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REGION I

Report No. 50-247/86-19

Docket No. 50-247

License No. DRP-26

Licensee: Consolidated Edison Company of New York, Inc.
Broadway and Bleakley Avenue
Buchanan, New York 10511

Facility Name: Indian Point Nuclear Generating Station Unit 2

Inspection At: Buchanan, New York

Inspection Conducted: July 21 - August 1, 1986

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Inspection Summary:
Inspection on July 21 - August 1, 1986 (Report No. 50-247/86-19)

Areas Inspected: Special announced inspection of equipment and activities identified in the Indian Point Probabilistic Safety Study dominant sequences as important to prevent or mitigate severe accidents. More specifically, selected

EXECUTIVE SUMMARY

A Probabilistic Risk Assessment (PRA) driven team inspection was conducted at the Indian Point Unit 2 station from July 21 through August 1, 1986. Detailed inspection plans were developed based on the "Indian Point Probabilistic Safety Study" (IPPSS). Two major techniques were used in conducting the inspection: (1) Operational Safety Simulations - in which the inspector witnessed simulated risk significant emergency actions by control room and nuclear plant operators, and (2) Hardware Availability Evaluations - in which the inspector verified the availability of risk significant equipment by performing physical inspections, witnessing surveillance and maintenance activities, reviewing procedures, and evaluating equipment operating experience.

Operational Safety Simulations were conducted for the "loss of offsite power" involving a number of important emergency operating procedures and for the "loss of coolant recovery" which requires the operator to manually take over control of Emergency Core Cooling System (ECCS) equipment to establish a recirculation path for the containment sump through RHR heat exchangers to the reactor. The procedures involved in both of these simulations were evaluated as risk significant in the IPPSS.

Hardware Availability Evaluations were conducted on the electrical distribution equipment, the emergency diesels, gas turbines, ECCS (controls, pumps, and critical valves) as well as some special equipment identified as risk important involving failure to scram, overpressurization of low pressure ECCS piping, and component cooling water equipment.

The overall results of the Operational Safety Simulations showed an experienced and knowledgeable operating staff with working knowledge of the Emergency Operating Procedures (EOPs). However, detailed simulations did identify a number of weaknesses in the written procedures that could cause misunderstandings or delay in carrying out important emergency evolutions. Examples of procedural weaknesses are as follows:

- The Boron Injection Tank has been retired but the EOPs still contain directions for its operation.
- The RHR Discharge MOV was not opened per an EOP.
- Containment Isolation could not be reset per several EOPs.
- Blackstart capability for gas turbine No. 2 was not clearly defined in procedures.
- There was no procedure for loss of the 138KV offsite power.

The BIT retirement was a planned evolution but the EOPs had not been updated. The simulations also identified several significant control room or equipment labeling weaknesses.

The overall results of the Hardware Availability Evaluations indicated that vital hardware exhibited adequate availability. Physical inspections and procedural reviews uncovered deficiencies such as the following:

- The Recirculating sump grating was left uninstalled.
- A relay in the RHR overpressure protection circuit was not tested.
- Diesel generator (DG) remote-local switch position could prevent voltage and speed control of the diesel without knowledge of control room operators.
- The DG fuel transfer pump requires manual re-energization after bus stripping, and
- Several labels were missing or in error (pumps, valves, compartments).

The sump grating left uninstalled, when combined with a number of similar observations, lead the team to conclude that maintenance restoration practices and containment closeout procedures may be weak. These practices are a direct indication of plant staff attitude toward "attention-to-detail."

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equipment and activities related to the emergency electrical power system and supplies; recirculation cooling; component cooling water system; reactor/turbine protection system; and licensee administrative controls were inspected. The inspection involved five region-based inspectors, one headquarters-based inspector, and one supervisor.

Results: Three violations were identified (failure to properly establish or maintain Emergency Operating Procedures, paragraph 4.1; failure to restore the configuration of the recirculation sump grating and screen to its design configuration specified by plant drawings, paragraph 4.8; and, failure to properly follow procedures following work activities which led to inadequate housekeeping, paragraph 9.1).

DETAILS

1.0 Persons Contacted

Within this report period, interviews and discussions were conducted with various licensee personnel including operators, engineers, maintenance, testing, and the licensee's management staff. Those persons contacted during this inspection are listed in Attachment A.

2.0 Summary

2.1 Inspection Scope and Rationale

The scope of the inspection was formulated based on a review of the dominant accident sequences identified in the Indian Point Probabilistic Safety Study (IPPSS), Amendment 2, and NUREG/CR-2934, an NRC sponsored peer review of the IPPSS by Sandia Laboratory. The risk significant accident initiators, equipment failures, and operator errors contained in the top twenty-four accident sequences were studied.

A number of sequences having similar characteristics were combined while other sequences were eliminated from consideration if covered by past inspections or judged for other reasons to be outside the inspection's scope.

The process identified the major areas for inspection as summarized in Table 2-1. These areas include recovery actions from a loss of offsite power event and recovery from a loss of coolant accident including switchover from the injection mode to the recirculation mode of core cooling. The detailed scoping process is presented in Attachment B which lists the dominant accident sequences. A plan was then developed that provided information on the specific equipment and activities to be inspected. This activity used the engineering insights of the IPPSS as well as the "Indian Point Unit 2 Probabilistic Safety Study-Based Inspection Plan" developed by EG&G for the NRC.

The inspection rationale is depicted in Figure 2-1. The operational readiness of the plant was assessed by evaluating risk significant hardware availability and important emergency and recovery actions by the plant staff.

Programmatic aspects of management controls, training, and human factors engineering and effective implementation of such programs was inspected to ascertain that the station activities were performed in accordance with prescribed written procedures. Measures to prevent equipment failures (including surveillance measures to detect potential failures and prompt corrective maintenance activities) were also evaluated. To assess the implementation of the programs, the "as found" state of the equipment was evaluated by performing "walkthrough" visual inspection, witnessing of the in-progress activities and simulations. The effectiveness of the preventive and corrective maintenance measures was evaluated by reviewing appropriate work records and the performance trend of the equipment.

Plant operations were evaluated to ascertain that operators were familiar with the plant equipment and the associated plant procedures during normal, abnormal and emergency situations. The operation of plant systems and equipment identified in the selected accident sequences was demonstrated by the plant staff during "operational safety simulations" in the station simulator, control room, and equipment spaces. The operations were evaluated for the operator's ability to utilize control room indications, to understand automatic features under design-base operations, to use operating procedures and to operate equipment manually. Local or alternate train operation was also evaluated when normal or recovery action was postulated to fail. Control room operations were assessed to assure that proper sympton-oriented emergency operating procedures were available and capable of being effectively used during the accident situation and under stress. Station procedures were evaluated for technical accuracy, clarity, and inclusion of important information.

2.2 Summary of Findings

The inspection findings demonstrated that the plant programs designed to assure hardware availability were adequate and the plant staff exhibited an excellent knowledge of plant operations, equipment and procedures. During simulated responses of events and activities, the plant staff readily demonstrated their knowledge of procedures, physical locations of equipment and familiarity with overall plant operations. The positive responses by the plant staff were indicative of the effective training on procedures and equipment. The high degree of equipment availability and operational readiness is indicative of effective management and administrative controls.

The equipment identified by the PRA study was found to be controlled to "safety related" standards, and, in general, the physical plant was well maintained and clean, except the areas identified hereafter as weaknesses or deficiencies.

Table 2-2 provides a summary of the deficiencies identified during the inspection. Refer to the referenced report section for detailed discussion of each item. All major deficiencies requiring future inspection follow-up are noted as unresolved items. A number of other weaknesses, mainly procedural details, judged not to require specific follow-up are also discussed in the body of the report.

TABLE 2-1 INSPECTION SCOPE

Operational Safety Simulations

* Loss of Offsite Power Simulation
  (4,5,6,10,12,16)
* LOCA Recovery Simulation
  (7,8,9)

Hardware Avialability Evaluations

* Electrical Distribution and Emergency Power Sources
  (4,10,12,16)
* SI Initiation and Recirc. (Controls, Pumps, and Critical Valves)
  (13,19)
* RHR Initiation and Recirc. (Controls, Pumps and Critical Valves)
  (11,14)
* Event V, Two MOV Configuration
  (24)
* CCW System Critical Cooling Functions
  (NUREG/CR-2934)

Note: Numbers in parentheses refer to the dominant core-melt sequences from the IPPSS, see Attachment B for details.

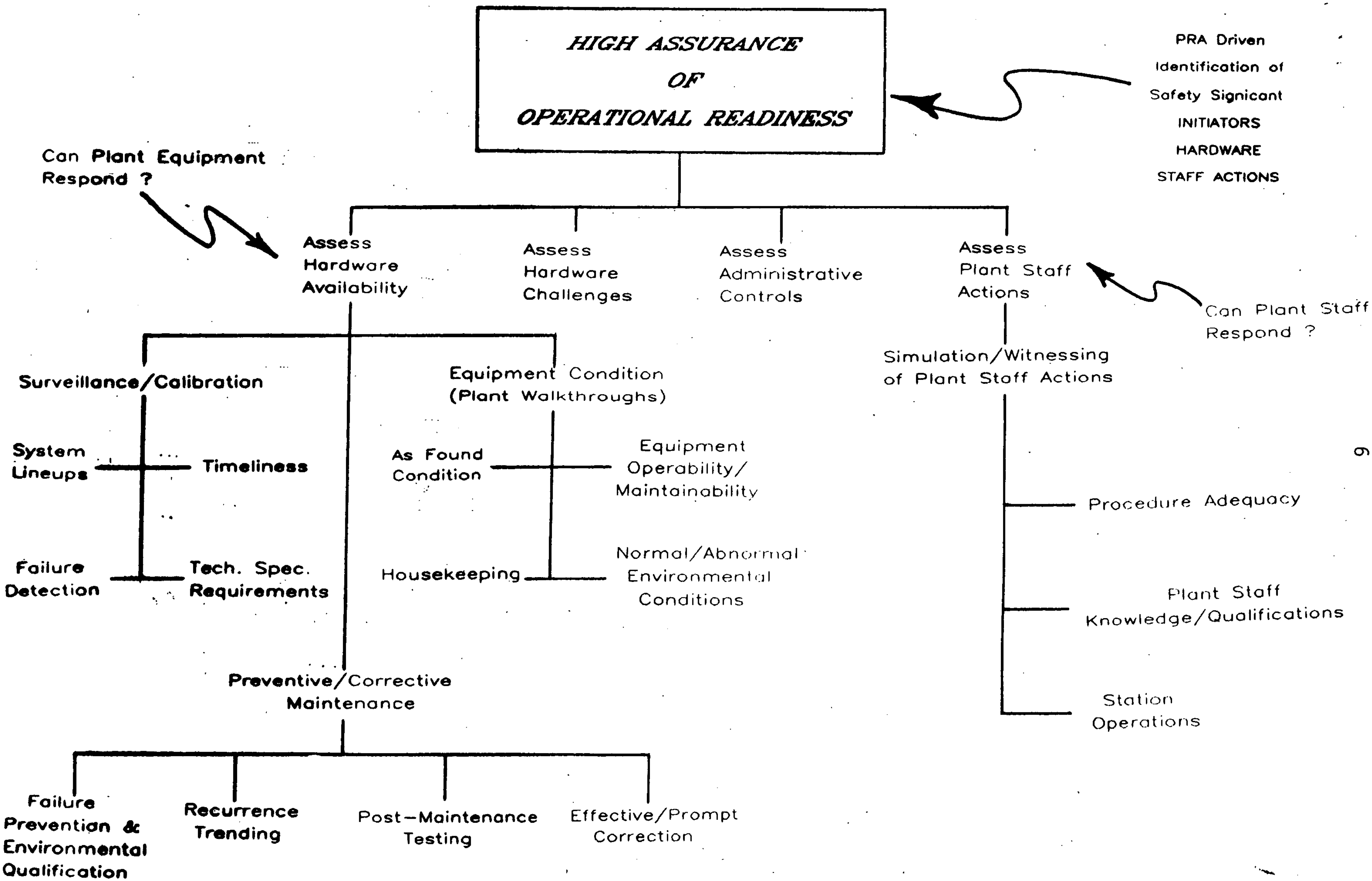

FIGURE 2-1 INSPECTION RATIONALE

TABLE 2-2 SUMMARY OF FINDINGS

Unresolved Items No.*	Deficiency	Proposed Licensee Corrective Actions	Report Section
01	Spurious trips of Bus 6A supply breaker	Identify root cause, correct fault	3.1(4)
02	FSAR drawing error	Properly indicate bus feeds for DG fuel transfer pumps	3.2(1)
03	No auto reset of power to DG fuel transfer pumps	Evaluate auto reset of breakers	3.2(2)
04	DG speed/voltage control switch can cause DG failure to start	Evaluate switch design to preclude DG inoperability	3.3(2)(c)
05	Unexplained existance of grounding cables on Battery 21 supports	Determine purpose, take appropriate action	3.4(2)
06	Emergency Operating Procedure Weaknesses (VIOLATION)		
	*ES 1.3 does not provide for opening of critical RHR MOV	Revise procedure	4.1(1)
	*Resetting of Cont. Iso. Phase A&B not adequately proceduralized	Revise applicable procedures	4.1(2)
	*BIT tank remains in several EOPs	Revise procedures	4.1(3)
	*No AOP for loss of 138KV power	Issue procedure	7.1(1)
07	Untested ECCS flow path	Flow path to Valves SS1A and SS1B will be tested	4.2
08	Recirc. sump grating & floor plates not properly installed (VIOLATION)	Install grating/plates and revise cont. closeout procedures	4.8
09	Failure to demonstrate reliable blackstart capability of GT #2	Demonstrate capability and revise blackout procedure	7.2
10	Inadequate implementation of Housekeeping Policy, multiple examples (VIOLATION)	Revise policy and improve it's implementation	9.1
11	Inadequate testing of RHR Stop Valve pressure permissive circuit	Issue surveillance procedure	11.0(3)
12	No blown fuse protection for certain relays in DG & GT circuits that may cause false tripping	Perform engineering evaluation on current design	3.1(5)

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3. Power Supplies and Distribution Equipment

3.1 Power Distribution and Fast Transfer

Scope and Inspection Criteria

The onsite Class 1E AC electrical power system consists of four 480 volt buses and three standby emergency diesel generators (EDG). These buses distribute power through their respective circuit breakers to the motors of safety system pumps, fans, valves and other related equipment.

Two of the buses (5A & 6A) are normally supplied from the preferred offsite 138KV system. The other two buses (2A & 3A) are normally supplied power which originates from the main generator. The Indian Point Probabilistic Safety Study (IPPSS) identified that the reliability of fast transfer from the main generator power source to the offsite 138 KV power source is important whenever there is a unit trip. This assures power to the buses (2A & 3A) without depending upon EDG 22.

This transfer occurs at the 6.9KV buses (2 & 3). Their respective supply breakers are opened and the tie breakers are closed to either 6.9KV bus (5 & 6) respectively. The transfer cycle is required to be completed in two tenths of a second or less to preclude 1) damage to the motors on the buses being transferred and 2) a transient voltage reduction causing buses (5A & 6A) to be separated from the offsite source and requiring them to be energized from their respective EDG 21 or 23.

Findings

(1) An examination of the control schematic for the fast transfer and circuit breakers indicated that the components which are designed to trip the supply breakers and cause closing of the bus tie breakers are a unit primary or backup protective lockout relay (in both the supply breaker trip circuit and the tie breaker closing circuit). In addition, the tie breaker closing circuit includes a control switch contact and a synchronizing (syn) check relay contact. A review of licensee event reports from 1973 to 1986 did not identify any failures associated with the fast transfer function. The syn check relay is calibrated and functionally tested during each refueling outage.

Preventive maintenance is conducted on the 6.9KV breakers during refueling outages. There is a scheduled functional check of the fast transfer during the refueling outages; however, there has been an average demand for this transfer function of six times per year as the result of the unit trips. This number of about sixty demands in a 10 year period with no failures indicates a reliable fast transfer function.

(2) During this inspection a layer of dust was noted on the top of the 6.9KV switchgear. Because of the potential of this dust affecting breaker functional reliability the licensee was informed of this condition and took prompt corrective action to have the dust removed.

(3) Preventive maintenance is conducted on the 480 volt breakers during refueling outages, and the overcurrent protective trip setting is normally calibrated (PTR-46). During a review of the electrical preventative maintenance and calibration schedule it was noted that 68 of 69 breaker overcurrent protective element calibrations had been deferred. These calibrations were postponed until after the refueling outage because these devices have been replaced with a solid state Amptector I-A, model LSG, which is expected to be more reliable and able to be calibrated with the unit on the line. The inspector reviewed a select number of the Amptector calibration records for the "as found" set points and noted that there was no set point drift.

Calibration of the overcurrent trip device for Service Water Pump 22 was observed by the inspector. Discussions with the station test personnel revealed that, when this test activity was conducted during the refueling outages, it was conducted by personnel who were not assigned to the station. This was the first time that these station personnel conducted this test. This test was being conducted using a temporary procedure change, TPC 86-137T, dated 7/28/86. The inspector noted that the Amptector tester calibration was current and not due for recalibration until April 31, 1987.

The above calibration was being conducted in the 480 volt switchgear room. The inspector noted dust lying on top of spare breakers. Discussions were held with the licensee about the effects of dust in the ventilation air on the future reliability of the circuit breakers. To preclude problems from dust, the licensee has established plans to filter the ventilation air at the entrance into the switchgear room. The inspector had no further questions in this area.

(4) Review of an event of August, 1980 indicated that the normal supply breaker for 480 volt bus 6A tripped due to a defective "B" overcurrent tripping device which also blocked EDG 23 output breaker from closing. This overcurrent trip device has been replaced by the new type Amptector.

Followup of an additional event of June 17, 1986, revealed that the supply breaker to bus 6A tripped out and caused a trip of EDG 23 output breaker. The licensee does not believe that the supply breaker tripped on overcurrent but was not able to determine the cause of the event. Trouble shooting and functional operation of the breakers did not reveal any problem. This is considered unresolved item until the root cause has been determined by the licensee (50-247/86-19-01).

(5) A review of the electrical protective systems for both the emergency diesel generators and the gas turbines revealed that the voltage restraint relays (51V) and the loss of field relays (40) are subject to false tripping upon a blown potential fuse. Further, there is no blocking of the voltage regulator if its associated fuse is also blown. Protection for a blown fuse in either the relay circuit or the voltage regulation circuit was not provided by a voltage balance - blocking relay (60). The licensee has plans to perform an engineering evaluation of the acceptability of this design. This will be followed during a future inspection (50-247/86-19-12). The inspector had no further questions at this time.

3.2 Manual Energization of Motor Control Centers 24, 27, and 29

Scope and Criteria

One of the dominant conditions which could lead to failure of the electric power system is the operator's failure to reclose MCC 24, 27, and 29 feeder breakers after an Emergency Diesel Generator autoload upon loss of power. The failure to energize these MCC's could result in all diesels running out of fuel in as little as 55 minutes.

Each diesel is serviced by a dedicated 175 gallon day tank which is sufficient for 55 minutes of full load operation with the tank 65% full. Decrease in level in any one of the three dedicated day tanks to 115 gallons will cause one of the fuel oil transfer pumps to start. The fuel oil transfer pump will transfer fuel oil from one of three 7700 gallon capacity storage tanks buried outside of the diesel generator building, and will continue to run until each of the day tanks is filled to approximately 158 gallons. The power to operate the fuel oil transfer pumps is fed through MCC's 24, 27, and 29 supply breakers and has to be reset manually in the 480 volt switchgear room in the Turbine Building. The 480 volt room is normally locked-closed, and the access is controlled by security equipment.

Findings

(1) Modifications of MCCs

In order to maintain proper channelization and separation of power feeds for the diesel generator fuel oil transfer pumps, the power feeds were changed per modification procedure ESG 81-2-11, and illustrated in the following table.

	Associated EDG No.		
	MCC 24	MCC 27	MCC 29
Before Modification	#22	#21 & #23	#22
After Modification	#22	#23	#21

The inspector identified that "As Built" Drawing #CCR9321-F-3005 of May 13, 1986, #CCR208507 of May 13, 1986, and #CCR9321-F-3004 of March 7, 1986, reflected the modifications. However, the associated drawings in the FSAR and system descriptions were not updated for the changes. The licensee stated that the system descriptions and the associated drawings were not controlled and should not be used for official purposes. However, the FSAR drawings would be updated and the changes would be incorporated into the Revision 5, which would be released by July 22, 1987. This is an open item pending revision of the FSAR drawings and subsequent NRC:RI inspection (50-247/86-19-02).

(2) Manual Reset of DG Fuel Oil Pump Breakers

The emergency, abnormal, and normal operating procedures were reviewed and an emergency "walkdown" resetting of the MCC's was simulated to ascertain that operators were aware of the resetting operation, and that potential human errors (by failing to reclose the MCCs 24, 27, and 29 after diesel start) were minimal.

The alarm response procedure for MCC breakers on control room panel SHF did not include specific action steps for MCCs 24, 27, and 29. Prior to the conclusion of the inspection the procedure was subsequently revised to include specific action statements for the MCC 24, 27 and 29 trouble alarms.

The System Operating Procedure (SOP) 27.3.1, Revision 7, "Diesel Generator Manual Operation", did not require the operator to verify the status of MCC 24, 27, and 29 feeder breakers prior to a diesel start. The licensee acknowledged the omission, and stated that the MCC verification step would be included in the procedure as an initial condition for diesel startup. This verification would ensure the availability of diesel fuel oil.

Emergency Operating Procedure, ES-0.1, "Reactor Trip Response" and ECA-0.0, "Loss of All AC Power" specify that upon loss of AC power and subsequent starts of emergency diesel generators the control room reactor operator is required to direct the Nuclear Plant Operator (NPO) to "reset lighting and MCCs" manually. In fact, the NPO is required to manually reset 15 breakers in the 480 volt switchgear room, including feeder breakers for MCC 24, 27, and 29. When a question concerning day tank capacity was raised to simulator instructors and a NPO, they did not know that the day tank could supply the diesel fuel for as little as one hour, and they thought that the tank could last for more than 6 hours. Failure to reset the above three feeder breakers within 55 minutes of diesel starts could stop the emergency diesel generators due to lack of fuel oil; and a potential exists that the breakers may not be reset within this time period during an accident situation and under stress and confusion. The inspector raised a concern to ensure that the ROs and NPOs reset the feeder breakers for MCC 24, 27, and 29 within 55 minutes to power the EDG fuel oil pumps.

The licensee immediately initiated a Field Engineering Request (FER) to evaluate a potential resolution of this concern:

- Provide Auto-reset capability for MCC 24, 27, and 29 feeder breakers, or
- transfer Diesel Generator Auxiliary breakers to MCCs which have auto-reset capability.

This item remains unresolved pending revision of procedure SOP 27.3.1, to ensure action within 55 minutes or other resolution and subsequent evaluation by NRC:RI inspection (50-247/86-19-03).

(3) <u>Availability of Feeder Breakers for MCC 24, 27, AND 29</u>

During the last 24 months, no corrective maintenance was required for the MCCs 24, 27, and 29, and two preventive maintenance items were performed. MCC 27 and MCC 29 feeder breakers were inspected and cleaned under Work Order No. NP-85-22511, NP-85-22509 respectively, both on December 10, 1985. Periodic surveillance tests for 480 volt Breaker Undervoltage Relays were performed on February 12, 1986, using surveillance procedure PT-R61, and no unacceptable conditions were identified.

The circuit breaker overcurrent tests were performed during the 1984 outage using surveillance procedure PT-R46. However, the test was postponed for 6 months pending completion of preventive maintenance during the 1986 outage. The licensee stated that the overcurrent tests are not required under the technical specifications, and the tests were postponed based on the administrative provision 3.9 of procedure TAD 7, Revision 7.

The inspector had no further questions and determined that the feeder breakers had a high degree of availability.

3.3 Emergency Diesel Generators

(1) Emergency Diesel Generator (EDG) Maintenance Outage Time

Scope and Criteria

The IPPSS determined that the time the diesels are out of service for maintenance significantly affects the overall diesel availability. With this in mind the inspector reviewed the preventive maintenance program for the diesels and witnessed some preventive maintenance activities of Diesel 21. The objective was to determine if preventive maintenance was being conducted in such a manner as to minimize unnecessary downtime.

Findings

Diesel 21 was removed from auto start status on Monday, July 21, 1986 and returned to auto start status on Thursday, July 24. During this four day period quarterly preventive maintenance activities were conducted. The inspector witnessed the power supply breaker maintenance. It was noted that the breaker was removed from its cabinet and placed on a work stand on July 21 and was not returned to its cabinet until July 23. Interviews with the maintenance staff indicated that the mechanical and electrical PM on the breaker could be done on one day shift. No evidence of mechanical PM directly on the diesel was noted during the four day period even though inspectors visited the diesel building several times each of the days. The head diesel mechanic was interviewed and the mechanical PMs were reviewed. He indicated that every attempt was made to place the diesel in an operative status at the end of each day, and that the great majority of PM activities could be recovered from quickly and the diesel made ready for operation within a short time. The procedure requiring the longest outage was the disassembly and cleaning of the jacket water heat exchangers and could take as long as eight hours. Maintenance is done only on the day shift; evening shifts are not routinely used.

Based on the above, the inspector questioned the maintenance manager regarding the diesel preventive maintenance outage. He indicated that the four day outage time was being studied as well as the required maintenance time for each of the required tasks. No commitment was made to shorten the scheduled outage time but that every effort would be made to reduce the actual downtime. He indicated that the diesels will be made part of the reliability centered maintenance program to be initiated in the future. The inspector had no further questions at this time.

(2) EDG Room General Conditions

Scope

The inspectors made several inspection tours of the EDG room to evaluate the general area cleanliness and verify the absence of fire hazards. The inspectors also observed the material condition of the EDGs and their auxiliary systems including looking for such items as leaking fittings and loose or missing parts.

Findings

(a) The inspectors, in general, found the area to be clean and free of fire hazards with several exceptions. On July 28, 1986 the inspectors observed a large puddle of oil on the lower level of the EDG room under the No. 22 EDG left side air start motor. The oil spill was cleaned up by the licensee after being notified by the inspectors. The oil spill appeared to be a result of EDG maintenance that was conducted over the weekend since the oil spill was not present on July 25, 1986. This item is further discussed in Paragraph 9 below.

Several other items were identified by the inspectors and discussed with the licensee. The items included the following:

- A 'U' clamp support for the 3 inch fuel oil day tank overfill pipe was hanging in place without its retaining nuts. This item was repaired by the licensee.

- Vegetation was growing on the EDG building fresh air (ventilation and combustion air) intake screens. The growth appeared to be climbing ivy and grape vines which had covered approximately 10 percent of the air intake. The plant growth was removed by the licensee.

- Certain questionable control switches and position indicating light conditions on the EDG and auxiliary control panels are discussed in Paragraph 3.3.3 below.

- Covers were left off two fuel oil day tank magnetrol level controllers. These covers were replaced by the licensee.

(b) A review of the emergency diesel generator fuel oil system revealed that the day tank fuel oil level switch associated with each tank had a common control and alarm function. The control is to start the pump and open the level control valve at 65% full. This is reversed at 90% full. The alarm setpoint is at 50% full. Should the level switch stick neither will the control function nor will the alarm be received.

This lack of independence between control and alarm is offset by a separate level indicator. The indication is at eye level in the building. All three indicators are located together and can be seen by the nuclear plant operator during his 4 hour tour of the building. Further assurance of detecting a level problem is the operating procedure requirement that the operator observed the full tank level before and after the monthly emergency diesel generator load test. The inspector determined that the licensee's actions were acceptable and had no further questions in this area.

(c) The three EDGs' start controls are located in the main control room and the generator output breakers can be closed onto a dead bus from the main control room. However, generator voltage and engine speed control is only provided at the control panel located in the EDG building. The control required to synchronize the generator to its respective bus (or its bus to its normal source) is located only at the control panel located in the EDG building.

The EDGs are started, synchronized to their respective buses and loaded once each month. A review of licensee event reports from 1973 to 1986 revealed only a few EDG failures. None of these failures appeared to be repetitive.

During the inspection it was noted that there was a local remote switch for each DG (in the EDG building) with a name plate denoting voltage regulation and speed control. Since there is no control for either function from the control room the licensee was requested to explain the effects of the switch being turned to the remote position, and whether this position was alarmed in the main control room. The licensee determined that with the switch in the remote position the EDG's would not be operable. In addition, this position was not alarmed in the control room.

There were no routine tours of the EDG room which verified the proper position of the switch. Regulatory Guide 1.47 states that equipment which may disable safety functions should be alarmed. The inspectors were concerned that these switches could easily be placed in the remote position without anyone being aware of it.

The licensee's immediate corrective action was to place caution tags on these switches. Other licensee plans included an engineering evaluation of the switch design to preclude EDG inoperability. This item is unresolved pending completion of the licensee's actions (50-247/86-19-04).

(d) All emergency diesel generators (EDG) are started automatically for the following conditions:

- low 480 volt bus voltage on any bus 2A, 3A, 5A or 6A;
- degraded 480 volt bus voltage on any bus 2A, 3A, 5A or 6A; and
- a safety injection (accident) signal.

Redundant voltage sensors (relays) provide a signal to coincident logic for the automatic EDG start signal. The low voltage setpoint is about 65% of the 480 volt bus voltage with a time delay of 2 to 4 seconds. The degraded voltage setpoint is about 85% of the 480 volt bus voltage with a time delay of 210 to 150 seconds. This later time delay precludes inadvertent action due to voltage transients associated with motor starting.

The EDGs and their respective bus breakers are supplied 125 volt DC from redundant battery supply systems. In addition, there are redundant supplies to each EDG and bus via automatic transfer switches.

A review of an event of March 1974 revealed that EDG 22 tripped due to a loss of field during a test. During an ascent to power following an unscheduled shutdown in April, 1974 a reactor trip and an SI signal followed. EDG 22 started but did not develop the required terminal voltage. The failure was attributed to a loss of primary DC control power and a failure of the transfer switch to transfer to the backup DC source. In addition, a faulty relay contact precluded alarm annunication. The transfer switches (4 for buses & 3 for EDG) were tested quarterly (PT-Q9) prior to 1984.

A number of switch problems were identified by the manufacturer (ASCO) during an inspection in June 24, 1983. ASCO issued a notification of possible recall of the switches on June 27, 1983. The seven switches were replaced during the next refueling outage. The switch test (PT-M60) frequency has been changed to monthly since February, 1984. This corrective action and increased surveillance by the licensee should increase the control power availability. No unacceptable conditions were identified.

3.4 125 Volt DC Battery System

Scope and Inspection Criteria

There are four independent 125 volt DC systems which supply DC power for input to four inverters. The original plant design included battery systems 21 & 22. The present design includes battery systems 23 & 24. The Indian Point Probabilistic Safety Study (IPPSS) did not specifically highlight failure of the DC power supplies; however, inspection of surveillance and maintenance history was included to review the reliability of the DC power systems because of their importance to other power distribution and control functions.

Findings

(1) The batteries are load tested during the refueling outage to determine the battery capacity. The load test procedure, PT-A4, conducted on February 14, 1986 was reviewed. It was noted that on page PT-A4-13, the data taken at the end of the equalizing charge for Battery 22 specific gravity (SG) was not corrected for temperature.

As an example, cell No. 3 SG reading was 1.210, and when corrected for temperature would be 1.195. This is the minimum SG value for an individual cell as stated in the operability criteria of procedure PT-Q1. Also, there is no indication of battery electrolyte level measurement or correction if not at the full mark. This could lead to a further correction required.

Discussions were held with the licensee about these procedures and the battery room high summer time temperature affecting battery life. The licensee has agreed to revise the procedures to address specific gravity correction for electrolyte level. The inspectors had no further questions at this time.

(2) The support racks of Battery 21 had temporary ground cables attached to the support and to the building steel with C clamps. These temporary grounds may have been placed when the new seismic designed racks were installed. Licensee representatives were not certain when and why they were connected. The licensee has been requested to evaluate the purpose of, and controls used for, the installation of these grounds. This is considered an unresolved item pending review of the management controls used for this installation (50-247/86-19-05).

The inspector concluded that the licensee's surveillance and preventative maintenance programs along with the above discussed changes should assure a high reliability of the 125 volt DC supply system.

4. Core Cooling; Injection-to-Recirculation

4.1 Emergency Procedure Simulations

Scope

The Indian Point 2 Containment Building contains a recirculation sump and two 3000 GPM recirculation pumps. The purpose of the sump and its pumps is to recirculate water from the containment building floor back to the reactor core following a loss of coolant accident (LOCA). This system enables the post LOCA recirculation mode to be performed entirely within containment rather than to have coolant leave containment via the residual heat removal (RHR) system.

Failure of the recirculation mode or delay in putting it into operation could significantly increase the probability of core melt following a LOCA. The scope of this inspection was to review licensee procedures and interview operations personnel to assure that the recirculation system could be operated when needed. Emphasis was placed on procedural adequacy, operator knowledge, and human factors. The inspection included operational safety simulations by reactor operators or senior reactor operators of the recirculation switchover sequence on three separate operating shifts; and, one walkthrough of the sequence at the IP-2 plant specific simulator located on site. In addition, inplant simulations were performed in the Primary Auxiliary Building (PAB) and diesel generator room with nuclear plant operators (NPOs) to determine the ability to locate, access, and operate valves and breakers as a backup to their remote operations from the control room.

Criteria

Since the recirculation system is used for emergency situations only, its operation is governed by emergency operation procedures (EOPs) rather than system operating procedures. In order to evaluate the satisfactory operation of switchover to the recirculation portions the following EOPs were reviewed and/or used for simulations:

- E-0, Reactor Trip or Safety Injection
- E-1, Loss of Reactor or Secondary Coolant
- ES-1.3, Transfer to Cold Leg Recirculation
- ES-0.1, Reactor Trip Responses
- *ES-1.2, Post LOCA Cooldown and Depressurization
- *ECA-1.1, Loss of Emergency Coolant Recirculation
- *ES-1.4, Transfer to Hot Leg Recirculation

*o Abnormal Operating Instructions (AOI)-27.1.9, Control Room Inaccessibility Safe Shutdown Control

(* Review only)

To evaluate the ability to achieve the recirculation mode when required the following attributes were used:

- Control Room Operators (ROs) knowledge of EOPs.
- ROs knowledge of criteria for initiating recirculation.
- NPOs knowledge of location and operation of valves specified in procedures.
- Procedures for establishing recirculation mode.
- Whether EOPs were technically correct and could be performed as written.
- Whether EOPs provided alternative steps when primary steps could not be performed, and
- Whether valves which required local operation were accessible and could be operated locally.

Findings

In general procedures for initiation of recirculation appeared to be good. Operators were knowledgeable of procedures and plant equipment. The licensee stated that operators received six weeks of training on EOPs. The degree of training was apparent during walkthroughs. Although some problems are noted below, the ability to achieve recirculation in a timely manner appear to be good. Plant equipment, both the nuclear PAB, and non-nuclear side, appeared to be good. Some findings were identified concerning the labeling of plant equipment; they are detailed in paragraph 13.2.

(1) As noted previously, in addition to procedure walkthroughs in the Control Room, EOP ES-1.3 was performed using the IP-2 simulator. ES-1.3 provides a means for transferring the recirculation function to the RHR system should the recirculation system fail to operate. While simulating this portion of the procedure at the inspectors request, RHR flow failed to start. The operators were able to determine that the RHR pumps discharge valve MOV-744 had not opened. Subsequently, it was determined that the procedure which closed MOV-744 in an earlier step failed to reopen it at this point.

The ability to establish recirculation in a timely manner is critical to prevent core melt. If RHR backup recirculation has to be established, some time has already been lost because normal recirculation has failed. The failure of a key valve to open in a timely manner will further slow down the establishment of recirculation and increase the risk of possible core melt. The failure of the procedure to re-open MOV-744 was an omission in the licensee's validation walkthroughs of all EOPs. This is considered an example of a violation for improperly established procedures (50-247/86-19-06). Several other examples of this violation are detailed later in this report.

(2) In order to perform the recirculation mode at the simulator, portions of procedures E-0 and E-1 must also be accomplished. Step 6 of E-1 requires the resetting of Phase A and Phase B containment isolation. The inspector noted that on performing this step, the operator made several attempts before Phase A containment isolation reset. The operator stated that two switches which must be operated had been initially overlooked.

Step 6.b states "Place control switches for all remaining Phase A isolation valves to close on SN panel". However, the procedure fails to recognize that two switches for the containment personnel and equipment hatch solenoids located on an adjacent panel SM must also be reset. The failure to include panel SM in the procedure may have caused the operator to initially overlook these switches even though their labels are color coded and they are located adjacent to panel SN. This is a second example of a violation for inadequately established procedures (50-247/86-19-06). Licensee representatives stated that this deficiency may have to be corrected in several other EOPs which also reset containment isolation.

(3) Because of the potential for clogging of the suction side of the safety injection pumps, the Boron Injection Tank (BIT) has been removed from service to prevent use. However, the licensee failed to change the appropriate EOPs to recognize this fact. For example E-0, steps 7 and 20, recognize operation of the BIT. Other EOPs also specify operation of BIT.

Although this problem was recognized by cognizant licensee personnel, it appeared that the EOPs were not revised because of a desire to wait for the completion of further modifications to remove the tank. This is an example of a violation for failure to properly maintain procedures (50-247/86-19-06).

(4) During review of ES-1.3 other procedural errors or weaknesses were observed by the inspector. The errors noted were not considered to be part of the violation but do require correction. The licensee was informed of and agreed to correct each of the items listed below:

- ES-1.3, step 1.a opens the diesel generator service water flow control valves, MOV-1176 and 1176A. However, the valve numbers are not given. This is inconsistent with instructions for procedure preparation and with the remainder of ES-1.3 which gives all valve numbers.

- ES-1.3, step 1.d energizes all motor operated valves (MOVs) on motor control centers (MCCs) 26A and 26B. Since this would energize the BIT valves also, it is not desired to energize all MOVs. The licensee stated it was not desirable to clutter the procedure with exceptions. To ensure that the BIT discharge valve MOVs are not energized the breakers will be tagged out. In addition, label plates are to be placed on the MCC breakers for the BIT stating "BIT RETIRED - DO NOT ENERGIZE". This should preclude operation of the BIT MCCs.

  This corrective action will be made to several other EOPs which call for the operation of all MOVs at MCC - 26A and 26B.

- ES-1.3, step 12.b operates MOV-1813. This valve is actually an air operated valve.

- ES-1.3, steps 13 and 19 close the RHR miniflow test line valves MOV-743 and MOV-1870. During some walkthroughs operators hesitated before realizing that these valves are operated from an MCC and an NPO must be dispatched to do this. Although not incorrect, the procedure would be improved if the location of operation were to be specified since these valves cannot be operated from the control room.

4.2 Recirculation Pumps and Piping Operability

Scope

In order to assure that the recirculation system will operate when called upon, recirculation system components must be operable. The Technical Specification for IP-2 states that all pumps, valves and associated piping for the recirculation system must be operable, but no specific surveillance tests are specified. Recirculation pumps and valves are included in the licensee's ASME Code, Section XI, pump and valve test program and are tested at each refueling outage. There are no specific functional tests for operability of piping. Because the recirculation system is located entirely in containment, it is normally tested only during cold shutdowns or refueling outages. The two recirculation pumps are rated at 3000 gpm each; however, they are not tested at full capacity since this may require pumping water from the recirculation sump to the reactor plant. The pumps are tested at 160 GPM via a small test line which recirculates water back to the recirculation sump.

Test procedures for the recirculation pumps and completed test data were reviewed for adequacy. The licensee was requested to demonstrate that various tests of ECCS systems verified operability of all recirculation system piping. The inspection consisted of review of test procedures, completed test data, and discussions with licensee test engineers.

Criteria

The recirculation system components are tested per ASME Section XI tests. Since the recirculation system interfaces with the RHR, safety injection, and containment spray systems, certain surveillance tests for these systems were reviewed to assure that flow was verified in all ECCS associated piping. For this reason the following tests were reviewed:

*o PT-R16, Recirculation Pumps Functional Test, Revision 7, July 24, 1984

*o PT-FY1, Containment Spray System Nozzle Test, Revision 1, August 23, 1984

o PT-R35, Containment Spray Pumps Functional Test, Revision 0, October 10, 1984

o PT-R64, SIS Accumulation Check Valve Flow, Revision 1, February 4, 1986

o PT-R66, Residual Heat Removal Pumps Full Flow Test, Revision 0, July 24, 1984

o PT-R65, Containment Spray Check Valves, Revision 2, January 20, 1986

o PT-3Y3, Containment Fan Cooler Units - Spray System Air Flow Test, Revision 1, September 4, 1984

*These procedures were reviewed for technical adequacy. Other procedures were reviewed to verify flow (operability) in all ECCS piping.

In addition, data for the following completed tests were reviewed:

o PT-R16, Recirculation Pumps Function Test, Revision 7, July 24, 1984, data reviewed for test conducted on September 25, 1984.

Revision 6, October 26, 1982, data reviewed for test conducted on December 21, 1982.

Revision 5, March 14, 1981, data reviewed for test conducted on April 29, 1981.

- PT-FY1, Containment Spray System Nozzle Test, Revision 1, August 23, 1984 and Revision 0, April 5, 1978, data reviewed for tests conducted on September 27, 1984 and May 1, 1978.

Procedures PT-R16 and PT-FY1 were reviewed for the following:

- Procedures were technically adequate.
- Operability of recirculation pumps was demonstrated.
- Recirculation pumps were tested at specified frequency.
- Associated piping is demonstrated operable.
- Satisfactory test results which met acceptance criteria was obtained.
- Thermographic pictures of containment spray nozzles adequately verified flow during air tests.

Findings

The Technical Specifications state that piping associated with the recirculation system shall be operable. Because of the system configuration, full flow cannot be achieved in the system during testing. For this reason proving piping operable as a minimum should require verification that piping is not blocked at the highest achievable flow in that piping.

The inspector observed that since recirculation pump discharge valves must remain shut, flow is never verified in the piping between the discharge valves and the RHR heat exchangers. The licensee stated that this piping had been used in the last test (September, 1984) to fill the recirculation sump from the RHR system hence this piping had been verified to have no blockage. The inspector concurred that this method would verify that this the pipe was unobstructed but noted that this method of fill was not documented in the test and did not assure that the parallel flow paths through valves 1802A and 1802B were both verified. Prior to the completion of the inspection, the licensee had prepared Revision 8, which documented fill of the recirculation sump through this piping. The inspector determined that this resolution will adequately verify that recirculation discharge piping is unobstructed when the test is performed during the next refueling outage.

The inspector observed that the piping between RHR heat exchanger outlet valves MOV-889 A and B and the containment spray headers is also untested. Because of the configuration of this piping it is not feasible to prove this piping in unobstructed by water flow. This piping would be used in the recirculation mode where some of the recirculated water would be diverted to the containment spray header.

The licensee must air test the containment spray nozzles every five years. This test was last performed September, 1984 and will next be scheduled during a 1989 refueling outage. The licensee issued a memorandum to file on July 31, 1986 stating a commitment to determine if air pressure exists at valves SS1A and SS1B while performing containment spray nozzle air flow test and thereby demonstrate no blockage in the piping. This item is unresolved pending completion of licensee action (50-247/86-19-07).

Since two ECCS flow paths which could be used during an accident situation were untested, the inspector was concerned that other such untested flow paths may exist. The licensee reviewed all ECCS flow paths and determined that all others were verified by some evolution which verified unobstructed piping. The inspector reviewed licensee procedures on a sampling basis and determined that other flow paths were tested.

4.3 Recirculation Switches

Scope

During a LOCA, water in the containment must be recirculated back to the core via the RHR heat exchangers after the refueling water stor age tank (RWST) reaches a low level. This switchover sequence is accomplished by operating a series of eight switches sequentially in the control room. Each switch causes certain pumps to stop or start and certain valves to open or close as appropriate. Switch 6 or 7 is operated depending on whether low pressure or high pressure injection is required during recirculation. The operability of the recirculation switches is critical to the successful attainment of the recirculation mode. There are no Technical Specification requirement for testing the operability of these switches; however, the licensee recognized the need to assure the switching mechanism is operational and has developed a test. Through a procedure review and discussions with licensee personnel, the inspector reviewed the adequacy of this testing.

Criteria

The following procedures were reviewed:

- PT-R13A, Recirculation Switches, Revision 3, January 10, 1986
- PC-Q2, Refueling Water Storage Tank Level, Revision 0, May 6, 1986
- PT-R2B, Recirculation Sump Level, Revision 6, March 1, 1986

- PC-EM16, Containment Pressure Transmitters, Revision 0, January 29, 1986

- PT-R2A, Containment Sump Pumps and Instrumentation, Revision 7, March 1, 1986

Completed test data for PT-R13A, Revision 2, performed on January 21, 1986 was also reviewed and the following criteria were employed:

- Procedure was technically adequate.

- All recirculation switches were tested and possible pump and valve combinations for each switching evolution were tested.

- Satisfactory test data and test results were acceptable.

- Operability of each recirculation switch was verified, and

- Procedures adequately test the switching requirements of emergency procedure ES-1.3 which operates the recirculation system.

Findings

Because most of the switches are aligned vertically on the control panel and switches 6 and 7 are aligned horizontally, the chances of operator error in the switching sequence appears to be minimal. Procedure PT-R13A was found to adequately test each of the eight recirculation switches. Some of the switches require various pump combinations to be in effect and PT-R13A tested all possible combinations. In addition, recirculation must be initiated when the RWST level reaches 10.23 ft. Procedure PC-Q2 adequately calibrates RWST level indication and the control room alarm setpoint of 10.23 ft. During the review of this procedure some minor deficiencies were noted. These deficiencies are not considered to be part of the violation concerning procedures which is detailed in paragraph 4.3 above. The licensee stated that the procedure would be revised to correct the following observations:

- Step 3.26 verifies completion of one cycle of testing for switch No. 5; however, there is no step to verify that the "cycle complete" light has illuminated. This is not consistent with the rest of the procedure and does not completely verify this evolution for the pump combination being tested.

- Step 3.43 places SWP #26 and SWP #25 in the "auto" position. Since it is desired to stop these pumps, the "auto-off" position should be specified.

- Step 3.48.1 states to jumper the interlock between valves MOV-730 and 731 and 888 A & B. This allows 888 A & B to open although 730 and 731 may be open when switch 6 is operated in step 3.49. Switch 6 also closes valves 842 and 843. This prevents backflow to the RWST from the RHR system. The inspector noted that once the jumper is in place valves 842 and 843 must function properly or there could be backflow to the RWST. The licensee concurred, and will revise the procedure to isolate the RWST with valves upstream of 842 and 843 before performing step 3.49.

- Step 3.49 tests every function of switch 6 except the automatic arming of safety injection pump low pressure alarm PT-947. The licensee noted that PT-947 was tested by procedure PM-328. However, the licensee reviewed the procedure and determined that for completeness PT-947 should be checked during this test also.

- Step 3.50 states in part to verify MOVs 1810 and 1813 close. Valve 1813. The procedure should be revised to reflect that valve 1813 is not an MOV.

4.4 Component Cooling Motor Operated Valves

Scope and Inspection Criteria

The component cooling water system provides heat removal from the RHR System during normal plant shutdown and also during the recirculation phase following a postulated accident. The outlet MOVs 822 A & B of the component cooling water system to the RHR heat exchangers 21 and 22, were identified in the IPSSS as important to prevent core melt.

Findings

A review of the maintenance records revealed that these valves failed to function 22 times from 1974 through 1984. Most of the problems were associated with the torque and, or limit switches. The records indicate that MOV 822B limitorque operator was replaced on May 19, 1981. The licensee indicated that the valve was also replaced at that time. The licensee had purchased about 14 MOV operators for replacement of undersized operators. Work order number NP-85-22669, origination date August 2, 1985, was issued for preventative maintenance to be conducted on MOV 822A during the refueling outage of 1986. The valve could only be moved by manual action of the motor control center motor contactor. The torque switch would open in both the close and open direction. This information was sent to engineering for evaluation on January 24, 1986. Work order number NP-85-22678 for the MOV 882B PM did not indicate any similar problems.

Although their reliability appears to have increased the licensee is continuing to review the root causes of these past valve operator problems. No violations were identified during this review.

4.5 Safety Injection System Motor Operated Valves

Scope

The motor operated valves (MOV) listed below, were selected for review and evaluation based on the licensee's IPPSS. Failure of the motor operated valves to open at the required time could cause degradation of the licensee's ability to mitigate the consequences of a design basis accident. These valves are not normally operated during plant operation, and testing is routinely conducted by the licensee in accordance with their inservice testing (IST) Program. The inspector reviewed the licensee's program (TAD 9, Rev. 4) and the records of testing performed to verify compliance with 10 CFR 50.55a and ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWV, Inservice Testing of Valves, 1980 edition with addenda through winter 1981. The following MOVs were selected for review and evaluation:

- Safety Injection System (SIS) MOV 881 and 888B, RHR/Recirculation system discharge cross connect to SI pump suction.
- SIS MOV 889 A and 889B, RHR/Recirculation system discharge to containment spray header, and
- SIS MOV 856B and 856F, Hot Leg Injection valves.

The inspector reviewed records for valves MOV 730 and 731, the normal RHR suction valves for long term (shutdown) cooling.

A primary containment entry was made by the inspector (discussed in Paragraph 4.9) to observe the physical condition of the above valves that were accessible. A listing of all work orders for the last three years for the SIS was also reviewed to determine any trends or problems with the valves identified above.

Findings

Four of the six valves initially selected above were tested quarterly (MOVs 888 A & B and 889 A & B). The inspector reviewed IST records from January 1978 through January 1986. The inspector noted one occasion in May of 1980 when valve stroke time increased significantly for MOVs 888 A and 888 B. Stroke time returned to normal on the subsequent test. No corrective action was taken during either case by the licensee. MOVs 856B and 856F are tested when the plant is in cold shutdown only. Records reviewed from October 1983 through January 1986 did not indicate any valve stroke time anomalies.

Review of MOV 730 and 731 IST records indicated a large increase in valve stroke times. The valves are stroke tested only when in cold shutdown. During the October 1984 test both valves full stroked in the open and close direction in about 160 seconds. During the January 1986 test the valves full stroked both open and closed in 225 to

230 seconds. During a subsequent test on April 29, 1986, MOV 730 stroked in approximately 200 seconds and MOV 731 stroked in approximately 230 seconds. The inspector noted that during licensee review of stroke time results for January 1986, a written statement to increase the frequency of testing to monthly was made; however, monthly tests were not conducted. The inspector questioned the licensee concerning the above and the anomalous stroke times of MOVs 888 A and B in 1980.

The licensee noted that during 1980 the data sheet acceptance criteria for MOVs 888 A and B was 120 seconds. Current data sheets have 120 seconds for maximum operability time but also have a further alert criteria to increase testing frequency to monthly if stroke times increase by 125 percent from previous stroke times of greater than 10 seconds and 150 percent for previous stroke times of less than 10 seconds. The above values are also stated in ASME Section XI.

The licensee stated that the large stroke time change for MOV 730 and 731 had been noted during the review process and monthly testing was scheduled. The licensee subsequently learned that these particular valves, which are 14 inch motor operated gate valves, should stroke at the rate of 4 inches per minute. The inspector requested and was provided a copy of Drawing No. 1973M4640 which denoted valve stroke rate as 4 inches per minute. The inspector verified that correct total valve stroke time should be about 210 seconds and that current stroke times appeared acceptable. No explanation for the previous 160 second stroke times was provided since no maintenance had been performed on these valves.

Through discussion with the licensee and further review of the licensees IST program and ASME Section XI, subsection IWV, it was determined that monthly stroke time tests could not be discontinued unless corrective maintenance had been performed on the valve with a subsequent post maintenance test (PMT) to establish a new baseline valve.

The licensee stated that a relief request would be submitted in accordance with this 2nd ten year IST program submittal of February 16, 1984, to NRR that would allow the licensee to evaluate a stroke time change considering such factors as system conditions, manufacturers information and previous stroke history. If a deviation could be satisfactorily explained the stroke time test frequency would not need to be increased. A copy of General Ruling Request 'E', dated July 30, 1986 was given to the inspector.

In an effort to determine if the above item was an isolated case or indication of a programmatic problem, the inspector reviewed the IST records of six (6) additional, randomly selected valves. All records indicated that the IST program was being followed. Four (4) of the additional valves reviewed had been placed on a monthly IST frequency until post maintenance testing had been satisfactorily performed.

The inspector determined, based on the sample reviewed, that failure to perform monthly tests of MOVs 730 and 731 was an isolated case. The licensees explanation agreed with manufacturers data and is in accordance with their General Relief Request 'E' submittal.

The inspector noted that the licensee's IST program has improved during the last two years. Valves that are not satisfying the alert criterion are being placed on the monthly test frequency and trending is routinely being performed. The licensee is also placing IST data obtained during testing into a computer tracking trending system which, when fully functional, will provide valuable trend information and extension of data to predict failures. The computer system will also receive pump IST data as well as emergency battery information.

No unacceptable conditions were identified.

4.6 Safety Injection System Check Valves

Scope and Acceptance Criteria

The inspector evaluated the availability and operational readiness of the Safety Injection Check Valves (897 A, B, C, D) and the RHR Check Valves (838 A, B, C, D). Acceptance criteria included satisfactory testing and maintenance in accordance with Technical Specifications and ASME, Section XI, and the appropriate station procedures.

Findings

The inspector reviewed surveillance test PT-V21, Revision 2, which tested valves 897 A, B, C, D and 838 A, B, C, D for reverse leakage. PT-V21 was considered to be a satisfactory test for determining back leakage through the valves. An examination of completed tests showed that PT-V21 had been performed in an acceptable manner and that all valves met the operability criteria of the surveillance.

Full flow through valves 897 A, B, C, D was tested by PT-R66, Revision 0, as modified by Temporary Procedure Change No. 86-30T, dated February 4, 1986. This procedure was adequately prepared and measured RHR pump flow to evaluate full flow through the check valves. A review of a completed tests revealed no discrepancies.

The inspector found that there had been no maintenance action required on check valves 897 A, B, C, D and 838 A, B, C, D during the preceeding two years.

No unacceptable conditions were found in the surveillance , testing and maintenance of valves 897 A, B, D, D and 838 A, B, C, D; the valves met criteria for availability and operational readiness.

4.7 Instrumentation

Scope and Criteria

Based on the licensee's PRA, certain instruments in the safety injection, recirculation, residual heat removal and the auxiliary cooling system were selected for review. The availability and operational readiness were evaluated. The failure, unreliable indication or loss of control function of any of the selected instruments could adversely affect the licensee's ability to mitigate the consequences of an accident. The inspectors reviewed records of calibration, surveillance and preventive maintenance for the selected instruments.

A listing of all work orders relating to the above systems was also reviewed to evaluate failure during operation and equipment reliability. The inspectors additionally entered containment to visually verify the material condition of selected instruments. The table below identifies the instruments evaluated and dates of calibration. Permits and procedures reviewed are listed in Attachment C.

Instrument		Calibration Dates
FT/FI 945A	RHR/Recirc. Containment Spray Flow Indication	5/6/77; 7/2/79; 3/16/81; 10/2/82; 6/29/84 and 1/28/86
FT/FI 945B	RHR/Recirc. Containment Spray Flow Indication	5/4/77; 7/2/79; 3/16/81; 10/2/82; 6/29/84 and 1/28/86
FT/FI 924,5,6,7	Safety Injection System Flow Indication	7/20/84 and 3/16/86
LT/LI 3303 LT/LI 3304	Containment Sump Level Indication and Alarm	12/8/82; 7/14/84 2/5/86 and 2/22/86
LT/LI 938 LT/LI 939	Recirculation Sump Level Indication	6/18/79; 1/5/81; 4/28/81; 12/16/82; 9/26/84 and 3/4/86
LT/LI 3300	Containment Sump Level Indication	12/18/82; 9/25/84 and 3/15/86
LT/LI 3301	Recirculation Sump Level Indication	
LT/LI 3302	Reactor Cavity Sump Level Indication	

PT/PI 922	Safety Injection Pump Discharge Pressure Indication	7/31/76; 3/25/78; 3/21/80; 3/5/81; 3/14/83 and 1/30/85
PT/PI 923	Safety Injection Pump Discharge Pressure Indication	3/25/78; 3/31/80; 3/5/81; 3/14/83 and 1/29/85
PT/PI 947	Safety Injection Pump Suction Pressure	7/31/76; 3/25/78; 1/24/79; 3/5/81; 3/23/83 and 2/4/85
PI/PC 635	RHR Pump Discharge Pressure Indication and Alarm	10/28/77; 10/12/79; 10/21/81 and 4/26/83
LT920/LC920B LIC 921	Refueling Water Storage Tank (RWST) Level Indication and Alarm	4/10/84 and 7/9/84; 9/20/84; 1/10/85; 4/11/85; 7/11/85 10/10/85; 1/8/86 and 3/2/86

Findings

Trending of environmentally qualified instruments is routinely performed by the licensee. During the review of the above instrument calibrations the inspector did not detect any abnormal trends, with two exceptions the RWST level indicator (LT 902 and LIC 921) and the low level alarm appeared to require adjustment during almost every performance test (quarterly). The RWST level transmitter and alarm setpoint drift problem have been recognized by the licensee. Prior to November 1982, calibration of these instruments was conducted on a refueling outage basis. On November 23, 1982 a system engineer recommended that the frequency of calibration be increased to quarterly because of instrument out of specification history. The licensee has continued to trend these instruments and has now increased the calibration frequency to monthly.

The licensee is taking further action to install a redundant level instrument, to both comply with Regulatory Guide 1.97, (concerning post accident environmental effects on instrumentation) and to mitigate the out of tolerance problems of the existing instrumentation. The current central engineering project scoping document (Project No. 62033) estimates completion of the project by March 1, 1988. The inspector noted that due to the licensee's trending program the RWST level instruments are receiving an adequate level of attention.

No unacceptable conditions were identified.

4.8 Recirculation Sump

Scope

On July 23, 1986 two NRC inspectors accompanied by two licensee representatives entered the primary containment during full power operation to perform a visual inspection of the physical condition of certain valves and instruments. The inspectors checked six (6) valves and twelve (12) instruments that were located outside the biological shield wall on the 68 and 46 foot elevations.

Findings

The inspectors had several questions concerning environmental qualification (EQ) of one transmitter and one valve. The licensee provided the inspectors with a copy of the ITT Barton technical manual and Franklin Institute Research Laboratories EQ test of motor operated valves and answered the inspector's questions concerning EQ. No problems were noted.

While inspecting the recirculation sump level instruments, the inspectors observed that a section (about 1 foot wide by 5 feet long) of the protective floor grating was not in place. In addition, a portion of floor plate which covers the recirculation sump filter screen had been moved out of place leaving a 5 foot long by 2 inch wide gap. Two large plastic bags were found laying by the open grating. The bags contained miscellaneous clear plastic tubing and other items that may have been used to pump down the recirculation sump during the last outage.

The recirculation sump is designed in three sections. See figure 4.8.1 for sump design. The first section is covered by the floor grating through which water would flow during a LOCA. Its openings are 1 inch by 4 inches and filters out large particles. Water from the first sump passes under a weir into a second sump at which time it flows upward through a second screen (¼ inch mesh) and over a weir to the recirculation pumps suction. The floor plate covers this filter screen and ensures that water and debris does not bypass both filters.

The inspector reviewed modification No. MPC 82-11004-10 which changed recirculation sump level instrument LT 939 in December 1982. At that time QC inspection records indicated that floor grating and floor plating were installed in accordance with drawings.

The inspector also reviewed the last four completed Station Operating Procedures (SOP) 10.6.2 Containment Entry and Egress, Revision 18. No abnormal conditions were indicated on March 12, June 5, July 7 and July 15, 1986. The inspector also reviewed PI-BW1, Revision 3, Containment Building Inspection for Anomalous Conditions, conducted on March 20, 1986 and PI-M2 Containment Building Revision 0 (replaced PI-BW1), completed on May 25, 1986. None of the above inspections

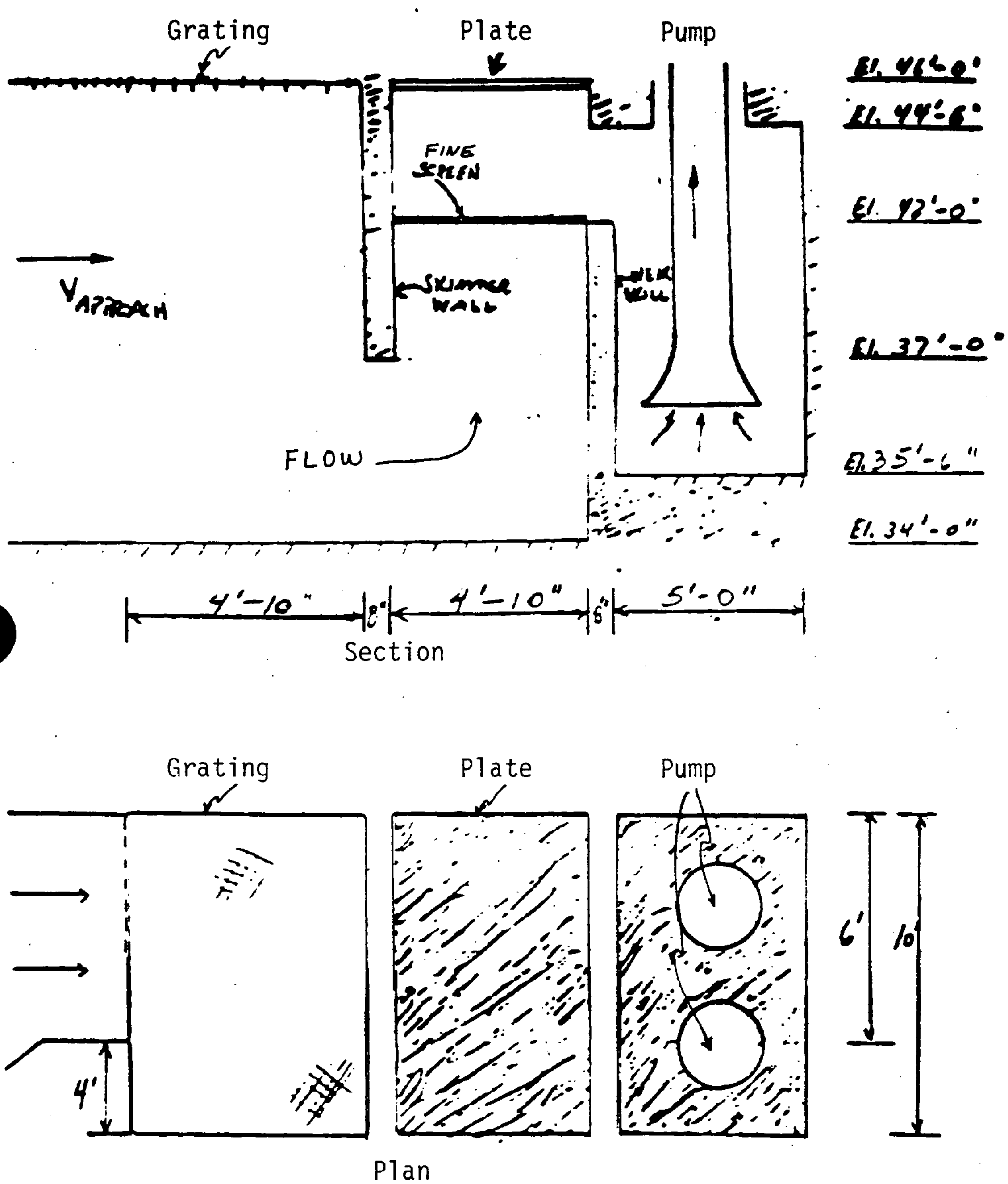

Figure 4.8.1
Recirculation Sump
Arrangement

directly check sump grating or the floor plate but do check the recirculation sump level and general trash and debris.

The licensee initially attempted to fit the grating into place but it would not fit properly. The plastic bags were immediately removed. The sump was returned to its correct design configuration on July 25, 1986 and a written safety assessment was provided to the inspection team on July 31, 1986.

The failure to replace the floor grating and decking was a violation of 10 CFR 50, Appendix B, Criterion V, since a change was made to the facility as described in the Final Safety Analysis Report (FSAR) and the Containment Arrangement Drawing No. 9321-F-2503 (50-247/86-19-08).

5.0 Component Cooling Water System (CCW)

5.1 CCW Pumps

Scope and Criteria

The hardware availability and operational readiness were evaluated by review of the IST records. Testing of pumps is conducted in accordance with TAD9, Revision 4, 10 CFR 50.55a and ASME, Section XI and is conducted on a quarterly basis. The inspector reviewed IST records for CCW pumps No. 21, 22 and 23 from October 4, 1984 through April 29, 1986.

Findings

For the period reviewed all pumps consistently discharged between 271 to 279 feet of head at 1500 GPM indicated flow. Discussions with the licensee indicate that the CCW pumps are reliable. The inspector also reviewed the last preventive maintenance (PM) alignment of pressure controller No. 600. This instrument monitors CCW pump discharge header pressure and will automatically start the standby pump and give a low pressure alarm at 80 psi decreasing. The PM was conducted on March 22, 1985 (2 year cycle). The instrument setpoint was found at 87 psi vice the specified 80 ± 2 psi. The instrument setpoint was adjusted and left at 80.5 psi. A functional test was performed and the pump start function and alarm were verified.

No unacceptable conditions were identified.

5.2 CCW Manual Valves

Scope and Acceptance Criteria

The inspector evaluated the availability and operational readiness of the following manually operated valves: SWN-31 and SWN-32, service water supply for the Component Cooling Water heat exchangers, and

ACW-734A and B, auxiliary cooling water supply and return for the safety injection and residual heat removal pumps. The inspector reviewed the licensee's controls to ensure that the valves were in the correct position and received adequate valve maintenance.

Findings

Valves SWN-31 and 32 and ACW 734 A and B were not subject to mechanical or operational testing.

Visual observation showed SWN-31 to be locked open and SWN-32 to be locked closed; both valves are checked in their postion weekly by Check Off List 24.2, Rev. 1, Service Water Essential Header Verification.

Visual observation showed valves ACW 734 A and B to be locked open; both valves are checked in this position monthly by Check Off List 10.0, Rev.0, Locked Safeguards Valves.

A check of maintenance files showed no record of preventive or corrective maintenance for these four valves, and the inspector considered that the controls used to ensure correct valve position are adequate.

5.3 Overall CCW Reliability

The Component Cooling Water System (CCWS) provides cooling water for the inboard and outboard seals and bearings of all three Safety Injection Pumps, and for the seal heat exchangers and the thermal barriers of the both Residual Heat Removal (RHR) pumps. The CCWS for the SIS and RHR pump has a single loop, and the cooling water is supplied through a normally-open 2" globe valve. Cooling for each of three SIS pumps and two RHR pumps takes a suction from a 2" common header via a parallel flow circuit, and may be individually isolated. A failure of this 2" line will cut off the pump cooling, resulting in failure of all three SIS pumps. However, the licensee stated that both RHR pumps can operate without cooling for up to 24 hours in the event of the CCW loss. The cooling water return from all five pumps merge into one 2" return line, and returns to the CCW pumps via a normally locked-open manual valve. A single failure of any one of the manual valves or plugging of the 2" line could result in a common mode failure of all SIS and RHR pumps. The system features and plant programs were reviewed to evaluate the system reliability and the plant safety:

- In the event component cooling water is lost, an emergency supply from the primary water system can be provided through valve 733C. Flange connections on discharge lines enable cooling water to be piped outside building.

- The failure mode of the system represents a single passive failure with low probability. The cooling water flow for the SIS pumps can be monitored from the local indicator individually, and low flow will be annunciated in the control room.
- The CCWS provides cooling water continuously, and the manual valves, 734A and 734B, are locked-open. Monthly surveillance inspection was provided per COL 10.0, "Locked Safeguards Valves" for the valve positions.
- Manual valves, 734A and 734B, are not regularly stroke tested nor are they required to have periodic preventive maintenance. They were closed and opened per ISI hydrotesting. No failure records were identified for last two years.
- The CCWS is a closed loop system with relatively low pressure and temperature, and the cooling water is treated with a corrosion inhibitor.

Findings

Based on the above, the inspector determined that station programs met regulatory requirements. Adequate procedures were provided to detect, correct, and recover from the loss of the CCWS for the pump cooling.

6.0 Accident Mitigating Systems

6.1 Turbine and Reactor Protection Trip Logic

Scope and Criteria

A generator protective function will trip the generator and the turbine. A turbine protective function will trip the turbine; and, the generator will trip after a one minute time delay. This time delay allows one minute of electrical power to be supplied to the reactor coolant pumps before a transfer to the offsite source. In addition it prevents the turbine from overspeed from the reheater steam. A turbine protective function will also trip the reactor when above 10% power. A reactor protective function will trip the reactor and the turbine. The reactor protection system is important to assure that the safety limits are not exceeded. The turbine trip is important after a reactor trip to prevent excessive heat removal from the primary system. The turbine overspeed protection is important to preclude turbine missile generation.

Findings

The inspector reviewed reactor protection events (13) and safety system events (20) from 1973 through 1985. Four of the safety system events were associated with the BIT level. This system has been retired in place. There were early bistable power supply failures which did not continue after 1976. The steam generator level impulse line blockage, December 1976, January 1977 has not been repeated after the January 1982 event. There have been no identified reactor-turbine-generator trips that did not operate upon actual protective demand. There are no recent events which appear to reflect on reactor protection system reliability.

6.2 Containment Fan Cooling Units

Scope

In the analyses of the dominant accident sequences, several nonconservative but realistic assumptions were made, in that the containment fan cooling units (FCU) would be available to mitigate the core melt accident. The air recirculation system consists of five 20% capacity air handling units, each with a motor, fan, cooling coils, filtering system, and an air distribution system. The fans are a part of the engineered safety features, and three of five fans are required to be started on a Safety Injection signal. The cooling coils are cooled by the service water system, and the dominant contributor to system failure includes the parallel air-operated valves, TCV 1104 and TCV 1105, which allow service water flow through the fan cooling coils. Thus, the scope of the inspection was focused on the hardware availability of the FCUs, and TCV 1104 and 1105.

Findings

In order to increase the reliability of the containment fan cooling system, several modifications have been completed. Under modification procedure No. MMS-85-42780, the following were completed during the 1986 refueling outage:

- Two new fan coolers, drain troughs, drip pans, and down spouts.
- New air duct on motor coolers.
- New service water supply and return piping, and
- New vents, drains, and differential transmitters.

Also, to provide a remote operational capability of the service water isolation valves to individual FCUs, the inlet (SWN-41) and outlet isolation valves (SWN-44) of each of the FCUs were replaced by flanged, MOVs. In addition, a manual 10" globe valve was installed on the return lines of the FCUs to balance the service water flow. These manual valves were locked into position; and modifications were completed per procedure Nos. MMS-81-2-02 and MMS-81-2-06.

Valves TCV-1104 and 1105 operate to bypass the normal supply valves to the FCUs upon receipt of a Safety Actuation Signal (SAS) to permit full flow under emergency conditions. The valves are temperature regulated, and air-operated 18" butterfly valves. They are in parallel and each can provide full flow. The inspector simulated, on the training simulator, the loss of instrument air for the valve operators, and verified that the valves fail open upon loss of the instrument air; and, that each one serves as a backup to other should one fail to open.

The In-service test procedure PT-Q13, Section XI, "Valve Exercise", Revision 6, was reviewed. The inspector determined that the testing procedure was consistent with the requirements specified in the ASME code, Section XI, valve testing. Valve operability was tested by stroking the valve and measuring the stem travel and stroke time. The following test records were reviewed:

	TCV-1104	TCV-1105
Test Dates	3/02/84	3/01/48
	10/30/84	10/30/84
	2/07/85	2/10/85
	5/10/85	5/07/85
	7/09/85	7/09/85
	10/15/85	10/15/85

The test results were acceptable, and opening/closing times met the acceptance criteria. The inspector found two corrective maintenance actions during the proceeding two years. A limit switch for TCV-1104 was replaced on June 27, 1985 for a weak spring. Faulty electrical wiring for TCV-1105 position indicating lights was repaired on January 21, 1986.

7.0 Recovery Actions On Loss Of Offsite Power

7.1 Recovery of External AC Power

Scope

Normal AC power is supplied to IP-2 through its own unit auxiliary transformer or from the 138 KV Buchanan station auxiliary. Other sources of power included a 13.8 KV Buchanan substation, and a direct IP-1 feed through the nuclear side alternate shutdown power which bypasses the Unit 2 480 volt switchgear. Loss of the normal 138 KV offsite power should not cause a reactor trip but loss of the unit transformer will.

Station emergency operating procedures are predicated, in part, that some AC power is available to power emergency equipment on the 480 volt vital busses. ECA-0.0, Loss of All AC Power, provides a procedure for use should there be a total station blackout and all 480 volt busses are deenergized. The thrust of this procedure is to maintain stable plant conditions, shutdown and cooldown the plant, and attempt to restore some AC power to 480 volt busses. Once normal offsite power is available, it is restored per system operating procedures for normal breaker alignments.

The inspector conducted one control room operational safety simulation with a reactor operator (R.O). using ECA 0.0 to discuss emergency actions and AC power recovery actions. In addition, one simulator walkthrough with one R.O. and S.R.O was conducted. The operators performed emergency actions on the simulator for the following three scenarios:

- Loss of 138 KV power with the unit station transformer power
- Loss of all external AC power with the diesel generators available
- Loss of all AC power (total station blackout) with subsequent recovery of the diesel generators.

In each instance, a loss of AC power was assumed with no safety injection present.

Should no AC power be available, the plant must be cooled down using the steam driven auxiliary boiler feed pump and the atmosphere steam dumps. This procedure requires operation of many valves locally on the non-nuclear side. The inspector selected a sampling of valves which can be operated locally by ECA 0.0. A walkthrough was conducted with an NPO to verify the ability to locate, identify and operate each valve selected. All valve operations were simulated.

Criteria

Loss of power recovery actions are performed in either emergency operating or abnormal operating procedures. These procedures were reviewed and walkthroughs were performed using ECA 0.0. Procedures for use of the gas turbines are detailed in paragraph 7.3 of this report. System operating procedures used for normal breaker alignments were not the subject of this inspection although some of these procedures may be used in recovery of normal power after it has been restored. The following procedures were reviewed:

- ECA-0.0, Loss of All AC Power, Revision 0
- ES-0.1, Reactor Trip Response, Revision 0

- ECA-0.1, Loss of All AC Power Recovery Without SI Required, Revision 0

- ECA-0.2, Loss of All Power Recovery with SI Required, Revision 0

- AOP-27.1.9, Control Room In-Accessibility Safe Shutdown Control, Revision 2

To evaluate the ability to recover from a loss of AC power the following criteria were used:

- ROs were knowledgable in the loss of power EOPs

- NPOs were knowledgable on location and operation of valves specified in the procedures

- Procedures existed for recovery from loss of AC power and were technically adequate

Findings

(1) During the simulator walkthrough, the first scenario was a loss of offsite power via the 138KV station auxiliary transformer. The operators performed the necessary actions to attempt to stabilize the plant. Although the unit transformer was not tripped, the reactor eventually tripped on low condenser vacuum. The reason for this trip is discussed in paragraph (2) below. However, in the actual plant a reactor trip should not have occurred.

Normal operation of the plant should have continued in a degraded power mode as the 6.9KV busses 5 and 6 would have been lost. The inspector determined that a procedure was not available for operation in this degraded mode.

Regulatory Guide 1.33-1972, Appendix A, paragraph F.3, states procedures shall be provided for loss of electrical power (and/or degraded power sources). Since the loss, the 138KV transformer degrades power available to the plant and requires specific operator actions, a procedure should have been established. This is a fourth example of a violation of the plant Technical Specifications for not properly establishing procedures identified previously in paragraph 4.1 (50-247/86-19-06).

(2) As stated previously, with the loss of 138KV power the simulator ultimately tripped on loss of condenser vacuum. The loss of busses 5 and 6 caused the loss of too many circulating water pumps. A modification in the plant was performed to cause only the loss of two circulating water pumps on a loss of busses 5

and 6. Although the modification was performed two years ago, it was not yet modeled at the simulator. The inspector expressed a concern over the time delay from modification performance to simulator update. The licensee's mechanism for handling the updating of the simulator is detailed paragraph 10.3.

(3) ECA 0.0, paragraph 8.b, states that 480 volt switchgear and cabling should be available. If the switchgear is not available, then the procedure requires operation from the safe shutdown panel per A-27.1.9. Operation of valves from the control room is not possible if 480 volt switchgear is not available. Power is assumed to be available from Unit 1 which bypasses Unit 2 switchgear.

The inspector noted that procedure A-27.1.9 assumes some AC power available for plant operation and does not take into consideration a complete station blackout. EOPs, on the other hand, provide procedures for stabilizing the plant from the control room during a total blackout. The licensee's procedure and equipment kit which is taken to the alternate safe shutdown panel does not contain any EOPs.

The inspector observed that procedures for a total blackout should also be available for operation at the primary side alternate shutdown panel. The licensee stated that the EOPs were written for control room use only and were not suited for operation elsewhere in the plant. Subsequently, the licensee stated that they will revise A-27.1.9 to include the alternate shutdown panel during a total blackout. The inspector had no additional questions.

7.2 Recovery of Onsite Power And Operation of Gas Turbines

Scope

As a backup source of electrical power IP-2 has three gas powered turbine generators (GTs). Two GTs (2 & 3) are located approximately one mile off site and one GT (GT-1) is located in the plant. Although the Technical Specification requires one gas turbine to be operable, the GTs are not considered to be safety related and are not constructed to Class 1E Criteria. The GTs are recognized by the EOPs as source of backup AC power should other sources of offsite power be lost and none of the diesel generators are able to supply the 480 volt emergency busses (total station blackout).

A purpose of this inspection was to determine the availability of the GTs (in the event of the station blackout) and procedures which exist for operation of the GTs. In both the FSAR and in a response to NRC order dated February 22, 1986, the licensee stated that all GTs have "black start capability" (i.e. the ability to start and come on line without any external power).

In addition to a review of procedures and the ability to recover AC power, the inspector performed a walkthrough of the licensee's ability to start each GT remotely from the control room. Each GT can be started from the control room; and GTs 2 and 3 will automatically synchronize to its bus. During this inspection GT-3 was undergoing repair and was considered inoperable. GT-2 was actually started to check (1) its ability to operate, (2) the ability of NPOs to operate the GT, (3) the ability of onsite personnel to reach the GTs in a timely manner, and (4) the ability of GT-2 to black start.

Criteria

Emergency operating procedures for loss of AC power are not specific about the restoration of AC power. They assume the diesel generators (at least) will automatically start and synchronize to the 480 volt emergency busses or other sources of power will be restored to the plant through normal breaker operation. Use of the GTs for power restoration is considered a backup method for restoring power. The following licensee procedures which refer to, or operate, the GTs were reviewed:

- ECA-0.0, Loss of All Power, Revision 0
- SOP-31.1.1, Gas Turbine #1 Operating Procedure - Remote, Revision 0, July 17, 1986
- SOP-31.1.2, Gas Turbine #1 Operating Procedure - Local, Revision D, September 16, 1985
- SOP-31.2, Black Start of Gas Turbine 1 or 3, Revision 1, July 17, 1986
- SOP-31.2.1, Gas Turbine #2 Operating Procedure - Remote, Revision 0, July 17, 1986
- SOP-31.3.1, Gas Turbine #3 Operating Procedure - Remote, Revision 0, July 17, 1986
- SOP-31.3.2, Gas Turbine #3 Operating Procedure - Local, Revision 0, July 17, 1986
- TOI-78, Gas Turbine #2 Operating Procedure - Local, Revision 0, July 21, 1986.

Operation of GTs was reviewed to the following criteria:

- Emergency operating procedures consider the GTs
- Operating procedures are available for all GTs
- NPOs were knowledgeable in the operation of GTs
- GTs had black start capability, and
- GTs could be started from the control room.

Findings

(1) The inspectors accompanied an NPO from the plant protected area to GT-2 (approximately one mile away) to determine the time in which GT-2 could be reached. Normally, an operations vehicle would be used to reach the GTs with the roving security patrol serving as backup transportation. The inspector rode to GT-2 and 3 area in a security vehicle to test the ability to reach the gas turbines and unlock the area in a timely manner.

Using procedure TOI-78, the NPO started GT-2 in a normal manner. After the start command, the computer control panel automatically starts GT-2 and brings it on line. The total time to start-up, synchronize to the grid, and reach 20 MW power is approximately 20 minutes. During the startup, the operator tried to adjust reactive load (VARs) to that specified by the procedure and the GT generator tripped. The NPO was unable to restart the generator and was aided by a mechanical foreman responsible for GT maintenance, who was present at the time. The GT was eventually brought on line up to 20 MW power.

The licensee stated that the reason for the trip was that the NPO tried to adjust the reactive load too quickly without giving the turbine controls sufficient time to respond. The operating procedure was to be revised to clarify this. The licensee further noted that although all NPOs received training on GT operation, they were operated too infrequently to receive a high degree of practical experience. Although this problem did occur, NPO training and the operating procedure appeared to be sufficiently adequate for the backup status expected from the GTs.

(2) The inspector requested that the black start capability of GT-2 be demonstrated, since it does not have its own black start diesel generator as do GT-1 and GT-3. In a blackout situation GT-2 fuel oil and lube oil pumps run on DC power until GT-2 is started and capable of supplying its own auxiliaries with AC power. During this demonstration an intermittent computer fault alarm was present in the GT control circuit.

The licensee isolated AC power from the GT and attempted a blackstart. The fault apparently became worse from a DC power source and prevented GT-2 from completing its start sequence. The GT then was successfully started on AC power. A second blackstart was unsuccessful and a second attempt to start the machine with AC power was also unsuccessful. After this demonstration, the inspectors questioned the operability of GT-2.

The licensee stated later in the day that they were able to successfully start the machine in normal mode and in blackstart. The licensee further stated they considered GT-2 operable and that blackstart capability was not part of the operability consideration.

Although the machine did not black start in the presence of the inspector, both the lube oil and fuel oil pumps did start on DC power. In addition, GT-2 logs were shown to the inspector where blackstarts were done on January 18 and February 8, 1984.

Since blackstart capability was not satisfactorily demonstrated to the inspector, the ability of the licensee to blackstart GT-2 could not be verified. Although the licensee provided records of previous black starts and they stated that GT-2 was black started later in the day of the demonstration, the ability of GT-2 to reliably black start is unresolved pending licensee's repair of the computer fault and demonstration of the ability of GT-2 to start in a reliable manner (50-247/86-19-09).

(3) While procedure SOP 31.2 was established for black starting GTs 1 and 3, there appeared to be no procedure for black starting GT-2. The licensee stated that since the GT-2 had no blackstart diesel, the normal start procedure TOI-78 will also blackstart the GT. The unsuccessful demonstration witnessed by the inspector, did not confirm this. The licensee stated that TOI-78 or SOP 31.2.2 (to be issued in the future as a permanent procedure for GT-2 operation) will be revised to specifically address applicability for blackstart.

EOP ECA 0.0, alternate step 6.b addresses placing a GT in service as a backup source of AC power and the black start of GT-1 or remote start of GT-2 or 3; but it does not specifically state that GT-2 or 3 can be blackstarted. In addition, EIA 0.0 refers to SOP 31.1 for normal operation of GTs 1, 2 and 3. SOP 31.1 has been deleted and other SOPs have been issued for operation of the GTs. The licensee stated that ECA 0.0 would be revised to refer to the correct SOPs and to refer to blackstart capability of GTs 2 and 3.

The inspector had no further questions.

8.0 Severe Weather; Hurricane and Tornado Alerts

Scope and Criteria

The IPPSS results indicate that loss of offsite power or failure of safety related structures and equipment due to high winds are initiators for a number of dominant accident sequences. Thus the level of station preparation when high winds are predicted was the subject of inspection. For this reason the hurricane alert procedure, Abnormal Operating Instruction 40.3, Rev. 1, and the Tornado Emergency procedure, IP-1032, dated March 26, 1985 were reviewed. In addition, plant logs for September 26-27, 1985 (when hurricane Gloria passed through) were reviewed and the involved personnel were interviewed.

Regulatory Guide 1.33, Appendix A, requires that written procedures be provided for combating emergencies caused by acts of nature such as tornadoes, floods and earthquakes. In addition, Technical Specification sections 3.14 and 4.17 require that the plant be shut down upon approach of a hurricane. Licensee procedures were reviewed to ensure as a minimum that they met the above requirements.

Findings

Written procedures for high wind emergencies are limited to the "Hurricane Alert" (AOI 40.3, Rev. 1) and the "Tornado Emergency" (IP-1032, Rev. 3/26/85). These procedures provide very little formal guidance as to the detailed preparatory activities to be taken when high winds are predicted. The Hurricane Alert focuses on satisfying the Technical Specification requirement of reactor shutdown, cooldown, and subsequent notification prior to hurricane passage. The Tornado Emergency establishes a tornado watch and provides some indication of other preparations, e.g., "advise the System Operator that you are going to start a gas turbine generator" and, "order all fuel handling operations halted."

In contrast to the above documents, the actual activities conducted during Gloria showed extensive preparation by the station's staff. Table 8-1 summarizes some of the preparations actually taken for the storm.

Appropriate severe weather preparations may not be considered or carried out, unless sufficient preplanning and guidance (such as procedures) are in effect, especially with events having limited warning times e.g., tornadoes, ice storms.

In view of the above general concern, the following specific finding is made concerning the anticipation of a station electrical blackout. The Hurricane Alert Procedure A40.3, Rev. 1, provides the following caution: "Anticipate potential for blackout." Aside from this vague caution, no detailed actions for blackout preparation are specified. Questions as to what constitutes optimum preparation concerning electrical power supply configuration were raised with the licensee. The inspector discussed this with utility personnel, especially the importance of any significant procedures, e.g., starting gas turbines, being reviewed by the Station Nuclear Safety Committee. The licensee acknowledged the inspector's concerns and indicated that the severe weather procedures would be reviewed and augmented by issuance of an administrative directive based, inpart, on the Hurricane Gloria experience. The inspector had no further questions in this area.

TABLE 8-1

ACTIVITIES CONSIDERED OR COMPLETED BY INDIAN POINT #2 STATION STAFF IN PREPARATION FOR HURRICANE GLORIA

Staffing

- Double Watch Coverage
- Expanded Support Staff
- Additional Food and Cafeteria Service
- Review All Appropriate Plant Procedures
- Check Communication Links

Blackout Preparation

- Shutdown and Cooldown Reactor
- Check Diesel Fuel Tanks
- Top Off GT 1 Tank
- Security to be Contacted to Access Diesels via PAB
- Check Crosstie with Unit 3 Diesels

Flood Preparation

- Sandbag: Transformer yard
480V Switchgear
15' PAB-RHR Pumps
Aux FW Pump
- Floor drains plugged
- All SW Pumps available and lined up
- Sump pumps for: 15' PAB
5' Turbine Plug
SWN 1111 & 1112 PIT
SW PIT

High Wind Preparation

- Remove: Ecolochem Truck
Hydrogen Truck
- Roof Hatches check and secured including CCW pump hatches
- Remove or tiedown all loose material; gas cylinders
- Place trucks against loading well doors
- Secure Gantry Crane Hooks and chock down
- Remove garbage dumpsters
- Fuel all vehicles

9.0 Administrative and Management Controls

9.1 Housekeeping

During routine tours of various plant areas, the inspectors noted that housekeeping conditions and plant cleanliness were generally satisfactory. However, two discrepancies that affected safety-related components and systems were identified.

In containment, in the vicinity of the recirculation pump sump, the inspector found two large plastic bags, containing a quantity of tygon tubing. This debris had the potential to foul the sump and the intake to the containment recirculation pumps which might have caused degradation of core cooling under post-accident conditions. This debris was promptly removed by the licensee (see paragraph 4.8 for further details).

In the Primary Auxiliary Building (PAB), on the level above the Safety Injection pumps and piping, the inspector found 16 unsecured and uncapped gas bottles containing compressed nitrogen and hydrogen. These bottles had the potential to damage and degrade operation of the Safety Injection pumps and piping. This condition was also promptly corrected by the licensee. These two conditions are examples of a violation of the requirements of Station Administrative Order No. 218, Rev. 0 (50-247/86-19-10).

The inspectors identified other housekeeping deficiencies for which corrective action was also initiated by the licensee:

NOTE: Items marked with an asterisk are further examples of violation 50-247/86-19-10.

*o Oil on floor of Cable Spreading Room.

*o Oil spill on the floor of the Emergency Diesel Generator Room.

o Two covers for the Emergency Diesel Generator Fuel tanks' level switches were not in place.

o Heavy dust accumulated on top of the 6.9 KV switchboard.

o Vegetation growth on the air intake to the Emergency Diesel Generator room with the potential to block the intake.

o Pipe support U-bolt missing nuts on a fuel tank overflow line in the DG room.

*o Plastic bags, rags, tools and debris inside the Fuel Handling Building and outside the No. 2 Fire House.

o A light fixture on the stairway to SI pump room broken; wiring exposed.

- o About one inch of standing water in the hallway leading from the radiological control access point to the PAB during and after rainstorms.

- *o Gantry crane (2-ton) and wheeled instrument tables not properly secured in the Cable Spreading Room, and

- *o Four wheeled instrument tables in the 480 volt switchgear room not properly secured.

Given these deficiencies, the inspectors concluded that, despite recent improvements in housekeeping conditions and plant cleanliness, additional attention in implementing the provisions of Station Administrative Order No. 218, Rev. 0, "Housekeeping Policy" was warranted.

9.2 Technical Staff and Organization Changes

In order to consolidate the technical capabilities, some of the corporate and site organizations have been combined with the site technical support group and moved to the plant. Nuclear Engineering is merging with the site technical support group under one general manager, and certain QA/QC groups were already moved to the Indian Point site. These changes are effective August 1, 1986, and by then, the Nuclear Engineering Department is to be physically relocated from the corporate headquaters. With this change, the licensing organization from headquarters would combine with the site licensing under one management. Furthermore, the site technical support group will have additional technical capability to deal with the issues directly, such as engineering analysis, fuel analyses, radiological and safety analyses, and PRA insights.

These changes appear to be a positive move to increase the plant capability and efficiency in technical and administrative areas, since the plant will have direct access to the diagonistic and analytical capabilities. The inspector noted that this change appears to be a good management initiative which may contribute to the enhancement of plant safety.

9.3 Management Controls and Quality Assurance

Station Administrative Order No. 218, Rev. 0, "Housekeeping Policy," prescribed plant practices and controls for maintaining cleanliness and for preventing accidents, fires and contamination. The Station Order, as written, appeared adequate to the task of maintaining proper plant housekeeping conditions and cleanliness.

The Order assigned responsibility for housekeeping in every area of the plant to a general manager. The inspector noted that the name of the person responsible for cleanliness in most rooms and areas was properly posted. In addition, the Order provided an inspection checklist and required inspection reports weekly during an outage and biweekly during normal operations. Interviews and record reviews revealed that these requirements were being followed.

The Order likewise required QA/QC inspections and reports on satisfactory and adverse conditions. The inspector determined that QA/QC personnel were making the required inspections using acceptable surveillance guidelines. However, follow-up and corrective action on housekeeping deficiencies appeared weak. An example was Surveillance Report No. 86-SR-198, performed on 2/14/86. This report identified a hazardous condition in containment (gas bottles unsecured) which was not corrected on the spot and which did not result in an open item report, deficiency report or other long term corrective action.

The problem was not assigned to a plant manager for correction and no group considered itself responsible. This failure to assign responsibility for a hazardous condition within containment may also be related to the unsecured gas bottles violation described in paragraph 9.1 above.

The program for housekeeping and cleanliness appeared to be satisfactorily established. However, the inspector considers that the implementation of the program was weak as evidenced by the housekeeping deficiencies described in Section 9.1.

10.0 Modifications

Administrative control of all modifications is delineated in Item IX, Section 3.0, of QA document, "Quality Assurance Program for Operation Nuclear Plants."

Station Administrative Order (SAO) No. 405, "Modifications to Indian Point Facilities," Revision 1, provides a specific procedure and modification program of all physical changes to plant structures, systems, or components, either permanent or temporary. The procedure assigns responsibilities and administrative controls of modifications, including initiation, review, tracking, installation, completion, and change to associated procedures and drawings. A modification form in SAO 405 tracks down details of the modification activities. Administrative Directive No. OAD-17, "Plant Modifications Procedures," Revision 0, establishes a policy for changes to operation procedures and control room drawings. Maintenance Administrative Directive (MAD) No. 4, "Procedure for Performing Maintenance," Revision 8, establishes guidelines for maintenance procedures associated with plant modifications, and physical changes are implemented using maintenance work orders.

10.1 Administrative Controls

A written request of a facility modification can be initiated in the form of a Field Engineering Request (FER). Subsequent reviews may result in an Engineering Service Request (ESR) from field engineering, who may provide Modification Procedure (MP) with a modification project number assigned to the procedure. The MP package includes engineering and safety evaluations, bases, and details of modifications. To implement the modification physically, either electrical or mechanical work orders have to be issued, depending on the nature of the changes. Upon completion of the modification, the work order packages have to be reviewed in conjunction with the MP packages, and related documents (drawings, procedures and tags, etc.) have to be updated and reviewed.

For a given single modification, there may be a MP package, an electrical work order package, a mechanical work order package, and an I&C package in order to complete the modification.

To track down such activities and post-modification updates of procedure/drawings and reviews, a project coordinator assigned to the modification is responsible to follow the progress using a SAO 405 Modification Tracking Form. Furthermore, status of the Work Orders can be checked instantly from the online computer system which was implemented in 1985. However, pre-1985 PM work orders were not updated into the computer system, and the tracking has to be followed manually and can be a time consuming process. Because of the various work to be done by different departments, final disposition of the modification could take a long time, particularly to update the changes in the procedures and drawings. The inspector was informed that such delays were common for those pre-1984 modifications, and that the licensee is in the process of updating computer data banks.

10.2 Review of Specific Modifications

The following modifications were reviewed:

(1) Reactor Vessel Level Instrumentation System (RVLIS) Transmitters (MP Nos. EGP-85-15743-11 & MPC-84-15743-11)

As per NUREG-0737 requirements, RVLIS level transmitters, LT-1311, -1312, -1321 and -1322, were replaced with transmitters which are qualified for both high radiation and seismic events; and the modifications were completed during the 1986 refueling outage.

The existing ITT Barton Model 752 differential pressure transmitters were removed from PAB, Elevation 51', and Model 1154 Rosemont transmitters were installed. Post-maintenance continuity checks and calibration checks were performed, and no unacceptable conditions were identified.

(2) RPC Seal Check Valves (MP No. MMT-81-21-03)

Check valves 4148, 4149, 4150 and 4151, were installed on the RCP seal leakoff No. 17 line for RCP 21, 22, 23 and 24 respectively. The new check valves will prevent backflow of seal leakoff water when the reactor coolant system pressure is low, and eliminate the possibility of contaminatng the seals which could cause premature failure. The inspector verified by review of drawing 9321-F-2720-45 that the modification was reflected on the controlled copy of the drawings.

(3) Motor Control Center #24 (MP No. CPG-81-2-13)

Security fence and 8 foot walls were installed around MCC #24 to provide a fire protection and secure the area, which houses instrumentation for actuation of the emergency diesel generator. No unacceptable items were identified.

(4) Boron Injection Tank (BIT) Removal (MP Nos. MPE-85-50714 & EPG-25876

The physical isolation and removal under MP specifications were not completed. However, to reflect the changes in technical specifications the BIT was valved out and isolated using Temporary Operating Instructions (TOIs) #67 and #68 in January, 1986. Valves were closed, breakers were deenergized, and the tank was drained. Surveillance and calibration procedures were reviewed and either revised or deleted to reflect the changes. The control room alarms except one were deenergized using jumper wires, as discussed in the following findings:

- Procedure OTI-68 made an error by omission. The alarm window 3-7, "BORON TANK LOW TEMP 155" on CCR panel SBF-2 was not disabled. The licensee installed a jumper for the alarm on July 28, 1986.

- Under TOIs 67 and 68, the BIT was removed from service and the associated MOV breakers were deenergized. However, there were no tags on the CCR and local breaker panels indicating the removal. A black sign, "BIT RETIRED" was installed on panel SB-2 in the CCR, and similar tags with a warning note were also installed on MCCs 26A (MOV 1821) and 26B (MOV 1822B).

- The removal of the BIT was not reflected in the emergency operating procedures. This item is an example of violation, which is addressed in paragraph 4.1.

(5) Structural Modifications for Seismic Events (MP Nos. CPG 82-10429 -00 and CPG 81-2-10)

As per NRC I&E Bulletin 80-11, various masonry walls were reinforced. For seismic considerations rubber pads at elevation 72' of the control building were installed. These pads would correct a problem associated with transmitting seismic impact forces between the unit 2 control building and the unit 1 superheater/generator building. The inspector toured the selected areas to inspect the workmanship and "As Built" conditions. The areas inspected included:

- The pads on the control building roof.
- Reinforced brackets in Unit 1 MG set room and Battery Rooms 1 & 2, Elevation 33'.
- Reinforced brackets by the elevator shaft at Elevation 15'.
- Reinforced brackets in 480 V switchgear room, Fuel Handling Building, and Unit 2 Battery Room.
- Masonry walls in the Fan House at Elevations 101' and 102' columns.

No unacceptable conditions were identified.

10.3 <u>Update of the Control Room Training Simulator</u>

<u>Scope and Acceptance Criteria</u>

During the simulation of loss of offsite power events and emergency procedure walkthroughs with operators, the inspector noted that the simulator did not respond in the same manner as the plant for the power supplies to two circwater pumps. A review of the licensee's process for updating the simulator was performed to determine whether the licensee's program for modifications involved the simulator.

<u>Findings</u>

The licensee's administrative controls for review, approval, and implementation of plant design changes includes a review for applicability to the simulator. The Training Section is also responsible for 1) training operators on plant modifications and, 2) monitoring the progress of upgrading the simulator hardware and, or software.

The licensee's Training Manager tracks the outstanding simulator service requests via a computer printout. The inspector reviewed the latest printout and noted that modifications to the circulating water pumps were being tracked for implementation. In addition, the training department provides the operators with a list of "differences" between the simulator and the plant for use in specific requalification training lesson plans. The inspector noted that Lesson No. SES-S-001, reactor startup to the point of adding heat (draft dated July 16, 1986), included the difference between the simulator losing pumps 25 and 26 and the plant losing pumps 22 and 26 upon loss of the 6.9 KV busses 5 and 6.

The inspector noted that, as a method of quality control, the Training Manager was limiting the number of computer software changes with each re-load of the simulator. The licensee stated that although this limited the pace of upgrading the simulator, it helped control the accuracy of the software. Future plans include changing machine language and providing the capability to upgrade the simulator (based on plant modifications) much quicker.

The inspector had no further questions. No violations were identified.

11.0 Residual Heat Removal Pressure Isolation Valves (Event V)

Scope

The IPPSS evaluated a number of event sequences. An Event V sequence involves the failure of pressure isolation valves that result in reactor coolant overpressurizing and rupturing a low pressure Emergency Core Cooling System (ECCS). The loss of the system in combination with a LOCA outside containment can ultimately result in a core melt accident that bypasses containment. The IPPSS calculations indicate that Event V sequences have low probabilities but, because they bypass containment, may result in high offsite consequences. As a result, the Event V sequences are ranked as important risk contributors.

The interfaces that dominated the Event V risk involved RHR Valves 730 and 731, which are series valves in the supply piping form the loop 2 hot leg to the RHR pumps. They are normally closed MOVs that isolate the high pressure reactor coolant from the low pressure RHR piping during power operation. At shutdown they are opened to permit the use of the RHR heat exchanger as the heat sink for decay heat removal.

The operation, surveillance testing, and maintenance of these valves was reviewed to assure that reasonable precautions are in place that assure the valves are functionally closed and remain closed during power operation (i.e., reactor pressure greater than the design pressure of the RHR piping and components).

Acceptance Criteria

FSAR Section 9.3-6 states that:

"Remotely operated double valving is provided to isolate the residual heat removal loop from the Reactor Coolant System. When Reactor Coolant System pressure exceeds the design pressure of the residual heat removal loop, interlocks between the Reactor Coolant Systems wide range pressure channels and the RHR inlet valves prevent the valves from opening."

Valve integrity and operability are tested at cold shutdown in accordance with the ASME Boiler and Pressure Vessel Code, Section XI, 1980 Edition.

The Technical Specifications require leak testing of all check valves identified as Event V pressure isolation valves. Valves 730 and 731 (which are MOVs) are not included in the Technical Specifications even though they function as RHR pressure isolation valves. The Technical Specifications do not require that the pressure permissives be tested, though the licensee does conduct certain tests for this purpose.

Findings

(1) Integrity of Valves 730 and 731

Procedure PT-R53, Revision 3, approved January 1986, "RHR Valves 730, 731 Integrity" test, was reviewed for adequacy; applicable test data from September 1982 to present was also reviewed. The procedure was judged to adequately measure valve leakage. Minor deficiencies in the procedure were noted and communicated to the licensee who stated that these defects will be corrected in the next revision. The test data indicated that both valves have remained essentially leaktight during the period investigated.

The inspector made a containment entry and conducted a visual inspection of Valve 731 and its supports. No deficiencies were noted.

A review of maintenance requests issued since 1982 was conducted. Preventive maintenance on the valve operator was performed in July 1984. No corrective maintenance on the valves has been performed during the period investigated. Maintenance Request No. 86-25897, originated on 3/5/86, indicated a potential torque or limit switch problem preventing closure of Valve 731. However, this request was cancelled on 5/19/86 based on amp meter testing during which the closure fault could not be duplicated.

The inspector reviewed the valve design information. Both are 14-inch Copes-Vulcan motor-operated gate valves rated at 2500 psig and 650°F. The valves utilize a split disc design with stellite seating surfaces. Full operating pressure is applied to the downstream split disc enhancing the effective leaktightness of the design. The valve internals have not been visually inspected during the period of investigation, but seat leak testing has been performed.

In light of the above review, the inspector noted that the integrity of the valves appeared acceptable. They have experienced no leakage to date, and are operated only a few times during each refueling outage so that no major integrity problems should be expected.

(2) Assurance of Closure at Startup

The dates of the integrity test previously discussed and the major outage periods indicate that valves 730 and 731 are leak tested as the plant is coming down in pressure at the start of a refueling outage. Thus the valves are tested in the as-found condition. Valve 730 is not moved prior to the integrity tests. After the test and during the refueling outage, both valves are opened and closed several times. All valve operability testing is also performed during the outage. At startup there is no verification that the valves will be properly closed and seated except for the limit switch lights in the control room. A limit switch, torque switch or other motor-operated malfunction of one valve may thus go undetected until the next outage period.

This concern was brought to the licensee's attention and methods to improve confidence of valve closure were discussed. The licensee proposed to perform a verification during plant startup that will accurately measure valve stem travel to provide the additional assurance that no gross motor-operator malfunction had occurred during the refueling outage. The inspector concluded that this was acceptable.

The potential for the operator failing to close the valves during startup was also reviewed. Plant Operating Procedure 1.1, Procedure Check Off-2, and System Operating Procedure 4.2 (with associated check off list) were reviewed to assure adequacy. Data sheets from the last ten startups were also reviewed and operating personnel were interviewed to determine that the procedures were understood and correctly followed.

It was determined that adequate independent verification existed to assure that the valves were closed and properly deenergized as per Check Off List 4.2, Rev. 1. The inspector visually determined that the breakers for 730 and 741 were opened and locked as required.

After the valves are deenergized per SOP 4.2.1, the limit switch lights in the control room go out so that valve position indication is lost to the control room. Later in the startup the operators are required to fill out Procedure Check Off-2 (PCO-2), Rev. 4. This check off requires that 730 and 731 be checked "closed" and "Deenergized and Locked at MCC." The licensee was questioned as to what steps must be taken to satisfy this check off. Several operating staff members believed that the valves must first be re-energized and the limit switch lights observed to check off the "Closed" entry in PCO-2.

Based on subsequent discussions with Generation Support personnel, it was determined that re-energization of the breakers is not required and that a review of previous system check-offs is adequate to document valve closure. The licensee indicated that re-energization of the valve motor did not appear appropriate for routine position checks and was made aware of the apparent misinterpretation of PCO-2 by some operators. The licensee further stated that operators will be made aware of the correct steps to take in satisfying PCO-2 and that, once deenergized, the valves should remain deenergized.

(3) Assurance that Valves Remain Closed

In the opening portion of the control circuit of both 730 and 731 are contacts of a relay that remain open when reactor pressure is greater than 450 psig. This prevents the valves from being inadvertently opened when reactor pressure is high. The inspector reviewed the calibration procedure and data for the pressure permissive instruments. ICPM-59 calibrates the pressure transmitter, and the bistable that trips at 450 psig. Further review and indicated that the relay in the valves' open circuit (which is energized by the bistable) is not adequately tested. Thus the relay could be failed closed and the I&C calibration or valve operability tests would not uncover the fault. This defect in the pressure permissive testing was discussed with the licensee. The licensee has committed to testing the relay during refueling outages by simulating high and low reactor pressures and commanding the valve to open, thus testing the entire permissive circuit. A surveillance procedure for this new test is planned to be completed for use during the next refueling outage. This item is unresolved pending completion of licensee action and subsequent NRC:RI review (50-247/86-19-11).

The possibility of inadvertent re-energization of the valves was reviewed. The valves' breakers are locked in the open position. However, the breakers were not included on the "Locked Safeguards Valves" Check Off List 10.0, Rev. 1, which provides a monthly check on all vital locked valves and breakers. The licensee plans to include this in Revision 2 of COL 10.0 to be issued by September 30, 1986.

Emergency procedures require that Valves 730 and 731 be re-energized in preparation for cooldown. The procedures require an operator to open all breakers at the applicable MCCs. Thus valves 730 and 731 may be re-energized while the reactor is at high pressure. This was done to anticipate the need to remove core decay heat during rare emergencies. The inspector observed that these actions would not significantly increase the risk of overpressurization because they would be rarely executed, and had no further questions at this time.

12. Licensee Actions Regarding PRA Applications

A meeting was held on July 23, 2986, between members of the inspection team and the licensee's Nuclear Engineering staff. The purpose was to provide NRC with the licensee's current status of PRA activities. Past efforts have focused mainly on licensing issues with the PRA staff responding mainly to corporate headquarters concerns. However, recent changes have been made, notably the relocation of the PRA staff to the plant site. The inspection team noted that this relocation should benefit plant reliability and safety in the future.

12.1 <u>Past Licensing Applications and Plant Modifications</u>

The IPPSS was placed in historic perspective. Two prior studies were discussed: (1) the NRC sponsored Indian Point site hazards evaluation in which the Reactor Safety Study's PWR (Surry) offsite consequence analysis was recalculated using the Indian Point population distribution (1980) and (2) the Con. Edison sponsored 6-month PRA study (evaluating internal events only) done with the help of Westinghouse (1981). After these studies, Indian Point 2 and 3 contacted the consulting company of Pickard, Lowe and Garrick, Inc. to produce the IPPSS including external events such as fire, flood, wind, and earthquake (the report was issued March 1982). A peer review of the IPPSS was conducted by Sandia Laboratories for the NRC and was reported in NUREG/CR-2934 (December 1982). Based on these comments a second amendment was issued in January 1983.

The primary objective of the IPPSS was to provide a high quality assessment of public risk resulting from the operation of the Indian Point plants. However, another outgrowth of the efforts was a number of improvements in operating procedures, surveillance testing and design. Upgrades in seismic and fire resistance were carried out along with reliability improvements regarding pressure isolation valves, service water, diesels, fan coolers, and station batteries.

12.2 <u>Development of a Living PRA Capability</u>

The licensee has retained a PRA staff cognizant of the IPPSS results and methodology. Currently this staff is concentrating on developing its inhouse capabilities to keep the PRA updated as follows:

- <u>Development of the RISKMAN Computer Model</u>

  With the aid of a consultant, the PRA staff plans to have available, by 1987, a computer based logic model of the IPPSS plant design. The staff will be capable of adjusting the model to test proposed modifications or to permanently update the model as modifications are completed.

- <u>Update RISKMAN to Current Plant Design</u>

  Once the IPPSS base case is completed, the PRA staff plans to update the model and maintain it based on the as-built IP #2 plant.

- <u>Update Reliability Data Base</u>

  The initiating event frequencies and component failure probabilities are planned to be reviewed and updated based on current

Indian Point and generic experience. The model will provide the updated core-melt and offsite consequences in terms of accident sequences and will also provide system and component importances based on their contribution to core-melt or risk. The result is expected to be a living plant reliability model with a spectrum of results useful for many applications.

12.3 PRA Staff Relocation and Future PRA Applications

The licensee's PRA staff is in the process of relocating to the IP #2 station. This relocation is planned to allow the staff to effectively assist the plant personnel in the following tentative general areas:

- Development of a "living schedule" for major activities and modifications.
- Assist the safety review committee by providing an additional safety review of activities and modifications.
- Provide PRA insights into the station training programs.
- Assist in Emergency Planning.
- Revising Technical Specifications (in cooperation with Westinghouse generic activities).
- Monitor station operating experience to help identify safety problems in a timely manner.
- Monitor the Reliability Centered Maintenance Program and provide risk based information.
- Assist QA in inspection priorities and,
- Identification of equipment for which maintenance outage times require close control.

12.4 Findings

The inspection team determined by means of interviews with station staff, e.g., maintenance and QA managers, and the examination of documents that the IPPSS has had no major impact on the maintenance or QA/QC programs. It appears, however, that in the future these departments may be influenced by the presence of the PRA staff onsite. In general, it appears that the licensee's planned PRA initiatives should have a positive influence on plant reliability and safety.

13. Human Factors

13.1 Manual Reset of Motor Control Centers (MCCs)

The 480 volt switchgear room is located on the 15' Elevation in the Turbine Building, and houses more than forty (40) 480 volt breakers. Each breaker is located in a separate compartment, and its position is displayed on the cover panel with a green or red position indication. The breaker identification tag and compartment number are also displayed on the panel. The reset/trip switches are on the breaker cover panel for those MCC feeder breakers and lighting breakers which have to be reset manually upon loss of bus power.

When AC power is lost, the emergency lighting powered by batteries provides the lighting for the access key-card door and the breaker cabinets. However, to provide additional assistance for the Nuclear Plant Operator (NPO) who would be resetting the lighting and MC breakers upon loss of power, reflector tapes were provided for each reset switch on the breaker cover panels. The breakers which have to be reset manually include:

- MCCs 21, 22, 23, 24, 25, 27, 28, 29 (28A is a backup for 28), 210 and 211.
- Lighting transformer breakers 21, 22, 23, and 21 (emergency).

The inspector noted that each unit NPO and one roving NPO are normally stationed in the NPO room located at 15' Elevation in the Turbine Building and have access keys to the equipment rooms.

The inspector simulated an event with two separate NPOs, and asked them how they would open the 480 volt switchgear room, assuming that the security key-card computer also lost its power upon loss of station AC power, and that "the lighting and MCCs" have to be reset manually. The NPOs did not have any problem resetting those breakers with the reflector tapes but missed MCC 211 feed breaker. The inspector also noted that the NPO had to find a 480 volt room key from a bundle of more than thirty keys, and that hand-held emergency lights were stored, not in the NPO station at Elevation 15', but in the emergency fire locker located 37' Elevation in Turbine Building.

Reflector tape was provided on all breakers except for MCC 211 feeder breaker on compartment #12C. The licensee stated that reflector tape would be provided for the MCC feed breaker reset/trip switch. The inspector determined that this was acceptable and had no further questions.

13.2 Equipment Identification

Scope

The inspectors observed identification of plant components, such as valves and switches, during various plant tours and procedural walkthroughs. The intent was to assess the impact on correct and timely operator action, during a postulated event and, or during normal plant operation.

Findings

The following are some examples of equipment identification deficiencies noted by the inspectors:

- Recirculation switches 6 and 7 in the main control room are used to switch either to low head or high head recirculation mode. The switches were labeled using a 150 PSI plant pressure criterion to determine which switch to use. However, emergency procedure ES-1.3 specifies an injection flow criteria to be used to determine which switch should be turned. After questioning by the inspector, the licensee removed the (possibly misleading) label.

- RHR MOV-744, the RHR pump discharge valve, was not identified and the RHR Pump suction valve RHR MOV-882 was identified with a piece of tape. Both valves were given temporary metal identification tags.

- MOV breakers at MCCs 26A and 26B had been identified with large labels to aid the operator. Many of the large labels were missing although all breakers were still identified with other small labels.

- The mechanical valve position indication on MOVs 1176 and 1176A in the diesel generator room were painted over. Local red and green valve position lights were available. The mechanical position indication was corrected prior to the end of this inspection.

- Mechanical valve position for the containment spray pump test line valve, 1813 was painted over.

- City water valve FCV-1205A, used as an emergency water source, was not identified.

- Breaker SWN 41-1B at MCC-26BB had two labels one of which was incorrect. The incorrect label was removed by the licensee.

- Labels for service water pump motor circuit breakers on MCCs 26AA and 26BB had fallen off. These were replaced by the licensee.

The licensee is currently in the process of upgrading the identification of plant equipment and stated that valve labeling is planned to be complete by March 1, 1987.

No violations were identified. The inspector had no further questions at this time.

13.3 Access To Equipment

(1) Walkthroughs of the Primary Auxiliary Building (PABs) and the non-nuclear plant indicated that access to equipment was good. Both nuclear and non-nuclear plant operators had keys which would admit them to safety equipment should the security key card computer fail. Nuclear side NPOs had keys which would admit them to high radiation areas. Additionally, nuclear side NPOs are allowed to remain in their anti-contamination suiting for ready access to equipment. This could help minimize the time to get to equipment in an emergency. As noted in paragraph 7.3, the roving security guard as well as the NPOs had the access keys to the gas turbine 2 and 3 areas.

NPOs were requested to unlock valves or motor control center breakers which were locked with a padlock and chain. In each instance, the NPO was able to produce the key and unlock the padlock. All valves sampled during this inspection (with the exception of the RHR pump suction MOV-882) were reachable by ordinary means. MOV-882 is in the overhead external to the RHR pump room and is normally inaccessible. However, a wooden step ladder is permanently maintained in the area to reach overhead valves.

It appeared that most areas in the plant are easy for an operator to transition from one area to another to operate equipment.

(2) During plant walkthroughs of emergency operating procedures, the inspector examined the NPOs ability to operate equipment locally in the plant as previously discussed in section 4. In some instances, breakers in the 480 volt switchgear room must be operated by hand using detachable hand tools which are mounted on a board in the room.

When questioned as to what actions would be taken should tools be missing, the NPO stated that backup tools were maintained in the senior watch supervisors safe near the control room. The senior watch supervisor on shift at the time also stated this. However, inspection of the safe revealed that the tools were no longer there. The backup tools were eventually located.

Although they are not required, the licensee thought these tools were important enough to be maintained and stated that the backup tools were placed in the safe.

13.4 Shift Staffing

Scope and Acceptance Criteria

The inspectors performed a limited review of the performance of the operations staff in light of the licensee's recent change to standard 12-hour shifts (7 a.m.-7 p.m., 7 p.m.-7 a.m.). Observations were made of both licensed personnel on shift in the control room as well as of non-licensed nuclear plant operators throughout the station.

This review was performed to determine whether there was evidence of any adverse impact on mental alertness or attention to, or capacity for, decision making. Criteria used as guidance for length of working hours (and overtime) included NUREG/CR-0737, item I.A.1.3, NRC Generic Letter 82-12, and NUREG/CR-4248, Recommendation for NRC Policy on Shift Scheduling and Overtime at Nuclear Power Plants.

Findings

No deficiencies were noted regarding mental alertness or attention to duty. Shift schedules average about 3 days on and 3 days off. Sufficient numbers of personnel were available on each shift to assist the inspection team in performing simulated evaluations and plant walkthroughs without holding people over or calling them in from off shift.

Long term experiences with standard 12-hour shifts will continue to be evaluated during future routine inspections of the facility.

14. Follow-up NRC IE Information Notice 86-52

IE Information Notice (IN) 86-52 concerned conduction insulation degradation on Foxboro Model E controllers. The problem addressed by IN 86-52 was insulation embrittlement of the individual conductors within a controller cable set. The cable set connects the controller to the panel. The problem occurs after about 10 years of service and can cause shorts within the cable set resulting in possible unanalyzed short circuit conditions.

The licensee informed the inspector that the facility uses Foxboro Model H (not Model E) controllers and therefore the problem does not apply to Indian Point Unit 2. The inspector requested and was provided correspondence relating to this Notice. Two letters from Foxboro dated June 4, 1986 stated that the cable set problem applied only to Model E Line controllers. No others were affected. The inspector also reviewed an internal licensee memoranda (July 1, 1986) which included attached literature that showed Model E face plates to be different from Model H face plates. The inspector observed several controllers in the control room and independently verified that the controllers in use were not Model E.

The inspector further questioned the licensee concerning the cable sets in Model H controllers since they are visually similar to the Model Es. The licensee had several cable sets checked and verified that no degradation of insulation had taken place in the cable sets inspected. Licensee action is considered acceptable and this item is considered closed.

15. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable, deviations or violations. Eight unresolved items were identified during this inspection and are detailed in paragraphs 3.1(4), 3.2(1), 3.2(2), 3.3(2)(c), 3.4(2), 4.2, 7.2, and 11.0(3).

16. Management Meetings

Licensee management was informed of the scope and purpose of the inspections at an advance meeting on July 10, 1986 and at an entrance meeting conducted on July 21, 1986. The findings of the inspection were brought to the attention of licensee representatives daily and at the conclusion of inspection activities. At each daily meeting new findings were presented and interim licensee responses to previous findings were discussed.

An exit interview was conducted on August 1, 1986 (see attachment A for attendees) at which time the final findings and conclusions of the inspections were presented to licensee management. At no time during this inspection was written material concerning inspection findings presented to the licensee by the inspectors.

Attachments

A. Persons Contacted
B. Dominant Accident Sequences
C. Documents Reviewed

ATTACHMENT A

Persons Contacted

Consolidated Edison Company of New York, Inc.

*M. Selman, Vice President, Nuclear Power
*J. O'Toole, Vice President, Nuclear Engineering - Quality Assurance (QA) and Reliability
*J. Basile, General Manager, Nuclear Power Generation
*M. Lee, General Manager, Technical Support
*W. Smith, Manager, Operations
*L. Liberatori, Manager, Nuclear Safety Assessment
*R. Remshaw, Manager, Nuclear Analysis
*R. Spring, Manager, Regulatory Affairs
*F. Inzirillo, Manager, Generation Support
*B. Marguglio, Manager, Nuclear Power QA F. Phillips, Manager, Nuclear Power Quality Control
*E. Cook, Engineer, Operations Support J. Odendahl, Manager, Instrumentation and Control
J. Blake, Manager, Maintenance
T. McKenna, General Foreman, Electrical
A. Wynne, Manager, Projects and Planning
T. Adinolfi, Assistant Manager, Maintenance
*J. Quirk, Engineer, Test and Performance
J. Curry, Chief Engineer, Technical Engineering
G. Rumold, Engineer, Test and Performance
H. Zitzelberger, Engineer, Balance of Plant QA
R. Stonum, Engineer, Nuclear Operations QA H. Sager, Manager, Nuclear Power QA Engineering
*M. Casella, Senior Engineer, Nuclear
*M. Whitney, Engineer, Regulatory Affairs
*J. Goebel, Engineer, Test
*G. Hinrichs, Engineer, Technical Support
*A. Hayes, Technical Writer, Technical Support
R. Orzo, Senior Watch Supervisor
W. Carson, Engineer Test
W. Krieble, Instructor
G. Dean, Senior Reactor Operator
R. Spangerberger, Operator
R. Sutton, Engineer, Reliability Technical Support
B. Liebler, Engineer, Emergency Planning
H. Reizenstein, Senior Engineer, Reliability
D. Gaynor, Engineer, Nuclear
R. Nichols, Supervisor, Maintenance
K. Naku, Engineer, Instrumentation and Control

U.S. Nuclear Regulatory Commission

*W. Johnston, Deputy Director, Division of Reactor Safety
*L. Norrholm, Chief, Section 2B, Division of Reactor Projects
*L. Rossbach, Senior Resident Inspector

*P. Kelley, Resident Inspector

*Denotes those present at the exit meeting on August 1, 1986.

ATTACHMENT B

Dominant Accident Sequences

The Indian Point Probabilistic Safety Study (IPPSS), Amendment #2, provides summary descriptions of the twenty-four accident sequences calculated as having the highest mean core-melt frequences. Among these sequences are those that also rank highest according to early death and latent effects. Table B-1 lists the sequences and their rankings. In addition, the table lists the core-melt frequency rankings as determined by the NRC peer review of the IPPSS conducted by Sandia, NUREG/CR-2934.

For planning the inspection each sequence was studied to understand the underlying reasons for importance and to identify the root causes for the sequences going to core-melt. Once all twenty-four sequences were understood, a determination was made as to what to inspect and what not to inspect. In the case of Indian Point #2, all dominant sequences were considered with none being eliminated due to low core-melt frequency. This was possible because many of the sequences involved the same equipment failures or human errors and they could be combined for the purposes of the inspection. In addition, some sequences were eliminated or de-emphasized because they had been covered by previous inspections. The column, "Chosen For Inspection" on Table B-1 indicates those sequences fully covered, YES, or eliminated, NO. The indication PARTIAL is used in those cases when only the most important aspects of the sequence were inspected or when inspection was not warranted, e.g. a high wind or a severe seismic event causing building collapse.

The inspection centered around three basic scenarios that incorporate many characteristics of the dominant sequence. The scenarios are discussed in the balance of this attachment.

Loss of Offsite Power Scenario

Dominant sequences Nos. 4, 5, 6, 10, 12, and 16 involve a loss of offsite power. These sequences are generally characterized as follows: An initiating event causes a loss of normal power and sets the plant on a transient. The initiating event may be a severe storm that affects power lines or switchyard equipment. A number of such events have occurred at Indian Point lasting as long as 6.47 hours. Hurricanes, tornadoes, ice storms, or lightning strikes could be the cause. Other causes of power loss are possible involving plant equipment; switchyard breakers or transformers, or bus problems. Once the initiating event occurs, the emergency diesels become the next line of defense. A diesel may be out for preventive maintenance and others fail to start because of control, electrical, or mechanical failures. Common cause failures involving a single root cause may prevent several or all diesels from starting resulting in a total AC blackout. At this stage the operators must first assure the reactor core is being cooled via DC powered equipment fed by the station batteries. Once core cooling is established recovery actions must begin. Offsite power may be reestablished, a gas turbine started, or a failed diesel fixed and started. One of these recovery actions must be successful within several hours, before the batteries are discharged. The operator will be under extraordinary stress during this period and thus clear emergency procedures, good communications, and well trained personnel will be required. The simulations conducted during the inspection were designed to detect weaknesses in the procedures, training, and man-machine interfaces involved during these recovery actions.

Loss of Coolant Scenario

Dominant sequences 7, 8, and 9 are initiated by a loss-of-coolant accident with the RHR and/or SI equipment successfully operating during the injection phase of ECCS. However, the operator then fails to properly place the ECCS equipment into the recirculation mode resulting in equipment failure and core-melt. The switchover process from injection to recirculation requires the operator to take manual control; to manipulate a number of pumps and valves, monitoring plant conditions, making decisions on proper ECCS lineups, and diagnosing possible equipment malfunctions. The simulations conducted during the inspection were designed to test the procedures, operator training, and man-machine interfaces involving this switchover task.

Somewhat related to the above scenario are the sequences involving ECCS equipment failure (see #s 11, 13, 14, and 19); here the ECCS fails during injection because of a pump, valve, or water supply fault. To cover these cases, the inspectors' focused on ECCS control and hardware availability by studying past failure experience and the implementation of good surveillance and maintenance practices.

Event V Scenario

Sequence # 24 involves a loss-of-coolant accident outside containment. Pressure isolation valves that protect low pressure ECCS equipment from high reactor pressures fail and initiate an overpressurization event resulting in rupture, loss of ECCS and eventual core-melt. The radiation release bypasses the accident mitigating features of the containment. Though the core-melt frequency of this event is low, its off-site consequences are high resulting in a high risk ranking. The inspection focused on the integrity of the normally closed MOVs that are in the RHR suction line on Loop # 2. These valves were identified as the most risk significant. Their design, leak tightness, operating experience, and related operations, surveillance and maintenance procedures were reviewed to evaluate the confidence that the valves are closed and stay closed during power operation.

TABLE B-1 INDIAN POINT 2 INSPECTION SCOPING

Team Inspection July 21 Thru August 1, 1986

Core Melt Rank	Sequence	Chosen For Inspection	Comments	Other Rankings		
				L	E	N
1	Seismic: loss of control or power	Partial	*Structual modifications review	1	3	2
2	Fire: specific fires in Electrical Tunnel and Switchgear Room causing RCP seal LOCA and failure of power cables to the Safety Injection pumps, Containment Spray pumps, and fan coolers	Partial	*Housekeeping and visual inspections *Modifications as a result of IPPSS were inspected during Sept. 1985, Appendix R Inspection #85-24	2	4	6
3	Fire: specific fires in Electrical Tunnel causing RCP seal LOCA and failure of power cables to all MCCs, Safety Injection pumps, RHR pumps, and Containment Spray pumps	Partial	*See #2	8	5	–
4	Turbine Trip Due To Loss Of Offsite Power: failure of two diesel generators, RCP seal LOCA, and failure to recover external AC or gas turbine generator within one hour	Yes	*LOP walkthrough *EDG common cause failure aspects *Fast transfer logic	9	8	9
5	Hurricane, etc., Wind: loss of all AC due to high winds	Partial	*High wind procedure review *LOP walkthrough	3	6	1
–	Loss Of Component Cooling: pipe break causing RCP seal LOCA and failure of SI pumps	Partial	*System integrity aspects *Operator recovery	–	–	5
6	Tornado and Missiles: causing loss of offsite power and Service Water pumps or Control Building	Partial	*See #5	4	7	11
7	Small LOCA: failure of recirculation cooling	Yes	*Operator failure to switch from inj. to recirc., LOCA walkthrough	10	9	8

more...

L=Latent Effects E=Early Deaths N=NUREG/CR-2934

TABLE B–1 INDIAN POINT 2 INPECTION SCOPING

(Continued)

Core Melt Rank	Sequence	Chosen For Inspection	Comments	Other Rankings L	Other Rankings E	Other Rankings N
8	Large LOCA: failure of low pressure recirculation cooling	Yes	*Operator failure to switch from inj. to recirc. *LOCA Walkthrough	11	10	3
9	Medium LOCA: failure of low pressure recirculation cooling	Yes	*Same as above	12	11	4
10	Turbine Trip Due To Loss Of Offsite Power: loss of all AC power (due to diesel failure and combined diesel and service water failures), RCP seal LOCA, and failure to recover offsite AC or gas turbine within one hour	Yes	*LOP walkthrough *EDG avail. & EDG cooling *GT avail. & black start	13	12	12
11	Large LOCA: failure of low pressure Safety Injection	Yes	*RHR availability	14	13	–
12	Turbine Trip Due To Loss Of Offsite Power: failure of two diesel generators, RCP seal LOCA, and failure to recover offsite AC or gas turbine	Yes	*See #10 *EDG common cause failure aspects	15	14	–
13	Small LOCA: failure of high pressure injection	Yes	*Water supply "singles" *SI availability *Part. coverage in #86–06	16	15	10
14	Medium LOCA: failure of low pressure injection	Yes	*See #11	17	17	–
15	Fire: specific fire in Cable Speading Room causing loss of all control power	Partial	*See #2	18	18	13

more...   L=Latent Effects   E=Early Deaths   N=NUREG/CR–2934

TABLE B-1 INDIAN POINT 2 INSPECTION SCOPING

(Continued)

Core Melt Rank	Sequence	Chosen For Inspection	Comments	Other Rankings		
				L	E	N
16	Turbine Trip Due To Loss Of Offsite Power: loss of all AC power (due to diesel generator failure and combined diesel/service water failures), RCP seal LOCA, and failure to recover offsite AC or gas turbine, cont. fans & sprays not available	Yes	*See #10	5	16	–
17	Turbine Trip: failure of AFWS and failure of of bleed and feed cooling	No	*AFWS covered under PRA directed inspection #86-06	19	19	–
18	Reactor Trip: failure of AFWS and failure of bleed and feed cooling	No	*See #17	20	20	–
19	Medium LOCA: failure of high pressure injection	Yes	*See #13	21	21	–
20	Loss Of Main Feedwater: failure of AFWS and failure of feed and bleed cooling	No	*See #17	22	22	–
21	Seismic: direct containment (backfill) failure	No	*Seismic design considerations outside scope of inspection	6	1	–
22	Turbine Trip: ATWS and failure of AFWS	Partial	*Check on status of turbine trip modification	23	23	–
23	Loss Of Main Feedwater: ATWS and failure of AFWS	Partial	*See #22	24	24	7
24	Interfacing System LOCA	Yes	*Event V inspection of the two MOV configuration	7	2	–

L=Latent Effects E=Early Deaths N=NUREG/CR-2934

ATTACHMENT C

DOCUMENTS REVIEWED

1. General

- Final Safety Analysis Report
- Safety Evaluation
- Technical Specification
- Indian Point Probabilistic Safety Study
- Review & Evaluation of the Indian Point Probability Safety Study NUREG/CR-2934

2. Quality Assurance

- CI-240-4 Quality Assurance Manual, June 2, 1986
- QA-760 Issue and Control of Open Item Reports, November 25, 1985
- QA-702 Nuclear Power QA Organization and Responsibility, January 24, 1985
- QA-761-1 Deficiency Report Processing, March 20, 1985

3. Station Administrative Orders

- SAO-102 Procedure/Procedure Change Approval Policy, Rev. 7
- SAO-215 Identification of System Components, Rev. 1
- SAO-218 Housekeeping Policy, Rev. 0
- SAO-405 Modifications to Indian Point Facilities, Rev. 1
- SAO-406 Quality Assurance Program - Balance of Plant, Rev. 0

4. Operations Administrative Directives

- OAD-5 Procedure Adherence and Use, Rev. 2
- OAD-7 Operating Procedure Development and Control, Rev. 11
- OAD-17 Plant Modification Procedures, Rev. 0
- OAD-26 Emergency Operating Procedures Maintenance Program, Rev. 0
- OAD-27 Temporary Procedure Change, Rev. 0

5. Emergency Operating Procedure

- E-0 Reactor Trip or Safety Injection, Rev. 0
- E-1 Loss of Reactor or Secondary Coolant, Rev. 0
- ES1.3 Transfer to Cold Leg Recirculation, Rev. 0
- ES-0.1 Reactor Trip Response, Rev. 0
- ES-1.2 Post LOCA Cooldown and Depressurization, Rev. 0
- ES-1.4 Transfer to Hot Leg Recirculation, Rev. 0
- ECA-0.0 Loss of All AC Power, Rev. 0
- ECA-0.1 Loss of All AC Power Without SI Required, Rev. 0
- ECA-0.2 Loss of All AC Power with SI Required, Rev. 0

6. Abnormal Operating Procedures

- A-27.1.9 Control Room Inaccessibility Safe Shutdown Control, Rev. 2

7. Station Operating Procedures or Temporary Operating Instruction

Instructions

- SOP-10.6.2 Containment Entry and Egress, Rev. 18
- SOP-10.1.4 Verification of Safeguards Relay Operability, Rev. 1, TPC 86-055
- SOP-24.1 Service Water System, Rev. 11
- SOP-26.4 Turbine Generator Startup, Synchronizing, Voltage Control and Shutdown, Rev. 9
- SOP-27.1.1 Operation of 345KV and 138KV Components, Rev. 3
- SOP-27.1.3 Operation of 13.8KV System, Rev. 6
- SOP-27.1.4 Operation of 6.9KV System, Rev. 0
- SOP-27.1.5 Operation of 480 volt System, Rev. 3, TPC 86-013
- SOP-27.1.6 Operation of Instrument Bus and DC Distribution System, Rev. 2, TPC 85-38
- SOP-27.1.7 Operation of Main, Station and Unit Auxiliary Transformers, Rev. 4
- SOP-27.3.1 Diesel Generator Manual Operation, Rev. 6, TPC 85-74, 85-53, 85-41, 84-171, 84-172
- SOP-27.3.2 Filling Diesel Fuel Oil Storage Tanks, Rev. 1
- SOP-31.1.1 Gas Turbine # 1 Operating Procedure - Remote, Rev. 0
- SOP-31.1.2 Gas Turbine # 1 Operating Procedure - Local, Rev. 0
- SOP-31.2 Black Start of Gas Turbine #1 or #3, Rev. 1
- SOP-31.2.1 Gas Turbine # 2 Operating Procedure - Remote, Rev. 0
- SOP-31.3.1 Gas Turbine # 2 Operating Procedure - Remote, Rev. 0
- SOP-31.3.2 Gas Turbine # 3 Operating Procedure - Local, Rev. 0
- TOI-78 Gas Turbine # 3 Operating Procedure - Local, Rev. 0

8. Inspection Procedure

- PI-M2 Containment Entry and Egress, Rev. 18
- PI-BW1 Containment Building Inspection for Anomalous Conditions, Rev. 3

9. Calibration Procedures

- PC-R5B 6.9KV Underfrequency Relays, Rev. 6, TPC 86-39T
- PC-R9 RHR System Flow Transmitter, Rev. 5, 6 & 7
- PC-R11 Refueling Water Storage Tank Level Transmitter, Rev. 7 & 8
- PC-R21 Level Transmitters in the 46 foot VC Sump, Reactor Cavity Sump and the Recir. Sump, Rev. 1, 2 & 3
- PC-R26 Containment Sump Rosemount Discrete Level Transmitter, Rev. 1 & 2
- PC-R35 Safety Injection Flow, Rev. 0 & 1
- PC-Q2 Refueling Water Storage Tank Level, Rev. 0
- PC-EM16 Containment Pressure Transmitter, Rev. 0

10. Test Procedures

- PT-D1 Emergency Diesel Generators, Rev. 9
- PT-W1 Emergency Diesel Generators, Rev. 8
- PT-M6A 6.9KV Undervoltage Relay Test, Rev. 5
- PT-M13 Turbine Electrical Overspeed Analog, Rev. 8
- PT-M13A Turbine Electrical Overspeed Logic, Rev. 5
- PT-M14B Safety Injection System, Rev. 12
- PT-M21 Diesel Generator, Rev. 18
- PT-M22 Station Battery Surveillance, Rev. 16 (Test February 18, 1986)
- PT-M38 Gas Turbine Generators, Rev. 2
- PT-M48 480 volt Undervoltage Alarm Functional Test, Rev. 2
- PT-M60 Automatic Transfer to Alternate DC Power Supply, Rev. 0
- PT-M63 Gas Turbine Battery Test, Rev. 0
- PT-Q1 Station Battery Surveillance and Charging, Rev. 15 (Test May 2, 1986)
- PT-Q13 ASME Section XI Inservice Valve Test, Rev. 6

Data Sheet (DS)

DS-68	PT-V24	MOV-822A	DS-69	PT-Q13	MOV-822B
DS-49	PT-Q13	MOV-745A	DS-50	PT-Q13	MOV-745B
DS-27	PT-Q13	MOV-888A	DS-06	PT-Q13	MOV-889A
DS-22	PT-V24	MOV-856F	DS-58	PT-V24	MOV-730
DS-59	PT-V24	MOV-731			
DS-18	PT-V24	MOV-856B	DS-28	PT-Q13	MOV-888B
DS-07	PT-Q13	MOV-889B			

- Inservice Testing Program Summary for the Interval July 1, 1984 through June 30, 1994

- PT-Q18 Refueling Water Storage Tank Level Transmitters, Rev. 0
- PT-Q30 Component Cooling Pump Operability, Rev. 0
- PT-R2B Recirculation Sump Level, Rev. 2 thru 6
- PT-R9 RHR System Flow Transmitter Calibration Rev. 5, 6 & 7
- PT-R25E Main, Unit and Station Auxiliary Power Bus Transfer, Rev. 1
- PT-R35 Inservice Valve Test, Rev. 4
- PT-R45 Battery Charger Ground Detector Test, Rev. 2
- PT-R61 480 volt Breaker Undervoltage Relay, Rev. 2
- PT-R66 RHR Pump Full Flow Test (RHR Check Valves), July 24, 1984, TCP 86-30T
- PT-R16 Recirculation Pumps Functional Test, Rev. 5, 6 and 7
- PT-FY1 Containment Spray Systems Nozzle Test, Rev.s 0 and 1
- PT-FY1 Containment Spray Systems Nozzle Test, Rev.s 0 and 1
- PT-Q35 Containment Spray Pumps Functional Test, Rev. 0
- PT-R64 SIS Accumulator Check Valve Slow, Rev. 1
- PT-R65 Containment Spray Check Valves, Rev. 2
- PT-3Y3 Containment Fan Cooler Units - Spray System Air Slow Test, Rev. 1
- PT-R13A Recirculation Switches, Rev. 3
- PT-R2A Containment Sump Pump and Instrumentation, Rev. 7

- PT-A4 Battery Load Test, Rev. 6, TPC 86-34T
- PT-V21 Low Head Injection and RHR Check Valves, Rev. 2
- PT-V24 Inservice Valve Test, Rev. 2
- COL-10.0 Service Water Essential Header Verification, Rev. 1

11. Maintenance Procedures

- MP-7.73 Overhaul, Repair and/or PM of RHR Pump Motor, Rev. 0
- MP-16.33 Reactor Trip and Bypass Breakers, BD-50 Type PM Semi-Annual Inspection, Rev. 3
- MP-16.44 Inspection of Motor Operated Valves - Limitorque Operators, Rev. 2
- MP-16.45 Overhaul of 480V Motors with Greased Ball/Roller Bearings - Class A, Rev. 0
- MP-16.46 PM Inspection of Westinghouse 6.9KV Air Circuit Breakers Model 75DHK500
- MP-16.50 Emergency Standby Diesel Generator Refueling Overhaul No. 1, 3, 5, 7, 9, Etc., Rev. 1 ° MP-16.54 Periodic Inspection and Maintenance of the Emergency 2188 KVA Generators, Rev. 0
- MP-16.84 Inspection and Cleaning of the 480V Motor Control Centers, Rev. 0

12. Preventive Maintenance Package

- PMP-124 FT-945B Calibration
- PMP-123 FT-945A Calibration
- PMP-106 PT-923 Calibration
- PMP-105 PT-922 Calibration
- PMP-96 PI/PC-635 Calibration
- PMP-328 PI/PC-947 Calibration
- PMP-1391 PI/PC-600 Calibration

13. Technical Administrative Directive

- TAD-6 Calibration and Control of Measuring and Test Equipment, Rev. 9
- TAD-9 Directive for Review of Test Quantities per ASME Sect. XI, Rev. 4

14. Other Documents

- Modification Work Request 11026, Modification No. EGP-84-30727, RX Trip Breakers Auto Shunt Trip

- OP-290-1 Engineering Operations Manual Section 5.6 Preparation and Review of Detailed Designs (Construction Drawings)

- Reactor Trips Summary 1981 thorugh 1986

- Work Order Number Search from 1984 through 1986 for Control Switches-Relays-And Breakers

- Weekly Maintenance Schedule July 28 through August 1
- Nuclear Power Experience PWR-2 Indian Point 2 Search VI Turbine Cycle System IX Instrumentation and Control XI Electrical
- Modification No. MPC 82-11004-10, Replace Level Instruments in the Reactor Cavity, Containment and Recirculation Sumps.
- Franklin Institute Report F-C2232-01, Appendix C, Test of a Limitorque Valve Operator Under a Simulated Reactor Containment Post Accident Steam and Chemical Environment.
- General Engineering Project Scoping Document Project 62033, RWST Redundant Level Instrument Channel, March 13, 1986

16. Other Documents

- Engineering Support Request
- ESR IP-60730 RWST Level Instrument LIC-921, April 2, 1986
- ESR 30709 RWST Level Instrumentation, August 31, 1983
- ESR 30709 Close out September 1, 1983
- Design Criteria Project No. 62033, RWST Redundant Level Instrument Channel, July 24, 1986

17. Drawings

Flow Diagrams

- 9321-F2738-49 Reactor Coolant System
- A227781-6 Auxiliary Coolant System
- 9321-F-2720-45 Auxiliary Coolant System
- CCR-209762 Service Water System
- CCR-9321-F-2722 Service Water System NSS Plant
- CCR-9321-F-2030 Diesel Generator Fuel Oil System
- CCR-9321-H-2028 Diesel Generator Jacket Water System
- CCR-9321-H-2029 Diesel Generator Starting Air System
- CCR-9321-F-2735Safety Injection System

Electrical One Line Diagrams

- 540F21 Main, Rev. 9
- 540F922 6900 Volt, Rev. 10
- CCR208088 480 Volt (Bus 2A, 3A, 5A, & 6A) As-built 11-15-83
- CCR208507 480 Volt Motor Control Centers, As-built 5-13-96
- CCR9321-F-3006 480 Volt Motor Control Center MCC26A&B As-built 11-29-83
- CCR9321-F-300B Direct Current Power Panels 21, 22, 23 & 24 As-built 12-14-83

Electrical Three Line Diagrams

- 9321-F-3011-26 Main, 5-9-86
- 9321-F-3007-10 480 Volt Emergency Diesel Generators & Buses, 2-6-86
- 609F982 Gas Turbine Control

Schematic Diagrams

- 9321-LL-3113 6900 Volt Switchgear 21 Sheet 1 through 18
- 9321-LL-3117 480 Volt Switchgear 21 Sheet 1 through 11, 21, 22 & 22A
- 9321-LL-3124 480 Volt Motor Control Center 24 Sheet 1, 10 & 11
- B225220-0 Motor Operated Valves Sheet 135
- B225233-0 Elementary Wiring Diagram Recirculation Switches and Indicating Lights, Sheet #148
- B225136-0 Elementary Wiring Diagram of Safety Injection Pump #22, Sheet #30
- B225135-0 Elementary Wiring Diagram of Safety Injection Pump #22, Sheet #29
- B225134-1 Elementary Wiring Diagram of Safety Injection Pumps #21 and #23, Sheet #28