U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 50-311/86-26

Docket No. 50-311

License No. DPR-75

Licensee: Public Service Electric and Gas Company

80 Park Plaza

Newark, New Jersey 07101

Facility Name: Salem Nuclear Generating Station - Unit 2

Inspection At: Hancocks Bridge, New Jersey

Inspection Conducted: August 26, 1986 - August 30, 1986

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S. D. Ebneter, Director, Division of Reactor Safety — date

Inspection Summary:
Inspections on August 26, 1986 - August 30, 1986 (Report Number 50-311/86-26)

Areas Inspected: This special inspection was conducted to evaluate a reactor trip with safety injection compounded by a false loss of offsite power (blackout) signal. The inspection team members reviewed licensee actions during and subsequent to the event.

Results: Several unresolved items were identified during the inspection. The items include:

1. Reanalysis of the addition of electrical loads including transient response and evaluation of the adequacy of the 10 CFR 50.59 review process. (Section 1.C.(2))

2. Implementation of the Task Force recommendations regarding troubleshooting and maintenance practices. (Section 2.A.(2))

3. Analysis of the August 26, 1986 event including the electrical system transfers and associated transfer schemes. (Section 2.B.(3))

4. Replacement of dissimiliar metal welded joints and the overall service water system pipe replacement program. (Section 2.C.)

5. Evaluation of the Emergency Operating Procedures and related operator training. (Section 2.D.)

6. Correction of the equipment problems identified during the August 26, 1986 event. (Appendix C)

Further NRC review of the above items will be conducted following licensee response to this inspection report.

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DETAILS

1. Event Description

A. Plant Conditions Prior to Event

The plant was operating at 100% thermal rated power for 12 days prior to this event.

(1) No. 11 Condensate Pump Crosstie to 2H Group Bus

- On July 10, 1986, installation of a temporary crosstie between Unit 1 No. 11 Condensate Pump and Unit 2 Group Bus 2H was completed, allowing Unit 1's third condensate pump to be placed in service subsequent to the loss of service of No. 1 auxiliary power transformer. See combined Salem inspection reports 86-15 and 86-19 for details leading up to the installation of the crosstie. The crosstie was in service at the time of the event of August 26, 1986.

(2) No. 2B Diesel Generator Tagged Out-of-Service

- At 5:04 a.m. on August 26, 1986, the 4,160 volt vital power 2B Emergency Diesel Generator was taken out of service to perform preventative maintenance.

(3) No. 22 Steam Generator Level Channel III Troubleshooting

- At 1:20 a.m. on August 26, 1986, No. 22 Steam Generator Instrument Channel III(C) Low-Level bistable tripped and the associated reactor protection system panel (RP-4) indicating light began flashing on and off. I&C personnel were in the process of investigating this problem at the time of the event. See Section 2A for details.

(4) No. 23 Pressurizer Spray Valve Inoperable

- On June 5, 1986, No. 23 Pressurizer Spray Valve 2PS3 was declared inoperable due to excessive leakage. 2PS3 was blocked by closing 2PS28. Several work orders have been written for this problem and repairs will be performed during the upcoming refueling outage.

(5) No. 22 Pressurizer Power Operated Relief Valve (PORV) Isolated

- On August 14, 1986, No. 22 Pressurizer PORV 2PR2 was isolated due to excessive leakage by closing motor operated valve (MOV) 2PR7. Maintenance on this valve (2PR2) will be performed during the upcoming refueling outage.

B. August 26, 1986 Event Scenario

The following is a sequence of major events following the Salem Unit 2 reactor trip

- 0823 - While taking a voltage measurement across an input relay coil, one voltage probe slipped against the chassis grounding "C" vital instrument bus causing a voltage spike. (refer to Section 2.A.)

- 0824 - The voltage spike on "C" vital instrument bus resulted in a spurious No. 23 reactor coolant pump breaker open signal which resulted in an indicated low reactor coolant system flow - P8 (reactor power greater than 36%) reactor trip. (refer to Section 2.A.)

  - The voltage spike also resulted in a spurious Nos. 22 and 23 Steam Generator low pressure signals which, in conjunction with normal steam transients following a plant trip and the resulting high steam flow indications, caused the safety injection (high pressure injection thru Boron Injection Tank). (refer to Section 2.A.)

  - Plant equipment responded as designed (i.e. auxiliary feed pumps running, diesels start, phase A containment isolation, etc.)

- 0825 - At approximately one minute after reactor trip/safety injection, i.e., following about 30 seconds delay for opening of generator breakers and the transfer of the Group Busses supplying normal station electrical service to offsite power, an undervoltage condition was sensed on at least two of the three vital busses resulting in a false loss of offsite power signal. The vital busses stripped their loads and the safeguards ("blackout") loads were sequenced on 2A and 2C diesel generators. (refer to Section 2.B) 2B diesel generator had been previously tagged out for preventive maintenance.

  - As part of "blackout" loading, component cooling water pumps were stripped from the bus and not sequenced back on bus.

Note: "Blackout" at Salem station is defined as loss of offsite power to the vital busses only.

- 0830 - Due to loss of component cooling water for reactor coolant pump motor bearing and thermal barrier cooling, shift supervision directed the operator to trip all four reactor coolant pumps. Natural circulation was established. (refer to Section 2.D)

  - Reactor coolant system pressure rose to the pressurizer power operated relief valve (PORV) setpoint causing a PORV (2 PR1) to lift numerous times during the event.

  - Unusual Event declared. NRC Resident Inspector arrived in the control room. Safety Injection reset.

- 0832 - Nos. 21 and 23 component cooling water pumps returned to service.

- 0835 - Unusual Event terminated.

- 0844 - Safety Injection flow to the reactor coolant system terminated.

- 0849 - No. 21 reactor coolant pump returned to service.

- 0856 - "B" 4KV vital bus energized via station power transformers (SPT) (offsite power).

- 0939 - No. 23 reactor coolant pump returned to service.

- 0942 - "A" 4KV vital bus power transferred from 2A diesel generator to offsite power.

- 1011 - "C" 4KV vital bus transferred from 2C diesel to offsite power.

- 1230 - Unit 2 stabilized in Mode 3.

In addition, the following occurred:

- 0930 - A No. 22 reactor coolant pump equipment protection fire alarm was received in the control room. A Site Protection team was dispatched to investigate. The alarm was determined to be spurious; however, the team reported a leak which they had observed in containment. Subsequently the licensee took the following actions:

  - Control room operator balanced charging and letdown, monitored pressurizer level, and determined that the leak was not from the reactor coolant system.

  - From the location of the leak reported by the Site Protection team and prior experience with containment fan cooler units (CFCU), the licensee determined that the leak was probably a service water leak.

  - A team was dispatched to investigate and they identified the leak as being located on the 2 inch to 10 inch pipe joint on the service water return line from the No. 23 CFCU motor cooler.

  - The service water to No. 23 CFCU was isolated. (refer to Section 2.C)

C. Narrative Description

(1) Control Room Actions

As described in detail in Section 2.A below, troubleshooting activities on No. 22 Steam Generator Level Channel III resulted in a momentary grounding of Vital Instrument Bus 2C. This resulted in a reactor trip and Safety Injection (SI) at 8:24 a.m. from the spurious signals generated to the Solid State Protection System. The operators responded with post-trip actions and began following Emergency Operations Procedure EOP-TRIP-1. Supervision and Operations Department management responded to the Control Room as planned. Initial actions were as expected. Initially, the cause of the SI was not obvious. There was additional concern when, 56 seconds into the event, a false loss of offsite power signal occurred and all three vital safeguards equipment electrical buses stripped their safeguards loads, isolated from offsite power and returned the loads in the "blackout" with SI sequence onto already running Diesel Generators (D/G) 2A and 2C; the events leading to this are discussed in detail later. Also, since D/G 2B had been removed from service for maintenance, it could not operate; equipment supplied from 2B Vital Bus did not operate until the off-site supply to the bus was restored at 8:56 a.m.. Thus, one minute into the event, the operators were presented with an reactor trip, unexplained SI and a blackout condition on the vital buses when all other indications of offsite power were normal. At this point, the control room was staffed by the two Reactor Operators, the Unit Senior Reactor Operator (SRO), the Shift Technical Advisor, the Senior Shift Supervisor (SSS) (SRO). In addition, the Assistant Plant Manager, Operations Supervisor, and Operating Engineer were present in the control room.

While the operators continued the post trip emergency actions, the Operations Supervisor and the Operating Engineer (both SRO licensed) were examining the computer printout of the sequence of events. The operators also verified safety injection performance parameters. As allowed by procedure and to be able to gain operator control of equipment which was under automatic control as a result of SI, a decision was made to reset SI about 6 minutes into the event.

Earlier, at about 5 minutes into the event, the SSS and other operators determined that the Reactor Coolant Pumps (RCP) should not be operated more than 5 minutes without component cooling water for the motor bearings and thermal barrier. This situation was not specifically addressed in the EOP since the usual scenario would be either offsite power available, in which case the component cooling water pumps would be running, or offsite power not available, in which case the RCPs would not be running. After reviewing this situation, a conscious decision was made to turn off the RCPs and establish natural circulation to remove plant decay heat.

Figure 1 is the Control Room recorder traces for a) Pressurizer Pressure, b) Pressurizer Level and c) typical Reactor Coolant System loop temperatures. The pressure trace shows the initial safety injection, a lift of the pressurizer Power Operated Relief Valve (PORV), a period of stable pressure, then pressure control by means of numerous actuations and resets of the PORV. Termination of SI about 21 minutes after event initiation appears as a downward pressure spike with recovery to the PORV control band. The turning off of the RCPs and the establishment of natural circulation can be clearly seen from the RCS loop temperatures; the hot and cold leg temperatures converge as forced circulation ceases, then diverge to about 30 F difference for natural circulation, then converge again when 21 RCP is returned to service about 25 minutes into the event. The pressurizer pressure also quickly returns to normal as pressurizer spray becomes available and normal pressure control can be resumed. By 9:45 a.m. a second RCP was returned to operation and two of the vital buses had been returned to offsite power. By 12:30 p.m., the unit was stable in hot standby (Mode 3).

(2) Electrical System

To understand why a false loss of offsite power signal was generated and why there were several transfers of vital buses, a great deal of analysis of available information was performed. This is described in some detail in Section 2.B. To explain a scenario, the pre-event electrical lineup depicted in Figure 2 is needed. In Fig. 2., it can be seen that the pre-event lineup had 2H, 2E, 2F and 2G Group Buses carrying normal station loads such as RCP's, Condensate Pumps, Circulating Water Pumps and Heater Drain Pumps connected to the Unit 2 generator thru No. 2 Auxiliary Power Transformer. In addition to its Unit 2 loads, the 2H Group Bus was supplying Unit 1 No. 11 Condensate Pump since a temporary hookup was completed on July 10, 1986. The Vital Bus alignment shows 2B connected to No. 21 Station Power Transformer (SPT 21) and buses 2A and 2C connected to SPT 22. The 2B D/G was out of service for maintenance and surveillance.

Following the reactor trip at 8:24 a.m., steam admission to the turbine stops quickly and the turbine and generator continue to rotate from inertia and stored energy. About 30 seconds after the trip the circuit breakers which connect the generator to the power distribution system open. It is then necessary to transfer the normal station equipment on the Group buses to an off-site power source since their onsite source, the Unit 2 generator, is no longer available. This is done by fast electrical transfer, for example opening circuit breaker 2AHGD on Fig. 2, then rapidly (about 0.1 sec.) closing 21HSD breaker; this reconnects 2H Group Bus to 21 SPT. This fast transfer was successful for all four Group Buses, since there were no interruptions of service for equipment powered from these buses.

The Vital Buses (VB) have protective relaying, denoted by the groups of circles on Figure 2, to maintain the quality (voltage, power availability) of their source of supply. The undervoltage protection levels shown on Fig. 2 are 91% for degraded grid protection, 70% for equipment protection and 35% for reclosure permissive logic. The combination of load on SPT 22, the relay setting and an appropriate (10.5 sec.) time delay resulted in a signal from only the A 91% protective relay on SPT 22 for VBA to affect a transfer from SPT 22 to SPT 21; this is shown in the upper left portion of Fig. 3. VBC should also have transferred, but did not. No relay trip flag was observed for VBC. The licensee's explanation for this is slight differences in relay settings. The transfer of VBA now increased the electrical load on SPT 21.

About 11.5 sec after transferring VBA to SPT 21 (recall there is a 10.5 sec time delay in the transfer), both VBA and VBB transfer to SPT 22 and remain there for only a few tenths of a second; finally, both VBA and VBB attempt to return to SPT 21 and fail; the licensee's explanation is that this demand on the 21ASD and 21BSD circuit breakers was too rapid for the auxiliary charging motor on the circuit breaker to reset the closing spring so that the breaker was unable to close upon demand signal.

It can be seen on Figure 3 "Vital Bus Transfer Scenario", that VBA and VBB were unpowered coincidently for about 2 seconds. This satisfied the undervoltage amplitude and time delay for each vital bus to generate a "blackout" signal. Since 2 of the 3 vital buses were in this condition at the same time, the logic generated a "blackout" signal for VBC as well, just after it transferred to SPT 21.

With the blackout logic satisfied and a Safety Injection signal present, the Safeguards Equipment Cabinets executed their program of stripping all loads from the Vital Buses, connecting the VBs to their respective D/Gs (A and C were already running in response to the original SI) and then reconnecting the safeguards equipment in the "blackout plus SI" mode. In this mode, the component cooling water pumps do not get connected, since the logic is responding to an apparent loss of offsite power, implying that normal station equipment such as RCPs have stopped and therefore do not need cooling water. This is the situation in which the Shift Supervisor elected to stop the RCPs.

As explained by the licensee at a meeting on August 30, 1986, the root cause for the initial power distribution situation was the incremental addition of permanent electrical loads with only the static consequences of these load additions considered in reviews and safety evaluations. The transient responses of the electrical system to upsets had not been analyzed since degraded grid studies were done in 1979-80. In this particular transient, the initial conditions and system response resulted in a false loss of offsite power signal to the vital buses. Reanalysis of load additions including transient response and the adequacy of the 50.59 review process is an Unresolved Item (311/86-26-06).

The inspectors reviewed an event (LER 86-004 for Salem Unit 2) that occurred on July 14, 1986 which was similar to the August 26, 1986 event. The initial bus connections and connection of No. 11 Condensate Pump to the 2H Group Bus were the same. The initiating event was similar - inadvertent grounding of Vital Instrument Bus 2B (rather than 2C). A reactor trip resulted; SI was not initiated by this inadvertent grounding. The plant responded as expected and no "blackout" resulted.

D. Interviews of Operators and Plant Staff

In addition to the Resident Inspector's direct control room observations during the event, the Senior Resident Inspector and Resident Inspector conducted post event briefings with the supervision and operators who were in direct control of the event. The following determinations were made from these conversations and observations:

- The Senior Shift Supervisor utilized the EOPs in the performance of the corrective actions. The deviation from EOP - TRIP 1 with regard to reactor coolant pumps was to address a situation which was not covered by the EOP. The situation had been addressed in the retraining program. Two other procedures were utilized by the senior reactor operators, "Loss of Component Cooling" and "Reactor Coolant Pump Operation", to address the running of reactor coolant pumps without component cooling water. The senior reactor operators collaborated and made a conscious decision to turn off the RCPs and to go on natural circulation.

- The Senior Shift Supervisor had been a control room operator during natural circulation testing on the Salem Unit and stated that he felt comfortable in going to a natural circulation condition.

- The Senior Shift Supervisor was clearly in charge; he received supporting data from the STA, Operations Supervisor and Operating Engineer. He utilized these inputs to make his decisions with regard to the shift actions.

- The decision to exit the Unusual Event was made when the Safety Injection was terminated. Entering the Unusual Event was based on Safety Injection as delineated in the Emergency Plan Event Classification Guide.

As a result of the interviews and review of the logs, charts, and other data, the inspectors determined that the operations staff utilized their operational training, plant parameters, procedures and operational knowledge to place the plant in a stable and safe condition within a relatively short period of time.

2. NRC Inspection Followup of Licensee Actions and NRC Concerns

A. No. 22 Steam Generator Level Channel Troubleshooting Effort and Initiating Event

(1) Description of the Troubleshooting and Resulting Initiation of The Event

At 1:20 a.m. on August 26, 1986, the control room alarm typewriter printed an alarm that No. 22 Steam Generator (SG) instrument channel III low level bistable tripped. The associated indicating light displayed on the reactor protection system status panel RP-4 began flashing on and off. All bistables, high SG level (Turbine Trip), low SG level (Reactor Trip) and the low-low SG level (Safety Injection) associated with level channel 2LC528C were tripped. In accordance with Administrative Procedure AP-6, the licensee prepared an Incident Report.

No. 22 SG low level channel III is a bistable input to the reactor trip solid state protection system (SSPS). The SG low level reactor trip is a 1 of 2 steam/feedwater flow mismatch in coincidence with 1 of 2 low steam generator water level indications per RCS loop.

I&C personnel were notified of the SG level channel problems and Work Order No. 8608260026 was issued to investigate and repair. The low level comparator 2LC-528C was determined to be faulty with an output voltage of about 65 volts ac instead of the normal 120 volts. However, after replacing 2LC-528C, the problem of the flashing indicating light continued. Further investigation determined that the problem was associated with the SG low level channel III input relays of the SSPS trains A & B. Relay K325B had an open relay contact (trip condition) and the K325A relay was heard to be chattering. The reason that the tripped bistable light continued to flash on and off was that the comparison detection circuit detected both the open (non tripped) contact of relay K325B and the closed (trip) contact of the K325A relay.

After the contact was found open on relay K325B, an I & C technician was taking a voltage measurement across the relay coil when one of the voltage probes came in contact with the cabinet housing, causing 120 volt ac vital instrument bus 2C to become grounded momentarily (0.15 sec). The grounded condition resulted in No. 23 Reactor Coolant Pump (RCP) spurious breaker open indication to the SSPS, tripping the reactor. This trip is a 1 of 1 logic when the permissive P-8 (reactor power greater than 36%) is met. At the time of the event, the unit power was 100%, hence above the P-8 condition. This trip anticipates a low reactor coolant loop flow condition. An auxiliary relay associated with the RCP breaker auxiliary "a" contact is normally energized by 2C vital instrument bus. The grounded condition caused the relay to become momentarily deenergized resulting in the reactor trip.

When the reactor tripped there was a high steam flow bistable trip from post-trip steam flow transients. High steam flow trip is an input to the SSPS with one of two sensors on two of four loops sensing high flow. This 2 of 4 logic coincident with either low Tavg in 2 of 4 reactor coolant loops or low steam pressure in 2 of 4 main steam lines results in a safety injection. Two of the low steam pressure sensors, IPC 526A and IPC 536A, are supplied power by the 120 volt ac vital instrument bus 2C which became momentarily grounded. This combination of high steam flow and spurious low steam pressure (grounded bus) on two loops caused the safety injection signal and a phase A containment isolation signal to occur.

(2) Review of Licensee Troubleshooting Activities

During the troubleshooting the I&C personnel used approved work orders and procedures. These documents are identified in Appendix B. The relays K235 A&B are manufactured by C. P. Clare. The section of the relay where the contact measurement was being taken was 3/4 inch by 3/4 inch with twelve wire connection points. There is a 3/4 inch square cutout in the relay panel through which the relay contacts are inserted. The relay coil leads extend through two 3/16 inch holes in the panel. Since the I&C technician was measuring the contacts from this location, he also attempted to measure the relay coil voltage there. The voltmeter measuring probe slipped from the relay coil terminal across the approximately 1/8 inch space to the grounded metal panel and the probe then shorted the terminal to the panel.

As the result of this troubleshooting activity and its potential for causing a reactor trip, a licensee task force was assembled to identify methods of preventing future occurrences of this nature. The Nuclear Training Department has developed a method to prevent grounds while taking voltage readings. This method consists of placing heat shrink tubing around the probes leaving only the metal probe tips exposed. During testing of this method, the training department was unable to introduce grounds while taking voltage readings on an equipment test rack. The training department lesson plans and I&C instructors have been updated to include this new method of taking voltage readings. Plant I&C personnel will be trained on the new method as they cycle through the training department for their normal periodic training. The Training Department also is looking at the applicability of using heat-shrunk tubing on probes in other troubleshooting situations.

The task force has also recommended that, for the subject relays or similar relays, coil voltage measurements be taken at a terminal block rather than at the panel. Implementation of the task force recommendations regarding troubleshooting and maintenance practices is an Unresolved Item (311/86-26-01).

B. Bus Transfer Scenario

(1) Summary Description of the Bus Transfer Scheme

Figure 2 shows a simplified electrical one line diagram of Salem Unit 2. During startup and shutdown, 4KV group buses 2E, 2F, 2G, and 2H and the vital buses 2A, 2B, and 2C are supplied from Station Power Transformers (SPTs) 21 and 22. After unit startup, the group buses are manually transferred to No. 2 Auxiliary Power Transformer (APT), which is the normal power supply for the group buses. On a unit trip, the group buses will automatically transfer to the SPTs (offsite source). When the unit is running, the vital buses continue to be supplied by SPTs 21 and 22. Normally two vital buses will be supplied from one SPT, while the third bus is supplied by the other SPT, with complete transferability between the two. On simultaneous loss of both SPTs, the vital buses are automatically powered by the standby diesel generators for engineered safeguards electrically driven equipment.

The automatic transfer of the group and the vital buses are initiated by various sets of undervoltage relays with appropriate time delays to perform their functions in a coordinated manner.

(2) Description of the Event

Prior to the event on August 26, 1986, the Unit 2 group buses were being supplied from the APT in the normal lineup, except that Unit 1 condensate pump 11 was temporarily powered from Unit 2 group bus 2H because of a problem with Unit 1 APT. When Unit 2 tripped, the group buses transferred to SPTs 21 and 22 as designed. The vital buses also transferred back and forth between SPT 21 and SPT 22. However, approximately 56 seconds after the initiation of the event, (reactor trip and safety injection signal) an undervoltage condition was sensed on two of the vital buses indicating an unsuccessful transfer of the vital buses between SPTs 21 and 22. Diesel generators 2A and 2C had automatically started (diesel generator 2B had been previously tagged out for preventive maintenance). All vital buses automatically shed their connected loads and the safeguard loads were automatically sequenced on diesel generators 2A and 2C through Safeguard Equipment Control (SEC) system as designed. As the plant was restored to normal conditions, the vital buses were returned to their normal sources, i.e., SPTs 21 and 22 (offsite power), with "B" Vital bus returned at 8:56, "A" at 9:42 and "C" at 10:11.

A detailed review and analysis of the bus transfer operations by examining voltage and current recordings was not possible because the recording tape containing this data was rendered unreadable. The bus transfer operation scenario was obtained by review of the sequence of events and auxiliary alarm typewriter information. This was obtained from inference from the timing of interruption and recovery of equipment and knowledge of which bus powered this equipment. The inspector developed a time sequence which showed a point 56 seconds into the event where both Vital Bus A and Vital Bus B were not powered from either SPT (shown in Figure 3); with two vital buses unpowered, the SEC logic generates a "blackout" signal. This condition removes all three vital buses from offsite power, strips the loads that were on the buses and sequences the loads back onto the buses in the "blackout plus safety injection" (SEC Mode III) order. The blackout signal occurred about 56 seconds after initiation. Those loads were reconnected to Vital Buses A and C in about 4 seconds since their respective diesel generators had been started by the original spurious Safety Injection signal. Since D/G 2B was out of service, loads served by this bus were not powered until about 30 minutes later when the bus was reconnected to offsite power.

(3) Followup of Licensee Actions

During the inspection period, the root cause of the unsuccessful transfer of the vital buses between the two offsite sources, i.e., SPTs 21 and 22, could not be positively identified. As stated above, the magnetic tape recording of the voltage and other electrical parameters which would have been useful in identifying the root cause was found damaged and unreadable. There is no other direct recording of the electrical parameters either on the plant process computer or strip chart recorders which would have facilitated the root cause identification. However, an interpretation of the process computer printouts (Sequence of Events Recorder and the Auxiliary Annunciator Printouts) indicates that the bus transfer did occur on several occasions. The flags indicating operation of certain undervoltage relays also give some clues to events.

The licensee initiated a number of actions which were in various stages of completion at the conclusion of the onsite inspection. These were:

- Check out, calibration, and operation of the transfer scheme undervoltage relays. This was completed on August 28, 1986, and no problems were identified.

- Performance of monthly surveillance tests of the undervoltage relays associated with the transfer scheme. This was completed on August 28, 1986, and no problems were identified.

- Check out the transfer scheme of vital buses 2A, 2B, and 2C between SPTs 21 and 22. As of August 28, 1986, 2A and 2C were complete. 2B had some problem with recording equipment. A successfully recorded test was completed on August 28.

- Calculate the degraded voltages at the group and vital buses based on a computer model of the electrical system under conditions of the event and worst case assumptions. As of August 28, 1986, the work was inconclusive.

- Verification of the group bus transfer scheme. As of August 28, 1986, the work had not yet started. Detailed planning and procedures were under development.

- Check out of the Solid State Protection System (SSPS) timers. As of August 28, 1986, the work had not yet started.

The licensee was continuing with the investigation of the problem and the identification of its root cause and will complete appropriate corrective actions before restart of the unit. The NRC staff will follow these licensee actions.

Subsequent to this inspection at a meeting in NRC Region I on August 30, 1986, the licensee presented a scenario which fits the observed data. NRC review of the detailed analysis of the electrical transient is an Unresolved Item (311/86-26-02). This scenario is summarized in Section 1.C.

C. Leak in Service Water System

As noted in the sequence of events, (see paragraph 1.B) a leak in the 2" piping return from the motor cooler of containment fan coil unit (CFCU) No. 23 to its 10" service water return line was identified. The leak was in the area of a weld of concrete-lined carbon steel 2" piping to a stainless steel sockolet in a 10" stainless steel spool piece. Upon examination, the carbon steel in the vicinity of the weld was badly corroded from both inside and outside the 2" pipe and most of the concrete lining was missing from the pipe one inch or more axially from the end welded into the sockolet. The section of pipe from the sockolet to an elbow, approximately 6 inches long, was removed and replaced on August 27, 1986. Three similar joints on CFCUs 21, 22 and 25 were inspected; CFCU 25 began weeping near the weld when wire-brushed for examination; it was removed on August 27, 1986 and replaced. The licensee elected to replace the similar sections of CFCU 21 and 22 prior to restart from the event of August 26, 1986. CFCU 24 has a carbon steel to carbon steel joint that has presented no corrosion problems.

The inspector reviewed past problems and inspection and repair plans for service water piping with licensee representatives. Much work has been done to replace piping and heat exchanger tubing in the service water system. The replacement of heat exchanger tubing will continue with retubing of No. 21 component cooling water heat exchanger in the October 1986 outage. In addition to pipe replacement for corroded piping, identification of sections of eroded pipe and replacement of the eroded zones with stainless steel spool pieces has been accomplished. To avoid galvanic corrosion situations, these were terminated in flanged fittings and coupled to carbon steel piping flanges by means of insulating kits. In Salem Unit 1, the 2" sockolet fitting with dissimilar metal weld was avoided by using the flanged joining method described. The licensee committed to eliminate the dissimilar metal weld joints, in Unit 2, and replace them with flanged joints during or shortly after the upcoming outage. Replacement of dissimiliar metal welded joints and the overall pipe replacement program on the service water system is an Unresolved Item (311/86-26-03).

D. Operator Actions and Review of Procedures

An Operations Department task force was established to perform the following actions.

- Construct a detailed scenario of the event
- Evaluate plant equipment response and timing during the event
- Evaluate Emergency Operations Procedures and procedural adequacy
- Evaluate operator training adequacy
- Identify lessons learned
- Produce operator feedback of event and provide to licensed operators for review.

The resident inspectors will followup on the above licensee actions as an Unresolved Item (311/86-26-04). Further, Appendix C lists problems identified early in the post-trip review by the licensee; correction or explanation of these problems is an Unresolved Item (311/86-26-05).

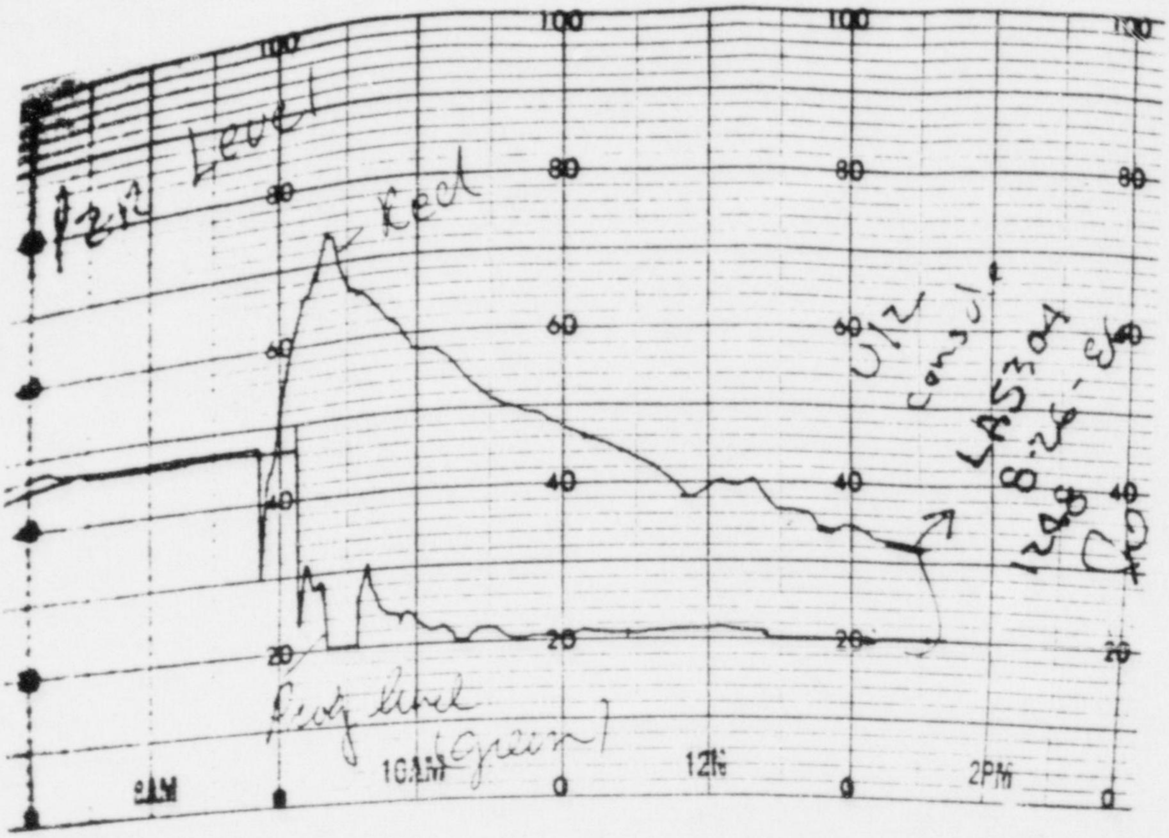
3. Unresolved Item

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations or deviations. The unresolved items identified during this inspection are discussed in paragraphs 1.C.(2), 2.A.(2), 2.B.(3), 2.D and Appendix C.

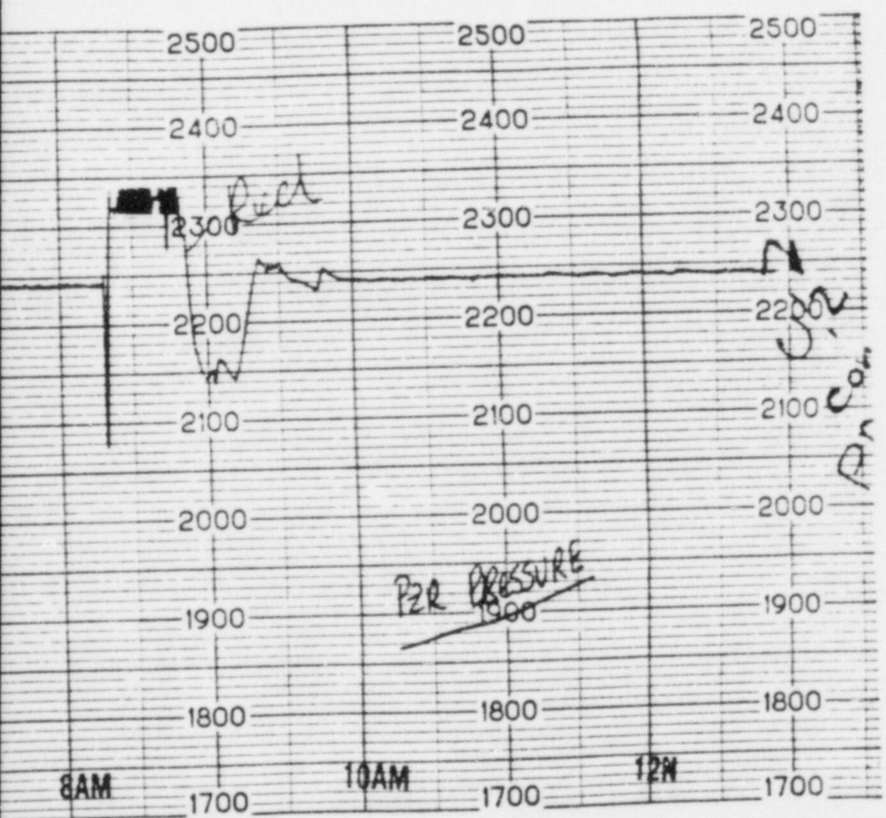
4. Exit Interview

At periodic intervals during the course of the inspection, meetings were held with senior facility management to discuss the inspection scope and findings. An exit interview was held with licensee management on August 28, 1986. The licensee did not identify 2.790 material.

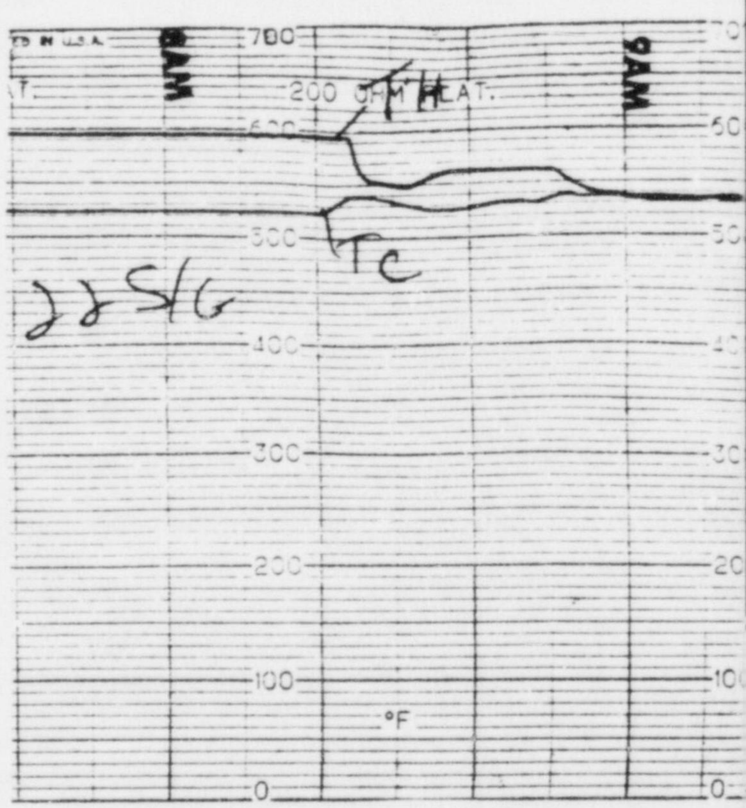
FIGURE I
REACTOR COOLANT SYSTEM PARAMETERS



B. Pressurizer Level



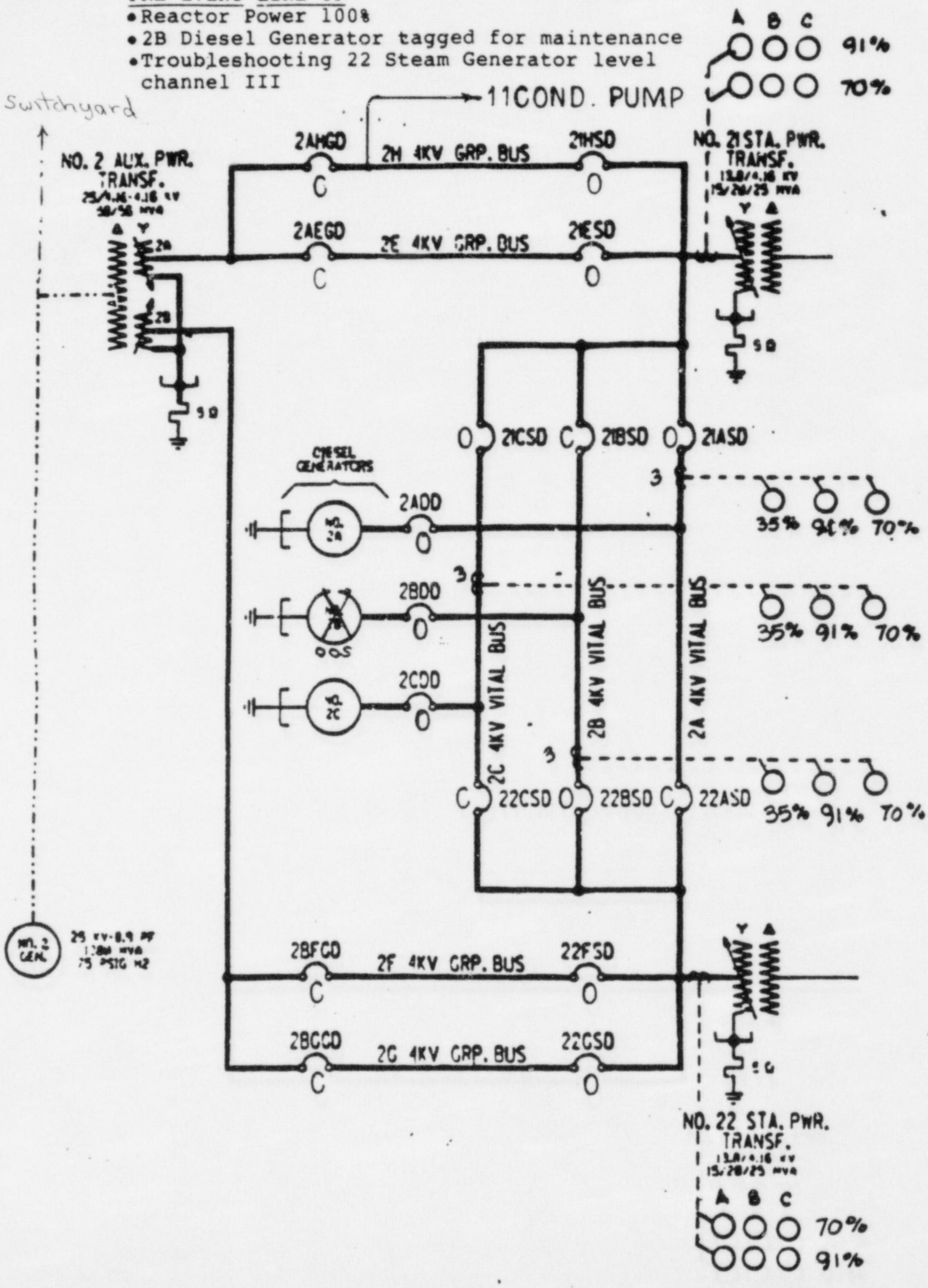
A. Pressurizer Pressure

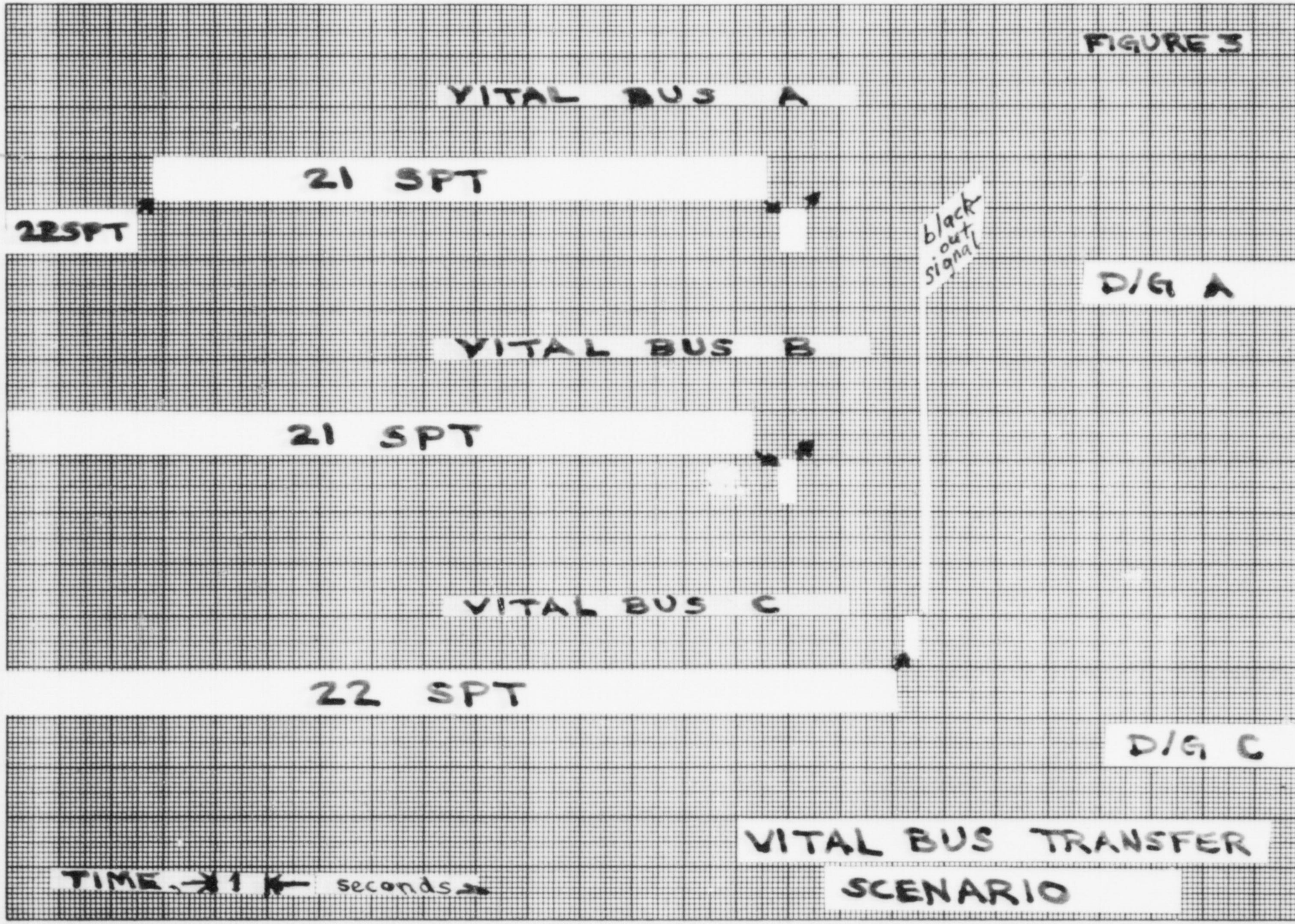


C. Typical RCS Loop Temperatures

FIGURE 2

PRE-EVENT LINE-UP
- Reactor Power 100%
- 2B Diesel Generator tagged for maintenance
- Troubleshooting 22 Steam Generator level channel III





1 millimeter/Division—5th, 10th Accent

Appendix A

Synopsis of Licensee Actions During and Subsequent to the August 26, 1986 Event

Licensee management was involved in the recovery and assessment of the reactor trip of August 26, 1986, since its onset. The Assistant Plant Manager, Operations Manager, and Operating Engineer were observed by the resident inspector in the control room area shortly after the trip occurred. The plant was placed in a stable condition. Plant management then conducted a series of meetings to summarize the collective information and to outline new strategies for the work to be done. Below is an outline of these meetings and the significant findings presented at the meetings.

August 26, 1986

- 11:00 A.M. Management meeting with the operating shift to ascertain the scenario of the events prior to and after the event described in Section 1.C of this report. The resident inspector attended this meeting.

- 1:00 P.M. Plant management initial meeting with all disciplines to collect the facts about the trip. At this meeting the licensee determined the cause of the trip and the Safety Injection, identified instruments and equipment that failed to function and formed the following groups:

    1. A task force to determine the cause for the false loss of offsite power during the Group bus transfer.

    2. A task force to determine the approach to the repair and to further investigate the fan cooler leaks.

    3. A task force to investigate and determine operator actions with regard to the event and the use of procedures in the performance of their actions. The task force was directed to identify lessons learned, training effectiveness and the need, if necessary, to reevaluate the current procedures.

    4. A task force to investigate and repair identified instruments and equipment that did not respond in proper fashion. These minor problems did not have any impact on course of events or the safe recovery of the unit. Appendix D is a list of these items.

    5. A task force to investigate maintenance practices for troubleshooting circuits while at power.

The above items will be followed up by inspectors. As noted in the report body, they are Unresolved Items 311/86-26-01 through 05.

- 4:00 P.M. First update on task forces evaluations. The key points identified were:

  1. All task forces discussed their progress and did not identify any new findings, but did indicate they had key personnel available for evaluating their assigned tasks.

  2. Design experts from the relay department were called to the site for additional support.

August 27, 1986

- 2:30 A.M. The licensee informed the Senior Resident Inspector by telephone that a leak had been identified in the service water system of fan cooler unit No. 25 in the same area as the initial leak on fan cooler unit No. 23. The leak was discovered during preparation for ultrasonic testing of the piping.

- 9:00 A.M. Management Meeting update

  1. The task force on the service water piping identified that similar connections to fan cooler unit Nos. 21 and 22 would need to be replaced. Number 24 fan cooler unit was identified to have different configuration than the other four units and would not be replaced.

  2. Other task forces gave updates on the progress of their investigations.

- 1:00 P.M. Management Meeting update

  1. Discussion on how repairs were to be made on fan cooler units and how hydrostatic testing was to be performed.

  2. Task force on the bus transfer problem discussed testing performed to date.

  3. Task force for operations identified that they had been in contact with Westinghouse with regard to emergency operating procedures, and stated they will issue a written report when the investigation is completed.

- 4:00 P.M. Management Meeting

  1. Discussion of a possible scenario of how the false loss of offsite power may have occurred.

2. Discussion of computer model of the station's electrical distribution system to be developed at the corporate office in Newark, N. J.

August 28, 1986

- 9:30 A.M.

1. Discussion of Corrective Actions (Appendix C).

2. Discussion by the Operations task force leader.

3. Discussion of the progress with piping replacement on fan cooler units and false loss of offsite power.

In addition, other meetings were held to keep abreast of status. NRC personnel attended the meetings and concluded that Station Management used the resources in the plant, the Engineering Staff and corporate headquarters to good advantage.

Appendix B

Documents Reviewed

2.A Documents reviewed:

-	EOP-TRIP-1, Rev. 0	Reactor Trip or Safety Injection
-	EOP-TRIP-3, Rev.0	Safety Injection Termination
-	I-4.15, Rev. 6	Loss of Component Cooling
-	II-1.3.1, Rev. 4	Reactor Coolant Pump Operation
-	AD-16, Rev. 6 Completed for August 26 Event	Post Reactor Trip/Safety Injection Review
-	EOP-Appendix-1, Rev. 0	Component Cooling Water Restoration
-	2IC-18.1.009	Functional Procedure Solid State Protection System - Train B
-	2PD-2.6.044	Channel Functional Test 2LT-528 No. 22 Steam Generator Level Protection Channel III
-	2IC-18.1.011	Functional Procedure - SSPS Train A Reactor Trip Breaker UV Coil and Auto Shunt Trip

- Technical Specifications
- Sequence of Events Computer Printout
- Alarm Typewriter Computer Printout
- Selected Operating Logs
- Selected Station Operations Review Committee (SORC) Meeting Minutes
- Selected Licensee Event Reports (LER)
- Maintenance Department Work Order Tracking System Printout
- Selected Maintenance and I&C Work Orders
- Selected Equipment History Cards

Appendix C

List of Corrective Actions for Equipment Problems Identified by Licensee During the Event of

August 26, 1986

1. The reason for No. 21 Steam Generator Feedwater Pump not tripping as a result of the safety injection signal.

2. The reason for the excessive time as indicated on sequence of events for tripping of No. 22 Steam Generator Feedwater Pump on safety injection signal.

3. The reason for no safety injection indicated on first out annunciator.

4. Verification of reactor trip breaker response time for loop 23 low flow - P-8 reactor trip signal.

5. Verification of response time of turbine stop valves and turbine remote emergency trip solenoid for loop 23 low flow - P-8 reactor trip signal.

6. Verification of the operation of manual reactor trip handle sequence of events indication.

7. Verification of the start time of No. 23 auxiliary feedwater pump from steam generator low-low level signals.

8. Return 2B diesel to service.

9. Repairs to service water piping for Containment Fan Cooler Units 21, 22, 23 and 25.

10. Repairs to No. 22 Steam Generator level Channel III.

11. The reason for no indication of boron injection tank outlet flow during event.