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REGION III

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Licensee: Northern States Power Company
414 Nicollet Mall
Minneapolis, MN 55401

Facility Name: Prairie Island Nuclear Generating Plant

Inspection at: Prairie Island Site, Red Wing, MN

Inspection Conducted: February 21 - 25, 1992

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Inspection Summary

Special, unannounced safety inspection by an NRC Augmented Inspection Team to determine the facts and to perform evaluations relating to a loss of residual heat removal system event at the Unit 2 reactor which occurred on February 20, 1992. Information was collected for an independent risk assessment. The onsite inspection effort concluded with a public "exit" meeting.

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DETAILS

I. Introduction

A. Background

Prairie Island Nuclear Generating Plant (PINGP), Unit 2, is a 2-loop pressurized water reactor plant of Westinghouse design. The licensed power limit is 1650 megawatts thermal.

On February 20, 1992, the Unit 2 reactor was in a cold shutdown condition, approximately two days into a scheduled refueling outage. Reactor core cooling was being provided by one train of the residual heat removal (RHR) system, with RHR pump No. 22 in service to provide cooling flow. Temperature was about 133 degrees Fahrenheit (F).

At 11:10 p.m. (C[illegible]) the operating RHR pump was shut off by plant operators because it was giving evidence of insufficient flow, apparently due to a too low water level in the pump suction from the reactor coolant system (RCS). Procedures were implemented to respond to the condition of low water level in the RCS and no cooling flow. These procedures provided for the addition of water and the re-establishment of cooling flow. They were effective in stopping the heatup of the RCS, which began at the onset of the event, and returning temperature to pre-event levels. During the event, however, temperatures as high as 221 degrees F were reached just above the reactor core.

The NRC Acting Senior Resident Inspector (SRI) was notified of the event at about 11:40 p.m. and went to the plant site. Post-event evaluation by on-shift management concluded with a determination that the event should be classified as an "Unusual Event" under the classification criterion of the applicable procedure. An official notification to NRC via the Emergency Notification System occurred at 1:26 a.m. on February 21, 1992.

B. Augmented Inspection Team (AIT) Formation

The NRC consulted on the event through the early hours of February 21, including discussions with the Acting SRI at the plant site. A conference call was held among NRC management and staff at Region III and in the NRC Office of Nuclear Reactor Regulation (NRR) and the Office for Analysis and Evaluation of Operational Data (AEOD), as well as staff of the Executive Director for Operations. Subsequently, the Acting Regional Administrator directed the formation of an AIT comprising Region III, NRR and AEOD personnel. A Region III Reactor Projects Section Chief was designated as Team leader.

C. AIT Charter

The charter for the AIT was prepared on February 21, and the special inspection formally commenced the following day at 9:30 a.m. with an entrance meeting and a licensee briefing concerning the event.

The Team leader discussed the purpose and scope of the AIT response, and requested licensee cooperation in scheduling interviews and in providing documents and other information relating to the event.

Concurrently with preparation of the charter and travel of the AIT members to the site, a Confirmatory Action Letter (CAL) was prepared. The CAL specified that the water level instrumentation in use at the time of the event was to be quarantined. The conditions for clearing this equipment from quarantine status were discussed at the entrance meeting.

The charter for the AIT specified that the following matters were to be evaluated:

1. Determine and validate the sequence of events associated with the loss of shutdown cooling event on February 20, 1992. Include consideration of equipment availability, containment integrity, and whether any other ongoing activities contributed to the loss of shutdown cooling or the significance of the event.

2. Adequacy of reactor coolant system level instruments, draindown/mid-loop procedures, knowledge, skills, and abilities of operators involved in process of draindown (including incorporation of NRC guidelines).

3. Adequacy of response to pump cavitation (operators, shift management, support organizations, licensee management) up to and including bases for concluding no damage occurred.

4. Adequacy of recovery procedures and actions taken; knowledge, skills, and abilities of operators for the event; and contingencies if the plant had not followed optimum recovery path. Adequacy of post event evaluation and decision to resume refueling operations.

5. Degree of management involvement and oversight in draindown and in the outage work activities in general (including shift management, STA, and site management).

6. Outage planning, existence of management pressure to expedite activities, concurrent activities at time of event, timing of draindown following reactor shutdown (shutdown risk analysis), operator burden during event.

7. Adequacy of licensee notification to NRC.

8. Status of NRC program implementation at this facility with regard to shutdown operations, including midloop/reduced inventory.

You will also collect and provide information for development of a risk management assessment including:

- equipment out of service
- alternate or backup equipment
- personnel training and qualification
- personnel availability

NOTE: In fulfillment of the Charter obligation to collect and provide information for development of an independent risk management assessment, as noted immediately above, the AIT supplied this information to Oak Ridge National Laboratory for utilization under an existing contract with NRC. The information will be evaluated with an Accident Sequence Precursor program developed by Oak Ridge. The results of that evaluation will be published separately from this report. This report covers all of the remaining AIT Charter directives.

II. Event Description

A. Initial Conditions

The unit was in day 2 of a scheduled 20-day refueling outage. Reactor vessel draindown was planned to lower reactor coolant level so steam generator primary side manways could be removed to allow steam generator nozzle dam installation.

Plant conditions just prior to the event were as follows:

Reactor coolant temperature	133 degrees F
Pressurizer Relief Tank pressure	3.0 psig
Residual heat removal (RHR) pump	22 RHR pump
RCS level indication for draindown evolution	1 Tygon tube 2 Electronic Indicators
Containment building	Personnel hatch open
Make-up pumps available	3 Charging pumps, 2 RHR pumps, and 2 safety injection pumps
Steam generator (S/G)	1 S/G > 70% level wide range

B. Event Overview

At approximately 11:10 p.m.(CST), on February 20, 1992, while Prairie Island Unit 2 was in cold shutdown mode, the licensee was lowering the reactor coolant system level to reactor vessel nozzle centerline elevation. This was in preparation for installing dams in the steam generator nozzles to permit steam generator eddy current testing. The No. 22 Residual Heat Removal pump was in use for decay heat removal. The draindown path was from a loop drain valve to the reactor coolant drain tank, which was in turn being pumped to a dedicated chemical and volume control system holdup tank. As draining continued, the licensee observed indications of gas ingestion in the No. 22 RHR pump (low level alarms, low RHR flow, and low RHR pump suction pressure and motor current). Draindown was stopped and the RHR pump was shut off shortly after these alarms were received. Water level was raised by using two charging pumps and the No. 21 RHR pump to transfer water from the refueling water storage tank. After water level was restored, the RHR system was realigned and the No. 21 RHR pump was restarted in the decay heat removal mode.

The reactor was without RHR system operation for approximately 21 minutes. Core temperature as indicated at the trended core thermocouple increased from 133 degrees F to 221 degrees F. Reactor coolant samples taken shortly after the event indicated that no fuel damage occurred. There was no radiological release to the environment.

C. Detailed Sequence of Events

See Appendix C.

III. Event Evaluation

A. Systems and Components

The inspection team evaluated the availability and operability of systems and components in use or in standby readiness for use during the event.

1. Reactor Coolant Level Measurement System

Reactor coolant level indication for reduced inventory operations is provided by electronic pressure transmitters located in each of the reactor coolant loops. Process line connections for the transmitters are at the intermediate leg in the reactor coolant pump loop slightly above the loop low point. An additional level indication is provided by a simple, permanently installed, "Tygon tube" in which the water level can be observed locally inside the containment building. The tube taps off the drainpipe from the reactor coolant loop A crossover leg at the bottom of the reactor coolant pump loop. The lower section of this tube is stainless steel while the vertical section, where level readings are observed, is made of clear, plastic, Tygon tube. The wall behind the Tygon tube is marked with reference marks to obtain a direct measurement of the water level. All three level measuring devices are referenced to the containment atmosphere. Figure 1 provides a diagram of the level instrumentation.

The electronic level indication can be observed in the control room by means of the Emergency Response Computer System (ERCS). The Tygon tube levels are communicated to the control room by radio call from a "tube watch" operator who is stationed at the tube to observe the water level.

The electronic level transmitters provide both wide range and narrow range indication. The wide range span is 0 to 100 inches. The narrow range is the bottom 28" of the wide range. The zero reference point is the bottom of the cold leg at elevation 722'-2.5". Mid-loop is at reactor vessel nozzle centerline at elevation 723'-4.25". The level indication is automatically compensated for any nitrogen overpressure on the coolant system by a pressure signal from a pressure transmitter for the pressurizer relief tank. If the level sensed by the transmitter exceeds its range capability, the computer will indicate a "failed" condition for the level transmitters. This condition existed during the event when the nitrogen overpressure was greater than about 3 psig.

Overpressure compensation for the Tygon tube readings is accomplished by means of a table in the procedures which provides a correction factor for the water level. The table can accommodate overpressures up to 1.5 psig. Compensation above 1.5 psig must be calculated by means of a formula provided in the procedure. The pressure reading for the correction of the Tygon tube level reading is obtained from the same pressure transmitter that provides an input to the electronic level transmitters.

Installation of the Tygon tube appeared to be well done. There were no kinks, sharp bends, or other indications that the tube was restricted in any way. There was also no evidence of boric acid crystals which could mask the reading. The control room computer display was clear and legible. The screen provided both a schematic and numerical display as well as trending capability. There were, however, a number of weaknesses which were evident.

Several valves in the stainless steel portion of the line must be kept open to allow the free flow of fluid. There was no tagging or markings at the valves to assure that no one would close or reposition the valves. This also applied to the electronic level transmitters.

Lighting in the area was barely adequate. In addition, the low level of the observation platform made direct reading of the tube difficult as the water level approached mid-loop levels.

A major design weakness was identified with the level measurement system involving a lack of redundancy. Both the electronic level transmitters and the Tygon tube use the same pressure sensor input for overpressure compensation. Failure of the single pressure sensor would result in incorrect level indications, even though the three instruments might be in agreement. Level indication could also be impacted by boiling in the reactor coolant, as this could pressurize the system with steam or lead to incorrect level indication due to water "slugs" in the reactor coolant system. This design weakness did not affect the February 20 event.

2. Residual Heat Removal System

The residual heat removal (RHR) system at Prairie Island Unit 2 performs the shutdown cooling function and also operates in the Low-Pressure Safety Injection mode as part of the Emergency Core Cooling System. The RHR system is a two train system with two pumps, two heat exchangers, and several suction and discharge locations. See Figure 2 for a schematic of this system.

Each train of RHR contains a Byron Jackson, Pump Division, centrifugal pump. The pumps are sized to meet plant cooldown requirements. Some suction piping is common to both trains of RHR.

Prior to the February 20, 1992, event the RHR system was aligned for shutdown cooling with the No. 22 RHR pump in operation. Operators were maintaining RHR flow at approximately 2000 gpm. They were maintaining component cooling water at approximately 85 degrees F in order to maintain RHR (and, thereby, reactor coolant) temperature less than 140 degrees F. The draindown procedure required RHR flow to be less than 1000 gpm as a prerequisite for draindown. This prerequisite was designed to help prevent vortex formation in the RHR pump suction. When this flow adjustment was performed, operators had to reduce component cooling water temperature to 65 degrees F in order to maintain RCS temperature less than 140 degrees F. This was due to the sizeable decay heat load (about 6 megawatts) that existed two days after shutdown. The RHR system performed as designed prior to the event and behaved as expected during the event considering the conditions to which it was exposed.

3. Alternate Heat Removal Capabilities

The procedure in effect required operators to maintain more than 70 percent wide range level in one "dedicated" steam generator as a prerequisite to draindown. This was a conservative step to provide diverse heat removal capabilities. The procedure also required the motor driven auxiliary feedwater pump to be operable so operators could use it to add water to the steam generator if required. Both of these prerequisites were satisfied. In addition, although not required and not "dedicated," the other steam generator was also available.

4. Inventory Addition Capabilities

The draindown procedure required the charging system to be operable (2 pumps) as a prerequisite. During this event all three charging pumps were available. The charging pump capacity is approximately 60 gpm per pump.

The procedure also required one safety injection (SI) pump to be available to inject into the reactor vessel and required both RHR pumps to be available. During this event both SI pumps were available. The

SI pump capacity is approximately 700 gpm at 1082 psig discharge pressure. The RHR pump capacity is greater than 2000 gpm.

Make-up water sources included both the boric acid storage tank and the refueling water storage tank, with a cumulative inventory in excess of the total capacity of the reactor coolant system. An additional inventory addition capability existed via a gravity feed lineup from the refueling water tank.

Train A electrical supply was in its normal lineup with three sources of offsite power and one diesel generator (D1) available as a backup. Train B electrical supply was also in its normal lineup with two sources of offsite power and the other diesel generator (D2) available as a backup.

5. Containment Integrity

The licensee stated that containment closure could have been readily achieved during the event if it had been necessary. The licensee identified two locations where containment was open; the personnel access door, and an instrument penetration containing temporary leads for eddy current testing of the steam generators. The inspectors examined both locations to determine if containment integrity could have been restored.

The instrument penetration consisted of a threaded tube about 2 inches in diameter. The electrical leads passing through the penetration were encapsulated in a sealing compound so that, effectively, the penetration was closed. The licensee stated that in the existing configuration the penetration could withstand a 40 psi pressure. Minor leakage could take place through the wire insulation. The penetration is at a level of about one foot above the floor outside containment and is easily accessible. Placing a metal cap over the penetration is necessary to close it. However, the inspectors considered the condition during the event acceptable for containment closure despite the potential for minor leakage.

Closure of the personnel access door requires removal of several floor plates weighing about 40 pounds each. Metal guards on three sides of the door lip need to be removed with the aid of a screwdriver. All necessary tools were easily accessible. Normally, the inboard and outboard access doors are interlocked to prevent both from opening at the same time. At the time of the event the interlock, which consists of a short tie rod connected to the movement mechanism of the inboard door, had been removed to allow both doors to be open. The tie rod was simply left loose. The inspection team believed it would be possible for the loose end of the tie rod to become jammed against the locking mechanism of the outboard door. If the rod jammed, neither door could be closed.

6. Fuel Integrity

The inspectors reviewed the licensee's actions to investigate for the possibility of failed fuel. An initial coolant sample was taken on February 21 immediately after midnight. This sample did not indicate any dose equivalent iodine. Samples were then taken every four hours until 4:30 p.m. on February 21, every eight hours through February 22, and every twelve hours thereafter. No dose equivalent iodine was detected in any of these samples. This indicates that no fuel damage occurred.

B. <u>Procedures</u>

The inspection team noted potentially significant weaknesses in procedure D2, revision 21, "RCS Reduced inventory Operation," which was the procedure in effect at the time of the event. The procedure did not specify requirements for the following:

* Points during the draindown where the evolution should be stopped to allow static readings to be taken and a comparison of all available data made.

* The maximum rate at which the coolant may be drained and how this maximum rate should be reduced as the target level is approached.

* The frequency at which Tygon tube readings should be taken and corrected levels calculated.

* The accuracy with which calculations were to be performed.

* The frequency at which holdup tank level is read and discharged reactor coolant volume is calculated.

* Maintaining a log of Tygon tube readings, nitrogen overpressure, time, and calculated level.

The procedure did not adequately describe the method to control nitrogen pressure throughout the draining process. There were references to maintaining nitrogen pressure, but these references were not clearly stated and were on occasion contradictory. The initial nitrogen pressure specified in the procedure was incompatible with the design of the electronic level transmitters. Therefore, the requirements to have the level instruments operable and an initial nitrogen pressure of 6 psig were mutually exclusive. The effect of the nitrogen overpressure on the rate at which the system drains was also not addressed in the procedure.

The procedure did not adequately specify the required instrumentation to be operable prior to draining the coolant. The procedure specified the Reduced Inventory computer display shall be operational and specified the primary inputs to this display. However, the procedure did not specifically state these primary instruments were required to be operable. This computer display was considered operational by the drain down crew even though both of the level instruments were showing "failed" on the display because they were overranged. The procedure also stated a comparison between the computer display and the Tygon tube reading should be made when the electronic level instruments came on scale. This comparison was not made because the level instruments did not come on scale until too late in the draining. The procedure did not state a level at which the comparison should be made, nor the necessary actions if sufficient agreement is not achieved.

One step of the procedure stated "If ERCS (the computer) becomes inoperable, stop draining the RCS and refer to D2.2". This step was inadequate in that the loss of the Reduced Inventory ERCS display or any of its primary inputs, rather than a loss of the entire computer system, should warrant stoppage of the draindown.

The inspection team concluded the draindown procedure was not adequate to its task considering other conditions which existed at the time of the event.

C. Operating Shift Crew

The unit control room duty operating crew consisted of a Shift Manager/Shift Technical Advisor (SM/STA), a Shift Supervisor (SS), Lead Plant Equipment & Reactor Operator (LPE&RO), and Plant Equipment & Reactor Operator (PE&RO). The duty crew was performing outage activities generally unrelated to the draindown. An extra crew of three operators who did not normally report to the duty shift manager present was also in the control room to assist during outage activities. Two of the extra operators were assigned to draining the Reactor Coolant System to mid-loop for installing nozzle dams. The junior of the two operators involved in the draindown was placed in charge by the duty LPE&RO as he was the first person available to relieve the off-going crew. The third extra operator was assigned to drain/fill operations of the steam generators.

The operators directly involved in the draindown had participated in previous draindowns, supported by an experienced engineer who provided technical direction and performed any calculations required. The draindown process required knowledge of water level in the coolant system at all times during the evolution. The electronic reactor vessel water level instruments, which were intended to provide level indication in the control room on the Emergency Response Computer System (ERCS), were in service but both showed "failed." The control room personnel accepted this over-ranged condition as an expected response during the early stages of draining when water level was above the range of the instrument. The only level indication available to the operators was the Tygon tube level. It was being monitored locally in the containment building. The level in the Tygon tube had been about eye-level at the containment station during previous draindowns. On this occasion, the nitrogen pressure on the system was elevating the tube level approximately 10 to 15 feet. At this elevation it was difficult for the operator to read because of poor lighting, hindered access, vague tube markings and a floor penetration which partially obscured vision. One of the operators in the control room was in constant communication with the operator in the containment to obtain level information.

A System Engineer, on duty to assist in this draindown, had limited experience, having only participated in the first one-third of a prior draindown. A final functional test for the level instrumentation had been assigned as a collateral duty of this System Engineer, to be completed during the draindown. During previous draindowns, an experienced engineer had given continuous direct support to the operating crew providing direction on adjusting nitrogen pressure and drain rates and performing required calculations.

The Tygon tube level had to be corrected for nitrogen overpressure effects to obtain the actual level in the system. Conversion from tube level to actual level involved several different units of measurement and calculations were necessary. Both draindown operators were calculating corrected levels and verifying each others calculations. In some instances, decimal values for pressure were rounded off to the nearest whole number when performing the conversions, introducing errors of up to one foot from the actual level value. The operators did not realize the magnitude of the error they introduced by the rounding off.

The Shift Manager performed a calculation at 10:50 p.m. to determine the time remaining before completion of the drain-down, based on total volume drained, by using the indicated level of the holdup tank which was collecting the reactor coolant. A conversion number from the plant tank data book of 622 gallons to one percent indicated level in the holdup tank was used. A time to completion of thirty minutes was determined and announced to the crew. A conversion of 637.5 gallons per percent (derived from values in Procedure D2 step 5 ".3.D) had been used by the experienced engineer in previous draindowns. This would have produced a calculated time of 17 minutes to the end point. The level of direction/support contained within operating procedure D2 and the limited experience of the Systems Engineer resulted in the operating crew performing the draindown without accurate level information. A potential method of recognizing the inaccurate level information, the calculated remaining drain time, provided a time calculation with no conservatism.

Communication between the draindown operators and operators in containment at the Tygon tube was satisfactory. Information concerning Tygon tube level was requested by the control room and received about every ten minutes. The draindown operators were concerned over the lack of electronic level measurement as the draining progressed. They related this fact to the System Engineer who left the control room at approximately 9:30 p.m. to enter containment to verify the level instrumentation system valve lineup. After the System Engineer left, the operators began to use the rounding off methods which produced erroneous corrected level values. Plant behavior appeared different with respect to the "burping" action of steam generator tubes compared to previous drain-downs. Several distinct increases in indicated level had been observed on previous draindowns. This time the onset of steam generator tube burping was difficult to identify and appeared to one of the operators to be a single continuous action. He was uncertain when it stopped. The operators did not relate these concerns to their supervisor nor did they immediately stop draining when they encountered unexpected conditions. Instead, they began venting the operating RHR pump.

The Shift Manager was aware of the level indication problem and had three different conversations with the System Engineer and an Instrument Technician concerning the electronic level indication. The Shift Manager and Shift Supervisor were both alerted to the serious RHR pump gas ingestion problem only by overhearing conversation of the draindown operators. The duty operators, who had responsibility for the unit, did not know the status of the draindown until problems were encountered, forcing the shutdown of the operating RHR Pump. The Shift Supervisor did not increase his involvement in the draindown when engineering support was not available in the control room. The supervision of the operators by the Shift Supervisor and Shift Manager was inadequate. Both managers periodically reviewed the draindown activities but did not provide sufficient attention given 1) the known inexperience of the assigned engineer, and 2) the additional tasks the engineer was trying to perform to return the electronic level instruments to service.

The operators were logging uncorrected Tygon tube levels which were significantly higher than actual values. This may have contributed to the feeling by the shift management that there was still time remaining.

The operator in charge of the draindown was junior to the operator assisting him. This created some tension during the draindown, particularly over the performance of the hand calculations required to correct Tygon level.

The inspection team concluded the operators were unprepared to conduct their assignment without the accustomed expert engineering support. They did not understand the limitations of their instruments and did not appreciate the significance of rounding off the nitrogen pressure in performing calculations, yet they proceeded. They proceeded in spite of unexpected system behavior and did not inform supervision. They did not exhibit an aggressive, questioning safety attitude. They believed they knew what the coolant level was when they did not.

D. <u>Management Involvement</u>

The planning of the outage was based primarily on experience gained from prior outages. Although the planning organization prepared the outage schedule, members of the operating crew expressed ownership in the schedule as they are all a part of the plant team. The schedule called for commencing the draindown at noon on February 20. At this time the decay heat load was still high and time to core boiling following a loss of decay heat removal capability at reduced inventory was determined to be 10 minutes. The draindown started at approximately 5 p.m. which was behind schedule. The scheduled completion time for draining to mid-loop was midnight on February 20. The operating crew thought they were on schedule for that completion time. All the operators stated they were aware of management's direction that safety came before schedule and they felt no urge to hurry to recover the lost hours, particularly as they were now back on schedule.

The additional reactor operators used to perform the draindown allowed these operators to concentrate on this task without distraction. However, the Shift Supervisor was still involved with outage activities and only provided limited oversight of the reactor operators. The system engineer was removed from any oversight activities because of his pursuit of the problems with the electronic level instruments.

Personnel at the Prairie Island Nuclear Generating Plant are empowered by management to perform tasks with minimal supervision. With this empowerment comes a level of responsibility which may have interfered with the operators' relaying of concerns to their management.

The inspection team concluded that time pressure was not a major factor in this event. Somewhat to the contrary, management was excessively detached from this very important evolution. Changes were made in instruments, procedures, and engineering support which were not adequately evaluated, either individually or in the aggregate. The working level staff thus received assignments for which they were not prepared. This included the System Engineer. Then, during the period immediately preceding the event, direct supervisory support was not focused enough to make up for the existing interactive deficiencies.

IV. Event Response

A. Systems and Components

The inspection team evaluated the performance of components called upon to perform in responding to the event.

1. Charging

Both the No. 21 and No. 22 charging pumps operated as designed during this event. Operators manually started the pumps, which were already aligned to take a suction on the refueling water storage tank. No problems were noted with their performance.

2. RHR valves

All valves, including both motor-operated and manual, operated as designed during this event. No problems were noted with their performance.

3. RHR pumps

During this event the in-service No. 22 RHR pump was observed to experience gas ingestion. This occurred at 11:08 p.m. and was approximately two and one-half minutes in duration. Operators stopped the No. 22 RHR pump at 11:10 p.m.

At 11:26 p.m. operators started the No. 21 RHR pump to raise water level. The pump was aligned to take suction on the refueling water tank. This lineup did not include any of the common RHR suction piping discussed earlier. Therefore, gas pockets that formed as a result of the event did not affect the No. 21 RHR pump. No abnormalities were observed while this pump was running.

After successfully restoring level, operators stopped the No. 21 RHR pump, realigned the RHR system for shutdown cooling, and restarted the No. 21 RHR pump for decay heat removal. Control room operators monitored RHR pump motor current, RHR loop flow, and RHR suction and discharge pressure. No abnormalities were observed. After the pump was started the RCS temperature was decreased to pre-event levels.

On February 21, 1992, at approximately 4:00 a.m., the No. 22 RHR pump was run in accordance with procedure D2 AOP1 to vent gas from the pump suction line. RHR flow was also increased to 2000 gpm to sweep gas from the system. During this evolution no RCS level change occurred. Upon completion of this venting procedure, RHR flow was returned to 1000 gpm.

On February 21, 1992, at approximately 7:00 p.m., operators recorded vibration data for both RHR pumps. No abnormalities were observed. The test was performed at a nominal 950 gpm and the maximum overall vibration amplitude was 0.15 in/sec for the No. 21 RHR pump and 0.12 in/sec for the No. 22 RHR pump. The amplitude and spectral values recorded for both pumps were nearly identical. The amplitude values are less than the previous monthly surveillance values because that test (SP 2089, "Residual Heat Removal Pumps and Suction Valves from the Refueling Water Storage Tank") was performed under different flow conditions. The monthly surveillance will be performed again prior to the first heat-up after the current refueling outage.

The licensee evaluated No. 22 RHR pump flow data that was recorded after the event and determined that hydraulic performance was not affected. Additionally, RHR pump hydraulic performance will be measured against expected values during performance of SP 2092D, "SI Check Valve Test (Head Off) Part D: Lo Head SI(RHR) DSCH Flow Path Verification." This test will be performed during pool flood.

The licensee contacted Byron Jackson, Pump Division, to discuss the effect of operating with adverse suction pressure on the RHR pumps. The licensee described the pump transient, including the motor current and discharge pressure variations during the event and the vibration data recorded after the event. The vendor indicated that the maximum vibration permitted for continuous operation is 3 inch/sec. Based upon the information the licensee presented, the vendor believed that no damage occurred during the transient.

The actions that the licensee completed and the tests that are scheduled for completion prior to start-up appear to provide an adequate evaluation for pump damage. No data recorded indicates pump damage occurred. The licensee's evaluation of the RHR pump operability, which was led by the Superintendent of Technical Support, appeared to be thorough and technically sound.

4. Containment (Evacuation)

As a result of the event, orders were given at 11:22 p.m. to evacuate the containment of all non-essential personnel. According to the maintenance air-lock log for February 20, 1992, 42 persons were logged into containment at 11 p.m. At 11:40, 13 persons remained in containment and by 11:50 p.m., 8 persons remained. Some personnel who exited containment did not log out immediately, and others may not have logged out at all, according to interviews. Instead, they waited near the airlock expecting to return shortly.

Based on a review of the security air-lock records, the inspectors concluded that proper evacuation of the containment had occurred. Once out of containment, it took some period of time to remove protective clothing and log out of the controlled area. This explains the time lag between the evacuation orders and containment log-out.

B. Procedures

Two procedures were used to respond to the event: Abnormal Operating Procedure D2 AOP1, "Loss of Coolant while in a Reduced Inventory Condition"; and Emergency Procedure 2E-4, "Core Cooling following Loss of RHR Flow". These procedures were effective in responding to this event. Procedure D2 AOP1 initiated the starting of two charging pumps to restore level. Procedure 2E-4 initiated the starting of an RHR pump in injection mode to rapidly restore RCS level.

1. Abnormal Operating Procedure D2 AOP1

This abnormal operating procedure was appropriately entered when the operating RHR pump had to be shut off, creating a condition wherein no heat removal system was functioning. The inspection team verified that applicable steps were followed and that the equipment called upon to operate functioned as designed. In the event under evaluation, core decay heat was substantial; so much so that addition of water to the coolant system by two charging pumps, as directed by D2 AOP1, was insufficient to stop a relatively rapid increase in temperature. Thus, this was a transitional procedure. It remained in effect for only eight minutes until temperature rose to the entry condition temperature for Emergency Procedure 2E-4. The inspection team evaluated D2 AOP1 relatively briefly. No notable procedure problems were identified.

2. Emergency Procedure 2E-4

This emergency procedure was appropriately entered and followed during the February 20 event. It was effective in mitigating the event prior to jeopardizing public health and safety, licensee personnel, or plant equipment. However, the procedure contained potentially significant weaknesses that may have rendered it ineffective for other scenarios for which it would have been applied.

The subject procedure had the following entry conditions:

1. 190 °F or greater as indicated on two core exit thermocouples while in a reduced inventory condition.

2. RHR flow has not been restored via RCS (reactor coolant system) makeup and venting of the RHR pump suction.

3. RHR pumping capability has been lost and cannot be restored in a timely fashion.

The procedure was entered in accord with condition 1.

Condition 2 might have been applied since makeup had been insufficient to allow RHR pump venting or restart, and it was reasonably obvious that an RHR restart could not be accomplished before criterion 1 was satisfied. However, an alternate interpretation is that condition 2 would apply only when refill and venting are accomplished and a subsequent restart attempt is unsuccessful. Neither refill nor venting had been completed.

Condition 3 was subject to two interpretations.

First, "RHR pumping capability" may mean the ability to operate an RHR pump to pump water in some way, such as to inject water into the RCS. By this interpretation, item 3 was not satisfied because RHR pump No. 21 was available to pump water from the refueling water storage tank - following appropriate valving.

Or, "RHR pumping capability" may mean the ability to operate an RHR pump in the RHR cooling configuration. By this interpretation, item 3 was satisfied because neither RHR pump could be operated. There was insufficient water level in the RCS to support pump operation.

The inspection team understood the operators used the first interpretation.

The Team found that the operators could have entered procedure 2E-4 earlier than they did, but the actual path they chose was not a violation of the procedure.

The following path was followed in procedure 2E-4:

STEP	ACTION
1	Check All Steam Generator Primary Manways INSTALLED (They were.)
2	Verify RCS - INTACT (It was.)
3	Go to Step 14
14	Establish Secondary Heat Sink In At Least One SG (steam generator) (One SG was at the 70% level and under administrative control as the "dedicated" secondary heat sink.)
15	Evacuate Containment of Non-essential Personnel (Accomplished.)
16	Continue to Monitor Containment Conditions To Determine Necessity For Total Containment Evacuation (There was no significant change.)
17	RHR Flow - RESTORED (It was not restored.) Return to Step 6.
6	Increase RCS Inventory Using RWST Supply to RHR Pump ...
	c. ...refill RCS to one foot below reactor vessel flange (Accomplished.)
	d. Stop RHR pump (This was accomplished when the specified reactor vessel level was reached.)
	e. Go to Step 9
9	Provide Makeup to RCS As Necessary To Maintain Level One Foot Below Reactor Vessel Flange (None was needed.)
10	Evacuate Containment of Non-essential Personnel (The instruction was already initiated.)
11	Continue to Monitor Containment Conditions To Determine Necessity For Total Containment Evacuation (There were no real changes in containment conditions.)
12	RHR Flow - RESTORED (This was accomplished after increasing the RCS inventory as addressed above, followed by stopping the RHR pump, reconfiguring to

heat removal alignment, and restarting the pump.)

13 Go To Step 35

35 (This is effectively the end of the procedure.)

The operators adhered to each procedure step and it was effective in providing operator guidance to mitigate the event for the conditions in which it occurred.

A general review of this procedure yielded the following observations and findings:

(a) 2E-4 was configured to provide effective mitigation guidance over a wide range of potential conditions and consequently was not optimum under all conditions. The NRC staff required broad coverage from emergency operating procedures (EOPs) for power operation, not optimized procedures with narrow coverage that required diagnosis prior to use. The licensee's approach was consistent with the power operation requirement. (The NRC has not established requirements for shutdown procedures.)

Following the event, the licensee changed the 190 °F entry criterion to 150 °F. This would provide an earlier filling of the coolant system while increasing the likelihood of spilling water into containment if the system were open. The earlier entry might have prevented heatup above 200 degrees as occurred in the event, although the actual temperature reached had no direct safety significance for the event that occurred.

(b) Diagnosis is generally not required to apply this procedure and guidance branch-points are based upon indications the licensee apparently thought would normally be available in the control room. This approach is consistent with NRC requirements for EOPs.

(c) The format of 2E-4 is consistent with the licensee's other emergency procedures. This format had been previously approved by the staff in the Westinghouse owners group emergency procedures guidelines, which form the basis for the licensee's procedures. Consequently, the operators were familiar with the branching logic and procedure organization.

(d) Wording and instructions are well formulated, readily understood, and not likely to introduce operator error. No errors were found related to such mistakes as transfer to the wrong procedure locations.

The inspection team also reviewed the procedure with a view to other possible scenarios for which it would be applied. Scenarios were identified for which procedure 2E-4 had steps that are cause for concern, particularly if core cooling via RHR cannot be restored. The following general observations were made:

* Verbatim compliance could unnecessarily lead to core damage because of incorrect or inappropriate operator guidance.

* Containment closure was not reasonably assured for events that initiate with the reactor coolant system in an unclosed condition.

* Personnel working in containment could be unnecessarily placed at risk due to failure to address containment environmental conditions.

* Instructions were provided that involve unanalyzed conditions and which have a potential to complicate a viable cooling method, although this complication probably will not lead to core damage unless the operators react inappropriately.

These same concerns were addressed at length in "Loss of Vital AC Power and the Residual Heat Removal System During Mid-loop Operations at Vogtle Unit 1 on March 20, 1990," NRC Incident Investigation Team Report, NUREG-1410, June, 1990. The concerns were considered generic to a number of pressurized water reactors as well as to some owners group guidance.

The Team also performed an evaluation of the effectiveness of the licensee's Emergency Operating Procedure 2E-4 under alternate, non-optimum scenarios. Details of this review are contained in Appendix D to this report.

C. Operating Shift Crew

The combined crew, both duty and extra personnel, responded to the event. The Shift Supervisor directed the implementation of the Abnormal and Emergency Operating Procedures and was supported by the Shift Manager as the Technical Advisor. Command and control, and the coordination of resources during the event response were satisfactory.

The utilization of the procedures was satisfactory but was not aggressive. The Shift Supervisor decided to wait until core exit thermocouples reached 190 degrees Fahrenheit before entering procedure 2E-4. This is one of three entry conditions for this procedure. The other entry conditions involve loss of RHR flow and loss of RHR pumping capability. Both of these conditions could be stated to exist when the loss of decay heat removal capability occurred. The Team considers either of these entry conditions could have been used to enter the procedure earlier as part of an aggressive response to this event.

D. Management Involvement

The Team interviewed licensee management staff and consulted with the Senior Resident Inspector to evaluate management's response to the occurrence of the event. In general, an aggressive personal involvement by many senior managers characterized the aftermath of the event. Most senior managers learned of the event by rapid informal networking even before the event was classified and a formal notification process initiated. These managers voluntarily came to the site to get involved and see whether and how they could help.

Various managers first started an information-collecting phase in their respective areas of responsibility. This was followed quickly by an informal assembly of management staff for discussion of preliminary findings and comparing notes and opinions. The licensee employees directly involved in the event were specifically consulted for any thoughts or recommendations they could provide on the event. These employees were encouraged, in effect, to air any complaints they might have about what had happened to them. No information received by the NRC Team from any source suggested that management approached the event from the perspective of finding someone to blame. Rather, operations department management exhibited a distress that they had done or failed to do something that had allowed the event to occur. The Plant Manager immediately focused on the potential that there had been a management-created sense of urgency which had contributed. Overall, there was a strong sense of management accountability for the event, accompanied by a resolve to figure out why it happened so that corrective and preventive measures could be taken.

Management identified three areas principally contributing to the event - the nitrogen overpressure and related ramifications, the lack of highly experienced engineering support on a continuous basis, and the lack of direct supervision from the chain of command. Actions were instituted to correct all three of these licensee-identified deficiencies as a prerequisite to recommencing draindown. The Plant Manager made the decision to authorize a return to reduced inventory conditions by draining down. He did so, however, in a collegial setting, after asking all present whether anyone had any reservations. No one did. Draining commenced again about six hours after the event. It was halted at NRC request some three to four hours after that. The inspection team concluded that the corrective actions implemented before the second draindown were sufficient to provide a high degree of assurance of success. These were the actions subsequently instituted when NRC released the "hold" on the draindown three days later.

Other issues and proposed actions were identified in the early aftermath of the event which the licensee's management did not consider critical to perform before proceeding. These included procedure enhancements which were forwarded to and approved by the onsite safety review committee. An internal event review process was initiated via the plant Error Reduction Task Force. Peer assessments were arranged through the owner's group and with a sister plant.

When the NRC inspection team met with licensee management onsite about 34 hours after the event, an exceptionally thorough presentation was ready. This gave evidence of a large effort on the part of the licensee to identify and prepare information for their own evaluation and for the evaluation by the NRC Team. Support to the inspection effort carried out by the Team was highly commendable throughout. All parties were open and forthcoming in responding to questions.

The Team concluded that management was profoundly impacted by the occurrence, but took responsibility for it, and focused prompt and intense attention to its evaluation and the development of effective corrective and preventive actions. Long-term preventive actions under consideration are progressive and design engineering oriented.

E. Reporting to NRC

The Team reviewed records and conducted discussions with licensee personnel to determine if the proper event classification was made and if the notifications to the NRC and to state and local agencies were timely.

1. Event Classification

The operation's shift management initially concluded that no emergency action level (EAL) directly applied to this event. After further review, shift management concluded that an event had occurred which met the EAL requirements for notification of an Unusual Event classification, in accordance with Emergency Plan Implementing Procedure (EPIP) F3-2, "Classifications Of Emergencies," Condition 19, "Conditions that warrant increased awareness on the part of plant operations staff or state and/or local offsite authorities".

The Team believed that the event should have been classified as an Alert. Their basis was that the RHR system was unable to perform its decay heat removal function because of low coolant water level and nitrogen intrusion in the shared suction piping. The Region III Emergency Preparedness (EP) Section was contacted to review and make a final ruling on this matter. They determined the licensee's classification at the Unusual Event Level was in compliance with applicable requirements. A detailed review was made of procedure F3-2, "Classifications of Emergencies," emphasizing Condition 12. This involved inability to maintain cold shutdown, as indicated by an inoperable RHR system and coolant system temperature increasing beyond 200 degrees F. In addition, discussions were held with the licensee staff. The licensee never considered the RHR system inoperable because the system always retained the ability to add cooling water. Core exit temperatures exceeded 200 degrees F but not overall system temperature. When the RHR system was placed in operation per procedure (after core exit temperature reached 190 degrees F) it injected coolant at a rate sufficient to lower the temperature and recover from the event. Based on the above, the NRC Emergency Preparedness staff concluded that the

RHR system was operable and available to maintain the plant in a cold shutdown condition.

2. Notification Timeliness

The licensee made the required notification to the state and local authorities within the required 15 minutes. However, notification to the NRC did not occur immediately thereafter, as required, but took 61 minutes. This also exceeded the 10 CFR 50.72 one-hour reporting requirements. The NRC notification was delayed because of indecisiveness by the licensee as to the event classification and notification responsibility. The Shift Emergency Communicator ultimately made the notification to the NRC. Procedure 5ACD3.6, "Reporting," specifies that reporting to NRC was to be made by Shift Management. The licensee evaluated the emergency classification and notification deficiencies and provided a draft of recommended improvements to the Team prior to its exit.

The timeliness of reporting and the underlying circumstances will also be referred to the NRC Region III Emergency Preparedness Section for evaluation and disposition.

V. Programmatic Issues

A. NRC Generic Issues Status (Generic Letter 88-17)

The licensee responded to Generic Letter 88-17, "Loss of Decay Heat Removal", in a letter dated January 6, 1989. The response described the licensee's expeditious actions and long term program enhancements related to loss of decay heat removal as requested in the generic letter.

The areas addressed by the expeditious actions included; training, containment closure, RCS temperature monitoring, RCS water level measurement, RCS perturbations, inventory additions, and procedures for installing nozzle dams. Long term enhancements addressed modifications to the level measurement system, decay heat removal system performance, procedures review, reliability of cooling equipment, and other enhancements.

In a letter dated June 12, 1989, the NRC concluded that the "response appears to meet the intent of the generic letter for expeditious actions but lacks some of the details requested." The NRC provided some observations for licensee consideration to assure the actions were adequately addressed. Final closeout of the generic letter was provided in an NRC letter dated May 14, 1990.

Two inspections were conducted to review the licensee's actions in response to Generic Letter 88-17. The results are provided in Inspection Report Nos. 50-282/89008(DRP), 50-306/89008(DRP), 50-282/90014(DRP), and 50-306/90014(DRP). No violations or deviations were reported.

The Augmented Inspection Team identified several deficiencies in the hardware and procedures related to decay heat removal:

(1) The two level transmitters and Tygon tube were not independent as believed, because of the common pressure transmitter providing an input to both methods of level indication.

(2) The level transmitters had range limitations that were not understood by licensee personnel who were operating the plant. As operated, the instrumentation did not meet the criteria in Generic Letter 88-17. Proper operation would have satisfied the criteria except as noted in item (1), above.

(3) The instruments used to provide anticipatory indication of loss of RHR may be inadequate because of the relatively slow (once each two seconds) sampling and indication updates. This is a generic concern and has been observed at a number of other plants.

(4) The criteria for initiating containment closure prior to core uncovery were not realistic. This is a generic concern.

(5) Core exit thermocouple operability was required only at reduced inventory whereas the generic letter specified "whenever the reactor vessel head is located on top of the reactor vessel." This has also been observed at other pressurized water reactors.

(6) Procedures and/or administrative controls did not adequately address the requirements for two independent level indications for draindown specified in GL 88-17. Meeting such criteria is clearly identified in Item (4) of the attachment to GL 88-17 and in Enclosure 3 to the GL, Item (8), as well as in other parts of the generic letter. The willingness of the licensee's personnel to continue draining operations without meeting these criteria is of serious concern.

(7) Development of a basis for operation as addressed by GL 88-17 has not been accomplished. (See, for example, page 16 of GL 88-17, Enclosure 2). This is a generic concern.

The AIT understands these deficiencies will be addressed by the NRC staff as part of the ongoing program to evaluate risk during shutdown and low power operation at all nuclear power plants.

B. Quality Assurance Audit of Shutdown Operation

In November, 1991, the licensee's Quality Assurance organization performed an audit of Monticello and Prairie Island. The audit covered schedules, procedures, and administrative control documents that implement shutdown cooling requirements; personnel interviews regarding policies and practices affecting adequate shutdown cooling; and review of training. The audit found:

(1) A formal policy establishing decay heat removal requirements had not been established. Although certain key principles for outage safety were recognized implicitly by management, they were not stated as a formal policy. An informal document (see Section V.C.2.(5)) was also discussed. It was judged to be well written, comprehensive in its coverage of decay heat removal, and provided some management expectations on decay heat removal. The audit report recommended preparation of a formalized management policy and provided recommendations as to what should be included.

(2) Prairie Island had satisfied the issues of NRC Generic Letter 88-17. All expeditious actions and all programmed enhancement actions were found to be complete, with the exception of technical specifications changes. Plans for these changes were on schedule.

(3) There were no outage surveillances to prevent errors, although normal control room walkdowns were conducted. The audit identified that specific outage surveillances to confirm the adequacy of decay heat removal capability were generally performed during power operation, but not during shutdown. The plant manager maintained that the existing controls and procedures were adequate.

(4) Licensed operator lecture training for outage emergency conditions were deemed adequate at Prairie Island. Simulator training did not include management of outage events, but training personnel were reported to be developing simulator training for operational tasks during outage conditions.

(5) Opportunities exist to improve administrative control mechanisms for decay heat removal during plant outages, although all critical concerns are met.

(6) LCO entry should be coordinated during the weekly planning meeting, confidence in operability of redundant equipment should be high, and other activities that could initiate a transient should be avoided.

(7) Voluntary LCO entry shall be authorized by stated management representatives.

The audit report identified no findings or deficiencies.

The AIT understands that parts of this audit are to be repeated.

C. <u>Risk Analysis</u>

1. Overview

The inspection team briefly reviewed and assessed Prairie Island's outage planning and operations. The assessment is based upon information obtained at the site and comparisons with the Team member's observations and experience with shutdown operation in the nuclear industry. No attempt was made to provide a quantitative risk assessment.

The February 20, 1990, event occurred early in the refueling outage. The planned outage schedule is summarized in Figure 3. Figure 4 shows the reactor coolant system water level during the outage. Note that:

a. The refueling outage was planned for 20 days. Prairie Island typically conducts refueling outages in 30 days or less. Prairie Island also enters midloop operation in as short a time as any licensee known to the inspection team. Many licensees will not routinely enter midloop until more time has passed since power operation, and some will not routinely enter midloop at all. They base these decisions on their judgement that an early midloop entry is risky, and they choose to avoid that risk.

b. Midloop operation was scheduled only two days after power operation. However, Prairie Island is typically operated for about 2 months following reaching a 0% boron condition. Power at initiation of the February 1992 outage was nominally about 2/3 of full power. The decay heat rate corresponds to roughly three days after full power operation, not two days. Also of interest - the early midloop was part of the critical path for the outage.

The major Team observations and conclusions regarding Prairie Island's outage approach were as follows:

(1) Prairie Island placed extreme reliance on individual, skilled personnel to achieve safe operation during outages. The licensee's outage planning and operation were heavily based upon individual knowledge and judgement that are not available if a key person is not provided in several positions. Although this reliance appears to have generally succeeded in the past, it partially failed when a less experienced person was assigned to provide operator guidance during the draindown that led to the February 20 event. Such flexibility has limitations within the outage approach that was in use at Prairie Island. For example, the Team review of selected procedures showed that in-depth knowledge was required to compensate for a lack of procedural detail, a direct contributor to the event. This was particularly true of the draining evolution where prudent steps were missing such as holding to confirm system status and stopping when there were equipment problems.

(2) The licensee routinely entered midloop operation within about two days of power operation. This is ordinarily considered to be a relatively high risk operation by the NRC staff and by much of the nuclear industry. The licensee

recognized the potential risk and took steps to reduce it. These involved a practice of having all safety related equipment available to mitigate potential events, taking steps to prevent event initiation, and attempting to minimize time spent in midloop operation. The early midloop contributes to a short outage time. Although it entails additional risk when compared to no early midloop, it also eliminates some operations that also entail risk. No risk balance data were available to permit comparison within the scope of this inspection.

(3) The licensee achieved short refueling outages via a combination of techniques. With the possible exception of item (2), none were identified by the inspection team as imprudent or risky steps during outage operations. A complete evaluation was beyond the scope and schedule of this inspection.

(4) Prairie Island maintained much of it's equipment, including major components of safety related equipment, while both units were in power operation. This reduces outage risk while increasing power operation risk. There are reasonable arguments for and against this practice; and little reliable data exist. The Team did not evaluate the risk trade-offs, but does judge the reduction of both outage risk and outage time to be significant.

(5) Northern States Power and the Prairie Island onsite management and personnel maintained a generally active concern in and involvement with shutdown operations. This was evidenced by their knowledge, information obtained by the Team at the site (including an internal audit performed at Prairie Island and Monticello) and the comprehensive and informative briefing provided to the Team during its first day at the site. In addition, most post-event licensee actions, and the informative support provided to the Team, evidenced significant management involvement.

(6) A limited scope shutdown safety evaluation was performed for Prairie Island. The licensee decided that it provided no new insights nor were the results trustworthy for quantitative application during shutdown operation. The Team believed this was a reasonable decision.

These and several related topics are explored in the following subsections of this inspection report.

2. Outage Planning

The Team was told that Prairie Island did not have a written outage planning document nor was there a formal safety foundation for outage planning. This is typical of much of the nuclear industry, where many licensees have no such documentation, some have various depths of coverage, and it is the exception to have reasonably complete documentation. The Team understood the licensee plans to generate a policy and/or guidance document.

The inspection team compiled Prairie Island's planning philosophy from:

* 5ACD 3.15, Rev. 11, "Plant Operations," Administrative Control Document Memorandum Number 92-01, reviewed by the Superintendent of Quality Services and approved by the Plant Manager with an effective date of January 14, 1992, and by the same personnel with an effective date and an Operations Committee review date of February 20, 1992,

* limited interviews with selected licensee personnel,

* informative discussions with the resident inspector,

* planning documents, and,

* where consistent with the above, from a five page undated report titled "An Intuitive View of Optimum Nuclear Plant Safety with Today's Design."

The first item above addresses such areas as management responsibilities, overtime, voluntary entry into limiting conditions for operations (LCOs), some aspects of emergency response, a startup hold point, and operation of vehicles in the substation and in the vicinity of transmission lines. The LCO aspects are presented as recommendations, although it is a requirement that the recommendations be addressed when preparing work requests. The last item above was described by licensee management as descriptive of actual practice and as the nearest thing to a policy document at the site. The author indicated that it was prepared for a discussion with the Westinghouse Owners Group some time ago, and was not necessarily intended to represent licensee policy.

These five information sources generated a picture of Prairie Island's approach to outage planning. Some aspects are:

a. The licensee considers that minimizing cold shutdown time directly reduces the risk associated with cold shutdown. This approach could cause undue pressure to stay on schedule. However, no evidence was found that indicates any pressure was applied to personnel to do this. Instead, the guidance appears to have been to take the time to do the job right.

b. Safety related equipment and systems that provide reactor coolant makeup were normally kept in service unless the reactor cavity was filled or the plant was in power operation. This included providing backup electrical power for the equipment. The Team was told that midloop would not be entered unless all safety related equipment were available, and that loss of safety related equipment while in midloop would be followed by exiting from midloop by the most expeditious means.

c. Nozzle dams were used to minimize time spent in midloop operation. The licensee planned to avoid activities that could initiate an event while in midloop. The licensee considered that this minimized exposure to the likelihood of losing residual heat removal due to midloop operation.

d. Prior to the outage, senior operations, maintenance, and engineering personnel reviewed work requests that could affect RCS inventory, decay heat removal, the containment boundary, or electrical power. The plant status required for the work was determined and documented. This document was provided to the shift supervisor during the outage.

Another aspect of outage planning was the critical path and insights it can provide. Some licensee's outages exhibit a flexible critical path, while others are fixed. The former may indicate consideration of concerns, particularly if safety dictates the critical path. The latter may also provide safety insights, as in one plant where the refueling floor was defined to be the critical path and everything else was forced to fit within that bound.

Critical paths for typical Prairie Island outages were described as associated with shutdown and cooldown, the integrated safety injection test, draining to midloop followed by nozzle dam installation, steam generator work and refueling operations (which may either or both represent critical path), draindown, head set, nozzle dam removal, cleanup for fill and vent, cleanup for heatup, and hot shutdown work. This indicated considerable optimization of the work to fit the parts of the outage together. Although there were no critical paths associated with safety during this outage, the licensee said that could occur if some work was not completed on schedule, which the inspectors confirmed by examining the schedule (see Figure 3). Note that delay of the early draindown, midloop, and nozzle dam installation would directly affect critical path and, if everything else remained the same, would extend the outage. The Team judged that other aspects of the outage would be changed to help compensate for such a change, but did not pursue this path.

The licensee stated that modifications were not allowed to become critical path, and cited as an example that all of the modifications deriving from the Three Mile Island accident were accomplished with only 4 hours being on critical path.

Prairie Island maintained it's outage schedule, and the essence of it's plan, on an approximately 6 foot by 30 foot wall mounted board. The Team was aware of one other licensee with such a board, but unlike that licensee, Prairie Island does not use a computerized outage planning/scheduling code in conjunction with the board. (The other licensee bega to use a computerized approach a year or two ago, but it's board was still the primary source of the outage plan. The computer followed the board.) Prairie Island personnel explained that they have evaluated available computer codes, and have not found one that would improve their operation.

The planning board is not erased following an outage, but is modified for the next outage to account for lessons learned and for differences from the previous outage. The licensee felt this resulted in many outage aspects being the same from outage to outage, and decreased the planning effort as well as reducing the likelihood of errors.

There are numerous other factors that influence the outage and outage time. The licensee's experience involves approximately 30 refueling outages at Prairie Island. The plant is relatively simple with numerous small innovations that have been added during it's history. (Several aids to personnel were observed that were unique to this plant in the experience of the Team.) The licensee felt the plant has a good design, is clean, and has been well maintained; and that this reduces outage work and makes the job easier. The plant is small, which is another benefit in some ways. For example, the amount of fuel that must be handled is less than in a larger plant.

The licensee claimed that a large spare parts inventory was maintained and that they anticipated problems via prior experience and through contingency planning. Although the Team did not evaluate these claims, it did note that a number of reactor vessel seal rings were stored inside containment so that there was less likelihood that the equipment hatch would have to be opened. One example of contingency planning was the licensee's ability to respond to an unscheduled outage, which can be a potential risk concern since the planning depth may be less than for a refueling or other scheduled outage. Prairie Island maintained a computerized list of work orders and the Team was told the plant will typically have an outage schedule within a few hours of an unscheduled shutdown. Work orders were the responsibility of individual personnel, and some will be complete at the time of shutdown; others will require completion. The Team's perception was that the licensee would have an outage plan soon after an unscheduled shutdown.

The Team briefly examined selected aspects of the existing outage for consistency with the philosophy picture that developed. One key was provision of safety related equipment. The licensee said that all major safety related equipment was planned to be available throughout the present outage with the exception of about 2 days while some electrical bus work was in progress. (Typical outages range from 3 days to a week for this condition.) This was planned for the flooded up condition. During this time, the operable RHR train would have an emergency diesel generator (EDG) and two sources of offsite power. The licensee added that a 4160 v bus is typically removed from service each outage while flooded, and that this was consistent with that practice. The Team also noted that the planning philosophy was consistent with safety related equipment available during the February 20 event.

The plan was to drain and fill the steam generators twice early in the outage, with partial layup chemicals added after the first draining and full wet layup chemicals added after the second draining. Draining was to be staggered so that at least one generator was always filled to more than 70% (wide range) and most of the time both would have a significant inventory. Normally, one would be maintained immediately available and both could be made available. Following the second refill, both were to be maintained in wet layup with a level of about 85 percent. The steam generator condition at initiation of the event was consistent with this plan. One was filled, and the other was being cycled. For practical purposes, both were immediately available.

The approach to battery work was also used as an example of safety considerations by the licensee. It's service building batteries were stated to be larger than the safety related batteries, and, although they are similar, they are not qualified as safety related. These are tied in to provide full battery capability in a transfer that takes about 4 hours. This provides a safety related battery set plus the larger service building battery set. The transfer is not accomplished during reduced inventory operation.

Benefits of performing maintenance on equipment while at power that were cited by licensee personnel included:

* assures capability when shutdown

* limits work that must be accomplished during an outage

* frees personnel to concentrate on work that must be accomplished during shutdown

* reduces the number of jobs the operator must accomplish

This background is key to the planning and conduct of Prairie Island's outages, which are nearly unique in the experience of the members of the inspection team.

3. Outage Implementation

As is the case for outage planning, there is no broad policy document that covers the conduct of outages at Prairie Island. However, the licensee does provide a "Refueling Outage Handbook," as do most other licensees. Such handbooks are provided to both contractor and licensee personnel, and sometimes provide insights into outage philosophies.

Prairie Island's handbook provides a stronger emphasis on safety and quality than do most, and this topic is emphasized by messages in the front of the handbook from the General Manager and from the Plant Manager. They also both emphasize taking the time to do the job right.

Finally, safety is stated to be a prerequisite to all outage goals, and the first outage goal is "No loss of decay heat removal capabilities." (A loss of decay heat removal is necessary in order to initiate an event that could lead to core damage.) This booklet also specifies:

* Work request processing be coordinated through the Outage Control Center. This reduces control room activity, operator work load, and operator distractions.

* Prework meetings should be performed on complex evolutions or when multi-discipline groups are involved.

* Maintenance of plant cleanliness, which has numerous benefits. The Team judged the licensee to be excellent in this respect.

The inspection team encountered no evidence that would indicate the booklet guidance was not followed, although, of course, a loss of a decay heat removal event did occur.

Other licensee documents addressed electrical equipment.

Electrical work in the plant substation was controlled by administrative directive and by the plant Shift Supervisor.

A flagperson was required should there exist an obstructed view from a motor vehicle and a tailgate meeting was required to cover the route, potential obstacles, and hazards before operating the vehicle.

Whenever possible, cranes were required to be positioned such that operator error could not cause the boom or load to come closer than 20 feet from overhead transmission lines or high voltage buses.

These electrical considerations were consistent with the NRC's findings following loss of electrical power at Vogtle in March, 1990 (NUREG-1410) and at Diablo Canyon in March 1991.

The resident inspector reported that the licensee emphasized electrical power supplies and was sensitive to shutdown issues. He reported that he had examined control room activities and had confirmed that such areas as the equipment required by selected procedures were adequately covered. He also had observed various shutdown evolutions, including initiation of the draindown that led to the February 20 event, and observed that while he was there, the draindown was being conducted carefully, professionally, with no apparent attempts to rush, and with no pressure on the operating personnel.

The licensee stated it's personnel were a major reason for it's successful outage record, and emphasized that it's people were qualified, that they cared, and that they work hard. The Team members had heard similar claims at many facilities. In this case, the Team's observations supported the licensee's claims.

Prairie Island stated they have used the same contractors for years and that this is an aid in obtaining excellent service. The licensee also stated that it works closely with it's contractors, conducts post-work conferences, and it generally has few contractor problems. There was no contractor component in the event which is the subject of this report.

Prairie Island used a computerized hold card and check list system in which the computer immediately provided a comparison as well as a list of work that must be accomplished. The licensee said this eliminated late check list problems and contributed to eliminating schedule slippage.

4. Prairie Island's At-Power Maintenance

Limitation of maintenance during shutdown has been a contributor to many aspects of Prairie Island's outage planning and the implementation of that planning. The licensee's approach to at-power maintenance consequently added insight to the overall risk picture. The licensee's guidance document 5ACD 3.15, "Plant Operations," provides the following regarding entering Limiting Conditions for Operation (LCO) during power operation:

* Voluntary entry into an LCO should be based on the premise that it will increase safety.

* Safeguards equipment maintenance should normally be scheduled during operating modes when the equipment is not required, but it is sometimes necessary to enter LCOs for preventive maintenance (PM), such as "with the recognized need to maintain more equipment operable for safety reasons when the plant is shutdown it may be necessary to perform more PMs at power."

* Planned work should not be scheduled for more than 50% of the allowable LCO time.

* No more than one prime mover (such as a safety injection pump or an RHR pump) or primary power supply (such as a diesel or an offsite power source) should be removed from service at any one time if the planned work exceeds an 8 hour shift. Another source provided the information that diesels not be removed from service during months of high tornado activity.

* More than one prime mover or power source may be removed from service for work within an 8 hour shift as long as Technical Specification requirements are met.

5. Probabilistic Risk Assessment (PRA)

In June, 1991, the licensee completed a brief probabilistic risk study of Prairie Island outages. The objectives were to illustrate the relative magnitude of risk and to determine the effort required to perform a full shutdown PRA by working with the Fall 1991 Unit 1 outage. That Unit 1 outage was atypical for Prairie Island because of motor operated valve work. The outage was planned for 29 days.

The PRA contained numerous conservative assumptions that skewed the results, such as assuming the water in a flooded reactor cavity would not contribute to the time to core uncovery. It also contained conservatisms compared to the information provided to the inspection team regarding Prairie Island's operations, such as:

* "... a significant amount of work on safeguards equipment is performed in a short time duration..." during shutdown. The Team understood only limited work is usually performed and that this was true of the ongoing Unit 2 outage.

* "Prairie Island does not take any major safeguards equipment out of service while the RCS is being drained to mid loop."

  The Team understood no decay heat removal equipment, including support equipment, is taken out of service unless the reactor cavity is flooded.

The study concluded that shutdown risk is controlled by operator actions and that there is a large uncertainty.

The licensee did not use this brief scoping study for it's planning or operations. However, this licensee is continuing to consider probabilistic techniques. Both units will be shut down simultaneously for a fall 1992 outage and the licensee is performing a limited scope PRA to evaluate outage work sequences.

VI. Management Interview

The inspection team conducted a public meeting with licensee representatives (as indicated in Appendix B) at the conclusion of the inspection on February 25, 1992. Mr. W. L. Forney, Deputy Director of the Region III Division of Reactor Projects led the meeting with the licensee. The inspection team leader summarized the scope and findings of the inspection, as described in this report. Licensee management was afforded opportunity, after each statement of findings or conclusions, to respond to or question them. The licensee did not disagree with any of the stated findings. Also, the licensee was asked whether any information likely to be contained in this report was proprietary in nature. No such information was identified.

Following the meeting with the licensee representatives, both NRC and licensee personnel responded to questions from the public and media representatives.

APPENDIX A

INSPECTION REPORT 50-306/92005

PERSONS CONTACTED

Licensee Employees:

* C. Blair, Executive Vice President - Power Supply
* L. Eliason, Vice President-Nuclear Generation
* E. Watzl, Site General Manager
* M. Sellman, Plant Manager
R. Lindsey, Assistant to the Plant Manager
* M. Wadley, General Superintendent, Plant Operations
J. Sorensen, Superintendent, Plant Scheduling and Services
* D. Schuelke, General Superintendent, Radiation Protection and Chemistry
* K. Albrecht, General Superintendent, Engineering
T. Silverberg, Shift Manager
J. Gosman, Shift Supervisor
J. Maurer, III, Outage Scheduling Specialist
D. Reynolds, Supervisor, Operations Training
M. Agen, Emergency Planning Lead Engineer
* R. Fraser, Superintendent, Mechanical Systems Engineering
D. Baxa, Production Engineer
J. Chase, Lead Reactor Operator
M. Weigenant, Lead Reactor Operator
E. Heineman, Reactor Operator
M. White, Reactor Operator
B. Lundberg, Nuclear Plant Attendant

APPENDIX B

INSPECTION REPORT 50-306/92005

DOCUMENTS REVIEWED

Inspection and Refueling Outage Schedule

PROCEDURES:

5 AWI 3.11.11, Rev 0, Engineer Qualification for and Turnover of Assignments
5ACD 3.15, Rev 11, Plant Operations
2E-4, Rev 2, Core Cooling Following Loss of RHR Flow
D2 AOP 1, Rev 1, Loss of Coolant While in a Reduced Inventory Condition
D2, Rev 21, RCS Reduced Inventory Operation
D2.2, Rev 1, RCS Reduced Inventory Operation with ERCS Out of Service
C47.41, Rev 17, Alarm Response Panel 47041, Annunciator location: 47516-0604, RHR System Trouble
2C15, Rev 1, Residual Heat Removal System
F3-2, Rev 13, Classifications of Emergencies
5ACD3.6, Rev 9, Reporting

OPERATOR'S DAILY LOGS: 2/20/92 - 2/22/92

Operations Log
Unit 2 Reactor Log
Unit 1 Reactor Log
Turbine Building Log
Auxiliary Building Log

CHECKLISTS

D2-4, Rev 15, Draining the Reactor Coolant System
D2-10, Rev 1, Draining the Reactor Coolant System to No. 121 CVCS HT
D2-12, Rev 1, Unit 2 Reduced Inventory SI Lineup
D2-14, Rev 4, Reduced Inventory and Refueling Integrity Containment Boundary Checklist

APPENDIX C

REPORT NO. 50-306/92005

DETAILED SEQUENCE OF EVENTS

DATE/TIME (CST)	EVENT
02/18/92	
10:34 p.m.	An operator opened the reactor trip breakers to shut down Prairie Island Unit 2 for a 20 day refueling outage.
02/19/92	
12:30 p.m.	The unit entered cold shutdown (temperature < 200 degrees F).
02/20/92	
5:04 p.m.	Plant operators commenced reactor coolant draindown to nozzle centerline procedure D-2, "RCS Reduced Inventory Operation."
5:16 p.m.	Operators placed the tygon tube in service when pressurizer level indication reached 5%.
5:45 p.m. (approx.)	Operators secured the draindown for shift turnover.
7:34 p.m.	Operators recommenced RCS draindown per procedure D-2.
8:00 p.m. (approx.)	Operators suspected problems with the Emergency Response Computer System (ERCS) level instruments (the 2 electronic indicators) because the instruments had not come on scale as anticipated. Draindown continued relying on tygon level only while attempts were made to diagnose the problem. Tygon tube level indications were being corrected for the nitrogen pressure on the reactor coolant system by a manual calculation.
10:55 p.m. (approx.)	Operators vented the suction line to the 22 RHR pump.
11:00 p.m.	RHR flow oscillations began to develop. Coolant temperature began to increase.

11:01 p.m.	The operators decided to stop the draindown. This instruction was relayed by radio to an operator inside containment to close a valve manually.
11:01 p.m.	The loop A electronic level instrument came on scale and indicated level was approximately four inches below nozzle centerline. This also resulted in a low level alarm.
11:03 p.m.	The loop B electronic level instrument came on scale and indicated level was approximately two inches below nozzle centerline. This also resulted in a low level alarm.
11:08 p.m.	RHR low flow, RHR pump low suction pressure and RHR pump low motor current alarms actuated.
11:09 p.m. (approx.)	Operators stopped the draindown by shutting the loop drain valve.
11:10 p.m.	Operators shut off the No. 22 RHR pump due to loss of suction head.
11:12 p.m.	Operators entered Abnormal Operating Procedure D2 AOP1, "Loss of Coolant while in a Reduced Inventory Condition."
11:13 p.m.	Operators started the No. 21 Charging Pump per DAOP1. This pump was aligned to take suction on the refueling water storage tank (RWST).
11:15 p.m.	Electronic level indication read approximately 8" below the nozzle centerline. (This was the lowest indicated level during the event).
11:1 p.m.	Operators started the No. 22 Charging Pump per procedure, aligned to the RWST.
11:20 p.m.	Core exit temperature reached 190 degrees F. Operators entered Emergency Procedure 2E-4, "Core Cooling Following Loss of RHR Flow."
11:22 p.m.	Operators ordered non-essential personnel to evacuate containment per Emergency Procedure 2E-4.
11:25 p.m.	Core exit temperature reached 200 degrees F., the (average) temperature which defines hot shutdown mode.
11:26 p.m.	Operators aligned the No. 21 RHR pump to take suction from the RWST and to discharge to the reactor vessel and started the pump.
11:27 p.m.	Core exit temperature reached 221.5 degrees F. (This was the highest recorded temperature during the event).

11:29 p.m. Level reached vessel flange elevation. Operators shut off the No. 21 RHR pump.

11:32 p.m. Operators realigned the RHR system for shutdown cooling and restarted the No. 21 RHR pump.

11:34 p.m. The core exit temperature decreased to less than 200 degrees F.

11:35 p.m. Operators shut off both charging pumps.

11:40 p.m. The NRC Senior Resident Inspector was informed of this event.

02/21/92

12:01 a.m. Unit 2 personnel drew a reactor coolant chemistry sample. (The sample did not indicate any Dose Equivalent Iodine. This indicated that no fuel damage had occurred).

12:25 a.m. The licensee declared and exited a Notice of Unusual Event.

12:30 a.m. The NRC Senior Resident Inspector arrived onsite to monitor licensee response to this event.

1:00 a.m. The licensee initiated action to remove the pressurizer manway. This action was taken to eliminate the nitrogen pressure effects on the level instrumentation.

1:26 a.m. The licensee notified the NRC Operations Center of this event via the Event Notification System (ENS). This notification was performed in accordance with both 10 CFR 50.72 (a)(1)(i) and 10 CFR 50.72 (b)(2)(iii)(B).

1:30 a.m.- 5:00 p.m. The licensee reviewed the event, modified the draindown procedure, and completed pressurizer manway cover removal.

5:08 a.m. Operators recommenced RCS draindown per procedure D-2. The process was stopped for a time for shift turnover around 6 a.m.

8:47 a.m. Operators were directed not to continue the draindown. This resulted from NRC/licensee management discussions.

4:00 p.m. NRC Region III issued a Confirmation of Action Letter (CAL) documenting the utility's commitment to investigate the incident, to quarantine the level instruments until an NRC inspection team arrived on site, and to maintain elevated water level pending further consultation between the Regional Administrator and the utility.

02/23/92

6:00 p.m.	Following review by the Regional Administrator and the inspection team, and a revision of Emergency Procedure 2E-4, the utility resumed activities associated with lowering the reactor coolant level for steam generator nozzle dam installation.

02/24/92

12:00 a.m.- 4:00 a.m.	The lowering of the RCS level was accomplished without incident under continuous NRC observation.

APPENDIX D

INSPECTION REPORT 50-306/92005

EMERGENCY PROCEDURE ALTERNATE SCENARIO EVALUATION

Examples of non-optimum recovery scenarios were considered. Concerns were identified as described below. Some of these concerns may be generic to pressurized water reactors. Specific deficiencies in procedure 2E-4 were as follows:

(1) Consider a coolant system condition with the nozzle dams installed and the pressurizer manway removed. This configuration would have been achieved in a few hours to about a day after the February 20 event had the licensee proceeded as planned. Entry into procedure 2E-4 following loss of RHR in this scenario would have the operator follow steps 1, 19 (containment closure), 20 (evacuate non-essential personnel), 21, 22, 23, and 24 to add water via the RHR pump to achieve 1 foot below the RV flange. Backup steps to 24 are 25 for safety injection (SI) and 26 for charging.

If RHR injects, step 24 causes a transfer to 27 after the injection is stopped. Step 27 instructs the operator to maintain level at 1 foot below the reactor vessel flange, followed by 28 which is a test for restoration of RHR. RHR not restored is a transfer back to 27, which initiates a loop with one exit: RHR restoration.

If RHR cannot be restored, no cooling is provided and the coolant system will heat until boiling develops. Boiling will force water into the pressurizer until the pressurizer surge line is cleared at the hot leg. This will create a system pressure ranging from a few psi to roughly 25 psi, depending upon the amount of water in the pressurizer. However, this pressure will not be indicated to the operator, since system pressure is determined from the pressurizer relief tank (PRT). The narrow range level indications may show "fail" since they will probably be over-ranged. The Tygon tube level will reflect a high water level and the pressurizer level indication will come on-scale, also indicating too much water in the system, but perhaps disagreeing with the Tygon indication. The only indicated operator action will continue to be to maintain level at 1 foot below the RV flange and to attempt to restore RHR operation. Restoration of RHR cooling probably cannot succeed because there will likely be insufficient water in the hot leg piping to support RHR operation.

Core uncovery could follow in about an hour and a half unless the operator deviates from the procedure and initiates water addition. If these actions are not taken, severe core damage will follow while the Tygon tube and pressurizer level instruments continue to incorrectly show a significant inventory.

Failure to achieve RHR pump injection from the RWST at step 24 causes entry into 25. Success causes one to remain at step 25 with the only action being maintaining level. (There is no exit, although operators will be attempting to restore RHR via other procedures.) In a practical sense the same conditions discussed above will result.

Failure in step 25 will cause entry into 26 where charging pump initiation is attempted. Success, as indicated by increasing RCS level, causes entry into the 27 - 28 loop discussed above. Note if boiling initiates, it may cause level increases at a rate far in excess of what should be attributed to pumped injection.

Failure at step 26 causes a transfer to 30 where incore thermocouples are checked for exceeding 200 °F. Unless RHR can be restored, temperature will soon surpass 200 °F since there is no cooling. Exceeding 200 °F instructs the operator to maintain charging pump flow at a rate calculated to make up for boiling. There is no cross-check in case the flow is not into the core or if the rate is insufficient. If no charging pump is available, the final option is gravity feed, but this may not be a long term solution as the pressurizer fills. No guidance is provided on gravity feed rate. The only exit remains RHR restoration.

(2) Consider a coolant system condition with the steam generator manways installed and the pressurizer manway removed, the configuration immediately after the February 20 event. Procedure 2E-4 steps are 1, 2, 4, 5 (removes Tygon tube from operation- an action that is not consistently followed in other parts of the procedure), 6 (fills RCS to one foot below the reactor vessel flange and stops water addition), 9 (maintains level), 10, 11, and 12. If RHR has not been restored, the operator is returned to 9. Behavior is similar to that discussed in item (1), immediately above, with one important exception - the steam generators can potentially provide cooling. As water is forced into the pressurizer by boiling, a path will also be opened to the steam generators. Steam condensation may follow as steam compresses the air into the generator tubes, but the condition is unanalyzed. Condensation may be "smooth" with a balance in pressure and steam flow into the pressurizer, or "chugging" may occur as the pressurizer "dumps" back into the coolant system, blocking steam flow into the steam generators. A pressurization will recur that forces water back into the pressurizer. Coolant inventory loss will continue.

(3) An intact coolant system will follow steps 1, 2, and 14, where steam generator cooling is established. (The Team did not investigate whether failure followed by establishing SG blowdown would work, but notes that only limited cooling can be provided by this path. Note also that the sensible heat represented by heating steam generator water provides a substantial heat sink.) Successful cooling is followed by 15, 16, and 17 where, if RHR flow is not restored, one is sent to step 6 and the scenario is similar to that discussed for item (2), immediately above. However, there is no coolant water loss path since the pressurizer is closed. Adding water to the coolant system will cause the steam flow path to the SGs to be lost so that SG cooling is lost. Rapid system pressurization followed by large pressure fluctuations may occur as an

unanalyzed condition is entered that may not be anticipated or understood by the operators. This is not of itself likely to be a core damage scenario unless operators make an inappropriate response in reaction to the potentially unexpected behavior.

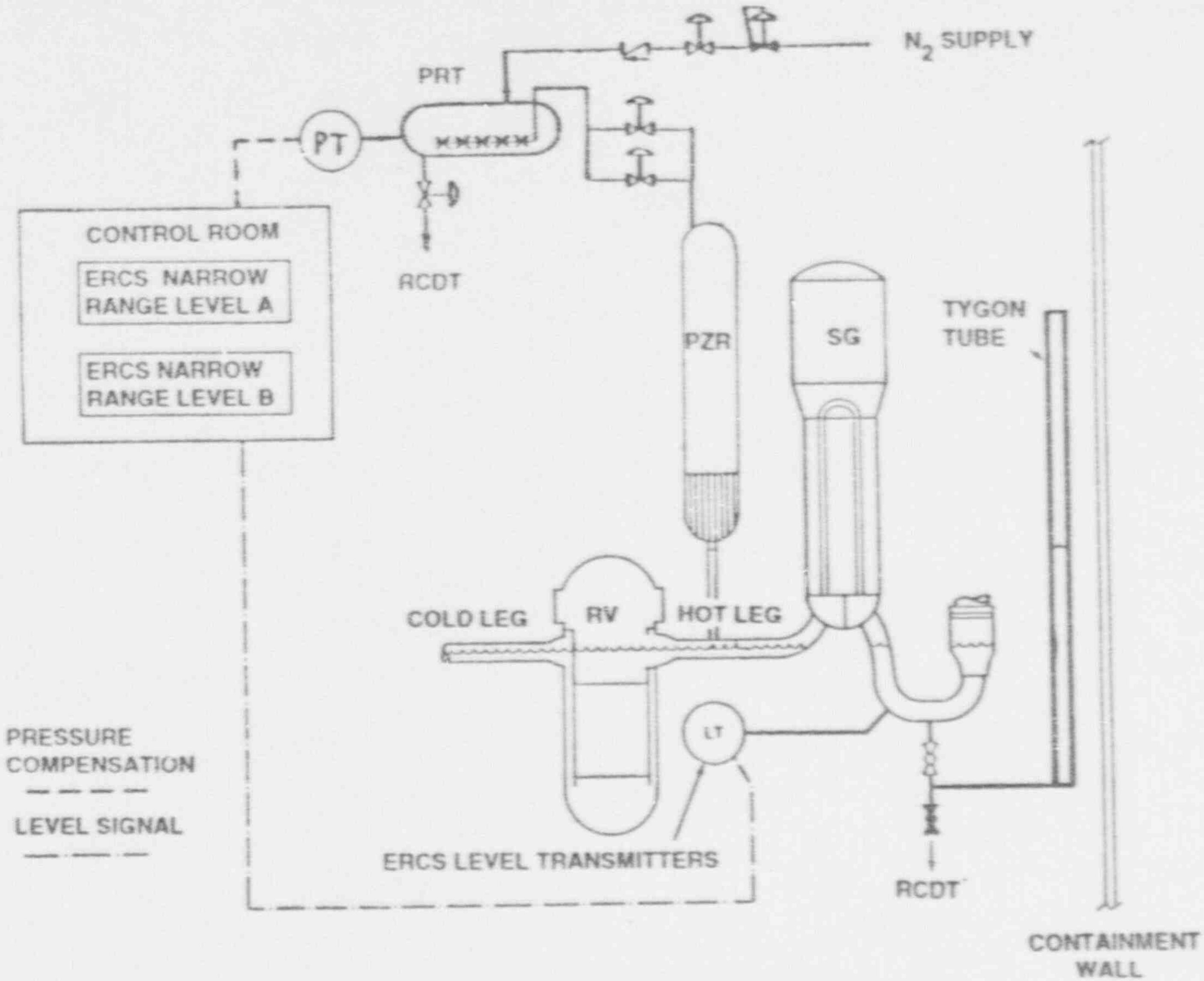
(4) For a configuration with steam generator manways open, the operator will follow steps 1, 19, 20, 21, 22, and 30, where the 200 °F test discussed in item (1) is encountered. Charging pump makeup will not be sufficient to prevent boiling and boiling initiation will cause "slugs" of water to be swept out of the hot legs by steam flow until a low level is attained. (This discharge of water into containment is the reason for using a low injection flow in the first place, but the objective is unlikely to be attained.) This is not a core damage path _if_ charging flow is sufficient to compensate for boiloff. However, there are no checks for adequacy, and one remains in this loop as long as RHR flow is not restored. Further, restoration of RHR may be unlikely because the hot leg water level is probably insufficient to support RHR operation.

No guidance is provided if level indication is not available. As illustrated above, phenomena could exist that cause level indication to be incorrect. This is unrecognized and untreated in the EOP. No guidance is provided if temperature indication is not available. The temperature test is only available as long as the thermocouples are connected. However, they are disconnected for significant times during a refueling outage and no alternate instructions are provided to the operators. This inadequacy also existed in the interim procedures written while the Team was at the site, although thermocouples were anticipated to be available for those evolutions. The licensee was aware of the situation and the operators were under verbal instructions to address any questionable condition by safety injection, which would deal with this and many other problems. However, permanent procedures should address such conditions, including an inadvertent loss of temperature indication. The Team understood the licensee plans to correct this condition.

Inadequate consideration was given to containment conditions that could develop if the coolant system is open. This may jeopardize personnel inside containment and may result in a condition where containment cannot be closed. First, procedure 2E-4 had an entry condition at a coolant temperature of 190 °F. Boiling could follow within a few minutes; not enough time to realistically evacuate containment or accomplish containment closure if penetrations were open. Although some personnel and containment closure steps were provided in the procedure, there was no recognition of the real personnel hazard - steam exiting a foot- and-a-half diameter manway at about 100 mph. Nor was there a response for failure to initiate containment cooling (step 22 for example) where increasing containment temperature and pressure may make it difficult or impossible to complete containment closure operations.

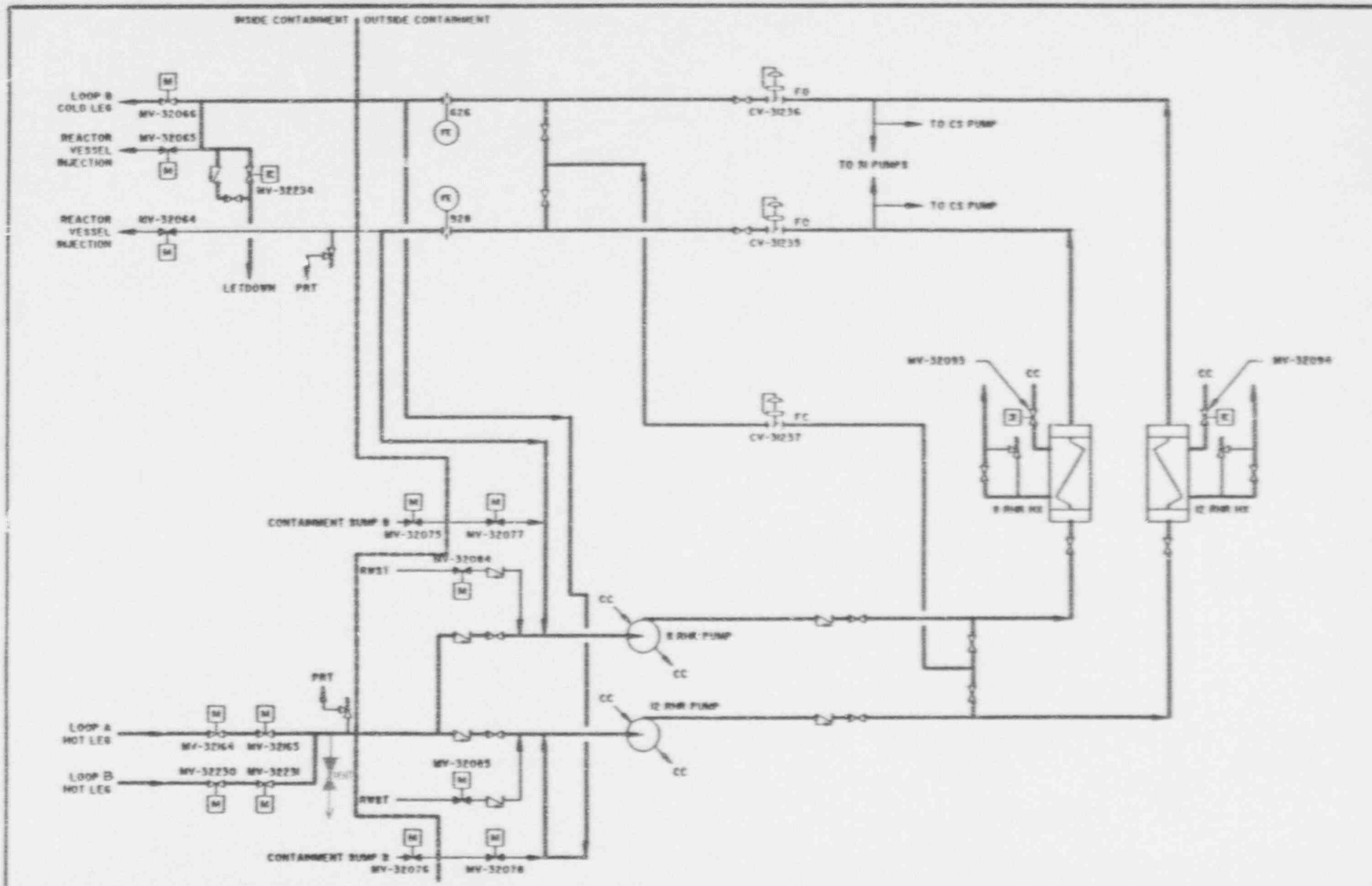
One evolution example will be provided, although others exist. Consider the previously discussed item (4) case of steam generator manways open that causes the operator to follow steps 1, 19, 20, 21, 22, and 30, where the 200 °F test is encountered. Note essential personnel may remain inside containment with the only check on the containment environment being provided by step 22. There may be a large variation of containment temperature and the presence of live steam in various parts of containment. This does not appear to be addressed.

The licensee change to 150 °F for entry to procedure 2E-4 provides additional response time, but soon after shutdown from power operation this is only a few minutes.



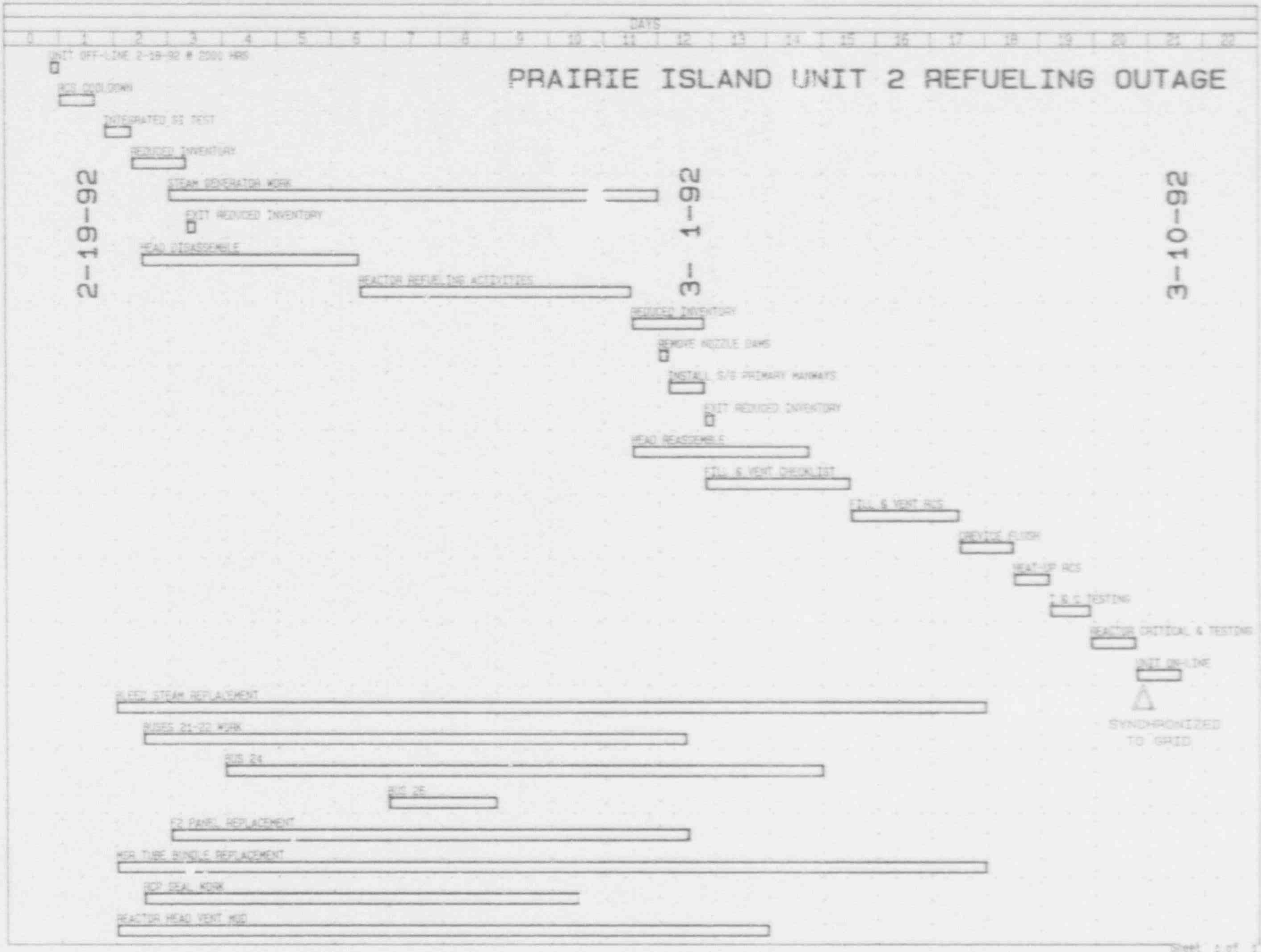
REACTOR COOLANT SYSTEM LEVEL INDICATION
FOR REDUCED INVENTORY OPERATIONS

FIGURE 2



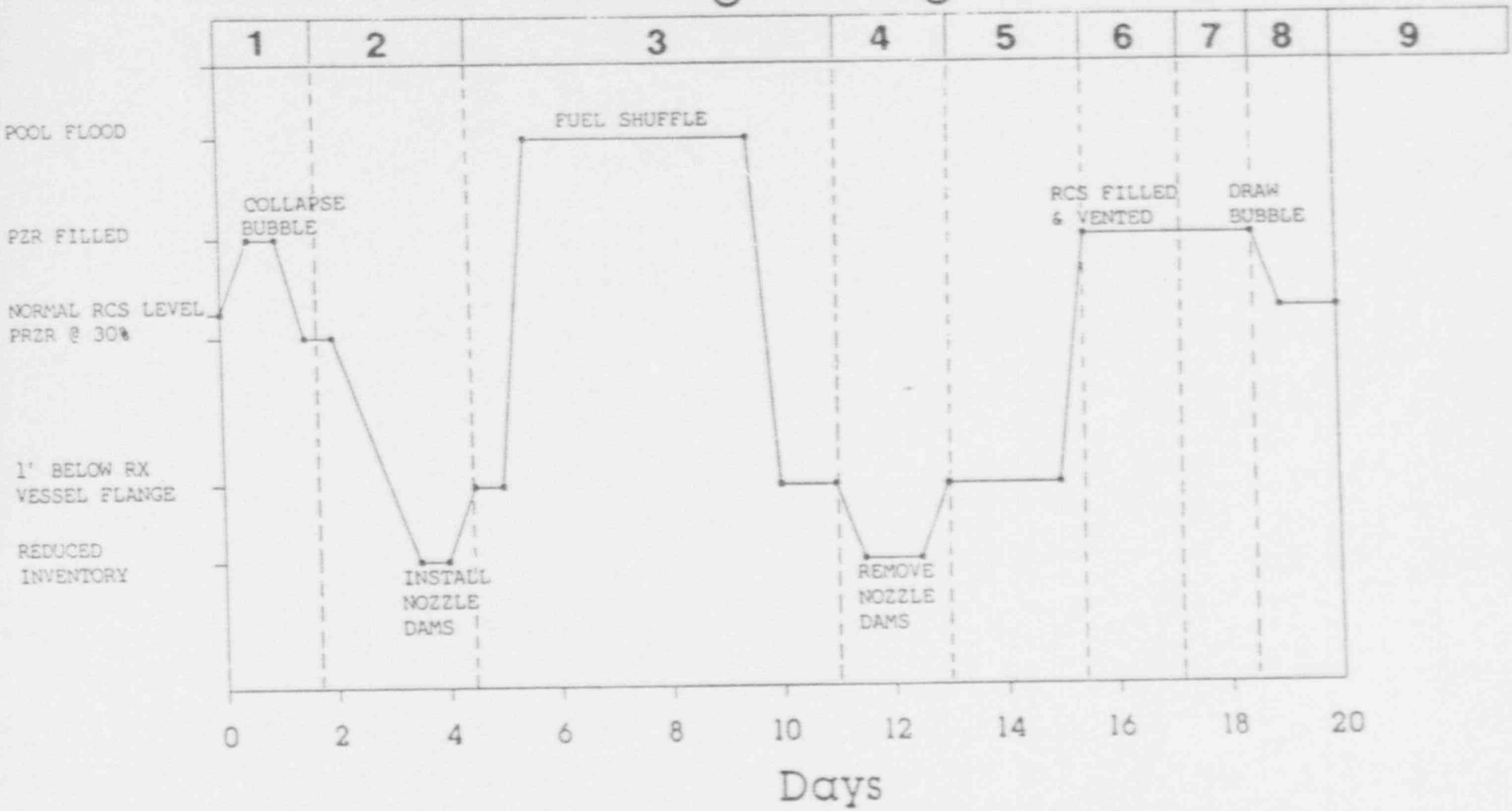
PRAIRIE ISLAND NUCLEAR GENERATING PLANT RED WING, MINNESOTA	RESIDUAL HEAT REMOVAL SYSTEM COOLDOWN FLOWPATH	DRAWN BY: M. PEKARIK REVIEWED BY:	REVISION: 3 DATE: 3/15/91	BI5-2

FIGURE 3


DAYS
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22
PRAIRIE ISLAND UNIT 2 REFUELING OUTAGE
2-19-92
3- 1-92
3-10-92
UNIT OFF-LINE 2-19-92 @ 2000 HRS
RCS COOLDOWN
INTEGRATED SI TEST
REDUCED INVENTORY
STEAM GENERATOR WORK
EXIT REDUCED INVENTORY
HEAD DISASSEMBLE
REACTOR REFUELING ACTIVITIES
REDUCED INVENTORY
REMOVE NOZZLE DAMS
INSTALL S/G PRIMARY MANWAYS
EXIT REDUCED INVENTORY
HEAD REASSEMBLE
FILL & VENT CHECKLIST
FILL & VENT RCS
CREVICE FLUSH
HEAT-UP RCS
I & C TESTING
REACTOR CRITICAL & TESTING
UNIT ON-LINE
SYNCHRONIZED
TO GRID
BLEED STEAM REPLACEMENT
BUSES 21-22 WORK
BUS 24
BUS 26
F2 PANEL REPLACEMENT
MSR TUBE BUNDLE REPLACEMENT
RCP SEAL WORK
REACTOR HEAD VENT MOD

RCS Water Inventory
During Outage

FIGURE 4



1-COMMENCE OUTAGE TO REDUCED INVENTORY
2-REDUCED INVENTORY NO 1
3-REFUELING & S/G WORK
4-REDUCED INVENTORY NO 2
5-FILL & VENT PREPARATIONS
6-FILL & VENT RCS
7-HEAT-UP
8-HOT SHUTDOWN TO ON-LINE
9-ON-LINE TO FULL POWER