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FACILITY: Hope Creek Nuclear Generating Station

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INSPECTORS: James Trapp, Team Leader, Region I
Dave Desaulniers, Human Factors Analyst, HFB, NRR
Dave Jaffe, Sr. Project Manager-Hope Creek, NRR
Ray Lorson, Resident Inspector-Peach Bottom
George Thomas, Reactor Engineer, RSB, NRR
Tracy Walker, Operation Engineer, Region I

REVIEWED BY: Jm Trapp 9-15-95
James M. Trapp, Senior Reactor Engr. Date
Division of Reactor Safety

APPROVED BY: A R Blough 9-22-95
A. Randy Blough, Acting Deputy Director Date
Division of Reactor Safety

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EXECUTIVE SUMMARY

Hope Creek Inspection Report 50-354/95-81

August 7-16, 1995

The objective of this inspection was to conduct an independent evaluation of the circumstances surrounding the July 7-9, 1995 partial bypass of shutdown cooling flow from the reactor vessel. The Special Team Inspection (STI) developed a sequence of events, assessed operator performance, evaluated the quality of procedures and training, and reviewed the post-event evaluation. The team also evaluated the safety significance and consequences of this event.

Hope Creek had a poor operating history regarding the loss of the shutdown cooling system. Many of the previous events were caused by inadequate procedure quality or the failure to follow procedures. Corrective actions have not been successful in preventing the loss of shutdown cooling. The principal causes of the most recent loss of shutdown cooling are inadequate communications and the failure to follow procedures.

This event was initiated when plant operators inappropriately left open the recirculation pump discharge valves. The failure to close these valves allowed shutdown cooling flow to bypass the reactor vessel. The bypass flow decreased the ability of the shutdown cooling system to remove decay heat and caused an increase in reactor coolant system temperature and pressure. This resulted in an undetected change in the plant operational condition (i.e., mode) from the desired cold shutdown to the hot shutdown condition.

Onshift communications and certain aspects of command and control by licensed plant operators were weak. Shift supervision was not informed of important information regarding the position of the recirculation pump discharge valves. The operators were also ineffective in soliciting assistance from other organizations in resolving equipment failures. The procedure adherence by plant operators during this event was inadequate. Operators failed to comply with the instructions provided in plant procedures for stroking the recirculation pump discharge valves. Plant procedures did not allow leaving the recirculation pump discharge valves open. Monitoring and assessment of plant indications by plant operators during this event were inadequate. The plant operators failed to assess the available plant indications to determine that the plant was departing the cold shutdown condition. Plant indications such as reactor vessel pressure, reactor head vent temperature, recirculation flow, and drywell leakage provided sufficient information for the operators to recognize that the reactor was no longer in the cold shutdown.

Poor quality procedure instructions and inadequate training were contributing causes of this event. The procedural guidance for stroking the recirculation pump discharge valves was not consistent between procedures and did not provide adequate detail. Procedural guidance was not available for monitoring reactor coolant system temperature when the shutdown cooling system was secured during surveillance testing. This lack of guidance contributed to the first mode change being undetected by plant operators. The training provided to plant operators in several areas was not adequate. Relevant industry operating experience on losses of shutdown cooling had not been adequately incorporated into operator training. Operators did not demonstrate adequate knowledge of expected plant indications during the cold shutdown condition. In addition, the operators demonstrated a lack of knowledge regarding the control logic for certain motor-operated valves.

Senior plant management initially failed to correctly assess the significance of this event. The failure resulted in a 10-day delay in initiating a comprehensive root cause evaluation and contributed to the failure to make the required notification to the NRC. The independent oversight organizations' assessments of this event were proactive, valid and timely. However, these organizations were ineffective in persuading senior plant management to adopt their findings regarding the significance of this event. The team determined that the final root cause evaluation identified most of the significant performance issues that were involved with this event. The corrective actions derived from the root cause evaluation addressed the significant performance deficiencies.

The STI concluded that this event was safety significant. However, the consequences of this event were minimal and this event had no direct adverse effect on the health and safety of the public or plant personnel. During this event two of the three primary fission product barriers were in a degraded condition with the reactor conditions above the cold shutdown condition. The third fission product barrier (fuel cladding) appeared to be adequately protected. There were no indications of fuel cladding damage and normal operating reactor vessel water level was maintained during this event. The Public Service Electric and Gas Company (licensee) and the NRC are continuing to evaluate the margin of safety for the third barrier that existed during this event. The identified weaknesses in both operator and management performance during and following this event were also significant. Several technical specification requirements were not complied with during this event.

DETAILS

1.0 INSPECTION OBJECTIVES

The objective of this inspection was to conduct an independent evaluation of the circumstances surrounding the July 7-9, 1995 partial bypass of shutdown cooling flow from the reactor vessel. Specific inspection objectives were provided to the team by the Regional Administrator in the Special Team Inspection Charter (Attachment 1). The team used the root cause evaluation techniques described in the NRC Human Performance Investigation Process manual to conduct this inspection.

2.0 BACKGROUND

2.1 System Description

A simplified drawing of the shutdown cooling system (SDC), recirculation system and the reactor vessel is provided in Attachment 2. The attached drawing illustrates 1 of 2 installed recirculation loops and SDC systems. The shutdown cooling system uses a residual heat removal (RHR) pump and heat exchanger to remove decay heat from the core. The SDC is used when the reactor is shutdown and the reactor coolant system is depressurized. The RHR pump takes a suction from the annulus region between the reactor vessel wall and the core shroud and discharges to the inlet of the RHR heat exchanger. The RHR heat exchanger transfers heat from the reactor coolant to the safety auxiliary cooling system (not shown in the attached drawing). The flow from the RHR heat exchanger passes through the jet pumps to the reactor core and back to the annulus region. Inside the reactor vessel, some SDC flow normally circumvents the core through the idle recirculation loop jet pumps, but this pathway normally does not jeopardize core cooling. The recirculation pumps are not inservice and the recirculation pump discharge valves (F031A&B) are normally closed during SDC operation; this normally prevents backflow through the loop, which could constitute a major flowpath bypassing the core. (But, in the July 7-9 event, these valves were not fully shut, so a core bypass flow did occur.) The recirculation pump suction valves (F023A&B) are normally maintained open during SDC operation.

2.2 Historical SDC System Performance

The team concluded that Hope Creek has a poor operating history regarding the loss of the shutdown cooling system. Many of the previous events were either caused by inadequate procedures or inadequate procedure adherence. Previous corrective actions have not been successful in preventing the loss of the shutdown cooling system.

The team reviewed the plant historical records and the licensee's "Shutdown Cooling Bypass Event," report (dated August 7, 1995) for information on previous losses of SDC. The licensee's SDC bypass event report identified that shutdown cooling has been inadvertently lost 10 times since 1987. All 10 events were documented in licensee event reports (LERs). Three of the five most recent events identified procedural adherence as inadequate. The last loss of shutdown cooling in March 1995 was also caused by the failure to follow procedures. A safety system functional review of the RHR system completed by the licensee's onsite safety review group on June 8, 1995, stated that "The team determined that shutdown cooling is lost in virtually every outage, and that the event has become so common that operators expect it to occur."

The recirculation pump discharge valve (F031B) thermally bound closed during a previous plant cooldown in March 1995. Thermal binding occurs as a result of differential contraction between a valve body and valve disc as the system cools. The differential contraction causes the valve disc to become tightly bound in the valve seat and can cause the failure of the valve to open. An apparent cause had not been determined and corrective actions had not been developed prior to the July event. The team determined that this was an opportunity missed to resolve the problems that the plant operators were experiencing with the recirculation pump discharge valves.

3.0 SEQUENCE OF EVENTS

3.1 Event Summary

The event was initiated when the recirculation pump discharge valve was partially opened to prevent the valve from thermally binding in the shut position during the plant cooldown. This allowed some of the SDC flow to bypass the reactor vessel through the recirculation loop and back to the RHR heat exchanger. The bypass flow reduced the amount of SDC flow through the reactor vessel core. This reduced the heat removal capacity of the SDC system and the mixing of coolant inside the reactor pressure vessel. These conditions resulted in thermal stratification of the reactor vessel coolant and an unintended production of steam. A detailed description of the event is discussed below.

3.2 Detailed Event Sequence

The team developed the following event sequence based on interviews, review of plant logs and operating data, and information from the licensee's event evaluation. Team comments regarding the event are contained in the bold and italicized text.

July 7, 1995:

6:30 p.m. Plant shutdown commenced due to the pending expiration of a seven day technical specification (TS) limiting condition for operation action statement for an inoperable control room chiller.

July 8, 1995:

12:18 a.m. The reactor was manually scrammed when the mode switch was placed in the "shutdown" position, plant entered into the hot shutdown condition (Mode 3).

7:00 a.m. Operating Shift Turnover.

7:54 a.m. The B RHR pump was placed in service to establish shutdown cooling (SDC) in accordance with procedure HC.OP-SO.BC-0001(Q)-Revision 17, "Residual Heat Removal System Operation." The indicated SDC flow was approximately 10,000 gallons per minute (gpm).

7:54 a.m. to 9:40 a.m. The A and B recirculation pump discharge valves (F031A and F031B) were stroked open and closed to prevent the valves from thermally binding in the closed position. *[This action was taken in an attempt to comply with a precaution and limitation note in procedure HC.OP-SO.BB-0002(Q)-Revision 22, "Reactor Recirculation System Operation." Opening the recirculation system discharge valves allowed some of the SDC flow to bypass the reactor vessel through the recirculation system and degraded the heat removal capability of the SDC system for the brief period of time the valves remained open. The team determined that stroking the valve in this manner was not in accordance with plant procedures.]*

9:40 a.m. Nuclear Controls Operator (NCO) unsuccessfully attempted to open F031A. *[The licensee later determined that this valve failure was due to thermal binding.]*

9:50 a.m. NCO unsuccessfully attempted to open F031A a second time. An action request (AR) was initiated to investigate and correct the valve failure. *[The team noted that the motor operated valve (MOV) component engineer was not contacted at this time regarding the F031A failure.]*

10:57 a.m. The plant was placed in the cold shutdown condition (Mode 4 - this condition requires the average reactor coolant temperature to be maintained less than or equal to 200°F).

11:00 a.m. The nuclear controls operator partially opened and left open valve F031B to prevent it from thermally binding in the closed position. *[The team determined through interviews that the nuclear shift supervisor (NSS) and the senior nuclear shift supervisor (SNSS) were not aware that the valve would be left open. The indicated B recirculation loop flow increased from zero to approximately 2000 gallons per minute (gpm) and caused a reduction in SDC flow to the reactor vessel due to the bypassing of flow through the recirculation system. The RHR heat exchanger inlet temperature was used to measure the average reactor coolant temperature, which indicated approximately 195°F. However, this temperature was not an accurate indication of average reactor coolant temperature since having F031B open allowed the relatively cool flow from the RHR heat exchanger outlet to mix with the SDC return flow from the reactor vessel prior to the combined flow reaching the RHR heat exchanger inlet temperature detector.]*

11:52 a.m. Reactor pressure indicated zero pounds per square inch gage (psig) and the reactor vessel head vent valves were opened in accordance with procedure HC.OP-IO.ZZ-004(Q)-Revision 23, "Shutdown From Rated Power To Cold Shutdown." *[The team noted that this activity breached the integrity of the reactor coolant system (RCS) pressure boundary. The RCS is one of the three primary fission product barriers.]*

12:59 p.m. The electrical supply breaker for the reactor water cleanup (RWCU) supply line inside isolation valve (F001) was opened to support a corrective maintenance activity. *[This defeated the ability to remotely operate the valve and thus degraded the ability to isolate the primary containment.]*

2:38 p.m. All high pressure automatic isolation signals for the SDC outboard isolation valves (F008, F015A, and F015B) and the inboard isolation valve (F009) were defeated and also the primary containment automatic isolation signal for F009 was defeated in accordance with procedure HC.OP-GP.SM-0001(Q)-Revision 3, "Defeating NSSSS Isolation Signals For Shutdown Cooling." These signals were defeated to prevent an inadvertent SDC isolation and also in preparation for reactor protection system (RPS) surveillance testing. *[This action rendered the F009 valve inoperable for its primary containment isolation function and would have prevented all SDC system isolation valves from automatically shutting on a high pressure condition in the RCS. The SDC system overpressure alarm and remote manual operation of the SDC isolation valves remained available and would have allowed the operators to manually protect the SDC system from an overpressure condition.]*

4:35 p.m. The SDC system was secured to facilitate manual operation of the SDC isolation valves per HC.OP-GP.SM-0001 to verify that the isolation valves could still be manually shut. This is a precautionary step performed following defeat of the automatic signals discussed above. *[Securing the SDC system resulted in a increase in reactor vessel pressure to approximately 25 psig and indicated the first inadvertent mode change (i.e. Mode 4 to Mode 3). The team noted that both the primary containment, (due to defeat of the RWCU F001 and the SDC F009 valves' automatic isolation capabilities) and the reactor coolant system boundary (due to the reactor head vent valves being open) were in a degraded condition during this mode change. The operators and the licensee's follow-up event review teams failed to identify this mode change.]*

[The team attributed the reactor pressure increase following the securing of the SDC system to thermal stratification of the reactor coolant combined with a higher than indicated average reactor coolant temperature. These two conditions resulted from leaving the recirculation pump discharge valve (F031B) open.]

5:09 p.m. SDC system returned to service. The RHR heat exchanger inlet temperature promptly increased from 163°F to 182°F, which led the operators to incorrectly believe that the SDC system was operating properly. ***[Restoring the SDC system did re-establish reactor decay heat removal as evidenced by the decreasing trend in reactor pressure back to 0 psig, however, the SDC system remained in a degraded condition due to the continued recirculation system bypass flow.]***

5:30 p.m Operators entered the drywell to perform outage activities, assess a drywell cooler leak and to investigate the reason for the F031A valve failure (refer to the 9:40 a.m. event).

5:54 p.m. Electrical supply breaker for the RWCU F001 was shut. ***[This restored the valve's automatic primary containment isolation operability.]***

6:45 p.m. Operators manually "cracked" open the F031A valve. Upon exiting the drywell, plant operators reported condensation on drywell surfaces and also that their glasses had "fogged" while inside the drywell. The NCO opened F031A up further until he received an electrical "dual" indication. ***[The report of drywell conditions was consistent with the plant pressure trend since the reactor vessel steam pressure build-up that developed when SDC was secured had subsequently vented to the drywell through the open reactor vessel head vent valves.]***

7:00 p.m. Operating Shift Turnover.

8:00 p.m SNSS turnover completed, however, the on-coming SNSS was involved with other activities and missed the shift briefing.

8:30 p.m. SNSS and NSS performed a control room panel walkdown and noted the 2000 gpm of recirculation system flow. They decided to shut the F031A and F031B valves.

8:45 p.m The drywell primary containment instrument gas (PCIG) system was tagged out and depressurized in preparation for outage maintenance activities. ***[This rendered the main steam isolation valve steam sealing (MSIV SS) system, which is required to be operable in Modes 1, 2, and 3, inoperable.]***

9:00 p.m. The NCO closed F031A since the RHR heat exchanger inlet temperature had decreased to about 155°F and the thermal binding limitation was no longer applicable. ***[The team noted that although both the SNSS and the NSS had decided to shut the F031A and F031B valves, this decision had not been clearly communicated to the NCO.]***

The NCO attempted to shut F031B, but was unsuccessful, and incorrectly attributed this to the valve not being open enough to complete its motor closure logic circuitry. The NCO opened the valve for an additional two to three seconds and then again attempted unsuccessfully to shut F031B. *[Further opening of the F031B valve resulted in an additional bypassing of the SDC flow through the recirculation system to about 4000 gpm. This initiated a reactor pressure build-up and associated reactor vessel head vent temperature increase, an increase in the drywell floor drain leakage flowrate, and also decreased the RHR inlet temperature to about 145°F. The SNSS was not informed that the NCO had opened the valve.]*

10:00 p.m. Reactor pressure was approximately 15 psig and increasing, which indicated that a second mode change from Mode 4 to Mode 3 had occurred. *[Plant entered Mode 3 with the MSIV SS system inoperable. TS 3.0.4 prohibited entry into an operating condition when the associated action statement would require a plant shutdown. TS 3.6.1.4 was applicable to the MSIV SS in Mode 3 and required a reactor shutdown as part of the action statement. The safety significance of the MSIV SS being inoperable was low due to the demonstrated existing low MSIV leak rate.]*

[The reactor coolant pressure boundary remained breached through the open reactor vessel head vent valves; the primary containment was degraded since the automatic primary containment isolation signals for the inboard SDC valve were defeated with the SDC system inservice.]

10:03 p.m. The electrical supply breaker for the RWCU F001 valve was opened in preparation for transferring the RPS system to its alternate power supply. *[This rendered the RWCU F001 valve inoperable for primary containment isolation purposes and further degraded the primary containment.]*

10:00 p.m. to 11:00 p.m. The NCO noted that reactor pressure was about 17 psig, but was not confident about the accuracy of the pressure indication at the low end of its range.

11:00 p.m. The operators noted that the drywell floor drain leakage had increased to 1-2 gpm (the leakage had been approximately 0.4 gpm at the start of the event). *[The operators discussed this increase with the NSS and attributed the leakage to the PCIG tagout which would have allowed leakage past a known defective drywell cooler drain valve. The operators also discussed the possibility that the increased leakage could have been from the reactor head vents, but noted that the RHR heat exchanger inlet/outlet temperatures, and the reactor bottom head drain temperature seemed to conflict with the positive reactor pressure and increased drywell leakage.]*

11:01 p.m. *[The TS 3.3.2 action statement one hour time limit was exceeded by not having the automatic pressure isolation signals operable or performing the required compensatory measures for the SDC F-008, F-009, F-015A, and F-015B valves while the reactor was in Mode 3.]*

July 9, 1995:

00:33 a.m. RWCU F001 valve returned to an operable condition. *[The valve was inoperable for about 2.5 hours which did not exceed the allowed 4 hour TS action statement time limit.]*

1:00 a.m. The NCO noted that a SDC high pressure trip unit indicated 60 psig. The operators directed an instrument technician to accurately determine reactor pressure by using a digital voltage meter. This reading indicated that reactor pressure was between 19-24 psig on all channels. *[The reactor pressure should have been 0 psig based on the assumed reactor operating condition (i.e. Mode 4, SDC inservice and the reactor vessel head vent valves open). The operators incorrectly believed the pressure readings were acceptable due to: (1) instrument error from the static pressure head of the reactor vessel water level; and/or (2) instrument calibration inaccuracies in the lower end of the instrument's 0-1500 psig range.]*

[These instruments are calibrated to account for the static pressure head and are accurate to within about ± 5 psig over the entire 0-1500 psig range. The team attributed the operators misunderstanding of how the pressure indications functioned to a training/knowledge deficiency, but, was concerned about the operators failure to correlate this apparently abnormal reading with the other available indications. Specifically, all four operating pressure channels indicated an increasing reactor pressure trend, the reactor head vent temperature was 280°F, and the drywell floor drain leakage was approximately 2 gpm.]

1:30 a.m. The operating crew decided to enter the drywell to identify the source of drywell leakage and manually shut valve F031B.

2:30 a.m. SNSS canceled the plan to enter the drywell due to personnel safety concerns with "footing" in the drywell. The NSS was not aware that the plan to enter the drywell had been canceled. *[The operators believed that valve F031B would close remotely when the RHR pump was secured and the differential pressure across the valve was reduced.]*

4:29 a.m. The high pressure automatic isolation signals for the SDC outboard isolation valves (F008, F015A, and F015B) and all automatic isolation signals for the SDC inboard isolation valve (F009) were restored in accordance with procedure HC.OP-GP.SM-0001. *[This restored the operability of the SDC F009 primary containment isolation valve and re-established automatic overpressure protection for the SDC system.]*

4:49 a.m. All automatic isolation signals for the SDC outboard isolation valves (F008, F015A, and F015B) and all automatic high pressure isolation signals for the SDC inboard isolation valve (F009) were defeated in accordance with procedure HC.OP-GP.SM-0001(Q)-Revision 3, "Defeating NSSSS Isolation Signals For Shutdown Cooling." These signals were defeated to perform surveillance testing on the reactor protection system (RPS) electrical protection assemblies (EPAs). ***[This action defeated the primary containment automatic isolation function of the F008, F015A and the F015B valves, and also defeated the SDC system automatic overpressure protection.]***

4:54 a.m. SDC removed from service in accordance with HC.OP-GP.SM-0001. An attempt to close valve F031B was unsuccessful. The operators fully opened valve F031B. Personnel were then dispatched to assist in closing the valve. ***[The operators opened the valve because of a misconception of the control logic for this valve. The operators assumed opening the valve would makeup a permissive that would allow the valve to close.]***

5:00 a.m. SNSS and NSS discussed closing the recirculation system suction valve as a contingency plan if the discharge valve could not be shut. They determined that no procedural basis existed to perform this activity and they also expected that the recirculation discharge valve would soon be shut.

5:08 a.m. SDC restored. The RHR heat exchanger inlet temperature increased approximately 7°F. With the F031B fully opened, the indicated recirculation flow was approximately 4000 gpm.

5:50 a.m. F031B manually shut, RHR inlet temperature increased to 191°F, the reactor vessel bottom head temperature increased from approximately 150 to 189°F in about two minutes, steam pressure trended down towards 0 psig, and the reactor vessel head vent temperature began decreasing from a maximum temperature of 280°F. ***[Throughout the event the operators consistently misdiagnosed the decreasing trend in RHR heat exchanger inlet temperature as proof that SDC was functioning properly. However, this indication was not an accurate measurement of average RCS temperature with the SDC bypassed from the reactor vessel. The actual average RCS temperature was greater than 191°F. The manual closure of F031B took approximately 20 minutes. This allowed time for a gradual increase in SDC flow to the vessel and reduced the peak measured temperature.]***

4.0 OPERATOR PERFORMANCE

4.1 Communications/Command and Control

The team concluded that onshift communications by plant operators were less than adequate. Important information regarding manipulation of the recirculation pump discharge valves was not effectively communicated to shift supervision. The command and control demonstrated by shift supervision for certain activities during this event was inadequate. For example, shift supervision failed to give the NCOs clear direction for operating the recirculation pump discharge valves.

The team conducted interviews with licensed operators and reviewed the operators written post event statements to assess the quality of operator communications during this event. The day shift Senior Nuclear Shift Supervisor (SNSS) and Nuclear Shift Supervisor (NSS) were unaware that recirculation pump discharge valves had been left in the open position. The Nuclear Control Operators (NCOs) independently decided to leave these valves open to prevent thermal binding without consulting shift supervision. The NCOs failed to inform shift supervision or solicit guidance in making this decision. The night shift SNSS was concerned with the possible bypass of shutdown cooling flow and instructed the NSS to close the recirculation pump discharge valves. However, the night shift SNSS and NSS failed to clearly communicate this expectation to the NCOs. The NCOs stated that they were unaware of shift supervision's concern with the potential for bypass flow or the importance of closing the valves in a timely manner. The SNSS on night shift was not aware that recirculation pump discharge valve (F031B) had been opened further when attempting to close the valve. The SNSS was also not aware of the NCO's concerns about conflicting reactor pressure indications. The SNSS decided to postpone the drywell entry, for personnel safety reasons, without discussion with the other operating crew members and without the benefit of the information that had led the rest of the crew to place higher priority on making the entry. This decision led to a delay in manually closing the failed open discharge valve. The narrative logs maintained by the NCOs and NSS/SNSS did not provide adequate documentation of the activities related to operation of the recirculation discharge valves or the problems encountered in maintaining shutdown cooling. The operators did not effectively request assistance of other organizations, such as technical support or maintenance personnel, to assist in troubleshooting the motor-operated valve (MOV) problems encountered during the event.

The team determined that certain aspects of command and control by shift operators and supervision were weak. Shift supervision failed to provide the NCOs clear direction for manipulating the recirculation pump discharge valves to prevent thermal binding. The NCOs manipulated the recirculation pump discharge valves without the direction, approval, or cognizance of shift supervision. Even following the identification of a concern with the bypass of shutdown cooling flow, shift supervision failed to directly instruct the NCOs to close the discharge valves. Shift supervision also did not solicit or receive feedback to ensure that the action had been successfully completed.

In an attempt to close the valves the NCOs twice opened the valves further. This action allowed the bypass flow to increase and exacerbated the degraded cooling condition. The NCO failed to request permission of shift supervision prior to opening the valve.

4.2 Procedure Usage

The team concluded that procedure usage by plant operators during this event was inadequate. The operators failed to comply with the reactor recirculation system operating procedure. The recirculation pump discharge valves (F031A & B) were left open, which was not in accordance with the instructions in the reactor recirculation procedure.

The reactor recirculation system operating procedure HC.OP-SO.BB-0002(Q)-Rev. 22, Precautions and Limitations (P&L), 3.2.17, states that, "When a recirculation pump loop is taken out of service with Rx coolant temp above 155°F thermal binding of the suction and discharge valve may occur if they are closed while the loop cools. To preclude thermal binding, the suction and discharge valves shall alternately be opened and closed for each 75°F temp drop in the isolated loop. This action need not be taken if the loop had been isolated to mitigate the effects of a leak." This P&L was added to the procedure in 1989. The plant operators failed to implement this precaution and limitation when manipulating the recirculation pump discharge valves. The suction and discharge valves were not alternately opened and closed. Had the suction valve been closed prior to opening the discharge valve, bypass shutdown cooling flow would not have occurred. The procedure did not allow the discharge valves to be left opened.

During an interview, one reactor operator stated that he recalled alternately opening and closing the suction and discharge valves during a previous plant cooldown. However, other documentation indicated that a failure to follow this P&L had occurred during past plant cooldowns. A June 1994 control room observation report by training instructors identified that "tribal knowledge" was used by the "savvy" operators to crack open the recirculation pump discharge valves. The operations and training staff did not take action to assure that this practice was in accordance with plant procedures.

4.3 Assessment of Plant Indications

The team concluded that the operators failed to correctly diagnose plant conditions based on available indications. The operators involved in the event did not use all available indications, failed to recognize that indications were inaccurate, and focussed on inaccurate indications. Specifically, the operators did not monitor recirculation flow following operation of the recirculation discharge valves. They relied on residual heat removal (RHR) heat exchanger inlet and reactor vessel bottom head temperatures to assure that SDC was performing its intended function and failed to recognize that the temperature indications were not accurate. Even though they were aware that bypass flow was occurring, the operators did not recognize the impact on the operability of shutdown cooling.

The operators on night shift did not use all available indications, did not believe some of their indications, and failed to follow through on investigation of conflicting or unusual indications. When one of the operators identified conflicting pressure indications, the crew did not follow through and assess all available indications to resolve the concerns. When the reactor pressure indications on the reactor pressure trip units were validated, the operators did not identify this as an abnormal condition for cold shutdown and failed to relate the unexpectedly high indications to the previously identified conflicting pressure indications. When the increase in drywell leakage was identified, the operators determined a possible cause and did not follow through in assessing other possible sources. Even though one of the operators identified that the reactor pressure vessel head vents discharged to the drywell floor drain system, the crew failed to connect the increased leakage with other indications that were indicative of steaming in the reactor vessel.

5.0 PROCEDURES AND TRAINING

5.1 Procedure Quality

The team concluded that the quality of procedural instructions for stroking the recirculation pump discharge valves to prevent thermal binding was inadequate. The team also noted there was insufficient guidance for monitoring plant conditions when the inservice shutdown cooling loop RHR pump was removed from service.

The P&L in the recirculation procedure that directed operation of the recirculation valves to prevent thermal binding was ambiguously worded and open to interpretation. The P&L contained conditional statements that were not clear and directed multiple actions. Most operators interviewed interpreted the step to allow opening the valves for a limited period of time. Nearly all the operators interviewed had unique interpretations of the actions allowed by this P&L.

The guidance provided in the reactor recirculation and RHR system operating procedures was not consistent. The recirculation procedure required stroking the recirculation discharge valves, while the RHR procedure required the valves remain closed. The direction to cycle the valves to prevent thermal binding had been added to the recirculation procedure in 1989 in response to Institute of Nuclear Power Operations (INPO) Significant Operating Event Report. A 1981 General Electric Service Information Letter (GESIL 368) recommended stroking the recirculation pump discharge valves to prevent thermal binding. A caution was added to the recirculation system operating procedure to cycle the valves every 5 minutes except during shutdown cooling or pump maintenance. The GESIL specifically excluded stroking the recirculation pump discharge valves when in shutdown cooling.

The RHR procedure did not specifically reference the recirculation procedure for securing the recirculation pump. The limitation in the recirculation procedure could have easily been missed if the operators had not referenced the procedure and reviewed all of the precautions and limitations. During the July 1995 cooldown, the limitation was brought to the attention of the control room operators by another off-shift operator. The team noted that direction of required actions in a P&L was a poor practice. Plant administrative procedures prohibited actions from being included in cautions and notes in the body of procedures, but do not preclude inclusion of actions in P&L.

There was no procedural guidance for monitoring average reactor temperature when the RHR pump was taken out of service. The failure to provide guidance to the operators contributed to the inadvertent mode change that occurred on July 8, 1995 when the SDC system was removed from service for surveillance testing.

5.2 Operator Training

The team concluded that operator training was inadequate. Operators were not provided adequate training on monitoring plant conditions while the plant was in cold shutdown. Several relevant industry operating experience events had not been adequately incorporated into the training curriculum. The operators also demonstrated a knowledge deficiency in the control logic of the recirculation pump discharge valves.

Classroom training on shutdown cooling addressed equipment, automatic functions, and flowpaths, but did not emphasize the operational characteristics during SDC. The plant operators failed to demonstrate adequate knowledge of expected indications during cold shutdown conditions during this event. The shutdown cooling simulator scenarios used during training always included a complete loss of shutdown cooling. This training emphasis led the operators to place priority on maintaining the recirculation pumps available to provide forced circulation in case of a loss of shutdown cooling.

The team reviewed the operating experience associated with the loss of shutdown cooling. Lessons learned from previous industry and station events had not been effectively implemented into the training curriculum. Operators had not been specifically trained on the effect of having RHR flow bypass the core, although several similar industry events had occurred.

Operators had not received adequate training on the control logic including limit interlocks for MOVs. Inadequate understanding of the control logic circuitry led the operators to unnecessarily open the recirculation discharge valve further when attempting to close the valve.

6.0 POST EVENT EVALUATION

6.1 Followup Sequence of Events

The team developed the following licensee post-event review sequence based on personnel interviews and licensee documentation (team comments are provided in bold and italicized text):

July 9, 1995:

- An Action Request (AR) was generated to describe the event.
- The SNSS was assigned responsibility for performing the event investigation.
- An Operating Engineer (OE) was assigned to review the event for any outstanding issues.

July 10, 1995:

- The Acting General Manager (GM) directed the OE to instruct the operations staff to not interpret procedures. The OE issued a "night order" book entry that instructed operators not to interpret procedures.
- The quality assessment (QA) and safety review groups (SRG) met with the Technical Engineering Manager and Acting GM to express the opinion that this event was reportable to the NRC per 10 CFR 50.72.
- An engineering team, consisting of representatives from system engineering, mechanical engineering, and nuclear fuels, was established to determine if a mode change had occurred during the event.
- The event was discussed during the Senior Management Issues meeting.
- QA/SRG began independent reviews of the event.

July 10-14, 1995:

- Acting GM sent voice messages to the SNSSs and the OEs regarding the event.
- Acting GM contacted the training department to ensure that the event lessons learned were incorporated into the training program.
- The SNSS expressed concern that he would not be able to perform this investigation while on-shift and the investigation due date was extended to 14 days.

July 12, 1995:

- The engineering analysis concluded that no mode change had occurred during the event. *[This was a qualitative analysis based on the plant indications during this event and not a rigorous quantitative analysis as was later completed on August 4, 1995.]*

July 13, 1995:

- SRG draft report provided to acting GM. *[The draft report findings were accurate and were largely consistent with the findings documented in the licensee's event team report on August 7, 1995.]*

July 14, 1995:

- A meeting was conducted between the SRG, Technical Engineering Manager, Nuclear Safety Review (NSR) Manager, and the acting GM to discuss the event. The acting GM agreed to issue a voluntary LER at this meeting.

July 17, 1995:

- The Plant GM returned to the site and assumed the duties previously performed by the acting GM. A meeting was held between the SNSS, SRG and QA to inform the GM about the event.

July 18, 1995:

- The SNSS root cause determination was completed. *[The team concluded that this evaluation was not a comprehensive root cause evaluation of this event. Plant management had not to this point, provided appropriate resources, such as investigation team, to adequately evaluate this event.]*

July 19, 1995:

- QA determined that the line organization did not fully understand the significance of the event, and recommended to the GM that a team be established to review the event.

July 20, 1995:

- The GM initiated a team, made up of representatives from engineering, training, and maintenance to investigate the event.

July 24-25, 1995:

- The unit was started-up and returned to operation.

July 27, 1995:

- The final SRG report describing the findings regarding this event was issued.

July 28, 1995:

- The preliminary conclusions of the event investigation team were discussed with the NRC Senior Resident Inspector.

July 31, 1995:

- A management meeting was held between the NRC and the licensee to discuss the preliminary conclusions of the event investigation team.

August 2, 1995:

- The QA monthly report was issued that included an evaluation of this event.

August 4, 1995

- The calculation that determined that a mode change had occurred was issued.

August 7, 1995:

- The licensee's Shutdown Cooling Bypass Event - Final Report was issued. ***[The team concluded that this report identified most of the significant performance issues.]***

August 9, 1995:

- LER 95-16 was issued describing this event and corrective actions.

6.2 Management Response

The team concluded that, initially, senior plant management did not correctly assess the significance of this event. The improper assessment of the significance of this event contributed to the delay in initiating a comprehensive investigation of the event and the failure to properly report this event to the NRC.

A significance level 1 (most significant) action request (AR) was written on July 9, 1995 describing the circumstances that led to this event. The condition resolution designated on the AR was to have the SNSS perform a root cause analysis and have engineering review the data for reportability concerns. The engineering analysis was completed on July 12, 1995. A qualitative analysis concluded that the measured maximum temperature at the RHR heat exchanger inlet (191°F) was indicative of the average reactor coolant system temperature. Therefore, engineering incorrectly concluded that a mode change had not occurred. The evaluation also recommended reporting this event to the NRC by issuing a LER. The team concluded that this analysis was not thorough and did not adequately determine the average reactor coolant temperature. The root cause evaluation provided a brief candid assessment of the event by the SNSS. However, the level of effort applied to complete this investigation was not consistent with the significance of this event. The root cause evaluation did not analyze for generic implications, determine why previous corrective actions failed, or identify corrective actions to prevent recurrence, as required by NAP-6, "Corrective Action Program." The failure by senior plant management to recognize the significance of this event led to the inappropriate attention placed on conducting this root cause investigation. This oversight by senior management was corrected on July 20, 1995 when the licensee's shutdown cooling bypass event team was chartered.

The licensee's shutdown cooling bypass event team root cause evaluation identified most of the significant performance issues identified by the NRC STI. Some noteworthy differences were as follows:.

- The first mode change that occurred at 4:35 p.m., on July 8, 1995, was not identified during the licensee's root cause investigation. The failure to identify this mode change was significant because, this event caused the team to review the availability of instrumentation and procedures during normal SDC operations. During this mode change the RHR pumps were secured in accordance with technical specifications to conduct surveillance tests. When the RHR pumps are secured the RHR heat exchanger inlet temperature is no longer a valid indication of bulk average reactor coolant temperature. Plant procedures did not provide adequate guidance on alternate means to determine average reactor coolant temperature when the RHR pumps were secured. Plant operators did not properly monitor other available plant indications to determine the conditions in the reactor vessel. Based on this finding, additional corrective actions were required.

- The shutdown cooling bypass event team report did not identify weak communications and command and control as causes of the event. The licensee was conducting a separate assessment of operator performance issues due to be completed by August 30, 1995. The General Manager stated that these issues would be evaluated during this assessment.

- The licensee's shutdown cooling bypass event team concluded that procedural deficiency was not a causal factor in this event. The STI concluded that procedural deficiencies did contribute to this event (See Section 5.1). The licensee's shutdown bypass event team report did recommend a corrective action to enhance the operating procedures. However, the report did not identify corrective actions to address the lack of guidance on maintaining adequate flow or monitoring average reactor coolant temperature.

6.3 Independent Oversight

The team concluded that the performance of the independent oversight organizations in the evaluation and followup of this event was mixed. Shortly following the event, both the Safety Review Group (SRG) and Quality Assessment (QA) identified valid concerns regarding the corrective actions being taken by plant management. Both organizations did an excellent job identifying the significance of the loss of shutdown cooling and the inadequacies in the management response. However, neither organization was initially successful convincing plant management of the significance of this event or bringing about improvements in the event response. Plant management did not respond to the QA and SRG findings for 7 days, until July 20, 1995, when the GM initiated the bypass event evaluation team.

The SRG had an early involvement in the loss of shutdown cooling event. The SRG members stated that they were first made aware of the event during a morning Planning Meeting on July 10, 1995. The SRG self-initiated an independent investigation of this event. The SRG provided a draft report describing the SRG findings to the acting General Manager on July 13, 1995. The draft SRG report identified the following issues:

- The event was reportable. The report indicated expressed frustration, on the part of the SRG, that the reportability issue was not being addressed.
- Plant operators were not properly aware of plant conditions during the event (e.g. operators did not believe the indications of reactor pressure).
- Several procedures and technical specifications were violated.
- There was a loss of the shutdown cooling safety function.
- There was a possible mode change.

The findings of the SRG investigation were largely consistent with the event evaluation team findings documented in the August 7, 1995 final report. The team determined that the evaluation performed by the SRG was timely and the findings were accurate. These findings were discussed with the acting General Manager during a July 14, 1995 meeting. At the meeting plant management agreed to submit a voluntary LER to the NRC describing this event. The SRG was unsuccessful in changing plant management's assessment of the significance of this event. A comprehensive event evaluation was not initiated until July 20, 1995, when the licensee's shutdown cooling bypass event evaluation team was chartered to investigate this event.

The Hope Creek QA group was also aware of the safety significance of this event. The QA Supervisor learned of the event on July 10, 1995. The QA Supervisor stated that he felt that SDC had been bypassed and a mode change had most likely occurred. These views were made known to the acting General Manager prior to the July 14, 1995, meeting. The concerns expressed by QA were documented in the QA, "Monthly Report-July 1995," dated August 2, 1995.

6.4 Reportability Determination

The team concluded that the licensee failed to notify the NRC of this event in accordance witn the requirements of Title 10 Code of Federal Regulations (CFR) Part 50.72. The licensee was required to make a four-hour report to the NRC for any event or condition that alone could have prevented the fulfillment of the safety function of systems that are needed to remove residual heat. The licensee properly submitted a LER (50-354/95-16) to the NRC within 30 days of the event in accordance with 10 CFR 50.73.

Title 10, CFR 50.72(b)(2)(iii)(B) requires that a four hour report be made to the NRC for any event or condition that alone could have prevented the fulfillment of the safety function of structures or systems that are needed to remove residual heat. NUREG-1022, "Event Reporting Guidelines 10 CFR 50.72 and 50.73," provides additional guidance on reporting requirements associated with loss or degradation of decay heat removal. The NUREG states that "The level of judgement for reporting an event or condition under this criterion [50.72(b)(2)(ii)(B)] is a reasonable expectation of preventing fulfillment of a safety function." During this event the decay heat removal (DHR) capabilities of both trains of SDC were degraded to the extent that it prevented the fulfillment of the safety function. This conclusion was consistent with the licensee's LER that states, "... this bypass event rendered that shutdown cooling mode of Residual Heat Removal (RHR) inoperable." The degradation was caused by leaving the recirculation pump discharge valve open that resulted in SDC flow being bypassed from the reactor vessel. The safety function of the decay heat removal system was to maintain the reactor in a cold shutdown condition. The safety function was not fulfilled as evidenced by vessel pressurization and the change of plant modes.

The reportability program is implemented in accordance with NAP-6, "Corrective Action Program". The SNSS/NSS are responsible for making immediate reports to the NRC. An Event Classification Guide provides additional reportability guidance. The SNSS/NSS did not initiate a four-hour report. Senior plant management also failed to properly direct the SNSS/NSS to initiate a four hour report. The operating shifts and senior plant management were slow to appreciate the extent of SDC degradation. Based upon interviews with the operating shifts, it appears that the status of SDC was viewed as operable, but degraded, since process temperatures indicated that heat was being removed by the SDC system. Accordingly, the operating shifts erroneously concluded that the event was not reportable under the requirements of 10 CFR 50.72.

The plant management team could not reach a consensus on reporting this event even after the significance of the event was fully appreciated. In an August 2, 1995, memorandum from Quality Assessment, it was stated that on July 12, 1995, the assessment team believed that "...the SDC system was operated in a degraded condition which could have prevented the fulfillment of its safety function". Such an assessment would support making a four-hour 50.72 report. In addition, a July 13 report from SRG identified the importance of this event and concluded that it was reportable. The licensee's final shutdown cooling bypass event report stated that the team was unable to reach a consensus for reporting this event under 10 CFR 50.72. However, the team did conclude that a voluntary notification would have been appropriate.

During a July 14 meeting to discuss the reportability of this event, the acting General Manager agreed that a "Voluntary LER" would be submitted to the NRC. The LER later became required when it was determined that a mode change had occurred that resulted in noncompliance with various technical specifications. LER 50-354/95-16, describing this event and corrective actions, was issued on August 9, 1995.

7.0 SAFETY SIGNIFICANCE

The team concluded that this event was safety significant. However, the consequences of this event were minimal and this event had no direct adverse effect on the health and safety of the public or plant personnel. During this event, two of the three primary fission product barriers were in a degraded condition with the reactor in the hot shutdown condition. The third fission product barrier (fuel cladding) appeared to be adequately protected. The team also determined that identified weaknesses in both operator and management performance during and following this event were also significant.

During this event two of three primary fission product barriers were in a degraded condition with the average reactor coolant system temperature in excess of the cold shutdown condition (greater than 200°F). The reactor coolant system fission product barrier was not established during this event, since the reactor vessel head vent valves were opened to vent the reactor coolant system to the primary containment. The primary containment fission product barrier was also not continuously established during this event. In the cold shutdown condition primary containment integrity is not required to be established. The aspects of primary containment integrity that were not established were the automatic containment isolation closure feature for a few RHR and RWCU system isolation valves. The main steam isolation valve sealing system would also be required to be operable above the cold shutdown condition. Secondary containment was maintained during this event. The plant operators had the ability to quickly re-establish the both open fission product barriers at all times during this event. The fission product barrier that remained established was the fuel cladding.

Adequate plant systems were available to remove decay heat in the event of a loss of shutdown cooling. The safety relief valves and accumulators remained operational and the RHR and core spray system were available to makeup inventory to the reactor vessel. In the event of no short-term operator action, the reactor vessel pressure would increase to a point that the operators would take action to restore shutdown cooling. The team concluded that there were adequate backup systems available to protect the third fission product barrier (fuel cladding). However, further review by the licensee and NRC continues to determine the extent of the safety margin associated with the third barrier.

The vessel pressurization transients were comparable to those experienced during a normal plant heatup. The highest reactor vessel pressurization rate (25 psig in 24 minutes) occurred during the first mode change on July 8, 1995, when the RHR pump was secured for surveillance testing. The reactor coolant system temperature and pressure were quickly returned to the normal cold shutdown condition when shutdown cooling was restored. Throughout the event the core decay heat continued to be principally removed by the RHR heat exchanger with a very small amount of decay heat being removed by the steam leaving the reactor coolant system head vents.

During the event the reactor vessel water level measured in the downcomer annulus region remained approximately 15 ft above the top of the fuel. The reactor coolant and offgas radiation levels indicated that fuel cladding was not damaged during this event. No abnormal offsite releases of radiation occurred as a result of this event. The additional radiation doses received by plant personnel making drywell entries, as a result of this event, were negligible.

7.1 Plant Instrumentation

The team concluded that the plant instrumentation and procedures did not provide adequate guidance to determine average reactor coolant system temperature during this event.

The pertinent temperature indications available in the control room during cold shutdown are the RHR heat exchanger inlet and outlet, bottom head drain line, RWCU system inlet, reactor head vent, and the reactor vessel metal temperatures. The reactor vessel pressure can be monitored in the control room using the normal reactor pressure (range 0-1500 psig) indicators or the main steam isolation valve sealing steam pressure gage (range 0-50 psig). The RHR heat exchanger inlet temperature is normally used by plant operators to determine average reactor coolant system temperature during cold shutdown conditions. With a RHR pump inservice and the recirculation pump discharge valves closed, the RHR heat exchanger inlet temperature indication provides an accurate representation of average reactor coolant system temperature. However, during this event the RHR heat exchanger inlet temperature indication did not accurately represent the average reactor coolant temperature. When the recirculation discharge valve was opened relatively cold water from the outlet of the RHR heat exchanger was mixed with the hot water returning from the vessel annulus region. This resulted in a false lower indication of average reactor coolant system temperature. In addition, the low shutdown cooling flow through the core allowed stratification of the reactor coolant inside the core shroud region. This caused additional inaccuracies in using the RHR heat exchanger inlet temperature to determine the average reactor coolant system temperature. Other plant indications available to the operators were discounted due to the indications being in the lower range of the instrument.

The first mode change (July 8, 1995, at 4:35 p.m.) occurred when the operators secured the operating RHR pump to conduct a surveillance test. There is no forced flow thorough the core or RHR heat exchanger when the RHR pump is secured. The RHR heat exchanger inlet temperature is not a valid indication of average reactor coolant system temperature when the RHR pump is secured. The RWCU system inlet temperature was not a valid indication of average RCS temperature. The RWCU system does not force flow through the core region. The team concluded that in cold shutdown, there are no valid plant indications of average RCS temperature when the RHR pumps are secured. During this event, monitoring of the reactor vessel metal temperatures would not have indicated that the RCS was heating up, since the vessel metal temperatures were greater than the RCS temperature and trending down. Monitoring the reactor vessel pressure would not have ensured that the average RCS temperature would be maintained below 200 °F, since reactor vessel would not begin to pressurize until 212 °F.

7.2 Mode Change

The team determined that the licensee's engineering analysis, completed on August 4, 1995, correctly concluded that two mode changes had occurred.

Calculation NFS-0142, "Hope Creek 07/08/95 Shutdown Cooling Bypass Event Peak Vessel Coolant Temperature Analysis," was completed on August 4, 1995. The Nuclear Fuels Section calculation concluded that a mode change had occurred. The steady state best estimate heat balance calculations performed by the licensee confirmed that the peak vessel average temperature reached approximately 207 °F. Sensitivity studies on the independent inputs to the calculation indicated that the temperature was accurate within $\pm$ 5 °F. The analysis and the assumptions were technically sound. The jet pump flow through the active loop and the jet pump flow in the idle loop was appropriately included in the calculation. General Electric Corporation (GE) engineers reviewed the licensee calculation and provided comments. The GE engineers agreed with the conclusion of the calculations.

7.3 Technical Specification Compliance

The team concluded that several technical specification (TS) limiting conditions for operation (LCO) requirements were not complied with during this event.

(1) <u>TS LCO 3.4.9.2, Residual Heat Removal- Cold Shutdown</u>

The TS states that two shutdown cooling mode loops of the residual heat removal system shall be operable and, unless at least one recirculation pump is in operation, at least one shutdown cooling mode loop shall be in operation. The shutdown cooling pump may be removed from operation for up to 2 hours per 8 hour period provided the other loop is operable. During the this event, the "B" RHR shutdown cooling loop was unable to perform its intended safety function (i.e. maintain the reactor in cold shutdown) and was inoperable. The "A" RHR shutdown cooling loop, while not in operation, was also affected by leaving the recirculation pump discharge valve (F031A) open and should have also been assumed to have been inoperable. The action statement requirement to demonstrate the operability of at least one alternate method capable of decay heat removal for each inoperable RHR shutdown cooling mode loop within one hour was not completed. The action statement requirement to establish reactor coolant circulation by an alternate method within one hour when no RHR shutdown cooling mode loops are operable was also not completed.

(2) TS LCO 3.3.2, Isolation Actuation Instrumentation, TABLE 3.3.2-1, Item 7, RHR System Shutdown Cooling Mode Isolation

The TS states that the RHR system shutdown cooling mode isolations for reactor vessel water level and pressure must be operable in operational condition 3. If the isolations are not operable the required action is to lock the affected system isolation valves closed within one hour and declare the affected system inoperable. At approximately 11 p.m. on July 8, 1995 the RHR system shutdown cooling mode pressure isolation signals were not operable for greater than one hour while the reactor was in operational condition 3. The required compensatory measures to lock the affected system isolation valves and declare the affected system inoperable were not completed.

(3) TS LCO 3.6.1.4 Main Steam Isolation Valve (MSIV) Sealing System and LCO 3.0.4

The TS states that two independent MSIV sealing system subsystems shall be operable in operational condition 3. The action requirements state that with one MSIV sealing system subsystem inoperable to return the subsystem to operable status within 30 days or be in cold shutdown in the next 36 hours. TS 3.0.4 requires that entry into an operational condition may be made in accordance with the action requirements when conformance to them permits continued operation of the facility for an unlimited period of time. The drywell primary containment instrument gas (PCIG) system was tagged out and depressurized on July 8, 1995 at 8:45 p.m. in preparation for outage maintenance activities. Removing the PCIG system from service rendered the main steam isolation valve steam sealing system subsystems inoperable. The change to operational condition 3, that occurred at 10 p.m. on July 8, 1995, with the MSIV sealing system subsystem inoperable was not in compliance with the TS.

7.4 Shutdown Risk

The team reviewed the plant activities shortly after shutdown and determined that the SDC system had been secured twice during this period to verify that the SDC isolation valves could be manually operated following defeat of the SDC high pressure automatic isolation signals. The team questioned whether securing the SDC system shortly after a plant shutdown unnecessarily increased the shutdown risk to the plant.

The SDC system automatic high pressure isolation signals were defeated either by operation of a key switch or by installation of jumpers in accordance procedure HC.OP-GP.SM-0001, "Defeating NSSSS Isolation Signals For Shutdown Cooling." The procedure directed that the SDC isolation valves be manually operated following defeat of the automatic high pressure isolation signals to ensure that the SDC system could still be manually isolated. The team reviewed the procedure and noted that since the methods used to defeat the high pressure automatic isolation signals did not involve the lifting of any leads, it did not appear likely that performance of this procedure could inadvertently defeat the ability to manually operate the SDC isolation valves.

The team was concerned that securing the SDC system shortly after a reactor shutdown (i.e when the expected reactor decay heat rate would typically be at a maximum level) increased the potential for a plant problem due to inadequate monitoring of parameters or to untimely restoration of the SDC system. Also, the operators did not have adequate information to determine the amount of time that the SDC system could be removed from service or a representative indication of the reactor coolant temperature while the SDC system was secured. The team concluded the above two factors or a SDC system equipment problem during the restoration could result in the SDC being secured for an excessive period of time.

The team discussed the above concerns with the appropriate engineering and operations personnel who indicated that they would review the HC.OP-GP.SM-0001 procedure to determine if the step for securing the SDC system was necessary. Additionally, the licensee indicated that enhanced operational guidance for securing the SDC system would be developed. The team determined that these planned actions were appropriate.

8.0 MANAGEMENT MEETING

The licensee's management was informed of the scope and purpose of this inspection at the entrance meeting on August 7, 1995. The findings of this inspection were discussed with the licensee's representative during the course of the inspection and presented to senior licensee management during an exit meeting was held at Hope Creek on August 24, 1995. The exit meeting was open for public observation and the slides used during this meeting are provided as Attachment 3. No proprietary materials were reviewed during this inspection. The licensee did not dispute the inspection findings at the exit meeting.

ATTACHMENT 1

NRC INSPECTION TEAM

CHARTER