UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

Report No. 50-325/90-29 and 50-324/90-29

Licensee: Carolina Power and Light Company
P. O. Box 1551
Raleigh, NC 27602

Docket Nos. 50-325 and 50-324 License No. DPR-71 and DPR-62

Facility Name: Brunswick 1 and 2

Inspection Conducted: August 1 - September 7, 1990

Lead Inspector: Robert E Carroll Jr. for 9/13/90
R. L. Prevatte Date Signed

Other Inspectors: W. Levis
D. J. Nelson

Approved By: [signature] 9/13/90
R. Carroll, Acting Section Ch. Date Signed
Reactor Projects Branch 1
Division of Reactor Projects

SUMMARY

Scope:

This routine safety inspection by the resident inspector involved the areas of maintenance observation, surveillance observation, operational safety verification, Augmented Inspection Team followup, onsite Licensee Event Reports (LER) review, Management Meeting, followup on Temporary Instructions, and action on previous inspection findings.

Results:

One violation was identified in the area of operational safety verification. An auxiliary operator in the process of implementing a clearance on a Unit 1 motor generator set for the reactor protection system, inadvertently de-energized the corrosponding Unit 2 motor generator set which resulted in a half scram and closure of group 2, 3, 6, and 8 inboard containment isolation valves. This caused a loss of shutdown cooling for approximately 22 minutes (paragraph 4.c).

Additionally, a review of the Augmented Inspection Team activities conducted from August 21-25, 1990, identified four apparent violations of NRC requirements. These included:

- A failure of Instrumentation and Control (I&C) technicians to follow procedures and falsifying test records (paragraph 5.a).

- Inadequate operator procedures and the failure of operators to follow the guidance provided by operator aids and procedures (paragraph 5.b).

- The failure to declare an unusual event after the failure of five safety relief valves to operate when their setpoint was exceeded (paragraph 5.c).

- The failure to make prompt notification to the NRC of engineered safety features actuations (paragraph 5.d).

These items will be discussed further in an enforcement conference scheduled for October 16, 1990, in the Region II office.

Unit 2 experienced three automatic reactor trips during the reporting period. Two were the result of equipment failures and one was the result of I&C technicians failing to follow procedural requirements (paragraphs 4.a, b, and c).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*K. Altman, Manager - Regulatory Compliance
F. Blackmon, Manager - Radwaste/Fire Protection
*A. Burkhart, Corporate Nuclear Services
*S. Callis, On-Site Licensing Engineer
T. Cantebury, Manager - Unit 1 Mechanical Maintenance
*G. Cheatham, Manager - Environmental & Radiation Control
M. Ciemnicki, Security
R. Creech, Manager - Unit 2 I&C Maintenance
J. Cribb, Manager - Quality Control (QC)
W. Dorman, Manager - Quality Assurance (QA)/(QC)
V. Grouse, Employee Relations
*J. Harness, General Manager - Brunswick Steam Electric Plant
W. Hatcher, Supervisor - Security
*R. Helme, Manager - Technical Support
J. Holder, Manager - Outage Management & Modifications (OM&M)
*B. Houston, Senior Specialist - Emergency Planning
L. Jones, Manager - Procurement
M. Jones, Manager - On-Site Nuclear Safety - BSEP
*D. Leonard, Manager - Training
R. Kitchen, Manager - Unit 2 Mechanical Maintenance
J. Leviner, Manager - Engineering Projects
*W. Martin, On-Site Nuclear Safety
J. McKee, Manager - QA
*C. Moseley, Corporate Nuclear Services
J. Moyer, Technical Assistant to Plant General Manager
*P. Musser, Manager - Maintenance Staff
B. Poteat, Administrative Assistant to Plant General Manager
R. Poulk, Manager - License Training
*M. Rogers, Quality Assurance Engineering
J. Simon, Manager - Operations Unit 2
*W. Simpson, Manager - Site Planning and Control
S. Smith, Manager - Unit 1 I&C Maintenance
*R. Starkey, Vice President - Brunswick Nuclear Project
*R. Tart, Manager - Operations Unit 1
J. Titrington, Manager - Operations Staff
*R. Warden, Manager - Maintenance
*K. Williamson, Manager - Nuclear Engineering Department (NED)
B. Wilson, Manager - Nuclear Systems Engineering

Other licensee employees contacted included construction craftsmen, engineers, technicians, operators, office personnel, and security force members.

*Attended the exit interview

Acronyms and initialisms used in the report are listed in the last paragraph.

2. Maintenance Observation (62703)

The inspectors observed maintenance activities, interviewed personnel, and reviewed records to verify that work was conducted in accordance with approved procedures, Technical Specifications, and applicable industry codes and standards. The inspectors also verified that: redundant components were operable; administrative controls were followed; tagouts were adequate; personnel were qualified; correct replacement parts were used; radiological controls were proper; fire protection was adequate; quality control hold points were adequate and observed; adequate post-maintenance testing was performed; and independent verification requirements were implemented. The inspectors independently verified that selected equipment was properly returned to service.

Outstanding work requests were reviewed to ensure that the licensee gave priority to safety-related maintenance.

The inspectors observed/reviewed portions of the following maintenance activities:

90-AMPR1	DG 4 Starting Air Left Header Pressure Reducing Valve
90-APAI1	2-B21-F022B Stroke Time Adjustment
90-APAJ1	2-B21-F022A Stroke Time Adjustment
90-APJG1	Unit 2 Startup Level Control Valve
90-VLR331	Monthly Lube and Inspection of SW Pump Strainers

On September 4, 1990, another example of the licensee's continued weakness in work control occurred. This event was similar to the wrong unit/train event discussed in paragraph 4, in that maintenance planned for a Unit 2 component was mistakenly commenced on the corresponding Unit 1 component.

WR/JO 90-AMUG2 documented an air leak on the actuator for AOG inlet secondary isolation valve, 2-AOG-HCV-148. This valve is located in the AOG building which is common to both units. The valve is normally open when AOG is in operation.

Repair of the air leak required that the valve be secured open since the repair involved removing the inlet air connection. This would vent the actuator and allow the valve to fail closed and thereby secure AOG operation for Unit 2. Two mechanics in the process of determining how to gag the valve open for repair mistakenly located the Unit 1 valve. The Unit 1 and 2 valves are located in adjacent valve pits. They incorrectly identified the valve as being for Unit 2 by its attached tag which correctly indicates that it is a Unit 1 valve. Neither mechanic detected this error. The Unit 1 valve coincidentally had an air leak which fit the description on the WR/JO for the Unit 2 valve. They returned later with a maintenance planner to explain their gagging plans and again went to the wrong valve. The planner did not detect the error. The two mechanics subsequently returned with an Operations AO and explained the gagging plans on the wrong valve. The AO did not detect the error either. The AO then placed a clearance on the Unit 2 air supply isolation valve located outside the valve pit area. The mechanics gagged the Unit 1 valve and attempted to remove the air line, but stopped because the air supply did not appear to be properly isolated. Concurrently, the Unit 2 valve actuator, with its air supply isolated, began to bleed down and the valve drifted shut securing Unit 2 AOG. After verifying the correct air supply isolation, the mechanics and AO determined that the wrong valve was being worked. The Unit 2 valve was then returned to normal. Unit 2 AOG was only momentarily interrupted.

The AOG System is not safety-related, therefore, this event has no reactor safety significance. However, the work control aspects are generic to safety-related equipment.

These events are indicative of the continuing problem the licensee is currently experiencing in maintaining proper work control.

Violations and deviations were not identified.

3. Surveillance Observation (61726)

The inspectors observed surveillance testing required by Technical Specifications. Through observation, interviews, and record review, the inspectors verified that: tests conformed to Technical Specification requirements; administrative controls were followed; personnel were qualified; instrumentation was calibrated; and data was accurate and complete. The inspectors independently verified selected test results and proper return to service of equipment.

The inspectors witnessed/reviewed portions of the following test activities:

1MST-RHR22M	RHR-LPCI, ADS CS LL3, HPCI LL2 Div. 1 Train Unit Channel Monthly Calibration
2MST-PCIS24M	PCIS High Condenser Pressure Trip Unit Channel Calibration
2MST-RCIC14M	RCIC Steam Leak Detection Channel Functional Test
2PT-40.2.8	Unit 2 MSIV Closure Testing
2PT-11.1.2	Unit 2 ADS and SRV Testing

Violations and deviations were not identified.

4. Operational Safety Verification (71707)

The inspectors verified that Unit 1 and Unit 2 were operated in compliance with Technical Specifications and other regulatory requirements by direct observations of activities, facility tours, discussions with personnel, reviewing of records and independent verification of safety system status.

The inspectors verified that control room manning requirements of 10 CFR 50.54 and the Technical Specifications were met. Control operator, shift supervisor, clearance, STA, daily and standing instructions, and jumper/bypass logs were reviewed to obtain information concerning operating trends and out of service safety systems to ensure that there were no conflicts with Technical Specification Limiting Conditions for Operations. Direct observations of control room panels and instrumentation and recorder traces important to safety were conducted to verify operability and that operating parameters were within Technical Specification limits. The inspectors observed shift turnovers to verify that system status continuity was maintained. The inspectors also verified the status of selected control room annunciators.

Operability of a selected engineered safety feature division was verified weekly by ensuring that: each accessible valve in the flow path was in its correct position; each power supply and breaker was closed for components that must activate upon an initiation signal; the RHR subsystem cross-tie valve for each unit was closed with the power removed from the valve operator; there was no leakage of major components; there was proper lubrication and cooling water available; and conditions did not exist which could prevent fulfillment of the system's functional requirements. Instrumentation essential to system actuation or performance was verified operable by observing on-scale indication and proper instrument valve lineup, if accessible.

The inspectors verified that the licensee's HP policies/procedures were followed. This included observation of HP practices and a review of area surveys, radiation work permits, postings, and instrument calibration.

The inspectors verified by general observations that: the security organization was properly manned and security personnel were capable of performing their assigned functions; persons and packages were checked prior to entry into the PA; vehicles were properly authorized, searched and escorted within the PA; persons within the PA displayed photo identification badges; personnel in vital areas were authorized; effective compensatory measures were employed when required; and security's response to threats or alarms was adequate.

The inspectors also observed plant housekeeping controls, verified position of certain containment isolation valves, checked clearances, and verified the operability of onsite and offsite emergency power sources.

a. Unit 2 Reactor Scram of August 16, 1990

On August 16, Unit 2 experienced a full reactor scram from 100% power due to a reactor vessel water level transient caused by a blown fuse in the steam flow circuit to the feedwater control system. All rods inserted as anticipated. The operators attempted to respond to the transient, but a turbine and subsequent reactor trip occurred due to high reactor vessel water level. Following the reactor scram and feedwater pump trip, reactor vessel level decreased and initiated isolation of PCIS Groups 2, 6 and 8. The operators manually initiated RCIC and HPCI to control reactor vessel level. The minimum level reached was 112 inches. SBGT was manually initiated. The recirculation pumps tripped as a result of the loss of power from their normal power source, which is ultimately supplied from the unit auxiliary transformer. Plant equipment, with the exception of the RCIC barometric condenser vacuum pump (which had an electrical fault), performed as anticipated. Some problems were experienced with thermal overloads on MOVs. A cooldown rate of approximately 140 degrees F was experienced on the bottom head of the reactor vessel due to a clogged line in the RWCU system. An analysis by GE determined that this cooldown did not result in any damage to the reactor vessel. Testing and analysis of the affected fuse and circuitry by the licensee determined that the fuse failure resulted from thermal aging. The unit was restarted on August 18, 1990. The licensee is currently preparing an LER on this item.

b. Unit 2 Scram on August 19, 1990

On August 19, Unit 2 experienced a full reactor scram from 100 percent power after the MSIVs closed on a group 1 isolation. The details of this event are contained in paragraph 5 of this report.

Prior to Unit 2 restart from the August 19, 1990 scram, the inspector conducted a closeout inspection of the Unit 2 drywell. Specific attention was paid to the areas where maintenance activities had occurred (i.e., MSIV and SRV areas). No discrepancies were noted. By use of a hand held instrument, the inspector noted that radiation levels at the recirculation system risers were higher than expected. The risers were replaced during the last Unit 2 outage. Current levels averaged at approximately 1 R/hr, compared to approximately 200 mR/hr prior to replacement. The licensee suspects that the high levels were due to a crud burst from the full power trip on August 19, with hydrogen water chemistry in service. Since recirculation pumps tripped during the trip, the crud could not be kept in suspension for cleanup and was deposited on the recirculation surfaces. Isotopic analysis confirmed the elevated levels to be from cobalt 60. The licensee expects the levels to decrease with future plant operation.

c. Loss of RPS Bus 2A

On August 22, 1990, at 4:38 a.m., while in cold shutdown, Unit 2 experienced an unplanned loss of RPS bus 2A when it was incorrectly de-energized by an AO while implementing a clearance on the RPS MG set for the corresponding RPS bus in Unit 1. The loss of RPS bus 2A resulted in the following automatic plant responses in Unit 2:

- SBGT A and B started
- Reactor building ventilation system isolation
- Closure of inboard isolation valves for primary containment isolation system groups 2, 3, 6, and 8
- Closure of group 8 valve E11-F015A, LPCI inboard injection valve
- Closure of group 1 solenoid valves 2B32-F019, inboard sample isolation valve, and 2B21-F016, main steamline drain inboard isolation valve

The partial Group 8 isolation resulted in loss of RHR shutdown cooling which was operating on RHR loop A only. Power was restored to RPS bus 2A at 4:40 a.m. Shutdown cooling was restored at 5:00 a.m.; reactor vessel temperature rose 5 degrees F (142 to 147) during the period that shutdown cooling was lost. All system actuations occurred as designed.

The cause of the event was personnel error, in that the Operations AO operated equipment in Unit 2 instead of Unit 1. The AO was completing Local Clearance 1-90-826 which was intended to remove the Unit 1 RPS MG set 1A from service and to danger tag the MG set output breaker to allow performance of 1-MST RPS21SA, RPS Electrical Protection Assembly Channel Calibration. The clearance consisted of only one danger tag (1A MG set output breaker), but was preceded by directions to transfer 1A RPS to its alternate power supply and to secure the MG set in accordance into the applicable portions of Operating Procedure OP-3, RPS Operating Procedure (Revision 15). Transfer to the alternate power supply was successfully accomplished by a Unit 1 control room operator who then directed the AO to secure the 1A MG set in accordance with 1-OP-3, section 7 (as stipulated on the clearance tag sheet), then place the clearance on the 1A MG set output breaker. The AO proceeded to the Unit 2 Cable Spreading Room, located below the control room area, and opened EPA breakers 1 and 2 on the 2A RPS bus, thereby deenergizing the bus and causing the event. The last steps of securing the MG set and placing the clearance tag on the output breaker were not completed because Unit 2 control room operators alerted the AO to stop work after the RPS power loss.

Administrative Instruction AI-58, Equipment Clearance Procedure (Revision 32), contains controls to ensure the removal of the correct components from service. This is accomplished by a modified independent verification requirement that requires two operators to simultaneously identify and verify the correct manipulation of equipment important to safety. This is referred to as "double verification" - independent verification, but not separated by time and distance. The AO implementing the clearance was not employing double verification, which could have prevented him from removing the wrong component from service. The AO stated that he was aware of the double verification requirement, but simply forgot. He also stated that his thought process at the time may have been affected by his knowledge that independent verification was required by the OP for switching to the alternate RPS power supply, which was already accomplished by control room operators at the time he was directed to complete the clearance.

The inspector determined that the intent of AI-58 double verification is unintentionally omitted in many clearances on components/systems important to safety. This occurs when a clearance involves the performance of a stand-alone OP to secure a component or system prior to tagging. Since OPs do not require double verification to ensure correct component operation, the clearance double verification occurs when the clearance tags are hung, after the component/system has already been affected and too late to prevent wrong-component events. The Licensee acknowledged that the intent of AI-58 is to require double verification for performance of OPs needed for clearances.

The inspector also determined that clearance tag sheets do not identify which clearances require double verification. AI-58 requires double verification for those systems listed in Table 11.7.1 of the Operating Manual Administrative Procedure: AP Volume I (Revision 126), which includes systems important to safety. It is reasonable to expect all operators to know which systems are important to safety. However, based on this event, it may be necessary to include a reminder on individual clearance forms that double verification is required.

The inspector verified that the EPA breakers are correctly labeled as to unit and bus, but noted that the overall physical appearance of the cable spreading rooms is nearly identical for the two units. The inspector also noted that the licensee does differentiate between units/trains by color code in other areas of the plant (i.e., service water building and 4160 volt emergency switchgear). A research of records indicates that wrong unit/train events have not been a chronic problem in recent years, although the 2A RPS bus was previously de-energized instead of the 1A RPS bus (LER 2-86-021). Another wrong unit event occurred on September 4, 1990, and is described in paragraph 2.

The failure to follow the requirements AI-58 is contrary to the requirements of Technical Specification 6.8.1.a and is a violation: Failure to Follow Procedures, 325,324/90-29-05.

During followup inspection on this event, the inspector determined that the OP for RHR, OP-17 (Revision 89), does not include provisions for restoration of shutdown cooling if lost. Currently, the operators must go through the entire portion of the OP used to establish shutdown cooling during a unit shutdown. This involves numerous steps that are unnecessary if shutdown cooling had already been established (i.e., RHR warm up). The operators' practice is to complete the entire procedure, but note the steps that are not applicable. The operators questioned were confident on what portions of the procedure would be omitted to re-establish shutdown cooling. No problems associated with shutdown cooling recovery have occurred recently, but operators stated that a specific procedure for shutdown cooling recovery would be helpful. Operations management has indicated that an RHR shutdown cooling recovery procedure is under consideration.

Based on the event described above and the personnel errors involved with the reactor scram of August 19, the licensee suspended all work activities in the power block on August 22, except work vital to the preservation of nuclear safety. During this work stoppage the licensee conducted work control briefings with all work groups to include review of the following recent events:

- Traversing incore probe event
- Locked high radiation area doors being found unlocked
- Personnel errors involved with the August 19, 1990 scram
- 1A/2A RPS bus event

The briefings were completed in approximately one shift and work activities resumed later on August 22. The licensee imposed new requirements for pre-job briefs to be performed by first line supervisors which include, but not limited to, the following major issues:

- Identification of critical tasks associated with the job
- Potential consequences of improper job performance
- Required interfaces
- Safety/ALARA considerations

d. Unit 2 Reactor Scram of August 30, 1990

On August 30, during a reactor startup, Unit 2 experienced a reactor water level transient due to the failure of the feedwater SULCV. This resulted in a reactor scram from low level 1 and a group 2, 6 and 8 isolation. The minimum reactor water level observed was 141 inches. The reactor water level was restored using the feedwater condensate system and control rod drive system. The failure of the SULCV was caused by a broken air supply line to its actuator. After extensive investigation, it was determined that there were defective "O" rings in the SULCV actuator and an improperly sized positioner for that valve, which had been installed on the valve under modification DR-87-0471, in May 1988. That modification changed the SULCV from a 2-inch to a 5-inch actuator and a 5-inch valve positioner. Present information indicates that the valve supplier did not have a 5-inch positioner available, so a 4-inch positioner was "rebuilt" and provided with the actuator. It presently appears that not all parts essential to this rebuild were, in fact, replaced. The licensee, with the assistance of a valve manufacturer technical representative, repaired the failed valve, replaced the positioner, calibrated, and tested the valve and associated controls. The unit was restarted on September 2, and returned to power on September 3, 1990.

The licensee has determined that an incorrect positioner is also installed in Unit 1. They plan to replace that component during the refueling outage scheduled to commence on September 26. They are additionally conducting a search to determine if other similar applications exist at Brunswick and if other CP&L units have this same problem. The licensee is additionally preparing a LER which will discuss this event in detail.

One violation was identified.

5. Augmented Inspection Team Followup (93800)

On August 19, Unit 2 experienced a full reactor scram from 100 percent power after the MSIVs closed on a group 1 isolation. The above occurred as the result of I&C Technicians failing to have Primary Containment High Condenser Pressure Channel A-2 cleared prior to starting the channel calibration maintenance surveillance on channel B-2. Five of the eleven safety valves failed to actuate, though their setpoint was exceeded during this event. The apparent failure of the SRVs to operate and a determination by the licensee that the technicians performing the above test had attempted to falsify test records to cover the root cause of the event, resulted in the NRC initiating an AIT to investigate the event. The AIT inspection was completed on August 25, and the results of that inspection are contained in Inspection Report 90-36.

Since the AIT was a fact finding investigation and, as such, was not directed to identify violations of NRC requirements, the findings of the AIT were reviewed by the resident inspectors to determine if any NRC requirements were violated. This review identified the following items:

a. The I&C technicians, while performing Maintenance Surveillance Test 2MST PCIS 24M, Primary Containment Isolation System High Condenser Pressure Trip Unit Calibration (Revision 4), failed to follow the requirements of Technical Specification 6.8.1.a; Appendix A of Regulatory Guide 1.33; and Plant Maintenance Procedure 0-MMM-001, Maintenance (Revision 13) and the Operating Manual Administrative Procedure: AP Volume I (Revision 126), which implement the above requirements for procedural compliance and independent verification of critical procedural steps on safety systems. Contrary to the above requirements, one I&C technician was performing this test without a second technician present to independently verify that each channel had been reset prior to proceeding to the next sequential channel test. Steps 7.5.15, 7.5.36, 7.5.37, 7.5.38, 7.5.39, 7.5.58, 7.5.59 and 7.5.63 were initialed as completed when they had not been performed. Additionally, steps 7.5.58 and 7.5.59, which required independent verification, were signed off without being performed. This improper testing resulted in a group 1 isolation and Unit 2 automatic reactor full scram. The technicians initially denied that they had caused the unit scram and only after being presented with security information showing that both individuals were not in the space where the test was being performed did they admit that they had completed the test records after the unit scram. This is an apparent violation: Failure to Follow Test Procedures Which Resulted in a Reactor Scram, 324/90-29-01.

b. (1) A review of computer print outs, plant logs and records, and interviews with licensed operators revealed that the operators failed to follow the requirements of TS 6.8.1.a; Appendix A of Regulatory Guide 1.33; and Plant Procedure OI-01, Operating Principles and Philosophy (Revision 32) and Annunciator Response Procedures A-05 5-3 (Revision 18) and A-04 6-1 (Revision 10), which implements the above requirements and provide steps for the operator to take in response to annunciator alarms for Group 1 Isolation Logic A/C Tripped and RPS Channel B Trip Cabinet Trouble Alarms. Contrary to the above requirement, the operator had received an alarm when Channel A2 was placed in test. He had acknowledged and silenced that alarm. When the Trouble alarm was received on Channel B2, he failed to stop the test that was in progress. When the I&C technician injected a trip test signal in Channel "B", the group 1 isolation and reactor scram occurred.

(2) The following procedures and/or operator aids in the main control room were determined to be inadequate:

(a) Operator aid 210099, used by the operator to open the MSIVs, did not require the operator to place the condenser vacuum bypass switch in bypass to allow opening the MSIVs under low vacuum conditions.

(b) Operator aid 210085, used to restart HPCI, did not require that the HPCI auxiliary oil pump be secured prior to opening the steam admission valve. Starting HPCI with the oil pump running could result in the pump turbine tripping on overspeed.

(c) Operating Procedure 2-OP-16, Reactor Core Isolation Cooling System (Revision 57), did not specify that the control switch for RCIC trip and throttle valve V8 be held in the close position for at least five seconds to ensure that the valve was relatched after a turbine trip.

(d) The operators failed to follow procedural guidance in their response to the scram and subsequent events, in that OP-16, which states that the duty cycle for DC limitorque valves is limited to three starts in five minutes followed by a fifty minute cooldown, was not followed. This resulted in the RCIC V8 valve's thermal overloads tripping after a fourth attempt to cycle the valve in a very short time period.

(e) Operating Procedure 2-OP-32, Condensate and Feedwater System (Revision 58), and General Operating Procedure, Plant Shutdown (Revision 43), require that the long cycle feedwater cleaning return to the condenser valve V177 not be opened unless the SULCV, 2-FW-LV-3269, is previously opened. The operator failed to follow this guidance and opened V177 with LV-3269 shut. This could result in draining this portion of the feedwater line to the condenser. Opening of the LV-3269 after draining of this line could result in serious water hammer in this system. This problem was immediately identified and corrected by other watchstanders.

The above items are multiple examples of inadequate procedures and multiple examples of a failure of licensed operators to follow prescribed procedures. This is an apparent violation: Inadequate Procedures and Procedural Compliance, 324/90-29-02.

c. A review of operator logs, computer printouts and other plant records determined that the licensee failed to meet the requirements of 10 CFR Part 50.47(b)(4); 10 CFR Part 50 Appendix E (IV)(B); Technical Specifications 6.8.1.e; and the Plant Emergency Procedure PEP 02.1, Initial Emergency Actions (Revision 27), which implements the above requirements for declaring and reporting the failure of five nuclear steam system SRVs to lift when their pressure setpoint was exceeded. The above requirements state that this failure shall initiate an Unusual Event requiring notification of the NRC, state, and local officials. The licensee, after questioning by the resident staff on the following day, stated that a decision had been made by the Operations Manager shortly after the event to defer declaring an Unusual Event until Technical Support evaluated the data and determined whether the SRVs should have opened. After discussions with the NRC resident staff and evaluation by Technical Support, an Unusual Event was declared and terminated at 5:45 p.m., on September 20, based on the failure of SRV C to open during the scram. This is an apparent violation: Failure to Declare an Unusual Event and Make Prompt Notification, 324/90-29-03.

d. Following the event, four ESF actuation signals were experienced. 10 CFR 50.72(b)(2)(ii) requires that the licensee notify the NRC Operations Center as soon as possible and in all cases within four hours of the occurrence of any event or condition that results in manual or automatic actuation of any ESF including the RPS. The FSAR, Chapter 6, provides a list of Engineered Safety Features which includes the Containment Isolation System. The licensee failed to make a report within four hours of a Group 1 containment isolation that occurred at 10:27 p.m., a Group 2, 6 and 8 actuation and a RPS trip signal that occurred at 11:17 p.m., on August 19, and 12:04 a.m., on August 20, 1990. These reports were made at 11:08 a.m., on August 21, after this item was brought to the licensee's attention by the resident inspection staff. An additional Group 3 Containment isolation signal that occurred at 12:27 a.m., on August 20, was reported to the NRC on September 7, 1990. The above is an apparent violation: Failure to Make Prompt Notification of ESF Actuations, 324/90-29-04.

The above items were discussed in detail during the AIT investigation, at the AIT exit held on August 25, and at the resident inspector's monthly exit on September 7. They will be further discussed at an enforcement conference in the Region II office on October 16, 1990.

6. Onsite Review of Licensee Event Reports (92700)

The below listed LERs were reviewed to verify that the information provided met NRC reporting requirements. The verification included adequacy of event description and corrective action taken or planned, existence of potential generic problems and the relative safety significance of the event. Onsite inspections were performed and concluded that necessary corrective actions have been taken in accordance with existing requirements, license conditions and commitments, unless otherwise stated.

a. (CLOSED) LER 1-88-22, PCIS Group 6 Isolation With Secondary Containment Isolation and SBGT Actuation Due to Stack Radiation Monitor High, High Trip. This event was due to an automatic switching of channel input signals to the effluent channel monitor computer due to a loss of the low range pump from an unidentified flow restriction. No root cause of this event could be identified, but it was firmly believed it was the result of E&RC sampling of the CAC purge system that was in progress at the time of the isolation. To prevent a recurrence of this event, the procedure, E&RC-1231, was revised to place the CAC purge vent isolation switch in the override position during the performance of monthly Tritium sampling. The plant will enter the LCO when this isolation switch is in the override position. This action should prevent spurious actuations during sampling.

b. (CLOSED) LER 2-88-02, Failure of Drywell Head Outer Seal and Reactor Feedwater Primary Containment Isolation Valves B21-F010B and F032B Revealed Through Local Leak Rate Testing. Licensee testing for root cause of the above determined that it was a packing material failure attributed to manufacturing defects. The above defective components were replaced with new and, in some cases, upgraded material components. The licensee actions on this item appear to be satisfactory for the circumstances involved.

c. (CLOSED) LER 2-89-19, RPS Trip on Low Level 1 Due to Startup Level Control Valve Not Opening on Dropping Reactor Level Due to Suspected High Differential Pressure. The licensee concluded that the failure of the valve to open was caused by an excessive D/P across the valve which resulted from opening the downstream return to condenser valve V177 prior to opening the SULCV. Procedure changes were made and training conducted so that the V177 valve would not be opened until the SULCV was opened.

   Subsequent to this event, as documented in Inspection Report 90-36, the licensee found that the valve was sized to open against a 1200 lbs. D/P which was sufficient. However, the flow characteristics of the valve installed in the plant differed from the flow characteristics of the valve modeled in the simulator. This fact, coupled with the drift experienced in the valve's controller, meant that a 50 percent demand signal was providing approximately 15 percent flow. The operators had not been trained in this valve's operation.

   The simulator model has since been changed so that the flow characteristics of the SULCV match those in the plant. Additional inspection of this item will be conducted in closeout of deficiencies identified in Inspection Report 90-36 and LER 2-90-12.

Violations and deviations were not identified.

7. Management Meeting (30703)

NRC and CP&L management met onsite on August 23, 1990, to discuss the status of the licensee's Integrated Action Plan for the company and the Brunswick Plant. The CP&L Senior Vice President, Nuclear and the Brunswick

Project Manager, gave an overview of the plan. This was followed by presentations by selected managers. The agenda and slides used in the presentation are included as an Attachment to this report.

Meeting Attendees

Licensee Employees:

L. W. Eury, Executive Vice President
R. A. Watson, Senior Vice President, Nuclear Generation
R. B. Starkey, Vice President, Brunswick Nuclear Project
J. L. Harness, Brunswick Plant General Manager
J. R. Holder, Manager, Outage Management & Modifications
W. W. Simpson, Manager, Control & Administration
H. W. Bowles, Assistant to the Department Head, Corporate QA/QC
L. H. Martin, Manager, Brunswick Training
J. W. Moyer, Technical Assistant to Plant General Manager
K. B. Altman, Manager, Regulatory Compliance
K. M. Core, Special Projects
L. I. Loflin, Manager, Corporate Nuclear Licensing
A. B. Cutter, Vice President/Director, Special Nuclear Projects
G. E. Vaughn, Manager, Nuclear Services Department
A. M. Lucas, Manager, Nuclear Engineering Department (NED)
J. M. Brown, Manager, Brunswick Engineering Support Section, NED
D. E. Moore, Manager, Projects - Outage Management
K. A. Williamson, Principal Engineer, On-Site Support, NED
L. E. Jones, Manager, Procurement Engineering
C. H. Gray, Manager, Materials & Contract Services
J. R. Kelly, Manager, Modifications, Outage Management Section
J. P. Leviner, Manager, Engineering Projects
A. G. Cheatham, Manager, Environmental & Radiation Control
R. L. Warden, Manager, Maintenance
B. R. Poteat, Administrative Assistant to Plant Manager
W. R. Hatcher, Manager, Security
G. F. Booth, Manager, BNP Biological Monitoring
M. S. Timberlake, Special Projects
W. J. Dorman, Manager, Quality Assurance/Quality Control
M. A. Jones, Manager, On-Site Nuclear Safety
S. H. Callis, On-Site Nuclear Licensing
M. S. Staton, North Carolina Power Agency

NRC Employees:

J. M. Taylor, Executive Director Operations - USNRC
R. W. Borchart, Region II Coordinator - Office of the EDO for Operations
G. C. Lainas, Assistant Director for Region II Reactors - NRR
E. G. Adensam, Director, Project Directorate II-1 - NRR
S. D. Ebneter, Regional Administrator - Region II
D. M. Verrelli, Branch Chief, Reactor Projects No. 1 - Region II
L. J. Watson, Section Chief, Operational Programs - Region II
R. L. Prevatte, Senior Resident Inspector - Brunswick
W. Levis, Resident Inspector - Brunswick
D. J. Nelson, Resident Inspector - Brunswick

8. Followup on TI 2500/20 (25020)

(CLOSED) TI 2500/20, Inspection to Determine Compliance With ATWS Rule 10CFR50.62. As stated in Inspection Report 89-02 dated February 27, 1989, three items needed to be accomplished to complete this item. These items and the associated completion actions are listed below:

- NRC acceptance of ARI and RPS electrical independence - NRC letter dated April 27, 1990, found the design of the system satisfactory with regard to the separation of power supplies for ARI/RPT and RTS. This conclusion was based on licensee analysis submitted on October 23, 1989 and March 13, 1990, that demonstrated the reliability of the power supplies and showed that common mode failures would not propagate through the power supplies and disable both the RTS and ARI/RPT systems.

- NRC acceptance of RPT single trip coil design - NRC letter dated March 8, 1989, concluded that this design was acceptable because the licensee demonstrated that it is of similar reliability as the Monticello RPT design.

- Replacement of ARI analog transmitter/trip units with one of a different design to ensure diversity from RPS - Although this issue is still under discussion with the BWR Owner's Group, the licensee replaced the Rosemount ARI ATTUs with ATTUs made by GE on Unit 2 during the last refueling outage. Replacement of the Unit 1 ATTUs is scheduled for the upcoming refueling outage beginning on September 26, 1990. This work will be completed under modification 86-033.

Violations and deviations were not identified.

9. Action on Previous Inspection Findings (92701, 92702)

a. (CLOSED) Violation 325/89-20-02 and 324/89-20-02, Failure to Follow SLC Operating Procedure and Inadequate CAD Procedure. The inspector reviewed the licensee's response to the Notice of Violation dated November 20, 1989. The licensee has revised their operating procedure valve lineup sheets to include the manual override for the CAC-CU-2714, along with other valves of the same type. Other procedures such as PTs and SDs were revised as required. SLC operating procedure was also revised to address concerns in the NOV and appropriate training on both events was conducted. The inspector verified the above actions by review of documentation.

b. (CLOSED) Violation 325/89-20-03 and 324/89-20-03, Inadequate Post Maintenance Testing of CAD System. The inspector reviewed the response to the NOV dated November 20, 1989, and the licensee's corrective actions to prevent recurrence. The licensee conducted training for the appropriate maintenance and operations personnel emphasizing the need to carefully assess the possible affects on components not directly involved in the maintenance when determining PMTRs. The inspector reviewed the lesson plan and the rosters and had no further questions.

c. (CLOSED) IFI 325/87-20-02 and 324/87-20-02, Review of Safety-Related MCC Breaker Coordination Results and Methodology. As a result of the inspector's concern on the above item, the licensee conducted a review of modifications that had been completed since 1979 to determine if they affected the 480 volt breaker coordination. This review identified some modifications where incomplete assumptions had been used in coordination methodology. The licensee corrected the majority of these items by breaker changeouts. Three remaining breakers that require replacement will be changed during the upcoming refueling outage. One additional breaker, MCC 14H feeder breaker AV5 with an OD4 trip unit, has been temporarily installed with the correct OD5 trip unit on back order and replacement is planned during the upcoming refueling outage. An analysis by the licensee determined that operation under the above circumstances did not place the plant in an unsafe or unanalyzed condition. As a result of this item and QA audit QAA/0021-90-01, the licensee has obtained the services of EBASCO to complete a new and updated coordination study for the safety-related load centers and vital MCCs. It is anticipated that this study will be completed by June, 1992. The above actions appear to adequately address the inspectors concerns and questions. This item is closed.

d. (CLOSED) IFI 325/89-34-10 and 324/89-34-10, Proper Receipt, Storage and Handling of Emergency Diesel Generator Oil. This IFI was opened to track completion of the licensee's QA/QC identified deficiencies pertaining to TI 2515/100, Proper Receipt, Storage and Handling of Emergency Diesel Generator Oil. The TI was originally inspected and documented in Inspection Report 89-05. The licensee has revised the FSAR commitment pertaining to Regulatory Guide 1.137, Fuel Oil Systems for Standby Diesel Generators, with respect to storage tank sampling and 10 year cleaning. The FSAR revision resolves the conflict between the Regulatory Guide and the Licensee's existing practice.

Violations and deviations were not identified.

10. Exit Interview (30703)

The inspection scope and findings were summarized on September 7, 1990, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection findings listed below. Dissenting comments were not received from the licensee. Proprietary information is not contained in this report.

Item Number	Description/Reference Paragraph
324/90-29-01	VIOLATION - Failure to Follow Test Procedures Which Resulted in a Reactor Scram, paragraph 5.a.
324/90-29-02	VIOLATION - Inadequate Procedures and Procedural Compliance, paragraph 5.b.
324/90-29-03	VIOLATION - Failure to Declare an Unusual Event and Make Prompt Notification, paragraph 5.c.

324/90-29-04 VIOLATION - Failure to Make Prompt Notification of ESF Actuations, paragraph 5.d.

325,324/90-29-05 VIOLATION - Failure to Follow Procedures, paragraph 4.c.

11. Acronyms and Initialisms

ADS	Automatic Depressurization System
AIT	Augmented Inspection Team
AO	Auxiliary Operator
AOG	Augmented Off Gas
AP	Administrative Procedure
ARI	Alternate Rod Injection
ATTU	Analog Transmitter Trip Unit
ATWS	Anticipated Transient Without Scram
BNP	Brunswick Nuclear Power
BSEP	Brunswick Steam Electric Plant
BWR	Boiling Water Reactor
CAC	Containment Atmospheric Control
CAD	Containment Atmospheric Dilution
CP&L	Carolina Power & Light Company
CS	Core Spray
DG	Diesel Generator
D/P	Differential Pressure
E&RC	Environmental & Radiation Control
EPA	Electrical Protection Assembly
ESF	Engineered Safety Feature
F	Degrees Fahrenheit
GE	General Electric
HPCI	High Pressure Coolant Injection
HP	Health Physics
I&C	Instrumentation and Control
IE	NRC Office of Inspection and Enforcement
IFI	Inspector Followup Item
IPBS	Integrated Planning, Budgeting and Scheduling
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LPCI	Low Pressure Coolant Injection
MCC	Motor Control Center
MG	Motor Generator
MOV	Motor Operated Valve
mR	Millirem
MSIV	Main Steam Isolation Valve
NED	Nuclear Engineering Department
NOV	Notice of Violation
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
OP	Operating Procedure
PA	Protected Area

PCIS	Primary Containment Isolation System
PMTR	Post Maintenance Testing Requirement
PNSC	Plant Nuclear Safety Committee
PT	Periodic Test
QA	Quality Assurance
QC	Quality Control
R	Rem
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
RPS	Reactor Protection System
RPT	Recirculation Pump Trip
RTS	Reactor Trip System
RWCU	Reactor Water Cleanup
SBGT	Standby Gas Treatment
SD	System Description
SLC	Standby Liquid Control
SRV	Safety Relief Valve
STA	Shift Technical Advisor
SULCV	Startup Level Control Valve
SW	Service Water
TI	Temporary Instruction
TS	Technical Specification
URI	Unresolved Item
WR/JO	Work Request/Job Order

ATTACHMENT

BRUNSWICK NUCLEAR PROJECT
INTEGRATED ACTION PLAN (IAP)
STATUS PRESENTATION

AUGUST 23, 1990

Carolina Power & Light Company

AGENDA
IAP STATUS MEETING WITH NRC
AUGUST 23, 1990
10:00 a.m. - 12:00 noon

ITEM	PRESENTER
Welcome	Watson/ Starkey
Integrated Action Plan Topics	
• Background	Simpson
• Summary of Overall IAP Status	Simpson
• Independent Verification Program	Simpson
• Status of Corporate Assessment Task Force	Bowles
• Status of Operator Training Items	Martin
Unit 1 Refueling Outage	Holder
• Recirc Pipe Replacement Project	
• Lessons Learned	
• Radiation Exposure Reduction Efforts	
Summary	Starkey

AREAS FOR ADDITIONAL ATTENTION

1. Implementation of an effective corporate oversight program to provide leadership and direction and to accurately monitor and assess Brunswick performance

2. Definition of site safety goals, priorities, and expectations which are effectively communicated to and understood at all levels

3. Implementation and monitoring the effectiveness of actions to establish the desired culture at Brunswick

4. Implementation of an effective corrective action program having a lower threshold for problem identification and effective measures for root cause determination

5. Implementation of an integrated program to correct engineering and technical support weaknesses involving both equipment failures and support activity weaknesses such as configuration control and safety evaluations

DEFINITION & COMMUNICATION OF SAFETY GOALS, PRIORITIES & EXPECTATIONS

COMMUNICATION STRATEGY OBJECTIVES:

- Ensure Standards and Expectations are Communicated and Understood
- Ensure Teamwork and Cooperation are Improved

METHODOLOGY/ACTIONS:

- Total Quality Training
- Goals Development
- Communications Team
- Information Flow
- Feedback
- Leadership Team
- Video System
- Management Information Meetings
- Employee Information Meetings

IMPLEMENT AND MONITOR THE EFFECTIVENESS OF ACTIONS TO ESTABLISH DESIRED CULTURE

Feedback as a Result of Communications Strategy

- Working Lunches
- Communication Team
- Lunch with Russ

Formal Survey Data

- Meeting Evaluations
- Formal Surveys

Leadership Evaluation Process

- Attributes Defined
- Process Developed
- Training Being Completed
- Base Line Scheduled
- Involves Evaluation by:
  - Subordinates
  - Peers
  - Supervisor

Performance Indicators

- AEOD
- INPO
- Site Developed
- Corporate Incentive

IAP STATUS PRESENTATION
TIME LINE

DATE	ACTION
April 1989	Cresap Report for Brunswick and Corporate Support Departments (152 Recommendations)
July 1989	NRC Diagnostic Evaluation Team Report (54 Findings)
September 1989	IAP, Level 1 Plan Developed (56 Actions)
November 1989	IAP, Level 2 Plan Developed (263 Actions)
On-going	Monthly IAP Status Reports
On-going	IAP Documentation/Verification Activities
March 1990	IAP Status Briefing to the NRC

IAP STATUS PRESENTATION
EXAMPLE OF LEVEL 1, LEVEL 2

IAP NO.	ACTION ITEM		MANAGER	TARGET DATE
D9	Implement Corrective Action Program Improvements		Harness	Complete
	A.	Develop BNP Nonconformance Policy	Harness	Complete
	B.	Establish Incentives for Self-Identification of Nonconformances	Harness	Complete
	C.	Issue Revisions to PLP-04	Moyer	Complete
	D.	Complete Additional Training on PLP-04	Moyer	Complete
	E.	Identify BNP Corrective Action Program Coordinator	Harness	Complete
	F.	Identify BNP HPES Coordinator	Harness	Complete
	G.	Issue PLP-06	Helme	Complete

IAP STATUS PRESENTATION

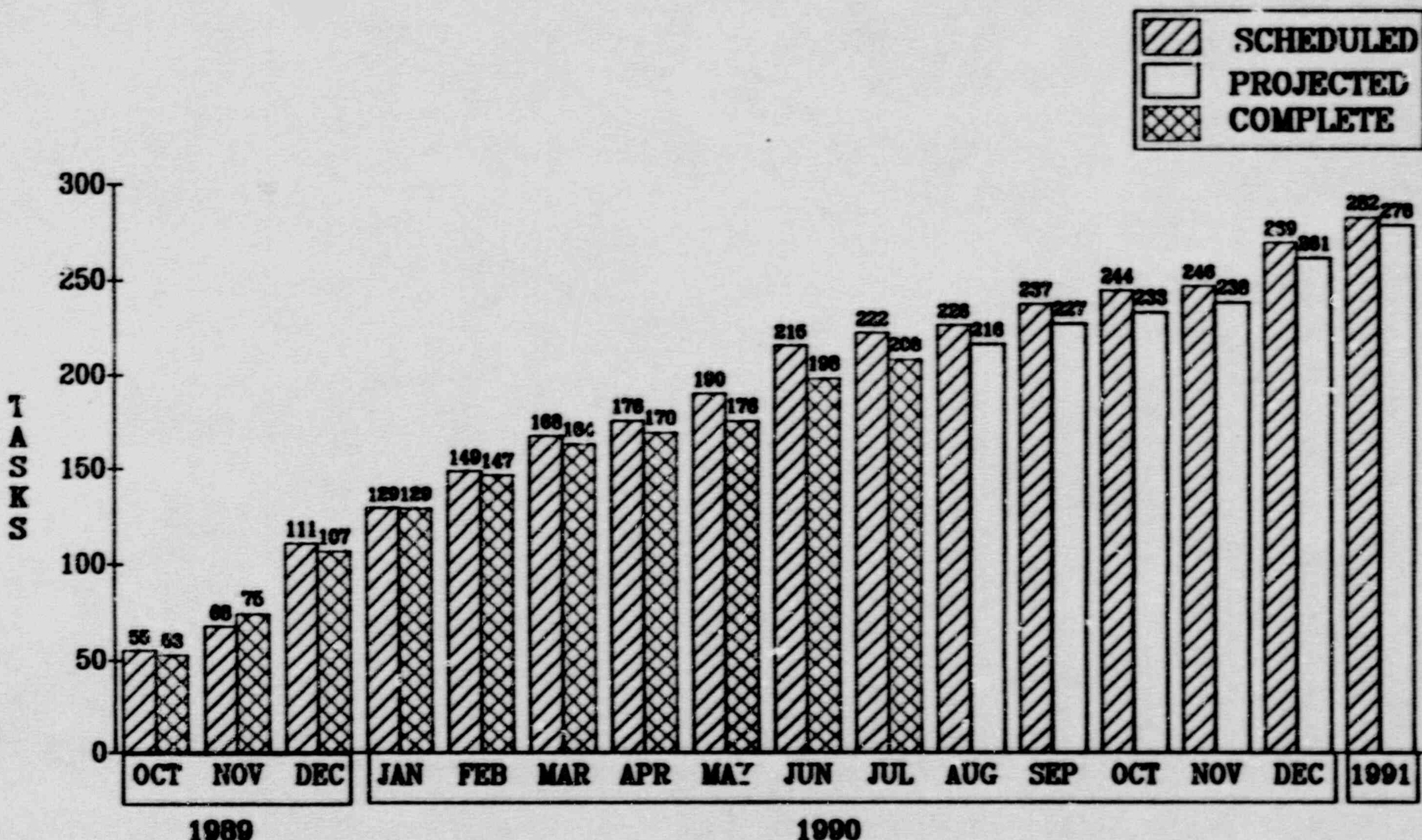
RESULTS TO DATE

LEVEL 1	~ 63% COMPLETE
LEVEL 2	~ 74% COMPLETE

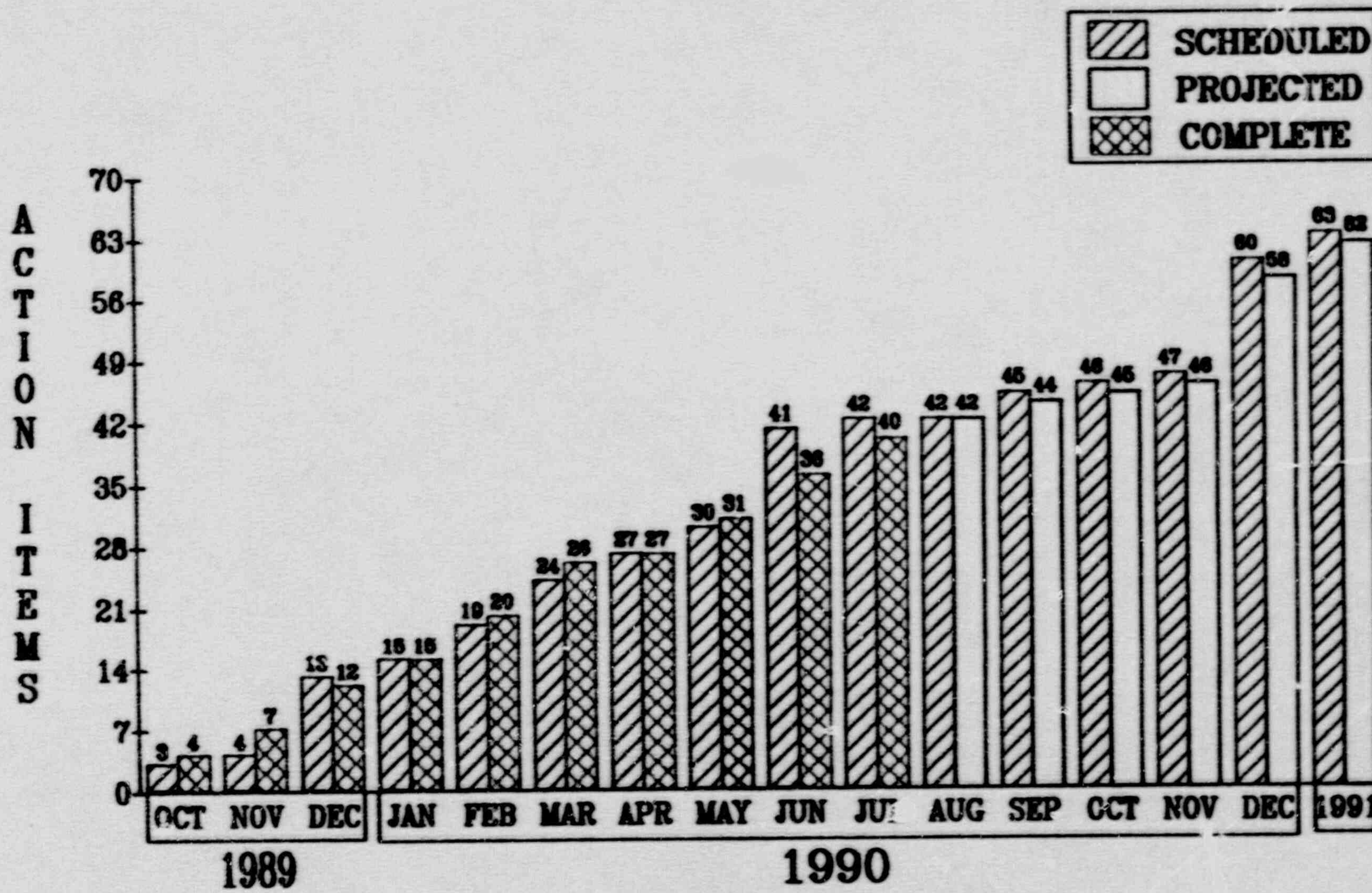
Level 1 = Summary-Level Action Items Identified in DET Response

Level 2 = Detailed Tasks Supporting Level 1 Action Items

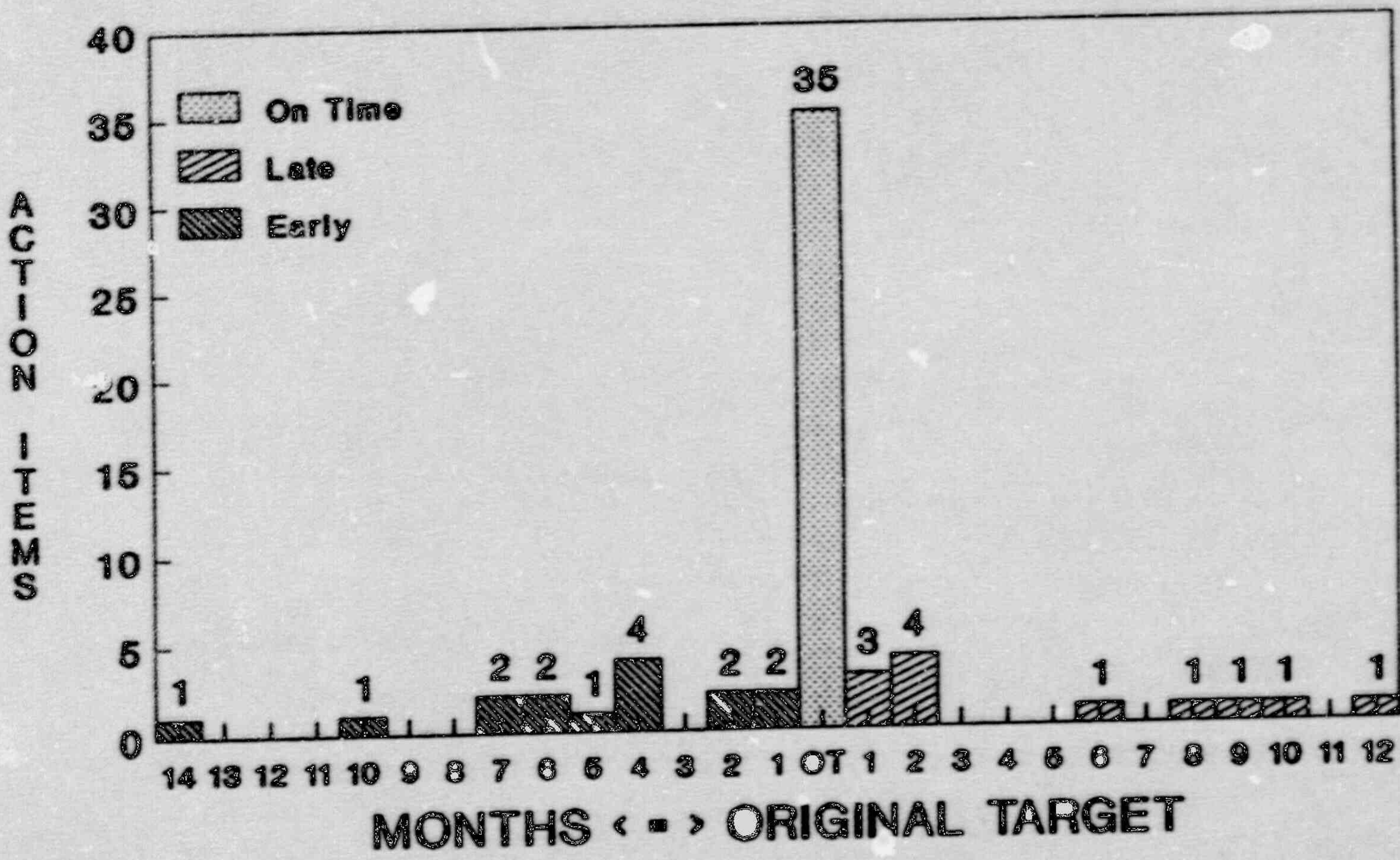
INTEGRATED ACTION PLAN
LEVEL 2 STATUS



INTEGRATED ACTION PLAN
LEVEL 1 STATUS



IAP LEVEL 1 SCHEDULE PERFORMANCE
40 COMPLETED ITEMS & 22 PROJECTED ITEMS
AS OF JULY 31, 1990



IAP5

IAP STATUS PRESENTATION
REASONS FOR DELAYED COMPLETION DATES
LEVEL 1 ACTION ITEMS

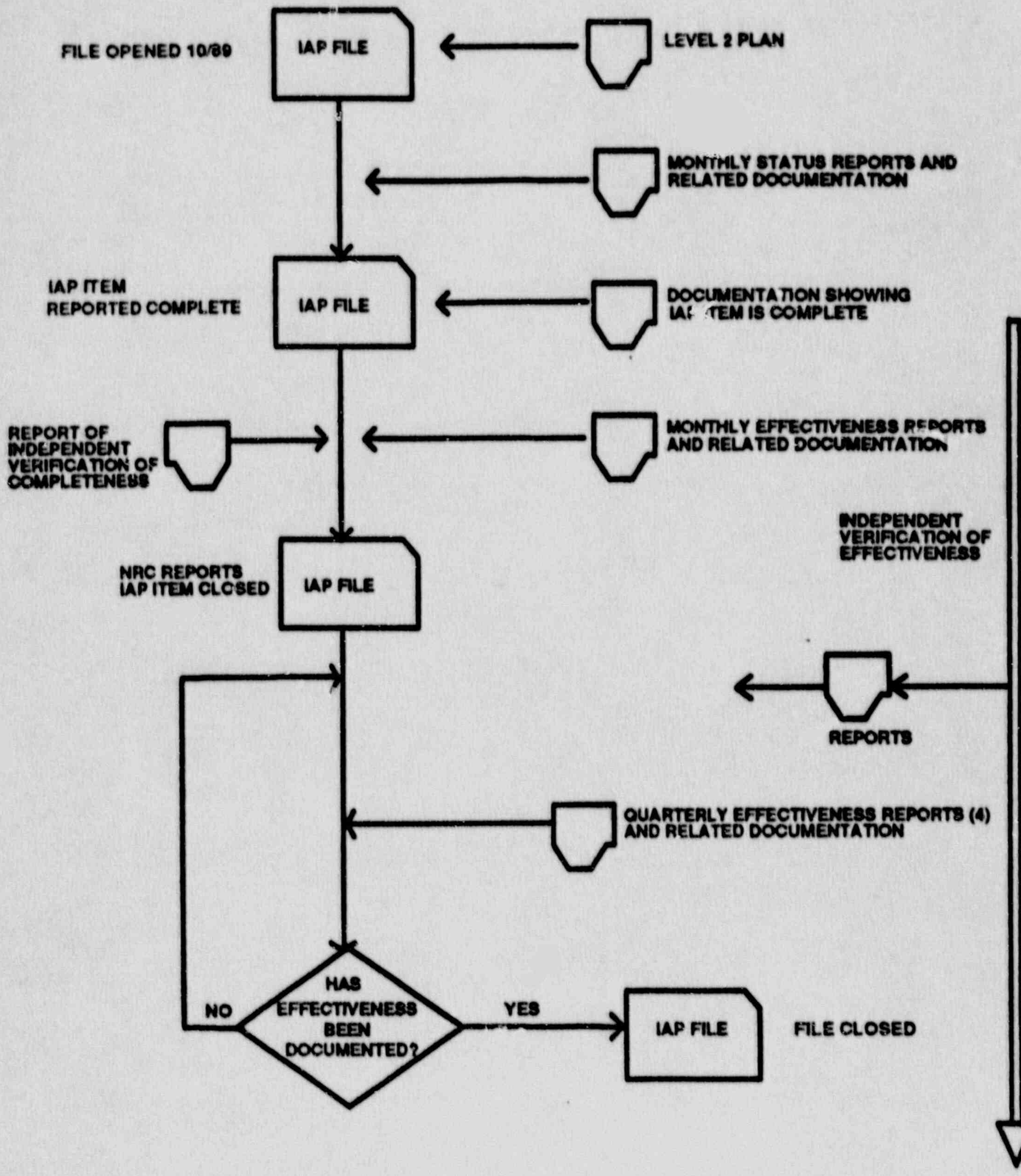
REASON	NO. OF ITEMS
Procedures/Guidelines not Approved as Originally Submitted	4
Significant Increases in Scope	3
Coordinate with Corporate Effort	2
Rescheduled in Accordance with Training Schedules	1
Independent Review Determined Actions Inadequate	1
Recruitment of Qualified Person	1
Original Target Date Inadequate for Scope	1
Total Items Delayed	13

IAP INDEPENDENT VERIFICATION PROGRAM OVERVIEW

- Philosophy
  - Line Management is Accountable for Obtaining and Documenting Results
  - Staff Support is Accountable for Assuring that Documentation Accurately Reflects Implementation and Effectiveness of IAP Actions and Variances are Reported

- Approach
  - Monthly Status Reporting
  - Independent Verification of Completeness
  - Independent Verification of Effectiveness
  - Monthly/Quarterly Reporting of Effectiveness
  - Final Documentation Review

INTEGRATED ACTION PLAN DOCUMENTATION/VERIFICATION PROCESS

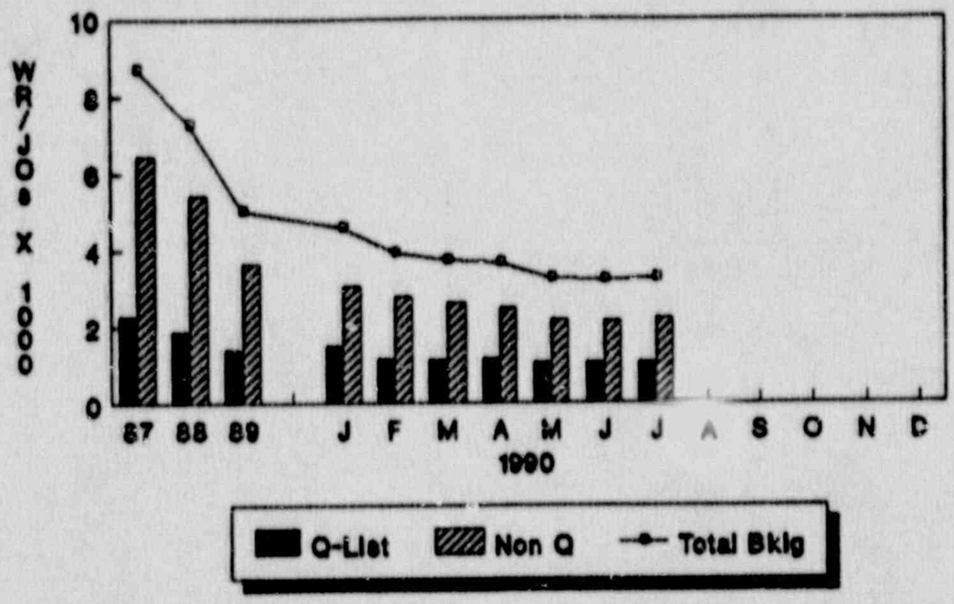


IAP STATUS PRESENTATION
EFFECTIVENESS OF COMMUNICATIONS STRATEGY

Change in Past 6 Months	Total Sample	Had TQ Training
Positive	47.2%	57.9%
No Change	29.1	21.5
Negative	23.7	20.6

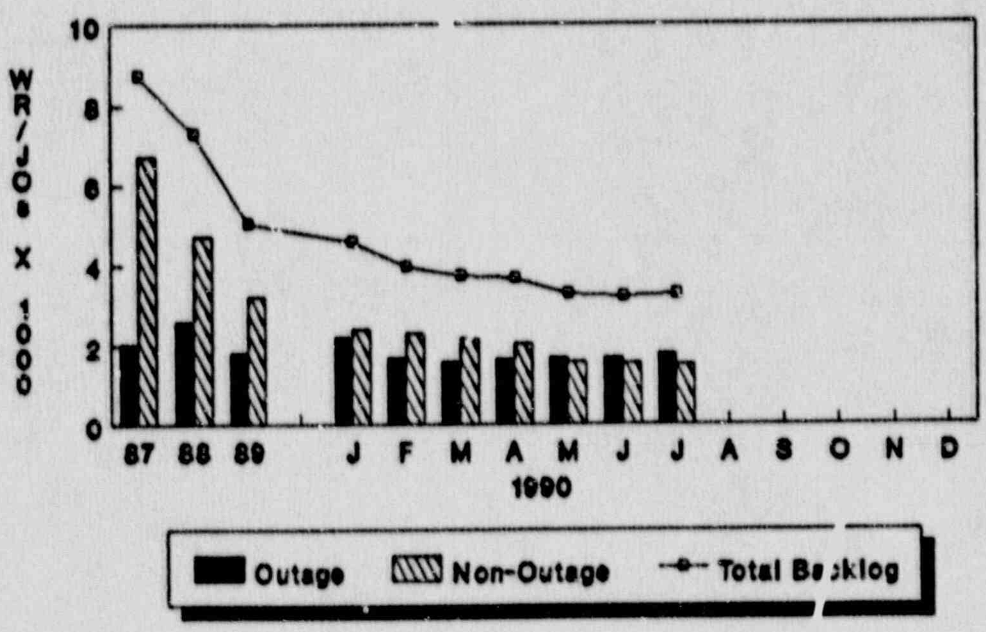
How has communication flow changed at the Brunswick Plant in the Past Six Months?

Corrective WR/JO Backlog
By Quality Class



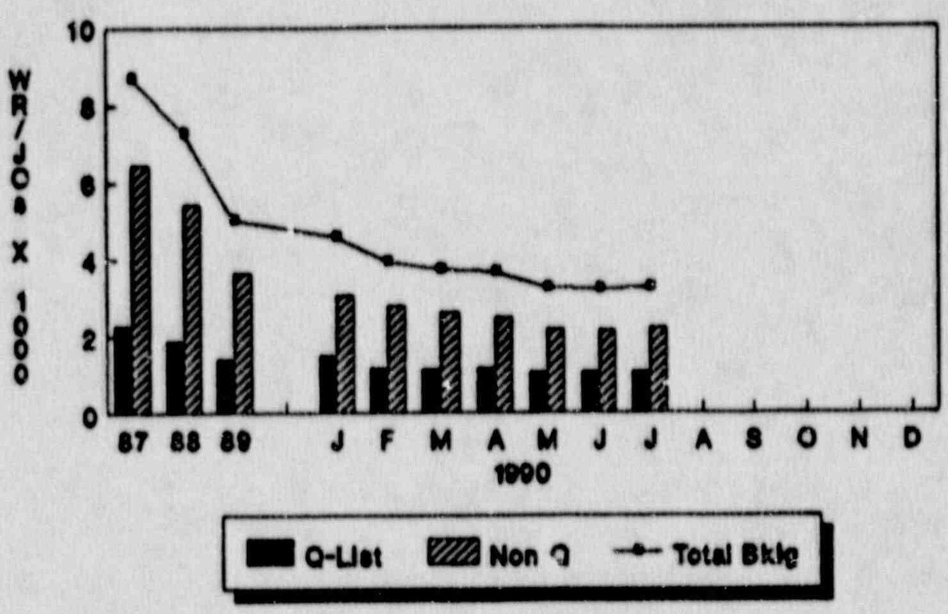
M3a

Corrective WR/JO Backlog
By Outage



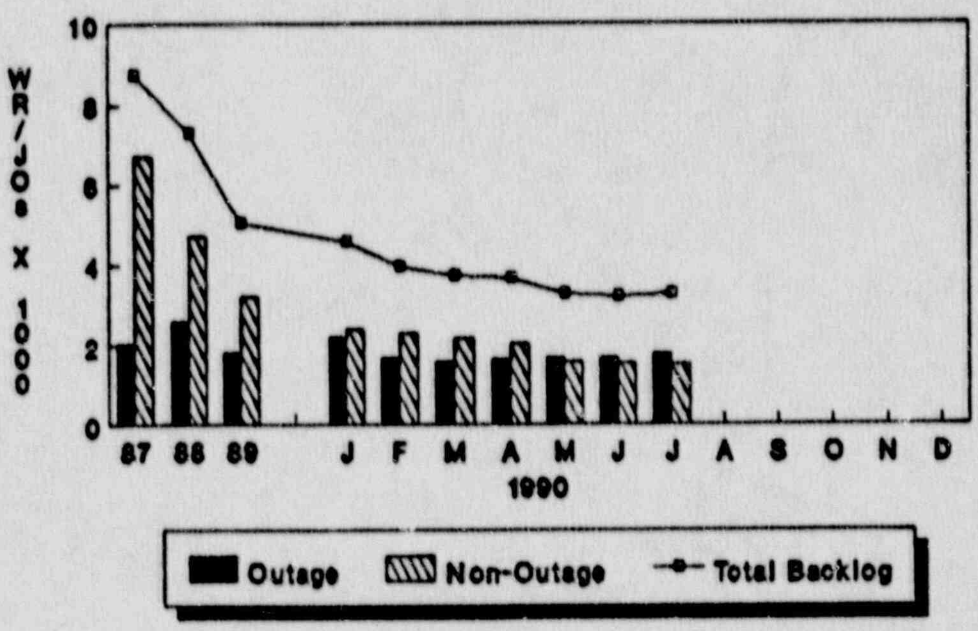
M3b

Corrective WR/JO Backlog
By Quality Class



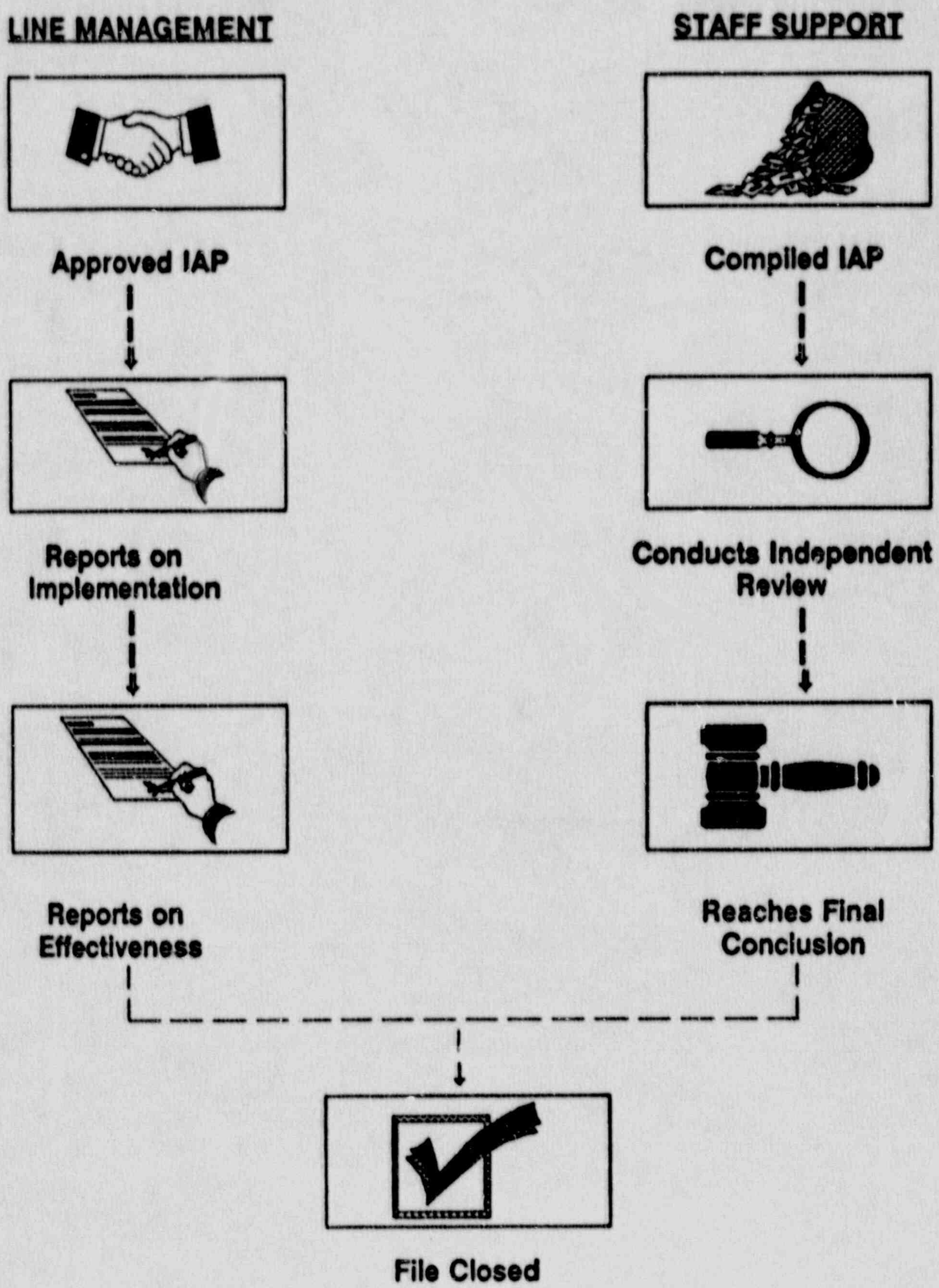
M3a

Corrective WR/JO Backlog
By Outage



M3b

IAP INDEPENDENT VERIFICATION PROGRAM
OVERVIEW



IAP INDEPENDENT VERIFICATION PROGRAM SUMMARY

- Program for Verification of <u>Completeness</u> Has Been Effective
  - One Level 1 Item Reopened Based Upon Independent Review
  - NRC Has Reviewed

- Program for Verification of <u>Effectiveness</u> Has Recently Been Enhanced

- Best Indicators of Overall IAP <u>Effectiveness</u> are Site Performance Indicators

NUCLEAR ASSESSMENT STATUS

- Team Chartered - October 1989
  - Written into Brunswick Integrated Action Plan
- Interim Recommendations - December 1989
- Final Recommendations - August 1990

ACTIONS TAKEN/UNDERWAY

- Performance-Basing of Corporate Audits
- Peer Evaluator Exchanges Initiated
- Summary-Level Evaluation Piloted

PERFORMANCE-BASED CORPORATE AUDIT PROGRAM

- Consultant Employed - November 1989

- Pilot Audit - January 1990

  - Formal Training (Root Cause, Observation, Performance-Based Techniques)

  - Nuclear Assessment Team Involvement

- Performance-Based Audits Now Standard

- Results:

  Findings More Directly Related to Nuclear Safety/Reliability

- "THE RADIATION CONTROL AND PROTECTION MANUAL RADIATION POSTING SIGN WORDS ARE INCONSISTENT WITH THE RNP RADIATION POSTING SIGN WORDS."

- "NINE OF 49 SIGNIFICANT CONDITION REPORTS HAD DUE DATES WHICH HAD PASSED WITHOUT A RESPONSE OR EXTENSION."

FEBRUARY 1990 QA AUDIT
ROBINSON MAINTENANCE

- "SAFETY INJECTION PUMP "C" HAD BEEN REMOVED FOR (EXTENDED) REPAIR . . . LEAVING CONNECTING PIPING SUPPORTED ONLY BY A CHAIN FALL. THIS CONSTITUTED AN UNANALYZED SEISMIC CONDITION."

- "BORIC ACID WAS FOUND LEAKING ONTO AN OPERATING SAFETY INJECTION PUMP FROM A COMPONENT WHICH HAD BEEN ON THE OUTSTANDING MAINTENANCE LIST FOR SEVERAL MONTHS."

PEER EVALUATOR EXCHANGES

- Agreements Initiated April 1990
- Exchanges With Two Utilities To Date
- Additional Exchanges Planned
- Results:

  Short-Term and Longer-Term Benefits of External Perspective

PILOT SUMMARY-LEVEL EVALUATION

- Currently in Progress - Robinson Nuclear Project
- Department Head Team Including INPO Member
- "Macro" Focus -- Sitewide/Corporate Issues
- Results Expected:
  - Identify and Remove Barriers to Sustained Performance
  - Forum for Evaluating "Micro" Issues for Broader Implications

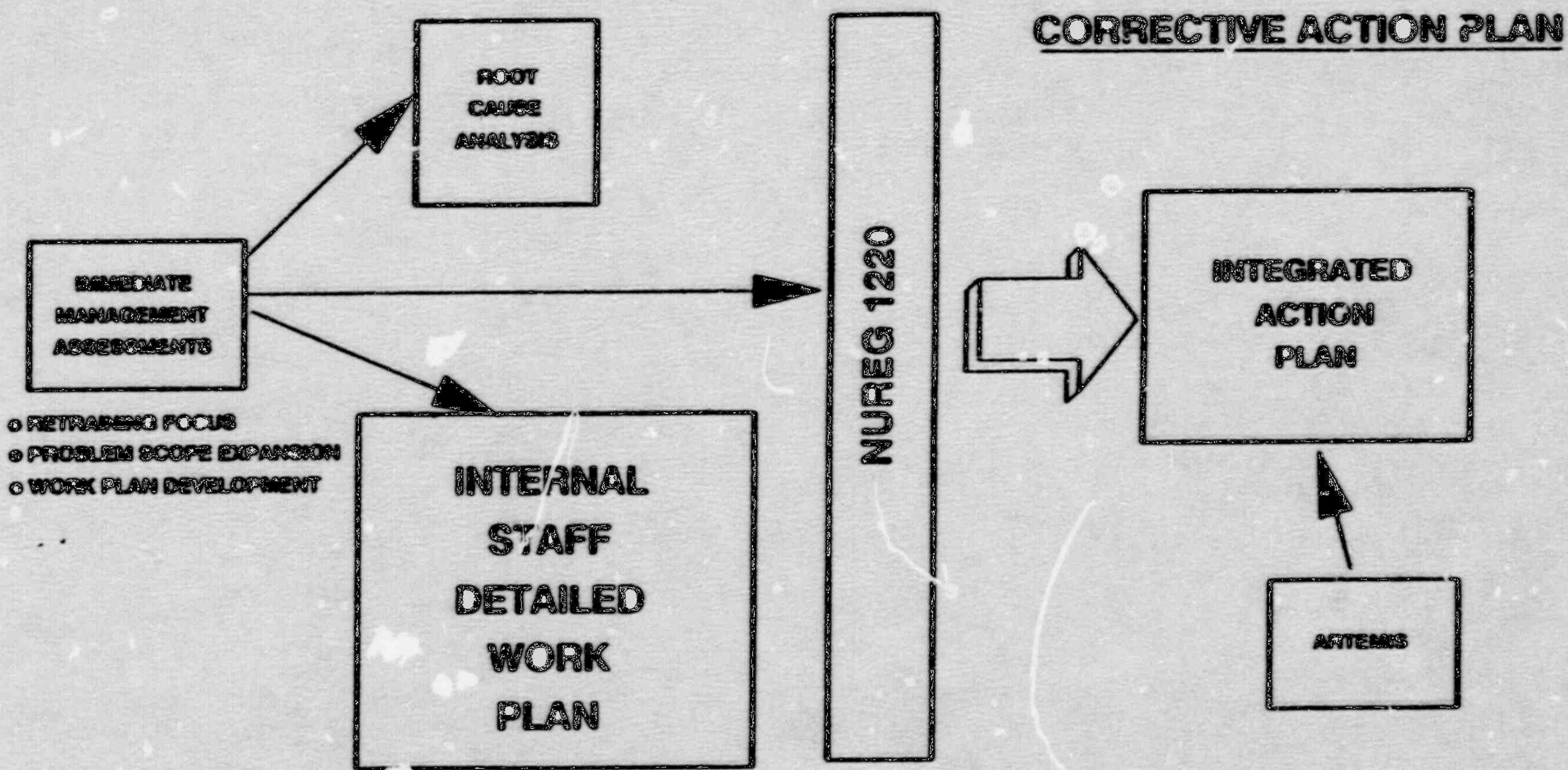
TEAM REPORT AND RECOMMENDATIONS

- Primary Areas for Improvement Identified
  - Self-Assessment/Quality Ownership by the Production Organizations
  - Coordination of Independent Evaluation/Assessment Activities
  - Quality of Analysis Provided to Senior Management
  - Effective Use of Independent Assessment Resources
  - Independent Assessment Staffing Practices

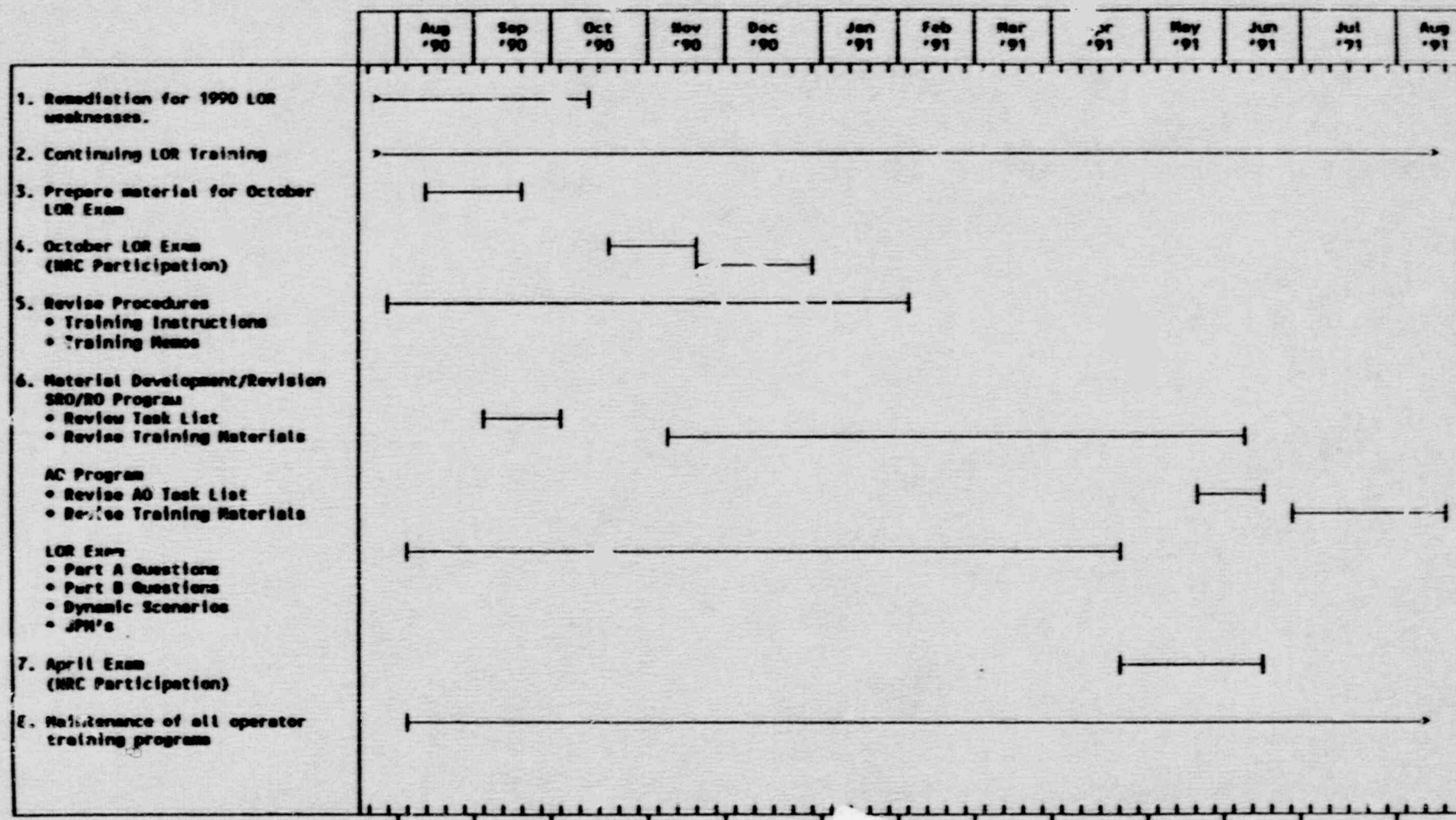
ADDITIONAL CHANGES

- Consolidated, Independent Assessment Organization
  - Internal Evaluation and Assessment
  - Senior Management's Staff for Objective Oversight
  - "Training Ground" for Rising Nuclear Managers
  - Four Functional Levels - "Micro" to "Macro"
    - Addition of Site Full-Scope Evaluations
    - Addition of Corporate Summary Evaluations
  - All Levels Performance-Based
- Organization in Place and Functioning by End of Year 1990

LICENSED OPERATOR TRAINING ASSESSMENT AND CORRECTIVE ACTIONS



OPERATOR TRAINING PROGRAM UPGRADE ACTION PLAN
(LEVEL 1)

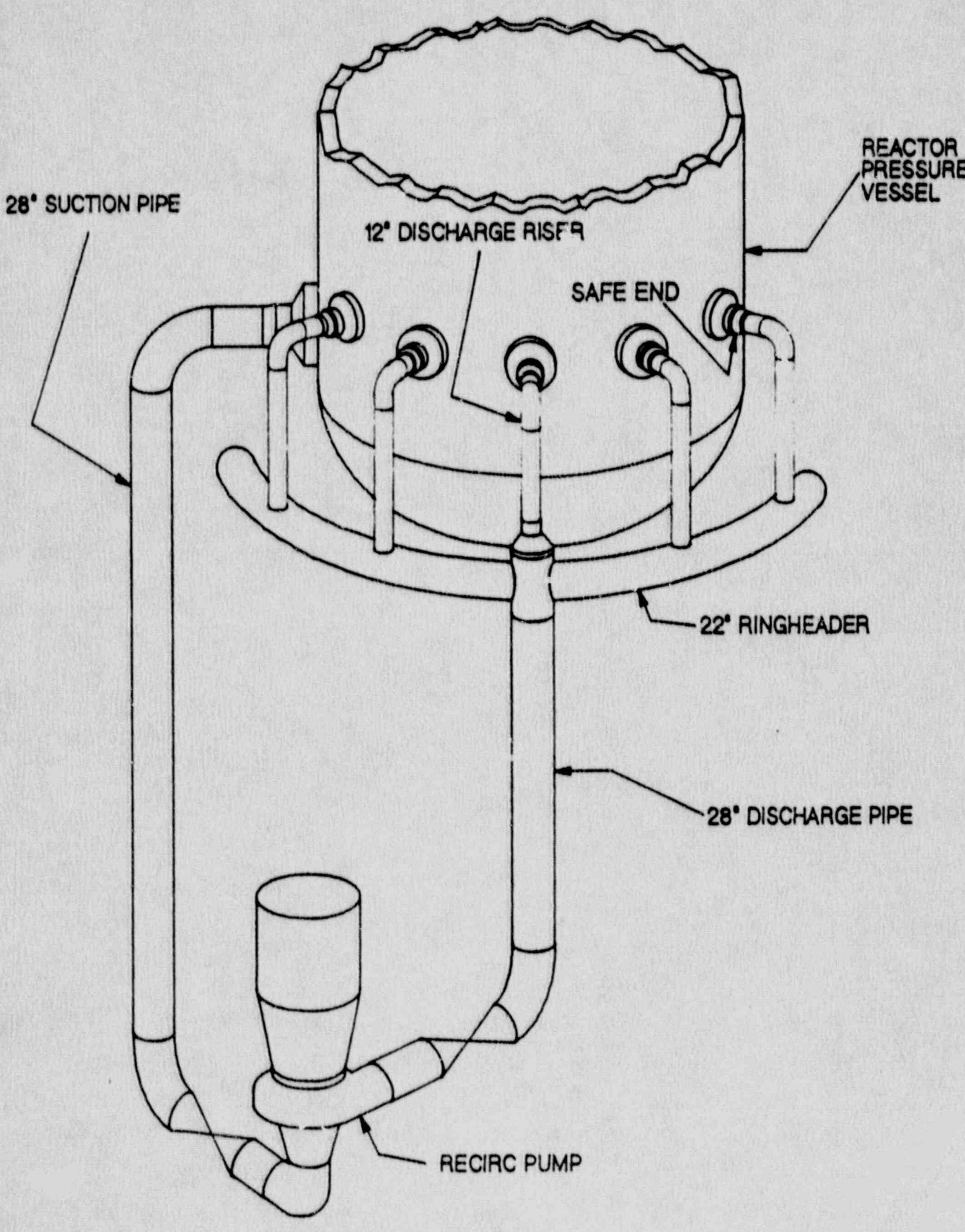


LICENSED OPERATOR TRAINING

MAJOR ACTION PLAN ELEMENTS

- LOR and OE Remediation
- October LOR Exam
- Process/Procedures Upgrade
- SRO/RO Program Upgrade
- AO Program Upgrade
- Ongoing LOR Program Upgrade
- April LOR Exam
- Simulator Upgrade and Certification
- Personnel Resources
- Continuing LOR Training

REACTOR COOLANT RECIRCULATION SYSTEM



(ONE LOOP SHOWN FOR CLARITY)

UNIT #1 PIPE REPLACEMENT PROJECT

- Training Improvements
- Procedure Improvements
- Nozzle Stainless Butter Welding Improvements
- ALARA/Schedule Improvements
- Summary

TRAINING IMPROVEMENTS

1. Process mock-up and Training

   - Will consist of hands-on and classroom instruction
   - Increased craft training duration from two to six weeks
   - Pass/fail criteria for Training
   - Expanded to include procedure training for craft personnel
   - The size of the training facilities has been increased

2. Personnel Processing

   - Newsletter being sent to prospective employees
   - Pre-employment packets mailed to personnel

PROCEDURE IMPROVEMENTS

1. Team effort by CP&L and GE to rewrite the procedures

    - Three CP&L employees and three GE employees have rewritten the procedures, drawing on a base of pipe replacements at nine different plants.

    - The procedure packages have been improved and simplified as a result of the rewrite effort.

2. CP&L and GE have jointly accomplished welding procedure improvement and parameter refinement at the GE Technical Center.

ALARA/ SCHEDULE IMPROVEMENTS

1. General

- The ALARA Goals that have been set are extremely aggressive, and ALARA incentives/penalties have been included in project related contracts.

- Improved vessel water level management

2. Process/Procedures

- Nozzle butter application improvements

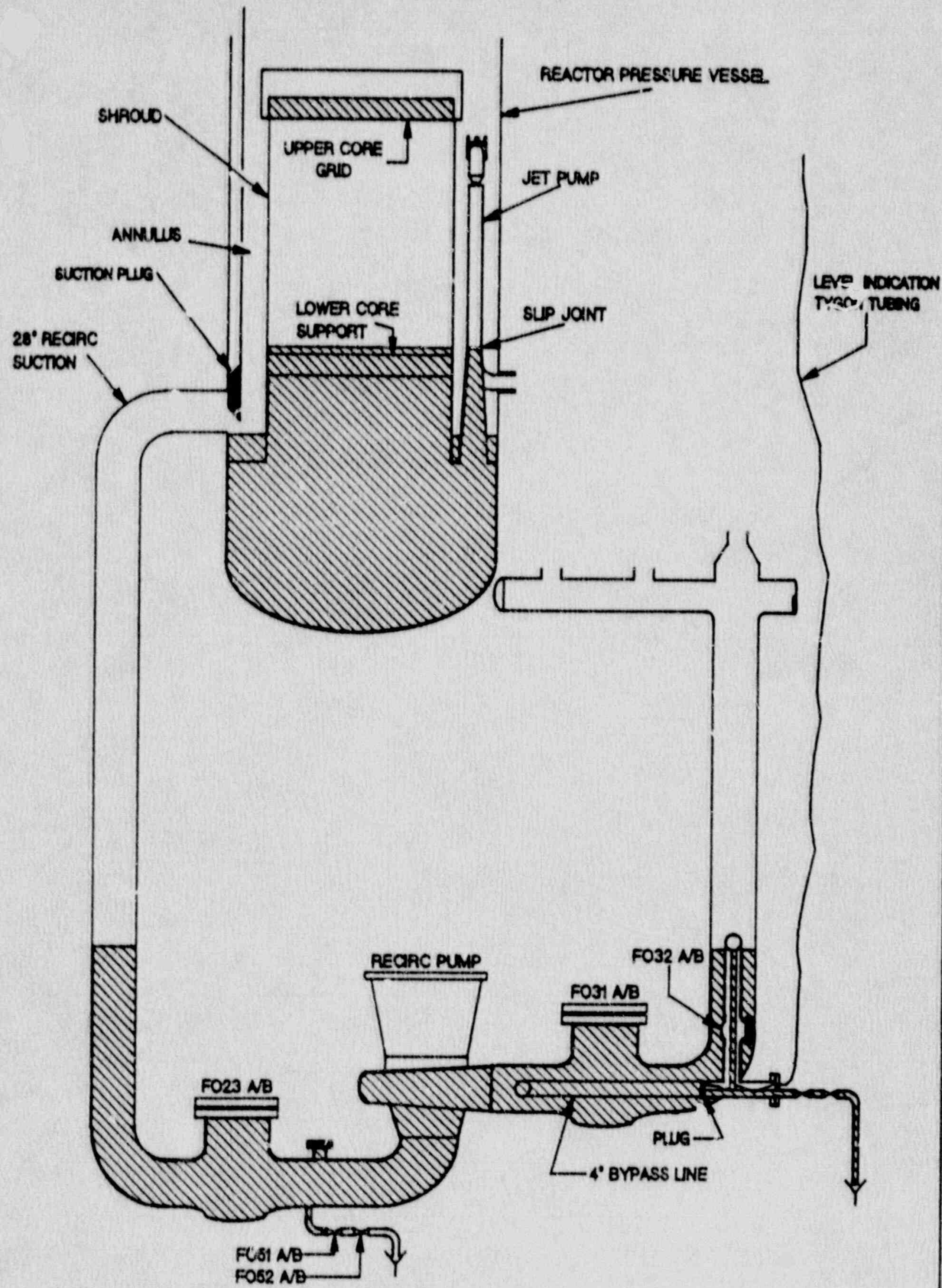
- Radial centering of the Thermal Sleeve

3. Equipment/Personnel

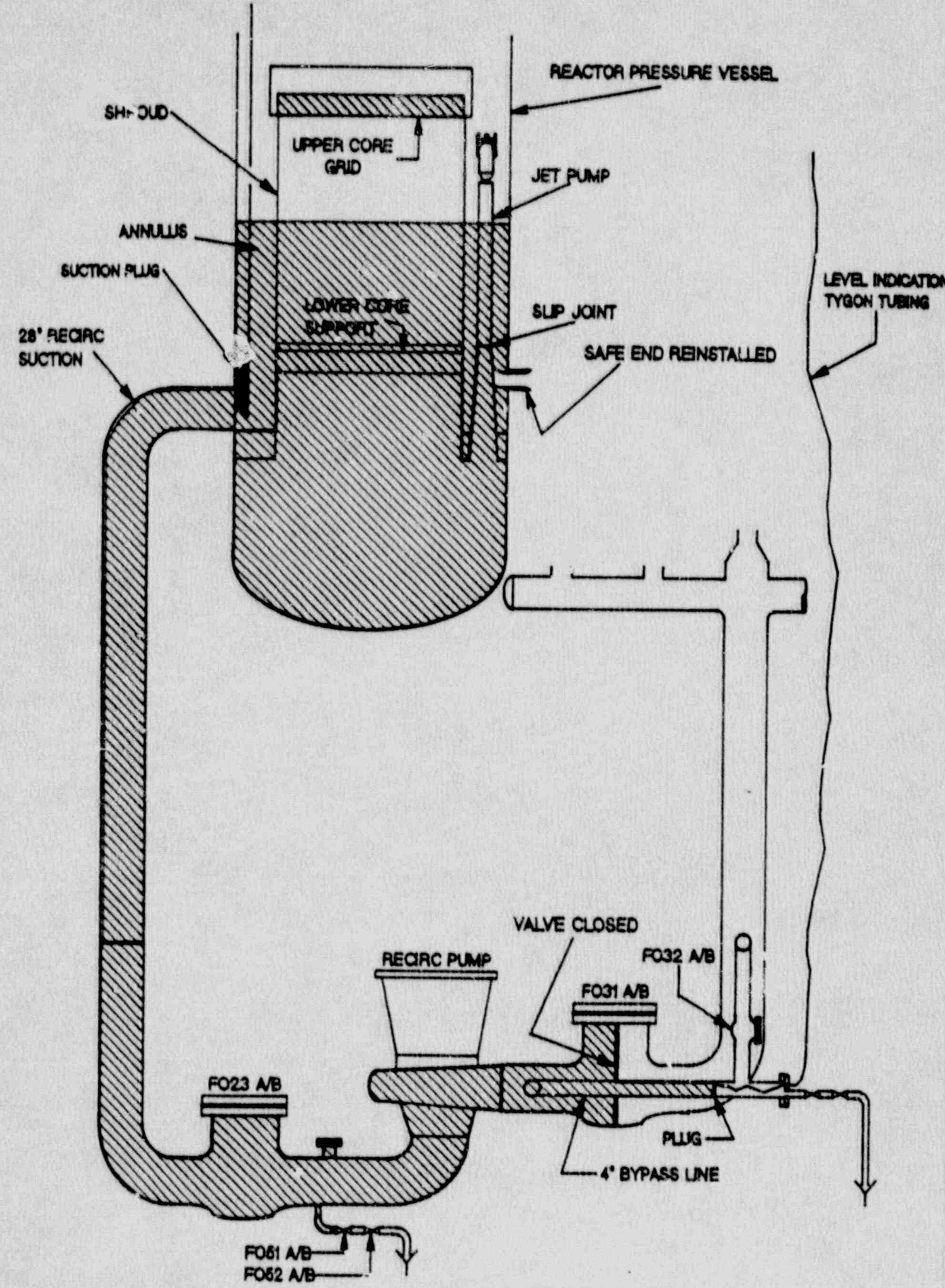
- Welding and machining equipment refinement

- A majority (85%) of the craft and supervisory personnel with Unit 2 experience are returning.

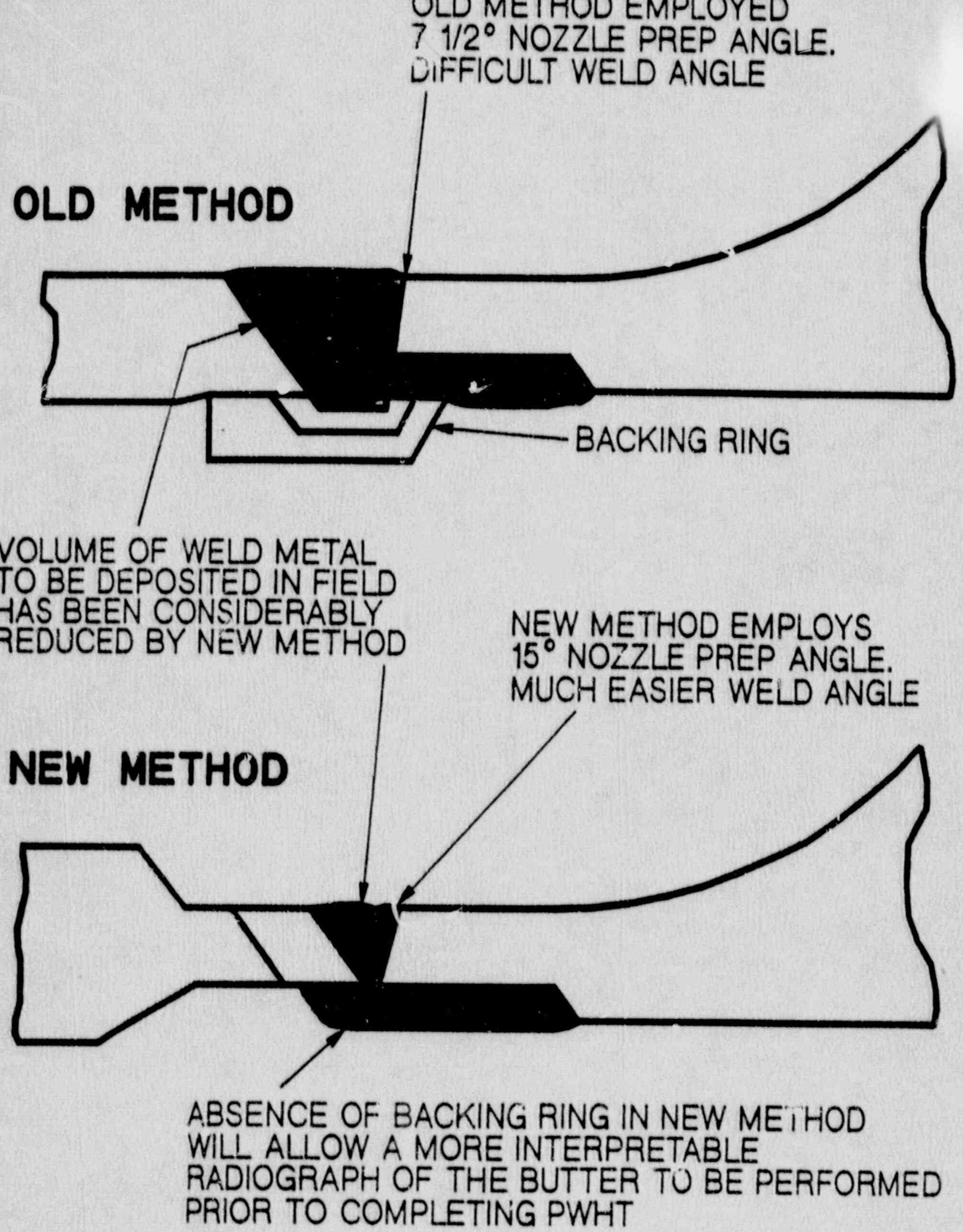
WATER LEVEL AT 17' ELEVATION DURING SAFE END REMOVAL



WATER LEVEL BELOW JET PUMP RAM'S HEAD AFTER SAFE END REINSTALLATION



WELDING OF SS BUTTER



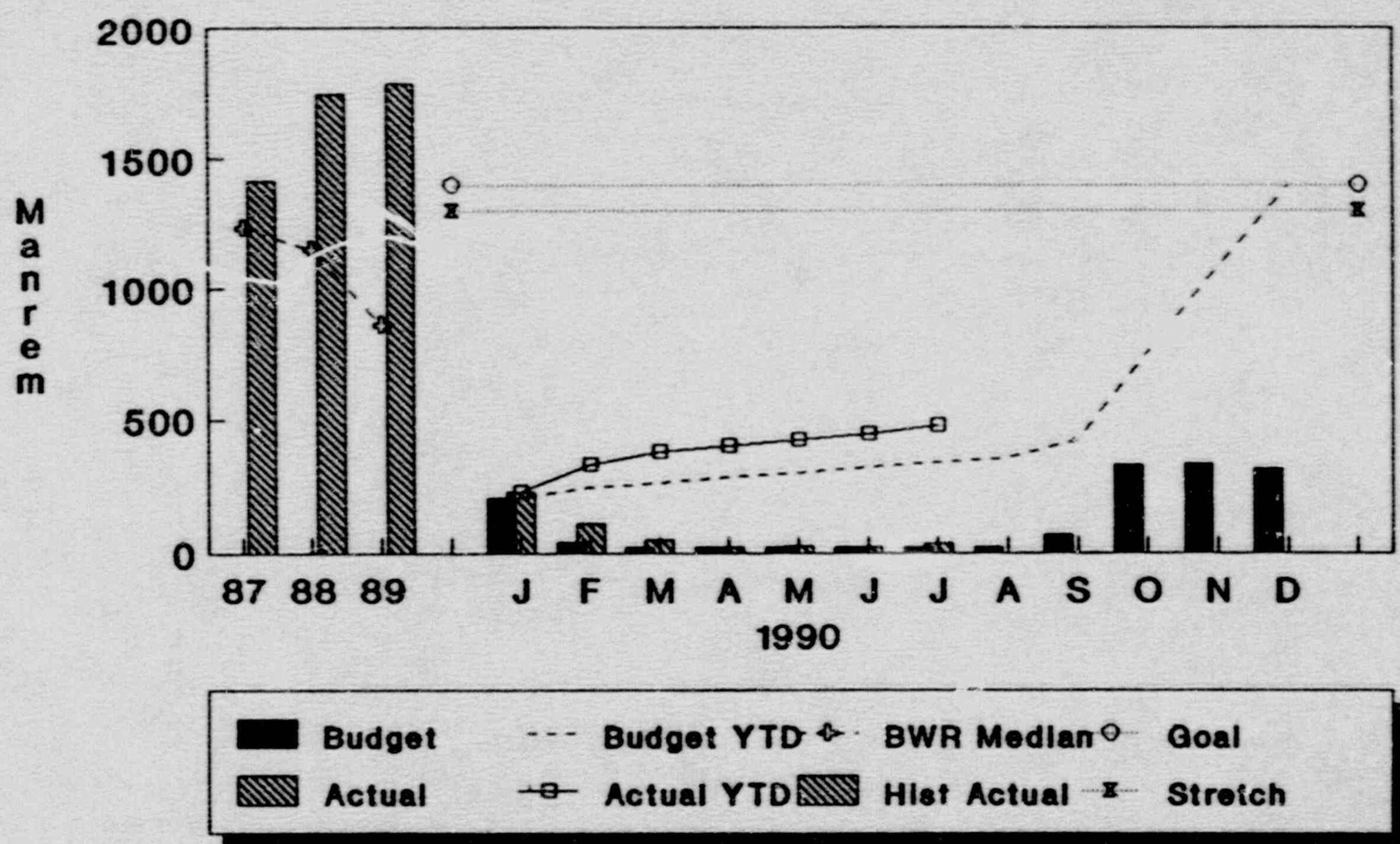
SUMMARY

1. Significant effort has been applied to preplanning and the evaluation and incorporation of lessons learned.

2. Equipment and software used for Unit 2 has been simplified, modified and improved to increase productivity and reduce exposure.

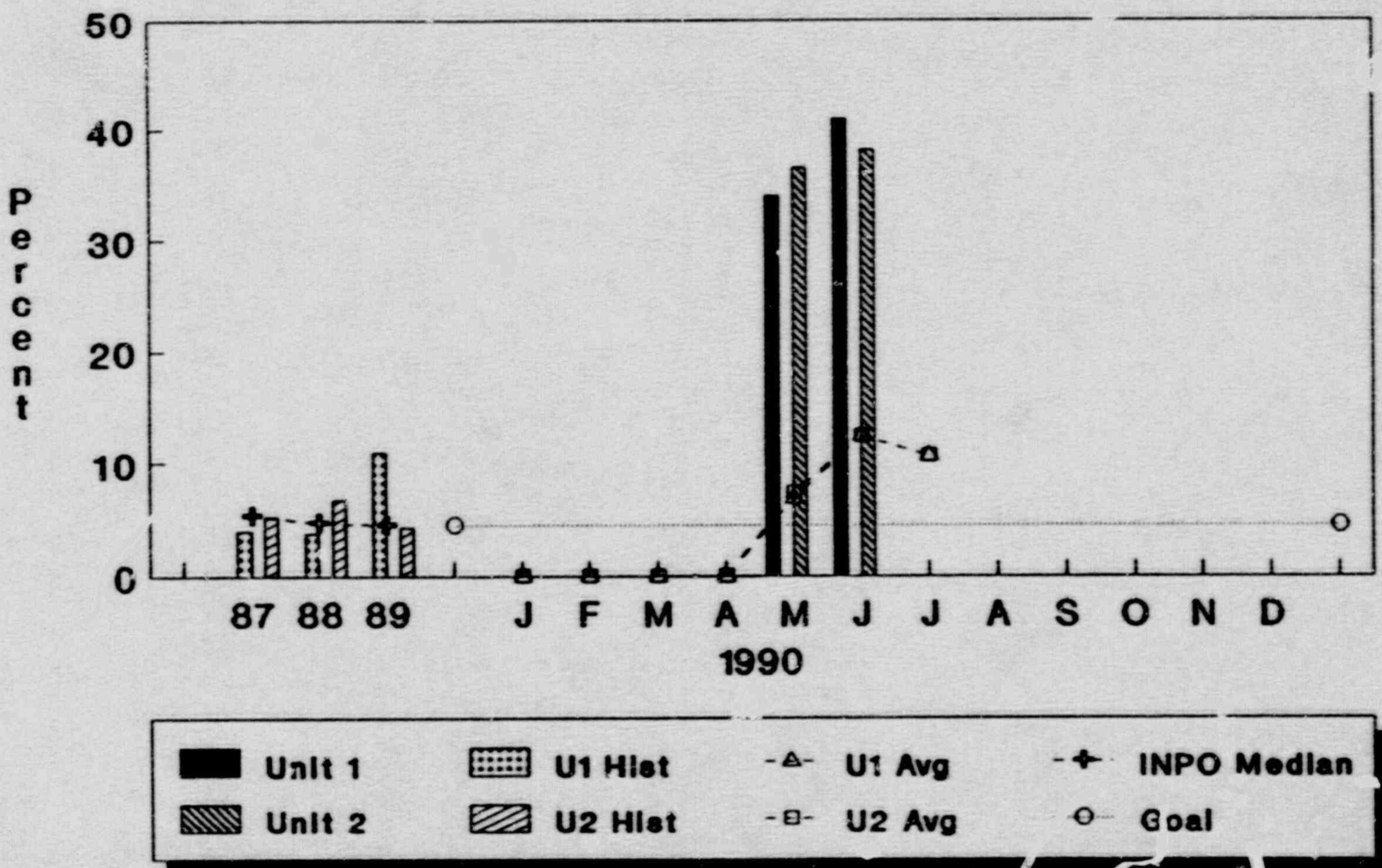
3. Team building between CP&L and GE has been stressed and will result in the successful completion of the project, from both an ALARA and Schedule standpoint, as a group effort.

Collective Radiation Exposure



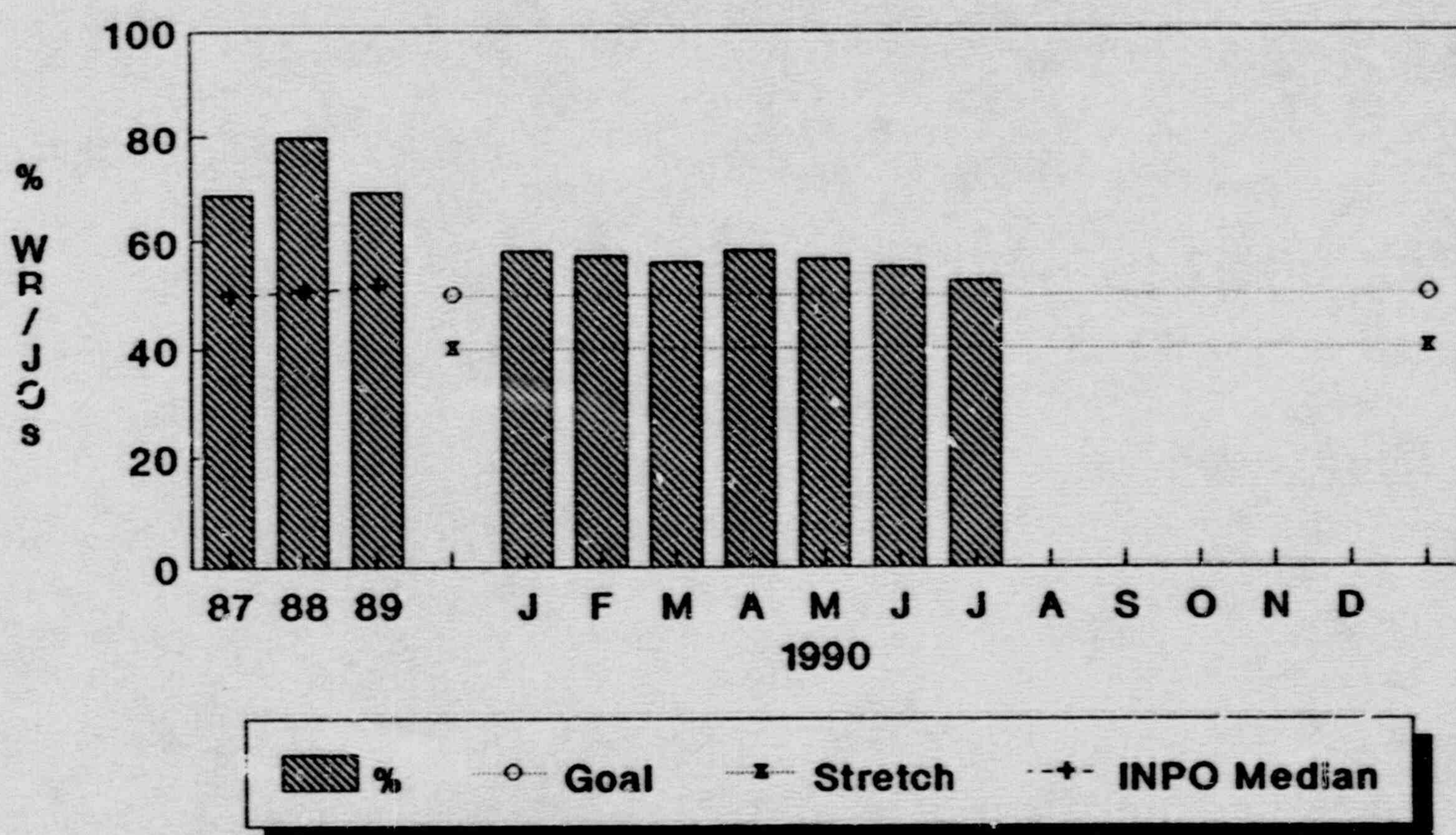
INPO Indicator
E5a

Forced Outage Rate



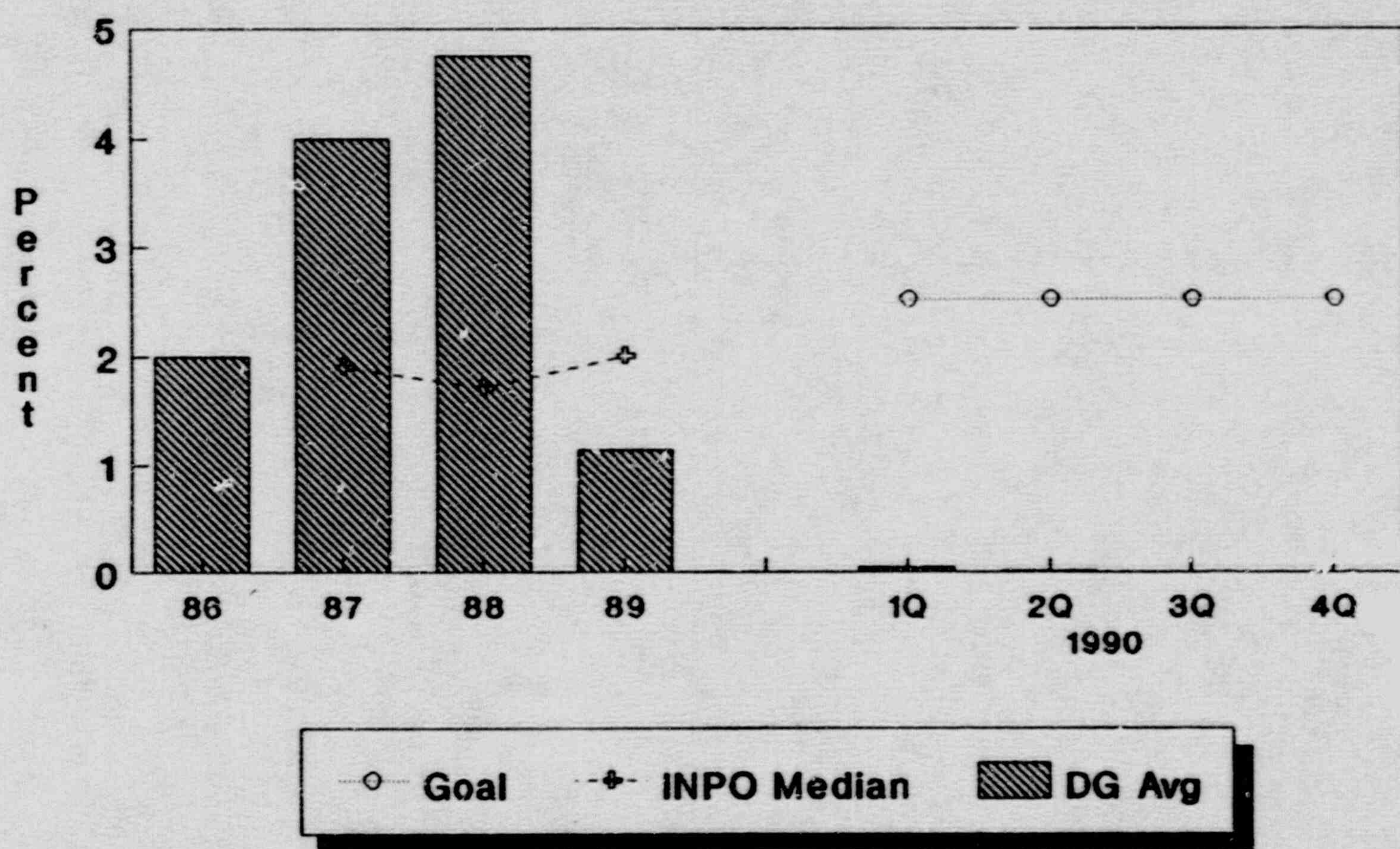
T2b

Corrective Maintenance Backlog
Non-Outage >3 Months Old



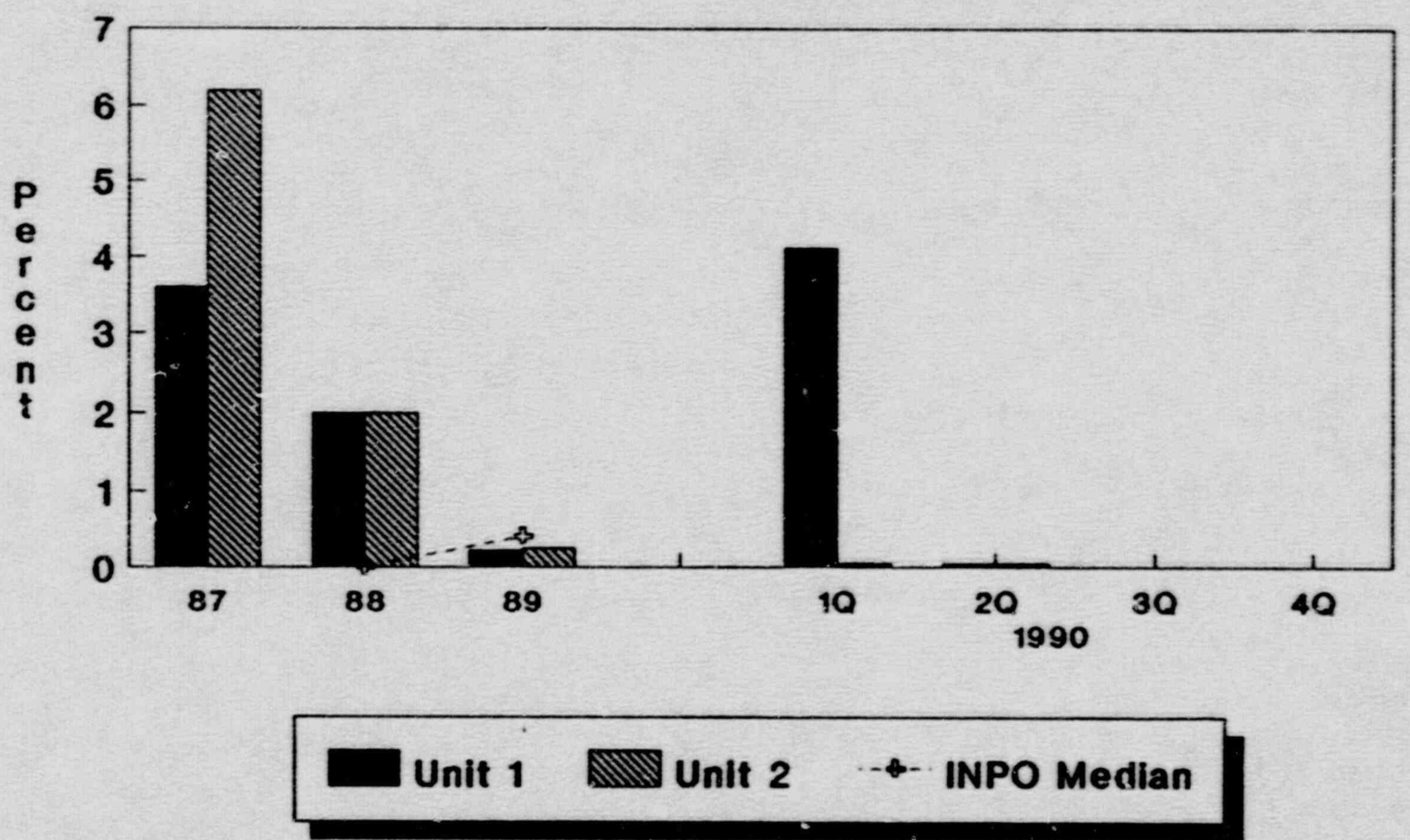
Manager Team Goal
INPO Indicator
PL7b

Safety System Unavailability
Diesel Generators



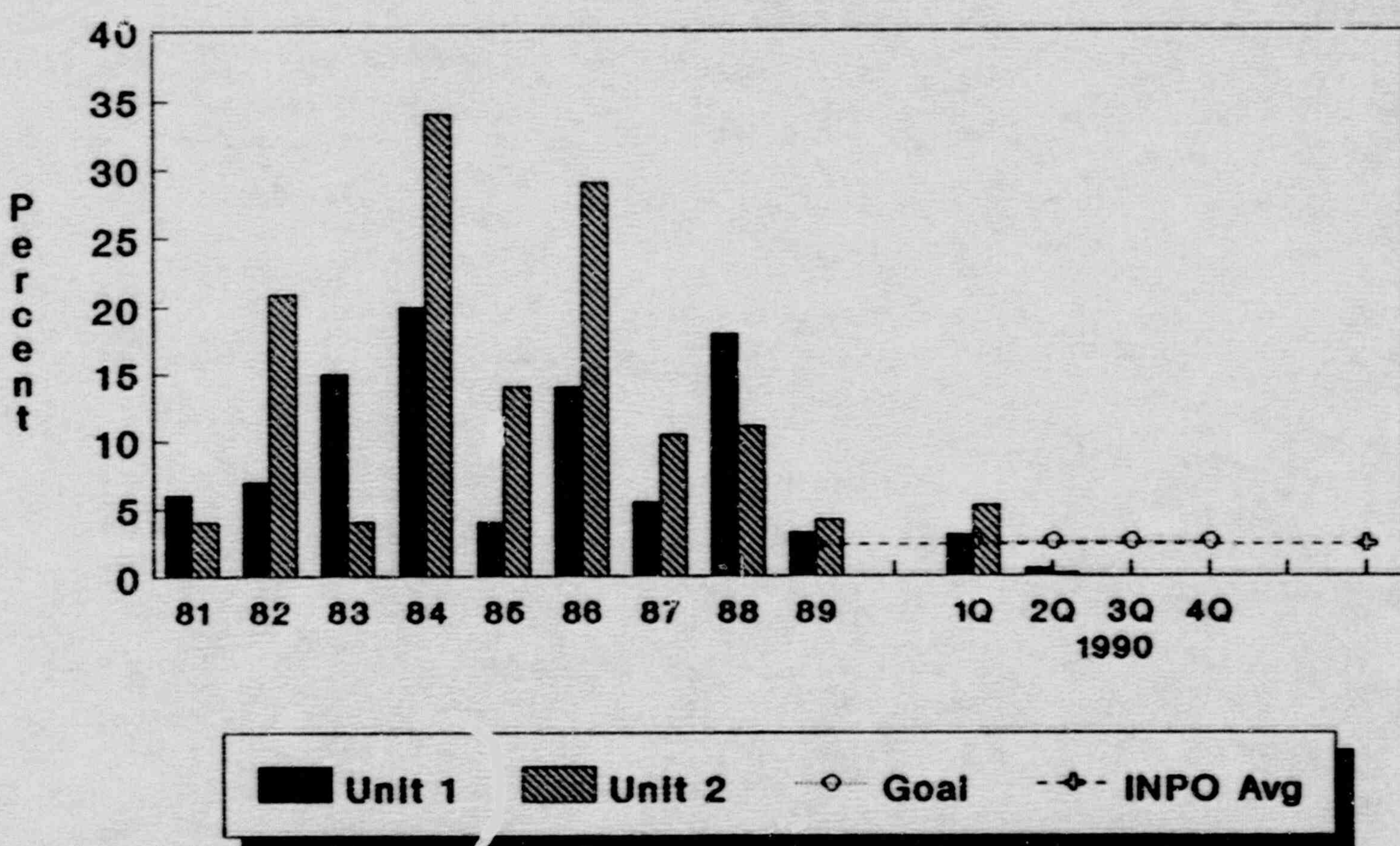
INPO Indicator
T6a

Safety System Unavailability
Torus Cooling



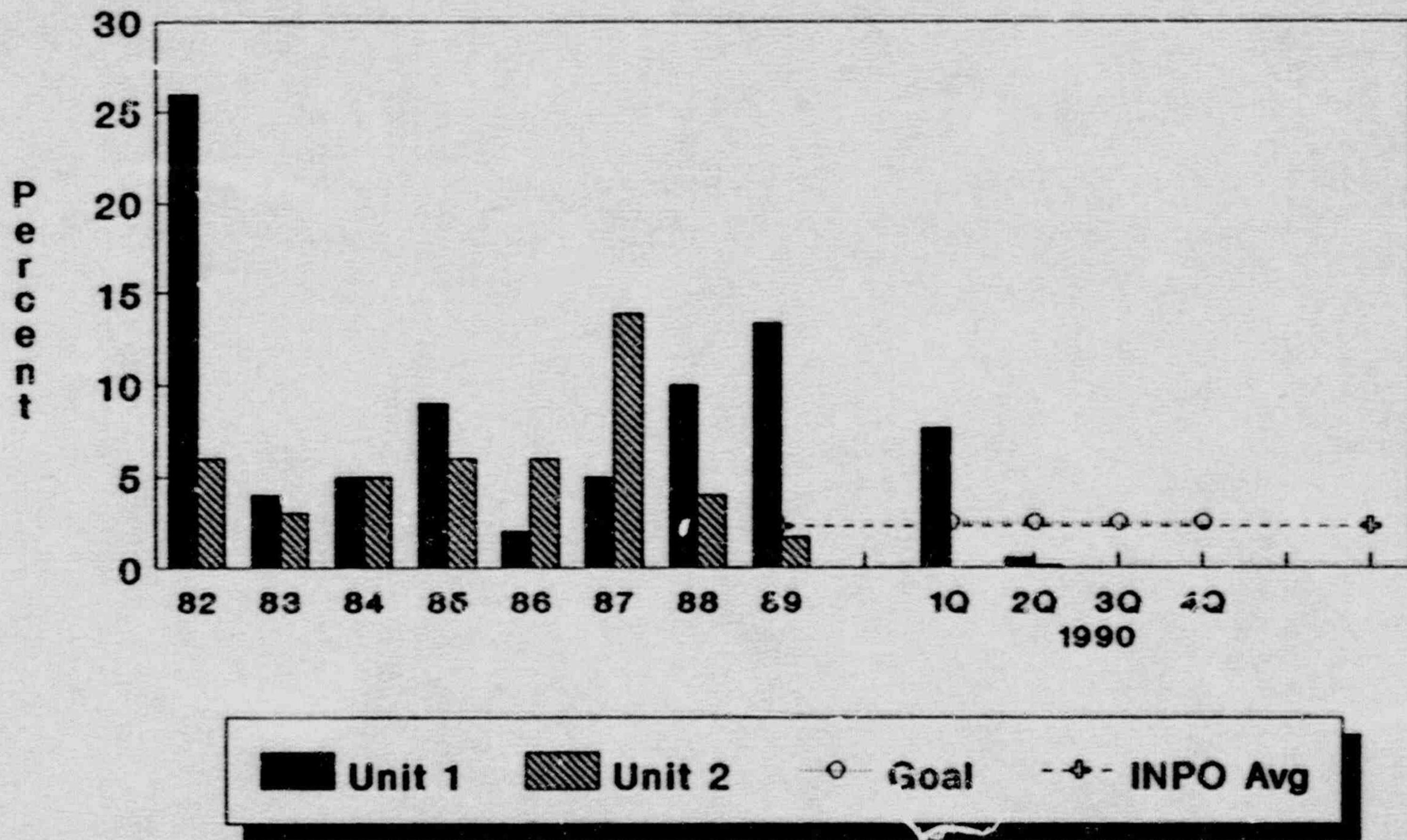
INPO Indicator
T5b

Safety System Unavailability
HPCI



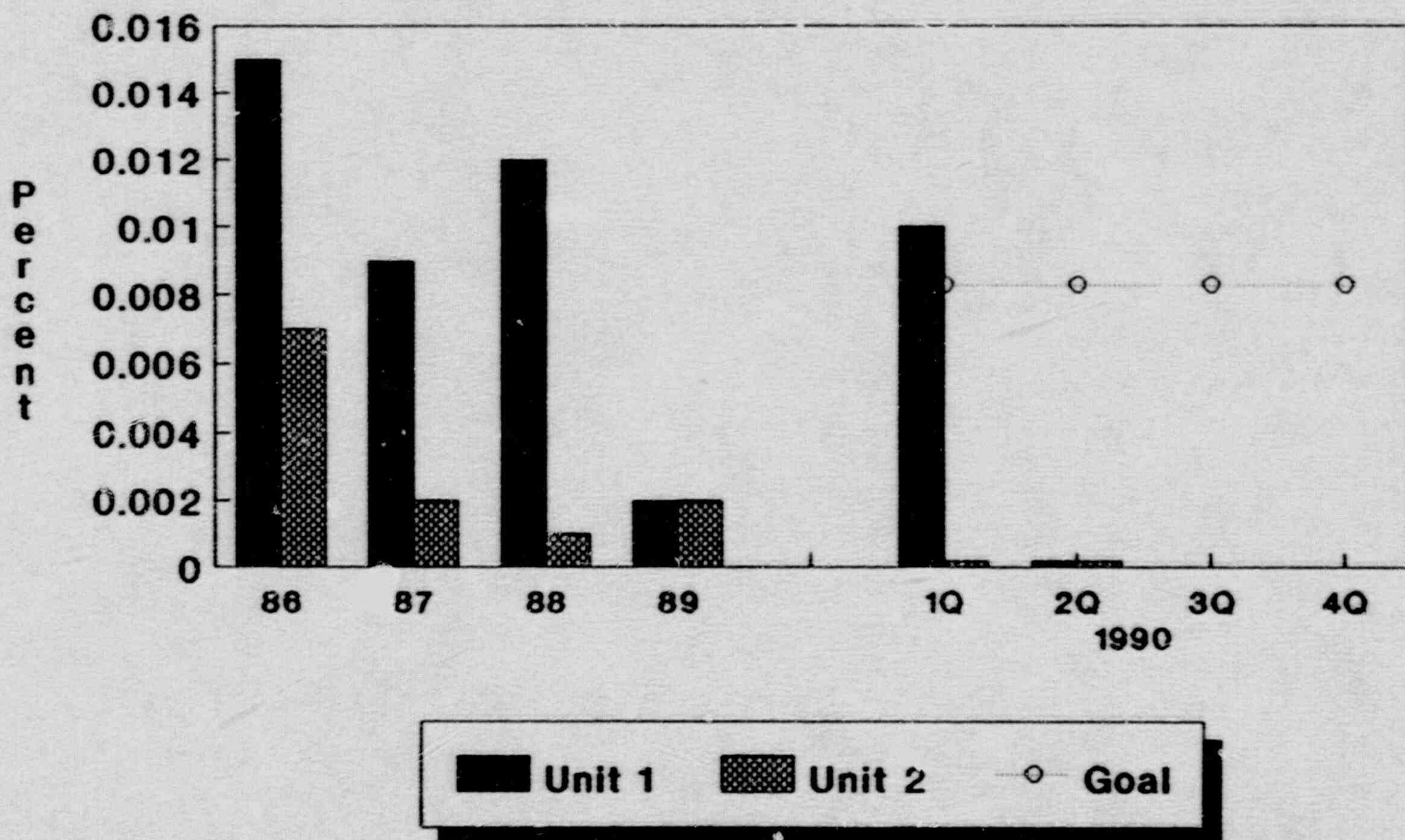
INPO Indicator
T4a

Safety System Unavailability
RCIC



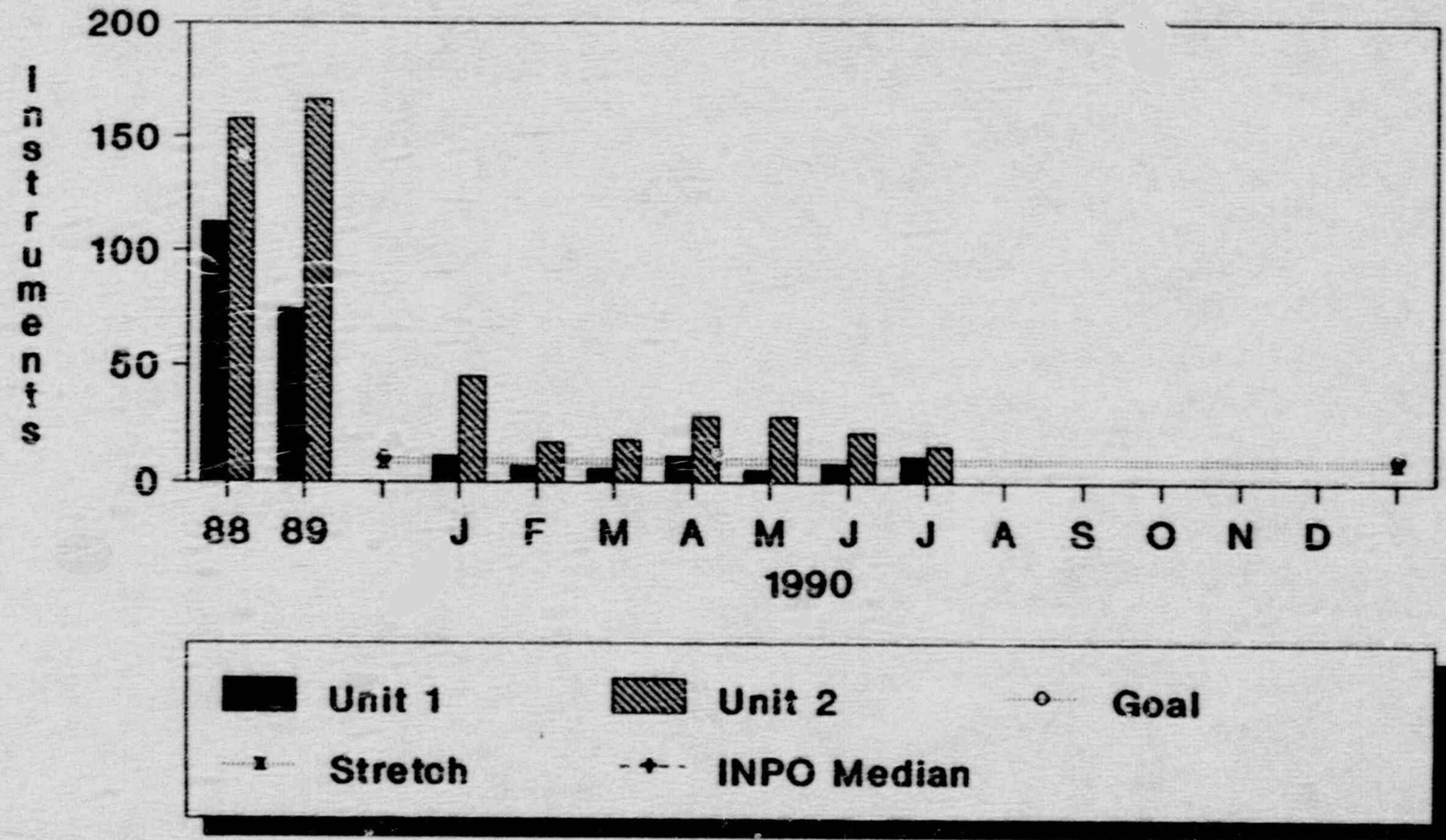
INPO Indicator
T4b

Safety System Unavailability
RHR

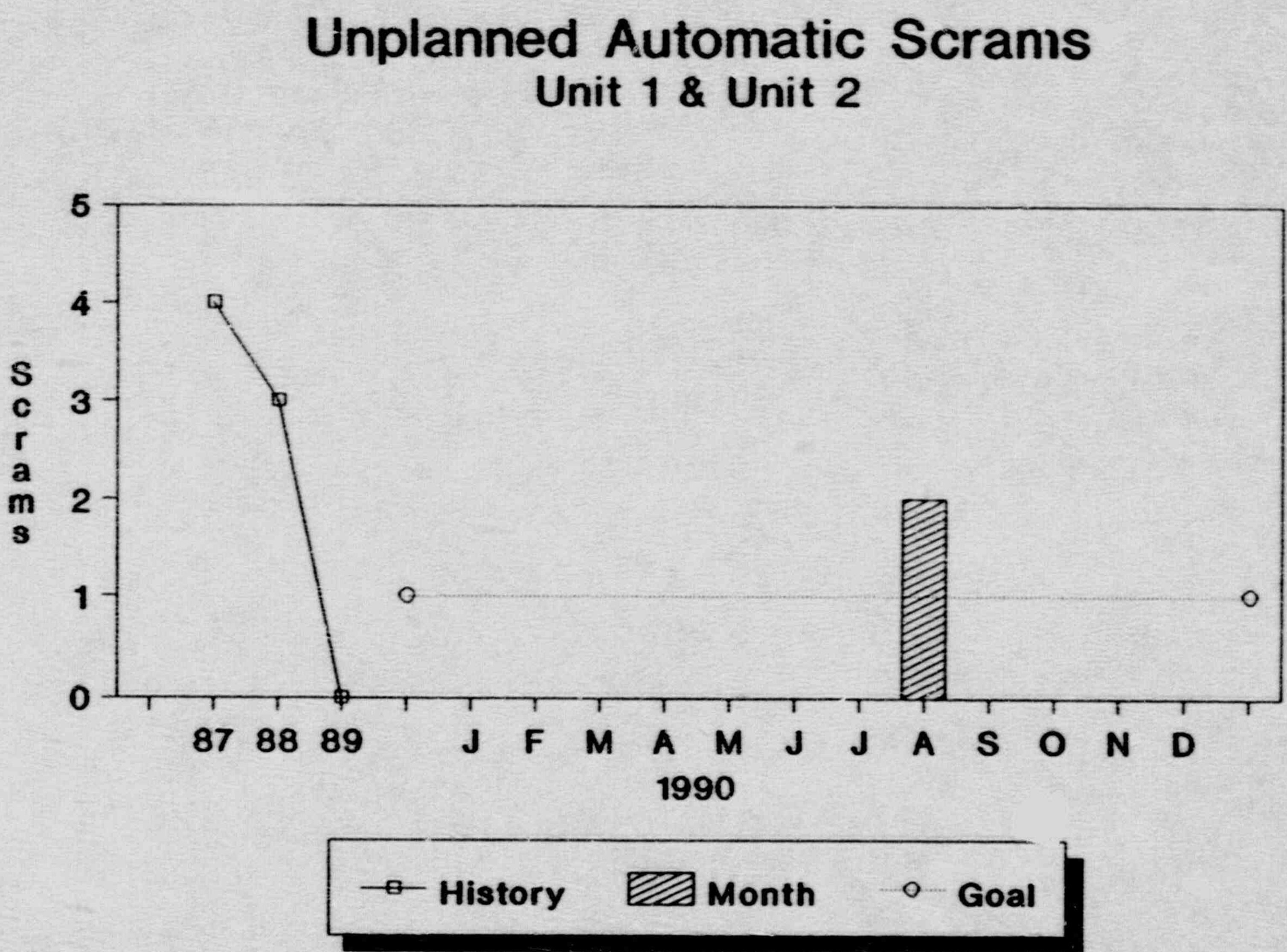


INPO Indicator
A3a

Control Room Instruments Out of Service
Total

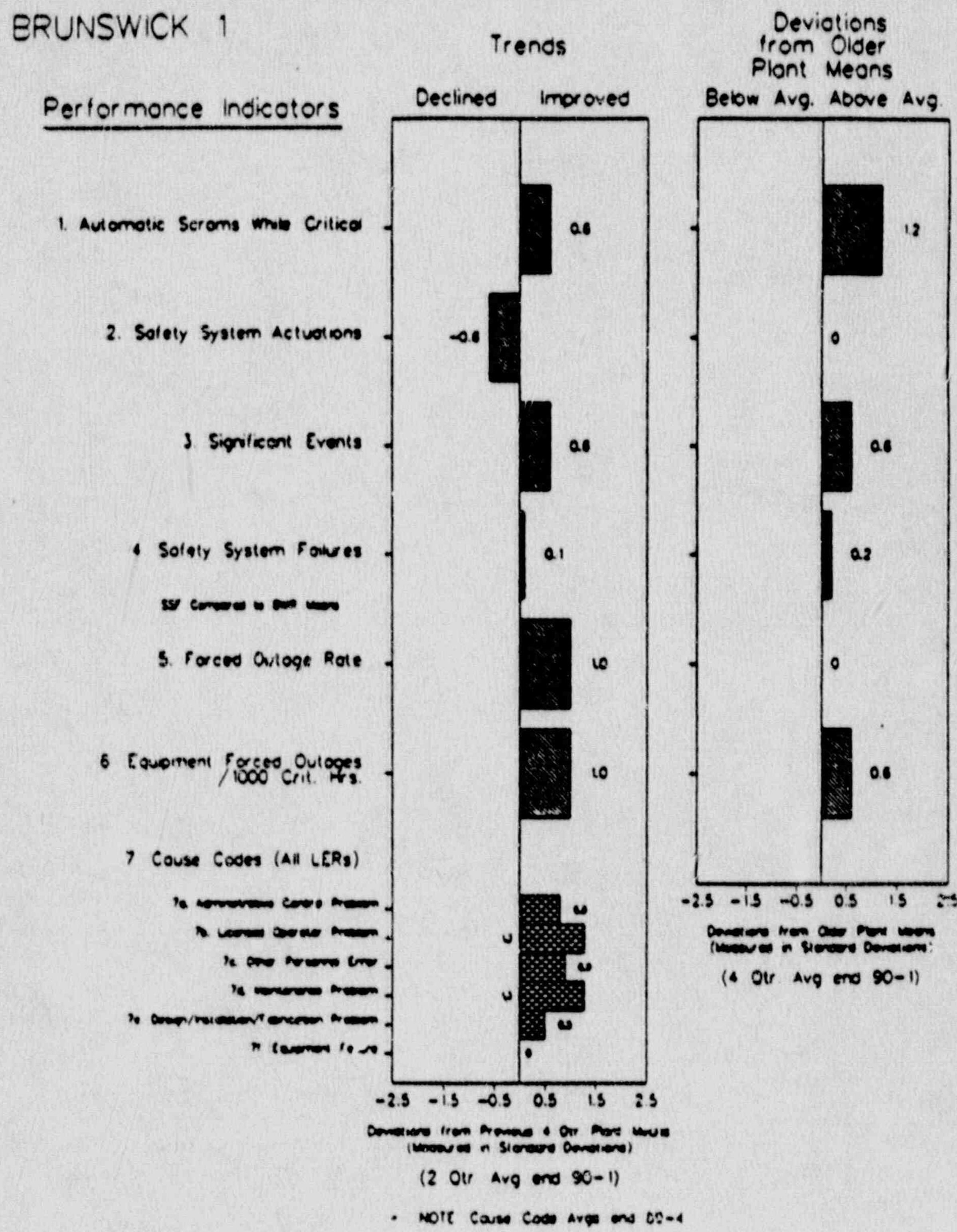


Manager Team Goal
PL6b


Unplanned Automatic Scrams
Unit 1 & Unit 2
Scrams
0
1
2
3
4
5
87
88
89
J
F
M
A
M
J
J
A
S
O
N
D
1990
History
Month
Goal

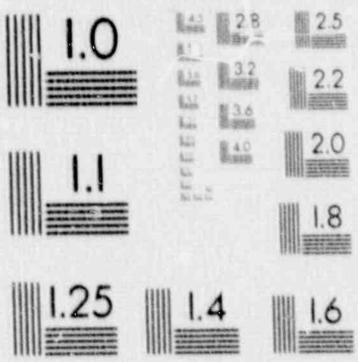
A1

FIGURE 4.11


BRUNSWICK 1
Performance Indicators
Trends
Declined
Improved
Deviations from Older Plant Means
Below Avg.
Above Avg.
1. Automatic Scrams While Critical
2. Safety System Actuations
3. Significant Events
4. Safety System Failures
5. Forced Outage Rate
6. Equipment Forced Outages /1000 Crit. Hrs.
7. Cause Codes (All LERs)
0.6
-0.6
0.6
0.1
1.0
1.0
1.2
0
0.6
0.2
0
0.6
-2.5 -1.5 -0.5 0.5 1.5 2.5
(2 Qtr Avg end 90-1)
(4 Qtr Avg end 90-1)

1

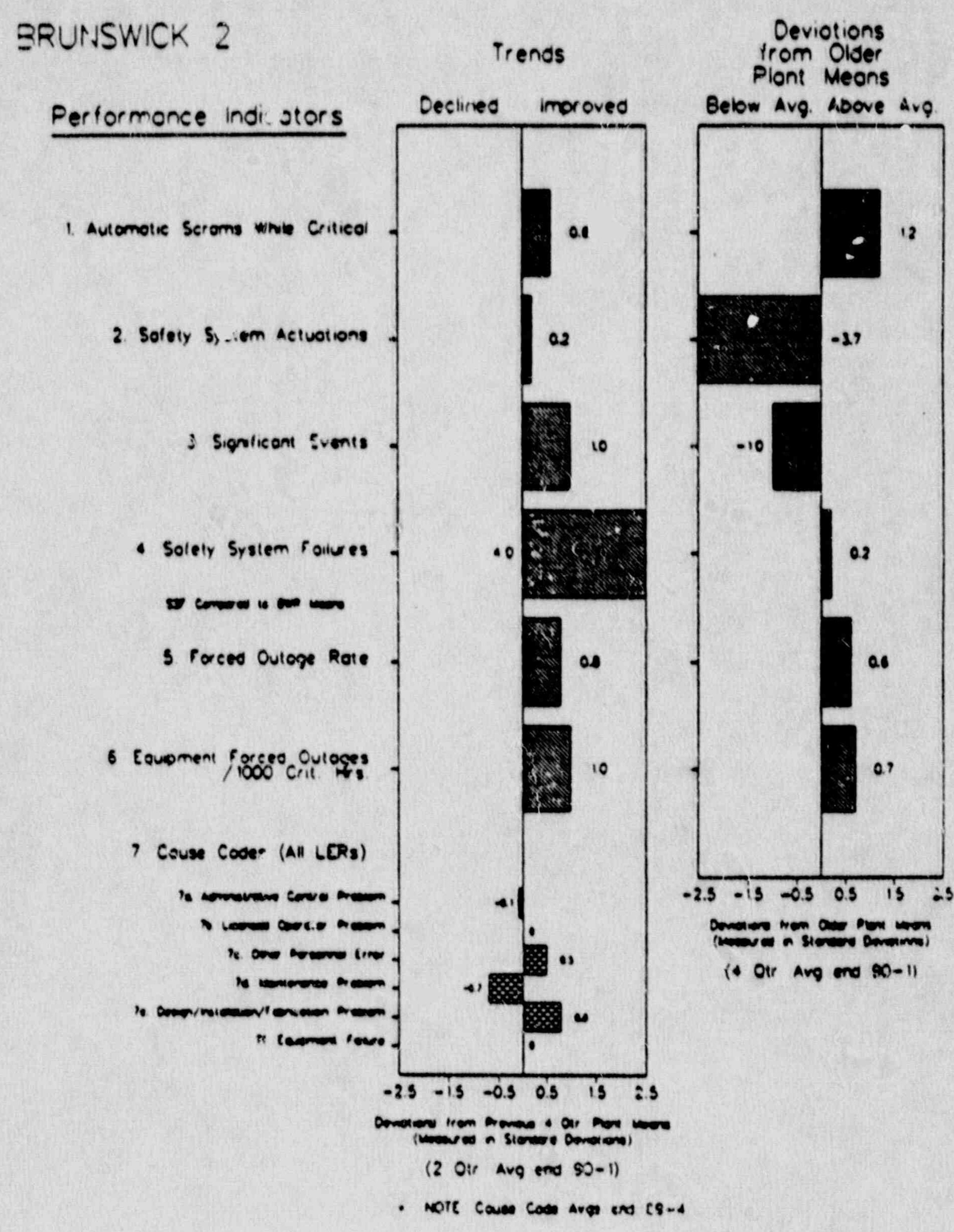
IMAGE EVALUATION TEST TARGET (MT-3)



150mm

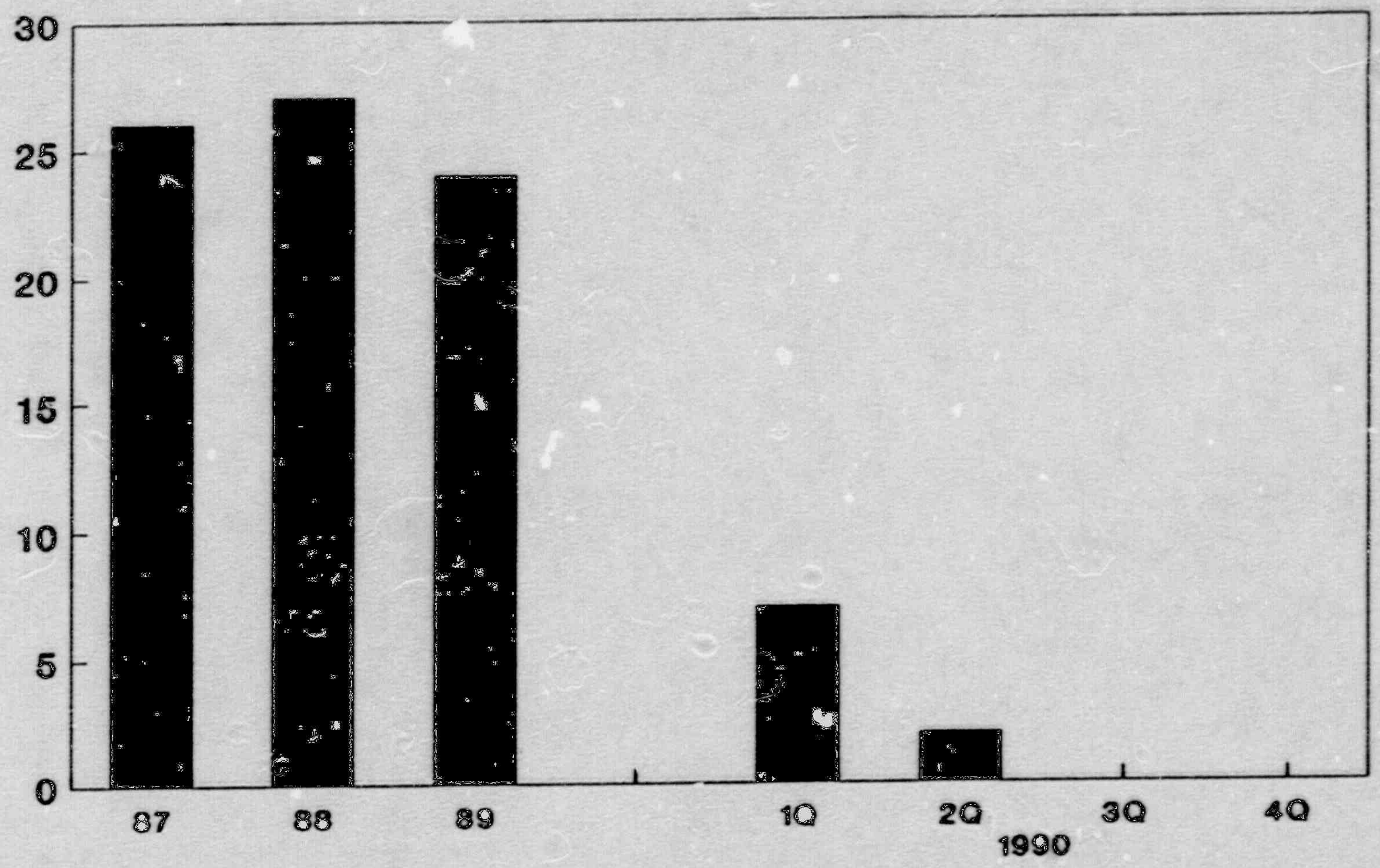
6"

FIGURE 4.12



BRUNSWICK 2
Performance Indicators
Trends
Declined
Improved
Deviations from Older Plant Means
Below Avg.
Above Avg.
1. Automatic Scrams While Critical
2. Safety System Actuations
3. Significant Events
4. Safety System Failures
5. Forced Outage Rate
6. Equipment Forced Outages /1000 Crit. Hrs.
7. Cause Codes (All LERs)
0.6
0.2
1.0
4.0
0.8
1.0
1.2
-3.7
-1.0
0.2
0.6
0.7
-2.5 -1.5 -0.5 0.5 1.5 2.5
(2 Qtr Avg end 90-1)
(4 Qtr Avg end 90-1)

Unplanned Engineered Safety
Feature Actuations



T10a