U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-219/85-28

Docket No. 50-219

License No. DPR-16 Priority --- Category C

Licensee: GPU Nuclear Corporation

Oyster Creek Nuclear Generating Station

P. O. Box 388

Forked River, New Jersey 08731

Facility Name: Oyster Creek Nuclear Generating Station

Inspection At: Forked River, New Jersey

Inspection Conducted: September 23-27, 1985

Inspectors: S. V. Pullani

S. V. Pullani, Lead Reactor Engineer 11-05-85 date

Approved by: C J Anderson

C. J. Anderson, Chief, 11/5/85 date
Plant Systems Section

Inspection Summary: Inspection on September 23-27, 1985 (Report No. 50-219/85-28)

Areas Inspected: Special announced inspection of: (1) followup of Unit Substation Transformers 1A2 and 1B2 low oil level event on August 9, 1985 and (2) implementation of the Fire Protection/Prevention Program. The second area inspected included followup of previous inspection findings; equipment maintenance, inspection and tests; fire brigade training; periodic inspections and quality assurance audits; and facility tour. The inspection involved 48 inspector-hours on site and 18 inspector-hours in office by one region based inspector.

Results: Of the two areas inspected, no violations were identified. One item remained unresolved at the end of inspection (see Section 2.5.2 of this report, for details).

DETAILS

1.0 Persons Contacted

1.1 GPU Nuclear Corporation (GPU)

K. Barnes, Licensing Engineer
*J. DeBlasio, Manager-Support Engineering
A. Dickinson, Supervisor-Electrical Engineering
P. Fiedler, Vice President and Director
T. Gaffney, Electrical/I&C Material Manager
D. Holland, Licensing Manager
*D. Jones, Plant Engineering
R. Kilian, Plant Engineering
D. Pino, Electrical Engineer
T. Prosser, Fire Protection Instructor
T. Quintenz, Manager-Maintenance Engineering
D. Ranft, Electrical Engineering Manager, Technical Functions
G. Simonetti, QA Audit Manager
*W. Smith, Plant Engineering Director
*K. Zimmerman, Fire Protection Coordinator

1.2 General Electric (GE)

E. Hritzo, Manager-Nuclear Plant Services, King of Prussia Office (By Telephone)

1.3 Nuclear Regulatory Commission (NRC)

W. Bateman, Senior Resident Inspector
J. Wechselberger, Resident Inspector

*Denotes those present at the exit interview.

2.0 Followup of Unit Substation Transformers 1A2 and 1B2 Low Oil Level Event

2.1 Summary

As a result of licensee preventive maintenance testing using an infrared scanning method for potential hot spots on switchgear connections, two 4160/480 Volt unit substation transformers 1A2 and 1B2 which supply redundant 480 Volt vital loads were found to have insufficient cooling oil. Both transformers were declared inoperable at 1800 hours on August 9, 1985. An orderly shutdown of the plant was initiated and the reactor was placed in cold shutdown in accordance with the Technical Specifications. Sufficient oil was added to the transformers to establish proper cooling and the plant was returned to power on August 10, 1985 without incident.

2.2 Plant Electrical Power System

To provide a better understanding of the function of these two transformers in the overall Plant Electrical Power System, and the event itself, a brief description of the Plant Electrical Power System is given below. (see FSAR Chapter 8 for a detailed description). The Plant Electrical Power System consists of an Offsite Power System and an Onsite Power System and is shown in Attachment 1.

2.2.1 Offsite Power System

The unit output power is normally connected to the Jersey Central Power and Light Company (JCP&L) grid via the 230 kV Oyster Creek substation. Two sources of offsite power are provided via two separate startup transformers fed from the 34.5 kV Oyster Creek substation. Power is supplied to the 34.5 kV Oyster Creek substation from the 34.5 kV JCP&L transmission system and the 230 kV Oyster Creek substation. The 230 kV Oyster Creek substation receives power from the unit itself, and from the 230 kV JCP&L transmission system.

2.2.2 Onsite Power System

The Onsite Power System consists of a non-Class IE system and two redundant Class IE (safety related) systems. The Onsite Power System consists of an ac power distribution system (4.16kV, 480/277V, 120/208V), a vital distribution system (120 V ac uninterruptible), and a 125 V dc power distribution system.

The normal source for both the non-Class IE and class IE distribution systems is the turbine generator, which feeds the Station Auxiliary Transformer through the generator isolated phase bus. The preferred power supply for the distribution systems during startup, shutdown, abnormal or accident conditions is the Startup Transformers, which are fed from the JCP&L transmission system via the 34.5 kV Oyster Creek substation.

Two separate and independent Emergency Diesel Generators are provided as the redundant onsite standby power supplies for safety related equipment.

2.2.3 480 Volt Distribution System

This is a subsystem of the Onsite Power system described in Sections 2.2.2 above. Unit substations are provided to step down the 4.16 kV system voltage to 480 Volts to supply the 480 Volt Distribution System. All the unit substations are fed from the 4.16 kV essential switchgear Bus Sections 1C and 1D, and in turn supply power to the motor control centers and motors throughout the station.

There are six unit substations, as shown in Attachment 2. The unit substations are identified, located in pairs, and generally provide power to station auxiliaries as follows:

- Unit Substations 1A1 and 1B1, in the Turbine Building basement, for Turbine Building loads (Non-essential)
- Unit Substations 1A2 and 1B2, in the 480 Volt Switchgear Room, for Reactor Building loads (Essential)
- Unit Substations 1A3 and 1B3, at the Intake Structure, for auxiliaries outside the plant in the vicinity of the Intake Structure (Non-essential)

Transformers 1A2 and 1B2 which feed the essential Unit Substations 1A2 and 1B2 and which are the subject of the event, are further described in Section 2.2.5 below. Transformers 1A1, 1B1, 1A3, and 1B3 which feed the respective non-essential unit substations are similar to the essential transformers except that they are of lower kVA rating.

2.2.4 Unit Substations 1A2 and 1B2

Unit Substations 1A2 and 1B2 supply power to the essential (vital) loads in the Reactor Building. Attachment 2 shows the connected loads on these unit substations. The loads shown in Attachment 3 (FSAR Table 8.3-1) are those emergency loads which are required to operate in case of a Loss of Coolant Accident (LOCA), Loss of Offsite Power (LOOP), and/or Single Failure consideration as shown.

2.2.5 Unit Substation Transformers 1A2 and 1B2

Transformers 1A2 and 1B2 are rated 2000 kVA, 3 phase, 4160-480V/277V, Delta-Star with solidly grounded neutral, class OA (Oil to Air, Self Cooled). The transformers are located indoors, in the 480 Volt Room in the Reactor Building. The transformers are filled with Pyranol which contains a large fraction of polychlorinated biphenyl (PCB). Because of its good fire resistance, heat transfer and electrical insulating properties, PCB containing Pyranol had been used for indoor applications such as 1A2 and 1B2.

These transformers are made by General Electric, Model F957245B. They are described in their Instruction Manual GEI-65074B, Secondary Unit Substation Transformers - Liquid Filled. The transformers were believed to be shipped liquid-filled, with approximately 225 gallons of oil. The top of the oil is normally maintained at a positive pressure with dry nitrogen to prevent intrusion of moisture.

Attachment 4 shows the front view of the model. The transformer consists of a rectangular tank of welded construction with a relief valve, tap changer attachment, and a vent plug on the top of the tank, and 206 cooling fin tubes (103 fins on both sides arranged in 13x8 array). A liquid level gauge, liquid temperature indicator, and a pressure-vacuum gauge are provided to monitor the condition of the transformer during operation. Attachment 5 shows the instrumentation.

The transformers are rated for a 65°C rise over an ambient of 30°C. The nominal liquid level at 25°C is 10.5 inches below the reference point which is 0.25 inches above the top of the tank (See Attachment 6). The nominal nitrogen pressure is approximately 2-3 psig. The relief valve is set to relieve the nitrogen pressure if it exceeds 5 psig.

2.3 Description of the Event

2.3.1 Plant Conditions Prior to the Event

The reactor was operating at a thermal power of 1981 MWt with the reactor mode switch in RUN position. The turbine generator was on line producing approximately 622 MWe of electric power.

2.3.2 Details of the Event

Thermographic photographs were taken of the 1A2 and 1B2 transformers on June 21, 1985 by Asplundh Infrared Services, licensee's contractor. These transformers were not in the scope of the original thermographic survey which was planned for identification of potential hot spots in the switchgear connections. The thermographic photograph was taken incidentally on 1B2 transformer which indicated that a problem might exist with the 1B2 transformer. The photograph was evaluated on July 12, 1985 which indicated a minor degradation of 1B2 transformer cooling capability. The 1A2 transformer also was subsequently surveyed which also indicated a similar condition. The licensee evaluated the degraded condition of the transformers and determined that it would not prevent the transformers from performing their safety function.

To better define the problem and to determine a means to restore the transformers to their full rating, the licensee contacted General Electric, the transformer manufacturer, to survey the transformers with special thermographic equipment and take oil samples to determine if the cooling fin tubes were plugged due to sludging. General Electric conducted the survey on August 7, 1985. It showed that at normal loads limited oil flow was occurring. A decision was made to perform a load test on 1A2 to determine if the condition was sludging or low oil level.

The 1A2 transformer was chosen because thermographic photographs indicated that it had less oil flow in its fin tubes than 1B2. The load test on 1A2 was conducted on August 8, 1985. During the test, it was noticed that the liquid temperature gauge located on a top fin tube header did not move from the 32°C mark. The tank temperature was 76.1°C, as measured with a contact pyrometer. Prior to the test, 32 out of a total of 206 tubes had flow; and after the test, an additional 64 tubes had flow (see Attachment 7). This indicated that, at higher loading of the transformer with resultant heating and volume increase of the oil, more tubes received flow of oil.

On August 9, 1985, a review of the above test results and other available information indicated that, due to low liquid level in both transformers, their cooling capability had been degraded. The transformers were declared inoperable at 1800 hours on August 9, 1985. Since the transformers should not be filled while energized, it was decided to shutdown the plant to add transformer oil. An orderly shutdown of the plant was initiated and performed in accordance with the plant Technical Specifications.

2.3.3 Apparent Cause of the Event

The apparent cause of the event was insufficient oil in the fin tubes. As a result of variable tube heights as the tubes extend into the fin tube headers, and the headers not being completely full of oil, flow of oil would not necessarily occur in all fin tubes. The licensee's investigations indicate that this condition has existed since the original plant installation. This is based on the following reasoning.

During the subsequent filling operation, the licensee measured the actual transformer oil levels and temperatures and back-calculated the equivalent levels at 25°C based on the name plate data of 0.39 inches rise in level/10°C rise. The calculated levels at 25°C were 11.63 inches and 11.42 inches for 1A2 and 1B2, respectively, below the top of the tank (See Reference 15). These values are equivalent to 11.88 and 11.67 inches below the GE reference level shown in Attachment 6. These levels are 1.38 and 1.17 inches less than the nominal value of of 10.5 inches below the reference level. The above as-found levels are also insufficient to establish natural convection flow through all tubes at normal operating temperatures, as evidenced during the event. As discussed below, the amount of oil withdrawn from the transformers as test samples does not account for the low level condition. Apparently this condition existed since the original plant installation.

The licensee estimates that approximately five quarts of oil samples could have been taken since the transformer installation. However, there was no accurate records of the volume of oil withdrawn as samples. The only record available was for a 500 milli-liter (approximately 1/8 gallon) sample taken on December 6, 1982 (Reference 18). The licensee's estimate of the sample volume does not account for the insufficient as-found oil levels. Furthermore, there was no apparent indication of leakage on or around the transformers. The transformer manufacturer did not have a record of the liquid level when it was shipped to the site, approximately 16-17 years ago. Because of the inadequacy of records, it could not be positively determined if the transformers were installed with insufficient oil or if excessive oil was lost during the operation because of sampling or other reasons.

Some problems with instrumentation were discovered during the licensee's investigation. The liquid temperature indicator on the 1A2 transformer did not give an accurate reading of the oil temperature. This also contributed to the event in that the instrument was not accurately indicating the status of the transformer. The temperature indicator is installed in a cooling fin tube header. To display an accurate liquid temperature reading, its sensor must be submerged in the transformer oil. This particular cooling fin tube header was one of those that did not receive any oil flow as a result of the low oil level. During licensee testing of the vital transformer, a portable pyrometer was used to measure the oil temperature. Once the oil flow in the cooling fin with the installed temperature device was established, the pyrometer and installed temperature sensor compared favorably. With the newly established higher levels in the transformers, this problem will not exist because the sensors of the liquid level indicators will be submerged in oil all the time.

Another instrument problem was the liquidlevel gauge. The accuracy of the level gauge required to sense small level changes in the transformer cooling headers is critical. The present level gauge may not have the required accuracy to indicate these small level changes in the cooling header to the extent that an operator could determine the onset of cooling degradation. In addition, the level indicator is not graduated to show the normal levels at various temperatures. It shows an acceptable range of level with minimum and maximum levels, the center point being the nominal level at 25°C (see Attachment 5). With the newly established higher levels in the transformers, the licensee plans to recalibrate the liquid level gauges to provide an accurate indication of the expected levels at various operating temperatures, or alternatively, provide a table or chart so that the operator can immediately determine if the levels are within acceptable limits.

In addition to the insufficient oil levels in both transformers, 1A2 transformer installation was off-level by 1/2 inch vertically over the width of the transformer (approximately 8-feet). This was the reason one side of the 1A2 transformer had significantly more tubes having flow than on the other side, as observed during the thermographic observations (See Attachment 7). However, the contribution to the event by this condition is determined to be less significant than those discussed previously.

2.3.4 Safety Evaluation of the Event

Technical Specifications require that the reactor be placed in a cold shutdown condition, if the availability of power falls below that required by specification 3.7.A. Due to low fluid level, the cooling capability of both of these redundant vital transformers was degraded. A single transformer failure would result in the necessary LOCA loads being supplied through one transformer. Under certain conditions (see discussion below), this would result in an overload situation. This design deficiency was previously reported in LER 85-09, 480 Volt USS Overload, dated June 14, 1985.

LER 85-09 resulted from an electrical overload study performed by the licensee (Reference 6). The study indicated that the 480 Volt Unit Substations 1A2 and 1B2 may be overloaded during a LOCA without a LOOP and concurrent loss of one unit substation. Without a LOOP, the non-essential loads will not get an undervoltage trip and will continue to run until manually tripped. Therefore, this is the worst case overload scenario. The cause of this deficiency has been determined to be the combination of both a design problem and the impact of plant modifications resulting in increased bus loading. If the unit substations are run in the anticipated overload condition, it will result in decreased transformer life.

A Standing Order (Reference 7) has been written, instructing Control Room personnel to monitor the loads on USS 1A2 and USS 1B2 after a LOCA, to shed unnecessary loads if amps drawn are too high, and to initiate automatic load shedding by transferring the buses to the diesel generators if manual shedding of loads is not sufficient to reduce transformer overload. This Standing Order will remain in effect until long term modifications to correct the overload problems are complete.

Long term actions to eliminate USS 1A2 and 1B2 transformer overload problem include:

1. Addition of fans to the transformers for USS 1A2 and 1B2 which will increase their capacity by 15% and bring the anticipated worst case loading within the rating of all the USS components.

2. Addition of an overcurrent alarm to the ammeter circuits for USS 1A2 and 1B2 in the Control Room.

The licensee committed to complete action item 1 during the April 1986 refueling outage (11R) and action item 2 during the October 1985 mini-outage (10M). Further, the licensee committed to strictly control the addition of further loads on the essential buses and update the load study periodically.

2.4 Reporting of the Event

The details of the transformer event are reported in LER 85-14, Unit Substation Transformers 1A2 and 1B2 Low Oil, dated September 11, 1985

2.5 Corrective Actions

2.5.1 Immediate Corrective Actions

The immediate corrective action taken was to initiate an orderly plant shutdown and then add oil to unit substation transformers 1A2 and 1B2. Sixteen (16) gallons of transformer oil were added to the 1A2 transformer. Twelve (12) gallons of transformer oil were added to the 1B2 transformer. After the oil was added, thermographic photographs were taken which verified that all cooling fins in both transformers had proper oil flow. The four (4) non-essential unit substation transformers at the site (1A1, 1A3, 1B1, and 1B2) were also tested and found to be in satisfactory condition.

The final levels in 1A2 and 1B2 transformers were 8.25 inches at 44°C and 8.875 inches at 46°C below the General Electric reference point. These values when corrected to 25°C, work out to be 8.99 inches and 9.69 respectively compared to 10.25 inches nominal level indicated on the transformer name plate. Therefore, the final levels in 1A2 and 1B2 transformers at 25°C were 1.51 and 0.80 inches above the nominal level. At the newly established final levels, the top fin tube headers will be covered and the transformers will have convection cooling flow through all fins at all operating temperatures. The licensee has requested General Electric to review the adequacy of the newly established levels and their cooling problem in general (References 14 and 15).

2.5.2 Long Term Corrective Actions

Long term corrective actions will include:

1. Periodic thermographic testing of the six (6) oil filled transformers on redundant plant buses; and

2. Obtain information and issue guidance for the sampling and filling of these transformers, and issue procedures where required.

With respect to item 1, the licensee committed to perform the thermographic testing every refueling outage. However, the licensee is taking credit for the recent thermographic tests and are not planning to do such tests during the April 1986 refueling outage.

Item 2 involves development of sampling and filling procedures and guidances. This item also includes the recalibration of the liquid level gauges to provide proper operator guidance on its use. The licensee committed to complete this item by the end of the April 1986 refueling outage.

The completion of items 1 and 2 should solve the level problem. Once the modifications discussed in Section 2.3.4 of this report are implemented, the transformer overload problem under the postulated emergency conditions will also be solved. The transformers would then be capable of supporting the postulated emergency loads.

The licensee's corrective actions and commitments discussed in Sections 2.3.4 and 2.5.2 will be followed up in a future inspection. This is an unresolved item pending completion of the above licensee actions and its review by NRC (50-219/85-28-01).

2.6 Conclusion

The licensee's corrective actions were adequate; when fully implemented will prevent the recurrence of the problem.

3.0 Fire Protection/Preventive Program Implementation

The inspector reviewed several documents in the following areas of the program to verify that the licensee had adequately implemented the program consistent with the Fire Hazard Analysis (FHA), Final Safety Analysis Report (FSAR), and Technical Specifications (TS). The documents reviewed, the scope of review, and the inspection findings for each area of the program are described in the following sections.

3.1 Followup of Previous Inspection Findings

(Closed) Unresolved Items (50-219/84-21-01) Lack of Procedure for Surveillance Testing and Inspections of Fire Dampers

The licensee developed a procedure 645.6.026, Fire Damper Functional Test, Revision 0, for surveillance testing and inspection of safety related fire dampers. The inspector reviewed the procedure for technical adequacy and found it acceptable.

This item is resolved.

(Closed) Deviation (50-219/84-21-02) Penetration in the Southwest Stairwell of the Reactor Building Allows Smoke Infiltration

On July 25, 1984, the licensee issued work request No. 19976 to seal the duct penetration noted in the deviation. The penetration was sealed on July 29, 1984 to prevent smoke infiltrations into the Reactor Building stairwell. The licensee has also initiated a preventive maintenance check sheet to visually inspect all stairwells for unsealed penetrations and through the wall cracks as committed in their letter dated September 23, 1985. This completes all corrective actions committed in the licensee response letter dated December 11, 1984. The inspector reviewed all corrective actions and found them acceptable.

This item is closed.

3.2 Equipment Maintenance, Inspection and Tests

The inspector reviewed the following randomly selected documents to determine whether the licensee had developed adequate procedures which established maintenance, inspection, and testing requirements for the plant fire protection equipment:

- Surveillance Test Procedure 645.4.001, Fire Pump Operability Test, Revision 0*
- Surveillance Test Procedure 645.4.018, Fire Pump Insurance Test, Revision 10*
- Surveillance Test Procedure 645.6.012, Fire Pump Functional Test, Revision 5*
- Surveillance Test Procedure 645.6.013, Fire Suppression Halon System Functional Test, Revision 4*
- Surveillance Test Procedure 645.6.016, Fire Suppression Low Pressure CO_2 System Functional Test, Revision 2*

- Surveillance Test Procedure 645.6.026, Fire Damper Functional Test, Revision 0

In addition to reviewing the above documents, the inspector reviewed the maintenance/inspection/test records of the items identified by an asterisk (*) to verify compliance with Technical Specifications and established procedures.

No unacceptable conditions were identified.

3.3 Fire Brigade Training

3.3.1 Procedure Review

The inspector reviewed the following licensee procedures:

- Procedure 101.2, Fire Protection Organization Responsibilities and Controls, Revision 7.

- Oyster Creek Fire Protection Program Manual

- Procedure 1780.0, Fire Brigade Training, September 22, 1983

- Safety Evaluation Report by NRR, November 13, 1979 and its Supplements 1, 2, and 3.

The scope of review was to verify that the licensee had developed administrative procedures which included:

a. Requirements for announced and unannounced drills;

b. Requirements for fire brigade training and retraining at prescribed frequencies;

c. Requirements for local fire department coordination and training; and

d. Requirements for maintenance of training records.

No unacceptable conditions were identified.

3.3.2 Records Review

The inspector reviewed randomly selected training records of randomly selected fire brigade members for calendar years 1984 and 1985 to ascertain that they had successfully completed the required quarterly training/meetings, annual fire brigade drills, and triennial hands-on fire extinguishment practice.

No unacceptable conditions were identified.

3.4 Periodic Inspections and Quality Assurance Audits

3 ' 1 Annual Audit

The inspector reviewed the reports of the following annual audits:

- S-OC-84-19 performed on September 7-15, 1984

- S-OC-85-09, performed on June 14-July 19, 1985

The scope of review was to verify that the audits were performed in accordance with TS 6.5.3.2.a. and the audit findings were being resolved in a timely and satisfactory manner.

No unacceptable conditions were identified.

3.4.2 Biennial Audit

The inspector reviewed the report of the following audits:

- S-OC-83-08, performed on October 19-28, 1983

- S-OC-85-09, performed on June 14-July 19, 1985

The scope of review was to verify that the audits were performed in accordance with TS 6.5.3.1.f. and th audit findings were being resolved in a timely and satisfactory manner.

No unacceptable conditions were identified.

3.4.3 Triennial Audit

Prior to January 1984, the licensee was not required to perform a triennial audit of their fire protection and loss prevention program by an outside qualified fire consultant. F cense amendment 69 dated January 12, 1984, Technical Spe cation 6.5.3.2.b, the licensee is required to perform suc audit at intervals no greater than 3 years. The licensee's st such audit is scheduled to be conducted during the fall o 1986.

No unacceptable conditions were identified.

3.5 Facility Tour

The inspector examined fire protection water systems, including fire water piping and distribution systems, post indicator valves, hydrants and contents of hose houses. The inspector toured accessible vital and nonvital plant areas and examined fire detection and alarm systems, automatic and manual fixed suppression systems, interior hose stations, fire barrier penetration seals, and fire doors. The inspector observed general plant housekeeping conditions and randomly checked tags of portable extinguishers for evidence of periodic inspections. No deterioration of equipment was noted.

No unacceptable conditions were identified.

4.0 Unresolved Items

Unresolved items are matters about which more information is required to ascertain whether they are acceptable items, violations or deviations. An unresolved item disclosed during the inspection is discussed in Section 2.5.2.

5.0 Exit Interview

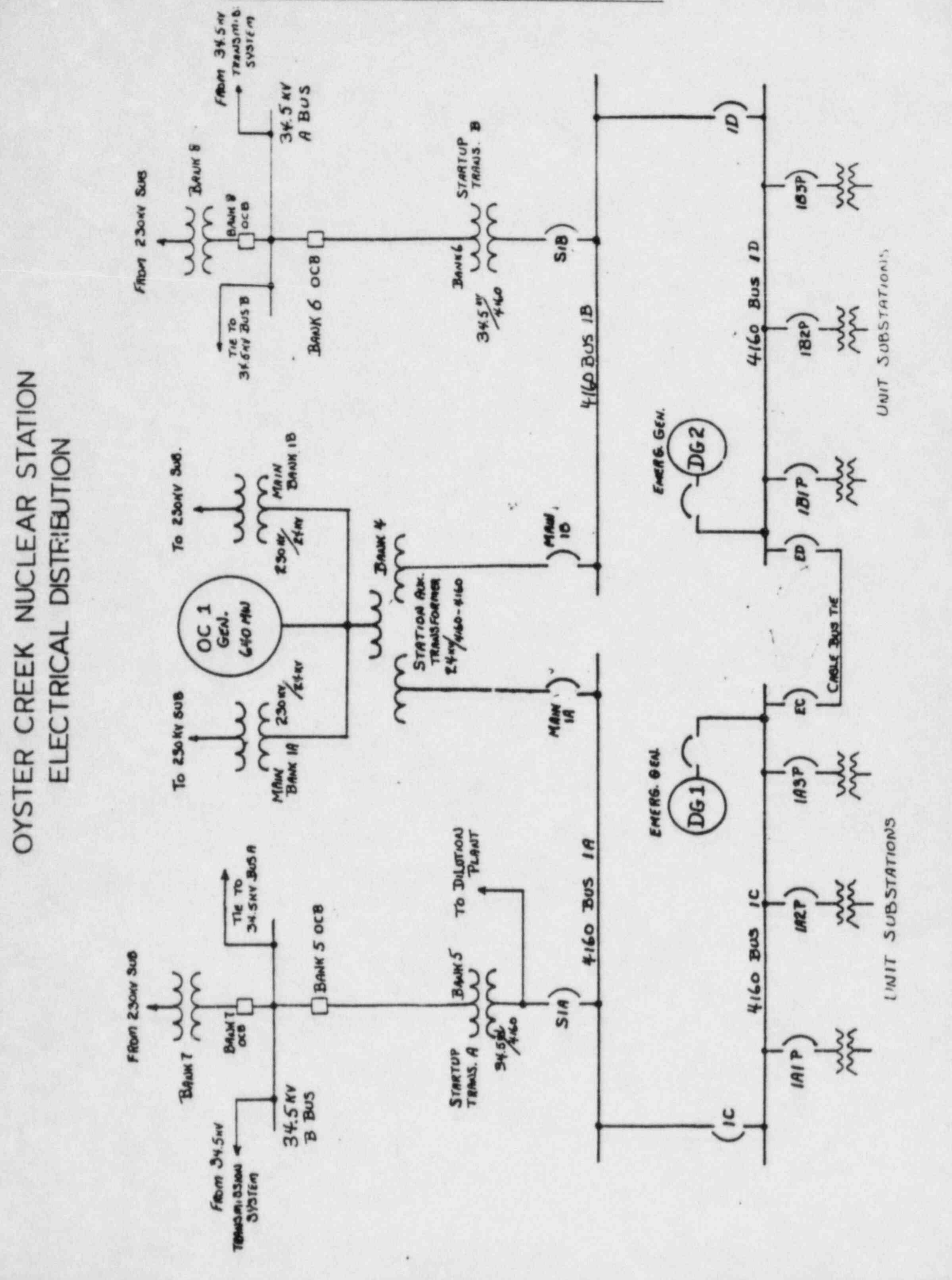
The inspector met with licensee management representatives (see Section 1.0 for attendees) at the conclusion of the inspection on September 27, 1985. The inspector summarized the scope and findings of the inspection at that time.

The inspector and the licensee discussed the contents of this inspection report to ascertain that it did not contain any proprietary information. The licensee agreed that the inspection report may be placed in the Public Document Room without prior licensee review for proprietary information (10 CFR 2.790).

At no time during this inspection was written material provided to the licensee by the inspector.

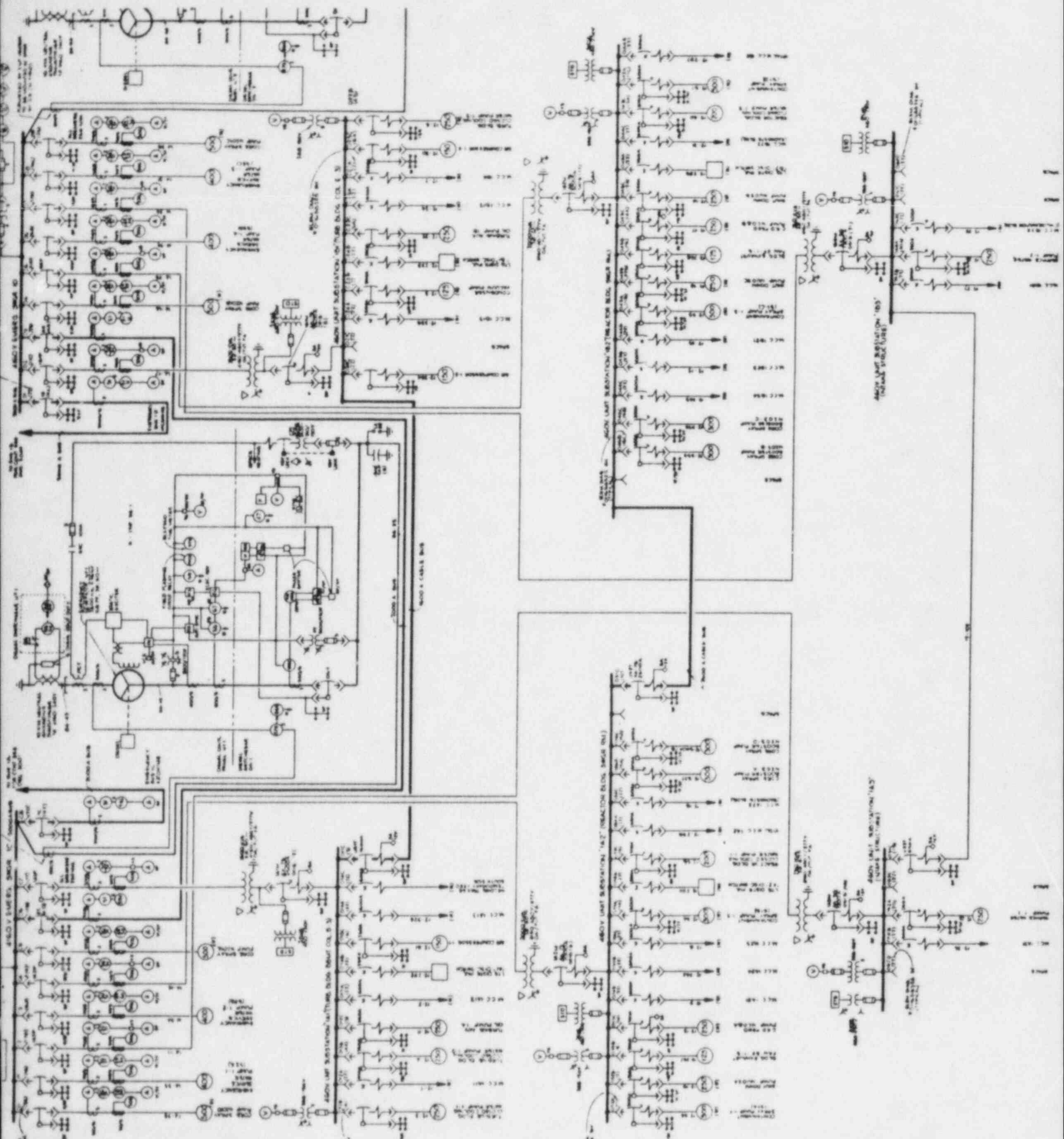
ATTACHMENT 1

SIMPLIFIED SKETCH OF PLANT ELECTRICAL SYSTEM



ATTACHMENT 2

UNIT SUBSTATIONS 1A1, 1A2, 1A3, 1B1, 1B2, and 1B2 AND CONNECTED LOADS



OCNGS
FSAR UPDATE

TABLE 8.3-1
(Sheet 1 of 1)

EMERGENCY BUSES AUTOMATIC LOADING SCHEDULE

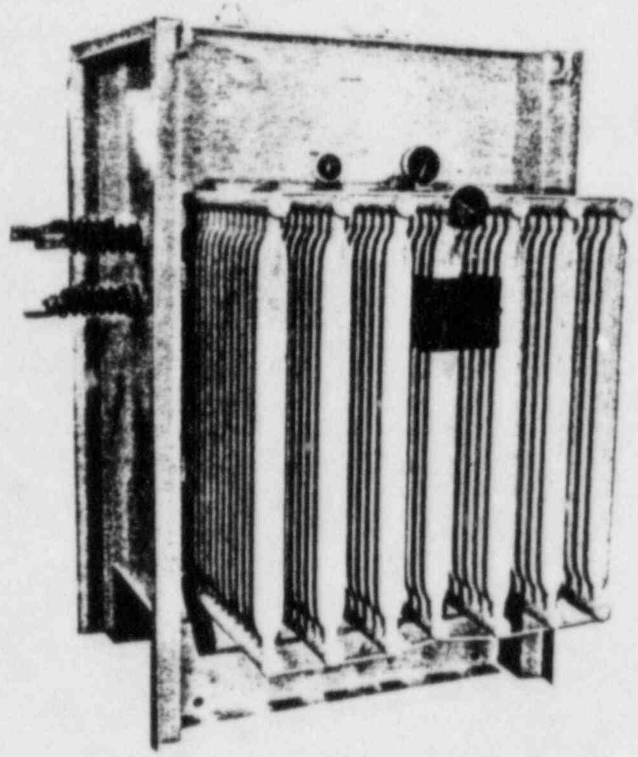
Loads	Time Delay (sec)	LOOP* Bus 1C (hp)	LOOP* Bus 1D (hp)	LOOP + LOCA* Bus 1C (hp)	LOOP + LOCA* Bus 1D (hp)	LOOP + LOCA + Single Failure Bus 1C or 1D (hp)
Isolation valves (load not included since it is too brief to add to peak load)	0	-	-	-	-	-
Lighting, Instrumentation and Controls, Ventilation, Security, Battery Chargers, miscellaneous small motors and transformer losses.	0	45	440	45	440	45 (440)
Containment Spray Pump	40	-	-	300	300	300
Emergency Service Water Pump	45	-	-	400	400	400
Control Rod Drive Feed Pump	60	250	250	250	250	250
Core Spray Pump	0**	-	-	500	500	1000
Core Spray Booster Pump	5	-	-	300	300	600
Service Water Pump	120	250	250	-	-	-
Reactor Building Closed Water Pump	166	200	200	-	-	-

* LOOP - Loss of Offsite Power, LOCA-Loss-of-Coolant Accident

** Immediately, however injection will begin when Reactor Coolant System pressure drops below the cperational range of the system.

ATTACHMENT 3

ATTACHMENT 4
FRONT VIEW OF TRANSFORMER



<u>ATTACHMENT 5</u>
<u>TRANSFORMER INSTRUMENTATION</u>

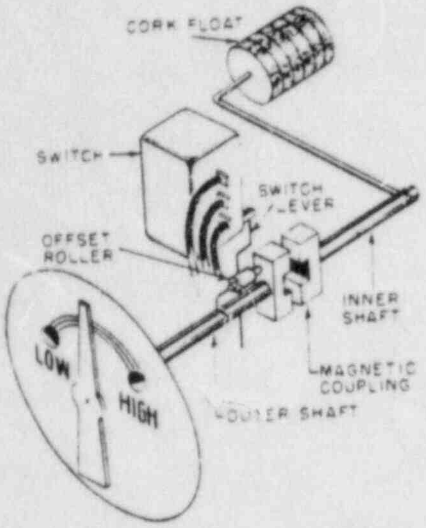


Fig. 1. Schematic view of magnetic liquid-level gage with alarm switch

Fig. 2. Type AL liquid temperature indicator

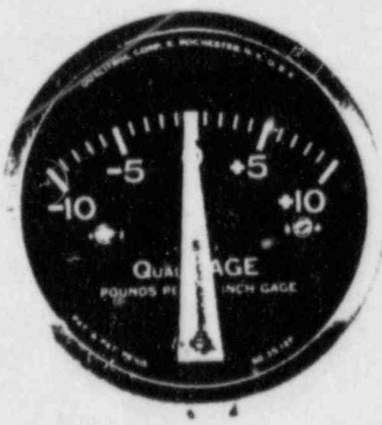
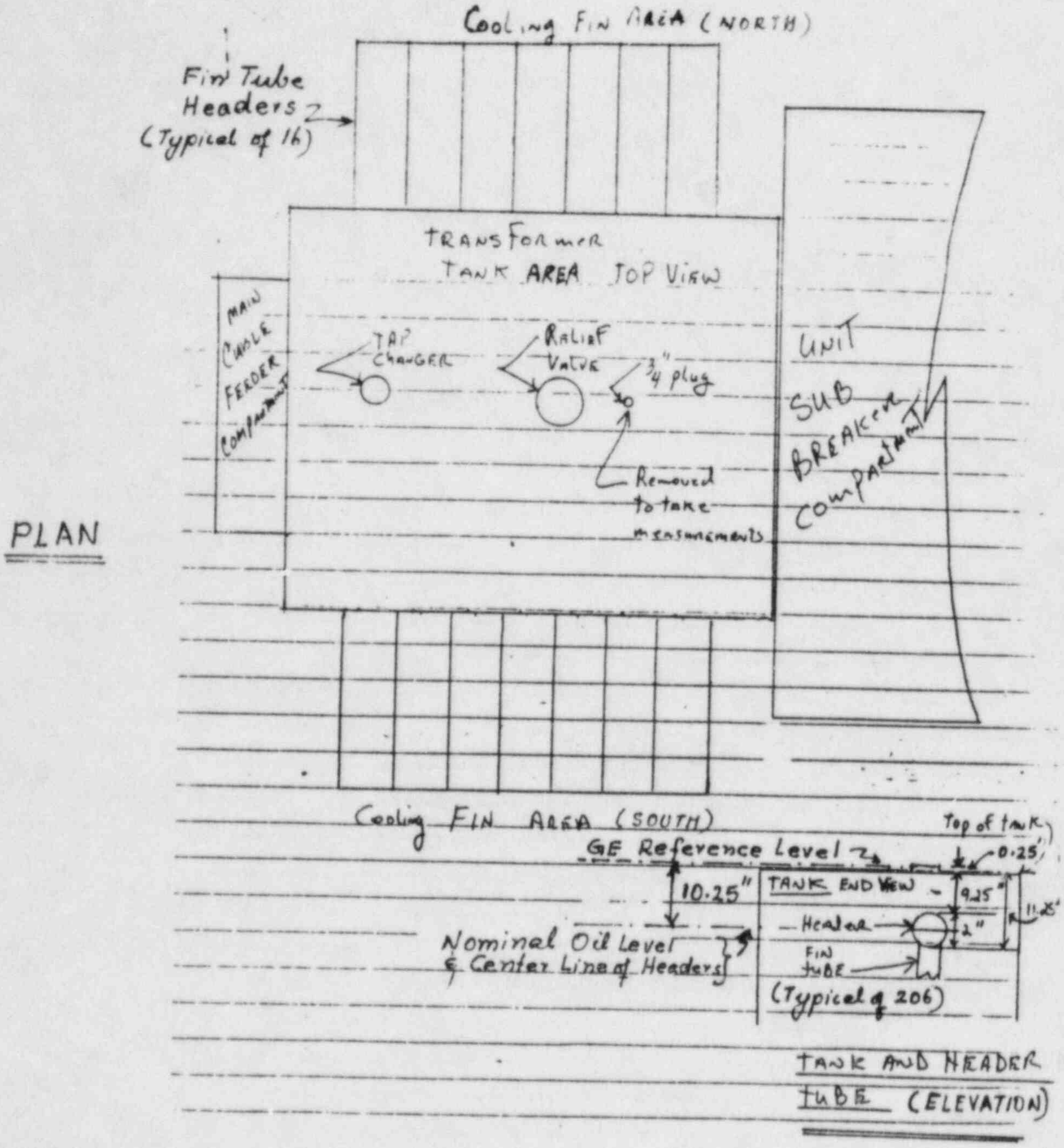


Fig. 3. Pressure-vacuum gage

ATTACHMENT 6

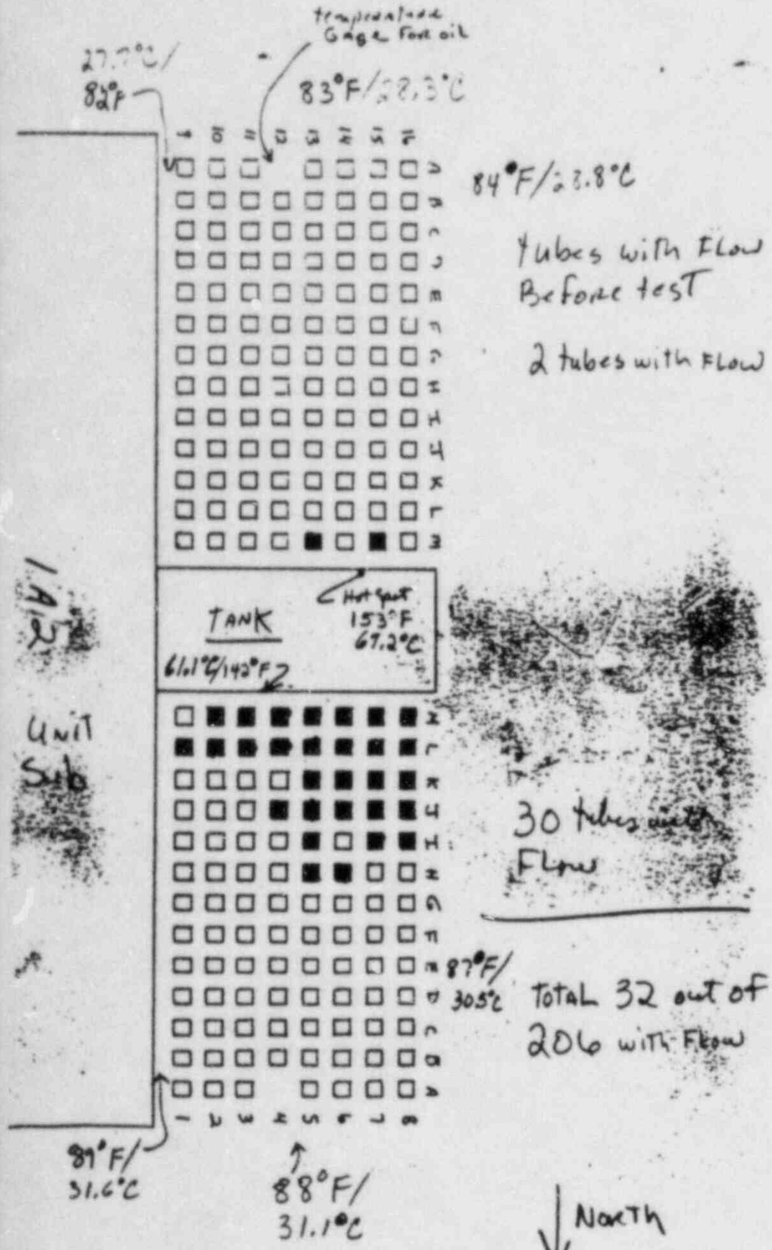
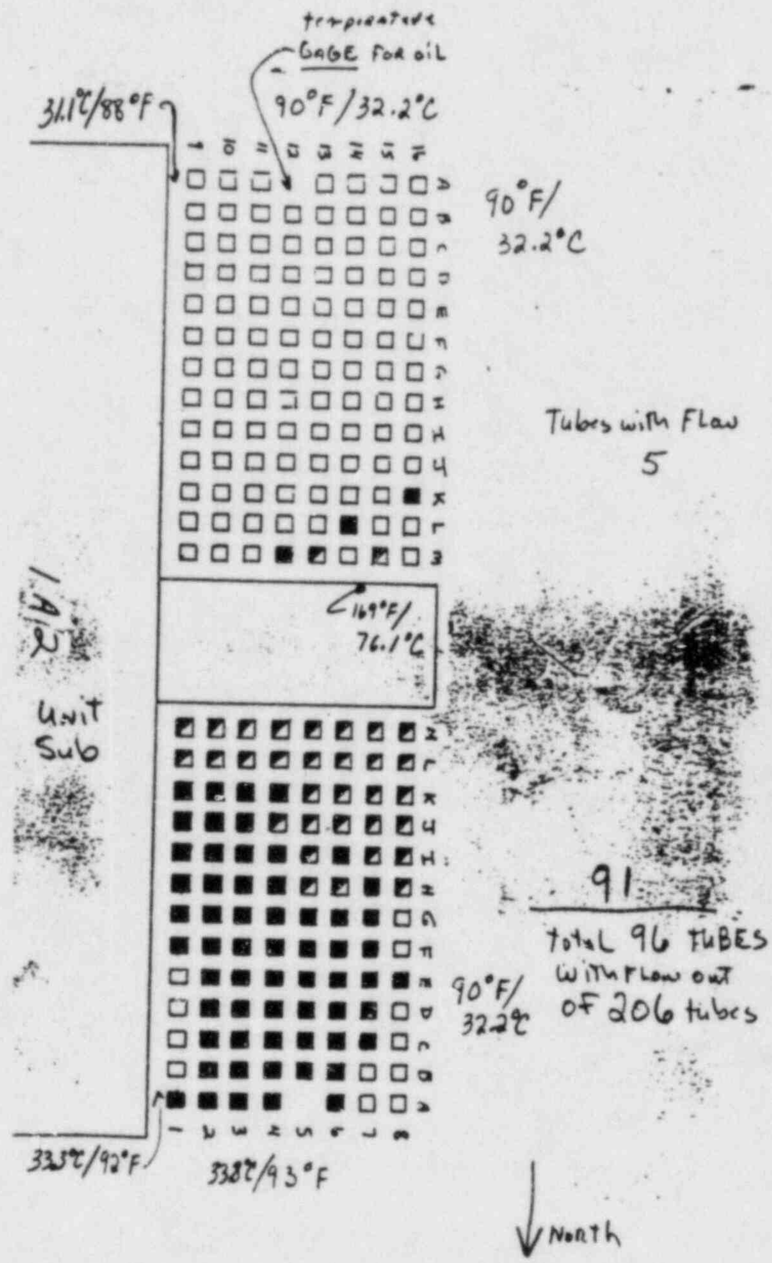
SKETCH OF TRANSFORMER SHOWING THE NOMINAL OIL LEVEL



ATTACHMENT 7

SKETCH OF FIN TUBES SHOWING FLOW

BEFORE AND DURING LOAD TEST ON 1A2

BEFORE	AFTER
	

ATTACHMENT 8
THERMOGRAMS OF 1B2 SHOWING OIL FLOW BEFORE, DURING, AND AFTER FILLING

Figure 1. Normal Photograph

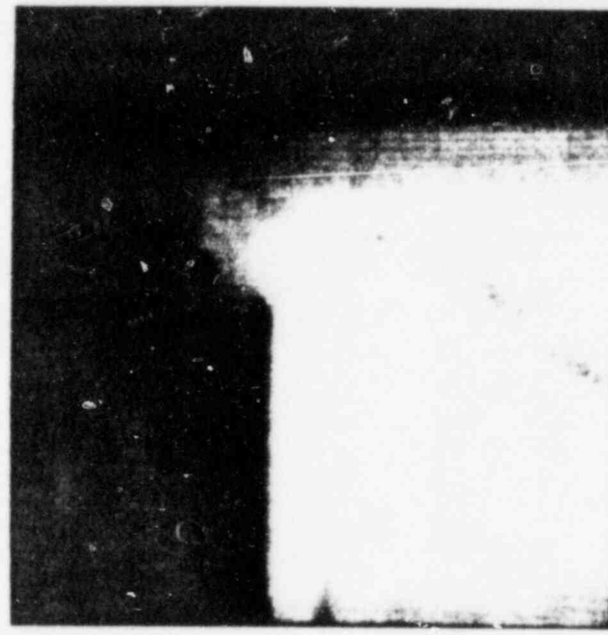


Figure 2. Thermogram (Before)

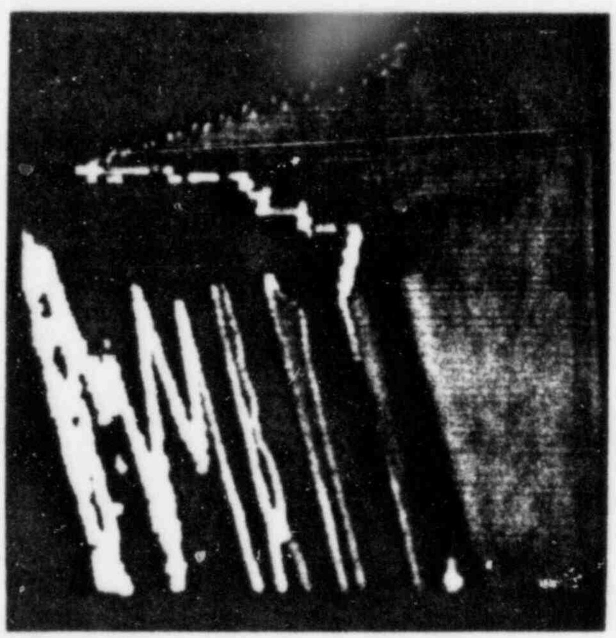


Figure 3. Thermogram (During)

Figure 4. Thermogram (After)

Explanatory Note: Figure 1 is a normal photograph of south side cooling fins of 1B2. Figures 2, 3, and 4 are thermograms of the same before, during, and after filling. Dark area in Figure 2 indicates lack of flow in the left side tubes. Figure 3 shows partial establishment of flow in these tubes during filling. Figure 4 shows the flow fully established.

ATTACHMENT 9
REFERENCES

1. Licensee Event Report (LER) 85-009, 480 Volt USS Overload, June 14, 1985.

2. LER 85-014, Unit Substation Transformers 1A2 and 1B2 Low Oil Level, September 11, 1985.

3. Oyster Creek FSAR Section 8.3, Onsite Power Systems, Revision 0, December 1984

4. General Electric Instruction GEI-65074B, Secondary Unit Substation Transformers.

5. Oyster Creek Technical Specifications, Section 3.7, Auxiliary Electrical Power

6. Oyster Creek Load Study (Draft).

7. Standing Order 37, Overload of USS 1A2 and USS 1B2 during LOCA without Loss of Offsite Power, Revision 0, June 21, 1985.

8. Preventive Maintenance Check Sheet (PM No. 1316), Record Temperatures and Load on Transformers 1A1, 1A2, 1A3, 1B1, 1B2, and 1B3.

9. Thermographic Survey Photographs taken on June 21, 1985 by Asplundh Infrared Services.

10. Licensee Internal Memorandum dated June 11, 1985, from M. Filippone, Plant Engineering to R. Chisholm, Manager-Electrical Power and Instrumentation, Subject: 460V Unit Substation 1A2 and 1B2 Transformers Cooling Fins.

11. Licensee Internal Memorandum dated August 9, 1985 from R. Chisholm, Manager-Electrical Power and Instrumentation and D. Ranft, Electrical Power Manager to W. Smith, Plant Engineering Director.

12. General Electric Report dated August 8, 1985 on their Thermographic Survey of Transformers 1A2 and 1B2 conducted on August 7, 1985.

13. General Electric Report dated August 28, 1985 on the Inspection of Transformers 1A2 and 1B2.

14. GPU letter to GE dated September 4, 1985, A. Dickinson to E. Hritzo requesting information on the transformers related to the event described in LER 85-014.

15. GPU letter to GE dated September 19, 1985, A. Dickinson to E. Hritzo, requesting additional information on the transformers related to the event described in LER 85-104.

16. Plant Engineering Department Incident Critique dated August 20, 1985.

17. S.D. Myers, J. J. Kelly and R. H. Parrish, A Guide to Transformer Maintenance, Published by Transformer Maintenance Institute.

18. Job Order No. 82-0097 dated December 6, 1982 for taking 500 milli-liter of oil from Transformer 1A1, 1A2, 1A3, 1B1, 1B2, and 1B3.

19. Resident Inspector's Inspection Report 50-219/85-23, Section 11, 480 Volt Unit Substation Transformer Low Oil Level.