APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-313/89-37
50-368/89-37

Operating Licenses: DPR-51
NPF-6

Dockets: 50-313
50-368

Licensee: Arkansas Power & Light Company
P.O. Box 551
Little Rock, Arkansas 72203

Facility Name: Arkansas Nuclear One (ANO), Units 1 and 2

Inspection At: Russellville, Arkansas (Onsite), and Arlington, Texas (NRC Region IV)

Inspection Conducted: October 16-20, and October 30 through November 3, 1989, (Onsite), October 23-27, 1989 (in NRC Region IV)

Inspectors: C J Paulk for — 11-22-89
P. J. Wagner, Reactor Inspector, Plant Systems Section, Division of Reactor Safety — Date

C J Paulk — 11-22-89
C. J. Paulk, Reactor Inspector, Plant Systems Section, Division of Reactor Safety — Date

Approved: T F Stetka — 11/22/89
T. F. Stetka, Chief, Plant Systems Section Division of Reactor Safety — Date

Inspection Summary

Inspection Conducted October 16 through November 3, 1989 (Report 50-313/89-37: 50-368/89-37)

Areas Inspected: Routine, unannounced inspection of the licensee's programs to: (1) control design changes to the facility (Unit 2 only), (2) comply with the provisions of 10 CFR 50.62 related to protection from anticipated

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transients without scram (ATWS) (Unit 2 only), (3) maintain and calibrate instrumentation (Unit 2 only), and (4) ensure proper installation of heat shrinkable tubing (both units). The inspectors also evaluated licensee actions in response to previously reported items and vendor problem notifications (10 CFR Part 21 Reports) for both units.

Results: Within the areas inspected, no violations were identified. A number of potential problems and inspector concerns were, however, discussed with licensee personnel.

The inspectors were hindered during the first week of onsite inspection by an apparent lack of coordination among licensee organizations but were able to complete most of the scheduled activities. An example of this problem, discussed in paragraph 5.a, related to instrumentation personnel not being aware of how Technical Specification calibration requirements were being fulfilled. The inspectors found the format and, in most cases, the technical content of the instrumentation related procedures reviewed to be adequate.

The inspectors found most of the design changes that were being implemented to be thorough and well planned but questioned the adequacy of the evaluation for one change being implemented on the Unit 2 emergency diesel generators (see paragraph 4.d). The inspectors' questioning of the diesel generator modification resulted in a commitment by the licensee to restore the circuitry to the original condition and to pursue a formal change process in the future. The inspectors also noted that most of these changes had been initiated a number of years ago but had not received final engineering approval until recently.

The inspectors also discussed the timeliness and technical adequacy of the licensee's program to respond to vendor identified problems reported under 10 CFR Part 21. The inspectors were concerned that no apparent action had been taken to provide assurance that problems with current transformers did not exist at ANO-2, even though the unit was in a shutdown condition and the recommended inspection could be quickly and easily performed. The licensee had informed NRC Region IV personnel of its intent to evaluate the ANO Part 21 Program prior to this inspection.

DETAILS

1. Persons Contacted

AP&L

R. Barnes, Supervisor, Design Engineering
N. Carns, Director, Nuclear Operations
*J. Fisicaro, Manager, Licensing
*J. Jacks, Nuclear Safety and Licensing Specialist
*G. Jones, General Manager, Engineering
*R. King, Supervisor, Licensing
D. Lomax, Plant Licensing Supervisor
*E. Rogers, Maintenance Engineering Superintendent
*J. Taylor-Brown, Quality Control/Quality Engineering Superintendent
M. Tull, Project Engineer
*J. Vandergrift, Director Nuclear Operations (Acting)
J. Waxenfelter, Unit 2 Maintenance Manager

NRC

R. Haag, Resident Inspector, ANO
*C. Johnson, Reactor Inspector, Region IV
*W. McNeill, Reactor Inspector, Region IV
C. Poslusny, Project Manager, ANO, Unit 2
*T. Stetka, Section Chief, Region IV
C. Warren, Senior Resident Inspector, ANO

*The above personnel attended the exit meeting held on November 3, 1989. The NRC inspectors contacted and interviewed numerous other AP&L personnel during the inspection.

2. Followup on Previously Reported Items - Units 1 and 2

a. 10 CFR Part 21 Reports (36100)

(1) (Open) 88-07; "Gamma-Metrics Cable Assemblies"

By letter dated May 10, 1988, Gamma-Metrics informed the NRC and affected licensees of possible problems with solder connections on cable assemblies installed as part of neutron flux monitoring systems at various nuclear power plants. The vendor identified solder joint leakage problems that could result in the failure of the neutron flux monitoring system during a design basis accident. Since ANO was identified as a customer that was being informed of the problem in the letter dated May 10, 1988, the inspectors reviewed the actions that had been taken in response to this issue.

The licensee had completed the necessary tests and repairs on the Unit 1 cables during the previous refueling outage. The work was completed under Job Order (JO) 766870. The Unit 2 work was being conducted under JO 796400 during this inspection period. This report will remain open pending a future NRC inspection to verify that the required repairs had been completed on Unit 2 prior to its return to service following the ongoing refueling outage.

(2) (Open) 89-05; "ABB Power Distribution, Inc., Current Transformer (CT) Encapsulate Material"

By letter dated April 17, 1989, ABB informed the NRC and affected licensees that problems had been identified with the epoxy-anhydride compound used to encapsulate electrical components. The compound had been identified as softening or reverting back to a liquid state in some installations; however, vendor testing was unable to predict the frequency of these occurrences. Therefore, ABB recommended that electrical components encapsulated in this compound be inspected at approximately 18 month intervals to ensure that the reversion process (which is slow but irreversible) had not started.

The licensee initiated Condition Report (CR) - C-89-067 for this problem on May 12, 1989. This CR called for a preventive maintenance inspection program to be developed by December 31, 1989. The inspector questioned why no physical observation efforts to assess the reported condition were being implemented during the ongoing Unit 2 refueling outage and was informed that some inspections had been conducted but had not been documented.

This report will remain open pending NRC verification that an acceptable CT encapsulating material inspection program has been implemented.

(3) (Open) 88-10; "Safety Grade Relays"

By letter dated August 5, 1988, Combustion Engineering, Inc., informed the NRC and affected licensees of potential problems with electrical relays provided by Potter & Brumfield, Inc. The motor driven relays (MDRs) had been found to fail to return the contacts to the normally open position when power was removed from the operating mechanism. The problem had been traced to internal mechanical binding which the relay's spring force was insufficient to overcome.

The licensee initiated CR-2-89-017 on January 11, 1989, and CR-C-89-021 on February 6, 1989, to evaluate the MDR problem. At ANO, both 28VDC and 125VDC relays were being evaluated. The corrective action evaluation in CR-C-89-021 recommended the replacement of the 125VDC MDRs during the ongoing refueling

outage for Unit 2 (2R7) and the next refueling outage for Unit 1 (1R9). These corrective actions, however, were being reevaluated and final documentation was not available.

This report will remain open pending future NRC review of the licensee's implemented corrective actions for all affected MDRs.

(4) (Open) 88-19; "Melamine Torque Switches in Limitorque Operators"

During a recent NRC Diagnostic Team Evaluation conducted during August and September 1989, a concern was raised over the licensee's handling of a Part 21 report issued by the Limitorque Corporation for valve operators. Limitorque issued the report in November 1988, and the licensee completed an evaluation in April 1989. When the Diagnostic Team questioned the adequacy of the evaluation, the licensee undertook another evaluation and performed testing that was recommended in the Part 21 report. The licensee's difficulty in identifying which valve operators were affected was attributed to having ineffective walkdown data. The licensee completed the reevaluation on November 1, 1989. The evaluation identified the potentially affected valve operators, described the testing that was performed, and discussed the future actions that would be taken for those valve operators inside the Unit 1 containment.

The reevaluation determined that there was no safety impact in continuing to operate Unit 1 until the mid-cycle shutdown outage scheduled for the end of November 1989. Corrective actions for Unit 2 were to be completed prior to startup from the ongoing refueling outage. The licensee committed to completing the inspection and necessary repairs to the Unit 1 valve operators prior to startup after the mid-cycle outage. This inspection and necessary repairs to the valve operators was delineated in the engineering evaluation submitted for NRC review by letter dated November 1, 1989.

During discussions on this subject, AP&L agreed that there may be short comings in the ANO Part 21 program and had previously informed NRC Region IV personnel of its intent to perform an assessment of possible improvements.

This report will remain open pending inspection of the completed corrective actions of Units 1 and 2.

The inspectors discussed their general observations of the Part 21 program with AP&L management personnel during the inspection and at the exit meeting held on November 3, 1989. Since the purpose of the Part 21 notifications is to inform licensees of problems identified at other facilities, the inspectors stated that they did not consider the AP&L program was taking full advantage of the information provided. The inspectors noted that there had been no licensee

documented inspections conducted, since being notified, to determine if the CT problem existed at ANO and that the licensee's operability determinations for the MDRs had been based solely on the absence of failures at ANO.

The problems with the Limitorque valve operators had been the subject of discussions prior to this inspection between AP&L and NRC Region IV personnel. As a result of those discussions, AP&L expressed its intent to reevaluate the ANO Part 21 program, to implement changes as needed, and to ensure that previously closed Part 21 reports had received an acceptable level of consideration.

No violations or deviations were identified.

b. Previous Inspection Findings (92701 and 92702)

(1) (Closed) Violation 50-313, 368/8805-04 Inadequate Procedures:

The licensee was found to have inadequate procedures to maintain the qualification status of the containment building fan motors. The specific issues involved the procedure for repair of electrical insulation, lubrication, and repair/replacement of motor bearings.

The licensee removed references from the procedures relating to the repair of the motor windings; any motors that require winding repair are to be sent to the manufacturer. The issue of lubricants was adequately addressed in Procedure 25.007, "EQ Listed Equipment's Approved Lubricants," Revision 3. The issue of bearing lubrication and repair/replacement was adequately addressed in Procedures 1025.017 "Lubrication Changeout," Revision 0; 1403.008, "Unit 1 Containment Cooling Fan Inspection and Repair," Revision 5; and, 2403.005, "Containment Cooling Fans," Revision 5. This item is considered to be closed.

(2) (Open) Open Item 50-313, 368/8829-05 Nylon Crimp Connectors in Limitorque Dual Voltage Motor Operators

The issue of the crimped connectors was identified during the 1986 Equipment Qualification (EQ) inspection at ANO (NRC Inspection Report 50-313/86-23, 50-368/86-24). At that time, adequate documentation to support the qualification of the splices was not available in the ANO EQ files.

The licensee contended that these connectors were only for mechanical protection and therefore were not required to be qualified for exposure to moisture. However, moisture intrusion into the valve operator switch compartments continues to be a valid concern and has been addressed in various Limitorque reports. The licensee agreed to replace the crimped connectors with a qualified replacement.

In order to verify that the nylon connectors had been replaced, the inspectors requested the documentation for those repairs. The licensee provided information for Unit 1, which showed that the connectors had been replaced under various work packages. A review of the work packages indicated that the connectors were replaced with tape splices in November 1988.

The tape splices that replaced the crimped connectors were required to be qualified in accordance with 10 CFR 50.49(1). The qualification of the taped splice configuration was also the topic of Violation 50-313, 368/8829-02. The licensee has responded to this violation; however, subsequent inspection of the corrective actions has not yet been performed. During this inspection, the licensee was informed that it did not appear that the taped splices were in a qualified configuration. The licensee committed to further evaluate the taped splice issue and inform the NRC prior to the scheduled November 1989 outage of Unit 1 as to what actions will be taken on this matter.

This item will remain open and will be reinspected during a future inspection in conjunction with the followup actions for Violation 50-313, 368/8829-02.

(3) (Open) Open Item 50-368/8829-04 Bunker Ramo Electrical Penetration Assembly (EPA) Qualification

The ANO EQ file did not contain adequate documentation to support qualification of the EPAs. The information was available but had not been incorporated into the qualification file. The licensee has subsequently included calculations in the file to derive the insulation resistance (IR) values to support qualification. The licensee has also obtained a test report that would qualify the EPAs to 10 CFR 50.49 standards, but had not incorporated the information into the file.

This item will remain open pending review of the EQ file to verify that the new information had been incorporated.

3. Compliance with 10 CFR 50.62 - Unit 2 (25020)

The NRC published 10 CFR 50.62, "Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-water Cooled Nuclear Power Plants" in June 1984. This regulation provided the technical and scheduler requirements to be implemented by the licensees to provide protection from ATWS events. Further guidance was provided in NRC Generic Letter 85-06, "QA Guidance for ATWS Equipment That is Not Safety Related," dated April 16, 1985. The AP&L request for partial exemption from the requirements of 10 CFR 50.62 for ANO-2 was denied by the NRC in letter dated February 16, 1989. The licensee was also found in violation

of the required implementation schedule for ANO-2 in NRC Inspection Report 50-313/89-10; 50-368/89-10 (the modifications were supposed to have been implemented during the previous refueling outage).

By letter dated June 21, 1989, the NRC provided a Safety Evaluation of the two portions of the ATWS protection being implemented during this refueling outage and reiterated that the third portion should also be implemented, independent of the staff's review, as required by the regulations.

The three systems being proposed for compliance with 10 CFR 50.62 at ANO-2 consist of a diverse reactor scram system (DSS), a diverse initiation of a turbine trip (DTT), and a diverse actuation of the auxiliary feedwater system (DAFW). The first two of these systems were being implemented during this inspection, the other (DAFW) was being delayed until a subsequent outage. The licensee discussed this implementation schedule in their June 14, 1989, response to the Notice of Violation dated May 15, 1989 (50-368/8910-03). The inspectors reviewed the Safety Evaluation and the licensee's letter dated September 25, 1989, which clarified the AP&L position on several points made in the safety evaluation. The inspectors also reviewed the implementing Design Change Package (DCP) 85-2073, Revision 3. This large DCP contained documents and drawings related to the specific design characteristics of the DSS and contained step-by-step installation instructions. The inspectors also verified the installation of the involved hardware. A listing of the pertinent drawings is included in Attachment 1.

The DSS being implemented at ANO-2 included the installation of four new pressure transmitters to monitor pressurizer pressure and provide trip signals if the pressure increased above the regular reactor trip system (RTS) setpoint. The transmitters were being piped to existing pressurizer taps and were powered from a separate power supply. The instrument trip signals were then compared by microprocessors to provide a 2 out of 4 trip logic. The processor output trip signals were sent to newly installed electrical contactors on the output of each of the control element drive mechanism (CEDM) motor generators. These motor generator sets provide the CEDM power, and opening of the new contactors would deenergize the CEDM buses, thereby causing a reactor scram. Since the new components, their power supplies, and cabling were independent of the RTS, an independent means of causing a reactor scram was being provided. The inspectors noted, however, that the system was not safety-related nor single failure protected. These provisions are not required by the regulation.

The DTT function was being provided at ANO-2 by utilizing existing equipment. The CEDM busses have undervoltage relays which provide a trip signal to the main turbine trip circuitry. Since the DSS provides a diverse means of deenergizing the CEDM busses and causing the attached undervoltage relays to trip, the licensee reasoned that a diverse means of turbine trip was inherently provided. NRC acceptance of this AP&L design was provided in the June 21, 1989, safety evaluation.

During the inspectors' detailed review of the DSS evaluations and drawings, the inspectors made the following observations:

- Most of the final engineering and evaluation sign-offs for this 1985 era DCP were completed in 1989, the DCP, therefore, reflected recent technical support activities.

- The DCP was complete and thorough as evidenced by the inclusion of consideration of factors such as fire zone hazards analyses, cable tray seismic and heat rise evaluations, installation details, testing and operating directions and a failure mode effects analysis evaluation.

- A number of minor problems were identified with some vendor provided drawings. The licensee agreed to evaluate the drawings and make the necessary corrections as part of the DCP closeout process.

The inspectors reviewed the draft procedures for the daily and monthly checks of the systems. These were evaluated to be acceptable after corrections have been made to the monthly test as a result of a walk-through of the test. The 18 month surveillance test had not been written at the time of the inspection and was not available for review. These procedures will be written and implemented prior to their next required performance.

Inspector Followup Item (368/8937-01): Evaluate the procedures being developed for testing and calibrating the DSS and DTT systems.

4. Design Changes - Unit 2 (37700)

The inspectors reviewed some of the Design Change Packages (DCPs) which were being implemented during the in progress refueling outage and made the following observations:

a. DCP 83-2173 "Breaker 2A308/2A408 Interlock"

An Engineering Action Request was written on August 30, 1983, because it was possible to manually close the Emergency Diesel Generator (EDG) output circuit breaker if the synchronizing meter switch was positioned to select that breaker even if the EDG was not running. The resolution proposed by AP&L engineering on February 1, 1985, was to add a synchronize check relay in the remote manual operating circuit for both the normal and emergency supplies to the affected busses (2A3 and 2A4). This relay would ensure that the voltages on both sides of the breaker to be closed were in the proper phase and magnitude before allowing the breaker to closed. The inspectors found the proposed modification to be acceptable and found the work package to provide clear and easily understood instructions. The inspectors also verified that the modification had no impact on the automatic operation of the circuit breakers.

b. DCP 85-2073 "ATWS Diverse Scram System"

This DCP was discussed in paragraph 3, above.

c. DCP 85-2075 "CPC System Permanent Tie-Ins"

This DCP was the final in a series of 6 DCPs which replaced the Core Protection Calculators (CPCs) with newer, more useful units. The DCP also replaced the isolation devices to separate the Class 1E circuits from the nonsafety-related circuits, with fiber optic isolators. The inspectors found this DCP to be well written in that it provided clear instructions on how and why the modification was being implemented. The completeness of the licensee's evaluation was evidenced by the reference to procedures which would need to be revised to reflect the new hardware and by the consideration of factors such as fire protection and the percentage of cable tray fill resulting from the addition of new cables installed for this modification.

Although the DCP indicated that a Technical Specification (TS) change would be required, there was no indication that a license amendment application had been submitted for NRC consideration. When questioned, licensee representatives provided a copy of AP&L's June 13, 1989, application.

d. DCP 85-2134 "Deletion of SIAS Bypass on EDG Fail To Start and SIAS Trip on Unit Auxiliary Breakers"

This DCP had been initiated by the licensee to provide the Emergency Diesel Generators (EDG) with the capability of saving starting air following a failure to start on receipt of a safety injection actuation signal (SIAS). In addition, the DCP stated that another change would prevent an inadvertent reactor trip caused by a spurious SIAS trip of the unit auxiliary transformer (UAT) supply breakers. The inspectors' review of the portion of the DCP to remove SIAS contacts from the UAT supply breakers found it to be acceptable; the review of the removal of the SIAS block of the EDG failure to start circuitry did, however, raise concerns.

The inspectors noted that included in a September 14, 1975, NRC request for additional information, the licensee had been informed that their response to a prior staff position related to the bypass of certain trips in the EDG circuitry was incomplete and unacceptable. The licensee was directed at that time to either bypass, or provide redundant protection for, among others, the EDG failure to start circuitry when a SIAS was present. The licensee had installed the required bypass prior to plant licensing but was in the process of removing that bypass via this DCP. The inspectors noted that Technical Specification (TS) 4.8.1.1.2.c.8c requires the licensee to simulate a loss of offsite power in conjunction with a SIAS and verify "that all diesel generator trips, except engine

overspeed, lube oil pressure, and generator differential, are automatically bypassed upon a Safety Injection Actuation Signal." The inspectors were informed by licensee personnel that it was AP&L's interpretation that the failure-to-start shutdown resulting from the timing circuitry was not a diesel generator trip but rather a failure to start and, therefore, no TS change was required to allow the modification to the EDG start circuitry.

The inspectors were also concerned that the timing relays, which had previously been configured in a parallel circuit that was bypassed by a SIAS signal, were being reconfigured into a series circuit but would retain the approximately 10 second setpoint. While this configuration would require both relays to "time-out" to produce a shutdown and thereby provided some degree of redundancy and reliability, the DCP did not provide adequate assurance that the existing setpoint was conservative for all accident conditions.

The inspectors discussed the above concerns with appropriate licensee personnel and pointed out the inconsistencies in the USAR related to the EDG starting air requirements. As a result of those discussions and further evaluations, AP&L engineering personnel committed to restore the SIAS bypass of the failure to start trip prior to resumption of reactor operations and to pursue a formal licensing change in the future. The inspectors found this commitment to adequately resolve their concerns and will verify the licensee's actions in a future inspection.

Inspector Followup Item (368/8937-02): Evaluate licensee actions to restore the SIAS bypass in the Unit 2 EDG start circuitry.

5. Instrument Maintenance and Calibration - Unit 2 (62704 and 56700)

The inspectors evaluated whether the corrective and preventive maintenance (PM) activities and the calibration activities relative to instrumentation components and systems were being conducted in accordance with approved procedures and instructions. The inspectors evaluated these procedures and instructions to determine if they were in conformance with license requirements, technical specifications, regulatory guides, licensee commitments, and industry codes and standards committed to by the licensee. The inspectors selected several systems and instruments for review; these included Remote Shutdown Monitoring, Core Protection Calculator System, Pressurizer Pressure, Reactor Coolant Temperature, Steam Generator Level and Pressure, and Condensate Storage Tank Level instruments. The procedures for these instruments were reviewed and are listed in Attachment 2. The procedures were generally acceptable; however, some concerns were identified and are discussed below.

The inspectors reviewed completed records and verified that the required calibrations and maintenance were being scheduled and performed as required. As of October 5, 1989, there were only 15 PMs that were past

due, and many of these were the result of the plant status at the time they were scheduled. No concerns were identified with the scheduling and performance of PMs.

a. Temperature Monitoring Instruments

While reviewing the Reactor Coolant Temperature Instrumentation Surveillance Test (2304.118), the inspectors noted that the only tests required for the temperature sensors (Steps 7.10, 7.15, 7.20, and 7.26 of Procedure 2304.118) were the measurement of the resistance of each of the two elements in each instrument. The resistances were then used to determine temperatures from the calibration table in the procedure and the two temperatures were compared to determine the operability of the temperature element. The temperature of the process being monitored was not determined. This determination was necessary to evaluate if the resistance readings were consistent with that required for the subject temperature. The inspectors reviewed additional procedures and noted similar requirements for other RTDs. The inspectors determined that the Technical Specification (TS) definition of a calibration requires that the sensing elements (i.e., the RTDs) be subjected to known values such that an instrument channel can be adjusted (calibrated) from the point of measurement. This calibration would ensure that the instrument channel would be within the prescribed range and accuracy requirements and that an RTD drift did not occur. Since these procedures did not apply a known value (temperature) to the RTDs and require the output of the RTDs to be compared to that known value, it did not appear that the licensee was properly calibrating the RTDs. The inspectors discussed this concern with licensee personnel during the first week of onsite inspection.

The inspectors asked I&C personnel if any isothermal cross-calibration of the RTDs were performed and were informed by these personnel that they were not aware of such a practice. The inspectors stated that they considered this to be an important item that needed to be resolved when the inspectors returned for the final week of the inspection.

During the entrance meeting for the final week of the inspection, the importance of receiving information on the calibration of RTDs was again stressed. The licensee did not provide any information on this topic until the next to last day of the inspection. At this time, the licensee determined that a cross-calibration check was performed at isothermal conditions during startup testing after each refueling outage. The procedures for performing these cross-calibrations were 1302.013, "Sequence for Physics Testing Following Refueling," and, 2302.036, "Process Variable Intercomparison," for Units 1 and 2, respectively. These procedures were reviewed and found to be acceptable.

b. Level Transmitter Replacement

During the first week of the onsite inspection, the inspectors attempted to observe instrument maintenance/calibration in progress but were hindered by a lack of an extended (5 day) schedule, which was never made available.

The inspectors witnessed the replacement of a wide range steam generator level transmitter (2LT-1079-1) that had been determined to be inoperable during its calibration. The licensee replaced the lower section (diaphragm) of the detector and the internal electronics (printed circuit boards), leaving the upper housing attached to the electrical conduit seal assembly (ECSA). The licensee explained that this was done because of the difficulty of removing and replacing the ECSA. The inspectors also examined the splice of the ECSA leads to the field cable with heat shrinkable tubing, which was located in a junction box, and found it to be acceptable.

The removal and installation of the transmitter was performed under Job Order (JO) 798228 and the calibration under JO 789246. The inspectors verified that all test equipment was in calibration and that the serial numbers were logged on the JO form for tracking purposes. The inspectors noted that the appropriate procedures were followed and had no questions related to this activity.

During the review of the Procedure 2304.119, "Pressurizer Level Instrumentation Surveillance," utilized for the above calibration, the inspectors questioned the scaling factors used to convert the measured differential pressure (DP) into an indicated water level. A review of additional level transmitter calibration procedures disclosed a number of variations in how the scaling formulae were derived and used. Factors which need to be accounted for in DP level measuring devices include the height of the water column and its density, the effects of any vapor column weight on either column, and any offsets in the elevation of the instrument relative to the lower level tap. The inspectors discussed this concern with licensee personnel and verified that any level error resulting from present formulae would be of little significance (see the following paragraph for an example). In addition, the licensee showed the inspectors a new manual being developed for ANO. The inspectors reviewed the "Instrument Loop Error Analysis and Setpoint Methodology Manual" Revision A (Draft), and noted that Section 8.1 on level measurement provided clear guidance on how a scaling formula should be derived. The inspectors had no further questions on this subject.

c. Reference Leg Addition

During the review of design changes being implemented on Unit 2, the inspectors noted that an additional reference leg was being added to the volume control tank. The licensee implemented DCP-85-2132 in

order to provide separate reference legs for both level transmitters. This would avoid having a recurrence of past level indicating problems with the two level indications because of a common reference leg. The inspectors reviewed the DCP and found it acceptable but had a problem with the scaling formula being utilized in calibration Procedure 2304.011, "Volume Control Tank Instrument Surveillance Test."

The formula presented in the procedure was acknowledged by licensee personnel to only be adequate for the 100 percent or full tank condition. The correction factors which were provided in the procedure were, however, determined to produce acceptable results. The licensee agreed to correct the formula error in the procedure and thereby resolved the inspector's concern.

d. Conclusions

The inspectors experienced a number of delays in conducting their activities because of an apparent lack of timely emphasis on the licensee's part for support to the NRC. This perception was based on the inability of the ANO organization to ensure that the correct personnel were involved in answering the inspectors' concerns and in providing information. The cooperation aspect was discussed with AP&L management and a definite improvement was noted during the second week of onsite inspection.

The inspectors also noted that there appeared to be little coordination between the various AP&L organizations. This observation was based on the lack of I&C personnel knowledge of how the Technical Specification calibration requirements for RTDs were implemented and how the scaling factors were derived. The inspectors were frequently required to go from one contact to another in order to receive a complete answer to a question.

No violations or deviations were identified.

6. Heat Shrinkable Tubing - Units 1 and 2 (25017)

The inspectors evaluated the adequacy of the heat shrinkable tubing (HST) installed at ANO. The inspection was conducted in accordance with Temporary Instruction 2500/17. The evaluation consisted of the review of procedures and installation records, and the physical examination of existing selected HST installations. The inspectors also witnessed the installation of HST over six splices in Unit 2.

The inspectors reviewed the applicable HST installation procedures listed in Attachment 2 and compared the instructions to the material manufacturer instructions. The inspectors found the splice range and length application guides to be consistent with manufacturer requirements and the step-by-step instructions to be clear and easy to follow.

The inspectors performed physical examinations of the splices to ensure that: the tubing was fully shrunk onto the electrical cable; sealing was assured by the appearance of a visible adhesive bead at the ends of the tubing indicating that the adhesive had melted and flowed; and the tubing exhibited a smooth and glossy appearance indicating the proper use of the heat source to cause shrinkage. The inspectors found all of the existing installations to meet the procedural requirements and to be acceptable. The installations in progress witnessed by the inspectors were also acceptable.

No violations or deviations were identified.

7. Exit Interview (30703)

The inspectors met with Mr. J. Vandergrift, Acting Director, Nuclear Operations, and other members of the AP&L staff identified in paragraph 1 at the end of the inspection. At this meeting, the inspectors summarized the scope and findings of the inspection and discussed the commitments documented in paragraphs 2.a.(4), 2.b.(2), and 4.d. The licensee acknowledged the inspection findings and agreed with the inspectors' statement of the AP&L commitments. The licensee did not identify as proprietary any of the material provided to, or reviewed by, the inspectors during this inspection.

ATTACHMENT 1

LIST OF DRAWINGS REVIEWED

DRAWING NO.	SHEETS	REVISION	TITLE
E-2192	1-3	5-1	RPS MG Sets Schematics
E-2193	9	4-1	Reactor Trip Schematic
E-2482	69	9-1	Computer Digital Inputs
E-2693	14	2-1	RPS Connection Diagram
E-2703	6	N-1	DSS Pressurizer Procedure Schematic
E-2014	4&5	6	Interconnection Diagrams
M-2001	M2-25	2-1	Reactor Trip Switchgear
APL-199346-001	1-18	N-1	Pressure Transmitter Details
APL-199346-002	1-3	N-1	DSS Schematics
APL-199380-001		N-1	DSS Functional Diagram
APL-199380-002		N-1	DSS Functional Diagram
APL-199380-003		N-1	DSS Functional Diagram
APL-199380-004		N-1	DSS Functional Digram
APL-199380-005	1-4	N-1	DSS Wiring Diagrams
APL-199380-006		N-1	DSS Power Distribution
APL-199380-007		N-1	DSS Termination Cabinet
APL-199380-008		N-1	DSS Equipment Arrangement

ATTACHMENT 2

LIST OF PROCEDURES REVIEWED

Station Administrative Procedres

1000.009, "Surveillance Test Program Control," Revision 20, dated June 21, 1989

1000.056, "Trending Program," Revision 1, June 25, 1988

1025.006, "Equipment Qualification (EQ) Maintenance Program," Revision 15, August 11, 1985

1025.007, "EQ Listed Equipment's Approved Lubricants," Revision 3, August 6, 1987

1025.017, "Lubrication Changeout Procedure," Revision 0, October 14, 1987

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