
NRC Region IV
611 Ryan Plaza Drive
Suite 400
Arlington, Texas 76011

Subject: Response to Request for Additional Information
Cooper Nuclear Station
Docket No. 50-298, DPR-46

References: 1. Confirmatory Action Letter (Revision 2) dated July 1, 1994 to Guy R. Horn - Nebraska Public Power District (CAL 4-94-06B).

2. Letter from G. R. Horn (NPPD) to L. J. Callan (NRC) dated July 29, 1994, "Response to Confirmatory Action Letter."

3. Meeting Between Nebraska Public Power District and the Nuclear Regulatory Commission on July 29, 1994, concerning restart readiness.

4. Confirmatory Action Letter Dated August 2, 1994, to Guy R. Horn - Nebraska Public Power District (CAL 4-94-08).

Dear Mr. Callan:

On July 1, 1994, Confirmatory Action Letter 4-94-06B was issued which verified, among other things, that Nebraska Public Power District (the District) would provide the Nuclear Regulatory Commission (NRC) Region IV office with a letter that discussed eight areas of interest.

On July 29, 1994, the District provided the letter to the NRC and participated in a meeting with the NRC to discuss plant restart. With these two activities completed, all items in CAL 4-94-06B that were agreed upon as a precursor to plant restart were satisfied. However, at this meeting, the NRC requested additional, more detailed information regarding the District's component and system preconditioning policy, and its relationship to the implementation of testing programs. The NRC also requested, prior to restart, that the District document some of the detailed discussions held during the meeting and, in some cases, provide more detailed information on how reviews addressed in the July 29, 1994, letter were conducted. Attachment 1 to this letter provides the detailed information.

On August 2, 1994, the NRC issued CAL 4-94-08, which requested that (as a supplement to the CAL 4-94-06B response) the District describe its basis for concluding that an adequate review of Cooper Station operational experience,

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industry experience, and NRC information has been conducted to support plant restart. The NRC requested that the District's discussion also address two recent cases where previous District reviews apparently did not address certain precursor information. Attachment 2 to this letter provides this information. The NRC requested that all of the above information be provided before plant restart and that the information be discussed at a public meeting, currently scheduled for August 12, 1994, at the Cooper Station.

All of the District's activities, collectively considered, represent an extensive amount of work aimed at confirming that there are no significant issues at the Cooper Station which would warrant continued plant shutdown. The District has been very responsive to NRC concerns and often has conducted investigations that typically would not be considered a condition for plant restart. The District acknowledges that some of its reviews (e.g., Operating Experience Reviews) may not have identified all issues. Although some investigations are ongoing, the District does not anticipate that its continuing efforts will uncover deficiencies that have a significant impact on public health and safety. If any safety significant findings occur, the District will take appropriate actions up to and including plant shutdown, if necessary. Of course, further evaluations will be conducted as soon as possible, consistent with schedules discussed with the NRC.

If there are any questions regarding information presented in the attachments, or on other matters, please call.

Sincerely,

G. R. Horn
Vice President, Nuclear

RCG/nr

Attachments

cc: U.S. Nuclear Regulatory Commission w/attachments
Attention: Document Control Desk

NRC Resident Inspector Office w/attachments
Cooper Nuclear Station

NPG Distribution w/attachments

ATTACHMENT 1

A. DETAILED DISCUSSION OF INITIATIVES

Recent events at Cooper Nuclear Station (CNS) prompted several District initiatives to determine the scope of the equipment and process deficiencies that exist at the Cooper Station. Many of the actions taken to correct immediate deficiencies have been detailed in meetings and/or other correspondence with the NRC. While there may be several ways to perform reviews of issues, the District is confident that its approach is satisfactory for determining restart readiness. The following section details actions taken by the District.

1. CONFIGURATION CONTROL - CABLE TIE

The District concludes that the following actions represent a comprehensive investigation of the cable tie issue and should prevent recurrence of similar deficiencies. The District took the following actions to determine the scope of the problem and to correct any actual or incipient configuration control deficiencies.

First, a walkdown was conducted to verify that no similar cable tie installations were in place. None were found. The next step was to review station mechanical and electrical maintenance procedures; surveillance procedures in the chemistry, operations, and instrument and control areas; and the 14.x series instrument and control procedures, to ensure that configuration control had been maintained. Three mechanical procedures and fifteen electrical procedures required revision, along with three minor discrepancies in the operations and instrument and control procedures. No discrepancies were identified in the chemistry procedures. The above listed items will be corrected prior to next use of the procedure and do not adversely impact restart of the plant.

Concurrent with these activities, field walkdowns were performed to look for deficiencies that could have been created as a result of using the deficient procedures. No equipment configuration discrepancies were found. Based on these activities it was reasonably concluded that the cable tie condition was limited to the example identified.

To ensure that configuration control continues to be procedurally maintained, a revision has been made to Maintenance Work Practice (MWP) 5.0.4 to add guidance to further ensure that any impairments, changes, or blocking devices installed during performance of maintenance are removed prior to completion of the procedure. Also, management has held meetings with maintenance personnel to emphasize expectations with regard to configuration control, procedure compliance, and immediate correction of ambiguous or incomplete procedures. Additional meetings will be held to ensure that sensitivity to this issue continues.

ATTACHMENT 1

2. LOGIC SYSTEM FUNCTIONAL TESTING

The activities summarized below provide adequate assurance that logic system functional testing at Cooper Station is adequate. This concern evolved as a result of the discovery of the RHR Service Water Booster pump contacts that had not been tested. The process utilized for this issue is described below:

When the District discovered that contacts had not been tested as required, a review of the following systems was begun:

High Pressure Coolant Injection	Standby Gas Treatment
Reactor Core Isolation Cooling	Reactor Building HVAC
Reactor Protection	Diesel Generator HVAC
Control Room HVAC	Reactor Equipment Cooling
Residual Heat Removal	Core Spray
Alternate Rod Insertion	Fire Protection
Service Water	Low-Low Set
Automatic Depressurization	Diesel Generator Lube Oil
Standby Liquid Control	Diesel Generator Auto Start
Diesel Generator Fuel Oil	Primary Containment Isolation (Gr 1-7)
Diesel Generator Starting Air	Anticipated Transient w/o Scram

The elementary logic diagrams for each system were reviewed, contact by contact, and correlated against the existing surveillances. The screening methodology was as follows:

a. Does an existing surveillance actually verify the operation of the contact directly? If yes, then no further action is necessary. If no, then proceed to b.

b. Does the contact perform an automatic essential function as determined by an engineering review of the Technical Specifications and the USAR? If yes, then test prior to startup. If no, test after startup.

This review was completed on June 5, 1994, and testing commenced. In mid-July, due to a question concerning the LOCA signal auto close contacts for the Core Spray full flow test valves (which had been scheduled for post startup testing), a re-review of the post startup population of contacts was directed by senior management using this additional criterion:

Is the contact operationally significant (i.e., interlock that prevents an operator error) and not verified by existing testing? If yes, then test before startup. If no, then test after startup.

The second screen was completed on July 18, 1994. All contacts have been satisfactorily tested. A plan will be generated to address contacts requiring testing after startup.

3. SURVEILLANCE REVIEW

The District concludes that the following activities adequately determined the extent of the surveillance deficiency revealed by the undervoltage and load shed testing inadequacies. A team of experienced Senior Licensed Operators reviewed the CNS Technical Specifications, USAR, and surveillance programs to identify any weaknesses or discrepancies. The major components (i.e., pumps and valves) of the following systems were reviewed: High Pressure Coolant Injection, Reactor Core Isolation Cooling, Residual Heat Removal (Low Pressure Coolant Injection mode), Core Spray, Automatic Depressurization, and Emergency Diesel Generators.

The review was performed as follows:

- An existing cross reference between Technical Specifications and surveillance procedures, which is maintained by the Surveillance Coordinator, was independently reviewed for correctness.
- The Technical Specification surveillance requirements were reviewed against the respective surveillance procedures to determine if the requirements were being met.
- USAR sections describing the six systems were reviewed to determine if the USAR requirements were being met by the surveillance.

The above reviews represent a significant undertaking by District personnel in a short period of time (July 2 to July 5, 1994). Reviewers developed a list of questions/discrepancies which was assigned to the appropriate departments (engineering, maintenance, etc.) for resolution. The discrepancies have been evaluated and incorporated into surveillance procedures, or corrected by USAR revisions. Additionally, the Design Basis Reconstitution Project will be accelerated and will include a review of surveillance testing adequacy for all systems in the project.

Based on the above reviews, the District has reasonable assurance that surveillance procedures adequately implement regulatory requirements.

4. DESIGN BASIS REVIEW OF THE ELECTRICAL DISTRIBUTION SYSTEM

While the reviews of various specific items were addressing individual concerns, the District determined that a comprehensive evaluation of the entire system should be performed to ensure that the problems were not endemic. As a secondary matter, this review also would address the adequacy of implementation of the Operating Experience Review (OER) program. This effort has received additional scrutiny because of its failure to adequately address the Westinghouse DB 50 breaker issue. The Electrical Distribution System (EDS) (AC Distribution, DC Distribution, and the Emergency Diesel Generators) was chosen because many of the recent problems appeared to affect electrical components and testing, and because of this system's critical nature. The investigation concluded that EDS components would have performed their intended safety function.

Starting on July 19, 1994, a multi-discipline integrated review of the EDS was performed. The team consisted of personnel from the Engineering Department and Senior Reactor Operators. This review utilized design criteria documents (DCD) and evaluated the actual requirements at not only the systems level, but also at the component level. Included in these system level and component level reviews were support systems such as DG fuel oil, HVAC, DG lube oil, etc. Each of the commitments affecting testing or plant safety was reviewed to determine if they were adequately met. The initial review of the DCDs resulted in 49 questions requiring further evaluation and were investigated by Design Engineering, System Engineering, Operations Engineering, Configuration Management, or Operations Support Group. All of these items have been addressed. The review was completed on July 28, 1994.

B. ADDITIONAL DISTRICT REVIEWS

While the actions taken as a result of the technical issues that arose during the current shutdown provide some assurance that systems and components required for plant operation will function as required, the District concluded that additional reviews were warranted before startup. Therefore, the following actions have been taken:

1. OPERATING EXPERIENCE REVIEW

In 1993, the District recognized that its Operating Experience Review (OER) Program must be improved. This effort began in September 1993. The 1993 program began with a review by the Corrective Action Program Overview Group (CAPOG) of twenty percent of approximately two years of operating experience documents. On December 1, 1993, due to approximately a ten percent rejection of OER assessments, the sample size was expanded by another twenty percent. As discussed further in Attachment 3, the SBM switch and REC corrosion-related correspondence were not in the CAPOG sample population. Again, CAPOG re-reviews were a sampling effort that was not intended to assess all OER closeout documentation. Therefore, the fact that these issues were not satisfactorily closed was not fostered by 1993 OER oversight efforts.

However, due to the failure of the 480 VAC undervoltage trip devices, the District has commenced an additional pre-startup review of closed OER information. The scope of this review covers all closed OER responses for the years 1992, 1993, and 1994, all closed pre-1987, and 25% of 1987-1991 responses. The 1992-1994 period was chosen to validate the adequacy of the current program and represents approximately 25% of the entire historical database. A 100% review of the pre-1987 period was chosen because there was an apparent lack of formality in the program at that time. A 25% sample of the 1987-1991 population was chosen to provide assurance of program adequacy after it was formalized in 1987. This recent limited review provides a reasonable basis for the District's conclusion that the OER program has not overlooked issues that have a significant impact on plant safety. The screening criteria used during this review are as follows:

- The item could adversely affect nuclear safety.
- The item is needed to comply with the CNS Technical Specifications.
- The consequences of not completing the OER action could affect the ability of a safety system to satisfy its design function.
- The consequences of not completing the OER action could result in reduced safety system availability.

The closure documentation for items meeting the screening criteria are then reviewed for adequacy. If the basis for closure does not appear fully adequate, the item will be re-reviewed by NPPD engineering. CNS management will determine if pre-startup actions are required for any inadequate responses as determined by engineering. If an item does not satisfy the above criteria, it is assumed that the previous review, if inadequate, would not have a significant safety impact.

Approximately 14% of the pre-1987 items, approximately 6% of the 1987 - 1991 items, and approximately 0.4% of the post 1991 items (2 out of 552) have been returned for review of response adequacy.

A full review of the OER database responses for adequacy will be performed with an estimated completion time of 2 years.

The LER database also is being screened to identify recurring issues. Recurrence of the same or similar issues is indicative of a potentially inadequate corrective action. Those items found by the screening will be evaluated against the criteria defined above to determine if corrective action review is required prior to startup and CNS management will determine if any followup corrective actions will be required prior to startup. The remaining items will be reviewed after startup and the need for further action determined.

2. ASSESSMENT OF COMMUNICATION EFFECTIVENESS

Recent events at CNS have shown that additional efforts are necessary to ensure that everyone understands management expectations, especially for those issues that have been named as causes of recently discovered deficiencies, e.g., procedure use, preconditioning, and importance of problem identification. Since the maintenance organization also has been involved in several recent findings, additional management meetings have been held with the maintenance staff to discuss issues and to communicate expectations.

To reenforce the expectations expressed in the management meetings, the Site Manager issued a memorandum to the site dated July 29, 1994. This memorandum specifically addressed preconditioning of components for the purpose of passing surveillance tests, maintaining a questioning attitude, and the importance of clear and precise communication.

Independent of the above, from July 30, 1994, to August 1, 1994, the QA Division conducted a series of interviews with maintenance, operations, instrumentation and control, and chemistry to assess the state of understanding and acceptance of management's expectations. A specific list of questions covering procedural adherence, preconditioning, and identification and reporting of deficiencies was used. The following discussion provides a summary of the QA effort.

Preconditioning

The interviews had mixed results. For example, within the areas explored, management has been effective in communicating its expectations to NPG personnel with one notable exception. While over 93% (222 of 238) of personnel interviewed had an acceptable understanding of what constitutes preconditioning, 45% (107 of 238) did not clearly understand the importance of not preconditioning. The majority of these personnel discussed the effects on as-found readings, the ability to accurately identify problems or the inability to trend problems. While these are also important factors, the key issue of functionality does not appear to have been adequately communicated and/or absorbed. It appears that this lack of full understanding is the result of inadequate training on the subject.

CNS management is currently evaluating appropriate ways to expand preconditioning training to ensure complete understanding of the policy by all personnel.

Procedure Adherence

Interview results indicate that there is a very good understanding of management's expectations throughout the Nuclear Power Group. Virtually every individual interviewed clearly understood both the need for procedural use and compliance, as well as the need to question the adequacy of the procedures and instructions they use as part of their daily routine. Fifteen percent of interviewees, however, expressed that they did not fully understand management's expectations, many because the expectations were changing so rapidly, it was difficult to definitively state that they were understood. This is an understandable reaction to the many recent culture improvement initiatives. Through continued management reenforcement of expectations, this concern will dissipate.

Problem Identification

The interview results indicate that management has been very effective in communicating expectations in this area. Virtually all of those interviewed expressed a clear understanding of their responsibility to identify and document problems and concerns to ensure that they are corrected. However, management is concerned that interviews also indicated that several individuals are reluctant and/or uncomfortable with escalating problems that they did not feel had been resolved to their satisfaction. In this regard, reluctance by one individual is too many. Therefore, management will be increasing its focus on this aspect of problem identification.

3. STARTUP AND POWER ASCENSION MANAGEMENT PLAN

Cooper Nuclear Station has developed a Startup and Power Ascension Management Plan to ensure that plant equipment, personnel performance, and organizational responsiveness are ready to support a safe and reliable plant startup and ascension to full power operation. A copy of this plan is provided (for information) as Attachment 3. The District does not anticipate forwarding subsequent revisions to the NRC. The Plan's purpose will be accomplished through the following objectives:

- Assign temporary positions and responsibilities to provide accountability and clear lines of responsibility during the startup and power ascension process.

- Establish communication paths to ensure accurate and timely transfer of information to support startup and power ascension.

- Describe outage activities to ensure completion of work supports a safe startup.

- Resolve emergent issues in a timely manner so safe startup and power ascension are not impeded.

- Conduct startup and surveillance testing in a safe and efficient manner to ensure that system and component operability support startup and power ascension

Two aspects of the plan are of special interest. First, each system engineer will review open items for his or her system to ensure there are no unresolved items which may impact that system. Open items for review include (among others) operating experience reviews, maintenance work requests, and temporary conditions. The completion of this review will be certified by the system engineer and reviewed by management.

Second, the manager of each station department will review open action items, condition reports, training, etc., to ensure that his department is ready to support startup and plant operation. As with the system engineer, the completion of the review will be certified by the department manager and reviewed by senior management.

Any item that meets one or more of the following criteria must be addressed prior to startup:

- The item could affect nuclear safety.

- The item is necessary for a safety system to satisfy its design function.

- The item is needed to comply with the CNS Technical Specifications.

- The item may result in reduced safety system availability, increased forced outage rate, or reduced capacity factor in the time before it is completed or resolved.

4. FIELD COACHING TEAM

Obtaining prompt and precise feedback on performance in the field has been a problem at Cooper Station. This has occurred in great part because effective communication methods to ensure that this information exchange occurred did not exist in all areas. To remedy this deficiency for the short term, CNS has established a multi-disciplined team of CNS personnel headed by an independent manager charged with monitoring operations, maintenance, and surveillance testing in the field to ensure management requirements for proper testing and maintenance are understood and executed.

Charter

A charter has been written for this Field Coaching Team (FCT) which establishes specific criteria for observation and evaluation of field activities. At a minimum, the FCT team will observe adherence to procedures, identification and resolution of procedural inadequacies, awareness of any potential for a process or activity to contribute to preconditioning, demonstration of effective communication, and the performance of work in a safe and quality manner.

Scope

This process will focus at a minimum on:

- Adherence to procedures/instructions.
- Identification and resolution of procedure/instruction problems and inadequacies.
- Identification and resolution of any potential preconditioning problem.
- Identification and resolution of ineffective communication.
- Ensuring effective utilization of resources to accomplish tasks safely and with quality results.
- Insuring any perceived schedule pressure is corrected.
- Insuring identification of problems and generation of CRs when appropriate.
- Application and consistent use of self-checking.
- Supervisory involvement in field activities.

Process

FCT personnel will be provided with orientation training by the Site Manager to ensure that they fully understand management expectations. Once trained, team members will disperse into the field, making their presence and function known to all personnel engaged in an observed activity. At no time will the team subvert the role of line management -- in fact, they will serve as augmentation to line management's ability to observe and correct inappropriate practices. Specific techniques for assessment will be as dictated by the activity being observed, with appropriate consideration to the level of intrusiveness necessary to fulfill the objective and purpose of the FCT process. The District currently anticipates that the FCT team will observe pre-startup testing, and startup and power ascension testing. Once the startup and power ascension is complete, the team will remain in place to observe field activities until its purpose has been fulfilled.

ATTACHMENT 2

SBM Switches and Reactor Equipment Cooling Piping

As noted in Attachment 1, the 1993 OER review effort established a screening criteria for determining which findings required additional focus. This effort utilized a sampling approach to determine with reasonable assurance that previous OER efforts were satisfactory. Results of an assessment of the 1993 reviews could fall in one of three primary categories: (1) the components were not part of the sample group and therefore, the District's re-review did not directly miss potential safety issues, (2) the components were reviewed by the District as part of its sampling effort and it was reasonably concluded that the issues had been adequately addressed, or (3) the components were reviewed by the District as part of its sampling effort and it was erroneously concluded that the issues had been adequately addressed.

A review was performed to determine whether the SBM switches and REC issues had been specifically assessed by the OER review. Neither the SBM switches nor the REC issues were included in the sampling review. Therefore, it is reasonable to conclude, based on current findings, that these previous reviews were adequate. This conclusion, however, should not be considered an excuse for not identifying the SBM switch and REC issues. Proper questioning attitudes should have led to further discussion and satisfactory resolution of these issues. Notwithstanding these conclusions, the District assessed the potential safety significance of SBM switch failures and the REC System. A brief summary of safety significance conclusions is provided below.

SBM Switches

A review of SBM switch operating history at CNS illustrates that since GE SIL 155, "Possible Failures of Type SBM Control Switches," recommended inspection and refurbishment of the switches in 1980, there have been two switch failures (February 1989 and July 1994) due to the phenomenon described in the SIL. Seven additional switches with broken cam followers have been observed. However, this condition did not result in switch failure and none of the failures or cracks have occurred in switches refurbished in 1980.

During recent inspections a majority of switches not refurbished in 1980, had one or more cam followers categorized as "Category B" per GE SIL 155. However, this status is not considered a failure. GE does not recommend these switches be replaced and has conducted testing that shows approximately 45,000 successful switch cycles can be expected before switch failure. Therefore, the Category B switches are expected to perform upon demand. However, the District will establish a replacement protocol for the pre-1976 switches.

With approximately 140 installed essential switches and 14 years of operating experience since switch refurbishment, two switch failures equals a failure rate of 0.001 failures per year or approximately one switch failure every eight years. Additionally, industry experience (as evidenced by industry data base searches) indicates an extremely reliable switch operating history.

The District evaluated whether any safety functions would have been defeated had the switch failures occurred during a design basis accident. In summary, no safety functions would have been adversely impacted. This is due primarily to

ATTACHMENT 2

a combination of design redundancy in the switch contacts and components that are not required to change position to perform their intended safety function.

REC System

On July 29, 1994, a pinhole leak was discovered in a 12 inch non-essential REC weld. A section of the weld containing the flaw was sent to General Electric for metallurgical examination. The examination determined that Intergranular Stress Corrosion Cracking (IGSCC) was the most likely cause. The root cause was then determined to be nitrite induced cracking similar to that experienced in 1979 and 1980 at CNS. Subsequently, a second leak was found in a 6 inch section of non-essential piping.

An inspection program was initiated using the methodology defined in NCIG-02 (revision 2), "Visual Weld Acceptance Criteria, Volume 2: Sampling Plan for Visual Reinspection of Welds." The scope of the inspection eventually encompassed Ultrasonic Testing (UT) of 117 welds in the essential portions of the system piping. Of the 117 welds examined, 5 were found to have crack-like indications. Of the 5 welds with indications, 4 were acceptable per IWB-3600. All 5 welds will be repaired prior to startup. The remaining 112 welds had no crack indications.

The District also has performed a preliminary safety assessment of the as-found condition of the REC system. Of the 5 flaws found, 4 were acceptable per IWB-3600 and did not represent a threat to piping integrity. The remaining indication was within the critical flaw size and therefore, had it continued to propagate, would have leaked before the structural integrity decreased below acceptable limits. The non-essential portions of the piping perform no safety function and are isolated on a design basis event.

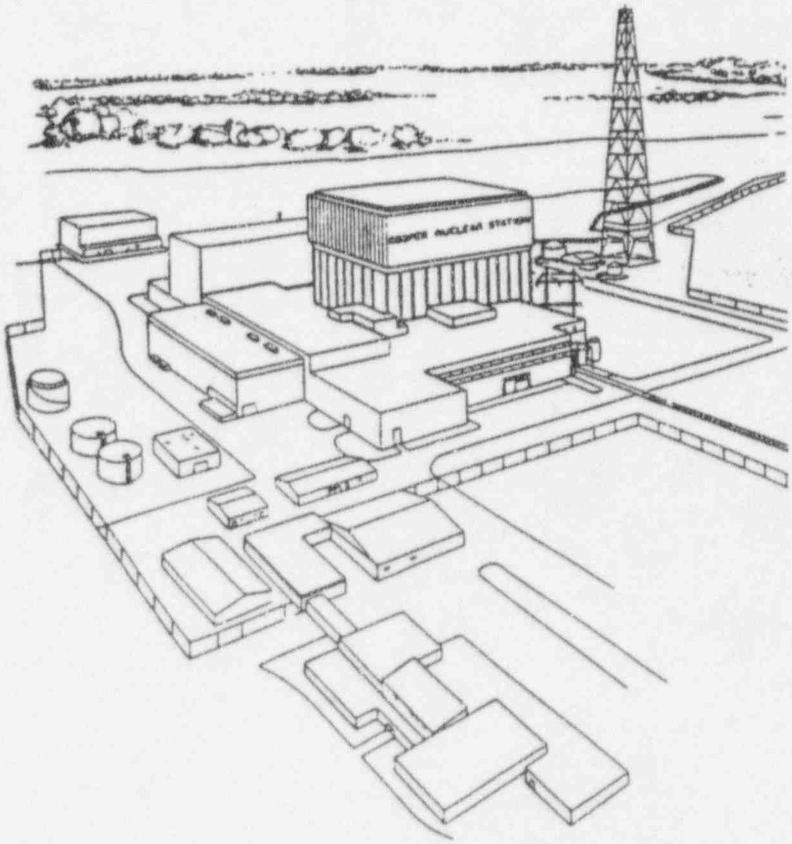
The only other safety related system in which nitrites are or were used is the Diesel Generator Jacket Water System. The use of nitrites as a corrosion inhibitor in diesel generator jacket cooling water is common industry practice. Per the Cooper-Bessemer "Model KSV Emergency Diesel Generator Lubricating Oil and Jacket Water Analysis Guidelines," (Revision 1 dated 1993), a nitrite based corrosion inhibitor program is recommended. Eight of nine current owners follow this recommendation. No leaks have occurred due to cracking in the Diesel Generator Jacket Water System at CNS and Cooper-Bessemer has no history of jacket water leakage as a result of nitrite use.

ATTACHMENT 3
NLS940026
August 8, 1994

COOPER NUCLEAR STATION

STARTUP AND POWER ASCENSION PLAN

(SHUTDOWN 94-03)



Nebraska Public Power District

Powerful Pride in Nebraska

COOPER NUCLEAR STATION

STARTUP AND POWER ASCENSION PLAN

Revision 1

APPROVED BY:

[signature]	8/2/94
Plant Manager	Date
[signature]	[illegible]
Site Manager	Date

STARTUP AND POWER ASCENSION PLAN

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Jodie Knapp
Wayne McKinzey

SUBMITTED:

8/2/94

Senior Manager Site Support　　Date

TABLE OF CONTENTS

* NOTE: Final revision will be provided within 24 hours preceding plant startup.

1. PURPOSE

The purpose of this document is to establish Management's expectations for ensuring the safe and controlled return to service of Cooper Nuclear Station from shutdown 94-03 that commenced May 25, 1994. This will be accomplished through the following objectives:

- Assign temporary positions and responsibilities to provide accountability and lines of responsibility during the startup and power ascension.
- Establish communication paths to ensure accurate and timely transfer of information to support the startup and power ascension.
- Describe outage activities to ensure completion of work supports a safe startup.
- Resolve emergent issues in a timely manner so safe startup and power ascension are not impeded.
- Conduct startup and surveillance testing in a safe and efficient manner to ensure that system and component operability support startup and power ascension.

2. SCOPE

This plan addresses the activities performed to ensure that plant operation, material condition, personnel performance, organizational responsiveness, and the functioning of administrative and work control processes are fully ready for a safe and reliable startup. The development and approval of this plan are part of the criteria on which the evaluation for startup is based. This plan consists of the following major elements:

- Startup Organization
- Outage Activities
- Startup Overview

3. REFERENCES

3.1 C.O.P. 2.0.1.1, Conduct of Infrequently Performed Tests or Evolutions

3.2 G.O.P. 2.1.1, Startup Procedure

3.3 G.O.P. 2.1.1.1, Plant Startup Review and Authorization

3.4 CNS Procedure 0.2, Station Organization and Responsibility

3.5 S.O.P. 2.2.28.1, Feedwater System Operation

4. STARTUP ORGANIZATION

This section describes the additional staffing (Attachment 1), their responsibilities, and the lines of communication used during preparations for and the conduct of startup and power ascension. As a minimum, the staffing shall be available from the time the Reactor Mode Switch is placed in the "Start & Hot Standby" position until the second Reactor Feed Pump is in service (Ref. 3.5). The staffing can be established prior to startup to develop the startup schedule and make startup preparations.

4.1. MANAGEMENT OVERSIGHT

The Management Representative is an experienced NPG Manager assigned on-shift to provide 24 hour coverage throughout startup and power ascension. He is responsible for maintaining an overall perspective of the startup process. Should any significant restraints or potential schedule impacts be encountered, he shall be informed. Additional responsibilities include but are not limited to:

- Ensuring plant personnel are aware of Management's expectations on the importance of open, two-way communication.
- Fostering and supporting our questioning attitude by ensuring concerns expressed by plant personnel are acknowledged and addressed in a timely manner.
- Allocating personnel and resources as needed.
- Apprising the Plant Manager of all off-normal and emerging issues that may impact plant startup and power ascension.
- Overseeing implementation of this plan.

4.2 NORMAL STAFF AUGMENTATION

4.2.1 Operations Department

4.2.1.1 Operations Management Representative

The Operations Management Representative is an experienced individual from Operations line management assigned on-shift (Ref 3.2) to provide continuous operations management representation and presence during the startup and power ascension. His primary function is to ensure that the exercise of command and control authority by the Shift Supervisor and Control Room Supervisor is not diluted by the increased level of activities inherent in the startup. His responsibilities include:

- Providing 24 hour, continuous shift coverage.
- Coordinating emergent work activities with the Outage Director.
- Representing the Operations Manager on-shift.
- Providing immediate on-scene consultation and evaluation of emergent conditions.
- Responding to issues identified by the Shift Supervisor, assigning actions, and ensuring that each issue is properly resolved by the assigned organizational units.
- Facilitating and coordinating emergent support activities provided by other organizational units.
- Attending the shift turnover meetings in the Control Room.
- Informing the Management Representative of significant re-

straints and potential schedule impacts.

4.2.1.2 Startup Test Coordinator

This position, assigned by Plant Management, is manned on a 24 hour basis by an individual holding an SRO License or SRO Certification. The Startup Test Coordinator assists the Shift Supervisor to ensure that post maintenance and system testing is completed to support system and component operability. These responsibilities include:

- Identifying post-maintenance/modification tests to be performed during the startup and power ascension evolution.
- Identifying additional testing of plant systems and components to be performed to provide assurance that safety-related and non-safety related systems will support safe and reliable operations.
- Maintaining a Startup Test File (Attachment 2) as a subset of the Power Ascension Schedule (Attachment 3).
- Coordinating the performance of test file items with the power ascension schedule.
- Updating the Operations Management Representative with testing status.
- Informing the Operations Management Representative of significant restraints and potential schedule impacts.

4.2.1.3 Operations

Shift staffing for startup and power ascension is increased over normal levels. Additional staffing includes a Senior Reactor Operator, a Licensed Operator, and a Station Operator. Their responsibilities (Ref 3.2) are as follows:

- The Senior Reactor Operator observes overall operation in the Control Room to alert the duty crew of potential problems. This Operator is to remain independent from the duty crew and manipulate controls only if absolutely necessary and at the direction of the duty crew.
- The Licensed Operator is dedicated to verifying control rod movements. This Operator is to remain independent from the duty crew and manipulate controls only if absolutely necessary and at the direction of the duty crew.
- The Station Operator assists the duty crew during times when work load prevents the duty crew from performing manipulations in a timely manner. When not needed to assist the duty crew, this Operator is to tour the plant being observant to potential plant problems.

4.2.1.4 Instrumentation and Controls Department

Department Personnel will be on shift to provide support for the following:

- Pre-planned or required surveillance procedures.
- Emergent issues as deemed necessary by the Shift Supervisor.

4.2.2 Other Departments

Chemistry, Health Physics, Maintenance, and support organization staffing is provided on shift during the startup and power ascension evolution. Maintenance support personnel are pre-selected and designated to respond to emergent work. The personnel, reporting through the Outage Organization are assigned to shift work and are available 24 hours per day in the event of emergent work.

4.2.2.1 Chemistry and Health Physics

- Health Physics will be available for 24 hour coverage to ensure radiological coverage for emergent work and/or emergency response.
- Chemistry will provide 24 hour support for increased number of reactor coolant chemistry samples and any other emergent work.

4.2.2.2 Maintenance

Department Personnel will be on shift to provide support for the following:

- Pre-planned or required surveillance procedures.
- Emergent issues as deemed necessary by the Shift Supervisor.

4.2.2.3 Support Units

Other organizational units will be available (on-site or on-call as appropriate) 24 hours per day to respond to emergent issues. These Support Units include personnel from the following areas:

- Nuclear Engineering Department
- Plant Engineering
- Site Services
- Training

4.3 FIELD COACHING TEAM

A Field Coaching Team (FCT) process will be employed for the purpose of independently assessing performance of startup and power ascension activities. These assessments are to ensure Management expectations are understood and complied with.

The organization includes an FCT Manager who is responsible for coordination of FCT activities and for communicating the results directly to the Site Manager. Personnel assigned will possess qualifications commensurate with the activities being assessed.

Functional areas targeted for assessment are Operations, Instrument and Control, Maintenance, Engineering, Chemistry, and Health Physics.

At a minimum, the Field Coaching Team will be focusing on the following areas:

- Identification and resolution of procedure and instruction inadequacies.
- Identification and resolution of any potential preconditioning concerns.
- Identification and resolution of ineffective communication .
- Insuring effective us of resources to accomplish tasks safely with quality results.
- Insure any perceived schedule pressure is corrected.
- Insuring Condition Reports are generated when appropriate.

4.4 COMMAND AND CONTROL

This section clarifies command and control authority and lines of communication.

The duty Shift Supervisor is in charge of plant configuration and control at all times (Ref 3.4). The temporary staffing established to augment the normal operating staff during the startup and power ascension is structured to support the command and control authority of the Shift Supervisor and Control Room Supervisor.

The Operations Management Representative supports forthcoming events and coordinates actions to resolve emergent issues. He interfaces with the Management Representative and is informed of testing status by the Startup Test Coordinator. All departments inform him of potential schedule impacts. This assures an adequate flow of information between management and plant startup support personnel.

5. OUTAGE ACTIVITIES

This section describes the more significant work which was performed during shutdown 94-03 to correct or improve plant configuration.

5.1 MAJOR WORK PERFORMED

Attachment 4 lists the major work items performed during the shutdown and includes a brief description of each.

5.2 MAJOR PLANT MODIFICATIONS

The documentation provided in this section addresses the improvements that support safe and reliable plant operation. The modifications are listed by Design Change number and description on Attachment 5.

5.3 TRAINING

Prior to startup the necessary training shall be accomplished as follows:

5.3.1 Modifications

5.3.1.1 DC94-01 Battery Rooms Exhaust Fans and Non-Essential Control Building HVAC Trip. This Design Change will be presented to operators in Lesson OTH015-94-08 which contains the following objectives:

- Identify the purpose of DC94-01.
- Identify the interlocks between the essential control building HVAC system and the battery room exhaust fans and control building non-essential HVAC system.
- Identify the location of HV-REL-9A, 9B, 8A, and 8B relay panel and testjack points ECBHI-1, 2, ECBHII-1 and 2.
- Identify the change to Procedures 2.3.2.9, 2.3.2.10, 2.3.2.18, 2.4.6.6., and 2.2.38 due to DC94-201.

5.3.1.2 DC94-166, 480V Breaker Shunt Trip
5.3.1.3 DC94-223, HPCI-PS-68A, B, & C
5.3.1.4 TDC94-224, CS-MO-5A & B Time Delay Relay

5.3.2 Procedures

Lesson OTH015-94-10 will be presented to operations personnel informing them of recent Primary Containment Valve Control additions to the following:

5.3.2.1 COP 2.0.1, Operations Department Policy
5.3.2.2 COP 2.0.2, Operations Logs and Reports
5.3.2.3 AP 0.26, Surveillance Program

5.3.3 Startup Training Provided for Operators

Prior to assuming the watch, the Operations crews responsible for the startup will be trained in the simulator for the evolutions they will be performing during startup. These major evolutions will consist of the following:

5.3.3.1 Achieving criticality.
5.3.3.2 Placing Reactor Feed Pump in service.
5.3.3.3 Placing Reactor Mode Switch to Run.
5.3.3.4 Synchronizing generator to grid.

6. STARTUP OVERVIEW

This section describes the approval required for startup, the power ascension schedule, and addresses emergent issues.

6.1 STARTUP VERIFICATION

Startup Verification is written conformation that the plant systems and individual Departments are ready to support safe startup and operation.

6.1.1 System Readiness Review Checklist (Attachment 6)

This checklist provides documentation of reviews on each system by System Engineers to ensure readiness for plant startup.

6.1.2 Management Verification for Startup (Attachment 7)

Department Managers verify readiness for plant startup.

6.2 STARTUP AUTHORIZATION

Department Managers and Supervisors are responsible for performing a plant startup review, thus ensuring all applicable open items are addressed prior to reactor startup. SORC is responsible for authorizing the plant startup upon satisfactory completion of the startup review. The following shall be reviewed and resolved by Management prior to startup authorization being granted (Ref. 3.3):

- Operations Manager or Operations Supervisor shall review:
  Equipment Clearance and Release Orders, Valve Seal Log, Special Orders, Plant Temporary Modifications Control, and Surveillance Procedures.

- Engineering Manager, Operations Engineering Supervisor, or Plant Engineering Supervisor shall review:
  Design and Equipment Specification Changes, Special Test Procedure/Special Procedures, Temporary Design Changes, and Reactor Post-Trip Review Procedure.

- Maintenance Manager or Maintenance Supervisor shall review:
  Work Item Tracking - Corrective Maintenance, Work Item Tracking - Preventative Maintenance, and Unscheduled Shutdown Item List.

- QA Manager shall review:
  QA Commitments.

- Technical Staff Manager shall review:
  Open Condition Reports requiring resolution prior to startup, Commitment and Open Item Tracking, Procedure Changes, Contact Licensing for Outstanding Commitments.

- SORC Chairman (Review and Authorization)
  Review all items above and any exceptions which are forwarded to the Operations Manager for tracking and closure.

Once these items are reviewed, Attachments 6 & 7 are completed, and with Site Manager's concurrence plant startup will be authorized by the Plant Manager.

6.3 POWER ASCENSION SCHEDULE

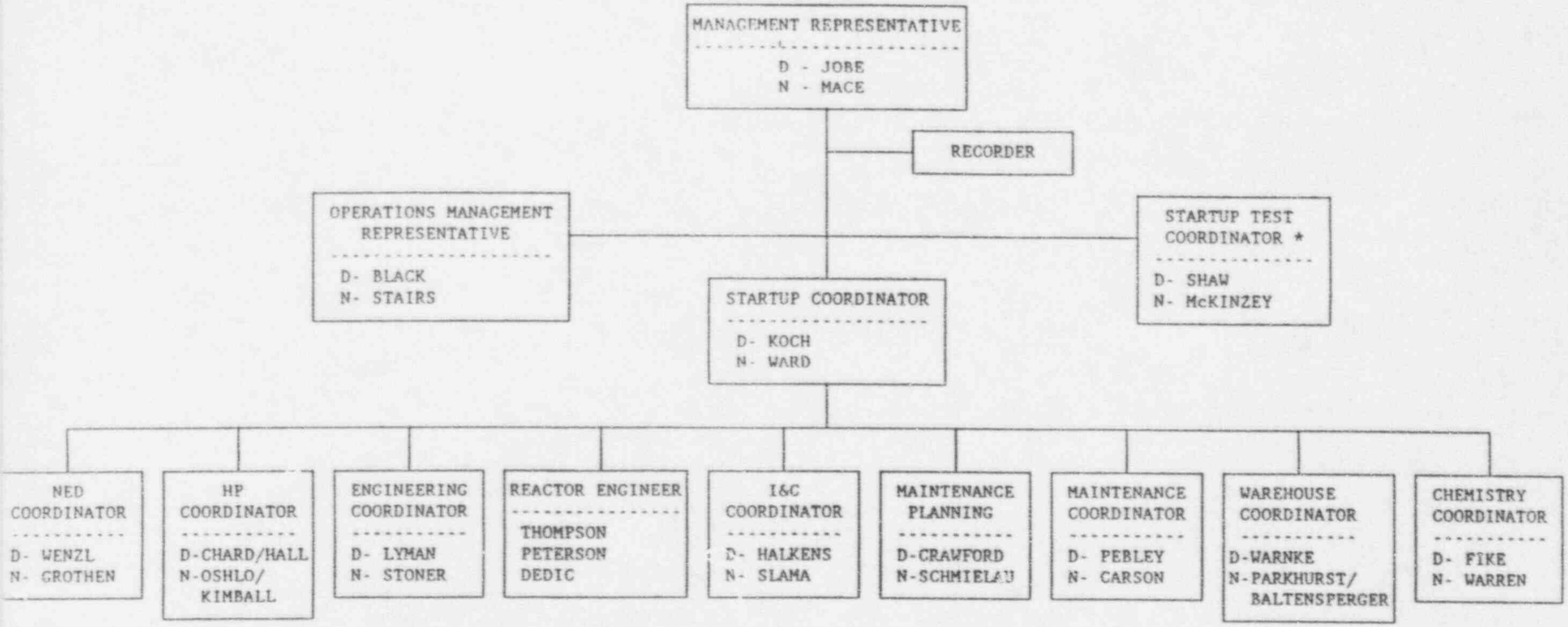
The Power Ascension Schedule (Attachment 3) is a schedule of the activities performed to progress from cold shutdown to full power operations. It is developed by the O & M Department and is based on procedural requirements for the startup. The Power Ascension Schedule begins when approval to commence the startup process has been granted.

6.4 RESOLUTION OF EMERGENT ISSUES

Emergent issues identified during startup need to be resolved effectively, with no degradation in plant configuration control, work quality, or safety. Existing processes are used to identify and track issues and to manage follow-up activities. These processes are augmented by the Operations Management Representative who evaluates new items, initiates notifications, and coordinates follow-up activities for priority items.

To ensure prompt management action, emergent issues and material discrepancies are reported in parallel to the Control Room and to the Operations Management Representative. Immediate response actions are initiated by the Control Room and follow-up actions such as initiating planning and scheduling, alerting maintenance personnel, initiating call-ins, etc., are initiated and coordinated by the Operations Management Representative with concurrence of the Management Representative.

STARTUP AND POWER ASCENSION ORGANIZATION



* - SRO LICENSE OR SRO CERTIFICATION
D - DAY SHIFT
N - NIGHT SHIFT

NOTE: 1) THE STARTUP AND POWER ASCENSION ORGANIZATION IS ESTABLISHED WHEN MODE SWITCH IS PLACED IN STARTUP AND SHALL REMAIN IN EFFECT UNTIL THE SECOND REACTOR FEED PUMP DISCHARGE VALVE IS FULLY OPEN.

2) COORDINATOR MEETINGS ARE CONDUCTED BY THE SENIOR MANAGEMENT REPRESENTATIVE AT 0630 AND 1830.

STARTUP PLAN ATTACHMENT 2

REVISION 1

MWRs BY SYSTEM
As of Aug 1, 1994

STARTUP TEST FILE

CIC	WI NUM	TEST REQUIRED	WORK PERFORMED
AOG-AOV-931AV	94-3283 94-3283	SOAP TEST STROKE VALVE	REBUILT OPERATOR REBUILT OPERATOR
AOG-HX-1B	94-3583	VERIFY NO LEAK	COVER GASKET LEAK
AOG-RV-11RV	92-2760	VERIFY LEAKAGE	REMOVED FOR TEST
AOG-RV-15RV	92-2843	VERIFY LEAKAGE	REMOVED FOR TEST
AOG-SOV-SPV11B	94-3807 94-3807	SOAP TEST VERIFY OPERATION	REBUILT SOV REBUILT SOV
AOG-TP-T2B	94-1425 94-1425	VERIFY OPERATION VERIFY LEKAGE	REBUILD REBUILD
AOG-V-330	94-1466	VERIFY LEKAGE AND OPERABILITY	REPACKED VALVE
AOG-V-331	94-1449	VERIFY LEKAGE AND OPERABILITY	REPACKED VALVE
AR-MOV-161MV	93-2936	VERIFY LEAKAGE	REBUILT VALVE
AS-AO-PCV810	94-1794 94-1392	VERIFY LEAKAGE VERIFY OPERATION	REPACKED REBUILT OPERATOR
AS-CV-15CV	93-4589	VERIFY LEKAGE	REBUILT VALVE
ASB-B-1C	94-1436 94-0685	VERIFY LEAKAGE MP 7.0.8.1	OPEN FOR INSPECTION REPAIRED LEAK
CD-AO-OCV64	94-2544 94-2544	SOAP TEST AIR LINE VERIFY OPERATION	REPLACE AIR LINE REPLACE AIR LINE
CD-V-119	94-1926	VERIFY NO LEAK	REPACKED VALVE
CD-V-131	94-2421	MP 7.0.8.1	CUT PIPE AT VALVE
CD-V-229	94-1927	VERIFY NO LEAK	REPLACED VALVE
CRD	94-0955	MP 7.0.8.1	WELDED IN LEAKING PIPE
CRD-ACC-125(38-27)	94-1542	NPP 10.9	REPLACED
CRD-ACC-125(46-27)	94-3591	NPP 10.9	REPLACED
CRD-AO-CV126(34-31)	94-2619 94-2416	NPP 10.9 NPP 10.9	ADJ CLOSE SWITCH ADJ VALVE OPERATION
CRD-AO-CV126(46-43)	94-2620 94-0889	NPP 10.9 NPP 10.9	ADJ CLOSE SWITCH ADJ VALVE OPERATION
CRD-AO-CV127(34-31)	94-2416	NPP 10.9	ADJ VALVE OPERATION
CRD-AO-CV127(46-43)	94-0889	NPP 10.9	ADJ VALVE OPERATION
CRD-AOV-CV126(22-19)	94-2370	NPP 10.9	ADJ LIMIT SWITCH

STARTUP PLAN ATTACHMENT 2
REVISION 1

MWRs BY SYSTEM
As of Aug 1, 1994

STARTUP TEST FILE

CIC	WI NUM	TEST REQUIRED	WORK PERFORMED
CRD-AOV-CV126(26-15)	94-2376	NPP 10.9	ADJ LIMIT SWITCH
CRD-AOV-CV126(30-11)	94-2375	NPP 10.9	ADJ LIMIT SWITCH
CRD-AOV-CV126(30-31)	94-2372	NPP 10.9	ADJ LIMIT SWITCH
CRD-AOV-CV126(34-27)	94-2374	NPP 10.9	ADJ LIMIT SWITCH
CRD-AOV-CV126(38-27)	94-2373	NPP 10.9	ADJ LIMIT SWITCH
CRD-AOV-CV126(46-43)	94-2371	NPP 10.9	ADJ LIMIT SWITCH
CRD-AOV-CV127(14-11)	94-2379	NPP 10.9	ADJ LIMIT SWITCH
CRD-AOV-CV127(14-23)	94-2378	NPP 10.9	ADJ LIMIT SWITCH
CRD-AOV-CV127(22-39)	94-2377	NPP 10.9	ADJ LIMIT SWITCH
CRD-AOV-CV127(30-19)	94-2383	NPP 10.9	ADJ LIMIT SWITCH
CRD-AOV-CV127(30-35)	94-2382	NPP 10.9	ADJ LIMIT SWITCH
CRD-AOV-CV127(30-39)	94-2381	NPP 10.9	ADJ LIMIT SWITCH
CRD-AOV-CV127(34-31)	94-2380	NPP 10.9	ADJ LIMIT SWITCH
CRD-SOV-SO117(30-07)	94-2349	NPP 10.9	REBUILT SOLENOID VALVED
CRD-SOV-SO117(38-27)	94-2350	NPP 10.9	REBUILD SOLENOID VALVED
CRD-SOV-SO117(42-11)	94-2348	NPP 10.9	REBUILT
CRD-SOV-SO117(46-43)	94-2347	NPP 10.9	REBUILT
CRD-SOV-SO118(30-07)	94-2349	NPP 10.9	REBUILD SOLENOID VALVED
CRD-SOV-SO118(38-27)	94-2350	NPP 10.9	REBUILD SOLENOID VALVED
CRD-SOV-SO118(42-11)	94-2348	NPP 10.9	REBUILT
CRD-SOV-SO118(46-43)	94-2347	NPP 10.9	REBUILT
CW-V-67	94-2343	MP 7.0.8.1	REPLACED VALVE
CW-V-71	94-2343	MP 7.0.8.1	REPLACED VALVE
EE-STR-250HPCI(MO14)	94-1271	SP 6.3.3.1.1	INSPECT MOTOR
ES-AO-NRV3	94-2351 94-2641	SP 6.4.8.10.1 STROKE FOR LEAKS	REPLACED OPERATOR CYLINDER REBUILT OPERATOR
ES-AOV-NRV3	94-2667	SP 6.4.8.10.1	REPLACED LIMIT SWITCH
ES-AOV-NRV4	93-4545	VERIFY OPERATION	PACKING ADJUSTMENT
ES-AOV-NRVSTV3	94-3053 94-3053	VERIFY OPERATION SOAP TEST AIR CONNECTIONS	REBUILTS REBUILTS

STARTUP PLAN ATTACHMENT 2

REVISION 1

MWRs BY SYSTEM
As of Aug 1, 1994

STARTUP TEST FILE

CIC	WI NUM	TEST REQUIRED	WORK PERFORMED
ES-MO-NRV4	93-4545	ADJUST PACKING	PACKING ADJUSTMENT
ES-SOV-NRVSTV12	94-3109	VERIFY OPERATION	REPAIR AIR LEAK
ES-SOV-NRVSTV2	94-3165 94-3165	VERIFY PROPER OPERATION SOAP TEST VERIFY NO LEAKS	REPLACED FOR LEAKING AIR AND BUZZING TOO LOUD REPLACED FOR LEAKING AIR AND BUZZING TOO LOUD
HPCI		SP 6.3.3.1.1	
HPCI-V-44	94-3413	SP 6.3.3.1.1	REPAIR
LO-F-BK01	94-3498	VERIFY D/P	REPLACED FILTER
LOGT-PI-205	94-3009	VERIFY PROP OPERATION	REPLACE GAUGE
MC-CR-1	93-4564	VERIFY PROPER OPERATION	
MC-CV-16CV	94-2060	VERIFY NO LEAKS	HINGE PIN COVER LEAK
MN APRM		SP 6.1.3	
MS-AOV-DRV8	94-1807	SP 6.4.8.2.8	REBUILT
MS-AOV-PCV62	94-1096	STROKE FOR LEAKS	REPACKED
MS-AOV-VARIOUS	93-3415	SP 6.4.8.10.1	REPAIR
MS-FE-122A	94-3060	ISLT	SWITCH SENSE LINE
MS-FE-127A&B	94-2500	VERIFY LEAKAGE	CLEANED AND INSPECTED, ADDED GAGES
MS-FE-SEVERAL	94-2499	VERIFY LEAKAGE	CLEANED AND INSPECTED, ADDED GAGES
MS-PR-SEVERAL	93-3192	VERIFY ANN OPERATION	CAL CHECKS
MS-SOV-SPV1331	94-2326] 94-2326	SOAP TEST FITTINGS VERIFY OPERATION	REBUILT SOLENOID REBUILT SOLENOID
MS-TP-1	94-2404 94-2404	MP 7.0.8.1 SP 6.4.8.9	REPLACED TRAP REPLACED TRAP
MS-TP-13	94-2404 94-2404	SP 6.4.8.9 MP 7.0.8.1	REPLACED TRAP REPLACED TRAP
MS-TP-16	94-2131	VERIFY OPERATION	REPLACED TRAP
MS-TP-SEVERAL	93-3277	SP 6.4.8.9	REPLACED TRAP
MS-V-27	94-2102	MP 7.0.8.1'	REPLACED VALVE
MS-V-663	94-1581	VERIFY LEAKAGE AND OPERATION	REPLACED VALVE

STARTUP PLAN ATTACHMENT 2

REVISION 1

MWRs BY SYSTEM
As of Aug 1, 1994

STARTUP TEST FILE

CIC	WI NUM	TEST REQUIRED	WORK PERFORMED
MS-V-766	94-1598	MP 7.0.8.1	ADJ PACKING
MS-V-771	94-2386	MP 7.0.8.1	REPLACED VALVE
MS-V-872	94-1316	MP 7.0.8.1	REPLACED VALVE
MSIV		SP 6.3.9.4	
NBI-SOV-SSV739	94-3490 94-3490	MP 7.0.8.1 MP 7.0.8.1	REPAIR REPAIR
NBI-V-632	94-0163	ISLT	REPLACED VALVES
NM		NBI 10.2	
NMT-NDC-(131-4C)	94-2315	PERFORM OD-1	REPLACED RELAY
OG-V-12	94-1582 94-1582	VERIFY OPERATION SOAP TEST	REBUILT REBUILT
OG-V-13	94-1582 94-1582	SOAP TEST VERIFY OPERATION	REBUILT REBUILT
PC-TE-500D	94-2700	VERIFY OPERATION	TROUBLE SHOOTING
PMIS	94-3475	VERIFY PROP OPER	REPAIR PTS
RCIC		SP 6.3.6.1.1	
RCIC-CV-26CV	94-2290	MP 7.0.8.1	6.3.10.26
RCIC-PS-3070	94-1645	ISLT	REPLACE TUBING
RCIC-SW-S1 (MO-15)	94-4022 94-4022	SP 6.3.10.24 SP 6.3.6.2	REPLACED SWITCH REPLACED SWITCH
RCIC-SW-S2 (MO-16)	94-3958 94-3958	SP 6.3.10.24 SP 6.3.6.2	REPLACED SWITCH REPLACED SWITCH
RF-AOV-FCV11BB	94-2468 93-3275 93-3275	ISLT VERIFY OPS ISLT	ADJUST PACKING ADJUST PACKING ADJUST PACKING
RF-SOV-TBTB	94-3070	VERIFY LEAKAGE	REINSTALL
RMP-RE-130B	94-2931	SP 6.3.7.2.3	REPLACE DETECTOR
RPIS (30-03)	94-3911	VERIFY OPERATION OF RED (FULL OUT) LIGHT	REBUILT CONNECTION
RPS/TG		SP 6.1.9	
RRV-155	93-4013	VERIFY PROPER RESPONSE	PACKING
RR-V-156	93-4013	VERIFY PROPER RESPONSE	PACKING

STARTUP PLAN ATTACHMENT 2
REVISION 1

MWRs BY SYSTEM
As of Aug 1, 1994

STARTUP TEST FILE

CIC	WI NUM	TEST REQUIRED	WORK PERFORMED
RR-V-186	93-4014	VERIFY PROPER RESPONSE	PACKING
RRLO-TI-1A	94-2223	VERIFY PROPER INDICATION	TEMP INDICATION
RRMG-EXC-MGA	94-2508	VERIFY OPERATION	REPLACED BRUSHES
RRMG-REL-K35A	94-2637	VERIFY LIMITER OPERATION	CAL RELAY
RRMG-REL-K35B	94-2638	VERIFY LIMITER OPERATION	CAL RELAY
RW-P-FDSP	94-2476	VERIFY LEAKAGE	REPLACED AND REPACKED
RWCU	94-3744	MP 7.0.8.1	RE TORQUED FLANGE BOLTS
RWCU-AOV-FCV55	93-3996	ISLT	REPAIR
RWCU-FE-102A	94-2964	MP 7.0.8.1	CLEANED AND INSPECT
RWCU-SOV-SPV109A	94-3289	VERIFY OPERATION	REBUILT SOV
SW-V-55	93-2223	VERIFY NO LEAK THROUGH	REPLACED VALVE
TG		SP 6.1.7	
TG-TU-VAC LINES	93-4003	VERIFY VAC INDICATION	CLEANED LINES
TG1-R-101	94-2604	SP 6.4.8.2.7	CAL VIB INST

STARTUP PLAN ATTACHMENT 3
Revision 1

DAYS

1	2	3	4	5

MODE SWITCH TO STARTUP, SOP 2.1.1

HEATUP TO RATED PRESSURE (50% BPV)

PERFORM 500# DRYWELL INSPECTION

PERFORM NOZZLE SURVEYS (DW)

INERTING THE DRYWELL

MODE SWITCH TO RUN

SP 6.3.1.1 D/W PERSONNEL AIRLOCK DOORS 58# TEST

SYNCHRONIZE TURBINE GENERATOR, SOP 2.1.1

SP 6.3.3.1.1 HPCI IST & QTRLY TEST MODE SURV

PERFORM POST MAINTENANCE TESTING

SP 14.6.11 DRAGON INSTR VLV GUIDE (SECT 8.3)

SP 6.3.6.1.1 RCIC IST & QTRLY TEST MODE SURV

SP 6.1.8 TURB CONTROL VLV FAST CLOSURE C/F

POWER ASCENSION TO 100%

SP 10.2 IRM POWER CALIBRATION (25% POWER)

SP 10.9 ROD SCRAM TIMING - 17 RODS

Plot Date	2AUG94 08:38
Data Date	1AUG94 18:00
Project Start	25MAY94 0:00
Project Finish	8AUG94 7:59

(c) Primavera Systems, Inc

Activity Bar/Early Dates
Critical Activity
Progress Bar
Milestone/Flag Activity

Sheet 1 of 1

COOPER NUCLEAR STATION
FORCED SHUTDOWN - DUE TO DG'S INOP
POWER ASCENSION SCHEDULE

Date	Revision	Checked	Approved

STARTUP PLAN ATTACHMENT 4
REVISION 1

ACTIVITY IDENTIFICATION	ACTIVITY DESCRIPTION
942370 through 942383 942387 through 942397	CRD-AOV-CV126 & 127 Align Limit Actuators (25 total)
943396	STP-94-100-1 CS B Flow Transient troubleshooting
942646	DG-RV-15RV Replacement
942520	EE-SWGR-480F As-build wiring
942521	EE-SWGR-480G As-build wiring
943055	EE-MCC-Q(10B) CS-MO-26A Ground-replace transformer
-----	SP 94-208 Perform UV Relay Testing
942486	T. Bldg. Exh & Supply fans DP <-.25
941768	Replace Air Side Seal Oil Pump
942548	LO-P-AS Replace mechanical seal
941495	MS-HO-GV1 Replace cylinder
942410	MS-HO-SV2 Replace cylinder
942411	MS-HO-GV2 Replace cylinder
942412	MS-HO-GV4 Replace cylinder
941932	NM-NAM-AR3 Wire harness binding
941933	NM-NAM-AR7 Wire harness binding
941934	NM-NAM-AR1 Wire harness binding
942537	NMI-NE-33E, NT-34E IRM E Spiking
942315	TIP Machine 3 K3 Relay replacement
943349	REC-P-C Inboard bearing failed-Repair/replace pump
942362	RF-CV-15CV Repair hinge pin cover gasket leak
943319-02	RHR-MO-39B LLRT repair
942510	RHR-MO-16B Examine internals-LMS Compartment
942508	RRMG A & B Exciter & Generator brushes
942408	TGC-CPU-DEH01 BPV#1 Repair/replace servo/LVDT
942568	NMI-NAM-41D IRM D Spiking

STARTUP PLAN ATTACHMENT 5

REVISION 1

DESIGN CHANGE	DESCRIPTION	STATUS REPORT DATE
DC 94-209	Personnel Airlock Test connections	6-04-94
DC 94-212	Penetration X-218 Modification	6-16-94
DC 94-212A	Penetration X-209 Modification	6-24-94
DC 94-212B	Penetration X-43 & X-44 Testable Flanges	7-08-94
DC 94-212C	REC LLRT Test Connections	7-11-94
DC 94-212D	IA & SA X-21 & X-22 Isolation valves and Test Connection	7-12-94
DC 94-212D-1	Install 2" Soft Seat CVs for 65CV & 78CV	7-12-94
DC 94-212E	Instrument Valves and Caps	7-09-94
DC 94-212F	Instrument Lines Into Containment	7-18-94
DC 94-212H	PASS System X-51F	7-08-94
DC 94-212J	Piping Penetrations 2N Upgrade	7-13-94
DC 94-212M	TIP CV Removal	7-22-94
DC 94-214	Emergency Diesel Cabinet Qualification	7-01-94
DC 94-166	480V Bkr Shunt Trip	7-04-94
DC 94-222	PC-PT-2104A & B, PC-DPT-20 Replacement	7-10-94
DC 94-223	HPCI-PS-68A, B, C, & D	7-19-94
TDC 94-224	CS-MO-5A & B TDR	7-26-94

STARTUP PLAN ATTACHMENT 6

Revision 1

SYSTEM READINESS REVIEW CHECKLIST

SYSTEM NAME

SYSTEM ENGINEER REVIEW SUMMARY (The System Engineer shall initial each item below to confirm reviews are complete)

________ System open Maintenance Work Requests
________ Plant Temporary Modifications
________ Preventative Maintenance
________ ACT items
________ System Walkdown performed
________ Nuclear Action Item Tracking

REMARKS (The System Engineer can provide any additional relevant information deemed necessary to provide a complete summary of system readiness)

System Engineer Signature ______________________ **Date** ________

ENGINEERING MANAGEMENT REVIEW & APPROVALS

Supervisor Signature ______________________ Date ________

Engineering Mgr Signature ______________________ Date ________

COMMENTS:

SORC APPROVAL

____
SORC Chairman

____
Date

SITE MANAGER APPROVAL *

____
Site Manager

____
Date

* Required if comments noted

STARTUP PLAN ATTACHMENT 6

Revision 1

SYSTEM READINESS REVIEW

System Engineer Responsibilities

A. Responsible for screening open items and development of the System Readiness Review Checklist (SRRC) as designated in this Attachment.

B. Responsible for ensuring that all open items related to startup are identified.

C. Responsible for review of non-open item (non-tracked) based issues that could impact system readiness, such as pending plant modifications, unanswered Engineering Memoranda, work/PMs that were scheduled to be done during the October '94 Outage, etc.

D. Responsible for evaluating the integrated effects of work and/or engineering issues on the system and developing justifications to include or reschedule open items based on nuclear safety and reliability.

E. A listing of all items reviewed shall be attached to the SRRC for documentation purposes.

F. Responsible for ensuring that no open items impact safe startup of the plant.

System Engineer Review Scope

A. Prior to startup, the responsible System Engineer shall review open items on the system. Open items will be documented in accordance with this procedure. In this review, the System Engineer must consider the following sources of relevant system information:

- Open Maintenance Work Requests
- Open ACT items
- Open PMs
- Open PTMs

B. The System Engineer shall also perform a system walkdown for startup related issues and attach the results to the SRRC.

C. The following guidance shall be used by the System Engineer to assess an open item:

- The item does not adversely affect nuclear safety;
- The item is not needed to comply with the Technical Specifications;
- The item will not affect the ability of any safety system to satisfy its design function;
- The item is not likely to result in reduced safety system availability, increased forced outage rate, or reduced capacity factor in the time before it is completed or resolved.

EXAMPLES OF OPEN ITEMS

Maintenance Work Requests

Backlogged Preventive Maintenance Work Requests

Plant Temporary Modifications

Open/Walkdown Inspection Findings

ACT items

NAIT items

Unanswered Engineering Memoranda

Open Operating Experience Items (NAIT)

Commitments (NAIT)

Preventive Maintenance Activities (PMs)

STARTUP PLAN ATTACHMENT 7

Revision 1

MANAGEMENT VERIFICATION FOR STARTUP

DEPARTMENT ________________ DEPARTMENT MANAGER ________________

In addition to G.O.P. 2.1.1.1 requirements, the following items have been reviewed to ensure no open items will impact safety on plant startup:

	Signature
1. All department open items reviewed including:	
• Maintenance Work Requests	____________
• Condition Reports	____________
• Commitment/Open Item Tracking	____________
• Procedure Changes	____________
• Training	____________
• Open OER Documents	____________
2. Any other items considered important to safety.	____________

I verify readiness to Startup and have completed an extensive walkdown of plant systems. The plant is ready to return to power operation. Any comments are noted below:

COMMENTS:

________________ ________________

DEPARTMENT MANAGER DATE

REVIEWED:

________________ ________________

SENIOR MANAGER DATE

________________ ________________

* SITE MANAGER DATE

* Required if comments noted