U. S. NUCLEAR REGULATORY COMMISSION

REGION I

050272-860414
050272-860425
050272-860512
050311-860416
050311-860502

Report Nos. 50-272/86-15
50-311/86-15

Docket Nos. 50-272
50-311

License Nos. DPR-70
DPR-75

Licensee: Public Service Electric and Gas Company
80 Park Plaza
Newark, New Jersey 07101

Facility Name: Salem Nuclear Generating Station - Units 1 and 2

Inspection At: Hancocks Bridge, New Jersey

Inspection Conducted: May 13, 1986 - June 16, 1986

Inspectors: T. J. Kenny, Senior Resident Inspector

Reviewed by: Kathy Halvey Gibson 6·26·86
K. H. Gibson, Reactor Engineer date
Reactor Projects Section No. 2B, DRP

Approved by: L J Norrholm 6/27/86
L. J. Norrholm, Chief, Reactor Projects date
Section No. 2B, Projects Branch No. 2, DRP

Inspection Summary:
Inspections on May 13, 1986 - June 16, 1986 (Combined Report Numbers 50-272/86-15 and 50-311/86-15)

Areas Inspected: Routine inspections of plant operations including: followup on outstanding inspection items, operational safety verification, maintenance, surveillance, review of special reports, licensee event followup, and review of Radiological Environmental Monitoring Program. The inspection involved 116 inspector hours by the resident and by region based NRC inspectors.

Results: No violations were identified by this inspection. One inspector follow item has been opened to review the determined cause of the No. 12 Auxiliary Feedwater Pump breaker failing to close.

DETAILS

1. Persons Contacted

   Within this report period, interviews and discussions were conducted with members of licensee management and staff as necessary to support inspection activity.

2. Followup on Outstanding Inspection Items

   (Closed) Unresolved Item (272/83-25-01) The inspector's concern was the inconsistencies found on the Master Equipment List (MEL) in that certain sections had an additional column dealing with Commercial Catalogue Items (CCI). However, no discrepancies were found with the safety classification of identical components within the system. Some of the CCI classifications appeared questionable. The licensee has completed a review of the MEL and has removed the column dealing with CCI to avoid the confusion. This item is closed.

   (Closed) Inspector Follow Item (311/83-37-01) This item was the result of the Loss of Residual Heat Removal system flow during the transfer of 2A vital instrument bus power supply from the inverter to the solatron. The licensee has reviewed the events and has issued revised procedures to perform the transfer. No similar incidents have occurred since the use of the new procedures. This item is closed.

   (Closed) Unresolved Item (311/84-08-03) This item was closed for Unit 1 in Inspection Report 84-32. The same work practices with regard to bezel covers and system tag outs apply in Unit 2 and this item is therefore closed.

   (Closed) Violation (272/84-47-04) This item was issued when a worker became contaminated on his neck and hair and the incident was not recorded in the TN Log as required by procedure. The licensee responded in a letter March 12, 1985, and has issued Radiation Protection Procedure RP1.027 "Handling of Contaminated Personnel", which clarifies the method of decontaminating and recording the incidents. No incidents of this nature have occurred since RP1.027 has been implemented. This item is closed.

   (Closed) Inspector Follow Item (272/85-07-03; 311/85-07-04) Broken bolts were found on the injector blocks on two diesel generators. An engineering analysis indicated that fatigue caused the failure. The licensee also conducted an evaluation that indicated that the threaded portion of the broken bolts were engaged in the plate that covers the injector. This was contrary to design and led to the fatigue of the bolts. All the bolts have been adjusted so that the threads are only in the base metal of the diesel and the threads are not engaged in the plate. No similar events have occurred since the correction was made. The inspector considers this item closed.

3. Operational Safety Verification

3.1 Documents Reviewed

- Selected Operators' Logs
- Senior Shift Supervisor's (SSS) Log
- Jumper Log
- Radioactive Waste Release Permits (liquid & gaseous)
- Selected Radiation Exposure Permits (REP)
- Selected Chemistry Logs
- Selected Tagouts
- Health Physics Watch Log

3.2 The inspector conducted routine entries into the protected areas of the plants, including the control rooms, Auxiliary Building, fuel buildings, and containments (when access is possible). During the inspection activities, discussions were held with operators, technicians (HP & I&C), mechanics, supervisors, and plant management. The purpose of the inspection was to affirm the licensee's commitments and compliance with 10 CFR, Technical Specifications, and Administrative Procedures.

(1) On a daily basis, particular attention was directed to the following areas:

- Instrumentation and recorder traces for abnormalities;
- Adherence to LCO's directly observable from the control room;
- Proper control room shift manning and access control;
- Verification of the status of control room annunciators that are in alarm;
- Proper use of procedures;
- Review of logs to obtain plant conditions; and,
- Verification of surveillance testing for timely completion.

(2) On a weekly basis, the inspector confirmed the operability of selected ESF trains by:

- Verifying that accessible valves in the flow path were in the correct positions;
- Verifying that power supplies and breakers were in the correct positions;

- Verifying that de-energized portions of these systems were de-energized as identified by Technical Specifications;

- Visually inspecting major components for leakage, lubrication, vibration, cooling water supply, and general operating conditions; and,

- Visually inspecting instrumentation, where possible, for proper operability.

(3) On a biweekly basis, the inspector:

- Verified the correct application of a tagout to a safety-related system;

- Observed a shift turnover;

- Reviewed the sampling program including the liquid and gaseous effluents;

- Verified that radiation protection and controls were properly established;

- Verified that the physical security plan was being implemented;

- Reviewed licensee-identified problem areas; and,

- Verified selected portions of containment isolation lineup.

3.3 Inspector Comments/Findings:

The inspector selected phases of the units operation to determine compliance with the NRC's regulations. The inspector determined that the areas inspected and the licensee's actions did not constitute a health and safety hazard to the public or plant personnel. The following are noteworthy areas the inspector researched in depth:

1. Unit 1

a. This report period began with the unit in Mode 3 following the unit trip from 95% power due to low feedwater flow and level in No. 14 Steam Generator. The trip occurred when both main feed pumps were lost due to a limit switch on the common recirculation valve (BF-65) going off its closed position. The switch, part of a trip demand circuit will trip both main feed pumps when not in the closed position. The actuating device was found deformed and tied shut with nylon line (which had broken). This had previously been installed in order to hold the switch in the closed position. (See Section 7 for additional details) At 2:07 p.m. on May 13, the unit returned to power.

b. At 5:23 p.m. on June 4, the licensee identified a 130 gpm leak to containment as monitored by the waste hold up tank level. An investigation by the licensee identified fan cooler leaks on No. 11 and No. 12 fan cooler units. No. 11 had a blown plug in the copper nickel line (the major source of the leak) and No. 12 had a flange leak (gasket). The units were isolated and notification was made via ENS in accordance with the Emergency Classification Guide and 10 CFR 50.72b. The unit remained at 100% power and repairs were made. The fan cooler units were returned to service within the time period allowed within the action statement of Technical Specifications. The licensee is conducting an investigation into the reason for the leaks and will report to the NRC in a special report. The inspector will review the report when issued.

c. At 2:40 p.m. on June 6, the unit tripped from 100% power when the Auxiliary Transformer Differential Protection Relay (ATDPR) actuated the generator protection system causing a turbine/reactor trip.

At 4:37 p.m. on June 7, the unit returned to power, restricted to 90% because one condensate pump and one circulating water pump were not started due to limited loading of Station Service transformers No. 11 and No. 12. An engineering study is being performed to determine electrical loadings of the Station Service transformers.

The licensee has investigated the cause of the ATDPR actuation and has determined that an internal connection of the 4KV section of the transformer had shorted. The reason at this writing is unknown. The licensee is in the process of removing the transformer to return it to Westinghouse for repair.

d. At 4:11 p.m. on June 12, the reactor tripped from 90% power due to feed flow/steam flow mismatch with a low level in No. 13 Steam Generator signal. The cause was attributed to a wetted PC Board in 15C feedwater heater control cabinet (located outside) which caused a false high level signal in 15C feedwater heater and closed valve 13CN27 which stops feedwater flow through a series of heat exchangers. This caused a low suction pressure in No. 11 feedwater pump, which tripped, causing the steam flow/feed flow mismatch. The event occurred during a severe thunder and lighting storm with heavy rains. The cabinet had been opened slightly to accommodate test leads that were installed to perform load reject testing on the unit following the last refueling.

During the trip the No. 12 auxiliary feedwater pump did not start; however, No. 11 and No. 13 pumps provided the necessary feedwater to the steam generators. The reason for the No. 12 auxiliary feedwater pump not starting appears to be a misalignment of the cam, ratchet and roller assembly such that the breaker will not latch in the closed position on every closure. The breaker will close with a close signal but will not latch closed and therefore opens and sets up the anti- pump feature (which prevents multiple closures on a continuous signal). The licensee is sending the breaker to the vendor for analysis and rebuilding. The item will remain open until the inspector can review the vendor's analysis. (272/86-15-01) The inspector also had discussions about the open cabinets. The licensee has stated that measures will be taken to seal the cabinets if any further testing is required. The inspector also witnessed the changing of degraded gaskets for outside cabinets.

e. At 3:34 p.m. on June 13, the unit was synchronized to the grid and at 3:41 p.m. on June 13, the unit tripped during the shifting of lube oil coolers when an oil pressure spike caused a momentary dip in lube oil pressure. The operators were swapping the coolers, in accordance with the procedure, because the throttling valve (11ST33) for No. 11 lube oil cooler had failed in the closed position. During the shifting of the coolers, the emergency bearing oil pump started, indicating the pressure dipped low enough to start the pump. The licensee performed subsequent testing of the lube oil cooler by repetitive shifting. However, they were unable to duplicate the low pressure surge. It is believed that a slug of air was present during the transfer which caused the initial spike in pressure. The licensee is continuing to assess the event.

2. Unit 2

a. Unit 2 operated at 100% power throughout the inspection with the exception of minor power reductions to facilitate surveillance testing.

4. Maintenance Observations

The inspector reviewed the following safety related maintenance activities to verify that repairs were made in accordance with approved procedures and in compliance with NRC regulations and recognized codes and standards. The inspector also verified that the replacement parts and Quality Control utilized on the repairs were in compliance with the licensee's QA program.

Work Order Number	Description
86-05-06-015-8	Preventative Maintenance Procedure M3T

The procedure tested the undervoltage setpoint and time responses for the Group and Vital Busses and also tested underfrequency setpoint and time responses for the same busses. The busses tested were 1A, 1B, 1C, 1E, 1F, 1G and 1H. The satisfactory testing of these busses satisfied the requirements of Technical Specification 4.3.1.1.1 and 4.3.2.1.1.

86-06-12-046-4	Troubleshooting of No. 12 Auxiliary Feedwater Pump Breaker
86-06-16-007-5	Replacement of No. 12 Auxiliary Feedwater Pump Breaker

The above work requests were performed to establish why the No. 12 Auxiliary Feedwater Pump breaker failed to close during the reactor trip of June 12, 1986. The work performed, which included testing by the factory representative, concluded that there was a misalignment of the cam, ratchet and roller assembly which aids in holding the breaker shut when the breaker closes. The licensee is sending the breaker off site and as previously stated the inspector will follow up on the results.

86-02-27-063-1	Visual inspection and time testing of No. 12 Auxiliary Feedwater Pump Breaker

This work order directed the inspection, rebuilding and testing of the breaker which was performed as part of the 5 year inspection program for breakers. The results of these tests and maintenance were all satisfactory.

No violations were identified.

5. Surveillance Observations

During this inspection period, the inspector reviewed in-progress surveillance testing as well as completed surveillance packages. The inspector verified that the surveillances were performed in accordance with licensee approved procedures and NRC regulations. The inspector also verified that the instruments used were within calibration tolerances and that qualified technicians performed the surveillances.

The following surveillances were reviewed:

Unit 1

SP(O)4.7.4.1a	Service Water Valve line-up. Verifies Service water valve line-up in accordance with Technical Specifications.
PD-4.2.003	1-R5 Channel functional test for Fuel Building.

Proves operability of Radiation Monitoring System for the Fuel Building.

Unit 2

SP(O)4.1.2.5a	Borated Water Sources Check. Demonstrates Technical Specifications 4.1.2.6a and 4.5.5a for Refueling Water Storage Tank, Boric Acid Tanks and Channel Check for Boric Acid Tanks.
SP(O)4.0.5-P-CC (21)(22)(23)	Inservice Testing of Component Cooling. Verifies operability of Nos. 21, 22, and 23 Component Cooling Pumps in accordance with Technical Specification 4.0.5.
SP(O)4.6.2.3a	Containment Systems - Cooling System. Verifies operability of the Fan Cooler Units in accordance with Technical Specification 4.6.2.3a and service water flow verification for Nos. 21, 22, 23 and 24 Fan Cooler Units.

No violations were identified.

6. Review of Periodic and Special Reports

Upon receipt, the inspector reviewed periodic and special reports. The review included the following: inclusion of information required by the NRC; test results and/or supporting information consistent with design predictions and performance specifications; planned corrective action for resolution of problems, and reportability and validity of report information. The following periodic reports were reviewed:

- Unit 1 Monthly Operating Report - April and May 1986
- Unit 2 Monthly Operating Report - April and May 1986

No violations were identified.

7. Licensee Event Report Followup

The inspector reviewed the following LERs to determine that reportability requirements were fulfilled, immediate corrective action was taken, and corrective action to prevent recurrence had been accomplished in accordance with Technical Specifications.

Unit 1

86-008 Not All of the Required Valves Were Listed in the Valve Position Verification Surveillances

This LER was issued when the licensee performed a routine review of the service water system surveillance procedure SP(O)4.7.4.a (which verifies valves that are not locked, sealed or otherwise secured in position) and identified additional valves that should be added to the procedure. In addition, the licensee also reviewed surveillances for containment integrity, auxiliary feedwater, emergency core cooling and boron injection flow path. Several more valves were identified. The valves were originally thought, by the licensee, to be verified by the normal operation of the serviced equipment. But a further review by the Plant Betterment Department has identified and added the valves to the appropriate surveillance. The inspector considers the LER closed.

86-009 Oxygen Content of Waste Gas Decay Tanks Exceeded Allowable Limits

This LER was issued when the required concentration of oxygen as required by Technical Specification (<2%) was exceeded. The identified concentrations were 3.10% and 2.14% in No. 11 and No. 13 waste gas decay tanks respectively. The systems were purged and brought back to specifications. However, the time required to perform the evolution was exceeded (48 hours). The cause has been attributed to procedural error which did not require the Reactor Coolant Drain Tank (RCDT) to be purged of oxygen following the fuel transfer canal draining operation. The unit was in a cold shutdown condition. Operating Instructions have been amended to ensure that the RCDT is properly purged following the draining of the refueling cavity. This issue is considered closed.

86-010 Reactor Trip From 95% Due to the Loss of Both Steam Generator Feedwater Pumps

This LER was issued when the unit tripped due to an interlock to trip the main feed pumps being tied down to prevent operation (this event was reported in Inspection Report 86-11/86-11). The inspector stated that licensee actions would be addressed in this LER review. The licensee identified the following as a result of their investigation.

- Failure to correct long standing design deficiency in a timely manner.

- Failure to control the disabling of an interlock in accordance with established procedures.

The following corrective actions have been taken by the licensee.

- The licensee began discussions with operators and maintenance personnel to identify any other devices being used within the plant that would prevent the fulfillment of a safety system. To date none have been identified.

- A discussion of the event was included in the Operation's Newsletter.

- A letter from the Station Manager strongly expressing concern by management over the matter accompanied by the LER was distributed to each employee in their pay envelope.

- The event is being presented in the training program.

The inspector considers this item closed.

Unit 2

86-002 Reactor Trip/Turbine Trip 50% - No. 23 S/G High-High Level

This LER identifies a reactor trip that occurred on April 16, 1986, which was discussed in Inspection Report 86-11/86-11. The inspector has no further questions and considers this item closed.

86-003 Reactor Trip/Safety Injection From 5% During Controlled Shutdown

This LER identifies a reactor trip that occurred on May 2, 1986, which was discussed in Inspection Report 86-11/86-11. The inspector has no further questions and considers this item closed.

No violations were identified.

8. Radiological Environmental Monitoring Program

The inspector reviewed the licensee's Radiological Environmental Monitoring Program annual report for 1985. This report summarizes the results of the sampling and analyses of environmental media to determine the radiological impact of station operations. These environmental media include air, water, vegetation, and aquatic plants and animals. In addition, direct radiation is monitored by placement of thermoluminescent dosimeters at various locations around the station.

As a result of this review, the inspector determined that the licensee has generally complied with its Technical Specification requirements for sampling frequencies, types of measurements, analytical sensitivities, and reporting schedules. Exceptions to the sampling and analysis program were adequately explained, e.g., low air sample volume due to a malfunction of the sampling mechanism. The report included summaries of the laboratory quality assurance program and the land use survey.

The analyses of environmental samples indicated that doses to humans from radionuclides of station origin were negligible.

9. Exit Interview

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

50-272 Superseded Per Revision 5 to UFSAR dtd [redacted] #8607290251
Revised 8/5/86 [illegible]

SALEM GENERATING STATION
UPDATED FSAR

LIST OF CURRENT PAGES AS OF JULY 22, 1985

FROM	TO	REV	FROM	TO	REV	FROM	TO	REV
i	iv	1	3.2-2	-	3	3.10-1	3.10-5	0
v	-	3	3.2-3	3.2-8	0	3.11-1	-	1
vi	ix	1	3.3-1	3.3-2	0	3.11-2	3.11-4	0
x	-	3	3.4-1	-	3	3A-1	-	3
xi	xvii	1	3.4-2	3.4-6	0	3A-2	-	0
xviii	-	3	3.5-1	3.5-3	0	3A-3	3A-6	1
xix	xxi	1	3.5-4	-	1	3A-7	3A-7A	3
xxii	xxiii	4	3.5-5	3.5-10	0	3A-8	3A-9	1
1-i	1-iii	0	3.5-11	-	3	3A-10	-	0
1.0-1	1.0-2	0	3.5-12	3.5-16	0	3A-11	3A-13	1
1.1-1	1.1-3	0	3.5-17	3.5-17a	3	3A-14	-	0
1.2-1	1.2-8	0	3.5-18	3.5-21	0	3A-15	-	1
1.3-1	1.3-2	1	3.6-1	3.6-6	0	3A-16	3A-21	0
1.4-1	1.4-4	0	3.6-7	-	0	3A-22	-	1
1.5-1	1.5-46	0	3.6-8	-	3	3A-23	3A-36	0
2-i	2-iii	0	3.6-9	3.6-15	0	3A-37	-	1
2-iv	-	4	3.6-16	-	4	3A-38	-	3
2-v	2-vi	0	3.6-17	3.6-28	0	3A-39	-	0
2-vii	-	3	3.6-29	-	4	3A-40	3A-41	1
2-viii	2-ix	0	3.6-30	3.6-32	0	3A-42	3A-51	0
2.1-1	-	1	3.6-33	3.6-35	4	3A-52	3A-54	1
2.1-2	2.1-28	0	3.6-36	-	3	3A-55	-	0
2.2-1	2.2-10	0	3.6-37	3.6-42	0	4-i	4-iii	0
2.2-11	-	4	3.6-43	-	3	4-iv	-	1
2.2-12	2.2-15	0	3.6-44	3.6-45	0	4-v	4-x	0
2.3-1	-	1	3.6-46	-	3	4.1-1	4.1-4	0
2.3-2	-	0	3.6-47	-	0	4.2-1	4.2-82	0
2.3-3	2.3-4	1	3.6-48	-	3	4.3-1	4.3-62	0
2.3-5	-	0	3.6-49	3.6-54	0	4.4-1	4.4-36	0
2.3-6	-	1	3.6A-1	3.6A-2	0	4.4-37	-	1
2.3-7	-	0	3.7-1	3.7-27	0	4.4-38	4.4-64	0
2.3-8	2.3-8A	3	3.7-28	-	3	4.4-65	-	1
2.3-9	2.3-11	0	3.7-29	-	0	4.5-1	4.5-2	1
2.3-12	2.3-14	1	3.8-1	3.8-66	0	4.5-2A	4.5-2C	4
2.3A-1	2.3A-66	0	3.8-67	-	4	4.5-3	-	1
2.4-1	2.4-18	0	3.8-68	3.8-74	0	4.5-3A	4.5-3H	4
2.4-19	-	4	3.8-75	-	1	5-i	-	1
2.4-20	2.4-23	0	3.8-76	-	0	5-ii	5-viii	0
2.4-24	-	1	3.8-77	3.8-78	1	5-ix	5-x	4
2.4-25	2.4-27	0	3.8-79	3.8-81	0	5.1-1	5.1-5	0
2.5-1	2.5-20	0	3.9-1	-	3	5.1-6	-	4
3-i	3-vi	0	3.9-2	-	0	5.1-7	5.1-7A	1
3-vii	-	3	3.9-3	3.9-19	0	5.1-8	-	0
3-viii	3-xvii	0	3.9-20	-	4	5.2-1	5.2-67	0
3.1-1	3.1-57	0	3.9-21	-	3	5.2-68	5.2-70	1
3.2-1	-	0	3.9A-1	3.9A-19	0	5.2-71	5.2-73	0

SALEM GENERATING STATION
UPDATED FSAR

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FROM	TO	REV	FROM	TO	REV	FROM	TO	REV
5.3-1	5.3-2	0	6.3-8	-	3	7.6-2	7.6-5	0
5.4-1	5.4-14	0	6.3-9	6.3-11	0	7.6-6	-	3
5.5-1	5.5-25	0	6.3-12	6.3-13	3	7.6-7	-	4
5.5-26	-	4	6.3-14	-	0	7.6-8	-	3
5.5-27	5.5-39	0	6.3-15	6.3-16	3	7.7-1	7.7-8	0
5.5-40	5.5-41	4	6.3-17	6.3-22	0	7.7-9	-	4
5.5-42	-	0	6.3-23	6.3-24	3	7.7-10	7.7-30	0
5.5-43	-	4	6.3-25	6.3-29	0	8-i	8-iii	4
5.5-44	5.5-48	0	6.3-30	-	1	8.1-1	-	4
5.5-49	-	1	6.3-31	6.3-36	0	8.1-2	8.1-4	0
5.5-50	5.5-52	0	6.3-37	-	4	8.1-5	-	4
5.5-53	5.5-54A	1	6.3-38	-	0	8.1-6	8.1-10	0
5.5-55	5.5-56	0	6.3-39	-	1	8.1-11	-	3
5.5-57	5.5-57A	3	6.3-40	6.3-42	0	8.1-12	-	1
5.5-58	5.5-59	0	6.3-43	-	0	8.2-1	8.2-3	4
5.5-60	-	3	6.3-44	-	3	8.2-4	-	0
5.6-1	-	4	6.4-45	-	0	8.3-1	-	0
5.6-2	-	0	6.3-46	-	4	8.3-2	8.3-3	4
5.6-3	-	3	6.3-47	-	3	8.3-4	8.3-5	0
5.6-4	5.6-7	0	6.3-48	6.3-49	0	8.3-6	-	4
5.6-7A	-	4	6.3-50	-	3	8.3-7	8.3-13	0
5.6-8	-	3	6.3-51	6.3-60	0	8.3-14	-	1
6-i	-	3	6.3-61	-	1	8.3-15	8.3-20	0
6-ii	6-vi	0	6.3-62	-	0	9-i	9-ii	1
6-vii	-	4	6.3-63	-	1	9-iii	9-iv	0
6-viii	6-ix	0	6.4-1	6.4-4	0	9-v	-	4
6-x	-	4	7-i	7-ii	3	9-vi	-	1
6.0-1	6.0-2	0	7-iii	7-v	0	9-vii	9-ix	4
6.1-1	6.1-9	0	7-vi	-	3	9.0-1	-	0
6.2-1	6.2-9	0	7-vii	-	0	9.1-1	9.1-1A	1
6.2-10	6.2-10A	3	7.1-1	7.1-1A	1	9.1-2	9.1-3	0
6.2-11	6.2-13	0	7.1-2	-	1	9.1-4	-	1
6.2-14	-	4	7.1-3	7.1-10	0	9.1-5	-	0
6.2-15	6.2-31	0	7.1-11	7.1-13	3	9.1-6	-	4
6.2-32	-	4	7.2-1	7.2-19	0	9.1-7	9.1-15	0
6.2-33	6.2-34	0	7.2-20	-	3	9.1-16	-	3
6.2-35	-	1	7.2-21	7.2-36	0	9.1-17	9.1-23	0
6.2-36	6.2-37	0	7.2-37	7.2-39	3	9.1-24	-	3
6.2-38	-	1	7.3-1	7.3-28	0	9.1-25	9.1-26	1
6.2-39	6.2-59	0	7.3-29	-	1	9.1-27	9.1-33	0
6.2-60	-	1	7.3-30	7.3-33	0	9.1-33A	9.1-34	1
6.2-61	6.2-88	0	7.4-1	7.4-5	0	9.1-35	-	3
6.3-1	6.3-3	0	7.5-1	7.5-9	0	9.1-36	-	0
6.3-4	-	4	7.5-10	7.5-12	3	9.1-37	-	4
6.3-5	-	3	7.5-13	-	0	9.2-1	-	4
6.3-6	6.3-7	0	7.6-1	-	4	9.2-2	9.2-2A	1

SALEM GENERATING STATION
UPDATED FSAR

LIST OF CURRENT PAGES AS OF JULY 22, 1985

FROM	TO	REV	FROM	TO	REV	FROM	TO	REV
9.2-3	-	4	9.4-37	9.4-38	0	11-vii	-	4
9.2-4	-	0	9.4-39	-	4	11.1-1	11.1-4	0
9.2-5	-	4	9.4-40	9.4-41	0	11.1-5	-	1
9.2-6	9.2-7	3	9.4-42	-	4	11.1-6	11.1-7	0
9.2-8	9.2-10	0	9.4-43	-	1	11.1-8	-	1
9.2-11	-	4	9.4-44	9.4-47	0	11:1-9	11.1-12	0
9.2-12	9.2-14	0	9.5-1	-	0	11.2-1	11.2-4	0
9.2-14A	-	1	9.5-2	9.5-15A	4	11.2-5	-	4
9.2-15	-	3	9.5-16	9.5-17	0	11.2-6	11.2-8	0
9.2-16	9.2-27	0	9.5-18	-	1	11.2-9	-	1
9.2-28	-	4	9.5-18A	9.5-18B	3	11.2-10	-	0
9.2-29	9.2-30	0	9.5-19	9.5-27	0	11.2-11	-	4
9.3-1	9.3-3	4	9.5-28	9.5-29	3	11.2-12	-	0
9.3-4	-	3	10-i	10-iv	0	11.2-13	-	4
9.3-5	-	0	10-v	10-vi	4	11.2-14	11.2-15	0
9.3-6	-	4	10.1-1	10.1-2	0	11.2-16	-	1
9.3-7	9.3-8	0	10.2-1	10.2-2	0	11.2-17	-	0
9.3-9	-	4	10.2-3	-	4	11.2-18	-	1
9.3-10	-	0	10.2-4	-	0	11.3-1	11.3-16	0
9.3-11	9.3-12	4	10.2-5	10.2-6	4	11.3-17	-	1
9.3-13	-	0	10.2-7	-	0	11.3-18	-	4
9.3-14	9.3-15	4	10.2-8	-	3	11.3-19	-	0
9.3-16	9.3-19	0	10.2-9	10.2-14	0	11.3-20	11.3-21	1
9.3-20	-	4	10.3-1	-	0	11.4-1	11.4-2	0
9.3-21	9.3-48	0	10.3-2	-	4	11.4-3	11.4-5	1
9.3-49	-	4	10.3-3	10.3-6	0	11.4-6	11.4-7	0
9.3-50	9.3-60	0	10.3-7	10.3-8	4	11.4-8	11.4-10	1
9.3-61	-	4	10.3-9	-	0	11.4-11	-	4
9.3-62	9.3-65	3	10.3-10	-	4	11.4-12	-	0
9.4-1	-	0	10.3-11	10.3-17	0	11.4-13	11.4-15	4
9.4-2	-	4	10.3-18	-	4	11.4-16	-	1
9.4-3	9.4-4	0	10.3-19	-	1	11.4-17	11.4-18	4
9.4-5	-	4	10.3-20	-	0	11.4-19	11.4-20	0
9.4-6	9.4-8	0	10.4-1	-	1	11.4-21	11.4-22	4
9.4-9	-	4	10.4-2	10.4-6	0	11.4-23	11.4-24	0
9.4-10	9.4-16	0	10.4-7	-	4	11.5-1	11.5-3	0
9.4-17	-	4	10.4-8	10.4.10	0	11.5-4	-	3
9.4-18	9.4-20	0	10.4-11	10.4-13	4	11.6-1	11.6-4	1
9.4-21	-	4	10.4-14	10.4-16	0	12-i	12-iii	0
9.4-22	9.4-27	0	10.4-17	-	4	12-iv	-	3
9.4-28	-	1	10.4-18	-	0	12.1-1	-	0
9.4-29	9.4-31	0	10.4-19	10.4-21	1	12.1-2	-	4
9.3-32	-	1	10.4-22	10.4-23	0	12.1-3	12.1-8	0
9.4-33	-	4	10.4-24	10.4-26	4	12.1-9	-	1
9.4-34	9.4-35	0	10.4-27	10.4-28	0	12.1-10	12.1-14	0
9.4-36	9.4-36A	3	11-i	11-vi	0	12.1-15	12.1-18	1

SALEM GENERATING STATION
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LIST OF CURRENT PAGES AS OF JULY 22, 1985

FROM	TO	REV	FROM	TO	REV	FROM	TO	REV
12.2-1	12.2-2	0	15.4-1	15.4-15	0			
12.3-1	12.3-8	1	15.4-15A	15.4-15(0)	1			
13-i	-	3	15.4-16	15.4-26	0			
13-ii	-	1	15.4-27	-	3			
13.1-1	-	0	15.4-28	15.4-42	0			
13.1-2	13.1-4A	1	15.4-43	-	3			
13.1-5	-	0	15.4-44	15.4-94	0			
13.1-6	13.1-9	1	15.4-95	-	4			
13.2-1	-	4	15.4-96	15.4-107	0			
13.3-1	-	1	16-1	-	0			
13.4-1	13.4-2	3	17-i	17-ii	4			
13.5-1	13.5-3	3	17-iii	-	0			
13.6-1	-	1	17-iv	-	1			
13.6-2	13.6-3	0	17.1-1	-	0			
13.7-1	-	1	17.2-1	17.2-34	4			
14-i	-	1	A-i	A-ii	0			
14-ii	14-iv	0	A-iii	-	3			
14.1-1	14.1-2	0	A-iv	-	0			
14.2-1	-	0	A-1	A-5	0			
14.3-1	14.3-5	0	A-6	A-7C	1			
14.4-1	14.4-4	0	A-8	-	0			
14.4-5	14.4-6	1	A-9	-	1			
14.5-1	14.5-9	0	A-10	A-11	0			
14.6-1	14.6-7	0	A-12	-	4			
15-i	15-ii	0	A-13	A-58	0			
15-iii	-	1	A-59	A-60	1			
15-iv	15-vi	0	A-61	A-70	0			
15-vii	15-x	1	A-71	-	1			
15-xi	15-xviii	0	A-72	-	0			
15-xix	15-xx	1	A-73	-	1			
15-xxi	-	0	A-74	A-75	0			
15-xxii	-	1						
15-xxiii	-	0						
15.1-1	15.1-25	0						
15.2-1	15.2-17	0						
15.2-17A	-	1						
15.2-18	15.2-19	1						
15.2-20	15.2-21	0						
15.2-22	15.2-22D	1						
15.2-23	15.2-24	3						
15.2-25	15.2-43	0						
15.2-44	-	4						
15.2-45	15.2-59	0						
15.2-60	-	1						
15.3-1	15.3-21	0						
15.3A-1	-	0						

SALEM GENERATING STATION
UPDATED FSAR

LIST OF CURRENT TABLES AS OF JULY 22, 1985

SALEM GENERATING STATION
UPDATED FSAR

LIST OF CURRENT FIGURES AS JULY 22, 1985

SALEM GENERATING STATION
UPDATED FSAR

LIST OF CURRENT FIGURES AS OF JULY 22, 1985

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14.0 INITIAL TESTS AND OPERATION

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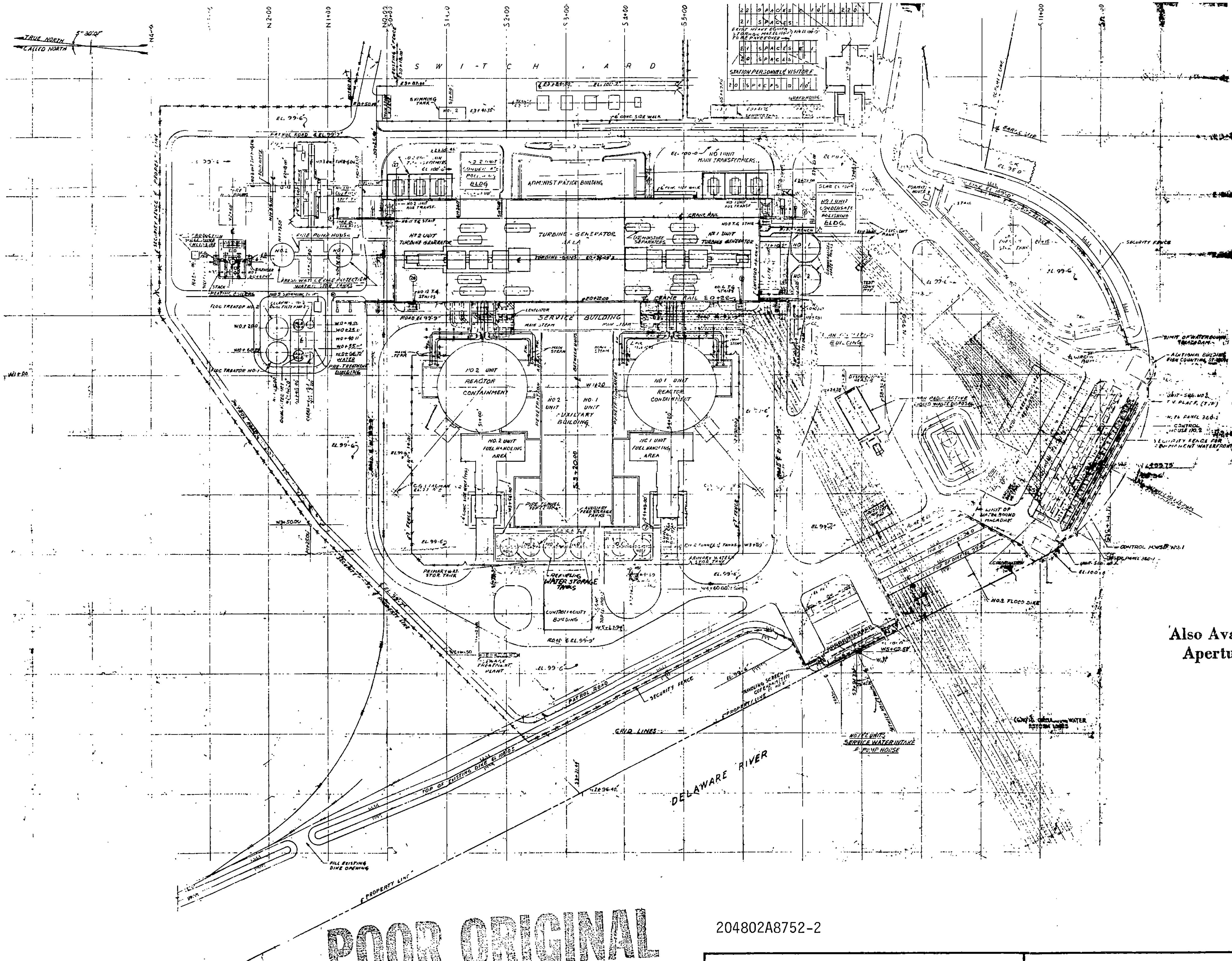

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Revision 3
July 22, 1984

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	General Plot Plan
	UPDATED FSAR FIG 1.2-1

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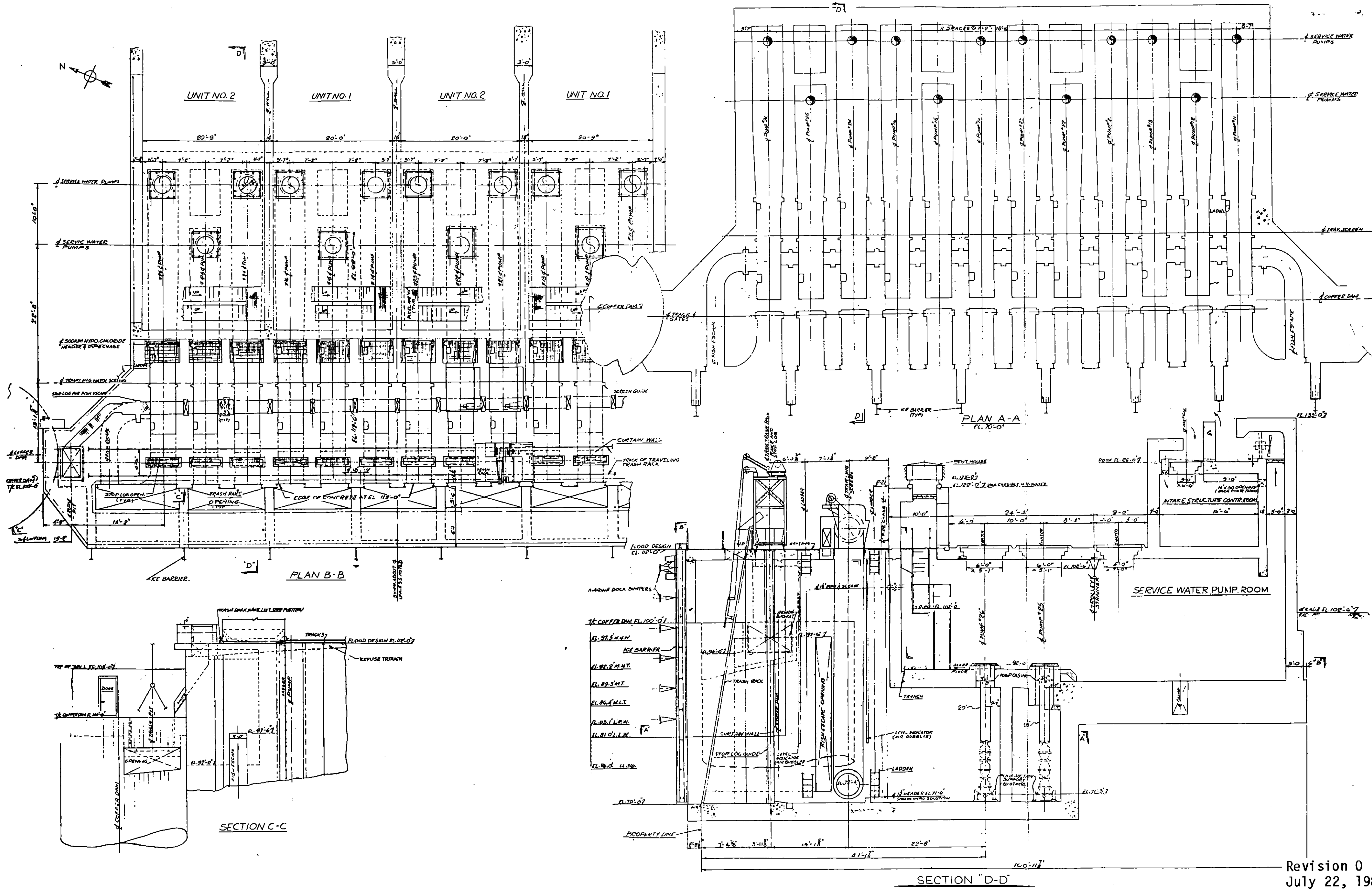


Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Service Water Intake
	Updated FSAR — Figure 2.4-3

Criterion 26 - Separation of Protection and Control Instrumentation Systems

Protection systems shall be separated from control instrumentation systems to the extent that failure or removal from service of any control instrumentation system component or channel, or of those common to control instrumentation and protection circuitry, leaves intact a system satisfying all requirements for the protection channels.

Discussion

Protection and control channels in the facility protection systems are designed in accordance with the IEEE-279, "Proposed IEEE Criteria for Nuclear Power Plant Protection Systems," August 30, 1968.

The coincident trip philosophy is also employed to prevent a single failure from causing a spurious trip or from defeating the function of any channel.

In general reactor trip circuits are designed so that the trip occurs upon deenergization of the circuit; and open circuit or loss of power to a channel will, therefore, result in the channel going into its trip mode. Redundancy within each channel provides reliability and independence of operation. Channel independence is carried throughout the system from the sensor to the relay providing the logic. In some cases, however, it is desirable to employ a common sensor for both a control and protection channel. Both functions are fully isolated in the remainder of the channel, control being derived from the primary safety signal path through an isolation amplifier. As such, a failure in the control circuitry does not adversely affect the safety channel. Those reactor trips requiring energy to trip are arranged such that single power supply failures cannot prevent a trip if required.

Criterion 27 - Protection Against Multiple Disability For Protection Systems

The effects of adverse conditions to which redundant channels or protection systems might be exposed in common, either under normal conditions or those of an accident, shall not result in loss of the protection function.

Discussion

Protection system components are designed and arranged so that the mechanical and thermal environment accompanying any emergency situation in which the components are required to function does not interfere with that function. Details of this protection are provided in the appropriate portions of Chapter 7.

Criterion 28 - Emergency Power for Protection Systems

In the event of loss of all offsite power, sufficient alternate sources of power shall be provided to permit the required functioning of the protection systems.

Discussion

The facility is supplied with normal and emergency power supplies to provide for the required functioning of the protection systems.

Emergency power for each unit is supplied by three emergency diesel generators, as described in Chapters 7 and 8 with two diesels being capable of supplying all the emergency power requirements of one unit.

In addition to the emergency diesel generators, the instrumentation and controls portions of the protection systems may be supplied from the 125 V DC station batteries as detailed in Chapter 8.

13. Control equipment, facilities and lines as required for the above items.

14. Waste Disposal Systems.

    Gas Decay Tanks.

    Compressors.

15. Containment Polar Crane.

16. Auxiliary Feedwater and Service Water Systems (portions).

17. Sampling System Piping (to outermost containment isolation valve).

18. Main Steam System (to isolation valve).

19. Feedwater System (to outermost containment isolation valve).

20. Combustible Gas Control System (partial).

21. Fuel Handling System.

22. Instrumentation and Control Systems required for safe shutdown, including safety-related instrumentation.

23. Electrical cable tunnels.

QA program controls as identified in Section 17.2 are applied, but not limited to, the above Class I Systems, structures and components.

<u>Class II</u>

The following list establishes a general category of Class II items:

1. Pressurizer Relief Tank.

2. Sampling System.

3. Spent Fuel Pool Cooling System.

4. Holdup Tank Transfer Pumps.

5. Evaporator.

6. Evaporator Condensate Demineralizers.

7. Waste Monitor Tanks.

8. Waste Monitor Tank Pumps.

9. Primary Water Storage Tanks.

10. Concentrates Holdup Tank.

Class III

The following list establishes a general category of Class III items:

1. Turbine Generator area structure.

2. Buildings containing conventional facilities.

3. Waste Disposal System (partial).

4. Chemical Mixing Tank.

5. Resin Fill Tank.

3.4 WATER LEVEL (FLOOD) DESIGN

3.4.1 FLOOD ELEVATIONS

Figure 3.4-1 displays the relationship between the Mean Sea Level (MSL) datum, the Public Service Datum (PSD), the plant grade level and water levels for various conditions. The PMH surge level for the site is 113.8 feet PSD as estimated by the Coastal Engineering Research Center.

The highest recorded water level at the site was +8.5 feet MSC in November, 1950. This elevation is referred to as high-high water or HHW. The site grade was established by fill at an elevation of +10.5 feet MSC, or two feet above HHW.

3.4.2 STRUCTURAL LOADINGS

Load combinations and calculations for Category I structures are described in Section 3.8.

3.4.3 FLOOD PROTECTION

3.4.3.1 Hurricane

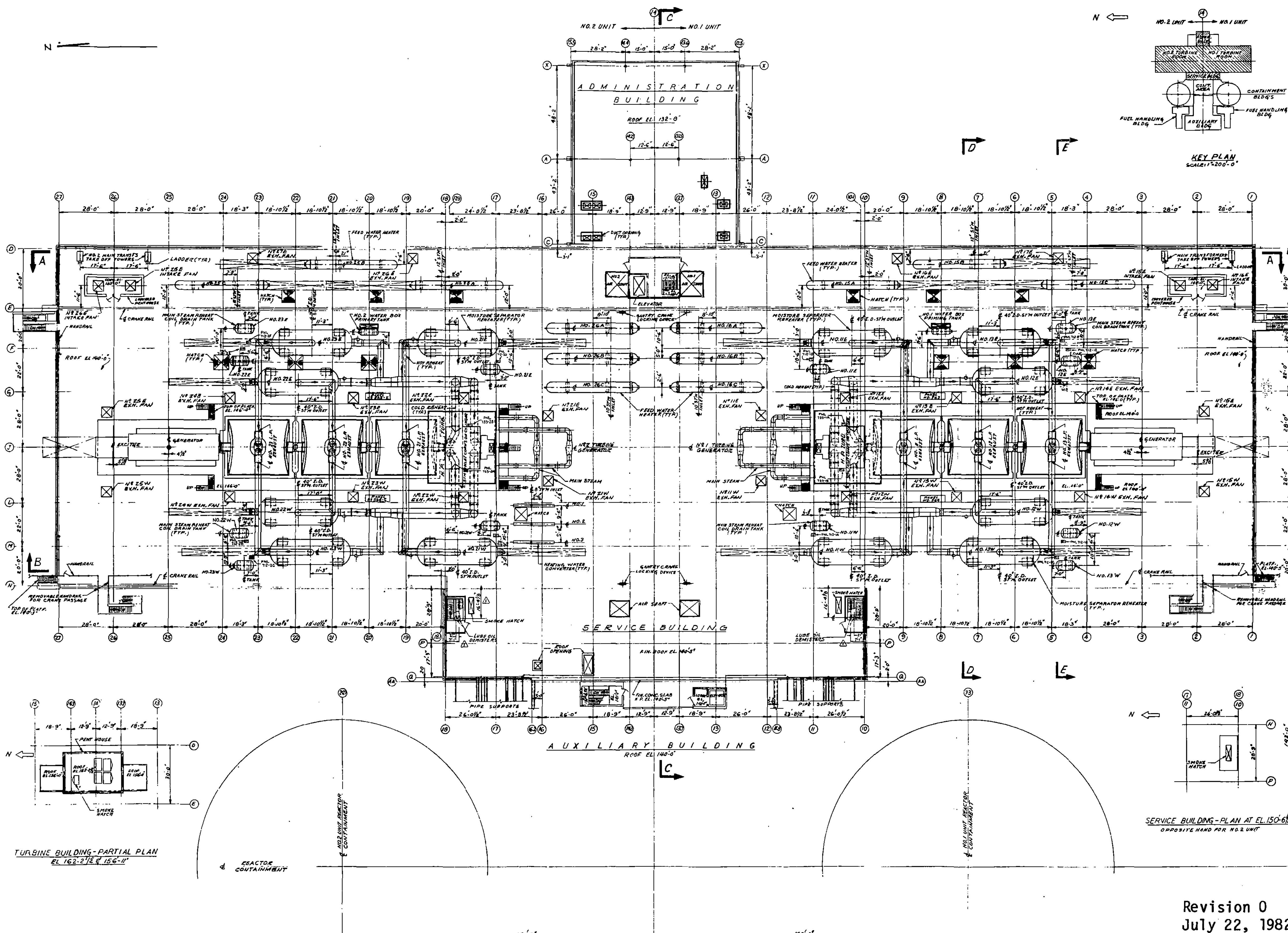
Safety related equipment required for cold shutdown are located inside the containment, service water intake, auxiliary building, and main steam and feedwater pipe penetration areas. The containment is watertight and can withstand the static and dynamic loads associated with a storm producing stillwater level of 113.8 feet PSD and the corresponding wave runup to 120.4 feet PSD.

The portion of the service water intake enclosing the pumps, motors and vital switchgear is watertight up to elevation 122 feet PSD. The service water intake can also withstand the static and dynamic effects of the storm. Each vertical, turbine type service water pump column bowl and suction bell is installed in an individual chamber which is open to the river. The chamber is isolated from the watertight compartments where the pump discharge heads and motors are located. The pump discharge heads are bolted down to pads to elevation 92'-6" PSD. The joint between the pump discharge head and the pad at elevation 92'-6" PSD is watertight to prevent leakage of water into the compartments. Provisions have also been made to prevent leakage from the discharge head glands and leakoff connections into the watertight compartments. A sump pump is provided in each compartment to remove any accumulated water in the event a minor leak should occur.

The auxiliary building is watertight up to elevation 115 feet PSD. All doors in the outer auxiliary building walls below elevation 120.4 PSD are watertight. All watertight doors and structural walls can withstand the static and dynamic effects associated with a storm that produces a stillwater level of 113.8 feet PSD with wave runup to el. 120.4 feet PSD. Conduit penetrations above elevation 115 feet PSD and below elevation 120.4 feet PSD will be packed to eliminate gross inleakage during the storm.

Each residual heat removal pump room, the lowest point in the auxiliary building, contains two 100 gpm capacity sump pumps. In the event of a major storm, which may be expected to cause flooding of the site, a number of temporary sump pumps will be available to remove any water which may enter the building. The minimum total capacity of these temporary pumps will be 2000 gpm and each pump will be capable of pumping from the lowest building elevation to above elevation 121 feet PSD.

The main steam and feedwater pipe penetration area will be watertight below elevation 120.4 feet PSD. The structural walls and watertight doors will also be capable of withstanding the static and dynamic effects of the storm which produces a stillwater level of 113.8 feet PSD and wave runup to 120.4 feet PSD.



Revision 0
July 22, 1982

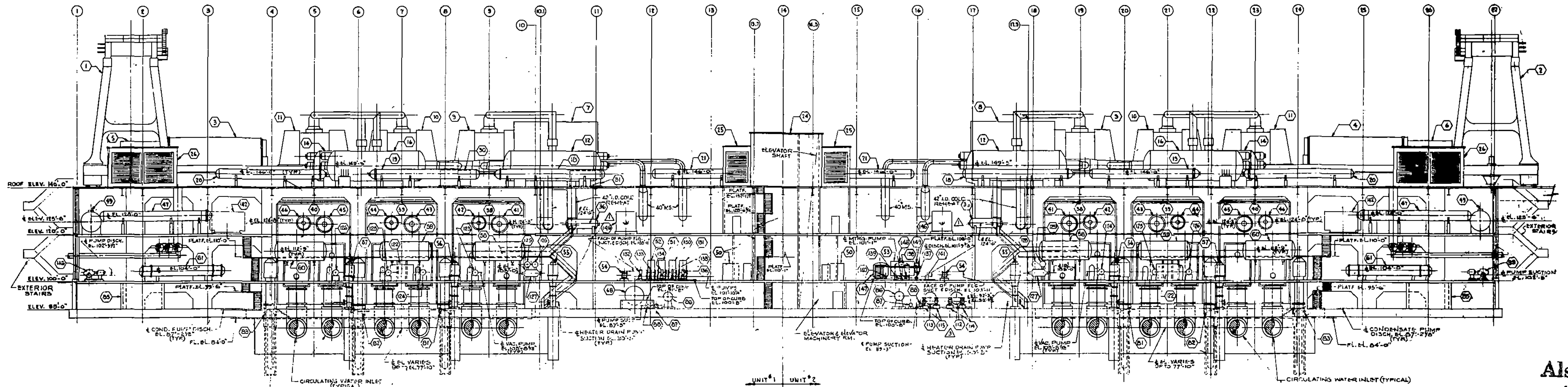
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Turbine Building
Plan View

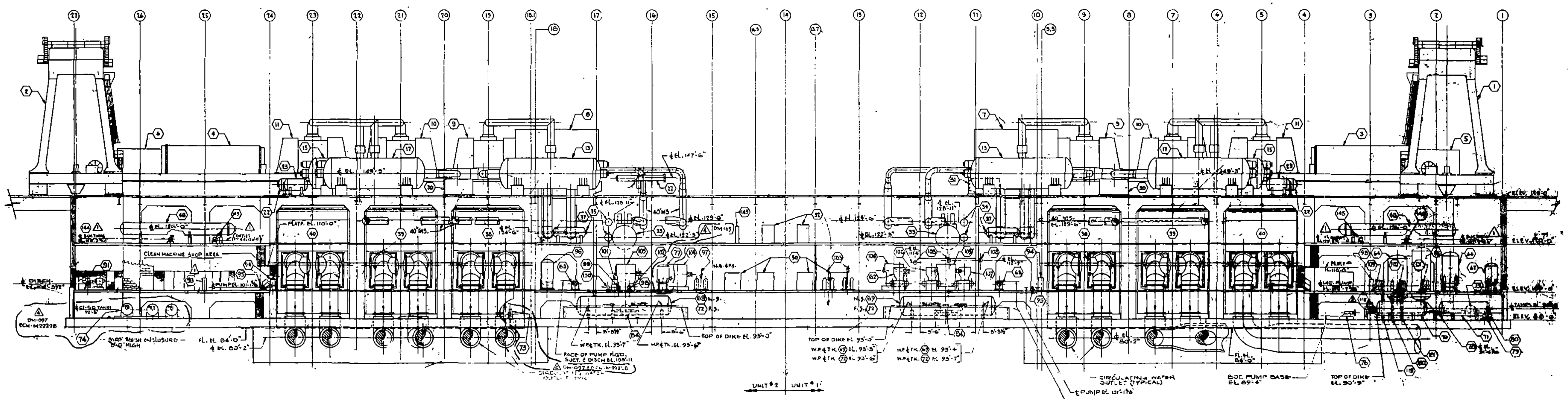
Updated FSAR

Figure 3.5-1

ITEM	EQUIP'T. NO. UNIT 1	EQUIP'T. NO. UNIT 2	DESCRIPTION
1	1	—	TURBINE AREA CRANE
2	—	1	AUXILIARY TURBINE AREA CRANE
3	1	—	GENERATOR
4	—	2	"
5	1	—	EXCITER
6	—	2	"
7	1	—	HIGH PRESSURE TURBINE
8	—	2	" " "
9	11	21	LOW PRESSURE TURBINE
10	12	22	" " "
11	13	23	" " "
12	11E	21E	MOISTURE SEPERATOR–REHEATER
13	11W	21W	MOISTURE SEPERATOR–REHEATER
14	12E	22E	" " "
15	12W	22W	" " "
16	13E	23E	" " "
17	13W	23W	" " "
18	15A	25A	FEEDWATER HEATER
19	15B	25B	" "
20	15C	25C	" "
21	16A	26A	" "
22	12W	22W	MAIN STEAM REHEAT COIL DRAIN TANK
23	13W	23W	" " " " " "
24	—	—	ELEVATOR & STAIRWELL PENTHOUSE
25	—	—	VENTILATION PENTHOUSE
26	—	—	" "
27	—	5	HEATING WATER CONVERTER
30	[illegible]	H.H.D.	INSTRUMENT PANEL
31	[illegible]	—	" "
32	1F	2F	460 VOLT SWITCH GEAR
33	1	2	TURBINE OIL RESERVOIR
34	11&12	—	TURBINE OIL COOLER
35	—	21&22	" " "
36	11	21	BLEED STEAM REHEAT COIL DRAIN TANK
37	12	22	BLEED STEAM REHEAT COIL DRAIN TANK
38	11	21	CONDENSER
39	12	22	"
40	13	23	"
41	11A	21A	FEEDWATER HEATER
42	12A	22A	" "
43	11B	21B	" "
44	12B	22B	" "
45	11C	21C	" "
46	12C	22C	" "
47	14A	24A	" "
48	13C	23C	" "
49	1	2	TURB. AUX. COOLING MAKE-UP & EXP. TANK
50	—	—	BUS SWITCH GEARS
51	1	—	(AMMONIA) SOLUTION TANK
52	1	—	HYDRAZINE SOLUTION TANK △
53	—	2	(AUX. CHEMICAL) MIXING TANK △
54	11	21	BLEED STEAM REHEAT COIL DR. TANK PUMP
55	11	21	HEATER DRAIN PUMP
56	12	22	" " "
57	13	23	" " "
58	1A	2A	FEEDWATER HEATER & M.S.R. DRAIN TK.
59	1B	2B	" " " " " "
60	1C	2C	" " " " " "
61	11	21	TURB. AUX. COOLING HEAT EXCHANGER
62	1	—	STATION AIR COMPRESSOR
63	12	22	BLEED STEAM REHEAT COIL DRAIN TK. PUMP
64	1	—	CATION EXCHANGER
65	1	—	VACUUM DEAERATOR
66	1	—	ANION EXCHANGER
67	1	—	MIXED BED EXCHANGER
68	1	—	TURBINE OIL RECEIVING & MAKE-UP TANK
69	12	22	TURBINE OIL STORAGE TANK
70	2	—	ACID STORAGE TANK
71	2	—	CAUSTIC STORAGE TANK
72	11	21	TURBINE OIL STORAGE TANK
73	—	21	FLUSHING WATER MIXING CIRCULATING TRANSFER PUMP △
74	—	21, 22 & 26	CI-60 TANKS △
75	1	—	CHEMICAL WASTE "
76	2	—	ACID METERING PUMP
77	—	21	CONTROL AIR RECEIVER △
78	—	—	CAUSTIC DILUTION WATER HEATER
79	1	—	REGENERATION WATER PUMP
80	2	—	" " "
81	11	21	CONDENSATE PUMP
82	12	22	" "
83	13	23	" "
84	1	2	STEAM GENERATOR FEED PUMP & TURBINE LUBE OIL TANK
85	—	—	RAW WATER BASIN
86	1	2	MISC CONDENSATE RETURN TANK
87	11	21	" " " PUMP
88	12	22	" " " "
89	11	21	TURBINE AUXILIARIES COOLING "
91	13	23	TURBINE AUXILIARIES COOLING PUMP
93	—	2	SERVICE WATER CHLORINE RESIDUAL ANALYZER
94	1	2	CHLORINE ANALYZER
95	1	2	CIRCULATING WATER SAMPLE PUMP
96	—	1	HEATING SYS. EXPAN. & PRESSURRING TANK
97	—	#21&22	CONTROL AIR DRYER
98	—	1	HEATING WATER CIRCULATING PUMP
99	—	2	" " " "
100	—	3	" " " "
101	1	2	TURBINE OIL SEPARATOR
102	1	2	WASTE WATER TANK (TURBINE OIL PURIFYING SYSTEM)
103	11&12	—	CONTROL AIR DRYER
104	11	21	STEAM GENERATOR FEED PUMP
105	12	22	" " " "
106	2	—	STATION AIR COMPRESSOR
107	3	—	" " "
108	—	—	AFTERCOOLER
109	1	—	DEAERATOR VACUUM PUMP
110	2	—	" " "
111	3	—	" " "
112	—	2	#21 & #22 ACID STORAGE TANKS △
113	—	2	#21 & #22 CAUSTIC STORAGE TANKS △
114	—	2	#21 & #22 ACID TRANS. PUMPS △
115	—	2	#21 & #22 CAUSTIC TRANS. PUMPS △
116	11	—	TURBINE AUXILIARIES COOLING PUMP
117	2	—	#11 & #12 CAUSTIC METERING PUMPS △
118	2	—	#11 & #12 ACID METERING PUMPS △
119	1	—	DEAERATOR WATER PUMP
120	2	—	" " "
121	3	—	" " "
122	1	2	FEED WATER ANALYSIS PANEL
123	11	—	VACUUM PUMP
124	12	22	" "
125	13	23	" "
126	14	24	" "
127	1	2	GLAND STEAM CONDENSER
128	11	21	GLAND STEAM CONDENSER EXHAUSTER
129	12	22	" " " "
130	2	—	HYDRAZINE SOLUTION TANK
131	2	—	(AMMONIA) " " △
132	1	—	HYDRAZINE & AMMONIA PUMP △
133	1	—	" METERING "
134	1	—	(AMMONIA) " " △
135	2	—	(HYDRAZINE) " "
136	2	—	(AMMONIA) " " △
137	—	21	(AUX. CHEMICAL) " " △
138	—	22	" " "
139	—	23	AUX. CHEMICAL METERING PUMP △
140	—	24	" " " "
141	—	2	" FEED "
142	1	2	SEAL OIL UNIT
143	22	—	TURBINE WEST CONTROL CENTER
144	1	2	LOOP SEAL TANK VAPOR EXTRACTOR △
145	1	2	HYDROGEN GAS DRYER △
146	1	1	TURBINE E.H. CONTROL FLUID RESERVOIR △
147		2A	QUARTZ FILTER
148		2B	ACTIVATED CARBON FILTER
149		2C	POLYELECTROLYTE FEED TANK & PUMP



LONGITUDINAL ELEVATION "A-A"
LOOKING WEST



LONGITUDINAL ELEVATION "B-B"
(LOOKING EAST)

LEGEND:
① – DENOTES EQUIPT. ITEM NO. FOR THIS DWG. ONLY AND REFERS TO EQUIPMENT DESCRIBED IN EQUIPT. INDEX TABLE AT TOP OF DRAWING.

Also Available On Aperture Card

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POOR ORIGINAL

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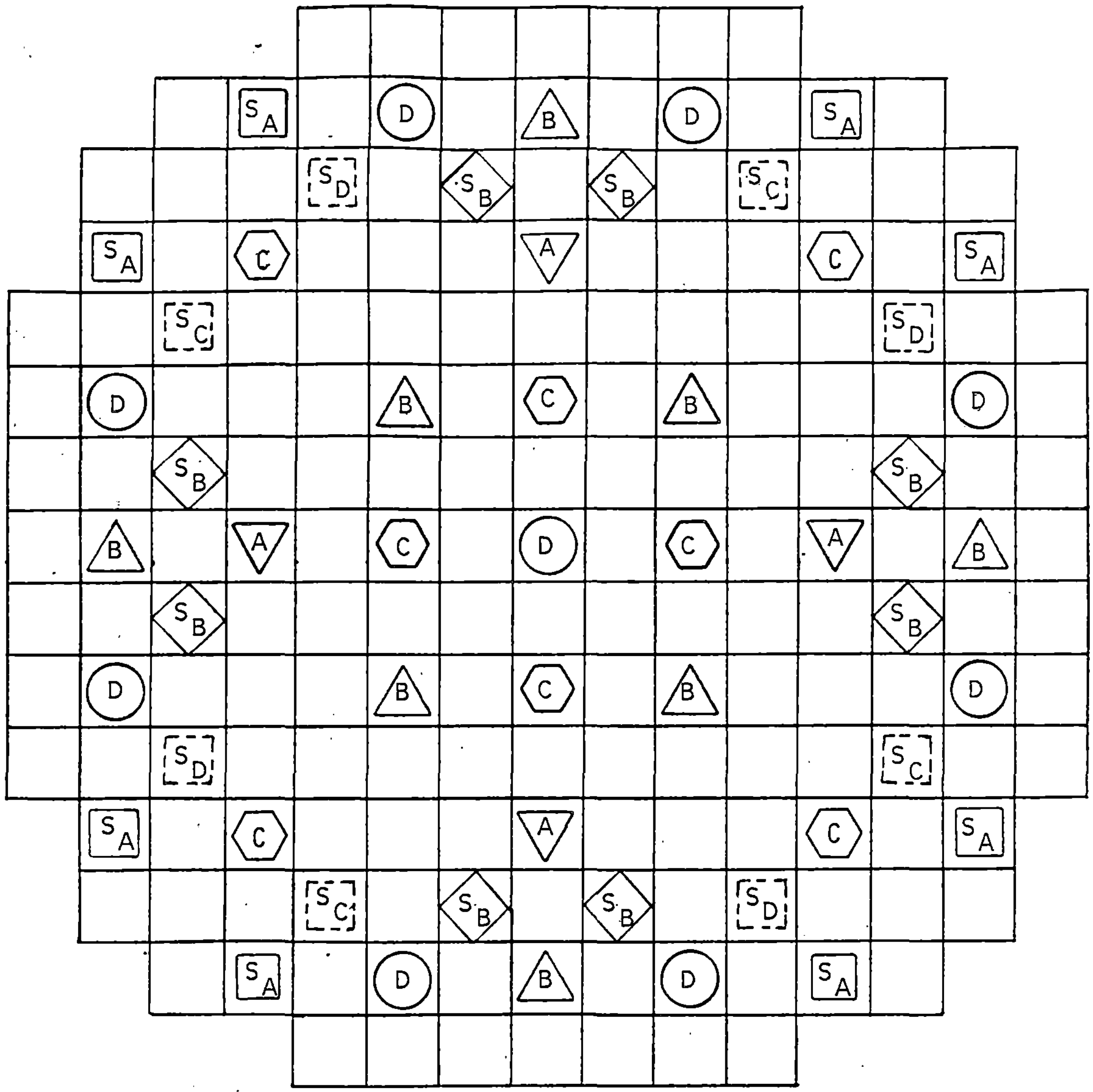
Revision 3
July 22, 1984

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Turbine Building Longitudinal Elevations
	UPDATED FSAR FIG 3.5-2

8408020108-04

LIST OF FIGURES (Continued)



TYPE OF ROD CLUSTER	FUNCTION & SYMBOL	NUMBER OF ROD CLUSTERS
SHUTDOWN BANK	S_A	8
SHUTDOWN BANK	S_B	8
SHUTDOWN BANK	S_C & S_D	4 & 4
CONTROL BANK	A	8
CONTROL BANK	B	8
CONTROL BANK	C	8
CONTROL BANK	D	9

Revision 4
July 22, 1985
Ref. Dwg. N/A

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Rod Cluster Control Assemly Pattern
Unit 2

Updated FSAR

Fig 4.3-35B

PSE&G

Public Service Electric and Gas Company P.O. Box 236 Hancocks Bridge, New Jersey 08038

Nuclear Department

Ref 1) NS-EPR-3545, 1/20/82

Ref 2) Letter Steven A. Varga(NRC) to R.A. Uderitz (PSE&G), Docket Nos. 50-272 & 50-311, dated November 1, 1982.

July 19, 1984

Director of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Attention: Mr. Steven Varga, Chief
Operating Reactors Branch #1
Division of Licensing

Gentlemen:

CYCLE 6 RELOAD ANALYSIS
FACILITY OPERATING LICENSE DPR-70
UNIT NO. 1
SALEM GENERATING STATION
DOCKET NO. 50-272

Salem Unit No. 1 concluded its fifth cycle of operation and commenced a refueling outage on February 24, 1984. Cycle 5 achieved a cycle burnup of 9,608 MWD/MTU. The Startup of Cycle 6 is scheduled for mid-August. The purpose of this letter is to inform you of PSE&G's plans regarding Salem No. 1 Cycle 6 reload core which is expected to achieve a burnup of 17,500 MWD/MTU.

The Cycle 6 reload core will utilize 84 new Region 8 Westinghouse 17 x 17 fuel assemblies and 1660 fresh burnable poison rods. The Region 8 feed fuel consists of 52 assemblies at 3.40 w/o enrichment and 32 assemblies at 3.80 w/o enrichment (see attached figure). All Region 8 assemblies are of the same mechanical, nuclear, and thermal hydraulic design as the Cycle 5 standard assemblies. The optimized fuel assemblies present in Cycle 5 will not be reinserted for Cycle 6.

W has completed the safety evaluation of the Cycle 6 reload core design in accordance with the Westinghouse reload methodology as outlined in the March 1978 Westinghouse topical report "Westinghouse

Reload Safety Evaluation Methodology (WCAP-9273)." Based on this methodology, those incidents analyzed and reported in the Salem FSAR that could potentially be affected by the fuel reload were addressed.

All the Cycle 6 peaking factors, rod worths and kinetics parameter values meet current limits except for the Cycle 6 SCRAM curve and the most negative Doppler coefficient. Those accidents affected by the slight change in the SCRAM curve were reanalyzed and all transients affected by the more negative Doppler coefficient were evaluated. Based on the results of these analyses, it was concluded that the Cycle 6 design does not cause the previously acceptable safety limits for any incident to be exceeded.

The dropped RCCA event was analyzed according to the new dropped rod methodology described in Reference 1. Results show that the DNB design basis is met for all dropped rod events initiated from full power so that the interim operating restrictions (Reference 2) are no longer necessary. However, until formal NRC notification is received to remove them, the plant shall continue to operate under the interim restrictions.

PSE&G has reviewed the bases of the Cycle 6 reload analysis and the Westinghouse Reload Safety Evaluation (RSE) Report with Westinghouse. The review demonstrated that the results of all the postulated events are within allowable limits. The reload safety evaluation demonstrated that Technical Specification changes are not required for operation of Salem Unit 1 at rated thermal power during Cycle 6. The Salem Station Operations Review Committee has concluded that no unreviewed safety questions as defined by 10CFR 50.59 are involved with this reload. Therefore, based on this review, application for amendment to the Salem Unit 1 operating license is not required.

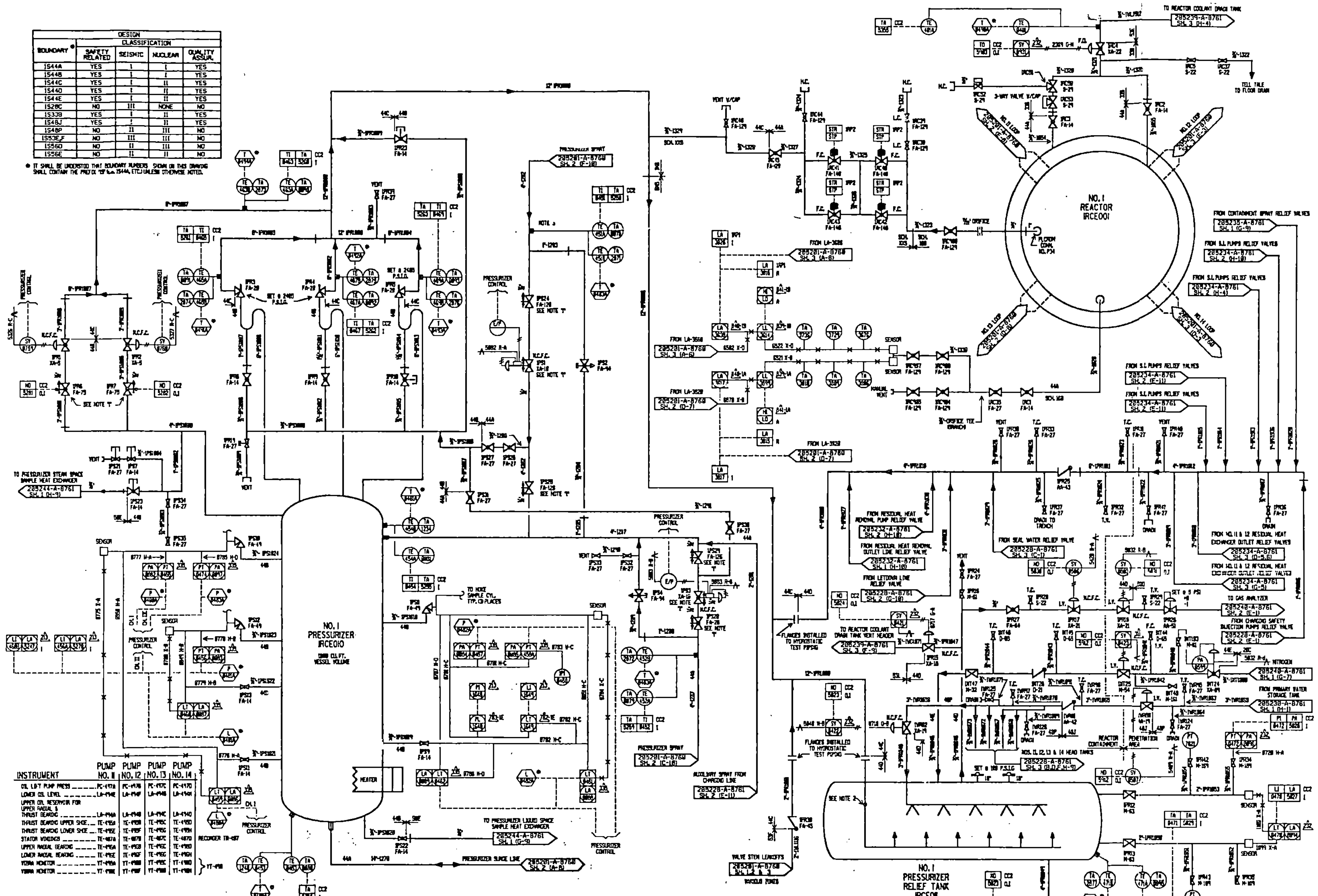
The reload core design will be verified during the startup physics testing program. This program will include, but is not limited to, the following tests:

1. Control rod drive tests and drop time
2. Critical boron concentration measurements
3. Control rod bank worth measurements
4. Moderator temperature coefficient measurement, and
5. Power distribution measurements using the incore flux mapping system.

Very truly yours,

E. A. Liden
Manager - Nuclear
Licensing and Regulation

RSK:td
Attachments



BOUNDARY*	DESIGN CLASSIFICATION: SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S44A	YES	I	I	YES
1S44B	YES	I	I	YES
1S44C	YES	I	II	YES
1S44D	YES	I	II	YES
1S44E	YES	I	II	YES
1S28C	NO	III	NONE	NO
1S33B	YES	I	II	YES
1S48J	YES	I	II	YES
1S48P	NO	II	III	NO
1S93E,F	NO	III	III	NO
1S56D	NO	II	III	NO
1S56E	NO	II	III	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

INSTRUMENT	PUMP NO. 11	PUMP NO. 12	PUMP NO. 13	PUMP NO. 14
OIL LIFT PUMP PRESS	PC-497A	PC-497B	PC-497C	PC-497D
LOWER OIL LEVEL	LA-494E	LA-494F	LA-494G	LA-494H
UPPER OIL RESERVOIR FOR UPPER RADIAL & THRUST BEARING	LA-494A	LA-494B	LA-494C	LA-494D
THRUST BEARING UPPER SHOE	TE-495A	TE-495B	TE-495C	TE-495D
THRUST BEARING LOWER SHOE	TE-495E	TE-495F	TE-495G	TE-495H
STATOR WINDINGS	TE-497A	TE-497B	TE-497C	TE-497D
UPPER RADIAL BEARING	TE-496A	TE-496B	TE-496C	TE-496D
LOWER RADIAL BEARING	TE-496E	TE-496F	TE-496G	TE-496H
VIBRA MONITOR	YT-498A	YT-498B	YT-498C	YT-498D
VIBRA MONITOR	YT-498E	YT-498F	YT-498G	YT-498H

RECORDER TR-497
YT-498

NOTES

1. VALVE LEAKOFFS TO BE PIPED AS SHOWN ON APPLICABLE ARRANGEMENT DWG. VALVE LEAKOFF PIPING IS CLASSIFIED UNDER PIPE SPEC [illegible]
2. HOLE IN 12" LINE [illegible] IS TO BREAK VACUUM IN LINE AFTER STEAM BLOW TO PREVENT LINE FROM FILLING WITH WATER.
3. LOCATE [illegible] TE-[illegible] & 452 MIDWAY BETWEEN LOOP & PRESSURIZER
4. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAX. ALLOWABLE PRESS. FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESS. & TEMP. PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE [illegible].
5. FOR DESIGN PRESS. & TEMP. PARAMETERS REFER TO THE DESIGN PRESS. & TEMP. PARAMETERS AT THE ORIGINAL SOURCE HEADER.
6. [illegible] DENOTES WITHOUT THE RUPTURE DISC.
7. ALL LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1RC" [illegible] EXCEPT WHERE OTHERWISE NOTED.

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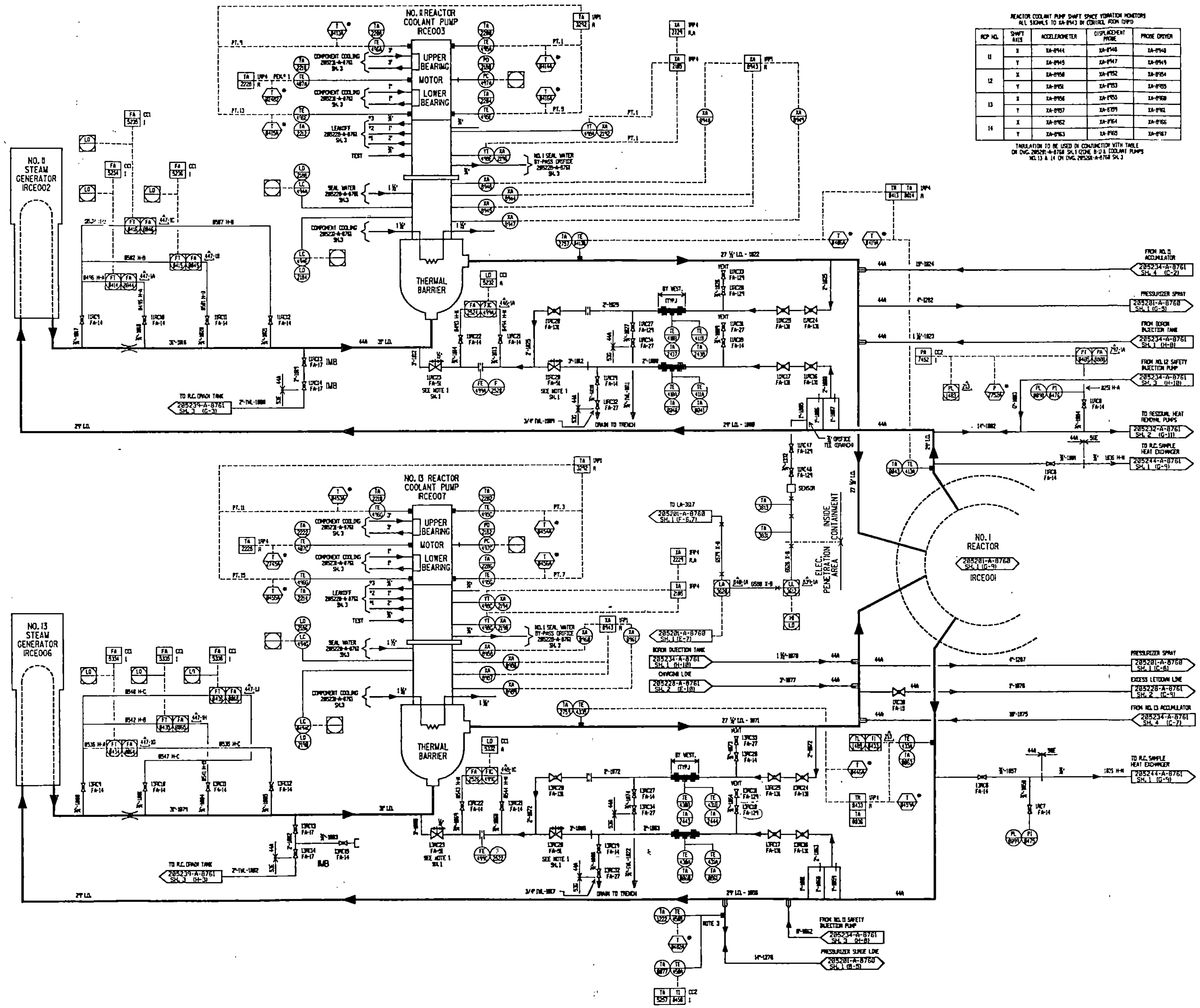
8507300447 -01

Revision 4
July 22, 1985
Ref. Dwg. 205201A8760-22

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Coolant System Flow Diagram Unit 1
	Updated FSAR Sheet 1 of 3 Fig 5.1-6A



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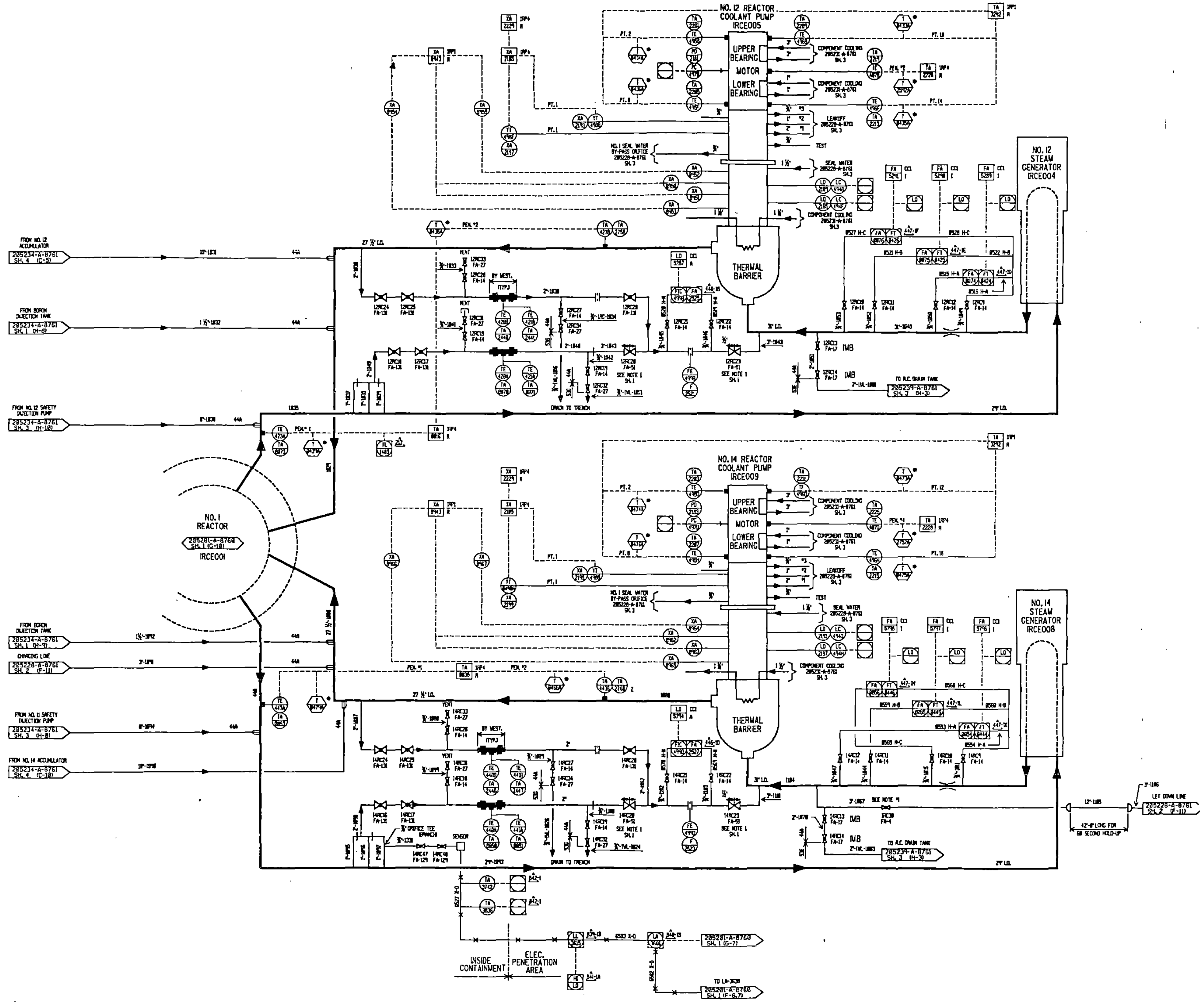
8507300447 -02

Revision 4
July 22, 1985
Ref. Dwg. 205201A8760-22

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Coolant System Flow Diagram Unit 1
	Updated FSAR Sheet 2 of 3 Fig 5.1-6A

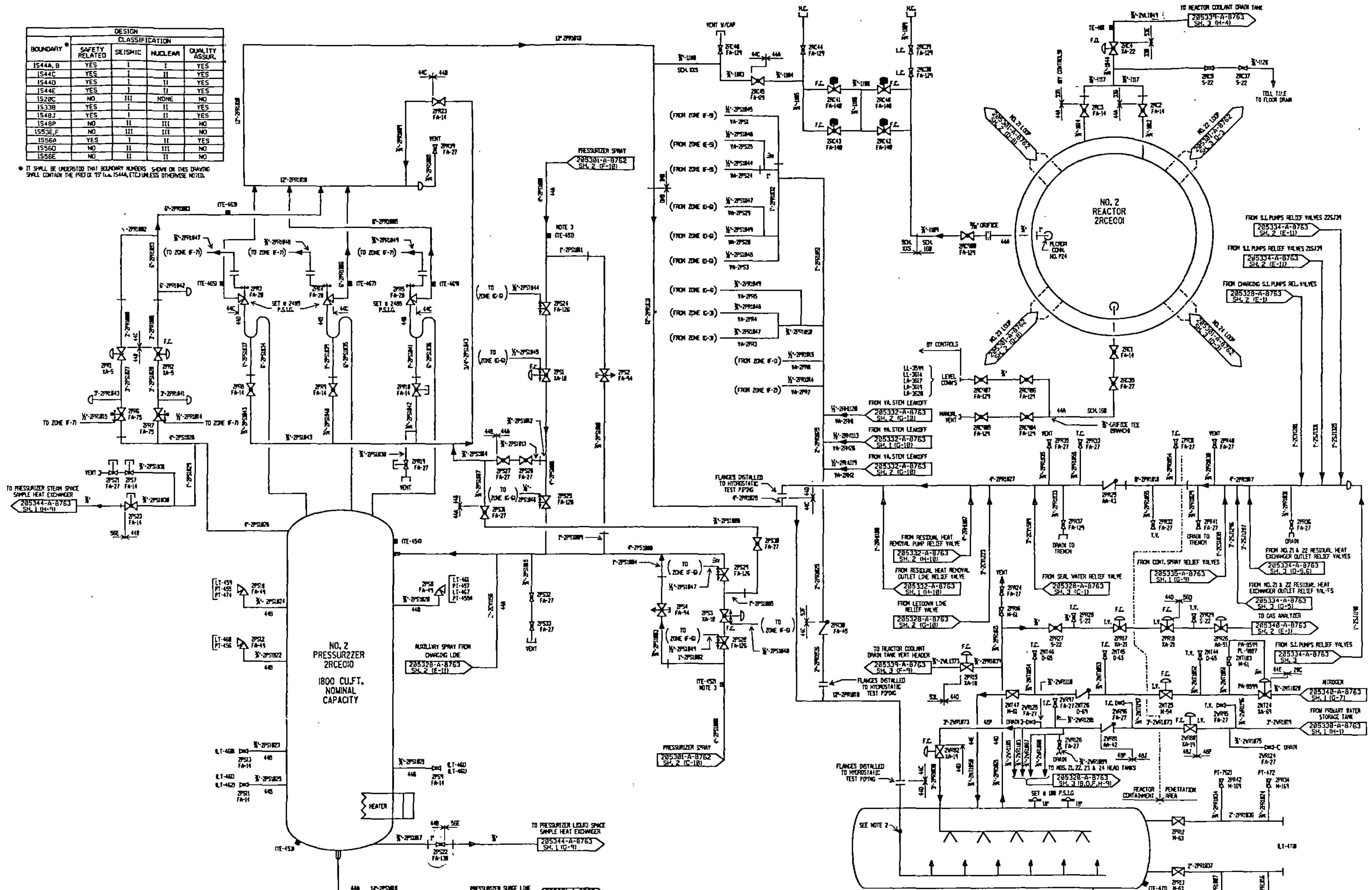


Revision 4
July 22, 1985
Ref. Dwg. 205201A8760-22

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Coolant System Flow Diagram Unit 1
	Updated FSAR Sheet 3 of 3 Fig 5.1-6A

BOUNDARY*	DESIGN CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S44A, B	YES	I	I	YES
1S44C	YES	I	II	YES
1S44D	YES	I	II	YES
1S44E	YES	I	II	YES
1S20C	NO	III	NONE	NO
1S33B	YES	I	II	YES
1S48J	YES	I	II	YES
1S48P	NO	II	III	NO
1S53E,F	NO	III	III	NO
1S56A	YES	I	II	YES
1S56D	NO	II	III	NO
1S56E	NO	II	II	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.



NOTES

1. LEAKOFFS FROM VA'S 21,22,23 & 24 RC 20,21,22,23 & 24, RC23 AND 2RC30 ARE CONT. ON DWG. NO. 205329-A-8763
2. HOLE IN 12" LINE 6-B-15 TO BREAK VACUUM IN LINE AFTER STEAM BLOW TO PREVENT LINE FROM FILLING WITH WATER
3. LOCATE INSTR. ITEMS TE-450,451 & 452 MIDWAY BETWEEN LOOP & PRESSURIZER
4. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAX. ALLOWABLE PRESS. FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESS. & TEMP. PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A[illegible]-MFD-051.
5. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2RC" (i.e. 2RC1000 etc.) EXCEPT WHERE OTHERWISE NOTED.
6. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION S1-6200. THE PIPING SCHEDULE AND GROUP NO.'S ARE AS NOTED ON THIS DWG. AND PREFIXED WITH "1S".
7. INSTRUMENT ITEMS IN PARENTHESIS ( ) ARE WESTINGHOUSE INSTRUMENT ITEMS REFER TO ISA-[illegible] FOR DESCRIPTION.
8. [illegible] DENOTES WITHOUT RUPTURE DISC.

INSTRUMENT	PUMP NO. 21	PUMP NO. 22	PUMP NO. 23	PUMP NO. 24	
OIL LIFT PUMP PRESS	PC-497A	PC-497B	PC-497C	PC-497D	
LOWER OIL LEVEL	LA-494E	LA-494F	LA-494G	LA-494H	
UPPER OIL RESERVOIR FOR UPPER RADIAL & THRUST BEARING	LA-494A	LA-494B	LA-494C	LA-494D	
THRUST BEARING UPPER SHOE	TE-495A	TE-495B	TE-495C	TE-495D	
THRUST BEARING LOWER SHOE	TE-495E	[illegible]	[illegible]	TE-495H	
STATOR WINDINGS	TE-407A	TE-407B	TE-407C	TE-407D	RECORDER TR-407
UPPER RADIAL BEARING	TE-496A	TE-496B	TE-496C	TE-496D	
LOWER RADIAL BEARING	TE-496E	TE-496F	TE-496G	TE-496H	
VIBRA TRANSMITTER	YT-498A	YT-498B	YT-498C	YT-498D	YT-498
VIBRA TRANSMITTER	YT-498E	YT-498F	YT-498G	YT-498H	YT-498

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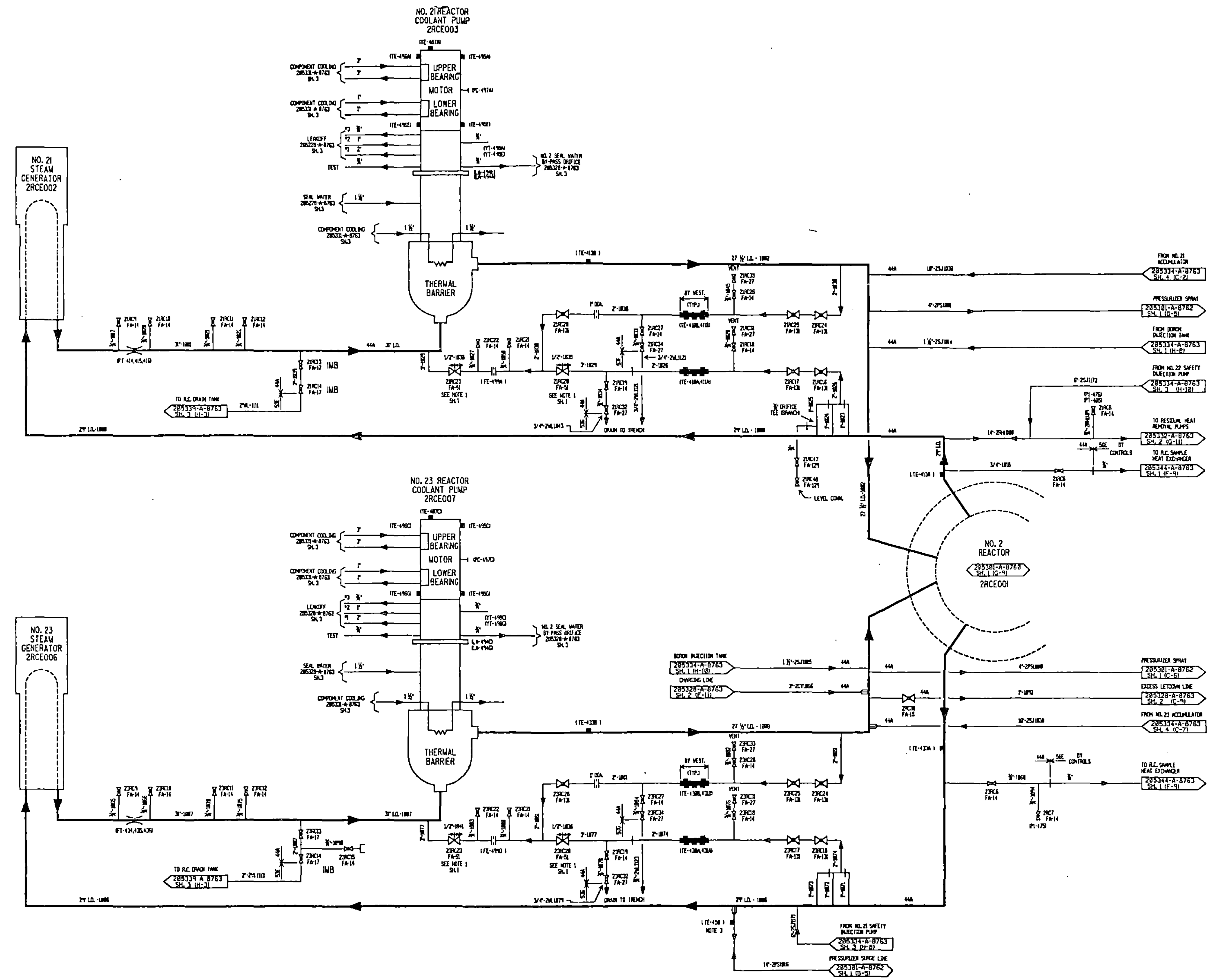
Revision 4
July 22, 1985
Ref. Dwg. 205301A8762-18

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Coolant System Flow Diagram Unit 2
	Updated FSAR Sheet 1 of 3 Fig 5.1-6B



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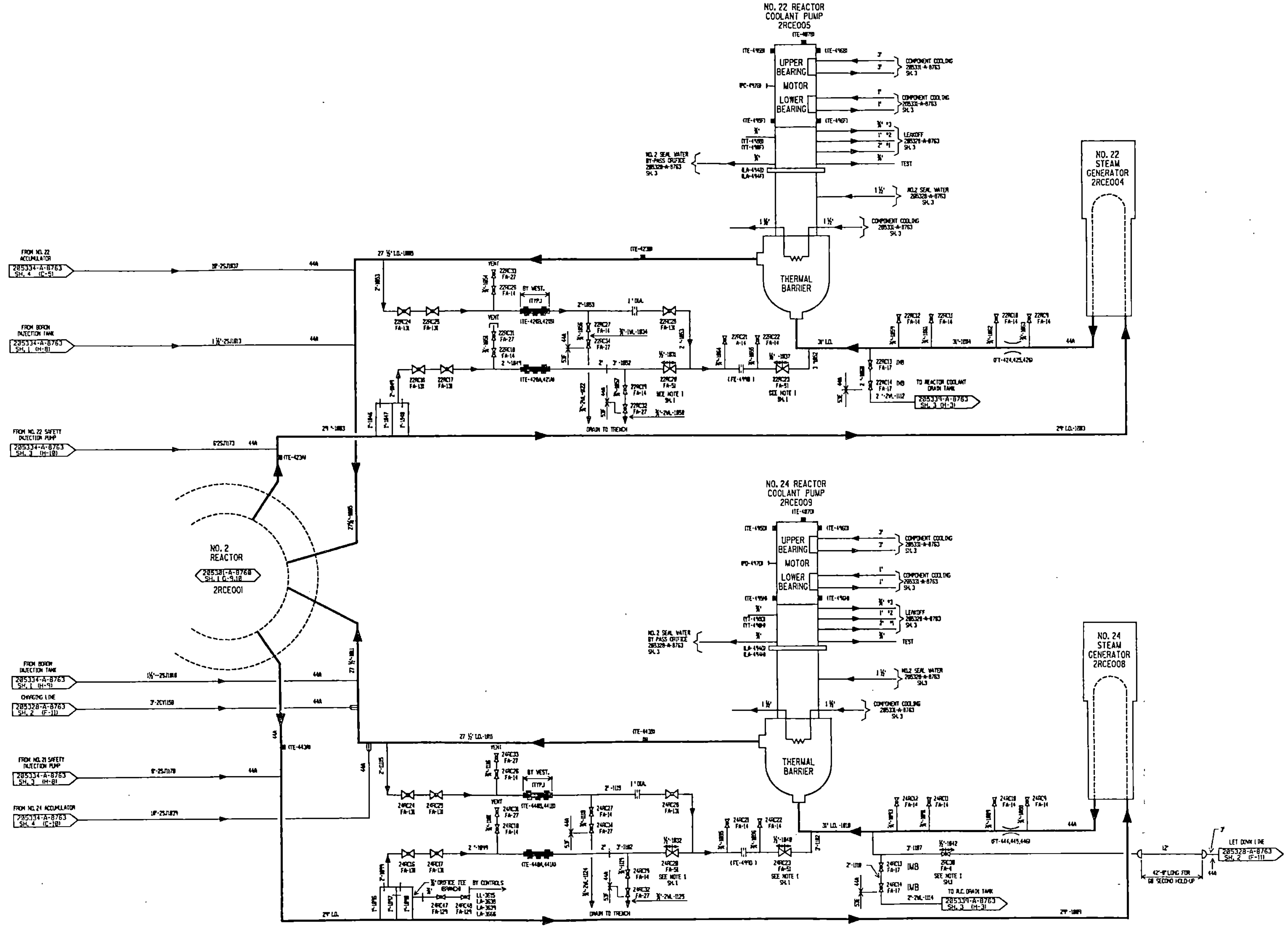
8507300447 -05

Revision 4
July 22, 1985
Ref. Dwg. 205301A8762-18

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Coolant System Flow Diagram Unit 2
	Updated FSAR Sheet 2 of 3 Fig 5.1-6B



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8507300447 -06

Revision 4
July 22, 1985
Ref. Dwg. 205301A8762-18

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Coolant System Flow Diagram Unit 2
	Updated FSAR Sheet 3 of 3 Fig 5.1-6B

tilting pad Kingsbury bearings. All are oil lubricated. The lower radial bearing and the thrust bearings are submerged in oil, and the upper radial bearing is oil fed from an impeller integral with the thrust runner. Component cooling water is supplied to the two oil coolers on the pump motor.

The motor is an air cooled, Class B thermalastic epoxy insulated, squirrel cage induction motor. The rotor and stator are of standard construction and are cooled by air. Six resistance temperature detectors are located throughout the stator to sense the winding temperature. The top of the motor consists of a flywheel and an anti-reverse rotation device.

The internal parts of the motor are cooled by air. Integral vanes on each end of the rotor draw air in through cooling slots in the motor frame. This air passes through the motor with particular emphasis on the stator end turns. It is then exhausted to the containment environment.

Each of the reactor coolant pumps is equipped for continuous monitoring of reactor coolant pump shaft and frame vibration levels. Shaft vibration is measured by two relative shaft probes mounted on top of the pump seal housing. The probes, one in line with the pump discharge and the other perpendicular to the pump discharge, are mounted in the same horizontal plane near the pump shaft. Frame vibration is measured by two velocity seismoprobes located 90 degrees apart in the same horizontal plane and mounted at the top of the motor support stand. Proximeters and converters convert the probe signals to linear output, which is displayed on monitor meters in the control room. The monitor meters automatically indicate the highest output from the relative probes and seismoprobes; manual selection allows monitoring of individual probes. Indicator lights display caution and danger limits of vibration.

All parts of the pump in contact with the reactor coolant are austenitic stainless steel, except for seals, bearings and special parts.

A removable shaft segment, the spool piece, is located between the motor coupling flange and the pump coupling flange. The spool piece allows removal of the pump seals with the motor in place. The pump internals, motor, and motor stand can be removed from the casing as a unit without disturbing the reactor coolant piping. The flywheel is available for inspection by removing the flywheel cover.

5.5.1.3 Design Evaluation

5.5.1.3.1 Pump Performance

The reactor coolant pumps are sized to deliver flow at rates that equal or exceed the required flow rates. Initial RCS tests confirm the total delivery capability, providing assurance of adequate forced circulation coolant flow prior to initial plant operation. The performance characteristic is shown in Figure 5.1-5.

The reactor trip system ensures that pump operation is within the assumptions used for loss-of-coolant flow analyses, and also assures that adequate core cooling is provided to permit an orderly reduction in power if flow from a reactor coolant pump is lost during operation.

An extensive test program has been conducted to develop the controlled leakage shaft seal for pressurized water reactor applications. Long-term tests were conducted on less than full scale prototype seals as well as on full size seals. Operating plants continue to demonstrate the satisfactory performance of the controlled leakage shaft seal pump design.

The support of the stationary member of the number 1 seal (seal ring) is such as to allow large deflections, both axial and tilting, while still maintaining its controlled gap relative to the seal runner. Even if all the graphite were removed from the pump bearing, the shaft could not deflect far enough to cause opening of the controlled leakage gap. The shaft would fail in torsion just below the coupling to the motor, thereby disengaging the flywheel and motor from the shaft. This would constitute a loss-of-coolant flow in the loop. Following such a postulated seizure, the motor would continue to run without any overspeed, and the flywheel would maintain its integrity, as it is still supported by the motor with two bearings.

There are no other credible sources of shaft seizure other than impeller rubs. Sudden seizure of the pump bearing is precluded by graphite in the bearing. Any seizure in the seals results in a shearing of the antirotation pin in the seal ring. The motor has adequate power to continue pump operation even after the above occurrences. Indications of pump malfunction in these conditions are initially by high temperature signals from the bearing water temperature detector and by excessive number 1 seal leakoff indications respectively. Following these signals, pump vibration levels are checked. Excessive vibration indicates mechanical trouble, and the pump is shut down for investigation.

5.5.1.3.6 Critical Speed

The reactor coolant pump shaft is designed so that its operating speed is below its first critical speed. This shaft design, even under the most severe postulated transient, gives low values of actual stress.

5.5.1.3.7 Missile Generation

Precautionary measures taken to preclude missile formation from reactor coolant pump components assure that the pumps will not produce missiles under any anticipated accident conditions. Each component of the pump is analyzed for missile generation. Any fragments of the motor rotor would be contained by the heavy stator. The same conclusion applies to the pump impeller, because the small fragments that might be ejected would be contained by the heavy casing.

5.5.1.3.8 Pump Cavitation

The minimum net positive suction head required by the reactor coolant pump at best estimate flow is approximately 170 feet (approximately 85 psi). In order for the controlled leakage seal to operate correctly, it is necessary to require a minimum differential pressure of approximately 275 psi across the number 1 seal. This corresponds to a primary loop pressure at which the minimum net positive suction head requirement is exceeded and no limitation on pump operation occurs from this source.

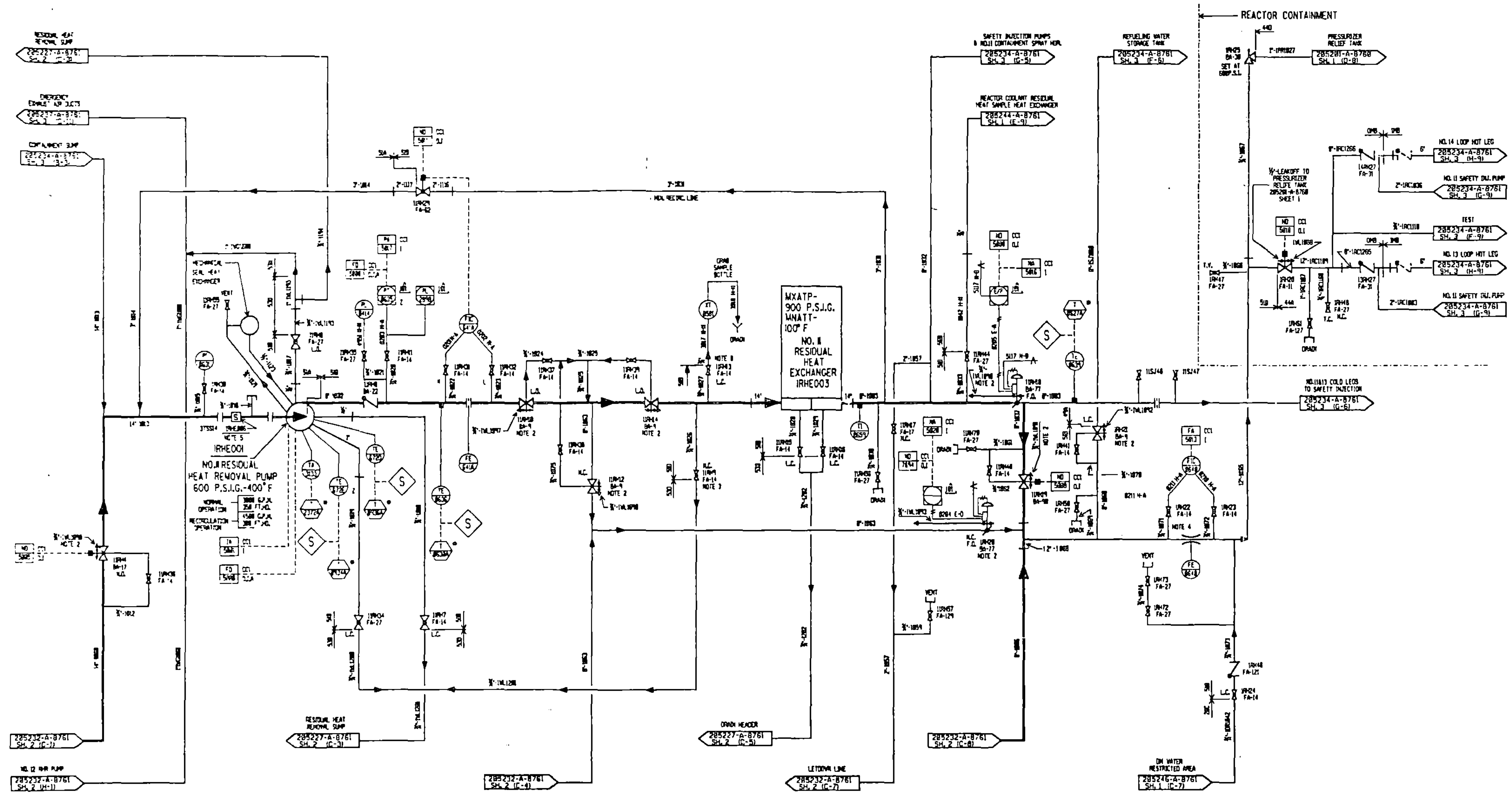
5.5.1.3.9 Pump Overspeed Considerations

For turbine trips actuated by either the reactor trip system or the turbine protection system, the generator breaker disconnects the generator permitting the reactor coolant pumps to remain connected to the external network for 30 seconds to prevent any pump overspeed condition.

An electrical fault requiring immediate trip of the generator (with resulting turbine trip) could result in an overspeed condition. However, the turbine control system and the turbine intercept valves limit the overspeed to less than 120 percent. As additional backup, the turbine protection system has a mechanical overspeed protection trip, usually set at about 110 percent of turbine speed. In case a generator trip deenergizes the pump buses, the reactor coolant pump motors are transferred to off-site power within six to ten cycles.

5.5.1.3.10 Anti-reverse Rotation Device

Each of the reactor coolant pumps is provided with an anti-reverse rotation device in the motor. This anti-reverse mechanism consists of pawls mounted on the outside diameter of the flywheel, a serrated ratchet plate mounted on the motor frame, a spring return for the ratchet plate and two shock absorbers.



NOTES:

1- VALVES 1RH1 & 2 ARE INTERLOCKED WITH REACTOR COOLANT SYSTEM PRESSURE SIGNALS
2- VALVE HAS LEAKOFF CONNECTION WHICH IS PERMANTLY PIPED TO EQUIPMENT DRAIN HEADER
3- VALVE HAS REACH ROD TO FLOOR ABOVE
4- ELBOW TAP FLOWMETER
5- TEMPORARY STRAINER IS PLACED IN LINE DURING INITIAL FLUSHING CAPPED LINE IS CONNECTED TO TEMPORARY PRESSURE GAGE AT THIS TIME
6- LOCATE VALVE BEHIND SHIELDING AND AT A LOWER ELEVATION THAN PIPE BEING SAMPLED
7- ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1RH" (i.e. 1RH1000, ETC.) EXCEPT WHERE OTHERWISE NOTED.
8- ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
9- ALL CONTROL VALVES TO HAVE OPEN & CLOSED LIMIT SWITCHES.

BOUNDARY	DESIGN CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S28C	NO	III	NONE	NO
1S44A	YES	I	I	YES
1S44D	YES	I	II	YES
1S49A	YES	I	III	YES
1S51A	YES	I	II	YES
1S51B	YES	I	II	YES
1S53D	NO	III	III	NO
1S53N	NO	III	III	NO
1S56B	NO	II	III	NO

IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

VENDOR INSTR. NO.	PSE&G INSTR. NO.
FE-0564B	F-1299
FE-641A	F-1368
FIC-0564B	FA-0432
FIC-641A	FA-2569
PI-0633	PL-0413
PI-0630	PA-1466
TE-0536	TA-1408
TE-0539	TA-1425
TE-672D	TA-3136
TE-672E	TA-3137
TI-0659	TL-1415

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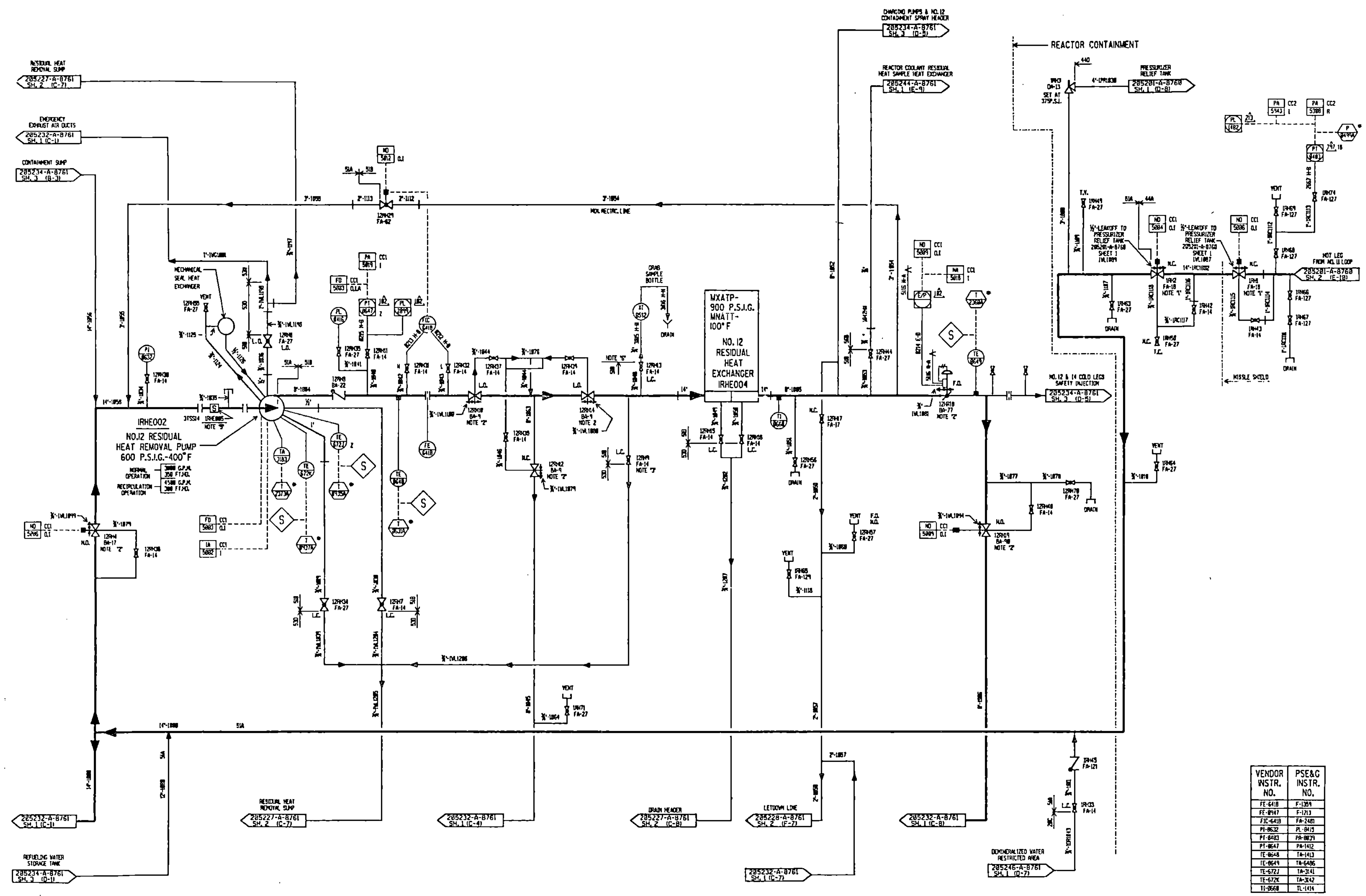
TI APERTURE CARD

8507300447 -09

Revision 4
July 22, 1985
Ref. Dwg. 205232A8761-15

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Residual Heat Removal System Unit 1
	Updated FSAR Sheet 1 of 2 Fig 5.5-1A



VENDOR INSTR. NO.	PSE&G INSTR. NO.
FE-641B	F-1359
FE-8947	F-1213
FIC-641B	FA-2481
PI-8632	PL-8419
PT-8403	PA-8839
PT-8647	PA-1412
TE-8648	TA-1413
TE-8649	TA-6486
TE-672J	TA-3141
TE-672K	TA-3142
TI-8660	TL-1414

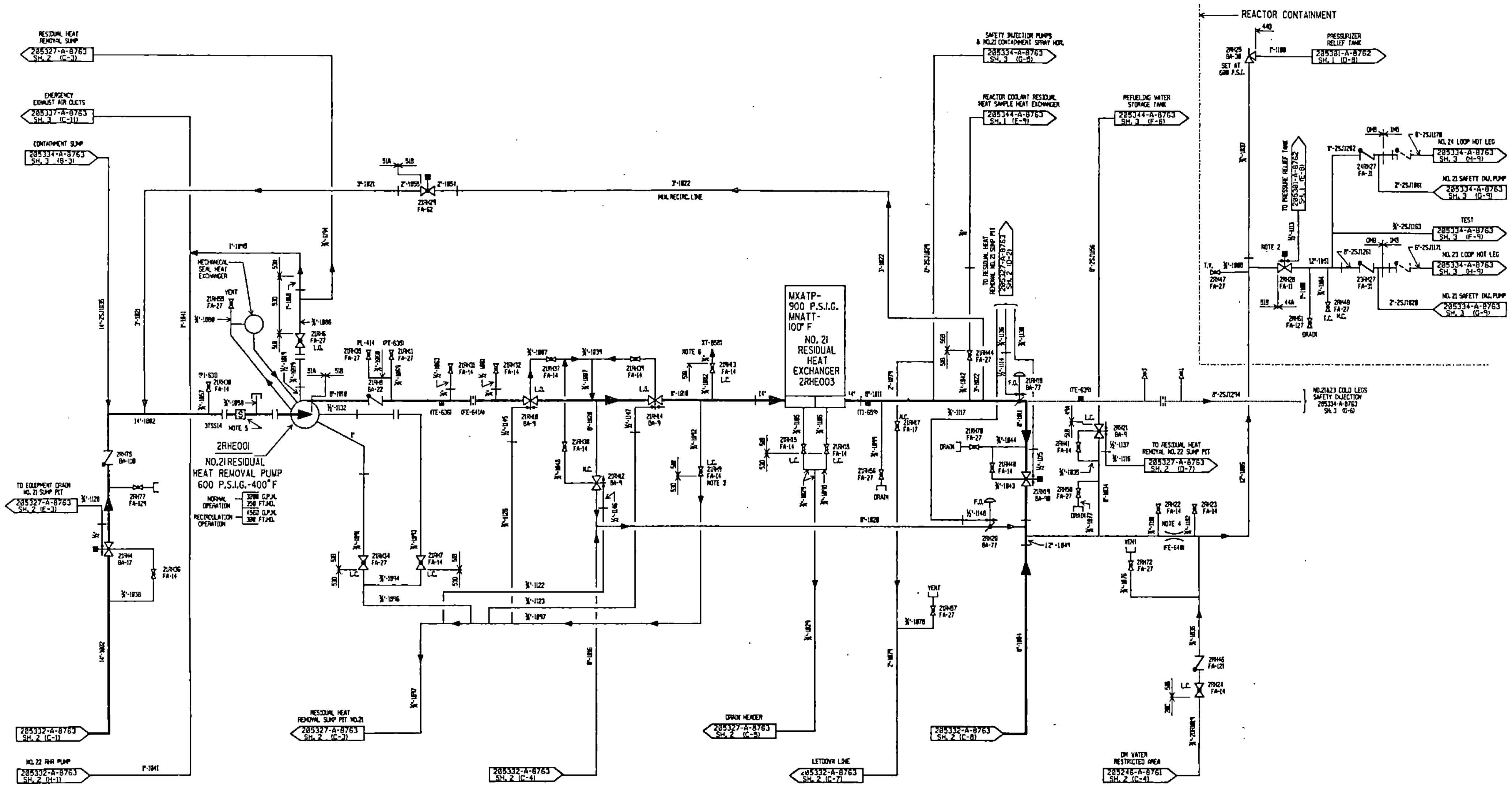
8507300447 -10

Revision 4
July 22, 1985
Ref. Dwg. 205232A8761-15

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Residual Heat Removal System
Unit 1

Updated FSAR Sheet 2 of 2 Fig 5.5-2A



NOTES:

1- ALL PIPING IS IN ACCORDANCE WITH PIPE SPEC. NO. 61-6200. THE PIPING SCHEDULE AND GROUP NO.S ARE AS NOTED ON THIS DWG. AND PREFIXED WITH "1S" IN THE PIPE SPEC.
2- VALVES 2RH1 & 2 ARE INTERLOCKED WITH REACTOR COOLANT SYSTEM PRESSURE SIGNALS
3- VALVE HAS REACH ROD TO FLOOR ABOVE
4- ELBOW TAP FLOWMETER
5- TEMPORARY STRAINER IS PLACED IN LINE DURING INITIAL START-UP. CAPPED LINE IS CONNECTED TO TEMPORARY PRESSURE GAGE AT THIS TIME
6- LOCATE VALVE BEHIND SHIELDING AND AT A LOWER ELEVATION THAN PIPE BEING SAMPLED
7- ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2RH" (i.e. 2RH1000, ETC.) EXCEPT WHERE OTHERWISE NOTED.
8- ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-0BL.
9- INSTRUMENT ITEMS IN PARENTHESIS ( ) ARE WESTINGHOUSE INSTRUMENT ITEMS. REFER TO ISA 5.1 FOR DESCRIPTION.

● BOUNDARY	DESIGN CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S20C	NO	III	NONE	NO
1S44A	YES	I	I	YES
1S44D	YES	I	II	YES
1S49A	YES	I	III	YES
1S51A	YES	I	II	YES
1S51B	YES	I	II	YES
1S53D	NO	III	III	NO
1S53N	NO	III	III	NO
1S56B	NO	II	III	NO

● IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

Also Available On Aperture Card

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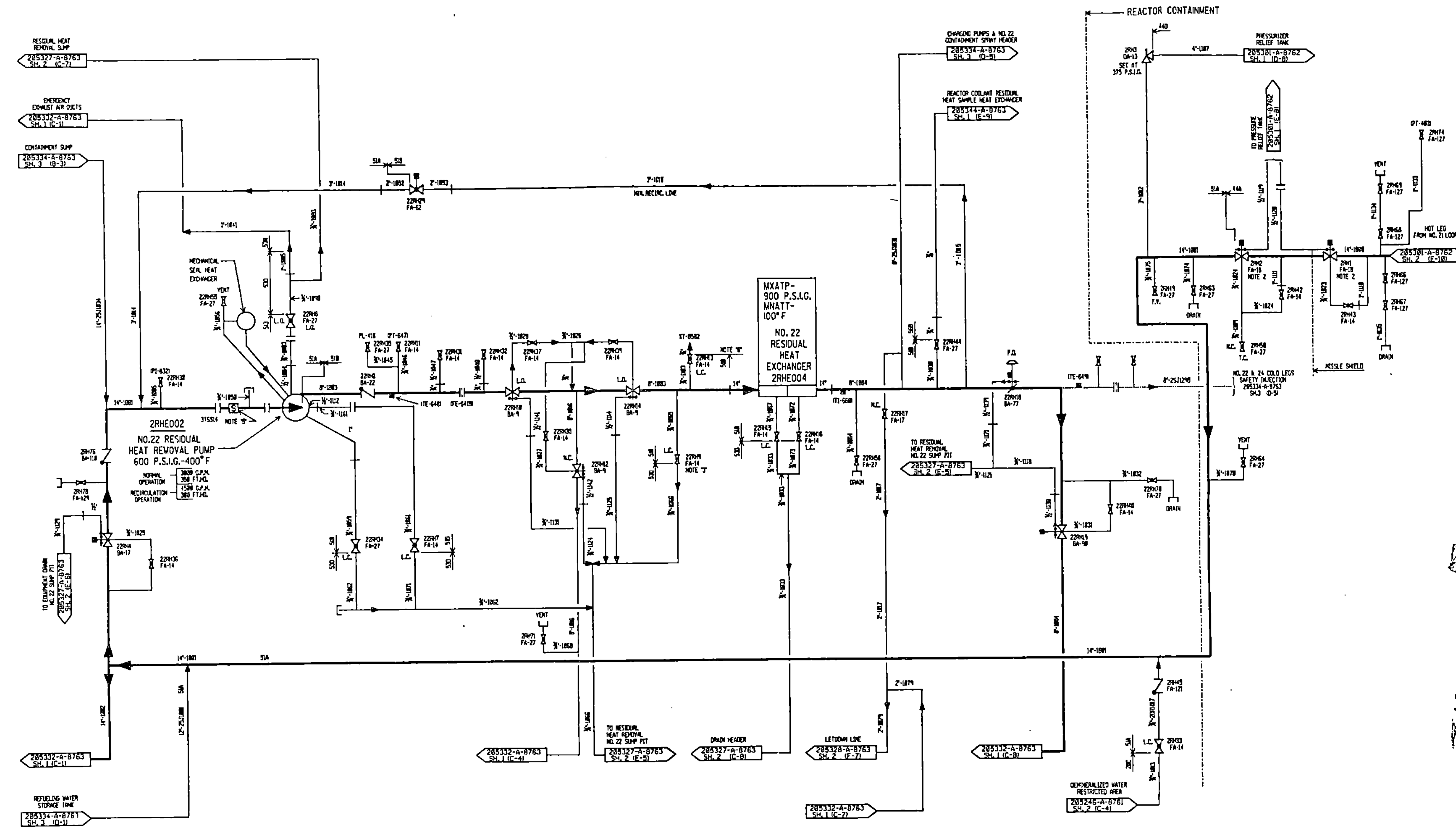
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Residual Heat Removal System Unit 2
	Updated FSAR Sheet 1 of 2 Fig 5.5-2B



8507300447-12

Revision 4
July 22, 1985
Ref. Dwg. 205332A8763-11

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Residual Heat Removal System Unit 2
	Updated FSAR Sheet 2 of 2 — Fig 5.5-2B

LIST OF FIGURES (Continued)

LIST OF FIGURES (Continued)

LIST OF FIGURES (Continued)

LIST OF FIGURES (Continued)

TABLE 6.2-10 (sheet 1 of 7)

CONTAINMENT ISOLATION - MAJOR PIPING PENETRATIONS

Figure	Service	Class	Status N	Status S	Status I	Valve	Inside Type	Pwr	Signal	Valve	Outside Type	Pwr	Signal	Auto Isol.Time	Fluid	Temp.
6.2-17	Gas Analyzer from Pressurizer Relief Tank	B	Int.	Closed	Closed	1PR17	Auto Trip	A	T	1PR18	Auto Trip	B	T	≤10 secs.	Gas	Cold
6.2-17	Primary Water Supply to Pressurizer Relief Tank	B	Int.	Closed	Closed	1WR81	Non Return	N/A	N/A	1WR80	Auto Trip	B	T	≤10 secs.	Liquid	Cold
6.2-17	Nitrogen Supply to Pressurizer Relief Tank	D	Int.	Closed	Closed	1NT26	Non Return	N/A	N/A	1NT25	Auto Trip	B	T	≤ 10 secs.	Gas	Cold
6.2-18	Pressurizer Dead Weight Calibrator	A	Closed	Closed	Closed	-	-	-	-	1SS901 1SS900	(2) Manual	N/A	N/A	N/A	Liquid	Cold
6.2-19	Relief Lines to Pressurizer Relief Tank	D	Int.	Closed	Closed	1PR25	Non Return	N/A	N/A	11-12CS5 1CV43 1SJ167 1SJ32 11-12SJ39 11-12SJ48	Relief Valves	N/A	N/A	N/A	Liquid	Cold
6.2-20	CVCS Letdown Line	D	Open	Closed	Closed	1CV3 1CV4 1CV5	(3)Auto Trip	B	T	1CV7	Auto Trip	B A C	T T T	≤ 10 secs.	Liquid	Hot
6.2-20	CVCS Charging Line	D	Open	Closed	Closed	1CV74	Non Return	N/A	N/A	1CV68 1CV69	(2)Auto Trip	B C	S S	≤ 10 secs.	Liquid	Hot
6.2-21	Reactor Coolant Pump Seal Water Supply	A	Open	Closed	Closed	11-14CV99	Non Return	N/A	N/A	11-14CV98	Manual	N/A	N/A	N/A	Liquid	Cold
6.2-21	Reactor Coolant Pump Seal Water Discharge	D	Open	Open	Open	1CV284	Auto Trip	B	T	1CV116	Auto Trip	C	T	≤10 secs.	Liquid	Cold
6.2-22	Residual Heat Removal Inlet From RCS	D	Closed	Open	Closed	1RH1 1RH2	(2)Rem. Manual	B A	N/A N/A	11RH4 12RH4	(2)Rem. Manual	A B	N/A N/A	N/A	Liquid	Hot
6.2-22	Residual Heat Removal Outlet to RCS	D	Closed	Open	Closed	1RH26	Rem. Manual	C	N/A	11RH19 12RH19	(2)Rem. Manual	A B	N/A N/A	N/A	Liquid	Hot
6.2-23	Excess Letdown Heat Exchanger Cooling Water Inlet	C	Closed	Closed	Closed	1CC109	Non Return	N/A	N/A	1CC215	Auto Trip	A	T	≤ 10 secs.	Liquid	Cold

TABLE 6.2-10 (sheet 2 of 7)

Figure	Service	Class	Status N	Status S	Status I	Valve	Inside Type	Pwr	Signal	Valve	Outside Type	Pwr	Signal	Auto Isol.Time	Fluid	Temp.
6.2-23	Excess Letdown Heat Exchanger Cooling Water Outlet	C	Closed	Closed	Closed	-	-	-	N/A	1CC113	Auto Trip	A	T	$\leq$ 10 secs.	Liquid	Cold
6.2-24	Reactor Coolant Pump Motor Cooling Water Supply	B	Open	Open	Closed	1CC119	Non Return	N/A	N/A	1CC117 1CC118	(2)Auto Trip	C A	P P	$\leq$ 10 secs.	Liquid	Cold
6.2-24	Reactor Coolant Motor Cooling Water Discharge	B	Open	Open	Closed	1CC187	Auto Trip	A	P	1CC136	Auto Trip	C	P	$\leq$ 10 secs.	Liquid	Cold
6.2-24	Reactor Coolant Pump Thermal Barrier Cooling Water Discharge	B	Open	Open	Closed	1CC190	Auto Trip	A	P	1CC131	Auto Trip	C	P	$\leq$ 10 secs.	Liquid	Cold
6.2-25	Gas Analyzer From RCDT	B	Int.	Closed	Closed	1WL96	Auto Trip	C	T	1WL97	Auto Trip	B	T	$\leq$ 10 secs.	Gas	Cold
6.2-25	N_2 Supply to RCDT	B	Closed	If Needed	Closed	1WL98	Auto Trip	C	T	1WL108	Auto Trip	B	T	$\leq$ 10 secs.	Gas	Cold
6.2-25	Reactor Coolant Drain Tank Vent	B	Open	Closed	Closed	1WL98	Auto Trip	C	T	1WL99	Auto Trip	B	T	$\leq$ 10 secs.	Gas	Cold
6.2-26	Reactor Coolant Drain Tank Pump Discharge	B	Int.	Int.	Closed	1WL12	Auto Trip	C	T	1WL13	Auto Trip	A	T	$\leq$ 10 secs.	Liquid	Hot
6.2-27	Accumulator N_2 Sup-ply	B	Int.	Int.	Closed	1NT34	Non Return	N/A	N/A	1NT32	Auto Trip	D	T	$\leq$ 10 secs.	Gas	Cold
6.2-28	Safety Injection Test Line	B	Closed	Closed	Closed	1SJ123	Auto Trip	A	T	1SJ53 1SJ60	(2)Auto Trip	D B	T T	$\leq$ 10 secs.	Liquid	Cold
6.2-29	RHR Outlets to Safety Injection System	B	Open	Closed	Open	11-14SJ43	Non Return	N/A	N/A	11SJ49 12SJ49	Rem. Manual	A	N/A	N/A	Liquid	Cold
6.2-30	Safety Injection Pumps Outlet To Cold Legs	B	Open	Closed	Open	11-14SJ144	Non Return	N/A	N/A	1SJ135	Auto Trip	A	T	$\leq$ 10 secs.	Liquid	Cold
6.2.30	Safety Injection Pumps Outlet To Hot Legs	B	Closed	Open	Open	11-14SJ139	Non Return	N/A	N/A	11SJ40 12SJ40	(2)Auto Trip	C A	P P	$\leq$ 10 secs.	Liquid	Cold

TABLE 6.2-10 (sheet 3 of 7)

Figure	Service	Class	Status N	Status S	Status I	Valve	Inside Type	Pwr	Signal	Valve	Outside Type	Pwr	Signal	Auto Isol. Time	Fluid	Temp.
6.2-31	Injection Line From Charging Pumps	B	Closed	Closed	Open	1SJ150	Non Return	N/A	N/A	1SJ12 1SJ13	Auto Trip	C	P	$\leq$ 10 secs.	Liquid	Cold
6.2-31	Flushing Line From Charging Pumps	B	Closed	Closed	Closed	1SJ150	Non Return	N/A	N/A	1SJ71	Manual	N/A	N/A	N/A	Liquid	Cold
6.2-32	Residual Heat Removal Suction From Sump	D	Closed	Closed	Open	11SJ44 12SJ44	Rem. Manual	A B	N/A	-	-	-	N/A	$\leq$ 10 secs.	Liquid	Cold
6.2-33	Containment Spray	B	Closed	Closed	If Needed	11CS48 12CS48	Non Return	N/A	N/A	11CS2 12CS2	Auto Trip	B	T	$\leq$ 10 secs.	Gas	Cold
6.2-33	RHR Outlet To Containment Spray	D	Closed	Closed	If Needed	11CS48 12CS48	Non Return	N/A	N/A	11CS36 12CS36	Auto Trip	B	T	$\leq$ 10 secs.	Gas	Cold
6.2-34	Sample Line From Pressurizer Steam Space	B	Open	Closed	Closed	1SS110	Auto Trip	A	T	1SS64	Auto Trip	A	T	$\leq$ 10 secs.	Gas	Cold
6.2-34	Sample Line From Accumulators	B	Closed	Closed	Closed	1SS103	Auto Trip	A	T	1SS27	Auto Trip	A	T	$\leq$ 10 secs.	Liquid	Hot
6.2-34	Sample Line From Hot Legs	B	Closed	Closed	Closed	1SS104	Auto Trip	A	T	1SS33	Non Return	D	T	$\leq$ 10 secs.	Gas	Cold
6.2-34	Sample Line From Pressurizer Liquid	B	Closed	Closed	Closed	1SS107	Auto Trip	A	T	1SS49	Auto Trip	B	T	$\leq$ 10 secs.	Liquid	Cold
6.2-34	Sample Lines From Steam Generator Blow-Down	C	Closed	Closed	Closed	11-14SS93	Rem. Manual	A	N/A	11-14SS94	Auto Trip	B	T	$\leq$ 10 secs.	Liquid	Hot
6.2-35	Containment Pressure Instruments	A	Open	Open	Open	-	-	-	-	-	-	-	-	-	(Filled System)	
6.2-36	Containment Air Monitor															
	Inlet - Normal	D	Open	Open	Closed	1VC11	Auto Trip	B	T	1VC12	Auto Trip	A	T	$\leq$ 10 secs.	Gas	Cold
	Inlet - Backup	D	Closed	Closed	Closed	1VC13	Rem. Manual	C	N/A	1VC14	Rem. Manual	C	N/A	N/A	Gas	Cold
	Outlet - Normal	D	Open	Open	Closed	1VC7	Auto Trip	B	T	1VC8	Auto Trip	A	T	$\leq$ 10 secs.	Gas	Cold
	Outlet - Backup	D	Closed	Closed	Closed	1VC9	Rem. Manual	C	N/A	1VC10	Rem. Manual	C	N/A	N/A	Gas	Cold
6.2-37	Pressure Vacuum Relief Inlet and Outlet	B	Int.	If Needed	Closed	1VC6	Auto Trip	C	T	1VC5	Auto Trip	B	T	$\leq$ 2 secs.	Gas	Cold

Figure	Service	Class	Status N	Status S	Status I	Valve	Inside Type	Pwr	Signal	Valve	Outside Type	Pwr	Signal	Auto Isol.Time	Fluid	Temp.
6.2-37	Purge Air Inlet (Containment)	B	Closed	If Needed	Closed	1VC2	Auto Trip	A	T	1VC1	Auto Trip	B	T	$\leq$ 2 secs.	Gas	Cold
6.2-37	Purge Air Outlet (Containment)	B	Closed	If Needed	Closed	1VC3	Auto Trip	A	T	1VC4	Auto Trip	B	T	$\leq$ 2 secs.	Gas	Cold
6.2.38	Demineralized Water Supply To Flushing Connections	B	Open	Closed	Closed	1DR30	Non Return	N/A	N/A	1DR29	Auto Trip	A	T	$\leq$ 10 secs.	Liquid	Cold
6.2-38	Service Air	B	Closed	Open	Closed	1SA119	Non Return	N/A	N/A	1SA118	Manual	N/A	N/A	N/A	Air	Cold
6.2-38	Instrument Air	B	Open	Open	Closed	11CA360 12CA360	Non Return	N/A	N/A	11CA330 12CA330	Auto Trip	A B	T T	$\leq$ 10 secs.	Air	Cold
6.2-39	Service Water To Fan Coolers	C	Open	If Needed	Open	-	-	-	-	11SW58 12SW58 13SW58 14SW58 15SW58	Rem. Manual	A B C B C	N/A N/A N/A N/A N/A	N/A	Liquid	Cold
6.2-39	Service Water From Fan Coolers	C	Open	If Needed	Open	-	-	-	-	11SW72 12SW72 13SW72 14SW72 15SW72	Rem. Manual	A B C B C	N/A N/A N/A N/A N/A	N/A	Liquid	Cold
6.2-40 thru 6.2-43	Steam Generator Main Steam Stop	C	Open	Closed	Closed	-	-	-	-	11-14MS167	Auto Trip	C-D	MSI	$\leq$ 5 secs.	Gas	Hot
6.2-40 thru 6.2-43	Steam Generator Steam Outlet Drain	C	Open	Closed	Closed	-	-	-	-	11MS7 12MS7 13MS7 14MS7	Auto Trip	C C D D	MSI MSI MSI MSI	$\leq$ 10 secs.	Gas	Hot
6.2-40 thru 6.2-42	Steam Generator Steam Outlet Bypass To Aux. Feed Pump Turbine	C	Closed	Int.	Open	-	-	-	-	1MS132	Rem. Manual	C	N/A	N/A	Gas	Hot
6.2-40 thru 6.2-43	Steam Generator Blowdown	C	Open	Closed	Closed	-	-	-	-	11-14GB4	Auto Trip	C	T	$\leq$ 10 secs.	Liquid	Hot

TABLE 6.2-10 (sheet 5 of 7)

Figure	Service	Class	N	S	I	Valve	Inside Type	Pwr	Signal	Valve	Outside Type	Pwr	Signal	Auto Isol.Time	Fluid	Temp
6.2-40 thru 6.2-43	Feedwater Supply (Control Valve)	C	Open	Closed	Closed	-	-	-	-	11BF22 12BF22 13BF22 14BF22 11BF19 12BF40 12BF19 12BF40 13BF19 13BF40 14BF19 14BF40	Non Return Auto Trip	B B A A C C C C D D D D	FWI FWI FWI FWI FWI FWI FWI FWI FWI FWI FWI FWI	N/A < 8 secs.	Liquid	Hot
6.2-40 thru 6.2-43	Steam Generator Main Steam Stop Bypass	C	Open	Closed	Closed	-	-	-	-	11MS18 12MS18 13MS18 14MS18	Auto Trip Trip Trip	C C D D	MSI MSI MSI MSI	≤ 10 secs.	Gas	Hot
6.2-40 thru 6.2-43	Auxiliary Feedwater Supply-Turbine Driven	C	Open	Int.	Open	-	-	-	-	11-14AF11	Rem. Manual	C	N/A	N/A	Liquid	Cold
6.2-40 thru 6.2-43	Auxiliary Feedwater Supply-Motor Driven	C	Closed	Int.	Open	-	-	-	-	11AF21 12AF21 13AF21 14AF21	Rem. Manual Manual Manual	B B A A	N/A N/A N/A N/A	N/A	Liquid	Cold
6.2-44	Fuel Transfer Tube	B	Closed	Open	Closed	-	Blind Flange	-	-	-	Manual	N/A	N/A	N/A	Liquid	Cold
6.2-44	Reactor Cavity Sump Pump Discharge to Waste Disposal	B	Open	Int.	Closed	1WL16	Auto Trip	C	T	1WL17	Auto Trip	B	T	≤ 10 secs.	Liquid	Cold
6.2-45	Fire Protection Water Supply	B	Closed	Closed	Closed	1FP148	Non Return	N/A	N/A	1FP147	Auto Trip	C	T	≤ 10 secs.	Liquid	Cold
6.2-45	Refueling Canal Supply	B	Closed	Closed	Closed	1WL190	Manual	N/A	N/A	1SF36	Manual	N/A	N/A	N/A	Liquid	Cold
6.2-45	Refueling Canal	B	Closed	Closed	Closed	1WL191	Manual	N/A	N/A	1SF22	Manual	N/A	N/A	N/A	Liquid	Cold

TABLE 6.2-10 (sneet 6 of 7)

Figure	Service	Class	Status N	Status S	Status I	Valve	Inside Type	Pwr	Signal	Valve	Outside Type	Pwr	Signal	Auto Isol.Time	Fluid	Temp.
6.2-45A	Post-LOCA Atmo. Sample	B	Closed	Closed	Int.	11VC19	Rem. Manual	A	N/A	11VC17	Rem. Manual	A	N/A	N/A	Gas	Cold
	Post-LOCA Atmo. Sample	B	Closed	Closed	Int.	11VC20	Rem. Manual	A	N/A	11VC18	Rem. Manual	A	N/A	N/A	Gas	Cold
	Post-LOCA Atmo. Sample	B	Closed	Closed	Int.	12VC20	Rem. Manual	C	N/A	12VC18	Rem. Manual	C	N/A	N/A	Gas	Cold
	Post-LOCA Atmo. Sample	B	Closed	Closed	Int.	12VC19	Rem. Manual	C	N/A	12VC17	Rem. Manual	C	N/A	N/A	Gas	Cold
6.2-45B	Post-LOCA RCS Sample	B	Closed	Closed	Int.	13SS184	Rem. Manual	C	N/A	13SS185	Rem. Manual	C	N/A	N/A	Liquid	Hot
	Post-LOCA RCS Sample	B	Closed	Closed	Int.	13SS182	Rem. Manual	C	N/A	13SS181	Rem. Manual	C	N/A	N/A	Liquid	Hot
	Post-LOCA RCS Sample	B	Closed	Closed	Int.	11SS182	Rem. Manual	A	N/A	11SS181	Rem. Manual	A	N/A	N/A	Liquid	Hot
	Post-LOCA RCS Sample	B	Closed	Closed	Int.	11SS188	Rem. Manual	A	N/A	11SS189	Rem. Manual	A	N/A	N/A	Liquid	Hot
6.2-45C	Fill line for Cont. Press. Inst.	B	Closed	Closed	Closed	1CS900	Manual	N/A	N/A	1CS902	Manual	N/A	N/A	N/A	Liquid	Cold
6.2-45D	Cont. Press. Test Inst.	B	Closed	Closed	Closed	1SA264	Manual	N/A	N/A	1SA262	Manual	N/A	N/A	N/A	Gas	Cold
	Cont. Press. Test Inst.	B	Closed	Closed	Closed	1SA267	Manual	N/A	N/A	1SA265	Manual	N/A	N/A	N/A	Gas	Cold
	Cont. Press. Test Inst.	B	Closed	Closed	Closed	1SA270	Manual	N/A	N/A	1SA268	Manual	N/A	N/A	N/A	Gas	Cold

N: Normal
S: Shutdown
I: Incident
Int: Intermittent
P: Tripped by Containment Isolation Signal - Phase B
T: Tripped by Containment Isolation Signal - Phase A
FWI: Feed Water Isolation
MSI: Main Steam Isolation

*Applies to No. 1 Unit only, No. 2 Unit valves have remote-manual motor operators.

TABLE 6.2-10 (sheet 7 of 7)

Notes

1. Valve designations are shown for No. 1 Unit although No. 2 Unit is similar (e.g. 11MS167 would be 21MS167 for No. 2 Unit). The

2. The column titled "class" contains the designators defined in Section 6.2.4.2.

3. The isolation valve power source is the vital channel designation and may be either 230 VDC or 125 VDC depending on the type of valve.

4. Normally closed manual valves are under administrative control.

5. The following lines contain remotely operated valves which are normally closed and under administrative control.

    1. Excess letdown heat exchanger cooling water lines.

    2. Safety injection system test line

    3. Steam generator steam actuators (drain and bypass)

    4. Sample lines from pressurizer

    5. Containment purge air inlet and outlet and pressure-vacuum relief dampers

    6. Nitrogen supply to reactor coolant drain tank

    7. Post-LOCA atmosphere and RCS sampling

CONTAINMENT ISOLATION VALVES SUBJECT TO TYPE C LEAK RATE TESTING

Valve Number	Function
1. 1 PR 17	Pressurizer Relief Tk. - Gas Analyzer Conn.
2. 1 PR 18	Pressurizer Relief Tk. - Gas Analyzer Conn.
3. 1 NT 25	Pressurizer Relief Tk. - N_2 Conn.
4. 1 NT 26	Pressurizer Relief Tk. - N_2 Conn.
5. 1 WR 80	Pressurizer Relief Tk. - Primary Water Conn.
6. 1 WR 81	Pressurizer Relief Tk. - Primary Water Conn.
7. 1 CV 3	CVCS - Letdown Line
8. 1 CV 4	CVCS - Letdown Line
9. 1 CV 5	CVCS - Letdown Line
10. 1 CV 7	CVCS - Letdown Line
11. 1 CV 68/69	CVCS - Charging Line
12. 1 CV 74	CVCS - Charging Line
13. 1 CV 284	CVCS - RCP Seals
14. 1 CV 296	CVCS - RCP Seals
15. 1 CV 116	CVCS - RCP Seals
16. 1 CV 215	Comp. Cooling - Excess Letdown Hx
17. 1 CV 113	Comp. Cooling - Excess Letdown Hx
18. 1 CC 117	Comp. Cooling - RCP Cooler
19. 1 CC 118	Comp. Cooling - RCP Cooler
20. 1 CC 187	Comp. Cooling - RCP Cooler
21. 1 CC 136	Comp. Cooling - RCP Cooler
22. 1 CC 190	Comp. Cooling - RCP Cooler
23. 1 CC 131	Comp. Cooling - RCP Cooler
24. 1 CC 186	Comp. Cooling - RCP Cooler
25. 1 CC 208	Comp. Cooling - RCP Cooler
26. 1 WL 96	RC Drain TK. - Gas Analyzer Conn.
27. 1 WL 97	RC Drain Tk. - Gas Analyzer Conn.
28. 1 WL 98	RC Drain Tk. - Vent Header Conn.
29. 1 WL 99	RC Drain Tk. - Vent Header Conn.
30. 1 WL 108	RC Drain Tk. - N_2 Connection
31. 1 WL 12	RC Drain Tk. Pumps
32. 1 WL 13	RC Drain Tk. Pumps
33. 1 NT 32	Accumulator N_2 Supply
34. 1 NT 34	Accumulator N_2 Supply
35. 1 SJ 123	SI Test Line
36. 1 SJ 60	SI Test Line
37. 1 SJ 53	SI Test Line
38. 11 CS 2	Containment Spray
39. 12 CS 2	Containment Spray
40. 11 CS 48	Containment Spray
41. 12 CS 48	Containment Spray
42. 1 SS 110	Pressurizer Steam Sampling
43. 1 SS 64	Pressurizer Steam Sampling
44. 1 SS 103	Accumulator Sampling
45. 1 SS 27	Accumulator Sampling
46. 1 SS 104	RCS Sampling

TABLE 6.2-12 (sheet 2 of 3)

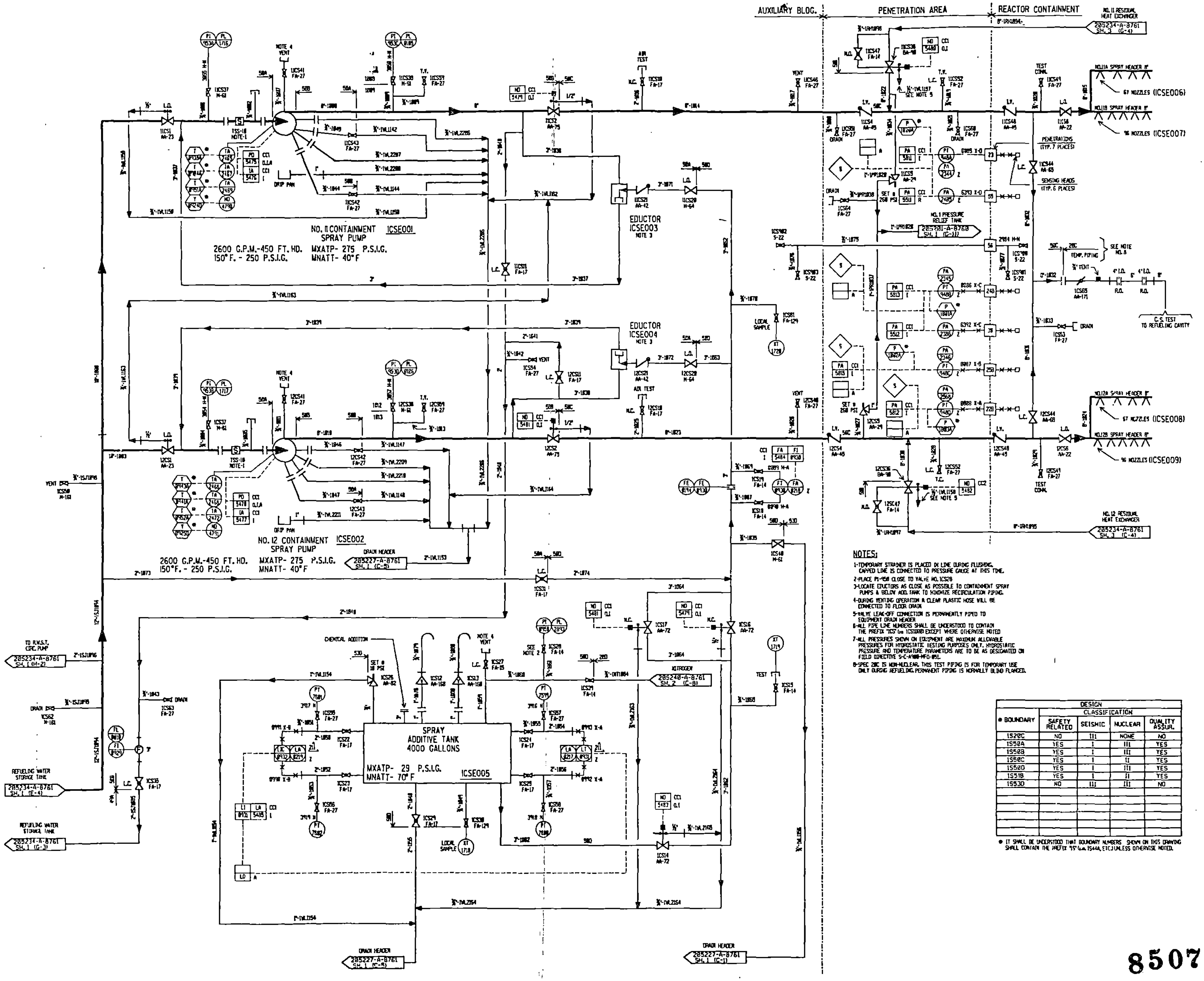
CONTAINMENT ISOLATION VALVES
SUBJECT TO TYPE C LEAK RATE TESTING
(CONTINUED)

Valve Number	Function
47. 1 SS 33	RCS Sampling
48. 1 SS 107	Pressurizer Liquid Sampling
49. 1 SS 49	Pressurizer Liquid Sampling
50. 1 VC 1	Purge Supply
51. 1 VC 2	Purge Supply
52. 1 VC 3	Purge Exhaust
53. 1 VC 4	Purge Exhaust
54. 1 VC 5	Pressure - Vacuum Relief
55. 1 VC 6	Pressure - Vacuum Relief
56. 1 VC 7	Containment Radiation Sampling
57. 1 VC 8	Containment Radiation Sampling
58. 1 VC 9	Containment Radiation Sampling - Alt
59. 1 VC 10	Containment Radiation Sampling - Alt
60. 1 VC 11	Containment Radiation Sampling
61. 1 VC 12	Containment Radiation Sampling
62. 1 VC 13	Containment Radiation Sampling - Alt
63. 1 VC 14	Containment Radiation Sampling - Alt
64. 1 DR 29	Demineralized Water Supply
65. 1 DR 30	Demineralized Water Supply
66. 1 SA 118	Compressed Air Supply
67. 1 SA 119	Compressed Air Supply
68. 11 CA 330	Instrument Air Supply
69. 12 CA 330	Instrument Air Supply
70. 1 WL 16	Containment Sump Discharge
71. 1 WL 17	Containment Sump Discharge
72. 1 FP 147	Fire Protection System
73. 1 FP 148	Fire Protection System
74. 1 WL 190	S.F. Demin. to Refueling Canal
75. 1 WL 191	Refueling Canal to S.F. Demin.
76. 1 SF 36	S.F. Demin to Refueling Canal
77. 1 SF 22	Refueling Canal to S.F. Demin.
78. 1 CS 900	Fill Line for Cont. Press. Instr.
79. 1 CS 901	Fill Line for Cont. Press. Instr.
80. 1 CS 902	Fill Line for Cont. Press. Instr.
81. 1 CS 903	Fill Line for Cont. Press. Instr.
82. 1 SA 262	Containment Press. Test Instr.
83. 1 SA 264	Containment Press. Test Instr.

CONTAINMENT ISOLATION VALVES
SUBJECT TO TYPE C LEAK RATE TESTING
(CONTINUED)

Valve Number	Function
84. 1 SA 265	Containment Press. Test Instr.
85. 1 SA 267	Containment Press. Test Instr.
86. 1 SA 270	Containment Press. Test Instr.
87. 11 SS 181	Post LOCA RCS Sampling
88. 11 SS 182	Post LOCA RCS Sampling
89. 11 SS 188	Post LOCA RCS Sampling
90. 11 SS 189	Post LOCA RCS Sampling
91. 13 SS 181	Post LOCA RCS Sampling
92. 13 SS 182	Post LOCA RCS Sampling
93. 13 SS 184	Post LOCA RCS Sampling
94. 13 SS 185	Post LOCA RCS Sampling
95. 11 VC 17	Post LOCA Atmos. Sampling
96. 11 VC 18	Post LOCA Atmos. Sampling
97. 11 VC 19	Post LOCA Atmos. Sampling
98. 11 VC 20	Post LOCA Atmos. Sampling
99. 12 VC 17	Post LOCA Atmos. Sampling
100. 12 VC 18	Post LOCA Atmos. Sampling
101. 12 VC 19	Post LOCA Atmos. Sampling
102. 12 VC 20	Post LOCA Atmos. Sampling

NOTE: Valve designations are shown for No. 1 Unit although No. 2 Unit is similar (e.g. 1 PR 17 would be 2 PR 17 for No. 2 Unit).



NOTES:

1- TEMPORARY STRAINER IS PLACED ON LINE DURING FLUSHING. CAPPED LINE IS CONNECTED TO PRESSURE GAUGE AT THIS TIME.
2- PLACE PI-950 CLOSE TO VALVE NO. 1CS28
3- LOCATE EDUCTORS AS CLOSE AS POSSIBLE TO CONTAINMENT SPRAY PUMPS & BELOW ADD. TANK TO MINIMIZE RECIRCULATION PIPING.
4- DURING VENTING OPERATION A CLEAR PLASTIC HOSE WILL BE CONNECTED TO FLOOR DRAIN
5- VALVE LEAK-OFF CONNECTION IS PERMANENTLY PIPED TO EQUIPMENT DRAIN HEADER
6- ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1CS" (i.e. 1CS1000) EXCEPT WHERE OTHERWISE NOTED
7- ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
8- SPEC 20C IS NON-NUCLEAR. THIS TEST PIPING IS FOR TEMPORARY USE ONLY DURING REFUELING. PERMANENT PIPING IS NORMALLY BLIND FLANGED.

● BOUNDARY	DESIGN CLASSIFICATION: SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S20C	NO	III	NONE	NO
1S50A	YES	I	III	YES
1S50B	YES	I	III	YES
1S50C	YES	I	II	YES
1S50D	YES	I	III	YES
1S51B	YES	I	II	YES
1S53D	NO	III	III	NO

● IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

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Revision 4
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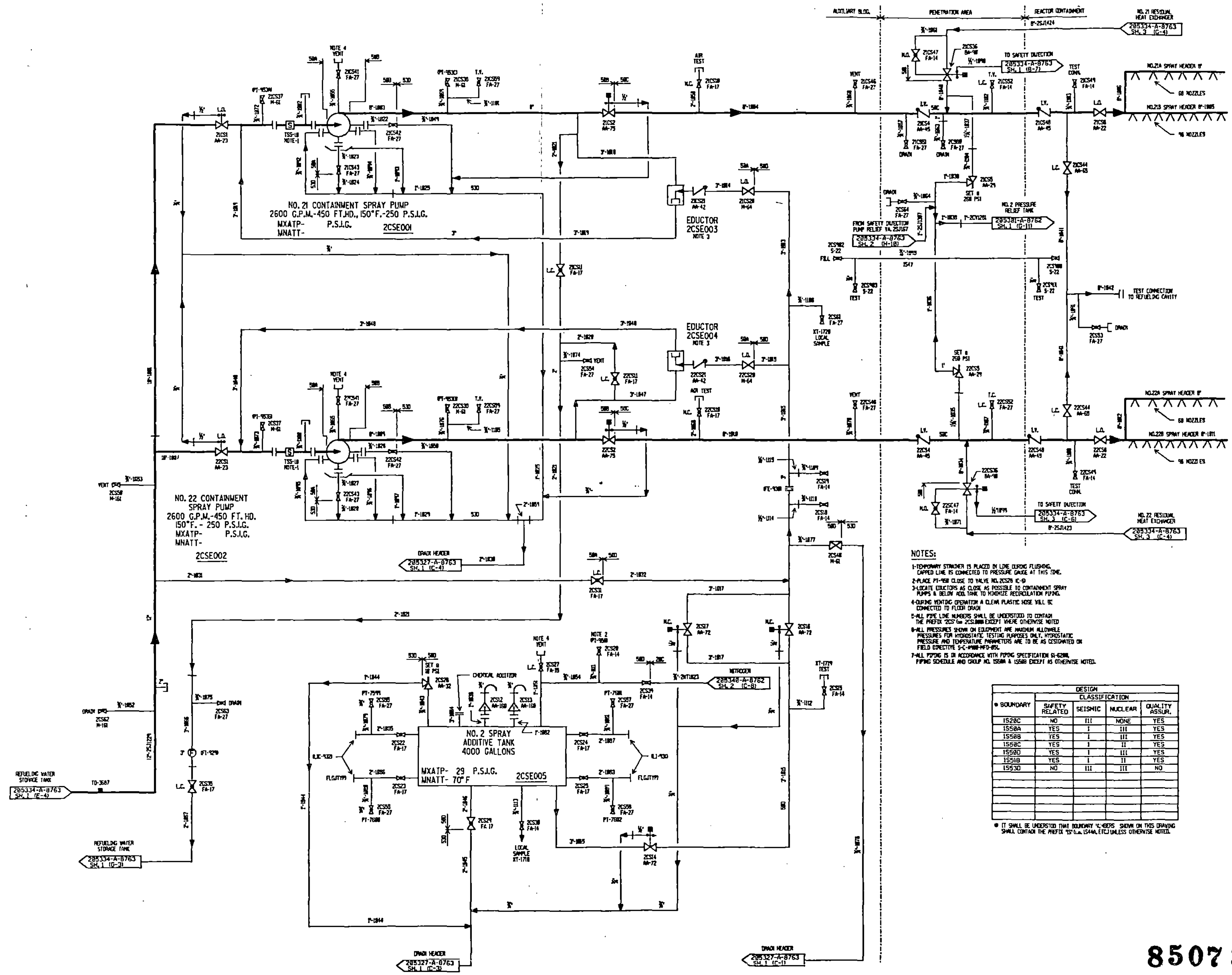
Ref. Dwg. 205235A8761-18

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Spray System Unit 1
	Updated FSAR — Fig 6.2-4A



NOTES:

1-TEMPORARY STRAINER IS PLACED IN LINE DURING FLUSHING. CAPPED LINE IS CONNECTED TO PRESSURE GAUGE AT THIS TIME.

2-PLACE PT-958 CLOSE TO VALVE NO. 2CS28 (C-9)

3-LOCATE EDUCTORS AS CLOSE AS POSSIBLE TO CONTAINMENT SPRAY PUMPS & BELOW ADD. TANK TO MINIMIZE RECIRCULATION PIPING.

4-DURING VENTING OPERATION A CLEAR PLASTIC HOSE WILL BE CONNECTED TO FLOOR DRAIN

5-ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2CS" (i.e. 2CSL[illegible]) EXCEPT WHERE OTHERWISE NOTED

6-ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-[illegible]-MFD-05L

7-ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION S1-62[illegible], PIPING SCHEDULE AND GROUP NO. 1S50A & 1S50B EXCEPT AS OTHERWISE NOTED.

* BOUNDARY	DESIGN CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S20C	NO	III	NONE	YES
1S50A	YES	I	III	YES
1S50B	YES	I	III	YES
1S50C	YES	I	II	YES
1S50D	YES	I	III	YES
1S51B	YES	I	II	YES
1S530	NO	III	III	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

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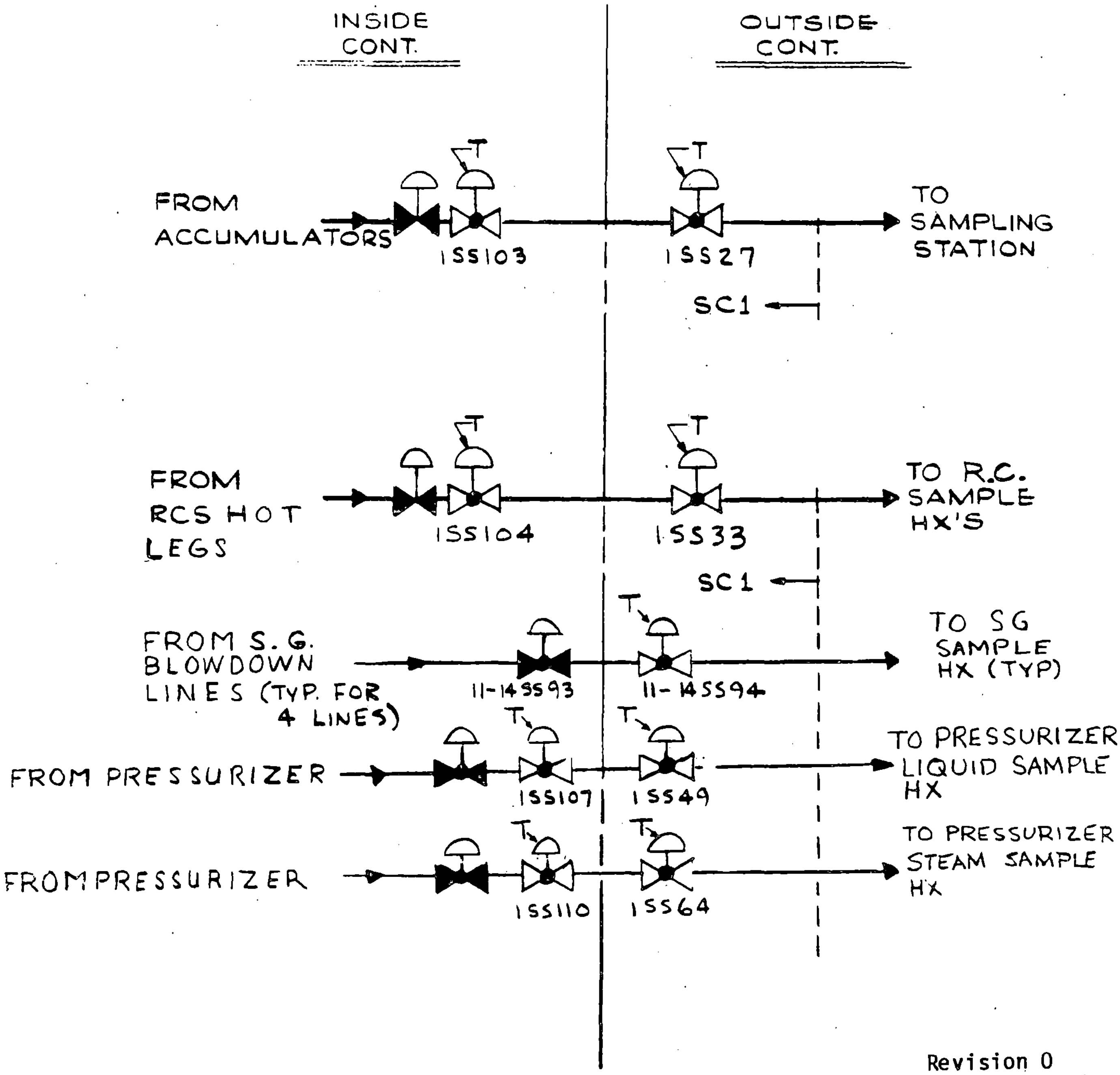
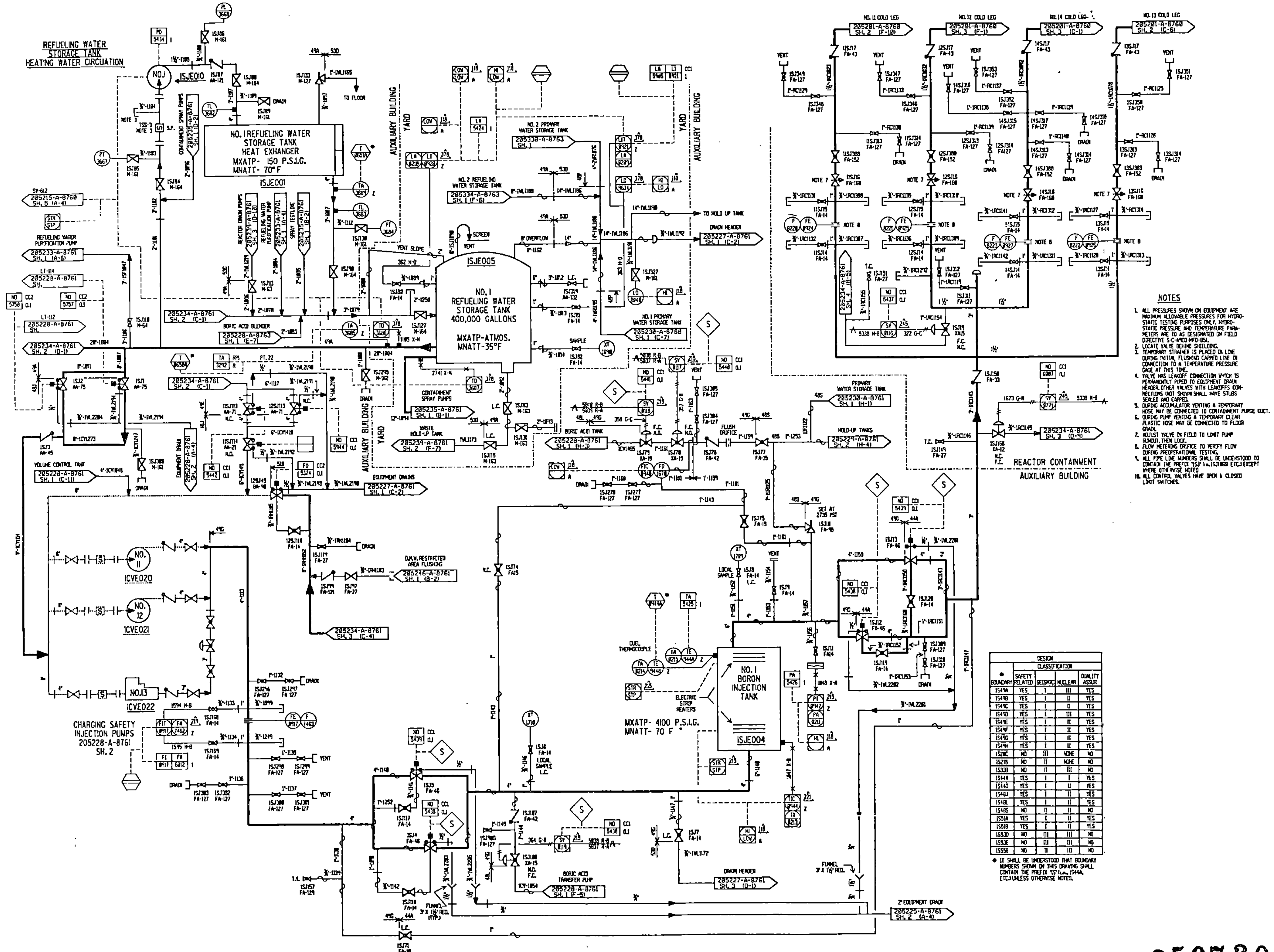
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Spray System Unit 2
	Updated FSAR — Fig 6.2-4B



Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation - Reactor Coolant, Steam Generator, Pressurizer, Accumulator Sampling
	Updated FSAR — FIG. 6.2-34



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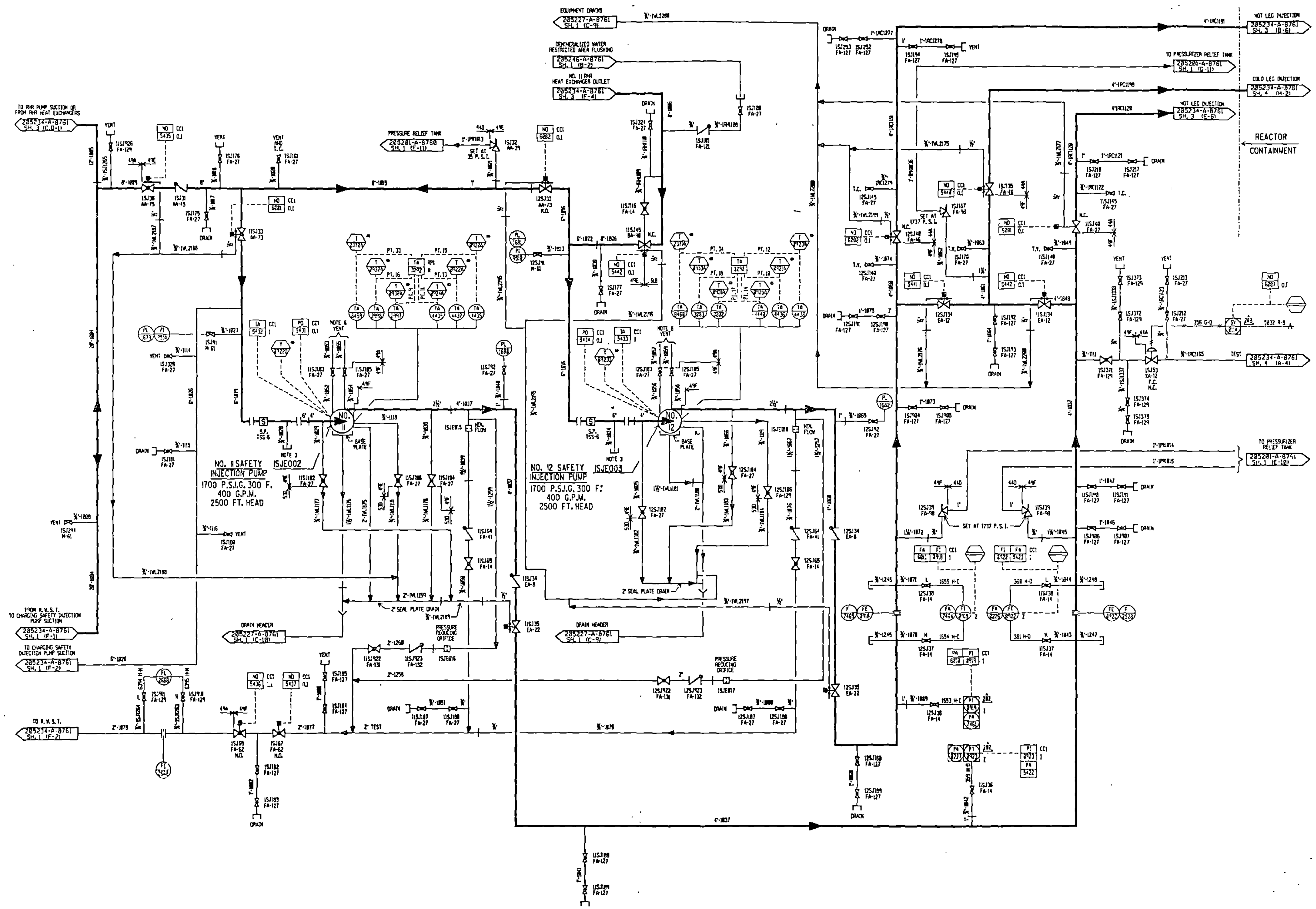
Revision 4
July 22, 1985
Ref. Dwg. 205234A8761-20

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Emergency Core Cooling System Unit 1
	Updated FSAR Sheet 1 of 4 Fig 6.3-1A



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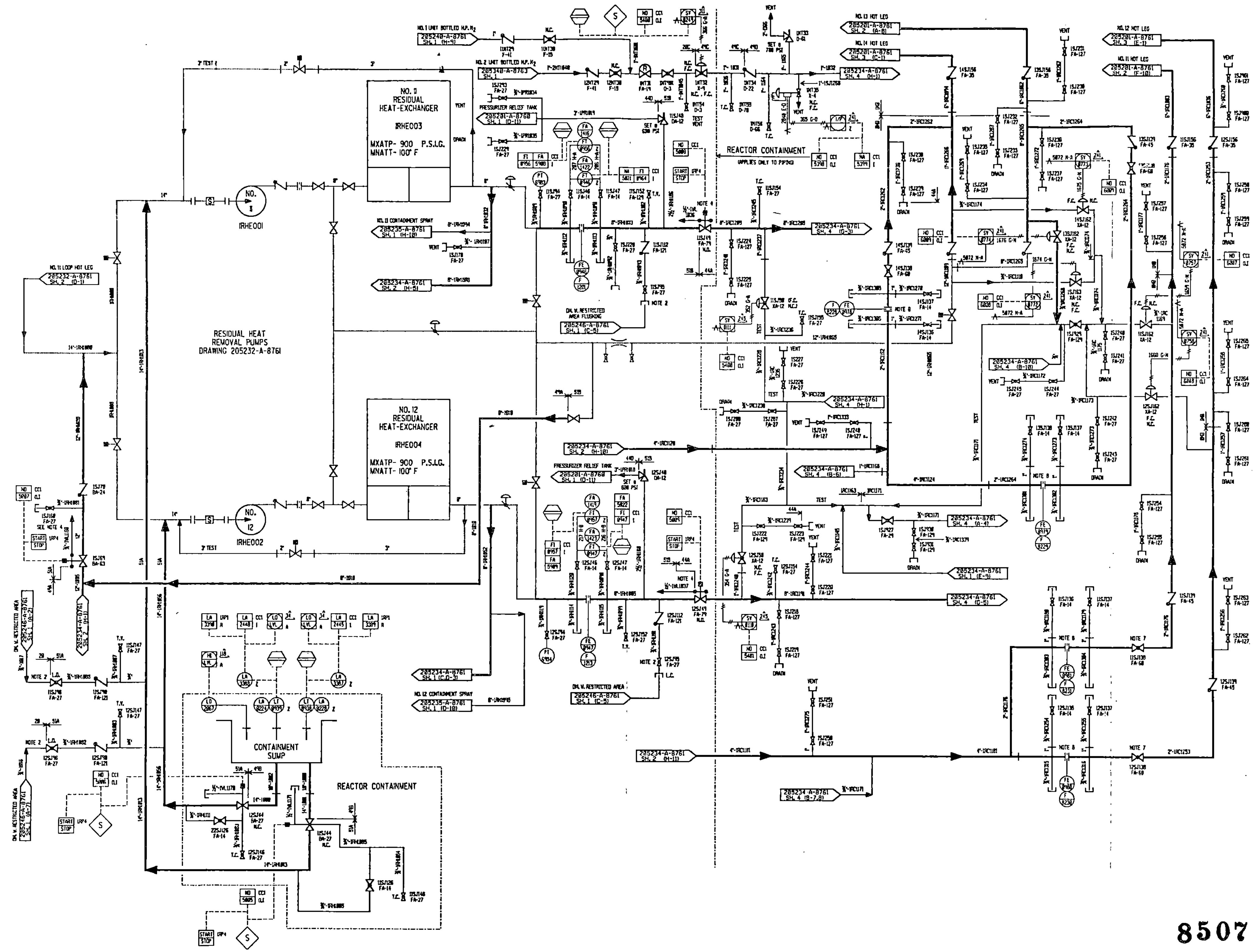
Revision 4
July 22, 1985
Ref. Dwg. 205234A8761-20

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Emergency Core Cooling System Unit 1
	Updated FSAR Sheet 2 of 4 Fig 6.3-1A



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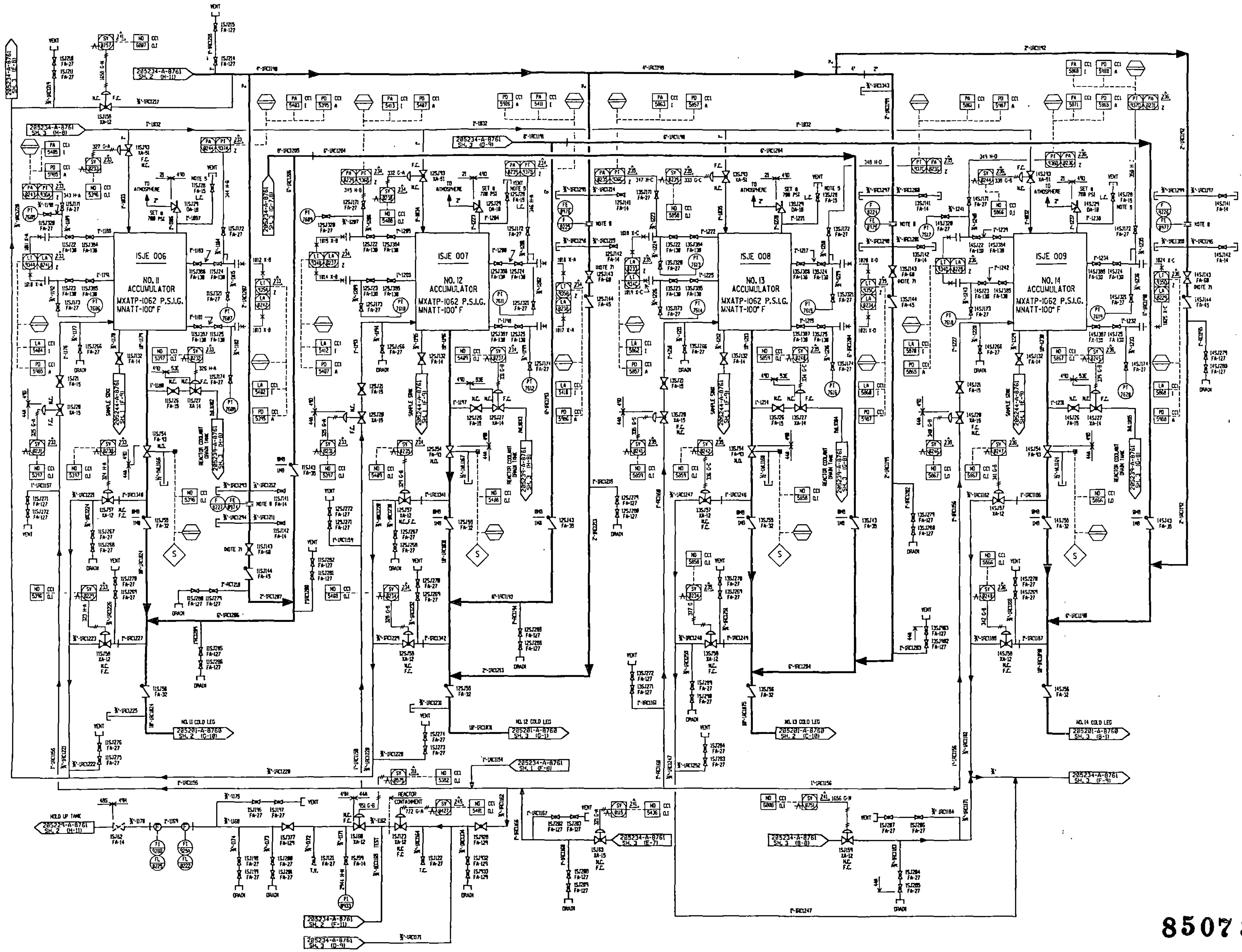
Revision 4
July 22, 1985
Ref. Dwg. 205234A8761-20

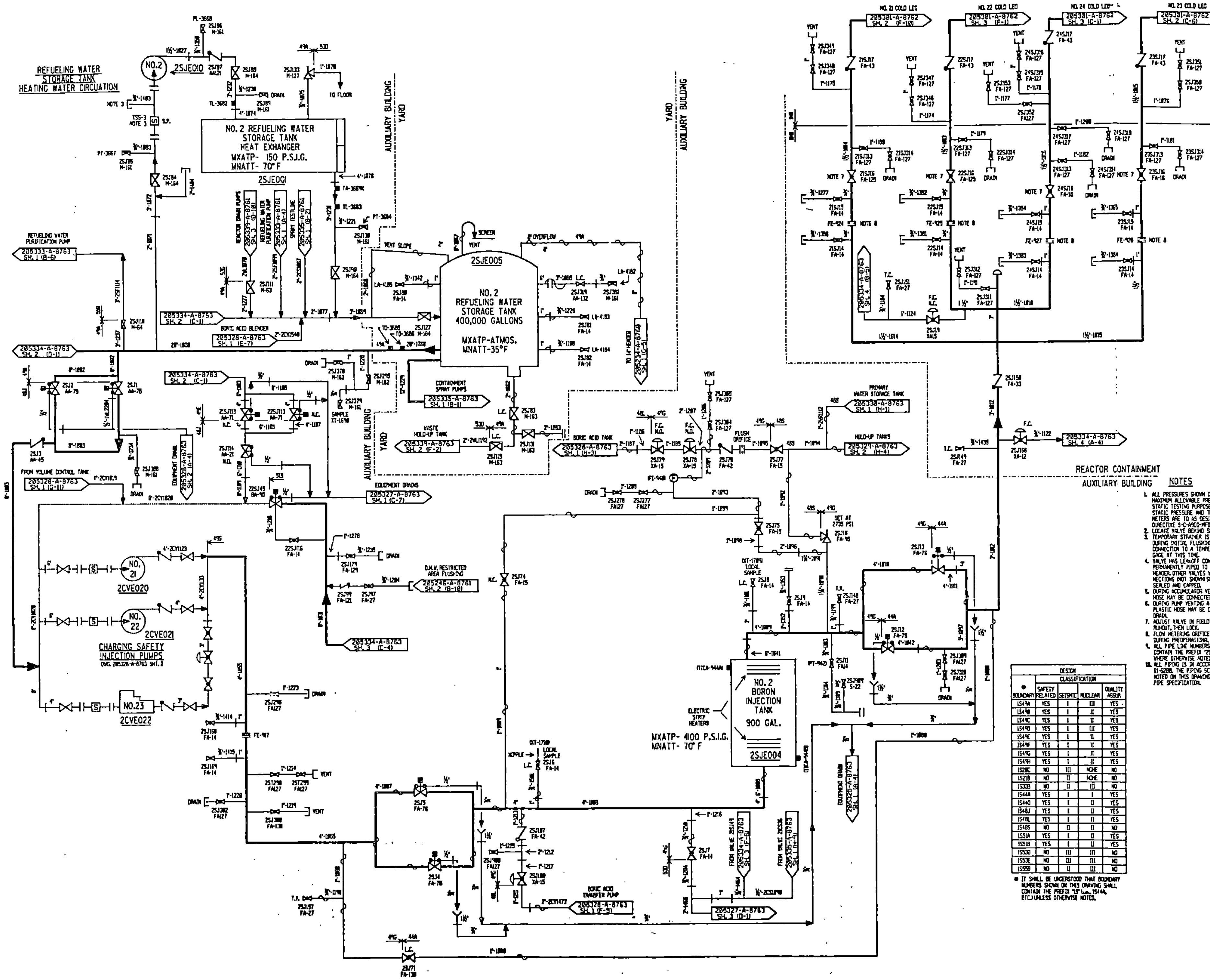
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Emergency Core Cooling System Unit 1
	Updated FSAR Sheet 3 of 4 Fig 6.3-1A



8507300447 -18

Revision 4
July 22, 1985
Ref. Dwg. 205234A8761-20

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Emergency Core Cooling System Unit 1
	Updated FSAR Sheet 4 of 4 Fig 6.3-1A



NOTES

1. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO AS DESIGNATED ON FIELD DIRECTIVE S-C-A9C0-MFD-051.
2. LOCATE VALVE BEHIND SHIELDING.
3. TEMPORARY STRAINER IS PLACED IN LINE DURING INITIAL FLUSHING CAPPED LINE IN CONNECTION TO A TEMPERATURE PRESSURE GAGE AT THIS TIME.
4. VALVE HAS LEAKOFF CONNECTION WHICH IS PERMANENTLY PIPED TO EQUIPMENT DRAIN HEADER. OTHER VALVES WITH LEAKOFFS CONNECTIONS NOT SHOWN SHALL HAVE STUBS SEALED AND CAPPED.
5. DURING ACCUMULATOR VENTING A TEMPORARY HOSE MAY BE CONNECTED TO CONTAINMENT PURGE DUCT.
6. DURING PUMP VENTING A TEMPORARY CLEAR PLASTIC HOSE MAY BE CONNECTED TO FLOOR DRAIN.
7. ADJUST VALVE IN FIELD TO LIMIT PUMP RUNOUT, THEN LOCK.
8. FLOW METERING ORIFICE TO VERIFY FLOW DURING PREOPERATIONAL TESTING.
9. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2SJ" (i.e. 2SJ1000 ETC.) EXCEPT WHERE OTHERWISE NOTED.
10. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200. THE PIPING SCHEDULE GROUP NUMBERS ARE AS NOTED ON THIS DRAWING AND PREFIXED WITH "15" IN THE PIPE SPECIFICATION.

● BOUNDARY	DESIGN CLASSIFICATION SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S49A	YES	I	III	YES
1S49B	YES	I	II	YES
1S49C	YES	I	II	YES
1S49D	YES	I	III	YES
1S49E	YES	I	II	YES
1S49F	YES	I	II	YES
1S49G	YES	I	II	YES
1S49H	YES	I	II	YES
1S20C	NO	III	NONE	NO
1S21B	NO	II	NONE	NO
1S33B	NO	II	III	NO
1S44A	YES	I	I	YES
1S44D	YES	I	II	YES
1S48J	YES	I	II	YES
1S48L	YES	I	II	YES
1S48S	NO	II	II	NO
1S51A	YES	I	II	YES
1S51B	YES	I	II	YES
1S53D	NO	III	III	NO
1S53E	NO	III	III	NO
1S55B	NO	II	III	NO

● IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

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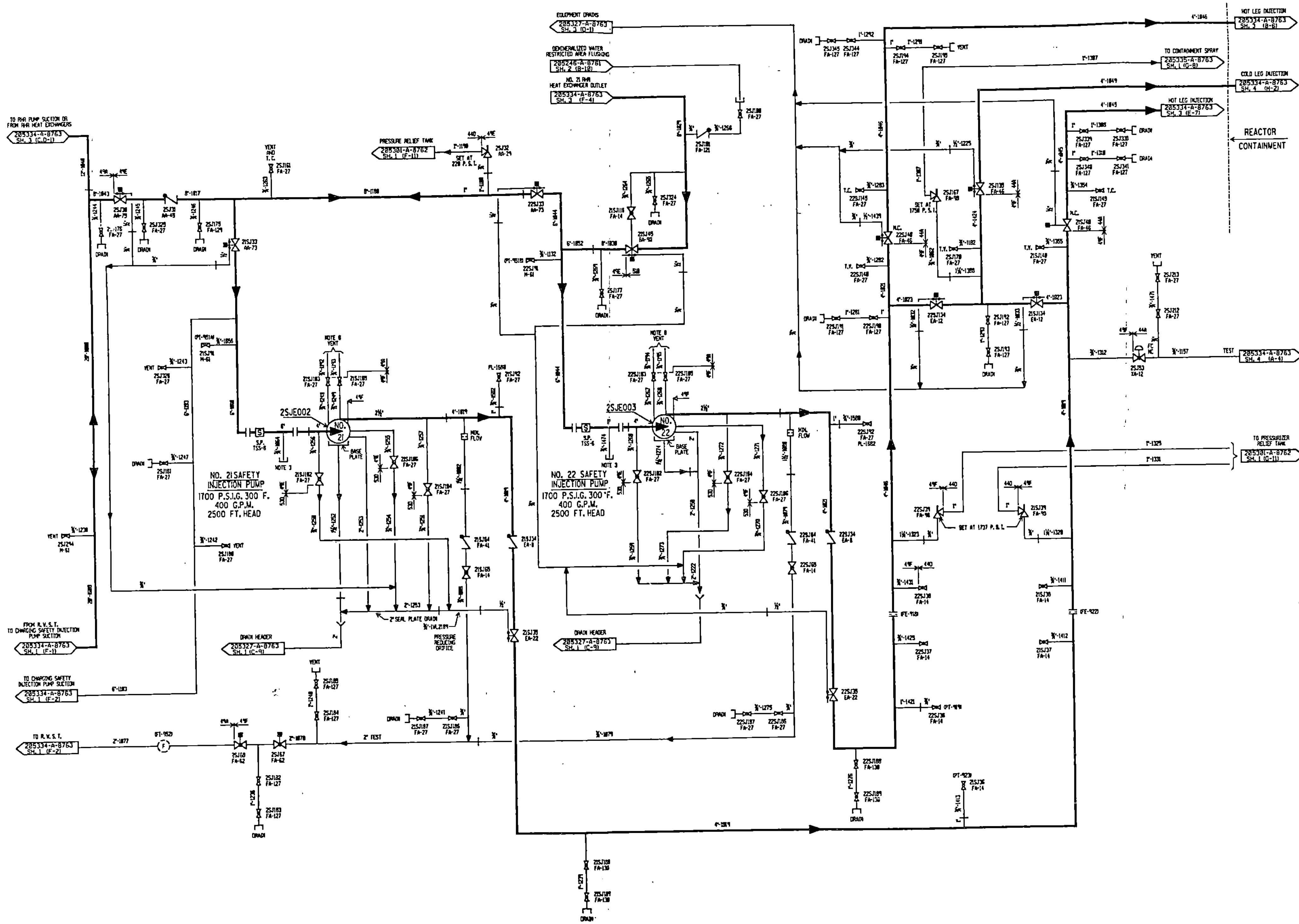
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Emergency Core Cooling System Unit 2
	Updated FSAR Sheet 1 of 4 Fig 6.3-1B



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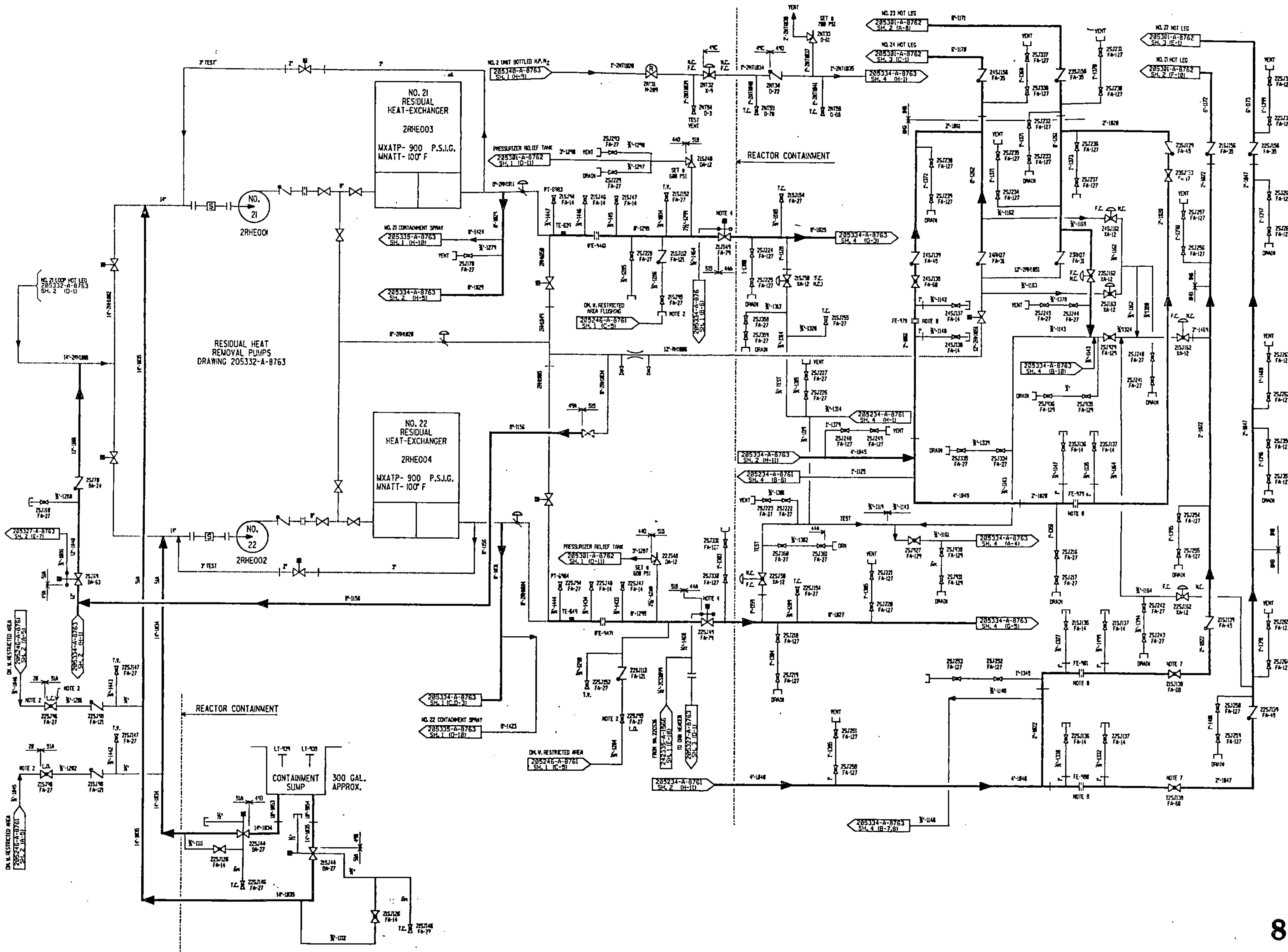
Revision 4
July 22, 1985
Ref. Dwg. 205334A8763-25

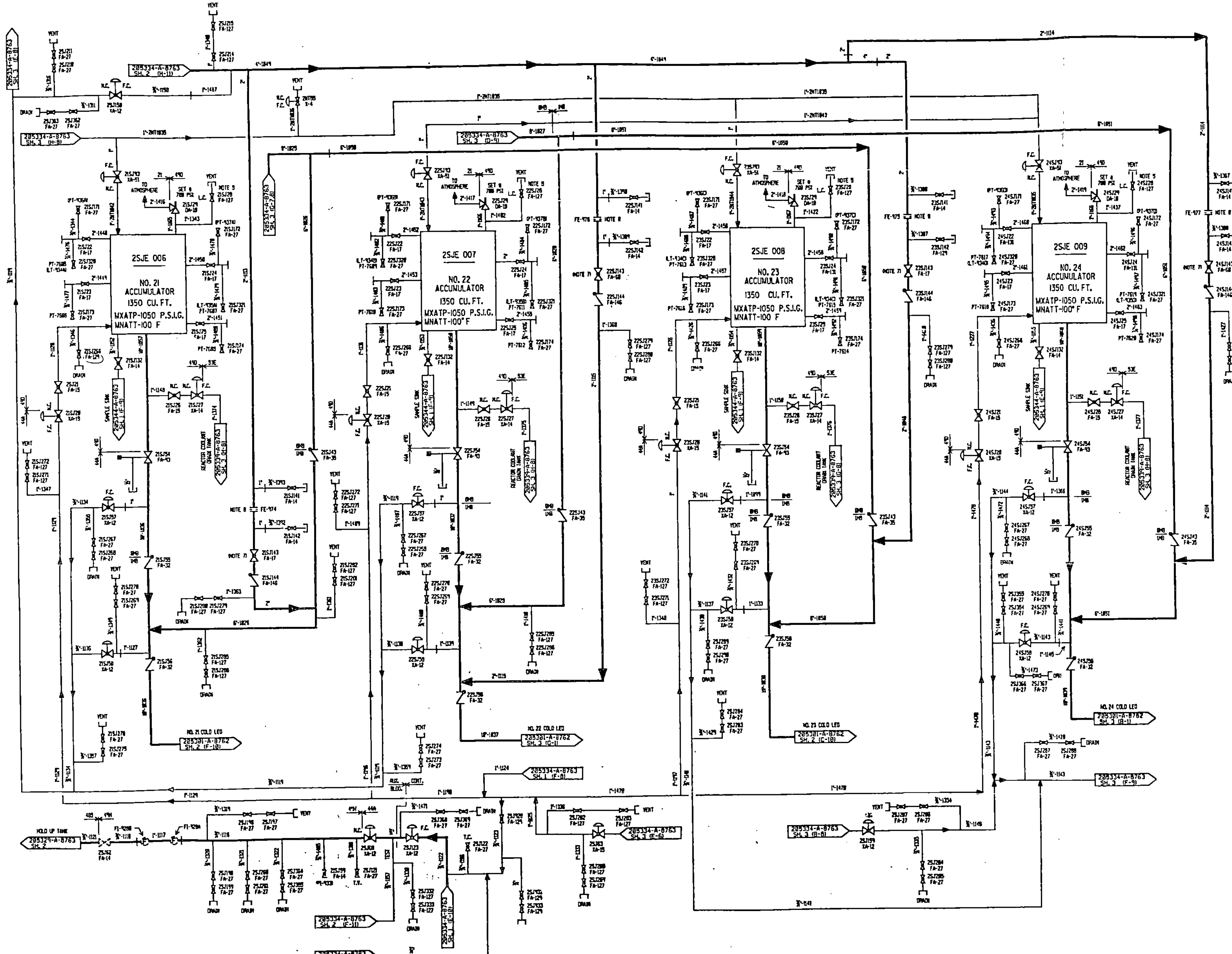
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Emergency Core Cooling System Unit 2
	Updated FSAR Sheet 2 of 4 Fig 6.3-1B



8507300447-21

Revision 4
July 22, 1985
Ref. Dwg. 205334A8763-25

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Emergency Core Cooling System Unit 2
	Updated FSAR Sheet 3 of 4 Fig 6.3-1b



8507300447-22

Revision 4
July 22, 1985
Ref. Dwg. 205334A8763-25

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Emergency Core Cooling System Unit 2
	Updated FSAR Sheet 4 of 4 Fig 6.3-1B

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7.1.1.3 Plant Comparison

The Salem Nuclear Plant protection and engineered safety features actuation systems are functionally identical to those in the D. C. Cook plant.

Both plants have solid state logic protection systems and extended testability of Engineered Safety Features actuation circuitry.

Both plants have incorporated the power range fast flux rate trip with the corresponding deletion of the automatic rod withdrawal block on indication of rod drop.

The design of both systems conforms to IEEE Std. 279-1971 and the General Design Criteria.

7.1.2 IDENTIFICATION OF SAFETY CRITERIA

7.1.2.1 Design Bases

Criterion: Core protection systems, together with associated equipment, shall be designed to prevent or to suppress conditions that could result in exceeding acceptable fuel damage limits.

If the Reactor Trip System receives signals which are indicative of an approach to unsafe operating conditions, the system actuates alarms, prevents control rod withdrawal, initiates load cutback, and/or opens the reactor trip breakers.

The basic reactor operating philosophy is to define an allowable region of power, pressure and coolant temperature conditions. This allowable range is defined by the primary tripping functions: The overpower ΔT trip, the overtemperature ΔT trip and the nuclear overpower trip. The operating region below these trip settings is designed so that no combination of power, temperatures, and pressure could result in departure from nucleate boiling ratio (DNBR) less than 1.3 for any credible operational transient with all reactor coolant pumps in operation. Tripping functions in addition to those stated above are provided to back up the primary tripping functions for specific abnormal conditions.

Rod stops from nuclear overpower, overpower ΔT and overtemperature ΔT deviation are provided to prevent abnormal power conditions which could result from excessive control rod withdrawal initiated by a malfunction of the reactor control system or by operator violation of administrative procedures.

7.1.2.2 Independence of Safety Related Systems

7.1.2.2.1 Redundancy and Independence of Safety Related Systems

Criterion: Redundancy and independence designed into safety related systems shall be sufficient to assure that no single failure or removal from service of any component or channel of such a system will result in loss of the protection function. The redundancy provided shall include, as a minimum, two channels of protection for each protection function to be served.

The Reactor Trip System is designed so that loss of voltage in a channel will result in a signal calling for a trip, except for reactor coolant pump bus undervoltage and underfrequency trips which require dc voltage to actuate. The trip system design combines redundant sensors and channel independence with coincident trip philosophy so that a safe and reliable system is provided in which a single failure will not violate reactor protection criteria.

The design philosophy for the reactor protection and control systems is to make maximum use, for both protection and control functions, of a wide range of measurements. The protection and control systems are

7.1.2.2.4 Protection System Failure Analysis Design

Criterion: The protection systems shall be designed to fail into a safe state or into a state established as tolerable on a defined basis if conditions such as disconnection of the system, loss of energy (e.g., electrical power, instrument air), or adverse environments (e.g., extreme heat or cold, fire, steam, or water) are experienced.

Reactor trip channels are generally designed on the "de-energize to operate" principle; a loss of power causes a channel to go into its trip mode. The only exceptions to this case are the reactor coolant pump bus undervoltage and underfrequency trips, which require dc voltage to actuate. All safety related air operated valves are spring loaded to move to the preferred position on loss of instrument air.

Reactor trip is implemented by simultaneously interrupting power to the magnetic latch mechanisms on all drives allowing the rods to insert by free fall. The protection system is thus inherently safe in the event of a loss of power. This equipment is selected to withstand the most adverse environmental conditions to which it will be subjected; this would also include post-accident conditions within the containment, if the equipment is required to operate in the post-accident environment.

7.1.2.2.5 Reactivity Control Systems Malfunctions

Criterion: The reactor trip systems shall be capable of protecting against any single malfunction of the reactivity control systems, such as unplanned continuous withdrawal (not ejection or dropout) of a control rod, by limiting reactivity transients to avoid exceeding acceptable fuel damage limits.

Reactor shutdown with rods is completely independent of the normal control functions since the trip breakers interrupt the power to the rod mechanisms regardless of existing control signals. Effects of continuous withdrawal of a rod and of deboration are described in Chapter 15.

7.1.2.3 Missile Protection

Criterion: Adequate protection for those engineered safety features, the failure of which would result in undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures.

The applicable portions of the missile protection criteria as stated in Section 1.3 apply to class I equipment in this chapter.

Several criteria related to all instrumentation and control systems but more specific to other plant features or systems are discussed in other Chapters, as listed:

Criterion	Discussion
Suppression of Power Oscillations	Chapter 3
Reactor Core Design	Chapter 3
Quality Standards	Chapter 1
Performance Standards	Chapter 1
Fire Protection	Chapter 9
Missile Protection	Chapter 5
Emergency Power	Chapter 8

7.1.2.4 Periodic Testing of the Protection Systems (IEEE-338-1971)

IEEE Std. 338-1971, "IEEE Trial-Use Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems", was used as a guide in developing the periodic testing program details for Salem.

mode transfers the bistable output from the logic circuitry and connects it to a proving lamp. This permits the electrical operation of the bistable to be observed and the bistable set point relative to the channel analog signal to be verified. Upon completion of the test of the analog channel, the bistable trip switches must be manually reset to their operate mode. Closing the cover of the test panel will not transfer the bistable trip switches from their tripped to their operate position.

Analog channel tests will be accomplished by simulating a process measurement signal, varying the simulated signal over its signal span and checking the correlation of bistable set points, channel readouts and other loop elements with precision portable read-out equipment. Test jacks are provided in the test panel for injection of the simulated process signal into each process analog protection channel. Tests points are provided in the channel to facilitate an independent means for precision measurement and correlation of the test signal. This procedure does not require any tool (other than test instruments) nor does it involve in any way the removal of wires in the channel under test. In general, the analog channel circuits are arranged so the channel power supply is loaded and is providing sensing circuit power during channel test. Load capability of the channel power supply is thereby verified by the channel test.

Nuclear Instrumentation Channel Testing

Nuclear Instrumentation System channels are tested by superimposing the test signal on the actual detector signal being received by the channel. The output of the bistable is not placed in a tripped condition prior to testing. A valid trip signal would then be added to the existing test signal, and thereby cause channel trip at a somewhat lower percent of actual reactor power. Protection bistable operation is tested by increasing the test signal (level signal) to the bistable trip level and verifying operation at control board alarms and/or at the Nuclear Instrumentation System racks.

An Nuclear Instrumentation System channel which can cause a reactor trip through 1 of 2 protection logic (source or intermediate range) is provided with a bypass function which prevents the initiation of a reactor trip from that particular channel during the short period that it is undergoing test. The power range channels do not require bypass of the reactor trip function for test, since the protection logic is 2 of 4. The power range trips will be active if required. No provision has been made in the channel test circuit for reducing the channel signal level below that signal being received from the Nuclear Instrumentation System detector.

Logic Channel Testing

The Solid State Protection System logic is designed to be capable of testing at power (Reference 3)

Reactor trip breaker testing is accomplished as follows: normally, reactor trip breakers 52/RTA and 52/RTB are in service, and bypass breakers 52/BYA and 52/BYB are (withdrawn) out of service. To test reactor trip breaker 52/RTA, as an example, the following is done.

1. Bypass breaker BYA is put into service.

   This act closes switchgear relay 52/BYA. It also interrupts one of the two signals to the Train A "and box" which is necessary to actuate subsequent logic causing turbine trip, feedwater isolation, and Safety Injection block logic.

2. A simulated trip signal is then applied to Train A only.

   This act deenergizes undervoltage coil 52(uv)/RTA which operates reactor trip breaker 52/RTA, which opens switchgear relay 52/RTA.

The reactor is not tripped because the control rods continue to receive rod drive bus power via switchgear 52/BYA and 52/RTB.

In the event that a real trip signal occurs during the testing of 52/RTA trip breaker, Train B will actuate the reactor trip and the logic following the Train B "and box".

Auxiliary contacts on the bypass breakers are connected into the alarm system of their respective train such that if either train is placed in test while the bypass breaker of the other train is closed, both reactor trip breaker and the bypass breaker will be automatically tripped by the General Warning Alarm circuits of the Solid State Protection System. The General Warning Alarm System is described in Reference 3.

7.2.2.4 Primary Power Source

The primary power sources for the Reactor Protection System are described in Chapter 8. The source of electrical power for the measuring elements and the actuation of circuits in the Engineered Safety Features instrumentation is also from these buses.

7.2.2.5 Protective Actions

Reactor Trip Description

Rapid reactivity shutdown is provided by the insertion of rod cluster control assemblies by free fall. Duplicate series-connected circuit breakers supply all power to the control rod drive mechanisms. The rods must be energized to remain withdrawn from the core. Automatic control rod insertion occurs upon the loss of power to the control rods. The trip breakers are opened by the undervoltage coils on both breakers. The undervoltage coils which are normally energized become de-energized by any one of the several trip signals.

The design of the devices providing signals to the circuit breaker undervoltage trip coils is such as to cause these coils to trip the breaker on reactor trip signal.

Certain reactor trip channels are automatically bypassed at low power where they are not required for safety. Nuclear source range and intermediate range trips are specifically provided for protection at low power or subcritical operation, and at higher power operations they are bypassed by manual action in conjunction with permissives.

During power operation, a sufficient amount of rapid shutdown capability in the form of shutdown control rods is administratively maintained by means of the control rod insertion limit monitors. Administrative control requires that all shutdown group rods be in the fully withdrawn position during power operation.

A listing of reactor trips, means of actuation and the coincident logic requirements may be found in Table 7.2-1 with references to interlocks as listed in Table 7.2-2.

Manual Trip

The manual actuating devices are independent of the automatic trip circuitry, and are not subject to failures which make the automatic circuitry inoperable. Actuating either of two manual trip switches located in the control room initiates a reactor trip and a turbine trip.

High Neutron Flux (Power Range) Trips

These circuits trip the reactor when two out of the four power range channels read above the trip set-point. There are two independent trip settings, a high and a low setting. The high trip setting provides protection during normal power operation. The low setting, which provides protection during start-up, can be manually bypassed when two out of the four power range channels read above approximately 10 percent of full power (P-10). Three-out-of-the-four channels below 10 percent power automatically reinstates the trip function. The high setting is always active.

Steam Lines Isolation Actuation	Coincidence Circuitry and Interlocks	Comments
22. Containment pressure (Note 1)	2/4 Hi-Hi containment pressure	
23. Manual (per steam line)	1/1 per steam line	
Auxiliary Feedwater Actuation		
24. Turbine driven pump	Coincidence of 2/3 low-low level in any two steam generators; undervoltage 1/2 twice on RCP busses; or manual (local and remote)	2/3 high level in steam generator trips main feedwater pumps
25. Motor drive pumps	2/3 low level in any steam generator: or trip of both main feedwater pumps, or safeguards sequence signal, or blackout sequence signal, or manual (local and remote)	Safeguards automatic loading signal blocks manual start
Main Feedwater Isolation		
26. Close main feedwater control valves (fast closure) and feedwater bypass valves and feedwater inlet stop valves	Actuated by: 1. Safety injection (See No. 10) 2. 2/3 Hi-Hi level in steam generator 3. Low actioneered T_{avg} and reactor trip	

leak. Core recirculation and containment spray recirculation (if necessary) can be manually initiated before the refueling water storage tank is empty.

Considerations have been given to all the instrumentation and information that will be necessary for the recovery time following a loss-of-coolant incident. Instrumentation external to the reactor containment such as radioactivity monitoring equipment will not be affected by this postulated incident and will be available to the operator.

7.3.1.1.10 Engineered Safety Features Control

All equipment required to keep the plant in a safe condition during the occurrences of Safety Injection, blackout, or both of these conditions, can be powered by three standby ac power systems per unit. The equipment is arranged such that safe shutdown can be achieved under all postulated abnormal conditions coincident with the loss of one diesel generator. Each unit has a separate and independent electrical system to provide power for engineered safeguards systems.

Each diesel generator is provided with an independent loading control system (Reference 2) which initiates the startup and/or loading of the diesel generators during the following plant conditions:

1. Safety injection only.
2. Loss of all outside power (blackout).
3. Safety injection coincident with loss of all outside power.
4. Safety injection coincident with undervoltage on the one 4kV vital bus.

During conditions of automatic startup and/or loading for all modes, the following criteria have been met in the control system design:

1. Each vital bus control is independent of the other two.
2. Manual control of equipment is locked out until the automatic load sequencing is complete.

3. Safeguard actuation signals cannot be interrupted by any automatic device.
4. Manual initiation of the loading sequence is available to the operator.
5. Off-normal diesel conditions are alarmed in the Control Room.
6. Safety injection conditions take precedence over all other operating modes.
7. Diesels operating in a TEST mode at the occurences of a blackout or Safety Injection are automatically tripped and reloaded according to prevailing conditions.
8. No sequential loading can occur until the diesel generator ACB is closed onto the bus.

7.3.1.1.10.1 Safety Injection Only

In this mode of operation, a Safety Injection signal initiates the following actions:

1. Start diesel generator units.
2. Lockout manual control of equipment circuit breakers until the loads are connected.
3. Connect all required accident loads.

Since outside power is available during this mode, the equipment not affected by the accident remains in service and required safeguards equipment is loaded immediately, except for the fan cooler units which are started for low-speed operation as soon as they have coasted down from normal high speed operation (approximately 15-20 sec.). The diesel generators are started automatically so as to be availabale in the event they are subsequently required. They are not automatically connected to the vital busses. The operator may shut down the diesels when operation of the required equipment has been verified.

7.3.1.1.10.2 Blackout Only

In this mode of operation, undervoltage signals for vital bus are combined in a 2/3 logic matrix per bus to develop a blackout loading signal

LIST OF FIGURES

8.0 - ELECTRIC POWER

8.1 INTRODUCTION

8.1.1 UTILITY GRID SYSTEM AND INTERCONNECTIONS

Each unit generates electric power at 25 kV which is fed through an isolated phase bus to the main transformer bank where it is stepped up to 500 kV and delivered to the switching station. The 500 kV switching station design incorporates a breaker-and-a-half scheme for high reliability and is connected to three 500 kV transmission lines. Two transmission lines go north, via separate right-of-way, to two of PSE&G's major switching stations, New Freedom and Deans. The New Freedom Switching Station is solidly connected to the PSE&G 230-kv bulk power system via three 500/230-kV autotransformers. Deans Switching Station is also connected to the PSE&G 230-kV bulk power system via three autotransformers but in addition, it is connected to the PJM 500-kV interconnected system.

8.1.2 ONSITE POWER SYSTEMS

The Onsite Power System for each unit consists of the main generator, the auxiliary power and station power transformers, the diesel generators, the group and vital bus sections and their related distribution systems. The 4160 volt vital buses, which feed safeguards equipment, are energized by either station power transformer served by the 13 kV ring bus. Preferred power is supplied to the 13 kV ring bus by two sources from the switchyard and also by an onsite 40 MW gas turbine generator.

Safeguards loads are divided among the vital buses in three independent load groups, each of these load groups is provided with a diesel generator which serves as a standby power supply in the event that the preferred source is unavailable.

Each unit has a 125 VDC power system to provide power to safeguards loads. This system also supplies power through inverters to the 115 VAC instrument buses. In addition, each unit is provided with a 250 VDC power system and a 28 VDC control system.

8.1.3 SAFEGUARDS LOADS

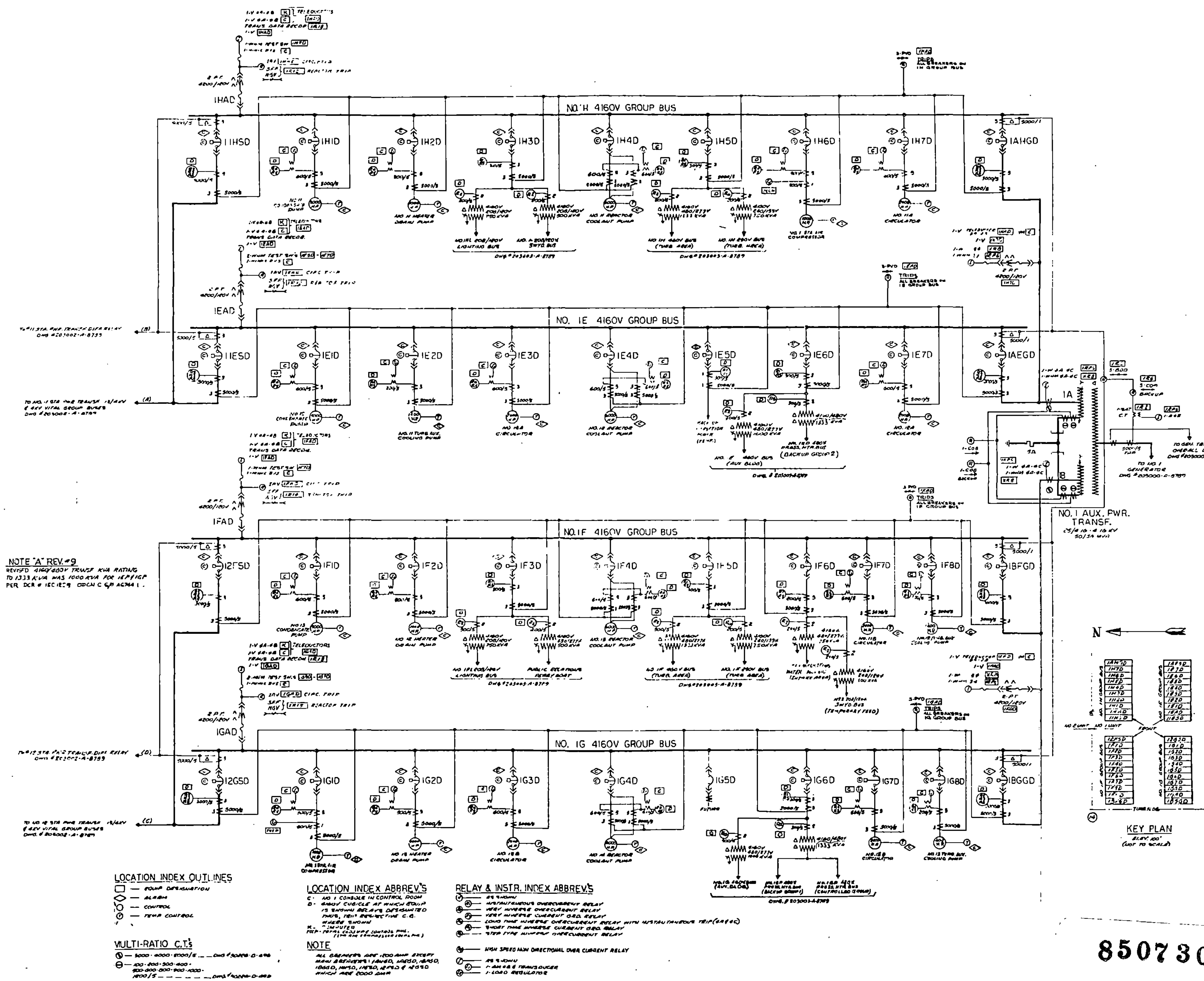
Safeguards loads are identified on the following figures:

Load Group	Figure No.
4160 VAC	8.3-4
460 VAC	8.3-4
230 VAC	8.3-5
28 VDC	8.3-6
125 VDC	8.3-7

8.1.4 DESIGN BASES

8.1.4.1 General

The plant has been designed to be capable of being safely shut down from full power in the event of the loss of all offsite power sources. Redundant and independent onsite power sources are provided to insure the availability of the necessary power for shutdown systems. Total loss of all onsite and offsite AC power is not a design basis event.



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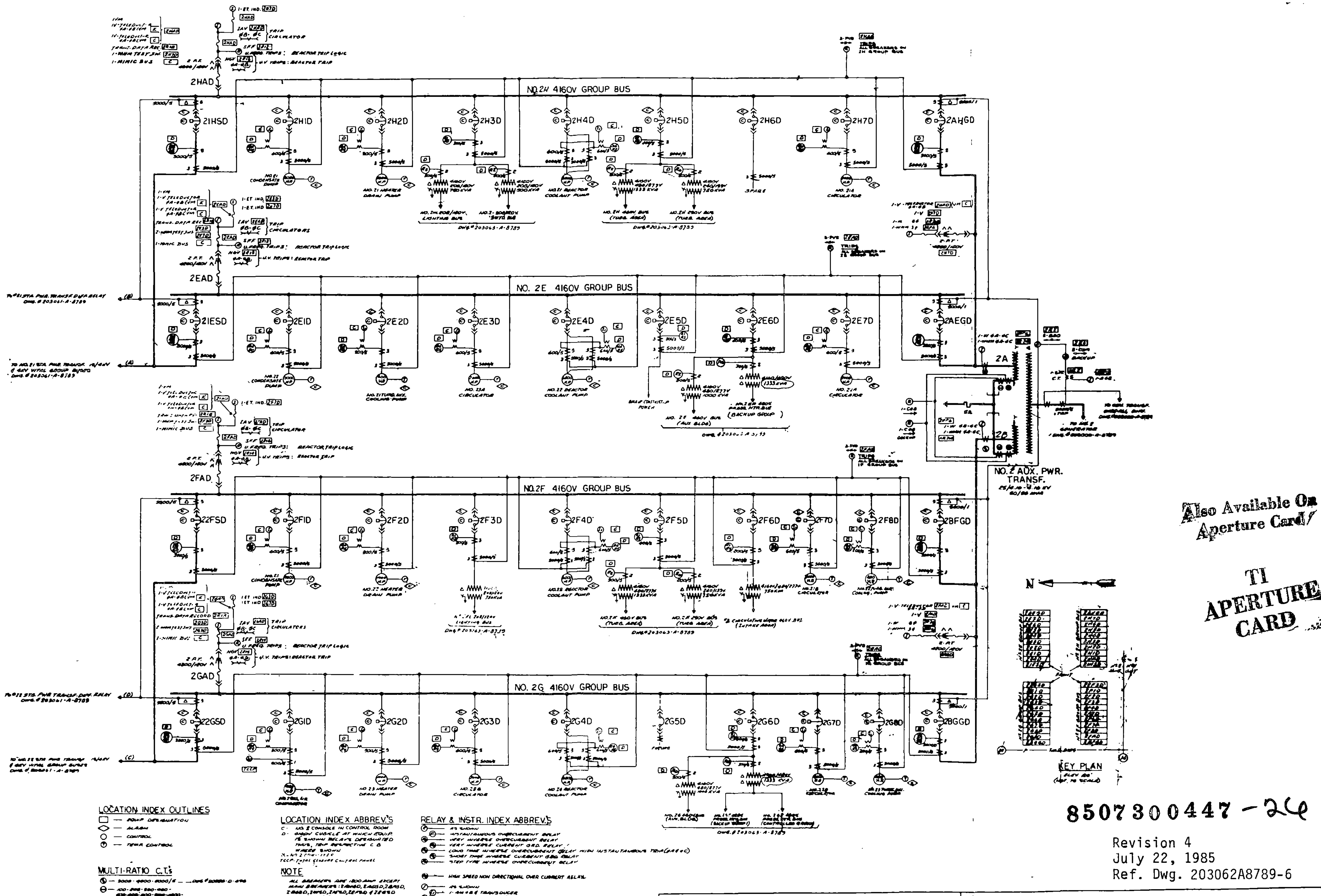
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Auxiliary Power System 4160 V. Group Buses Diagram - Unit 1
	Updated FSAR Fig 8.3-3A



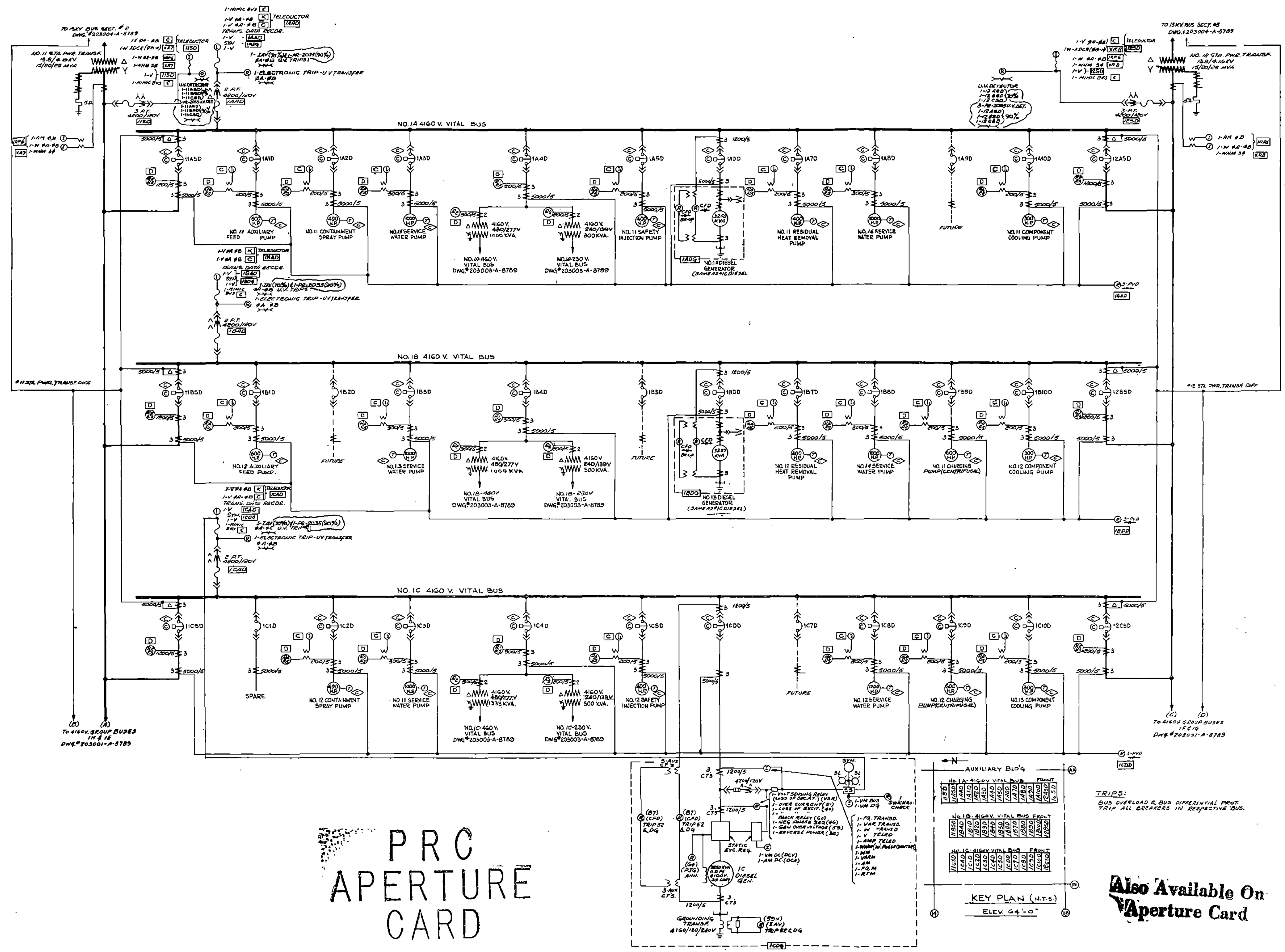
Also Available On Aperture Card

TI APERTURE CARD

8507300447 -26

Revision 4
July 22, 1985
Ref. Dwg. 203062A8789-6

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Auxiliary Power System - 4160 V. Group Buses Diagram - Unit 2
	Updated FSAR Fig 8.3-3B



PRC APERTURE CARD

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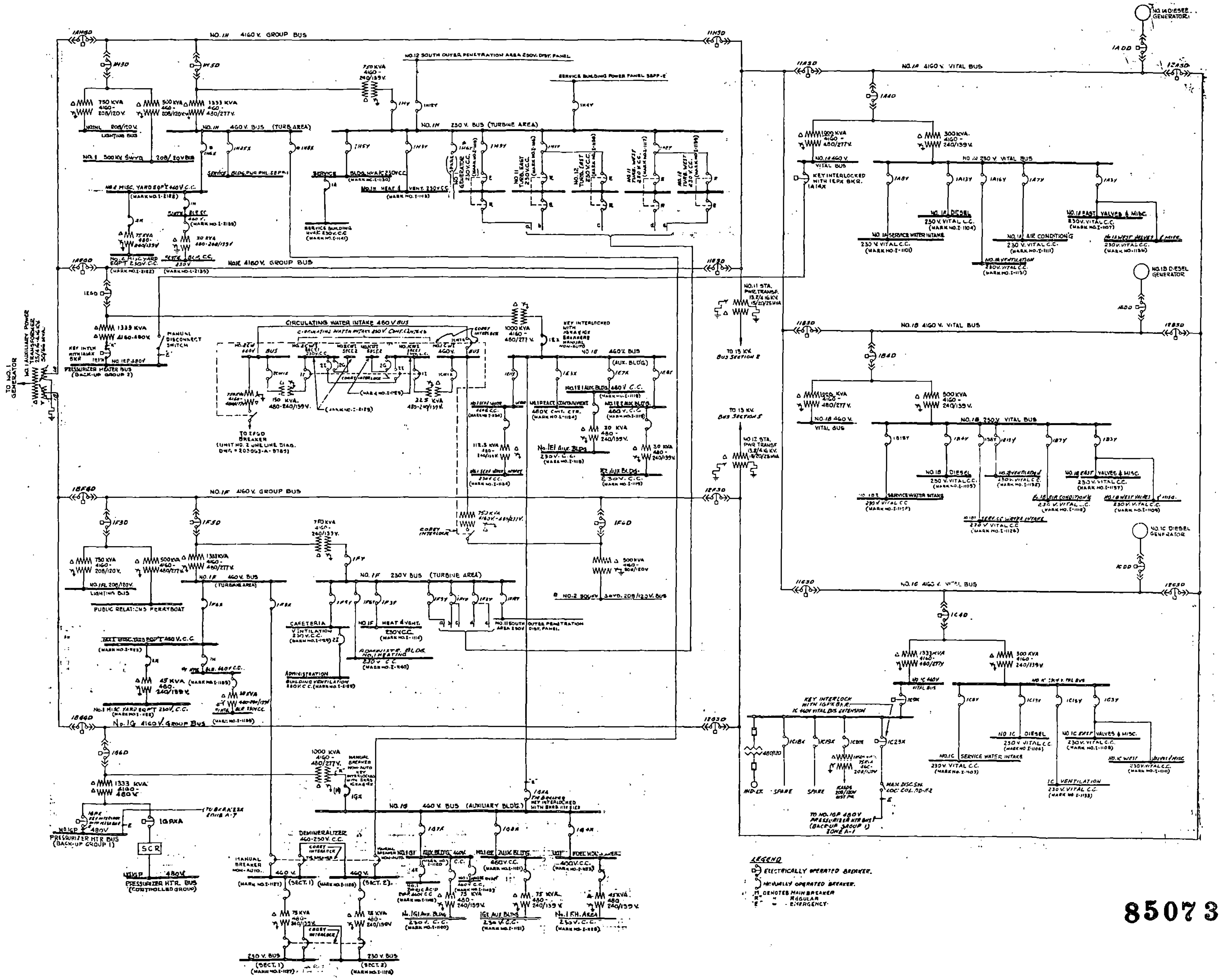
203002A8789-6

Revision 1
July 22, 1983

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	4160 V. Vital Buses One Line UPDATED FSAR FIG 8.3-4

8308100027 - 05



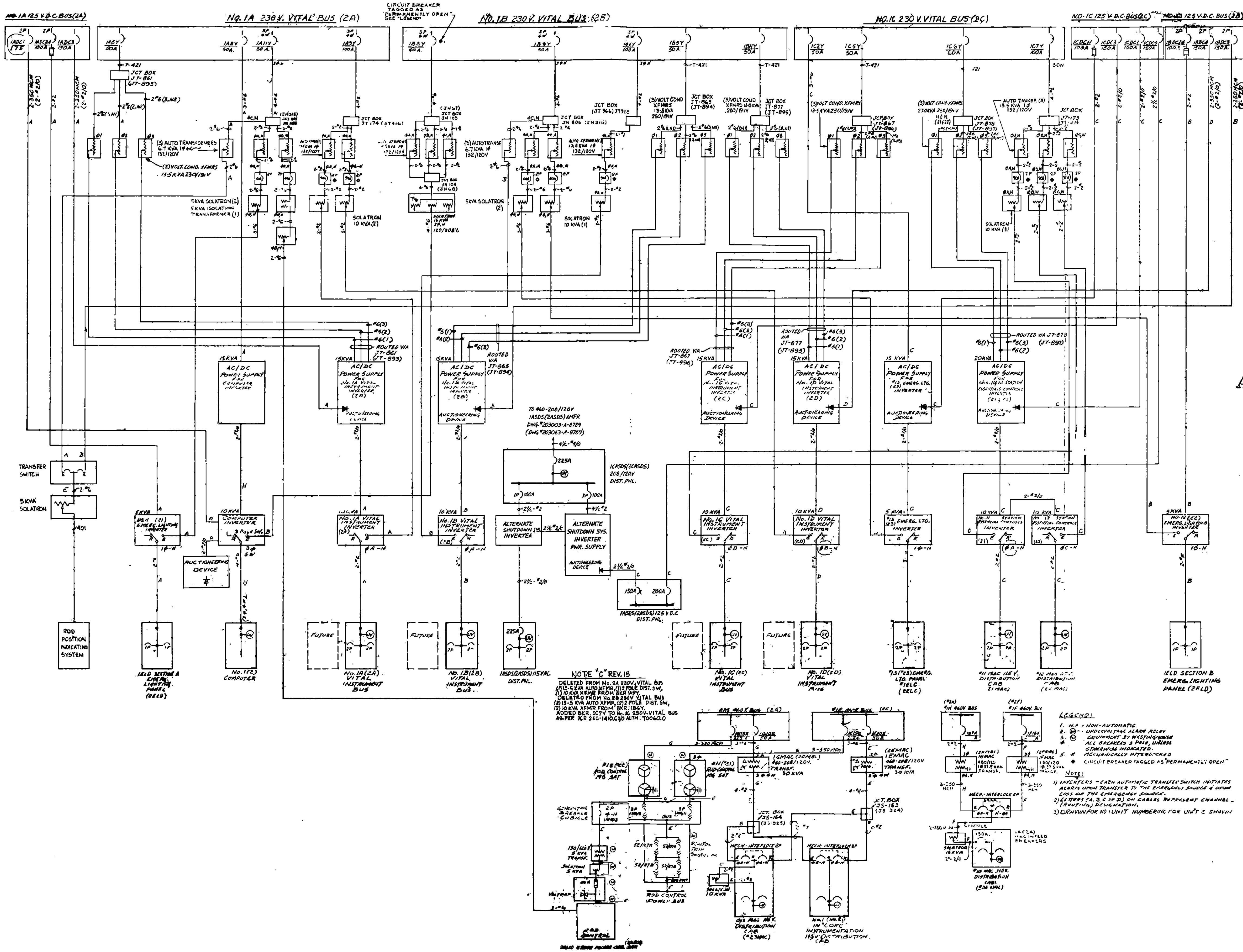
Also Available On Aperture Card

TI APERTURE CARD

8507300447 - 27

Revision 4
July 22, 1985
Ref. Dwg. 203003A8789-13

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	460 V. & 230 V. Group Buses & Vital Buses One Line Control
	Updated FSAR Fig 8.3-4A



Also Available On Aperture Card

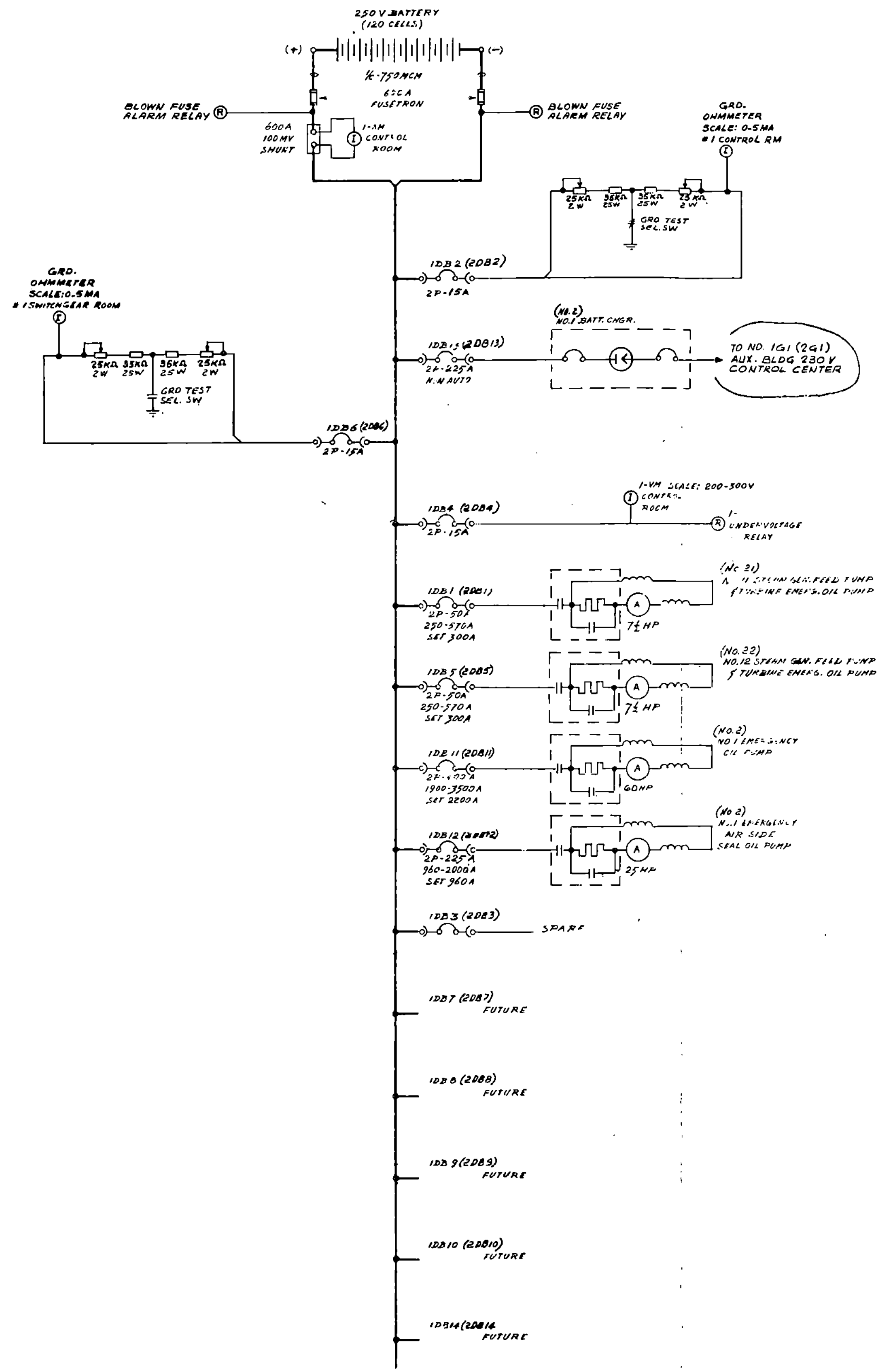
TI APERTURE CARD

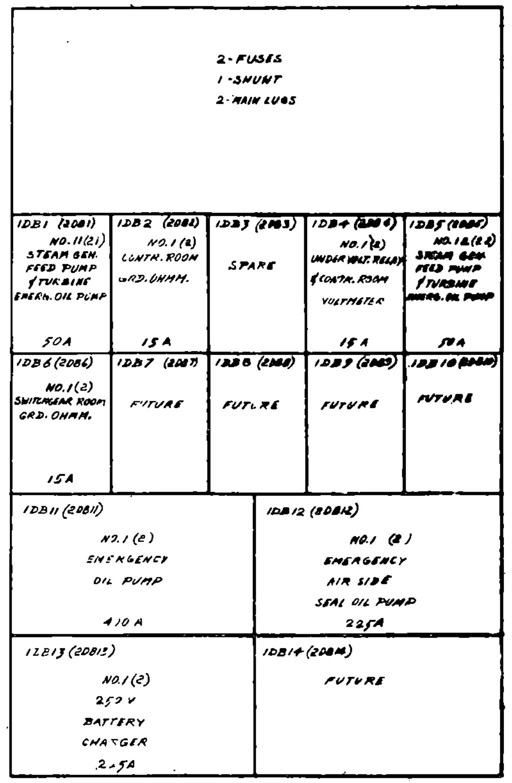
211370A8859-17

Revision 3
July 22, 1984

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	115 V. Control Power System-Unit 1&2
	UPDATED FSAR FIG 8.3-5

8408020108-/8





FRONT VIEW
N.T.S.

NOTES:
1. ALL CIRCUIT BREAKERS SHALL BE 2-POLE & SHALL HAVE 20,000 A.D.C. MINIMUM INTERRUPTING CAPACITY.
2. -MOULDED TYPE PLUG-IN CIRCUIT BREAKER.
3. DRAWN FOR UNIT No.1, UNIT No.2 SHOWN ( )

TI APERTURE CARD

Also Available On Aperture Card

203008AB3616-3

Revision 3
July 22, 1984

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	250 Volt One Line UPDATED FSAR FIG 8.3-8

8408020108-19

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9.1 FUEL STORAGE AND HANDLING

The Fuel Handling and Storage System provides a safe, effective means of storing, transporting and handling fuel from the time it reaches the plant in an unirradiated condition until it leaves the plant after post-irradiation cooling. Each unit has a completely independent Fuel Handling and Storage System. The following description is for unit one with the second unit having an identical system.

The system is designed to minimize the possibility of mishandling or of mal-operations that could cause fuel damage and potential fission product release.

9.1.1 NEW FUEL STORAGE

9.1.1.1 Design Bases

The new fuel assemblies are received and stored dry in racks in the new fuel storage area, located in the Fuel Handling Building (see Figure 9.1-1). New fuel is delivered to the reactor by lowering it into the transfer pool and taking it through the transfer system. The new fuel storage area is sized for storage of the fuel assemblies and control rods normally associated with the replacement of one-third of a core.

9.1.1.2 Safety Evaluation

The new fuel storage racks have been designed in accordance with the 1963 AISC Code. Seismic loads as well as dead load of fuel assemblies are considered in the design.

The new fuel storage racks are designed so that it is impossible to insert the assemblies in other than the prescribed locations. The 21 inch nominal spacing between fuel assemblies will maintain a subcritical array even if the pool is flooded with unborated demineralized water.

Adequate shutdown margin is maintained for 17 x 17 fuel with 4.5 w/o enrichment. A potential optimum moderation condition is precluded in the new fuel storage area by the following design features.

1. The new fuel storage building has no fire fighting hose stations,

2. The new fuel storage building has no installed aqueous fire suppression systems (e.g., sprinklers, fog, or sprays),

3. New fuel is covered with a protective metal plate during storage which prevents the introduction of low density water into the fuel racks from above.

The only accessible fire fighting hoses available for use in the new fuel storage area are connected to hose stations in the auxiliary building and will be equipped with straight-stream nozzles.

9.1.2 SPENT FUEL STORAGE

The spent fuel storage pool is the storage space for irradiated spent fuel from the Reactor. This pool is not required for any plant safety-related function.

9.1.2.1 Design Bases

The spent fuel storage racks are designed in a subcritical array such that k_{eff} is limited to a value of less than or equal to 0.95 even if the pool is flooded with demineralized water. The spent fuel racks are built to ensure a nominal 10.5 inch center-to-center distance between fuel assemblies stored in the racks. The storage capacity is limited to 1170 spent fuel assemblies, which will cover a period of 18 years, assuming that one-third of the core is replaced annually. The reactor cavity, refueling canal and spent fuel storage pool are reinforced concrete structures with seam-welded stainless steel plate liners. These Seismic Category I structures are designed to withstand the anticipated earthquake loadings and to prevent liner leakage even in the event the reinforced concrete develops cracks.

Design criteria for spent fuel storage racks assure conformance with recognized codes and applicable regulatory guides, as follows:

1. The spent fuel storage rack design is based on the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Sub-section NF, Class III linear supports.

2. Regulatory Guide 1.13 - The design conforms with Guide, except that high radiation instrumenation does not actuate the filtration system.

3. Regulatory Guide 1.29 - The spent fuel storage racks are designed as Seismic Category I Structures.

4. Regulatory Guide 1.92 - Seismic load combinations of vibrational modes and three orthogonal component motions (two horizontal and one vertical) will meet the provisions of the Regulatory Guide.

5. Design loads and load combinations meet the requirements of the Standard Review Plan, Section 3.8.4, Structural Design Criteria for Seismic Category I Structures Outside Containment and ASME Section III NF-3400.

9.1.2.2 System Description

A stainless steel lined spent fuel storage pool is provided for on site storage of spent fuel assemblies until they are shipped to a reprocessing facility. Sufficient space is available to hold approximately 6 cores and the depth is sufficient to provide a minimum shielding depth over the top of the stored fuel of 10 feet of water. The pool is designed to prevent inadvertent drainage below a water elevation of 124 feet 8 inches. Storage racks located in the pool are physically arranged such that the assemblies are always maintained in a subcritical condition. Adjacent to the spent fuel pool and separated by a structural wall is the transfer pool. The transfer pool serves to provide the fuel transfer operation between the fuel handling building and containment. It is also the pool where the spent fuel cask is placed for shipment. The cask is handled by the cask handling crane which is prevented by structural restraint from moving over the spent fuel pool. Thus the fuel shipping casks cannot be carried over the spent fuel pool.

The high density (poison) spent fuel racks construction is shown in Figure 9.1-2. The design utilizes a stiffened module base and an upper box structure consisting of plate diaphragms and a top grid. The storage module is constructed of stainless steel, mostly Type 304. The vertical loads are carried by the module base. Horizontal seismic loads are carried to the module base through the plate diaphragms. Tipping is prevented by interconnection of adjacent racks by a bolted connection at the top grid level.

The design of the spent fuel storage cells is illustrated in Figure 9.1-3. Each cell is a square cross-section formed from an inner shroud of stainless steel, a center sheet of aluminum clad boron carbide (B_4C), and an outer shroud of stainless steel. This cell acts as storage space and provides sufficient neutron absorption to allow close spacing of spent fuel. The fuel weight is carried directly on the module base. A flared guide and transition section is provided at the top of each storage cell. This transition is designed to assure ease of entry and to preclude fuel assembly hang-up and damage.

After a sufficient decay period the fuel may be removed from storage and loaded into a shipping cask for removal from the site.

9.1.2.3 <u>Design Evaluation</u>

Borated water is used to fill the spent fuel storage pool at a concentration to match that used in the reactor cavity and refueling canal during refueling operations. The fuel is stored in a vertical array with sufficient center-to-center distance between assemblies to assure $k_{eff} \leq 0.95$ even if unborated water is used to fill the pool. (Based on 17x17 fuel with 4.05 w/o enrichment).

The spent fuel storage pool is provided with a Spent Fuel Cooling System which is discussed in Section 9.1.3. The system maintains pool temperature below approximately 120 °F.

The design of the Fuel Handling Building is such that it is physically impossible for a load greater than 5 tons to be carried over the spent fuel pool. This is a result of both the physical arrangement of the Fuel Handling Building and limits on the fuel handling crane. Administrative controls prohibit loads greater than that of a fuel assembly to travel over the spent fuel pool. The maximum height at which a fuel assembly can be carried is restricted by limit switches on the crane to 15 inches over the top of the spent fuel racks. The spent fuel racks have been designed to absorb the energy released by a fuel assembly dropping from 15 inches above them.

The Spent Fuel Storage Pool and New Fuel Storage Pit are outside the area over which the fuel cask may travel by design (travel restricted by a limit stop switch). The Cask Handling Crane travels only over the Truck Bay, Decontamination Pit and Fuel Transfer Pool, as indicated in Figure 9.1-1.

Gamma radiation is continuously monitored in the Fuel Handling Building. A high level signal is alarmed locally and is annunciated in the Control Rooms.

All fuel and waste storage facilities are contained and equipment designed so that accidental releases of radioactivity directly to the atmosphere are monitored and will not exceed the guidelines of 10 CFR 100.

A controlled ventilation system removes gaseous radioactivity from the atmosphere in fuel and waste treating areas of the fuel handling and auxiliary buildings and discharges it to the atmosphere via the plant vent. Radiation monitors are in continuous service in these areas to actuate high-activity alarms in the Control Rooms.

9.1.3 SPENT FUEL POOL COOLING SYSTEM

9.1.3.1 Design Bases

Each unit has a completely independent Spent Fuel Pool Cooling System. The following description is for one unit with the second unit having an identical system.

The Spent Fuel Pool Cooling System is designed to remove from the spent fuel pool the heat generated by stored spent fuel elements. The system serves the spent fuel pool which is located in the fuel handling building adjacent to the containment building. A secondary function is to clarify and purify spent fuel pool, transfer pool, and refueling water. The system design considers the possibility that during the life of the plant it will become necessary to totally unload a reactor at the time when spent fuel is in the fuel pool.

The system design incorporates redundant active components. System piping is arranged so that failure of any pipeline does not drain the spent fuel pool below the top of the stored fuel elements.

The spent fuel pool water is normally limited to 120°F except in for the unloading of a full core, in which case temperature is limited to 150°F with one pump in operation. Boron concentration in the pool fluid is maintained at a minimum of 2,000 ppm.

9.1.3.2 System Description

The schematic diagram for the Spent Fuel Pool Cooling System is shown on Figures 9.1-4A and B. The Spent Fuel Pool Cooling System consists of three subsystems, the cooling system, the purification system, and the skimmer system.

Austenitic stainless steel piping is used in the Spent Fuel Pool Cooling System. All piping and components of the system are designed to the applicable codes and standards listed in Table 9.1-1.

The cooling loop consists of the spent fuel pool pumps and the spent fuel pool heat exchanger. The purification loop consists of the spent fuel pool pump, the spent fuel pool filter, the spent fuel pool demineralizer, the refueling water purification pump, and the refueling water purification filter. The skimmer loop consists of the skimmer pump, strainer, and filter.

During the heat removal operation, fuel pool water flows from the spent fuel pool to a spent fuel pool pump suction, and is pumped through the tube side of the heat exchanger, and is returned to the pool. The suction line, which is protected by a strainer, is located at an elevation four feet below the pool normal water level, while the return line terminates in the pool at an elevation approximately six feet above the top of the fuel assemblies. If the spent fuel pool pump fails, the second pump supplies 100 percent backup.

The Spent Fuel Pool Cooling System has its maximum duty during the refueling operation when the decay heat from the spent fuel is the highest. The system is normally placed in operation prior to the transfer of any fuel and is continued in operation as long as required to maintain temperature at the required level and water purity.

While the heat removal operation is in process, a portion of the spent fuel pool water, 100 gpm, may be diverted through the spent fuel pool demineralizer and spent fuel pool filter to maintain spent fuel pool water clarity and purity. Transfer canal water may also be circulated through the same demineralizer and filter. This is accomplished by having the gate between the transfer pool and the spent fuel pool removed. This purification loop is sufficient for removing fission products and other contaminants which may be introduced if a leaking fuel assembly is transferred to the spent fuel pool.

The demineralizer may be isolated, by manual valves, from the heat removal portion of the Spent Fuel Pool Cooling System. By so doing, it may be used together with the refueling water purification filter to clean and purify the refueling water while spent fuel pool heat removal operations proceed. Connections are provided to the isolated loop such that the refueling water may be pumped from either the refueling water storage tank or the refueling cavity, through the demineralizer and filter, and discharged to either the refueling cavity or the refueling water storage tank.

To further assist in maintaining spent fuel pool water clarity, the water surface is cleaned by a skimmer loop. This system consists of two skimmers, a skimmer pump, a strainer and a filter. Water is removed from the surface by the skimmer, pumped through the strainer and filter, and returned to the pool surface at three locations remote to the skimmers.

The spent fuel pool is initially filled with water that is at the same boron concentration as that in the refueling water storage tank. This may be accomplished by filling the pool with water from plant sources. Boron may then be added to the pool from the Chemical and Volume Control System. Borated water from the plant sources may be supplied from the refueling water storage tank via the refueling water purification pump connection, or by placing a temporary line from the boric acid blender, located in the Chemical and Volume Control System, directly into the pool. Demineralized water is also added to the pool for make-up purposes by a connection in the recirculation return line.

The pool water may be separated from the water in the transfer pool by a sluice gate. The gate is installed so that the transfer pool may be drained for maintenance on the fuel transfer equipment. The draining is accomplished by pumping transfer pool water into the spent fuel pool with a portable pump. The excess water from the spent fuel pool is directed to a holdup tank in the Chemical and Volume Control System or to the decontamination for temporary storage.

An evaluation has been performed to determine the capability of the Spent Fuel Cooling System to provide the cooling capacity required for both the annual discharge of 65 fuel assemblies and for a full core discharge of 193 fuel assemblies into the spent fuel pool after 15 years accumulation of spent fuel. ANS Standard 5.1 was used for decay heat load calculations. It has been determined that the Spent Fuel Cooling System can provide the necessary cooling for the normal annual discharge as early as 100 hours after reactor shutdown. A full core discharge can be accomplished with an appropriate time delay after reactor shutdown, which is dependent on the number of regions stored in the spent fuel pool at the time. For example, it has been calculated that with one pump running at design capacity and with 150 hours of decay heat (after reactor shutdown) at the 18th refueling, the maximum spent fuel pool outlet water temperature will be 134°F. For the full core addition to the spent fuel pool that fills the pool (15 prior annual refuelings), the required decay cooling time in the reactor vessel that will be needed to keep the pool water temperature below 150°F with only one pump running will be approximately 570 hours (24 days) after reactor shutdown.

Provisions have been made for the addition of an additional heat exchanger, should this be required in the future.

Spent Fuel Pool Cooling System component design data are listed in Table 9.1-2. The following is a description of each component utilized in the Spent Fuel Cooling System:

Spent Fuel Pool Heat Exchanger

The spent fuel pool heat exchanger is of the shell and U-tube type with the tubes welded to the tube sheet. Component cooling water circulates through the shell, and spent fuel pool water circulates through the tubes. The tubes are austenitic stainless steel and the shell is carbon steel.

Spent Fuel Pool Pumps

The spent fuel pool pumps circulate water in the Spent Fuel Pool Cooling System. All wetted surfaces of the pumps are austenitic stainless steel, or equivalent corrosion resistant material. The pumps are operated manually from a local station.

Spent Fuel Pool Filter

The spent fuel pool filter removes particulate matter larger than 5 microns from the spent fuel pool water. The filter cartridge is of synthetic fiber and vessel shell is austenitic stainless steel.

Spent Fuel Pool Strainer

A stainless steel strainer is located at the inlet of the spent fuel pool cooling suction line for removal or relatively large particles which might otherwise clog the spent fuel pool demineralizer.

Spent Fuel Pool Demineralizer

The demineralizer is sized to pass 100 gpm of the loop circulation flow to provide adequate purification of the fuel pool water for unrestricted access to the working area and to maintain optical clarity.

Refueling Water Purification Pump

The refueling water purification pump circulates water in a loop between the refueling water storage tank and the spent fuel pool demineralizer and the refueling water purification filter. All wetted surfaces of the pump are austenitic stainless steel. The pump is operated manually from a local station.

Refueling Water Purification Filter

The refueling water purification filter removes particulate matter larger than 5 microns from the refueling water purification flow.

Spent Fuel Pool Cooling System Valves

Manual stop valves are used to isolate equipment and lines and manual throttle valves provide flow control. Valves in contact with spent fuel pool water are austenitic stainless steel or equivalent corrosion resistant material.

Spent Fuel Pool Cooling System Piping

All piping in contact with spent fuel pool water is austenitic stainless steel. The piping is welded except where flanged connections are used to facilitate maintenance.

Spent Fuel Pool Skimmers

Two spent fuel pool skimmers are provided to remove water from the surface of the spent fuel pool. The skimmer heads are manually positioned to take water from any elevation from the water surface to four inches below the surface. The elevation of the skimmers head can be manually adjusted over a total range of two feet.

Spent Fuel Pool Skimmer Pump

The spent fuel pool skimmer pump circulates surface water through a strainer, a filter, and returns it to the pool.

Spent Fuel Pool Skimmer Strainer

The spent fuel pool skimmer strainer is designed to remove debris from the skimmer process flow.

Spent Fuel Pool Skimmer Filter

The spent fuel pool skimmer filter is designed to remove insoluble particles which are not removed by the strainer.

9.1.3.3 Design Evaluation

The most serious failure of this system would be complete loss of water in the spent fuel pool. To protect against this possibility, the spent fuel pool cooling suction connection enters near the normal water level so that the pool cannot be gravity-drained. The cooling water return lines contain anti-siphon holes to prevent the possibility of gravity draining the pool. There are no drains or permanently connected systems to the spent fuel pool (Seismic Class I) which, in the event of failure, could cause loss of coolant from the pool that would uncover the fuel. Also, provisions have been made to supply makeup to the spent fuel pool as noted below.

The rate of pool heatup with cooling interrupted for 1/3 of the core removed for refueling is approximately 6°F per hour at 150 hours after shutdown. The rate of heatup for a full core at the end of an operating cycle plus the 1/3 core removed at the previous refueling is approximately 12°F per hour with cooling interrupted. An interruption in the operation of the spent fuel cooling system for an extended period is not considered to be a credible occurence. Maintenance will be scheduled when the decay heat loads are light. Two fully redundant, spent fuel pool pumps are provided, each receiving power from individual vital bus sections. As noted below, a number of makeup water sources are available and are capable of providing emergency cooling.

Water loss from the spent fuel pool due to the accidental opening of a sluice gate when the transfer pool is empty will not occur due to the redundancy in the sluice gates. Two sluice gates separate the spent fuel pool from the transfer pool.

A heavy load handling accident would not result in water leakage severe enough to uncover the spent fuel. The maximum load carried over the spent fuel pool is that of a fuel assembly, however, it is not possible to drop a fuel assembly on the spent fuel pool liner plate. In addition, integrity of the spent fuel pool will not be breached due to a fuel cask drop in the fuel transfer pool since each of the pool structures are separate and distinct.

Pool water level indication is provided by individual high and low water level alarms. The alarms are actuated by deviation from normal water level (El. 128'-8") of plus or minus 6 inches. The alarms are annunciated in the fuel handling building at the spent fuel pool and in the Control Room.

Annunciation of an alarm will be confirmed by visually checking the spent fuel pool water level. Alarms may be expected to occur occasionally due to gradual changes in pool water temperature and surface evaporation. If needed, makeup will be added. Alarms occurring with unusual frequency or for reasons not readily apparent will be further investigated. Frequent inspections will also be made of the fuel handling building sump, and, through annunciators provided in the Control Room, the running frequency of the sump pump will be observed.

The normal source of makeup water to the spent fuel pool is the demineralized water system which distributes water from two 500,000 gallon demineralized water tanks. The tanks and the distribution system do not have seismic classification. Make up is also available from the primary water storage tank via the Primary Water Makeup Pumps (Seismic Class II) and from the Chemical and Volume Control System hold-up Tanks via the Hold-up Tank Recirculation Pump (Seismic Class II).

Valves have been installed on the existing 6-inch spare nozzles on both refueling water storage tanks (350,000 gallons each). These tanks are Class I (seismic). A portable pump, with appropriate suction and discharge connections and hose, will be provided with the capability to deliver approximately 100 gpm makeup water flow from one of the refueling water storage tanks directly to the spent fuel pool. Assuming the maximum heat load in the pool, and inability to provide makeup from normal sources, the quantity of water stored in one refueling water storage tank would provide a period of approximately 100 hours in which emergency repairs to the spent fuel pool cooling system could be made, without significant loss of water level in the spent fuel pool. The valves installed on the refueling water storage tanks will be locked, closed and capped, and will be under administrative control. The portable pump and hose will also be under administrative control to ensure constant and timely availability.

Up to 100 gallons per minute of makeup is also available from the refueling water storage tank via the refueling water purification loop.

If a leaking fuel assembly is stored in the spent fuel pool, a small quantity of fission products may enter the cooling water. Fission products and other contaminants are removed by the spent fuel pool purification loop.

A failure analyses of system pumps, heat exchangers and valves is presented in Table 9.1-3.

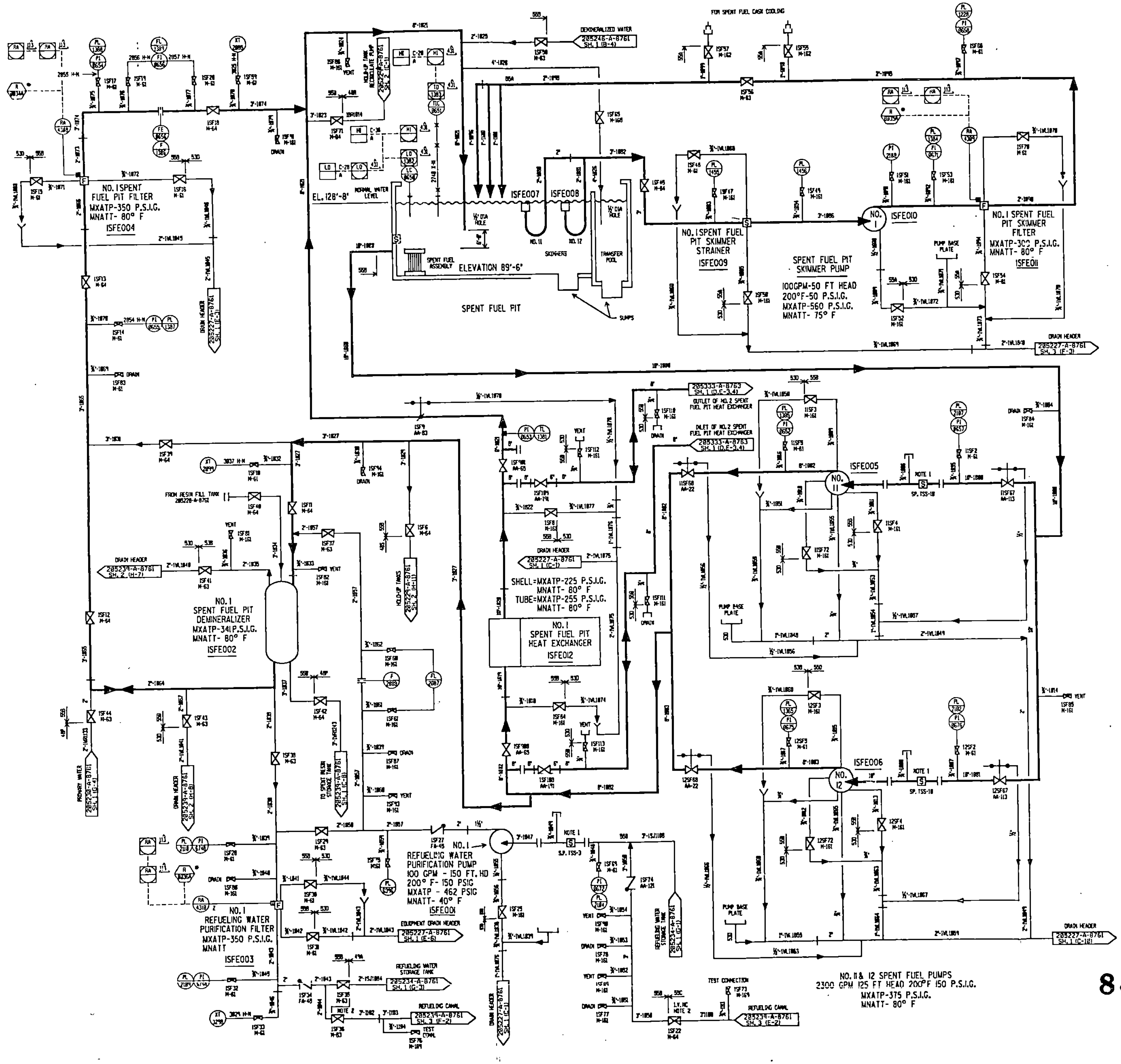
The spent fuel pool water is normally limited to 120°F except in unusual circumstances as previously described. Boron concentration in the pool fluid is maintained at a minimum of 2,000 ppm.

9.1.3.4 Test and Inspections

The active components of the system are in continuous use during normal plant operation and no additional periodic tests are required. Periodic visual inspections and preventative maintenance are conducted following normal industrial practice.

9.1.4 FUEL HANDLING SYSTEM

The fuel handling system consists of equipment and structures utilized for handling new and spent fuel assemblies in a safe manner during refueling and fuel transfer operations. The fuel handling system is shown in Figure 9.1-5.



NOTES:

1. TEMPORARY STRAINER IS PLACED ON THE SPOOL PIECE DURING INITIAL FLUSHING OPERATIONS. STRAINER MUST BE REMOVED BEFORE PLANT START-UP. CAPPED LINE IS CONNECTED TO A TEMPORARY PRESSURE GAGE AT THIS TIME.
2. LOCATE VALVE AS CLOSE TO CONTAINMENT AS POSSIBLE.
3. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1SF" (i.e. 1SF1000 ECT.) EXCEPT WHERE OTHERWISE NOTED.
4. ALL PRESSURES SHOWN ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-0531.
5. INSTRUMENT ITEMS IN PARENTHESIS ( ) ARE WESTINGHOUSE INSTRUMENT ITEMS. REFER TO ISA S1 FOR DESCRIPTION.

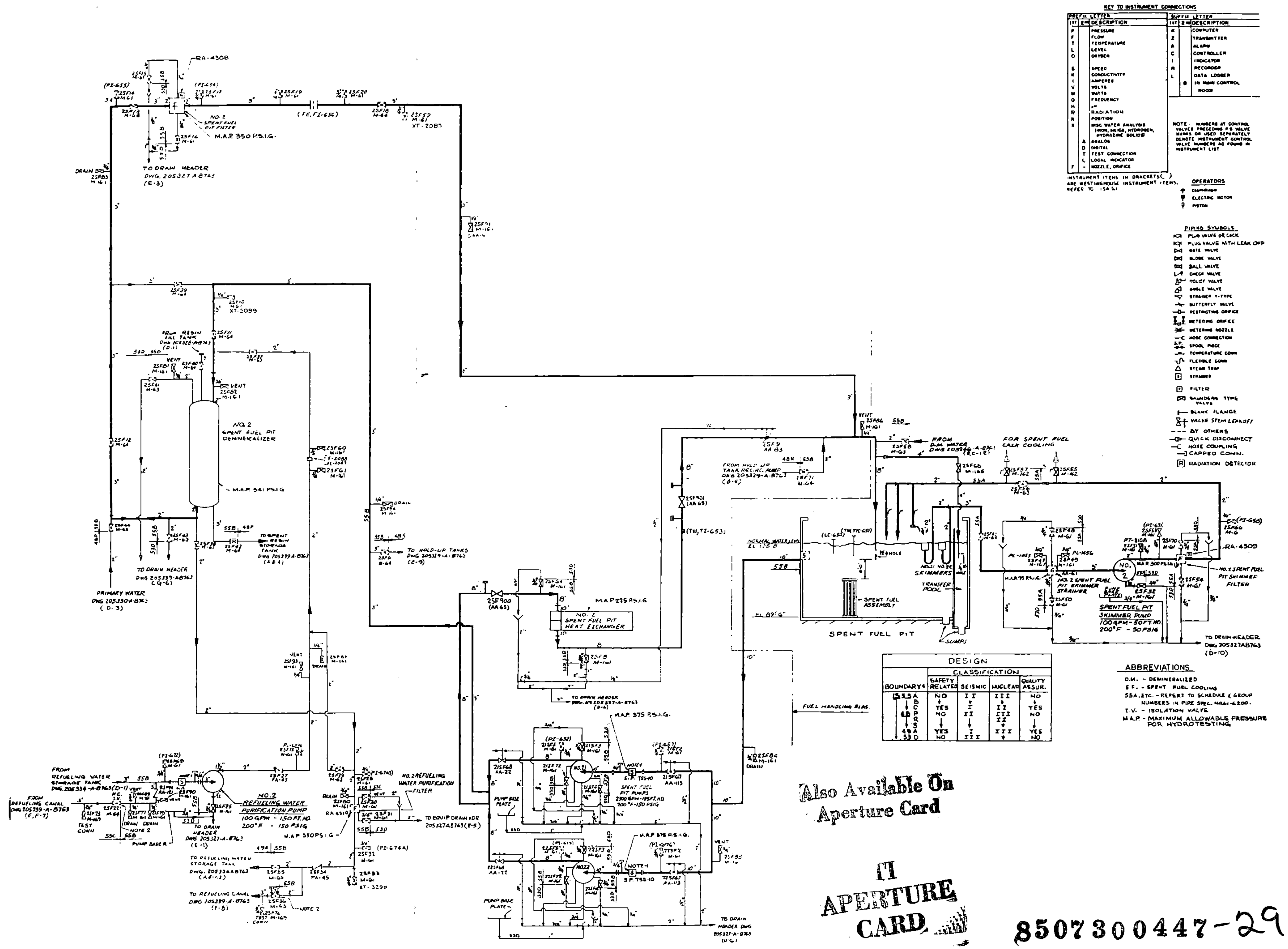
Also Available On Aperture Card

APERTURE CARD

8507300447 -28

Revision 4
July 22, 1985
Ref. Dwg. 205233A8761-12

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Spent Fuel Cooling System Unit 1
	Updated FSAR — Fig 9.1-4A



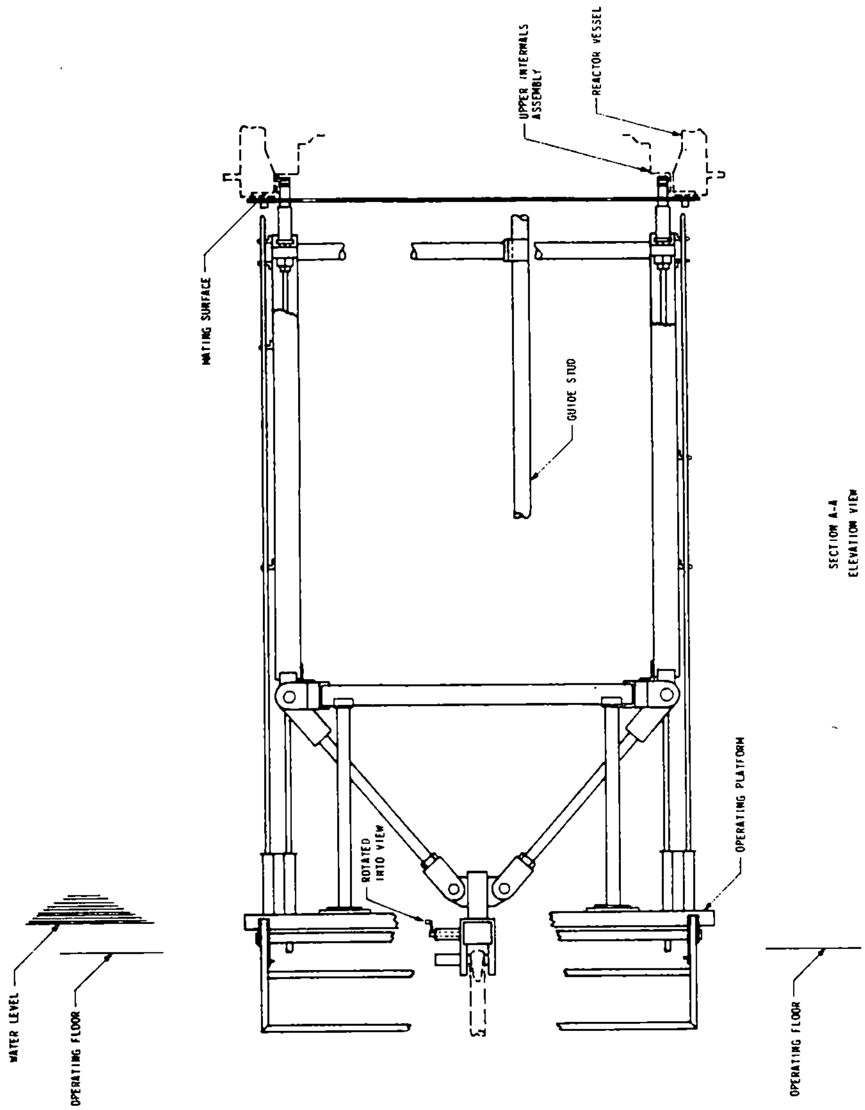
Also Available On Aperture Card

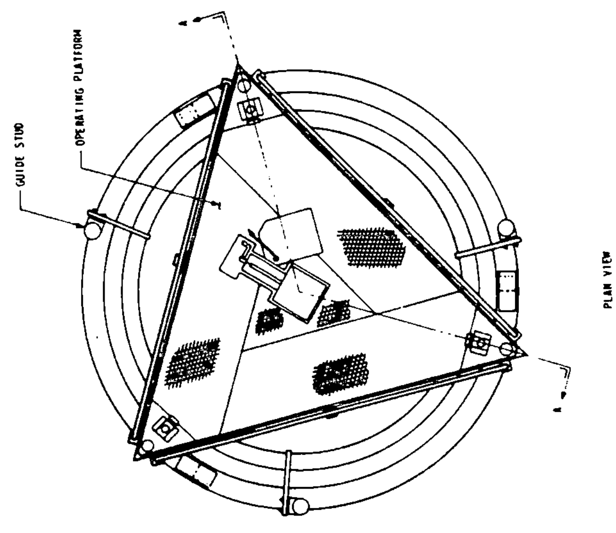
APERTURE CARD

8507300447-29

Revision 4
July 22, 1985
Ref. Dwg. 205333A8763-9

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Spent Fuel Cooling System Unit 2
	Updated FSAR — Fig 9.1-4B





Note: The platform structure shown on
this drawing is installed in Unit 2 only.

Revision 1
July 22, 1983

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Internals Lifting Rig	
	UPDATED FSAR	FIG 9.1-9

TABLE 9.2-4 (Sheet 1 of 2)

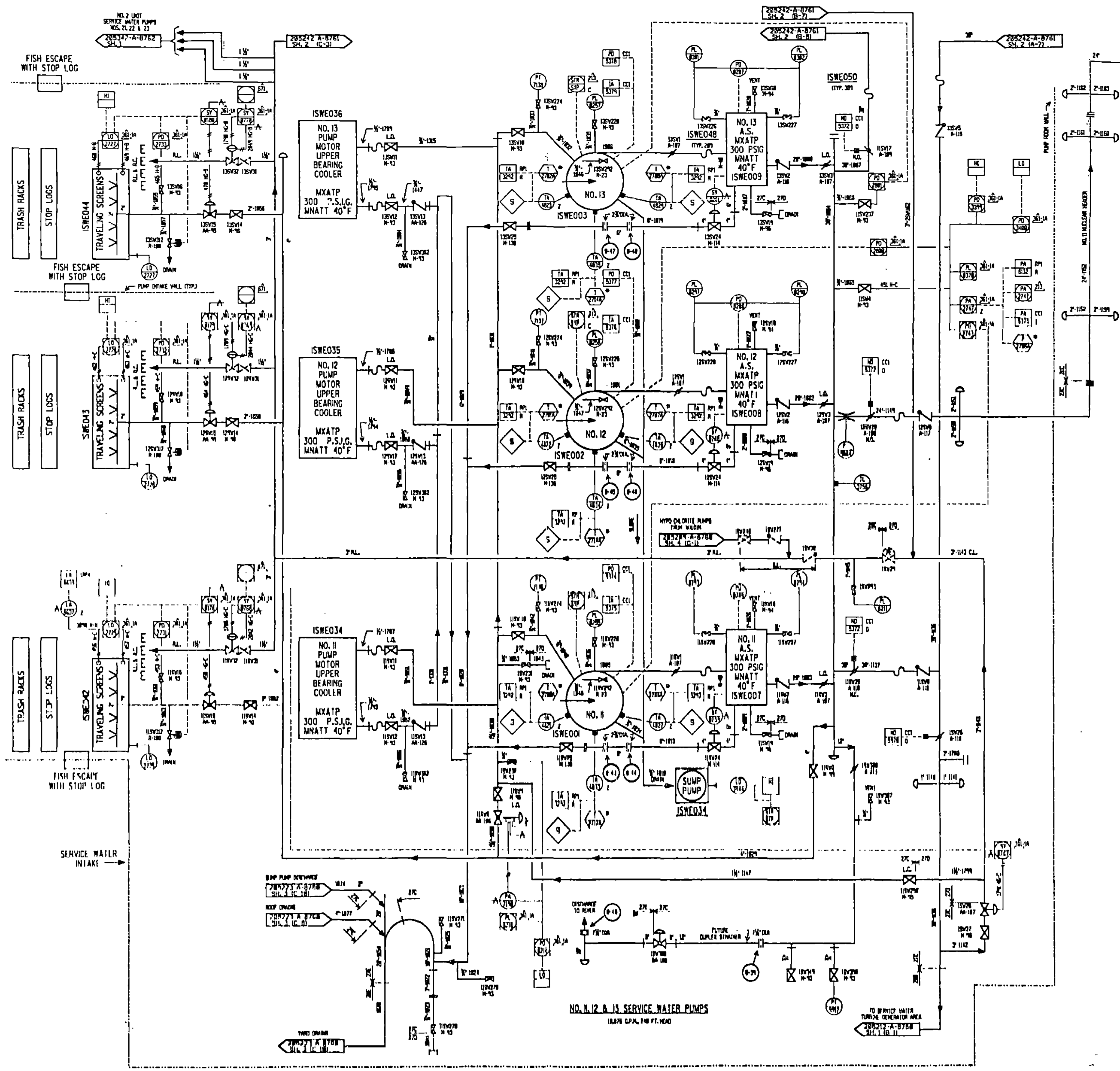
COMPONENT COOLING SYSTEM
COMPONENT DESIGN DATA

Component Cooling Pumps

Quantity	3
Type	Horizontal Centrifugal
Rated capcity, gpm	4600
Rated head, ft. H_2O	200
Design pressure, psig	150
Design temperature, ^oF	200
Available NPSH, ft.	25
Material	Carbon steel

Component Cooling Heat Exchangers (Shell and Tube Type)

Number		3[(a)]
Design heat transfer, Btu/hr		44.2×10^6
	Shell	Tube
Design pressure, psig	150	150
Design temperature, ^oF	200	200
Design flow rate, lb/hr	3.41×10^6	4.99×10^6
Design inlet temperature, ^oF	107.9	85
Design outlet temperature, ^oF	95	93.9
Fluid	Component cooling water	Service Water
Material	Carbon steel	90-10 copper-nickel alloy for No. 11 and No. 21. Titanium for No. 22.



NOTES:

1. PIPING SCHEDULE DESIGNATIONS SHOWN ONLY FOR SEISMIC AND/OR NUCLEAR PIPING.
2. FOR DESIGN PRESSURE & TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE & TEMPERATURE PARAMETERS AT THE ORIGINAL SOURCE HEADER.
3. ALL PIPING NUMBERS SHALL HAVE THE PREFIX "1SW" (I.E. 1SW1088, ETC.) EXCEPT WHERE OTHERWISE NOTED.
4. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-0861
5. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 62-6288. THE PIPING SCHEDULE AND GROUP NOS. ARE AS NOTED ON THIS DRAWING AND PREFIXED WITH "1S".
6. VALVE INSTALLED, NOT HOOKED UP TO PANEL

DESIGN				
BOUNDARY *	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S27B	YES	I	III	YES
1S27C	YES	I	III	YES
1S27D	NO	III	NONE	NO
1S27E	NO	III	NONE	NO
1S29B	YES	I	III	YES
1S29C	YES	I	III	YES
1S29D	NO	III	NONE	NO
1S29	NO	III	NONE	NO
1S27A	YES	I	II	YES

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (I.E. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

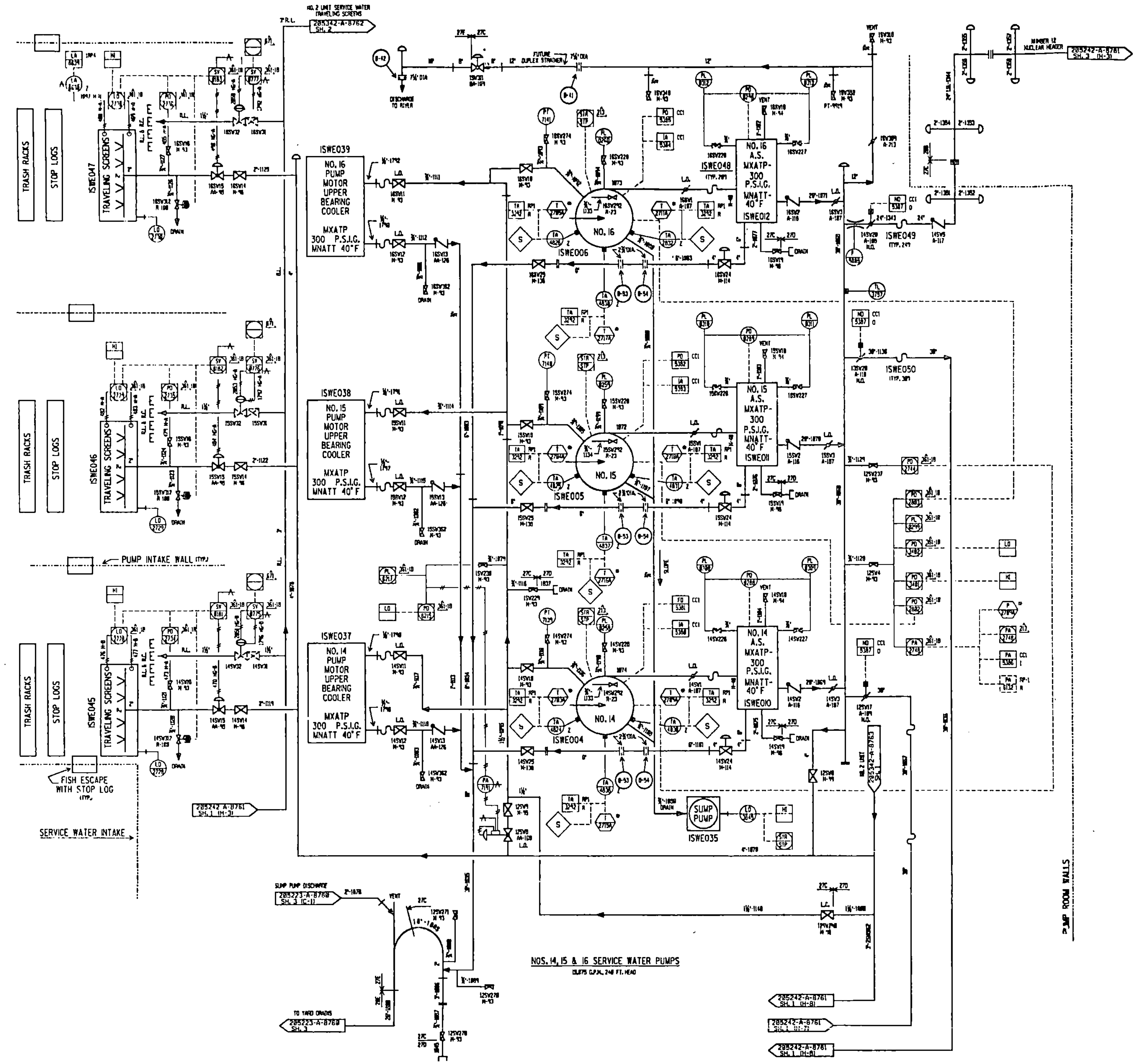
Also Available On Aperture Card

APERTURE CARD

8507300447-30

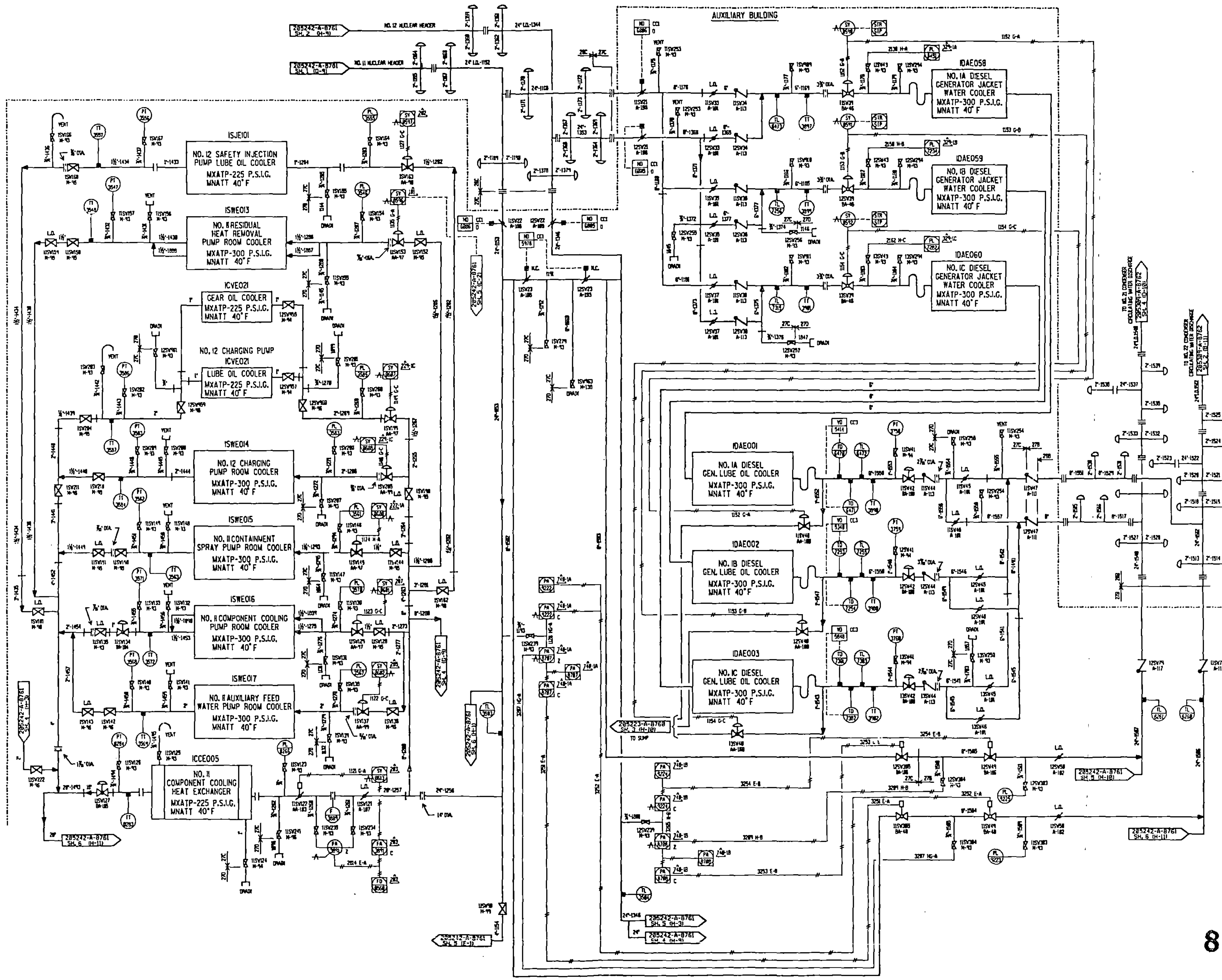
Revision 4
July 22, 1985
Ref. Dwg. 205242A8761-32

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Service Water System - Nuclear Area Unit 1
	Updated FSAR Sheet 1 of 6 Fig 9.2-1A



Revision 4
July 22, 1985
Ref. Dwg. 205242A8761-32

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Service Water System - Nuclear Area Unit 1 Updated FSAR Sheet 2 of 6 Fig 9.2-1A



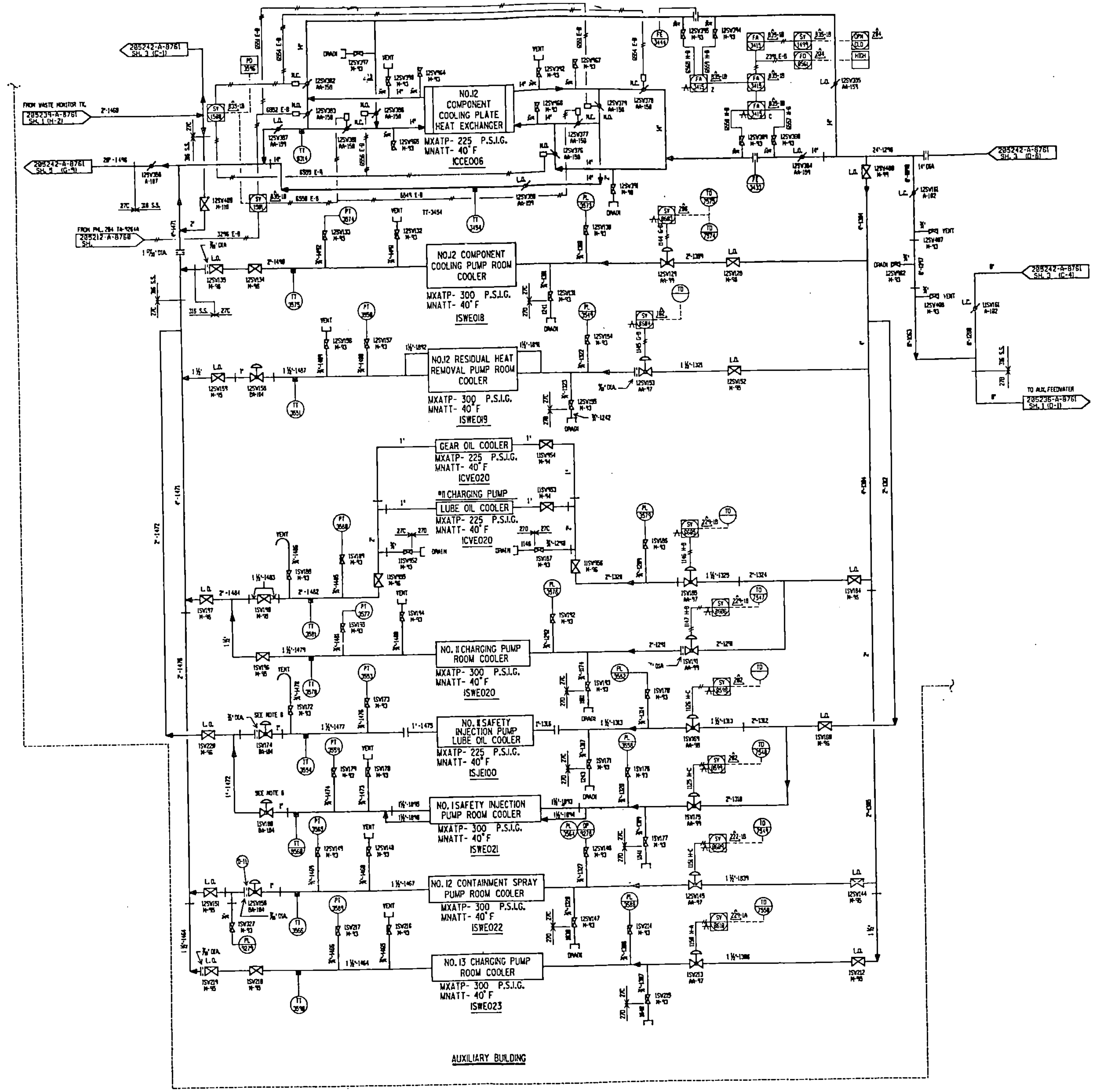
Also Available On Aperture Card

APERTURE CARD

8507300447 -32

Revision 4
July 22, 1985
Ref. Dwg. 205242A8761-32

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Service Water System - Nuclear Area Unit 1
	Updated FSAR Sheet 3 of 6 Fig 9.2-1A



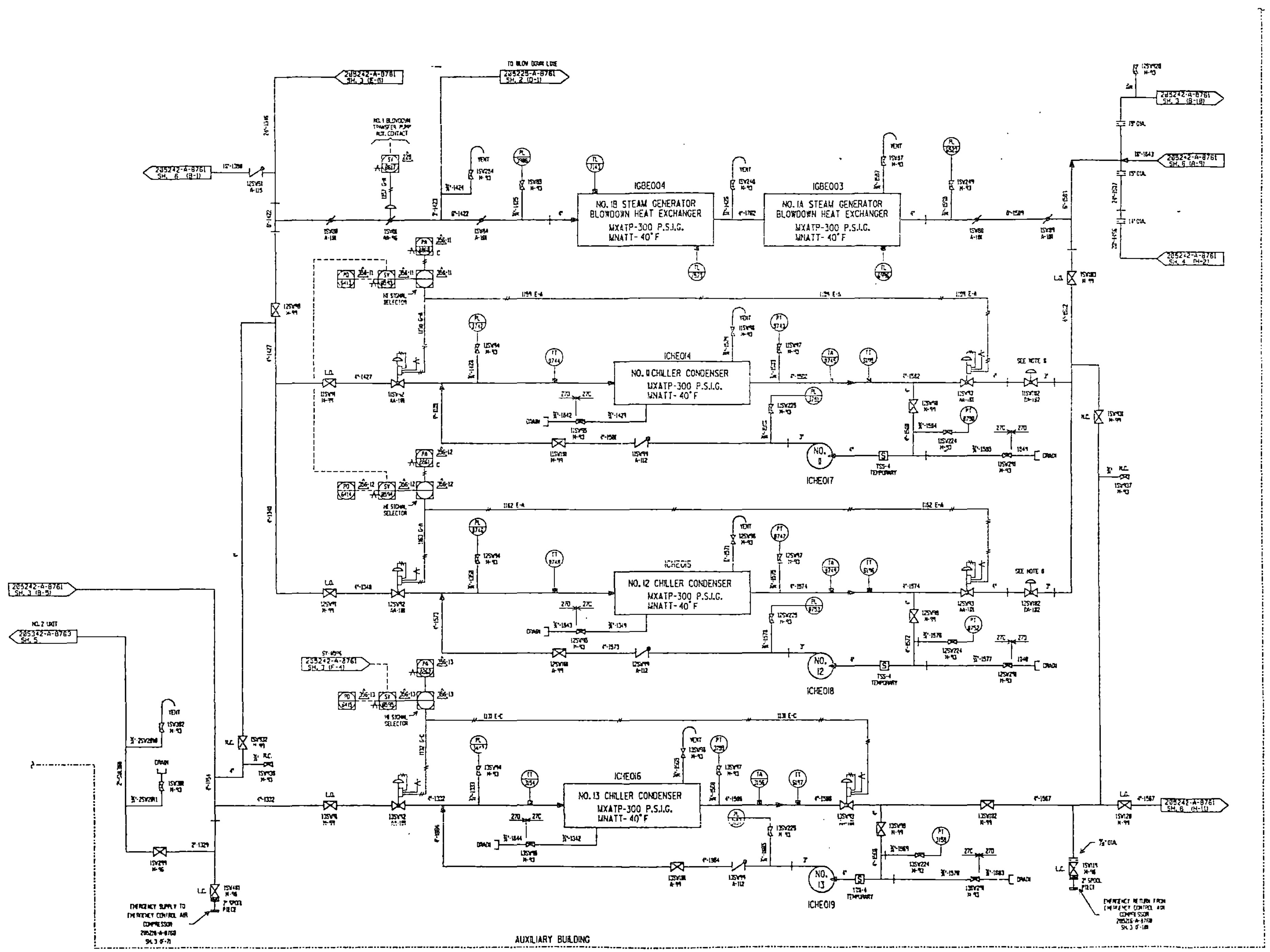
Also Available On Aperture Card

APERTURE CARD

8507300447-33

Revision 4
July 22, 1985
Ref. Dwg. 205242A8761-32

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Service Water System - Nuclear Area Unit 1
	Updated FSAR Sheet 4 of 6 Fig 9.2-1A



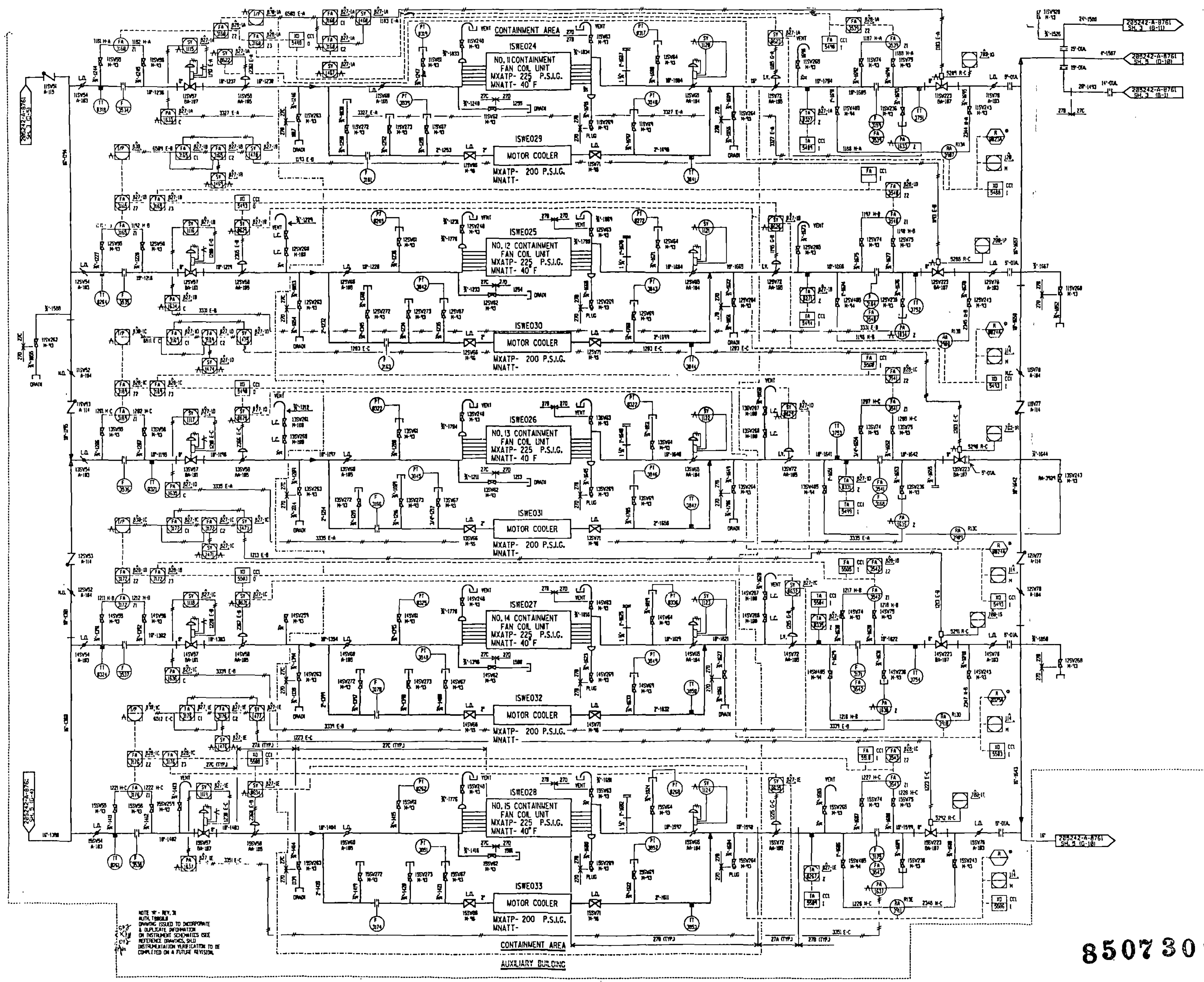
Also Available On Aperture Card

TI APERTURE CARD

8507300447-34

Revision 4
July 22, 1985
Ref. Dwg. 205242A8761-32

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Service Water System - Nuclear Area Unit 1
	Updated FSAR Sheet 5 of 6 Fig 9.2-1A



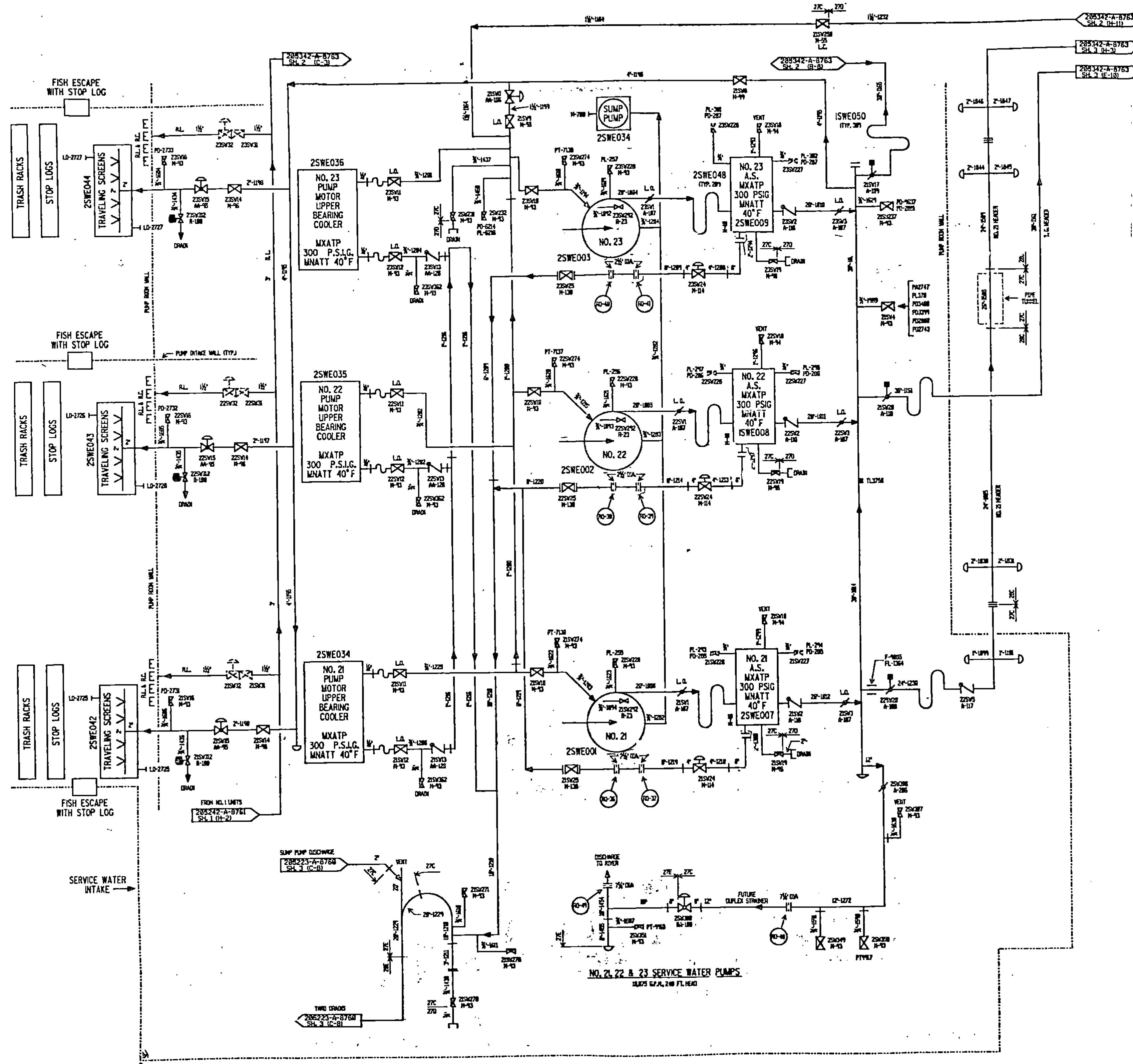
Also Available On Aperture Card

TI APERTURE CARD

8507300447 -35

Revision 4
July 22, 1985
Ref. Dwg. 205242A8761-32

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Service Water System - Nuclear Area Unit 1
	Updated FSAR Sheet 6 of 6 Fig 9.2-1A



NOTES:

1. ALL PIPING NUMBERS SHALL HAVE THE PREFIX "2SW" (I.E. 2SW1000, ETC.) EXCEPT WHERE OTHERWISE NOTED.
2. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED BY FIELD DIRECTIVE S-C-[illegible]-MFD-[illegible]
3. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200. THE PIPING SCHEDULE AND GROUP NO'S ARE 1S27 & 1S28 EXCEPT AS OTHERWISE NOTED.

DESIGN				
BOUNDARY *	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S27B	YES	I	III	YES
1S27C	YES	I	III	YES
1S27D	NO	III	NONE	NO
1S27E	NO	III	NONE	NO
1S28B	YES	I	III	YES
1S28C	YES	I	III	YES
1S28D	NO	III	NONE	NO
1S29	NO	III	NONE	NO
1S27A	YES	I	II	YES

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (I.E. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

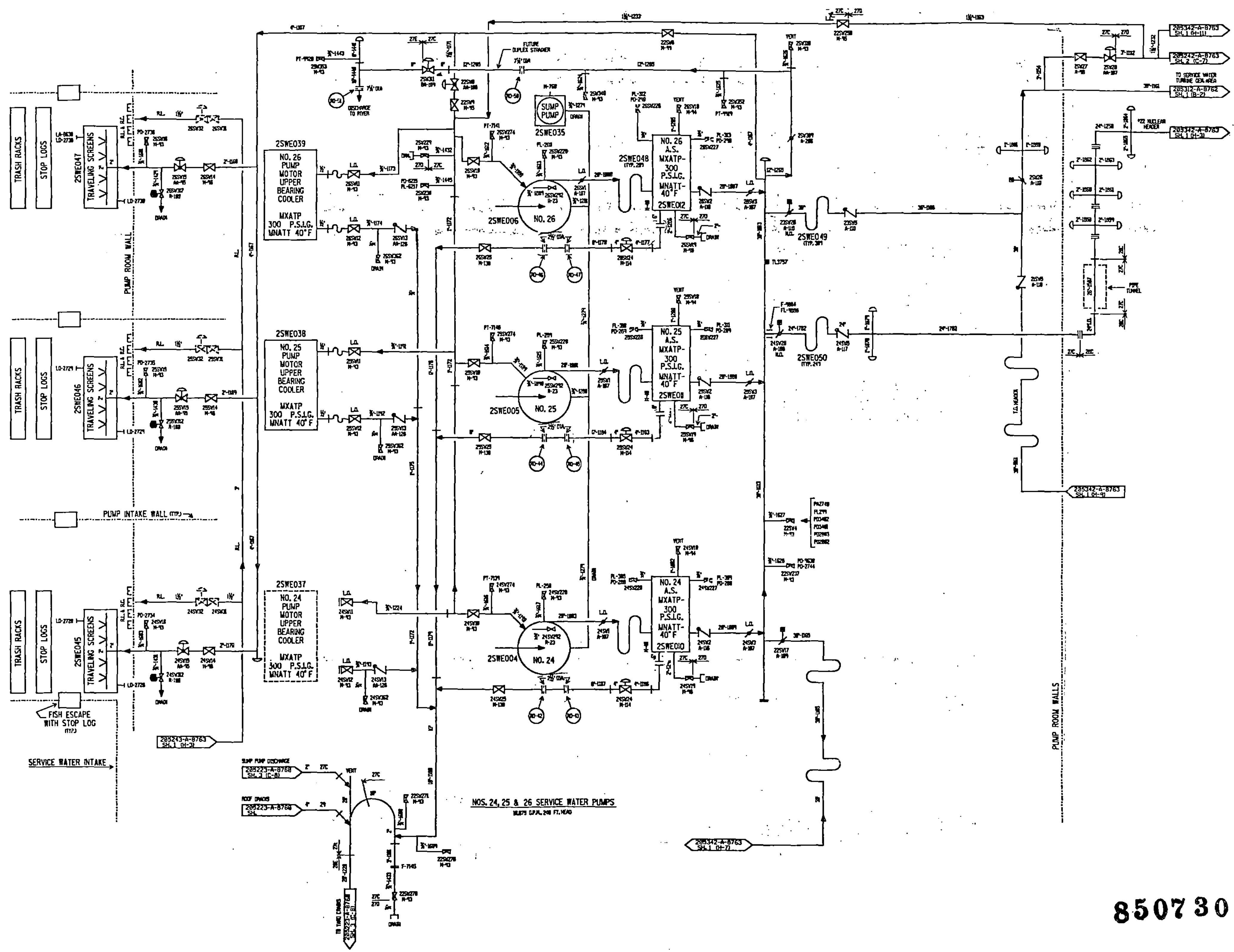
Also Available On Aperture Card

TI APERTURE CARD

8507300447-36

Revision 4
July 22, 1985
Ref. Dwg. 205342A8763-23

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Service Water System - Nuclear Area Unit 2
	Updated FSAR Sheet 1 of 6 Fig 9.2-1B



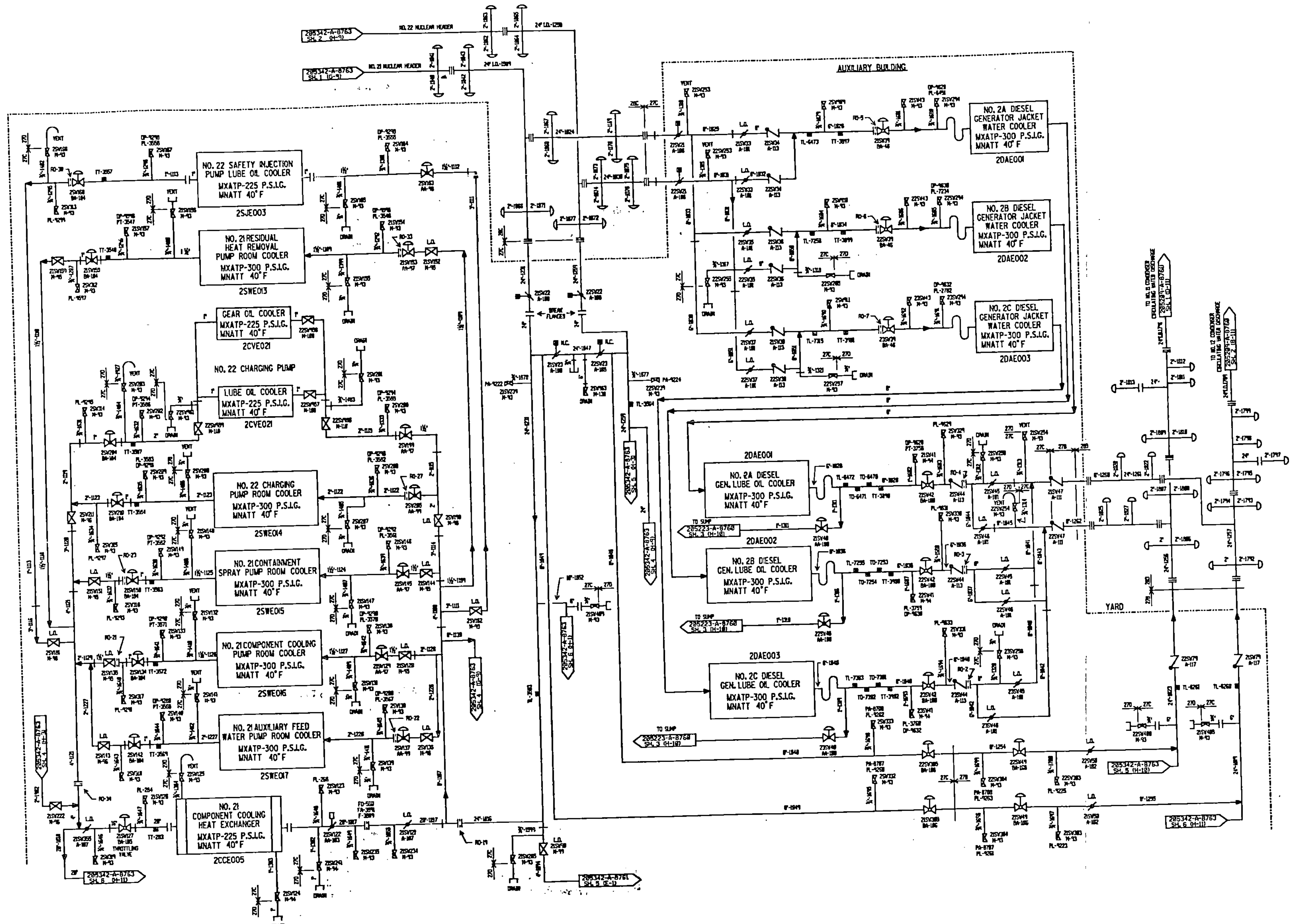
Also Available On Aperture Card

TI APERTURE CARD

8507300447-37

Revision 4
July 22, 1985
Ref. Dwg. 205342A8763-23

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Service Water System - Nuclear Area Unit 2
	Updated FSAR Sheet 2 of 6 Fig 9.2-1B



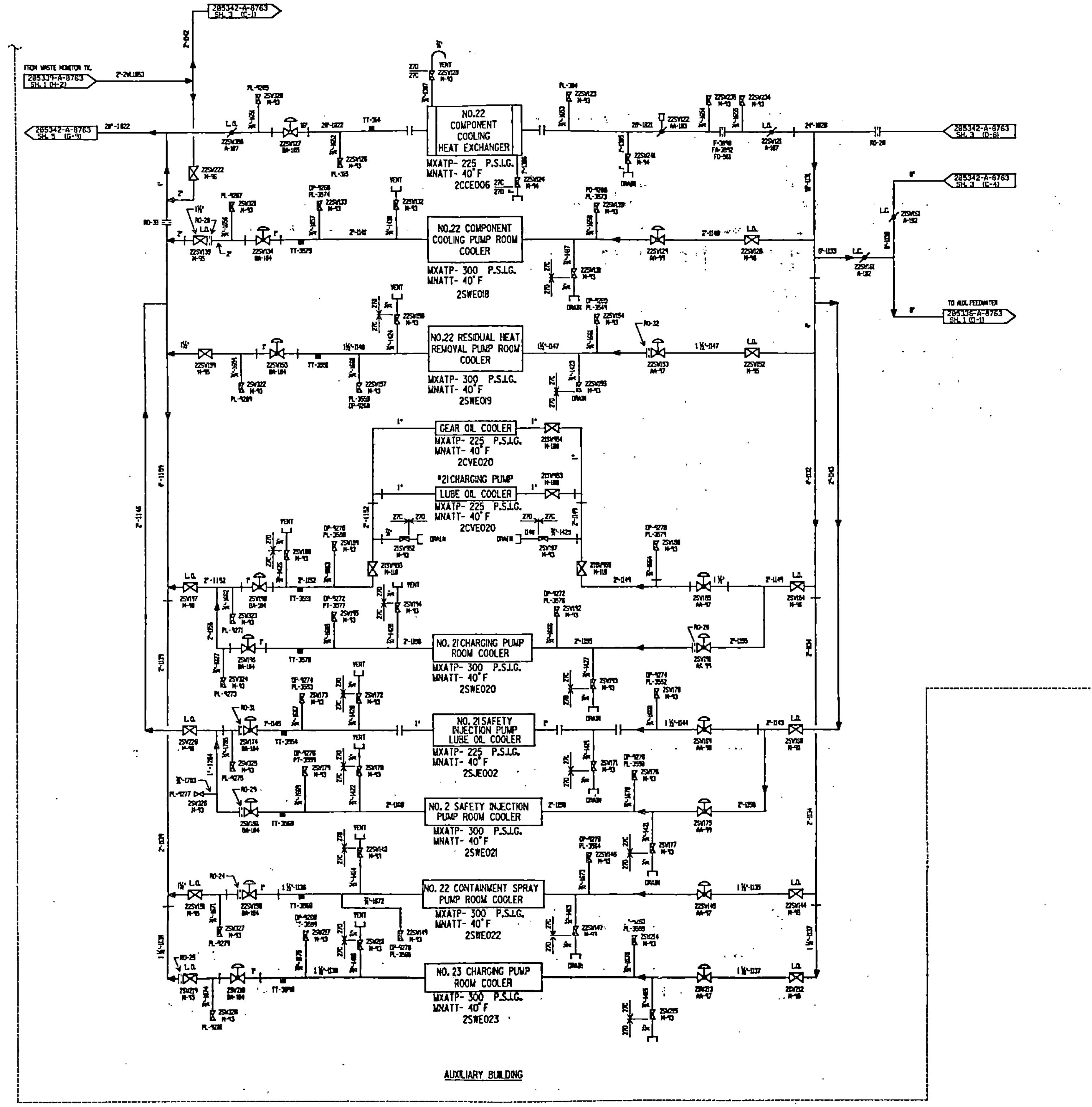
Also Available On Aperture Card

TI APERTURE CARD

8507300447 -38

Revision 4
July 22, 1985
Ref. Dwg. 205342A8763-23

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Service Water System - Nuclear Area Unit 2
	Updated FSAR Sheet 3 of 6 Fig 9.2-1B



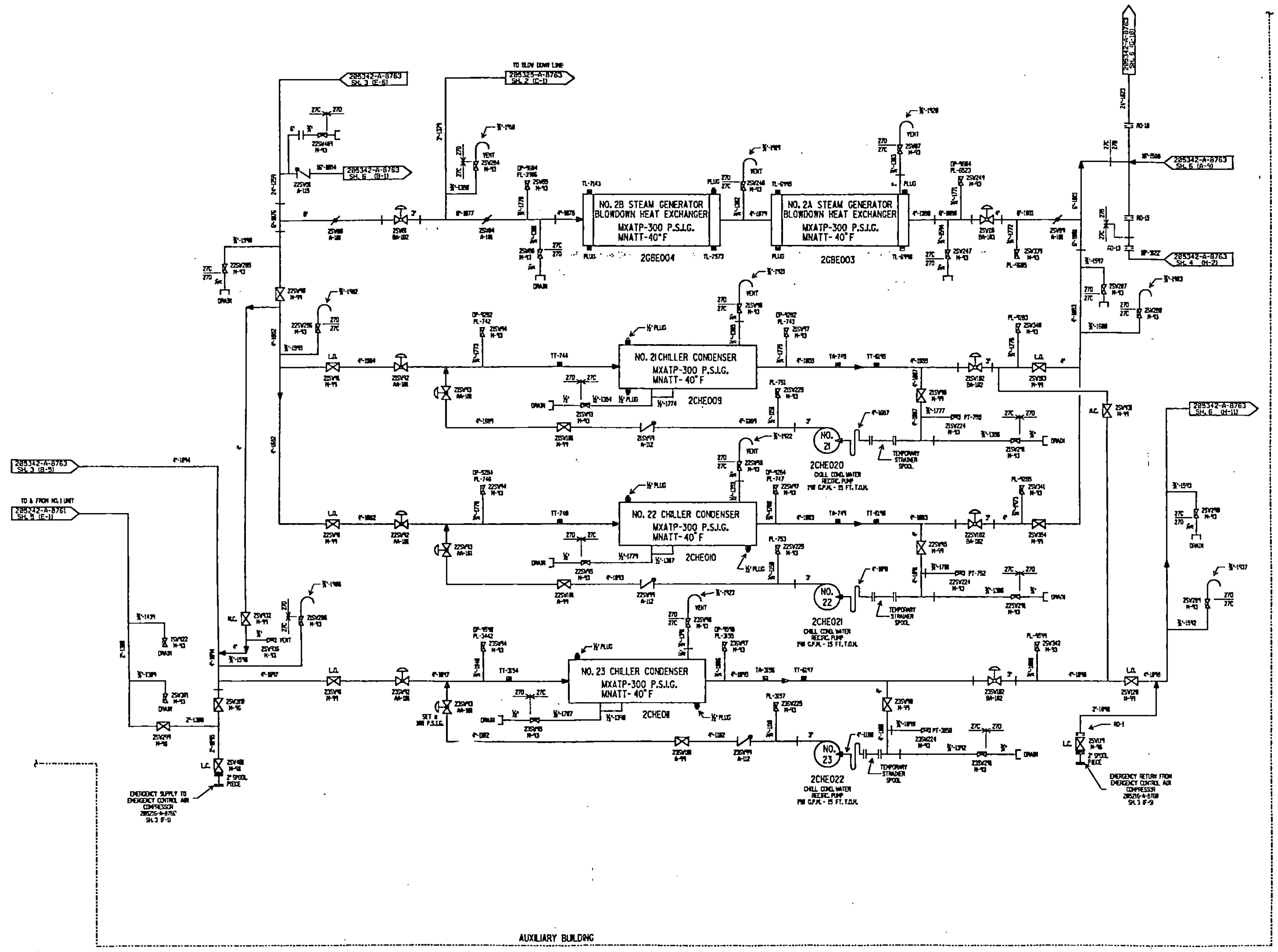
Also Available On Aperture Card

TI APERTURE CARD

8507300447-39

Revision 4
July 22, 1985
Ref. Dwg. 205342A8763-23

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Service Water System - Nuclear Area Unit 2
	Updated FSAR Sheet 4 of 6 Fig 9.2-1B



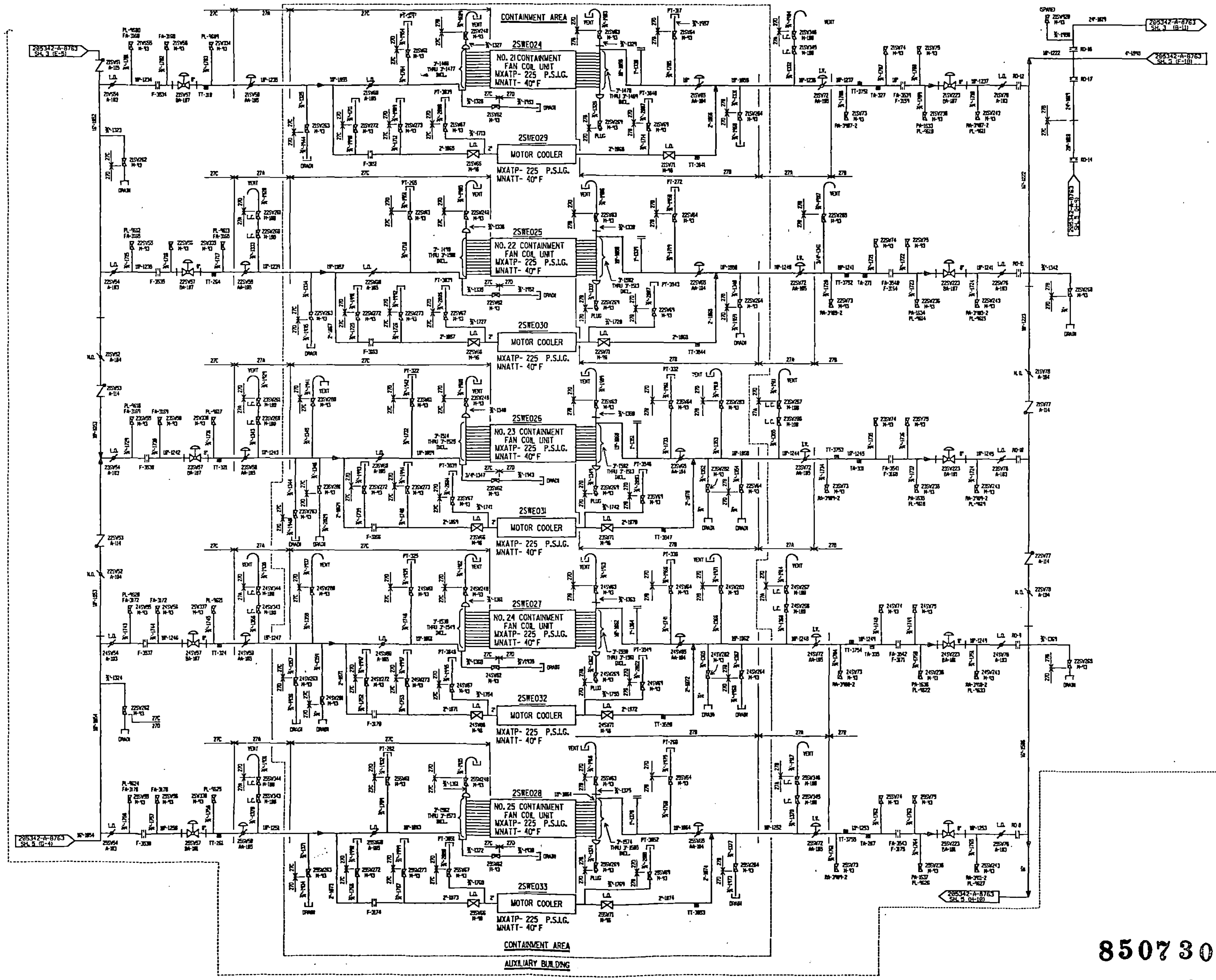
Also Available On Aperture Card

TI APERTURE CARD

8507300447-40

Revision 4
July 22, 1985
Ref. Dwg. 205342A8763-23

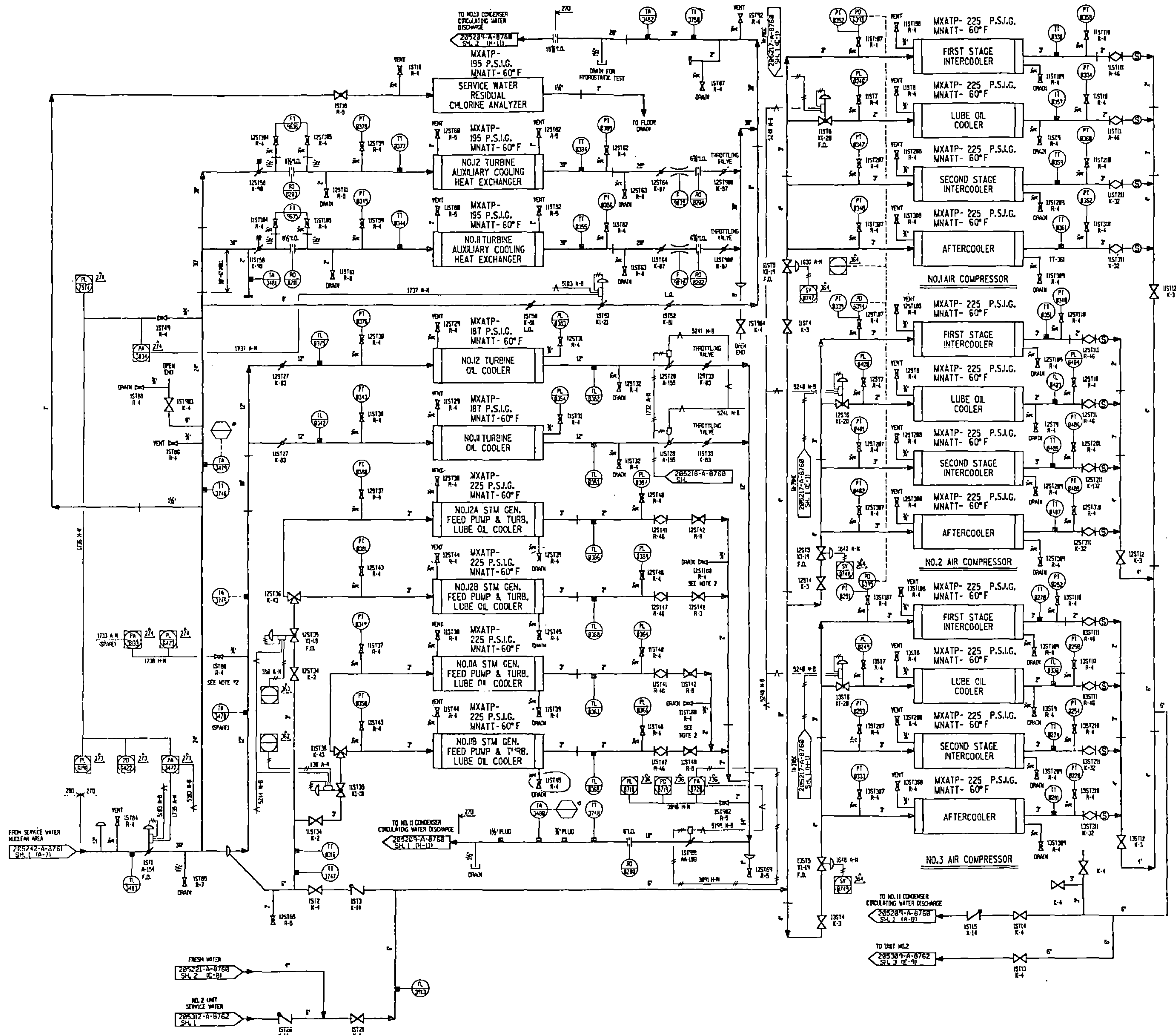
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Service Water System - Nuclear Area Unit 2
	Updated FSAR Sheet 5 of 6 F 9.2-1B



8507300447 -41

Revision 4
July 22, 1985
Ref. Dwg. 205342A8763-23

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Service Water System - Nuclear Area Unit 2
	Updated FSAR Sheet 6 of 6 Fig 9.2-1B



NOTES:

1. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
2. NOT PRESENTLY INSTALLED.

Also Available On Aperture Card

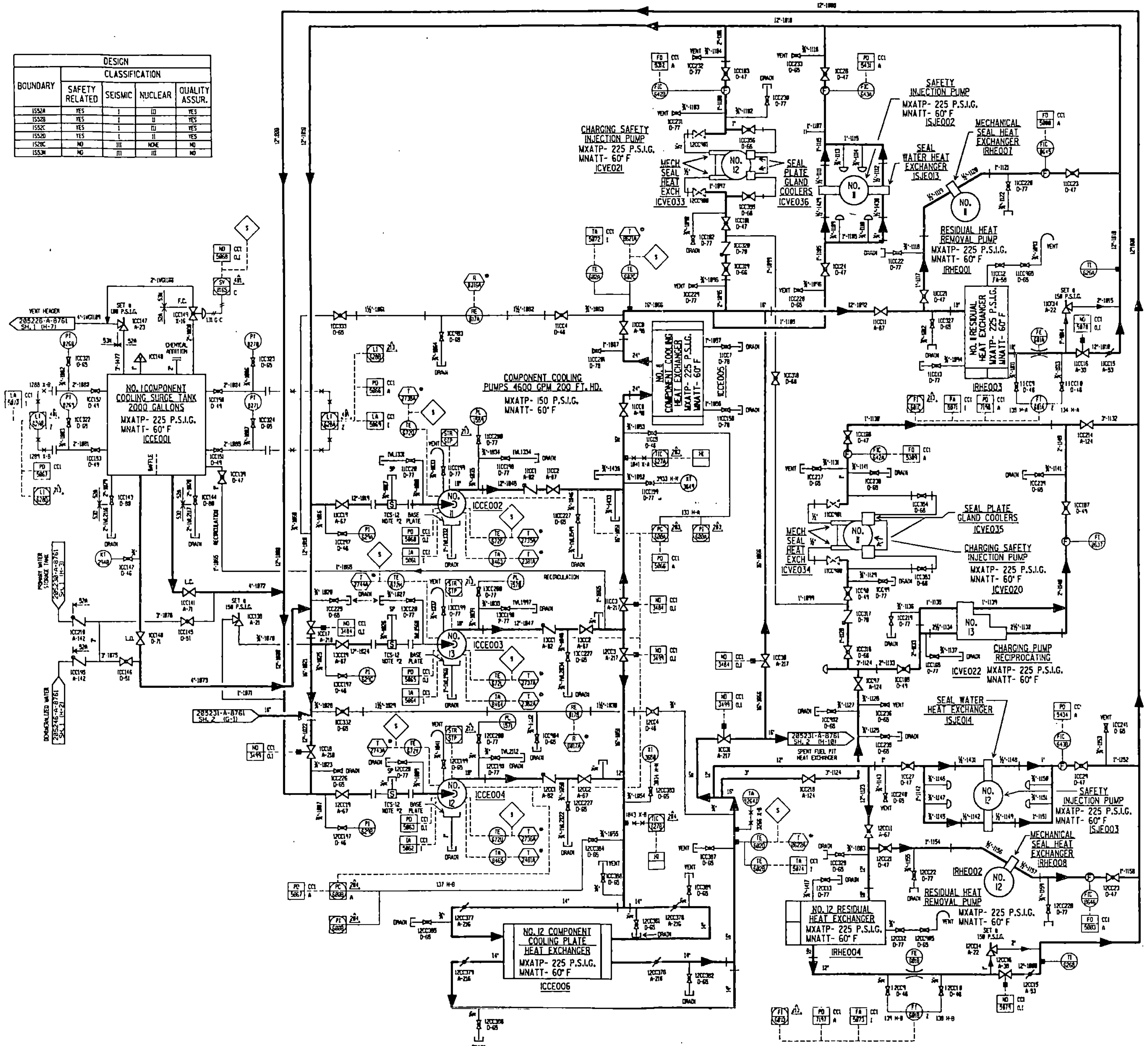
TI APERTURE CARD

8507300447-42

Revision 4
July 22, 1985
Ref. Dwg. 205212A8760-19

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Service Water System - Turbine Area
	Updated FSAR Fig 9.2-2

BOUNDARY	DESIGN CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S52A	YES	I	III	YES
1S52B	YES	I	II	YES
1S52C	YES	I	III	YES
1S52D	YES	I	II	YES
1S28C	NO	III	NONE	NO
1S53N	NO	III	III	NO



VENDOR INSTR. NO.	PSE&G INSTR. NO.
LI-628D	LA-5869
LT-628B	LA-1584
LT-628A	LA-1583
TIC-628A	TD-1561
TE-682A	TA-1564
TE-682C	TA-2882
FIC-642B	FD-2957
FIC-643A	FD-1566
FIC-0645	FD-1567
FT-681A	FA-1565
FE-681A	F-1248
TI-626A	TL-1568
PI-629A	PL-1569
PI-629C	PL-1581
PC-608A	PD-1562
PI-608A	PL-1563
FIC-642A	FD-1687
FT-0637	FL-1578
PI-629B	PL-1582
PC-608B	PD-1574

VENDOR INSTR. NO.	PSE&G INSTR. NO.
PI-608B	PL-1575
FIC-643B	FD-1733
TIC-627B	TD-1573
TE-682D	TA-2883
TE-682B	TA-1576
FIC-0646	FD-1579
FT-681B	FA-1577
FE-681B	F-1254
TI-626B	TL-1580
TE-672O	TA-1195
TE-672P	TA-1162
TE-672M	TA-2299
TE-672L	TA-2298
TE-672Y	TA-1997
TE-672U	TA-1996

NOTES

1. THESE VALVES TO BE LOCATED OUTSIDE RADIATION SHIELD.
2. TEMPORARY STRAINER TO BE PLACED IN SPOOL PIECE DURING INITIAL FLUSHING OPERATION. STRAINER MUST BE REMOVED BEFORE PLANT START UP.
3. IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (I.E. 1S44A, ETC.) UNLESS OTHERWISE NOTED.
4. ALL PIPING SPECIFICATIONS 52A UNLESS OTHERWISE NOTED.
5. ALL VALVES SHOWN WITH CAPS OR HOSE CONNECTIONS SHALL HAVE PIPE SPEC. END AT VALVE I.E. 52A
6. FOR PRESSURE AND TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE AND TEMPERATURE PARAMETERS AT THE ORIGINATING SOURCE HEADER.
7. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1CC" (I.E. 1CC1800 ETC.) EXCEPT WHERE OTHERWISE NOTED.
8. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-0511

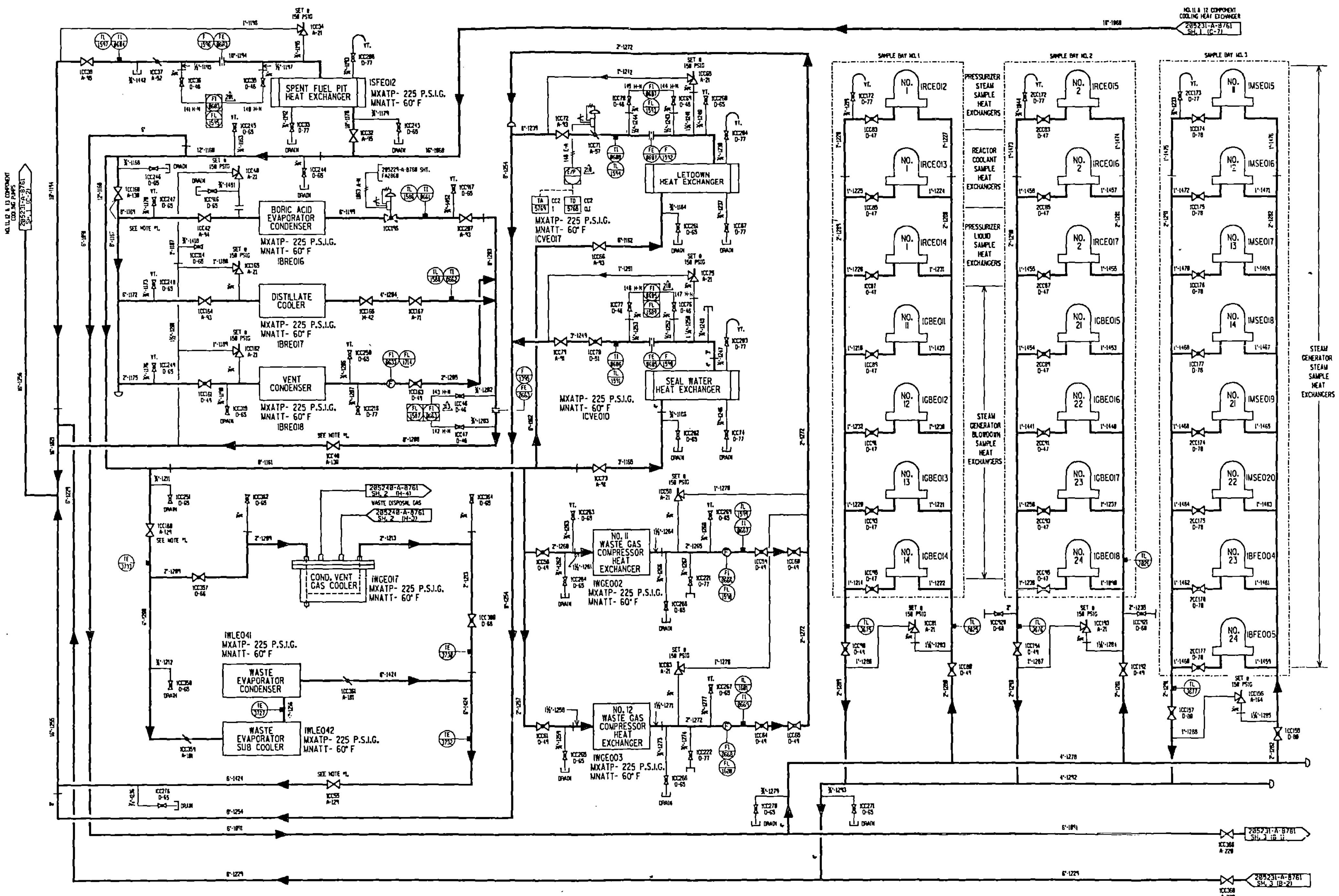
Also Available On Aperture Card

TI APERTURE CARD

8507300447-43

Revision 4
July 22, 1985
Ref. Dwg. 205231A8761-26

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Component Cooling System Unit 1
	Updated FSAR Sheet 1 of 3 Fig 9.2-4A



Also Available On Aperture Card

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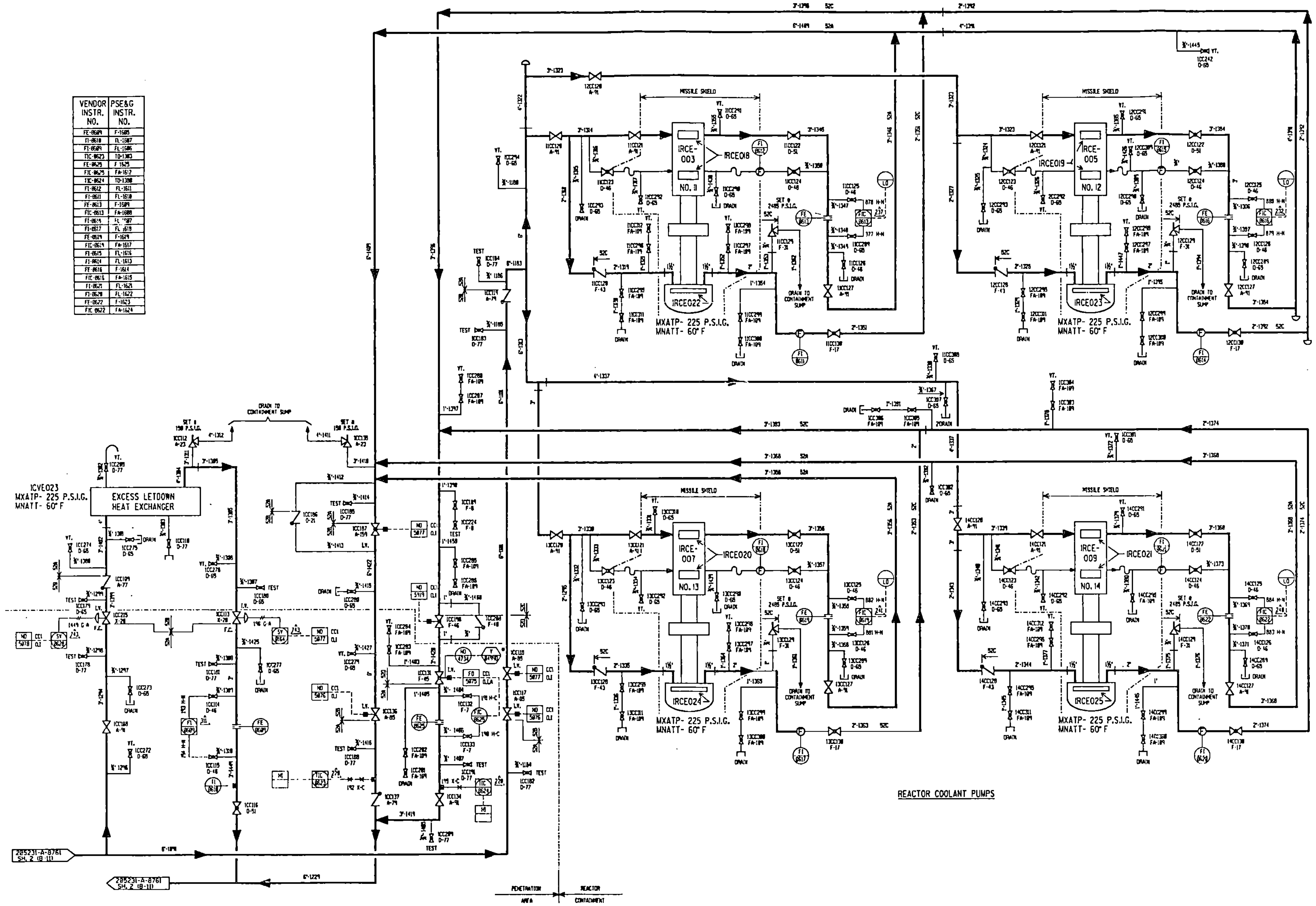
8507300447-44

Revision 4
July 22, 1985
Ref. Dwg. 205231A8761-26

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Component Cooling System Unit 1
	Updated FSAR Sheet 2 of 3 Fig 9.2-4A



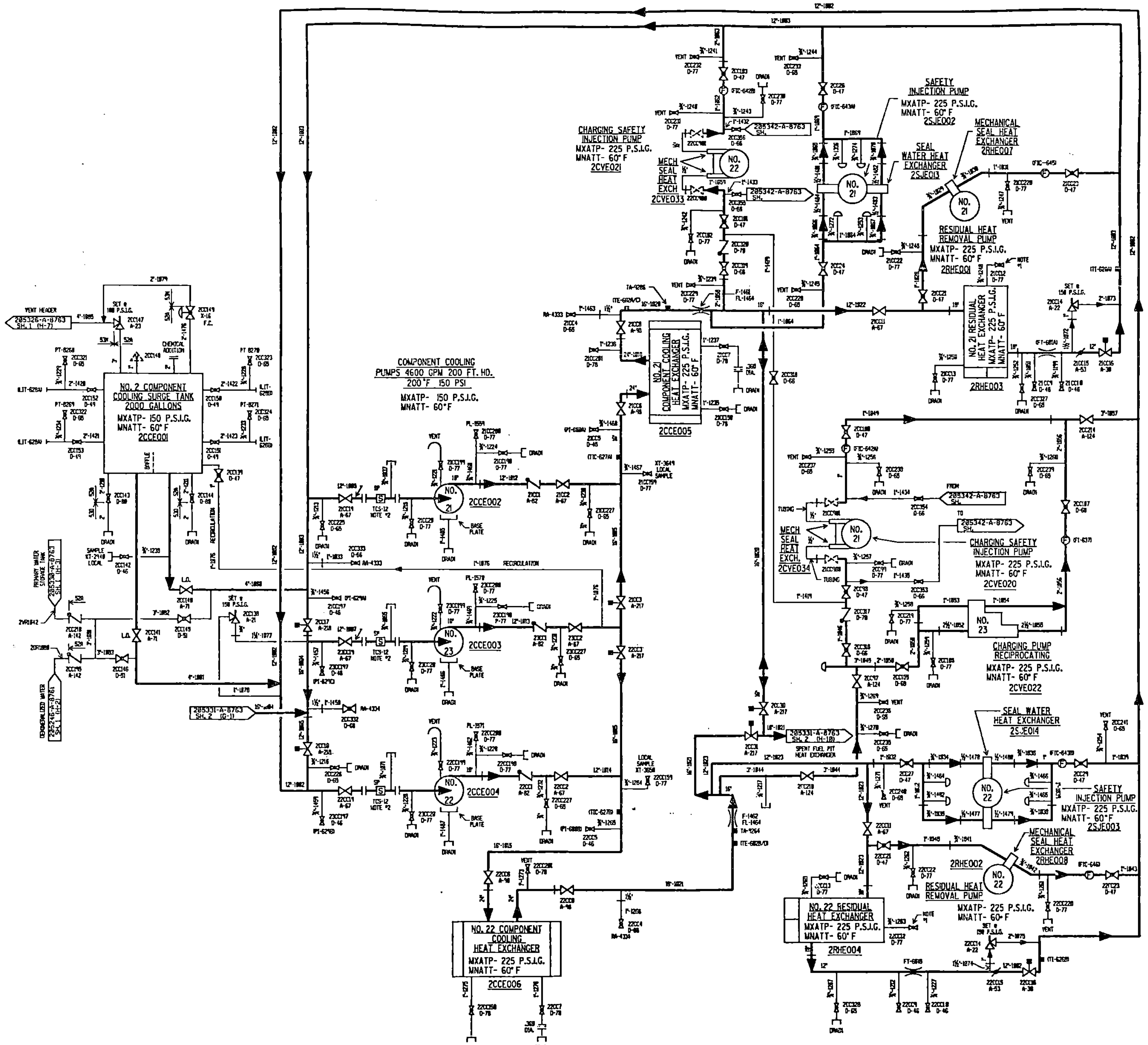
VENDOR INSTR. NO.	PSE&G INSTR. NO.
FE-0609	F-1605
FI-0610	FL-1607
FT-0609	FL-1606
TIC-0623	TD-1303
FE-0625	F-1625
FIC-0625	FA-1612
TIC-0624	TD-1308
FT-0612	FL-1611
FI-0611	FL-1610
FE-0613	F-1609
FIC-0613	FA-1608
FT-0615	[illegible]
FI-0617	FL-1618
FE-0619	F-1619
FIC-0619	FA-1617
FI-0615	FL-1616
FI-0614	FL-1613
FE-0616	F-1614
FIC-0616	FA-1615
FI-0621	FL-1621
FT-0620	FL-1622
FE-0622	F-1623
FIC-0622	FA-1624

Revision 4
July 22, 1985
Ref. Dwg. 205231A8761-26

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Component Cooling System
Unit 1

Updated FSAR Sheet 3 of 3 Fig 9.2-4A



DESIGN				
BOUNDARY (NOTE *3)	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S62A	YES	I	III	YES
1S62B	YES	I	II	YES
1S62C	YES	I	III	YES
1S62D	YES	I	II	YES
1S28C	NO	III	NONE	NO
1S53N	NO	III	III	NO

NOTES

1. THESE VALVES TO BE LOCATED OUTSIDE RADIATION SHIELD.
2. TEMPORARY STRAINER TO BE PLACED IN SPOOL PIECE DURING INITIAL FLUSHING OPERATION. STRAINER MUST BE REMOVED BEFORE PLANT START UP.
3. IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (I.E. 1S44A, ETC.) UNLESS OTHERWISE NOTED.
4. ALL PIPING SPECIFICATIONS 52A UNLESS OTHERWISE NOTED.
5. ALL VALVES SHOWN WITH CAPS OR HOSE CONNECTIONS SHALL HAVE PIPE SPEC. END AT VALVE - i.e. 52A
6. FOR PRESSURE AND TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE AND TEMPERATURE PARAMETES AT THE ORIGINATING SOURCE HEADER.
7. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2CC" (i.e. 2CC1800 ETC.) EXCEPT WHERE OTHERWISE NOTED.
8. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051

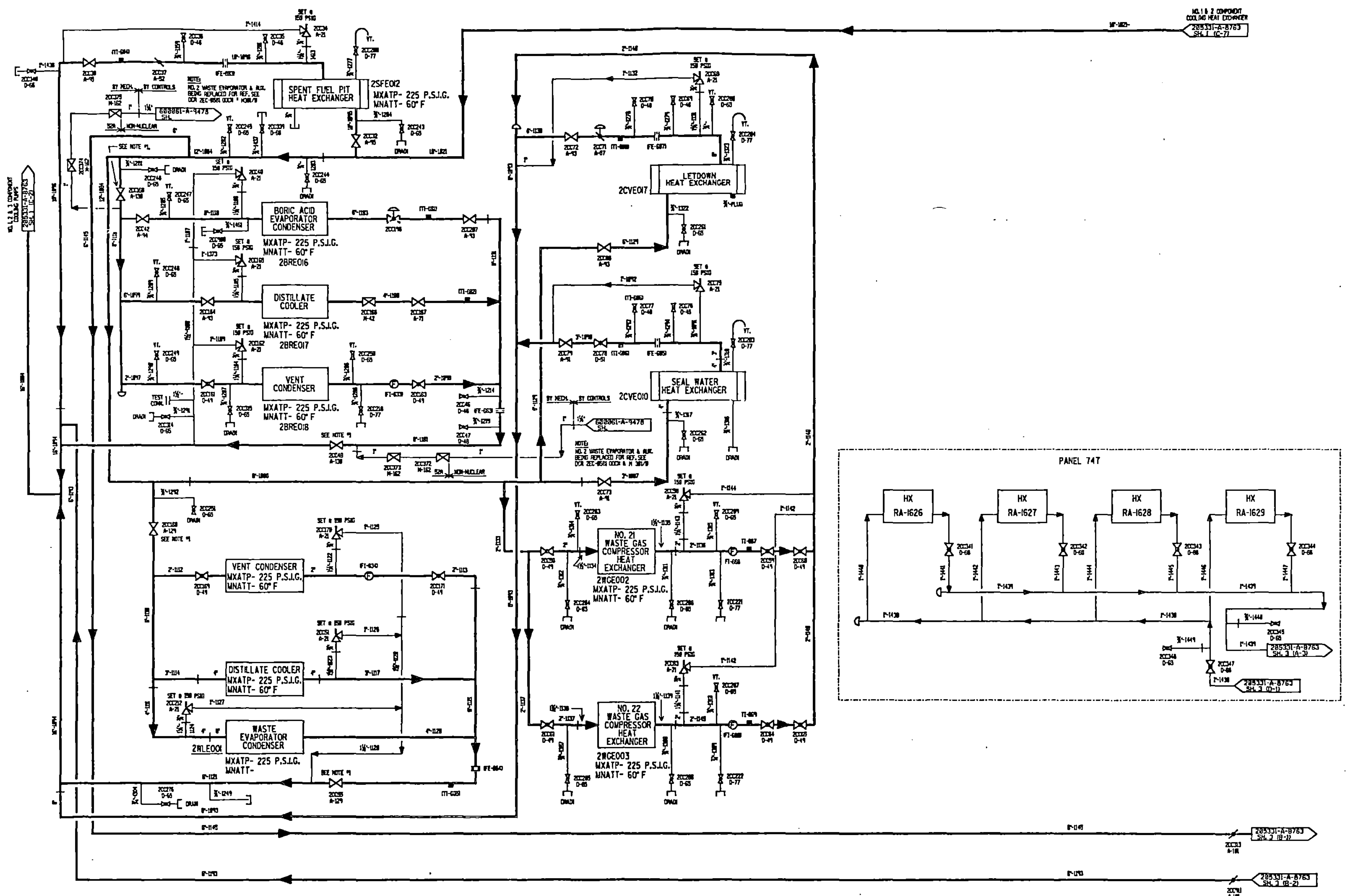
Also Available On Aperture Card

TI APERTURE CARD

8507300447-46

Revision 4
July 22, 1985
Ref. Dwg. 205331A8763-23

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Component Cooling System Unit 2
	Updated FSAR Sheet 1 of 3 Fig 9.2-4B



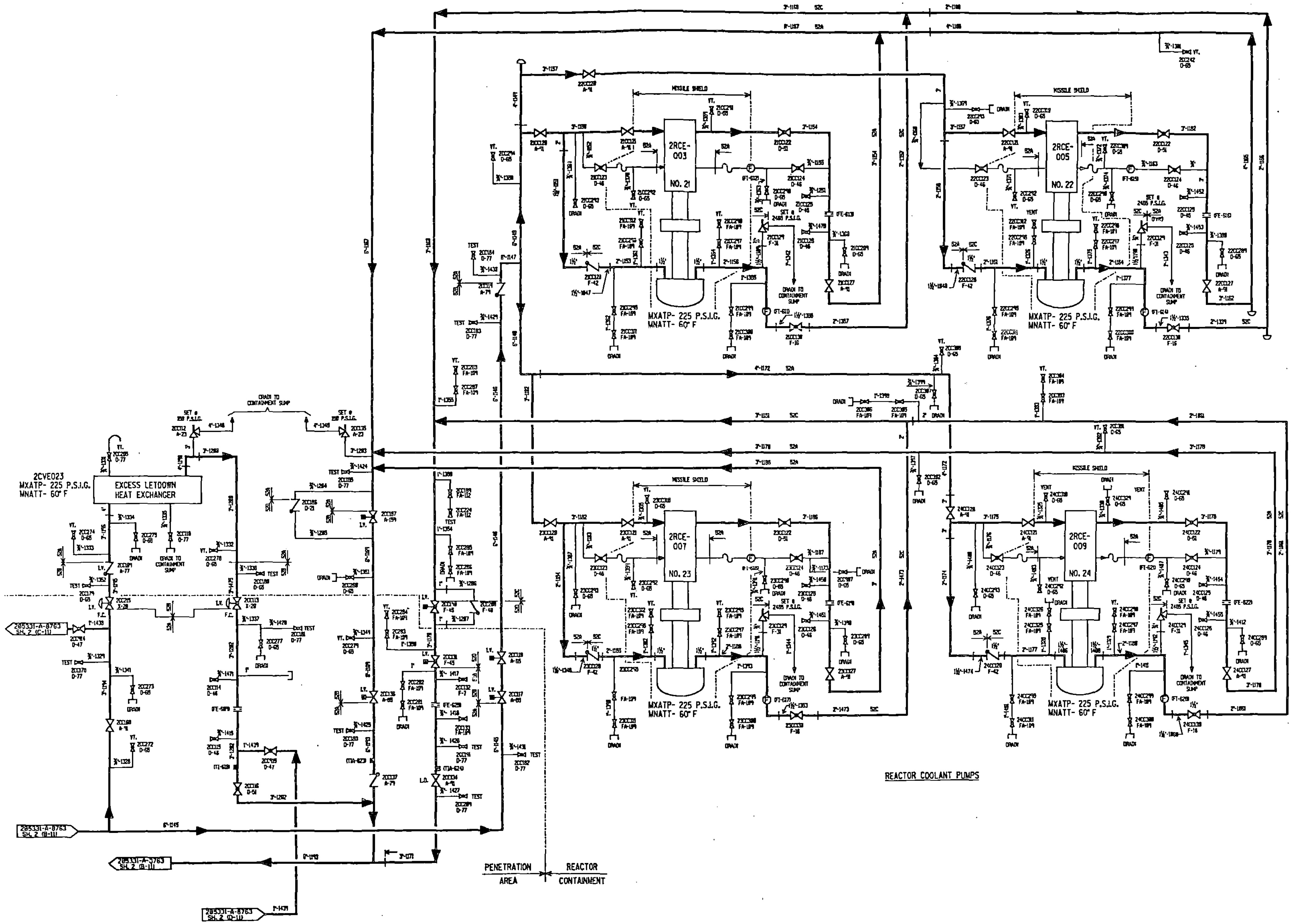
Also Available On Aperture Card

TI APERTURE CARD

8507300447-47

Revision 4
July 22, 1985
Ref. Dwg. 205331A8763-23

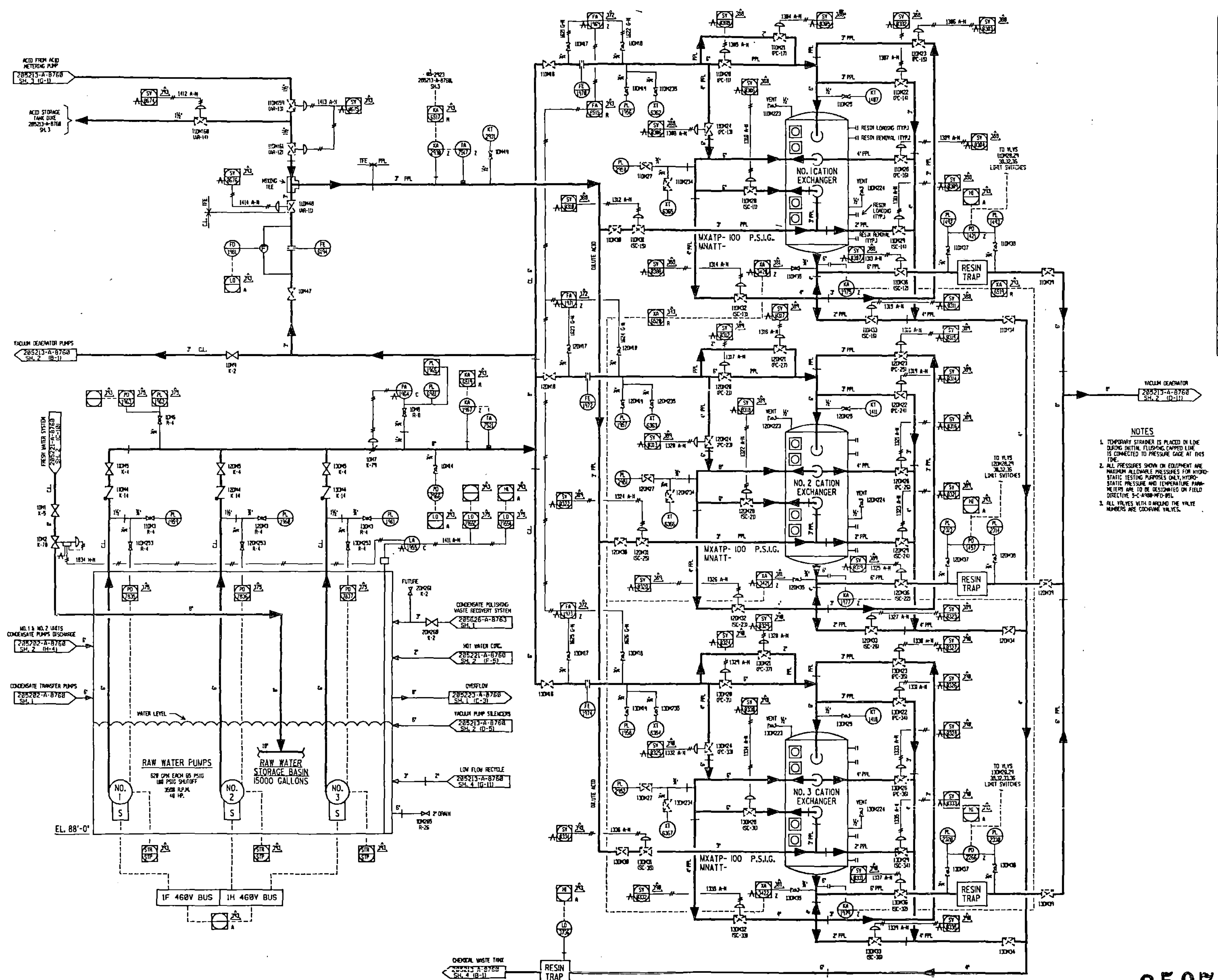
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Component Cooling System Unit 2
	Updated FSAR Sheet 2 of 3 Fig 9.2-4B



8507300447-48

Revision 4
July 22, 1985
Ref. Dwg. 205331A8763-23

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Component Cooling System Unit 2
	Updated FSAR Sheet 3 of 3 Fig 9.2-4B



PS INSTR. NO.	VENDOR INSTR. NO.
SY-300	SY-PC-11
SY-301	SY-PC-13
SY-302	SY-PC-14
SY-303	SY-PC-15
SY-304	SY-PC-16
SY-305	SY-PC-17
SY-306	SY-SC-11
SY-307	SY-SC-12
SY-308	SY-SC-13
SY-309	SY-SC-14
SY-310	SY-SC-15
SY-311	SY-SC-16
SY-312	SY-PC-21
SY-313	SY-PC-23
SY-314	SY-PC-24
SY-315	SY-PC-25
SY-316	SY-PC-26
SY-317	SY-PC-27
SY-318	SY-SC-21
SY-319	SY-SC-22
SY-320	SY-SC-23
SY-321	SY-SC-24
SY-322	SY-SC-25
SY-323	SY-SC-26
SY-324	SY-PC-31
SY-325	SY-PC-33
SY-326	SY-PC-34
SY-327	SY-PC-35
SY-328	SY-PC-36
SY-329	SY-PC-37
SY-330	SY-SC-31
SY-331	SY-SC-32
SY-332	SY-SC-33
SY-333	SY-SC-34
SY-334	SY-SC-35
SY-335	SY-SC-36
SY-676	SY-AR-11
SY-675	SY-AR-12-13
SY-674	SY-AR-14

NOTES

1. TEMPORARY STRAINER IS PLACED IN LINE DURING INITIAL FLUSHING. CAPPED LINE IS CONNECTED TO PRESSURE GAGE AT THIS TIME.
2. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-05L.
3. ALL VALVES WITH D AROUND THE VALVE NUMBERS ARE COCHRANE VALVES.

Also Available On Aperture Card

TI APERTURE CARD

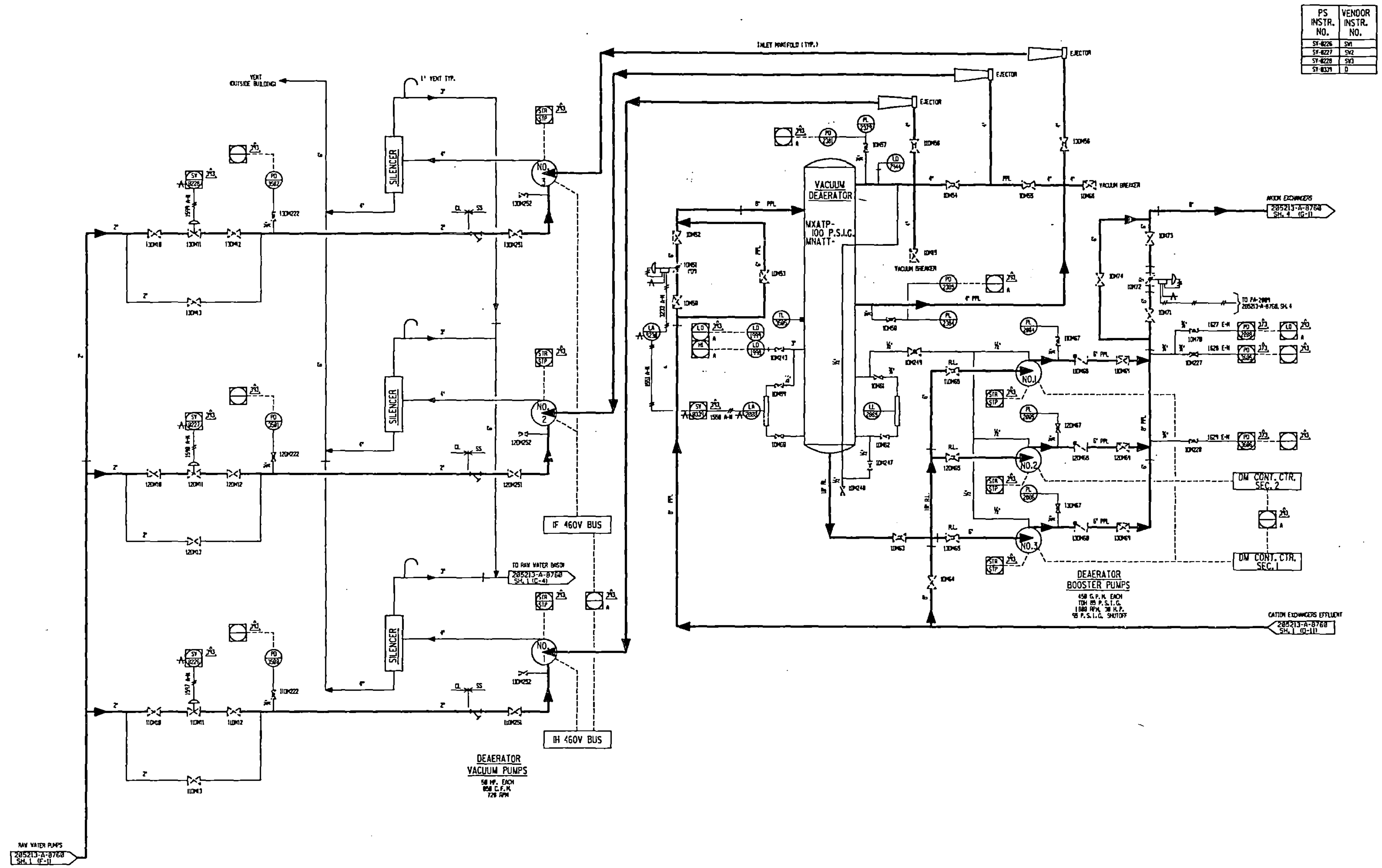
8507300447-49

Revision 4
July 22, 1985
Ref. Dwg. 205213A8760-22

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Demineralized Water Makeup System
Unit 1 & 2

Updated FSAR Sheet 1 of 6 Fig 9.2-11



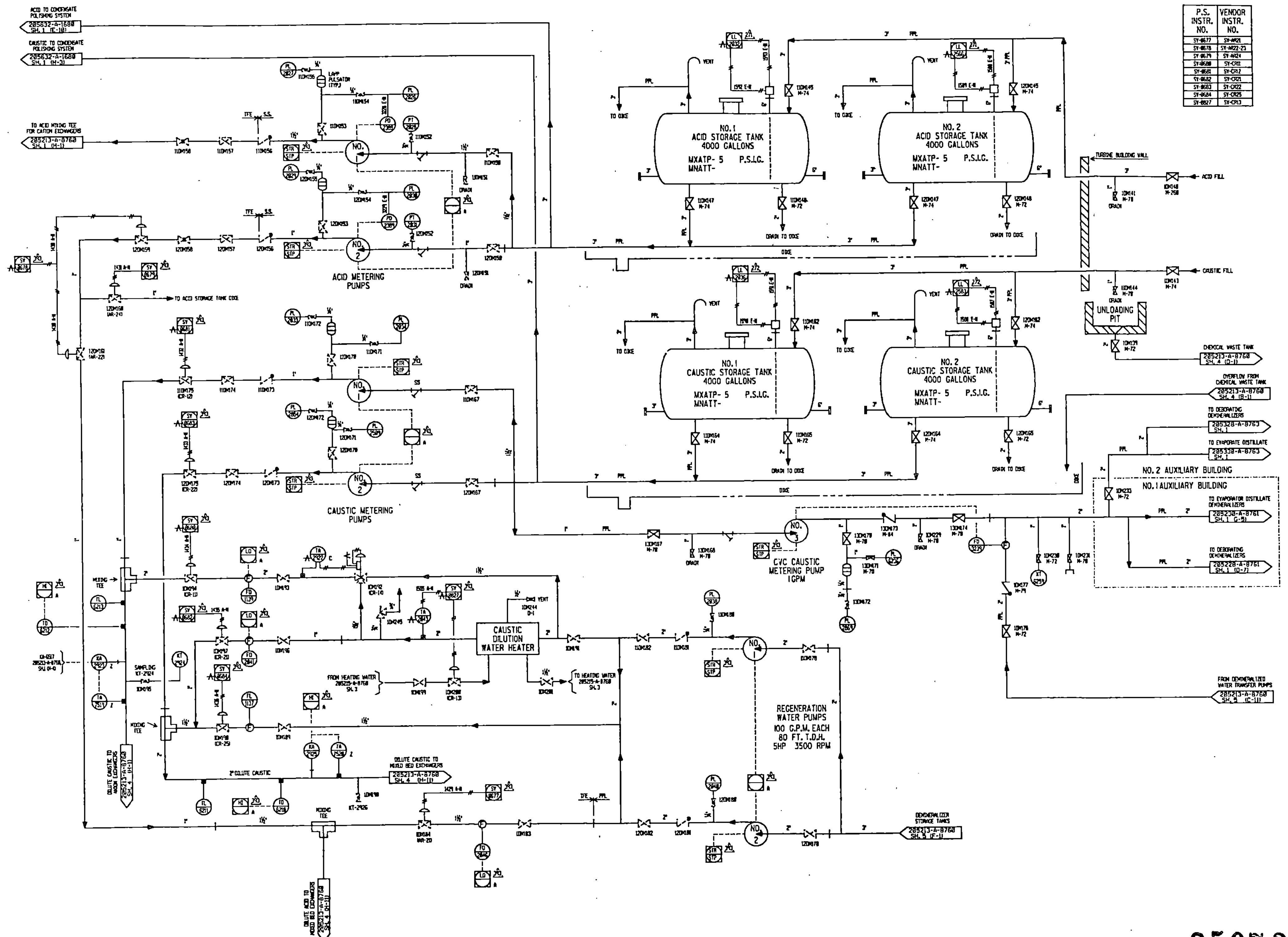
Also Available On Aperture Card

TI APERTURE CARD

8507300447 -50

Revision 4
July 22, 1985
Ref. Dwg. 205213A8760-22

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Demineralized Water Makeup System Unit 1 & 2
	Updated FSAR Sheet 2 of 6 Fig9.2-11

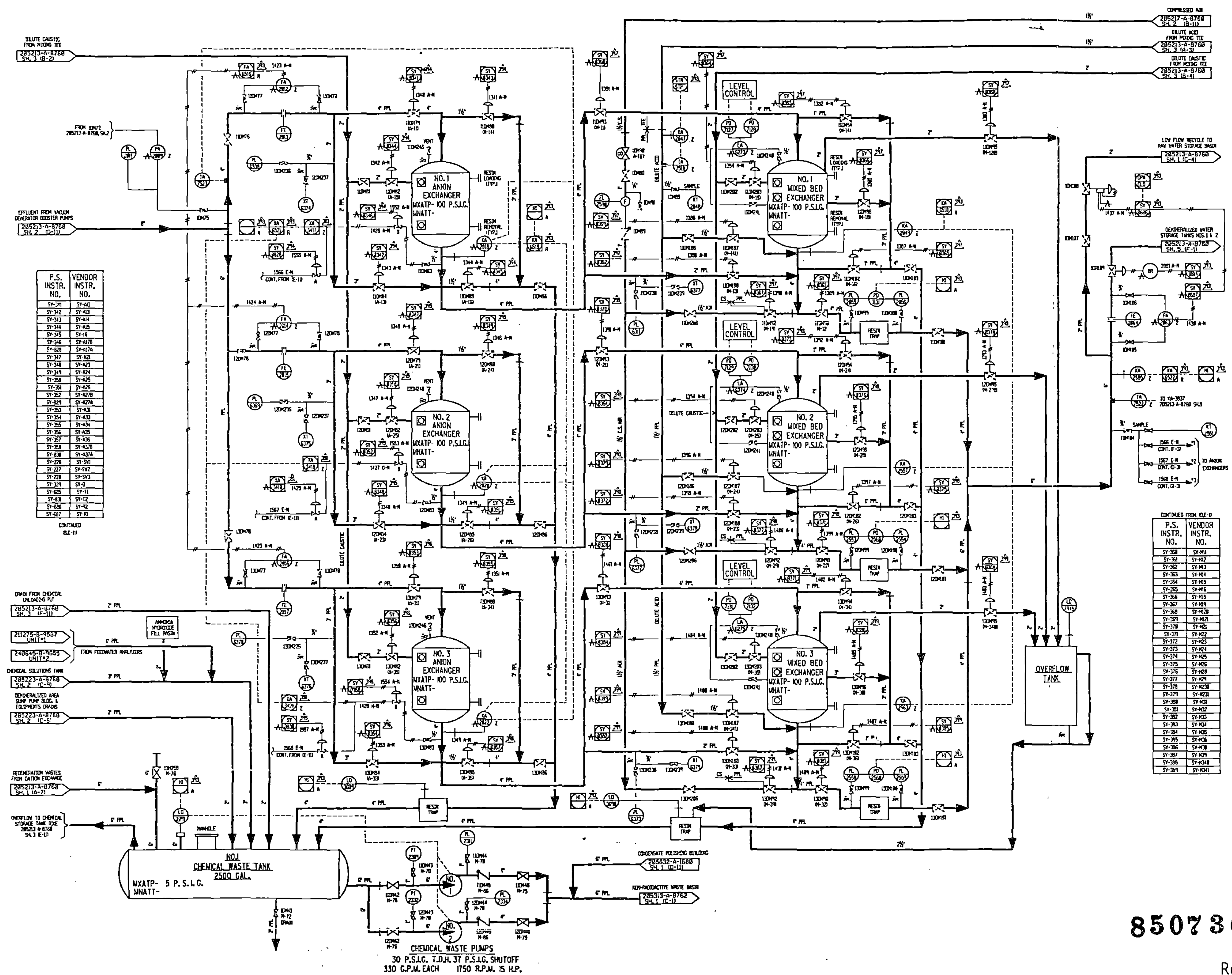


Revision 4
July 22, 1985
Ref. Dwg. 205213A8760-22

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Demineralized Water Makeup System
Unit 1 & 2

Updated FSAR Sheet 3 of 6 Fig 9.2-11



P.S. INSTR. NO.	VENDOR INSTR. NO.
SY-341	SY-A11
SY-342	SY-A13
SY-343	SY-A14
SY-344	SY-A15
SY-345	SY-16
SY-346	SY-A17B
SY-828	SY-A17A
SY-347	SY-A21
SY-348	SY-A23
SY-349	SY-A24
SY-350	SY-A25
SY-351	SY-A26
SY-352	SY-A27B
SY-829	SY-A27A
SY-353	SY-A31
SY-354	SY-A33
SY-355	SY-A34
SY-356	SY-A35
SY-357	SY-A36
SY-358	SY-A37B
SY-830	SY-A37A
SY-226	SY-SV1
SY-227	SY-SV2
SY-228	SY-SV3
SY-339	SY-D
SY-685	SY-T1
SY-931	SY-T2
SY-686	SY-R2
SY-687	SY-R1

CONTINUED (B,C-11)

CONTINUED FROM (C,E-D)

P.S. INSTR. NO.	VENDOR INSTR. NO.
SY-360	SY-M11
SY-361	SY-M12
SY-362	SY-M13
SY-363	SY-M14
SY-364	SY-M15
SY-365	SY-M16
SY-366	SY-M18
SY-367	SY-M19
SY-368	SY-M120
SY-369	SY-M121
SY-370	SY-M21
SY-371	SY-M22
SY-372	SY-M23
SY-373	SY-M24
SY-374	SY-M25
SY-375	SY-M26
SY-376	SY-M28
SY-377	SY-M29
SY-378	SY-M230
SY-379	SY-M231
SY-380	SY-M31
SY-381	SY-M32
SY-382	SY-M33
SY-383	SY-M34
SY-384	SY-M35
SY-385	SY-M36
SY-386	SY-M38
SY-387	SY-M39
SY-388	SY-M340
SY-389	SY-M341

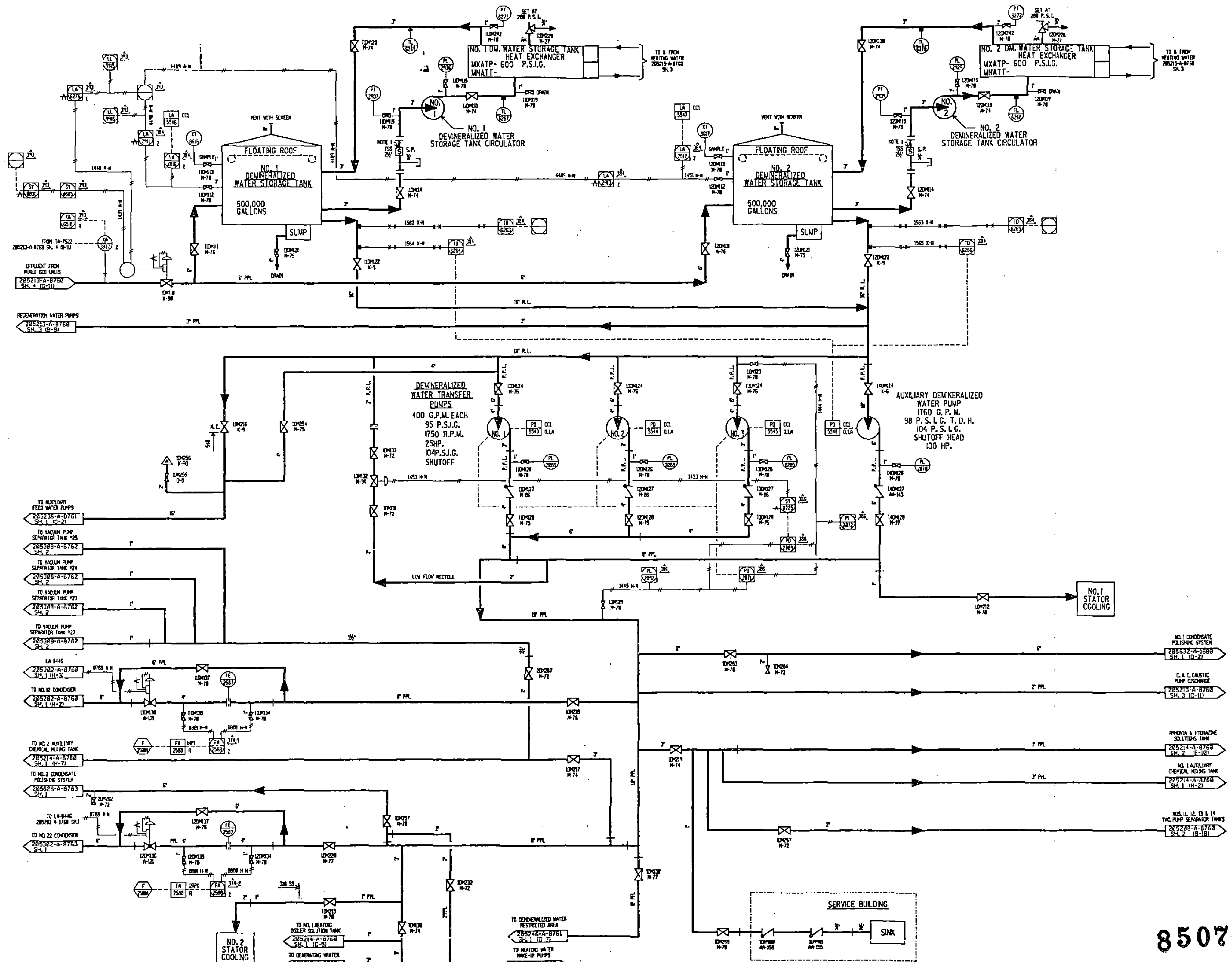
Also Available On Aperture Card

TI APERTURE CARD

8507300447-52

Revision 4
July 22, 1985
Ref. Dwg. 205213A8760-22

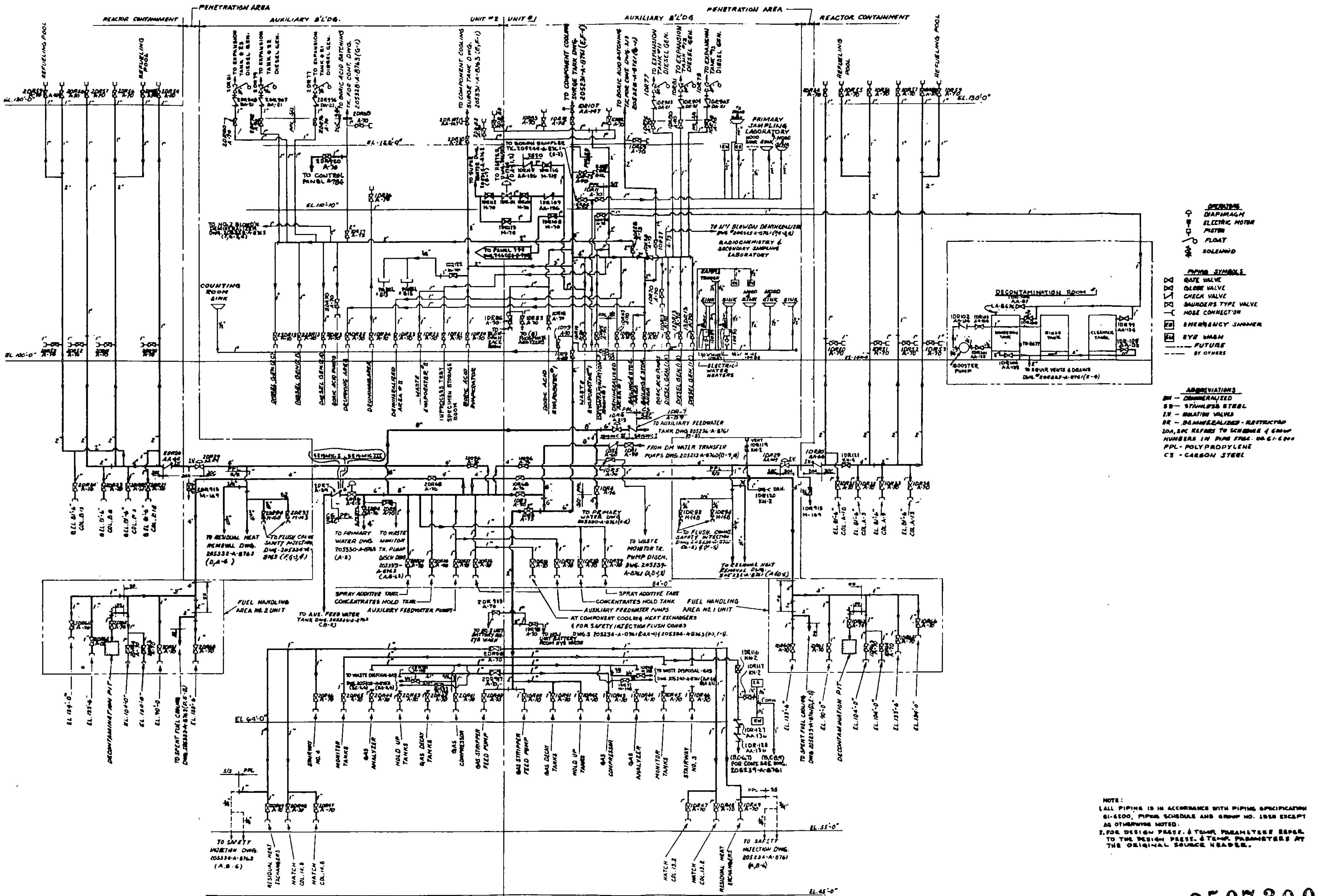
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Demineralized Water Makeup System Unit 1 & 2
	Updated FSAR Sheet 4 of 6 Fig 9.2-11



8507300447 -53

Revision 4
July 22, 1985
Ref. Dwg. 205213A8760-22

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Demineralized Water Makeup System Unit 1 & 2
	Updated FSAR Sheet 5 of 6 Fig9.2-11



Also Available On Aperture Card

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8507300447 -54

Revision 4
July 22, 1985
Ref. Dwg. 205246A8761-16

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Demineralized Water Makeup System Unit 1 & 2
	Updated FSAR Sheet 6 of 6 Fig 9.2-11

9.3 PROCESS AUXILIARIES

9.3.1 COMPRESSED AIR SYSTEM

The Compressed Air System provides the station with a reliable supply of clean, oil free air which is directed to various locations for services as required. The system is illustrated on Figures 9.3-1A and B.

9.3.1.1 Design Bases

The system provides a reliable supply of clean, oil free, dry air at temperatures and pressures suitable for use as control air and for containment penetration cooling, as well as for miscellaneous services and maintenance.

The Compressed Air System is designed such that any single failure will not result in loss of function.

9.3.1.2 System Description

9.3.1.2.1 General

The Compressed Air System is supplied by three motor driven, oil free, centrifugal compressors which draw air from the atmosphere. The intakes of the air compressors are located to avoid drawing in toxic or corrosive gases. Each compressor has a capacity of 4000 scfm at 110 psig discharge pressure. Two compressors are operated to satisfy the normal requirements of station air and control air for both units as well as to supply containment penetration cooling air for both units. A third compressor serves as standby. Each compressor is furnished with a 1000 hp motor, intake filter-silencer, blow-off silencer and total closure controls, intercoolers, aftercooler, moisture separator and automatic condensate traps and drains. The compressors discharge into two independent service air headers, with an air receiver tied to each header.

The station air header for each unit is supplied from either of the two service air headers. This station air header provides operating and service requirements at various locations.

The containment penetration cooling system for each unit is furnished with two supply lines. The normal supply is taken from the station air header and the backup supply from either of the two service air headers.

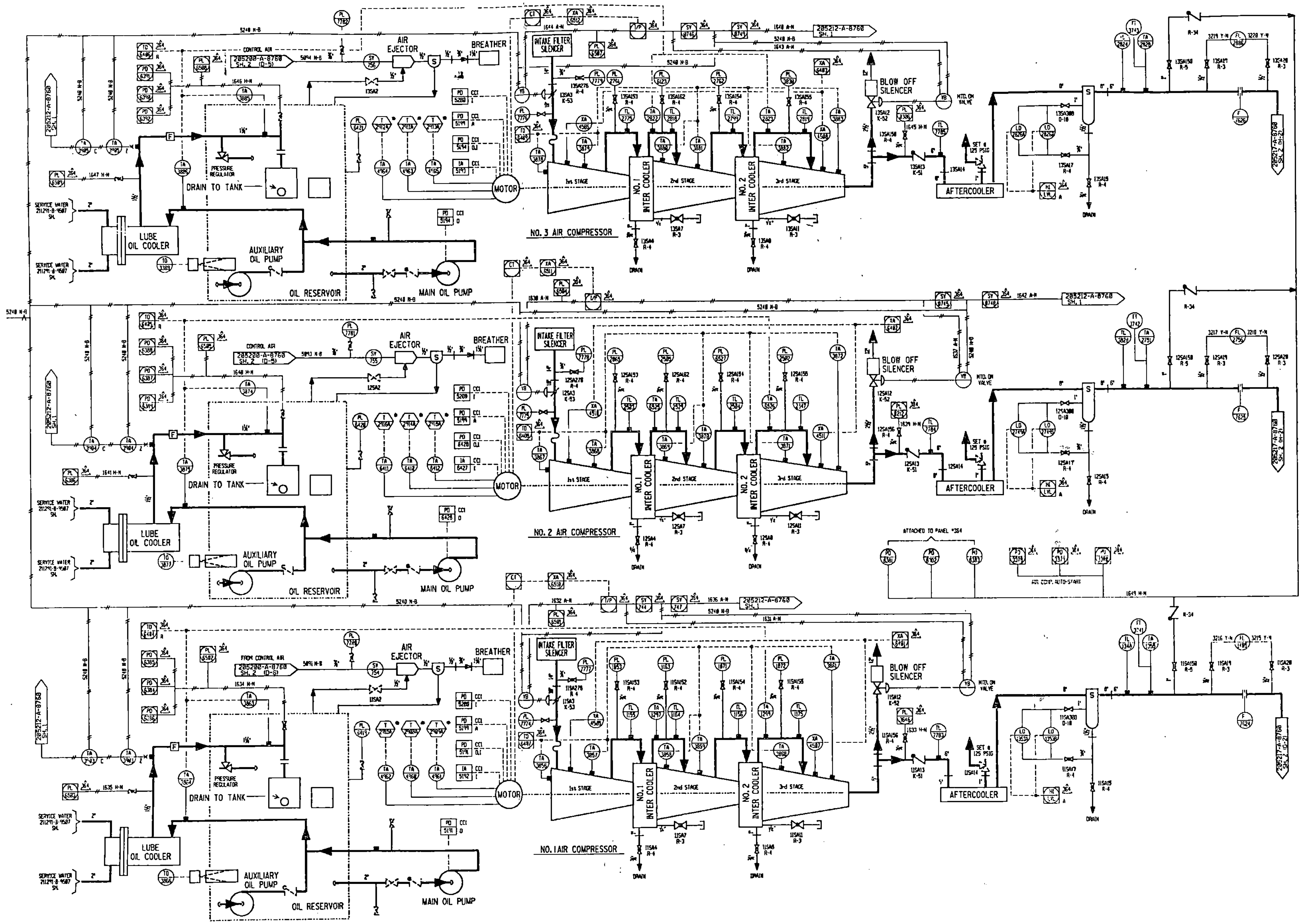
9.3.1.2.2 Control Air

The control air system for each unit consists of a dual header arrangement as shown on Figures 9.3-2A and B. This control air for each unit is supplied through two distinct parallel paths. One path is supplied from the unit one station air system and the other is supplied from the unit two station air system. Control air for the safety related portions is automatically backed up by an emergency control air compressor. Control air is fed from the station air system through heatless, desiccant type air dryers.

The dual station service air headers are fed by three 100 percent capacity air compressors, any one of which can supply the total service and control air requirements for both units.

In addition to the normal air supply from the service air headers, each system has an emergency control air compressor complete with its own dryer and accessories to supply the safety related headers. The emergency control air for either system may be directed to supply air for the opposite system through a valved connection. Each emergency control air compressor motor is energized from the standby AC power supply. The emergency control air system is designated Class I (seismic) and is located in a Class I (seismic) structure.

Each emergency control air compressor has a capacity of 500 scfm at 110 psig and is driven by a 125 hp motor. Accessory equipment includes an



NOTES:

1. VALVES TO BE LOCKED OPEN AFTER ENTIRE SYSTEM IS COMPLETED.
2. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
3. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6298. THE PIPING SCHEDULE AND GROUP NOS. ARE AS NOTED ON THIS DRAWING AND PREFIXED WITH "1S".

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8507300447-55

Revision 4
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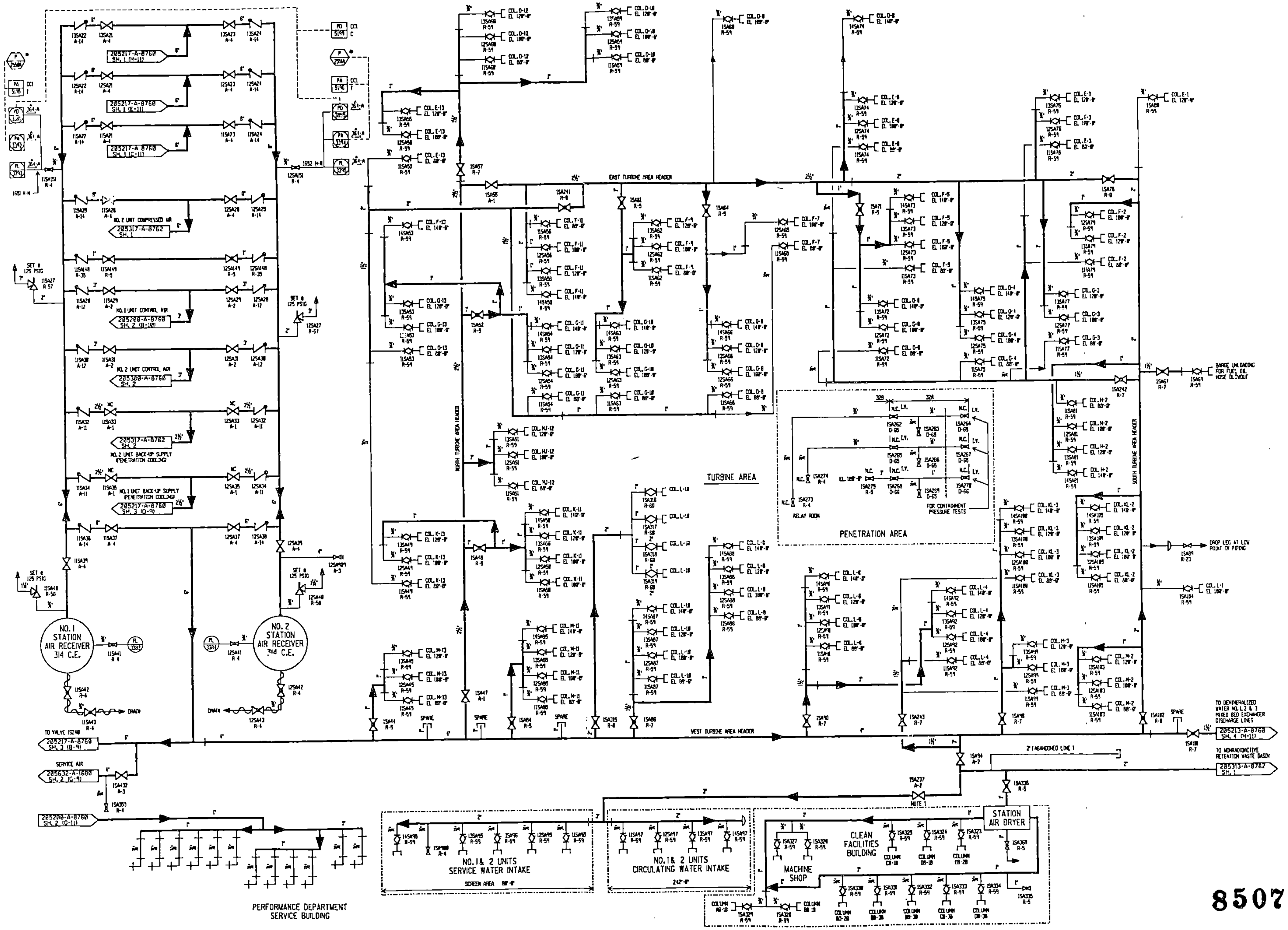
Ref. Dwg. 205217A8760-22

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Compressed Air System Unit 1
	Updated FSAR Sheet 1 of 3 Fig 9.3-1A



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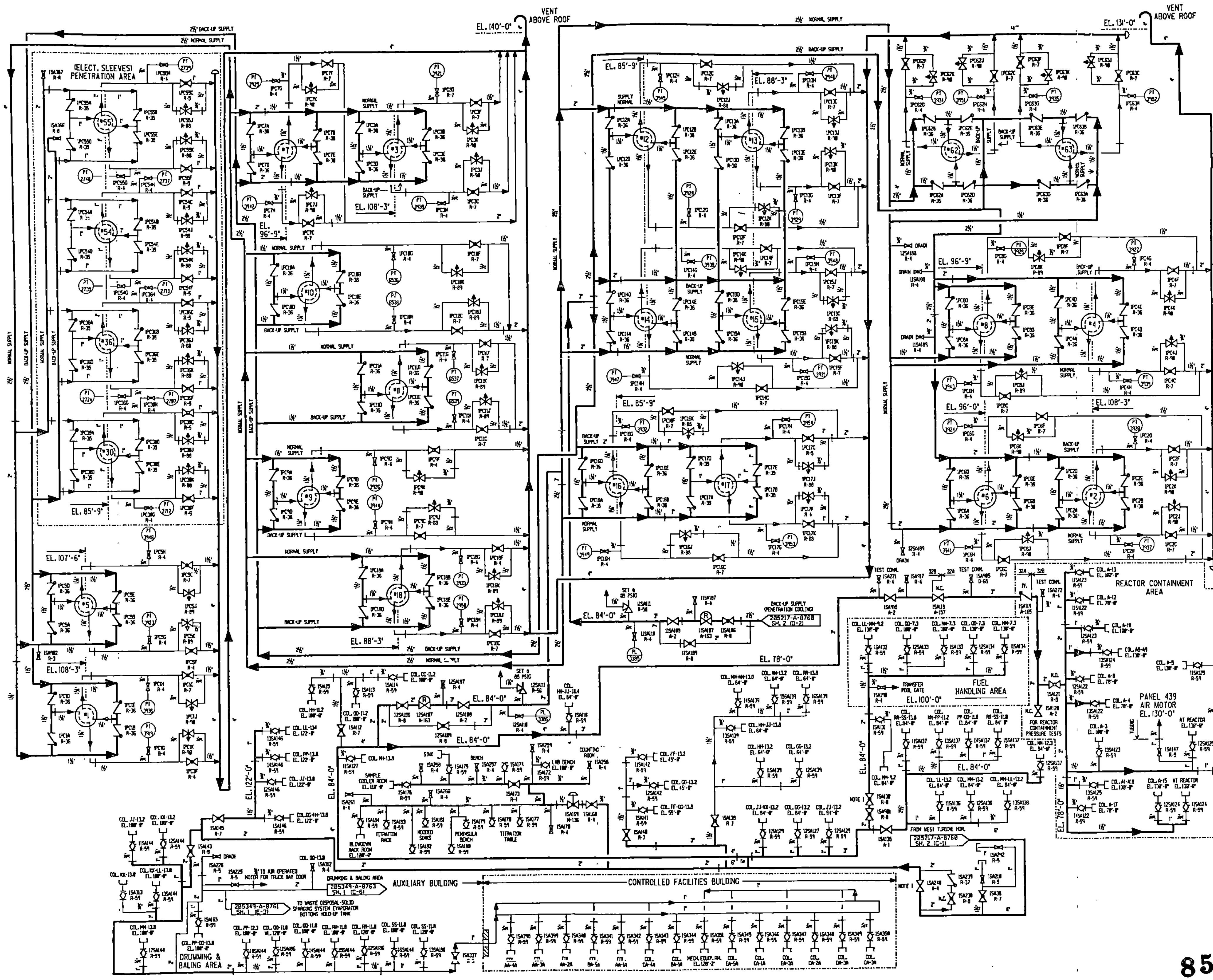
Revision 4
July 22, 1985
Ref. Dwg. 205217A8760-22

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Compressed Air System Unit 1
	Updated FSAR Sheet 2 of 3 Fig9.3-1A



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Revision 4
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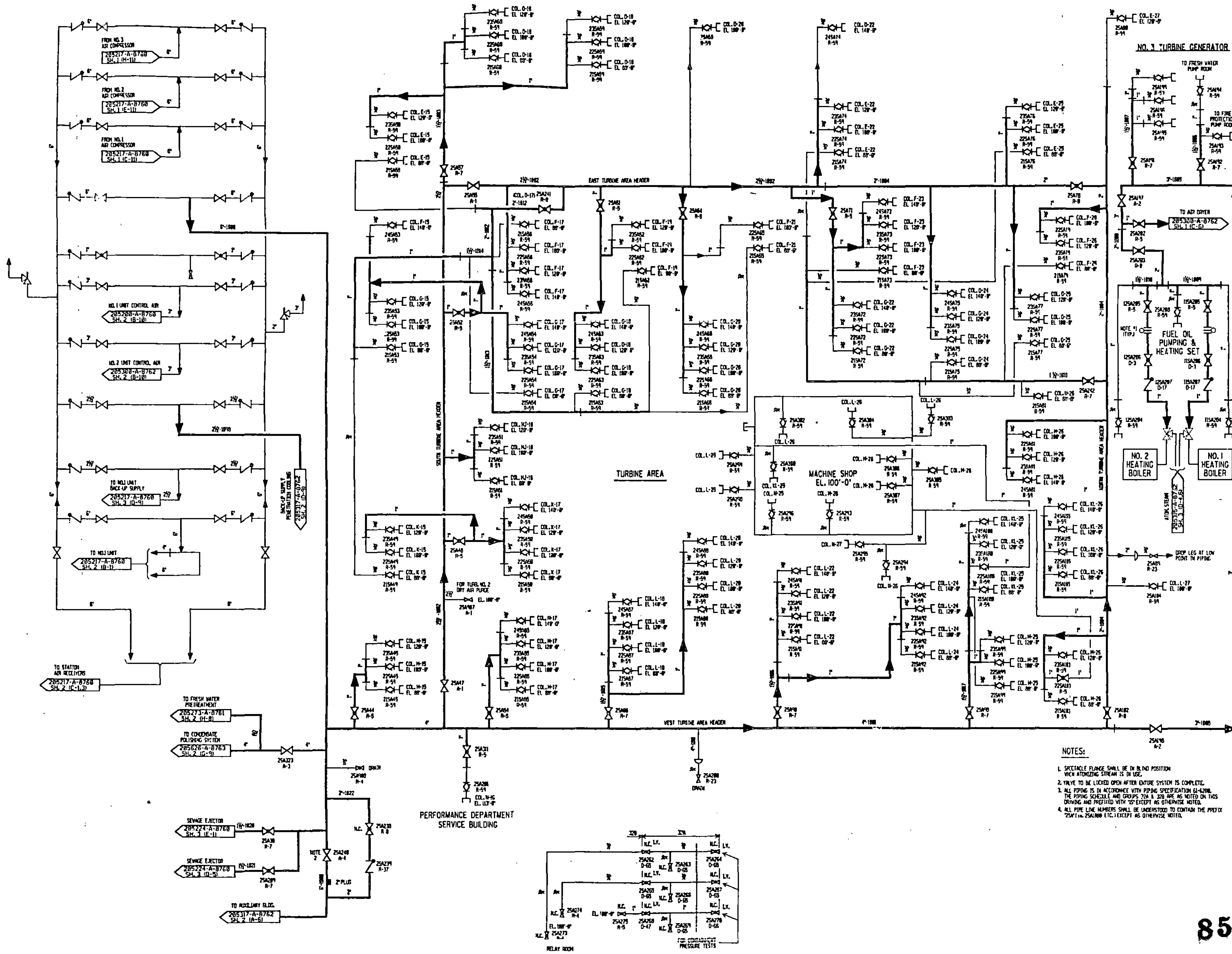
Ref. Dwg. 205217A8760-22

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Compressed Air System Unit 1
	Updated FSAR Sheet 3 of 3 Fig 9.3-1A



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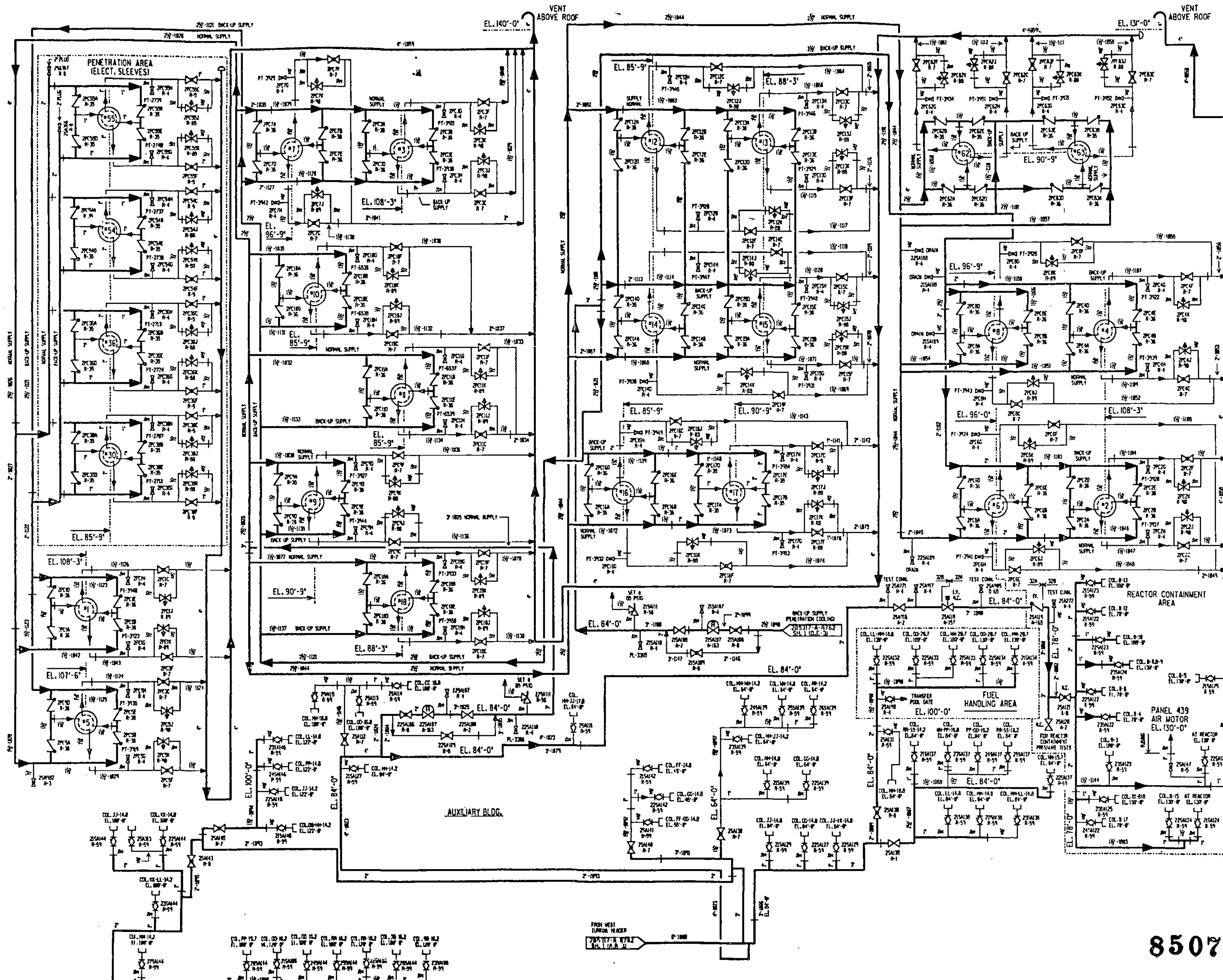
Revision 4
July 22, 1985
Ref. Dwg. 205317A8760-10

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Compressed Air System Unit 2
	Updated FSAR Sheet 1 of 2 Fig 9.3-1B



Revision 4
July 22, 1985
Ref. Dwg. 205317A8760-10

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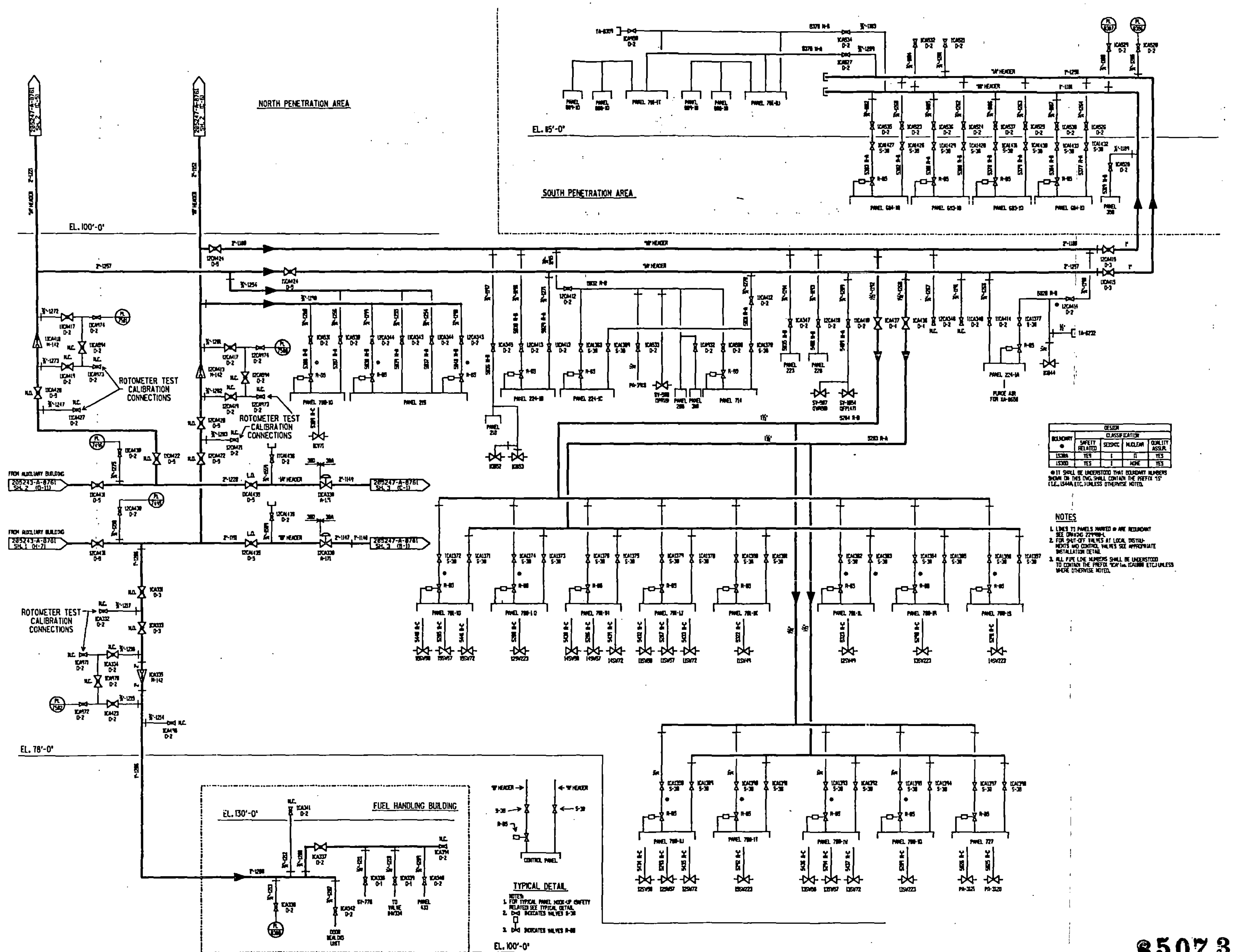
	Updated FSAR Sheet 2 of 2 Fig9.3-1B



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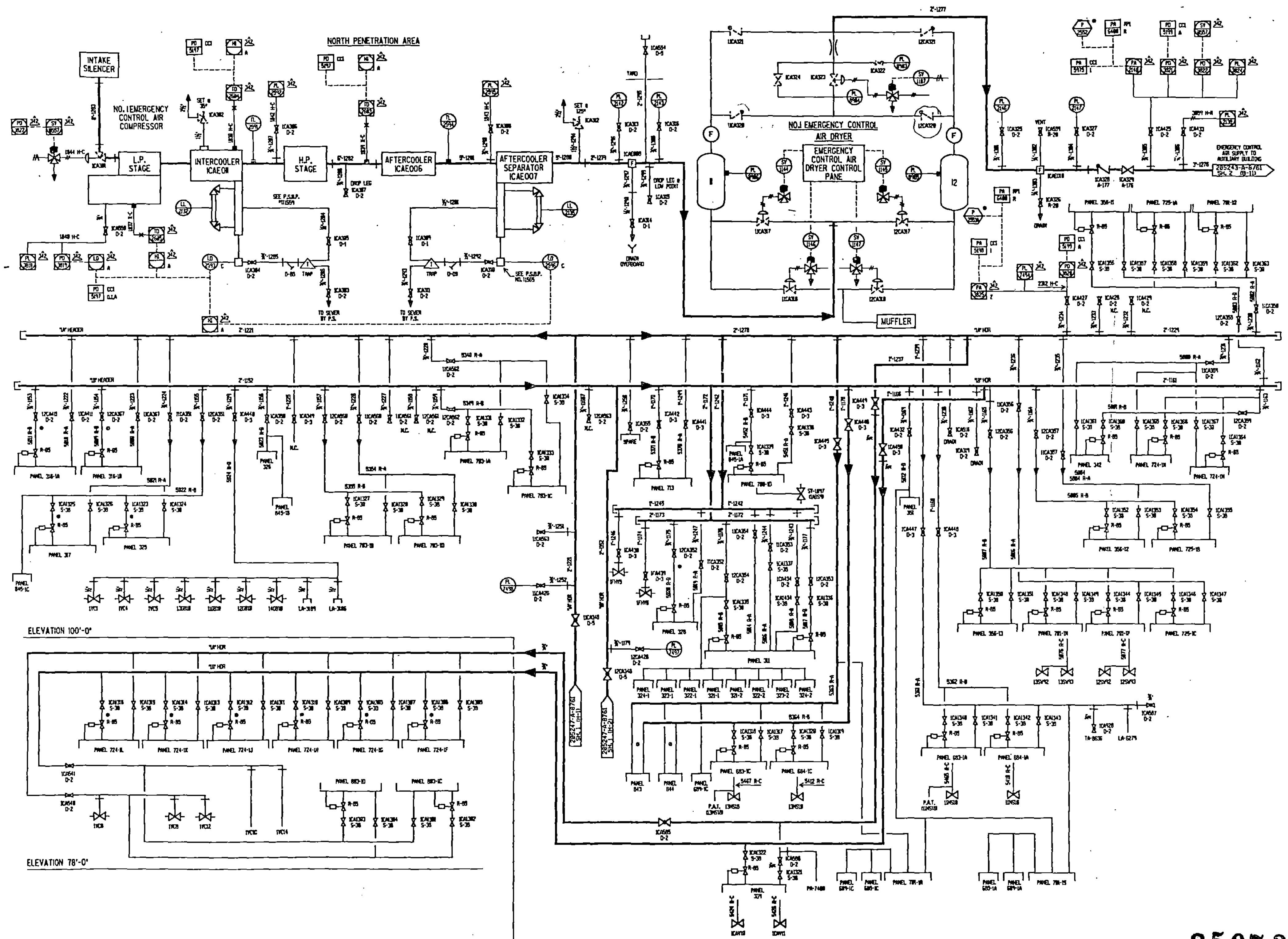
Revision 4
July 22, 1985
Ref. Dwg. 205247A8760-25

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Control Air System Unit 1
	Updated FSAR · Sheet 1 of 3 · Fig 9.3-2A



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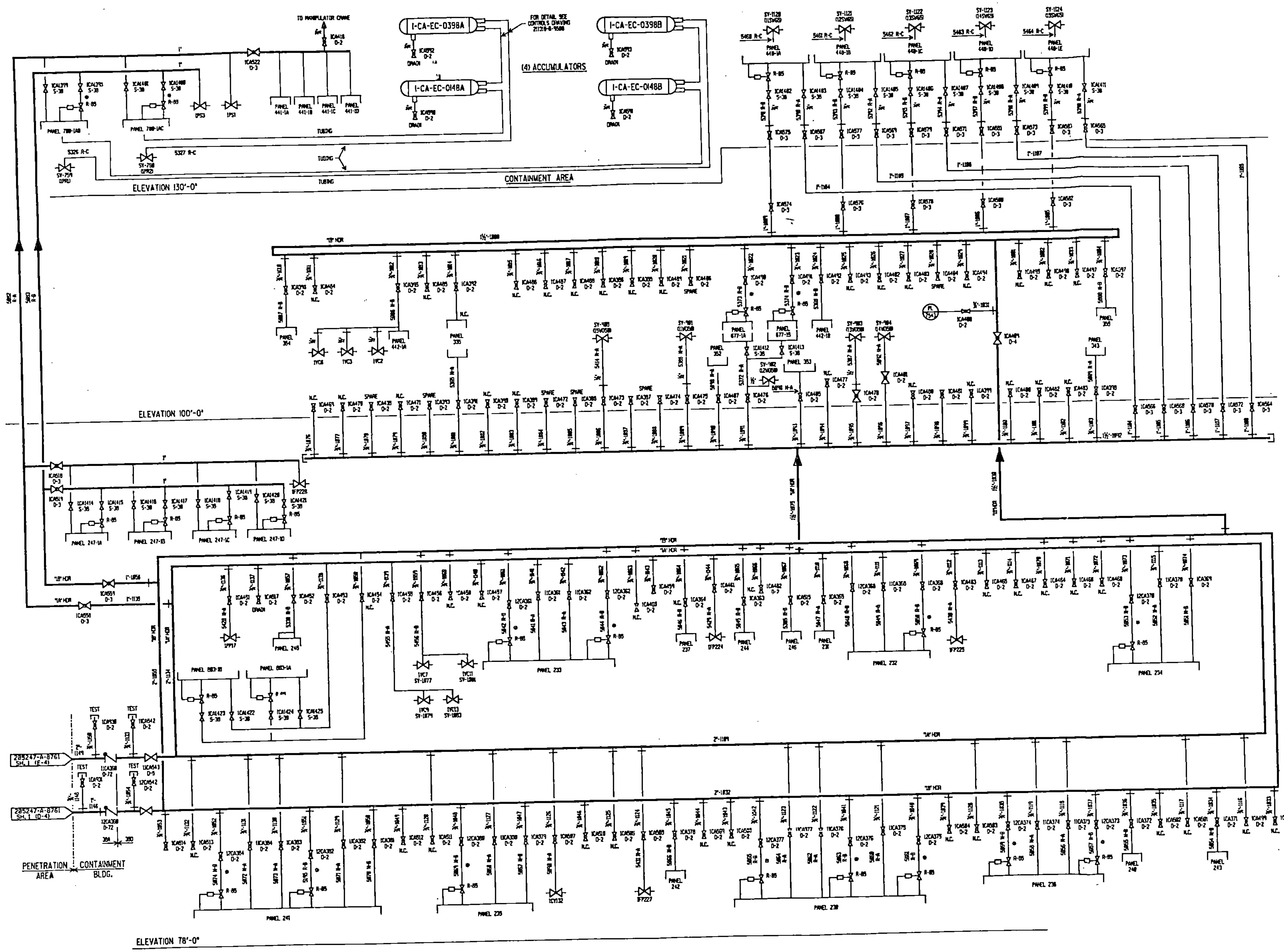
8507300447-61

Revision 4
July 22, 1985
Ref. Dwg. 205247A8760-25

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Control Air System Unit 1
	Updated FSAR Sheet 2 of 3 Fig 9.3-2A



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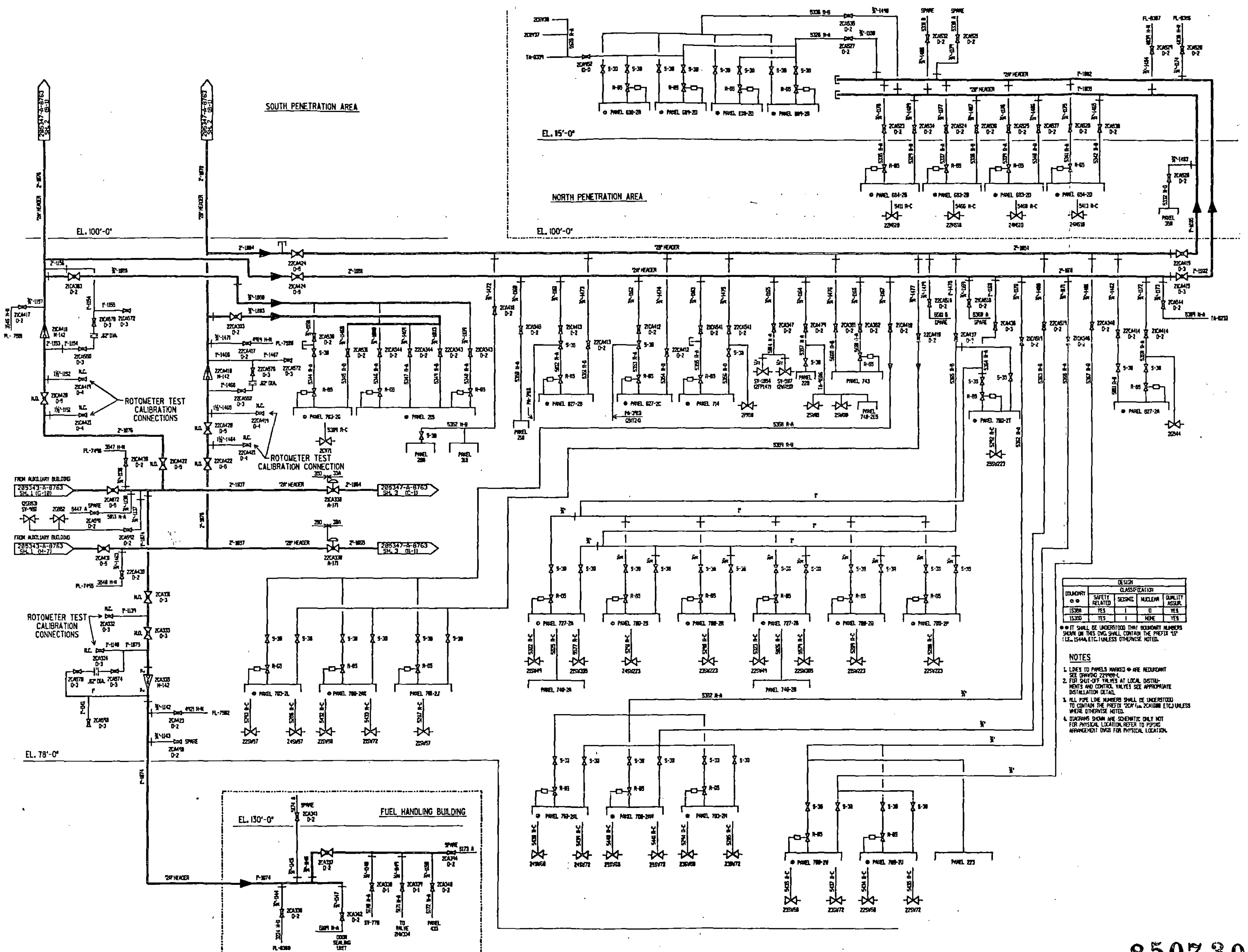
8507300447 -62

Revision 4
July 22, 1985
Ref. Dwg. 205247A8760-25

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Control Air System Unit 1 Updated FSAR Sheet 3 of 3 Fig 9.3-2A



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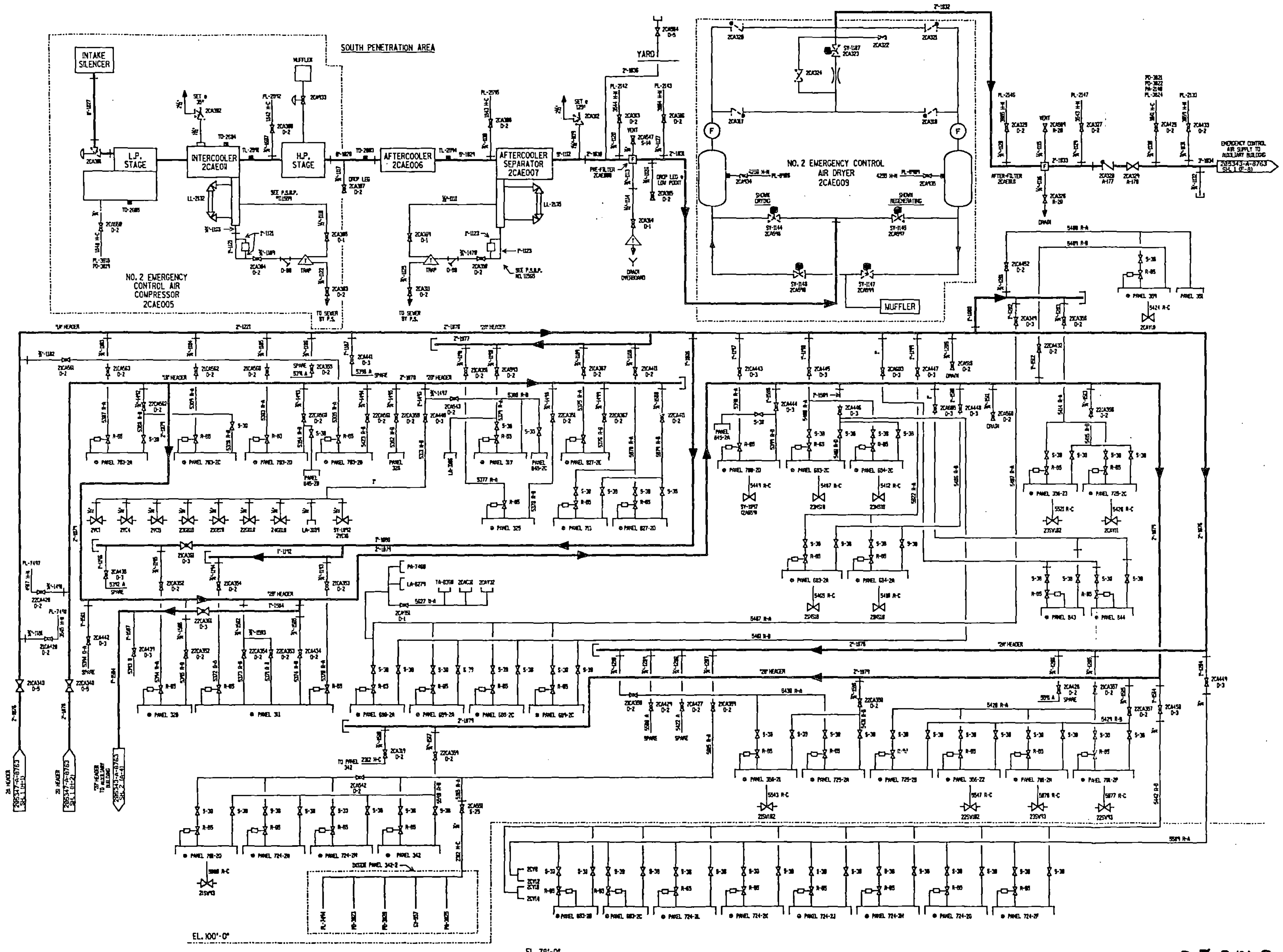
Revision 4
July 22, 1985
Ref. Dwg. 205347A8763-12

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Control Air System Unit 2
	Updated FSAR Sheet 1 of 3 Fig 9.3-2B



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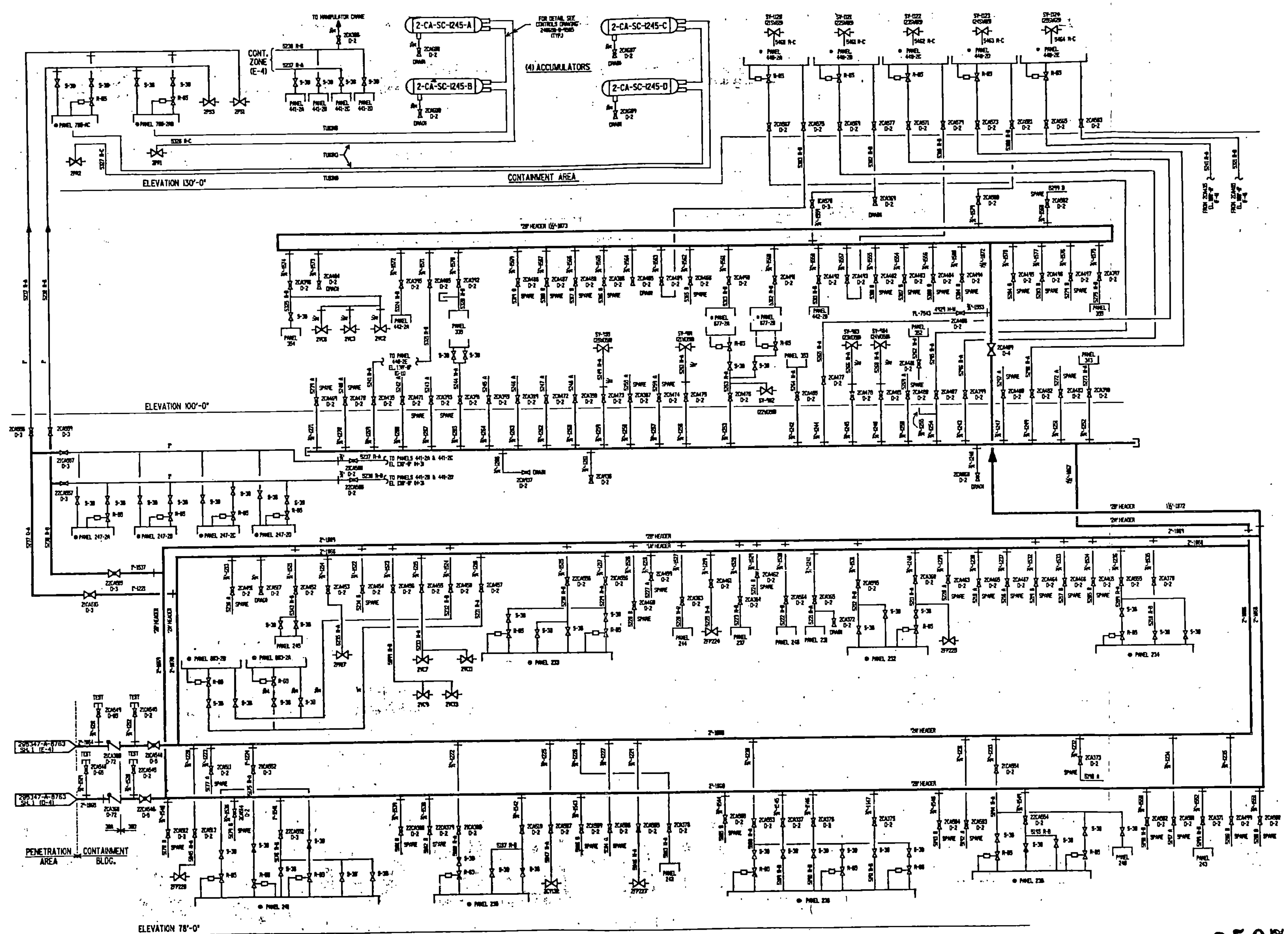
Ref. Dwg. 205347A8763-12

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Control Air System Unit 2		
	Updated FSAR	Sheet 2 of 3	Fig 9.3-2B



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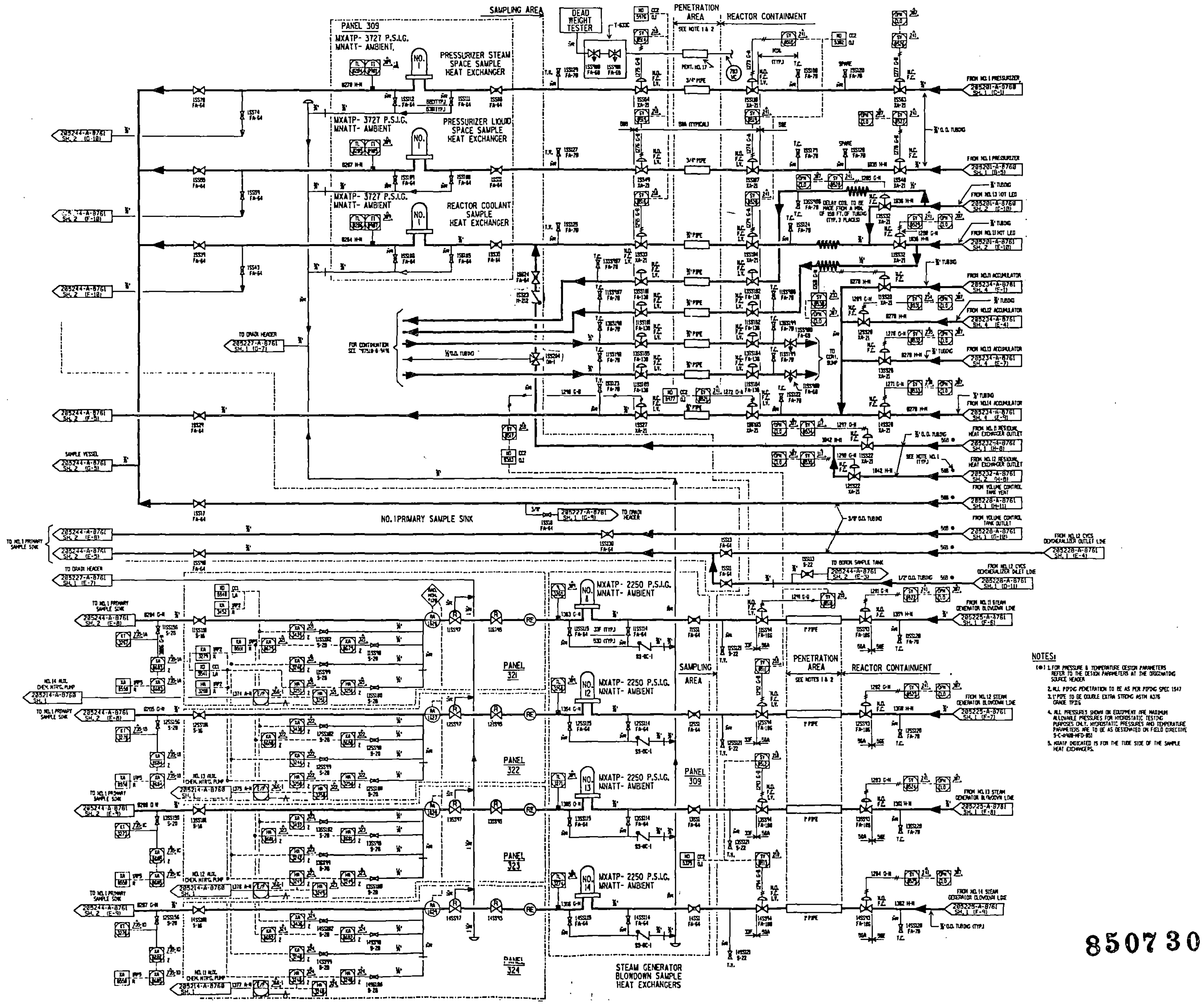
Revision 4
July 22, 1985
Ref. Dwg. 205347A8763-12

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Control Air System Unit 2
	Updated FSAR Sheet 3 of 3 Fig 9.3-2B



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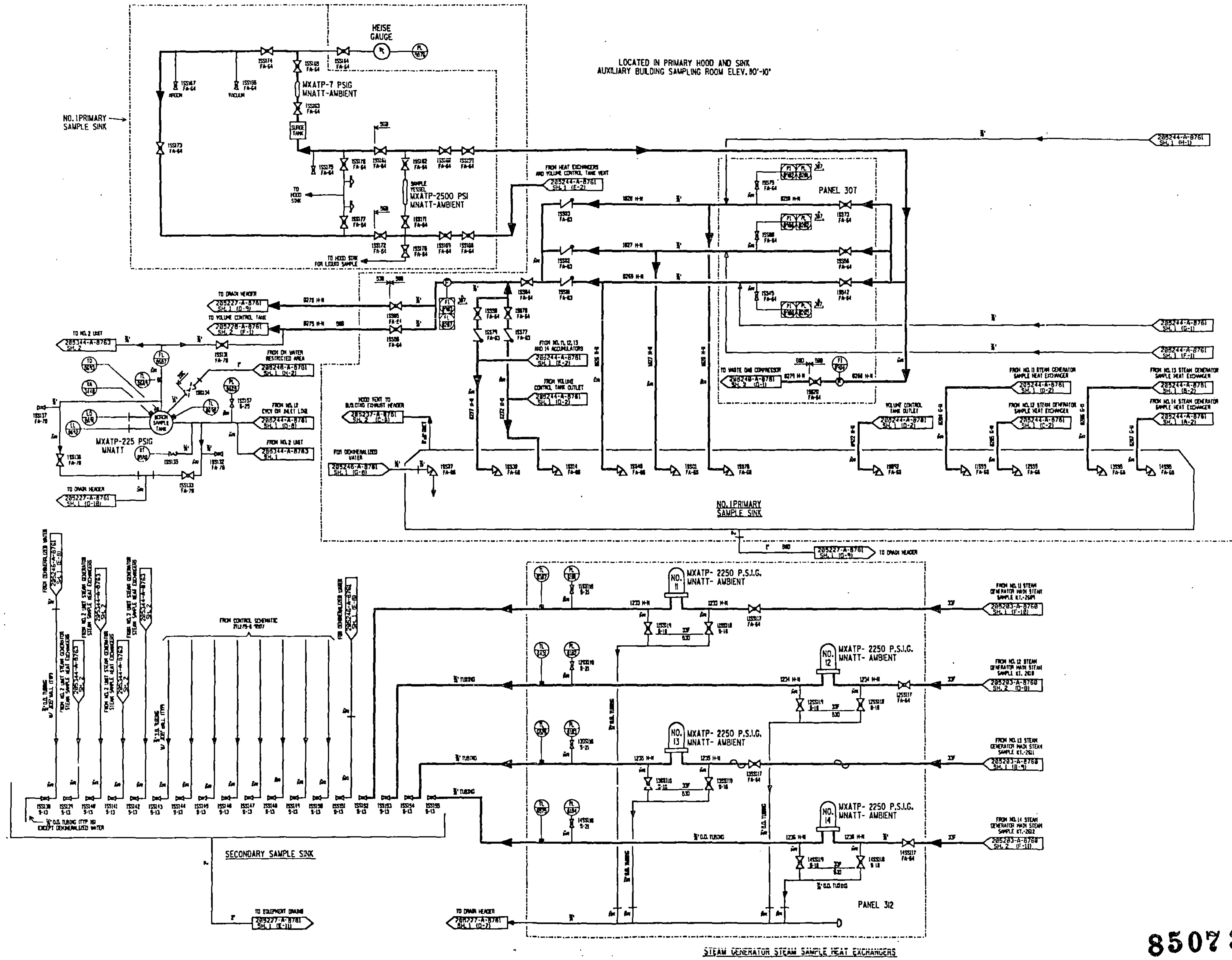
Revision 4
July 22, 1985
Ref. Dwg. 205244A8761-18

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Sampling System Unit 1
	Updated FSAR Sheet 1 of 2 Fig 9.3-3A



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Revision 4
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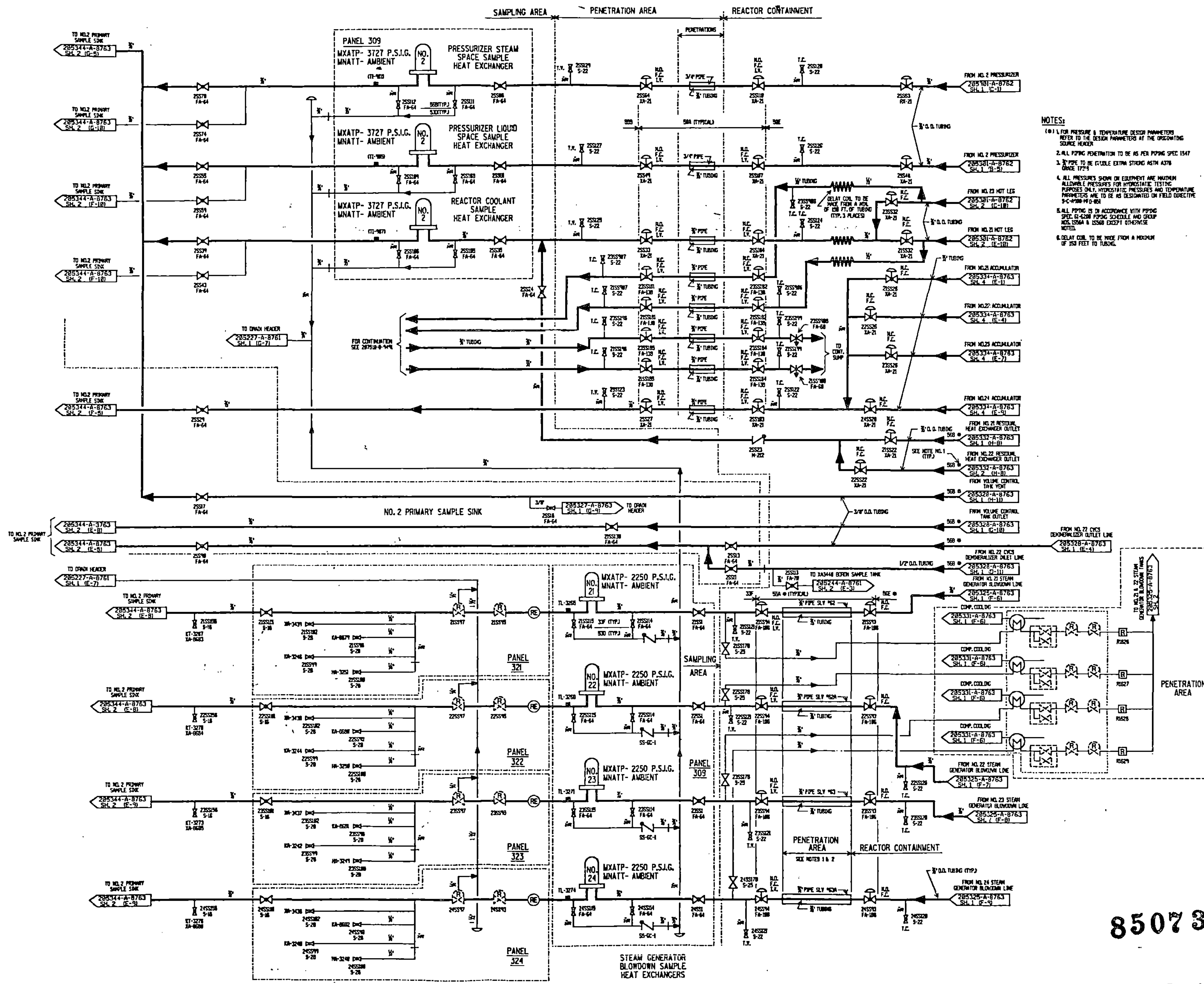
Ref. Dwg. 205244A8761-18

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Sampling System Unit 1
	Updated FSAR Sheet 2 Of 2 Fig 9.3-3A



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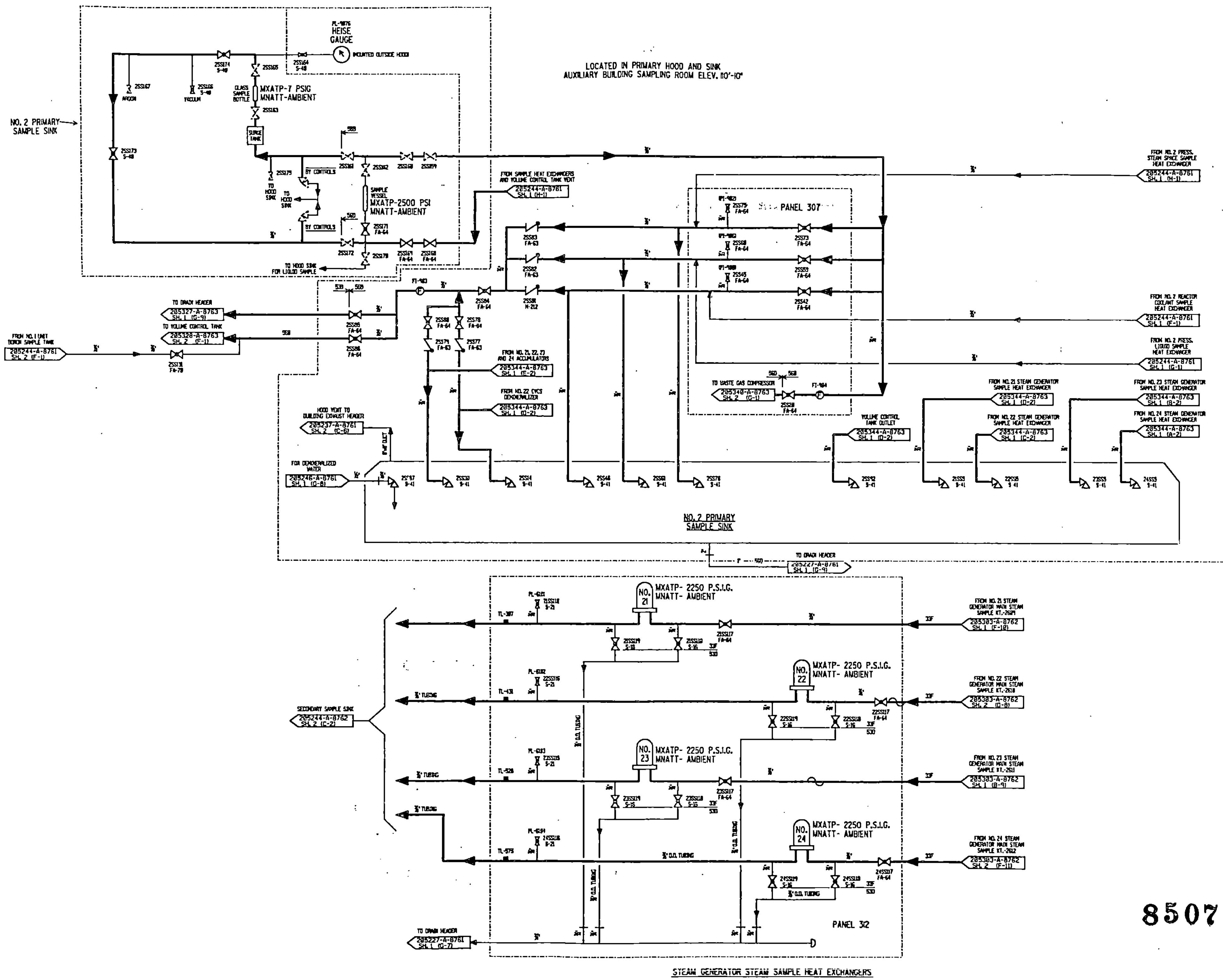
Revision 4
July 22, 1985
Ref. Dwg. 205344A8763-12

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Sampling System Unit 2
	Updated FSAR Sheet 1 of 2 Fig 9.3-3B



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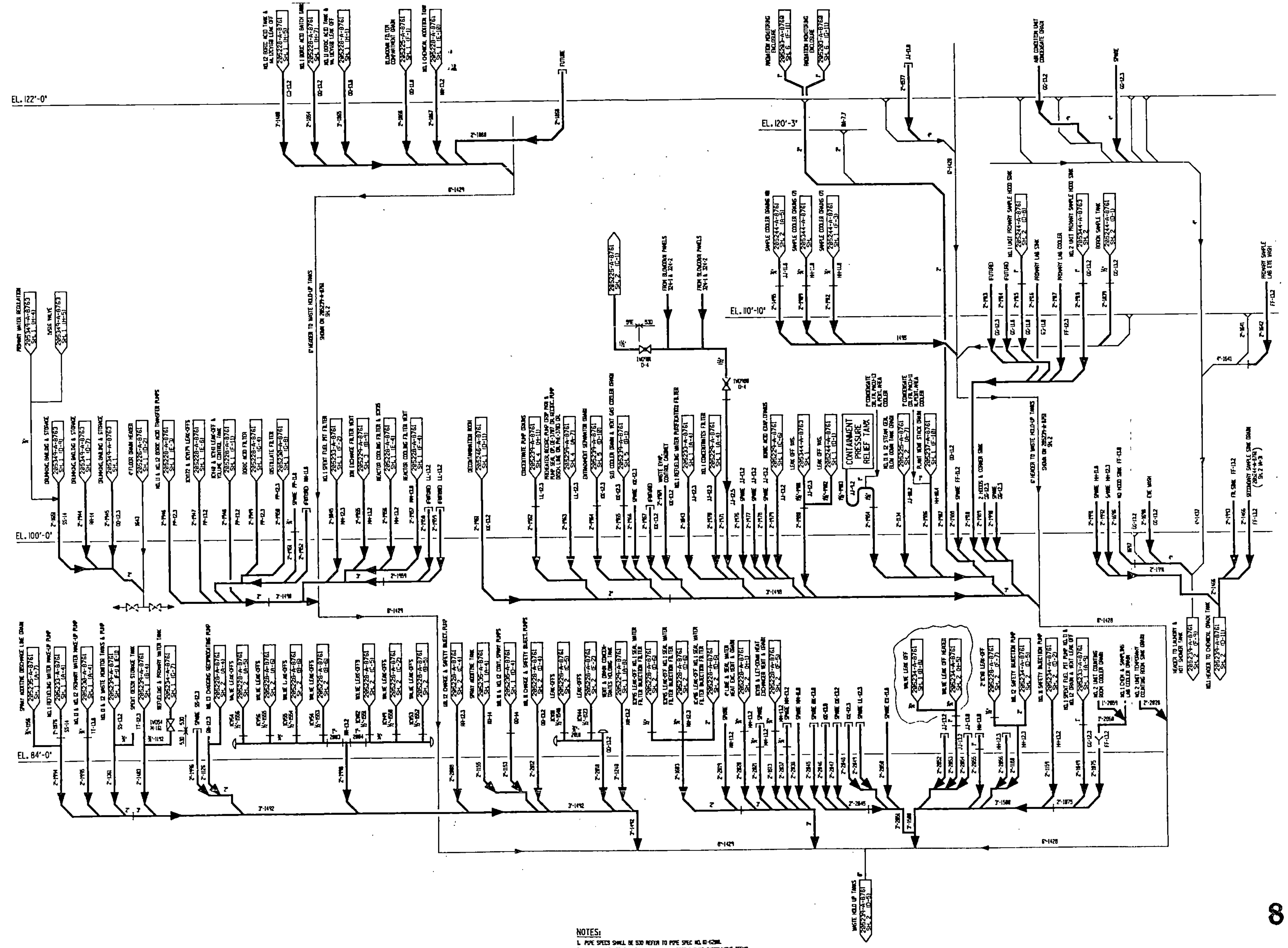
Revision 4
July 22, 1985
Ref. Dwg. 205344A8763-12

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Sampling System Unit 2
	Updated FSAR Sheet 2 of 2 Fig 9.3-3B



NOTES:

1. PIPE SPECS SHALL BE 530 REFER TO PIPE SPEC NO. [illegible]
2. INSTRUMENT ITEMS IN BRACKETS [ ] ARE WESTINGHOUSE INSTRUMENT ITEMS. REFER TO [illegible] FOR DESCRIPTION.
3. FOR DESIGN PRESSURE & TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE & TEMPERATURE PARAMETERS AT THE ORIGINAL SOURCE HEADER.
4. ALL PIPELINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1WL" (I.E. 1WL[illegible], ETC.) EXCEPT WHERE OTHERWISE NOTED.

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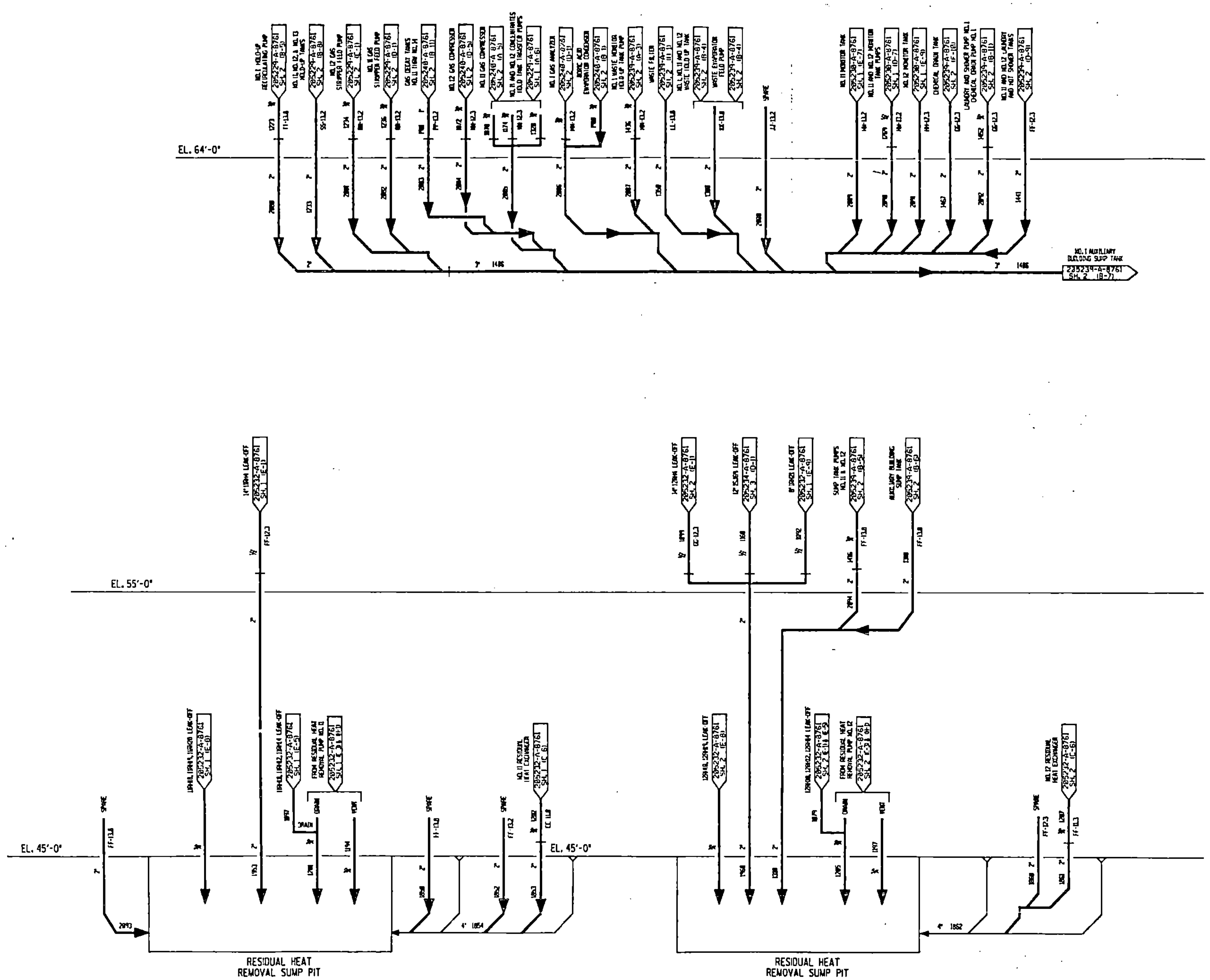
Ref. Dwg. 205227A8761-16

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Equipment Vents and Drains Unit 1
	Updated FSAR Sheet 1 of 3 Fig 9.3-4A



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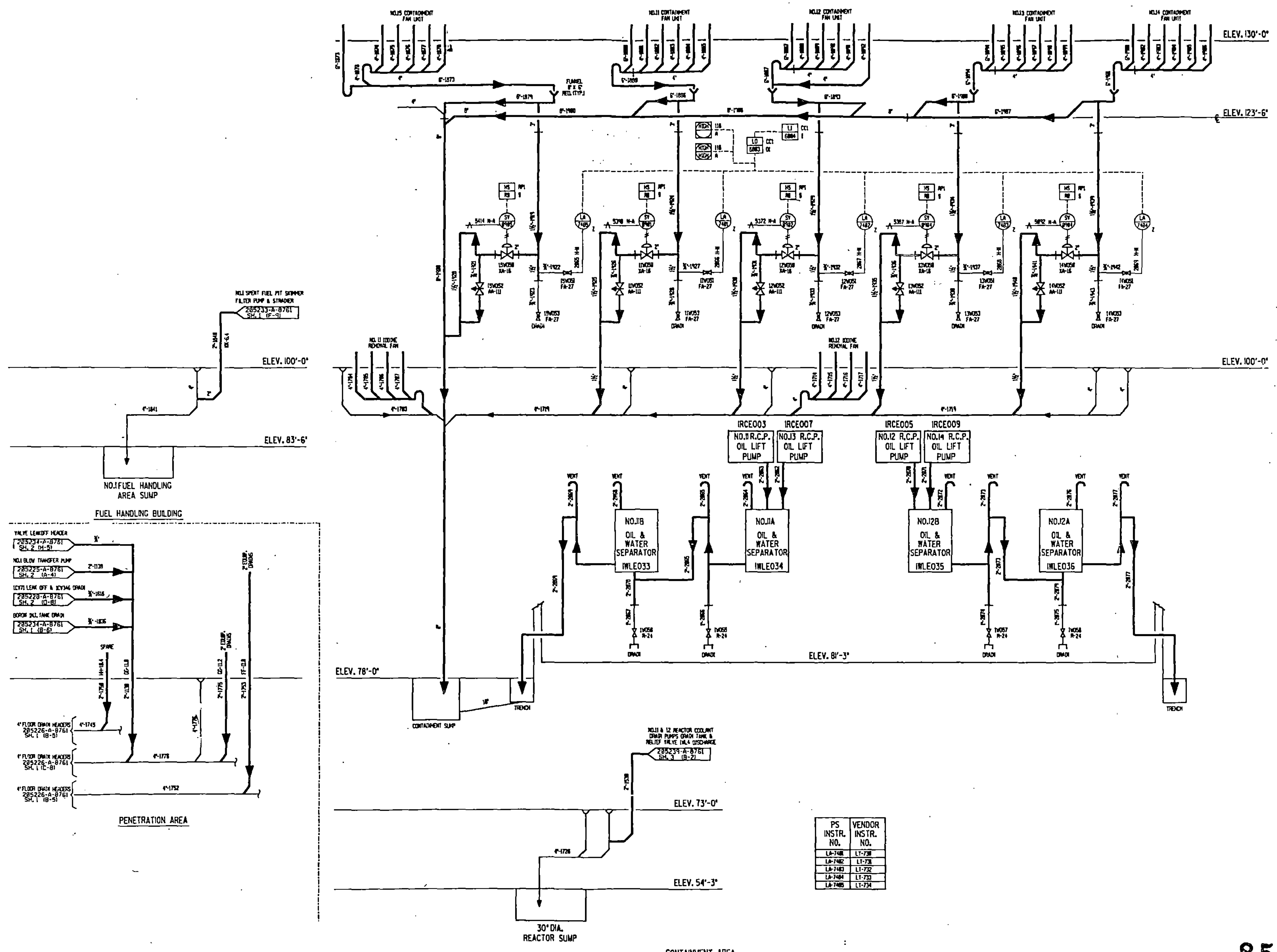
Revision 4
July 22, 1985
Ref. Dwg. 205227A8761-16

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Equipment Vents and Drains Unit 1 Updated FSAR Sheet 2 of 3 Fig 9.3-4A



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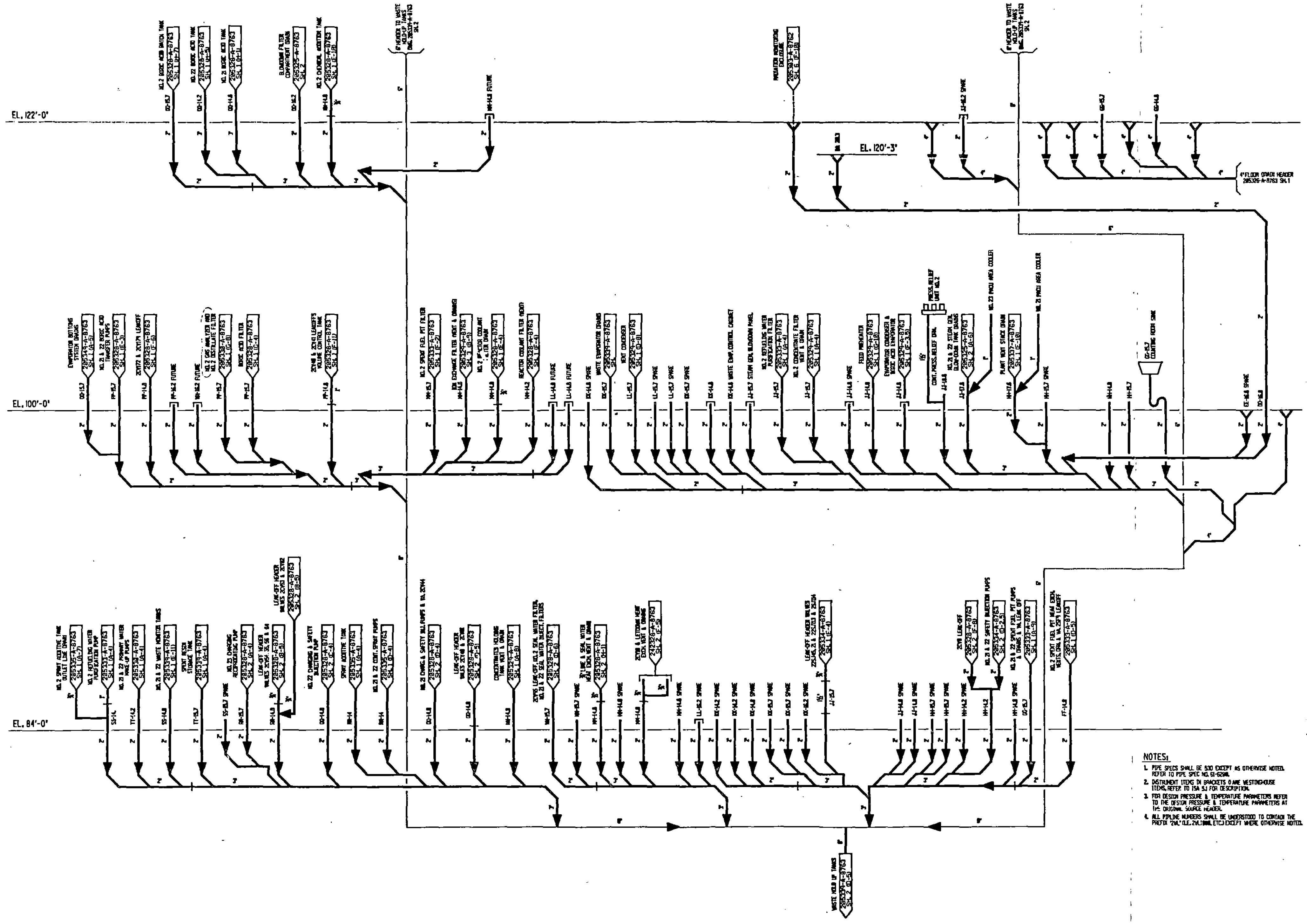
Revision 4
July 22, 1985
Ref. Dwg. 205227A8761-16

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Equipment Vents and Drains Unit 1
	Updated FSAR Sheet 3 of 3 Fig 9.3-4A



NOTES:

1. PIPE SPECS SHALL BE 530 EXCEPT AS OTHERWISE NOTED. REFER TO PIPE SPEC NO. 61-620[illegible].
2. INSTRUMENT ITEMS IN BRACKETS ◊ ARE WESTINGHOUSE ITEMS. REFER TO ISA S.1 FOR DESCRIPTION.
3. FOR DESIGN PRESSURE & TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE & TEMPERATURE PARAMETERS AT THE ORIGINAL SOURCE HEADER.
4. ALL PIPLINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX '2WL' (I.E. 2WL1[illegible], ETC.) EXCEPT WHERE OTHERWISE NOTED.

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Revision 4
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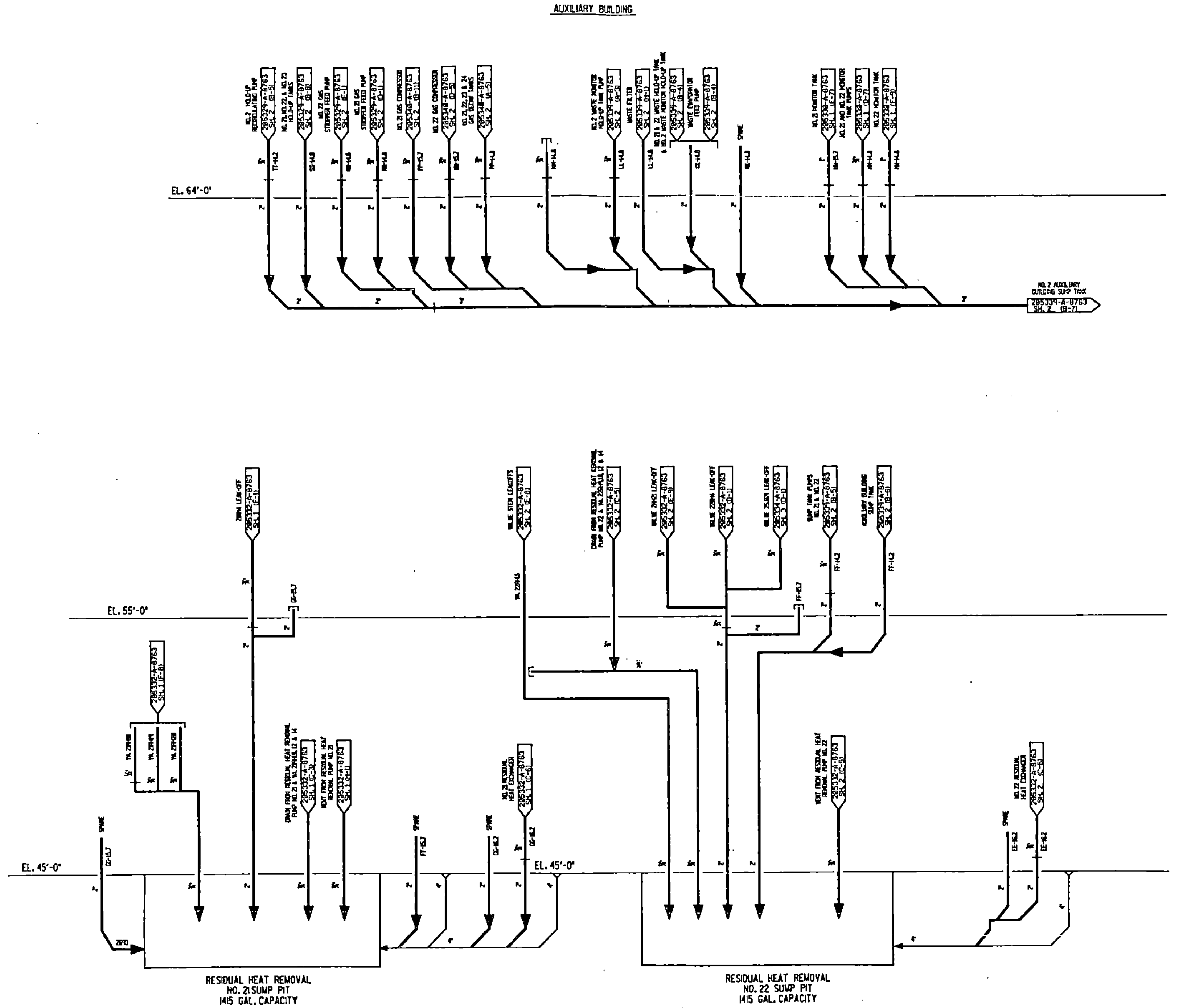
Ref. Dwg. 205327A8763-15

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Equipment Vents and Drains Unit 2
	Updated FSAR Sheet 1 of 3 — Fig 9.3-4B



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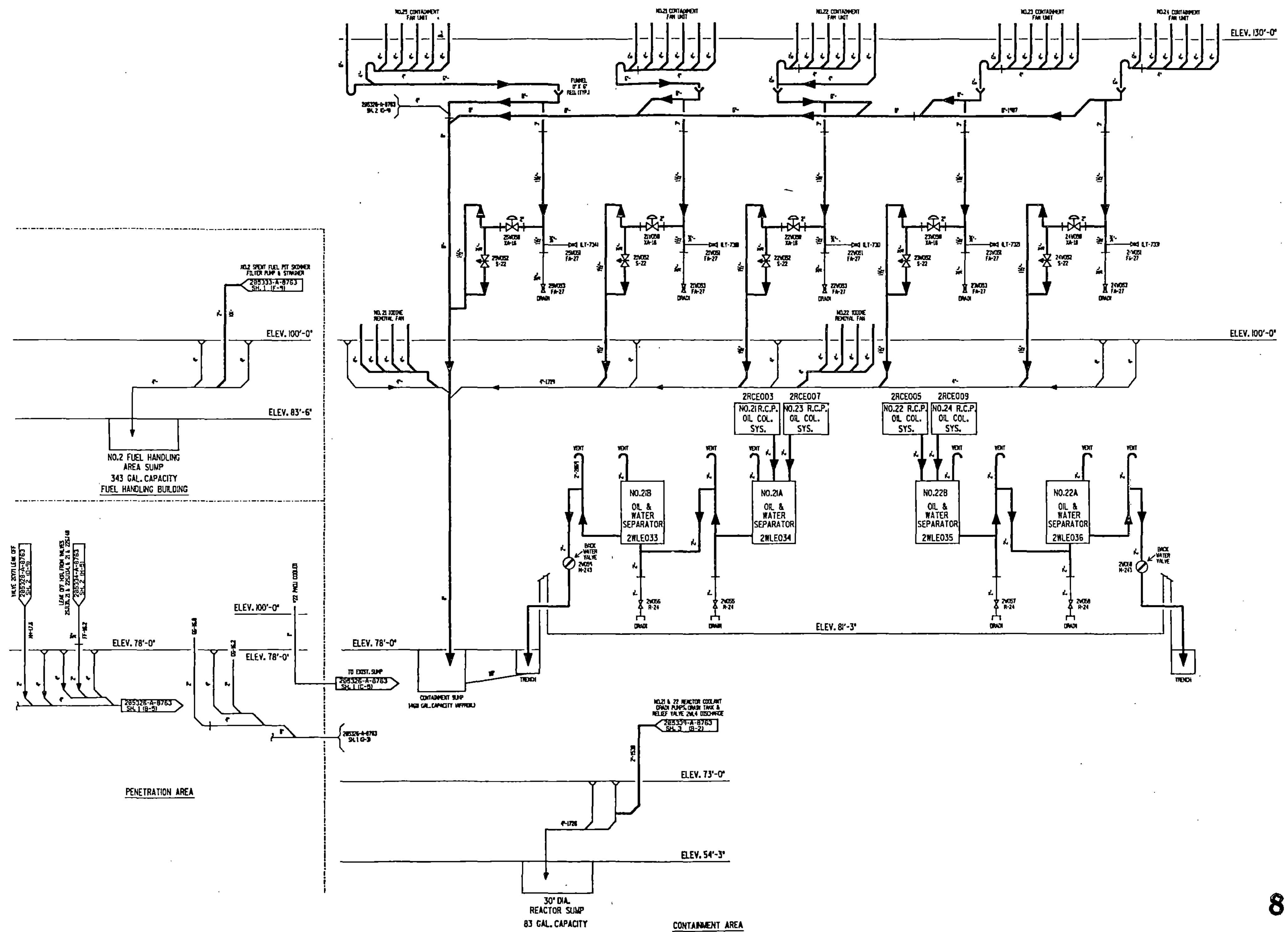
8507300447 -74

Revision 4
July 22, 1985
Ref. Dwg. 205327A8763-15

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Equipment Vents and Drains Unit 2
	Updated FSAR Sheet 2 of 3 Fig 9.3-4B



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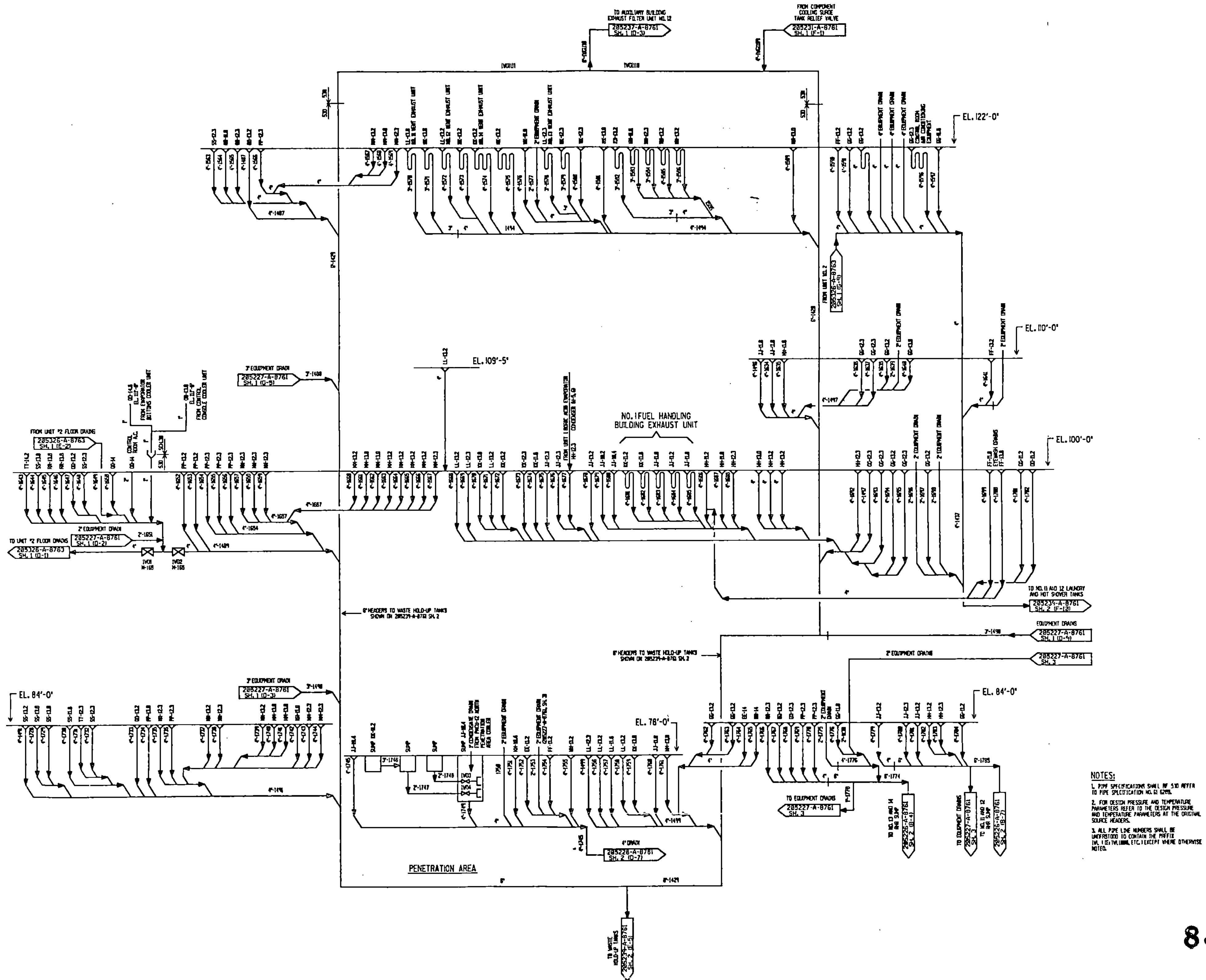
Revision 4
July 22, 1985
Ref. Dwg. 205327A8763-15

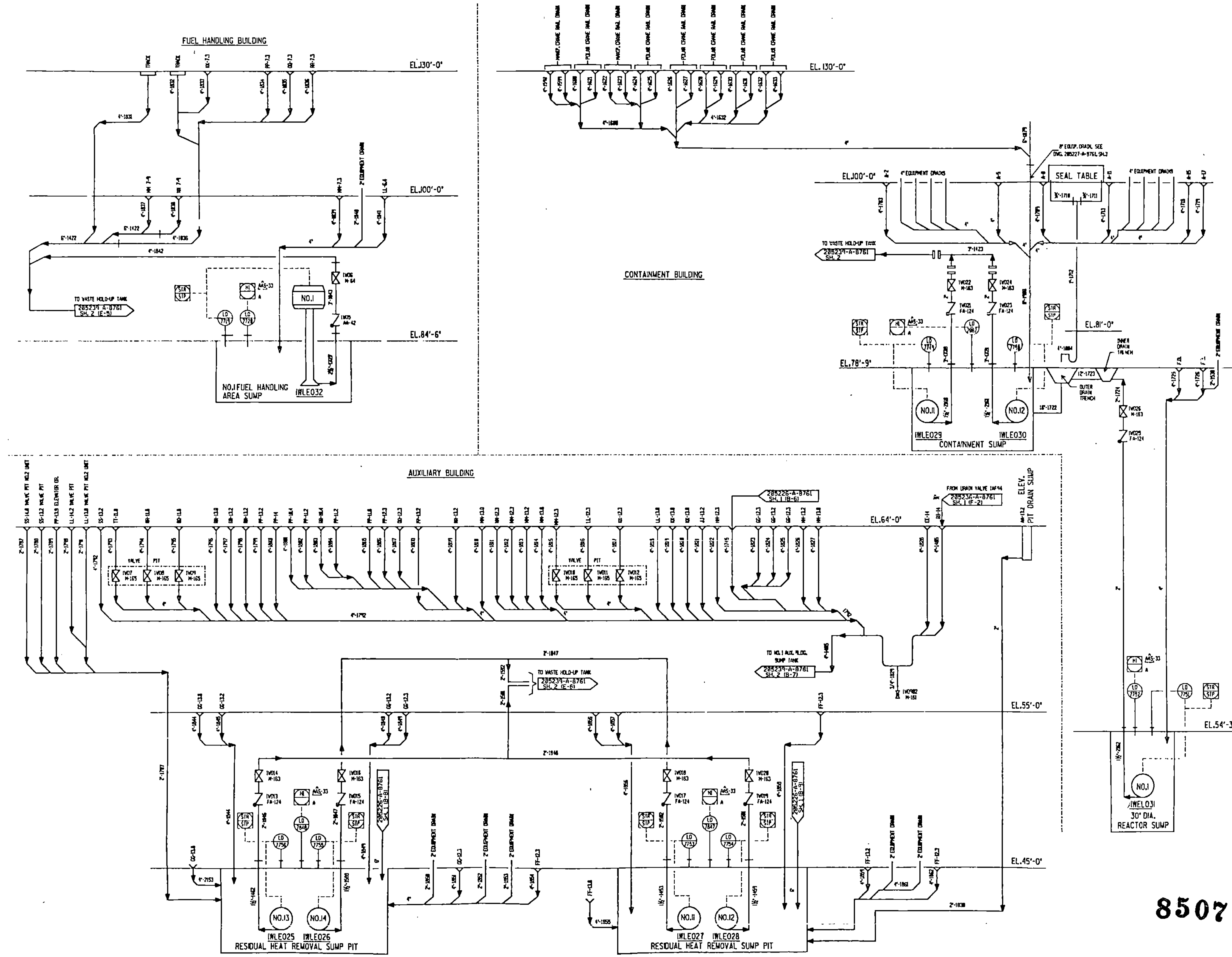
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Equipment Vents and Drains Unit 2 Updated FSAR Sheet 3 of 3 Fig 9.3-4B



8507300447-76

Revision 4
July 22, 1985
Ref. Dwg. 205226A8761=19

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Floor Drains Unit 1
	Updated FSAR Sheet 1 of 2 Fig 9.3-5A



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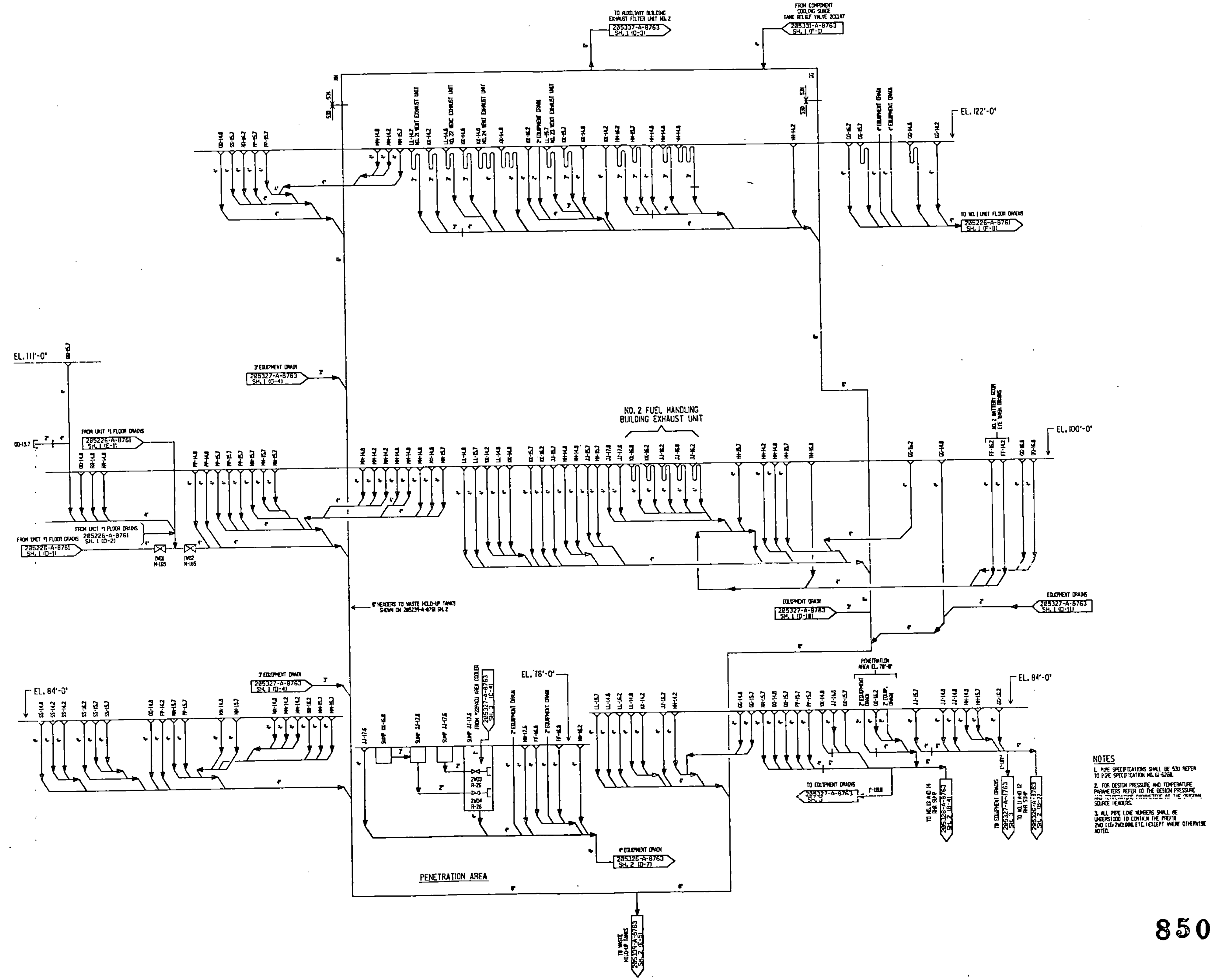
8507300447-77

Revision 4
July 22, 1985
Ref. Dwg. 20522A8761-19

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Floor Drains Unit 1
	Updated FSAR Sheet 2 of 2 Fig 9.3-5A



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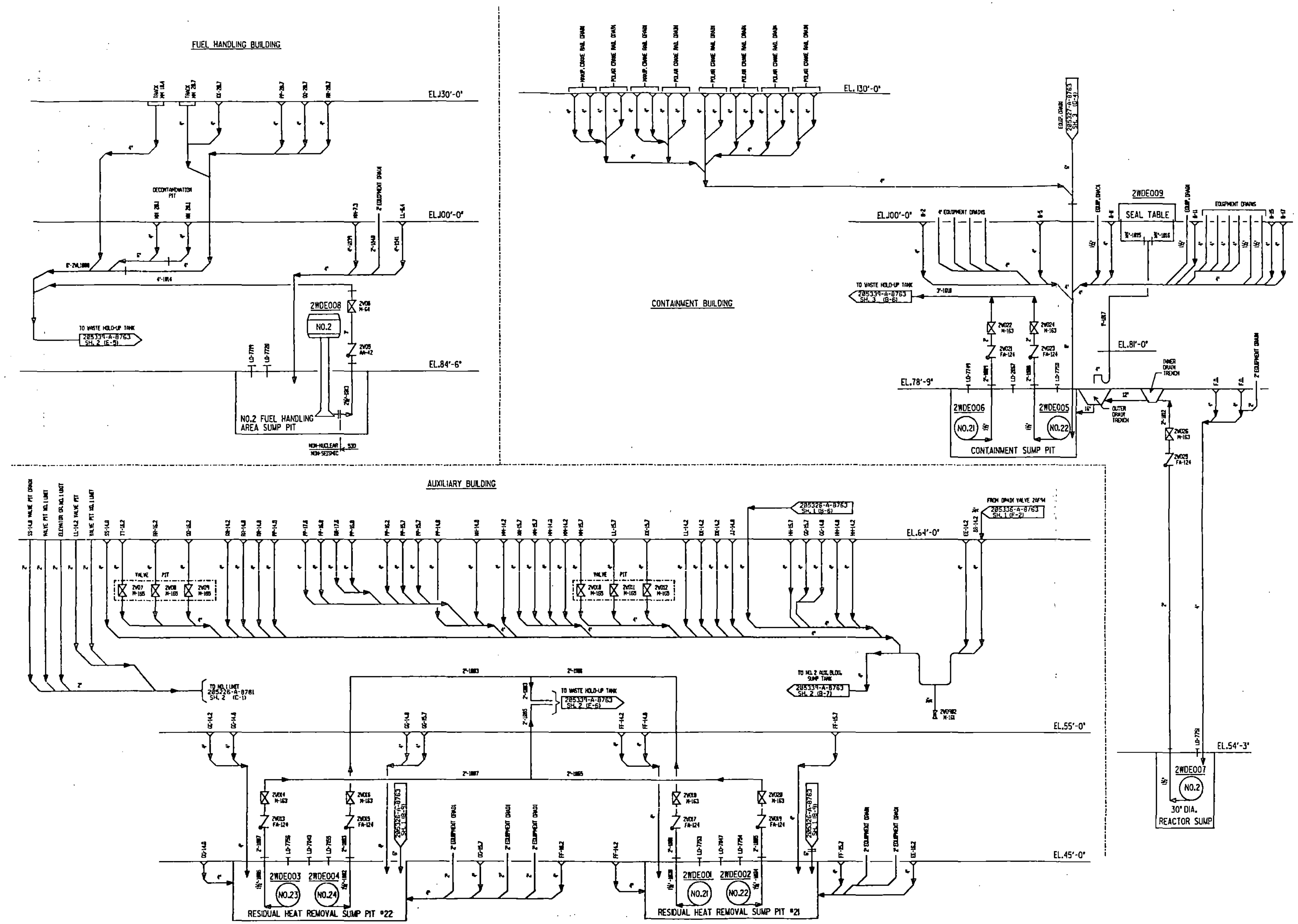
Revision 4
July 22, 1985
Ref. Dwg. 205326A8763-12

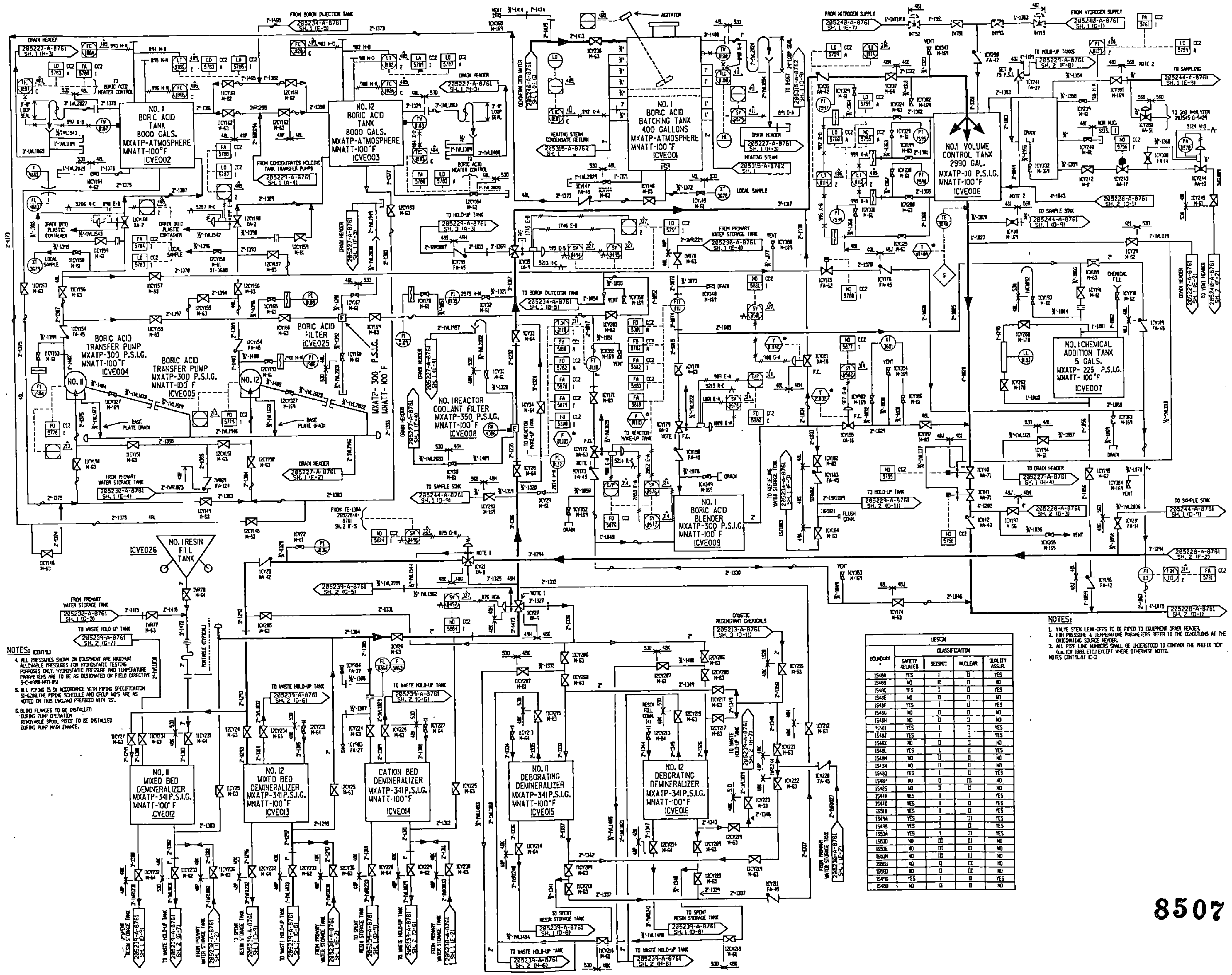
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Floor Drains Unit 2
	Updated FSAR Sheet 1 of 2 Fig 9.3-5B



8507300447-79

Revision 4
July 22, 1985
Ref. Dwg. 205326A8763-12

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Floor Drains Unit 2
	Updated FSAR Sheet 2 of 2 Fig 9.3-5B



NOTES:

1. VALVE STEM LEAK-OFFS TO BE PIPED TO EQUIPMENT DRAIN HEADER.
2. FOR PRESSURE & TEMPERATURE PARAMETERS REFER TO THE CONDITIONS AT THE ORIGINATING SOURCE HEADER.
3. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1CY" (i.e. 1CY 1088, ETC.) EXCEPT WHERE OTHERWISE NOTED.

NOTES CONT'D. AT C-3

NOTES: (CONT'D)

4. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051
5. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6280, THE PIPING SCHEDULE AND GROUP NO'S ARE AS NOTED ON THIS DWG. AND PREFIXED WITH "1S".
6. BLIND FLANGES TO BE INSTALLED DURING PUMP OPERATION REMOVABLE SPOOL PIECE TO BE INSTALLED DURING PUMP MAINTENANCE.

BOUNDARY •	DESIGN CLASSIFICATION: SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S48A	YES	I	II	YES
1S48B	NO	II	II	NO
1S48C	YES	I	II	YES
1S48E	NO	II	II	NO
1S48F	YES	I	II	YES
1S48G	NO	II	II	NO
1S48H	NO	II	II	NO
1S48I	YES	I	II	YES
1S48J	YES	I	II	YES
1S48K	NO	II	II	NO
1S48L	YES	I	II	YES
1S48M	NO	II	II	NO
1S48N	NO	II	II	NO
1S48O	YES	I	II	YES
1S48P	NO	II	III	NO
1S48S	NO	II	II	NO
1S44A	YES	I	I	YES
1S44D	YES	I	II	YES
1S51B	YES	I	II	YES
1S49A	YES	I	III	YES
1S49B	YES	I	II	YES
1S53A	YES	I	III	YES
1S53D	NO	III	III	NO
1S53E	NO	III	III	NO
1S53M	NO	III	III	NO
1S86B	NO	II	III	NO
1S86D	NO	II	III	NO
1S49G	YES	I	II	YES
1S48D	NO	II	II	NO

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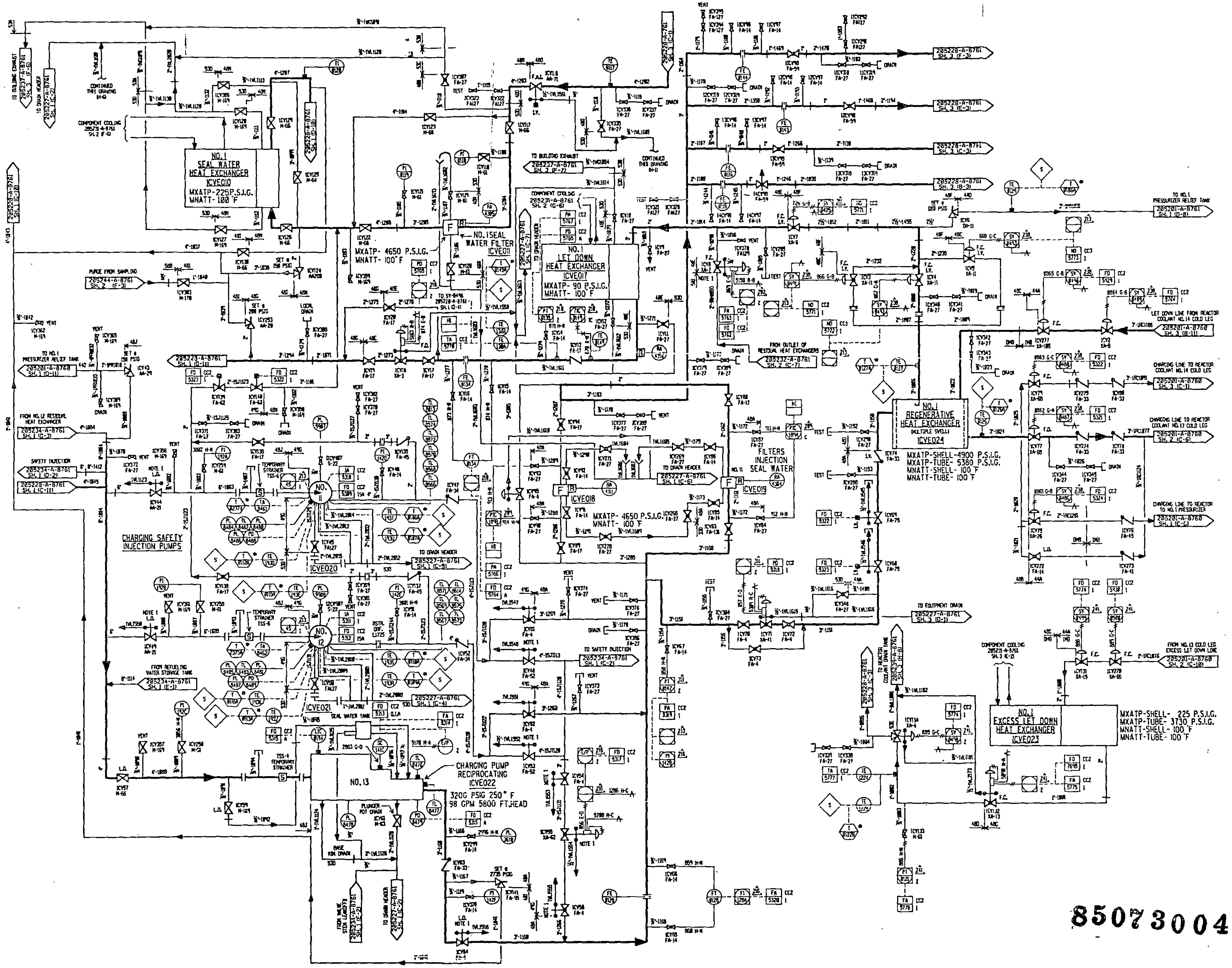
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Chemical Volume and Control System Operation
Unit 1

Updated FSAR Sheet 1 of 3

Fig 9.3-6A



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Revision 4
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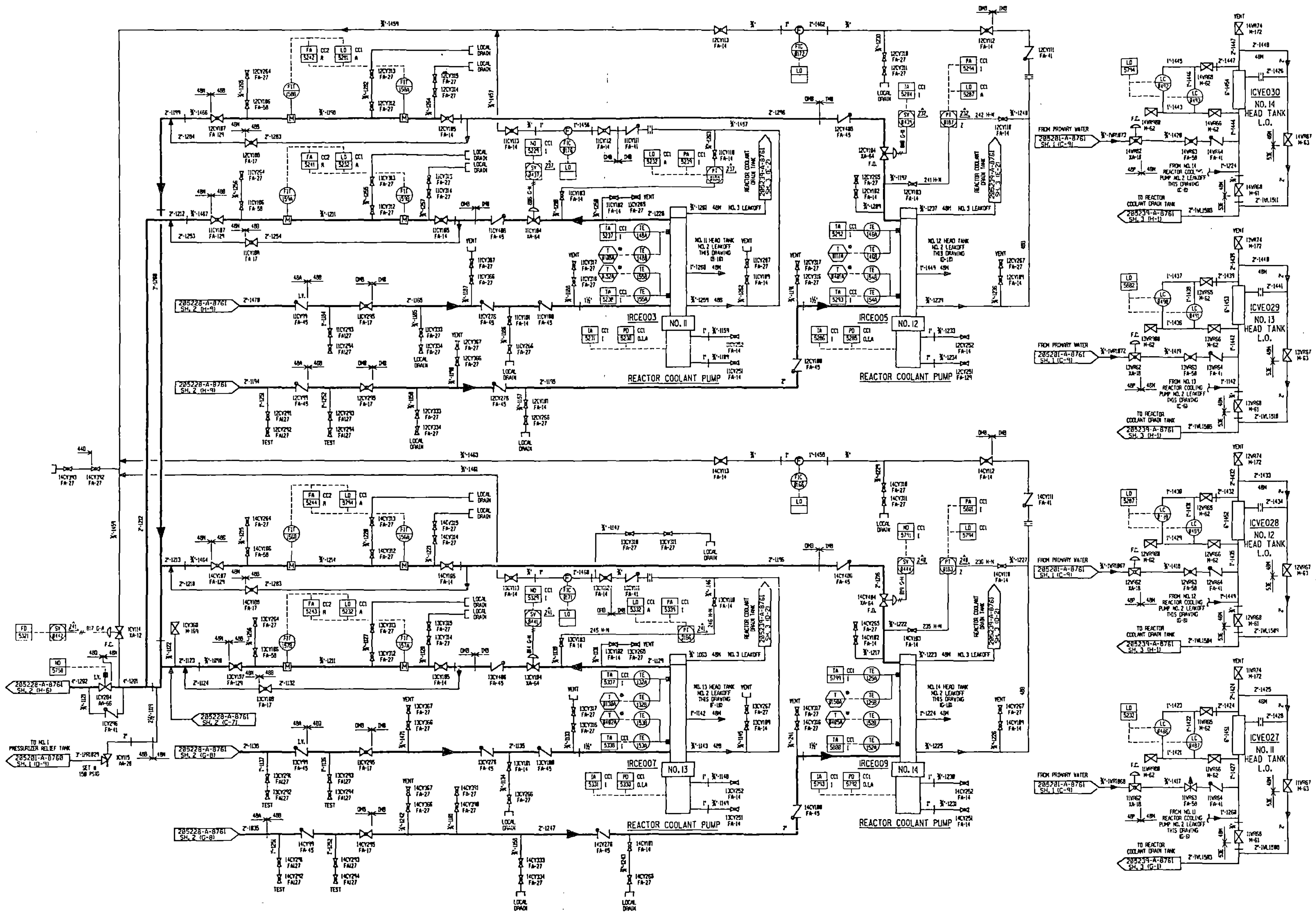
Ref. Dwg. 205228A8761-27

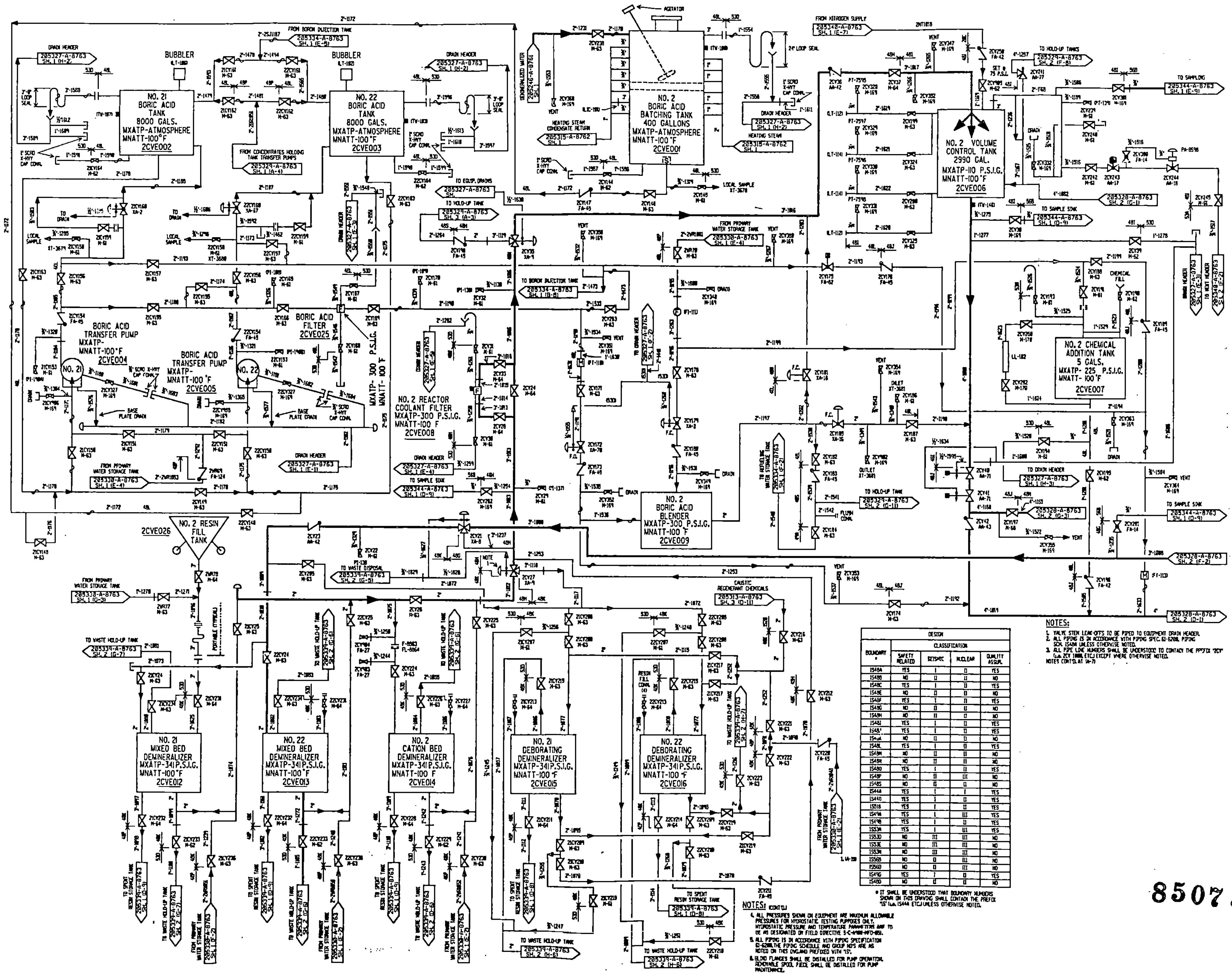
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Chemical Volume and Control System Operation Unit 1
	Updated FSAR Sheet 2 of 3 Fig 9.3-6A



8507300447-82

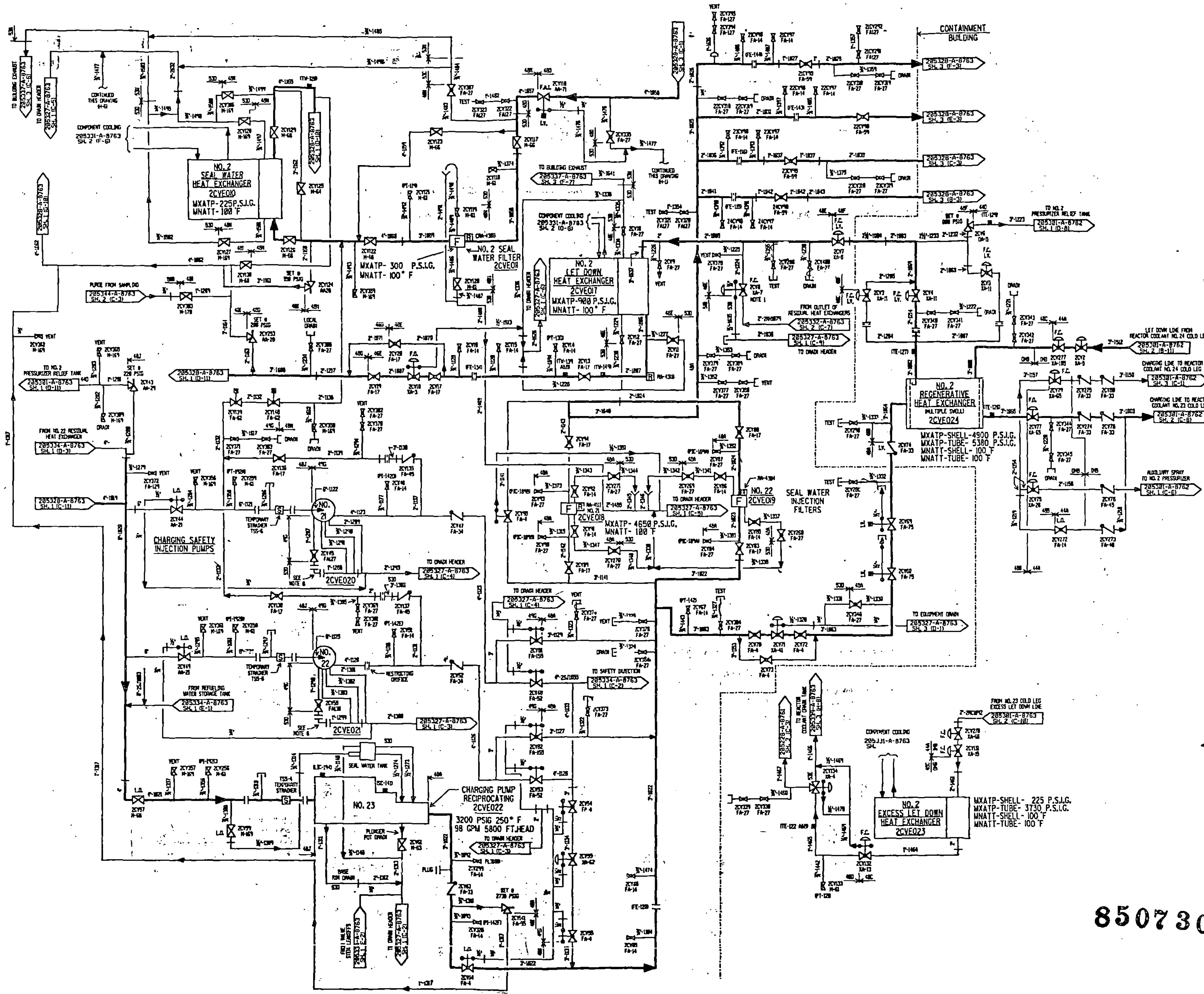
Revision 4
July 22, 1985
Ref. Dwg. 205228A8761-27

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Chemical Volume and Control System Operation Unit 1
	Updated FSAR Sheet 3 of 3 Fig 9.3-6A



Revision 4
July 22, 1985
Ref. Dwg. 205328A8763-22

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Chemical Volume and Control System Operation Unit 2
	Updated FSAR Sheet 1 of 3 Fig 9.3-6B



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Revision 4
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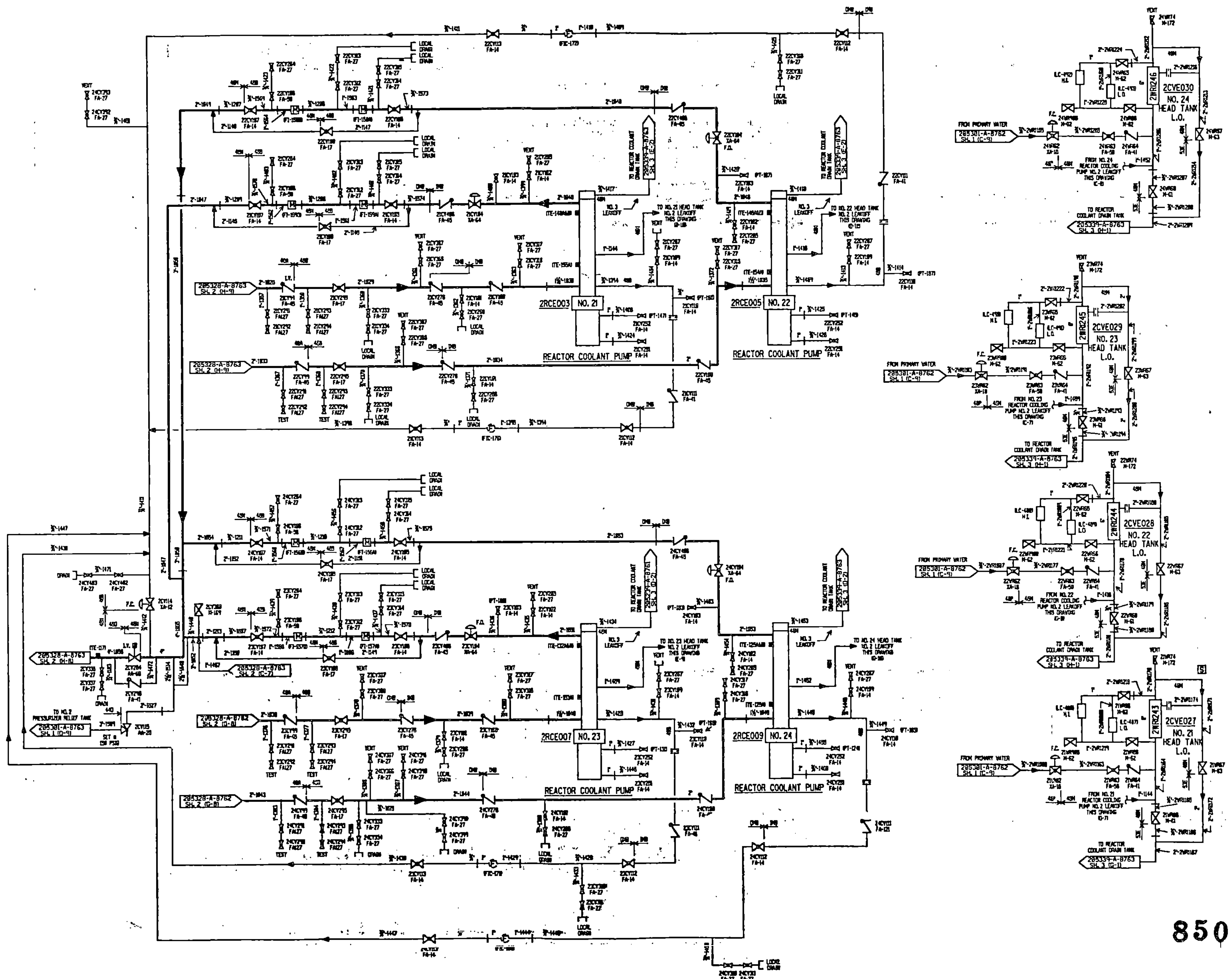
Ref. Dwg. 205328A8763-22

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Chemical Volume and Control System Operation Unit 2
	Updated FSAR Sheet 2 of 3 Fig 9.3-6B



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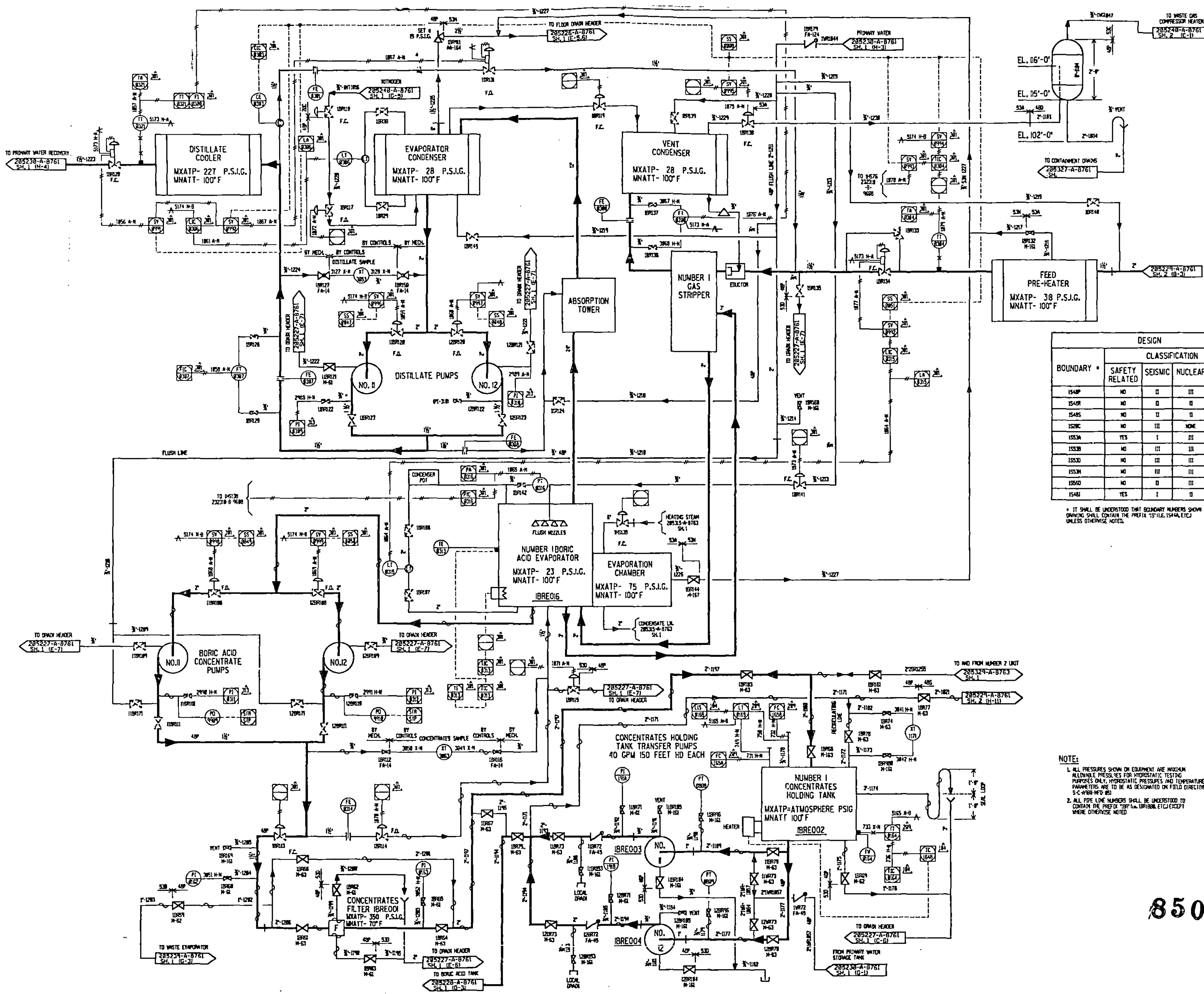
8507300447-85

Revision 4
July 22, 1985
Ref. Dwg. 205328A8763-22

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Chemical Volume and Control System Operation Unit 2
	Updated FSAR Sheet 3 of 3 Fig 9.3-6B



DESIGN				
BOUNDARY *	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR
1548P	NO	II	III	NO
1548R	NO	II	II	NO
1548S	NO	II	II	NO
1528C	NO	III	NONE	NO
1553A	YES	I	III	YES
1553B	NO	III	III	NO
1553D	NO	III	III	NO
1553N	NO	III	III	NO
1556D	NO	II	III	NO
1548J	YES	I	II	YES

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (I.E. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

NOTE:

1. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A780-MFD-851
2. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1BR" (i.e. 1BR1808, ETC.) EXCEPT WHERE OTHERWISE NOTED

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8507300447-86

Revision 4
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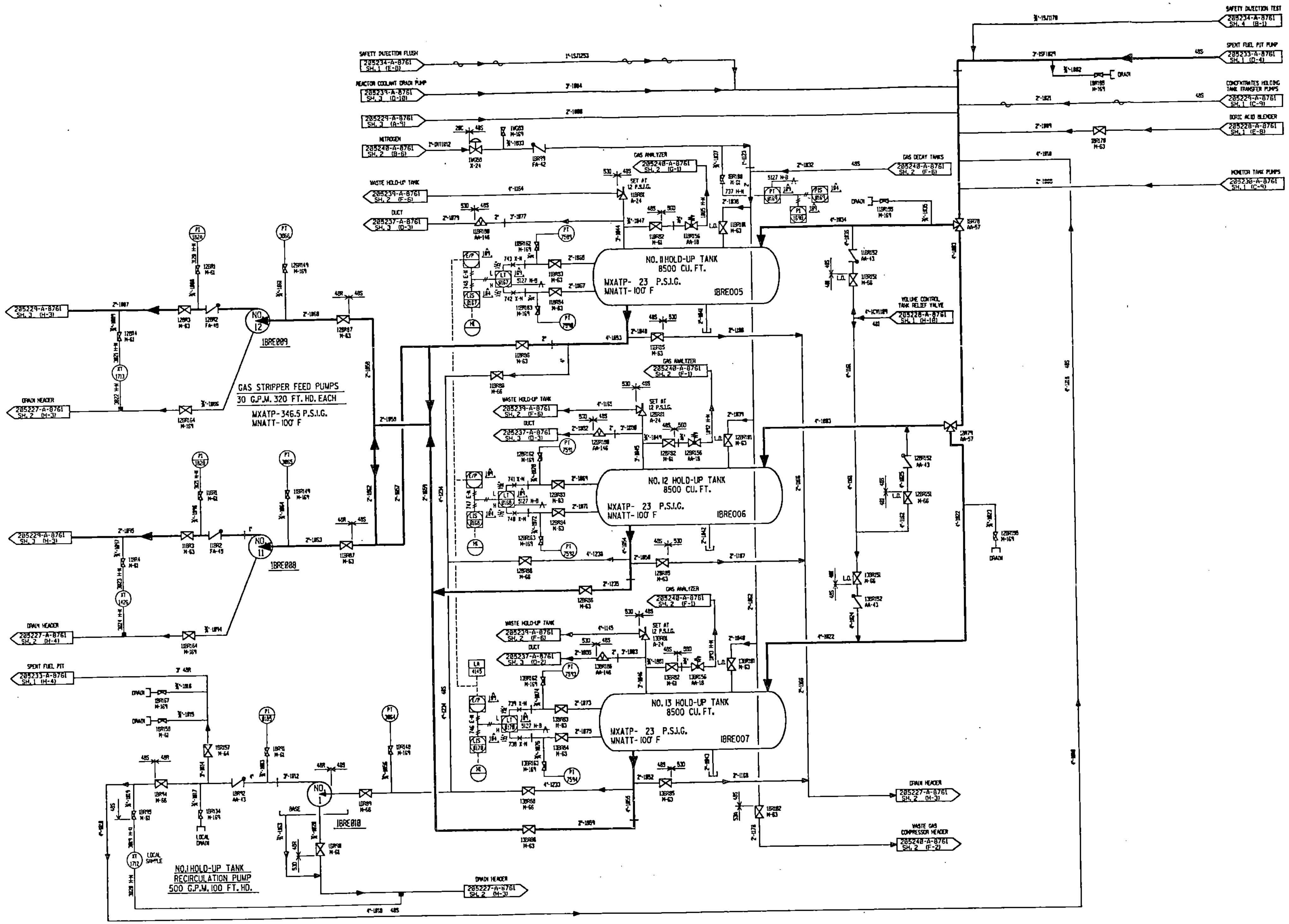
Ref. Dwg. 205229A8761-16

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Chemical Volume and Control System Boric Acid Recovery - Unit 1
	Updated FSAR Sheet 1 of 3 Fig 9.3-7A



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8507300447-87

Revision 4
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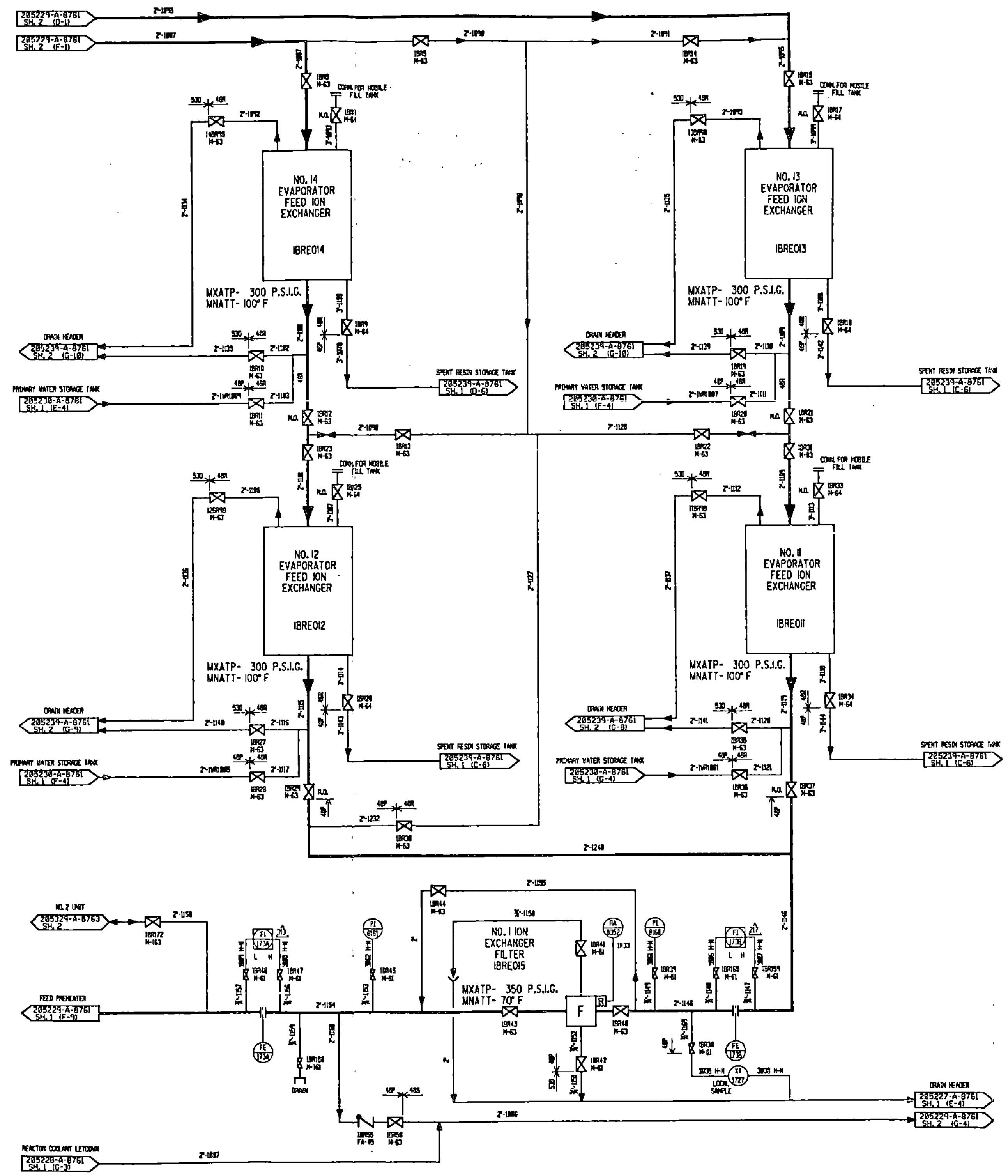
Ref. Dwg. 205229A8761-16

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Chemical Volume and Control System Boric Acid Recovery - Unit 1
	Updated FSAR Sheet 2 of 3 Fig 9.3-7A



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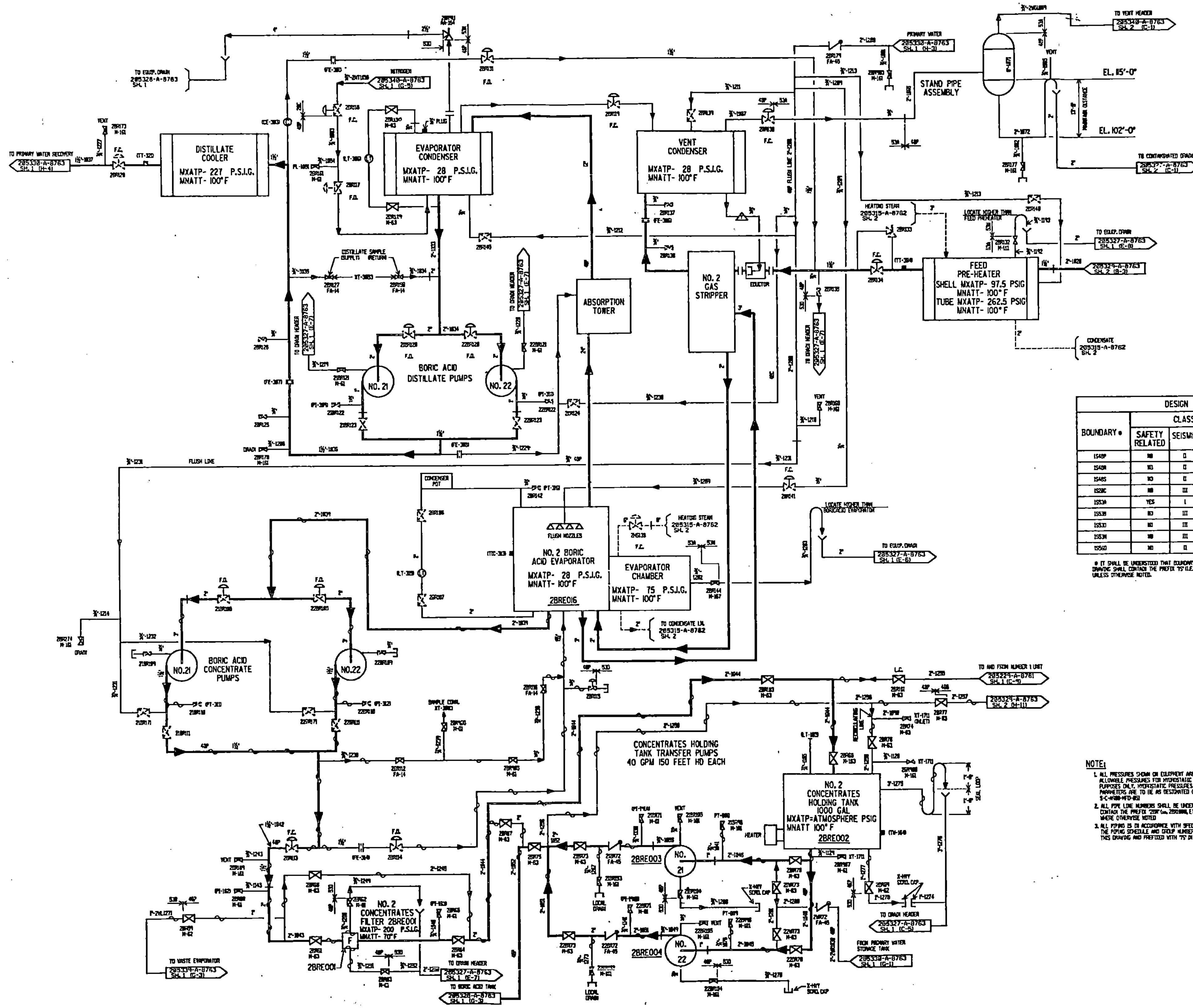
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Chemical Volume and Control System
Boric Acid Recovery - Unit 1

Updated FSAR Sheet 3 of 3 Fig 9.3-7A



DESIGN				
BOUNDARY ●	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR
1S48P	NO	II	III	NO
1S48R	NO	II	II	NO
1S48S	NO	II	II	NO
1S28C	NO	III	NONE	NO
1S53A	YES	I	III	YES
1S53B	NO	III	III	NO
1S53D	NO	III	III	NO
1S53N	NO	III	III	NO
1S56D	NO	II	III	NO

● IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (I.E. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

NOTE:

1. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-[illegible]
2. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2BR" ([illegible], ETC.) EXCEPT WHERE OTHERWISE NOTED
3. ALL PIPING IS IN ACCORDANCE WITH SPEC. NO. [illegible] THE PIPING SCHEDULE AND GROUP NUMBERS ARE AS NOTED ON THIS DRAWING AND PREFIXED WITH "TS" IN THE PIPE SPEC.

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Revision 4
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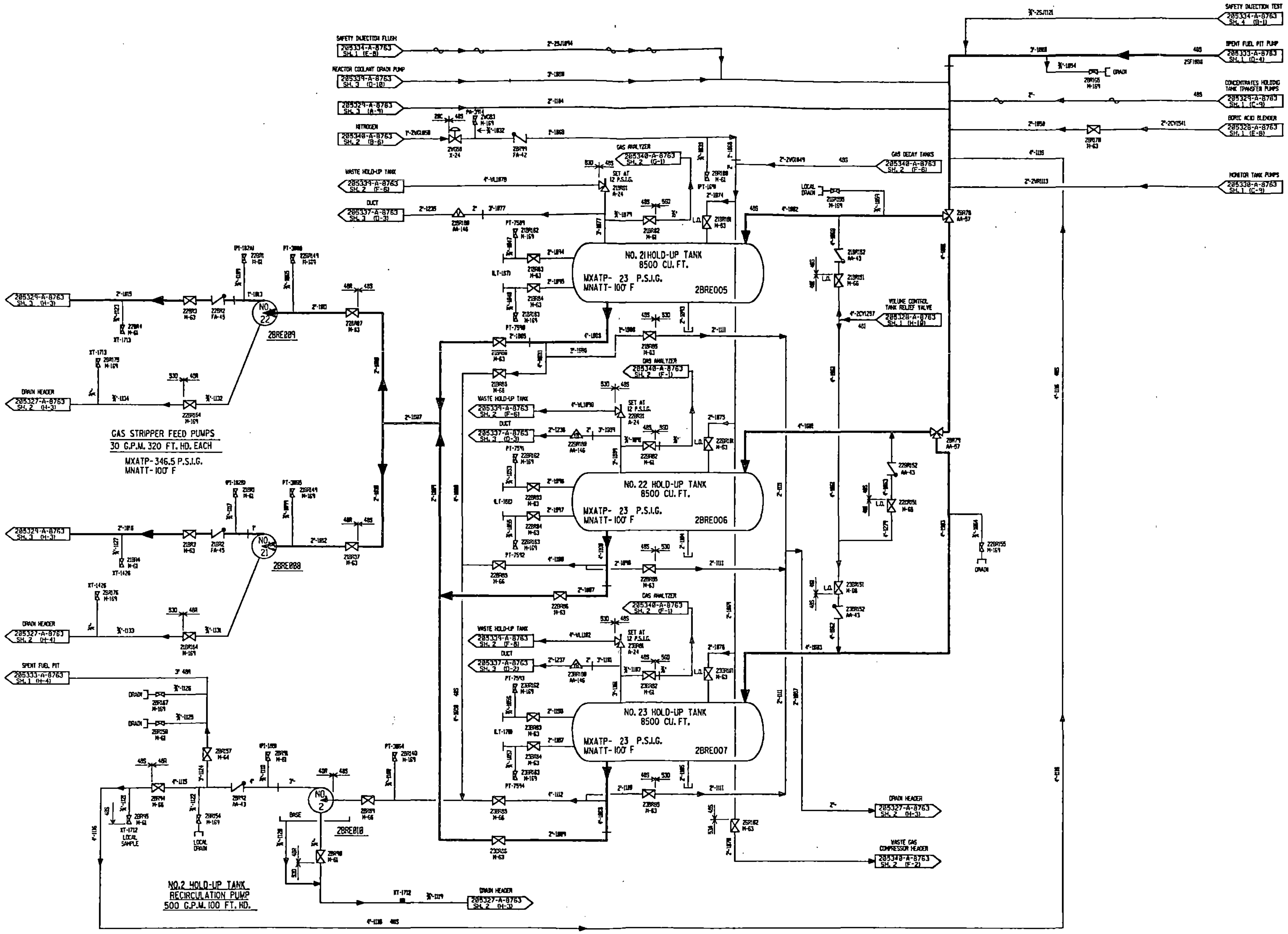
Ref. Dwg. 205329A8763-15

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Chemical Volume and Control System Boric Acid Recovery - Unit 2
	Updated FSAR Sheet 1 of 3 Fig 9.3-7B



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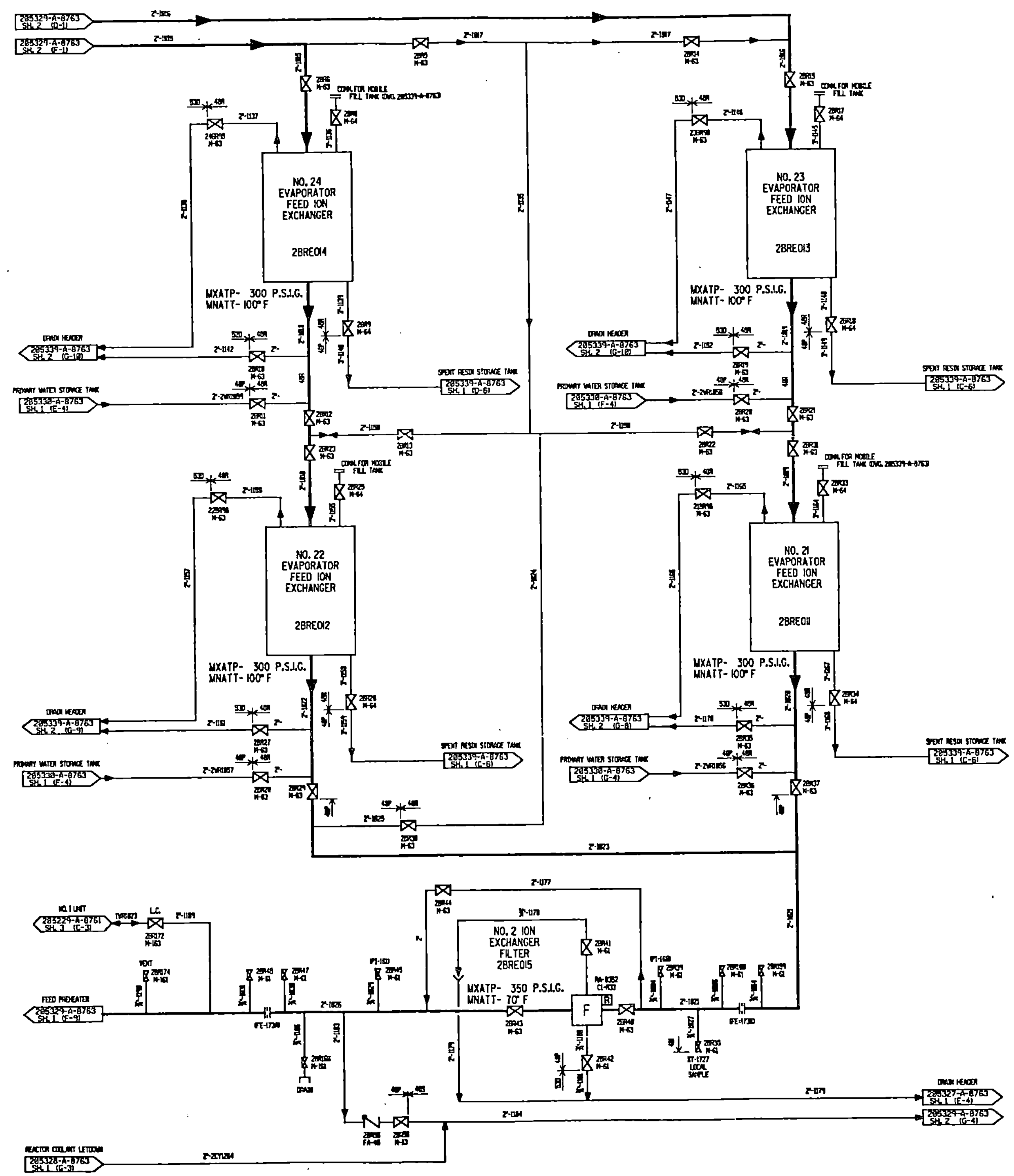
8507300447-90

Revision 4
July 22, 1985
Ref. Dwg. 205329A8763-15

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Chemical Volume and Control System Boric Acid Recovery - Unit 2 Updated FSAR Sheet 2 of 3 Fig 9.3-7B



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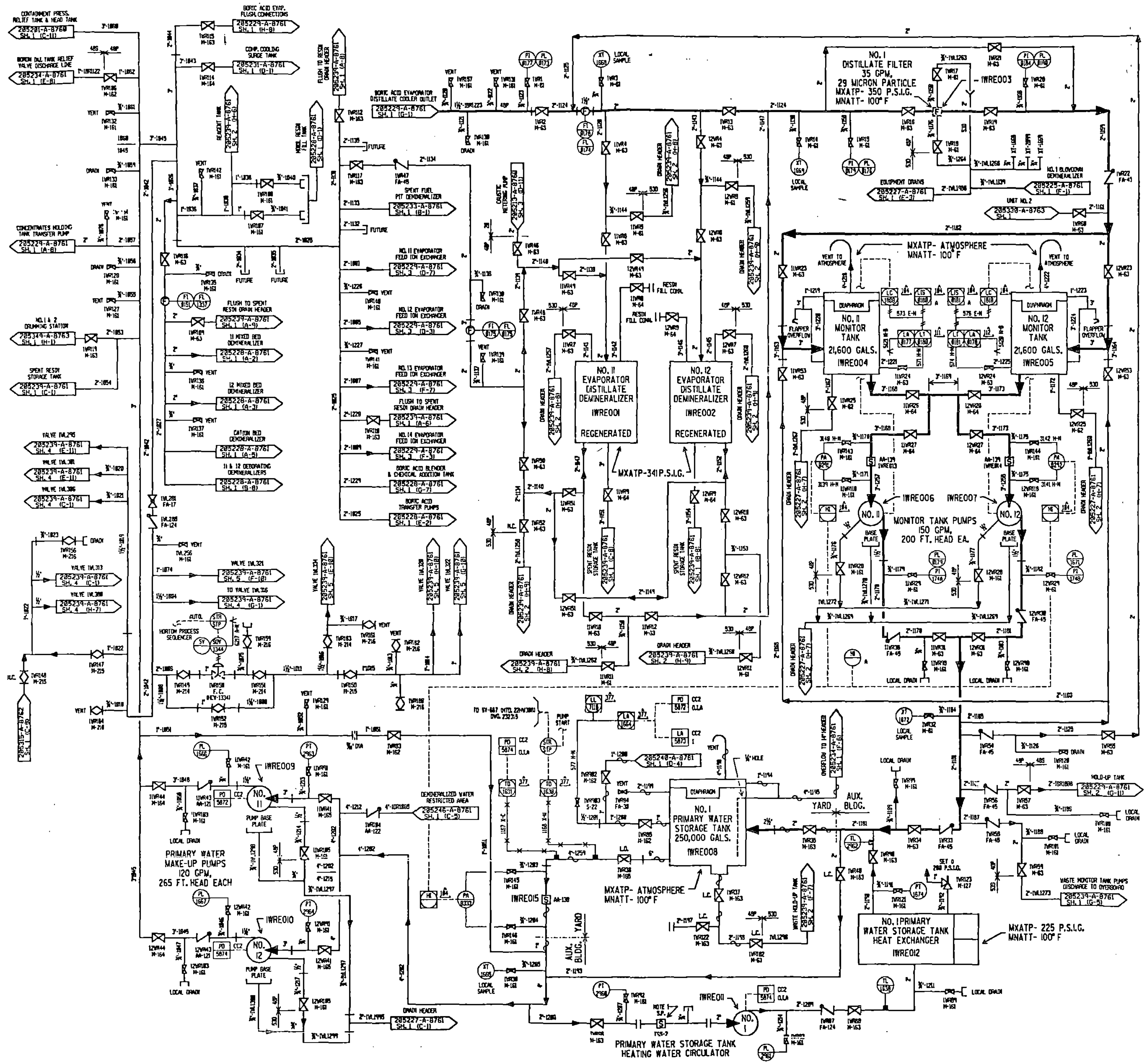
8507300447-91

Revision 4
July 22, 1985
Ref. Dwg. 205329A8763-15

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Chemical Volume and Control System Boric Acid Recovery - Unit 2
	Updated FSAR Sheet 3 of 3 Fig 9.3-7B



NOTES:

1. TEMPORARY STRAINER IS PLACED IN LINE DURING INITIAL FLUSHING-CAPPED CONN. IS FOR A TEMPORARY PRESSURE GAGE AT THIS TIME.
2. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A920-NFD-051
3. FOR DESIGN PRESSURE AND TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE AND TEMPERATURE PARAMETERS AT THE ORIGINAL SOURCE HEADER.
4. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1VR" i.e. 1VR100, ETC.) EXCEPT WHERE OTHERWISE NOTED.
5. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION S1-S2[illegible]. THE PIPING SCHEDULE AND GROUP NOS. ARE AS NOTED ON THIS DRAWING AND PREFIXED WITH "1S".

* BOUNDARY	DESIGN CLASSIFICATION: SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S28C	NO	III	NONE	NO
1S48P	NO	II	III	NO
1S48S	NO	II	II	NO
1S53B	NO	III	III	NO
1S53D	NO	III	III	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

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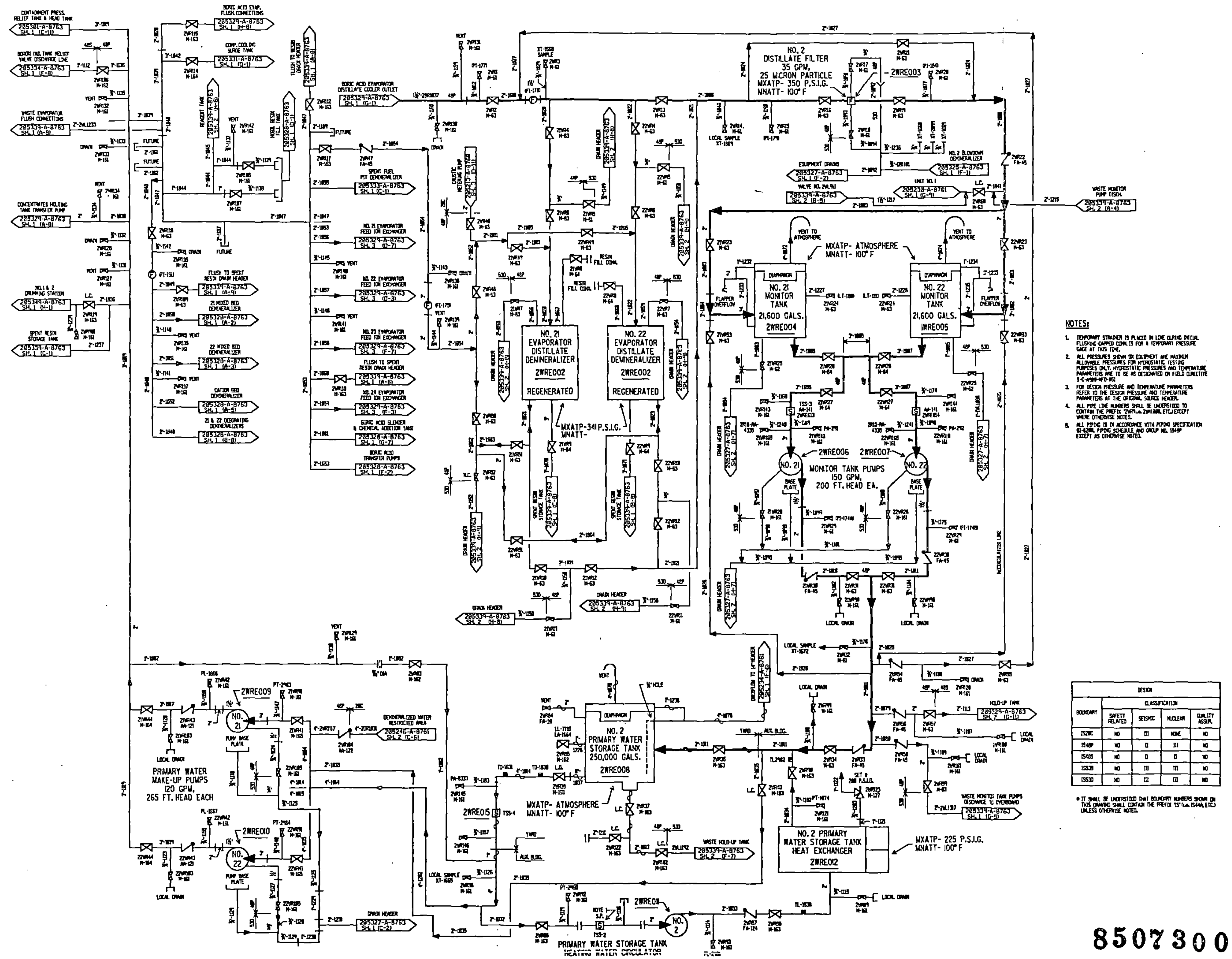
Revision 4
July 22, 1985
Ref. Dwg. 205230A8761-16

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Chemical Volume and Control System Primary Water Recovery - Unit 1
	Updated FSAR — Fig 9.3-8A



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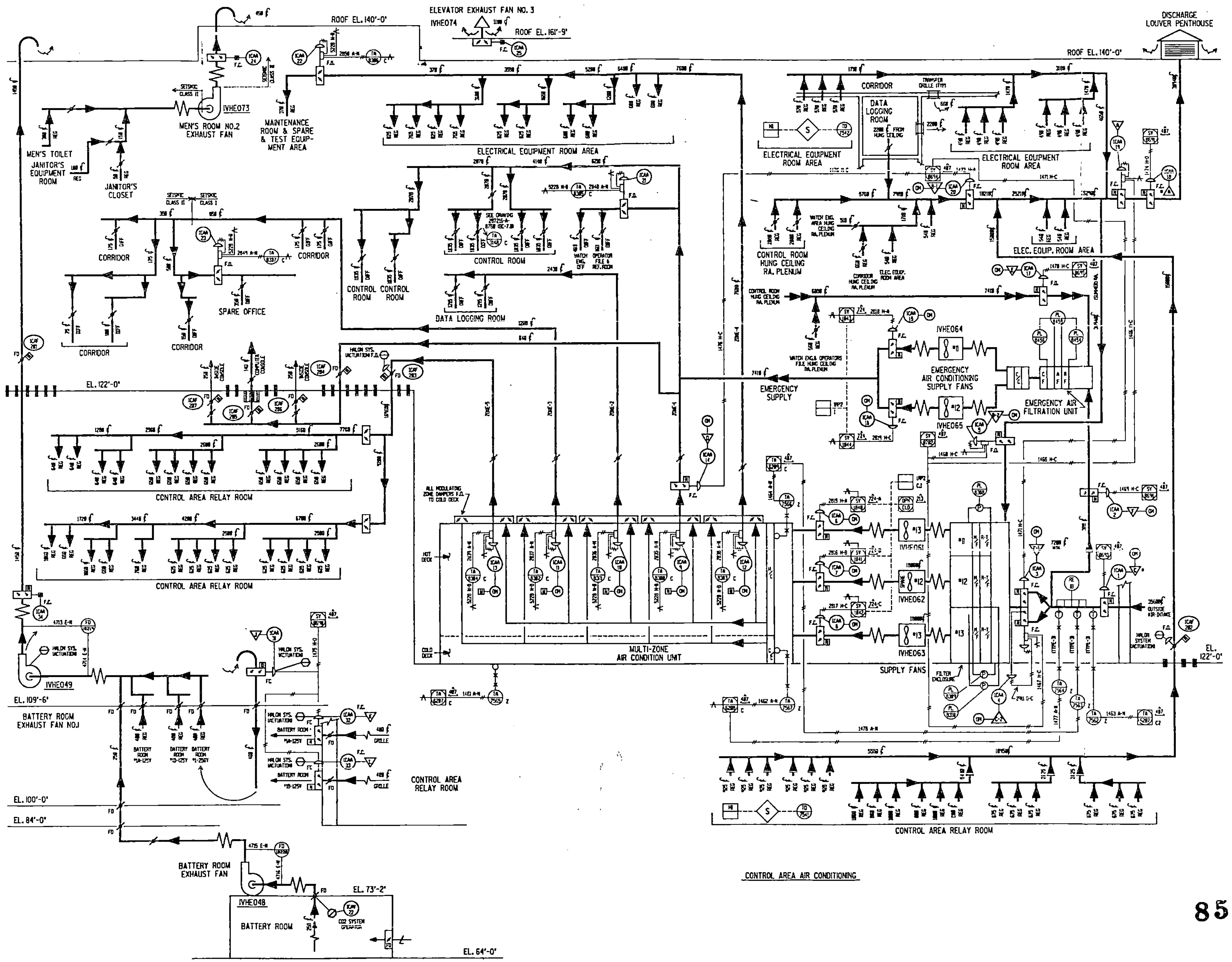
8507300447-93

Revision 4
July 22, 1985
Ref. Dwg. 205330A8763-10

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Chemical Volume and Control System Primary Water Recovery - Unit 2
	Updated FSAR — Fig 9.3-8B



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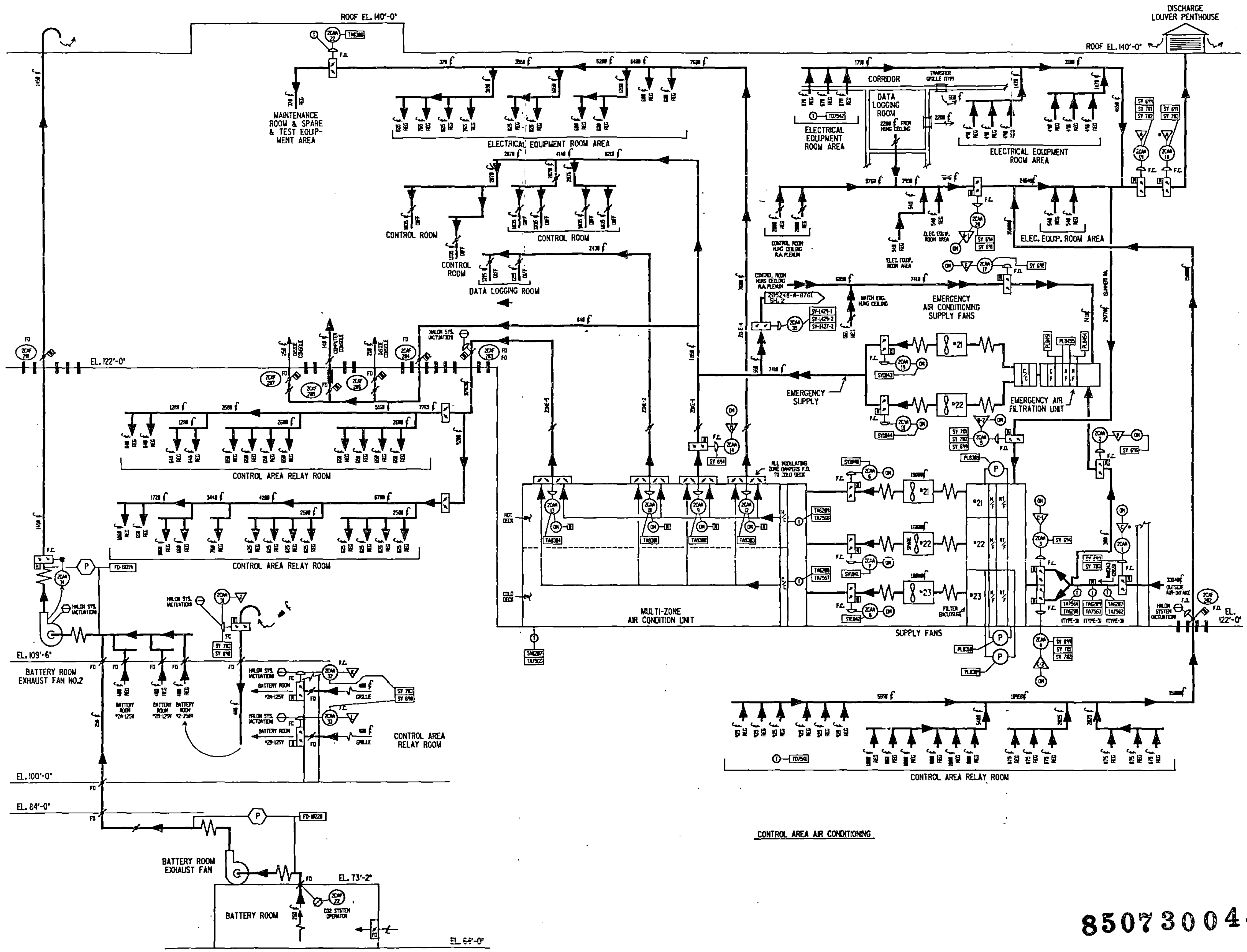
8507300447 -94

Revision 4
July 22, 1985
Ref. Dwg. 205248A8761-13

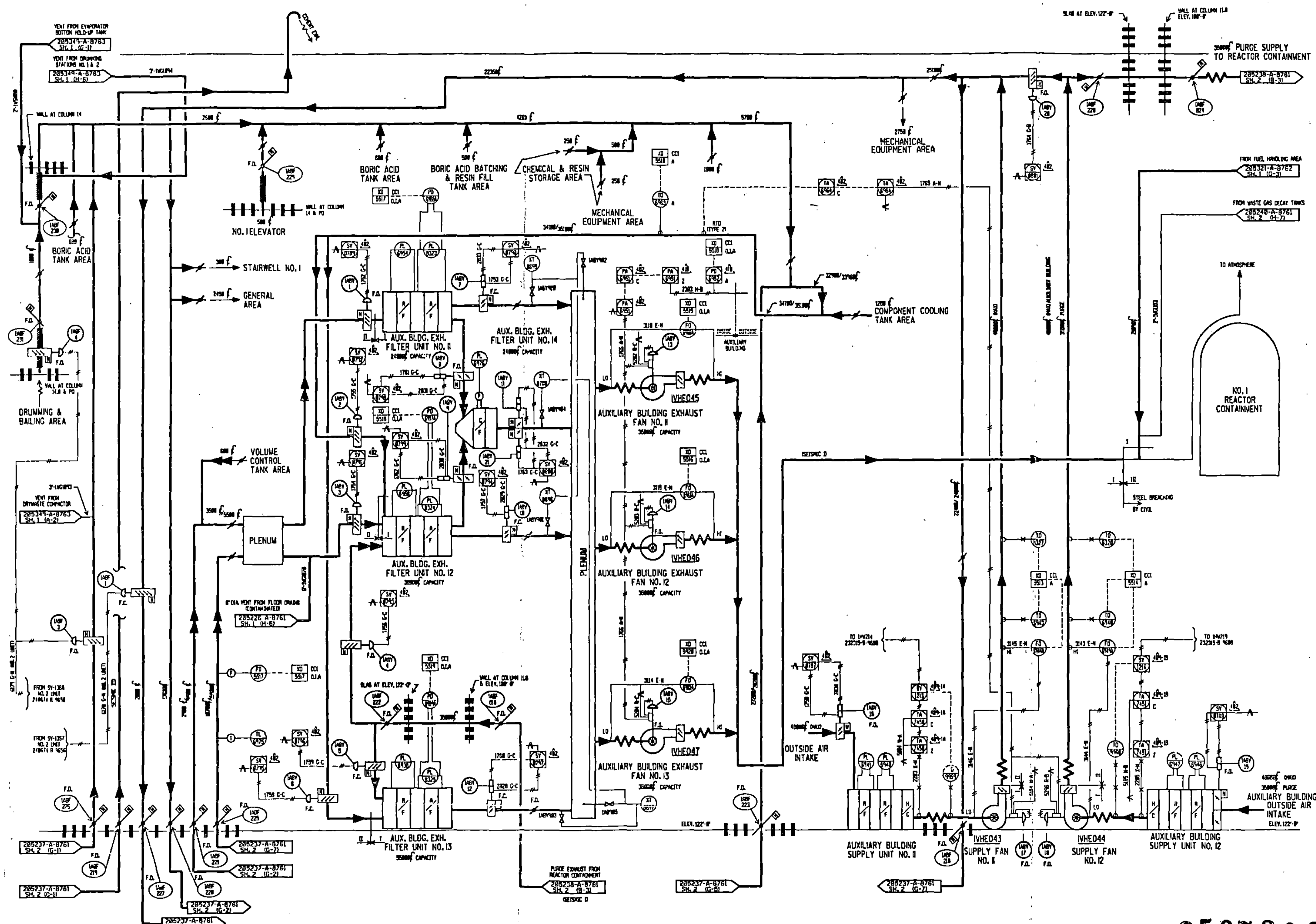
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Control Area Air Conditioning System Unit 1
	Updated FSAR — Fig 9.4-1A



8507300447 -95

Revision 4
July 22, 1985
Ref. Dwg. 205348A8763-14

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Control Area Air Conditioning System Unit 2
	Updated FSAR — Fig 9.4-1B



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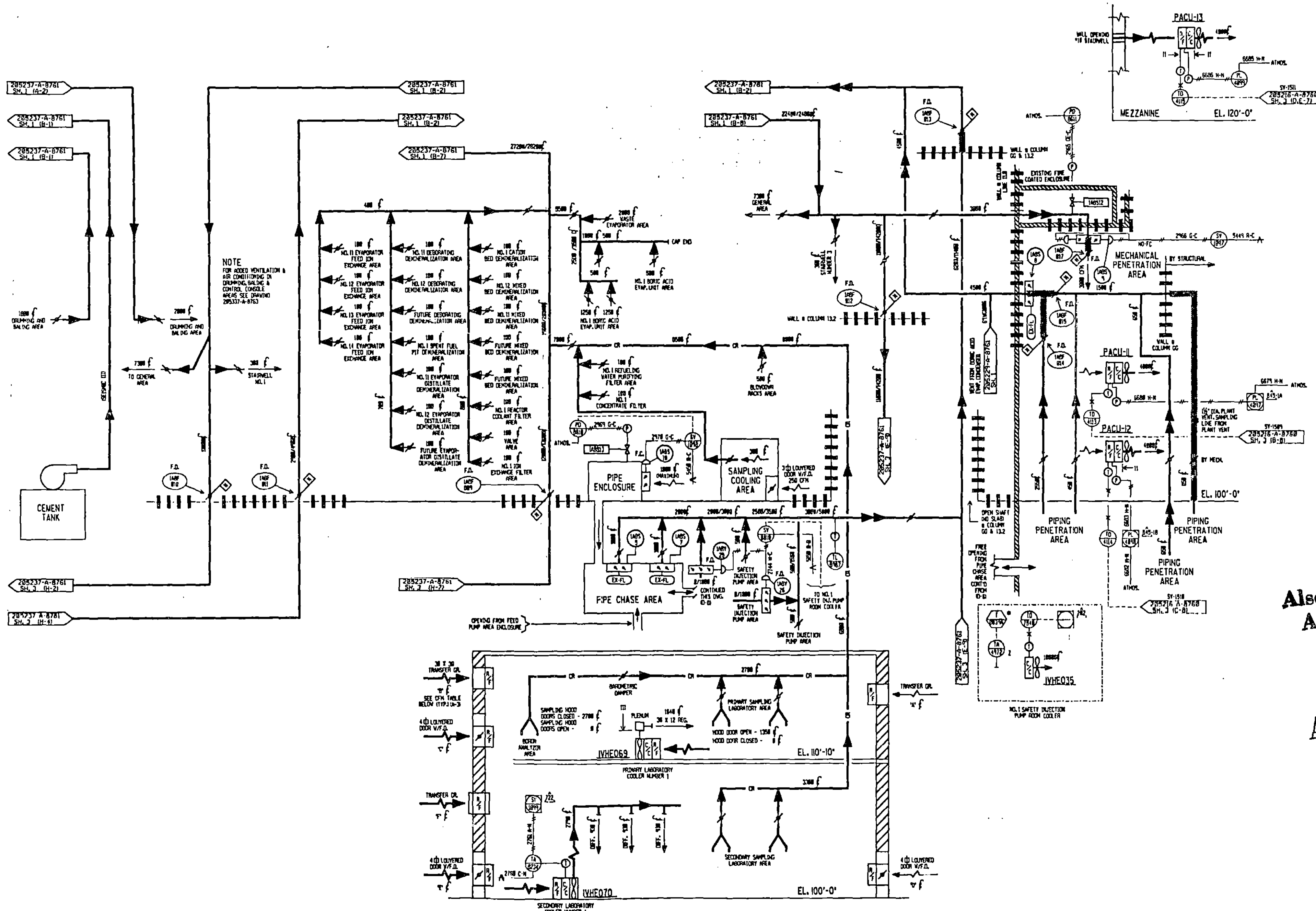
8507300447 -96

Revision 4
July 22, 1985
Ref. Dwg. 205237A8761-19

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Auxiliary Building Ventilation System Unit 1
	Updated FSAR Sheet 1 of 3 Fig 9.4-2A



ROOM SUPPLY	CFM
"A"	200 MAXIMUM
"B" + "C"	2500 MINIMUM
"D"	2000 MINIMUM
* "E" + "F"	[illegible]
* NOTE: "E" + "F" + 3300 - "D"; SET "D" AS HIGH AS POSSIBLE	

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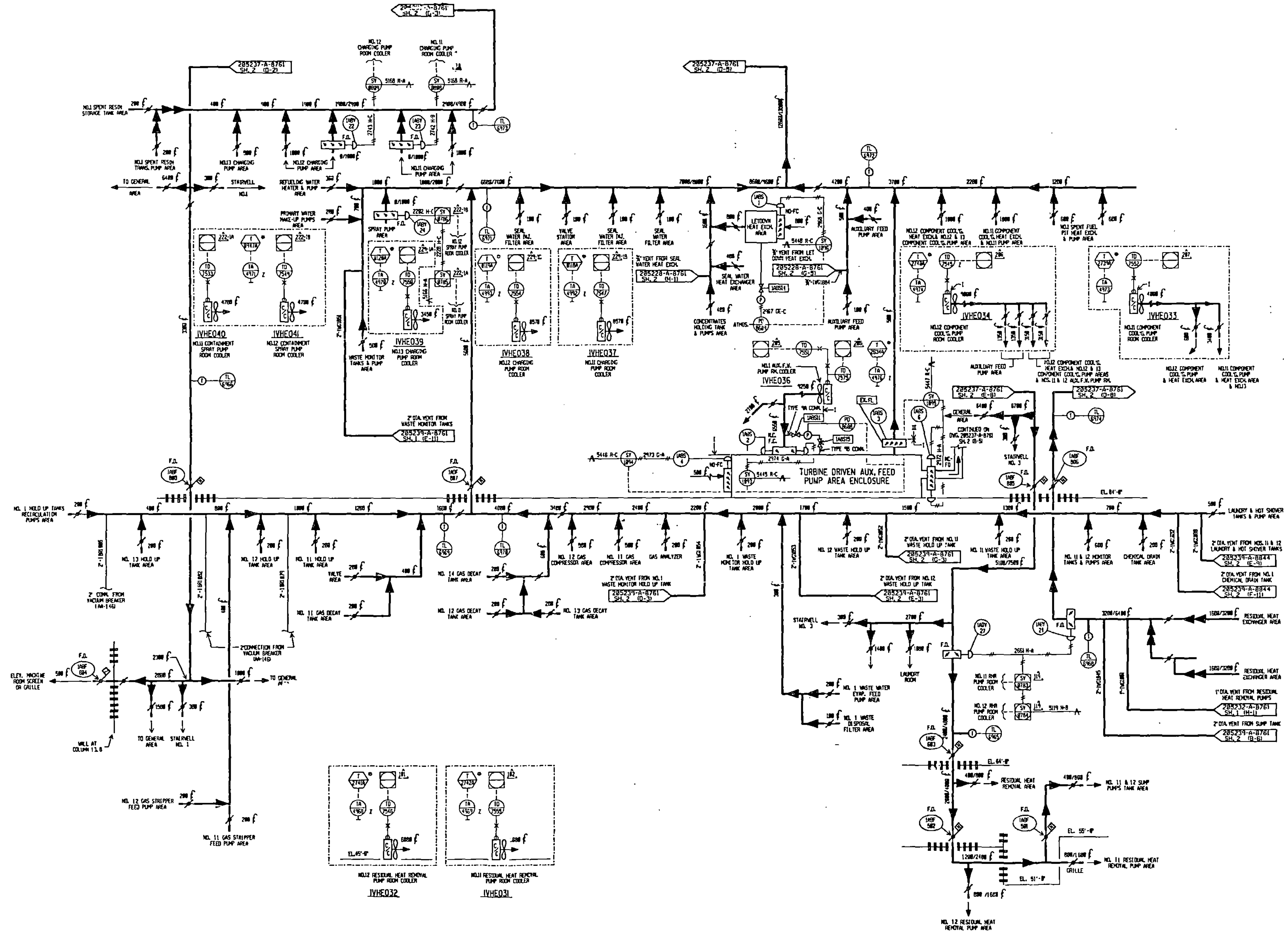
Revision 4
July 22, 1985
Ref. Dwg. 205237A8761-19

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Auxiliary Building Ventilation System Unit 1
	Updated FSAR Sheet 2 of 3 Fig 9.4-2A



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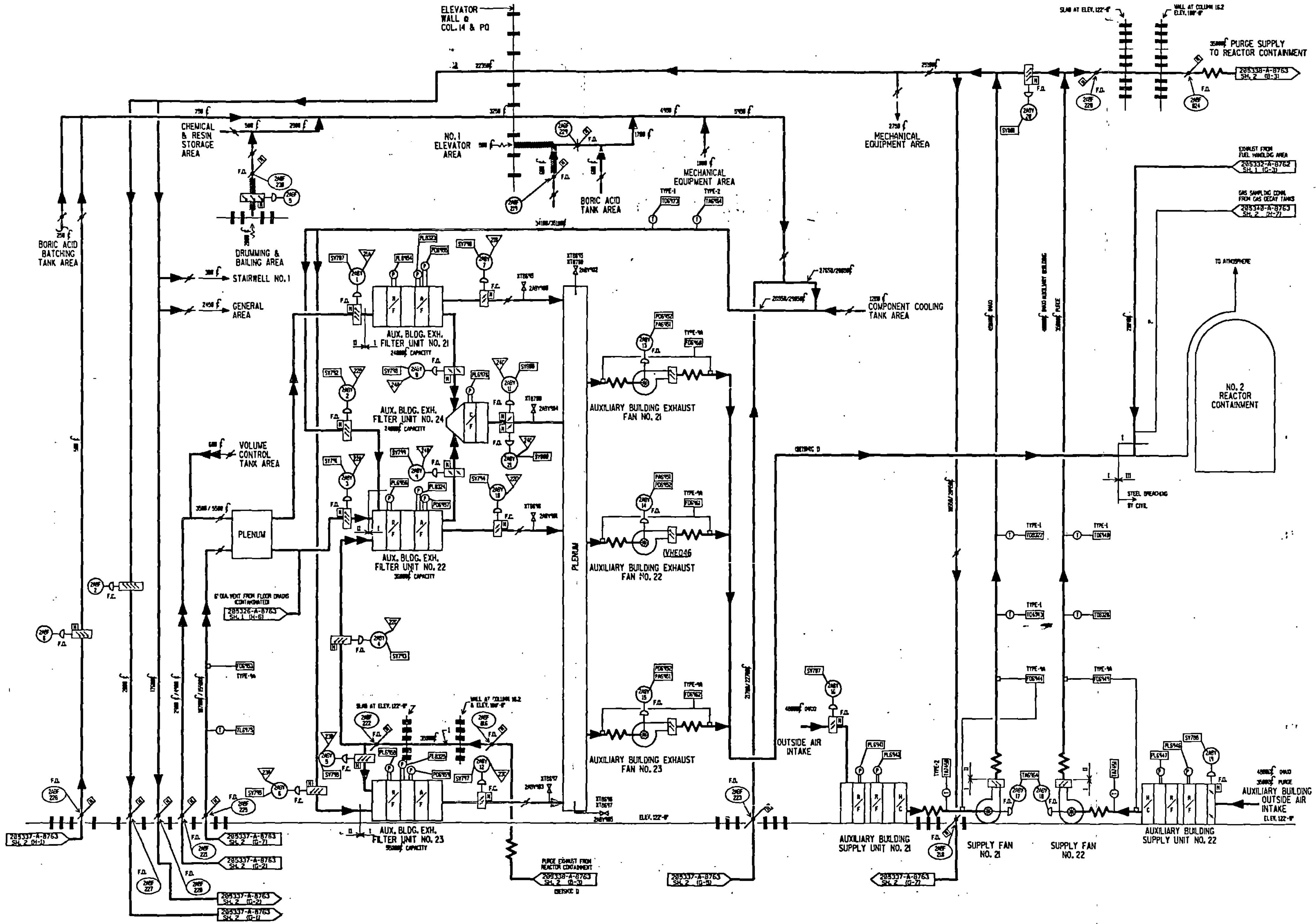
July 22, 1985
Ref. Dwg. 205237A8761-19

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Auxiliary Building Ventilation System Unit 1
	Updated FSAR Sheet 3 of 3 Fig 9.4-2A



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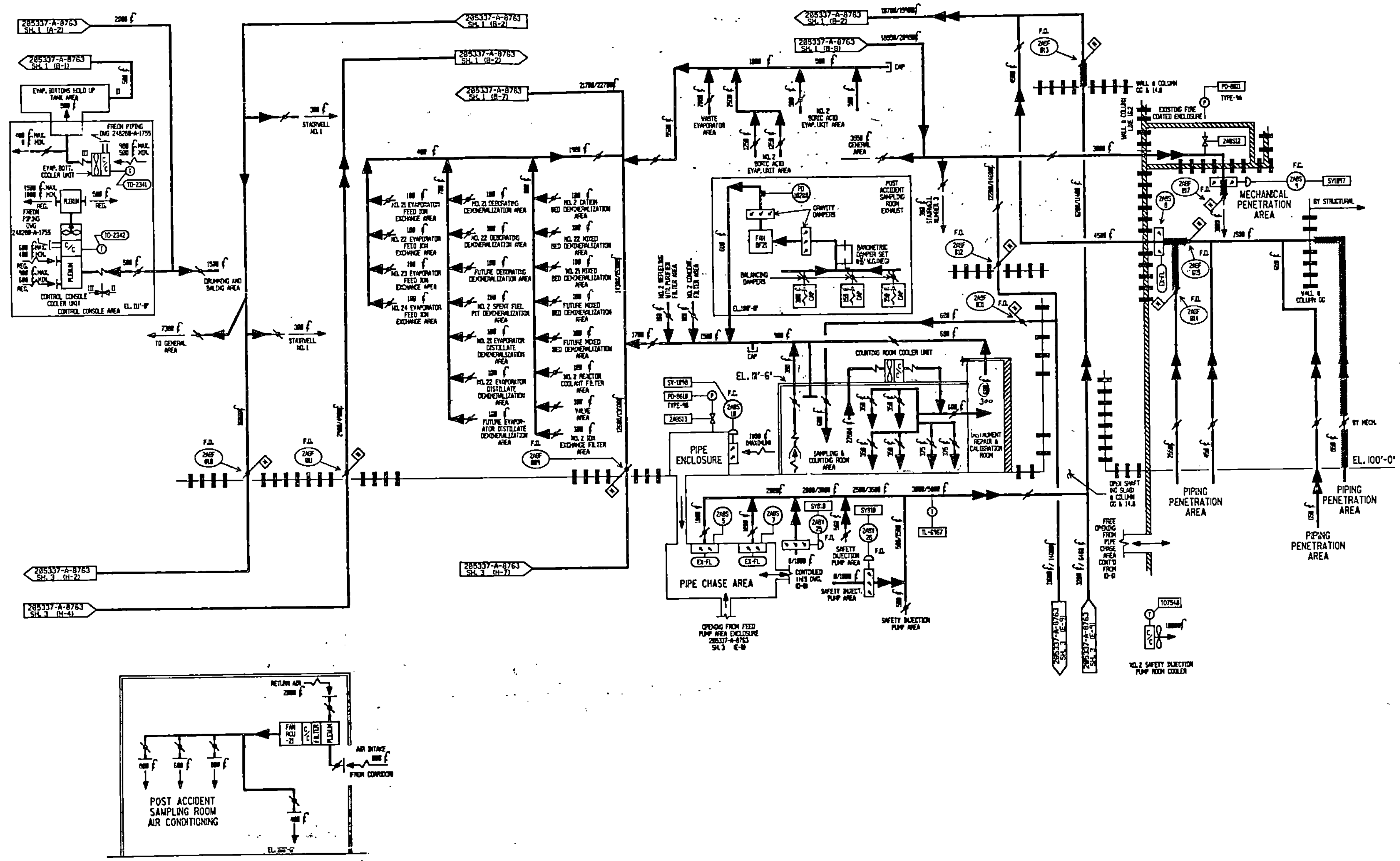
Revision 4
July 22, 1985
Ref. Dwg. 205337A8763-10

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Auxiliary Building Ventilation System Unit 2
	Updated FSAR Sheet 1 of 3 Fig 9.4-2B



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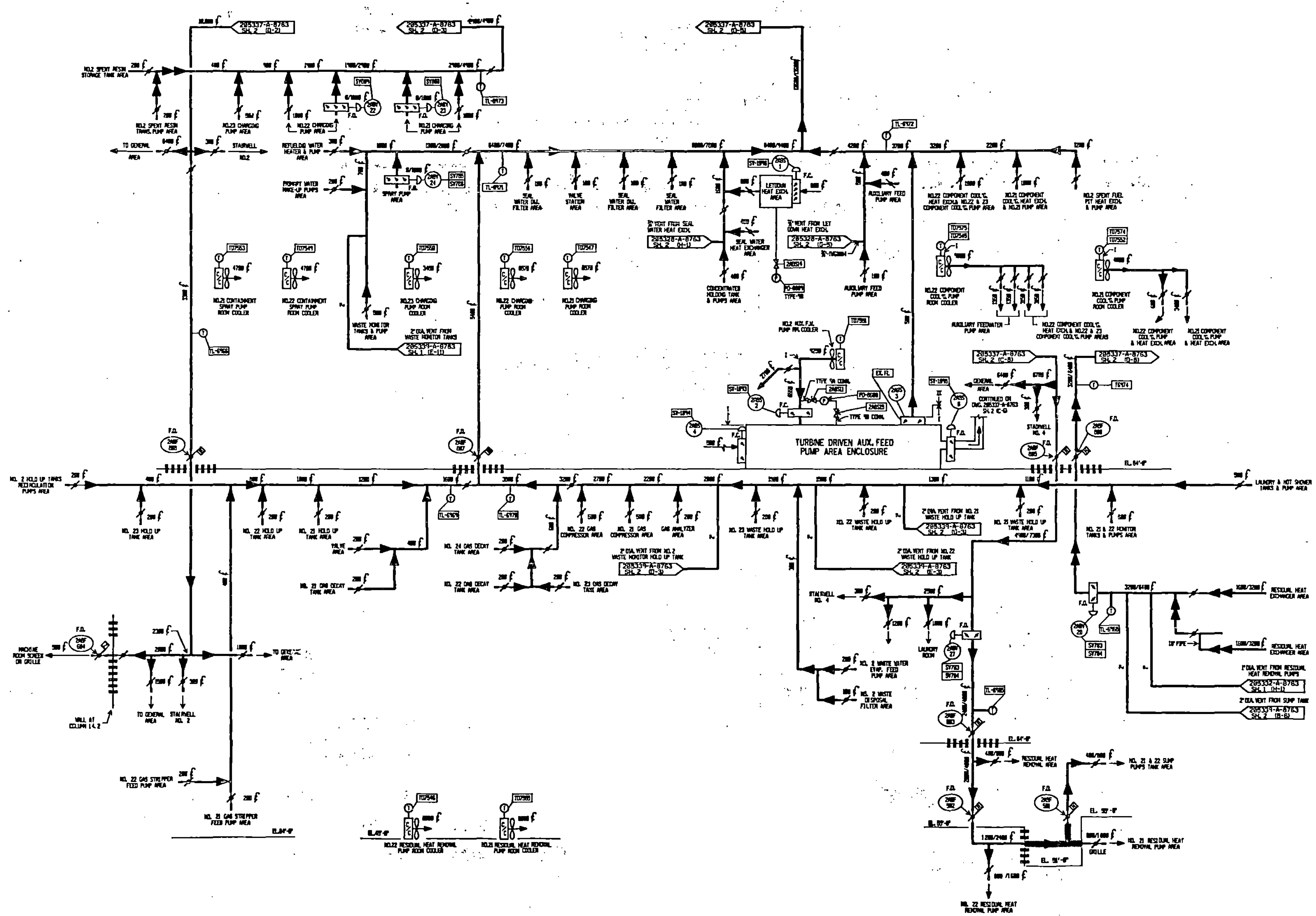
8507300447 -100

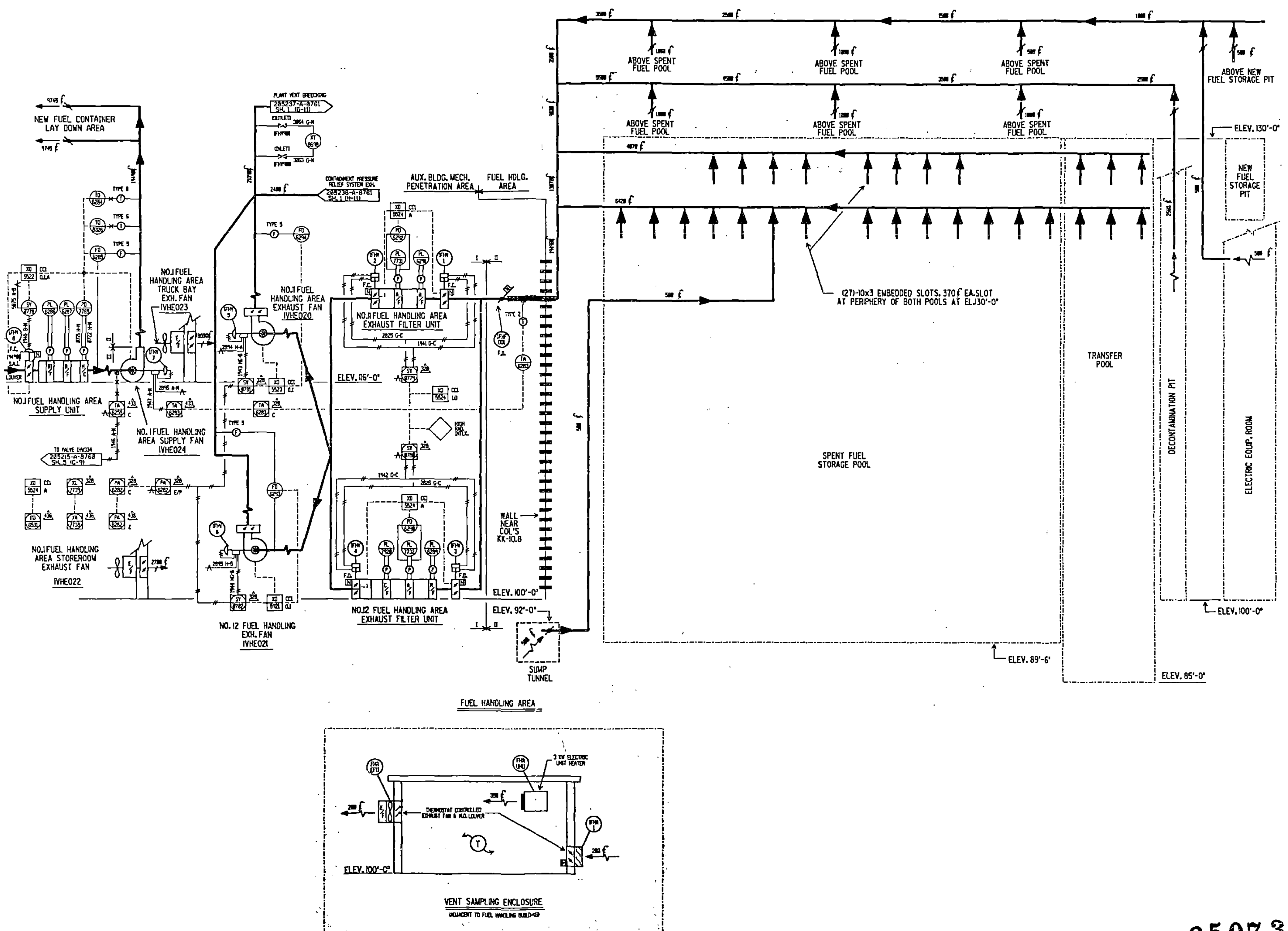
Revision 4
July 22, 1985
Ref. Dwg. 205337A8763-10

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Auxiliary Building Ventilation System Unit 2
	Updated FSAR Sheet 2 of 3 Fig 9.4-2B



Revision 4
July 22, 1985
Ref. Dwg. 205337A8763-10

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Auxiliary Building Ventilation System Unit 2
	Updated FSAR Sheet 3 of 3 Fig 9.4-2B



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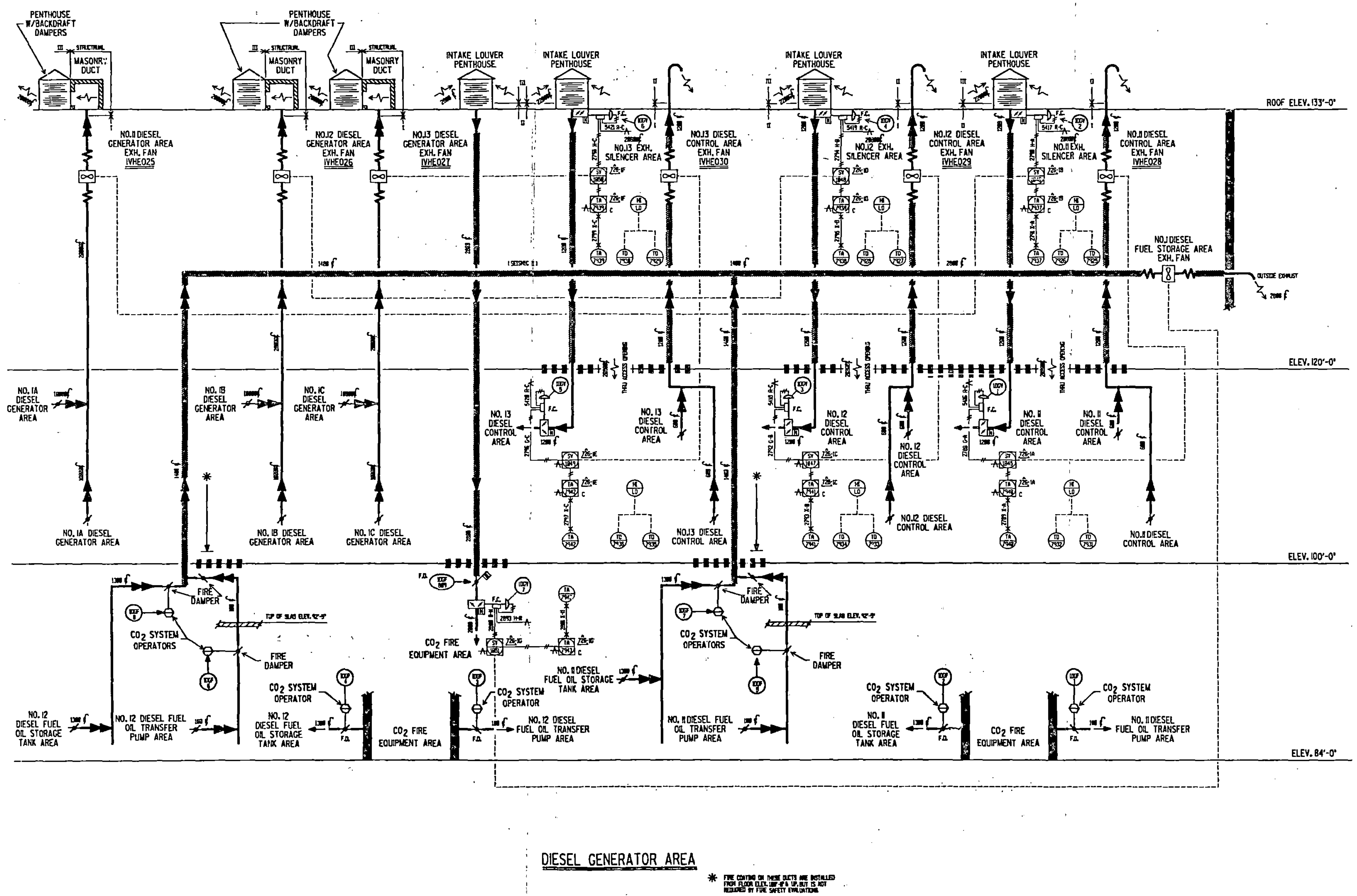
Revision 4
July 22, 1985
Ref. Dwg. 205321A8762-11

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Fuel Handling Area Ventilation System Unit 1
	Updated FSAR Sheet 1 of 2 Fig 9.4-3A



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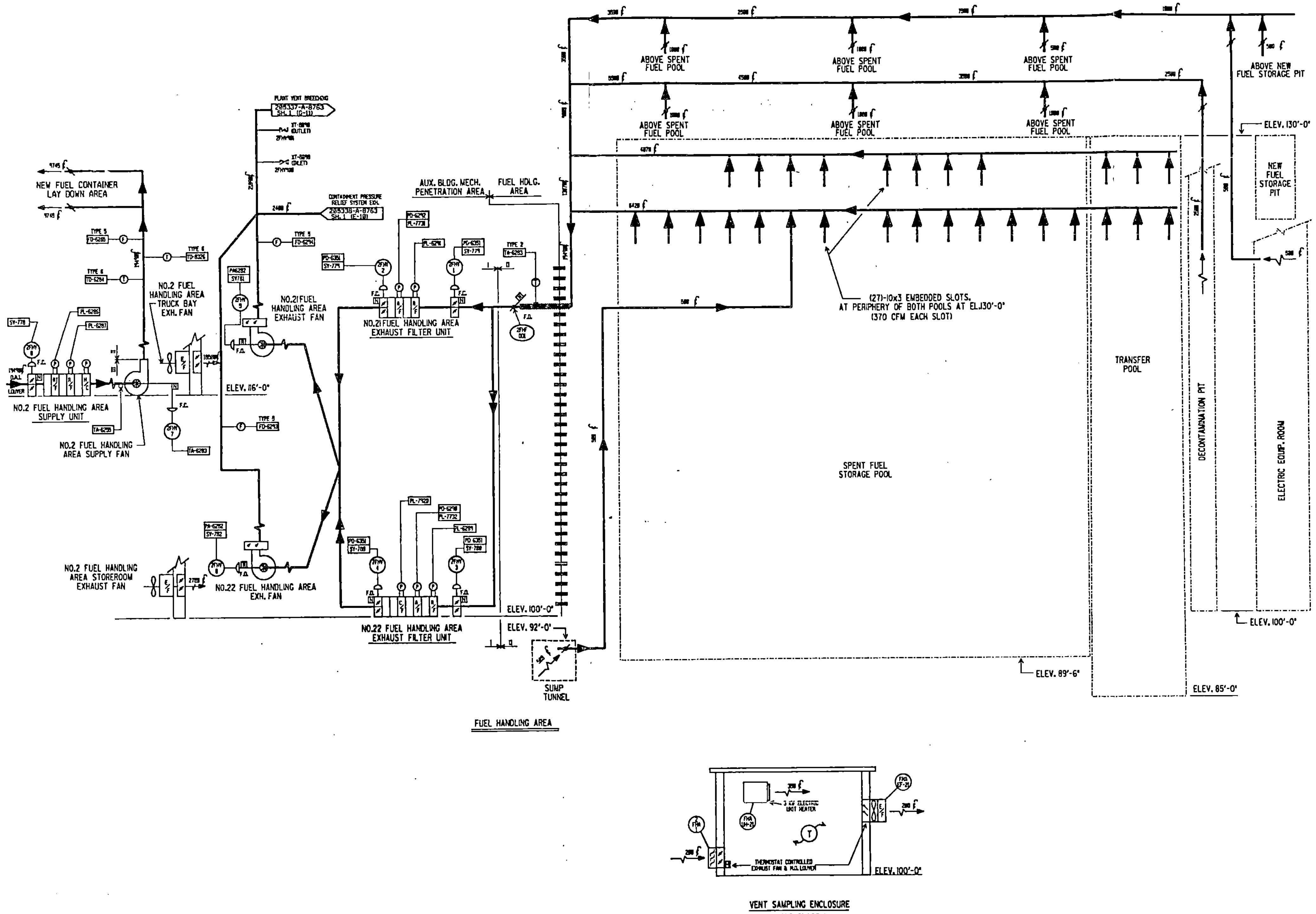
8507300447 -103

Revision 4
July 22, 1985
Ref. Dwg. 205321A8762-11

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Fuel Handling Area Ventilation System Unit 1
	Updated FSAR Sheet 2 of 2 Fig 9.4-8A



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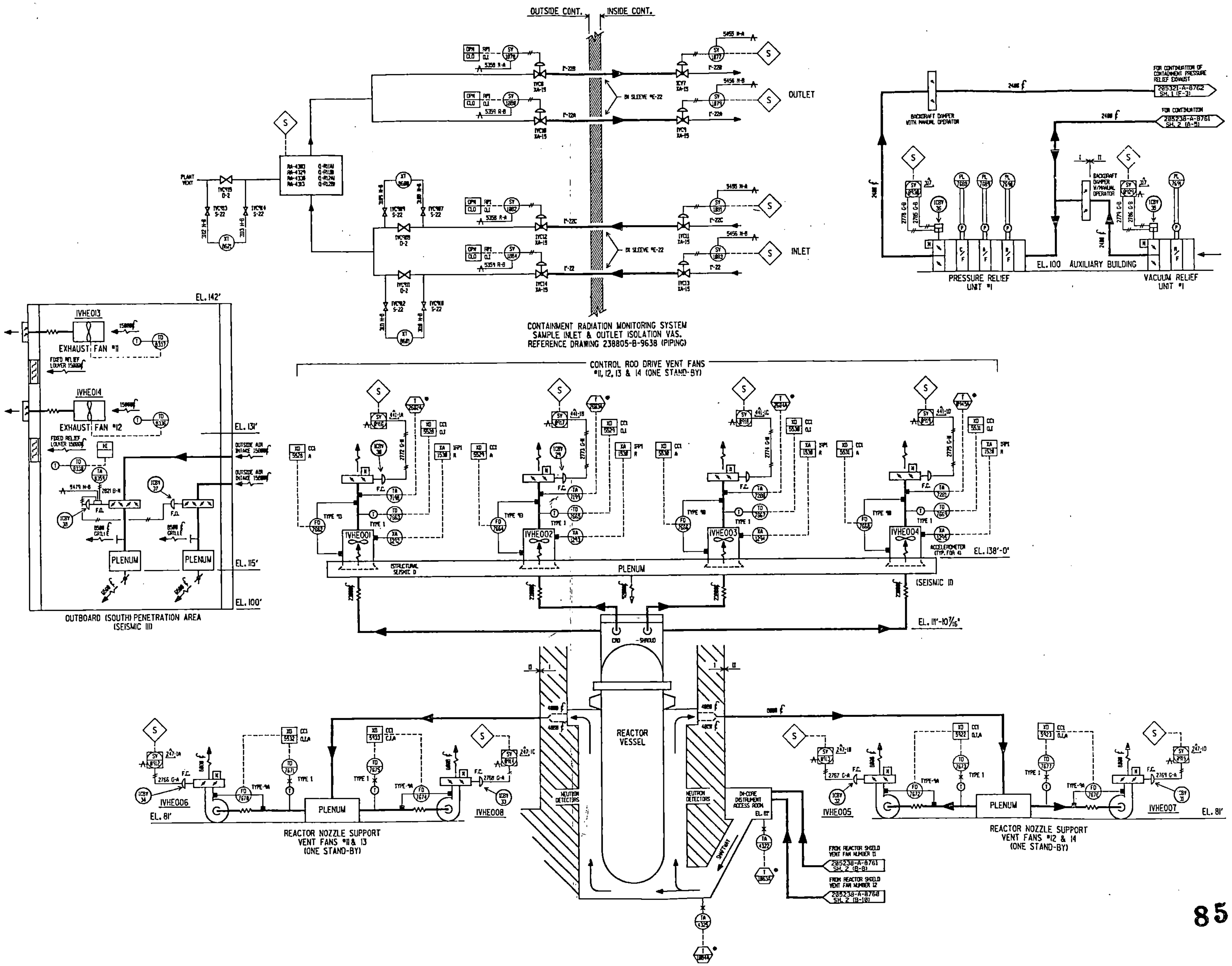
8507300447 -104

Revision 4
July 22, 1985
Ref. Dwg. 205322A8762-10

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Fuel Handling Area Ventilation System Unit 2
	Updated FSAR — Fig 9.4-3B



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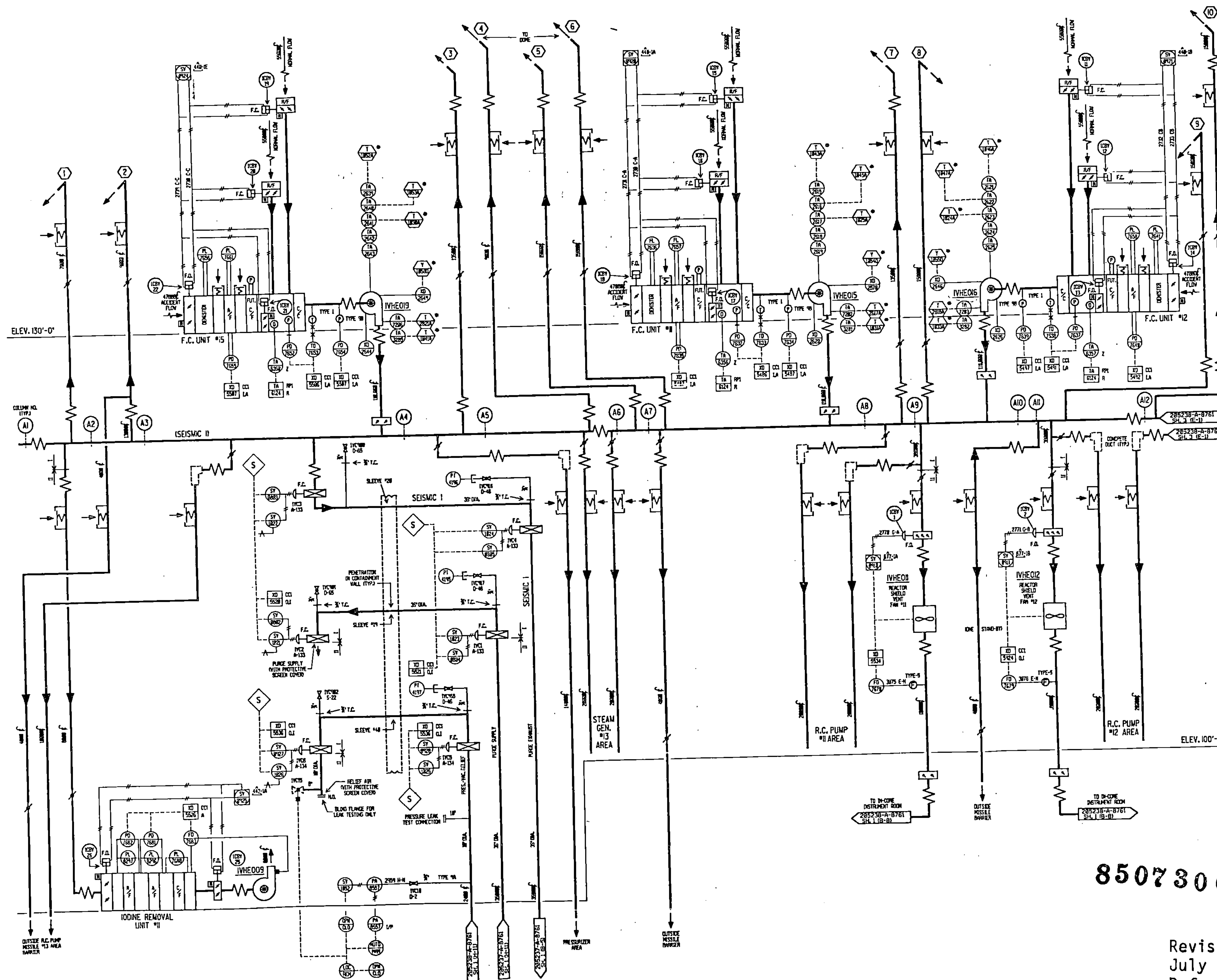
Revision 4
July 22, 1985
Ref. Dwg. 205238A8761-18

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Ventilation System Unit 1
	Updated FSAR Sheet 1 of 3 Fig 9.4-4A



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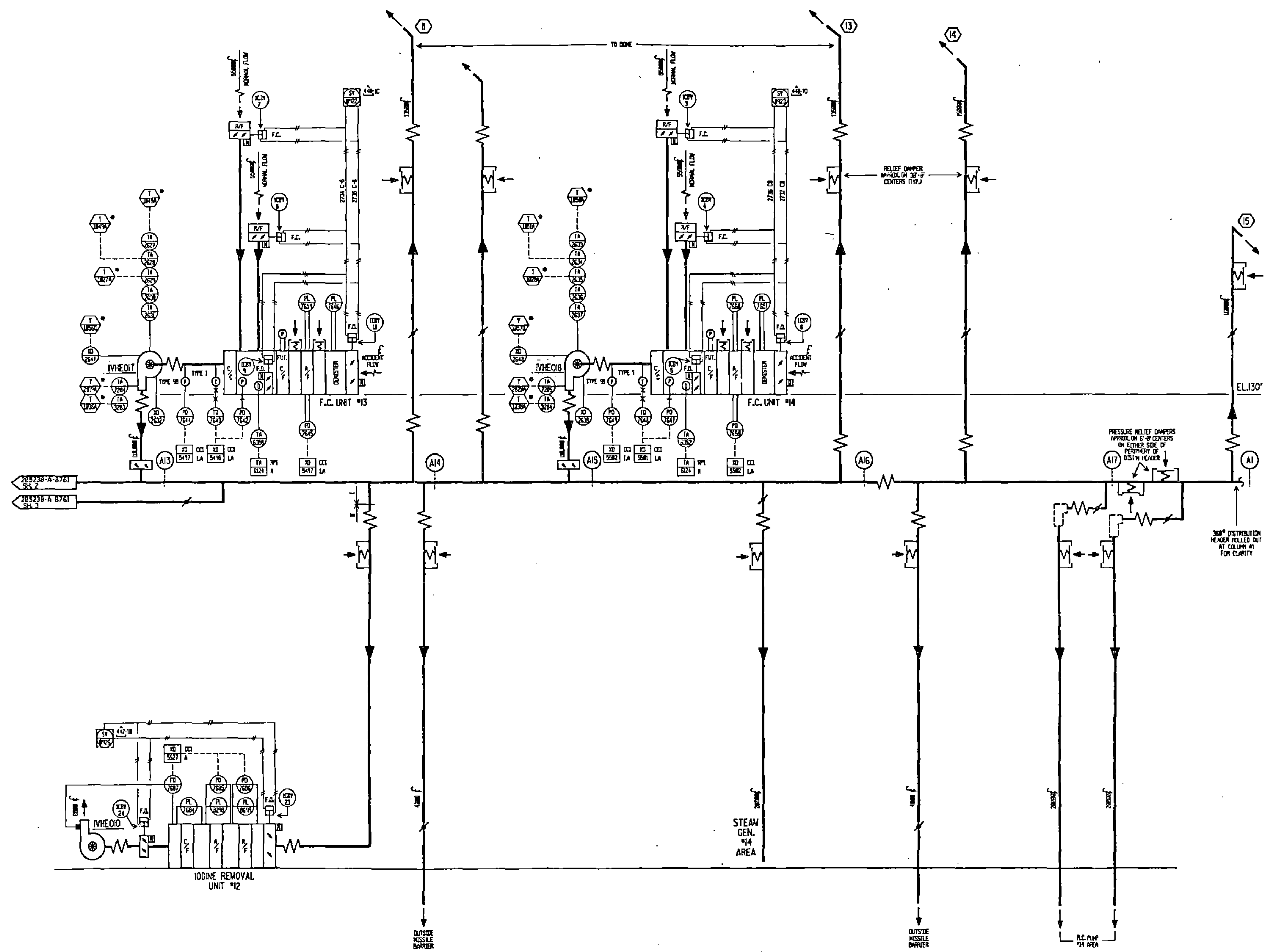
8507300447-106

Revision 4
July 22, 1985
Ref. Dwg. 205238A8761-18

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Ventilation System Unit 1
	Updated FSAR Sheet 2 of 3 Fig 9.4-4A



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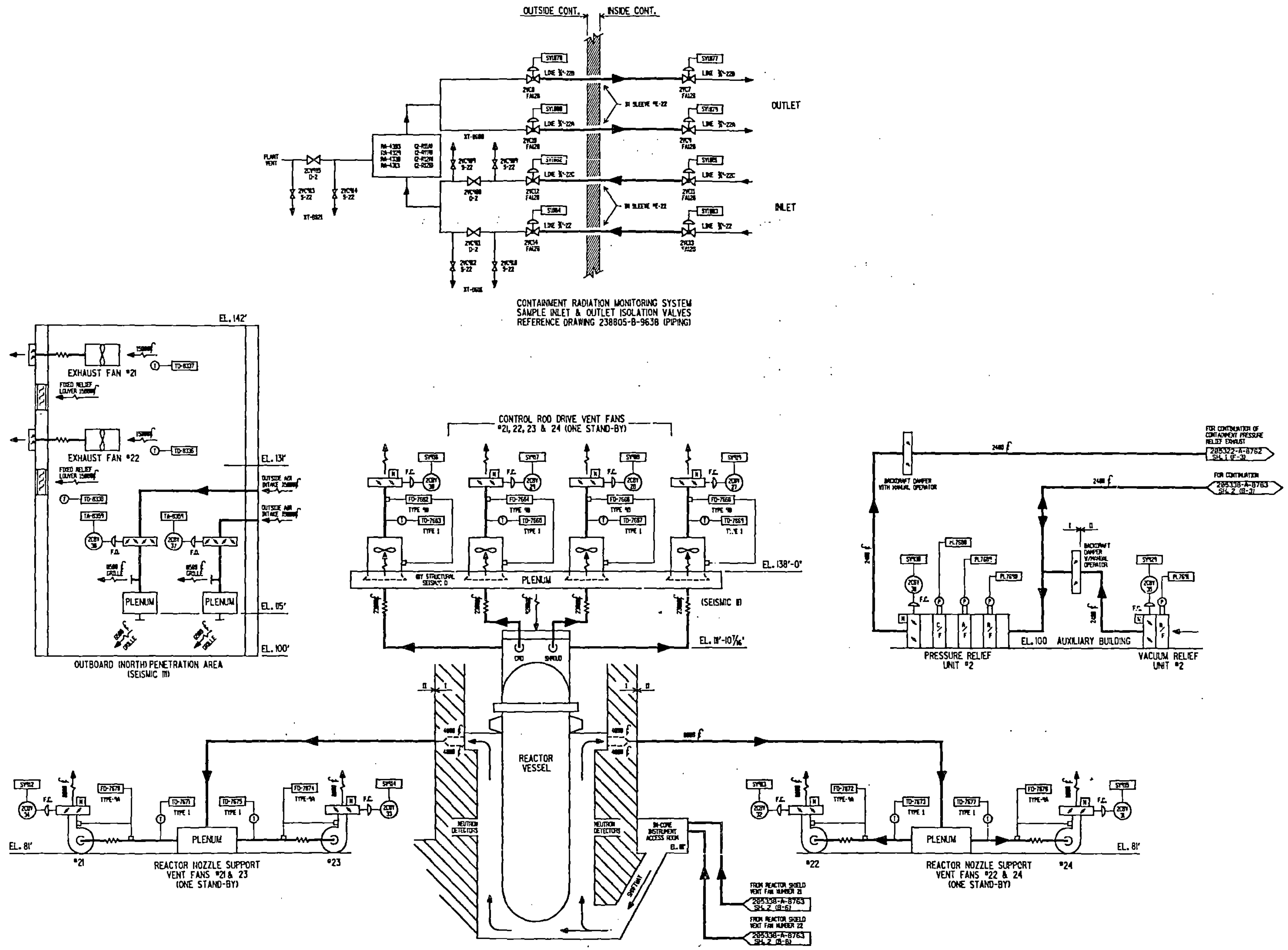
Revision 4
July 22, 1985
Ref. Dwg. 205238A8761-18

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Ventilation System Unit 1
	Updated FSAR Sheet 3 of 3 Fig 9.4-4A



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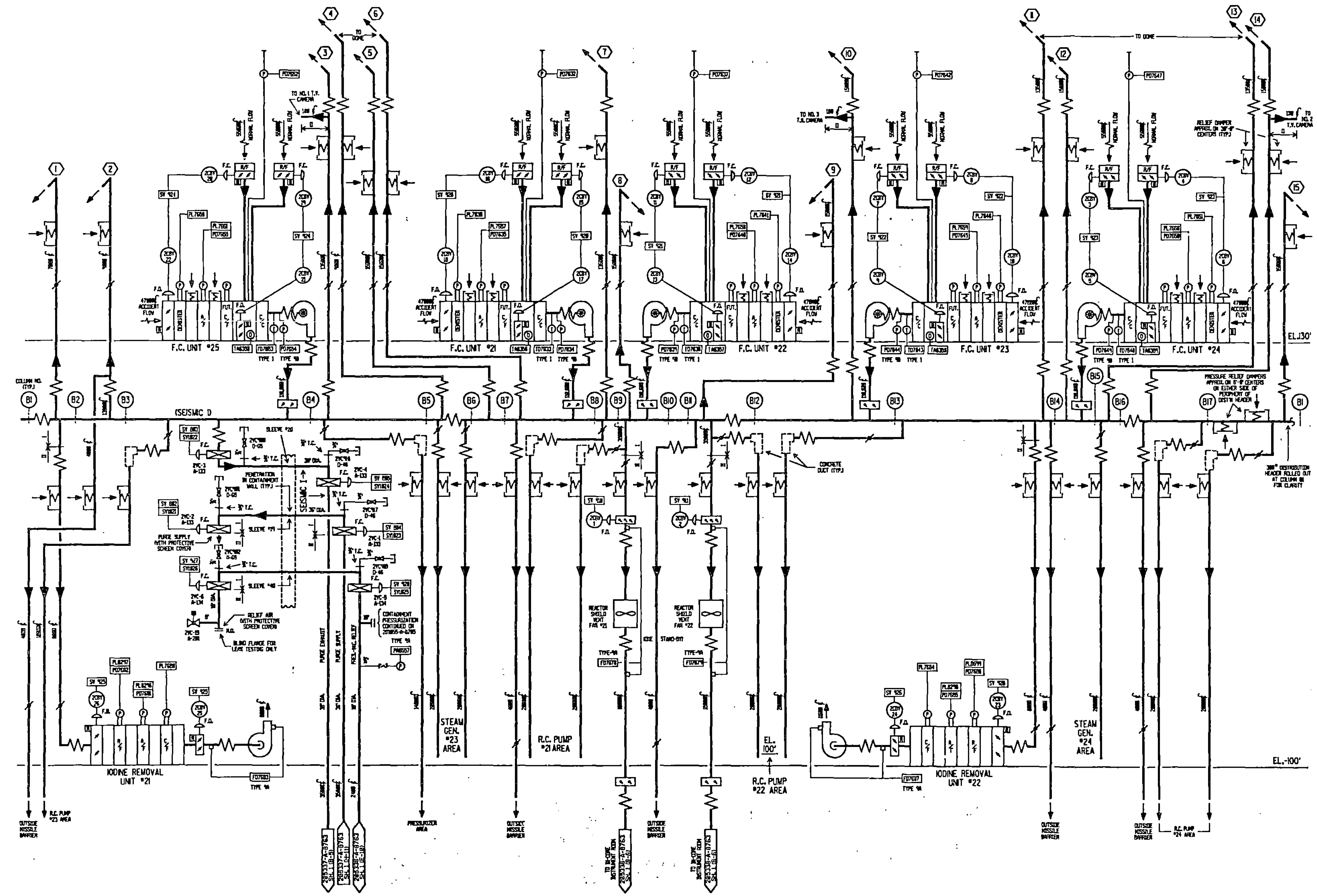
8507300447-108

Revision 4
July 22, 1985
Ref. Dwg. 205338A8763-14

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Ventilation System Unit 2
	Updated FSAR Sheet 1 of 2 Fig 9.4-4B



Also Available On Aperture Card

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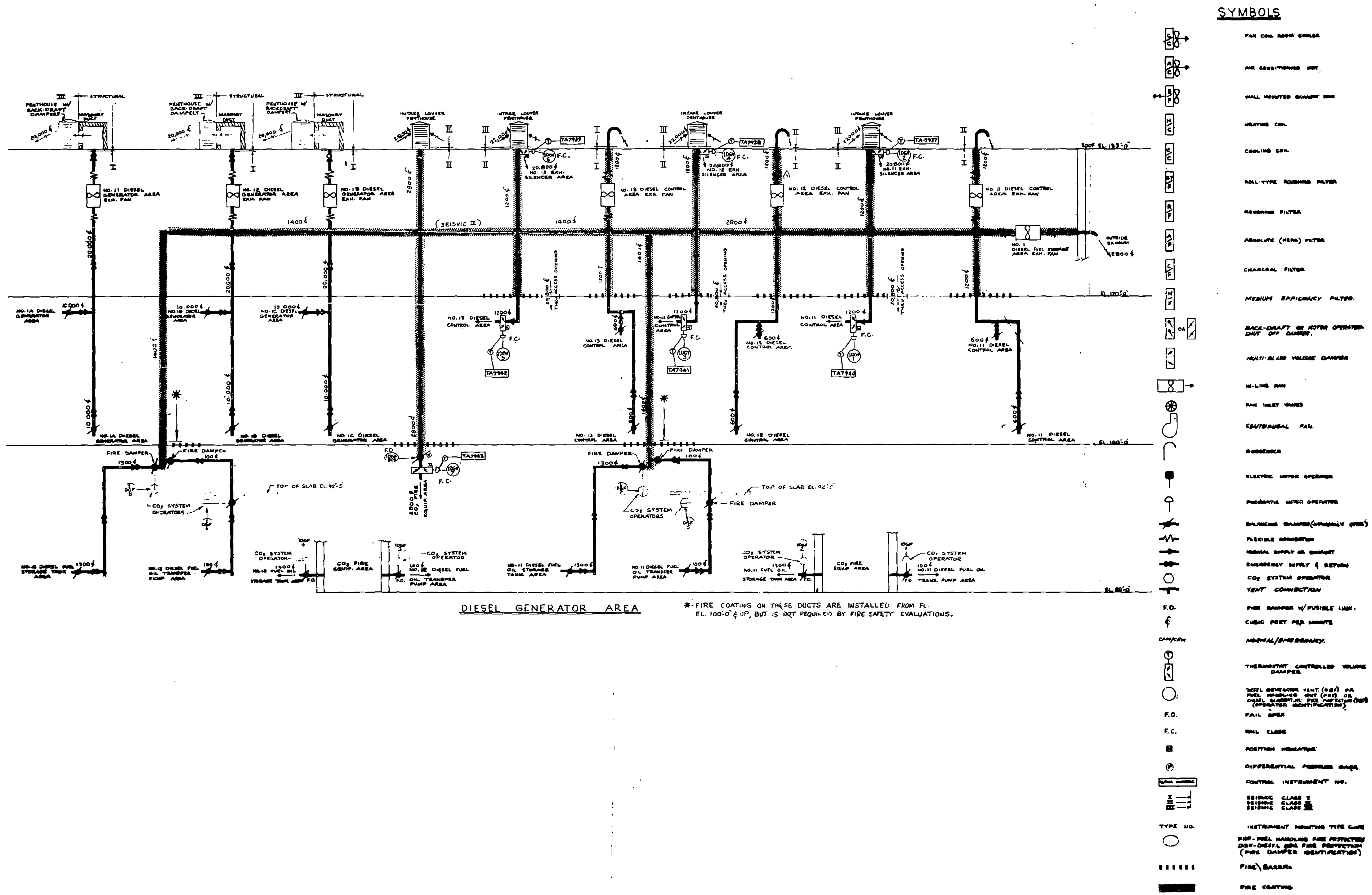
8507300447 -109

Revision 4
July 22, 1985
Ref. Dwg. 205338A8763-14

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Ventilation System Unit 2
	Updated FSAR Sheet 2 of 2 Fig 9.4-4B



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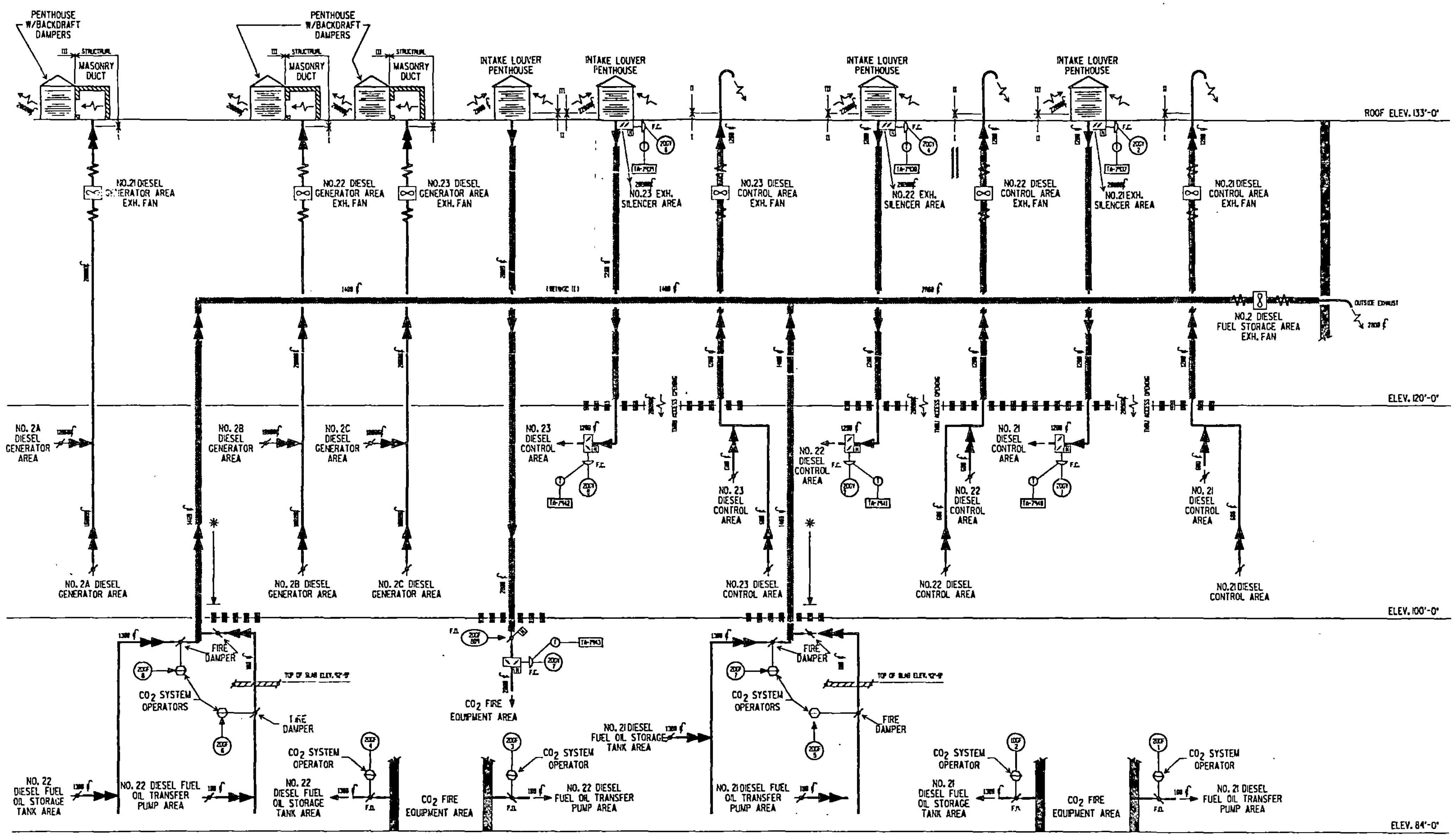
Revision 4
July 22, 1985
Ref. Dwg. 205321A8762-8

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Diesel Generator Rooms Ventilation System Unit 1
	Updated FSAR — Fig 9.4-5A



DIESEL GENERATOR AREA

Also Available On Aperture Card

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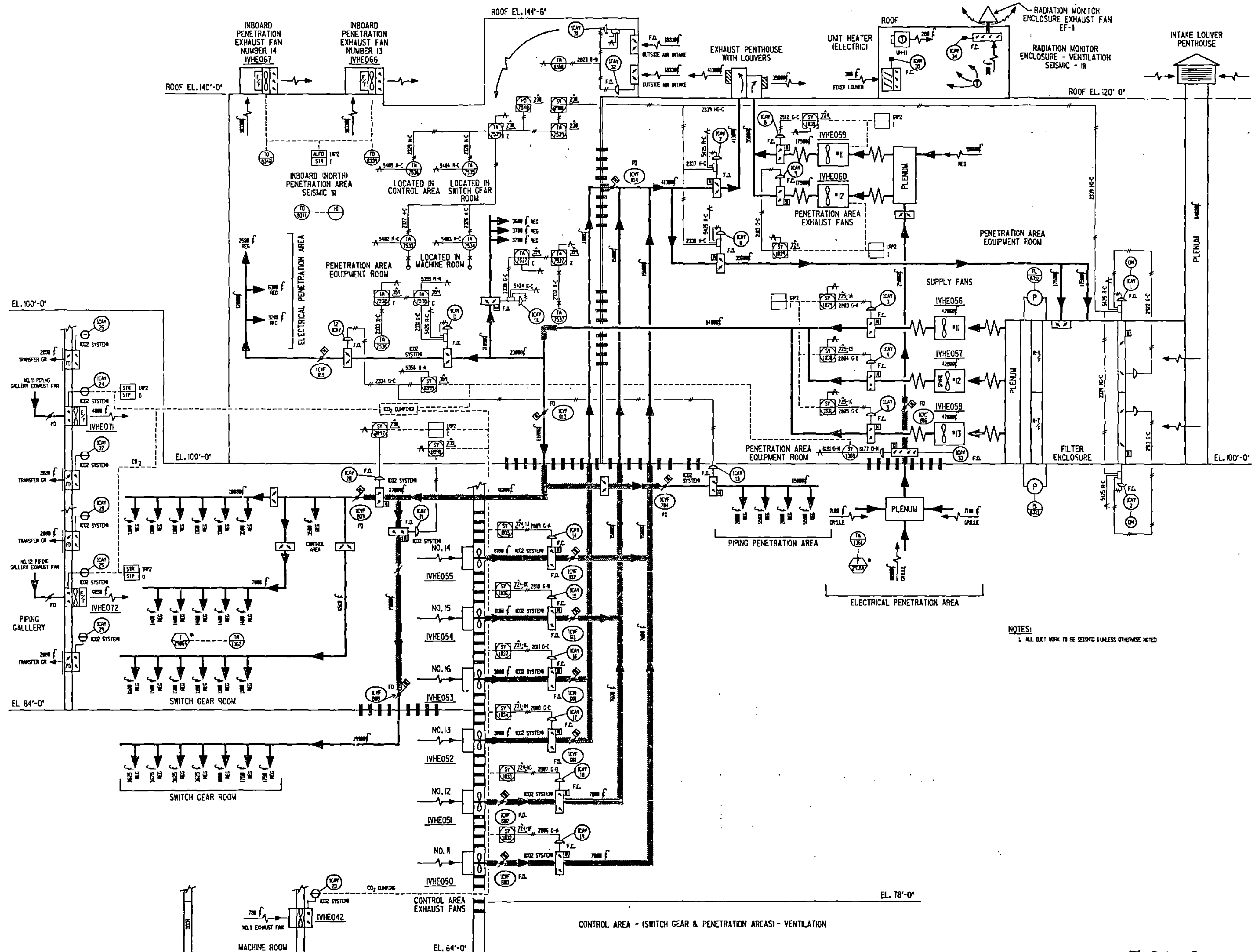
8507300447 -111

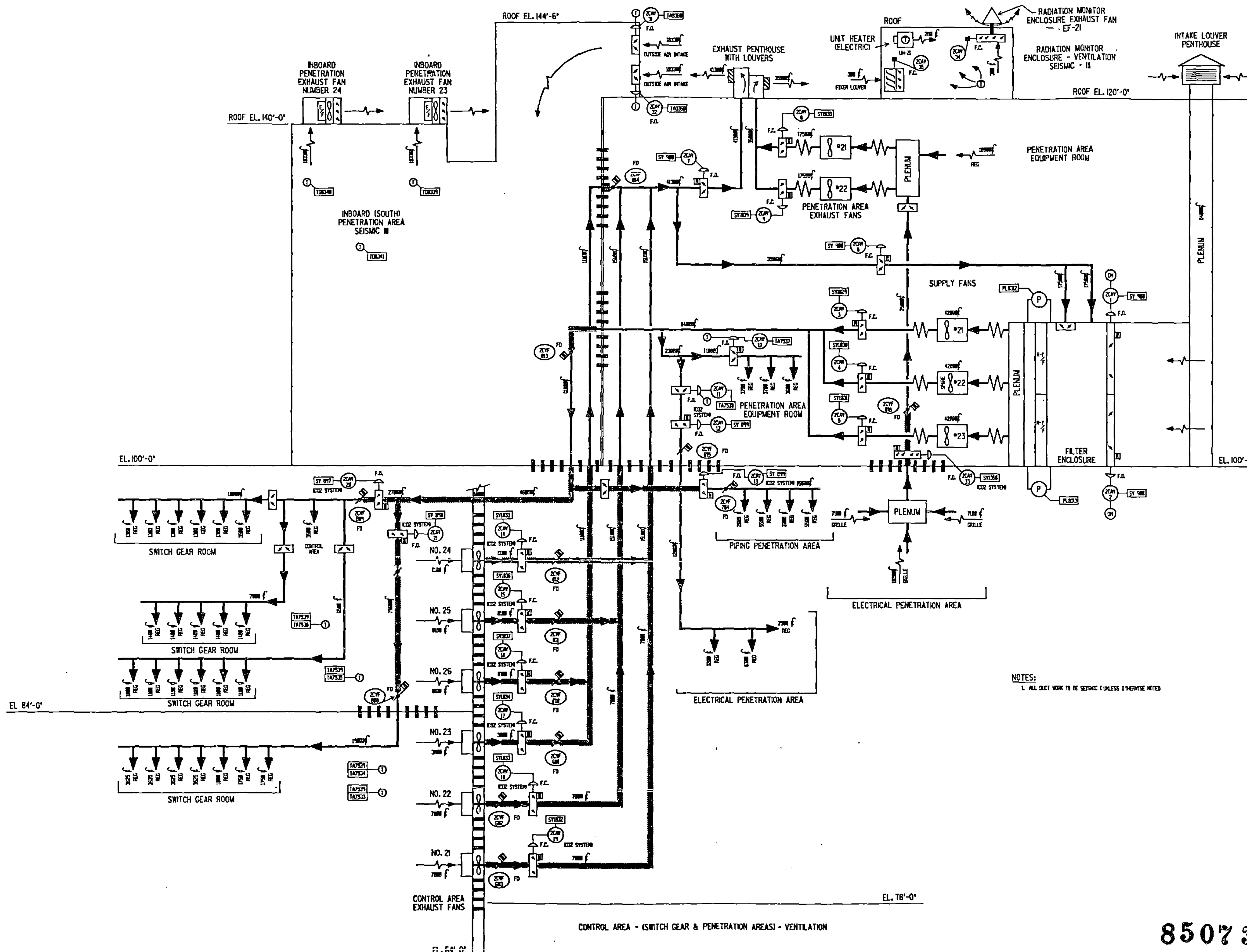
Revision 4
July 22, 1985
Ref. Dwg. 205322A8762-10

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Diesel Generator Rooms Ventilation System Unit 2
	Updated FSAR Fig 9.4-5B



Revision 4
July 22, 1985
Ref. Dwg. 205248A8761-13

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Switchgear and Penetration Areas Ventilation - Unit 1
	Updated FSAR Fig 9.4-6A



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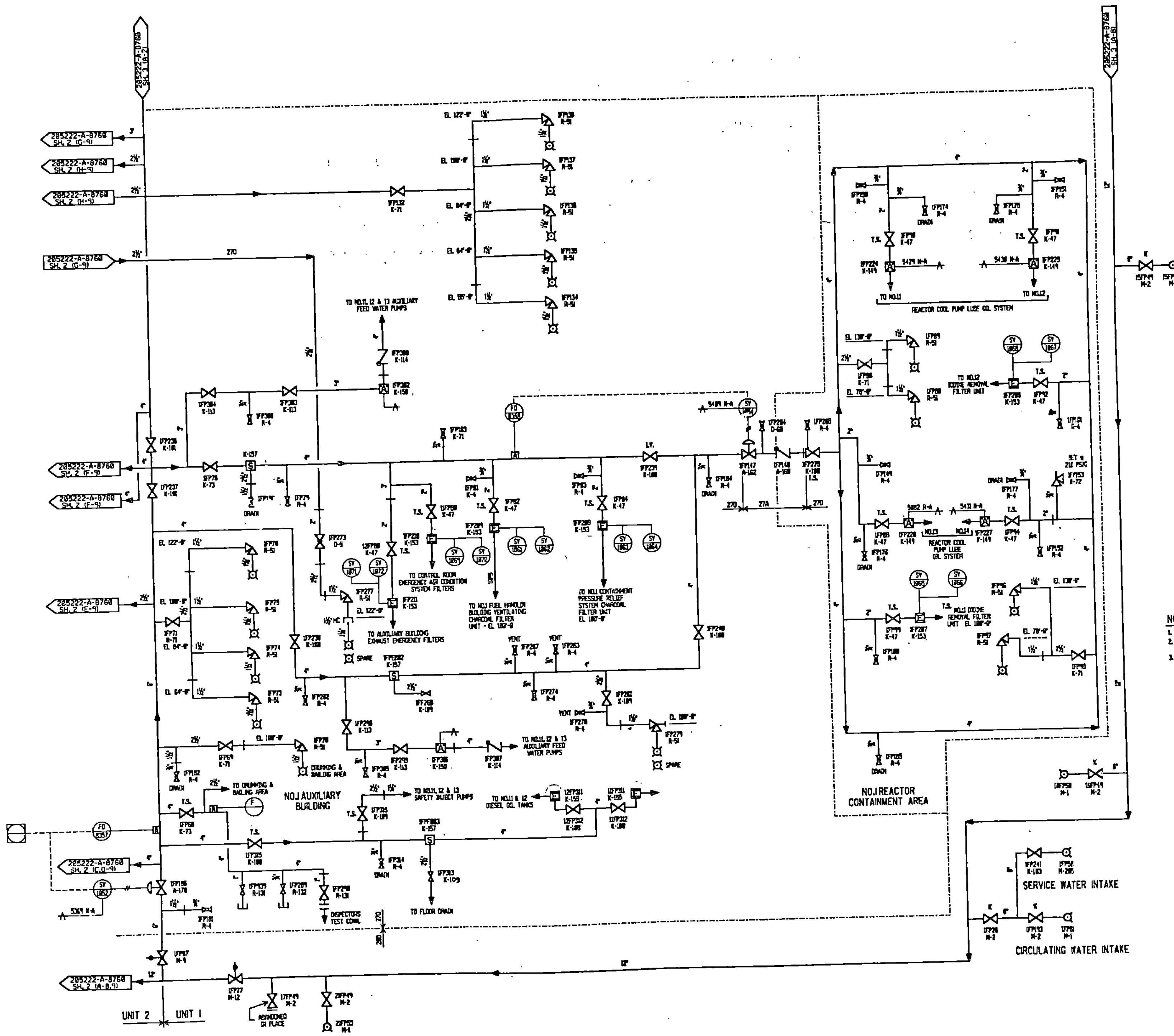
8507300447-113

Revision 4
July 22, 1985
Ref. Dwg. 205348A8763-14

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Switchgear and Penetration Areas Ventilation - Unit 2
	Updated FSAR — Fig 9.4-6B

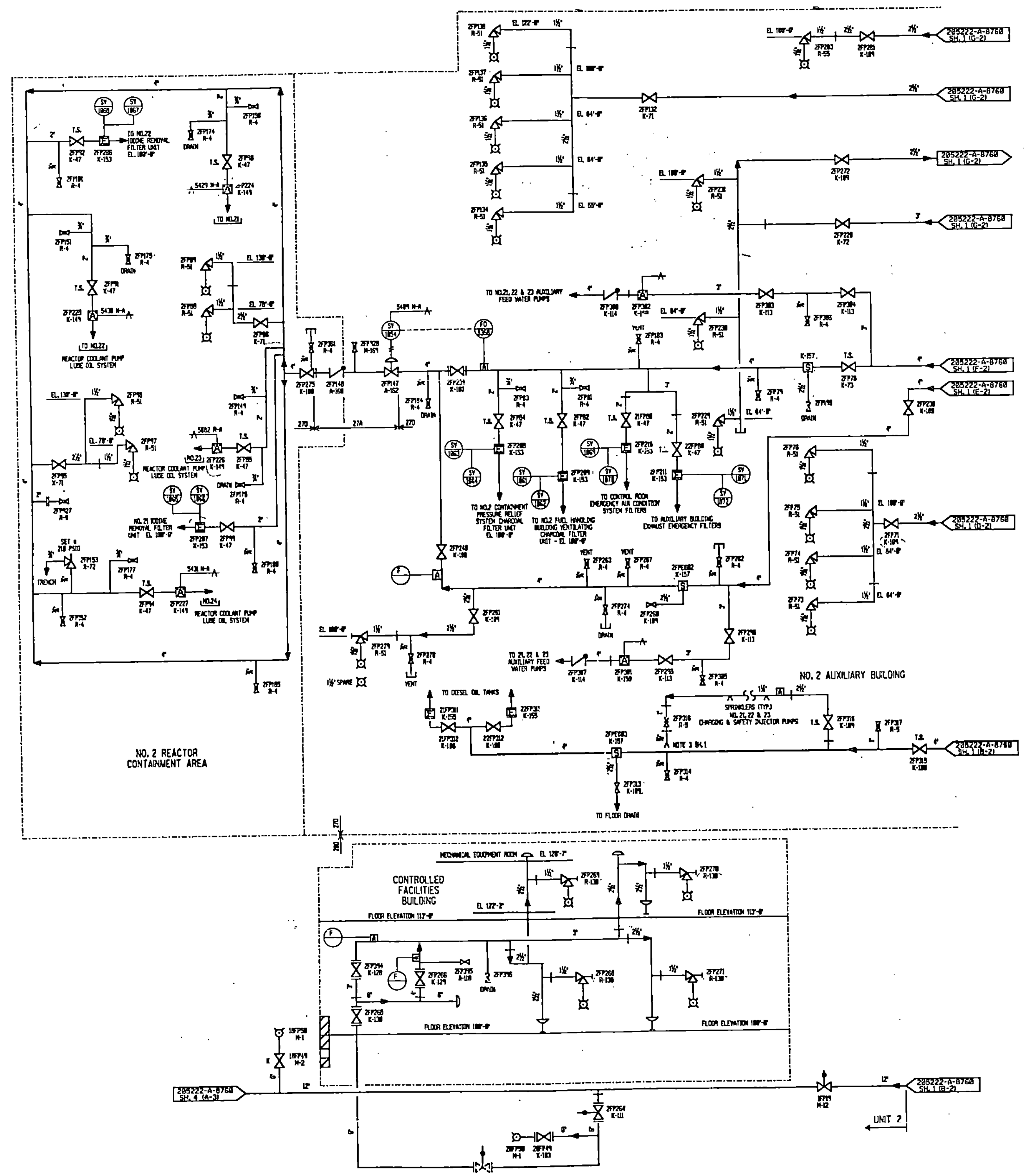


NOTES:

8507300447 -114

Revision 4
July 22, 1985
Ref. Dwg. 205222A8760-27

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Fire Protection System
	Updated FSAR Sheet 1 of 4 Fig 9.5-1



Also Available On
Aperture Card

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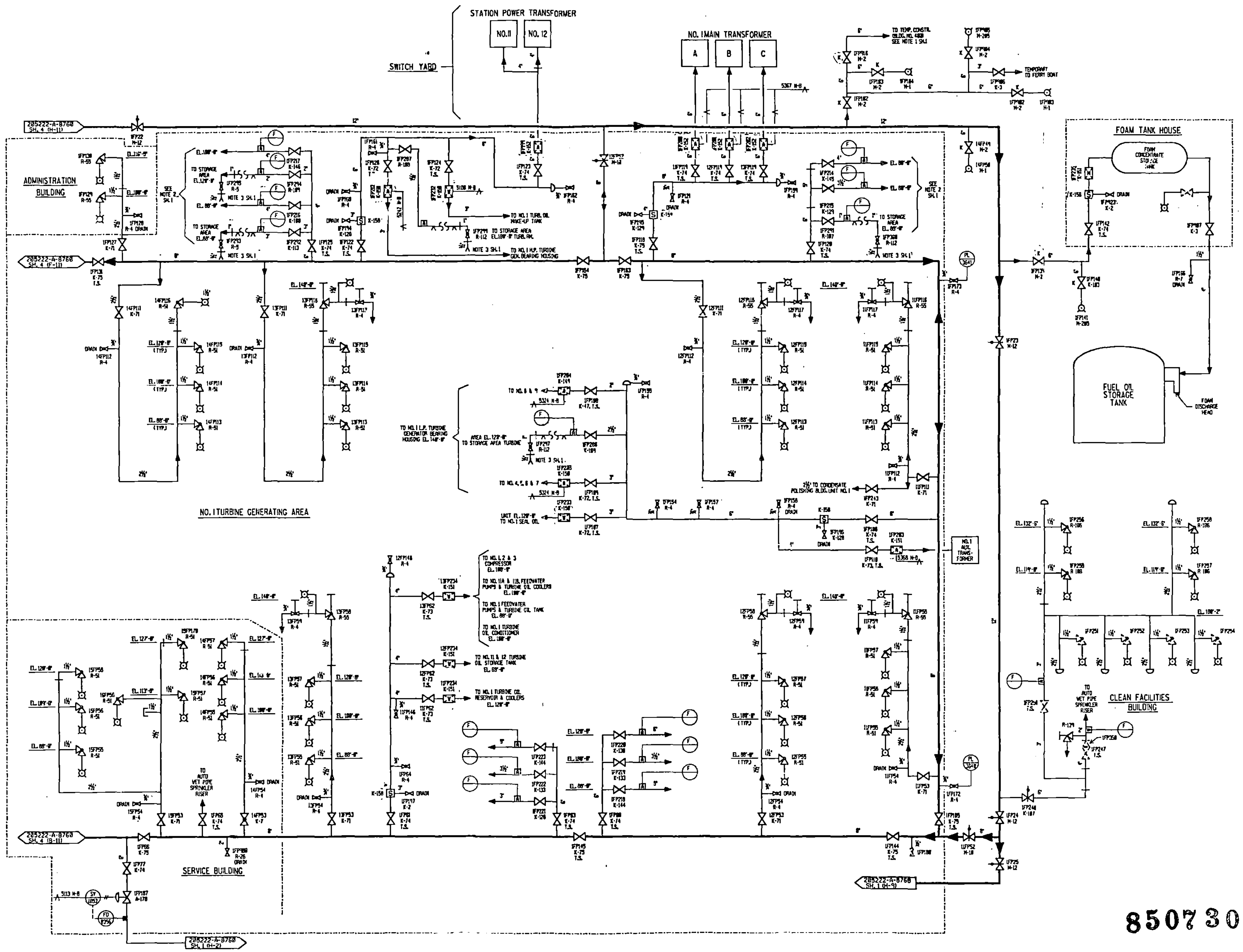
Revision 4
July 22, 1985
Ref. Dwg. 205222A8760-27

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Fire Protection System
	Updated FSAR Sheet 2 of 4 Fig 9.5-1



Also Available On Aperture Card

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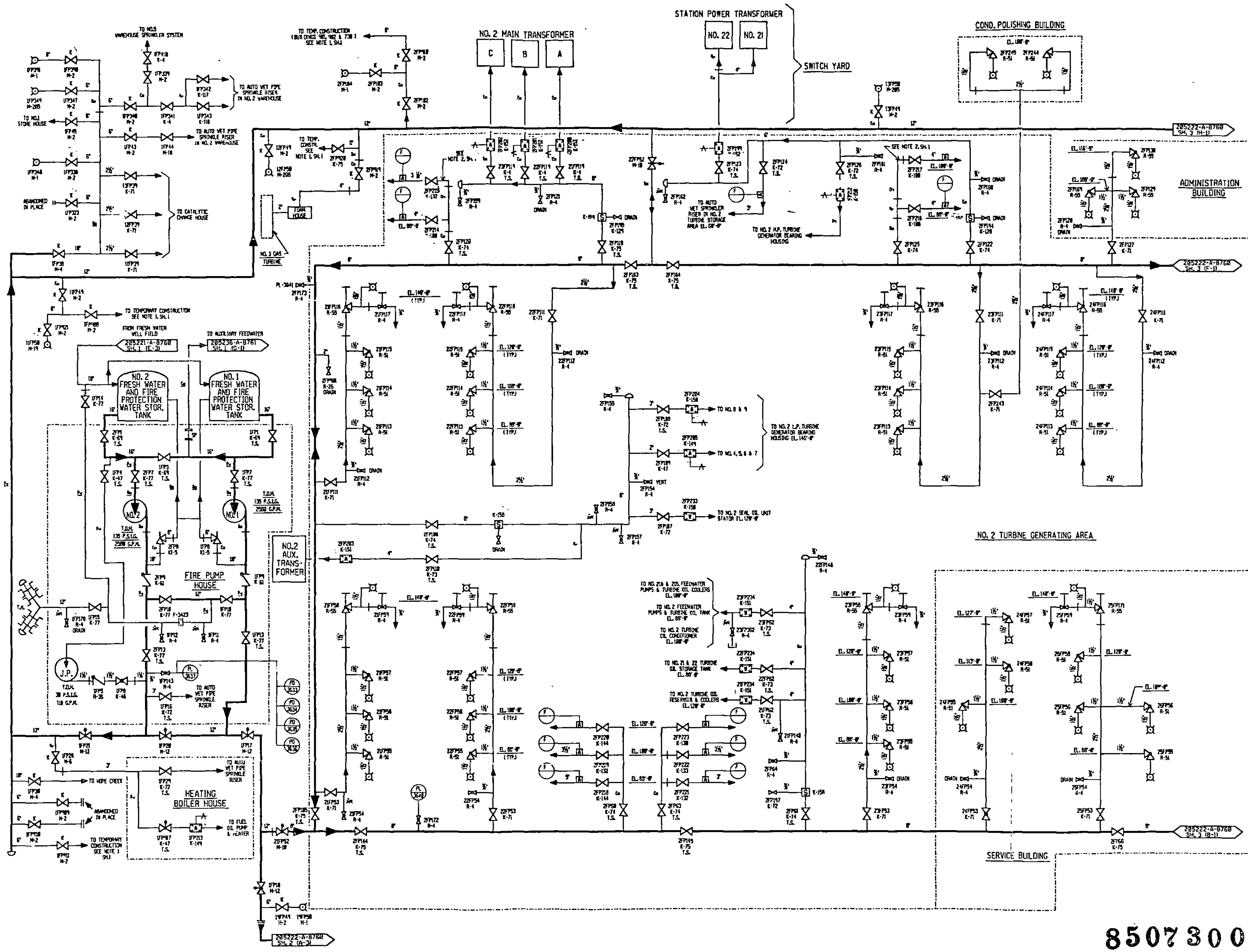
8507300447 -116

Revision 4
July 22, 1985
Ref. Dwg. 205222A8760-27

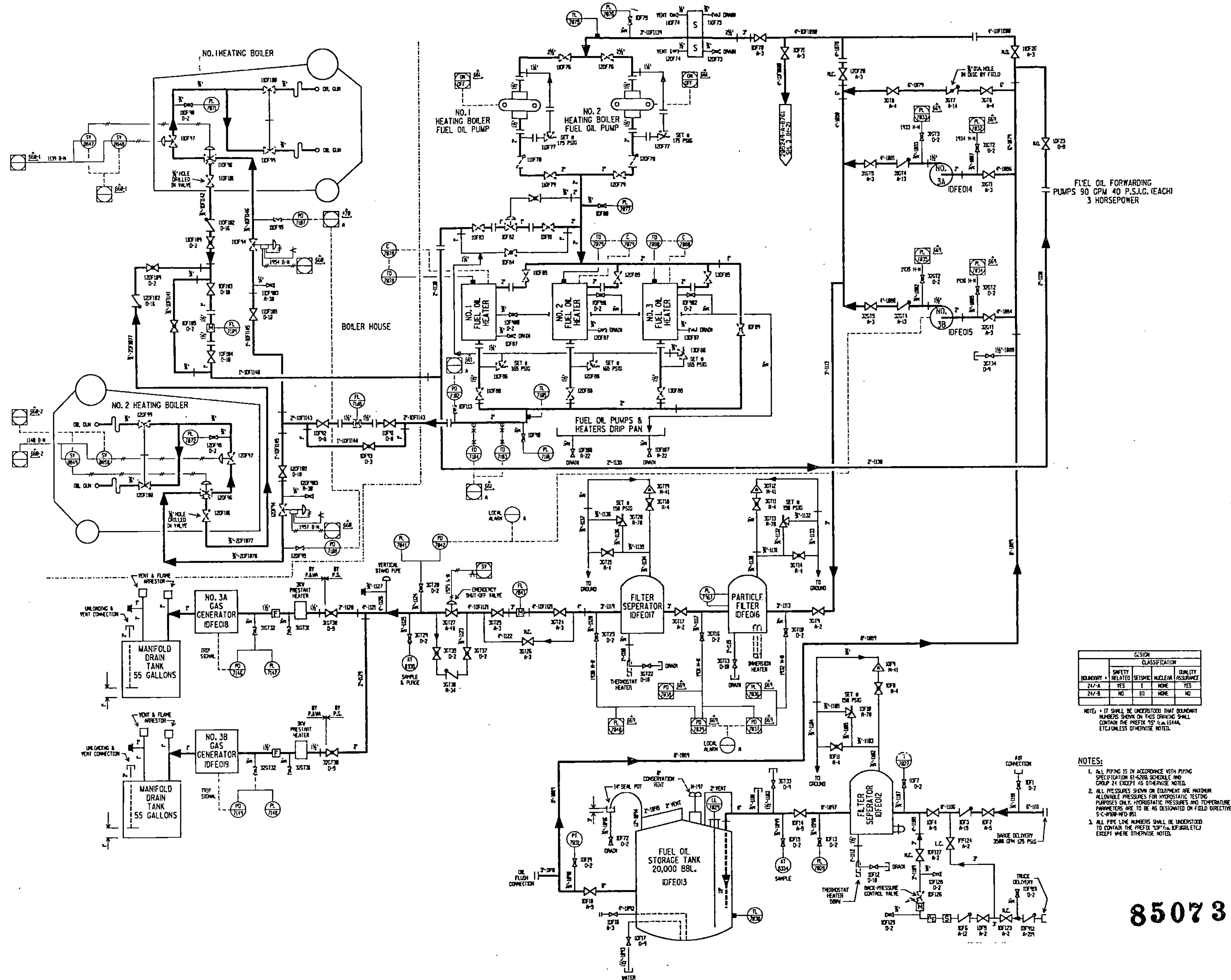
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Fire Protection System
	Updated FSAR Sheet 3 of 4 Fig 9.5-1



8507300447 -117

Revision 4
July 22, 1985
Ref. Dwg. 205222A8760-27

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Fire Protection System
	Updated FSAR Sheet 4 of 4 Fig 9.5-1



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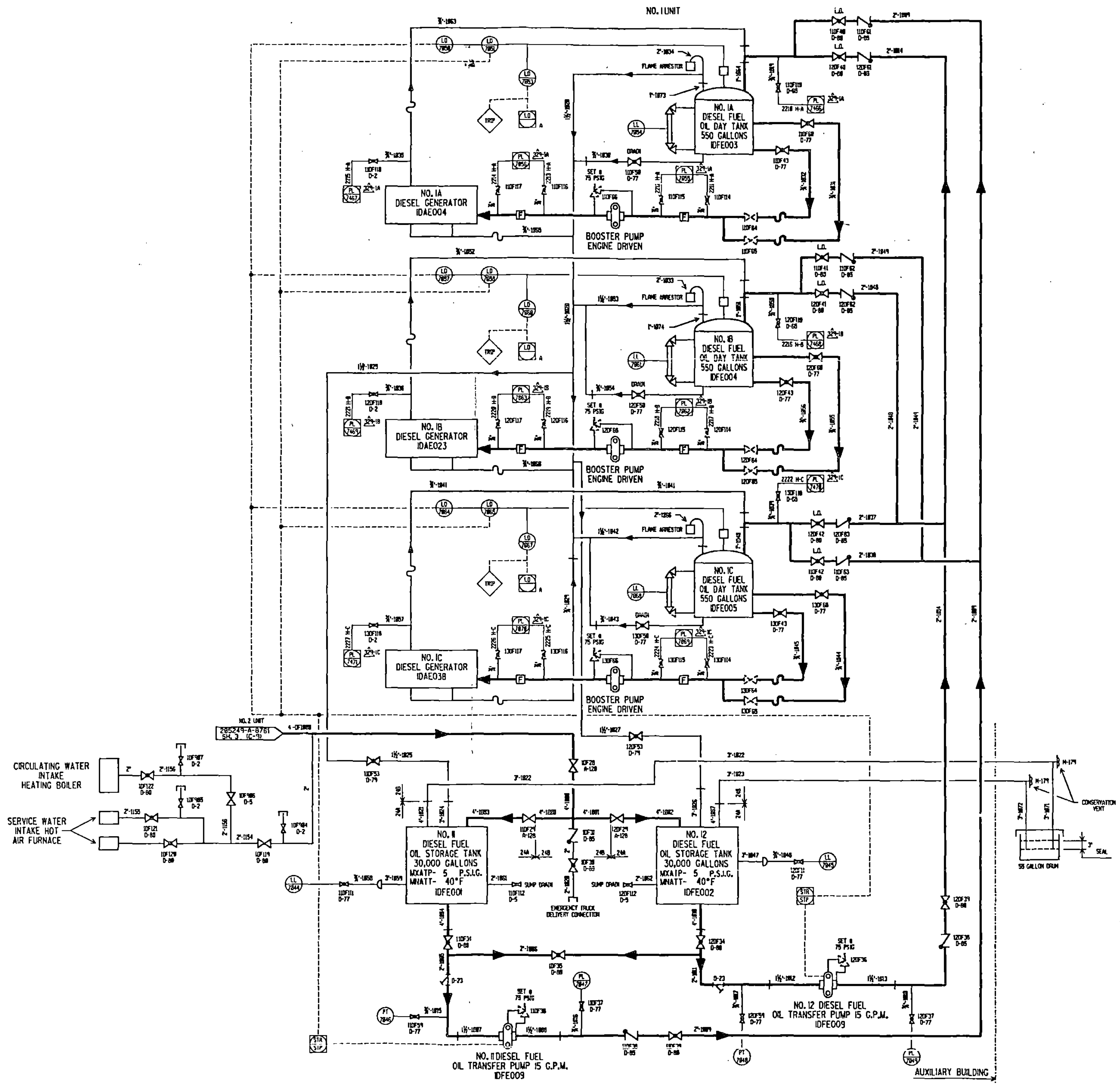
TI APERTURE CARD

8507300447 -118

Revision 4
July 22, 1985
Ref. Dwg. 205249A8761-15

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Fuel Oil System
	Updated FSAR Sheet 1 of 3 Fig 9.5-2



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Revision 4
July 22, 1985
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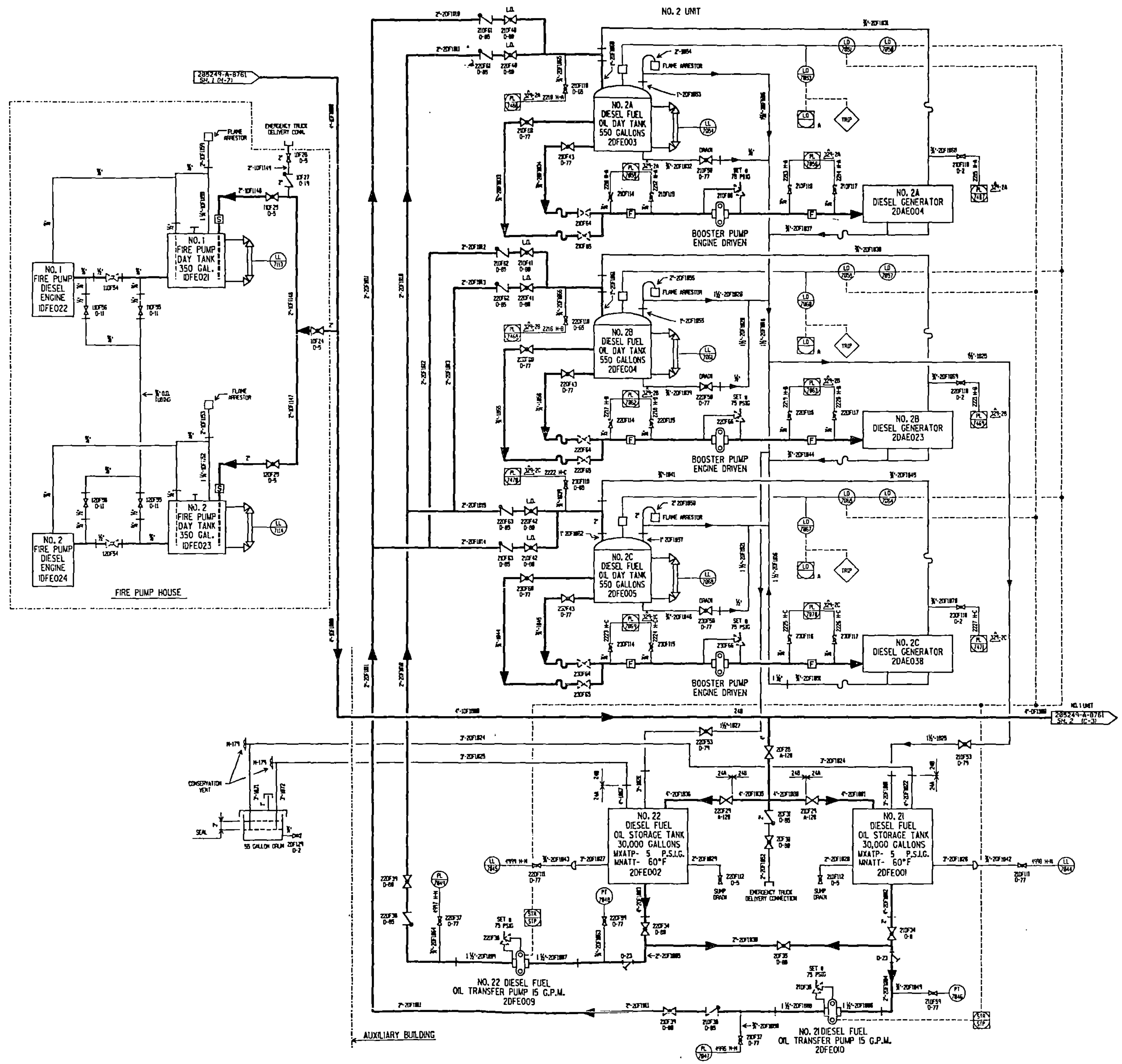
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Fuel Oil System
	Updated FSAR Sheet 2 of 3 Fig 9.5-2



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July 22, 1985
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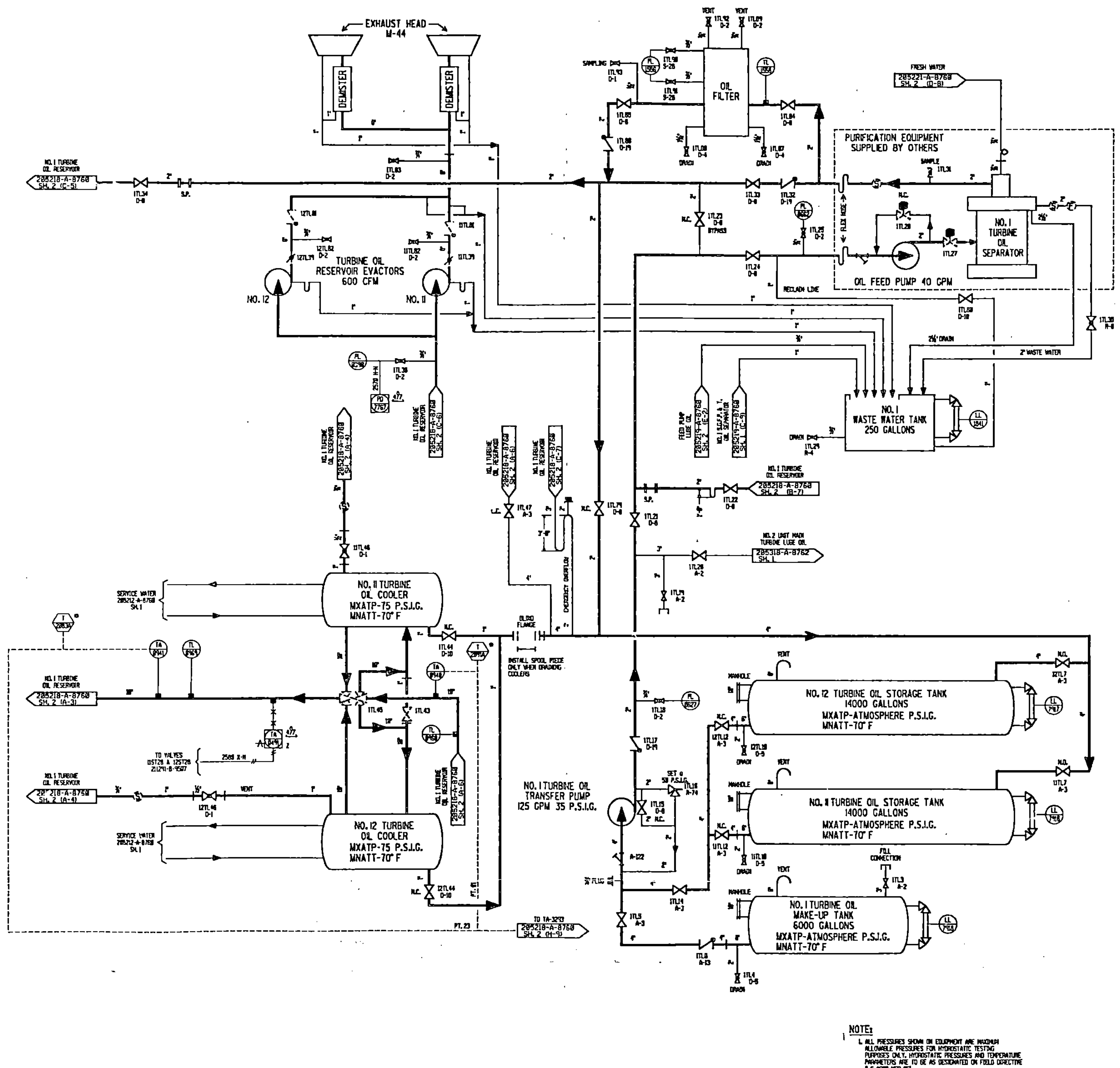
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Fuel Oil System	
	Updated FSAR Sheet 3 of 3	Fig 9.5-2



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1PI-641	PL-2456
1PI-17	PL-8041
1PI-3	PL-3647
1PI-727	PL-6184
1PT-41	PA-8245
1PI-9	PL-6185
1PI-141	PL-6186
1PS-15	PD-7767
1PI-66	PL-8398
1PI-220	PL-2458
1PS-67	PD-8457
1PI-68	PL-2459
1TT-645	TA-8491
1PS-209	PD-8828
1PS-210	PD-8829
1PS-211	PD-8830
1PS-212	PD-8831
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	TA-8912
	TA-8913

VENDOR INSTR. NO.	P.S. INSTR. NO.
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1TE-641	TA-8941
1TT-815	TL-8969
1TE-640	TA-8940
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1SV-302	SY-8802
1SV-303	SY-8803
1SV-310	SY-8828
1SV-311	SY-8829
1SV-312	SY-8813

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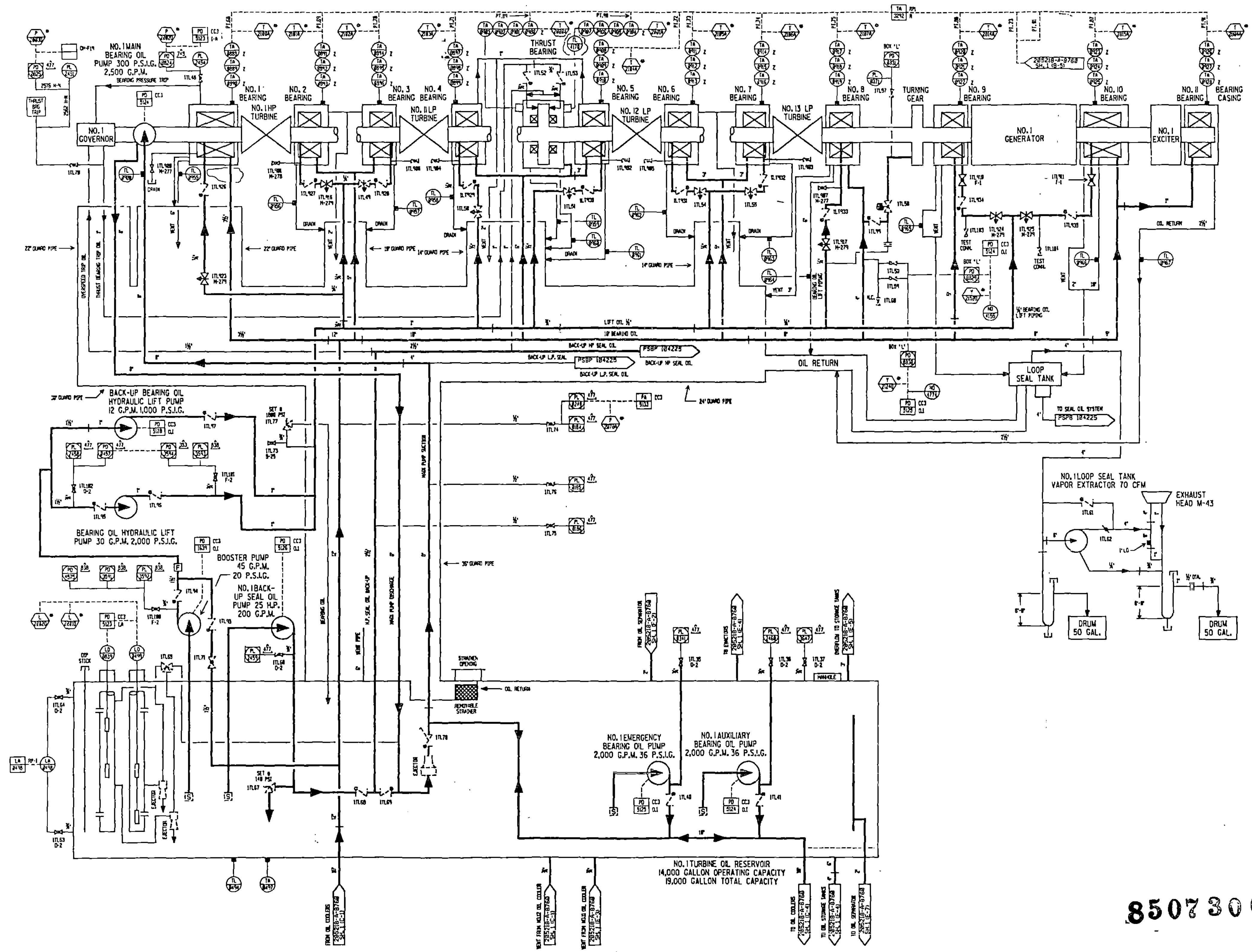
Ref. Dwg. 205218A8760-16

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Main Turbine Lubricating Oil System
	Updated FSAR Sheet 1 of 2 Fig 10.2-1



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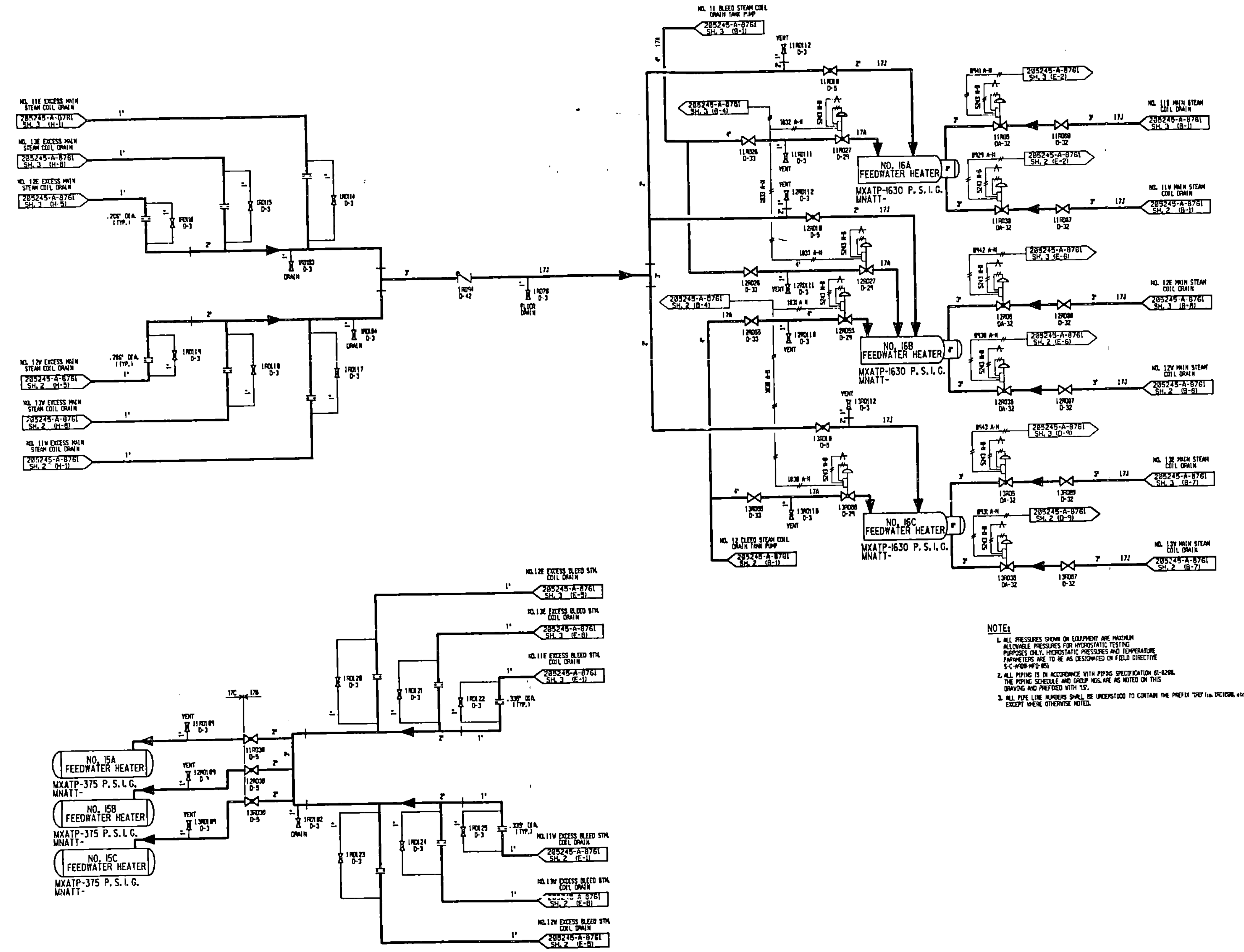
Revision 4
July 22, 1985
Ref. Dwg. 205218A8760-16

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Main Turbine Lubricating Oil System
	Updated FSAR Sheet 2 of 2 Fig 10.2-1



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Revision 4
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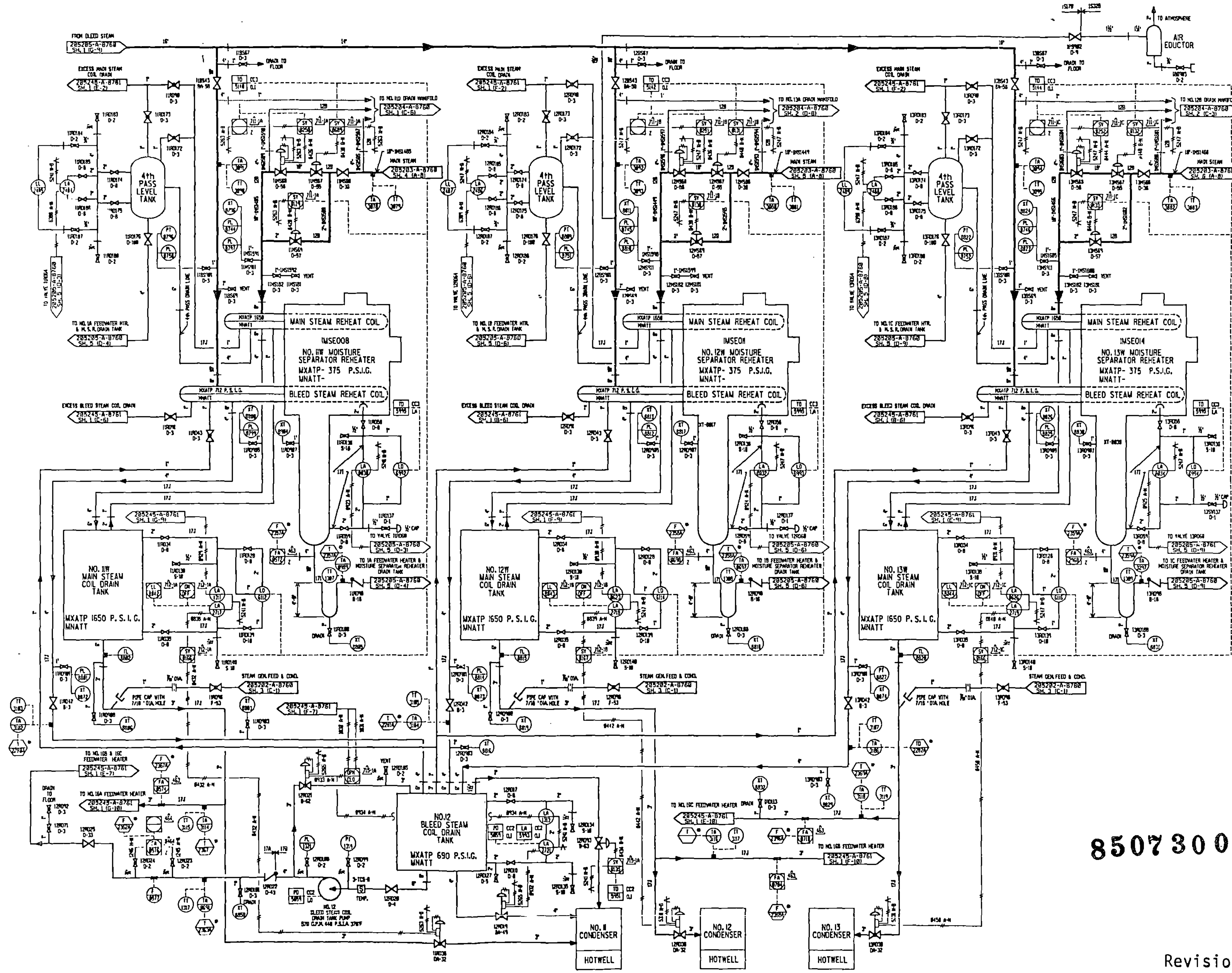
Ref. Dwg. 205245A8761-13

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Moisture Separator Reheaters, Steam and Drains - Unit 1
	Updated FSAR Sheet 1 of 3 Fig 10.2-2A



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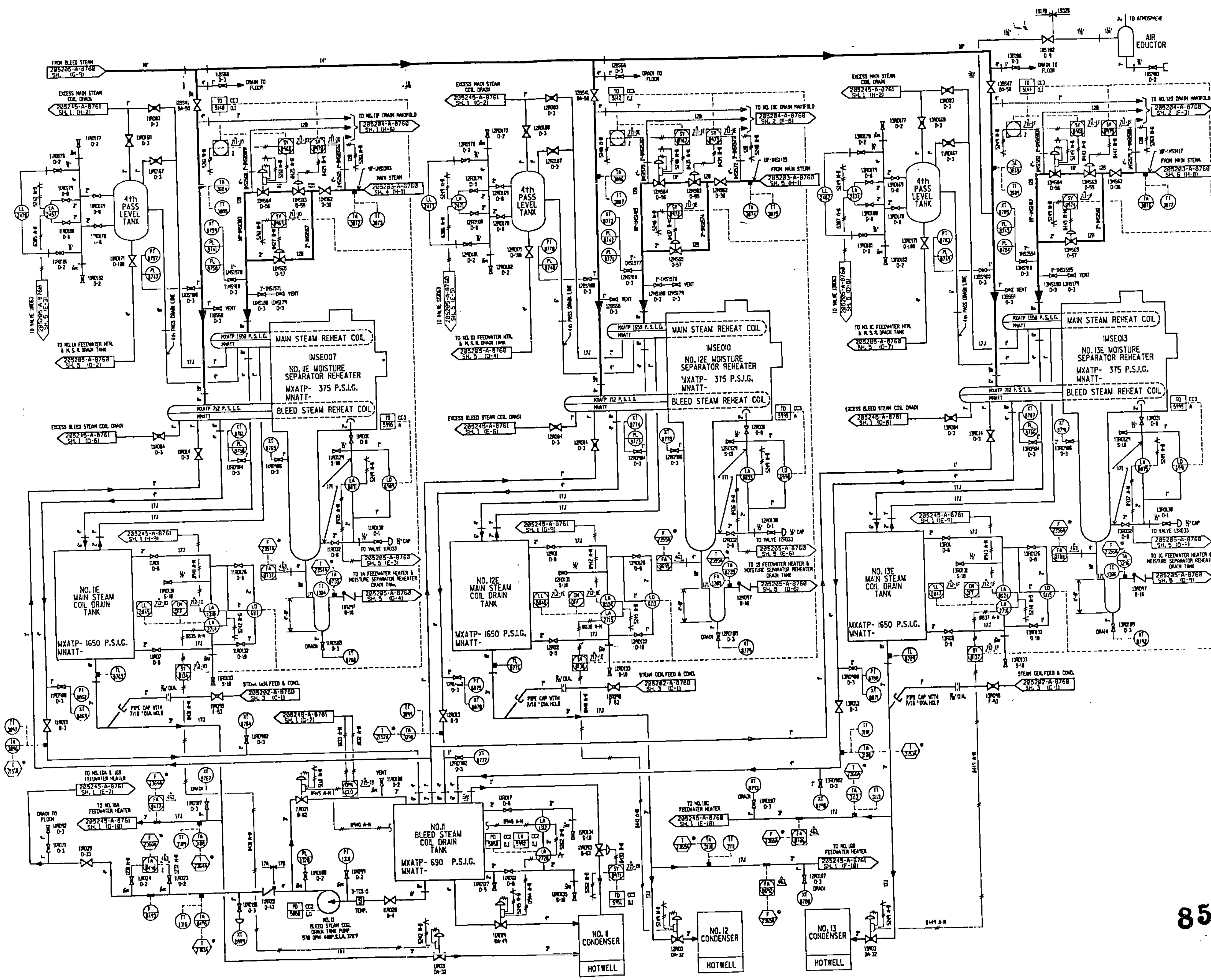
Revision 4
July 22, 1985
Ref. Dwg. 205245A8761-13

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Moisture Separator Reheaters, Steam and Drains - Unit 1
	Updated FSAR Sheet 2 of 3 Fig 10.2-2A



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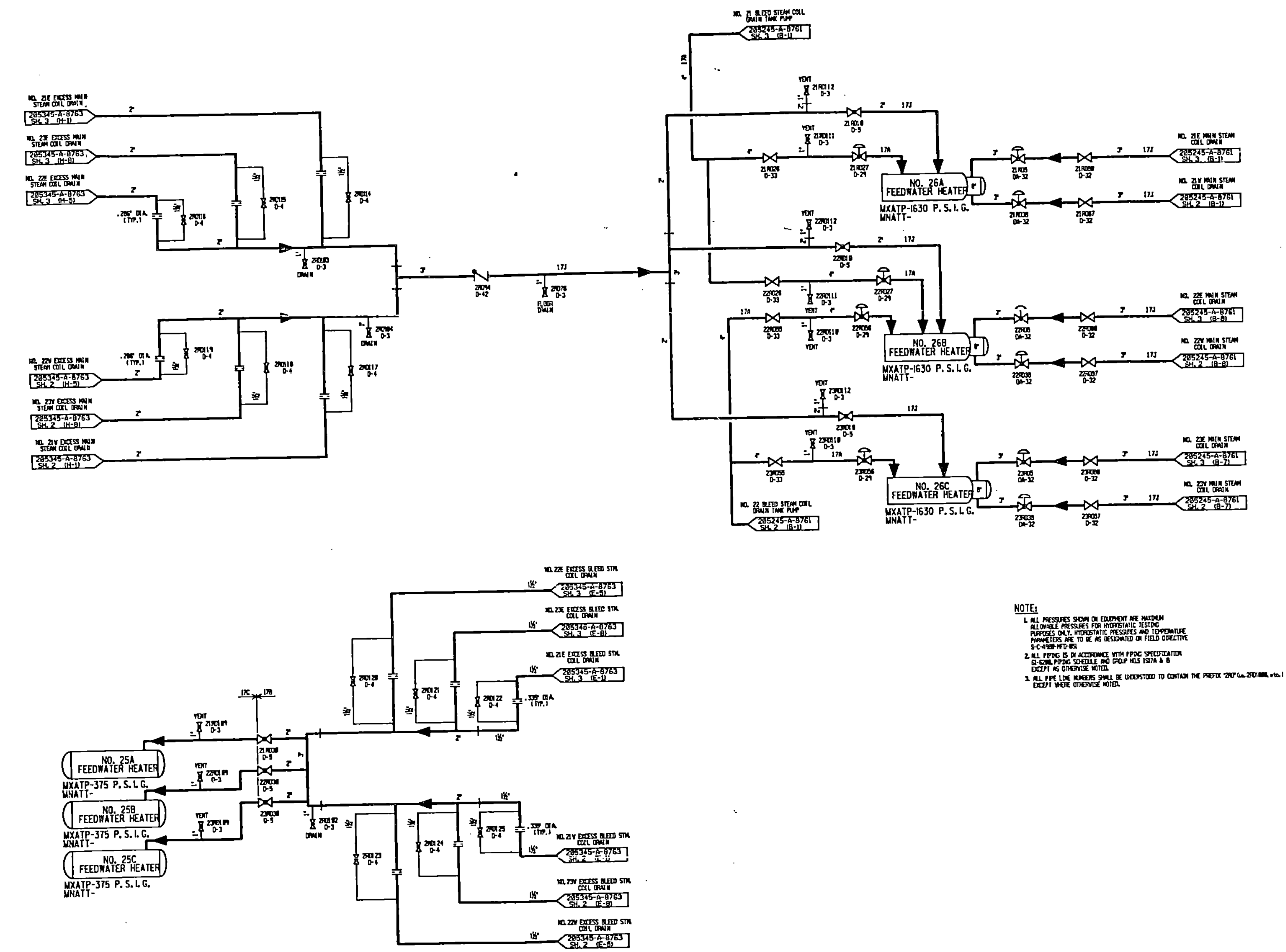
Revision 4
July 22, 1985
Ref. Dwg. 205245A8761-13

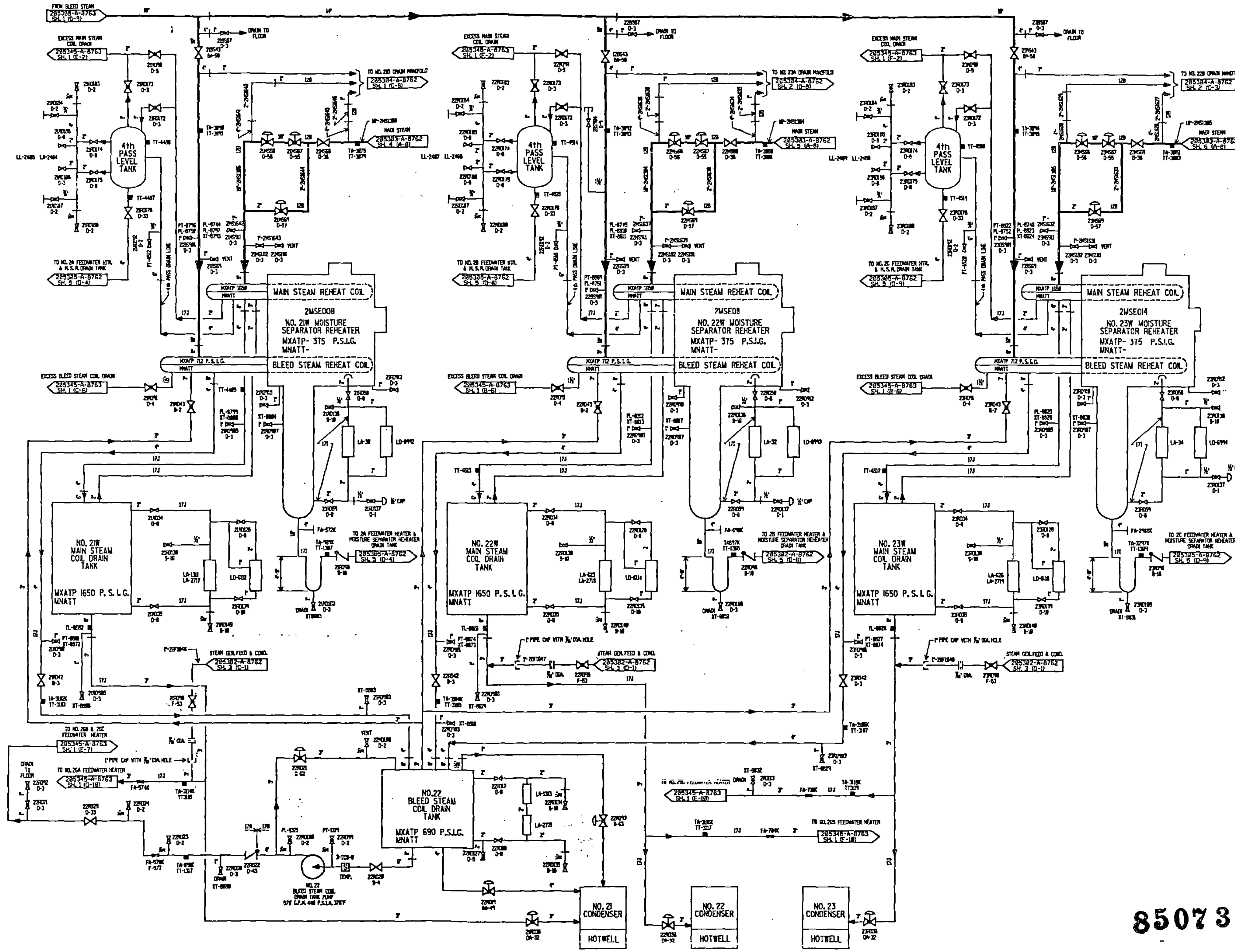
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Moisture Separator Reheaters, Steam and Drains - Unit 1
	Updated FSAR Sheet 3 of 3 Fig 10.2-2A



8507300447-126

Revision 4
July 22, 1985
Ref. Dwg. 205345A8763-10

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Moisture Separator Reheaters, Steam and Drains - Unit 2
	Updated FSAR Sheet 1 of 3 Fig 10.2-2B



Revision 4
July 22, 1985
Ref. Dwg. 205345A8763-10

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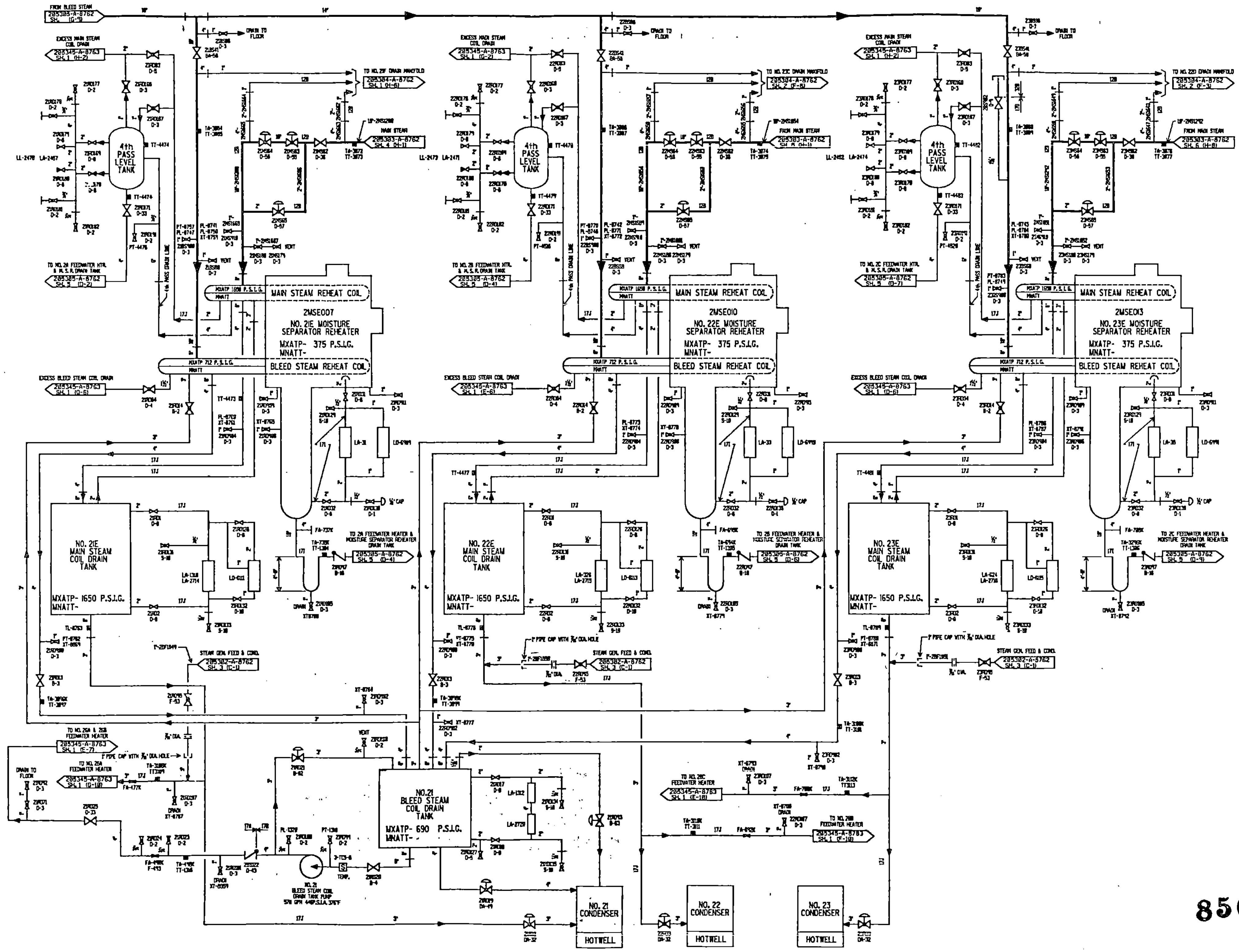
	Updated FSAR Sheet 2 of 3 Fig 10.2-2B



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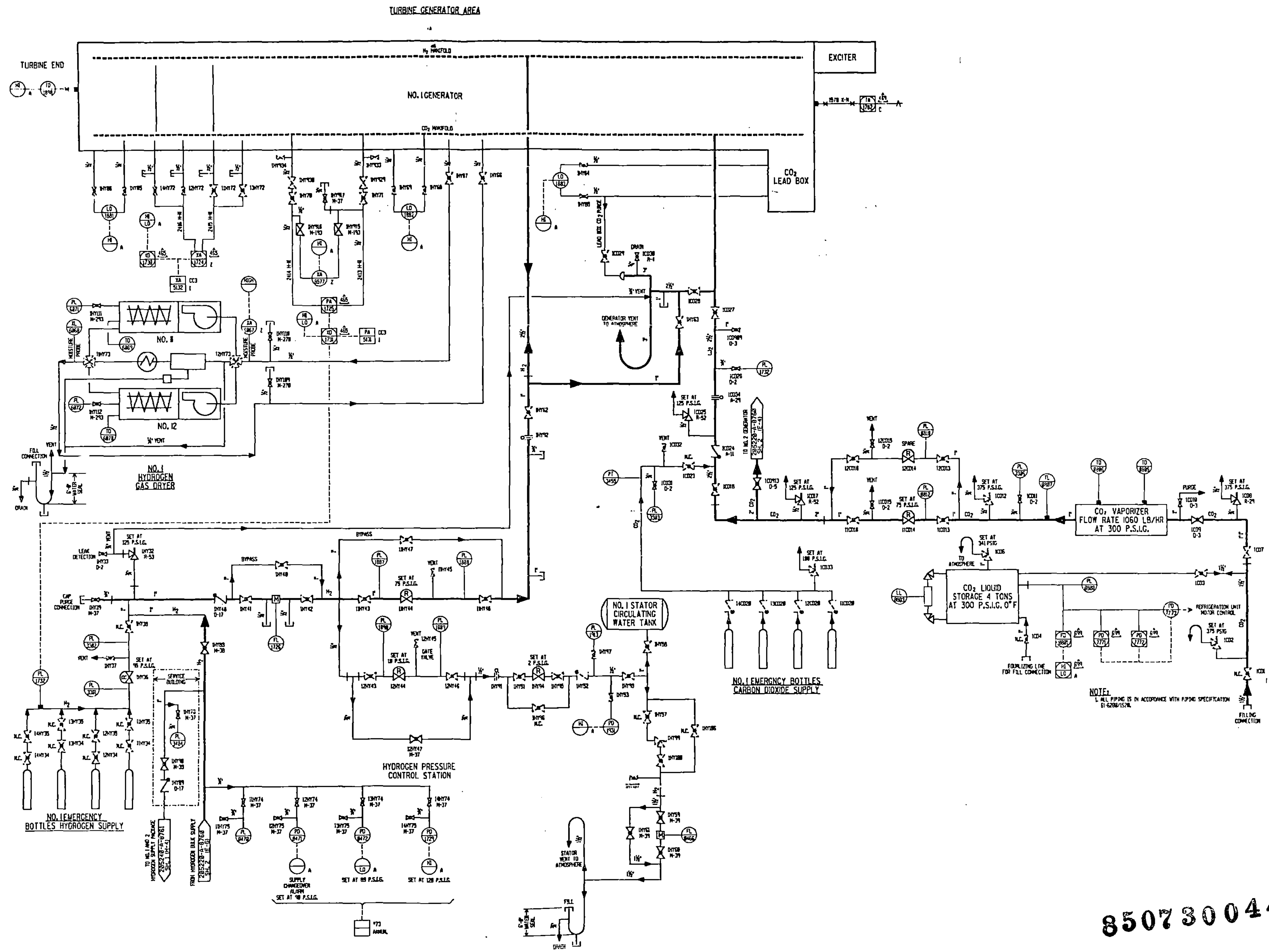
Ref. Dwg. 205345A8763-10

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Moisture Separator Reheaters, Steam and Drains - Unit 2
	Updated FSAR Sheet 3 of 3 Fig 10.2-2B



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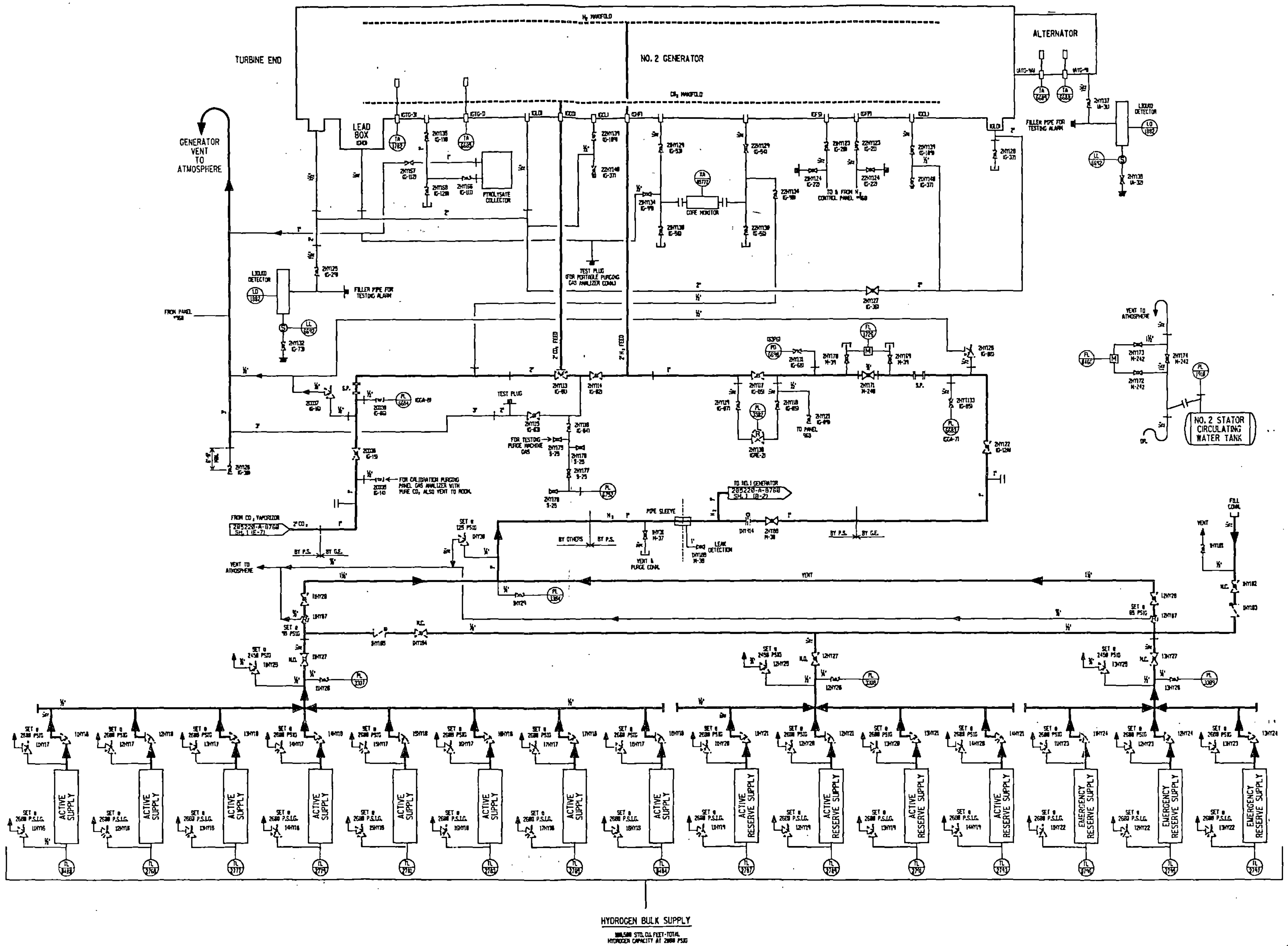
Revision 4
July 22, 1985
Ref. Dwg. 205220A8760-19

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Hydrogen and Carbon Dioxide Systems
	Updated FSAR Sheet 1 of 2 Fig 10.2-3



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Revision 4
July 22, 1985
Ref. Dwg. 205220A8760-19

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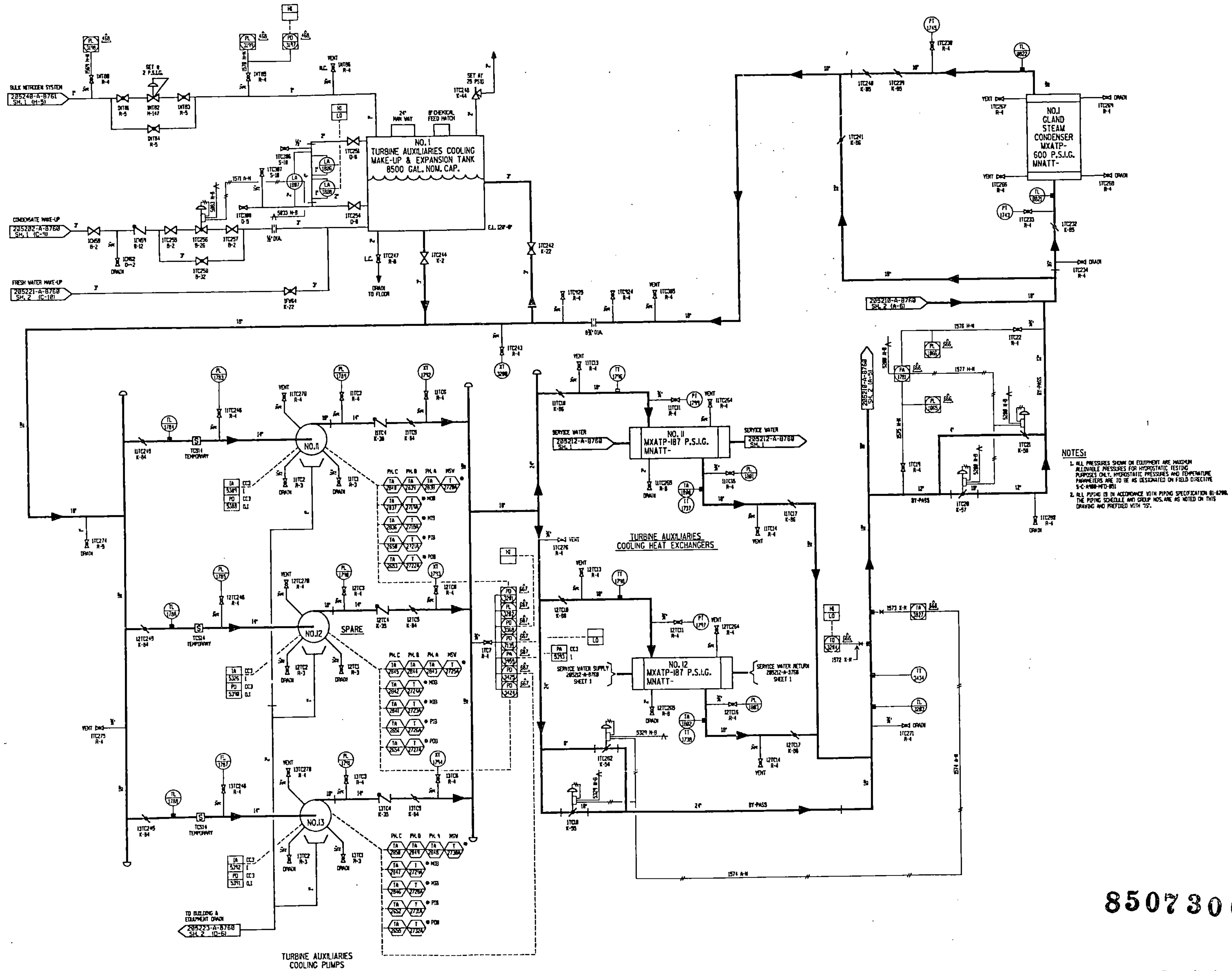
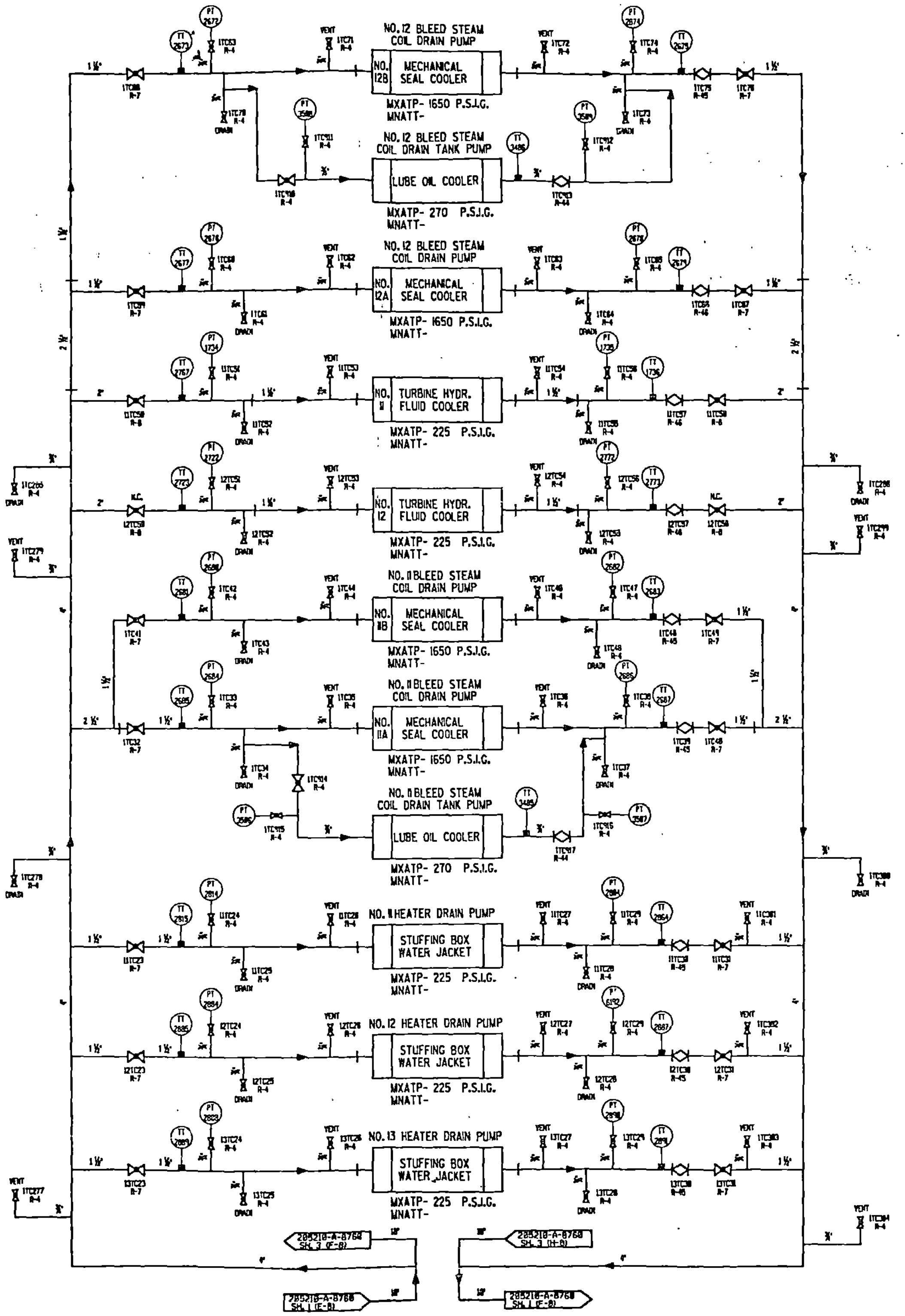
	Updated FSAR Sheet 2 of 2 Fig 10.2-3



8507300447-131

Revision 4
July 22, 1985
Ref. Dwg. 205210A8760-17

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Turbine Auxiliaries Cooling System
	Updated FSAR Sheet 1 of 4 Fig 10.2-4



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Revision 4
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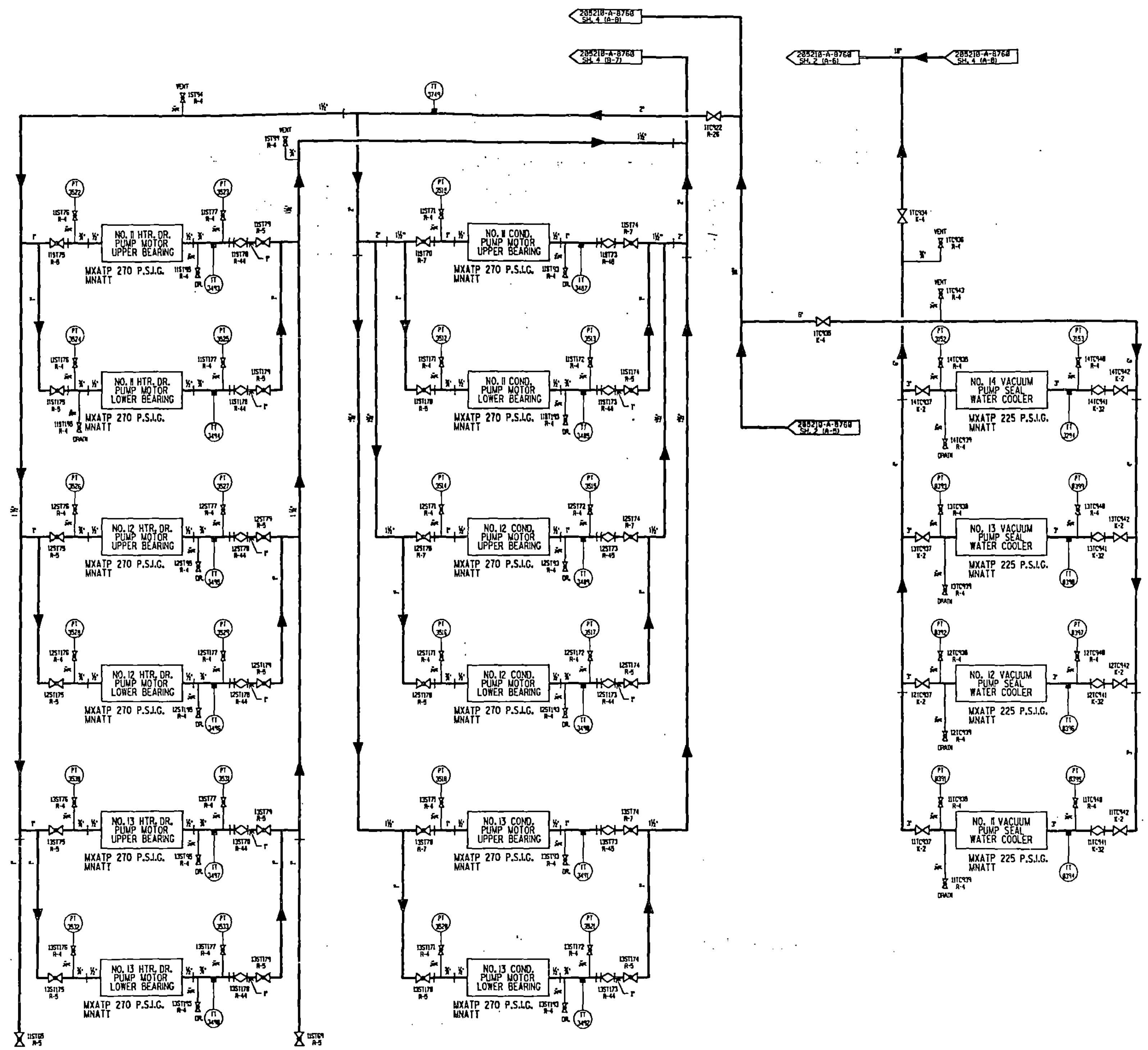
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Turbine Auxiliaries Cooling System
	Updated FSAR Sheet 2 of 4 Fig 10.2-4



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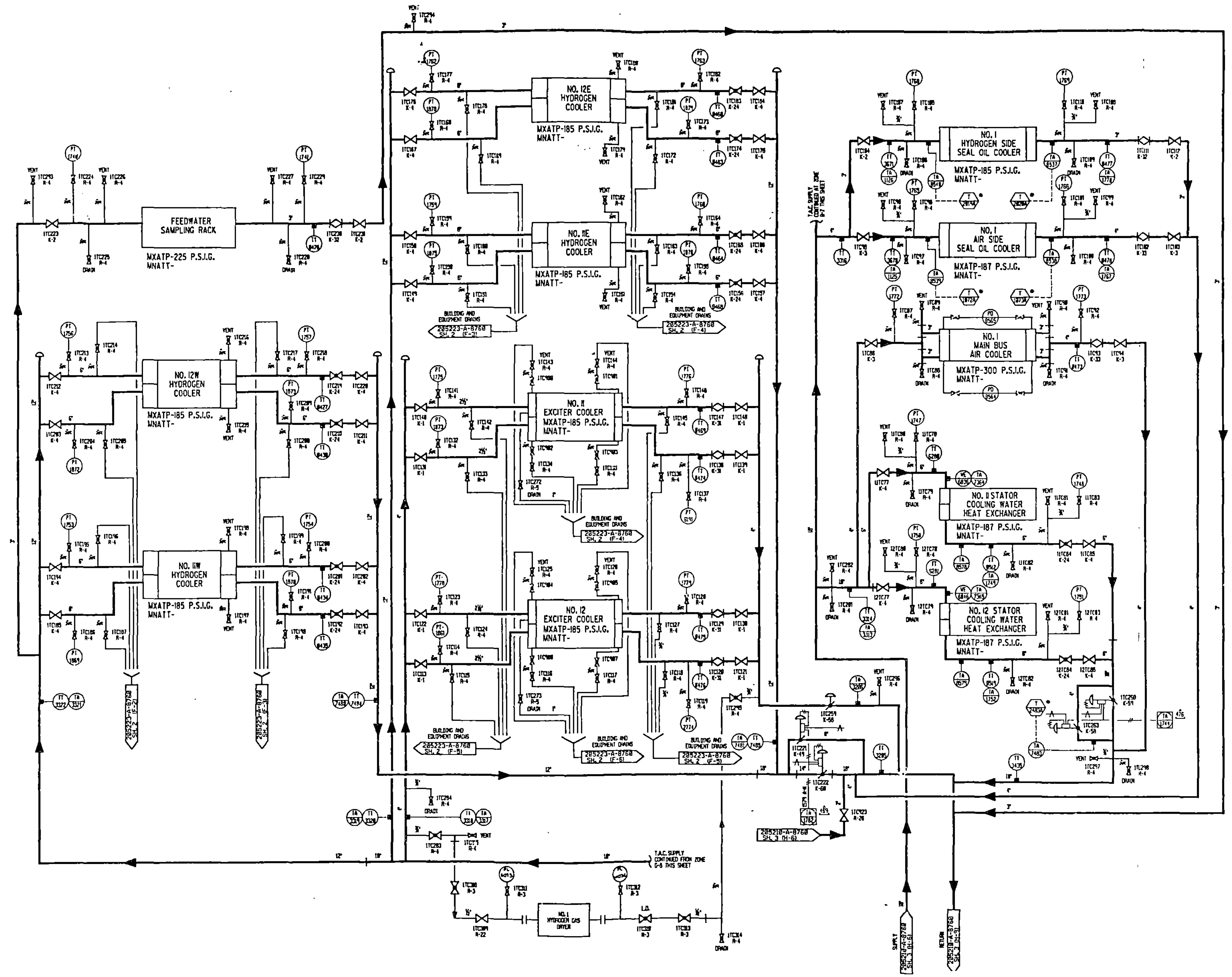
Ref. Dwg. 205210A8760-17

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Turbine Auxiliaries Cooling System Updated FSAR Sheet 3 of 4 Fig 10.2-4



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Ref. Dwg. 205210A8760-17

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Turbine Auxiliaries Cooling System
	Updated FSAR Sheet 4 of 4 Fig 10.2-4

10.3.3.4 Radioactivity

Under normal conditions, there is no radioactivity present in the system. The system may only become contaminated through primary to secondary leaks in the steam generators. Should this occur, radiation monitors installed in the steam generator blowdown and condenser vacuum pump effluent streams detect and indicate the presence of radioactivity.

Assuming operation with the maximum permissible primary system activity and a maximum permissible primary to secondary system leakage rate, the dose rate around the steam generator is approximately 325 mr/hr at contact with the steam generator secondary water section just above the U-tubes. The dose rate on the operating floor outside the steam generator biological shield would be approximately 150 mr/hr, due to the secondary water in the steam generator which is above the top of the biological shield.

The dose rates from a main steam line were calculated to be about 8 mr/hr at contact and less than 1 mr/hr at 10 feet away. Dose rates from the turbine will be less than this due to the thick steel turbine casing serving as a shield, and lower source densities as the steam travels through the turbine. The primary contributors to the dose rates from the main steam lines and turbine are the noble gases and N-16. Since the noble gases are removed at the condenser by the condenser air removal system and there is sufficient storage time in the hotwell to allow for the decay of the N-16 to negligible levels, the only remaining source in the feedwater is 0.25 percent of the non-gaseous fission products that are carried over with the steam. Dose rates from feedwater lines were calculated to be approximately 4 mr/hr at contact and less than 1 mr/hr at 10 feet away.

Dose rates from a 3" blowdown line were calculated to be approximately 280 mr/hr at 1 foot away and 75 mr/hr at 3 feet away. The dose rate from the blowdown tank was approximately 800 mr/hr at 3 feet away.

Measurements during plant operation have yet to indicate radiation levels above background.

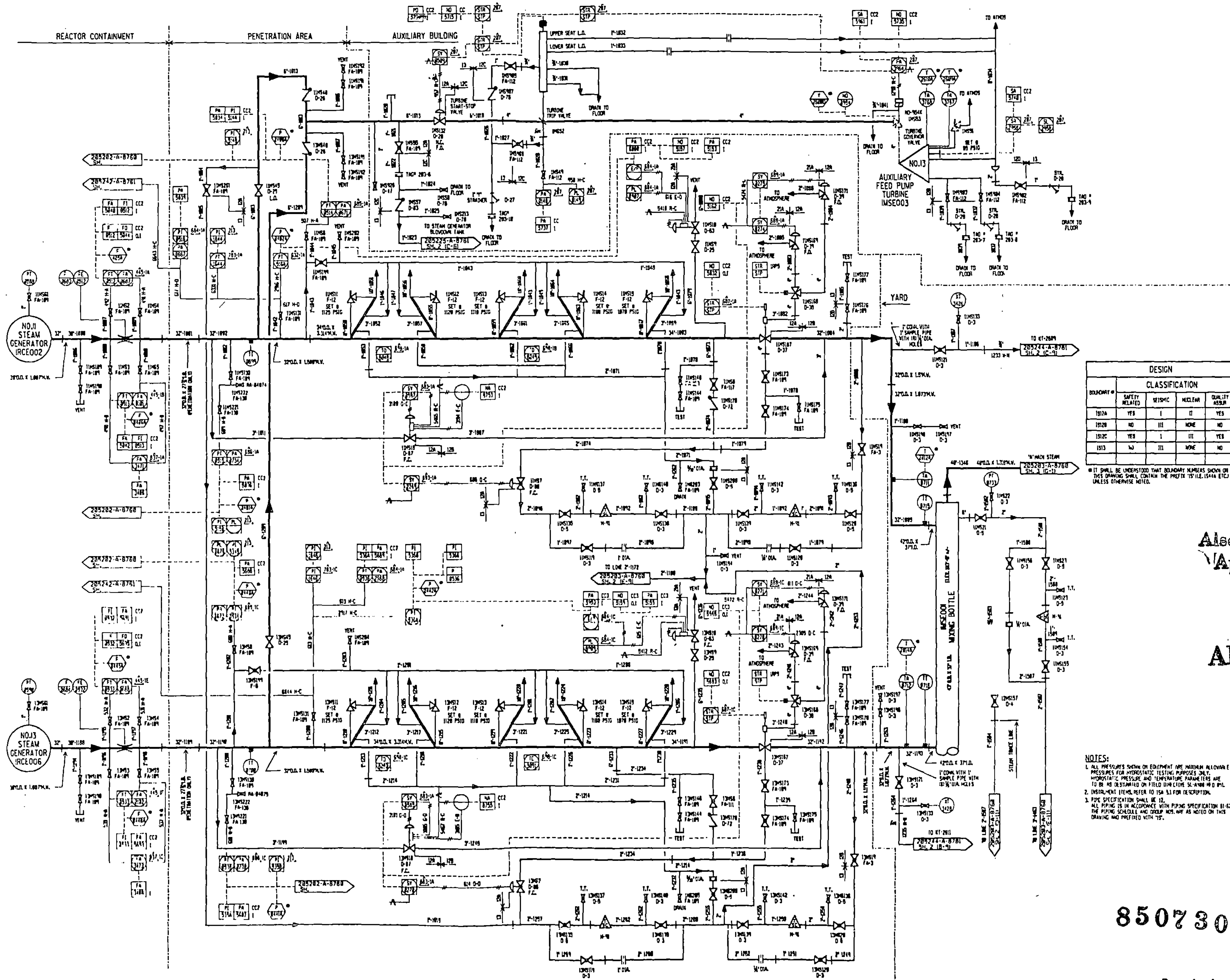
Shielding around the steam generators is designed to reduce radiation levels from the U-tubes. Since primary to secondary leakage is not expected to occur at all times, and access to the containment is minimal during operation, higher dose rates on the operating floor are acceptable. However, high dose rates in this area may require reduced access time. Radiation levels in other accessible areas of the containment (outside the crane wall and below the operating floor) will not be severely affected.

Shielding around the main steam line, turbine, condenser and feedwater system piping is not necessary since radiation levels in this area would only occur in the event of primary to secondary leakage, and the dose rates would be low. In this event, access to the turbine building would be controlled.

The blowdown lines pass through the mechanical penetration area where some higher radiation levels normally exist, and no additional shielding is required. The blowdown tank is in a relatively low radiation area, but can be temporarily shielded if access to the area is necessary. Piping to the blowdown demineralizer is in a shielded pipe alley and the demineralizer is in a shielded cubicle. The remainder of the system is in an area where access can be controlled. If access to blowdown system components is necessary for maintenance while the higher dose rates exist, temporary shielding can be installed and access times limited.

Assumptions

1. A conservative primary to secondary leak rate of 8 gpm was assumed (the expected leak rate is currently being determined - a lower value will decrease the main steam line and turbine dose rates).



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Revision 4
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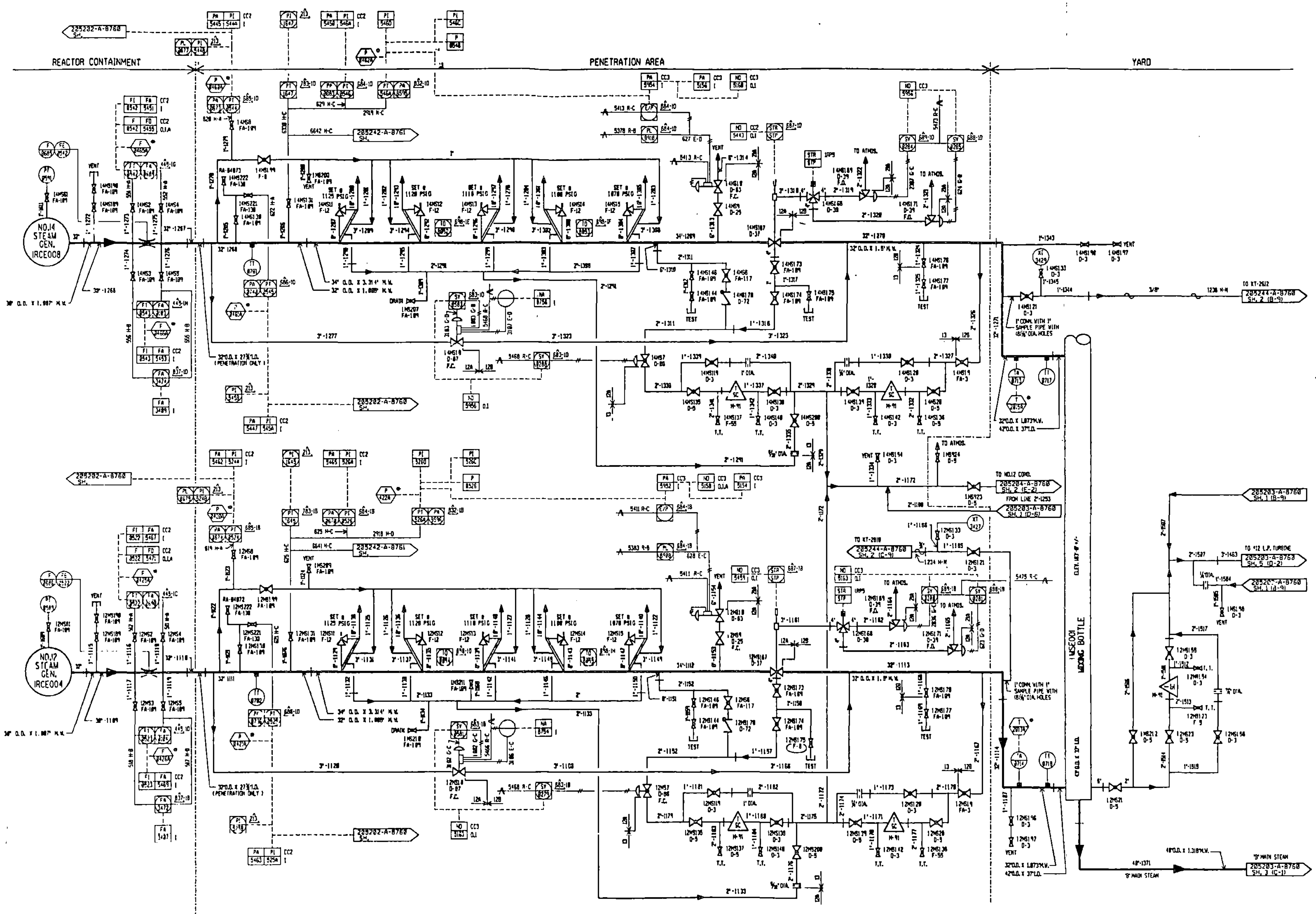
Ref. Dwg. 205203A8760-32

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Main, Reheat and Turbine Bypass Steam Unit 1
	Updated FSAR Sheet 1 of 6 Fig 10.3-1A



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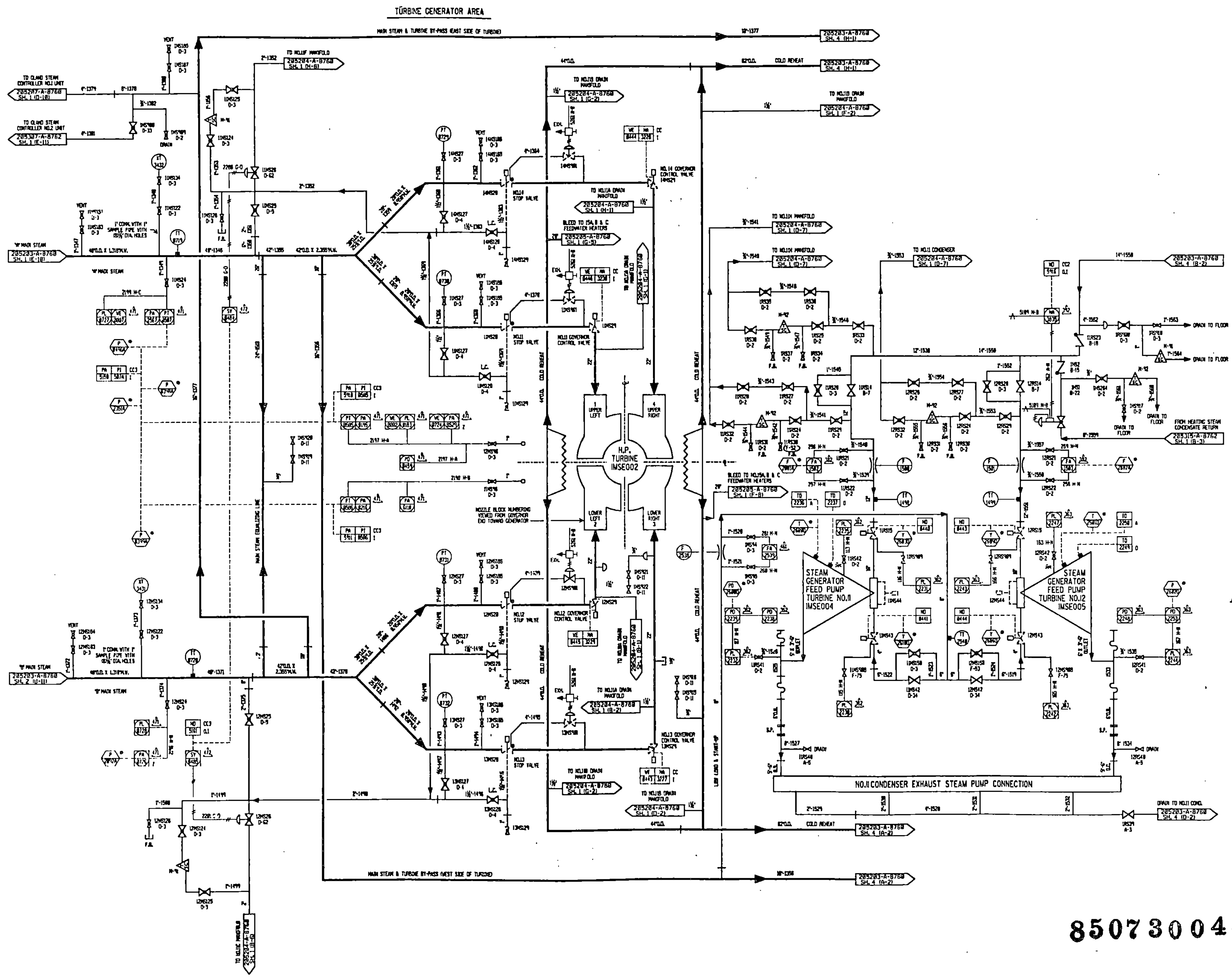
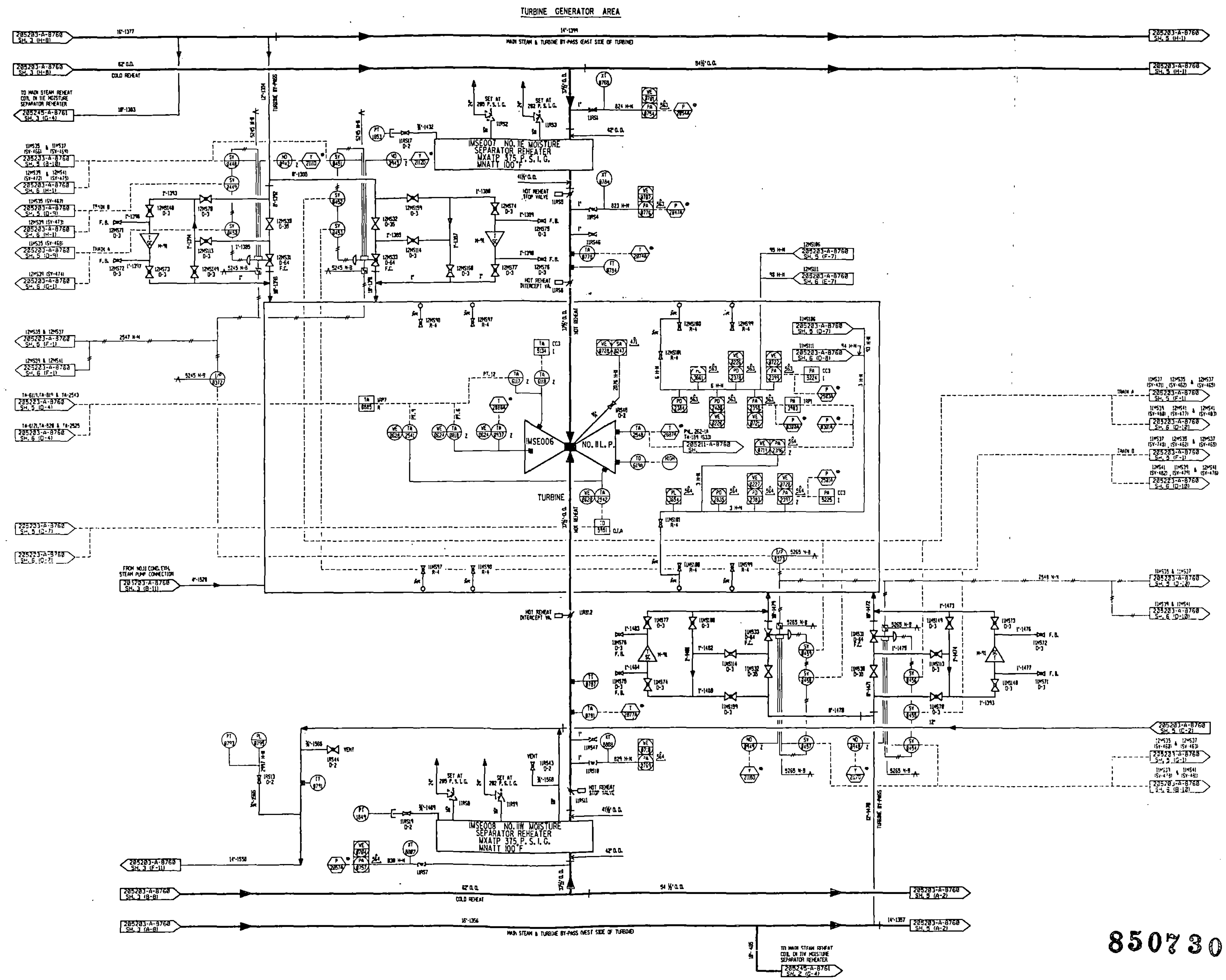
Revision 4
July 22, 1985
Ref. Dwg. 205203A8760-32

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Main, Reheat and Turbine Bypass Steam Unit 1
	Updated FSAR Sheet 2 of 6 Fig. 10.3-1A



Revision 4
July 22, 1985
Ref. Dwg. 205203A8760-32

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Main, Reheat and Turbine Bypass Steam Unit 1
	Updated FSAR Sheet 3 of 6 Fig 10.3-1A



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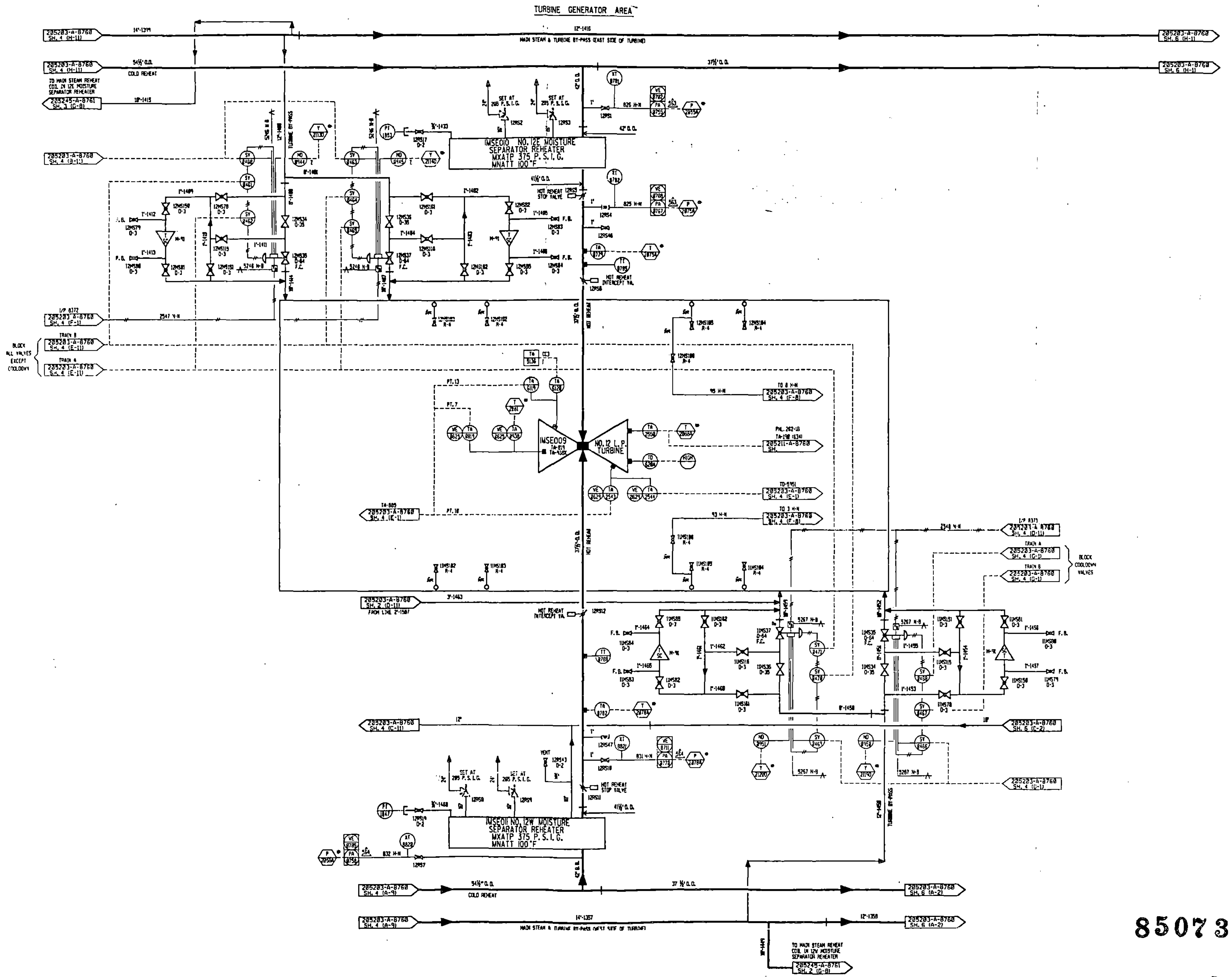
Revision 4
July 22, 1985
Ref. Dwg. 205203A8760-32

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Main, Reheat and Turbine Bypass Steam Unit 1
	Updated FSAR Sheet 4 of 6 Fig 10.3-1A



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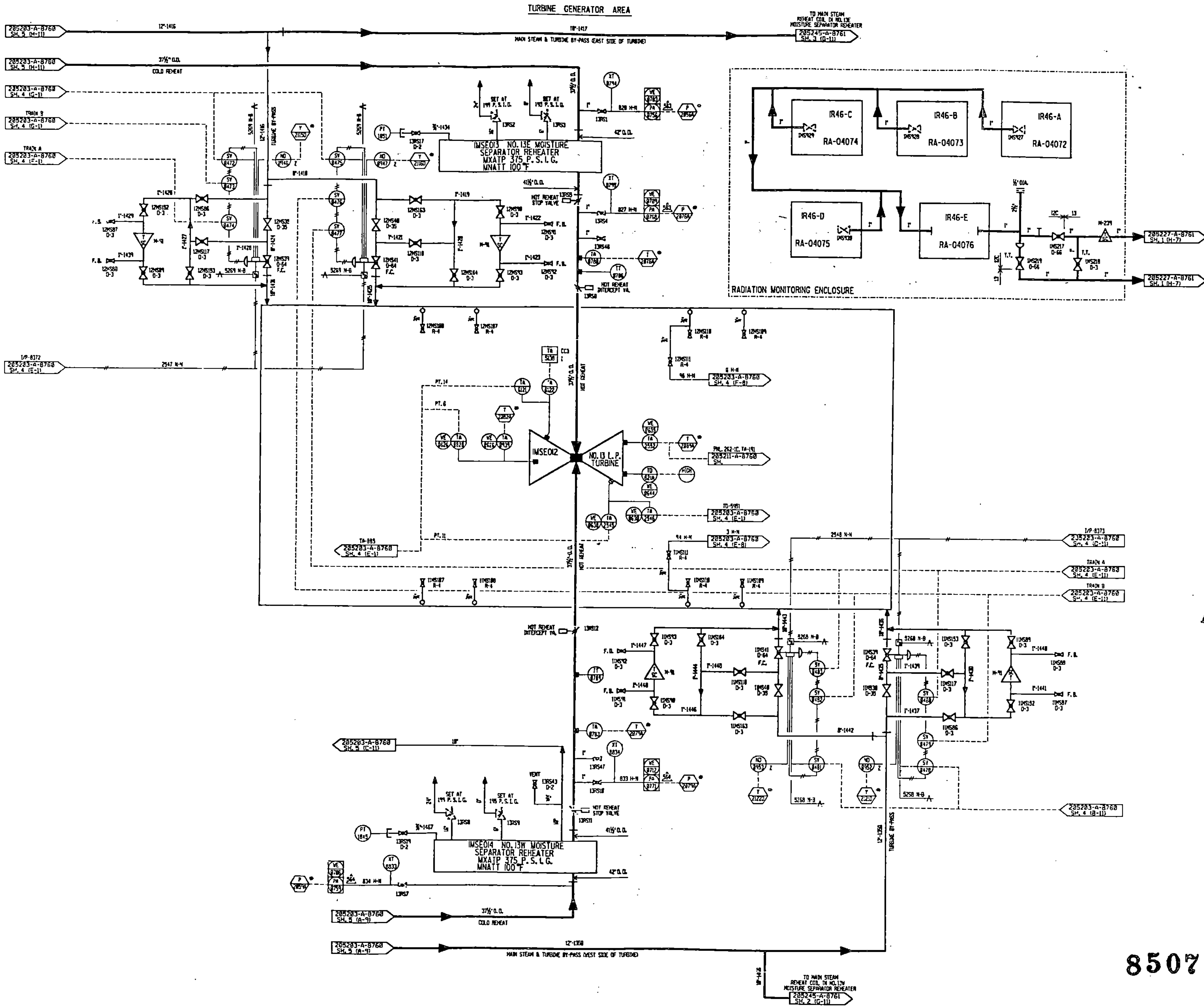
Revision 4
July 22, 1985
Ref. Dwg. 205203A8760-32

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Main, Reheat and Turbine Bypass Steam Unit 1
	Updated FSAR Sheet 5 of 6 Fig 10.3-1A



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Revision 4
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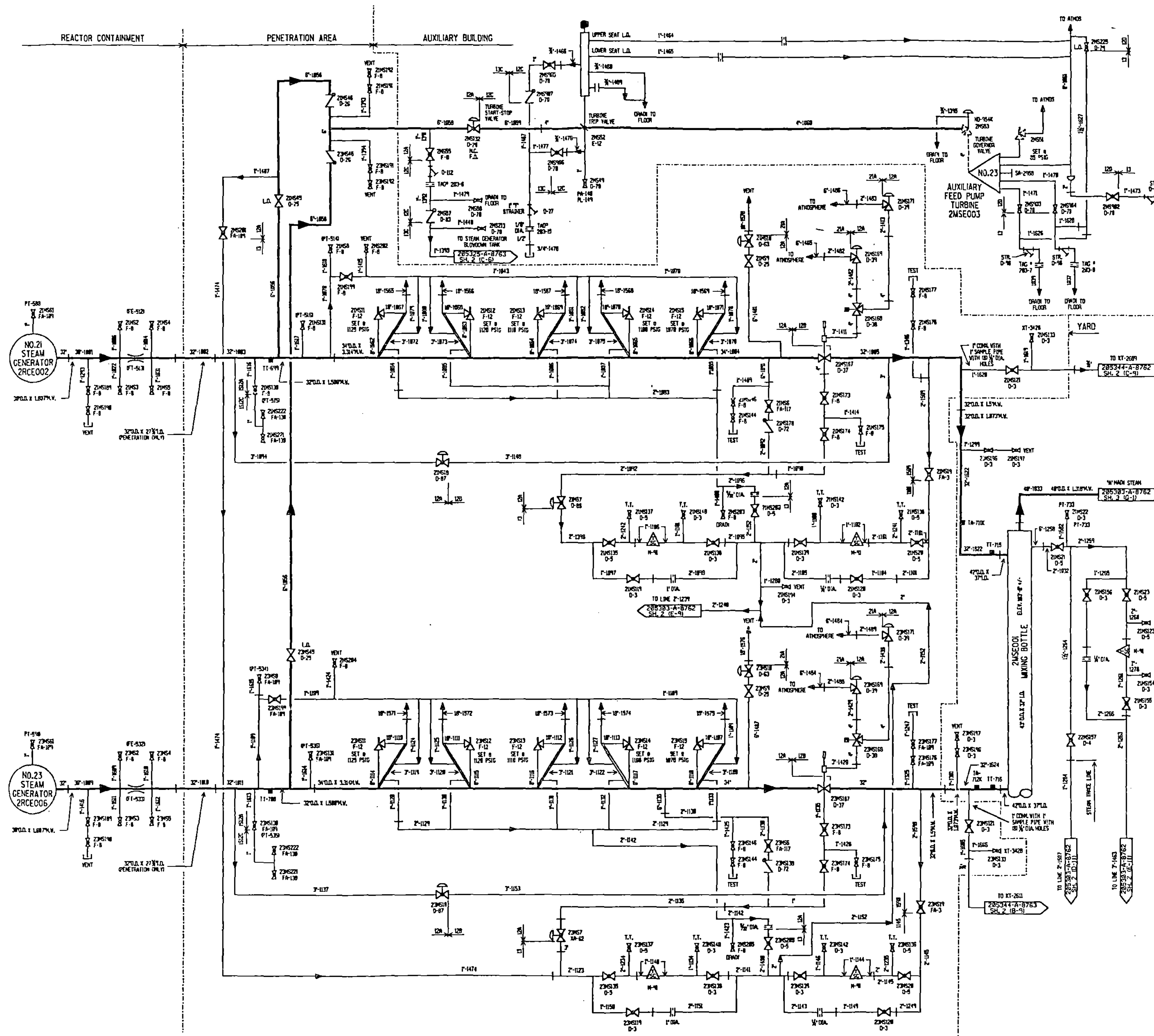
Ref. Dwg. 205203A8760-32

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Main, Reheat and Turbine Bypass Steam Unit 1
	Updated FSAR Sheet 6 of 6 Fig 10.3-1A



DESIGN				
BOUNDARY *	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR
1S12A	YES	I	II	YES
1S12B	NO	III	NONE	NO
1S12C	YES	I	III	YES
1S13	NO	III	NONE	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (I.E. 1S44A ETC.) UNLESS OTHERWISE NOTED.

NOTES:

1. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE SC-A900-MFD-051.
2. ALL PIPING LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2MS (i.e. 2MS 1884, ETC.) EXCEPT WHERE OTHERWISE NOTED.
3. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200, SCHEDULE 1546 EXCEPT WHERE OTHERWISE NOTED.

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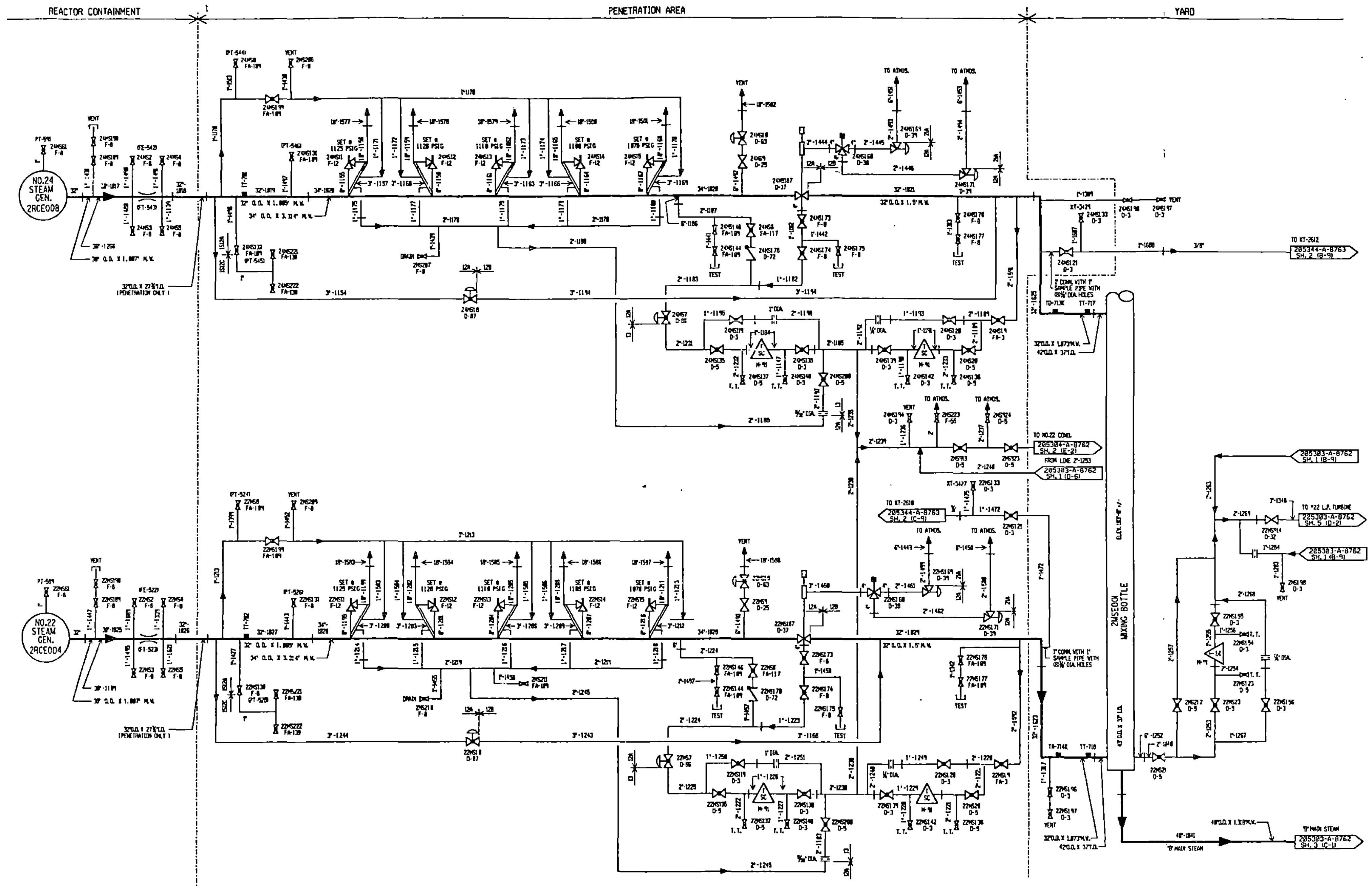
Revision 4
July 22, 1985
Ref. Dwg. 205303A8762-22

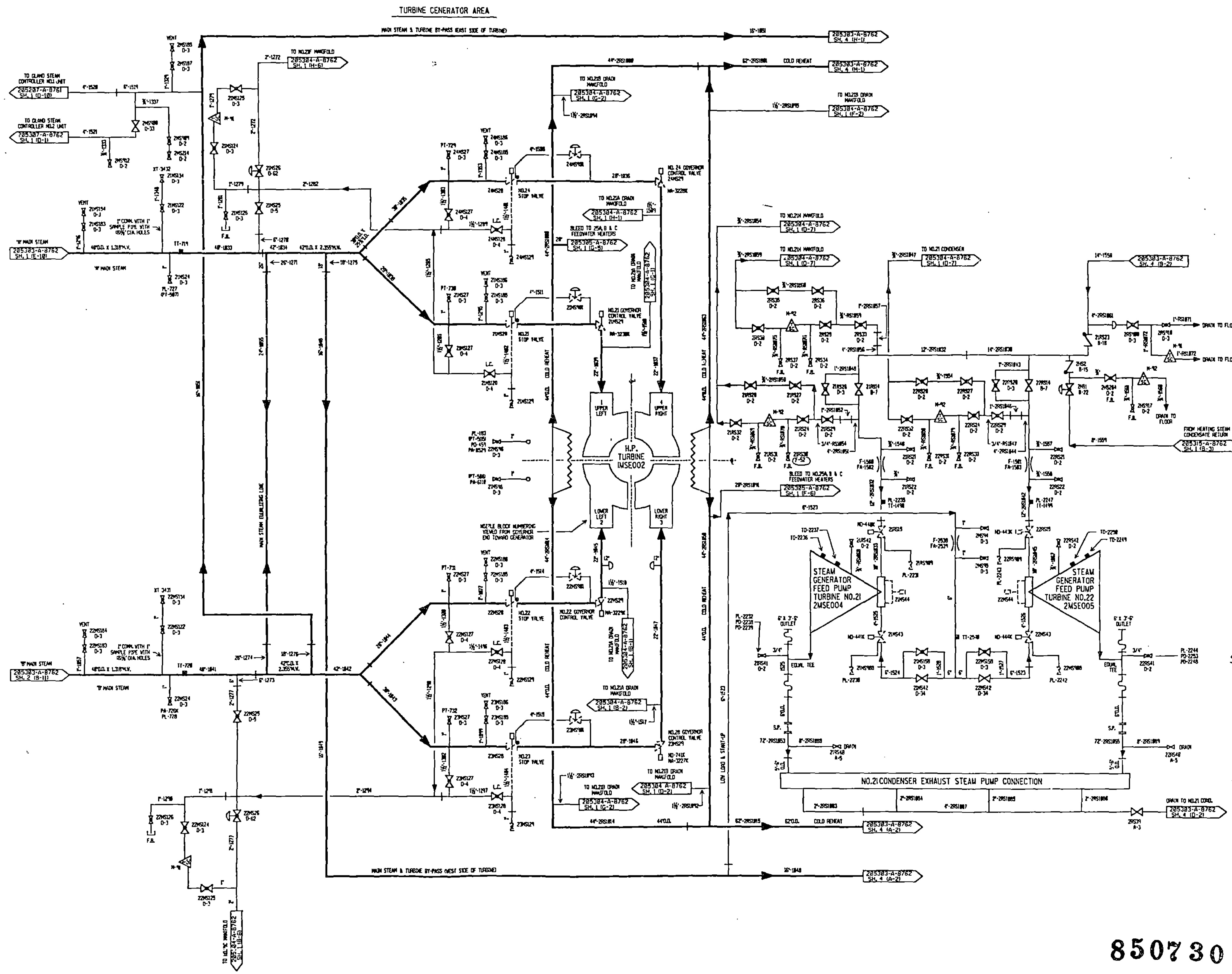
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Main, Reheat and Turbine Bypass Steam Unit 2
	Updated FSAR Sheet 1 of 6 Fig 10.3-1B



8507300447 -142

Revision 4
July 22, 1985
Ref. Dwg. 2050303A8762-22

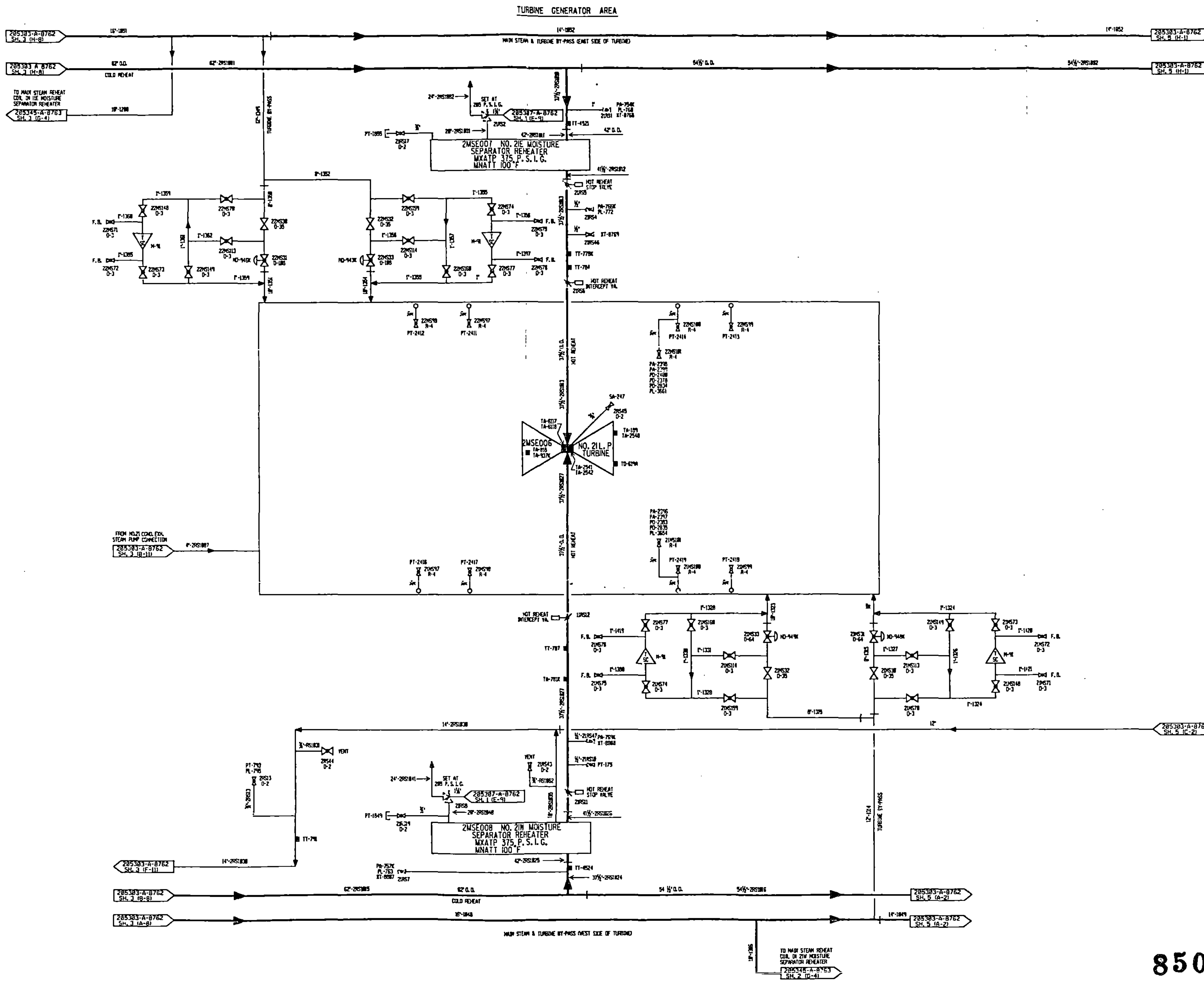
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Main, Reheat and Turbine Bypass Steam Unit 2
	Updated FSAR Sheet 2 of 6 Fig 10.3-1B



8507300447-143

Revision 4
July 22, 1985
Ref. Dwg. 205303A8760-22

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Main, Reheat and Turbine Bypass Steam Unit 2
	Updated FSAR Sheet 3 of 6 Fig 10.3-1B



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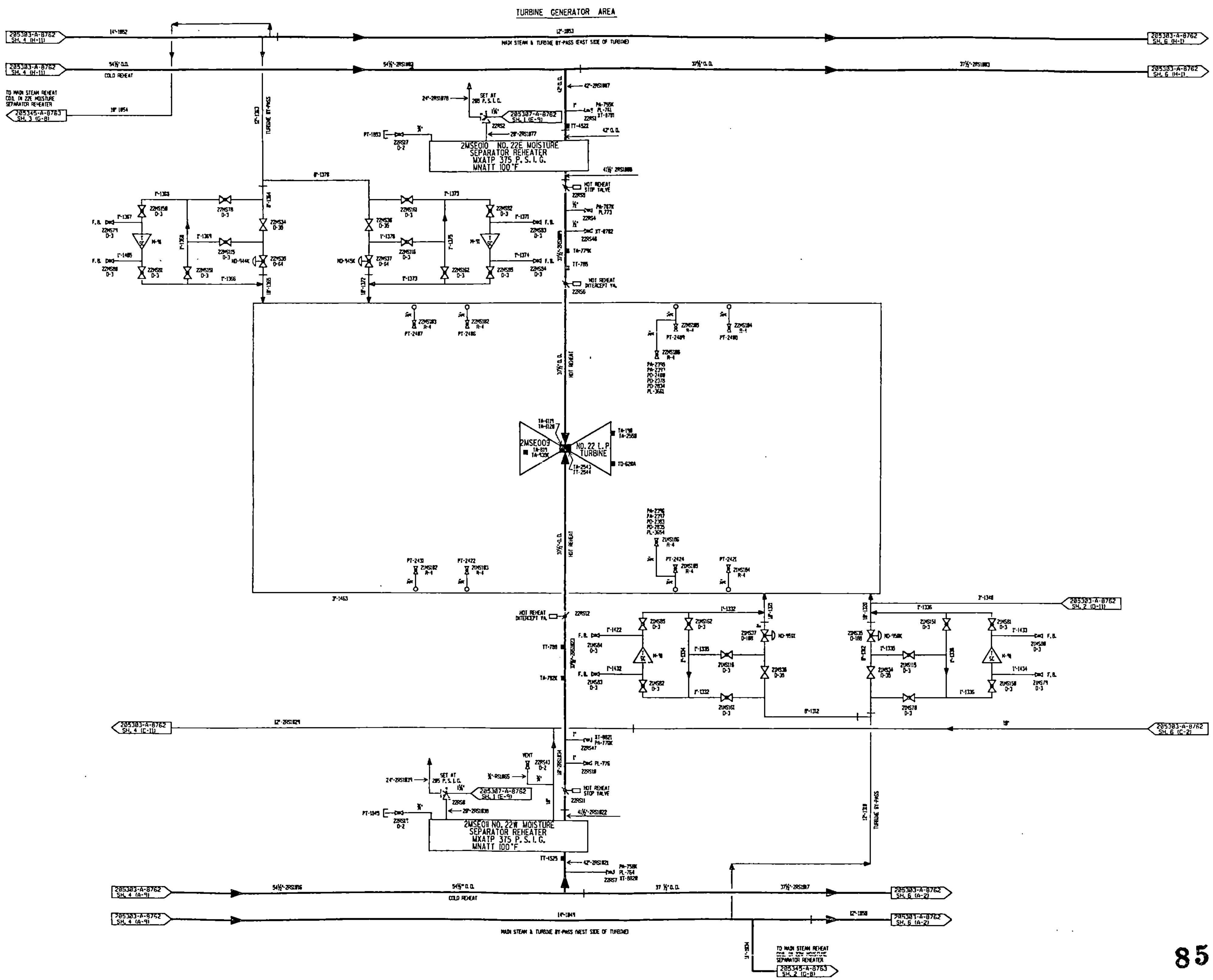
Revision 4
July 22, 1985
Ref. Dwg. 205303A8760-22

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Main, Reheat and Turbine Bypass Steam Unit 2
	Updated FSAR Sheet 4 of 6 Fig 10.3-1B



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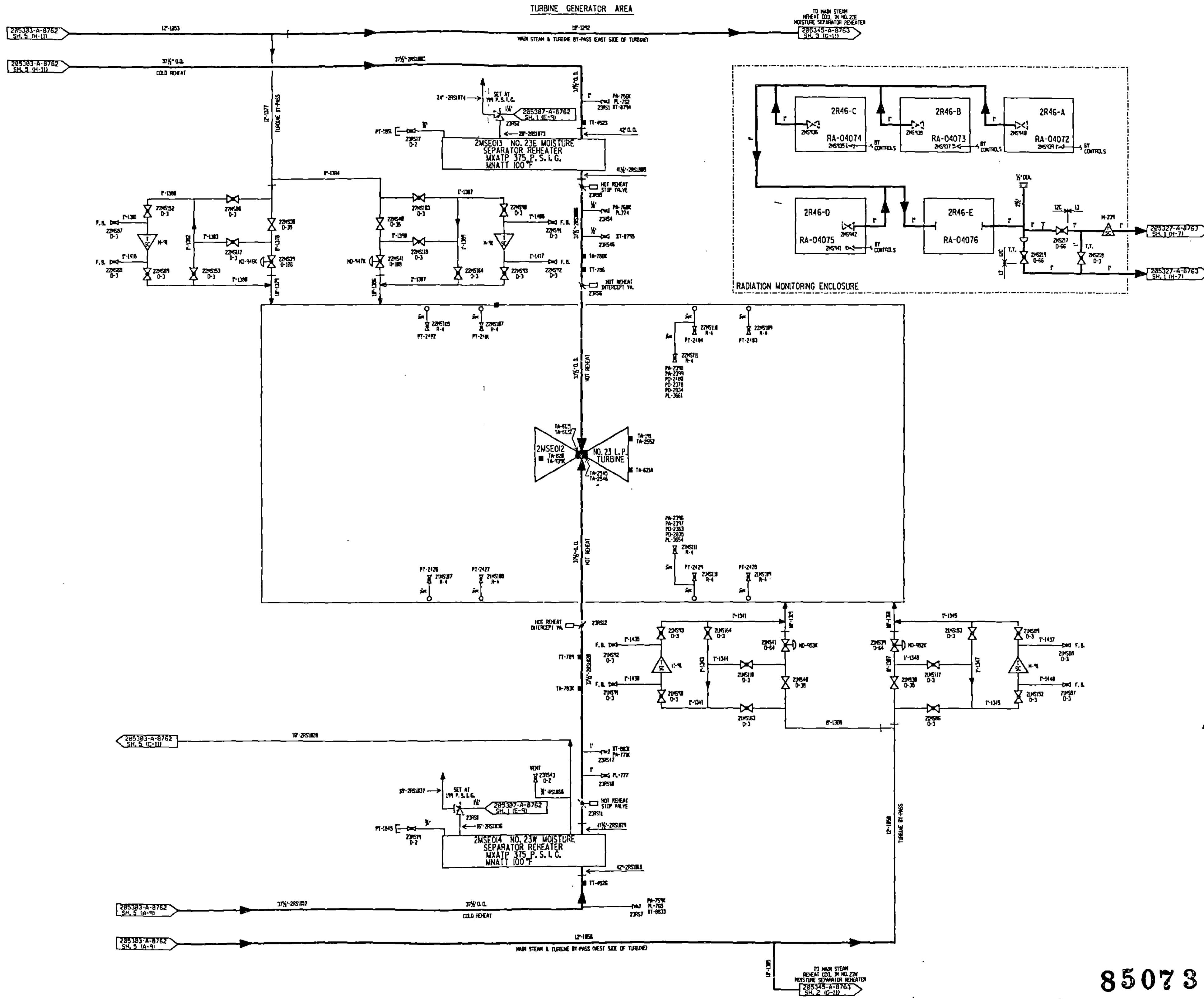
Revision 4
July 22, 1985
Ref. Dwg. 205303A8760-22

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Main, Reheat and Turbine Bypass Steam Unit 2
	Updated FSAR Sheet 5 of 6 Fig 10.3-1E



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Revision 4
July 22, 1985
Ref. Dwg. 205303A8760-22

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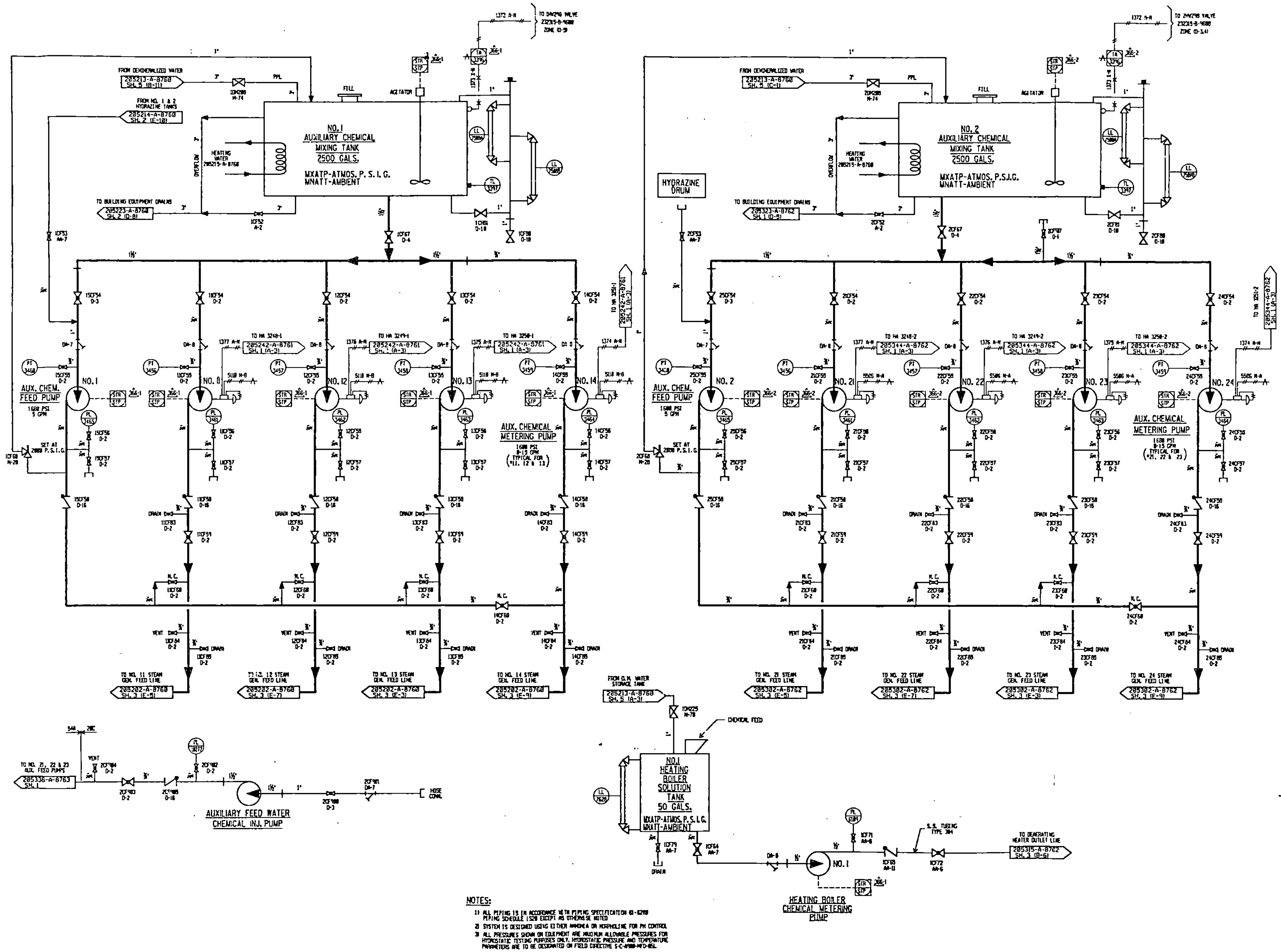
	Updated FSAR Sheet 6 of 6 Fig 10.3-1B



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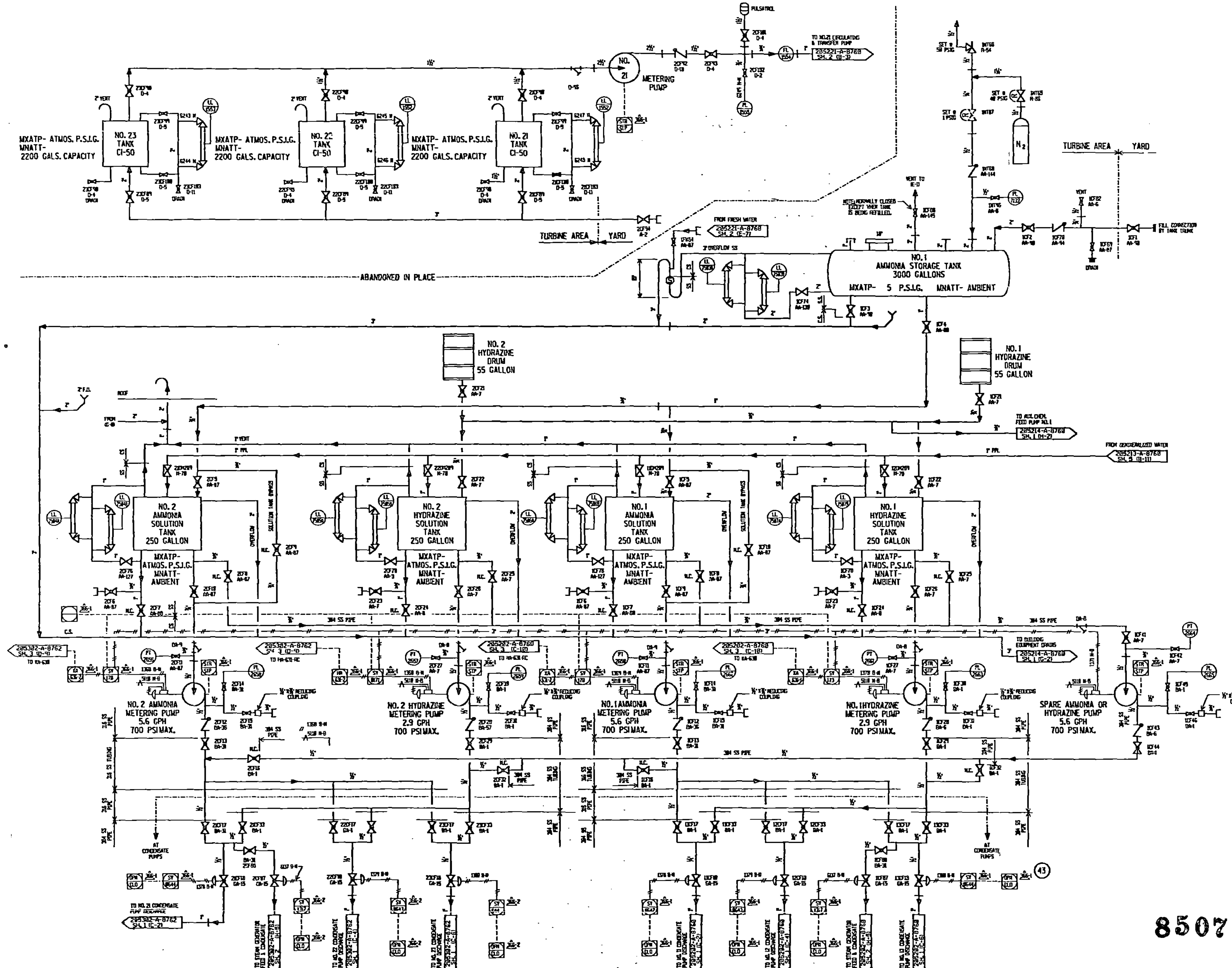
Revision 4
July 22, 1985
Ref. Dwg. 205214A8760-15

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Feedwater Chemical Treatment System
	Updated FSAR Sheet 1 of 2 Fig 10.3-3



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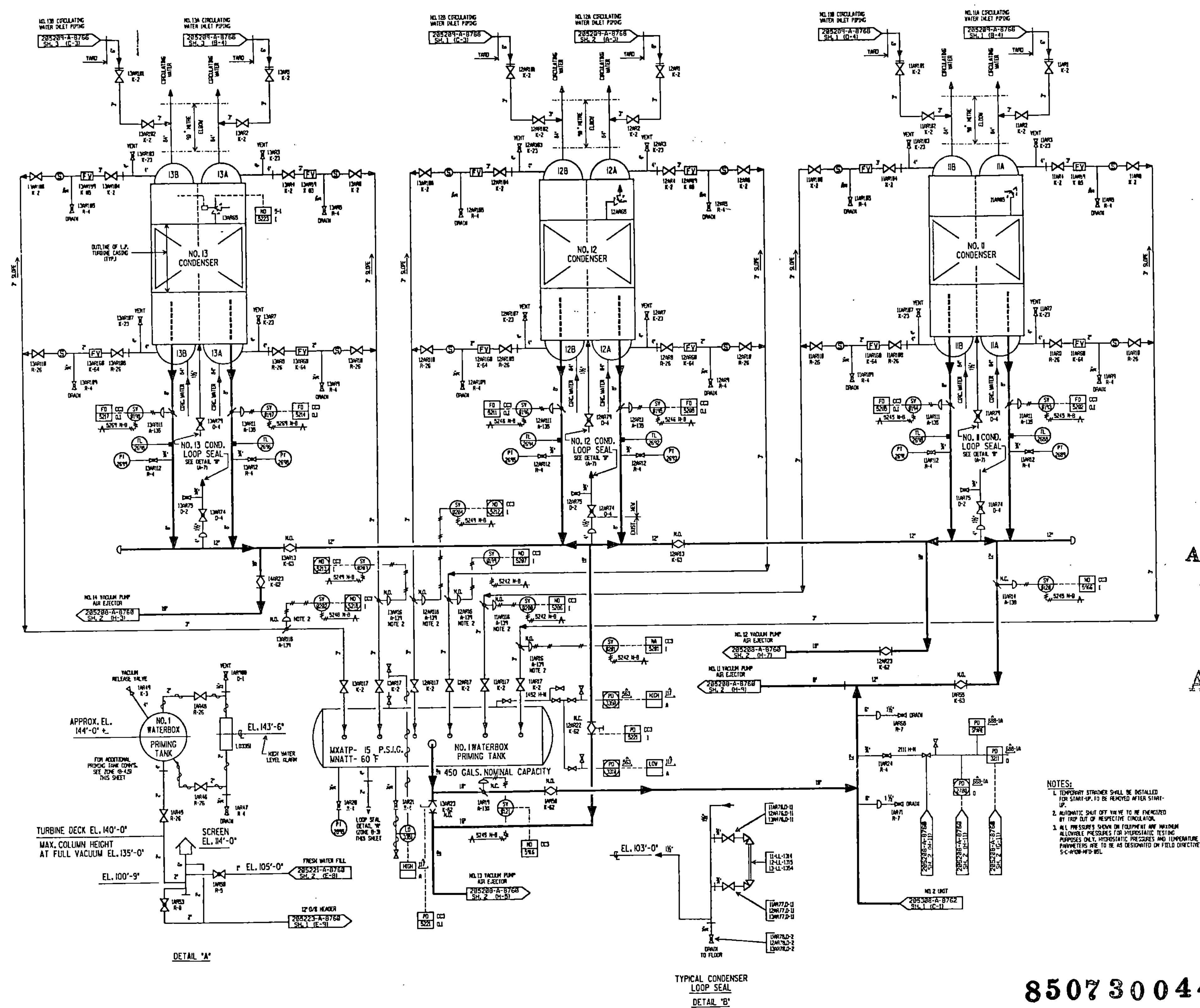
8507300447 -148

Revision 4
July 22, 1985
Ref. Dwg. 205214A8760-16

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Feedwater Chemical Treatment System
	Updated FSAR Sheet 2 of 2 Fig 10.3-3



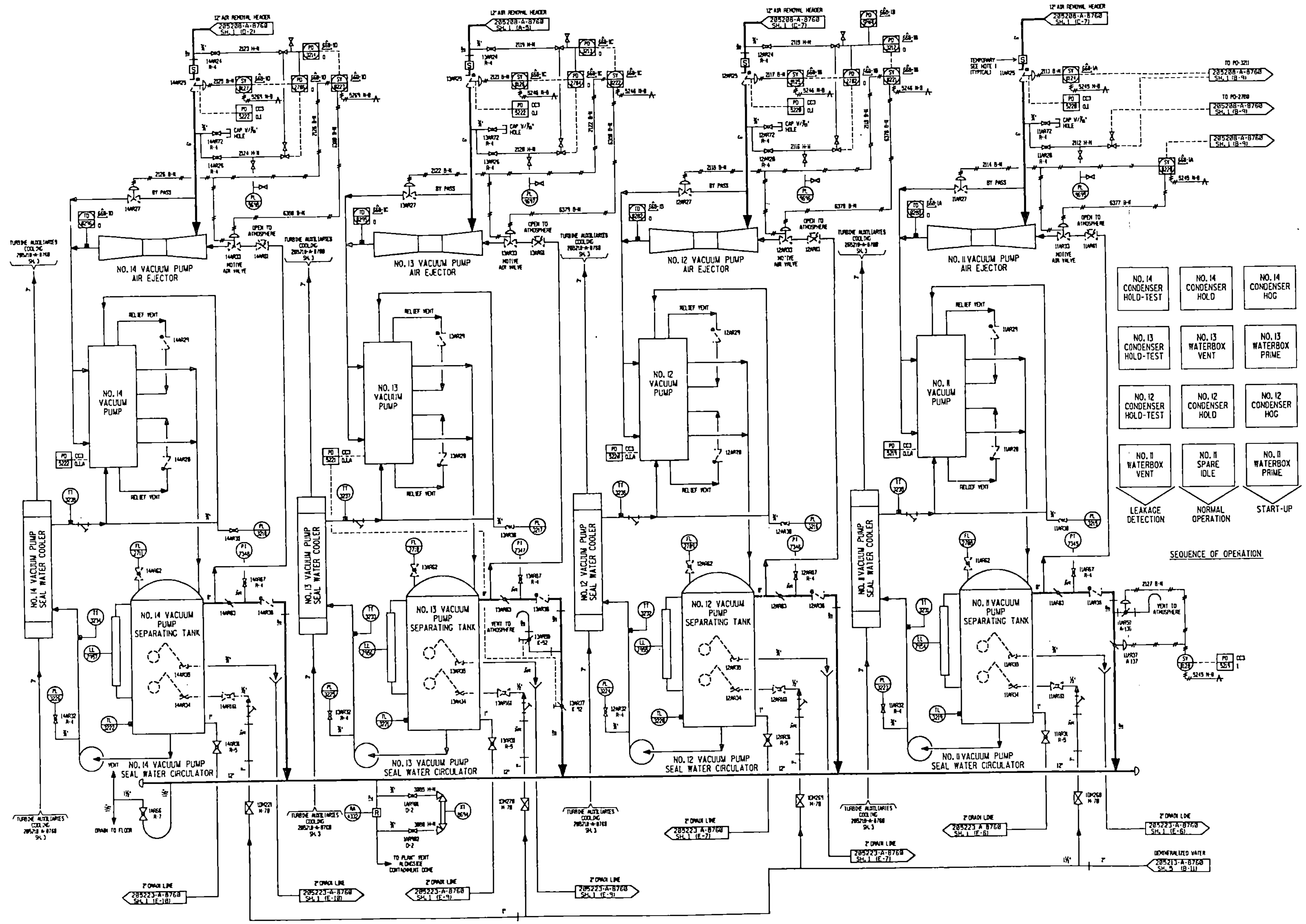
Also Available On Aperture Card

TI APERTURE CARD

8507300447-149

Revision 4
July 22, 1985
Ref. Dwg. 205208A8760-16

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Condenser Air Removal and Priming
	Updated FSAR Sheet 1 of 2 Fig 10.4-1



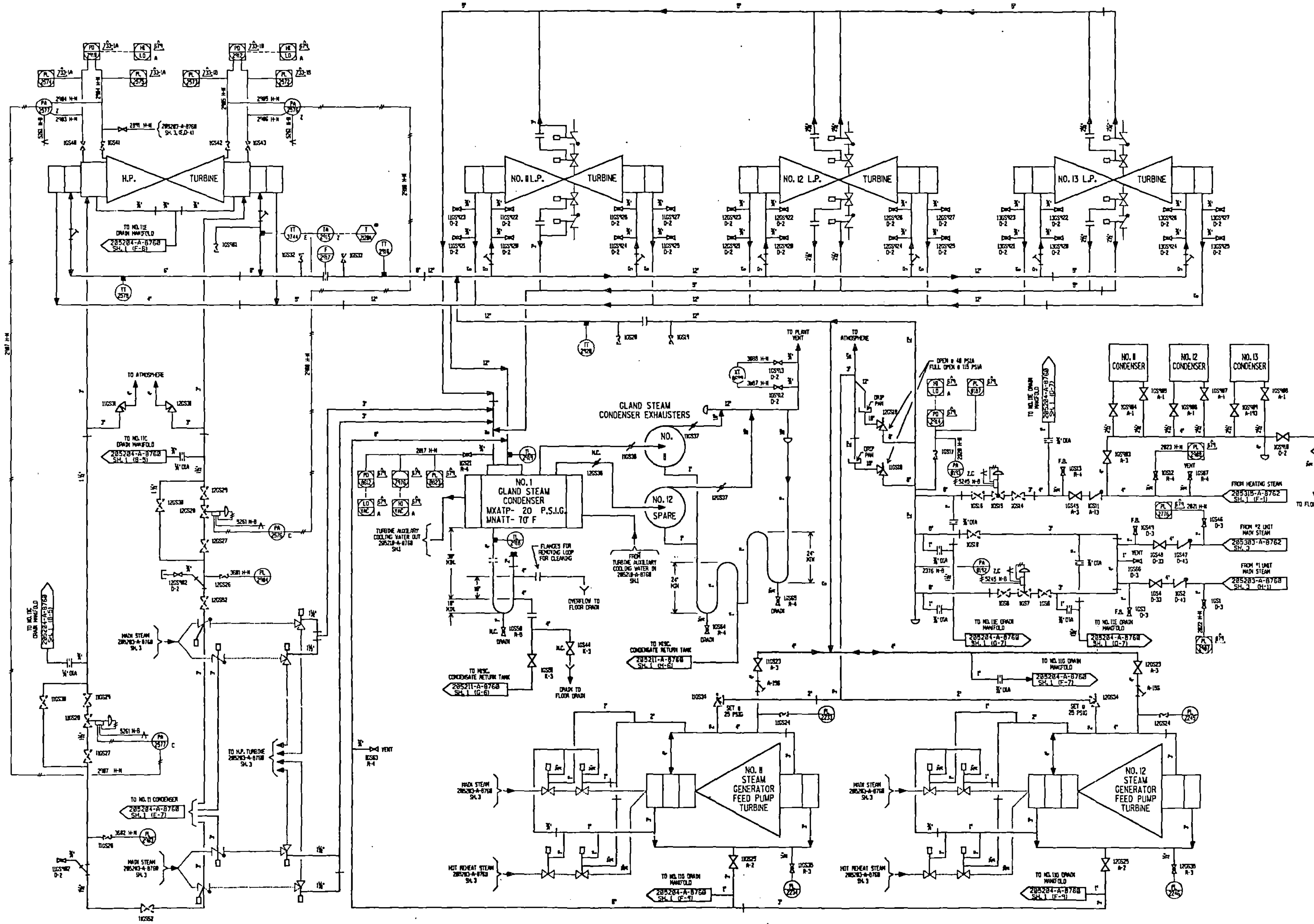
Also Available On Aperture Card

TI APERTURE CARD

8507300447-150

Revision 4
July 22, 1985
Ref. Dwg. 205208A8760-16

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Condenser Air Removal and Priming
	Updated FSAR Sheet 2 of 2 Fig 10.4-1

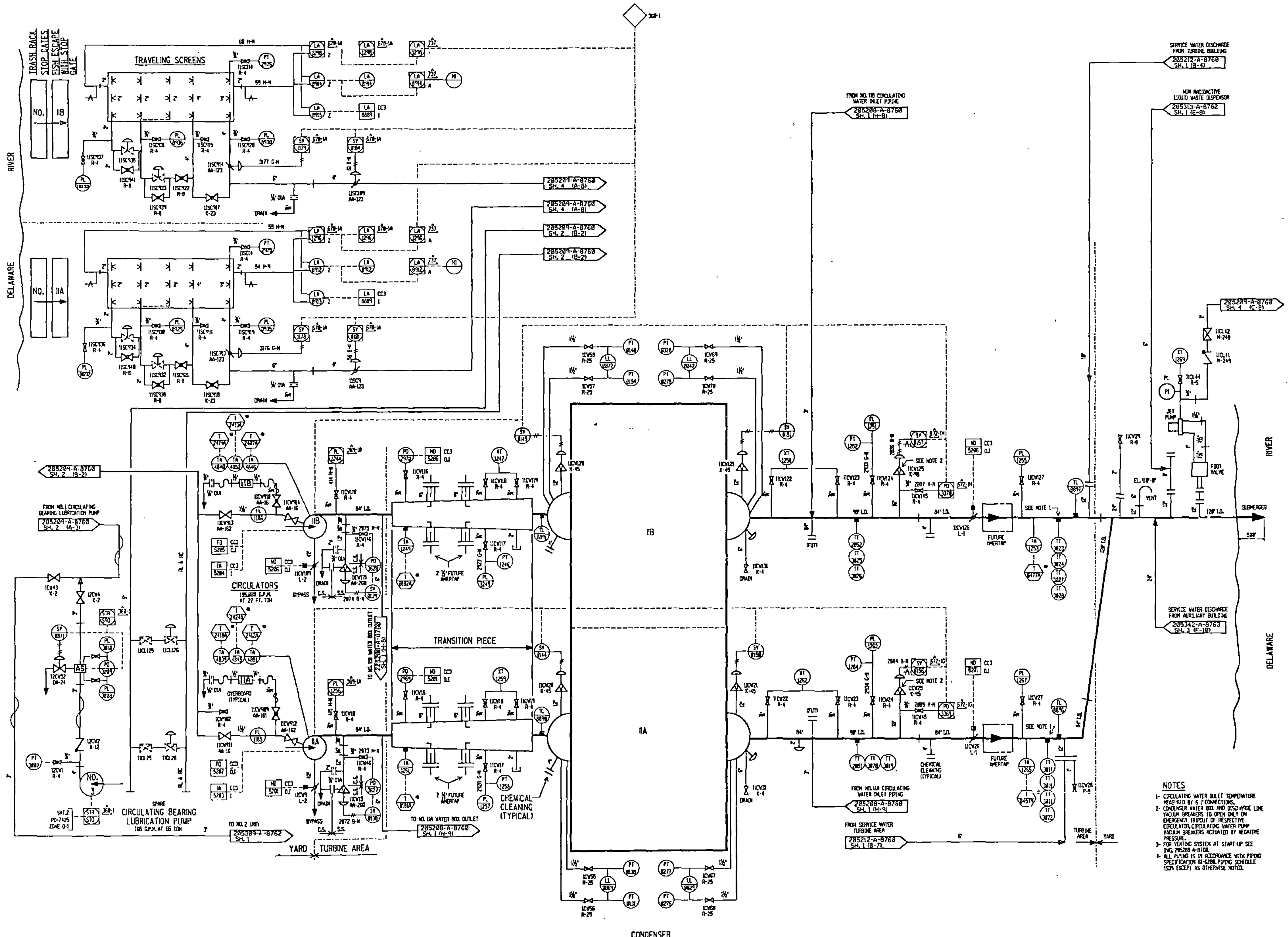


NOTE:

8507300447-151

Revision 4
July 22, 1985
Ref. Dwg. 205207A8760-11

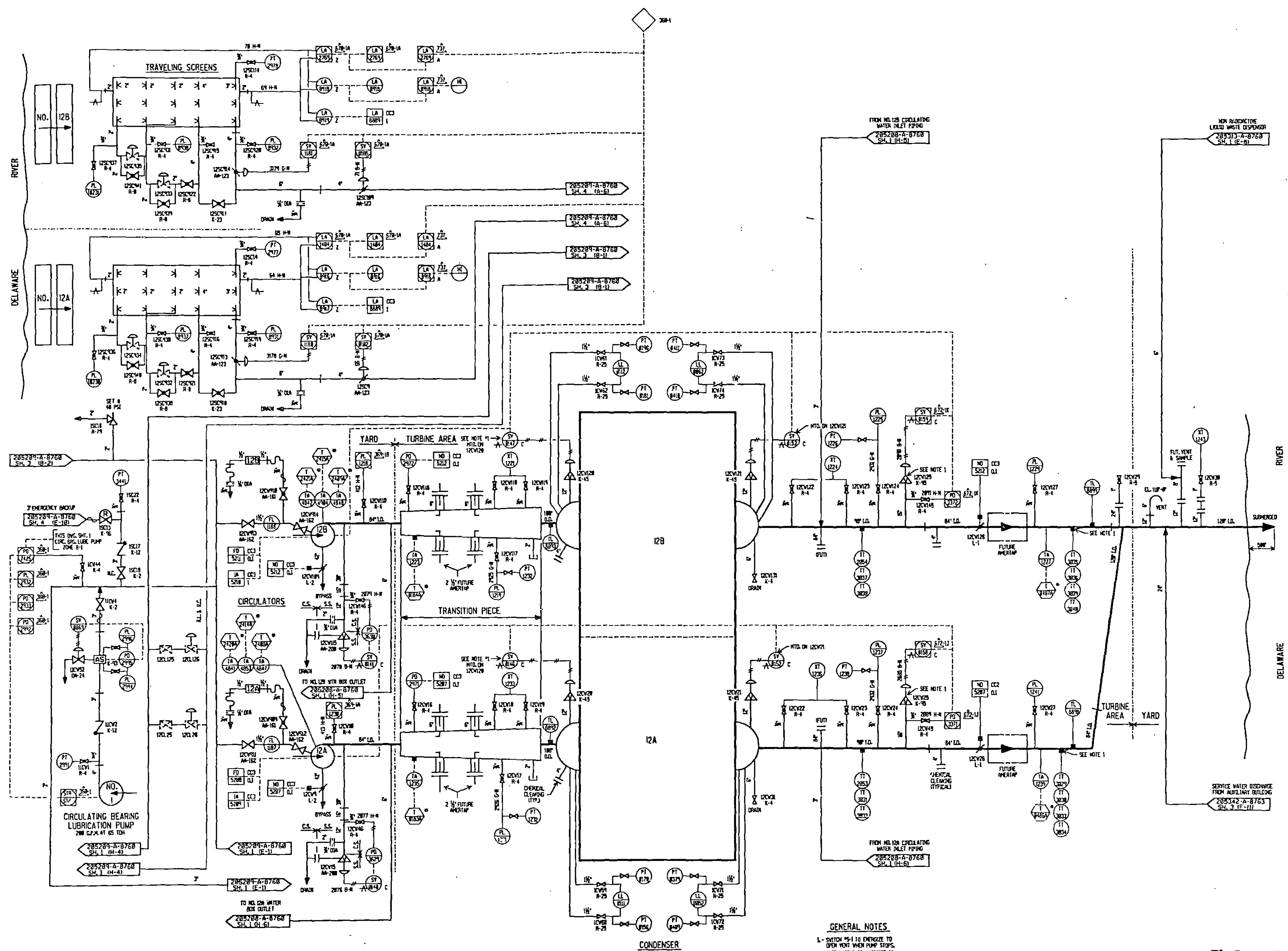
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Turbine Gland Sealing Steam and Leak-Off
	Updated FSAR Fig 10.4-2



8507300447-152

Revision 4
July 22, 1985
Ref. Dwg. 205209A8760-24

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Circulating Water System Unit 1
	Updated FSAR Sheet 1 of 4 Fig 10.4-3A



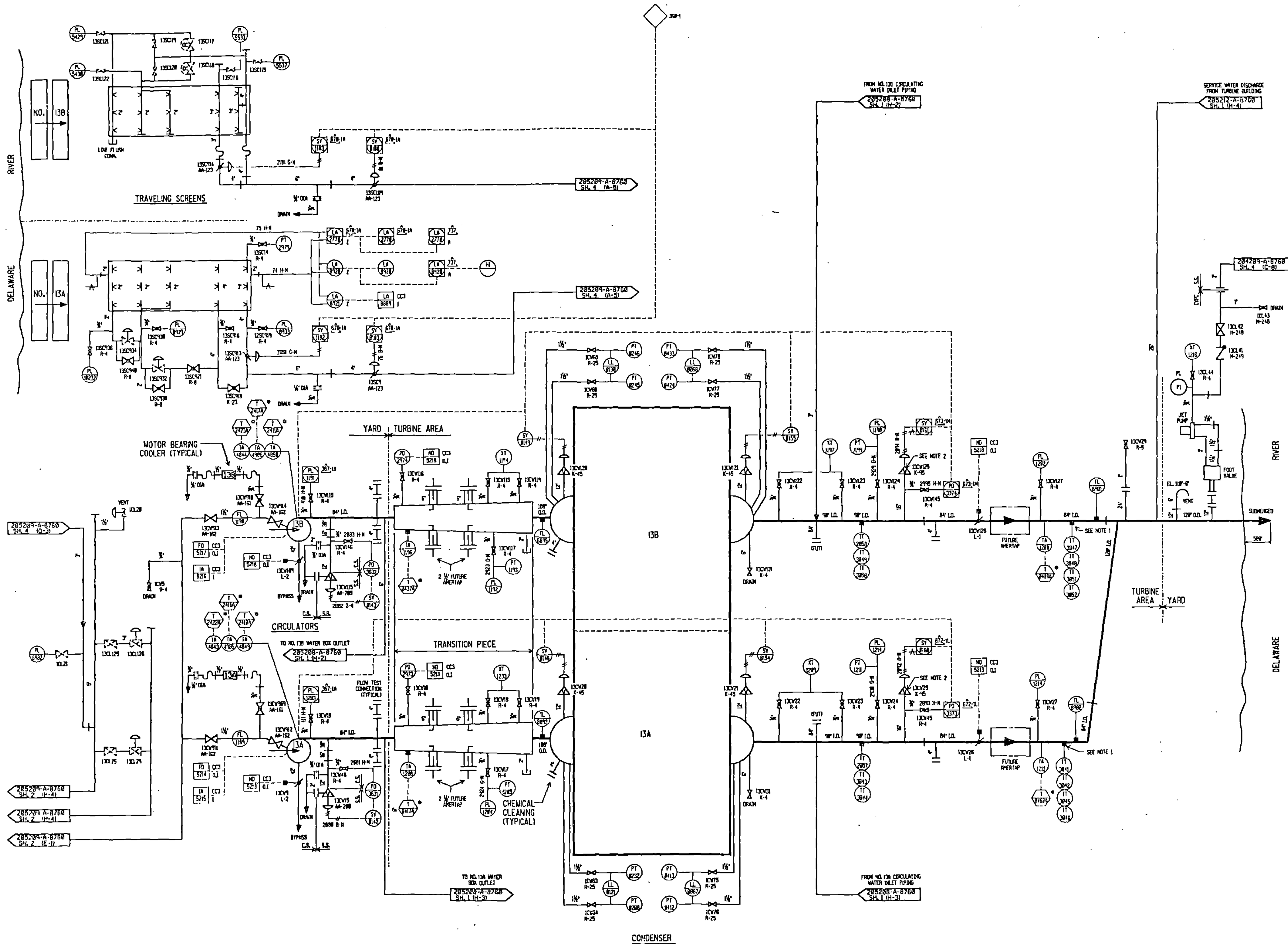
Also Available On
Aperture Card

TI
APERTURE
CARD

8507300447 -153

Revision 4
July 22, 1985
Ref. Dwg. 205209A8760-24

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Circulating Water System Unit 1
	Updated FSAR Sheet 2 of 4 Fig 10.4-3A



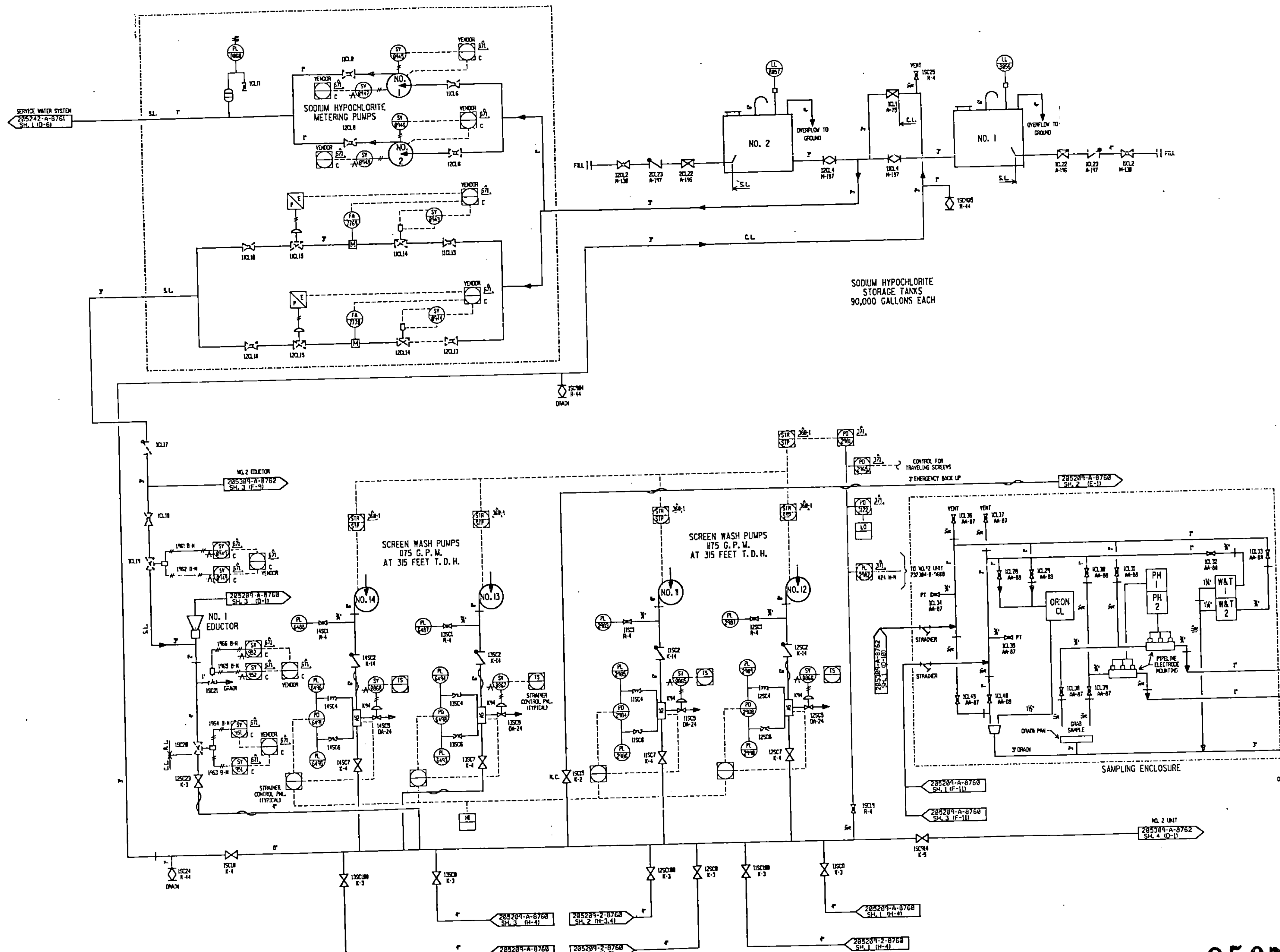
Also Available On Aperture Card

TI APERTURE CARD

8507300447-154

Revision 4
July 22, 1985
Ref. Dwg. 205209A8760-24

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Circulating Water System Unit 1
	Updated FSAR Sheet 3 of 4 Fig 10.4-3A



Also Available On Aperture Card

TI APERTURE CARD

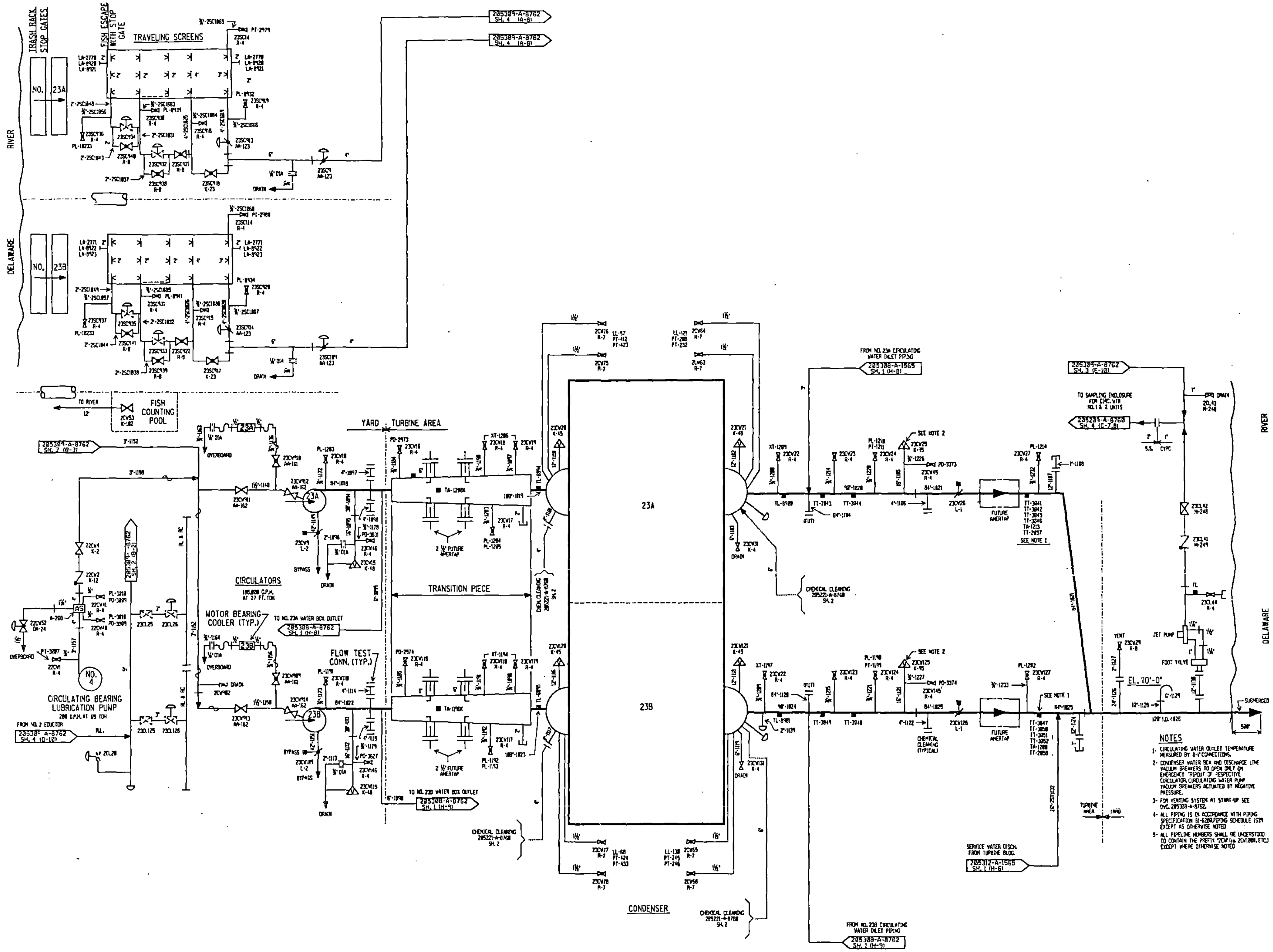
8507300447-155

Revision 4
July 22, 1985
Ref. Dwg. 205209A8760-24

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Circulating Water System
Unit 1

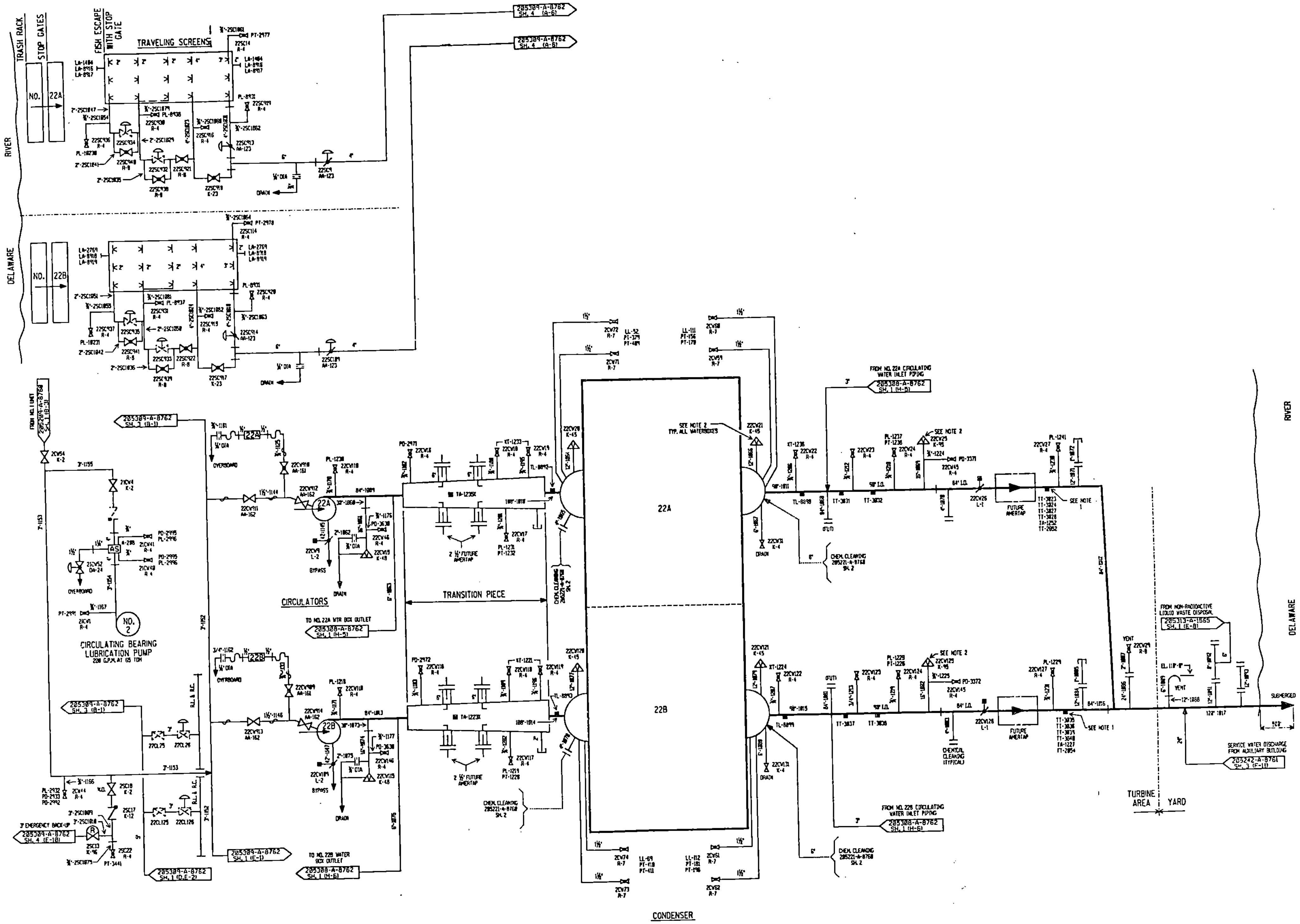
Updated FSAR Sheet 4 of 4 Fig 10.4-3A



8507300447 -156

Revision 4
July 22, 1985
Ref. Dwg. 205309A8762-20

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Circulating Water System Unit 2
	Updated FSAR Sheet 1 of 4 Fig 10.4-3B



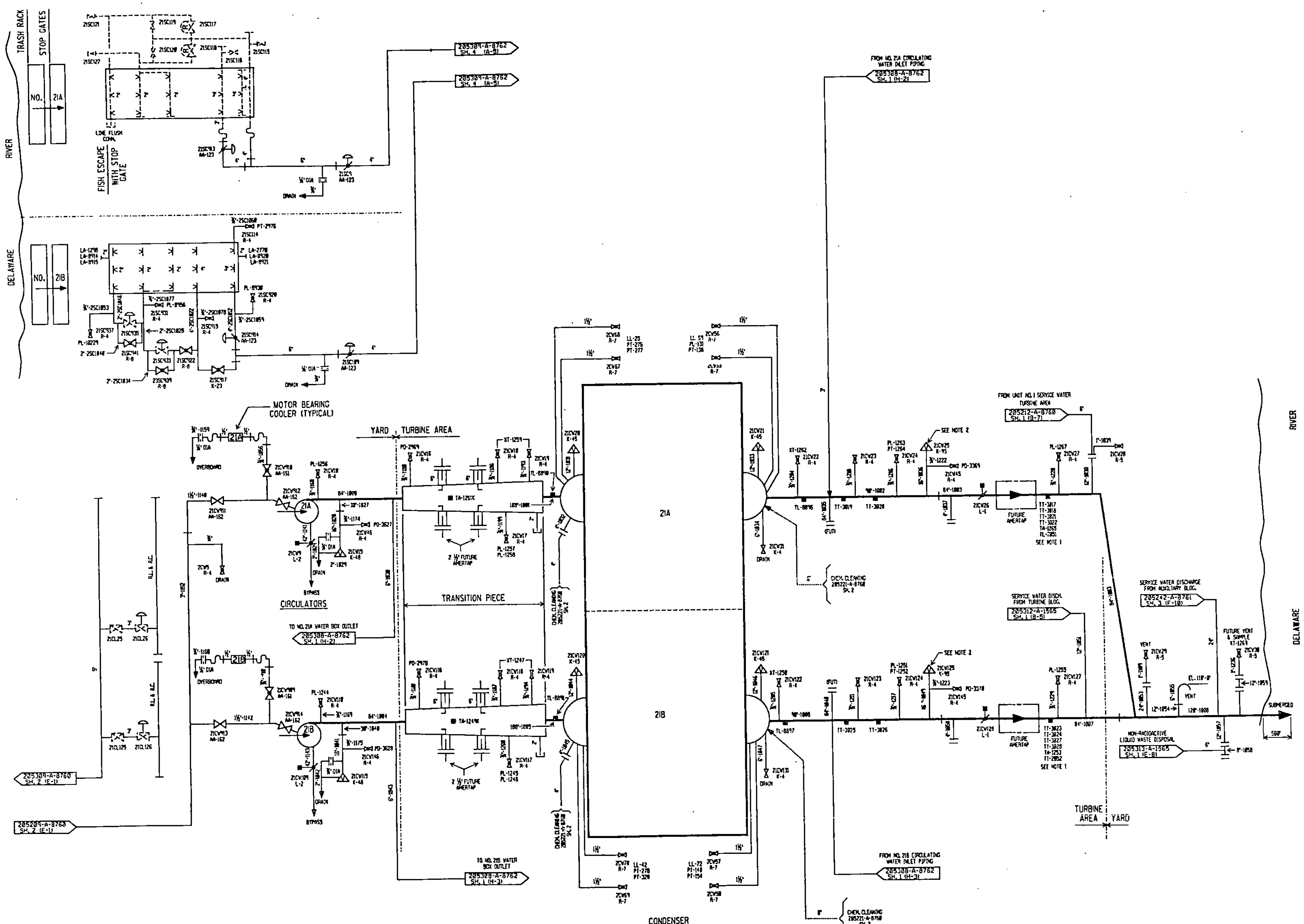
Also Available On Aperture Card

TI APERTURE CARD

8507300447-157

Revision 4
July 22, 1985
Ref. Dwg. 205309A8762-20

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Circulating Water System Unit 2
	Updated FSAR Sheet 2 of 4 Fig 10.4-3B



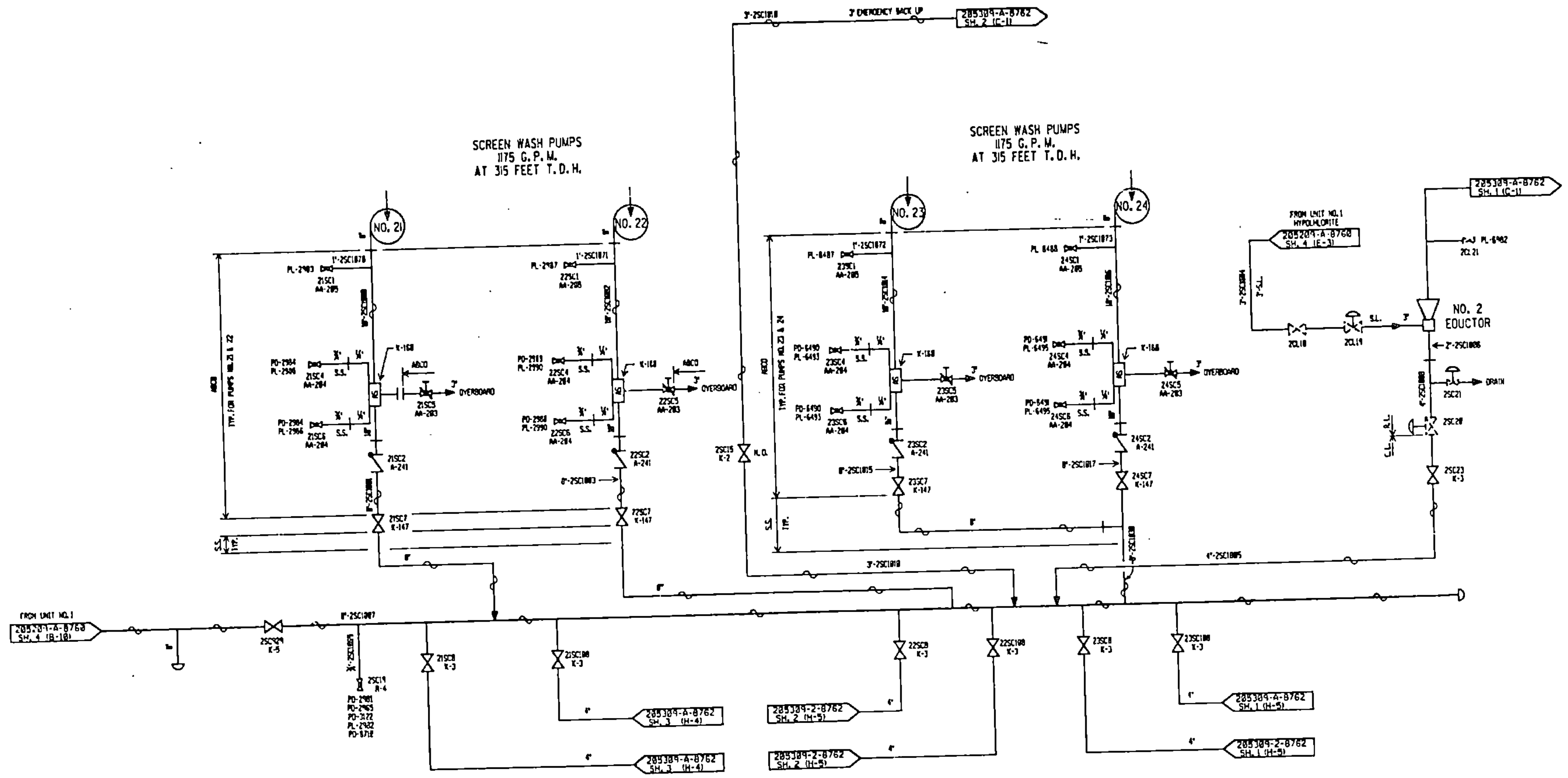
Also Available On Aperture Card

TI APERTURE CARD

8507300447 -158

Revision 4
July 22, 1985
Ref. Dwg. 205309A8762-20

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Circulating Water System Unit 2
	Updated FSAR Sheet 3 of 4 Fig 10.4-3B



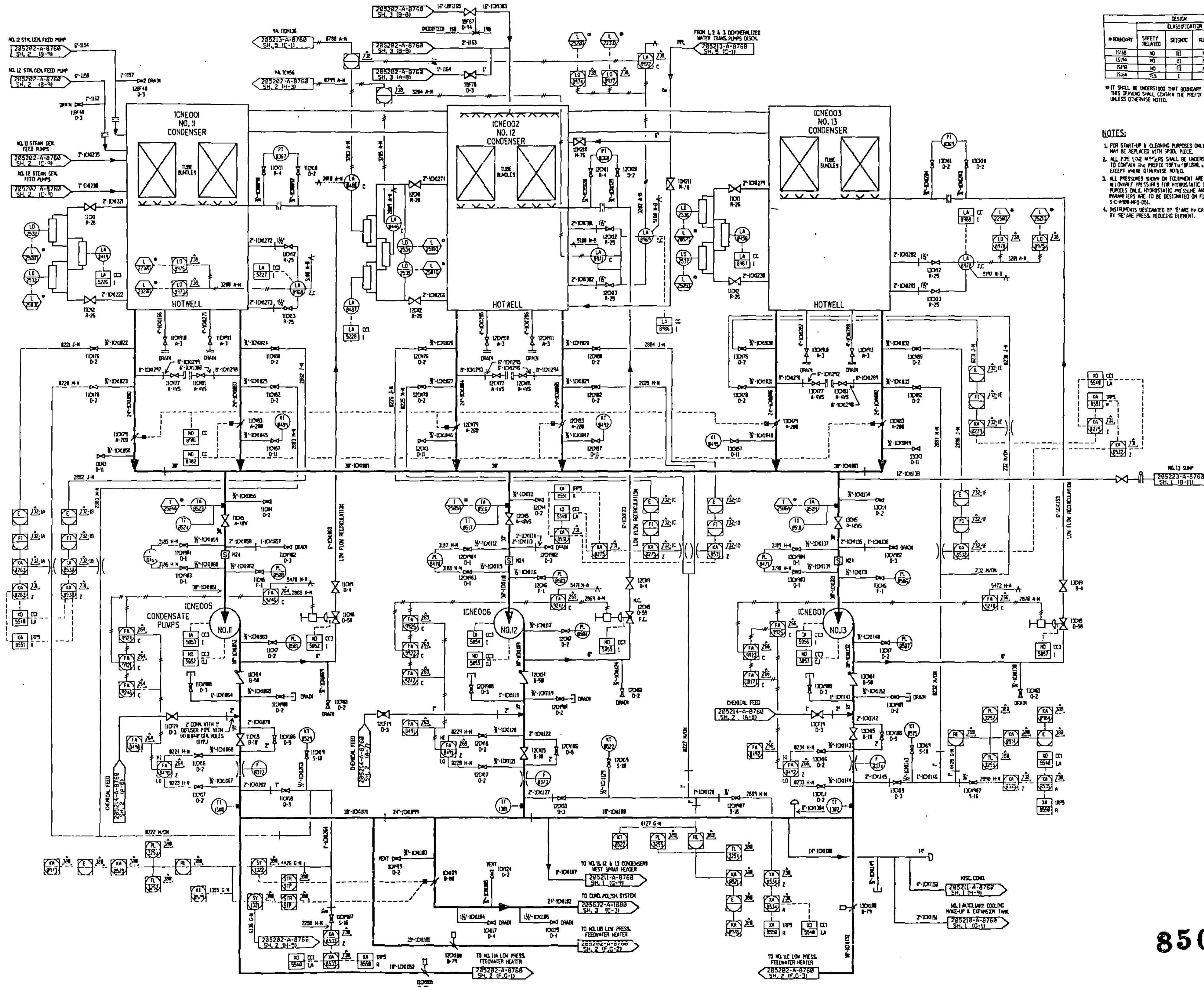
Also Available On
Aperture Card

TI
APERTURE
CARD

8507300447 -159

Revision 4
July 22, 1985
Ref. Dwg. 205309A8762-20

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Circulating Water System Unit 2
	Updated FSAR Sheet 4 of 4 Fig 10.4-3B



	DESIGN			
	CLASSIFICATION			
* BOUNDARY	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S16B	NO	III	NONE	NO
1S19A	NO	III	NONE	NO
1S19B	NO	III	NONE	NO
1S16A	YES	I	II	YES

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

NOTES:

1. FOR START-UP & CLEANING PURPOSES ONLY. MAY BE REPLACED WITH SPOOL PIECE.
2. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1BF" (i.e. 1BF18AH, etc.) EXCEPT WHERE OTHERWISE NOTED.
3. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
4. INSTRUMENTS DESIGNATED BY 'E' ARE H+ CATION EXCHANGER, BY 'RE' ARE PRESS. REDUCING ELEMENT.

Also Available On Aperture Card

TI APERTURE CARD

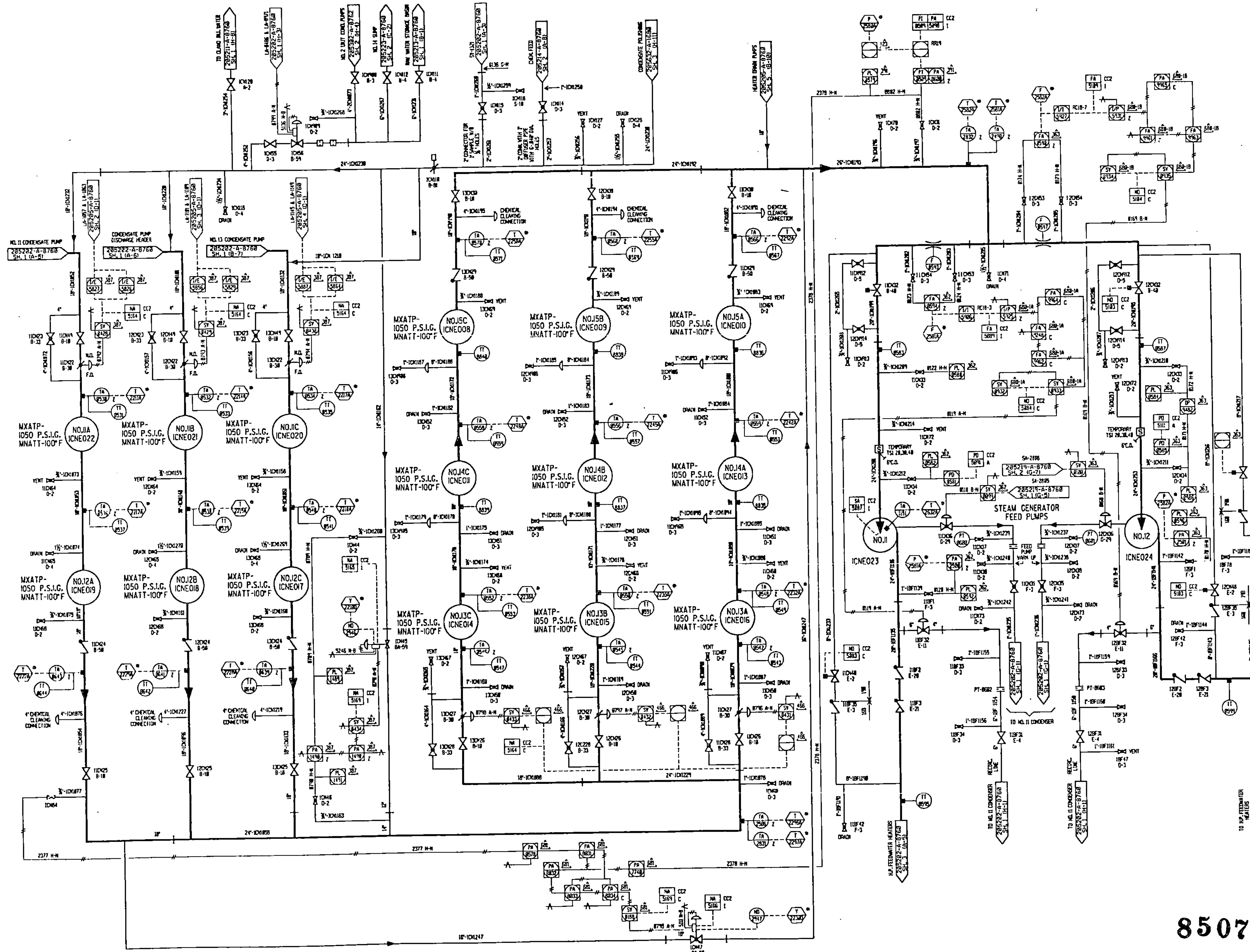
8507300447-160

Revision 4
July 22, 1985
Ref. Dwg. 205202A8760-24

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Steam Generator Feed and Condensate System
Unit 1

Updated FSAR Sheet 1 of 3 Fig 10.4-5A



LOW PRESSURE FEEDWATER HEATERS

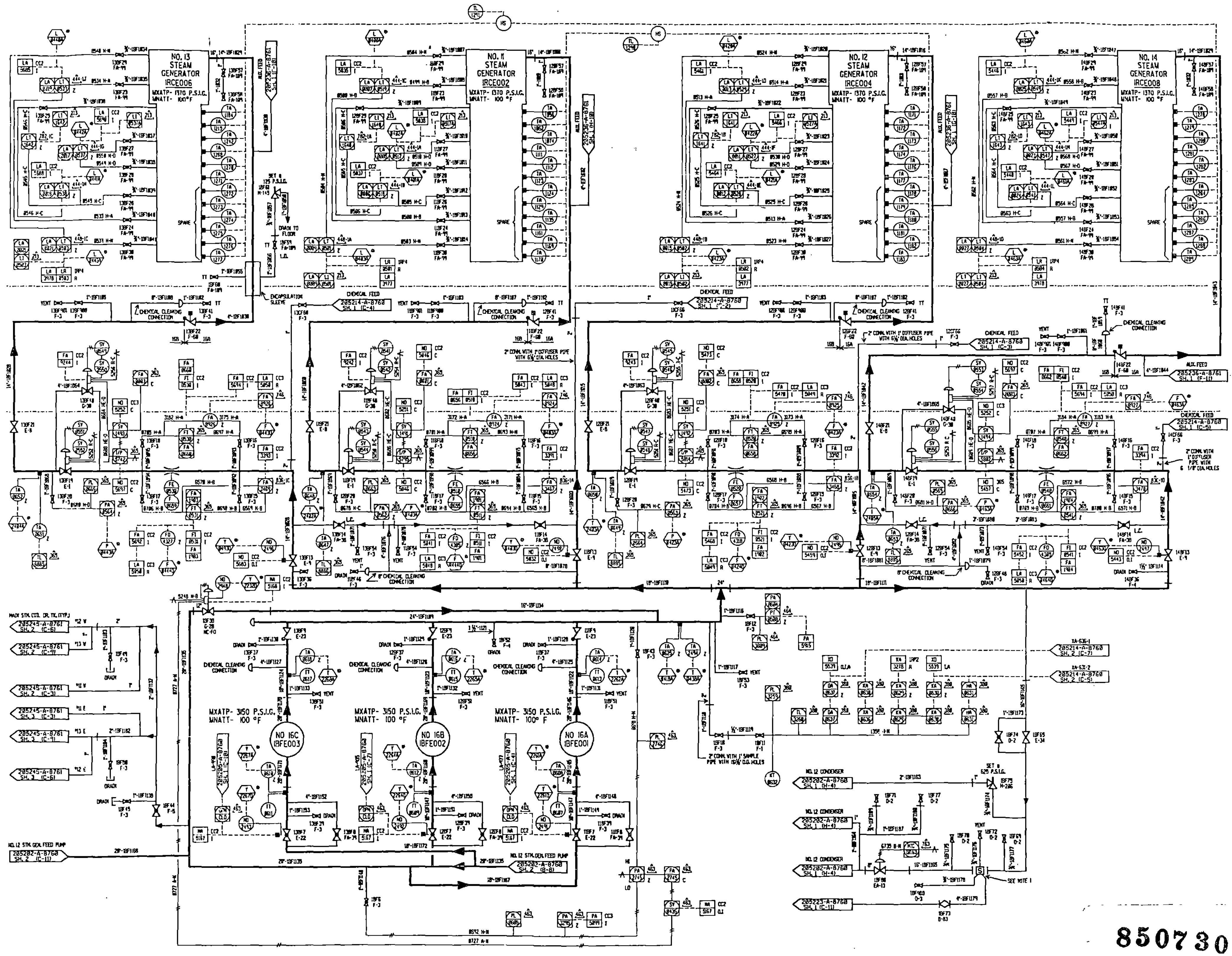
Also Available On Aperture Card

TI APERTURE CARD

8507300447 -16

Revision 4
July 22, 1985
Ref. Dwg. 205202A8760-24

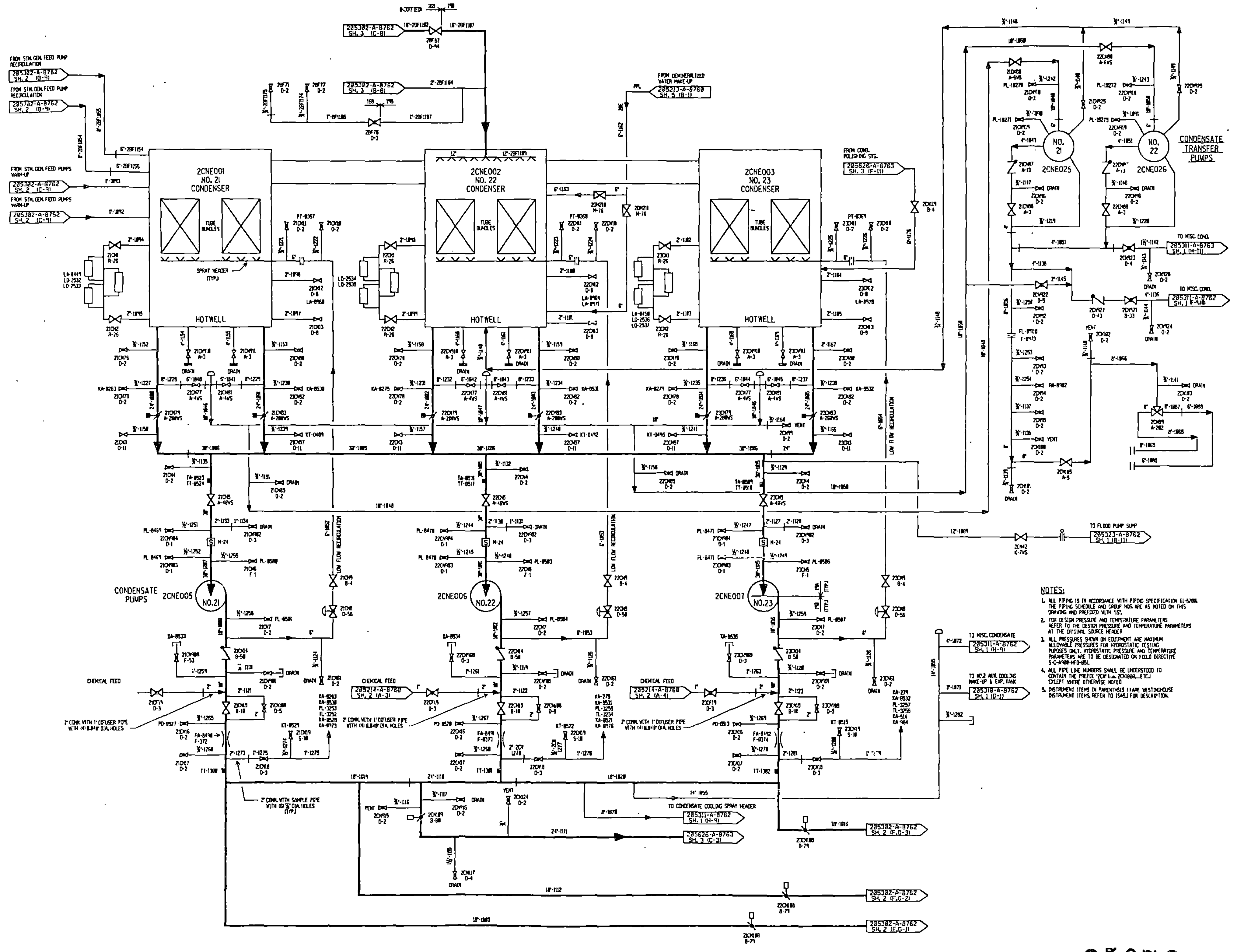
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Steam Generator Feed and Condensate System Unit 1
	Updated FSAR Sheet 2 of 3 Fig 10.4-5A



8507300447-1602

Revision 4
July 22, 1985
Ref. Dwg. 205202A8760-24

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Steam Generator Feed and Condensate System Unit 1
	Updated FSAR Sheet 3 of 3 Fig 10.4-5A



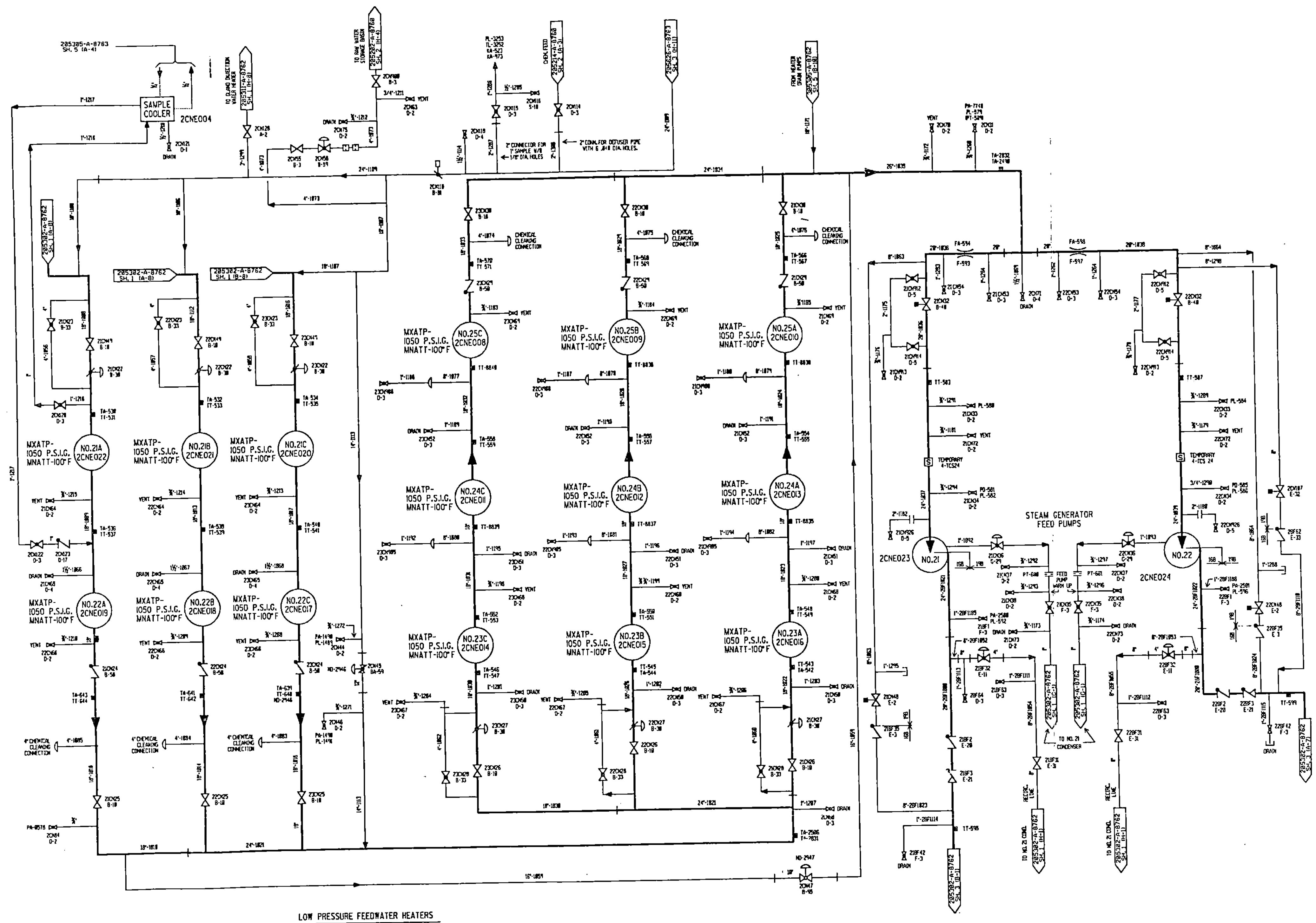
NOTES:

1. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-5200L. THE PIPING SCHEDULE AND GROUP NOS. ARE AS NOTED ON THIS DRAWING AND PREFIXED WITH "15".
2. FOR DESIGN PRESSURE AND TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE AND TEMPERATURE PARAMETERS AT THE ORIGINAL SOURCE HEADER.
3. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-085L.
4. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2CN" (i.e. 2CN1008,...ETC.) EXCEPT WHERE OTHERWISE NOTED.
5. INSTRUMENT ITEMS IN PARENTHESIS ( ) ARE WESTINGHOUSE INSTRUMENT ITEMS, REFER TO (SAS) FOR DESCRIPTION.

8507300447 -163

Revision 4
July 22, 1985
Ref. Dwg. 205302A8762-21

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Steam Generator Feed and Condensate System Unit 2
	Updated FSAR Sheet 1 of 3 Fig 10.4-5B



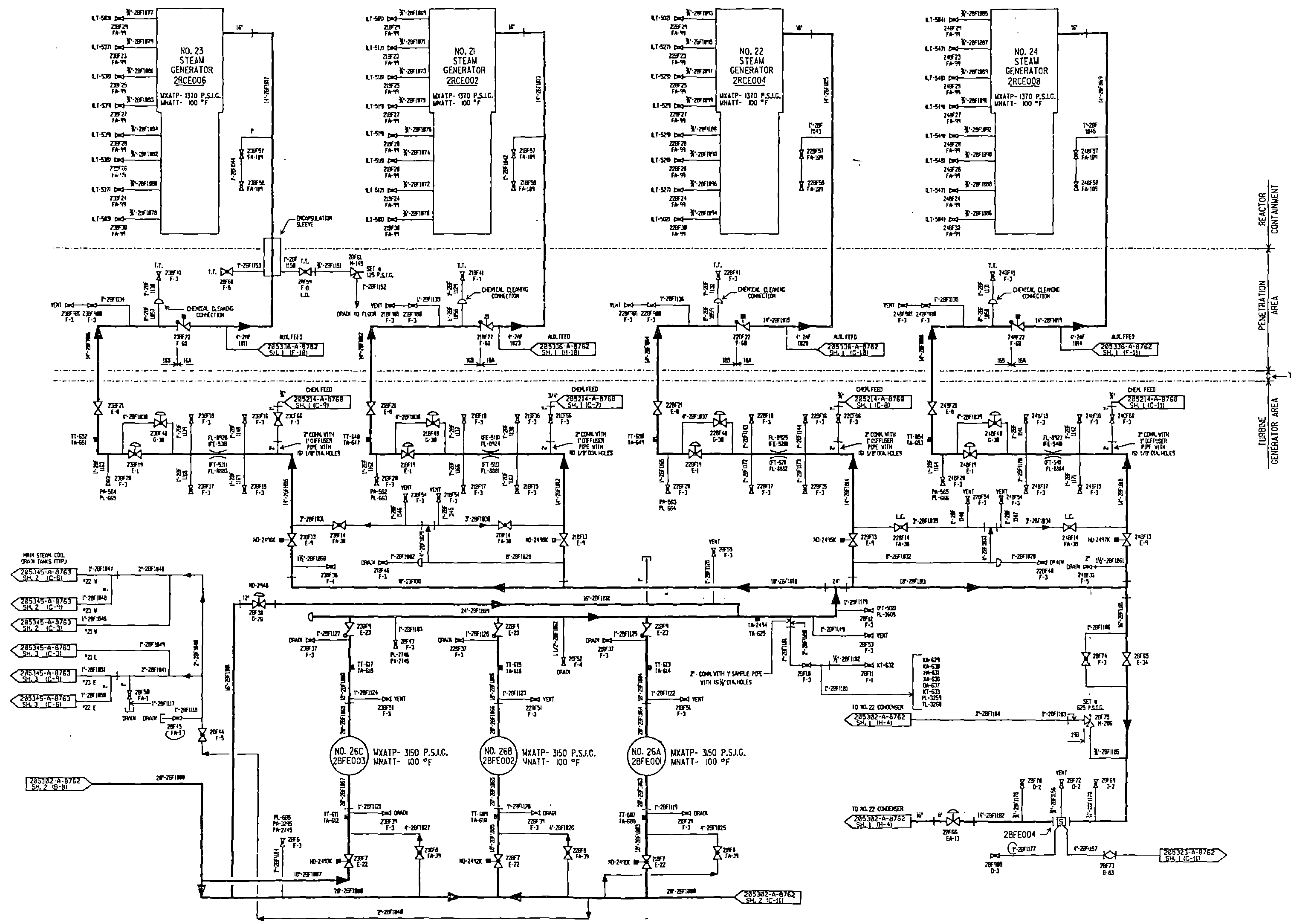
Also Available On Aperture Card

TI APERTURE CARD

8507300447 -104

Revision 4
July 22, 1985
Ref. Dwg. 205302A8762-21

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Steam Generator Feed and Condensate System Unit 2
	Updated FSAR Sheet 2 of 3 Fig 10.4-5B



HIGH PRESSURE FEEDWATER HEATERS

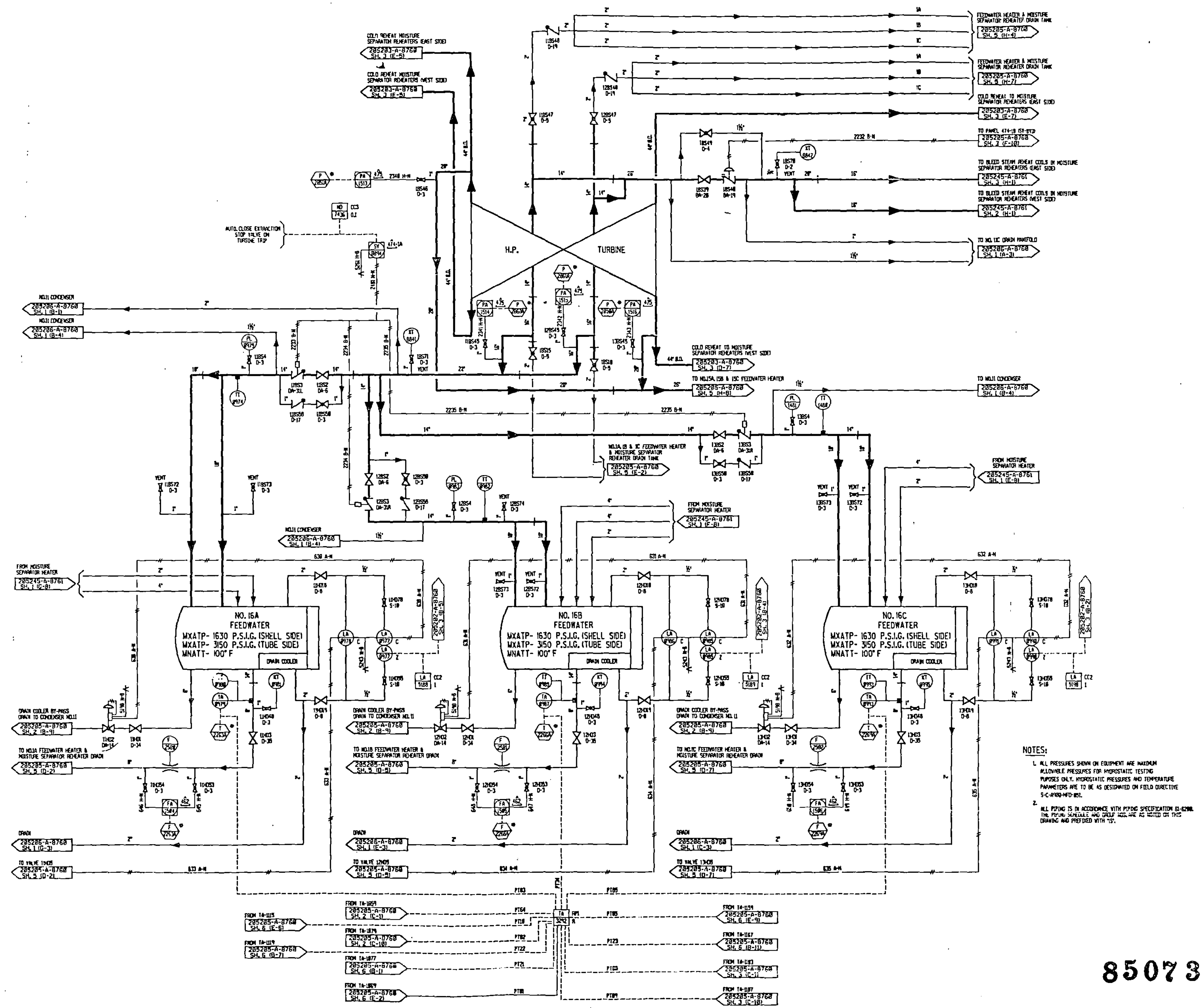
Also Available On Aperture Card

TI APERTURE CARD

8507300447-165

Revision 4
July 22, 1985
Ref. Dwg. 205302A8762-21

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Steam Generator Feed and Condensate System Unit 2
	Updated FSAR Sheet 3 of 3 Fig 10.4-5B



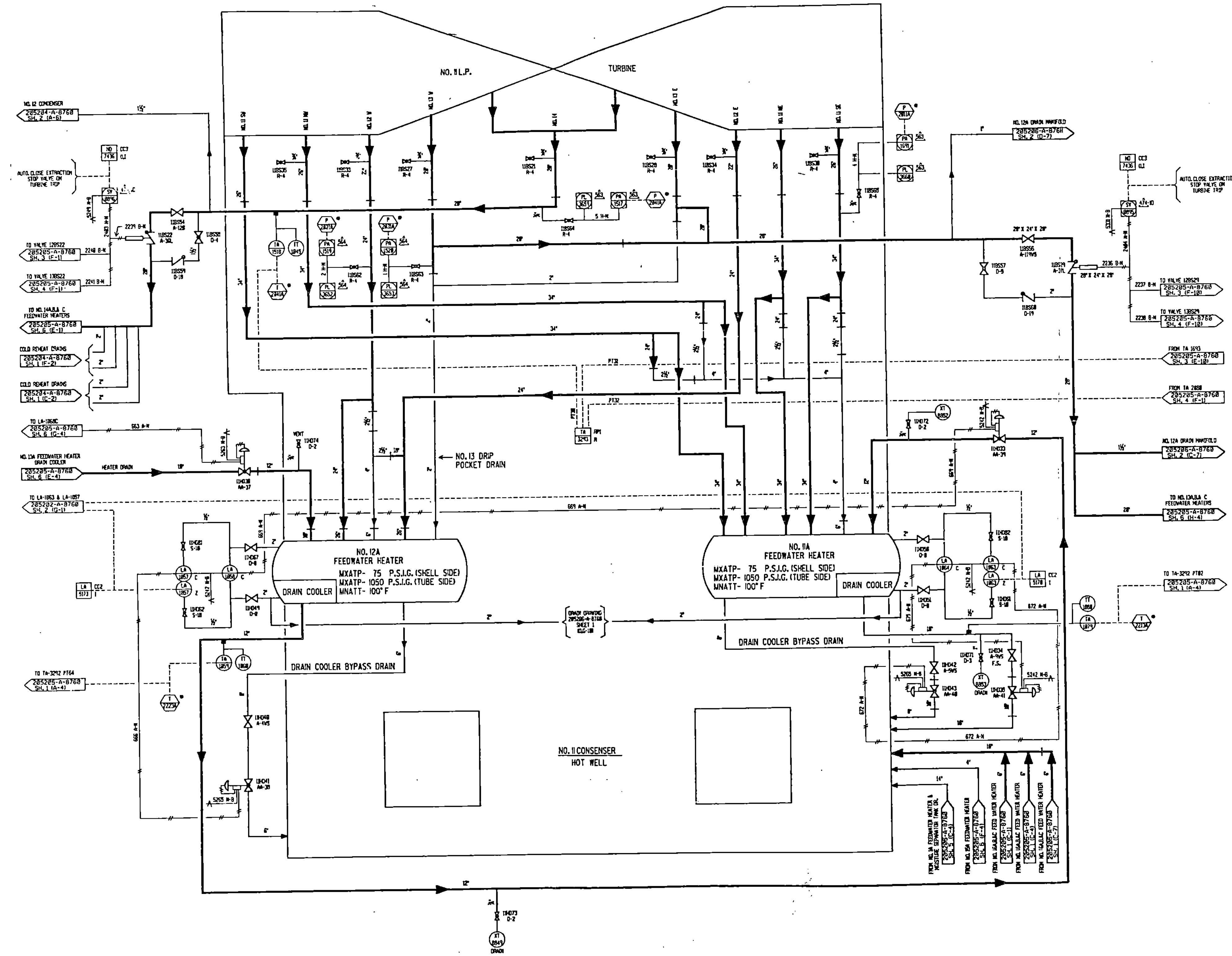
Also Available On Aperture Card

TI APERTURE CARD

8507300447 -166

Revision 4
July 22, 1985
Ref. Dwg. 205205A8760-18

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Bleed Steam and Heater Drains Unit 1
	Updated FSAR Sheet 1 of 6 Fig 10.4-6A



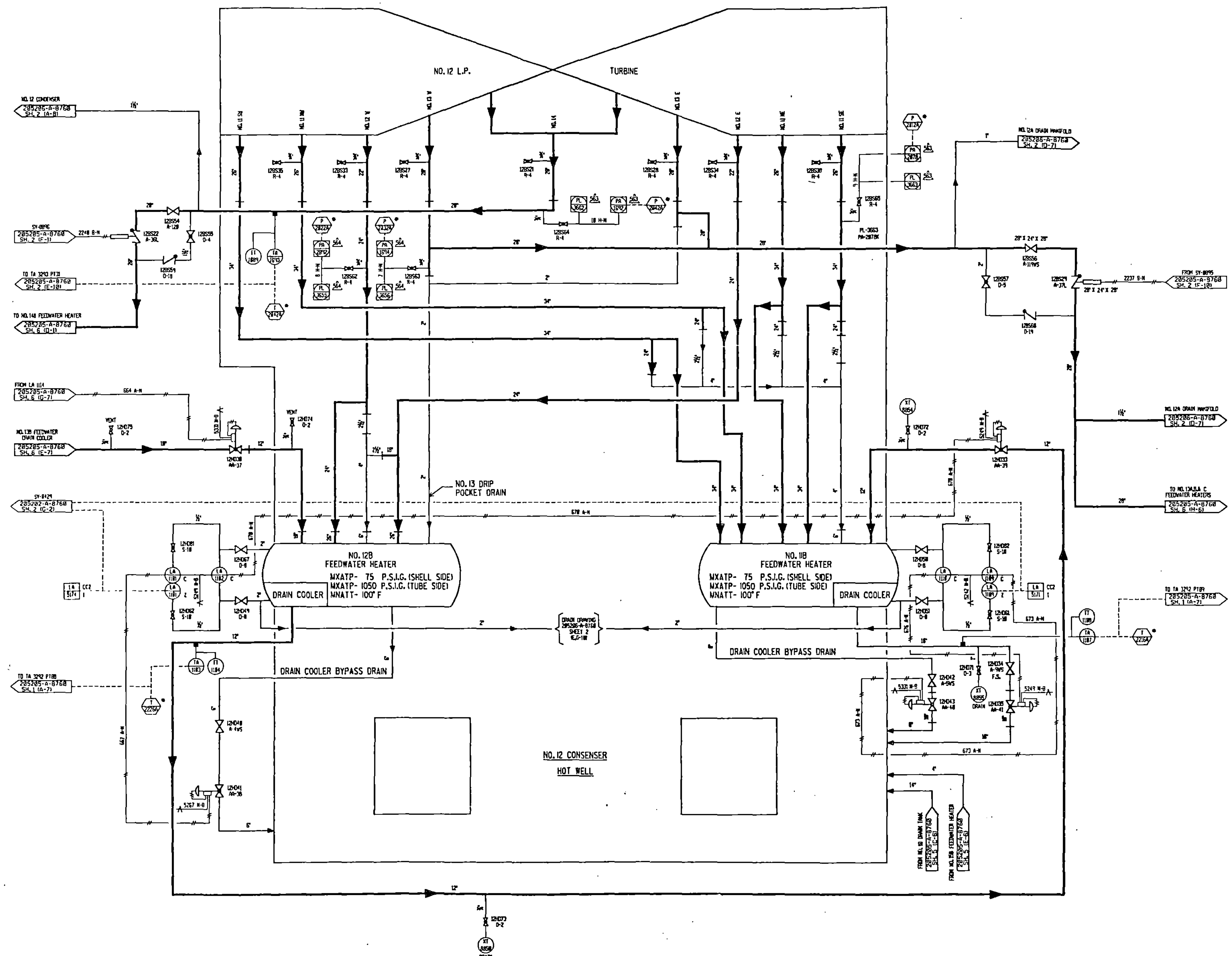
Also Available On Aperture Card

TI APERTURE CARD

8507300447-167

Revision 4
July 22, 1985
Ref. Dwg. 205205A8760-18

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Bleed Steam and Heater Drains Unit 1
	Updated FSAR Sheet 2 of 6 Fig 10.4-6A



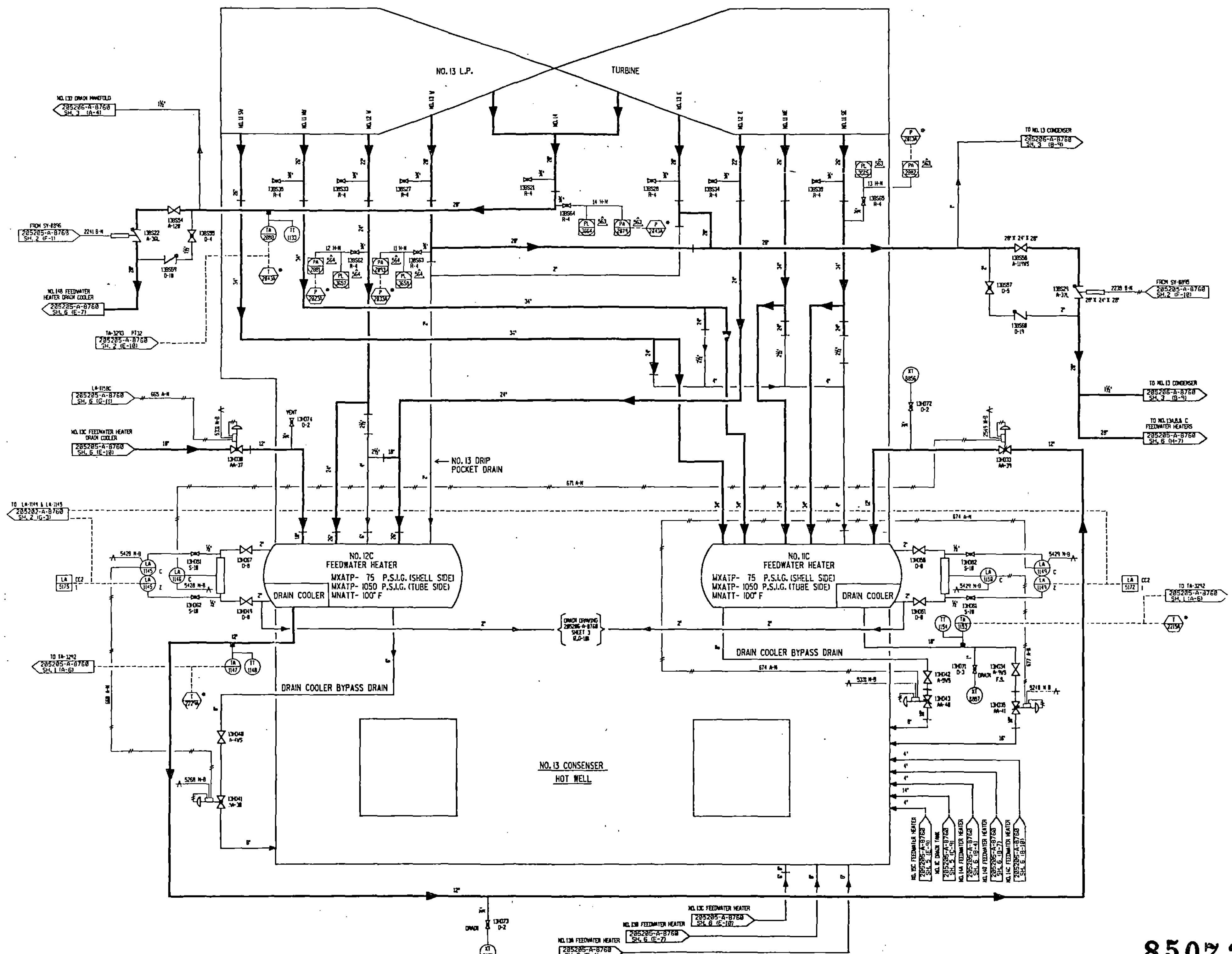
Also Available On Aperture Card

TI APERTURE CARD

8507300447-168

Revision 4
July 22, 1985
Ref. Dwg. 205205A8760-18

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Bleed Steam and Heater Drains Unit 1
	Updated FSAR Sheet 3 of 6 Fig 10.4-6A



Also Available On Aperture Card

TI APERTURE CARD

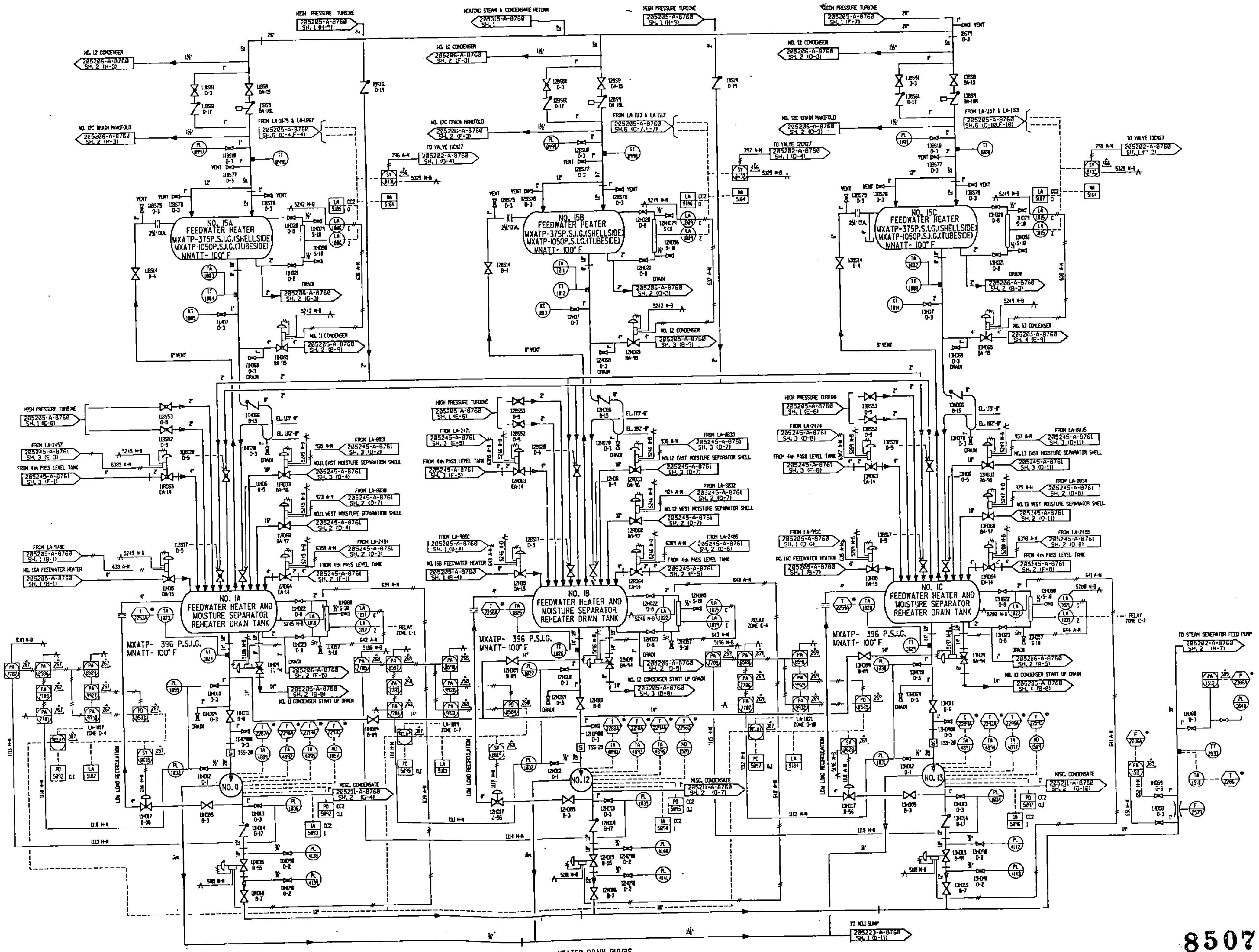
8507300447-169

Revision 4
July 22, 1985
Ref. Dwg. 205205A8760-18

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Bleed Steam and Heater Drains
Unit 1

Updated FSAR Sheet 4 of 6 Fig 10.4-6A



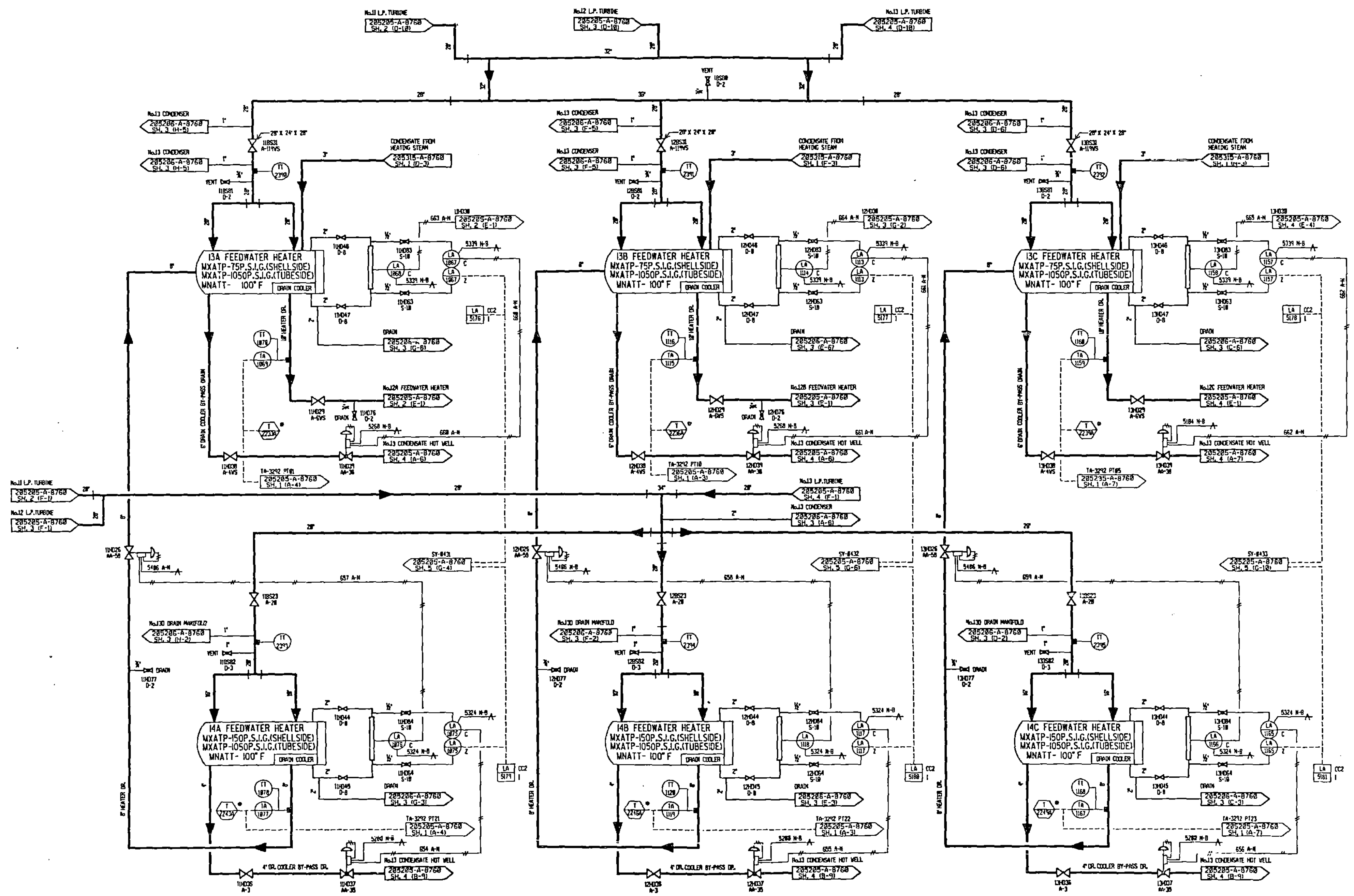
Also Available On Aperture Card

TI APERTURE CARD

8507300447-170

Revision 4
July 22, 1985
Ref. Dwg. 205205A8760-18

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Bleed Steam and Heater Drains Unit 1
	Updated FSAR Sheet 5 of 6 Fig 10.4-6A



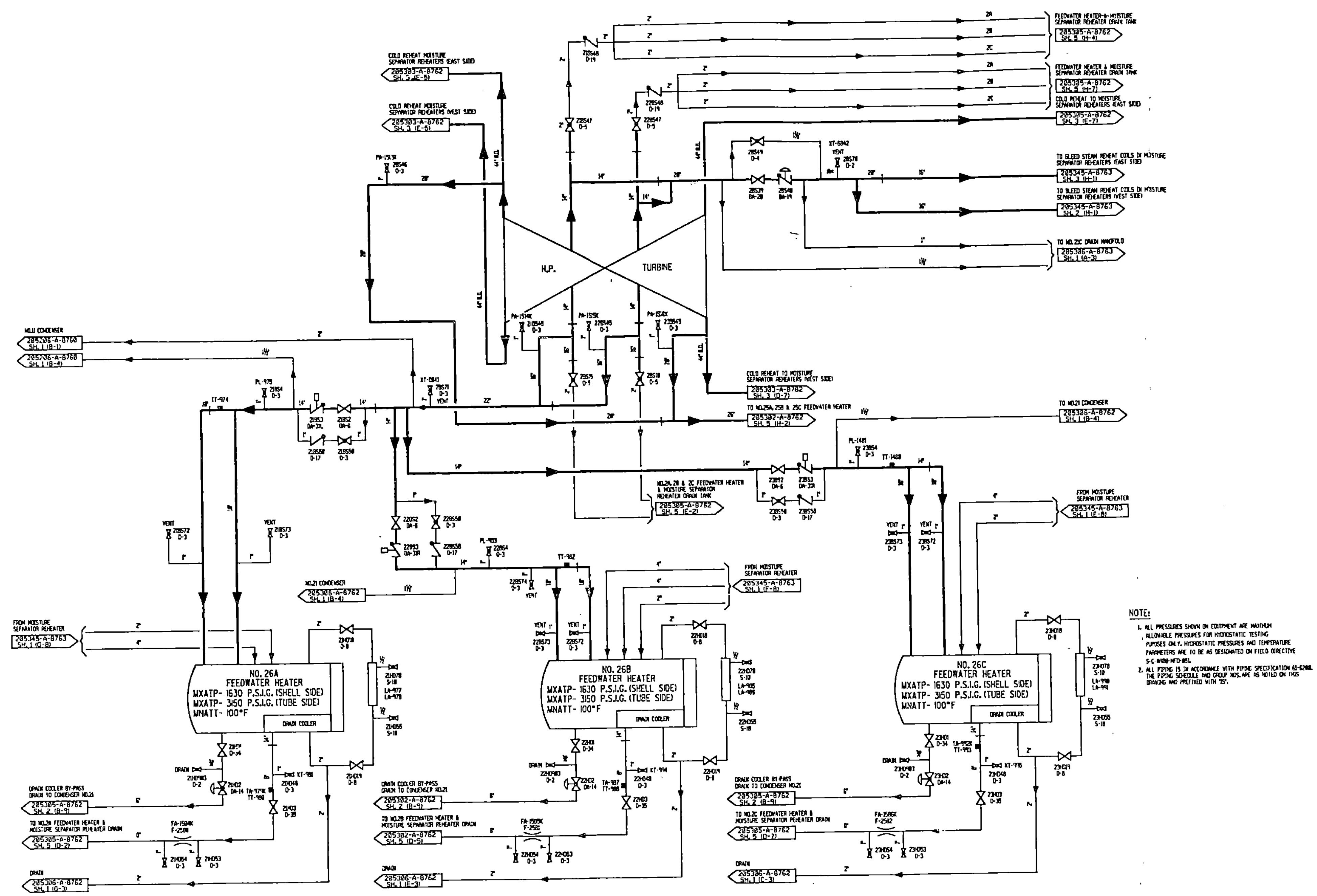
Also Available On Aperture Card

TI APERTURE CARD

8507300447 -171

Revision 4
July 22, 1985
Ref. Dwg. 205205A8760-18

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Bleed Steam and Heater Drains Unit 1 Updated FSAR Sheet 6 of 6 Fig 10.4-6A



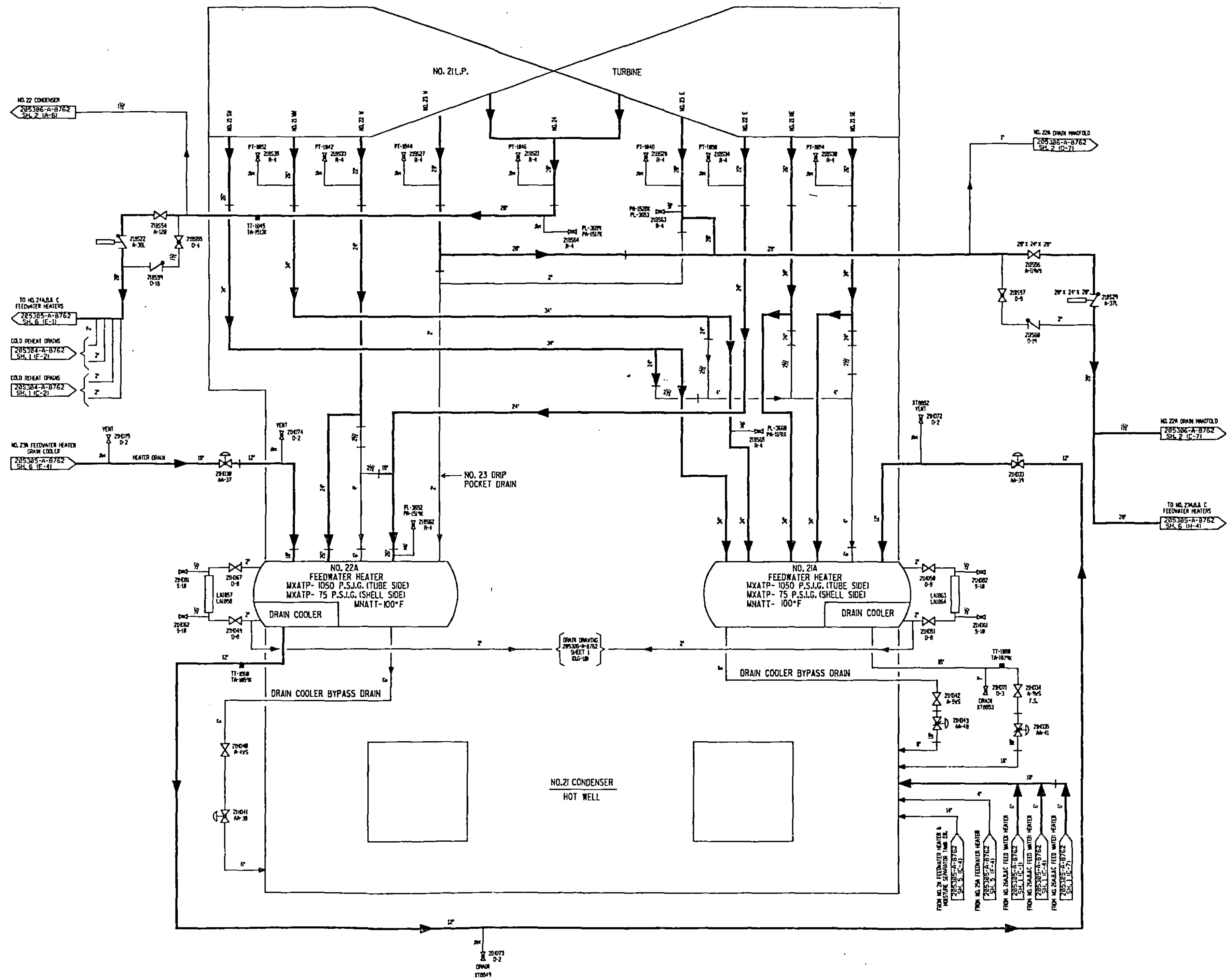
Also Available On
Aperture Card

TI
APERTURE
CARD

8507300447 -172

Revision 4
July 22, 1985
Ref. Dwg. 205305A8762-17

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Bleed Steam and Heater Drains Unit 2
	Updated FSAR Sheet 1 of 6 Fig 10.4-6B



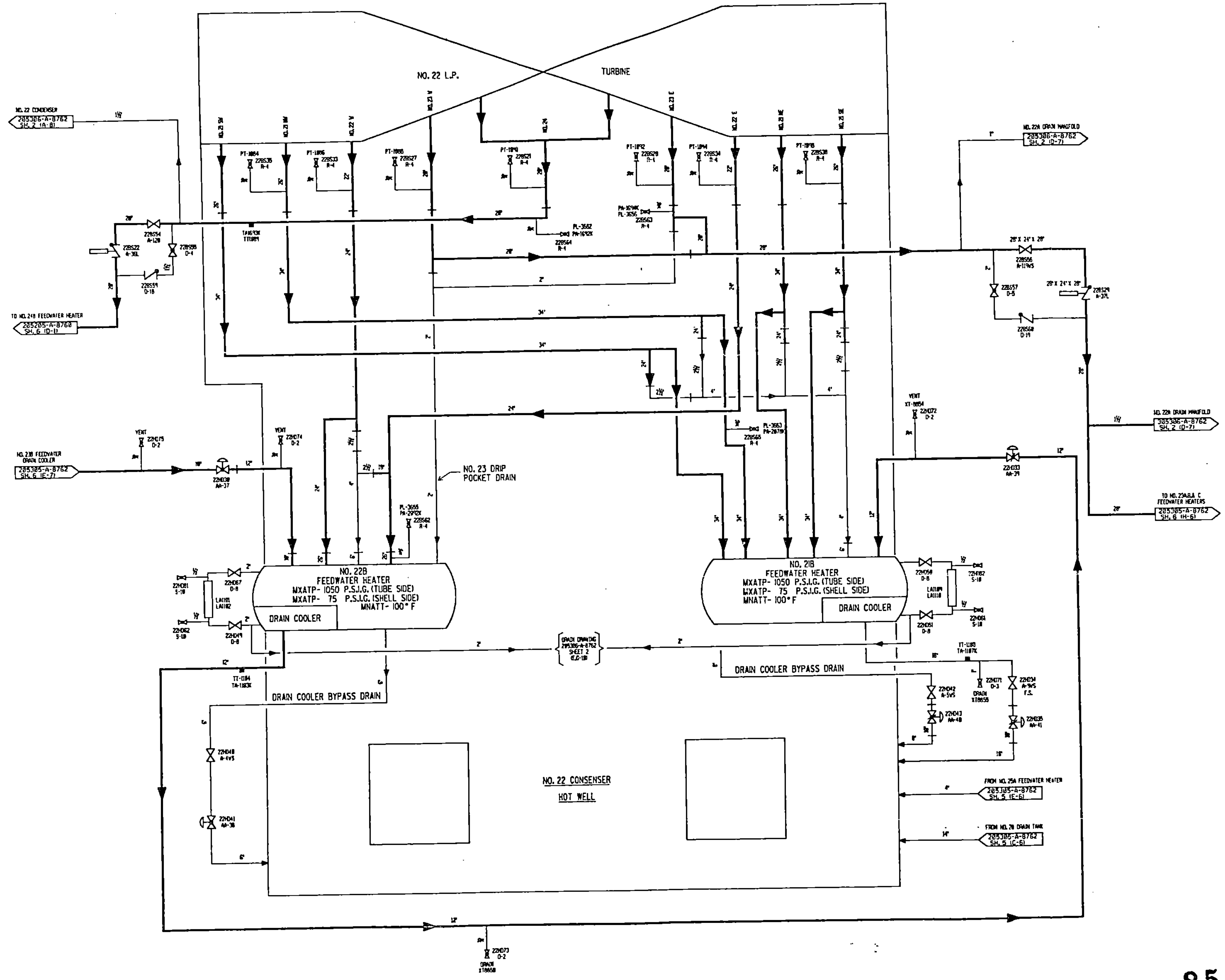
Also Available On Aperture Card

TI APERTURE CARD

8507300447-173

Revision 4
July 22, 1985
Ref. Dwg. 205305A8762-17

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Bleed Steam and Heater Drains Unit 2 Updated FSAR Sheet 2 of 6 Fig10.4-6B



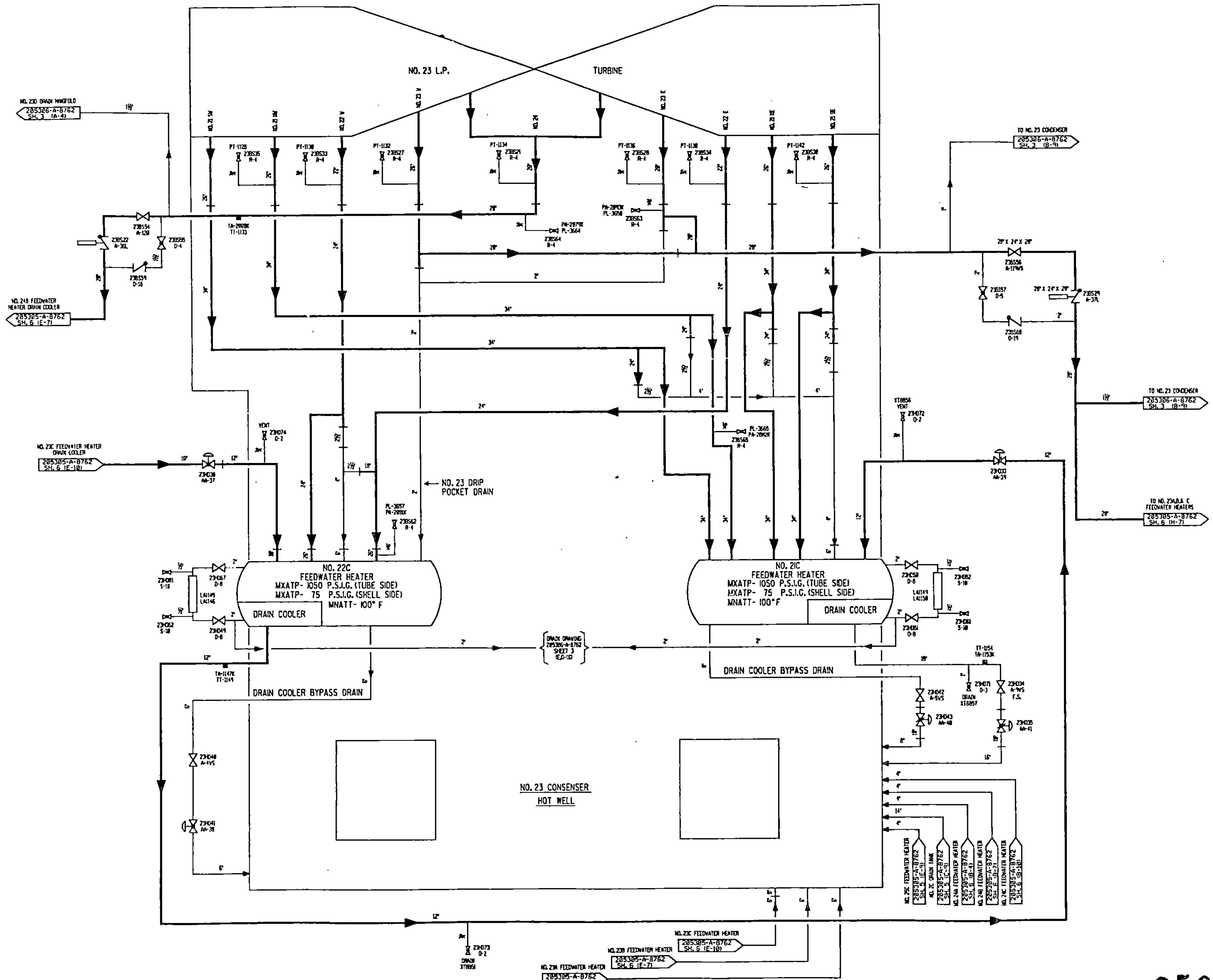
Also Available On Aperture Card

TI APERTURE CARD

8507300447 -174

Revision 4
July 22, 1985
Ref. Dwg. 205305A8762-17

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Bleed Steam and Heater Drains Unit 2
	Updated FSAR Sheet 3 of 6 Fig 10.4-6B



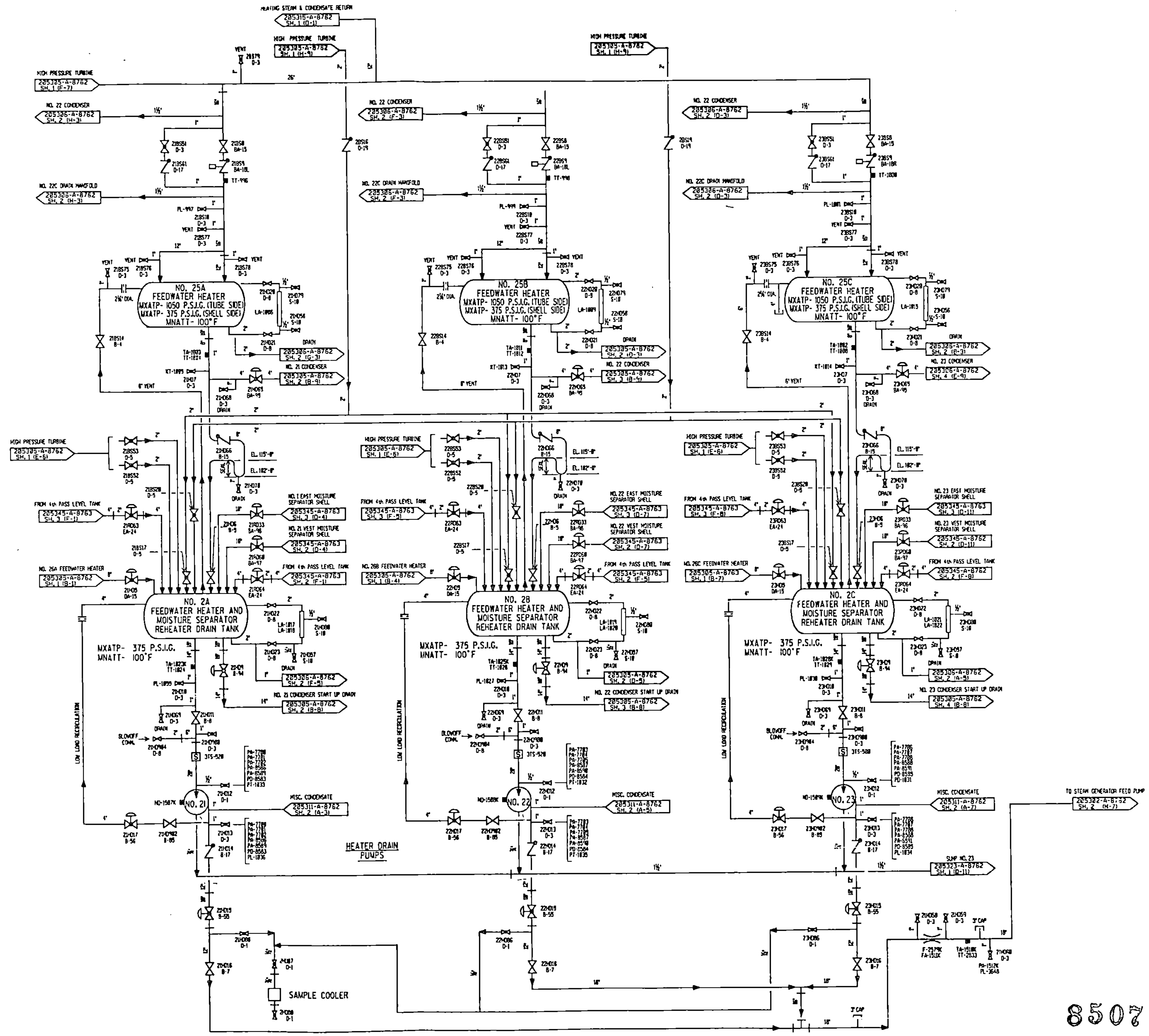
Also Available On Aperture Card

TI APERTURE CARD

8507300447-175

Revision 4
July 22, 1985
Ref. Dwg. 205305A8762-17

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Bleed Steam and Heater Drains Unit 2
	Updated FSAR Sheet 4 of 6 Fig 10.4-6B



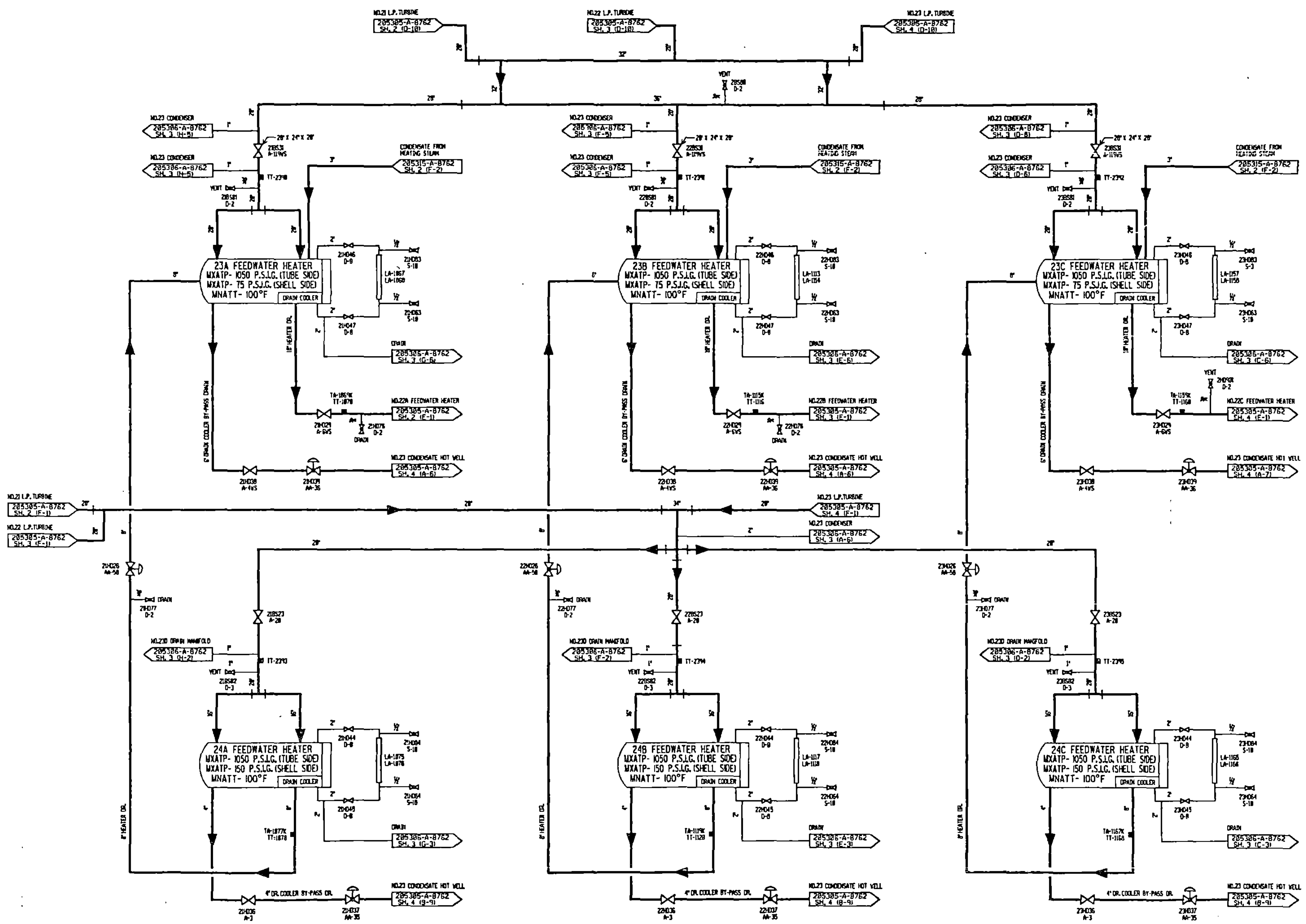
Also Available On Aperture Card

TI APERTURE CARD

8507300447 -176

Revision 4
July 22, 1985
Ref. Dwg. 205305A8762-17

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Bleed Steam and Heater Drains Unit 2
	Updated FSAR Sheet 5 of 6 Fig 10.4-6B



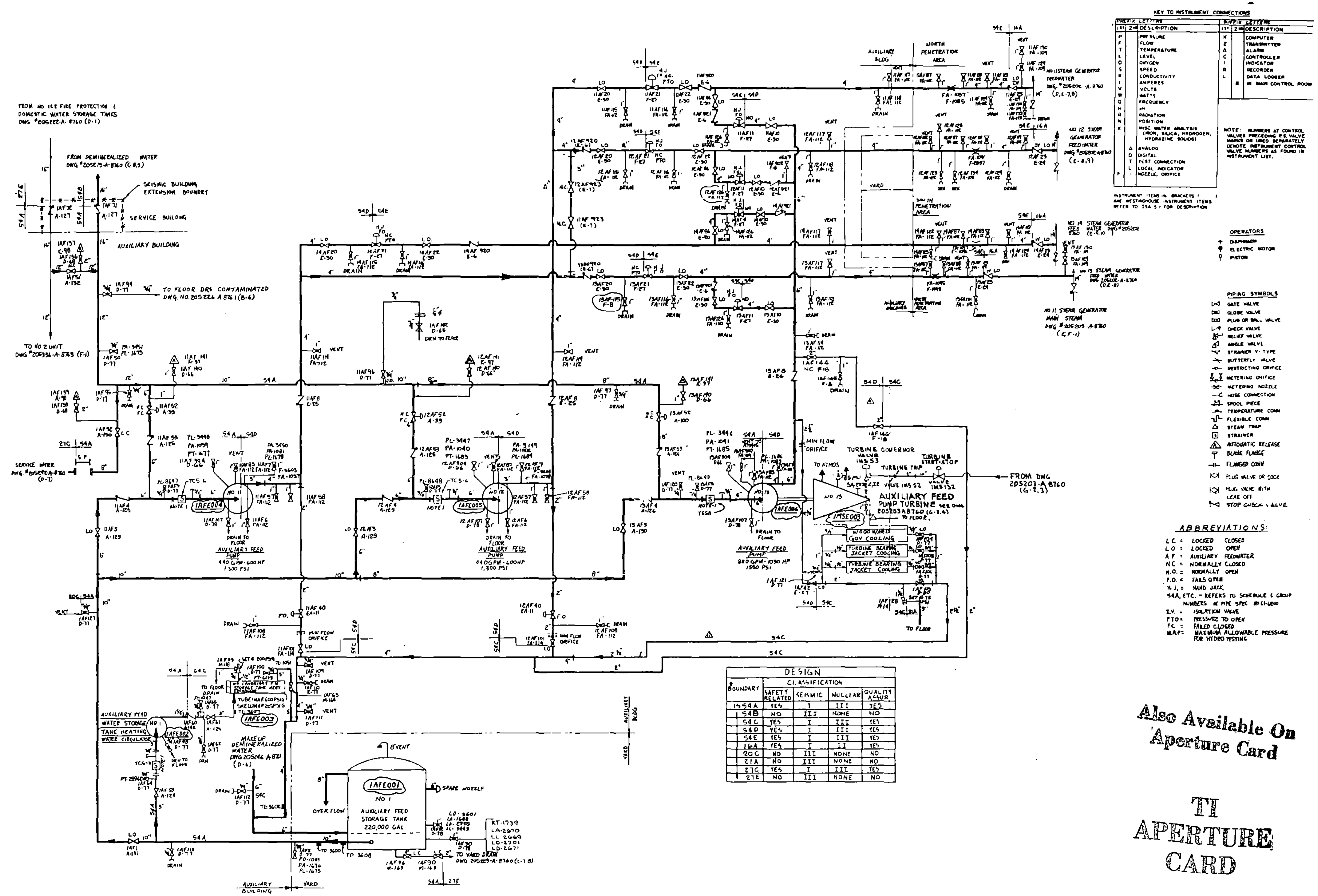
Also Available On Aperture Card

TI APERTURE CARD

8507300447-177

Revision 4
July 22, 1985
Ref. Dwg. 205305A8762-17

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Bleed Steam and Heater Drains Unit 2
	Updated FSAR Sheet 6 of 6 Fig 10.4-6B



Boundary	Design Classification			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR
1554A	YES	I	III	YES
54B	NO	III	NONE	NO
54C	YES	I	III	YES
54D	YES	I	III	YES
54E	YES	I	III	YES
16A	YES	I	II	YES
20C	NO	III	NONE	NO
21A	NO	III	NONE	NO
27C	YES	I	III	YES
27E	NO	III	NONE	NO

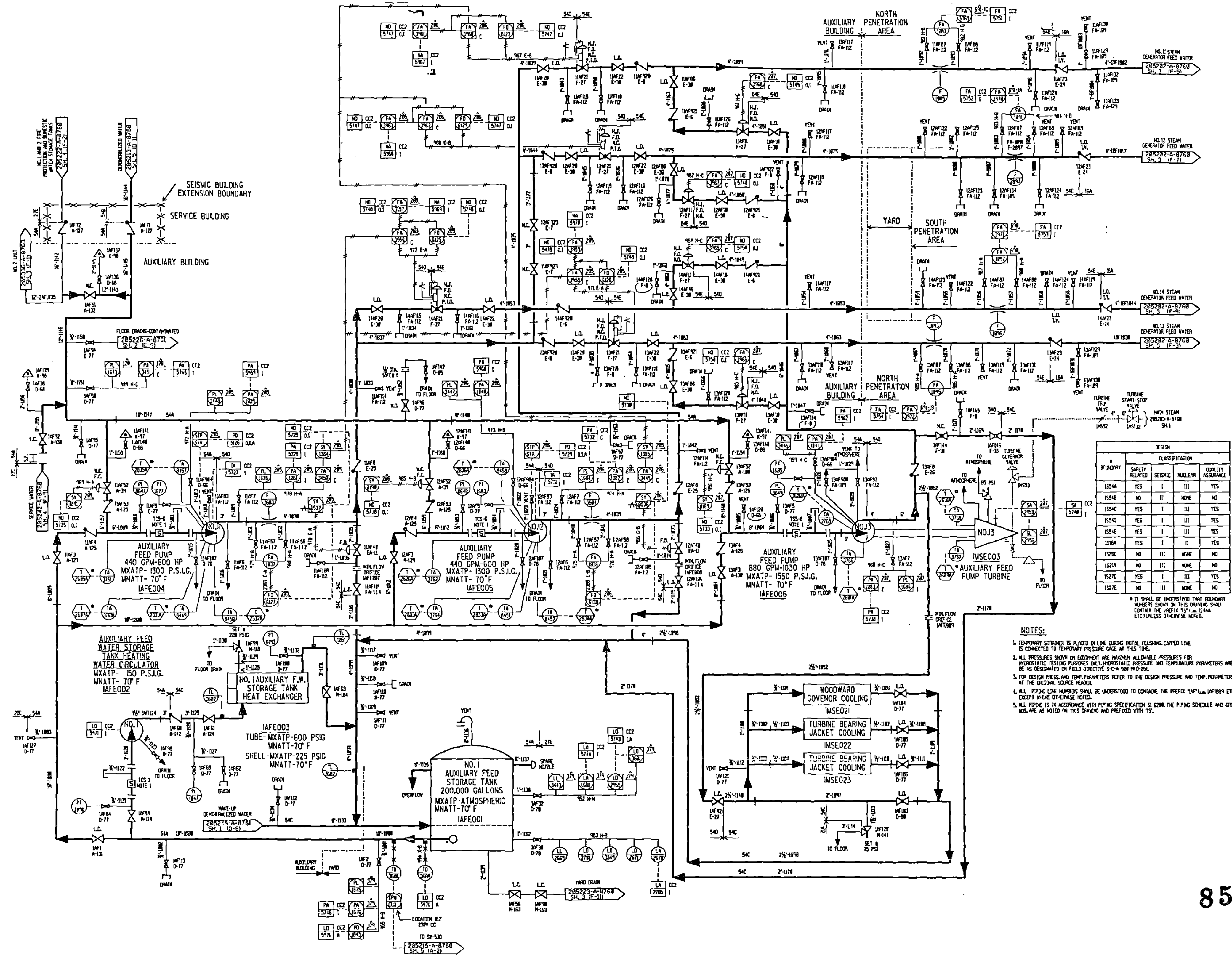
Revision 4
July 22, 1985
Ref. Dwg. 205236A8761-13

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Auxiliary Feedwater System
Unit 1

Updated FSAR

Fig 10.4-17A



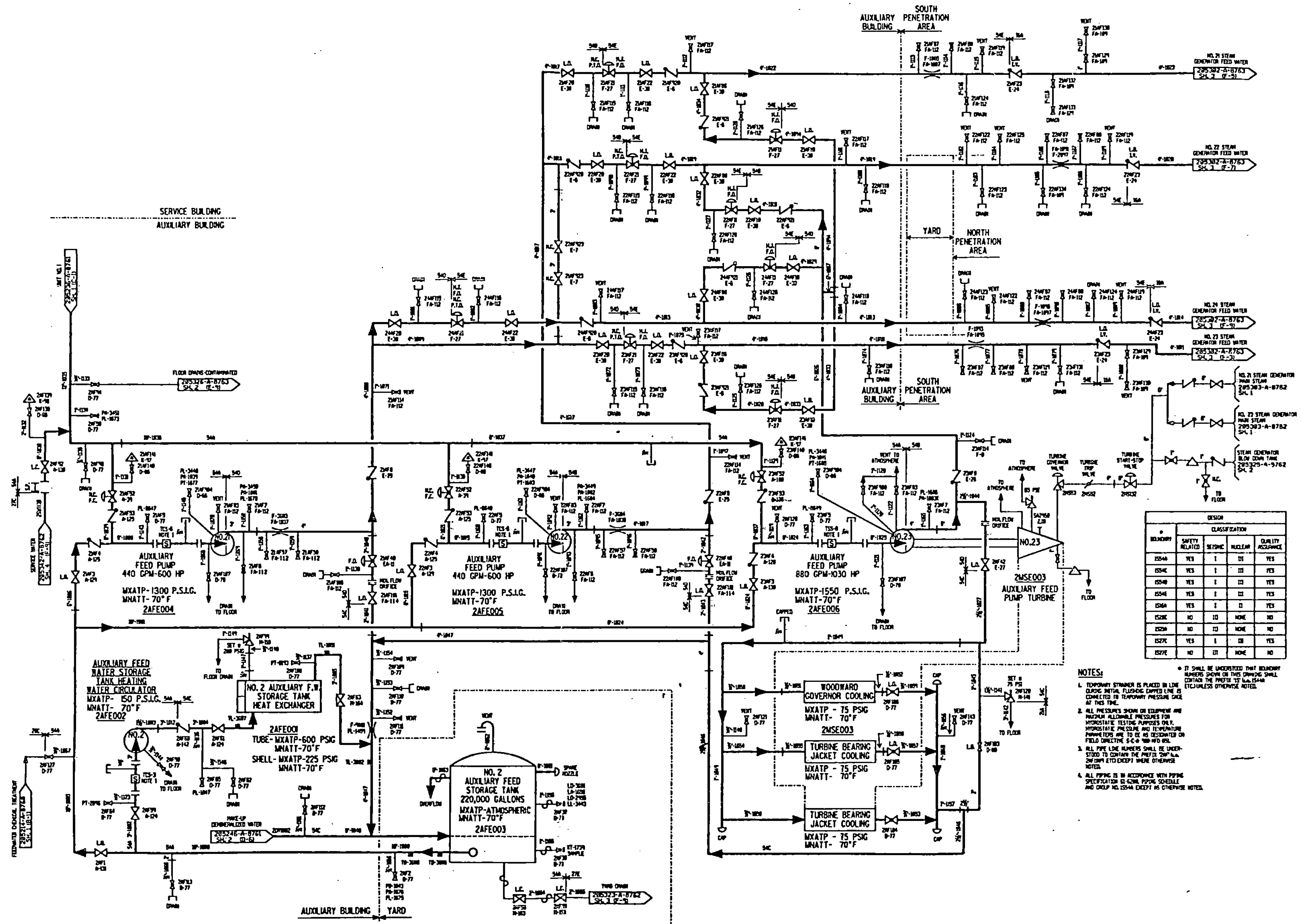
Also Available On Aperture Card

TI APERTURE CARD

8507300447-179

Revision 4
July 22, 1985
Ref. Dwg. 205336A8763-12

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Auxiliary Feedwater System Unit 2
	Updated FSAR Sheet 1 of 2 Fig 10.4-17B



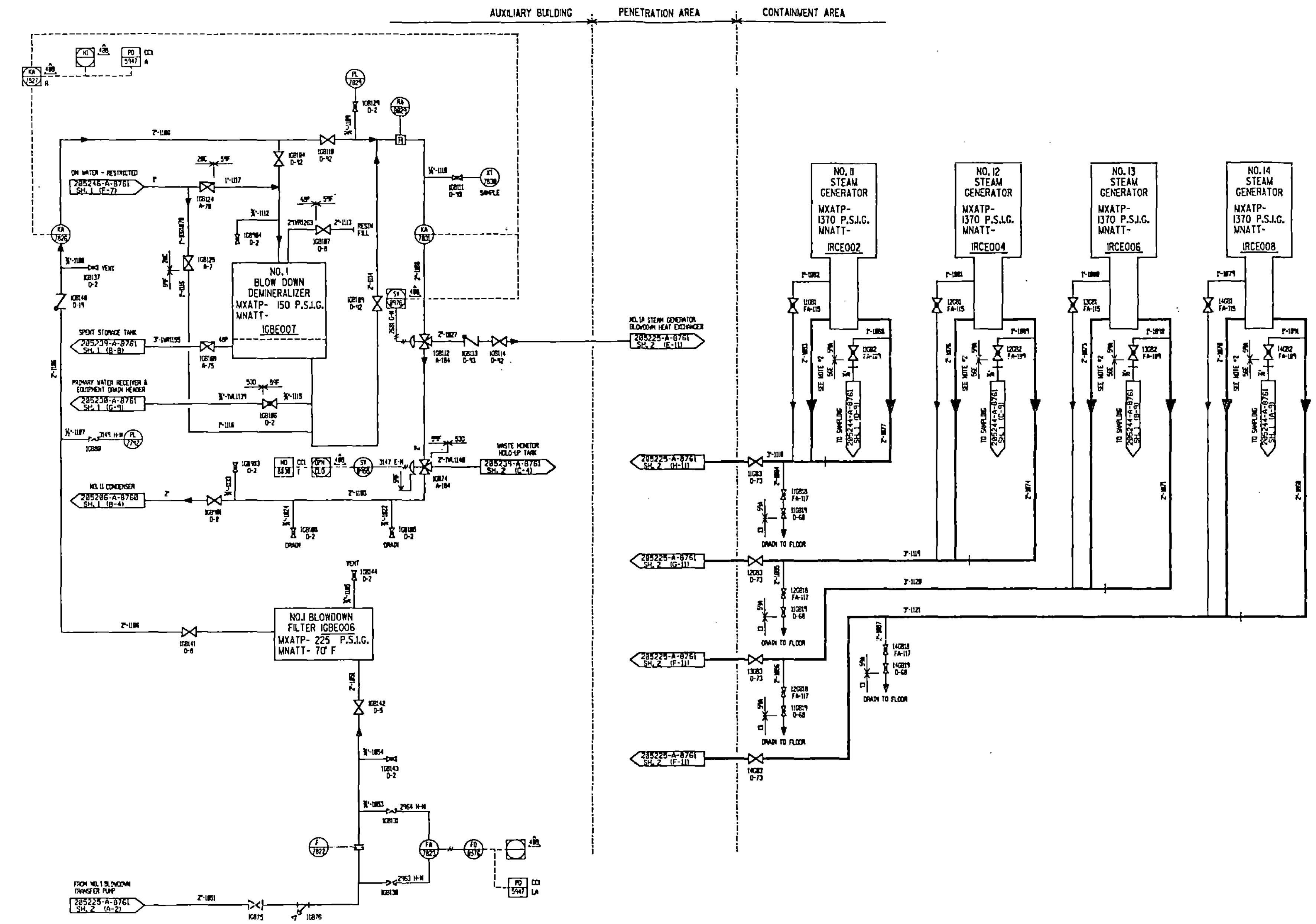
Also Available On Aperture Card

TI APERTURE CARD

8507300447 -180

Revision 4
July 22, 1985
Ref. Dwg. 205336A8763-12

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Auxiliary Feedwater System Unit 2
	Updated FSAR Sheet 2 of 2 Fig10.4-17B



DESIGN				
	CLASSIFICATION			
* BOUNDARY	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S59A	YES	I	II	YES
1S59B	NO	III	NONE	NO
1S59C	NO	III	NONE	NO
1S59D	NO	III	NONE	NO
1S59E	NO	III	NONE	NO
1S59F	NO	III	NONE	NO
1S28C	NO	III	NONE	NO
1S27C	YES	I	III	YES
1S40F	NO	II	III	NO
1S53D	NO	III	III	NO
1S13A	NO	III	NONE	NO
1S56E	NO	II	II	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (I.E. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

NOTES:

1. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROTESTING PURPOSES ONLY.
   HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
2. FOR PRESSURE AND TEMPERATURE PARAMETERS REFER TO THE CONDITIONS AT THE ORIGINATING SOURCE HEADER.
3. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1GB" (I.E. 1GB100, ETC.) EXCEPT WHERE OTHERWISE NOTED.

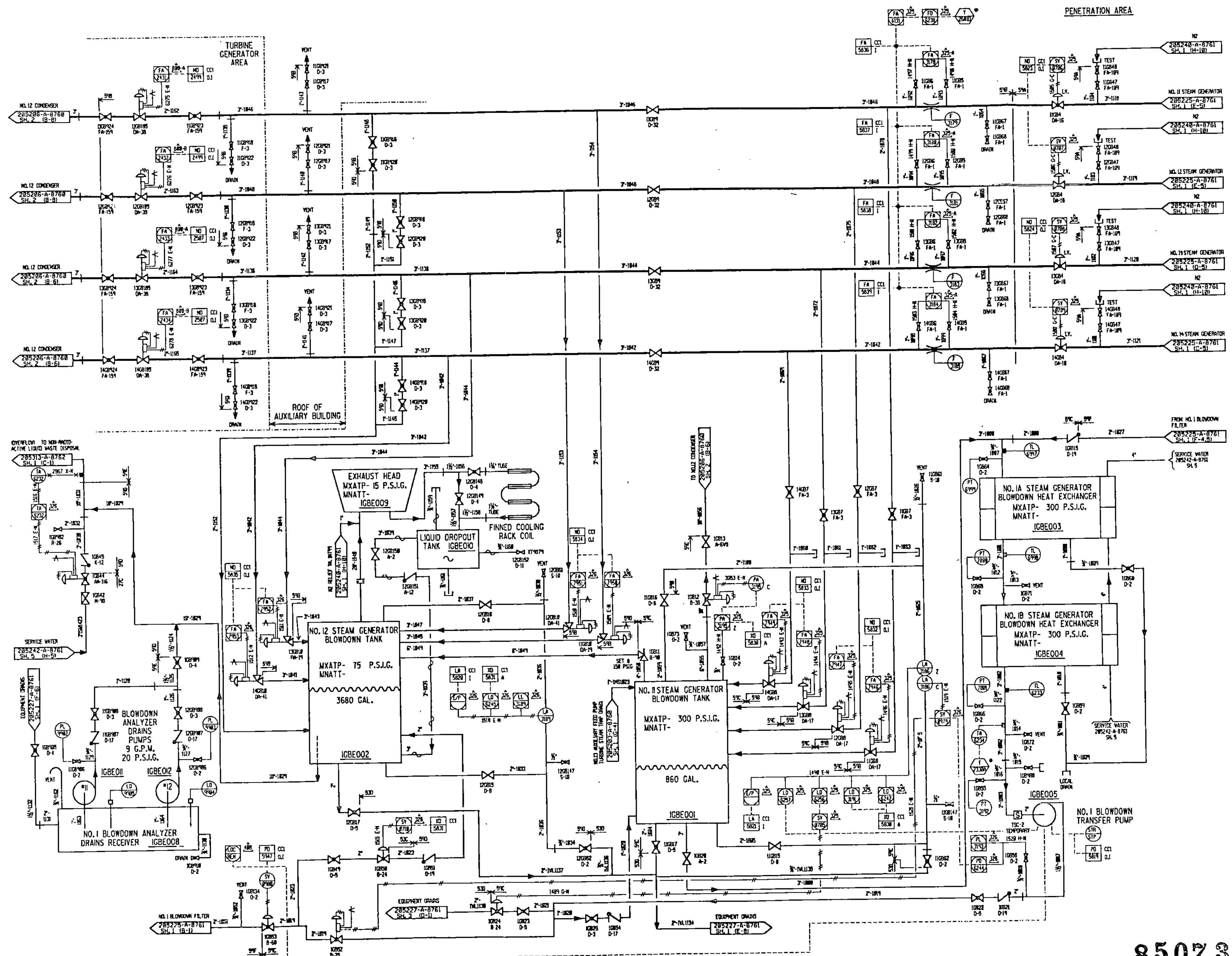
Also Available On Aperture Card

TI APERTURE CARD

8507300447 -18

Revision 4
July 22, 1985
Ref. Dwg. 205225A8761-21

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Steam Generator Drains and Blowdown Unit 1
	Updated FSAR Sheet 1 of 2 Fig10.4-18A



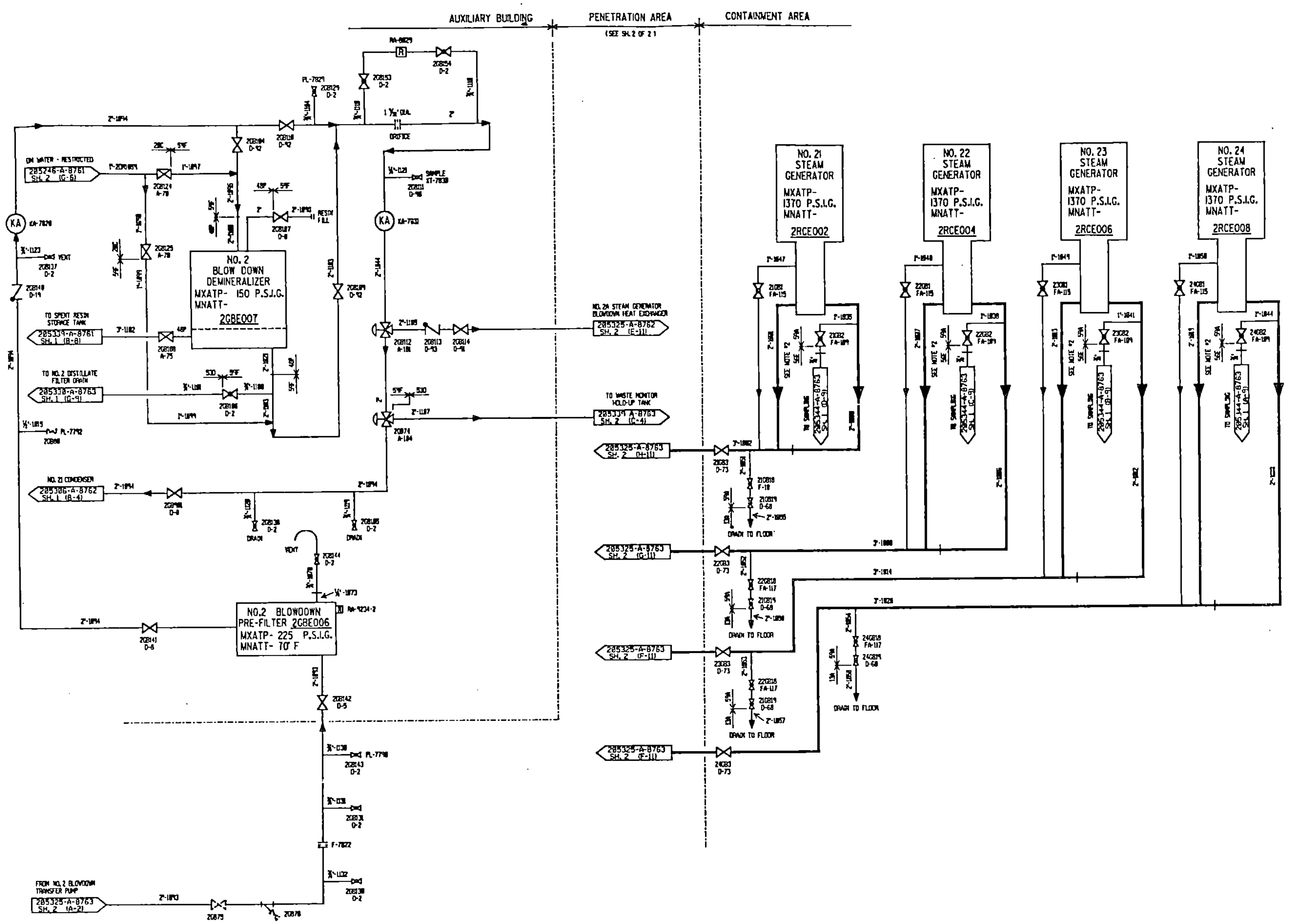
Also Available On Aperture Card

TI APERTURE CARD

8507300447 -182

Revision 4
July 22, 1985
Ref. Dwg. 205225A8761-21

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Steam Generator Drains and Blowdown Unit 1
	Updated FSAR Sheet 2 of 2 Fig 10.4-18A



* BOUNDARY	DESIGN CLASSIFICATION: SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S59A	YES	I	II	YES
1S59B	NO	III	NONE	NO
1S59C	NO	III	NONE	NO
1S59D	NO	III	NONE	NO
1S59E	NO	III	NONE	NO
1S59F	NO	III	NONE	NO
1S20C	NO	III	NONE	NO
1S27C	YES	I	III	YES
1S48F	NO	II	III	NO
1S53D	NO	III	III	NO
1S13A	NO	III	NONE	NO
1S56E	NO	II	II	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (I.E. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

NOTES:

1. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROTESTING PURPOSES ONLY.
   HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
2. FOR PRESSURE AND TEMPERATURE PARAMETERS REFER TO THE CONDITIONS AT THE ORIGINATING SOURCE HEADER.
3. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2GB" (I.E. 2GB1800, ETC.) EXCEPT WHERE OTHERWISE NOTED.
4. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200, PIPING SCHEDULE 59A & 59B EXCEPT AS OTHERWISE NOTED.

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Revision 4
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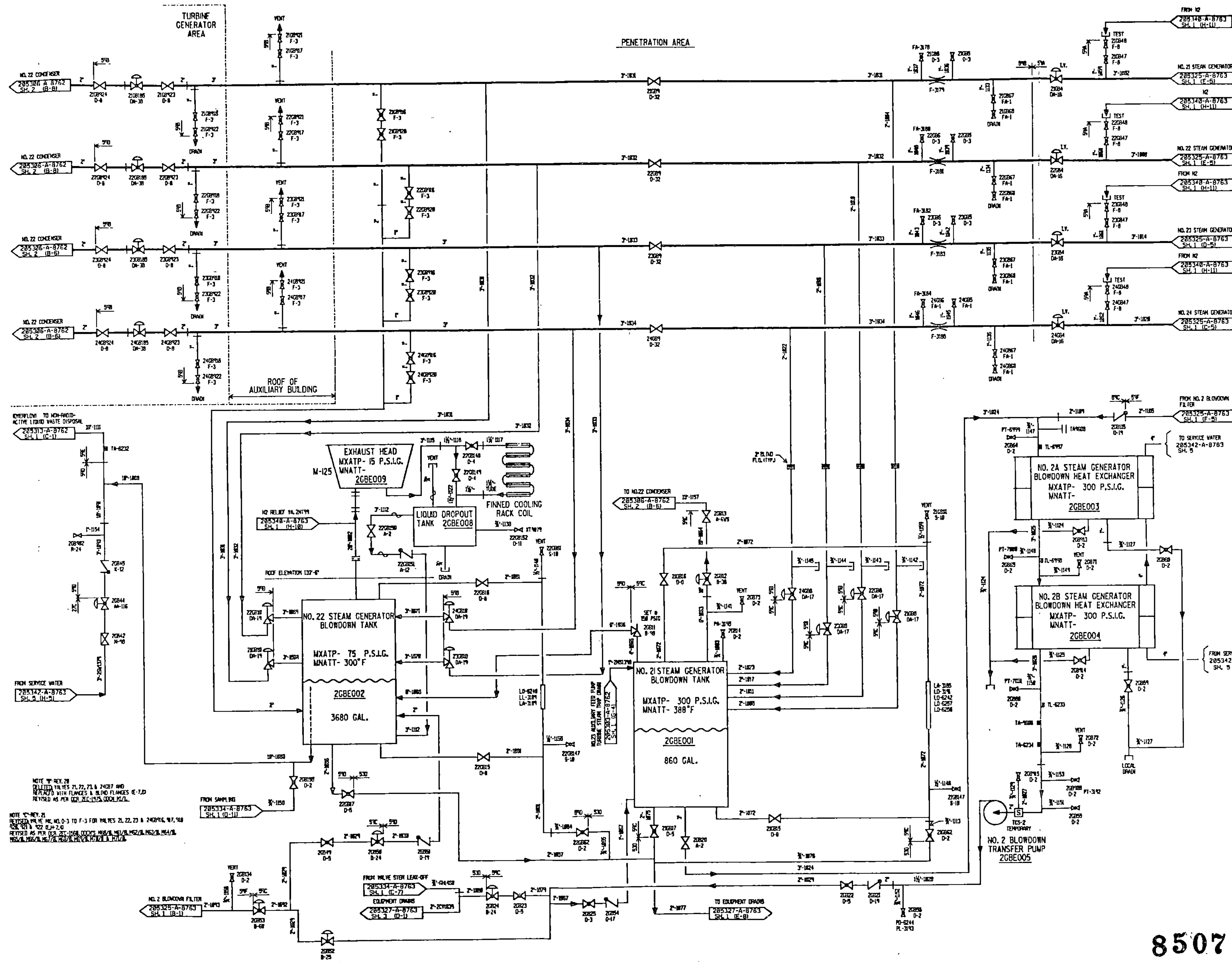
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Steam Generator Drains and Blowdown Unit 2
	Updated FSAR Sheet 1 of 2 Fig10.4-18B



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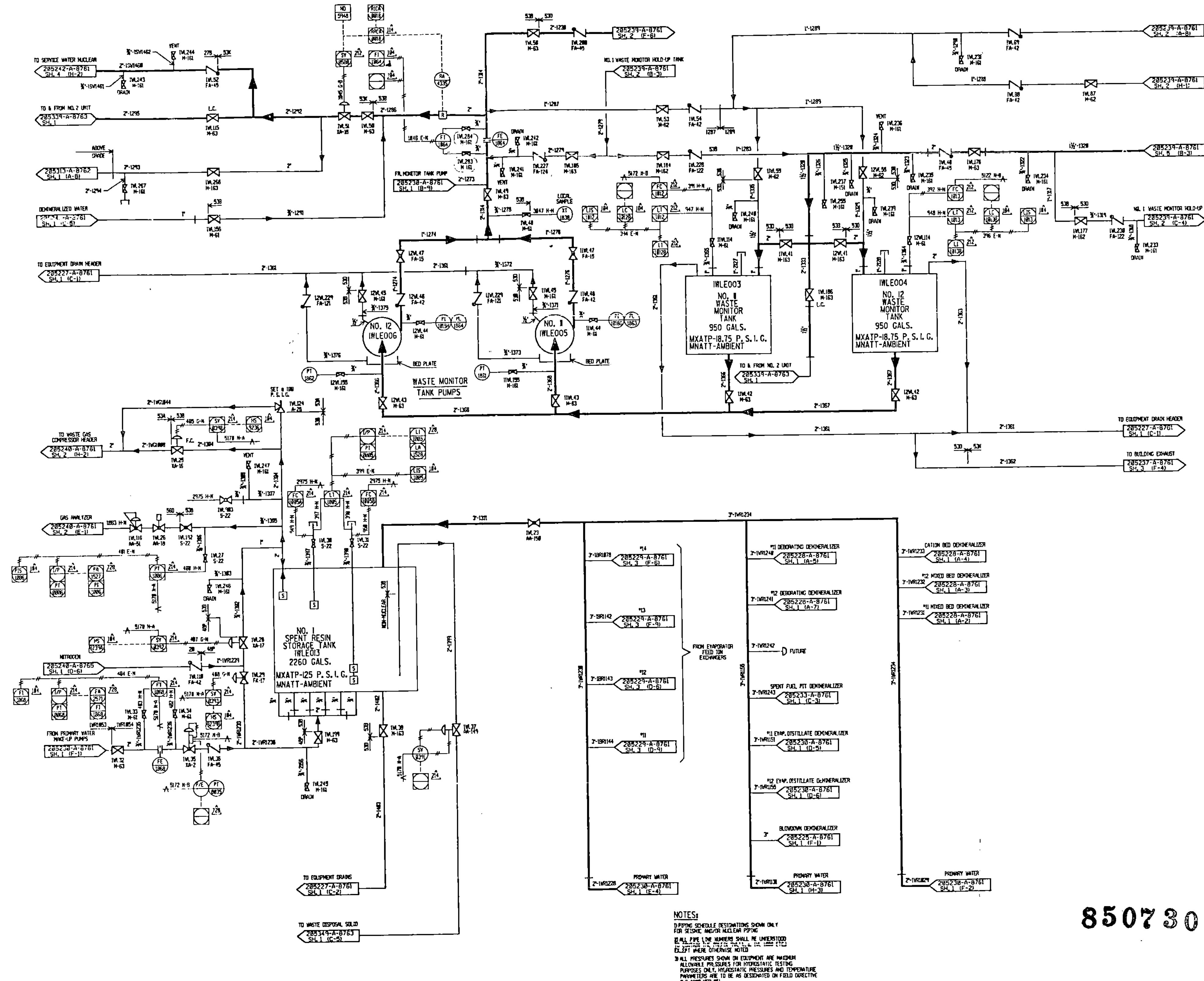
Revision 4
July 22, 1985
Ref. Dwg. 205325A8763-21

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Steam Generator Drains and Blowdown Unit 2
	Updated FSAR Sheet 2 of 2 Fig10.4-18B



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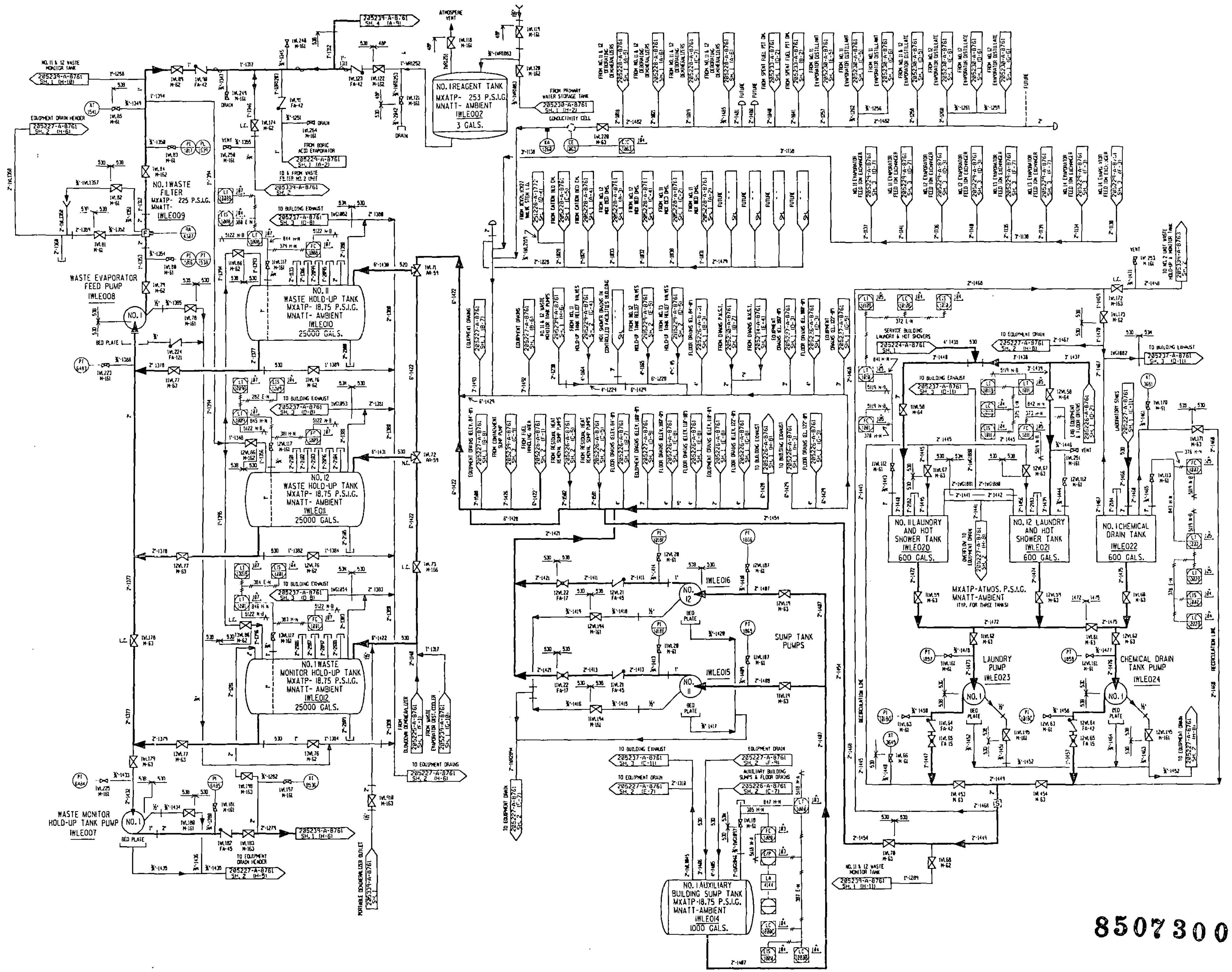
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Liquid Waste Disposal System
Unit 1

Updated FSAR Sheet 1 of 5 Fig 11.2-1A



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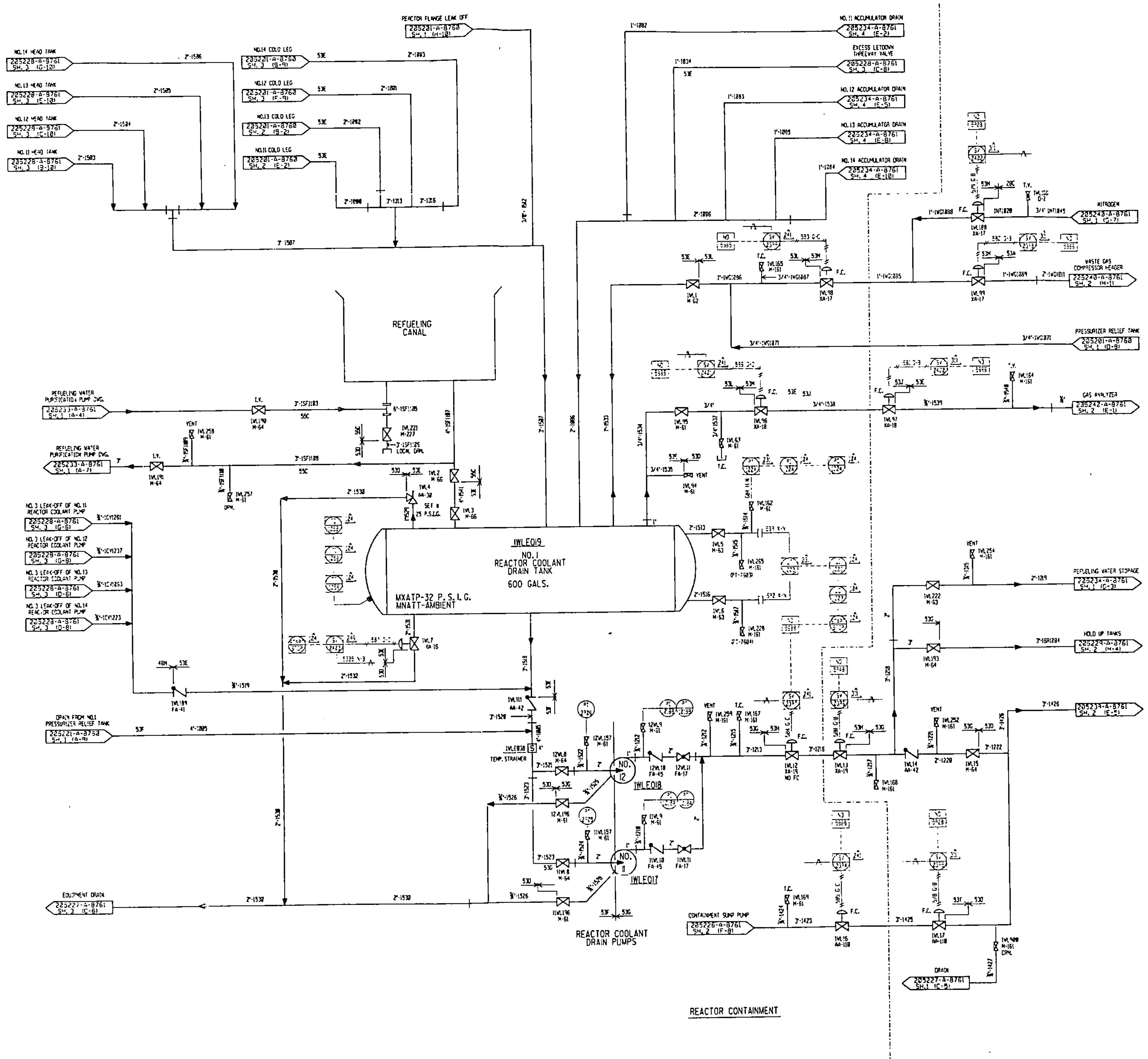
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Liquid Waste Disposal System Unit 1
	Updated FSAR Sheet 2 of 5 Fig11.2-1A



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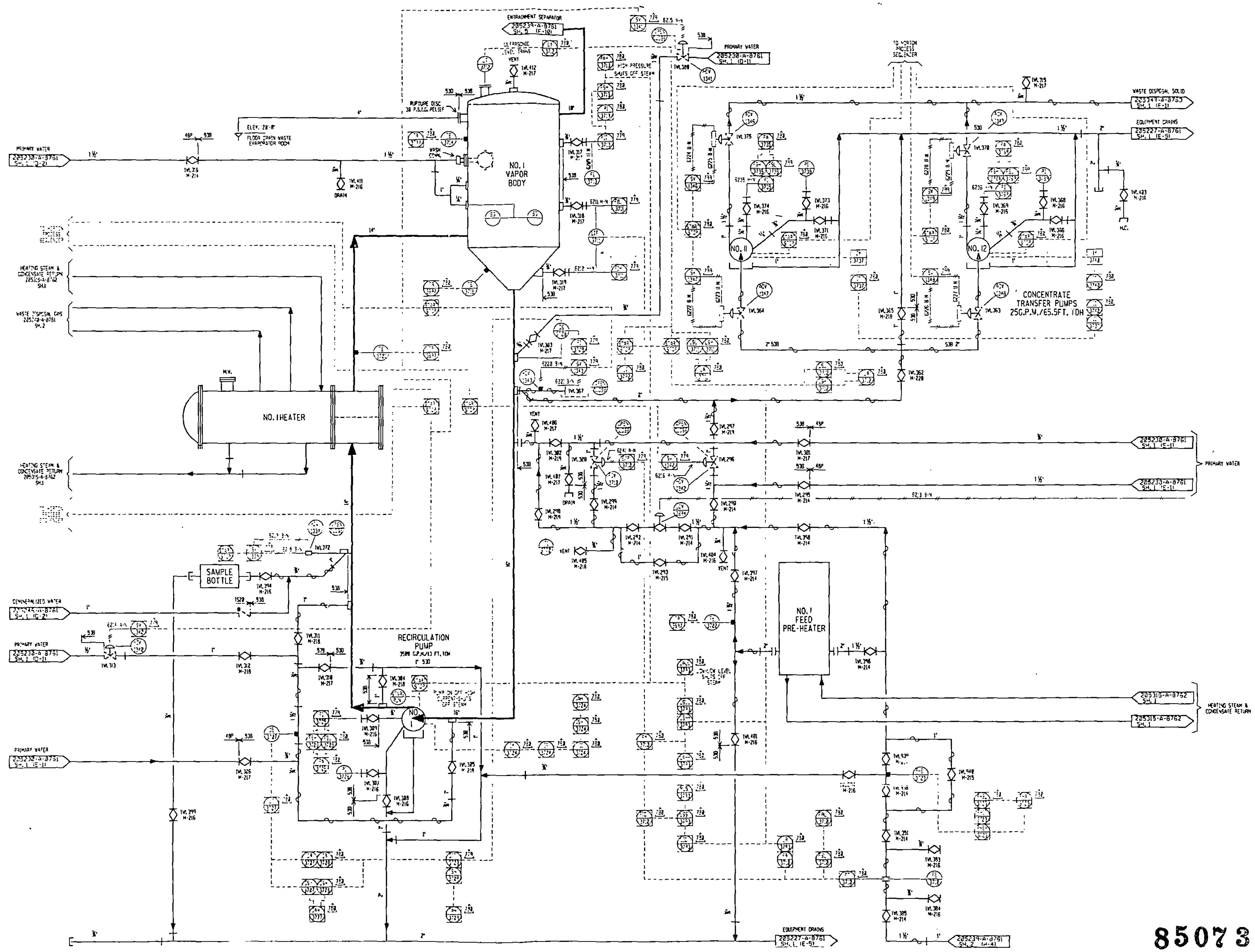
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Liquid Waste Disposal System Unit 1
	Updated FSAR Sheet 3 of 5 Fig 11.2-1A



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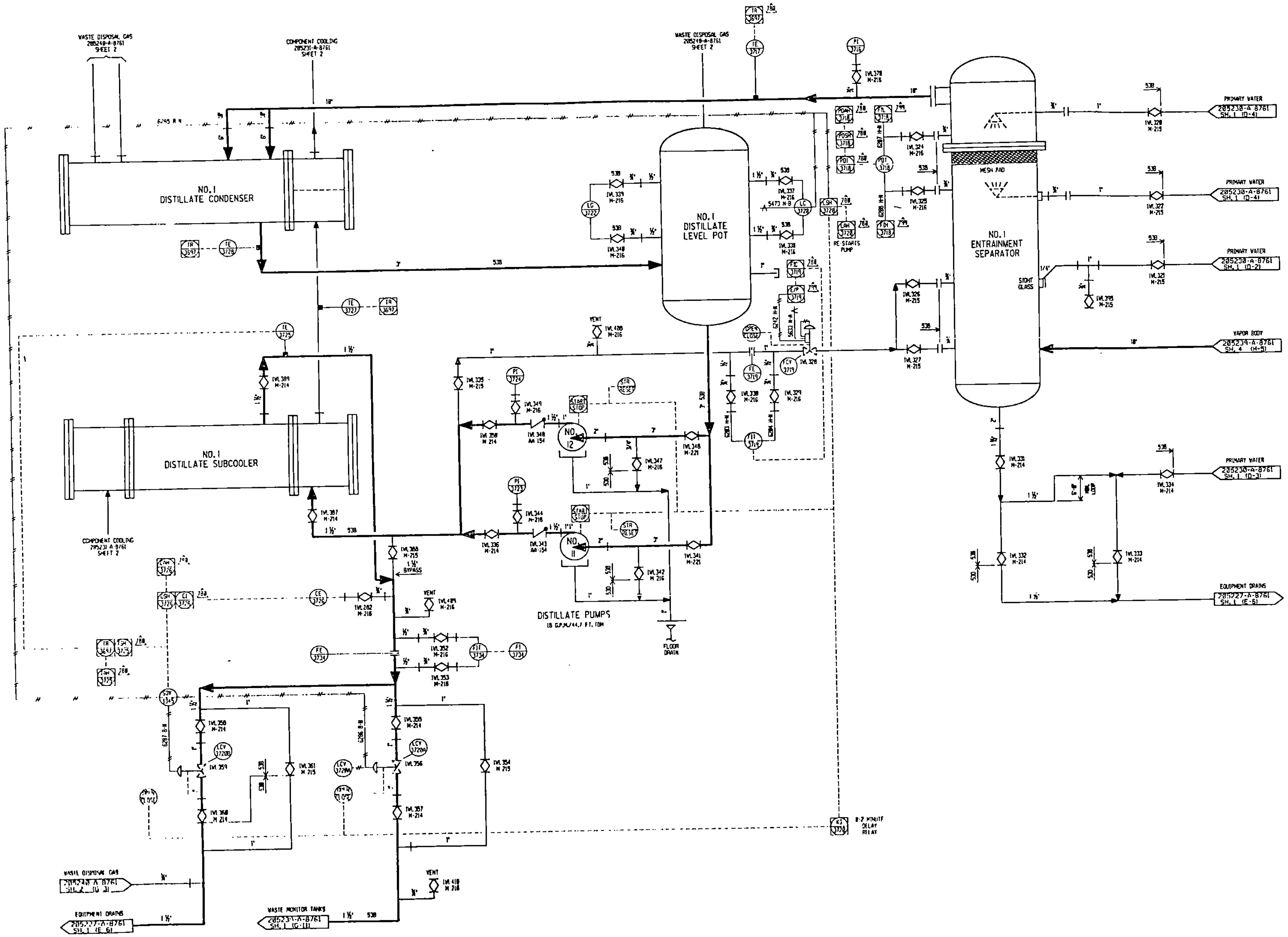
Revision 4
July 22, 1985
Ref. Dwg. 205239A8761-23

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Liquid Waste Disposal System Unit 1
	Updated FSAR Sheet 4 of 5 Fig 11.2-1A



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Ref. Dwg. 205239A8761-23

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Liquid Waste Disposal System Unit 1
	Updated FSAR Sheet 5 of 5 Fig11.2-1A

activity. Signal processing is performed by the digital Radiation Monitoring System to provide data on a significant increase of gross gamma activity. A significant increase of gross gamma activity would be indicative of a fuel cladding failure.

12. Steam Generator Blowdown Filter Discharge (1-R35 and 2-R35)
This channel continuously monitors the line from the Steam Generator Blowdown Filter to the condenser for possible radioactivity. A high radiation signal will automatically divert the contaminated liquid to the Waste Monitor Holdup Tank 3-way valve. Alarm and indication is provided in the control room.

13. Evaporator and Feed Preheaters Condensate (1-R36 and 2-R36)
Heating Steam is supplied to the Boric Acid and Waste Evaporators and Feed Heater. Condensate from the evaporators and Feed Heater is returned to the condensate receivers from whence it is pumped back to the Heating Boiler. Steam is used in the tubes of the evaporators and in the heater for process heating. Since the evaporators and heater can contain radioactive fluids, a tube rupture could result in a contamination of the condensate system, Heating Boiler, and Heating Steam System.

This channel continuously monitors the activity in the common condensate piping from each unit's evaporators. This channel employs an off line sampler. A high radiation level alarm will automatically close the condensate line valve for each unit's evaporator packages. Alarm and indication are provided in the control room. A manually valved drain is provided for disposal of any contaminated condensate to the Waste Disposal System.

14. Plant Vent High Range Monitors (1R45A-D and 2R45A-D)

The Plant Vent High Range Monitoring System complies with NUREG-0737 Item II.F.1 and Regulatory Guide 1.97. The system provides a sampling capability of 10^2 μci/cc for iodines and particulates and 10^5 μci/cc for noble gases. The monitors are safety grade and qualified for the post-accident environment.

The system interfaces with plant vent radiation monitors (R41A-C) (Items 2, 3 and 4 above) and with the supplemental plant vent sampling system (Section 11.4.3). During normal operation monitors (R41A-C) and the plant vent sampling system are in operation; monitors R45A-D are in standby. If monitor R41C detects an activity level in excess of $1x10^{-4}$ μci/cc, the sample pump for monitors R45A-D is energized and the sample pump for the supplemental plant vent sampling system is deenergized when monitor R45B (the intermediate range of the three noble gas monitors, R45A, B, C) comes "on scale." If the concentration of radioactivity continues to increase, such that the channels could be damaged, monitors R41A-C are deenergized. As noble gas activity decreases this process is reversed to return to normal monitor operation. Non-safety related heat tracing is provided to preclude freezeup of these sampling lines during plant outages coincident with adverse weather conditions.

15. Main Steam High Range Monitors (1R46A-E and 2R46A-E)

The Main Steam High Range Monitoring System complies with NUREG-0737, Item II.F.1 and Regulatory Guide 1.97. The system provides a detection capability of 10^3 μci/cc. The monitors are safety grade and qualified for the post-accident environment. Channels R46A-D each monitor one of the main steam lines. Channel R46E monitors the effluent from channels R46A-D and therefore provides redundancy for each steam line.

11.4.2.3 Process Filter Monitoring System Channel Descriptions

Area-type radiation monitors are provided on these liquid (process) filters to determine when they should be replaced by indicating the level of activity given off by the filter. A high radiation level alarm is initiated in the control room. A radiation indicator and alarm light are located at the filter.

The filters which are monitored include:

1. Seal Water Injection Filter
   1R24A, B and 2-R24A, B
2. Seal Water Filter
   1-R25 and 2-R25
3. Reactor Coolant Filter
   1-R26 and 2-R26
4. Liquid Waste Filter
   1-R27 and 2-R27
5. Spent Fuel Pool Filter
   1-R28 and 2-R28
6. Spent Fuel Pool Skimmer Filter
   1-R29 and 2-R29
7. Refueling Water Purification Filter
   1-R30 and 2-R30
8. Ion Exchange Filter
   1-R33 and 2-R33
9. Steam Generator Blowdown Filter
   2-R38 (Unit 2 only)
10. Condensate Filter
    1-R40 and 2-R40

All No. 1 Unit Process Filter Monitors are G. M. Tubes and have a range of 10^1-10^6 mR/hr. All No 2 Unit Process Filter Monitors are ion chambers and have a range of 10^{-1}-10^6 mR/hr. They perform no control function.

This system has the additional function of supplying N_2 at 800 psi to the accumulator in the Safety Injection System. If the need ever arises, this pressurized gas will inject borated liquid from the accumulators into the reactor coolant loops. Design data for the manifold are as follows:

Type	Automatic switching dual header
Number per unit	1
Number of separate header per package	2
Number of cylinders per header	18
Design flow rate, SCFM	40
Design delivery pressure, psig	100

Station Bulk L.P. Nitrogen Supply

A station bulk low pressure nitrogen supply package has been added to the above system to provide additional capability. Two liquid nitrogen storage tanks, each with a self-contained vaporizer are supplied. One storage tank and its vaporizer are used at a time to supply the operating headers for both units. Design data are as follows:

Manufacturer	Air Products ə Chemicals, Inc.
Model No.	CLC-6
Type	Vertical cylindrical, Double walled
N_2	55,866 scf
O_2	69,030 scf
Argon	67,470 scf
Operating pressure (Max.)	245 psig
Design pressure (Max.)	249 psig
Design temperature	-320°F - 100°F
Empty weight	4,400 lbs

Hydrogen Manifold

A dual manifold serves as a backup to the bulk hydrogen system to supply hydrogen to the volume control tank and to maintain the hydrogen partial pressure as hydrogen dissolves in the reactor coolant. A pressure controller, (1-PIA-1065) which automatically switches from the normal system to the backup system, assures a continuous supply of gas. The operation of the backup header is essentially the same as for the Nitrogen Manifold System. Design data are as follows:

Type	Automatic switching dual header
Number per unit	1
Number of separate headers per package	2
Number of cylinders per header	6
Design flow rate, SCFM	30
Design delivery pressure, psig	100

Gas Analyzer

A gas analyzer is provided to automatically monitor the concentrations of oxygen and hydrogen in the system, in order to indicate when the accumulation of these gases might reach an explosive mixture. Upon indication by alarm that the oxygen level is approaching a hazardous level, provisions must be made to either isolate the component or purge with nitrogen to the waste gas system. The gas analyzer samples the following items:

Waste Gas to Plant Vent
Reactor Coolant Drain Tank
Spent Resin Storage Tank
Gas Decay Tanks (2 points)

CVCS Holdup Tanks
Boric Acid Evaporator and Gas Stripper
Volume Control Tank
Pressure Relief Tank

The analyzer utilizes a sequencer that samples each sample stream automatically every three minutes. This automatic sequencing system may be defeated by pushing the stream readout bypass switch for each stream until the desired stream is reached. After reading this stream, the analyzer will continue to sequence automatically. Separate feed lines with individual bottles of nitrogen, oxygen, and hydrogen are provided for analyzer calibration purposes. The span calibration gas is 2 percent oxygen, 80 percent hydrogen, and 18 percent nitrogen by volume and the zero calibration gas is high purity nitrogen. This mixture allows calibrating the analyzer to the conditions expected in the sample stream at alarm conditions. Design data for the analyzer are as follows:

Manufacturer	Servomex Controls, Ltd.
Oxygen	By paramagnetic attraction
	0-2.5 , 0-5 , 0-10
	0-25 , 0-100 , O_2, in N_2
Hydrogen	By thermal conductivity
	0-5 , 0-50 , 0-100 , H_2 in N_2
Automatic stepping switch	16 steps
Recorded readout	16 points
Temperature, °F	120
Location	

All major equipment in the gaseous radwaste disposal system is located outside of the Reactor Containment Building in the Auxiliary Building, Elevation 64 feet.

Piping

Gas piping is carbon steel. Piping connections are welded except where flanged connections are necessary to facilitate equipment maintenance.

Valves exposed to gases are carbon steel.

Isolation valves are provided to isolate each piece of equipment for maintenance, to direct the flow of waste through the system, and to isolate storage tanks for radioactive decay.

Relief valves are provided for tanks containing radioactive wastes if the tanks might be overpressurized by improper operation or component malfunction.

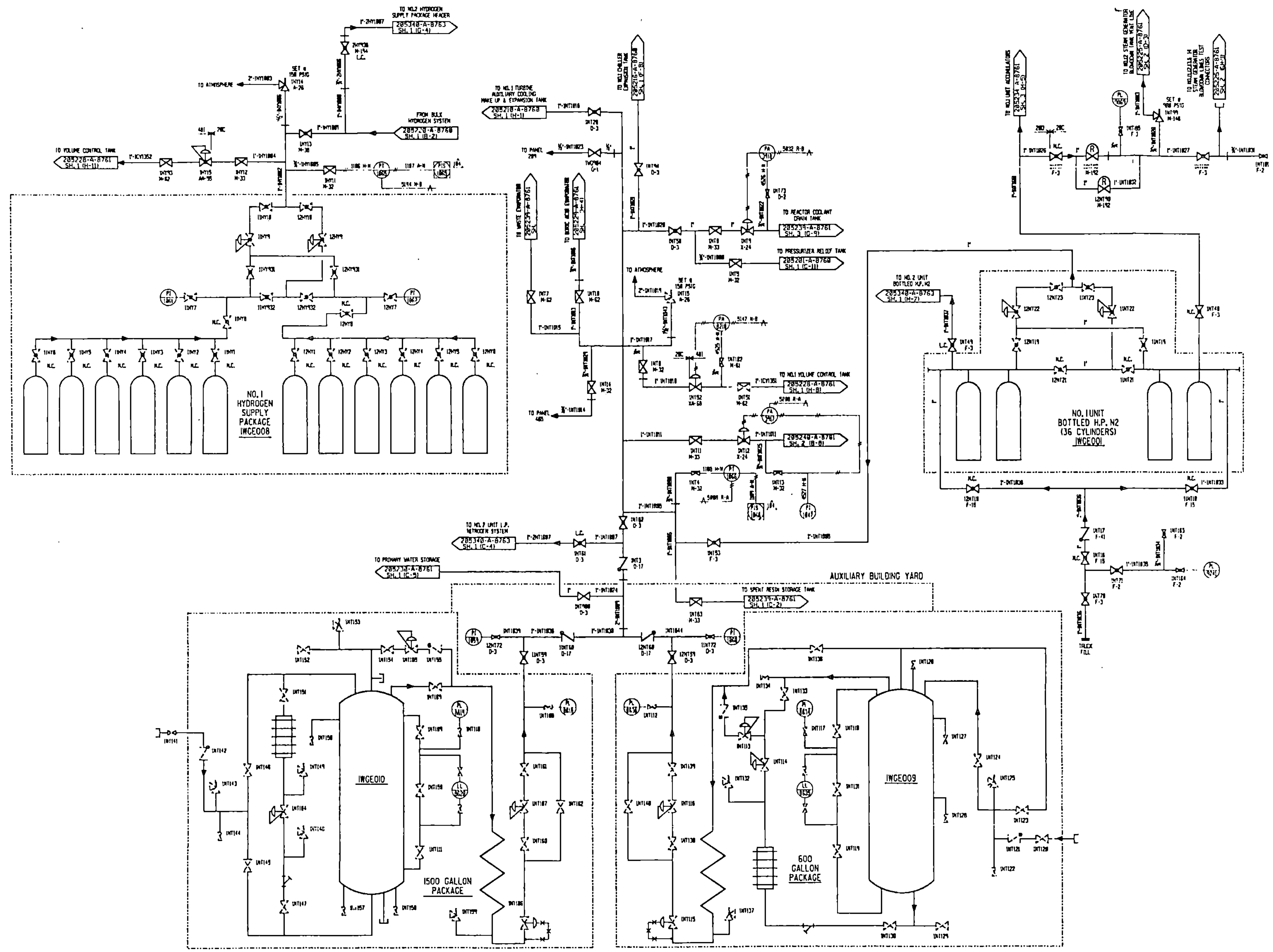
Codes and Standards

Additional information is presented in Table 11.2-3 for system piping, valves and compressors.

11.3.4 OPERATING PROCEDURES

The gaseous wastes processed by this system consist primarily of hydrogen stripped from reactor coolant during boron recycle and degassing operations and nitrogen from the various tank cover gases and from the degassing operation. These gases are discharged to the vent header which feeds the suction of the waste gas compressors.

One of the two waste gas compressors will be operating with the other compressor being on standby. The operating compressor maintains a negative pressure, in the vent header, of 6 to 10 inches of water. If the vent header pressure rises to 2 psig, the standby compressor automatically energizes. The compressors can be used to: (1) pump gas to the waste decay tanks; (2) transfer gas between tanks; and (3) pump gas directly to the Chemical and Volume Control System holdup tanks.



NOTES:

1. PIPING SCHEDULE DESIGNATIONS SHOWN ONLY FOR SEISMIC AND/OR NUCLEAR PIPING.
2. FOR DESIGN PRESSURE & TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE & TEMPERATURE PARAMETERS AT THE ORIGINAL SOURCE HEADER.
3. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING ~~PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE~~ PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-052
4. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1WG" [illegible] EXCEPT WHERE OTHERWISE NOTED.
5. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION [illegible]. THE PIPING SCHEDULE AND GROUP NOS. ARE AS NOTED ON THIS DRAWING AND PREFIXED WITH "IS".

Also Available On Aperture Card

TI APERTURE CARD

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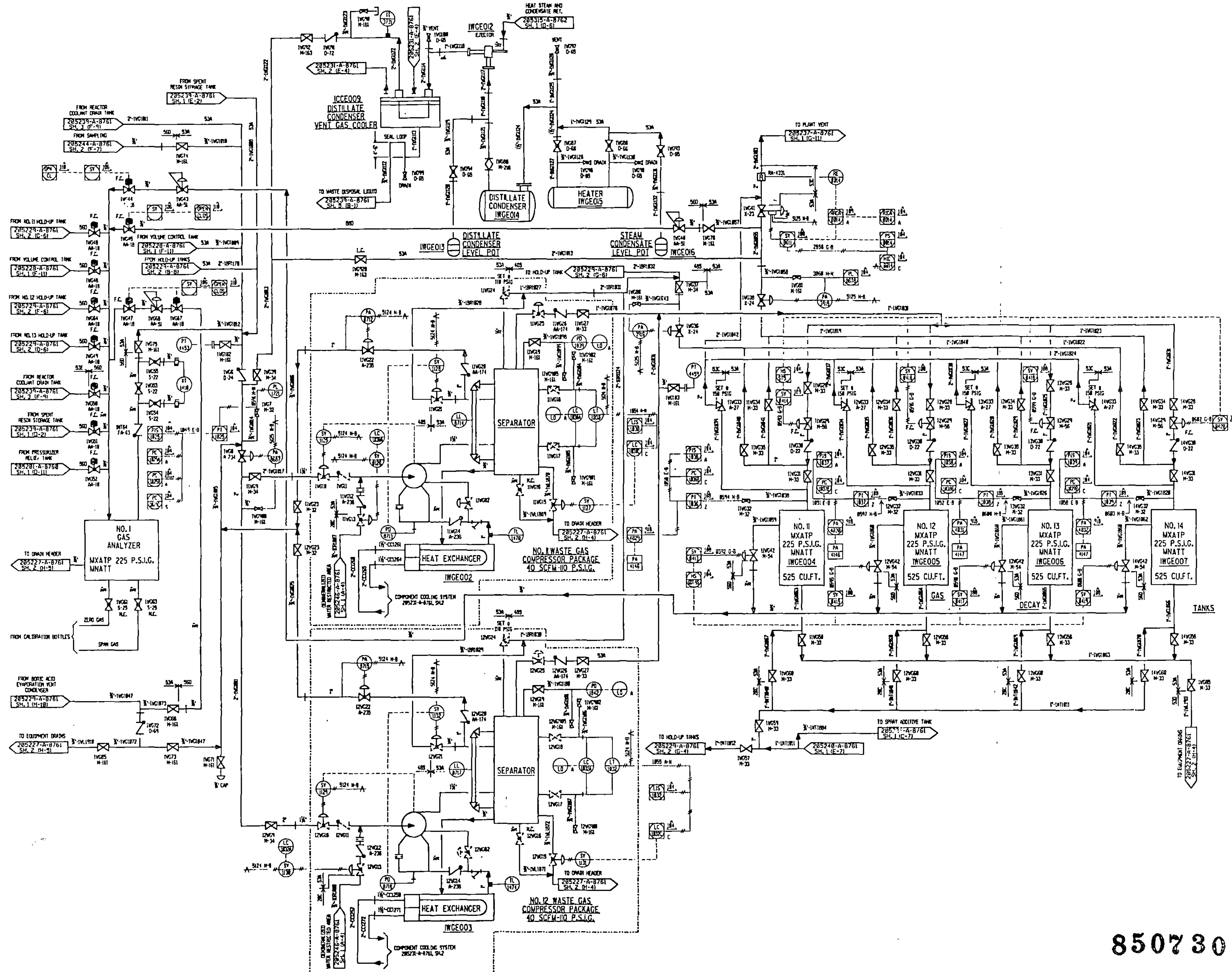
Revision 4
July 22, 1985
Ref. Dwg. 205240A8761-17

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Gaseous Waste Disposal System Unit 1
	Updated FSAR Sheet 1 of 2 Fig 11.3-1A



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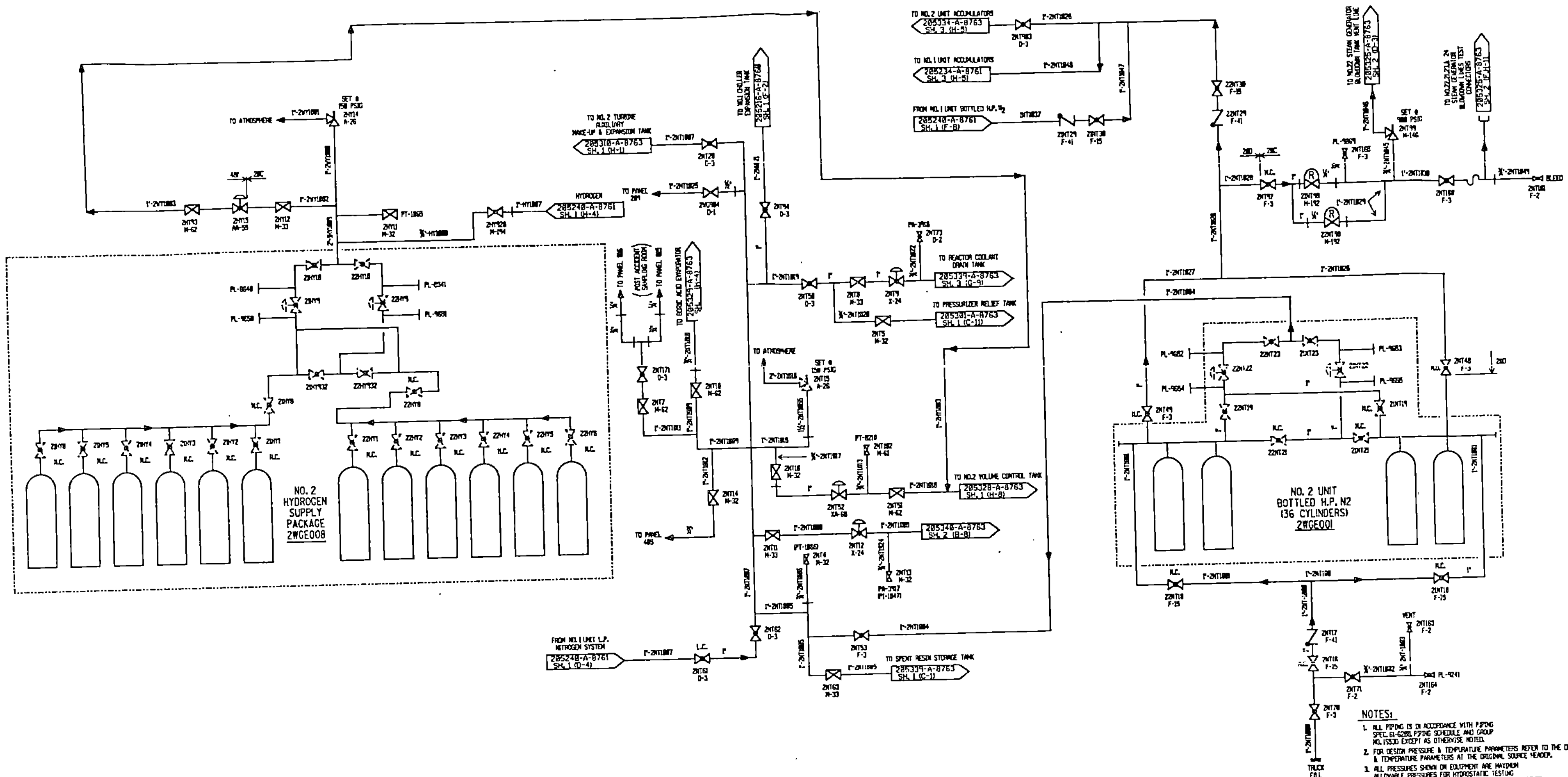
Revision 4
July 22, 1985
Ref. Dwg. 205240A8761-17

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Gaseous Waste Disposal System Unit 1
	Updated FSAR Sheet 2 of 2 Fig 11.3-1A



NOTES:

1. ALL PIPING IS IN ACCORDANCE WITH PIPING SPEC. 61-6281 PIPING SCHEDULE AND GROUP NO. 1S53D EXCEPT AS OTHERWISE NOTED.
2. FOR DESIGN PRESSURE & TEMPURATURE PARAMETERS REFER TO THE DESIGN PRESSURE & TEMPERATURE PARAMETERS AT THE ORIGINAL SOURCE HEADER.
3. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051
4. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2WG" (I.E. 2WG1008, ETC.) EXCEPT WHERE OTHERWISE NOTED.

DESIGN				
● BOUNDARY	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S53A	YES	I	III	YES
1S53C	YES	I	III	YES
1S53D	NO	III	III	NO
1S28C	NO	III	NONE	NO
1S28D	NO	II	NONE	NO
1S48I	YES	I	II	YES
1S48S	NO	II	II	YES
1S56D	NO	II	III	NO

● IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (I.E. 1S 44A, ETC.) UNLESS OTHERWISE NOTED.

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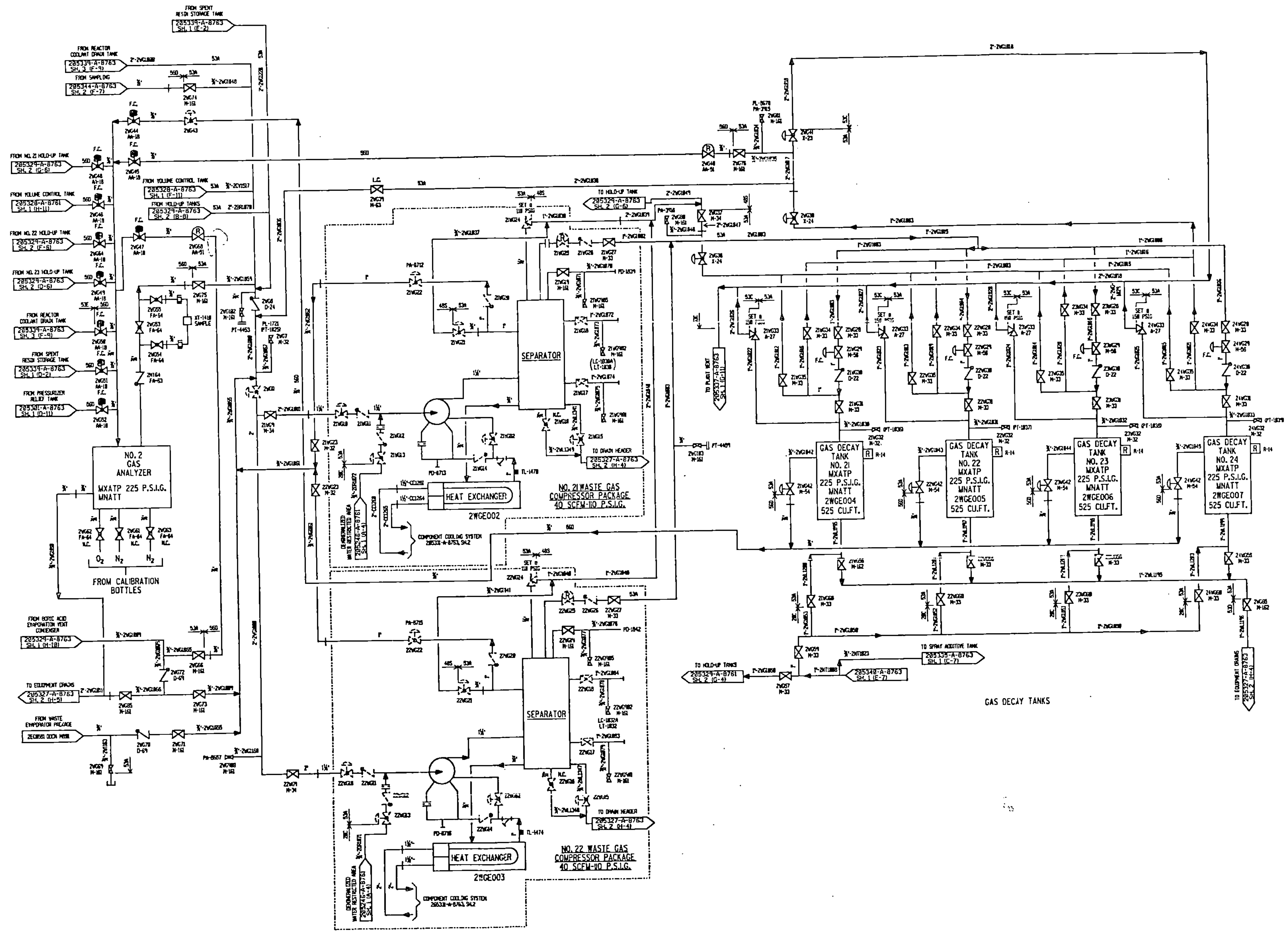
Revision 4
July 22, 1985
Ref. Dwg. 205340A8763-17

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Gaseous Waste Disposal System Unit 2
	Updated FSAR Sheet 1 of 2 Fig 11.3-1B



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Ref. Dwg. 205340A8763-17

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Gaseous Waste Disposal System Unit 2 Updated FSAR Sheet 2 of 2 Fig 11.3-1B

TABLE 11.4-1 (Sheet 3 of 4)

Channel No.	Type of Detector	Channel Description	Minimum Detectable Level	Control Function/Interlocks
1-R35	Gamma Scintillator	S.G. Blowdown Filter Discharge	10^{-5}uCi/cc ^{137}Cs	Blowdown Filter to Waste Monitor Holdup Tank/Condenser Line
1-R36	Gamma Scintillator	Evaporator and Feed Heater Condensate	10^{-5}uCi/cc ^{137}Cs	Condensate Line Valve
1-R41A	Beta Scintillator	Plant Vent Particulate	10^{-11}uCi/cc ^{90}Sr	---
1-R41B	Gamma Scintillator	Plant Vent Iodine	10^{-11}uCi/cc ^{131}I(2)	---
1-R41C	Beta Scintillator	Plant Vent Noble Gas	10^{-6}uCi/cc ^{133}Xe	---
1-R45A	GM Tube	Plant Vent Shield Background	0.1 MR/HR to 10,000 MR/HR	Section 11.4.2.2, Item 15
1-R45B	GM Tube	Plant Vent Noble Gas (Inter.)	0.1 MR/HR to 10,000 MR/HR	Section 11.4.2.2, Item 15
1-R45C	GM Tube	Plant Vent Noble Gas (High)	0.1 MR/HR to 10,000 MR/HR(3)	Section 11.4.2.2, Item 15
1-R45D	GM Tube	Plant Vent Bulk Filter	0.1 MR/HR to 10,000 MR/HR	Section 11.4.2.2, Item 15

TABLE 11.4-2 (Sheet 3 of 4)

Channel No.	Type of Detector	Channel Description	Minimum Detectable Level	Control Function/Interlocks
2-R31	Gamma Scintillator	Letdown Line	10^{-6}uCi/cc^{137}Cs	---
2-R35	Ion Chamber	Steam Generator Blowdown Filter Discharge	10^{-7}uCi/cc^{137}Cs	Diverts Blowdown Treatment Discharge to Waste Handling System
2-R36	Gamma Scintillator	Evaporator and Feed	10^{-6}uCi/cc^{137}Cs	Closes Condensate Valve from Waste Evaporator and Feedwater Preheater
2-R41A	Beta Scintillator	Plant Vent Particulate	10^{-11}uCi/cc^{90}Sr(2)	Containment Ventilation Isolation
2-R41B	Gamma Scintillator	Plant Vent Iodine	10^{-11}uCi/cc^{131}I(2)	Containment Ventilation Isolation
2-R41C	Beta Scintillator	Plant Vent Noble Gas	10^{-6}uCi/cc^{133}Xe	Containment Ventilation Isolation; Closes Waste Gas Discharge Valve
2-R45A	GM Tube	Plant Vent Shield Background	0.1 MR/HR to 10,000 MR/HR	Section 11.4.2.2, Item 15
2-R45B	GM Tube	Plant Vent Noble Gas (Inter.)	0.1 MR/HR to 10,000 MR/HR	Section 11.4.2.2, Item 15
2-R45C	GM Tube	Plant Vent Noble Gas (High)	0.1 MR/HR to 10,000 MR/HR(3)	Section 11.4.2.2, Item 15

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13.0 CONDUCT OF OPERATIONS

Public Service Electric and Gas Company is responsible for all station operations at Salem Generating Station. The Westinghouse Electric Corporation provided technical assistance during the period of pre-operational testing, initial core loading, and pre-commercial operation. A continuous training program is established with the goal of maintaining sufficient Public Service personnel with operating licenses to satisfy NRC requirements during normal station operation.

This section outlines the manner in which the station is operated. It includes corporate and station organization, functions, responsibilities, and authorities, training of the operating personnel, operating and emergency instructions, emergency planning, records, and administrative procedures to assure safe operations.

13.1 OPERATIONAL STRUCTURE

13.1.1 CORPORATE ORGANIZATION

That segment of the corporate structure of Public Service Electric and Gas Company which relates to the activities of the Salem Generating Station are shown in Figure 6.2-1 of the Salem Technical Specification

13.1.1.1 Corporate Functions, Responsibilities, and Authorities

Senior Vice President - Energy Supply and Engineering

Provides direction for the Engineering and Construction, Fuel Supply, Nuclear, and Production Departments and the Quality Assurance Department. Initiates and implements broad policies and general procedures relating to the functions of these departments. Reviews performance of departments under his supervision with respect to goals and objectives. Plans for future developments.

Vice President - Production

Provides maintenance, computer, and technical support to all Production facilities and oversees operation of the Central Maintenance Shop.

Plans and coordinates Production Department facility major maintenance, including the development of schedules and manpower utilization. Provides services as required by the Nuclear Department.

Vice President - Engineering and Construction

Furnishes engineering, design, and construction services required to provide major new facilities. Provides similar services for major modifications to and major maintenance on existing facilities. Plans and executes such work to meet scheduling budgetary, and technical requirements. Furnishes consulting engineering and design services as required by the Nuclear Department.

Vice President - Fuel Supply

Procures uranium and conversion, enrichment, fabrication, and spent fuel disposal services for PSE&G-operated nuclear units. Prepares specifications, selects bidders, evaluates bids, and negotiates contracts, with the assistance, concurrence and advice of other departments where necessary. Schedules deliveries, administers contracts, monitors supplier performance and fabrication quality. Submits and administers nuclear fuel expenditure budget items and associated authorizations. Provides predictive and actual nuclear fuel burnup costs. Manages nuclear fuel economic utilization and provides evaluations of nuclear fuel resources. Formulates strategies. Coordinates and manages Fuel Data Bank providing fuel price forecast information and nuclear fuel capital expenditure estimates. Prepares testimony on nuclear fuel matters for presentation to regul¨tory agencies and provides comments and assistance to the Corporate Rate Counsel, Governmental Affairs, and Law Departments.

General Manager - Nuclear Assurance and Regulation

Provides management with an independent basis for evaluating the effectiveness of nuclear safety and quality assurance programs. Performs independent management assessment of environmental technical performance. Pursues licensing, safety analysis and environmental programs as required to obtain and retain regulatory approvals for existing facilities and new projects. Maintains appropriate liaison and coordinates Company participation in meetings and public hearings with local, state, regional and federal regulatory agencies. Provides a management focal point for generic regulatory matters.

Vice President - Nuclear

The Vice President - Nuclear is the Senior Nuclear Manager in the overall charge of the nuclear programs at Artificial Island, including plant operations and nuclear safety. The General Manager - Salem Operations, General Manager - Hope Creek Operations, General Manager - Nuclear Support, General Manager - Nuclear Services, Manager - Methods and Administration - Nuclear, and the Manager - Quality Assurance Nuclear Operations report directly to the Vice President - Nuclear. In the event of a nuclear emergency at Artificial Island, the Vice President - Nuclear assumes the role of Emergency Response Manager and takes command and control of all PSE&G on-site and off-site response activities. Additionally, the Vice President - Nuclear establishes policies on nuclear operations matters within the Company, subject to the advice and consent of senior corporate management. Where questions or disagreements arise with the nuclear organization concerning nuclear safety matters, the Vice President - Nuclear will establish Company policy. In addition, he has the authority and responsibilty to determine when the plants must be shut down to maintain the safety of the facilities.

As the Senior Nuclear Manager in overall charge of Company nuclear programs, the Vice President - Nuclear provides management direction and control for the operation and support activities associated with the nuclear facilities at Artificial Island. This includes the establishment of qualification requirements for management positions which directly support plant operations, the development of goals, objectives and Company policy relating to the safe and reliable operation of the nuclear units, and implementation of formalized programs, such as security, fire protection, radiation protection, and operator training.

The senior nuclear manager is actively involved in plant operational activities and reviews significant operating deficiencies and violations of Technical Specifications. He monitors the activities of the Nuclear Review Board which performs the independent review function of important matters affecting nuclear operation and safety. Close attention to unanticipated and unusual plant occurrences and review of operational trend analysis by the Senior Nuclear Manager assures that the highest standards affecting plant operations are maintained.

Manager - Methods and Administration - Nuclear

Reporting directly to the Vice President - Nuclear is the Manager - Methods and Administration - Nuclear, who is responsible for planning and scheduling, cost control, systems development, computer applications, and coordination of all personnel and administrative functions including payroll, accounting, employment and compensation, and medical services.

Manager - Quality Assurance Nuclear Operations

The Manager - Quality Assurance Nuclear Operations reports directly to the Vice President - Nuclear and is Responsible for all Quality Assurance activities regarding the engineering, design, procurement, operation, maintenance, refueling, and modifications for operating nuclear plants.

General Manager - Salem Operations

The General Manager - Salem Operations is responsible for the safe and efficient operation of the nuclear units and general direction of the Operating, Maintenance, Radiation Protection, and Technical Support Departments. Reporting directly to the station General Manager is an Assistant General Manager, followed by four major station department heads, the Operations Manager, Maintenance Manager, Technical Manager, and Radiation Protection Engineer.

The General Manager is responsible for compliance with all applicable requirements of the NRC Operating License and Technical Specifications, and the prompt reporting of unusual events, deficiencies and corrective action implementation. He monitors the activities of the Station Operations Review Committee (SORC), involving evaluations of plant safety related activities. Additionally, he is responsible for assuring that the nuclear station needs for engineering, maintenance, and other site support services are identified and can be adequatly satisfied by the site support organizations to meet all requirements for safe and reliable plant operation.

The General Manager is responsible for assuring that plant staff positions are maintained by fully qualified and trained personnel. He directs the implementation of a radiation protection program that assures that radiation exposure of plant and support personnel is maintained as low as reasonably achievable. He is also responsible for the approval of operating procedures as required by Technical Specifications and for the development and control of budgets for the operation and maintenance of the station.

General Manager - Nuclear Support

The General Manager - Nuclear Support is responsible for providing support to the nuclear stations in the areas of engineering and design, reactor engineering and fuel management, the maintenance of the operating licenses, and review of the investigations conducted by the Safety Review Group.

The station General Manager will direct the General Manager - Nuclear Support to provide assistance for performance of the required work in these areas of responsibility. The General Manager - Nuclear Support will make the determination of which activities are performed by on-site and/or off-site personnel, and furthermore provide technical direction for all off-site support functions performed in these areas. All off-site communications regarding these areas of responsibility shall be through the Nuclear Support Department.

Reporting directly to the General Manager - Nuclear Support are the Safety Review Group; three department managers responsible for licensing and regulation, nuclear safety and assessment, and fuel cycle; and the Assistant General Manager - Nuclear Engineering who, in turn, directs four additional department managers whose responsibilities include plant systems, engineering and design.

General Manager - Nuclear Services

The General Manager - Nuclear Services is responsible for providing technical services to the station organizations in the area of radiation protection; site protection including fire, security and emergency preparedness; training of licensed and non-licensed personnel; in-service inspection and non-destructive examination. The organization also provides the stations with calibration and instrument repair, radwaste management, and maintenance support services. In addition, he is responsible for material management, warehousing and control of all contractor activities.

The station General Manager will direct the General Manager - Nuclear Services to provide assistance for performance of the required work in these areas of responsibility. The General Manager - Nuclear Services will make the determination of which activities are performed on-site and/or off-site personnel, and furthermore provide technical direction for all off-site support functions performed in these areas. All off-site communications regarding these areas of responsibility shall be through the Nuclear Services Department.

Reporting to the General Manager - Nuclear Services are six department managers who provide services to the two nuclear stations. Under the direction and control of the General Manager - Nuclear Services, common activities required by both nuclear stations are combined to provide improved utilization of resources and greater control of the identified support functions.

13.1.1.2 Interrelationships with Contractors and Suppliers

Westinghouse Electric Corporation provides technical assistance (engineering studies, analyses and/or technical guidance) in support of unit operations as requested regarding the nuclear system equipment, instrumentation, and material supplied by Westinghouse.

13.1.2 OPERATING ORGANIZATION

13.1.2.1 Plant Organization

The station organization of the Salem Nuclear Generating Station is shown in Figure 6.2-2 of the Salem Technical Specifications. The organization is divided into four major functional departments: operations, maintenance, technical, and radiation protection.

13.1.2.2 Personnel Functions, Responsibilities, and Authorities

The General Manager - Salem Operations has overall responsibility for the plant and for directing and coordinating the activities of the four major departments to insure safe, reliable, and efficient functioning of the plant.

The Assistant General Manager is responsible to the General Manager - Salem Operations for the safe, reliable, and efficient operation of the plant in conformance with the operating license. This includes the plant nuclear fuel management responsibilities, coordination of maintenance with technical and operating department activities, training and retraining of supervisors and operators to qualify for necessary licenses and the preparation of operating and emergency instructions. He has the responsibility and authority to act for the General Manager in his absence.

The Maintenance Manager is in charge of the Maintenance Department, which performs the electrical, mechanical, and other maintenance work of the plant. He reports directly to the Assistant General Manager - Salem Operations with overall responsibilities for the management, administration, personnel, and industrial relations work of the Maintenance Department. In general, the Maintenance Manager plans, organizes, directs, coordinates, and controls the work of his department.

The Operations Manager reports to the Assistant General Manager - Salem Operations. Directly supervising the Operating Department, the Operations Manager coordinates and directs the shift units, analyzes operating records, prepares and revises operating, and emergency instructions and, in general, assures that the plant is operated in a safe, efficient manner by qualified personnel.

The Technical Manager reports to the Assistant General Manager - Salem Operations and directs the Technical Department. He is responsible for the following plant activities: unit performance testing, routine station reports, plant water chemistry, demineralized water plant operation, control of environmental releases, calibration and maintenance of all instruments and controls, preparation of core performance and fuel burnup data to guide plant operation, and the input of information to the General Office Fuel Supply Department needed for the overall fuel management program. The Technical Manager also plans, coordinates, and directs the receipt, storage and movement of new and spent fuel and coordinates station input to FSAR and Technical Specification matters.

The Radiation Protection Engineer reports to the Assistant General Manager - Salem Operations. He develops, implements, and directs the radiological safety and radioactive material control programs to insure that radiation exposure of personnel and releases of radioactive material to the environment are as low as reasonably achievable. Performs personnel radiation monitoring and dosimetry. Operates radioactive waste processing, storage and transfer equipment.

13.1.2.3 Shift Crew Composition

The shift crew composition, position titles, license qualifications, and number of personnel on each shift are provided in the Salem Technical Specifications, Section 6.0, Administrative Controls.

13.1.3 MINIMUM PERSONNEL QUALIFICATIONS

Minimum qualifications for supervisory and professional personnel on the plant staff are as stated in Section 6.0 of the Technical Specifications.

13.4 REVIEW AND AUDIT

13.4.1 ADMINISTRATIVE CONTROL

Administrative control of plant operations is directed by the Vice President - Nuclear through the General Manager - Salem Operations. Further details on administrative control are provided in the Technical Specifications.

13.4.2 ROUTINE REVIEW

A daily review of station logs and other operating data will be made by the Operating Department. All non-routine operations and conditions will also be reviewed by other reponsible departments, as appropriate. In addition to these reviews, periodic station staff meetings will be held to keep all operating personnel advised of conditions in the station.

To establish and ensure formal review and evaluation of plant operations, a Station Operations Review Committee (SORC) and a Nuclear Review Board (NRB) were established and are described in the Salem Technical Specifications, Section 6.0, Administrative Controls.

13.4.3 NUCLEAR OVERSIGHT COMMITTEE

The purpose of the Nuclear Oversight Committee is to provide management with an independent basis for evaluating the effectiveness of Nuclear Safety. The Committee consists of 3-5 members and will include nuclear utility operations executives, college professors and former regulators. Support for the Nuclear Oversight Committee will be provided by personnel from appropriate PSE&G organizations.

The Nuclear Oversight Committee holds meetings at least quarterly and at any time upon request of a member.

The Nuclear Oversight Committee submits reports to the Vice President - Nuclear following each quarterly meeting. Reports include: (1) an evaluation of overall management attention to nuclear safety, and (2) progress being made towards resolving the open issues identified in the commitments made by PSE&G to the Nuclear Regulatory Commission. Copies of these reports will be forwarded to the Nuclear Regulatory Commission.

The Committee in the performance of its duties may engage such technical and consulting services as warranted.

Following a year's experience with the operation of the Nuclear Oversight Committee, PSE&G will evaluate the need for its continuance.

13.4.4 SAFETY REVIEW GROUP (SRG)

The SRG is composed of five dedicated, full-time engineers and functions to examine plant operating characteristics, NRC issuances, industry advisories, LER's, and other sources of information which may indicate areas for improvement of plant safety.

The SRG is responsible for maintaining surveillance of selected plant activities to provide independent verification that these activities are performed correctly. The group functions under the general guidelines contained in NUREG-0737 and serves no line functions.

Recommendations for improving plant safety which result from SRG reviews are reported to management and are tracked as open items until they are resolved. The SRG has free access to all levels of management within the Nuclear Department to discuss issues requiring immediate attention and to discuss issues having a potential impact on safety.

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with respect to the fuel rod thermal time constant the fuel temperatures are illustrated on Figures 4.4-1 and 4.4-2. For transients which are fast with respect to the fuel rod thermal time constant, for example, rod ejection, a detailed heat transfer calculation is made.

15.1.3 TRIP POINTS AND TIME DELAYS TO TRIP ASSUMED IN ACCIDENT ANALYSES

A reactor trip signal acts to open two trip breakers connected in series feeding power to the control rod drive mechanisms. The loss of power to the mechanism coils causes the mechanisms to release the rod cluster control assemblies which then fall by gravity into the core. There are various instrumentation delays associated with each trip function, including delays in signal actuation, in opening the trip breakers, and in the release of the rods by the mechanisms. The total delay to trip is defined as the time delay from the time that trip conditions are reached to the time the rods are free and begin to fall. Limiting trip setpoints assumed in accident analyses and the time delay assumed for each trip function are given in Table 15.1-3. Reference is made in that table to overtemperature and overpower ΔT trip shown in Figure 15.1-1.

The overtemperature ΔT setpoints shown in Figure 15.1-1 along with all other evaluated DNBR'S were calculated assuming approximately 15 percent margin in the critical heat flux calculation, as discussed in Section 4.4.2.1.

The difference between the limiting trip point assumed for the analysis and the nominal trip point represents an allowance for instrumentation channel error and setpoint error. During preliminary start-up tests, it will be demonstrated that actual instrument errors and time delays are equal to or less than the assumed values.

15.1.4 INSTRUMENTATION DRIFT AND CALORIMETRIC ERRORS - POWER RANGE NEUTRON FLUX

The instrumentation drift and calorimetric errors used in establishing the maximum overpower setpoint are presented in Table 15.1-4.

The calorimetric error is the error assumed in the determination of core thermal power as obtained from secondary plant measurements. The total ion chamber current (sum of the top and bottom sections) is calibrated (set equal) to this measured power on a periodic basis. The secondary power is obtained from measurement of feedwater flow, feedwater inlet temperature to the steam generators and steam pressure. High accuracy instrumentation is provided for these measurements with accuracy tolerances much tigher than those which would be required to control feedwater flow.

15.1.5 ROD CLUSTER CONTROL ASSEMBLY INSERTION CHARACTERISTICS

The negative reactivity insertion following a reactor trip is a function of the acceleration of the rod cluster control assemblies and the variation in rod worth as a function of rod position.

With respect to accident analyses, the critical parameter is the time of insertion up to the dashpot entry or approximately 85 percent of the rod cluster travel. For accident analyses it is conservatively assumed that the insertion time to dashpot entry is 2.2 seconds. The rod cluster control assembly position versus time assumed in accident analyses is shown in Figure 15.1-2.

Figure 15.1-3 shows the fraction of total negative reactivity insertion for a core where the axial distribution is skewed to the lower region of the core. An axial distribution which is skewed to the lower region of the core can arise from a xenon oscillation or can be considered as representing a transient axial distribution which would exist after the

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15. Burnett, T. W. T., McIntyre, C. J., Buker, J. C. and Rose, R. P., "LOFTRAN Code Description", WCAP-7907, June 1972.

16. Barry, R. F., "LEOPARD, a Spectrum Dependent Non-Spatial Depletion Code for the IBM-7094", WCAP-3269-26, September 1963.

17. Barry, R. F. and Altomare, S., "The TURTLE 24.0 Diffusion Depletion Code": WCAP-7213, June 1968, (Westinghouse NES Proprietary); WCAP-7758, September 1971.

18. Risher, D. H., Jr. and Barry, R. F., "TWINKLE - A Multi-Dimensional Neutron Kinetics Computer Code", WCAP-7979, November 1972.

19. Fairbrother, D. B. and Hargrove, H. G., "WIT-6 Reactor Transient Analysis Computer Program Description", WCAP-7980, November 1972.

20. Bordelon, F. M., "Calculation of Flow Coastdown After Loss of Reactor Coolant Pump (PHOENIX Code)", WCAP-7969, September 1972.

TABLE 15.1-3

TRIP POINTS AND TIME DELAYS TO TRIP ASSUMED IN ACCIDENT ANALYSIS

Trip Function	Limiting Trip Point Assumed In Analyses	Time Delay (Seconds)
Power Range High Neutron Flux, High Setting	118 percent	0.5
Power Range High Neutron Flux, Low Setting	35 percent	0.5
Overtemperature ΔT	Variable, see Figure 15.1-1	6.0*
Overpower ΔT	Varible, see Figure 15.1-1	6.0*
High Pressurizer Pressure	2410 psig	2.0
Low Pressurizer Pressure	1845 psig	2.0
Low Reactor Coolant Flow (from loop flow detectors)	87 percent loop flow	1.0
Undervoltage Trip	68 percent nominal	1.2
Turbine Trip	Not Applicable	1.0
Low-Low Steam Generator Level	0 percent of Narrow Range Level Span	2.0
High Steam Generator level trip of the feedwater pumps and closure of feedwater system valves, and turbine trip	75 percent of Narrow Range Level Span	2.0
Underfrequency Trip	6Hz/sec	1.35

* Total time delay (including RTD bypass loop fluid transport delay, affect bypass loop piping thermal capacity, RTD time response, and trip circuit channel electronics delay) from the time the temperature difference in the coolant loops exceeds the trip setpoint until the rods are free to fall.

b. Maximum Reactivity Feedback. A conservatively large positive moderator density coefficient and a large (in absolute magnitude) negative Doppler power coefficient are assumed.

3. The reactor trip on high neutron flux is assumed to be actuated at a conservative value of 118 percent of nominal full power. The ΔT trips include all adverse instrumentation and setpoint errors, while the delays for the trip signal actuation are assumed at their maximum values.

4. The rod cluster control assembly trip insertion characteristic is based on the assumption that the highest worth assembly is stuck in its fully withdrawn position.

5. The maximum positive reactivity insertion rate is greater than that for the simultaneous withdrawal of the combination of the two control banks having the maximum combined worth at maximum speed.

This is also much greater than the maximum reactivity insertion rate associated with withdrawal of a part length rod cluster control assembly.

The effect of rod cluster control assembly movement on the axial core power distribution is accounted for by causing a decrease in overtemperature and overpower ΔT trip setpoints proportional to a decrease in margin to DNB.

15.2.2.3 Results

Figures 15.2-4 and 15.2-5 show the response of neutron flux, pressure, average coolant temperature, and DNBR to a rapid rod cluster control assembly withdrawal incident starting from full power. Reactor trip on high neutron flux occurs shortly after start of the accident. Since this is rapid with respect to the thermal time constants of the plant, small changes in T_{avg} and pressure result and a large margin to DNB is maintained.

The response of neutron flux, pressure, average coolant temperature, and DNBR for a slow control rod assembly withdrawal from full power is shown in Figures 15.2-6 and 15.2-7. Reactor trip on overtemperature ΔT occurs after a longer period and the rise in temperature and pressure is consequently larger than for rapid rod cluster control assembly withdrawal.

Figure 15.2-8 shows the minimum DNBR as a function of reactivity insertion rate from initial full power operation for the minimum and maximum reactivity feedback. It can be seen that two reactor trip channels provide protection over the whole range of reactivity insertion rates. These are the high neutron flux and overtemperature ΔT trip channels. The minimum DNBR is never less than 1.30.

Figures 15.2-9 and 15.2-10 show the minimum DNBR as a function of reactivity insertion rate for rod cluster control assembly withdrawal incidents starting at 60 and 10 percent power respectively. The results are similar to the 100 percent power case, except as the initial power is decreased, the range over which the overtemperature ΔT trip is effective is increased. In neither case does the DNBR fall below 1.30.

15.2.2.4 Conclusions

The high neutron flux and overtemperature ΔT trip channels provide adequate protection over the entire range of possible reactivity insertion rates, i.e., the minimum value of DNBR is always larger than 1.30.

15.2.3 ROD CLUSTER CONTROL ASSEMBLY MISALIGNMENT

15.2.3.1 Identification of Causes and Accident Description

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17.2 QUALITY ASSURANCE DURING THE OPERATIONS PHASE

OVERALL APPROACH AND SCOPE

Public Service Electric and Gas Company (PSE&G) is responsible for assuring that the operation, maintenance, refueling and modification of the Salem Generating Station is accomplished in a manner which protects public health and safety and which is in compliance with applicable regulatory requirements. To carry out this responsibility, PSE&G developed and implemented a comprehensive Operational Quality Assurance Program which was applicable to the design, construction, and testing phases, and is now applied to the operation phase of the Salem Generating Station.

This Operational Quality Assurance Program, hereafter also referred to as "the QA Program," is maintained by Nuclear Operations Quality Assurance (NQA), and is documented in the Vice President Nuclear - Procedure Manual. The Program provides the measures essential for controlling the quality of safety related structures, systems, components, materials, and services. The Quality Assurance Program encompasses fire protection of safety-related areas and other activities enumerated in Regulatory Guide 1.33. A planned monitoring and audit program assures that specified requirements of the Operational Quality Assurance Program are met. The Program provides coordinated and centralized quality assurance direction, control, and documentation as required by the NRC criteria set forth in 10CFR50, Appendix B. In addition, the Operational Quality Assurance Program is based upon the policy statements of PSE&G Management. It is implemented through Procedures, Instructions, Standards, Specifications, and Forms which provide the details of how that policy is implemented for 10CFR50, Appendix B. Applicable NRC Regulatory Guides, codes and standards, and the policy statements contained in the Nuclear Department Manual are used by PSE&G organizations performing safety-related activities to prepare appropriate implementing procedures. To assess the effectiveness of the Operational Quality Assurance Program, independent auditors from outside the company audit the program every two years for compliance with 10CFR50 Appendix B and other regulatory commitments. Reports of such audits are made directly to upper management.

PSE&G requires its suppliers and contractor to assume responsibility for establishing and implementing QA/QC programs, as applicable, to meet 10CFR50, Appendix b. NQA reviews those programs and conducts appropriate monitoring and auditing as required to assure that suppliers properly implement their QA/QC programs. The Operational QA Program verifies that requirements necessary to assure quality are properly included or referenced in procurement documents. In addition, PSE&G suppliers are required to extend applicable PSE&G QA requirements to sub-suppliers, as documented in the suppliers' procurement documents.

17.2.1 ORGANIZATION

17.2.1.1 General

The Operational QA Program, referred to hereafter as the QA Program, assures that adequate administrative and management controls are established for the safe operation of Salem Generating Station.

Implementation is assured by ongoing review, monitoring and audit under the direction of the Manager - Nuclear Operations Quality Assurance (NQA) who reports to the Vice President - Nuclear.

Company organization is shown in Figures 17.2-1 through 17.2-4. Responsibilities for quality assurance related activities are described in the following sections.

17.2.1.2 Nuclear Department

The Vice President - Nuclear reports to the Senior Vice President - Energy Supply and Engineering and is responsible for managing and directing the nuclear activities of the Company. Reporting to the Vice President - Nuclear are the General Manager - Nuclear Services, General Manager - Nuclear Support, General Manager - Salem Operations, and General Manager - Hope Creek Operations and Manager - NQA. Also reporting to the Senior Vice President - Energy Supply and Engineering is the General Manager - Nuclear Assurance and Regulation. The Manager - Corporate Quality Assurance reports to the General Manager - Nuclear Assurance and Regulation.

The General Managers are responsible for the implementation of quality assurance requirements by their staff. These QA requirements are contained in the station administrative procedures and in other department manuals.

17.2.1.2.1 Nuclear Department - Nuclear Services

The General Manager - Nuclear Services is responsible for providing technical support to Station organization in the areas of radiation protection, site protection, (including fire, security, and emergency preparedness) planning and scheduling of plant betterment and maintenance work, in-service inspection, nuclear procurements and materials control, and station personnel training.

17.2.1.2.2 Nuclear Department - Nuclear Support

The General Manager - Nuclear Support is responsible for providing support to the station in the areas of reactor engineering, engineering and design, fuel management, licensing and regulatory activity, nuclear safety, and risk assessment analysis.

17.2.1.2.3 Nuclear Department - Salem Operations

The General Manager - Salem Operations is responsible for the safe and efficient operation of the plant, and for the general direction of the station Operating, Maintenance, Radiation Protection, and Technical Support Departments. The General Manager - Salem Operations directs the activities of the Station Operations Review Committee (SORC) and is responsible for assuring that plant positions are staffed by fully qualified and trained personnel.

17.2.1.2.4 Nuclear Operations Quality Assurance

The Manager NQA is responsible for the approval and coordination of nuclear-related QA programs established and implemented by Company departments. He is responsible for conducting independent audits, with his staff or consultants, or quality related activities of Company departments, suppliers, and contractors.

The Manager NQA has the authority and responsibility to:

1. Establish and implement a Quality Assurance Program in conformance with the requirements of 10CFR50, Appendix B.

2. Maintain the Operational QA Program as defined and documented in the Vice President Nuclear - Procedure Manual.

3. Provide centralized coordination of Quality Assurance functions regarding Nuclear Operations.

4. Review and approve PSE&G procedures which implement the QA Program to the extent necessary to verify compliance with applicable quality-related Regulatory Guides and standards as committed to in the Updated Final Safety Analysis Report (UFSAR).

5. Establish and interpret quality assurance requirements and policies for other departments.

6. Interpret quality assurance requirements of regulatory commitments and assist upper management in establishing policies needed to meet those commitments.

7. Assure compliance with PSE&G Quality Assurance policies and applicable government regulations including Regulatory Guides, Standards, Codes, etc., as committed in the UFSAR and licenses.

8. Provide top management with visibility into the status and adequacy of implementation of the QA Program by reporting significant quality problems and their solutions, and recommending preventive or corrective action to prevent their recurrence.

9. Provide support to other PSE&G departments in order to assure that nuclear facilities are designed, fabricated, constructed, tested, operated, maintained, and modified in a manner which protects public health and safety.

10. Represent the PSE&G Nuclear Operations Quality Assurance at regulatory agency public hearings and other meetings, on matters affecting the Operational QA Program.

11. Stop work when significant conditions adverse to quality require such action.

The PSE&G policies and organization structure assure that the Manager - Nuclear Operations Quality Assurance has sufficient organizational freedom and independence to carry out his responsibilities.

17.2.1.2.4.1 Nuclear Operations Quality Assurance (NQA) Personnel Qualifications

Qualification requirements for NQA positions are a bachelor's degree and/or a high school diploma or equivalent, plus two years experience and demonstrated technical ability which may be as an inspector, test engineer, or by special study of quality control techniques, testing and inspection methods, and/or by having acquired working knowledge of and familiarity with the requirements of the applicable Codes and Standards for accomplishing quality activities performed in the nuclear power industry.

The Manager - NQA shall fulfill the above qualifications with the addition of the following:

1. Knowledge and experience in Quality Assurance.

2. High level of leadership with the ability to command the respect and cooperation of company personnel, vendors, and operations forces.

3. Initiative and judgement to establish related policies to attain high achievements and economy of operations.

The Managers and engineers reporting directly to the Manager, Nuclear Operations Quality Assurance must each have a combination of six years experience in the fields of quality assurance and operations. At least one of these six years experience must be nuclear power plant experience in the overall implementation of a quality assurance program. A minimum of one year and a maximum of four years of this six years experience may be fulfilled by related technical or academic training. Personnel performing inspections, examinations and test activities are certified as Level I, Level II or Level III as appropriate to their responsibilities, also in accordance with Regulatory Guide 1.58 as noted.

17.2.1.2.5 Independent Review Groups

Two advisory groups are responsible for reviewing and evaluating activities affecting nuclear safety. The onsite advisory group is designated the Station Operations Review Committee (SORC). Composed of key station personnel, its responsibilities include review of plant operations, reportable occurrences, investigation of Technical Specification violations (with recommendation to preclude recurrence), and procedure reviews for safety-related activities or plant modifications. Recommendations of this advisory group are forwarded to the General Manager - Salem Operations, with copies to the Chairman of the Nuclear Review Board. The SQAE is invited to all SORC meetings and attends them periodically as part of the planned surveillance program. He receives minutes of all the meetings.

The off-site advisory group is the Nuclear Review Board (NRB), which advises the Vice President - Nuclear in matters affecting nuclear safety or relating to plant operation or modification to the plant design. The NRB is responsible for performing an independent review of plant activities. In addition, NRB is responsible for selected planned, independent audits of plant operations in accordance with Technical Specification requirements. These audits are generally conducted by NQA under NRB cognizance. The Manager, NQA is a member of the Nuclear Review Board.

SORC and NRB organization and responsibilities are delineated in the Technical Specifications.

In addition to these two groups, the onsite Safety Review Group also provides independent review of activities affecting the safe operation of the station. See Section 13.4.4.

17.2.1.3 Research & Testing Laboratory

The Research and Testing Laboratory is a part of the PSE&G Research Corporation which is a subsidiary.

The Research & Testing Laboratory performs calibrations, analyses and evaluations of systems, equipment, and materials as requested by PSE&G departments, and maintains compliance with its own QA program.

17.2.1.4 Fuel Supply Department

The General Manager - Fuel Supply reports to the Vice President - Fuel Supply. The Vice President - Fuel Supply reports to the Senior Vice President - Energy Supply and Engineering. The Fuel Supply Department is responsible for arranging the procurement of uranium ore, conversion and enrichment services and fuel assembly fabrication services to satisfy Nuclear Department core designs, enrichment requirements, and delivery schedules.

17.2.1.5 Transmission and Distribution Department

The Vice President - Transmission and Distribution reports to the Senior Vice President - Customer Operations. This organization is responsible for transmitting electrical energy to the area of use and for distributing it to the consumers. It is responsible for setting and testing protective relays for the external vital power supplies at the Station.

17.2.1.6 Purchasing Department

The General Manager - Purchasing reports to the Vice President - Corporate Services under the Senior Vice President - Administration.

Initiation of requests for procurement of materials, equipment, structures, and services required to support operations at the Station is the responsibility of the Nuclear Department. Procurement of same is the responsibility of the General Manager - Purchasing. Both activities are bound by Corporate purchasing policies established by the Purchasing Department.

17.2.1.7 Nuclear Assurance and Regulation Department

The General Manager - Nuclear Assurance and Regulation reports to the Senior Vice President - Energy Supply & Engineering. The Nuclear Assurance & Regulation Department provides management with independent evaluation of the effectiveness of nuclear safety and quality programs; pursues licensing, safety analysis and environmental programs as required to obtain and retain regulatory approval; coordinates company participation in meetings and public hearings with local, state, regional, and federal regulatory agencies; and provides a management focal point for generic regulatory matters.

17.2.2 OPERATIONAL QUALITY ASSURANCE PROGRAM

The Operational QA Program is designed to comply with the requirements of 10CFR50, Appendix B and with the Fire Protection Program requirements of Appendix A of Branch Technical Position No. 9.5-1. Items and activities covered by the QA Program are delineated in the Salem Q-list (Table 17.2-1). Procedures require that personnel also utilize the Master Equipment List (MEL) in conjunction with the Component List for determining whether an activity is safety-related and/or whether the QA Program applied to the activity. Once an activity has thus been determined to be safety-related or applicable to the Operational QA Program, established approved procedures are utilized in the performance of the activity.

The QA Program is applied during the operational phase using a graded approach to an extent consistent with the item's or activity's importance to safety. These activities are performed in compliance with license requirements and with applicable regulatory guidance. Such regulatory guidance, with exceptions noted, includes:

1. Regulatory Guide 1.8, "Personnel Selection and Training", 9/75, (endorses N18.1).

2. Regulatory Guide 1.17, "Protection of Nuclear Plants Against Industrial Sabotage", 6/73, (endorses N18.17).

3. Regulatory Guide 1.29, "Seismic Design Classification", 8/73.

4. Regulatory Guide 1.30, "Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation Electric Equipment", 8/72, (endorses N45.2.4).

5. Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)", 2/78, (endorses N18.7-1976/ANS-3.2).

6. Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants", 3/73, (endorses N45.2.1).

7. Regulatory Guide 1.38, "Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants", 10/76, (endorses N45.2.2).

8. Regulatory Guide 1.39, "Housekeeping Requirements for Water-Cooled Nuclear Power Plants", 3/73, (endorses N45.2.3).

9. Regulatory Guide 1.52, "Design, Testing and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Absorption Units of Light Water-Cooled Nuclear Power Plants", 6/73.

10. Regulatory Guide 1.54, "QA Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants", 6/73, (endorses N101.4).

11. Regulatory Guide 1.58, "Qualification of Nuclear Power Plant Inspection, Examination, and Testing Personnel", 9/80, (endorses N45.2.6).

All PSE&G personnel performing inspection, examination, or testing, are qualified in accordance with this Regulatory Guide, with the following exception:

> Paragraph 6 of Regulatory Guide 1.58 requires that for "... Level I, II, and III personnel, the candidate should be a high school graduate or have earned the General Education Development Equivalent of a high school diploma."
>
> Other factors may provide reasonable assurance that a person can competently perform a particular task. The other factors which may demonstrate capability in a given job are previous performance or satisfactory completion of testing. These two factors will be considered when evaluating education and experience requirements for certification. Personnel requiring certification in accordance with Regulatory Guide 1.58 are limited to NQA personnel who perform inspection and test activities, members of the Operational Test Group (OTG) who perform post-design modification testing, and Salem Operations Department personnel who perform visual inspection as part of the Inservice Inspection Program. Personnel requiring certification are evaluated to establish their qualification for the respective level and discipline. Recertification is based upon demonstrated continued proficiency, or requalification if necessary. These personnel receive a periodic training needs assessment to identify additional supportive training needs as well as to evaluate individual post-training performance. The assessment period is three years or less. Inspection and test activities not requiring personnel certification per Regulatory Guide 1.58 include Technical Specification surveillances and periodic inspection and test of fire protection equipment. These personnel are qualified and retrained in accordance with applicable requirements of Regulatory Guide 1.8.

12. Regulatory Guide 1.64, "Quality Assurance Requirements for the Design of Nuclear Power Plants", 10/73, (endorses N45.2.11).

13. Regulatory Guide 1.74, "Quality Assurance Terms and Definitions", 2/74, (endorses N45.2.10).

14. Regulatory Guide 1.88, "Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records", 10/76, (endorses ANSI N45.2.9), as modified by provisions stated in Section 17.4 of NUREG-0800 (Standard Review Plan), Revision 2, July 1981.

15. Regulatory Guide 1.94, "Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel during the Construction Phase of Nuclear Power Plants", 4/76 (endorses N45.2.5). Major modifications made to the Salem Station will comply with Regulatory Guide 1.94.

16. Regulatory Guide 1.137, "Fuel-Oil Systems for Standby Diesel Generators", 10/79. Diesel fuel oil sampling is performed as follows:

    1. A fuel oil sample is taken from each truck delivering fuel oil to Salem whenever possible. However, if several trucks arrive at once, a minimum of 1 in 4 trucks is sampled depending on the shift, staffing, and existing personnel work load at the time.

    2. All newly received fuel oil is pumped into the 20,000 barrel Fuel Oil Storage Tank. Fuel oil in this tank is sampled at least once every 30 days.

    3. A small percentage of the fuel oil in the 20,000 barrel tank is introduced into the diesel fuel oil storage system as necessary. This small percentage is added infrequently to the four 30,000 gallon Diesel Fuel Oil Storage Tanks (two for each unit) as necessary to maintain the minimum level above the 20,000 gallon limit in each Diesel Fuel Oil Storage Tank as specified by the Salem Technical Specifications.

    4. Fuel oil in the four 30,000 gallon Diesel Fuel Oil Storage Tanks is sampled as required by the Salem Technical Specifications.

5. All fuel oil samples taken in actions 1-4 above are sent to an independent laboratory within 48 hours of the time the sample is taken. The analysis performed is consistent with Regulatory Guide 1.137 and the analysis report is submitted to the Salem Station within 30 days of receipt of the sample at the laboratory.

6. All fuel oil deliveries, samples taken, and related analysis reports are logged at the station. When reports indicate that fuel oil quality is not within acceptable limits, station management will take appropriate action to restore it to within acceptable limits.

7. Actions 1-6 above are subject to verification during routine monitoring and audits of the fuel oil program and procedures conducted by NQA personnel.

17. Regulatory Guide 1.144, "Auditing Quality Assurance Programs for Nuclear Power Plants", 9/80, (endorses N45.2.12).

18. Regulatory Guide 1.146, "Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants", 8/80, (endorses N45.2.23).

19. Branch Technical Position APCSB 9.5-1, Appendix A, "Guidelines for Fire Protection for Nuclear Power Plants Docketed Prior to July 1, 1976", 2/77.

    The QA Program is applied to the Fire Protection Program to an extent consistent with the requirements of Section C of Appendix A to Branch Technical Position APCSB 9.5-1.

PSE&G organizations performing activities affecting nuclear safety, prepare and maintain implementing procedures and instructions. These procedures and instructions, and subsequent revisions thereto, are subject to NQA review and approval to an extent necessary to verify compliance with the Operational QA Program and the applicable quality-related Regulatory Guides and standards identified above.

The General Manager - Salem Operations has instituted and will maintain an Administrative Procedures Manual for Salem Generating Station to implement the detailed requirements of the Program relative to the station.

The Station Administrative Procedures and all subsequent revisions thereto are prepared by the Technical Manager, are reviewed by the Assistant General Manager, and are approved by the General Manager - Salem Operations and the Manager - Nuclear Operational Quality Assurance.

Regulatory Guide 1.33 requires that safety-related plant activities be conducted in accordance with written administrative controls prepared by management. The departmental procedures and instructions by which plant activities are performed are prepared by the responsible station department, as required by the Station Administrative Procedures, reviewed by the SQAE for inspection requirements, approved by the department head responsible for the activity, reviewed by the SORC (if safety related), and approved by the General Manager - Salem Operations. Procedures cannot be implemented unless the review/approval process is accomplished. Station Administrative Procedures provide a means to accommodate on-the-spot changes to sub-tier implementing procedures. The routine practice for revising a procedure is to repeat the original review and approval sequence.

Implementation of the Operational QA Program is verified by means of independent inspections, monitoring, and audits conducted by NQA.

NQA reviews and analyzes quality-related problems occurring during the operational phase. Items subject to review include:

1. Documented nonconformances occurring at the vendor's facility and during receiving, storage, installation, test and operation (e.g., Deficiency Reports, Non-Conformance Reports, Licensee Event Reports, etc.).

2. Documented corrective actions taken on significant noncompliances and on audit findings.

3. NRC inspection findings, notices, bulletins, etc.

The Manager - Nuclear Operations Quality Assurance or his designee, has the authority to stop work where continuance of an activity would seriously compromise safety or constitute a persistent and deliberate failure to correct a serious deficiency.

NQA reports significant problems affecting the Program to respective management along with:

1. Measures taken to improve QA program controls.

2. Appropriate recommendations to achieve compliance with applicable requirements.

Management policy and implementing procedures provide all personnel awareness and direction for reporting of defects and non-compliances pursuant to 10CFR21.

The Operational QA Program requires that activities affecting nuclear safety, including activities affecting the fire protection of safety-related areas, be accomplished under suitably controlled conditions. The program takes into consideration the need for procedures, special controls, cleanliness, special processes, test equipment, tools, and skills to obtain the required quality and the verification of quality by inspection, test, examination, monitoring and independent review and audit. These activities include, but are not limited to, designing, purchasing, fabricating, handling, shipping, storing, cleaning, erecting, installing, inspecting, testing, operating, maintaining, repairing, refueling, and modifying.

Personnel who have the responsibility to implement the Operational Quality Assurance Program also have the responsibility and authority to escalate unresolved quality problems to the level of management necessary to effect resolution. This escalation is applied by NQA personnel, who are independent of cost and scheduling, to increasingly higher levels of management up the the Vice President - Nuclear as required.

Personnel performing safety-related activities are trained and/or indoctrinated as necessary to assure that suitable proficiency is achieved and maintained. The Manager - Nuclear Operations Quality Assurance is responsible for the training of NQA personnel. Orientation is provided for new employees entering the NQA Department, whether from other parts of PSE&G or from outside the Company. An outline of the course content is contained in the NQA Orientation, Training, and Qualification Manual. The training and indoctrination program is designed to familiarize the employee with:

1. Codes, regulations, specifications, etc., applicable to nuclear and other power generation equipment.

2. QA procedures, instructions, specifications, documentation, records, etc..

3. Auditing objectives and techniques.

4. Nuclear Operations QA Program.

5. The QA program and the organization of major contractors.

6. Other organizations within PSE&G with which NQA interfaces.

7. The general theory, structure, function and mode of operation of nuclear generating stations.

NQA also offers formal training sessions for personnel in the Nuclear Department and other departments such as Construction, Engineering, Fuel Supply, Research & Testing Laboratory, etc., who perform activities related to nuclear operations safety.

NQA personnel requiring certification are evaluated to establish their qualifications for the respective level. The qualifications are approved by NQA management for the required certification level.

The Nuclear Training Center is responsible for the licensed operator training and retraining in addition to other technical and supervisory training programs including general Employee Indoctrination which is required for all personnel having access to the station.

17.2.3 DESIGN CONTROL

The Nuclear Support Department procedures, approved by the Manager - NQA, provide implementation direction for the intent of Regulatory Guide 1.64 "Quality Assurance Requirements for the Design of Nuclear Power Plants." Within that department, the Nuclear Engineering Department has the following responsibilities:

1. Prepare and update detailed engineering and design documents, including drawings and specifications, for all systems, components and structures.

2. Specify applicable codes, standards, regulatory and quality requirements, acceptance standards and other design input in design output documents.

3. Identify systems, components, and structures which are covered by the QA Program.

4. Perform design verification for systems, components, and structures.

5. Perform safety evaluations of proposed design changes.

6. Prepare documents for procurement of equipment, materials and components.

7. Recommend engineering consultants and laboratories for procurement services and coordinate their activities.

8. Review design documents submitted by suppliers (including the NSSS supplier) and contractors.

9. Specify, or approve as required, inspections and/or tests.

10. Designate whether they will use the services of other qualified engineering organizations both inside and outside PSE&G.

The cognizant engineer is responsible for the identification and completion of design analyses. The purpose of design analyses is to assure that the technical design is accomplished in a planned, controlled and correct manner. Types of design analyses include, but are not limited to, reactor physics, stress, seismic, thermal, hydraulic and accident.

Design verification is performed on design analyses, drawings, specifications and other design documents, as applicable. Design verification is the process of reviewing, confirming or substantiating the adequacy of a design by one or more methods. Design verification is performed on changes to previously verified designs including evaluation of the effects of those changes on the overall design. Design verification is performed by competent individuals or groups other than those who performed the original design with the following exception: A design verifier may be the design originator's supervisor provided that he did not specify a singular design approach or rule out certain design considerations and did not establish the design inputs used in the design, or if the supervisor is the only individual competent to perform the verification. This design verification provision requires prior authorization on an individual basis. Control of this function will be assured through periodic QA audits.

Design verification methods include but are not limited to:

1. Design reviews.

2. Alternate or independent calculations.

3. Qualification testing.

Changes to specifications prepared by the Engineering Department for items covered by the QA Program are reviewed and approved by NQA to assure that the QA Program requirements are specified. Specifications are forwarded to NQA for review and approval of quality and quality assurance requirements. NQA performs the same function in this case as during the original design stage.

The SORC reviews proposed changes affecting nuclear safety and makes recommendations concerning implementation of the change to the General Manager - Salem Operations. If the proposed modification involves a Technical Specification change or is considered by the SORC to involve an unreviewed safety question (10CFR50.59), the matter is submitted to the NRB for a determination of its safety implication before a license change request is submitted for NRC approval.

External interfaces with manufacturers, consultants, and other departments, including procedures for the preparation, transmittal, review and approval of design information, are identified in documents such as contracts, specifications, purchase orders, design data sheets, and drawings.

Updating of records, including drawings, blueprints, instructions and technical manuals, and specifications resulting from design changes, is the responsibility of the Nuclear Support Department.

17.2.4 PROCUREMENT DOCUMENT CONTROL

All initial procurement documents for the purchase of Q-listed material, equipment or services, are reviewed and approved by NQA prior to issuance by the Purchasing Department to the prospective supplier. Procurement documents for subsequent reorders of Q-listed material, equipment or services are selectively reviewed and approved by NQA prior to issuance by the Purchasing Department to the prospective supplier. NQA review assures that spare and replacement parts are procured utilizing controls which are at least equivalent to the original procurement.

The review also assures that procurement documents adequately and correctly:

1. Identify applicable QA Program requirements.

2. Reference applicable regulatory requirements, codes, and standards.

3. Provide right of access for source surveillance and audit by NQA or its agents.

4. Provide for required supplier documentation to be submitted to PSE&G or maintained by the supplier, as appropriate.

5. Provides for PSE&G review and approval of critical procedures prior to fabrication, as appropriate.

6. Account for special testing and/or qualification testing requirements.

Procurement documents require suppliers and contractors of other than commercial grade items to provide services or components in accordance with a QA program which complies with applicable criteria of 10CFR50 Appendix B.

17.2.5 INSTRUCTIONS, PROCEDURES AND DRAWINGS

Organizations engaged in Q-listed activities are required to perform these activities in accordance with written and approved procedures, instructions or drawings, as appropriate.

Simple routine activities, that can be performed by qualified personnel with normal skills, do not require a detailed written procedure. Complex activities shall require detailed instructions.

Procedures include, as appropriate, scope, statement of applicability, references, prerequisites, precautions, limitations, and checkoff lists of inspection requirements in addition to the detailed steps required to accomplish the activity. Instructions, procedures, and drawings also contain acceptance criteria where appropriate.

The General Manager - Salem Operations is responsible for assuring that station procedures are prepared, approved, and implemented in compliance with the Station Administrative Procedures. Documents affecting nuclear safety are reviewed by the SORC for technical content, and by the SQAE for inspection requirements including designation of QA hold points where required and are approved by the responsible station department head and the General Manager - Salem Operations.

The General Manager - Nuclear Support is responsible for issuing specifications, drawings, blueprints, instruction manuals and technical manuals associated with structures, systems, and components covered by the QA Program. These reference documents are kept up to date for the life of the station by the incorporation of approved and implemented modifications and design changes. Master lists of current editions or revisions of these documents are issued by the General Manager - Nuclear Support to the General manager - Salem Operations periodically to assure that only current, approved reference documents are used at the station.

The SQAE reviews and approves selected station inspection plans and procedures for test, calibration, maintenance, modification and repair. Changes to these documents are also reviewed and approved. In addition NQA is responsible for review and approval of the following documents: PSE&G specifications, test procedures, and results of preoperational testing.

17.2.6 DOCUMENT CONTROL

Instructions, procedures, and drawings and changes thereto are approved by appropriate levels of management of the PSE&G organizations producing such documents. Supplier documents are controlled according to contractual agreements with suppliers.

The following is a generic listing of documents for the operational phase showing organizational responsibility for review and approval, including changes thereto:

Design Specifications: Nuclear Department/Engineering Department, NQA

Design, Manufacturing, Construction and Installation Drawings: Nuclear Department/Engineering Department

Procurement Documents: Nuclear Department/Engineering Department, Purchasing Department, NQA

VPN Manual: Vice President Nuclear, NQA

Station Administrative Procedures: General Manager - Salem Operations, NQA

Maintenance, Modification, Calibration Procedures for Q-listed Station Work Activities: General Manager - Salem Operations, NQA (involving QA inspection requirements)

Operating Procedures: General Manager - Salem Operations, Station Operations Review Committee (SORC)

FSAR: Nuclear Department, NQA

Manufacturing, Inspection and Testing Instructions: Nuclear Department/ Engineering Department, NQA

Test Procedures: Nuclear Department, NQA

Design Change Requests: Nuclear Department/Engineering Department, NQA

The establishment and maintenance of a document control system for all instructions, procedures, specifications, and drawings received from the Nuclear Department/Engineering Department, or prepared at the station for use in operating, maintaining, refueling, or modifying the nuclear safety-related structures, components and systems is the responsibility of the General Manager - Salem Operations. The Station Administrative Procedures Manual describes the control of specific documents. Control of station practices is included in Administrative Procedures and in department instructions authorized by the responsible station department heads.

Measures have been established to insure that the Administrative Procedures and department instructions are up to date, are properly authorized, are changed only after required review and the approvals are obtained, and are distributed to cognizant personnel.

17.2.7 CONTROL OF PURCHASED MATERIAL, EQUIPMENT AND SERVICES

NQA maintains an up-to-date listing of approved suppliers of material, equipment, and services covered by the QA Program. This list identifies suppliers and contractors which have demonstrated the ability to supply acceptable material, equipment, or services. The list need not include original manufacturers of commercial catalog items. All QA Program procurements are made from approved suppliers.

Selection and evaluation of prospective bidders and suppliers are performed by the responsible engineer and the NQA. The responsible engineer determines the technical competence of the supplier. The NQA evaluates the prospective supplier's quality assurance program for compliance with the capability of meeting applicable requirements of 10CFR50 Appendix B and for the requirement that applicable program requirements be extended to subtier suppliers.

Qualified NQA personnel evaluate the prospective supplier's quality assurance capability utilizing one or more techniques including, but not necessarily limited to:

1. Evaluation of supplier's or contractor's procedures or manuals and changes thereto.

2. ASME code stamp approval.

3. CASE register listing.

4. Satisfactory past history of providing similar items.

5. Survey of supplier's facility.

The evaluation of prospective suppliers is conducted utilizing standard checklist/forms designed to include the 18 quality criteria of 10CFR50 Appendix B as appropriate. Surveys of supplier's capabilities shall include evaluation of management systems, and manufacturing process, as well as adherence to QA/QC procedures. The results of supplier evaluations are documented by the appropriate checklist/form and filed.

Supplier control is maintained through a planned inspection, monitoring and audit program by NQA.

A review of the manufacturing process for complex manufactured items such as pumps, valves, heat exchangers, vessels, electrical panels, etc. is conducted by NQA and the responsible sponsor engineer. This review establishes critical inspection points and establishes a Notification Point Program for the identified inspection or surveillance activities. The established inspection or surveillance activities are implemented by qualified NQA personnel or NQA agents. Standard catalog items, where quality can be verified by receiving inspection or installation checkout, are not normally included in the Notification Point Program.

Monitoring of suppliers/contractors during fabrication, installation, modification, repair, inspection, testing and shipment of materials, equipment and services, is conducted by qualified NQA personnel or NQA agents at the supplier's/contractor's facility or at the generating station. Surveillances are conducted in accordance with written procedures and are designed to assure conformance with procurement requirements in accordance with the safety significance of the item or service. Consistent with the importance or complexity of the item or service, periodic evaluations of the supplier/contractor quality program are conducted. Dependent upon the evaluation, additional audits or corrections may be required of the supplier/contractor.

Procurement of replacement parts is by adherence to the original design criteria, where feasible (such as NSSS components in accordance with Westinghouse documentation, other code components in accordance with AQQA, AISC, SPCC and ASME Section III 1971 and Summer 1972 Addenda or later). This will provide the intended level of safety, and will not result in redesign of the system. Quality assurance requirements are consistent with the FSAR commitments.

The requirement for appropriate supplier documentation of conformance to applicable code, standard, specification or other quality requirement is provided by the procurement document. The supplier-provided documentation is reviewed either at the supplier's facility during an inspection or surveillance visit, or at receiving inspection. A data review check off is provided and utilized documenting the acceptability of the supplier provided data or identifying discrepancies.

Receiving inspection of supplier equipment, material and services is conducted by qualified personnel to verify correct identification, and appropriate documentation, and to verify that the item is acceptable and can be released for storage, installation, or use.

Nonconforming items identified at receiving inspection are tagged or segregated to prevent inadvertent use. Nonconforming items are controlled as described in Section 17.2.15.

17.2.8 IDENTIFICATION AND CONTROL OF MATERIAL, PARTS, AND COMPONENTS

Procurement document controls provide assurance that materials, parts, and components received can be properly identified. The identification is marked directly on the item, or on records traceable to it. The data review conducted at receiving assures that proper documentation of received items is available. Materials and items received without proper identification are tagged or segregated until satisfactory documentation and identification is obtained.

Procedures require that Q-listed materials, parts, and components be marked or otherwise identified and require that such identity be maintained either on the item or on records traceable to it throughout receipt, storage, installation, and use. Protection against use of incorrect or defective items is also provided.

Material identification and traceability shall be maintained for repairs, replacement, and modifications throughout operation.

17.2.9 CONTROL OF SPECIAL PROCESSES

Procedures for special processes such as welding, heat treating, and NDE, assure compliance with codes and design specifications. The General Manger - Nuclear Support is responsible for preparing special process specifications. These specifications are reviewed and approved by NQA for necessary quality content.

Procedures for implementing the requirements of the specifications are prepared either by the Nuclear Department or by supplier personnel, and are approved by the General Manager - Nuclear Support (with the exception of special process procedures prepared by code suppliers holding an "N" stamp). Procedures prepared by suppliers are also reviewed and approved by NQA.

17.2.10 INSPECTION

A planned inspection program is conducted by personnel appropriately qualified in accordance with Section 17.2.2. The inspection program verifies conformance to the established procedure, code or standard, consistent with the activity's importance to safety.

When required, Inspection Hold Points, to be accomplished by the applicable NQA representative, are identified and included in the procedure or instruction.

Station Department Heads are responsible for inserting inspection hold points for critical activities in procedures they approve. These hold points are witnessed by members of the SQAE staff. The Station Operations Review Committee (SORC) may recommend to the General Manager - Salem Operations, additional or different hold points, as a result of their review. Selected procedures are reviewed by NQA prior to issuance and additional inspection hold points may be added to a procedure. The hold points must not be passed without authorization from the applicable NQA representative. Typical critical activities include:

1. Visual and NDE of ASME pressure boundary welds.

2. Verification of cleanliness prior to closing safety-related systems.

3. Verification of reactor trip and Engineered Safety Features initiation setting after adjustment.

4. Packaging and loading of radioactive material for shipment.

5. Hydrostatic testing of safety-related systems.

6. Acceptance testing of safety-related system modifications.

7. Acceptance testing of major repairs on safety-related systems.

Inspection of operating activities (work functions associated with the normal operation of the plant, routine maintenance, and certain technical services) shall be conducted by qualified individuals other than those who performed or directly supervised the activity being inspected. These activities typically include periodic inspections of:

1. Storage areas.

2. Housekeeping (General).

3. Fire protection equipment.

4. Special handling tools and equipment.

5. NDE visual inspection required by the Inservice Inspection Program.

The applicable inspection and retest requirements necessary to assure that modifications or repairs have been accomplished correctly are provided by the design change package, work order, or procedure. The inspection and retest requirements for modification and repair are based on the original inspection and test program, and the nature and scope of the modification or repair activity.

A planned and documented monitoring program is conducted for Q-listed activities. Monitoring of implementation of the QA Program by station personnel is conducted by the SQAE. NQA performs monitoring of supplier and contractor activities. Discrepancies discovered during the conduct of the monitoring are brought to the attention of the management responsible for accomplishment of the activity.

17.2.11 TEST CONTROL

Q-listed equipment or components (a) which require seismic or environmental qualification, (b) which must be tested periodically to assure satisfactory performance, or (c) which have been replaced, modified or repaired, are tested by qualified personnel in accordance with written procedures which provide acceptance criteria.

Retest requirements following repair or modification are provided by engineering specifications and/or the responsible engineer, as were the original test requirements. The Operational Test Group is responsible for preparation of test procedures incorporating the engineering parameters.

Test procedures prescribe:

1. Prerequisites,

2. Instrumentation and equipment for conduct of the test adequate to the test objective,

3. Suitable environmental conditions and adequate test methods, and

4. Acceptance criteria.

Test results are documented and reviewed for acceptability by the qualified department representative. System tests performed following modifications to safety-related systems require review of test procedures and test results by the SORC.

The SQAE maintains monitoring over the conduct of the design change acceptance tests to assure compliance with the test procedure. Test results are reviewed for the following:

1. Presentation of proper documentation.

2. Assurance that tests meet objectives.

3. Identification and reporting of unacceptable results and initiation of corrective measures.

Retention of test reports are described in Administrative Procedures.

17.2.12 CONTROL OF MEASURING AND TEST EQUIPMENT

Test equipment, instrumentation, and controls used to monitor and measure activities affecting quality and personnel safety are identified, controlled, and calibrated at specific intervals. Written procedures for meeting these requirements include provisions for:

1. Specifying calibration frequency,

2. Recording and maintaining calibration records,

3. Controlling and calibrating primary and secondary standards,

4. Determining methods of calibration, and

5. Tracing use on safety-related components.

Prior use of measuring and test equipment found to be out of calibration is evaluated for possible effect on safety-related equipment or functions. Measurements are repeated where necessary.

Secondary standards are calibrated by certified calibration laboratories and are traceable to the National Bureau of Standards (NBS) or best industry standards where no NBS standards exist. The accuracy of the primary standards used to perform this calibration is at least greater than the accuracy of the device being calibrated to the extent permitted by the state-of-the-art.

Test equipment is marked to indicate the latest calibration date and the next required calibration date.

Out-of-calibration identification is used for instruments and controls to indicate this status pending calibration, repair, or replacement.

17.2.13 HANDLING, STORAGE AND SHIPPING

The control of handling, storage, cleaning, and preservation of material and equipment covered by the QA Program is the responsibility of the various departments involved in these activities. The Nuclear Material Control Group is responsible for control of material in storage, including preservation and the application of appropriate shipping controls on items or materials shipped from the station. The station departments are responsible for system cleanliness and handling of equipment during operational maintenance or modification. Nuclear Engineering is responsible for specifying equipment requirements (performance characteristics, operational characteristics, special storage and handling characteristics). Manufacturer's instructions and recommendations, design requirements, and applicable codes and standards are implemented, as appropriate. Compliance with specific handling, storage or shipping requirements, as established by the cognizant Nuclear Department/ Engineering Department engineer is required. Requirements for new components and spares, where applicable, are included in the procurement documents.

17.2.14 INSPECTION, TEST AND OPERATING STATUS

Procedures are required to specify the periodic tests and inspections required for equipment covered by the QA Program, and to include the necessary management controls to assure that such required tests and/or inspections are completed in accordance with specified requirements.

Equipment awaiting repairs, under repair, or repaired, and received materials are marked to indicate the status of inspection and test requirements and/or acceptability for use. Procedures provide for tagging valves and switches to prevent inadvertent operation. These procedures are designed to prevent operation of valves and/or switches which could result in personnel hazard or equipment damage.

Valve and equipment status boards or logs are maintained to indicate status.

17.2.15 NONCONFORMING MATERIALS, PARTS OR COMPONENTS

Nonconforming materials, parts or components identified during receiving inspection or during performance testing of equipment are identified and, where practical, segregated to prevent installation or use until proper approvals are obtained. Materials, parts, or components which have failed in service are identified, and where practical segregated. Documentation of the nonconformance includes a description of the nonconformance, and the disposition and inspection or retest requirements, as appropriate. All dispositions for repair or use-as-is are required to be approved by the responsible engineering representative. Rework or repair of nonconforming material, parts, or components are inspected and/or retested in accordance with specified test and inspection requirements established by the cognizant engineer based on applicable code requirements. NQA reviews the disposition of all reports of nonconforming conditions and verifies completion of the disposition.

NQA and other organizations in the Nuclear Department review nonconformance reports for quality problems and initiate reports to higher management, identifying significant quality problems with recommendations for appropriate action.

17.2.16 CORRECTIVE ACTION

Organizations involved in activities covered by the QA Program are required to maintain corrective action programs commensurate with their scope of activity. Noncompliances with the QA Program identified by NQA are documented and controlled by the issuance of an Action Request. NQA reviews Action Requests for quality trends and periodically reports the status and review results to management.

Responses to Action Requests are based on the four elements of corrective action which are:

1. Identification of cause of deficiency.
2. Action taken to correct deficiency and results achieved to date.
3. Action taken or to be taken to prevent recurrence.
4. Date when full compliance was or will be achieved.

Proper implementation of corrective action is verified through monitoring or audit as appropriate.

The General Manager - Salem Operations is responsible for assuring that conditions adverse to quality are promptly identified and corrected for all activities involving station operation, maintenance, testing, refueling and modification.

Administrative procedures which govern station activities covered by the QA Program, provide for the timely discovery and correction of non-conformances. This includes receipt of defective material, failure or malfunction of equipment, deficiencies or deviations of equipment from design performance, and deviations from procedures. In cases of significant conditions adverse to quality, the cause of the condition is determined and measures established to preclude recurrence. Such events, together with corrective action taken, are documented and reported as described in Section 17.2.15. Corrective action is initiated by the responsible department head.

NQA maintains close monitoring over station conditions requiring corrective action. The SQAE has the authority to stop work when significant conditions adverse to quality require such action.

Repetitive deficiencies, procedure or process violations at the Station which are not classified as Operational Incidents or Reportable Occurrences or nonconformances under the QA Program are documented by the SQAE by the issuance of an Action Request. This request will provide the SQAE with a formal administrative vehicle to alert management of conditions adverse to quality that require corrective action.

17.2.17 QUALITY ASSURANCE RECORDS

Records necessary to demonstrate that activities important to quality have been performed in accordance with applicable requirements, originated by the station or other departments, are identified and maintained in accordance with Regulatory Guide 1.88 as noted in 17.2.2.

Design and construction records are replicated via microfilm and stored in record facilities at the generating station and at off-site locations.

The General Manager - Salem Operations is responsible for the permanent storage of station records. The retention period for records, the permanent storage location, and methods of control, identification, and retrieval are specified by administrative procedure. Individual station department heads are responsible for submitting applicable department records to the Technical Document Room for retention.

17.2.18 AUDITS

Audits of PSE&G and supplier organizations which implement the QA Program are performed by the NQA to verify compliance with the applicable portions of the Quality Assurance Program.

Audits are conducted by audit teams comprised of a certified lead auditor, and certified auditors.

Audits are conducted using pre-established written procedures and checklists. Areas of deficiency revealed by audits are reviewed with management and are required to be corrected in a timely manner. Required corrective action shall be documented and verified. Follow-up action, including reaudit of deficient areas, is performed.

The audit program conducted by NQA includes, but is not limited to, the following activities covered by the QA Program.

1. Operation, maintenance, and modification.

2. Preparation, review, approval, and control of design, specifications, procurement documents, instructions, procedures, and drawings.

3. Inspection programs.

4. Indoctrination and training.

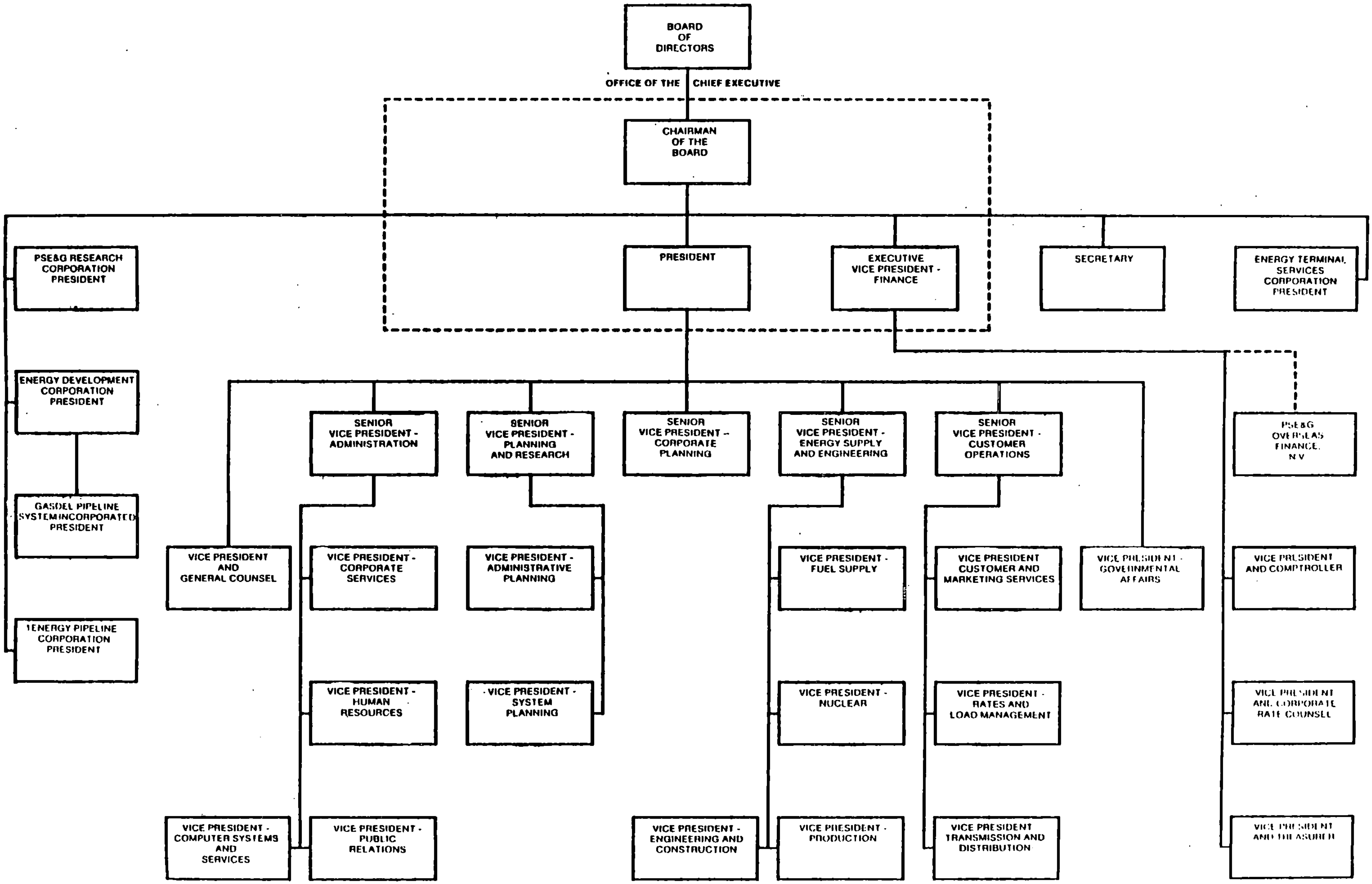
5. Implementation of operating and test procedures.

6. Calibration of measuring and test equipment.

7. Fire protection.

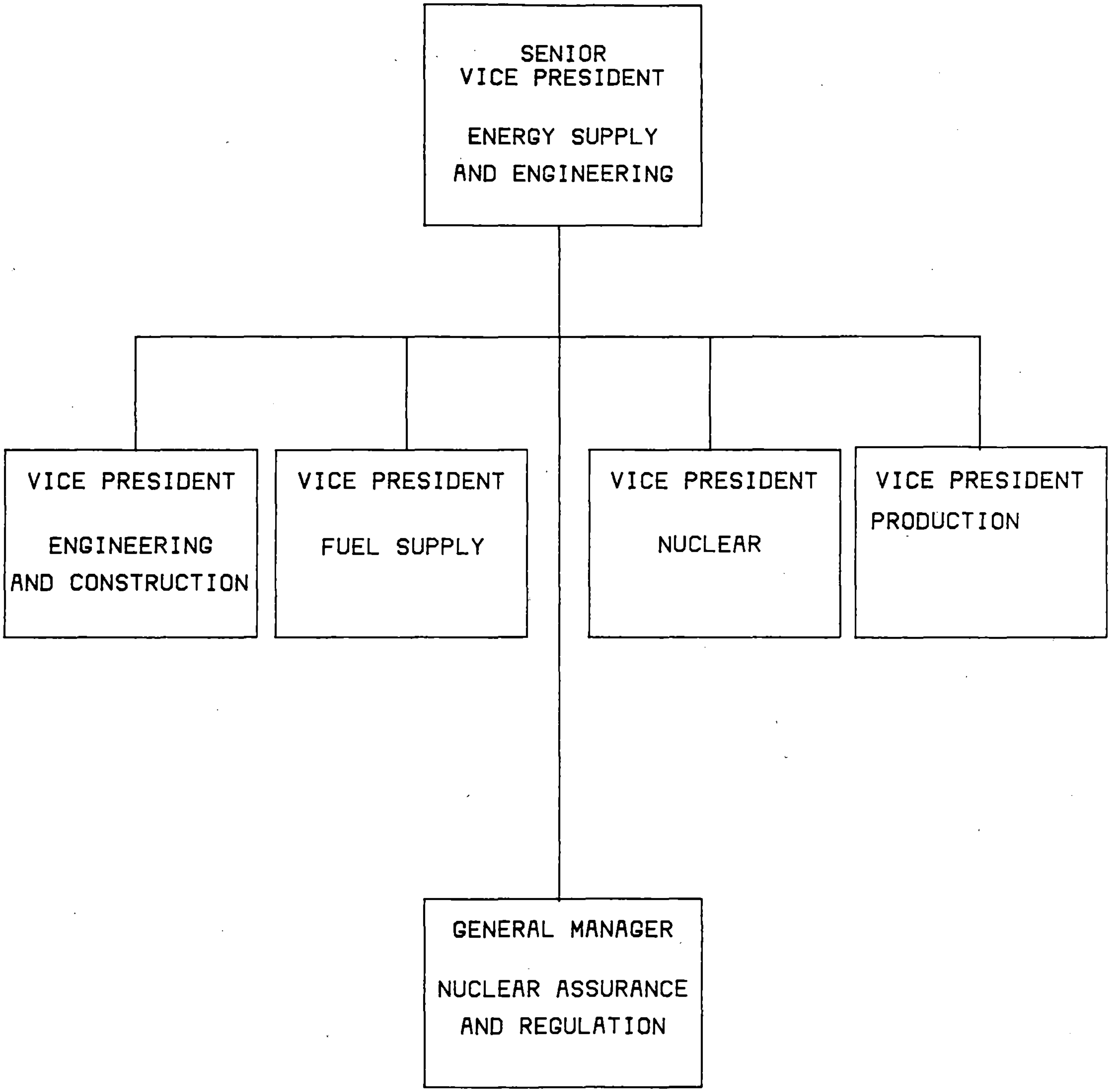
8. Other applicable activities delineated in Table 17.2-1.

A written report of the results of each audit is distributed to appropriate management representatives of the organization(s) audited as well as other affected management personnel. NQA is audited by independent auditors every two years to verify implementation of the corporate QA Program. Reports of these audits are directed to appropriate PSE&G management personnel.



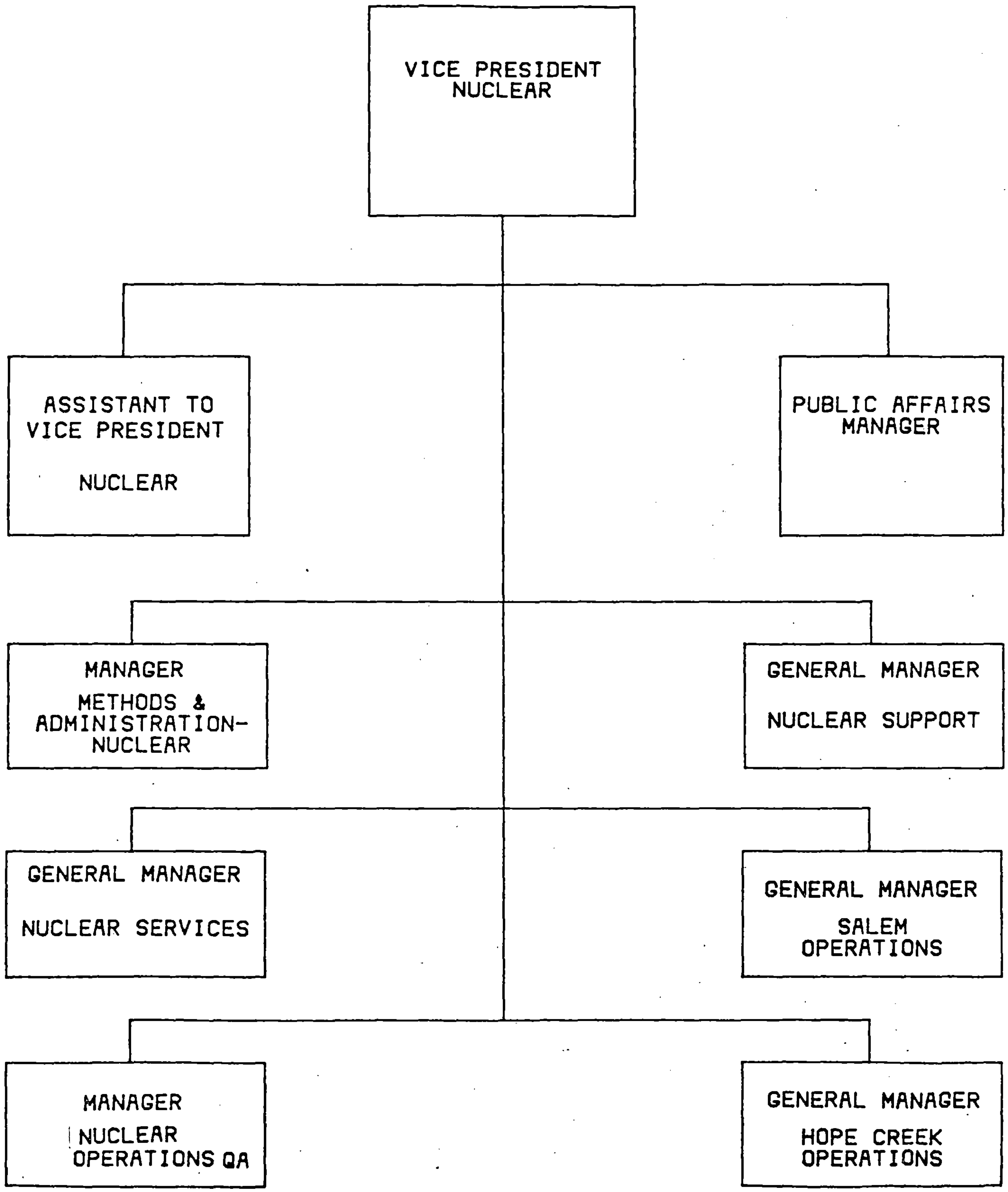
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	General Company Organization Chart
	UPDATED FSAR FIG 17.2-1

Revision 1
July 22, 1983



Revision 1
July 22, 1983

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Office of the Senior Vice President- Energy Supply and Engineering
	UPDATED FSAR FIG 17.2-2



Revision 3
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PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Nuclear Department UPDATED FSAR FIG 17.2-3

SALEM GENERATING STATION

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SALEM GENERATING STATION

UNITS 1 AND 2

UPDATED FINAL SAFETY ANALYSIS REPORT

Volume 3

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5.0 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.1 SUMMARY DESCRIPTION

The Reactor Coolant System (RCS) consists of four similar heat transfer loops connected in parallel to the reactor vessel. Each loop contains a steam generator, a pump, loop piping and instrumentation. The pressurizer surge line is connected to one of the loops. Auxiliary system piping connections into the reactor coolant piping are provided as necessary.

RCS design data is listed in Table 5.1-1.

Pressure in the RCS is controlled by the pressurizer, where water and steam pressure is maintained through the use of electrical heaters and sprays. Steam can either be formed by the heaters, or condensed by a pressurizer spray to minimize pressure variations due to contraction and expansion of the coolant. Instrumentation used in the pressure control system is described in Chapter 7. Spring-loaded safety valves and power-operated relief valves are connected to the pressurizer and discharge to the pressurizer relief tank, where the discharged steam is condensed and cooled by mixing with water.

The RCS provides a boundary for containing the coolant under operating temperature and pressure conditions. It serves to confine radioactive material and limits to acceptable values its release to the secondary system and to other parts of the plant under conditions of either normal or abnormal reactor behavior. During transient operation the systems heat capacity attenuates thermal transients generated by the core or steam generators. The RCS accommodates coolant volume changes within the protection system criteria presented in Chapter 7.

Reactor Vessel

The reactor vessel (Figure 5.1-1) is cylindrical with a welded hemispherical bottom head and a removable, flanged and gasketed, hemispherical upper head. The vessel contains the core, core support structures, control rods, thermal shield, and other parts directly associated with the core. The reactor vessel closure head contains head adaptors. These head adaptors are tubular members, attached by partial penetration welds to the underside of the closure head. The upper end of these adaptors contain acme threads for the assembly of the control rod drive mechanisms and/or instrumentation adaptors. The seal arrangement at the upper end of these adaptors consists of a welded flexible canopy seal. The vessel has inlet and outlet nozzles located in a horizontal plane just below the vessel flange but above the top of the core. Coolant enters the inlet nozzles and flows down the core barrel-vessel wall annulus, turns at the bottom and flows up through the core to the outlet nozzles.

The bottom head of the vessel contains penetration nozzles for connection and entry of the nuclear in-core detection instrumentation. Each tube is attached to the inside of the bottom head by a partial penetration weld.

The reactor vessel is designed to provide the smallest and most economical volume required to contain the reactor core, control rods and the necessary supporting and flow-directing internals. Inlet and outlet nozzles are spaced around the vessel. Outlet nozzles are located on opposite sides of the vessel to facilitate optimum layout of the RCS equipment. The inlet nozzles are tapered from the coolant loop-vessel interfaces to the vessel inside wall to reduce loop pressure drop.

Pressurizer

The pressurizer (Figure 5.1-2) provides a point in the RCS where liquid and vapor can be maintained in equilibrium under saturated conditions for control purposes.

The pressurizer is a vertical, cylindrical vessel with hemispherical top and bottom heads constructed of carbon steel, with austenitic stainless steel cladding on all surfaces exposed to the reactor coolant. Electrical heaters are installed through the bottom head of the vessel while the spray nozzle, relief and safety valve connections are located in the top head of the vessel. The heaters are removable for maintenance or replacement.

The pressurizer is designed to accommodate positive and negative surges caused by load transients. The surge line, which is attached to the bottom of the pressurizer, connects the pressurizer to the hot leg of a reactor coolant loop.

Pressurizer Relief Tank

The pressurizer relief tank condenses and cools the discharge from the pressurizer safety and relief valves as well as several smaller relief valves. The tank normally contains water in a predominantly nitrogen atmosphere; however, provisions are made to permit the gas in the tank to be periodically analyzed to monitor the concentration of hydrogen and/or oxygen.

The pressurizer relief tank, by means of its connection to the waste disposal system, provides a means for removing any non-condensable gases from the RCS which might collect in the pressurizer vessel.

Steam enters the tank through a sparger pipe under the water level. This condenses and cools the steam by mixing it with water that is near ambient temperature. The tank is equipped with an internal spray and a drain which are used to cool the tank following a discharge. The tank is protected against overpressurization by two rupture discs which discharge into the reactor containment. The tank is carbon steel with a corrosion-resistant coating on the wetted surfaces. A flanged nozzle is provided on the tank for the pressurizer discharge line connection. This nozzle and the discharge piping and sparger within the vessel are austenitic stainless steel.

Steam Generators

The steam generators are vertical shell and U-tube evaporators with integral moisture separating equipment. The reactor coolant flows through the inverted U-tubes, entering and leaving through the nozzles located in the hemispherical bottom head of the steam generator. The head is divided into inlet and outlet chambers by a vertical partition plate extending from the head to the tube sheet. Manways are provided for access to both sides of the divided head. Steam is generated on the shell side and flows upward through the moisture separators to the outlet nozzle at the top of the vessel. The units are primarily carbon steel. The heat transfer tubes are Inconel, the primary side of the tube sheets are clad with Inconel and the interior surfaces of the reactor coolant channel heads and nozzles are clad with austenitic stainless steel. A steam generator is shown in Figure 5.1-3.

Reactor Coolant Pumps

Each reactor coolant loop contains a vertical single stage mixed flow pump which employs a controlled leakage seal assembly. The pump is shown in Figure 5.1-4 and NPSH characteristics are shown in Figure 5.1-5.

Reactor coolant is drawn up through the primary pump impeller, discharged through passages in the diffuser and out through a discharge nozzle in the side of the casing. The rotor-impeller can be removed from the casing for maintenance or inspection without removing the casing from the piping. All parts of the pump in contact with the reactor coolant are austenitic stainless steel or equivalent corrosion resistant materials.

Reactor Coolant Piping

The reactor coolant piping and fittings which make up the loops are austenitic stainless steel. All smaller piping which comprise part of the RCS boundary, such as the pressurizer surge line, spray and relief lines, loop drains and connecting lines to other systems are also austenitic stainless steel. The nitrogen supply line for the pressurizer relief tank is carbon steel. All joints and connections are welded, except for the pressurizer relief and the pressurizer code safety valves, where flanged joints are used. Thermal sleeves are installed at points in the system where high thermal stresses could develop due to rapid changes in fluid temperature during normal operational transients.

Valves

All valves in the RCS which are in contact with the coolant are constructed primarily of stainless steel. Other materials in contact with the coolant are special materials such as hard surfacing and packing.

All RCS valves which are 3 inches and larger, which contain radioactive fluid and which normally operate above 212°F, are provided with double-packed stuffing boxes and stem intermediate lantern gland leakoff connections. All throttling control valves, regardless of size, are provided with double-packed stuffing boxes and with stem leakoff connections. All leakoff connections are piped to the reactor coolant drain tank or pressurizer relief tank.

Reactor Coolant System High Point Venting

Venting of the RCS during abnormal conditions, permits removal of non-condensible gases, thereby aiding natural circulation flow. There are three principal high points in the RCS: the pressurizer, the reactor vessel head and the steam generator tube bundle invert.

The pressurizer power-operated relief valve serves as a vent and provides remote venting capability from the control room. This vent is safety grade and meets the single failure criterion.

The high points created by the tube bundle in the steam generator cannot be vented at that location. A Westinghouse study (Reference 1) has concluded, however, that only a small amount of non-condensables would be present during any transient which would depend significantly on the steam generators for decay heat removal. It further concluded that the presence of small amount of non-condensables would not significantly impact natural circulation in the system.

The reactor vessel is vented though a piping system connected to the part-length control rod drive mechanism (CRDM) nearest to the center of the vessel head. As shown in the RCS flow diagram (Figures 5.1-6A and B), the vessel head can be vented either to the pressurizer relief tank or to the containment.

The existing lead screw in the part-length CRDM was removed prior to using it as a connection for head vent. The connection from this part-length CRDM cap (cap with a 0.815 inch diameter hole) is through a 1 inch Schedule 160 pipe connection and includes a 11/32 inch diameter orifice close to the reactor vessel. The vent then runs to the pressurizer relief tank through a redundant grouping of solenoid valves. Break flanges are provided to allow the reactor vessel head removal and to provide room for the manipulator crane movement. The piping is supported to Seismic Category I requirements to ensure that allowable loadings on the part length CRDM housing are not exceeded. The piping and valves are stainless steel.

The reactor vessel head vent is designed to meet the requirements of NUREG-0737 (Reference 2). The vent can be remote-manually actuated from the control room utilizing a key lock switch and will have power removed during normal operation. The solenoid operated vent valves are powered from two redundant vital D. C. buses. Open/close indications for the solenoid valves are provided in the control room with both visual and audible alarms. Valve operating logic is shown in Figure 5.1-6, Sheet 3.

Piping, valves, and components for the reactor vessel vent are classified as Seismic Category I and Safety Class 2. Design pressure and temperature of the piping valves and components are 2485 psi and 650^{O}F, respectively.

Maximum conditions (pressure and temperature) for the vent piping are as specified in PSE&G's specifications which meet the intent of SRP Section 5.2.3 requirements.

The reactor vessel vent system size is kept below the LOCA definition size (3/8 inch) through a 11/32 inch diameter orifice, which permits venting 1/2 gas volume of the RCS in one hour. This minimizes the challenges to the emergency core cooling system (ECCS) since inadvertent vent opening would not require ECCS actuation.

A pipe break in either the pressurizer or reactor vessel head vent lines is an infrequent fault and is covered in Chapter 15 as a loss of reactor coolant accident resulting from a small bore ruptured pipe. The analysis presented in Chapter 15 shows that the high head portion of the ECCS together with the accumulators provide sufficient core flooding to keep the calculated peak clad temperature below the required limits of 10CFR50.46. The 3/4" reactor head vent line was analyzed not as a source but as a target fo HELB. The normally pressurized portion of the pressurizer vent system is located within the pressurizer missile shield. The effects of internal missiles on these lines have been analyzed and found acceptable. The head vent and pressurizer vent have been analyzed for the following failures and found not to prevent essential operation of safety-related systems required for safe reactor shutdown or mitigation of the consequences of a design basis accident.

1. Seismic failure of any pressurizer vent components that are not designed to withstand the safe shutdown earthquake.

2. Postulated missiles generated by failure of pressurizer vent components.

3. Dynamic effects associated with the postulated rupture of pressurizer vent piping greater than one-inch nominal size.

Operability testing of the reactor vessel head vent valves will be performed in accordance with subsection IWV of Section XI of the ASME Code.

5.1.1 PIPING AND INSTRUMENTATION DIAGRAM

The RCS is shown in Figure 5.1-6, sheets 1 and 2, and the system design and operating parameters are given in Table 5.1-1.

5.1.2 ARRANGEMENT DRAWING

Figures 5.1-7 through 5.1-13 are plan and elevation drawings providing principal dimension of the RCS.

REFERENCES FOR SECTION 5.1

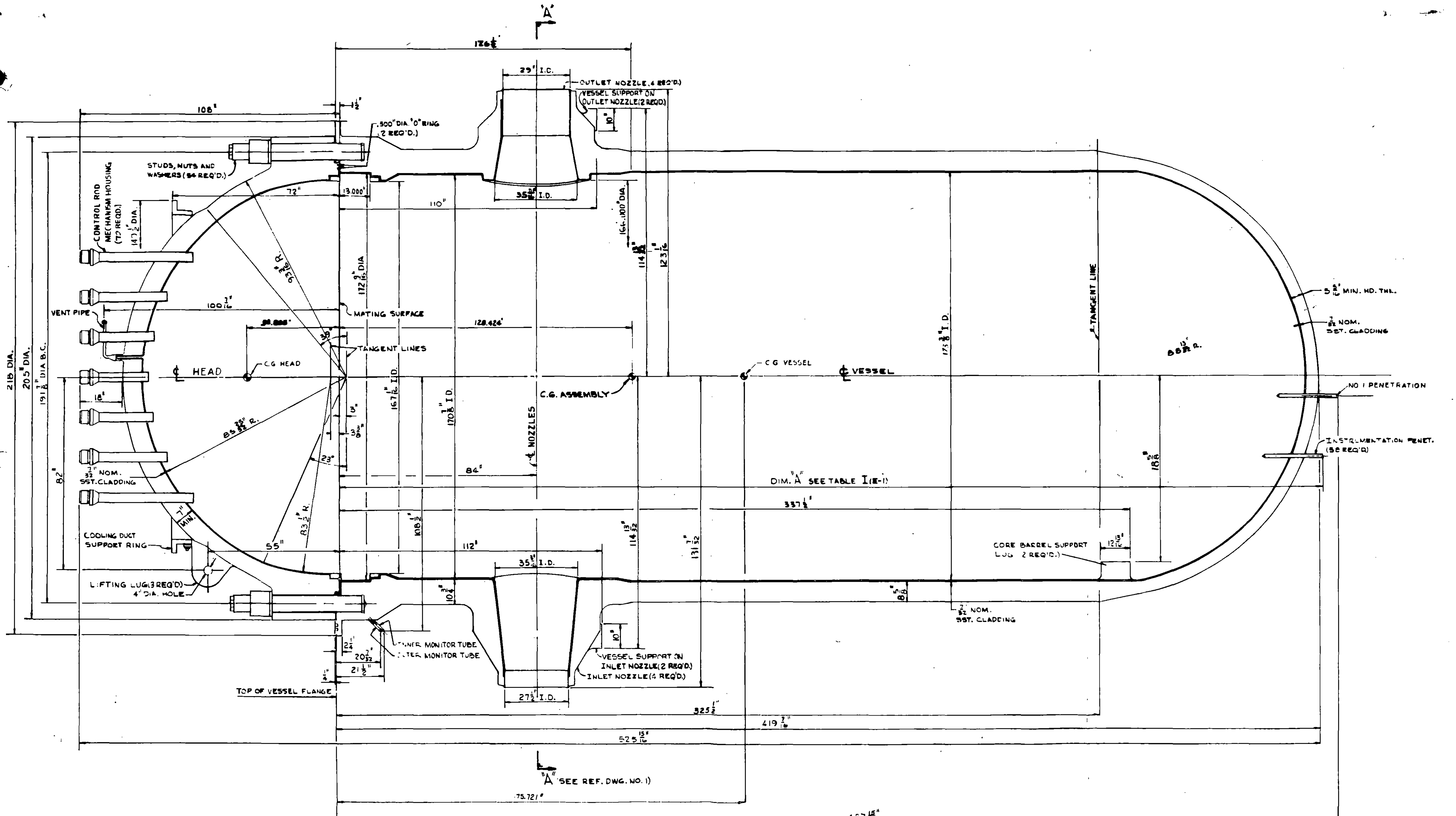
1. "Report on Small Break Accidents for Westinghouse Nuclear Steam Supply System", WCAP-9600 (Proprietary) and WCAP-9601 (Non-Proprietary), June, 1979.

2. NUREG-0737, "Clarification of TMI Action Plan Requirements," U. S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, November, 1980.

TABLE 5.1-1

SYSTEM DESIGN AND OPERATING PARAMETERS

	Unit 1	Unit 2
Plant design life, years	40	40
Number of heat transfer loops	4	4
Design pressure, psig	2485	2485
Nominal operating pressure, psig	2235	2235
Total system volume including pressurizer and surge line (ambient conditions), ft^3	12,612	12,612
System liquid volume, including pressurizer and surge line (ambient conditions), ft^3	11,892	11,892
Total heat output (100 percent power), Btu/hr	$11,431 \times 10^6$	$11,680 \times 10^6$
Reactor vessel coolant temperature at full power:		
Inlet, nominal, °F	544.4	545.0
Outlet, °F	608.3	610.2
Coolant temperature rise in vessel at full power, avg, °F	63.9	65.2
Total coolant flow rate, lb/hr	134.1×10^6	133.9×10^6
Steam pressure at full power, psia	805	805



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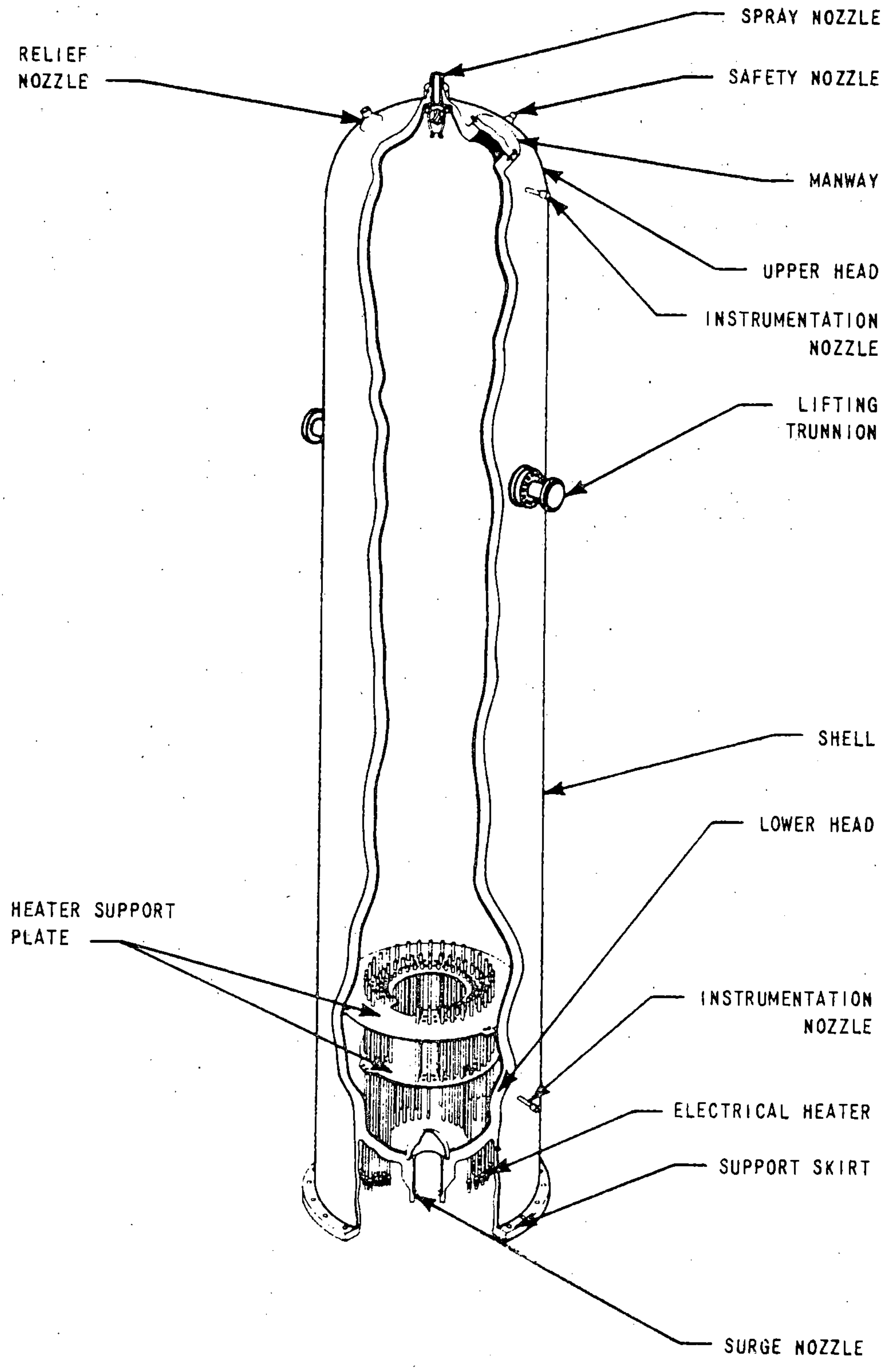
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Vessel Schematic
	Updated FSAR — Figure 5.1-1



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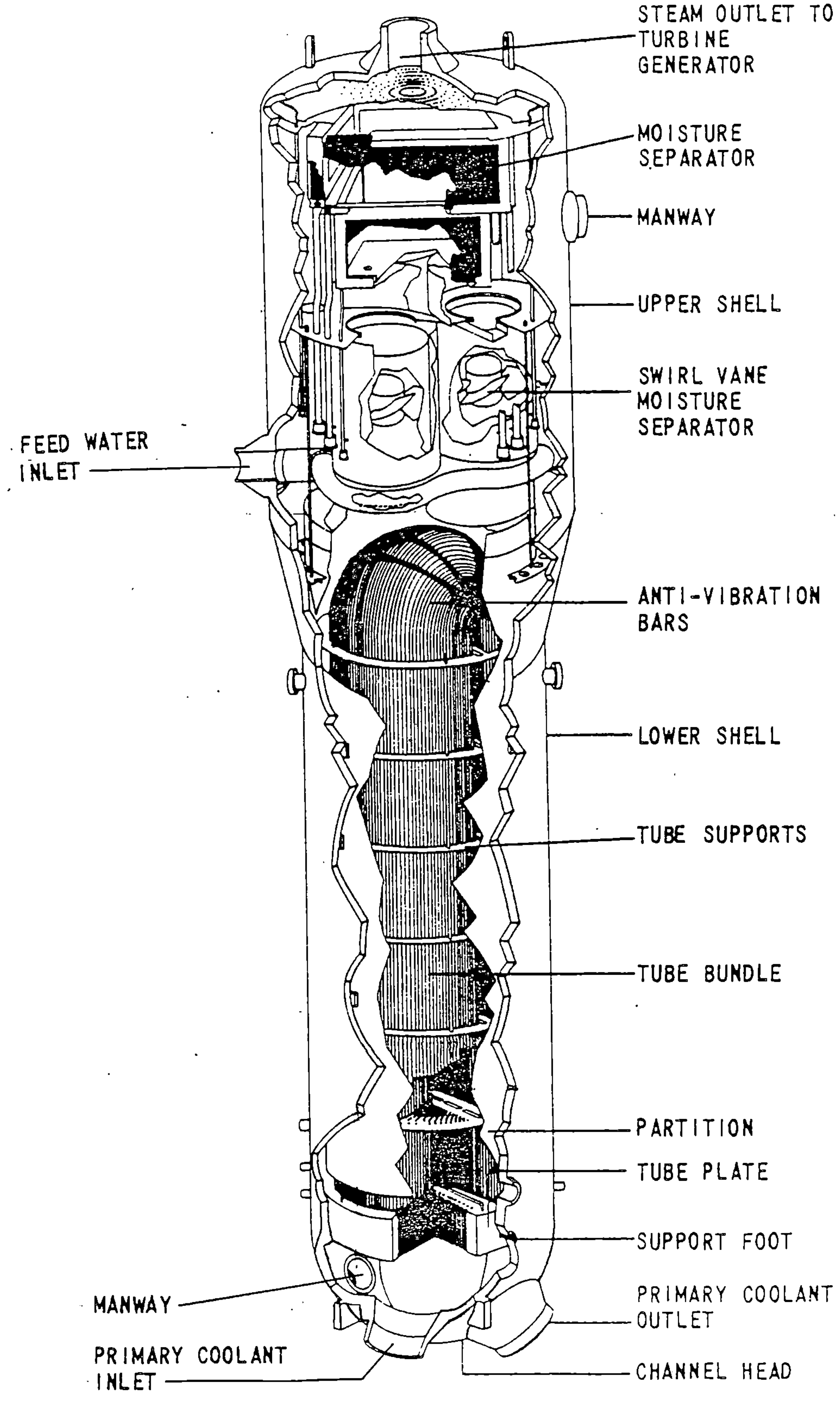
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Cutaway View of Pressurizer	
	Updated FSAR	Figure 5.1-2



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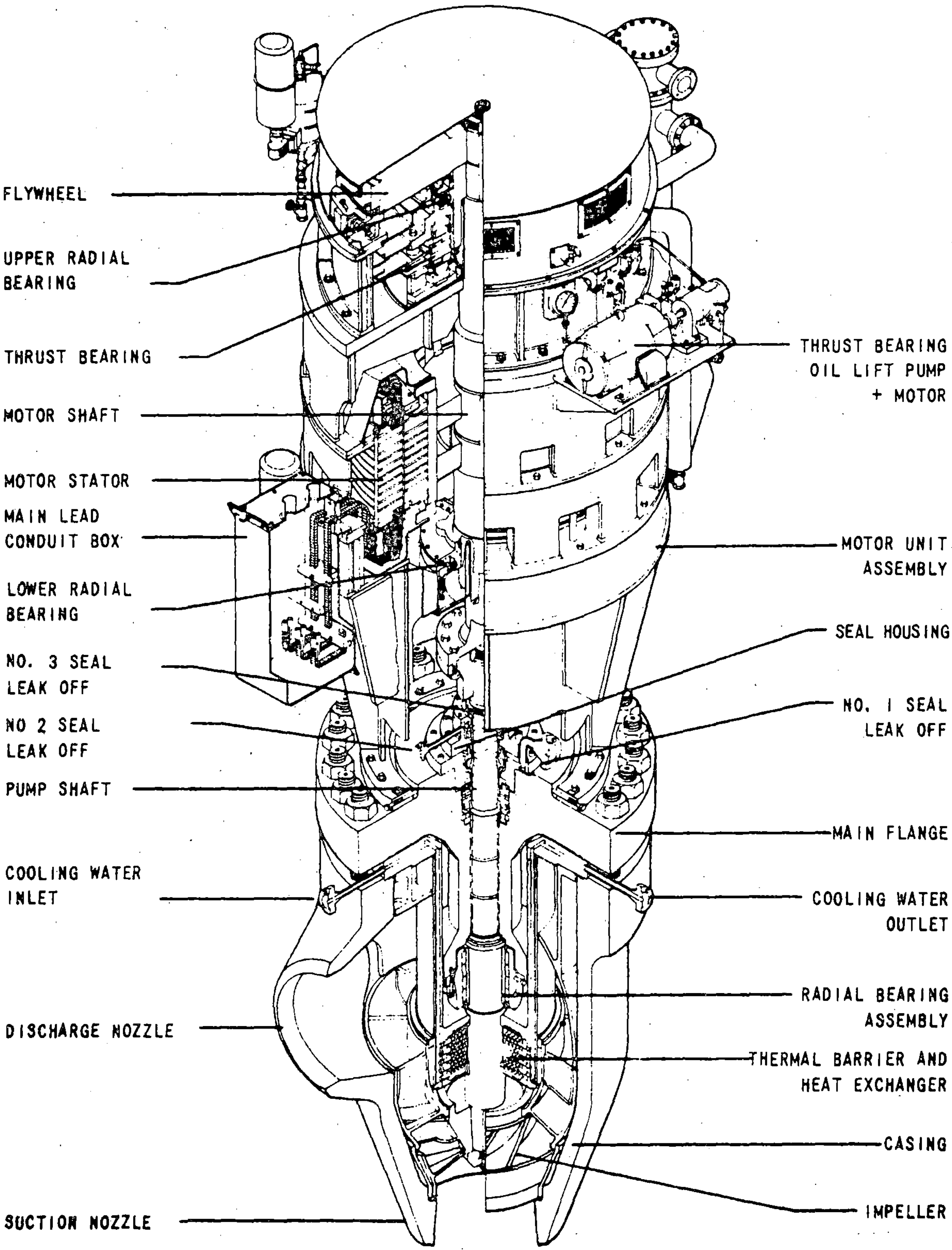
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Steam Generator
	Updated FSAR — Fig 5.1-3



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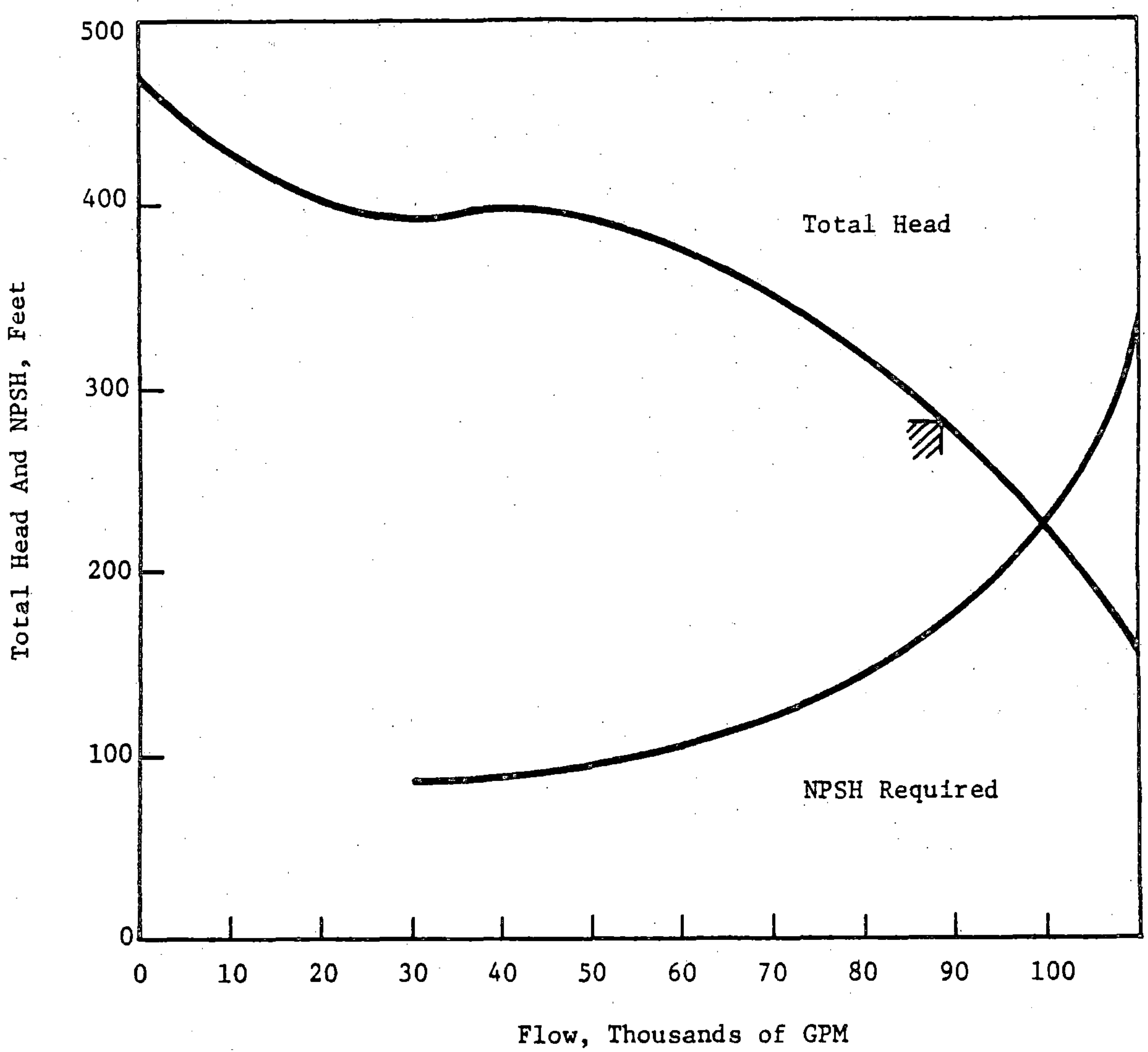
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Cutaway View of Reactor Coolant Pump
	Updated FSAR Figure 5.1-4



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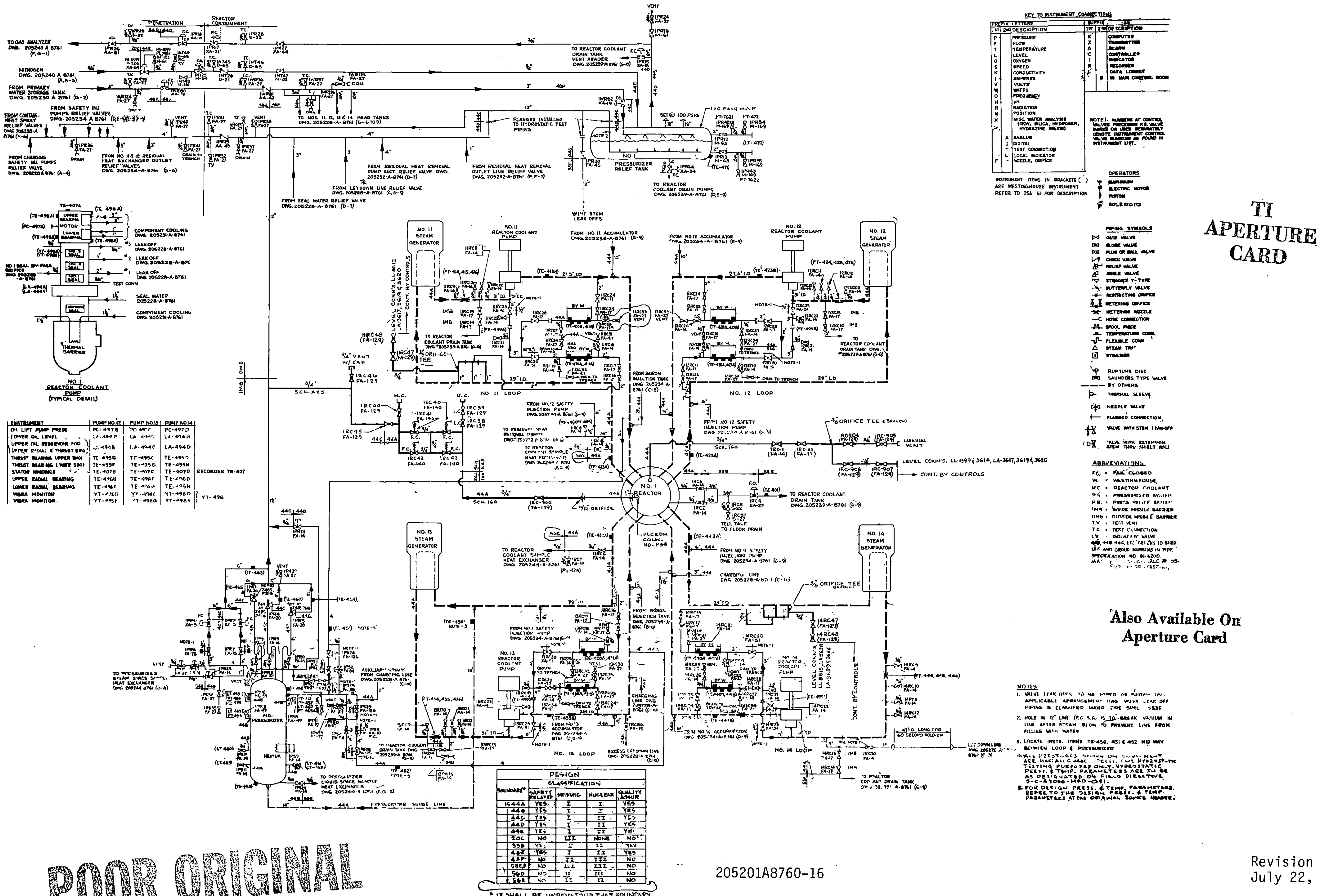
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Coolant Pump Performance Characteristics	
	Updated FSAR	Figure 5.1-5



INSTRUMENT	PUMP NO.12	PUMP NO.13	PUMP NO.14	
OIL LIFT PUMP PRESS	PC-497B	PC-497C	PC-497D	
LOWER OIL LEVEL	LA-494F	LA-494G	LA-494H	
UPPER OIL RESERVOIR FOR UPPER RADIAL & THRUST BRG	LA-494B	LA-494C	LA-494D	
THRUST BEARING UPPER SHOE	TE-495B	TE-495C	TE-495D	
THRUST BEARING LOWER SHOE	TE-495F	TE-495G	TE-495H	
STATOR WINDINGS	TE-407B	TE-407C	TE-407D	RECORDER TR-407
UPPER RADIAL BEARING	TE-496B	TE-496C	TE-496D	
LOWER RADIAL BEARING	TE-496F	TE-496G	TE-496H	
VIBRA MONITOR	YT-498B	YT-498C	YT-498D	YT-498
VIBRA MONITOR	YT-498F	YT-498G	YT-498H	

DESIGN				
BOUNDARY*	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR
1S44A	YES	I	I	YES
44B	YES	I	I	YES
44C	YES	I	II	YES
44D	YES	I	II	YES
44E	YES	I	II	YES
20C	NO	III	NONE	NO
53B	YES	I	II	YES
48J	YES	I	II	YES
48P	NO	II	III	NO
53E,F	NO	III	III	NO
56D	NO	II	III	NO
56E	NO	II	II	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (I.E. 1S44A, ETC.) UNLESS OTHERWISE NOTED

TI APERTURE CARD

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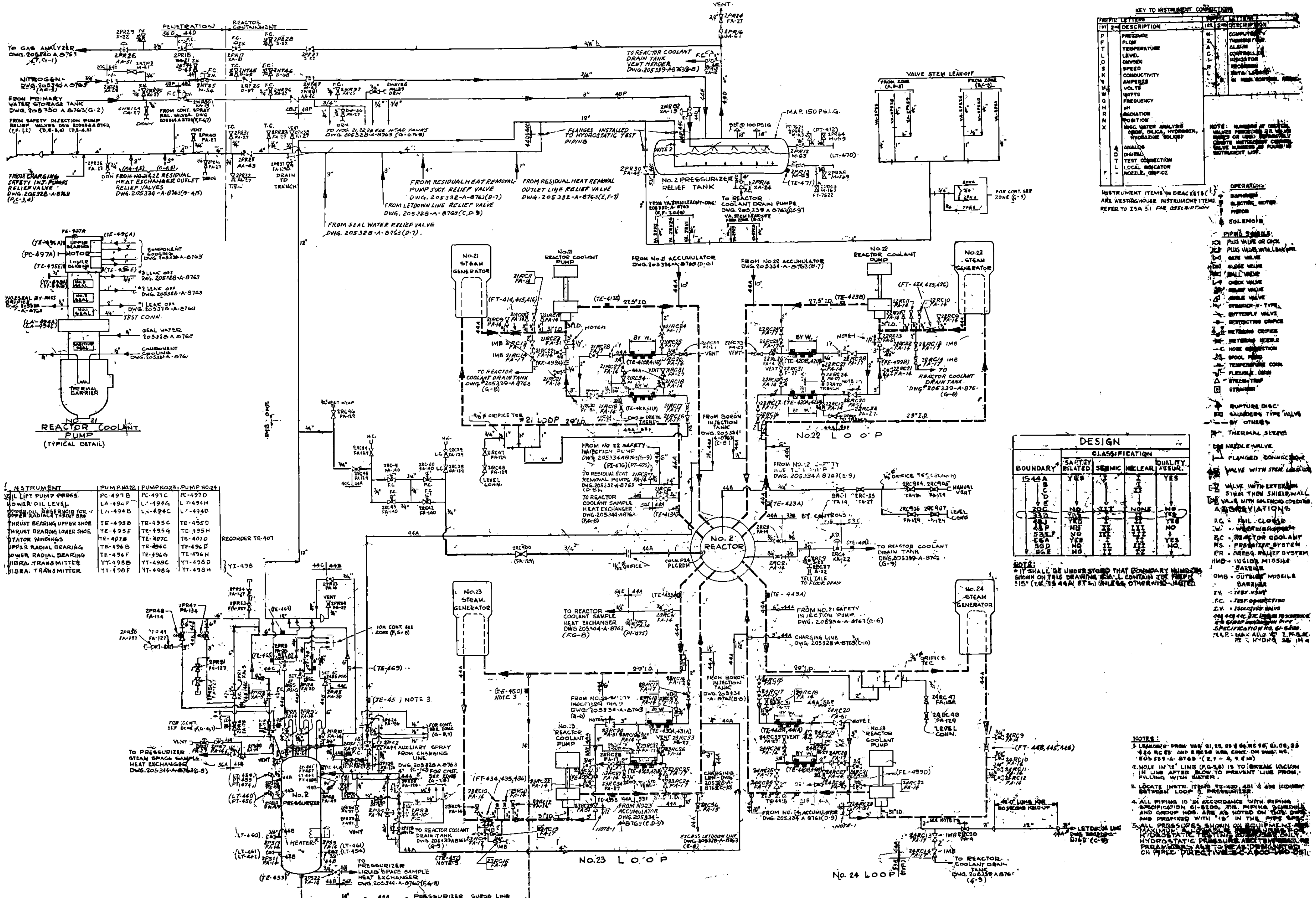
POOR ORIGINAL

205201A8760-16

Revision 3
July 22, 1984

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Coolant System Flow Diagram - Unit 1
	UPDATED FSAR Sheet 1 of 3 FIG 5.1-6

8408020108-09



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Also Available On Aperture Card

POOR ORIGINAL

205301A8762-12

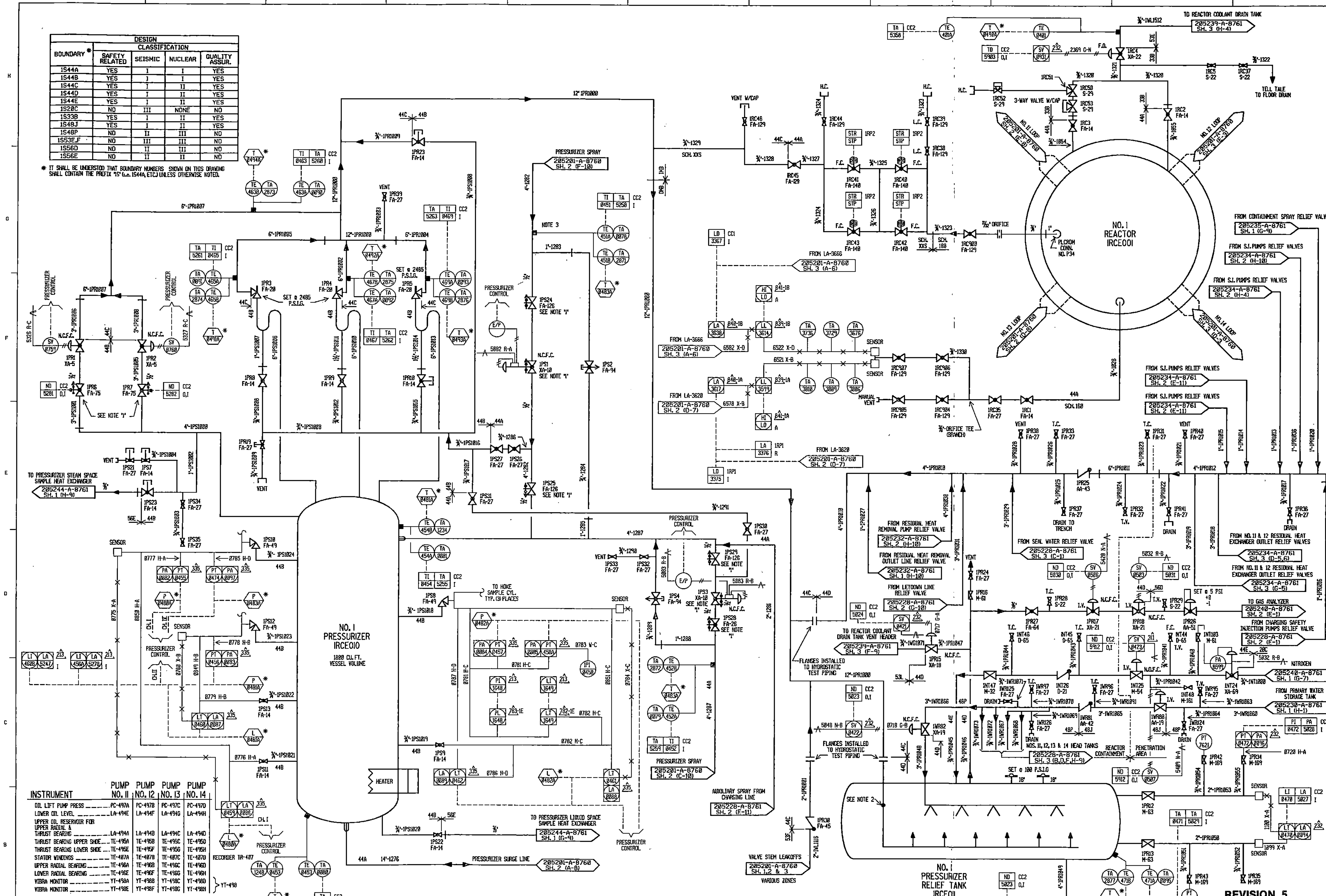
Revision 3
July 22, 1984

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Coolant System Flow Diagram - Unit 2 UPDATED FSAR Sheet 2 of 3 FIG 5.1-6

8408020108-09

BOUNDARY *	DESIGN CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S44A	YES	I	I	YES
1S44B	YES	I	I	YES
1S44C	YES	I	II	YES
1S44D	YES	I	II	YES
1S44E	YES	I	II	YES
1S20C	NO	III	NONE	NO
1S33B	YES	I	II	YES
1S48J	YES	I	II	YES
1S48P	NO	II	III	NO
1S53E,F	NO	III	III	NO
1S56D	NO	II	III	NO
1S56E	NO	II	II	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.



INSTRUMENT	PUMP NO. 11	PUMP NO. 12	PUMP NO. 13	PUMP NO. 14	
OIL LIFT PUMP PRESS	PC-497A	PC-497B	PC-497C	PC-497D	
LOWER OIL LEVEL	LA-494E	LA-494F	LA-494G	LA-494H	
UPPER OIL RESERVOIR FOR UPPER RADIAL & THRUST BEARING	LA-494A	LA-494B	LA-494C	LA-494D	
THRUST BEARING UPPER SHOE	TE-495A	TE-495B	TE-495C	TE-495D	
THRUST BEARING LOWER SHOE	TE-495E	TE-495F	TE-495G	TE-495H	
STATOR WINDINGS	TE-407A	TE-407B	TE-407C	TE-407D	RECORDER TR-407
UPPER RADIAL BEARING	TE-496A	TE-496B	TE-496C	TE-496D	
LOWER RADIAL BEARING	TE-496E	TE-496F	TE-496G	TE-496H	
VIBRA MONITOR	YT-498A	YT-498B	YT-498C	YT-498D	YT-498
VIBRA MONITOR	YT-498E	YT-498F	YT-498G	YT-498H	YT-498

TI APERTURE CARD

Also Available On Aperture Card

REFERENCE DRAWINGS

VALVE LIST 206766-L
CHEM. & VOLUME CONTROL OPERATION DIAG. 205228-A-8761
CHEM. & VOLUME CONTROL PRIM. WATER DIAG. 205230-A-8761
COMPONENT COOLING DIAG. 205231-A-8761
SAFETY INJECTION DIAG. 205234-A-8761
WASTE DISPOSAL LIQUID DIAG. 205239-A-8761
WASTE DISPOSAL GAS DIAG. 205240-A-8761
R.C.S. INSTR. SCH. 207515-B-9491-17
R.C. PRESS. & TKS. INSTR. SCH. 211310-B-9508-12
REACTOR VESSEL TRANS. INSTR. SCH. 252024-B-9952-2
R.C. #12 & 22 R.C.P. PNL. 232 .... ARRGMT. 205339-A-8772
R.C. NO. 1 PRESS. PNL. 335 .... ARRGMT. 211698-A-8863
#11,12,13 & 14 R.C. LOOP PNL. 446 .... ARRGMT. 211698-A-8863
#11,12,13 & 14 R.C. LOOP PNL. 447 .... ARRGMT. 211698-A-8863
SAMPLING DIAG. 205244-A-8761
LEGEND SHEET 600658-A-8727
205201-A-8760
SH. 1 .... NO. 1 REACTOR, PRESSURIZER & PRESSURIZER RELIEF TANK
SH. 2 .... NO. 11, & NO. 13 LOOP
SH. 3 .... NO. 12, & NO. 14 LOOP

NOTES

1. VALVE LEAKOFFS TO BE PIPED AS SHOWN ON APPLICABLE ARRANGEMENT DWG. VALVE LEAKOFF PIPING IS CLASSIFIED UNDER PIPE SPEC 1S53F
2. HOLE IN 12" LINE (B-8) IS TO BREAK VACUUM IN LINE AFTER STEAM BLOW TO PREVENT LINE FROM FILLING WITH WATER
3. LOCATE INSTR. ITEMS TE-450,451 & 452 MIDWAY BETWEEN LOOP & PRESSURIZER
4. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAX. ALLOWABLE PRESS. FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESS. & TEMP. PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
5. FOR DESIGN PRESS. & TEMP. PARAMETEERS REFER TO THE DESIGN PRESS. & TEMP. PARAMETERS AT THE ORIGINAL SOURCE HEADER.
6. ⊠ DENOTES WITHOUT THE RUPTURE DISC.
7. ALL LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1RC" (ie: 1RC1000, etc.) EXCEPT WHERE OTHERWISE NOTED.

REVISION 5
JULY 25, 1986

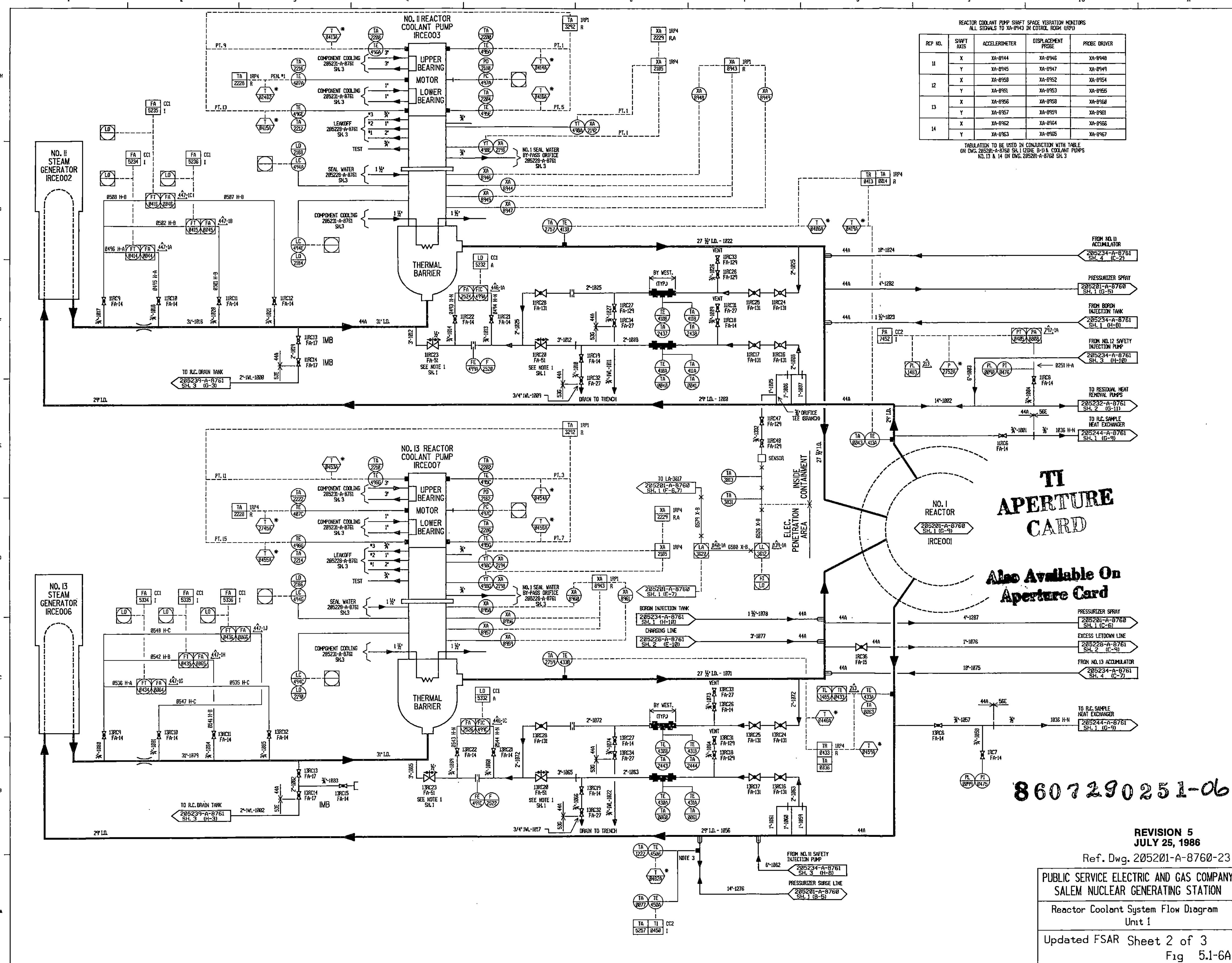
Ref. Dwg. 205201-A-8760-23

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Reactor Coolant System Flow Diagram
Unit 1

Updated FSAR Sheet 1 of 3
Fig 5.1-6A

8607290251-05



REACTOR COOLANT PUMP SHAFT SPACE VIBRATION MONITORS
ALL SIGNALS TO XA-8943 IN COTROL ROOM (1RP1)

RCP NO.	SHAFT AXIS	ACCELEROMETER	DISPLACEMENT PROBE	PROBE DRIVER
11	X	XA-8944	XA-8946	XA-8948
	Y	XA-8945	XA-8947	XA-8949
12	X	XA-8950	XA-8952	XA-8954
	Y	XA-8951	XA-8953	XA-8955
13	X	XA-8956	XA-8958	XA-8960
	Y	XA-8957	XA-8959	XA-8961
14	X	XA-8962	XA-8964	XA-8966
	Y	XA-8963	XA-8965	XA-8967

TABULATION TO BE USED IN CONJUNCTION WITH TABLE ON DWG. 205201-A-8760 SH. 1 (ZONE B-1) & COOLANT PUMPS NO. 13 & 14 ON DWG. 205201-A-8760 SH. 3

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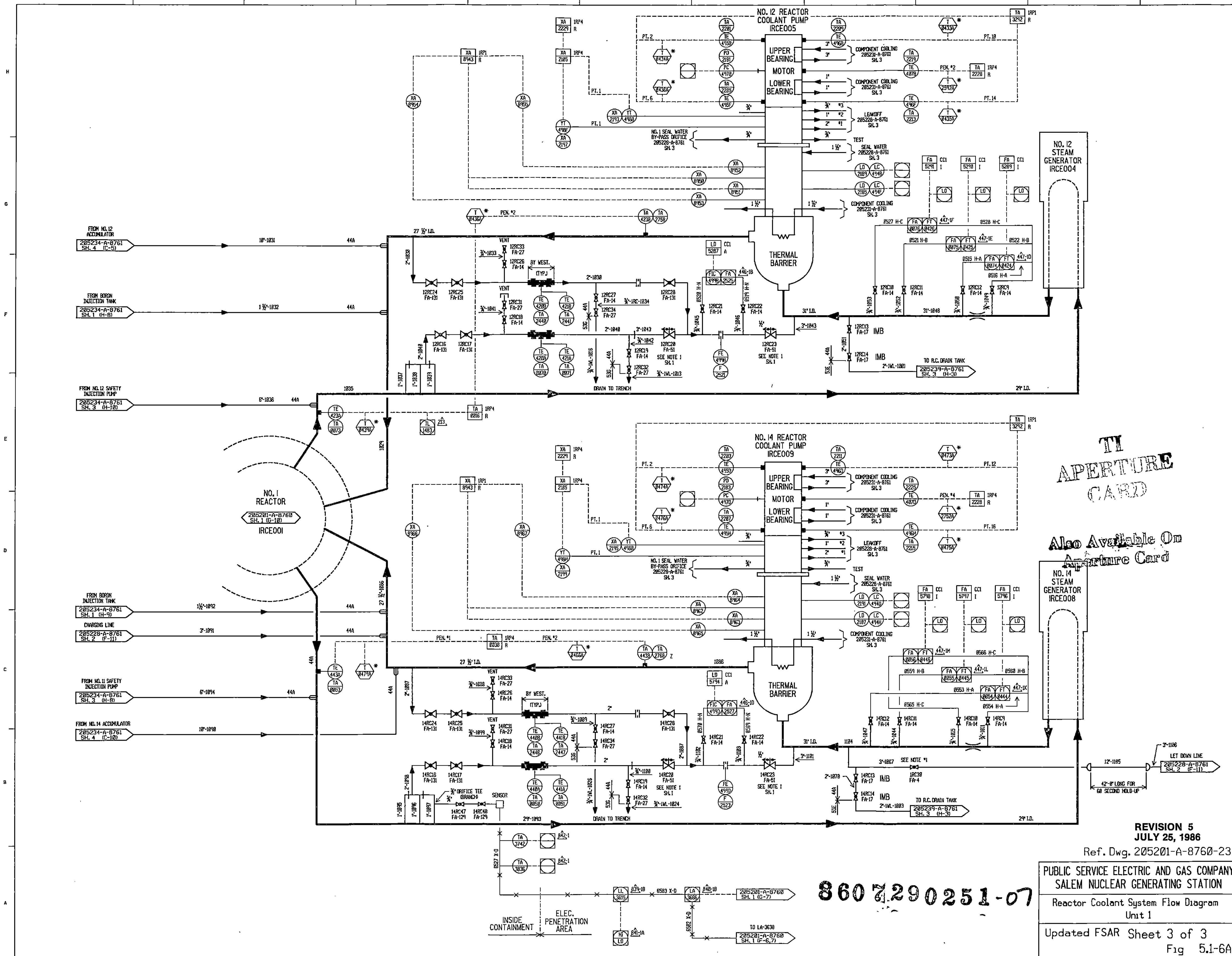
Ref. Dwg. 205201-A-8760-23

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Reactor Coolant System Flow Diagram
Unit 1

Updated FSAR Sheet 2 of 3
Fig 5.1-6A



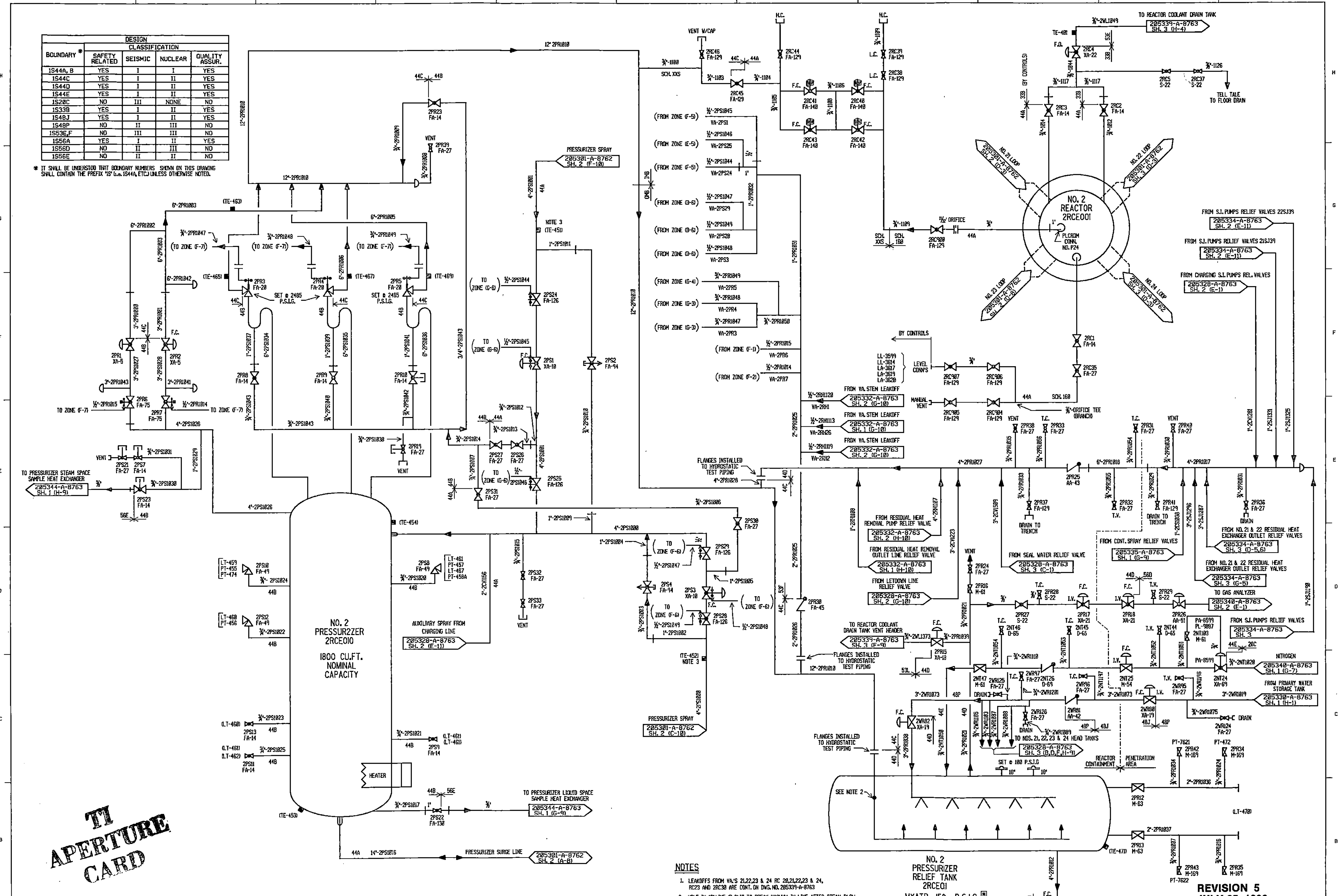
REVISION 5
JULY 25, 1986

Ref. Dwg. 205201-A-8760-23

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Reactor Coolant System Flow Diagram
Unit 1

Updated FSAR Sheet 3 of 3
Fig 5.1-6A



BOUNDARY *	DESIGN CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S44A, B	YES	I	I	YES
1S44C	YES	I	II	YES
1S44D	YES	I	II	YES
1S44E	YES	I	II	YES
1S20C	NO	III	NONE	NO
1S33B	YES	I	II	YES
1S48J	YES	I	II	YES
1S48P	NO	II	III	NO
1S53E,F	NO	III	III	NO
1S56A	YES	I	II	YES
1S56D	NO	II	III	NO
1S56E	NO	II	II	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

INSTRUMENT	PUMP NO. 21	PUMP NO. 22	PUMP NO. 23	PUMP NO. 24	
OIL LIFT PUMP PRESS	PC-497A	PC-497B	PC-497C	PC-497D	
LOWER OIL LEVEL	LA-494E	LA-494F	LA-494G	LA-494H	
UPPER OIL RESERVOIR FOR UPPER RADIAL & THRUST BEARING	LA-494A	LA-494B	LA-494C	LA-494D	
THRUST BEARING UPPER SHOE	TE-495A	TE-495B	TE-495C	TE-495D	
THRUST BEARING LOWER SHOE	TE-495E	TE-495F	TE-495G	TE-495H	
STATOR WINDINGS	TE-407A	TE-407B	TE-407C	TE-407D	RECORDER TR-407
UPPER RADIAL BEARING	TE-496A	TE-496B	TE-496C	TE-496D	
LOWER RADIAL BEARING	TE-496E	TE-496F	TE-496G	TE-496H	
VIBRA TRANSMITTER	YT-498A	YT-498B	YT-498C	YT-498D	YT-498
VIBRA TRANSMITTER	YT-498E	YT-498F	YT-498G	YT-498H	YT-498

REFERENCE DRAWINGS

VALVE LIST	206766-L
CHEM. & VOLUME CONTROL OPERATION DIAG.	205328-A-8763
CHEM. & VOLUME CONTROL PRIM. WATER DIAG.	205330-A-8763
COMPONENT COOLING DIAG.	205331-A-8763
SAFETY INJECTION DIAG.	205334-A-8763
WASTE DISPOSAL LIQUID DIAG.	205339-A-8763
WASTE DISPOSAL GAS DIAG.	205340-A-8763
SAMPLING DIAG.	205344-A-8763
LEGEND SHEET	600658-A-8727

205301-A-8762
SH. 1 ____ NO. 2 REACTOR, PRESSURIZER & PRESSURIZER RELIEF TANK
SH. 2 ____ NO. 21, & NO. 23 LOOP
SH. 3 ____ NO. 22, & NO. 24 LOOP

NOTES

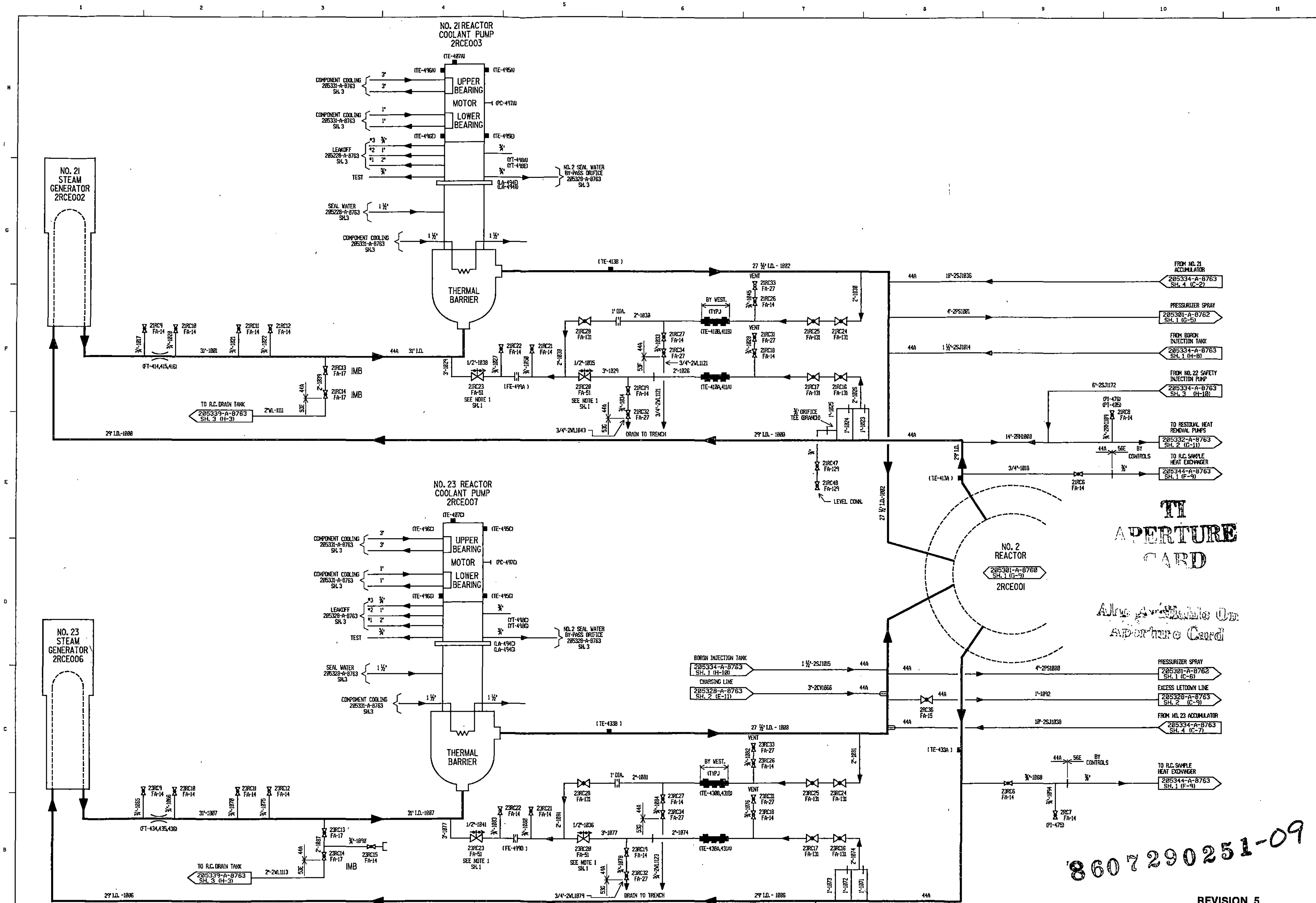
1. LEAKOFFS FROM VA.'S 21,22,23 & 24 RC 20,21,22,23 & 24, RC23 AND 2RC30 ARE CONT. ON DWG. NO. 205339-A-8763
2. HOLE IN 12" LINE (B-8) IS TO BREAK VACUUM IN LINE AFTER STEAM BLOW TO PREVENT LINE FROM FILLING WITH WATER
3. LOCATE INSTR. ITEMS TE-450,451 & 452 MIDWAY BETWEEN LOOP & PRESSURIZER
4. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAX. ALLOWABLE PRESS. FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESS. & TEMP. PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A9000-MFD-051.
5. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2RC" (ie 2RC1000 etc.) EXCEPT WHERE OTHERWISE NOTED.
6. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200. THE PIPING SCHEDULE AND GROUP NO.'S ARE AS NOTED ON THIS DWG. AND PREFIXED WITH "1S".
7. INSTRUMENT ITEMS IN PARENTHESIS ( ) ARE WESTINGHOUSE INSTRUMENT ITEMS REFER TO ISA5.1 FOR DESCRIPTION.
8. ⊠ DENOTES WITHOUT RUPTURE DISC.

REVISION 5
JULY 25, 1986
Ref. Dwg. 205301-A-8762-19

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Reactor Coolant System Flow Diagram
Unit 2

Updated FSAR Sheet 1 of 3
Fig 5.1-6B

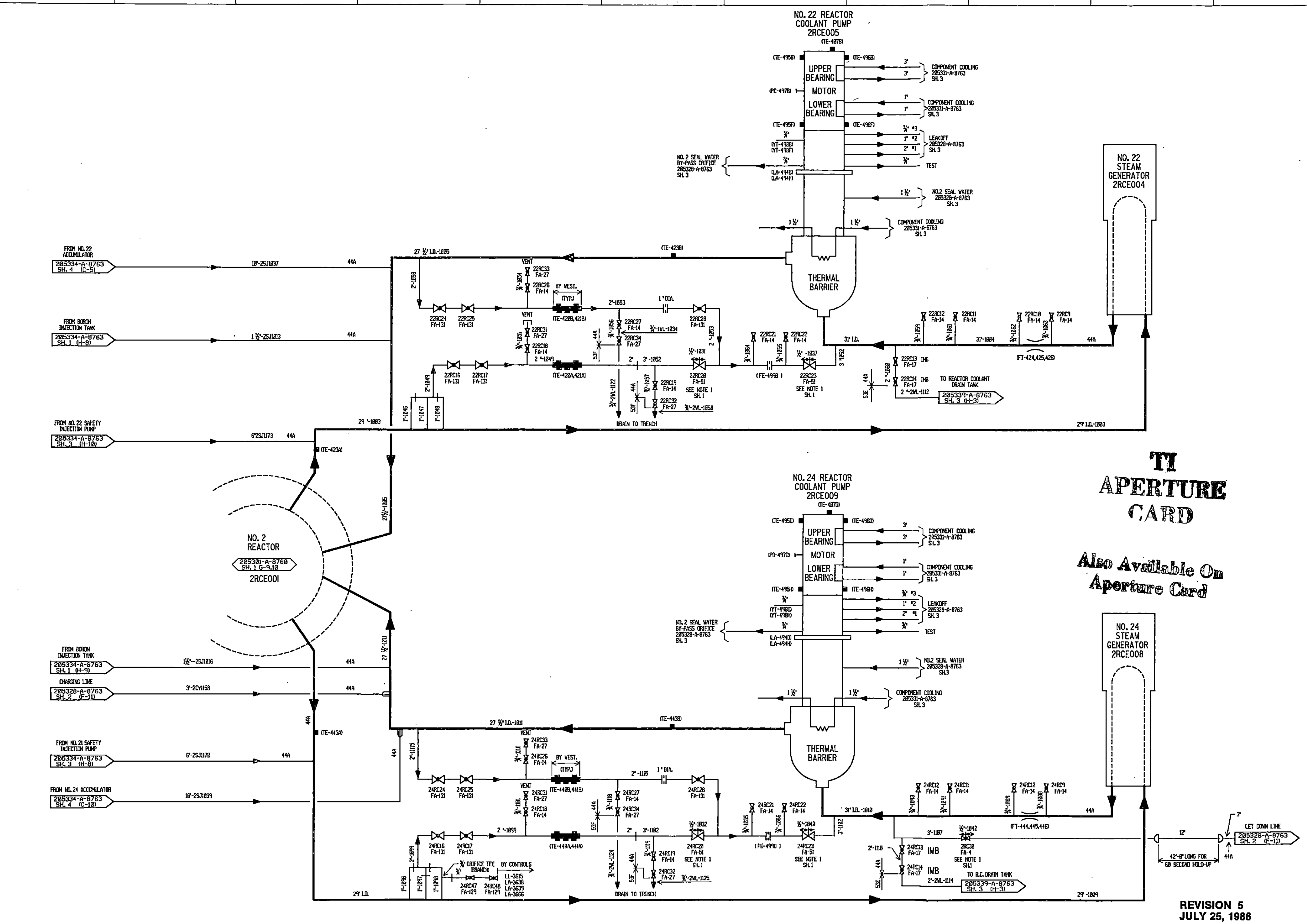


REVISION 5
JULY 25, 1986
Ref. Dwg. 205301-A-8762-19

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Reactor Coolant System Flow Diagram
Unit 2

Updated FSAR Sheet 2 of 3
Fig 5.1-6B



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REVISION 5
JULY 25, 1986

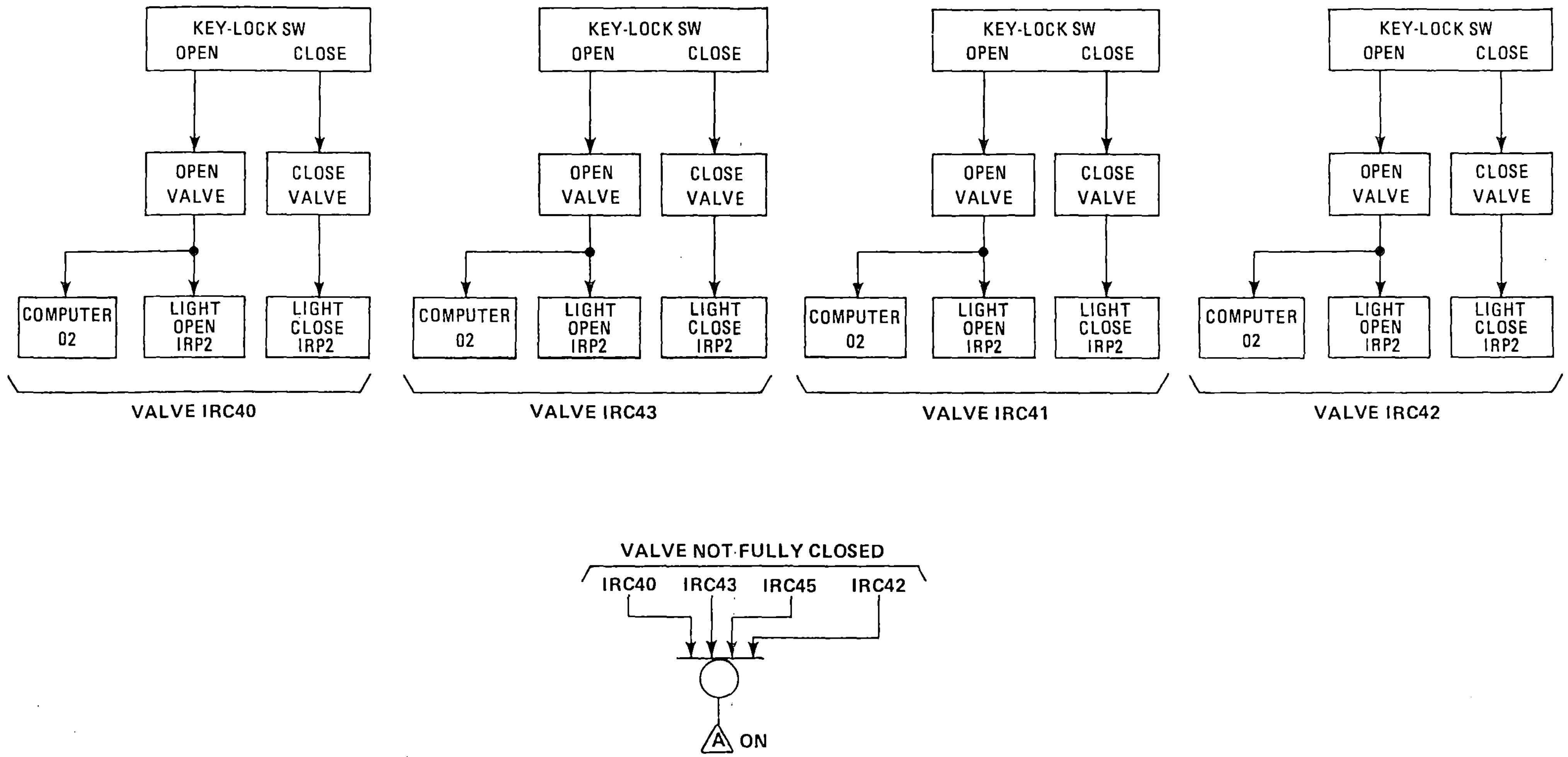
Ref. Dwg. 205301-A-8762-19

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Reactor Coolant System Flow Diagram
Unit 2

Updated FSAR Sheet 3 of 3
Fig 5.1-6B

8607290251-10



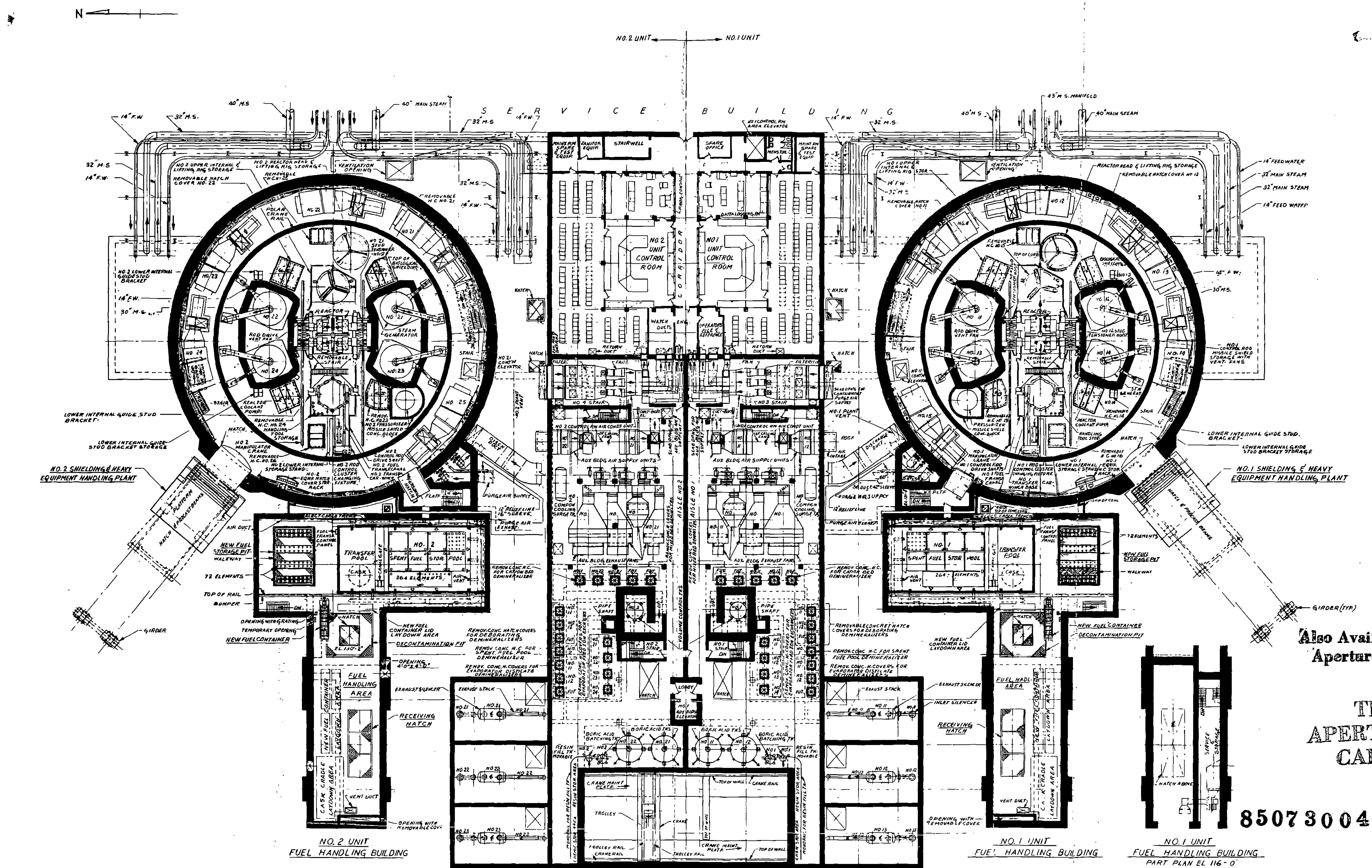
Also Available On Aperture Card

TI APERTURE CARD

8507300447-07

Revision 4
July 22, 1985
Ref. Dwg. N/A

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Logic Diagram, Head Vent System Unit 1 & 2
	Updated FSAR Fig 5.1-6C



Also Available On Aperture Card

TI APERTURE CARD

8507300447-08

Revision 4
July 22, 1985
Ref. Dwg. N/A

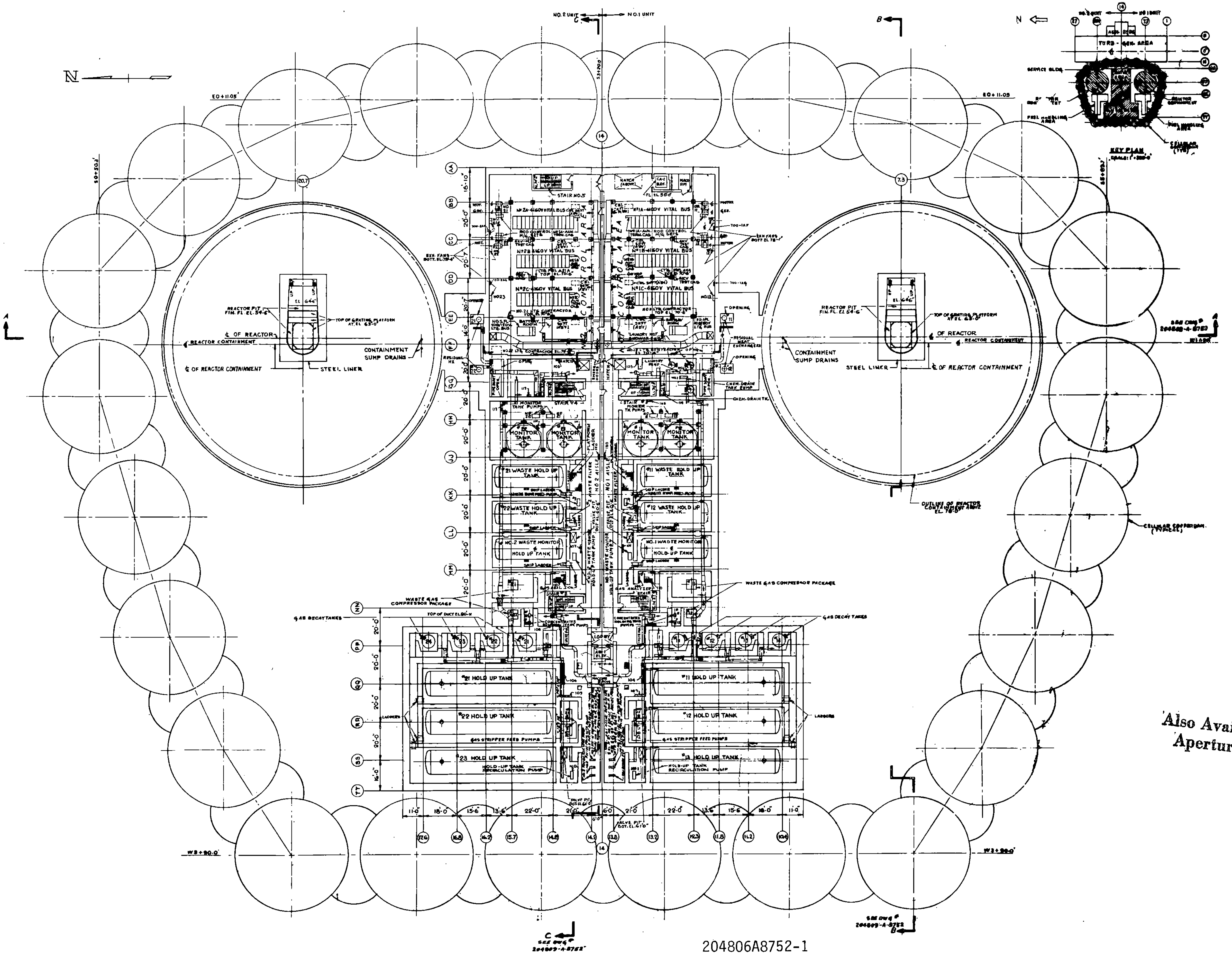
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	No. 1&2 Units - General Arrangement Auxiliary Building El. 122' Containment & Fuel Handling Bldg. El. 130'
	Updated FSAR — Fig 5.1-7

FIGURE 5.1-8 intentionally deleted.

Refer to Figure 3.6-27

FIGURE 5.1-9 intentionally deleted.

Refer to Figure 3.6-26.



TI APERTURE CARD

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204806A8752-1

Revision 3
July 22, 1984

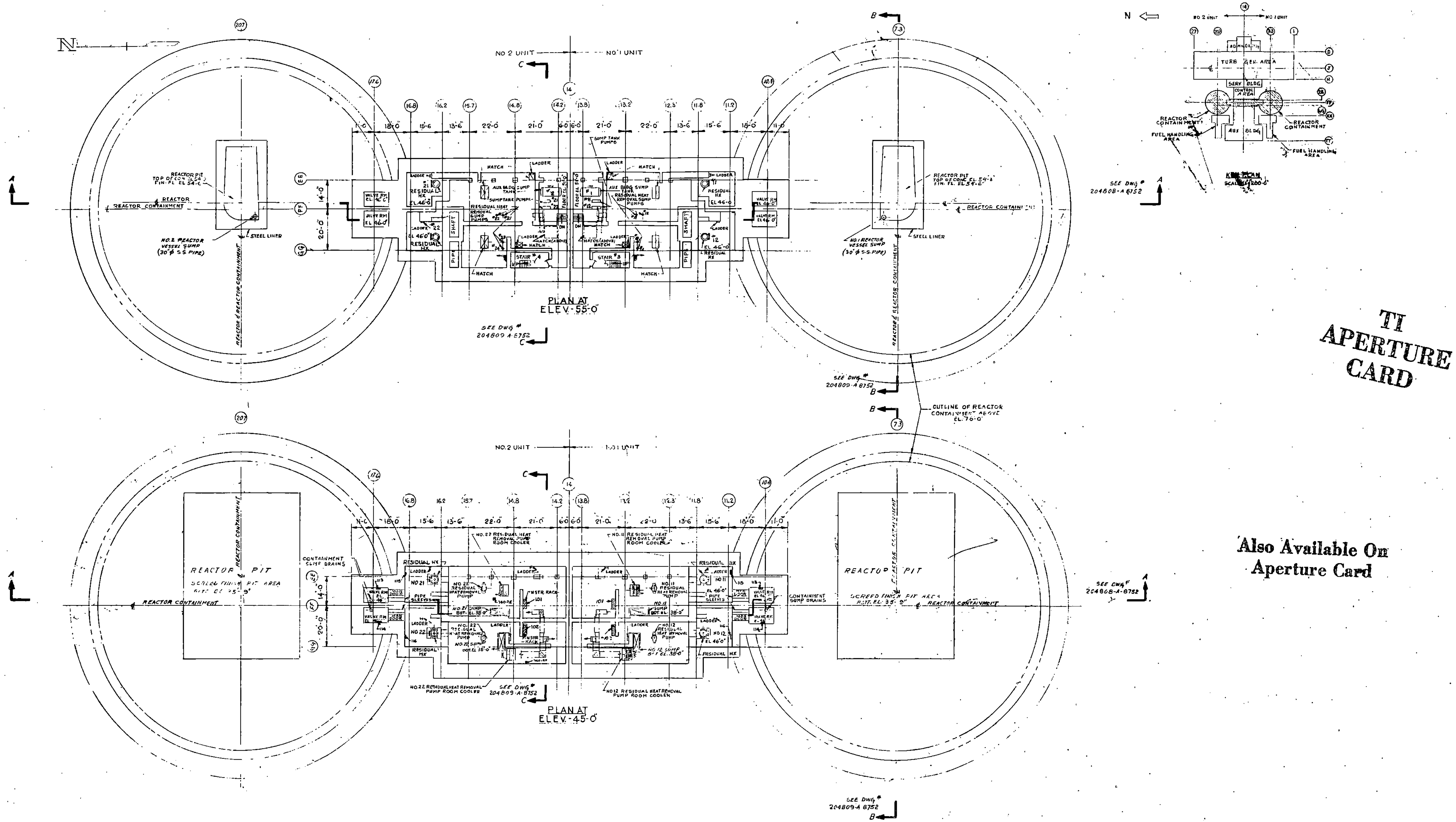
POOR ORIGINAL

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

No. 1&2 Units - General Arrangement
Auxiliary Building El. 64'

UPDATED FSAR FIG 5.1-10

8408020108-10



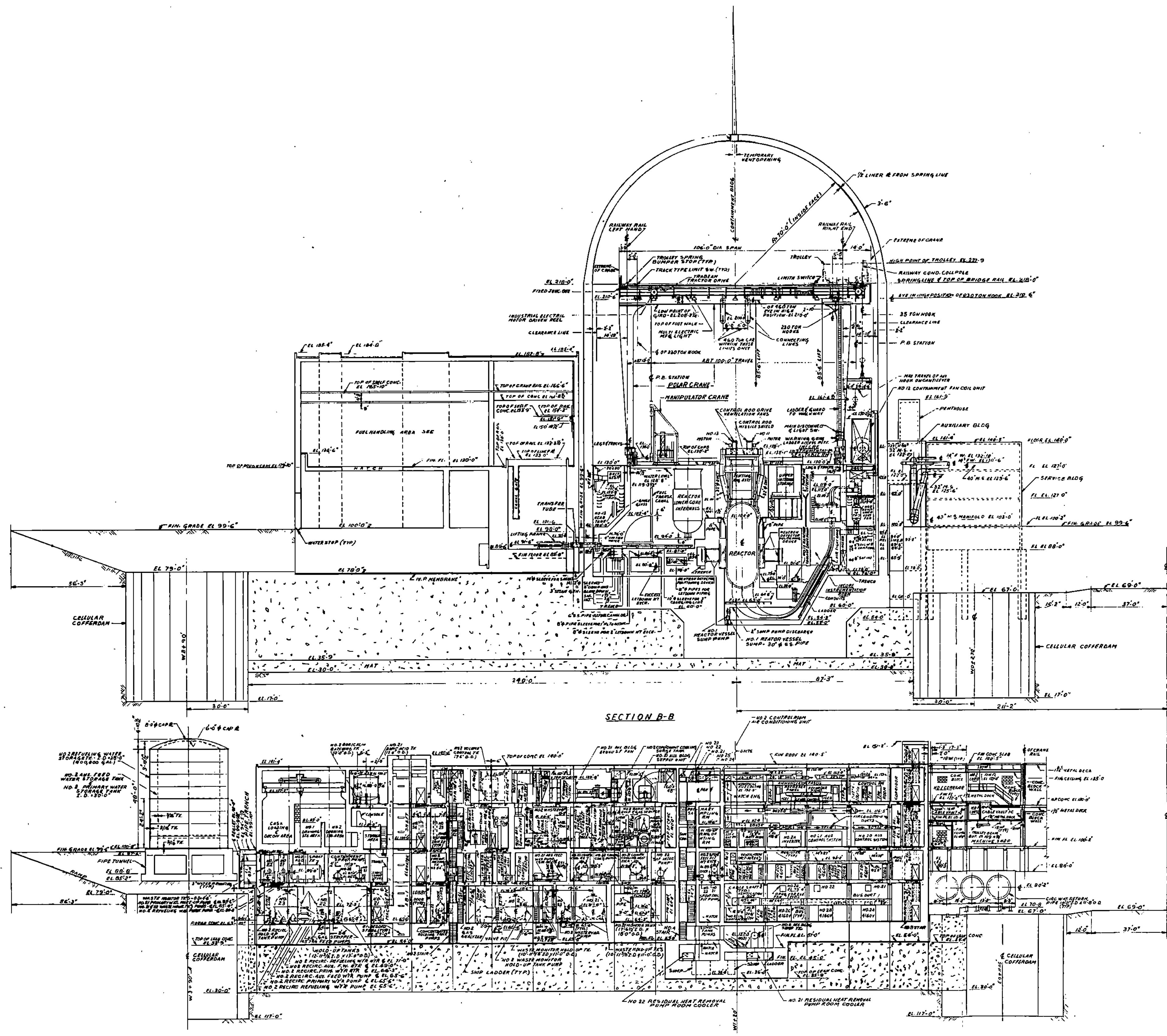
Also Available On Aperture Card

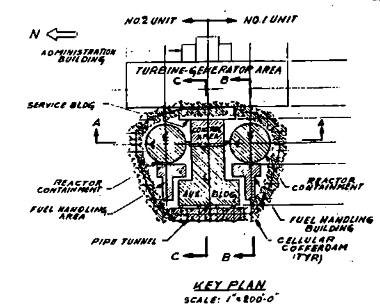
204807A8752-1

Revision 3
July 22, 1984

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	No. 1&2 Units - General Arrangement Auxiliary Building El. 45 & 55
	UPDATED FSAR FIG 5.1-11

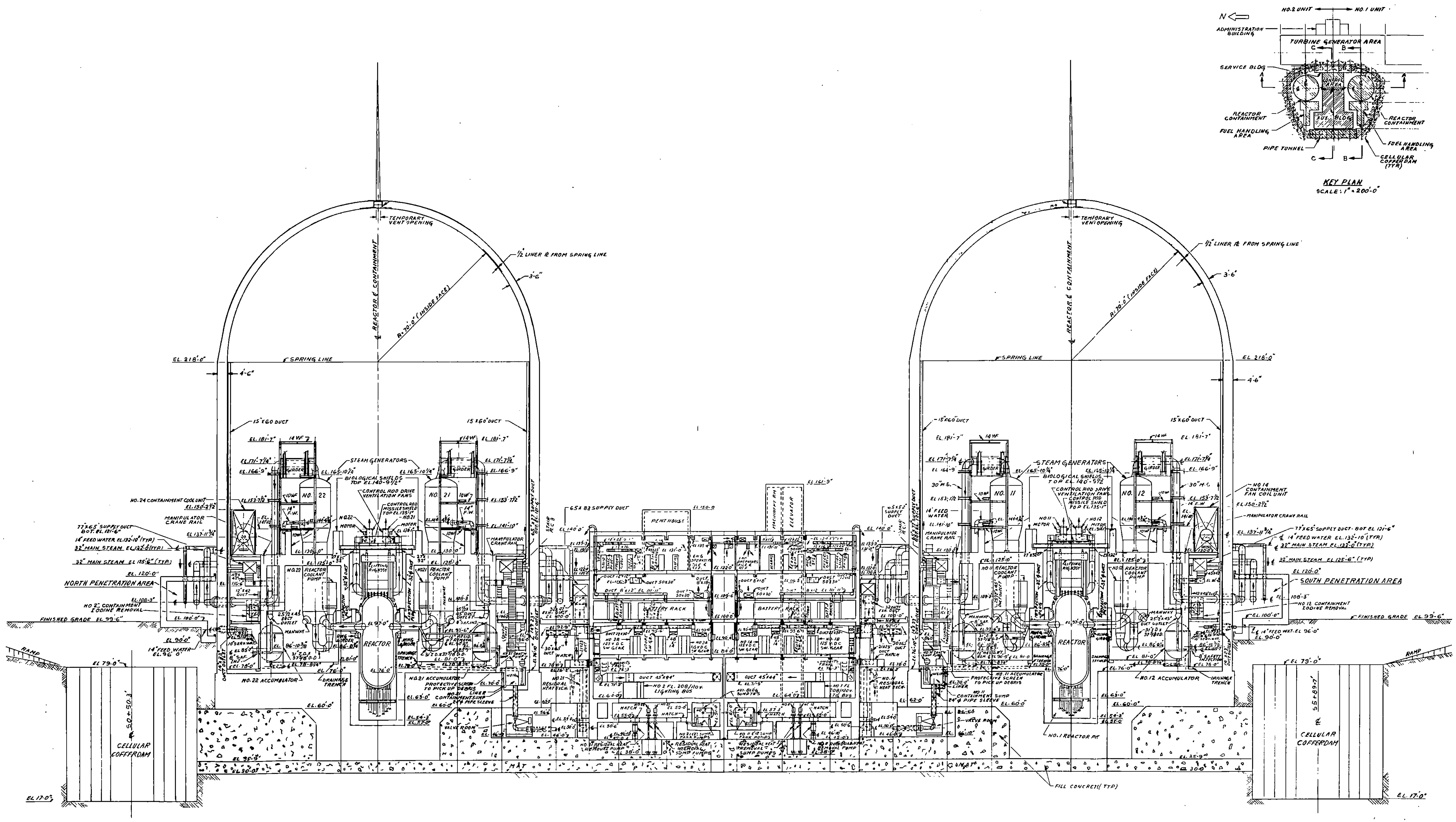
8408020108-11





Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Auxiliary Building and Reactor Containment Elevation	
	Updated FSAR	Figure 5.1-12



Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Auxiliary Building and Reactor Containment Elevation Updated FSAR — Figure 5.1-13

5.2 INTEGRITY OF REACTOR COOLANT PRESSURE BOUNDARY

The reactor coolant system (RCS) is of primary importance with respect to its safety function in protecting the health and safety of the public.

Quality standards of material selection, design, fabrication and inspection conform to the applicable provisions of recognized codes and good nuclear practice.

The materials of construction of the pressure retaining boundary of the RCS are protected by control of coolant chemistry from corrosion phenomena which might otherwise reduce the system structural integrity during its service lifetime.

System conditions resulting from anticipated transients or malfunctions are monitored and appropriate action is automatically initiated to maintain the required cooling capability and to limit system conditions so that continued safe operation is possible.

The system is protected from overpressure by means of pressure relieving devices, as required by Section III of the ASME Boiler and Pressure Vessel Code.

This section discusses the measures employed to provide and maintain the integrity of the reactor coolant pressure boundary (RCPB).

5.2.1 DESIGN OF REACTOR COOLANT PRESSURE BOUNDARY

5.2.1.1 Performance Objectives

The RCS transfers the heat generated in the core to the steam generators where steam is generated to drive the turbine generator. Demineralized light water is circulated at the flow rate and temperature consistent with achieving the reactor core thermal-hydraulic performance. The water also acts as a neutron moderator and reflector, and as a solvent for the neutron absorber used in chemical shim control.

The RCS provides a boundary for containing the coolant under operating temperature and pressure conditions. It serves to confine radioactive material and limits to acceptable values its release to the secondary system and to other parts of the plant under conditions of either normal or abnormal reactor behavior. During transient operation the systems heat capacity attenuates thermal transients generated by the core or steam generators. The RCS accommodates coolant volume changes within the protection system criteria.

The inertia of the reactor coolant pumps reduces the thermal-hydraulic effects to a safe level during the pump coastdown, which would result from a loss-of-flow situation. The layout of the system assures the natural circulation capability following a loss of flow to permit decay heat removal without overheating the core. Part of the system piping serves as part of the emergency core cooling system (ECCS) to deliver cooling water to the core during a loss-of-coolant accident (LOCA).

5.2.1.2 Design Parameters

Design Pressure

The RCS design and operating pressure together with the safety, power relief and pressurizer spray valves set points, and the protection system set point pressures are listed in Table 5.2-1. The selected design margin includes operating transient pressure changes from core thermal lag, coolant transport times and pressure drops, instrumentation and control response characteristics, and system relief valve characteristics. Table 5.2-2 gives the design pressure drop of the RCS components.

Design Temperature

The design temperature for each component was selected to be above the maximum coolant temperature in that component under all normal and anticipated transient load conditions. The design and operating temperatures of the respective system components are listed in Tables 5.2-3 through 5.2-8.

Seismic Loads

The seismic loading conditions were established by the operating basis earthquake (OBE) and design basis earthquake (DBE). The former was selected to be typical of the largest probable ground motion based on the site seismic history. The latter was selected to be the largest potential ground motion at the site based on seismic and geological factors and their uncertainties.

For the OBE loading condition the nuclear steam supply system (NSSS) is designed to be capable of continued safe operation. Therefore, for this loading condition critical structures and equipment needed for this purpose are required to remain operable. The seismic design for the DBE is intended to provide a margin in design that assures capability to shut down and maintain the nuclear facility in a safe condition. In this case, it is only necessary to ensure that the RCS components do not lose their capability to perform their safety function. This has come to be referred to as the "no-loss-of-function" criteria and the loading condition as the "no-loss-of-function" loading condition.

The criteria adopted for allowable stresses and stress intensities in vessels and piping subjected to normal loads plus seismic loads are defined in Chapter 3.

Design and construction practices in accordance with these criteria assure the integrity of the RCS under seismic loading. The combination of seismic loads with operating and pipe rupture loads for the design of the RCS support structures and their respective allowable stresses are given in Table 5.5-3.

5.2.1.3 Compliance with 10CFR50.55a

All pressure-containing components of the RCS were designed, fabricated, inspected and tested in conformance with the applicable codes listed in Table 5.2-9.

The RCS is classified as Class 1 for seismic design, requiring that there will be no loss of function of such equipment in the event of the assumed DBE ground acceleration acting in the horizontal and vertical directions simultaneously, when combined with the RCS steady state stresses.

5.2.1.4 Applicable Code Cases

Code cases applied in the RCS design are listed in Table 5.2-9.

5.2.1.5 Design Transients

The RCS and its components are designed to accommodate 10 percent of full power step changes in plant load and 5 percent of full power per minute ramp changes over the range from 15 percent full power up to and including but not exceeding 100 percent of full power without reactor trip. The RCS can accept a complete loss of load from full power with reactor trip. In addition, the steam dump system makes it possible to accept a 50 percent loss of external load from full power without reactor trip.

All components in the RCS are designed to withstand the effects of cyclic loads due to reactor system temperature and pressure changes. These cyclic loads are introduced by normal power changes, reactor trip, and startup and shutdown operations. The number of thermal and loading cycles used for design purposes and their bases are given in Table 5.2-10. During unit startup and shutdown, the rates of temperature and pressure changes are limited as indicated below.

To provide the necessary high degree of integrity for the equipment in the RCS, the transient conditions selected for equipment fatigue evaluation were based on a conservative estimate of the magnitude and frequency of the temperature and pressure transients resulting from normal operation, normal and abnormal load transients and accident conditions. To a large extent, the specific transient operating conditions were considered for equipment fatigue analyses were based upon engineering judgment and experience. Those transients were chosen which were representative of transients to be expected during plant operation, sufficiently severe or frequent to be of possible significance to component cyclic behavior.

Clearly it is difficult to discuss in absolute terms the transients that the plant will actually experience during the 40 years operating life. For clarity, however, each transient condition is discussed in order to make clear the nature and basis for the various transients.

5.2.1.5.1 Heatup and Cooldown

The normal heatup or cooldown cases are conservatively represented by a continuous operation performed at a uniform temperature rate of 100°F per hour.

For these cases, the heatup occurs from ambient to the no-load temperature and pressure condition and the cooldown represents the reverse situation. In actual practice the rate of temperature change of 100°F per hour is not attained because of other limitations such as:

1. Material nil ductility transition (NDT) considerations which establish maximum permissible temperature rates of change, as a function of plant pressure and temperature, which are below the design rate of 100°F per hour.

2. Slower initial heatup rates when using pumping energy only.

3. Interruptions in the heatup and cooldown cycles due to such factors as drawing a pressurizer steam bubble, rod withdrawal, sampling, water chemistry and gas adjustments.

The number of such complete heatup and cooldown operations is specified at 200 times each which corresponds to five such occurrences per year for the 40-year plant design life. For the ideal plant only one heatup and one cooldown would occur per 100 percent full power year, i.e., the period between refueling. In practice, experience to date indicates that during the first year or so of operation additional unscheduled plant cooldowns may be necessary for plant maintenance; the frequency of maintenance shutdowns reduce as the plant matures. As experience was gained with Yankee-Rowe, the number of shutdowns decreased; for example Core II ran for a year from 1962 to 1963 with no cooldowns. Table 5.2-11 is a summary of the Yankee-Rowe plant outage for the period 1964 to 1969.

5.2.1.5.2 Unit Loading and Unloading

The unit loading and unloading cases are conservatively represented by a continuous and uniform ramp power change of 5 percent per minute between 15 percent load and full load. This load swing is the maximum possible consistent with operation with automatic reactor control. The reactor coolant temperature will vary with load as prescribed by the temperature control system. The number of each operation is specified at 18,300 times or 1 time per day with approximately 40 percent margin for plants with 40 year design life.

5.2.1.5.3 Step Increase and Decrease of 10 Percent

The ± 10 percent step change in load demand is a control transient which is assumed to be a change in turbine control valve opening which might be occasioned by disturbances in the electrical network into which the plant output is tied. The reactor control system is designed to restore plant equilibrium without reactor trip following a ± 10 percent step change in turbine load demand initiated from nuclear plant equilibrium conditions in the range between 15 percent and 100 percent full load, the power range for automatic reactor control. In effect, during load change conditions, the reactor control system attempts to match turbine and reactor outputs in such a manner that peak reactor coolant temperature is minimized and reactor coolant temperature is restored to its programmed set point at a sufficiently slow rate to prevent excessive pressurizer pressure decrease.

Following a step load decrease in turbine load, the secondary side steam pressure and temperature initially increase since the decrease in nuclear power lags behind the step decrease in turbine load. During the same increment of time, the RCS average temperature and pressurizer pressure also initially increase. Because of the power mismatch between the turbine and reactor and the increase in reactor coolant temperature, the control system automatically inserts the control rods to reduce core power. With load decrease, the reactor coolant temperature will be ultimately reduced from its peak value to a value below its initial equilibrium value at the inception of the transient. The reactor coolant average temperature set point change is made as a function of turbine-generator load as determined by first stage turbine pressure measurement. The pressurizer pressure will also decrease from its peak pressure value and follow the reactor coolant decreasing temperature trend. At some point during the decreasing pressure transient, the saturated water in the pressurizer begins to flash which reduces the rate of pressure decrease. Subsequently the pressurizer heaters come on to restore the plant pressure to its normal value.

Following a step load increase in turbine load, the reverse situation occurs, i.e., the secondary side steam pressure and temperature initially decrease and the reactor coolant average temperature and pressure initially decrease. The control system automatically withdraws the control rods to increase core power. The decreasing pressure transient is reversed by actuation of the pressurizer heaters and eventually the system pressure is restored to its normal value. The reactor coolant average temperature will be raised to a value above its initial equilibrium value at the beginning of the transient. The number of each operation is specified at 2000 times or 50 per year for the 40-year plant design life.

5.2.1.5.4 50 Percent Step Decrease in Load

This transient applies to a 50 percent step decrease in turbine load of such magnitude that the resultant rapid increase in reactor coolant average temperature and secondary side steam pressure and temperature will automatically initiate a secondary side steam dump system that will prevent a reactor shutdown or lifting of steam generator safety valves. If a steam dump system was not provided to cope with this transient, there would be such a strong mismatch between what the turbine is asking for and what the reactor is furnishing that a reactor trip and lifting of steam generator safety valves would occur.

The number of occurrences of this transient is specified at 200 times or 5 per year for the 40-year plant design life. Reference to the Yankee-Rowe record indicates that this basis is adequately conservative.

5.2.1.5.5 Loss of Load

This transient applies to a step decrease in turbine load from full power occasioned by the loss of turbine load without immediately initiating a reactor trip and represents the most severe transient on the RCS. In this assumed case the reactor and turbine eventually trip as a consequence of a high pressurizer level trip initiated by the reactor protection system (RPS).

The number of occurrences of this transient is specified at 80 times or 2 per year for the 40-year plant design life. Since redundant means of tripping the reactor upon turbine trip are provided as part of the RPS, transients of this nature are not expected.

5.2.1.5.6 Loss of Power

This transient applies to a blackout situation involving the loss of outside electrical power to the station and a reactor and turbine trip, on low reactor coolant flow, culminating in a complete loss of plant electrical power. Under these circumstances, the reactor coolant pumps are de-energized and following the coastdown of the reactor coolant pumps, natural circulation builds up in the system to some equilibrium value. This condition permits removal of core residual heat through the steam generators which at this time are receiving feedwater from the auxiliary feedwater system (AFS) operating from diesel generator power. Steam is removed for reactor cooldown through atmospheric pilot-operated relief valves provided for this purpose.

The number of occurrences of this transient is specified at 40 times or 1 per year for the 40-year plant design life.

5.2.1.5.7 Loss of Flow

This transient applies to a partial loss of flow accident from full power in which a reactor coolant pump is tripped out of service as a result of a loss of power to that pump. The consequences of such an accident at a high power level are a reactor and turbine trip on low reactor coolant flow, followed by automatic opening of the steam dump system and flow reversal in the affected loop. The flow reversal results in reactor coolant at cold-leg temperature, being passed through the steam generator and cooled still further. This cooler water then passes through the hot leg piping and enters the reactor vessel outlet nozzles. The net result of the flow reversal is a sizeable reduction in the hot leg coolant temperature of the affected loop.

The number of occurrences of this transient is specified at 80 times or 2 per year for the 40-year plant design life.

5.2.1.5.8 Reactor Trip from Full Power

A reactor trip from full power may occur for a variety of causes resulting in temperature and pressure transients in the RCS and in the secondary side of the steam generator. This is the result of continued heat transfer from the reactor coolant in the steam generator. The transient continues until the reactor coolant and steam generator secondary side temperatures are in equilibrium at zero power conditions. A continued supply of feedwater and controlled dumping of secondary steam remove the core residual heat and prevent the steam generator safety valves from lifting. The reactor coolant temperature and pressure undergo a rapid decrease from full power values as the RPS causes the control rods to drop into the core.

The number of occurrences of this transient is specified at 400 times or 10 per year for the 40-year plant design life.

5.2.1.5.9 Turbine Roll Test

This transient is imposed upon the plant during the hot functional test period for turbine cycle checkout. Reactor coolant pump power was used to heat the reactor coolant to operating temperature and the steam generated used to perform a turbine roll test. However, the plant cooldown during this test exceeded the 100°F per hour maximum rate specified in Section 5.2.1.5.1 above.

The number of such test cycles is specified at 10 times to be performed at the beginning of plant operating life prior to irradiation.

5.2.1.5.10 Hydrostatic Test Conditions

The pressure tests are outlined below:

Primary Side Hydrostatic Test Before Initial Startup

The pressure tests covered by this section include both shop and field hydrostatic tests which occur as a result of component or system testing. This hydrostatic test was performed at a water temperature which was compatible with reactor vessel material ductility transition temperature (DTT) requirements and a minimum test pressure of 3107 psig. In this test, the primary side of the steam generator was pressurized to 3107 psig coincident with the secondary side pressure of 0 psig. The RCS is designed for 5 cycles of this hydrostatic test.

Secondary Side Hydrostatic Test Before Initial Startup

The secondary side of the steam generator was pressurized to 1356 psig with a minimum water temperature of 70°F coincident with the primary side at 0 psig.

The steam generator may experience 5 cycles of this test.

5.2.1.5.11 Primary Side Leak Test

This type of test is performed to test the integrity of the RCS after a maintenance procedure has been completed in which the RCS boundary has been opened. To account for the shift in DTT on the reactor vessel due to irradiation effects later in life, this leak test is analyzed at a minimum water temperature above NDT and an assumed system pressure of 2485 psig. The design heatup rate is limited to 100°F per hour. Since pumping power is used to heat the water, the actual heatup rate is considerably below 100°F per hour. The number of these tests is specified at 50 for the 40-year plant design life. The normal requirement is that which follows a refueling operation.

5.2.1.5.12 Pressurizer Surge and Spray Line Connections

The surge and spray nozzle connections at the pressurizer vessel are subject to cyclic temperature changes resulting from the transient conditions described previously. The various transients are characterized by variations in reactor coolant temperature which in turn result in water surges into or out of the pressurizer. The surges manifest themselves as changes in system pressure which depending upon whether an increase or decrease in pressure occurs, result in introducing spray water into the pressurizer to reduce pressure or actuating the pressurizer heaters to increase pressure to the equilibrium value. To illustrate a load change cycle as it affects the pressurizer, consider a design step increase in load. The pressurizer initially experiences an outsurge with a drop in system pressure which actuates the pressurizer heaters to restore system pressure. As the reactor control system reacts, the reactor coolant temperature is increased which causes an insurge into the pressurizer raising system pressure. As pressure is increased, the heaters go off and at some pressure set point, the spray valves open to limit the pressure rise and restore system pressure. Thus the pressurizer surge nozzle is subjected to a temperature increase on the outsurge followed by a temperature decrease on the insurge during this load transient. The pressurizer spray nozzle is subjected to a temperature decrease when the spray valve opens to admit reactor coolant cold leg water into the pressurizer. The pressurizer experiences a reverse situation during a load decrease transient, i.e., an insurge followed by an outsurge. It is assumed that the spray valve opens to admit spray water into the pressurizer once at the design flowrate for each design step change in plant load. Thus the number of occurrences for the spray nozzle corresponds to that shown for the other components in Table 5.2-10.

During plant cooldown, spray water is introduced into the pressurizer to cool down the pressurizer. The maximum pressurizer cooldown rate is specified at 200°F per hour which is twice the rate specified for the other RCS components.

5.2.1.5.13 Accident Conditions

The effect of the accident loading was evaulated in combination with normal loads to demonstrate the adequacy to meet the stated plant safety criteria.

A brief description of each accident transient that was considered follows. In each case one occurrence was evaluated.

Reactor Coolant Pipe Break

This accident involves the rupture of a RCS pipe resulting in a loss of primary coolant. It is conservatively assumed that the system pressure and temperature are reduced rapidly and the safety injection system (SIS) is initiated to introduce 70°F water into the RCS. The safety injection signal also results in a turbine and reactor trip. Because of the rapid blowdown of coolant from the system and the comparatively large heat capacity of the metal sections of the components, it is likely that the metal is still at no-load temperature conditions when the 70°F safety injection water is introduced into the system.

Steam Line Break

For component evaluation, the following conservative conditions were considered:

1. The reactor is initially in a hot, zero-load, just critical condition assuming all rods in except the most reactive rod which is assumed to be stuck in its fully withdrawn position.

2. A steam line break occurs inside the containment resulting in a reactor and turbine trip.

3. Subsequent to the break, there is no return to power and the reactor coolant temperature cools down to 212°F.

4. The ECCS pumps restore the reactor coolant pressure to 2500 psia.

The above conditions result in the most severe temperature and pressure variations which the component will encounter during a steam break accident.

Steam Generator Tube Rupture

This accident postulates the double-ended rupture of a steam generator tube resulting in a decrease in pressurizer level and reactor coolant pressure. Reactor trip will occur due to a safety injection signal on coincidence of low pressurizer pressure and low pressurizer level. When the accident occurs, some of the reactor coolant blows down into the affected steam generator causing the level to rise. If the level rises sufficiently, a high level alarm will occur and the feedwater regulating valve will close. Approximately 10 minutes after the rupture, the primary system pressure is reduced below the secondary safety valve settings (~1100 psia). At this time, the planned procedure to recovery from this accident calls for isolation of the steam line leading from the affected steam generator. Therefore, this accident will result in a transient which is no more severe than that associated with a reactor trip. For this reason, it requires no special treatment in so far as fatigue evaluation is concerned.

5.2.1.6 Protection Against Environmental Factors

Essential equipment has either been designed to withstand a credible tornado including a single large missile generated thereby, or has been placed in a structure which will withstand the tornado and missile. Where sufficient redundancy exists equipment may be physically separated without protection against tornado missiles.

Engineered safety features are protected against dynamic effects and missiles resulting from equipment failures. The means for accomplishing this protection are described in Section 3.5.

5.2.1.7 Protection Against Proliferation of Dynamic Effects

5.2.1.7.1 Criteria

Protection, in the form of barriers, restraints, supports and physical separation has been provided to assure that in the unlikely event of an accident the following criteria will be met:

1. Containment integrity will be protected throughout the accident.

2. A second accident will not occur as a result of the original accident.

3. For a steam system rupture, no more than one steam generator will blow down.

For the purpose of the above criteria an accident is defined as the rupture of a pipe in any one of the following systems:

1. Reactor coolant system (LOCA)

2. Main steam system, from each steam generator up to and including the main steam stop outside the containment.

3. Feedwater system, from each steam generator up to and including the non-return valve outside the containment.

5.2.1.7.2 Dynamic Effects

Protection has been provided against the following effects:

1. Jet forces resulting from the release of high pressure steam or water from a ruptured line.

2. Pipe whip caused by the formation of a plastic hinge in a pipe due to a rupture somewhere else in the same pipe.

3. Missiles which can be generated in coincidence with an accident.

5.2.1.7.3 Barriers

The polar crane wall serves as a barrier between the reactor coolant loops and the containment liner. In addition, the refueling cavity walls, various structural beams, the operating floor and the crane wall provide some separation of the reactor coolant loops, thereby minimizing the effects of an accident occurring in any one loop on another loop or the containment.

The Class 1 portion of the steam and feedwater lines from each steam generator have been routed behind barriers which separate these lines from the steam and feedwater lines from the other steam generators, as well as from the reactor coolant piping.

The barriers described above will withstand loadings caused by jet forces, pipe whip impact forces, or the generation of all credible missiles coincident with an accident.

All equipment inside the containment, required for safe shutdown in the event of an accident is located between the crane wall and the containment wall and is thereby protected from all dynamic effects of an accident occurring within the loop compartment.

5.2.1.7.4 Restraints

All lines connected to the reactor coolant loop, which penetrate the containment wall are anchored to the crane wall. Each anchor is designed to be stronger than the pipe. Should a reactor coolant loop rupture occur, the resulting jet force will therefore not be transferred through to the containment wall through any branch lines.

Main steam and feedwater lines are anchored outside the containment so that a rupture anywhere in the line will not affect containment integrity. These lines are also restrained inside the containment to prevent whipping and to maintain containment integrity.

5.2.1.7.5 Supports

Major components of the RCS (reactor vessel, steam generators, pumps) are supported to isolate the effects of an initial rupture so that a second accident cannot occur.

5.2.1.7.6 Physical Separation

Physical separation is accomplished primarily by placing redundant essential equipment on either side of a barrier so that one, but not both items may be vulnerable to missiles, jet forces and pipe whip.

Safeguards lines serving the RCS are routed so that main headers are located outside the crane wall and are not vulnerable to any dynamic effects. Branch lines serving an individual loop penetrate the crane wall as close to the loop as possible. In this manner branch lines serving unaffected loops will not be damaged by the loop in which the accident may have occurred.

5.2.1.8 Design Criteria for Vessels and Piping

5.2.1.8.1 Load Combinations and Stress Criteria

This section deals with the loads imposed on RCS components and supports during normal conditions as well as during seismic events and pipe rupture. Stress criteria are preseated as a function of the various load combinations. Two types of seismic loading are considered: operating basin earthquake (OBE) and design basis earthquake (DBE).

For the OBE loading condition, the nuclear steam supply system is designed to be capable of continued safe operation. Therefore, for this loading condition critical structures and equipment needed for this purpose are required to operate within design limits. The seismic design for the DBE is intended to provide a margin in design that assures capability to shutdown and maintain the nuclear facility in a safe condition. In this case, it is only necessary to ensure that required critical structures and components do not lose their capability to perform their safety function. This has come to be referred to as the "no-loss-of-function" criteria and the loading condition as the "design basis earthquake" loading condition.

Not all critical components have the same functional requirements for safety. For example, the reactor containment must retain capability to restrict leakage to an acceptable level. Therefore, general elastic behavior of this structure under the "design basis earthquake" loading condition was ensured. On the other hand, many components can experience significant permanent deformation without loss of function. Piping and vessels are examples of the latter where the principal requirement is that they retain their contents and allow fluid flow.

The normal as well as abnormal loads are considered singly and in combination (see Table 5.2-12, and the allowable stress limits for each of the possible combinations are limited to those specified in Table 5.2-13. The design limit curves that give the allowable stresses for faulted conditions were developed by using the approach presented in Reference 1. This report develops limit curves by using 50 percent of the ultimate strain as the maximum allowable membrane strain. Subsequent to the submission of Reference 1, the allowable membrane strain was limited to 20 percent of the uniform strain. Design limit curves were developed by using the following procedure:

1. Use material data to develop stress-strain curves.

   Stress-strain curves of Type 304 stainless steel, Inconel 600 and SA302B low allow steel at 600°F have been generated from tests using graphs of applied load versus cross-head displacement as automatically plotted by the recorder of the tensile test apparatus. The scale and sensitivity of the test apparatus recorder assure accurate measurement of the uniform strain.

   For other materials, stress-strain curves are developed by conserative use of pertinent available material data (i.e., lowest values of uniform strain and initial strain hardening). Should the available data not be sufficient to develop a reliable stress-strain curve, three standard ASTM tensile tests of the material in question will be performed at design temperature. These data could conservatively apply in developing a stress-strain curve as described above.

2. Normalize the ordinate (stress) of the stress-strain curves to the measured yield strength (Figure 5.2-1).

3. Use 20 percent of the uniform strain as defined on the curve developed under Item 1 as the allowable membrane strain.

4. Establish the normalized stress ratio at 20 percent of uniform strain on the normalized stress ratio-strain curves developed under Item 2.

5. Establish the value of membrane stress limit.

   Multiply the normalized stress ratio in Item 4 by the applicable code yield strength at the design temperature to get the membrane stress limit. As an alternate, the actual physical properties as determined for standard ASTM tensile tests on specimens from the same heats may be used to determine the membrane stress limit. If such an approach is adopted, sufficient documentation will be provided to support the actual material properties used.

6. Develop limit curves for the combination of local membrane and bending stresses.

   The limit curves are developed by using the analytical approach presented in Reference 1 land the stress-strain curve up to the membrane stress limit as developed under Item 5. Stress and stability analysis results are to be compared with these limits.

Examples of design limit curves are developed by using the above procedure are given in Figures 5.2-2 and 5.2-3.

5.2.1.8.2 Stress Analysis for Structural Adequacy

<u>Reactor Vessel</u>

The following components of reactor pressure vessel were analyzed in detail through systematic analytical procedures.

1. Control rod housings
2. Closure head flange and shell

3. Main closure studs
4. Inlet nozzle (and vessel support)
5. Outlet nozzle (and vessel support)
6. Vessel wall transition
7. Core-barrel support pads
8. Bottom head to shell juncture
9. Bottom head instrument penetrations etc.

1. An interaction analysis was performed on the CRDM housing. The flange was assumed to be a ring and the tube a long cylinder. The different values of Young's Modulus and coefficients of thermal expansion of the tubes were taken into account in the analysis. Local flexibility was considered at appropriate locations. The closure headway treated as a perforated spherical shell with modified elastic constants. The effects of redundants on the closure head were assumed to be local only. Using the mechanical and thermal stresses from this analysis, a fatigue evaluation was made for the J weld.

2. The closure head, closure head flange, vessel flange, vessel shell and closure studs were all evaluated in the same analysis. An analytical model was developed by dividing the actual structure into different elements such as sphere, ring, long cylinder and cantilever beam, etc. An interaction analysis was performed to determine the stresses due to mechanical and thermal loads. These stresses were evaluated in light of the strength and fatigue requirements of the ASME Boiler and Pressure Vessel Code Section III.

3. An analysis similar to Item 2 was performed for the vessel flange to vessel shell juncture; and main closure studs.

4. For the analysis of nozzle and nozzle to shell juncture, the loads considered were internal pressure, operating transients, thermally induced and seismic pipe reactions, static weight of vessel,

earthquake loading and expansion and contraction, etc. A combination of methods was used to evaluate the stresses due to mechanical and thermal loads and external loads resulting from seismic pipe reactions, earthquake and pipe break, etc.

For fatigue evaluation, peak stresses resulting from external loads and thermal transients were determined by concentrating the stresses as calculated by the above described methods. Combining these stresses enables the fatigue evaluation to be performed.

5. The method of analysis for outlet nozzle and vessel supports was the same as described above for Item 4.

6. Vessel wall transition was analyzed by means of a standard interaction analysis. The thermal stresses were determined by the skin stress method where it was assumed that the inside surface of the vessel is at the same temperature as the reactor coolant and the mean temperature of the shell remains at the steady state temperature. This method is considered conservative.

7. Thermal, mechanical and pressure stresses were calculated at various locations on the pad and at the vessel wall. Mechanical stresses were calculated by the flexure formula for bending stress in a beam. Pressure stresses were taken from the analysis of the vessel to bottom head juncture and thermal stresses were determined by the conservative method of skin stresses. The stresses due to the cyclic loads were multiplied by a stress concentration factor where applicable and used in the fatigue evaluation.

8. Standard interaction analysis and skin stress methods were employed to evaluate the stresses due to mechanical and thermal stresses respectively. The fatigue evaluation was made on cumulative basis where superposition of all transients was taken into consideration.

9. An interaction analysis was performed by dividing the actual structure into an analytical model composed of different structural elements. The effects of the redundants on the bottom head were assumed to be local only. It was also assumed that for any condition where there is interference between the tube and the head no bendings at the weld can exist. Using the mechanical and thermal stresses from this analysis a fatigue evaluation was made for the J weld.

The location and geometry of the areas of discontinuity and/or stress concentration are shown in Figures 5.2-4, 5.2-5, and 5.2-6.

A summary of the estimated primary plus secondary stress intensity for components of the reactor vessel and the estimated cumulative fatigue usage factors for the components of the reactor vessel is given in Tables 5.1-14 and 5.2-15.

The cycles specified for the fatigue analysis are the results of an evaluation of the expected plant operation coupled with experience from nuclear power plants then in service, such as Yankee-Rowe.

The conservatism of the design fatigue curves used in the fatigue analysis has been demonstrated by the Pressure Vessel Research Committee (PVRC) in a series of cyclic pressurization tests of model vessels fabricated to the Code. The results of the PVRC tests showed that no crack initiation was detected at any stress level below the code allowable fatigue curve and that no crack progressed through a vessel wall in less than three times the allowable number of cycles. Similarly fatigue tests have been performed on irradiated pressure vessel steels with comparable results (Reference 2).

The vessel design pressure is 2485 psig while the normal operating pressure will be 2235 psig. The resulting operating membrane stress is therefore amply below the code allowable membrane stress to account for operating pressure transients.

The stress allowed in the vessel in relation to operation below NDT temperature and DTT (NDT temperature plus 60°F) to preclude the possibility of brittle failure are:

1. At DTT, a maximum stress of 20 percent yield

2. From DTT to DTT minus 200°F; a maximum stress decreasing from 20 to 10 percent yield

3. Below DTT minus 200°F; a maximum stress of 10 percent yield

These limits are based on a conservative interpretation of the Fracture Analysis Diagram developed at the Naval Research Laboratory (References 3, 4 and 5) after many years of research and confirmed by extensive correlations with service failures. There have been no known service failures under conditions permitted by these limits. The Fracture Analysis Diagram is the most widely known and generally accepted criterion for brittle fracture prevention and includes linear elastic fracture mechanics concepts. The limits established by the Fracture Analysis Diagram have been correlated with linear elastic fracture mechanics insofar as possible, (Reference 6) and are conservative in providing protection against brittle fractures. The stress limits are maintained by operating procedures which prescribe pressure and temperature control limits during heatup and cooldown as described in Reference 7.

The actual shift in NDT temperature is established periodically during plant life by testing of vessel material samples which are irradiated cumulatively by securing them near the inside wall of the vessel in the core area. To compensate for any increase in the NDT temperature caused by irradiation, the pressure-temperature limits are periodically changed to stay within the stress limits.

The vessel closure contains fifty-four 7-inch studs. The stud material is ASTM A-540 which has a minimum yeild strength of 104,400 psi at design temperature. The membrane stress in the studs when they are at the steady state operational condition is less than half this value. This means that about half of the fifty-four studs have the capability of withstanding the hydrostatic end load on vessel head without the membrane stress exceeding yield strength of the stud material at design temperature.

In establishing the temperature-pressure limits, emphasis is placed on heatup and cooldown because the normal operating temperature always exceeds even the highest anticipated DTT during the life of the plant. Conservatism is emphasized during heatup and cooldown because long term irradiation of the vessel raises the DTT and thereby limits the heatup or cooldown rates. The following conservative limits are applied:

1. Use of a stress concentration factor of 4 on assumed flaws in calculating the stress.

2. Use of nominal yield of material instead of actual yield.

3. Neglecting the increase in yield strength resulting from radiation effects.

The factor of four is not an actual stress concentration factor such as described in Article 4 Design of Section III but is a margin of conservatism based on the Fracture Analysis Diagram in ASTM E-208 as well as the stress limits maintained by the prescribed operating procedures which rely upon administrative pressure and temperature control during heatup and cooldown.[6] At the DTT, the stress are 20 percent of the yield strength versus a prescribed upper limit of 80 percent of the yield strength; therefore, at this point there is a margin of four (80/20).

Since the Fracture Analysis Diagram is based on a plot of nominal stress versus temperature and different size flaws (cracks) are assumed, the use of actual stress concentration factor do not apply.

As part of the plant operator training program, supervisory and operating personnel were instructed in reactor vessel design, fabrication and testing, as well as precautions necessary for pressure testing and operating modes. The need for record keeping was stressed, such records being helpful for future summation of time at power level and temperature which tends to influence the irradiated properties of the material in the core region. These items are incorporated in the operating instructions.

Piping

The analysis of the reactor coolant loop/supports system is described in Section 3.9.

Steam Generators

Calculations confirm that the steam generator tube sheet will withstand the loading (which is quasi-static rather than a shock loading) caused by loss of reactor coolant. The maximum primary membrane plus primary bending stress in the tube sheet under these conditions is 23,853 psi. This is well below ASME Section III yield strength of 41,112 psi at 660°F. Because the pressure in the primary channel head would drop to zero under the condition postulated, no damage will result to the channel head.

The rupture of primary or secondary piping was assumed to impose a maximum pressure differential of 2485 psi across the tubes and tube sheet from the primary side or a maximum pressure differential of 1100 psi across the tubes and tube sheet from the secondary side, respectively. Under these conditions there is no rupture of the primary to secondary boundary, including tubes and tube sheet. This criterion prevents any violation of the containment boundary.

To meet this criterion, it was established that under the postulated accident conditions, where a primary to secondary side differential pressure of 2250 psia exists, the primary membrane stresses in the tube sheet ligaments, averaged across the ligament and through the tube sheet thickness, do not exceed 90 percent of the material yield stress at the operating temperature.

A complete tube sheet analysis was performed to verify the structural integrity of the primary-secondary boundary under blowdown plus seismic conditions.

Also, the primary membrane plus primary bending stress in the tube sheet ligaments, averaged across the ligament width at the tube sheet surface location giving maximum stress, do not exceed 135 percent of the material yield stress at the operating temperature. This criterion is felt to be applicable to abnormal operating circumstances in that it is consistent with the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels, Paragraph N-712 for hydrotest criteria. The stresses and stress factors in the actual design tube sheet, obtained by using the above stress criteria, are given in Table 5.2-16.

The tubes were designed to the requirements (including stress limitations) of Section III for normal operation, assuming 2485 psig as the normal operating pressure differential. Hence, the secondary pressure loss accident condition imposes no extraordinary stress on the tubes beyond that normally expected and considered in Section III requirements.

No significant corrosion of the Inconel tubing is expected during the life-time of the unit. The corrosion rates reported by Berry and Fink (Reference 8) show a "worst case" rate of 15.9 mg/dm^2 in the 2000-hour test under steam generator operating conditions. Conversion of this rate to a 40 year plant life gives a corrosion loss of 1.3 x 10^{-3} inches which is insignificant compared to the nominal tube wall thickness of 0.050 inch.

Analysis of the collapse pressure of the 7/8-.045 (minimum wall) Inconel steam generator tubes according to methods of Strum and O'Brian (Reference 9) and Bergman (Reference 10) reflected in the pressure design charts for external pressure in Article I-11 of the ASME Boiler and Pressure Vessel Code Section III for Nuclear Vessels indicated a collapse pressure of 2310 psi for tubes having the minimum properties required by the ASTM specification for this material. This indicates a minimum factor of safety of 1.92 against collapse for minimum property straight circular tubes under application of secondary shall design external pressure in the absence of primary pressure at design operating temperature.

Collapse tests of 7/8-.050 wall straight tubes at room temperature indicate actual tube strengths are significantly higher than ASTM minimum specification. As a consequence, collapse pressures in excess of 6000 psi were recorded for the straight circular tubes, whereas analytic consideration according to aforementioned References 9 and 10 would indicate a room temperature collapse pressure of 2740 psi.

Collapse test of U-bend specimens have indicated a compensative effect of ovality due to the bending process and the increased collapse resistance due to the curvature of the toroidal form of the U-bend. The effect of ovality on straight tubes indicated a reduction in collapse pressure from over 6000 psi to 3600 psi at the maximum permitted ovality of 5 percent.

Conservatively using straight tube collapse test data corrected to design temperature for actual tube material properties, emperical relationships indicated a collapse pressure ranging from 5230 psi for perfectly circular tubes to 3040 psi for tubes having 5 percent ovality. This indicates a minimum safety factor variation of from 4.41 to 2.56 respectively (not considerang the increase due to the toroidal shape in the U-bend region).

Consideration was given to the superimposed effects of secondary side pressure loss and the design basis earthquake loading. The fluid dynamic forces on the internal components affecting the primary-secondary boundary (tubes) were considered as well. For this condition, the criterion is that no rupture of primary to secondary boundary (tubes and tube sheet) occurs.

For the case of the tube sheet, the design basis earthquake loading will contribute an equivalent static pressure loading over the tube sheet of less than 10 psi (for vertical shock). Such an increase is small when compared to the pressure differentials (up to 2485 psig) for which the tube sheet is designed. Under horizontal shock loading of the design basis earthquake the stresses are less than those for 1.0g gravity loading experienced in a horizontal position, which the design can readily accept.

The fluid dynamic forces on the internals under secondary steam break accident conditions indicated, in the most severe case, that the tubes are adequate to constrain the motion of the baffle plates with some plastic deformation, while boundary integrity is maintained.

The ratio of the allowable stresses on various components (based on an allowable membrane stress of 0.9 of the nominal yield stress of the material) to the computed stresses for a primary to secondary pressure differential of 2485 psi are summarized in Table 5.2-17.

Evaluation of the steam generator tube sheets was performed according to rules of the ASME Boiler and Pressure Vessel Code for Nuclear Vessels, Section III, Article 4 - Design. The design criteria considered encompassed consideration of both steady state, transient and emergency operations specified in the Equipment Specification. Due to the complex nature of the tube-tubesheet-shell-head structure, the analysis of the tubesheet required the application of results of related research programs (such as the design data on perforated plates resulting from PVRC programs) and the utilization of current techniques in computer analysis, the application of which was verified by comparison of analytical and experimental results for related equipment.

Examination of the introductory paragraph I-900 of the ASME Boiler and Pressure Vessel Code, Section III - Nuclear Vessels, reveals that consideration may be given to the stiffening effect of tubes in perforations, the staying action of the tubes if applicable, and the effect of stiffening on the plate stress levels, etc. Furthermore, it is noted that the stress analysis methods in Appendix I of Section III are described as accepted techniques for obtaining solutions to problems for which these procedures are applicable. It allows and requires use of other valid analytical or experimental techniques where necessary.

Although the Nuclear Pressure Vessel Code Article I-9 provides for rules and techniques in analysis of perforated plates, it is noted that the stress intensity levels for perforated plate are given for triangular performation arrays. Westinghouse tube sheets contain square hole arrays. Hence, Westinghouse utilizes its own data and that obtained from PVRC research in square array perforation patterns for development of similar charts for stress intensity factors and elastic constants. The resulting stress intensity levels and fatigue stress ranges are evaluated according to the stress limitation of the Code.

The Westinghouse analysis of the steam generator tube sheets was included as part of the Stress Report requirement for Class A Nuclear pressure vessels. The evaluation was based on the stress and fatigue limitations outlined in Article 4 Design of Section III. The stress analysis techniques utilized included all factors considered appropriate to conservative determination of the stress levels utilized in evaluation of the tube sheet complex. The analysis of the tube sheet complex included the effect of all appurtenances attached to the perforated region of the tube sheet considered appropriate to conservative analysis of stress for evaluation on basis of Section III stress limitations. The evaluation involved the heat conduction and stress analysis of the tube sheet, channel head, secondary shell structure for particular steady design conditions for which Code stress limitations were to be satisfied and for discrete points during transient operation for which the temperature/pressure conditions must be known to evaluate stress maxim and minima for fatigue life usage. In addition, limit analyses were performed to determine tube sheet capability to sustain emergency operating conditions for which elastic analysis does not suffice. The analytic techniques utilized were computerized and significant stress problems were verified experimentally to justify the techniques where possible.

Generally, the analytic treatment of the tube-tube sheet complex included determination of elastic equivalent plate stress within the perforated region from an interaction anlaysis utilizing effective elastic constants appropriate to the nature of the perforation array. For the perforated region of the tube sheet, the flexural rigidity was based on studies of behavior of plates with square hole arrays utilizing techniques such as those reported by O'Donnell (Reference 11), Mahoney (Reference 12), Lemcoe (Reference 13), and others. Similarly, stress intensity factors were determined for square hole arrays using the combined equivalent plate interaction forces and moments applied to results of photo-elastic tests of model coupons of such arrays as well as verification using computer analysis techniques such as "point Matching" or "Collocation". The stress analysis considered stress due to symmetric temperature and pressure distribution as well as asymmetric temperature distribution due to temperature drop across the tube sheet divider lane.

The fatigue analysis of the complex was performed at potentially critical regions in the complex such as the junction between tube sheet and channel head or secondary shell as well as at many locations throughout the perforated region of the tube sheet. For the holes for which fatigue evaluation was done, several points around the hole periphery were considered to assure that the maximum stess excursion has been considered. The fatigue evaluation was computerized to include stress maxima-minima excursions considered on the intra-transient basis.

The evaluation of the tube-to-tube sheet juncture was based on a stress analysis of the interaction between tube and tube sheet hole for the significant thermal and pressure transients that are applied to the steam generator in its predicted histogram of cyclic operation. The evaluation was based on the numberical limits specified in the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels.

Of importance in the analysis of the interaction system is the behavior of the tube hole, where it is recognized that the hole behavior is a function of the behavior of the entire tube sheet complex with attached head and shell. Hence, the output of the tube sheet analysis giving equivalent plate stresses in the perforated region was utilized in determining the free boundary displacements of the performation to which the tube is attached.

Analysis of the juncture for the fillet-type weld was made with consideration of the effect of the rolled-in joint in the weld region as well as with the conservative assumption that the tube flexure relative to the perforation is not inhibited with the rolled-in effect.

The major concern in fatigue evaluation of the tube weld was the fatigue strength reduction factor to be assigned to the weld root notch. For this reason, Westinghouse conducted low-cycle fatigue tests of tube material samples to determine the fatigue strength reduction factor and applied them to the analytic interaction analysis results in accordance with the accepted techniques in the Nuclear Pressure Vessel Code for Experimental Stress Analysis. The fatigue strength reduction factor determined therefrom was not different from that reported in the well known paper on the subject by O'Donnell and Purdy (Reference 14). An actual tube sheet joint contained in a tube sheet was successfully tested under thermal transient conditions much more severe than that achieved in anticipated power plant operation.

A wide range of computational tools were utilized in these solutions including finite element, heat conduction and thin shell computer solutions. In addition, analysis techniques were verified by photo-elastic model tests and strain gaging of prototype models of an actual steam generator tube sheet.

Finally, in order to evaluate the ultimate safety of structural complex, a computer program for determining a lower-bound pressure limit for the complex based on elastic-plastic analysis was developed and applied to the structure. This was verified by a strain gage steel model of the complex tested to failure.

In all cases evaluated, the steam generator tube sheet complex met the stress limitations and fatigue criteria specified in Article 4 of the Code as well as emergency condition limitations specified in the Equipment Specifications.

In this way, the tube-tube sheet integrity was demonstrated under the most adverse conditions resulting from a major breach in either the primary or secondary system piping.

Tabulations of significant results of the tube sheet complex are in Tables 5.2-18 through 5.2-25 and Figures 5.2-7 through 5.2-9. Figure 5.2-10 denotes the primary-secondary boundary components shell locations.

Pressurizer

The pressurizer was analyzed for fatigue conditions in accordance with Section III of the ASME Boiler and Pressure Vessel Code using the thermal and pressure transient conditions listed elsewhere in this Section.

The pressurizer vessel was analyzed for the following loading conditions:

1. Normal operation loadings which included:

   a. Weight of water based on the vessel filled with cold water, and including insulation.

   b. Normal loadings exerted by connecting piping.

2. Sesimic loadings which included:

   a. For the operation basis earthquake (OBE), the pressurizer vessel is designed to resist earthquake loadings simultaneously in the horizontal and vertical directions and to transmit such loadings through the vessel supports to the foundation. The OBE results in mechanical loadings and their combination with the normal operational loads is to be considered an lupset condition. The components of loadings exerted by the external piping due to the OBE were included in this evaluation.

   b. For the design basis earthquake (DBE), pressurizer vessel function is not impaired so as to prevent a safe and orderly shutdown of the reactor plant when the DBE loadings both horizontal and vertical acting simultaneiously are imposed on the vessel. These loadings and the centers of gravity involved were determined on the basis of the vessel at normal operating pressure, temperature and water level.

The DBE was considered a faulted condition with the following exceptions:

1. The combination of all primary stress intensities in the vessel support skirt was required to be within the support skirt material yield strength specified in Section III of the ASME Boiler and Pressure Vessel Code.

2. The stress intensity limits of the vessel associated with the DBE in combination with the normal operational were as follows:

   $Pm \leq 1.2$ Sm or tabulated yield (Sy) whichever is greater
   $Pl + Pb \leq 1.8$ Sm or 1.5 Sy whichever is greater

The components of loadings exerted by the external piping due to the DBE were included in this evaluation.

3. The pressurizer vessel, nozzles and vessel supports were designed to resist pipe break loadings in combination with the normal operational loads. The moment and forces were considered as acting in combination with each force separately. The pipe break accident was considered to be a faulted condition with the exception of the stress intensity limits being those specified under the DBE condition.

4. The pressurizer vessel, nozzles land vessel supports were analyzed for the combination of normal operating loads plus the DBE loads plus the pipe break loads. The resulting stress intensities did not

exceed the stress intensity limits of Paragraph N17.11 (faulted conditions) in Section III of the Code with the following exception. The combination of all primary stress intensities in the vessel supports were within the support material yield strength specified in the Code. If necessary, higher stress intensitity values are adopted in the vessel supports where plastic instability analyses of the support and supported component system are performed in accordance with paragraph N 417.11 of ASME Code Section III.

A plastic instability analysis of the support and supported system was not needed since the adequacy was proved by elastic analysis.

Reactor Coolant Pump

All the pressure bearing parts of the reactor coolant pump were analyzed in accordance with Article 4 of the ASME Code, Section III. This included the casing, the main flange and the main flange bolts. The analysis included pressure, thermal and cyclic stresses, and these were compared with the allowable stresses in the code.

Mathematical methods of the reactor coolant pump parts were prepared and used in the analysis which proceeded in two phases.

1. In the first phase, the design was checked against the design criteria of the ASME Code with pressure stress calculations, although thermal effects were included implicitly with the experience factors. By this procedure, the shells were profiled to attain optimum metal distribution with stress levels adequate to meet the more limiting requirements of the second phase.

2. In the second phase the interactive forces needed to maintain geometric capability between the various components were determined at design pressure and temperature and applied to the components along with the external loads to determine the final stress state of

the components. There were finally compared with the Code allowable values.

There were no other sections of the Code which were specified as areas of compliance, but where Code methods, allowable stresses, fabrication methods, etc., were applicable to a particular component, these were used to give a rigorous anlaysis and conservative design.

5.2.2 OVERPRESSURIZATION PROTECTION

5.2.2.1 Pressure-Relieving Devices

The RCS is protected against overpressure by control and protective circuits such as the high pressure trip and by relief and safety valves connected to the top head of the pressurizer. The relief and safety valves discharge into the pressurizer relief tank which condenses and collects the valve effluent. The safety valves are sized to prevent system pressure from exceeding the design pressure by more than 10 percent, in accordance with Section III of the ASME Boiler and Pressure Vessel Code. Their capacity is determined from considerations of the reactor protective system and accident or transient conditions which may potentially cause overpressure.

The combined capacity of the safety valves is equal to or greater than the maximum surge rate resulting from complete loss of load without a direct reactor trip or any other control, except that the safety valves on the secondary plant are assumed to open when the steam pressure reaches the secondary plant safety valve setting. Safety and relief valve design parameters are shown in Table 5.2-8.

5.2.2.2 Report on Overpressure Protection

The "Report on Overpressure Protection" is not a part of the Code requirement for the Salem plant. Applicable codes for this plant are:

1. Unit 1 - ASME Section III, Winter 1965 Addendum
2. Unit 2 - ASME Section III, Winter 1966 Addendum

However, the overpressure protection capability of Westinghouse PWR's, including Salem, is discussed in Reference 21.

5.2.2.3 RCS Pressure Control During Low Temperature Operation

Refer to Chapter 7 for a discussion of the overpressure protection system for low temperature operation.

5.2.3 GENERAL MATERIAL CONSIDERATIONS

Table 5.2-26 summarizes the quality assurance program with regard to inspections performed on RCS components. In addition to the inspections shown in Table 5.2-26, there were those which the equipment supplier performed to confirm the adequacy of material received and those performed by the material manufacturer in producing the basic material. The inspections of reactor vessel, pressurizer, and steam generator were governed by ASME Code requirements. The inspection procedures and acceptance standards required on pipe materials and piping fabrication were governed by USAS B31.1 and Westinghouse requirements and are equivalent to those performed on ASME coded vessels.

Procedures for performing the examinations were consistent with those established in the ASME Code Section III and were reviewed by qualified engineers. These procedures have been developed to provide the highest assurance of quality material and fabrication. They consider not only the size of the flaws, but equally as important, how the material was fabricated, the orientation and type of possible flaws, and the areas of most severe service conditions. In addition, the accessible external surfaces of the primary RCS pressure containing segments receive a 100 percent surface inspection by magnetic particle or liquid penetrant testing after hydrostatic test. All reactor vessel plate material was subjected to angle beam gas well as straight beam ultrasonic testing to give maximum assurance of quality. All reactor vessel forgings received the same inspection. In addition, 100 percent of the material volume was covered in these tests as an added assurance over the grid basis required in the Code.

Quality control engineers monitored the supplier's work, witnessing key inspections not only in the supplier's shop but in the shops of sub-vendors of the major forgings and plate material. Normal surveillance included verification of records of material, physical and chemical properties, review of radiographs, performance of required tests, and qualification of supplier personnel.

Section III of the ASME Code requires that nozzles carrying significant external loads are attached to the shell by full penetration welds. This requirement was carried out in the reactor coolant piping, where all auxiliary pipe connections to the reactor coolant loop were made using full penetration welds.

The RCS components were welded under procedures which required the use of both preheat and post-heat. Preheat requirements, not mandatory under Code rules, were performed on all weldments including P1 and P3 materials which are the materials of construction in the reactor vessel, pressurizer and steam generators. Preheat and post-heat of weldments both served a common purpose: the production of tough, ductile metallurgical structures in the completed weldment. Preheating produces tough ductile welds by minimizing the formation of hard zones whereas postheating achieves this by tempering any hard zones which may have formed due to rapid cooling.

5.2.3.1 Material Specifications

Each of the materials used in the RCS is selected for the expected environment and service conditions. The major component materials are listed in Table 5.2-27.

All RCS materials which are exposed to the coolant are corrosion-resistant. They consist of stainless steels and Inconel, and they were chosen for specific purposes at various locations within the system for their superior compatibility with the reactor coolant. The chemical composition of the reactor coolant is maintained within the specification given in Table 5.2-28. Reactor coolant chemistry is further discussed in Section 5.2.3.4.

5.2.3.2 Compatibility with Reactor Coolant

The water in the secondary side of the steam generators is held within the chemistry specification given in Table 5.2-29 to control deposits and corrosion inside the steam generators. Further detail on secondary side chemistry control is provided in Chapter 10.

The phenomena of stress-corrosion cracking and corrosion fatigue are not generally encountered unless a specific combination of conditions is present. The necessary conditions are a susceptible alloy, an aggressive environment, stress, and time.

It is a characteristic of stress corrosion that combinations of alloy and environment which result in cracking are usually quite specific. Environments which have been shown to cause stress-corrosion cracking of stainless steels are free of alkalinity in the presence of chlorides, fluorides and free oxygen. However, the reactor coolant chemistry is controlled to avoid the occurrence of these species in any significant contribution. The steam generator contains Inconel tubes. Testing to investigate the susceptibility of heat exchanger construction materials to stress corrosion in caustic and chloride aqueous solutions has indicated that Inconel alloy has excellent resistance to general and pitting-type corrosion in severe operating water conditions. Extensive operating experience with Inconel units has confirmed this conclusion.

5.2.3.3 Compatibility With External Insulation

All external insulation of RCS components is compatible with the component materials. The cylindrical shell exterior and closure flanges and bottom head of the reactor vessel are insulated with stainless steel metallic reflective insulation. The closure head is insulated with stainless metallic reflective insulation. All other external corrosion-resistant surfaces in the RCS are insulated with low or halide-free insulating material as required.

5.2.3.4 Chemistry of Reactor Coolant

The water chemistry is selected to provide the necessary boron content for reactivity control and to minimize corrosion of RCS surfaces.

Periodic analysis of the coolant chemical composition is performed to monitor the adherence of the system to the reactor coolant water quality listed in Table 5.2-28. Maintenance of the water quality to minimize corrosion is accomplished using the chemical and volume control system (CVCS) and sampling system which are described in Chapter 9.

5.2.3.5 Electoslag Weld Quality Assurance

The Salem 90° elbows were electroslag welded. The following efforts were performed for quality assurance of these components.

1. The electroslag welding procedure employing one wire techniques was qualified in accordance with the requirements of ASME Boiler and Pressure Vessel Code Section IX and Code Case 1355 plus supplementary evaluations as requested by Westinghouse. The following test specimens were removed from a 5 inch thick weldment and successfully tested:

a. 6 transverse tensile bars - as welded

b. 6 transverse tensile bars - 2050°F, H_2O quench

c. 6 transverse tensile bars - 2050°F, H_2O quench + 750°F stress relief heat treatment

d. 6 transverse tensile bars - 2050°F H_2O quench, tested at 650°F

e. 12 guided side bend test bars

2. The casting segments were surface conditioned for 100 percent radiographic and penetrant inspections. The acceptance standards were ASTM E-186 severity level 2 except no category D or E defectiveness was permitted and USAS Code Case N-10, respectively.

3. The edges of the electroslag weld preparations were machined. These surfaces were penetrant inspected prior to welding. The acceptance standards were USAS Code Case N-10.

4. The completed electroslag weld surfaces were ground flush with the casting surface. Then, the electroslag weld and adjacent base material were 100 percent radiographed in accordance with ASME Code Case 1355. Also, the electroslag weld surfaces and adjacent base material were penetrant inspected in accordance with USAS Code Case N-10.

5. Weld metal and base metal chemical and physical analysis were determined and certified.

6. Heat treatment furnace charts were recorded and certified.

The Salem reactor coolant pumps casings were electroslag welded. The following efforts were performed for quality assurance of the components.

The electroslag welding procedure employing two and three wire techniques was qualified in accordance with the requirements of the ASME Boiler and Pressure Vessel Code Section IX and Code Case 1355 plus supplementary evaluations as requested by Westinghouse. The following test specimens were removed from an 8 inch thick and from a 12 inch thick weldment and successfully tested for both the 2 wire and the 3 wire techniques, respectively:

1. Two wire electroslag process - 8" thick weldment

   a. 6 transverse tensile bars - 750°F post weld stress relief
   b. 12 guided side bend test bars

2. Three wire electroslag process - 12 inch thick weldment

   a. 6 transverse tensile bars - 750°F post weld stress relief
   b. 17 guided side bend test bars
   c. 21 charpy vee notch specimens
   d. Full section macroexamination of weld and heat affected zone
   e. Numerous microscopic examinations of specimens removed from the weld and heat affected zone regions
   f. Hardness survey across weld and heat affected zone

3. A separate weld test was made using the 2 wire electroslag technique to evaluate the effects of a stop and restart of welding by this process. This evaluation was performed to establish proper procedures and techniques as such an occurrence was anticipated during production applications due to equipment malfunction, power outages, etc. The following test specimens were removed from an 8 inch thick weldment in the stop-re-start-repaired region and successfully tested:

   a. 2 transverse tensile bars - as welded
   b. 4 guided side bend test bars
   c. Full section macroexamination of weld and heat affected zone.

4. All of the weld test blocks in Items 1, 2, and 3 above were radiographed using a 24 Mev Betatron. The radiographic quality level as defined by ASTM E-94 obtained was between one-half of 1 percent to 1 percent. There were no discontinuities evident in any of the electroslag welds.

   a. The casting segments were surface conditioned for 100 percent radiographic and penetrant inspections. The radiographic acceptance standards were ASTM E-186 severity level 2 except no category D or E defectiveness was permitted for section thickness up to 4-1/2 inches and ASTM E-280 severity level 2 for section thicknesses greater than 4-1/2 inches. The penetrant acceptance standards were ASME Boiler and Pressure Vessel Code Section III, paragraph N-627.

   b. The edges of the electroslag weld preparations were machined. These surfaces were penetrant inspected prior to welding. The acceptance standards were ASME Boiler and Pressure Vessel Code Section III, paragraph N-627.

   c. The completed electroslag weld surfaces were ground flush with the casting surface. Then, the electroslag weld and adjacent base material were 100 percent radiographed in accordance with ASME Code Case 1355. Also, the electroslag weld surfaces and adjacent base material were penetrant inspected in accordance with ASME Boiler and Pressure Vessel Code Section III, paragraph N-627.

   d. Weld metal and base metal chemical and physical analyses were determined and certified.

   e. Heat treatment furnace charts were recorded and certified

5.2.4 FRACTURE TOUGHNESS

5.2.4.1 Compliance with Code Requirements

Assurance of adequate fracture toughness of the RCS is provided by compliance with the requirements for fracture toughness testing included in the Summer 1972 Addenda to Section III of the ASME Boiler and Pressure Vessel Code, implemented by the Code Case 1514.

5.2.4.2 Acceptable Fracture Energy Levels

Allowable pressures as a function of the rate of temperature change and the actual temperature relative to the vessel RT_{NDT} will be established according to the methods given in Appendix G 2000, Protection Against Non Brittle Failure, published in the Summer 1972 Addenda of Section III of the ASME Boiler and Pressure Vessel Code, covered by Code Case 1514. Typical curves incorporating allowances for instrument error in measurement of temperature and pressure are given in Figures 5.2-11 and 5.2-12.

The results of the radiation surveillance program will be used to verify that the ΔRT_{NDT} predicted from Figure 5.2-13 is appropriate, and to make any changes necessary to correct Figure 5.2-13.

The use of an RT_{NDT} that includes a ΔRT_{NDT} to account for radiation effects on the core region material, automatically provides additional conservatism for the non-irradiated regions. Therefore, the flanges, nozzles and other regions not affected by radiation will be favored by additional conservatism approximately equal to the assumed ΔRT_{NDT}.

5.2.4.3 Operating Limitations During Starting and Shutdown

Operating limits for the RCS with respect to heatup and cooldown rates are defined in the Technical Specifications.

The heatup and cooldown curves for the plant are based on the actual measured fracture toughness properties of the vessel materials, determined in accordance with the above mentioned new fracture toughness requirements.

5.2.4.3.1 Maximum Heating and Cooling Rates

The RCS operating cycles used for design purposes are given in Table 5.2-10 and described in Section 5.2.1.5. The normal system heating and cooling rate is 50°F per hour. Sufficient electrical heaters are installed in the pressurizer to permit a heatup rate, starting with a minimum water level of 55°F per hour. This rate takes into account the small continuous spray flow provided to maintain the pressurizer liquid homogeneous with the coolant.

5.2.4.3.2 Maximum Pressure

The RCS serves as a barrier preventing radionuclides contained in the reactor coolant from reaching the atmosphere. In the event of a fuel cladding failure the RCS is the primary barrier against the uncontrolled release of fission products. By establishing a system pressure limit, the continued integrity of the RCS is assured. Thus, the safety limit of 2735 psig (110 percent of design pressure) has been established. This represents the maximum transient pressure allowable in the RCS under the ASME Code, Section III. RCS pressure settings are given in Table 5.2-1.

5.2.4.3.3 System Minimum Operating Conditions

Minimum operating conditions for the RCS for all phases of operation are given in the Technical Specifications.

5.2.4.4 Compliance with Reactor Vessel Material Surveillance Program Requirements

In the surveillance program, the evaluation of the radiation damage is based on pre-irradiation testing of Charpy V-notch and tensile specimens and post-irradiation testing of Charpy V-notch, tensile, and wedge opening loading (WOL) fracture mechanics test specimens. These programs are directed toward evaluation of the effect of radiation on the fracture toughness of reactor vessel steels based on the transition temperature approach and the fracture mechanics approach, and is in accordance with ASTM-E-185-70, "Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels." The surveillance program does not include thermal control specimens. These specimens are not required since the surveillance specimens will be exposed to the combined neutron irradiation and temperature effects and the test results will provide the maximum transition temperature shift. Thermal control specimens are considered in ASTM-E-185-70 would not provide any additional information on which the operational limits for the reactor vessel are set.

The reactor vessel surveillance program uses eight specimen capsules. The capsules are located about 3 inches from the vessel wall directly opposite the center portion of the core. Sketches of an elevation and plan view showing the location and dimensional spacing of the capsules with relation to the core, thermal shield and vessel and weld seams are shown in Figures 5.2-14 and 5.2-15 respectively. The capsules can be removed when the vessel head is removed, and can be replaced when the internals are removed. The capsules contain reactor vessel steel specimens from the limiting shell plate or plates located in the core region of the reactor and associated weld metal and heat affected zone metal. (As part of the surveillance program, a report of the residual elements in weight percent to the nearest 0.01 percent will be made for surveillance material base metals and as deposited weld metal.) In addition, correlation monitors made from full documented specimens of SA-533 Grade B Class 1 material obtained through Subcommittee II of ASTM Committee

E10, Radioisotopes and Radiation Effects, are inserted in the capsules of Unit 1 only. The eight capsules contain tensile specimens, Charpy V-notch specimens (which include weld metal and heat affected zone material) and WOL specimens. Dosimeters including Ni, Cu, Fe (Unit 2 only) Co-Al, Cd shielded Co-Al, Cd shielded Np-237 and Cd shielded U-238 are placed in filler blocks drilled to contain the dosimeters. The dosimeters permit evaluation of the flux seen by the specimens and vessel wall. In addition, thermal monitors made of low melting alloys are included to monitor temperature of the specimens. The specimens are enclosed in a tight fitting stainless steel sheath to prevent corrosion and ensure good thermal conductivity. The complete capsule is helium leak tested. Vessel material sufficient for at least 2 capsules will be kept in storage should the need arise for additional replacement test capsules in the program.

Each of three capsules (S, V and Y) for Unit 1 contain the following specimens:

Material	No. Charpy	No. Tensile	No. WOL
Plate	8	2	2
Weld Metal	8	8	2
Heat Affected Zone Metal	8	-	-
ASTM Reference	8	-	-

Note: Each capsule contains baseplate material from a different plate.

Capsule S - Plate 1

Capsule V - Plate 2

Capsule Y - Plate 3

Dosimeters:

Pure Cu
Pure Ni
CoAl (0.15 percent Co)
CoAl (Cadmium Shielded)
U-238 (Cadmium Shielded)
Np-237 (Cadmium Shielded)

Thermal Monitors:

97.5 percent Pb, 2.5 percent Ag (579°F MP)
97.5 percent Pb, 1.75 percent Ag, 0.75 percent Sn (590°F MP)
(MP = Melting Point)

Each of five additional capsules (T, U, W, X, and Z) for Unit 1 contain the following specimens:

Material	No. Charpy	No. Tensile	No. WOL
Plate No. 1	8	1	2
Plate No. 2	8	1	2
Plate No. 3	8	1	2
ASTM Reference	8	-	-

Dosimeters:

Pure Cu
Pure Ni
CoAl (0.15 percent Co)
CoAl (Cadmium Shielded)

Thermal Monitors:

97.5 percent Pb, 2.5 percent Ag (579°F MP)

97.5 percent Pb, 1.75 percent Ag, 0.75 percent Sn (590°F MP)

Each of four capsules S, V, W and X for Unit 2 contains the following specimens:

Material	No. Charpy	No. Tensile	No. WOL
Limiting Plate*	8	-	-
Limiting Plate**	12	2	4
Weld Metal	12	2	-
Heat Affected Zone Metal	12	-	-

Each of four additional capsules (T, U, Y and Z) for Unit 2 contains the following specimens:

Material	No. Charpy	No. Tensile	No. WOL
Limiting Plate*	8	-	-
Limiting Plate**	12	2	-
Weld Metal	12	2	4
Heat Affected Zone Metal	12	-	-

*Specimens oriented parallel to the principal rolling direction.
**Specimens oriented normal (transverse) to the principal rolling direction.

Dosimeters:

Pure Cu
Pure Fe
Pure Ni
CoAl (0.15 percent Co)
CoAl (Cadmium shielded)
U-238 (Cadmium shielded)
NP-237 (Cadmium shielded)

Thermal Monitors

97.5 percent Pb, 2.5 percent Ag (579°F MP)
97.5 percent Pb, 1.75 percent Ag, 0.75 percent Sn (590°F MP)

The fast neutron exposure of the specimens occurs at a faster rate than that experienced by the adjacent vessel. Since these specimens experience accelerated exposure and are actual samples from the materials used in the vessel, the nil ductility transition temperature (NDTT) measurements are representataive of the vessel at a later time in life. Data from fracture toughness samples (WOL) are expected to provide additional information for use in determining allowable stresses for irradiated material.

The calculated maximuim fast neutron exposure (E > 1 Mev) at the vessel wall is computed to be 2.8 x 10^{19} n/cm^2 for Unit 1 and 2.9 x 10^{19} n/cm^2 for Unit 2 for 40 years operation at 3250 MWt at 70 percent load factor. The reactor vessel surveillance capsules are located at 4° and 40° as shown in Figure 5.2-15. The relative exposures of the capsules and the adjacent vessel wall, and the vessel maximum are listed below:

Capsules at Unit 1	Unit 2	Lead Adjacent Vessel Wall by Multiplying Factor of:	Lead Vessel Maximum by a Multiplying Factor of:
4° (V, X, U and W)	(S, V, W and Z)	2.6	0.6
40° (S, Y, T and Z)	(T, U, X and Y)	2.7	2.6

Correlations between the calculations and the measurements on the irradiated samples in the capsules, assuming the same neutron spectrum at the samples and the vessel inner wall, are described in Section 5.4.3 and have indicated good agreement. The calculation of the integrated flux at the vessel wall is conservative by up to 20 percent.

The anticipated degree to which the specimens will perturb the fast neutron flux and energy distribution will be considered in the evaluation of the surveillance specimen data. Verification and possible readjustment of the calculated wall exposure will be made by use of data on all capsules withdrawn.

The tentative schedule for removal of Unit 1 capsules is as follows:

Capsule T	Replacement of 1st Region (Postirradiation test)
Capsule Y	5 years (Postirradiation test)
Capsule Z	10 years (Postirradiation test)
Capsule V	10 years (Reinsert in Capsule T location)
Capsule X	10 years (Reinsert in Capsule Y location)
Capsule U	10 years (Reinsert in Capsule Z location)
Capsule S	15 years (Postirradiation test)
Capsule W	20 years (Reinsert in Capsule S location)

The tentataive schedule for removal of Unit 2 capsules is as follows:

Capsule T	Replacement of 1st Region (Postirradiation test)
Capsule X	10 years (Postirradiation test)
Capsule S	10 years (Reinsert in Capsule T location)

Capsule V	10 years (Reinsert in Capsule X location)
Capsule U	10 years (Reinsert in Capsule S location)
Capsule W	10 years (Reinsert in Capsule U location)
Capsule Y	15 years (Postirradiation test)
Capsule Z	20 years (Reinsert in Capsule Y location)

The surveillance program for the Unit 1 was prepared to meet ASTM E 185-70, Section 3.3. The test materials were procured and machined in 1969 prior to publication of ASTM E 185-70 and prior to issuance of "Reactor Vessel Material Surveillance Program Requirements," 10CFR50, Appendix H. Therefore, the eight capsules to be provided do not include five capsules which contain specimens from base metal, weld metal and heat affected zone (HAZ) metal as required in 10CFR50, Appendix H.

The three plates from the intermediate shell course which were opposite the center line of the core were selected for the program. They had essentially the same nil ductility transition temperature (NDTT) of -30° to -40°F. The heat affected zone of Plate 2 was selected for surveillance since it was the highest NDTT plate of the three based on Charpy V-notch and drop weight tests.

In 1972, a proposed revision to ASTM E 185 recommended that the weld and base material to be included in the program be based on initial transition temperature; upper shelf energy level, and estimated increase in transition temperature considering chemical compositon (Cu and P) and neutron fluence. Using this approach for Unit 1 the limiting material for reactor operation will be Plate 1 containing 0.24 percent Cu and 0.010 percent P and which has a higher RT_{NDT} (from ASME Code Case 1514). The weld metal (containing 0.16 percent Cu and with a lower RT_{NDT}) will not be limiting. Six of the eight capsules will contain Plate 1.

The program is considered adequate for monitoring the radiation-induced changes in fracture toughness of the reactor vessel. Heat affected zone specimens from Plate 1 will not be used but radiation induced changes should similar since Plate 2 contains Cu (0.24 percent) and P (0.010 percent) content equivalent to Plate 1.

As part of the program on irradiation effects, transverse tests (normal to principal rolling direction) of the three Unit 1 intermediate core region plates were irradiated at 3×10^{19} nvt >1 Mev at operating temperatures 550°F in the Union Carbide Research Reactor (by NRL). The data was presented at the ASTM 1972 Annual meeting in Los Angeles (Effect of Irradiatin on Upper Shelf Energy Level of Commercial Pressure Vessel Grade Steel). The results were as follows:

	Cu	P	ΔTT-°F based on 30 ft lb	ΔTT-°F based on 50 ft lb
Plate 1	0.24	0.010	170	180
Plate 2	0.24	0.010	180	180
Plate 3	0.22	0.011	150	155

The actual values of radiation effect shown above are less than the predicted values.

Detailed information on the as-built material properties of the Unit 2 reactor vessel were provided by letter dated November 16, 1967.

For Unit 2 the surveillance program has been revised to meet proposed ASTM and NRC requirements reflecting ASTM Code Case 1514 and will include eight capsules, each of which will contain the most limiting base plate, weld metal and heat affected zone material.

5.2.5 AUSTENITIC STAINLESS STEEL

The core support structural load bearing members and the stainless steel reactor coolant pressure boundary components were welded in accordance with the Westinghouse criteria, which are as follows:

Type 308 weld filler material is used for all welding applications to avoid microfissuring. As an option, Type 308L weld filler metal analysis is substituted for consumable inserts when this technique is used for the weld root closure. Bare weld filler metal materials, including consumable inserts used in inert gas welding processes, conform to ASME SFA-5.9 and are procured to contain not less than 5 percent delta ferrite. All weld filler metal materials used in flux shielded welding processes conform to ASME SFA-5.4 or SFA-5.9 and are procured in a wire-flux combination to be capable of providing not less than 5 percent delta ferrite in the deposit. Electrodes conforming to SFA-5.4 are of the -15 or -16 (lime type) current characteristics.

All welding materials are tested by the fabricator using the specific process(es) and the maximum welding energy inputs to be employed in production welding. These tests are in accordance with the requirements of ASME Section III, NB-2430 and in addition, shall include delta ferrite determinations. These determinations are made by calculation using the "Schaeffler Constitution Diagram for Stainless Steel Weld Metal". Subsequent in-process delta ferrite determinations are not required. Other methods of ferrite determinations are useable on the basis of the developmental data and recommendations concurrently existing from the Advisory Subcommittee for Welding Stainless Steel of the High Alloy Committee in the Welding Research Council.

Methods used in manufacturing components of the reactor coolant pressure boundary and core structural load bearing members to minimize possible problems with severly sensitized stainless steel are as follows:

Reactor Vessel (Unit 1)

Primary nozzle safe ends are wrought austenitic stainless steel attached to the nozzles prior to final post weld heat treatment and therefore are sensitized. Other safe ends were installed after post weld heat treatments.

The part length control rod drive mechanisms (CRDMs) are fabricated of wrought Type 403 stainless steel with ends buttered with austenitic stainless steel weld metal. Then they are post weld heat treated and later welded to the austenitic stainless steel tube.

Reactor Vessel (Unit 2)

The primary nozzle safe ends, other safe ends and the part length CRDMs are fabricated the same as Unit 1.

Steam Generators

The nozzle safe ends are prepared by buttering with austenitic stainless steel weld metal.

Pressurizers

Safe ends are of Type 316 stainless steel. Safe end post weld heat treatment consisted of heating to 1125 - 25°F for 9 hours on Unit 1 and 5 hours on U nit 2 with heating and cooling rates in accordance with the ASME Section III code rules. Testing to determine the degree of sensitization thjat could have occurred as a result of the PWHT cycle was not performed.

Internals (Both Units)

For internals where austenitic stainless steel must be given a stress relieving treatment above 800°F, a high temperature stabilizing procedure is used. This is performed in the temperature range of 1600°F to 1900°F with holding times sufficient to achieve chromium diffusion to the grain boundary regions and would be expected to pass ASTM-A-393. No tests were performed on the core structural components to determine whether or not desensitization was accomplished by the elevated temperature stabilization treatment.

Internals (Unit 1)

The Unit 1 austenitic stainless steel core structural components were weld fabricated using the manual gas shielded tungsten arc, manual shielded metal arc and semi-automatic submerged arc welding processes. All of these welding processes and welders were previously qualified to 1965 ASME Section IX code rules. All of the welds were limited to a 350°F maximum interpass temperature. The heat input in kilojoules/inch were as follows, using the formula $H = \frac{EI \times 60}{S}$ where H = joules/inch energy input, E = volts, I = current in amperes, and S = travel speed in in./min.

GTAW Energy Input = 16.5 to 36.4 kj
SMAW Energy Input = 27.0 to 94.5 kj
SAW Energy Input = 45.4 to 62.0 kj

All full penetration welds in the core structural components were penetrant tested at the root level and in the final finished condition on the "nearside" surfaces. The welds were radiographically examined through 100 percent of the volume using 2-2T sensitivity techniques with the acceptance standards conforming to 1968 ASME Section III code rules, paragraph N624.3. All continuous partial penetration welds used in attaching accessory internal parts to the core structural components were progressively penetrant tested at the root level, each additional 1/2 inch of deposit thickness and on the final finished surface. All non-continuous partial penbetration fillet welds used in attaching accessory internal parts, locking devices, to the core structural components were visually examined using 5x magnification to determine freedom from any type of linear discontinuity.

Internals (Unit 2)

The Unit 2 austenitic stainless steel core structural components were weld fabricated using the manual gas shielded tungsten arc, manual shielded metal arc, automatic gas shielded hot-wire tungsten arc and the automatic submerged arc welding processes. The qualifications, interpass temperature control and non-destructive testing of these components was the same as for the Unit 1 components.

The heat input in kilojoules/inch were as follows for each of the applied welding processes.

Manual GTAW Energy Input = 22.5 to 43.2 kj

Manual SMAW Energy Input = 18.0 to 120 kj

Automatic GTAW-HW Energy Input = 11.0 to 35 kj

Automatic SAW Energy Input = 63.4 to 138 kj (DC + AC)

For core support structural load bearing members and stainless steel reactor coolant pressure boundary welds, all welding on stainless steel was conducted by procedures that limit the interpass temperature to 350°F maximum.

The pressure or strength bearing stainless steel components or parts in the reactor vessel and associated RCS that may have become furnace sensitized* during the fabrication sequence include:

1. Reactor Vessels

   Primary nozzle safe ends - Type 316 stainless steel forgings

   Part length CRDMS - weld metal buttered ends

2. Steam Generators

   Primary nozzle safe ends - weld metal buttered ends

3. Pressurizers

		Unit 1	Unit 2
Surge nozzle safe end	-	Type 316 forging	Type 316L forging
Spray nozzle safe end	-	Type 316 forging	Type 316L forging
Relief Nozzle safe end	-	Type 316 forging	Type 316L forging
Safety (3) nozzle safe end	-	Type 316 forging	Type 316L forging

Westinghouse has evaluated the use of sensitized stainless steel and reactor components in pressurized water reactors. The results of this evaluation are summarized in Reference 22 which covers the nature of sensitization, conditions leading to stress corrosion and associated problems with both sensitized and non-sensitized stainless steel. The results of extensive testing and service experience that justify the use

*The term "furnace sensitized" is interpreted as austenitic stainless steel wrought material and weld metal components which have been post weld heat treated in accordance with ASME Section III requirements, and which on the basis of its composition and thermal history would not be expected to pass ASTM-A-393.

of stainless steel in the sensitized condition for components in Westinghouse systems is presented in Reference 22. References 22 through 26 provide evidence that the addition of nitrogen does not adversely affect the corrosion resistance of sensitized stailness steels.

A program has been established to monitor systems in which stainless steel piping contains stagnant, oxygenated, borated water as defined in I and E Bulletin 79-17. The affected systems are: residual heat removal, safety injection, containment spray and chemical and volume control. The program which complies with I and E Circular 76-06 consists of hydrotesting, visual leak examination, volumetric examination, periodic chloride analysis and qu-service inspection.

5.2.6 PUMP FLYWHEELS

A flywheel on the shaft above the motor provides additional inertia to extend flow coastdown. Each pump contains a ratchet mechanism to prevent reverse rotation. The reactor coolant pump flywheel is shown in Figure 5.2-16.

Precautionary measures, taken to preclude missile formation from primary coolant pump components, assure that the pumps will not produce missiles under any anticipated accident condition.

Each component of the primary pump motors has been analyzed for missile generation. Any fragments of the motor rotor would be contained by the heavy stator. The same conclusion applies to the pump impeller because the small fragments that might be ejected would be contained by the heavy casing.

The most adverse operating condition of the flywheels is visualized to be the loss-of-load situation. The following conservative design-operation conditions preclude missile production by the pump flywheels. The wheels are fabricated from rolled, vacuum-degassed, ASTM A-533 steel plates. Flywheel blanks are flame-cut from the plate, with allowance for exclusion of flame-affected metal. A minimum of three charpy tests are made from each plate parallel and normal to the rolling direction; they determine that each blank satisfies design requirements. An NDTT less than +10°F is specified. The finished flywheels are subjected to 100 percent volumetric ultrasonic inspection. The finished machined bores are also subjected to magnetic particle, or liquid penetrant examination.

These design-fabrication techniques yield flywheels with primary stress at operating speed (shown in Figure 5.2-17) less than 50 percent of the minimum specified material yield strength at room temperature (100 to 150°F). Bursting speed of the flywheels has been calculated on the basis of Griffith-Irwin's results (References 27 and 28), to be 3900 rpm, more than three times the operating speed.

A fracture mechanics evaluation was made on the reactor coolant pump flywheel. This evaluation considered the following assumptions:

1. Maximum tangential stress at an assumed overspeed of 125 percent.

2. A crack through the thickness of the flywheel at the bore.

3. 400 cycles of start up operation in 40 years.

Using critical stress intensity factors and crack growth data obtained on flywheel material, the critical crack size for failure was greater than 17 inches radially and the crack growth data was 0.030 inches to 0.060 inches per 1000 cycles.

5.2.7 REACTOR COOLANT PRESSURE BOUNDARY LEAKAGE DETECTION SYSTEMS

RCS components were manufactured to exacting specifications which exceed normal code requirements. In addition, per use of the welded construction of the RCS and the extensive non-destructive testing to which it is subjected, it is considered that leakage through metal surface or welded joints is very unlikely.

However, some leakage from the RCS is permitted by the reactor coolant pump seals. Also all sealed joints are potential sources of leakage even though the most appropriate sealing device is selected in each case. Thus, because of the large number of joints and the difficulty of assuring complete freedom from leakage in each case, a small integrated leakage is considered acceptable.

5.2.7.1 Leakage Detection Methods

The existence of leakage from the RCS to the containment regardless of the source of leakage, is detected by one or more of the following:

1. Two radiation sensitive instruments provide the capability for detection of leakage from the RCS. The containment air particulate monitor is quite sensitive to low leak rates and can be used to alarm the presence of new leaks, if desired. The containment radiogas monitor is much less sensitive but can be used as a backup to the air particulate monitor.

2. A third instrument used in leak detection is the humidity detector. This provides a backup means of measuring overall leakage from all water and steam systems within the containment but furnishes a less sensitive measure. The humidity monitoring method provides backup to the radiation monitoring methods.

3. An increase in the amount of coolant makeup water which is required to maintain normal level in the pressurizer, or an increase in containment sump level.

5.2.7.1.1 Containment Air Particulate and Containment Radiogas Monitors

The containment air particulate monitor is the most sensitive instrument of those available for detection of reactor coolant leakage into the containment. This instrument is capable of detecting particulate radioactivity in concentrations as low as 10^{-9} μc/cc of containment air.

The sensitivity of the air particulate monitor to an increase in reactor coolant leak rate is dependent upon the magnitude of the normal base-line leakage into the containment. The sensitivity is greatest where base-line leakage is low as has been demonstrated by the experience of Indian Point Unit No. 2, Yankee Rowe and Dresden Unit 1. Where containment air particulate activity is below the threshold of detectability, operation of the monitor with stationary filter paper would increase leak sensitivity to a few cubic centimeters per minute. Assuming a low background of containment air particulate radioactivity, a reactor coolant corrosion product radioactivity (Fe, Mn, Co, Cr) of 0.2 μc/cc (a value consistent with little or no fuel cladding leakage), and complete dispersion of the leaking radioactivity into the containment air, sensitivity calculations indicate the air particulate monitor to be capable of detection leaks as small as approximately 0.13 gpm (50 cc/min.) within 30 minutes after they occur. If only 10 percent of the particulate activity is actually dispersed in the air, the threshold of detectable leakage is raised to approximately 1.3 gpm (500 cc/min.).

For cases where base-line reactor coolant leakage falls within the detectable limits of the air particulate monitor, the instrument can be adjusted to alarm on leakage increases from two to five times the base-line value.

The containment radiogas monitor is inherently less sensitive (threshold at 10^{-6} μc/cc) than the containment air particulate monitor, and would function only in the event that significant reactor coolant gaseous activity exists due to fuel cladding defects. Assuming a reactor coolant gas activity of 0.3 $\mu c/cc$, the occurrence of a leak of 5 gpm would be detected within an hour. In these circumstances this instrument would be useful as a backup to the air particulate monitor.

The air particulate and radiogas monitors are calibrated using a pulse generator to drive the counting circuits and using a check source to check detectors and input circuitry to the instruments. The alarm setpoints were verified at calibration. The system operability is checked during shutdown of the reactor.

5.2.7.1.2 Humidity Detector

The humidity detection instrumentation offers another means of detection of leakage into the containment. This instrumentation has not nearly the sensitivity of the air particulate monitor, but has the advantage of being sensitive to vapor originating from all sources, the reactor coolant, the steam, and the feedwater systems. Plots of containment air dew point variations above a base-line maximum established by the cooling water temperature to the air coolers should be sensitive to incremental leakage equivalent to 0.2 to 1.0 gpm.

The sensitivity of this method is dependent on cooling water temperature, containment air temperature variation and condensation on internal surfaces. With the least sensitivity, based on peak summer cooling water temperatures, it is estimated that an increase of 0.2 gpm in leak rate will cause a rise in containment dew point temperature of 1°F.

The dew point measuring equipment is checked for accuracy by using calibrated check coils. The system operability is checked during shutdown of the reactor.

5.2.7.1.3 Liquid Inventory in the Process Systems and in the Containment Sump

An increase in the amount of coolant makeup water which is required to maintain normal level in the pressurizer, is indicated by an increase in charging flow.

Gross leakage is indicated by a rise in normal containment sump level and periodic operation of containment sump pumps.

5.2.7.1.4 Condensate Measuring System

The condensate measuring system permits measurements of the flow rate of liquid run-off from the drain pans under each containment fan cooler unit. It consists of a vertical standpipe, valves and instrumentation installed in the drain piping of the fan cooler unit.

Depending on the number of fan cooler units in operation, the drainage flow rate from each unit due to normal condensation is calculated. With the initiation of a leak, the containment humidity and condensate run-off rate both increase, the water level rises in the vertical pipe and the high condensate flow alarm is actuated.

The containment specific humidity increases proportionately to time and leakage until the dew point is reached at the fan cooler cooling coils. With the increasing specific humidity, the heat removal capacity needed to cool the steam-air mixture to its dew point decreases. Therefore, increases in specific humidity and available heat removal capacity from the cooling coils result in added condensate flow. The condensate flow rate is then a function of specific humidity. Through accurate measurements of condensate flow variation, a reliable estimate of the reactor coolant leakage rate can be made.

A preliminary estimate of the leakage can be obtained from the rate of condensate flow increase during the transient; a better estimate can be made from the steady state condensate flow at equilibrium conditions. The device alarms on a 0.06 gpm condensate flow rate, which indicates that a one gpm or larger leak has been developing for about five minutes.

The system can be checked during reactor shutdown.

5.2.7.1.5 Inter-system Leakage Detection

The following provisions are available for the detection of intersystem leakage from the RCS:

1. Radiation monitors are provided for the steam generator blowdown system and condenser air removal effluent line which alert the operator to reactor coolant leakage into the main steam and feedwater systems from steam generator tube leaks.

2. Radiation monitors are provided for the component cooling system to detect reactor coolant leakage into the system from the residual heat removal system. Surge tank level is also an indicator for leakage detection.

3. The accumulators are isolated from the RCS by two check valves. They are also provided with a remote manual valve. Leakage would be detected by level and pressure changes in the accumulators.

4. The charging/boron injection tank line is isolated from the RCS by two check valves and normally closed remote manual valves. Leakage from the RCS would be detected by pressure changes in the line.

5. The residual heat removal system and safety injection system are isolated from the RCS by two check valves and normally closed remote manual valves. Leakage would cause operation of the relief valves

which discharge to the pressurizer relief tank. Changes in level and pressure in this tank could be indicative of reactor coolant leakage.

RCS leakage can also be detected by level changes in the volume control tank, as well as by RCS water inventory balances, which are perfomed periodically. The indications identified above are provided, with apropriate alarms, in the control room.

5.2.7.2 Indication in Control Room

Positive indications in the control room of leakage of coolant from the RCS to the lower containment compartment are provided by equipment which permits continuous monitoring of the lower containment compartment air activity and humidity, and condensate run-off from the fan coolers. This equipment provides indication of normal background which is indicative of a basic level of leakage from primary systems and components. Any increase in the observed parameters are an indication of change within the lower containment compartment, and the equipment provided is capable of monitoring this change. The basic design criterion is the detection of deviations from normal containment environmental conditions including air particulate activity, radiogas activity, humidity, condensate and in addition, in the case of gross leakage, the liquid inventory in the process systems and containment sump.

5.2.8 INSERVICE INSPECTION PROGRAM

Preservice and inservice inspection for Class 1, 2 and 3 components is in accordance with the rules of 10CFR50.55(a), Paragraph (g) to the extent practical. Deviations from the applicable ASME Section XI inspection requirements have been transmitted in the Inservice Inspection and Testing Program for Salem No. 1 Unit, dated February 28, 1977, and supplemented October 11, 1977 and January 18, 1978.

5.2.8.1 Provisions for Access to Reactor Coolant Pressure Boundary

Provisions have been made in the design and arrangement of the RCS, engineered safety systems and certain associated auxiliary systems to allow access for inservice inspection.

Public Service has considered problems associated with inservice inspection during the design of the plant. These considerations have provided increased access such as the main coolant nozzle-to-pipe welds.

5.2.8.2 Equipment for Inservice Inspections

The preservice baseline examination and subsequent inservice examinations of the reactor vessels were accomplished with mechanized equipment called the Reactor Vessel Examination Device (RVED). This inspection device has been used for accomplishing the same examinations on other reactor vessels.

The areas subject to examination relative to the reactor vessel primary nozzles were also accomplished by use of the RVED inspection device. A separate search unit manipulator is attached to the RVED and inserted into each nozzle for inspection of the nozzle-to-shell welds, nozzle radius areas, and primary nozzle-to-safe end welds. These examinations can be performed on primary outlet nozzles with the core barrel in place; however a more typical sequence for performing these examinations is to perform them in conjunction with other examinations requiring use of the RVED. Essentially 100 percent of all longitudinal and circumferential shell welds can be examined using the RVED once the core barrel has been removed.

5.2.8.3 Recording and Comparing Data

Southwest Research Institute (SWRI) has developed special forms and procedures for manual and mechanized inspections. Results of manual and mechanized inspections are recorded and can be compared with preservice and previous inservice data. Data is stored for correlation and subsequent inspections.

5.2.8.4 Reactor Vessel Acceptance Standards

Examination results are evaluated in accordance with the applicable edition of ASME, Section XI. Results of mechanized scans are recorded on a data acquisition system, used by SWRI. This system uses television cameras and recorders to record information presented on a data panel. The panel contains analog and digital counters that denote the position of the inspection device and digital time and amplitude information. Recording is done by strip chart recorder in addition to TV camera and manually.

5.2.8.5 Coordination of Inspection Equipment with Access Provisions

Liaison is maintained with SWRI to discuss and resolve matters relating to access for future inspection of components. Of consideration during plant erection were the items to be inspected, as defined by the applicable editions of Section XI of the ASME Boiler and Pressure Vessel Code, and the capabilities of mechanized equipment either in use or in the development stages by SWRI. This information is constantly under review since additional experience is gained at other plants during inservice inspections. The item of most concern for access is the reactor vessel, which was examined using the RVED, allowing examination of essentially all shell and nozzle welds. Those areas where examination is limited or prevented entirely by access restrictions have been identified in relief requests submitted to the NRC on February 28, 1977 and October 11, 1977.

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TABLE 5.2-1

REACTOR COOLANT SYSTEM DESIGN PRESSURE SETTINGS

	Pressure, psig
Design Pressure	2485
Operating Pressure	2235
Safety Valves	2485
Power Relief Valves	2335
Pressurizer Spray Valves (Begin to Open)	2260
Pressurizer Spray Valves (Full Open)	2310
High Pressure Trip	2385
High Pressure Alarm	2335
Low Pressure Trip	1800
Low Pressure Alarm	2135
Hydrostatic Test Pressure	3107
Backup Heaters On	2185
Proportional Heaters (Begin to Operate)	2250
Proportional Heaters (Full Operation)	2220

TABLE 5.2-2

REACTOR COOLANT SYSTEM DESIGN PRESSURE DROP

	Pressure Drop, psi (estimated)
Across Pump Discharge Leg	1.5
Across Vessel, Including Nozzles	52.0
Across Hot Leg	1.9
Across Steam Generator	31.9
Across Pump Suction Leg	1.8
Total Pressure Drop	89.1

TABLE 5.2-3 (Sheet 1 of 2)

REACTOR VESSEL DESIGN DATA

	Unit 1	Unit 2
Design/Operating Pressure, psig	2485/2235	2485/2235
Hydrostatic Test Pressure, psig	3107	3107
Design Temperature, °F	650	650
Overall Height of Vessel and Closure Heat, ft-in. (bottom head OD to top of control rod mechanism adapter	43-10	43-10
Thickness of Insulation, min., in.	3	3
Number of Reactor Closure Head Studs	54	54
Diameter of Reactor Closure Head Studs, in.	7	7
ID of Flange, in.	172.5	172.5
OD of Flange, in.	205	205
ID at Shell, in.	173	173
Inlet Nozzle ID, in	27-1/2	27-1/2
Outlet Nozzle ID, in.	29	29
Clad Thickness, min., in.	5/32	5/32
Lower Head Thickness, min., in. (base metal)	5-3/8	5-3/8
Vessel Belt-Line Thickness, min., in. (base metal)	8.5	8.5
Closure Heat Thickness, in.	7	7
Reactor Coolant Inlet Temperature, °F	544.4	545.0
Reactor Coolant Outlet Temperature, °F	608.3	610.2
Reactor Coolant Flow, lb/hr	134.1×10^6	133.9×10^6
Total Water Volume Below Core, ft^3	1050	1050
Water Volume in Active Core Region, ft^3	665	665

TABLE 5.2-3 (Sheet 2 of 2)

REACTOR VESSEL DESIGN DATA

	Unit 1	Unit 2
Total Water Volume to Top of Core, ft^3	2164	2164
Total Water Volume to Coolant Piping Nozzles Centerline, ft^3	2929	2959
Total Reactor Vessel Water Volume, (with core and internals in place), ft^3	4945	4945
Total Reactor Coolant System Volume, ft^3	12,612	12,612

TABLE 5.2-4

PRESSURIZER AND PRESSURIZER RELIEF TANK DESIGN DATA

Pressurizer

Design/Operating Pressure, psig	2485/2235
Hydrostatic Test Pressure (cold), psig	3107
Design/Operating Temperature, °F	680/653
Water Volume, Full Power, ft^{3}*	1080
Steam Volume, Full Power, ft^3	720
Surge Line Nozzle Diameter, in.	14
Shell ID, in.	84
Electric Heaters Capacity, kW	1800
Heatup Rate of Pressurizer (using heaters only) °F/hr	55 (approximately)
Maximum spray rate, gpm	800

Pressurizer Relief Tank

Design pressure, psig	100
Rupture Disc Release Pressure, psig	85
Design temperature, °F	340
Normal water temperature, °F	Containment Ambient (120°F max.)
Total Volume, ft^3	1800
Total Rupture Disc Relief Capacity, lb/hr	1.60×10^6

*60 percent of net internal volume (maximum calculated power)

TABLE 5.2-5 (Sheet 1 of 2)

STEAM GENERATOR DESIGN DATA*
(Model 51)

	Unit 1	Unit 2
Number of Steam Generators	4	4
Design Pressure (Reactor coolant/steam), psig	2485/1085	2485/1085
Reactor Coolant Hydrostatic Test Pressure (tube side-cold), psig	3107	3107
Design Temperature (reactor coolant/steam), °F	650/600	650/600
Reactor Coolant Flow, lb/hr	33.53×10^6	33.47×10^6
Total Heat Transfer Surface Area, ft^2	51,500	51,500
Heat Transferred, Btu/hr	2857×10^6	2920×10^6
Steam Conditions at Full Load, Outlet Nozzle:		
Steam Flow, lb/hr	3.61×10^6	3.74×10^6
Steam Temperature, °F	519	519
Steam Pressure, psig	805	805
Maximum Moisture Carryover, wt percent	0.25	0.25
Feedwater, °F	435	435
Overall Height, ft-in.	67-8	67-8
Shell OD (upper/lower), in.	175-3/4 / 135	175-3/4 / 135
Number of U-tubes	3388	3388
U-tube OD, in.	0.875	0.875
Tube Wall Thickness (minimum), in.	0.050	0.050
Number of Manways/ID in.	4/16	4/16
Number of handholes/ID, in.	2/6	2/6

*Quantities are for each steam generator

TABLE 5.2-5 (Sheet 2 of 2)

STEAM GENERATOR DESIGN DATA*
(Model 51)

	Unit 1 Rated Load	Unit 2 No Load
Reactor Coolant Water Volume, ft^3	1080	1080
Primary Side Fluid Heat Content, Btu	28.7×10^6	27.7×10^6
Secondary Side Water Volume, ft^3	1838	3524
Secondary Side Steam Volume, ft^3	4030	2344
Secondary Side Steam Fluid Heat Content, Btu	5.738×10^7	9.628×10^7

*Quantities are for each steam generator

TABLE 5.2-6

REACTOR COOLANT PUMPS DESIGN DATA

(Model 93A)

Number of Pumps	4
Design Pressure/Operating Pressure, psig	2485/2235
Hydrostatic Test Pressure (cold), psig	3107
Design Temperature (casing), °F	650
RPM at Nameplate Rating	1180
Suction Temperature, °F	559
Developed Head, ft	277
Capacity, gpm	88,500
Seal Water Injection, gpm	8
Seal Water Return, gpm	3
Pump Discharge Nozzle ID, in.	27 1/2
Pump Suction Nozzle ID, in.	31
Overall Unit Height, ft-in	25-5 1/4
Water Volume, ft^3	56
Pump-Motor Moment of Inertia, $lb\text{-}ft^2$	82,000
Motor Data:	
Type	AC Induction Single Speed, Air Cooled
Voltage	4160
Insulation Class	B Thermalastic Epoxy
Phase	3
Frequency, cps	60
Starting	
Current, amp	4800
Input (hot reactor coolant), kW	4260
Input (cold reactor coolant), kW	5690
Power, HP (nameplate)	6000
Pump Weight, lb. (dry)	169,200

TABLE 5.2-7

REACTOR COOLANT PIPING DESIGN PARAMETERS

	Unit 1	Unit 2
Reactor Inlet Piping ID, in.	27-1/2	27-1/2
Reactor Inlet Piping Nominal Thickness, in.	2.38	2.38
Reactor Outlet Piping ID, in.	29	29
Reactor Outlet Piping Nominal Thickness, in.	2.50	2.50
Coolant Pump Suction Piping ID, in.	31	31
Coolant Pump Suction Piping Nominal Thickness, in.	2.66	2.66
Pressurizer Surge Line Piping ID, in.	11.500	11.188
Pressurizer Surge Line Piping nominal Thickness, in.	1.25	1.460
Design/Operating Pressure, psig	2485/2235	2485/2235
Hydrostatic Test Pressure (Cold), psig	3107	3107
Design Temperature, °F	650	650
Design Temperature (pressurizer surge line), °F	680	680
Water Volume, (all 4 loops including surge line) ft^3	2455	1455
Design Pressure (pressurizer relief lines), psig	(1)	(1)
Design Temperature (pressurizer relief lines), °F	(1)	(1)

(1) From pressurizer to safety valve 2485 psig 650°F
From safety valve to pressurizer relief tank 600 psig 600°F.

TABLE 5.2-8 (Sheet 1 of 3)

PRESSURIZER VALVES DESIGN PARAMETERS

PRESSURIZER SPRAY CONTROL VALVES

Number of Valves	2/Unit
Design Pressure	2485 psig
Design Temperature	650°F
Design Flow (valves full open, each)	400 gpm
Fluid Temperature	545°F
Position (after failure of actuating force)	Closed

SAFETY VALVES

1. VALVE PARAMETERS

Number of Valves	3/Unit
Manufacturer	Crosby Valve and Gage Co.
Type	Crosby HB-BP-86 6M6 Safety Valve (Loop Seal Internals)
Set Point	2485 psig
Size	6" Inlet x 6" Outlet Orifice Size = 2.154 ($3.644\ in^2$)
Rated Capacity (Saturated Steam)	420,000 lb/hr each
Design Pressure and Temp.	2485 psig and 680°F
Constant Back Pressure	
Normal	3-5 psig
Expected During Discharge	478 psig
Inlet Flange Rating	1500 #ASA
Discharge Flange Rating	600 #ASA

PRESSURIZER VALVES DESIGN PARAMETERS

2. INLET PIPING PARAMETERS

Diameter	6" Sch 160	
Length	Unit 1	Unit 2
Loop 3	14.553'	12.054'
Loop 4	12.873'	12.241'
Loop 5	12.309'	11.719'
Type	Loop Seal	

POWER OPERATED RELIEF VALVES

1. VALVE PARAMETERS

Number of Valves	2/Unit
Manufacturer	Copes-Vulcan Division
Type	Diaphragm Operated Relief Valve
Set Point	2315 psig
Size	2" Valve with 3" inlet and outlet BW connection Orifice 2"
Rated Capacity (Saturated Steam)	210,000 lb/hr at 2335 psig
Design Pressure and Temp.	2485 psig and 680°F
Valve	1500 #ASA

2. INLET PIPING PARAMETERS

Type	Loop Seal

TABLE 5.2-8 (Sheet 3 of 3)

PRESSURIZER VALVES DESIGN PARAMETERS

PORV BLOCK VALVES

Number of Valves	2/Unit
Valve Manufacturer	Velan Engineering Co.
Operator Manufacturer	Limitorque
Type	3" Motor Operated Gate Valve 3GM58FN with BW ends and SMB-00-15 motor operator
Valve Rating	1500 #ASA

TABLE 5.2-9 (Sheet 1 of 2)

REACTOR COOLANT SYSTEM - CODES
(UNIT 1)

Component	Code	Date and Agenda	Code Cases
Reactor Vessel	ASME III	1965 and all addenda through Winter 1965	All applicable in effect prior to 4/.26/66
Steam Generator*	ASME III	1969 and all addenda through Winter 1965	All applicable in effect prior to 8/27/66
P/L CRDMs	ASME III	1968 (no addenda)	1337-2
F/L CRDMs	ASME III	1965 and all addenda through Summer 1966	--
Reactor Coolant Pump	No Code	(Design per ADME III - Article 4)	--
Pressurizer	ASME III	1965 and all addenda through Winter 1966	All Applicable in effect at the time
Pressurizer Relief Tank	ASME III	1968 and all addenda through Summer 1968	All applicable in effect at the time
Pressurizer Safety Valves	ASME III	1968 and all addenda through Summer 1968	--
Reactor Coolant Piping	ASA B31.1	1955	Applicable portions of ASA N-7 and N-10
System Piping and Fittings	ASA B31.1	1955	Applicable portions of ASA N-7 and N-10
System Valves	ASA B16.5, or MSS-SP-66, or ASME-III	1964 1964 1968	Applicable portions of N-10 -- --

*The shell side of the steam generator conforms to the requirements for Class A vessesl and is so stamped as permitted under the rules of Section III.

TABLE 5.2-9 (Sheet 2 of 2)

REACTOR COOLANT SYSTEM - CODES
(UNIT 2)

Component	Code	Date and Agenda	Code Cases
Reactor Vessel	ASME III	1965 and all addenda through Winter 1966	All applicable in effect prior to 4/3/.67
Steam Generator *	ASME III	1965 and all addenda through Summer 1966	All applicable in effect prior to 6/8/67
P/L CRDMs	ASME III	1968 and all addenda through	1337-2
F/L CRDMs	ASME III	1968 (no addenda)	--
Reactor Coolant Pump Casing	ASME III		
Pressurizer	ASME III	1965 and all addenda through Winter 1966	All applicable in effect at the time
Pressurizer Relief Tank	ASME III	1968 and all addenda through Summer 1968	All applicable in effect at the time
Pressurizer Safety Valves	ASME III	1968 and all addenda through Summer 1968	--
Reactor Coolant Piping	USAS B31.1.0	1967	Applicable portions of ASA N-7 and N-10
System Piping and Fittings	USAS B31.1.0	1967	Applicable portions of ASA N-7 and N-10
System Valves	B16.5, or MSS-SP-66, or ASME-III	1964 1964 1968	Applicable portions of N-10 -- --

*The shell side of the steam generator conforms to the requirements for Class A vessels and is so stamped as permitted under the rules of Section III.

TABLE 5.2-10 (Sheet 1 of 2)

DESIGN THERMAL AND LOADING CYCLES*

	Design Cycles**
1. Heatup at 100°F/hr	200
Cooldown at 100°F/hr (Pressurizer 200°F/hr)	200
2. Unit Loading at 5 Percent of Full Power/Min	18,300
Unit Unloading at 5 Percent of Full Power/Min	18,300
3. Step Load Increase of 10 Percent of Full Power	2,000
Step Load Decrease of 10 Percent of Full Power	2,000
4. 50 Percent Step Decrease in Load (with steam dump)	200
5. Loss of Load (without immediate turbine or reactor trip)	80
6. Loss of Power (blackout with natural circulation in the RCS)	40
7. Loss of Flow (partial loss of flow one pump only	80
8. Reactor Trip From Full Power	400
9. Turbine Roll Test	10

* The ASME Section III Nuclear Power Plant Components Code is inapplicable to the Salem plant; hence, the normal, upset, emergency and faulted conditions terminology does not apply to the transients identified in this table. However, since the RCS vessels (reactor vessel, pressurizer and steam generators) are basically standard components, analysis on these vessels with the more recent ASME Code conditions (normal, upset, emergency and faulted) have been performed as discussed in Sections 5.1.2.8.1 and 5.1.2.8.2.

** Estimated for equipment design purposes (40-year life) and not intended to be an accurate representation of actual transients or to reflect actual operating experience.

TABLE 5.2-10 (Sheet 2 of 2)

DESIGN THERMAL AND LOADING CYCLES

	Design Cycles
10. Hydrostatic Test Conditions	
a. Primary Side Hydrostatic Test Before Initial Startup	5
b. Secondary Side Hydrostatic Test Before Initial Startup	5
11. Primary Side Leak Test	50
12. Accident Conditions	
a. Reactor Coolant Pipe Break	1
b. Steam Pipe Break	1
c. Steam Generator Tube Rupture	1
13. Steady State Fluctuations - the reator coolant average temperature for purposes of design is assumed to increase and decrease a maximum of 6°F in one minute. The corresponding reactor coolant pressure variation is less than 100 psi. It is assumed that an infinite number of such fluctuations will occur.	
14. Design Earthquake Cycles	
a. Operating Basis Earthquake	50
b. Design Basis Earthquake	10

TABLE 5.2-11 (Sheet 1 of 2)

SUMMARY OF PLANT OUTAGE FOR YANKEE ROWE (1964 to 1969)

STARTING DATE	DURATION DAYS	DURATION HOURS	OUTAGE TYPE	CASE EQUIPMENT/SYSTEM
1/17/64	-	3.1	Forced	Turbine Trip
2/12/64	-	21.8	Scheduled	Control Rod Drop Testing
3/11/64	-	4.5	Forced	Moistdure separator level switch tripped due to vibration
3/26/64	-	4	Forced	Control Valves Sticking
5/18/64	-	5.4	Forced	Low condensate pump discharge pressure
8/2/64	35	-	Scheduled	Refueling and general maintenance
9/9/64	-	2.4	Scheduled	Check of Overspeed Trip
9/11/64	-	14.7	Forced	Spurious Reactor Trip
10/18/64	-	12.2	Forced	Condenser Noise
10/22/64	-	22.4	Forced	Neutron Counter Gain Control
2/12/65	-	15.2	Forced	Switchyard Electric
3/5/65	-		Scheduled	Switchyard Electric
8/9/65	93	6	Scheduled	Refueling
11/26/65	2	20	Scheduled	Turbine Repair-Physics Testing
2/4/66	-	3.12	Forced	Reactor Scram
4/4/66	-	89.5	Scheduled	Leaking Pressurizer Safety Valves
7/10/66	-	3.68	Forced	Reactor Scram
8/25/66	-	2.40	Forced	Reactor Scram
10/4/66	34	10.23	Scheduled	Refueling

TABLE 5.2-11 (Sheet 2 of 2)

SUMMARY OF PLANT OUTAGE FOR YANKEE ROWE (1964 to 1969)

STARTING DATE	DURATION DAYS	DURATION HOURS	OUTAGE TYPE	CASE EQUIPMENT/SYSTEM
12/24/66	-	2.88	Forced	Reactor Scram
12/28/66	-	2.12	Forced	Reactor Scram
3/8/67	11	21	Scheduled	Steam Generator Leak Repair
5/12/67	-	16.87	Scheduled	Condenser Cleaning
7/9/67	17	1.5	Scheduled	Steam Generator Leak Repairs
10/28/67	-	9	Scheduled	AEC Operator Examinations
10/13/67	-	2.6	Forced	Reactor Scram
3/23/68	38	-	Scheduled	Core VI-VII Refueling and Maintenance
7/20/68	1	10	Scheduled	Repair Leak from No. 1 M.C. Pump Stator Cap
11/8/68	6	16.42	Scheduled	Repair No. 4 Main Coolant Pump Thermal Barrier Leak and other Maintenance
1/18/69	1	2.1	Scheduled	Operator Training
2/15/69	1	1.8	Scheduled	Operator Training
3/1/69	-	11	Scheduled	AEC Operator Examination
4/11/69	4	18	Forced	Repair Reactor Instrument Leak
7/17/69	-	4.8	Forced	Reactor Scram
8/2/69	53	18.5	Scheduled	Refueling Maintenance
10/16/69	-	6.1	Forced	Reactor Scram
10/29/69	-	12	Scheduled	Turbine Valve Flange Steam Leak Repair

TABLE 5.2-12 (Sheet 1 of 2)

LOAD COMBINATIONS AND STRESS LIMITS

Load Combination	Stress Limit (Note 1)
1. Normal (deadweight, thermal and pressure)	Normal Conditions
2. Normal and Operation Basis Earthquake	Upset Condition
3. Normal and Design Basis Earthquake	Faulted Condition
4. Normal and Pipe Rupture	Faulted Condition
5. Nornmal and Design Basis Earthquake and Pipe Rupture	Faulted Condition

NOTE 1: Definition of Operating Condition categories from Summer 1968 Addenda to the ASME Boiler and Pressure Vessel Code, Section III.

1. Normal Condition - Any condition in the course of system startup, operation in the design power range and system shutdown, in the absence of Upset, Emergency or Faulted Conditions.

2. Upset Condition - Any deviations from Normal Conditions anticipated to occur often enough that design should include a capability to withstand the conditins without operational impairment. The Upset Condition includes those transients caused by a fault in a system component requiring its isolation from the system, transients due to a loss of load or power an any system upset not resulting in a forced outage. The estimated duration of an Upset Condition shall be included in the Design Specifications. The Upset Conditions include the effect of the specified earthquake for which the system must remain operational or must regain its operational status.

TABLE 5.2-12 (Sheet 2 of 2)

LOAD COMBINATIONS AND STRESS LIMITS

3. Emergency Condition - Any deviations from normal conditions which require shutdown for correction of the conditions or repair of damage in the system. The conditions have a low probability of occurence but are included to provide assurance that no gross loss of structural integrity will result as a concommitant effect of any damage developed in the system. The total number of postulated occurrences for such events shall not exceed twenty-five (25).

4. Faulted Condition - Those combinations of conditions associated with extremely low probability postulated events whose consequences are such that the integrity and operability of the nuclear energy system may be impaired to the extent where considerations of public health and safety are involved. Such considerations require compliance with safety criteria as may be a specified by jurisdictional authorities. Among the Faulted Conditions may be a specified earthquake for which safe shutdown is required.

TABLE 5.2-13 (Sheet 1 of 5)

LOADING CONDITIONS AND STRESS LIMITS: PRESSURE VESSELS

Loading Conditions	Stress Intensity Limits	Note
1. Normal Condition	(a) $P_m \leq S_m$	
	(b) P_m (or P_L) + $P_B \leq 1.5S_m$	1
	(c) P_m (or P_L) = P_B + Q $\leq 3.0S_m$	2
2. Upset Condition	(a) $P_m \leq S_m$	
	(b) P_m (or P_L) + $P_B \leq 1.5S_m$	1
	(c) P_m (or P_L) = P_B + Q $\leq 3.0S_m$	2
3. Emergency Condition	(a) $P_m \leq 1.25S_m$ or S_y, whichever is larger	
	(b) P_m (or P_L) + $P_B \leq 1.5(1.2S_m)$ or $1.5S_y$, whichever is larger	
4. Faulted Condition	Design Limit Curves as discussed in the text and attached.	4

where:

P_m = primary general membrane stress intensity

P_L = primary local membrane stress intensity

P_B = primary bending stress intensity

Q = secondary stress intensity

S_m = stress intensity value for ASME B and PV Code, Section III, Nuclear Vessels

S_u = minimum specified material yield (ASME B and PV Code, Section III, Table N-421 or equivalent)

TABLE 5.2-13 (Sheet 2 of 5)

LOADING CONDITIONS AND STRESS LIMITS: PRESSURE PIPING

Loading Conditions	Stress Intensity Limits
1. Normal Conditions	(a) $P_m \leq S$ (b) P_m (or $P_L + P_B \leq S$
2. Upset Conditions	(a) $P_m \leq 1.25$ (b) P_m (or $P_L + P_B \leq 1.2S$
3. Emergency Conditions	(a) $P_m \leq 1.2S$ (b) P_m (or $P_L + P_B \leq (1.5)(1.2)$ S
4. Faulted Conditions	Design Limit Curves as discussed in the text and attached.

where:

P_m = primary general membrane stress
P_L = primary local membrane stress
P_B = primary bending stress
S = allowable stress from USASI B31.1 Code for Pressure Piping

TABLE 5.2-13 (Sheet 3 of 5)

LOADING CONDITIONS AND STRESS LIMITS: EQUIPMENT SUPPORTS

Loading Conditions	Stress Intensity Limits
1. Normal Condition	Working Stresses or Applicable Factored Load Design Values
2. Upset Condition	Working Stress or Aplicable Factored Load Design Values
3. Emergency Condition	Within lyield after load redistribution
4. Faulted Condition	Permanent Deflection of Supports Limited to Maintain Supported Equipment Within Design Limit Curves as discussed in the text.

Note 1: The limits on local membrane stress intensity ($P_L \leq 1.5S_m$) and primary membrane plus primary bending strss intensity (P_L (or P_L) + $P_B \leq 1.5S_m$) need not be satisfied at a specific location if it can be shown by means of limit analysis or by tests that the specified loadings do not exceed 2/3 or the lower bound collapse load as per paragraph N-417.6 (b) of the ASME B and PV Code, Section III, Nuclear Vessels.

Note2: In lieu of satisfying the specific requirements for the local membrane ($P_L \leq 1.5S$) or the primary plus secondary stress intensity ($P_L + P_B + 0 \leq 3S_m$) at a specific location, the structural action may be calculated on a plastic basis and the design will be considered to be acceptable if shakedown occurs, as opposed to continuing deformation, and if the deformations which occur prior to shakedown do no exceed specified limits, as per paragraph N-417.6(a) (2) of the ASME B and PV Code, Section III, Nuclear Vessels.

Note 3: The limits on local membrane stress intensity ($P_L \leq 1.5S_m$) and primary membrane plus primary bending stress intensity (P_M (or P_L) + $P_B \leq 1.5S_m$) need not be satisfied at a specific location if it can be shown by means of limit analysis or by tests that the specified loadings do not exceed 120 percent of 2/3 of the lower bound collapse load as per paragraph N-417.10 (c) of the ASME B and PV Code, Section III, Nuclear Vessels.

Note 4: As an alternate to the design limit curves which represent a pseudo plastic instability analysis, a plastic instability analysis may be performed in some specific cases considering the actual strain-hardening characteristics of the material, but with yield strength adjusted to correspond to the tabulated value at the appropriate temperature in Table N-424 or N-425, as per paragraph N-417.11 (c) of the ASME B and PV Code, Section III, Nuclear Vessels. These specific cases will be justified on an individual basis.

TABLE 5.2-14

SUMMARY OF ESTIMATED PRIMARY PLUS SECONDARY STRESS INTENSITY FOR COMPONENTS OF THE REACTOR VESSEL

Area	Stress Intensity (psi)	Allowable Stress (psi) (at Operating Temperatures)
Control Rod Housing	54,700	69,900
Head Flange	49,300	80,000
Vessel Flange	58,200	80,000
Primary Nozzles	51,600	80,000
Stud Bolts	91,800	110,200
Vessel Support	*	80,000
Core Support Pad	41,800	69,900
Bottom Heat to Shell	34,100	80,000
Bottom Instrumentation	63,700	69,900
Vessel Wall Transition	31,900	80,000

*Lower than primary nozzle stress

TABLE 5.2-15

SUMMARY OF ESTIMATED CUMULATIVE FATIGUE USAGE FACTORS FOR COMPONENTS OF THE REACTOR VESSEL

Item	Usage Factor*[a]
Control Rod Housing	0.06
Head Flange	0.03
Vessel Flange	0.019
Stud Bolts	0.40
Primary Nozzles	0.034
Vessel Support	0.05
Core Cupport Pad (lateral)	0.011
Bottom Head to Shell	0.005
Bottom Instrumentation	0.103

*covers all transients

[a]as defined in Section III of the ASME Boiler and Pressure Vessel Code, Nuclear Vessels.

TABLE 5.2-16

STRESS DUE TO MAXIMUM STEAM GENERATOR TUBE SHEET PRESSURE DIFFERENTIAL (2485 PSIG)

Stress	(660°F) Computed Value	Allowable Value
Primary Membrane Stress	24,356 psi	37,000 psi (.9 Sy)
Primary Membrane plus Primary Bending Stress	54,946 psi	55,600 psi (1.35 Sy)

In addition to the foregoing evaluation, elasto-plastic limit analysis of the tube sheet-head-shell combination indicates a limit pressure of 3050 psi at operating conditions, giving a safety factor of 1.23 for the abnormal condition.

TABLE 5.2-17

RATIO OF ALLOWABLE STRESS TO COMPUTED STRESSES
FOR A STEAM GENERATOR TUBE
SHEET PRESSURE DIFFERENTIAL OF 2485 PSIG

Component Part	Stress Ratio
Channel Head	1.34
Channel Head-Tube Sheet Joint	1.80
Tubes	1.20
Tube Sheet	
Max. Avg. Ligament	1.01
Effective Ligament	1.52

TABLE 5.2-18

STEAM GENERATOR PRIMARY-SECONDARY BOUNDARY COMPONENTS

CONDITION: 100 PERCENT LOAD OPERATION - 2485/885 psig* 1650/600°F
Normal Operation Stress Limits

Location	Description	Inside Limit Center Limit Outer Limit	Stress Limit Center Limit Stress Limit	Inside Surface Stress Center Surface Stress Outer Surface Stress
	JCT OF SHORT	3 S_m	80,100	-10,063 psi
7	CYL WITH	S_m	26,700	+ 8,597 psi
	TUBESHEET	3 S_m	80,100	+27,247 psi
	1/2 THROUGH	$3S_m$	80,100	+ 9,514 psi
8	SHORT CYL	S_m	26,700	+ 8,597 psi
	DISCONTINUITY	$3S_m$	80,100	+ 7,670 psi
	JCT OF SHORT	3 S_m	80,100	+10,740 psi
9	CYL WITH	S_m	26,700	+ 8,597 psi
	SHELL	3 S_m	80,100	6,443 psi
		3 S_m	80,100	+10,269 psi
10	ON SHELL	S_m	26,700	+ 8,597 psi
		3 S_m	80,100	+ 6,912 psi
		3 S_m	80,100	+ 9,746 psi
11	ON SHELL	S_m	26,700	+ 8,597 psi
		3 S_m	80,100	+ 7,435 psi
	JCT OF PRI	3 S_m	80,100	+58,701 psi
12	SHORT CYL WITH	S_m	26,700	+14,528 psi
	TUBE PLATE	3 S_m	80,100	-29,646 psi
	1/2 THROUGH	3 S_m	80,100	+50,836 psi
13	PRIM SHORT	S_m	26,700	+14,528 psi
	CYL DISCON.	3 S_m	80,100	-21,781 psi
	JCT OF PRI	3 S_m	52,200	42,286 psi
14	SHORT CYL	S_m	19,400	+14,528 psi
	WITH HEAD	3 S_m	52,200	-13,231 psi

TABLE 5.2-19

STEAM GENERATOR PRIMARY-SECONDARY COMPONENTS

CONDITION: PRIMARY HYDROTEST - 3107/0 psig

Location	Description	Code Limit	Primary Membrane Stress Limit	Axial Primary Membrane Stress Intensity
7	JCT OF SHORT CYL WITH TUBESHEET	.9 Sy	45,000	0 psi
8	1/2 THROUGH SHORT CYL DISCONTINUITY	.9 Sy	45,000	0 psi
9	JCT OF SHORT CYL WITH SHELL	.9 Sy	45,000	0 psi
10	ON SHELL	.9 Sy	45,000	0 psi
11	ON SHELL	.9 Sy	45,000	0 psi
12	JCT OF PRI SHORT CYL WITH TUBE PLATE	.9 Sy	45,000	18,158 psi
13	1/2 THROUGH PRIM SHORT CYL DISCON.	.9 Sy	45,000	18,158 psi
14	JCT OF PRI SHORT CYL WITH HEAD	.9 Sy	36,000	18,158 psi

TABLE 5.2-20

STEAM GENERATOR PRIMARY-SECONDARY BOUNDARY COMPONENTS

CONDITION: SECONDARY CHAMBER HYDROTEST - 0/1356 psig

Location	Description	Code Limit	Primary Membrane Stress Limit	Axial Primary Membrane Stress Intensity
7	JCT OF SHORT CYL WITH TUBESHEET	$.9\ S_y$	45,000	13,169 psi
8	1/2 THROUGH SHORT CYL DISCONTINUITY	$.9\ S_y$	45,000	13,169 psi
9	JCT OF SHORT CYL WITH SHELL	$.9\ S_y$	45,000	13,169 psi
10	ON SHELL	$.9\ S_y$	45,000	13,169 psi
11	ON SHELL	$.9\ S_y$	45,000	13,169 psi
10	JCT OF PRI SHORT CYL WITH TUBE PLATE	$.9\ S_y$	36,000	0 psi
11	1/2 THROUGH PRIM SHORT CYL DISCON.	$.9\ S_y$	36,000	0 psi
12	JCT OF PRI SHORT CYL WITH HEAD	$.9\ S_y$	36,000	0 psi

TABLE 5.2-21

STEAM GENERATOR PRIMARY-SECONDARY BOUNDARY COMPONENTS

CONDITION: LOSS OF SECONDARY PRESSURE (STEAM LINE BREAK) - FAULTED CONDITION
2485/0 psig 660°F

Location	Description	Primary Membrane Stress Emergency Condition Limits Code Limit	Stress	Primary Membrane Stress
7	JCT OF SHORT CYL WITH TUBESHEET	S_y	41,112	0 psi
8	1/2 THROUGH SHORT CYL DISCONTINUITY	S_y	41,112	0 psi
9	JCT OF SHORT CYL WITH SHELL	S_y	41,112	0 psi
10	ON SHELL	S_y	41,112	0 psi
11	ON SHELL	S_y	41,112	0 psi
10	JCT OF PRI SHORT CYL WITH TUBE PLATE	S_y	41,112	14,528 psi
11	1/2 THROUGH PRIM SHORT CYL DISCON.	S_y	41,112	14,528 psi
12	JCT OF PRI SHORT CYL WITH HEAD	S_y	29,000	14,528 psi

*Complete Tubesheet Structure Complex also evaluated on Limit Analysis Basis

TABLE 5.2-22

51,500 SQ. FT. STEAM GENERATOR
USAGE FACTORS (INDIVIDUAL TRANSIENTS)
PRIMARY AND SECONDARY BOUNDARY COMPONENTS

			JUNCTION OF HEAD AND TUBESHEET IN TUBESHEET						DIVIDER PLATE ON TUBESHEET FACE						INHEAD							UNPERFORATED OUTER RING			JUNCTION OF SHELL TO TUBE SHEET		
		NO. OF	INLET			OUTLET			INLET			OUTLET			INLET			OUTLET				PRIM.		SEC.			
NO.	TRANSIENT	CYCLES	SARS*	SASH	SRSH	SASR	SASH	SRSH	SASR	SASH	SRSH	SASR	SASH	SRSH	SASR	SASH	SRSH	SASR	SASH	SRSH	INLET	OUTLET	INLET	OUTLET	HAHH	HAHR	HHHR
1	Heatup-Cooldown	200	.008	.01	0	.008	.01	0	0	0	0	0	0	0	.009	.003	0	.009	.003	0	0	0	0	0	0	0	0
2	Loading-Unloading	18,300	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	.019	.082	.056	0
3	Small Step Increase	2,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Small Step Decrease	2,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Large Step Decrease	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	.002	.001	0
6	Loss of Load	80	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	.001	.001	0	0	0	.001	.002	.006	.005	0
7	Loss of Power	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Loss of Flow	80	.008	.009	0	.008	.016	0	0	0	0	0	0	0	.011	.003	.001	.012	.006	0	0	0	.002	.004	.002	.002	0
9	Reactor Trip	400	0	0	0	0	.001	0	0	0	0	0	0	0	00	0	0	0	0	0	0	0	.001	.005	.012	.008	0
10	React. Cool. Pipe Break	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Steam Line Break	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	.001	0
12	Primary Hydro-test	5	.004	.007	0	.004	.007	0	0	0	0	0	0	0	.005	.002	0	.005	.002	0	0	0	.001	.001	.001	.001	0
13	Sec. Hydro-test	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	.001	.002	0
14	Turbine Roll Test	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

*Principal Stress Difference Codes

TABLE 5.2-23

51,500 SQ. FT. STEAM GENERATOR
USAGE FACTORS (INDIVIDUAL TRANSIENT)
CENTER OF TUBESHEET

		No. of	Primary Inlet Angle							Primary Outlet Angle							Secondary Inlet Angle							Secondary Outlet Angle						
No.	Transient	Cycles	0°	15°	30°	45°	60°	75°	90°	0°	15°	30°	45°	60°	75°	90°	0°	15°	30°	45°	60°	75°	90°	0°	15°	30°	45°	60°	75°	90°
1.	Heatup-Cooldown	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Loading-Unloading	18,300	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	Small Step Increase	2,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.	Small Step Decrease	2,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.	Large Step Decrease	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.	Loss of Load	80	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.	Loss of Power	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Loss of Flow	80	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Reactor Trip	400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10.	React. Cool. Pipe Break	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Steam Line Break	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12.	Primary Hydrotest	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Secondary Hydro	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Turbine Roll Test	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

* Angular location around perforation

TABLE 5.2-24

TUBE SHEET STRESS ANALYSIS RESULTS

FOR 51,500 SQ. FT. STEAM GENERATORS

Conditions		Maximum Primary Membrane Plus Primary Bending Average Ligament Stress psi		Maximum Effective Ligament Membrane Stress psi
100 Percent Normal Operation	2485/885 psi 650/600°F	33, 979	(40,050)[1]	15,853 (26,700)[2]
Primary Hydrotest	3107/0 psi 100°F	67,300	(67,500)[3]	30,365 (45,000)[4]
Secondary Hydrotest	0/1356 psi 100°F	29,811	(67,500)[3]	13,159 (45,000)[4]
Steam Line Break (Fault Condition)	2485/0 psi	56,785	(Limit)[5]	24,356 (Limit)[6]

Parenthesis Indicate Code Allowable Stress

1 $1.5S_m$

2 $1.0\ S_m$

3 $1.35\ S_y$

4 $.9\ S_y$

5 Limit Analysis Results Apply

6

TABLE 5.2-25

LIMIT ANALYSIS CALCULATION RESULTS

TABLE OF STRAINS, LIMIT PRESSURES, AND FATIGUE EVALUATIONS FOR 51,500 SQ. FT. STEAM GENERATORS

Case	Location	Meridional Strain, In/In	Circum-ferential Strain, In/In	Peak Stress Intensity, Psi	Allowable Number of Cycles, N_1	Number of Cycles, N_2	Usage Factor N_2/N_1	Limit Pressure Psi
Hot	Channel/Primary Shell	.0188	-.000559	508,0o00	46	10	.22	
2500/0 PSI	Tubesheet/Secondary Shell	-.00193	.000602	83,700	5,000	10	.0020	3,158
650°F	Tubesheet Center	.00159	.00159	77,400	6,600	10	.0015	
Cold Hydro.	Tubesheet/Primary Shell	.0145	-.000537	434,000	80	5	.053	
3105/0 PSI	Tubesheet/Secondary Shell	-.00220	.000684	10-6,000	3,500	5	.0014	3,887
70°F	Tubesheet Center	.00177	.00177	95,400	5,000	5	.0010	
Cold Hydro With	Tubesheet/Primary Shell	.00730	-.00348	218,000	500	5	.0001	4,401
Secondary Pressure	Tubesheet/Secondary Shell	-.000962	.000560	50,700	40,000	5	.0001	4,401
3105/700 PSI 70°F	Tubesheet Center	.00147	.00147	79,000	8,000	5	.005	
Hot Hydro	Tubesheet/Primary Shell	.00777	-.000407	222,000	400	50	.13	
2485/0 PSI	Tubesheet/Secondary Shell	-.00176	.000551	80,900	7,000	50	.0071	3,354
400°F	Tubesheet Center	.00148	.00148	76,300	8,500	50	.0059	

TABLE 5.2-26 (Sheet 1 of 3)

REACTOR COOLANT SYSTEM
QUALITY ASSURANCE PROGRAM

Component	RT*	UT*	PT*	MT*	ET*
1. Steam Generator					
1.1 Tube Sheet					
1.1.1 Forging		yes		yes	
1.1.2 Cladding		yes(1)	yes(2)		
1.2 Channel Head					
1.2.1 Casting	yes			yes	
1.2.2 Cladding			yes		
1.3 Secondary Shell and Head					
1.3.1 Plates		yes			
1.4 Tubes		yes			yes
1.5 Nozzles (forgings)		yes		yes	
1.6 Weldments					
1.6.1 Shell, longitudinal	yes			yes	
1.6.2 Shell, circumferential	yes			yes	
1.6.3 Cladding (channel head-tube sheet joint cladding restoration)			yes		
1.6.4 Steam and Feedwater Nozzle to Shell	yes			yes	
1.6.5 Support brackets				yes	
1.6.6 Tube to Tube Sheet			yes		
1.6.7 Instrument Connections (primary and secondary)				yes	
1.6.8 Temporary Attachments After Removal				yes	
1.6.9 After Hydrostatic Test (all welds and complete channel head - where accessible)				yes	
1.6.10 Nozzle Safe Ends			yes		
(weld deposit)	yes				
2. Pressurizer					
2.1 Heads					
2.1.1 Casting	yes			yes	
2.1.2 Cladding			yes		
2.2 Shell					
2.2.1 Plates		yes		yes	
2.2.2 Cladding			yes		
2.3 Heaters					
2.3.1 Tubing(4)		yes	yes		
2.3.2 Centering of element	yes				
2.4 Nozzle		yes	yes		

TABLE 5.2-26 (Sheet 2 of 3)

REACTOR COOLANT SYSTEM
QUALITY ASSURANCE PROGRAM

Component	RT*	UT*	PT*	MT*	ET*
2.5 Weldments					
2.5.1 Shell, longitudinal	yes			yes	
2.5.2 Shell, circumferential	yes			yes	
2.5.3 Cladding			yes		
2.5.4 Nozzle Safe End (if forging)	yes		yes		
2.5.5 Nozzle Safe End (if weld deposit)			yes		
2.5.6 Instrument Connections			yes		
2.5.7 Support Skirt				yes	
2.5.8 Temporary Attachments After Removal				yes	
2.5.9 All Welds and Cast Heads After Hydrostatic Test				yes	
2.6 Final Assembly					
2.6.1 All Accessible Surfaces After Hydrostatic Test				yes	
3. Piping					
3.1 Fittings and Pipe (Castings)	yes		yes		
3.2 Fittings and Pipe (Forgings)		yes	yes		
3.3 Weldments					
3.3.1 Circumferential	yes		yes		
3.3.2 Nozzle to Runpipe (No RT for nozzles less than 4 inches)	yes		yes		
3.3.3 Instrument Connections		yes	yes		
4. Pumps					
4.1 Casting	yes		yes		
4.2 Forgings					
4.2.1 Main Shaft		yes	yes		
4.2.2 Main Studs		yes	yes		
4.2.3 Flywheel (Rolled Plate)		yes			
4.3 Weldments					
4.3.1 Circumferential	yes		yes		
4.3.2 Instrument Connections			yes		
5. Reactor Vessel					
5.1 Forgings					
5.1.1 Flanges		yes		yes	
5.1.2 Studs		yes		yes	
5.1.3 Head Adapters		yes	yes		

TABLE 5.2-26 (Sheet 3 of 3)

REACTOR COOLANT SYSTEM
QUALITY ASSURANCE PROGRAM

Component	RT*	UT*	PT*	MT*	ET*
5.1.4 Head Adapter Tube		yes	yes		
5.1.5 Instrumentation Tube		yes	yes		
5.1.6 Main Nozles		yes		yes	
5.1.7 Nozzle Safe Ends (if forging is employed)		yes	yes		
5.2 Plates		yes		yes	
5.3 Weldments					
5.3.1 Main Steam	yes			yes	
5.3.2 CRD Head Adapter Connection			yes		
5.3.3 Instrumentation Tube Connection			yes		
5.3.4 Main nozzles	yes			yes	
5.3.5 Cladding		yes(3)	yes		
5.3.6 Nozzle-Safe Ends (if forging)	yes		yes		
5.3.7 Nozzle Safe Ends (If weld deposit)	yes		yes		
5.3.8 Head Adaptor Forging to Head Adapter Tube	yes		yes		
5.3.9 All Welds After Hydrotest				yes	
6. Valves					
6.1 Castings	yes		yes		
6.2 Forgings (No UT for valves two inch and smaller)		yes	yes		

---

* RT - Radiographic
UT - Ultransonic
PT - Dye Penetrant
MT - Magnetic Particle
ET - Eddy Current

(1) Flat Surfaces Only
(2) Weld Deposit Areas Only
(3) UT of Clad Bond-to-Base Metal
(4) Or a UT and ET

TABLE 5.2-27 (Sheet 1 of 2)

MATERIALS CONSTRUCTION OF THE REACTOR COOLANT SYSTEM COMPONENTS

Component	Section	Materials
Reactor Vessel	Pressure Plate	ASTM A-533 Grade B Class 1
	Pressure Forgings	ASTM A-508 Class 2
	Cladding, Stainless	Type 304 or equivalent
	Stainless Weld Rod	Type 308, 309, or Type 312
	O-Ring Head Seals	Inconel - 718
	CRDM Housings	SA-182 Type 304
	Lower Tube	SB-167
	Studs	SA-540 Grade B-23
	Instrumentation Nozzles	Inconel SB 167
	Insulation	Stainless Steel
Steam Generator	Pressure Plate	ASTM A-533 Grade A Class 1
	Pressure Forgings	ASTM A-508 Class 2
	Cladding for Heads, Stainless	Type 304 or equivalent
	Stainless Weld Rod	Type 304, Type 3081, or Type 309
	Cladding for Tube Sheets	Inconel
	Tubes	Inconel - 600
	Channel Head Castings	ASTM A-216 Grade WCC
Pressurizer	Shell	SA-533 Class 1
	Heads	SA-216 Grade WCC
	Support Skirt	SA-516 Grade 70
	Nozzle Weld Ends	SA-182 F316
	Inst. Tube Coupling	SA-182 F316
	Cladding, Stainless	Type 304 or equivalent

TABLE 5.2-27 (Sheet 2 of 2)

MATERIALS CONSTRUCTION OF THE REACTOR
COOLANT SYSTEM COMPONENTS

Component	Section	Materials
Pressurizer (cont.)	Internal Plate	SA-240 Type 304
	Inst. Tubing	SA-213 Type 304
	Heater Well Tubing	SA-213 Type 316 Seamless
	Heater Well Adaptor	SA-182 F316
Pressurizer Relief Tank	Shell	ASTM A-285 Grade C
	Heads	ASTM A-285 Grade C
	Internal Coating	Amercoat 55
Pipe	Pipes	ASTM A-376 Type 316
	Fittings	ASTM A-351 Grade CF8M
	Nozzles	ASTM A-182 Grade F316
Pump	Shaft	ASTM A-182 Grade F347
	Impeller	ASTM A-351 Grade CF8
	Casing	ASTM A-351 Grade CF8
Valves	Pressure Containing Parts	ASTM A-351 Grade CF8M and ASTM A-182 Grade F316

TABLE 5.2-28

REACTOR COOLANT WATER CHEMISTRY SPECIFICATION

Electrical Conductivity	Determined by the concentration of boric acid and alkali present. Expected range is < 1 to 40 μ Mhos/cm at 25°C.
Solution pH	Determined by the concentration of boric acid and alkali present. Expected values range between 4.2 (high boric acid concentration) to 10.5 (low boric acid concentration) at 25°C.
Oxygen, ppm, max.	0.10
Chloride, ppm, max.	0.15
Fluoride, ppm, max.	0.15
Hydrogen, cc (STP)/kg H_2O	25-35
Total Suspended Solids, ppm, max.	1.0
pH Control Agent (Li^7OH)	0.3×10^{-4} to 3.2×10^{-4} molal (equivalent to 0.22 to 2.2 ppm Li^7)
Boric Acid as ppm B	Variable from 0 to ~4000

TABLE 5.2-29

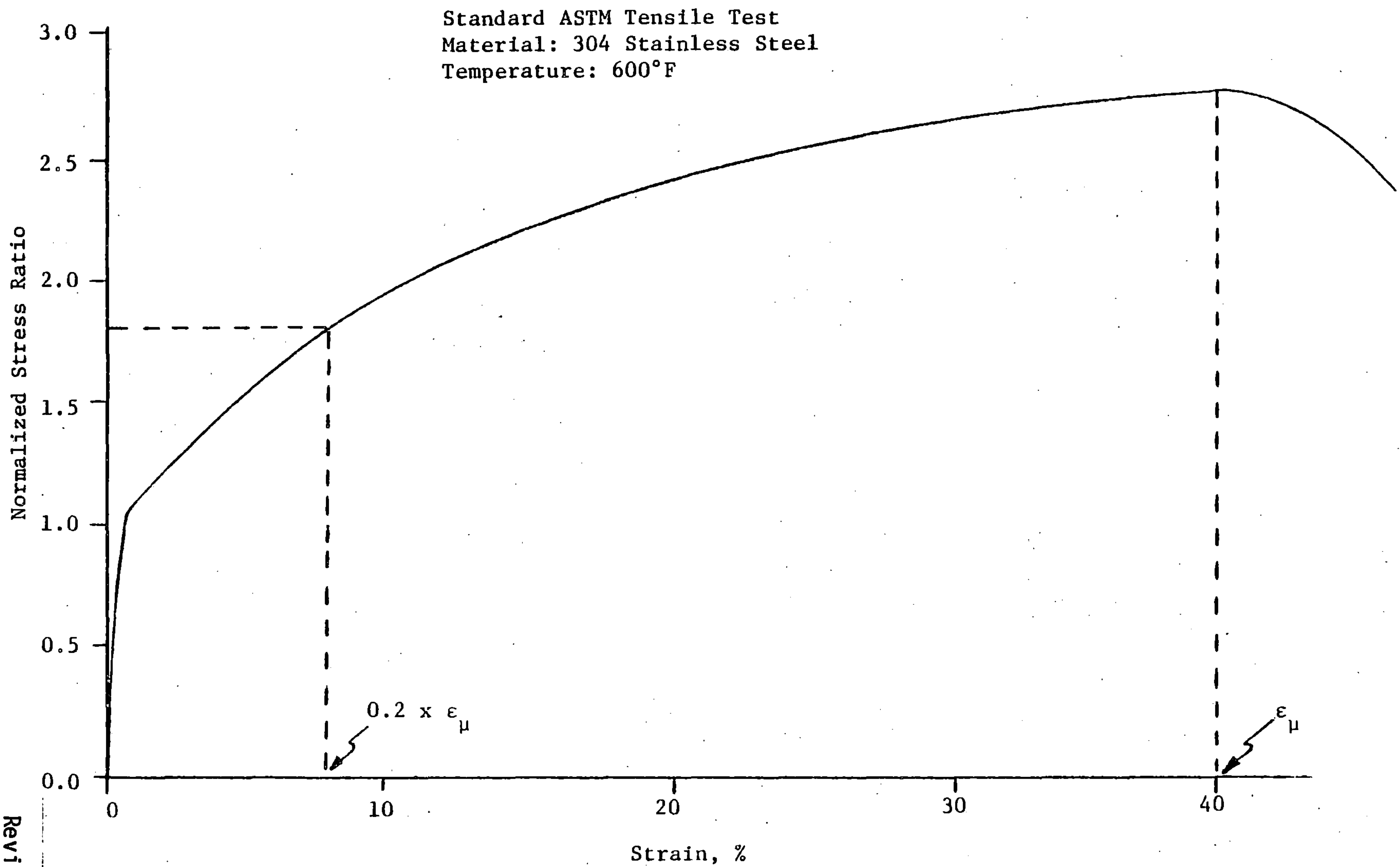
SALEM NUCLEAR GENERATING STATION STEAM GENERATOR WATER CHEMISTRY

NORMAL LIMITS OF CONTROL

Water Sample Location	Cation Conductivity MHOS/CM at 25°C	pH at 25°C	Sodium PPB	Chloride PPM	Free Hydroxide PPM
Steam Generator Blowdown	$\leq$ 2.0	8.5-9.2	N/A	$\leq$ 0.15	$\leq$ 0.15

LIMITING SPECIFICATIONS

Water Sample Location	Control Parameter	Period to Return to within Normal Limits of Control: 14 days	72 hours	Immediate
Steam Generator	Cation Conductivity, Mhos/.cm at 25°C	> 2.0 but $\leq$ 120	N/A	> 120
	pH at 25°C	8.0 - 9.4	N/A	< 8.0 or > 9.4
	Chloride, ppm	N/A	> 0.15 but < 1.0	$\geq$ 1.0
	Free Hydroxide, ppm	N/A	> 0.15 but < 1.0	$\geq$ 1.0



PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Typical Stress - Strain Curve

Updated FSAR

Figure 5.2-1

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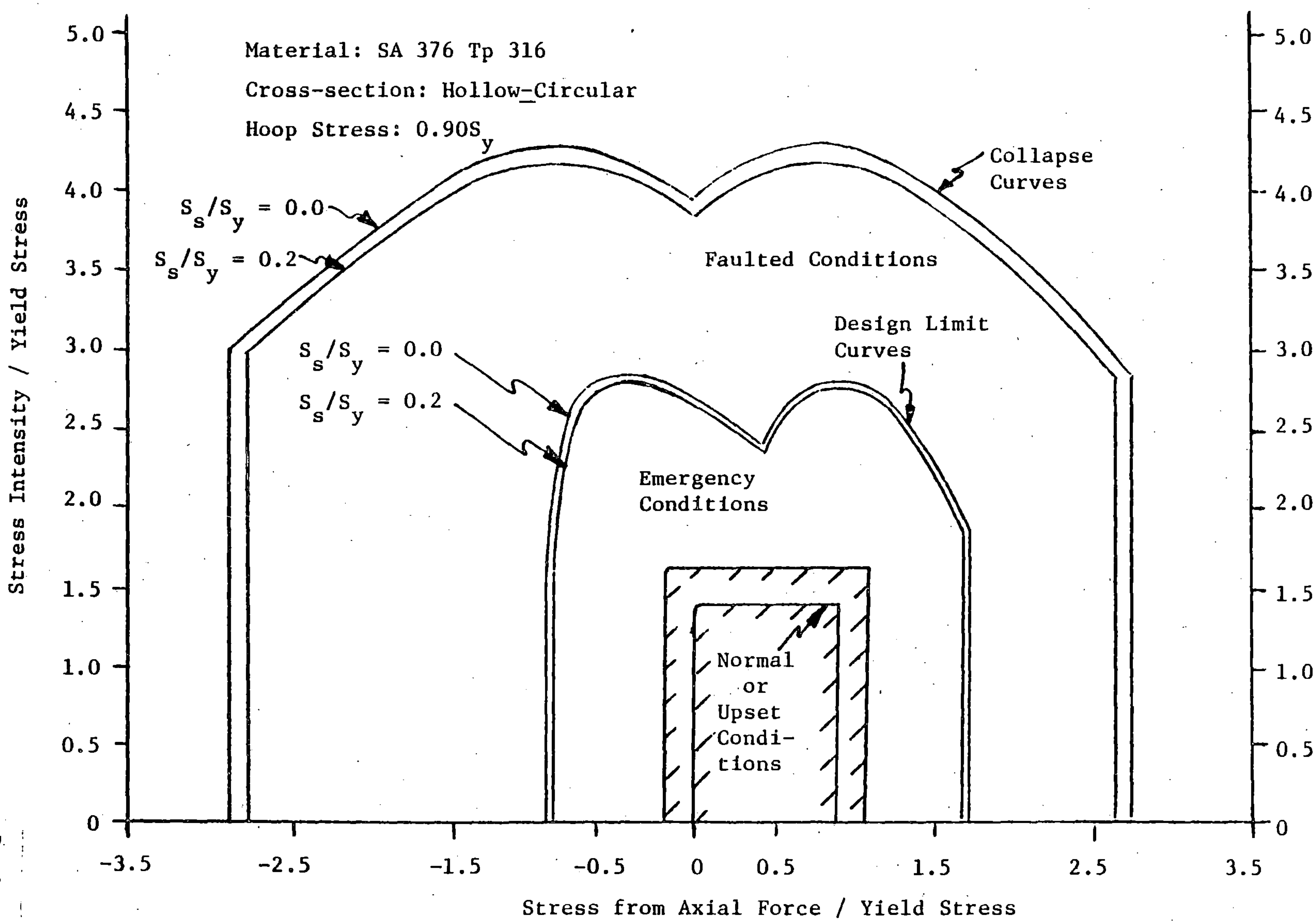
July 22, 1982



PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Comparison Between Design and Collapse Conditions ($0.90 S_y$)

Updated FSAR

Figure 5.2-2

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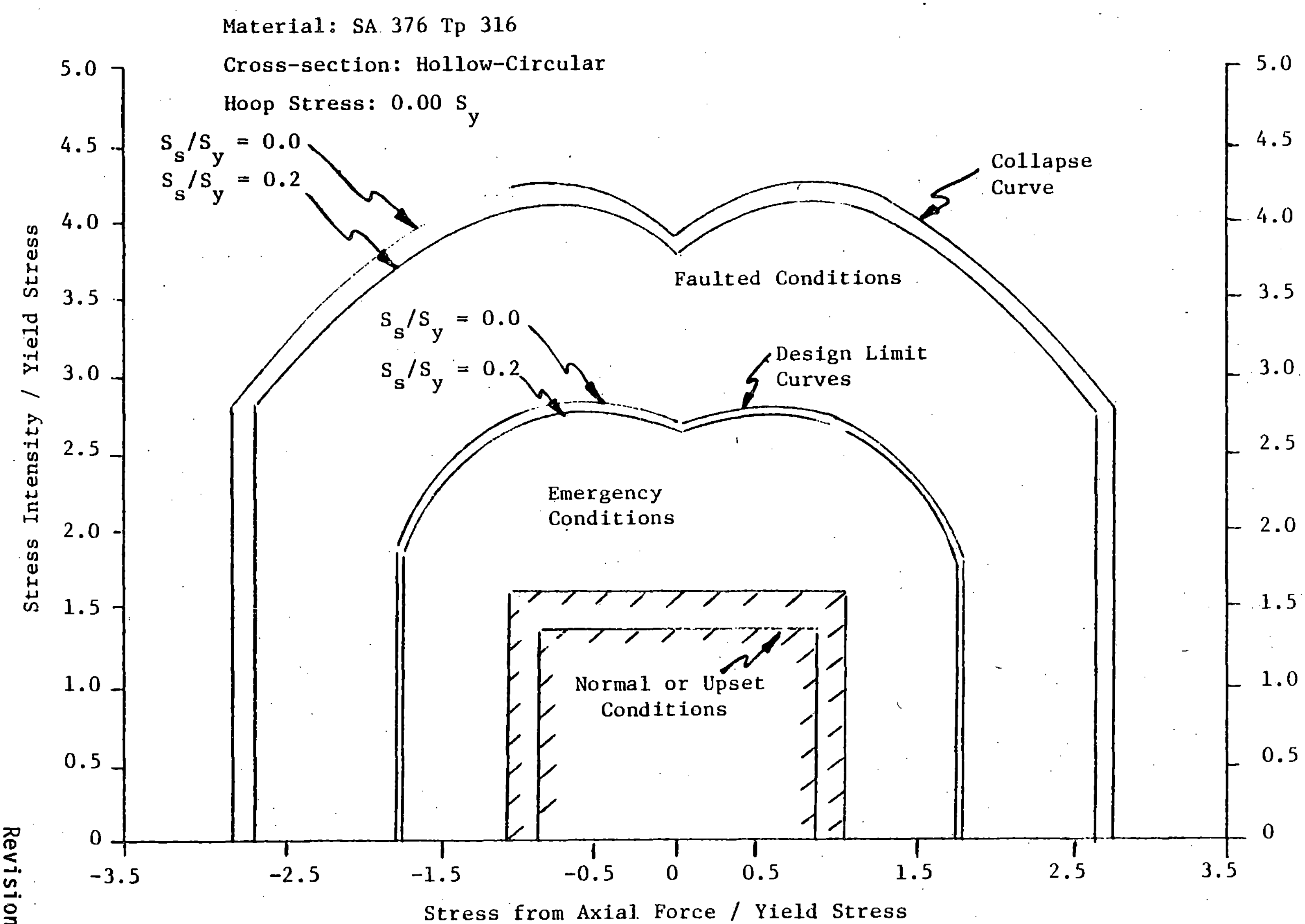

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Updated FSAR

Comparison Between Design and Collapse Conditions (0.00 S_y)

Figure 5.2-3

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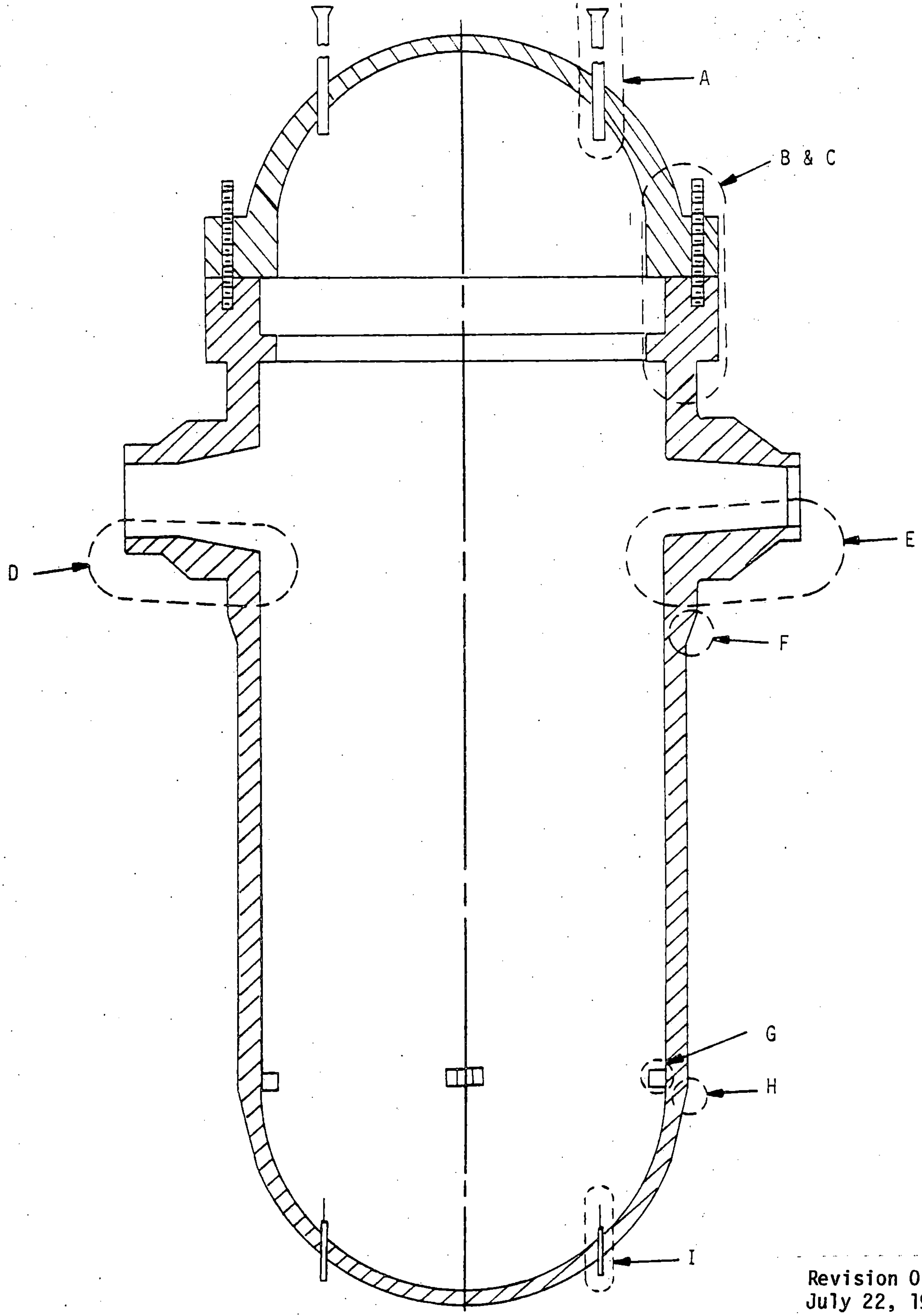
July 22, 1982



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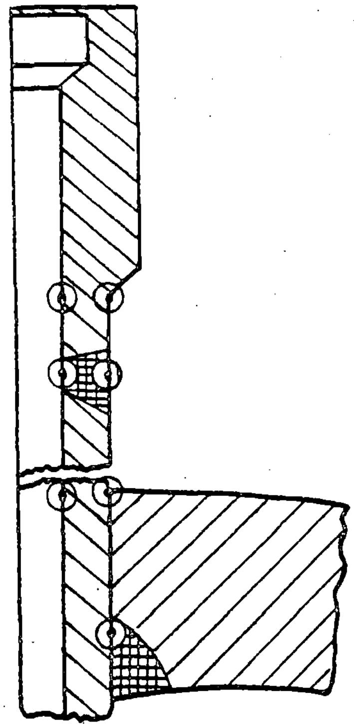
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Vessel Stress Analysis Areas Examined Updated FSAR Figure 5.2-4



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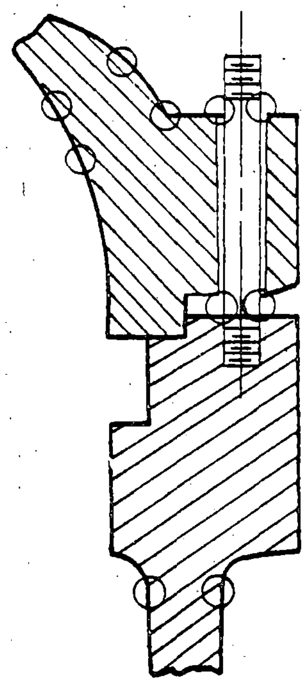

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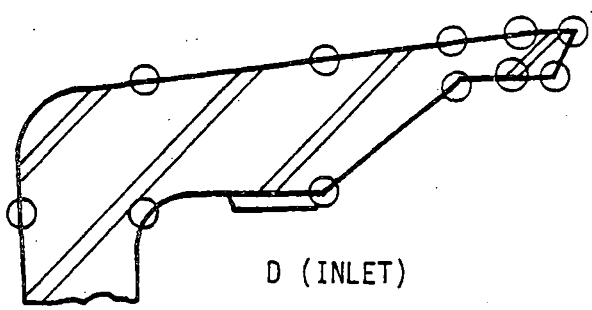
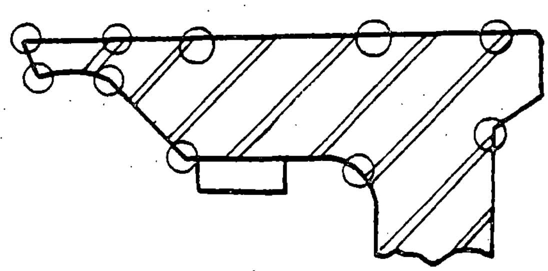


D (INLET)



E (OUTLET)

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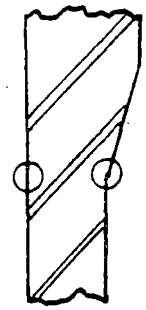
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Vessel Stress Analysis Details - Upper
	Updated FSAR — Figure 5.2-5



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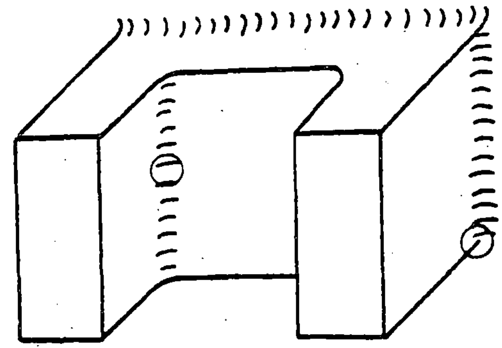

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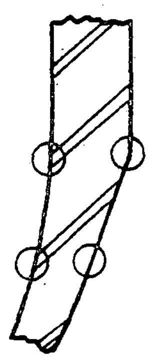

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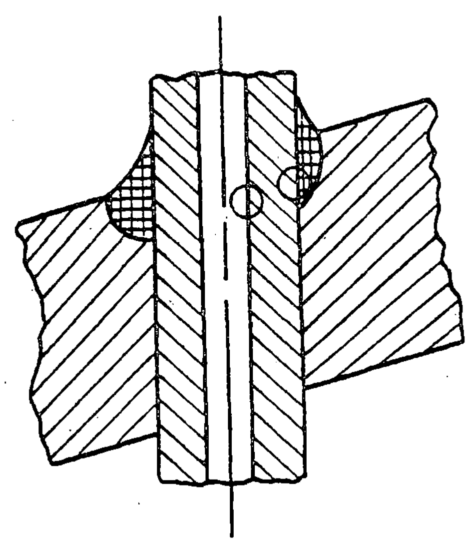

H

NOTE:

THE POINTS CIRCLED IN THE SKETCHES REPRESENT THE GENERAL LOCATION AND GEOMETRY OF THE AREAS OF DISCONTINUITY AND/OR STRESS CONCENTRATION.

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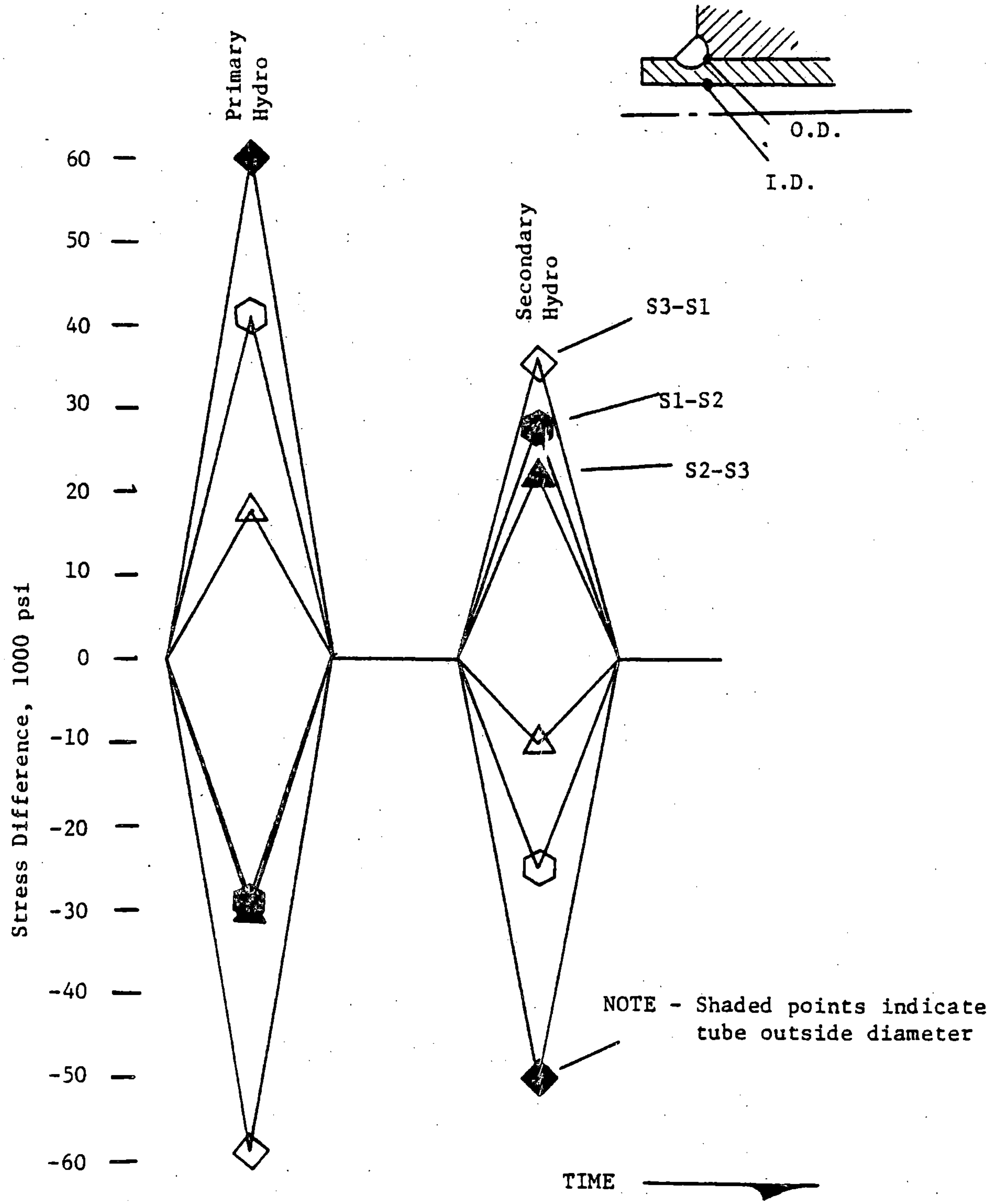
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Vessel Stress Analysis Details - Lower	
	Updated FSAR	Figure 5.2-6



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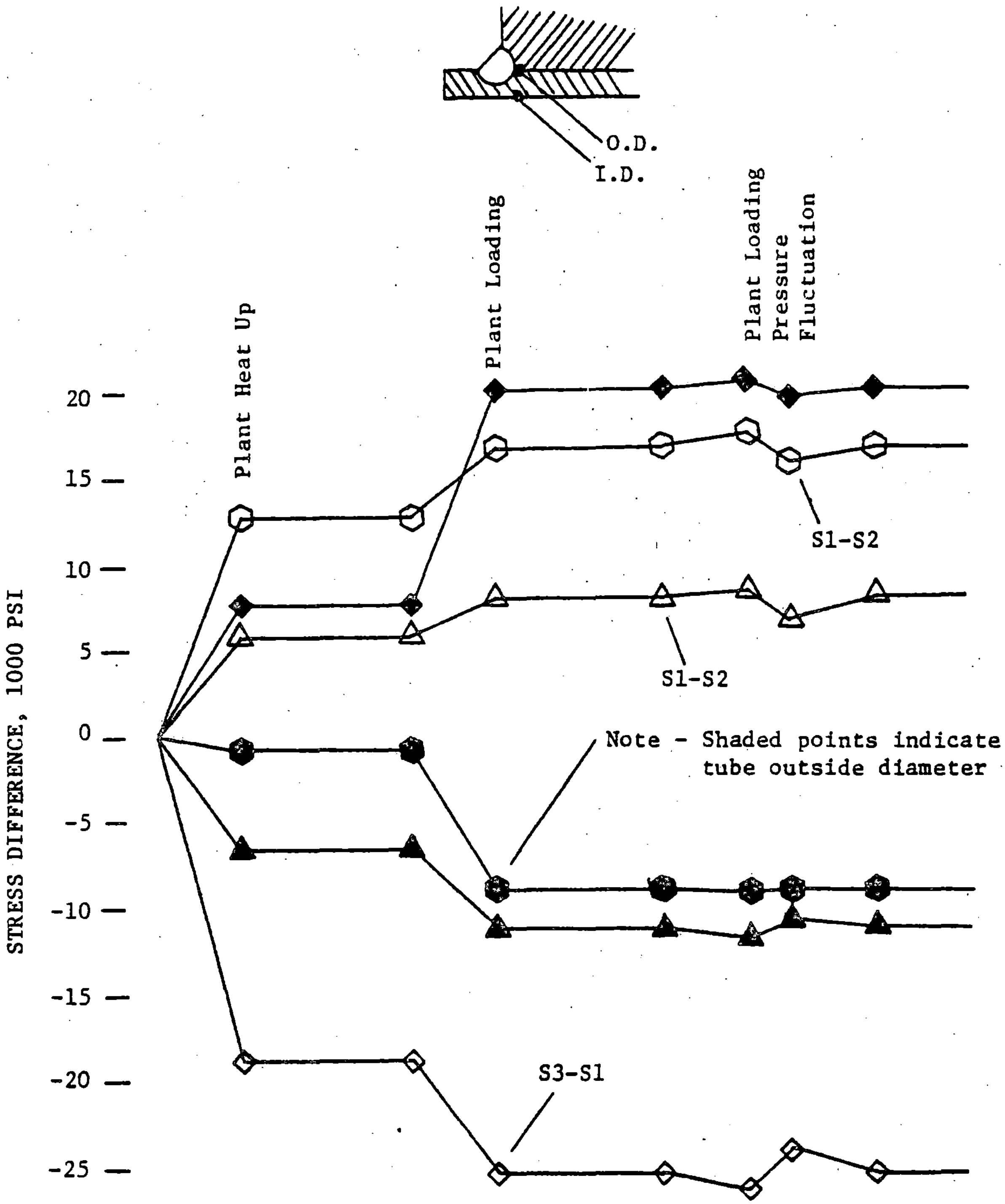
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Primary and Secondary Hydrostatic Test Stress History for the Center Hole Location
	Updated FSAR — Figure 5.2-7



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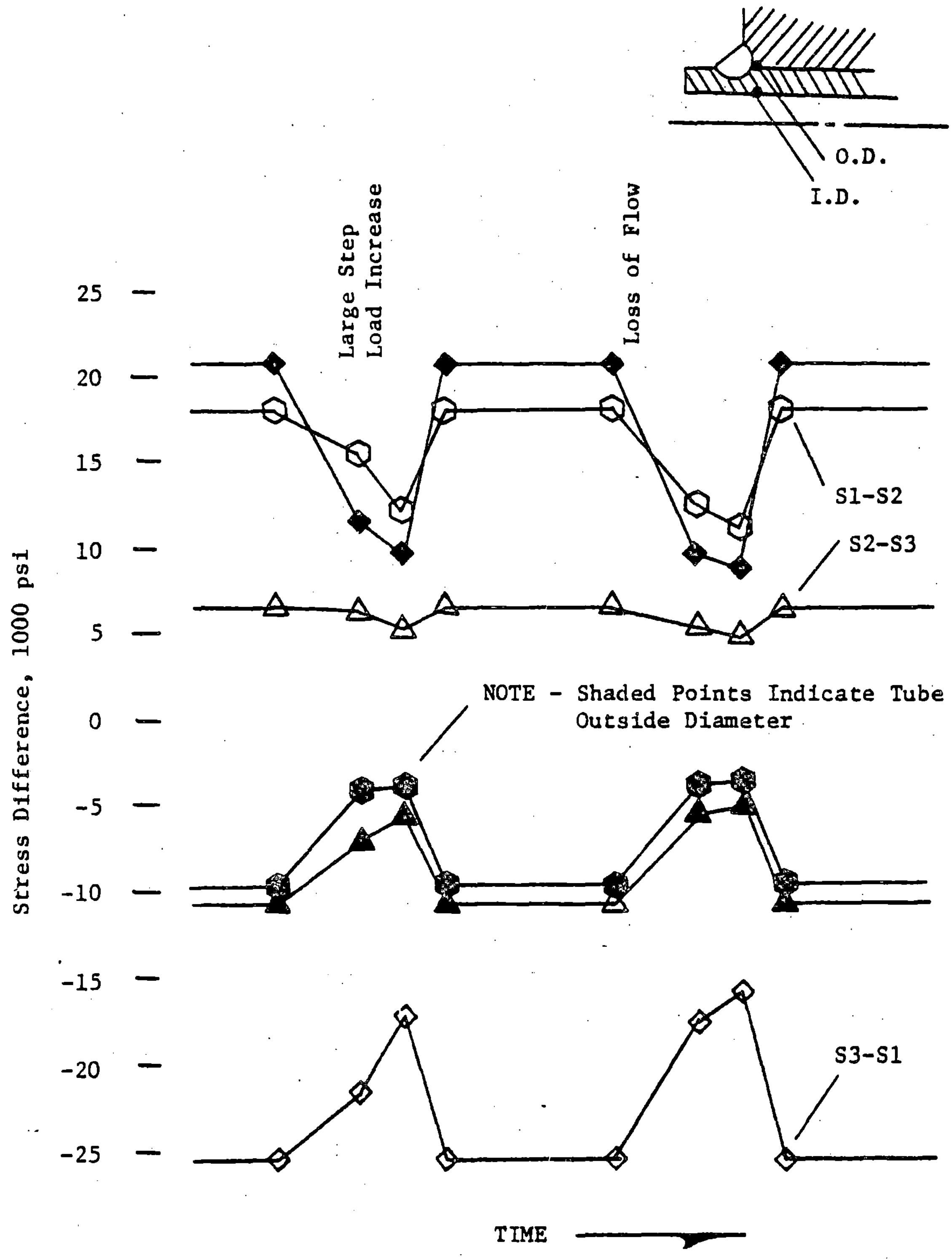
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Plant Heatup and Operational Loading Transients (With Steady-State Plateau) Stress History for the Hot Side Center Hole Location
	Updated FSAR — Figure 5.2-8



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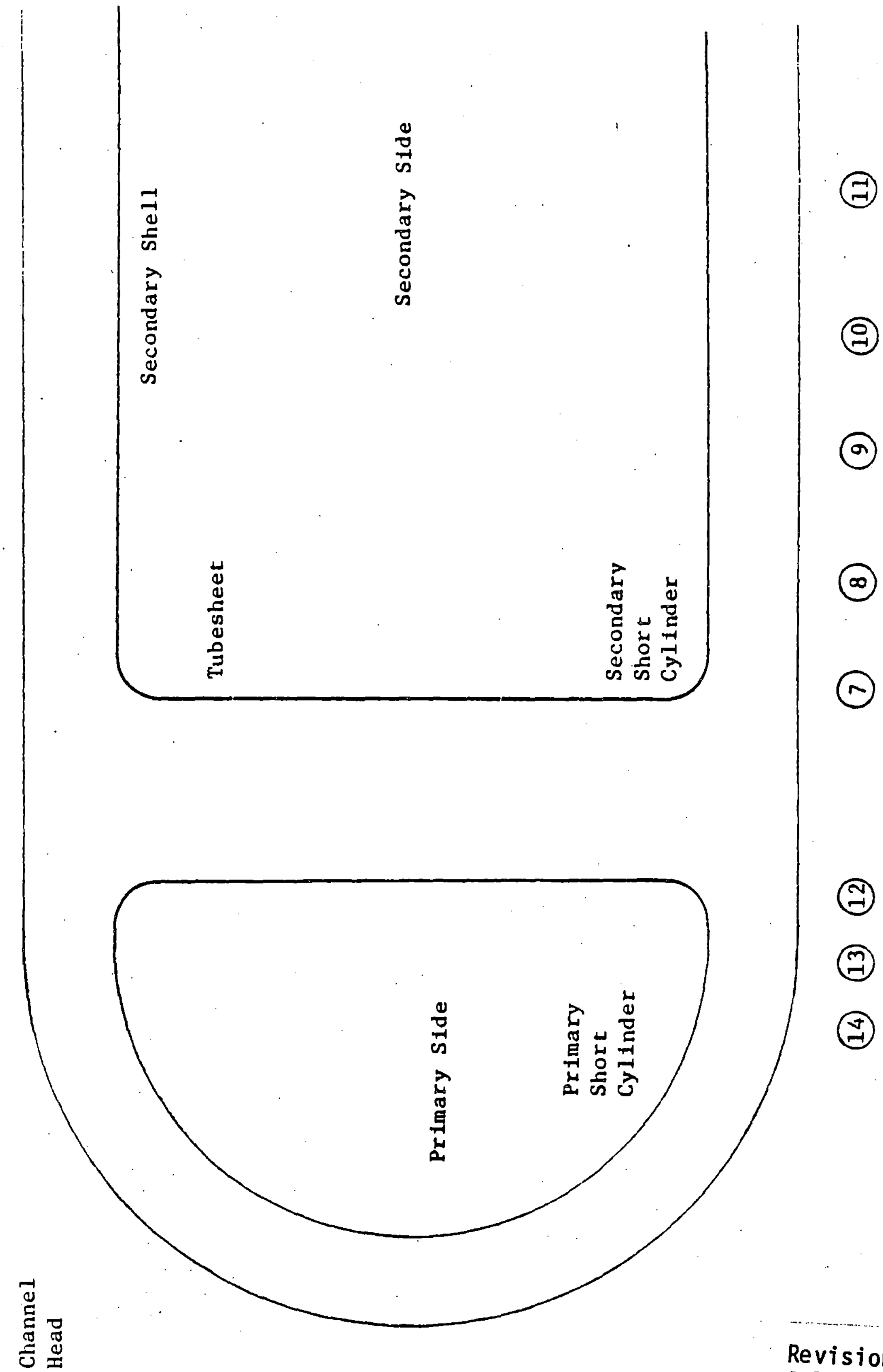
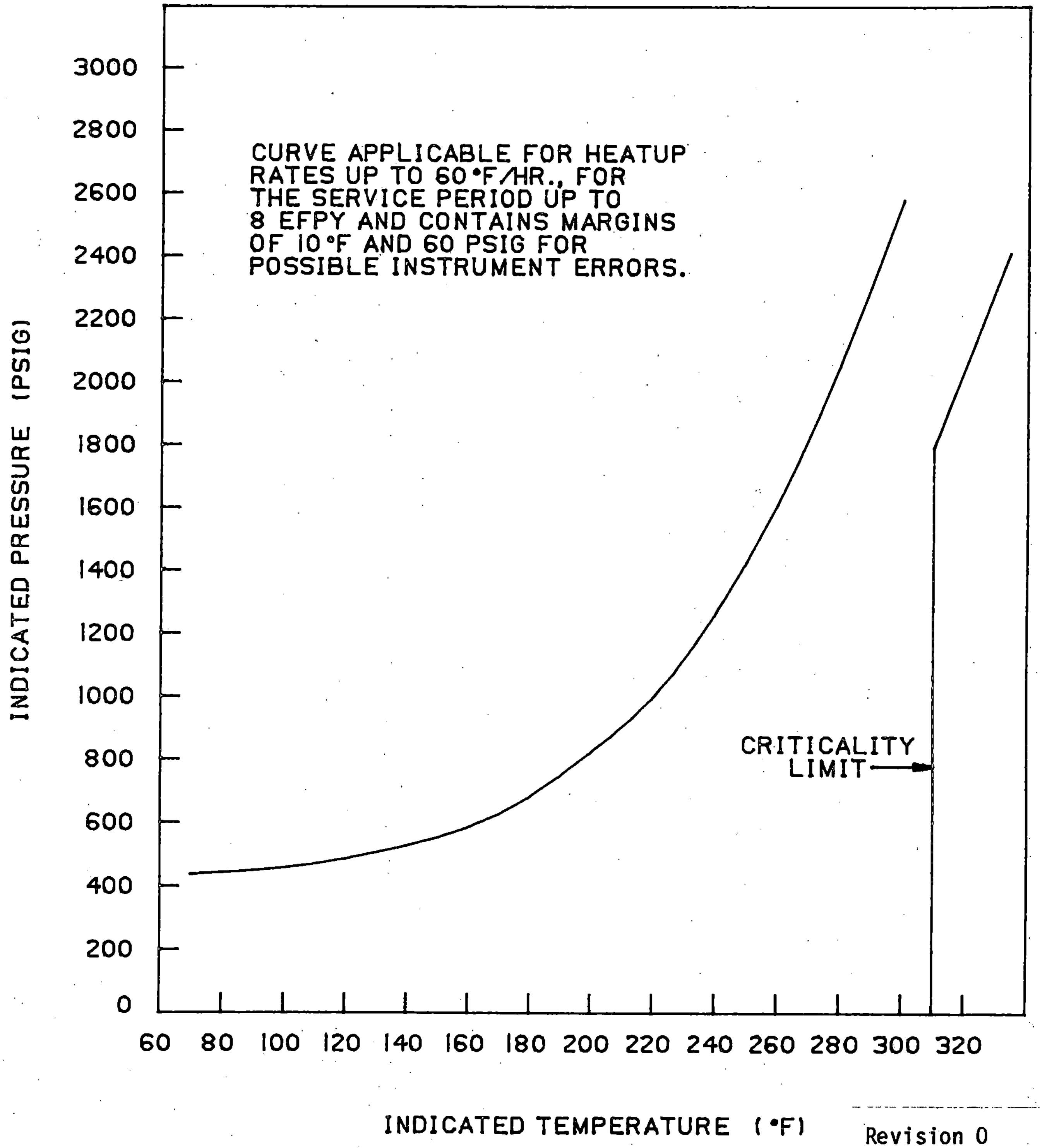
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Large Step Load Decrease and Loss of Flow Stress History for the Hot Side Center Hole Location
	Updated FSAR — Figure 5.2-9



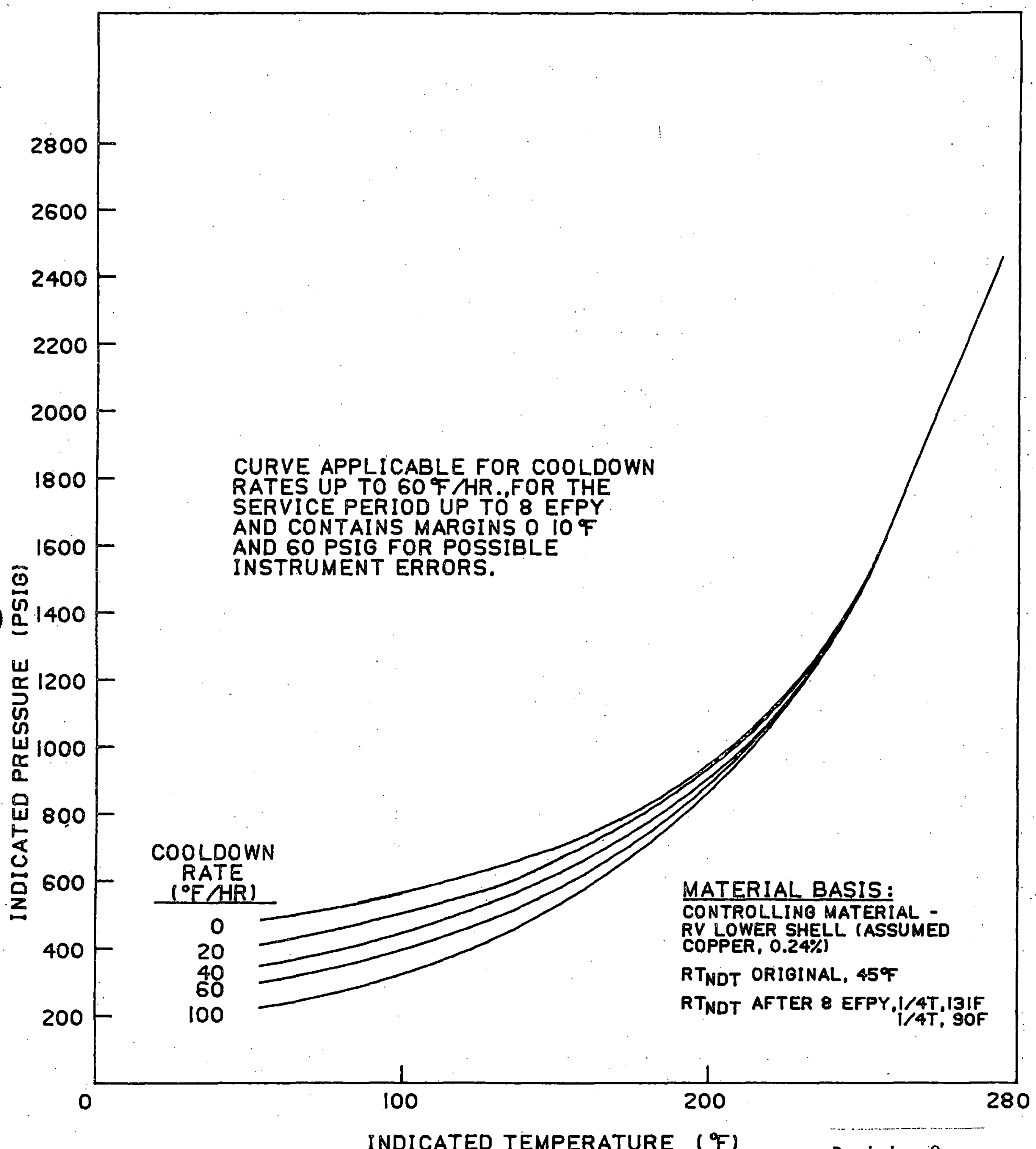
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Primary and Secondary Boundary Components Shell Locations of Stress Investigations	
	Updated FSAR	Figure 5.2-10



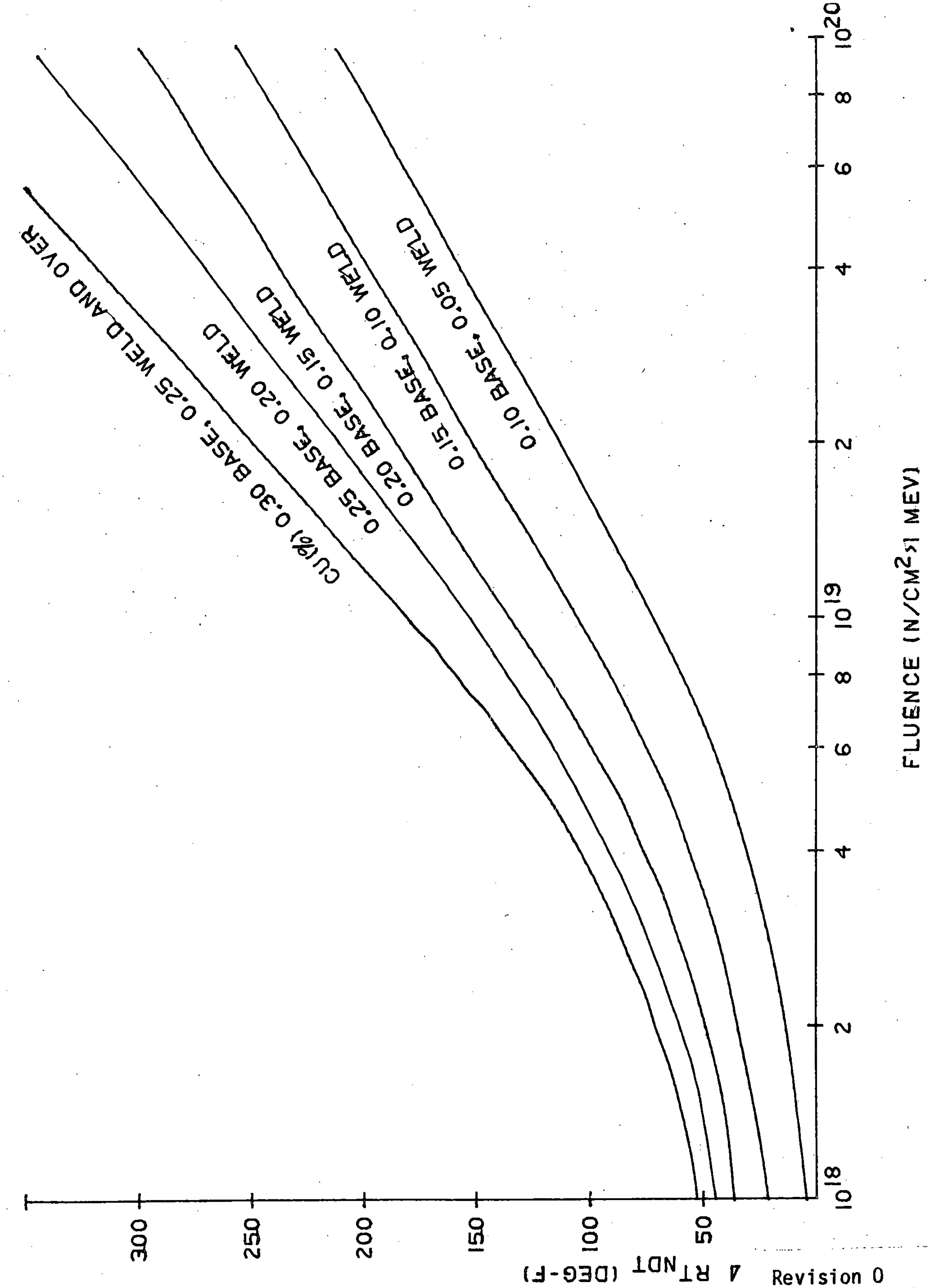
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Coolant System Heatup Limitations for First 8 EFPY of Operation
	Updated FSAR — Figure 5.2-11



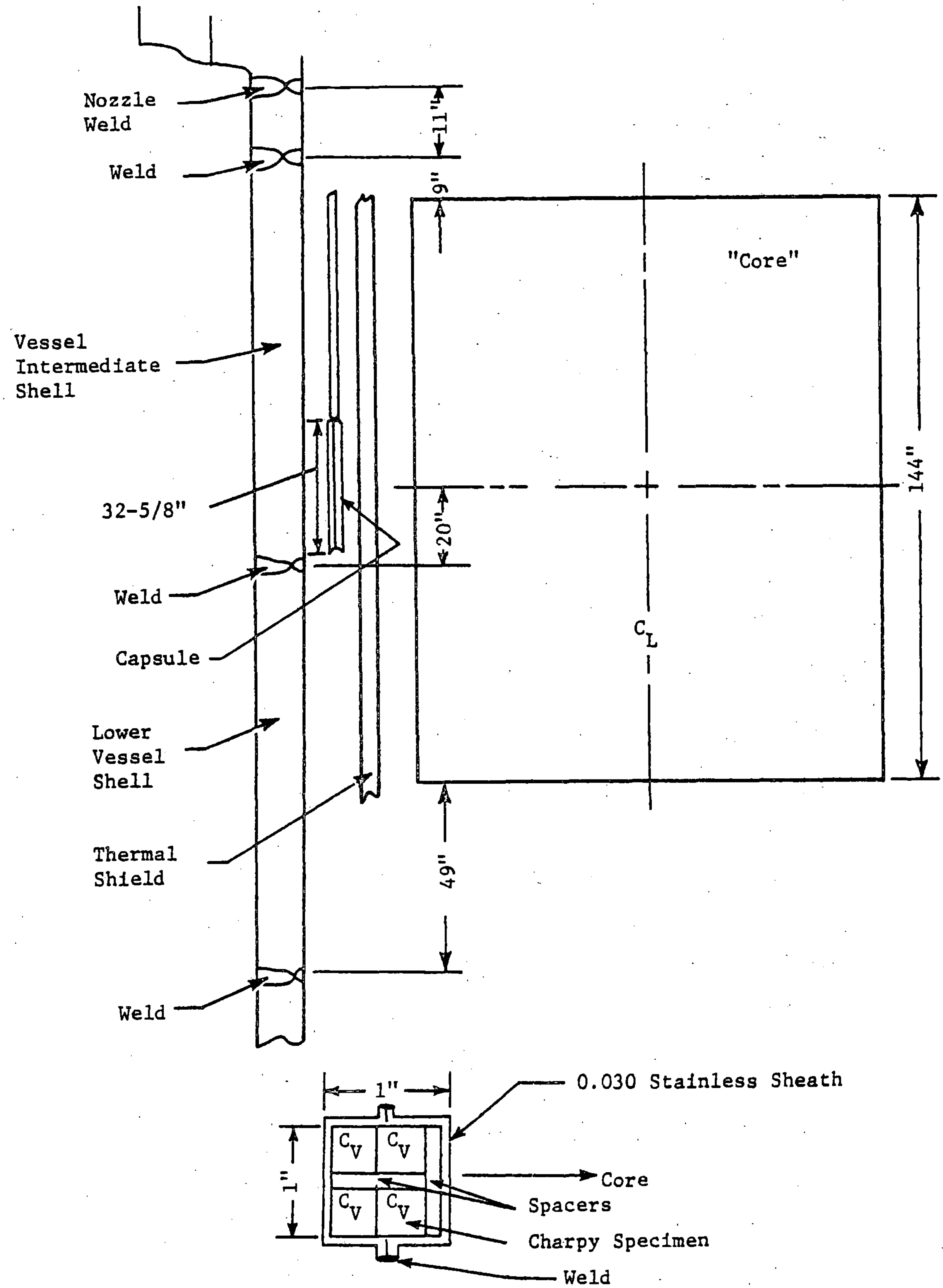
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Coolant System Cooldown Limitations for First 8 EFPY of Operation
	Updated FSAR — Figure 5.2-12



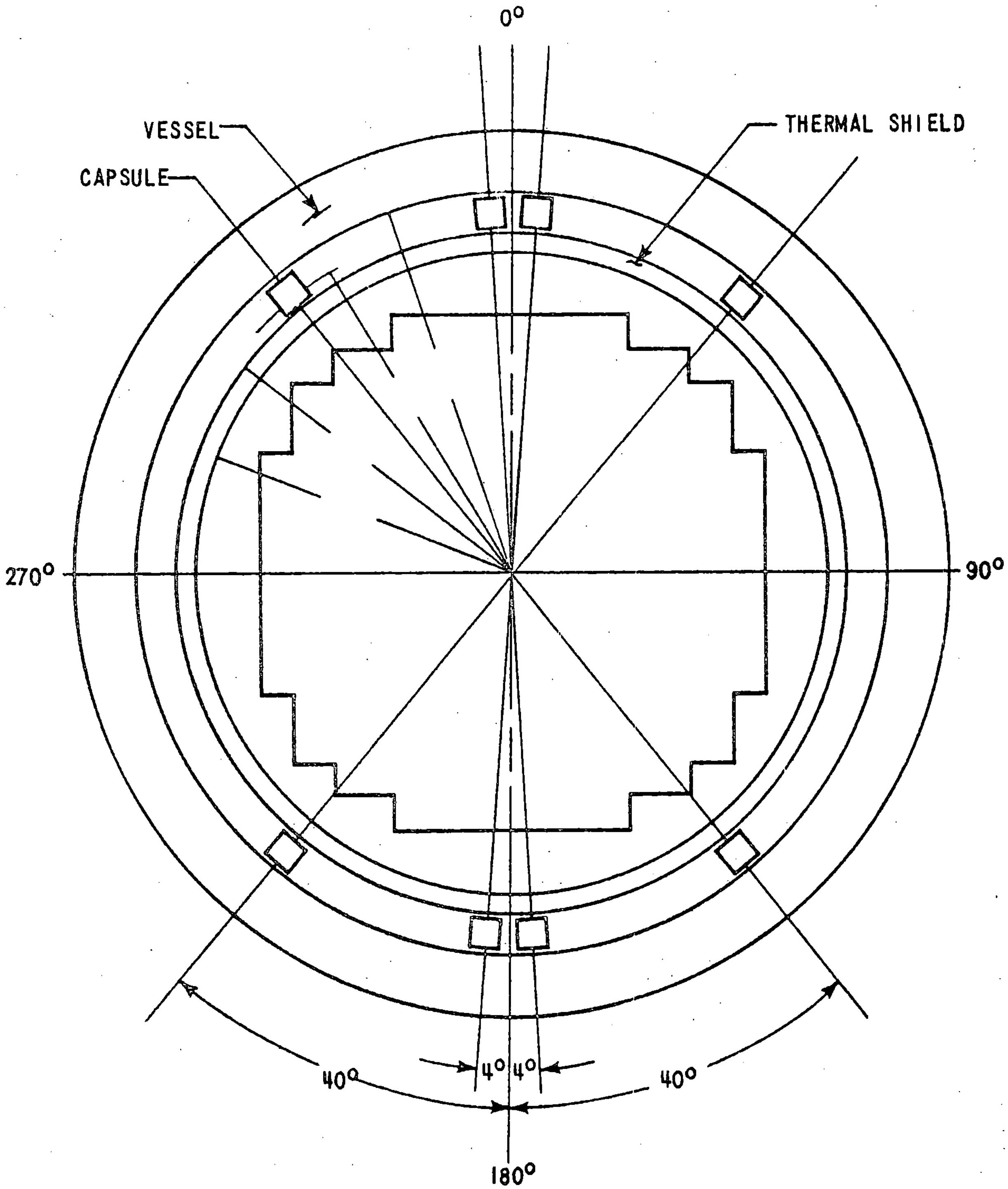
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Effect of Fluence and Copper Content on Shift of RT_{NDT} for RV Steels Exposed to 550°F Temperature	
	Updated FSAR	Figure 5.2-13



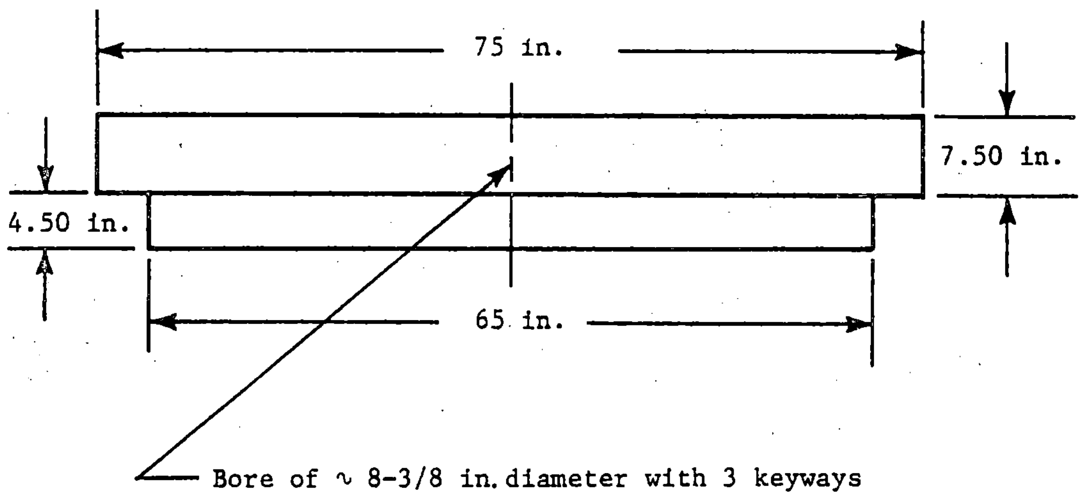
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Typical Surveillance Capsule Elevation View
	Updated FSAR Figure 5.2-14



Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Surveillance Capsule Plan View	
	Updated FSAR	Figure 5.2-15



NOTE: The plates are bolted together with the bolts aligned perpendicular to the planes of the plates.

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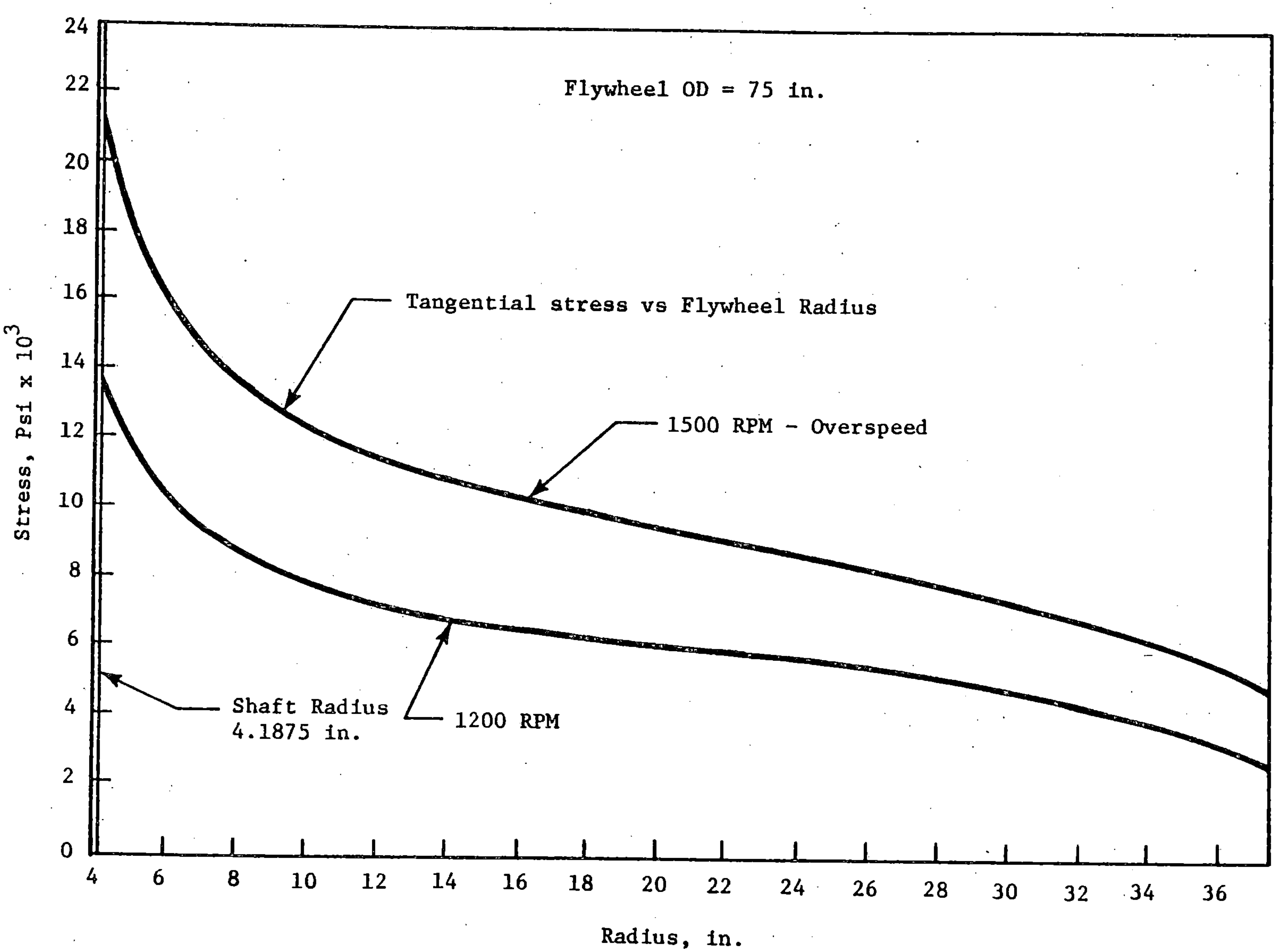
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Coolant Pump Flywheel
	Updated FSAR — Figure 5.2-16



PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Updated FSAR

Flywheel Characteristics Curve

Figure 5.2-17

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5.3 THERMAL HYDRAULIC SYSTEM DESIGN

5.3.1 ANALYTICAL METHODS AND DATA

The thermal and hydraulic design bases of the reactor coolant system (RCS) are described in Chapter 4.

5.3.2 OPERATING RESTRICTIONS ON PUMPS

The minimum net position suction head (NPSH) and minimum seal injection flow rate must be established before operating the reactor coolant pumps. Requirements are set forth in the pump operating instructions.

5.3.3 TEMPERATURE-POWER OPERATING MAP

Reactor power is controlled to maintain average coolant temperature at a value which is a linear function of load.

5.3.4 LOAD FOLLOWING CHARACTERISTICS

Load following is discussed in Section 5.2.1.5.2.

5.3.5 TRANSIENT EFFECTS

Transient effects on the RCS are evaluated in Chapter 15.

5.3.6 THERMAL AND HYDRAULIC CHARACTERISTICS SUMMARY TABLE

The thermal and hydraulic characteristics are given in Tables 4.3-1, 4.4-1 and 4.4-2.

5.3.7 NATURAL CIRCULATION CAPABILITY

The capability to perform natural circulation cooldown has been analyzed following a transient in a PWR of different design in which significant void formation occurred in the reactor vessel head. The analysis took into account such factors as the amount of bypass flow to the upper head region, RCS cooldown/depressurization rate, heat removal via the Control Rod Drive Mechanism (CRDM) cooling fans and ambient losses. Salem is a "T-Hot" plant, i.e., one in which the upper head water temperature is assumed equal to the hot leg temperature. Analysis results are summarized below.

The average cooldown rate of the upper head fluid due to the 25°F/hr natural circulation cooldown rate is about 10°F/hr. The total upper head cooldown rate due to both the natural circulation cooldown and the CRDM fans varies from 42°F/hr initially to around 27°F/hr when the upper head temperature is cooled to 350°F. Thus, with the CRDM fans operating during the cooldown with no void formation occurring in the upper head area. The operator is required to maintain 50°F subcooling during the depressurization.

Without the CRDM fans in operation, the plant can be cooled down to Residual Heat Removal (RHR) System conditions at a natural circulation cooldown rate of 25°F/hr with no void formation occurring in the upper head. The operator is required to maintain 50°F subcooling until the primary system pressure reaches 1900 psia. After the automatic safety injection signals are blocked, the operator establishes 200°F subcooling (approximately 430°F in the hot leg) and maintains 200°F subcooling (or the Technical Specification limit if it is more restrictive) to a primary system pressure of 1200 psia. Depressurization is stopped at 1200 psia and the cooldown is continued until the primary system temperature is less than 350°F. At this point the operator is required to wait for approximately 20 hours to allow the upper head to cool off to a temperature corresponding to a saturation pressure of 400 psia. Finally the primary system is depressurized to 400 psia and the RHR System used for further cooldown.

5.4 REACTOR VESSEL AND APPURTENANCES

Section 5.4 is divided into four principal subsections - (1) design basis, (2) description, (3) evaluation, and (4) tests and inspections.

5.4.1 DESIGN BASES

The reactor vessel was designed and fabricated to Class A of the ASME Boiler and Pressure Vessel Code, Section III. Material specifications are discussed in Section 5.2.3.1. Fracture toughness of the reactor vessel materials is discussed in Section 5.2.4. Design transients are discussed in Section 5.2.1.

5.4.2 DESCRIPTION

The reactor vessel is cylindrical with a welded hemispherical bottom head and a removable, flanged and gasketed, hemispherical upper head. The vessel contains the core, core support structures, control rods, thermal shield and other parts directly associated with the core. The reactor vessel closure head contains head adaptors. These head adaptors are tubular members, attached by partial penetration welds to the underside of the closure head. The upper end of these adaptors contain acme threads for the assembly of the control rod drive mechanisms and/or instrumentation adaptors. The seal arrangement at the upper end of these adaptors consists of a welded flexible canopy seal. The vessel has inlet and outlet nozzles located in a horizontal plane just below the vessel flange but above the top of the core. Coolant enters the inlet nozzles and flows down the core barrel-vessel wall annulus, turns at the bottom and flows up through the core to the outlet nozzles.

The bottom head of the vessel contains penetration nozzles for connection and entry of the nuclear in-core detection instrumentation. Each tube is attached to the inside of the bottom head by a partial penetration weld.

The reactor vessel is designed to provide the smallest and most economical volume required to contain the reactor core, control rods and the necessary supporting and flow-directing internals. Inlet and outlet nozzles are spaced around the vessel. Outlet nozzles are located on opposite sides of the vessel to facilitate optimum layout of the reactor coolant system (RCS) equipment. The inlet nozzles are tapered from the coolant loop-vessel interfaces to the vessel inside wall to reduce loop pressure drop.

The reactor vessel flange and head are sealed by two hollow metallic O-rings. Seal leakage is detected by means of two leak-off connections; one between the inner and outer ring, and one outside of the outer O-ring. Piping and associated valving are provided to direct any leakage to the reactor coolant drain tank. Leakage will be indicated by a high- temperature alarm from a detector in the leakoff line.

Ring forgings have been used in the following areas of the reactor vessel:

1. Closure head flange.

2. Vessel flange.

3. Eight primary nozzles.

The cylindrical portion of the reactor vessel below the refueling seal ledge is permanently insulated with a metallic reflective-type insulation supported from the reactor coolant nozzles. This insulation consists of inner and outer sheets of stainless steel spaced 3 inches apart with multilayers of stainless steel as the insulating agent. Removable panels of the metallic reflective type insulation described above are provided for the reactor vessel head and closure region. These panels are supported on the refueling seal ledge and vent shroud support ring. The rest of the closure head is insulated with removable panels of at least 3 inches of the reflective insulation described or halide free insulating material. The bottom head is also insulated with reflective insulation, but it is not removable.

A schematic of the reactor vessel is shown in Figure 5.1-1. The materials of construction are given in Table 5.2-27 and the design parameters are given on Table 5.2-3.

The following summarizes those features which preclude wetting of the reactor vessel studs with boric acid.

Refueling procedures include removal of studs before moving the head, and replacement only after the head is sealed. Hole plugs with O-ring seals are placed in the stud holes whenever the head is off. The flange will be dried completely before replacing the head and removing the stud hole plugs.

Spilling of boric acid onto the studs during venting will be precluded by the following precautions:

1. Detailed step-by-step venting procedures exist.

2. Personnel have accurate knowledge of RCS level during venting.

3. Only a small quantity of coolant is released at each venting step.

4. The small quantity of released coolant is piped into portable containers for collection.

5.4.3 EVALUATION

5.4.3.1 Compliance With 10 CFR 50 Appendices G and H

The No. 2 Unit reactor vessel was built to the 1965 Edition of the ASME Boiler and Pressure Vessel Code, Section III, and Addenda up to and including the Summer of 1966. Thus the ferritic materials in the reactor vessel were not tested by the vessel fabricator to meet later editions of Section III of the ASME Code as required by 10 CFR 50 Appendix G. Westinghouse performed tests, as part of the surveillance program, on the reactor vessel intermediate and lower shell course plates, which surround the effective height of the fuel assemblies. Full Charpy test curves were obtained on these plates from specimens oriented normal to the principal rolling direction. A summary of the results of these tests are shown in Table 5.4-1.

Based on the test results shown in Table 5.4-1, the core region shell plates have a minimum upper shelf energy (USE) greater than 75 ft-lbs as required by Appendix G.

The stress intensity factors for various reactor vessel locations were not calculated to determine if they are lower than the reference stress intensity factors specified in Appendix G of the Code. Westinghouse has performed these calculations for many older reactor vessels with similar properties and the results have always shown that the calculated stress intensity factors are lower than the reference stress intensity. Thus, based on past experience, Westinghouse is confident that if the calculation was performed, the results would be shown to be acceptable and be lower than the reference stress intensity factors as required by Appendix G of the ASME Code.

Heatup and cooldown limit curves, including preoperational system leakage and hydrostatic pressure tests, were determined in accordance with the method described in Appendix G of the ASME Code.

Reactor vessel bolting material tests were not performed to demonstrate conformance with the minimum requirement of 25 mils lateral expansion, and 45 ft-lbs at the preload temperature or at the lowest service temperature, whichever is lower. Tests were performed to meet 35 ft-lbs at 10°F. The results of the tests are shown in Table 5.4-2.

Table 5.4-2 shows that all the bolting material met the 45 ft-lb requirement at 10°F except for one end of one bar, which was used for closure head nuts and washers. It is expected that this bar would exhibit at least 45 ft-lb if tested at 50°F which is considered to be the lowest preload or service temperature.

At the time the tests were conducted, lateral expansion measurements were not required. However, it is expected that these materials would exhibit at least 25 mils lateral expansion if tested at 50°F, based on test results from other bolting materials where both impact energy and lateral expansion data were obtained.

The reactor vessel is designed to permit a thermal annealing treatment to recover material toughness properties of ferritic materials in the reactor vessel beltline.

Reactor vessel beltline region materials will be monitored by a surveillance program which includes eight surveillance capsules which will receive a neutron flux at least as high, but not more than three times as high as that received by the vessel inner surface. The surveillance program is in compliance with ASTM E-185-73 with the exception of the surveillance weld. The high flux region of the reactor vessel was fabricated from different combinations of weld wire and lots of welding flux for which sufficient tests and chemical analyses are not available to select surveillance weld metal as required by ASTM E-185-73. The surveillance weld, although fabricated using the same weld wire and flux lot number as used in core region vertical seams, may not be limiting material in the reactor vessel.

Information relative to the maximum change in RT_{NDT} and upper shelf energy of the core region materials, using Westinghouse predictions, is shown in Tables 5.4-3 and 5.4-4.

5.4.3.2 Measurement of Integrated Fast Neutron (E < 1.0 Mev) Flux at the Irradiation Samples

Information on the spectrum of neutron fluxes at the location of the irradiation samples is obtained from the multigroup diffusion code P1MG (Reference 1). Dosimeters including U-238, Np-237, Co-Al, Cu, Ni, Cd shielded Co Al, and Fe from specimens are contained in the capsule assemblies.

The procedure for measurement of fast neutron flux by the ^{54}Fe $(n,p)^{54}Mn$ reaction is described below. The measurement technique for the other dosimeters, which are sensitive to different portions of the neutron spectrum, is similar.

The ^{54}Mn product of this reaction has a half life of 314 days and emits gamma rays of 0.84 Mev energy which are easily detected using the NaI scintillator. In irradiated steel samples, chemical separation of the ^{54}Mn may be performed to ensure freedom from interfacing activities. This separation is a simple and very effective, yielding sources of very pure ^{54}Mn activity. In some samples all the interferences may be corrected for by the gamma spectrometric methods without any chemical separation. The count data is used to give the specific activity of ^{54}Mn per gram of iron. Because of the relatively long half life of ^{54}Mn the flux may be calculated for irradiation periods up to about 2 years. Beyond this time the dosimeter begins to reflect the later stages of the irradiation. Calculation of total dose is from flux and integrated power output. The burnout of ^{54}Mn produced is not significant until the thermal flux is about 10^{14} neutrons cm^{-2} sec^{-1}.

The analysis of the sample requires that two steps are completed: one the measurement of ^{54}Mn disintegration rate per unit mass of sample and second measurement of iron content of the sample. Having completed these analyses the calculation of the flux is as follows:

For an irradiation the activity of any activation product (A) is given by:

$$A = \phi \, \sigma \, N \, (1 - e^{-\lambda t_i}) \, e^{-\lambda t_d} \qquad (1)$$

Where

ϕ = the neutron flux, n/cm^2 sec

σ = the cross-section, barns

N = number of target atoms

λ = decay constant of product, sec^{-1}

t_i = irradiation time, sec

t_d = decay time from end of irradiation to counting time, sec

Then for a power reactor operating at various power levels over some long period we allow for flux changes by dividing the exposure period into several parts and normalizing the flux in each part as that fraction of full power represented. Then for τ periods:

$$A = \phi_m \sigma N \sum_{1}^{t} (1-e^{-\lambda t_{i_n}}) \, e^{\lambda t_{d_n}} F_n \qquad (2)$$

Where ϕ_m = flux at maximum power, n/cm^2 sec

t_{i_n} = cooling time for end of nth period, sec

t_{d_n} = cooling time for end of nth period, sec

F_n = flux normalizing factor which is

$$\frac{\text{Actual Power output in } n^{th} \text{ period}}{\text{maximum possible in } n^{th} \text{ period}}$$

If now we write

$$\phi_m \sigma N = c \sum_{.1}^{55} \phi_{P1MG} (E, r) \cdot \sigma_{Fe} (E) \qquad (3)$$

Where E is the energy

r = radial distance from core center line.

where the right hand side of equation (3) is the sum of the products of P1MG fluxes and the ^{54}Fe (n,p) ^{54}Mn cross section (Reference 2) averaged over the P1MG energy groups, then the measured neutron flux (E > 1 Mev) is given by:

$$\phi \, (E > 1 \text{ Mev}) = C \sum_{E = 1.0}^{10 \text{ Mev}} \phi_{P1MG}^{(E,r)}$$

where C is a constant

The error involved in the measurement of the specific activity of the dosimeter after irradiation is estimated to be $\pm$ 5 percent.

5.4.3.3 Calculation of Integrated Fast Neutron (E > 1.0 Mev) Flux at the Irradiation Samples

The method to be described herein is an approximation to the ideal three dimensional neutron transport solution but correlations between its predictions and measurements on samples irradiated in the Yankee and Saxton cores indicate good agreement.

The spectrum of neutron fluxes at the capsule locations is obtained from the one dimensional multigroup diffusion code P1MG (Reference 1) for the array of annular shields surrounding a cylindrical core of infinite height. The cylindrical core has a cross-sectional area equal to that of the actual core. The radial source distribution chosen for the core represents the expected average over the life of the station. The magnitude of the neutron fluxes generated by the P1MG Code, which does not treat transport effects, is adjusted by application of a spatial correction factor. This factor is the ratio of the fast neutron dose rate calculated by the SPIC-1 code (Reference 3) for an all water medium surrounding a typical Westinghouse PWR to the fast neutron dose rate obtained by P1MG in the identical geometry. The SPIC-1 fast neutron dose rate calculation uses an empirical fast neutron attentuation kernel in the form of a linear combination of single exponentials which are fitted to the experimental fast neutron dose rate distribution in pure water.

The axial and azimuthal variations of neutron flux at the capsule location are determined separately. The axial distribution is expressed as the ratio of the normalized results of two calculations using PDQ4 (Reference 4) a two dimensional 4 group (r,z) diffusion code. In the first of these an infinitely high equivalent cylindrical core with a fission neutron source strength S_I, per unit height is surrounded by an all water medium containing the capsule location. In the second, the finite height is surrounded by an all water medium.

The fixed source option of the PDQ4 code is selcted so that the axial variation of source strength in the core represents a good approximation to the average over the core life. The radial distribution is identical to that chosen for P1MG. The ratio,

$$\frac{\phi\ (E,\ r,\ z)_F}{S_F} \times \frac{S_I}{\phi\ (E,r)_I}$$

where subscripts F and I denote finite and infinite core representations respectively, is the required axial correction term.

The azimuthal distributions of neutron fluxes at the sample location are derived from a comparison of the results of the two dimensional 4 group (x,y) code PDQ3 (Reference 5) and the one dimensional 4 group diffusion program AIM-5 (Reference 6). In the PDQ3 calculation the core, whose shape can be specified exactly, is sourrounded by an all water medium. The radial and azimuthal source distributions in the core are both reasonable approximations to the averages expected during the core life. The radial source distribution in the AIM-5 calculation, in which the equivalent cylindrical core is surrounded by an all water medium, is identical to that chosen by P1MG.

The product of,

1. The spatially corrected P1MG results,

2. Axial correction term, and

3. Azimuthal correction term,

defines the three dimensional verification of neutron flux at the sample locations.

The technique indicated above overpredicts Saxton measurement by 30 percent and the Yankee measured values by 14 percent. In both reactors the measured results are averages for a set of specimens in a capsule located outside the thermal shield opposite a core corner. More recently, results from SELNI specimens were overpredicted by 10 percent.

The reported technique also gives excellent agreement with measured data reported for the PM2A reactor. Based on the above evidence, it is concluded that the P1MG calculation, corrected as described, is conservative by approximately 20 percent.

5.4.3.4 Measurement of the Initial NDTT of the Reactor Pressure Vessel Base Plate and Forging Material

The unirradiated or initial NDT temperature of pressure vessel base plate and forging materials is presently measured by two methods. These methods are the drop weight test per ASTM E208 and the Charpy V-notch impact test (Type A) per ASTM E23. The NDT temperature is defined in ASTM E208 as "the temperature at which a specimen is broken in a series of tests in which duplicate no break performance occurs at 10°F higher temperature". Using the Charpy V-notch test, the NDTT is defined as the temperature at which the energy required to break the specimen is a certain "fixed" value.

For SA 533B Class 1 and A508 Class 2 and Class 3 steel the ASME III Table N-421 specifies an energy value of 30 ft-lb. This value is based on a correlation with the drop weight test and is referred to as the "30 ft-lb-fix". A curve of the temperature versus energy absorbed in breaking the specimen is plotted. To obtain this curve, 15 tests are performed which include three tests at five different temperatures. The intersection of the energy versus temperature curve with the 30 ft-lb ordinate is designated as the NDTT.

As part of the Westinghouse surveillance program, Charpy V-impact tests, tensile tests, and facture mechanics specimens are taken from the core region plates and forgings, and core region weldments including heat-affected zone material. The test locations are similar to those used in the tests by the fabricator at the plate mill.

The uncertainties of measurement of the NDTT of base plate are:

1. Differences in Charpy V-notch foot pound values at a given temperature between specimens.

2. Variation of impact properties through plate thickness.

The facture toughness technology for pressure vessels and correlation with service failures based on Charpy V-notch impact data are based on the averaging of data. The Charpy V-notch 30 ft-lb "fix" temperature is based on multiple tests by the material supplier, the fabricator, and by Westinghouse as part of the surveillance program. In the review of available data, differences of 0 to approximately 40°F are observed in comparing curves plotted through the minimum and average values respectively. The value of NDTT derived from the average curve is judged to be representative of the material because of the averaging of at least 15 data points, consistent with the specified procedures of

ASTM E23. In the case of the assessment of NDTT shift due to fast neutron flux, the displacement of transition curves is measured. The selection of maximum, minimum of average curves for this assessment is not significant since like curves are used.

There are quantitative differences between the NDT temperature measurement at the surface, 1/4 thickness or the center of a plate. Differences in NDT temperature between 1/4T and the center in heavy plates had been observed to vary from improvement in the NDT temperature to increases up to 85°F. The NDT temperature at the surface had been measured to be as much as 85°F lower than at 1/4T.

The 1/4T location is considered conservative since the enhanced metallurgical properties of the surface are not used for the determination of NDT temperature. In addition, the limiting NDT temperature for the reactor vessel after operation is based on the NDT temperature shift due to irradiation. Since the fast neutron dose is highest at the inner surface, usage of the 1/4T NDT temperature criterion is conservative.

Data are being accumulated on the variation of NDT across heavy section steels at Westinghouse Nuclear Energy Systems. Similarly, the Pressure Vessel Research Committee sponsors an evaluation of properties of pressure vessel steels in plates and forgings greater than 6 inches thick. Preliminary data show NDT temperature differences between 1/4T and center of less than 20°F. The present criteria of using NDT temperature + 60°F at the 1/4T location without taking advantage of the enhanced properties at the surface of reactor vessel plates is conservative.

To assess any possible uncertainties in the consideration of NDT temperature shift for welds heat affected zone, and base metal, test specimens of these three "material types" are included in the reactor vessel surveillance program.

5.4.4 TESTS AND INSPECTIONS

The inspections of the reactor vessel were governed by the ASME Code requirements. The reactor vessel inspections are summarized in Table 5.2-26.

A preoperational volumetric examination utilizing ultrasonic techniques was performed on both reactor pressure vessels. This preoperational examination established a base line upon which the results of subsequent inservice inspections can be compared.

The preservice examination and subsequent inservice examinations of the reactor pressure vessels will be accomplished with the Wisconsin - Michigan Inspection Device (WMID). This inspection device has been used for accomplishing the same examinations on other reactor vessels. The use of the WMID for both the preservice and inservice inspections of the reactor vessel meets the intent of Section XI of the ASME Code that preoperational examinations be as closely representative of the examination to be performed later as possible.

All of the detailed examinations, as set forth in the Technical Specifications were performed completely, once, as part of the preservice inspection program, except that the examinations were extended where practicable to include 100 percent of the pressure - containing welds. Evaluation shall be made of any indications detected during any of the examinations which exceed the standards for materials and welds specified in the ASME Code, Section III edition applicable to the construction of the component to determine disposition and/or the need to make repairs.

The inservice inspection program is discussed in Section 5.2.8.

REFERENCES FOR SECTION 5.4

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2. "Radiation Damage Exposure and Embrittlement of Reactor Pressure Vessels," Shure K. Nuclear Applications, Vol. 2 (April 1966).

3. "SPIC-I, An IBM-704 Code to Calculate the Uncollided Flux Outside a Right Circular Cyclinder," Gillis P. A. et. a., WAPD-TM-176 (1959).

4. "PDQ4, A Program for the Solution of the Neutron Diffusion Equations in Two Dimensions on the Philco-2000," Cadwell, W. R., WAPD-TM-239 (1961).

5. "PDQ3, A Program for the Solution of the Neutron Diffusion Equations in Two Dimensions on the IBM-704," Cadwell, W. R., WAPD-TM-179 (May 1960).

6. "AIM-5, A Multigroup One Dimensional Diffusion Equation Code," Flatt, H. P. and Baller, D. C., NAA-SR-4694 (March 1960).

7. Yanichko, S. E., "Review of Selected Material Properties For Reactor Pressure Vessels Relative To 10 CFR 50, Appendix G," WCAP-8291, May, 1974.

TABLE 5.4-1

REACTOR VESSEL MATERIAL PROPERTIES

Core Region Shell Plate	Plate No.	T_{NDT} °F	50 Ft-Lb 35 Mil Temp. °F	RT_{NDT} °F	USE* Ft-Lbs
Inter. Shell	B4712-1	0	<60	0	105
Inter. Shell	B4712-2	-20	72	12	97
Inter. Shell	B4712-3	-50	70	10	107
Lower Shell	B4713-1	-10	68	8	98
Lower Shell	B4713-2	-20	68	8	103
Lower Shell	B4713-3	-10	70	10	122

*USE (Upper Shelf Energy)

TABLE 5.4-2

REACTOR VESSEL MATERIAL PROPERTIES

CLOSURE HEAD STUDS

Heat No.	Mat'l Spec. No.	Bar No.	0.2 ys Ksi	UTS* Ksi	Elong.	RA**	Energy At 10°F Ft-Lbs
37677	A540, B24	237-1	150.5	165.0	17.0	57.1	50, 54, 48
37677	A540, B24	237	151.0	164.5	17.0	57.3	54, 54, 50
37677	A540, B24	203-1	155.5	165.0	16.0	57.3	58, 60, 60
37677	A540, B24	203	148.0	164.0	15.0	56.4	48, 48, 47
37677	A540, B24	204-1	151.5	166.0	16.5	57.3	54, 50, 56
37677	A540, B24	204	148.5	162.5	16.0	56.4	54, 54, 55

CLOSURE HEAD NUTS AND WASHERS

Heat No.	Mat'l Spec. No.	Bar No.	0.2 ys Ksi	UTS* Ksi	Elong.	RA**	Energy At 10°F Ft-Lbs
46251	A540, B23	5	157.5	170.0	16.0	54.7	42, 46, 46
46251	A540, B23	5-1	149.5	163.0	17.0	55.8	50, 54, 53
46251	A540, B23	8	152.5	164.0	16.5	55.3	50, 50, 49
46251	A540, B23	8-1	151.5	162.2	17.0	56.9	50, 50, 54
46251	A540, B23	11	151.0	163.5	17.0	55.8	50, 50, 50
46251	A540, B23	11-1	151.0	164.0	17.0	56.5	52, 54, 50
46251	A540, B23	10	150.5	161.0	17.0	56.0	50, 50, 53
46251	A540, B23	10-1	148.5	161.0	17.0	56.8	50, 55, 48
46251	A540, B23	13	153.0	164.0	17.0	57.3	54, 50, 53
46251	A540, B23	13-1	147.2	159.0	17.0	56.5	56, 50, 51
46251	A540, B23	17	148.8	161.5	17.0	56.5	52, 50, 55
46251	A540, B23	17-1	155.5	167.5	16.0	54.2	51, 51, 50
46251	A540, B23	21	155.5	168.0	16.5	55.5	48, 50, 48
46251	A540, B23	21-1	150.5	162.0	16.5	56.2	54, 54, 54
46251	A540, B23	22	150-2	162.5	16.0	56.0	54, 52, 50
46251	A540, B23	22-1	147.0	160.0	17.0	57.3	54, 56, 54

* UTS (Ultimate Tensile Stress)

**RA (Reduction Area)

TABLE 5.4-3

MAXIMUM INNER WALL END OF LIFE-PLATES

Plate No.	Fluence N/CM 2	ΔRT NDT (°F)	ΔUSE (Ft-LB)*
B4712-1	2.1 x 10.9	117	26
B4712-2	2.1 x 10.9	123	28
B4712-3	2.1 x 10.9	100	22
B4713-1	2.1 x 10.9	108	24
B4713-2	2.1 x 10.9	108	24
B4713-3	2.1 x 10.9	108	24

*Estimated using methods identified in Reference 7.

TABLE 5.4-4

MAXIMUM INNER WALL END OF LIFE-WELDS

Weld Location	Fluence N/CM 2	ΔRT NDT (°F)	ΔUSE (Ft-LB)
Nozzle Shell to Inter Shell Seam 8-442	4.4×10^{17}	79	-
Inter. Shell Vert. Weld Seam 2-442A	6.8×10^{18}	171	-
Inter. Shell Vert. Weld Seams 2-442 B C	1.2×10^{19}	202	-
Inter. to Lower Shell seam 9-442	2.1×10^{19}	185	34
Lower Shell Vert. Weld Seams 3-442 A C	1.2×10^{19}	202	-
Lower Shell Vert. Weld Seam 3-442B	6.8×10^{18}	171	-

*All values except seam 9-442 estimated using upper limit curves since Cu + P content of welds is not available.

5.5 COMPONENT AND SUBSYSTEM DESIGN

5.5.1 REACTOR COOLANT PUMPS

5.5.1.1 Design Bases

The reactor coolant pump ensures an adequate core cooling flow rate for sufficient heat transfer in order to maintain a departure from nucleate boiling ratio greater than 1.3 within the parameters of operation. The required net positive suction head is by conservative pump design always less than that available by system design and operation.

Sufficient assembly rotational inertia is provided by a flywheel, motor rotor, and pump rotating parts to provide adequate flow during coast-down. This forced flow following an assumed loss of pump power and the subsequent natural circulation effect provides the core with adequate cooling.

The reactor coolant pump motor is capable of operation without mechanical damage at overspeeds up to and including 125 percent of normal speed.

The reactor coolant pump is shown in Figure 5.5-1, and its design parameters are given in Table 5.2-6. Code and material requirements are provided in Tables 5.2-9 and 5.2-27.

5.5.1.2 Design Description

The reactor coolant pump is a vertical, single stage, centrifugal shaft seal pump designed to pump large volumes of reactor coolant at high temperatures and pressures. The pump consists of three areas from bottom to top: the hydraulics, the shaft seals and the motor.

1. The hydraulic section consists of an impeller, a diffuser, casing, thermal barrier, heat exchanger, lower radial (pump) bearing, main flange, motor stand, and pump shaft.

2. The shaft seal section consists of three seals. They are the number 1 controlled leakage, film riding face seal and the numbers 2 and 3 rubbing face seals. These seals are contained within the seal housings.

3. The motor section consists of a vertical solid shaft, a squirrel cage induction type motor, an oil lubricated double Kingsbury type thrust bearing, two oil lubricated radial bearings and a flywheel.

Attached to the bottom of the pump shaft is the impeller. The reactor coolant is drawn up through the impeller, discharged through passages in the diffuser and out through the discharge nozzle in the side of the casing. Above the impeller is a thermal barrier heat exchanger, which limits heat transfer between hot system water and seal injection water. Component cooling water is supplied to the thermal barrier heat exchanger.

High pressure seal injection water is introduced through a connection on the thermal barrier. A portion of this water flows through the seals; the remainder flows down the shaft through and around the bearing and the thermal barrier (where it acts as a buffer to prevent system water from entering the radial bearing and seal section of the unit) and into the Reactor Coolant System (RCS). The thermal barrier heat exchanger provides a means of cooling reactor coolant to an acceptable level in the event that seal injection flow is lost. The water lubricated journal-type pump bearing, mounted above the thermal barrier heat exchanger, has a self-aligning spherical seat.

The reactor coolant pump motor bearings are of conventional design. The radial bearings are the segmented pad type, and the thrust bearings are tilting pad Kingsbury bearings. All are oil lubricated. The lower radial bearing and the thrust bearings are submerged in oil, and the upper radial bearing is oil fed from an impeller integral with the thrust runner. Component cooling water is supplied to the two oil coolers on the pump motor.

The motor is an air cooled, Class B thermalastic epoxy insulated, squirrel cage induction motor. The rotor and stator are of standard construction and are cooled by air. Six resistance temperature detectors are located throughout the stator to sense the winding temperature. The top of the motor consists of a flywheel and an anti-reverse rotation device.

The internal parts of the motor are cooled by air. Integral vanes on each end of the rotor draw air in through cooling slots in the motor frame. This air passes through the motor with particular emphasis on the stator end turns. It is then exhausted to the containment environment.

Each of the reactor coolant pumps is equipped for continuous monitoring of reactor coolant pump shaft and frame vibration levels. Shaft vibration is measured by two relative shaft probes mounted on top of the pump seal housing. The probes, one in line with the pump discharge and the other perpendicular to the pump discharge, are mounted in the same horizontal plane near the pump shaft. Frame vibration is measured by two velocity seismoprobes located 90 degrees apart in the same horizontal plane and mounted at the top of the motor support stand. Proximeters and converters convert the probe signals to linear output, which is displayed on monitor meters in the control room. The monitor meters automatically indicate the highest output from the relative probes and seismoprobes; manual selection allows monitoring of individual probes. Indicator lights display caution and danger limits of vibration.

All parts of the pump in contact with the reactor coolant are austenitic stainless steel, except for seals, bearings and special parts. The pump internals, motor, and motor stand can be removed from the casing as a unit without disturbing the reactor coolant piping. The flywheel is available for inspection by removing the flywheel cover.

5.5.1.3 Design Evaluation

5.5.1.3.1 Pump Performance

The reactor coolant pumps are sized to deliver flow at rates that equal or exceed the required flow rates. Initial RCS tests confirm the total delivery capability, providing assurance of adequate forced circulation coolant flow prior to initial plant operation. The performance characteristic is shown in Figure 5.1-5.

The reactor trip system ensures that pump operation is within the assumptions used for loss-of-coolant flow analyses, and also assures that adequate core cooling is provided to permit an orderly reduction in power if flow from a reactor coolant pump is lost during operation.

An extensive test program has been conducted to develop the controlled leakage shaft seal for pressurized water reactor applications. Longterm tests were conducted on less than full scale prototype seals as well as on full size seals. Operating plants continue to demonstrate the satisfactory performance of the controlled leakage shaft seal pump design.

The support of the stationary member of the number 1 seal (seal ring) is such as to allow large deflections, both axial and tilting, while still maintaining its controlled gap relative to the seal runner. Even if all the graphite were removed from the pump bearing, the shaft could not deflect far enough to cause opening of the controlled leakage gap. The "spring-rate" of the hydraulic forces associated with the maintenance of the gap is high enough to ensure that the ring follows the runner under very rapid shaft deflections.

Testing of pumps with the number 1 seal entirely removed, which puts full system pressure on the number 2 seal, shows that relatively small leakage rates would be maintained for a period of time which is sufficient to secure the pump. Even if the number 1 seal fails entirely during normal operation, the number 2 seal would maintain these small leakage rates if the proper action is taken by the operator. The plant operator is warned of number 1 seal damage by the increase in number 1 seal leakoff rate. Following warning of excessive seal leakage conditions, the plant operator should close the number 1 seal leakoff line and secure the pump, as specified in the instruction manual. Gross leakage from the pump does not occur if the proper operator action is taken subsequent to warning of excessive seal leakage conditions.

5.5.1.3.2 Coastdown Capability

It is important to reactor protection that the reactor coolant continues to flow for a short time after reactor trip. In order to provide this flow in a station blackout condition, each reactor coolant pump is provided with a flywheel. Thus, the rotating inertia of the pump, motor and flywheel is employed during the coastdown period to continue the reactor coolant flow. The pump motor system is designed for the safe shutdown earthquake at the site. Hence, it is concluded that the coastdown capability of the pumps is maintained even under the most adverse case of a blackout coincident with the safe shutdown earthquake.

5.5.1.3.3 Flywheel Integrity

Demonstration of integrity of the reactor coolant pump flywheel is discussed in Section 5.2.6.

5.5.1.3.4 Bearing Integrity

The design requirements for the reactor coolant pump bearings are primarily aimed at ensuring a long life with negligible wear, so as to give accurate alignment and smooth operation over long periods of time. The surface-bearing stresses are held at a very low value and, even under the most severe seismic transients, do not begin to approach loads that cannot be adequately carried for short periods of time.

Because there are no established criteria for short time stress-related failures in such bearings, it is not possible to make a meaningful quantification of such parameters as margins to failure, safety factors, etc. A qualitative analysis of the bearing design, embodying such considerations gives assurance of the adequacy of the bearing to operate without failure.

Low oil levels in the lube oil sumps signal an alarm in the control room and require shutting down of the pump. Each motor bearing contains embedded temperature detectors, and initiation of failure, separate from loss of oil, is indicated and alarmed in the control room as a high bearing temperature. This again requires pump shutdown. Even if these indications are ignored, and the bearing proceeded to failure, the low melting point of Babbitt metal on the pad surfaces ensures that no sudden seizure of the bearing occurs. In this event, the motor continues to operate as it has sufficient reserve capacity to drive the pump under such conditions. The high torque required to drive the pump, however, demands high current, which leads to the motor being shut down by the electrical protection systems.

5.5.1.3.5 Locked Rotor

It may be hypothesized that the pump impeller might severely rub on a stationary member and then seize. Analysis has shown that under such conditions, assuming instantaneous seizure of the impeller, the pump shaft would fail in torsion just below the coupling to the motor, thereby disengaging the flywheel and motor from the shaft. This would constitute a loss-of-coolant flow in the loop. Following such a postulated seizure, the motor would continue to run without any overspeed, and the flywheel would maintain its integrity, as it is still supported by the motor with two bearings.

There are no other credible sources of shaft seizure other than impeller rubs. Sudden seizure of the pump bearing is precluded by graphite in the bearing. Any seizure in the seals results in a shearing of the anti-rotation pin in the seal ring. The motor has adequate power to continue pump operation even after the above occurrences. Protective relays are provided to trip the supply breaker on an overcurrent condition during pump startup and normal operation. Indication of pump malfunction is provided by the following alarms; bearing water high temperature, excessive number 1 seal leakoff, and excessive pump vibration. If a pump malfunction is indicated, the affected pump is taken out of service for investigation.

5.5.1.3.6 Critical Speed

The reactor coolant pump shaft is designed so that its operating speed is below its first critical speed. This shaft design, even under the most severe postulated transient, gives low values of actual stress.

5.5.1.3.7 Missile Generation

Precautionary measures taken to preclude missile formation from reactor coolant pump components assure that the pumps will not produce missiles under any anticipated accident conditions. Each component of the pump is analyzed for missile generation. Any fragments of the motor rotor would be contained by the heavy stator. The same conclusion applies to the pump impeller, because the small fragments that might be ejected would be contained by the heavy casing.

5.5.1.3.8 Pump Cavitation

The minimum net positive suction head required by the reactor coolant pump at best estimate flow is approximately 170 feet (approximately 85 psi). In order for the controlled leakage seal to operate correctly, it is necessary to require a minimum differential pressure of approximately 275 psi across the number 1 seal. This corresponds to a primary loop pressure at which the minimum net positive suction head requirement is exceeded and no limitation on pump operation occurs from this source.

5.5.1.3.9 Pump Overspeed Considerations

For turbine trips actuated by either the reactor trip system or the turbine protection system, the generator breaker disconnects the generator permitting the reactor coolant pumps to remain connected to the external network for 30 seconds to prevent any pump overspeed condition.

An electrical fault requiring immediate trip of the generator (with resulting turbine trip) could result in an overspeed condition. However, the turbine control system and the turbine intercept valves limit the overspeed to less than 120 percent. As additional backup, the turbine protection system has a mechanical overspeed protection trip, usually set at about 110 percent of turbine speed. In case a generator trip deenergizes the pump buses, the reactor coolant pump motors are transferred to off-site power within six to ten cycles.

5.5.1.3.10 Anti-reverse Rotation Device

Each of the reactor coolant pumps is provided with an anti-reverse rotation device in the motor. This anti-reverse mechanism consists of pawls mounted on the outside diameter of the flywheel, a serrated ratchet plate mounted on the motor frame, a spring return for the ratchet plate and two shock absorbers.

After the motor has slowed and come to a stop, the dropped pawls engage the ratchet plate and, as the motor tends to rotate in the opposite direction, the ratchet plate also rotates until it is stopped by the shock absorbers. The rotor remains in this position until the motor is energized again. When the motor is started, the ratchet plate is returned to its original position by the spring return.

As the motor begins to rotate, the pawls drag over the ratchet plate. When the motor reaches sufficient speed, the pawls are bounced into an elevated position and are held in that position by friction resulting from centrifugal forces acting upon the pawls. Considerable plant experience with the anti-reverse rotation device has shown high reliability of operation.

5.5.1.3.11 Shaft Seal Leakage

Leakage along the reactor coolant pump shaft is controlled by three shaft seals arranged in series. Charging flow is directed to each reactor coolant pump via a seal water injection filter. It enters the pump and is directed to a point between the pump shaft bearing and the pump seals. The flow splits and a portion flows down the shaft through and around the lower radial bearing, down past the thermal barrier heat exchanger and into the RCS; the remainder flows up the pump shaft annulus and provides a back pressure on the number 1 seal and a controlled flow through the seal. Above the seal, most of the flow leaves the pump via the number 1 seal leak-off line. Minor flow passes through the number 2 seal and its leak-off line, and through the number 3 seal and its leak-off line.

5.5.1.3.12 Seal Discharge Piping

Discharge pressure from the number 1 seal is reduced to that of the volume control tank. Water from each pump's number 1 seal is piped to a common manifold, through the seal water return filter and through the seal water heat exchanger, where the temperature is reduced to that of the volume control tank. The number 2 and number 3 leak-off line dump number 2 and number 3 seal leakage to the reactor coolant drain tank.

5.5.1.3.13 Loss of Offsite AC Power

During normal operation, seal injection flow from the chemical and volume control system is provided to cool the reactor coolant pump seals and the component cooling water system provides flow to the thermal barrier heat exchanger to limit the heat transfer from the reactor coolant to the reactor coolant pump internals. In the event of loss of offsite power, the reactor coolant pump is deenergized and both of these cooling supplies are terminated; however, the diesel generators are automatically started and either seal injection flow or component cooling water to the thermal barrier heat exchanger is automatically restored within seconds. Either of these cooling supplies is adequate to provide seal cooling and prevent seal failure due to loss of seal cooling during a loss of offsite power to at least two hours.

5.5.1.3.14 Loss of Component Cooling Water

Loss of Component Cooling Water and its effects on the RCP are discussed in Section 9.2.

5.5.1.4 Test and Inspections

Pressure boundary parts of the reactor coolant pumps can be inspected in accordance with the ASME Code for "Inservice Inspection of Nuclear Reactor Coolant Systems," Section XI.

The pump casing is cast in two pieces, and joined by electroslag welding. Support feet are cast integral with the casing to eliminate a weld region.

The design enables disassembly and removal of the pump internals for usual access to the internal surface of the pump casing.

The reactor coolant pump quality assurance program is given in Table 5.2-26.

5.5.2 STEAM GENERATORS

5.5.2.1 Design Bases

Steam generator design data are given in Table 5.2-5. Estimates of radioactivity levels anticipated in the secondary side of the steam generators during normal operation, and the bases for the estimates are given in Chapter 11. Rupture of a steam generator tube is discussed in Chapter 15.

The internal moisture separation equipment is designed to assure that moisture carryover does not exceed 0.25 percent by weight under the following conditions:

1. Steady state operation up to 105 percent of full load steam flow, with water at the normal operating level.

2. Loading or unloading at a rate of 5 percent of full power steam flow per minute in the range from 15 percent to 105 percent of full load steam flow.

3. A step load change of 10 percent of full power in the range from 15 percent to 105 percent full load-steam flow.

The steam generator tube sheet complex meets the stress limitations and fatigue criteria specified. Codes and materials requirements of the steam generator are given in Tables 5.2-9 and 5.2-27.

The steam generator design maximizes integrity against hydrodynamic excitation and vibration failure of the tubes for plant life.

The water chemistry in the reactor side is selected to provide the necessary boron content for reactivity control and to minimize corrosion of RCS surfaces. The water chemistry of the steam side is given in Table 5.2-29.

5.5.2.2 Design Description

The steam generator shown in Figure 5.1-3 is a Model 51, vertical shell and U-tube evaporator with integral moisture separating equipment. The reactor coolant flows through the inverted U-tubes, entering and leaving through the nozzles located in the hemispherical bottom head of the steam generator. The head is divided into inlet and outlet chambers by a vertical partition plate extending from the head to the tube sheet. Manways are provided for access to both sides of the divided head. Steam is generated on the shell side and flows upward through the moisture separators to the outlet nozzle at the top of the vessel. The unit is primarily carbon steel. The heat transfer tubes and the divider plate are Inconel and the interior surfaces of the reactor coolant channel heads and nozzles are clad with austenitic stainless steel. The primary side of the tube sheet is weld clad with Inconel.

Feedwater flows directly into the annulus formed by the shell and tube bundle wrapper before entering the boiler section of the steam generator. Subsequently, water-steam mixture flows upward through the tube bundle and into the steam drum section. A set of centrifugal moisture separators, located above the tube bundle, removes most of the entrained water from the steam. Steam dryers are employed to increase the steam quality to a minimum of 99.75 percent (0.25 percent moisture). The moisture separators recirculate flow mixes with feedwater as it passes through the annulus formed by the shell and tube bundle wrapper.

The steam drum has two bolted and gasketed access openings for inspection and maintenance of the dryers, which can be disassembled and removed through the opening.

5.5.2.3 Design Evaluation

5.5.2.3.1 Natural Circulation Flow

The steam generators (which provide a heat sink) are at a higher elevation than the reactor core (which is the heat source). Thus, natural circulation is assured for the removal of decay heat.

5.5.2.3.2 Secondary System Fluid Flow Instability Prevention

In order to prevent the occurrence of water hammer, which has been experienced at other plants, the feedwater distribution ring headers have been modified in both Units 1 and 2. The flow from the headers takes place through the top of the headers, rather than out the bottom as originally designed. This modification has been demonstrated to preclude water hammer as discussed in detail in Section 10.4.

The limiting case for heat transfer capability is the "Nominal 100 Percent Design" case. The steam generator effective heat transfer coefficient is based on the coolant conditions of temperature and flow for this case, and includes a conservative allowance for tube fouling. Adequate tube area is selected to assure that the full design heat removal rate is achieved. The best estimate for the heat transfer coefficient is 1301 Btu/hr-ft^2-°F, which is approximately 5 to 10 percent less than the heat transfer performance experienced at a number of operating plants. The coefficient incorporates a specified fouling factor resistance of 0.00005 hr-ft^2-°F/Btu, which is the value selected to account for the differences in the measured and calculated heat transfer performance as well as provide the margin indicated above. Although margin for tube fouling is available, operating experience to data has not indicated that steam generator performance decreases over a long-term period.

5.5.2.3.3 Tube and Tube Sheet Stress Analyses

Tube and tube sheet stress analyses of the steam generator are given in Section 5.2.

Calculations confirm that the steam generator tube sheet will withstand the loading (which is quasi-static rather than a shock loading) caused by loss of reactor coolant.

5.5.2.3.4 Flow Induced Vibration

In the design of the steam generators, consideration has been given to the possibility of vibratory failure of tubes due to mechanical or flow induced excitation. This consideration includes detailed analysis of the tube supporting system as well as an extensive research program with tube vibration model tests.

The major cause of tube vibratory failure in heat exchanger components is that due to hydrodynamic excitation by the fluid outside the tube.

Consideration is given to three regions where the possibility of flow induced vibration may exist:

1. At the entrance of downcomer feed to the tube bundle (cross flow)

2. Along the straight sections of the tube (parallel flow)

3. In the curved tube section of the U-bend (cross flow)

From the description of these regions, it is noted that two types of flow exist, namely, cross flow and parallel flow. For the case of parallel flow, analysis is done to determine the vibratory deflections. Analysis of the steam generator tubes indicates the flow velocities to be sufficiently below that required for damaging fatigue or impacting vibratory amplitudes. The support system, therefore, is deemed adequate to preclude parallel flow excitation. For the case of flow excitation, it is noted in the literature that several techniques for the analysis of the tube vibration exist. The design problem is to ascertain that the tube natural frequency is well above the vortex shedding frequency. In order to avoid resonant vibration, adequate tube supports are provided.

Since the problem of cross flow induced vibration was of major concern in the design of shell and tube heat exchangers, consideration was given to the experimental evaluation of the behavior of tube arrays under cross flow. While consideration was given to instrumentation of actual units in service, the hostile environment would limit the amount and quality of information obtained therefrom. As a result, it was deemed prudent to undertake a research program which would allow the study of fluid elastic vibrator behavior of tubes in arrays. A wind tunnel was built specifically for this purpose. The research facilities for the tube vibration study have since been expanded with the construction of a water tunnel facility.

The results of this research confirm the vortex shedding mechanism. More significant, however, is the evaluation of a fluid elastic mechanism not associated with vortex shedding. This phenomenon is not commonly understood and could be a source of vibration failure. Steam generators are evaluated on this basis in addition to the aforementioned techniques and found adequately designed. Testing has also been conducted using specific parameters of the steam generator and the results show the support system to be adequate.

Summarizing the results of analysis and tests of steam generator tubes for flow induced vibration, it can be stated that a check of support adequacy has been made using all published techniques believed appropriate to heat exchanger tube support design. In addition, the tube support system is consistent with accepted standards of heat exchanger design utilized throughout the industry (spacing, clearance, etc.). Furthermore, the design techniques are supplemented with a continuing research and development program to understand the complex mechanism of concern.

Service experience of steam generators shows that flow induced vibration and cavitation effects do not cause tube thinning. Preliminary estimates of tube degradation from erosion/corrosion mechanisms indicate that approximately 2-1/2 mils wall thinning (2 mils primary, 1/2 mil secondary side) will result over the 40 year lifetime.

The effects of vibration, erosion and cavitation have been given consideration and the stress limitations for each category have been met. Analysis of loss of coolant accident blowdown forces on as-fabricated U-tubes has shown that the maximum bending load elastic stress intensity is well below the faulted condition limit. The maximum bending load elastic stress intensity (based on the minimum tube wall thickness) would increase only within the range of 5 to 10 percent and would still be below the faulted condition limit. Therefore, as a minimum, at least 2-1/2 mils (per wall) thinning can be tolerated without exceeding the allowable stress limits. Vibration effects are eliminated during normal operation by the supporting system. Under loss of coolant accident conditions, vibration is of a short duration and there is no endurance problem.

Further consideration is given to the possibility of mechanically excited vibration, in which resonance of external forces with tube natural frequencies must be avoided. It is believed that the transmissibility of external forces either through the structure or from fluid within the tubes is negligible and should cause little concern.

Finally, it should be noted that successful operational experience with several steam generator designs has given confidence in the overall approach to the tube support design problem.

Tests and Inspections

The steam generator quality assurance program is given in Table 5.2-26.

Radiographic inspection and acceptance standards are in accordance with the requirements of Section III of the ASME Code.

Liquid penetrant inspection is performed on weld deposited tube sheet cladding, channel head cladding, tube-to-tube sheet weldments, and weld deposit cladding.

Liquid penetrant inspection and acceptance standard are in accordance with the requirements of Section III of the ASME Code.

Magnetic particle inspection is performed on the tube sheet forging, channel head casting, nozzle forgings, and the following weldments:

1. Nozzle to shell

2. Support brackets

3. Instrument connections (primary and secondary)

4. Temporary attachments after removal

5. All accessible pressure containing welds after hydrostatic test.

Magnetic particle inspection and acceptance standard are in accordance with requirements of Section III of the ASME Code.

An ultrasonic test is performed on the tube sheet forging, tube sheet cladding, secondary shell and heat plate and nozzle forgings.

The heat transfer tubing is subjected to eddy current test.

Hydrostatic tests are performed in accordance with Section III of the ASME Code.

In addition, the heat transfer tubes are subjected to a hydrostatic test pressure prior to installation into the vessel which is not less than 1.25 times the primary side design pressure multiplied by the ratio of the material allowable stress at the testing temperature.

Manways are to provide access to both the primary and secondary sides.

Steam generator tube inspection will be performed in accordance with Technical Specifications. Due to activity in the channel head and the large number of tubes involved, tube testing is done on a per plant basis. The extent of tube testing planned in any particular plant will depend on tube performance to date, the channel head activity and the results of tube sample testing. An eddy current testing method is available if the tubes should require inspection.

5.5.3 REACTOR COOLANT PIPING

5.5.3.1 Design Bases

The RCS piping is designed and fabricated to accommodate the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions. Code and material requirements are provided in Section 5.2.

Materials of construction are specified to minimize corrosion/erosion and assure compatibility with the operating environment.

RCS pressure boundary piping codes for both units are stated in Table 5.2-9.

5.5.3.2 Design Description

Principal design data for the reactor coolant piping for both units are given in Table 5.2-7.

The RCS piping is specified in the smallest sizes consistent with system requirements. In general, high fluid velocities are used to reduce piping sizes. This design philosophy results in the reactor inlet and outlet piping diameters given in Table 5.2-7. The line between the steam generator and the pump suction is larger to reduce pressure drop and improve flow conditions to the pump suction.

All piping within the reactor coolant pressure boundary is made of austenitic stainless steel with the main piping being seamless forged. Fittings are one piece castings with the exception of the reactor coolant pump inlet 90 degree elbow which is two half castings joined by electroslag welding.

All smaller piping which comprise part of the RCS boundary, such as the pressurizer surge line, spray and relief line, loop drains and connecting lines to other systems are also austenitic stainless steel. The nitrogen supply line for the pressurizer relief tank is carbon steel. All joints and connections are welded, except for the pressurizer relief and the pressurizer code safety valves, where flanged joints are used. Thermal sleevese are installed at points in the system where high thermal stresses could develop due to rapid changes in fluid temperature during normal operational transients. These points include:

1. Charging connections at the primary loop from the chemical and volume control system.

2. Both ends of the pressurizer surge line.

3. Pressurizer spray line connection at the pressurizer.

4. Safety injection/residual heat removal system return.

Thermal sleeves are not provided for the remaining injection connections of the emergency core cooling system since these connections are not in normal use.

All piping connections from auxiliary systems are made above the horizontal centerline of the reactor coolant piping, with the exception of:

1. Residual heat removal pump suction, which is 45 degrees down from the horizontal centerline. This enables the water level in the RCS to be lowered in the reactor coolant pipe while continuing to operate the residual heat removal system, should this be required for maintenance.

2. Loop drain lines and the connection for temporary level measurement of water in the RCS during refueling and maintenance operation.

3. The differential pressure taps for flow measurement are downstream of the steam generators on the first 90 degree elbow.

Penetrations into the coolant flow path are limited to the following:

1. The spray line inlet connections extend into the cold leg piping in the form of a scoop so that the velocity head of the reactor coolant loop flow adds to the spray driving force.

2. The reactor coolant sample system taps protrude into the main stream to obtain a representative sample of the reactor coolant.

3. The resistance temperature detector hot leg bypass connections are scoops which extend into the reactor coolant to collect a representative temperature sample for the resistance detector manifold.

4. The wide range temperature detectors are located in resistance temperature detector wells that extend into the reactor coolant pipes.

Separate bypass manifolds (loops) for each reactor coolant loop hot and cold leg are provided so that individual temperature signals may be developed for use in the reactor control and protection system. The bypass manifold around each steam generator obtains a representative hot leg temperature by mixing the flow from three scoop connections, which extend into the flow stream at locations 120 degrees apart in the cross sectional plane, on the reactor coolant leg. The hot leg bypass flow exits the manifold to a common return line.

Flow for the cold leg bypass manifold, which bypasses the reactor coolant pump, is obtained downstream of the pump discharge. Because of the mixing action of the pump, only one connection is required to obtain a representative sample. This connection is located as close as possible to the weld connection at the pump discharge and is in the same relative position in each loop.

The bypass manifold lines join downstream of each of the hot and cold leg manifolds and discharge into a common line. The combined bypass flow passes through a flow indicator before discharging to the suction side of the reactor coolant pump.

The manifolds are not provided with thermometer wells. Instead, the resistance temperature detectors extend directly into the flow path to reduce the time delay to a minimum. Therefore, two isolation valves in series are provided on each side of the bypass manifold to allow for resistance temperature detector maintenance. The valve nearest the connection to the main coolant piping is located above the elevation of the reactor vessel nozzles to permit valve repair during cold shutdown, without draining the RCS. In addition, vents and drains are provided in each manifold to be used, in conjunction with the isolation valve, for maintenance.

Signals from these instruments are used to compute the reactor coolant ΔT (temperature of the hot leg, T_{hot}, minus the temperature of the cold leg, T_{cold},) and an average reactor coolant temperature (T_{avg}). The T_{avg} for each loop is indicated on the main control board.

The RCS pressure boundary piping includes those sections of piping interconnecting the reactor vessel, steam generator, and reactor coolant pump. It also includes the following:

1. Charging line and alternate charging line from the isolation valve up to the branch connections on the reactor coolant loop.

2. Letdown line and excess letdown line from the branch connections on the reactor coolant loop to the isolation valve.

3. Pressurizer spray lines from the reactor coolant cold legs to the spray nozzle on the pressurizer vessel.

4. Residual heat removal lines to or from the reactor coolant loops up to the designated isolation or check valve.

5. Safety injection lines from the designated isolation or check valve to the reactor coolant loops.

6. Accumulator lines from the designated isolation or check valve to the reactor coolant loops.

7. Resistance temperature detector manifold by-pass loop piping.

8. Loop fill, loop drain, sample, and instrument lines to or from the designated isolation valve to or from the reactor coolant loops.

9. Pressurizer surge line from one reactor coolant loop hot leg to the pressurizer vessel inlet nozzle.

10. Resistance temperature detector scoop element, pressurizer spray scoop, sample connection with scoop, reactor coolant temperature element installation boss, and the temperature element well itself.

11. All branch connection nozzles attached to reactor coolant loops.

12. Pressure relief lines from nozzles on top of the pressurizer vessel up to and through the power-operated pressurizer relief valves and pressurizer safety valves.

13. Seal injection water and labyrinth differential pressure lines to or from one the reactor coolant pump inside reactor containment.

14. Auxiliary spray line from the isolation valve to the pressurizer spray line header.

15. Sample lines from pressurizer to the isolation valve.

Details of the materials of construction of reactor coolant piping and fittings are listed in Table 5.2-26.

5.5.3.3 Design Evaluation

Piping load and stress evaluation for normal operating loads, seismic loads, blowdown loads, and combined normal, blowdown and seismic loads is discussed in Section 5.2.

5.5.3.4 Material Corrosion/Erosion Evaluation

The water chemistry is selected to minimize corrosion. A periodic analysis of the coolant chemical composition is performed to verify that the reactor coolant quality meets the specifications.

An upper limit of about 50 feet per second is specified for internal coolant velocity to avoid the possibility of accelerated erosion. All pressure containing welds out to the second valve that delineates the reactor coolant pressure boundary are available for examination with removable insulation.

5.5.3.5 Tests and Inspections

Inservice inspection is discussed in Section 5.2.8. The RCS piping quality assurance program is given in Table 5.2-26.

A description of the quality assurance inspections of these components is contained in Section 5.2.3.5.

5.5.4 MAIN STEAM LINE FLOW RESTRICTORS

Each steam line is provided with a flow restrictor to limit the blowdown rate of steam from the steam generators in the event of a main steam line rupture. The flow restrictors are described in detail in Section 10.3.

5.5.5 MAIN STEAM LINE ISOLATION SYSTEM

Main steam isolation valves are described in Section 10.3.

5.5.6 REACTOR CORE ISOLATION COOLING SYSTEM

This section is not applicable to pressurized water reactors.

5.5.7 RESIDUAL HEAT REMOVAL SYSTEM

5.5.7.1 Design Bases

The Residual Heat Removal System (RHRS) is designed to remove residual and sensible heat from the core and reduce the temperature of RCS during the second phase of plant cooldown. During the first phase of cooldown, the temperature of the RCS is reduced by transferring heat from the RCS to the steam and power conversion system (Chapter 10).

The RHRS is placed in operation approximately 4 hours after reactor shutdown when the pressure and temperature of the RCS are approximately 400 psig and less than 350°F, respectively. Under normal operating conditions, the RHRS will reduce the temperature of the reactor coolant to 140°F within 20 hours following reactor shutdown. The design residual heat load is based on the residual heat fraction of full core MW (thermal) power level that exists at 20 hours following reactor shutdown from an extended power run near full power.

As a secondary function, the RHRS is used to transfer refueling water between the refueling water storage tank and the refueling cavity at the beginning and end of refueling operations.

In addition, portions of the system are utilized as parts of the emergency core cooling system and the containment spray system. These function and the associated analyses are discussed in Chapter 6.

The RHRS provides sufficient capability in the emergency operational mode to accommodate any single active or passive failure and still function in a manner to avoid risk to the health and safety of the public. Refer to Chapters 6 and 15 for a discussion of the operability and capability of the RHRS in an emergency core cooling role.

The system design precludes any significant reduction in the overall design reactor shutdown margin when cooling water is introduced into the core for decay heat removal or during emergency core cooling recirculation mode of operation.

System components whose design pressure and temperature are less than the RCS design limits are provided with redundant isolation means and overpressure protection devices.

All system active components which are relied upon to perform the system functions are redundant and the system design includes provision for hydrostatic testing of system components to applicable code test pressures.

Piping and components of the RHRS are designed to the applicable codes and standards listed in Table 5.5-1. Since the loop contains reactor coolant when it is in operation, austenitic stainless steel piping is employed.

5.5.7.2 System Description

The RHRS (shown in Figures 5.5-2A and B) consists of two residual heat exchangers, two residual heat removal pumps and associated piping valves, and instrumentation.

During system operation, coolant flows from the RCS to the residual heat removal pumps, through the tube side of the residual heat exchangers and back to the RCS. The inlet line to the RHRS loop begins at the hot leg of one reactor coolant loop and the return line is connected to the cold legs of two separate reactor coolant loops. The heat loads are transferred by the residual heat exchangers to the component cooling water.

The cooldown rate of the reactor is controlled by regulating the flow through the tube side of the residual heat exchangers. A bypass line with a remotely operated control valve around the residual heat exchangers is used to maintain a constant flow through the RHRS.

Coincident with plant cooldown, a portion of the reactor coolant flow may be diverted to the chemical and volume control system for cleanup. By regulating diverted flow rate, the RCS pressure may be controlled within the pressure range dictated by the nil-ductility limits of the reactor vessel and the Number 1 seal differential pressure and NPSH requirement of the reactor coolant pumps.

Design data for the RHRS components described below are listed in Table 5.5-1.

RESIDUAL HEAT EXCHANGER

Two residual heat exchangers are installed in the system. Each exchanger is designed to remove one-half of the residual heat load. The installation of two exchangers assures that the heat removal capacity of the residual system is only partially lost if one exchanger fails or becomes inoperative. Two exchangers also allow maintenance of one exchanger while the other unit is in operation.

The residual heat exchangers are of the shell and U-tube type. Reactor coolant circulates through the tubes, while component cooling water circulates through the shell. The tubes are welded to the tube sheet to prevent leakage of reactor coolant.

RESIDUAL HEAT REMOVAL PUMPS

Two identical pumps are installed in the RHRS. Each pump is sized to deliver sufficient reactor coolant flow through the residual heat exchangers to meet the plant cooldown requirements. The use of two pumps, installed in parallel, assures that pumping capacity is only partially lost should one pump become inoperative. This also allows maintenance on one pump while the other pump is in operation. In addition to the residual heat removal duty, the pumps are used for transfer of refueling water before and after a refueling operation.

The two residual heat removal pumps are, vertical, centrifugal units with mechanical seals to prevent reactor coolant leakage to the atmosphere. All pump parts in contact with reactor coolant are austenitic stainless steel or equivalent corrosion resistant material.

RHRS VALVES

The valves used in the RHRS are constructed of austenitic stainless steel or equivalent corrosion resistant material.

Manual isolation valves are provided to isolate equipment for maintenance. Throttle valves are provided for remote manual control of residual heat exchanger tube side flow, and for remote manual control of bypass flow. Check valves prevent reverse flow through the residual heat removal pumps.

Isolation of the RHRS is achieved with two remotely operated series stop valves in the line from the RCS to the residual heat removal pump suction and by two check valves in series in each line from the residual heat removal pump discharge to the RCS plus a remotely operated stop valve in each discharge line. Overpressure in the RHRS is relieved through a relief valve to the pressurizer relief tank in the RCS.

Valves that perform a modulating function are equipped with two sets of packing and an intermediate leakoff connection that discharges to the waste disposal system.

Manually operated valves have backseats to facilitate repacking and to limit the steam leakage when the valves are open. Leakoff connnections are provided where required by valve size and fluid conditions.

RESIDUAL HEAT REMOVAL PIPING

RHRS piping is austenitic stainless steel. Piping joints and connections are welded except where flanged connections are required to facilitate maintenance.

5.5.7.3 Design Evaluation

For RCS cooldown, the unit is provided with two residual heat removal pumps and two residual heat exchangers. If one of the two pumps or one of the two heat exchangers or one pump and one heat exchanger is not operable, safe cooldown of the plant is not compromised; however, the time for cooldown is extended.

To assure reliability, the two residual heat removal pumps are connected to two separate buses so that each pump will receive power from a different source.

An emergency power source is required to supply essential electrical equipment if a total loss of power should occur while the system is in service. Each pump is connected to a separate emergency power supply.

5.5.7.3.1 Leakage Provisions

The design operating leakage rate of the RHR is 50 gpm due to a pump seal failure. The residual heat removal pumps are in separate rooms each having two 75 gpm sump pumps which discharge to the waste disposal system. Sump pump reliability is ensured by placing pump motors on the floor above the residual heat removal rooms. In the remote event that no sump pumps are operable there is adequate volume in the residual heat removal rooms to contain the design percentage while the pump is isolated.

Should a large tube side to shell side leak develop in a residual heat exchanger, the water level in a component cooling surge tank would rise, and the operator would be alerted by a high water alarm. In addition, a leak will be detected by a radiation monitor located in each component cooling header.

If the leaking residual heat exchanger could not be isolated from the component cooling system before the inflow completely filled the surge tank, the overflow-vent line would discharge the excess water to the waste disposal system.

Since the RHRS is required for long-term post-accident removal of decay heat from the reactor core and containment, independent piping systems are provided for the redundant components so that excessive leakage resulting from the deterioration of, or failure in, some passive element in the system can be identified and isolated without complete system loss-of-function.

Massive failure of piping is not considered credible because long term operation of system occurs only at low pressures and temperatures and system is protected from environmental conditions by the Class I (seismic) structures.

5.5.7.3.2 RCS Isolation Provisions

The residual heat removal discharge lines are isolated from the RCS by two check valves in series for each line and a remote operated valve in each line.

There are two motor operated isolation valves (1RH1 and 1RH2), in series, in the single letdown line connnecting the low pressure RHRS to the high pressure RCS. 1RH1 is the upstream valve (closest to the RCS) and 1RH2 is the downstream valve. The position indication provided for these valves consists of "open-closed" indication on the main control console and valve "off-normal" indication in the auxiliary alarm system.

The interlock system consists of following:

1. 1RH1 is interlocked with a pressure control signal derived from a pressure transmitter to pervent its opening whenever the RCS pressure is greater than the residual heat removal system design pressure.

2. The pressure transmitter used in item 1 is connected to the reactor coolant loop which contains the residual heat removal suction line. The pressure transmitter is connected into the residual heat removal suction line inside the containment.

3. The control for valve 1RH2 is administratively locked to prevent inadvertent manual opening.

4. A second pressure channel will be added to provide a pressure control signal to interlock valve 1RH2 located adjacent to the residual heat removal system. This will be used to prevent its opening whenever the reactor coolant pressure is greater than the residual heat removal system design pressure.

5. This additional pressure transmitter will be connected by a separate connection into the residual heat removal suction line inside the containment. Therefore, the residual heat removal suction line will contain two separate connections, one for each pressure transmitter.

6. The control circuitry for both valves 1RH1 and 1RH2 will be modified to automatically close if they have not already been manually closed before the reactor coolant pressure reaches a selected fraction of residual heat removal design pressure.

The interlocks and closure devices are designed to conform to IEEE-279.

5.5.7.3.3 Failure Analysis

A failure analysis of residual heat removal pumps, heat exchangers and valves is present in Table 5.5-2.

5.5.7.3.4 Compliance with Branch Technical Position RSB 5-1

This section addresses the items contained in Table II for PWR Class 2 plants. The numbering corresponds to the numbering in Table II.

1. Double drop line (or valves in parallel) from the RCS.

   A single residual heat removal suction line with two suction isolation valves in series is provided as described in Section 5.5.7.3.2. Compliance is not required since the plant can be maintained in a safe hot standby condition while any required manual actions are taken.

2. Safety grade dump valves, operators, air and power.

   One safety grade steam generator power operated relief valve is provided for each of the four steam generators. Safety grade remote operators and power supplies are not required since hot standby can be achieved and maintained using the safety grade steam generator safety values. The steam generator power operated relief valves are provided with handwheels and can be operated locally to permit plant cooldown. See the cold shutdown scenario and single failure evaluation provided below.

3. Capability to cooldown to shutdown assuming most limiting single failure in less than 36 hours.

Compliance is not required since the plant can be maintained in a safe hot standby condition while any required manual actions are taken. The plant is capable of reaching residual heat removal initiation conditions in approximately 36 to 48 hours, including time required to perform any manual actions.

4. Depressurization with only safety-grade systems assuming single failure.

   Compliance is not required since the plant can be maintained in a hot standby condition while any required manual actions are taken.

5. Boration with only safety grade systems assuming single failure.

   Compliance is not required since the plant can be maintained in a safe hot standby condition while any required manual actions are taken.

6. Provisions for collection and containment of residual heat removal pressure relief discharge.

   The residual heat removal relief valves discharge to the pressurizer relief tank (inside containment).

7. Additional tests to study mixing of the added borated water and cooldown under natural circulation conditions with and without a single failure of an atmospheric dump valve.

   Salem Nuclear Generating Station is similar to Diablo Canyon Power Station in design, both being Westinghouse PWR. Due to the similarity of the two plants, no special tests will be conducted by Salem Unit to establish boron mixing and cooldown capability under natural circulation since Diablo Canyon Station has committed to perform these tests. The results of the tests on Diablo Canyon will be applicable for Salem.

8. Specific operational procedures for cooldown under natural circulation.

   Salem Nuclear Generating Station will generate specific operational procedures that will enable the operators to bring the plant from hot standby condition to cold shutdown status using the systems and operating functions given in item 9 (Cold Shutdown Scenario).

9. Seismic Category 1 AFW supply for at least four hours at hot shutdown plus cooldown to RHR cut-in based on longest time (for only onsite or offsite power and assuming worst single failure).

   A long-term source of auxiliary feedwater is provided by a connection to the Seismic Category 1 service water system.

COLD SHUTDOWN SCENARIO (Assuming loss of all non-seismic Category 1 equipment)

The safety shutdown design basis of Salem Unit 2 is hot standby. the plant can be maintained in a safe hot standby condition while manual actions are taken to permit achievement of cold shutdown conditions following a safe shutdown earthquake with loss of offsite power. Under such conditions the plant is capable of achieving residual heat removal initiation conditions (approximately 350°F, 400 psig) in approximately 36 to 48 hours, including the time required for any manual actions. To achieve and maintain cold shutdown, four key functions must be performed. These are: (1) circulation of the reactor coolant, (2) removal of residual heat, (3) boration and makeup, and (4) depressurization.

1. Circulation of Reactor Coolant

Circulation of the reactor coolant has two stages in a cooldown from hot standby to cold shutdown. The first stage is from hot standby to 350°F. During this stage, circulation of the reactor coolant is provided by natural circulation with the reactor core as the heat source and steam generators as the heat sink. Steam release from the steam generators is initially via the steam generator safety valves and occurs automatically as a result of turbine and reactor trip. Steam release for cooldown is via the steam generator power operated relief valves which are operated manually with their handwheels. The steam generator power operated relief valves are accessible for local operation. The status of each steam generator can be monitored using Class 1E instrumentation located on the console in the control room. Three separate channels of indications for both steam generator pressure and water level are available.

Feedwater to the steam generators is provided from the auxiliary feedwater system which has a 220,000 gallon Seismic Category 1 auxiliary feedwater storage tank as the primary source and two separate Seismic Category 1 piping sub-systems. The first-system is composed of two motor-driven pumps each powered from a different emergency power train, and the second sub-system incorporates a turbine driven pump which can receive motive steam from either of two steam generators. There are additional sources of feedwater backup which can be manually accesses. Initial backup is provided by the demineratlized water storage tank, the domestic water storage tank and the fire protection water tank. Additional backup is from the Seismic Category 1 service water system. The operation of the auxiliary feedwater system can be monitored using Class 1E instrumentation located on the control console in the control room. There is a single indication of the flows into each steam generator, pump operating status lights for the motor driven pumps, discharge and suction pressure indication for turbine driven pump. There are also two separate indications of the level in the auxiliary feedwater storage tank.

The second stage of reactor coolant circulation is from 350°F to cold shutdown. During this stage, circulation of the reactor coolant is provided by the residual heat removal pumps.

2. Removal of Residual Heat

Removal of residual heat also has two stages in a cooldown from hot standby to cold shutdown. The first stage is from hot standby to 350°F.

During this stage, the steam generators act as the means of heat removal from the RCS. Initially, steam is released from the steam generators via the steam generator safety valves to maintain hot standby conditions. When the operators are ready to begin the cooldown, the steam generators power operated relief valves are slightly opened by local operation with their handwheels. As the cooldown proceeds, the operators will occasionally adjust these valves to increase the amount they are open. This allows a reasonable cooldown rate to be maintained. Feedwater makeup to the steam generators is provided from the auxiliary feedwater system. The auxiliary feedwater system has the ability to remove decay heat by providing feedwater to all four steam generators for extended periods of operation.

The second stage is from 350°F to cold shutdown. During this stage the RHRS is brought into operation. The RHRS is brought into operation. The residual heat removal heat exchangers in the RHRS act as the means of heat removal from the RCS. In the heat exchanger, the residual heat is transferred to the component cooling system which ultimately transfers the heat to the service water system. The component cooling and the service water system are both designed to

Seismic Category 1. The RHRS includes two residual heat removal pumps and two residual heat removal heat exchangers. Each pump is powered from different emergency power trains and each heat exchanger is cooled by a different component cooling loop. If any component in one loop becomes inoperable, cooldown of the plant is not compromised, however, the time for cooldown would be extended.

The operation of the RHRS can be monitored using Class 1E instrumentation on the control console in the control room. For each loop there is indication of the pump discharge flow, the pump operation status and the component cooling flow from he discharge of the heat exchanger.

3. Boration and Makeup

Boration is accomplished using portions of the chemical and volume control system (CVCS). Boric acid (12 weight percent) from the boric acid tanks is supplied to the suction of the centrifugal charging pumps by the boric acid transfer pumps. The centrifugal charging pumps inject the borated water into the RCS via the normal charging and reactor coolant pump seal injection flow paths. The two boric acid tanks, two boric acid transfer pumps, and the associated piping are of Semisic Category 1 design. There is sufficient boric acid capacity to provide for a cold shutdown with the most reactive rod withdrawn. The boric acid transfer pumps are each powered from different emergency power trains. The boric acid tank level can be monitored to verify the operability of the boration portion of the CVCS. For this credit is taken for operator action in using a portable differential pressure indicator which can be connected to the level signal lines from the boric acid tanks.

Makeup, in excess of that provided as 12 weight precent boric acid is provided from the refueling water storage tank (RWST) using centrifugal charging pumps and the same injection flow paths as described for boration. Two motor operated valves, each powered from different emergency power trains and connected in parallel, will transfer the suction of the changing pumps to the RSWT. Makeup from the RWST can be monitored using Class 1E instrumentation on the control console in the control room. Two separate channels of RWST level indication exist.

4. Depressurization

Depressurization is accomplished using portions of the CVCS. Either 12 weight percent boric acid or refueling water can be used as desired for depressurization with the flow path being from the centrifugal charging pumps to the auxiliary spray valve in the pressurizer. The two centrifugal charging pumps of the CVCS are of Seismic Category I, and are powered from different emergency power trains. The pumps can be operated from and its operating status monitored in the control room. The depressurization of the reactor coolant system can be monitored using Class 1E instrumentatin on the control console in the control room. Available to the operator are four channels of pressurizer pressure, three channels of pressurizer level and two channels of reactor coolant pressure.

MAINTAINING RCS TEMPERATURE AND PRESSURE WITHOUT LETDOWN

In performing the cooldown, the operator will integrate the functions of heat removal, boration and makeup, and depressurization so that these functions can be accomplished without letdown from the RCS. Boration, cooldown, and depressurization will be accomplished in series of short steps arranged to keep RCS temperature and pressure and pressurizer level in the desired relationships. However, to demonstrate that boration and depressurization can be done without letdown, a simpler scenario can be used. First, the operators borate the RCS to the cold shutdown conditions, taking advantage of the steam space available into the pressurizer. Second, the operators use the cooldown contraction to lower the pressurizer water level. Finally, the operators use auxiliary spray from the CVCS to depressurize the plant to 425 psia.

The assumed initial conditions follow plant trip are:

RCS Temperature	= 547°F
RCS Pressure	= 2250 psia
Pressurizer Water Volume	= 500 ft^3
Pressurizer Steam Volume	= 1300 ft^3

To calculate if boration can be accomplished without letting down and without taking the plant water solid, worst case conditions of end of life and maximum peak Xenon were assumed. The result in a requirement for 600 ft^3 of 12 weight percent boric acid at 165°F to reach cold shutdown conditions. When added to the RCS, the boric acid would be heated to 547°F and would expand to 800 ft^3 available in the pressurizer steam space, boration to cold shutdown concentrations can be accomplished without letdown, without taking the plant water solid, and without cooling down.

The cooldown from 547°F to 350°F decreased the volume of water in the RCS by approximately 1700 ft^3. Some of this contraction is used to reduce the pressurizer water level to the no-load water level (following the increase caused by the boration) and the remainder is compensated for by makeup from the refueling water storage tank.

To calculate if depressurization can be accomplished without letting down and without taking the plant water solid, it was assumed that the pressurizer was at saturated conditions with 500 ft^3 of water, 1300 ft^3 of steam, and the pressurizer metal, all of 653°F (2250 psia). It was further assumed that no additional water would be removed from the pressurizer by the cooldown contraction. With these assumptions, and including the effect of each input from the pressurizer metal, it was determined that spraying in approximately 820 ft^3 of 165°F water would produce saturated conditions at 425 psia (450°F) with a water volume of 1550 ft^3 and a steam volume of 250 ft^3.

The results of the calculations described above demonstrate that boration and depressurization can be accomplished without letdown, without taking the plant water solid, and without taking full credit for the available volume created by the cooldown contraction.

SINGLE FAILURE EVALUATION

I. Circulation of the Reactor Coolant

A. From hot standby to 350°F (refer to Figures 5.1-6A, B and C, 10.3-1A and B and 10.4-7) - Four reactor coolant loops and steam generators are provided, any one of which can provide sufficient natural circulation flow to provide adequate core cooling. Even with the most limiting single failure (of a steam generator power operated relief valve), three of the reactor coolant loops and steam generators remain available.

B. From 350°F to cold shutdown (refer to Figures 5.5-2A and B) - Two RHR pumps are provided, either one of which can provide adequate circulation of the reactor coolant.

II. Removal of Residual Heat

A. From hot standby to 350°F (refer to Figures 9.2-1A and B and 9.2-2).

1. Steam generator power operated relief valves - Four are provided (one per steam generator), any one of which is sufficient for residual heat removal. In the event of a single failure, three power operated relief valves remain available.

2. Auxiliary feedwater pumps - Two motor driven and one steam driven auxiliary feedwater pumps are provided. In the event of a single failure, two pumps remain available, either of which can provide sufficient feedwater flow.

3. Flow control valves - Air operated, fail open valves. In the event of a single failure of one flow control valve (which effects flow to one steam generator from either a motor driven pump or the steam driven pump) auxiliary feed flow can still be provided to all four steam generators from the other pumps.

4. Backup source - A backup source of auxiliary feedwater can be provided via a spool piece from either train of the Seismic Category I service water system.

B. From 350°F to 200°F (refer to Figures 5.5-2A and B and 9.2-2).

1. Suction isolation valves 1RH1 and 1RH2 - These valves are each powered from different emergency power trains. Failure of either power train or of either valve operator could prevent initiation of residual heat removal cooling in the normal manner from the control room. In the event of such a failure, operator action could be taken to open the affected valve manually. The mechanical failure of the disc separating from the stem has been investigated (Reference 1) and its probability has been found to be in the range of 10^{-4} to 10^{-3} per year. The probability of an earthquake larger than the operating basis earthquake is less than $8X10^{-5}$ per year. The combined probability of valve stem failure coincident with the earthquake ($<8X10^{-8}$) is so low that it need not be considered in the single failure analysis. In the event of a failure, the plant would remain in a safe

hot standby condition with heat removal via the steam generators.

2. Isolation valves 11RH4 and 12RH4 - If either of these normally open motor operated valves, which are powered from different emergency power trains, were to close spuriously, residual heat removal cooling would be provided by the uneffected residual heat removal pump and heat exchanger. The affected valve could be de-energized and opened with its handwheel.

3. Pumps 11 and 12 - Each pump is powered from a different emergency power train. In the event of a single failure, either pump provides sufficient residual heat removal flow.

4. Heat exchangers 11 and 12 - If either heat exchanger is unavailable for any reason, the remaining heat exchanger provides sufficient heat removal capability.

5. Flow control valves 11RH18 and 12RH18 - If either of these normally open fail open valves should close spuriously, sufficient residual heat removal cooling would be provided by the unaffected residual heat removal train.

6. RHR/SIS cold leg isolation valves 11SH49 and 12SJ49 - If either of these normally open, motor operated valves, which are powered from different emergency power trains, should close spuriously, sufficient residual heat removal cooling would be provided by the unaffected valve could be deenergized and opened with its handwheel.

7. Component cooling water system - Two redundant subsystems provided for safety related loads. Either subsystem can

provide sufficient heat removal via one of the residual heat removal heat exchangers.

8. Service water system - Two redundant subsystems provided for safety related loads. Either subsystem can provide sufficient heat removal via one of the component cooling water heat exchangers.

III. Boration and Makeup (refer to Figures 5.1-6A, B and C, 6.3-1A and B and 9.3-6A and B).

A. Boric acid tanks 11 and 12 - Two boric acid tanks are provided. Each tank contains sufficient 12 percent boric acid to borate the reactor coolant system for cold shutdown.

B. Boric acid transfer pumps 11 and 12 - Each pump is powered from a different emergency power train. In the event of a single failure, either pump will provide sufficient boric acid flow.

C. Isolation valve 1CV175 - If valve 1CV175, which is supplied from emergency power and is normally closed, cannot be opened due to power train or operator failure, it can be opened locally with its handwheel. If valve 1CV175 cannot be opened with its handwheel, an alternate flow path is available via air operated, fail open valve 1CV172 and normally closed manual valve 1CV174.

D. Isolation valves 1SJ1 and 1SH2 - Each valve is powered from a different emergency power train, only one of these normally closed motor operated valves needs to be opened to provide a makeup flow path from the RWST to the centrifugal charging pumps.

E. Centrifugal charging pumps 11 and 12 - Each pump is powered from a different emergency power train. In the event of a single failure, either pump provides sufficient boration or makeup flow.

F. Flow control valve 1CV55 - This normally open valve fails closed on loss of air or power. If 1CV55 closed spuriously, the charging pumps would operate on their miniflow circuits until operator action could open bypass valves 1CV81 and 1CV82.

G. Flow control valve 1CV71 - This normally open valve fails closed on loss of air or power. Use of a portable nitrogen bottle would allow 1CV71 to be reopened. If 1CV71 was stuck closed as a result of a single failure, manual bypass valve 1CV73 could be opened locally.

H. Isolation valves 1CV68 and 1CV69 - If either of these normally open, motor operated valves, each of which is powered from a different emergency power train, should close spuriously, operator action could be used to deenergize the valve operator and reopen the valve with its handwheel.

I. Isolation valve 1CV77 - If the normally open valve should close spuriously, alternate charging valve 1CV79, which fails open, could be used.

V. Depressurization

A. Auxiliary spray valve 1CV75 - This normally closed valve fails closed on loss of air or power. Use of a portable nitrogen bottle would allow 1CV75 to be opened. If 1CV75 was stuck closed as a result of a single failure, the redundant Seismic Category 1 overpressure protection system valves can be used to depressurize the RCS by venting the pressurizer to the pressurizer relief tank.

B. Charging valves 1CV77 and 1CV79 - These valves fail open on loss of air or power. Use of portable nitrogen bottles would allow 1CV77 and 1CV79 to be closed. If either was stuck open, the redundant seismic category 1 overpressure protection system valves can be used to depressurizer the RCS by venting the pressurizer to the pressurizer relief tank.

ENVIRONMENTAL QUALIFICATION OF THE RHR SUCTION ISOLATION VALVES

The residual heat removal suction isolation valves are qualified for the steam line break environment. Therefore, they are qualified for the less severe environment which would result for venting the pressurizer to depressurize the RCS.

5.5.7.3.5 Hydraulic Performance at Run-out

An RHR pump was tested for the highest runout flow for the worst hydraulic configuration. This configuration is when one RHR pump is feeding two charging pumps, two safety injection pumps and also discharging directly into two cold legs. The test indicated that the RHR pump flow exceeded the design runout flow.

The system resistance on the discharge side for the RHR pumps was, therefore, increased by changing the orifices on the flow elements (up and downstream of the RHR heat exchanger) on the 8 inch RHR headers. The resized orfices at both the flow elements together provided the required resistance in the RHR system.

NPSH was evaluated for a pump flow of 4800 gpm (greater than the maximum pump flow). Under this condition, available NPSH exceeds the required NPSH.

5.5.7.4 Tests and Inspections

The residual heat removal pump flow instrumentation is calibrated periodically. Periodic visual inspections and preventative maintenance are conducted during plant operation.

5.5.8 REACTOR COOLANT CLEANUP SYSTEM

The chemical and volume control system provides reactor coolant cleanup and is discussed in Chapter 9. The rad-waste considerations are discussed in Chapter 11.

5.5.9 MAIN STEAM LINE AND FEEDWATER PIPING

The main steam line and the feedwater piping are discussed in Chapter 10.

5.5.10 PRESSURIZER

5.5.10.1 Design Bases

The general configuration of the pressurizer is shown in Figure 5.1-2. Design data are given in Table 5.2-4. Codes and material requirements are provided in Table 5.2-9.

5.5.10.1.1 Pressurizer Surge Line

The surge line is sized to limit the pressure drop between the RCS and the safety valves with the design discharge flow from the safety valves. Overpressure of the RCS does not exceed 110 percent of the design pressure.

The surge line is designed to withstand the thermal stresses that result from volume surges occurring during operation.

5.5.10.1.2 Pressurizer Volume

The volume of the pressurizer is equal to or greater than the minimum volume of steam, water or the total of the two that satisfies all the following requirements:

1. The combined saturated water volume and steam expansion volume is sufficient to provide the desired pressure response to system volume changes.

2. The water volume is sufficient to prevent the heaters from being uncovered during a step load increase of 10 percent of full power.

3. The steam volume is large enough to accommodate the surge resulting from 50 percent reduction of full load with automatic reactor control and steam dump without the water level reaching the high level reactor trip point.

4. The steam volume is large enough to prevent water relief through the safety valves following a loss of load with the high water level initiating a reactor trip.

5. The pressurizer does not empty following reactor trip and turbine trip.

6. The safety injection signal is not activated during reactor trip and turbine trip.

5.5.10.2 Design Description

5.5.10.2.1 Pressurizer Surge Line

The pressurizer surge line connects the pressurizer to one reactor coolant loop hot leg. The line enables continuous volume pressure adjustments between the RCS and the pressurizer.

The surge line is sized to limit the pressure drop during the maximum anticipated surge to less than the difference between the maximum allowable pressure in the reactor vessel and the loops (at the point of highest pressure) and the pressure in the pressurizer at the maximum allowable accumulation with the code safety valves discharging.

The surge line and the thermal sleeves at each end are designed to withstand the thermal stresses resulting from volume surges of relatively hotter or colder water which may occur during operation.

5.5.10.2.2 Pressurizer

The pressurizer is a vertical, cylindrical vessel with hemispherical top and bottom heads constructed of carbon steel, with austenitic stainless steel cladding on all surfaces exposed to the reactor coolant.

The surge line nozzle and electric heaters are installed in the bottom head. The heaters can be removed for maintenance or replacement. A thermal sleeve is provided to minimize stresses in the surge line nozzle. A screen at the surge line nozzle and baffles in the lower section of the pressurizer prevents an insurge of cold water from flowing directly to the steam/water interface and also assists mixing.

The spray line nozzle and relief and safety valve connections are located in the top head of the vessel. Spray flow is modulated by automatically controlled air-operated valves. The spray valves can also be operated manually by a switch in the control room.

A small, continuous spray flow is provided through a manual bypass valve around the power-operated spray valves to assure that the pressurizer liquid is homogenous with the coolant and to prevent excessive cooling of the spray piping.

During an outsurge from the pressurizer, the flashing of water to steam and the generation of steam by automatic actuation of the heaters keep the pressure above the minimum allowable limit. During an insurge from the RCS, the spray system, which is fed from two cold legs, condenses steam in the vessel to prevent the pressurizer pressure from reaching the setpoint of the power-operated relief valves for normal design transients. Heaters are energized on high water level during insurge to heat the sub-cooled surge water that enters the pressurizer from the reactor coolant loop.

PORV's provide the means for pressurizer venting and a procedure for such an application is included within the Station Emergency Instructions for "natural circulation". Pressurizer vent paths have been evaluated and shown not to result in inadvertent opening or failure to close after initial opening.

Material specifications for the pressurizer, the pressurizer relief tank and the surge line are provided in Table 5.2-27.

In the list below, several other aspects of the pressurizer are discussed.

1. Pressurizer Support

   The skirt type support is attached to the lower head and extends for a full 360 degrees around the vessel. The lower part of the skirt terminates in bolting flange with bolt holes for securing the vessel to its foundation. The skirt type support is provided with ventilation holes around its upper perimeter to assure free convection of ambient air past the heater and connector ends for cooling.

2. Pressurizer Instrumentation

   Refer to Chapter 7 for details of the instrumenation associated with pressurizer pressure, level and temperature.

3. Spray Line Temperatures

   Temperatures in the spray lines from the cold legs of two loops are measured and indicated. Insufficient flow in the spray lines results in low spray line temperature. Low alarms from these temperature channels are actuated to warn the operator of low bypass spray flow rate.

4. Safety and Relief Valve Discharge Temperature

Temperatures in the pressurizer safety and relief valve discharge lines are measured and indicated. An increase in a discharge line temperature is an indication of leakage or relief through the associated valve. High temperature alarms are actuated if the leakage is abnormal.

5.5.10.3 Design Evaluation

5.5.10.3.1 System Pressure Control

Whenever a steam bubble is present within the pressurizer, RCS pressure is controlled by the pressurizer. Analyses indicate that proper control of pressure is maintained for the normal operating conditions. Tweaty banks of "backup" heaters can be powered from the vital distribution system. This provides assurance that pressure control for natural circulation can be maintained during a loss of offsite power.

A safety limit has been set to ensure that the Reactor Coolant System presssure does not exceed the maximum transient value allowed under the ASME Code, Section III. Thereby, continued integrity of the Reactor Coolant System components is assured. Evaluation of plant conditions of operation indicates that this safety limit is not reached.

During startup and shutdown, the rate of temperature change is controlled by the operator. Heatup rate is controlled by pump energy and by the pressurizer electrical heater capacity.

When the pressurizer is filled with water (i.e., near the end of the second phase of plant cooldown and during initial system heatup) RCS pressure is controlled by operation of a charging pump. The appropriate letdown flow is provided via the shutdown path from the residual heat removal system.

5.5.10.3.2 Pressurizer Level Control

The normal operating water volume at full load conditions is approximately 60 percent of the free internal vessel volume. Under part load conditions, the water volume in the vessel is reduced for proportional reductions in plant load to approximately 25 percent of free vessel at zero power level.

5.5.10.3.3 Pressure Setpoints

The RCS design and operating pressures are listed in Table 5.2-1 together with the safety, power-operated relief and pressurizer spray valves setpoints. The design pressure allows for operating transient pressure changes. The selected design margin considers core thermal lag, coolant transport times and pressure drops, instrumentation and control response characteristics and system relief valve characteristics.

5.5.10.3.4 Pressurizer Spray

Two separate, automatically controlled spray valves with remote manual overrides are used to initiate pressurizer spray. In parallel with each spray valve is a manual throttle valve, which permits a small continuous flow through both spray lines to reduce thermal stresses and thermal shock when the spray valves open and to help maintain uniform water chemistry and temperature in the pressurizer. Temperature sensors with low alarms are provided in each spray line to alert the operator to insufficient bypass flow. The layout of the common spray line piping to the pressurizer forms a water seal, which prevents the steam buildup back to the control valves. The design spray rate is selected to prevent the pressurizer pressure from reaching the operating setpoint of the power relief valves during a step reduction in power level of 10 percent of full load.

The presssurizer spray lines and valves are large enough to provide adequate spray using as the driving force the differential pressure between the surge line connection in the hot leg and the spray line connection in the cold leg. The spray line inlet connections extend into the cold leg piping in the form of a scoop, so that the velocity head of the reactor coolant loop flow adds to the spray driving force. The spray valves and spray line connections are arranged so that the spray will operate when one reactor coolant pump is not operating. The spray line also assists in equalizing the boron concentration between the reactor coolant loops and the pressurizer.

A flow path from the chemical and volume control system to the pressurizer spray line is also provided. This additional facility provides an auxiliary spray flow path to the vapor space of the pressurizer during cooldown if the reactor coolant pumps are not operating. The thermal sleeve on the pressurizer spray connection and the spray piping is designed to withstand the thermal stresses resulting from the introduction of cold spray water.

5.5.10.4 Tests and Inspections

The pressurizer is designed and fabricated in accordance with the ASME Code, Section III, Safety Class 1 vessels.

The pressurizer quality assurance program is given in Table 5.2-26.

5.5.11 PRESSURIZER RELIEF TANK

5.5.11.1 Design Bases

Design data for the pressurizer relief tank are given in Table 5.2-4. Codes and materials are given in Table 5.2-9 and Table 5.2-27.

The tank design is based on the requirement to condense and cool a discharge of pressurizer steam equal to 110 percent of the volume above the full-power pressurizer water level setpoint. The tank is not designed to accept a continuous discharge from the pressurizer.

5.5.11.2 Design Description

The pressurizer relief tank condenses and cools the discharge from the pressurizer safety and relief valves. Discharges from specific relief valves located inside the containment are also piped to the relief tank. The tank normally contains water and a predominantly nitrogen atmosphere; however, provision is made to permit the gas in the tank to be periodically analyzed to monitor the concentration of hydrogen or oxygen.

By means of its connection to the waste processing system, the pressurizer relief tank provides a means for removing any noncondensable gases from the RCS that might collect in the pressurizer vessel.

Steam is discharged through a sparger pipe under the water level. This arrangement provides for condensing and cooling the steam by mixing it with water that is near ambient temperature. A flanged nozzle is provided on the tank for the pressurizer discharge line connection to the sparger pipe.

The pressurizer relief tank has pressure, temperature, and level indications and alarms in the control room.

5.5.11.3 Design Evaluation

The volume of water in the tank is capable of absorbing heat from the assumed discharge, assuming an initial temperature of 120 °F and increasing to a final temperature of 200 °F. If the temperature in the tank rises above 120 °F during plant operation, the tank is cooled by spraying in cool water and draining out the warm mixture to the waste disposal system.

The spray rate is designed to cool the tank from 200/?F to 120/?F in approximately 1 hour following the design discharge of pressurizer steam. The volume of nitrogen gas in the tank is selected to limit the maximum pressure following a design discharge to 50 psig.

The rupture discs on the relief tank have a relief capacity equal to or greater than the combined capacity of the pressurizer safety valves. The tank design pressure, and the maximum rupture disc burst point, is twice the calculated pressure resulting from the maximum design safety valve discharge described above. The tank and rupture disc holders are also designed for full vacuum to prevent tank collapse if the contents cool following a discharge without nitrogen being added.

The PRT rupture disc is the vent path for both the reactor vessel head and the pressurizer vent. The annulus area containing the PRT is well ventilated. With 3 out of 5 fan coil units running at reduced speed during an accident condition, the annulus area containing the PRT is adequately ventilated with an air change every hour. A review of possible sources of ignition in the immediate vicinity of interest indicates no concern. Venting through the PRT rupture disc will not adversely affect any system or component essential for safe shutdown.

The discharge piping from the safety and relief valves to the relief tank is sufficiently large to prevent back-pressure at the safety valves from exceeding 20 percent of the setpoint pressure at full flow.

5.5.12 VALVES

Valves in contact with the reactor coolant are primarily constructed of stainless steel. For certain applications, such as hard surfacing and packing, design and functional considerations dictate the use of materials other than stainless steel.

All manual and motor-operated valves of the RCS that are three inches and larger are provided with double-packed packing boxes and intermediate lantern ring leakoff connections. All throttling control valves regardless of size, are provided with double-packed stuffing boxes and with stem leakoff connections. Leakage to the atmosphere is essentially zero for these valves. RCS valve codes, materials and quality assurance measures are summarized in Tables 5.2-9, 5.2-27 and 5.2-26, respectively.

5.5.13 SAFETY AND RELIEF VALVES

5.5.13.1 <u>Design Bases</u>

The capacity of the pressurizer safety valves accommodates the maximum surge resulting from complete loss of load. By the opening of the steam generator safety valves when steam pressure reaches the steam side safety setting, this objective is met without reactor trip or any operator action.

The RCS uses pressure control equipment in addition to the ASME Code safety valves. Although this pressure control equipment is not required by the ASME Code, it is used to assist in maintaining the Reactor Coolant System within the normal operating pressure.

The pressurizer power-operated relief valvers are designed to limit pressurizer pressure to a value below the high-pressure reactor trip setpoint. They are designed to fail to the closed position on loss of air supply. No provision is necessary to ensure activation of the valves should the air supply fail, since the valves are classified as inactive.

The pressurizer power-operated relief valves are not required to open in order to prevent the overpressurization of the RCS. Failure of the power-operated relief valves to open results in higher reactor coolant pressures, but does not result in overpressurization of the system. In fact, the opening of the power-operated relief valves is a conservative assumption for the departure-from-nucleate-boiling limited transients by tending to keep the primary system pressure down.

The pressurizer spray control valves are also utilized to control pressurizer pressure variations. During an insurge, the spray system, which is fed from the cold legs, condenses steam in the pressurizer to prevent the pressure from reaching the setpoint of the power-operated relief valves.

5.5.13.2 Design Description

The pressurizer safety valves are totally enclosed pop-type valves. The valves are spring-loaded, self-activated and with back-pressure compensation designed to prevent system pressure from exceeding the design pressure by more than 110 percent, in accordance with the ASME Boiler and Pressure Code, Section III. The set pressure of the valves is 2485 psig.

A water seal is maintained below each safety valve seat to minimize leakage. The 6 inch pipes connecting the pressurizer nozzles to their respective code safety valves, are shaped in the form of a loop seal. Condensate, as a result of normal heat losses to the ambient, will accumulate in the loop, thus flooding the valve seat. The water will prevent any leakage of hydrogen gas or steam through the safety valve seats. If the pressurizer pressure exceeds the set pressure of the safety valves, they will start lifting, and the water from the seal will discharge during the accumulation period. A temperature indicator in the safety valve discharge manifold alerts the operator to the passage of steam due to leakage or valves lifting.

The pressurizer is equipped with power-operated relief-valves which limit system pressure for a large power mismatch and thus prevent actuation of the fixed high-pressure reactor trip. The relief valves are operated automatically or by remote manual control. The operation of these valves also limits the undesirable opening of the springloaded safety valves. Remotely operated stop valves are provided to isolate the power-operated relief valves if excessive leakage occurs.

The relief valves are designed to limit the pressurizer pressure to a value below the high-pressure trip setpoint for all design transients up to and including the design percent step load decrease with steam dump but without reactor trip.

Design parameters for the pressurizer spray control, safety, and power relief valves are given in Table 5.2-8.

5.5.13.3 Design Evaluation

The pressurizer safety valves prevent RCS pressure from exceeding 110 percent of system design pressure, in compliance with the ASME Code Section III. Safety valve position is monitored by limit switches which alarm in the control when any valve is not in the fully closed position.

The pressurizer power-operated relief valves prevent actuation of the reactor high-pressure trip for all design transients up to and including the design step load decreases with steam dump. The relief valves also limit opening of the spring-loaded safety valves. The opening of any pressurizer power operated relief valve is annunciated in the control room.

Westinghouse has completed a generic study(2) of PORV reliability and concluded that PORVs are adequately reliable so as not to require automatic block valve closure. PSEG has determined that the information provided in the generic report is applicable to the Salem Generating Station. Accordingly, automatic isolation of the PORVs is not provided.

5.5.14 REACTOR COOLANT SYSTEM COMPONENT SUPPORTS

5.5.14.1 Description

Reactor vessel supports are assemblages of plates built up to seat the reactor vessel nozzle shoes. There are four shoe supports for each reactor vessel. The support assemblages are air cooled by negative pressure ducts that draw the air away from the space surrounding the vessel through vent holes drilled in the multiple plates. For support details see Figure 5.5-3.

The steam generator supports are shown in Figure 5.5-4. The weight of the steam generator is transferred through four steel columns at its base to the supporting frame. The steam generator penetrates the operating floor of the containment building. The elevation of the operating floor is approximately at the center of gravity of the steam generator. It is supported at the floor by two sets of snubbers and bumper blocks which resist the horizontal forces and overturning moments generated from pipe rupture or earthquake motion. The supporting frame has its upper bay braced in both directions. The lower bay consists of two parallel planar trusses which are pin-hinged at the top and bottom to allow for thermal displacement. The horizontal forces at the base of the steam generator are transferred through combined truss and frame action to the lower bay of the support structure. The primary loop piping provides lateral support for the frame in the direction normal to the plane of the trusses. Lateral restraint for blowdown is provided at the top of the support structure by two struts connected to the reactor shield wall. The struts are in two bolted sections with gaps for free thermal travel and adjustment.

The reactor coolant pump supports as shown in Figure 5.5-5 also consist of an upper and lower section. The upper section is a welded steel assembly and is constructed to accommodate the bolts of the feet of the reactor coolant pump. The lower section is composed of two parallel planar trusses, pin-hinged at the top and bottom to provide for thermal expansion. Lateral support in th direction normal to the plane of the trusses is provided by the primary loop piping. Blowdown restraint is provided at the top of the supporting structure by struts connected to the shield wall. The struts are in bolted sections with gaps for free thermal travel and adjustment.

The steam generator and reactor coolant pump supports are anchored to the containment base slab by heavy welded steel frames embedded in the concrete and tied to the base mat by 6 and 4 inch diameter bolts, 18.5 feet long. Typical details for the embedded steel for equipment supports are shown in Figure 5.5-6.

The pressurizer also penetrates the operating floor of the reactor containment. Stop lugs are embedded in the floor slab to provide the lateral support for the pressurizer at its midheight. The vessel skirt is bolted to a steel plate which is in turn welded to the top of the support structure. The support structure frame is braced in both directions. It is further constrained against lateral movement at its top by four short wide flange struts, two in each perpendicular direction, connected to the polar crane support wall. For pressurizer support details see Figure 5.5-7.

5.5.14.2 Fabrication

All shop welding was done in accordance with AWS D2.0, "Specification for Welded Highway and Railway Bridges." Detailed joint procedure specifications were submitted by the fabricator for review and approval by PSE G engineering personnel. The following preheat requirements were specified to minimize residual stress:

1. Material less than 3/4 inch thick shall be preheated to 100°F if the ambient temperature falls below 40°F.

2. Material 3/4 to 1-1/2 inches thick shall be preheated to 150°F prior to welding.

3. Material 1-1/2 to 2-1/2 inches thick shall be preheated to 225°F before welding.

4. Material over 2-1/2 inches thick shall be preheated to 300°F before welding.

Most intersecting primary members are connected flange to flange by butt welds or are connected to gusset plates by fillet welds. These types of connections are not susceptible to lamellar tearing.

5.5.14-3 Evaluation

Analysis of the RCS supports is discussed in Section 3.9. Steam generator and reactor coolant pump support load combinations and allowable stress limits are given in Table 5.5-3. The average operating temperature of these supports is approximately 100°F, with a minimum of 70°F. Material for primary component support structures subject to high intensity impact loads was required to pass a Charpy impact test of 20 ft.-lb. at 20°F to verify its fracture toughness characteristics. This fracture toughness assures that brittle behavior will not be exhibited.

5.5.14-4 Inspection

All welds were subject to visual inspection in accordance with AWS requirements. All full penetration shop welds were subject to magnetic particle inspection at four depths supplemented, where practical, by ultrasonic inspection of the finished weld. After installation, welds on the supports were subject to another magnetic particle inspection. This inspection revealed only minor surface defects on some welds, none critical to the structural integrity of the supports. Nonetheless, these welds were repaired.

REFERENCES FOR SECTION 5.5

1. Hill, R. A., et. al., "Evaluation of Mispositioned ECCS Valves," WCAP-8966 (Proprietary) and WCAP-9207 (Non-Proprietary), September, 1977.

2. Westinghouse Electric Corp., "Probabilistic Analysis and Operational Data in Response to NUREG-0737, Item II.K.3.2, for Westinghouse NSSS Plants," WCAP-9804, February 1981.

TABLE 5.5-1 (Sheet 1 of 3)

RESIDUAL HEAT REMOVAL SYSTEM DESIGN PARAMETERS

Code Requirements

Residual Heat Exchangers (Tube Side)	ASME III, Class C
(Shell Side)	ASME VIII
Residual Heat Removal Piping and Valves	ANSI B31.1.0*
	ANSI B31.7**

General

Plant design life, years	40
Component cooling water supply temperature design, °F	95
Reactor coolant temperature at startup of decay heat removal °F	350
Time to cool Reactor Coolant System from 350°F to 140°F, starting at 4 hours after shutdown, hr	16
Refueling water storage temperature, °F	Ambient
Decay heat generation at 20 hours after shutdown, Btu/hr	70.6×10^6 (Unit No. 1)
	72.1×10^6 (Unit No. 2)
H_3BO_3 concentration in refueling water storage tank, ppm boron	~2000

* Used for design.

** For piping not supplied by the NSSS supplier, material inspection fabrication and quality control conform to ANSI B31.7. Where not possible to comply with ANSI B31.7, the requirements of ASME III-1971, which incorporated ANSI B31.7, were adhered to.

TABLE 5.5-1 (Sheet 2 of 3)

RESIDUAL HEAT REMOVAL SYSTEM DESIGN PARAMETERS

COMPONENTS

Residual Heat Exchangers

Number		2 (per unit)
Design heat transfer, Btu/hr		34.15×10^6
	Shell	Tube
Design pressure, psig	150	600
Design temperature, °F	200	400
Design flow rate, lb/hr	2.475×10^6	1.48×10^6
Design outlet temperature, °F	108.8	114
Design inlet temperature, °F	95	137
Fluid	Component cooling water	Reactor coolant (borated demineralized water)
Material of construction	Carbon steel	Austenitic stainless steel

Residual Heat Removal Pumps

Number	2 (per unit)
Type	Vertical centrifugal
Design pressure, psig	600
Design temperature, °F	400
Shutoff head, psi	170
Design flow rate, gpm	3,000
Design head, ft.	350
Available NPSH at design flow rate, ft.	25
Temperature of pump fluid, °F	40 - 350
Normal fluid	Reactor coolant
Fluid during LOCA recirculation phase	Radioactive borated water with H_2 and NaOH in solution
Material of construction	Austenitic stainless steel

TABLE 5.5-1 (Sheet 3 of 3)

RESIDUAL HEAT REMOVAL SYSTEM DESIGN PARAMETERS

Piping and Valves

	Pump Suction	Pump Discharge
Residual heat removal loop (piping and valves in isolated loop):		
Design pressure, psig	450	600
Design temperature, °F	400	400
Residual loop isolation valves and piping:		
Design pressure, psig		2,485
Design temperature, °F		650

TABLE 5.5-2 (Sheet 1 of 3)

RESIDUAL HEAT REMOVAL SYSTEM FAILURE ANALYSIS

Component	Malfunction	Comments and Consequences
1. Residual heat removal pumps	Rupture of a pump casing	The casing and shell are designed for 600 psi and 400°F. The pump is protected from overpressurization by two normally closed valves in the pump suction line by an open relief line, containing a relief valve, back to the pressurizer relief tank. The pump is inspectable and is located in the auxiliary building protected against credible missiles. Rupture is considered unlikely but in any event the pump can be isolated.
2. Residual heat removal pump	Pump fails to start	One operating pump furnishes half of of the flow required to meet design cooldown rate. This increases the time necessary for plant cooldown.
3. Residual heat removal pump	Manual valve on pump suction is closed	This is prevented by prestartup and startup and operational checks.
4. Residual heat removal pump	Stop valve on discharge line closed or check valve sticks closed	Stop valves are locked open. Prestartup and operational checks confirm position of valves.

RESIDUAL HEAT REMOVAL SYSTEM FAILURE ANALYSIS

Component	Malfunction	Comments and Consequences
5. Remote operated valves inside containment in pump suction line	Valve fails to open	In the improbable event that one of the remote operated valves on the suction line to the residual heat removal pumps is inoperable, an attempt will be made to open it manually. If this is impossible, the plant will be cooled to about 280°F with steam dump from the steam generators, and kept at that temperature for several weeks until decay heat could be matched by the letdown heat exchangers and by feed and bleed. Feed and bleed through the CVCS will be done intermittently to prevent heat transfer through the regenerative heat exchanger. The pressurizer level will be brought to minimum during the bleed operation and to maximum during the feed operation. It is estimated that plant cooldown may be accomplished within a month.
6. Remote operated valves inside containment on pump discharge line	Valve fails to open	Pump discharge pressure gage shows pump shut-off head indicating no flow. The low head safety injection lines may be opened and utilized to direct flow to the RCS hot legs. A reactor coolant pump must be operated.

TABLE 5.5-2 (Sheet 3 of 3)

RESIDUAL HEAT REMOVAL SYSTEM FAILURE ANALYSIS

	Component	Malfunction	Comments and Consequences
7.	Residual heat exchanger	Tube or shell rupture	Rupture is considered unlikely, but in any event the faulty heat exchanger may be isolated.
8.	Residual heat exchanger vent or drain valve	Left open	This is prevented by prestartup operational checks.

TABLE 5.5-3

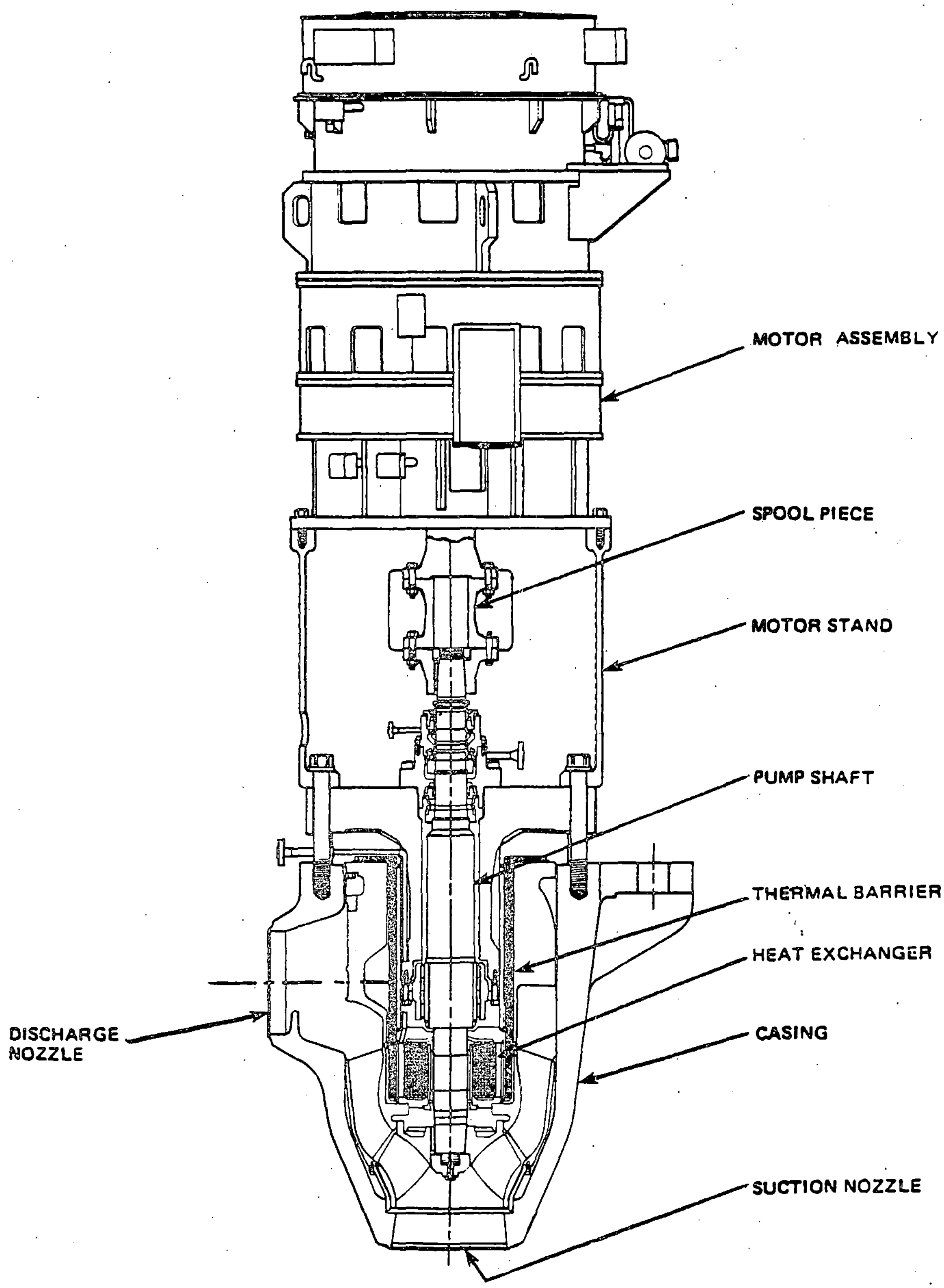
SALEM NUCLEAR GENERATING STATIONS

UNITS NO. 1 and 2

STEAM GENERATOR AND REACTOR COOLANT PUMP SUPPORTS

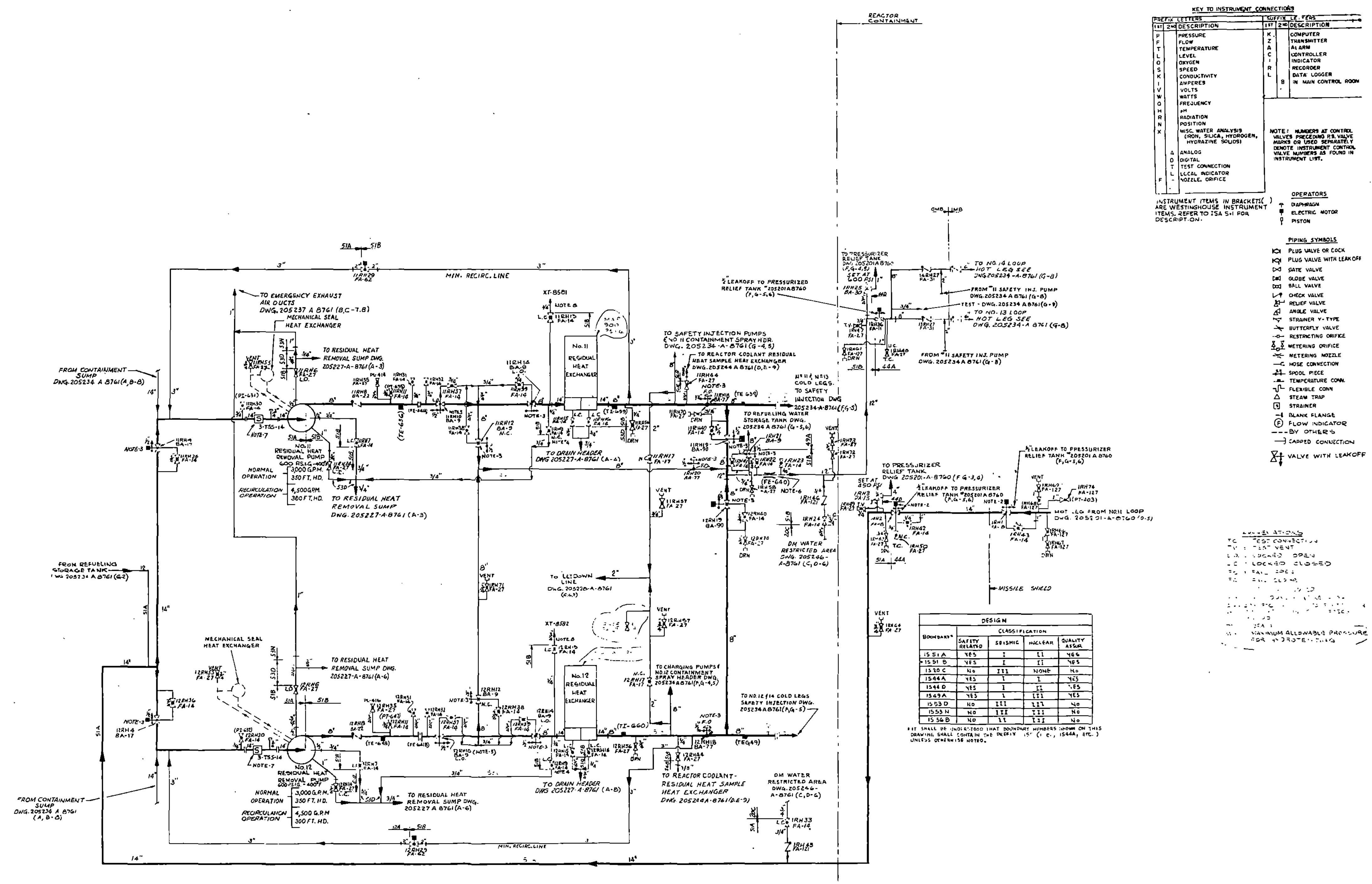
LOADING COMBINATION AND ALLOWABLE STRESS LIMITS

LOADING COMBINATIONS	SUPPORTS - ALLOWABLE STRESS LIMIT
1. Normal Loads	Working stresses per AISC code
2. Normal loads + operating base earthquake (upset condition)	1-1/3 working stresses AISC code
3. Normal loads + pipe rupture loads (emergency condition)	90 percent of yield stress of material
4. Normal loads + design base	90 percent of yield stress of material
5. Normal loads + design base earthquake + pipe rupture loads (faulted condition)	Yield stress of material



Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Coolant Pump	
	Updated FSAR	Figure 5.5-1

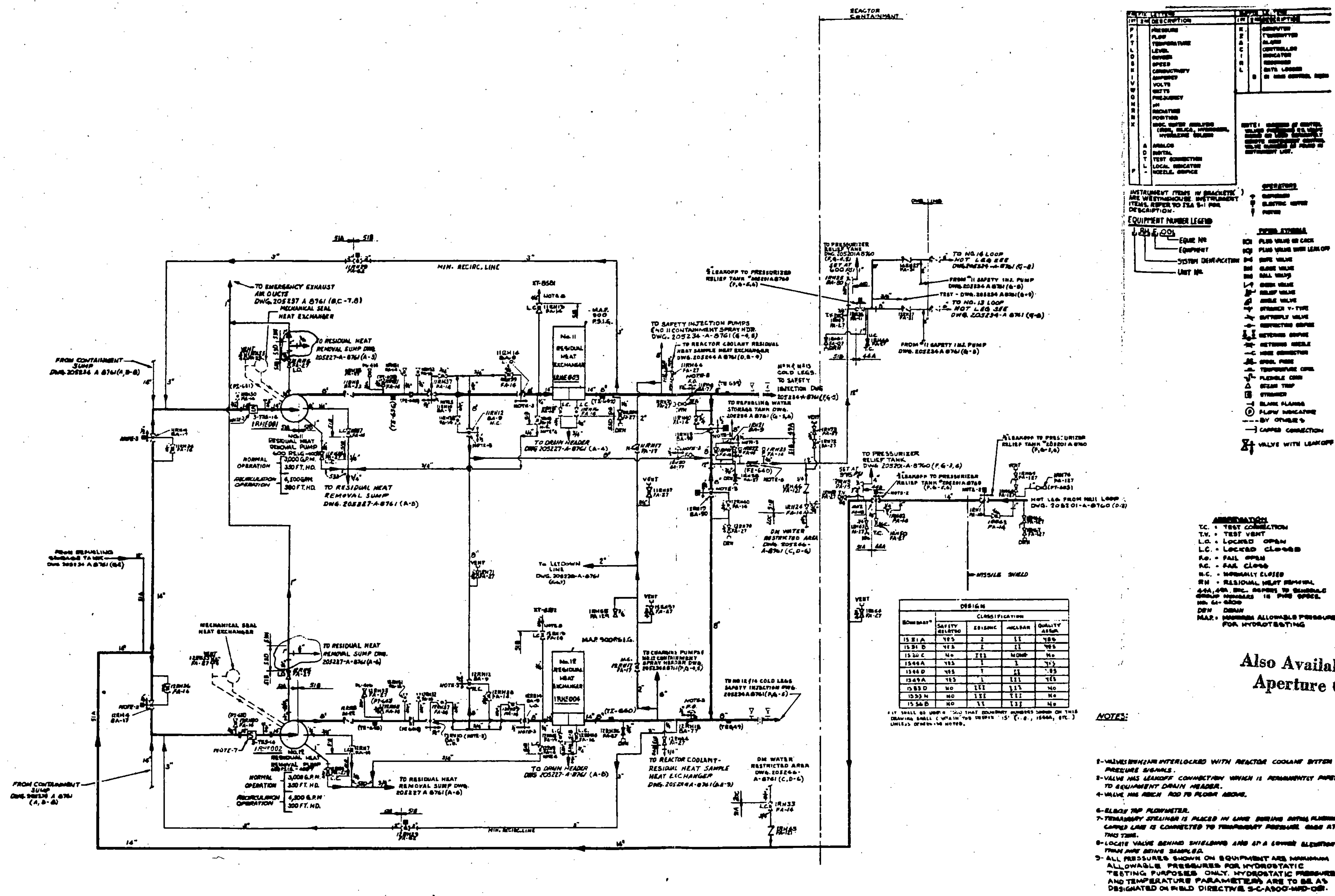


DESIGN				
BOUNDARY*	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S51A	YES	I	II	YES
•1S51B	YES	I	II	YES
1S20C	NO	III	NONE	NO
1S44A	YES	I	I	YES
1S44D	YES	I	II	YES
1S49A	YES	I	III	YES
1S53D	NO	III	III	NO
1S53N	NO	III	III	NO
1S56B	NO	II	III	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e., 1S44A, ETC.) UNLESS OTHERWISE NOTED.

Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Residual Heat Removal System - Unit No. 1
	Updated FSAR — Sheet 1 of 2 — Figure 5.5-2



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Revision 3
July 22, 1984

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Residual Heat Removal System-Unit No. 1
	UPDATED FSAR Sheet 1 of 2 FIG 5.5-2

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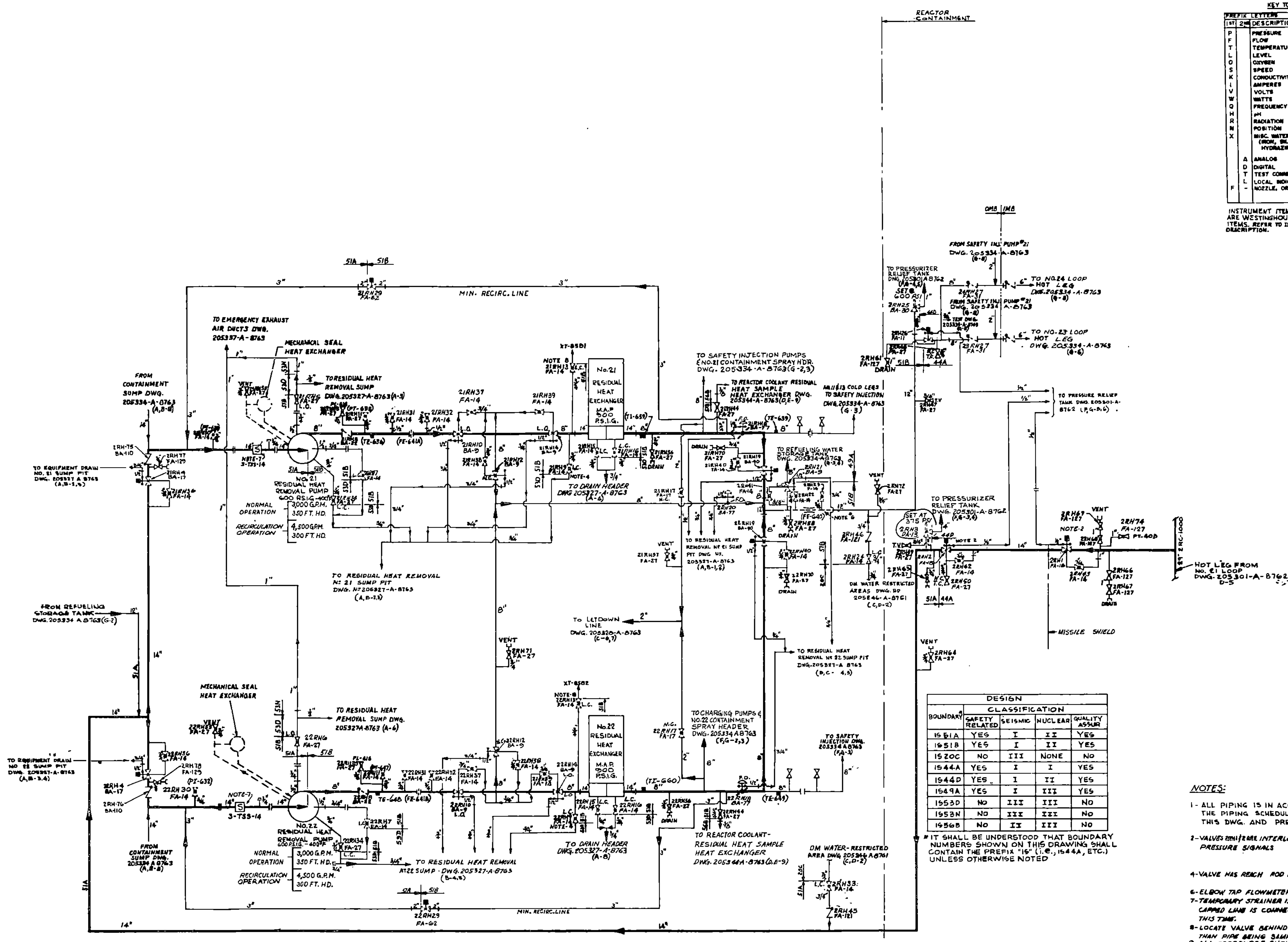


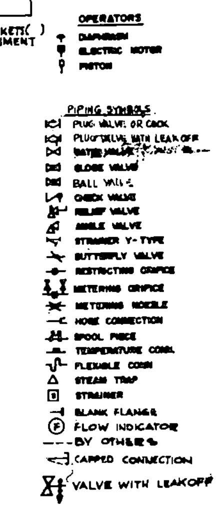
KEY TO INSTRUMENT CONNECTIONS

PREFIX LETTERS 1ST	2ND	DESCRIPTION
P		PRESSURE
F		FLOW
T		TEMPERATURE
L		LEVEL
O		OXYGEN
S		SPEED
K		CONDUCTIVITY
I		AMPERES
V		VOLTS
W		WATTS
Q		FREQUENCY
H		pH
R		RADIATION
N		POSITION
X		MISC. WATER ANALYSIS (IRON, SILICA, HYDROGEN, HYDRAZINE SOLIDS)
	A	ANALOG
	D	DIGITAL
	T	TEST CONNECTION
	L	LOCAL INDICATOR
F	-	NOZZLE, ORIFICE

SUFFIX LETTERS 1ST	2ND	DESCRIPTION
K		COMPUTER
Z		TRANSMITTER
A		ALARM
C		CONTROLLER
I		INDICATOR
R		RECORDER
L		DATA LOGGER
	B	IN MAIN CONTROL ROOM

NOTE: NUMBERS AT CONTROL VALVES PRECEDING F.C. VALVE MARKS OR USED SEPARATELY DENOTE INSTRUMENT CONTROL VALVE NUMBERS AS FOUND IN INSTRUMENT LIST.

INSTRUMENT ITEMS IN BRACKETS( ) ARE WESTINGHOUSE INSTRUMENT ITEMS. REFER TO ISA S.1 FOR DESCRIPTION.



TI APERTURE CARD

ABBREVIATION

T.C. = TEST
TV = TEST VENT
L.O. = LOCKED OPEN
L.C. = LOCKED CLOSED
F.O. = FAIL OPEN
F.C. = FAIL CLOSE
N.C. = NORMALLY CLOSED
RH = RESIDUAL HEAT REMOVAL
44A, 49A, ETC. REFERS TO SCHEDULE & GROUP NUMBERS IN PIPE SPECS. NO. G1-6200
DRN = DRAIN
M.A.P. = MAXIMUM ALLOWABLE PRESSURE FOR HYDROTESTING

DESIGN				
BOUNDARY*	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR
1561A	YES	I	II	YES
1551B	YES	I	II	YES
1520C	NO	III	NONE	NO
1544A	YES	I	I	YES
1544D	YES	I	II	YES
1549A	YES	I	III	YES
1553D	NO	III	III	NO
1553N	NO	III	III	NO
1556B	NO	II	III	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "15" (i.e., 1544A, ETC.) UNLESS OTHERWISE NOTED

Also Available On Aperture Card

NOTES:

1- ALL PIPING IS IN ACCORDANCE WITH PIPE SPEC. NO. G1-6200 THE PIPING SCHEDULE AND GROUP NOS. ARE AS NOTED ON THIS DWG. AND PREFIXED WITH "15" IN THE PIPE SPEC.

2- VALVES 22RH1/2 ARE INTERLOCKED WITH REACTOR COOLANT SYSTEM PRESSURE SIGNALS

4- VALVE HAS REACH ROD TO FLOOR ABOVE

6- ELBOW TAP FLOWMETER

7- TEMPORARY STRAINER IS PLACED IN LINE DURING INITIAL STARTUP CAPPED LINE IS CONNECTED TO TEMPORARY PRESSURE GAGE AT THIS TIME.

8- LOCATE VALVE BEHIND SHIELDING AND AT A LOWER ELEVATION THAN PIPE BEING SAMPLED.

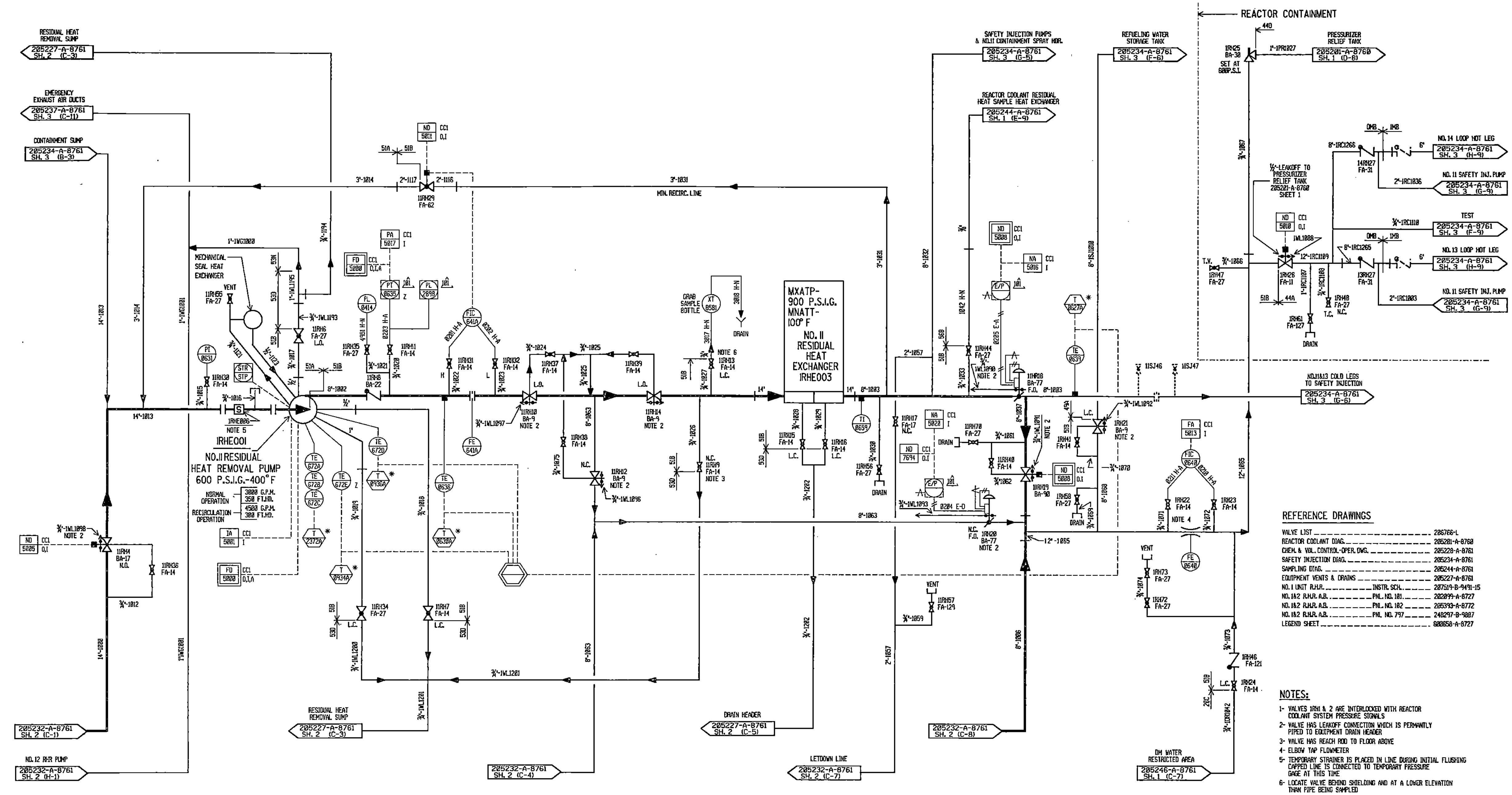
9- ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A500-MFD-051

205332A8763-9

Revision 3
July 22, 1984

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Residual Heat Removal System-Unit No. 2
	UPDATED FSAR Sheet 2 of 2 FIG 5.5-2

8408020108 -13



REFERENCE DRAWINGS

VALVE LIST		206766-L
REACTOR COOLANT DIAG.		205201-A-8760
CHEM. & VOL. CONTROL-OPER. DWG.		205228-A-8761
SAFETY INJECTION DIAG.		205234-A-8761
SAMPLING DIAG.		205244-A-8761
EQUIPMENT VENTS & DRAINS		205227-A-8761
NO. 1 UNIT R.H.R.	INSTR. SCH.	207519-B-9491-15
NO. 1&2 R.H.R. A.B.	PNL. NO. 101	202099-A-8727
NO. 1&2 R.H.R. A.B.	PNL. NO. 102	205393-A-8772
NO. 1&2 R.H.R. A.B.	PNL. NO. 797	248297-B-9807
LEGEND SHEET		600658-A-8727

NOTES:

1- VALVES 1RH1 & 2 ARE INTERLOCKED WITH REACTOR COOLANT SYSTEM PRESSURE SIGNALS
2- VALVE HAS LEAKOFF CONNECTION WHICH IS PERMANTLY PIPED TO EQUIPMENT DRAIN HEADER
3- VALVE HAS REACH ROD TO FLOOR ABOVE
4- ELBOW TAP FLOWMETER
5- TEMPORARY STRAINER IS PLACED IN LINE DURING INITIAL FLUSHING CAPPED LINE IS CONNECTED TO TEMPORARY PRESSURE GAGE AT THIS TIME
6- LOCATE VALVE BEHIND SHIELDING AND AT A LOWER ELEVATION THAN PIPE BEING SAMPLED
7- ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1RH" (i.e. 1RH1000, ETC.) EXCEPT WHERE OTHERWISE NOTED.
8- ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
9- ALL CONTROL VALVES TO HAVE OPEN & CLOSED LIMIT SWITCHES.

DESIGN				
BOUNDARY	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S20C	NO	III	NONE	NO
1S44A	YES	I	I	YES
1S44D	YES	I	II	YES
1S49A	YES	I	III	YES
1S51A	YES	I	II	YES
1S51B	YES	I	II	YES
1S53D	NO	III	III	NO
1S53N	NO	III	III	NO
1S56B	NO	II	III	NO

IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

8607290251-11

TI APERTURE CARD

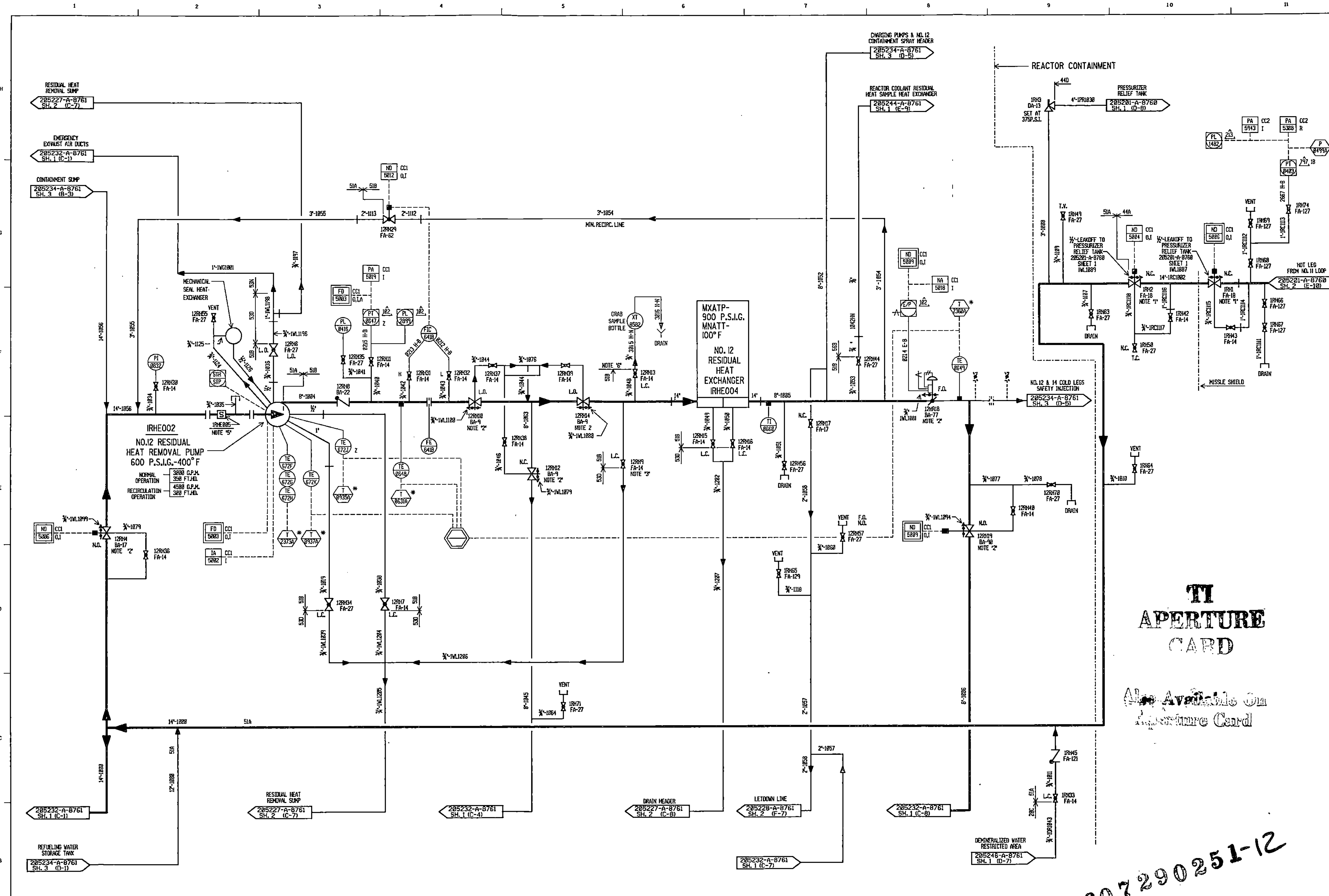
Also Available On Aperture Card

REVISION 5
JULY 25, 1986
Ref. Dwg. 205232-A-8761-16

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Residual Heat Removal System
Unit 1

Updated FSAR Sheet 1 of 2
Fig 5.5-2A



TI APERTURE CARD

Also Available On Aperture Card

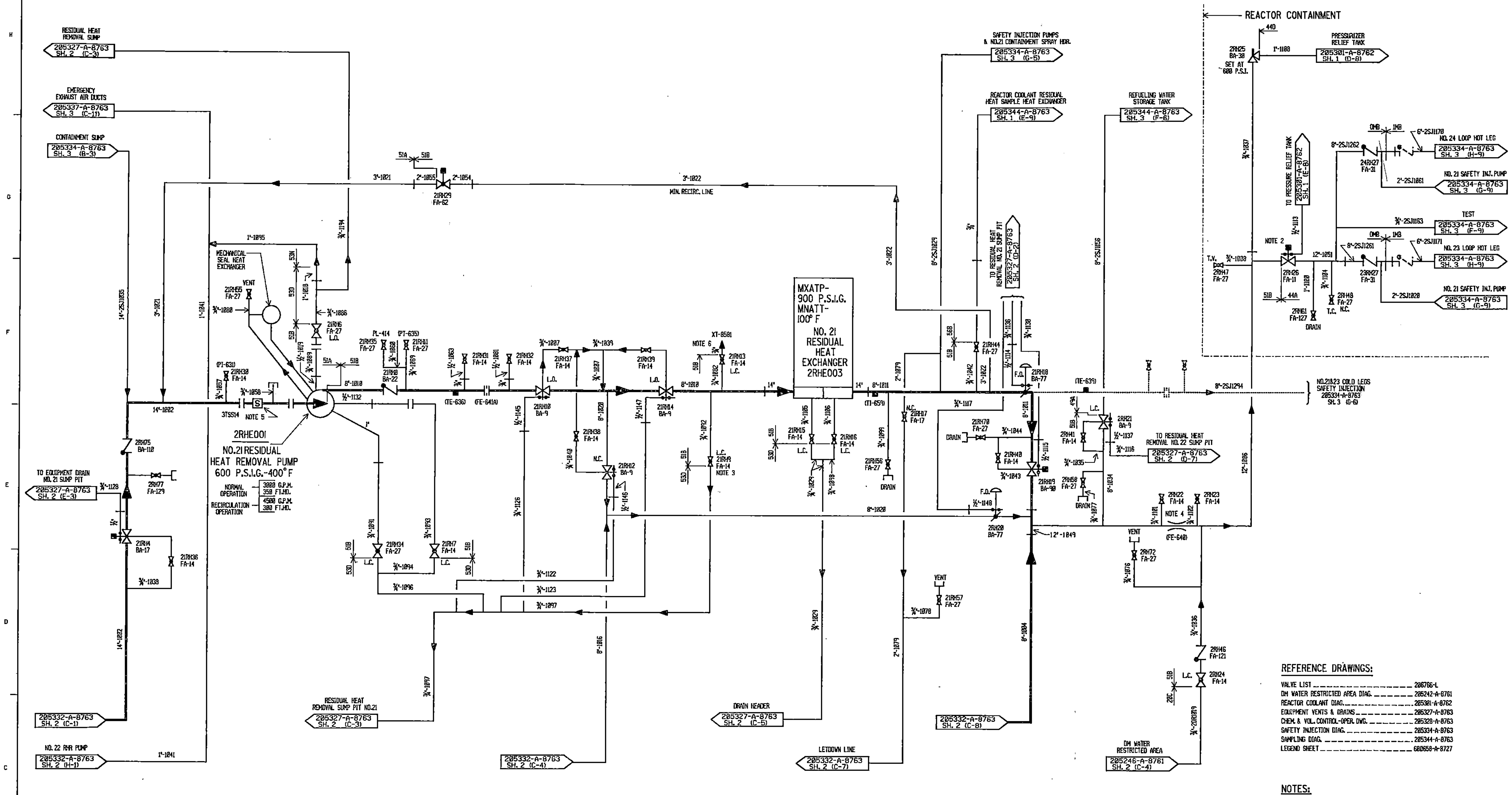
8607290251-12

REVISION 5
JULY 25, 1986
Ref. Dwg. 205232-A-8761-16

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Residual Heat Removal System
Unit 1

Updated FSAR Sheet 2 of 2
Fig 5.5-2A



REFERENCE DRAWINGS:

VALVE LIST ____ 206766-L
DM WATER RESTRICTED AREA DIAG. ____ 205242-A-8761
REACTOR COOLANT DIAG. ____ 205301-A-8762
EQUIPMENT VENTS & DRAINS ____ 205327-A-8763
CHEM. & VOL. CONTROL-OPER. DWG. ____ 205328-A-8763
SAFETY INJECTION DIAG. ____ 205334-A-8763
SAMPLING DIAG. ____ 205344-A-8763
LEGEND SHEET ____ 600658-A-8727

NOTES:

1- ALL PIPING IS IN ACCORDANCE WITH PIPE SPEC. NO. 61-6200. THE PIPING SCHEDULE AND GROUP NO.S ARE AS NOTED ON THIS DWG. AND PREFIXED WITH "1S" IN THE PIPE SPEC.
2- VALVES 2RH1 & 2 ARE INTERLOCKED WITH REACTOR COOLANT SYSTEM PRESSURE SIGNALS
3- VALVE HAS REACH ROD TO FLOOR ABOVE
4- ELBOW TAP FLOWMETER
5- TEMPORARY STRAINER IS PLACED IN LINE DURING INITIAL START-UP, CAPPED LINE IS CONNECTED TO TEMPORARY PRESSURE GAGE AT THIS TIME
6- LOCATE VALVE BEHIND SHIELDING AND AT A LOWER ELEVATION THAN PIPE BEING SAMPLED
7- ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2RH" (i.e. 2RH1000, ETC.) EXCEPT WHERE OTHERWISE NOTED.
8- ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
9- INSTRUMENT ITEMS IN PARENTHESIS ( ) ARE WESTINGHOUSE INSTRUMENT ITEMS. REFER TO ISA 5.1 FOR DESCRIPTION.

* BOUNDARY	DESIGN CLASSIFICATION: SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S20C	NO	III	NONE	NO
1S44A	YES	I	I	YES
1S44D	YES	I	II	YES
1S49A	YES	I	III	YES
1S51A	YES	I	II	YES
1S51B	YES	I	II	YES
1S53D	NO	III	III	NO
1S53N	NO	III	III	NO
1S56B	NO	II	III	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

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JULY 25, 1986

Ref. Dwg. 205332-A-8763-11

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Residual Heat Removal System
Unit 2

Updated FSAR Sheet 1 of 2
Fig 5.5-2B

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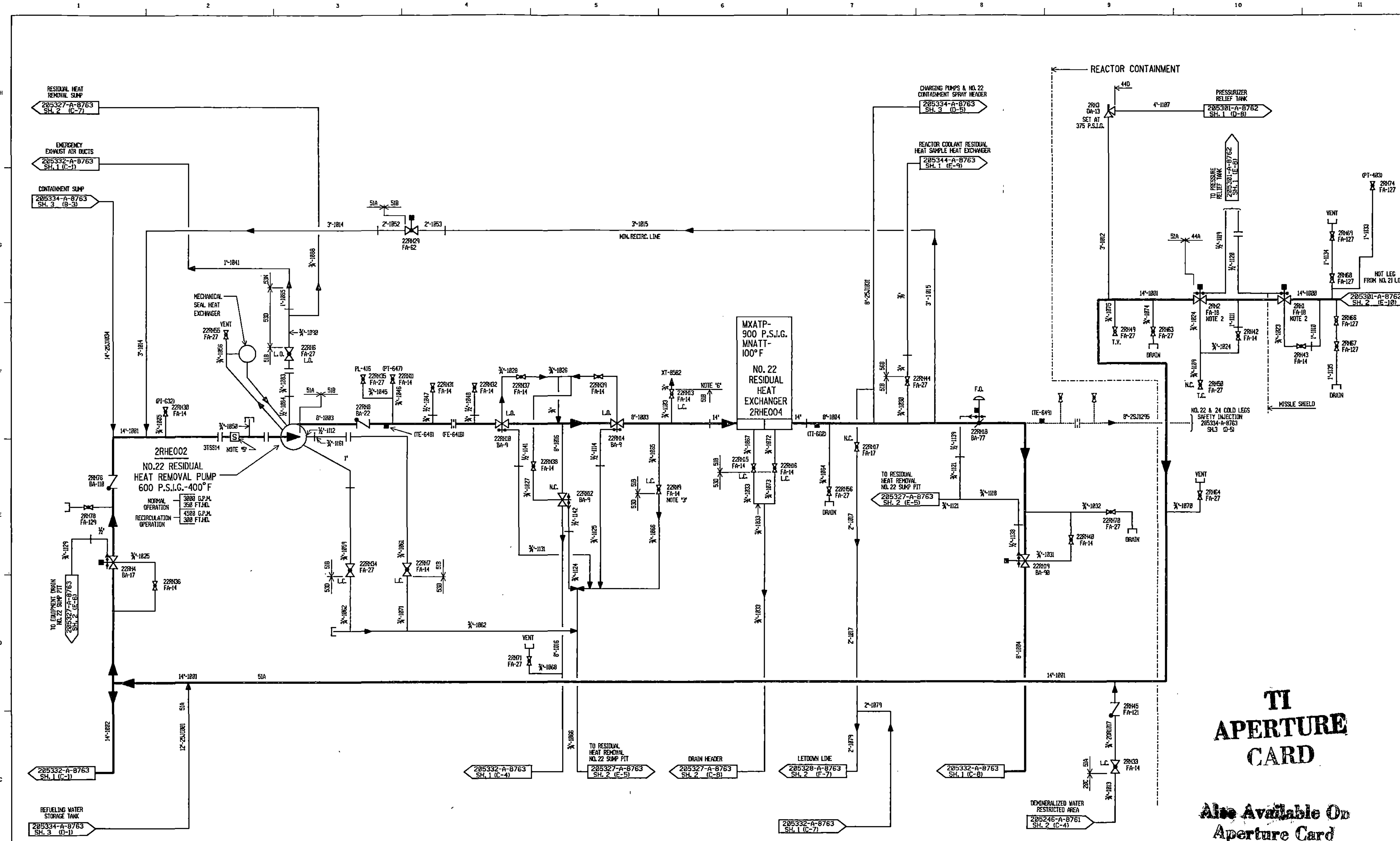


TI APERTURE CARD

Also Available On Aperture Card

8607290251-14

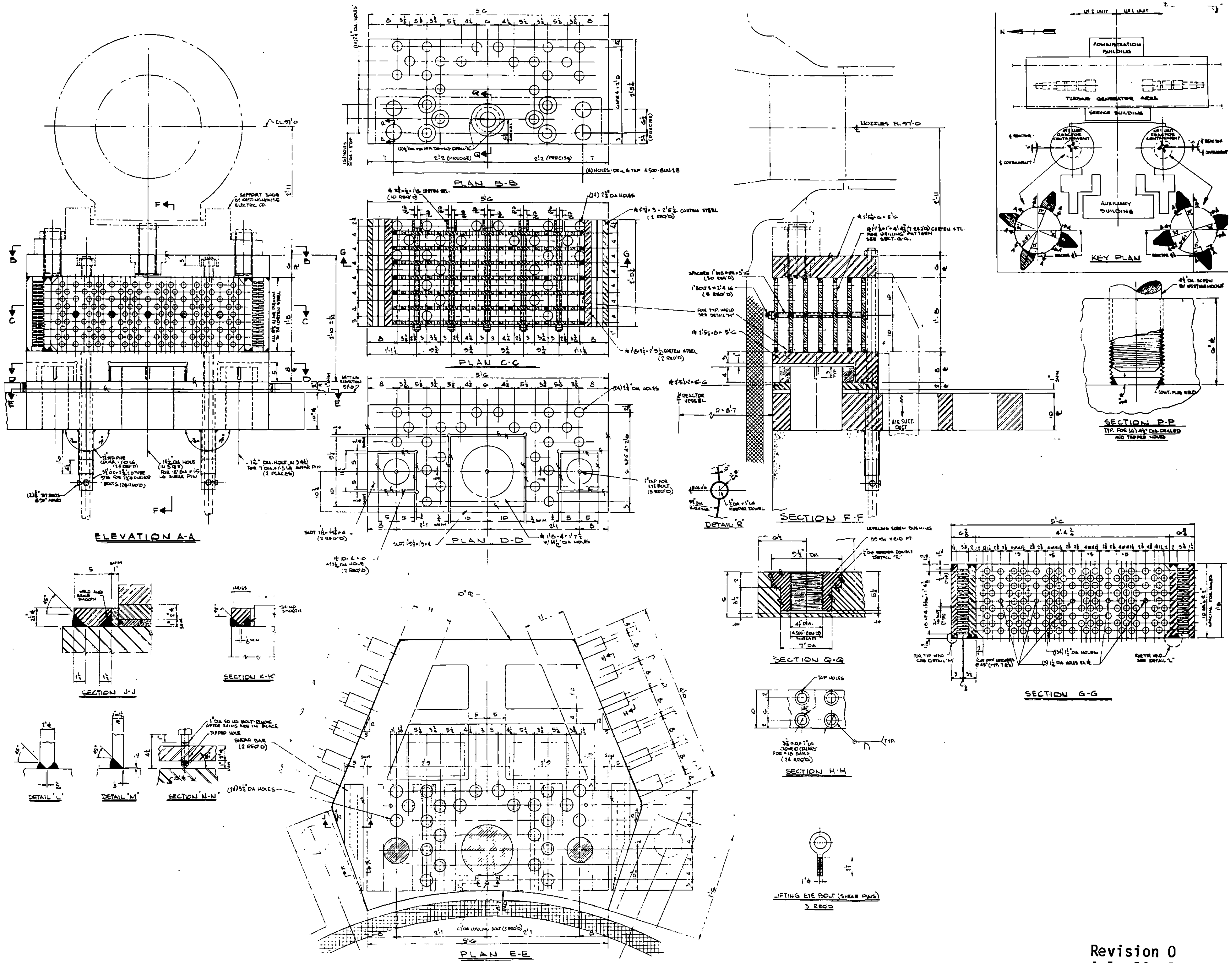
REVISION 5
JULY 25, 1986

Ref. Dwg. 205332-A-8763-11

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

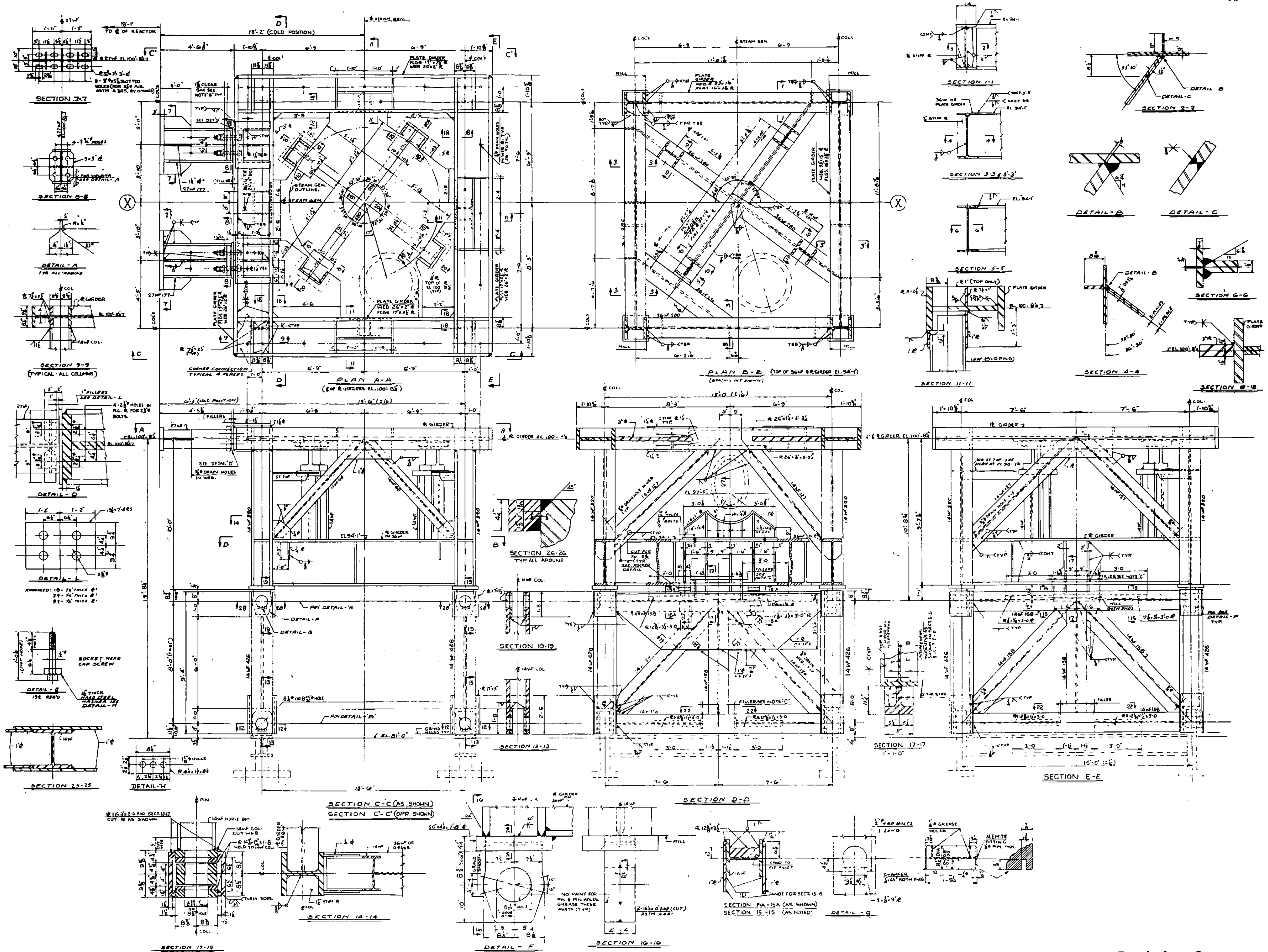
Residual Heat Removal System
Unit 2

Updated FSAR Sheet 2 of 2
Fig 5.5-2B



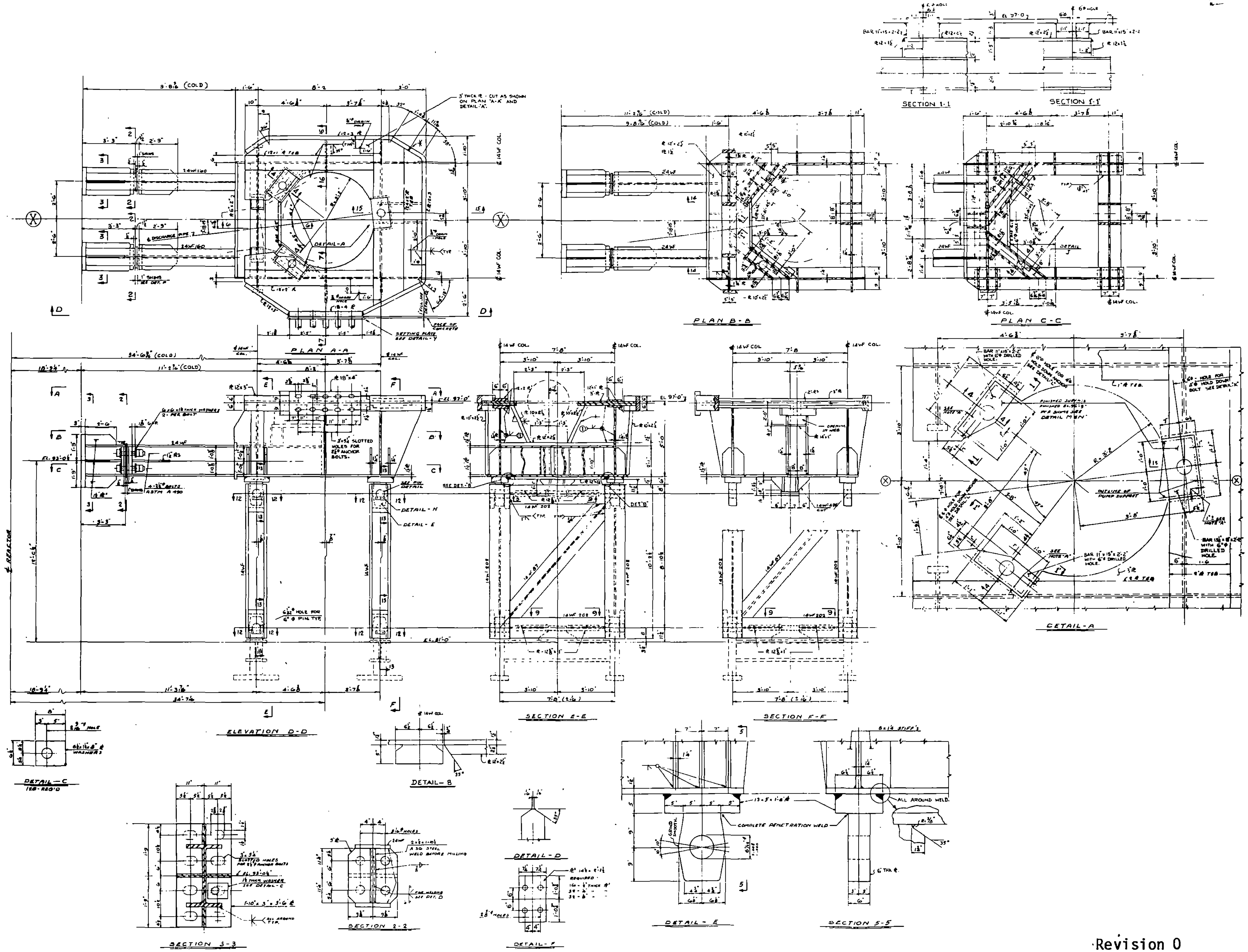
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Vessel Supports
	Updated FSAR — Figure 5.5-3



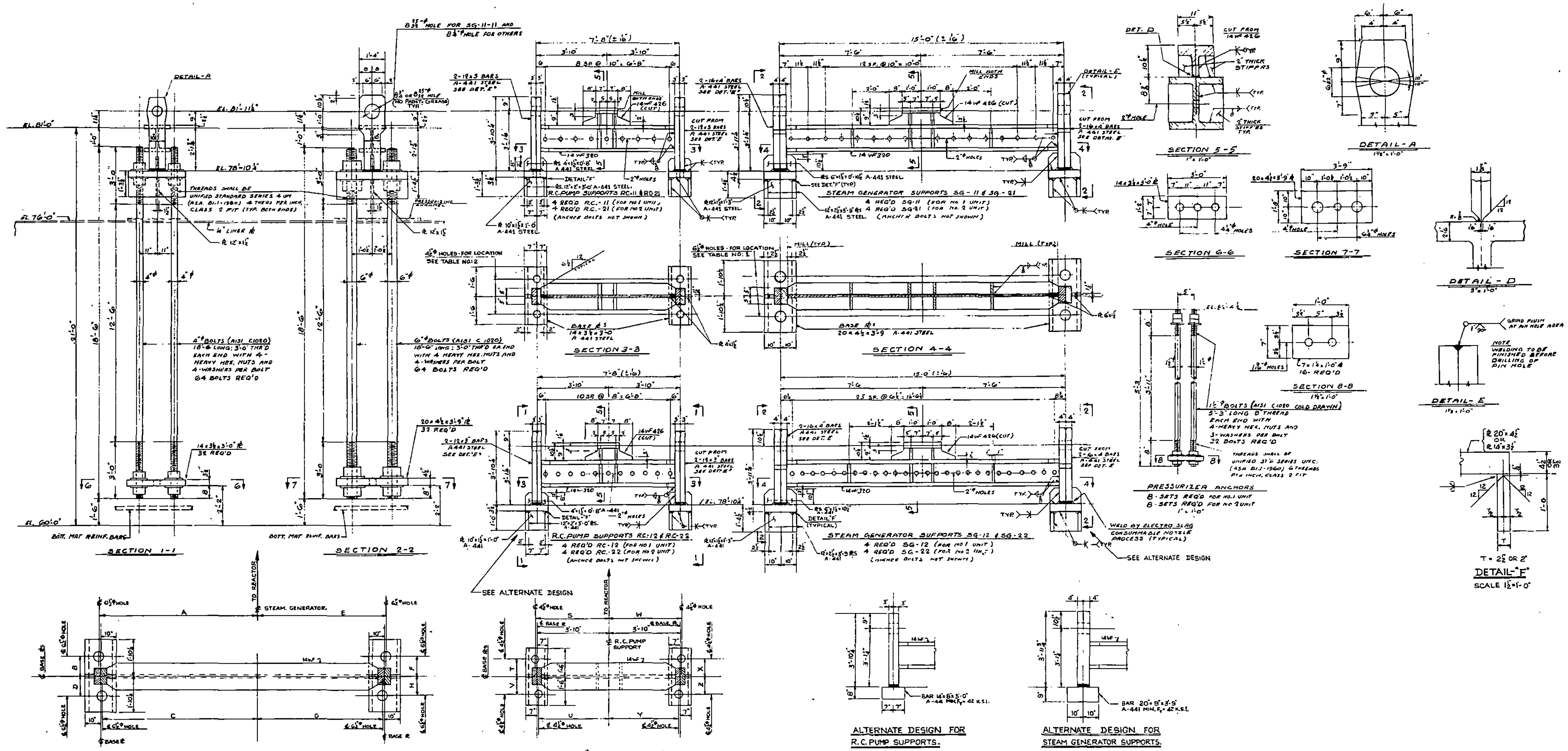
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Steam Generator Supports	
	Updated FSAR	Figure 5.5-4



Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Coolant Pump Supports	
	Updated FSAR	Figure 5.5-5



LOCATION OF 6½"φ HOLES IN BASE ℞S. TO MATCH EXISTING LOCATION OF 6"φ ANCHOR BOLTS FOR STEAM GENERATOR SUPPORTS. SEE TABLE NO: 1.

LOCATION OF 4½"φ HOLES IN BASE ℞S TO MATCH EXISTING LOCATION OF 4"φ ANCHOR BOLTS FOR R.C. PUMP SUPPORTS. SEE TABLE NO: 2.

SHOP NOTE:
FABRICATOR TO SHOW "SUPPORT MARKS" CLEARLY AND INDICATE ARROW TO REACTOR.

TABLE NO: 1.

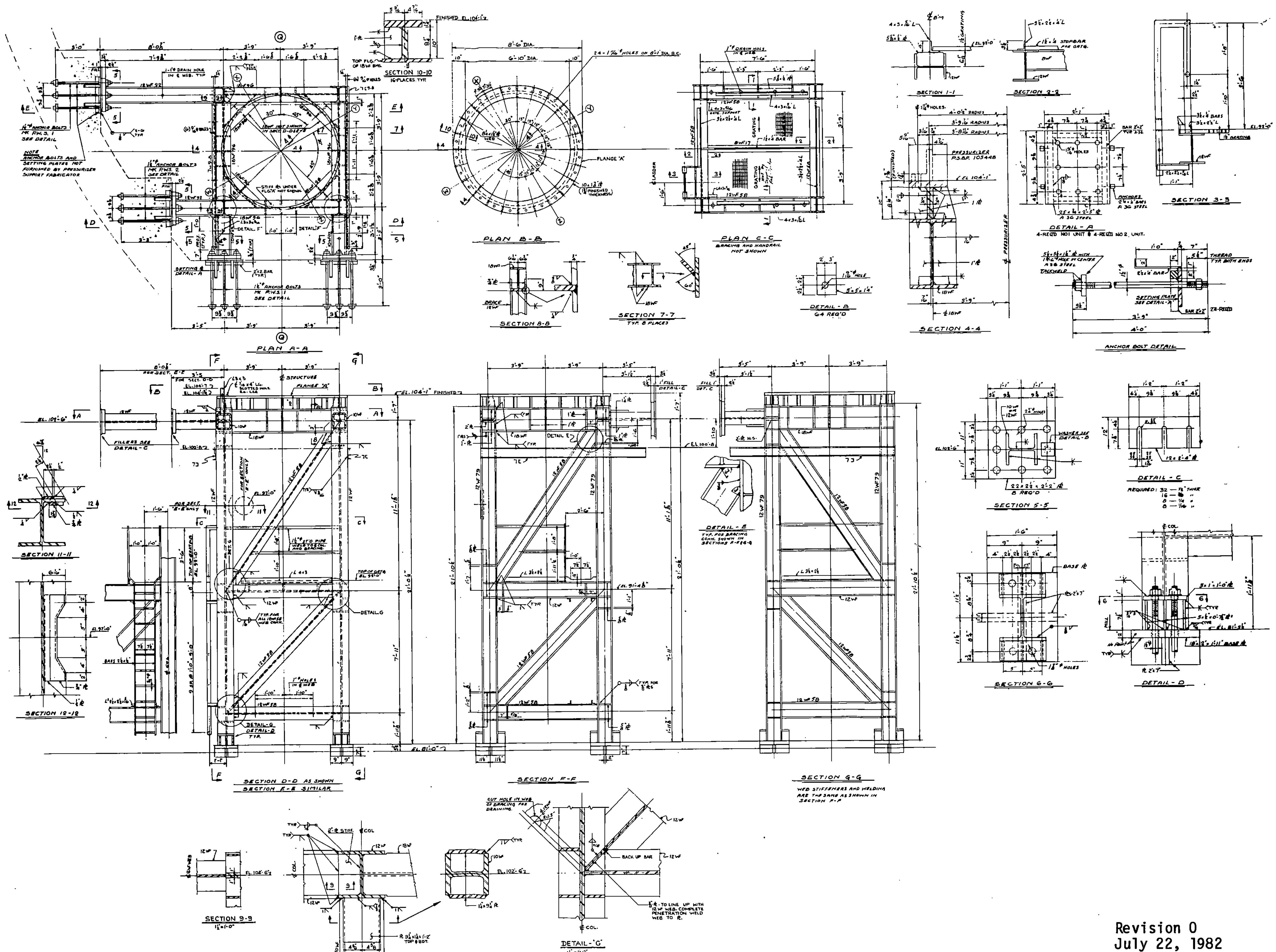
	SUPPORT MARK	A	B	C	D	E	F	G	H
NO.1 UNIT	S.G.-12-14	8'-3 3/8"	1'-0 1/4"	8'-3"	1'-0 13/16"	6'-8 11/16"	1'-0 5/16"	6'-8 3/8"	1'-0 7/16"
	S.G.-11-14	8'-3 1/16"	1'-0 5/16"	8'-2 3/4"	1'-0 3/4"	6'-9 3/16"	1'-0 9/16"	6'-9"	1'-0 9/16"
	S.G.-12-13	6'-9 1/16"	1'-0 7/16"	6'-8 15/16"	1'-0 9/16"	8'-3 3/8"	1'-0 1/2"	8'-2 15/16"	1'-0 1/2"
	S.G.-11-13	6'-8 7/8"	1'-0 7/16"	6'-8 13/16"	1'-0 3/4"	8'-3 1/8"	1'-0 1/2"	8'-3 1/8"	1'-0 3/4"
	S.G.-12-12	6'-9"	1'-0 11/16"	6'-8 7/8"	1'-0 1/2"	8'-3"	1'-0 3/4"	8'-3"	1'-0 5/16"
	S.G.-11-12	6'-9 1/16"	1'-0 1/2"	6'-9"	1'-0 5/8"	8'-3"	1'-0 11/16"	8'-2 7/8"	1'-0 3/8"
	S.G.-12-11	8'-2 7/8"	1'-0 1/2"	8'-2 7/8"	1'-0 1/2"	6'-8 15/16"	1'-0 1/2"	6'-9 1/8"	1'-0 1/2"
	S.G.-11-11	8'-2 15/16"	1'-0 1/2"	8'-3"	1'-0 9/16"	6'-9 1/8"	1'-0 5/8"	6'-8 15/16"	1'-0 1/2"
NO.2 UNIT	S.G.-21-22	8'-9	1'-0 1/4	8'-3	1'-0 3/16	6'-9	1'-0 13/16	6'-9 1/16	1'-0 3/16
	S.G.-22-22	8'-3 1/8	1'-0 1/4	8'-3	1'-0 3/16	6'-8 7/8	1'-0 1/4	6'-8 7/8	1'-0 3/16
	S.G.-21-24	6'-8 15/16	1'-0 1/2	6'-8 15/16	1'-0 1/2	8'-3 1/16	1'-0 1/2	8'-3 1/16	1'-0 1/2
	S.G.-22-24	6'-9	1'-0 1/2	6'-8 7/8	1'-0 1/2	8'-3 1/8	1'-0 1/2	8'-3 1/16	1'-0 1/2

TABLE NO: 2.

	SUPPORT MARK	S	T	U	V	W	X	Y	Z
NO.1 UNIT	R.C.-12-14	3'-9 15/16"	0'-10 3/4"	3'-9 5/8"	0'-11 3/8"	3'-10 5/16"	0'-10 7/8"	3'-10 1/8"	0'-11 1/2"
	R.C.-11-14	3'-9 7/8"	0'-11 1/8"	3'-9 9/16"	0'-11 1/16"	3'-10 5/16"	0'-10 9/16"	3'-10 1/4"	0'-11 3/4"
	R.C.-12-13	3'-9 13/16"	0'-10 7/8"	3'-10 1/16"	0'-11 1/4"	3'-10 3/16	0'-11"	3'-10 1/16"	0'-11 1/8"
	R.C.-11-13	3'-9 7/8	0'-10 13/16"	3'-9 15/16"	0'-11 1/8"	3'-10 1/8"	0'-10 15/16"	3'-10"	0'-11 1/16
	R.C.-12-12	3'-10"	0'-11 7/16"	3'-9 15/16"	0'-10 3/4"	3'-9 15/16"	0'-11 1/16"	3'-10 1/16"	0'-11"
	R.C.-11-12	3'-9 11/16	0'-11 1/8	3'-10 1/8"	0'-10 3/4"	3'-10 3/16"	0'-11"	3'-10	0'-11"
	R.C.-12-11	3'-10 1/16	0'-11"	3'-10 1/16	0'-11"	3'-10"	0'-11 1/16"	3'-9 7/8"	0'-11 3/16
	R.C.-11-11	3'-10 1/16	0'-11 1/8"	3'-9 7/8"	0'-10 7/8"	3'-9 7/8"	0'-11"	3'-10"	0'-11 1/8"
NO.2 UNIT	R.C.-21-22	3'-10 1/4	0'-11 1/16	3'-10 1/4	0'-10 15/16	3'-9 3/4	0'-10 13/16	3'-9 3/4	0'-11 1/8
	R.C.-22-22	3'-10 1/4	0'-11	3'-10 1/4	0'-11 1/16	3'-9 13/16	0'-10 7/8	3'-9 3/4	0'-11
	R.C.-21-24	3'-9 11/16	0'-11 1/4	3'-9 3/4	0'-10 5/8	3'-10 1/4	0'-11 1/16	3'-10 1/4	0'-10 15/16
	R.C. 22-24	3'-9 3/4	0'-11	3'-9 3/4	0'-10 7/8	3'-10 1/8	0'-11	3'-10 1/8	0'-11

Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Embedded Steel for Equipment Supports
	Updated FSAR — Figure 5.5-6



Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Pressurizer Supports

Updated FSAR

Figure 5.5-7

5.6 INSTRUMENTATION APPLICATION

Process control instrumentation is provided for the purpose of acquiring data on the pressurizer and on a per loop basis for the key process parameters of the RCS (including the reactor pump motors) as well as for the residual heat removal system. The pick-off points for the reactor coolant system are shown in the flow diagram (Figures 5.1-6A, B and C); and for the residual heat removal system, in flow diagram Figures 5.5-2A and B.

In general these input signals are used for the following purposes:

1. Provide input to the reactor trip system described in Chapter 7.

2. Provide input to the engineered safety features actuation system described in Chapter 7.

3. Furnish input signals to the non-safety related control systems and surveillance circuits.

5.6.1 LOOP TEMPERATURE

A Resistance Temperature Detector Bypass Manifold is provided for each reactor coolant loop hot and cold leg. A bypass manifold around each steam generator obtains hot leg temperature by mixing the flow from three scoop connections, which extend into the flow stream at locations 120^{o} apart in the cross-sectional plane, on the reactor coolant leg. The hot leg bypass flow exits the manifold to a common return line.

Flow for the cold leg bypass manifold is obtained downstream of the pump discharge. Because of the mixing action of the pump, only one connection is required to obtain a representative sample. This connection is located as close as possible to the pump discharge in order to minimize RTD bypass piping and to obtain optimum fluid mixing. This connection is in the same relative position in each loop.

The resistance temperature detectors extend directly into the flow path (without thermo wells) to reduce the time delay to a minimum. Two isolation valves in series are provided on each side of the bypass manifold to allow for resistance temperature detector maintenance. The valve nearest the connection to the main coolant piping is located above the elevation of the reactor vessel nozzles to permit valve repair during cold shutdown, without draining the Reactor Coolant System. In addition, vents and drains are provided in each manifold to be used, in conjunction with the isolation valve, for maintenance.

The hot and cold bypass manifold join to form a common discharge line. The combined (hot and cold leg) flow passes through a flow indicator before discharging to the suction side of the reactor coolant pump.

Temperature detectors, located in the thermo wells in the cold and hot leg piping of each loop, supply signals to wide-range temperature recorders. This information is used by the operator to control coolant temperature during startup and shutdown.

5.6.2 PRESSURIZER TEMPERATURE

There are two temperature detectors in the pressurizer, one in the steam phase and one in the water phase. Both detectors supply signals to temperature indicators and high-temperature alarms. The steam-phase detector, located near the top of the vessel, alerts the operator if the steam becomes superheated. In addition, it is used during startup to determine water temperature when the pressurizer is completely filled with water. The water phase detector, located at an elevation near the center of the heaters, is used during cooldown to ensure that the pressurizer temperature is consistent with the Reactor Coolant System.

Temperatures in the pressurizer safety and relief valve discharge lines are measured and indicated. An increase in a discharge line temperature is an indication of leakage through the associated valve. An alarm is actuated on high temperature.

The fluid temperatures in each spray line are measured and indicated. Alarms from these signals are actuated by low spray water temperature. Alarm conditions indicate insufficient flow in the spray lines through the manual throttle valves.

The temperature of the water in the pressurizer relief tank is indicated over a range of 50°F to 350°F, and an alarm, actuated by a high temperature, informs the operator that cooling of the tank contents is required.

The temperature in the leakoff line from the reactor vessel flange O-ring seal leakage monitor connections is indicated. An increase in temperature above ambient is an indication of O-ring seal leakage. High temperature actuates an alarm.

5.6.3 PRESSURE

Four pressurizer pressure transmitters provide signals for individual indicators in the control room, for actuation of a low pressure trip, for high pressure reactor trip and for alarms. One of the four signals may be selected by the operator for display on a pressure recorder. Three transmitters provide independent low pressure signals for safety injection initiation and for safety injection signals to allow manual block during plant shutdown and automatic unblock during plant startup. In addition, these pressure transmitters provide inputs for pressurizer heater, spray valve and power-operated relief valve control.

A narrow range differential pressure transmitter provides a signal for indication of the differences between pressurizer pressure and the pressure generated by a dead weight tester located outside the reactor containment. The indication is used for on-line calibration checks of the four pressurizer pressure signals.

Two wide-range transmitters provide pressure indication over the full operating range. The indicators serve as a guide to the operator during plant startup and shutdown and also provide the open permissive signals and automatic closure signals for the Residual Heat Removal Loop isolation valves interlock circuit.

Two local pressure indicators are provided for operator reference during shutdown. They are located in two separate loops and are provided with maximum (drag) pointers to indicate the maximum pressure attained since the last re-setting of the pointers.

A pressurizer relief tank pressure transmitter provides a signal to close valve PCV-472 on high pressure should it be open when a safety valve lifts discharging steam into the pressurizer relief tank.

5.6.4 PRESSURIZER WATER LEVEL

Three pressurizer liquid level transmitters provide signals for use in the Reactor Control and Protection System, the Safety Injection System and the Chemical and Volume Control System. Each transmitter provides an independent high water level signal that is used to actuate an alarm and, upon two out of the three transmitter signals, will cause a reactor trip. The transmitters may also provide independent low water level signals that will activate an alarm. Upon a coincident low pressurizer water level and low pressurizer pressure signal, safety injection will be initiated. Each transmitter also provides a signal for a level indicator that is located on the main control board.

In addition, either of the three level transmitters may be selected for display on a level recorder located on the main control board.

Two of the three transmitters may be selected to provide an alarm when the liquid level falls to the fixed low level set point. The same signal will trip the pressurizer heaters "off" and close the letdown line isolation valves. Two transmitters are similarly selected to supply a signal to the liquid level set point controller.

A fourth independent pressurizer level transmitter is calibrated for low temperature conditions, provides water level indication during startup, shutdown and refueling operations.

A pressurizer relief tank level transmitter supplies a signal for an indicator and for high and low level alarm.

5.6.5 REACTOR VESSEL WATER LEVEL

The Reactor Vessel Level Instrumentation System (RVLIS) uses three sets of differential pressure (d/p) cells, with two identical cells per set for redundancy, to measure the water level in the vessel. Each of these sets uses cells with different ranges to obtain three different vessel water level measurements.

One set of two d/p cells is installed to sense the fluid pressure differential betwen the top of the vessel and the loop piping. One side of each cell is connected to vessel head vent connection and the other sides of the cells are connected to the hot legs of Loops 1 and 4 via the RTD bypass line. Each cell's level indicator in the control room shows reactor vessel water level between the hot leg and the top of the vessel. If one Reactor Coolant Pump (RCP) is operating, the associated level indicator will read off-scale. Normally, with all RCP's operating, the readings from both indicators will be off-scale.

Two d/p cells are installed to sense the fluid pressure differential between the bottom and top of the reactor vessel. One side of each cell is connected to the head vent penetration; the other side is connected to an in-core instrumentation conduit at or near the seal table. When only one RCP is operating, these cells measure reactor core and internal pressure drop, provides an indication of the relative void content of density of the circulating coolant. The associated level indicator reads off-scale if more than one RCP is operating.

Two d/p cells with installation identical to that of the two cells used for narrow range measurement, measure reactor core and internal pressure drop for any combination of operating RCPs which, when compared with the normal single phase pressure drop, provides an indication of the relative void content or density of the circulating coolant. These cells may be used on a continuous basis.

All of the d/p cells are located outside of containment to minimize post-accident environmental effects and to facilitate calibration, cell replacement, reference leg checks, and filling and venting. Hydraulic sensors (inside containment) and hydraulic isolators (outside containment), connected by a seal sensing line, are installed between each d/p cell and its connection to the vessel/RCS. These features assure containment isolation in case of a sensing line break and prevent flow of primary coolant to outside containment. To obtain the required accuracy for vessel water level measurement, the d/p cell indications are compensated using measured temperatures of both the d/p cell reference legs and the reactor coolant.

Additional information is presented in Chapter 7.

5.6.6 REACTOR COOLANT FLOW

Flow in each reactor coolant loop is monitored by three differential pressure measurements at a piping elbow tap in each reactor coolant loop. These measurements on a two-out-of-three coincidence circuit per loop provide a low flow signal to actuate a reactor trip.

Elbow taps are used in the RCS as an instrument device that indicates the status of the reactor coolant flow. The basis function of this device is to provide information as to whether or not a reduction in flow rate has occurred. The correlation between flow reduction and elbow tap read out has been well established by the following equation: $\frac{\Delta P}{\Delta P_0} = (\frac{\omega}{\omega_0})^2$, where ΔP_0 is the referenced pressure differential with the corresponding referenced flow rate ω_0 and ΔP is the pressure differential with the corresponding referenced flow rate ω. The full flow reference point is established during initial plant startup. The low flow trip point is then established by extrapolating along the correlation curve. The technique has been well established in providing core protection against low coolant flow in Westinghouse PWR plants. The expected absolute accuracy of the channel is within ±10 percent and field results have shown the repeatability of the trip point to be within ± 1 percent. The analysis of the loss of flow transient presented in Section 14.1 assumed instrumentation error of ±3 percent.

The combined flow from the hot and cold leg resistance temperature detector manifolds passes through an orifice before discharging back to the Reactor Coolant System at the suction side of the reactor coolant pump. The flow is indicated locally by a DP gauage and by status lights in the control room. Low flow through either the hot or cold leg warns of possible inaccuracy in the corresponding temperature signals; therefore, an alarm is actuated.

5.6.7 REACTOR COOLANT PUMP MOTOR INSTRUMENTATION

A dual purpose switch is provided on the high pressure oil lift system. Upon low oil pressure the switch actuates an alarm on the main control board. In addition, the switch is part of an interlock system that prevents starting of the pump until the oil lift system is operating and oil pressure is established. A local pressure gauge is also provided.

Level switches are provided in the motor radial bearings and thrust bearing oil reservoirs. The switches actuates high and low level alarms on the main control board.

Thermocouples are located in the upper and lower thrust bearing shoes. These elements provide signals for multi-point recorder on the main control board and actuate an alarm on high temperature.

A reactor coolant pump trip criterion has been adopted which assures pump trip for all losses of primary coolant for which pump trip is considered necessary, but which also permits pump operation during most non-LOCA events, including steam generator tube rupture events up to the design basis double-ended tube rupture. The controlling parameter selected for pump trip actuation is reactor coolant system pressure. The reactor coolant system wide-range pressure instrumentation will be monitored.

5.6.8 LOOSE PARTS MONITORING

A Loose Parts Monitoring (LPM) system supplied by Westinghouse Electric Corporation has been installed for each of the two units of Salem Nuclear Generating Station. (This LPM system has been designated as the Metal Impact Monitoring (MIM) system by Westignhouse). The LPM system has been designed to enable early detection of the presence of metallic debris, loose parts or restrained loose parts, inside the Nuclear Steam Supply System (NSSS) during plant start-up and commercial operation. Any form of metallic debris, loose parts or restrained loose parts, when carried or agitated by the reactor coolant flow may attain sufficient velocities to impact and damage the interior of the NSSS pressure boundary.

The LPM system is realized by on-line processing, transmission and conditioning of the signals from a group of strategically located Piezoelectric accelerometers (a total of 12) mounted externally to the wall of NSSS with proper indication and alarms. When the insides of the reactor and steam generator walls are struck by metallic debris, loose parts or restrained loose parts, the structure is shock excited producing local wall acceleration that can be detected in time and frequency domain. These impact signatures can be separated in the frequency domain from the general vessel and background signature. Once the proper frequency band is selected, a threshold amplitude detection system and associated rate can be used to activate an alarm system.

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6.0 ENGINEERED SAFETY FEATURES

The central safety objective in reactor design and operation is control of reactor fission products. The methods used to assure this objective are:

1. Design of the reactor core in conjunction with the reactor control and protection systems to preclude release of fission products from the fuel (Chapters 4 and 7).

2. Retention of fission products in the reactor coolant for whatever leakage occurs (Chapters 5 and 6).

3. Retention of fission products by the containment for operational and accidental releases beyond the reactor coolant boundary (Section 3.8 and Chapter 6).

4. Limiting fission product dispersal to minimize population exposure for an accidental release beyond the containment (Chapters 2, 12 and 15).

The engineered safety features are the provisions in the plant which embody methods 2 and 3 above to prevent the occurrence or to ameliorate the effects of serious accidents.

The engineered safety features in this plant are:

1. The steel-lined, reinforced concrete containment, concrete cylindrical wall and reinforced concrete base and dome. These form a virtually leak tight barrier to the escape of fission products should a loss of coolant occur - detailed in Section 3.8.

2. The emergency core cooling system, which provides borated water to cool the core in the event of an accidental depressurization of the

Reactor Coolant System. The combination of the control rods and the boron in the injected water provides the necessary control of reactivity required - detailed in Section 6.3.

3. The containment spray system which is used to reduce containment pressure and remove iodine from the containment atmosphere - detailed in Section 6.2.

4. The containment fan cooling system is used to recirculate and cool the containment atmosphere in the event of a loss-of-coolant accident - detailed in Section 6.2.

Evaluations of techniques and equipment used to accomplish the central objectives including accident cases are detailed in Chapters 3, 5, 6 and 15.

The design philosophy with respect to active components in the engineered safety systems is to provide duplicate equipment so that maintenance is possible during operation without impairment of the safety function of the systems. Routine servicing and maintenance of equipment of this type would generally be scheduled for periods of refueling and maintenance outages.

Conditions on continued reactor operation during such outages that are provided in the Technical Specifications will conform to reasonable experienced judgment and industry practice and will be shown to ensure safe operation.

6.1 CRITERIA

Criteria applying in common to all engineered safety features are given in Section 6.1.1. Criteria which are related to engineered safety features but are more specific to other plant features or systems are listed and cross-referenced in Section 6.1.2.

Those criteria which are specific to one of the engineered safety features are discussed in the description of that system.

6.1.1 ENGINEERED SAFETY FEATURES CRITERIA

The criteria applying to all engineered safety features are given below.

6.1.1.1 Engineered Safety Features Basis for Design

The design, fabrication, testing and inspection of the core, reactor coolant pressure boundary and their protection systems give assurance of safe and reliable operation under all anticipated normal, transient, and accident conditions. However, engineered safety features are provided in the facility to back up the safety provided by these components. These engineered safety features have been designed to cope with any size pipe break up to and including the circumferential rupture of reactor coolant pipe assuming unobstructed discharge from both ends, and to cope with any steam or feedwater line break.

The release of fission products from the containment is limited in three ways:

1. Blocking the potential leakage paths from the containment. This is accomplished by:

   a. A steel-lined concrete reactor containment with liner weld channels and high integrity piping penetrations utilizing testable expansion bellows to form a virtually leak-tight barrier preventing the escape of fission products should a loss-of-coolant accident occur.

b. Isolation of process lines by the containment isolation system which imposes double barriers for each line which penetrates the containment.

2. Reducing the fission product concentration in the containment atmosphere. This is accomplished by chemically treated spray which removes elemental iodine vapor from the containment atmosphere by washing action, and by recirculation of containment atmosphere through HEPA filter units.

3. Reducing the containment pressure and thereby limiting the driving potential for fission product leakage. This is accomplished by the containment spray system which cools the containment atmosphere or by recirculation of containment atmosphere through fan cooler units.

6.1.1.2 Reliability and Testability of Engineered Safety Features

A comprehensive program of plant testing is formulated for all equipment systems and system control vital to the functioning of engineered safety features. The program consists of performance tests of individual pieces of equipment in the manufacturer's shop, integrated tests of the system as a whole, and periodic tests of the activation circuitry and mechanical components to assure reliable performance, upon demand, throughout the plant lifetime.

The initial tests of individual components and the integrated test of the system as a whole complement each other to assure performance of the system as designed and to prove proper operation of the actuation circuitry.

Routine periodic testing of the engineered safety features component is intended. In the event that one of the redundant components should require maintenance as a result of failure to perform during the test according to prescribed limits, the necessary corrections or minor maintenance are made and the unit retested immediately. Satisfactory performance of the remaining redundant component(s) is proof of the availability of that safety feature, and it is not necessary to adjust plant load during the brief period that a safety feature component may be out of service.

6.1.1.3 Protection Against Dynamic Effects and Missiles

A loss-of-coolant accident or other plant equipment failure might result in dynamic effects or missiles. For such engineered safety features as are required to assure safety in the event of such an accident or equipment failure, protection from these dynamic effects or missiles is considered in the layout of plant equipment and missile barriers. Fluid and mechanical driving forces are calculated, and consideration is given to the possibility of damage due to fluid jets and missiles which might be produced by the action of such jets. Consideration is given during the design of the plant to the following sources of missiles: instrument thimbles including installed sensors, bolts, and complete control rod drive shafts and/or mechanisms (refer to Chapters 3 and 5).

Layout and structural design specifically protect safety injection lines to unbroken reactor coolant loops against damage as a result of the maximum reactor coolant pipe rupture. Injection lines penetrate the main missile barrier and the injection headers are located in the missile-protected area between the main missile barrier and the containment wall. Individual injection lines, connected to the injection header, pass through the barrier and then connect to the loops. Separation of the individual injection lines is provided to the maximum extent practicable. Movement of the injection line, associated with a rupture of a reactor coolant loop, is accommodated by line flexibility and by the design of the pipe supports such that no damage outside the missile barrier is possible.

In addition, missile protection is provided for engineered safety features located outside the containment. The containment structure is capable of withstanding the effects of missiles originating outside the containment and might be directed toward it so that no loss-of-coolant accident can result. The control room enclosure is also capable of withstanding such credible missiles as may be directed toward it, assuring capability to maintain control of the plant. Consideration is also given to the layout of other equipment outside the containment which is required to place the plant in a safe shutdown condition and maintain it in that condition until repairs can be effected.

Missile protection will be afforded by:

1. Judicious location of piping and equipment otherwise subject to possible damage, behind existing wall or other barriers with appropriate credit for spatial separation of redundant components.

2. Local shielding to stop potential missiles at their source.

3. Addition of missile barriers to protect vulnerable piping and equipment.

All hangers, stops and anchors are designed in accordance with ANSI B31.1 Code for Pressure Piping and ACI 318 Building Code Requirements for Reinforced Concrete which provide minimum requirements for material, design and fabrication with ample safety margins for both dead and dynamic loads over the life of the equipment.

6.1.1.4 Engineered Safety Features Performance Capability

Each engineered safety feature provides sufficient performance capability to accommodate any single failure and still function in a manner to avoid undue risk to the health and safety of the public.

During the recirculation phase the emergency core cooling system (ECCS) is tolerant of one active or one passive failure, but not in addition to a single failure in the injection phase. One active or passive failure in the systems required for long-term ECCS operation will not prevent the accomplishment of the ECCS objectives nor cause the total off-site dose to exceed 10CFR100 guidelines, with credit for detection and operator action.

In the particular case of an ECCS pump being out for maintenance, an additional active or passive failure is not considered. The maximum period that operation would be continued with one pump out for maintenance is specified in the Technical Specifications.

The extreme upper limit of public exposure is taken as the levels and time periods presently outlined in 10CFR100, i.e., 300 rem to the thyroid or 25 rem whole body in 2 hours at the exclusion radius, and 300 rem to the thyroid or 25 rem whole body over the duration of the accident at the low population zone distance. The accident condition considered is the hypothetical case of a release of fission products as in TID 14844. Also, the total loss of all outside power is assumed concurrently with this accident.

Under the above accident conditions, the containment spray and fan cooling systems are designed and sized so that, operating with partial effectiveness, it can supply the necessary post-accident cooling capacity to assure the maintenance of containment integrity; that is, keep the pressure below design pressure at all times, assuming that the core residual heat is released to the containment as steam. Partial effectiveness is defined as operation of a system with at least one active component failure.

The ECCS and related pumps which must operate following the design basis accident include the residual heat removal, safety injection, containment spray, centrifugal charging, component cooling water, and service water pumps.

Minimum available net positive suction head (NPSH) to the safety injection, centrifugal charging, and containment spray pumps occurs when all are taking suction from the refueling water storage tank during the injection operation immediately following the design basis accident.

Since maximum required NPSH and minimum available NPSH occur at the runout flow for the pumps, this flow was assumed for calculation purposes. The temperature of the refueling water storage tank water varies between 40°F and 100°F.

Available NPSH at runout flow to these pumps at both the high and low temperatures was calculated. Suction line friction losses are higher at 40°F, but the higher vapor pressure of 100°F water leaves less available NPSH to the pumps. Friction losses were calculated using the conservative pipe and fitting resistances given in the Crane Co. Technical Paper Number 410.

The residual heat removal pumps take suction during the post-accident recirculation phase from the containment sump. The water is at a higher temperature than during injection, but the elevated containment pressure following a design basis accident somewhat offsets the higher vapor pressure of the water; however, no credit is taken for this. In addition, the piping to the pump suctions is quite direct, hence friction losses are small.

Service water pumps are vertical turbine pumps taking suction directly at the plant intake. Suction location is 44 inches below low-low water elevation (El. 76'), temperature 85°F. The component cooling water pumps have suction head tanks which maintain pressure in the closed system equal to the maximum elevation of the system piping.

6.1.1.5 Engineered Safety Features Components Capability

Active components of the ECCS and the containment spray system are located outside the containment and not subject to containment accident conditions.

6.1.1.6 Accident Aggravation Prevention

The reactor is maintained subcritical following a pipe rupture accident. Introduction of borated cooling water into the core does not result in a net positive reactivity addition. The control rods insert and remain inserted.

The supply of water by the ECCS to cool the core cladding does not produce significant water-metal reactions. The delivery of cold emergency core cooling water to the reactor vessel following accidental expulsion of reactor coolant does not cause further loss of integrity of the Reactor Coolant System boundary. Accumulator actuation, including possible nitrogen addition is evaluated in Chapter 15 and is shown not to aggravate any loss-of-coolant accident.

Instrumentation, motors, cables and penetrations located inside the containment which are required to function are selected to meet the most adverse accident conditions to which they may be subjected. These items are either protected from containment accident conditions or are designed to withstand, without failure, exposure to the worst combination of temperature, pressure, and humidity expected during the required operational period.

The ECCS pipes serving each loop are restrained at the missile barrier in each loop area to restrict potential accident damage to the portion of piping beyond this point. The anchorage is designed to withstand, without failure, the thrust force of any branch line severed from the reactor coolant pipe and discharging fluid to the atmosphere, and to withstand a bending moment equivalent to that which produces failure of the piping under the action of free end discharge to atmosphere or motion of the broken reactor coolant pipe to which the emergency core cooling pipes are connected. This prevents possible failure at any point upstream from the support point including the branch line connection into the piping header.

6.1.1.7 Sharing of Systems

For all shared systems and/or components analyses confirm that there is no interference with basic function and operability of these systems due to sharing, and hence no undue risk to the health and safety of the public results.

The residual heat removal pumps and heat exchangers serve dual functions. Although the normal duty of the residual heat removal exchangers and residual heat removal pumps is performed during periods of reactor shutdown, during all plant operating periods this equipment is aligned to perform the low head injection function of emergency core cooling. During the recirculation phase of the accident, the residual heat removal pumps take suction from the containment sump. Each pump has a separate suction line. Operational testing of the system, performed during each refueling period before plant startup, provides assurance of correct system alignment for the safety function of the components.

During the injection phase, the safety injection and centrifugal charging pumps do not depend on any portion of other emergency core cooling systems. During the recirculation phase, if Reactor Coolant System pressure stays high due to a small break accident, suction to the high head and centrifugal charging safety injection pumps is provided by the residual heat removal pumps.

The ability of the above systems to perform their dual function is discussed in Sections 6.2 and 6.3 and in Chapters 5 and 15.

6.1.2 RELATED CRITERIA

The following are criteria which, although related to all engineered safety features are more specific to other plant features or systems, therefore are discussed in other sections, as listed.

Name	Discussion
Quality Standards	Chapter 17
Performance Standards	Section 3.1
Records Requirements	Chapter 17
Instrumentation and Control Systems	Chapter 7
Engineered Safety Features Protection System	Chapter 7
Emergency Power	Chapter 8
Seismic Design Criteria	Section 3.7

6.2 CONTAINMENT SYSTEMS

6.2.1 CONTAINMENT FUNCTIONAL DESIGN

6.2.1.1 Design Basis

The reactor containment completely encloses the entire reactor coolant system and ensures that post-accident leakage is limited to a safe rate of 0.1 percent of the containment free volume per day at the design pressure of 47 psig. A steel liner and leaktight penetrations are provided to ensure that the leakage limits is not exceeded. The structure provides biological shielding for both normal and accident situations.

The reactor containment is designed to safely withstand the loading combinations described in Section 3.8.

Containment and associated systems are designed, fabricated and erected to quality and performance standards with appropriate testing and inspection requirements. Records of design, fabrication, construction and testing of the containment are maintained throughout the life of the plant.

The reactor containment system is designed to maintain its capability in case of fire to safely shut down and isolate the reactor.

The design pressure and temperature of the containment is equal to or greater than the peak pressure and temperature occurring as the result of the complete blowdown of the reactor coolant through any rupture of the reactor coolant system up to and including the complete severance of a reactor coolant pipe. Energy contribution from the steam generators is included in the calculation of the containment pressure transient due to the reverse heat transfer through the steam generator tubes. Reactor coolant system supports are designed to withstand the blowdown forces associated with the sudden severance of the reactor coolant piping but not steam piping since the coincidental rupture of the steam system is not credible. In addition, containment design pressure is not exceeded during any subsequent long-term pressure transient determined by the combined effects of heat sources such as residual heat and limited metal-water reactions, structural heat sinks and the operation of the engineered safeguards utilizing only the emergency on-site electric power supply.

The reactor coolant system contains approximately 526,900 pounds of water at a weighted average enthalpy of 583 Btu/lb for a total energy of 307,200,000 Btu. In a design basis accident, this water is released through a double-ended break of the largest reactor coolant pipe, causing a rapid pressure rise in the containment. The reactor coolant pipe used in the accident is the 29 inch inside diameter section because rupture of the 31 inch inside diameter section requires that the blowdown go through both the 29 inch and the 27-1/2 inch inside diamater pipes and would, therefore, result in a less severe transient.

Additional energy release was considered from the following sources:

1. Stored heat in the reactor core.

2. Stored heat in the reactor vessel piping and other reactor coolant system components.

3. Residual heat production.

4. Limited metal-water reaction energy and resulting hydrogen-oxygen reaction energy.

The containment is also designed to withstand credible external pressures. In the event of inadvertent spray actuation, the containment would depressurize until the temperature of the atmosphere was approximately the temperature of the spray. A bounding calculation was performed to determine the maximum outside to inside pressure differential. The following initial conditions were assumed.

1. The containment is initially at 120°F which maximizes the temperature differential between the containment atmospnere and the spray, which is at a temperature of 40°F.

2. The containment pressure is 14.7 psia.

3. The relative humidity is at a maxmimum value of 100 percent.

As the air temperature is reduced from 120 to 40°F, the partial pressure of the air decreases from 12.91 to 11.13 psi. The steam partial pressure decreases from 1.6927 to 0.12163 psi. Thus, a containment equilibrium pressure of 11.25 psia is produced. This causes a differential pressure of 3.45 psi across the containment shell, with no credit taken for the operation of the containment pressure-vacuum relief system. In the long-term, the pressure-vacuum relief system will be operated to return the containment pressure to normal.

The pressure difference between the design and maximum calculated negative pressure is 0.05 psi. This margin is adequate due to the conservatism used in the external pressure analysis.

The containment design provides limited access through personnel hatches with the reactor at power. This type of access is intended primarily for inspection and maintenance of the air recirculation equipment, incore ion chamber drives, seal table, operating deck and reactor coolant drain tank. Opening of the containment equipment hatch or both doors in the personnel locks is limited by the Technical Specifications.

After shutdown, the containment is purged to reduce the concentration of radioactive gases and airborne particulates. A purge system is provided to reduce the radioactivity level to doses defined by 10CFR20 for a 40 hour occupational work week, within 2 hours after plant shutdown, based on 1 percent fuel defects. To assure removal of particulate matter, the purge air is passed through a high efficiency filter before being released to the atmosphere through the plant vent.

The primary reactor shield is designed so that access to the primary equipment is limited by the activity of the primary system equipment and not the reactor.

6.2.1.2 Containment Structural Acceptance Test

6.2.1.2.1 General Description

The completed containment structure was tested for structural integrity by subjecting the structure to an air pressure test of 54 psig, which is equivalent to 115 percent of the design pressure. The basic requirements of Regulatory Guide 1.18, "Structural Acceptance Test for Concrete Primary Reactor Containments," were satisfied in the performance of the test.

Containment pressurization was accomplished in incremental steps to 12 psig, 24 psig, 36 psig, 47 psig, and a final test pressure of 54 psig. Except for the final pressure level, the containment pressure was increased to 1 psig above the level at which measurement readings were to be taken. The pressure was then reduced to the specified value and, after a minimum time delay of 10 minutes to permit equalization of strains in the structure, the observations and measurements were made.

The final test pressure of 54 psig on the building was maintained for a period of 1 hour. During this time, measurements and observations were made to verify the adequacy of the structural design.

After the structural integrity test at 54 psig (held for 1 hour minimum) the pressure was reduced in the same incremental steps to 0 psig prior to performance of the containment liner leakage test.

Temperature, barometric pressure and weather conditions were recorded hourly during the test period.

Prior to the strength test, predicted stress and strain at various locations were developed for an internal pressure of 54 psig. Although strain gauges were installed on designated areas of the liner and concrete reinforcement, the analytically derived strains were not used as acceptance figures for the actual value. Values obtained, however, were analyzed and evaluated to determine the magnitude and direction of principal strains. Test data in excess of the predicted extremes required resolution through review of the design, evaluation of measurement errors and material variability and, if necessary exploration of the structure.

Excessive crack widths, if any, observed during the test were required to be satisfactorily resolved in a manner similar to that discussed above for displacements.

6.2.1.2.2 Test Measurements and Instrumentation

An instrumentation program to determine the degree of agreement between predicted and observed deflection values at various points on the pressurized structure was employed to verify the design.

Radial and vertical growth of the cylinder was measured using linear motion transducers wired to electrical indicators along four approximately equally spaced meridians. Due to the equipment layout, it was not possible to run transducer wires across at six points at each circumference as recommended in Regulatory Guide 1.18. However, numerous additional strain gauges were used on the liner plate and rebar to supplement the measurements. The radial deflections of the containment were measured at the spring line, mid-height of the cylinder and at 13.5

feet above the structural mat. Vertical deflections were measured at the apex and spring line of the dome.

Longitudinal and circumferential growth of the liner was measured by means of electrical strain gauges attached to the exposed face of the liner in an area which is subjected solely to membrane forces (see Figure 6.2-1).

Strain gauges were attached to selected hoop and meridional bars in the cylindrical wall and dome, as well as selected radial and circumferential top and bottom bars in the base slab. Also, strain gauges were attached to representative circumferential bars around the equipment access opening and around both of the personnel access openings. Approximately 200 sets of strain gauges had been attached to reinforcing bars at various locations in the containment structure.

Strain gauges were attached to the steel liner to record strains at the junction with the mat liner, at mid-height, at the spring line and in the dome. Additional strain gauges were attached to the liner around the equipment access and personnel hatches.

Redundancy of instrumentation was attained through multiplicity of points and gauges at which measurements were made, such that loss or damage to any one position would not be critical.

Two basic types of gauges were used: (1) BLH, or equivalent, foil gauges bonded to the members with epoxy cement, and (2) Microdot, Inc., weldable gauges spot-welded to the members.

Where possible, gauges were installed on reinforcing bars in the laboratory and the bars cadwelded in place.

Measurements around the personnel and equipment hatches were made using linear motion transducers between the hatches and the polar crane wall or other fixed supports as shown in Figure 6.2-2. Twelve linear motion transducers at each equipment and personnel hatch were used to measure the deflections, in accordance with Regulatory Guide 1.18.

During the structural acceptance test, all gauges were read and recorded with a multichannel data acquisition system. Readings were obtained just prior to pressurization, at the various selected incremental pressures during pressurization and depressurization, and after depressurization.

The No. 2 Unit Containment is a non-prototype structure, not requiring strain measurement. However, a small number of rebar and liner strain gauges were read for comparison and study at locations that had exhibited high strain when the test as performed on the No. 1 Unit.

LVDT measurements were not taken on the No. 2 Unit personnel hatches, since the test performed on the No. 1 Unit demonstrated that the personnel hatches were structurally loaded in a manner similar to the equipment hatch.

Crack patterns in the concrete were measured and recorded at the quarter points of circumference at the maximum test pressure. A strain sensitive coating was used to make the crack pattern more discernible (see Figure 6.2-3). Crack patterns in the areas of the large penetrations were visually checked to ascertain agreement with predicted stress patterns.

The range of strains and deformations expected at the 54 psig test pressure were as follows:

1. Increase in containment diameter: not more than 1.75 inches.

2. Maximum vertical elongation of the structure: not more than 2 inches.

3. Maximum width of new cracks or increase in existing cracks: not more than 0.03 inch.

4. Residual width of new cracks or increased width of existing cracks (after containment pressure is reduced to atmospheric): not more than 0.02 inch.

Since the containment structure was expected to remain in the elastic range during the pressure test, there was not expected to be any permanent distortion in the liner or in the concrete once the pressure was reduced to atmospheric or below. However, it was fully expected that small residual cracks in the concrete would appear as a result of concrete creep during pressurization.

6.2.1.2.3 Acceptance Criteria

The structural acceptance test determined whether the containment structure is capable of withstanding the magnitudes of loading used in the design. The acceptance criteria is that under the test load. The behavior of the structure under the test load must be such as to indicate its ability to withstand the loadings used for design.

Were the test acceptance criterion to equal or exceed the stresses computed under the factored loadings, then destruction of some elements would result.

It was not necessary to test up to design stresses to verify the structural integrity of the containment. Prediction and verification of deformation patterns, using the same design and analysis procedures for both design and test conditions, serves to verify the design.

Tensile stresses in the liner plate during the structural acceptance test were expected to be greater than those which would occur under the accident condition. The reason for this was that there was no temperature rise associated with the test condition. Compressive stresses would be created by the high temperatures associated with an accident condition, which overcome the tension in the liner. Stresses in the reinforcing bars were expected to be lower during the test condition than the values calculated for the accident condition.

With regard to the liner, the largest number and length of seams occurs in the cylinder and dome and, therefore, the greatest potential for leakage. The test condition was expected to yield tensile stresses in the dome and most of the cylinder that are higher than the design condition. The exception was the lower cylinder wall, where design tensile stresses are expected to be higher. With the exception of this area, the test placed a greater stress condition on the potential leakage paths than any of the design conditions.

The acceptance criterion requires demonstration that the overall structure exhibited elastic behavior throughout the test range. Inelastic behavior at localized stress concentrations was considered acceptable. Greatest agreement between the computed strains and those actually observed was anticipated to have been in the shell of the containment. Greater disparity between observed and calculated strains was contemplated around openings and at other discontinuities, where theoretical analysis becomes more complex. The acceptance criterion for cracking was based on the width and spacing of cracks, as determined through review of predicted crack size and crack spacing. Data obtained during the test were evaluated and a comparison with the values predicted by design was made to assess the structural behavior of the containment with regard to local and overall response.

6.2.1.3 Containment Overall Integrated Leakage Rate Tests

6.2.1.3.1 Preoperational Test

The preoperational containment overall integrated leakage rate test was performed following successful completion of the structural acceptance test. The test was performed to satisfy the requirements of 10CFR50, Appendix J, "Primary Reactor Containment Leakage Testing for Water Cooled Power Reactors," for Type A tests.

The test was performed according to the peak pressure test program, using the "absolute" method, to ascertain that the leakage rate did not exceed 0.1 percent of the containment free volume per day at the design pressure of 47 psig. The test was performed at 47 psig.

6.2.1.3.2 Periodic Tests

A set of three overall integrated leakage rate tests will be performed at approximately equal intervals, during each 10-year service period, with the third test of each set coinciding with the end of the 10-year service period.

The performance of these tests will be limited to periods when the plant is non-operational and secured in the shutdown condition.

The periodic tests will be performed at a peak pressure of 47 psig.

Detailed test requirements are contained in the Technical Specifications. Should deviations become necessary they will be the subject of License Change Requests (LCR) accompanied by appropriate justification. LCR 83-04, PSEG memo Liden to Varga, dated July 22, 1983 documents such a request for Unit 1.

6.2.1.4 Penetration Leakage Rate Tests

6.2.1.4.1 Preoperational Tests

Penetration leakage rate tests (Type B tests) were performed in accordance with 10CFR50, Appendix J, "Primary Reactor Containment Leakage Testing for Water Cooled Power Reactors." Only the free volume of the double penetrations was included in the test. Because this volume is very small when compared to the containment free volume, the sensitivity and accuracy attainable in this leakage rate test was increased correspondingly over that attainable through integrated leakage rate testing.

All containment piping penetrations fitted with bellows are tested at Pa. Each bellows in penetrations utilizing more than one bellows is subjected to Type B testing.

The penetration leakage rate tests were performed with the penetrations pressurized to 47 psig, and the containment building at atmospheric pressure.

The combined leakage rate for the double penetrations and isolation valves was limited to less than 0.06 percent of the containment free volume per day.

6.2.1.4.2 Periodic Tests

Periodic leakage rate testing for penetrations will be conducted in a manner similar to the preoperational tests. The periodic tests will be performed according to the required frequencies set forth in 10CFR50, Appendix J, "Primary Reactor Containment Leakage Testing for Water Cooled Power Reactors," for Type B tests.

6.2.2 CONTAINMENT HEAT REMOVAL SYSTEMS

Adequate post-accident heat removal capability for the containment is provided by two separate, full capacity, engineered safety features systems. These are the containment spray system, described in Section 6.2.2.1, and the containment fan cooling system, described in Section 6.2.2.2. These systems are of different engineering principles and serve as independent backups for each other.

Any of the following combinations of containment spray and fan cooler equipment trains will provide sufficient heat removal capability to maintain the post-accident containment pressure below the design value, assuming that the core residual heat is released to the containment as steam:

1. All five containment fan coolers

2. Both containment spray pumps

3. Three of the five containment fan coolers and one containment spray pump along with one train of the emergency core cooling system.

6.2.2.1 <u>Containment Spray System</u>

6.2.2.1.1 Design Bases

The primary purpose of the containment spray system is to spray cool water into the containment atmosphere in the event of a loss-of-coolant accident and thereby ensure that containment pressure does not exceed the design value of 47 psig at 271°F (100 percent relative humidity). This protection is afforded for all pipe break sizes up to and including the hypothetical instantaneous circumferential rupture of a reactor coolant pipe. Pressure and temperature transients for loss-of-coolant accident are presented in Chapter 15. Although the water in the core after a loss-of-coolant accident is quickly subcooled by the safety injection system, the containment spray system design is based on the conservative assumption that the core residual heat is released to the containment as steam.

The containment spray system is designed to spray at least 2600 gpm of borated water into the containment building whenever two out of four (Hi-Hi) containment pressure signals occur or a manual signal is given.

Either of two subsystems containing a pump and associated valving and spray headers are independently capable of delivering 2600 gpm.

The design basis is to provide sufficient heat removal capability to maintain the post-accident containment pressure below the design pressure assuming that the core residual heat is released to the containment as steam.

A second purpose served by the containment spray system is to remove elemental iodine from the containment atmosphere should it be released in the event of a loss-of-coolant accident. The analysis of off-site thyroid dose after a hypothetical LOCA is presented in Chapter 15. Iodine removal effectiveness is described in Section 6.2.3.

The spray system is designed to operate over an extended time period, following a primary coolant system failure as required to restore and maintain containment conditions at near atmospheric pressure. It has the capability of reducing the containment post-accident pressure taking into account any reduction in capacity due to a single failure.

Portions of other systems which share functions and become part of the containment spray system when required are designed to meet the criteria of this section. Any single failure of an active component in either spray subsystem does not degrade the minimum containment cooling or fission product removal capability of the containment spray system, as the containment pressure-temperature analysis in Chapter 15 assumes the most restrictive single failure.

Those portions of the spray systems located outside of the containment which are designed to circulate, under post-accident conditions, radioactively contaminated water collected in the containment meet the following requirements:

1. Adequate shielding to maintain radiation levels within the guidelines of 10CFR100 (Section 11.2).

2. Collection of discharges from pressure relieving devices into closed systems.

3. Means to limit radioactivity leakage to the environs, consistent with guidelines set forth in 10CFR100.

System active components are redundant. System piping located within the containment is redundant and separable in arrangement.

All portions of the system located within containment are designed to withstand, without loss of functional performance, the post-accident containment environment and operate without benefit of maintenance for the duration of time to restore and maintain containment conditions at near atmospheric pressure.

Table 6.2-1 tabulates the codes and standards to which the containment spray system components are designed.

6.2.2.1.2 System Design

System Description

Adequate containment cooling and iodine removal are provided by the containment spray system shown in Figures 6.2-4A and B whose components operate in sequential modes. These modes are:

1. Spray a portion of the contents of the refueling water storage tank into the containment atmosphere using the containment spray pumps. During this mode, the contents of the spray additive tank (sodium hydroxide) are mixed into the spray stream to enhance the iodine removal capability of the containment spray system.

2. Recirculation of water from the containment sump is provided by the diversion of a portion of the recirculation flow from the discharge of the residual heat removal heat exchangers to the containment spray header after injection from the refueling water storage tank has been terminated.

The bases for the selection of the various conditions requiring system actuation is presented in Chapter 15.

The principal components of the containment spray system are: Two pumps, one spray additive tank, two eductors, spray ring headers and nozzles, and the necessary piping and valves. The containment spray pumps and the spray additive tank are located in the auxiliary building and the spray pump suctions are normally lined up to the refueling water storage tank. Following an accident the containment spray pumps are utilized until the water in the refueling water storage tank is depleted.

During the recirculation phase, the system utilizes the two residual heat removal pumps, two residual heat exchangers and associated valves and piping of the safety injection system.

The spray system is actuated by two out of four hi-hi containment pressure signals. The starting signal energizes the pumps and opens the discharge valves to the spray headers. The valves associated with the spray additive tank are opened on the same signal. If necessary, the operator can manually actuate the entire system from the control room.

During the period of time that the spray pumps draw from the refueling water storage tank a small portion of the spray flow is diverted from the spray pump discharge line through the eductor and back to the pump suction. Valve CS14 in the spray additive tank discharge line is provided with redundant position indication to assure effective chemical addition to the spray system. The liquid from the spray additive tank then mixes with the liquid entering the suction of the pumps. The result is a solution suitable for the removal of iodine from the containment atmosphere. The analysis of the iodine removal capability of the containment spray system, presented in Section 6.2.3, shows that more than 99 percent of the removable iodine in the containment atmosphere is washed out in the injection phase.

After the injection operation, spray pump flow is discontinued when the water in the refueling water storage tank is depleted. Containment pressure control can then be maintained with the residual heat removal system functioning through the containment spray headers.

If, for any reason, the containment pressure should be observed to increase, the operator can direct part of the discharge flow from the residual heat exchangers to the spray headers thereby initiating recirculation spray flow.

The procedure for the change-over from injection to recirculation and cooling water for the residual heat exchangers are described in Section 6.3.

Components

All associated components, piping, structures, and power supplies of the containment spray system are designed to Class I (seismic) criteria.

The containment spray system shares the refueling water storage tank liquid capacity with the safety injection system. Refer to Section 6.3 for a detailed description of this tank.

Pumps

The two containment spray pumps are of the horizontal centrifugal type, driven by electric motors which can be supplied with power from the standby AC power supply.

The design head of the pumps is sufficient to continue at rated capacity with a minimum level in the refueling water storage tank against a head equivalent to the sum of the design pressure of the containment, the head to the uppermost nozzles, and the line and the nozzle pressure losses. Pump motors are direct-coupled and large enough for the maximum power requirements of the pumps. The materials of construction are stainless steel or equivalent corrosion resistant material. Design parameters are presented in Table 6.2-2 and the pump head characteristic curve is presented in Figure 6.2-5.

The containment spray pumps are designed in accordance with the specifications discussed for the pumps in the safety injection system, Section 6.3.

The pump motors are non-overloading to the end of the pump curve.

Each containment spray pump is provided with a steel enclosure for missile protection.

Details of the component cooling pumps and service water pumps, which serve the safety injection system, are presented in Chapter 9.

Spray Headers and Nozzles

The containment spray header piping arrangement is shown in Figures 6.2-6 and 6.2-7. These figures illustrate the spray nozzle orientation, which has been designed to provide maximum spray coverage of the containment. The arrangement consists of four 360 degree ring headers at different elevations, with alternate headers connected. The header diameters are 101 ft at El. 244'-6", 96 ft at El. 247'-0", 53 ft at El. 266'-6", and 48 ft at El. 269'-0".

The spray headers are stainless steel of a hollow-cone pressure nozzle design, with a 3/8 inch diameter orifice. The nozzles have no internal parts which would be subject to clogging. The nozzles produce a drop size spectrum with a Sature mean drop size of less than 100 microns with the spray pump operating at design conditions and the containment at full design pressure and temperature.

The spray header supports are shown in Figures 6.2-8, 6.2-9 and 6.2-10. These figures illustrate the relationship of the support steel to the headers and the containment building wall. The supports are designed such that interference with the spray pattern is kept to a minimum and their structural integrity under accident and seismic conditions is maintained.

The design is such that the alternate connected ring headers and corresponding sections of riser (from the last anchor point on the containment wall) will act as a unit under design thermal and seismic conditions. The pipe hangers and restraints are designed to support and restrain the pipe under design thermal and seismic conditions.

Spray Nozzles

The spray nozzles are of a hollow-cone pressure nozzle design without any internal parts subject to clogging. The nozzles produce a drop size spectrum with a Sauter mean drop size less than 1000 microns with the spray pump operating at design conditions and the containment at design pressure and temperature.

During spray recirculation operation, the water is screened through a 1/4 inch mesh before leaving the containment sump. The spray nozzles are stainless steel and have a 3/8 inch diameter orifice. The nozzles are connected to four 360 degree ring headers of ring headers (alternating headers connected) of diameter 101' (El. 244'6"), 53' (El. 266'6"), 96' (El. 247'), 48' (El. 269').

The nozzles and headers are so oriented as to maximize coverage of the containment volume.

All stresses are within those allowed by ANSI B31.1.0 piping code. Heavier walled pipe is used at anchor points and points of restraint to eliminate high stress regions.

Containment Dome Access System - No. 2 Unit

The No. 2 Unit utilizes a different design, the containment dome access system. This system serves the dual purpose of supporting the containment spray system ring header piping and providing access for maintenance and inspection to the ring headers and the containment dome liner (see Figure 6.2-11). This system consists of the following components:

1. An orbital inclined service bridge and trolley capable of carrying personnel and material, including an auxiliary hoist. It is designed to provide maximum coverage of both the containment dome liner and the spray header piping (see Figure 6.2-11).

2. A structural steel girder, beam and the support structure for the access bridge and spray piping (see Figure 6.2-12).

Both components are seismic Class I and have been statically dynamically designed to withstand the effects of the design basis earthquake. They have combined total weight of 394,000 pounds.

The support beams for this system penetrate the containment liner plate and are anchored into the concrete wall of the reactor containment building. In order to maintain containment integrity, the penetrations through the liner plate are seal welded into place and vacuum box tested. A leak chase box is installed around each embedded beam to enable leak rate testing of the welds at any time (see Figure 6.2-13).

The orbital service bridge, the spray header support or basket and the spray piping were mathematically modeled as a system of node points interconnected by various weightless springs. The springs were assigned and stiffness characteristics of the structural beam and functional pipe elements of the system. All weights and inertias were distributed among the nodes. The degrees of freedom of the nodes were chosen to closely simulate the response of the system to external loading; the materials were assumed to be linearly elastic.

Static analysis was performed to obtain the maximum stresses under dead load and thermal variations.

Using the above mathematical model, a dynamic modal analysis was also performed to determine the modal frequencies and mode shapes. SEE response spectra with 1/2 percent damping factor at the proper structural elevations were used as the input for the response spectrum analysis. The element stresses of those modes with meaningful participation for a given excitation direction were summed as a square root of the sum of their squares. When mode frequencies occurred within 10 percent of each other, an absolute summation of stresses was made prior to RMS summation.

The design stresses for the system are the summations of the maximum static and dynamic stresses for the respective members.

The analysis assumed the orbital bridge was locked to the rail in its storage location, the personnel cage was locked in the down (stored) position on the bridge with no load on the hoist and the containment spray piping empty of liquid. This analysis simulates actual conditions during reactor operation.

The calculations performed on the dome access system indicate that none of the elements are subjected to loads beyond the allowable value of 32.40 ksi, which is 90 percent of the minimum yield strength of A36 steel. The loads obtained from the calculations for the dome access system were then used to design the dome access system containment interface tie-supports. These tie-supports which are made of A442 Grade 60 steel with an allowable stress of 19 ksi, will be sujbected to a stress of only 10.92 ksi.

The allowable load on the access system will not be exceeded due to required administrative control.

The dome access system, consisting of the orbital service bridge and supporting basket and the spray header piping were analyzed for a Safe shutdown earthquake using response spectrum curves at 1/2 percent damping with the bridge in the storage location. The bridge, basket and piping were mathematically modeled as a multi-degree of freedom system with node points interconnected by various springs. ANSYS, a large scale, general purpose computer program, was used to perform the modal analysis.

Spray Additive Tank

The capacity of the tank is sufficient to contain enough sodium hydroxide solution which, upon mixing with the refueling water from the refueling water storage tank, the boric acid from the boron injection tank, the borated water contained within the accumulators and primary coolant, will bring the concentration of sodium hydroxide in the containment sump to approximately 0.2 weight percent solution caustic and 1.2 weight percent boric acid. This maintains a pH of at least 8.5 and assures the continued iodine removal effectiveness of the containment spray during the recirculation phase of operation as well as adequate retention of the absorbed iodine in the sump liquid. A level indicating alarm is provided in the control room if, at any time, the solution tank contains less than the required amount of sodium hydroxide solution. Periodic sampling confirms that proper sodium hydroxide concentration exists in the tank. Also, a flow indication is provided in the control room to alert the operator if there is low flow from the tank when required.

The tank design parameters are given in Table 6.2-3.

Heat Exchangers

The two residual heat exchangers are used during the recirculation phase are described in Section 6.3.

Valves

The valves for the containment spray system are designed in accordance with the specifications for the valves in the safety injection system.

Valving descriptions and valve details are shown in Section 6.3.

Piping

The piping for the containment spray system is designed in accordance with the specifications for piping in the safety injection system (Section 6.3).

The system piping is designed for 250 psig at 150°F.

Motors for Pumps and Valves

The motors for the Containment Spray System are designed in accordance with the specifications discussed for motors in the Safety Injection System (Section 6.3).

6.2.2.1.3 Design Evaluation

Range of Containment Protection

During the injection phase following the maximum loss-of-coolant accident (i.e., during the time that the containment spray pumps take their suction from the refueling water storage tank) the containment spray system provides the design heat removal capacity for the containment. After the injection phase, each train of the recirculation system provides sufficient cooled recirculated water to keep the core flooded as well as providing, if required, sufficient flow to the containment spray headers to maintain the containment pressure below the design value. This applies for all reactor coolant pipe break sizes up to and including the hypothetical instantaneous circumferential rupture of a reactor coolant pipe. Only one spray header is required to operate for this capability at the earliest time recirculation is initiated.

The containment spray and fan cooler systems are capable of removing sufficient energy to maintain the pressure below the containment design pressure even in the event of a single failure. Each of these systems consists of independent equipment and components supplied from separate power sources. One containment spray train and three of five fan coolers, along with one train of the emergency core cooling system, is sufficient to ensure containment integrity.

During the injection and recirculation phases the spray water is raised to the temperature of the containment in falling through the steam-air mixture. The minimum fall path of the droplets is approximately 110 feet from the lowest spray ring headers to the operating deck. The actual fall path is longer due to the trajectory of the droplets sprayed out from the ring header. Heat transfer calculations show that thermal equilibrium is reached by all droplets in the first few feet of their fall. Thus, the spray water reaches essentially the containment saturation temperature. The model for spray heat removal is discussed in Chapter 15.

In addition to heat removal, the spray system is effective in scrubbing fission products from the containment atmosphere. However, quantitative credit is taken only for absorption of iodine in the elemental (I_2 vapor) form in the analysis of the hypothetical LOCA (Chapter 15). A discussion of the effectiveness of containment spray as fission product removal process is contained in Section 6.2.3.

One containment spray pump provides sufficient iodine scrubbing capability to ensure that post-accident fission product leakage (based on TID-14844 release fractions) would not result in doses exceeding the limits of 10CFR100.

<u>System Response</u>

The starting sequence of the containment spray pumps and their related emergency power equipment is designed so that delivery of the minimum required flow is reached within 25 seconds. The pumps are signalled to start at about 20 seconds after the occurrence of the safety injection signal. The containment pressure analysis is based on the assumption that a pump reaches full speed at 25 seconds.

Single Failure Analysis

A failure analysis has been made on all active components of the system to show that the failure of any single component will not prevent fulfilling the design function. This analysis is summarized in Table 6.2-4.

The loss-of-coolant accident analysis presented in Chapter 15 reflects the single failure analysis.

Reliance on Interconnected Systems

The containment spray system initially operates independently of other engineered safety features following a loss-of-coolant accident. It provides backup cooling to the containment fan cooling system. For extended operation in the recirculation mode, water is supplied through the residual heat removal pumps and heat exchangers.

During the recirculation phase some of the flow leaving the residual heat exchangers may be bled off and sent to either the discharge of the containment spray pumps or to the suction of the safety injection pumps and centrifugal charging pumps. Minimum flow requirements will be set for the flow being sent to the core and for the flow being sent to the containment spray pump discharge. Sufficient flow instrumentation is provided so that the operator can perform appropriate flow adjustments with the remote throttle valves in the flow path.

Shared Function Evaluation

Tables 6.2-5 presents an evaluation of the main components which have been discussed previously and a brief description of how each component functions during normal operation and during the accident.

NPSH and Spray Water Entrapment

Spray recirculation has been evaluated considering loss of water through entrapment outside the containment sump. There are three areas within the containment where reactor coolant blowdown liquid and spray water may become trapped: the reactor cavity, the refueling canal, and the reactor instrumentation tunnel. The reactor cavity has ventilation openings around the reactor that would allow spray water to drain to the lower elevations of the containment. The refueling canal is normally isolated from the fuel handling building and would trap no more than 9,500 gallons of liquid from containment spray system. The instrumentation tunnel has a water capacity of approximately 70,000 gallons, none of which would drain to the sump.

The total quantity of water relased to the containment at the beginning of the recirculation phase of the containment spray system operation, assuming a design basis accident with reactor coolant loop piping half full of water, is approximately 275,000 gallons. Discounting the water volume trapped in the refueling canal and the reactor instrumentation tunnel, the volume available at the suction of the RHR pump used for containment spray is approximately 190,000 gallons. The required NPSH for the RHR pump is a water level relative to the bottom (El. 70') of the 8 foot deep containment sump. The indicated available water volume is a water level several feet above the containment sump top. There is therefore no significant effect on the required static head for the RHR pump.

Available and required NPSH for the containment spray pumps and the residual heat removal pumps are provided in Table 6.2-6. Compliance with Regulatory Guide 1.1 is discussed in Appendix 3A.

Environmental Protection

During operation a movable shield provides missile protection for the area immediately above the reactor vessel. The spray headers are therefore protected from missiles originating within the shield.

Active components of the containment spray system are located outside the containment, and hence are not required to operate in the steam-air environment produced by the accident.

Material Compatibility

Parts of the system in contact with borated water, sodium hydroxide spray additive, or mixtures of the two are stainless steel or an equivalent corrosion resistant material.

6.2.2.1.4 Tests and Inspections

Inspection Capability

Where practicable, all active components and passive components of the containment spray system are inspected periodically to assure system readiness. The pressure containing systems are inspected for leaks from pump seals, valve packing, flanged joints and safety valves. During operational testing of the containment spray pumps, the portions of the systems subjected to pump pressure are inspected for leaks. Design provisions for inspection of the safety injection system, which also functions as part of the containment spray system, are described in Section 6.3.

System and Component Testing

Active components of the containment spray system were adequately tested both in pre-operational performance tests in the manufacturer's shop and in place after installation. Thereafter, periodic tests are also performed after component maintenance.

Means are provided to test initially under conditions as close to design as is practical the full operational sequence that would bring the containment spray system into action.

The containment spray pumps can be tested individually by opening the valves in the miniflow line. Each pump in turn can be started by operator action and checked for flow establishment. The spray injection valves can be tested with the pumps shutdown.

The spray additive tank valves can be opened periodically for testing. The contents of the tank will be periodically sampled to determine that the proper solution is present.

During these tests the equipment will be visually inspected for leaks. Leaking seals, packing, or flanges will be tightened to eliminate the leak. Valves and pumps will be operated and inspected after any maintenance to ensure proper operation.

Permanent test lines for all spray loops are located so that the system, up to and including the isolation valves at the spray header, can be tested. These isolation valves can be checked separately.

Flow bypass through the eductors was checked during the initial pre-operational tests of the spray system. Subsequent system tests will be made with the spray additive tank bypass valves closed.

The air test lines for checking spray nozzles connect downstream of the isolation valves. Air flow through the nozzles is monitored as required by the Unit 2 Technical Specifications.

The functional test of the ECCS described in Section 6.3 includes the operation of the containment spray system. A test signal simulating the containment spray initiating signal is used to demonstrate operation of the spray system up to the isolation valve on the pump discharge.

Spray Nozzles

The spray nozzles are of a hollow-cone pressure nozzle design without any internal parts subject to clogging. The nozzles produce a drop size spectrum with a Sauter mean drop size less than 1000 microns with the spray pump operating at design conditions and the containment at design pressure and temperature.

During spray recirculation operation, the water is screened through a 1/4 inch mesh before leaving the containment sump. The spray nozzles are stainless steel and have a 3/8 inch diameter orifice. The nozzles are connected to four 360 degree ring headers of ring headers (alternating headers connected) of diameter 101' (El. 244'6"), 53' (El. 266'6"), 96' (El. 247'), 48' (El. 269').

The nozzles and headers are so oriented as to maximize coverage of the containment volume.

6.2.2.2 Containment Fan Cooling System

6.2.2.2.1 Design Basis

The containment fan cooling system is designed to recirculate and cool the containment atmosphere in the event of a loss-of-coolant accident and thereby ensure that the containment pressure will not exceed its design value of 47 psig at 271°F (100 percent relative humidity). Although the water in the core after a loss-of-coolant accident is quickly subcooled by the safety injection system, the containment fan cooling system is designed on the conservative assumption that the core residual heat is released to the containment as steam.

The containment ventilation system (Section 9.4) which includes the containment fan cooling system, is designed to remove the normal heat loss from equipment and piping in the reactor containment during plant operation and to remove sufficient heat from the reactor containment, following the initial loss-of-coolant accident containment pressure transient, to keep the containment pressure from exceeding the design pressure. The fan cooler units continue to remove heat after the loss-of-coolant accident and reduce the containment pressure close to atmospheric within the first 24 hours.

In addition to the design bases specified above, the following objectives are met to provide the engineered safety features functions:

1. Each of the five fan-cooler units is capable of transferring heat at the rate of 22,500 Btu/sec (81×10^6 Btu/hr) from the containment atmosphere at the post-accident design conditions, i.e., a saturated air-steam mixture at 47 psig and 271°F. This heat transfer rate is that assigned to the fan-cooler units in the accident analyses of Chapter 15.

   The establishment of basic heat transfer design parameters for the cooling coils of the fan-cooler units, and the calculation by computer of the overall heat transfer capacity are discussed in Chapter 15. Among the topics covered are selection of the tube side fouling factor, effect of air side pressure drop, effect of moisture entrainment in the air steam mixture entering the fan-coolers, and calculation of the various air side to water side heat transfer resistances.

2. In removing heat at the design basis rate, the cooler coils are capable of discharging the resulting condensate without impairing the air flow capacity of the fan coolers and without raising the exit temperature of the service water to the boiling point. Since condensation of water from the air-steam mixture is the principal mechanism for removal of heat from the post-accident containment atmosphere by the cooling coils, the coil fins will operate as wetted surfaces under these conditions. Entrained water droplets added to the air-steam mixture, such as by operation of the containment spray system, will therefore have essentially no effect on the heat removal capability of the coils.

In addition to the above design bases, the equipment is designed to operate at the post-accident conditions of 47 psig and 271°F for 3 hours, followed by operation in an air-steam atmosphere at 20 psig, 219°F for an additional 21 hours. The equipment design will permit subsequent operation of an air-steam atmosphere at 5 psig, 152°F for an indefinite period.

All components are capable of withstanding or are protected from differential pressures which may occur during the rapid pressure rise to 47 psig in 10 seconds.

Portions of other systems which share functions and become part of this containment cooling system when required are designed to meet the criteria of this section. Neither a single active component failure in such systems during the injection phase nor an active/passive failure during the recirculation phase will degrade the heat removal capability of containment cooling.

Where positions of these other systems are located outside of containment, the following features are incorporated in the design for operation under post-accident conditions:

1. Means for isolation of any section.

2. Means to detect and control radioactivity leakage into the environs, to the limits consistent with guidelines set forth in 10CFR100.

6.2.2.2.2 System Description

The containment fan cooling system is illustrated in Figures 9.4-4A and B.

Individual system components and their supports meet the requirement for Class I (Seismic) structures and are isolated from fan vibration.

The fan cooler system consists of five air handling units, each including motor, fan, motor heat exchanger, cooling coils, roughing filters, dampers, duct distribution system, instrumentation and controls. The units are located on the operating floor, between the containment wall and the polar crane wall.

Each fan is designed to supply 110,000 cfm at approximately 7.3" s.p. (0.075 lb/ft^3 density) during normal operation and 47,000 cfm, at approximately 3.75" s.p. (0.175 lb/ft^3 density), during accident operation. The fans are direct driven, centrifugal type, and the coils are plate fin-tube type. Each air handling unit is capable of removing 81 x 10^6 Btu/hr from the containment atmosphere under accident conditions. 2550 gpm of service (cooling) water is supplied to each unit during accident conditions. The design maximum river water inlet temperature is 85^oF which results in an outlet temperature of 150^oF.

Duct work distributes the cooled air to the various containment compartments and areas. During normal operation, the flow sequence through each air handling unit is as follows: inlet dampers, roughing filters, cooling coils, fan, discharge header. During post-accident operation, air is drawn through a moisture separator, a post-accident HEPA filter section and cooling coils and is discharged to the duct header.

Tight closing dampers isolate the post-accident filter section from the normally operating components. These dampers are tripped to the accident position upon either manual or automatic actuation of the respective fan. Electrically operated four-way solenoid valves control instrument air to the damper control cylinders. On a loss of either control air or control power the dampers fail to the accident (open) position.

The fan cooling system is actuated (in the post-accident mode) during the safeguards sequence following the generation of a containment high pressure signal. Either all 5 fans or a minimum of 3 fans are started by the safeguards equipment controller, depending on the availability of emergency power.

A flow switch at each fan indicates whether air is circulating in the intended normal or post-accident flowpath. Indication and alarms are provided in the control room.

Flow Distribution and Flow Characteristics

The location of the distribution ductwork outlets, together with the location of the fan cooler unit inlets, ensures that the air will be directed to all areas requiring ventilation before returning to the units.

In addition to ventilating areas inside the periphery of the polar crane wall, the distribution system also includes branch ducts located at opposite extremes of the containment wall for ventilating the upper portion of the containment. These ducts extend upward along the containment wall as required to permit the throw of air from the ducts to reach the dome area and assure that the discharge air will mix with the atmosphere.

The air discharged inside the periphery of the polar crane wall circulates and rises above the operating floor through openings around the steam generators where it mixes with air displaced from the dome area. This mixture is returned to the fan coolers located on the operating floor. The temperature of this air will be essentially the design ambient for the containment vessel (120°F average maximum).

The steam-air mixture from the containment entering the cooling coils initially during the accident will be at approximately 271°F and have a density of 0.175 pounds per cubic foot. Most of the water vapor will condense on the cooling coil, and the air leaving the fan cooler will be saturated at a temperature slightly below 271°F.

With a flow rate of 47,000 cfm from each fan under accident conditions and a containment free volume of 2,620,000 ft^3 the recirculation rate with five fans operating is approximately 5.4 containment volumes per hour.

Cooling Water for the Fan Cooler Units

The cooling water requirements for all five fan cooler units during a loss-of-coolant accident and recovery are supplied by the service water system. The service water system is described in Chapter 9. The design basis river water temperature for service water to the containment fan coolers is 85°F, although river water temperatures throughout the year are normally less. The service water temperature rise through the containment fan coolers is 9°F for normal operation. In the unlikely event of an accident, this temperature rise will be a maximum of 65°F for a period of less than 1 hour, after which it will decrease. It is not expected that any significant amount of calcium carbonate precipitation on the heat exchange surfaces will occur at these temperatures, and, therefore, there will be no subsequent plugging of the fan coolers.

Service water discharge from the cooling coils is monitored for radioactivity by routing a small bypass flow from each fan cooler unit through a radiation monitor. An alarm is annunciated in the control room upon detection of high radioactivity in an effluent line.

Flow and temperature indication is provided outside containment for service water flow to and from each fan cooler unit. Abnormal flow alarms for in-service fan cooler units are provided in the control room.

During normal operation, a dual setpoint service water flow controller will position the flow control valve to give the required 700 gpm flow. During conditions of safety injection, a signal to the controller changes the setpoint to 2500 gpm. The control valve closes when the fan cooler unit is not in use.

Components

Roughing and HEPA Filters

The roughing filters in each fan cooler unit are designed to remove the larger particles of suspended dust and dirt from the containment atmosphere during normal power operation, normal reactor shutdown and loss of offsite power conditions. Removal of the particles also prevents build-up on the cooling coils, thus avoiding a reduction in heat transfer.

The roughing filters are arranged in two banks, each consisting of structural steel frame and removable filter cells. Each filter cell contains a fiberglass media which is capable of removing 90 percent of visible dust particles. The media efficiency is 70 percent on NBS type test ratings.

The HEPA filters in each fan cooler are provided to remove any particulate matter from the containment atmosphere.

The HEPA filters are arranged in a structural steel frame and are individually removable. The filter media is fiberglass with asbestos separators and is capable of collecting 99 percent of particles 0.3 microns and larger in size from a saturated (100 percent relative humidity) 271°F atmosphere processed through the filter at 250-300 fpm. The HEPA filter media meets MIL-F-51079 and MIL-STD-282.

Fan-Motor Units

The five containment cooling fans are of the centrifugal, non-overloading direct drive type. Each fan provides a minimum flow rate of 47,000 cfm when operating against the system resistance of approximately 3.75 s.p. existing during accident conditions (0.175 lb/ft^3 density, a containment pressure of 47 psig, and temperature of 271°F).

The two-speed containment fan cooler motors are totally enclosed, water cooled, 300 horse power (high speed), induction type, 3 phase, 60 cycle, 1200 RPM, 460 volt with ample insulation margin. At lowspeed the motor delivers 274 horsepower. Insulation is Class F (NEMA rated total temperature 155°C) Westinghouse Thermalastic. It is impregnated and coated to give a homogeneous insulation system which is highly impervious to moisture. Internal leads and the terminal box-motor interconnection are given special design consideration to assure that the level of insulation matches or exceeds that of the basic motor system. At incident ambient and load conditions, (271°F and 100 HP) the motor insulation hot spot temperature is not expected to exceed 113°C.

Fan cooler motors are cooled by an air-to-water heat exchanger which is connected to the motor to form an entirely enclosed cooling system. Air movement is through the heat exchanger and is returned to the motor. Two vent valves permit containment ambient air to enter the cooling compartment (on increasing containment pressure) so the motor bearings will not be subjected to an excessive differential pressure. An open condensate drain line will enable the cooling compartment to equalize with the containment pressure as containment pressure is reduced by the motor heat exchanger. Cooling water is supplied by the service water system.

The motors are equipped with high temperature grease lubricated ball bearings to withstand the design basis incident ambient temperatures. Continuous bearing temperature monitoring is provided which will alarm in the control room.

Fan motor leads are brought out of the frame through a seal and into a cast iron sealed explosion-proof type of conduit box. Overload protection for the fan motors is provided at the switchgear by overcurrent trip devices in the motor feeder breakers. The breakers can be operated from the control room and can be reclosed from the control room following a motor overload trip.

In addition to the usual quality control tests which are performed to give assurance that the motors meet design specifications, special tests are performed to demonstrate that insulation margins are built in as expected. The completely wound stators are given a special high potential test to ground. The stators are immersed in water, meggered and given a high potential test while immersed. After passing the water tests, the motor is baked and given a final coating dip. The stator and rotor are then baked again.

Cooling Coils

Coils are fabricated of AL-6 X tubing. The heat removal capability of the cooling coils is 81 x 10^6 Btu/hr per fan cooler unit at saturation conditions (271°F, 47 psig). The design internal pressure of each coil is 200 psig and the coils can withstand an external pressure of 47 psig at a temperature of 271°F without damage.

Each recirculating unit consists of 12 coil units mounted in two banks of 6 coils high. These banks are located one behind the other for horizontal series air flow, and the tubes of the coil are horizontal with vertical fans.

A moisture separator in each fan cooler removes the larger droplets of suspended moisture from the containment atmosphere in the event of a loss-of-coolant accident. Removal of the droplets prevents any significant water deluge over the face of the HEPA filters and thus avoids a serious reduction in filter effectiveness. The separator consists of a structural steel frame with removal separator elements. Each element is capable of removing 95 percent of water droplets 10 microns and larger in size, at the rate of 0.35 pounds of water per 1000 cfm of processed atmosphere traveling at 350 to 500 fpm through the element.

The coils are provided with drain pans and drain piping to prevent flooding during accident conditions. This condensate is drained to the containment sump.

Ducting

The ducts are designed to withstand the sudden release of reactor coolant system energy and energy from associated chemical reactions without failure due to shock or pressure waves by incorporation of damper along the ducts which open at slight overpressure, 3.0 psi. The ducts are designed and supported to withstand thermal expansion during an accident.

Ducts are of welded and flanged construction. All longitudinal seams are welded. Where flanged joints are used, joints are provided with gaskets suitable for temperatures to 300°F.

Ducts are constructed of galvanized sheet metal.

Dampers

All air control dampers that are an integral part of the fan coolers are designed to Class I seismic criteria. The damper construction is designed to withstand the design basis earthquake concurrent with the pressure transients, thermal energy and chemical activity resulting from a loss-of-coolant accident. Each damper is constructed of specially painted steel, with multiple blades that operate in unison and edge seals to minimize air leakage.

The backdraft damper at the discharge of each fan cooler is a normally closed counter-weighted device that opens automatically when the fan operates. It is designed to remain intact and operable during any loss-of-coolant accident by withstanding an approximate 7 psi air pressure surge over a 10 second period. This damper prevents the pressure surge from damaging the fan-motor assembly.

Two-position shutoff dampers are provided at each fan cooler to divert air flow through the HEPA filters and moisture separators during any loss-of-coolant accident or through the roughing filters during normal operation. The roughing filter dampers are normally open and fail closed. The HEPA filter dampers are normally closed and fail open. Both sets of dampers revert to their fail positions after a safety injection signal.

Each two-position shut-off damper is provided with redundant pneumatic operators that can provide 150 percent of the design operating torque. Each damper assembly is designed to remain intact and operable during any loss-of-coolant accident by withstanding a 3 psi air pressure surge over a 10 second period.

The fan coolers are equipped with pressure relief dampers in the filter enclosures. These dampers are normally closed counter-weighted devices that open progressively as the pressure differential across them exceeds 0.25 psi. In the event of a loss-of-coolant accident, the pressure-relief dampers limit the pressure differential to 3 psi and thus maintain the structural integrity of the fan coolers during the pressure transient.

6.2.2.2.3 Design Evaluation

Range of Containment Protection

The containment fan cooler System provides the design heat removal capacity for the containment following a loss-of-coolant accident assuming that the core residual heat is released to the containment as steam. The system accomplishes this by continuously recirculating the air-steam mixture through cooling coils to transfer heat from containment to service water. Any of the following combinations of equipment provide sufficient heat removal capability to maintain the post-accident containment pressure below the design value:

1. All five containment fan cooler units.

2. Both containment spray loops.

3. Three containment fan cooler units and one containment spray loop.

The performance of the containment fan cooler system in pressure reduction is discussed in Chapter 15.

System Response

Automatic starting of the standby fan cooler units (under design conditions, up to four of the fans and two service water pumps operate during normal power operations for containment ventilation) and the related emergency power equipment is designed so that the required air flow and cooling water flow for an accident condition is reached in approximately 35 seconds. The containment pressure analysis is based on the assumption that there is a delay time of 40 seconds for starting of the fan coolers.

The intended starting sequence is:

		Seconds
1.	Initiation of safety injection signal, including instrument lag	1.2
2.	Starting of diesel generators	11
3.	Starting of last containment fan cooler	35

The water valves and air dampers are actuated to the accident position by closure of the fan cooler low speed breaker.

Single Failure Analysis

A failure analysis for all active components of the system shows that the failure of any single active component will not prevent fulfilling the design function. This analysis is summarized in Table 6.2-7.

The analysis of the loss-of-coolant accident presented in Chapter 15 is consistent with the single failure analysis.

Reliance on Interconnected Systems

The containment fan cooling system is dependent on the operation of the service water system. Cooling water to the coils is supplied from the service water system. Six service water pumps are provided, only two of which are required to operate during the post-accident period.

Shared Function Evaluation

Table 6.2-8 is an evaluation of the main components which have been discussed previously and a brief description on how each component functions during normal operation and during the accident.

Reliability Evaluation of the Fan Cooler Motor

The design of the motor and motor heat exchanger is such that the accident environment is prevented, in a significant sense, from entering the motor winding. When entering in the very limited amount required to equalize motor interior pressure, the incoming atmosphere is directed to the heat exchanger coils where moisture is condensed. If some quantity of moisture should pass through the coil, the motor interior environment would "clean up" since interior air continually recirculates through the heat exchanger.

The motor insulation hot spot temperature is not expected to exceed 113°C even under accident conditions; normal life would be expected with a continuous hot spot of 155°C. The insulation has resistance to moisture, and tests indicate that the insulation system would survive the accident ambient moisture condition without failure. The heat exchanger system of preventing moisture from reaching the winding keeps the winding in much more favorable conditions. In addition, the motors are furnished with an insulation voltage margin beyond the operating voltage of 480 volts.

To prove the effectiveness of the heat exchanger in inhibiting large quantities of the steam air mixture from impinging on the winding and bearings, a full scale motor of the same type was subjected to prolonged exposure to accident conditions. The test exposed the motor to a steam air mixture as well as boric acid and alkaline spray at 80 psig and saturated temperature conditions. Insulation resistance, winding and bearing temperature, relative humidity, voltage and current as well as heat exchanger water temperature and flow were recorded periodically during the test. Following the test the motor was disassembled and inspected to further assure that the unit performed as designed. The post-testing inspection showed no degradation of the motor components (Reference 1). The fan motor bearings are designed to perform in the accident ambient temperature conditions. However, the interior bearing housings are cooled by the heat exchanger. It is expected that bearing temperatures would be 125°C to 140°C, under accident conditions. The heat exchanger is designed using a conservative 0.002 fouling factor.

Throughout the lifetime of the plant, these motors perform the normal heat removal service and are loaded to approximately 275 HP.

Environmental Protection

All of the fan cooler units are located on the operating floor adjacent to the containment wall. The distribution header is located below the operating floor, between the polar crane wall and the containment wall. This arrangement provides missile protection for all components.

System control and instrumentation devices required for post-accident operation are also installed in locations such as to minimize the danger of control loss due to missile damage.

The fan motor enclosures, electrical insulation and bearings are designed for operation during accident conditions. Surfaces in contact with the containment atmosphere are protected against corrosion.

6.2.2.2.4 Inspection and Testing

Inspection

Access is available for visual inspection of the containment fan-cooler components including fans, cooling coils, dampers, and ductwork.

Component and System Testing

Each fan cooling unit was tested after installation for proper flow through the duct distribution system.

The containment fan cooling system is designed such that the components can be tested periodically, and after any component maintenance, for operability and functional performance.

Four of the fan cooling units are in use during normal operation. The fan not in use can be started from the control room to verify readiness. The dampers directing flow through the post-accident filter section can be tested when the fan is running on low speed.

The functional test of the ECCS described in Section 6.3 will demonstrate proper transfer of the fan units in the event of a loss of power. A test signal is used to initiate damper motion and fan starting. This test will verify proper functioning of the air flow switch provided for each fan.

6.2.3 CONTAINMENT ATMOSPHERE IODINE REMOVAL

6.2.3.1 Introduction

The containment spray system is an engineered safety system employed to reduce pressure and temperature in the containment following a postulated loss-of-coolant accident. For this purpose, subcooled water is sprayed into the containment atmosphere through a large number of nozzles from spray headers located in the containment dome.

Because of the large surface area between the spray solution and the containment atmosphere, the spray system also serves as a removal mechanism for fission products postulated to be dispersed in the containment atmosphere. Radioiodine in its various forms is the fission product of primary concern in the evaluation of a loss-of-coolant accident. The major benefit of the containment spray is its capacity to absorb molecular iodine from the containment atmosphere. To enhance this iodine absorption capacity of the spray, the spray solution is adjusted to an alkaline pH which promotes iodine hydrolysis to nonvolatile forms.

According to the known behavior of elemental iodine in highly dilute solutions the hydrolysis reaction

$$I_2 + OH^- \rightleftharpoons HIO + I^-$$

proceeds nearly to completion (Reference 2) at pH > 8. The iodide form is highly soluble, and HIO readily undergoes additional reactions to form iodate.

The overall reaction is:

$$3I_2 + 3H_2O \rightleftarrows 5HI + HIO_3$$

Values for the spray removal half-life of the molecular iodine in a typical containment are on the order of minutes, or less. This makes the spray system a very efficient fission product removal system, in comparison to such alternatives as charcoal filtration systems.

6.2.3.2 Iodine Removal Model

Containment spray performance has been determined using the spray model developed by Westinghouse. This model includes the effects of spray drop size distribution, droplet coalescence, and liquid phase mass transfer resistance. Its use results in conservative values of spray iodine removal constants when compared with test results.

Method of Calculation

In order to eliminate the need of scale-up factors from experimental results to full-sized reactor containments, the size dependent calculations in this model were programmed for discrete size parameters, i.e., the calculations are repeated for incremental height steps, and for 40 different drop-size groups to represent the effects of the drop-size distribution. No significant effect on results was observed by increasing the number of groups. The resulting model with discrete size-dependent parameters has been programmed for a digital computer.

In the computer code, the sprayed volume of the containment is divided into layers of incremental height and area equal to the total sprayed area at any height z. The height-dependent calculations such as drop trajectories and the change in the drop size distribution due to coalescence, are performed for each height step, using the parameters calculated in the previous step as input for the next step.

Drop Size Distribution

The drop-size distribution used in the model is based on data obtained from measurements of the actual size distribution from the Spraco 1713 nozzle for the range of pressure drops encountered during operation of the spray system. The results obtained for 20, 30, 40, and 50 psi pressure drops across the nozzle have been used in this evaluation.

Analysis of these drop-size measurements shows that the drop-size distribution from this nozzle may be represented by a continuous distribution function, which is used as the input to the computer code.

Condensation

As the spray solution enters the high temperature containment atmosphere, steam will condense on the spray drops. The amount of condensation is easily calculated by a mass balance on the drop:

$$mh + m_c h_g = m' h_f$$

where:

m and m' = the mass of the drop before and after condensation, lbs.

m_c = the mass of condensate, lbs.

h = the initial enthalpy of the drop, Btu/lb.

h_g and h_f = saturation enthalphy of water vapor and liquid, Btu/lb.

The increase in each drop diameter in the distribution, therefore, is given by:

$$\left(\frac{d'}{d}\right)^3 = \left(\frac{v}{v_f}\right) \left(\frac{h_g - h}{h_{fg}}\right)$$

where:

v_f = the specific volume of liquid at saturation, ft^3/lb

v = the specific volume of the drop before condensation, ft^3/lb

h_{fg} = the latent heat of evaporation, Btu/lb

h_g = the enthalpy of steam at saturation, Btu/lb

d = the drop diameter, cm before condensation

d' = the drop diameter, cm after condensation

This increase in drop size due to condensation is expected to be complete in a few feet of fall for the majority of drop sizes in the distribution. More detailed calculations by Parsly (Reference 3) show that even for the largest drops in the distribution thermal equilibrium is reached in less than half of the available drop fall height. The change in the drop size distribution due to condensation was conservatively modeled by a step increase to the equilibrium size immediately after the drops emerge from the nozzle.

Drop Trajectories

A description of the actual drop trajectories is required to obtain accurate drop residence times, and to obtain the trajectory angle required for the coalescence calculations described below. These trajectories are obtained by integrating the equations of motion for each drop size.

The equations of motion were integrated numerically, with the drag coefficient being determined iteratively from Reynolds number and terminal velocity.

These calculation yield the following results:

1. Spread and Nozzle Interference

   Trajectory results for a range of drop sizes show that the horizontal velocities of the drops are quickly attenuated. For the smaller drop sizes (<400μ) the trajectory essentially is a straight fall. Even for 1000μ drops, the horizontal velocity component diminished to less than 10 percent of the total velocity in less than 10 feet. The effect of temperature and pressure on drop trajectories has also been calculated. The resulting spray envelope is of smaller diameter at higher temperatures and pressure.

2. Drop Residence Time

   For downward-directed spray nozzles, the initial vertical velocity is higher than the termainal velocity, resulting in a slightly shorter residence time than that calculated with the assumption of terminal velocity. An accurate account of the residence time is obtained from consideration of the actual trajectories followed by the drop.

Correction factors are calculated for each drop size in the spectrum, so that the drop fall-times used for the iodine removal calculations are the actual drop residence times.

A measure of conservatism is added to the drop residence calculations by the use of the drop diameters after condensation. Actually, the drop velocities would have been attenuated to a fraction of the initial nozzle velocity by the time condensation is complete.

Drop Coalescence

This effect will tend to decrease the overall surface-to-volume ratio of the spray, thereby affecting the fission product removal capability of the system. Concern has been centered particularly on the effect of coalescence on scale-up factors applied to data obtained from small-scale experiments. The effects of this phenomenon are accounted for by a mathematical model which is dependent of the containment size. The mathematical model used to account for drop coalescence due to the effects of overlapping spray patterns and due to larger drops overtaking smaller ones shows the number of coalescences to be functions of the collision and coalescence efficiencies, as well as the trajectory angle, drop velocities, drop size, and drop density.

The coalescence efficiency is the probability that a collision will result in the formation of a single larger drop. The collision efficiency describes the probability that two drops on a geometric collision course, (i.e., their centers of motion are separated by a distance less than the sum of the radii of the two drops), will actually collide.

The results calculated with the drop coalescence model show that the smaller drops with diameters near the mode of the distribution are affected most. This is expected, since these sizes have the highest density of drop population. Due to the considerably larger volumes of the larger diameter drops, however, the increase in the larger drop population is not very pronounced.

Mass Transfer

The basic equation for the iodine concentration in the containment atmosphere is derived from a material balance of the elemental iodine in the containment. The iodine removal by the spray system may be expressed by

$$V_c \frac{dC_g}{dt} = -EF(HC_g - C_{L2})$$

V_c = containment free volume in cc

C_g = the iodine concentration in the containment atmosphere, gm/cc

H = the iodine partition coefficient, (gm/liter of liquid)/(gm/liter of gas)

F = the spray flow rate, cc/sec

The resulting change in the drop size distribution is taken into consideration in the mass transfer calculations described below.

The variable E is the absorption efficience, which may also be described as the fractional approach to saturation:

$$E = \frac{C_{L2} - C_{L1}}{C_L^* - C_{L1}}$$

where:

C_{L1} = the iodine concentration in the liquid entering the dispersed phase, gm/cc

C_{L2} = the iodine concentration in the liquid leaving the dispersed phase, gm/cc

C_L^* = the equilibrium concentration in the liquid, gm/cc

This absorption efficiency may be calculated from the time-dependent diffusion equation for a rigid sphere, with the gas film mass transfer resistance as a boundary condition. This mass transfer model was suggested by L. F. Parsly, (Reference 4) who give the solution to the diffusion equation with the above-mentioned boundary condition as:

$$E = 1 - \sum_{n=1}^{\infty} \frac{6Sh^2 \exp(-\alpha_n^2 \theta_f)}{\alpha_n^2 [\alpha_n^2 + Sh (Sh-1)]}$$

where:

SH = is the dimensionless group $\frac{k_g a}{HD_L}$

a = the drop radius, cm

k_g = the gas film mass transfer coefficient, cm/sec

D_L = the liquid diffusivity, cm^2/sec

θ_f = the dimensionless drop residence time

α_n = the eigenvalues of the solution

It is noted that this solution, which applies to the rigid drop model, is based on the assumption that molecular diffusion is the only mechanism for the transport of iodine from the surface to the interior of the drop. Since a high degree of mixing is expected in the drops, particularly in the presence of sizable temperature and concentration gradients, it is apparent that this stagnant drop model presents a conservative approach to the calculation of iodine absorbtion by the drops.

The absorbtion efficiency calculated with the model described above is a function of drop size. The removal constant, λ_s in reciprocal hours, for the entire spray, therefore, is obtained by an appropriate summation over all drop size groups:

$$\lambda_s = \sum_{i=1}^{n} \frac{E_i F_i H}{V_c}$$

6.2.3.3 Experimental Verification Of the Iodine Removal Model

To demonstrate that the ability of the model described above conservatively estimates actual spray performance, the Westinghouse model was applied to the rest runs made at ORNL and BNWL. Comparison of the results of these tests with the above described spray removal model, show the spray removal model to be conservative in all cases.

6.2.3.4 Iodine Removal Evaluation

6.2.3.4.1 Injection Phase Operation

The analysis of iodine removal by containment spray water is based on the assumption that:

1. One of two spray pumps is operating.

2. The emergency core cooling system (ECCS) is operating at its maximum capacity.

The latter assumption includes operation of two safety injection, two low head (RHR) pumps, and two charging pumps, conservatively limits the spray injection phase to 18 minutes. The ECCS is switched to the recirculation mode at the time when approximately 105,000 gallons remain in the refueling water storage tank. Operation of the spray system is continued for another 47 minutes in the injection mode, until the remaining 105,000 gallons are depleted. Thus the spray pumps will operate for a minimum of 60 minutes with fresh spray solution.

An eductor system, described in Section 6.2.2.1 is used to maintain the spray solution at a pH of 10.0 to ensure efficient and rapid removal of the iodine from the containment atmosphere.

The performance of the spray system was conservatively evaluated at the peak temperature and pressure resulting from a double-ended rupture of the reactor coolant system, with no credit taken for the subcooling of the ECCS. These pressure and temperature conditions, listed in Table 6.2-9, were assumed throughout the injection phase operation of the containment spray system.

The spray flow rate of 2460 gpm per pump, used in the calcualtion of λ, corresponds to this back-pressure in the containment.

Since this peak pressure condition is expected to exist at most for a few minutes, and since both mass transfer parameters and spray flow rate improve with decreasing pressure, an appreciable conservatism is added to this evaluation by this assumption.

The removal constant for the spray system, calculated with the model described and with the above mentioned assumptions is 31.0 hrs^{-1}.

6.2.3.4.2 Recirculation Phase

Under the assumptions stated in Section 6.2.3.4.1, the spray recirculation phase would be initiated 60 minutes after the start of safety injection. At this time, sump water would have reached its minimum equilibrium pH of 8.5. Although the iodine removal capability remains high under these conditions, no credit is taken for any iodine removed after the decontamination factor (DF) of 100 is reached during the injection phase.

During the spray recirculation phase the sump pH will remain at 8.5 since no additional water is added to the system.

6.2.3.4.3 Re-Evolution of Iodine

Any re-evolution of dissolved iodine from the sump to the containment atmosphere is dependent on the concentration gradient between the liquid and vapor phases. The equilibrium between these concentrations is given by the partition coefficient, H, and, therefore, is a function of iodine concentration, pH, and temperature. A plot of the sump alkalinity, as a function of the time after the start of injection, is shown in Figure 6.2.14. The resulting partition coefficient, based on a constant iodine concentration equal to the concentration corresponding to a DF of 100 in the containment atmosphere, is shown in Figure 6.2-15 for sump temperatures of 150°F and 212°F. The equations given by Eggleton (Reference 5) were used to calculate the partition coefficient.

Although the iodate reaction, i.e.

$$3I_2 + 3H_2O \rightleftarrows IO_3^- + 5I^- + 6H^+$$

is expected to contribute significantly (Reference 5) to the iodine partition at the high sump pH values, this reaction is conservatively neglected in these calculation.

From Figure 6.2-15 it is apparent that the partition coefficient of 4.3 x 10^3, which is required to maintain a DF of 100 in the vapor phase, is exceeded at all times during the recirculation phase.

6.2.4 CONTAINMENT ISOLATION SYSTEM

The containment isolation system provides the means of isolating the containment atmosphere and reactor coolant system as required to prevent the release of radioactivity to the outside environment in the event of a loss-of-coolant accident.

6.2.4.1 Design Bases

The following conditions and definitions are used in the design of the containment isolation system to assure that subsequent to an accident, there will be two barriers between the atmosphere outside the containment and the containment atmosphere.

1. The design parameters of all piping and connected equipment within the isolated boundaries are equal to or greater than the design basis accident environment of the containment, 47 psig, 271°F.

2. All valves and equipment which are isolation barriers are protected against missiles and water jets, both inside and outside the containment.

3. Lines which, due to safety considerations, must remain in service subsequent to certain accidents have as a minimum one manual isolation valve outside the containment.

4. All isolation valves and equipment are designed to Class I seismic criteria.

5. The two barriers may consist of:

   (a) two closed piping systems or vessels, one inside and one outside the containment, (b) two automatic isolation valves, one inside and one outside the containment, (c) an automatic isolation valve inside the containment and a closed system outside the containment, or (d) an automatic isolation valve outside the containment and a closed system inside the containment.

6. A check valve on an incoming line or a normally closed valve is considered an automatic valve.

6.2.4.2 System Description

The following four classes of piping arrangement are provided in the containment isolation system. These classes are illustrated in Figure 6.2-16.

Class A

Class A piping is connected to a normally closed system outside the containment, and is separated from the reactor coolant system and the containment atmosphere by a closed system inside the containment,

For Class A piping no additional valves are required for isolation.

Class B

Class B piping is connected to open systems outside the containment, and is connected to the reactor coolant system or is open to the containment atmosphere.

For Class B piping the following is provided, as a minimum, for isolation:

1. Incoming Lines: Two auto-trip valves (one inside, one outside), or a check valve inside and an auto-trip valve outside.

2. Outgoing Lines: Two auto-trip valves (one inside, one outside).

Class C

Class C piping is connected to open systems outisde the containment, and is separated from the reactor coolant system and the containment atmosphere by a closed system.

For Class C piping, the following is provided, as a minimum, isolation:

1. Incoming Lines: One check valve or auto-trip valve outside. No valve inside.

2. Outgoing Lines: One auto-trip valve outside. No valve inside.

Class D

Class D piping is connected to a closed system outside the containment, and is connected to the reactor coolant system or is open to the containment atmosphere.

For Class D piping the following is provided, as a minimum, isolation:

a. Incoming Lines: One auto-trip valve or check valve inside. No valve outside.

b. Outgoing Lines: One auto-trip valve inside. No valve outside.

In addition to Classes B and C, for lines 1-inch nominal pipe size and larger which penetrate the containment and which are connected to the reactor coolant system, at least two valves are provided inside the containment. The valves are normally closed or have automatic closure. For incoming lines, check valves are permitted and are considered as automatic. Piping which penetrates the containment, but which represents normally closed lines, also falls under this criterion. In this case, manual isolation valves are acceptable.

In order to be considered a "closed" system inside containment, a system must meet the following requirements:

1 Does not communicate with either the reactor coolant system or the containment atmosphere.

2. Safety classification same as for engineered safety systems.

3. Must withstand external pressure and temperature equal to containment design pressure and temperature.

4. Must withstand accident transient and environment.

5. Must be missile protected.

In order to be considered a "closed system outside containment", a system must meet the following requirements:

1. Does not communicate with the atmosphere outside the containment.

2. Safety classification same as for engineered safety systems.

3. Internal design pressure and temperature must be at least equal to containment design pressure and temperature.

For incoming lines to the containment, check valves are used whenever an additional barrier is provided. Use of check valves in this service is confined to either liquid lines or lines that are closed outside the containment. These check valves shut under a differential pressure when the higher pressure is on the containment side of the check valve.

These isolation valving arrangements were designed in accordance with AEC proposed General Design Criteria published in 1967, which were in effect at the construction permit stage. The valving arrangements that deviate from AEC General Design Criteria 55, 56, and 57 dated July 7, 1971 are the following:

1. Residual heat removal connections between the reactor coolant system and the RHR pumps discharge. Redundant isolation protection is provided by a normally closed motor operated valve inside the containment and the closed system (RHR) outside the containment.

2. Seal water supply line from the seal water injection filters to the reactor coolant pump seals. Redundant isolation protection is provided by a check valve inside the containment and the closed system (CVCS) outside the containment.

3. Safety injection recirculating suction line from the containment sump to the suction of the RHR pumps. Redundant isolation protection is provided by normally closed motor operated valves inside protective chambers considered part of containment and the closed system (RHR) outside the containment.

4. Containment pressure instrument lines. (See below)

5. The main feedwater lines are provided with one stopcheck valve (BF 22) outside containment. On Unit 2 these valves include remote-manual motor operators.

Instrument Lines

Instrument lines which penetrate the containment are the following:

a. The containment pressure instrument used to initiate safeguards consists of four instrument lines penetrating the containment. Each line consists of a sealed, filled measuring system whose isolation consists of a diaphragm type sensor which separates the containment atmosphere from the seal fluid and another diaphragm in the transmitter which separates the seal from the atmosphere outside the containment.

b. The containment air sample radiation monitor normal inlet and outlet sample lines are each equipped with two automatic trip valves, one inside and one outside the containment, which close upon receipt of a containment isolation phase A signal. The backup inlet and outlet sample lines are normally closed and under administrative control with two remote operated isolation valves, one inside and one outside the containment for each line.

c. The pressurizer dead-weight prressure calibrator has a single line penetrating the containment. Isolation is accomplished with two manual valves located just outside the containment. These manual-valves are normally closed and are opened only under administratively controlled conditions.

d. Three lines penetrate the containment for instrumentation required for leak rate testing. Each line is isolated with two manual valves, one inside and one outside containment. These valves are normally closed and under administrative control.

These provisions meet the requirements of Regulatory Guide 1.11.

Containment Isolation Valve Summary

Table 6.2-10 lists the major piping penetrations through the reactor containment for each fluid system and summarizes the specific isolation provisions for each penetration. Valve positions during normal operation, shutdown, and accident conditions are also listed. Isolation valving arrangements are shown graphically in Figures 6.2-17 through 6.2-46.

The 20 inch inside diameter fuel transfer tube between the refueling canal inside the containment and the fuel transfer pool is sealed with a blind flange inside the containment. The terminus of the tube outside the containment is closed by a gate valve.

The equipment hatch (door) is under administrative control to assure that it is properly closed and sealed whenever containment integrity is required. No instrumentation is provided for the equipment hatch.

Actuation Provisions

Containment isolation is actuated under the following conditions:

1. A safety injection signal generates the containment isolation signal (Phase A), which actuates most containment isolation valves. The Phase A isolation signal closes all trip valves which are located in lines which are connected to the reactor coolant loops and penetrate the containment, thereby preventing loss of reactor coolant through the lines in which the automatic trip valves are located. Normally closed motor operated containment isolation valves in the safety injection systems are opened by the safety injection signal to permit safety injection system operation.

2. A rise in containment pressure to the high containment pressure set point also generates the Phase A isolation signal.

3. A further rise in containment pressure, indicating a major loss-of-coolant accident, results in a containment high-high pressure signal which generates both the containment spray and containment isolation Phase B signal. All normally open lines which penetrate the containment which are not closed by the Phase A isolation signal are closed by the Phase B isolation signal. Normally closed motor operated containment spray systems valves are opened by the high-high containment pressure signal to permit containment spray system operation.)

Lines which penetrate the containment and are normally closed by means of valves under administrative control are assumed to be already closed and do not receive an isolation signal.

Automatic containment isolation valves can be actuated from the control room if any of the valves fail to close in response to the Phase A or Phase B isolation signal.

6.2.4.3 Design Evaluation

The following provisions apply to all lines penetrating the containment to prevent inadvertent opening of these lines to the atmosphere outside the containment:

1. Automatic isolation valves can be opened only upon cessation and manual reset of the actuating signal.

2. Automatic isolation valves are capable of manual actuation from the control room with the limitations for re-opening of the valve noted in item 1 (above).

3. Remote manual valves are operated only under administrative control.

4. Manual valves are operated under administrative control.

5. Check valves open only when the fluid pressure is higher on the side outside the containment.

6. The design pressure of all piping and connecting components within the isolation boundary is not less than the design pressure of the containment, 47 psig.

7. Automatic valves, once opened by a safety injection signal, can only be closed upon cessation and manual reset of the actuating signal.

For Items 1, 2, 3, and 4, (above), and for flanged closures, specific administrative procedures define the positioning of these closures in the containment isolation system during normal operation, shutdown, and accident conditions.

Instrumentation and adjunct control circuits associated with automatic isolation valve closure are fail safe (initiate closure) upon loss of voltage and/or control air. The isolation valves are air to open, spring return, diaphragm operated; thus providing a fail safe design. The automatic isolation valves inside the containment will function properly under all accident conditions. The isolation valve closing force is provided by a spring; control air is applied to the diaphragm of the isolation valve to open it. To close the isolation valve, an electrically operated solenoid valve located in the air supply line to the isolation valve operator vents the control air applied to the isolation valve diaphragm through the solenoid to the containment atmosphere, causing the spring to close the automatic isolation valve. Since the spring side of the isolation valve diaphragm is also vented to the containment atmosphere, the spring will force the valve to close when the solenoid vents the air line. Circuits which control redundant automatic valves are redundant in the sense that no single failure will preclude isolation. Means are provided to periodically test the functioning of the automatic isolation equipment such as the set point of sensors, speed of response, and operability of fail safe features. The containment isolation instrumentation is discussed in Chapter 7.

Valves used for containment isolation are capable of tight shutoff against gas leakage from containment design pressure down to zero psig.

Isolation valves and equipment are protected from missiles and water jets originating from the reactor coolant system. Missile protection for isolation valves, actuators and controls is provided by locating isolation valves between the polar crane wall and the containment wall or locating isolation valves outside the containment structure. The pressure sensing devices which detect high containment pressure are located outside the containment. Location of the pressure sensing devices outside the containment protects them from missiles developed by a loss-of-coolant accident. Isolation valves and piping or vessels which provide one of the isolation barriers outside the containment are similarly protected.

Radiological Basis for Isolation Valve Closure Time

The closure times for the containment isolation valves are such that, in the event of a loss of coolant accident, no significant release of radioactivity to the environment through containment penetrations can occur.

In evaluating possible radioactive releases during a LOCA, the only release pathways considered were through those normally open penetrations associated with open systems outside the containment which are connected to the Reactor coolant system or are open to the containment atmosphere (see Table 6.2-10).

A loss of off-site power was assumed coincident with a LOCA. The diesel generators were assumed to be ready for loading in 11 seconds. The closure time for motor operated valves is 10 seconds. Therefore, the total closing time for these valves is 21 seconds. It is conservatively assumed that these valves remain completely open for the time required to activate and completely close them.

The closure time for air operated valves is conservatively estimated to be 10 seconds. Operation of these valves is initiated when a containment pressure of 4.0 psig is reached. A conservative estimate of the time required to attain this pressure, assuming a double ended cold break, is 3 seconds. Therefore, the total closing time for these air operated valves is 13 seconds. One exception is the isolation valve for containment pressure - vacuum relief. This valve has a closure time of 2 seconds, resulting in a total closing time of 5 seconds for this analysis.

The activity released to the containment during the time required to close all isolation valves is limited to that contained in the Reactor Coolant System prior to the accident. This is based on the time required to close the isolation valves being sufficiently small that no clad perforation would occur before the valves were completely closed.

If it is assumed that the entire reactor coolant activity inventory is instantaneously released to the containment, the airborne activity concentration would initially be at the levels indicated in Table 6.2-11. 50 percent plateout of halogens was assumed in the calculation. The maximum activity possible for release through the isolation valves was then determined by conservatively estimating the maximum possible mass flow rate through each isolation valve.

Using the off-site dose calculational methods presented in Chapter 15, off-site thyroid exposures of 0.028 rem at the minimum exclusion radius and 0.0023 rem at the low population zone radius were calculated. Off-site whole body gamma kexposures of 0.00026 rem at the minimum exclusion radius and 0.00002 rem at the low population zone radius were calculated. Beta skin exposures were calculated to be 0.00066 rem at the minimum exclusion radius and 0.00005 rem at the low population zone radius. These exposure values are well below the values given in Table 15.3-12 and 15.3-13 of total LOCA doses calculated in Chapter 15, which themselves are within the guideline values of 10lCFR100.

Hence, it is concluded that the containment isolation valve closure times are sufficiently short that there is no undue risk to the health and safety of the public.

6.2.4.4 Tests and Inspections

Preoperational Tests

Preoperational tests were performed on all valves in lines which penetrate the reactor containment and perform a containment isolation function to verify operability and leaktightness.

Valve operability testing was conducted prior to leakage testing. Each isolation valve was tested to demonstrate proper closure of normally open valves (or opening and closing of normally closed valves) upon receipt of an isolation signal. Closure of containment isolation valves was accomplished by normal operation and without any preliminary exercising or adjustment.

Valve leakage testing was performed by local pressurization in accordance with the applicable requirements of 10CFR50, Appendix J, "Primary Reactor Containment Leakage Testing for Water Cooled Power Reactors", for Type C tests. Valves were pressurized with air or nitrogen to a pressure of 47 psig. Where practical, pressure was applied in the same direction as the valve would experience during performance of its safety function.

Valve leakage was determined by measurement of the rate of pressure loss or by the flowrate of makeup air or nitrogen required to maintain test pressure.

The containment integrated leakage rate test procedure identified vent and drain valves which were opened in order to ensure exposure of the system piping penetrating containment to the foil containment test pressure differential. Certain lines in the service water, component cooling water, and residual heat removal systems are required for containment environmental control or decay heat removal and were not included in the integrated leakage rate test. The isolation valves in these lines were tested separately using a Type C test and any detected leakage was added to the Type A containment integrated leakage rate test results.

The combined leakage rate for the isolation valves and the double penetrations was limited to less than 0.06 percent of the containment free volume per day.

Periodic Tests

Periodic operability and leakage tests on isolation valves will be conducted throughout the lifetime of the plant according to the schedule specified in 10CFR50, Appendix J, "Primary Reactor Containment Leakage Testing for Water Cooled Power Reactors." The periodic isolation valve tests will be performed in accordance with the requirements for preoperational testing.

Tables 6.2-12 and 6.2-13 identify those containment isolation valves that will and will not be subjected to periodic Type C leak rate testing, respectively.

The piping arrangement provided to test the leaktightness of each isolation valve consists of a monitoring tap on the main line downstream of the valve. To test for valve tightness, the main piping section upstream of the valve is pressurized and evidence of leakage is checked at the downstream tap. When not in use, the monitoring lines are valves closed at the open end. Test pressures will be applied from the same direction as the pressure existing when the valve is required to perform its safety function.

The operability of the majority of containment isolation valves is fully testable at power except for those valves lised below. The valves are checked for circuit continuity up to and including the valve actuator during power operation by use of the SSPS output test cabinet.

Containment isolation valves: CA-330, SJ-12, SJ-13, CV-7 CV-68, CV-69,
CV-116, CV-284, CC-117, CC-118, CC-131, CC-136, CC-187 and CC-190

Main steam isolation valves: MS-167

Feedwater isolation valves: BF-19 and BF-40

All other valves can be operationally tested at power from the SSPS output test cabinet to simulate accident operating conditions and verify the valve closing logic. All valves can be tested from the main control console as operating conditions permit.

6.2.5 COMBUSTIBLE GAS CONTROL

6.2.5.1 Hydrogen Production

Hydrogen accumulation in the containment atmosphere following the design basis accident can be the result of production from several sources. The potential sources of hydrogen are the zirconium-water reaction, corrosion of construction materials, and radiolytic decomposition of the emergency core cooling solution. The latter source, solution radiolysis, includes both core solution radiolysis and sump solution radiolysis.

6.2.5.1.1 Methods of Analysis

The quantity of zirconium which reacts with the core cooling solution depends on the performance of the emergency core cooling system. The criteria for evaluation of the emergency core cooling system requires that the zircaloy-water reaction be limited to 1 percent by weight of the total quantity of zirconium in the core. Emergency core cooling system calculations have shown the zircaloy-water reaction to be less than 0.1 percent, much less than required by the criteria.

The use of aluminum inside the containment is limited, and is not used in safety related components which are in contact with the recirculating core cooling fluid. Aluminum is much more reactive with the containment spray alkaline borate solution than other plant materials such as galvanized steel, copper and copper nickel alloys. By limiting the use of aluminum the agregate source of hydrogen over the long term is essentially restricted to that arising from radiolytic decomposition of core and sump water. The upper limit rate of such decomposition can be predicted with ample certainty to permit the design of effective countermeasures.

It should be noted that the zirconium-water reaction and aluminum corrosion with containment spray are chemical reactions and thus essentially independent of the radiation field inside the containment following a loss of coolant accident. Radiolytic decomposition of water is dependent on the radiation field intensity. The radiation field inside the containment is calculated for the maximum credible accident in which the fission product activities given in TID-14844 (Reference 6) are used.

Two hydrogen generation calculations are performed; one using the Westinghouse model (Reference 7), the other using the AEC model discussed in Safety Guide 7. (Reference 8)

6.2.5.1.2 Zirconium-water reaction

The zirconium-water reaction is described by the chemical equation:

$$Zr + 2H_2O \rightarrow Zr\,O_2 + 2H_2 + \text{Heat}$$

The hydrogen generation due to this reaction will be completed during the first day following the loss of coolant accident. The Westinghouse model assumes a 2 percent zirconium-water reaction and the AEC model assumes a 5 percent zirconium-water reaction. The hydrogen generated is assumed to be realeased immediately to the containment atmosphere.

6.2.5.1.3 Corrosion of Plant Materials

Oxidation of metals in aqueous solution results in the generation of hydrogen gas as one of the corrosion products. Extensive corrosion testing has been conducted to determine the behavior of various metals used in the containment in the emergency core cooling solution at design basis accident conditions. Metals tested include Zircaloy, Inconel, aluminum alloys, coppernickel alloys, carbon steel, galvanized carbon steel, and copper. Tests conducted at ORNL (Reference 9 and 10) have also verified the compatibility of the various metals (exclusive of aluminum) with alkaline borate solution. As applied to the quantitative definition of hydrogen production rates, the results of the corrosion tests have shown that only aluminum will corrode at a rate that will significantly add to the hydrogen accumulation in the containment atmosphere.

The corrosion of aluminum may be described by the overall reaction:

$$2\ Al + 3\ H_2O \rightarrow Al_2O_3 + 3\ H_2$$

Therefore, three moles of hydrogen are produced for every two moles of aluminum that is oxidized. (Approximately 20 standard cubic feet of hydrogen for each pound of aluminum corroded).

The time-temperature cycle (Table 6.2-14) considered in the calculation of aluminum corrosion is based on a conservative step-wise representation of the postulated post-accident containment transient. The corrosion rate design curve shown in Figure 6.2-47. Aluminum corrosion data points include the effects of temperature, alloy, and spray solution conditions. Based on these corrosion rates and the aluminum inventory given in Table 6.2-15, the contribution of aluminum following the design basis accident has been calculated. For conservative estimation, no credit was taken for protective shielding effects of insulation or enclosures from the spray, and complete and continuous immersion was assumed.

Calculations based on Safety Guide 7 are performed by allowing an increased corrosion rate during the final step of the post-accident containment temperature transient (Table 6.2-14) corresponding to 200 mils/yr (15.7 $mg/dm^2/hr$). The corrosion rates earlier in the accident sequence are the higher rates determined from Figure 6.2-47.

Hydrogen is also produced through the corrosion of zinc inside containment. Sources of zinc within containment are the following:

1. Cable trays and hangers

2. Conduit

3. Junction Boxes

4. Ductwork

These components are galvanized with approximately 2 oz/ft^2 of zinc, and the surface area and weight of zinc associated with each is as follows:

Item	Sq. Ft.	Weight of Zn or Zinc
1. Cable trays and hangers	35,000	4,375 lbs.
2. Conduit	15,000	1,875 lbs.
3. Junction Boxes	1,500	188 lbs.
4. Ductwork	35,000	4,375 lbs.
		10,813 lbs.

The corrosion rate of zinc as a function of temperature is shown in Figure 6.2-48.

The experimental data used as the basis for hydrogen production due to zinc was obtained from Reference 11.

6.2.5.1.4 Radiolysis

Water radiolysis is a complex process involving reactions of numerous intermediates. However, the overall radiolytic process may be described by the reaction:

$$H_2O \Longleftrightarrow H_2 + 1/2\ O_2$$

Of interest here is the quantitative definition of the rates and extent of radiolytic hydrogen production following the design basis accident.

An extensive program has been conducted by Westinghouse to investigate the radiolytic decomposition of the core cooling solution following the design basis accident. In the course of this investigation, it became apparent that two separate radiolytic environments exist in the containment at design basis accident conditions. In one case, radiolysis of the core cooling solution occurs as a result of the decay energy of fission products in the fuel. In the other case, the decay of dissolved fission products, which have escaped from the core, results in the radiolysis of the sump solution. The results of these investigations are discussed in Reference 12.

Core Solution Radiolysis

As the emergency core cooling solution flows through the core, it is subjected to gamma radiation by decay of fission products in the fuel. This energy deposition results in solution radiolysis and the production of molecular hydrogen and oxygen. The initial production rate of these species will depend on the rate of energy absorption and the specific radiolytic yields.

The energy absorption rate in solution can be assessed from knowledge of the fission products contained in the core, and a detailed analysis of the dissipation of the decay energy between core materials and the solution. The results of Westinghouse studies show essentially all of the beta energy will be absorbed within the fuel and cladding and that this represents approximately 50 percent of the total beta-gamma decay energy. This study shows further that of the gamma energy, a maximum of 7.4 percent will be absorbed by the solution in core. Thus, an overall absorption factor of 3.7 percent of the total core decay energy ($\beta + \gamma$) is used to compute solution radiation dose rates and the time-integrated dose. Table 6.2-16 presents the total decay energy ($\beta + \gamma$) of a reactor core, which assumes a full power operation time of 830 days prior to the accident. For the maximum credible accident case, the contained decay energy in the core accounts for the assumed TID-14844 release of 50 percent halogens and 1 percent other fission products. To be conservative, the noble gases have been assumed to remain in the core, whereas in reality, the noble gases are assumed by the TID-14844 model to escape to the containment vapor space where little or no water radiolysis would result from decay of these nuclides.

The radiolysis yield of hydrogen in solution has been studied extensively by Westinghouse and ORNL. The results of static capsule tests conducted by Westinghouse indicate that hydrogen yields much lower than the maximum of 0.44 molecules per 100 ev would be the case in-core.

With little gas space to which the hydrogen formed in solution can escape, the rapid back reactions of molecular radiolytic products in solution to reform water is sufficient to result in very low net hydrogen yields.

However, it is recognized that there are differences between the static capsule tests and the dynamic condition in core, where the core cooling fluid is continuously flowing. Such flow is reasoned to disturb the steady-state conditions which are observed in static capsule tests, and while the occurrence of back reactions would still be significant, the overall net yield of hydrogen would be somewhat higher in the flowing system.

The study of radiolysis in dynamic systems was initiated by Westinghouse, which formed the basis for experimental work performed at ORNL. Both studies clearly illustrate the reduced yields in hydrogen from core radiolysis, i.e., reduced from the maximum yield of 0.44 molecules per 100 ev. These results were recently published (Reference 12 and 13).

For the purpose of this analysis, the calculations of hydrogen yield from core radiolysis are performed with the very conservative value of 0.44 molecules per 100 ev. That this value is conservative and a maximum for this type of aqueous solution and gamma radiation is confirmed by many published works. The Westinghouse results from the dynamic studies show 0.44 to be a maximum at very high solution flow rates through the gamma radiation field. The referenced ORNL (Reference 13) work also confirms this value as a maximum at high flow rates. A. O. Allen (Reference 14) presents a very comprehensive review of work performed to confirm the primary hydrogen yield to be a maximum of 0.44 to 0.45 molecules per 100 ev.

On the foregoing basis, the production rate and total hydrogen produced from core radiolysis, as a function of time, has been conservatively estimated for the maximum credible accident case.

Calculations based on Safety Guide 7 assume a hydrogen yield value of 0.5 molecules per 100 ev and that 10 percent of the gamma energy produced from fission products in the fuel rods is absorbed by the solution in the region of the core.

Sump Solution Radiolysis

Another potential source of hydrogen assumed for the post-accident period arises from water contained in the reactor containment sump being subjected to radiolytic decomposition by fission products. In this consideration, an assessment must be made as to the decay energy deposited in the solution and the radiolytic hydrogen yield, much in the same manner as given above for core radiolysis.

The energy deposited in solution is computed using the following basis:

1. For the maximum credible accident, a TID-14844 release model is assumed where 50 percent of the total core halogens and 1 percent of all other fission products, excluding noble gases, are released from the core to the sump solution.

2. The quantity of fission product release is equal to that from a reactor operating at full power for 830 days prior to the accident.

3. The total decay energy from the released fission products, both beta and gamma, is assumed to be fully absorbed in the solution.

Within the assessment of energy release by fission products in water, account is made of the decay of halogens, and a separate accounting for the slower decay of the 1 percent other fission products. To arrive at the energy deposition rate and time-integrated energy deposited, the contribution from each individual fission product class was computed. The overall contributions from each of the two classes of fission products is shown in Table 6.2-17.

The yield of hydrogen from sump solution radiolysis is more nearly represented by the static capsule tests performed by Westinghouse and ORNL with the alkaline sodium borate solution. The differences between these tests and the actual conditions for the sump solution, however are important and render the capsule tests conservative in their predictions of radiolytic hydrogen yields.

In this assessment, the sump solution will have considerable depth, which inhibits the ready diffusion of hydrogen from solutions, as compared to the case with shallow-depth capsule tests. This retention of hydrogen in solution will have a significant effect in reducing the hydrogen yields to the containment atmosphere. The build-up of hydrogen concentration in solution will enhance the back reaction to formation of water and lower the net hydrogen yield, in the same manner as a reduction in gas to liquid volume ratio will reduce the yield. This is illustrated by the data presented in Figure 6.2-49 for capsule tests with various gas to liquid volume ratios. The data show a significant reduction in the apparent or net hydrogen yield from the published primary maximum yield of 0.44 molecules per 100 ev. Even at the very highest ratios, where capsule solution depths are very low, the yield is less than 0.30, with the highest scatter data point at 0.39 molecules per 100 ev.

With these considerations taken into account, a reduced hydrogen yield is a reasonable assumption to make for the case of sump radiolysis. While it can be expected that the yield will be on the order of 0.1 or less, a conservative value of 0.30 molecules per 100 ev has been used in the maximum credible accident case.

Calculations based on Safety Guide 7 do not take credit for a reduced hydrogen yield in the case of sump radiolysis and a hydrogen yield value of 0.5 molecules per 100 ev has been used.

6.2.5.1.5 Coatings

The use of zinc-rich protective coatings for application on carbon steel components in a nuclear reactor containment has been evaluated from the standpoint of hydrogen generation during the post DBA period. The zinc-rich coatings afford resistance of the steel substrate to corrosion caused by accidental spillage, environmental agents and design basis accident (DBA) conditions of temperature, moisture and chemistry. Tests conducted by Westinghouse (Reference 15) and the Oak Ridge National Laboratory (Reference 16) demonstrated that the coating systems recommended by Westinghouse for use in the reactor containment are virtually unaffected when exposed to DBA test conditions.

Westinghouse conducted tests to determine the extent of hydrogen generation during gamma irradiation of the type topcoating (Phenoline 305 by Carboline Co., St. Louis, Missouri) used at AEP. The tests simulated the long-term post-accident chemistry and temperature conditions. The test results showed conclusively that no hydrogen was generated above the level for solution radiolysis.* The protective coating did not contribute to the hydrogen production in the post-accident environment.

6.2.5.1.6 Chemical and Volume Control System

The source of hydrogen from the chemical and volume control system is automatically cut-off upon receipt of a safety injection signal.

6.2.5.1.7 Results

The results of the calculations for hydrogen production and accumulation from zirconium-water reactions, aluminum corrosion and radiolytic decomposition of core and sump solution are shown in Figures 6.2-50, 6.2-51, 6.2-52 and 6.2-53.

* Testing was performed in a gamma irradiated environment with simulated post-accident chemistry and temperature conditions. The amount of hydrogen produced using this test setup was the same irrespective of whether the Phenoline 305 sample was in or out of the test chamber.

Figures 6.2-50 and 6.2-51 show the hydrogen production rate as a function of time following a loss-of-coolant accident up to 100 days for the maximum credible accident. Similar information for the first 10 days is shown in Figure 6.2-54.

Figures 6.2-52 and 6.2-53 show the total quantity of hydrogen accumulated in the containment as a function of time for the maximum credible accident case up to 100 days. The contribution of the individual source is also shown (note that zinc corrosion is not included).

Figure 6.2-55 shows the hydrogen production rate from aluminum and zinc corrosion for the first ten days following a LOCA. Figure 6.2-56 shows the hydrogen concentration in containment as a function of time for various conditions of hydrogen recombiner operability (the hydrogen source from zinc corrosion is included in this figure).

Total hydrogen accumulated from all sources inside containment was reanalyzed following the TMI accident to show compliance with 10CFR 50.44. Figure 6.2-57 shows the analysis results for all combinations of operating recombiners. As is evident, the limiting hydrogen concentration of 4 volume percent (Regulatory Guide 1.7) is satisfied with operation of one recombiner.

6.2.5.2 Hydrogen Control

Potential accumulation in the post-accident environment is controlled by electric hydrogen-oxygen recombiners.

The electric recombiner uses electric heating elements to elevate the temperature of the containment atmosphere passing through it to a level where hydrogen-oxygen recombination can take place. The recombiner works by drawing in the containment atmosphere by natural convection. The flow path through the recombiner is shown in Figure 6.2-58.

As the atmosphere is passed over the heaters, any hydrogen in it is recombined with oxygen to form steam. This processed gas is then mixed with containment atmosphere in a plenum above the heaters before it is returned to the containment.

The decision as to when to operate the electric recombiners is based on containment air samples which are analyzed for hydrogen in the radiochemical laboratory. The recombiner should be started within approximately 24 hours following a LOCA to limit potential hydrogen concentration to a safe value. Once started, the recombiner can be left on permanently or can be cycled as hydrogen generation rates decrease with time.

6.2.5.2.1 Hydrogen Recombiner Description

There are two electric recombiners located in the upper containment compartment. The recombiners are Seismic Class I, redundant, physically separated, with each recombiner equally capable of performing the design function. Each recombiner consists of an outer housing with inlet ducts and an internal housing which contains the electric heating units. The inner housing contains an orifice which has been sized to ensure a minimum flow of not less than 100 scfm.

The electric recombiner operates on the natural convection developed with heat produced by the electric heaters to induce flow through the unit. The device is operated entirely in a passive mode and requires no moving parts for its operation.

In the event of a loss-of-coolant accident, containment atmosphere is processed by the hydrogen recombiners and fan coolers, which discharge to a common duct system through which processed atmosphere is distributed throughout the containment. The flow path of the containment atmosphere after being processed by the fan coolers assures that mixing occurs below the operating deck of the containment. Above the operating deck, mixing is accomplished by air discharged from the ducts equally spaced around the containment wall. Each of the duct outlets discharges processed air at the rate of 15,000 scfm into the containment dome. This mixing of cool air and the displacement of the hydrogen from the dome area to the operating deck allows the hydrogen to be processed by the hydrogen recombiners.

Each recombiner has a separate control panel, transformer, and fuses located outside the containment in the auxiliary building. Each control panel consists of a switch to actuate the recombiner and sufficient instrumentation to assure that the recombiner is receiving proper power.

The recombiners are designed to operate at total pressures in the range of 0 to 5 psig. Equipment inside the containment will withstand, without impairment of function, exposure to the design temperature and pressure transient in the containment, and will be resistant to the chemical and radiation environment of the post-accident containment as well. Components external to containment incorporate the following features for operational safety and reliability.

1. Alarms to indicate inadequate power to each recombiner,

2. Capability to test the system at any time by a complete activation of either or both recombiners. This test can be conducted from operating stations outside the containment, although direct access to the units is permissible during power operation,

3. System redundancy so that no single component failure can disable both recombiners,

4. No active components inside the containment.

Instruments, controls, and suitable panels are provided to perform all these functions in a safe and reliable manner. Radiation levels in the vicinity of the control panel after the maximum hypothetical accident (TID-14844 model source levels) will permit required access. The following features are incorporated in the control system and panel design to ensure operational safety and reliability:

1. A separate control panel for each recombiner.

2. Physical and functional separation of redundant features such that no single failure can invalidate both features.

3. Separate electric power supply and circuit protection equipment for each recombiner.

A detailed description of the electric recombiner is given in Reference 17.

6.2.5.2.2 Recombiner Test Program

Preliminary test results from the initial Waltz Mill experiments showed that electric recombination was entirely successful for air atmospheres containing from 0.15 to 3.8 percent hydrogen (Reference 18). These tests also showed that contamination on the surface of the electric heating elements will not effect the efficiency of recombination of hydrogen and oxygen.

Tests on a full size prototype of the electric recombiner were conducted at Westinghouse Electric Corporation to:

1. Demonstrate that the recombiner operates satisfactorily in range of inlet gas concentrations.

2. Demonstrate the effect of varying inlet temperature.

3. Show absence of recirculation from the recombiner outlet to inlet in the combined presence of simulated containment sprays and the air currents from recirculation fans.

4. Confirm recombiner flow.

5. Confirm power requirements, sheath temperature, and system heat balance.

During the test program, the recombiner orifice was sized to assure a minimum flow through the unit of 100 scfm.

The results of the initial development and testing of an electric hydrogen recombiner, as well as its calculated performance in PWR containments is given in Reference 18. The design requirements, design performance characteristics, the results of proof of principle tests, and the results of tests on a full size prototype recombiner unit are given in Reference 17. The test results demonstrate that the electric recombiner will operate satisfactorily on a scale suitable for use in the Salem plant for control of post-accident hydrogen accumulation.

Vibration monitoring was performed during the pre-operational test program in order to verify that the hydrogen recombiners are not subjected to excessive vibrations as a result of fan coolers operation.

6.2.5.2.3 Recombiner In-service Testing

Because the recombiner has been completely proof tested during the prototype tests, proof of in-service operation can be attained by assurance that the heater elements are operable.

The electric heaters in the recombiner will be periodically checked as a regular part of the plant maintenance. Proper operation can be confirmed by the temperature indications from the thermocouples located at the recombiner outlet during testing.

Periodic surveillance requirements to demonstrate operability of the hydrogen recombiners are included in the Technical Specifications.

6.2.5.2.4 Hydrogen Purge

There is no specific controlled hydrogen purge capability in the Salem design, other than the three different and independent purge modes described in Section 9.4. There is, however, an inherent "backup" in the multiple exhaust fans and filters that are available in the purge system. Purge system valve actuation periodic surveillance requirements are included in the Technical Specifications.

6.2.5.3 Hydrogen Monitoring

A hydrogen monitoring system is provided for continuous measurement of hydrogen concentration at two sample locations within containment. The system is designed in accordance with NUREG-0737 and Regulatory Guide 1.97.

The analyzing unit is mounted inside containment such that only electrical penetrations are required. Equipment located inside containment is operable under post-accident conditions of pressure, temperature and radiation. All system components are seismically designed.

Hydrogen concentration is measured by a hydrogen partial pressure sensor in conjunction with a total pressure sensor. The partial pressure sensor is galvanic in nature, consisting of a platinum black electrode and a platinum oxide counter electrode within a polysulfone housing.

The range of measurement is 0 to 10 volume percent with an accuracy of 2 percent of full scale. Output is displayed in the control room. Alarms are provided for high hydrogen concentration, power failure, system error and calibration mode.

Power is supplied from vital sources.

In addition to the hydrogen monitoring system, hydrogen concentration may be determined by taking a grab sample using the post-accident sampling system described in Section 9.3.

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TABLE 6.2-1

CONTAINMENT SPRAY SYSTEM - CODE REQUIREMENTS

Component	Code
Spray Additive Tank	ASME Section VIII
Valves	ANSI B16.5
Piping (including headers and spray nozzles)	ANSI B31.1*
pumps	

* For piping not supplied by the NSSS supplier, material inspections, fabrication and quality control conform to ANSI B31.7. Where not possible to comply with ANSI B31.7, the requirements of ASME III-1971, which incorporated ANSI B31.7, were adhered to.

TABLE 6.2-2

CONTAINMENT SPRAY PUMP DESIGN PARAMETERS

Quantity	2
Design Pressure, discharge, psig	250
Design Temperature, °F	150
Design Flow Rate, gpm	2600
Design Head, ft.	450
Shutoff Head, ft.	~530
Motor HP	400
Type	Horizontal-Centrifugal

TABLE 6.2-3

SPRAY ADDITIVE TANK DESIGN PARAMETERS

Number	1
Total Volume (empty), gal.	4000
NaOH concentration, w/o	30
Design temperature, °F	300
Design pressure, psig	14
Material	Austenitic Stainless Steel

TABLE 6.2-4 (Sheet 1 of 2)

SINGLE FAILURE ANALYSIS - CONTAINMENT SPRAY SYSTEM

Component	Malfunction	Comments and Consequences
A. Spray Nozzles	Clogged	Large number of nozzles render clogging of a significant number of nozzles as incredible.
B. Pumps		
1) Containment Spray Pump	Fails to start	Two provided. Evaluation based on operation of one pump in addition three out of five containment cooling fans operations during injection phase.
2) Residual Heat Removal Pump	Fails to start	Two provided. Evaluation based on operation of one pump.
3) Service Water Pump	Fails to start	Six provided. Operation of two pumps during recirculation required.
4) Component Cooling	Fails to start	Three provided. Operation of one pump during recirculation required.
C. Automatically operated Valves: (Open on two out of four [HiHi] containment pressure signals)		
1) Containment spray pump discharge isolation valve	Fails to open	Two complete systems provided.
D. Valves Operated From Control Room		
(a) Injection		
1) Spray Additive tank outlet isolation valve	Fails to open	Two parallel valves provided. Operation of one required.

TABLE 6.2-4 (Sheet 2 of 2)

SINGLE FAILURE ANALYSIS - CONTAINMENT SPRAY SYSTEM

Component	Malfunction	Comments and Consequences
(b) Recirculation		
1) Containment sump isolation valve	Fails to open	Two lines in parallel. One line required.
2) Containment spray header isolation valve from residual heat exchangers	Fails to open	Two complete loops provided. Operation of one required.

TABLE 6.2-5

SHARED FUNCTIONS EVALUATION

Component	Normal Operating Function	Normal Operating Arrangement	Accident Function	Accident Arrangement
Spray Additive Tank	None	Lined up for spray water diversion	Source of sodium hydroxide for spray water	Lined up for spray water diversion
Containment Spray Pumps (2)	None	Lined up to spray headers	Supply spray water to containment atmosphere	Lined up to spray headers

Note: Refer to Section 6.2 for a brief description of the refueling water storage tank, residual heat removal pumps, service water pumps, component cooling pumps, residual heat exchangers and component cooling heat exchangers which are also associated either directly or indirectly with the containment spray system.

TABLE 6.2-6

NET POSITIVE SUCTION HEADS FOR CONTAINMENT SPRAY

Pump	Elevation	Flow and Condition	Suction Source and Elevation	Minimum Available NPSH	Required NPSH	Maximum Water Temperature
Containment Spray	86'-3"	2600 gpm Rated flow	RWST 101'-8"	29.9 ft	10 ft	100°F
Residual Heat Removal	46'-10"	4500 gpm Runout flow	Containment Sump 78'-8"	24.9 ft	19.5 ft	Saturation

The available NPSH was calculated for the pumps indicated above using the following conservative assumptions:

1. All calculations assume an empty refueling water storage tank.
2. No credit is taken for RWST fluid temperature below 100°F.
3. No credit is taken for subcooling of fluid in containment sump.
4. No credit is taken for increased containment pressures following the LOCA.

TABLE 6.2-7

SINGLE FAILURE ANALYSIS - CONTAINMENT FAN COOLING SYSTEM

Component	Malfunction	Comments and Consequences
Containment Cooling Fan	Fails to start	Five provided. Evaluation based on three fans in operation and one containment spray pump operating during the injection phase.
Service Water Pumps	Fails to start	Six provided. Two required for operation.
Automatically Operated Valves: (Open on equipment start)	Fails to open	Independent valves provided for redundant equipment

TABLE 6.2-8

SHARED FUNCTION EVALUATION

Component	Normal Operating Function	Normal Operating Arrangement	Accident Function	Accident Arrangement
Containment Cooling Fan Units (5)	Circulate and cool containment atmosphere	Up to four fan units in service	Circulate and cool containment atmosphere	Five fan units in service
Service Water Pumps (6)	Supply river cooling water to fan units	Four pumps in service	Supply river cooling water to fan units	Two pumps in service

TABLE 6.2-9

SPRAY EVALUATION PARAMETERS

Power, MWt	3423
Containment Pressure, psia	61.7
Containment Temperature °F	271
Spray flow rate, gpm	2460
pH	10.0
Containment free volume, ft^3	2.5×10^6
Spray fall height, ft	116

λ_s (hrs^{-1})	31

TABLE 6.2-10 (sheet 1 of 7)

CONTAINMENT ISOLATION - MAJOR PIPING PENETRATIONS

			Status			Inside				Outside				Auto		
Figure	Service	Class	N	S	I	Valve	Type	Pwr	Signal	Valve	Type	Pwr	Signal	Isol. Time	Fluid	Temp.
6.2-17	Gas Analyzer from Pressurizer Relief Tank	B	Int.	Closed	Closed	1PR17	Auto Trip	A	T	1PR18	Auto Trip	B	T	≤10 secs.	Gas	Cold
6.2-17	Primary Water Supply to Pressurizer Relief Tank	B	Int.	Closed	Closed	1WR81	Non Return	N/A	N/A	1WR80	Auto Trip	B	T	≤10 secs.	Liquid	Cold
6.2-17	Nitrogen Supply to Pressurizer Relief	D	Int.	Closed	Closed	INT26	Non Return	N/A	N/A	INT25	Auto Trip	B	T	≤10 secs.	Gas	Cold
6.2-18	Pressurizer Dead Weight Calibrator	A	Closed	Closed	Closed	-	-	-	-	ISS901 ISS900	(2) Manual	N/A	N/A	N/A	Liquid	Cold
6.2-19	Relief Lines to Pressurizer Relief Tank	D	Int.	Closed	Closed	1PR25	Non Return	N/A	N/A	11-12CS5 1CV43 1SJ167 1SJ32 11-12SJ39 11-12SJ48	Relief Valves	N/A	N/A	N/A	Liquid	Cold
6.2-20	CVCS Letdown Line	D	Open	Closed	Closed	1CV3 1CV4 2CV5	(3)Auto Trip	B	T	1CV7	Auto Trip	B A C	T T T	≤10 secs.	Liquid	Hot
6.2-20	CVCS Charging Line	D	Open	Closed	Closed	1CV74	Non Return	N/A	N/A	1CV68 1CV69	(2)Auto Trip	B C	S S	≤10 secs.	Liquid	Hot
6.2-21	Reactor Coolant Pump Seal Water Supply	A	Open	Closed	Closed	11-14CV99	Non Return	N/A	N/A	11-14CV98	Manual	N/A	N/A	N/A	Liquid	Cold
6.2.21	Reactor Coolant Pump Seal Water Discharge	D	Open	Open	Open	1CV284	Auto Trip	B	T	1CV116	Auto Trip	C	T	≤10 secs.	Liquid	Cold
6.2.22	Residual Heat Removal Inlet From RCS	D	Closed	Open	Closed	1RH1 1RH2	(2)Rem. Manul	B A	N/A N/A	11RH4 12RH4	(2)Rem. Manual	A B	N/A N/A	N/A	Liquid	Hot
6.2-22	Residual Heat Removal Outlet to RCS	D	Closed	Open	Closed	1RH26	Rem. Manual	C	N/A	11RH19 12RH19	(2)Rem. Manual	A B	N/A N/A	N/A	Liquid	Hot
6.2-23	Excess Letdown Heat Exchanger Cooling Water Inlet	C	Closed	Closed	Closed	1CC109	Non Return	N/A	N/A	1CC215	Auto Trip	A	T	≤10 secs.	Liquid	Cold

TABLE 6.2-10 (sheet 2 of 7)

				Status		Inside				Outside				Auto		
Figure	Service	Class	N	S	I	Valve	Type	Pwr	Signal	Valve	Type	Pwr	Signal	Isol. Time	Fluid	Temp.
6.2-23	Excess Letdown Heat Exchanger Cooling Water Outlet	C	Closed	Closed	Closed	-	-	-	N/A	1CC113	Auto Trip	A	T	$\leq$10 secs.	Liquid	Cold
6.2-24	Reactor Coolant Pump Motor Cooling Water Supply	B	Open	Open	Closed	1CC119	Non Return	N/A	N/A	1CC117 1CC118	(2)Auto Trip	C A	P P	$\leq$10 secs.	Liquid	Cold
6.2-24	Reactor Coolant Motor Cooling Water Discharge	B	Open	Open	Closed	1CC187	Auto Trip	A	P	1CC136	Auto Trip	C	P	$\leq$10 secs.	Liquid	Cold
6.2-24	Reactor Coolant Pump Thermal Barrier Cooling Water Discharge	B	Open	Open	Closed	1CC190	Auto Trip	A	P	1CC131	Auto Trip	C	P	$\leq$10 secs.	Liquid	Cold
6.2-25	Gas Analyzer From RCDT	B	Int.	Closed	Closed	1WL96	Auto Trip	C	T	1WL97	Auto Trip	B	T	$\leq$10 secs.	Gas	Cold
6.2-25	N_2 Supply to RCDT	B	Closed	If Needed	Closed	1WL98	Auto Trip	C	T	1WL108	Auto Trip	B	T	$\leq$10 secs.	Gas	Cold
6.2-25	Reactor Coolant Drain Tank Vent	B	Open	Closed	Closed	1WL98	Auto Trip	C	T	1WL99	Auto Trip	B	T	$\leq$10 secs.	Gas	Cold
6.2-26	Reactor Coolant Drain Tank Pump Discharge	B	Int.	Int.	Closed	1WL12	Auto Trip	C	T	1WL13	Auto Trip	A	T	$\leq$10 secs.	Liquid	Hot
6.2-27	Accumulator N_2 Supply	B	Int.	Int.	Closed	1NT34	Non Return	N/A	N/A	1NT32	Auto Trip	D	T	$\leq$10 secs.	Gas	Cold
6.2-28	Safety Injection Test Line	B	Closed	Closed	Closed	1SJ123	Auto Trip	A	T	1SJ53 1SJ60	(2)Auto Trip	D B	T T	$\leq$10 secs.	Liquid	Cold
6.2-29	RHR Outlets to Safety Injection System	B	Open	Closed	Open	11-14SJ43	Non Return	N/A	N/A	11SJ49	Rem. Manual	A	N/A	N/A	Liquid	Cold

TABLE 6.2-10 (sheet 3 of 7)

				Status		Inside				Outside				Auto		
Figure	Service	Class	N	S	I	Valve	Type	Pwr	Signal	Valve	Type	Pwr	Signal	Isol. Time	Fluid	Temp.
6.2-30	Safety Injection Pumps Outlet to Cold Legs	B	Open	Closed	Open	11-14SJ144	Non Return	N/A	N/A	1SJ135	Auto Trip	A	T	≤10 secs.	Liquid	Cold
6.2-30	Safety Injection Pumps Outlet to Hot Legs	B	Closed	Open	Open	11-14SJ139	Non Return	N/A	N/A	11SJ40 12SJ40	(2)Auto Trip	C A	P P	≤10 secs.	Liquid	Cold
6.2-31	Injection Line From Charging Pumps	B	Closed	Closed	Open	1SJ150	Non Return	N/A	N/A	1SJ12 1SJ13	Auto Trip	C	P	≤10 secs.	Liquid	Cold
6.2-31	Flushing Line From Charging Pumps	B	Closed	Closed	Closed	1SJ150	Non Return	N/A	N/A	1SJ71	Manual	N/A	N/A	N/A	Liquid	Cold
6.2-32	Residual Heat Removal Suction From Sump	D	Closed	Closed	Open	11SJ44 12SJ44	Rem. Manual	A B	N/A	-	-	-	N/A	N/A	Liquid	Cold
6.2-33	Containment Spray	B	Closed	Closed	If Needed	11CS48 12CS48	Non Return	N/A	N/A	11CS2 12CS2	Auto Trip	B	T	≤10 secs.	Gas	Cold
6.2-33	RHR Outlet To Containment Spray	D	Closed	Closed	If Needed	11CS48 12CS48	Non Return	N/A	N/A	11CS36 12CS36	Auto Trip	B	T	≤10 secs.	Gas	Cold
6.2-34	Sample Line From Pressurizer Steam Space	B	Open	Closed	Closed	1SS110	Auto Trip	A	T	1SS64	Auto Trip	A	T	≤10 secs.	Gas	Cold
6.2-34	Sample Line From Accumulators	B	Closed	Closed	Closed	1SS103	Auto Trip	A	T	1SS27	Auto Trip	A	T	≤10 secs.	Liquid	Hot
6.2-34	Sample Line From Hot Legs	B	Closed	Closed	Closed	1SS104	Auto Trip	A	T	1SS33	Non Return	D	T	≤10 secs.	Gas	Cold
6.2-34	Sample Line From Pressurizer Liquid	B	Closed	Closed	Closed	1SS107	Auto Trip	A	T	1SS49	Auto Trip	B	T	≤10 secs.	Liquid	Cold
6.2-34	Sample Lines From Steam Generator Blow-Down	C	Closed	Closed	Closed	-	- Manual	-	-	11-14SS94	Auto Trip	B	T	≤10 secs.	Liquid	Hot
6.2-35	Containment Pressure Instruments	A	Open	Open	Open	-	-	-	-	-	-	-	-	-	(Filled System)	

TABLE 6.2-10 (sheet 4 of 7)

Figure	Service	Class	Status N	Status S	Status I	Inside Valve	Inside Type	Inside Pwr	Inside Signal	Outside Valve	Outside Type	Outside Pwr	Outside Signal	Auto Isol. Time	Fluid	Temp.
6.2-36	Containment Air Monitor															
	Inlet - Normal	D	Open	Open	Closed	1VC11	Auto Trip	B	T	1VC12	Auto Trip	A	T	≤10 secs.	Gas	Cold
	Inlet - Backup	D	Closed	Closed	Closed	1VC13	Rem. Manual	C	N/A	1VC14	Rem. Manual	C	N/A	N/A	Gas	Cold
	Outlet - Normal	D	Open	Open	Closed	1VC7	Auto Trip	B	T	1VC8	Auto Trip	A	T	≤10 secs.	Gas	Cold
	Outlet - Backup	D	Closed	Closed	Closed	1VC9	Rem. Manual	C	N/A	1VC10	Rem. Manual	C	N/A	N/A	Gas	Cold
6.2-37	Pressure Vacuum Relief Inlet and Outlet	B	Int.	If Needed	Closed	1VC6	Auto Trip	C	T	1VC5	Auto Trip	B	T	≤ 2 secs.	Gas	Cold
6.2-37	Purge Air Inlet (Containment)	B	Closed	If Needed	Closed	1VC2	Auto Trip	A	T	1VC1	Auto Trip	B	T	≤2 secs.	Gas	Cold
6.2-37	Purge Air Outlet (Containment)	B	Closed	If Needed	Closed	1VC3	Auto Trip	A	T	1VC4	Auto Trip	B	T	≤2 secs.	Gas	Cold
6.2-38	Demineralized Water Supply to Flushing Connections	B	Open	Closed	Closed	1DR30	Non Return	N/A	N/A	1DR29	Auto Trip	A	T	≤10 secs.	Liquid	Cold
6.2-38	Service Air	B	Closed	Open	Closed	1SA119	Non Return	N/A	N/A	1SA118	Manual	N/A	N/A	N/A	Air	Cold
6.2-38	Instrument Air	B	Open	Open	Closed	11CA360 12CA360	Non Return	N/A	N/A	11CA330 12CA330	Auto Trip	A B	T T	≤10 secs.	Air	Cold
6.2-39	Service Water to Fan Coolers	C	Open	If Needed	Open	-	-	-	-	11SW58 12SW58 13SW58 14SW58 15SW58	Rem. Manual	A B C B C	N/A N/A N/A N/A N/A	N/A	Liquid	Cold
6.2-39	Service Water from Fan Coolers	C	Open	If Needed	Open	-	-	-	-	11SW72 12SW72 13SW72 14SW72 15SW72	Rem. Manual	A B C B C	N/A N/A N/A N/A N/A	N/A	Liquid	Cold

TABLE 6.2-10 (sheet 5 of 7)

Figure	Service	Class	Status N	Status S	Status I	Inside Valve	Inside Type	Inside Pwr	Inside Signal	Outside Valve	Outside Type	Outside Pwr	Outside Signal	Auto Isol. Time	Fluid	Temp.
6.2-40 thru 6.2-43	Steam Generator Main Steam Stop	C	Open	Closed	Closed	-	-	-	-	11-14MS167	Auto Trip	C-D	MS1	≤5 secs.	Gas	Hot
6.2-40 thru 6.2-43	Steam Generator Steam Outlet Drain	C	Open	Closed	Closed	-	-	-	-	11MS7	Auto Trip	C	MSI	≤10 secs.	Gas	Hot
										12MS7		C	MSI			
										13MS7		D	MSI			
										14MS7		D	MSI			
6.2-40 thru 6.2-42	Steam Generator Steam Outlet Bypass to Aux. Feed Pump Turbine	C	Closed	Int.	Open	-	-	-	-	1MS132	Rem. Manual	C	N/A	N/A	Gas	Hot
6.2-40 thru 6.2-43	Steam Generator Blowdown	C	Open	Closed	Closed	-	-	-	-	11-14GB4	Auto Trip	C	T	≤10 secs.	Liquid	Hot
6.2-40 thru 6.2-43	Feedwater Supply (Control Valve)	C	Open	Closed	Closed	-	-	-	-	11BF22	Non Return	B	FWI	N/A	Liquid	Hot
										12BF22		B	FWI			
										13BF22		A	FWI			
										14BF22		A	FWI			
										11BF19	Auto Trip	C	FWI	<8 secs.		
										12BF40		C	FWI			
										12BF19		C	FWI			
										12BF40		C	FWI			
										13BF19		D	FWI			
										13BF40		D	FWI			
										14BF19		D	FWI			
										14BF40		D	FWI			
6.2-40 thru 6.2-43	Steam Generator Main Steam Stop Bypass	C	Open	Closed	Closed	-	-	-	-	11MS18	Auto Trip	C	MS1	≤10 secs.	Gas	Hot
										12MS18	Trip	C	MSI			
										13MS18	Trip	D	MSI			
										14MS18	Trip	D	MSI			
6.2-40 thru 6.2-43	Auxiliary Feedwater Supply-Turbine Driven	C	Open	Int.	Open	-	-	-	-	11-14AF11	Rem. Manual	C	N/A	N/A	Liquid	Cold

TABLE 6.2-10 (sheet 6 of 7)

			Status			Inside				Outside				Auto		
Figure	Service	Class	N	S	I	Valve	Type	Pwr	Signal	Valve	Type	Pwr	Signal	Isol. Time	Fluid	Temp.
6.2-40 thru 6.2-43	Auxiliary Feedwater Supply-Motor Driven	C	Closed	Int.	Open	-	-	-	-	11AF21 12AF21 13AF21 14AF21	Rem. Manual Manual Manual	B B A A	N/A N/A N/A N/A	N/A	Liquid	Cold
6.2-44	Fuel Transfer Tube	B	Closed	Open	Closed	-	Blind Flange	-	-	-	Manual	N/A	N/A	N/A	Liquid	Cold
6.2-44	Reactor Cavity Sump Pump Discharge to Waste Disposal	B	Open	Int.	Closed	1WL16	Auto Trip	C	T	1WL17	Auto Trip	B	T	$\leq$10 secs.	Liquid	Cold
6.2-45	Fire Protection Water Supply	B	Closed	Closed	Closed	1FP148	Non Return	N/A	N/A	1FP147	Auto Trip	C	T	$\leq$10 secs.	Liquid	Cold
6.2-45	Refueling Canal Supply	B	Closed	Closed	Closed	1WL190	Manual	N/A	N/A	1SF36	Manual	N/A	N/A	N/A	Liquid	Cold
6.2-45	Refueling Canal	B	Closed	Closed	Closed	1WL191	Manual	N/A	N/A	1SF22	Manual	N/A	N/A	N/A	Liquid	Cold
6.2-45A	Post-LOCA Atmo. Sample	B	Closed	Closed	Int.	11VC19	Rem. Manual	A	N/A	11VC17	Rem. Manual	A	N/A	N/A	Gas	Cold
	Post-LOCA Atmo. Sample	B	Closed	Closed	Int.	11VC20	Rem. Manual	A	N/A	11VC18	Rem. Manual	A	N/A	N/A	Gas	Cold
	Post-LOCA Atmo. Sample	B	Closed	Closed	Int.	12VC20	Rem. Manual	C	N/A	12VC18	Rem. Manual	C	N/A	N/A	Gas	Cold
	Post-LOCA Atmo. Sample	B	Closed	Closed	Int.	12VC19	Rem. Manual	C	N/A	12VC17	Rem. Manual	C	N/A	N/A	Gas	Cold
6.2-45B	Post-LOCA RCS Sample	B	Closed	Closed	Int.	13SS184	Rem. Manual	C	N/A	13SS185	Rem. Manual	C	N/A	N/A	Liquid	Hot
	Post-LOCA RCS Sample	B	Closed	Closed	Int.	13SS182	Rem. Manual	C	N/A	13SS181	Rem. Manual	C	N/A	N/A	Liquid	Hot
	Post-LOCA RCS Sample	B	Closed	Closed	Int.	11SS182	Rem. Manual	A	N/A	11SS181	Rem. Manual	A	N/A	N/A	Liquid	Hot
	Post-LOCA RCS Sample	B	Closed	Closed	Int.	11SS188	Rem. Manual	A	N/A	11SS189	Rem. Manual	A	N/A	N/A	Liquid	Hot
6.2-45C	Fill Line for Cont. Press. Inst.	B	Closed	Closed	Closed	1CS900	Manul	N/A	N/A	1CS902	Manual	N/A	N/A	N/A	Liquid	Cold

TABLE 6.2-10 (sheet 7 of 7)

				Status		Inside				Outside				Auto		
Figure	Service	Class	N	S	I	Valve	Type	Pwr	Signal	Valve	Type	Pwr	Signal	Isol. Time	Fluid	Temp.
6.2-45D	Cont. Press. Test Inst.	B	Closed	Closed	Closed	1SA264	Manual	N/A	N/A	1SA262	Manual	N/A	N/A	N/A	Gas	Cold
	Cont. Press. Test Inst.	B	Closed	Closed	Closed	1SA267	Manual	N/A	N/A	1SA265	Manual	N/A	N/A	N/A	Gas	Cold
	Cont. Press. Test Inst.	B	Closed	Closed	Closed	1SA270	Manual	N/A	N/A	1SA268	Manual	N/A	N/A	N/A	Gas	Cold
6.2-45E	Cont. Airlock Seal Test	C	Closed	Closed	Closed	-	-	-	-	1CA1714	Rem. Manual	N/A	N/A	N/A	Air	Cold
6.2-45E	Cont. Airlock Seal Test	C	Closed	Closed	Closed	-	-	-	-	1CA1715	Rem Manual	N/A	N/A	N/A	Air	Cold

N: Normal
S: Shutdown
I: Incident
Int: Intermittent
P: Tripped by Containment Isolation Signal - Phase B
T: Tripped by Containment Isolation Signal - Phase A
FWI: Feedwater Isolation
MSI: Main Steam Isolation

Notes

1. Valve designations are shown for No. 1 Unit although No. 2 Unit is similar (e.g., 11MS167 would be 21MS167 for No. 2 Unit).

2. The column titled "class" contains the designators defined in Section 6.2.4.2.

3. The isolation valve power source is the vital channel designation and may be either 230 VDC or 125 VDC depending on the type of valve.

4. Normally closed manual valves are under administrative control.

5. The following lines contain remotely operated valves which are normally closed and under administrative control.

    1. Excess letdown heat exchanger cooling water lines
    2. Safety injection system test line
    3. Steam generator steam actuators (drain and bypass)
    4. Sample lines from pressurizer
    5. Containment purge air inlet and outlet and pressure-vacuum relief dampers
    6. Nitrogen supply to reactor coolant drain tank
    7. Post-LOCA atmosphere and RCS sampling

TABLE 6.2-11

POTENTIAL RELEASES TO THE ENVIRONMENT THROUGH CONTAINMENT ISOLATION VALVES

Isotope	Activity Present in Reactor Coolant* uCi/cc	Containment Airborne Concentration uCi/cc	Release to Environment Ci
I-131 (equivalent	2.8	6.6×10^{-3}	0.110
Kr-85	3.93	1.9×10^{-2}	0.317
Kr-85m	1.70	8.0×10^{-3}	0.134
Kr-87	0.94	4.4×10^{-3}	0.074
Kr-88	2.66	1.2×10^{-2}	0.20
Xe-133	195	9.2×10^{-1}	15.4
Xe-133m	2.09	9.9×10^{-3}	0.165
Xe-135	5.45	2.6×10^{-2}	0.434
Xe-135	0.132	6.3×10^{-4}	0.0105
Xe-138	0.468	2.2×10^{-3}	0.0367

*Based on 1 percent fuel defects

TABLE 6.2-12 (sheet 1 of 3)

CONTAINMENT ISOLATION VALVES
SUBJECT TO TYPE C LEAK RATE TESTING

Valve Number	Function
1. 1 PR 17	Pressurizer Relief Tk. - Gas Analyzer Conn.
2. 1 PR 18	Pressurizer Relief Tk. - Gas Analyzer Conn.
3. 1 NT 25	Pressurizer Relief Tk. - N_2 Conn.
4. 1 NT 26	Pressurizer Relief Tk. - N_2 Conn.
5. 1 WR 80	Pressurizer Relief Tk. - Primary Water Conn.
6. 1 WR 81	Pressurizer Relief Tk. - Primary Water Conn.
7. 1 CV 3	CVCS - Letdown Line
8. 1 CV 4	CVCS - Letdown Line
9. 1 CV 5	CVCS - Letdown Line
10. 1 CV 7	CVCS - Letdown Line
11. 1 CV 68/69	CVCS - Charging Line
12. 1 CV 74	CVCS - Charging Line
13. 1 CV 284	CVCS - RCP Seals
14. 1 CV 296	CVCS - RCP Seals
15. 1 CV 116	CVCS - RCP Seals
16. 1 CV 215	Comp. Cooling - Excess Letdown Hx
17. 1 CV 113	Comp. Cooling - Excess Letdown Hx
18. 1 CC 117/118	Comp. Cooling - RCP Cooler
19. 1 CC 119	Comp. Cooling - RCP Cooler
20. 1 CC 187	Comp. Cooling - RCP Cooler
21. 1 CC 136	Comp. Cooling - RCP Cooler
22. 1 CC 190	Comp. Cooling - RCP Cooler
23. 1 CC 131	Comp. Cooling - RCP Cooler
24. 1 CC 186	Comp. Cooling - RCP Cooler
25. 1 CC 208	Comp. Cooling - RCP Cooler
26. 1 WL 96	RC Drain Tk. - Gas Analyzer Conn.
27. 1 WL 97	RC Drain Tk. - Gas Analyzer Conn.
28. 1 WL 98	RC Drain Tk. - Vent Header Conn.
29. 1 WL 99	RC Drain Tk. - Vent Header Conn.
30. 1 WL 108	RC Drain Tk. - N_2 Connection
31. 1 WL 12	RC Drain Tk. Pumps
32. 1 WL 13	RC Drain Tk. Pumps
33. 1 NT 32	Accumulator N_2 Supply
34. 1 NT 34	Accumulator N_2 Supply
35. 1 SJ 123	SI Test Line
36. 1 SJ 60	SI Test Line
37. 1 SJ 53	SI Test Line
38. 11 CS 2	Containment Spray
39. 12 CS 2	Containment Spray
40. 11 CS 48	Containment Spray
41. 12 CS 48	Containment Spray
42. 1 SS 110	Pressurizer Steam Sampling
43. 1 SS 64	Pressurizer Steam Sampling
44. 1 SS 103	Accumulator Sampling
45. 1 SS 27	Accumulator Sampling
46. 1 SS 104	RCS Sampling

TABLE 6.2-12 (sheet 2 of 3)

CONTAINMENT ISOLATION VALVES
SUBJECT TO TYPE C LEAK RATE TESTING
(CONTINUED)

Valve Number	Function
47. 1 SS 33	RCS Sampling
48. 1 SS 107	Presssurizer Liquid Sampling
49. 1 SS 49	Pressurizer Liquid Sampling
50. 1 VC 1	Purge Supply
51. 1 VC 1	Purge Supply
52. 1 VC 3	Purge Exhaust
53. 1 VC 4	PUrge Exhaust
54. 1 VC 6	Pressure - Vacuum Relief
55. 1 VC 6	Pressure - Vacuum Relief
56. 1 VC 7	Containment Radiation Sampling
57. 1 VC 8	Containment Radiation Sampling
58. 1 VC 9	Containment Radiation Sampling - Alt
59. 1 VC 10	Containment Radiation Sampling - Alt
60. 1 VC 11	Containment Radiation Sampling
61. 1 VC 12	Containment Radiation Sampling
62. 1 VC 13	Containment Radiation Sampling - Alt
63. 1 VC 14	Containment Radiation Sampling - Alt
64. 1 DR 29	Demineralized Water Supply
65. 1 Dr 30	Demineralized Water Supply
66. 1 SA 118	Compressed Air Supply
67. 1 SA 119	Compressed Air Supply
68. 11 CA 330	Instrument Air Supply
69. 12 CA 330	Instrument Air Supply
70. 1 WL 16	Containment Sump Discharge
71. 1 WL 17	Containment Sump Discharge
72. 1 FP 147	Fire Protection System
73. 1 FP 148	Fire Protection System
74. 1 WL 190	S.F. Demin. to Refueling Canal
75. 1 WL 191	Refueling Canal to S.F. Demin.
76. 1 SF 36	S.F. Demin. to Refueling Canal.
77. 1 SF 22	Refueling Canla to S.F. Demin.
78. 1 CS 900	Fill Line for Cont. Press. Instr.
79. 1 CS 901	Fill Line for Cont. Press. Instr.
80. 1 CS 902	Fill Line for Cont. Press. Instr.
81. 1 CS 903	Fill Line for Cont. Press. Instr.
82. 1 SA 262	Containment Press. Test Instr.
83. 1 SA 264	Containment Press. Test Instr.

TABLE 6.2-12 (sheet 3 of 3)

CONTAINMENT ISOLATION VALVES
SUBJECT TO TYPE C LEAK RATE TESTING
(CONTINUED)

Valve Number	Function
84. 1 SA 265	Containment Press. Test Instr.
85. 1 SA 267	Containment Press. Test Instr.
86. 1 SA 270	Containment Press. Test Instr.
87. 11 SS 181	Post LOCA RCS Sampling
88. 11 SS 182	Post LOCA RCS Sampling
89. 11 SS 188	Post LOCA RCS Sampling
90. 11 SS 189	Post LOCA RCS Sampling
91. 13 SS 181	Post LOCA RCS Sampling
92. 13 SS 182	Post LOCA RCS Sampling
93. 13 SS 184	Post LOCA RCS Sampling
94. 13 SS 185	Post LOCA RCS Sampling
95. 11 VC 17	Post LOCA Atmos. Sampling
96. 11 VC 18	Post LOCA Atmos. Sampling
97. 11 VC 19	Post LOCA Atmos. Sampling
98. 11 VC 20	Post LOCA Atmos. Sampling
99. 12 VC 17	Post LOCA Atmos. Sampling
100. 12 VC 18	Post LOCA Atmos. Sampling
101. 12 VC 19	Post LOCA Atmos. Sampling
102. 12 VC 20	Post LOCA Atmos. Sampling
103. 1 SA 268	Containment Press. Test Instr.
104. 11 CA 360	Instrument Air Supply
105. 12 CA 360	Instrument Air Supply
106. 1 CA 1714	Airlock Seal Test Supply
107. 1 CA 1715	Airlock Seal Test Supply

NOTE: Valve designations are shown for No. 1 Unit although No. 2 Unit is similar (e.g. 1 PR 17 would be 2 PR 17 for No. 2 Unit).

TABLE 6.2-13 (sheet 1 of 2)

CONTAINMENT ISOLATION VALVES NOT SUBJECT TO TYPE C LEAK RATE TESTING

Valve Number	Function	Exemption
1. 11 MS 7	Main Steam Drain	Not Required for PWR's*
2. 12 MS 7	Main Steam Drain	" " " "
3. 13 MS 7	Main Steam Drain	" " " "
4. 14 MS 7	Main Steam Drain	" " " "
5. 11 MS 18	Main Steam Bypass	" " " "
6. 12 MS 18	Main Steam Bypass	" " " "
7. 13 MS 18	Main Steam Bypass	" " " "
8. 14 MS 18	Main Steam Bypass	" " " "
9. 11 BF 19	Main Feedwater Isolation	" " " "
10. 12 BF 19	Main Feedwater Isolation	" " " "
11. 13 BF 19	Main Feedwater Isolation	" " " "
12. 14 BF 19	Main Feedwater Isolation	" " " "
13. 11 BF 40	Main Feedwater Isolation	" " " "
14. 12 BF 40	Main Feedwater Isolation	" " " "
15. 13 BF 40	Main Feedwater Isolation	" " " "
16. 14 BF 40	Main Feedwater Isolation	" " " "
17. 11 MS 167	Main Steam Isolation	" " " "
18. 12 MS 167	Main Steam Isolation	" " " "
19. 13 MS 167	Main Steam Isolation	" " " "
20. 14 MS 167	Main Steam Isolation	" " " "
21. 1 MS 132	Steam Supply to Aux. Feed Pump Turbine	" " " "
22. 11 BF 22	Feedwater Control Valve	" " " "
23. 12 BF 22	Feedwater Control Valve	" " " "
24. 13 BF 22	Feedwater Control Valve	" " " "
25. 14 BF 22	Feedwater Control Valve	" " " "
26. 11 AF 11	Aux. Feed Supply	" " " "
27. 12 AF 11	Aux. Feed Supply	" " " "
28. 13 AF 11	Aux. Feed Supply	" " " "
29. 14 AF 11	Aux. Feed Supply	" " " "
30. 11 AF 21	Aux. Feed Supply	" " " "
31. 12 AF 21	Aux. Feed Supply	" " " "
32. 13 AF 21	Aux. Feed Supply	" " " "
33. 14 AF 21	Aux. Feed Supply	" " " "
34. 11 SS 94	SG Blowdown Sampling	" " " "
35. 12 SS 94	SG Blowdown Sampling	" " " "
36. 13 SS 94	SG Blowdown Sampling	" " " "
37. 14 SS 94	SG Blowdown Sampling	" " " "
38. 11 GB 4	SG Blowdown Isolation	" " " "
39. 12 GB 4	SG Blowdown Isolation	" " " "
40. 13 GB 4	SG Blowdown Isolation	" " " "
41. 14 GB 4	SG Blowdown Isolation	" " " "
42. 1 SJ 135	SI to Cold Legs	Required to Open on Iso. Signal
43. 11 SJ 40	SI to Cold Legs	" " " " " "
44. 12 SJ 40	SI to Cold Legs	" " " " " "
45. 1 SJ 12	High Head Safety Injection	" " " " " "

TABLE 6.2-13 (sheet 2 of 2)

CONTAINMENT ISOLATION VALVES NOT SUBJECT TO TYPE C LEAK RATE TESTING

CONTINUED

Valve Number	Function	Exemption Basis
46. 1 SJ 13	High Head Safety Injection	Req'd. to open on isol. signal
47. 11 CS 36	RHR to Containment Spray	" " " " " "
48. 12 CS 36	RHR to Containment Spray	" " " " " "

NOTE: Valve designations are shown for No. 1 Unit although No. 2 Unit is similar (e.g. 11 MS 7 would be 21 MS 7 for No. 2 Unit).

* These valves connect to the steam generator and are not exposed normally or post-LOCA either to the containment atmosphere or to the reactor coolant. Isolation of these valves is based on steam generator functional requirements. The steam generator and its connecting lines are a closed system inside containment as defined by paragraph II.6.(o) of Standard Review Plan 6.2.4 Revision 2.

TABLE 6.2-14

POST-ACCIDENT CONTAINMENT TEMPERATURE TRANSIENT
USED IN THE CALCULATION OF ALUMINUM CORROSION

Time Interval (sec)	Temperature (°F)
0 - 300	271
300 - 1000	230
1000 - 2000	188
2000 - 4000	175
> 4000	147

TABLE 6.2-15

INPUT PARAMETERS AND ALUMINUM INVENTORY
PARAMETERS USED TO DETERMINE HYDROGEN GENERATION

Plant Thermal Power Rating	3575 MWt
Containment Temperature at Accident	120°F
Containment Free Volume	2,500,000 ft^3
Weight of Zirconium	47,946 lb
Hydrogen Generated by Zirc-Water Reaction	
Based on 2 percent value	7,575 SCF
Based on 5 percent value	18,940 SCF
Corrodable Metal	Aluminum

INVENTORY OF ALUMINUM IN CONTAINMENT (NUCLEAR STEAM SUPPLY SYSTEM

Item	Weight (lbs)	Surface Area (ft^2)
Source, Intermediate and Power	244	83
Control Rod Drive Mechanism Connectors	193	42
Paint	140	18,000
Contingency (Nuclear Steam Supply System	250	85
Flux Mapping Drive System	122	84
Miscellaneous Valves	230	86

TABLE 6.2-16

CORE FISSION PRODUCT ENERGY
AFTER 830 FULL POWER DAYS

Core Fission Product Energy/1

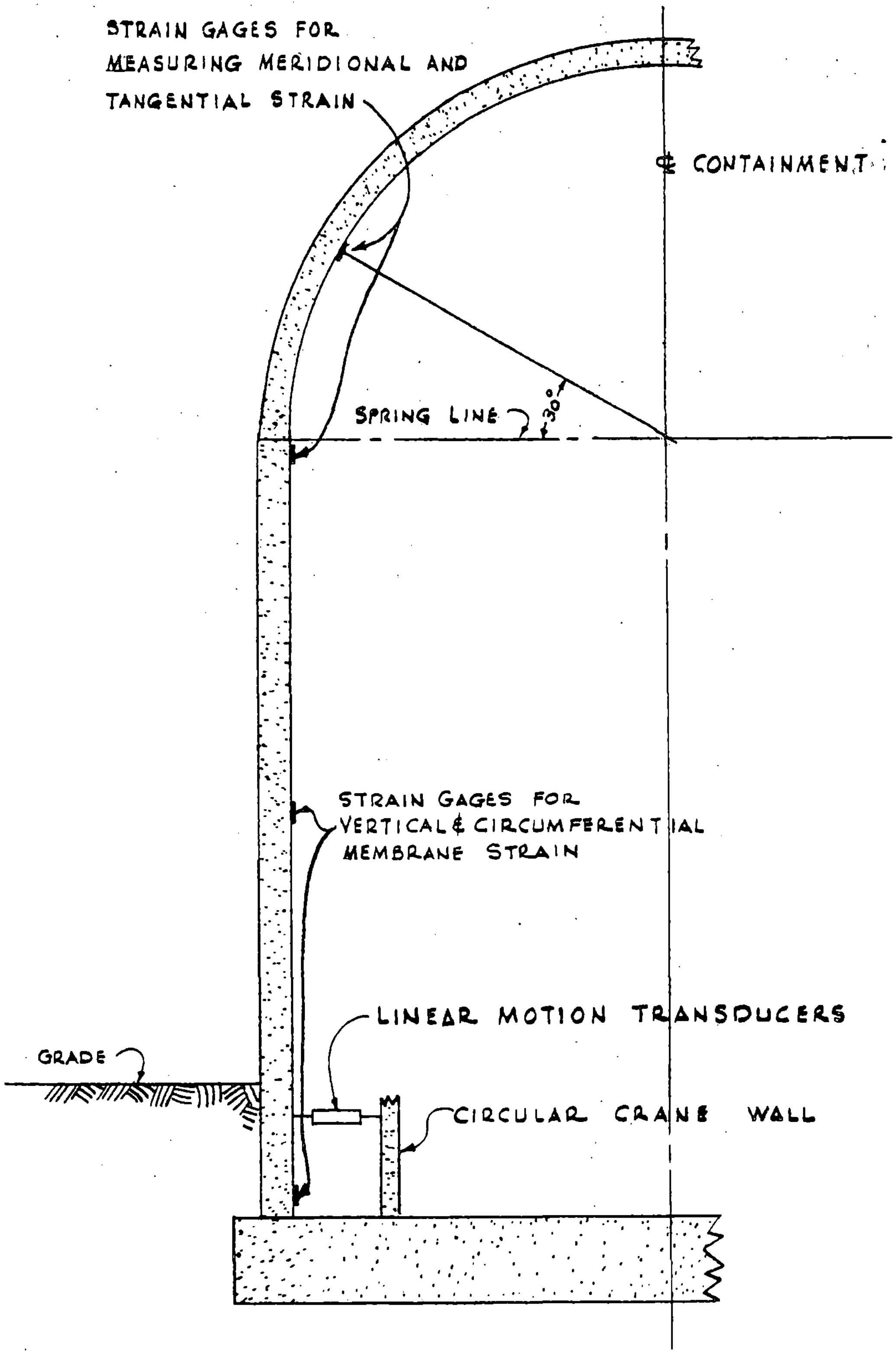
Time After Reactor Trip Days	Energy Release Rate Watts/Mwtx10^{-3}	Integrated Energy Release Watt-Days/MWtx10^{-4}
1	3.887	0.574
5	2.595	1.777
10	2.211	2.967
20	1.760	4.934
30	1.475	6.541
40	1.291	7.919
50	1.163	9.143
60	1.068	10.259
70	0.992	11.289
80	0.926	12.249
90	0.867	13.139
100	0.814	13.979

/1Assumes release of 50 percent core halogens +1 percent other fission products, includes 100 percent noble gases. Values are for for total (β and γ) energy.

TABLE 6.2-17

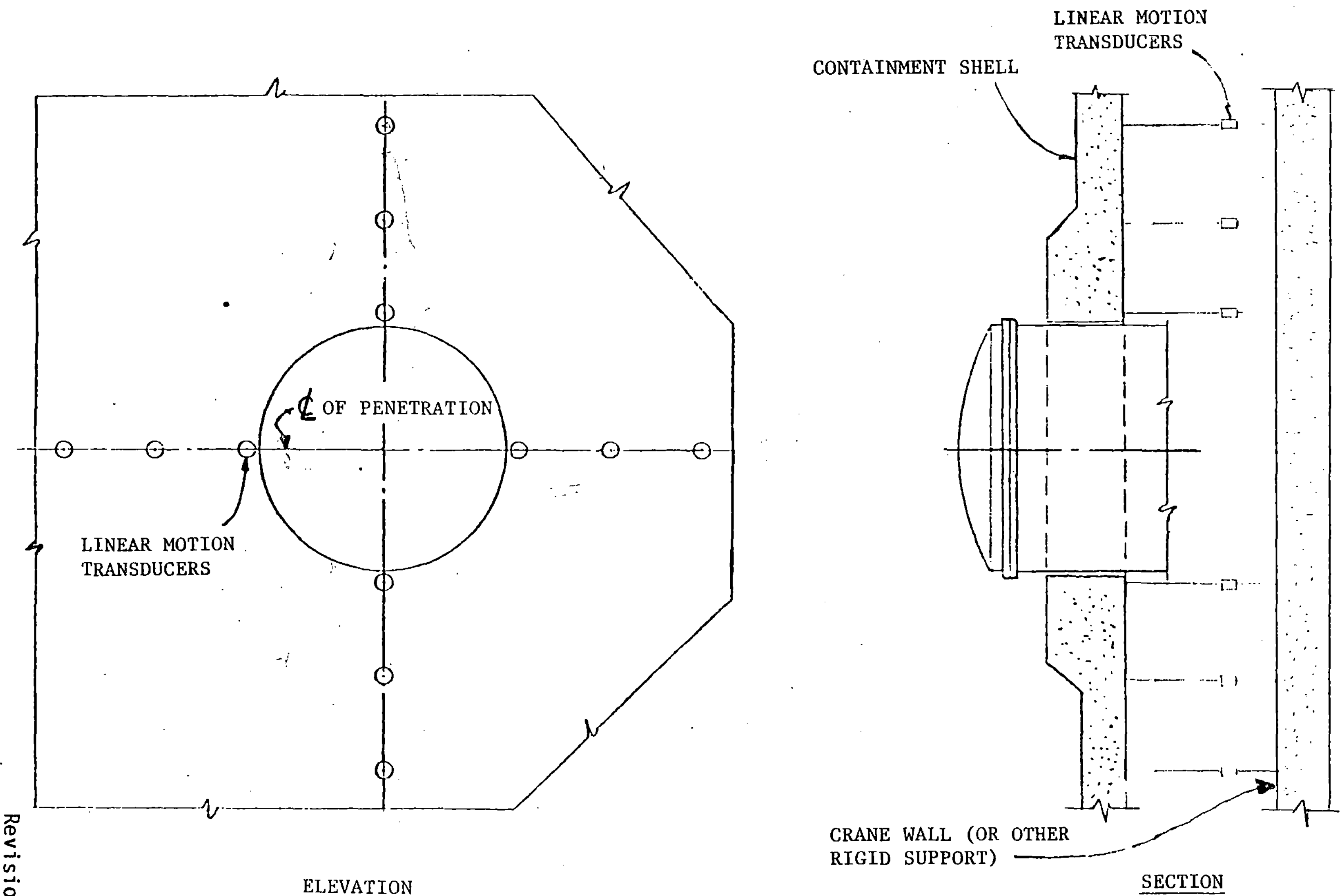
FISSION PRODUCT DECAY DEPOSITION IN SUMP SOLUTION

Time After Reactor Trip Days	50 Percent Halogens Energy Release Rate Watts/MWt	50 Percent Halogens Integrated Energy Release Watt-Day/Mwtx10^{-2}	1 Percent Other Fission Products Energy Release Rate Watts/MWtx 10^{-1}	1 Percent Other Fission Products Integrated Energy Release Watt-Day/MWtx10^{-2}	Total Energy Release Rate Watts/Mwtx10^{-1}	Total Integrated Energy Release Watt-Day/MWtx10^{-3}
1	145	4.27	3.78	0.536	18.28	0.481
3	49.4	5.88	2.90	1.18	7.85	0.707
5	31.0	6.65	2.59	1.73	5.69	0.838
10	18.2	7.82	2.22	2.92	4.03	1.07
20	7.63	9.03	1.77	4.89	2.53	1.39
30	3.22	9.54	1.49	6.51	1.81	1.61
40	1.36	9.76	1.30	7.90	1.44	1.77
60	0.241	9.89	1.08	10.3	1.10	2.02
80	0.043	9.91	0.935	12.3	0.940	2.22
100	0.008	9.92	0.822	14.0	0.823	2.39



Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Instrumentation	
	Updated FSAR	Figure 6.2-1



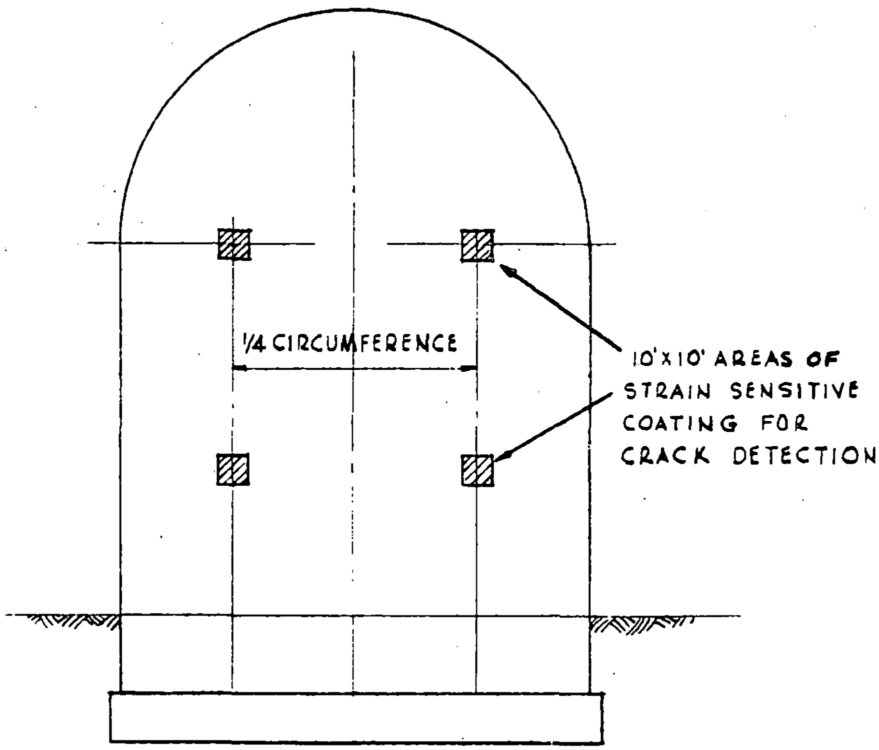
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Large Penetration Instrumentation
(Equipment and Personnel Hatches)

Updated FSAR

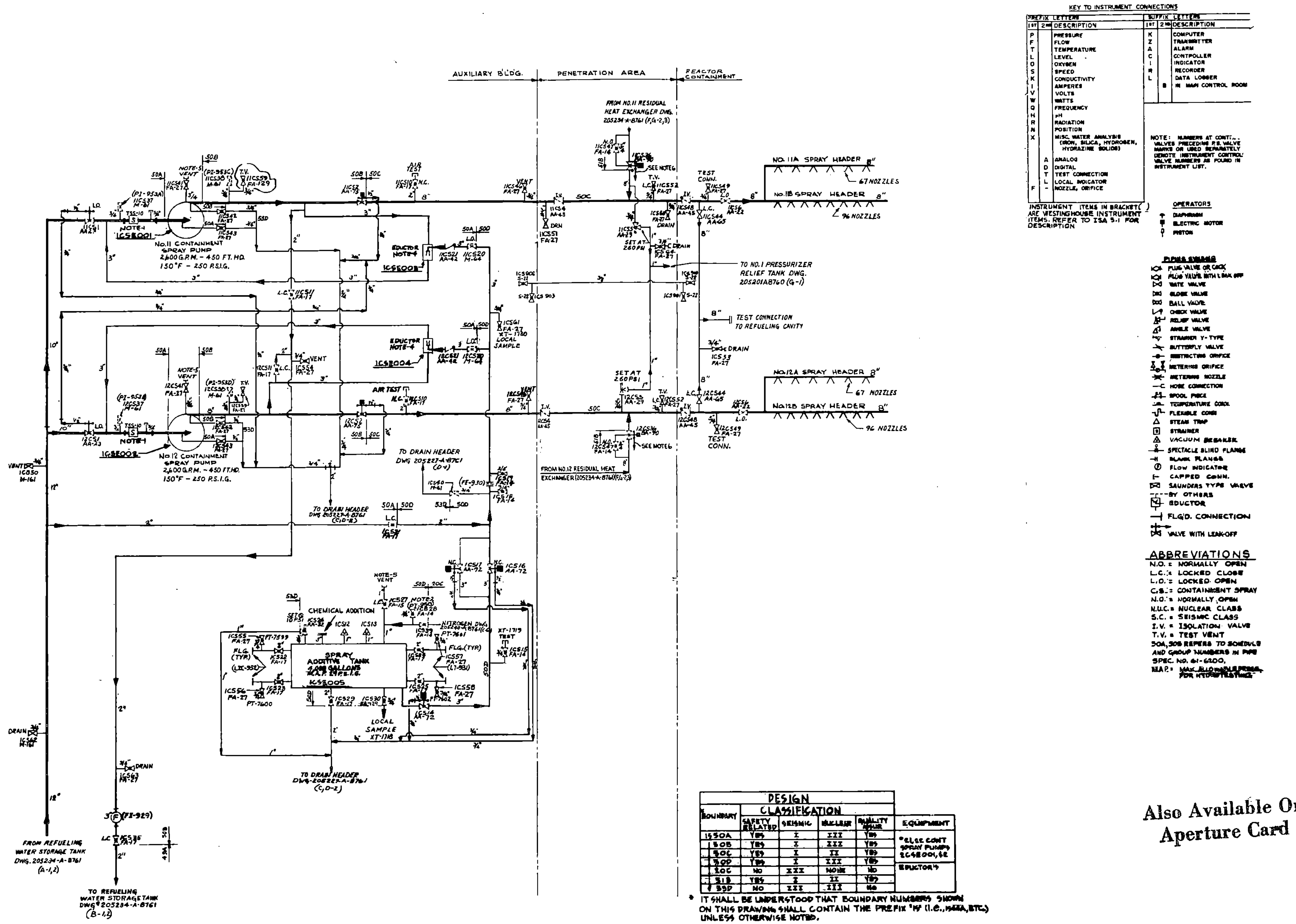
Figure 6.2-2

Revision 0
July 22, 1982



Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Location of Strain Sensitive Coatings on the Containment	
	Updated FSAR	Figure 6.2-3



BOUNDARY	DESIGN CLASSIFICATION				EQUIPMENT
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY REPAIR	
1550A	YES	I	III	YES	*11,12 CONT SPRAY PUMPS 1CS8001,12
50B	YES	I	III	YES	
50C	YES	I	II	YES	
50D	YES	I	III	YES	
20C	NO	III	NONE	NO	EDUCTORS
51B	YES	I	II	YES	
55D	NO	III	III	NO	

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX '15' (I.E., 1550A, ETC.) UNLESS OTHERWISE NOTED.

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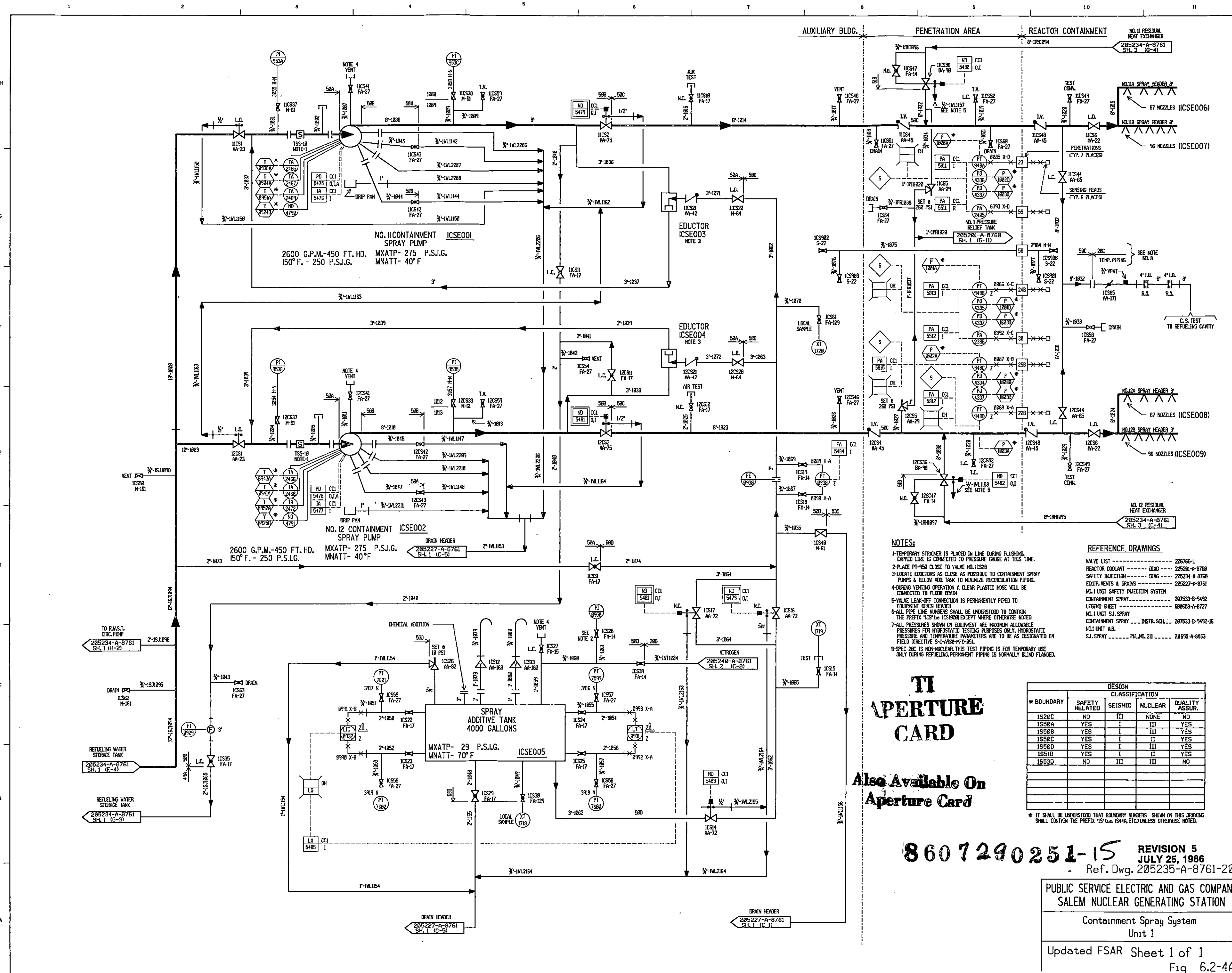
Revision 3
July 22, 1984

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Spray System
	UPDATED FSAR — FIG 6.2-4



NOTES:

1-TEMPORARY STRAINER IS PLACED IN LINE DURING FLUSHING. CAPPED LINE IS CONNECTED TO PRESSURE GAUGE AT THIS TIME.

2-PLACE PT-950 CLOSE TO VALVE NO. 1CS28

3-LOCATE EDUCTORS AS CLOSE AS POSSIBLE TO CONTAINMENT SPRAY PUMPS & BELOW ADD. TANK TO MINIMIZE RECIRCULATION PIPING.

4-DURING VENTING OPERATION A CLEAR PLASTIC HOSE WILL BE CONNECTED TO FLOOR DRAIN

5-VALVE LEAK-OFF CONNECTION IS PERMANENTLY PIPED TO EQUIPMENT DRAIN HEADER

6-ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1CS" (i.e. 1CS1001) EXCEPT WHERE OTHERWISE NOTED

7-ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.

8-SPEC 20C IS NON-NUCLEAR. THIS TEST PIPING IS FOR TEMPORARY USE ONLY DURING REFUELING, PERMANENT PIPING IS NORMALLY BLIND FLANGED.

REFERENCE DRAWINGS

VALVE LIST ------------------- 206766-L
REACTOR COOLANT ------ DIAG ---- 205201-A-8760
SAFETY INJECTION ------ DIAG ---- 205234-A-8760
EQUIP. VENTS & DRAINS ----------- 205227-A-8761
NO. 1 UNIT SAFETY INJECTION SYSTEM
CONTAINMENT SPRAY ------------- 207533-B-9492
LEGEND SHEET ---------------- 600658-A-8727
NO. 1 UNIT S.I. SPRAY
CONTAINMENT SPRAY ___ INSTR. SCH. __ 207533-B-9492-16
NO. 1 UNIT A.B.
S.I. SPRAY ______ PNL. NO. 211 _____ 211695-A-8853

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APERTURE
CARD

Also Available On
Aperture Card

DESIGN				
* BOUNDARY	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S20C	NO	III	NONE	NO
1S50A	YES	I	III	YES
1S50B	YES	I	III	YES
1S50C	YES	I	II	YES
1S50D	YES	I	III	YES
1S51B	YES	I	II	YES
1S53D	NO	III	III	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

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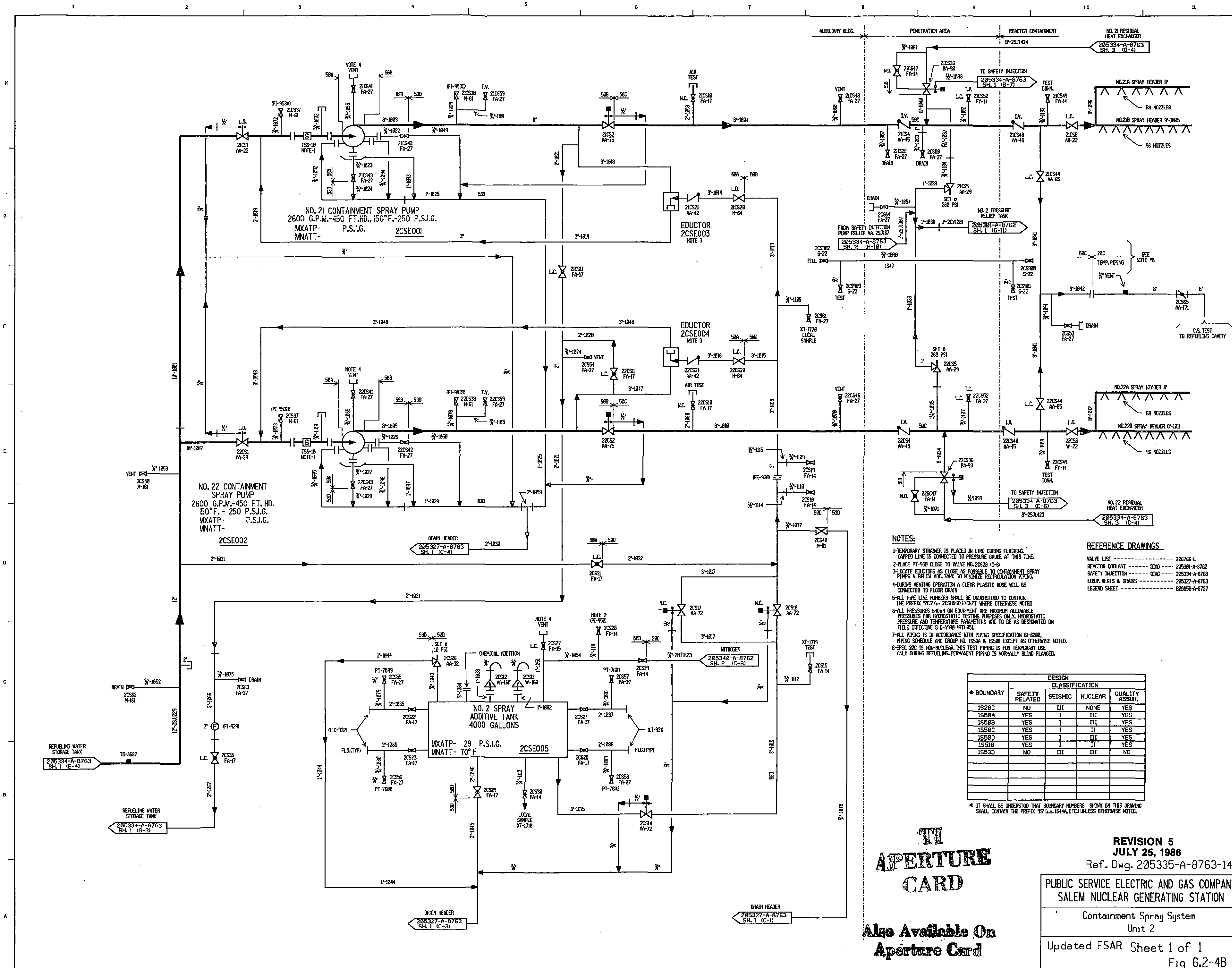
REVISION 5
JULY 25, 1986

Ref. Dwg. 205235-A-8761-20

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Containment Spray System
Unit 1

Updated FSAR Sheet 1 of 1
Fig 6.2-4A



NOTES:

1-TEMPORARY STRAINER IS PLACED IN LINE DURING FLUSHING. CAPPED LINE IS CONNECTED TO PRESSURE GAUGE AT THIS TIME.

2-PLACE PT-950 CLOSE TO VALVE NO. 2CS28 (C-6)

3-LOCATE EDUCTORS AS CLOSE AS POSSIBLE TO CONTAINMENT SPRAY PUMPS & BELOW ADD. TANK TO MINIMIZE RECIRCULATION PIPING.

4-DURING VENTING OPERATION A CLEAR PLASTIC HOSE WILL BE CONNECTED TO FLOOR DRAIN

5-ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2CS" (i.e 2CS1020) EXCEPT WHERE OTHERWISE NOTED

6-ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.

7-ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200, PIPING SCHEDULE AND GROUP NO. 1S50A & 1S50B EXCEPT AS OTHERWISE NOTED.

8-SPEC 20C IS NON-NUCLEAR. THIS TEST PIPING IS FOR TEMPORARY USE ONLY DURING REFUELING. PERMANENT PIPING IS NORMALLY BLIND FLANGED.

REFERENCE DRAWINGS

VALVE LIST ---------------- 206766-L
REACTOR COOLANT ------ DIAG ---- 205301-A-8762
SAFETY INJECTION ------ DIAG ---- 205334-A-8763
EQUIP. VENTS & DRAINS ---------- 205327-A-8763
LEGEND SHEET -------------- 680658-A-8727

* BOUNDARY	DESIGN CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S20C	NO	III	NONE	YES
1S50A	YES	I	III	YES
1S50B	YES	I	III	YES
1S50C	YES	I	II	YES
1S50D	YES	I	III	YES
1S51B	YES	I	II	YES
1S53D	NO	III	III	NO

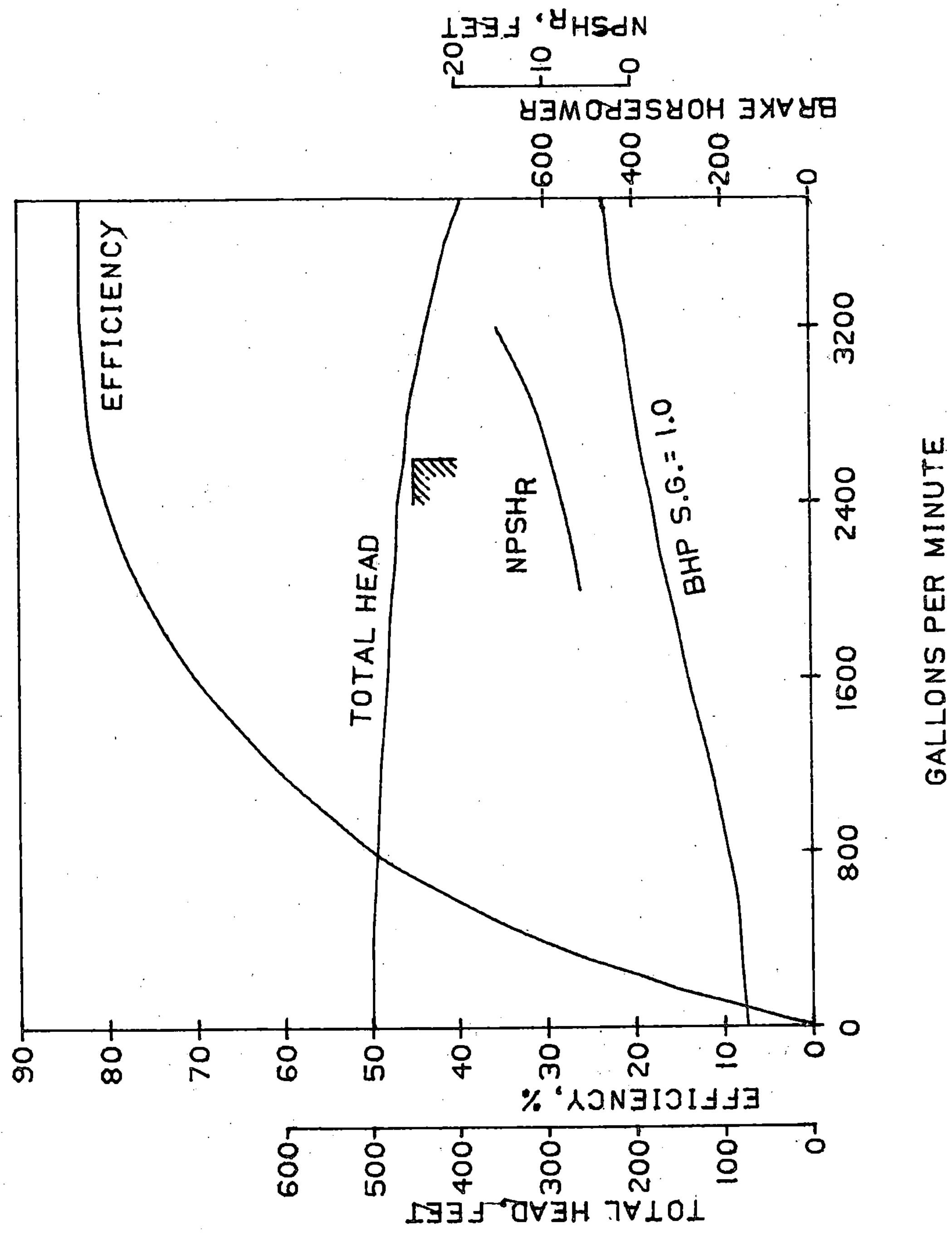
* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX '1S' (i.e. 1S44A, ETC) UNLESS OTHERWISE NOTED.

REVISION 5
JULY 25, 1986
Ref. Dwg. 205335-A-8763-14

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

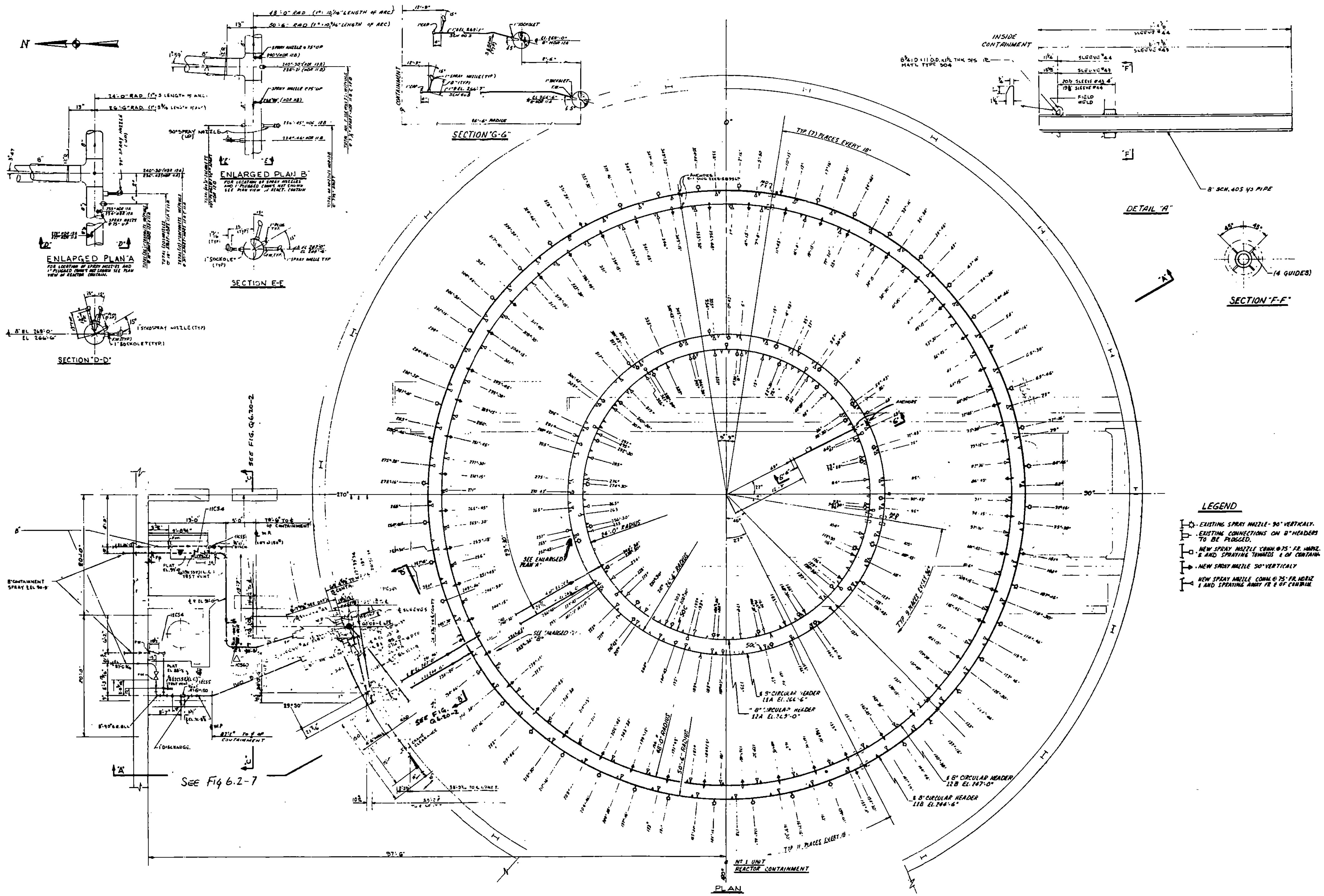
Containment Spray System
Unit 2

Updated FSAR Sheet 1 of 1
Fig 6.2-4B



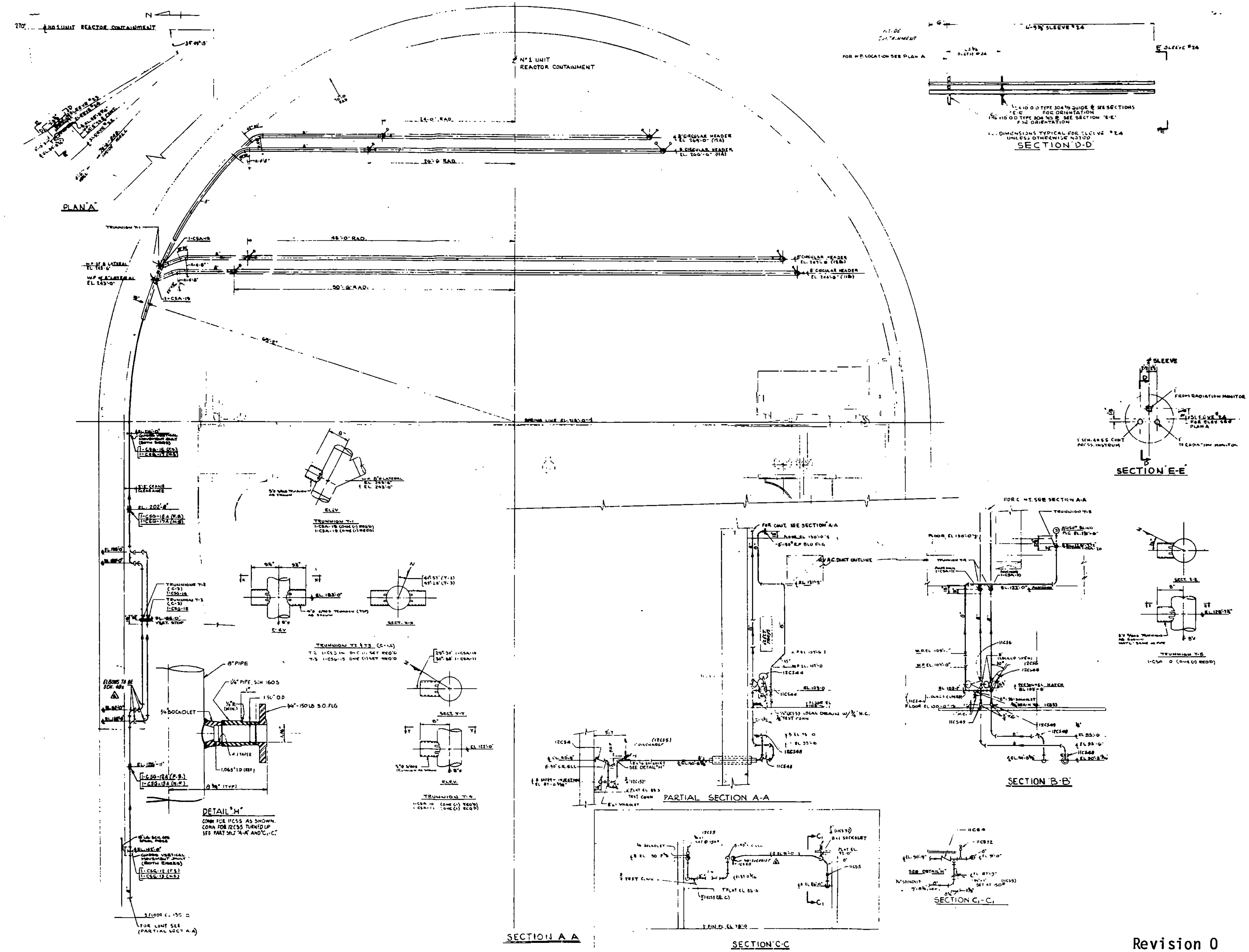
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Pump Head Characteristic Curve Containment Spray Pump
	Updated FSAR — FIG. 6.2-5



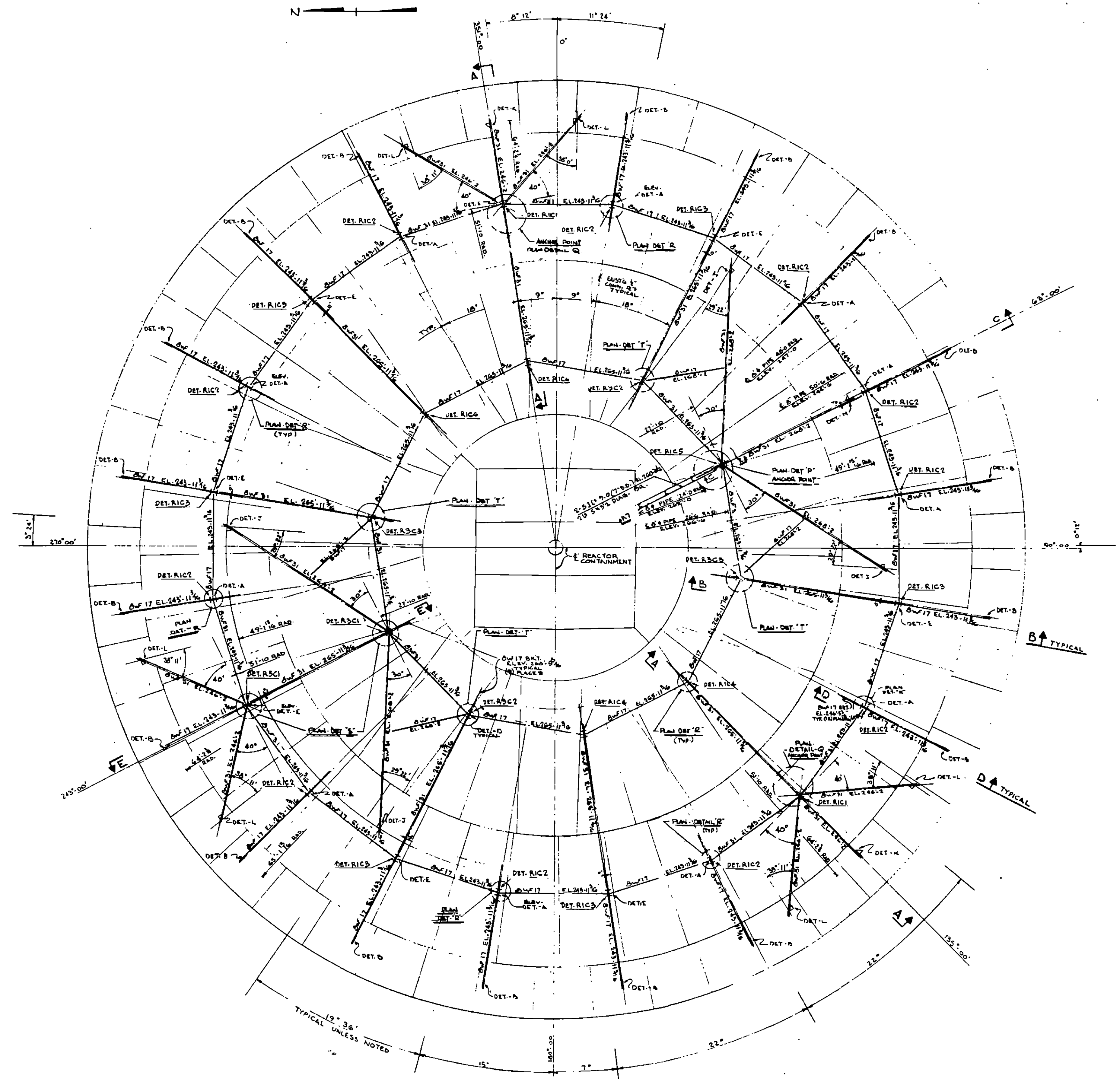
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Spray Piping – Plan
	Updated FSAR — Figure 6.2-6



Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Spray Piping – Section
	Updated FSAR — Figure 6.2-7

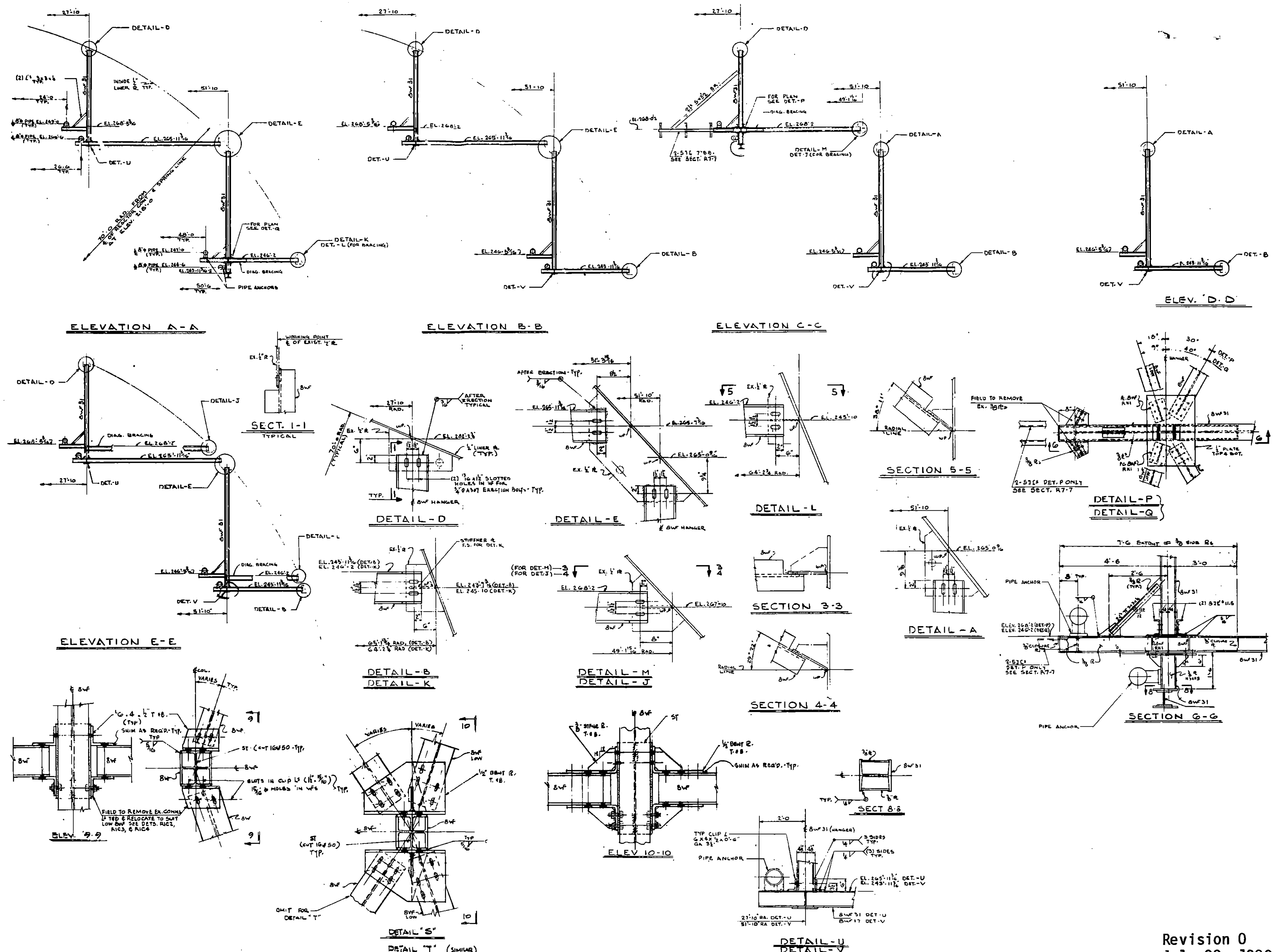


PLAN

ELEVATIONS GIVEN ARE TOP OF STEEL

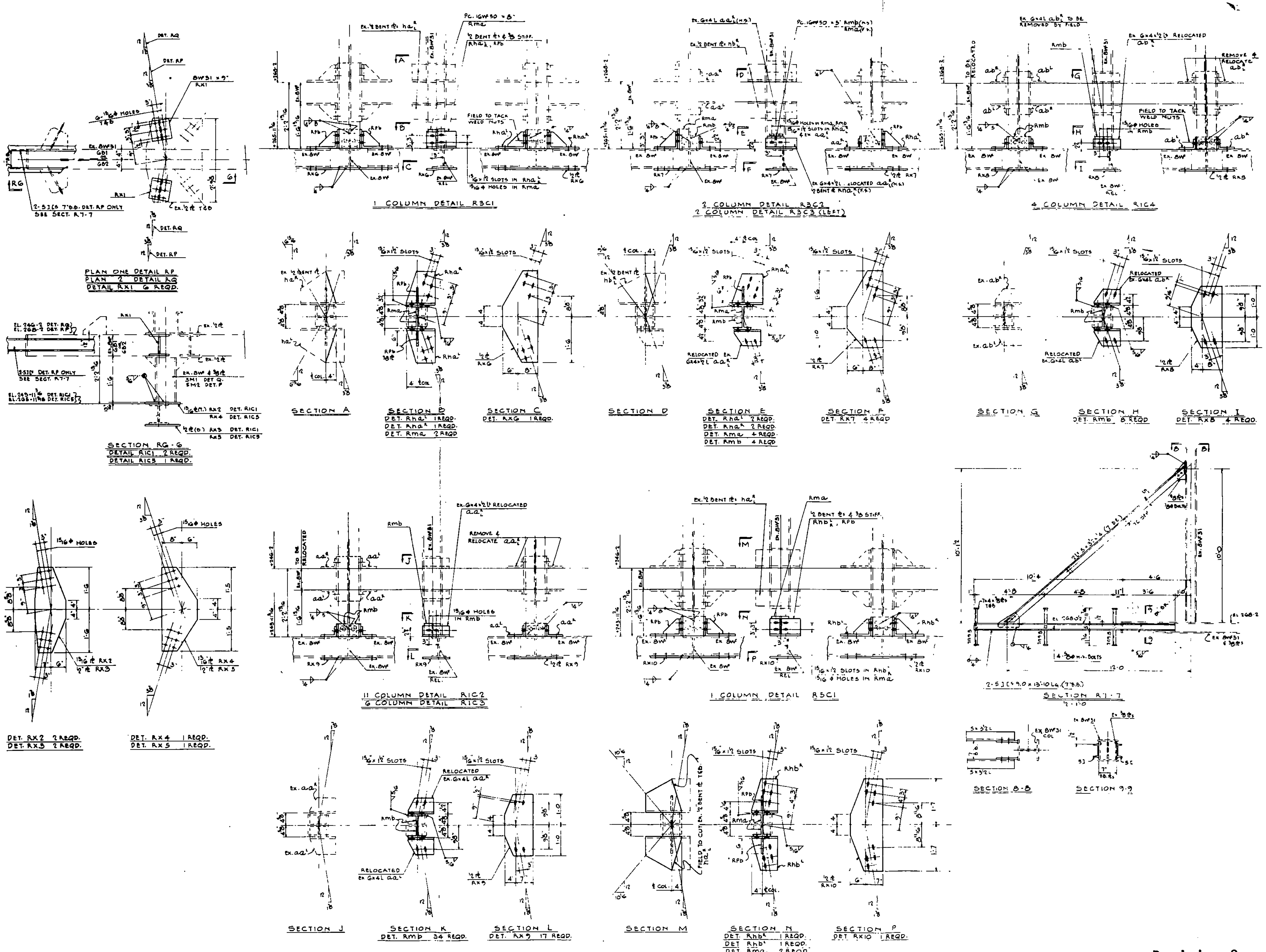
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Dome Liner – Miscellaneous Supports
	Updated FSAR — Figure 6.2-8



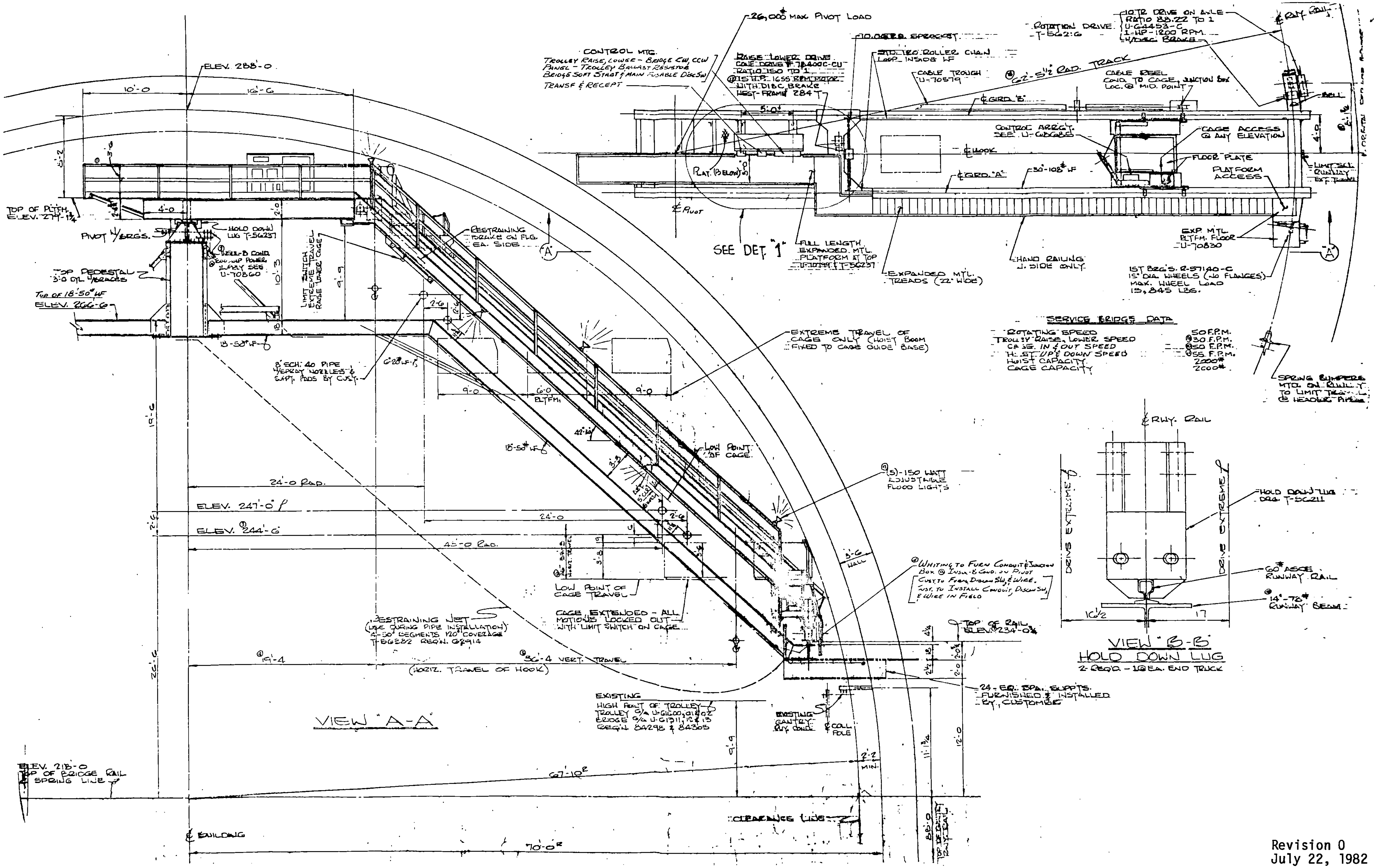
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Dome Liner — Miscellaneous Supports
	Updated FSAR Figure 6.2-9



Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Dome Liner – Miscellaneous Supports
	Updated FSAR — Figure 6.2-10



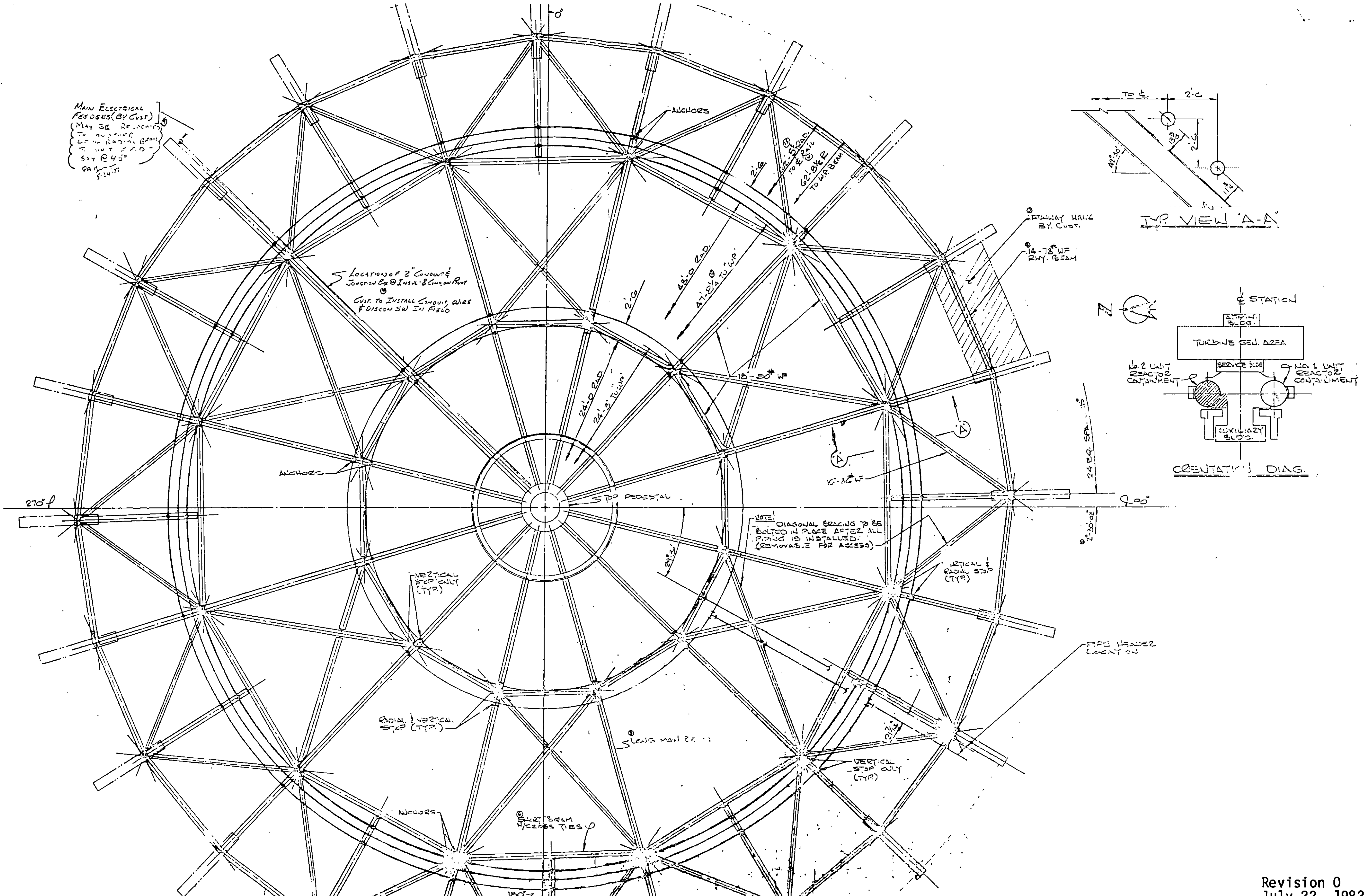
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Containment Dome Access System - Section View Orbital Bridge

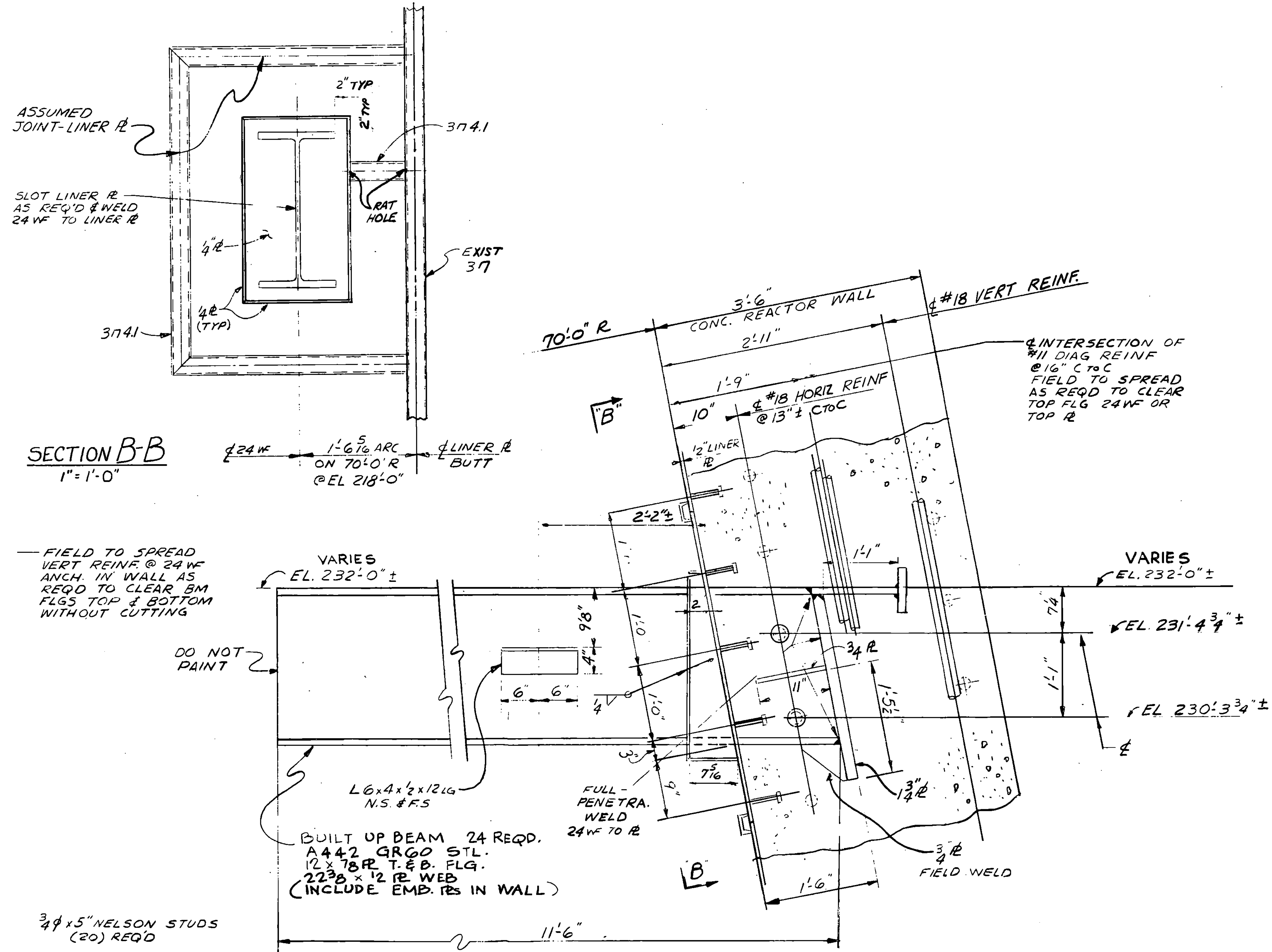
Updated FSAR

Figure 6.2-11



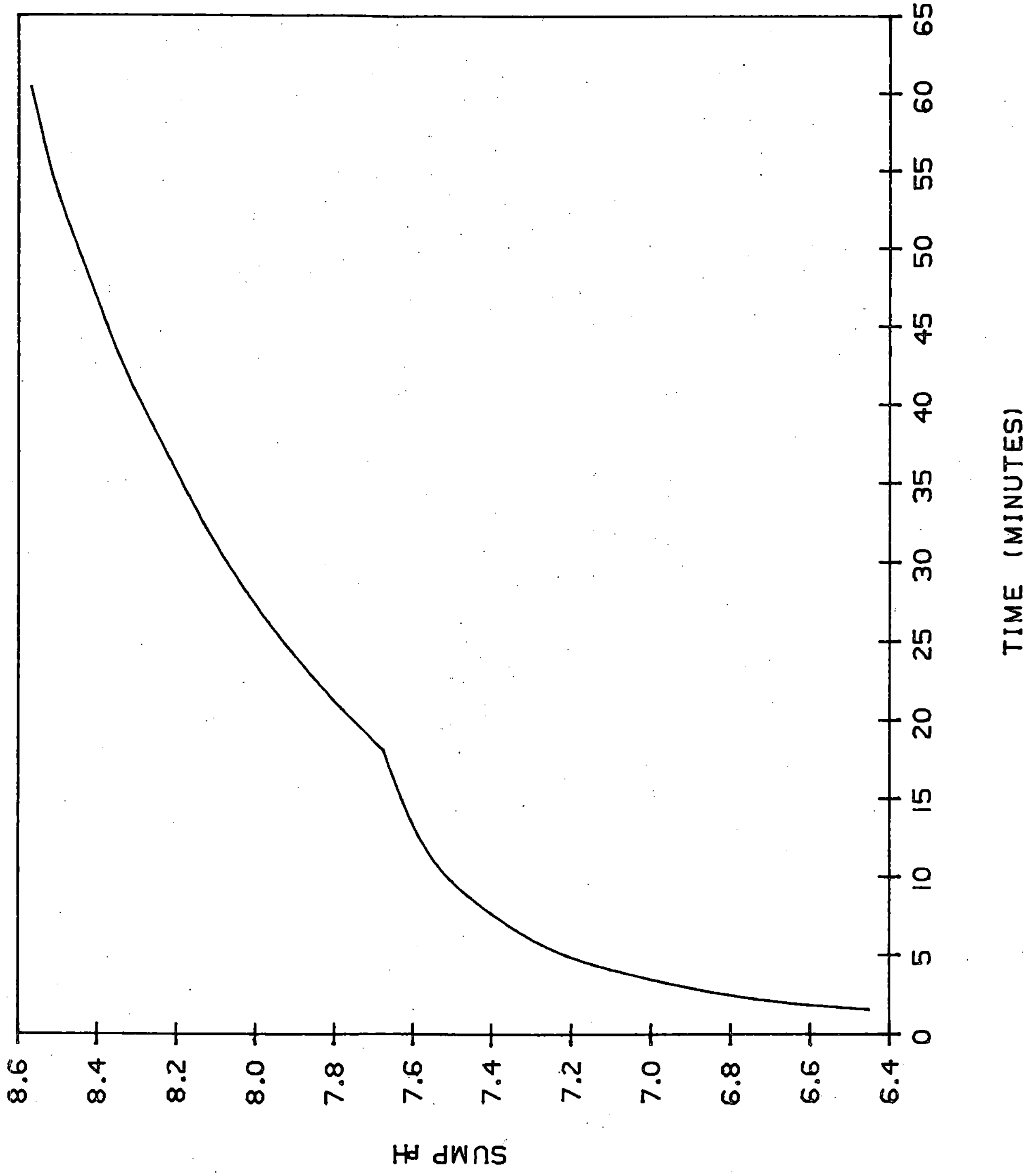
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Dome Access System Support Structure	
	Updated FSAR	Figure 6.2-12



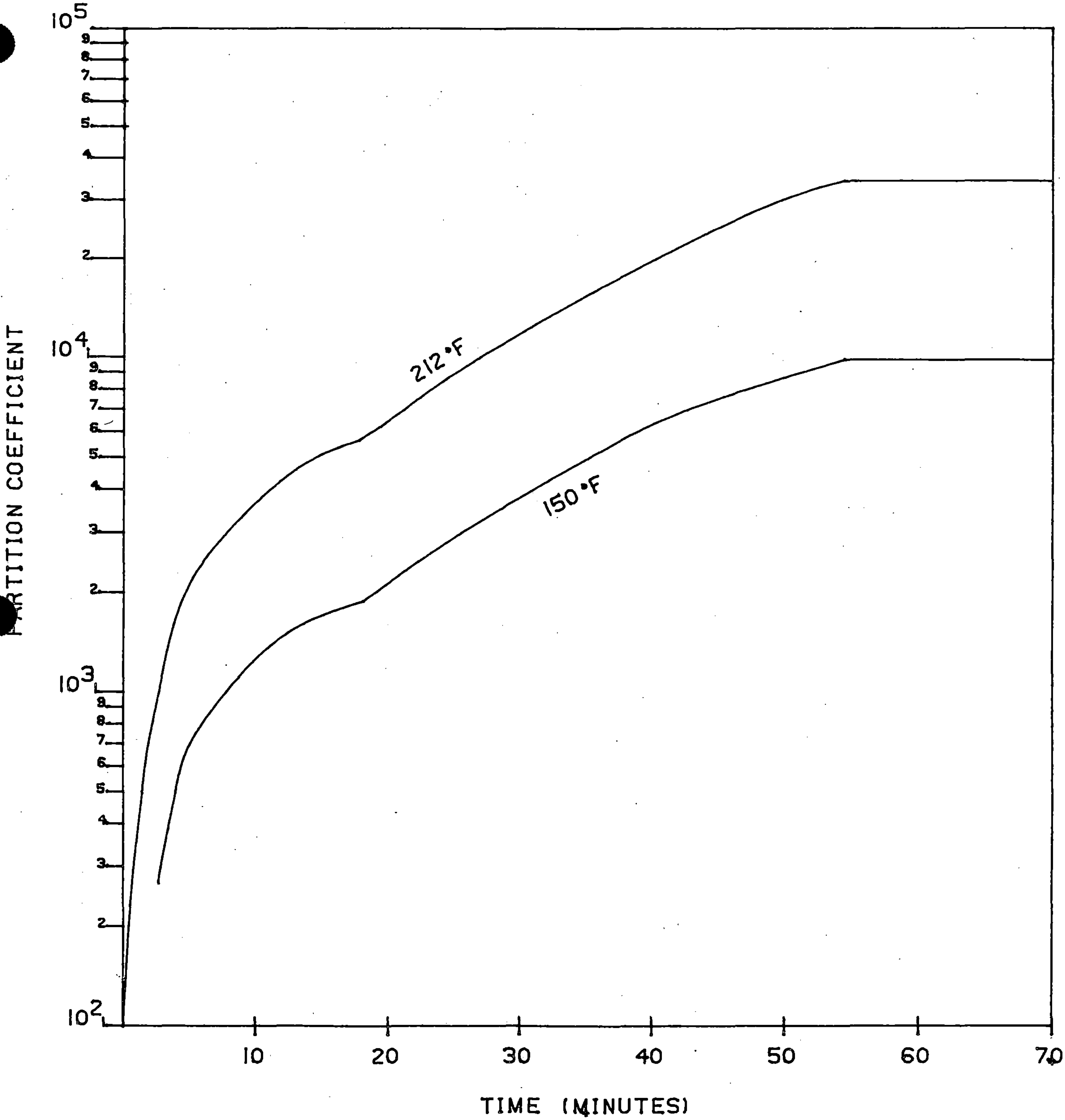
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Dome Access System Support Connection - Typical	
	Updated FSAR	Figure 6.2-13



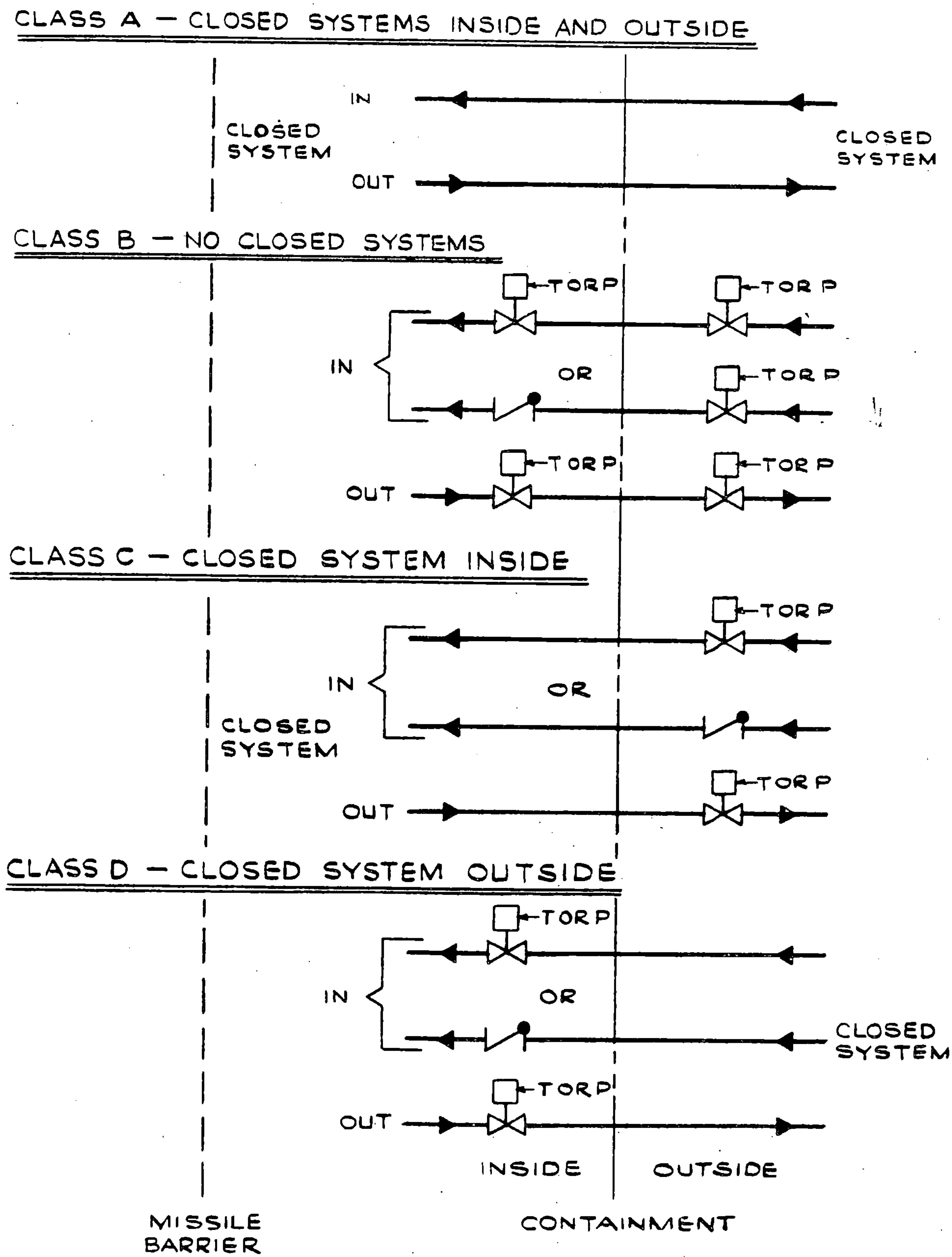
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Minimum Sump pH vs Time Updated FSAR FIG. 6.2-14



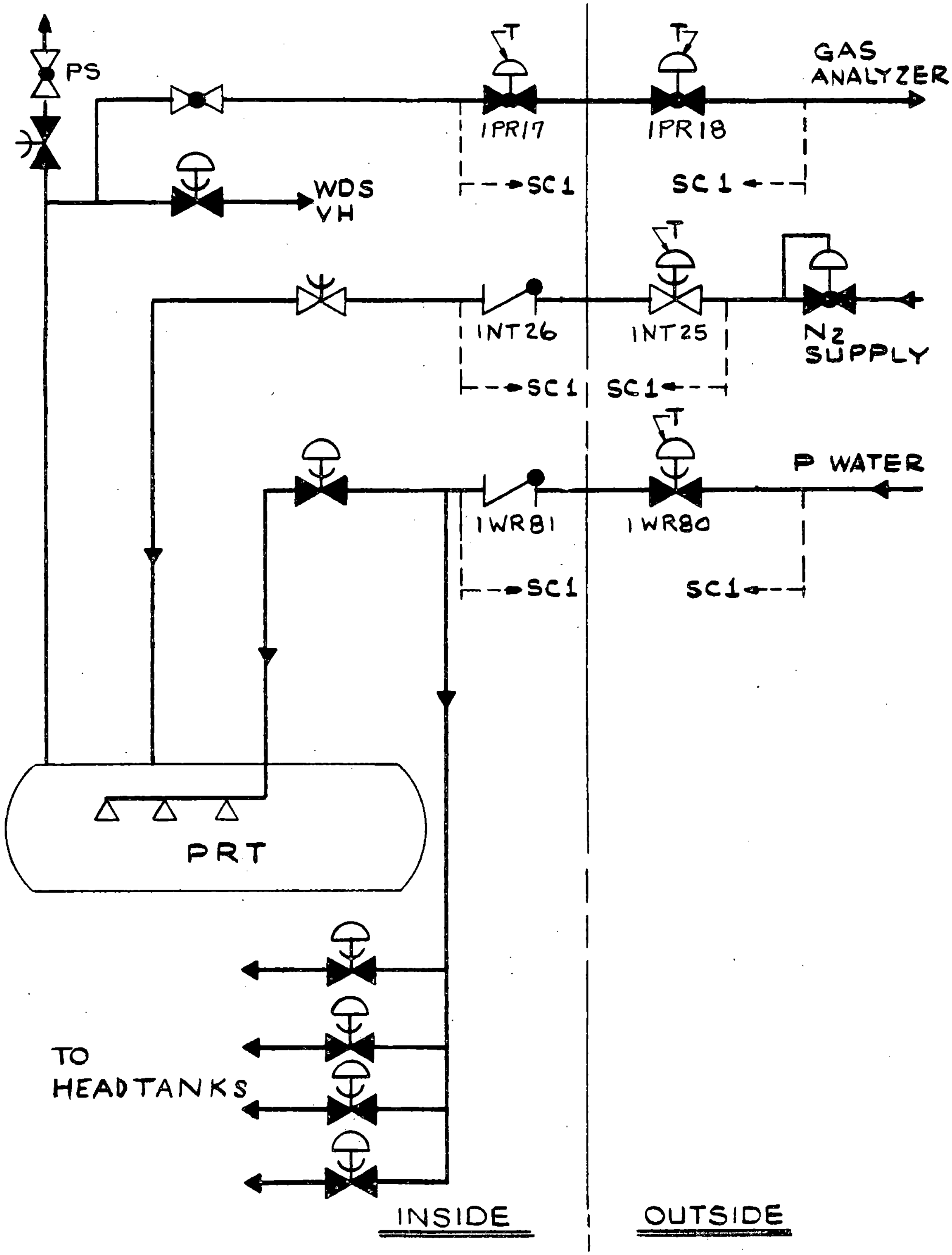
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Minimum Sump Partition Coefficient vs Time (Iodine Reaction not Included)
	Updated FSAR FIG. 6.2-15



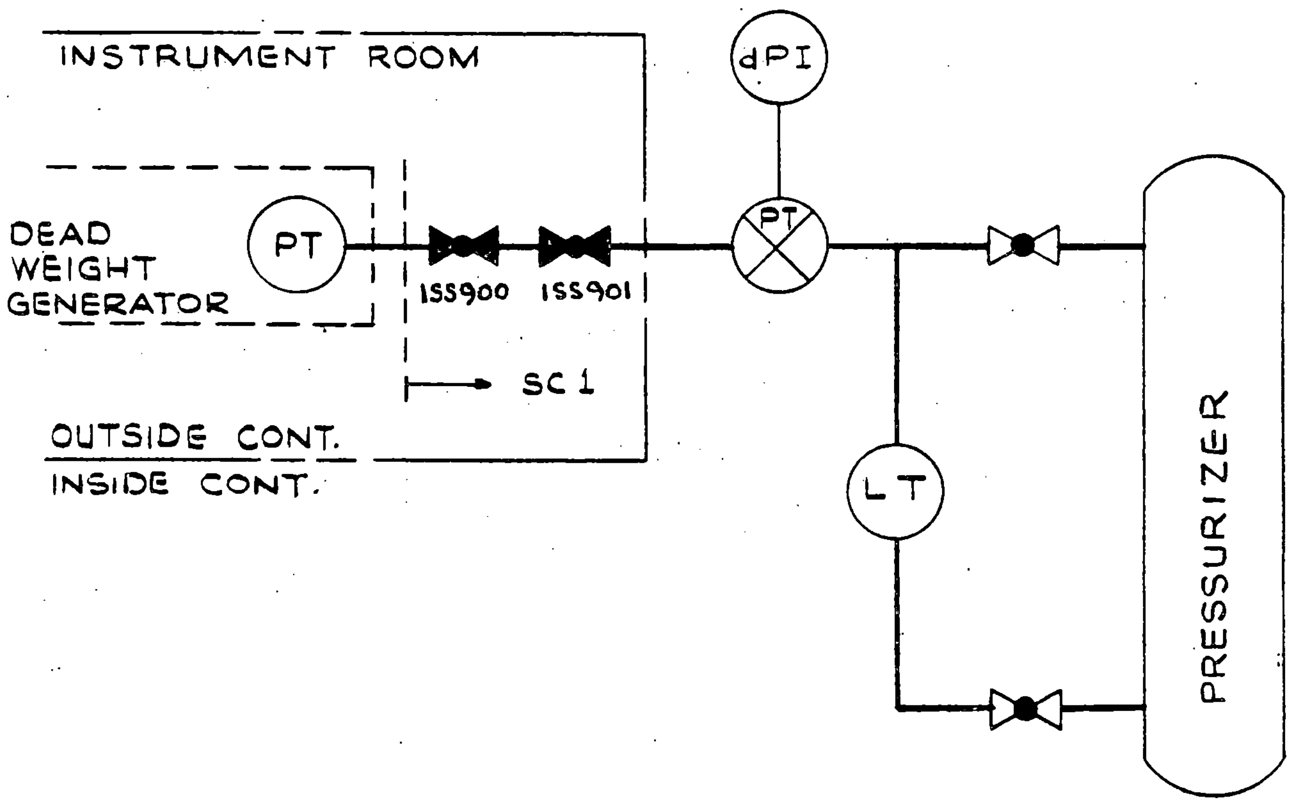
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Piping Classes	
	Updated FSAR	FIG. 6.2-16



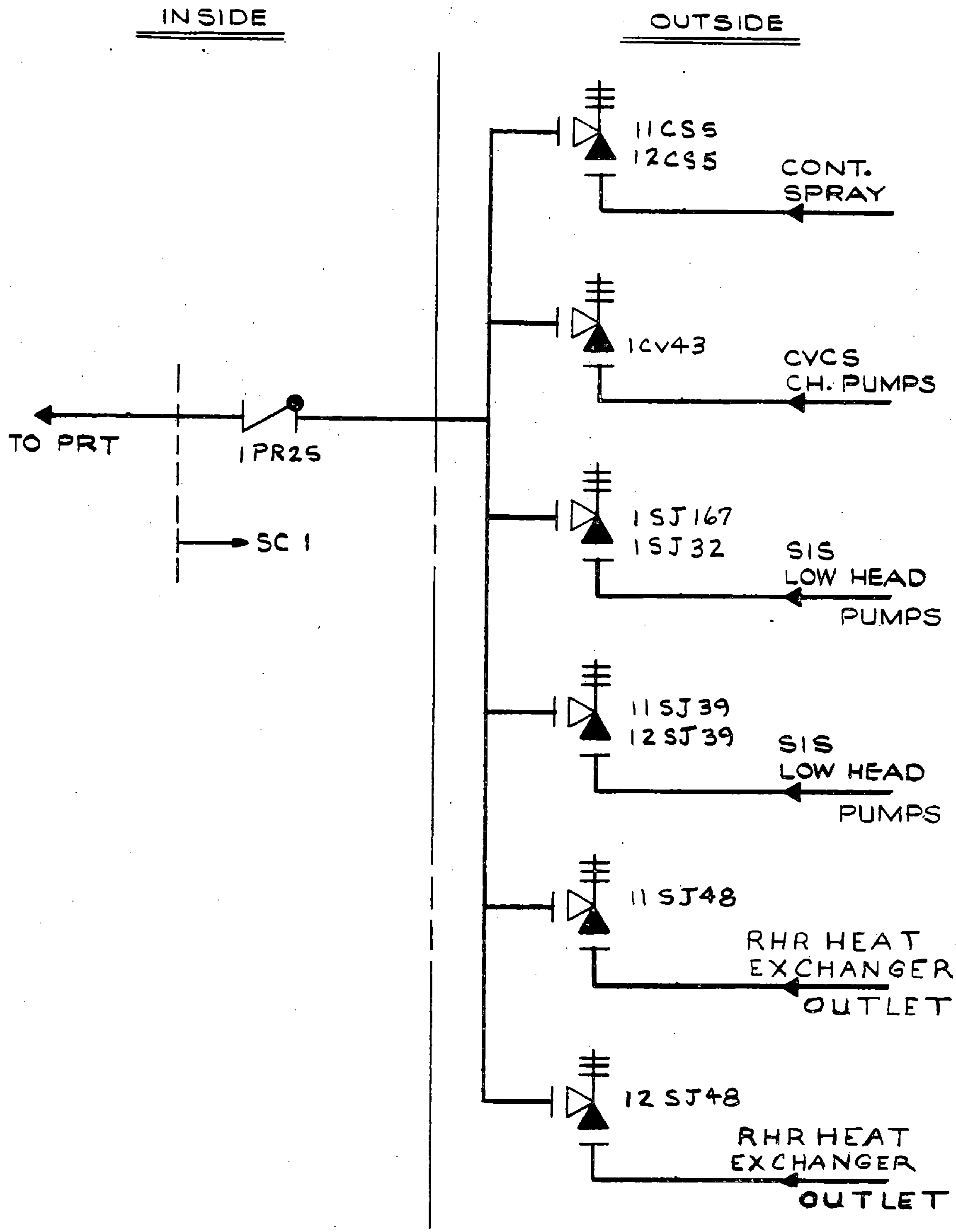
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Pressurizer Relief Tank Connections
	Updated FSAR — FIG. 6.2-17



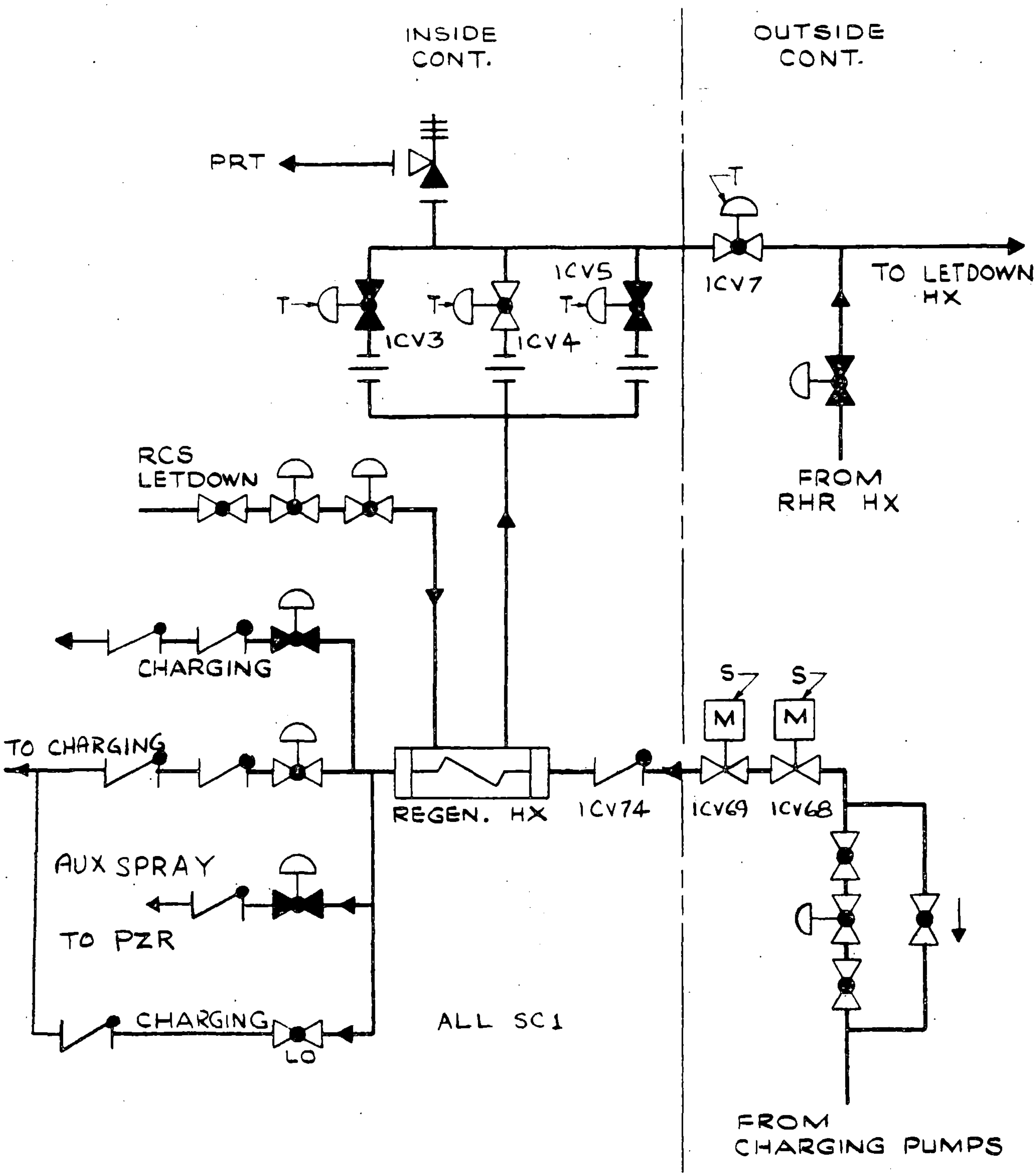
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Dead Weight Calibrator
	Updated FSAR — FIG. 6.2-18



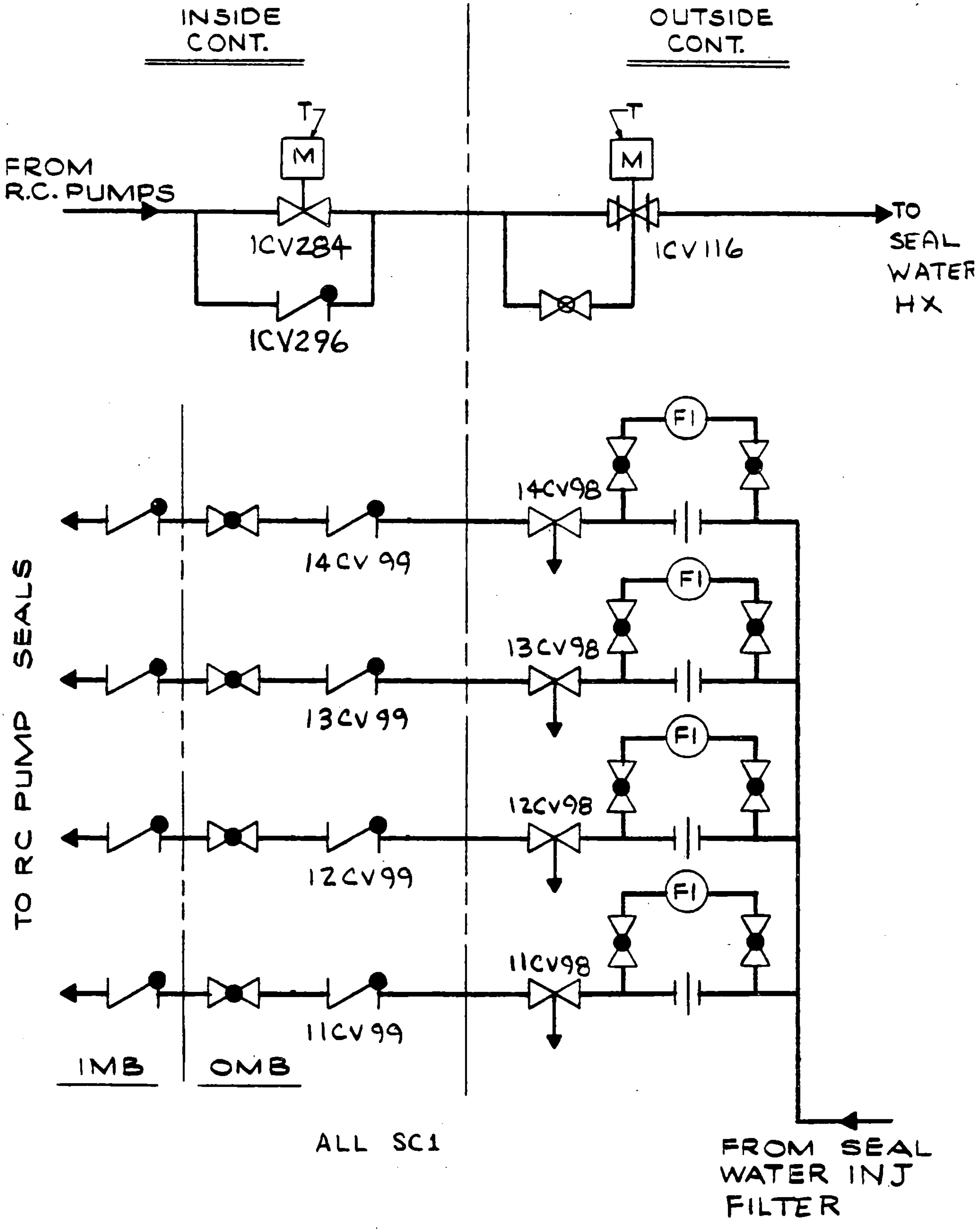
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Relief Lines to Pressurizer Relief Tank
	Updated FSAR — FIG. 6.2-19



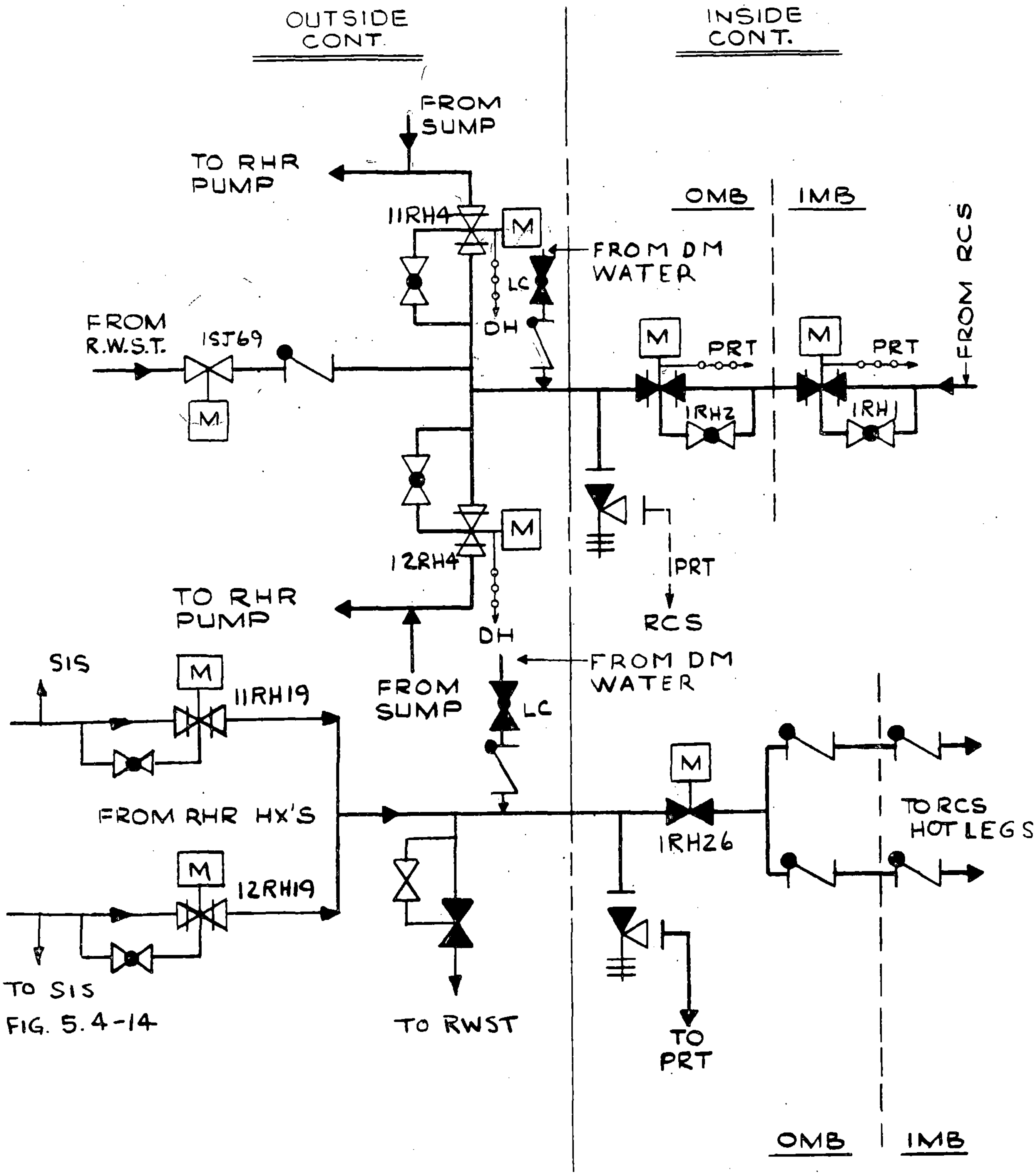
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Letdown and Charging Lines
	Updated FSAR — FIG. 6.2-20



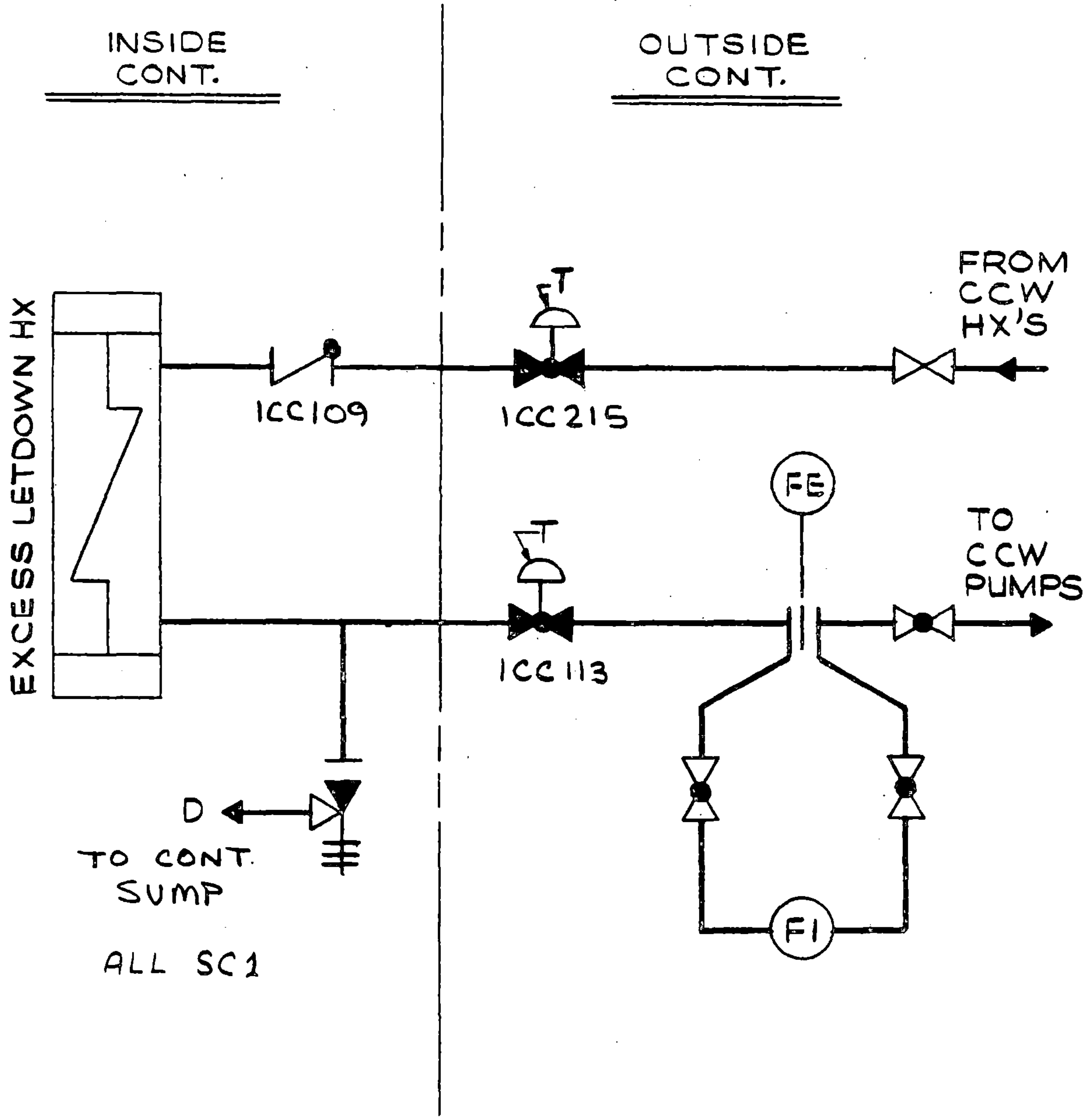
Revision 1
July 22, 1983

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Seal Water Supply and Return for R.C. Pumps
	Updated FSAR — FIG. 6.2-21



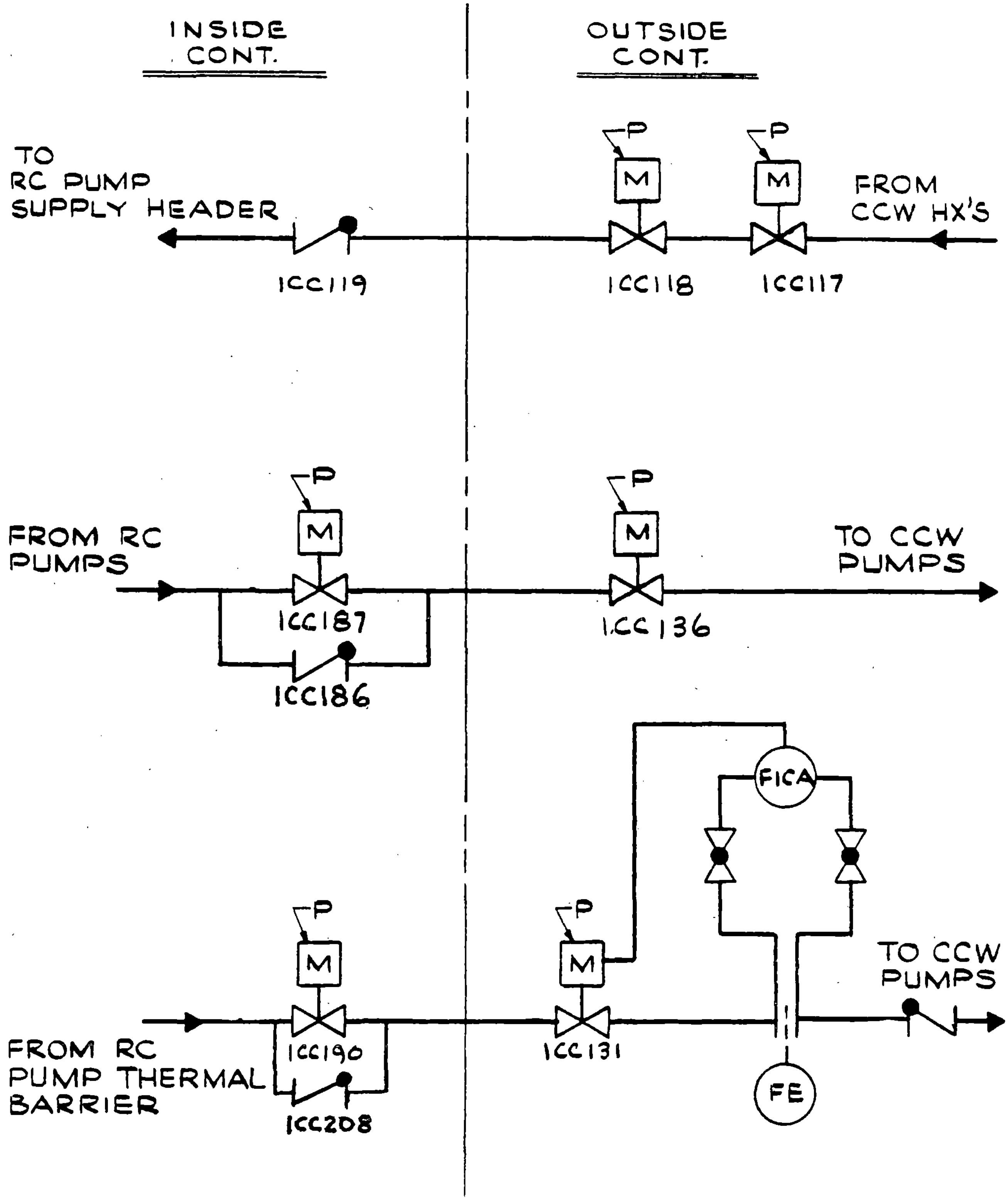
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Residual Heat Removal Connections	
	Updated FSAR	FIG. 6.2-22



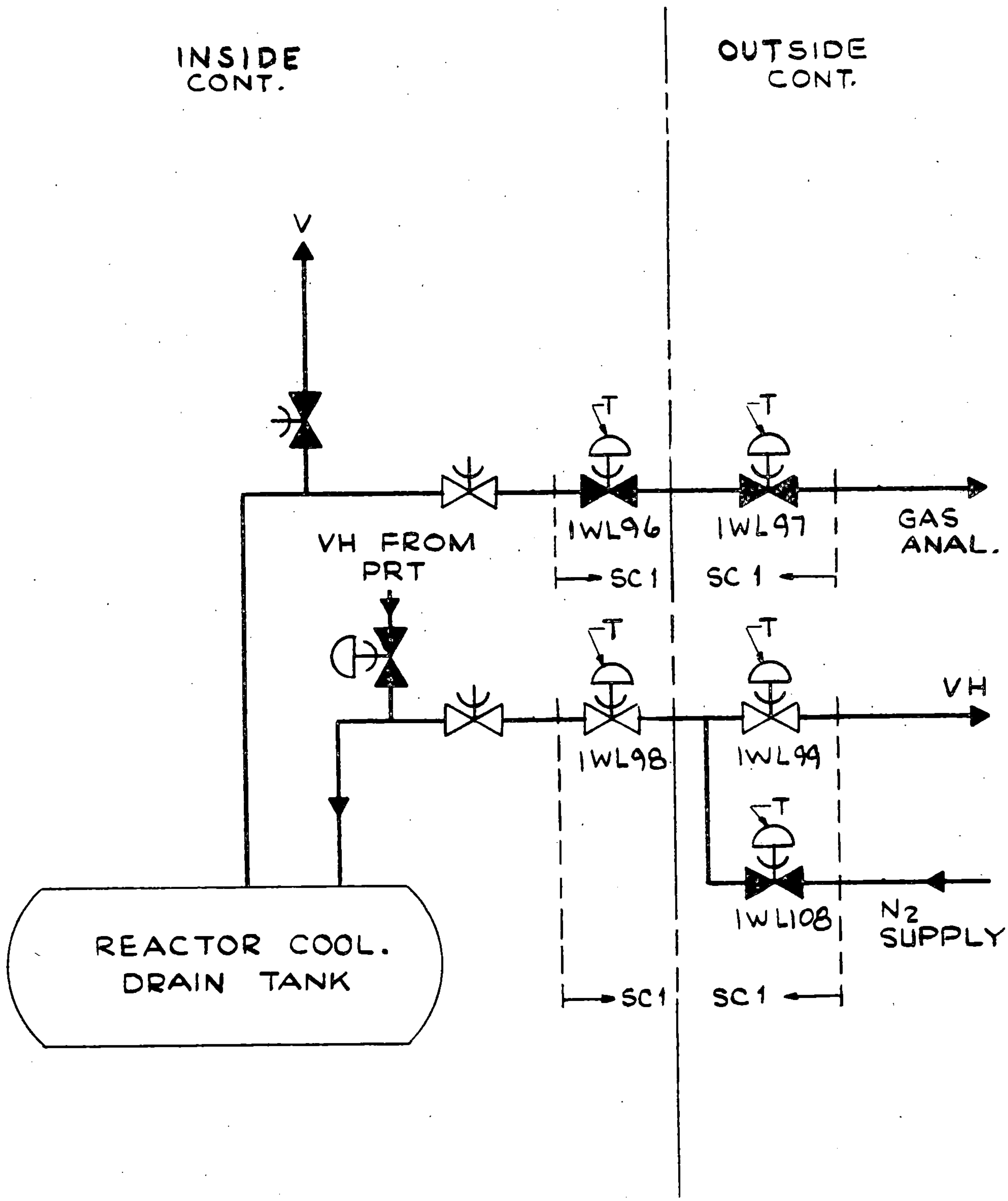
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Component Cooling for Excess Letdown HX
	Updated FSAR — FIG. 6.2-23



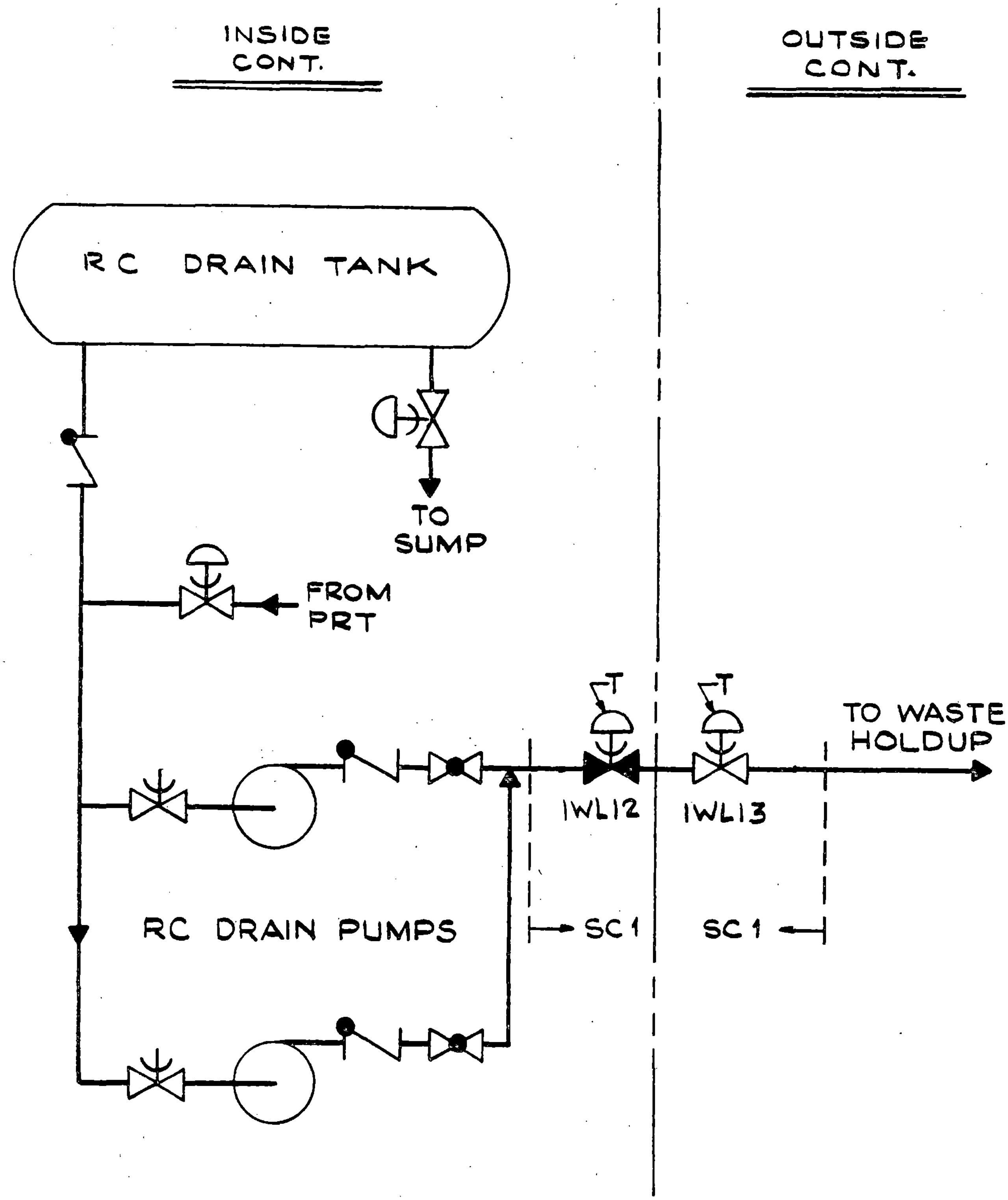
Revision 1
July 22, 1983

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Component Cooling For Reactor Coolant Pumps	
	Updated FSAR	FIG. 6.2-24



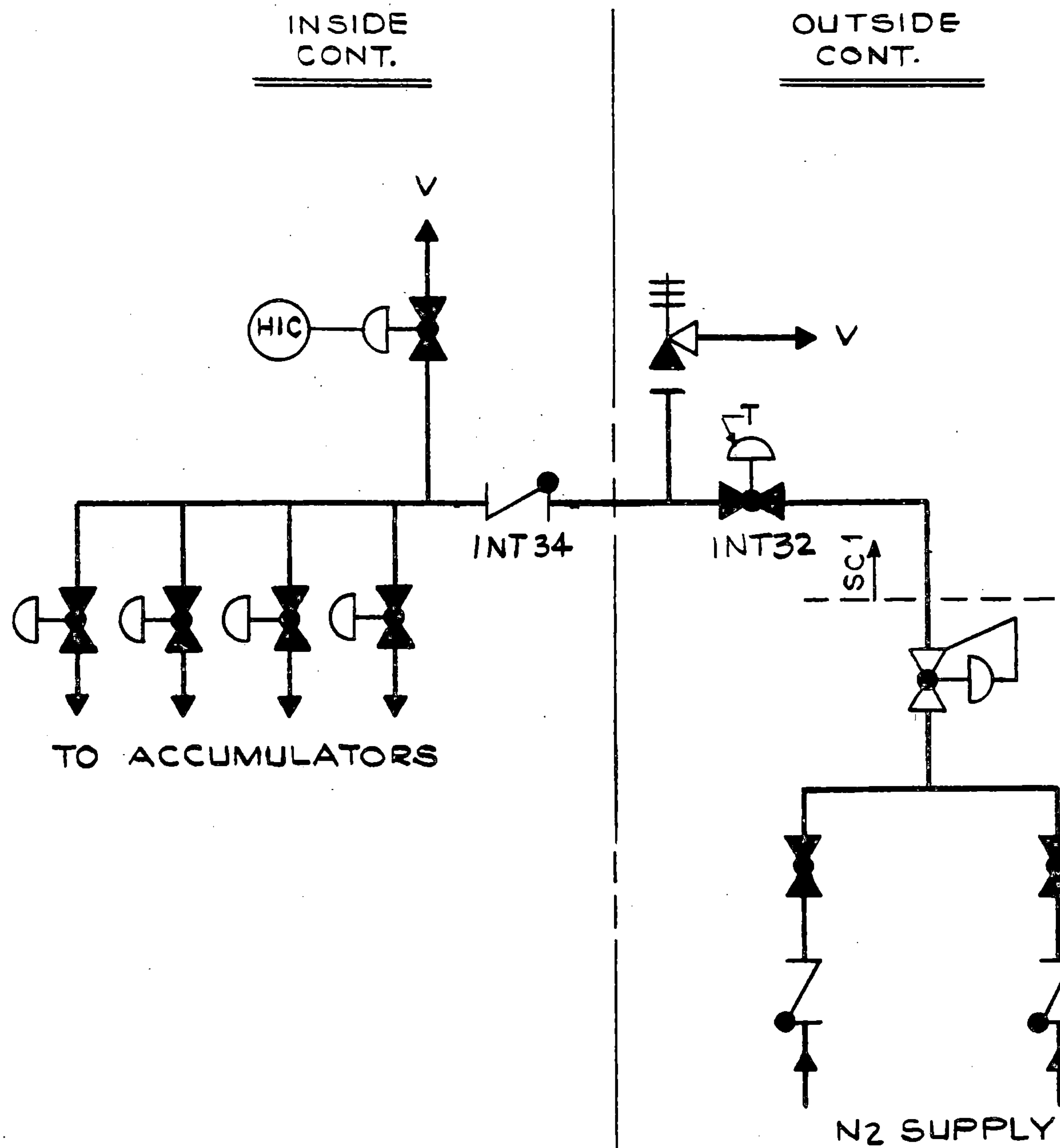
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Reactor Coolant Drain Tank Connections	
	Updated FSAR	FIG. 6.2-25



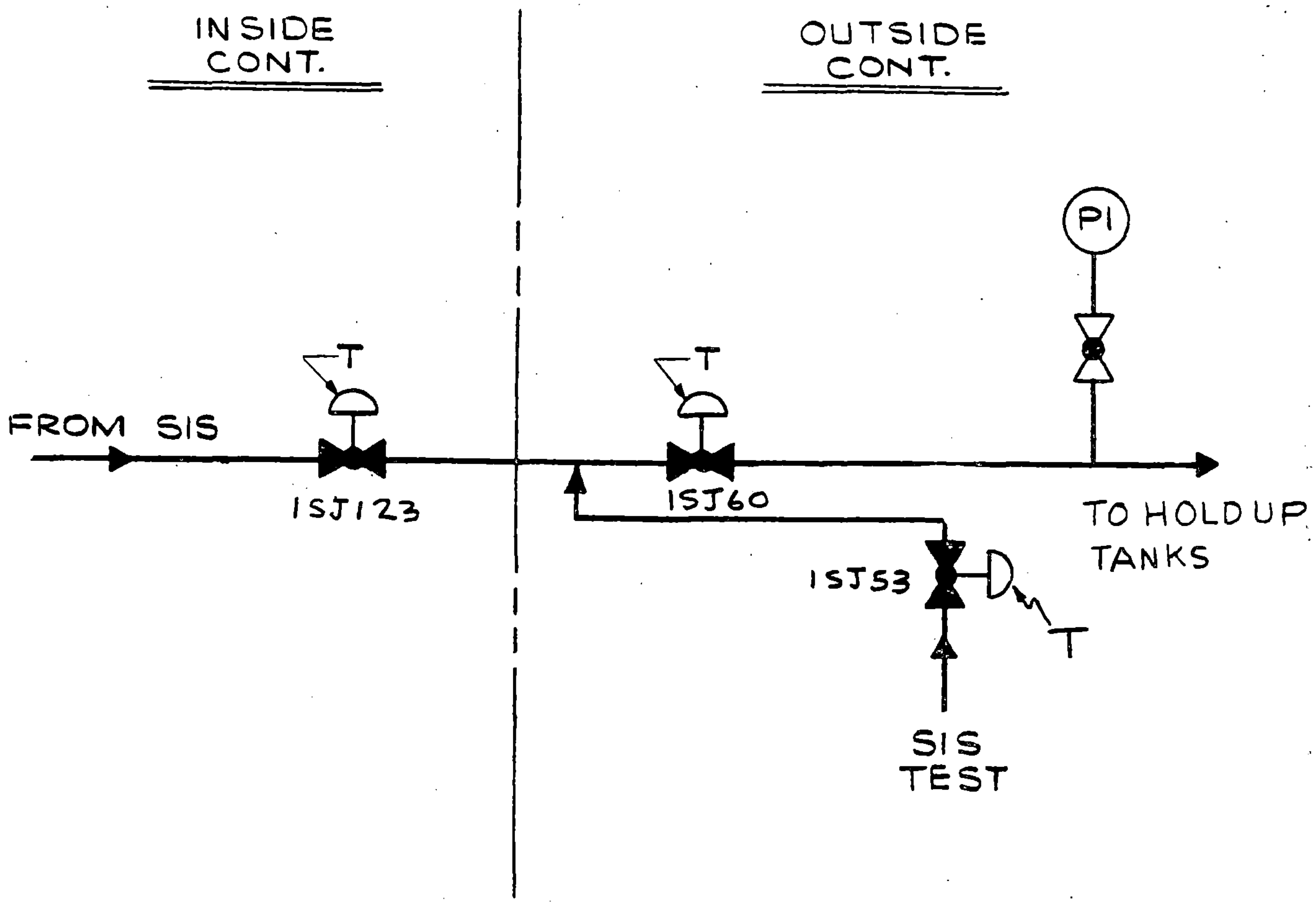
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Reactor Coolant Drain Tank Pumps	
	Updated FSAR	FIG. 6.2-26



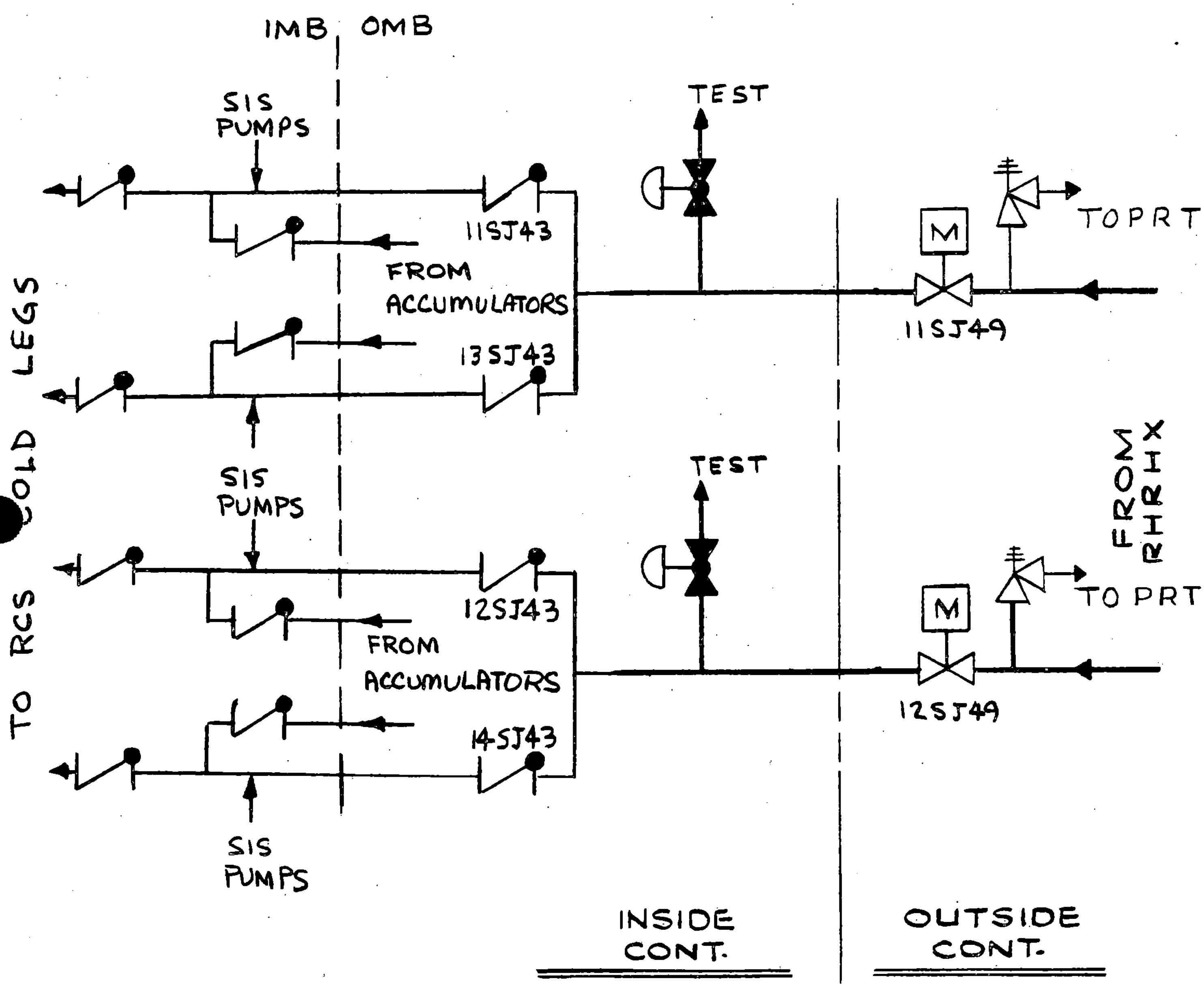
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Accumulator Nitrogen Supply	
	Updated FSAR	FIG. 6.2-27



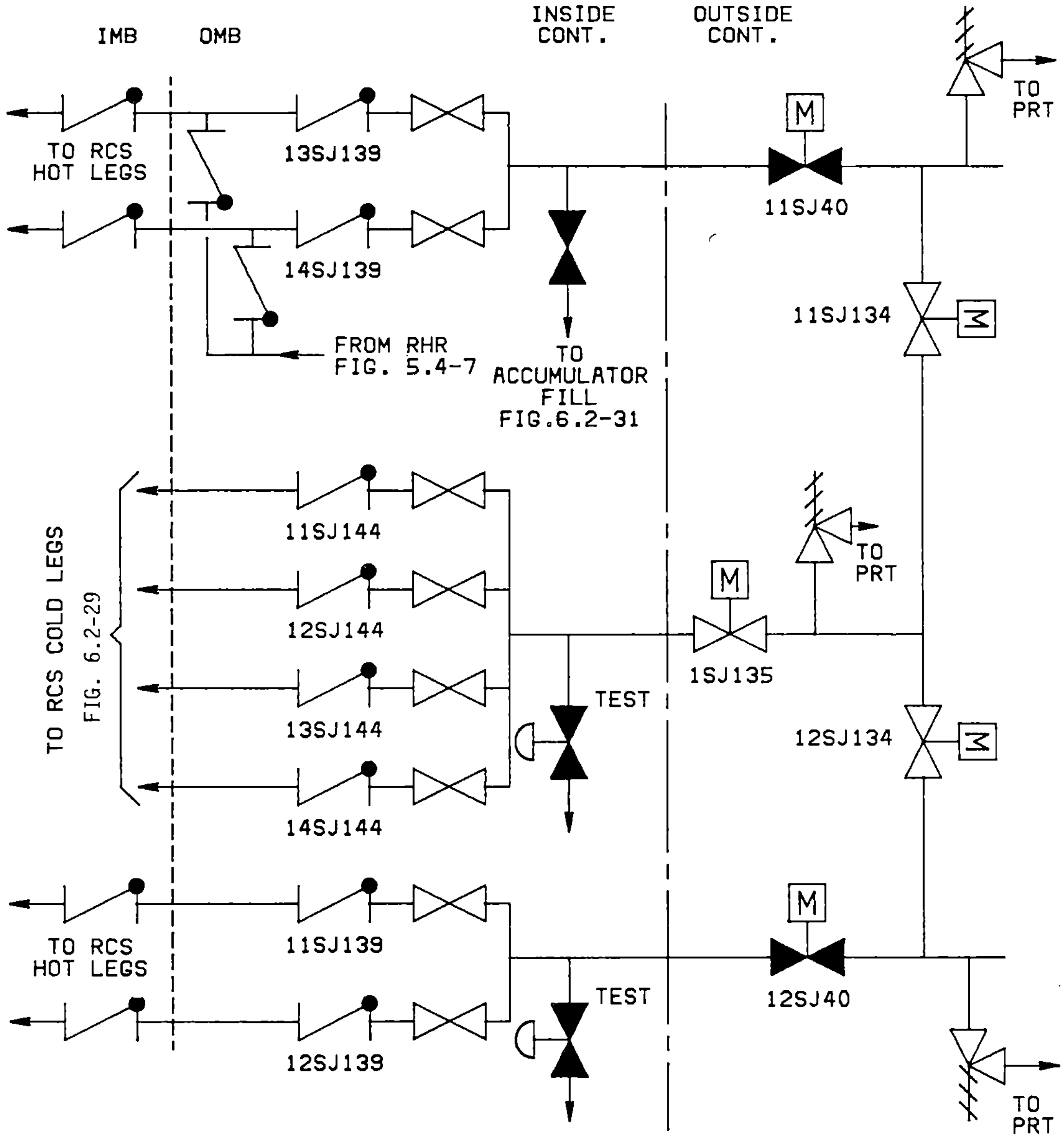
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Safety Injection Test Line
	Updated FSAR — FIG. 6.2-28



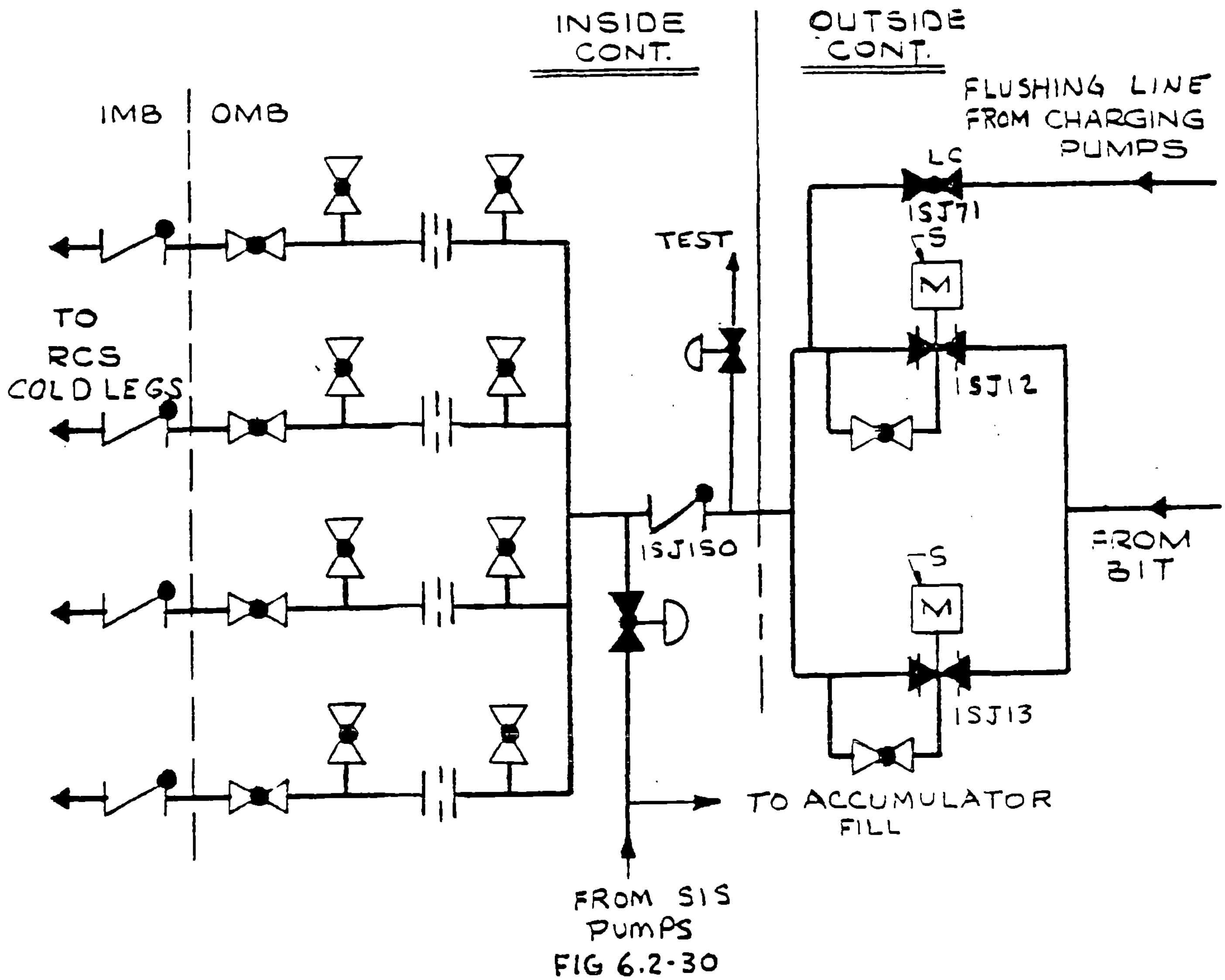
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation RHR Safety Injection Connections Updated FSAR FIG. 6.2-29



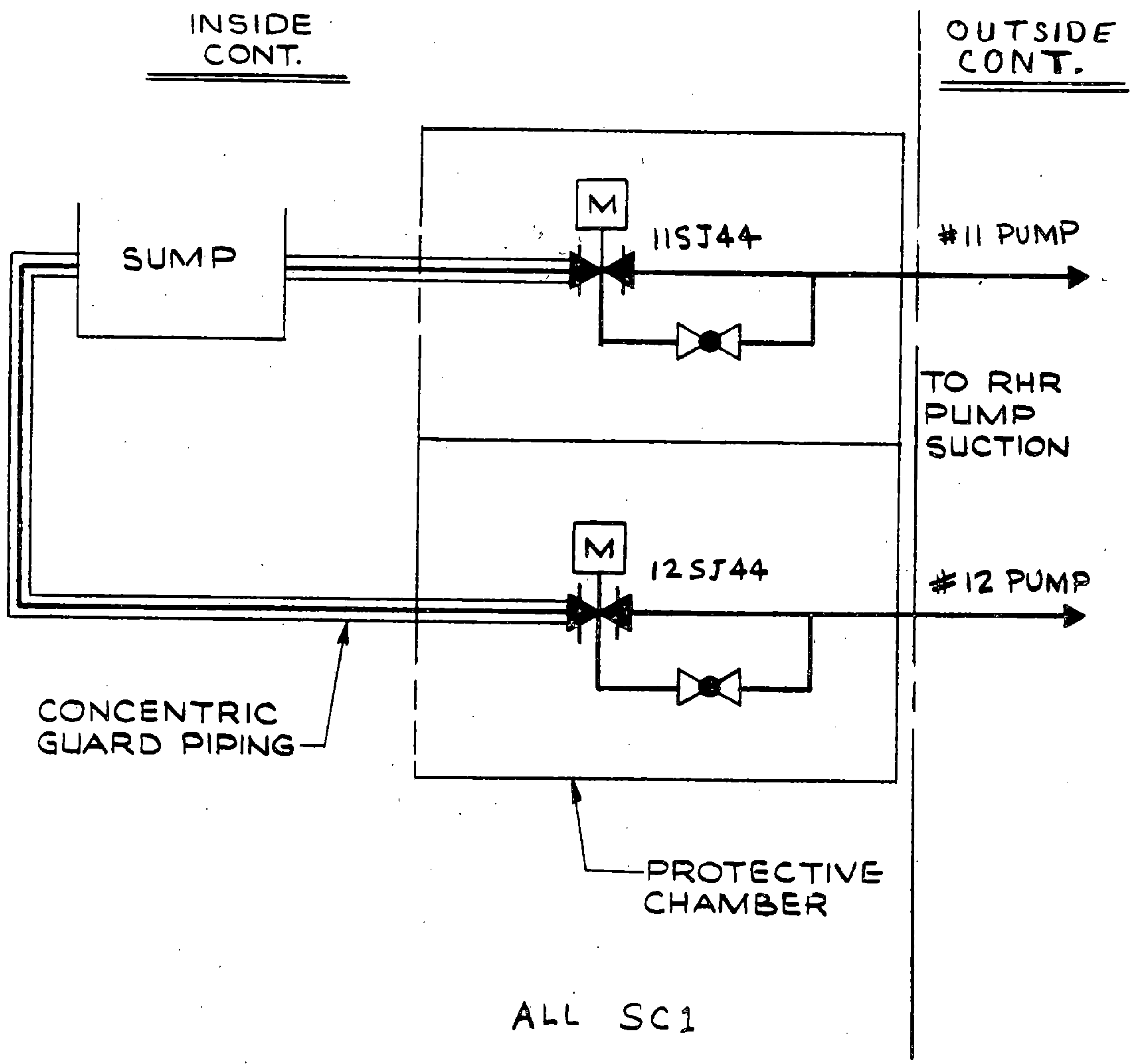
Revision 1
July 22, 1983

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Safety Injection Pump Connections
	UPDATED FSAR FIG 6.2-30



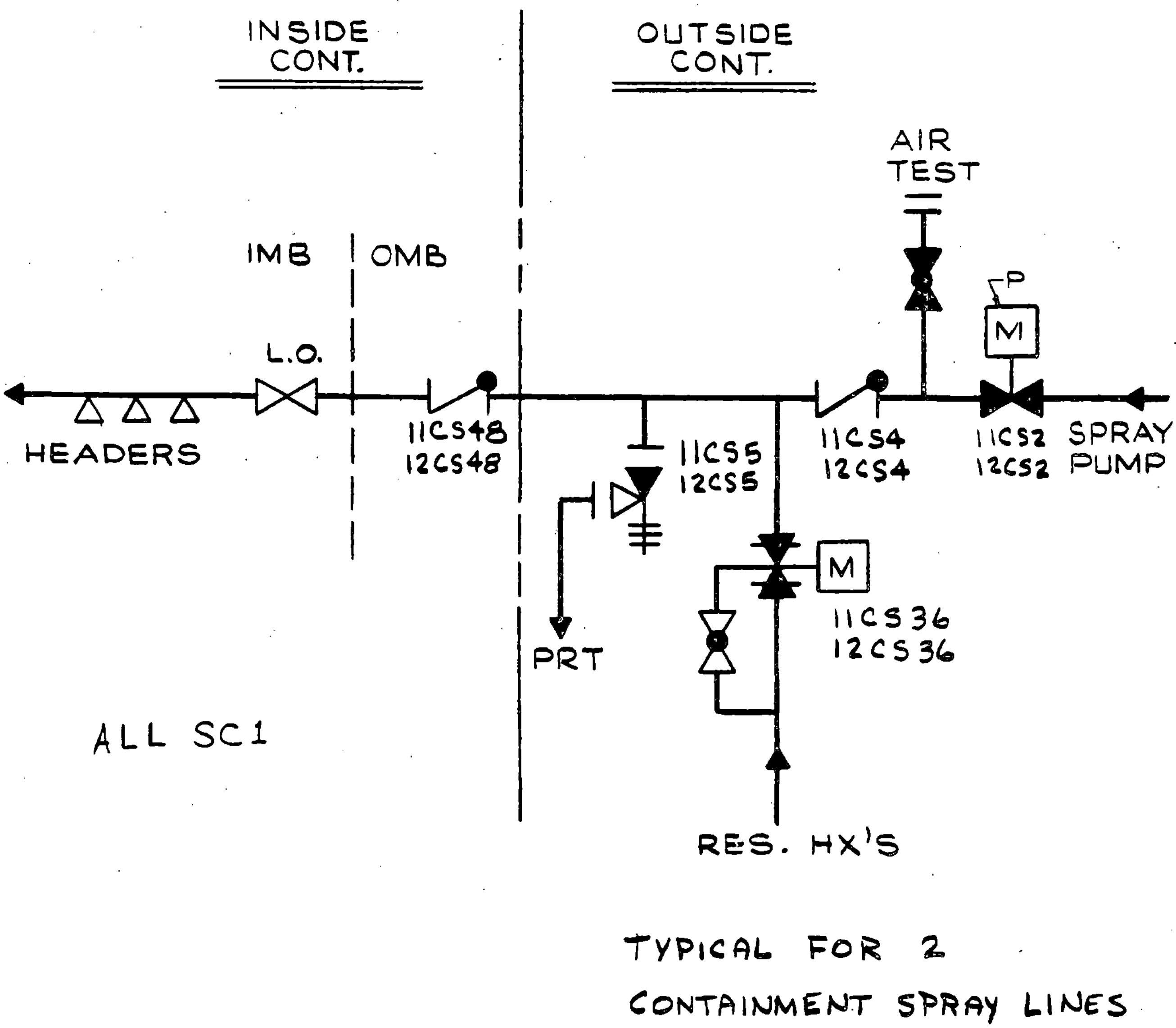
Revision 1
July 22, 1983

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Charging Pump Connections
	UPDATED FSAR FIG 6.2-31



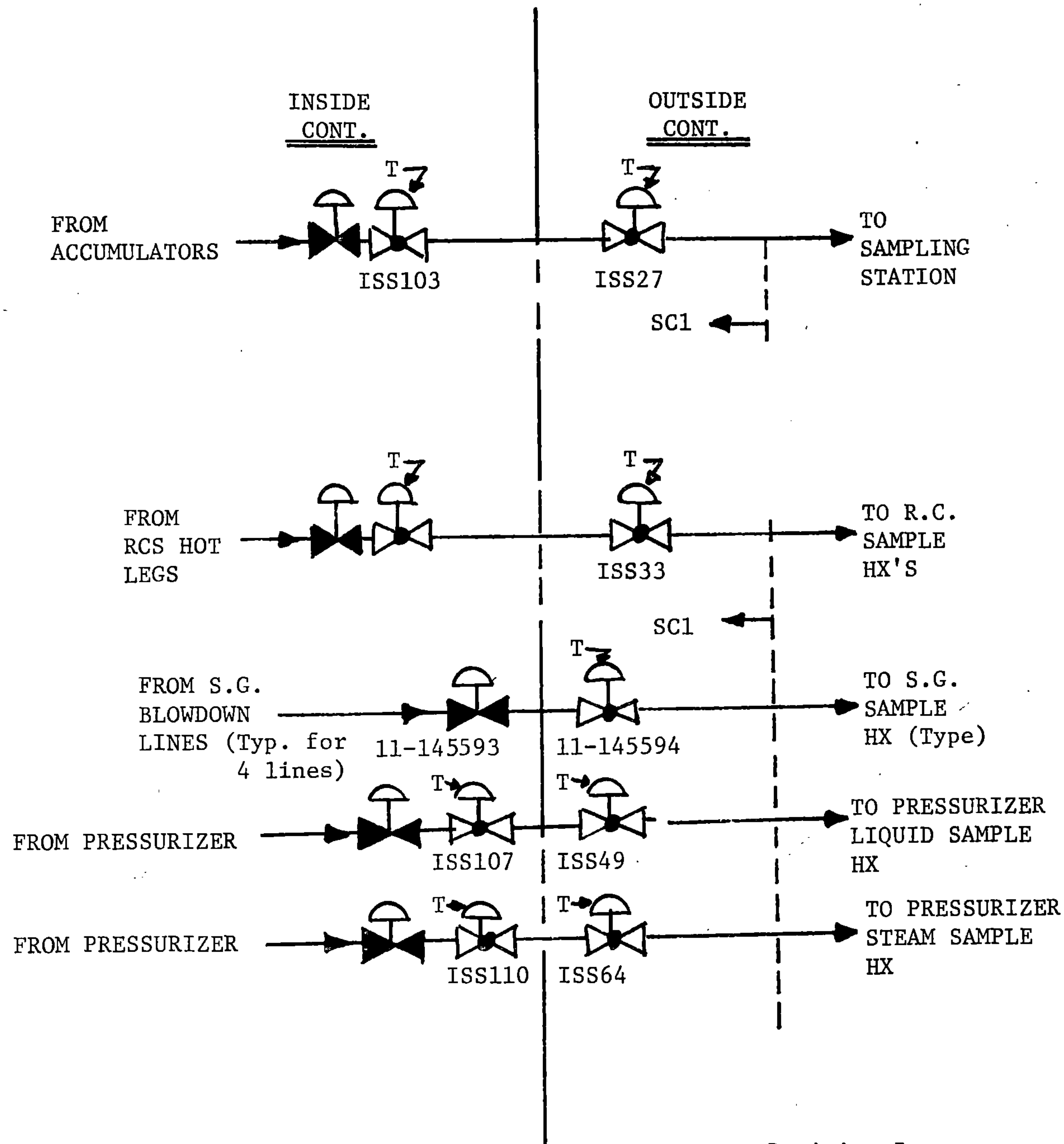
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Safety Injection Recirculation From Sump
	Updated FSAR — FIG. 6.2-32



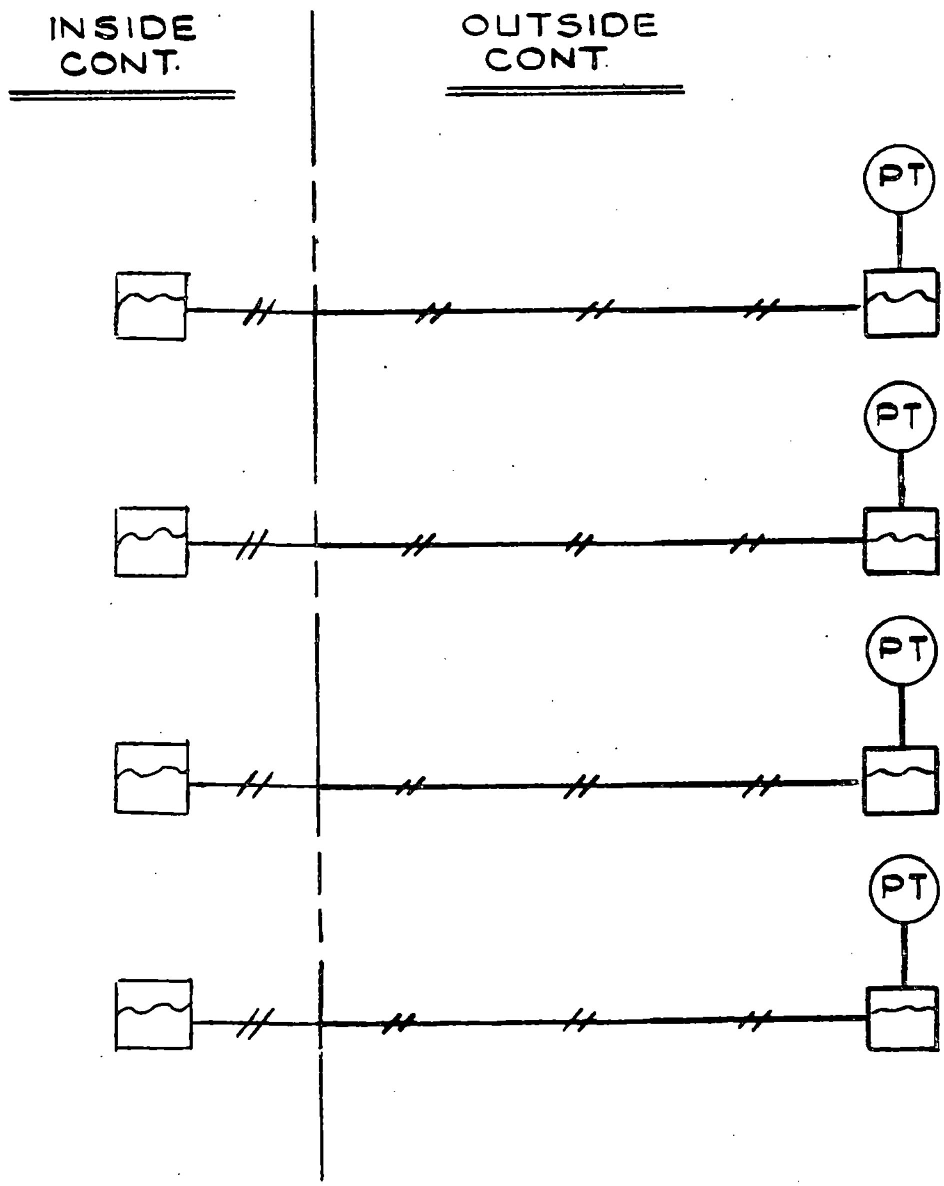
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Containment Spray System	
	Updated FSAR	FIG. 6.2-33



Revision 5
July 25, 1986

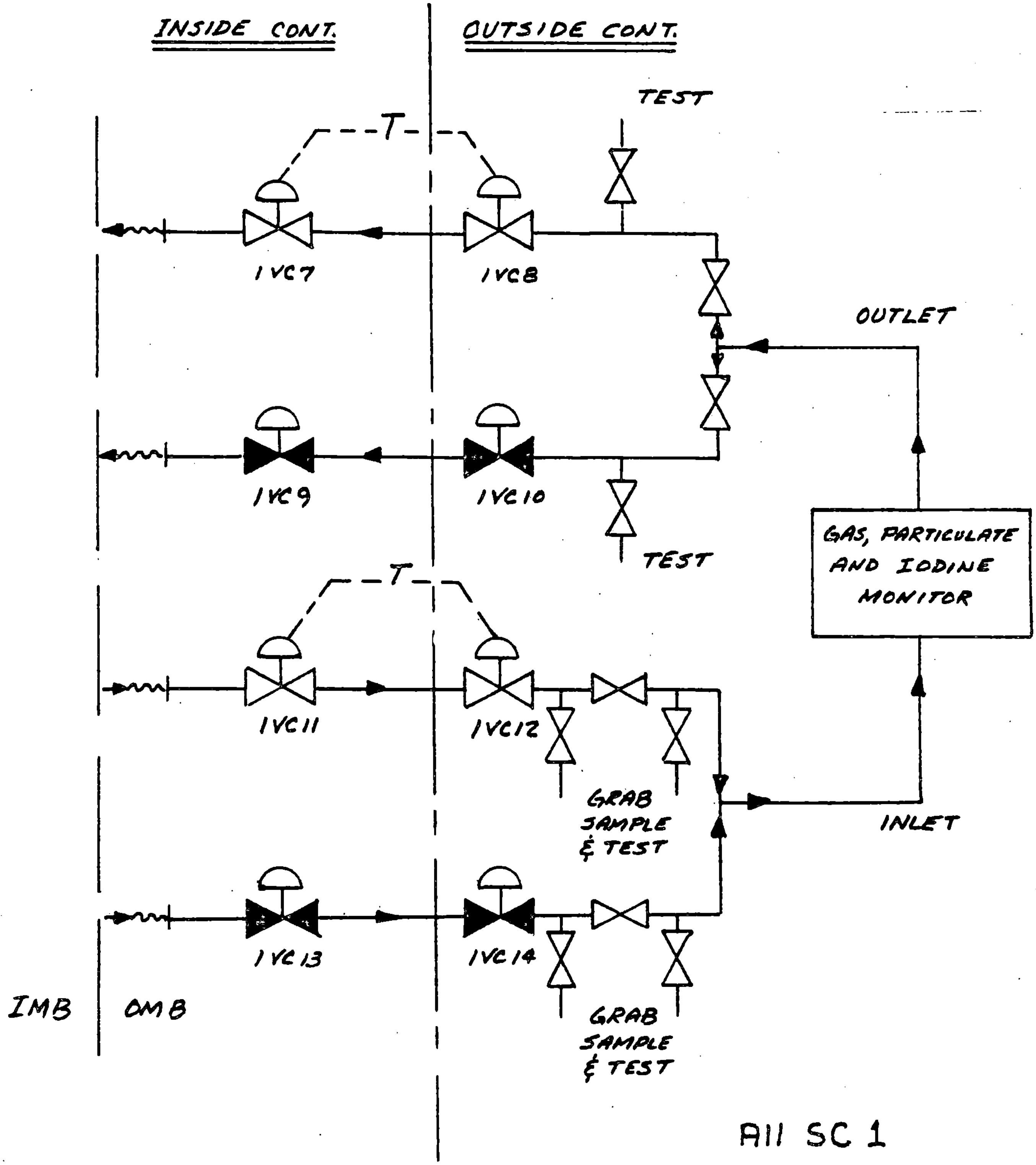
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation - Reactor Coolant, Steam Generator, Pressurizer, Accumulator Sampling
	UPDATED FSAR Fig. 6.2-34



SEALED SYSTEM

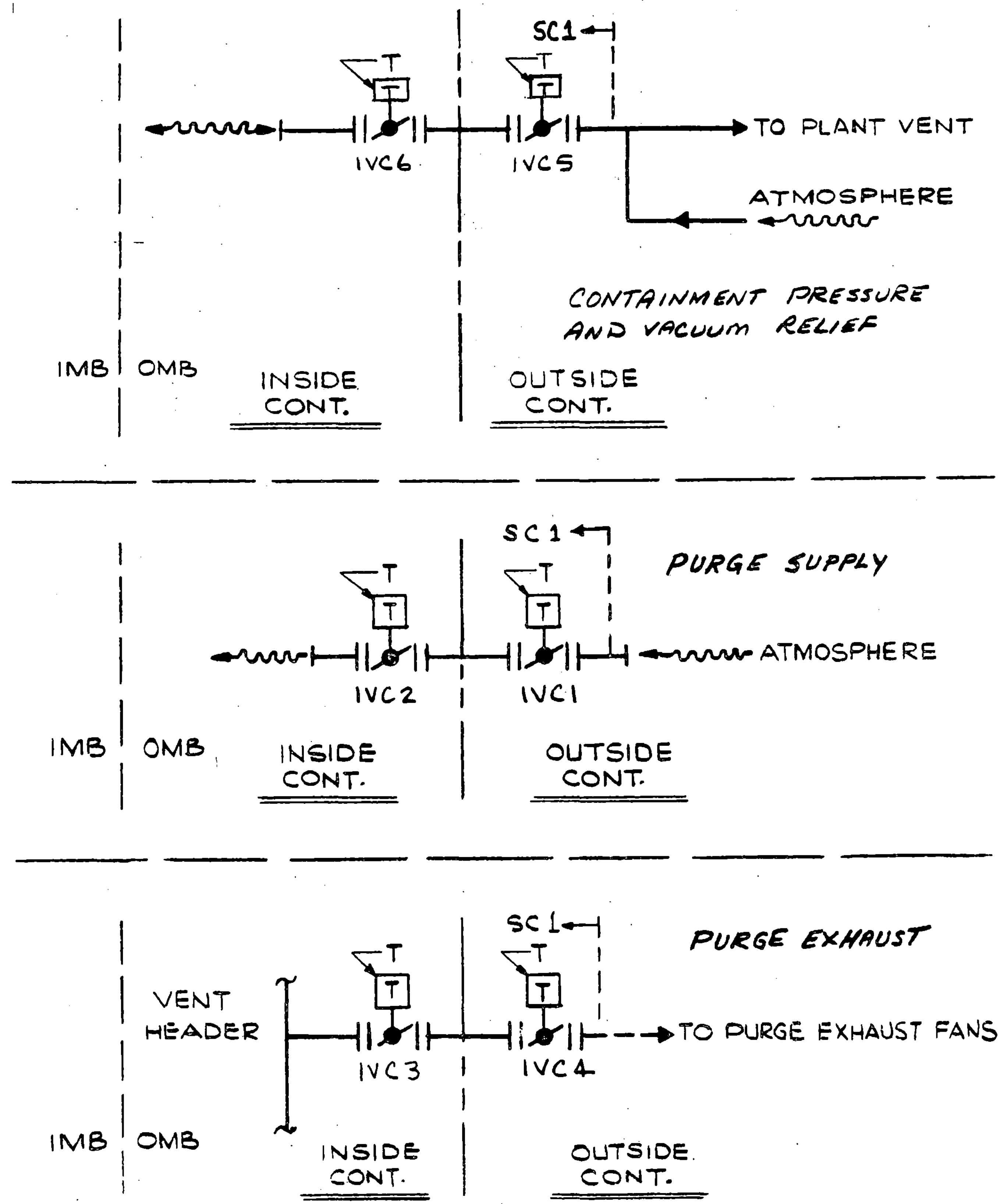
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Containment Pressure Instrumentation
	Updated FSAR FIG. 6.2-35



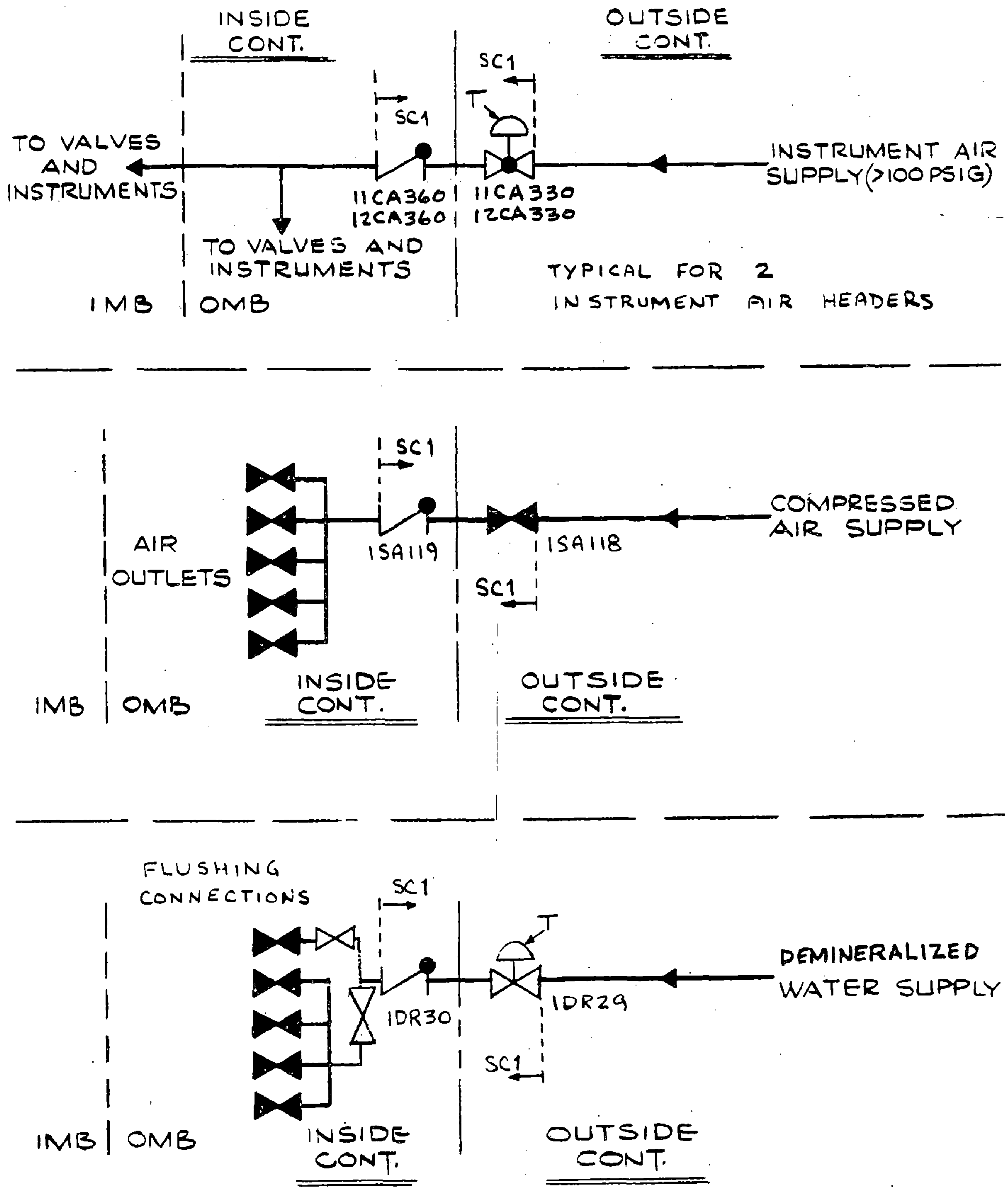
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Containment Air Sampler
	Updated FSAR — FIG. 6.2-36



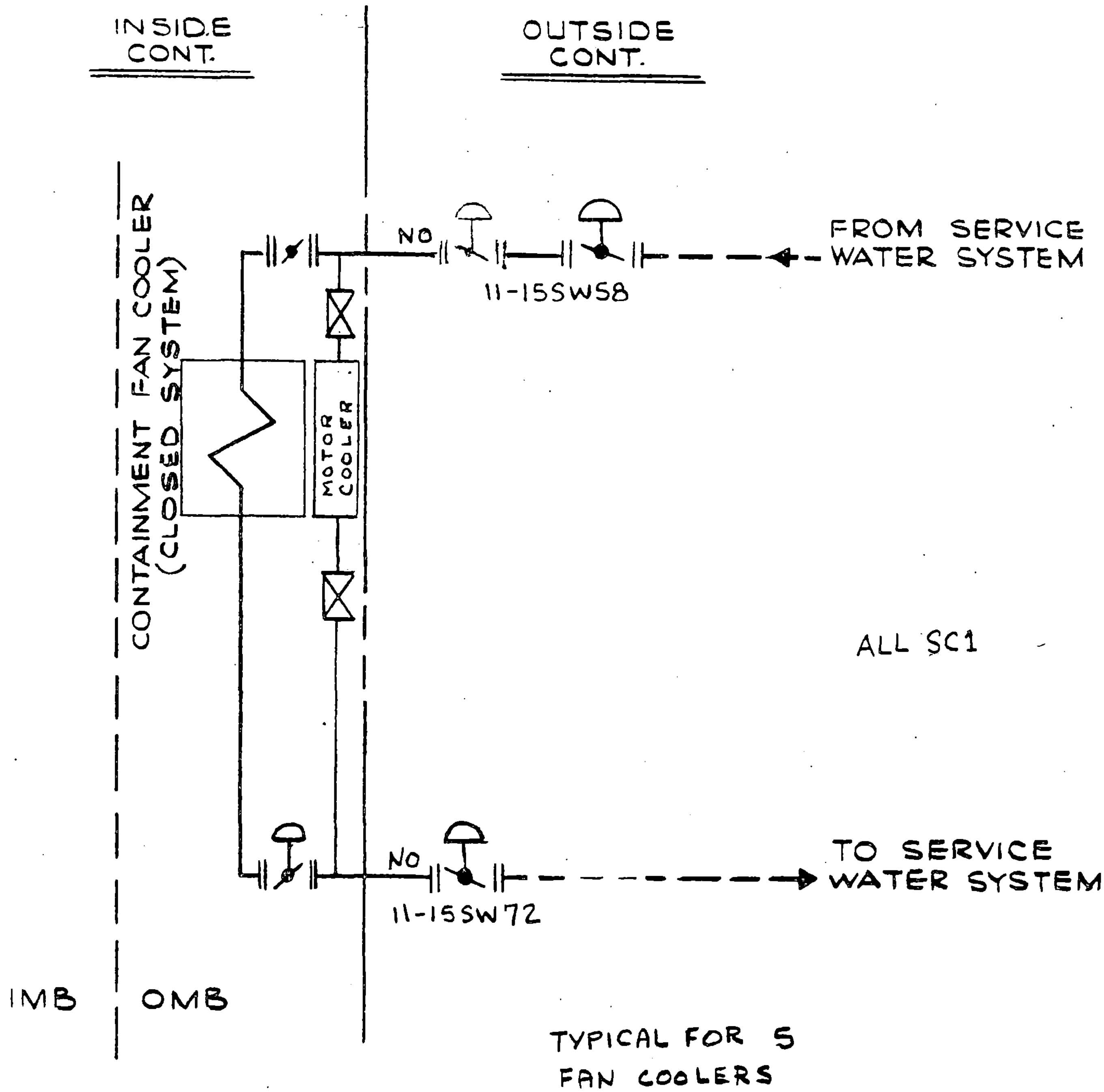
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Containment Pressure Relief and Purge	
	Updated FSAR	FIG. 6.2-37



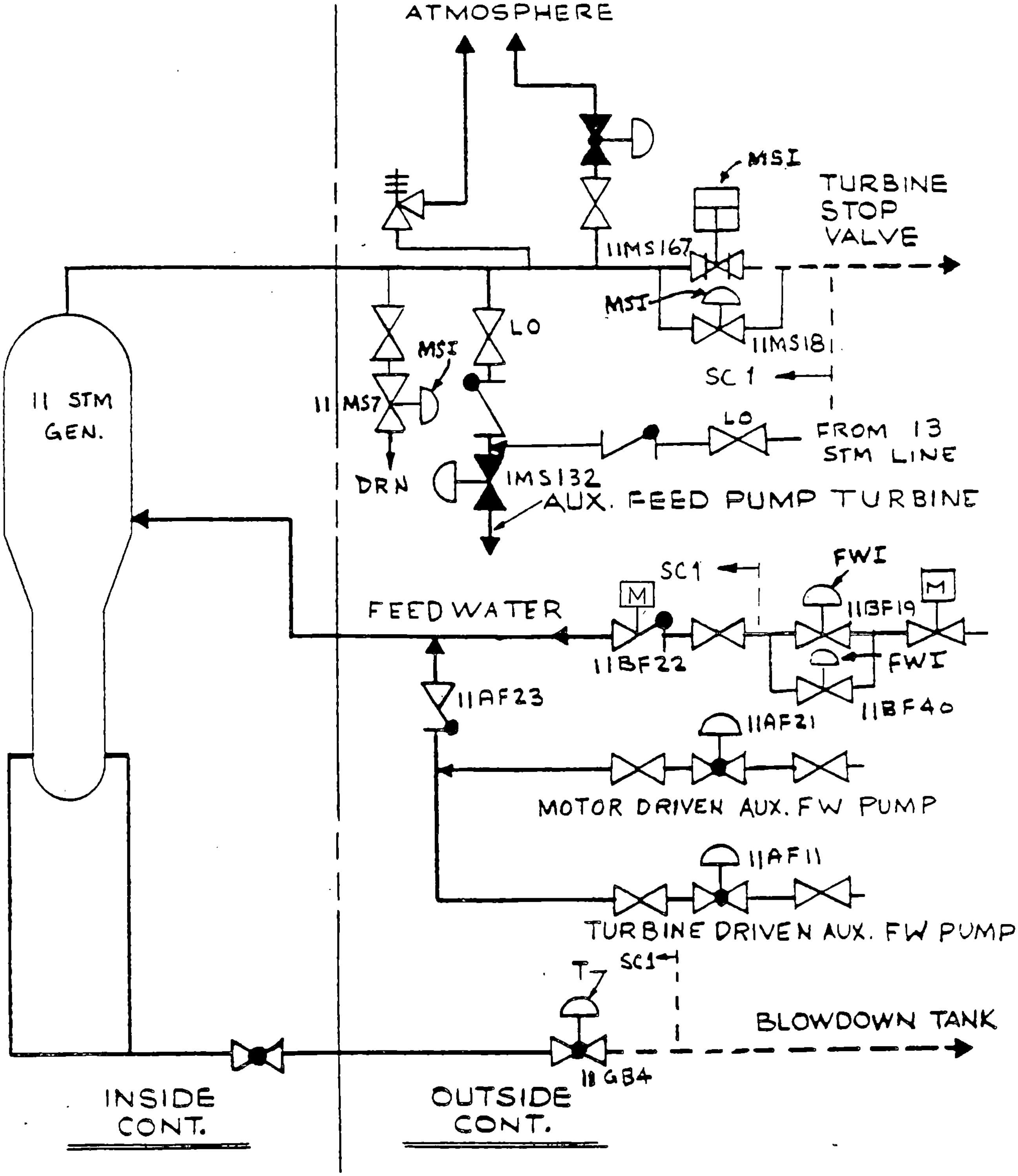
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Service Air, Instrument Air and Domestic Water
	Updated FSAR — FIG. 6.2-38



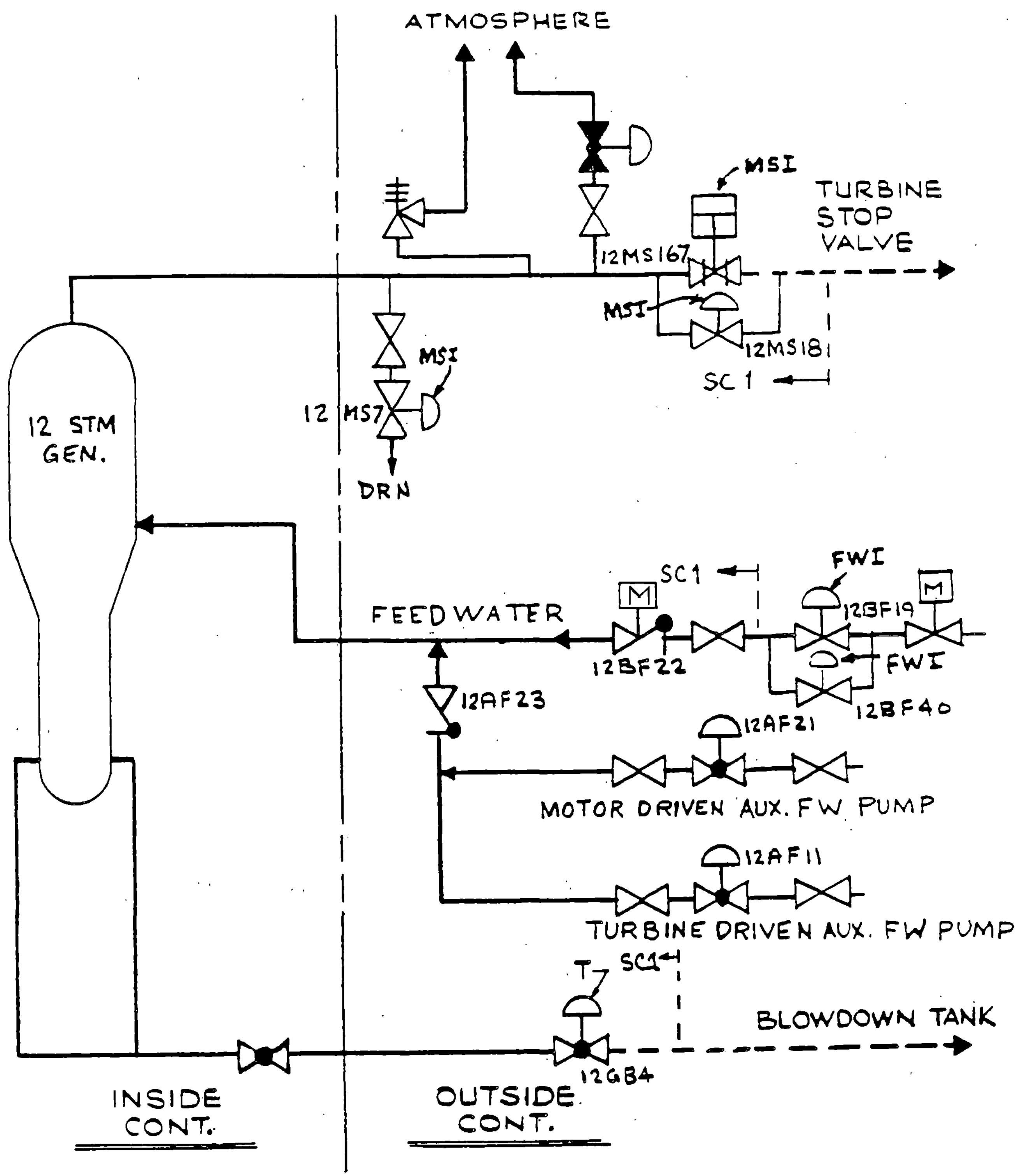
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Containment Fan Cooling Water
	Updated FSAR — FIG. 6.2-39



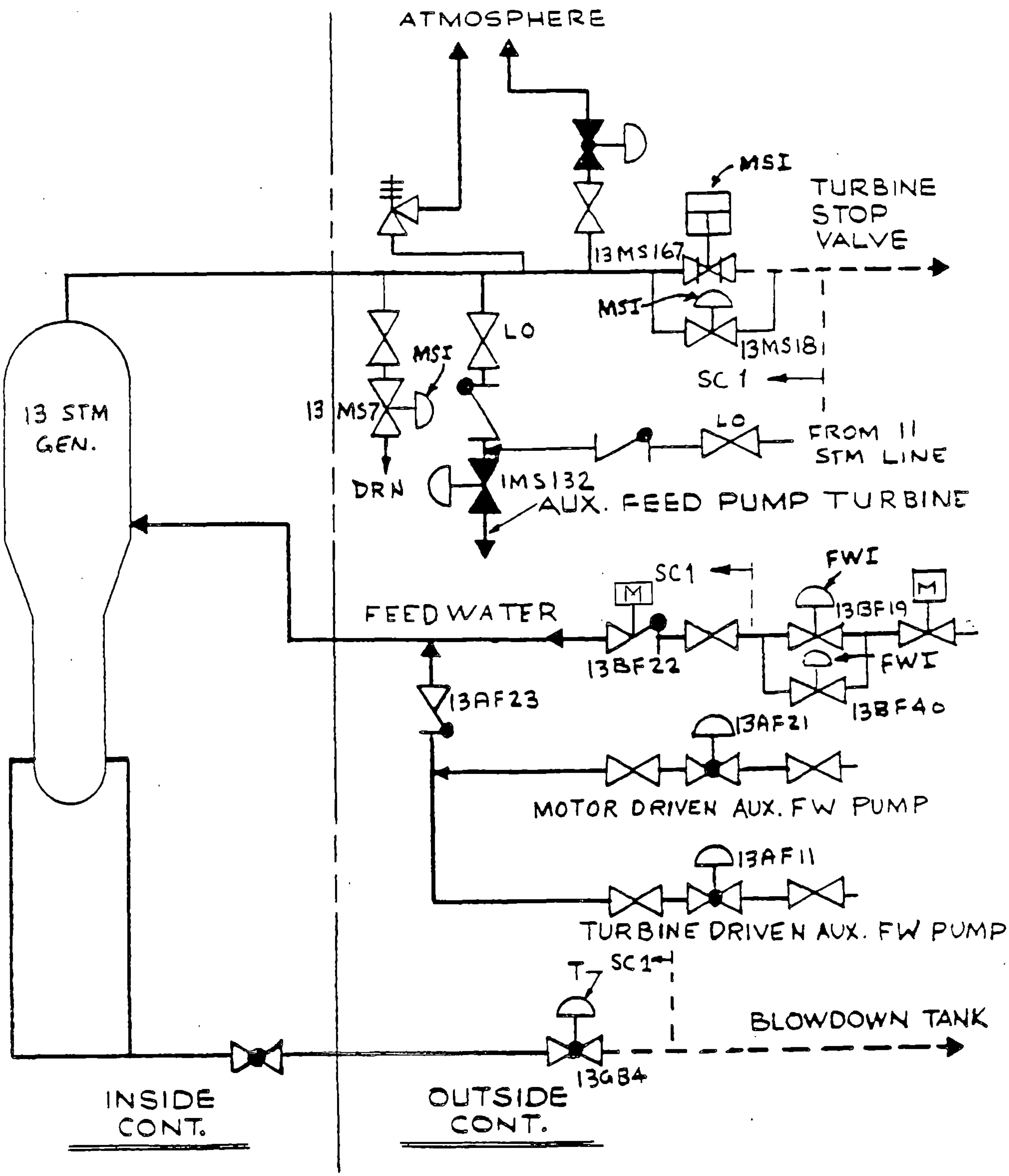
Revision 4
July 22, 1985

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation - Main Stream, Feedwater and Blowdown (11 Stm Gen)	
	Updated FSAR	FIG. 6.2-40



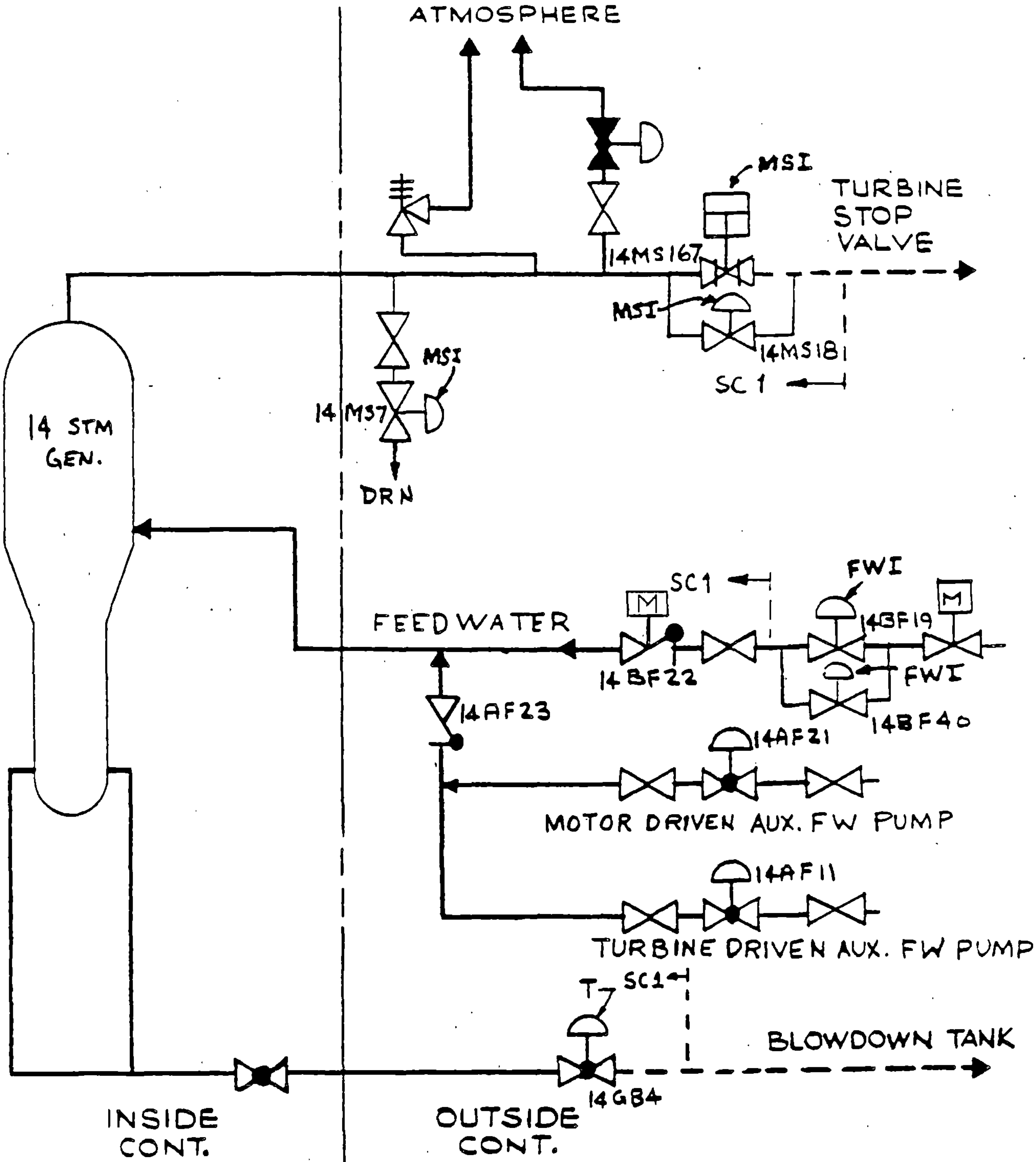
Revision 4
July 22, 1985

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation - Main Steam, Feedwater and Blowdown (12 Stm Gen)
	Updated FSAR — FIG. 6.2-41



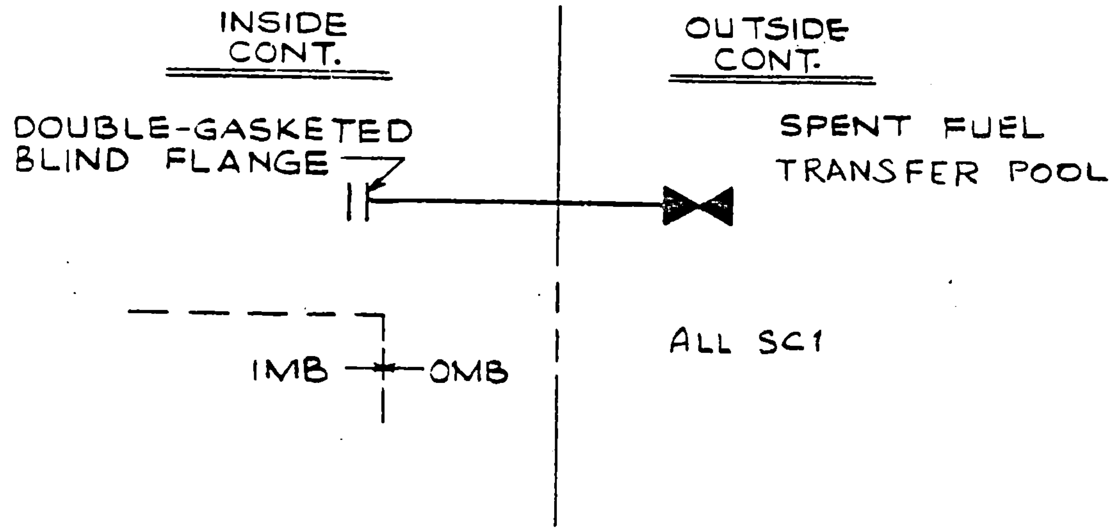
Revision 4
July 22, 1985

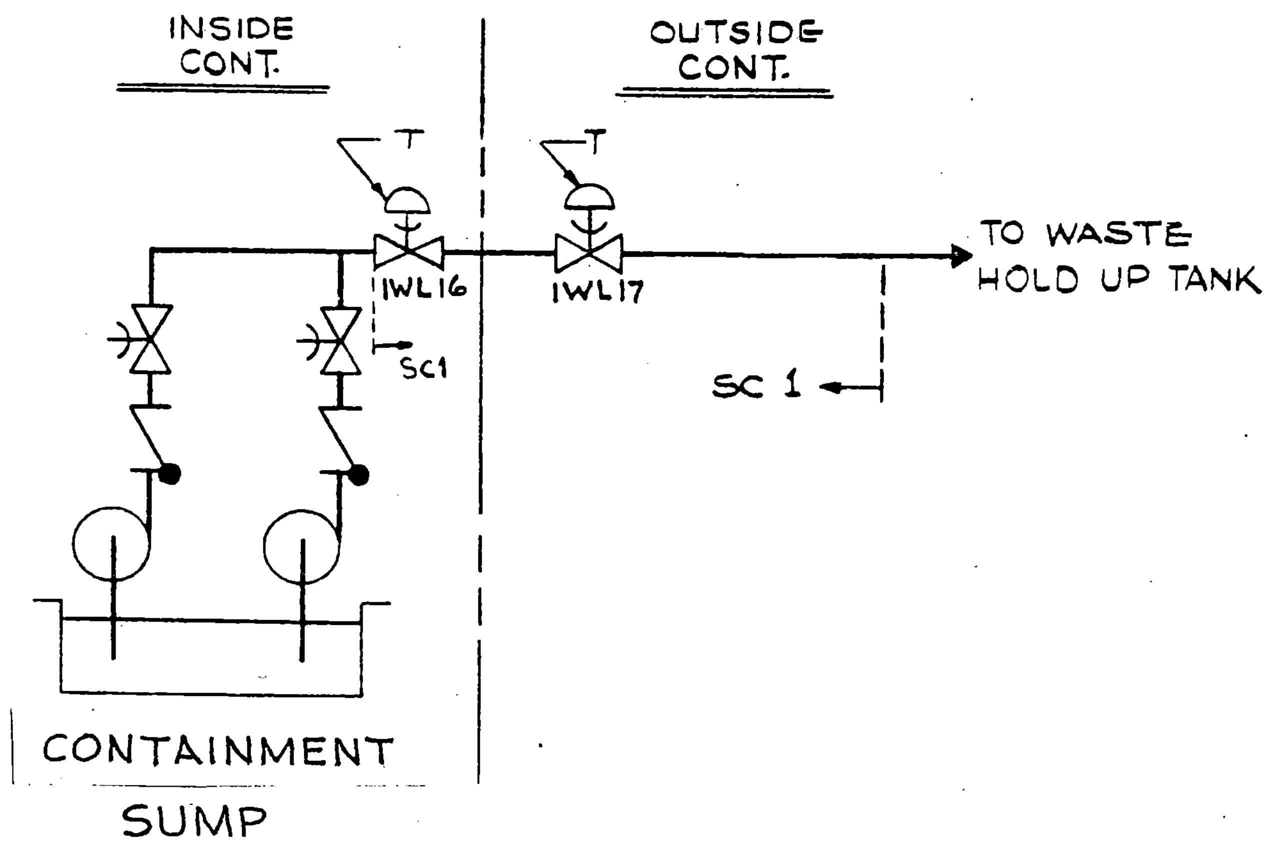
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation - Main Steam, Feedwater and Blowdown (13 Stm Gen)
	Updated FSAR — FIG. 6.2-42



Revision 4
July 22, 1985

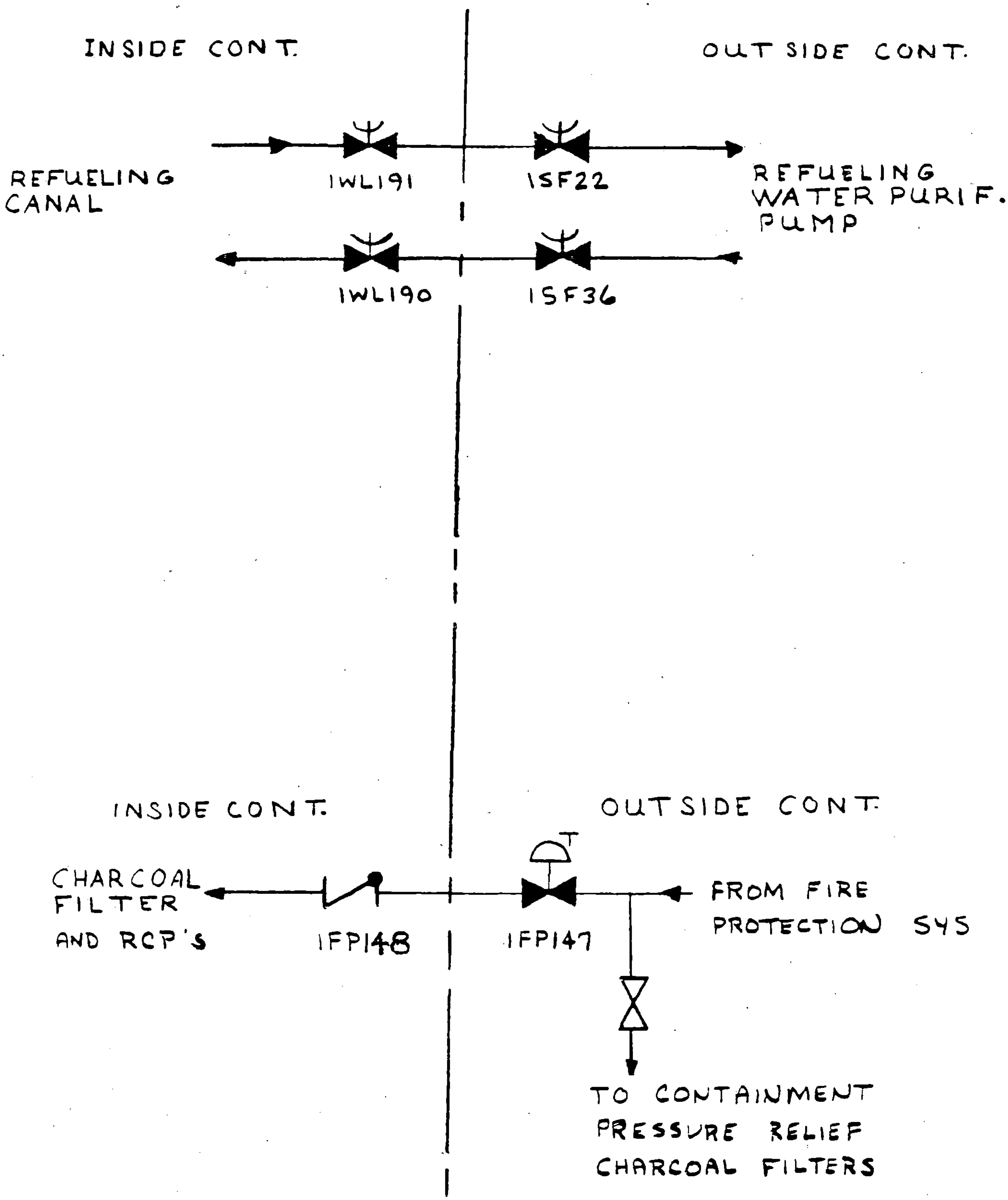
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation - Main Steam, Feedwater and Blowdown (14 Stm Gen)	
	Updated FSAR	FIG. 6.2-43





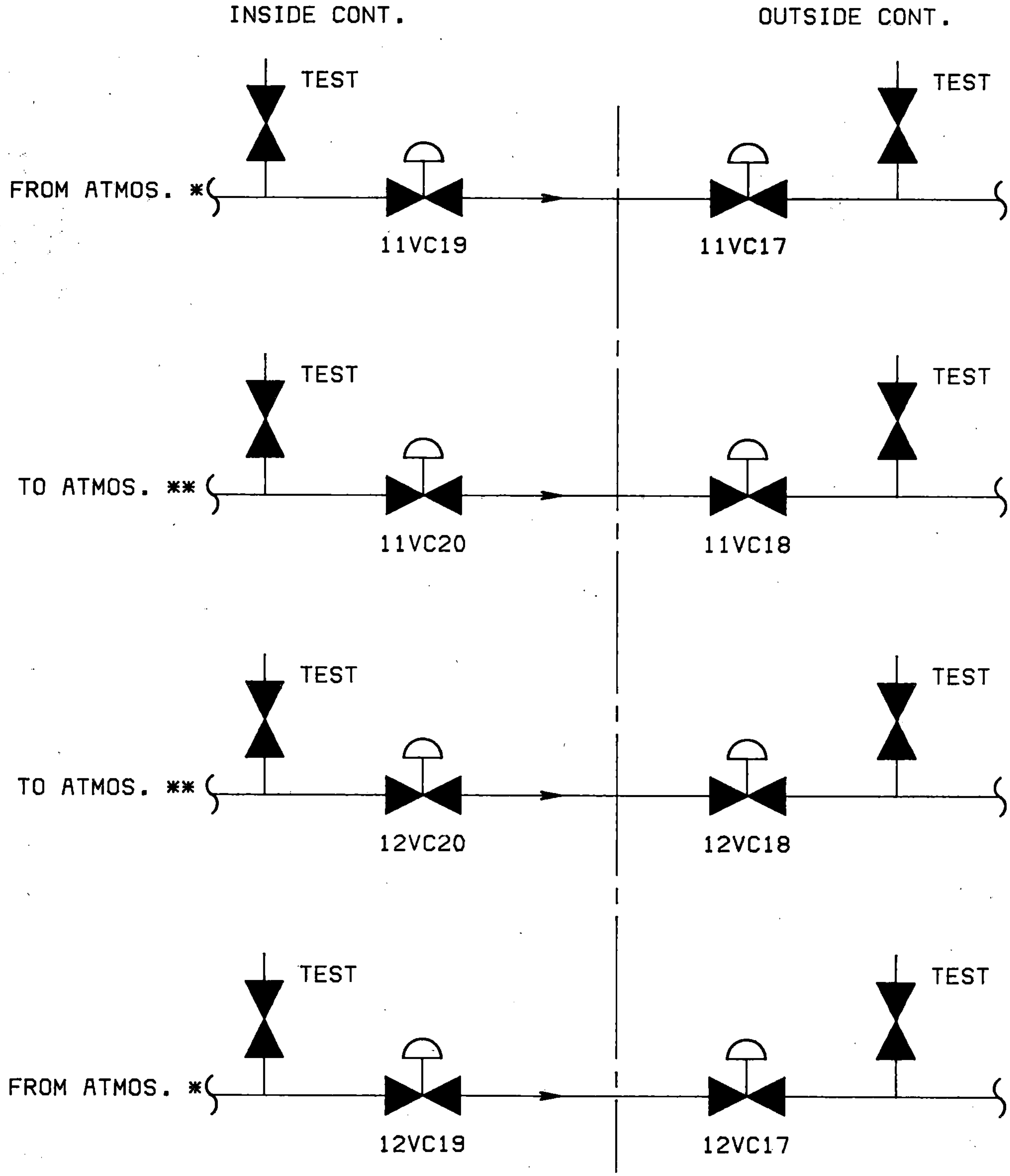
Revision 3
July 22, 1984

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	**Containment Isolation** **Containment Sump Discharge, Fuel Transfer Tube**
	Updated FSAR — FIG. 6.2-44



Revision 1
July 22, 1983

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation - Refueling Canal Supply and Discharge, Fire Water Supply
	Updated FSAR FIG. 6.2-45



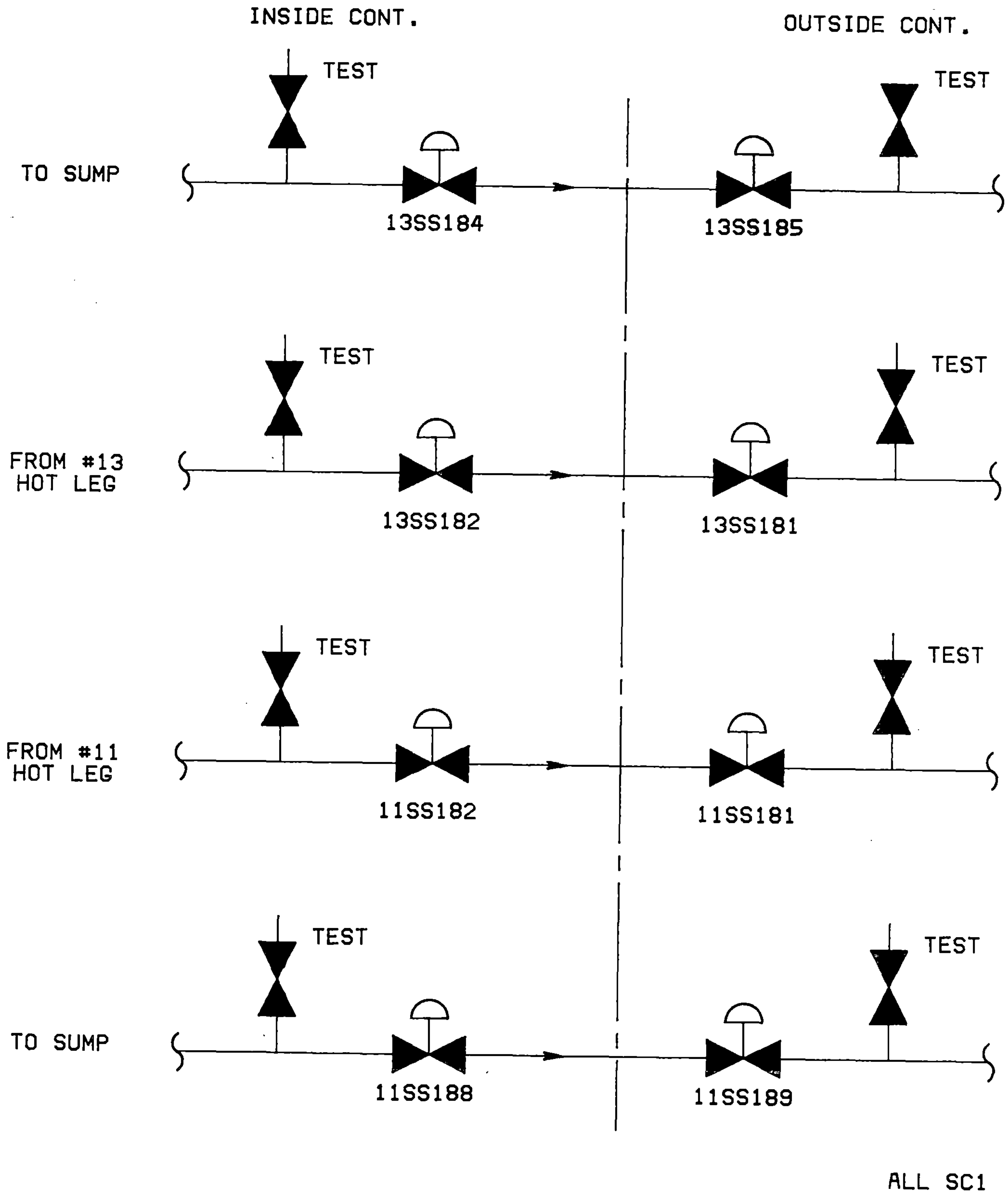
* IRA RADIATION MONITORING SYSTEM (RMS) SAMPLE SUPPLY LINE

** IRA RMS SAMPLE RETURN LINE

ALL SC1

Revision 1
July 22, 1983

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Post-LOCA Atmosphere Sample
	UPDATED FSAR FIG 6.2-45A



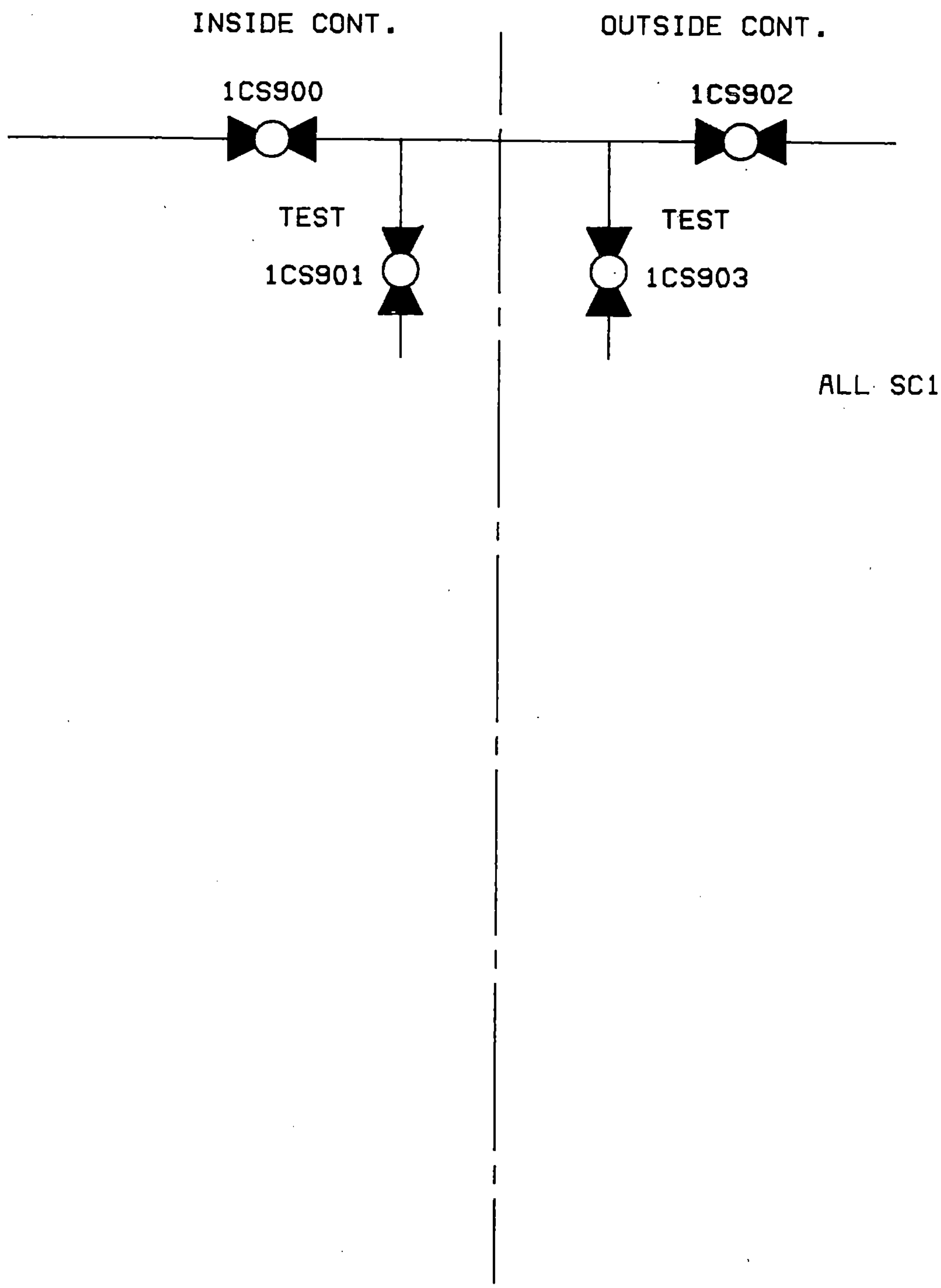
Revision 1
July 22, 1983

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Containment Isolation
Post-LOCA RCS Sample

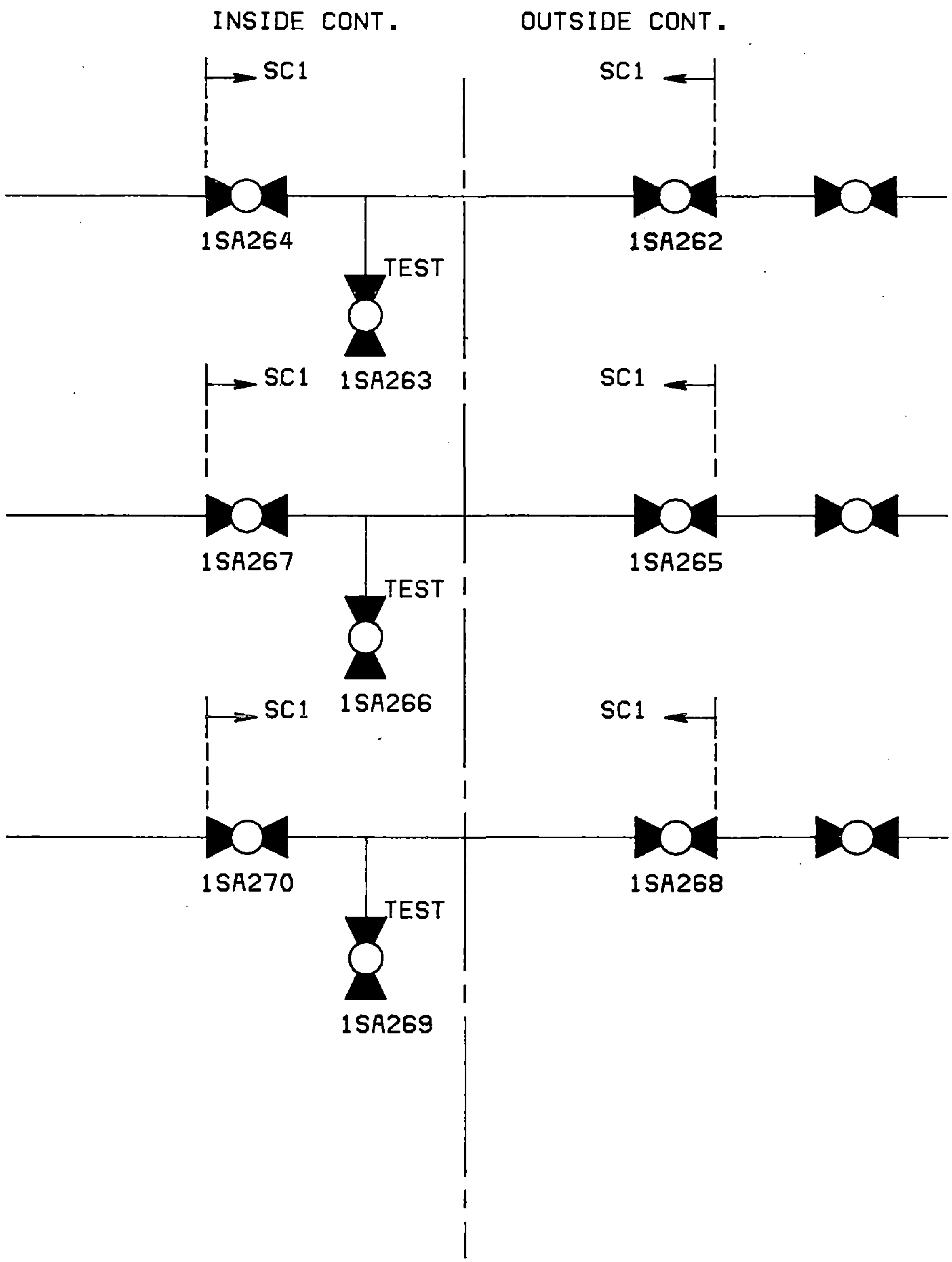
UPDATED FSAR

FIG 6.2-45B



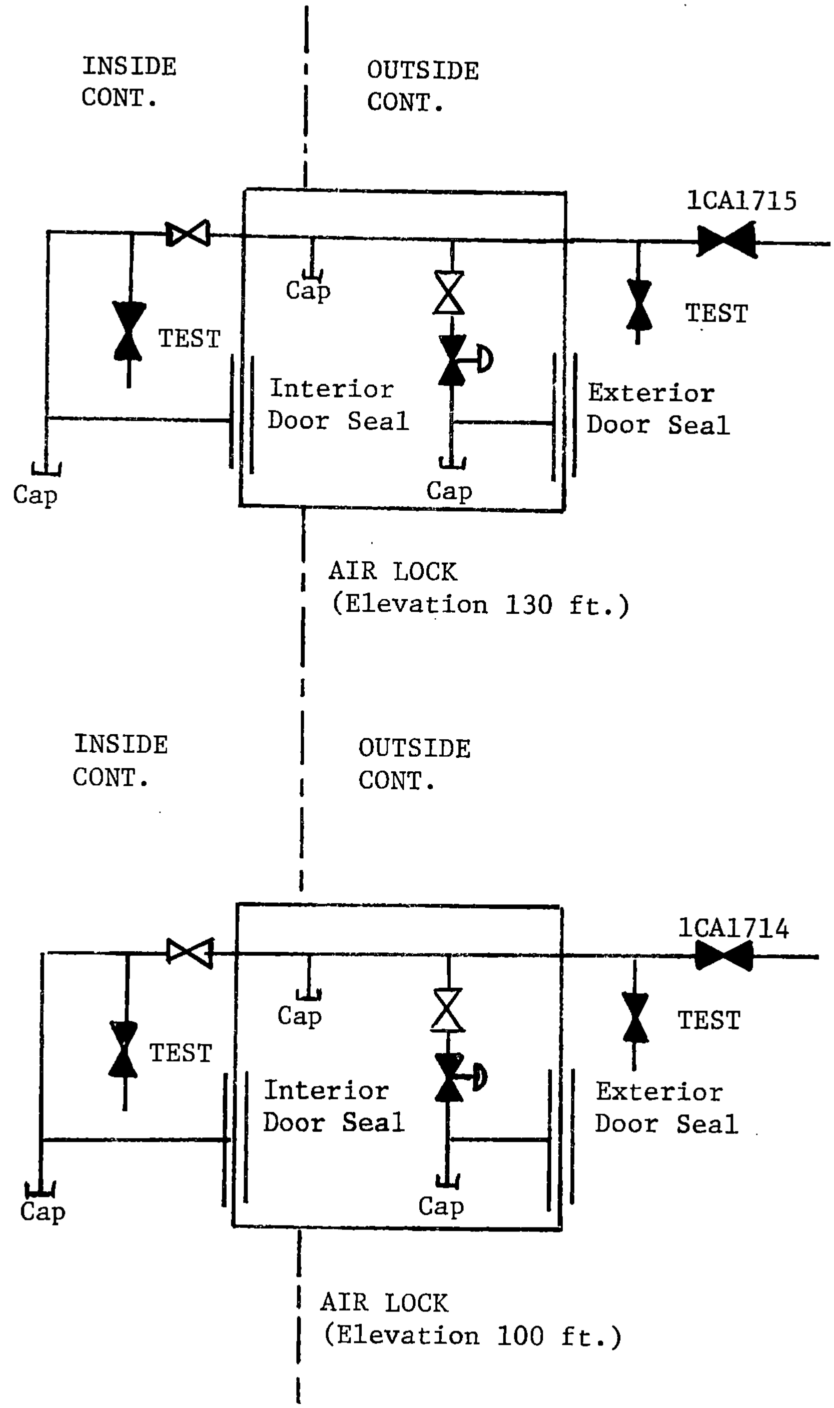
Revision 1
July 22, 1983

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Fill Line for Containment Pressure Instruments
	UPDATED FSAR FIG 6.2-45C



Revision 1
July 22, 1983

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Containment Pressure Test Instrumentation
	UPDATED FSAR FIG 6.2-45D



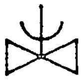
Revision 5
July 25, 1986

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Containment Airlock Test Instrumentation	
	UPDATED FSAR	Fig. 6.2-45E

VALVES

 DOUBLE DISC GATE

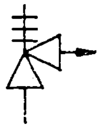
 GLOBE

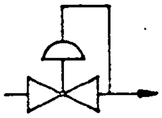
 DIAPHRAGM

 GATE

 CHECK

 BUTTERFLY

 SAFETY OR RELIEF

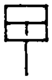
 SELF CONTAINED
RPRESSURE REGULATOR

 NEEDLE

 STOP CHECK

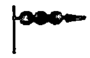
OPERATORS

 AIR OPERATOR

 PISTON

 MOTOR

DARKENED SYMBOL
INDICATES NORMALLY
CLOSED VALVE

 VALVE STEM LEAKOFF

 FILLED SYSTEM

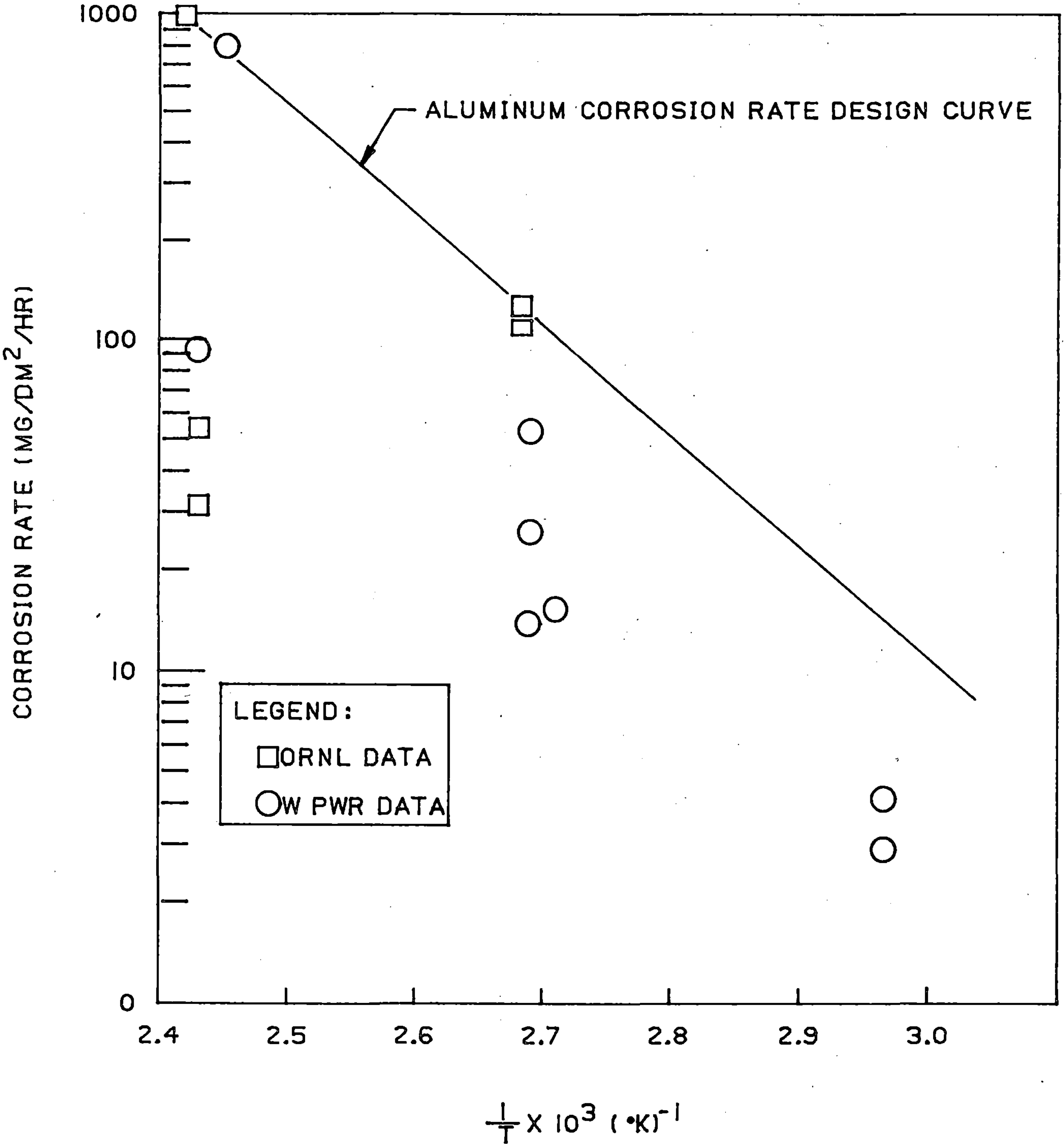
 SAUNDERS VALVE

NOTATION

NO -NORMALLY OPEN
NC -NORMALLY CLOSED
FO -FAIL OPEN
FC -FAIL CLOSED
FAI -FAIL AS IS
LO -LOCKED OPEN
LC -LOCKED CLOSED
T -TRIPPED BY CONTAINMENT ISOLATION SIGNAL - PHASE A
P -TRIPPED BY CONTAINMENT ISOLATION SIGNAL - PHASE B
S -SAFETY INJECTION SIGNAL
SCL -SEISMIC CLASS I DESIGN
IMB -INSIDE MISSILE BARRIER
OMB -OUTSIDE MISSILE BARRIER
MSI -MAIN STEAM ISOLATION SIGNAL
FWI -FEEDWATER ISOLATION SIGNAL

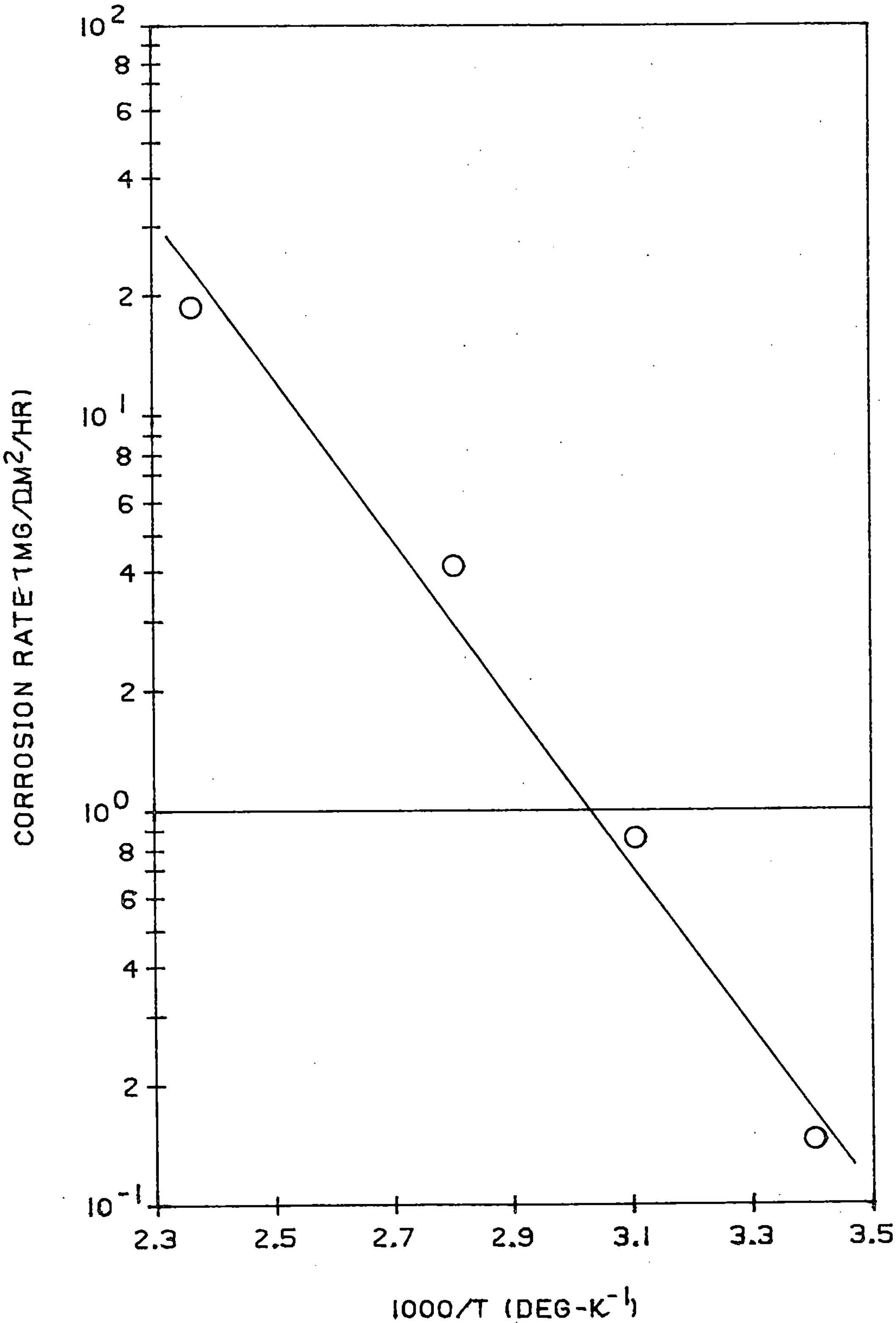
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation Legend	
	Updated FSAR	FIG. 6.2-46

Revision 3
July 22, 1984



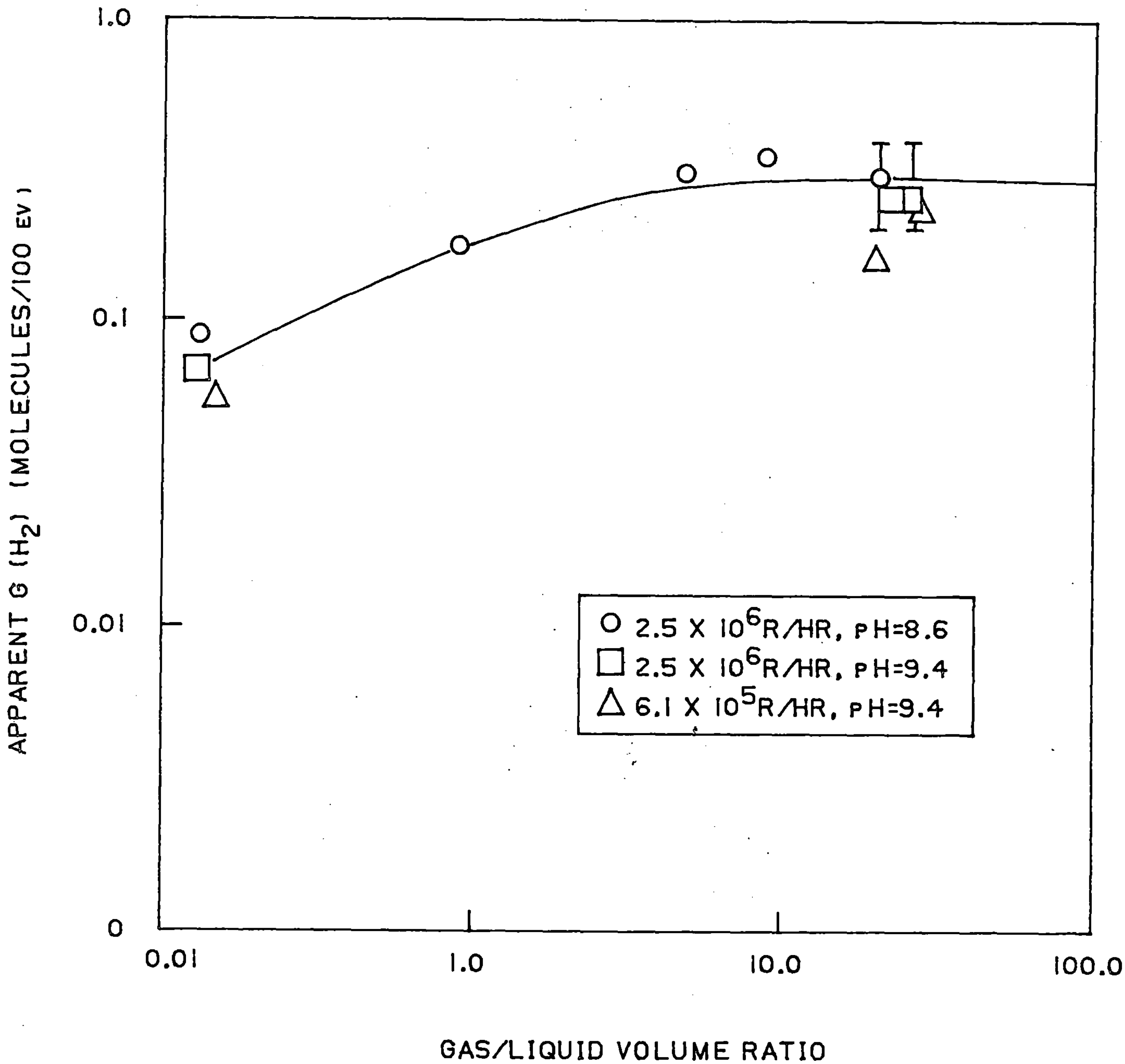
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Aluminum Corrosion in DBA Environment	
	Updated FSAR	FIG. 6.2-47



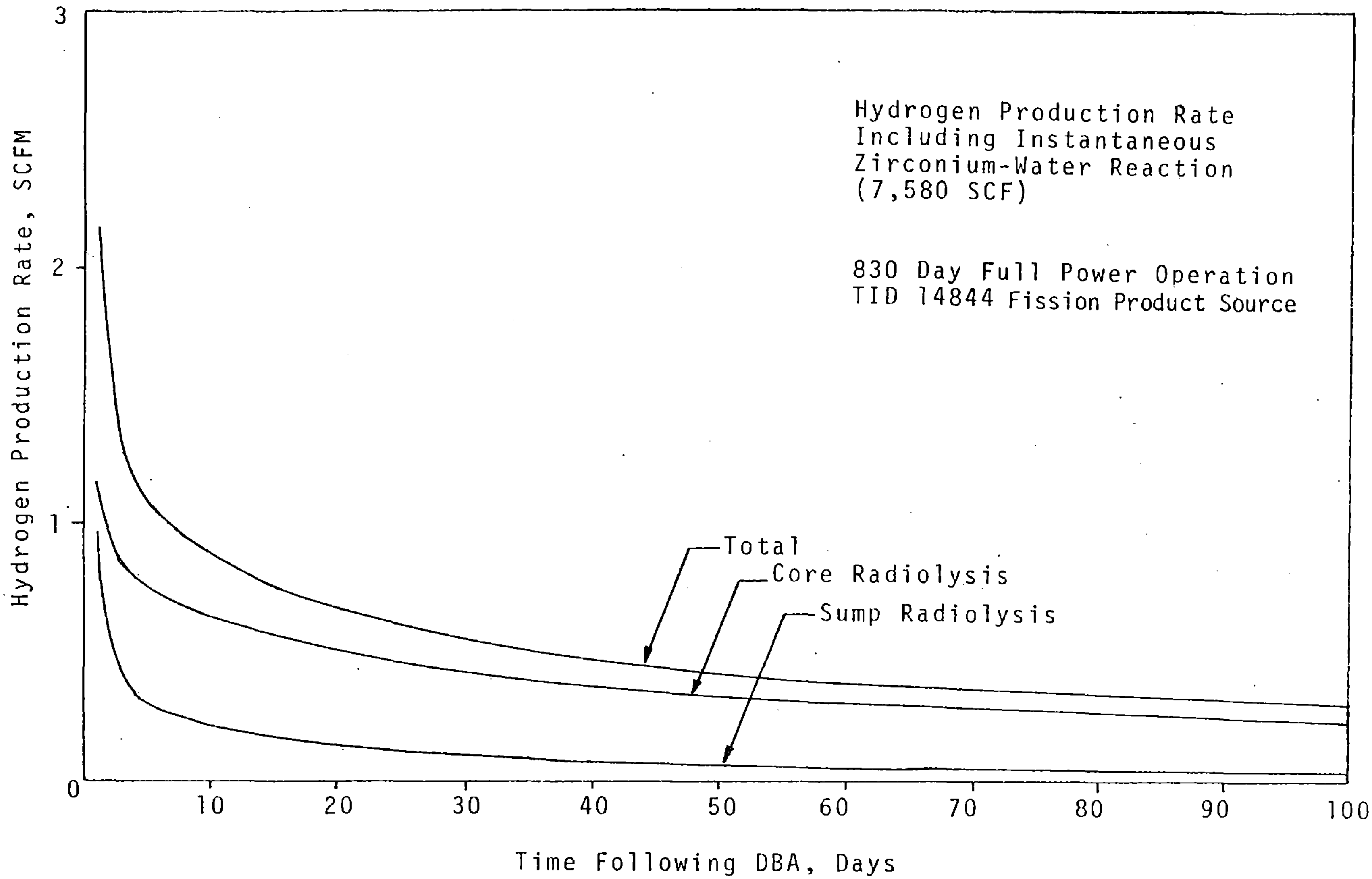
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Zinc Corrosion in DBA Environment	
	Updated FSAR	FIG. 6.2-48



Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Results of Westinghouse Capsule Irradiation Tests
	Updated FSAR — FIG. 6.2-49



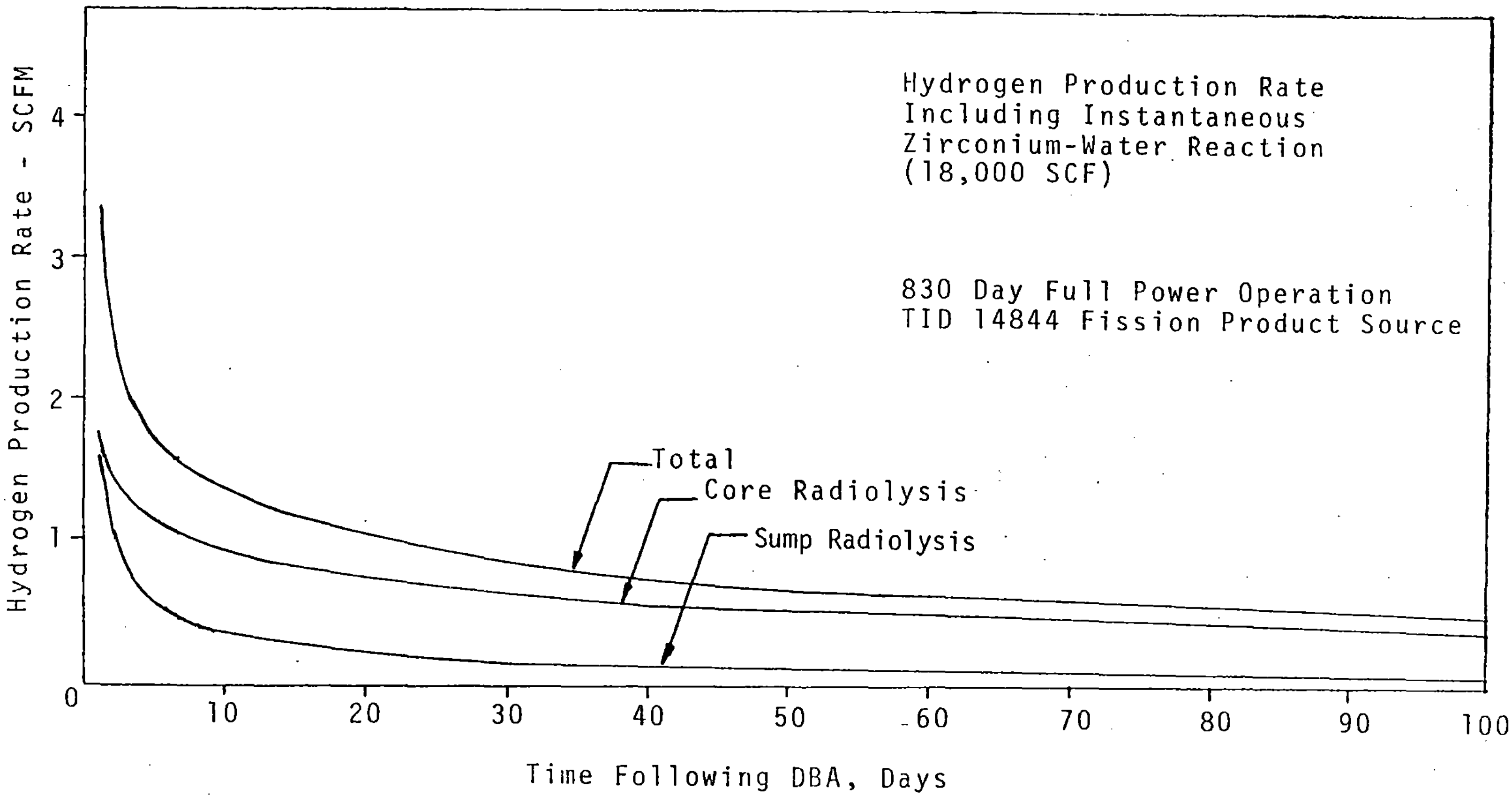
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Updated FSAR

Hydrogen Production Rate – Westinghouse Model

Figure 6.2-50



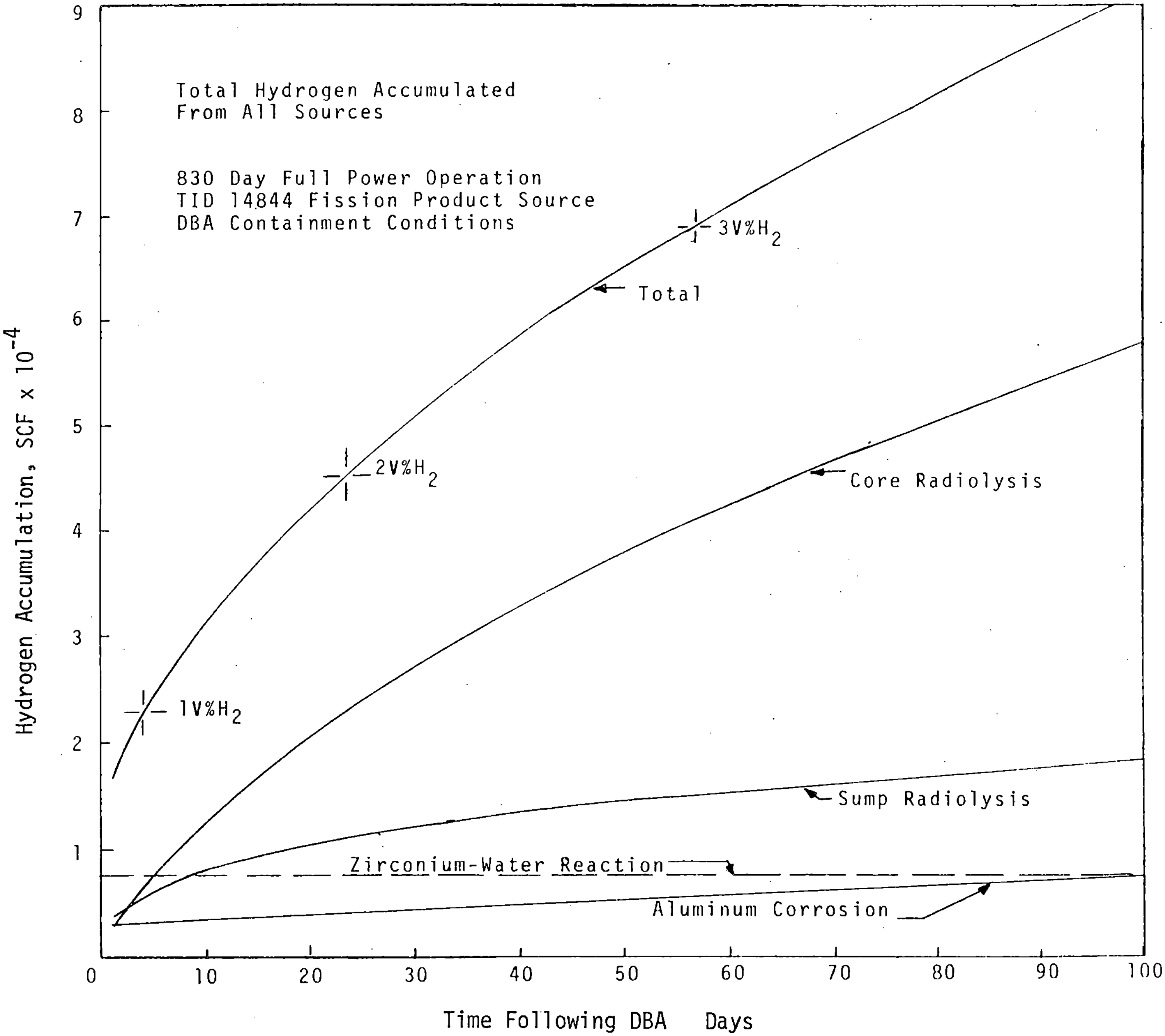
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Updated FSAR

Hydrogen Production Rate — AEC Model

Figure 6.2-51

Revision 0
July 22, 1982



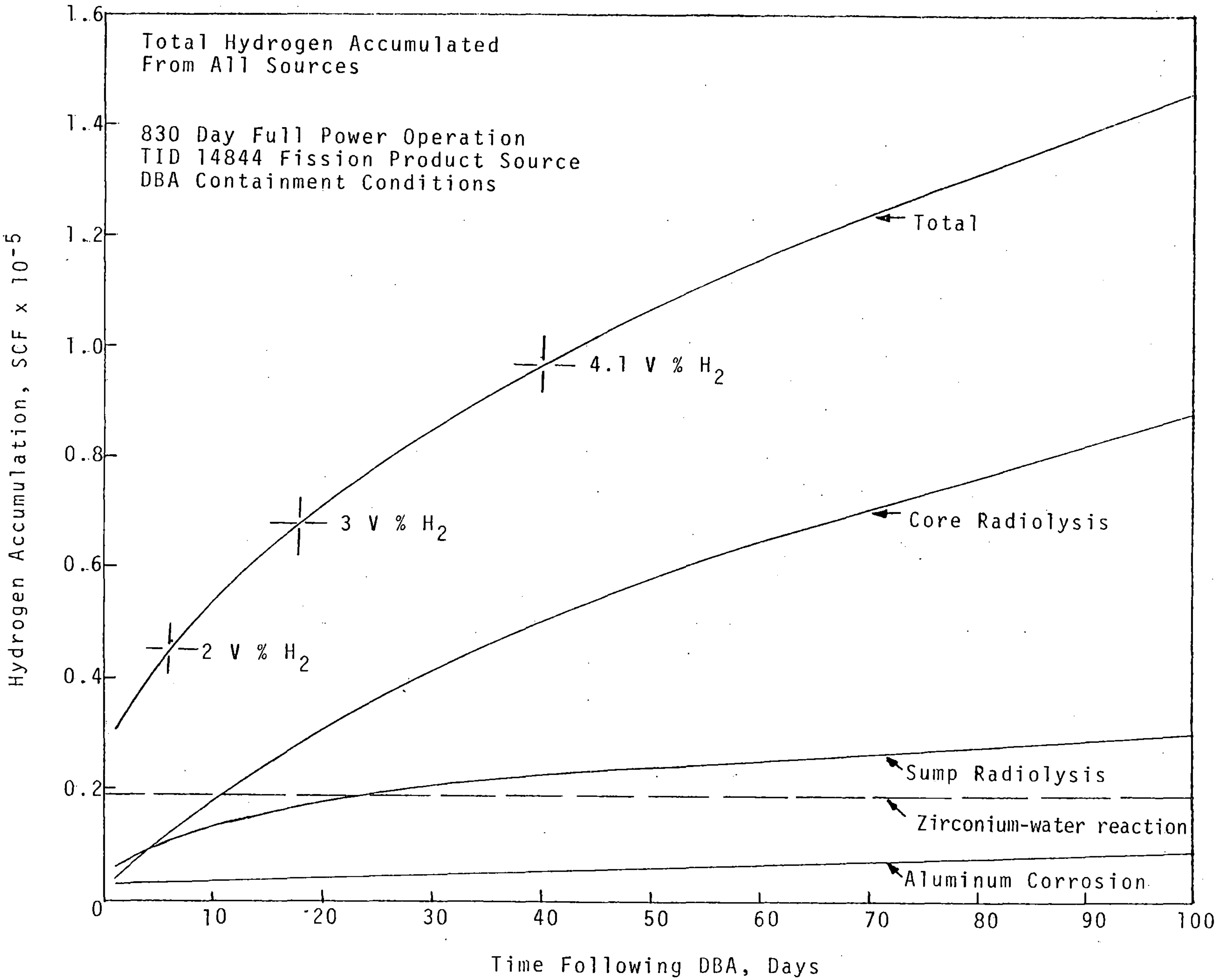
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Updated FSAR

Total Hydrogen Accumulated from All Sources
Westinghouse Model

Figure 6.2-52



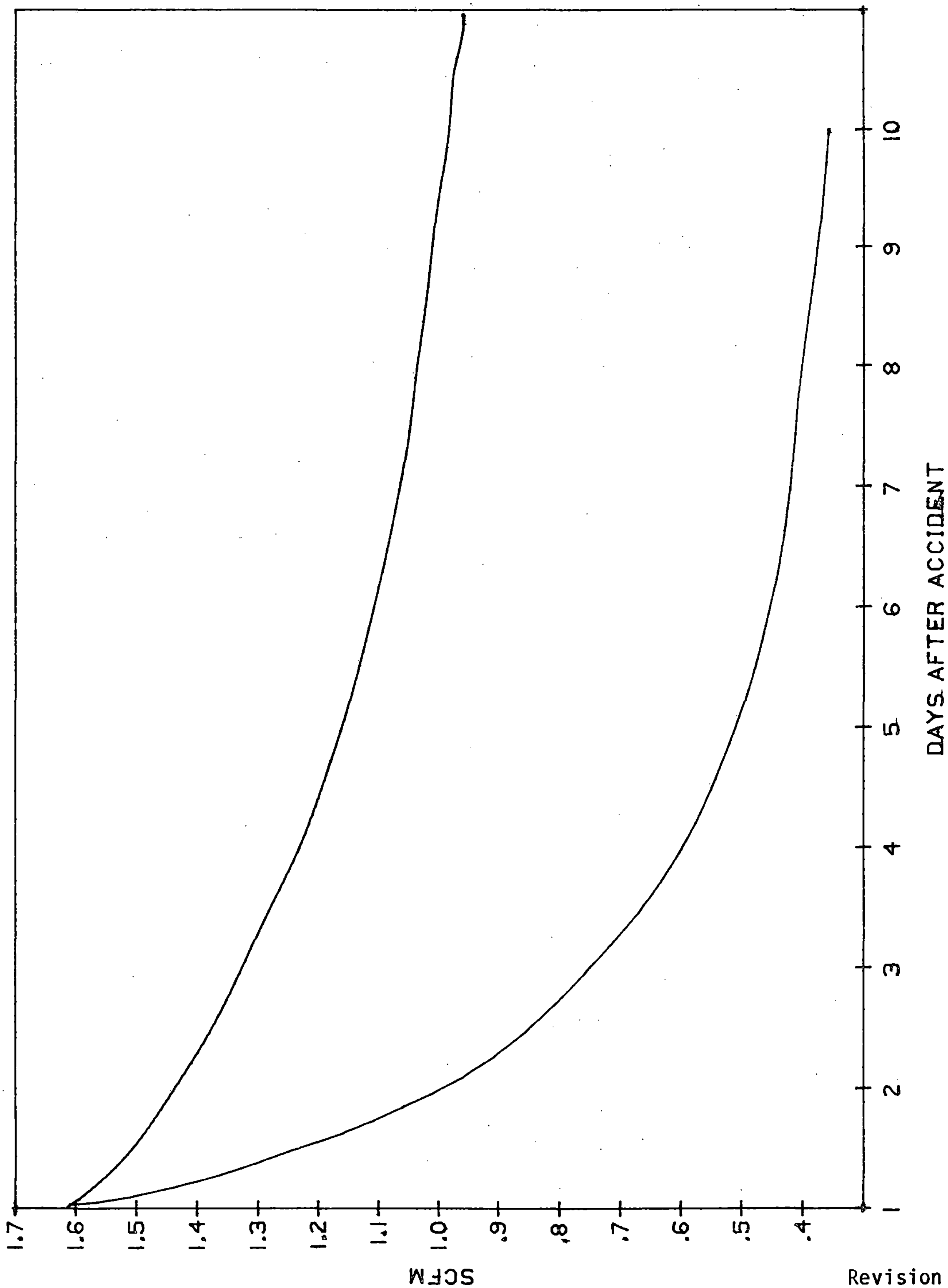
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Updated FSAR

Total Hydrogen Accumulated from All Sources
AEC Model

Figure 6.2-53

Revision 0
July 22, 1982



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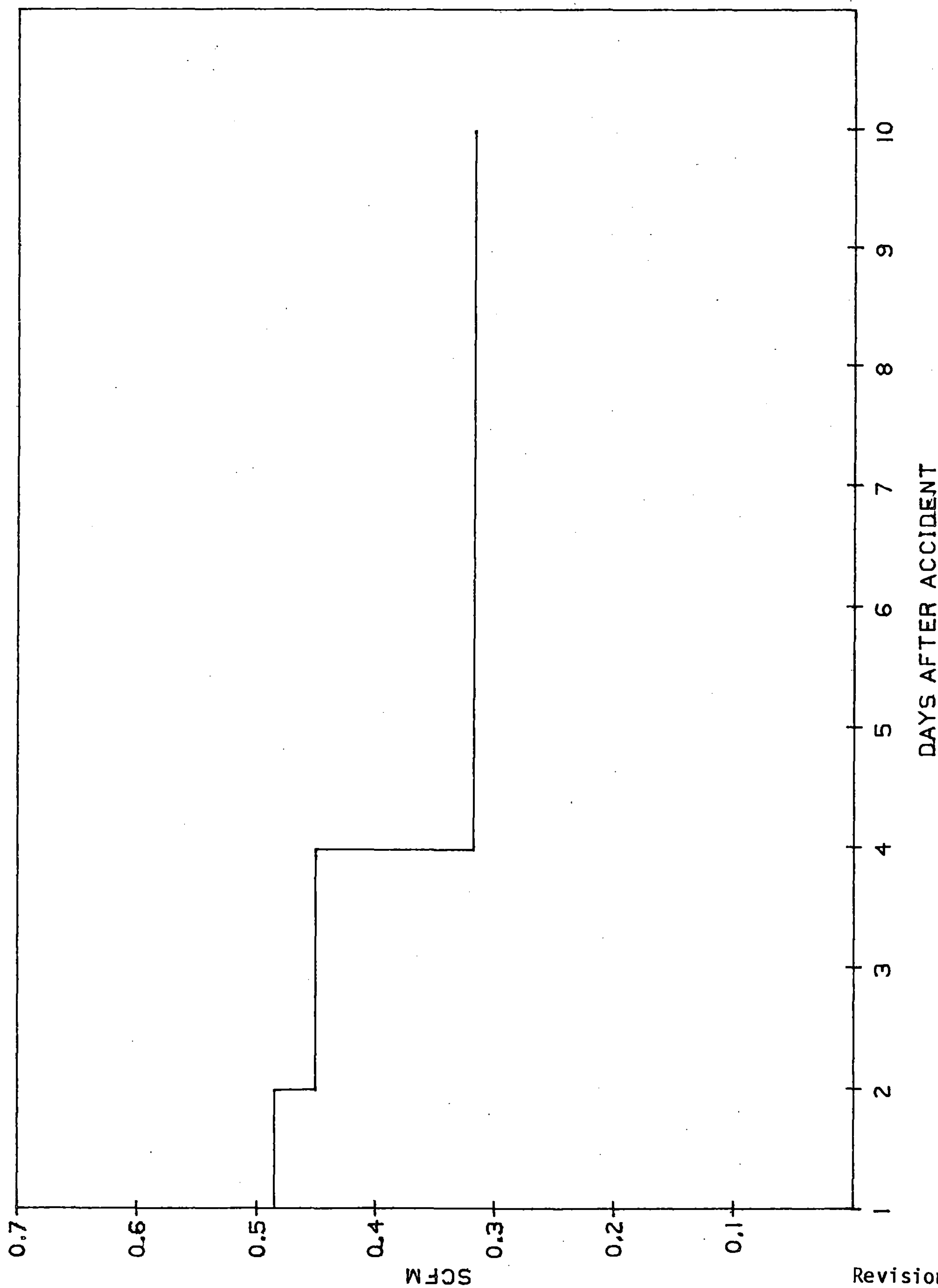
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Hydrogen Generated by Radiolysis	
	Updated FSAR	FIG. 6.2-54



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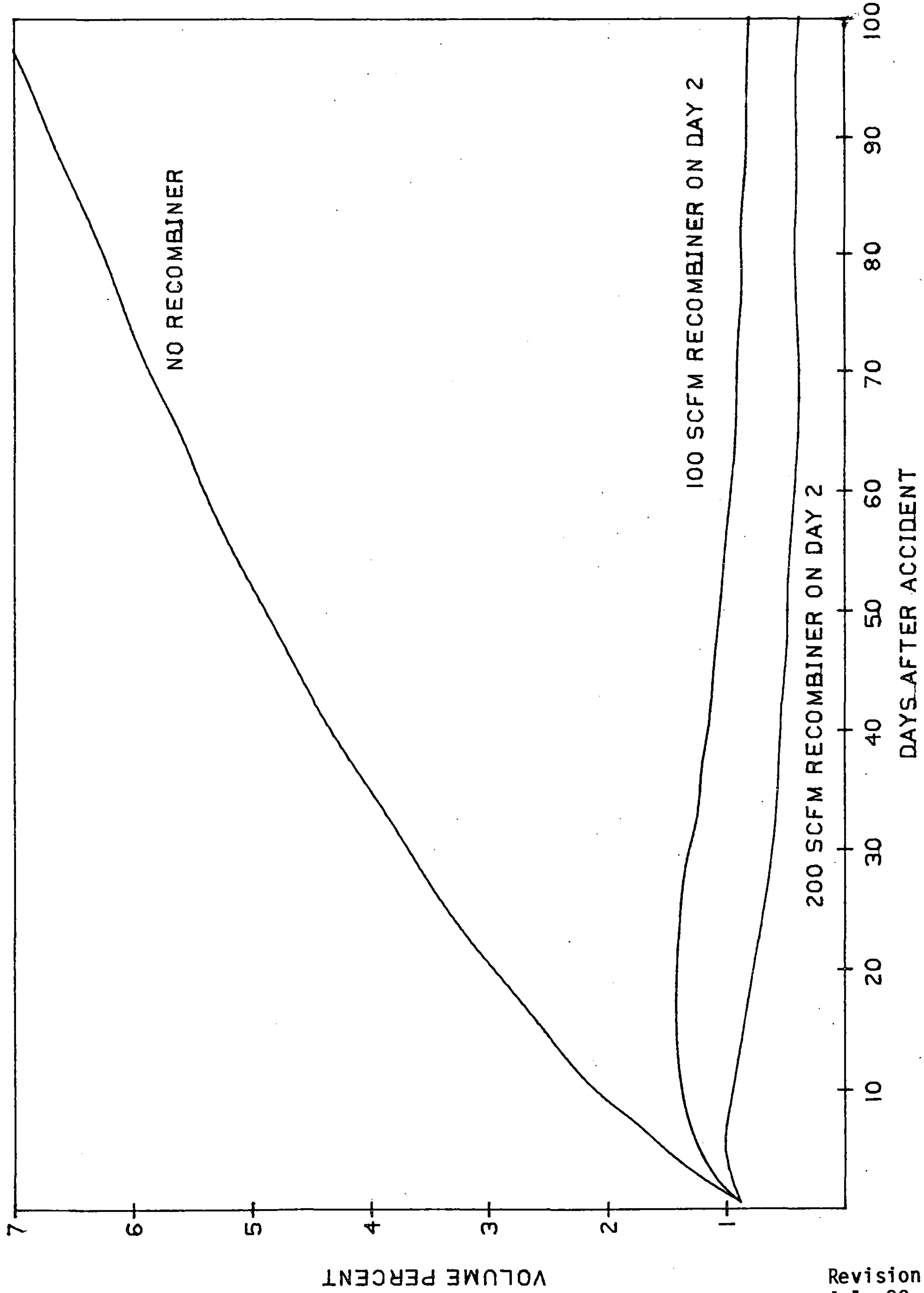
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Hydrogen Generated from Metal Corrosion (Aluminum and Zinc)
	Updated FSAR — FIG. 6.2-55



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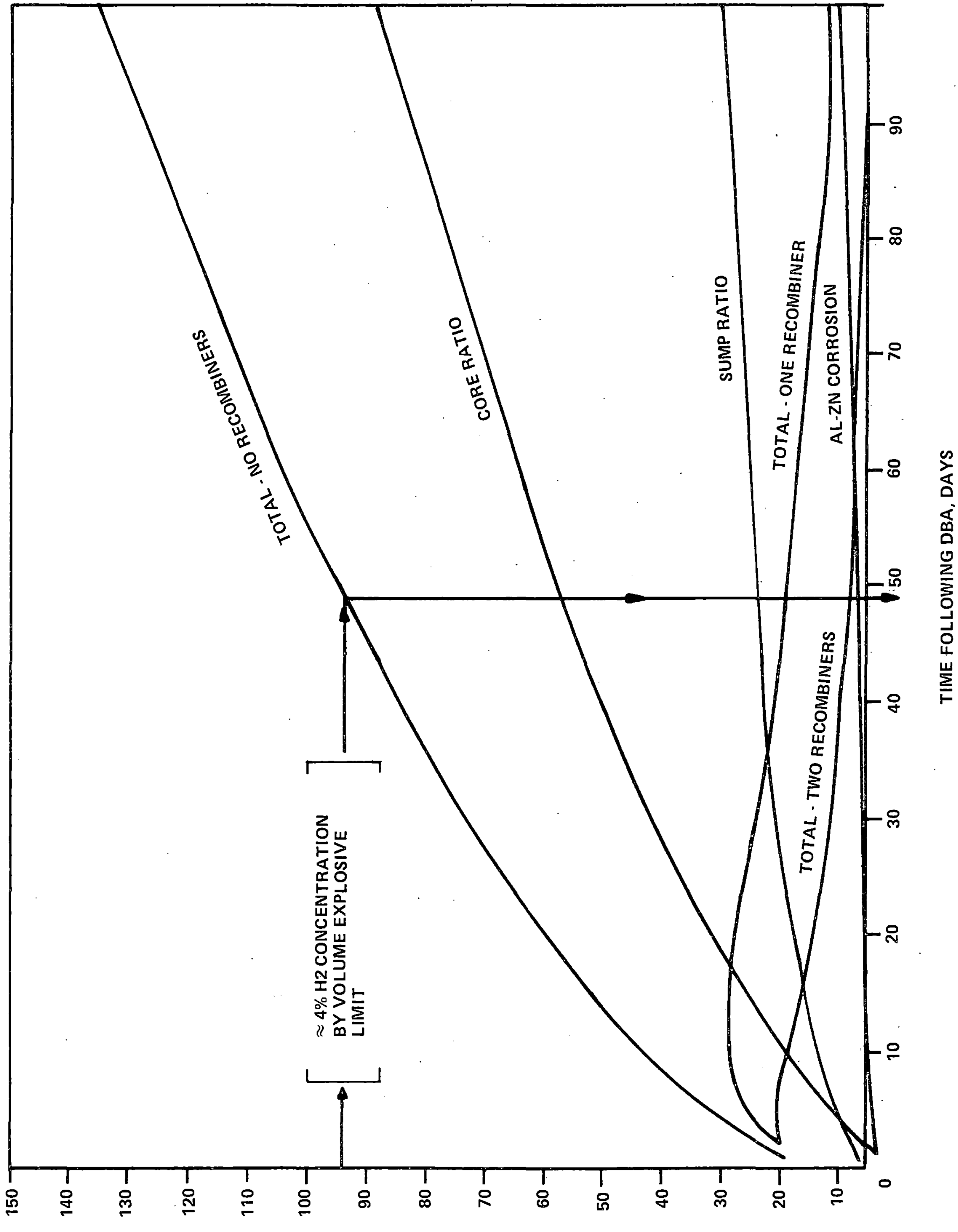
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Total Hydrogen Generated from All Sources	
	Updated FSAR	FIG. 6.2-56



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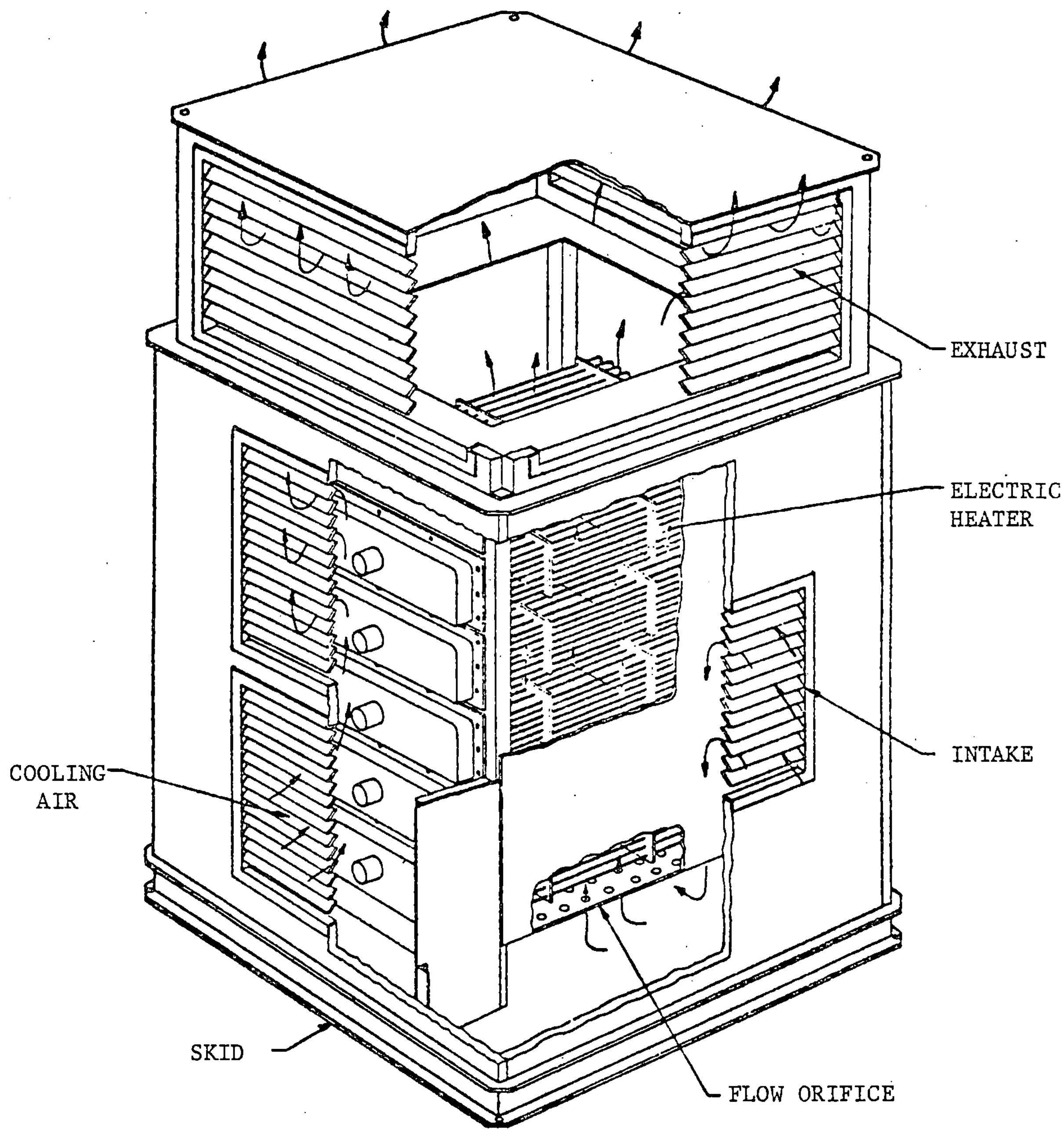
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Hydrogen Accumulation After DBA	
	Updated FSAR	Figure 6.2-57



Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Electric Hydrogen Recombiner	
	Updated FSAR	Figure 6.2-58

6.3 EMERGENCY CORE COOLING SYSTEM

6.3.1 DESIGN BASES

6.3.1.1 Range of Coolant Ruptures and Leaks

The emergency core cooling system (ECCS) automatically delivers cooling water to the reactor core in the event of a loss-of-coolant accident. This limits the fuel clad temperature and thereby ensures that the core will remain substantially intact and in place, with its essential heat transfer geometry preserved. This protection is afforded for:

1. All pipe break sizes and locations in the reactor coolant system up to and including the hypothetical instantaneous circumferential rupture of a reactor coolant loop, assuming unobstructed discharge from both ends.

2. A loss of coolant associated with the rod ejection accident.

3. Pipe breaks in the steam system, up to and including the instantaneous circumferential rupture the largest pipe in the steam system.

4. A steam generator tube rupture.

The criteria for loss-of-coolant accident evaluations are defined in Chapter 15.

Furthermore, for the rupture of any steam or feedwater line, the criteria are:

1. Assuming a stuck rod cluster control assembly, with or without offsite power, and assuming a single failure in the engineered safety features there is no consequential damage to the primary system and the core remains substantially in place and intact.

2. Energy release to the containment from the worst steam pipe break does not cause failure of the containment structure.

3. Assuming a stuck rod cluster control assembly, there will be no return to criticality after reactor trip, for a break equivalent to the spurious opening, with failure to close, of the largest of any single relief or safety valve.

Redundancy and segregation of instrumentation and components is incorporated to assure that postulated malfunctions will not impair the ability of the system to meet the design objectives. The system is effective in the event of loss of normal station auxiliary power coincident with the loss of coolant, and is tolerant of failures of any single component or instrument channel to respond actively in the system. During the recirculation phase of a loss of coolant, the system is tolerant of a loss of any part of the flow path since back up alternative flow path capability is provided.

6.3.1.2 Fission Product Decay Heat

The ECCS removes the stored and fission product decay heat from the reactor core such that fuel rod damage, to the extent that it would impair effective cooling of the core, is prevented. The acceptance criteria for accidents, as well as accident analyses are provided in Chapter 15.

6.3.1.3 Reactivity Required for Cold Shutdown

The ECCS provides shutdown capability for the accidents noted above by means of shutdown chemical (boron) injection. The most critical accident for shutdown capability is the steam line break. Following a steam line break, the reactor control system, in response to the apparent load increase, would increase reactor power. For larger breaks, an overpower reactor trip would occur. Continued secondary steam blowdown would cool the reactor coolant causing a positive reactivity insertion. Analyses described in Chapter 15 indicate that breaks large enough to produce a reactivity insertion sufficient to cause a return to criticality also produce sufficient depressurization and shrinkage of the primary coolant to initiate safety injection. The high pressure delivery of concentrated boric acid by the centrifugal charging pumps then re-established adequate shutdown margin even for the case where the highest worth control rod is stuck in the fully withdrawn position.

6.3.1.4 Capability to Meet Functional Requirements

In order to ensure that the ECCS will perform its desired function during the accidents listed above, it is designed to tolerate a single active failure during the short term immediately following an accident, or to tolerate a single active or passive failure during the long term following an accident.

The ECCS is designed to meet its minimum required level of functional performance with either on-site electrical power system operation (assuming off-site power is not available) or with off-site electrical power system operation for any of the above abnormal occurrences assuming a single failure as defined above.

Portions of the system located within the containment are designed to operate under the most adverse accident conditions without benefit of maintenance and without loss of functional performance for the duration of time the component is required following the accident.

The ECCS is designed to perform its function of ensuring core cooling and providing shutdown capability following an accident under simultaneous safe shutdown earthquake loading.

6.3.2 SYSTEM DESIGN

6.3.2.1 Schematic Piping and Instrumentation Diagrams

The flow diagram of the ECCS is shown in Figures 6.3-1A and B. The codes and standards to which the individual components of the emergency core cooling system are designed are listed in Table 6.3-1. Pertinent design and operating parameters for the components of the ECCS are given in Tables 6.3-2 through 6.3-5.

The operation of the ECCS Core Cooling System, following a loss of coolant accident, can be divided into two distinct phases: 1) the injection phase in which any reactivity increase attending the accident is terminated, initial cooling of the core is accomplished, and coolant lost from the primary system is replenished, and 2) the recirculation phase in which long term core cooling is provided during the accident recovery period. A discussion of each phase is given below.

Injection Phase of Operation

The major equipment involved in the implementation of the injection phase functions are:

1. Two centrifugal charging pumps (a third positive displacement charging pump may be aligned for safety injection purposes if component cooling water is available for the lube oil coolers)

2. Two safety injection pumps

3. Two residual heat removal pumps

4. Four accumulators (one for each loop)

5. One boron injection tank

6. Refueling water storage tank

7. Associated valves and piping

The relative importance of the various pieces of injection equipment is dependent upon the size and location of the primary system break. For a large break, the accumulators represent the principle injection mechanism. They are the first piece of equipment to be effective. (For the double ended cold leg break, they begin to inject approximately 10.0 seconds after the break whereas the remainder of the system has a time delay associated with it on the order of 25 seconds). They deliver at a very high flow rate (approximately 47,000 gpm maximum for a double ended break versus a maximum of 2400 gpm for the remainder of the system).

The accumulators, utilizing the stored energy of the compressed nitrogen, inject borated water into the cold legs of the reactor coolant piping when the primary system pressure falls below 600 psig. One accumulator is provided for each cold leg of the reactor coolant system. They are located inside the containment but outside the missile barrier, and are therefore protected against possible missiles. Accumulator water level can be adjusted remotely during normal power operation. Borated makup water from the refueling water storage tank is added using a safety injection pump. Water level is reduced by draining to the CVCS holdup tanks. Samples of the solution in the accumulator tanks are taken at the sampling station for periodic checks of boron concentration. Provisions are also included for remote nitrogen makeup. The accumulators are passive components of the injection system because they require no external source of power or signal in order to function. The remainder of the major pieces of equipment comprising the safety injection system are active components which are actuated by any of the following safety injection signals:

1. Low pressurizer pressure (2/3).

2. High containment pressure (2/3 Hi).

3. High steam line differential pressure between any two steam generators (2/3).

4. High steamline flow in two of four lines (1/2 measurements per line) in coincidence with either low T_{avg} (2/4) or low steamline pressure (2/4).

5. Manual actuation (1/2).

The safety injection signal initiates a reactor trip (this may have already occurred), starts the diesel generators, and initiates the safeguards sequence which in turn initiates the required action. Finally a safety injection signal will produce a Phase A containment isolation signal which results in the closure of the majority of the automatic containment isolation valves.

The active components serve three functions during the injection phase:

1. Provide rapid injection of high concentration shutdown chemical (boron dissolved in the form of boric acid)

2. Complete the reflooding process for large area ruptures where the initial refill is accomplished by the accumulators

3. Provide injection for small area ruptures where the primary coolant pressure does not drop below the accumulator pressure for an extended period of time.

In accident analyses with coincident loss of outside power, full flow from the safety injection system occurs at no later than 25 seconds. The basis of this valve is discussed in a later section of this chapter. This delay time is independent of whether or not the accumulators have injected.

During safety injection, the centrigugal charging pumps deliver borated water at the prevailing reactor coolant system pressure to the four cold legs of the reactor coolant system. The injection points are separate from those used by the accumulators. The boron injection tank is the source of the borated water initially injected by the centrifugal charging pumps. This tank contains boric acid at a nominal concentration of 12 weight percent and is normally isolated on both the inlet and outlet lines by parallel motor operated gate valves. These valves open upon receipt of a safety injection signal and the discharge from the centrifugal charging pumps sweeps the concentrated boric acid into the reactor coolant system. The safety injection signal also operates motor operated valves which transfer the suction of the centrifugal charging pumps from the volume control tank to the refueling water storage tank.

The safety injection pumps take suction from the refueling water storage tank and deliver borated water to four cold legs via the accumulator discharge lines. These pumps develop a maximum discharge pressure of about 1520 psig at shutoff, and as a result, deliver to the primary system only after its pressure is reduced below this value. Prior to this, they recirculate water back to the storage tank. This limitation on discharge pressure does not significantly reduce the effectiveness of the safety injection pumps since any break of sufficient size to require safety injection will reduce the coolant pressure below 1500 psig.

In the safety injection mode the residual heat removal pumps take suction from the refueling water storage tank and deliver borated water to the same four cold leg connections used by the safety injection pumps, i.e., via the accumulator discharge lines. The residual heat removal pumps deliver only when the reactor coolant system is depressurized to about 170 psig.

All active components of the safety injection system which operate during the injection phase of a loss of coolant accident are located outside the containment system. The centrifugal charging, safety injection and residual heat removal pumps discussed above are all located in the auxiliary building.

Change-Over from Injection Phase to Recirculation Phase

The sequence, from the time of the safety injection signal, for the changeover from injection to recirculation is as follows:

1. First, containment sump level indication shows that sufficient water is delivered to the containment floor to provide the required net positive suction head (NPSH) for the residual heat removal pumps to change to recirculation.

2. Second, the low level alarm on the refueling water storage tank sounds. The operator, at this point, takes appropriate action to switch over to recirculation. One spray pump continues to run until the refueling water storage tank is nearly empty, or until the spray additive tank is empty.

3. Finally the low-low level alarm on the refueling water storage tank sounds. At this time, the operator stops the spray pump. Spraying is continued at this time for approximately 24 hours using the residual heat removal pumps pumping to the spray header located at the residual heat removal heat exchanger discharge.

The changeover from injection to recirculation is effected by the operator in the control room via a series of manual switching operations. The changeover sequence is given in Table 6.3-6.

Recirculation Phase of Operation

After the injection operation, water collected in the containment sump is cooled and returned to the reactor coolant system by the low head/ high head recirculation flow path. The reactor coolant system can be supplied simultaneously from the residual heat removal pumps, and from a portion of the discharge from the residual heat exchangers which is directed to the charging pumps and safety injection pumps, which return the water to the reactor coolant system. The latter mode of operation assures flow in the event of a small rupture where the depressurization proceeds more slowly such that the reactor coolant system pressure is still in excess of the shutoff head of the residual heat removal pumps at the onset of recirculation.

At approximately 22.5 hours after the switchover to cold leg recirculation, hot leg recirculation will be initiated to assure termination of boiling.

Since the injection phase of the accident is terminated before the refueling water storage tank is completely emptied, all pipes are kept filled with water before recirculation is initiated. Water level indication and alarms on the refueling water storage tank inform the operator that difficient water has been injected into the containment to allow iniitation of recirculation with the residual heat removal pumps and to provide ample warning to terminate the injection phase while the operating pumps still have adequate net positive suction head. Two level indicators are provided in the containment sump to provide backup indication that injection can be terminated and recirculation initiated.

Redundancy in the external recirculation loop is provided for by the inclusion of duplicate charging, safety injection, and residual heat removal pumps and residual heat exchangers. Inside the containment, the high-pressure injection system is divided into two separate flow trains. For coldleg recirculation, the charging pumps deliver to all four cold legs and the safety injection pumps also deliver to all four cold legs by separate flow paths. For hot leg recirculation, each safety injection pump delivers through separate paths to two reactor coolant loops.

The low head pumps take suction through separate lines from the containment sump and discharge through separate paths to the reactor coolant system. The sump design provides sufficient flow area over the trash curb ahead of the sump and adequate NPSH for the residual heat removal pumps to operate in the recirculation mode.

The low flow velocity across the containment floor approaching the sump permits the bulk of the debris denser than water to settle to the floor of the containment rather than enter the sump. Perforated plates prevent entrance of other suspended matter of a size that could jeopardize the recirculation system. A weir in the sump prevents floating debris from entering the sump.

The sump isolation valves are located in small steel-lined pressure-tight compartments. This arrangement contains any isolation valve leakage and assures that leakage during long term recirculation will not impair the integrity of the containment or recirculation system.

The containment sump is described in Section 6.3.2.2. Special attention is paid to the design, materials and fabrication of the sump, the suction piping, guardpipes and isolation valves to provide assurance that the sump and piping will remain functional under the accident environment and continue to provide suction for the long term recirculation.

A sample connection is provided in the residual heat removal system to remotely sample recirculated liquid in the sample room during post-accident operations. Additives can be supplied to the sump through the existing boron makeup equipment if measurements indicate the sump liquid is outside the desired pH range of 8.5 to 10.0.

6.3.2.2 Equipment and Component Description

The major components of the ECCS are:

Accumulators

The accumulators are pressure vessels containing borated water and pressurized with nitrogen gas. During normal operation, each accumulator is isolated from the reactor coolant system by two check valves in series. Should the reactor coolant system pressure fall below the accumulator pressure, the check valves open and borated water is forced into the reactor coolant system. One accumulator is attached to each of the cold legs of the reactor coolant system. Mechanical operation of the swing disc check valves is the only action required to open the injection path from the accumulators to the core via the cold leg.

The accumulators are passive engineered safety features because the gas forces injection; no external source of power or signal transmission is needed to obtain fast-action, high-flow capability when the need arises. One accumulator is attached to each of the cold legs of the reactor coolant system.

The design capacity of the accumulators is based on the assumption that flow from one of the accumulators spills onto the containment floor through the ruptured loop, and the flow from the remaining accumulators provides sufficient water to fill the volume outside of the core barrel below the nozzles, the bottom plenum, and portion of the core. This assumption is based on no water remaining in the vessel after blowdown but takes credit for the water delivered by three accumulators. All the effects that could cause loss of accumulator water are evaluated in Chapter 15.

The accumulators are carbon steel, clad with stainless steel and designed to ASME Section III, Class C. Connections for remotely draining or filling the fluid space, during normal plant operation, are provided. The accumulator design parameters are given in Table 6.3-2.

The margin between the minimum operating pressure and design pressure provides a band of acceptable operating conditions within which the accumulator system meets its design core cooling objectives. The band is sufficiently wide to permit the operator to minimize the frequency of adjustments in the amount of contained gas or liquid to compensate for leakage.

The accumulator tank pressure and level are continuously monitored during plant operation and flow from the tanks can be checked at any time using test lines.

The accumulators and the safety injection piping up to the final isolation valve is maintained full of borated water at refueling water concentration while the plant is in operation. The accumulators and injection lines will be refilled with borated water as required by using the safety injection pump to recirculate refueling water through the injection headers. A small bypass line and a return line are provided for this purpose.

Level and pressure instrumentation are provided for each accumulator tank.

Boron Injection Tank

The boron injection tank contains a nominal 12 percent by weight concentrated boric acid solution and is connected to the discharge of the centrifugal charging pumps. Upon actuation of the safety injection signal, the centrifugal charging pumps provide the pressure to inject the boric acid solution into the reactor coolant system when the isolation valves open.

The boron injection tank (BIT) is maintained in a 100 percent full condition. Whenever the plant is at power, a recirculation path is set up to recirculate the BIT contents to and from the boric acid tanks. Since the boric acid tanks are at a higher elevation than the BIT, they act as a surge tank and this, along with the recirculation flow path (from bottom of BIT to top) ensures that the BIT is always 100 percent full. The BIT is most important for the steam line break, which is presented in Chapter 15. For this analysis the full contents of the tank are assumed to be available for injection into the reactor coolant system. However, the peak post accident flux is very insensitive to the volume of the BIT. The volume of the BIT is such that no significant dilution occurs from continued injections during the period of the steam break transient (ä2 min.). Therefore it is expected that a significant change in BIT volume would not affect the peak flux.

In the extremely unlikely event of leakage from the system, indication of such leakage would be furnished by a falling level in the boric acid tanks. Level indication and low level alarms for the boric acid tanks are furnished in the control room.

The normal temperature of the BIT and its associated lines is 160°F, with a low temperature alarm set at 155°F. The boric acid lines have duplicate heat trace cables, each fed from a separate vital bus.

The boron injection tank has two temperature detectors. One provides heater control, control room alarm, and local indication. The other provides control room indication, backup heater control, and control room alarm.

The equipment employed with the boron injection tank is designed to the same quality standards and codes as the rest of the engineered safety features equipment and is Seismic Class I design.

Refueling Water Storage Tank

In addition to its usual service of supplying borated water to the refueling canal for refueling operations, this tank provides borated water to the centrifugal charging pumps, safety injection pumps, residual heat removal pumps and the containment spray pumps for the loss-of-coolant accident. During normal power operation, storage tank water is valved to the suction of the safety injection pumps, residual heat removal pumps and containment spray pumps. The suction of the charging pumps is automatically valved to the storage tank by a safety injection signal.

The minimum quantity of the refueling water storage tank is ~350,000 gallons and is based on the requirement for filling the refueling canal. This volume also provides a sufficient amount of borated water to meet the following conditions:

1. Adequate volume during the injection phase to meet ECCS design objective.

2. Increase the concentration of recirculation water to a point that assures no return to criticality with the reactor at cold shutdown and all control rods, except the most reactive rod cluster control assembly, inserted into the core.

3. Fill the containment sump to permit the initiation of recirculation.

4. Fulfill spray requirements.

The water in the tank is borated to a concentration which assures reactor shutdown by approximately 10 percent $\Delta k/k$ when all rod cluster control assemblies are inserted and when the reactor is cooled down for refueling.

The design parameters are presented in Table 6.3-4.

The refueling water storge tank is classified Class I for seismic design. This requires that there will be no loss of function or spillage of its contents for loads from two times the design earthquake when combined with the normal loads. The effect of water sloshing within the tank is considered in determining the seismic loads.

Compressive stresses in the shell of the tank are limited by allowable buckling stresses, determined in a manner similar to Paragraph I-1150 of the ASME Code, Section III.

The tank is provided with a high level alarm and the overflow line is piped to the diked area around the No. 13 CVCS holdup tank, from where any overflow can be pumped to the liquid waste disposal system. The overflow line includes a collection pot which is also provided with a high level alarm. Both alarms are indicated in the control room.

Anti-vortex plates are installed in the containment spray suction line from the RWST. Verification of vortex control in the containment sump is discussed in Section 6.3.2.6 and 6.3.4.4.

The temperature of the water in the refueling water storage tank is prevented from dropping below 32°F by automatic initiation of a circulating and heating system which draws water from the tank through the safety injection system suction pipe and the containment spray system suction pipe. The water is then pumped through a heat exchanger located in the auxiliary building and enters the tank via the return line from the refueling water purification pump. Thus, the water in the tank and the water in the connecting piping is heated and circulated.

The instrumentation which actuates the heating system senses the temperature in the safety injection system suction pipe. This temperature and the temperature of the return water are monitored and alarmed in the control room. The system has provision for local manual actuation.

Electrical heat tracing is provided for the instrument connections to the tank and for that portion of the tank drain piping which could otherwise freeze. Thermal insulation is also provided for the exposed piping.

Valves 1SJ30 and 1SJ69 (in the RWST suction line to the ECCS pumps) are provided with the same type of redundant positon indication as the accumulator discharge valves, described in Section 6.3.2.15.

Residual Heat Removal Pumps

The two residual heat removal pumps are vertical electric motor driven single stage pumps. All parts of the pump in contact with the pumped fluid are stainless steel or of equivalent corrosion resistant material.

A minimum flow bypass line is provided for the pumps to recirculate through the residual heat exchangers and return the cooled fluid to the pump suction should these pumps be started with their normal flow paths blocked. Once flow is established to the reactor coolant system, the bypass line is automatically closed. This line prevents deadheading the pumps and permits pump testing during normal operation.

Centrifugal Charging Pump

The two centrifugal charging pumps are horizontal electric motor driven multi-stage pumps. All parts of the pump in contact with the pumped fluid are stainless steel or equivalent corrosion resistant material. Mini flow protection is provided during ECCS operation.

Safety Injection Pump

The two safety injection pumps are horizontal electric motor driven multistage pumps. All parts of the pump in contact with the pumped fluid are stainless steel or equivalent corrosion resistant material. A minimum flow bypass line is provided on each pump discharge to recirculate flow to the refueling water storage tank in the event that the reactor coolant system pressure is above the shutoff head of the pumps. A 100 gpm test line is provided in parallel to the mini-flow line. This line is used for inservice testing and is locked out at other times.

Pump Design, Materials and Fabrication

The pressure containing parts of the pumps are stainless steel castings conforming to ASTM A-351 Grade CF8 or CF8M, stainless steel forgings frocured per ASTM A-182 Grade F304 and F316, or Carbon Steel forgings to ASTM A-181, Grade 1, clad with austenitic steel. Parts fabricated of stainless plate are constructed to ASTM A-240, Type 304 or 316. All bolting material conforms to ASTM A-192.

Materials such as weld-deposited Stellite or Colomony are used at points of close running clearances in the pumps to prevent galling and to ensure continued performance ability in high velocity areas subject to erosion. In other cases wear points are of ASTM A-420 Grade stainless steel, heat treated to give the required anti-galling properties.

All pressure containing parts of the pumps are chemically and physically analyzed and the results are checked to assure conformance with the applicable ASTM specification. In addition, all pressure containing parts of the pump are liquid penetrant inspected in accordance with Appendix VIII of Section VIII of the ASME Code. The acceptance standard for the liquid penetrant test is the ASME Pump and Valve Code.

Pump design is reviewed with special attention to the reliability and maintenance aspects of the working components. Specific areas include evaluation of the shaft seal and bearing design to determine that they are adequate for the specified service.

Where welding of pressure containing parts is necessary, a welding procedure including joint detail is submitted for review and approval by Westinghouse.

This procedure includes evidence of qualification necessary for compliance with Section IX of the ASME Code Welding Qualifications. This requirements also applies to any repair welding performed on pressure containing parts.

The pressure-containing parts of the pump were assembled and hydrostatically tested to 1.5 times the design pressure for 30 minutes.

Each pump was given a complete shop performance test in accordcance with Hydraulic Institute Standards. The pumps were run at design flow and head, shut-off head and three additional points to verify performance characteristics. Where NPSH is critical, this value is established at design flow by means of adjusting suction pressure.

A qualitative analysis shows that any flooding resulting from a leak in one pumping train will not incapacitate the redundant pump.

Heat Exchangers

The two residual heat exchangers of the residual heat removal system cool the recirculated sump water. These heat exchangers are sized for the cooldown of the reactor coolant system. The design parameters of the heat exchangers are presented in Section 5.5.

The residual heat exchangers are designed to the ASME Code, and to conform to the requirements of TEMA (Tubular Exchanger Manufacturers Association) for Class R heat exchangers.

Additional design and inspection provisions include: confined-type gaskets, general construction and mounting brackets suitable for the plant seismic design requirements, tubes and tube sheet capable of withstanding full shell side pressure and temperature with atmospheric pressure on the tube side, radiographic inspection in accordance with Sections UW-11, UW-12-b and UW52 of ASME Section VIII, ultrasonic inspection in accordance with Paragraph N-324.3 of Section III of the ASME Code of all tubes before bending, penetrant inspection in accordance with Paragraph N-627 of Section III of the ASME Code of all welds and all hot or cold formed parts, a hydrostatic test duration of not less than 30 minutes, the witnessing of hydro and penetrant tests by a qualified inspector, a thorough final inspection of the unit for workmanship and the absence of any gouge marks or other scars that could act as stress concentration points, a review of the radiographs and of the certified chemical and physical test reports for all material used in the unit.

The residual heat exchangers are convential vertical shell and U-tube type units. The tubes are seal welded to the tube sheet. The shell connections are flanged to facilitate shell removal for inspection and cleaning of the tube bundle. Each unit has a SA 515GR70 carbon steel shell, SA-213 TP-304 stainless steel tubes, SA-240 Type 304 stainless steel channel, SA-240 Type 304 stainless steel channel cover and a tube sheet of forged steel SA-105 GR.III with 1/4 inch minimum TP-304 weld overlay.

Valves (General)

Design features employed to minimize valve leakage include:

1. Where possible, packless valves are used.

2. Other valves which are normally open, except valves and those which perform a control function, are provided with backseats to limit stem leakage.

3. Normally closed globe valves are installed with recirculation fluid pressure under the seat to prevent stem leakage of recirculated (radioactive) water.

4. Relief valves are enclosed, i.e., they are provided with a closed bonnet and discharge to a closed system.

5. Control and motor operated valves (3 inches and above) exposed to recirculation flow have double packed stuffing boxes and stem leak-off connections to the waste processing system.

All parts of valves used in the safety injection system in contact with borated water are austenitic stainless steel or equivalent corrosion resistant material. The motor operators on the injection line isolation valves are capable of rapid operation. All valves required for initiation of safety injection or isolation of the system have remote limit position indication in the control room.

Valving is specified for exceptional tightness and, where appropriate, packless diaphragm valves are used. All valves, except those which perform a control function, are provided with backseats which are capable of limiting leakage to less than 1.0 cc per hour per inch of stem diameter, assuming no credit taken for valve packing. Those valves which are normally open are backseated. Normally closed globe valves are installed with recirculation flow under the seat to prevent leakage of recirculated water through the valve stem packing. Relief valves discharge to an enclosed system. Control and motor-operated valves, 2 inches and above, which are exposed to recirculation, are provided with double-packed stuffing boxes and stem leakoff connections which are piped to the equipment drain system.

The check valves which isolate the ECCS from the reactor coolant system are installed near the reactor coolant piping to reduce the probability of an injection line rupture causing a loss-of-coolant accident.

Portions of the ECCS piping are protected by relief valves. The relieving capacity of these valves is based on a flow several times greater than the expected leakage rate through the check valves. The valves relieve to the pressurizer relief tank.

The residual heat removal system is protected by four relief valves: one on the header from the RCS to the pumps, two on the cold leg injection headers, and one on the hot leg return header.

These valves discharge to the pressurizer relief tank.

The gas relief valves on the accumulators protect them from pressures in excess of the design value.

Motor Operated Valves

The pressure containing parts (body, bonnet and discs) of the motor-operated valves employed in the safety injection system are designed per criteria established by the ANSI B16.5 or MSS SP66 specifications. The materials of construction for these parts are procured per ASTM A182, F316 or A351, GR CF8M, or CF8, All material in contact with the primary fluid, except the packing, is austenitic stainless steel or equivalent corrosion resisting material. The pressure containing cast components are radiographed in accordance with ASTM, E-94 and the acceptance standard as outlined in ASTM E-71. The body, bonnet and discs are liquid penetrant inspected in accordance with ASME Pump and Valve Code. The liquid penetrant acceptable standard as outlined in the ASME Pump and Valve Code.

When a gasket is employed the body-to-bonnet joint is designed per ASME Code Section VIII and/or ANSI B16.5 with a fully trapped, controlled compression, spiral wound asbestos gasket with provisions for seal welding, or of the pressure seal design with provisions for seal welding. The body-to-bonnet bolting and nut materials are procured per ASTM A193 and A194, respectively.

The entire assembled unit is hydrotested as outlines in MSS SP-61 with the exception that the test is maintained for a minimum period of 30 minutes. Any leakage is cause for rejection. The seating design is of the Darling parallel disc design, the Crane flexible wedge design, or the equivalent. These designs have the feature of releasing the mechanical holding force during the first increment of travel. Thus, the motor operator has to work only against the frictional component of the hydraulic unbalance on the disc and the packing box friction. The discs are guided throughout the full disc travel to prevent chattering and provide ease of gate movement. The seating surfaces are hard faced (Stellite No. 6 or equivalent) to prevent galling and reduce wear.

The stem material is ASTM A276 Type 316 condition B or precipitation hardened 17-4 PH stainless procured and heat treated to Westinghouse Specifications. These materials are selected because of their corrosion resistance, high tensile properties, and their resistance to surface scoring by the packing. The valve stuffing box of motor-operated valves having leakoff is designed with a lantern ring leak-off connection with a minimum of a full set of packing below the lantern ring; a full set of packing is defined as a depth of packing equal to 1-1/2 times the stem diameter. The experience with this stuffing box design and the selection of packing and stem materials have been very favorable in both conventional and nuclear power plants.

The motor operator is extremely rugged and is noted throughout the power industry for its reliability. The unit incorporates a "hammer blow" feature that allows the motor to impact the discs away from the fore or backseat upon opening or closing. This "hammer blow" feature not only impacts the disc but allows the motor to attain its operational speed.

Each valve is assembled, hydrostatically tested, seat-leakage tested (fore and back), operationally tested, cleaned and packaged per specifications. All manufacturing procedures employed by the valve supplier such as hard facing, welding, repair welding and testing are submitted to Westinghouse for approval.

For fast operated valves up to and including 8 inches, 10 second maximum operators are provided. For all fast operated valves above 8 inches the operating speed is 49 inches/minute. For slow operators 12 inches/ minute is specified, for valves up to and including 8 inches. For all slow valves above 8 inches, 120 second maximum closing time is specified.

Manual Valves

The stainless steel manual globe, gate and check valves are designed and built in accordance with the requirements outlined in the motor operated valve description above.

The carbon steel valves are built to conform with ANSI B16.5. The materials of construction of the body, bonnet and disc conform to the requirements of ASTM A105 Grade II, A181 Grade II or A216 Grade WCB or WCC. The carbon steel valves pass only non-radioactive fluids and are subjected to hydrostatic test as outlined in MSS SP61 except that the test pressure is maintained for at least 30 minutes. Since the fluid controlled by the carbon steel valves is not radioactive, the double packing and seal weld provisions are not provided.

Accumulator Check Valves

The pressure containing parts of this valve assembly are designed in accordance with ASME B and PV Code, Section III, 1968. All parts in contact with the operating fluid are of austenitic stainless steel or of equivalent corrosion resistant materials procured to applicable ASTM or WAPD specifications. The cast pressure-containing parts are radiographed in accordance with ASTM E-94 and the acceptance standard as outlined in ASTM E-71. The cast pressure-containing parts, machined surfaces, finished hard facings, and gasket bearing surfaces are liquid penetrant inspected per ASME Pump and Valve Code and the acceptance standard is as outlined in the ASME Pump and Valve Code. The final valve is hydrotested per MSS SP-66 except that the test pressure is maintained for at least 30 minutes. The seat leakage test is conducted in accordance with the manner prescribed in MSS SP-61 except that the acceptable leakage is 3cc/hr/in, nominal pipe diameter.

The valve is designed with a low pressure drop configuration with all operating parts contained within the body, which eliminates those problems associated with packing glands exposed to boric acid. The clapper arm shaft is manufactured from 17-4 PH stainless steel heat treated to Westinghouse Specifications. The clapper arm shaft bushings are manufactured from Stellite No. 6 material. The various working parts are selected for their corrosion resistant, tensile and bearing properties.

The disc and seat rings are manufactured from a forging. The mating surfaces are hard faced with Stellite No. 6 to improve the valve seating life. The disc is permitted to rotate, providing a new seating surface after each valve opening.

The valves are intended to be operated in the closed position with a normal differential pressure across the disc of approximately 1600 psi. The valves shall remain in this position except for testing and safety injection. Since the valves will not be required to normally operate in the open condition and hence be subjected to impact loads caused by sudden flow reversal, it is expected that these valves will perform their required functions without difficulty.

When the valve is required to operate, a differential pressure of less than 25 psig will shear any particles that may otherwise prevent the valve from funtioning. Although the working parts are exposed to the boric acid solution contained within the reactor coolant loop, a boric acid "freeze up" is not expected with the low boric acid concentrations used.

The experience derived from the check valves employed in the emergency injection system of the Caroline - Virginia Tube Reactor (CVTR) in a similar system indicates that the system is reliable and workable.

The CVTR emergency injection system, normally maintained at containment ambient conditions was separated from the main coolant piping by a single 6 inch check valve. A leak detection was provided at a proper elevation to accumulate any leakage coming back through the check valve and level alarm provided a signal on excessive leakage. The pressure differential was 1500 psi and the system was stagnant. The valve was located 2 to 3 feet from the main coolant piping which resulted in some heatup and cooldown cycling. The CVTR went critical late in 1963 and operated until 1967 during which time the level sensor in the leak detector never alarmed due to check valve leakage.

Relief Valves

The accumulator relief valves are sized to pass nitrogen gas at a range in excess of the accumulator gas fill line delivery rate. The relief valves will also pass water in excess of the expected leak rate, but this is not necessary because the time requied to fill the gas space gives the operator ample opportunity to correct the situation. For an inleakage rate 15 times the manufacturing test rate, there will be in excess of 1000 days before water will reach the relief valves. Prior to this, level and pressure alarms would have been actuated.

The ECCS relief valves are provided to relieve any pressure, above design, that might build up in the safety injection piping. The valve will pass a flow rate which is far in excess of the manufaturing design leak rate of 24 cc/hr.

Valve Leakage Specifications

The specified leakage across the valve disc required to meet the equipment specification and hydrotest requirements is as follows:

1. Conventional globe - 3 cc/hr/in. of nominal pipe sizes

2. Gate valves - 3 cc/hr/in. of nominal pipe size; 10 cc/hr/in for 300 and 150 pound ANSI Standard

3. Motor-operated gate valves - 3 cc/hr/in. of nominal pipe size; 10 cc/hr/in for 300 and 150 pound ANSI Standard

4. Check valves - 3 cc/hr/in. of nominal pipe size; 10 cc/hr/in for 300 and 150 pound ANSI Standard

5. Accumulator check valves - 3 cc/hr/in. of nominal pipe size

Piping

All ECCS piping in contact with borated water is austenitic stainless steel. All major piping joints are welded except for the flanged connections at pumps.

The piping beyond the accumulator stop valves is designed for reactor coolant system conditions.

The safety injection pump suction piping from the refueling water storage tank is designed for low pressure losses to met net positive suction head requirement of the pumps.

The safety injection high pressure branch lines are designed for high pressure losses to limit the flow rate out of the branch line in the event of rupture at the connection to the reactor coolant loop. The branch lies are sized so that a break will not result in a violation of the design criteria for the ECCS.

The piping is designed to meet the requirements set forth in (1) the ANSI B31.1 Code for Pressure Piping, (2) ANSI Standards B36.10 and B36.19, and (3) ASTM Standards.

Pipe fittings materials are procured in conformance with all requirements of the latest ASTM and ANSI specifications. All materials are verified for conformance to specifications and documented by certification of compliance to ASTM-material requirements. Specifications impose additional quality control upon the suppliers of pipes and fittings as listed below.

1. Check analyses are performed on both the purchased pipe and fittings.

2. Pipe branch lines between the reactor coolant pipes and the isolation stop valves conform to ASTM A376 and meet the supplementary requirement S6 covering an ultrasonic test, on 100 percent of the pipe wall volume. The S6 supplementary requirement applies to pipes of nominal sizes 3 inches and larger.

3. Pipe fittings in the branch lines between the reactor coolant pipes and the isolation stop valves conform to the requirements of ASTM A403; all fittings have requirements for liquid penetrant examination.

Shop fabrication of piping subassemblies is performed by reputable suppliers in accordance with specifications which define and govern material procurement, detailed design, shop fabrication, cleaning, inspection, identification, packaging and shipment.

Welds for pipes sized 2-1/2 inches and larger are of the full penetration type. Reducing tees are used where the branch size exceeds 1/2 of the header size. All welding is performed by welders and welding procedures qualified in accordance with the ASME Code Section IX, Welding Qualifications.

All high pressure piping butt welds containing radioactive fluid, at greater than 600°F temperature and 600 psig pressure or equivalent, are radiographed. The remaining piping butt welds are randomly radiographed. The technique and acceptance standards are those outlined in Appendix B of ANSI B31.7. In addition, butt welds are liquid penetrant examined in accordance with the procedures of Appendix B of ANSI B31.7. Finished branch welds are liquid penetrant examined on the outside and where size permits, on the inside root surfaces.

A post-bending solution anneal heat treatment is peformed on hot-formed stainless steel pipe bends. Completed bends are then completely cleaned of oxidation from all affected surfaces. The shop fabricator is required to submit the bending, heat treatment and clean-up procedures for review and approval prior to release for fabrication.

General cleaning of completed piping subassemblies (inside and outside surfaces) is governed by basic ground rules set forth in the specifications.

Packaging of the piping subassemblies for shipment is done so as to preclude damage during transit and storage. Openings are closed and sealed with tight-fitting covers to prevent entry of moisture and foreign material. Flange facings and weld end preparations are protected from damage by means of wooden cover plates and securely fastened in position. The packing arrangement proposed by the Shop Fabricator is subject to approval.

Pump and Valve Motors

ECCS pump motors are used on the following pumps:

1. Centrifugal Charging
2. Safety Injection
3. Residual Heat Removal

The motors are designed in accordance with the National Electric Manufacturers Association Standards (NEMA). These standards are used by the industry and provide requirements for construction, test, performance and manufacture of alternating current and direct current motors and generators, that by experience demonstrate a high quality level. (NEMA, Standard Publication for Motors and Generators, No. MG 1-1967.)

ECCS motors are specified to an Equipment Specification and the following design classifications:

1. Drip Proof Enclosure
2. Class B Insulation System
3. Service Factor Rating of 1.15
4. 80 percent starting voltage capability.

The integrity of the insulation system is considered of prime importance. To assure this integrity motors are sized such that NEMA temperature limits for the service factor rating of the motor are not exceeded. (NEMA MG 1-12.42).

Table 6.3-7 shows system parameters and brake horsepower for both normal and accident conditions. The brake horsepower requirements are well below NEMA horsepower ratings, these motors will operate below the temperature limits as specified by NEMA MG 1-12.42. Further, complete engineering tests are performed on all prototype motor frame sizes to confirm design calculations.

Motors Outside the Containment

Motor electrical insulation systems are supplied in accordance with USAS, IEEE and NEMA standards and are tested as required by such standards. Temperature rise design selection is such that normal long life is achieved even under accident loading conditions.

Criteria for motors of the ECCS require that under normal plant operating conditions the motors operate below their nameplate rated horsepower, i.e., below a 1.0 service factor. For no other anticipated operating mode including safeguards operation, do the motors exceed the maximum rating allowed by the nameplate, including their specified 1.15 service factor.

Motors Inside the Containment (Valve Motor Operators)

Tests which demonstrate the adequacy of valve motor operators to be functional after exposure to high temperatures, pressures, and radiation, have been conducted. The results of the tests are confirmed in Reference 1.

Containment Sump

The physical arrangement of the containment sump is shown in Figure 6.3-2. All water entering the containment sump will have been strained either by the drain trench covers (which have 3/16 inch diameter holes drilled in them), by the floor drain gratings, or by the large inverted basket-type strainer installed on the containment sump cover (see Figure 6.3-3). An anti-vortex baffle minimizes the possibility of pump cavitation through optimal placement based on model tests (2).

The sump design differs from Regulatory Guide 1-82 in the following ways:

1. The small drainage sump for collecting and monitoring normal leakage within the containment is at the same location as the RHR sump. The liquid radwaste and RHR systems share a common sump. A weir plate is installed to isolate normal drainage from the RHR pump suction.

2. The majority of containment sump screening consists of two-level horizontal screens.

Blockage of drains and containment sump screens will not be caused by circulation materials following an accident. Because of the structural nature of the insulation, large quantities of this material would not be dislodged from pipes in which breaks could occur or from surrounding pipes due to jet impingement. Reflective, totally encapsulated, and semi-encapsulated materials are designed to withstand severe loadings. Only the material directly adjacent to a high energy pipe break would be dislodged from the pipe. Although material directly in the path of a jet stream may become saturated, the lagging or strapping system will keep it on all insulated surfaces.

The following is a summary of insulation materials used inside containment:

Reflective: This is an all-metallic stainless steel insulation. Seven foil stainless sheets are rigidly secured within a heavy gauge metal housing. This material is used on the reactor coolant system.

Encapsulated: This is a ceramic fiber insulation "cera-blanket" totally enclosed in a rigid stainless steel structure. This material is used on the ECCS piping and equipment in the containment.

Semi-Encapsulated: This application of "cera-blanket" insulation utilizes an outer heavy gauge stainless steel surface with an interior surface of formed stainless steel foil or heavy gauge stainless steel channels and straps (panel insulation). Foil-enclosed insulation is used for heat retention on Nuclear Class III piping and equipment while panel insulation is used on the steam generators.

Min "K": This is a high-efficiency powder-like insulation totally enclosed in stainless steel. Small amounts of this insulation are used on the RCS where physical arrangement does not permit the use of thicker reflective insulation.

Fiberglass: This is a fibrous insulation covered by stainless steel and a vapor barrier used to prevent sweating of cold water systems (component cooling and service water).

Calcium Silicate: This rigid solid insulation is used on straight portions of the feedwater and main steam systems. This material is also covered with stainless steel. Welds in these systems are covered with encapsulated insulation.

Mineral Wool: This fibrous insulation is applied to the lower 34-feet of the containment liner and is also covered with stainless steel lagging and a vapor barrier.

6.3.2.3 Applicable Codes and Classifications

The codes and standards to which the individual ECCS components are designed are listed in Table 6.3-1

6.3.2.4 Materials Specification and Compatibility

Materials are selected to meet the applicable material requirements of the codes in Table 6.3-1 and the following additional requirements:

1. All parts of components in contact with borated water are fabricated of or clad with austenitic stainless steel or equivalent corrosion resistant material.

2. All parts of components in contact (internal) with sump solution during recirculation are fabricated of austenitic stainless steel or equivalent corrosion resistant material.

3. Valve seating surfaces are hard faced with Stellite Number 6 or equivalent to prevent galling and to reduce wear.

4. Valve stem materials are selected for their corrosion resistance, high tensile properties, and resistance to surface scoring by the packing.

The elevated temperature of the sump solution during recirculation is well within the design temperature of all ECCS components. In addition, consideration has been given to the potential for corrosion of various types of metals exposed to the fluid conditions prevalent immediately after the accident or during long term recirculation operations.

6.3.2.5 Design Pressures and Temperatures

The component design pressure and temperatures are given in Tables 6.3-2 through 6.3-5. These pressure and temperature conditions are specified as the most severe conditions to which each component is exposed during either normal plant operation or during operation of the ECCS. For each component, these conditions are considered in relation to the code to which it is designed. By designing the components in accordance with applicable codes and with due consideration for the design and operating conditions, the fundamental assurance of the structural integrity of the ECCS components is maintained.

6.3.2.6 Coolant Quantity

The minimum storage volume for the accumulators is given in Table 6.3-2. The total volume of the RWST is 400,000 gallons. At the minimum volume permitted by the Technical Specifications (364,500 gallons) approximately 334,500 gallons are available to the ECCS pumps (As noted below there is an unusable volume of 15,500 gallons in the RWST).

The amount of water injected into the core during a postulated LOCA must be of sufficient quantity to provide core cooling and adequate RHR pump NPSH in the containment sump. 193,000 gallons of RWST volume is required to meet these requirements. In order for this volume of water to be available for injection, additional water volume must be provided for the following reasons:

Instrumentation Errors

An incremental volume is necessary to account for the accuracy of the instruments which measure and display RWST level. The design error for each train of instrumentation is ± 1.1 percent. However, for the purpose of conservatism, a ± 2.5 percent (of full scale) instrument error was assumed in the analysis. This error requires an additional 10,500 gallons of required capacity.

Working Allowance

An allowance above the required capacity of 364,500 gallons is necessary to prevent alarms under static conditions. A nominal 10,500 gallons over and above the design capacity is desired for this margin.

Transfer Allowance

Additional water is required to accommodate the delay time associated with the transfer of the ECCS pump suctions from the RWST to the containment sump. The required actions along with the volume of water used during each step of the procedure are described and analyzed in Table 6.3-8. The result is that approximately 73,000 gallons are required for transfer.

Single Failure Allowance

The most limiting single failure with respect to tank capacity results if the control room operator is unable to trip one RHR pump. Consequently, the pump draws water from the RWST for an extended period. The effect of this failure is analyzed in Table 6.3-8.

The single failure allowance is the difference in volume between the normal transfer allowance and the single failure transfer allowance (both are computed in Table 6.3-8); the difference amounts to approximately 30,500 gallons.

Unusable Volume

Once the inlet of the pump suction pipes are reached, the pumps are assumed to lose suction. Therefore, any remaining water in the RWST is considered unusable. This amount is 15,500 gallons.

The RWST low-level alarm setpoint is at 150,500 gallons of tank volume. At this time, approximately 135,000 gallons are available to the ECCS pumps.

The low-low level setpoint is at 21,200 gallons of tank volume. At this volume, approximately 5,700 gallons are available to the pumps.

The switchover from injection to recirculation begins when the RWST reaches its low-level setpoint. Assuming a conservative switchover time of 13 minutes, the volume of water used during the process is approximately 73,000 gallons, leaving approximately 62,000 gallons of water in the tank. Of the remaining amount, approximately 46,500 gallons is still usable.

The worst single failure which relates to RWST operation is defined as one which reduces the amount of time available to complete the changeover from injection to recirculation. The most limiting factor would be the inability to trip one RHR pump. This would increase the amount of water drawn from the RWST during the process of changeover from injection to recirculation by an amount corresponding to the flow rate of one RHR pump (see Table 6.3-8).

Total lack of operator response to the RWST low-level alarm is not considered to be a credible event. At least two licensed operators are present in the control room at all times which minimizes the possibility of the low-level alarm being completely ignored. To protect against low level alarm annunciator failure, a backup low level alarm is provided at 119,000 gallons. This set point allows the injection recirculation changeover to be completed prior to depleting the RWST. In addition, operator training for mitigating a LOCA includes the necessary awareness of RWST level. Also, the emergency instruction pertaining to the event specifically calls for observation of the RWST level so that the changeover from injection to recirculation may begin at the proper time.

At the time RWST low-level is reached and assuming 2 minutes are required to trip the necessary pumps, there are 26 minutes available to switch from injection to recirculation. Experience gained through simulator training indicates that all the remaining functions that are required in the switchover procedure can be completed in approximately 11 minutes.

A large break LOCA is the most limiting event from the standpoint of RWST draw down time since the flow rates experienced for this event would be much greater than for a small break LOCA.

The functions that must be performed during the switchover procedure are described and analyzed in Section 6.3.2.1 and in Tables 6.3-6 and 6.3-8. The entire switchover process involves nine steps and will take approximately 13 minutes.

The control room is arranged in a manner which expedites completion of the switchover procedure. The controls for the required equipment are installed on the control console in close proximity to each other in order to facilitate operator actions. All of the indications are mounted in plain view such that valve positions, RWST level, and equipment operating status is easily observed.

It is therefore concluded that adequate time is available for the injection-to-recirculation switchover process prior to receiving an RWST low-low level alarm.

ECCS operation was tested after system installation was completed. As a part of the test, the ECCS pumps were run with the RWST level below the low-level setpoint. No evidence of vortexing appeared during the test.

Under postulated LOCA conditions, both RHR pumps and one containment spray pump would be tripped when the RWST reaches its low-level setpoint. The charging and safety injection pumps are taken off, RWST suction during the process of changeover from injection to recirculation. Consequently, no air entrapment is expected to occur in these pumps.

6.3.2.7 Pump Characteristics

Pump performance curves for the Residual Heat Removal are shown in Figure 6.3-4.

6.3.2.8 Heat Exchanger Characteristics

Residual heat exchanger characteristics presented in Section 5.5.

6.3.2.9 Emergency Core Cooling System Flow Diagrams

An ECCS flow diagram is given in Figures 6.3-1A and B.

6.3.2.10 Relief Valves

The ECCS relief valve capacities and leak rates are given in Section 6.3.2.2.

6.3.2.11 System Reliability

Specific design features of the ECCS to assure its ability to meet single failures include:

1. Inclusion of two charging pumps in the injection system which deliver into the four cold legs through 1.5 inch diameter lines. Accumulator injection into the cold legs employ completely independent piping and connections from the charging pumps. The two charging pumps will supply recirculation flow from the containment

sump (via the residual heat removal pump discharge/charging pump suction cross tie) to the four cold legs through the same line.

2. Location of the boron injection tank in the discharge of the charging pumps. This, together with the cold leg connections, provides early delivery of the highly concentrated boric acid solution.

3. Inclusion of two safety injection pumps in the injection system which delivers to four cold leg injection points via the accumulator discharge lines during the injection phase and initial portion of the recirculation phase. Later in the recirculation phase of operation, flow from each of these pumps will be directed via a separate 4 inch header to two hot leg injection points in order that subcooling of the core can be completed. Redundant headers are provided for this phase of operation to assure at least one pump can deliver even in the case of a passive failure in one line. During recirculation operation, the safety injection pumps (as well as the charging pumps mentioned previously) take suction from the recirculation sump via the RHR pump discharge or safety injection/centrifugal charging pump suction cross tie. This cross tie connection from the suction of the charging to the suction of the safety injection pumps assures that during recirculation with either a passive or an active failure, at least one charging and one safety injection pump or two safety injection or two charging pumps will deliver.

4. Inclusion of two residual heat removal pumps in the injection system which delivers to four cold leg injection points (one on each loop) via the accumulator discharge lines during the injection phase and initial portion of the recirculation phase of operation. During recirculation the RHR pumps taking suction from the recirculation sump also provide flow to the suction of the charging and safety injection pumps. Later in the recirculation period, the injection flow provided directly by the RHR pumps will be redirected from the cold legs to four hot leg connections in order to complete subcooling of the core.

Thus injection flow of borated water from the refueling water storage tank is provided to all four reactor coolant system (RCS) cold legs from the three pumping systems. During the recirculation phase of the accident all three pumping systems are capable of providing recirculation sump fluid flow to all four cold legs with the low head pumps (RHR) providing flow to the high head pumps (safety injection and charging pumps). The capability of long term recirculation flow to the RCS hot legs is provided from both the residual heat removal and the safety injection pumps.

Failure Analysis

Separate single failure analysis were performed for both the injection and recirculation phases of an accident. Two basic types of failure were considered:

1. Active failure, which is defined as the inability of any single dynamic component or instrument to perform its design function when called upon to do so by the proper actuation signal. Such functions include change of position of a valve or electrical breaker, operation of a pump, fan or diesel generator action of a relay contact, etc.

2. Passive failure which is defined as a failure affecting a device involved with the transport of fluid which limits its effectiveness in carrying out its design function. Most passive failure involve the development of abnormal leakage in valve stem packings, pump seals, etc. Although passive failures concerned with abnormal flow restriction in lines are also considered.

Table 6.3-9 summarizes the results of the single failure analysis applied during the injection phase. All failures during this phase are assumed to be active failures. It is during this phase that the pumps are starting and automatic isolation valves are required to move. All credible active failures are considered, and are included in the accident analyses described in Chapter 15. A comprehensive failure analysis for post-accident electrical and control components is presented in Chapter 7.

The accumulators which are a principle factor of the injection system are not subject to active failure. The only moving parts in the accumulator injection train are the two check valves. The working parts of the check valves are exposed to fluid of relatively low boric acid concentration. Even if some unforseen deposition accumulated, calculations indicate that a reversed differential pressure of about 25 psi can shear any particles in the bearing surfaces that may tend to prevent valve functioning.

When the reactor coolant system is being pressurized during the normal plant heatup operation, the check valves are tested for leakage as soon as there is about 100 psi differential across the valve. This test confirms the seating of the disc and provides a quantitative leakage rate measurement which can be compared with the results of earlier tests. When this test is completed, the discharge line test valves are opened and the reactor coolant system pressure increase continued. There should be no increase in leakage from this point on since increasing reactor coolant pressure increases the seating force and decreases the probability of leakage.

The accumulators can accept some leakage back from the reactor coolant system without compromising their availability. Table 6.3-10 indicates the frequency that the accumulator level would have to be readjusted as a function of leakage rate. It should also be noted that an accumulator can be isolated with a motor operated valve if leakage becomes excessive.

Tables 6.3-9 and 6.3-11 summarize the single failure analyses of recirculation phase.

Leakage During Recirculation

Table 6.3-12 summarizes the potential leakage from recirculation loop leak sources. The table lists conservative estimates of the maximum leakage expeced from each leak source. However, a value of 50 gpm is employed as a design basis for sizing auxiliary building sump pumps which will be required to dispose of this leakage to the waste disposal system. The ECCS is separable into two complete sub-systems during the long-term cooling period, either of which is capable of providing the minimum core cooling functions. Should a leak develop in either of these two sub-systems, the only actions necessary to isolate it are the closing/opening of valves and the starting/stopping of pumps.

Leakage from the valve stem leakoffs is piped to the equipment drain system.

The total leakage resulting from all sources is about 1800 cc/hr to the auxiliary building compartment floor and about 50 cc/hr to the equipment drain system. Recirculation loop leakage is summarized in Table 6.3-12.

With respect to piping and mechanical equipment outside the containment, considering the provisions for visual inspection and leak detection, leaks will be detected before they propogate to major proportions. A review of the equipment in the system indicates that the largest sudden leak potential would be the sudden failure of a pump shaft seal. Evaluation of the leak rate assuming only the presence of a seal retention ring around the pump shaft showed that flows less than 50 gpm would result. Piping leaks, valve packing leaks, or flange gasket leaks have been of a nature to build up slowly with time and are considered less severe than the pump seal failure.

Means are also provided to detect and isolate such leaks in the emergency core cooling flow path with 30 minutes. The RHR pumps and heat exchangers are located in individual compartments. Each compartment has a volume of 200 ft^3 to accommodate a 50 gpm leak for a period of 30 minutes.

Valving is provided to allow an operator to isolate, drain and flush the residual heat removal heat exchangers and pumps. The operation of the drain valves will be done by means of remote valve reach rod operators located in a shielded valve gallery. The radiation shielding criterion for this valve gallery will be the same as for manual containment isolation valves. Post-accident radiation levels around recirculation loop equipment are discussed in Chapter 15.

The layout permits the detection of a leaking recirculation loop component by means of a radiation monitor which samples the air in the plant vent. Alarms in the control room will alert the operator when the activity exceeds a preset level. Sump level and operation of sump pumps will be indicated in the control room as a backup for detection of water leaks.

Should a tube side to shell side leak develop in a residual heat exchanger, the operator will be warned by a component cooling water high radiation alarm. For large leaks the operator will also be warned by a component cooling water surge tank high level alarm. In the event that the leak cannot be isolated before the tank fills, the tank relief valve will pass the excess water to the waste holdup tank.

The Operator actions required to detect, isolate and realign a leaking component and, subsequently, realign the system depend upon the location of the leak (i.e., which system, actual physical location). Depending on the location of the leak, the operator will carry out a series of actions. For each break location, a different set of actions will be required. The actions taken by the operator will be manual (e.g., starting or stopping pumps, opening or closing valves). These actions would be performed from the control room.

For the service water system, the rupture of a large pipe will be indicated to the operator by decreasing pump discharge header pressure. Low pump header pressure will cause a backup service water pump to start.

In the event that a pipe rupture occurs in a watertight pump compartment of the intake structure, which is larger than the capacity of the sump pump high sump level for the affected compartment will be alarmed in the control room. The operator can remotely close the tie valves and header block valves at the intake structure to isolate the affected compartment.

In the event that a main yard supply header is ruptured, the affected header can be isolated and the tie valves at the auxiliary building opened. Rupture of a header pipe in the pipe tunnel can be detected by a pipe tunnel sump high level alarm. The operator can determine the affected header by remotely closing the intake tie valves and observing which pump header is affected by low pressure. Once the ruptured header is isolated, the intake tie valves can be reopened and all service water pumps made available.

In the event that a service water pipe rupture occurs inside the containment, the difference between flows entering and leaving the containment will be sensed and alarmed in the control room. High level alarms in the containment sump and fan cooler drain pots will also be indicated in the control room. The operator can remotely close the isolation valves to isolate the leaking fan cooler.

In the event that radiation is detected at one of the service water outlets from the containment, the condition is alarmed in the control room and the isolation valves on the affected line automatically closed.

6.3.2.12 Protection Provisions

All four injection lines penetrate the containment adjacent to the auxiliary building.

One portion of the high head injection system within the containment is connected to the low head injection lines attached to each loop's accumulator injection piping. The other portion of the high head injection system within the containment is connected directly to the injection nozzles on the cold leg piping of the loops.

For most of the routing, these lines are outside the reactor and steam generator shielding, and hence they are protected from missiles originating within these areas.

The coolant loop supports are designed to restrict the motion to about one-tenth of an inch, whereas the attached safety injection piping can sustain a 3 inch displacement without exceeding the working stress range.

Hangers, stops and anchors are designed in accordance with ANSI B31.1 Code for Pressure Piping and ACI 318 Building Code Requirements for Reinforced Concrete which provide minimum requirements on materials, design and fabrication with ample safety margins for both dead and operational dynamic loads over the life of the equipment.

Materials used in accordance with ASTM specifications which establish quality levels for the manufacturing process, minimum strength properties, and for test requirments which ensure compliance with the specifications. Qualification of welding processes and welders for each class of material welded and for types and positions of welds.

Allowable stress values are established which provide an ample safety margin on yield strength for normal loads and ultimate strength for design basis accident or maximum hypothetical seismic loads.

6.3.2.13 Provisions for Performance Testing

The provisions incorporated to facilitate performance testing of component are discussed in Section 6.3.4.

6.3.2.14 Pump Net Positive Suction Head

NPSH data for pumps which are required to operate post-accident are provided in Table 6.3-13.

6.3.2.15 Control of Motor Operated Isolation Valves

Position indication and alarm circuits for the motor-operated valves, located between the accumulator tanks and the primary cooling system, are designed to provide assurance that these valves will be open when required. These valves are normally open and under administrative control with the motive power for the valves locked out during normal power operation. Redundant and independent information is provided in the control room to indicate when any one valve is not in the fully open position.

Valve status (fully open or fully closed) is indicated on the main control board via backlighted pushbuttons. These status lights are actuated by limit switches on the valve motor operator. In addition, an alarm is provided on the overhead annunciator system in the event the valve is not in the fully open position.

Another independent means of determining that the valve is not in its proper position is provided through the auxiliary alarm system which will initiate an audible signal and print out an alarm message indicating when the valve is not in the fully open position. This indication and alarm is derived from a separate valve stem limit switch and is energized from an independent power supply from that used for the overheat annunciator.

A safety injection signal also automatically initiates the opening of these valves.

6.3.2.16 Motor-Operated Valves and Controls

Remotely operated valves in the safety injection system which are in the "ready" position and which do not receive an "S" signal, are assured to be in the proper position for injection by means of the following:

1. Redundant indication of valve position in the control room for those valves in common, or non-redundant flow paths of an ECCS subsystem,

or valves whose inadvertent operation could degrade the ECCS. The indication provided is identical to that of the accumulator discharge valves, described in Section 6.3.2.15.

2. Valves in redundant flow paths are provided with position indication on the main control console and "off-normal" indication in the auxiliary annunciator system (i.e., 11RH4, 12RH4, 11SJ33, 12SJ33, 11SJ134, 12SJ134, 11RH19, 12RH19).

3. Manually operated valves are under administrative control to assure that they are in the proper position. Additionally, the valves cited in item 1 above are placed in the proper position for injection with the motive power removed from the valve.

Valves with redundant position indication (as described in Section 6.3.2.15) and power lockouts are:

1SJ30*	11SJ40*	11SJ54*
1SJ69*	12SJ40*	12SJ54*
1SJ135*	1RH26*	13SJ54*
11SJ49*	1CS14*	14SJ54*
12SJ49*	1SJ67*	11SJ44*
	1SJ68*	12SJ44*

Requirements for disconnecting AC power to these valves and for locking them in position are set forth in the plant Technical Specifications.

Valves marked with an asterisk (*) are provided with the capability to restore control power from the control room.

The safety injection initiation signal was removed from the centrifugal charging pump (CCP) miniflow isolation valves, CV 139 and CV 140, thus preventing automatic termination of miniflow. In addition, manual valve CV 197, which directs reactor coolant pump (RCP) sealwater return flow to the suction of the CCP's will be locked closed and manual valve CV

130 will be locked open which will route RCP sealwater return and CCP miniflow water to the volume control tank (VCT). This valve alignment will cause the VCT to fill solid during a safety injection initiation; the VCT relief valve, CV 241, would then open, directing miniflow to the CVCS holdup tanks. Procedurally, the operator will be instructed to terminate miniflow below an RCS pressure 1500 psig (when the RCP's are stopped), and to reestablish miniflow if RCS pressure rises again to 2000 psig.

Emergency instructions will call for closure of the miniflow valves within 15 minutes of safety injection initiation in the event of a small-break LOCA without rapid RCS depressurization.

6.3.2.17 Manual Actions

No manual actions are required of the operator for proper operation of the ECCS during the injection mode of operation. The only manual actions required be taken by the operator are those necessary to complete the realignment of the system for its cold-leg recirculation mode of operation and, subsequently, to realign the system for its hot-leg recirculation mode of operation.

The transfer from the injection phase to the recirculation phase is described in Section 6.3.2.1 and in Table 6.3-6.

6.3.2.18 Process Instrumentation

Process instrumentation available to the operator in the control room to assist in assessing post-loss-of-coolant accident conditions are tabulated in Section 6.3.5 and Chapter 7.

6.3.2.19 Materials

Materials employed for components of the ECCS are given in Table 6.3-14. These materials are chosen based upon their ability to resist pyrolytic decomposition.

6.3.3 DESIGN EVALUATION

6.3.3.1 Evaluation Model

This information is provided in Chapter 15.

6.3.3.2 Small Break Analysis

This information is presented in Chapter 15.

6.3.3.3 Steam Line Rupture Analysis

This information is presented in Chapter 15.

6.3.3.4 Fuel Rod Perforations

Discussions of peak clad temperatures and metal-water reactions appear in Section 3.4. Analyses of the radiological consequences of a fission product release due to the rupture of a pipe in the reactor coolant system are presented in Section 3.4.3.9.

6.3.3.5 Effects of Core Cooling System Operation on the Core

The effects of the ECCS on the reactor core are discussed in Chapter 4.

6.3.3.6 Use of Dual Function Components

The ECCS contains components which have no other operating function, as well as components which are shared with other systems and perform normal operating functions.

1. Components of the ECCS which perform no other operating functions are:

    a. One accumulator for each loop which discharges borated water into its respective cold leg of the reactor coolant system.

b. One boron injection tank

c. One boron injection surge tank.

d. Two boron injection recirculation pumps continuously recirculate the concentrated boric acid from the boron injection tank to the boron injection surge tank via a closed loop.

e. Associated piping, valves, and instrumentation.

2. Components which also have a normal operating function are as follow:

a. The two residual heat removal pumps and residual heat exchangers: These components are normally used during the latter stages of normal reactor cooldown and when the reactor is held at cold shutdown for core decay heat removal. However, during all other plant operating periods, they are aligned to perform the low-head injection function.

b. The refueling water storage tank: This tank is used to fill the refueling canal for refueling operations, provide a makeup source to the spent fuel pit as well as an emergency makeup source to the reactor coolant system via the chemical and volume control system charging pumps. These functions place no limitations on the function of the emergency core cooling system. During all plant operating periods, the refueling water storage tank is aligned to the suction of the safety injection pumps, residual heat removal pumps and the containment spray pumps.

c. The two high-head safety injection pumps: These pumps are used periodically to provide make up to the two passive accumulators during normal plant operation. However, they are normally aligned to perform their high-head safety injection function.

An evaluation of all components required for ECCS operation demonstrates that either:

1. The component is not shared with other systems.

2. If the component is shared with other systems, it is aligned during normal plant operation to perform its accident function.

Dependence on Other Systems

Other systems which operate in conjunction with the ECCS are as follows:

1. The component cooling system cools the residual heat exchangers during the recirculation mode of operation. It also supplies cooling water to the residual heat removal pumps during the injection and recirculation modes of operation.

2. The service water system provides cooling water to the component cooling heat exchangers and to the safety injection pumps.

3. The electrical system provide normal and emergency power sources for the ECCS.

4. The engineered safety features actuation system generates the initiation signal for emergency core cooling.

5. The auxiliary feedwater system supplies feedwater to the steam generators.

Limiting Conditions for Maintenance During Operation

The Technical Specifications establish limiting conditions governing the maintenance of ECCS components during plant operation with the core critical. It is expected that maintenance on a component will be permitted if the remaining components meet the minimum conditions for operation and the following conditions are also met:

Maintenance on an active component will be permitted if the remaining components meet the minimum conditions for operation and the following conditions are also met:

1. The remaining equipment has been demonstrated to be in operable condition, ready to function just before the initiation of the maintenance.

2. A suitable time limit is placed on the total time span of successful maintenance which returns the components to an operable condition, ready to function.

The design philosophy with respect to active components in the high-head/low-head injection system is to provide backup equipment so that maintenance is possible during operation without impairment of the safety function of the system. Routine servicing and maintenance of equipment of this type would generally be scheduled for periods of refueling and maintenance outages.

6.3.3.7 Lag Times

To provide protection for large area ruptures of the reactor coolant system, the ECCS must respond to rapidly reflood the core following the depressurization and core voiding that is characteristic of large area ruptures. The accumulators act to perform the rapid reflooding function with no dependence on the normal or emergency power sources, and also with no dependence on the receipt of an actuation signal. With three of the four available accumulators delivering their contents to the reactor vessel, the peak clad temperature is maintained below the cladding melting temperature as discussed in Chapter 15.

The function of the centrifugal charging, safety injection, and residual heat removal pumps is to complete the refill of the vessel and ultimately return the core to a subcooled state. The starting sequence of the ECCS pumps and the related emergency power equipment is designed so that delivery of the minimum required flow is reached within 25 seconds.

The starting sequence is discussed in Chapter 7 and is summarized below:

Time (sec.)	Action
0-1.2	Initiation of safety injection signal plus associated instrument lag.
1.2-11	Start diesel generators and attain rated speed and voltage.
11	Energize motor control centers and apply opening/-closing signals to motor operated valves. Typical operating times for the larger valves are 10 seconds.
11	Start centrifugal charging pumps.
11, 15	Start Safety injection pumps
15	Start residual heat removal pumps

Thus the safety injection system is operational after an elapsed time of approximately 25 seconds, including the time to bring the residual heat removal pumps up to full speed. The above times are consistent with the delay times used in the loss of coolant accident analyses for large and small breaks.

6.3.3.8 Thermal Shock Considerations

Thermal shock considerations are discussed in Chapter 15.

6.3.3.9 Limits on System Parameters

The limiting conditions for operation are detailed in the Technical Specifications. These conditions will apply to both active components and coolant storage components of the ECCS.

6.3.4 Tests and Inspections

All active and passive components of the ECCS are inspected periodically to demonstrate system readiness.

The pressure containing systems are inspected for leaks from pump seals, valve packing, flanged joints and safety valves during system testing.

In addition, to the extent practical, the critical parts of the injection nozzles, pipes, valves and safety injection pumps are inspected visually or by boroscopic examination for erosion, corrosion and vibration wear evidence. A plan for periodic component and system testing and material examinations will be prepared prior to plant operation for use throughout plant life.

Environmental testing of ECCS componentry which are located inside the containment and are required to operate following a loss of coolant accident, is discussed in Reference 1.

6.3.4.1 Components Testing

Pre-operational performance tests of the components are performed in the manufacturer's shop. An initial system flow test demonstrates proper functioning of the system. Thereafter, periodic tests demonstrate that components are functoning properly.

Active components of the ECCS may be individually actuated on the normal power source during plant operation to demonstrate operability. The test of the safety injection pumps employs the minimum flow recirculation test line which connects back to the refueling water storage tank. Remote operated valves are exercised and actuation circuits tested. The automatic actuation circuitry, valves and pump breakers also may be checked during integrated system tests performed when the plant is cooled down and the residual heat removal loop is in operation.

Containment sump isolation valves are normally closed. Inadvertent opening is prevented by using control power lockouts and electrical interlocks which prevent the opening of the valves whenever the corresponding RHR pump suction isolation valve is open. The valves will be exercised and tested after closing the appropriate RHR pump suction isolation valve during normal operation or refueling at a frequency specified in the Technical Specifications.

The containment sump valves will be tested only after closing the suction and discharge valves of the associated RHR pump. The isolated RHR line is located at elevation 46'-10" and the center line of the sump valves at 53'-0". Due to the elevation difference, no stagnant refueling water is expected to interfere with the sump valve tests.

If the necessity arises for the draining of this line, provisions have been provided to drain it through the RHR pump to the residual heat removal sump. Sump interconnection with the liquid radwaste system provides satisfactory processing provisions for this drainage.

Inleakage through each of the check valves which isolate the safety injection system from the reactor coolant system can be tested by opening the remote test valves in the appropriate test line. Flow through the test line can be measured and the opening and closing of the discharge line stop valves can be verified by the flow instrumentation.

6.3.4.2 System Testing

Testing is conducted during plant shutdown to demonstrate proper automatic operation of the ECCS. A test signal is applied to initiate automatic action and verification made that the safety injection pumps attain required discharge heads. The test demonstrates the operation of the valves, pump circuit breakers, and automatic circuitry.

The operation of the residual heat removal pumps is verified periodically. Performance of the centrifugal charging pumps is verified by their operation during normal plant operation and cooldown. Starting of these pumps by a safety injection signal is also verified during plant shutdown.

The test is considered satisfactory if control board indication and visual observations indicate all components have operated and sequenced properly.

The periodic testing of pumps in the residual heat removal, safety injection, and containment spray systems requires recirculation of water from the refueling water storage tank. Demonstration of proper operation of these pumps will also demonstrate the operability of the line from the refueling water storage tank. The boron injection tank and piping normally contain 12 weight percent boric acid solution. The operability of the lines local to the boron injection tank is demonstrated by recirculation of the boric acid solution through the lines, employing the boric acid transfer pump.

The accumulator pressure and level are continuously monitored during plant operation and flow from the tanks can be checked at any time using test lines.

The accumulators and the injection piping up to the final isolation valve are charged with borated water while the plant is in operation. The accumulator boron concentration is checked periodically by sampling. The accumulators and injection lines are replenished with borated water as required by using the safety injection pumps to recirculate refueling water through the injection lines. A small test line is provided for this purpose in each injection header.

Flow in the centrifugal charging pumps common discharge line, safety injection pumps main flow lines, and in the main flow line for the residual heat removal pumps is monitored by flow indicators in the control room. Pressure instrumentation is also provided for the main flow paths of the safety injection and residual heat removal pumps and is located in the control room.

6.3.4.3 Operational Sequence Testing

The ECCS and the containment spray system were operationally tested prior to initial reactor fueling. The tests included individual pump performance tests, accumulator operation and an integrated system tests.

Each centrifugal charging, safety injection, residual heat removal and containment spray pump were tested at rated flow capacity. The containment spray pumps discharged through a test line to the refueling canal, while the others discharged to the open reactor coolant system through the normal injection path. Additionally, the pumps were run for a minimum of 1 hour to ensure reliable operation. The purpose of these tests is to evaluate the hydraulic and mechanical performance of the pumps and to detect deficiencies which might occur during sustained operation.

Flow distribution tests will also be performed in which the pumps will deliver from the RWST to the reactor coolant system through the normal injection paths for emergency core cooling. Adjustments will be made where flow resistances are unacceptably low or high to limit pump runout and balance the flow between piping branches. Total flow and relative flows between branch lines will be compared with minimum acceptable flows as determined in the safety analysis.

The accumulators will be tested by charging them to normal water level and a pressure of 100 psia with the isolation valves closed. The isolation valves will be opened, discharging the accumulator into the open reactor vessel. Performance will be verified by extrapolating the data to normal accumulator pressure.

It is neither practical nor feasible to perform these tests at simulated reactor operating conditions. With the reactor at normal operating temperature and pressure, there are no means available to change the primary system parameters as rapidly as required to simulate a 100 percent loss of coolant accident, thereby allowing the ECCS to inject water into the system. The system will be tested during hot functional testing, however, to verify that the high pressure components (centrifugal charging pumps) can deliver water to the reactor through the normal injection path while the plant is at normal operating pressure. The test will be conducted by manually initiating the safety injection sequence.

A complete operational test will also be performed to demonstrate overall system performance. The purpose of this test is to demonstrate the proper functioning of actuation and instrumentation circuits, emergency power sources and electrical load sequencing of the integrated safeguards system. Data obtained will be used to verify design operation and confirm various sequencing and operating times and logic.

The systems are accepted only after demonstration of proper actuation of all components and after demonstration of flow delivery of all components within design requirements.

6.3.4.4 Conformance with Regulatory Guide 1.79

The Salem preoperational testing program meets the requirements of Regulatory Guide 1.79, "Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors". The scheduled tests, however, may deviate in part from certain specific test descriptions included in the guide. These deviations are enumerated below.

Regulatory Position C.3.a.(2)

Not all injection pumps will be tested at operating conditions, nor will the auxiliary feed system be actuated by a safety injection signal. Check valves on the charging/safety injection cold leg injection path will be tested utilizing a charging/safety injection pump which will be started by manually initiating a safety injection signal. The check valves on the safety injection hot leg and cold leg injection paths will be tested by pressurizing the test line and throttling water through the check valves. A significant portion of Safeguards equipment not directly involved in the delivery of emergency core cooling water to the reactor coolant system will be omitted from the test. Thermal shock is not expected, since the total quantity of water injected will be minimized. Branch line throttle valves will be initially shut and then slowly opened, one at a time, to demonstrate flow through the check valves.

Regulatory Position C.3.b.(2)

Adequate NPSH from the containment sump will be verified by taking a suction from a full sump with one RHR pump and discharging into the reactor coolant system. Duration of test run is estimated to be 45 seconds. Vortex control verification will be accomplished by visual observation at the sump. Pressure drop across sump screen will not be measured as it is considered negligible and will not compromise NPSH evaluation.

Regulatory Position C.3.c.(1)

The accumulators will be discharged, one at a time, into the open reactor vessel. With the reactor coolant system closed, pressurized, and solid, as the guide infers, there is no convenient way to rapidly depressurize at a rate which would provide a meaningful accumulator discharge.

The discharge flow rate will be calculated from the measurement of accumulator pressure changes versus time vice level versus time.

Regulatory Position C.3.c(2)

Only the normal power supply will be used for this test. Emergency power system capability will be demonstrated during other tests utilizing the emergency diesel generators.

Regulatory Position C.3.c(3)

Flow through accumulator check valves will be demonstrated at normal operating temperature and pressure by pressurizing test lines with a charging/safety injection pump.

6.3.5 INSTRUMENTATION APPLICATION

Instrumentation and associated analog and logic channels employed for initiation of ECCS operation is discussed in Chapter 7. This section describes the instrumentation employed for monitoring ECCS components during normal plant operation, and also ECCS post-accident operation. All alarms are annunciated in the control room.

6.3.5.1 Temperature Indication

Boron Injection Tank Temperature

Duplicate temperature control channels are provided for the boron injection tank electric strip heaters. Both actuate high and low temperature alarms. Both channels provide local temperature indication.

Residual Heat Exchanger Outlet Temperature

The fluid temperature at the outlet of each residual heat exchanger is recorded in the control room.

Heat Tracing Temperature

Separate thermostatic controls are provided for each section of the heat tracing in the boron recirculation loop to maintain the temperature within the specified range. High and low temperature alarms are provided to warn of failure to maintain the temperature within the control band.

6.3.5.2 Pressure Indication

Boron Injection Tank Pressure

Boron injection tank pressure is indicated in the control room. A high-pressure alarm is provided.

Safety Injection Header Pressure

Safety injection pump discharge header pressure is indicated in the control room.

Accumulator Pressure

Duplicate pressure channels are installed on each accumulator. Pressure indication in the control room and high and low pressure alarms are provided by each channel.

Test Line Pressure

A local pressure indicator used to check for proper seating of the accumulator check valves between the injection lines and the reactor coolant system is installed on the leakage test line.

Residual Heat Removal Pump Discharge Pressure

Residual heat removal discharge pressure for each pump is indicated in the control room. A high pressure is actuated by each channel.

6.3.5.3 Flow Indication

Safety Injection Pump Header Flow

Flow through each safety injection pump header is indicated in the control room.

Test Line Flow

Local indication of the leakage test line flow is provided to check for proper seating of the accumulator check valves between the injection lines and the reactor coolant system.

Residual Heat Removal Pump Flow

The flow of reactor coolant through each residual heat removal header during injection or recirculation is indicated in the control room.

Safety Injection Pump Minimum Flow

A flow indicator is installed in the safety injection pump minimum flow line.

Residual Heat Removal Pump Minimum Flow

A flow indicator is installed in each residual heat removal pump minimum flow line.

6.3.5.4 Level Indication

Refueling Water Storage Tank Level

The level of water in the refueling water storage tank is measured by two separate instruments with readouts on the main control board. All are set to alarm at the proper level to initiate the switch from injection to cold leg recirculation.

Accumulator Water Level

Each accumulator tank has two level measuring instruments with readouts on the main control board. Each instrument is set to alarm if the tank level falls or rises by more than a set amount from the normal operating level.

Boron Injection Surge Tank Level

Two level indicators give local indication and alarm in the control room.

Containment Building Sump Level

The containment building has two inter-connected by piping sumps - containment recirculation sump and reactor building sump. The containment recirculation sump has two redundant sump water level indicators on the console bezel in the main control room. Each of these sumps has a high level alarm on the overhead annunciator.

6.3.5.5 Valve Position Indication

Valve positions which are indicated on the control board are done so by a "normal off" system; i.e., should the valve not be in its proper position; a bright white light will be lit and thus give a highly visible indication to the operator.

Accumulator Isolation Valve Position Indication

The accumulator motor operated valves are provided with red (open) and green (closed) position indication lights located at the control switch for each valve. These lights are powered by valve control power and actuated by valve motor operator limit switches.

A monitor light that is on when the valve is not fully open is provided in an array of monitor lights that are all off when their respective valves are in proper position enabling safeguards operations. This light is energized from a separate monitor light supply and actuated by a valve motor operated limit switch.

An alarm annunciator point is activated by both a valve motor operator limit switch and by a valve position limit switch activated by stem travel whenever an accumulator valve is not fully open for any reason with the system at pressure (the pressure at which the safety injection block is unblocked). A separate annunciator point is used for each accumulator valve. The motor operator limit switch alarm will be recycled at approximately one hour intervals to remind the operator of the improper valve lineup.

REFERENCES FOR SECTION 6.3

1. Igne, E. G. and Locante, J. "Environmental Testing of Engineered Safety Features Related Equipment (NSSS-Standard Scope)", WCAP-7410-L (Proprietary) December, 1970 and WCAP-7744 (Non-Proprietary), Vol. 1, August, 1971 and Vol. 2, September, 1970.

2. J. B. Nystrom, "Experimental Evaluation of Flow Patterns in an RHR Sump With Simulation of Screen Blockage--Salem Nuclear Station, Alden Research Center, Worcester Polytechnic Institute, January, 1981.

TABLE 6.3-1

ECCS CODE REQUIREMENTS

Component	Code
Refueling Water Storage Tank	API 650
Residual Heat Exchanger	
Tube Side	ASME Section III Class C
Shell Side	ASME Section VIII
Accumulators	ASME Section III Class C
Valves	ANSI B16.5 or MSS-SP-66 or ASME Code, Section III, 1968
Piping	ANSI B31.1*
Boron Injection Tank	ASME Section III Class C
Pumps	
Centrifugal Charging	ASME Section III
Safety Injection	ASME Section III
Residual Heat Removal	ASME Section III

*For piping not supplied by the NSSS supplier, material inspections, fabrication and quality control conform to ANSI B31.7. Where not possible to comply with ANSI B31.7, the requirements of ASME III-1971, which incorporated ANSI B31.7, were adhered to.

TABLE 6.3-2

ACCUMULATOR DESIGN PARAMETERS

Number	4
Type	Stainless steel clad/carbon steel
Design pressure, psig	700
Design temperature, °F	300
Operating temperature, °F	50-150
Normal operating pressure, psig	650
Minimum operating pressure, psig	600
Total volume, ft^3	1350
Minimum water volume at operating conditions, ft^3	850
Volume N_2 gas, ft^3	500
Boron concentration (as boric acid)	
nominal, ppm	2000
minimum, ppm	1900
Code	ASME III Class C

TABLE 6.3-3

BORON INJECTION TANK DESIGN PARAMETERS

Number	1
Total volume, gal (also useable volume)	900
Boron concentration	
Nominal, ppm	21,000
Maximum, ppm	22,500
Minimum, ppm	20,000
Design pressure, psig	2735
Design temperature, °F	150-180
Material	SS Clad Carbon Steel
Code	ASME III Class C

HEATERS

Number	2
Capacity, kw	6
Type	Strip

TABLE 6.3-4

REFUELING WATER STORAGE TANK DESIGN PARAMETERS

Number	1
Tank capacity, gal.	400,000
Minimum volume, (solution) gal.	350,000
Operating pressure	atmospheric
Operating temperature, °F	40 - 100°F
Outside diameter, ft (approx.)	38
Straight side height, ft	48
Straight side height, ft	48
Material	ASTM-A240 Type 304L stainless steel
Design pressure	atmospheric
Design temperature, °F	120
Boron concentration,	
Nominal, ppm	2000
Minimum, ppm	1950

TABLE 6.3-5

DESIGN PARAMETERS - ECCS PUMPS

	Centrifugal Charging Pumps	Safety Injection Pumps	Residual Heat Removal Pumps
Number	2	2	2
Design pressure, psig	2800	1700	600
Design temperature, °F	300	300	400
Design flow rate, gpm	150	425	3000
Design head, ft.	5800	2500	350
Max. flow rate, gpm	550	650	4500
Head at max. flow rate, ft	1300	1500	300
Discharge pressure at shutoff, psig	2670	1520	170
Motor horsepower	600	400	400
Type	Horizontal multi-stage centrifugal	Horizontal multi-stage centrigugal	Vertical single-stage centrifugal
Material	Stainless steel clad carbon steel	Stainless steel	Stainless steel

TABLE 6.3-6 (Sheet 1 of 4)

SEQUENCE OF CHANGEOVER OPERATION INJECTION TO RECIRCULATION

The following sequence of operations should be used when terminating the injection mode and starting the recirculation mode when low level is reached in the RWST:

1. Stop 11 and 12 RHR pumps.

2a. Open the component cooling water supply valve to each RHR heat exchanger prior to restarting the RHR pumps. (11CC16 and 12CC16)

b. Close the RHR pump suction valves which connect the RHR system to the RWST. (11RH4 and 12RH4 or 1SJ69)

c. Open the RHR pump suction lines to the containment sump. (11SJ44 and 12SJ44)

d. Close the RHR crossover line valves 11RH19 and 12RH19.

3. Start 11 and 12 RHR pumps.

4. Close the safety injection pumps miniflow line isolation valves 1SJ67 and 1SJ68.

5. Open valve 12SJ45, which aligns 12 RHR pump discharge to the charging pumps suction. Open valve 11SJ45, which aligns 11 RHR pump discharge to the suction of the safety injection pumps.

6. Open the parallel valves in the common line between the charging pumps and safety injection pumps suction. (11SJ113 and 12SJ113)

7. Close valves 1SJ1 and 1SJ2 to terminate charging pump suction from the RWST. Close valve 1SJ30 to terminate safty injection pump suction from the RWST.

8. When low-low level in the RWST is reached,

   a. Stop the containment spray pumps.

   b. Close valve 12SJ49 to terminate RHR flow to the cold legs.

   c. Open valve 12CS36 to provide RHR flow to the containment spray header.

TABLE 6.3-6 (Sheet 2 of 4)

SEQUENCE OF CHANGEOVER OPERATION INJECTION TO RECIRCULATION

The Emergency Core Cooling System is now aligned for cold leg recirculation as follows:

a. RHR pump No. 12 is delivering from the recirculation sump directly to the spray header and to the suction of the charging pumps through valve 12SJ45.

b. RHR pump No. 11 is delivering from the recirculation sump directly to the cold legs via valve 11SJ49 and to the suction of the safety injection pumps via valve 11SJ45.

TABLE 6.3-6 (Sheet 3 of 4)

SEQUENCE OF CHANGEOVER OPERATION INJECTION TO RECIRCULATION

Approximately 22.5 hours after the accident, realign the safety injection system for hot leg recirculation. The sequence of operations for change-over from the cold leg recirculation phase to the hot leg recirculation phase is as follows:

Close the spray header isolation valve (12CS36).

Open the cross-tie isolation valve (12RH19) at the RHR pump discharge.

Open the hot leg isolation valve (1RH26).

Close isolation valve (11SJ49).

Stop safety injection pump number 11.

Close the safety injection pump cross-tie isolation valve (11SJ134).

Open hot leg isolation valve (11SJ40).

Start safety injection pump number 11.

Stop safety injection pump number 12.

Close the cold leg isolation valve (1SH135) and close the safety injection pump cross-tie isolation valve (12SJ134).

Open hot leg isolation valve (12SJ40).

Start safety injection pump number 12.

TABLE 6.3-6 (Sheet 4 of 4)

SEQUENCE OF CHANGEOVER OPERATION INJECTION TO RECIRCULATION

The residual heat removal pumps and safety injection pumps are now aligned for hot leg recirculation as follow:

a. RHR pump number 12 is delivering from the recirculation sump to the reactor coolant system through the hot leg injection header and to the suction of the centrifugal charging pumps which are delivering to the cold legs.

b. RHR pump number 11 is delivering from the recirculation sump to the suction header of the safety injection pumps.

c. Number 11 and 12 safety injection pumps are delivering to the reactor coolant system through individual hot leg injection headers.

TABLE 6.3-7

4-LOOP PUMP PARAMETERS

PUMP	NORMAL CONDITION PARAMETERS			ACCIDENT CONDITION PARAMETERS			MOTOR HORSEPOWER SELECTION			
	HEAD (FT.)	FLOW (GPM)	BRAKE HORSEPOWER REQUIRED (HP)	HEAD (FT.)	FLOW (GPMP)	BRAKE HORSEPOWER REQUIRED (HP)	SPECIFIED FULL LOAD HORSEPOWER (HP)	SERVICE FACTOR	SERVICE FACTOR RATING (HP)***	NEMO TEMPERATURE LIMIT FOR SERVICE FACTOR RATING OF 1.15 CLASS B
Centrifugal Charging	5800	150	500	1400	550	625	600	1.15	690	140°C
Safety Injection	---	---	---	2500* 1500**	425 650	360 390	400	1.15	460	140°C
Residual Heat Removal	350	3000	340	300	4500	400	400	1.15	460	140°C

Note: 1. *Design Flow Condition of Pump
2. **Runout Condition of Pump
3. ***(Full Load HP) X (Service Factor) = Service Factor Rating

NEMA REFERENCE: MG 1-12.42

TABLE 6.3-8

CHANGEOVER DEPLETION ANALYSIS

Operator Action	Time Req'd To Complete Action (Min)	RWST VOLUME USED TO COMPLETE ACTION (GALLONS) Normal Flowrate	Single Failure Flowrate
Stop No. 21 and No. 22 RHR Pumps and either No. 21 or No. 22 Cont. Spray Pump	2	28,600	28,600
Close RHR Pump Suction Valves which connect RHR System to RWST (21 RH4 and 22 RH4 or 1SJ69)*	2.5	10,250	19,750
Open RHR Pump Suction Lines to Cont. Sump (21SJ44 and 22SJ44)*	1	4,100	7,900
Close RHR Crossover Line Valves 21RH19 and 22RH19	1	4,100	7,900
Start 21RHR Pump	1.5	6,150	11,850
Start 22RHR Pump**	1.5	6,150	--
Close SI Pumps Miniflow Line Isol. Valves 2SJ67 and 2SJ68	1.5	6,150	11,850
Open 22SJ45 (Aligns 22RHR Pump Disch. to Chg. Pumps Suction) and open 21SJ45 (Aligns 21RHR Pump Disch. to SI Pumps Suctions	1	4,100	7,900
Open Parallel Valves (21SJ113 and 22SJ113) in Common Line Between SI and Chg. Pumps Suctions	1	3,525	7,725
TOTAL	13(***)	73,125	103,475

*For single failure, the operation of valves associated with the affected RHR pump would not be performed.

**For single failure, step would not be performed.

***For RHR pump failure to trip, the total time required to complete the procedure is 11.5 minutes.

TABLE 6.3-9 (Sheet 1 of 3)

SINGLE ACTIVE FAILURE ANALYSIS EMERGENCY CORE COOLING SYSTEM

INJECTION PHASE

Component	Malfunction	Comments
A. Accumulator	Deliver to broken loop	Total passive system with one accumulator per loop. Evaluation based on three accumulators delivering to the core and one spilling from ruptured loop.
B. Pump:		
1) Centrifugal Charging	Fails to start	Two provided. Evaluation based on operation of one
2) Safety injection	Fails to start	Two provided. Evaluation based on operation of one
3) Residual heat removal	Fails to start	Two provided. Evaluation based on operation of one
C. Automatically operated valves:		
1) Boron injection tank isolation		
a) Inlet	Fails to open	Two parallel valves; one valve is required to open
b) Outlet	Fails to open	Two parallel valves; one valve is required to open
c) Recirculation to boric acid tank valve	Fails to close	Two valves in series; only one required to close

TABLE 6.3-9 (Sheet 2 of 3)

SINGLE ACTIVE FAILURE ANALYSIS EMERGENCY CORE COOLING SYSTEM

INJECTION PHASE

Component	Malfunction	Comments
2) Centrifugal charging		
a) Suction line to RWST isolation	Fails to Open	Two parallel valves; one valve is required to open
b) Discharge line to the normal charging path* isolation	Fails to close	Two valves in series; only one valve required to close
c) Bypass line isolation	Fails to close	Two valves in series; only one valve required to close
d) Suction from volume control tank isolation	Fails to close	Two valves in series; only one valve required to close

* The reactor coolant pump seal water path is left open.

RECIRCULATION PHASE

Component	Malfunction	Comments
A. Valves operated from control room for recirculation:		
1. Containment sump recirculation isolation	Fails to open	Two lines parallel; only one valve in either line is required to open
2. Residual heat removal pumps suction line to RWST isolation	Fails to open	Two gate valves in series; operation of only one valve is required
3. Safety injection pumps suction line to RWST	Fails to close	Check valve in series with gate valve; operation of only one valve required

TABLE 6.3-9 (Sheet 3 of 3)

SINGLE ACTIVE FAILURE ANALYSIS EMERGENCY CORE COOLING SYSTEM

INJECTION PHASE

Component	Malfunction	Comments
4. Centrifugal charging pumps suction line to RWST isolation	Fails to close	Check valve in series with wo parallel gate valves. Operation of either the check valve or the gate valves required
5. Safety injection pump suction line discharge of residual heat exchangers	Fials to open	Separate and independent high head injection path via the centrifugal charging pumps taking suction from discharge of alternate residual heat exchanger. A cross-over line allows flow from one heat exchanger to reach both safety injection and charging pump if necessary.
B. Pumps:		
1) Component cooling	Fails to start	Three provided. Evaluation based on operation of one.
2) Service water	Fails to start	Six provided. Evaluation based on operation of two.
3) Residual heat removal pump	Fails to start	Two provided. Evaluation based on operation of one.
4) Charging pump	Fails to operate	Same as injection phase
5) Safety injection pumps	Fails to operate	Same as injection phase

TABLE 6.3-10

ACCUMULATOR INLEAKAGE

Observed Leak Rate cc/hr	Time Period Between Level Adjustments	Total Integrated Leakage ft^3*+
2470	1 month	124.5
830	3 months	42.5
415	6 months	20.8
276	9 months	18.8
208	1 year	10.4

* A total of 163.4 cubic feet, added to the initial amount, can be accepted in each accumulator before an alarm is sounded.

\+ Max. allowed leak rate for manufacturers acceptance test is 20cc/hr (Back leakage through check valves)

TABLE 6.3-11 (Sheet 1 of 2)

SINGLE PASSIVE FAILURE ANALYSIS - EMERGENCY CORE COOLING SYSTEM

RECIRCULATION PHASE

Flow Path	Indication of Loss of Flow Path	Alternate Flow Path
Low Head Recirculation (Cold Leg)		
From containment sump to low head injection header via the residual heat removal pumps and the residual heat exchangers	Reduced flow in the discharge line from one of the residual heat exchangers (one flow monitor in each discharge line)	Via the independent, Identical low head flow path utilizing the second residual heat exchanger
High Head Recirculation (Cold Leg)		
From containment sump high injectijon header via residual heat removal pump, residual heat exchanger to the safety injection pumps and charging pump (using the cross-tie	Reduced flow in the discharge lines from the safety injection pump and centrifugal charging pump (a flow monitor in the discharge lines of each set of pumps)	From containment sump to the high head cold leg injection headers via alternate residual heat removal pump, alternate residual heat exchanger and the centrifugal charging/safety injection pumps. A cross-tie with two parallel valves is provided.

TABLE 6.3-11 (Sheet 2 of 2)

SINGLE PASSIVE FAILURE ANALYSIS - EMERGENCY CORE COOLING SYSTEM

RECIRCULATION PHASE

Flow Path	Indication of Loss of Flow Path	Alternate Flow Path
Low Head Recirculation (Hot Leg)		
From containment sump to hot leg Low-head injection header via RHR pumps and RHR heat exchangers.	Reduced flow in the common header to the hot leg injection points	Same as for cold leg recirculation
High Head Recirculation (Hot Leg)		
From containment sump to the high head hot leg injection headers via residual heat removal pump No. 2, residual heat exchanger No. 2, and the RHR-to-SI pump suction line to No. 2 safety injection pump.	Reduced flow in the discharge from No. 2 safety injection pump.	From containment sump to the high head via hot leg injection points via residual heat removal pump No. 1, residual heat exchanger No. 1, and safety injection pump crossover line.)

TABLE 6.3-12

RECIRCULATION LOOP LEAKAGE

Items	No. of Units	Type or Leakge Control and Unit Leakage Rate Used in the Analysis	Leakage to Atmosphere cc/hr	Leakage to Equipment Drain System cc/hr
1. Residual Heat Removal Pumps (Low Head Safety Injection	2	Mechanical seal with Leakoff - 10 cc/hr/seal(1)	20	0
2. Centrifugal Charging Pump	2	Same as residual heat removal pump	40	0
3. Safety injection pumps	2	Same as residual heat removal pump	40	0
4. Flanges:		Gasket - asjusted to zero leakage following		
a. Pump	8	any test - 10 drops/min/flange used in	0	0
b. Valves; Bonnet, Body (larger than 2")	40	analysis	1200	0
c. Control Valves	6		180	0
5. Valves - Stem Leakoffs	40	Backseated, double packing with leakoff - 1/cc/hr/in. stem diameter	0	40
6. Misc., Small Valves	50	Flanged body packed stems - 1 drop/min used	150	0

(1) Seals are acceptance tested to essentially zero leakage.

TABLE 6.3-13

NET POSITIVE SUCTION HEADS FOR
POST-ACCIDENT OPERATIONAL PUMPS

Pump	Elevation	Flow and Condition	Suction Source and Elevation	Minimum Available NPSH	Required NPSH	Maximum Water Temperature
Safety Injection	86'-3"	600 gpm runout	RWST 101'-8"	31.3 ft	22 ft	100°F
Centrifugal Charging	87'-5"	550 gpm runout	RWST 101-8"	38 ft	23 ft	100°F
Residual Heat Removal	46'-10"	1 pump operating 4500 gpm runout flow	RWST 101'-8"	63.3 ft	19.5 ft	100°F
Residual Heat Removal	46'-10"	2 pumps operating 3000 gpm/pump rated flow	RWST 101'-8"	53.2 ft	11 ft	100°F
Containment Spray	86'-3"	2600 gpm rated flow	RWST 101'-8"	29.9 ft	10 ft	100°F
Component Cooling	86'-0"	4600 gpm rated flow	Head Tank 128'	40 ft	14 ft	135°F
Service Water	Impeller Suction 72'-3" Pump Dis. 94'-0"	10,875 gpm rated flow	Plant Intake Water Level 76'	34.1 ft	33 ft	85°F
Residual Heat Removal	46'-10"	4500 gpm Runout flow	Containment Sump 78'-8"	24.9 ft	19.5 ft	Saturation

The available NPSH was calculated for the pumps indicated above using the following conservative assumptions:
1. All calculations assume an empty refueling water storage tank.
2. No credit is taken for RWST fluid temperature below 100°F.
3. No credit is taken for subcooling of fluid in containment sump.
4. No credit is taken for increased containment pressures following the LOCA.

TABLE 6.3-14 (Sheet 1 of 3)

MATERIALS EMPLOYED FOR
EMERGENCY CORE COOLANT SYSTEM COMPONENTS

Component	Material
Accumulators	Carbon steel, clad with Austenitic stainless steel
Boron injection tank	Austenitic stainless steel
Boron injection tank	Austenitic stainless steel
Pumps	
Safety injection	Austenitic stainless steel
Residual heat removal	Austenitic stainless steel
Boron injection tank	
Recirculation pump	Austenitic stainless steel
Residual heat exchangers -	
Shell	Carbon steel
Shell end cap	Carbon steel
Tubes	Austenitic stainless steel
Channel	Austenitic stainless steel
Channel	Austenitic stainless steel
Tube sheet	Austenitic stainless steel
Valves -	
Motor operated valves	
Containing radioactive fluide	
Pressure	Austenitic stainless steel
Containing parts	or equivalent

TABLE 6.3-14 (Sheet 2 of 3)

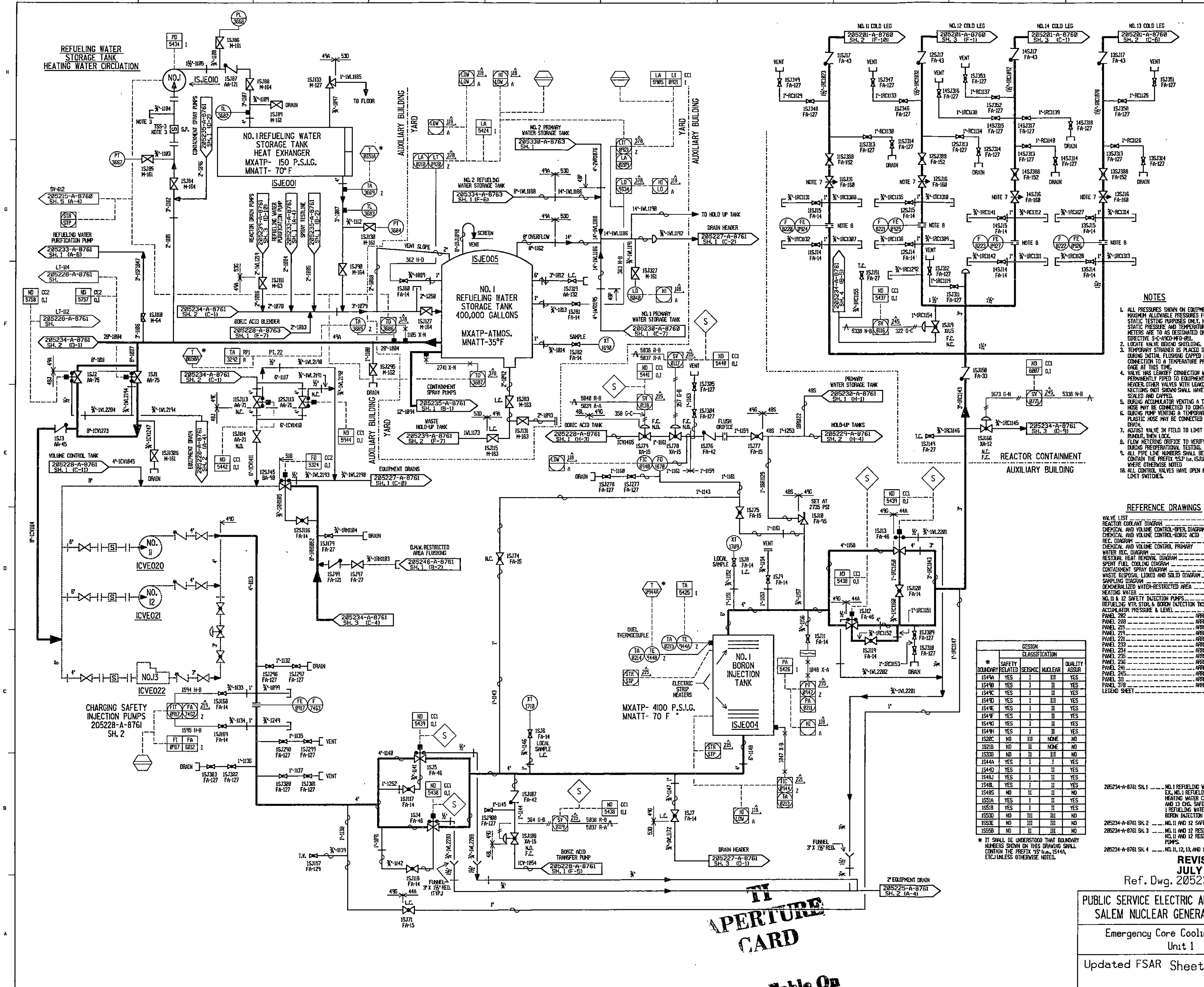
MATERIALS EMPLOYED FOR
EMERGENCY CORE COOLING SYSTEM COMPONENTS

Component	Material
Body-to-bonnet Bolting and nuts	Low alloy steel
Seating surfaces	Stellite No. 6 or equivalent
Stems	Austenitic stainless steel or, 17-4PH stainless
Motor operated valves Containing non-radioactive, Boron - free fluids	
Body, bonnet and flange	Carbon steel
Stems	Corrosion resistance steel
Diaphragm valves	Sustenitic stainless steel
Accumulator check valves	
Parts contacting Borated water	Austenitic stainless steel
Clapper arm Shaft	17-4PH stainless

TABLE 6.3-14 (Sheet 3 of 3)

MATERIALS EMPLOYED FOR
EMERGENCY CORE COOLING SYSTEM COMPONENTS

Component	Material
Relief valves	
Stainless steel bodies	Stainless steel
Carbon steel bodies	Carbon steel
All nozzles, discs, Spindles and guides	Austenitic stainless steel
Bonnets for stainless Steel valves without a Balancing bellows	Stainless steel or Plated carbon steel
All other bonnets	Carbon steel
Piping -	
All piping in contact with borated water	Austenitic stainless steel



NOTES

1. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO AS DESIGNATED ON FIELD DIRECTIVE S-C-A9CO-MFD-051.
2. LOCATE VALVE BEHIND SHIELDING.
3. TEMPORARY STRAINER IS PLACED IN LINE DURING INITIAL FLUSHING CAPPED LINE IN CONNECTION TO A TEMPERATURE PRESSURE GAGE AT THIS TIME.
4. VALVE HAS LEAKOFF CONNECTION WHICH IS PERMANENTLY PIPED TO EQUIPMENT DRAIN HEADER. OTHER VALVES WITH LEAKOFFS CONNECTIONS (NOT SHOWN) SHALL HAVE STUBS SEALED AND CAPPED.
5. DURING ACCUMULATOR VENTING A TEMPORARY HOSE MAY BE CONNECTED TO CONTAINMENT PURGE DUCT.
6. DURING PUMP VENTING A TEMPORARY CLEAR PLASTIC HOSE MAY BE CONNECTED TO FLOOR DRAIN.
7. ADJUST VALVE IN FIELD TO LIMIT PUMP RUNOUT, THEN LOCK.
8. FLOW METERING ORIFICE TO VERIFY FLOW DURING PREOPERATIONAL TESTING.
9. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1SJ" (i.e. 1SJ1000 ETC.) EXCEPT WHERE OTHERWISE NOTED
10. ALL CONTROL VALVES HAVE OPEN & CLOSED LIMIT SWITCHES.

REFERENCE DRAWINGS

VALVE LIST		206766-L
REACTOR COOLANT DIAGRAM		205201-A-8760
CHEMICAL AND VOLUME CONTROL-OPER. DIAGRAM		205228-A-8761
CHEMICAL AND VOLUME CONTROL-BORIC ACID REC. DIAGRAM		205229-A-8761
CHEMICAL AND VOLUME CONTROL PRIMARY WATER REC. DIAGRAM		205230-A-8761
RESIDUAL HEAT REMOVAL DIAGRAM		205232-A-8761
SPENT FUEL COOLING DIAGRAM		205233-A-8761
CONTAINMENT SPRAY DIAGRAM		205235-A-8761
WASTE DISPOSAL LIQUID AND SOLID DIAGRAM		205239-A-8761
SAMPLING DIAGRAM		205244-A-8761
DEMINERALIZED WATER-RESTRICTED AREA		205246-A-8761
HEATING WATER		205215-A-8760
NO. 11 & 12 SAFETY INJECTION PUMPS	INSTR. SCH.	207518-B-9491-8
REFUELING WTR. STOR. & BORON INJECTION TKS.	INSTR. SCH.	207531-B-9492-16
ACCUMULATOR PRESSURE & LEVEL	INSTR. SCH.	207532-B-9492-12
PANEL 202	ARRGT.	205760-A-8939
PANEL 208	ARRGT.	229974-A-1355
PANEL 215	ARRGT.	218993-A-8920
PANEL 219	ARRGT.	223863-A-1212
PANEL 221	ARRGT.	205599-A0-3592
PANEL 233	ARRGT.	205686-A-8863
PANEL 234	ARRGT.	205687-A-8863
PANEL 235	ARRGT.	205688-A-8863
PANEL 236	ARRGT.	205689-A-8863
PANEL 241	ARRGT.	233036-A-1399
PANEL 245	ARRGT.	202095-A-8727
PANEL 311	ARRGT.	205690-A-8939
PANEL 378	ARRGT.	223873-A-1212
LEGEND SHEET		600658-A-8727

* BOUNDARY	DESIGN CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR
1S49A	YES	I	III	YES
1S49B	YES	I	II	YES
1S49C	YES	I	II	YES
1S49D	YES	I	III	YES
1S49E	YES	I	II	YES
1S49F	YES	I	II	YES
1S49G	YES	I	II	YES
1S49H	YES	I	II	YES
1S20C	NO	III	NONE	NO
1S21B	NO	II	NONE	NO
1S33B	NO	II	III	NO
1S44A	YES	I	I	YES
1S44D	YES	I	II	YES
1S48J	YES	I	II	YES
1S48L	YES	I	II	YES
1S48S	NO	II	II	NO
1S51A	YES	I	II	YES
1S51B	YES	I	II	YES
1S53D	NO	III	III	NO
1S53E	NO	III	III	NO
1S55B	NO	II	III	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e., 1S44A, ETC.) UNLESS OTHERWISE NOTED.

205234-A-8761 SH. 1 ___ NO. 1 REFUELING WATER ST. TANK HEATER EX., NO. 1 REFUELING WATER ST. TANK HEATING WATER CIRCULATION PUMP, NO 11, 12 AND 13 CHG. SAFETY INJECTION PUMP, NO. 1 REFUELING WATER ST. TANK AND NO. 1 BORON INJECTION TANK.

205234-A-8761 SH. 2 ___ NO. 11 AND 12 SAFETY INJECTION PUMPS

205234-A-8761 SH. 3 ___ NO. 11 AND 12 RESIDUAL HEAT EXCHANGE NO. 11 AND 12 RESIDUAL HEAT REMOVAL PUMPS.

205234-A-8761 SH. 4 ___ NO. 11, 12, 13, AND 14 ACCUMULATORS

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JULY 25, 1986
Ref. Dwg. 205234-A-8761-21

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Emergency Core Cooling System
Unit 1

Updated FSAR Sheet 1 of 4
Fig 6.3-1A

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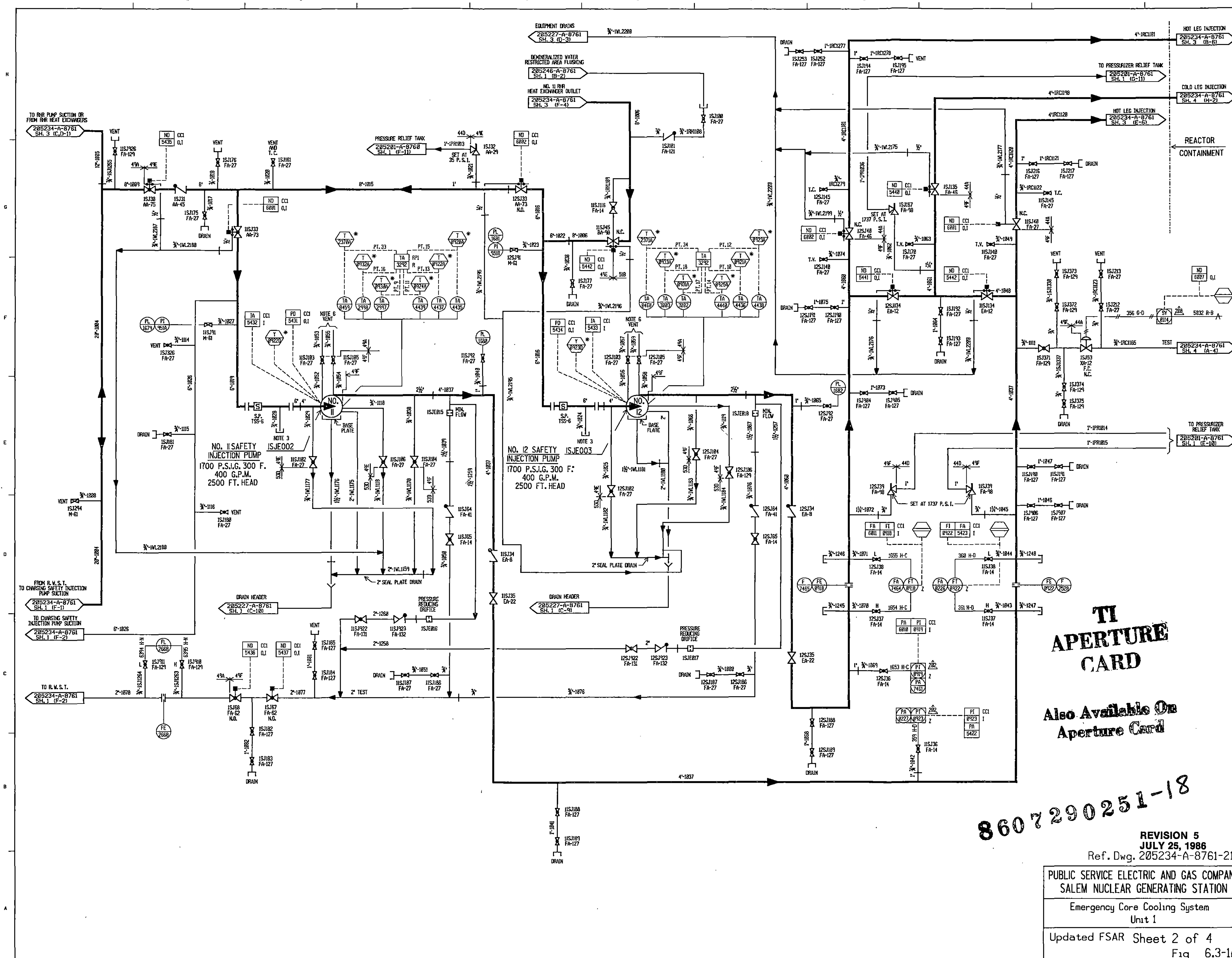

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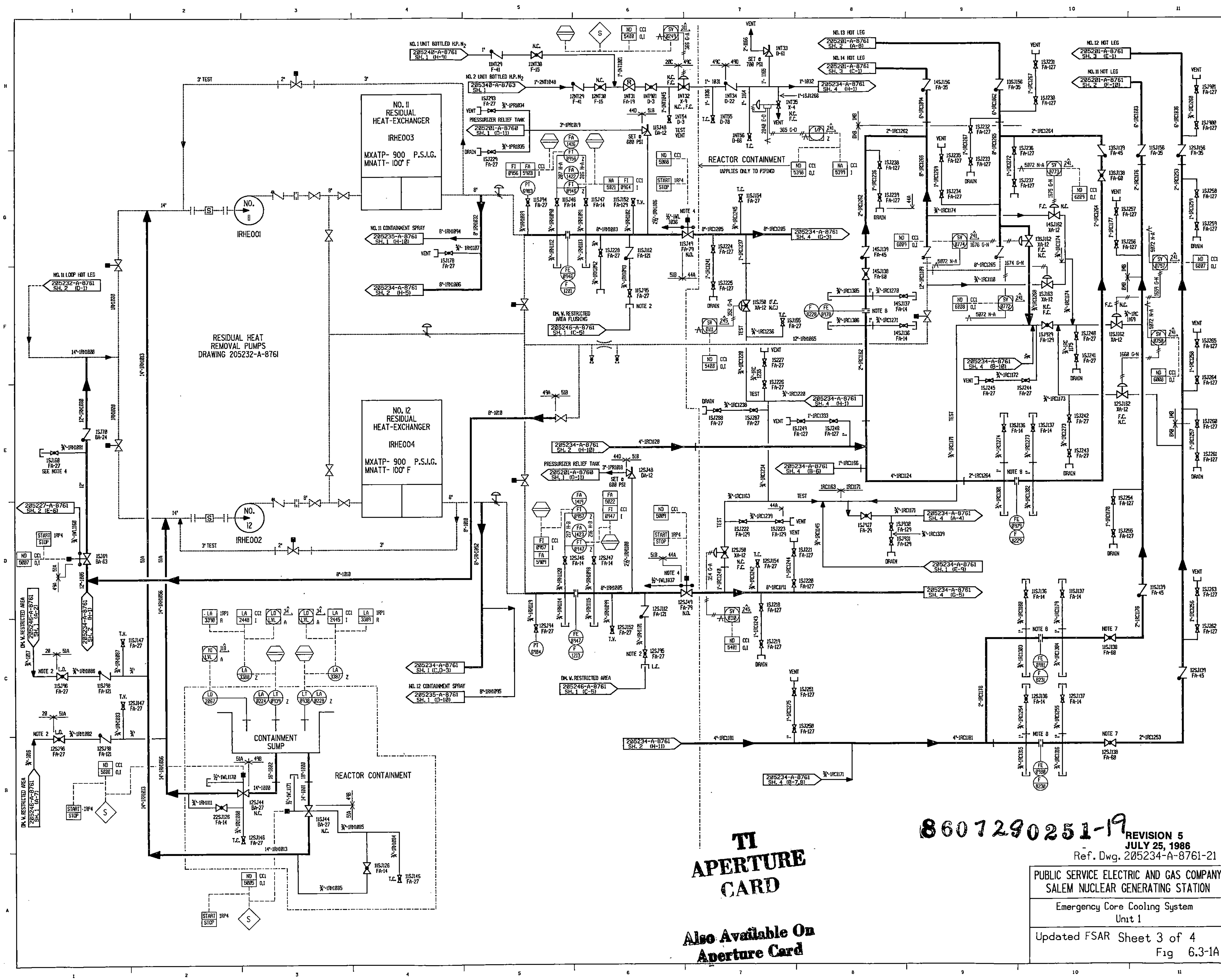
SALEM NUCLEAR GENERATING STATION

Emergency Core Cooling System
Unit 1

Updated FSAR Sheet 2 of 4
Fig 6.3-1A



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Emergency Core Cooling System
Unit 1

Updated FSAR Sheet 3 of 4
Fig 6.3-1A

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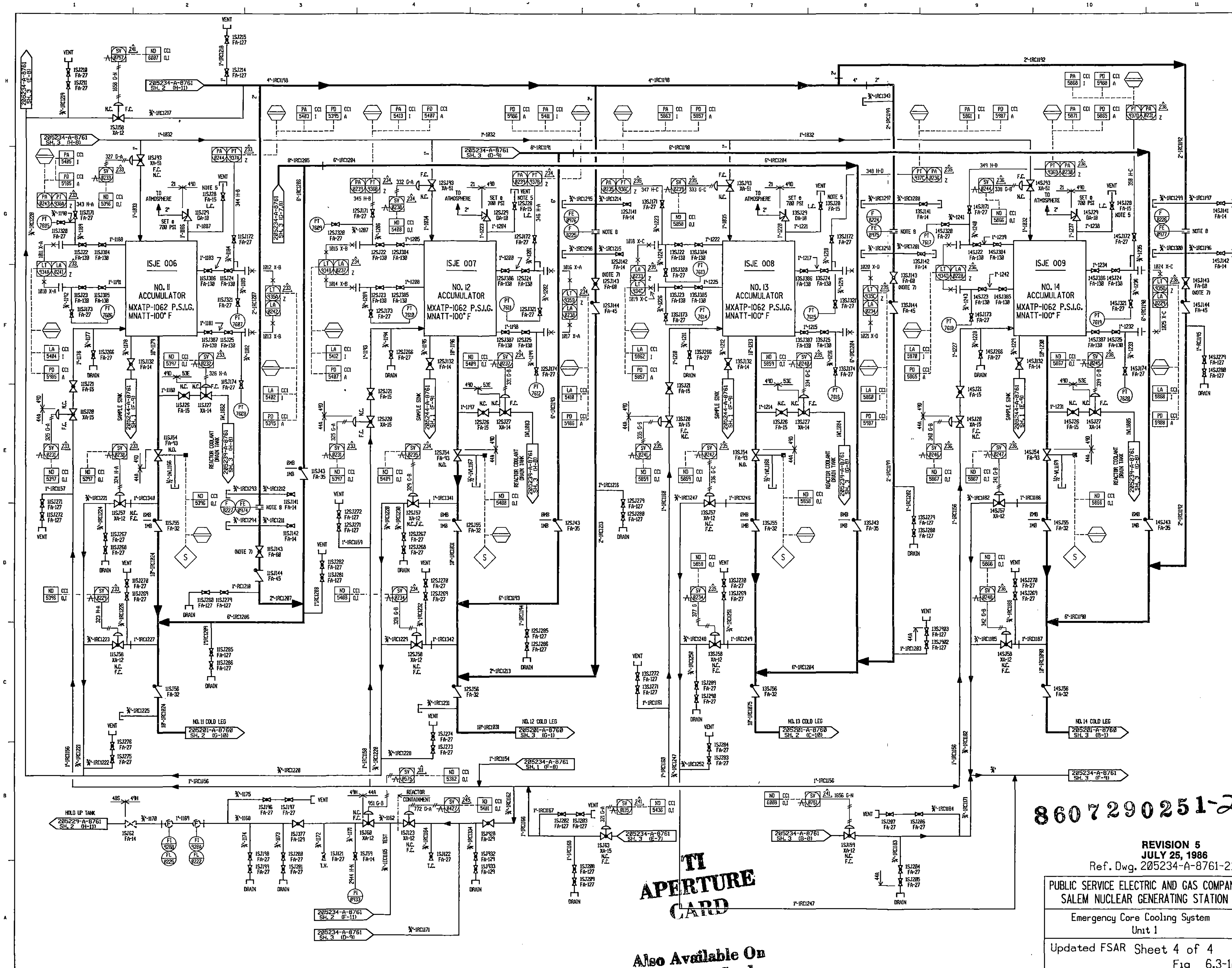

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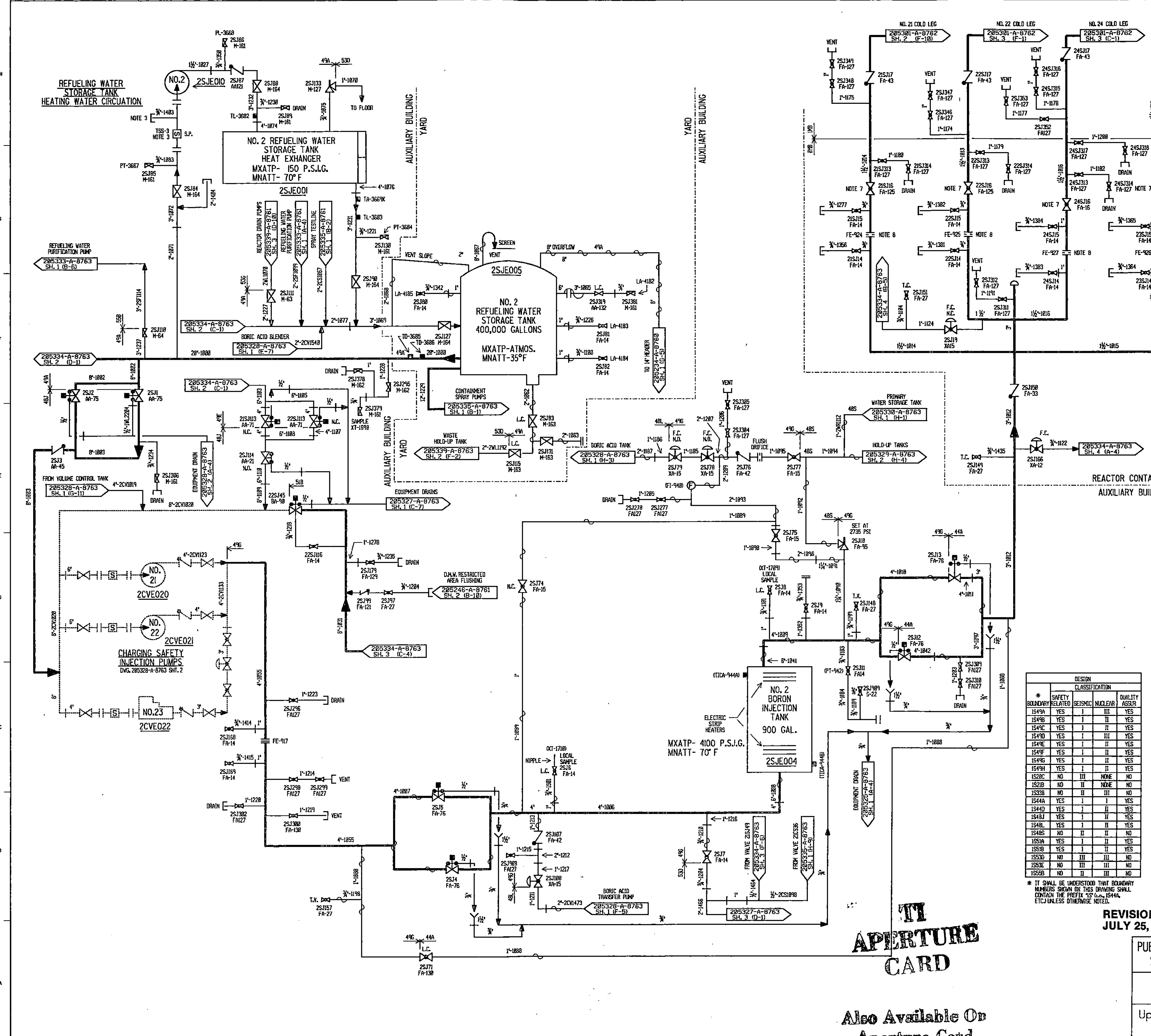
SALEM NUCLEAR GENERATING STATION

Emergency Core Cooling System
Unit 1

Updated FSAR Sheet 4 of 4
Fig 6.3-1A



NOTES

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2. LOCATE VALVE BEHIND SHIELDING.
3. TEMPORARY STRAINER IS PLACED IN LINE DURING INITIAL FLUSHING CAPPED LINE IN CONNECTION TO A TEMPERATURE PRESSURE GAGE AT THIS TIME.
4. VALVE HAS LEAKOFF CONNECTION WHICH IS PERMANENTLY PIPED TO EQUIPMENT DRAIN HEADER. OTHER VALVES WITH LEAKOFFS CONNECTIONS (NOT SHOWN) SHALL HAVE STUBS SEALED AND CAPPED.
5. DURING ACCUMULATOR VENTING A TEMPORARY HOSE MAY BE CONNECTED TO CONTAINMENT PURGE DUCT.
6. DURING PUMP VENTING A TEMPORARY CLEAR PLASTIC HOSE MAY BE CONNECTED TO FLOOR DRAIN.
7. ADJUST VALVE IN FIELD TO LIMIT PUMP RUNOUT, THEN LOCK.
8. FLOW METERING ORIFICE TO VERIFY FLOW DURING PREOPERATIONAL TESTING.
9. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX '2SJ' (i.e. 2SJ1000 ETC.) EXCEPT WHERE OTHERWISE NOTED
10. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200. THE PIPING SCHEDULE GROUP NUMBERS ARE AS NOTED ON THIS DRAWING AND PREFIXED WITH '15' IN THE PIPE SPECIFICATION.

* BOUNDARY	DESIGN CLASSIFICATION SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR
1S49A	YES	I	III	YES
1S49B	YES	I	II	YES
1S49C	YES	I	II	YES
1S49D	YES	I	III	YES
1S49E	YES	I	II	YES
1S49F	YES	I	II	YES
1S49G	YES	I	II	YES
1S49H	YES	I	II	YES
1S20C	NO	III	NONE	NO
1S21B	NO	II	NONE	NO
1S33B	NO	II	III	NO
1S44A	YES	I	I	YES
1S44D	YES	I	II	YES
1S48J	YES	I	II	YES
1S48L	YES	I	II	YES
1S48S	NO	II	II	NO
1S51A	YES	I	II	YES
1S51B	YES	I	II	YES
1S53D	NO	III	III	NO
1S53E	NO	III	III	NO
1S55B	NO	II	III	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e., 1S44A, ETC.) UNLESS OTHERWISE NOTED.

REFERENCE DRAWINGS

VALVE LIST ____ 206766-L
REACTOR COOLANT DIAGRAM ____ 205301-A-8762
CHEMICAL AND VOLUME CONTROL-OPER. DIAGRAM ____ 205328-A-8763
CHEMICAL AND VOLUME CONTROL-BORIC ACID REC. DIAGRAM ____ 205329-A-8763
CHEMICAL AND VOLUME CONTROL PRIMARY WATER REC. DIAGRAM ____ 205330-A-8763
RESIDUAL HEAT REMOVAL DIAGRAM ____ 205332-A-8763
SPENT FUEL COOLING DIAGRAM ____ 205333-A-8763
CONTAINMENT SPRAY DIAGRAM ____ 205335-A-8763
WASTE DISPOSAL LIQUID AND SOLID DIAGRAM ____ 205339-A-8763
SAMPLING DIAGRAM ____ 205344-A-8763
DEMINERALIZED WATER-RESTRICTED AREA ____ 205246-A-8761
HEATING WATER ____ 205215-A-8760
LEGEND SHEET ____ 600658-A-8727

205334-A-8763 SH. 1 ____ NO. 2 REFUELING WATER ST. TANK HEATER EX., NO. 2 REFUELING WATER ST. TANK HEATING WATER CIRCULATION PUMP, NO 21, 22 AND 23 CHG. SAFETY INJECTION PUMP, NO. 2 REFUELING WATER ST. TANK AND NO. 2 BORON INJECTION TANK.
205334-A-8763 SH. 2 ____ NO. 21 AND 22 SAFETY INJECTION PUMPS
205334-A-8763 SH. 3 ____ NO. 21 AND 22 RESIDUAL HEAT EXCHANGE NO. 21 AND 22 RESIDUAL HEAT REMOVAL PUMPS.
205334-A-8763 SH. 4 ____ NO. 21, 22, 23, AND 24 ACCUMULATORS

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SALEM NUCLEAR GENERATING STATION

Emergency Core Cooling System
Unit 2

Updated FSAR Sheet 1 of 4
Fig 6.3-1B

Also Available On Aperture Card

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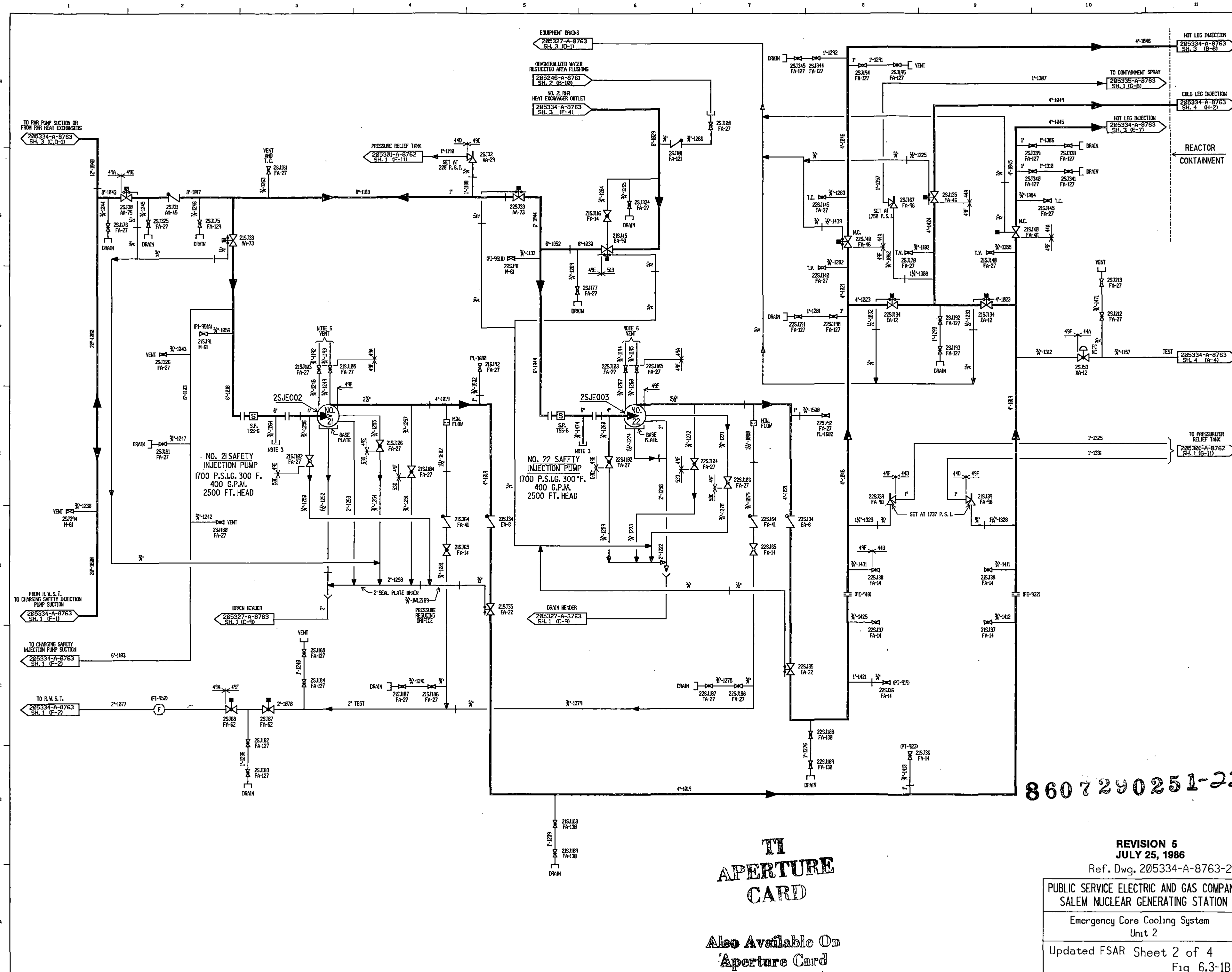

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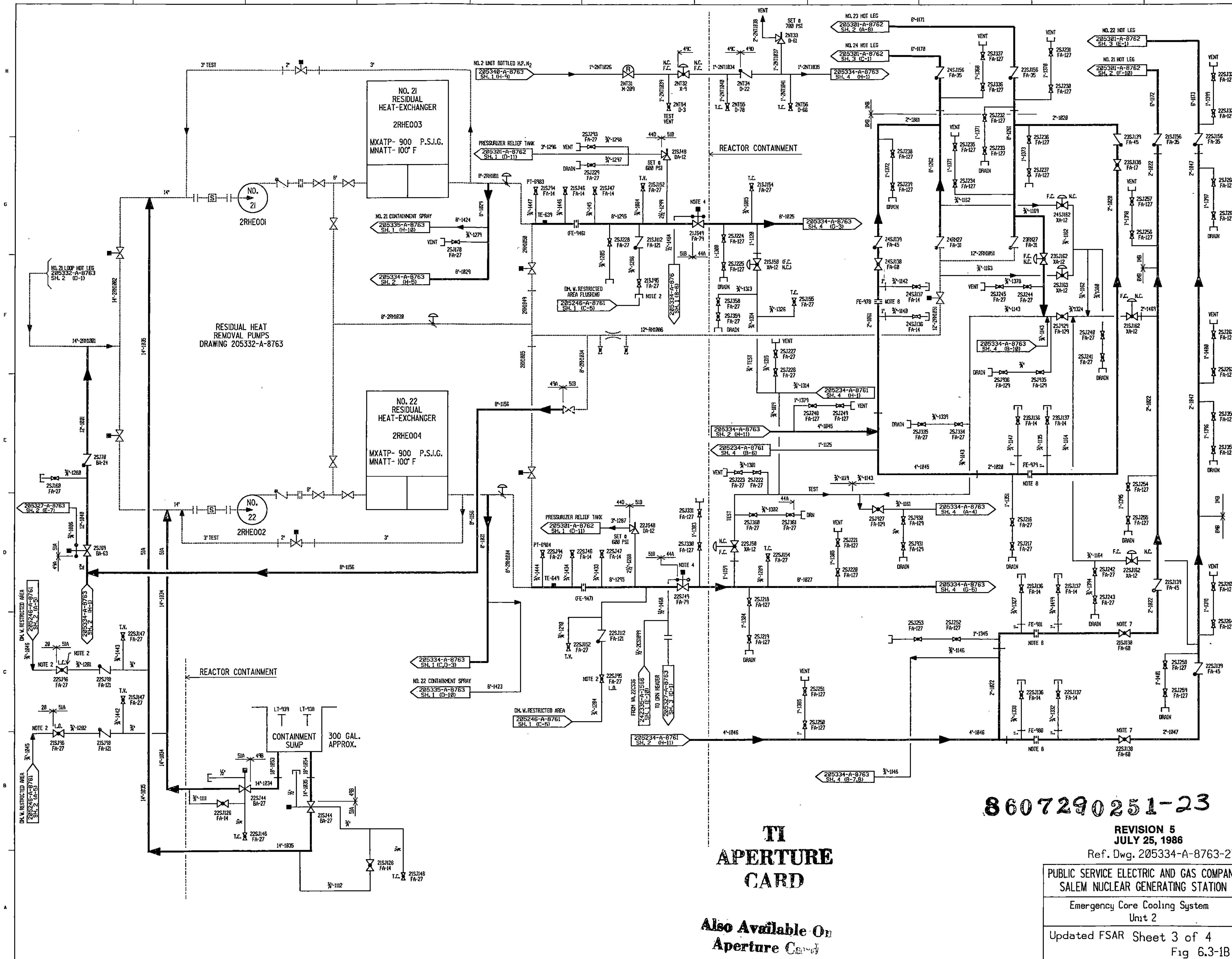
SALEM NUCLEAR GENERATING STATION

Emergency Core Cooling System
Unit 2

Updated FSAR Sheet 2 of 4
Fig 6.3-1B



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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Emergency Core Cooling System
Unit 2

Updated FSAR Sheet 3 of 4
Fig 6.3-1B

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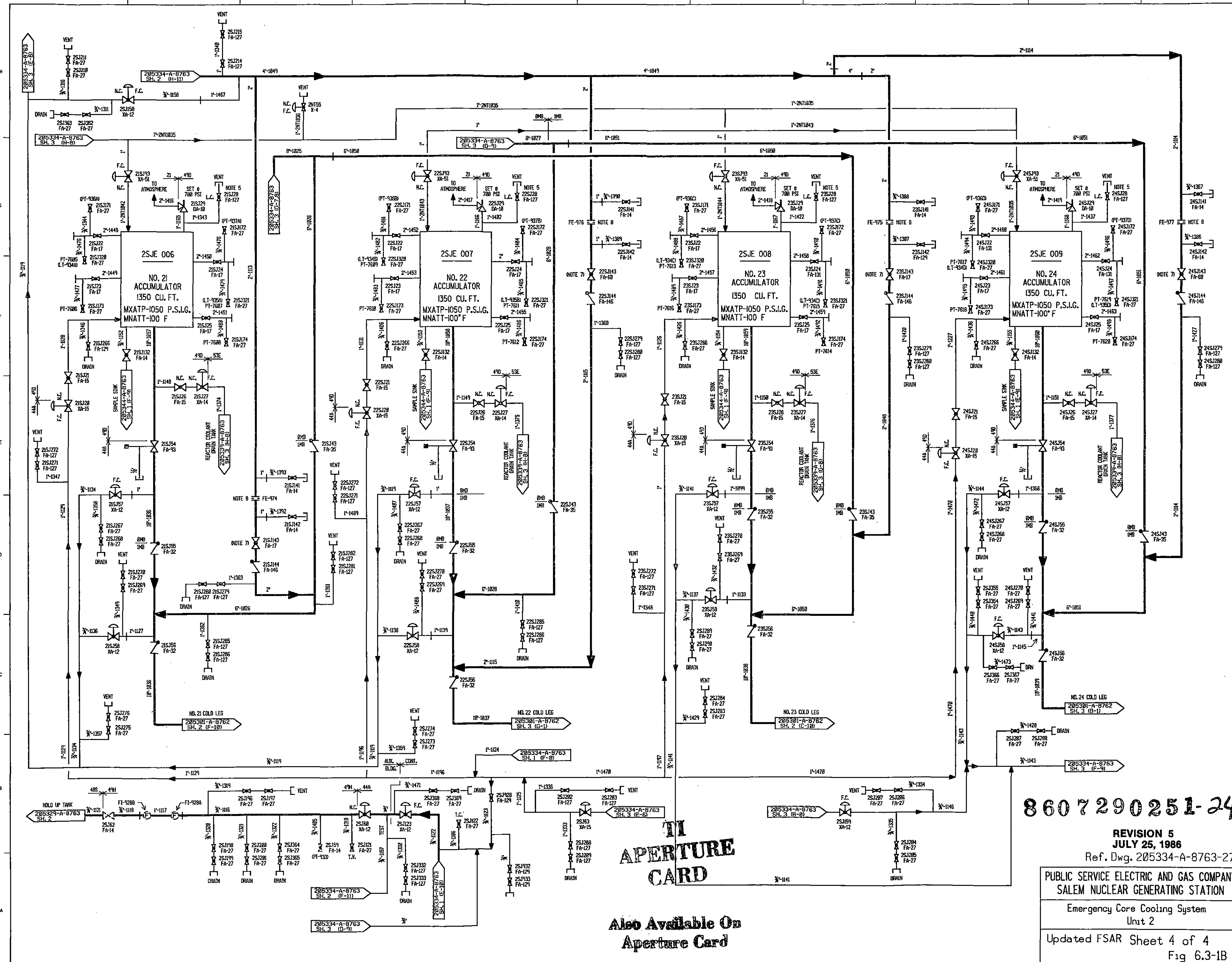

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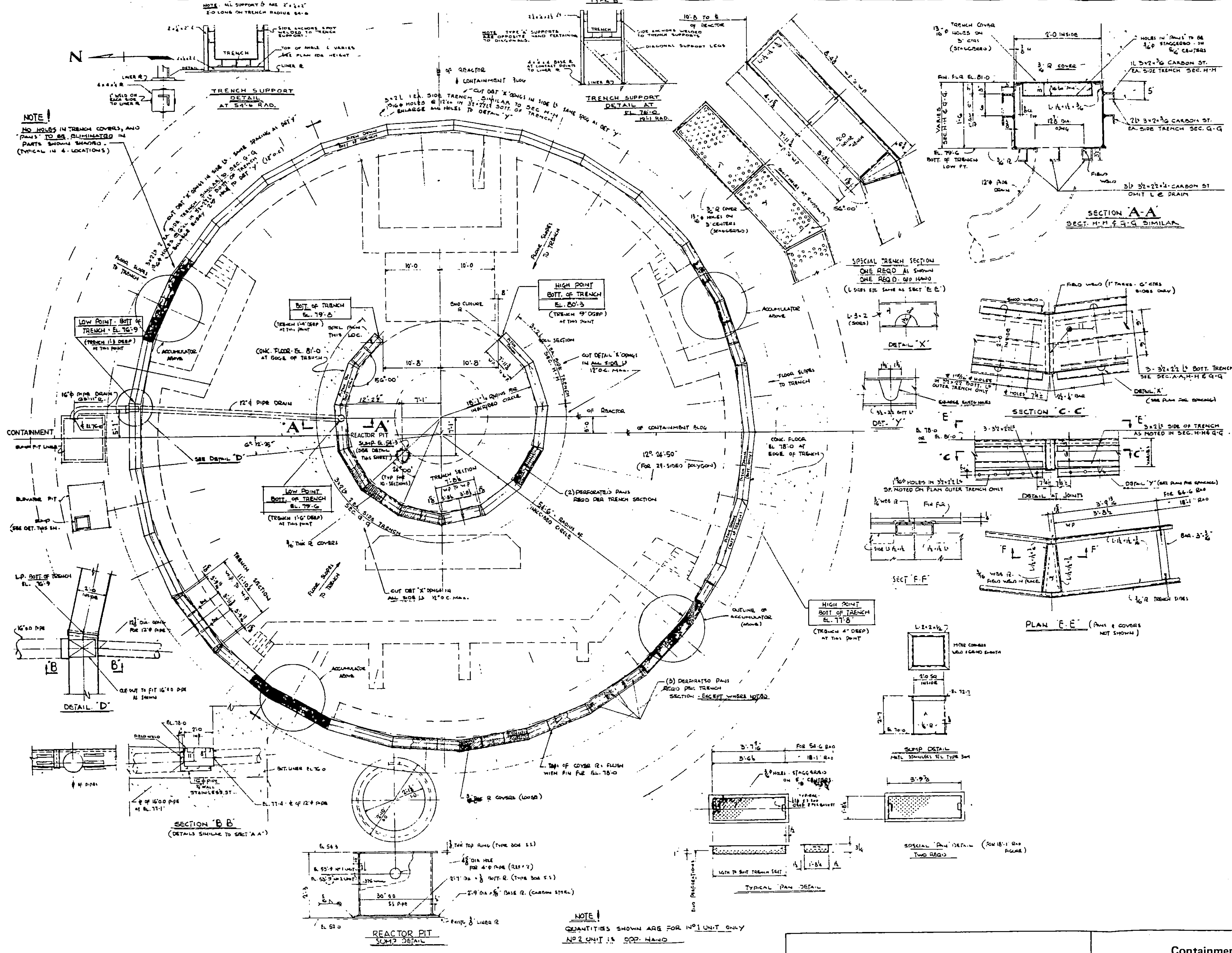
SALEM NUCLEAR GENERATING STATION

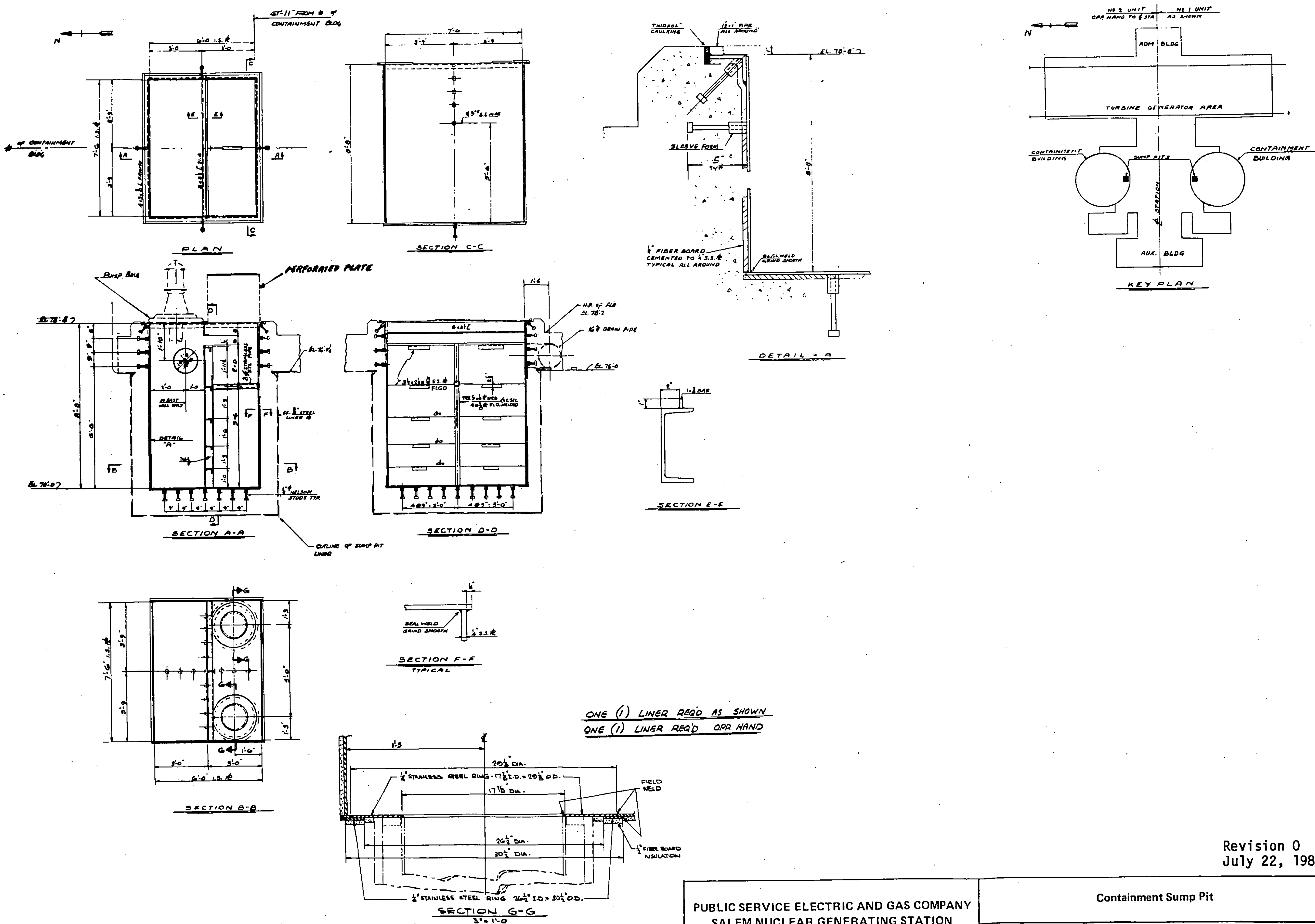
Emergency Core Cooling System
Unit 2

Updated FSAR Sheet 4 of 4
Fig 6.3-1B



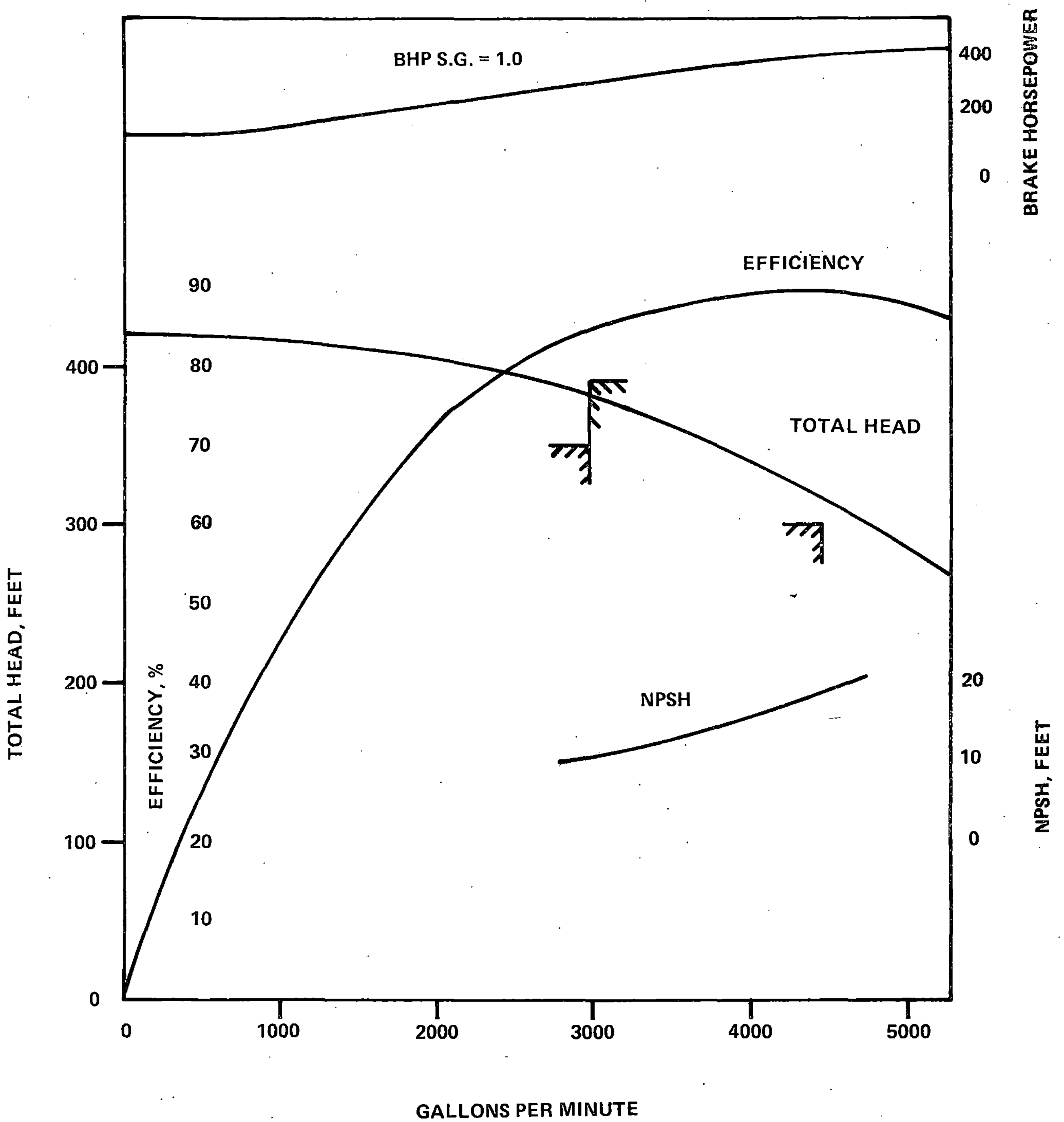
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Sump and Drain Trench
	Updated FSAR — Figure 6.3-2



Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Sump Pit
	Updated FSAR — Figure 6.3-3



Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Pump Head Characteristic Curve RHR Pump
	Updated FSAR — Figure 6.3-4

6.4 HABITABILITY SYSTEMS

Each unit is equipped with a separate control room which contains those controls and instrumentation necessary for operation of that unit under normal and abnormal conditions. The control room is continuously occupied by the operating personnel under all operating conditions.

Control room shielding and venitlation are designed such that the occupants of the room would not receive doses in excess of 5 rem to the whole body, or its equivalent to any part of the body, during the course of a loss-of-coolant accident. This includes doses received druing ingress and egress. LOCA dose analyses are presented in Chapter 15 and Chapter 12.

Plant systems affecting control room habitability are the following:

Fire Protection	(Section 9.5.1)
Communications	(Section 9.5.2)
Ventilation	(Section 9.4.1)
Lighting	(Section 9.5.3)
Shielding	(Chapter 12)

Regulatory Guide 1.78 requires that hazardous chemicals, such as those indicated in Table C-1 of the Guide, be considered in an analysis of control room habitability if they are frequently shipped within a 5 mile radius of the plant. The Guide also defines frequent shipments as being 50 or more trips per year for barge traffic. Chemicals stored or situated at distances greater than 5 miles from the facility need not be considered in the habitability analysis.

The Salem site is located in a rural area with no major manufacturing or chemical plants located within 5 miles to the site. The only major transportation route within 5 miles of the plant is the Delaware River, with the intra-coastal waterway passing 1 mile west of the site.

The Salem Nuclear Generating Station uses a sodium hypochlorite biocide system, thus eliminating an onsite chlorine hazard. The control room is equipped with smoke and combustible detectors located in the air conditioning unit ducts. These detectors provide alarms in the control room in the event of smoke or combustible hazards present. The control room is equipped with radiatiation detectors which provide annunciation, automatically isolate the controol room, and switch the ventilation system to the recirculation mode. There are a sufficient number of structures on the site between any release point and the control room air intake, such that dispersion of any effluent is provided. The calculated χ/Q is sufficiently small to reduce any concentrations of these hazardous chemical releases to low values. The control room air intakes for both Units 1 and 2 are located inboard of their respective containments, i.e., in between the containments on the north side of the Unit 1 containment and the south side of the Unit 2 containment. Any potentially hazardous chemical is stored on the opposite side of the containment, thus prohibiting any direct indiluted intake of hazardous chemicals.

Table 6.4-1 provides a tabulation of estimated quantities of hazardous chemicals shipped past Artificial Island which are listed in Table C.1 of Regulatory Guide 1.78. These estimates are based on data collected from References 1 through 6. Table 6.4-2 summarizes data for those hazardous chemicals considered further in the habitability analysis.

The only significant mobile source of hazardous chemicals is the sulfuric acid shipped on the Delaware River. A total of 90 vessel trips per year were made in transporting a total of 73,000 short tons, which resulted in an average of 812 short tons per vessel per trip. Assuming that in a collision accident, the vessel cargo is released, a quantity of 812 short tons could spill in the water. The sulfuric acid would be diluted by the river water. Since an insignificant amount of vaporization would occur, control room habitability would not be affected by this event.

The only hazardous chemicals stored on site are sulfuric acid and nitrogen. Sulfuric acid is stored in a 3000 gallon tank, and calculations show that (assuming the failure of the tank) the rate of vaporization would be only 1.2 x 10^{-6} mg/second due to the low volatility of sulfuric acid. Using $\chi/Q=7.35\times10^{-4}$ second/cubic meter, for a distance of 600 feet, the sulfuric acid concentration at the control room air intake is calculated to be 8.81 x 10^{-10} mg/m^3, which is much lower than the toxicity limit given in Table C-1 of Regulatory Guide 1.78. Also, two tanks with a capacity of 4,000 gallon each, containing sulfuric acid, are located in the turbine building, at elevation 88'. They are located on a diked area, and, assuming the failure of one tank, the rate of vaporization would be 1.2 x 10^{-6}mg/sec. The turbine building ventilation system will disperse and evacuate the sulfuric acid vapor. Assuming (conservatively) that there would be no dispersion from the turbine building exhaust to the control room air intake, the concentration at the control room air intake would be 1.2 x 10^{-6} mg/m^3, much lower than the toxicity limit given in Table C-1 of Regulatory Guide 1.78.

Nitrogen is stored in a 500 gallon tank, 1600 feet away from the control room air intake, and in 36 bottles, each containing 300 cubic feet of nitrogen, at a pressure of 2300 psi located at elevation 122' in the auxiliary building. Due to the small quantity stored, there would be no discernible increase in the natural concentration of nitrogen in the air in the event of a failure of the 500 gallon tank. A failure of one nitrogen bottle would lead to the dispersion of its contents in the auxiliary building, dilution, and its evacuation by the auxiliary building ventilation system, 70' above the control room air intake at a speed of 7 m/sec and in a direction opposite the control room air intake. Therefore, the nitrogen release would pose no significant hazard to control room personnel. Fire fighting agents used at the Salem Nuclear Generating Station are Halon, stored in tanks located inside the auxiliary building at Elevation 144' and CO_2 stored at elevation 84' in the auxiliary building. Since they are stored inside the building, they will have no effect on the control room air intake.

Table 6.4-3 summarizes data on the control room ventilation system, which is described in detail in Section 9.4.1.

It is concluded that control room personnel are adequately protected against the effects of accidental release of toxic and radioactive gases and that the plant can be safely operated or shut down under design basis accident conditions. Due to the use of sodium hypochlorite, there is no chlorine hazard. A postulated sulfuric acid spill results in a miniscule concentration reaching the control room air intake and the postulated nitrogen release will dissipate in the environment well before reaching the control room.

REFERENCES FOR SECTION 6.4

1. "Waterborne Commerce of the United States", U. S. Army Corps of Engineers Annual Publication.

2. Commodity traffic data for imports and exports collected by the Philadelphia Maritime Exchange.

3. Foreign trade cargo movements collected by the Delaware River Port Authority.

4. U.S. Dept. of Commerce, Census Bureau (handling foreign trade data for customs purposes).

5. Interstate Oil Transport, Inc. (which handles most of the barge operations of the Delaware River).

6. U. S. Coast Guard, Captain of the Port, Philadelphia (which is cognizant of all hazardous materials shipments in the Delaware River).

TABLE 6.4-1 (sheet 1 of 2)

ESTIMATES OF HAZARDOUS CHEMICALS TRAFFIC*

Chemical	Thousands of Short Tons/yr	Vessel Trips/yr
Acetaldehyde	negligible	-
Acetone	negligible	-
Acrylonitrile	negligible	-
Anhydrous Ammonia	160	12
Aniline	negligible	-
Benzene (+ Toluene)	288	29
Butadiene	100	12
Butenes	negligible	-
Carbon Dioxide	"	-
Carbon Monoxide	"	-
Chlorine	negligible	-
Ethyle Chloride	"	-
Ethyl Ether	"	-
Ethylene Dichloride	50	10
Flourine	negligible	0
Formaldehyde	"	-
Helium	"	-
Hydrogen Cyanide	"	-
Hydrogen Sulfide	"	-
Methanol	40	12
Nitrogen	negligible	-

TABLE 6.4-1 (sheet 2 of 2)

ESTIMATES OF HAZARDOUS CHEMICALS TRAFFIC*

Chemical	Thousands of Short Tons/yr	Vessel Trips/yr
Sodium Hydroxide	242	30-50
Sulfur Dioxide	negligible	-
Sulfuric Acid	73	90
Vinyl Chloride	185	15
Xylene	50	5

* Estimates are based primarily on 1976 statistics, but upgraded with more current information where available.

TABLE 6.4-2

HAZARDOUS CHEMICALS STORED ON-SITE

NAME OF CHEMICAL	SULFURIC ACID	NITROGEN
TYPE OF SOURCE	ONSITE & MOBILE	ONSITE
HUMAN DETECTION THRESHOLD (mg/m^3)	1	ASPHYXIANT
MAXIMUM ALLOWABLE TWO-MINUTE CONCENTRATION (mg/m^3)	2	ASPHYXIANT
MAXIMUM QUANTITY OF CHEMICAL INVOLVED	1) 3000 GAL. ONSITE 2) 812 SHORT-TONS	1) 500 GAL. 2) 1 Bottle = 300 cu. ft
MAXIMUM CONTINUOUS RELEASE RATE	N/A	N/A
VAPOR PRESSURE (TON)	N/A	2300 psi for bottle
FRACTION OF CHEMICAL FLASHED AND RATE OF BOIL OFF WHEN SPILLING OCCURS	N/A	1) 25% for tank 2) All for bottle
DISTANCE OF SOURCE FROM CONTROL ROOM	600 feet (onsite) 1 mile (mobile)	1600 Feet for tank
FIVE PERCENTILE METEOROLOGICAL DILUTION FACTOR	7.35×10^{-4} * sec/m^3	7.35×10^{-4} * sec/m^3

* The dilution factor is calculated as described in Chapter 15. The cross-sectional area of the containment was reduced to account for only the first 31 feet of elevation. The wind speed was assumed to be 1.5 m/sec. As indicated in Chapter 15 stability has little effect on χ/Q.

TABLE 6.4-3

CONTROL ROOM VENTILATION SYSTEM PARAMETERS

		CAACS(*)	EACS(*)
1.	VOLUME OF CONTROL ROOM	5000 m^3	500 m^3
2.	NORMAL FLOW RATES:		
	- unfiltered inleakage	100 cfm	100 cfm
	- filtered makeup air	0-33,840 (when needed)	0-33,840 (when needed)
	- filtered recirculated air	6850 cfm	6850 cfm
3.	EMERGENCY FLOW RATES:		
	- unfiltered inleakage	100 cfm	100 cfm
	- filtered makeup air	300 cfm (when needed)	300 cfm (when needed)
	- filtered recirculated air	6550-6850	6550-6850
4.	TIME REQUIRED TO ISOLATE THE CONTROL ROOM	1 minute manually (conservative) 5 seconds automatically	

* EACS = Emergency Air Conditioning System
CAACS = Control Area Air Conditioning System

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SALEM GENERATING STATION

UNITS 1 AND 2

UPDATED FINAL SAFETY ANALYSIS REPORT

Volume 4

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7.0 INSTRUMENTATION AND CONTROLS

7.1 INTRODUCTION

Instrumentation and control systems provide the reactor operator with the required information and control capability to operate the plant in a safe and efficient manner. Where safety functions are involved, logic circuitry and actuators are provided to execute equipment actions without operator action.

Instrumentation and control systems are broadly classified as being either safety related systems or control systems. The Nuclear Instrumentation (Reference 1) and Engineered Safety Features circuits are discussed in separate parts of this section. Other specific design features or topics also separately discussed are: in-core instrumentation, operating control stations and engineered safeguards sequence control. Controls and electrical drawings for safety related equipment can be found in Reference 2.

Instrumentation and controls are provided to monitor and maintain all operationally important reactor operating parameters such as neutron flux, system pressures, flow rates, temperatures, levels and control rod positions within prescribed operating ranges. The quantities and types of instrumentation provided are adequate for safe and orderly operation of all systems and processes over the full operating range of the plant.

Process variables which are required on a continuous basis for the startup, power operation and shutdown of the plant are indicated in, recorded in, and controlled as necessary from the control room. The operating staff is cognizant and in control of all test, maintenance and calibration work and can fully assess all abnormal plant conditions knowing the extent to which specific and related operating tasks are in process.

Control system failure analyses have been conducted for Unit 2 and were reported to NRC on June 2, 1982 in a report entitled, "Salem Generating Station, Unit 2, Control Systems Failure Analysis." The systems reviewed were (1) Steam Dump, (2) Excore Nuclear Instrumentation, (3) Pressurizer Pressure and Level Control, (4) Feedwater Control and (5) Rod Control. The systems were evaluated for (1) Break of Common Instrument Lines, (2) Loss of Power to all components powered from a single source and (3) Break of any single instrument line. It was concluded that the consequences of single control system failures are adequately bounded by the accidnet analyses of Chapter 15.

7.1.1 IDENTIFICATION OF SAFETY RELATED SYSTEMS

7.1.1.1 Reactor Trip Systems

The Reactor Trip System consists of equipment which initiates reactor trip or activates engineered safety features. All equipment from sensors to actuating devices is considered a part of the protective system. The reactor trip breakers and the undervoltage attachment are safety-related. Engineered safety features are discussed in Section 7.3.

Design criteria permit maximum effective use of process measurements both for control and protection functions, thus enhancing the capability to provide an adequate system to deal with the majority of common-mode failures as well as to provide redundancy for critical control functions. The design approach provides for monitoring of numerous system variables by different means, i.e., system diversity. This diversity has been evaluated for a wide variety of postulated accidents (Reference 3).

7.1.1.2 Fission Process Monitors and Controls

Criterion: Means shall be provided for monitoring or otherwise measuring and maintaining control over the fission process throughout core life under all conditions that can reasonably be anticipated to cause variations in reactivity of the core.

The Nuclear Instrumentation System described in Section 7.2 safeguards the reactor by monitoring the neutron flux and generating appropriate trips and alarms for various phases of reactor operating and shutdown conditions. It also provides indication of reactor status during startup and power operation.

A comprehensive discussion of the Nuclear Instrumentation System, covering design bases and a detailed description of the system, can be found in Reference 1.

7.1.1.3 Plant Comparison

The Salem Nuclear Plant protection and engineered safety features actuation systems are functionally identical to those in the D. C. Cook plant.

Both plants have solid state logic protection systems and extended testability of Engineered Safety Features actuation circuitry.

Both plants have incorporated the power range fast flux rate trip with the corresponding deletion of the automatic rod withdrawal block on indication of rod drop.

The design of both systems conforms to IEEE Std. 279-1971 and the General Design Criteria.

7.1.2 IDENTIFICATION OF SAFETY CRITERIA

7.1.2.1 Design Bases

Criterion: Core protection systems, together with associated equipment, shall be designed to prevent or to suppress conditions that could result in exceeding acceptable fuel damage limits.

If the Reactor Trip System receives signals which are indicative of an approach to unsafe operating conditions, the system actuates alarms, prevents control rod withdrawal, initiates load cutback, and/or opens the reactor trip breakers.

The basic reactor operating philosophy is to define an allowable region of power, pressure and coolant temperature conditions. This allowable range is defined by the primary tripping functions: The overpower $^{\Delta}$T trip, the overtemperature $^{\Delta}$T trip and the nuclear overpower trip. The operating region below these trip settings is designed so that no combination of power, temperatures, and pressure could result in departure from nucleate boiling ratio (DNBR) less than 1.3 for any credible operational transient with all reactor coolant pumps in operation. Tripping functions in addition to those stated above are provided to back up the primary tripping functions for specific abnormal conditions.

Rod stops from nuclear overpower, overpower $^{\Delta}$T and overtemperature $^{\Delta}$T deviation are provided to prevent abnormal power conditions which could result from excessive control rod withdrawal initiated by a malfunction of the reactor control system or by operator violation of administrative procedures.

7.1.2.2 Independence of Safety Related Systems

7.1.2.2.1 Redundancy and Independence of Safety Related Systems

Criterion: Redundancy and independence designed into safety related systems shall be sufficient to assure that no single failure or removal from service of any component or channel of such a system will result in loss of the protection function. The redundancy provided shall include, as a minimum, two channels of protection for each protection function to be served.

The Reactor Trip System is designed so that loss of voltage in a channel will result in a signal calling for a trip, except for reactor coolant pump bus undervoltage, underfrequency, and auto shunt trip which require dc voltage to actuate. The trip system design combines redundant sensors and channel independence with coincident trip philosophy so that a safe and reliable system is provided in which a single failure will not violate reactor protection criteria.

The design philosophy for the reactor protection and control systems is to make maximum use, for both protection and control functions, of a wide range of measurements. The protection and control systems are separate and identifiable. The design approach permits not only redundancy of control, providing its own desirable increment to overall plant safety, but also provides a protection system which continuously monitors numerous system variables by different means; i.e., protection system diversity.

The extent of protection system diversity has been evaluated for a wide variety of postulated accidents.[3] Generally, two or more diverse protection functions would terminate an accident before intolerable consequences could occur.

The protection system is independent of the control system, although the control system is dependent upon signals derived from the protection system through isolation amplifiers. The design approach is to make maximum and thereby most efficient use, for both control and protection purposes, of all measurements of plant variables.

In the Reactor Protection System, two reactor trip breakers are actuated by two separate logic matrices which interrupt power to the rod cluster control assembly drive mechanisms. The breakers are connected in series with the power supply so that opening either breaker interrupts power to all full length rod drive mechanisms permitting the rods to free fall into the core.

Further detail on redundancy is provided through the description of the respective systems covered by the various subsections in this chapter. The power supply for the protection systems is discussed in Chapter 8.

7.1.2.2.2 Protection Against Multiple Disability for Safety Related Systems

Criterion: The effects of adverse conditions to which redundant channels or protection systems might be exposed in common, either under normal conditions or those of an accident, do not result in loss of the protection function or shall be tolerable on some other basis.

Separation of redundant analog protection channels originates at the process sensors and continues through the wiring route and containment penetrations to the analog protection racks. Physical separation is used to achieve separation of redundant transmitters. Separation of wiring is achieved using separate wireways, cable trays, conduit runs and containment penetrations for each redundant channel. Redundant analog equipment is separated by locating modules in different protection rack sets. Each redundant protection channel set is energized from a separate instrument bus, which can be energized by the standby AC power system.

7.1.2.2.3 Demonstration of Functional Operability of Safety Related Systems

Criterion: Means shall be included for suitable testing of the active components of protection systems while the reactor is in operation to determine if failure or loss of redundancy has occurred.

The signal conditioning equipment of each protection channel in service at power is capable of being calibrated and tested independently by simulated analog input signals to verify its operation without tripping the reactor. The testing scheme includes checking through the trip logic to the trip breakers. Thus, the operability of each trip channel can be determined conveniently and without ambiguity. Functional operation of the power sources for the protection system is discussed in Chapter 8.

7.1.2.2.4 Protection System Failure Analysis Design

Criterion: The protection systems shall be designed to fail into a safe state or into a state established as tolerable on a defined basis if conditions such as disconnection of the system, loss of energy (e.g., electrical power, instrument air), or adverse environments (e.g., extreme heat or cold, fire, steam, or water) are experienced.

Reactor trip channels are generally designed on the "de-energize to operate" principle; a loss of power causes a channel to go into its trip mode. Exceptions to this case are the reactor coolant pump bus undervoltage and underfrequency trips, and the automatic reactor shunt trip feature which require dc voltage to actuate. All safety related air operated valves are spring loaded to move to the preferred position on loss of instrument air.

Reactor trip is implemented by simultaneously interrupting power to the magnetic latch mechanisms on all drives allowing the rods to insert by free fall. The protection system is thus inherently safe in the event of a loss of power. This equipment is selected to withstand the most adverse environmental conditions to which it will be subjected; this would also include post-accident conditions within the containment, if the equipment is required to operate in the post-accident environment.

7.1.2.2.5 Reactivity Control Systems Malfunctions

Criterion: The reactor trip systems shall be capable of protecting against any single malfunction of the reactivity control systems, such as unplanned continuous withdrawal (not ejection or dropout) of a control rod, by limiting reactivity transients to avoid exceeding acceptable fuel damage limits.

Reactor shutdown with rods is completely independent of the normal control functions since the trip breakers interrupt the power to the rod mechanisms regardless of existing control signals. Effects of continuous withdrawal of a rod and of deboration are described in Chapter 15.

7.1.2.3 Missile Protection

Criterion: Adequate protection for those engineered safety features, the failure of which would result in undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures.

The applicable portions of the missile protection criteria as stated in Section 1.3 apply to Class I equipment in this chapter.

Several criteria related to all instrumentation and control systems but more specific to other plant features or systems are discussed in other Chapters, as listed:

Criterion	Discussion
Suppression of Power Oscillations	Chapter 3
Reactor Core Design	Chapter 3
Quality Standards	Chapter 1
Performance Standards	Chapter 1
Fire Protection	Chapter 9
Missile Protection	Chapter 5
Emergency Power	Chapter 8

7.1.2.4 Periodic Testing of the Protection Systems (IEEE-338-1971)

IEEE Std. 338-1971, "IEEE Trial-Use Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems", was used as a guide in developing the periodic testing program details for Salem.

1. The response time specified in Paragraph 4.1 of IEEE 338 is not checked periodically as is the set point accuracy. The response time of protection system instruments is checked during preoperational testing and after replacement of any component effecting the response time. Response times are checked during refueling outages.

2. The reliability goals specified in Paragraph 4.2 of IEEE 338 are not applicable since the test frequencies are dictated in the Technical Specifications.

3. The periodic test frequency discussed in Paragraph 5.2 of IEEE 338, and specified in the Technical Specifications, is conservatively selected to assure that equipment associated with protection functions has not drifted beyond its minimum performance requirements.

4. The test interval discussed in Paragraph 5.2 IEEE 338, is developed on past operating experience and analytical methods, and will be modified if necessary to assure that system and subsystem protection is reliably provided.

7.1.2.5 Conformance to IEEE Standard 344-1971

The Reactor Protection System, Engineered Safety Feature circuits, and the Emergency Power System have been designed to assure that these systems do not lose their capability to perform the required functions in the event of a design basis earthquake. Such equipment is designed Class I as defined in Section C.1. A listing for the general category of Class I items is given in Section C.2.

The protection system has been designed and qualified to assure its capability to initiate a protective action during the design basis earthquake. The Engineered Safety Feature circuits have been designed and qualified to assure their capability in performing the required functions during post-accident operation. There may be deformation of the equipment, however, functional capability must be maintained. Equipment suppliers have been given the seismic design requirements, and the ability of such equipment to perform its required functions has been verified either by analysis or by testing. Typical protection system and Engineered Safety Features system equipment are subjected to type tests under simulated seismic motion and/or dynamic mathematical analysis to demonstrate ability to function.

Type testing has been done on this equipment by using conservatively large accelerations and applicable frequencies. This testing conformed to the guidelines set forth in IEEE Std. 344-1971, "IEEE Guide for Seismic Qualification of Class I Electrical Equipment for Nuclear Power Generating Stations".

References (4, 5, 6, 7) provide the seismic evaluation of safety related equipment. The results show that there were no electrical irregularities that would leave the plant in an unsafe condition even though some trips were initiated.

Table 3.10-1 contains all the safety related electrical equipment that requires seismic qualification.

7.1.2.6 Conformance and Exceptions to IEEE 323-1971

IEEE No. 323-1971, "IEEE Trial-Use Standard Guide for Qualifying Class I Electric Equipment for Nuclear Power Generating Stations".

The safety related equipment is type tested to substantiate the adequacy of design. This is the preferred method as indicated in IEEE-323. Type tests already performed (References 4, 8, 9, and 10), in accordance with criteria standards established at the time of the construction permit, may not conform to the format guidelines set forth in IEEE-323.

7.1.2.7 Conformance to IEEE 336-1971

Conformance to IEEE-Standard 336-1971 "IEEE Standard Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations". Installation, inspection and testing activities for instrumentation and electric equipment are in accord with this standard. The overall quality assurance program is described in Chapter 17.

7.1.3 Control Room Design Review

A preliminary design review assessment of the Salem Unit 2 control room was undertaken in the spring of 1980 by Public Service Electric and Gas Company in conjunction with human factors personnel from Essex Corporation. It was concluded in the preliminary review that "the design of the Salem-2 control room, which was repeatedly developed through the use of mockups and operator walk-throughs, evidences a high level of concern for the capabilities and limitations of the human operator, with some notable exceptions." The authors cautioned that the human engineering discrepancies and conclusions were tentative pending further evaluation and analysis. A detailed control room design review (DCRDR)[11] was subsequently undertaken. The DCRDR was performed for Units 1 and 2 in accordance with the intent of NUREG-0700[12]. The detailed control room design review process was divided into the following major steps:

- o Operating Experience Review
- o Control Room Inventory
- o Control Room Survey
- o System Function Review and Task Analysis
- o Verification of Task Performance Capabilities
- o Validation of Control Room Functions and Integrated Performance Capabilities

Design review team members assessed the identified and prioritized human engineering discrepancies (HEDs) and recommended corrective actions, if applicable, for the resolution of each. Recommendations for HED resolution were developed for all significant HEDs using the resources of the DCRDR team and other specialists (e.g., Plant Engineering and Operating Departments). These recommendations took into account the impact of the correction on operating effectiveness, system safety, acceptability of design, and consistency with present control room characteristics.

A list of all HEDs requiring plant changes appears in section 3.1.1 of the DCRDR report[11]. All HEDs identified during the review are listed in Volume 2 of the same report.

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10. Locante, J., "Environmental Testing of Engineered Safety Features Related Equipment (NSSS - Standard Scope)," WCAP-7410-L, Volume 1 (Proprietary), December, 1970 and WCAP-7744, Volume 1 (Non-Proprietary), August, 1971.

11. "Public Service Electric & Gas Co.", Salem Generating Station, Units 1 and 2, Detailed Control Room Design Review, Volumes 1 and 2, December, 1983.

12. USNRC, NUREG-0700, "Guidelines for Control Room Design Reviews"

7.2 REACTOR TRIP SYSTEM

7.2.1 DESCRIPTION

7.2.1.1 System Description

The Reactor Trip System consists of equipment designed to cause or initiate Engineered Safety Features. All equipment from sensors to the trip breakers or initiation circuits of Engineered Safety Features are part of the Reactor Trip System. Engineered Safety features are discussed in Section 7.3.

Design criteria for this system (refer to Section 7.1) permit maximum effective use of process measurements both for control and protection functions, thus enhancing the capability to provide an adequate system to deal with the majority of common-mode failures as well as to provide redundancy for critical control functions. The design approach provides system diversity which has been evaluated for a wide variety of postulated accidents (Reference 1).

The Reactor Trip System consists of an aggregate lineup of the following systems. System descriptions may be found throughout this section and in the associated references:

Nuclear Instrumentation System (Reference 2)
Process Control System
Solid State Protection System (Reference 3)

Figure 7.2-1 illustrates core limits and shows the maximum trip points which are used for the protection system. The solid lines indicate a typical locus of DNBR = 1.30 at four pressures, and the dashed lines indicate maximum permissible trip points for the overtemperature ΔT reactor trip. Actual set points (the safety limits are given in the

Technical Specifications) are lower to allow for measurement and instrumentation errors. The overpower ΔT reactor trip limits the maximum core power independent of departure from nucleate boiling ratio (DNBR).

Adequate margins exist between the maximum nominal steady state operating point (which includes allowance for temperature, calorimetric, and pressure errors) and required trip points to preclude a spurious trip during design transients.

7.2.1.2 Nuclear Instrumentation

The Nuclear Instrumentation System is an integral part of the Reactor Trip System as described in these sections.

The Nuclear Instrumentation System uses information from three separate types of instrumentation channels to provide three discrete protection levels. Each range of instrumentation (source, intermediate, and power) provides the necessary overpower reactor trip protection required during operation in that range. The overlap of instrument ranges provides reliable continuous protection beginning with source level through the intermediate and low power level. As the reactor power increases, the overpower protection level is increased by administrative procedures after satisfactory higher range instrumentation operation is obtained. Automatic reset to more restrictive trip protection is provided when reducing power.

Various types of neutron detectors, with appropriate solid-state electronic circuitry, are used to monitor the leakage neutron flux from a completely shutdown condition to 120 percent of full power. The power range channels are capable of recording overpower excursions up to 200 percent of full power.

The neutron flux covers a wide range between these extremes. Therefore, monitoring with several ranges of instrumentation is necessary. The lowest range ("source" range) covers six decades of leakage neutron flux. The next range ("intermediate" range) covers eight decades. Detectors and instrumentation are chosen to provide overlap between the higher portion of the source range and the lower portion of the intermediate range. The highest range of instrumentation ("power" range) covers approximately two decades of the total instrumentation range. This is a linear range that overlaps with the higher portion of the intermediate range.

The system described above provides control room indication and recording of signals proportional to reactor neutron flux during core loading, shutdown, startup and power operation, as well as during subsequent refueling. Startup rate indication for the source and intermediate range channels is provided at the control board. Reactor trip and rod stop control and alarm signals are transmitted to the Reactor Control and Protection System for automatic plant control.

The Salem design used the Ion-Chamber Current Recorders (NR-41 through NR-44) to record the upper and lower neutron flux of the same detector instead of the upper and lower neutron flux of the diagonally opposite detectors.

A block diagram of the Reactor Trip System showing various reactor trip functions and interlocks is shown in Figure 7.2-2.

7.2.1.3 Principles of Design

The identification of applicable safety criteria is covered in Section 7.1. The Reactor Trip System is designed in accordance with IEEE 279-1971. Detailed descriptions of the implementation of these principles are presented here in Section 7.2 and in Section 7.5.

7.2.1.4 Electrical Isolation

The design criterion used to assure electrical isolation is that no analog signal which is required for initiation of reactor protection or Engineered Safety Feature actuation is allowed to leave a set of protection channels. Where protection signal intelligence is required for other than protection functions an isolation amplifier (part of the protection set) is used to transmit the intelligence. The isolation amplifier prevents the perturbation of the protection channel signal (input) due to any distrubance of the isolated signal (output) which normally could occur near any termination of the output wiring external to the protection racks. A description of the nuclear instrumentation isolation amplifiers is given in Reference 4. A description of the process control system isolating device is given in Reference 5.

Isolation of the reactor protection and Engineered Safety Feature signals from control signals has been demonstrated. Tests have confirmed the adequacy of isolation devices in protection system designs.

7.2.1.5 Protection System Identification

All non-rack mounted protective equipment and components are provided with an identification tag or name plate. Small electrical components such as relays have name plates on the enclosure which houses them. All cables are numbered with identification tags. These numbers are included in the cable control report which specified cable routing.

For protection racks which house the portection rack mounted equipment, a color coded nameplate on the rack is used to differentiate between protective and non-protective sets. This provides immediate and unambiguous identification of protection sets. The color coding of the nameplates is as follows:

Protection Set I - Green with white lettering
II - Gray with white lettering
III - Blue with white lettering
IV - Coco with white lettering

7.2.1.6 Manual Actuation

Means are provided for manual initiation of protective system action. Failure in the automatic system does not prevent the manual actuation of protective functions. Manual actuation is designed to require the operation of a minimum of equipment.

7.2.1.7 Channel Bypass or Removal from Operation

The system is designed to permit any one analog channel to be maintained, tested or calibrated during power operation without system trip. (Note: This does not include such backup trips as manual trip and reactor coolant pump breakers open trip.) During such operation the active parts of the system continue to meet the single failure criterion, since the channel under test is either tripped or makes use of superimposed test signals which do not negate the process signal.

EXCEPTIONS: 1. "One-out-of-two" systems are permitted to violate the signal failure criterion during channel bypass provided that acceptable reliability of operation can be otherwise demonstrated and bypass time interval is short. 2. Containment spray actuation channels are tested by bypassing or negating the channel under test. This is acceptable since there are 4 channels, and the two-out-of-four trip logic reduces to two-out-of-three during the test.

7.2.1.8 Capability for Test and Calibration

The bistable portions of the protective system (e.g., switches, on-off controllers etc.) provide trip signals only after signals from analog portions of the system reach preset values. Capability is provided for calibrating and testing the performance of the bistable portion of protective channels and various combinations of the logic networks during reactor operation.

The analog portion of a protective channel (e.g., sensor and amplifier) provides an analog signal of the reactor or plant parameter. Any of the following methods for checking the analog portion of a protective channel during reactor operation are used:

1. Varying the monitored parameter.

2. Introducing and varying a substitute transmitter signal.

3. Cross checking between identical channels or between channels which bear a known relationship to each other and which have readouts available.

The design provides for administrative control for the purpose of manually bypassing channels for test and calibrating purposed if required.

The design provides for administrative control of access to trip settings, module calibration adjustments, test points, and signal injection points.

7.2.1.9 Information Readout and Indication of Bypass

The protective system provides the operator with complete information pertinent to system status and safety.

Indication is provided in the control room if some part of the system has been administratively bypassed or taken out of service.

Trips are indicated and identified down to the channel level.

7.2.1.10 Vital Protective Functions and Functional Requirements

The Reactor Protection System in conjunction with inherent plant characteristics is designed to prevent anticipated abnormal conditions from exceeding limits established in Chapters 3 and 4.

Completion of Protective Action (Interlock)

Where operating requirements necessitate automatic or manual bypass of a protective function, the design is such that the bypass is removed automatically whenever permissive conditions are not met. Devices used to achieve automatic removal of the bypass of a protective function are part of the protective system and are designed in accordance with the criteria of this section.

The protective systems are so designed that, once initiated, a protective action goes to completion. Return to normal operation requires action by the operator.

Multiple Trip Settings

For monitoring nuclear flux, multiple trip settings are used. When a more restrictive trip setting becomes necessary to provide adequate protection for a particular mode of operation or set of operating conditions, the protective system as designed provides positive assurance that the more restrictive trip setting is used. The devices used to prevent improper use of less restrictive trip settings are considered a part of the protective system and are designed in accordance with the criteria presented in this section.

Protective Actions

The Reactor Trip System automatically trips the reactor. Trip limits for these conditions are established during the final design.

For anticipated abnormal conditions, protective systems, in conjunction with inherent characteristics and engineered safeguards, are designed to assure that limits for energy release to the containment and for radiation exposure (as in 10CFR100) are not exceeded.

Indication

Transmitted analog signals (flow, pressure, temperature, etc.) which can lead to a reactor trip are either indicated or recorded for every channel.

All nuclear flux power range currents (top detector, bottom detector and algebraic difference and average of bottom and top detector currents) are indicated and/or recorded.

Alarms and Annunciators

Alarms and annunciators are also used to alert the operator of deviations from normal operating conditions so that he may take corrective action to avoid a reactor trip. Further, actuation of any abnormal rod stop or trip of any reactor trip channel will actuate an alarm.

Alarms and/or annunciators also alert the operator when a protection channel is placed in the test condition. There is no audible or visual alarm associated with the reactor nuclear instrumentation system panel doors. Improper opening of these doors is prevented by administrative control. Interlocks are provided on the doors of each of the process control analog racks, in all four protection sets, which actuate an alarm in the control room if any door in any protection set is opened.

7.2.1.11 Operating Environment

The protective channels are designed to perform their functions when subjected to adverse environmental conditions. See Section 7.3.1.2.2 for those portions of the protective system that must operate in a post-accident environment.

7.2.2 DESIGN BASIS INFORMATION

7.2.2.1 Separation of Redundant Instrumentation and Controls

The Reactor Protection System uses four separate and independent channels of instrumentation to provide inputs to two separate logic systems. The design of the Reactor Protection System incorporates physical and electrical separation of the four channels from the sensing element to the logic systems. The logic systems outputs are also separated to preserve the independence of redundant functions.

Redundant instrumentation and control cables are routed through separate containment penetrations to maintain independence.

The four independent channel signals are wired to four separate sets of analog protection racks located in the vicinity of the plant control room. These racks contain the isolation amplifiers which reproduce the sensed signal for use in the plant process control systems.

7.2.2.2 Design Basis for Protection Circuits

Both reactor trip and Engineered Safety Features actuation functions are performed by the solid state protection system. Non-protective control type functions are also provided of which several can be classified as equipment protection.

The two redundant reactor trip logic channels are physically separated and electrically isolated from one another. The Reactor Protection System is comprised of identifiable channels which are physically, electrically and functionally separated and isolated from one another. For additional information of this topic, see Reference 3.

The a-c power feeds to the Solid State Logic System are in accordance with the split-bus concept shown on Figure 22 of WCAP-7488-L. The only exception to the system depicted in Figure 22 is that the Salem design uses vital instrument Bus II to supply the a-c power to the Train B output relays and Bus IV (instead of Bus II) to provide one-half of the Train A DC logic power and Bus II (instead of Bus IV) to provide one-half of the Train B DC logic power. Refer to Figure 8.3-5 for the 115V system.

The electrical supply and control conductors for redundant or back-up circuits of the plant have such physical separation as is required to assure that no single credible event will prevent operation of the associated function by reason of electrical conductor damage. Critical circuits and functions include power, control and analog instrumentation associated with the operation of reactor protection, engineered safeguards, reactor shutdown and Residual Heat Removal Systems. Credible events include, but are not limited to, the effects of short circuits, pipe rupture, missiles, etc.

General

1. Cables of redundant or backup circuits are run in separate conduits, cable trays, ducts, penetrations, etc.

2. Control and instrumentation cables are not placed in trays with cables operating above 250 volts.

3. Low level instrumentation cables are not routed in cable trays containing power or control cables unless a barrier is provided. Instrumentation cables are shielded.

4. Cables are clearly identified at the terminations as being safety-related and to what separation group they belong.

Specific Systems

1. Reactor Trip System

   a. Separate routing is maintained for the four basic protection channel analog sensing signals, bistable output signals and power supplies for such systems.

   b. Separate routing of the two reactor trip trains (logic matrix outputs) is maintained.

2. Engineered Safeguards System

   a. Separate routing is maintained for the four basic safeguards analog sensing signals, bistable output signals and power supplies for such systems.

   b. Separate routing is also provided for the automatic actuation, control and power circuits to retain the redundancy of the multiple "train" concept provided in the system design and power supplies.

3. Shutdown Systems - Separate routing of control and power circuits associated with boric acid injection capability to retain the redundancies provided in the system design and power supplies is provided.

4. Residual Heat Removal System - Separate routing of control and power circuits associated with residual heat removal capability to retain the redundancies of system design and power supplies is provided.

5. Auxiliary Feedwater System - Separate routing of control and power circuits associated with auxiliary feedwater capability to retain the redundancies of system design and power supplies is provided.

6. Reactor Protection System analog circuits, Paragraph 1. (a), and engineered safeguards system analog circuits, Paragraph 2. (a), may be routed in the same wireways provided circuits have the same characteristics such as power supply and channel set identity (I, II, III or IV).

7. Power and control conductors for the engineered safeguards systems, Paragraph 2. (b); Shutdown Systems, Paragraph 3.; Residual Heat Removal System, Paragraph 4.; and Auxiliary Feedwater System, Paragraph 5., may be routed in the same wireways provided circuits have the same characteristics, such as train or power supply.

Power Sources

These separation criteria also apply to the power supplies to the separate load centers and buses distributing power to redundant components and to the control of these supplies.

Protective System Independence

The protective system is designed to be independent of the status of the control system, plant data logging computer, indicators, recorders, and plant annunciators. However, these systems and monitors derive signals from the protective systems through isolation amplifiers which are part of the protective systems. The isolation amplifiers prevent any perturbation of the protection signal (input) due to disturbances of the isolated signal (output) which could occur near any termination of the output wiring external to the protection and safeguards racks. A detailed discussion of the isolation amplifier is given in References 4 and 5.

Reactor Trip Signal Testing

Provisions are made, for process variables, to manually place the output of the bistable in a tripped condition if required for "at power" testing. Except as noted below, administrative procedure requires that the final element in a trip channel (required during power operation) is placed in the trip mode before that channel is taken out of service for repair or testing, if required, so that the single failure criterion is met by the remaining channels.

In the source and intermediate ranges, where the trip logic is one-out-of-two for each range, bypasses are provided for this testing procedure.

Nuclear instrument power range channels are tested by superimposing a test signal on the sensor signal so that the reactor trip protection is not bypasses. Based upon coincident logic (2/4) this will not trip the reactor; however, a trip will occur if a reactor trip is required.

Containment spray actuation channels are tested by bypassing or negating the channel under test. This is acceptable since there are 4 channels, and the two-out-of-four trip logic reduces to two-out-of-three during the test.

Provision is made for the insertion of test signals in each analog loop. Verification of the test signal is made by portable instruments at test points specifically provided for this purpose. This enables testing and calibration of meters and bistables. Transmitters and sensors are checked against each other and against plant read-out equipment when required during normal power operation.

All analog signals which are used to initiate reactor trip or engineered safeguards are indicated or recorded on devices which are not dependent upon the plant computer. In addition, a plant computer program monitors various signals which are derived from process variables used as inputs to the protection system. The computer inputs are isolated from the protection system channels.

A manual trip signal is initiated by the control room operator depressing either one of two pushbuttons. Since either button will actuate both Train A and Train B logic, the manual trip is not testable at power.

7.2.2.3 Reactor Protection Systems Testing

Process Analog Protection Channel Testing

For a description of the overlap between the typical analog channel and the corresponding logic circuits, see Reference 3.

Each protection rack includes a test panel containing those switches, test jacks and related equipment needed to test the channels contained in the rack. A hinged cover encloses a portion of the test panel. Opening the cover or placing the test-operate switch in the "TEST" position automatically initiates an alarm. These alarms are arranged in rack "sets":. The test panel cover is designed such that it cannot be closed (and the alarm cleared) unless the test signal plugs (described below) are removed. Closing the test panel cover mechanically returns the test switched to the "OPERATE" Position.

Test procedures will require the bistable output relays of the channel under test to be placed in the tripped mode prior to proceeding with the analog channel tests. Placing the bistable trip switch in the tripped mode transfers the bistable output from the logic circuitry and connects it to a proving lamp. This permits the electrical operation of the bistable to be observed and the bistable set point relative to the channel analog signal to be verified. Upon completion of the test of the analog channel, the bistable trip switches must be manually reset to their operate mode. Closing the cover of the test panel will not transfer the bistable trip switches from their tripped to their operate position.

Analog channel tests will be accomplished by simulating a process measurement signal, varying the simulated signal over its signal span and checking the correlation of bistable set points, channel readouts and other loop elements with precision portable read-out equipment. Test jacks are provided in the test panel for injection of the simulated process signal into each process analog protection channel. Test points are provided in the channel to facilitate an independent means for precision measurement and correlation of the test signal. This procedure does not require any tool (other than test instruments) nor does it involve in any way the removal of wires in the channel under test. In general, the analog channel circuits are arranged so the channel power supply is loaded and is providing sensing circuit power during channel test. Load capability of the channel power supply is thereby verified by the channel test.

Nuclear Instrumentation Channel Testing

Nuclear Instrumentation System channels are tested by superimposing the test signal on the actual detector signal being received by the channel. The output of the bistable is not placed in a tripped condition prior to testing. A valid trip signal would then be added to the existing test signal, and thereby cause channel trip at a somewhat lower percent of actual reactor power. Protection bistable operation is tested by increasing the test signal (level signal) to the bistable trip level and verifying operation at control board alarms and/or at the Nuclear Instrumentation System racks.

An Nuclear Instrumentation System channel which can cause a reactor trip through 1 of 2 protection logic (source or intermediate range) is provided with a bypass function which prevents the initiation of a reactor trip from that particular channel during the short period that it is undergoing test. The power range channels do not require bypass of the reactor trip function for test, since the protection logic is 2 of 4. The power range trips will be active if required. No provision has been made in the channel test circuit for reducing the channel signal level below that signal being received from the Nuclear Instrumentation System detector.

Logic Channel Testing

The Solid State Protection System logic is designed to be capable of testing at power (Reference 3).

Reactor trip breaker testing is accomplished as follows: normally, reactor trip breakers 52/RTA and 52/RTB are in service, and bypass breakers 52/BYA and 52/BYB are (withdrawn) out of service. To test reactor trip breaker 52/RTA, as an example, the following is done.

1. Bypass breaker BYA is put into service.

   This act closes switchgear relay 52/BYA. It also interrupts one of the two signals to the Train A "and box" which is necessary to actuate subsequent logic causing turbine trip, feedwater isolation, and Safety Injection block logic.

2. A simulated trip signal is then applied to Train A only.

   This act deenergizes undervoltage coil 52 (UV)/RTA and the automatic shunt trip interposing relay which operates reactor trip breaker 52/RTA. Test pushbuttons are installed to determine and verify that each breaker tripping device (shunt coil, undervoltage coil) operated properly.

The reactor is not tripped because the control rods continue to receive rod drive bus power via switchgear 52/BYA and 52/RTB.

In the event that a real trip signal occurs during the testing of 52/RTA trip breaker, Train B will actuate the reactor trip and the logic following the Train B "and box".

Auxiliary contacts on the bypass breakers are connected into the alarm system of their respective train such that if either train is placed in test while the bypass breaker of the other train is closed, both reactor trip breaker and the bypass breaker will be automatically tripped by the General Warning Alarm circuits of the Solid State Protection System. The General Warning Alarm System is described in Reference 3.

7.2.2.4 Primary Power Source

The primary power sources for the Reactor Protection System are described in Chapter 8. The source of electrical power for the measuring elements and the actuation of circuits in the Engineered Safety Features instrumentation is also from these buses.

7.2.2.5 Protective Actions

Reactor Trip Description

Rapid reactivity shutdown is provided by the insertion of rod cluster control assemblies by free fall. Duplicate series-connected circuit breakers supply all power to the control rod drive mechanisms. The rods must be energized to remain withdrawn from the core. Automatic control rod insertion occurs upon the loss of power to the control rods. The trip breakers are opened by the undervoltage coils and shunt trip coils on both breakers. The undervoltage coils which are normally energized become deenergized by any one of the several trip signals. The shunt trip coil is energized by an interposing relay which is installed in parallel with the undervoltage coils.

The design of the device providing signals to the circuit breaker undervoltage trip coils is such as to cause these coils to trip the breaker on reactor trip signal.

Certain reactor trip channels are automatically bypassed at low power where they are not required for safety. Nuclear source range and intermediate range trips are specifically provided for protection at low power or subcritical operation, and at higher power operations they are bypassed by manual action in conjunction with permissives.

During power operation, a sufficient amount of rapid shutdown capability in the form of shutdown control rods is administratively maintained by means of the control rod insertion limit monitors. Administrative control requires that all shutdown group rods be in the fully withdrawn position during power operation.

A listing of reactor trips, means of actuation and the coincident logic requirements may be found in Table 7.2-1 with references to interlocks as listed in Table 7.2-2.

Manual Trip

The manual actuating devices are independent of the automatic trip circuitry, and are not subject to failures which make the automatic circuitry inoperable. Actuating either of two manual trip switches located in the control room initiates a reactor trip and a turbine trip.

High Neutron Flux (Power Range) Trips

These circuits trip the reactor when two out of the four power range channels read above the trip set-point. There are two independent trip settings, a high and a low setting. The high trip setting provides protection during normal power operation. The low setting, which provides protection during start-up, can be manually bypassed when two out of the four power range channels read above approximately 10 percent of full power (P-10). Three-out-of-the-four channels below 10 percent power automatically reinstates the trip function. The high setting is always active.

High Neutron Flux (Intermediate Range) Trip

This circuit trips the reactor when one out of the two intermediate range channels reads above the trip set-point. This trip, which provides protection during reactor start-up, can be manually bypassed if two out of four power range channels are above approximately 10 percnt of full power (P-10). Three-out-of-four channels below this value automatically reinstates the trip function. The intermediate channels (including detectors) are separate from the power range channels.

High Neutron Flux (Source Range) Trip

This circuit trips the reactor when one of the two source range channels reads above the trip set-point. This trip, which provides protection during reactor start-up, can be manually bypassed when one of two intermediate range channels reads above the P-6 set-point value and is automatically reinstated when both intermediate range channels decrease below this value (P-6). This trip is automatically bypassed by two out of four high power range signals (P-10). The trip function can also be reinstated below P-10 by an administrative action requiring coincident manual actuation. The trip point is set between the source range cutoff power level and the maximum source range power level.

Overtemperature ΔT Trip

The purpose of this trip is to protect the core against departure from nucleate boiling (DNB). This trips the reactor on coincidence of two-out-of-the-four signals, with one set of temperature measurements per loop. The set-point for this reactor trip is continuously calculated for each loop by solving the following equation:

$$\Delta T_{setpoint} = K_1 - K_2 \left[\frac{1 + \tau_1 s}{1 + \tau_2 s}\right] T_{avg} + K_3 P - f\,(\Delta \phi)$$

Where

T_{avg} = average reactor coolant temperature (F)

P = Pressurizer pressure (psig)

K_1 = set point bias (F)

K_2, K_3 = constants based on the effect of temperature and pressure on the DNB limits, (F/F, F/psig).

f(Δ.) = a function of the flux diference between upper and lower long ion chamber sections (F). (See Figure 7.2-3)

$\tau_1 \tau_2$ = lead-lag time constants (sec^{-1})

s = Laplace transform variable

The four long ion chamber units separately feed each overtemperature %T trip channel. Thus, a single failure neither defeats the function nor causes a spurious trip. Changes in f ($\Delta\phi$) can only lead to a decrease in trip setpoint.

Initiation of automatic turbine load runback by means of an overtemperature ΔT signal is discussed later.

<u>Power Range High Positive Neutron Flux Rate Trip</u>

This circuit trips the reactor when an abnormal rate of increase in nuclear power occurs in 2 out of 4 power range channels. This trip provides protection against rod ejection accidents of low worth from mid-power and is always active.

<u>Power Range High Negative Neutron Flux Rate Trip</u>

This circuit trips the reactor when an abnormal rate of decrease in nuclear power occurs in 2 out of 4 power range channels. This trip provides protection against two or more dropped rods and is always active.

<u>Overpower ΔT Trip</u>

The purpose of this trip is to protect against excessive power (fuel rod rating protection). This trips the reactor on coincidence of two out of the four signals, with one set of temperature measurements per loop.

The set point for this reactor trip is continuously calculated for each channel by solving equations of the form:

$$\Delta T_{setpoint} = K_4 - \left[K_5 \frac{\tau_3 s}{\tau_3 s = 1} T_{avg} \right] + \left[K_6 \left(T_{avg_0} - T_{avg} \right) \right] - f(\Delta\phi)$$

Where

$f(\Delta\phi)$ = is a function of flux difference between upper and lower ion chamber section (F) (See Figure 7.2-3)

K_4 = a preset manually adjustable bias (F)

K_5, K_6 = constants relating the effect of T_{avg} and rate of change of T_{avg} on overpower limit

T_{avg_0} = a setpoint bias (F)

T_{avg} = average reactor coolant temperature (F)

τ_3 = rate-lag time constant, (sec^{-1})

s = Laplace transform variable

Variables in brackets are individually low limited to zero.

Initiation of automatic turbine load runback by means of an overpower ΔT signal is discussed below.

Low Pressurizer Pressure Trip

The purpose of this trip is to protect against excessive core steam voids and to limit the necessary range of protection afforded by the overtemperature ΔT trip. This trips the reactor on coincidence of two out of the four low pressurizer pressure signals. This trip is blocked when three of the four power range channels and two of two turbine first stage pressure channels read below approximately 10 percent power (P-7). Each channel is lead-lag compensated.

High Pressurizer Pressure Trip

The purpose of this trip is to limit the range of required protection from the overtemperature ΔT trip and to protect against Reactor Coolant System overpressure. The reactor is tripped on coincidence of two out of the four high pressurizer pressure signals.

High Pressurizer Water Level Trip

This trip is provided as a backup to the high pressurizer pressure trip. The coincidence of two out of the three high pressurizer water level signals trips the reactor. This trip is blocked when three of the four power range channels and two of the two turbine first stage pressure channels read below approximately 10 percent power (P-7).

Low Reactor Coolant Flow Trip

This trip protects the core from DNB following a loss-of-coolant flow. The means of sensing loss-of-coolant flow are described below:

1. Low Primary Coolant Flow Trip

   A loop low flow signal is generated by 2 out of 3 low flow signals per loop. Above the P-7 setpoint (approximately 10 percent of full power) low flow in any two loops results in a reactor trip. Above the P-8 setpoint (approximately 60 percent of full power) low flow in any loop results in a reactor trip.

2. Reactor Coolant Pump Breaker Position Trip

   One open breaker signal is generated for each reactor coolant pump. Above the P-7 setpoint the reactor trips on two open breaker signals. Above the P-8 setpoint the reactor trips on one open breaker signal.

3. Reactor Coolant Pump Undervoltage and Underfrequency Trips

   There is one underfrequency and one undervoltage sensor per bus. A 1/2 taken twice underfrequency signal-directly trips all of the reactor coolant pumps, and also produces a direct reactor trip (interlocked by P-7). (An indirect trip is produced by the pump breaker-position trip.) For undervoltage protection, there is an undervoltage sensor on each of the four busses. Reactor trip above P-7 is actuated by a 1/2 logic taken twice.

All of these low reactor coolant flow trips are blocked below the P-7 setpoint (approximately 10 percent power).

<u>Safety Injection System Actuation Trip</u>

A reactor trip occurs when the safety injection system is actuated. The means of actuating the Safety Injection System trips are:

1. Low pressurizer pressure (2/3 pressure signals). Manual block is permitted by 2/3 low pressurizer pressure.

2. High containment pressure (2/3)

3. Two of three low steam line pressure of one line compared to other three lines. (High Differential Pressure)

4. High steam flow in two of four lines (1/2 measurements per line) (2/4 lines) in coincidence with low T_{avg} (2/4) or low steam line pressure (2/4).

5. Manual (1/2).

These trips are listed in Table 7.2-1.

Reactor Trip on Turbine Generator Trip (Anticipatory)

A turbine trip is sensed by two out of three signals from low autostop oil pressure or all stop valves closed signals. A turbine trip causes a direct reactor trip above approximately 10 percent power (P-7) and results in a controlled short term release of steam to the condenser which removes sensible heat from the Reactor Coolant System and thereby avoids steam generator safety valve actuation. This reactor trip is anticipatory and included as part of good engineering practice and prudent design. No credit is taken in any of the safety analyses for this trip.

The turbine control system automatically trips the turbine generator under any of the conditions listed in Section 10.2.2.2.

Low Feedwater Flow Trip

This trip protects the reactor from a loss of its heat sink. The trip is actuated by a steam/feedwater flow mismatch (1/2) in coincidence with low water level (1/2) in any steam generator.

Low-Low Steam Generator Water Level Trip

The purpose of this trip is to prevent a loss of the reactor's heat sink in the case of a sustained steam/feedwater flow mismatch of insufficient magnitude to cause a low feedwater flow reactor trip. The trip is actuated on two out of the three (2/3) low-low water level signals in any steam generator.

7.2.2.6 Reactor Coolant Flow Measurement

Elbow taps are used on each of the four loops in the primary coolant system as an instrument device that indicates the status of the reactor coolant flow. The basic function of this device is to provide information as to whether or not a reduction in flow rate has occurred. The correlation between flow reduction and elbow tap read-out has been well established by the following equation: $\frac{\Delta P}{\Delta P_0} = (\frac{\omega}{\omega_0})^2$, where ΔP_0 is the referenced pressure differential with the corresponding referenced flow rate ω_0 and ΔP is the pressure differential with the corresponding referenced flow rate ω. The full flow reference point is established during initial plant startup. The low flow trip point is then established by extrapolating along the correlation curve. The technique has been well established in providing core portection against low coolant flow in Westinghouse PWR plants. The expected absolute accuracy of the channel is within $\pm$ 10 percent and field results have shown the repeatability of the trip point to be within $\pm$ 1 percent. The analysis of the loss of flow transient presented in Chapter 15 assumes instrumentation error of $\pm$ 3 percent.

7.2.3 SYSTEM EVALUATION

7.2.3.1 Reactor Protection System and DNB

The following is a description of how the Reactor Protection System prevents DNB.

The plant variables affecting the DNB ratio are:

1. Thermal power
2. Coolant flow
3. Coolant temperature
4. Coolant pressure
5. Core power distribution

Figure 7.2-1 illustrates the core limits for which DNBR for the hottest fuel rod is 1.3 and shows the overpower and overtemperature ΔT reactor trips locus as a function of T_{avg} and pressure. This illustration is derived from the inlet temperature versus power relationships.

Reactor trips for a fixed high pressurizer pressure and for a fixed low pressurizer pressure are provided to limit the pressure range over which core protection depends on the overpower and overtemperature ΔT trips.

Reactor trips on nuclear overpower and low reactor coolant flow are provided for direct, immediate protection against rapid changes in these parameters. However for all cases in which the calculated DNBR approaches 1.3, a reactor trip on overpower and/or overtemperature ΔT would also be actuated.

For the postulated abnormal conditions, the exact combination of conditions (reactor coolant pressure, temperature and core power, instrumentation inaccuracies, etc.) will not cause a DNBR to go below 1.30 before a reactor trip. The simultaneous loss of power to all of the reactor coolant pumps is the accident condition most likely to approach a DNBR of 1.30 for the calculated worst fuel rod. In any event the DNBR is near 1.30 for only a few seconds.

The ΔT trip functions are based on the differences between measured hot leg and cold leg temperatures. These differences are proportional to core power.

The ΔT trip functions are provided with a nuclear differential flux feedback to reflect a measure of axial power distribution. This will assist in preventing an adverse axial distribution which could lead to exceeding the allowable core conditions.

In the event of a difference between the upper and lower ion chamber signals that exceeds the desired range, automatic feedback signals are provided to reduce the overpower-overtemperature trip setpoints, which in turn block rod withdrawal and reduce the load to maintain appropriate operating margins.

7.2.3.2 Specific Control and Protection Interactions

Nuclear Flux

Four power-range nuclear flux channels are provided for overpower protection. Isolated outputs from all four channels are auctioneered for automatic rod control. If any channel fails in such a way as to produce a low output, that channel is incapable of proper overpower protection. In principle, the same failure may cause rod withdrawal and hence, overpower. Two out of four overpower trip logic will ensure an overpower trip if needed even with an independent failure in another channel.

In addition, the control system will respond only to rapid changes in indicated nuclear flux; slow changes or drifts are compensated by the temperature control signals. Finally, an overpower signal from any nuclear channel will block automatic rod withdrawal. The set point for this rod stop is below the reactor trip set point.

Coolant Temperature

One hot leg and one cold leg temperature measurement is made for each reactor coolant loop to provide protection. In addition, by use of isolation amplifiers located in the protection rack, the temperature difference measurements for each loop are used for protection with one channel per loop and 2/4 reactor trip logic. The reactor control system uses the highest of the four isolated T_{avg} temperature signals.

The hot and cold leg Resistance Temperature Detectors (RTD's) are inserted into reactor coolant bypass loops - a bypass loop from upstream of the steam generator to downstream of the steam generator is used for the hot leg RTD's and a bypass loop from downstream of the reactor coolant pump to upstream of the pump is used for the cold leg RTD's. The RTD's are located in manifolds within the containment and are directly inserted into the reactor coolant bypass loop flow without thermowells. Thermowells are not used in order to keep the detector thermal lag small. The bypass arrangement permits replacement of defective temperature elements while the plant is at hot shutdown without draining or depressurizing the reactor coolant loops.

Three sampling probes are installed in a cross-sectional plane of each hot leg at approximately 120 degree intervals. Each of the sampling probes, which extends several inches into the hot leg coolant stream, contains five inlet orifices distributed along its length. In this way a total of fifteen locations in the hot leg stream are sampled providing a representative coolant temperature measurement. The two inch diameter pipe leading to the manifold containing the temperature measuring elements (RTD's) provides mixing of the samples to give an accurate temperature measurement.

Care has been taken to distribute the flow evenly among the five orifices of each probe by effectively restricting the flow through the orifices. This has been done by designing a smaller overall orifice flow area than that of the common flow channel within the probe. This arrangement has also been applied to the flow transition from the three probe flow channels to the pipe leading to the temperature element manifold. The total flow area of the three probe channels has therefore been designed to be less than that of the 2" pipe connecting the probes to the manifold.

The cold leg primary coolant flow is well mixed by the reactor coolant pump. Therefore, the cold leg sample is taken directly from an ordinary two inch pipe tap off the cold leg downstream of the pump.

The main requirment for reactor protection is that the temperature difference between the hot leg and cold leg vary linearly with power. All ΔT setpoints are in terms of the full power ΔT; thus, absolute ΔT measurements are not required. Linearity of ΔT with power will be verified during startup tests.

Reactor protection logic using reactor coolant loop temperatures is 2/4 with one channel per reactor coolant loop. This complies with all applicable IEEE 279 criteria.

Reactor control is based upon signals derived from protection system channels after isolation by isolation amplifiers such that no feedback effect can perturb the protection channels.

Since control is based on the highest average temperature from the four loops, the control rods are always moved based upon the most pessimistic temperature measurement with respect to margins to DNB. A spurious low average temperature measurment from any loop temperature control channel will cause no control action. A spurious high average temperature measurement will cause rod insertion (safe direction).

Individual low flow alarms with individual status lights for each reactor coolant loop bypass flow is provided on the main control board. The alarm and status lights provide the operator with immediate indication of a low flow condition in the bypass loops associated with any reactor coolant loop.

Local indicators are provided to monitor total flow through the RTD bypass manifolds for each loop. The indicators are located inside containment but are accessible during power operations.

Flow will be monitored:

1. Prior to restoring temperature channels to normal service following reopening of bypass loop isolation valves whenever a bypass loop has been out of service.

2. On a periodic basis.

3. Following any bypass loop low flow alarm (see above).

In addition, channel deviation signals in the control system will give an alarm if any temperature channel deviates significantly from the auctioneered (highest). Automatic rod withdrawal blocks will also occur if any one of four nuclear channels indicates an overpower condition or if any two of four temperature channels indicate an overtemperature or overpower condition. Two-out-of-four (2/4) trip logic is used to ensure that an overtemperature or overpower ΔT trip will occur if needed even with an independent failure in another channel. Finally, as shown in Section 15.1, the combination of trips on nuclear overpower, and high pressurizer pressure also serve to limit an excursion for any rate of reactivity insertion.

For operation with a loop out of service only one safety related setpoint must be manually reset to a more restrictive value. The setpoint involved is the overtemperature ΔT reactor trip. The setpoint change must be made to one protection channel for each of the operating loops.

If the overtemperature ΔT setpoints can be reset (lowered) before turning off one pump, the setpoint should be reset during operation with all loops in service. If the overtemperature ΔT setpoints cannot be reset without causing a reactor trip before turning off one pump, reactor power should be reduced below the setpoint of P-8, the affected pump turned off, and the setpoints reset. Any time one pump is turned off or trips off when above P-8, an automatic reactor trip will occur.

The P-8 acts essentially as a high neutron flux reactor trip when operating with one loop not in service.

The P-8 setpoint will normally be set in such a way that the DNBR is above 1.30 (for anticipated transients) even without resetting the overtemperature ΔT trips to the values appropriate for operation with a loop out of service. Setting P-8 in this way restricts the operating power level with a loop out of service to a value considerably lower than that which can be safely allowed after resetting the overtemperature ΔT setpoints. After the overtemperature ΔT setpoints have been reduced to the values required for operation with a loop out of service, the P-8 setpoint will be increased to the maximum value allowed consistent with maintaining the DNBR above 1.30 during all anticipated transients.

Setpoints appropriate for operation with one loop out of service has been included in the Technical Specifications. The resetting of the ΔT trip will be carried out under prescribed administrative procedures and only under the direction of authorized supervision.

Pressurizer Pressure

The four pressurizer pressure protection channel signals are used for high and low pressure protection and as inputs to the overtemperature ΔT trip protection function (See Fig. 7.2-4). Isolated output signals from these channels are used for pressure control. These are used to control pressurizer spray and heaters and power operated relief valves. Pressurizer pressure is sensed by fast response pressure transmitters with a time response of better than 0.2 seconds. A one second response time is used which is more than adequate to cover the response characteristics of the tripping channels.

A spurious high pressure signal from one channel can cause low pressure by actuation of either spray or a relief valve. Additional redundancy is provided in the protection system to ensure low pressure protection, i.e., two-out-of-four low pressure reactor trip logic and two out of three logic for safety injection.

The pressurizer heaters are incapable of overpressurizing the Reactor Coolant System. Maximum steam generation rate with heaters is about 15,000 lb/hr, compared with a total capacity of 1,260,000 lb/hr for the three safety valves and a total capacity of 420,000 lb/hr for the two power-operated relief valves. Therefore, overpressure protection is not required for a pressure control failure; however, two out of four high pressure trip logic is used.

In addition, either of the two relief valves can easily maintain pressure below the high pressure trip point. The two relief valves are controlled by independent pressure channels, one of which is independent of the pressure channel used for heater control. Finally, the rate of pressure rise achievable with heaters is slow, and ample time and pressure alarms are available for operator action.

Pressurizer Level

Three pressurizer level channels are used for reactor trip (2/3 high level). Isolated signals from these channels are used for pressurizer water level control, increasing or decreasing the pressurizer water level as required. A failure in the level control system could fill or empty the pressurizer at a slow rate (on the order of half an hour or more). (See Figure 7.2-5).

The design of the pressurizer water level instrumentation is a slight modification of the usual tank level arrangement using differential pressure between an upper and a lower tap. (See Figure 7.2-6). The modification consists of the use of a sealed reference leg instead of the conventional open column of water.

Experience has shown that hydrogen gas can accumulate in the upper part of the condensate pot on conventional open reference leg systems in pressurizer water level service. At Reactor Coolant System operating pressures, high concentrations of dissolved hydrogen in the reference leg water are possible. On sudden depressurization accidents, it has been hypothesized that rapid effervescence of the dissolved hydrogen could blow water out of the reference leg and cause a large level error, measuring higher than actual level. To eliminate the possibility of such effects, a bellows is used in a pot at the top of the reference leg to provide an interface seal and prevent dissolving of hydrogen gas into the reference leg water.

The reference leg is uninsulated and will remain at local ambient temperature. This temperature will vary somewhat over the length of the reference leg piping under normal operating conditions but will not exceed approximately 140°F. During a blowdown accident, any reference leg water flashing to steam will be confined to the condensate steam interface in the condensate pot at the top of the temperature barrier leg and will have only a small (about one inch) effect on measured level. Some additional error may be expected due to effervescence of hydrogen in the temperature barrier water. However, even if complete loss of this water is assumed, the error will be less than one foot and can be tolerated.

The first pressurizer level channel utilizing the sealed reference leg was installed and checked at the R. E. Ginna plant in March, 1970. Operational accuracy has been verified by long term use of the sealed reference leg system in parallel with on open reference leg channel. No effects of operating pressure variation on either the accuracy or integrity of the channel have been observed.

Calibration of the sealed reference leg system is done in place after installation by application of known pressure to the low pressure side of the transmitter and measurement of the height of the reference column. The effects of static pressure variations are predictable. The largest effect is due to the density change in the saturated fluid in the pressurizer itself. The effect is typical of level measurements in all tanks with two phase fluid and is not particuliar to the sealed reference leg technique. In the sealed reference leg, there is a slight compression of the fill water with increasing pressure, but this is taken up by the flexible bellows. A leak of the fill water in the sealed reference leg can be detected by comparison of redundant channel readings on line and by physical inspection of the reference leg off line with the channel out of service. Leaks of the reference leg to atmosphere will be immediately detectable by off-scale indications on the control board. Further detection of leakage is provided by the plant computer alarms for deviation between redundant channels.

High Level

A reactor trip on pressurizer high level is provided to prevent filling the pressurizer in the event of a rapid thermal expansion of the reactor coolant. A rapid change from high rates of steam relief to water relief could be damaging to the safety valves, relief piping, and pressure relief tank. However, a level control failure cannot actuate the safety valves because the high pressure reactor trip is set below the safety valve set pressure. With the slow rate of charging available, overshoot in pressure before the trip is effective is much less than the difference between reactor trip and safety valve set pressures. Therefore, a control failure does not require protection system action. In addition, ample time and alarms are available for operator action.

Low Level

For control failures which tend to empty the pressurizer, ample time and alarms exist for operator action.

Steam Generator Water Level; Feedwater Flow

Before describing control and protection interaction for these channels, it is beneficial to review the protection system basis for this instrumentation. (See Figure 7.2-7).

The basic function of the reactor protection circuits associated with low steam generator water level and low feedwater flow is to preserve the steam generator heat sink for removal of long term residual heat. Should a complete loss of feedwater occur with no protective action, the steam generators would boil dry and cause an overtemperature-overpressure excursion in the reactor coolant. Reactor trips on temperature and pressure will trip the unit before there is any damage to the core or Reactor Coolant System. Redundant auxiliary feedwater pumps are provided to prevent residual heat after trip from causing thermal expansion and discharge of the reactor coolant through the pressurizer relief valves. Reactor trips act before the steam generators are dry to reduce the required capacity and starting time requirements of these pumps and to minimize the thermal transient on the Reactor Coolant System and steam generators. Independent trip circuits are provided for each steam generator for the following reason:

> Should severe mechanical damage occur to the feedwater line to one steam generator, it is difficult to ensure the functional integrity of level and flow instrumentation for that unit. For instance, a major pipe break between the feedwater flow element and the steam generator would cause high flow through the flow element. The rapid depressurization of the steam generator would drastically affect the relation between downcomer water level and steam generator water inventory.

A spurious high signal from the feedwater flow channel being used for control would cause a reduction in feedwater flow and prevent that channel from tripping. A reactor trip on low-low water level, independent of indicated feedwater flow, will ensure a reactor trip if needed.

In addition, the three-element feedwater controller incorporates reset on level, such that with expected controller settings a rapid increase in the flow signal would cause only a small decrease in level before the controller reopened the feedwater valve. A slow increase in the feedwater signal would have no effect at all.

A spurious low steam flow signal would have the same effect as a high feedwater signal, discussed above.

A spurious high water level signal from the protection channel used for control will tend to close the feedwater valve. This level channel is independent of the level and flow channels used for reactor trip on low flow coincident with low level.

1. A rapid increase in the level signal will completely stop feedwater flow and lead to an actuation of a reactor trip on low feedwater flow coincident with low level.

2. A slow drift in the level signal may not actuate a low feedwater signal. Since the level decrease is slow, the operator has time to respond to low level alarms. Since only one steam generator is affected, automatic protection is not mandatory and reactor trip on two out of three low-low level is acceptable.

Steam Line Pressure

Three pressure channels per steam line are used for steam line break protection. These are combined with other signals as shown in Table 7.2-1. 2/4 high steam flow in coincidence with 2/4 low T_{avg} or 2/4 low steam line pressure will actuate safety injection.

7.2.3.3 Reactor Trip Breakers

Trip Breaker failure in Unit 1 occurred on February 22 and 25, 1983. Following these events a comprehensive corrective action plan was developed by PSEG and submitted to the NRC by letters dated April 8 and 28, 1983 (Uderitz to Eisenhut). PSEG subsequently engaged the BETA Corporation to review the corrective action plan. BETA's report[6] and findings were submitted to the NRC by letter dated May 31, 1983 (Uderitz to Eisenhut). In response to the Unit 1 event, the NRC issued Generic Letter 83-28 addressing a number of broad implications. In addition to information in the corrective action plan, PSEG responded specifically to Generic Letter 83-28 by letters dated July 22, 1983 and November 7, 1983 (both Liden to Varga). Subjects discussed in these documents which are reflected in other sections of the FSAR are as follows:

Vendor Manuals	13.5.4
Preventive Maintenance	13.5.4
Safety Review Group	13.4.4
Nuclear Oversight Committee	13.4.3
Master Equipment List	17.2.2
Procurement Document Control	17.2.4

7.2.3.4 Tests and Inspections

A plan for periodic component and system testing and material examinations was prepared for use throughout plant life. Requirements for inspection and testing of reactor trip and bypass breakers are outlined in correspondence from R. A. Uderitz to D. G. Eisenhut dated March 14, 1983, April 8, 1983, April 28, 1983, and May 31, 1983.

REFERENCES FOR SECTION 7.2

1. Burnett, T. W. T., "Reactor Protection System Diversity in Westinghouse PWR's," WCAP-7306, April, 1969.

2. Lipchak, J. B., Stokes, R. A., "Nuclear Instrumentation System," WCAP-7380-L (Proprietary), December, 1970 and WCAP- 7669 (Non-Proprietary), April, 1971.

3. Katz, D. N., "Solid State Logic Protection System Description," WCAP-7488-L (Proprietary), January, 1971 and WCAP- 7672 (Non-Proprietary), June, 1971.

4. "Test Report - Nuclear Instrumentation System Isolation Amplifier," WCAP-7819-R1-A, Revision 1 (Non-Proprietary), January, 1972.

5. Bruno, J., "Isolation Tests - Process Instrumentation Isolation Amplifier, Westinghouse Computer and Instrumentation Division, Model 131-110," WCAP-7509-L (Proprietary), April, 1970 and WCAP-7824 (Non-Proprietary), December, 1971.

6. Basic Energy Technology Associates (BETA), " A Review of Public Service Electric and Gas Company Corrective Action Program Related to Reactor Trip Breaker Failures at Salem Generating Station, Unit No. 1", May 27, 1983.

TABLE 7.2-1 (Sheet 1 of 5)

LIST OF REACTOR TRIPS, ENGINEERED SAFETY FEATURES, CONTAINMENT AND STEAM LINE ISOLATION AND AUXILIARY FEEDWATER

	Reactor Trip	Coincidence Circuitry and Interlocks	Comments
1.	Manual	1/2, no interlocks	
2.	High neutron flux (Power Range)	2/4, low setpoint interlocked with P-10	High and low settings; manual block and automatic reset of low setting by P-10, Table 7.2-2
3.	Overtemperature ΔT	2/4, no interlocks	
4.	Overpower ΔT	2/4, no interlocks	
5.	Low pressurizer pressure	2/4, interlocked with P-7	
6.	High pressurizer pressure	2/4, no interlocks	
7.	High pressurizer water level	2/3, interlocked with P-7	
8.	Low reactor coolant flow	2/3 signals per loop, interlocked with P-7, and P-8	Blocked below P-7. Low flow in 1 loop permitted below P-8.
9.	Monitored electrical supply to reactor coolant pumps:		
9A.	Undervoltage	1/2 taken twice, interlocked with P-7	
9B.	Underfrequency	1/2 taken twice, interlocked with P-7	1/2 twice underfrequency signals trip all reactor coolant pumps and directly actuate reactor trip: interlocked with P-7. (Opening of the coolant pump breakers will also actuate a reactor trip)
9C.	Reactor coolant pump breakers	Interlocked with P-8 and P-8	Blocked below P-7. Open breaker in 1 loop permitted below P-8.

	Reactor Trip	Coincidence Circuitry and Interlocks	Comments
10.	Safety injection signal (actuation)	Low pressurizer pressure (2/3) or 2/3 high containment pressure; or 2/3 differential steam line pressure signals of one line compared with the other three lines; or 2/4 high steam flow in coincidence with 2/4 low T_{avg} or 2/4 low steam line pressure; or manual 1/2 (See 7.2 System Description-Protective Action For Interlocks).	Trips main feedweater pumps. Closes all feedwater control valves. Closes feedwater pump discharge valves and initiates Phase A isolation. Initiates turbine trip.
11.	Turbine-generator trip	2/3 low auto stop oil pressure (interlocked with P-7) or all stop valves closed.	(Anticipatory trip of the reactor. No credit taken in accident analysis.)
12.	Low Feedwater Flow	1/2 steam/feedwater flow mismatch in coincidence with 1/2 low steam generator water level, per loop.	
13.	Low-low steam generator Water Level	2/3, per loop	
14.	Intermediate range neutron flux	1/2, manual block permitted by P-10	Manual block and automatic reset
15.	Source range neutron flux	1/2, manual block permitted by P-6, interlocked with P-10	Manual block and automatic reset
16.	High flux rate trips	2/4, no interlocks	Positive and negataive high flux rate trips provided

TABLE 7.2-1 (Sheet 3 of 5)

Containment Isolation Actuation	Coincidence Circuitry and Interlocks	Comments
17. Containment pressure (Note 1)	Coincidence of 2/3 containment high pressure or 1/2 manual	Actuates all non-essential process lines containment isolation trip valves-isolation Phase A
	Coincidence of 2/4 containment Hi-Hi pressure or 2/2 manual	Actuates all remaining trip valves (except those required for operation of engineered safeguard systems)
18. High containment activity	High activity signal, from either air particulate detector or radiogas detector, or 1/2 manual	Closes containment purge supply, exhause ducts and all others necessary to isolate containment atmosphere
Engineered Safeguards Systems Actuation		
19. Safety injection signal (S)	See Item 10	
20. Containment spray signal (P)	See second part of item 17	
21. NaOH addition	Containment Spray Actuation Signal	
Steam Lines Isolation Actuation		
22. Steam flow	High steam line flow in 2 out of 4 lines coincident with either low T_{avg} in 2 our of 4 loops or low steam pressure in 2 out of 4 lines	

TABLE 7.2-1 (Sheet 4 of 5)

Steam Lines Isolation Actuation	Coincidence Circuitry and Interlocks	Comments
22. Containment pressure (Note 1)	2/4 Hi-Hi containment pressure	
23. Manual (per steam line)	1/1 per steam line	
Auxiliary Feedwater Actuation		
24. Turbine driven pump	Coincidence of 2/3 low-low level in any two steam generators; undervoltage 1/2 twice on RCP busses; or manual (local and remote)	2/3 high level in steam generator trips main feedwater pumps
25. Motor drive pumps	2/3 low-low level in any steam generator: or trip of both main feedwater pumps, or safeguards sequence signal, or blackout sequence signal, or manual (local and remote)	Safeguards automatic loading signal blocks manual start
Main Feedwater Isolation		
26. Close main feedwater control valves (fast closure) and feedwater bypass valves and feedwater inlet stop valves	Actuated by: 1. Safety injection (see No. 10) 2. 2/3 Hi-Hi level in steam generator 3. Low actioneered T_{avg} and reactor trip	

NOTE 1: Definition of "S", "T:, and "P" signals:

Signal	Initiated by:	Action
"S"	Safety injection signal	Actuates safety injection
"T"	Safety injection signal	Actuates containment isolation Phase A (All non-essential process lines)
"P"	2/4 Hi-Hi Containment Pressure	Activates containment spray, steam lines isolation and Phase B containment isolation (remaining process lines)

TABLE 7.2-2 (Sheet 1 of 3)

INTERLOCK CIRCUITS

Designation	Derivation	Function
P-4	Reactor trip	Actuates turbine trip Closes main feedwater valves on T_{avg} below setpoint Prevents opening of main feedwater valves which were closed by safety injection or high steam generator water level
P-6	1/2 Neutron flux (intermediate) range) above setpoint	Allows manual block of source range reactor trip
	2/2 Neutron flux (intermediate) range) below setpoint	Defeats the block of source range reactor trip
P-7	3/4 Neutron flux (power range) below setpoint (from P-10) and 2/2 Turbine impulse chamber pressure below setpoint (from P-13)	Blocks reactor trip on: Low flow or reactor coolant pump breakers open in more than one loop, undervoltage, underfrequency, turbine trip, pressurizer low pressure, and pressurizer high level
P-8	3/4 Neutron flux (power range below setpoint	Blocks reactor trip on low flow or reactor coolant pump breaker open in a single loop
P-10	2/4 Neutron flux (power range) above setpoint	Allows manual block of power range (low setpoint) reactor trip Allows manual block of intermediate range reactor trip and intermediate range rod stops (C-1) Blocks source range reactor trip (back-up for P-6)

TABLE 7.2-2 (Sheet 2 of 3)

Designation	Derivation	Function
P-10 cont.	3/4 Neutron flux (power range) below setpoint	Defeats the block of power range (low setpoint) reactor trip Defeats the block of intermediate range reactor trip and intermediate range rod stops (C-1) Input to P-7
P-11	2/3 Pressurizer pressure below setpoint	Allows manual block of safety injection actuation on low pressurizer pressure signal coincident with low pressurizer level signal
	2/3 Pressurizer pressure above setpoint	Defeats manual block of safety injection actuation
P-12	2/4 T_{avg} below setpoint	Actuates safety injection and steamline isolation on high steamline flow. Allows manual block of safety injection actuation on high steam line flow Blocks steam dump to all valves Allows manual bypass of steam dump block for the cooldown valves only
	3/4 T_{avg} above setpoint	Defeats the manual block of safety injection actuation on high steam line flow Defeats the manual bypass of steam dump block
P-13	2/2 Turbine impulse chamber pressure below setpoint	Input to P-7
P-14	2/3 Hi-Hi steam generator level above setpoint on any steam generator	Trips all feedwater pumps, isolates feedwater and trips turbine
C-1	1/2 Neutron flux (intermediate range) above setpoint	Blocks automatic and manual control rod withdrawal

TABLE 7.2-2 (Sheet 3 of 3)

Designation	Derivation	Function
C-2	1/4 Neutron flux (power range) above setpoint	Blocks automatic and manual control rod withdrawal
C-3	2/4 Overtemperature ΔT above setpoint	Blocks automatic and manual control rod withdrawal
		Actuates turbine runback via load reference
C-4	2/4 Overpower ΔT above setpoint	Blocks automatic and manual control rod withdrawal
		Starts turbine runback via load reference
C-5	1/1 Turbine impulse chamber pressure below setpoint	Blocks automatic control rod withdrawal
C-6	1/2 Turbine impulse chamber pressure below setpoint	Blocks turbine runback via load limit
C-7	1/1 Time derivative (absolute value) of turbine impulse chamber pressure (decrease only) above setpoint	Makes steam dump valves available for either tripping or modulation
C-8	2/3 Turbine auto stop oil pressure below setpoint or all stop valves closed	Blocks steam dump control via load rejection controller
	2/3 Turbine auto stop oil pressure above setpoint and 1/4 stop valves open	Blocks steam dump control turbine trip controller
C-9	Any Condenser pressure above setpoint <u>or</u> All circulation water pump breakers open	Blocks steam dump to condenser

TABLE 7.2-3 (Sheet 1 of 2)

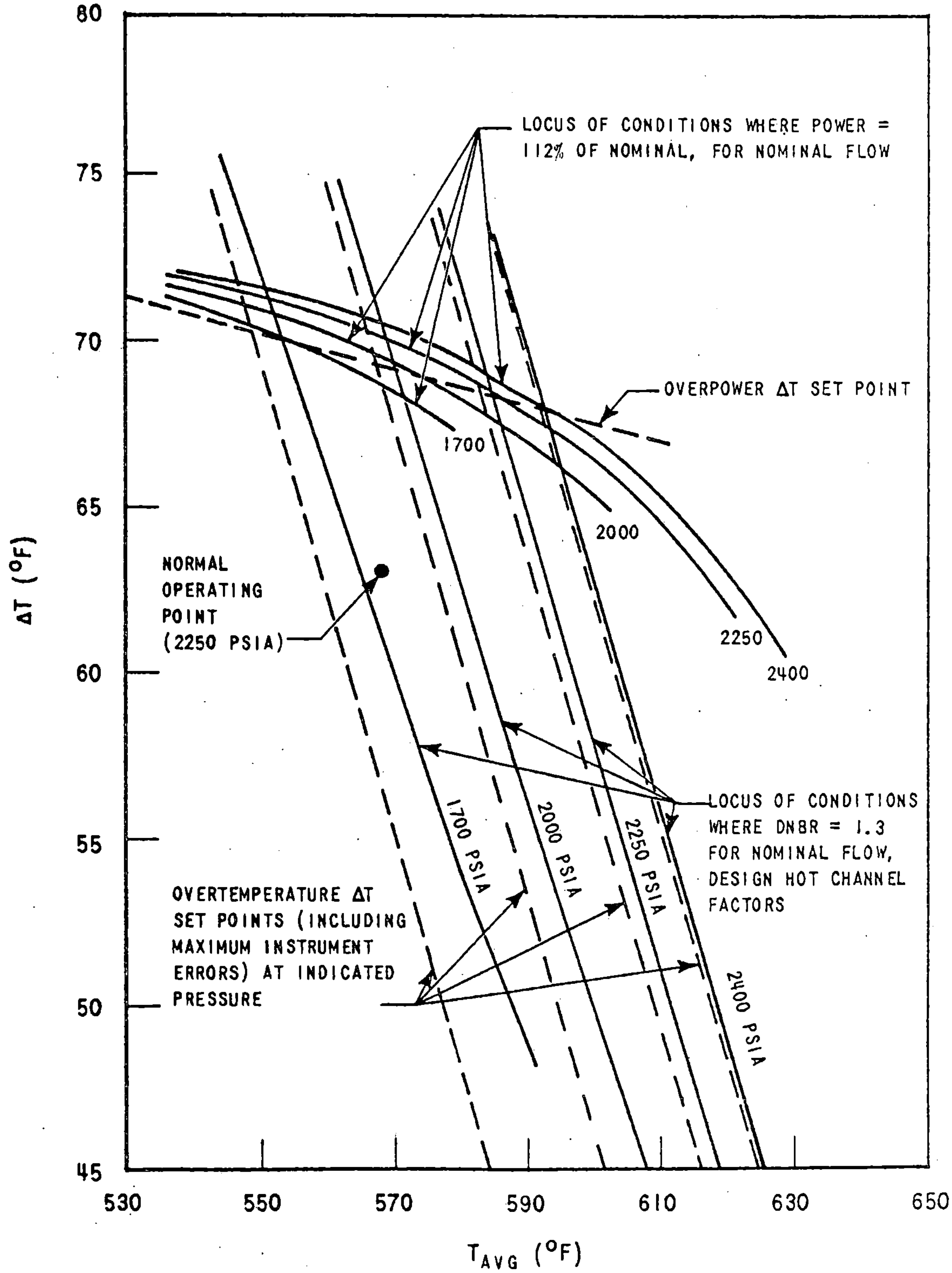
LEGEND OF ANALOG SYMBOLS

Al	- Alarm
Buf	- Buffer
f	- Special Function (such as a pressure compensation - unit or lead/lag compensation)
F	- Amplifier
FC	- Flow controller (off-on unless output signal is shown)
FI	- Flow Indicator
FLTR	- Filter
FS	- Flow Stream
FT	- Flow Transmitter
FW	- Flow Water
Hi LTR	- High Level Reactor Trip
HI PRT	- High Pressure Reactor Trip
I/I	- Isolation Current Repeater
ISOL	- Isolation (other than I/I)
LC	- Level Controller (off-on unless output signal is shown)
LI	- Level Indicator
L-Low	- Low Level
Lo L	- Low Level
Lo LRT	- Low Level Reactor Trip
Lo PRT	- Low Pressure Reactor Trip
L_{ref}	- Programmed Reference Level
L/L	- Lead/Lag
LT	- Level Transmitter
NC	- Nuclear Flux Controller (Bistable)
NE	- Nuclear Detector
NI	- Nuclear Flux Indicator
NM	- Nuclear Modifier
NQ	- Nuclear Power Supply
P	- Pressure

TABLE 7.2-3 (Sheet 2 of 2)

LEGEND OF ANALOG SYMBOLS

PC	- Pressure Controller (off-on unless output signal is shown)
PI	- Pressure Indicator
PM	- Pressure Modifier
P_{ref}	- Programmed Reference Pressure
PS	- Power Supply
PT	- Pressure Transmitter
QM	- Flux Modifier
R/I	- Resistance to Current Connector
RT	- Reactor Trip
RTD	- Resistance Temperature Detector
S	- Control Channel Transfer Switch (used to maintain auto channel during test of the protection channel)
SI	- Safety Injection
sp	- Set Point
T	- Transmitter
TC	- Temperature Controller
TE	- Temperature Element
TI	- Temperature Indicator
TJ	- Test Signal Insertion Jack
TM	- Temperature Modifier
TP	- Test Point
øU, L	- Out of core upper or lower ion chamber flux signals
FLTR	- Filter
$\frac{d}{dt}$	- Time Rate Change
Σ	- Sum



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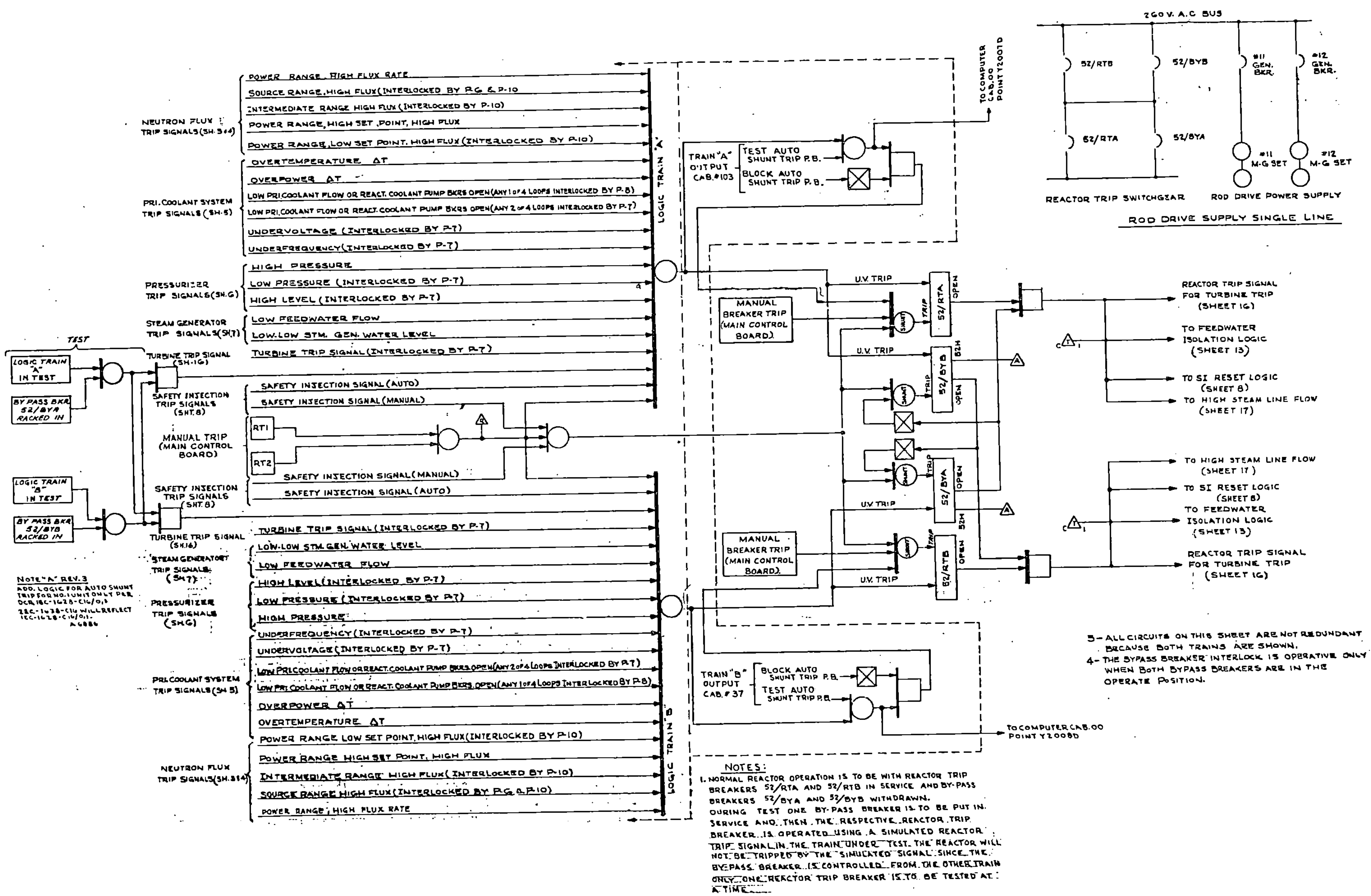
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Illustration of Overpower and Overtemperature ΔT Set Points (ΔT versus T_{avg})
	Updated FSAR — Figure 7.2-1



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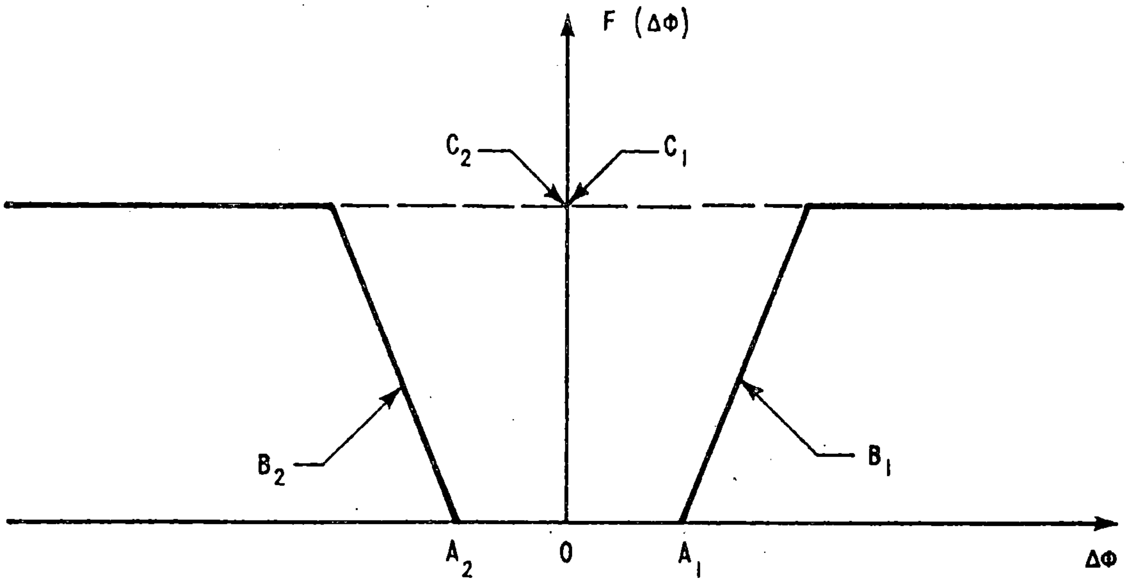
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Protection System Unit 1 & 2
	Updated FSAR — Fig 7.2-2



ΔΦ - NEUTRON FLUX DIFFERENCE BETWEEN UPPER AND LOWER LONG ION CHAMBERS.

A_1, A_2 - LIMIT OF F(ΔΦ) DEADBAND

B_1, B_2 - SLOPE OF RAMP; DETERMINES RATE AT WHICH FUNCTION REACHES IT'S MAXIMUM VALUE ONCE DEADBAND IS EXCEEDED

C_1, C_2 - MAGNITUDE OF MAXIMUM VALUES THE FUNCTION MAY ATTAIN

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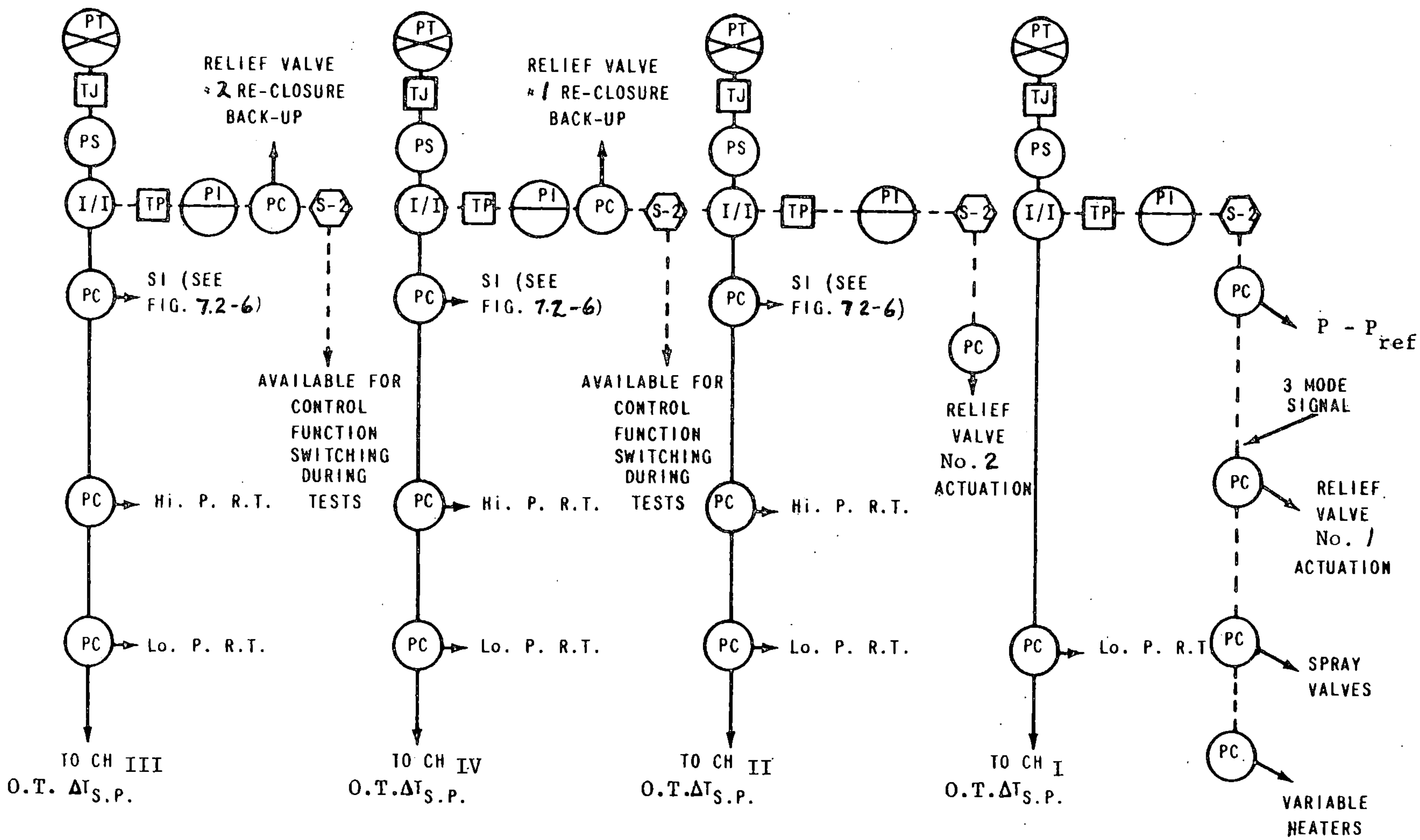
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Setpoint Reduction Function for Overpower and Overtemperature ΔT Trips	
	Updated FSAR	Figure 7.2-3

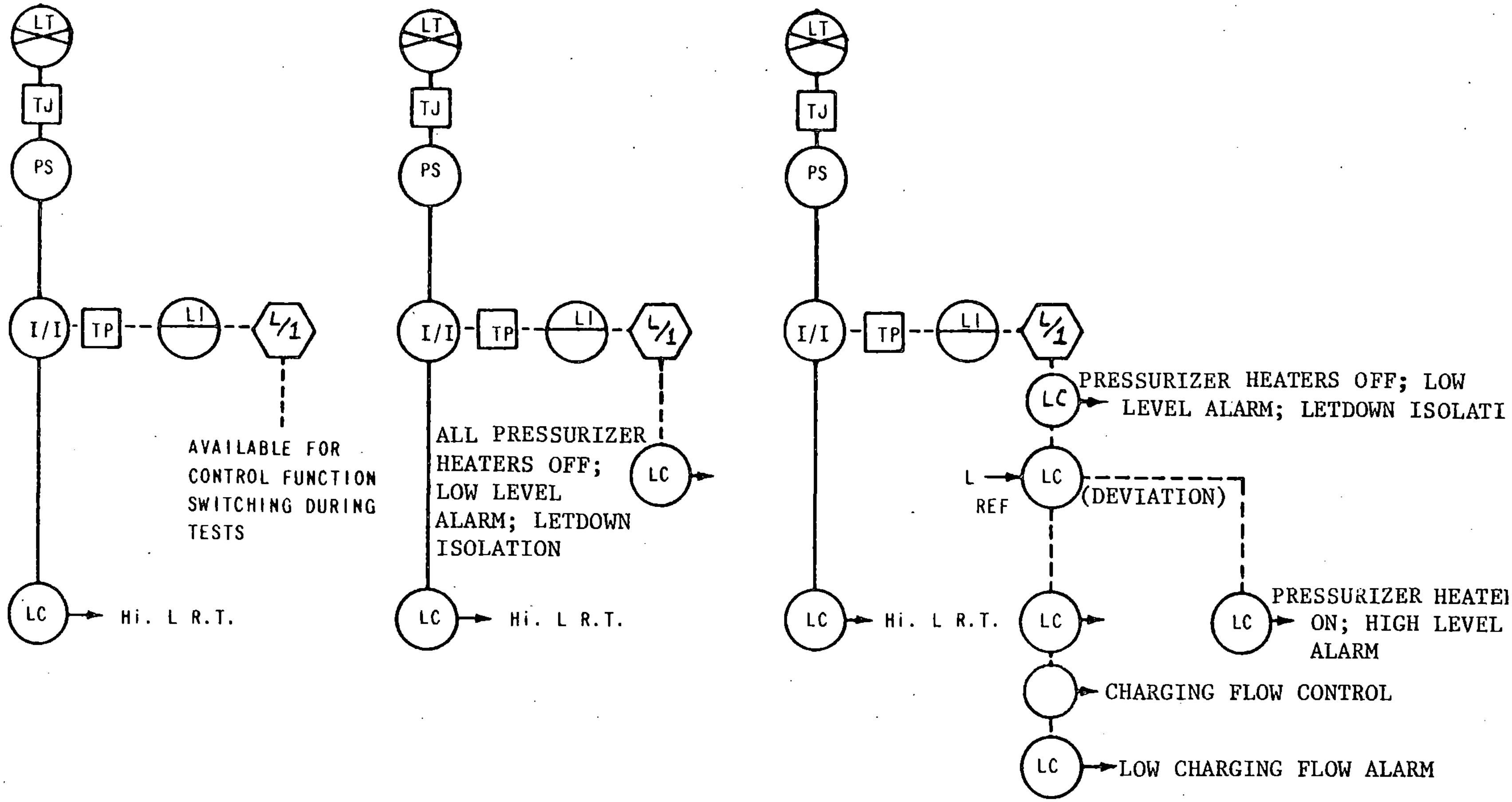


PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Updated FSAR

Pressurizer Pressure Control and Protection System

Figure 7.2-4



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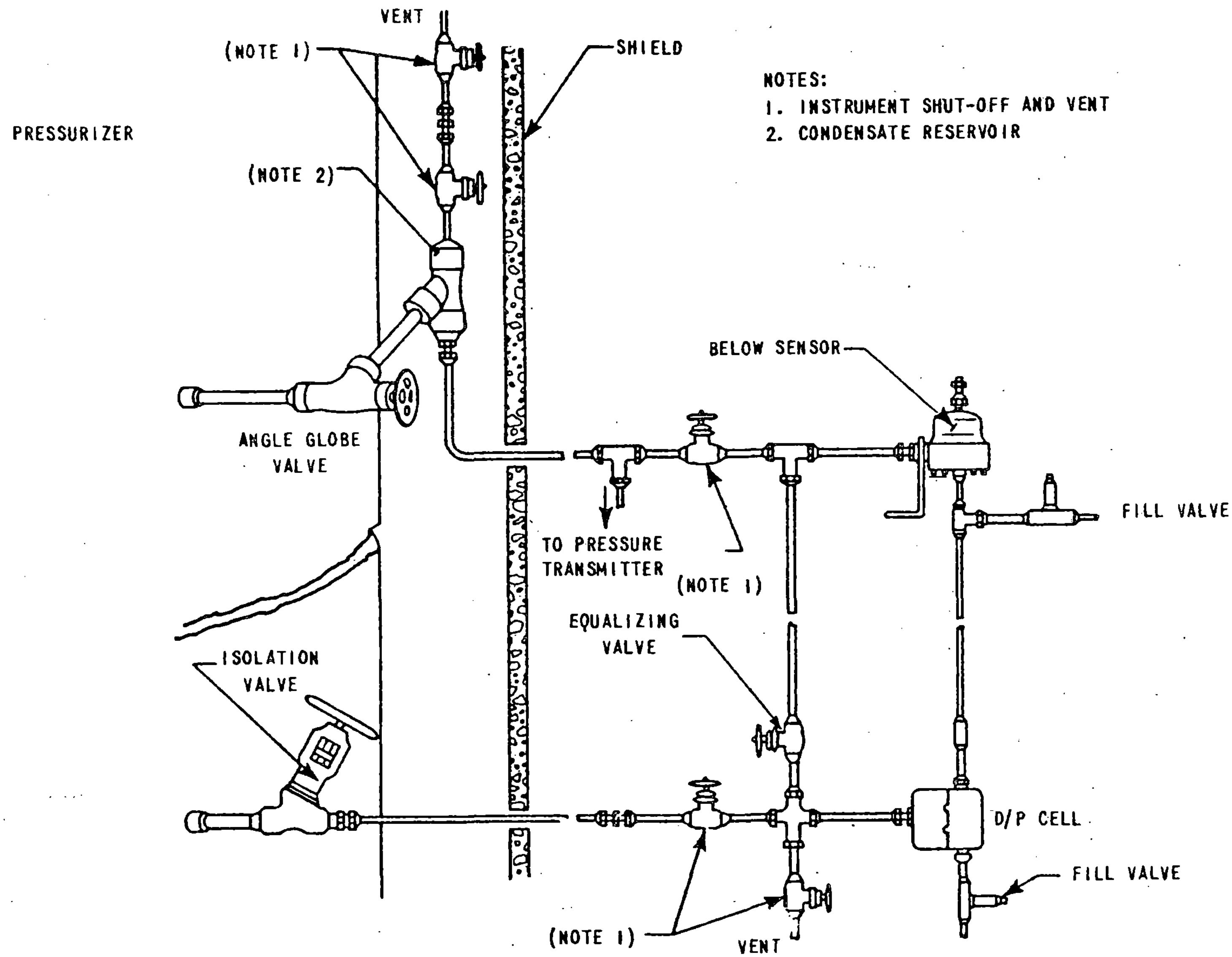
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Updated FSAR

Pressurizer Level Control and Protection System

Figure 7.2-5



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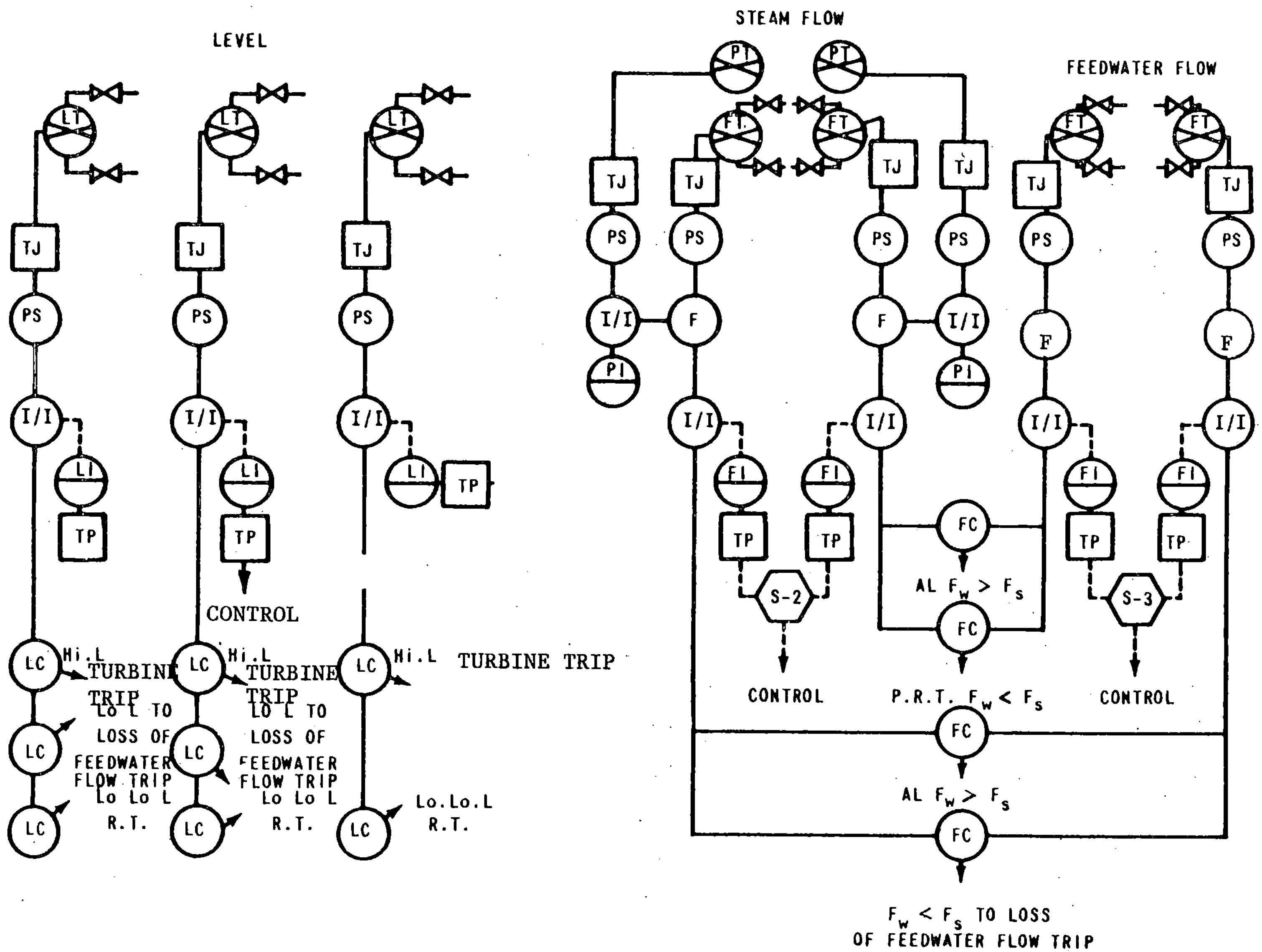
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Pressurizer Sealed Reference Leg Level System

Updated FSAR

Figure 7.2-6



PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Updated FSAR

Steam Generator Level Control and Protection System

Figure 7.2-7

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July 22, 1982

7.3 ENGINEERED SAFETY FEATURES INSTRUMENTATION

7.3.1 DESCRIPTION

The Engineered Safety Features Systems are actuated by redundant logic and coincidence networks similar to those used for reactor protection. Each network actuates a device that operates the associated Engineered Safety Features equipment, motor starters and valve operators. The channels are designed to combine redundant sensors, and independent circuitry, and coincident trip logic. Where possible, different but related parameter measurements are utilized. This ensures a safe and reliable system in which a single failure will not defeat the intended function. The action initiating sensors are listed in Table 7.3-1. The Engineered Safety Features Instrumentation System actuates (depending on the severity of the condition) the Safety Injection System, Containment Isolation, Containment Spray System and the Diesel Generators.

Availability of control power to the Engineered Safety Features trip channels is continuously monitored. In general, the loss of instrument power to the sensors, instruments, or logic devices in the engineered safety features instrumentation, places that channel in the trip mode. An exception is the containment spray initiating channels which require instrument power for actuation.

The passive accumulators of the Emergency Core Cooling System (ECCS) do not require signal or power sources to perform their functions. The actuation of the active portion of the Emergency Core Cooling System is from signals described in Table 7.2-1.

Containment spray operation is initiated by containment High-High pressure. Containment Spray Actuation Signal logic (CSAS) is shown on Figure 7.3-1. The containment pressure is sensed by four independent pressure detectors which are combined in a two-out-of-four logic network. The output sig- nal provides two independent channels for containment spray actuation via the two logic trains. Each CSAS channel initiates operation of a containment spray pump and associated valving.

In the event of a CSAS, the containment spray pumps would be operated from the normal source of power. If this is not available, or subsequently becomes unavailable, the power would be supplied by the emergency diesel generators.

Each spray system isolation valve is opened on a CSAS by a Hi-Hi containment pressure signal. Containment isolation backup is provided by check valves in the spray system piping.

The spray pump motor starting circuits and spray valve control circuits are provided with manual control switches in the control room. Each pump and isolation valve has test features to permit periodic operability testing of components and circuitry without causing interruption of the spray into the containment building.

The logic which initiates containment isolation is shown on Figure 7.3-1. There are four independent containment pressure detectors. Three of the pressure detectors are combined in a two-out-of-three logic to provide the signal for containment isolation for non-essential process lines if the high pressure set point is reached. This initiates Phase A containment isolation and Safety Injection. All four pressure detectors are combined in a two-out-of-four logic to provide the Containment Isolation signal for all penetrations (including those open to the containment atmosphere), except those required for operation of the Engineered Safety Features if the high-high pressure set point is reached. This initiates Phase B containment isolation, steam line isolation and containment spray.

A table of isolation valve schemes is given in Chapter 6.2. Air operated isolation valves will automatically go to their Engineered Safety Features position on loss of control air.

The design of the control air system precludes the total loss of control air to all systems and equipment. The control air systems are designed to provide a reliable supply of control air during normal and abnormal plant conditions, assuming a single failure in the system. See Section 9.3 for a detailed description of the system.

Isolation valves will be tested when the unit is off-line. The power supply to the containment isolation system is the vital electrical supply described in Chapter 8.

Manual actuation of each channel may be accomplished from central control or local switches and individual valve control switches located in the control room for isolation valve operation.

Each valve has test features to permit periodic testing of components and circuitry without causing interruption of the containment isolation initiating signal.

The containment isolation signals provide the means of isolating the various pipes passing through the containment walls as required to prevent the release of radioactivity to the outside environment in the event of an accident. The signals for actuation of the containment isolation are given in Table 7.2-1 and Figure 7.3-1.

7.3.1.1 System Design

7.3.1.1.1 Engineered Safety Features Actuation Instrumentation Description

The Engineered Safety Features actuation circuitry and hardware layout are designed to maintain channel isolation up to and including the bistable operated logic relay similar to that of the reactor protection circuitry as discussed in Section 7.2. See Reference (1) for a complete description of the instrumentation.

7.3.1.1.2 Engineered Safety Features and Associated Systems Actuation

Table 7.2-1 lists the Engineered Safety Features and associated systems actuation signals.

7.3.1.1.3 Engineered Safety Features Vital Functions

The engineered safety features actuation system automatically performs the following vital functions:

1. Starts operation of the Safety Injection System upon: a) low pressurizer pressure signals; b) high containment pressure signals; c) High differential steam pressure between steam lines; or d) high steam line flow signals with low T_{avg} or low steam line pressure.

2. Operates the containment isolation valves in non-essential process lines (Phase A Isolation) upon detection of high containment pressure signals.

3. Starts the Containment Spray System and operates the remaining containment isolation valves (Phase B Isolation) upon detection of high-high containment pressure.

4. Closes all steam line stop valves on high steam flow coincident with low T_{avg} or low steam pressure or high-high containment pressure signals.

5. Safety Injection signal will isolate the feedwater lines by closing all control valves (main and bypass valves), trip the main feedwater pumps and close the steam generator feedwater inlet stop valves, and actuate the auxiliary feedwater system. It also directly trips the turbine and the reactor.

7.3.1.1.4 Engineered Safety Features Calibration and Test

The Engineered Safety Features actuation channels are designed with sufficient redundancy to provide the capability for channel calibration and test during power operation. Except for containment spray actuation, removal of one actuation channel for test is accomplished by placing that channel in a tripped mode, i.e., a two out-of-three matrix logic becomes a one-out-of-two matrix logic. Testing does not trip the system unless a trip condition occurs in a redundant channel.

Containment spray actuation channels (from containment pressure) are tested by removing the channel from service. Since 2/4 logic is used, 2/3 logic remains active during testing.

See Reference 1 for a description of analog and logic testing.

7.3.1.1.5 Feedwater Isolation

Any Safety Injection signal will isolate the main feedwater lines by closing all control valves, tripping the main feedwater pumps and closing the steam generator feedwater inlet stop valves.

7.3.1.1.6 Main Steam Isolation

Protection against a steam line break is provided by Safety Injection actuation, feedwater isolation to prevent excessive cooldown of the primary side, and main steam isolation to prevent uncontrolled blowdown of more than one steam generator. Closure of all steam line stop valves is initiated by high steam flow in 2 of 4 coincident with either low T_{avg} in 2 of 4 loops or low steam pressure in 2 of 4 lines, by 2 of 4 high-high containment pressure signals, or by 1 of 1 manual pushbuttons per loop. The automatic actuation system is designed to meet the requirements for protective systems as described in sections 7.1.2 and 7.2.1.

7.3.1.1.7 Indication

All transmitted signals (flow, pressure, temperature, etc.) which can cause actuation of the engineered safety features are either indicated or recorded.

7.3.1.1.8 Engineered Safety Features Instrumentation

The following instrumentation ensures monitoring of the effective operation of the Engineered Safety Features.

Containment Pressure

Containment pressure is monitored by four taps, each connected to a pressure sensor as shown on Figure 7.3-1. Each sensor provides an analog signal to its associated bistables which will trip at present signal values. These tripped bistables provide input to the protection logic circuits which in turn trip the relays to actuate the safeguards system.

Three of the taps each have two bistables, the first of which is set to trip at the Hi containment pressure value. When two of the three bistables are tripped, the logic circuits produce an "S-signal" and a "T-signal." The "S-signal" actuates the Safety Injection System while the "T-signal" initiates Phase A containment isolation. These first bistables are normally energized and become de-energized when tripped. Thus, a loss of power to two or more channels will produce a trip and initiate safety injection and containment isolation. However, the loss of one channel will neither cause nor prevent the above actions.

The fourth tap has only one bistable associated with its pressure sensor. This bistable, along with the second bistables associated with the other three channels, is set to trip at the Hi-Hi containment pressure value. When two of the four bistables are tripped, the logic circuits will initiate the containment spray and steamline isolation, and also produce a "P-signal." The "P-signal" initiates Phase B isolation. The bistables in this second set are normally de-energized and become energized when tripped. Thus, a momentary loss of power or voltage dip will not cause a spurious trip which would actuate the Hi-Hi containment signal. It should be noted that for containment spray the logic changes from 2/4 to 2/3 when a channel is placed on test.

Each channel is supplied with electrical power from one of four independent busses. These busses can draw power from the station's batteries through static inverters; a blackout or momentary loss of station power will not cause an interruption in the power supplied to the instruments.

Indicators and alarms are provided in the control room to inform the operator of system status and to guide actions taken during recovery operations.

Containment Radiation

There are two detectors, one monitoring containment particulate activity and the other monitoring containment gaseous activity. High radiation from either monitor will close containment ventilation isolation valves. These two monitors are not part of the safeguards system and are not designed to meet the criteria of IEEE-279.

Refueling Water Storage Tank Level

Level instrumentation on the refueling water storage tank consists of two channels. One channel provides a local and remote indication of level, a high level alarm to warn of an overflow condition, and a low level alarm. The second channel provides remote indication on the control panel, a low level backup alarm, and a low-low level alarm.

Emergency Core Cooling System Pumps Discharge Pressure

The discharge pressure for each of the Safety Injection pumps and the residual heat removal pumps is indicated in the control room.

The common discharge header pressure for the charging pumps is indicated in the control room.

Pump Energization

The status (i.e., motor opened or closed) of each safeguards pump is indicated in the control room.

Valve Position

All Engineered Safety Features remote-operated valves have position indication on the control board to show valve limit position. Air-operated and solenoid-operated valves move in a preferred direction with the loss of air or power. Motor operated valves fail as is upon loss of power.

The position of key valves in the ESF systems is also provided in a mimic fashion, according to safety function, on a vertical wall-panel in the main control room.

Sump Instrumentation

The containment sump instrumentation consists of two level switches designed to operate in a post accident environment. The level lights housings are located above any possible flooding level. The indicator level lights and alarm systems are located in the control room.

In addition to the above, the following local instrumentation is available.

1. Residual heat removal pumps discharge pressure

2. Residual heat exchanger exit temperatures

3. Containment spray test lines total flow

4. Safety injection test line pressure and flow

7.3.1.1.9 Instrumentation Used During Loss-of-Coolant Accident

Instruments which are designed to function for various periods of time following the major loss-of-coolant accident are those which govern the operation of Engineered Safety Features. Pressurizer pressure and level, and steam generator level sensors are located inside the containment because an equivalent signal cannot be obtained from a sensor location more isolated from the reactor. Steam flow is also measured inside the containment. Pressurizer pressure transmitters may be required to actuate Engineered Safety Features as a result of a loss-of-coolant accident.

It should be emphasized, however, that for the large loss-of-coolant incidents the initial suppression of the transient is independent of any detection or actuation signal because the water level will be restored to the core by the passive accumulator system.

The reactor vessel level microprocessor instrumentation system utilizes three sets of d/p cells. These cells measure the pressure drop from the bottom of the reactor vessel to the top of the reactor vessel, and from the top of the reactor vessel to the reactor coolant hot leg piping. The differential pressure measuring system utilizes cells of differing ranges to cover different flow behavior with and without pump operation.

One pair of sensors provide an indication of the reactor vessel water level above the hot leg pipe when the reactor coolant pump in the loop with the hot leg connection is not operating. When the reactor coolant pumps are operating in that loop, the instrument reading will be off scale.

A second pair of sensors (narrow range) provide an indication of reactor vessel water level from the bottom to the top of the vessel when no pumps are operating. The instrument will also measure the reactor core and internals pressure drop, and therefore provide an indication of the relative void content or density of the circulating fluid, when only one reactor coolant pump is operating. When more than one reactor coolant pump is operating; the instrument reading will be off scale.

The third pair of sensors (wide range) provide an indiction of reactor core, internals, and outlet nozzle pressure drop for any combination of operating reactor coolant pumps. Comparison of the measured pressure drop with the normal, single phase pressure drop will provide an approximate indication of the relative void content or density of the circulating fluid. This instrument will monitor core conditions on a continuing basis.

To provide the required accuracy for water level measurement, temperature measurements of the reference legs are provided. These measurements together with the existing reactor coolant temperature measurements are used to compensate the d/p transducer outputs for differences in system temperature and reference leg temperature, particularly during the change in the environment inside the containment structure following an accident.

All pumps used for Safety Injection and containment spray are located outside the containment. The operation of the equipment can be verified by instrumentation that reads in the control room. This instrumentation will not be affected by the accident.

Depending upon the magnitude of the loss-of-coolant incident, information relative to the pressure of the Reactor Coolant Sytem will be useful to the operator to determine which pumps will be used for recirculation in the event of a small break. The discharge pressure of the charging pumps, as read on instrumentation outside the containment, will serve this purpose. The containment sump level and refueling water tank instrumentation will also provide information for evaluating the conditions necessary to initiate the recirculation mode of operation. See Chapter 6 for further details.

The refueling water storage tank level instrumentation provides additional information to determine the relative size of a reactor coolant leak. Core recirculation and containment spray recirculation (if necessary can be manually initiated before the refueling water storage tank is empty.

Considerations have been give to all the instrumentation and information that will be necessary for the recovery time following a loss-of-coolant incident. Instrumentation external to the reactor containment such as radioactivity monitoring equipment will not be affected by this postulated incident and will be available to the operator.

7.3.1.1.10 Engineered Safety Features Control

All equipment required to keep the plant in a safe condition during the occurrences of Safety Injection, blackout, or both of these conditions, can be powered by three standby ac power systems per unit. The equipment is arranged such that safe shutdown can be achieved under all postulated abnormal conditions coincident with the loss of one diesel generator. Each unit has a separate and independent electrical system to provide power for engineered safeguards systems.

Each diesel generator is provided with an independent loading control system (Reference 2) which initiates the startup and/or loading of the diesel generators during the following plant condition:

1. Safety injection only.
2. Loss of all outside power (blackout).
3. Safety injection coincident with loss of all outside power.
4. Safety injection coincident with undervoltage on the one 4kV vital bus.

During conditions of automatic startup and/or loading for all modes, the following criteria have been met in the control system design:

1. Each vital bus control is independent of the other two.
2. Manual control of equipment is locked out until the automatic load sequencing is complete.

3. Safeguard actuation signals cannot be interrupted by any automatic device.
4. Manual initiation of the loading sequence is available to the operator.
5. Off-normal diesel conditions are alarmed in the Control Room.
6. Safety injection conditions take precedence over all other operating modes.
7. Diesels operating in a TEST mode at the occurrences of a blackout or Safety Injection are automatically tripped and reloaded according to prevailing conditions.
8. No sequential loading can occur until the diesel generator ACB is closed onto the bus.
9. Inadvertent tripping of the diesel generator output breaker is precluded by locking out the shutdown relay when a safeguard initiation signal is present.

7.3.1.1.10.1 Safety Injection Only

In this mode of operation, a Safety Injection signal initiates the following actions:

1. Start diesel generator units.
2. Lockout manual control of equipment circuit breakers until the loads are connected.
3. Connect all required accident loads.

Since outside power is available during this mode, the equipment not affected by the accident remains in service and required safeguards equipment is loaded immediately, except for the fan cooler units which are started for low-speed operation as soon as they have coasted down from normal high speed operation (approximately 15-20 sec.). The diesel generators are started automatically so as to be available in the event they are subsequently required. They are not automatically connected to the vital busses. The operator may shut down the diesels when operation of the required equipment has been verified.

7.3.1.1.10.2 Blackout Only

In this mode of operation, undervoltage signals for vital bus are combined in a 2/3 logic matrix per bus to develop a blackout loading signal for that bus. The blackout signal and the associated control system perform the following functions on each bus:

1. Trip all 4160V and selected 460V vital bus breakers.
2. Start the diesel generator.
3. Lockout manual control of bus loads until diesel generator loading is completed.
4. Connect the diesel generator to its bus.
5. Sequence the required blackout loads provided that an accident has not occurred and the diesel generator is ready to accept load.

During this mode of operation, manual control of individual circuit breakers is prevented until the automatic loading is completed. After a time delay has elapsed, the operator can manually reset the loading sequence signal and restore manual control of manual.

7.3.1.1.10.3 Safety Injection Plus Blackout

This mode of operation differs from that of Safety Injection only in that circuit breakers of safety equipment cannot be closed until the diesel is ready to accept loads. These breakers are then closed sequentially.

The necessary logic required to recognize the existence of this mode is comprised of the coincidence of Safety Injection and blackout signals. This signal will trip selected 460V and all 4kV vital bus breakers.

Manual control of the individual loads is prevented by a time delay until diesel generator loading is complete. At that time, the loading sequence control can be reset and capability for manual control is restored.

The safeguards equipment required during an accident and blackout are atuomatically sequenced to start by the Safeguards Equipment Control System (SEC). This is discussed further in Chapter 8. The starting of the containment spray pumps requires a high-high containment pressure signal in addition to the SEC actuation signal. The containment spray pumps will normally start approximately 20 seconds following an accident. If the pumps do not start at the required sequence time, the SEC actuation signal will be delayed until the end of the loading sequence to prevent the spray pumps from starting when other equipment is required to start. The loss-of-coolant accident (LOCA) break sizes analyzed in Chapter 15 will result in the contianment high-high pressure signal ("P" signal) before the SEC actuation signal calls upon the spray pumps to start. Break sizes which do not result in a "P" signal prior to the pump start initiation will result in a peak containment pressure at the end of the spray pump lockout period considerably lower than for the situations analyzed in Chapter 15. The postulated spray pump delay has no adverse effect on the safety of the plant and is not a controlling factor relative to maximum containment pressure design analyses.

The topics discussed in NUREG-0138 were addressed in a meeting with USNRC Region 1, Inspection and Enforcement personnel prior to the start-up of Salem Unit No. 1. The meeting resulted in a modification to the LOCA Emergency Instruction which requires the plant operating personnel to restart LOCA loads in the event of a loss of offsite power subsequent to reset of the Safety Injection signal. This procedure change is applicable to Unit 2 and it adequately addresses the positions taken by the NRC in NUREG-0138.

7.3.1.1.10.4 Safety Injection Plus One 4kV Vital Bus Undervoltage

In this mode, the bus undervoltage signal is derived from the same group of relays which are used for the blackout signal logic matrices.

Bus undervoltage by itself will not directly cause any action to be taken in the sequencing of equipment. If an accident were to occur in coincidence with a single bus undervoltage condition, the following functions are performed by the controller:

1. Start the diesel on the affected bus.
2. Trip all vital bus equipment breakers.
3. Sequence the accident loads when the diesel is ready for loading.
4. Lock out manual control of breakers on the affected bus until diesel generator loading is complete.

7.3.1.1.10.5 Tests and Inspections

The emergency power control system is provided with means to:

1. Check the operational capability of each input sensor during reactor operation,
2. Check that the logic combinations of input signals result in proper logic outputs or control system actions for each mode of operation,
3. Permit any one sensor to be maintained, tested or calibrated during power operation without initiating system action, and
4. Assure that when tests are completed the system is returned to its proper operational state.

7.3.1.2 Design Bases

7.3.1.2.1 General Design Criteria:

Criterion: Protection systems shall be provided for sensing accident situations and initiating the operation of necessary Engineered Safety Features.

The Engineered Safety Features instrumentation monitors parameters to detect failures and to initiate Engineered Safety Features equipment operation.

The Engineered Safety Features instrumentation measures temperatures, pressures, flows, levels in the reactor coolant system, steam system, reactor containment and auxiliary systems. It actuates the Engineered Safety Features and monitors their operation. Process variables required on a continuous basis for the start-up, operation, and shutdown of the unit are indicated or recorded and controlled from the control room. The quantity and types of process instrumentation provided ensure safe and orderly operation of all systems and processes over the full operating range of the plant.

Certain controls and indicators which require a minimum of operator attention, or are only in use intermittently, are located on local control panels near the equipment to be controlled. Monitoring of the alarms of such control systems is provided in the control room. Design criteria for redundancy, separation and diversity are essentially the same as those used for the protection system, and described in Sections 7.1, 7.2 and Chapter 8.

7.3.1.2.2 Environmental Capability

The Engineered Safety Features instrumentation equipment inside the containment is designed to operate under the accident environment of a steam-air mixture and radiation.

Electrical equipment for the Engineered Safety Features is located inside the containment and in the auxiliary building. Table 7.3-2 is a listing of the equipment inside the containment which is required for post-LOCA operation and indicates how long the equipment is required to function as well as specifying which components require qualification testing.

Failure of the equipment in Table 7.3-2 after the specified time will not increase the severity or consequence of the accident. The reactor protection control and instrumentation equipment and electrical equipment for Engineered Safety Features located in the auxiliary building will operate in a normal ambient environment following a major loss-of-coolant accident.

7.3.2 SYSTEM EVALUATION

Redundant instrumentation has been provided for all inputs to the protective systems and vital control circuits. Where wide process variable ranges and precise control are required, both wide range and narrow range instrumentation is provided. Instrumentation components are selected from standard commercially available products with proven operating reliability. The instrument power to electrical and electronic instrumentation required for safe and reliable operation is supplied from the four instrument busses which can be energized from the diesel generator sources.

The engineered safeguards initiation, control and power supply systems are designed so that no single fault in components, units, channels or sensors will prevent Engineered Safety Features operation. The timing of initiation and start-up of the Engineered Safety Features is such as to provide conservative protection.

The wiring is grouped so that no single fault or failure, including either an open or shorted circuit, will negate Engineered Safety Features operation. Wiring for redundant circuits is protected and routed independently so that damage to any one path will not prevent the protective action.

The detailed design incorporates the following characteristics in order to counteract faults resulting in loss of power:

1. Redundant components are powered from separate busses;
2. The 125-volt dc and 115-volt ac power busses used are discussed in detail in Chapter 8;
3. The 4160-volt and 460-volt systems are discussed in Chapter 8;
4. The starting and loading of diesel generators is described in Section 7.3.1.1.10.

7.3.2.1 Pressurizer Pressure

Credible accident conditions requiring emergency core cooling would involve low pressurizer pressure. The present design for emergency core cooling is accomplished by the Safety Injection System actuation from primary system variables. Actuation is initiated by low pressurizer pressure.

Pressurizer pressure is sensed by fast response pressure transmitters. An overall one (1) second pressure channel response time, as used, is more than adequate to cover the response characteristics of the tripping channels.

Instrument delays are small in comparison with the computed lag in pressurizer pressure, which lags behind the reactor coolant pressure during blowdown.

A Safety Injection block switch is provided to permit the primary system to be depressurized, such as for refueling operations without actuation of the Safety Injection System. This manual block switch will be interlocked with pressurizer pressure in such a way that the blocking action will automatically be removed as operating pressure is approached. If two out of three pressure signals are above this preset pressure, blocking action cannot be initiated. The block condition will be indicated by a status light in the control room.

7.3.2.2 Motor and Valve Control

For starting pump and fan motors, the control relays are energized to energize the closing coil on the circuit breaker or the motor starter. When motor starters are used the starter operating coil will be supplied by power from the same source as the subject motor. When circuit breakers are used for motor control the circuit breakers close and trip coils will be supplied by power from a 125-volt dc battery bus.

For valve motor control, the control relay causes the coil on the main contactor for the closing circuit to be energized.

Air actuated containment isolation valves are spring loaded to close upon loss of air pressure.

7.3.2.3 Manual Control of ESF

Manual control of Engineered Safety Features equipment from the main control console is achieved through the use of a 28V dc logic interface system.

The manual control system is comprised of four groups of logic cabinets, terminal cabinets, and wiring to the main control console. The console contains the back-lighted push-button stations used to initiate a control action. A momentary contact energizes the relays in the logic cabinets, which in turn cause the desired system action in the primary control circuit (115V or 125V). The output contacts of the logic relays are wired to the terminal cabinets and then out to the field equipment control centers.

Power for logic relays is provided by the two 28V batteries. This is the supply voltage which appears across the contacts of the console pushbuttons. Wiring between the console and the logic cabinets consists of teflon insulated plug-in cables.

This system is used to manually initiate protection functions such as reactor trip, containment isolation, and containment spray. IEEE Standard No. 279-1971, Paragraph 4.17 is applicable to these functions. The 28V control system meets the requirements of Paragraph 4.17. All automatic operation of the Engineered Safety Features equipment does not require any action in the 28V circuitry.

7.3.2.4 Testing

The method of periodic testing of Engineered Safety features instrumentation and control equipment is discussed below. The Engineered Safety Features actuator testing is discussed below.

The discussions of system testability in Section 7.2 are applicable to the sensors, analog circuitry, and logic trains of the Engineered Safety Features Actuation System. The following information describes those areas in which the testing provisions differ from those for the Reactor Trip System.

The Engineered Safety Features Systems are tested to provide assurance that the systems will operate as designed and will be available to function properly in the unlikely event of an accident and/or loss of offsite power. The testing program includes:

1. Prior to initial plant operations, Engineered Safety Features System tests will be conducted.

2. Subsequent to initial startup, Engineered Safety Features System tests will be conducted during each regularly scheduled refueling outage.

3. During on-line operation of the reactor the Engineered Safety Features analog and logic circuitry will be tested. In addition, essentially all of the Engineered Safety Features actuators will be tested. The remaining few final actuators whose operation is incompatible with on-line plant operation will be partially tested.

4. During normal operation the operability of testable final actuation devices of the Engineered Safety Features Systems will be tested by manual initiation.

During reactor operation the basis for Engineered Safety Features Actuation System acceptability will be the successful completion of the overlapping tests performed on the Reactor Trip and the Engineered Safety Features Actuation Systems. Analog checks verify operability of the sensors. Analog checks and test verify the operability of the analog circuitry from the input of these circuits up to and including the logic input relays. Solid state logic testing checks the digital signal path from the logic input relay contacts through the logic matrices and master relays and performs continuity tests on the coils of the output slave relays; final actuator testing operates the output slave relays and verifies operability of those devices which require safeguards actuation, and which can be tested without causing plant upset. A continuity check is performed on the actuators of the untestable devices. Operation of the final devices is confirmed by control board indication and visual observation of the devices.

Maintenance checks (performed during regularly scheduled refueling outages), such as resistance to ground of signal cables in radiation environments, are based on qualification test data which identify acceptable radiation, thermal, etc. degradation.

Considered in the design are:

1. Testing shall minimize the potential for accidental shutdown of the unit or initiation of emergency core cooling.

2. Test circuitry shall be designed to maintain overall reliability of the engineered safeguards systems.

The operation of the engineered safety features includes function of both the Solid State Protection System (SSPS) and the Safeguards Equipment Controller (SEC). The test provision for the SSPS is described below.

Description of Initiation Circuitry

Initiating relays are provided for the following systems or functions in each of the two trains of the Solid State Protection System:

a. Safety Injection.
b. Containment Isolation Phase A.
c. Containment Isolation Phase B.
d. Containment Spray.
e. Containment Ventilation Isolation.
f. Main Steam Line Isolation.
g. Main Feedwater Line Isolation.
h. Safeguards Equipment Control (one for each diesel-generator unit).

The output of the initiation circuits each consists of a master relay which drives slave relays for contact multiplication. The logic, master, and slave relays are mounted in cabinets designated Train A and Train B, respectively for the redundant counterparts. The slave relay circuits operate some circuit breakers, motor operated valves and solenoid operated valves.

Actuator Testing

After testing of the initiation circuits in the SSPS and SEC has been accomplished, the SSPS master relays can be reset for testing of the slave relays and the devices controlled by their contacts. By operation of these relays one at a time, all breakers and valves that can be operated on line are tested.

Breakers and valves are assigned to the slave relays such that no undesired effect on plant operation can occur. Controls mounted in a Solid State Protection Test Panel are used for actuator testing. Separate panels are used for the A and B Trains. A four-position selector switch permitting rotation in one direction only is used to test all SSPS output relays. Turning the switch to the first position blocks those outputs which cannot be tested with the plant at power. This blocking is accomplished by latch-type test relays in the test panel. For those outputs where blocking is not required, this position is not used.

When the switch is moved to the second position, the output relay is activated. For those circuits with no blocking, the field devices function and are tested. For those circuits that are blocked, the test relay places a built-in "press-to-test" indicator light in series with the field device. Due to the low current, the field device does not operate. For normally closed output relay contacts, the test relay switches a bypass contact around the output relay contact. Current flow is determined by reading the voltage drop across small resistors in series with the normal and bypass contacts. (Maximum drop = 1 volt.)

Position 3 resets the output relay. The test lights or resistors are used to verify contact resetting. Final position 4 resets the test relay. Again, the test lights or resistors verify that the test relay has reset. Whenever a test switch is out of position 4 or a test relay is latched, an SSPS test alarm is activated in the Control Room.

The method of using a four-position test switch and lights or resistors for verifying field device continuity permits testing without activating the field device and verifies that the system has been reset and is in the same state as before testing. Depressing the test light lens holder breaks the normal circuit and makes up a test circuit such that the lamp can be checked instantly.

Administratively, only one test switch is operated at a time so only one SSPS output relay is tested.

During output testing, close communication between the main control room operator and the man at the test panel is maintained. Prior to operating a slave relay the operator in the main control room assures that plant conditions will permit operation of the equipment that will be actuated by the relay. After the tester has actuated a slave relay the main control room operator observes that all equipment has operated properly. Prepared check lists are used to verify proper operation and keep a permanent record of tests. By means of the procedure outline above, all equipment actuated by engineered safeguard system initiation circuits (with the following list of exceptions) are operated by the test circuitry:

1. Feedwater Isolation Valves.
2. Main Steam Isolation Valves.
3. Control Air Isolation Valves.
4. Turbine Trips.
5. Steam Generator Feedwater Pump Turbine Trip.
6. Steam Generator Feedwater Pump Stop Valves.
7. Reactor Coolant Pump Trip.
8. Auxiliary Feedwater Pumps.
9. Generator Trip.
10. Safety Injection System Valves 1SJ1, 1SJ2, 1SJ4, 1SJ5, 1SJ12, 1SJ13.
11. Chemical and Volume Control System Valves 1CV40, 1CV41, 1CV68, 1CV69, 1CV116, 1CV284, 1CV7.
12. Reactor Coolant Pump Seal and Thermal Barrier Cooling Valves 1CC117, 1CC118, 1CC131, 1CC136, 1CC187, 1CC190.

The method described provides capability for checking from the process signal to the logic cabinets and from there to the individual field equipment including all field cabling actually used in the circuitry. For those devices whose operation could have an effect plant stability, the procedure provides for checking from the process signal to the logic rack and continutiy determination for output cables and field devices, however, the actuated equipment will be manually initiated as plant conditions permit.

The SEC Units have the following test capability during power operation:

1. Check the operational capability of each bus undervoltage sensor and its input to the logic.

2. Check the operational capability of the LOCA signal, "S", from the SSPS logics.
3. Check that the logic combinations of input signals result in proper operation of the various functions, including automatic load sequencing, without actuation of any motors and a verification of the timed loading sequence.
4. Check the output relay capability to actuate the driven equipment.

The SEC Units can also be checked for complete system operability from sensor to actuated equipment during plant shutdowns.

Reactor trip system and Engineered Safety features actuation system response time tests are required by and will be performed in accordance with the Technical Specifications.

7.3.2.5 Containment Flooding Analysis

The postulated flood level within the containment following a major loss of coolant accident has been determined to be elevation 83'-1" (PSE G datum). Table 7.3-3 lists all electrical components which are in the containment at or below elevation 83'-1" and may be subjected to the effects of flooding. This list includes both safety related and non-safety related components and distinguishes between vital circuit (Class 1E) and non-vital circuit association. In addition there are some temperature elements which were not listed which may become flooded. These devices, however, do not perform a safety function, but are used for computer or annunciator alarms and will not have any affect on vital circuits or the safe operation of the plant following a LOCA.

Safety Significance

An analysis has been performed on the safety significance of the failure consequences of vital circuits due to postulated flooding. Submerged circuit components were examined for function and whether the function was required for the accident and performed prior to flooding. Tables 7.3-4, 7.3-5, 7.3-6 and 7.3-7 present the results in tabular form of the detailed analysis for 125V DC circuits, 115V AC circuits, 230 AC Control Center circuits and junction/terminal boxes respectively. A detailed analysis of non-vital circuits is not required since their failure or improper operation will not affect the safety functions necessary for a LOCA incident.

The analysis demonstrates that the safety functions required for an accident will be performed. Containment isolation and accumulator pressure monitoring were found to be the major safety functions required and were not adversely affected by the flooding before the functions were performed.

Air operated containment isolation valves were designed to close upon loss of power and are signalled to close prior to significant flooding. The flooding could cause short circuits, thereby tripping the control circuit breaker open and assuring that the safety function is performed. Motor operated isolation valves also perform their function prior to flooding.

Indication of isolation valve position has been determined not to be of safety significance because the valves will have performed their function prior to flooding, and the closed status of the valves will be indicated before flooding can cause a trip of the circuit breaker and subsequent loss of the indication. If this occurs, alarms are provided to indicate loss of the control circuit. The fail-closed circuitry design assures that loss of power results in valve closure. The failure of isolation valve indication resulting from flooding is therefore considered to be of no safety significance.

The accumulator pressure monitoring function will be available for the five minutes that it is required. The instruments are located at approximately elevation 82' and will not become flooded until after they have performed their function.

The loss or improper operation of other instrumentation will not affect the operator's response to post accident conditions since they are neither required for the accident nor for post accident monitoring.

Effect on Class 1E Sources

Class 1E electrical power sources will not be adversely affected by the flooding of individual electrical circuits because of the circuit protection provided. Circuit protection for those items affected by the flooding is indicated in the tables for each circuit analysis.

Each 125V DC circuit is protected by Class 1E, 15 amp circuit breakers which will trip open if short circuits are caused by the flooding of components in the containment. Power to the entire circuit would be lost. All components on the affected 125V DC circuits, whether flooded or not, were examined to determine if their loss was acceptable.

Each 115V AC circuit providing power to the process group racks and protection racks is also protected by Class 1E, 15 amp circuit breakers. However, in this case the entire circuit will not be lost due to flooding of components in part of the circuits. Each individual process or protection control/indication loop is provided with its own internal power supply with 0.2 amp fuse protection. The development of faults from flooding of components in the loop would blow the fuses and thereby isolate that portion of the circuit. Other functions powered from that particular circuit would not be affected.

In the analysis of 115V AC circuits only those devices which would become submerged were examined as to function and need. Non-submerged components of the circuit will not be affected by the flooding. In the case of submerged devices in the 115V AC circuit it may be possible that total loss of control power will not occur, and that some control loops would provide anomalous indication or control. This has been examined and those devices which are required to operate properly do so for the required time period prior to submergence. Once submerged their functions are not required, and any improper operation would not be detrimental to the necessary safety functions following a LOCA.

Each 230V Motor Control Center circuit is provided with Class 1E circuit breakers. The control circuit power developed from a 230/115V transformer is protected by 15 amp fuses. Any isolation valves will have performed their function prior to becoming submerged. The reactor nozzle support vent fans are tripped during an accident. These power circuits are protected during flooding conditions since voltage to the devices is removed by open motor starter contacts.

Design Changes

During the course of the review two instances were discovered which required a redesign to assure that the emergency core cooling systems can be operated effectively. They are described below.

1. Position interlock circuits for valve 1SJ67 and 1SJ68, although not flooded, were found to be on 125V DC circuits which are affected by the flooding of other components. The position interlock circuit of 1SJ67 was on circuit 13 of the 1CCDC distribution cabinet and the position interlock circuit of 1SJ68 was on circuit 13 of the 1AADC distribution cabinet. Coincident flooding of components in portions of the circuits could trip the circuit breakers, thereby losing the interlock capability for opening 11SJ45 and 12SJ45. The power circuit for the 1SJ67 and 1SJ68 position interlocks were changed to circuits which can not be affected by flooding.

2. The containment sump level instruments provide backup indication for initiating the recirculation phase of an accident and are above the flood level. However two junction boxes, JN106 and JN108, used for the routing of the indication circuits were located below the flood level. This situation could have caused anomalous indication to the operator and possibly affected his response to accident conditions. These two junction boxes were raised above the flood level.

In summary, with incorporation of the design changes, the entire analysis demonstrates that flooding within the containment will not adversely affect the safe operation of the plant following a LOCA even though a number of vital circuits and non-vital circuits could be lost. The necessary safety functions will be performed.

7.3.2.6 Single Failure of Components

There are no single electrically operated fluid system components whose failure could result in the loss of capability of the Emergency Core Cooling System to perform its safety function. In order to achieve this, design changes were incorporated for certain manually controlled electrically operated valves. These changes are illustrated for typical valves on Figures 7.3-2 and 7.3-3 and are described below.

Figure 7.3-2 illustrates the design provided for valves which have motive power "locked out" at the 230V motor limit switches which provide redundant position indication as described in Section 7.6.2. All valves with this design are provided with a separate 125V DC supply to provide power for control board position indication which would normally be unavailable due to the "power lockout."

Figure 7.3-3 illustrates the design provided for valves whose control power can be restored from the control room. The design incorporates a switch which isolates the operating coil of the motor starter which could cause spurious movement to the undesirable valve position. The switch is monitored by a light which would indicate failure of the switch to provide isolation, and by a separate light which gives positive indication that the motor is "locked out". Similar to the other valves previously described, these valves are provided with a separate 125V DC supply for control board position indicating lights.

7.3.2.7 Electrical Interlocks

Electrical interlocks are provided in the control circuits of several redundant Emergency Core Cooling System valves. These interlocks assure that the proper sequence of operations occur when switching to the recirculation phase of a LOCA. The interlocks also serve to prevent unacceptable system lineups during normal plant operations. All of the interlocks use redundant devices to prevent single failures from either defeating the ECCS safety function, or the operational restrictions during normal power operation. In addition to the interlock circuitry, some of the valves are provided with control "power lockout" to meet other criteria are described below along with an assessment of the effects of failures in the circuits.

Valve 1CV40 and 1CV41

These valves are located in the normal suction line to the charging pumps. The closing of these valves requires opening of either 1SJ1 or 1SJ2 (charging pump suction lines from the RWST) to assure that the charging pumps do not lose suction. The normal operation of the interlocks requires 1SJ1 or 1SJ2 to be fully open prior to initiating closure of the 1CV40 and 1CV41 valves. If either interlock were to fail in the direction allowing premature closure of 1CV40 or 1CV41 during a LOCA, suction to charging pumps would not be lost since 1SJ1 and SJ2 would be opening at the same time. This simultaneous operation of all four valves occurs since "S" signals from the plant protection system would be transmitted to the valve control circuits simultaneously.

The devices used to develop the interlock circuits are redundant. If either interlock were to fail in the direction which would prevent closure of the 1CV40 or 1CV41 valves, the redundant interlock would function to close the valves.

Valves 11RH4 and 12RH4

These valves are located in the suction lines to the No. 11 and 12 RHR pumps respectively. The opening of each valve is enabled by the closed condition of its respective containment sump isolation valve (11SJ44 interlocks 11RH4 and 12SJ44 interlocks 12RH4). The normal status of 11RH4 and 12RH4 is "open" and ready for the injection phase of a LOCA. The interlocks are arranged on a "Train" basis so that no possible interconnection of the interlocks can occur. A failure of either interlock would affect only the opening circuit of the RH4 valve associated with that interlock. The required safety function of the RH4 valves is to be closed when initiating the recirculation phase of a LOCA. The closure of an RH4 valve cannot be defeated by any failure in the interlocking circuitry (i.e. an opening permissive from the SJ44 valve interlock would not cause automatic opening of RH4 nor would it prevent closure of RH4).

Valves 11SJ44 and 12SJ44

These are the containment sump valves which provide suction to the RHR pumps during the recirculation phase of a LOCA. The opening of each valve is enabled by the closure of its respective RH4 valve. The normal status of these valves is "closed" with control power "locked out" in the control room. The purpose of the interlock is to assure that spurious opening of the valve will not result in emptying the RWST into the containment sump. The interlocks are fully independent on a "Train" basis so that failures could affect only one RHR pumping path. The required safety function of these valves is to open when initiating recirculation after the RH4 valves have been closed.

A failure of the interlock in a manner tending to prematurely open an SJ44 valve would have no consequence since the control power is removed from the valve circuit. The control power is not restored until the RH4 valve is closed. A failure of the interlock in a manner which would prevent opening the sump valve is acceptable since the other pumping path would not be affected by this interlock failure.

Valves 1SJ67 and 1SJ68

These are the safety injection pump miniflow line valves which allow flow back to the RWST. The valves are both normally open with the control power "locked out" in the main control room to assure that the SI pumps have a flow path until RCS pressure falls below the shutoff head of the pumps. These valves are to be closed when transferring to the recirculation phase of a LOCA. The opening of either valve is enabled by the "closed" condition of valves 11SJ45 and 12SJ45. The closing of these valves is not interlocked.

A failure of the interlock circuitry tending to open the valve would have no consequence because the normal position of the valve is open, and it also has control power "locked out." The interlock circuitry could not fail in a manner which would automatically open the valve or prevent its closure. If the interlock were to fail subsequent to the valve's being closed for recirculation, only one of the valves could be affected by the failure. The valve affected in this case would not open unless the operator erroneously initiated an "open" signal from the main control console. Even if this were to occur, the redundant valve would remain closed.

Valves 11CS36 and 12CS36

These valves are opened in the recirculation phase of a LOCA to provide flow to the containment spray headers from the RHR system. The normal position of the valve is "closed" and opening requires the opening of its associated containment sump valve (11SJ44 interlocks 11CS36 and 12SJ44 interlocks 12CS36) and the closure of either 1RH1 or 1RH2 (the normal RHR cooldown path from the RCS). The devices used to develop the interlocks are redundant so that any interlock failure would affect only one of the CS36 valves.

Interlock failures tending to prevent opening of the valve can affect only one pumping path; the other path would provide the safety function. Interlock failures which would tend to open a valve prematurely are acceptable since such failures alone are not sufficient to open the valves (operator action is required in addition to fulfilling the interlock requirements).

Valves 11SJ45 and 12SJ45

These valves are used in independent piping loops during the recirculation phase of a LOCA to provide suction to the high-head pumps from the RHR pumps. The required safety function of these valves is to open. Each valve's opening circuitry is enabled by the closure of either 1RH1 or 1RH2, the opening of its associated sump valve (11SJ44 interlocks 11SJ45; 12SJ44 interlocks 12SJ45), and the closure of either 1SJ67 or 1SJ68. The devices used to develop these interlocks are redundant such that any interlock failure affects only one valve.

Interlock failures tending to prevent opening of the valve can affect only one pumping path; the other path would provide the safety function. Interlock failures which would tend to open a valve prematurely are acceptable since such failures alone are not sufficient to open the valves (operator action is also required).

The circuits for valves 1SJ67 and 1SJ68 which provide the opening interlock for valves 11SJ45 and 12SJ45 have been moved to 125V DC circuits not affected by containment flooding following a LOCA.

REFERENCES FOR SECTION 7.3

1. Katz, D. N., "Solid State Logic Protection System Description," WCAP-7488-L (Proprietary), January, 1971 and WCAP- 7672 (Non-Proprietary), June, 1971.

2. "Safeguards Equipment Control System - Supplementary Documentation," Salem Nuclear Generating Station, Units 1 and 2, Public Service Electric and Gas Company, October 31, 1974. (Instruction Manual, Reliability/Availability Analysis, Seismic Qualification, Schematic Diagrams.)

TABLE 7.3-1

PROCESS INSTRUMENTATION FOR RPS AND ESF ACTUATION

Parameter	Transmitter Sensors	Read-out	Power	Prot/Safeguards Use	Taps
Reactor Coolant Temperature	8 RTD's	C.B. Meter	Ext.	Δ trips, T_{avg} permissives	1 each
Pressurizer Pressure	4 Transmitters	C.B. Meter	Ext.	Hi/Lo Pressure Trips, SIS	3 (Top Level) One Shared
Pressurizer Level	3 ΔP Transmitters	C.B. Meter	Ext.	R. T.	3 (Top Level) 3 (Bottom Level)
Steam Flow	8 ΔP Transmitters	C.B. Meter	Ext.	Mismatch Trip, SIS	1 Pair Each
Feedwater Flow	8 ΔP Transmitters	C.B. Meter	Ext.	Mismatch Trip	1 Pair Each
Steam Pressure	12 Transmitters	C.B. Meter	Ext.	SIS, Steam Line Isolation	1 Each
Steam Generator Level	12 ΔP Transmitters	C.B. Meter	Ext.	Mismatch Trip Low Level Trip	1 Pair Each
Reactor Coolant Flow	12 ΔP Transmitters	C.B. Meter	Ext.	Low Flow Trip	1 High Pressure Shared/Loop 1 Low Pressure Each
Containment Pressure	4 Transmitters	C.B. Meter	Ext.	SIS (3) Spray (4) Cont. Isol.	4
Turbine 1st Stage Pressure	2 Transmitters	C.B. Meter	Ext.	Set Point Programs and Turbine Power Permissives	1 Each

*C.B is Control Board

TABLE 7.3-2

POST-ACCIDENT EQUIPMENT (INSIDE CONTAINMENT)
OPERATIONAL AND TESTING REQUIREMENTS

Equipment Name and Tag Number	Operating Mode	Duration of Operation	Environmental Testing
CATEGORY 1 - INSTRUMENTATION			
Pressurizer pressure channels: PT-455, 456, 457, 474	Continuous	1/2 hr (S.I. initiation)	Required
Pressurizer level channels: LT-459, 460, 461	Continuous	1/2 hr (S.I. initiation)	Required
Accumulator pressure channels PT-936A,B,C,D, 937A,B,C,D	During injection phase	1 hr	Required
Containment sump level channels: LT-938, 939	Continuous	Available to 1 year	Not required
CATEGORY 2 - VALVES			
Containment Sump isolation valves: MOV-8982A,B (11SJ44, 12SJ44)	Continuous	Within 1/2 hr after accident	Required
Accumulator isolation valves: MOV-8808A,B,C,D (11SJ54, 12SJ54, 13SJ54, 14SJ54)	During injection phase	1/2 hr minimum	Required
CATEGORY 3 - MISCELLANEOUS ITEMS			
Fan cooler motors	Continuous	Available for 1 year	Required
Safeguard equipment power, control control and instrument cable	Continuous	Available for 1 year	Required

TABLE 7.3-3 (Sheet 1 of 2)

POSTULATED SUBMERGED ELECTRICAL COMPONENTS IN THE CONTAINMENT FOLLOWING A LOCA

Vital Circuits	Non-Vital Circuits
I. Motor Operated Valves	
1CV284, 1CC187, 1CC190	
II. Panel Mounted Instruments	
	Panel 231 - PT1004, LT1003
Panel 232 - PT187, LT470, PT472, SV421 SV422, SV424	Panel 232 - FIC616, SV439, SV931
Panel 233 - PT936A, PT937A, LT934A, LT935A SV229, SV230, SV231, SV232, SV233	Panel 233 - SV530
Panel 234 - PT936B, PT937B, LT934B, LT935B, SV234, SV235, SV236, SV237, SV238	Panel 234 - SV531
Panel 235 - PT936C, PT937C, LT934C, LT935C, SV239, SV240, SV241, SV242, SV243	Panel 235 - SV532
Panel 236 - PT936D, PT937D, LT934D, LT935D, SV244, SV245, SV246, SV247, SV248	Panel 236 - SV533
Panel 237 - PT188, PT405	Panel 237 - FIC613, SV437
Panel 238 - SV486, SV487, SV488, SV489, SV490, SV491, SV492, SV493	
Panel 240 - PT183, SV444	Panel 240 - FIC622
Panel 241 - PT403, PT186, PT121, SV115, SV751, SV757, SV758, SV772, SV773, SV774, SV399, SV397, SV394, SV401, SV518, SV519, SV520, SV521, SV498, SV499, SV500, SV442, E/P(INT35), E/P(ICV132)	Panel 241 - FIC619, SV441, SV528, SV526, SV523, SV522, SV529, SV527, SV525, SV524
Panel 245 - SV110, SV111, SV116, SV427, SV753, SV771	
Panel 246 - SV403	

TABLE 7.3-3 (Sheet 2 of 2)

POSTULATED SUBMERGED ELECTRICAL COMPONENTS IN THE CONTAINMENT FOLLOWING A LOCA

Panels 447 1A through 1M - FT414, FT415, FT416, FT424, FT425, FT426, FT434, FT435, FT436, FT444, FT445, FT446

Panels 247 1A through 1D - SV912, SV913, SV914, SV915

Panels 446 1A through 1D - FIC499A, FIC499B, FIC499C, FIC499D

III. Valve Limit Switches

Control Valves - 11SJ20, 11SJ27, 12SJ20, 12SJ27, 12SJ57, 13SJ20, 14SJ20, 14SJ27, 11SJ162, 1CV2, 1CV3, 1CV5, 1CV75, 1CV77, 1CV79, 1CV131, 1CV132, 1CV134 1CV277, 1PR14, 1WL7, 1PR17, 1SS104, 1SS107, 1SS110, 1SS103

Motor Operated Valves - 1CC187, 1CC190, 1CV284

Dampers - 1CBV31, 1CBV32, 1CBV33, 1CBV34

Control Valves - 1RC4, 11SS93, 12SS93, 13SS93, 14SS93, 11SS26, 12SS26, 13SS26, 14SS26

IV. Miscellaneous and Local Mounted Instruments

No. 11-14 Reactor Nozzle Support Fans, Triaxial Accelerometer (Seismic Instrument)
FIT159A, FIT159B, FIT158A, FIT158B, FIT157A, FIT157B, FIT156A, FIT156B, SV506, FD7670, FD7672, FD7674, FD7676, TD7671, TD7673 TD7675, TD7677

No. 11 Containment Sump Pump
No. 12 Containment Sump Pump
No. 1 Reactor Sump Pump
No. 11 Reactor Coolant Drain Tank Pump
No. 12 Reactor Coolant Drain Tank Pump
FIC166, FIC171, FIC172, FIC176, LC486, LC487, LC488, LC489, LC490 LC491, LC492, LC493

V. Terminal/Junction Boxes

JT11, JT12, JT13, JT14, JT122, JT210, JT212, JN140

JT420, JT423, JT425, JS7, JS93, JS94, JS131, JS132, JS133, JS134, JN31, JN63, JN64, JN143, JN616, JN36

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 6

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-487 (Panel 238)	Control for valve 1CV77 (Charging Line to Reactor Coolant Cold Leg)	None	N/A	None
SV-442 (Panel 241)	Control for valve 1CV114 (Reactor Coolant Pump Seal Bypass Flow)	None	N/A	None
Limit Switches CVO, CVC (1CV77)	Position indication circuitry for valve 1CV77	None	N/A	None

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X/1CI 33Y/1CI 33X/SBF 33Y/SBF	Valve position indication for 1CV77 and 1CV114	None	N/A	None
Limit Switches CVO, CVC (1CV114)	Position indication circuitry for valve 1CV114	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

TABLE 7.3-4 (Sheet 2 of 32)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 9

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-492 (Panel 238)	Control for valve 1CV4 (Containment Isolation Valve)	Valve 1CV4 closes for an accident (T signal) solenoid valve de-energizes	Fail close circuitry - function performed prior to submergence, function still performed when submerged since breaker will trip open	Safety function will be performed

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X/LOB 33Y/LOB	Valve position indication for 1CV4 (Isol. Valve)	None	N/A	None
Relay 74DC/LOB	Provides loss of 125V DC Alarm for 1CV4 Control circuit	None	Breaker trip due to submerged components will alarm loss of voltage for this circuit	None
Aux. Relay 43LX/LOB	Provides indication of local control	None	N/A	None
Local CMC Indicating Lights (213)	Provide local indication of valve position, etc.	None	N/A	None
Limit Switches CVO, CVC (1CV4)	Position indicates circuitry for valve 1CV4 (Isol. Valve)	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 125 VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 11

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-110 (Panel 245)	Control for valve 12SJ50 (SI Test Valves)	None	N/A	None
SV-111 (Panel 245)	Control for valve 11SJ50 (SI Test Valves)	None	N/A	None
SV-427 (Panel 245)	Control for valve 1SJ123 (Containment Isolation Valve)	Valve 1SJ123 closes for an accident (T signal) solenoid valve de-energizes	Fail close circuitry - function performed prior to submergence, function still performed when submerged since breaker will trip open	Safety function will be performed

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-249	Control for valve 1NT32 (Containment Isolation Valve)	Valve 1NT32 closes for an accident (T signal) solenoid valve de-energizes	Fail close circuit design whether breaker trips or not due to submerged components, solenoid will de-energize (check valve is redundant Isol. valve)	Safety function will be performed
Limit Switches CVO, CVC (1NT32)	Position indication circuitry for valve 1NT32 (Isol. Valve)	None		None
Aux. Relays 33X/1NT32 33Y/1NT32 33X/1SJ123 33Y/1SJ123	Valve position indication for 1NT32 and 1SJ123 (Isol. Valves) Also 33Y/... aux. relays provide loss of 125V DC control voltage or valve out of position alarm	None	Breaker trip due to submerged components will alarm loss of control voltage or valve out of position	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

TABLE 7.3-4 (Sheet 4 of 32)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 11

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS (Cond't.)

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Limit Switches CVO, CVC (11SJ50 and 12SJ50)	Position indication circuitry for valves 11SJ50 and 12SJ50	None	N/A	None
Limit Switches CVO, CVC (1SJ123)	Position indication circuitry for valve 1SJ123 (Isol. Valve)	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

TABLE 7.3-4 (Sheet 5 of 32)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 12

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-421 (Panel 232)	Control for valve 1PR15 (Pressurizer Relief Tank Vent Valve)	None	N/A	None
SV-506 (MTD. on valve)	Control for valve 1PR17 (Containment Isol. Valve)	Valve 1PR17 closes for an accident (T signal) solenoid valve de-energizes	Fail close circuitry - function performed prior to submergence, function still performed when submerged since breaker will trip open	Safety function will be performed
Limit Switches CVO, CVC (1PR17)	Position indication circuitry for valve 1PR17 (Isol. Valve)	None	N/A	None

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X/VV 33Y/VV	Valve position indication for 1PR15	None	N/A	None
Aux. Relays 33X/AV 33Y/AV	Valve position indication for 1PR17 (Isol. Valve)	None	N/A	None
Aux. Relays 95/GAX 96/CIX	Associated with automanual circuitry for valve 1PR17	None	N/A	None
Relay 74/DC	Provides loss of 125V DC alarm for circuit 12	None	Breaker trip due to submerged components will alarm loss of voltage for this circuit	None
Limit Switches CVO, CVC (1PR15)	Position indication circuitry for valve 1PR15	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

TABLE 7.3-4 (Sheet 6 of 32)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 13

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-115 (Panel 241)	Control for valve 1SJ63 (SI Accumulator Fill)	None	N/A	None

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X/1SJ63 33Y/1SJ63	Valve position indication for 1SJ63	None	N/A	None
Limit Switches CVO, CVC (11SJ40)	Position indication circuitry for valve 11SJ40	None	Valve is position for safety injection with power locked out loss of indication will not affect need to operate at some time during recirc phase of accident - position alarm in aux. annunciator not affected so that position information is provided	None
Aux. Relays 33X/11SJ40 33Y/11SJ40	Valve position indication for 11SJ40	None	Same as above for the limit switches for valve 11SJ40	None
Limit Switches CVO, CVC (1SJ63)	Position indication circuitry for valve 1SJ63	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

TABLE 7.3-4 (Sheet 7 of 32)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 15

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-229 (Panel 233)	Control for valve 11SJ58 (No. 11 Accumulator Test Line Valve)	None	Fail close circuitry	None
SV-230 (Panel 233)	Control for valve 11SJ57 (No. 11 Accumulator Test Line Valve)	None	Fail close circuitry	None
SV-231 (Panel 233)	Control for valve 11SJ20 (No. 11 Accumulator Fill Line Valve)	None	Fail close circuitry	None
SV-232 (Panel 233)	Control for valve 11SJ27 (No. 11 Accumulator to Reactor Coolant Drain Tank)	None	Fail close circuitry	None
SV-233 (Panel 233)	Control for valve 11SJ93 (No. 11 Accumulator Nitrogen Supply)	None	Fail close circuitry	None
Limit Switches CVO, CVC (11SJ20, 11SJ27)	Position indication circuitry for valves	None	N/A	None

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X/11SJ93 33Y/11SJ93 33X/11SJ58 33Y/11SJ58 33X/11SJ27 33Y/11SJ27 33X/11SJ57 33Y/11SJ57 33X/11SJ20 33Y/11SJ20	Valve position indication for 11SJ93, 11SJ58, 11SJ27, 11SJ57, and 11SJ20 Also 337/...aux. relays provide alarm either loss of control power or valves out of position	None	Breaker trip due to submerged components will alarm loss of control voltage or valves out of position	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 15

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT (Cond't.)

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X/11SJ54 33Y/11SJ54	Valve position indication for 11SJ54 (Motor Operated)	None	Valve 11SJ54 in position for safety injection with power locked out	None
Limit Switches CVO, CVC (11SJ58, 11SJ57 and 11SJ93)	Position indication circuitry for valves 11SJ58, 11SJ57 and 11SJ93	None	N/A	None
Limit Switches CVO, CVC (11SJ54 Motor Operated)	Position indication circuitry for valve 11SJ54 (Acc. Discharge)	None	Valve 11SJ54 in position for safety injection with power locked out	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 29

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-518 (Panel 241)	Control for valve 1SS110 (Containment Isolation Valve)	Valve 1SS110 closes for an accident (T signal) solenoid valve de-energizes	Fail close circuitry - function performed prior to submergence, function still performed when submerged since breaker will trip open	Safety function will be performed
SV-519 (Panel 241)	Control for valve 1SS107 (Containment Isolation Valve)	Valve 1SS107 closed for an accident (T signal) solenoid valve de-energizes	Same as above for valve 1SS110	Safety function will be performed
SV-520 (Panel 241)	Control for valve 1SS104 (Containment Isolation Valve)	Valve 1SS104 closes for an accident (T signal) solenoid valve de-energizes	Same as above for valve 1SS110	Safety function will be performed
SV-521 (Panel 241)	Control for valve 1SS103 (Containment Isolation Valve)	Valve 1SS103 closes for an accident (T signal) solenoid valve de-energizes	Same as above for valve 1SS110	Safety function will be performed
Limit Switches CVO, CVC (1SS110, 1SS107, 1SS104 and 1SS103)	Position indication circuitry for valves 1SS110, 1SS107, 1SS104 and 1SS103 (Isolation Valves)	None	N/A	None

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X/1 33Y/1 33X/2 33Y/2 33X/3 33Y/3 33X/4 33Y/4	Valve position indication for 1SS110, 1SS107, 1SS104 and 1SS103 (Isolation Valves) Also for off normal alarm or loss of 125V DC voltage alarm	None	Breaker trip due due to submerged components will alarm loss of control voltage or valve out of position	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

TABLE 7.3-4 (Sheet 10 of 32)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 7

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-486 (Panel 238)	Control for valve 1CV75 (Auxiliary Spray to Pressurizer	None	N/A	None
Limit Switches CVO, CVC (1CV75)	Position indication circuitry for valve 1CV75	None	N/A	None

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X/CAS 33Y/CAS	Valve position indication for 1CV75	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

TABLE 7.3-4 (Sheet 11 of 32)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 10

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Limit Switches CVO, CVC (1CV132)	Position indication circuitry for valve 1CV132 (Excess Let-down HX)	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

TABLE 7.3-4 (Sheet 12 of 32)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 11

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-244 (Panel 236)	Control for valve 14SJ93 (No. 14 Accumulator Nitrogen Supply)	None	Fail close circuitry	None
SV-245 (Panel 236)	Control for valve 14SJ27 (No. 14 Accumulator to Reactor Coolant Drain Tank)	None	Fail close circuitry	None
SV-246 (Panel 236)	Control for valve 14SJ20 (No. 14 Accumulator Fill Line Valve)	None	Fail close circuitry	None
SV-247 (Panel 236)	Control for valve 14SJ57 (No. 14 Accumulator Test Line Valve)	None	Fail close circuitry	None
SV-248 (Panel 236)	Control for valve 14SJ58 (No. 14 Accumulator Test Line Valve)	None	Fail close circuitry	None
Limit Switches CVO, CVC (14SJ27, 14SJ20)	Position indication circuitry for valves 14SJ27 and 14SJ20	None	N/A	None

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X/14SJ93 33Y/14SJ93 33X/14SJ58 33Y/14SJ58 33X/14SJ27 33Y/14SJ27 33X/14SJ57 33Y/14SJ57 33X/14SJ20 33Y/14SJ20	Valve position indication for 14SJ93, 14SJ58, 14SJ27, 14SJ57, and 14SJ20 Also 33Y/...aux. relays provide alarm either loss of control power or valves out of position	None	Breaker trip due to submerged components will alarm loss of control voltage or valves out of position	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 11

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS (Cond't.)

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X/14SJ54 33Y/14SJ54	Valve position indication for 14SJ54 (Motor Operated)	None	Valve 14SJ54 in position for safety injection with power locked out	None
Limit Switches CVO, CVC (14SJ93, 14SJ57, 14SJ58)	Position indication circuitry for valves 14SJ93, 14SJ57, 14SJ58	None	N/A	None
Limit Switches CVO, CVC (14SJ54 Motor Operated)	Position indication circuitry for valve 14SJ54 (Acc. Discharge)	None	Valve 14SJ54 in position for safety injection with power locked out	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 16

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-424 (Panel 232)	Control for valve 1PR14 (Pressurizer Relief Tank to Coolant Drain Tank Pumps)	None	N/A	None
SV-422 (Panel 232)	Control for valve 1WR82 (Primary Water to Pressurizer Relief Tank Spray Header)	None	N/A	None
Limit Switches CVO, CVC (1PR14)	Position indication circuitry for valve 1PR14	None	N/A	None

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-423 (Panel 311)	Control for valve 1NT25 (Containment Isolation Valve)	Valve 1NT25 closes for accident (T signal) solenoid valve de-energizes	Fail close circuitry design whether breaker trips or not due to submerged components solenoid will de-energize	Safety function will be performed
SV-505 (Mounted on valve)	Control for valve 1NT18 (Containment Isolation Valve)	Valve 1PR18 closes for an accident (T signal) solenoid valve de-energizes	Similar analysis as above for SV423	Safety function will be performed
SV-507 (Mounted on valve)	Control for valve 1WR80 (Containment Isolation Valve)	Valve 1WR80 closes for an accident (T signal) solenoid valve de-energizes	Similar analysis as above for SV423	Safety function will be performed
Aux. Relays 33X/PWS 33Y/PWS 33X/N_2S 33Y/N_2S 33X/AV 33Y/AV	Valve position indication for 1NT25, 1PR18 and 1WR80 (Isolation Valves)	None	N/A	None
Aux. Relays 33X/DV 33Y/DV 33X/SV 33Y/SV	Valve position indication for 1PR14 and 1WR82	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

TABLE 7.3-4 (Sheet 15 of 32)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 16

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT (Cond't.)

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relay 33X-1/DV	Interlock with reactor coolant drain tank pump control circuit	None	N/A	None
Limit Switches CVO, CVC (1NT25, 1PR18 and 1WR80)	Position indication circuity for valves 1NT25, 1PR18 and 1WR80 (Isolation Valves)	None	N/A	None
Relay 74/DC	Provides loss of 125V DC alarm for circuit 16	None	Breaker trip due to submerged components will alarm loss of voltage for this circuit	None
Limit Switches CVO, CVC (1WR82)	Position indication circuity for valve 1WR62	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

TABLE 7.3-4 (Sheet 16 of 32)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 17

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-234 (Panel 234)	Control for valve 12SJ58 (No. 12 Accumulator Test Line Valve)	None	Fail close circuitry	None
SV-235 (Panel 234)	Control for valve 12SJ57 (No. 12 Accumulator Test Line Valve)	None	Fail close circuitry	None
SV-236 (Panel 234)	Control for valve 12SJ20 (No. 12 Accumulator Test Line Valve)	None	Fail close circuitry	None
SV-237 (Panel 234)	Control for valve 12SJ27 (No. 12 Accumulator to Reactor Cool-and Drain Tank)	None	Fail close circuitry	None
SV-238 (Panel 234)	Control for valve 12SJ93 (No. 12 Accumulator Nitrogen Supply)	None	N/A	None
Limit Switches CVO, CVC (12SJ57, 12SJ20, 12SJ27)	Position indication circuitry for valves 12SJ57, 12SJ20 and 12SJ27	None	N/A	None

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-575 (Panel 311)	Control for valve 1SJ60 (Containment Isolation Valve)	Valve 1SJ60 closes for accident (T signal) solenoid valve de-energizes	Fail close circuitry design whether breaker trips or not due to submerged components solenoid will de-energize	Safety function will be performed
Aux. Relays 33X/1SJ60 33Y/1SJ60	Valve position indication for 1SJ60 also 33Y/1SJ60 provides alarm either loss of control power or valves out either loss of control power or valves out of position	None	Breaker trip due to submerged components will alarm loss of control power or valve out of position	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 17

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT (Cont'd.)

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Limit Switches CVO, CVC (1SJ60)	Position indication circuitry for valve 1SJ60	None	N/A	None
Aux. Relays 33X/12SJ54 33Y/12SJ54	Valve position indication for 12SJ54 (Motor Operated)	None	Valve 12SJ54 in position for safety injection with power locked out	None
Aux. Relays 33X/12SJ93 33Y/12SJ93 33X/12SJ58 33Y/12SJ58 33X/12SJ27 33Y/12SJ27 33X/12SJ57 33Y/12SJ57 33X/12SJ20 33Y/12SJ20	Valve position indication for 12SJ93, 12SJ58, 12SJ27, 12SJ57, and 12SJ20 Also 33Y/...aux. relays provide alarm either loss of control power or valves out of position	None	Breaker trip due to submerged components will alarm loss of control voltage or valves out of position	None
Limit Switches CVO, CVC (12SJ58 and 12SJ93)	Position indication circuitry for valves 12SJ58 and 12SJ93	None	N/A	None
Limit Switches CVO, CVC (12SJ54 Motor Operated)	Position indication circuitry for valve 12SJ54 (Acc. Discharge)	None	Valve 12SJ54 in position for safety injection with power locked out	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

TABLE 7.3-4 (Sheet 18 of 32)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 19

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-489 (Panel 238)	Control for valve 1CV2 (CVCS Letdown Valve)	None	N/A	None
SV-490 (Panel 238)	Control for valve 1CV277 (CVCS Letdown Valve)	None	N/A	None
SV-491 (Panel 311)	Control for valve 1CV3 (Containment Isolation Valve)	Valve 1CV3 closes for accident (T signal) solenoid valve de-energizes	Fail close circuitry function performed prior to submergence, function still performed when submerged since breaker will trip open	Safety function will be performed
Limit Switches CVO, CVC (1CV2 and 1CV277)	Position indication circuitry for valves 1CV2 and 1CV277	None	N/A	None
Limit Switches CVO, CVC (1CV3)	Position indication circuitry for valve 1CV3 (Isol. Valve)	None	N/A	None

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-525 (Panel 311)	Control for valve 1CV7 (Containment Isolation Valve)	Valve 1CV7 closes for accident (T signal) solenoid valve de-energizes	Fail close circuitry design whether breaker trips or not due to submerged components solenoid will de-energize	Safety function will be performed
Limit Switches CVO, CVC (1CV7)	Position indication circuitry for valve 1CV7 (Isol. Valve)	None	N/A	None
Aux. Relays 33X/LIC 33Y/LIC	Valve position indication for 1CV7 (Isol. Valve)	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

TABLE 7.3-4 (Sheet 19 of 32)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 17

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT (Cont'd.)

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X/LOA 33Y/LOA	Valve position indication for 1CV3 (Isol. Valve)	None	N/A	None
Aux. Relays 43X/LOA	Associated with auto-manual circuitry for valve 1CV3	None	N/A	None
Local CMC Indicating Lights (213)	Provide local indication of valve position, etc.	None	N/A	None
Relay 74DC/LTV	Provides loss of 125V DC alarm for circuit 19	None	Breaker trip due to submerged components will alarm loss of voltage for this circuit	None
Aux. Relays 33X1/459 33X2/459 33X3/459 33Y/459 33X1/460 33X2/460 33X3/460 33Y/460	Valve position indication for 1CV2 and 1CV277 Also 33X1/... 33X2/...Aux. 33X3... Relays provide open interlocks for letdown orifice valves 1CV3, 1CV4 and 1CV5	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 10

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-488 (Panel 238)	Control for valve 1CV79 (Charging line to reactor coolant cold leg)	None	N/A	None
Limit Switches CVO, CVC (1CV79)	Position indication circuitry for valve 1CV79	None	N/A	None

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X/2CI 33Y/2CI	Valve position indication for 1CV79	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 13

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-401 (Panel 241)	Control for valve 1WL96 (Containment Isolation Valve)	Valve 1WL96 closes for an acci-dent (T signal) solenoid valve de-energizes	Fail close circuitry - function performed prior to sub-mergence, function still performed when submerged since breaker will trip open	Safety function will be per-formed
SV-394 (Panel 241)	Control for valve 1WL16 (Containment Isolation Valve)	Valve 1WL16 closed for an accident (T signal) solenoid valve de-energizes	Same as above for valve 1WL96	Safety function will be per-formed
SV-399 (Panel 241)	Control for valve 1WL98 (Containment Isolation Valve)	Valve 1WL98 closes for an accident (T signal) solenoid valve de-energizes	Same as above for valve 1WL96	Safety function will be per-formed
SV-397 (Panel 241)	Control for valve 1WL12 (Containment Isolation Valve)	Valve 1WL12 closes for an accident (T signal) solenoid valve de-energizes	Same as above for valve 1WL96	Safety function will be per-formed
SV-403 (Panel 246)	Control for valve 1WL7 (Reactor Coolant Drain Tank Valve)	None	N/A	None
Limit Switches CVO, CVC (1WL7)	Position indication circuitry for valve 1WL7	None	N/A	None

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X/3 33Y/3 33X/4 33Y/4 33X/1 33Y/1 33X/2 33Y/2	Valve position indication for 1WL98, 1WL12, 1WL96, 1WL16 (Isol. Valves)	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 13

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT (Cond't.)

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relay 33X/14	Valve 1WL12 position Interlock with reactor coolant drain tank pumps	None	N/A	None
Aux. Relay 95/1	Valve 1WL96 isolation function relay	Relay de-energizes on accident signal to close valve	Fail safe circuitry design relay will de-energize whether breaker trips or not due to submerged components	Safety function will be performed
Aux. Relay 95-3	Reactor coolant drain tank sampling control via 1WL96	None	N/A	None
Relay 74/DC	Provides loss of 125V DC alarm for circuit 13	None	Breaker trip due to submerged components will alarm loss of voltage for this circuit	None
Aux. Relay 20/X	Valve 1WL12 isolation function relay	Relay de-energizes on accident signal to close valve	Fail safe circuitry design relay will de-energize whether breaker trips or not due to submerged components	Safety function will be performed
Aux. Relay 20T, 95/2 and 43/LX	Part of valve 1WL12 auto-manual circuit	None	N/A	None
Local Indicating Lights	Local position indication for valves 1WL98, 1WL12, 1WL96 1WL7 and 1WL16	None	N/A	None
Limit Switches CVO, CVC (1WL98, 1WL96, 1WL12 and 1WL16	Position indication circuitry for valves 1WL98, 1WL96, 1WL12 and 1WL16 (Isol. Valves)	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 15

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-493 (Panel 238)	Control for valve 1CV5 (Containment Isolation Valve)	Valve 1CV5 closes for an accident (T signal) solenoid valve de-energizes	Fail close circuitry - function performed prior to submergence, function still performed when submerged since breaker will trip open	Safety function will be performed
SV-498 (Panel 241)	Control for valve 1CV134 (Excess Letdown HX valve)	None	N/A	None
SV-499 (Panel 241)	Control for valve 1CV131 (Excess Letdown HX valve)	None	N/A	None
SV-500 (Panel 241)	Control for valve 1CV278 (Excess Letdown HX valve)	None	N/A	None
Limit Switches CVO, CVC (1CV134 1CV131)	Position indication circuitry for valves 1CV134, 1CV131	None	N/A	None

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X/LOC 33Y/LOC	Valve position indication for 1CV5 (Isol. Valve)	None	N/A	None
Aux. Relays 43LX/LOC	Associated with auto-manual circuitry for valve 1CV5	None	N/A	None
Local CMC Indicating Lights (213)	Provide local indication of valve position, etc.	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 15

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT (Cond't.)

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X/ELD 33Y/ELD 33X/ELIB 33Y/ELIB 33X/ELIA 33Y/ELIA	Valve position indication for 1CV134, 1CV131 1CV278	None	N/A	None
Limit Switches CVO, CVC (1CV278)	Position indication circuitry for valve 1CV278	None	N/A	None
Relay 74DC	Provides loss of 125V DC alarm	None	Breaker trip due to submerged components will alarm loss of voltage for this circuit	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

TABLE 7.3-4 (Sheet 25 of 32)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 17

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-239 (Panel 235)	Control for valve 13SJ93 (No. 13 Accumulator Nitrogen Supply)	None	Fail close circuitry	None
SV-240 (Panel 235)	Control for valve 13SJ27 (No. 13 Accumulator to Reactor Coolant Drain Tank)	None	Fail close circuitry	None
SV-241 (Panel 235)	Control for valve 13SJ20 (No. 13 Accumulator Fill Line Valve)	None	Fail close circuitry	None
SV-242 (Panel 235)	Control for valve 13SJ57 (No. 13 Accumulator Test Line Valve)	None	Fail close circuitry	None
SV-243 (Panel 235)	Control for valve 13SJ58 (No. 13 Accumulator Test Line Valve)	None	Fail close circuitry	None
Limit Switches CVO, CVC (13SJ20)	Position indication circuitry for valve 13SJ20	None	N/A	None

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X/13SJ93 33Y/13SJ93 33X/13SJ58 33Y/13SJ58 33X/13SJ27 33Y/13SJ27 33X/13SJ57 33Y/13SJ57 33X/13SJ20 33Y/13SJ20	Valve position indication for 13SJ93, 13SJ58, 13SJ27, 13SJ57 and 13SJ20 Also 33Y/... aux. relays provide alarm either loss of control power or valves out of position	None	Breaker trip due to submerged components will alarm loss of control voltage or valve out of position	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

TABLE 7.3-4 (Sheet 26 of 32)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 17

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS (Cond't.)

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X/13SJ54 33Y/13SJ54	Valve position indication for 13SJ54 (Motor Operated)	None	Valve 13SJ54 in position for safety injection with power locked out	None
Limit Switches CVO, CVC (13SJ93, 13SJ27, 13SJ57 and 13SJ58)	Position indication circuitry for valves 13SJ93, 13SJ27, 13SJ57 and 13SJ58	None	N/A	None
Limit Switches CVO, CVC (13SJ54 Motor Operated)	Position indication circuitry for valve 13SJ54 (Acc. Discharge)	None	Valve 13SJ54 in position for safety injection with power locked out	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

TABLE 7.3-4 (Sheet 27 of 32)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 20

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-116 (Panel 245)	Control for valve 1SJ19 Accumulator Fill Valve)	None	N/A	None

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-118 (Panel 215)	Control for valve 1SJ79 (Boron Injection Tank to Boric) Acid Tank)	Valve closes for an accident (T signal) solenoid valve de-energizes	Fail close circuitry design whether breaker trips or not due to submerged components, solenoid will de-energize	Safety function will be performed by either 1SJ79 or 1SJ78
Limit Switches CVO, CVC (1SJ79)	Position indication circuitry for valve 1SJ79	None	N/A	None
Aux. Relays 33X/1SJ79 33Y/1SJ79	Valve position indication for 1SJ79	None	N/A	None
Relay 74/DC	Provides loss of 125V DC alarm for circuit	None	Breaker trip due to submerged components will alarm loss of voltage for this circuit	None
Aux. Relays 33X/1SJ19 33Y/1SJ19	Valve position indication for 1SJ19	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 17

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS (Cond't.)

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Limit Switches CVO, CVC (1SJ30, 1SJ40, 1RH26, 1SJ69)	Position indication circuitry for valves 1SJ30, 1SJ40, 1RH26 and 1SJ69 (Motor Operated)	None	Valves 1SJ30 and 12SJ40 in position for safety injection with power locked out - loss of indication will not affect need to operate at some time during recirc phase of accident - position alarm in aux. annunciator not affected so that position information is provided	None
Aux. Relays 33X/1SJ30 33Y/1SJ30 33X/12SJ40 33Y/12SJ40 33X/RSTV 33Y/RSTV 33X/CLIV 33Y/CLIV	Valve position indication for 1SJ30, 12SJ40, 1SJ69 and 1RH26 (Motor Operated)	None	Same as above	None
Limit Switches CVO, CVC (1SJ19)	Position indication circuitry for valve 1SJ19	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

TABLE 7.3-4 (Sheet 29 of 32)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 17

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-772 (Panel 241)	Control for valve 1SJ163 (SI Test Valve)	None	N/A (fair close circuit)	None
SV-773 (Panel 241)	Control for valve 14SJ162 (SI Test Valve)	None	N/A (fair close circuit)	None
SV-774 (Panel 241)	Control for valve 13SJ162 (SI Test Valve)	None	N/A (fair close circuit)	None

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X/TLVC 33Y/TLVC 33X/TLV3 33Y/TLV3	Valve position indication for 1SJ163, 1SJ162 and 14SJ162 Also 33Y... aux. relays provide off normal position alarm or loss of 125V DC control voltage	None	None Breaker trip due to submerged components will alarm loss of control power or valve out of postion	None
Limit Switches CVO, CVC (1SJ163, 13SJ162 and 14SJ162)	Position indication circuitry for valves 1SJ163, 13SJ162 and 14SJ162	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

TABLE 7.3-4 (Sheet 30 of 32)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 28

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-757 (Panel 241)	Control for valve 1SJ163 (SI Test Valve)	None	N/A (fair close circuit)	None
SV-771 (Panel 245)	Control for valve 1SJ166 (SI Test Valve)	None	N/A (fair close circuit)	None
SV-751 (Panel 241)	Control for valve 1SJ159 (SI Test Valve)	None	N/A (fair close circuit)	None
SV-758 (Panel 241)	Control for valve 12SJ162 (SI Test Valve)	None	N/A (fair close circuit)	None
SV-753 (Panel 245)	Control for valve 1SJ158 (SI Test Valve)	None	N/A (fair close circuit)	None
Limit Switches CVO, CVC (11SJ162)	Position indication circuitry for valve 11SJ162	None	N/A	None

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-114 (Panel 208)	Control for valve 1SJ53 (Containment Isolation Valve)	Valve 1SJ53 closes for an accident (T signal) solenoid valve de-energizes	Fail close circuit design whether breaker trips or not due to submerged components, solenoid will de-energize	Safety function will be performed
Limit Switches CVO, CVC (1SJ53)	Position indication circuitry for valve 1SJ53 (Isol. Valve)	None	N/A	None
Aux. Relays 33X/1SJ53 33Y/1SJ53	Valve position indication for 1SJ53 (Isol. Valve)	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 28

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS (Cond't.)

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X/11SJ162 33Y/11SJ162 33X/1SJ166 33Y/1SJ166 33X/1SJ159 33Y/1SJ159 33X/12SJ162 33Y/12SJ162 33X/1SJ158 33Y/1SJ158	Valve position indication for 11SJ162, 1SJ159 12SJ162, 1SJ166 and 1SJ158 Also 33Y/... aux. relays provide out of position alarm includes 33Y/1SJ53	None	Breaker trip due to submerged components will alarm loss of control voltage or valve out of position	None
Limit Switches CVO, CVC (1SJ166, 12SJ159, 12SJ162 and 1SJ158)	Position indication circuitry for valves 1SJ166, 1SJ159, 12SJ162 and 1SJ158	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

125V DC Distribution Cabinet 1AADC - Circuit 35

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-444 (Panel 240)	Control for valve 14CV104 (RCP Seal Leak Off)	None	N/A	None

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-443 (Panel 355)	Control for valve 14WR62 (Standpipe Supply)	None	N/A	None
Limit Switches CVO, CVC (14WR62, 14CV104)	Position indication circuitry for valve 14WR62 and 14CV104	None	N/A	None
Aux. Relays 33X/SSV 33Y/SSV 33X/SLV 33Y/SLV	Valve position indication for 14CV104 and 14WR62	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 125VDC
CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER

TABLE 7.3-5 (Sheet 1 of 8)

Safety Evaluation - Submerged Electrical Components in the Containment During Post LOCA Conditions
115V AC Vital Instrument Bus 1A - Circuit 19

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Control Gr. Affiliation	Accident/Safety Requirements	Analysis	Results/Effects
PT-936A (Panel 233)	Accumulator Pressure No. 11	Process Gr. 1 Rack 21	Required during injection phase for up to 5 minutes following an accident	Instrument will function for the required time period prior to any flooding - Panel 233 is located at El. 78" with the instrument approx. 4' up from the bottom	Safety function will be performed
LT-934A (Panel 233)	Accumulator Level No. 11	Process Gr. 1 Rack 21	None	N/A	None
PT-937B (Panel 234)	Accumulator Pressure No. 12	Process Gr. 1 Rack 21	Required during injection phase for up to 5 minutes following an accident	Instrument will function for the required time period prior to any flooding - Panel 234 is located at El.78' with the instrument approx. 4' up from the bottom	Safety function will be performed
LT-935B (Panel 234)	Accumulator Level No. 12	Process Gr. 1 Rack 21	None	N/A	None
PT-188 (Panel 237)	No. 11 Reactor Coolant Pump Seal Water Diff. Pressure	Process Gr. 1 Rack 21	None	N/A	None
FIT-159A (Local)	No. 11 Reactor Coolant Pump Seal Leakoff Flow	Process Gr. 1 Rack 21	None	N/A	None
FIT-159B (Local)	No. 11 Reactor Coolant Pump Seal Leakoff Flow	Process Gr. 1 Rack 21	None	N/A	N/A

CIRCUIT PROTECTION - ENTIRE 115V AC CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER. INDIVIDUAL PROCESS/PROTECTION CONTROL AND INDICATION LOOPS PROVIDED WITH THEIR OWN INTERNAL POWER SUPPLIES AND 0.2 AMP FUSE PROTECTION

Safety Evaluation - Submerged Electrical Components in the Containment During Post LOCA Conditions
115V AC Vital Instrument Bus 1A - Circuit 20

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Control Gr. Affiliation	Accident/Safety Requirements	Analysis	Results/Effects
PT-405 (Panel 237)	Reactor Coolant Pressure	Protection Channel I Rack 4	Provides Interlock for Valve 1RH2 - not required for an accident	Valve 1RH2 is closed and the loss of PT405 will not affect equipment required for the accident	None
PT414 (Panel 447-1A)	No. 11 Reactor Coolant Loop Flow	Protection Channel I Rack 3	Provides input to reactor trip logic, not required for long term accident conditions	Instrument is provided for loss of flow protection. Reactor will trip on safety injection signal for a loss of coolant accident. The loss of the instrument due to flooding is acceptable	None - Safety function is performed
FT-424 (Panel 447-1D)	No. 12 Reactor Coolant Loop Flow	Protection Channel I Rack 3	Provides input to reactor trip logic, not required for long term accident conditions	Same analysis as for FT-414 above	None - Safety function is performed
FT-434 (Panel 447-1G)	No. 13 Reactor Coolant Loop Flow	Protection Channel I Rack 3	Provides input to reactor trip logic, not required for long term accident conditions	Same analysis as for FT-414 above	None - Safety function is performed
FT-444 (Panel 447-1K	No. 14 Reactor Coolant Loop Flow	Protection Channel I Rack 3	Provides input to reactor trip logic, not required for long term accident conditions	Same analysis as for for FT-414 above	None - Safety function is performed

CIRCUIT PROTECTION - ENTIRE 115 V AC CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER
INDIVIDUAL PROCESS/PROTECTION CONTROL AND INDICATION LOOPS PROVIDED WITH THEIR OWN INTERNAL POWER SUPPLIES AND 0.2 AMP FUSE PROTECTION

TABLE 7.3-5 (Sheet 3 of 8)

Safety Evaluation - Submerged Electrical Components in the Containment During Post LOCA Conditions
115V AC Vital Instrument Bus 1B - Circuit 15

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Control Gr. Affiliation	Accident/Safety Requirements	Analysis	Results/Effects
PT-472 (Panel 232)	Pressurizer Relief Tank Pressure	Process Gr. 2 Rack 20	None	N/A	None
LT-470 (Panel 232	Pressurizer Relief Tank Level	Process Gr. 2 Rack 20	None	N/A	None
PT-187 (Panel 232)	No. 12 Reactor Coolant Seal Water Diff. Pressure	Process Gr. 2 Rack 16	None	N/A	None
PT-937A (Panel 233)	Accumulator Pressure No. 11	Process Gr. 2 Rack 16	Required during injection phase for up to 5 minutes following an accident	Instrument will function for the required time period prior to flooding - Panel 233 is located at El.78' with the instrument approx. 4' up from the bottom	Safety function will be performed
LT-935A (Panel 233)	Accumulator Level No. 11	Process Gr. 2 Rack 16	None	N/A	None
PT-936B (Panel 234)	Accumulator Pressure No. 12	Process Gr. 2 Rack 16	Required during injection phase for up to 5 minutes following an accident	Instrument will function for the required time period prior to flooding - Panel 234 is located at El.78' with the instrument approx. 4' up from the bottom	Safety function will be performed
LT-934B (Panel 234)	Accumulator Level No. 12	Process Gr. 2 Rack 16	None	N/A	None
PT-121 (Panel 241)	Excess Letdown Pressure	Process Gr. 2 Rack 16	None	N/A	None
E/P Converter (Panel 241)	Control for Valve 1CV132	Process Gr. 2 Rack 16	None	N/A	None
FIT-158A (Local	No. 12 Reactor Coolant Pump Seal Leakoff Flow	Process Gr. 2 Rack 16	None	N/A	None
FIT-158A (Local)	No. 12 Reactor Coolant Pump Seal Leakoff Flow	Process Gr. 2 Rack 16	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 115 V AC CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER
INDIVIDUAL PROCESS/PROTECTION CONTROL AND INDICATION LOOPS PROVIDED WITH THEIR OWN INTERNAL POWER SUPPLIES AND 0.2 AMP FUSE PROTECTION

TABLE 7.3-5 (Sheet 4 of 8)

Safety Evaluation - Submerged Electrical Components in the Containment During Post LOCA Conditions
115V AC Vital Instrument Bus 1B - Circuit 16

UBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Control Gr. Affiliation	Accident/Safety Requirements	Analysis	Results/Effects
PT-403 (Panel 241)	Reactor Coolant Pressure	Progection Channel II Rack 6	Provide interlock for Valve 1RH1 - not required for an accident	Valve 1RH1 is closed and the loss of PT403 will not affect equipment required for the accident	None
PT-415 (Panel 447-1B)	No. 11 Reactor Coolant Loop Flow	Protection Channel II Rack 7	Provides input to reactor trip logic, not required for long term accident conditions	Instrument is provided for loss of flow protection. A reactor trip will be initiated by a safety injection signal for the loss of coolant accident. The loss of the instrument due to flooding acceptable	None - Safety function is performed
FT-425 (Panel 447-1E)	No. 12 Reactor Coolant Loop Flow	Protection Channel II Rack 7	Provides input to reactor trip logic, not required for long term accident conditions	Same analysis as for FT-415 above	None - Safety function is performed
FT-435 (Panel 447-1H)	No. 13 Reactor Coolant Loop Flow	Protection Channel II Rack 7	Provides input to reactor trip logic, not required for long term accident conditions	Same analysis as for FT-415 above	None - Safety function is performed
-445 Panel 447-	No. 14 Reactor Coolant Loop Flow	Protection Channel II Rack 7	Provides input to reactor trip logic, not required for long term accident conditions	Same analysis as for FT-415 above	None - Safety function is performed

CIRCUIT PROTECTION - ENTIRE 115 V AC CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER
INDIVIDUAL PROCESS/PROTECTION CONTROL AND INDICATION LOOPS PROVIDED WITH THEIR OWN INTERNAL POWER SUPPLIES AND 0.2 AMP FUSE PROTECTION

TABLE 7.3-5 (Sheet 5 of 8)

Safety Evaluation - Submerged Electrical Components in the Containment During Post LOCA Conditions
115V AC Vital Instrument Bus 1C - Circuit 12

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Control Gr. Affiliation	Accident/Safety Requirements	Analysis	Results/Effects
PT-936C (Panel 235)	Accumulator Pressure No. 13	Process Gr. 3 Rack 24	Required during injection phase for up to 5 minutes following an accident	Instrument will function for the required time period prior to any flooding - Panel 235 is located at El.78' with the instrument approx. 4' up from the bottom	Safety function will be performed
LT-934C (Panel 235)	Accumulator Level No. 13	Process Gr. 3 Rack 24	None	N/A	None
PT-937D (Panel 236)	Accumulator Pressure No. 14	Process Gr. 3 Rack 24	Required during injection phase for up to 5 minutes following an accident	Instrument will function for the required time period prior to any flooding - Panel 236 is located at El.78' with the instrument approx. 4' up from the bottom	Safety function will be performed
LT-935D (Panel 236)	Accumulator Level No. 14	Process Gr.f 3 Rackf 24	None	N/A	None
PT-186 (Panel 241)	No. 13 Reactor Coolant Pump Seal Water Diff. Pressure	Process Gr. 3 Rack 24	None	N/A	None
FIT-157A (Local)	No. 13 Reactor Coolant Pump Seal Leakoff Flow	Process Gr. 3 Rack 24	None	N/A	None
FIT-157B (Local	No. 13 Reactor Coolant Pump Seal Leakoff Flow	Process Gr. 3 Rack 24	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 115 V AC CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER
INDIVIDUAL PROCESS/PROTECTION CONTROL AND INDICATION LOOPS PROVIDED WITH THEIR OWN INTERNAL POWER SUPPLIES AND 0.2 AMP FUSE PROTECTION

TABLE 7.3-5 (Sheet 6 of 8)

Safety Evaluation - Submerged Electrical Components in the Containment During Post LOCA Conditions
115V AC Vital Instrument Bus 1C - Circuit 13

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Control Gr. Affiliation	Accident/Safety Requirements	Analysis	Results/Effects
FT-416 (Panel 447-1C)	No. 11 Reactor Coolant Loop Flow	Protection Channel III Rack 12	Provides input to reactor trip logic, not required for long term accident conditions	Instrument is provided for loss of flow protection. A reactor trip will be initiated by a safety injection signal for the loss of coolant accident. The loss of the instrument due to flooding is acceptable	None - Safety function is performed
FT-426 (Panel 447-1F)	No. 12 Reactor Coolant Loop Flow	Protection Cahnnel III Rack 12	Provides input to reactor trip logic, not required for long term accident conditions	Same analysis as FT-416 above	None - Safety function is performed
FT-436 (Panel 447-1J)	No. 13 Reactor Coolant Loop Flow	Protection Channel III Rack 12	Provides input to reactor trip logic, not required for long term accident conditions	Same analysis as FT-416	None - Safety function is performed
FT-446 (Panel 447-1M)	No. 14 Reactor Coolant Loop Flow	Protection Channel III Rack 12	Provides input to reactor trip logic, not required for long term accident conditions	Same analysis as FT-416	None - Safety function is performed

CIRCUIT PROTECTION - ENTIRE 115 V AC CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER
INDIVIDUAL PROCESS/PROTECTION CONTROL AND INDICATION LOOPS PROVIDED WITH THEIR OWN INTERNAL POWER SUPPLIES AND 0.2 AMP FUSE PROTECTION

Safety Evaluation - Submerged Electrical Components in the Containment During Post LOCA Conditions
115V AC Vital Instrument Bus 1D - Circuit 7

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Control Gr. Affiliation	Accident/Safety Requirements	Analysis	Results/Effects
PT-937C (Panel 235)	Accumulator Pressure No. 13	Process Gr. 4 Rack 28	Required during injection phase for up to 5 minutes following an accident	Instrument will function for the required time period prior to flooding - Panel 235 is located at El.78' with the instrument approx. 4' up from the bottom	Safety function will be performed
LT-935C (Panel 235)	Accumulator Level No. 13	Process Gr. 4 Rack 28	None	N/A	None
PT-936D (Panel 236)	Accumulator Pressure No. 14	Process Gr. 4 Rack 28	Required during injection phase for up to 5 minutes following an accident	Instrument will function for the required time period prior to flooding - Panel 236 is located at El.78' with the instrument approx. 4' up from the bottom	Safety function will be performed
LT-934D (Panel 236)	Accumulator Level No. 14	Process Gr. 4 Rack 27	None	N/A	None
PT-183 (Panel 240)	No. 14 Reactor Coolant Pump Seal Water Diff. Pressure	Process Gr. 4 Rack 27	None	N/A	None
E/P Converter (Panel 241)	Control for Valve INT35	Process Gr. 4 Rack 28	None	N/A	None
FIT-156A (Local	No. 14 Reactor Coolant Pump Seal Leakoff Flow	Process Gr. 4 Rack 28	None	N/A	None
FIT-156B (Local	No. 14 Reactor Coolant Pump Seal Leakoff Flow	Process Gr. 4	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 115 V AC CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER
INDIVIDUAL PROCESS/PROTECTION CONTROL AND INDICATION LOOPS PROVIDED WITH THEIR OWN INTERNAL POWER SUPPLIES AND 0.2 AMP FUSE PROTECTION

Safety Evaluation - Submerged Electrical Components in the Containment During Post LOCA Conditions
115V AC Vital Instrument Bus 1D - Circuit 7

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Component	Function	Control Gr. Affiliation	Accident/Safety Requirements	Analysis	Results/Effects
Triaxial Accelerometer	Seismic Instrumention	N/A	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 115V AC CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER.
ONLY THE SEISMIC INSTRUMENTATION SYSTEM IS CONNECTED TO THIS CIRCUIT.

TABLE 7.3-6 (Sheet 1 of 7)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

230V AC Vital Control Center 1A Ventilation - Circuit Section 1D

SUBMERGED ELECTRIC COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-912 (Panel 247-1A)	Control for Damer 1CBV34 (No. 11 Reactor Nozzle Support Fan)	None	N/A	None
FD-7670 (Local)	Low Flow Alarm for No. 11 Reactor Support Vent System	None	N/A	None
TD-7671 (Local)	Hi Temperature Alarm for No. 11 Reactor Support Vent System	None	N/A	None
No. 11 Reactor Nozzle Support Fan	Nozzle Support Vent System	None	N/A	None
Limit Switch CDO for Damper 1CBV34	Position Indication Circuitry for Damper	None	N/A	None

NON SUBMERGED ASSOCISTED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X 63X 23X	Alarm Circuitry for Damper Position, Low Air Flow, Hi Air Temperature for No. 11 Reactor Nozzle Support Vent System	None	N/A	None
Aux. Relays 6X, 3X, 6Y and Starter Relay Relay 6	Fan and Damper Operation Control	None	N/A	None
Relay 74/AC	Provides Loss of 115V AC Control Voltage for No. 11 Circuit	None	230V Breaker/ Control circuit fuse trip due to submerged components will alarm loss of control voltage for this circuit	

CIRCUIT PROTECTION - MOTOR CONTROL CENTER CIRCUIT PROVIDED WITH MANUAL CLASS 1E CIRCUIT BREAKER. VENT FAN MOTOR POWER CIRCUIT PROTECTED BY OPEN MOTOR STARTER CONTACTOR. CONTROL CIRCUIT (DEVELOPED FROM A 130/115V TRANSFORMER) IS PROTECTED BY 15 AMP FUSES.

TABLE 7.3-6 (Sheet 2 of 7)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

230V AC Vital Control Center 1B Ventilation - Circuit Section 1D

SUBMERGED ELECTRIC COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-913 (Panel 247-1A)	Control for Damper 1CBV32) (No. 12 Reactor Nozzle Support Fan)	None	N/A	None
FD-7672 (Local)	Low Flow Alarm for No. 12 Reactor Support Vent System	None	N/A	None
TD-7673 (Local)	Hi Temperature Alarm for No. 12 Reactor Support Vent System	None	N/A	None
No. 12 Reactor Nozzle Support Fan	Nozzle Support Vent System	None	N/A	None
Limit Switch CDO for Damper 1CBV32	Position Indication Circuitry for Damper	None	N/A	None

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X 63X 23X	Alarm Circuitry for Damper Position, Low Air Flow, Hi Air Temperature for No. 12 Reactor Nozzle Support Vent System	None	N/A	None
Aux. Relays 6X, 3X, 6Y, and Starter Relay 6	Fan and Damper Operation Control	None	N/A	None
Relay 74/AC	Provides Loss of 115V AC Voltage for No. 12 Fan Control Circuit	None	230V Breaker/ Control circuit fuse trip due to submerged componets will alarm loss of control voltage for this circuit	

CIRCUIT PROTECTION - MOTOR CONTROL CENTER CIRCUIT PROVIDED WITH MANUAL CLASS 1E CIRCUIT BREAKER. VENT FAN MOTOR POWER CIRCUIT PROTECTED BY OPEN MOTOR STARTER CONTACTOR. CONTROL CIRCUIT (DEVELOPED FROM A 230/115V TRANSFORMER) IS PROTECTED BY 15 AMP FUSES.

TABLE 7.3-6 (Sheet 3 of 7)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

230V AC Vital Control Center 1C Ventilation - Circuit Section 1A

SUBMERGED ELECTRIC COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-914 (Panel 247-1A)	Control for Damper 1CBV33) (No. 13 Reactor Nozzle Support Fan)	None	N/A	None
FD-7674 (Local)	Low Flow Alarm for No. 13 Reactor Support Vent System	None	N/A	None
TD-7675 (Local)	Hi Temperature Alarm for No. 13 Reactor Support Vent System	None	N/A	None
No. 13 Reactor Nozzle Support Fan	Nozzle Support Vent System	None	N/A	None
Limit Switch CDO for Damper 1CBV33	Position Indication Circuitry for Damper	None	N/A	None

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X 63X 23X	Alarm Circuitry for Damper Position, Low Air Flow, Hi Air Temperature for No. 13 Reactor Nozzle Support Vent System	None	N/A	None
Aux. Relays 6X, 3X, 6Y, and Starter Relay 6	Fan and Damper Operation Control	None	N/A	None
Relay 74/AC	Provides Loss of 115V AC Voltage for No. 13 Fan Control Circuit	None	230V Breaker/ Control circuit fuse trip due to submerged componets will alarm loss of control voltage for this circuit	

CIRCUIT PROTECTION - MOTOR CONTROL CENTER CIRCUIT PROVIDED WITH MANUAL CLASS 1E CIRCUIT BREAKER. VENT FAN MOTOR POWER CIRCUIT PROTECTED BY OPEN MOTOR STARTER CONTACTOR. CONTROL CIRCUIT (DEVELOPED FROM A 230/115V TRANSFORMER) IS PROTECTED BY 15 AMP FUSES.

TABLE 7.3-6 (Sheet 4 of 7)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

230V AC Vital Control Center 1C Ventilation - Circuit Section 2A

SUBMERGED ELECTRIC COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
SV-915 (Panel 247-1A)	Control for Damper 1CBV31) (No. 14 Reactor Nozzle Support Fan)	None	N/A	None
FD-7676 (Local)	Low Flow Alarm for No. 14 Reactor Support Vent System	None	N/A	None
TD-7677 (Local)	Hi Temperature Alarm for No. 14 Reactor Support Vent System	None	N/A	None
No. 14 Reactor Nozzle Support Fan	Nozzle Support Vent System	None	N/A	None
Limit Switch CDO for Damper 1CBV31	Position Indication Circuitry for Damper	None	N/A	None

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X 63X 23X	Alarm Circuitry for Damper Position, Low Air Flow, Hi Air Temperature for No. 14 Reactor Nozzle Support Vent System	None	N/A	None
Aux. Relays 6X, 3X, 6Y, and Starter Relay 6	Fan and Damper Operation Control	None	N/A	None
Relay 74/AC	Provides Loss of 115V AC Voltage for No. 14 Fan Control Circuit	None	230V Breaker/ Control circuit fuse trip due to submerged componets will alarm loss of control voltage for this circuit	

CIRCUIT PROTECTION - MOTOR CONTROL CENTER CIRCUIT PROVIDED WITH MANUAL CLASS 1E CIRCUIT BREAKER. VENT FAN MOTOR POWER CIRCUIT PROTECTED BY OPEN MOTOR STARTER CONTACTOR. CONTROL CIRCUIT (DEVELOPED FROM A 230/115V TRANSFORMER) IS PROTECTED BY 15 AMP FUSES.

TABLE 7.3-6 (Sheet 5 of 7)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

230V AC Vital Control Center 1A East Valves - Circuit Section 4I

SUBMERGED ELECTRIC COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
1CC190 (Motor operated)	Reactor Coolant Pump Thermal Barrier Component Cooling Water Return (Containment Isolation Valve)	Valve closes for an accident (P signal)	Valve closes on signal prior to valve becoming submerged (located at approx. El.79')	Safety function wil be performed
Limit and Torque Switches for Valve 1CC190	Control and position indications for valve 1CC190	Control portion of function needed till valve operates as required	Same analysis as above for the valve itself	Safety function wil be performed

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X 33Y	Valve position indicationf for 1CC190	None	N/A	None
Relay 74AC/TBV	Provides loss of 115V AC control voltage for 1CC190 control circuit	None	230 Breaker/ Control circuit fuse trip due to submerge components will alarm loss of control voltage for this circuit	None
Aux. Relays 9X/O, 9X/C and starter 9/O 9/C	Valve Operation Control	Needed till valve operates as required	Will operate as required	Safety function wil be performed

CIRCUIT PROTECTION - MOTOR CONTROL CENTER CIRCUIT PROVIDED WITH MANUAL CLASS 1E CIRCUIT BREAKER. VENT FAN MOTOR POWER CIRCUIT PROTECTED BY OPEN MOTOR STARTER CONTACTOR. CONTROL CIRCUIT (DEVELOPED FROM A 230/115V TRANSFORMER) IS PROTECTED BY 15 AMP FUSES.

TABLE 7.3-6 (Sheet 6 of 7)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

230V AC Vital Control Center 1A East Valves - Circuit Section 5E

SUBMERGED ELECTRIC COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
1CC187 (Motor operated)	Reactor Coolant Pump Component Cooling Water Return (Containment Isolation Valve)	Valve closes for an accident (P signal)	Valve closes on signal prior to valve becoming submerged (located at approx. El.79')	Safety function wil be performed
Limit and Torque Switches for Valve 1CC187	Control and position indications for valve 1CC187	Control portion of function needed till valve operates as required	Same analysis as above for the valve itself	Safety function wil be performed

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X/14B 33Y/14B	Valve position indicationf for 1CC187	None	N/A	None
Relay 74AC/14B	Provides loss of 115V AC control voltage for 1CC187 control circuit	None	230 Breaker/ Control circuit fuse trip due to submerge components will alarm loss of control voltage for this circuit	None
Aux. Relays 9X/O, 9X/C and starter 9/O 9/C	Valve Operation Control	Needed till valve operates as required	Will operate as required	Safety function wil be performed

CIRCUIT PROTECTION - MOTOR CONTROL CENTER CIRCUIT PROVIDED WITH MANUAL CLASS 1E CIRCUIT BREAKER. VENT FAN MOTOR POWER CIRCUIT PROTECTED BY OPEN MOTOR STARTER CONTACTOR. CONTROL CIRCUIT (DEVELOPED FROM A 230/115V TRANSFORMER) IS PROTECTED BY 15 AMP FUSES.

TABLE 7.3-6 (Sheet 7 of 7)

Safety Evaluation - Electrical Components And Circuits That Are Affected By the Flooding Of Components Within The Containment During Post LOCA Conditions

230V AC Vital Control Center 1B East Valves - Circuit Section 5A

SUBMERGED ELECTRIC COMPONENTS IN CONTAINMENT

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
1CC284 (Motor operated)	Reactor Coolant Pump Seal Water Return (Containment Isolation Valve)	Valve closes for an accident (P signal)	Valve closes on signal prior to valve becoming submerged (located at approx. El.79')	Safety function wi[ll] be performed
Limit and Torque Switches for Valve 1CC184	Control and position indications for valve 1CC184	Control portion of function needed till valve operates as required	Same analysis as above for the valve itself	Safety function wi[ll] be performed

NON SUBMERGED ASSOCIATED ELECTRICAL COMPONENTS

Component	Function	Accident/Safety Requirements	Analysis	Results/Effects
Aux. Relays 33X/SWB 33Y/SWB	Valve position indicationf for 1CC284	None	N/A	None
Relay 74AC/SWB	Provides loss of 115V AC control voltage for 1CC284 control circuit	None	230 Breaker/ Control circuit fuse trip due to submerge components will alarm loss of control voltage for this circuit	None
Aux. Relays 9X/O, 9X/C and starter 9/O 9/C	Valve Operation Control	Needed till valve operates as required	Will operate as required	Safety function wi[ll] be performed

CIRCUIT PROTECTION - MOTOR CONTROL CENTER CIRCUIT PROVIDED WITH MANUAL CLASS 1E CIRCUIT BREAKER. VENT FAN MOTOR POWER CIRCUIT PROTECTED BY OPEN MOTOR STARTER CONTACTOR. CONTROL CIRCUIT (DEVELOPED FROM A 230/115V TRANSFORMER) IS PROTECTED BY 15 AMP FUSES.

TABLE 7.3-7

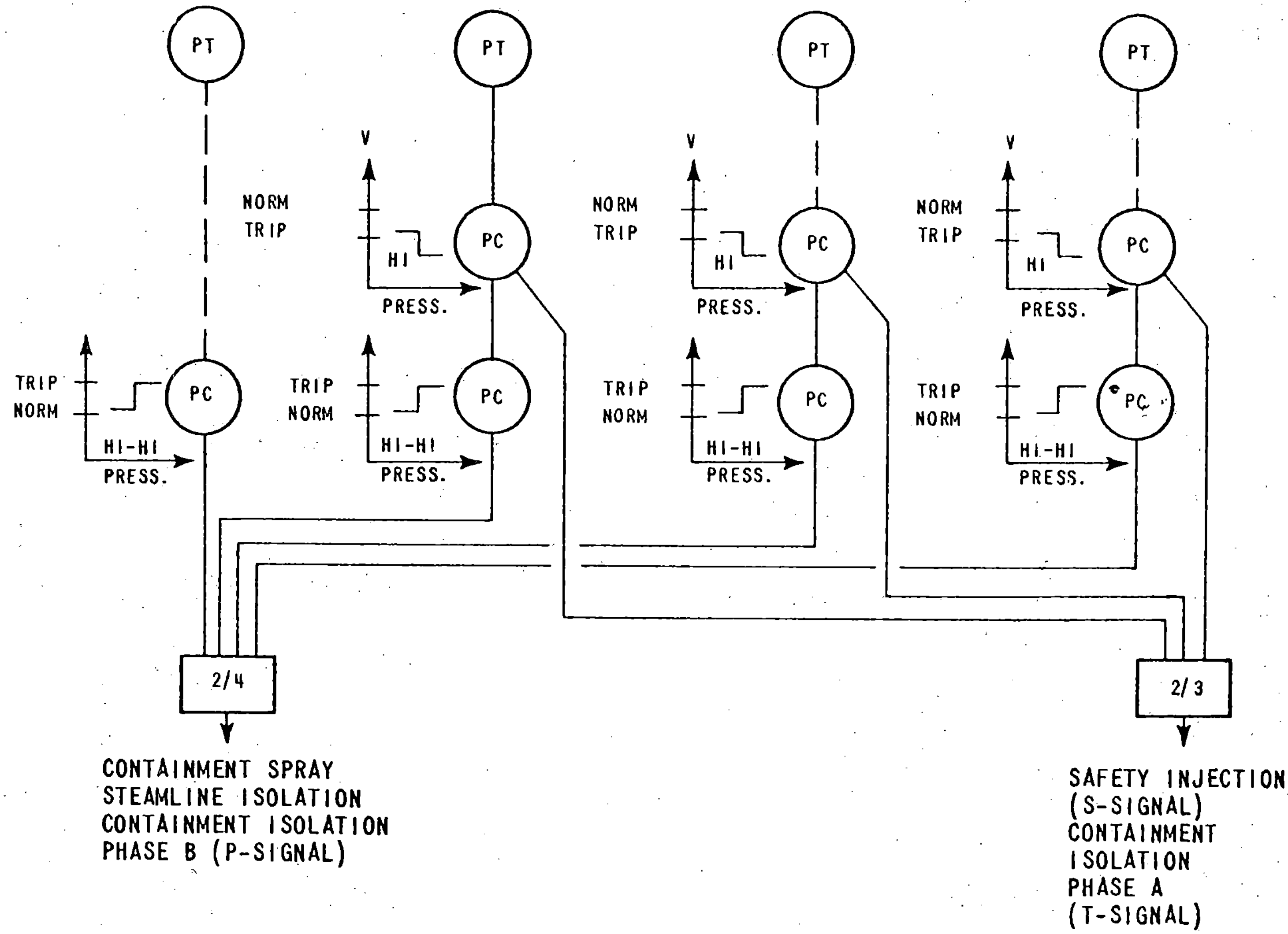
Safety Evaluation - Electrical Components and Circuits That are Affected By the Flooding of Components Within The Containment During Post LOCA Conditions

Junction/Terminal Boxes

SUBMERGED ELECTRICAL COMPONENTS IN CONTAINMENT

Jun/Ter Box	Functions	Circuit Affiliation	Accident/Safety Requirements	Analysis	Results/ Effects
JT 11	Limit Switches for Valves 11SJ20, 11SJ27, 11SJ57, 11SJ58, 11SJ93 (Position Indication)	1AADC - No. 15	None	N/A	None
JT 12	Limit Switches for Valves 12SJ20, 12SJ27, 12SJ57, 12SJ58, 12SJ93 (Position Indication)	1BBDC - No. 17	None	N/A	None
JT 13	Limit Switches for Valves 13SJ20, 13SJ27, 13SJ57, 13SJ58, 13SJ93 (Position Indication)	1CCDC - No. 17	None	N/A	None
JT 14	Limit Switches for Valves 14SJ20, 14SJ27, 14SJ57, 14SJ58, 14SJ93 (Position Indication)	1BBDC - No. 11	None	N/A	None
JT 210	Limit Switches for Valves 1CV2, 1CV3, 1CV75, 1CV277 (Position Indication)	1BBDC - No. 7, 19	None	N/A	None
JT 212	Limit Switches for Valves 1CV278, 1CV131, 1CV134 (Position Indication)	1CCDC - No. 15	None	N/A	None
JT 122	Limit Switches for Valves 11SJ162, 12SJ162 1SJ159, 13SJ162, 14SJ162, 1SJ163 (Position Indication)	1DDC - No. 16, 28	None	N/A	None
JT 120	Limit Switches for Valves 1PR17 (Position Indication)	1AADC - No. 12	None	N/A	None

CIRCUIT PROTECTION - REFER TO DC CIRCUIT ANALYSIS TABLES Q6.28-2.1 THROUGH Q6.28-2.21



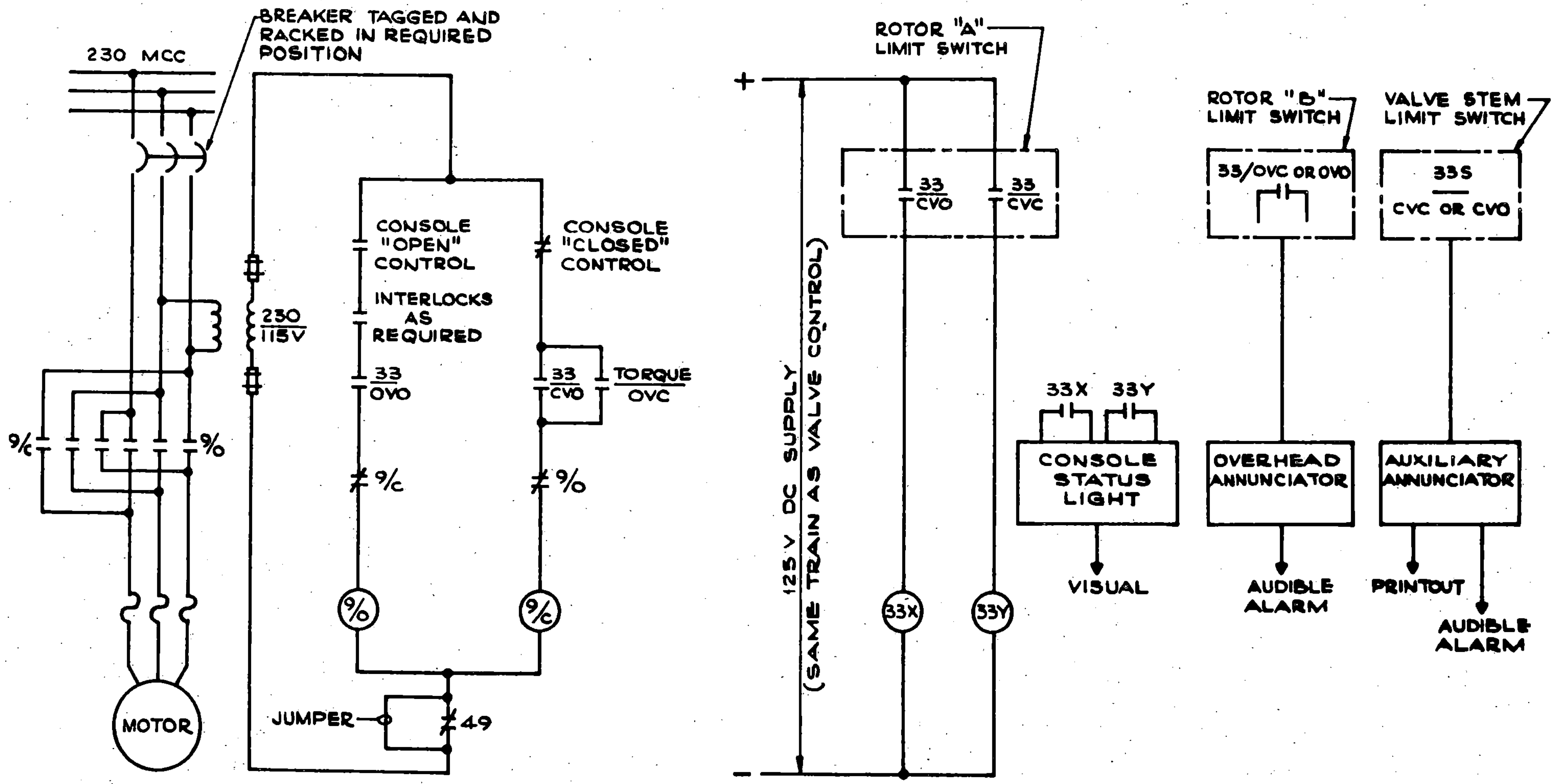
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Updated FSAR

Containment Pressure Instrumentation

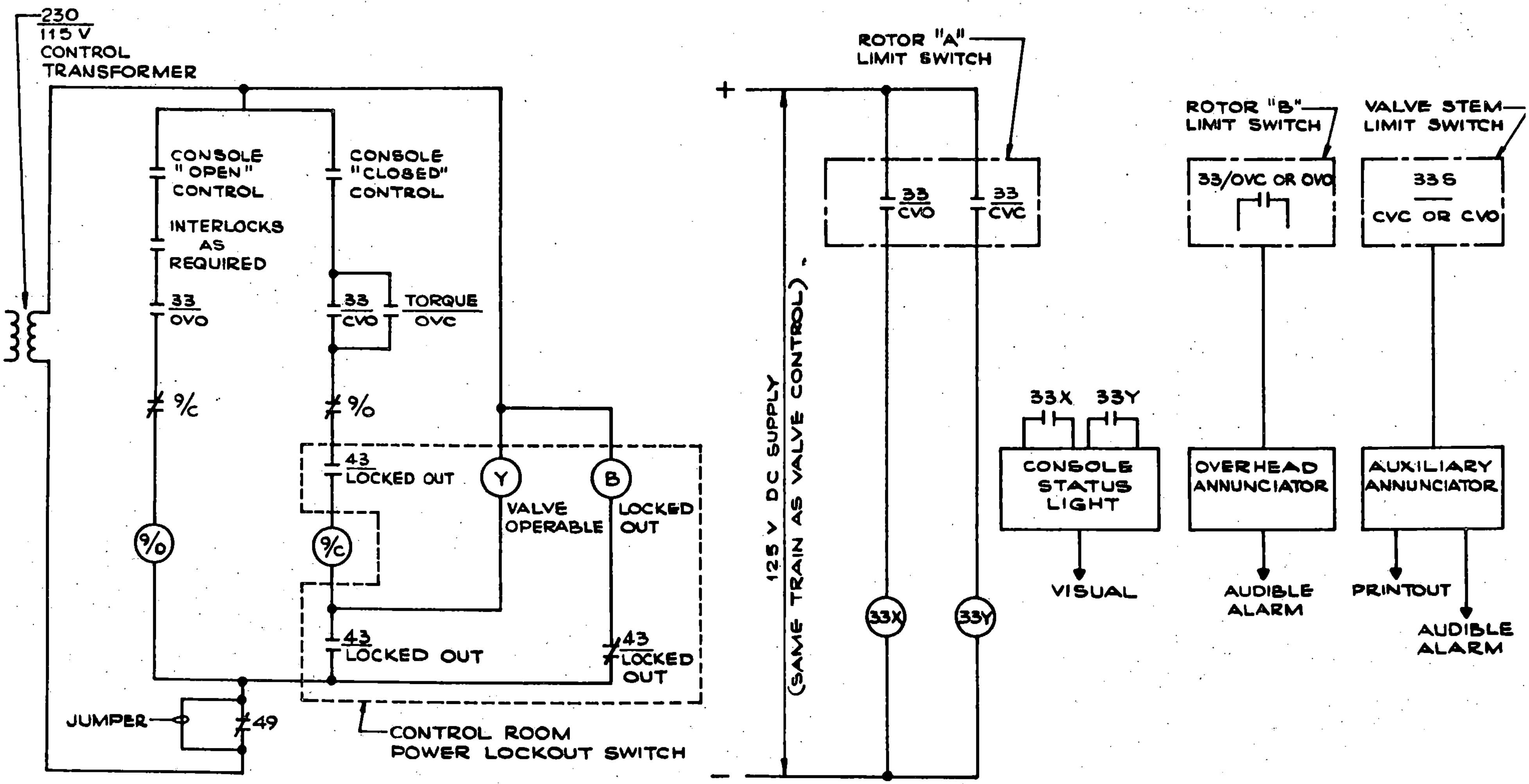
Figure 7.3-1

Revision 0
July 22, 1982



Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Typical MOV 230 V Power Lockout
	Updated FSAR Figure 7.3-2



Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Typical MOV Control Power Lockout
	Updated FSAR — Figure 7.3-3

7.4 SYSTEMS REQUIRED FOR SAFE SHUTDOWN

The process of attaining safe shutdown in accordance with Branch Technical Position RSB 5-1 is described in Section 5.5. Equipment for attaining safe shutdown from outside the Control Room is discussed in the following sections.

7.4.1 HOT SHUTDOWN OUTSIDE THE CONTROL ROOM

The probability of the Control Room becoming inaccessible as a result of any cause is considered extremely small. If the operator must leave the Control Room, however, operating procedures require that he trip the reactor and turbine generator prior to leaving, thus ensuring control at the hot shutdown control stations. If necessary, the required trips can be accomplished at locations outside the Control Room.

The reactor unit can be maintained in a hot shutdown condition from the hot shutdown control stations. The following control features are provided:

1. Core residual heat removal
2. Boration of the Reactor Coolant System
3. Pressurizer level and pressure control
4. Containment fan cooler operation

These functions require the operation of auxiliary feedwater pumps, charging pumps, boric acid transfer pumps, service water pumps and containment fan cooler units. Appropriate process instrumentation such as pressurizer pressure and level, steam generator pressure and level, component cooling flow and service water pressure are provided. This equipment is sufficient to safely maintain the unit in a hot shutdown condition for an extended period of time.

7.4.2 COLD SHUTDOWN OUTSIDE THE CONTROL ROOM

There is no reason to assume any significant damage to equipment in the Control Room area nor is there any reason to believe that access to the Control Room could not be regained during the extended period of hot shutdown. However, we believe the plant design does not preclude the possibility of bringing the reactor to a cold shutdown condition from outside the Control Room. On a long term basis (a week or more) an assessment of plant conditions could be made and methods established for making physical changes to instrumentation and control equipment as necessary to permit cold shutdown. The systems and equipment which would be utilized to attain cold shutdown, assuming no significant damage to equipment in the Control Room area, are given below:

<u>Process Systems</u>

1. Heat removal - natural or forced circulation (reactor coolant pumps)

    a. Controlled steam release and feedwater supply
    b. Residual Heat Removal System

2. Boration capability

3. Nuclear Instrument System

    a. Source range and intermediate range

4. Reactor coolant inventory control

    a. Charging and letdown

5. Pressurizer pressure control

    a. Heaters

b. Spray
c. Relief valves

6. Control air service

Equipment

1. Reactor coolant pump
2. Auxiliary feedwater pumps
3. Boric acid transfer pumps
4. Charging pumps
5. Service water pumps
6. Containment fan coolers
7. Control Room air conditioning
8. Component cooling pumps
9. Residual heat removal pumps
10. Certain motor control center and switchgear sections

Instrumentation

1. Pressurizer

   a. Level indicators
   b. Pressure indicators

2. Steam Generators

   a. Level indicators
   b. Pressure indicators

3. Reactor coolant wide range temperature indicators

4. Reactor coolant wide range pressure indicators

5. Source range indication

6. Intermediate range indication

7. Component cooling water temperature indication

8. Reactor coolant pump instrumentation

9. Residual heat removal system instrumentation

10. Radiation monitors

Controls

Controls are required for all Equipment listed above, and also the following:

1. Steam dump control (for atmospheric relief valve and condenser steam dump valve)

2. Feedwater supply

3. Manual control of residual heat removal throttle valves

4. Make-up of reactor coolant shrinkage by manual control of charging

5. Pressurizer heater on/off controls

6. Pressurizer relief valves

7. Pressurizer auxiliary spray open/close control

8. Reactor coolant pump oil lift pump

9. Open/close switch control of letdown isolation valve

10. Safeguards controls

    a. Defeat Safety Injection System automatic operation

7.5 SAFETY RELATED DISPLAY INSTRUMENTATION

7.5.1 DESCRIPTION

Table 7.5-1 lists the major process parameters available to the operator to enable him to perform required manual functions and to determine the effect of manual actions taken following a reactor trip due to operational occurences or accident conditions discussed in Chapter 15. The table lists the readouts required to maintain the plant in a hot shutdown condition or to proceed to cold shutdown within the limits of the Technical Specifications. Reactivity control after operational occurrences will be maintained by administrative sampling of the reactor coolant for boron to insure that the concentration is sufficient to maintain the reactor subcritical.

As shown in the table sufficient duplication of information is provided. The information is part of the operational monitoring of the plant which is under surveillance by the operator during normal plant operation. This is functionally arranged on the control board to provide the operator with timely and pertinent information on plant conditions. Comparisons between duplicate information channels or between functionally related channels will enable the operator to readily identify a malfunction in a particular channel.

The information system that provides the signals to the indicators and/or recorders listed in the table is described in Section 7.2, with the exceptions of the refueling water storage tank level and the steam generator wide range water level. The refueling water storage tank level is indicated and alarmed by two independent single channel systems. Each steam generator water level (wide range) is indicated by independent single channel systems and recorded by a single channel system. No automatic protection or control functions are provided by these devices. The remaining signals are obtained through isolation amplifiers from the protection channels.

This allows the automatic protection system to function independently of any failure of the non-protection equipment and provides the most reliable means of obtaining the information.

There is no basis for assuming that the occurence of an accident itself degrades the display system. Therefore, the status and reliability of the information is known to the operator before, during, and after the accident.

The design criteria used in the display system are listed below:

1. Range and accuracy requirements are determined through the analyses of postulated occurences as described in Chapter 15. The display meets the following requirements:

    a. The range of the readouts extend over the maximum expected range of the variable being measured.

    b. The combined indicated accuracies are within the errors assumed in the safety analyses.

2. Power for the display instruments is obtained from the 115 V power system described in Chapter 8.

3. Those channels which have been determined to provide useful information in charting the course of events are recorded.

Table 7.5-2 lists the indications available to the operator to monitor significant plant parameters during normal operation.

7.5.2 BYPASS INDICATION

The Containment Spray System is a typical Engineered Safety Features (ESF) system which incorporates status indications. The spray pumps and the system motor-operated valves have open/close lights on the main control console pushbutton stations and loss of control voltage alarms in the auxiliary alarm system. The spray additive tank valve, 1CS14, also has an "off-normal position" alarm on the overhead annunciator.

Any equipment taken out of service for maintenance or other purposes is under the administrative control of the plant operating personnel, which includes logging of unavailable equipment and covering the control station with a plastic cover.

Bypasses of the Solid State Protection System outputs associated with the spray system are described below.

In general, if any analog channel in the ESF actuation system is taken out of service for any reason, the channel is placed in the tripped mode, and a channel trip status light is lit in the control room. In addition, an alarm will sound and an associated annunciator panel light will be lit. This holds true for the containment pressure channel associated with Safety Injection and steam line isolation functions. The channel bistable output relays associated with the containment spray function are not tripped, to reduce the possibility of inadvertent actuation, but are bypassed for test and maintenance purposes. An alarm indicating a bypassed condition is provided for each channel.

The plant design includes one, or a combination, of the following indications to show the operator the status of plant systems and to highlight the existence of an incorrect configuration:

1. Indication lights (red-open and green-closed) at the push-button control station for valves.

2. A separate monitor light indication grouped with lights for other devices having a similar function such that the lights in the group are all on or are all off to provide for quick operator evaluation

of systems status during the injection or recirculation mode of a Loss-of-Coolant Accident (LOCA).

3. Auxiliary annunciation redundant to the above indications which serve to alert the operator of the improper state, relative to plant conditions, of a critical device (pump, valve, etc.).

By looking at equipment status indications, and operator can determine if components in the ESF systems have been isolated or bypassed.

The following alarms have been provided in the Control Room to indicate test of bypass for ESF systems:

Spray channel comparator tripped (4 alarms)
Spray channel comparator on test (4 alarms)
Solid state protection Train A trouble
Solid state protection Train B trouble
Solid state protection Train A on test
Solid state protection Train B on test
Reactor protection channel on test (4 alarms)
Nuclear instrument channel on test
Rod position indication on test
Safeguards equipment control systems on test (3 alarms)
NIS loss of detector of compensation voltage (5 alarms)
NIS source range high flux at shutdown blocked
NIS source and intermediate range trip bypass
Diesel generator urgent trouble (3 alarms)
Diesel generator fuel oil day tank trouble
4Kv vital bus alarms (18 alarms)

The following lights on the status panel indicate bypass conditions:

Source range trip blocked (2 lights)
Source range Trains A and B trip blocked

Intermediate range trip blocked (2 lights)
Intermediate range trip A and B trip blocked
Power range (low setpoint) trains A and B trip blocked
Steamline isolation Trains A and B safety injection blocked
Safety injection blocked Trains A and B
Automatic Safety Injection blocked
Overpower rod stop manual bypass (4 lights)
Steam dump block T average bypass

The system has been designed to meet the intent of IEEE-279, Paragraph 4.12; that is, bypasses are removed automatically when permissive conditions are not met.

7.5.3 EVALUATION

An evaluation of the Salem Unit No. 2 instrumentation systems to determine its degree of compliance with Regulatory Guide 1.97 has been completed. Since the Salem design bases for instrument systems were developed and approved by the NRC significantly prior to the issuance of this guide, the evaluation was based on compliance with the overall intent of the guide.

Demonstration of compliance with the intent of the Regulatory Guide required that any specific differences between the Salem design bases and those of the Regulatory Guide be identified. The identification of these differences are specified in Section 7.5.3.1.

The key elements of the overall evaluation can be summarized as follows:

1. Compliance of existing systems and instrumentation is based upon meeting the intent of the Regulatory Guide.

2. Compliance of new equipment is based upon application of the Regulatory Guide to the extent that existing design can accommodate the change without compromising the existing system.

3. Previous commitments to modify existing equipment or to add new equipment were considered (e.g. NUREG-0588 and NUREG-0737) in the context of those commitments which pre-date Regulatory Guide 1.97.

The results of this evaluation have been classified into five basic types of "compliance levels". These compliance levels have been selected to illustrate the resolution actions planned for the equipment to demonstrate the overall plant compliance with Regulatory Guide 1.97. This information is included in Section 7.5.3.2 and 7.5.3.3.

7.5.3.1 <u>Identification of Design Basis Differences From Regulatory Guide 1.97</u>

To establish a baseline set of criteria for this evaluation, the Regulatory Guide 1.97 recommendations have been reviewed for similarity to the Salem plant design bases. In those instances where the Salem bases agree with the Regulatory Guide 1.97, no differences are listed below. For those cases which involve differences, a comparison is provided below to demonstrate that the intent of the guide is adequately achieved.

1. The Salem plant design bases were effectively established prior to issuance of the Regulatory Guides referenced in Regulatory Guide 1.97. Although the Salem plant conforms to the intent of the Regulatory Guides, strict compliance has not been required. In many cases, the Guides have been revised to incorporate subsequent revisions of referenced standards; and in some cases, the Guides are not applicable to the previously approved design (e.g., Regulatory Guide 1.75).

   For the purpose of compliance with Regulatory Guide 1.97, the Salem design will conform with the intent of the referenced Guides and Standards to the same extent as specified in previous responses to the NRC on the subject documents.

2. Regulatory Guide 1.89 - "Qualification of Class IE Equipment for Nuclear Power Plant". The Salem plant review basis is NUREG-0588, Category II for existing instrumentation and NUREG-0588, Category I (i.e., IEEE 323-74) for new equipment. Evaluations for equipment in harsh environments have been completed. Evaluations for noncontrolled benign environments will be completed per NRC established schedules.

   Recorders, indicators, and other instrumentation located in controlled benign environments such as the Control Room, have been considered as meeting the intent of Regulatory Guide 1.97, pending the completion of the NUREG 0588 benign environment review.

3. Regulatory Guide 1.100 - "Seismic Qualification of Electric Equipment for Nuclear Power Plants". The Salem plant review basis is IEEE 344-71, for existing equipment and IEEE 344-74, for new equipment.

4. Regulatory Guide 1.75 - "Physical Independence of Electric Systems". The Salem plant electric systems do not conform to the recommendation in Regulatory Guide 1.75, since this was not an original design criterion. New equipment will be integrated into our existing separation provisions. The Salem separation criteria has been approved by the the NRC staff as described in Safety Evaluation Report, Supplement No. 4, Section 8.4.5.

5. Regulatory Guide 1.32 - "Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants. The Salem plant review basis is IEEE 308-71, "Class IE Electric Systems for Nuclear Power Generating Stations".

6. Quality Assurance: Regulatory Guides

a. Regulatory Guide 1.28, "Quality Assurance Program Requirements (Design and Construction)" Revision 2, dated February, 1979. The Salem plant review basis is Safety Guide 28, which endorses ANSI 45.2.1 of 1971.

b. Regulatory Guide 1.38, Revision 2, dated May, 1977, "Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants". The Salem plant review basis is Regulatory Guide 1.38, Revision 1, dated October, 1976.

c. Regulatory Guide 1.64, dated June, 1976, "Quality Assurance Requirements for the Design of Nuclear Power Plants". The Salem plant review basis is Regulatory Guide 1.64, Revision 0, dated October, 1973.

d. Regulatory Guide 1.123, dated July 7, 1977, "Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants". The Salem plant review basis is ANSI 45.2.13, of 1976.

e. Regulatory Guide 1.144, Revision 1, dated September, 1980 "Auditing of Quality Assurance Programs for Nuclear Power Plants". The Salem plant review basis is ANSI 45.2.12, Draft 4, Revision 2.

f. Regulatory Guide 1.146, dated August 1980, "Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants". The Salem plant review basis does not include a commitment to Regulatory Guide 1.146.

7. Unique Identification: The instruments are not specifically identified on the control panels as those intended for use under accident conditions. The instrumentation on the control panels in the Salem Control Room is presently grouped on a functional basis. Additional markings could add confusion to a control panel layout that was favorably reviewed during the NRC "Human Factors Review of the Salem No. 2 Unit Control Room" in March of 1980.

8. Regulatory Guide 1.118 - "Periodic Testing of Electric Power and Protection Systems". The Regulatory Guide invokes the requirements of IEEE 338-1975, which is applicable to protection for Regulatory Guide 1.97, is not considered to be part of the protection system and does not require all of the testing specified in IEEE-338. The plant equipment being used for compliance with Regulatory Guide 1.97 has been designed to incorporate testing capabilities as discussed in Chapter 7.2. Testing frequencies will be in accordance with the applicable Technical Specifications.

9. <u>Type "A"Variables</u> (Plant Specific)

The definition of Type "A" Variables given by Regulatory Guide 1.97, Paragraph 1.1 is:

"Those variables to be monitored that provide the primary information required to permit the control room operators to take the specified manually controlled actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for design basis events."

The Salem Emergency Operating Procedures were reviewed to determine which Regulatory Guide 1.97, Type "A" parameters are required using the following baseline interpretation of Regulatory Guide 1.97, Paragraph 1.1.

The operating procedures specify certain operator verification of automatic actions, and if the automatic actions have not been performed (presumably due to system failure), the operator is required to manually perform those actions. The parameter selection does not include either the verification step or the manual backup action. The parameter selection includes those required for operator actions needed for system functioning where no automatic signal/system exists.

Where important, the manual Type "A" operator actions must be monitored to assure that the action has been performed. This monitoring of Type "A" operation is performed by "Type B" variables as defined by Regulatory Guide 1.97.

In reviewing the Emergency Operating Procedures, the event "end point" for parameter selection is a stable hot condition for all events except LOCA's (large or small) that cannot be isolated. The end point for LOCA's that cannot be isolated is a cold depressurized condition.

See Table 7.5-3 for an index of Class "A" Variables.

7.5.3.2 Regulatory Guide 1.97 Compliance Levels

The evaluation revealed varying degrees of compliance with Regulatory Guide 1.97 which were classified into five "compliance levels". These classifications evolved from consideration of the design bases, existing NRC commitments and specific new changes, where possible, to meet the Regulatory Guide. The overall results of this effort are summarized in Table 7.5-4. Table 7.5-5 provides justification for regulatory guide non-conformances. The Regulatory Guide 1.97 variables will be displayed on the Safety Parameter Display System (SPDS). SPDS monitors are located in the TSC and EOF. Additional information is contained in a letter from E. A. Liden to S. Varga dated September 21, 1983.

The description of each "compliance level" is provided below:

1. Items in Compliance

   The items categorized under this heading meet the PSE&G design basis as outlined in Section 7.5.3.1.

2. Items Where Design Precludes Compliance

   The items categorized under this heading are presently installed, but by nature of the present design, may not meet the recommendations in the Guide such as environmental and seismic qualifications. These items are generic to Westinghouse plants.

3. Items Which Are Being Replaced/Added

   The items categorized under this heading deviate from one or more recommendations in the Guide. These items will be replaced with devices modified to meet the appropriate recommendations. Replacement/Installation/Modification for each item will be made to:

   a. Meet requirements imposed by other documents such as NUREG-0588 and NUREG-0737.

   b. Meet the recommendations of Regulatory Guide 1.97.

4. Items Which Are Not Being Replaced

   The items categorized under this heading are presently installed, but deviate from one or more recommendations of the Guide. This is based on:

   a. Devices located in non-harsh environment, that require qualification review in accordance with NUREG-0588 for benign environments which will be completed by June 30, 1982.

b. Devices located in a harsh environment that are not utilized in accident emergency instructions for operators to maintain plant safety.

c. Devices currently meeting Technial Specification requirements but the specified ranges do not meet the recommendations in Regulatory Guide 1.97.

5. <u>Items Not Part of Salem Design</u>

The items categorized under this heading are not part of the Salem design and are not being installed. Alternate capabilities are available which meet or will meet our requirements and provide adequate information for maintenance of plant safety. An example is meteorological conditions. PSEG has 24 hour contact with Wilmington Airport and a written agreement to obtain information on meteorological conditions.

7.5.3.3 <u>Planned Actions</u>

<u>Compliance Level 1</u>

No action planned. The instrumentation in this compliance level meets the intent of Regulatory Guide 1.97 in accordance with the criteria specified in Section 7.5.3.1.

<u>Compliance Level 2</u>

No equipment replacement planned at this time pending resolution of generic problems.

<u>Compliance Level 3a</u>

Instruments are being replaced or upgraded as a result of prior commitments related to NUREG-0588 and NUREG 0737. The devices will comply with Regulatory Guide 1.97 in accordance with the criteria specified in

Section 7.5.3.1 by the dates specified in previous correspondence to the NRC staff.

Compliance Level 3b

Instruments will be upgraded to meet Regulatory Guide 1.97 in accordance with the criteria specified in Section 7.5.3.1 by 6/1/83.

Compliance Level 4a

The equipment will be evaluated in accordance with the requirements of the NUREG-0588 benign environment review, and appropriate actions will be taken where required.

Compliance Level 4b

No action planned. The importance of the device is deemed to be relatively low or insignificant.

Compliance Level 4c

The existing devices comply with Technical Specification. Requirements and should not be modified.

Compliance Level 5

No action planned. Other provisions exist which negate the need for the instrumentation.

All items currently planned to remain unchanged have been evaluated for potential effects on plant safety. This evaluation concludes that plant safety is not affected by the lack of compliance to Regulatory Guide 1.97.

TABLE 7.5-1 (Sheet 1 of 4)

MAIN CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR

Parameter	Channels Available	Range	Accuracy	Indicator/ Recorder	Purpose
OPERATIONAL OCCURRENCES					
1. T_{cold} or T_{hot} (measured, wide range)	1 T_{hot} 1 T_{cold} per loop	0-700°F	$\pm$4 % of full range	All channels are recorded	Ensure maintenance of proper cooldown rate and to ensure maintenance of proper relationship between system pressure and temperature NDTT considerations.
2. Pressurizer water level	3	Entire distance between taps (475"/H_2O)	$\pm$ 3.5 % of ΔP at 2250 psia	All three channels indicated; one channel is selected for recording	Ensure Maintenance of proper reactor coolant inventory.
3. System pressure	2	0-3000 psig	$\pm$ 4%of Full Range	Indicated and recorded	Ensure maintenance of proper relationship between system pressure and temperature for NDTT considerations.
4. Containment pressure	4	0-115 % of design pressure (-5 to +55 psig)	$\pm$ 3.5 % of Full Scale	All four are indicated; two are also recorded	Monitor containment conditions to indicate need for potential safeguards actuation.
5. Steam line pressure	3/Loop	0-1200 psig	$\pm$ 4 % of Full Scale	All channels are indicated	Monitor steam generator temperature conditions during hot shutdown and cooldown, and for use in recovery from steam generator tube ruptures.

MAIN CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR

Parameter	Channels Available	Range	Accuracy	Indicator/ Recorder	Purpose
OPERATIONAL OCCURRENCES					
6. Steam generator water level (wide range)	1/Steam generator	+ 7 to -41 feet from nominal full load water level	± 5% level span (cold)	All channels recorded	Ensure maintenance of reactor heat sink.
7. Steam generator water level (narrow range)	3/Steam generator	+ 7 to -5 feet from nominal full load water level	+ 4% of level span (hot)	All channels indicated; the channels used for control are recorded	Ensure maintenance of reactor heat sink
ACCIDENT CONDITIONS					
1. Containment pressure	4	0-115% of design pressure (-5 to +55 psig)	± 10% of full span	All four are indicated; two are also recorded	Monitor post-LOCA containment conditions
	2	(-5 to +180 psig)		Both are recorded	
2. Refueling water storage tank water level	2	0-100% of span (48 ft./H_2O)	±3% of level span	Both are indicated and alarmed	Ensure that water is flowing to the safety injection system after a LOCA and determine when to shift from injection to recirculation mode.
3. Steam generator water level (narrow range)	3/Steam generator	+7 to -2 feet from nominal full load level	±10% of level span	All channels indicated; the channels used for control are recorded	Detect steam generator tube rupture; monitor steam generator water level following a steam line break.

TABLE 7.5-1 (Sheet 3 of 4)

MAIN CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR

Parameter	Channels Available	Range	Accuracy	Indicator/ Recorder	Purpose
ACCIDENT CONDITIONS					
4. Steam generator water level (wide range)	1/Steam generator	+7 to -41 feet from nominal full load level	±10% of level span	All channels are recorded	Detect steam generator tube rupture; monitor steam generator water level following a steam line break.
5. Steam line pressure	3/Steam line	0-1200 psig	±5% of full scale	All channels are indicated	Monitor steam line pressures following steam generator tube rupture or steam line break.
6. Pressurizer water level	3	Entire Distance between taps (475"/H_2O)	Indicate the level is somewhere between 0 and 100 of span	All three indicated and one is for recording	Indicate that coolant inventory restored in pressurizer following cooldown after steam generator tube rupture or steam line break.
7. Containment hydrogen level	2	0-10% vol	2% of full scale	Both channels are recorded	NUREG 0737
8. Containment area monitors (high range)	2	1-10^7 R/hr		Both channels are recorded	NUREG 0737

MAIN CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR

Parameter	Channels Available	Range	Accuracy	Indicator/ Recorder	Purpose
ACCIDENT CONDITIONS (cont'd)					
9. Reactor vessel level	2	Hot leg - top of R.V.	6% without RCPs running		Detect inadequate core cooling
	4	Bottom - top of R.V.			
10. Containment liquid level	2			Both channels are recorded	

MAIN CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR
MONITOR SIGNIFICANT PLANT PARAMETERS DURING NORMAL OPERATION

Parameter	No. of Channels Available	Range	Accuracy	Indicator/ Recorder	Notes
NUCLEAR INSTRUMENTATION					
1. Source Range					
a. Count rate	2	1 to 10^6 counts/ sec.	$\pm$7% of the linear full scale analog voltage	Both channels indicated. Either may be selected for recording.	One two-pen recorder is used to record any of the 8 nuclear channels (2 source range, 2 intermediate range and 4 power range)
b. Startup rate	2	-1.0 to 5.0 decades/min.	$\pm$7% of the linear full scale analog voltage	Both channels indicated.	
2. Intermediate Range					
a. Flux level	2	10^{-11}-10^{-3} AMPS	$\pm$7% of the linear full scale analog voltage and $\pm$3% of the linear full scale voltage in the range of 10^{-4} to 10^{-3} amps	Both channels indicated. Either may be selected for recording using the recorder in Item 1 above.	

MAIN CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR
MONITOR SIGNIFICANT PLANT PARAMETERS DURING NORMAL OPERATION

Parameter	No. of Channels Available	Range	Accuracy	Indicator/ Recorder	Notes
NUCLEAR INSTRUMENTATION					
b. Startup rate	2 decades/min.	-1.0 to 5.0 full dcale analog	±7 % of the linear indicated.	Both channels	
3. Power Range					
a. Uncalibrated ion chamber current (top and bottom uncompensated ion chambers)	4	0 to 120 % of full power current	±1 % of full power	All 8 current signals indicated.	
b. Calibrated ion chamber current (top and bottom uncompensated ion chambers)	4	0-120 % of full power	±2 % of full power	All 8 current signals recorded (four 2 pen recorders). Recorder 1 - upper currents for two diagonally opposed Recorder 2 - opposed currents for remaining detectors. Recorder 3 - lower currents for two	

MAIN CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR
MONITOR SIGNIFICANT PLANT PARAMETERS DURING NORMAL OPERATION

Parameter	No. of Channels Available	Range	Accuracy	Indicator/ Recorder	Notes
				diagonally opposed detectors. Recorder 4 - lower currents for remaining detectors.	
c. Upper and Lower ion Chamber current difference	4	-50 to +50%	±3% of full power	Diagonally opposed channels may be selected for recording at the same time using recorder in item 1.	
d. Average flux of the top and bottom	4	0 to 120% of full power	±3% of full power for indication ±2% for recording	All 4 channels indicated. Any 2 of the four channels may be recorded using recorder in item 1 above.	
e. Average flux of the top and bottom ion chambers	4	0 to 200% of full power	±2% of full power to 120 ±6% of full power to 200%	All 4 channels recorded.	

MAIN CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR
MONITOR SIGNIFICANT PLANT PARAMETERS DURING NORMAL OPERATION

Parameter	No. of Channels Available	Range	Accuracy	Indicator/ Recorder	Notes
f. Flux difference of the top and bottom ion chambers	4	-30 to +30 %	±4 %	All 4 channels indicated.	
REACTOR COOLANT SYSTEM					
1. $T_{average}$ (measured)	1/Loop	540 -615°F	±4 °F	All channels indicated.	
2. ΔT (measured)	1/Loop	0 to 150 of full power ΔT	±4% of full power ΔT	All channels indicated. One channel is selected for recording.	
a. T_{cold} or T_{hot} (measured, wide range)	1-T_{hot} and 1-T_{cold} per loop	0 - 700°	±4%	Both channels recorded.	
3. Overpower ΔT Setpoint	1/Loop	0-75°F	±4 % of full power ΔT	All channels indicated. One channel is selected for recording.	
4. Overtemperature ΔT Setpoint	1/Loop	0-75°F	±4 % of full power ΔT	All channels indicated. One channel is selected for recording.	

TABLE 7.5-2 (Sheet 5 of 9)

MAIN CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR
MONITOR SIGNIFICANT PLANT PARAMETERS DURING NORMAL OPERATION

	Parameter	No. of Channels Available	Range	Accuracy	Indicator/ Recorder	Notes
5.	Pressurizer Pressure	4	1700 to 2500 psig	±28 psi	All channels indicated. One channel is selected for recording.	
6.	Pressurizer Level	3	Entire distance between taps 0-100 %	±3.5 %of level at 2250 psia	All channels indicated. One channel is selected for recording.	Two pen recorder used, second pen records reference level signal
7.	Primary Coolant Flow	3/Loop	0 to 120 %of rated flow	Repeatability of ±4 %of full flow	All channels indicated.	
8.	System Pressure	2	0 - 3000 psig.	±4 %	All channels indicated and recorded.	
	REACTOR CONTROL SYSTEM					
1.	Demanded rod speed	1	0 to 100 %of rated speed	±2 %	The one channel is indicated.	
2.	Auctioneered $T_{average}$	1	540° to 615°F	±4°F	The one channel is recorded.	Any one of the T_{avg} channels into the auctioneer may be bypassed.

MAIN CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR
MONITOR SIGNIFICANT PLANT PARAMETERS DURING NORMAL OPERATION

Parameter	No. of Channels Available	Range	Accuracy	Indicator/ Recorder	Notes
3. $T_{reference}$	1	540° to 615°F	±4°F	The one channel is recorded.	
4. Control rod Position					If system not available, borate and sample accordingly
a. Number of steps of demanded rod withdrawl	1/group	0 to 230 steps	± 1 step	Each group is indicated during rod motion.	These signals are used in conjunction with the measured position signals (4c) to detect deviation of any individual rod from the demanded position. A deviation will actuate an alarm and annunciator.
b. Demanded position of the part length rod bank.	1	0 to 230 steps	± 1 step	The bank is indicated during rod motion.	
c. Full and part length rod measured position	1 for each rod	0 to 228 steps	±4 steps at full accuracy ±8 steps at 1/2 accuracy	Each rod position is indicated.	

MAIN CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR MONITOR SIGNIFICANT PLANT PARAMETERS DURING NORMAL OPERATION

Parameter	No. of Channels Available	Range	Accuracy	Indicator/ Recorder	Notes
5. Control rod bank demanded position	4	0 to 230 steps	±2.5% of total travel	All 4 control rod bank positions are recorded along with the low-low limit alarm for each bank.	1. One channel for each control bank. 2. An alarm and annunciator is actuated when the last rod control bank to be withdrawn reaches the withdrawal limit, when any rod control bank reaches the low insertion limit and when any rod control bank reaches the low-low insertion limit
CONTAINMENT SYSTEM					
Containment pressure	4	0 - 115 of design pressure (-5 to +55 psig)	±3 %	All 4 channels indicated and 2 are also recorded.	

TABLE 7.[illegible]-2 (Sheet 8 of 9)

MAIN CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR

MONITOR SIGNIFICANT PLANT PARAMETERS DURING NORMAL OPERATION

Parameter	No. of Channels Available	Range	Accuracy	Indicator/ Recorder	Notes
FEEDWATER AND STEAM SYSTEMS					
1. Auxiliary feed-water flow	1/Steam line	0-250000 PPH		All channels indi-cated.	One channel to measure the flow to each steam generator
2. Steam generator level (narrow range)	3/Steam generator	+7 to -5 feet from nominal full load level	±4 % of P level (hot)	All channels indi-cated. The channels used for control are recorded.	
3. Steam generator level (wide range)	1/Steam generator	+7 to -41 feet from nominal	±5 % of level (cold)	All channels recorded.	
4. Programmed steam generator level signal	1/Steam generator	+7 to -5 feet	±4	All channels indicated.	
5. Main feedwater flow	2/Steam generator	0 to 120% of maximum calcu-lated flow	±5 %	All channels indicated. The channels used for control are recorded.	
6. Magnitude of signal controlling main and bypass feedwater control valves	1/main 1/bypass	0 to 100% of valve opening	±1.5 %	All channels indicated.	1. One channel for each main and bypass feed-water control valve 2. OPEN/SHUT indication is provided in the control room for each main and bypass feedwater control valve.

MAIN CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR
MONITOR SIGNIFICANT PLANT PARAMETERS DURING NORMAL OPERATION

	Parameter	No. of Channels Available	Range	Accuracy	Indicator/ Recorder	Notes
7.	Steam flow	2/Steam generator	0 to 120% of miximum calculated flow	$\pm$5.5 %	All channels indicated. The channels used for control are recorded.	
8.	Steam line pressure	3/Loop	0 to 1300 psig	$\pm$4%	All channels indicated and 1 is recorded.	
9.	Steam dump modulated signal	1	0 - 85% max. calculated steam flow	$\pm$1.5%	The one channel is indicated	OPEN/SHUT indication is provided in the control room for each steam dump valve.
10.	Turbine impulse chamber pressure	2	0 to 120% of max. calculated turbine load	$\pm$3.5%	Both channels indicated.	OPEN/SHUT indication is provided in the control room for each turbine stop valve

TABLE 7.5-3

INDEX TYPE "A" VARIABLES

Variable Description	Variable Reference No.
Reactor Coolant System Hot Leg Water Temperature	5
Reactor Coolant Pressure	6
Degrees of Subcooling	9
Containment Pressure	11
Effluent Radioactivity Noble Gas Effluent from Condenser Air Removal System Exhaust	16
Refueling Water storage Tank Level	27
Pressurizer Level	30
Steam Generator Pressure	36
Auxiliary Feedwater Flow	39
Auxiliary Feedwater Storage Tank Level (Condensate Storage Tank)	40
Steam Generator Radiation	73

TABLE 7.5-4 (Sheet 1 of 6)

SUMMARY OF INSTRUMENTATION COMPLIANCE WITH REGULATORY GUIDE 1.97

Variable Ref. No.	Variable Description	Compliance Level
1	Neutron Flux (Source Range, Intermediate range, Power range) - Monitors	2
2	Control Rod Position	1
3	RCS Soluble Boron Concentration	1
4	RCS Cold Leg Water Temperature	
	- RTD's	3a
	- Indication	3b
5	RCS Hot Leg Water Temperature	
	- RTD's	3a
	- Indication	3b
6	RCS Pressure - Transmitters	3a
7	Core Exit Temperature - Themocouples	2
8	Coolant Level in Reactor	1
9	Degrees of Subcooling - Display (inputs - See variable Ref. No. 6 and 7)	1
10	Containment Sump Water Level - Transmitters	3a
11	Containment Pressure (narrow and wide range) - Transmitters	3a
12	Containment Isolation Valve Position (excluding check valves) - Limit Switches	3a
13	Radioactivity Concentration or Radiation Level in Circulating Primary Coolant	5

TABLE 7.5-4 (Sheet 2 of 6)

SUMMARY OF INSTRUMENTATION COMPLIANCE WITH
REGULATORY GUIDE 1.97

Variable Ref. No.	Variable Description	Compliance Level
14	Analysis of Primary Coolant (Gamma Spectrum)	5
15	Containment Area Radiation - Monitors	3a
16	Effluent Radioactivity - Noble Gas Effluent from Condenser Air Removal System Exhaust - Monitors	3a
17	Containment Hydrogen Concentration - Analyzers	3a
18	Containment Effluent Radioactivity Nobles Gases from Identified Release Points - Monitors	3b
19	Radiation Exposure Rate (Electrical Penetration Area) - Monitor	3b
19A	Radiation Exposure Rate (Fuel Handling Building and Penetration Area) - Monitors	4a
20	RHR System Flow - Transmitters	3a
21	RHR Heat Exchanger Outlet Temperature - Thermocouples	4b
22	Accumulator Tank Level and Pressure -	
	- Transmitters	3b
	- Transmitter Range	4c
23	Accumulator Isolation Valve Position	1
24	Boric Acid Charging Flow - Transmitters	3a
25	Flow in HPI System - Transmitters	3a
26	Flow in LPI System - Transmitters	3a

TABLE 7.5-4 (Sheet 3 of 6)

SUMMARY OF INSTRUMENTATION COMPLIANCE WITH REGULATORY GUIDE 1.97

Variable Ref. No.	Variable Description	Compliance Level
27	Refueling Water Storage Tank Level and Low Level Alarm - Transmitters - Transmitter Range	3a 4c
28	Reactor Coolant Pump Status	1
29	Primary System Safety Relief Valve Positions (including PORV and code valves) or Flow through or Pressure in Relief Valve Lines	1
30	Pressurizer Level - Transmitters - Transmitter Range	3a 4c
31	Pressurizer Heater Status (Current) - Heaters	2
32	Quench Tank Level (Pressurizer Relief Tank) - Transmitter Range	4c
33	Quench Tank Temperature (Pressurizer Relief Tank) - Transmitter Range	3b
34	Quench Tank Pressure (Pressurizer Relief Tank) -	1
35	Steam Generator Level - Transmitters	3a
36	Steam Generator Pressure - Transmitters	3a
37	Safety/Relief Valve Positions or Main Steam Flow - Transmitters	3a
38	Main Feedwater Flow	1
39	Auxiliary Feedwater Flow - Transmitters	3a

TABLE 7.5-4 (Sheet 4 of 6)

SUMMARY OF INSTRUMENTATION COMPLIANCE WITH
REGULATORY GUIDE 1.97

Variable Ref. No.	Variable Description	Compliance Level
40	Condensate Storage Tank Water Level (Auxiliary Feedwater Storage Tank) - Transmitters	4a
41	Containment Spray Flow	5
41A	Containment Spray Flow Additive Rate - Transmitters	3a
42	Heat Removal by the Containment Fan Heat Removal System - Transmitters	3a
43	Containment Atmosphere Temperature	4b
44	Containment Sump Water Temperature	5
45	CVCS Makeup Flow-in - Transmitters	3a
46	Letdown Flow - Transmitters	3b
47	Volume Control Tank Level - Transmitters	4a
48	Component Cooling Water Temperature to ESF System - Transmitters	4a
49	Component Cooling Water Flow to ESF System - Transmitters	4b
50	High-Level Radioactive Liquid Tank Level - Indication	3b
51	Radioactive Gas Holdup Tank Pressure-Indication	3b
52	Emergency Ventilation Damper Position - Control Room Damper Limit Switches	4a
52a	Emergency Ventilation Damper Position - Auxiliary Bldg. Damper Limit Switches	4a

SUMMARY OF INSTRUMENTATION COMPLIANCE WITH REGULATORY GUIDE 1.97

Variable Ref. No.	Variable Description	Compliance Level
52B	Emergency Ventilation Damper Position - Fuel Handling Bldg.	4a
53	Status of Standby Power	1
53A	Status of Control Air	1
54	Containment or Purge Effluent	N/A
55	Reactor Shield Building Annulus Effluent	N/A
56	Auxiliary Building Effluent	N/A
57	Condenser Air Removal System Exhaust	N/A
58	Common Plant Vent or Multi-Purpose Vent Discharging any of above releases - Monitor	3a
59	Vent from Steam Generator Safety Relief Valves or Atmospheric Dump Valves - Monitors	5
60A	All other identified Release Points (Decontamination Bldg.) - Monitor	3b
60B	All other identified Release Points (Auxiliary Feed Pump Turbine Exhaust) - Monitor	5
61	All Identified Plant Release Points - Monitor (Particulates and Halogens)	3a
62	Radiation Exposure Meters	5
63	Airborne radiohalogens and particulates (portable sampling with onsite analysis capability)	1

TABLE 7.5-4 (Sheet 6 of 6)

SUMMARY OF INSTRUMENTATION COMPLIANCE WITH
REGULATORY GUIDE 1.97

Variable Ref. No.	Variable Description	Compliance Level
64	Plant and Environs Radiation - Instrument Range	4c
65	Plant and Environs Radioactivity	1
66	Wind Direction	1
67	Wind Speed	1
68	Estimation of Atmospheric Stability	1
69	Primary Coolant (Grab sample)	1
70	Containment Air (Grab sample)	1
71	Containment Sump (Grab sample)	1
72	Effluent Radioactivity - Noble Gases - Monitor	3a
73	Steam Generator Blow-down Radiation - Monitor	5

TABLE 7.5.-5 (Sheet 1 of 4)

JUSTIFICATION FOR NON-CONFORMANCE TO REGULATORY GUIDE 1.97

Variable Reference No.	Justification
4	Isolation devices are not provided for these variables. However, these variables will be on the safety parameter display system and class 1E multiplexors will have qualified isolation devices.
5	Same as 4
13	There is radiation monitoring on the letdown line; however, during an accident this line is isolated. The back-up or alternate means of measuring this variable is the Post Accident Sampling System.
14	The Post Accident Sampling System obviates the need for this variable.
24	Same as 4
27	Same as 4
35	Same as 4
39	Same as 4
40	Same as 4

JUSTIFICATION FOR NON-CONFORMANCE TO REGULATORY GUIDE 1.97

Variable Reference No.	Justification
41	An alternate means of determining the containment spray flow is the spray additive tank flow rate, which is available (refer to Variable Code #41a). The spray additive tank flow rate is the flow of liquid which is educted to the suction of the containment spray pumps. The eduction is accomplished by recirculating the containment spray liquid from the discharge to the suction of the containment spray pumps. Indication of the spray additive flow provides confirmation of containment spray pumps operation.
42	Same as 4
44	The containment sump temperature indication is not required in Safety Guide 1, "Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps". PSE&G's Emergency Core Cooling and Containment Heat Removal System pumps, specifically the Residual Heat Removal pumps which take suction from the containment sump when the refueling water storage tank is empty, were designed to meet the criteria in Safety Guide 1.
45	Same as 4
46	Same as 4

TABLE 7.5-5 (Sheet 3 of 4)

JUSTIFICATION FOR NON-CONFORMANCE TO REGULATORY GUIDE 1.97

Variable Reference No.	Justification
47	Same as 4
49	Same as 4
59	The steam generator safety relief valves and the atmospheric dump valves are located on the main steam line, upstream of the main steam stop valve. A radiation monitor is installed on the main steam line of each steam generator also upstream of the main steam stop valve. This monitor will therefore give an indication of the level of radiation in the steam from the vents if the steam generator safety relief valves or the atmospheric dump valves should open.
60B	The steam supply to the auxiliary feed pump is taken from the main steam line of #11 (21) and #13 (23) steam generators, upstream of the main steam stop valves. A radiation monitor is installed on the main steam line of each steam generator also upstream of the main steam stop valve. If the auxiliary feed pump is in operation, this monitor will therefore give an indication of the level of radiation in the exhaust.
62	This variable was deleted in Revision 3 of Reg. Guide 1.97.

TABLE 7.5-5 (Sheet 4 of 4)

JUSTIFICATION FOR NON-CONFORMANCE TO REGULATORY GUIDE 1.97

Variable Reference No.	Justification
73	This variable does not meet the requirements of Regulatory Guide 1.97 in the area of environmental qualification for Units 1 and 2, and seismic qualification for Unit 1. A monitor, however, which is located on the main steam line of each steam generator, upstream of the main steam valve, does provide adequate indication of the blowdown radiation level. The main steam monitors meet the requirements of Regulatory Guide 1.97.

7.6 ALL OTHER INSTRUMENTATION REQUIRED FOR SAFETY

7.6.1 RESIDUAL HEAT REMOVAL ISOLATION VALVES

There are two motor operated isolation valves (1RH1 and 1RH2), in series, in the single letdown line connecting the low pressure Residual Heat Removal (RHR) System to the high pressure Reactor Coolant System. 1RH1 is the upstream valve (closest to the Reactor Coolant System) and 1RH2 is the downstream valve.

The position indication provided for these valves consists of "open-closed" indication on the main control console.

The control system consists of the following:

1. 1RH1 is interlocked with a pressure control signal derived from a pressure transmitter to prevent its opening whenever the Reactor Coolant System pressure is greater than the RHR System design pressure.

2. The pressure transmitter used in (1) is connected to the reactor coolant loop which contains the RHR suction line. The pressure transmitter is connected into RHR suction line inside the containment.

3. The control for valves 1RH1 and 1RH2 is administratively locked to prevent inadvertent manual opening.

4. A second pressure channel is provided as a pressure control signal to interlock valve 1RH2 located adjacent to the RHR System. This will be used to prevent its opening whenever the reactor coolant pressure is greater than the RHR system design pressure.

5. This 1RH2 associated pressure transmitter is connected by a separate connection into the RHR suction line inside the containment. Therefore, the RHR suction line will contain two separate connections, one for each pressure transmitter.

6. Both valves 1RH1 and 1RH2 will automatically close if they have not already been manually closed before the reactor coolant pressure reaches a selected fraction of RHR design pressure.

The interlocks and closure devices are designed to conform to IEEE 279.

7.6.2 ACCUMULATOR ISOLATION VALVES

Position indication and alarm circuits for the motor-operated valves, located between the accumulator tanks and the primary cooling system, are designed to provide assurance that these valves will be open when required. These valves are normally open and under administrative control with the motive power for the valves locked out during normal power operation. Redundant and independent information is provided in the control room to indicate when any one valve is not in the fully open position.

Valve status (fully open or fully closed) is indicated on the main control board via backlighted pushbuttons. These status lights are actuated by limit switches on the valve motor operator. In addition, an alarm is provided on the overhead annunciator system in the event the valve is not in the fully open position.

Another independent means of determining that the valve is not in its proper position is provided through the auxiliary alarm message indicating when the valve is not in the fully open position. This indication and alarm is derived from a separate valve stem limit switch and is energized from an independent power supply from that used for the overhead annunciator.

A Safety Injection signal also automatically initiates the opening of these valves.

The valve status and alarm provisions are shown functionally on Figure 7.6-1.

7.6.3 PRESSURIZER OVERPRESSURE PROTECTION SYSTEM (POPS)

7.6.3.1 Design Bases

The POPS instrumentation measures Reactor Coolant System Pressure and temperature. It initiates opening of pressurizer releif valves during pressure transients which could occur when the Reactor Coolant System is below 312°F. The equipment used to open the relief valves is designed to esentially the same criteria as that used in the design for the Protection System described in Section 7.2.

Design Criterion: Credit for Operator Action

Criterion: No credit can be taken for operator action until 10 minutes after the operator is aware that a pressure transient is in progress.

The POPS requires no operator action other than to arm the system prior to entry into a water-solid condition during startup, or prior to reaching 312°F during shutdown from power. All protective action is performed automatically.

Design Criterion: Single Failure Criteria

Criterion: The pressure protection system should be designed to protect the vessel given a single failure that initiates the pressure transient. In this area, redundant or diverse pressure protection systems would be considered as meeting the single failure criteria.

The POPS incorporates redundancy and separation of pressure transmitters, logic, and valves in a channelized system. Single failures within the POPS will not defeat the safety function. Single failures which are capable of initiating a pressure transient cannot cause failures in the POPS which would render it unable to provide protection.

Design Criterion: Testability

Criterion: The equipment design should include some provision for testing on a schedule consistent with the frequency that the system is used for pressure protection.

The POPS design provides for testing of the analog circuitry any time the RHR suction valves for the Reactor Coolant System are closed. The relief valves can be tested prior to entry into a water-solid condition by use of the POPS functional test pushbutton. The POPS is designed to function during the relatively infrequent occurrences of potential low temperature pressure transients, therefore periodic testing of the system during power operation is not planned.

Design Criterion: Seismic Design and IEEE 279 Criteria

Criterion: Ideally, the pressure protection system should meet both seismic Category 1 and IEEE-279 criteria. The basic objective, however, is that the system should not be vulnerable to an event which both causes a pressure transient and causes a failure of equipment needed to terminate the transient.

The POPS design meets seismic Category 1 criteria for all equipment required to open the relief valves. The instrumentation and actuating circuitry meet the applicable requirements of IEEE 279-1971.

7.6.3.2 System Design and Operation

The POPS is a two-train system which uses separate and independent pressure transmitters to open two pressurizer relief valves if Reactor

Coolant System pressure exceeds a preset value of 375 psi. This automatic action takes place provided the system has been armed by placing two key-locked pushbuttons in the "ON" position. The system is required to be armed whenever the Reactor Coolant System is below 312°F.

Each relief valve is actuated by its own logic output relay which is energized by a bistable device. The bistable is energized if Reactor Coolant System pressure exceeds the setpoint. Existing pressure sensors are used to develop the signal for valve actuation. These are the same sensors which provide automatic closing of the RHR suction paths at 600 psi.

The operation of the POPS is governed by two administratively controlled, keylocked pushbuttons which perform three functions. When the Reactor Coolant System temperature is less than 312°F, the system is armed by depressing the "ON" pushbutton for each POPS train. This action opens the motor operated valves upstream of the relief valves, and provides an alarm permissive to indicate that the POPS is armed should temperature increase above 312°F. In this mode of operation, the relief valve will automatically open if Reactor Coolant System pressure exceeds 375 psi. Actuation of the relief valve is alarmed in the Control Room.

When Reactor Coolant System temperature is above 312°F, the "OFF" pushbutton for each POPS train is depressed. This action removes the opening permissive from the relief valve, removes the opening signal from its associated motor operated valve, and provides an alarm input to indicate that the system is disarmed should Reactor Coolant System temperature fall below 312°F.

If either relief valve is opened by the POPS, it will remain open until the system pressure falls below 375 psi.

A testing provision in the POPS circuitry allows for test opening of the relief valves prior to use of the system below 312°F. The "TEST" push-button, when depressed, will operate the relief valve provided that the associated motor operated valve is closed. Other portions of the POPS can be tested in a manner similar to other protection system functions.

The existing power operated relief valves (PORV's) are utilized for overpressure protection at low temperature in the No. 1 and No. 2 Units.

7.6.3.3 Design Evaluation

The POPS is designed as a "protection grade" system in accordance with the applicable portions of IEEE 279-1971. The use of proven devices provides assurance that the system is compatible with other protection system equipment. The use of administrative controls to arm the POPS is considered aceptable due to the expected infrequent need for overpressure protection at low temperature.

The POPS relief valves protect the RCS from pressure transients which could exceed the limits of Appendix G to 10CFR Part 50 when one or more RCS cold leg temperature is at or below 312°F. Either POPS has adequate relieving capacity to protect the RCS from overpressurization as a result of the limiting heat input or mass input cases: (1) the start of an idle Reactor Coolant Pump (RCP) with the secondary water temperature of the steam generator less than or equal to 50°F above RCS cold leg temperature or (2) the start of a safety injection pump and its injection into the water solid RCS. A number of provisions for prevention of pressure transients below P-7 (when the RCS temperature is below 312°F) presently exists in the Technical Specifications.

In order to cause an unwanted relief valve opening at normal operating pressures, an operator would have to erroneously arm the POPS system. This would require bypassing the administrative control of the key associated with the keylocked pushbutton station. Another potential way to initiate a relief would be an unlikely short-circuit of a relay contact in the relief valve control circuit. This latter case however is also true of the previous circuitry for the relief valves.

Spurious opening of the relief valve at pressures below normal operations pressure could be caused by an unlikely failure of a pressure transmitter in the "high" direction. Such valve openings would result in a "low pressure" coolant inventory reduction similar to that associated with a "true" signal for relief valve operation. This type of incident could be readily terminated by the operator and poses no threat to the safety of the plant.

The effects of various failures have been considered in the POPS design. These failures included "loss of station power." Failures within the POPS cannot cause a loss of protective function due to the dual train design, and failures capable of causing an overpressurization cannot cause failures within the POPS or prevent operation of the system.

The "loss of air" situation is accounted for by provision of an air accumulator for each relief valve. The accumulators are sized to provide control air for up to 100 cycles of valve opening and closing. The accumulators are designed to seismic Category I requirements. The air accumulators are provided with an alarm for low air pressure. The accumulator design precludes a total loss of control air to the relief valves.

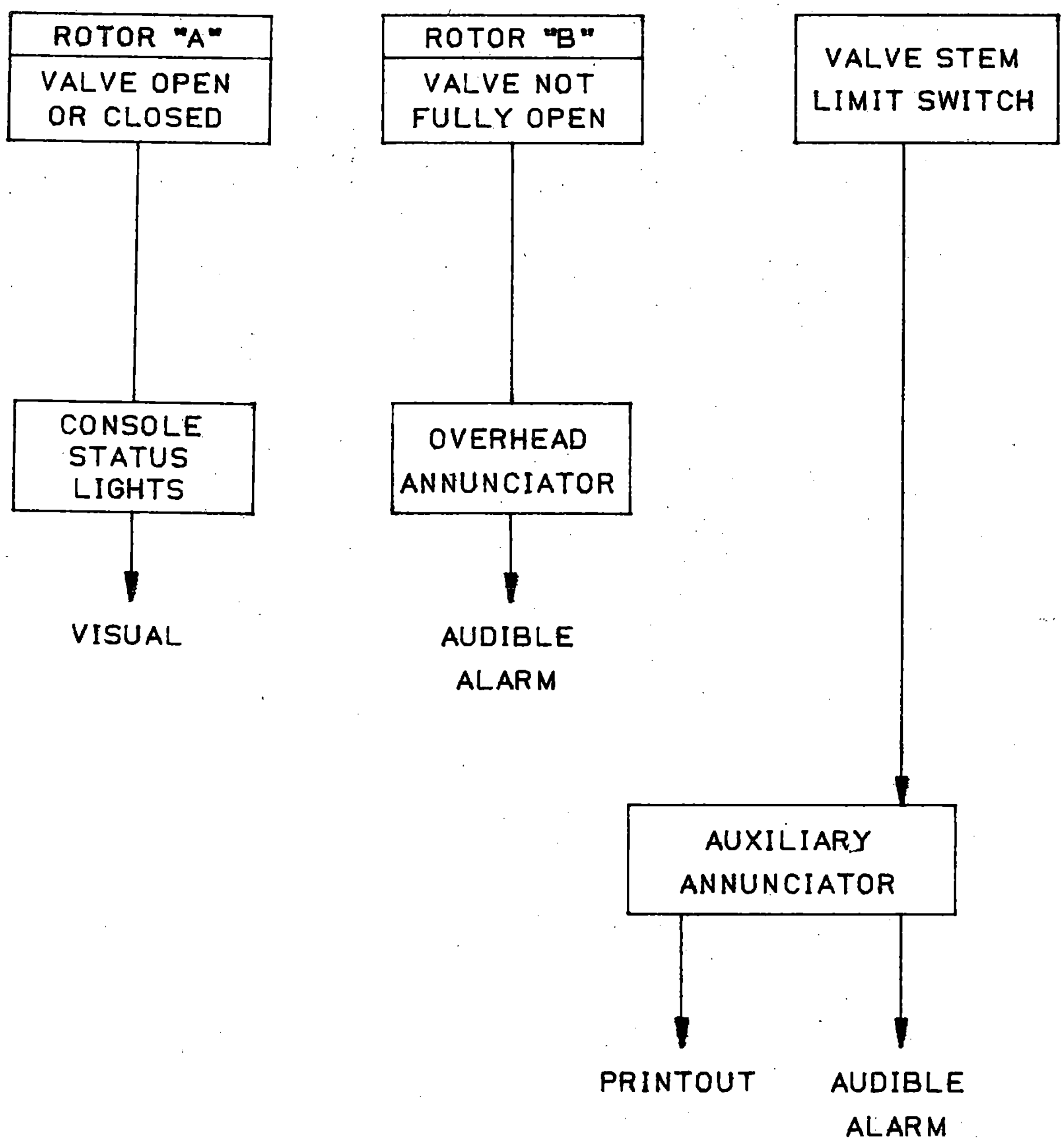
A "loss of station power" will have no effect on the POPS since the protection logic power is provided by inverters and control power for the relief valves originates at the batteries.

7.6.4 FEEDWATER PUMP TURBINE TRIPS

There are two steam generator feedpumps and turbines. Each has its own trip sensing scheme which actuates a turbine trip for any of the following conditions:

1. Low feedpump suction pressure
2. High turbine exhaust temperature
3. Loss of vacuum at turbine exhaust
4. Excessive thrust bearting wear
5. Low lube oil pressure
6. Low oil reservoir level
7. Over speed trip-electrical sensor and detector
8. Over speed trip-mechanical (internal to turbine)
9. Safety injection or high-high level in any steam generator
10. Manual trip lever at turbine
11. Remote manual trip switch

Automatic trip of either feedwater pump turbine will activate a separate audible and visual alarm in the Control Room.



Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Accumulator Discharge Valves — Status Monitoring	
	Updated FSAR	Figure 7.6-1

7.7 CONTROL SYSTEMS NOT REQUIRED FOR SAFETY

The nuclear steam systems controls for the Salem Nuclear Plant and the D. C. Cook Plant are functionally the same.

7.7.1 DESIGN BASIS

7.7.1.1 Reactor Control System

The Reactor Automatic Control System is designed to reduce nuclear plant transients for the design load perturbations, so that reactor trips will not occur for these load changes.

Overall reactivity control is achieved by the combination of chemical shim and Rod Cluster Control Assemblies (RCCA). Long-term regulation of core reactivity is accomplished by adjusting the concentration of boric acid in the reactor coolant. Short-term reactivity control for power changes is accomplished by moving RCCA's.

The function of the reactor control system is to provide automatic control of the RCCA's during power operation of the reactor. The system used input singnals including neutron flux, coolant temperature, and turbine load. The Chemical and Volume Control System (CVCS)(Chapter 9) supplements the reactor control system by the addition and removal of varying amounts of boric acid solution.

There is no provision for a direct continuous visual display of primary coolant boron concentation. When the reactor is critical, the best indication of reactivity status in the core is the position of the control group in relation to power and average coolant temperature. There is a direct relationship between control rod position and power and it is this relationship which established the lower insertion limit calculated by the rod insertion limit monitor. There are two alarm setpoints to alert the operator to take corrective action in the event a control group approaches or reaches its lower limit.

Any unexpected change in the position of the control group under automatic control, or a change in coolant temperature under manual control provides a direct and immediate indication of a change in the reactivity status of the reactor. In addition, periodic samples are taken for determination of the coolant boron concentration. The variation in concentration during core life provides a further check on the reactivity status of the reactor including core depletion.

The reactor control system is designed to enable the reactor to follow load changes automatically when the output is above approximately 15 percent of nominal power. Control rod positioning may be performed automatically when plant output is above this value, and manually at any time.

The operator is able to select any single bank of rods for manual operation. This is accomplished with a multiposition switch so that he may not select more than one bank. He may also select automatic or manual reactor control, in which case the control banks can be moved only in their normal sequence with some overlap as one bank reaches its full withdrawal position and the next bank begins to withdraw.

The system enables the nuclear unit to accept a step load increase of 10 percent and a ramp increase of 5 percent per minute within the load range of 15 percent to 100 percent without reactor trip subject to possible xenon limitations. Similar step and ramp load reductions are possible within the range of 100 percent to 15 percent of nominal power. The steam dump system permits the plant to accept an addition 40 percent load reduction without reactor or turbine trip.

The control system is capable of restoring coolant average temperature to within the programmed temperature deadband, following a scheduled or unexpected change in load.

The pressurizer water level is programmed to be a function of the auctioneered coolant average temperature. This is to minimize the requirements on the Chemical and Volume Control and Waste Disposal System resulting from coolant density changes during loading and unloading from full power to zero power.

Following a reactor and turbine trip, sensible heat stored in the reactor coolant is removed without actuating the steam generator safety valves by means of controlled steam dump to the condenser and by injection of auxiliary feedwater into the steam generators. Reactor Coolant System temperature is reduced to the no load condition. This no load coolant temperature is maintained by steam dump to the condensers which removes residual heat.

7.7.1.2 Operating Control Stations

The Salem Nuclear Generating Station has a separate control room for each unit, as shown on Figure 1.2-2. The Control Rooms, located in the Auxiliary Building, are physically separated by a hallway from where operations may be observed through glass windows. The information presented in this section pertains to both Control Rooms, although only one is described.

Each unit is equipped with a separate control room which contains those controls and instrumentation necessary for operation of that unit under normal and abnormal conditions. The control room is continuously occupied by the operating personnel under all operating conditions. Equipment in this area had been designed to minimize the possibility of a condition which could lead to inaccessibility or evacuation.

Control room shielding and ventilation are designed such that the occupants of the room shall not receive doses in excess of 5 rem to the whole body, or its equivalent to any part of the body, during the course of a loss-of-coolant accident. This includes doses received during ingress and egress. The Control Room Air Conditioning System is described in Chapter 9.

The Control Room is designed to be continuously occupied by qualified operating personnel under all operating and Design Basis Accident (DBA) conditions. Both control rooms share a number of separate communication systems. One system consists of direct dialing telephones. Another independent communication system is a party line and voice paging system which provides the primary means of communication between plant operations personnel throughout the station. Battery operated portable two-way transceivers are provided for special purposes. There is a separate system interconnecting the containment building, control room and refueling area. These systems are energized from inverter powered buses.

The capability to bring the reactor to a hot shutdown condition is provided at locations outside the Control Room. The majority of equipment for this condition is located in the auxiliary feedwater pump area.

7.7.2 SYSTEM DESIGN

Two independent control systems, of different principles provide redundancy of reactivity control. One of the two reactivity control systems employs RCCA's to regulate the position of the neutron absorbers within the reactor core. The other reactivity control system employs the CVCS to regulate the concentration of boric acid solution neutron absorber in the Reactor Coolant System. These systems are described in Chapters 3 and 9, respectively.

The reactor control system is designed to provide stable system control over the full range of automatic operation throughout core life without requiring operator adjustment of setpoints other than normal calibration.

A simplified block diagram of the reactor control system is shown in Figure 7.7-1. The reactor control system controls the reactor coolant average temperature by regulation of control rod bank position. The system is capable of restoring reactor coolant average temperature to the programmed value following a change in load. The programmed coolant average temperature increases linerly from zero power to the full power condition.

The reactor control system will also initially compensate for reactivity changes caused by fuel depletion and/or xenon transients. Long-term compensation for these two effects is periodically made by adjustment of the boron concentration to return the control rod bank to its normal operating range.

The reactor coolant loop average temperatures are determined from hot leg and cold leg measurements in each reactor coolant loop. The error between the programmed average temperature and the highest of the measured average temperatures from each of the reactor coolant loops constitutes the primary control signal as shown on Figure 7.7-1. An additional control input signal is derived from the reactor power vs. turbine load mismatch signal. This additional control input signal improves system performance by enhancing response and reducing transients peaks. From these input signals, the rod direction command signals are derived. The rod speed command signal varies over the corresponding range of 3.75 to 45 inches per minute depending on the magnitude and the rate of change of the input signals. The rod direction command signal is determined by the positive or negative value of the temperature difference signal. The rod speed and rod direction command signals are fed to the rod control system.

7.7.2.1 Rod Cluster Control Assembly Arrangements

There are 53 Rod Cluster Control Assemblies (RCCA's) divided into four shutdown banks of 24 RCCA's and four control banks of 29 RCCA's. The control banks are the only rods that can be maniplulated under automatic control. The control rods are divided into groups to obtain smaller incremental reactivity changes per step. All RCCA's in a group are electrically paralleled to move simultaneously. There is individual position indication for each RCCA.

7.7.2.2 Rod Control

For a complete description of rod control and position indication systems, see References 1 and 2.

7.7.2.2.1 Control Bank Rod Insertion Monitor

The purpose of the control bank rod insertion monitor is to give warning to the operator of a decrease in shutdown margin. Since the amount of shutdown reactivity required for the design shutdown margin following a reactor trip increases with increasing power, the allowable rod insertion limits must be decreased with increasing power. Two parameters which are proportional to power are used as inputs to the insertion monitor. These are the ΔT between the hot leg and the cold leg, which is a direct function of reactor power, and T_{avg}, which is programmed as a function of power. The rod insertion monitor uses these parameters for each control rod bank as follows:

$$Z_{LL} = A(\Delta T)_{auct} + B(T_{avg})_{auct} + C$$

where Z_{LL} = maximum permissible insertion limit for affected control bank

$(\Delta T)_{auct}$ = Highest ΔT for all four loops

$(T_{avg})_{auct}$ = Highest T_{avg} of all three loops

A,B,C = constants chosen to maintain $Z_{LL} \geq$ actual limit based on physics calculations

The actual control rod bank position (Z) is compared to Z_{LL} as follows:

If $Z - Z_{LL} \leq D$ a low alarm is actuated

If $Z - Z_{LL} \leq E$ a low-low alarm is actuated

Since the highest values of T_{avg} and ΔT are chosen by the auctioneering unit, a conservatively high representation of power is used in the insertion limit calculation.

Actuation of the low alarm alerts the operator of an approach to a reduced shutdown reactivity situation. Administrative procedures require the operator to add boron following normal procedures with the Chemical and Volume Control System. Actuation of the low-low alarm requires the operator to initiate emergency boration procedures. The value for "E" is chosen to account for all instrumentation errors so that the low-low alarm would normally be actuated before the insertion limit is reached. The value for "D" is chosen to allow the operator to follow normal boration procedures. Figure 7.7-2 shows a schematic representation of the control rod insertion monitor. In addition to the rod insertion monitor for the control banks, an alarm system is provided to warn the operator if any shutdown RCC leaves the fully withdrawn position.

7.7.2.2.2 Rod Deviation Alarm

The demand and actual rod position signals are displayed on the control console. They are also monitored by the plant computer which provides a visual printout and an audible alarm whenever an individual rod position signal deviates from the bank demand signal by a preset limit. Figure 7.7-3 is a block diagram of the rod deviation comparator and alarm system. The design criterion for this system is that the alarm be actuated before rod deviation, which would allow the core design hot channel factors to be exceeded, with appropriate allowance for instrument error.

7.7.2.3 Plant Control System Interlocks

7.7.2.3.1 Rod Stops

Rod stops are provided to prevent abnormal power conditions which could result from excessive control rod withdrawal initiated by either a control system malfunction or operator violation of administrative procedures.

Rod stops are given in Table 7.7-1.

7.7.2.3.2 Automatic Turbine Load Runback

Automatic turbine load runback is initiated by an approach to an overpower or overtemperature condition. This will prevent high power operation which might lead to an overpower or an overtemperature ΔT trip.

Turbine load reference reduction is initiated by either an overtemperature or overpower ΔT signal in two of four loops.

7.7.2.4 Pressurizer Pressure Control

The reactor coolant system pressure is maintained at constant value by using either the heaters (in the water region) or the spray (in the steam region of the pressurizer). The electrical immersion heaters are located near the bottom of the pressurizer. A portion of the heater groups are proportional heaters which are used to control small pressure variations. These variations are due to heat losses, including heat losses due to a small continuous spray. The remaining (backup) heaters are turned on when the pressurizer pressure controller signal is below a given value.

The spray nozzles are located on the top of the pressurizer. Spray is initiated when the pressure controller signal is above a given set point. The spray rate increases proportionally with increasing pressure until it reaches a maximum value. Steam condensed by the spray reduces the pressurizer pressure. A small continuous spray is normally maintained to reduce thermal stresses and thermal shock and to help maintain uniform water chemistry and temperature in the pressurizer.

Two power relief valves limit system pressure for large load reduction transients.

Spring-loaded safety valves limit system pressure should a complete loss of load occur without direct reactor trip or turbine bypass.

7.7.2.5 Pressurizer Level Control

The water inventory in the Reactor Coolant System is maintained by the Chemical and Volume Control System. During normal plant operation, the pressurizer level is controlled by the charging-flow controller which controls the positive displacement charging-pump speed to product the flow demanded by the pressurizer-level controller. The pressurizer water level is programmed as a function of coolant average temperature. The pressurizer water level decreases as the load is reduced from full load. This is the result of coolant contraction following programmed coolant temperature reduction from full power to low power. The programmed level is designed to match as nearly as possible the level changes resulting from the coolant temperature changes. To permit manual control of pressurizer level during startup and shutdown operations, the charging flow can be manually regulated from the main control room.

7.7.2.6 Steam Generator Water Level Control

Each steam generator is equipped with a three-element feedwater controller (see Figure 7.2-7) which maintains a programmed water level as a function of load on the secondary side of the steam generator. The three-element feedwater controller regulates the feedwater valve by continuously comparing the feedwater flow signal, the water level signal and the pressure compensated steam flow signal. The steam generators are operated in parallel.

Continued delivery of feedwater to the steam generators is required as a sink for the heat stored and generated in the reactor coolant following a reactor trip and turbine trip. An override signal closes the feedwater valves when the average coolant temperature is below a given temperature.

Following a turbine trip, the feedwater regulating valves are closed at approximately a uniform rate, decreasing flow to a low percent of full flow at about one minute after the trip. This provides an optimum heat sink. Subsequently, the operator remotely controls the valves to maintain steam generator water level. Manual override of the feedwater control system is available at all times.

7.7.2.7 Steam Dump Control

The steam dump system is designed to relieve steam from the steam generators to the condenser to reduce the sensible heat in the primary system in the event of load reduction not exceeding 50 percent.

The bypass system can accommodate 40 percent of full load flow, which, in conjunction with the 10 percent load follow capability of the reactor control system, enables the Nuclear Steam Supply System to accept a 50 percent load rejection from full load without reactor trip. All steam dump steam flows to the main condenser via the bypass lines.

When a load rejection occurs, if the difference between the required temperature set point of the Reactor Coolant System and the actual average temperature exceeds a predetermined amount, a signal will actuate the load rejection steam dump controller.

This circuit prevents a large increase in reactor coolant temperature following a large, sudden load decrease. The error signal is a difference between the lead/lag compensate auctioneered T_{avg} and the reference T_{avg} and is based on turbine impulse chamber pressure.

The T_{avg} signal is the same as that used in the Reactor Coolant System. The lead/lag compensation for the T_{avg} signal is to compensate for lags in the plant thermal response and in valve positioning. Following a sudden load decrease, T_{ref} is immediately decreased and T_{avg} tends to increase, thus generating an immediate demand signal for steam dump. Since control rods are available in this situation steam dump terminates as the error comes within the maneuvering capability of the control rods.

The steam dump flow reduces proportionally as the control rods act to reduce the average coolant temperature. The artificial load is therefore removed as the coolant average temperature is restored to its programmed equilibrium value.

The purpose of the Steam Dump System is to reduce Reactor Coolant System transients following a substantial turbine load reduction by bypassing main steam directly to the condenser, thereby maintaining an artificial load on the steam generators. The control rod system can then reduce the reactor temperature to a new equilibrium value without causing overtemperature and/or overpressure conditions.

The dump valves are modulated by the reactor coolant average temperature signal. The required number of steam dump valves can be tripped quickly to stroke full open or modulate, depending upon the magnitude of the temperature error signal resulting from loss of load.

Following a reactor and turbine trip, decay heat and sensible heat stored in the reactor coolant are removed without actuating the steam generator safety valves by means of controlled steam dump to the condenser and by injection of feedwater to the steam generators.

Following a turbine trip, as monitored by the turbine trip signal, the load rejection steam dump controller is defeated and the Turbine Trip Steam Dump controller becomes active. Since control rods are not available in this situation the demand signal is the error signal between the lead/lag compensated auctioneered T_{avg} and the no load reference T_{avg}. When the error signal exceeds a predetermined set point the dump valves are tripped open in a prescribed sequence. As the error signal reduces in magnitude indicating that the Reactor Coolant System T_{avg} is being reduced toward the reference no-load value, the dump valves are modulated by the plant trip controller to regulate the rate of removal of decay heat and thus gradually establish the equilibrium hot shutdown condition.

The error signal determines whether a group of valves is to be tripped open or modulated open. In either case, they are modulated when the error is below the trip-open set points.

7.7.2.8 Incore Instrumentation

The in-core instrumentation is designed to yield information on the neutron flux distribution and fuel assembly outlet temperatures at selected core locations. Using the information thus obtained, it is possible to confirm the reactor core design parameters.

7.7.2.9 Operating Control Stations

The Control Room provides the necessary controls and indication to start, operate and shutdown the unit with sufficient redundant information displays and alarm indications to ensure safe and reliable operation under all normal and abnormal conditions.

The most important unit controls are located on the control console, which is of free-standing, horse-shoe shaped design, constructed of steel. The front horizontal portion contains the most frequently used operating controls while the rear vertical portion contains less frequently used controls and indication. Controls and indicators are functionally grouped on a system basis to facilitate safe, reliable operation of the unit during transients as well as normal operation. Those systems requiring more frequent operator attention are located in the central area, while less frequently used controls are located on either side.

Most of the console instruments consist of plug-in, back-lighted push-button stations and vertical scale indicators. Operator action consists of a momentary push of a button. The lights in the buttons are used for status, information and alarm indication.

Alarms are provided in the Control Room to alert the operator of abnormal plant conditions. The alarm displays are located either on a console pushbutton control station, where corrective action would be taken, or on the overhead annunciator. An alarm signal causes a back-lighted push-button to flash and the console audible alarm to sound until acknowledged by the operator. Upon clearing of an alarm condition, the console audible ringback is sounded. Other alarms are displayed on an annunciator panel located overhead above the console. This panel consists of illuminated windows and separate audible alarm and ringback tones. Two first-out annunciator panels indicate, by means of red and white lights, the first reactor or turbine trip to occur.

A comprehensive status panel, employing the same type of illuminated windows as the console, indicates the condition of trip channels and alarms. By means of a "mimic bus" arrangement, the interaction of trip conditions and permissives can be quickly analyzed. Diesel generator automatic load sequencing, critical valve status and other important information are also clearly displayed.

A computer is employed to assist the operator and to monitor the unit. Selected parameter trends can be recorded while alarm conditions are indicated to the operator. The computer output consists of a video display mounted on the console and logging typewriters located at the computer output terminal on the other side of the room. The video display and logging typewriters are independent devices.

Vertical panels form the walls of the Control Room and contain controls for systems which require only occasional operator attention as well as miscellaneous recorders and indicators.

Reliability and ease of service has been designed into the Control Room. The majority of the console instruments are plug-in modules. In the unlikely case that a pushbutton station or indicator on the console malfunctions, it can be readily removed and replaced from the front of the console. No access to the inside of the console is needed. Relamping can also be quickly accomplished from the front of the pushbutton.

All pushbutton stations, the fire protection display panel, the overhead annunciator and the status panel contain at least two lamps at each point for increased reliability. Low voltage (28V dc) control is utilized for the console pushbutton stations. A relay logic system performs the required switching and memory functions and provides the interface between the 28V dc and the control voltage (125V dc or 115V ac) for the equipment.

The Relay Room and Control Equipment Room contain equipment used for signal conditioning, circuit switching and logic operations. The wiring between the console and equipment cabinets in these rooms makes use of plug-in cables which reduces the exposure of terminations. Normal servicing of devices in the console requires no access to the inside of the console.

For ease of servicing and maintenance, much of the equipment in the Relay Room and Control Equipment Room is designed for plug-in module type construction. Relays are heavy duty plug-in units. All components are carefully chosen and conservatively rated.

The Control Room, Relay Room, Control Equipment Room and Computer Room are air conditioned to maintain a clean, temperature-controlled environment.

Reliable sources of control power, as described in Chapter 8, are provided to ensure continual operation of controls and instrumentation. Emergency lighting is provided in the Control Room, Control Equipment Room and Relay Room as well as other parts of the station.

7.7.2.10 Plant Alarm and Annunciator Systems

The alarm and annunciator systems for this plant consist of three major areas of alarm indication. They are:

1. The overhead annunciator.

2. The auxiliary annunciator (sequential data operations record).

3. The control console alarm system.

These systems serve to indicate and/or record all abnormal or alarm conditions to be brought to the operators immediate attention inside the Control Room.

Each system is discussed below independently; however, mention is made when there is redundancy of alarm indication.

The Overhead Annunciator System

This system is comprised of seven cabinets containing all the power supplies, relays, terminals, hardware and logic to actuate ten groups of

48 - 2" x 3" backlighted windows for a system total capacity of 480 alarms. The ten displays are located in a dropped ceiling fascia above the control console for easy viewing by the control operator.

The various plant alarms are grouped into systems or related areas, and situated above the console section containing the associated system control pushbuttons and indicators.

The ten displays of the Overhead Annunciator System do not represent ten specific alarm groupings but ten 48-point alarm window displays. Each 48-point display contains various plant alarms, however, alarms which are common to a system or of a related nature are grouped together within a display. There may be several such groupings on a display, see Table 7.7-2.

Most of the assigned inputs to the Auxiliary Alarm System contain status information for safety-related equipment. This information can be considered a backup to the other annunciator systems provided.

Since indication and alarm systems are not part of the plant protection system, and failures within these systems cannot affect the operation of the protection system, there is no reason to impose limiting conditions for operation on the alarm systems. Alarm systems cannot be considered as part of a safety-related system, since they perform no function in the acutation of safety-related equipment. Limiting conditions for operation are imposed on the plant protection systems and equipment to assure the safe operation of the unit.

One display serves as first-out indication and is divided into two separate and independent systems. These are "Reactor Trip First-Out" and "Turbine Trip First-Out".

There are two pushbuttons, located on the control console, which the operator uses to acknowledge all alarms except the "first-out" indication. Two key operated switches are provided to acknowledge firstout indication. A test switch is located on the main console for periodic testing of the entire system.

The Overhead Annunciator System is powered by two separate 115V ac, 60 Hz supplies. Each supply is connected to an isolation transformer which in turn feeds redundant power supplies. Each display section has a normal and back-up power supply which are diode actioneered to an isolated bus. The output of each power supply is monitored to alarm on loss of potential.

Loss of either the normal or the backup ac will initiate a loss of power alarm on this system and also a back-up alarm on the auxiliary annunciator. System ground detection is provided for an annunciation upon grounding of any alarm point.

The alarm logic is a solid state design for high reliability. Each alarm point can be selected to actuate from a normally open or normally closed initiating contact or by the application or removal of 115V ac or 125V dc. A contact change of state or change in voltage level indicates an alarm condition until it returns to its normal condition.

The remotely located annunciator logic cabinets are connected by plug-in cables to the overhead display units. When an alarm condition exists, 28V dc is applied to the corresponding display window lamps and audible speaker driver.

The test switch on the control console simulates an alarm condition into the input logic of every alarm point. Through the operation of the test switch and acknowledge pushbutton, the operator can observe the operability of all alarms simultaneously at any time and detect any abnormalities. Operation of the test function does not effect the normal operation of the annunciator system. The system test is conducted once per shift.

The Auxiliary Alarm System

The Auxiliary Alarm System is a sequential data-operations recorder system used primarily for alarming and recording the loss of control circuits' potential and the off-normal position of valves. This system consists of four remote cabinets containing all the input terminals, input logic, sequential memory, control logic, magnetic drum, relays, power supplies, clock, and hardware necessary to output alarm conditions to a printer located in the Control Room.

The system capacity is 960 inputs. Each input is provided with relays to provide electrical isolation. Normal conditions involve the application of 125V dc to an alarm point or a closed contact, with the loss of 125V dc or contact opening causing an alarm condition.

An alarm is printed out on the printer as follows:

1. The time of the event in hours, minutes, seconds, and milliseconds.

2. A four digit number identifying the input causing the printout.

3. Alarm Status - an A, N, T, or S to indicate the event is an Alarm, return to Normal, Test of Summary print.

4. Legends - up to 47 characters of storage is provided to label the event.

Up to 20 rapid events can be sequenced. The time of the occurrence is stored until the alarm is printed. This system will scan each input once every 1.4 milliseconds.

This system is powered by two separate 115V ac supplies and redundant dc power supplies. Loss of either 115V ac feed or dc power supply results in an alarm being initiated internal to the system as well as to the Overhead Annunciator System.

A ground detection unit is supplied which will detect chassis or earth ground either the positive or negative side of the alarm potential power supply. An alarm on the Overhead Annunciator system also indicates when the Auxiliary System is printing.

A test button is provided on the printer which initiates a test print and checks one input circuit plus the serial, or common circuitry of the system. The same test can be initiated automatically every hour. Actual events will take priority over the test function.

An alarm summary request can be initiated on demand by the operator to obtain a summary printout of all events currently in the "alarm" status. New events occurring during an alarm summary printout have priority and will interrupt the alarm summary. Upon completion of the printing of new events, the alarm summary will resume printing.

To facilitate operation of the plant, certain alarms are located on pushbutton control satations on the control console. These alarms are located to facilitate immediate corrective action and are actuated by either the process control systems or the plant motor controls.

An alarm signal causes a back-lighted pushbutton to flash and the console audible alarm to sound until acknowledged by the operator.

Acknowledgement of an alarm condition causes the audible signals to be silenced and the alarm pushbutton to remain lit. When the alarm condition is cleared, the console audible rinb-back signal sounds and the back-lighted pushbutton flashes again. Acknowledgement silences the audible signal and turns off the back-lighted pushbutton.

To facilitate the location of any pushbutton in alarm, the control console is divided into six sections, referred to as Audible Alarm Groups. Each group or console section has a bullseye indication light at the top to direct the operators attention to that specific section of the control console containing the pushbutton in alarm. One cabinet contains the terminals, power supply and six outputs to actuate each individual Group Audible Alarm indicating light and audible signal.

The process control systems provide alarms via four separate and independent alarm interface cabinets, one per process control group, each containing all the necessary input terminals, alarm logic, power supplies, and hardware to actuate the associated console alarms. The alarm cabinets are connected to the pushbutton stations via plug-in cables.

Each alarm cabinet is powered by two 115V ac, 60 Hz feeds, which feed redundant dc power supplies. The outputs of both power supplies are diuode auctioneered to a common bus. Each ac feed and dc potential is monitored and will actuate an alarm on the auxiliary annunciator sysem upon loss of voltage.

The alarm logic is entirely solid state design for increased reliability. Each alarm point can be actuated from either a normally closed initiating contact or by the application or removal of 115V ac or 125 dc. A contact change of state or change in voltage level indicates an alarm condition until it returns to its normal state. Alarm contacts are monitored by internally supplied 125V dc.

The plant motor control systems provide for numerous alarms from various plant systems. These alarms are initiated by field contacts which are monitored by the internal relay logic of the system to actuate the associated pushbutton alarm. These alarms are either of the ring-back type as previously described or of the non-ring-back type.

This system is supplied from 115V ac, 125V dc and 28V dc sources. There are no internal power supplies. Each 28V dc control circuit is protected by the use of independent breakers.

7.7.3 SYSTEM DESIGN EVALUATION

7.7.3.1 Unit Stability

The Rod Control System is designed to limit the amplitude and the frequency of continuous oscillation of coolant average temperature about the control system setpoint within acceptable values. Continuous oscillation can be inducted by the introduction of a feedback control loop with an effective loop gain which is either too large or too small with respect to the process transient response, i.e, instability induced by the control system itself. Because stability is more difficult to maintain at low power under automatic control, no provision is made to provide automatic control below 15 percent of full power.

The control system is designed to operate as a stable system over the full range of automatic control throughout core life.

7.7.3.2 Step Load Changes Without Steam Dump

A typical power control requirement is to restore equilibrium conditions, without a trip, following a plus or minus 10 percent step change in load demand, over the 15 to 100 percent power range for automatic control. The design must necessarily be based on conservative conditions and a greater transient capability is expected for actual operating conditions. A load demand greater than full power is prohibited by the turbine control load limit devices.

The function of the control system is to minimize the reactor coolant average temperature deviation during the transient within a given value and to restore average temperature to the programmed setpoint within a given time. Excessive pressurizer pressure variations are prevented by using spray and heaters in the pressurizer.

The margin between over-temperature ΔT set point and the measured ΔT is of primary concern for the step load changes. This margin is influenced by nuclear flux, pressurizer pressure, reactor coolant temperature, and temperature rise across the core.

7.7.3.3 Loading and Unloading

Ramp loading and unloading of 5 percent/minute can be accepted over the 15 to 100 percent power range under automatic control without tripping the plant. The function of the control system is to maintain the coolant average temperature and pressure as functions of turbine-generator load. The minimum control rod speed provides a sufficient reactivity insertion rate to compensate for the reactivity changes resulting from the moderator and fuel temperature changes.

The coolant average temperature increases during loading and causes a continuous insurge to the pressurizer as a result of coolant expansion. The sprays limit the resulting pressure increase. Conversely, as the coolant average temperature is decreasing during unloading, there is a continuous outsurge from the pressurizer resulting from coolant contraction. The heaters limit the resulting system pressure decrease. The pressurizer level is programmed such that the water level is above the set point at which the heaters cut out during the loading and unloading transients. The primary concern during loading is to limit the overshoot in average coolant temperature and to provide sufficient margin in the overtemperature ΔT setpoint.

The automatic load controls are designed to safely adjust the unit generation to match load requirements within the limits of the unit capability and licensed rating.

7.7.3.4 Loss of Load With Steam Dump

The Reactor Control System is designed to accept load reduction not exceeding 50 percent for which no reactor trip or turbine trip should be actuated.

The automatic steam dump system is able to accommodate this abnormal load rejection and to reduce the effects of the transient imposed upon the Reactor Coolant System. The reactor power is reducd at a rate consistent with the capability of the Rod Control System. Reduction of the reactor power is automatic down to 15 percent of full power. The steam dump flow reduction is as fast as RCCA's are capable of inserting negatave reactivity.

The pressurizer power operated relief valves might be actuated for the most adverse conditions, e.g., the most negative Doppler coefficient, and the minimum incremental rod worth. The relief capacity of the power operated relief valves is sized large enough to limit the system pressure to prevent actuation of high pressure reactor trip for the above conditions.

7.7.3.5 Turbine-Generator Trip With Reactor Trip

Whenever the turbine-generator unit trips at an operating level above 10 percent power, the reactor also trips. The unit is operated with a programmed average temperature as a function of load, with the full load average temperature significantly greater than the saturation temperature corresponding to the steam generator pressure at the safety valve setpoint. The thermal capacity of the Reactor Coolant System is greater than that of the secondary system, and because the full load average temperature is greater than the no load steam temperature, a heat sink is required to remove heat stored in the reactor coolant to prevent actuation of steam generator safety valves for a trip from full power.

This heat sink is provided by the combination of controlled release of steam to the condenser and by makeup of cold feedwater to the steam generators.

The steam dump system is controlled from the reactor coolant average temperature signal whose setpoint values are reset upon trip to the no load value. Actuation of the steam dump must be rapid to prevent actuation of the steam generator safety valves. With the dump valves open the average coolant temperature starts to reduce quickly to the no load set point. A direct feedback of temperature acts to proportionally close the valves to minimize the total amount of steam which is bypassed.

Following the turbine trip, the steam voids in the steam generator will collapse and the fully opened feedwater valves will provide sufficient feedwater flow to restore water level in the downcomer. The feedwater flow is cut off when the average coolant temperature decreases below a given temperature value or when the steam generator water level reaches a given high level.

Additional feedwater makeup is then controlled manually to restore and maintain steam generator water level while assuring that the reactor coolant temperature is at the desired value. Heat removal is maintained by the steam header pressure controller (manually selected) which controls the amount of steam flow to the condensers. This controller operates a portion of the same steam dump valves to the condensers which are used during the initial transient following turbine and reactor trip.

The pressurizer pressure and level fall rapidly during the transient because of coolant contraction. The pressurizer water level is programmed so that the level following the turbine and reactor trip is above the low level safety injection setpoint. If heaters become uncovered following the trip, the Chemical and Volume Control System will provide full charging flow to restore water level in the pressurizer. Heaters are then turned on to restore pressurizer pressure to normal.

7.7.3.6 Incore Instrumentation

The in-core instrumentation system consists of thermocouples, positioned to measure fuel assembly coolant outlet temperature at preselected locations; and flux thimbles, which run the length of selected fuel assemblies to permit measurement of the neutron flux distribution within the reactor core. The design calls for 65 thermocouples and 58 flux thimbles. The high pressure seals for the thermocouples and flux thimbles are shown on Figure 7.7-5.

The data obtained from the in-core temperature and flux distribution instrumentation system, in conjunction with previously determined analytical information, can be used to determine the fission power distribution in the core at any time throughout core life. This method is more accurate than using calculational techniques alone. Once the fission power distribution has been established, the maximum power output is primarily determined by thermal power distribution and the thermal and hydraulic limitation which determine the maximum core capability.

The in-core instrumentation provides information which may be used to calculate the coolant enthalpy distribution: the fuel burnup distribution; and to estimate the coolant flow distribution.

Both radial and azimuthal symmetry of power distributions may be evaluated by comparing the detector and thermocouple information from one quadrant with similar data obtained from the other three quadrants.

7.7.3.6.1 Thermocouples

Chromel-alumel thermocouples are threaded into guide tubes that penetrate the reactor vessel head through seal assemblies, and terminate at the exit flow end of the fuel assemblies. The thermocouples are enclosed in stainless steel sheaths within the guide tubes to facilitate replacement when necessary. Thermocouple readings are monitored by the computer with backup readout provided by a precision indicator with manual point selection. Information from the incore instrumentation is available even if the computer is not in service. The support of the thermocouple guide tubes in the upper core support assembly is described in Chapter 3.

7.7.3.6.2 Moveable Miniature Neutron Flux Detectors

Miniature neutron flux detectors, remotely positioned in the core, provide remote readout for flux mapping. The basic system for the insertion of these detectors is shown in Figures 7.7-4 and 7.7-6. Retractable thimbles, into which the miniature detectors are driven, are pushed into the reactor core through conduits that extend from the bottom of the reactor vessel down through the concrete shield area, then to a thimble seal table.

The thimbles are closed at the leading ends, are dry inside, and serve as the pressure barrier between the reactor water pressure and the atmosphere. Mechanical seals between the retractable thimbles and the conduits are provided at the seal line.

During reactor operation, the retractable thimbles are stationary. They are extracted downward from the core during refueling to avoid interference within the core. A space above the seal line is provided for the retraction operation.

The drive system for the insertion of the miniature detectors consists of six combinations of drive assemblies, five-path rotary transfer devices, and ten-path rotary transfer devices, as shown in Figure 7.7-6. The drive system pushed hollow helical-wrap drive cables into the core. Miniature detectors are attached to the leading ends of the cables and small diameter sheathed coaxial cables threaded through the hollow centers back to the ends of the drive cables. Each drive assembly consists of a gear motor which pushes a helical-wrap drive cable and detector through a selective thimble path by means of a special drive box which includes a storage device that accommodates the total drive cable length. Further information on mechanical design and support is provided in Chapter 3.

The control and readout system provides means to rapidly traverse the miniature neutron detectors to and from the reactor core at seventy-two feet per minute, and to traverse the reactor core at twelve feet per minute, while plotting the thermal neutron flux versus detector position. The control system consists of two sections: one physically mounted with the drive units, and the other contained in the control room. Limit switches in each tubing run provide signals to the path display to indicate the active detector path during the flux mapping operation. Each gear box drives an encoder for position indication. One five-path group path selector is provided for each drive unit to route the detector into one of the flux thimble groups or to storage. A ten-path rotary transfer assembly is used to route a detector into any one of up to ten selectable thimbles. Manually operated isolation valves on each thimble allow free passage of the detector and drive cable when open. When closed, these valves prevent steam leakage from the core in case of a thimble rupture. Provision is made to separately route each detector into a common flux thimble to permit cross calibration of the detectors.

The Control Room contains the necessary equipment for control, position indication and flux recording. Panels are provided to indicate the position of the detectors, and for plotting the flux level versus the detector position. Additional panels are provided for such features as drive motor controls, core path selector switches, plotting and gain controls. A "flux-mapping" operation consists of selecting (by panel switches) flux thimbles in given fuel assemblies at various core locations. The detectors are driven to the top of the core and stopped automatically. An x-y plot (position vs. flux level) is initiated with the slow withdrawal of the detectors through the core from top to a point below the bottom. In a similar manner, other core locations are selected and plotted.

Each detector provides axial flux distribution data along the center of a fuel assembly. Various radial positions of detectors are then compared to obtain a flux map for a region of the core.

The thimbles are distrubuted nearly uniformly over the core, with about the same number of thimbles in each quadrant. The number and location of these thimbles have been chosen to permit measurment of local to average peaking factors to an accuracy of $\pm$ 10 percent (95 percent confidence). Measured nuclear peaking factors will then be increased by 10 percent to allow for possible instrument error. The DNB ratio calculated with the measured hot channel factor will be compared to the DNB ratio calculated from the design nuclear hot channel factors. If the measured power peaking is larger than expected, reduced power capability will be indicated.

This unit will have the capability for using fixed in-core detectors, if required.

7.7.3.7 Operating Control Systems

7.7.3.7.1 Control Room Availability

The Control Room is designed to be available at all times. Safe occupancy of the Control Room during an abnormal condition is provided in the design of the Auxiliary Building. Adequate shielding, ventilation and air conditioning are used to maintain the environment within established limits (see Section 9.4).

To limit the possibility and potential magnitude of a fire in the Control Room, Relay Room or Control Equipment Room, many precautions are taken. Non-combustible materials are used in construction. Control Room furnishings are of metal construction. The control console and side panels are made of steel. Combustible supplies, such as records, logs, procedures, manuals, etc., are limited to the number required for station operation. All areas of the Control, Relay and Control Equipment Rooms are readily accessible. Portable fire extinguishers and breathing apparatus are provided. The Control Room is occupied at all times by an operator who has been trained in fire fighting techniques. Detectors sensitive to smoke and combustion are installed in the Control Room, control console, ventilation plenum and throughout the Relay and Control Equipment Rooms. Fire detection alarms are provided in the Control Room with indication of the detector zone actuated. Further description of the fire protection provisions is given in Section 9.5.

The probability of the Control Room becoming inaccessible as a result of any cause is considered extremely small. If the operator must leave the Control Room, however, operating procedures require that he trip the reactor and turbine generator prior to leaving, thus ensuring control at the Hot Shutdown Control Stations. If necessary, the required trips can be accomplished at locations outside the Control Room.

7.7.3.7.2 Control Room Evaluation

The Control Room is designed to provide the operator with the controls, indications and alarms necessary to control the unit during normal or abnormal conditions. It is also designed for continuous occupancy, but provisions are made to attain and maintain hot shutdown from outside the control room.

7.7.3.8 Secondary System Design Evaluation

All equipment is designed with highly reliable components. Maximum use is made of solid state components in the electronic instruments; spring loaded diaphragm control valves are employed to fail safe on loss of air or power.

All instrumentation and control, where possible, is installed outside of the containment structure and in locations accessible for inspection and maintenance. Automatic control instruments in selected systems are provided with backup manual control. Alarms are provided to warn of abnormal conditions.

REFERENCES FOR SECTION 7.7

1. Blanchard, A., Katz, D.N., "Solid State Rod Control System - Full Length," WCAP-9012-L (Proprietary), January, 1970 and WCAP-7778 (Non-Proprietary).

2. Blanchard, A., "Rod Position Monitoring" WCAP-7571, March, 1971.

TABLE 7.7-1
ROD STOPS

Rod Stop	Actuation Signal	Rod Motion To Be Blocked
1. Nuclear Overpower	1/4 high power range nuclear flux or 1/2 high intermediate range nuclear flux	Automatic and Manual Withdrawal
2. High ΔT	2/4 overpower ΔT or 2/4 overtemperature ΔT	Automatic and Manual Withdrawal
3. Low Power	Low turbine impulses Pressure	Automatic Withdrawal

Actuation of rod stop No. 2 above is accompanied by the initiation of turbine load reference reduction.

TABLE 7.7-2 (1 of 2)

OVERHEAD ANNUNCIATOR GROUPINGS

The alarm groupings are as follows:

DISPLAY A

General Alarms - including overhead annunciator power failure, fire protection, battery and dc control bus, and Auxiliary Alarm System Alarms.

DISPLAY B

Test Alarms

Miscellaneous - including Radiation Monitoring, Fresh Water and Heating Steam Service Water.

DISPLAY C

Containment

Auxiliary Cooling

Reactor Coolant Pumps

Turbine Auxiliary Cooling

Chemical and Volume Control

DISPLAY D

Waste Disposal

Reactor Coolant System Leak Detection

Safety Injection

Nuclear Instrumentation

DISPLAY E

Rod Control

Reactor Coolant System

Main Steam

Circulating Water

TABLE 7.7-2 (2 of 2)
OVERHEAD ANNUNCIATOR GROUPINGS

DISPLAY F

Reactor Trip First Out
Turbine Trip First Out

DISPLAY G

Turbine and Condenser
Generator
Unit Protection

DISPLAY H

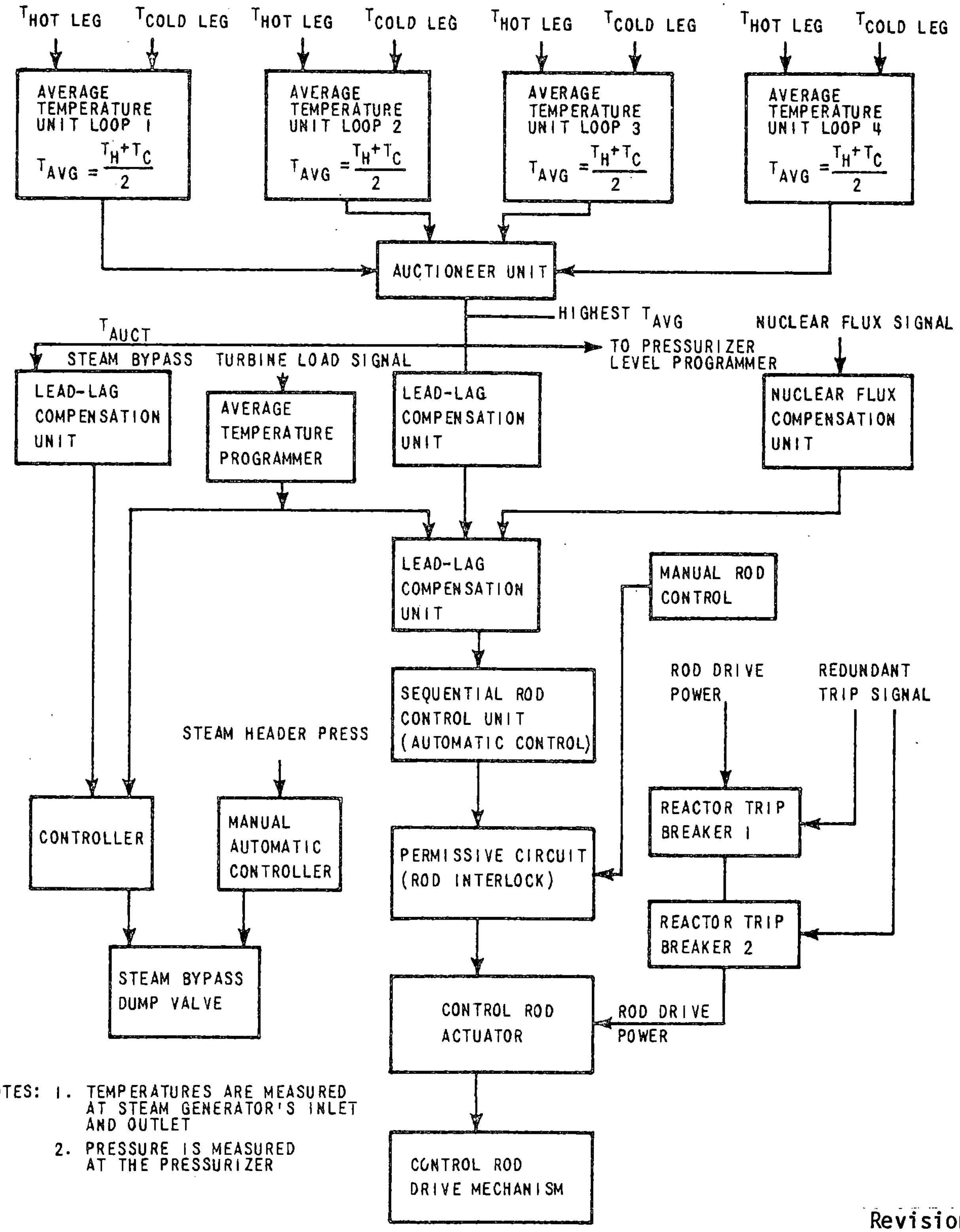
Main Transformer
Auxiliary Transformer
Station Power Transformer 11 and 12
Station Power Transformer 1 and 2

DISPLAY J

4 kV System
13 kV System

DISPLAY K

13 kV System
500 kV System



NOTES: 1. TEMPERATURES ARE MEASURED AT STEAM GENERATOR'S INLET AND OUTLET

2. PRESSURE IS MEASURED AT THE PRESSURIZER

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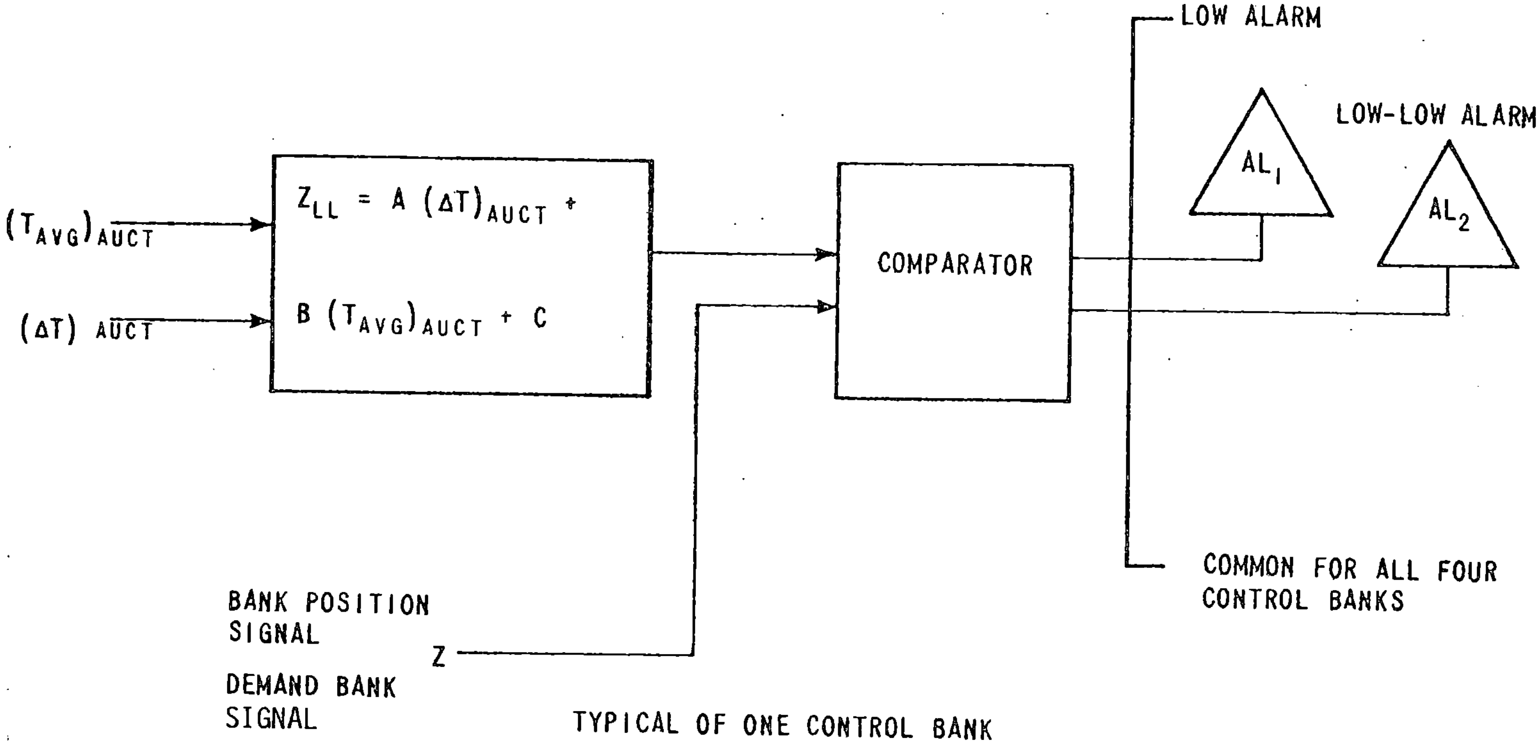
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	**Block Diagram of Reactor Control System** Updated FSAR — Figure 7.7-1



TYPICAL OF ONE CONTROL BANK

NOTE: 1. ANALOG CIRCUITRY IS USED FOR THE COMPARATOR NETWORK
2. COMPARISON IS DONE FOR ALL CONTROL BANKS

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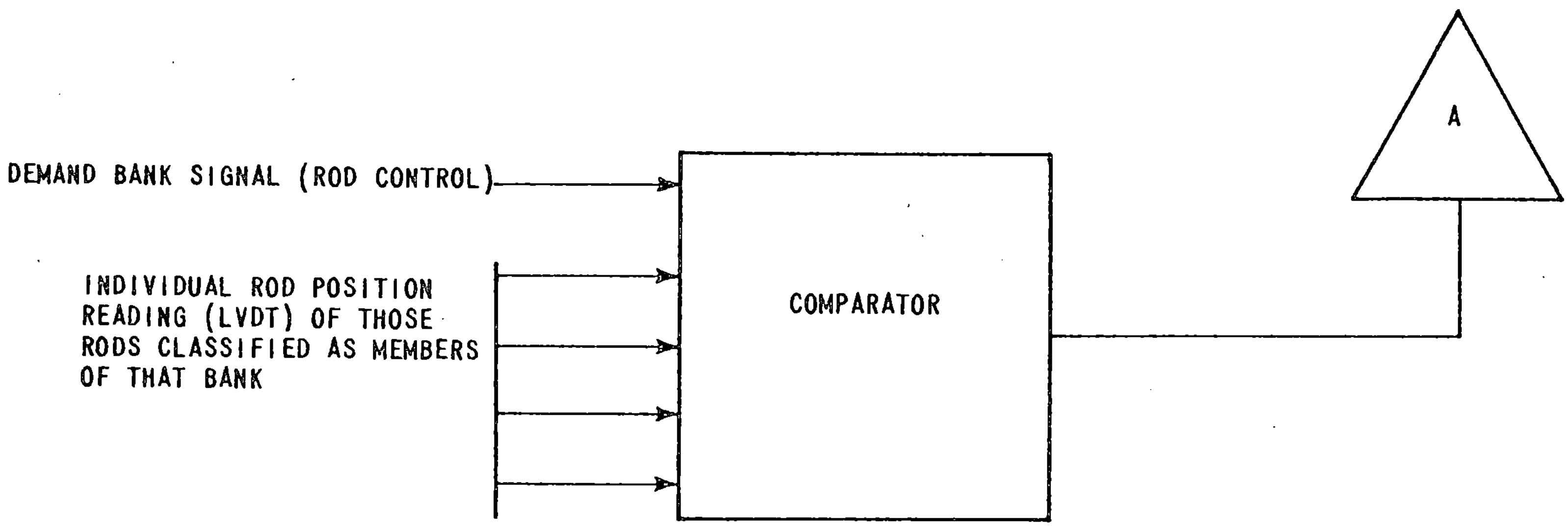
SALEM NUCLEAR GENERATING STATION

Updated FSAR

Control Bank Rod Insertion Monitor

Figure 7.7-2



NOTE:

1. DIGITAL OR ANALOG SIGNALS MAY BE USED FOR THE COMPARATOR COMPUTER INPUTS.
2. THE COMPARATOR WILL ENERGIZE THE ALARM IF THERE EXISTS A POSITION DIFFERENCE GREATER THAN A PRESENT LIMIT BETWEEN ANY INDIVIDUAL ROD AND THE DEMAND BANK SIGNAL.
3. COMPARISON IS INDIVIDUALLY DONE FOR ALL CONTROL BANKS.

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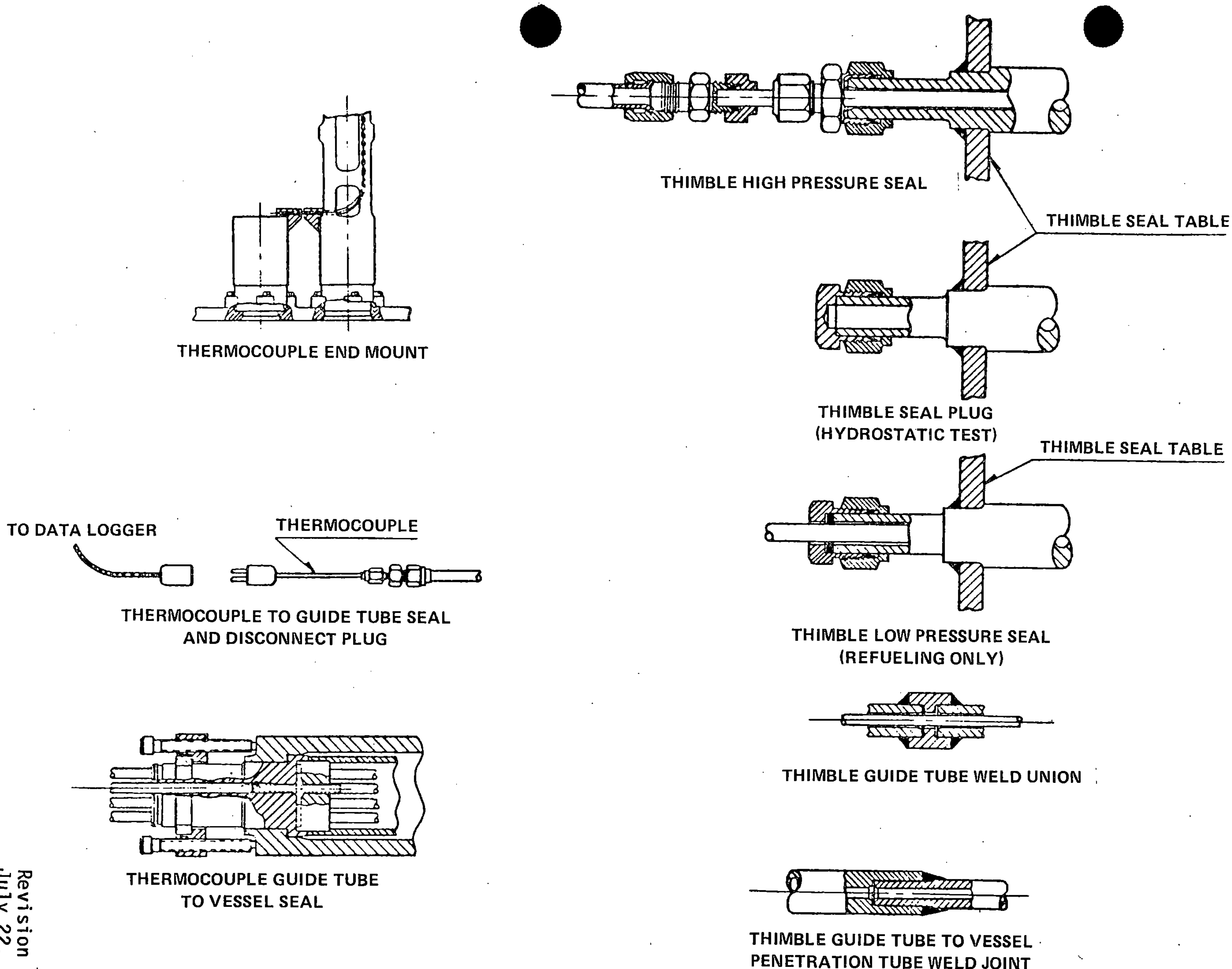
SALEM NUCLEAR GENERATING STATION

Rod Deviation Comparator

Updated FSAR

Figure 7.7-3



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SALEM NUCLEAR GENERATING STATION

Updated FSAR

In - Core Instrumentation Details

Figure 7.7-4

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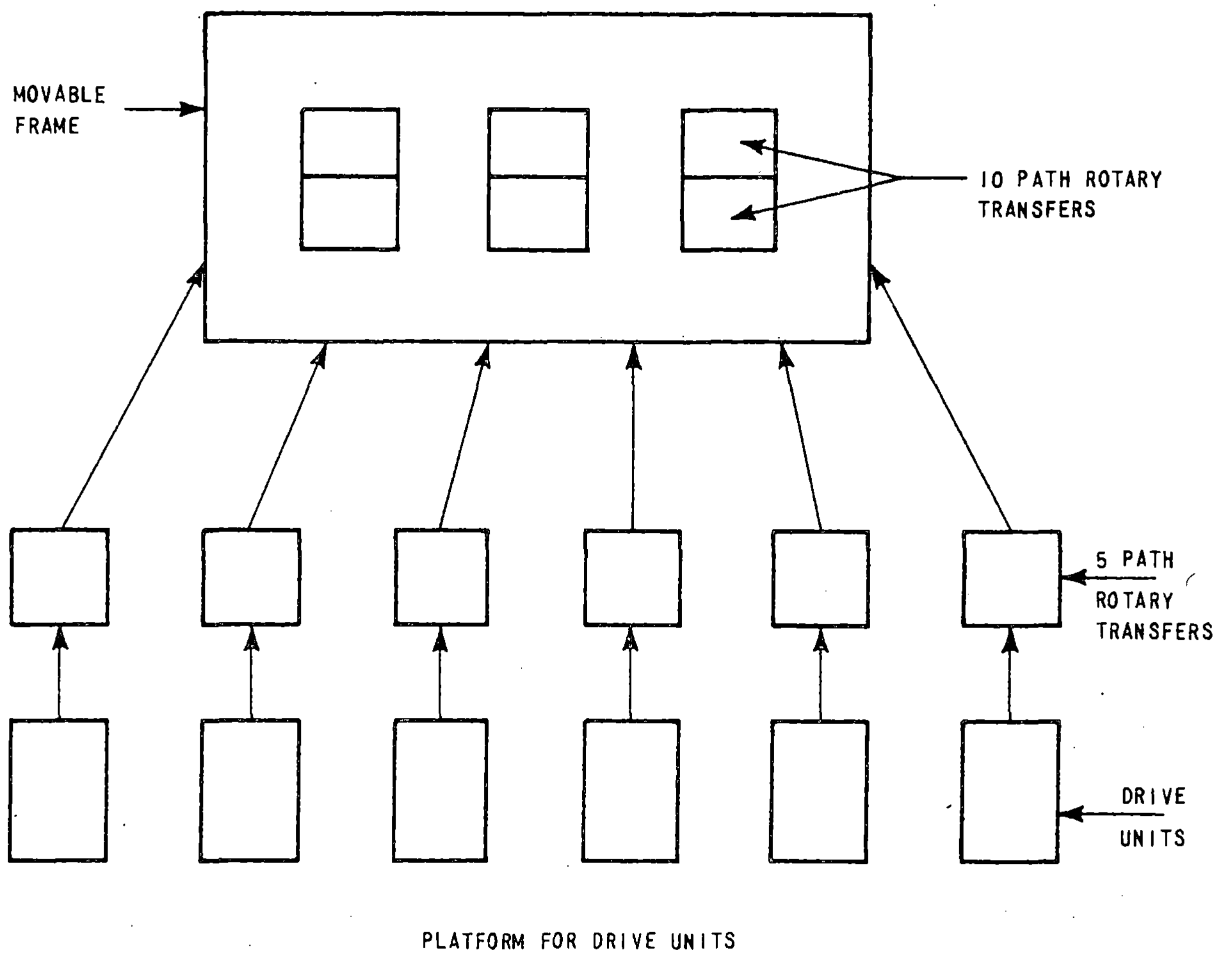

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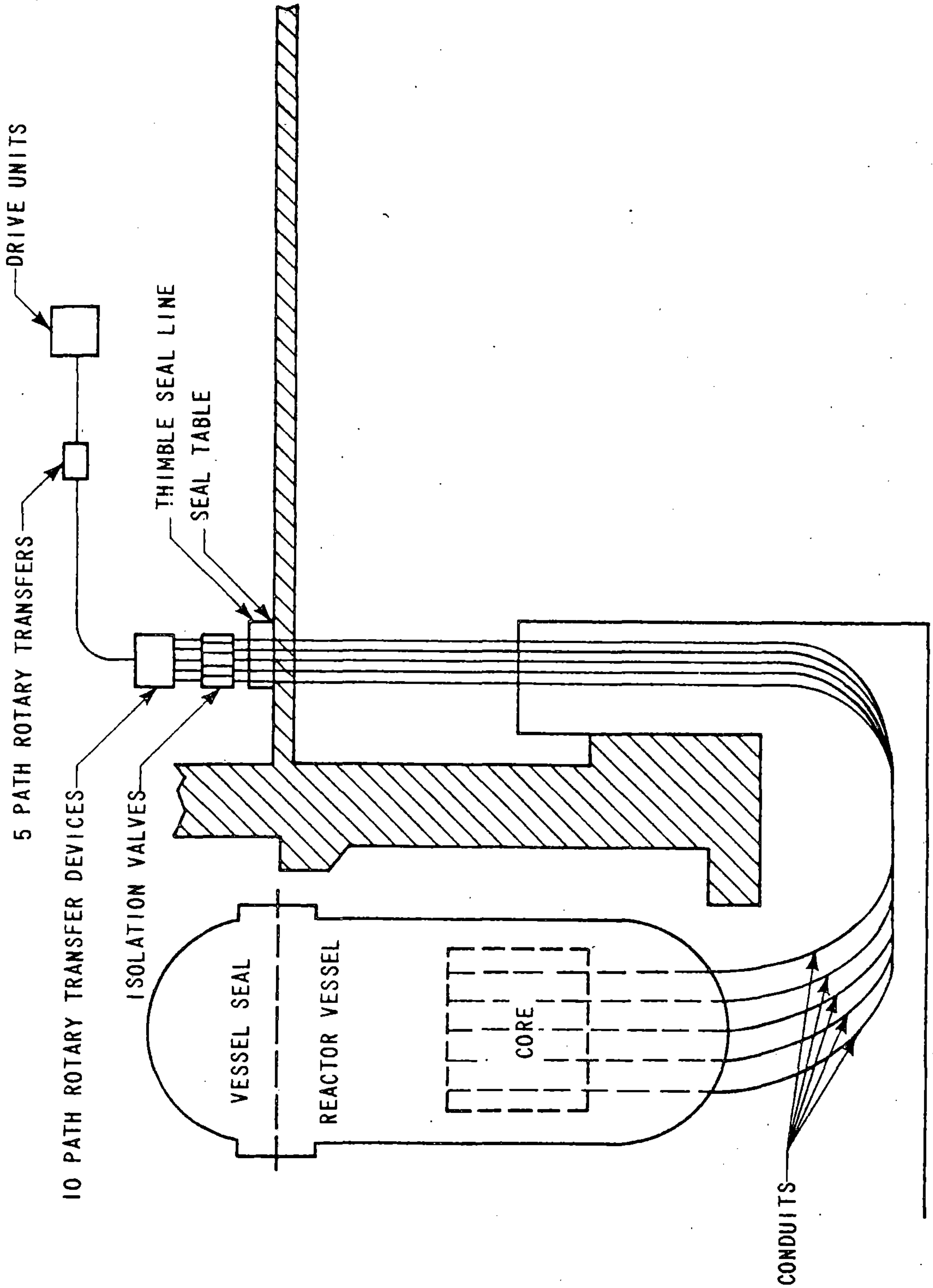
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Schematic Arrangement of In-Core Flux Detectors (Plan View)	
	Updated FSAR	Figure 7.7-5



Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Typical Arrangement of Movable Miniature Neutron Flux Detector System (Elevation)
	Updated FSAR — Figure 7.7-6

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8.0 - ELECTRIC POWER

8.1 INTRODUCTION

8.1.1 UTILITY GRID SYSTEM AND INTERCONNECTIONS

Each unit generates electric power at 25 kV which is fed through an isolated phase bus to the main transformer bank where it is stepped up to 500 kV and delivered to the switching station. The 500 kV switching station design incorporates a breaker-and-a-half scheme for high reliability and is connected to three 500 kV transmission lines. Two transmission lines go north, via separate right-of-way, to two of PSE&G's major switching stations, New Freedom and Deans. The New Freedom Switching Station is solidly connected to the PSE&G 230-kV bulk power system via three 500/230-kV autotransformers. Deans Switching Station is also connected to the PSE&G 230-kV bulk power system via three autotransformers but in addition, it is connected to the PJM 500-kV interconnected system. The third transmission line serves as a tie line to the adjacent Hope Creek 500-kV switchyard which is also integrated into the PJM 500-kV interconnected system.

8.1.2 ONSITE POWER SYSTEMS

The Onsite Power System for each unit consists of the main generator, the auxiliary power and station power transformers, the diesel generators, the group and vital bus sections and their related distribution systems. The 4160 volt vital buses, which feed safeguards equipment, are energized by either station power transformer served by the 13 kV ring bus. Preferred power is supplied to the 13 kV ring bus by two sources from the switchyard and also by an onsite 40 MW gas turbine generator.

Safeguards loads are divided among the vital buses in three independent load groups, each of these load groups is provided with a diesel generator which serves as a standby power supply in the event that the pre-ferred source is unavailable.

Each unit has a 125 VDC power system to provide power to safeguards loads. This system also supplies power through inverters to the 115 VAC instrument buses. In addition, each unit is provided with a 250 VDC power system and a 28 VDC control system.

8.1.3 SAFEGUARDS LOADS

Safeguards loads are identified on the following figures:

Load Group	Figure No.
4160 VAC	8.3-4
460 VAC	8.3-4
230 VAC	8.3-5
28 VDC	8.3-6
125 VDC	8.3-7

8.1.4 DESIGN BASES

8.1.4.1 General

The plant has been designed to be capable of being safely shut down from full power in the event of the loss of all offsite power sources. Redundant and independent onsite power sources are provided to insure the availability of the necessary power for shutdown systems. Total loss of all onsite and offsite AC power is not a design basis event.

The distribution system for each unit and the network interconnections are designed, fabricated, and erected with sufficient independence, redundancy, capacity, and testability to provide reliable power to unit auxiliaries during startup, operation and shutdown. The Class 1E portion of the distribution system of each unit is designed to meet the intent of "IEEE No. 308, Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations".

Onsite electrical systems and components vital to plant safety, including the emergency diesel generators, are designed so that their integrity is not impaired by a design basis earthquake, high winds, floods or disturbances on the electrical system. Power, control and instrument cabling, motors and other electrical equipment required for operation of the engineered safety features are suitably protected against the effects of either a nuclear system accident or of severe external environmental phenomena in order to assure a high degree of confidence in the operability of such components in the event their use is required. Considerations which reflect the above requirements and which have been incorporated in the electrical system are evidenced by the following:

1. The enclosures for motors and electrical switchgear suit the local conditions and are designed in accordance with specifications issued by the National Electrical Manufacturers Association (NEMA). All electrical equipment operates within its rated limits.

2. All switchgear is of metal-clad construction. The 4160 V and 460 V switchgear control power is taken from the station 125 V DC sources. Each breaker cubicle is separated from the adjacent cubicle by metal barriers and each bus section is physically separated from all others. Vital switchgear, unit substations, and

motor control centers are confined to Seismic Category I areas. Separation of redundant power equipment has been maintained throughout the plant. This equipment is coordinated electrically to permit safe operation under normal, overload, and short circuit conditions.

The station batteries and associated chargers are in separate rooms within a Seismic Category I structure.

3. Adequate communications systems are provided for station operating personnel which include a page and party line communication system, a direct dial telephone system with Telephone Company central office tie lines, and a system of portable transceivers with fixed repeaters. Sound-powered phones are also provided.

8.1.4.2 Cabling

Further information for protection circuits is presented in Chapter 7.

8.1.4.1.2 Cable Ratings

"Power Cable Ampacity", AIEE Pub. No. 5-135-1/IPCEA pub. No P-46-426 has been explicitly used as the criteria to determine allowable cable ratings as appropriate for tray, conduit and raceway applications. A further derating factor of 0.90 has been used for sizing cable for additional conservatism.

Power and control cable insulation selection was based on an optimum combination of insulation, fire resistance, and non-propagation qualities. Appropriate instrumentation cables are shielded to minimize induced voltage and magnetic interference.

8.1.4.2.2 Fire Protection

In areas where safety-related cables are installed, the following fire protection and/or detection is provided:

1. Electrical Switchgear Rooms and Penetration Areas - ionization type products of combustion detectors, manually operated CO_2 total flooding systems.

2. Relay Room (cable spreading rooms) - ionization type products of combustion detectors and independent Halon 1301 fire extinguishing system which is actuated either automatically upon receipt of a coincident signal from both zones of the cross zone fire detection system, or manually by either operation of a remote pull station or by depressing the STRIKE button on the Halon system control panel.

3. Control Room - ionization type products of combustion detectors and manual fire alarm pull-stations.

4. Diesel Generator Compartments - rate of rise thermostats and automatic CO_2 total flooding systems.

At all fire barrier walls, floors, and ceilings, fire stops are provided for all openings through which cables pass. A fire detection system is installed in critical areas throughout the station. Additional information regarding fire protection is presented in Section 9.5.1.

8.1.4.2.3 Marking

The cable identification system provides distinctive markings in order to readily enable detection of any violation of the independence criteria, by visual inspection. It provides that a cablemark channel (for such non-safety related cables that run with safety-related cables), be applied to each cable as it is installed. The locations for these tags are: (1) at each end; (2) in the vicinity of each traymark of the route; (3) both sides of penetrations of walls, etc.; and (4) at the entrance and exit of all conduit or duct runs. Installation conformance to design criteria is assured by quality control surveillance during installation and separate audits performed after installation as indicated in Section 8.1.4.2.6.

To facilitate installation audits by others, colored tape is employed to offer further evidence of conformance to the independence criteria. The colored tape is applied, during installation, adjacent to the cablemark tags indicated above and will serve for construction conformance purposes only. The tape is a different solid color for each of the four safety related channels and the same four colors striped for the associated non-safety related channels (when non-safety related cables are run with safety related cables, as noted in Section 8.1.4.2.4).

Cable identifications consist of a series of alphanumeric digits associating with its system, origin, or function. Safety related cables, and non-safety related cables which are run with safety-related cables, are suffixed by a "-" and a letter indicating channel. These cables must follow the rules for routing described below.

Identifying Mark No.	Examples Digits (s)	Significance
1A4D-A	1	Unit No.
(Power Cable)	A	Bus designation
	4	Breaker Position
	D	Voltage Level
	-A	Safety Related Channel A
1RMS48-GT	1	Unit No.
(Control Cable)	RMS	Radiation Monitoring System
	48	Sequential Designation
	-G	Non-Safety Related Channel G
	T	Digital Signal

Each cable tray run has its own five digit identification number. This number defines the unit number, building, elevation, and general area. This number will also appear on cable schematics and on cable and conduit schedules. Safety-related trays are color coded to distinguish the safety from the non-safety related cable trays. In addition, all wireways containing safety related cables are distinctly identified as such.

8.1.4.2.4 Separation In-Plant

The routing of control, instrumentation, and power cables is such as to minimize their vulnerability to damage. Power and control cables are distributed from the switchgear and control areas by means of rigid metal conduits or ladder type cable trays.

Three separate trays are provided for 4160 V, 460 V and 230 V power, control and instrumentation cables. 4160 V power cables are limited to a single layer, 460 V power cables are limited to two layers and 230 V power, control and instrumentation trays are not filled above the side rails.

Four independent protection channels, A, B, C and D are provided. In general, the design criteria is a minimum vertical and horizontal spacing between redundant trays of 18" and 12", respectively, with additional design conservatism as indicated below. Vertical tiers and crossing of redundant trays are generally avoided. When redundant trays cross each other at less than 18", a fire resistant blanket is provided on the top of the lower trays, extending a minimum of 24 inches beyond each side of the crossover. Dissimilar channel designated safety related trays are color coded at crossover points.

There are 3 instances in the Salem Units where 460 V power cable trays run beneath control cable trays in a vertical tier. These instances do not involve cables from different safety related channels. The Salem tray design criteria is such that cable trays are arranged in order of ascending voltage except where it is not possible to do so. In these cases a fire resistant barrier has been provided in the upper tray.

Extensive flame tests performed on the cables proved that the combination of cable construction and minimum spacings used is adequate to prevent propagation of fire.

Even though the tests have proved the 18" vertical spacing as acceptable when redundant cables are involved, an additional fire resistant blanket is provided for each tier (except bottom tier) in the control room, relay room and all other congested areas where the vertical spacing is 18" or less. The blanket is a fire resistant type and will prevent propagation of fire.

In general, the ordinal arrangement of trays is higher voltage trays on top with control cable trays at the bottom.

The safety-related cables are physically separated in accordance with channel designations, A, B, C and D; non-safety related cables are routed, if necessary, in trays containing safety-related cables as follows:

E with B
F " C
G " D
H " A

Where E, F, G and H are the non-safety related cables

The grouping of penetrations in the electrical penetration area and the selection of conductors for each penetration follows the criteria established for the separation of redundant cables and provides for the implementation of these criteria for the cables approaching and leaving the area.

Written design and installation procedures are established to assure that non-safety related cables only run with one safety-related channel.

8.1.4.2.5 Separation in Control Areas and Components

The control boards, panels and relay racks have been designed to provide independance and separation necessary to fulfill the single failure requirement of IEEE 279 "Criteria for Protection System for Nuclear Power Generating Stations".

Control Console

The control console is a free standing unit that is totally enclosed including a dropped floor with a steel bottom plate. All cables entering the console pass through sealing bushings installed in the steel bottom plate on six-inch centers. Up to eight cables may pass through a numbered sealing bushing; however, only cables of the same separation designation are permitted in a single bushing. Safety related and non-safety related cables may be assigned to the same bushing in accordance with the criteria stated above.

Once in the console, cables are assigned to a four-section cable lattice arrangement with supports which have a minimum center to center distance of 1-7/8 inches and are two inches high. Cables go through the lattice to the plug-in instruments. The lattice is assigned separation designations and is also divided horizontally into a numbered grid system. Each cable is assigned a separation designation, a bushing, and a lattice position number. Therefore, the location and path of each cable in the console is individually defined. Installed cables are fastened to the lattice supports.

The plug-in cables terminate at the rear of the console-mounted equipment. All pushbutton stations and vertical indicators plug into indentical steel housings which have a rear-mounted receptacle for the plug-in cable.

The steel housings provide physical separation for adjacent pushbutton stations or indicators. There are no exposed terminations associated with the control stations and indicators.

Each pushbutton station has functions associated with one separation designation. The minimum center-to-center distance between the double barriered control station housings is 1-1/2 inches and is based on the use of low voltage controls and special teflon insulated plug-in cables. This minimum distance occurs at the entrance to plug-in modules containing terminations which are enclosed in a steel housing. From the modules, the cables are separated in the lattice system described above which provides for specific routing of the cables to the floor bushings. Redundant cables are "fanned out" from the modules to achieve a greater separation as soon as practical; however, the separation is never less than 1-1/2 inches, center to center. Safety related wiring other than the plug-in cables is run in conduit.

The reactor trip swithces' wiring is not of plug-in cable construction. Reactor trip wiring is run in conduit (using two separate paths for the two trains) from the entrance to the console up to the switches. Wiring for redundant functions is separated by using the front and rear decks of the multi-deck switch.

Each circuit in the 28 VDC logic system is protected by circuit breakers of 0.5 to 2.0 amps. Current overload tests have been performed on the multi-conductor plug-in cable based upon the calculated current which would occur if the circuit protection failed to interrupt a short circuit due to failures in the pushbutton control stations. These tests showed that a fault occurring in a pushbutton control station could not cause a fire in the console space.

Within the console, color coding is used to identify the cables and connectors associated with each of the four safety and non-safety related channels.

Panels and Racks

Redundant safety-related components/wiring are generally located in physically separated panels or racks. For those exceptions where redundant components/wiring are located in the same panel, and are required for completion of a protection action then the components' design, the materials and the wiring arrangement are such that the possibility of propagation of an electrical failure/fire from one separation group to the redundant one is minimized. Color coding is used to identify panels and racks containing sensors and logic for reactor protection and safeguards actuation.

8.1.4.2.6 Quality Assurance

In addition to the specifications and drawings, documents are prepared to identify the requirements for implementation of the design and construction criteria. These documents are prepared or approved by the responsible engineer and are further reviewed and approved by the responsible supervisory engineering personnel prior to their release.

The following procedures are established to verify that the cable installation is in accordance with the applicable criteria:

1. Each cable has a "pulling card" which shows the cable number, segregation code and cable routing. The foreman of each crew installing the cable signs each card, certifying that the cable has been installed as specified.

2. The Field Quality Control Group's surveillance of the field installed cable assures proper identification and routing.

3. Random audits are performed by Nuclear Operations Quality Assurance on the cable system to insure that they have been installed as specified.

8.1.5 PENETRATIONS

Electrical penetrations comply with IEEE-317-1971. A fuse is placed in series with the primary interrupting device for select electrical penetration circuits. This provides a second level of overcurrent protection for the respective penetration assembly where deemed necessary.

8.2 OFFSITE POWER SYSTEM

8.2.1 DESCRIPTION

Each unit generates electric power at 25 kV which is fed through an isolated phase bus to the main transformer bank where it is stepped up to 500 kV and delivered to the switching station. The 500 kV switching station design incorporates a breaker-and-a-half scheme for high reliability and is connected to three 500 kV transmission lines. Two transmission lines go north via separate rights-of-way to two of PSE&G's major switching stations, New Freedom and Deans. The New Freedom Switching Station is solidly connected to the PSE&G 230 kV bulk power system via three 500/230 kV autotransformers. Deans Switching Station is also connected to the PSE&G 230 kV bulk power system via three autotransformers but in addition, it is connected to the PJM 500 kV interconnected system.

The third transmission line serves as a tie line to the adjacent Hope Creek 500 kV Switchyard which is also integrated into the PHM 500 kV interconnected system. All three 500 kV power lines are available for either or both units.

Site transmission lines are routed as shown on Figure 8.2-1. A one-line diagram of the 500 kV switching station electrical system is shown on Figure 8.2-2.

There are no present plans to incorporate automatic load dispatching for the Salem units.

8.2.2 ANALYSIS

Reliability considerations to minimize the possibility of power failure due to faults in the network interconnections and the associated switching are as follows:

1. Each of the three transmission lines takes a separate route to its destination.

2. The breaker-and-a-half switching scheme in the 500 kV switching station.

3. Primary and backup relaying systems have been provided for each circuit along with circuit breaker failure protection.

4. Two independent DC circuits are provided for each 500 kV breaker from the two independent and separate sources of DC control power which are supplied to the 500 kV switchyard from the station batteries. Loss of either DC source will not prevent connection of the station auxiliary power system to a 500 kV source.

System network performance has been analyzed and evaluated on a computer model for critical three-phase faults cleared by primary relay protection. The Salem nuclear units are stable for the following postulated conditions:

a. Loss of One Salem Nuclear Unit

For the loss of one of the two Salem nuclear units (i.e., a fault in the generator or in its step-up transformer), the remaining Salem nuclear unit is stable. From the stability standpoint, the loss of a Salem unit is less severe than the loss of the most critical line as described below.

b. Loss of Largest Generating Unit on the Grid

The largest generators on the system are the Salem units. Therefore, the results of "a" above apply.

c. Loss of the Most Critical Transmission Line

There are three 500 kV transmission outlets from Salem Generating Station, one to New Freedom Switching Station, one to Deans Switching Station and one to the adjacent Hope Creek 500 kV Switchyard.

For stability analysis purposes, a three-phase fault at Salem was simulated on each of the three 500-kV circuits. A fault on the Salem-Hope Creek 500-kV line is the most critical line fault in evaluating Salem stability. For a fault on this line, the Salem units will remain stable.

The above considerations minimize the possibility of loss of more than one offsite power source. In the event of a loss of all offsite power sources, the engineered safeguards systems will be supplied from the standby AC power supply (see Section 8.3.1.5).

The following material addresses the hypothetical station blackout in accordance with NRC Generic Letter 81-04. In general, no credible mechanism has been identified which would lead to a total loss of onsite and offsite AC power. The plant and system conditions following a hypothetical blackout are many and varied. For this reason it is not possible to address questions such as the time to restore offsite power, the procedure for restoring offsite and the procedure for restoring onsite power. As noted in this chapter generally, considerable redundancy is included in both the onsite and offsite power systems to prevent a loss of AC power. The actions necessary and equipment available to maintain core cooling (with only DC power available) include the following:

The turbine driven auxiliary feedwater pump would be utilized for heat removal along with the steam atmospheric relief valves or steam safety relief valves. The turbine driven pump requires DC power to be operational and is not dependent on component cooling. The steam atmospheric relief valves can be manually operated via handwheels. The steam safety relief valves are pressure actuated, spring control valves. Required instrumentation is powered by vital instrument bus inverters from batteries.

Startup testing of Unit 2 included maintenance of natural circulation conditions without AC power. The startup tests indicated that the plant can be maintained in a safe condition for a limited time during a total loss of AC power. This includes operation without ventilation system fans.

Emergency lighting is provided throughout various areas of the plant where operator action may be required. In addition, 8 hour battery pack lights have been provided in selected areas of the plant as part of the fire protection program. Sufficient lighting exists for postulated loss of AC power events. No action is required for these lights to be operational.

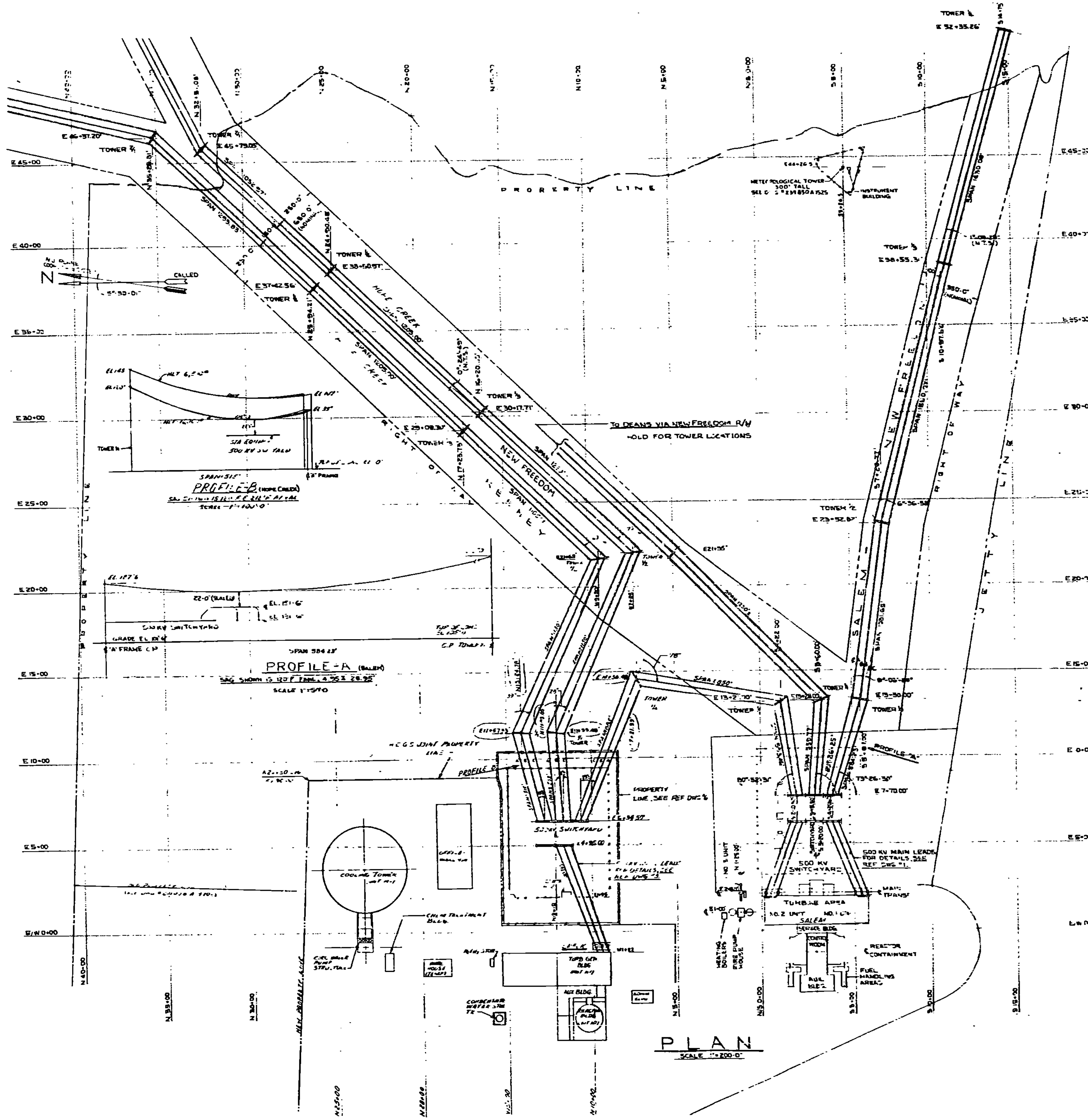

TABLE OF CIRCUIT CONSTRUCTION DRAWINGS				
CIRCUIT DESIGNATIONS	CIRCUIT PLAN & PROFILE DRAWINGS	TOWERS		
		DESIGNATION	SUPERSTRUCTURE DRAWING NO.	FOUNDATION DRAWING NO.
HOPE CREEK KEENEY	11407-R-II	[illegible]	DO-12543-R	DO-11592-R
		[illegible]	DO-12540-R	DO-11591-R
		[illegible]	DO-12532-R	DO-11586-R
		[illegible]	DO-12537-R	DO-11586-R
		[illegible]	DO-12539-R	DO-11590-R
HOPE CREEK NEW FREEDOM	11454-R-II	[illegible]	DO-12543-R	DO-11592-R
		[illegible]	DO-12540-R	DO-11591-R
		[illegible]	DO-12532-R	DO-11586-R
		[illegible]	DO-12532-R	DO-11586-R
		[illegible]	DO-12539-R	DO-11589-R
SALEM NEW FREEDOM	1155[illegible]-R-II	[illegible]	DO-12543-R	DO-11592-R
		[illegible]	DO-12542-R	DO-11559-R
		[illegible]	DO-12533-R	DO-11587-R
		[illegible]	DO-12538-R	DO-11587-R
HOPE CREEK SALEM	13452-R	1/1	DO-12543-R	DO-11592-R
		1/2	DO-12542-R	DO-11559-R
		1/1	DO-12543-R	DO-11592-R
SALEM DEANS VIA NEW FREEDOM	FUTURE			

LISTED ABOVE ARE TRANSMISSION DEPT. DWGS.
SEE NOTES NO. 3 & 5.

NOTES:

1- TOWER COORDINATES SHOWN ARE CIRCUIT CENTER POINTS. FOR SPECIFIC TOWER LOCATIONS, SEE FOUNDATION DRAWINGS LISTED IN TABLE.
2- ANGLES AND SPANS INDICATED ARE FOR CIRCUIT CENTER POINTS AND ARE TAKEN FROM CIRCUIT PLAN AND PROFILE DRAWINGS LISTED IN TABLE.
3- TRANSMISSION DEPARTMENT CIRCUIT PLAN AND PROFILE DRAWINGS ARE BASED ON THE N.J. PLANE COORDINATE SYSTEM. THIS DRAWING CORRELATES THIS SYSTEM TO STATION GRID.
4- THIS DRAWING IS NOT TO BE USED FOR CONSTRUCTION. DRAWINGS LISTED IN TABLE ARE THE AUTHORITY.
5- DRAWING LISTED ARE ALUM. SUPERSTRUCTURE AND FOUNDATION. FOR DETAILS OF STEEL LEGS, CONTACT TRANSMISSION ENGR. DEPT.
6- CONDUCTOR USED ON ALL CIRCUITS IS 2493 MCM, [illegible] ACAR (1.821" O.D.), 2 PER PHASE.
7- SHIELD WIRE USED ON ALL CIRCUITS IS [illegible] ALUMOWELD, 2 PER CIRCUIT.

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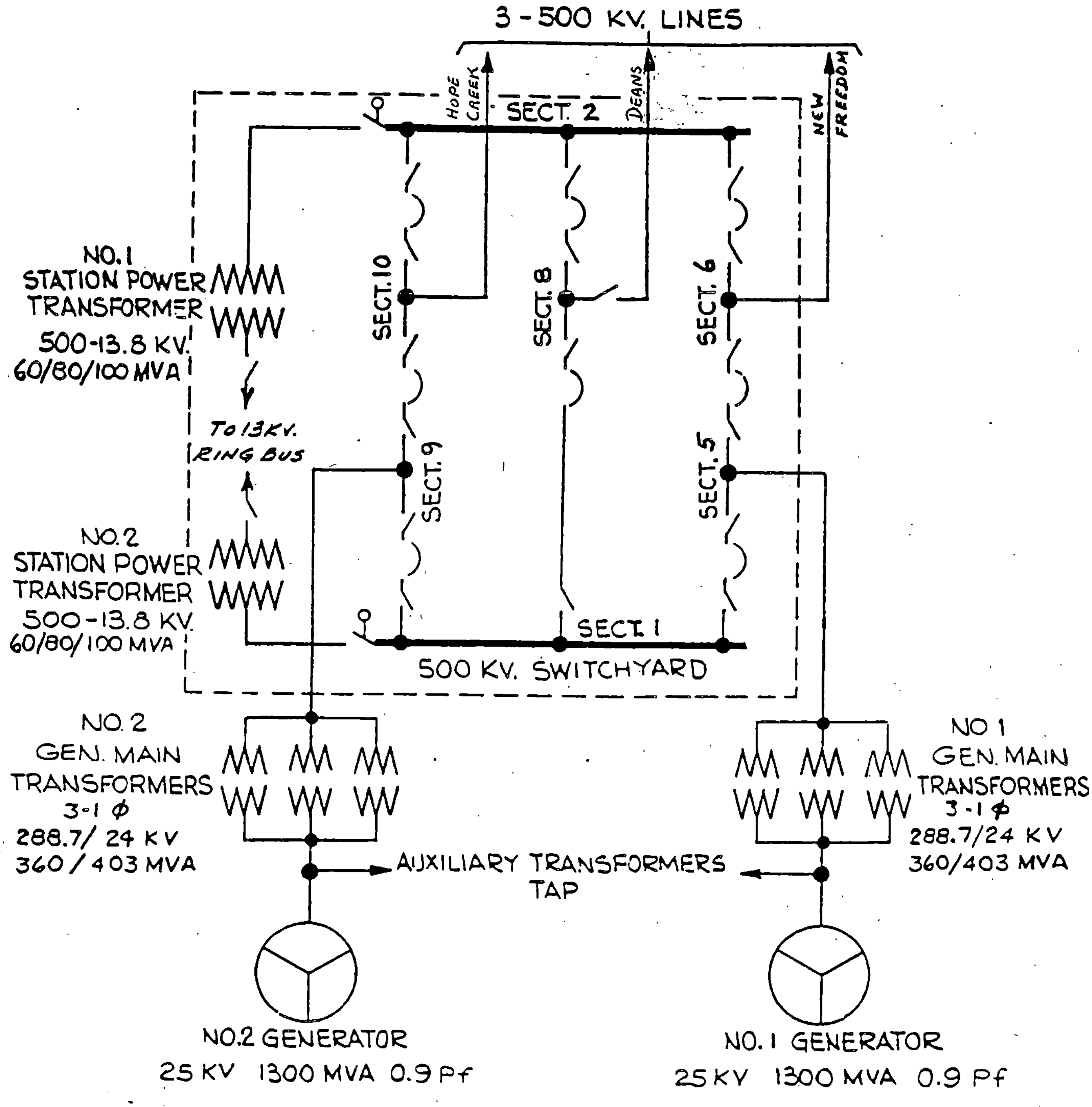
July 22, 1985
Ref. Dwg. 205415A8765-4

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Site Transmission Lines
	Updated FSAR — Fig 8.2-1



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Ref. Dwg. N/A

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	500 kV Switch yard Diagram
	Updated FSAR Fig 8.2-2

8.3 ONSITE POWER SYSTEM

The description in this section is on a unit basis. Unit 1 and Unit 2 are identical in configuration and differ only in nomenclature.

The Distribution System for each unit consists of the various auxiliary electrical systems designed to provide reliable electrical power during all modes of operation and shutdown conditions. The systems have been designed with sufficient power sources, redundant buses, and required switching to provide reliable electrical power.

A one-line diagram of the station's electrical distribution system is shown on Figure 8.3-1, which indicates that power to supply the station electrical requirements is available via the Station Power Transformers and the Auxiliary Power Transformer.

The Offsite Power System in combination with the onsite distribution has been shown by analysis and test to possess sufficient capacity and capability to automatically start and subsequently operate all safety loads within their voltage ratings for anticipated transients and accidents. The worst sustained under-voltage condition in the distribution system was found to occur with a severely degraded 500 kV offsite system simultaneous with a concurrent LOCA on Unit 2 and Unit trip on Unit 1 (or vice versa). This under-voltage condition results from the automatic transfer of the group buses from the auxiliary power transformers to the station power transformer and the automatic start of the required vital bus loads. The 4160 V undervoltage protection system is described in Section 8.3.1.2.

8.3.1 AC POWER

8.3.1.1 Station Power and Auxiliary Power Transformers

The 500-13 kV Station Power Transformers are connected to different bus sections of the 500 kV Switching Station as indicated in Figure 8.2-2. Each has the capacity to start both units at the same time.

The 13 kV ring bus arrangement is shown in Figure 8.3-2. Sectionalizing breakers in this ring bus are normally open and each 500-13 kV transformer feeds two (one for each unit) 13-4 kV Station Power Transformers. This arrangement assures a continuous preferred power supply to each unit in the event one 500-13 kV transformer should become inoperable.

If one of the 500-13 kV transformers is out of service, the 13 kV ring bus breakers can be closed and the remaining 500-13 kV transformer can supply the four 13-4 kV transformers for the two units.

Each 13-4 kV Station Power Transformer connects to a pair of group buses and to the three vital buses.

The 25-4-4 kV Auxiliary Power Transformer primary side is connected to the generator isolated phase bus. Each of the two 4 kV secondary windings is connected to two 4160 V group buses.

8.3.1.2 4160 Volt System

The 4160 V system is divided into four group bus sections and three vital bus sections as shown in Figures 8.3-3A and B.

The group buses feed plant auxiliaries other than engineered safeguards equipment. The group buses are energized by the 13-4 kV Station Power Transformers during start-up. After the generator is synchronized to the 500 kV system, the group buses are manually transferred to the 25-4-4 kV Auxiliary Power Transformer. Should a unit trip, each 4160 V group bus automatically transfers from the Auxiliary Power Transformer source to the Station Power Transformer source.

The vital buses are fed directly from either Station Power Transformer (13-4 kV). During normal operation, two of the vital buses are supplied from one Station Power Transformer and the third from the other Station Power Transformer. The in-feed breakers on each vital bus from the two Station Power Transformers are electrically interlocked to prevent paralleling both sources through a vital bus. These in-feed breakers provide means for transferring between sources in the event of an interruption of power from one source. Control power for each of the three 4160 V vital buses is provided by a normal feed from one battery and an emergency feed from another battery through two manually-operated, mechanically-interlocked molded case circuit breakers. Each 4 kV vital bus provides power to a 460 volt and 230 volt bus. There are no interconnections between the redundant 460 or 230 volt vital buses.

The group and vital bus arrangements are shown in Figures 8.3-3A and B, 8.3-4 and 8.3-4A.

In the following discussion, component numbers for Unit No. 1 are used. The functional description applies to Unit No. 2 as well.

The 4 kV vital buses are normally energized from either No. 11 or No. 12 station power transformer through in-feed breakers 11ASD or 12ASD. In the event the normal source to a 4 kV bus becomes unavailable, that bus can be automatically transferred to its alternate source, provided the following conditions are met (assume No. 11 transformer is the normal source):

1A bus differential or overload relays have not operated.
Voltage on the bus is below a predetermined value.
11ASD breaker is open.

1ADD breaker (diesel-generator) is open.
No. 12 station power transformer is energized.
SEC bus undervoltage relay has not operated.

In the event all offsite power is lost, the standby diesel-generators are automatically started and the normal in-feed breakers to each 4 kV vital bus are opened. When the diesel-generator is up to speed and voltage, its generator breaker is closed to energize that 4 kV bus. An interlock from the diesel-generator breaker prevents closure of either in-feed breaker to that bus, thereby preventing any interconnection between redundent 4 kV buses.

The above controls and interlocks are in conformance with the provisions of Regulatory Guide 1.6.

Undervoltage protection on the 4160 V vital buses is provided in two levels as described below.

The first level uses undervoltage relays to sense the loss of offsite power. These relays monitor the 4160 V vital buses. When the voltage on these buses drops below 70 percent of its rated voltage, the undervoltage relays drop out. The drop-out action of the relays isolates the buses from the offsite sources, starts the emergency diesel generator, initiates load shedding, and permits closure of the diesel generator breakers.

The second level of undervoltage protection is comprised of two sets of relays: a set for undervoltage "transfer" and a set for diesel-generator "blackout" signals.

The second level undervoltage protection relays react instantaneously when the voltage drops below the setpoint of 91 percent of rated voltage. There is also an external timer with adjustable time delay. The time delay of the second level undervoltage "transfer" relay is 10.5

seconds when the output of the station power transformers is below 91 percent of the rated voltage.

The second level undervoltage "blackout" relays consist of three undervoltage relays per unit and one relay for each of the three 4160 V vital buses. The time delay of the "blackout" relays is 13 seconds when the voltage on the affected bus (or buses) is below 91 percent of rated voltage. The output from the timer in each bus energizes three auxiliary relays. One auxiliary relay output from each bus is combined in a two-out-of-three matrix with its redundant counterpart from the other two buses. One of the three two-out-of-three matrices thus formed is assigned to each emergency bus. The output from the two-out-of-three matrices signifies that an undervoltage condition has occurred on at least two buses. This intelligence is input to each of the three independent safeguards equipment controllers which act to disconnect the offsite power source from the emergency buses.

When an undervoltage condition at a 4160 V vital bus (or buses) persists below 91 percent of the rated voltage for at least 10.5 seconds, the affected bus (or buses) is automatically transferred to the alternate source by the action of the vital bus "transfer" relay. The vital bus "transfer" relays allow the affected bus (or buses) to be transferred to the remaining station power transformer before the bus "blackout" relays are actuated. If the supply voltage to the vital buses falls below 91 percent of the rated voltage and a transfer is not accomplished, the second level "blackout" relays will provide a signal to start the diesel generators.

In order to permit reactor coolant pump startup, a "Defeat Second Level Undervoltage" override is provided in the Control Room. This override remains in effect for approximately two minutes following actuation.

8.3.1.3 460 and 230 Volt Systems

The 460 V auxiliary system feeds most motors from 20 to 300 hp. The 230 V system feeds smaller loads and, for convenience of operation, a few motors larger than 15 hp. The 4160 V system feeds the 460 V and 230 V systems via 4160-460 V and 4160-240 V transformers.

The 460 V and 230 V vital bus systems are divided into three bus sections which correlate to their respective 4160 V vital buses.

8.3.1.4 115 V AC Instrumentation Power

Four (4) 115 VAC vital instrument buses derive power from individual uninterruptable power system inverters (UPS) to form redundant channels for reactor control and protection instrumentation and safety related equipment. Each vital instrument bus UPS inverter has an automatic transfer switch to divert its vital instrument bus load to an emergency AC source on an associated UPS malfunction. This emergency source, which supplies 132/120 VAC regulated power through an auto-transformer and solatron arrangement, is supplied from a 230 VAC vital MCC by administrative control of a normally open circuit breaker.

The DC input power to a vital instrument bus inverter is normally provided by an AC/DC converter which is in turn supplied from a 230 VAC vital MCC. Each vital instrument bus UPS has an auctioneer unit to divert its inverter load to a 125 VDC station battery on an associated AC/DC converter malfunction.

Table 8.3-3 depicts channel designations for each vital instrument bus power feed. The 115 VAC control power system for Units 1 and 2 is illustrated in Figure 8.3-5.

8.3.1.5 Standby Power Supplies

The standby AC power source consists of three automatically starting diesel generators. Each diesel-generator set supplies power to one 4160 V vital bus in the event of a loss of off-site power. The system is shown on Figure 8.3-1.

The nameplate continuous rating of the diesel-generator units is 2600 kW, 900 rpm, 4160 V, 3 phase, 60 cycles. The units are sized to handle the loads necessary for a design basis loss-of-coolant accident coincident with the loss of all offsite power. The diesel-generators are designed to be ready to accept load within ten seconds after receipt of a signal to start.

The diesel-generator units are located in the auxiliary building at elevation 100 ft. Within the building the diesel-generators are isolated from each other and from other equipment in the area by fire walls and fire doors. An automatic CO_2 fire protection system is installed for the protection of the diesel-generator equipment. Separate detectors are located in each compartment so that only the area containing the fire is blanketed.

The two 30,000 gallon fuel-oil storage tanks are located below the diesels at elevation 84. Each diesel-generator has its own fuel oil day tank with a 550 gallon capacity. The tank is mounted above the unit for gravity feed of fuel at startup. Each diesel-generator unit has its own lube-oil jacket cooling, ventilation and dual air starting system. Cooling water is supplied by the Service Water System.

Any two of the diesel-generators and their associated vital buses can supply sufficient power for operation of the required safeguards equipment for a design basis loss-of-coolant accident coincident with a loss of offsite power. Sufficient redundancy is provided in the safety features and their assignment to the vital buses so that failure to energize any one vital bus does not prevent operation of the required minimum safety equipment.

In addition to the emergency diesel-generators, there is a gas turbine generator installed at the site. This unit is rated at approximately 40 MW and is normally used for peaking purposes.

The gas turbine unit is connected to the auxiliary electrical system such that it can be paralleled with the normal source of plant start-up or standby power.

Figure 8.3-2 shows the gas turbine connection to the 13 kV ring bus system.

8.3.1.5.1 Diesel-Generator Capacity and Loading

Each diesel-generator unit is rated as follows:

Continuous	-	2600 kW
2000 hr.	-	2750 kW
30 minute	-	3100 kW

A detailed and conservative loading study has been performed for the diesel-generator units using the conditions of a design basis loss-of-coolant accident coincident with a blackout (blackout loads are significantly less than the loads postulated). Results of the study indicate the maximum load to be 2750 kW for a maximum of about 30 minutes duration at which time the changeover to recirculation is completed. The time period beyond 30 minutes, however, is characterized by a load no greater than 2600 kW. Tables 8.3-1 and 8.3-2 indicate the loads connected during various conditions (LOCA and Blackout, Blackout only).

In addition to prototype tests conducted in the manufacturer's plant, testing has been performed at the station to simulate the various modes of loading. These tests verified that the specified diesel-generator load acceptance criteria have been met.

The diesel-generators have the capability to attain rated speed and voltage within 10 seconds after receipt of the start signal, and to accept load in the sequence shown in Table 8.3-1. The loading control system will automatically energize the required loads within 35 seconds.

The Safeguards Equipment Control (SEC) System, which controls the loading of the diesel-generators, is described in Chapter 7. Control power for the controller in each train (A, B and C) is supplied from the 115 VAC instrument bus in that train.

8.3.1.5.2 Diesel-Generator Control and Trip Functions

The diesel-generators are started automatically by the safety injection signal or indication of a loss of all offsite power to the 4160 V vital buses. The latter signal, determined using 2/3 logic, initiates the loading sequence for each vital bus. The loading sequence trips the vital bus in-feed breakers and all motor feeder breakers, closes the diesel-generator breaker after the unit comes up to rated speed and voltage, and connects the required safeguard loads in a predetermined sequence. The loading sequence logic for each vital bus is separate and independent of that for the other buses. The diesel-generator loading sequences under emergency conditions are discussed in Chapter 7.

Following an automatic start (by loss of normal auxiliary power or by an accident signal), the following automatic protective devices are in service during emergency startup and operation of the diesel-generator:

1. Shutdown the diesel-generator and trip the D/G breaker due to:

   a. <u>Mechanical</u>
      1) Engine overspeed
      2) Lube oil pressure low

b. <u>Electrical</u>

1) Generator differential current relays

2. Trip the diesel-generator breaker only due to:

a. <u>Electrical</u>

1) 4 kV Bus differential

Manual diesel-generator control is provided as follows:

1. On the local diesel-generator control panels:
Diesel-generator "START - STOP" selector switch, "EMERGENCY STOP" pushbutton, "LOCK-OUT" switch (key operated), "AUTO-MANUAL" mode selector switch.

Diesel-generator breaker "TRIP - CLOSE" selector switch

Generator voltage "RAISE - LOWER" control switch

Speed "RAISE - LOWER" control switch

Regulator "MANUAL - AUTO" switch

Diesel unit trip relay "RESET"

Fuel transfer pump "OFF - AUTO - RUN" selector switch, "REGULAR - BACKUP" selector switch

Starting air compressor "OFF - AUTO - RUN" selector switch

Turbo air compressor "OFF - AUTO - RUN" selector switch

2. In the control room:

   Diesel-generator "START - STOP" pushbuttons, "CLOSE - TRIP" pushbuttons.

Following a manual start, the following automatic protective devices are in service during startup and operation of the diesel-generator:

1. Shutdown the diesel-generator and trip its 4 kV circuit breaker due to:

   a. Mechanical
      1) Engine overspeed
      2) Lube oil pressure low
      3) Jacket water temperature high
      4) Lube oil temperature high
      5) Engine overcrank

   b. Electrical
      1) Generator differential current relays
      2) Loss of generator excitation
      3) Diesel-generator breaker failure protection

2. Trip the diesel-generator breaker only due to:

   a. Electrical
      1) Overcurrent relay
      2) Reverse power Relay

Elimination of trips could cause damage to the diesel-generators if a trip condition were to occur.

8.3.1.5.3 Diesel-Generator Instrumentation

To facilitate control and adjustment of the diesel-generators, the following instrumentation and alarms are provided.

1. Controls on the local diesel-generator control panels:

   Generator Ammeter (with phase selector switch), Wattmeter,
   Voltmeter (with phase selector switch), Frequency Meter,
   Varmeter, Field Ammeter, Field Voltmeter, Synchroscope,
   Synchronizing Lights, Synchroscope Switch, 4 kV bus voltmeter
   (with phase selector switch) Diesel generator running time meter,
   RPM meter
   Jacket water pressure gauge
   Raw water pressure gauge
   Fuel oil header pressure gauge
   Fuel oil transfer pump pressure gauge
   Air manifold pressure gauge
   Starting air pressure at engine (Duplex Gauge)
   Starting air tank pressure (Duplex Gauge)
   Turbo air tank pressure (two Duplex Gauges)
   Jacket water heat exchanger diff. pressure (Duplex Gauge)
   Lube oil filter diff. pressure (Duplex Gauge)
   Lube oil strainer diff. pressure (Duplex Gauge)
   Fuel oil primary filter diff. pressure (Duplex Gauge)
   Fuel oil secondary filter diff. pressure (Duplex Gauge)

   Lube oil header pressure
   Lube oil pump discharge pressure
   Lube oil heat exchanger differential pressure

2. Controls in the control room:

   Diesel generator voltage, frequency, watts, amps.

3. Alarms local to the diesel-generator:

   Cooling water temperature low
   Cooling water temperature high
   Jacket water temperature high
   Jacket water heater failure
   Lube oil temperature high
   Lube oil heater failure
   Fuel oil day tank level low
   Expansion tank level high
   Crankcase level high/low
   Engine lube oil header pressure low
   Generator vibration high
   Engine vibration high
   Fail to start (overcrank)
   Diesel-generator tripped
   Generator negative phase sequence
   Fuel oil day tank level high
   Pre-lube pump failure
   Crankcase blower failure
   Exciter regulator on manual control
   Diesel-generator locked out (for maintenance)
   D.C. control voltage failure-A single alarm to
     include the following:
       Loss of DC power to the engine control
       Loss of DC power to the generator field
       Loss of DC power to the unit trip circuit
       Loss of DC power to the local alarm system

Air receiver No. 1 pressure low
Air receiver No. 2 pressure low
Generator breaker trip
Generator field ground
Expansion tank level low
Generator overspeed
Generator overvoltage
Generator loss of PT secondary
voltage
Generator ground fault
Turbo air receivers low pressure

4. Alarms in the control room:

Diesel-generator trouble (a common alarm which will be actuated by the operation of any of the above local alarms).

Diesel-generator urgent trouble a single alarm to include the following:

Jacket water temperatrue high
Lube oil temperature high
Engine lube oil heater pressure low
Air receiver pressure low
Pre-lube pump failure
Generator ground fault
Turbo air receivers low pressure

Fuel oil day tank level trouble (a common alarm for all three unit day tanks).

Loss of DC power to the engine control, generator field, trip circuits.

Diesel-generator in Local-Manual control mode, failure to start, emergency trip, locked out.

Generator breaker spring charger failure, breaker trip.

8.3.1.5.4 Diesel-generator Support Systems

Diesel-generator support systems are described in the following sections:

Fuel Storage and Transfer System	Section 9.5.4
Jacket Water Cooling System	Section 9.5.5
Starting Air System	Section 9.5.6
Lube Oil System	Section 9.5.7

8.3.1.6 Tests and Inspections

Periodic tests will be conducted to insure proper operation of electrical features necessary for plant safety. Tests will be conducted to identify and correct electrical or mechanical deficiencies before they result in a system failure.

Tests will be conducted periodically to verify the starting of the diesel-generators on loss of voltage to the 4160 V vital buses and their ability to carry load.

The standby AC power sources (diesel-generators) are automatically started and connected to the vital buses in the event the normal offsite sources become unavailable. The standby diesel-generators are automatically started by either a safety injection signal or a 2 out of 3 undervoltage signal derived from undervoltage relays located on the three 4 kV vital buses. Testability of each of these signals is provided. The Solid State Protection System (SSP) test cabinet is used to check the continuity of the SSP output relay contact, the field wiring, and the Safeguards Equipment Controls (SEC) input relay without actually operating the SEC unit.

The undervoltage relays can be tested by operating test switches to simulate a single bus undervoltage condition. During the test mode an alarm is actuated in the Control Room signifying that diesel-generator automatic start is defeated.

Since the SEC units are completely independent of each other, the SSP test cabinets are used to provide independent output signals from both SSP trains to the three SEC units. Buffer relays are used on each vital bus undervoltage sensor to supply independent signals to each SEC unit. Thus, complete channel independence is maintained.

The SEC units are completely redundant. Both SSP trains feed each SEC; a failure of an SSP train will not negate safeguards operation. Failure of a bus undervoltage relay to operate will not negate safeguards operation since a 2/3 undervoltage logic is used to sense blackout conditions. If only one bus experiences undervoltage, and the sensor on that bus fails to recognize the condition, only that bus will not be loaded; the remaining buses will supply power to the required amount of safeguards equipment.

The diesel-generators can be started and loaded during power operation. As discussed above, the 4 kV bus undervoltage relays can also be tested during power operation. The complete operation of detecting the loss of normal power sources, starting of the standby power sources and connecting these sources to the vital buses can be accomplished during plant shutdown.

These design provisions satisfy GDC-18.

8.3.2 DC POWER

8.3.2.1 250, 125 and 28 Volt Systems

Separate 125 V and 250 V DC sources supply power for operation of switchgear, annunciators, vital instrument buses, inverters, emergency lighting, communications, and turbine generator emergency auxiliaries. Three independent 125 V DC sources provide power to the engineered safety features. Figures 8.3-6, 8.3-7, and 8.3-8 illustrate the 28 V, 125 V, and 250 V DC systems, respectively. Safety-related loads are identified by the use of the symbols A, B, C, D on the feeders.

As shown in Figure 8.3-7, three 125 V batteries are provided for each unit to supply an independent source of control power for each of the three 4160 V and 460 V vital buses and for the 125 V distribution cabinets. A backup source of control power for each of these buses is provided via manually operated, mechanically interlocked breakers under adminstrative control.

The DC systems provide a continuous source of power for operation of circuit breakers, valve controls, inverters, etc. No initiation or control is required to connect the batteries to the DC buses.

8.3.2.2 Batteries

The battery system includes one 250 V, three 125 V and two 28 V batteries, static battery chargers for each battery and a ground detection system and undervoltage alarm relay for each bus.

The batteries are mounted on corrosion resistant, seismically designed steel racks in separately ventilated and isolated areas. The 250 V, 125 V and 28 V batteries are rated 1200, 2320 and 800 ampere hours respectively at the 8 hour rate of discharge.

Each charger maintains a floating charge on its associated battery, and is capable of supplying the required equalizing charge when necessary. Each 125 V and 28 V battery system (one battery, two chargers and one switchgear unit) has a ground detection system, undervoltage alarm relay and DC voltmeters and ammeters. Each charger is equipped with an AC failure relay. Loss of AC input and/or DC output is annunciated in the Control Room.

Each battery is connected directly to its associated switchgear through protective fuses. The DC distribution switchgear consists of metal-clad structures, each with an ungrounded main bus, and 2 pole air circuit breakers.

During normal operation, the DC load is fed from the battery chargers with the batteries floating on the system. Upon loss of DC power from a battery charger, the DC load is drawn from the batteries. The batteries are sized for two hours of operation after a loss of AC power, based upon the required operation of the DC emergency equipment. If all off-site power is lost, the battery chargers are energized from the emergency diesel-generators and resume their function automatically.

8.3.2.3 Battery Monitoring

Two chargers, each capable of 100 percent normal load, are provided for each 28 V and 125 V DC battery. Each normal charging source supplies the continuous DC loads and maintains a float charge on the battery to insure the capability of each battery to deliver its emergency DC requirements. The 28 V and 125 V chargers are fed from the vital AC buses. Each 28 V and 125 V battery is fed from two separate vital buses. One charger is under administrative control to assure that the 230 V AC busses will not become interconnected.

One 250 V DC charger is provided due to the nature of the 250 V DC loads, with a provision to tie in the other unit's 250 V charger, if needed.

Each of the 6 batteries per unit is continuously monitored in the control room for voltage and discharge current. Listed below are all the monitoring devices associated with each battery. A brief description of the function of each device and its location is given.

Battery Voltmeter - Monitors DC bus voltage with continuous readout in control room.

Battey Load Ammeter - Monitors discharge current with continuous readout in control room.

Ground Detectors - Monitors leakage from positive and negative buses to station ground with continuous readout in control room. In addition, local ground detection circuit is provided adjacent to each charger for test purposes.

Undervoltage Alarm - Monitors each DC bus and alarms in control room when bus voltage drop below a preset value.

Charger Voltmeter - Monitors charger output voltage at charger cabinet.

Charger Failure Alarm - Monitors AC input to charger and alarms in control room upon loss of input voltage to either both 125 DC or both 28 V DC chargers. The 250 volt and 125 volt DC chargers also have an over-voltage alarm in the control room should the bus voltage rise above a preset value.

D-C Distribution Cabinet Undervoltage Alarm - Each 28 V and 125 V DC distribution cabinet is provided with an undervoltage relay which monitors bus voltage and alarms in the control room.

Blown Fuse Alarm - Each battery fuse is monitored to alarm in the control room if the fuse should blow.

Protection against overcharging is provided within the charger itself which is a constant voltage-current limited device.

Surveillance requirements are set forth in the Technical Specifications.

The general cleanliness of battery, float charge, cell cracks, electrolyte leakage, ventilation equipment, cell to cell connections, etc., are periodically inspected to assure good service and long battery life. Thus, degradation can be monitored and rectified during surveillance and testing program.

TABLE 8.3-1

DIESEL GENERATOR LOADING SEQUENCE

FOR ACCIDENT PLUS BLACKOUT

	Diesel A		Diesel B		Diesel C	
	Load (BHP)	Elapsed Time* (sec)	Load (BHP)	Elapsed Time* (sec)	Load (BHP)	Elapsed Time* (sec)
1. 230 V Vital Buses	185kW	0	166kW	0	215kW	0
2. Centrifugal Charging Pumps	-	-	625	1	625	1
3. Safety Injection Pumps	390	1	-	-	390	5
4. RHR Pumps	425	5	425	5	-	-
5. Containment Spray Pumps	390	9	-	-	390	9
6. Service Water Pumps	1000	13	1000	9	1000	13
6a. Alternate Pump (If Failure)	-	18	-	14	-	18
7. Containment Fan Coolers (Low Speed)	103	22	206	18	206	22
8. Auxiliary Feedwater Pump	600	26	600	22	-	-
9. Control Room Air Conditioning (Chillers)	75	30	75	26	75	26
10. Emergency Control Air Compressor	-	-	-	-	125	25
11. Auxiliary Building Supply and Exhaust Fans	60	30	100	26	100	26
12. Electrical Equipment Rooms (El, 84, 64) - Ventilation (Main Supply Fans)	25	30	25	26	25	26
13. Pressurizer Heaters	-	-	-	-	207 kW	-
TOTALS (HP/KW)	3068/2731		3056/2702		2936/2652	

The component cooling pumps and Hydrogen Recombiners are manually energized during the recirculation phase only after prior reduction of the diesel load by manual shutdown of equipment not required for the recirculation phase. Prior to closing the vital bus breaker supplying the pressurizer backup heaters, the operator shall verify that the additional load will not exceed the 2000 hour rating (2760 kW) of the diesel-generator.

*Elapsed time from diesel-generator breaker closure

TABLE 8.3-2

DIESEL GENERATOR LOADING SEQUENCE

FOR BLACKOUT

	Diesel A		Diesel B		Diesel C	
	Load (BHP)	Elapsed Time* (sec)	Load (BHP)	Elapsed Time* (sec)	Load (BHP)	Elapsed Time* (sec)
1. 230 V Vital Buses	195kW	0	182kW	0	232kW	0
2. Centrifugal Charging PUmps	-	-	625	1	625	1
3. Component Cooling Water Pumps	300	1	300	5	300	5
4. Auxiliary Feedwater Pumps	600	5	600	9	-	-
5. Service Water Pump	1000	9	1000	13	1000	9
5a. Alternate Pump (If Failure)	-	14	-	18	-	14
6. Emergency Control Air Compressor	-	-	-	-	125	18
7. Control Room Air Conditioning (Chillers)	75	20	75	20	75	20
8. Auxiliary Building Supply and Exhaust Fans	60	20	100	20	100	20
9. Electrical Equipment Rooms (El, 84, 64) Ventilation (Main Supply Fans)	25	20	25	20	25	20
10. Reactor Shield Vent Fans	10	20	10	20	-	-
11. Reactor Nozzle Support Vent Fans	10	20	10	20	20	20
12. Pressurizer Heaters	-	-	-	-	207 kW	-
TOTAL (HP/KW)	2080/1922		2745/2461		2270/2117	

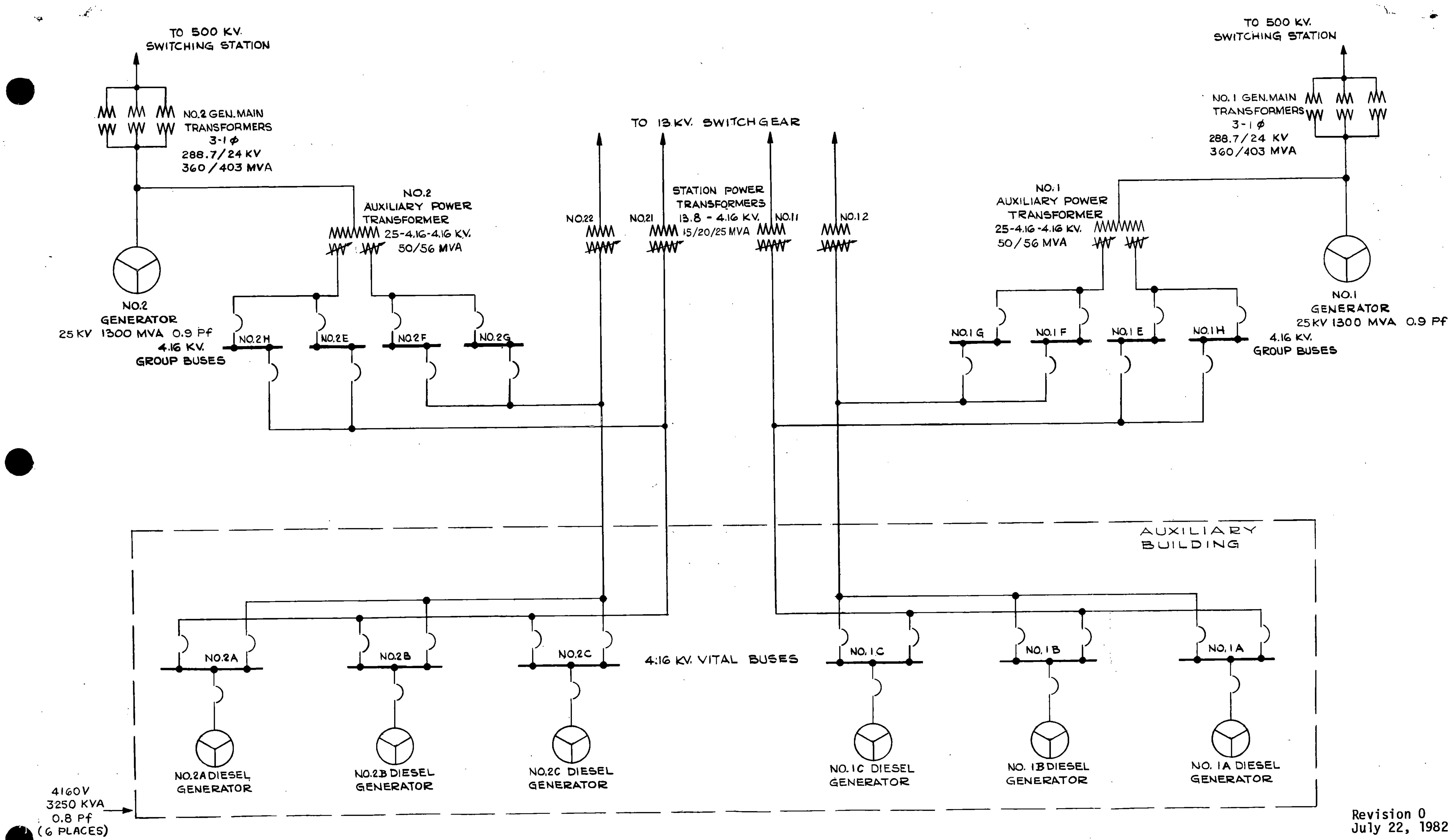
The reciprocating charging pump, containment fan cooler units and other equipment will be manually energized as required only after prior reduction of diesel load by manual shutdown of equipment not required for long-term operation. Prior to closing the vital bus breaker supplying the pressurizer backup heaters, the operator shall verify that the additional load will not exceed the 2000 hour rating (2760 kW) of the diesel-generator.

*Elapsed time from diesel-generator breaker closure.

TABLE 8.3-3

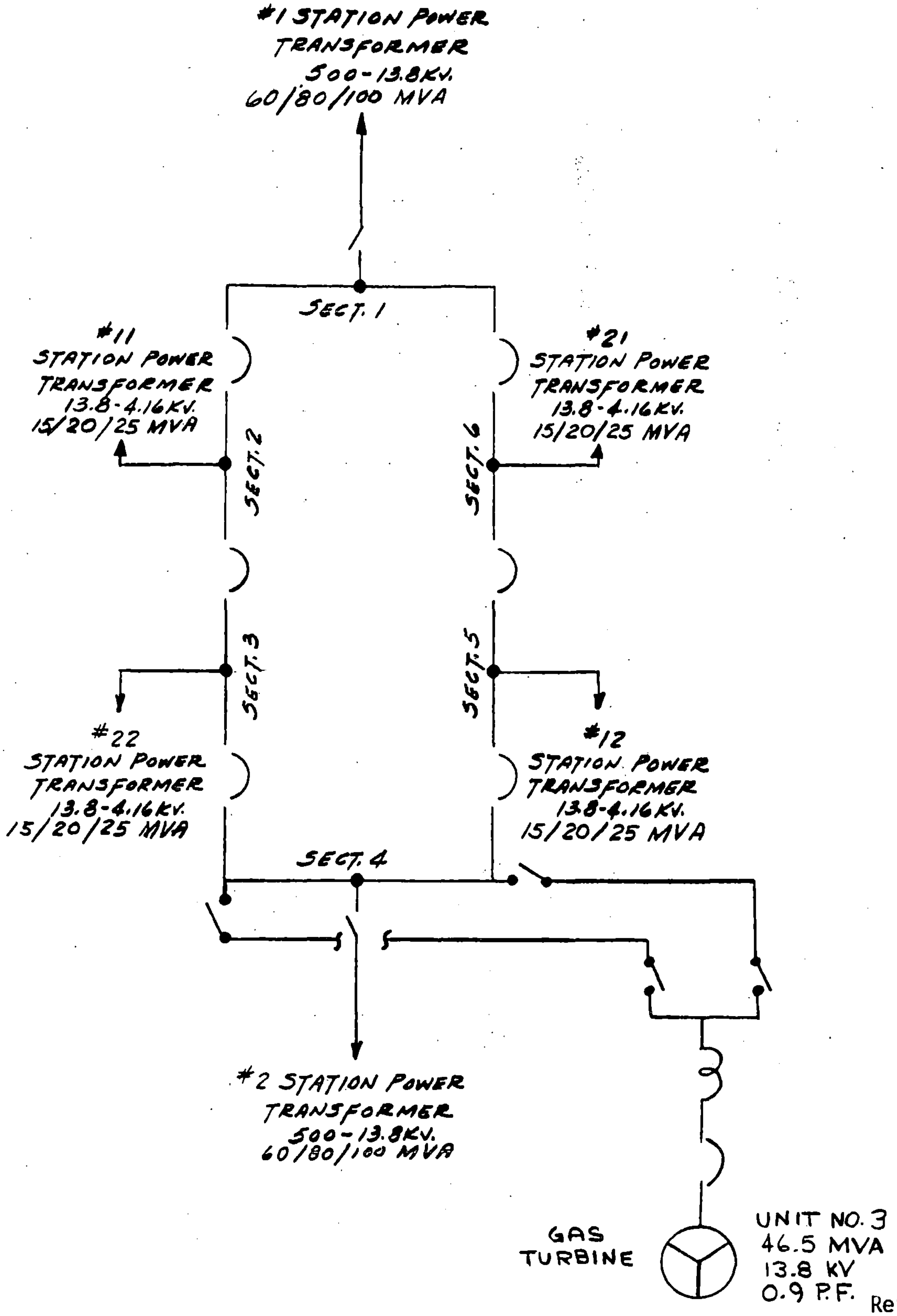
DIFFERENT FEEDS TO THE VITAL INSTRUMENT BUSSES

	Battery Feed to pwr supply	230V CC Feed to pwr supply	230V CC Feed (Emerg. Feed)
No. 1A Vital Bus	A	A	A
No. 1B Vital Bus	B	B	B
No. 1C Vital Bus	C	C	C
No. 1D Vital Bus	B	B	A



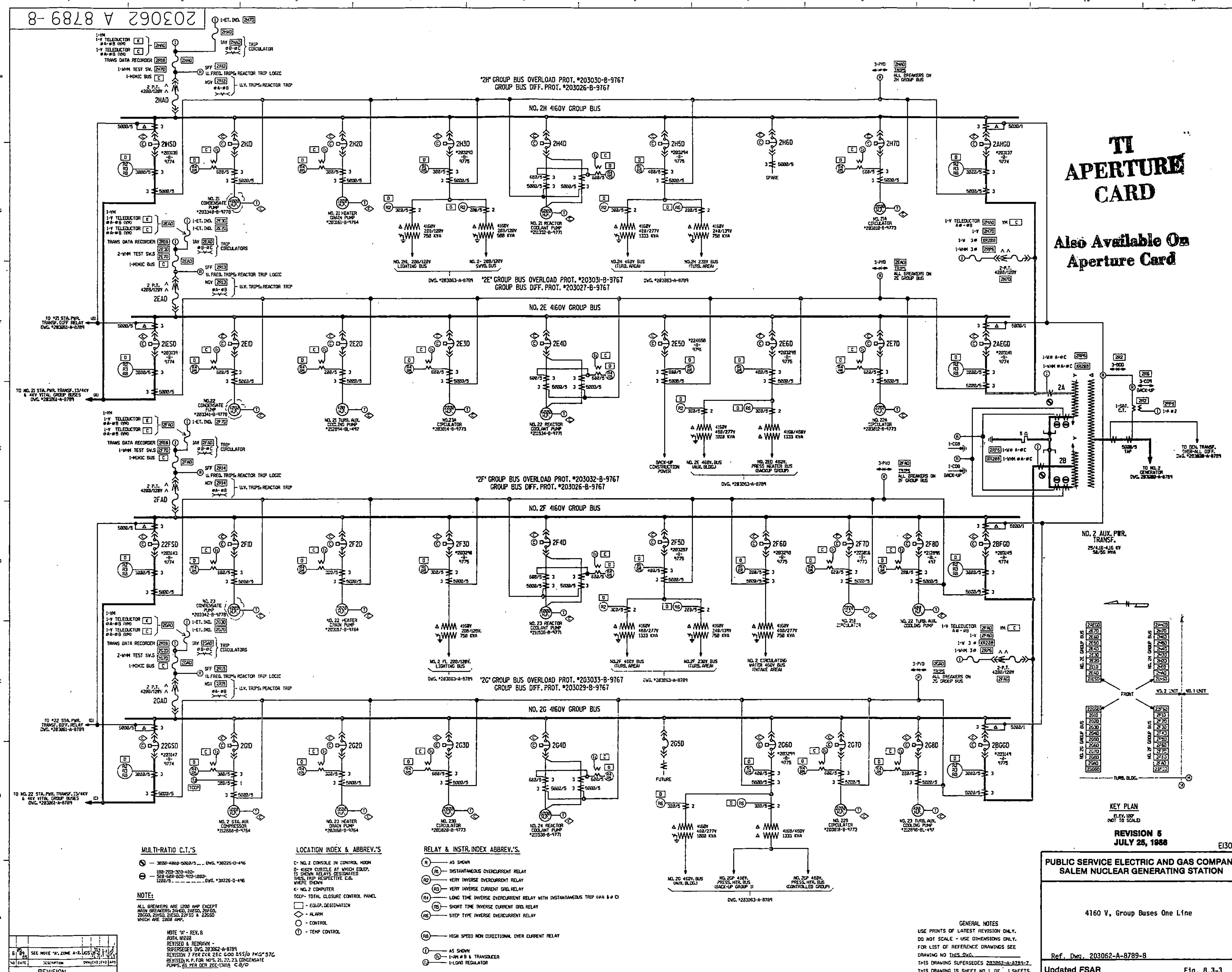
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Auxiliary Power System Diagram
	Updated FSAR — Figure 8.3-1



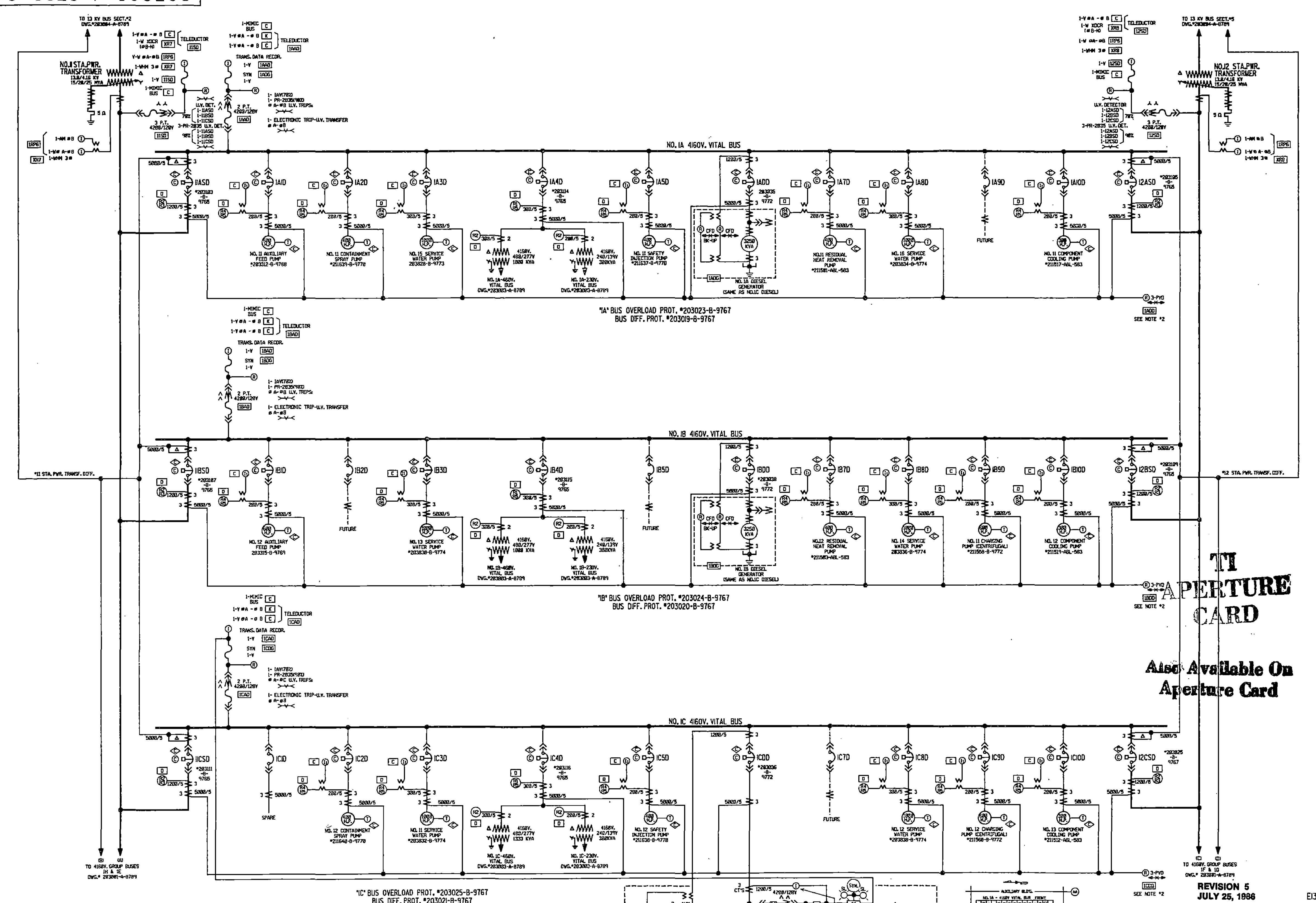
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	13 kV Ring Bus Diagram
	Updated FSAR — Figure 8.3-2



8607290251-25

203002 A 8789-8



TI APERTURE CARD

Also Available On Aperture Card

NOTES:

1. ALL INFEED BREAKERS ARE 2000 AMP. ALL FEEDER BREAKERS ARE 1200 AMP.
2. BUS OVERLOAD & BUS DIFFERENTIAL PROT. TRIP ALL BREAKERS IN RESPECTIVE BUS.

NOTE 'A' - REV. 8
AUTH. N1000
REVISED & REDRAWN -
SUPERSEDES DWG. 203002-A-8789
REVISION 7 PER DCR 1ED 100A
E&T/D PKG # 865

LOCATION INDEX & ABBREV'S.

- □ — EQUIP. DESIGNATION
- ◇ — ALARM
- ○ — CONTROL
- Ⓣ — TEMP. CONTROL
- C — NO. 1 CONSOLE IN CONTROL ROOM
- D — 4160V CUBICLE AT WHICH EQUIP. IS SHOWN. RELAYS DESIGNATED THUS, TRIP RESPECTIVE C.B. WHERE SHOWN.
- DG — EQUIPMENT LOCATED AT DIESEL GEN. UNIT
- K — COMPUTER

RELAY & INSTR. INDEX ABBREV'S.

- R — AS SHOWN
- R1 — INSTANTANEOUS OVERCURRENT RELAY
- R2 — VERY INVERSE OVERCURRENT RELAY
- R3 — VERY INVERSE CURRENT GRD. RELAY
- R4 — LONG TIME INVERSE OVERCURRENT RELAY WITH INSTANTANEOUS TRIP ØA & ØC
- R5 — SHORT TIME INVERSE CURRENT GRD. RELAY
- R6 — STEP TYPE INVERSE OVERCURRENT RELAY
- I — AS SHOWN
- I1 — 1-AM ØB & TRANSDUCER

8		SEE NOTE 'A', ZONE A-2.					
NO	DATE	DESCRIPTION					

REVISION

KEY PLAN - ELEV. 64'-0"

GENERAL NOTES

USE PRINTS OF LATEST REVISION ONLY.
DO NOT SCALE - USE DIMENSIONS ONLY.
FOR LIST OF REFERENCE DRAWINGS SEE DRAWING NO THIS DRAWING
THIS DRAWING SUPERSEDES 203002-A-8789-7
THIS DRAWING IS SHEET NO 1 OF 1 SHEETS.

REVISION 5
JULY 25, 1986

E130

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

4160 V Vital Buses One Line

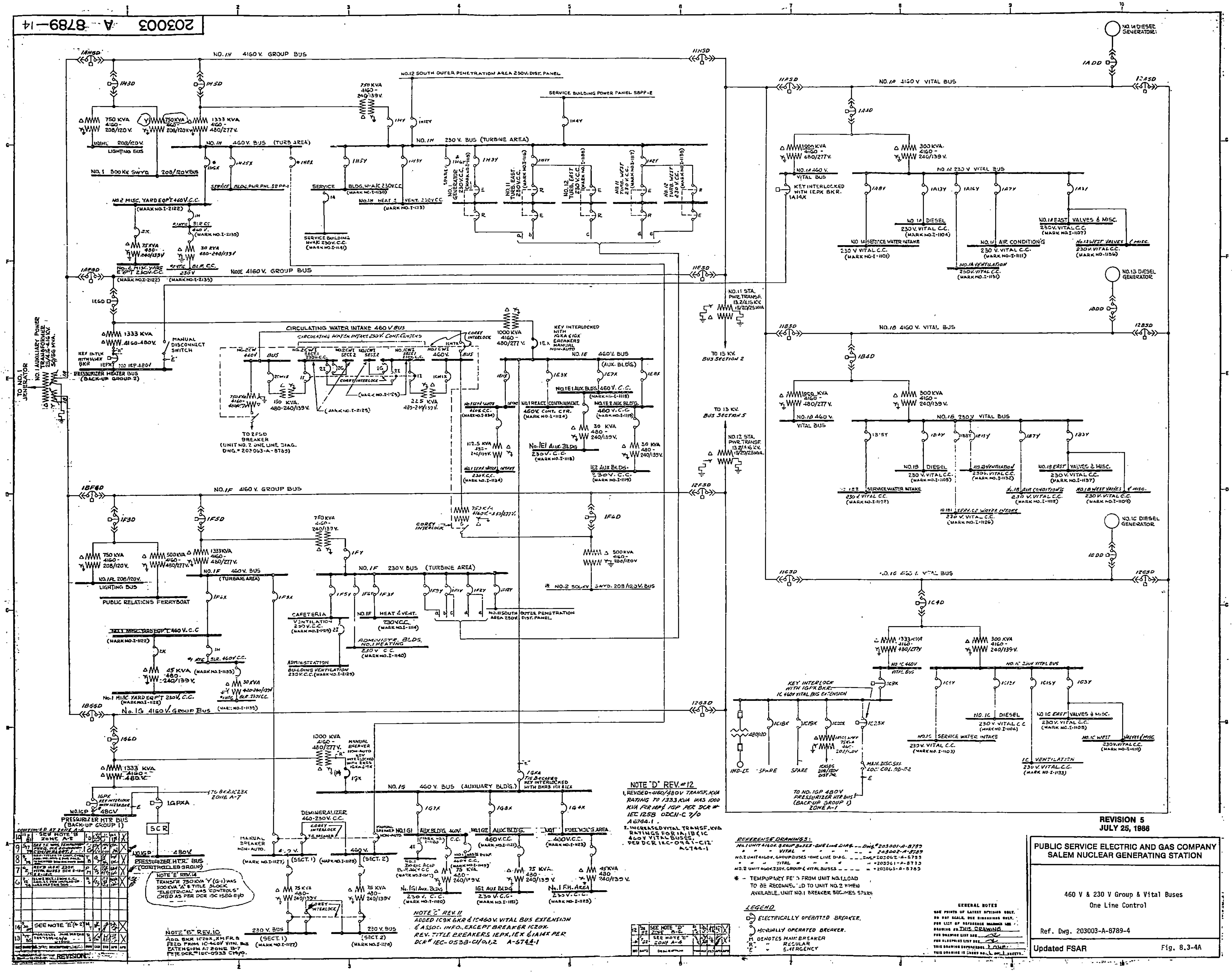
Ref. Dwg. 203002-A-8789-8

Updated FSAR — Fig. 8.3-4

8607290251-26

TI APERTURE CARD

Also Available On Aperture Card



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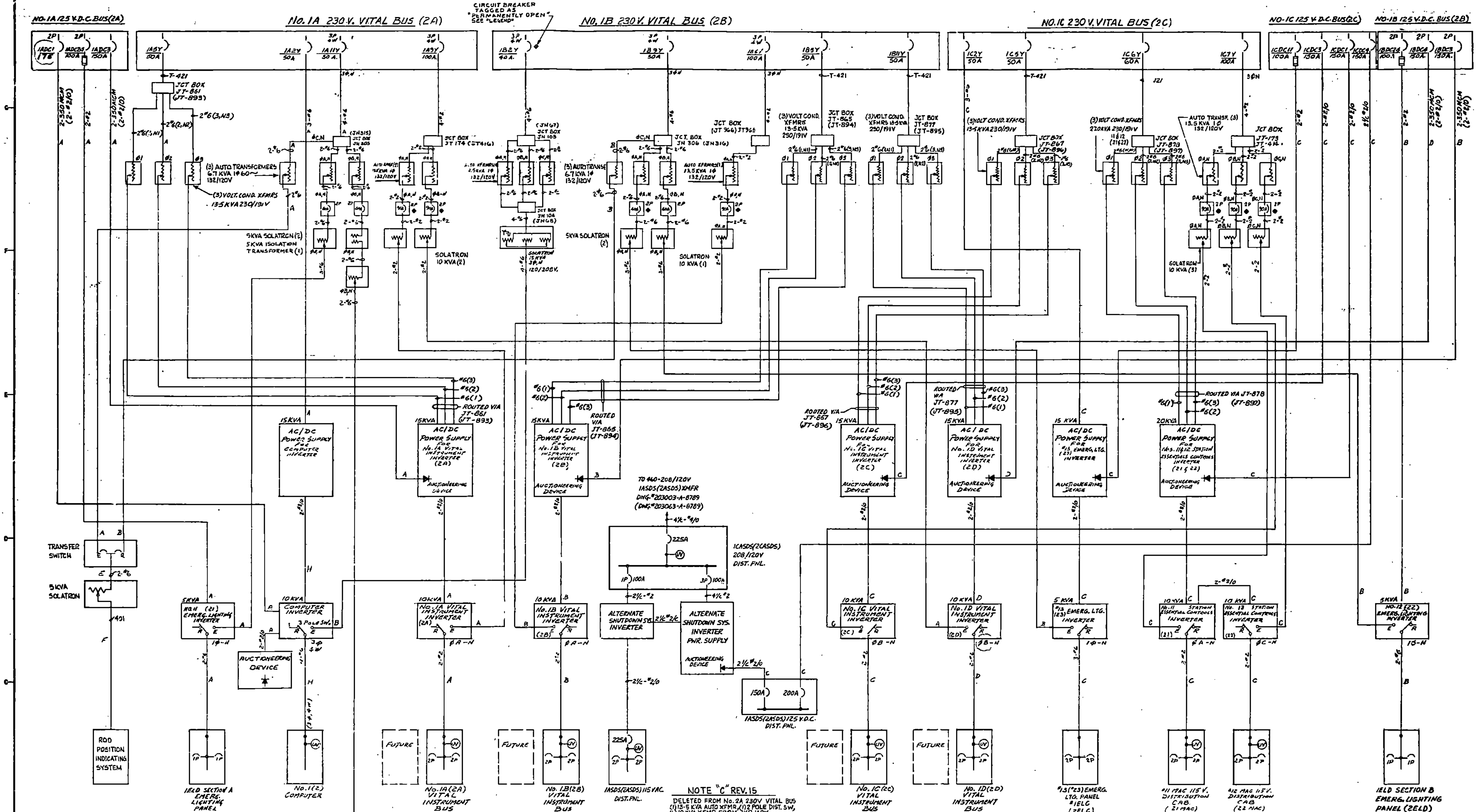
211370 A 8859-18



NOTE "B" REV. 14

DELETED FROM No. 1A 230V VITAL BUS (1) 13.5 KVA AUTO XFMR, (1) 2 POLE DIST. SW, (1) 10KVA XFMR FROM BKR. 1A9Y. DELETED FROM No. 1B 230V VITAL BUS (2) 13.5 KVA AUTO XFMR, (2) 2 POLE DIST. SW, (2) 10KVA XFMR FROM BKR. 1B6Y. ADDED BKR 1C7Y TO No. 1C 230V VITAL BUS. AS PER. DCR 1EC-1409 C2/0 AUTH: T0060.0

NOTE "D" REV. 16

REVISE PER DCR-2SC-0296A-C2/0 FOR UNIT #2 AS ACCOMPLISHED ON REVISION 15 FOR UNIT #1 T0060.0

NOTE "A" REV. 12

1. ADDED (3) VOLT. CONDITIONING TRANSFORMERS & (1) JCT BOX AT EACH AC INPUT TO POWER SUPPLY FOR VITAL INSTR. INVERTERS FOR UNIT 1 PER DCR 1EC-0563-C1/0,1. A-6055.1 FOR UNIT 2 PER DCR 2EC-0564-C1/0. A-6300.1
2. ADD AC ONE LINE FOR ALTERNATE SHUTDOWN SYSTEM FOR UNIT #1 PER DCR 1EC0933 C1/0,1 (A6478.1), FOR UNIT #2 PER DCR 2EC0934 C1/0,1 (A6300.1)

NOTE "E" (REV. 18)

DRAWING VOID SUPERSEDED BY COMPUTER GRAPHIC DRAWING, SAME DRAWING No. REV. 19. PER DCR 1ED-100A.

NOTE "C" REV. 15

DELETED FROM No. 2A 230V VITAL BUS (1) 13.5 KVA AUTO XFMR, (1) 2 POLE DIST. SW, (1) 10 KVA XFMR FROM BKR 1A9Y. DELETED FROM No. 2B 230V VITAL BUS (2) 13.5 KVA AUTO XFMR, (2) 2 POLE DIST. SW, (2) 10 KVA XFMR FROM BKR. 1B6Y. ADDED BKR. 2C7Y TO No. 2C 230V VITAL BUS AS PER DCR 2EC-1410, C2/0 AUTH: T0060.0

REFERENCE DRAWINGS:

ROD POSITION INDICATOR SYSTEM — WIRING DIAGRAM — DWG #205642-A-8858 (#227867-A-1403)
NO. 1H (2H) 460V. A.C. BUS — BUS WIRING DIAGRAM — DWG #211328-A-8859 (#218686-A-8918)
No. 1A (2A) 125 V.D.C. VITAL BUS WIRING DIAGRAM — DWG. #211342-A-8859 (#220800-A-8918)
" " " ARRANGEMENT — PS B/P #112728 (PS B/P #119341)
No. 1B (2B) " " " " (" ")
" " " WIRING DIAGRAM — DWG. #211343-A-8859 (#220801-A-8918)
No. 1A (2A) 230 V.A.C. " " ARRANGEMENT — PS B/P #112723 (PS B/P #119339)
" " " WIRING DIAGRAM — DWG. #211334-B-9483 (#218692-B-9544)
No. 1B (2B) " " ARRANGEMENT — PS B/P #112724 (PS B/P #119342)
" " " WIRING DIAGRAM — DWG. #211335-B-9483 (#218693-B-9544)
No. 1C (2C) " " ARRANGEMENT — PS B/P #112723 (PS B/P #119339)
" " " WIRING DIAGRAM — DWG. #211336-B-9483 (#218694-B-9544)
No. 1&2 UNIT COMPUTER INVERTER WIRING DIAGRAM — DWG. #211368-B-9511
EMERGENCY LIGHTING PANEL 1ELD (2ELD) WIRING DIAG. — " #211371-B-9511 (#221416-B-9545)
No. 1B(2B) EMER. LTG. PANEL 1ELC (2ELC) " " — " #218680-B-9511
No. 1A (2A) VITAL INSTRUMENT BUS WIRING DIAGRAM — DWG. #211364-B-9511 (#220812-B-9544)
No. 1B (2B) " " " — " #211365-B-9511 (#220813-B-9544)
No. 1C (2C) " " " — " #211366-B-9511 (#220814-B-9544)
No. 1D (2D) " " " — " #211367-B-9511 (#220815-B-9544)
No. 1&2 UNIT VITAL INSTRUMENT BUS INVERTERS — " #218631-A-6912
No. 1&2 UNIT No 11,12,13 (21,22,23) EMERG. LTG. & STA. ESS. CONTR. INVERTERS — " #218682-A-6912
No. 1G (2E) 460V. BUS WIRING DIAGRAM — " #211329-A-8859 (#218687-A-8918)
No. 1G (2G) 460V. BUS " " — " #211331-A-8859 (#218689-A-8918)
No. 1F (2F) 460V. BUS " " — " #211330-A-8859 (#218688-A-8918)
No. 11 (21) MAC 115V DISTRIBUTION PNL. WIRING DIAG. — " #211361-B-9511 (#220817-B-9545)
No. 12 (22) " " " — " #211362-B-9511 (#220818-B-9545)
No. 13 (23) " " " — " #211363-B-9511 (#220819-B-9545)
No. 14 (24) " " " — " #231936-B-9545 (#231937-B-9545)
No. 1&2 IN-CORE INSTRUMENT 115V. A.C. DIST. CAB. W.D. — " #211360-B-9511
No. 1C (2C) 125 V.D.C. VITAL BUS WIRING DIAG. — " #220637-A-8961 (#220835-A-8961)
" " " 125 V.D.C. VITAL BUS ARRANGEMENT — P.S. B.P. #119341

12	6/30/81	SEE NOTE A ZONE B-2						
11	6/30/76	ADD ISOL. TRANS. ZONE G-3 C-16336						
10	5/7/76	ADD FEED TO RPI SYS. PER ECN						
9		TEMPORARY CABLES						
8		FEED FOR 1A (2A) MAC						
18		SEE NOTE "E" ZONE B-4						
17		[illegible]						
16		SEE NOTE "D" ZONE B-1						
15		SEE NOTE "C" ZONE C-5						
14		SEE NOTE "B" ZONE B-2						
13		[illegible]						

REVISION

LEGEND:

1. N.A. - NON-AUTOMATIC
2. (UV) - UNDERVOLTAGE ALARM RELAY
3. (W) - EQUIPMENT BY WESTINGHOUSE
4. -- ALL BREAKERS 3 POLE, UNLESS OTHERWISE INDICATED.
5. * MECHANICALLY INTERLOCKED
◆ CIRCUIT BREAKER TAGGED AS "PERMANENTLY OPEN"

NOTE:

1) INVERTERS — EACH AUTOMATIC TRANSFER SWITCH INITIATES ALARM UPON TRANSFER TO THE EMERGENCY SOURCE & UPON LOSS OF THE EMERGENCY SOURCE.
2) LETTERS (A, B, C OR D) ON CABLES REPRESENT CHANNEL (ROUTING) DESIGNATION.
3) DRAWN FOR NO. 1 UNIT. NUMBERING FOR UNIT 2 SHOWN ( )

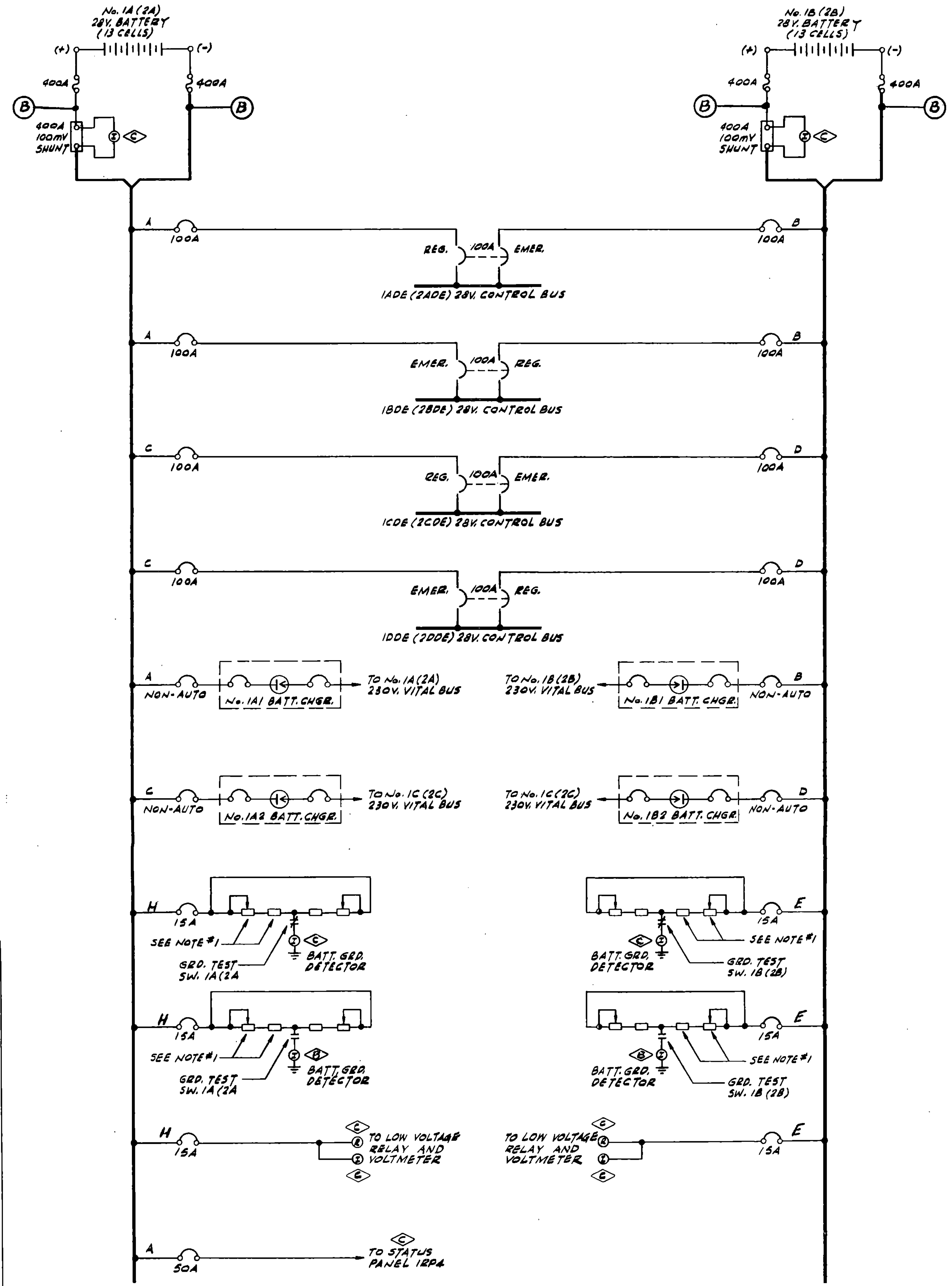
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

115 V Control Power System

Ref. Dwg. 211370-A-8859-18

Updated FSAR — Fig. 8.3-5

8607290251-28



LEGEND

- MECHANICALLY INTERLOCKED MANUAL OPERATED BREAKER
- UNDERVOLTAGE ALARM RELAY
- INSTRUMENT
- FUSE
- CONTROL ROOM
- BATTERY ROOM
- BLOWN FUSE ALARM RELAY

NOTES

1- COMBINED VALUE OF POTENTIOMETER & ASSOCIATED FIXED RESISTOR IS 28kΩ.
2- DRAWN FOR UNIT No. 1 & UNIT No. 2.

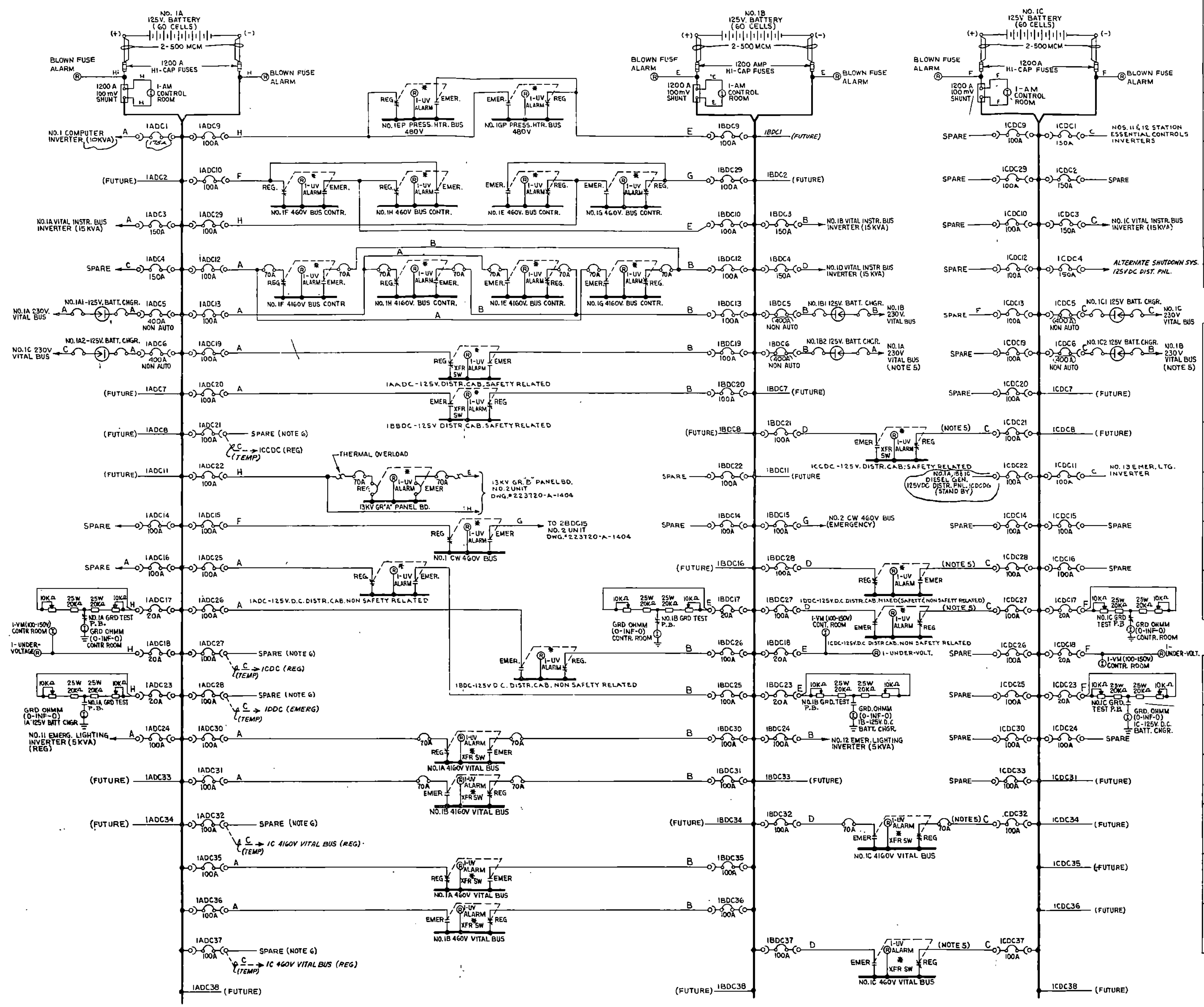
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Updated FSAR

28 Volt One Line

Figure 8.3-6



2 FUSES 1 SHUNT 4 MAIN LUGS (2 PER LEG)		1ADC9 NO'S. 1EP, 1GP PRESS. HTR. BUSES CONTR. PWR. 1EP (REG) 1GP (EMER) 100A	1ADC10 NO'S. 1F, 1H 460V BUSES CONTR. PWR. 1F (REG) 1H (EMER) 100A	1ADC11 FUTURE	1ADC12 NO'S. 1F, 1G 4160V. BUSES CONTR. PWR. 1F (REG) 1G (EMER) 100A	1ADC13 NO'S 1H, 1E 4160V. BUSES CONTR. PWR 1H (REG) 1E (EMER) 100A
		1ADC14 SPARE 100A	1ADC15 NO.1 CW 460V BUS CONTR. PWR. (REG) 100A	1ADC16 SPARE 100A	1ADC17 NO. 1A GRD. OHMM CONTR. ROOM (5KVA) 20A	1ADC18 NO. 1A UNDERVOLT. RELAY CONTR. ROOM V.M. 20A
1ADC1 NO.1 COMPUTER INVERTER (10KVA) 175A	1ADC2 FUTURE	1ADC19 1AADC DISTR. CAB. (REG) 100A	1ADC20 1BBDC DISTR. CAB. (EMER) 100A	1ADC21 SPARE (SEE NOTE 6) 100A	1ADC22 13 KV BKRS & RLYS GR"A" (REG) GR"B" (EMER) 100A	1ADC23 NO. 1A 125V. BATT. GRD. OHMM. 20A
1ADC3 NO. 1A VITAL INSTR. BUS INVERTER (15KVA) 150A	1ADC4 SPARE 150A	1ADC24 NO. 1ELD-A EMER. LIGHT. INVERTER (REG) (5 KVA) 100A	1ADC25 1ADC-125VDC DISTR. CAB. (REG) 100A	1ADC26 1BDC 125VDC DISTR. CAB. (EMER) 100A	1ADC27 SPARE (SEE NOTE 6) 100A	1ADC28 SPARE (SEE NOTE 6) 100 A
1ADC5 NO. 1A1 125V BATTERY CHARGER 400 A	1ADC6 NO. 1A2 125V BATTERY CHARGER 400A	1ADC29 NO'S. 1E, 1G 460V BUSES CONTR. PWR. 1E (REG) 1G (EMER) 100A	1ADC30 NO. 1A 4160V VITAL BUS CONTR. PWR (REG) 100A	1ADC31 NO. 1B 4160V VITAL BUS CONTR. PWR. (EMER) 100A	1ADC32 SPARE (SEE NOTE 6) 100A	1ADC33 FUTURE
1ADC7 FUTURE	1ADC8 FUTURE	1ADC34 FUTURE	1ADC35 NO. 1A 460V VITAL BUS CONTR. PWR. (REG) 100A	1ADC36 NO. 1B 460V VITAL BUS CONTR. PWR. (EMER) 100A	1ADC37 SPARE (SEE NOTE 6) 100A	1ADC38 FUTURE

FRONT VIEW
NO. 1A 125V. D.C. BUS

2 FUSES 1 SHUNT 4 MAIN LUGS (2 PER LEG)		1BDC9 NO'S. 1GP, 1EP PRESS. HTR. BUSES CONTR. PWR. 1GP (REG) 1EP (EMER) 100A	1BDC10 NO'S. 1H, 1F 460V BUSES CONTR. PWR. 1H (REG) 1F (EMER) 100A	1BDC11 FUTURE	1BDC12 NO'S. 1G, 1F 4160V BUSES CONTR. PWR. 1G (REG) 1F (EMER) 100A	1BDC13 NO'S. 1E, 1H 4160V BUSES CONTR. PWR. 1E (REG) 1H (EMER) 100A
		1BDC14 SPARE 100A	1BDC15 NO. 2 CW 460V. BUS CONTR. PWR. (EMER) 100A	1BDC16 FUTURE	1BDC17 NO. 1B GRD. OHMM CONTR. ROOM 20A	1BDC18 NO. 1B UNDER-VOLT. RELAY CONTR. ROOM V.M. 20A
1BDC1 *FUTURE*	1BDC2 FUTURE	1BDC19 1AADC DISTR. CAB. (EMER) 100A	1BDC20 1BBDC DISTR. CAB. (REG) 100A	1BDC21 1CCDC DISTR. CAB. (EMER) 100A	1BDC22 SPARE 100A	1BDC23 NO. 1B 125V. BATT. GRD. OHMM 20A
1BDC3 NO. 1B VITAL INSTR. BUS INVERTER (15KVA) 150 A	1BDC4 NO. 1D VITAL INSTR. BUS INVERTER (15KVA) 150A	1BDC24 NO. 12 LIGHTING INVERTER (5KVA) 100A	1BDC25 1ADC 125V. D.C. DISTR. CAB. (EMER) 100A	1BDC26 1BDC 125V. D.C. DISTR. CAB. (REG) 100A	1BDC27 1CDC 125V. D.C. DISTR. CAB. (EMER) 100A	1BDC28 1DDC 125V. D.C. DISTR. CAB. (REG) 100A
1BDC5 NO. 1B1 125V BATTERY CHARGER 400 A	1BDC6 NO. 1B2 125V BATTERY CHARGER 400A	1BDC29 NO'S. 1G, 1E 460V BUSES CONTR. PWR. 1G (REG) 1E (EMER) 100 A	1BDC30 NO. 1A 4160V VITAL BUS CONTR. PWR (EMER) 100A	1BDC31 NO. 1B 4160V. VITAL BUS CONTR. PWR. (REG) 100A	1BDC32 NO. 1C 4160V. VITAL BUS CONTR. PWR. (EMER) 100A	1BDC33 FUTURE
1BDC7 FUTURE	1BDC8 FUTURE	1BDC34 FUTURE	1BDC35 NO. 1A 460V. VITAL BUS CONTR. PWR. (EMER) 100A	1BDC36 NO. 1B 460V VITAL BUS CONTR. PWR. (REG) 100A	1BDC37 NO. 1C 460V VITAL BUS CONTR. PWR. (EMER) 100A	1BDC38 FUTURE

FRONT VIEW
NO. 1B 125V. D.C. BUS

1CDC9 SPARE 100A	1CDC10 SPARE 100A	1CDC11 NO. 13 EMER. LTG. INVERTER 100A	1CDC12 SPARE 100A	1CDC13 SPARE 100A	2 FUSES 1 SHUNT 4 MAIN LUGS (2 PER LEG)	
1CDC14 SPARE 100A	1CDC15 SPARE 100A	1CDC16 SPARE 100A	1CDC17 NO. 1C GRD. OHMM CONTR. ROOM 20A	1CDC18 NO. 1C UNDER-VOLT. RELAY CONTR. ROOM V.M. 20A		
1CDC19 SPARE 100A	1CDC20 SPARE 100A	1CDC21 1CCDC DISTR. CAB. (REG) 100A	1CDC22 1CDCDG DISTR. PNL. (STAND BY) 100A	1CDC23 NO. 1C 125V BATT. GRD. OHMM 20A	1CDC1 NOS. 11 & 12 STA. ESSENTIAL CONTROLS INVERTERS 150 A	1CDC2 SPARE 150A
1CDC24 SPARE 100A	1CDC25 SPARE 100A	1CDC26 SPARE 100A	1CDC27 1CDC 125V. D.C. DISTR. CAB. (REG) 100A	1CDC28 1DDC 125V. D.C. DISTR. CAB. (EMER.) 100A	1CDC3 NO. 1C VITAL INSTR. BUS INVERTER (15KVA) 150A	1CDC4 *ASDS 125 VDC DIST. PNL.* *150A*
1CDC29 SPARE 100A	1CDC30 SPARE 100A	1CDC31 FUTURE 100A	1CDC32 NO. 1C 4160V. VITAL BUS (REG) 100A	1CDC33 SPARE 100A	1CDC5 NO. 1C1 125V BATTERY CHARGER 400A	1CDC6 NO. 1C2 125V BATTERY CHARGER 400A
1CDC34 FUTURE	1CDC35 FUTURE	1CDC36 FUTURE	1CDC37 NO. 1C 460V. VITAL BUS (REG) 100A	1CDC38 FUTURE	1CDC7 FUTURE	1CDC8 FUTURE

FRONT VIEW
NO. 1C 125V. D.C. BUS

PRC
APERTURE
CARD

Also Available On Aperture Card

203007A8789-15

Revision 1
July 22, 1983

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	125 V.D.C. One Line
	UPDATED FSAR FIG 8.3-7

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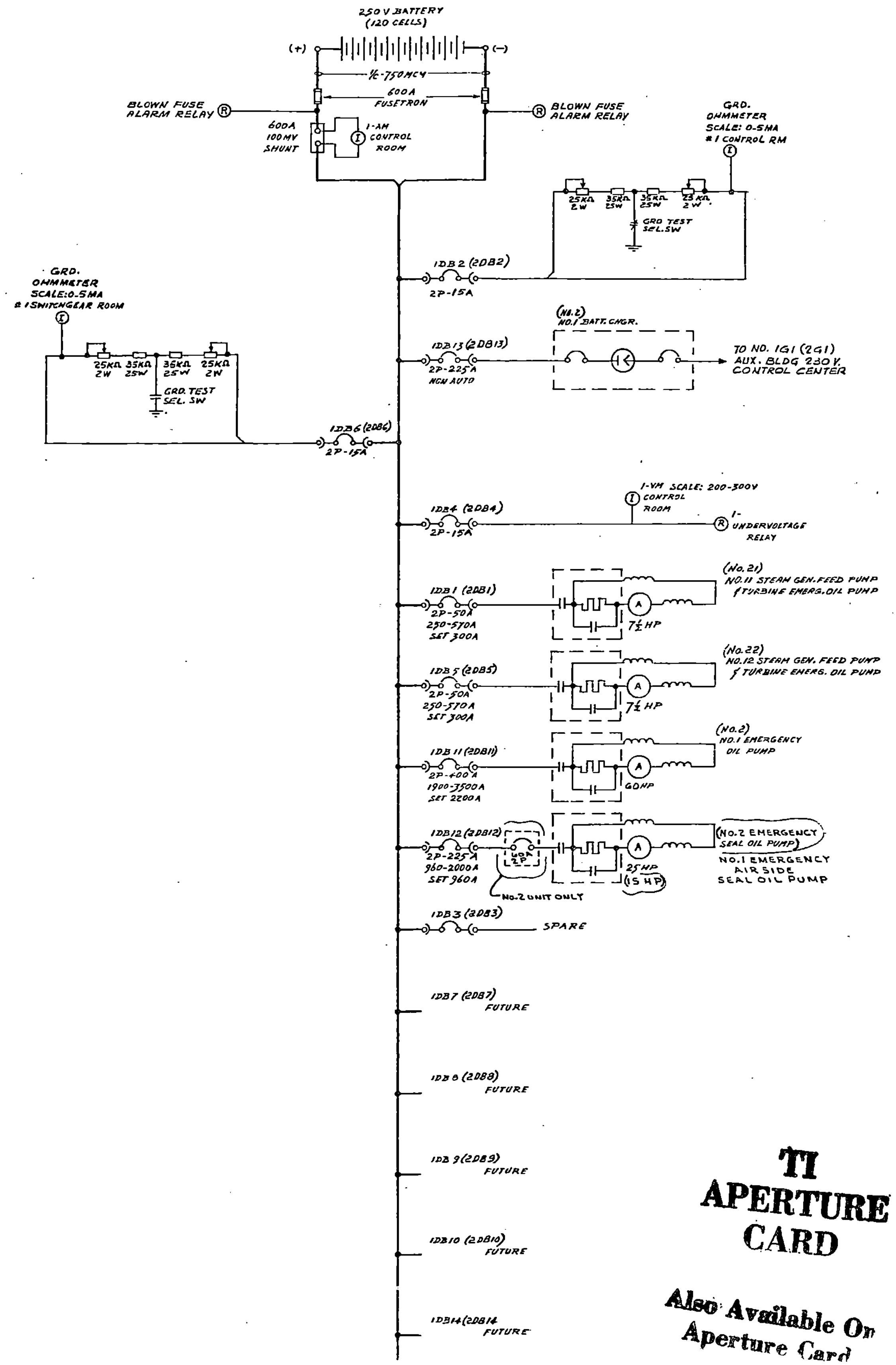
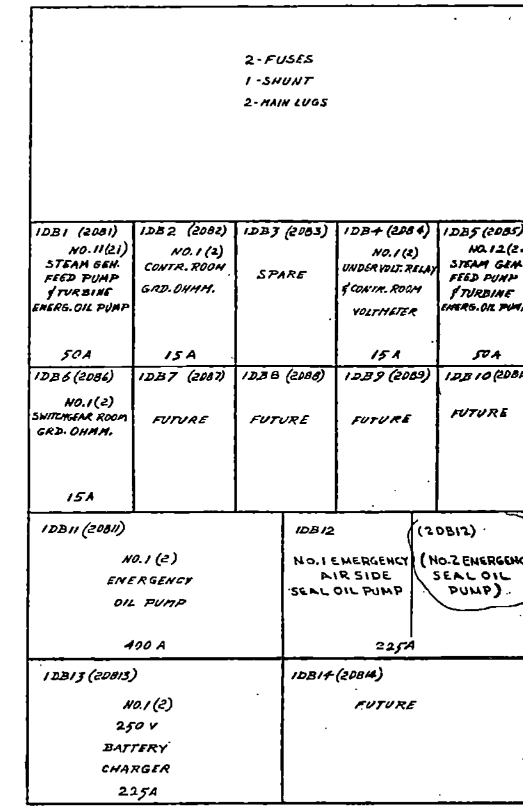
203008 AB 3616 – 4





FRONT VIEW
N.T.S.
No.1 (No.2) 250 V.D.C. BUS

REFERENCE DRAWINGS:
#1-250 V.D.C. BUS — W.D. DWG # 211341-B-9983
#2-250 V.D.C. BUS — W.D. DWG # 218639-B-9544

NOTES:
1. ALL CIRCUIT BREAKERS SHALL BE 2-POLE & SHALL HAVE 20,000 A.D.C. MINIMUM INTERRUPTING CAPACITY.
2. —MOULDED TYPE PLUG-IN CIRCUIT BREAKER.
3. DRAWN FOR UNIT No.1, UNIT No.2 SHOWN ( )

8607290251-29

E230

TI APERTURE CARD

Also Available On Aperture Card

4		ADD No.2 EMERG. SEAL OIL PUMP						X
3		REVISED 1DB13 (2DB13)						X
2		ADDED: BLOWN FUSE ALARM RELAY						X
1		REV. GRD. DETECTS.						X
NO	DATE	DESCRIPTION	DWN	CKD	EXD	APD	APD	

REVISION

GENERAL NOTES
USE PRINTS OF LATEST REVISION ONLY.
DO NOT SCALE. USE DIMENSIONS ONLY.
FOR LIST OF REFERENCE DRAWINGS SEE THIS DWG.
FOR DRAWING LIST SEE 206502-L
FOR BLUEPRINT LIST SEE 206506-L
THIS DRAWING SUPERSEDES ___
THIS DRAWING IS SHEET NO. 1 OF 1 SHEETS.

REVISION 5
JULY 25, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

250 Volt One Line

Ref. Dwg. 203008-AB-3616-4

Updated FSAR

Fig. 8.3-8

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TABLE OF CONTENTS (Continued)

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LIST OF FIGURES (Contd)

LIST OF FIGURES (Contd)

9.0 AUXILIARY SYSTEMS

The Auxiliary Systems are supporting systems required for safe operation and servicing of the Reactor and the Reactor Coolant System and Engineered Safeguards Systems.

9.1 FUEL STORAGE AND HANDLING

The Fuel Handling and Storage System provides a safe, effective means of storing, transporting and handling fuel from the time it reaches the plant in an unirradiated condition until it leaves the plant after post-irradiation cooling. Each unit has a completely independent Fuel Handling and Storage System. The following description is for unit one with the second unit having an identical system.

The system is designed to minimize the possibility of mishandling or of mal-operations that could cause fuel damage and potential fission product release.

9.1.1 NEW FUEL STORAGE

9.1.1.1 Design Bases

The new fuel assemblies are received and stored dry in racks in the new fuel storage area, located in the Fuel Handling Building (see Figure 9.1-1). New fuel is delivered to the reactor by lowering it into the transfer pool and taking it through the transfer system. The new fuel storage area is sized for storage of the fuel assemblies and control rods normally associated with the replacement of one-third of a core.

9.1.1.2 Safety Evaluation

The new fuel storage racks have been designed in accordance with the 1963 AISC Code. Seismic loads as well as dead load of fuel assemblies are considered in the design.

The new fuel storage racks are designed so that it is impossible to insert the assemblies in other than the prescribed locations. The 21 inch nominal spacing between fuel assemblies will maintain a subcritical array even if the pool is flooded with unborated demineralized water.

Adequate shutdown margin is maintained for 17 x 17 fuel with 4.5 w/o enrichment. A potential optimum moderation condition is precluded in the new fuel storage area by the following design features.

1. The fuel handling building has no fire fighting hose stations,
2. The fuel handling building has no installed aqueous fire suppression systems (e.g., sprinklers, fog, or sprays),
3. New fuel is covered with a protective metal plate during storage which prevents the introduction of low density water into the fuel racks from above.

The only accessible fire fighting hoses available for use in the new fuel storage area are connected to hose stations in the auxiliary building will be equipped with straight-stream nozzles.

9.1.2 SPENT FUEL STORAGE

The spent fuel storage pool is the storage space for irradiated spent fuel from the Reactor. This pool is not required for any plant safety-related function.

9.1.2.1 Design Bases

The spent fuel storage racks are designed in a subcritical array such that k_{eff} is limited to a value of less than or equal to 0.95 even if the pool is flooded with demineralized water. The spent fuel racks are built to ensure a nominal 10.5 inch center-to-center distance between fuel assemblies stored in the racks. The storage capacity is limited to 1170 spent fuel assemblies, which will cover a period of 18 years, assuming that one-third of the core is replaced annually. The reactor cavity, refueling canal and spent fuel storage pool are reinforced concrete structures with seam-welded stainless steel plate liners. These Seismic Category I structures are designed to withstand the anticipated earthquake loadings and to prevent liner leakage even in the event the reinforced concrete develops cracks.

Design criteria for spent fuel storage racks assure conformance with recognized codes and applicable regulatory guides, as follows:

1. The spent fuel storage rack design is based on the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Sub-section WF, Class III linear supports.
2. Regulatory Guide 1.13 - The design conforms with Guide, except that high radiation instrumentation does not actuate the filtration system.
3. Regulatory Guide 1.29 - The spent fuel storage racks are designed as Seismic Category I Structures.
4. Regulatory Guide 1.92 - Seismic load combinations of vibrational modes and three orthogonal component motions (two horizontal and one vertical) meets the provisions of the Regulatory Guide.

5. Design loads and load combinations meet the requirements of the Standard Review Plan, Section 3.8.4, Structural Design Criteria for Seismic Category I Structures Outside Containment and ASME Section III NF-3400.

9.1.2.2 System Description

A stainless steel lined spent fuel storage pool is provided for on site storage of spent fuel assemblies until they are shipped to a reprocessing facility. Sufficient space is available to hold approximately 6 cores and the depth is sufficient to provide a minimum shielding depth over the top of the stored fuel of 10 feet of water. The pool is designed to prevent inadvertent drainage below a water elevation of 124 feet 8 inches. Storage racks located in the pool are physically arranged such that the assemblies are always maintained in a subcritical condition. Adjacent to the spent fuel pool and separated by a structural wall is the transfer pool. The transfer pool serves to facilitate the fuel transfer operation between the fuel handling building and containment. It is also the pool where the spent fuel cask is placed for shipment. The cask is handled by the cask handling crane which is prevented by structural restraint from moving over the spent fuel pool.

The high density (poison) spent fuel racks construction is shown in Figure 9.1-2. The design utilizes a stiffened module base and an upper box structure consisting of plate diaphragms and a top grid. The storage module is constructed of stainless steel, mostly Type 304. The vertical loads are carried by module base. Horizontal seismic loads are carried to the module base through the plate diaphragms. Tipping is prevented by interconnection of adjacent racks by a bolted connection at the top grid level.

The design of the spent fuel storage cells is illustrated in Figure 9.1-3. Each cell is a square cross-section formed from an inner shroud of stainless steel, a center sheet of aluminum clad boron carbide (B_4C), and an outer shroud of stainless steel. This cell acts as storage space and provides sufficient neutron absorption to allow close spacing of spent fuel. The fuel weight is carried directly on the module base. A flared guide and transition section is provided at the top of each storage cell. This transition is designed to assure ease of entry and to preclude fuel assembly hang-up and damage. Swelling of the inner stainless steel shroud has been observed in a number of the spent fuel storage cells. The swelling is the result of hydrogen gas buildup from the corrosion of the aluminum in the Boral Poison Plates. The gas buildup has bowed or swollen the cells, thereby reducing the inner cell dimension. An ongoing program to monitor the condition of the spent fuel storage cells is being conducted. The hydrogen gas will be vented from the swollen cells to allow the shroud to return to some position closer to the original. This may allow the cell to be returned to service as an available spent fuel storage location. The hydrogen gas is radiologically stable and does not present a personnel hazard. The insignificant volume of gas released will not increase the hydrogen concentration in the area into the explosive range.

This condition was reviewed by the NRC in Supplement 4 of NUREG 0517, Safety Evaluation Report, Salem Generating Station Unit 2, April 1980. It was concluded that the minor degradation of the Boral Poison Plates resulting from the corrosion of the aluminum would not preclude the spent fuel storage cells from performing their intended function.

After a sufficient decay period the fuel may be removed from storage and loaded into a shipping cask for removal from the site.

9.1.2.3 Design Evaluation

Borated water is used to fill the spent fuel storage pool at a concentration to match that used in the reactor cavity and refueling canal during refueling operations. The fuel is stored in a vertical array with sufficient center-to-center distance between assemblies to assure $k_{eff} \leqq 0.95$ even if unborated water is used to fill the pool. (Based on 17 x 17 fuel with 4.05 w/o enrichment).

The spent fuel storage pool is provided with a Spent Fuel Cooling System which is discussed in Section 9.1.3. The system maintains pool temperature below approximately 120°F.

The design of the Fuel Handling Building is such that it is physically impossible for a load greater than 5 tons to be carried over the spent fuel pool. This is a result of both the physical arrangement of the Fuel Handling Building and limits on the fuel handling crane. Administrative controls prohibit loads greater than that of a fuel assembly to travel over the spent fuel pool. The maximum height at which a fuel assembly can be carried is restricted by limit switches on the crane to 15 inches over the top of the spent fuel racks. The spent fuel racks have been designed to absorb the energy released by a fuel assembly dropping from 15 inches above them.

The Spent Fuel Storage Pool and New Fuel Storage Pit are outside the area over which the fuel cask may travel by design (travel restricted by a limit stop switch). The Cask Handling Crane travels only over the Truck Bay, Decontamination Pit and Fuel Transfer Pool, as indicated in Figure 9.1-1.

Gamma radiation is continuously monitored in the Fuel Handling Building. A high level signal is alarmed locally and is annuciated in the Control Rooms.

All fuel and waste storage facilities are contained and equipment designed so that accidental releases of radioactivity directly to the atmosphere are monitored and will not exceed the guidelines of 10CFR100.

A controlled ventilation system removes gaseous radioactivity from the atmosphere in fuel and waste treating areas of the fuel handling and auxiliary buildings and discharges it to the atmosphere via the plant vent. Radiation monitors are in continuous service in these areas to actuate high-activity alarms in the Control Rooms.

9.1.3 SPENT FUEL POOL COOLING SYSTEM

9.1.3.1 Design Bases

The following description is for one unit with the second unit having an identical system.

The Spent Fuel Pool Cooling System is designed to remove from the spent fuel pool the heat generated by stored spent fuel elements. The system serves the spent fuel pool which is located in the fuel handling building adjacent to the containment building. A secondary function is to clarify and purify spent fuel pool, transfer pool, and refueling water. The system design considers the possibility that during the life of the plant it will become necessary to totally unload a reactor at the time when spent fuel is in the fuel pool.

The system design incorporates redundant active components. System piping is arranged so that failure of any pipeline does not drain the spent fuel pool below the top of the stored fuel elements.

The spent fuel pool water is normally limited to 120°F except in for the unloading of a full core, in which case temperature is limited to 150°F with one pump in operation. Boron concentration in the pool fluid is maintained at a minimum of 2,000 ppm.

9.1.3.2 System Description

The schematic diagram for the Spent Fuel Pool Cooling System is shown on Figures 9.1-4A and B. The Spent Fuel Pool Cooling System consists of three subsystems, the cooling system, the purification system, and the skimmer system.

Austenitic stainless steel piping is used in the Spent Fuel Pool Cooling System. All piping and components of the system are designed to the applicable codes and standards listed in Table 9.1-1.

The cooling loop consists of the spent fuel pool pumps and the spent fuel pool heat exchanger. The purification loop consists of the spent fuel pool pump, the spent fuel pool filter, the spent fuel pool demineralizer, the refueling water purification pump, and the refueling water purification filter. The skimmer loop consists of the skimmer pump, strainer, and filter.

During the heat removal operation, fuel pool water flows from the spent fuel pool to a spent fuel pool pump suction, and is pumped through the tube side of the heat exchanger and is returned to the pool. The suction line, which is protected by a strainer, is located at an elevation four feet below the pool normal water level, while the return line terminates in the pool at an elevation approximately six feet above the top of the fuel assemblies. If the spent fuel pool pump fails, the second pump supplies 100 percent backup.

The Spent Fuel Pool Cooling System has its maximum duty during the refueling operation when the decay heat from the spent fuel is the highest. The system is normally placed in operation prior to the transfer of any fuel and is continued in operation as long as required to maintain temperature at the required level and water purity.

Piping and valves are installed which allow the Unit 1 and 2 heat exchangers to be cross connected. During normal plant operation, the heat exchangers operate independently to meet the cooling requirements of the individual units. However, during unusual circumstances, (e.g.: complete core unload in one unit) both heat exchangers may be used in parallel to minimize the temperature rise in the spent fuel pool. The cross connect also allows one heat exchanger to be used to alternatively cool the spent fuel pools in both units during times when one heat exchanger is out for maintenance.

While the heat removal operation is in process, a portion of the spent fuel pool water, 100 gpm, may be diverted through the spent fuel pool demineralizer and spent fuel pool filter to maintain spent fuel pool water clarity and purity. Transfer canal water may also be circulated through the same demineralizer and filter. This is accomplished by having the gate between the transfer pool and the spent fuel pool removed. This purification loop is sufficient for removing fission products and other contaminants which may be introduced if a leaking fuel assembly is transferred to the spent fuel pool.

The demineralizer may be isolated, by manual valves, from the heat removal portion of the Spent Fuel Pool Cooling System. By so doing, it may be used together with the refueling water purification filter to clean and purify the refueling water while spent fuel pool heat removal operations proceed. Connections are provided to the isolated loop such that the refueling water may be pumped from either the refueling water storage tank or the refueling cavity, through the demineralizer and filter, and discharged to either the refueling cavity or the refueling water storage tank.

To further assist in maintaining spent fuel pool water clarity, the water surface is cleaned by a skimmer loop. This system consists of two skimmers, a skimmer pump, a strainer and a filter. Water is removed from the surface by the skimmer, pumped through the strainer and filter, and returned to the pool surface at three locations remote to the skimmers.

The spent fuel pool is initially filled with water that is at the same boron concentration as that in the refueling water storage tank. This may be accomplished by filling the pool with water from plant sources. Boron may then be added to the pool from the Chemical and Volume Control System. Borated water from the plant sources may be supplied from the refueling water storage tank via the refueling water purification pump connection, or by placing a temporary line from the boric acid blender, located in the Chemical and Volume Control System, directly into the pool. Demineralized water is also added to the pool for makeup purposes by a connection in the recirculation return line.

The pool water may be separated from the water in the transfer pool by a sluice gate. The gate is installed so that the transfer pool may be drained for maintenance on the fuel transfer equipment. The draining is accomplished by pumping transfer pool water into the spent fuel pool with a portable pump. The excess water from the spent fuel pool is directed to a holdup tank in the Chemical and Volume Control System or to the decontamination for temporary storage.

An evaluation has been performed to determine the capability of the Spent Fuel Cooling System to provide the cooling capacity required for both the annual discharge of 65 fuel assemblies and for a full core discharge of 193 fuel assemblies into the spent fuel pool after 15 years accumulation of spent fuel. ANS Standard 5.1 was used for decay heat load calculations. It has been determined that the Spent Fuel Cooling System can provide the necessary cooling for the normal annual discharge as early as 100 hours after reactor shutdown. A full core discharge can be accomplished with an appropriate time delay after reactor shutdown, which is dependent on the number of regions stored in the spent fuel pool at the time. For example, it has been calculated that with one pump running at design capacity and with 150 hours of decay heat (after reactor shutdown) at the 18th refueling, the maximum spent fuel pool outlet water temperature will be 134°F. For the full core addition to the spent fuel pool that fills the pool (15 prior annual refuelings), the required decay cooling time in the reactor vessel that will be needed to keep the pool water temperature below 150°F with only one pump running will be approximately 570 hours (24 days after reactor shutdown).

Provisions have been made for the addition of an additional heat exchanger, should this be required in the future.

Spent Fuel Pool Cooling System component design data are listed in Table 9.1-2. The following is a description of each component utilized in the Spent Fuel Cooling System:

Spent Fuel Pool Heat Exchanger

The spent fuel pool heat exchanger is of the shell and U-tube type with the tubes welded to the tube sheet. Component cooling water circulates through the shell, and spent fuel pool water circulates through the tubes. The tubes are austenitic stainless steel and the shell is carbon steel.

Spent Fuel Pool Pumps

The spent fuel pool pumps circulate water in the Spent Fuel Pool Cooling System. All wetted surfaces of the pumps are austenitic stainless steel, or equivalent corrosion resistant material. The pumps are operated manually from a local station.

Spent Fuel Pool Filter

The spent fuel pool filter removes particulate matter larger than 5 microns from the spent fuel pool water. The filter cartridge is of synthetic fiber and vessel shell is austenitic stainless steel.

Spent Fuel Pool Strainer

A stainless steel strainer is located at the inlet of the spent fuel pool cooling suction line for removal of relatively large particles which might otherwise clog the spent fuel pool demineralizer.

Spent Fuel Pool Demineralizer

The demineralizer is sized to pass 100 gpm of the loop circulation flow to provide adequate purification of the fuel pool water for unrestricted access to the working area and to maintain optical clarity.

Refueling Water Purification Pump

The refueling water purification pump circulates water in a loop between the refueling water storage tank and the spent fuel pool demineralizer and the refueling water purification filter. All wetted surfaces of the pump are austenitic stainless steel. The pump is operated manually from a local station.

Refueling Water Purification Filter

The refueling water purification filter removes particulate matter larger than 5 microns from the refueling water purification flow.

Spent Fuel Pool Cooling System Valves

Manual stop valves are used to isolate equipment and lines and manual throttle valves provide flow control. Valves in contact with spent fuel pool water are austenitic stainless steel or equivalent corrosion resistant material.

Spent Fuel Pool Cooling System Piping

All piping in contact with spent fuel pool water is austenitic stainless steel. The piping is welded except where flanged connections are used to facilitate maintenance.

Spent Fuel Pool Skimmers

Two spent fuel pool skimmers are provided to remove water from the surface of the spent fuel pool. The skimmer heads are manually positioned to take water from any elevation from the water surface to four inches below the surface. The elevation of the skimmers head can be manually adjusted over a total range of two feet.

Spent Fuel Pool Skimmer Pump

The spent fuel pool skimmer pump circulates surface water through a strainer, a filter, and returns it to the pool.

Spent Fuel Pool Skimmer Strainer

The spent fuel pool skimmer strainer is designed to remove debris from the skimmer process flow.

Spent Fuel Pool Skimmer Filter

The spent fuel pool skimmer filter is designed to remove insoluble particles which are not removed by the strainer.

9.1.3.3 Design Evaluation

The most serious failure of this system would be complete loss of water in the spent fuel pool. To protect against this possibility, the spent fuel pool cooling suction connection enters near the normal water level so that the pool cannot be gravity-drained. The cooling water return lines contain anti-siphon holes to prevent the possibility of gravity draining the pool. There are no drains or permanently connected systems to the spent fuel pool (Seismic Class I) which, in the event of failure, could cause loss of coolant from the pool that would uncover the fuel. Also, provisions have been made to supply makeup to the spent fuel pool as noted below.

The rate of pool heatup with cooling interrupted for 1/3 of the core removed for refueling is approximately 6°F per hour at 150 hours after shutdown. The rate of heatup for a full core at the end of an operating cycle plus the 1/3 core removed at the previous refueling is approximately 12°F per hour with cooling interrupted. An interruption in the operation of the spent fuel cooling system for an extended period is not considered to be a credible occurrence. Maintenance will be scheduled when the decay heat loads are light. Two fully redundant, spent fuel pool pumps are provided, each receiving power from individual vital bus sections. As noted below, a number of makeup water sources are available and are capable of providing emergency cooling.

The use of the cross connect is controlled by appropriate procedures. Four manual values, two per unit, have to be opened to cross connect the heat exchangers. Prior to placing both heat exchangers in parallel to minimize the temperature transient for a full core unload, the heat load in the spent fuel pool to be isolated, is evaluated to ensure it can tolerate the temporary loss of cooling. Similarly, before taking one heat exchanger out of service for maintenance, the heat loads in both spent fuel pools are evaluated to verify that the remaining heat exchanger can, in an alternating fashion, be used to cool both spent fuel pools.

Water loss from the spent fuel pool due to the accidental opening of a sluice gate when the transfer pool is empty will not occur due to the redundancy in the sluice gates. Two sluice gates separate the spent fuel pool from the transfer pool.

A heavy load handling accident would not result in water leakage severe enough to uncover the spent fuel. The maximum load carried over the spent fuel pool is that of a fuel assembly, however, it is not possible to drop a fuel assembly on the spent fuel pool liner plate. In addition, integrity of the spent fuel pool will not be breached due to a fuel cask drop in the fuel transfer pool since each of the pool structures are separate and distinct.

Pool water level indication is provided by individual high and low water level alarms. The alarms are actuated by deviation from normal water level (el. 128'-8") of plus or minus 6 inches. The alarms are annunciated in the fuel handling building at the spent fuel pool and in the Control Room.

Annunciation of an alarm will be confirmed by visually checking the spent fuel pool water level. Alarms may be expected to occur occasionally due to gradual changes in pool water temperature and surface evaporation. If needed, makeup will be added. Alarms occurring with unusual frequency or for reasons not readily apparent will be further investigated. Frequent inspections will also be made of the fuel handling building sump, and, through annunciators provided in the Control Room, the running frequency of the sump pump will be observed.

The normal source of makeup water to the spent fuel pool is the demineralized water system which distributes water from two 500,000 gallon demineralized water tanks. The tanks and the distribution system do not have seismic classification. Makeup is also available from the primary water storage tank via the Primary Water Makeup Pumps (Seismic Class II) and from the Chemical and Volume Control System Hold-up Tanks via the Hold-up Tank Recirculation Pump (Seismic Class II).

Valves have been installed on the existing 6-inch spare nozzles on both refueling water storage tanks (350,000 gallons each). These tanks are Class I (seismic). A portable pump, with appropriate suction and discharge connections and hose, will be provided with the capability to deliver approximately 100 gpm makeup water flow from one of the refueling water storage tanks directly to the spent fuel pool. Assuming the maximum heat load in the pool, and inability to provide makeup from normal sources, the quantity of water stored in one refueling water storage tank would provide a period of approximately 100 hours in which emergency repairs to the spent fuel pool cooling system could be made, without significant loss of water level in the spent fuel pool. The valves installed on the refueling water storage tanks will be locked, closed and capped, and will be under administrative control. The portable pump and hose will also be under administrative control to ensure constant and timely availability.

Up to 100 gallons per minute of makeup is also available from the refueling water storage tank via the refueling water purification loop.

If a leaking fuel assembly is stored in the spent fuel pool, a small quantity of fission products may enter the cooling water. Fission products and other contaminants are removed by the spent fuel pool purification loop.

A failure analyses of system pumps, heat exchangers and valves is presented in Table 9.1-3.

The spent fuel pool water is normally limited to 120°F except in unusual circumstances as previously described. Boron concentration in the pool fluid is maintained at a minimum of 2,000 ppm.

9.1.3.4 Test and Inspections

The active components of the system are in continuous use during normal plant operation and no additional periodic tests are required. Periodic visual inspections and preventative maintenance are conducted following normal industrial practice.

9.1.4 FUEL HANDLING SYSTEM

The fuel handling system consists of equipment and structures utilized for handling new and spent fuel assemblies in a safe manner during refueling and fuel transfer operations. The fuel handling system is shown in Figure 9.1-5.

The design of the Fuel Handling System conforms to the recommendations of Regulatory Guide 1.13.

The fuel handling system components are not generally designed to Class I (seismic) requirements because they do not fit within the definition of Class I (seismic) structures. Those components are designed to Class III requirements. The spent fuel racks, spent fuel pool and spent fuel pool bridge structure, however, are designed to Class I (seismic) requirements. Other components of the fuel handling system are not required to operate following a design basis seismic event.

9.1.4.1 System Design and Operation

9.1.4.1.1 System Description

The Reactor is refueled with equipment designed to handle the spent fuel under water from the time it leaves the Reactor until it is placed in a cask for shipment from the site. Underwater transfer of spent fuel provides an effective, economic and transparent radiation shield, as well as a reliable cooling medium for removal of decay heat. Boric acid is added to the water to ensure subcritical conditions during refueling.

In the reactor cavity, fuel is removed from the reactor vessel, transferred through the water and placed in the fuel transfer system by a manipulator crane. In the spent fuel pool, fuel is removed from the transfer system and placed in storage racks with a long manual tool suspended from the fuel handling crane.

9.1.4.1.2 Refueling Operation

The refueling operation follows a detailed procedure which provides a safe, efficient refueling operation. The following significant points are assured by the refueling procedure:

1. The refueling water and the reactor coolant will contain approximately 2,000 ppm boron. The concentration together with the control rods is sufficient to keep the core approximately 5 percent Δk/k subcritical during the refueling operations. It is also sufficient to maintain the core subcritical if all of the rod cluster control (RCC) assemblies were removed from the core.

2. The water level in the refueling canal will be high enough to keep the radiation levels within acceptable limits when the fuel assemblies are being removed from the core. This water also provides adequate cooling for the fuel assemblies during transfer operations.

While one unit is being refueled, there will be no restrictions on the operation of the other unit. Refueling of one unit will not affect the safety aspects of the other unit.

9.1.4.1.3 <u>Refueling Procedure</u>

Preparation

1. The reactor is shut down, borated to refueling concentration, and cooled to ambient conditions.

2. A radiation survey is made and the containment is entered.

3. The control rod drive mechanism (CRDM) missile shield is removed to storage.

4. CRDM cables and cooling air ducts are disconnected and removed to storage.

5. Reactor vessel flange area head insulation and instrument leads are removed.

6. The in-core instrumentation thimble guides are disconnected at the seal table and extracted downward through the bottom of the reactor vessel.

7. The reactor vessel head nuts are loosened with the hydraulic tensioner.

8. The reactor vessel head studs are removed to storage.

9. The canal drain holes are plugged and the fuel transfer tube flange is removed.

10. The reactor vessel cavity seal is installed and inflated.

11. Checkout of the fuel transfer device and manipulator crane is started.

12. Guide studs are installed in three holes and the remainder of the stud holes are plugged.

13. Final preparation of underwater lights and tools is made. Checkout of manipulator crane and Fuel Transfer System is completed.

14. The reactor vessel head is unseated and raised one foot with the polar crane.

15. The reactor cavity is filled with water to the vessel flange.

16. The reactor vessel head is slowly lifted while the water is pumped into the reactor cavity. The water level and vessel head are raised simultaneously keeping the water level just below the head.

17. The reactor vessel head is taken to the storage pedestal.

18. The control rod drive shafts are unlatched.

19. The reactor vessel internals lifting rig is lowered into position by the polar crane and latched to the support plate.

20. The reactor vessel internals are lifted out of the vessel and placed in the underwater storage rack.

21. The core is now ready for refueling.

Refueling

The refueling sequence is now started with the manipulator crane. The sequence for fuel assemblies in non-control positions is as follows:

1. Spent fuel is removed from the center region of the core and placed into the Fuel Transfer System for removal to the spent fuel pool.

2. Partially spent fuel is transferred from the intermediate region of the core to the vacated positions in the center region.

3. Partially spent fuel is transferred from the outer region of the core to vacated positions in the intermediate region.

4. New fuel assemblies are brought in from the spent fuel pool through the transfer system and loaded into the outer region.

5. Whenever new fuel is added to the reactor core, a reciprocal curve of source neutron multiplication is recorded to verify the subcriticality of the core.

The refueling sequence is modified for fuel assemblies containing (RCC) elements, as required. If a transfer of the RCC elements between fuel assemblies is required, the assemblies are taken to the RCC change fixture to exchange the RCC elements from one assembly to another. Such an exchange is required whenever a spent fuel assembly containing a RCC element is removed from the core and whenever a fuel assembly is placed in or taken out of a control position during refueling rearrangement.

Reactor Reassembly

1. The fuel transfer car is parked and the fuel transfer tube isolation valve closed.

2. The reactor vessel internals package is picked up by the polar crane and replaced in the vessel. The reactor vessel internals' lifting rig is removed to storage.

3. The full-length control rod drive shafts are relatched to the RCC elements.

4. The manipulator crane is parked.

5. The old seal rings are removed from the reactor vessel head, the grooves cleaned and new rings installed.

6. The reactor vessel head is picked up by the plant crane and positioned over the reactor vessel.

7. The reactor vessel head is slowly lowered as the water level is lowered.

8. When the reactor vessel head is about one foot above the flange, the reactor cavity is completely drained and the flange surface is manually cleaned.

9. The reactor vessel head is seated.

10. The guide studs are removed to their storage rack. The stud hole plugs are removed.

11. The head studs are replaced and retorqued.

12. The canal drain holes are unplugged and the fuel transfer tube flange is replaced.

13. The reactor vessel to cavity seal ring is vented and removed.

14. Electrical leads and cooling air ducts are reconnected to the CRDM's.

15. Vessel head insulation and instrumentation leads are replaced. In-core flux thimbles are inserted back into core area.

16. A hydrostatic test is performed on the reactor vessel.

17. Control rod drives are checked.

18. The CRDM missile shield is picked up with the plant crane and replaced.

19. Equipment access door is closed and sealed.

20. Pre-operational tests are performed.

9.1.4.1.4 <u>Major Structures Required for Refueling</u>

Reactor Cavity

The reactor cavity is a reinforced concrete structure that forms a pool above the reactor when it is filled with borated water for refueling.

The cavity is filled to a depth that limits the radiation at the surface of the water to 2.5 mn/hr during those brief periods when a fuel assembly is transferred over the reactor vessel flange.

The reactor vessel flange is sealed to the bottom of the reactor cavity by an inflatable seal ring which prevents leakage of refueling water from the cavity. This seal is installed and inflated after reactor cooldown but prior to flooding the cavity for refueling operations.

The cavity is large enough to provide storage space for the reactor upper and lower internals, the control cluster drive shafts, and miscellaneous refueling tools.

The floor and sides of the reactor cavity are lined with stainless steel.

Refueling Canal

The refueling canal is a passageway extending from the reactor cavity to the inside surface of the reactor containment. The canal is formed by two concrete shielding walls which extend upward to the same elevation as the reactor cavity. The floor of the canal is at a lower elevation than the reactor cavity to provide the greater depth required for the fuel transfer upending device and the control cluster changing fixture located in the canal. The transfer tube enters the reactor containment and protrudes through the end of the canal. Canal wall and floor linings are similar to the reactor cavity.

Decontamination Facilities

A decontamination pit located in the fuel handling area has been provided for the decontamination of spent fuel shipping casks prior to their loading on trucks for shipment to a reprocessing facility.

New Fuel Storage Pit

A dry pit with storage racks having a safe geometry is provided in the fuel handling area for storage of approximately 1/3 of a core. This pit is located outside of the area over which a spent fuel shipping cask may travel.

9.1.4.1.5 Major Equipment Required for Refueling

Reactor Vessel Stud Tensioner

The stud tensioner is a hydraulically operated (oil as the working fluid) device provided to permit preloading and unloading of the reactor vessel closure studs at cold shutdown conditions. Stud tensioners were chosen in order to minimize the time required for the tensioning or unloading operations. Three tensioners are provided and they are applied simultaneously to three studs 120° apart. One hydraulic pumping unit operates the tensioners which are hydraulically connected in parallel. The studs are tensioned to their operational load in two steps to prevent high stresses in the flange region and unequal loadings in the studs. Relief valves are provided on each tensioner to prevent overtensioning of the studs due to excessive pressure. Charts indicating the stud elongation and load for a given oil pressure are included in the tensioner operating instructions. In addition, micrometers are provided to measure the elongation of the studs after tensioning.

Reactor Vessel Head Lifting Rig

The reactor vessel head and lifting rig are shown on Figure 9.1-6.

The three vertical legs and platform assembly are permanently attached to the reactor vessel head lifting lugs. The sling assembly is attached to the three vertical legs and is used when installing and removing the reactor vessel head. The total estimated weight of the reactor vessel head with lifting rig is 150 tons.

During plant operations, the sling assembly is removed and the three vertical legs and platform assembly remain attached to the reactor vessel head.

The maximum drop height of the reactor vessel head is 63 feet, which is the limit of travel of the polar crane hook with the reactor vessel head and lifting rig attached.

Load bearing members are not stressed to greater than 1/5 the ultimate strength when subjected to the static load of the assembled reactor vessel head. All primary load bearing members are constructed with material purchased to ASTM Standards. All welding and non-destructive testing of the head lifting rig is in accordance with approved Westinghouse Process Specification and ASME Boiler and Pressure Vessel Codes.

The following loading data apply to the reactor vessel head lifting rig.

1. The design load rating for the head lifting rig is 215 tons.

2. Pre-operational load tests for the head lifting rig is the actual weight of the assembled reactor vessel head and is done at the plant site, followed by non-destructive testing of key load bearing areas.

3. The maximum operating load for the head lifting rig is 155 tons.

4. The head lifting rig is permanently attached to the reactor vessel head and is not removed during the life of the facility. Therefore, load testing prior to lifting the head is not feasible.

Missle Shield Structure Lifting Rig

The missile shield structure above the reactor vessel and its handling fixture are shown in Figures 9.1-7 and 9.1-8 respectively.

The missile shield structure is a 17'-0 x 17'-0 x 1'-0 concrete slab with a one inch steel plate on the bottom face. The structure, along with the attached fans, plenum chamber and ducts, weighs about 42 tons.

The missile shield lifting rig is a four-legged structural frame device which connects the polar crane hook to the missile shield structure for handling operations. It is connected by means of pins and clevises to the missile shield structure. The lifting rig will be proof tested to 125 percent of its operating load of approximately 42 tons.

The maximum drop height of the missile shield is 64 feet, which is the limit of travel of the polar crane hook with the missile shield structure and lifting rig attached.

Reactor Internals Lifting Rig

The internals lifting rig is a 3-legged structural frame device which connects the main crane hook to the upper or lower internals package for handling operations. It connects to the internals flanges by means of screw threads. The internals lifting rig is shown in Figure 9.1-9.

The maximum drop height of the core barrel assembly is 69 feet, which is the limit of travel of the polar crane hook with the upper core barrel assembly and lifting rig attached.

Load bearing members of the rig are not stressed to greater than 1/5 of the ultimate strength when subjected to the static weight of the rig and the lower internals package. All primary load bearing members are constructed with materials purchased to ASTM Standards. All welding and non-destructive testing is done in accordance with approved Westinghouse Design Specifications or the ASME Boiler and Pressure Vessel Codes.

The following loading data apply to the reactor internals lifting rig:

1. Pre-operational load tests for the internals lifting rig is the actual weight of the lower internals (estimated at 171 tons with lifting rig), followed by non-destructive testing of key load bearing areas.

2. The maximum operating load for the internals lifting rig is approximately 171 tons.

3. The Westinghouse NES operating instructions for the lifting rig include non-destructive testing of key areas prior to lifting as a routine precaution.

Manipulator Crane

The manipulator crane is a rectilinear bridge and trolley crane with a vertical mast extending down into the refueling water. The bridge spans the reactor cavity and runs on rails set into the floor along the edge of the reactor cavity. The bridge and trolley motions are used to position the vertical mast over a fuel assembly in the core.

A long tube with a pneumatic gripper on the end is lowered down from the mast to grip the fuel assembly. The gripper tube is long enough so the upper end is still contained in the mast when the gripper end contacts the fuel. A winch mounted on the trolley raises the gripper tube and fuel assembly up into the mast tube. The fuel, while inside the mast tube, is transported to its new position.

All controls for the manipulator crane are mounted on a console on the trolley. The bridge is positioned on a coordinate system laid out on one rail. The electrical readout system on the console indicates the position of the bridge. With the aid of a scale the trolley is positioned on the bridge structure. The scale is read directly by the operator at the console. The drives for the bridge, trolley and winch are variable speed, including a separate inching control on the winch. Electrical interlocks and limit switches on the bridge and trolley drives protect the equipment. In an emergency, the bridge, trolley and winch can be operated manually using a handwheel on the motor shaft.

In addition to the travel limit switches on the bridge and trolley drives, the following safety features are incorporated in the system:

1. Bridge, trolley, and winch drives are mutually interlocked to prevent simultaneous operation of any two drives.

2. Bridge and trolley main motor drive operation is prevented except when the GRIPPER TUBE UP position switch is actuated.

3. The engage and disengage solenoid valves in the air line to the gripper are de-energized except when zero suspended weight is indicated by a force gage. A back-up protection for this interlock is the mechanical weight actuated lock in the gripper prevents operation of the gripper under load even if air pressure is applied to the operating cylinder.

4. Hoist drive circuit in the up direction is opened when the GRIPPER IS DISENGAGED OR when the EXCESSIVE SUSPENDED WEIGHT switch is actuated by a loading in excess of 110 percent of a fuel assembly weight. Fuel loading procedures require close observance of the load cell readout and stopping crane motion on predetermined load differentials during fuel assembly movement in the core.

5. Hoist drive circuit in either direction is operated only when either the OPEN and CLOSED indicating switch or the gripper is actuated.

6. Bridge and trolley drives are interlocked in the direction of the transfer system so that the bridge is prevented from traveling beyond the core area unless the trolley is aligned with the refueling canal centerline. The trolley drive is locked out when the bridge is moved beyond the edge of the core.

Suitable restraints are provided between the bridge and trolley structures and their respective rails to prevent derailing due to the design basis earthquake. The manipulator crane is designed to prevent disengagement of a fuel assembly from the gripper under the design basis earthquake.

Fuel Handling Crane

The fuel handling crane is a semi-gantry type crane used to transport new or spent fuel assemblies between their shipping container, storage racks and upending device. Fuel assemblies are handled by means of a special tool suspended from the crane hook. When handling spent fuel the hook travel and tool length are designed to limit the maximum lift of a fuel assembly to a safe shielding depth.

The fuel handling crane is a separate structure from the spent fuel pool bridge, although they can be coupled together to enable the two to travel as a single unit. The fuel handling crane and its components are designed as Class I (seismic). The crane components are designed to remain intact during a design basis seismic event.

Fuel Transfer System

The Fuel Transfer System, shown in Figure 9.1-5, is an electrically driven underwater conveyor car that runs on tracks extending from the refueling canal through the transfer tube and into the transfer pool. The conveyor car receives a fuel assembly in the vertical position from the manipulator crane. The fuel assembly is lowered to a horizontal position for passage through the tube, and then is raised to a vertical position in the transfer pool.

During plant operation the conveyor car is stored in the refueling canal. A blind flange is bolted on the transfer tube to seal the reactor containment. A valve seals the transfer tube on the fuel building side.

Cask Handling Crane

The cask handling crane is a bridge and trolley crane used to: 1) transfer new fuel containers from the truck bay to the laydown area near the new fuel storage area and 2) move spent fuel shipping casks from the transfer pool to the decontamination pit and to the truck bay.

The arrangement of the fuel handling area limits the drop height from the cask handling crane to 30 feet, except over the truck bay area. Administrative control will limit the lift of the cask handling crane to 30 feet or less above the area of the truck bay.

The main hoist is driven by an electric motor connected to the hoist gearing which drives drum pinion that in turn meshes with the gear attached to end of the cable drum. Each end of the hoist cable is attached to end of the cable drum with wire rope anchor. There is sufficient grooving on the drum to accommodate all of the cable that is required to make the specified lifts. The cable passes from the drum to the center sheaves of the block and then around sheaves mounted on the trolley frame, returning to the block and back to the trolley frame until a total of 12 parts of cable support the block.

The load block is equipped with a hook having a bearing to permit it to revolve under load and so arranged that it can swing a vertical plane. The cable is all one piece so that each part is subjected to approximately an equal load. The cable was selected to have a strength more than five time greater than the load which would be applied with the rated load attached to the crane hook.

The hoist motor is equipped with two independent braking systems to assure safety and accuracy of control. One braking system is electrical, arranged to release when power is applied to the motor and to set and stop the motor and load when power is applied to the motor and to set and stop the motor and load when power is turned off or is interrupted for any reason. The second braking system is mechanical and is interposed in the mechanism between the motor pinion and the hoist drum. This mechanical load brake will sustain the rated load at rest, independent of any other brake, and requires power to lower a load. Either brake is capable of stopping and holding the rated load in any position.

The driving equipment is selected to lift the rated load and overcome the friction of the gears, ropes, sheaves, and the like without exceeding the rated torque of the motor. A motor of this type is capable of exerting approximately 250 percent of its rated torque for acceleration, and also provides a good margin for reliable crane operation.

In addition to the normal five step, plane, reversion controls with Class 92 (Continuous duty) resistors, the hoist is equipped with a separate clutch-connected micro-drive motor making a drive system known as "Inching".

The hoist is equipped with one paddle-operated counter-weight type upper limit switch, one screw type upper limit switch, and one screw type lower limit switch; all to prevent hook overtravel.

The following load data apply to the Cask Handling Crane:

Design Load Rating - Tons (5 to 1 S.F.)	Test Load - Tons	Max. Operating Load - Tons	Life Test Load - Tons
110	138	110	138

The design of gearing, shafting, cables, and keys is based on the loads that are applied to each particular part with a factor of safety of at least 5, based on the average ultimate strength of the materials.

The applicable codes and standards for the Cask Handling Crane are the following:

Federal:

Safety Code for Overhead and Gantry Cranes, USA Standard B 30.2.0 - 1967 (Now ANSI B 30.2.0 - 1967)

New Jersey:

New Jersey Administrative Code, Title 12, Chapter 148, Overhead and Gantry Cranes

Other:

Electric Overhead Crane Institute Specification No. 61 (Now superseded by Crane Manufacturers Association of America Specification No. 70)

One or more of these codes and standards cover the design, fabrication, installation, and testing of the cranes. The hooks, cables, hoists, trolleys, and bridges are tested after erection to a minimum of 125 percent of their design load rating and thereby testing the supporting structure and rails.

Polar Gantry Crane (Containment Crane)

The polar gantry crane was fabricated by Whiting Corporation. Earthquake analysis was performed by using the Jet Propulsion Laboratory Structural Analysis Computer Program No. SL-S780 as modified by the Illinois Institute of Technology Research Institute. Floor response spectrum at the crane rail level was supplied by Conrad Associates. A critical damping factor of 1 percent was used. The maximum stresses induced from the Design Basis Earthquake do not exceed 90 percent of the yield strength of the materials used in each gantry crane member.

Rail lugs and stops, which are used to prevent the gantry from overturning or rolling during earthquake motion are designed to withstand the vertical and horizontal earthquake excitations simultaneously as well as overturning or rolling. Heavy anchor bolts, rail clamps and rail lugs are provided to withstand the uplift force and prevent the crane from being dislodged.

In terms of detailed description the polar crane is the same as the cask handling crane with the following exceptions:

1. 16 parts of cable support the block

2. The two independent braking systems are both electric and described with the addition of eddy-current brakes for control braking

3. Class 162 resistors

The codes and standards identified for the cask handling crane also apply to the polar crane.

The following load data apply to the polar crane:

Design Load Rating - Tons (5 to 1 S.F.)	Test Load - Tons	Max. Operating Load - Tons	Life Test Load - Tons
230 (460)*	500	230 (460)*	288

*Special reeving required for 460 tons.

The design of gearing, shafting, cables, and keys is based on the loads that are applied to each particular part with a factor of safety of at least 5, based on the average ultimate strength of the materials. There are two independent braking systems, each capable of stopping and holding the rated load at any position.

Administrative controls shall be in effect during handling of objects over an opended reactor vessel.

Rod Cluster Control (RCC) Changing Fixture

RCC elements are transferred from one fuel assembly to another by means of the RCC changing fixture. Five major subassemblies comprise the changing fixture including: (1) frame and track structure, (2) carriage, (3) guide tube, (4) gripper, and (5) drive mechanism. The carriage is a movable container supported by the frame and track structure. The tracks provide a guide for the four flanged carriage wheels and allow horizontal movement of the carriage during changing operations. Positioning stops on both the carriage and frame locate each of the three carriage compartments directly below the guide tube. Two of these compartments are designed to hold individual fuel assemblies while the third is made to support a single RCC element. Situated above the carriage and mounted on the refueling canal wall is the guide tube. This assembly provides for the guidance and proper orientation of the gripper and RCC element as they are being raised or lowered. The gripper is pneumatically actuated mechanism responsible for engaging the RCC element. It has two flexure fingers which can be inserted into the top of the RCC element when air pressure is applied to the gripper piston. Normally the fingers are locked in a radially extended position. Mounted on the operating deck is the drive mechanism assembly. Its components include: (1) manual carriage drive mechanism, (2) revolving stop operating handle, (3) pneumatic selector valve for actuating the gripper piston, and (4) electric hoist for elevation control of the gripper. The RCC change fixture is located in the containment and, since it is not in the proximity of the spent fuel pool, there is no likelihood of its dropping or falling and damaging stored fuel.

Spent Fuel Shipping Cask

The specific cask to be used at Salem for spent fuel shipment has not been selected. The largest cask that can be used is approximately 88" in diameter, 204.5" long and weighs approximately 200,000 lbs. when loaded.

9.1.4.2 Design Evaluation

Gamma radiation levels in the containment and fuel storage areas are continuously monitored. These monitors provide an audible alarm at the initiating detector indicating an unsafe condition. During reactor vessel head removal and while loading and unloading fuel from the Reactor, the boron concentration is maintained at not less than that required to shut down the core to a $k_{eff} = 0.95$. This shutdown margin is sufficient to maintain k_{eff} 0.99, even if all control rods are withdrawn from the core.

Adequate shielding for radiation is provided during reactor refueling by conducting all spent fuel transfer and storage operations under water. This permits visual control of the operation at all times while maintaining low radiation levels, less than 2.5 mr/hr. for periodic occupancy of the area by operating personnel. Pool water level is monitored, and water removed from the pool must be pumped out since there are no gravity drains.

Direct communication between the Control Room and the refueling cavity manipulator crane is available whenever changes in core geometry are taking place.

This provision allows the Control Room operator to inform the manipulator operator of any impending unsafe condition detected from the main control board indicators during fuel movement.

Detailed instructions are available for use by refueling personnel. These instructions, safety limits and conditions and the design of the fuel handling equipment incorporating built-in interlocks and safety features, provide assurance that no incidents occur during the refueling operations that result in a hazard to public health and safety.

When core geometry is being changed, core subcritical neutron flux is continuously monitored by at least two neutron monitors, each with continuous visual indication and one with audible indication in the containment. When core geometry is not being changed, at least one neutron flux monitor is in service. This permits maintenance of the instrumentation. Normally a "high flux at shutdown" condition will cause the containment evacuation horn to sound. During shutdown, and while welding is in progress inside containment, automatic sounding of the containment evacuation horn is defeated. Instead, the control room operator evaluates high flux at shutdown alarms. If produced by welding (a spike is seen on the source range recorders) no action is taken. If no spike is seen, the operator will assume that high radiation exists and will manually sound the containment evacuation horn.

At least one residual heat removal pump is operable. The residual heat removal pump is used to maintain a uniform boron concentration. When changes in core geometry are taking place, one charging pump capable of injecting borated water to the reactor coolant is available at all times.

When the Emergency Core Cooling or Containment Spray Systems are specified to be operable, the refueling water storage tank contains not less than the minimum required to permit circulation after the loss-of-coolant accident and has a boron concentration of not less than refueling concentration requirements.

The refueling water storage tank capacity is 400,000 gallons. For the initial fuel loading, a shutdown k_{eff} of 0.09 or less is required. This is obtained by using refueling water with a boron concentration of 2000 ppm.

Cold shutdown can always be achieved because the remainder of the first core and subsequent cores are less reactive than the initial fuel loading, and because the refueling conditions are required to be maintained whenever the reactor is critical. Analysis of loss-of-coolant incidents shows that the quantity of water in storage is sufficient for limiting core temperatures and containment pressure following any incident.

9.1.4.3 Analysis of Load-Drop Accidents

The physical limitations on maximum drop height are set by the limit of travel of the polar crane hook; however, no components are lifted to a height greater than that necessary for manueverability during handling operations. For the worst case postulated, that of dropping the 150 ton reactor vessel head onto the reactor vessel, a drop height of 28'-6" was assumed. The total impact load was calculated to be 54 x 10^6 lbs., or 13.5 x 10^6 lbs. acting on each reactor vessel support.

Using this load, the maximum stress at the nozzle-to-shell juncture occurs on the outlet nozzle and is 45,500 psi. This compares favorably with the allowable stress of 80,000 psi (faulted condition). The maximum calculated direct shear stress on the nozzles is 10,400 psi, which is less than the allowable stress of 33,600 psi (faulted condition). The shear stress calculated by driving the nozzle support pad through the nozzles is 20,000 psi, which is less than the yield stress of 44,500 psi.

All stresses are within those allowable and, therefore, the structural integrity of the nozzle and nozzle supports should be maintained.

No reduction in dynamic load was taken due to the damping effect of the head falling through 26 feet of water.

It is very unlikely that the dropping of the reactor vessel head would disrupt the flow of coolant to and from the reactor vessel and refueling canal.

Some local yielding of the nozzles (supports) may occur which could cause relative displacement between the vessel seal ledge and concrete seal support ring which could cause seal failure. However, loss of refueling water above the seal has no safety significance, since no fuel handling is in progress during reactor vessel head handling operations.

During the postulated drop of the reactor vessel head or upper core barrel assembly to the reactor vessel some fuel rods may fail with subsequent release of the fission gases. The radiation monitoring system, however, will detect the released radioactive gas and immediately isolate the reactor containment.

No heavy loads are handled over equipment required for the safe shutdown of the plant during the movement of fuel from the reactor cavity to the spent fuel pool or vice versa, or the movement of a cask. The handling of fuel is all within the reactor cavity, fuel transfer canal and spent fuel pool. The cask is moved within certain areas of the fuel handling building. No equipment required for safe shutdown is located in any of these areas.

The physical arrangement of the Fuel Handling Building is such that the transfer pool is separated from the spent fuel pool. The cask can travel only over the transfer pool. For this reason, no analysis of cask drop in the transfer pool was required, nor was any performed.

9.1.4.4 Tests and Inspections

Prior to initial fueling, preoperational check outs of the fuel handling equipment were performed to ensure proper performance of the fuel handling equipment and to familiarize plant operating personnel with operation of the equipment.

Prior to subsequent refueling operations, the equipment is inspected for operability and certain components, such as the fuel transfer car and manipulator crane, are operated to ensure reliable performance prior to moving irradiated fuel.

9.1.5 Control of Heavy Loads

A list of overhead handling systems from which heavy loads can be dropped, resulting in damage to safety-related equipment, is given in Table 9.1-4. Compliance of these systems with the requirements of NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," are evaluated in detail in References 1 and 2. These evaluations considered the following factors:

1. Load paths and the location of safety-related components.
2. Measures to ensure heavy load are moved within safe pathways.
3. Written procedures for heavy load handling.
4. Procedures for inspection, testing, maintenance and (crane) operator training.
5. Verification of crane design against the guidelines of industry standards such as CMAA-70[3] and ANSI B30.2-76[4].

As a result of the initial study[1], lifting devices are being more clearly marked to indicate lift capacity and to distinguish monorail lifting and non-lifting devices. As a result of the follow-up study[2] PSE&G considers the entire program on the evaluation of heavy loads to be complete.

Section 9.1.5 References

1. Quadrex Corporation, Six-Month Response for Control of Heavy Loads, Units 1 and 2, Salem Nuclear Station, December 17, 1981.

2. Quadrex Corporation, Nine-Month Response for Control of Heavy Loads, Salem Nuclear Station Units 1 and 2, February 11, 1985.

3. Crane Manufacturers Association of America, Specification for Electric Overhead Traveling Cranes, CMAA-70, 1970.

4. American National Standards Institute, American National Standard for Overhead and Gantry Cranes, ANSI B30.2.0, 1976.

TABLE 9.1-1

SPENT FUEL POOL COOLING SYSTEM CODE REQUIREMENTS

Spent fuel pool heat exchanger,	Tube Side	ASME III, Class C
	Shell Side	ASME VIII
Spent fuel pool filter		ASME III, Class C
Spent fuel pool demineralizer		ASME III, Class C
Refueling water purification filter		ASME III, Class C
Spent fuel pool piping		ANSI B31.1.0* ANSI B31.7**
Spent fuel pool cooling pump		ASME III, Class C
Spent fuel pool valves		ASA B16.5 or MSS-SP-66

* Used for design

** For piping not supplied by the NSSS supplier, material inspection, fabrication and quality control conform to ANSI B31.7. Where not possible to comply with ANSI B31.7, the requirements of ASME III-1971, which incorporated ANSI B31.7, were adhered to.

TABLE 9.1-2 (Sheet 1 of 3)

SPENT FUEL POOL COOLING SYSTEM COMPONENT DESIGN DATA

Spent fuel pool heat exchanger		
Number		1
Design heat transfer, Btu/hr.		11.94×10^6
	Shell	Tube
Design pressure, psig	150	150
Design temperature, °F	200	200
Design flow rate, lb/hr.	1.49×10^6	1.14×10^6
Design inlet temperature, °F	95	120
Design outlet temperature, °F	103	109.5
Fluid	Component Cooling water	Spent fuel pool water (borated demineralized water)
Material	Carbon Steel	Stainless steel
Spent fuel pool pump		
Number		2
Design pressure, psig		150
Design temperature, °F		200
Design flow rate, gpm		2300
Minimum developed head, ft.		125
Temperature of pumped fluid, °F		80 - 150
Fluid		Spent fuel pool water (borated demin. water)
NPSH, ft.		15
Material		Austenitic Stainless Steel
Spent fuel pool skimmer pump		
Number		1
Design pressure, psig		50
Design temperature, °F		200
Design flow rate, gpm		100
Minimum developed head, ft.		50
Temperature of pumped fluid, °F		75 - 150
Fluid		Spent fuel pool water
NPSH, ft.		15
Material		Austenitic Stainless Steel

TABLE 9.1-2 (Sheet 2 of 3)

SPENT FUEL POOL COOLING SYSTEM COMPONENT DESIGN DATA

Refueling water purification pump	
Number	1
Design pressure, psig	150
Design temperature, °F	200
Design flow, gpm	100
Minimum developed head, ft.	200
Temperature of pumped fluid, °F	40 - 140
Fluid	Borated reactor coolant
NPSH	15
Material	Austenitic Stainless Steel
Spent fuel pool demineralizer	
Number	1
Type	Flushable
Vessel design pressure, psig Internal - psig	200
External - psig	15
Vessel design temperature, °F	250
Design flow rate, gpm Maximum	100
Minimum D/F	10
Normal flow, gpm	100
Normal operating temperature, °F	120
Normal operating pressure, psig	Approximately 50
Resin type	anion and cation
Spent fuel pool filter	
Number	1
Type	Replaceable (Cage Assembly)
Internal design pressure, psig	200
Design temperature, °F	250
Rated flow, gpm	Nom. 100, Max. 150
Filtration requirement	98 percent retention of particles above 5 micron
Spent fuel pool skimmer filter	
Number	1
Type	Replaceable (Cage Assembly)
Internal design pressure, psig	200
Design temperature, °F	250
Rated flow, gpm	150
Filtration requirement	98 percent retention of particles above 5 micron

TABLE 9.1-2 (Sheet 3 of 3)

SPENT FUEL POOL COOLING SYSTEM COMPONENT DESIGN DATA

Refueling water purification filter	
Number	1
Type	Cage assembly
Internal design pressure, psig	200
Design temperature, °F	250
Rated flow, gpm	150
Filtration requirement	98 percent retention of particles above 5 micron
Spent fuel pool strainer	
Number	1
Design flow, gpm	2300
Fluid	Borated demineralized water
Spent fuel pool skimmer strainer	
Number	1
Type	Basket
Rated flow, gpm	100
Design pressure, psi	50
Design temperature, °F	200
Spent fuel pool skimmers	
Number	2
Flow per unit, gpm	50
Manual adjustment, ft	2

TABLE 9.1-3

SPENT FUEL POOL COOLING SYSTEM MALFUNCTION ANALYSIS

	Component	Malfunction	Comments and Consequences
1.	Spent fuel pool pump	Rupture of a pump casing	The casing and shell are designed for 150 psi and 200°F which exceeds maximum operating conditions. The pump is inspectable and is located in the auxiliary building protected against credible accidents. Rupture is not considered credible. (Also see no. 2 below).
2.	Spent fuel pool pump	Pump stops running and cannot be restarted	The remaining full capacity pump can be brought into operation.
3.	Spent fuel pool pump	Manual valve on pump suction or discharge is closed	This is prevented by prestartup and operational checks.
4.	Spent fuel pool pump	Suction strainer plugs	Strainer is cleaned and flow restored.
5.	Spent fuel pool heat exchanger	Tube or shell rupture	Rupture is considered incredible because of low operating pressure.
6.	Spent fuel pool skimmer pump	Pump stops running and cannot be restarted	Spent fuel assemblies continue to be cooled by spent fuel pool pump. Pool water may become slightly murky possibly decreasing visual observations until pump is restored to service. Fuel pool water is clarified to some extent by bypassing spent fuel pool water through spent fuel pool demineralizer.

TABLE 9.1-4

OVERHEAD HANDLING SYSTEMS

OVERHEAD HANDLING SYSTEMS			HEAVY LOAD			
Description	Rated Capacity (ton)	Location	Description	Weight (lb)	Drop Height (ft)	Safety Related Equipment/Components Involved in Dropped Lift
Polar Gantry Cranes with Equipment Hatch Jib	230 Main (each) 35 Aux (each)	Containment Building Elevation 130'	Upper Internals w/Lifting Rig	147,750	10	Reactor Vessel, Primary System Piping, Fuel in Reactor Vessel
		Containment Building Elevation 130'	Lower Internals w/Lifting Rig	341,500 (no fuel)	10	
		Containment Building Elevation 130'	Reactor Vessel Head w/Lifting Rig	165,500	30	
		Containment Building Elevation 130'	Missile Shield w/CRDM Fans & Seismic Restraints	54,000	80	
		Containment Building Elevation 130'	Box Guides (Missile Shield)	40,000	80	
			Bottom Block	12,700	80	
		Containment Building Elevation 130'	Rack of 9 Studs w/Nuts & Washers	6,940	30	
		Containment Building Elevation 130'	Access Stairway	4,000	40	

TABLE 9.1-4 (Continued) (Sheet 2 of 5)

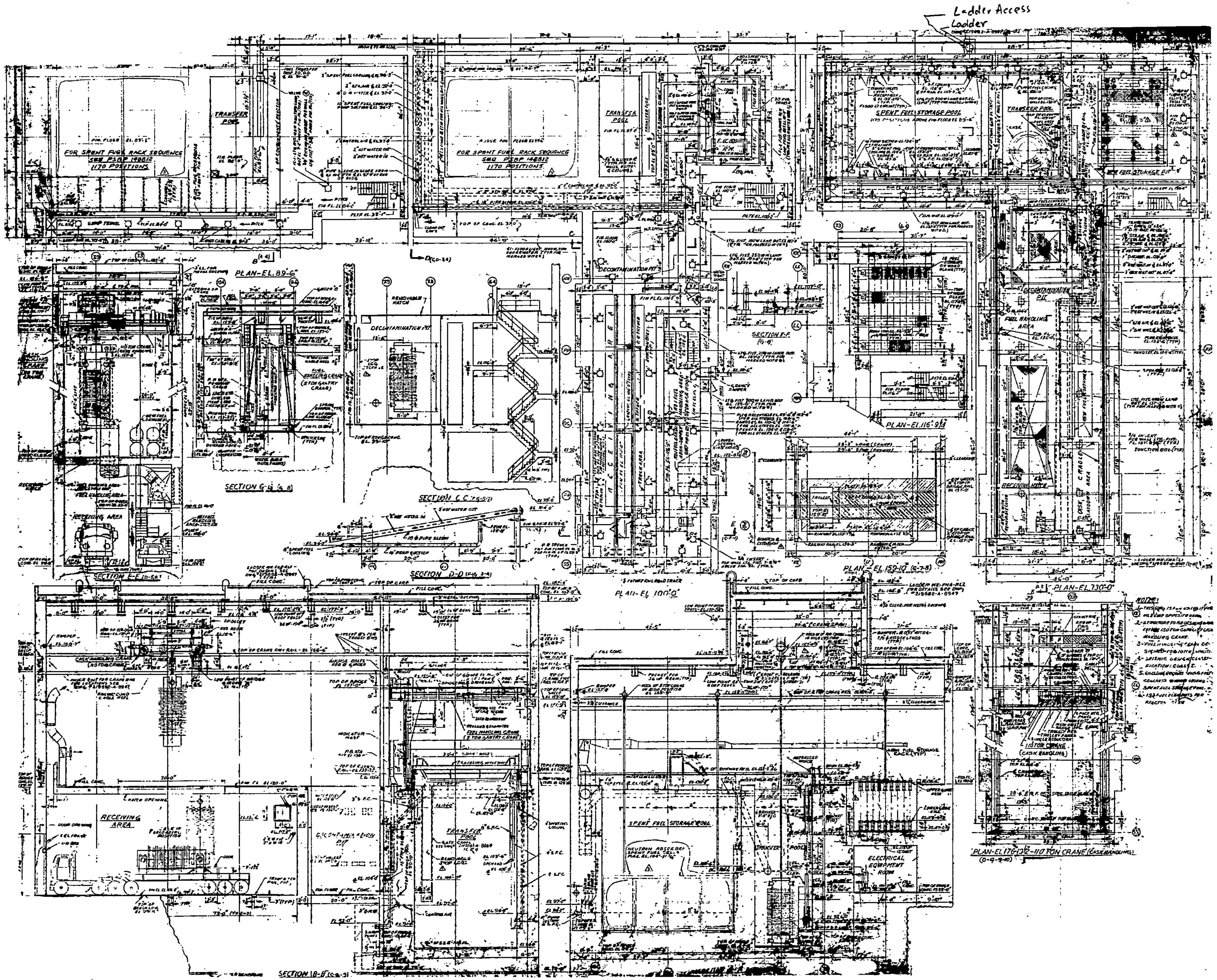
OVERHEAD HANDLING SYSTEMS			HEAVY LOAD			
Description	Rated Capacity (ton)	Location	Description	Weight (lb)	Drop Height (ft)	Safety Related Equipment/Components Involved in Dropped Lift
		Containment Building Elevation 130'	RCP Motor Access Plugs	18,000	1	
		Containment Building Elevation 130'	RCP Motor	77,000	30	
		Containment Building Elevation 130'	RCP Motor Flywheel	13,200	23	
Polar Crane Jib		Containment Building Elevation 130'	Equipment Hatch	14,000	3	
Mobile Cherry Pickers (2)	12.5 15	Containment Building Elevation 130'	Reactor Head Studs (9)	6,399	30	
Demineralizer & Ion Exchanger Service Monorail	6	Auxiliary Building Elevation 122'	Lead Filled Plugs	10,000	7	CVC system control cables running in Trays 1A418, 1A420; 2A418, 2A420, Drawing 205841.
			Concrete Floor Plugs	5,000	1	
Filter Handling Systems						
1. Spent Fuel Pit Filter Monorail	4	Auxiliary Building Elevation 100'	Filter & Filter Bell	3,500	7	Seal water heat exchanger & associated piping, some nearby safety-related cables (not directly below the dropped lift).

TABLE 9.1-4 (Continued) (Sheet 3 of 5)

OVERHEAD HANDLING SYSTEMS			HEAVY LOAD			
Description	Rated Capacity (ton)	Location	Description	Weight (lb)	Drop Height (ft)	Safety Related Equipment/Components Involved in Dropped Lift
2. Reactor Coolant Ion Exchanger & Filter Underhung Bridge Crane	4	Auxiliary Building Elevation 100'	Filter & Filter Bell	3,500	7	1B & 2B Motor Control Center & associated Cable Trays, Filters inside the bell.
3. Refueling Water Purification & Concentrate Filter Monorail	4	Auxiliary Building Elevation 100'	Filter & Filter Bell	3,500	7	Refueling Water Purification & Concentrate Filter, possible load swing into liquid waste. Component cooling heat exchanger and piping on the elevation below.
4. Seal Water Injection & Return Filter Monorails	4	Auxiliary Building Elevation 84'	Filter & Filter Bell	3,500	7	Waste gas compressor package, cable trays on the elevation below.
Solid Radwaste Overhead Crane	20	Auxiliary Building Elevation 100'	Large Casks	25,000 max	14	Numerous pieces of safe shutdown equipment at Elevation 84', such as containment spray pumps 12 & 22, charging pump 23, associated piping and electric cables.
			Hittman Casks (Loaded Waste Cask)	48,000 max	14	
Auxiliary Feedwater Pumps Monorails	3,300#	Auxiliary Building Elevation 84'	Motor Driven Pump Motor	4,400	3	Redundant Air Supply
			Turbine Driven Pump	3,300	3	Redundant Air Supply

OVERHEAD HANDLING SYSTEMS			HEAVY LOAD			
Description	Rated Capacity (ton)	Location	Description	Weight (lb)	Drop Height (ft)	Safety Related Equipment/Components Involved in Dropped Lift
Charging Pump Monorails	4,900#	Auxiliary Building Elevation 84'	Centr. Charging Pump Casing	7,500	3	Associated CVC piping and waste decon. tanks on the elevation below.
			Recip. Charging Pump Casing	11,800	3	
Component Cooling Pump Monorails	3,200#	Auxiliary Building Elevation 84'	Component Cooling Pump Motor	2,650	3	There may be occasion to lift over operable component cooling pump in the case of pumps 12 & 13. Waste holdup tanks, monitor tanks, vital cable trays, and service water piping on elevation below.
Safety Injection Pump Monorails	2,600#	Auxiliary Building Elevation 84'	Safety Injection Pump Motor	2,450	3	Safety Injection pump & piping.
Containment Spray Pump Monorails		Auxiliary Building Elevation 84'	Containment Spray Pump Motor	4,000	3	Associated containment spray piping. Chemical Volume Control (CVC) System and service water piping and vital cable trays on the elevation below.
Monorail Serving Elevation 55' and Elevation 45'	4,300#	Auxiliary Building Elevation 55'	Residual Heat Removal Pump Motor	3,950	15	Residual heat removal pump and piping.
			Access Plug	8,000		
18T Grove Crane (194)	18	Outside Auxiliary Building				

OVERHEAD HANDLING SYSTEMS			HEAVY LOAD			
Description	Rated Capacity (ton)	Location	Description	Weight (lb)	Drop Height (ft)	Safety Related Equipment/Components Involved in Dropped Lift
Cask Handling Overhead Crane	110 Main 3 Aux	Fuel Handling Building Elevation 130'	Spent Fuel Cask w/Spent Fuel	200,000	32	Spent fuel in cask, transfer pool liner.
			Bottom Block	4,200	32	Transfer pool liner.
Service Water Strainers Monorails	5	Service Water Intake Structure above Structure Q	Service Water Strainer	6,000	12	Service water piping and header. Intake bays pump suctions on elevation below.
80T Grove Crane (193) and 900 Series American Crawler Crane	80 225	Intake Structure and Outside Yard	Service Water Concrete Cover Plug	12,000	1	
			Service Water Pump	12,000	1 in the yard	
			Service Water Pump Motor	13,200	1 in the yard	
900 Series American Crawler Crane	225	Intake Structure and Outside Yard	Traveling Screens	17,325	12	
			Fish Gate	3,000	12	



Also Available On Aperture Card

TI APERTURE CARD

POOR ORIGINAL

204836A8753-3

Revision 3
July 22, 1984

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Fuel Handling Area
	UPDATED FSAR FIG 9.1-1

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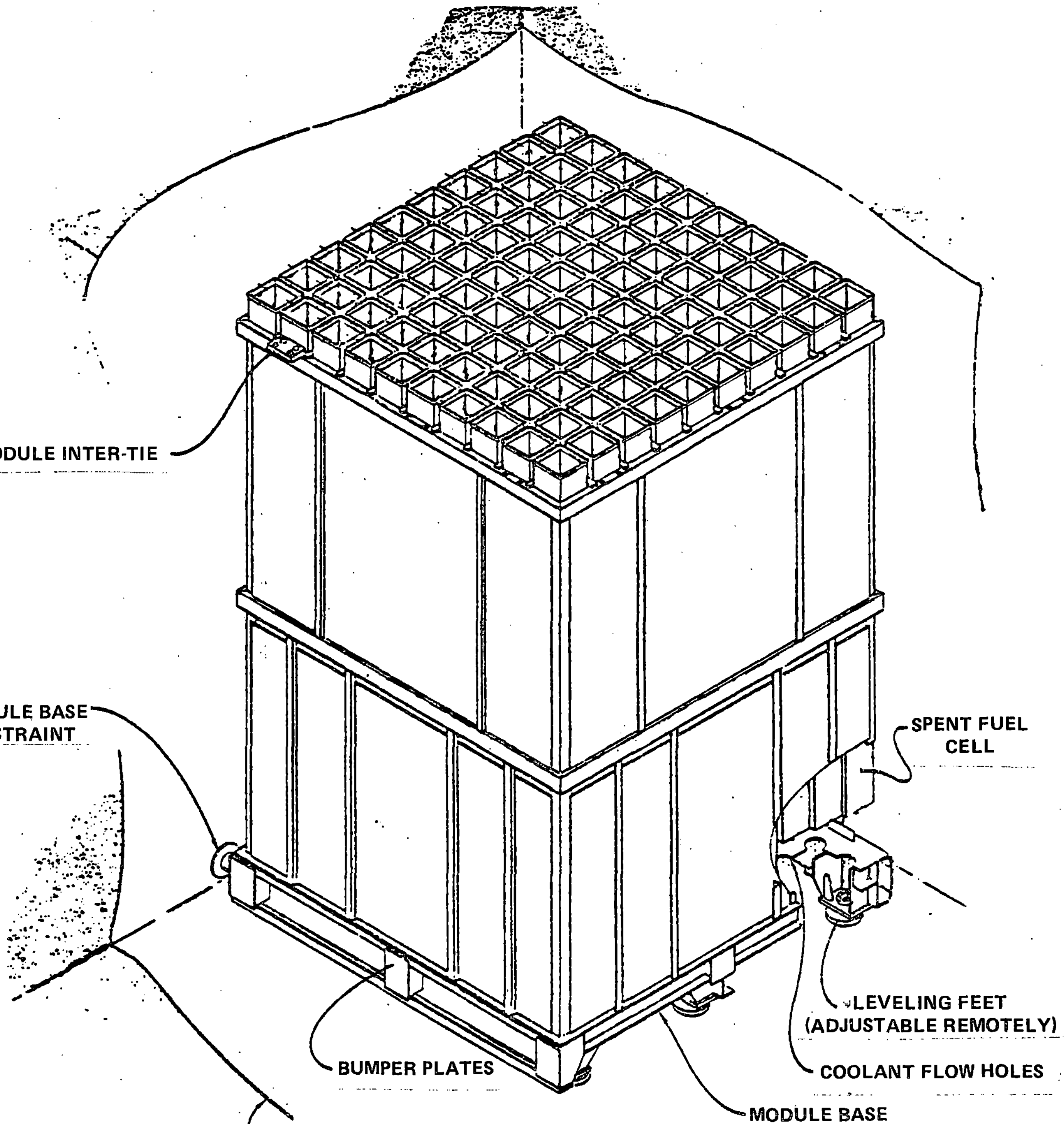
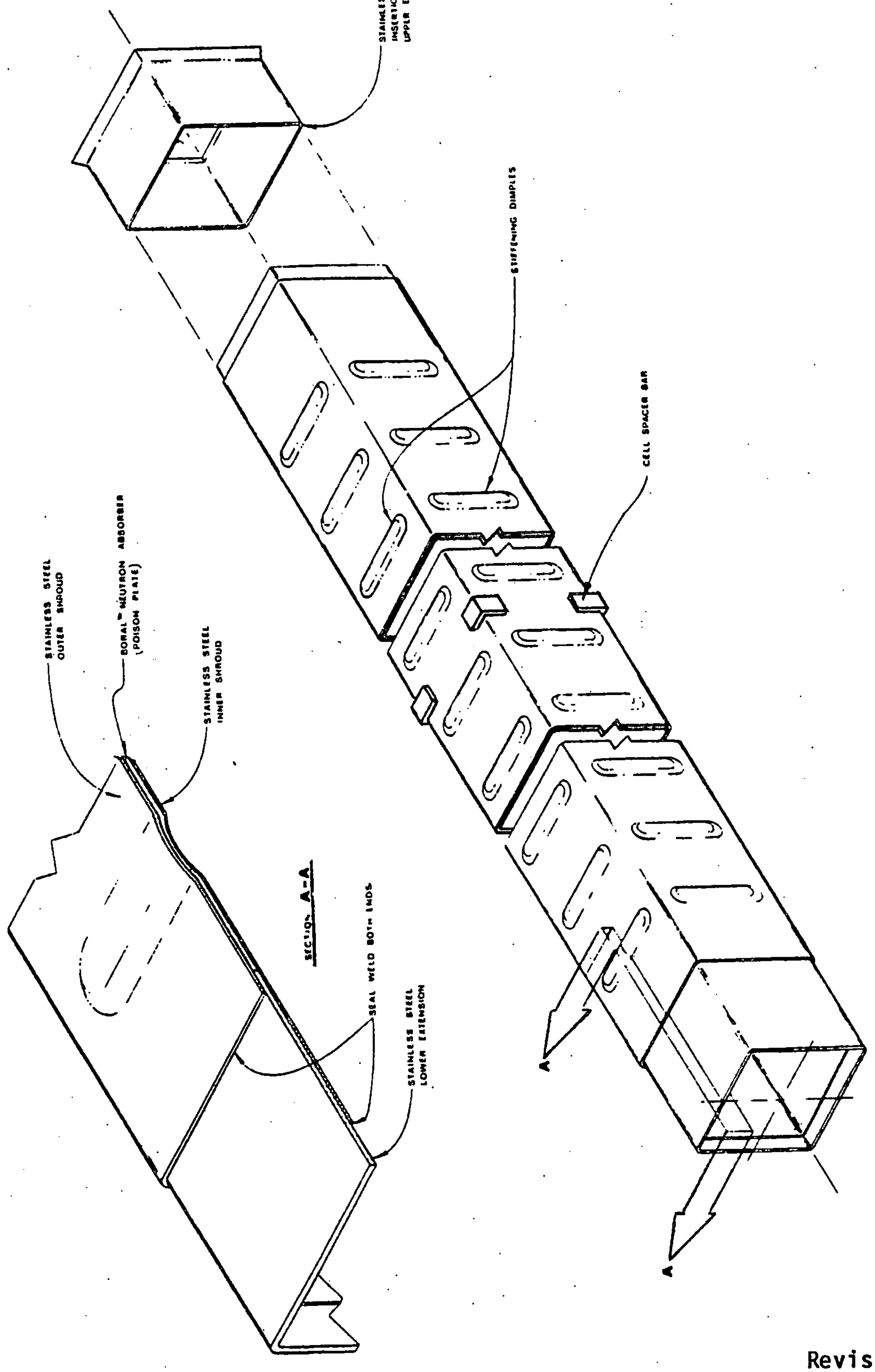


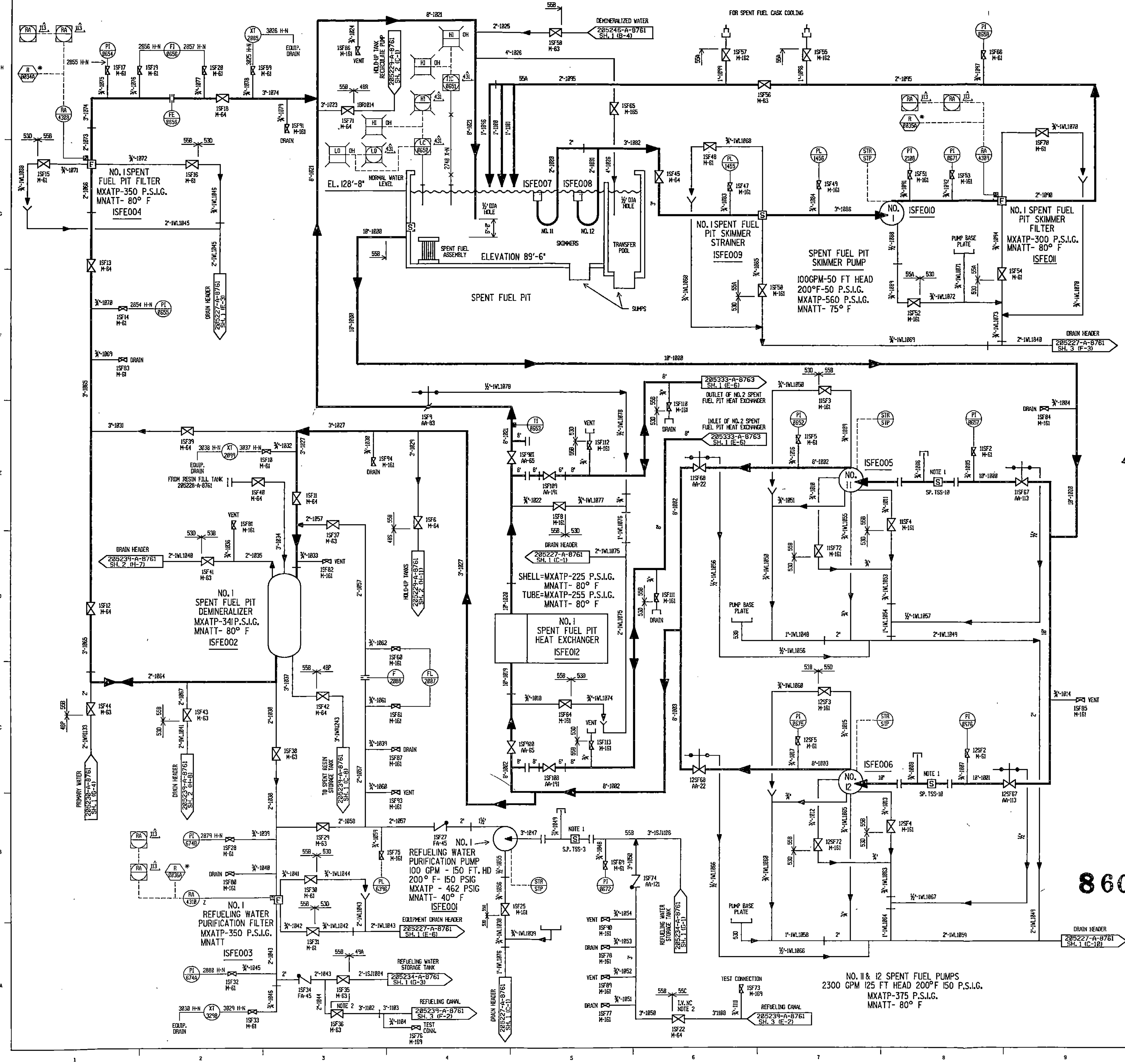
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	High Density Poison Spent Fuel Storage Module	
	Updated FSAR	Figure 9.1-2



Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Poison Spent Fuel Storage Cell	
	Updated FSAR	Figure 9.1-3



TI APERTURE CARD

Also Available On Aperture Card

NOTES:

1. TEMPORARY STRAINER IS PLACED IN THE SPOOL PIECE DURING INITIAL FLUSHING OPERATIONS. STRAINER MUST BE REMOVED BEFORE PLANT START-UP. CAPPED LINE IS CONNECTED TO A TEMPORARY PRESSURE GAGE AT THIS TIME.
2. LOCATE VALVE AS CLOSE TO CONTAINMENT AS POSSIBLE.
3. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1SF" (i.e. "1SF"1000 ECT.) EXCEPT WHERE OTHERWISE NOTED.
4. ALL PRESSURES SHOWN ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
5. INSTRUMENT ITEMS IN PARENTHESIS ( ) ARE WESTINGHOUSE INSTRUMENT ITEMS, REFER TO ISA 51 FOR DESCRIPTION.

REFERENCE DRAWINGS:

VALVE LIST		206766-L
EQUIPMENT VENTS & DRAINS-CONTAMINATED		205227-A-8761
CHEMICAL & VOLUME CONTROL-BORIC ACID RECOVERY		205229-A-8761
CHEMICAL & VOLUME CONTROL-PRIMARY WATER RECOVERY		205230-A-8761
SAFETY INJECTION		205234-A-8761
WASTE DISPOSAL-LIQUID		205239-A-8761
DM WATER-RESTRICTED AREA		205246-A-8761
LEGEND SHEET		600658-A-8727
NO. 1 UNIT SPENT FUEL PIT COOLING LOOP	INSTR. SCH.	232316-B-9608-5
NO. 1 UNIT ANN. DESIGNATIONS SHT. 1		218161-B-9783
SPENT FUEL POOL CONTROLS	PNL. 431	228474-B-9588
RADIATION MONITORING SYSTEM	PNL. 113	233048-A-1399
RADIATION MONITORING CABINET	PNL. 113	203692-A-8990
RECORDER PANEL 1RP1		226960-A-1290
RECORDER PANEL 1RP1 HIGH RADIATION ALARMS W.D.		203546-A-1375

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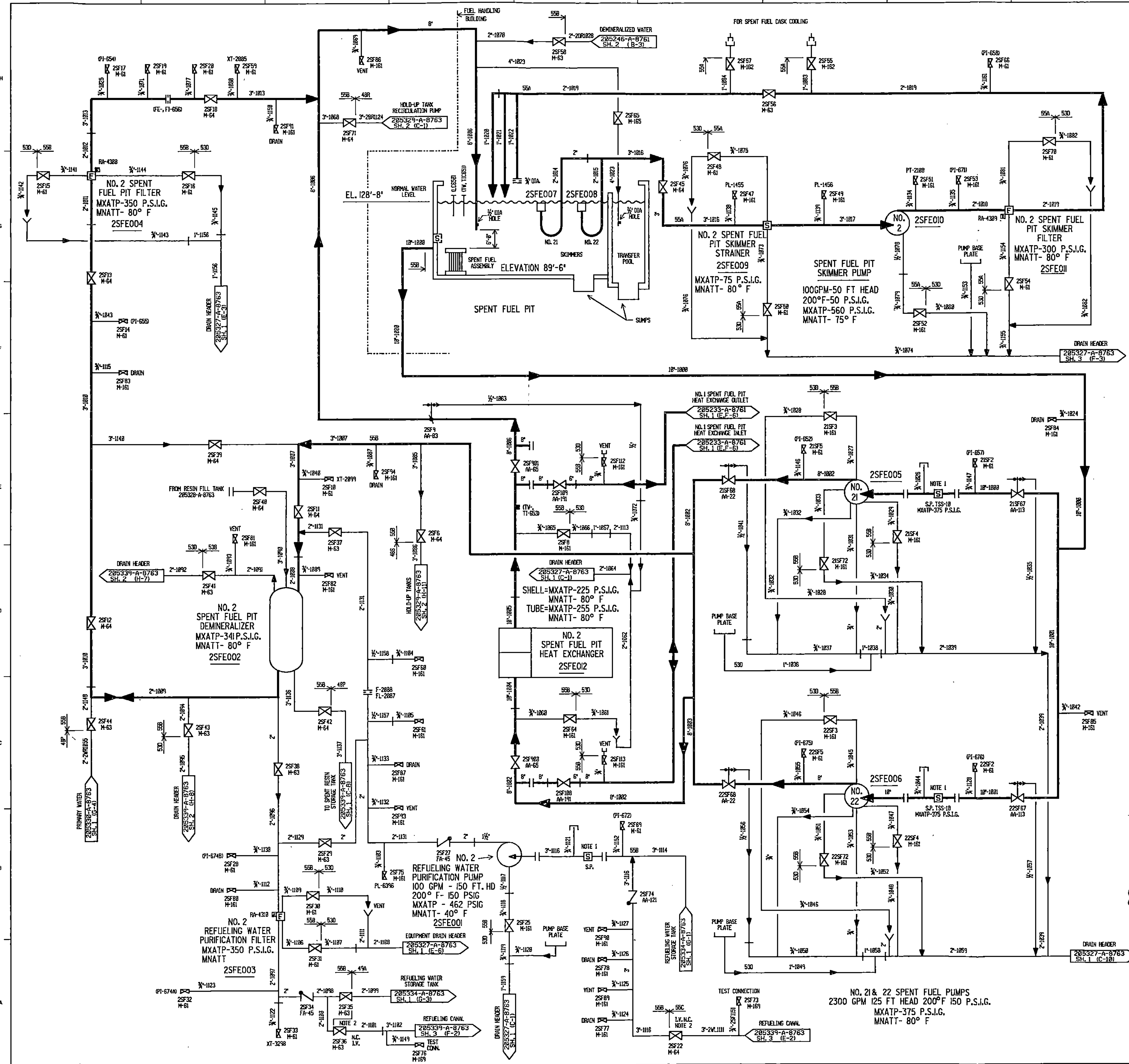
REVISION 5
JULY 25, 1986
Ref. Dwg. 205233-A-8761-13

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Spent Fuel Cooling System
Unit 1

Updated FSAR Sheet 1 of 1
Fig 9.1-4A



TI APERTURE CARD

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DESIGN				
	CLASSIFICATION			
* BOUNDARY	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
IS55A	NO	II	III	NO
IS55B	NO	II	III	NO
IS55C	YES	I	II	YES
IS48P	NO	II	III	NO
IS48R	NO	II	II	NO
IS48S	NO	II	II	NO
IS53D	NO	III	III	NO
IS49A	YES	I	III	YES

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "IS" (i.e. IS44A, ETC.) UNLESS OTHERWISE NOTED.

NOTES:

1. TEMPORARY STRAINER IS PLACED IN THE SPOOL PIECE DURING INITIAL FLUSHING OPERATIONS. STRAINER MUST BE REMOVED BEFORE PLANT START-UP. CAPPED LINE IS CONNECTED TO A TEMPORARY PRESSURE GAGE AT THIS TIME.
2. LOCATE VALVE AS CLOSE TO CONTAINMENT AS POSSIBLE.
3. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2SF" (i.e. "2SF"1000 ECT.) EXCEPT WHERE OTHERWISE NOTED.
4. ALL PRESSURES SHOWN ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
5. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200, PIPING SCHEDULE AND GROUP NO. IS55A EXCEPT AS OTHERWISE NOTED.

REFERENCE DRAWINGS:

VALVE LIST — 206766-L
EQUIPMENT VENTS & DRAINS-CONTAMINATED — 205327-A-8763
CHEMICAL & VOLUME CONTROL-BORIC ACID RECOVERY — 205329-A-8763
CHEMICAL & VOLUME CONTROL-PRIMARY WATER RECOVERY — 205330-A-8763
SAFETY INJECTION — 205334-A-8763
WASTE DISPOSAL-LIQUID — 205339-A-8763
DM WATER-RESTRICTED AREA — 205246-A-8761
LEGEND SHEET — 600658-A-8727

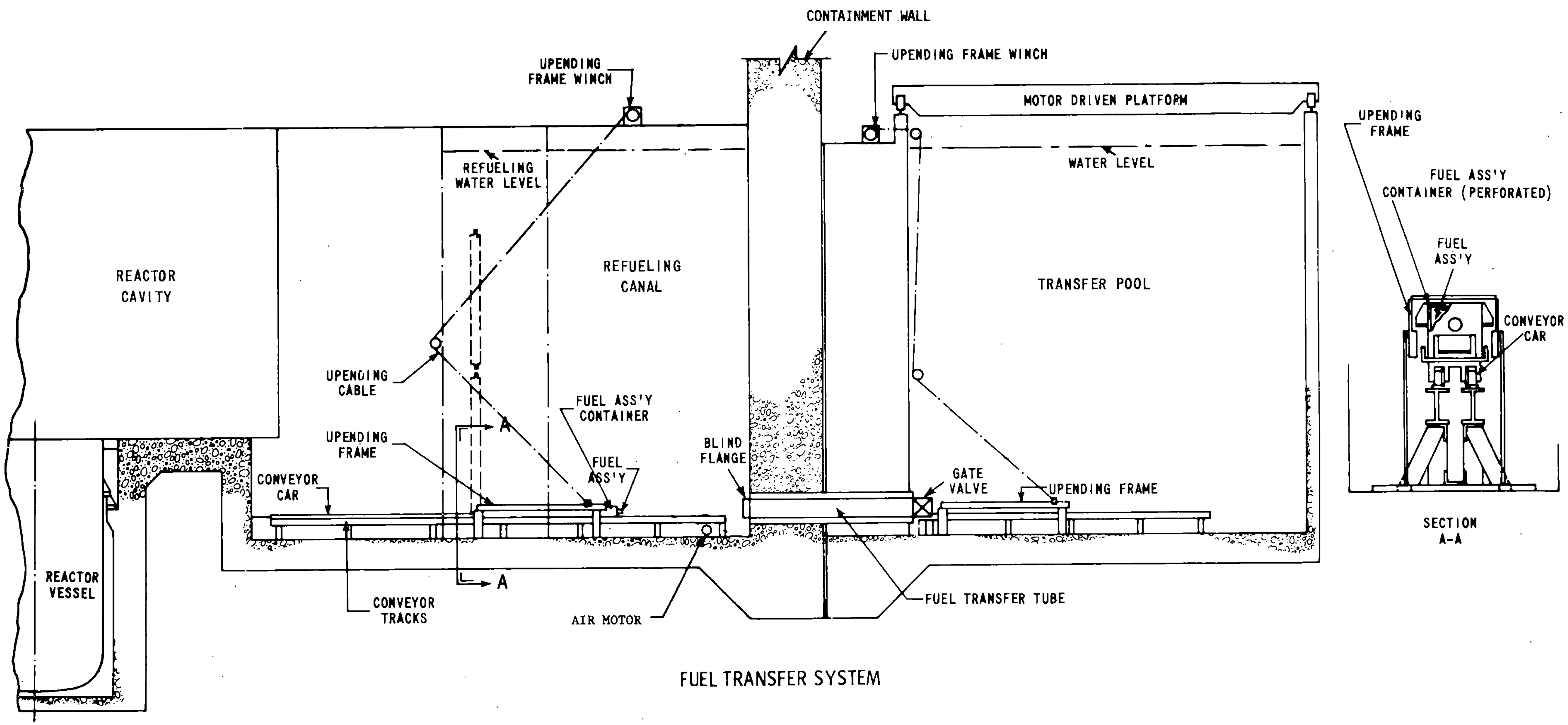
8607290251-31

REVISION 5
JULY 25, 1986
Ref. Dwg. 205333-A-8763-12

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Spent Fuel Cooling System
Unit 2

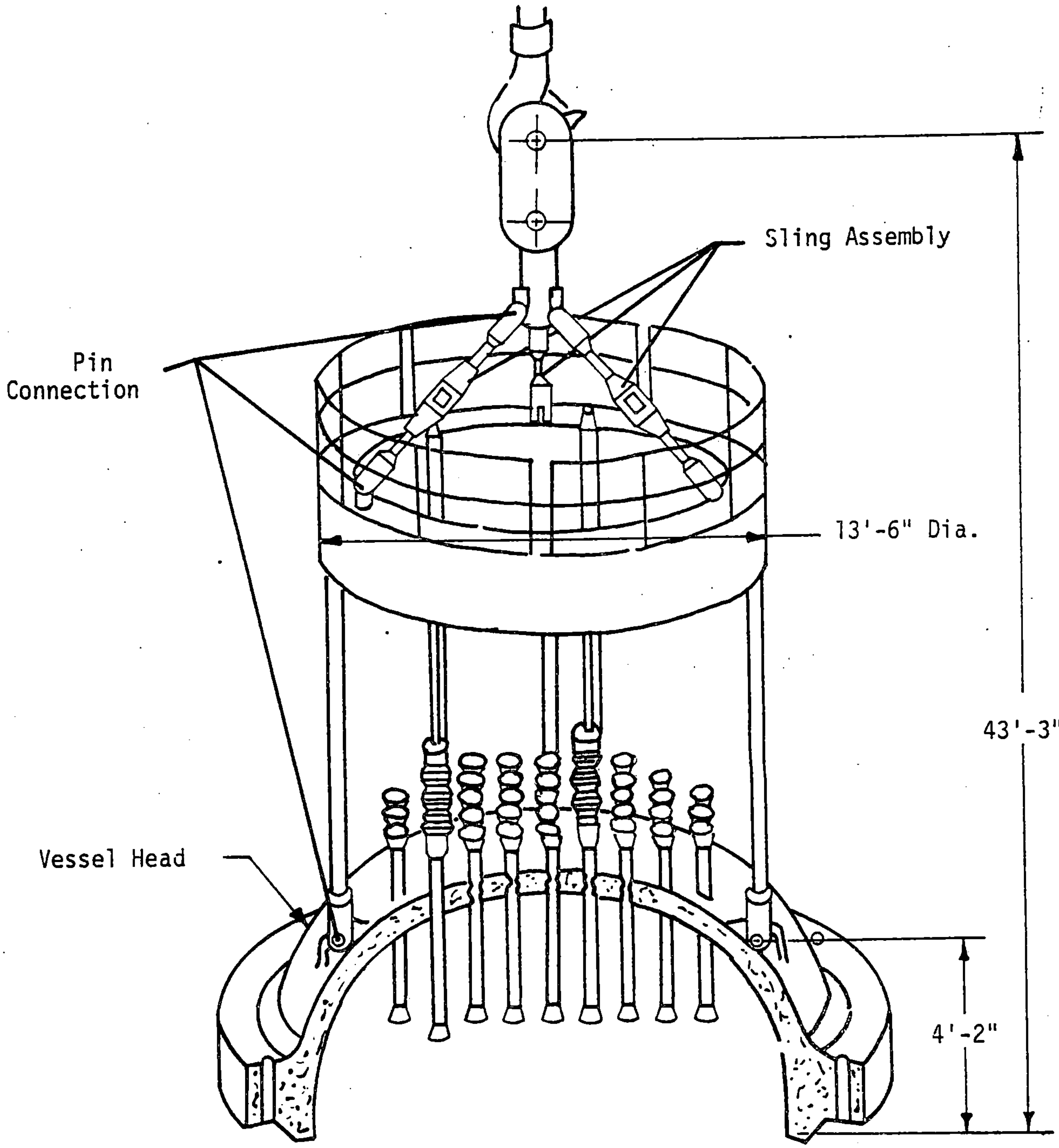
Updated FSAR Sheet 1 of 1
Fig 9.1-4B



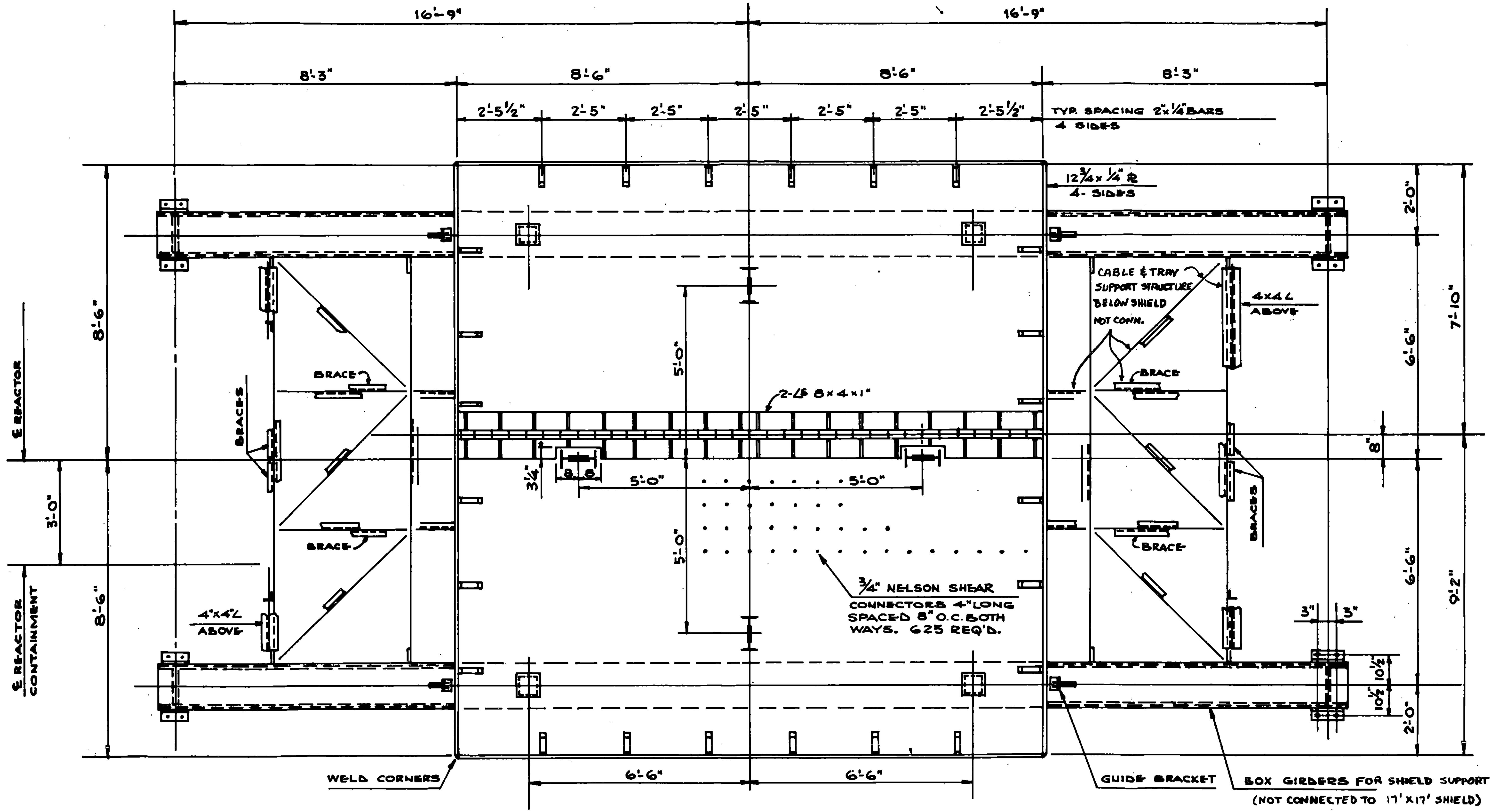
FUEL TRANSFER SYSTEM

Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Fuel Transfer System (Typical)	
	Updated FSAR	Figure 9.1-5

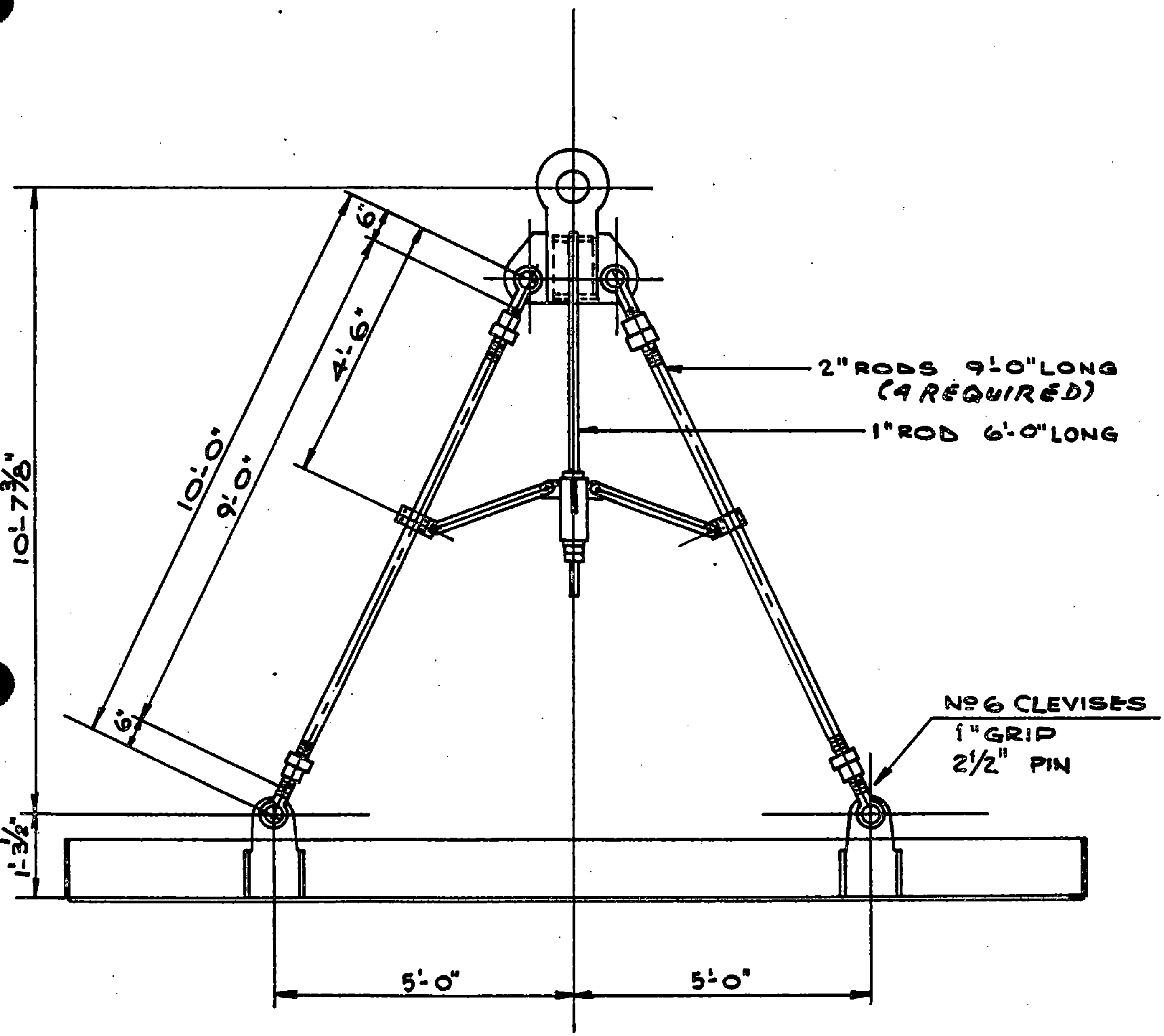


Revision 0
July 22, 1982



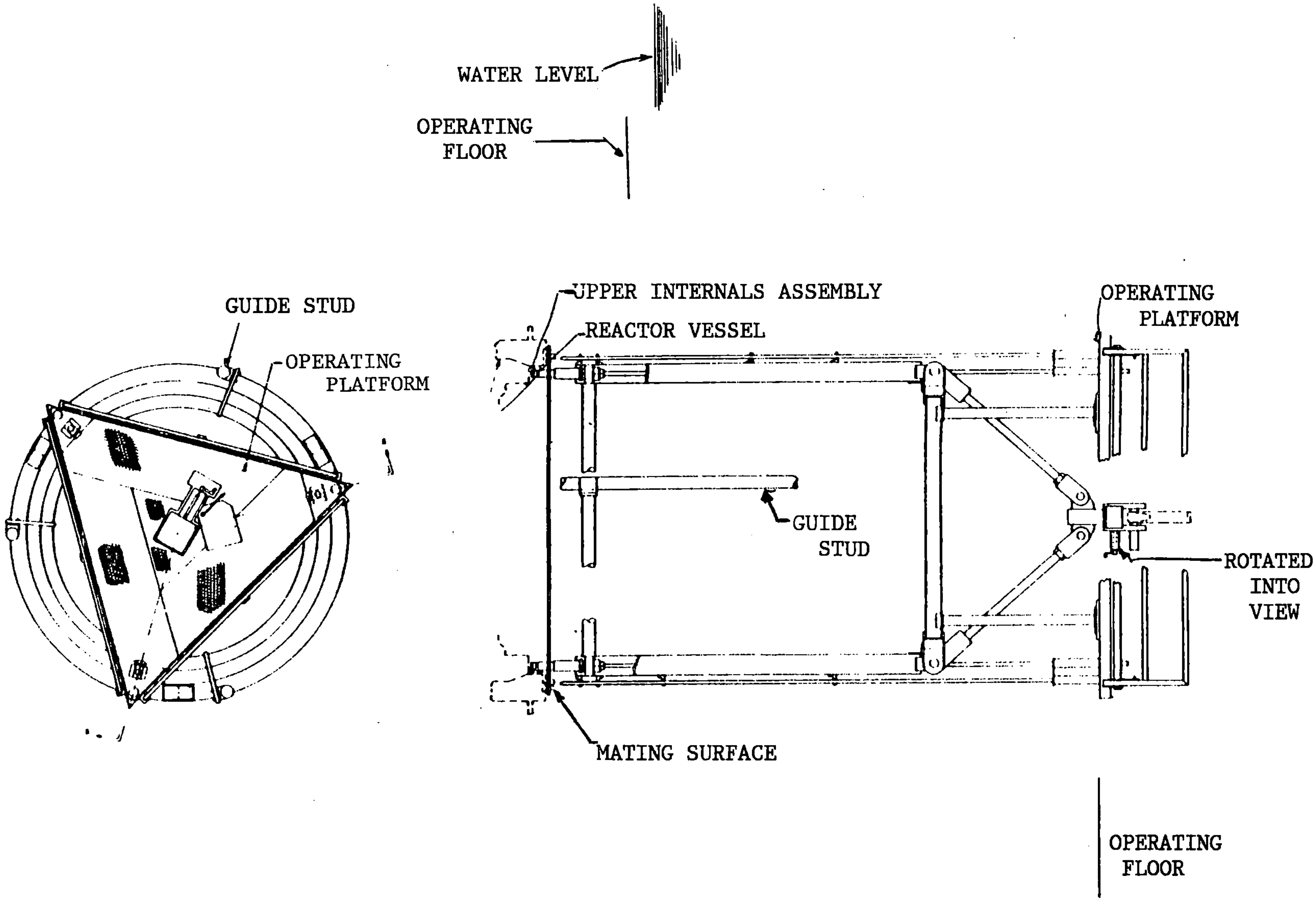
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Missile Shield
	Updated FSAR — Figure 9.1-7



Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Missile Shield Handling Fixture
	Updated FSAR — Figure 9.1-8



SECTION A-A

ELEVATION VIEW

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

UPDATED FSAR

Internals Lifting Rig

FIG 9.1-9

Revision 5
July 25, 1986

9.2 WATER SYSTEMS

9.2.1 SERVICE WATER SYSTEM

9.2.1.1 Design Basis

The Service Water System is designed to supply an adequate supply of cooling water to the reactor safeguard and auxiliary equipment under all credible seismic, flood, drought, and storm conditions. Coolant flow is divided into two portions, namely, the Nuclear Area and the Turbine Generator Area. These are illustrated on Figures 9.2-1A and B and 9.2-2, respectively. The following equipment is supplied with Service Water:

1. Reactor Containment Building
   a. Reactor containment fan cooler units.

2. Auxiliary Building
   a. Component cooling heat exchangers
   b. Diesel generator units
   c. Chiller condensers
   d. Steam generator blowdown system
   e. Auxiliary equipment lube oil coolers
   f. Auxiliary equipment room coolers

3. Turbine Generator Building
   a. Steam generator feed pump coolers
   b. Station air compressor units
   c. Vacuum pump seal water coolers
   d. Turbine lube oil coolers
   e. Turbine auxiliary cooling water heat exchangers
   f. Condensate pump motor bearing coolers
   g. Heater drain pump motor bearing coolers
   h. Bleed steam coil pump lube oil coolers

4. Pump Intake Structure

   a. Traveling screen backwash
   b. Service water pump bearing Lubrication
   c. Service water pump motor bearing coolers
   d. Sump pump bearing lubrication
   e. Sodium hypochlorite dilution water

9.2.1.2 System Description & Operation

Each unit is equipped with six vertical turbine-type pumps which provide strained Delaware River Water to the plant before discharging via the circulating water outlet piping. The pumps for both units are installed in an enclosed intake structure which features four independent pump room compartments containing three pump units each. Each group of three pumps is valved into one of two independent, full-sized, supply headers per unit, which are situated in alternating compartments of the intake structure. A double-valved, normally open, interconnection between the two pump headers is provided to permit the continued operation of the system with any combination of pumps in the event of a supply line outage. Each supply line to the nuclear services portion of the Service Water System normally feeds one unit, or approximately 1/2 of the total nuclear area requirement. In addition, each line is valved at all terminations and provided with double-valved interconnections to permit the removal of either supply line from service without affecting plant operations. Recirculation control (to enable smooth multiple combination pump operation) is provided for each pump room compartment. Pump discharge is recirculated back to the pump intakes through a valve serving the three pumps within each compartment. These valves are modulated by service water pressure measured within the common manifold connecting the discharge of the three pumps within each compartment. Pump requirements on a per unit basis for various plant conditions are outlined as follows:

Plant Conditions	No. of Pumps
1. Normal Operation	4
2. Loss-of-Coolant Accident	
a. Safety Injection Phase	2
b. Recirculation Phase	3(1)

(1) Minimum recirculation requirements can be met with two pumps.

Emergency diesel generators are provided to power three pumps during a failure of normal power supply. The total system requirements during various modes of plant operation are listed on Table 9.2-1 which lists the required pumping requirements based on a maximum river temperature of 85°F.

The reactor containment fan cooler (RCFC) units are supplied by individual lines from the containment area service water header. Each inlet and discharge line penetrating the containment wall is provided with a remotely-operated, automatically controlled shut-off valve. This provision allows each fan cooler to be isolated on an individual basis from outside the containment area.

The diesel generators can be provided with service water for cooling from either nuclear supply header through connections located upstream of the Auxiliary Building tie valves. Each nuclear header connection to the diesel generator coolers is provided with a normally open motor operated isolation valve inside the Auxiliary Building, as indicated in Figures 9.2-1A and B. Either of the motor operated isolation valves can be closed by the operator from the Control Room. Downstream of the motor operated isolation valves, each service water supply header connection to each diesel generator cooler is provided with a check valve and a normally open maintenance valve which is operated by a reach rod from the diesel generator compartment.

Rupture of the service water supply pipe downstream of the check valve will cut off cooling water to the affected diesel generator cooler. The affected diesel generator will alarm a high jacket water and high lube oil temperature condition to the Control Room approximately three minutes after loss of cooling water. The control room operator can temporarily close one of the motor operated isolation valves to reduce service water leakage to the compartment while maintaining service water supply to the two other diesel generators. The service water flow control valve to one of the two component cooling heat exchangers can be closed from the component cooling heat exchanger control panel and the service water maintenance valve to the affected diesel generator cooler can be closed with the reach rod. The affected diesel generator can then be unloaded and shut down. All valve operators and controls that are not in the Control Room can be readily reached from the control room by operating personnel through corridors and stairways in the Auxiliary Building.

Failure of one of the nuclear supply headers downstream of the tie valves in the Auxiliary Building will not interrupt the supply of service water to the equipment required to operate following a loss-of-coolant accident. Each of the two service water loops provides service water to one component cooling heat exchanger, one charging pump lube oil cooler, one safety injection pump lube oil cooler and three containment fan cooler units.

The service water pumps are of the vertical, multistage, turbine type each rated at 10,875 gpm and 240 ft. head and are directly driven by 1000 HP induction motors powered from the plant vital buses. The pumps for each unit are mounted in two individual dewaterable cells of the intake structure with three pumps to a cell. The intake structure, shown in Figure 9.2-3, is physically apart from the turbine condenser circulating water pump intake. The pumps are arranged to afford adequate submergence during the lowest credible water level elevation of 76.0 ft. The motors are protected from flooding to an elevation of 121.0 ft. by the watertight pump room compartments which contain sump pumps. Automatic traveling water screens are provided at each intake cell and combine with full depth trash racks to filter debris from the incoming flow. A mobile mechanical trash rake unit is provided to maintain unobstructed passageways at the trash racks. Two-foot wide fish escape passages are located abreast of the traveling screens to minimize the entrapment of fish in the individual intake cells. Organic buildup in the pumps, piping and heat exchangers is prevented by means of injecting sodium hypochlorite at the suction of each pump. Each pump discharges to an automatic, self-cleaning strainer and check valve prior to entering the compartment supply header.

The Service Water System Intake Structure is located about 200 yards from the Delaware River shipping channels. It is expected that shipping will not approach the intake since the channel is marked by buoys and lights. Due to the large distance between the intake and the shipping channel, vessels, which may be adrift, can be secured, anchored, or grounded before coming into the vicinity of the intake. In the event that small unattended barges do drift into the vicinity of the intake, marine dock bumpers have been installed to prevent damage to the structure.

The six service water pumps for each unit are arranged in groups of 3 pumps each, and each group of pumps for one unit are installed in alternate watertight compartments inside the intake structure, as indicated in Figures 9.2-1A and B. Each Service Water Pump is recessed approximately 50 feet from the river face of the intake. Based on the above, damage or blockage to two adjacent compartments of the intake can occur without cutting off the supply of service water to each unit.

In the event that an oil spill occurs in the vicinity of the Service Water Intake, floating oil spill booms installed in the two end cell fish escape passages opening to the river prevent oil from entering the intake at any river water level above 81 feet. A curtain wall at elevation 81' extending across the entire intake structure, except in the fish escape passages prevents any oil from entering the intake at any river level above this elevation. Lowest recorded river water level is 83'-1. The vertical turbine type Service Water Pumps take suction at elevation 71'-3, which is below the minimum credible river water level of 76'. Based on the above, oil floating on the river surface will not be drawn into the pumps. Should the river water level drop below elevation 81' with water borne oil present, the plant would be shut down.

The Service Water System is designed for Class I (seismic) conditions except for the turbine area service water piping outside of the service water intake structure, which is of non-Class I (seismic) design. The Class I (seismic) service water piping inside the service water intake structure which supplies the turbine area is provided with two motor operated valves, SW-20 and SW-26, in series, to isolate the non-Class I (seismic) portion of the system upon receipt of a safety injection signal or a blackout. The two motor operated valves in series are powered from separate vital buses to ensure isolation of the non-Class I (seismic) portion of the Service Water System.

The hypochlorite system piping inside the service water intake structure is designed for Class II (seismic) conditions, but the pipe supports are designed to Class I (seismic) criteria.

The separated redundant service water lines between the service water pumps and the No. 1 Unit Component Cooling Heat Exchangers are not located in open trenches as such, but rather are constructed of reinforced concrete pipe completely buried in the ground. Thus, in effect, they are located in "separate trenches". The principal supply line piping runs are separated by about 13 feet. This separation, in conjunction with the depth at which they have been buried, makes these lines essentially invulnerable to damage from a single postulated event.

The above discussion also applies to the service water piping to the No. 2 Unit Component Cooling Heat Exchangers except for one section of piping running along the west side of the Auxiliary Building. Though not buried, this piping is located within a 4'-6" thick reinforced concrete pipe tunnel. The redundant supply lines within the tunnel are separated by a 3' thick reinforced concrete wall, again precluding coincident failure due to a single event.

Status is displayed and control of each service water pump is available on the main control panel so that an operator can determine if an abnormal number of pumps are operating. Status and control of all service water system isolation valves and motor operated header block and tie valves is also available to the opertor in the control room. The motor operated valve operators complete their closing or opening cycle in one minute while the containment isolation valves can close in 10 seconds.

The rupture of a large pipe will be indicated to the operator by decreasing pump distance header pressure shown on the main control panel. If outside power is available, low pump header pressure will automatically start a backup service water pump. If pump discharge header pressure continues to fall, low low pressure is alarmed to the main control room.

In the event that a pipe rupture occurs in a watertight pump compartment in the service water intake structure, which is beyond the capacity of the 100 gpm sump pump, high sump level for the affected compartment will be alarmed to the control room. The control room operator can remotely close the tie valves and header block valves at the intake structure to isolate the affected compartment and remotely start the remaining pumps in the other pump compartment to permit an orderly plant shutdown.

In the event that a main yard supply header is ruptured, the affected header can be isolated by the control room operator who can also open the tie valves at the Auxiliary Building. Rupture of a header pipe for No. 2 Unit in the pipe tunnel can also be detected by high level to the control room alarm from the sumps each containing 200 gpm pumps. The control room operator can determine the affected header by remotely closing the intake tie valves and observing which pump header is affected by low low pressure. One the rupture yard header is isolated the intake tie valves can be opened and all service water pumps made available.

Service water piping in the Auxiliary Building is for the most part accessible during operation for inspection by the operators.

In the event that a pipe rupture occurs in the service water piping inside the containment, the difference between flows entering and leaving the containment will be sensed and alarmed to the control room. High level alarms in the containment sump and the fan cooler drain pot will also be transmitted to the control room. The control room operator can remotely close the containment isolation valves to isolate the leaking fan cooler unit.

In the event that radiation is detected at one of the service water outlet from the containment, the condition is alarmed in the Control Room. The final decision to isolate the coils is based on plant conditions, analyses and indications.

The service water flow through the containment fan cooler units is indicated on the control console along with a differnetial flow measurement which alarms under flow mismatch conditions. A flow mismatch could occur due to a leak in the fan cooler unit in the containm,ent area.

A temperature detector monitors the fan cooler outlet temperature, which is indicated on the control console; high water temperature could be an indication of inadequate flow.

The service water flow through the component cooling heat exchanger is maintained at 10,000 gpm by means of a control valve. The valve is controlled by an indicating controller mounted in an instrument panel which is located in the Auxiliary Building in the vicinity of the heat exchanger. In addition, a flow transmitter alarms a service water high flow condition on the overhead annunciator in the Control Room.

Material inspection, fabrication and quality control conform to ANSI B31.7. Where not possible to comple with ANSI B31. 7, the requirements of ASME III-1971, which incorporated ANSI B31.7, were adhered to.

Radiographs of Nuclear Class III cement lined pipe were difficult to interpret. The 1970 addenda to B31.7 allowed 100 percent magnetic particle inspection in lieu of random radiography. This provision was also incorporated into Section III, 1971 Edition. The Service Water System contains Nuclear Class III cement lined pipe for which this alternate inspection method was utilized.

The use of a later code was restricted to inspection and did not involve any requirements from Section III such as material, stress calculations, etc., that would modify our original design. Consequently, other requirements from a later Code would not be applicable. Therefore, it is believed that the integrity of field welds has not been compromised and that we have complied with our commitment to use ANS B31.7 wherever possiole.

9.2.1.3 Design Evaluation

The Service Water System is designed to remain operable under each of the following conditions:

1. Any one pump failure and one pump under maintenance.
2. One main supply header failure.
3. Loss-of-coolant accident coincident with loss of offsite power and subsequent 4KV vital bus failure.

The minimum engineered safeguards equipment required to safely shut down the unit will not be limited by any of these failures.

9.2.1.4 Tests and Inspections

The system was hydrostatically tested prior to station operation. All active components (valves, pumps and controls) were functionally tested prior to startup. Surveillance requirements for inservice inspection and testing of components is in accordance with the Technical Sepcifications.

9.2.2 COMPONENT COOLING SYSTEM

An independent Component Cooling System, shown in Figure 9.2-4 is provided for each unit. All information in this section refers to one unit. Unit No. 2 is a similar design.

9.2.2.1 Design Bases

The system is designed to remove residual and sensible heat from the Reactor Coolant System, via the Residual Heat Removal System during plant shutdown, cool the spent fuel pool water and the letdown flow to the Chemical Volume and Control System during power operation and provide cooling to dissipate waste heat from various primary plant components.

Active system components which are considered vital to the cooling function are redundant. Redundancy of components in the Component Cooling System, when provided, does not degrade the performance or reliability of any system which the Component Cooling System serves. Any single active or passive failure in the system will not prevent the system from performing its design function.

The system design provides means for detection of radioactivity entering the system from the Reactor Coolant System and its associated auxiliary systems and includes provisions for isolation of system components.

The design of the Component Cooling System is based on a maximum service water supply temperature of 85°F. It has been noted that during exceptionally hot weather and rare tide conditions, the service water temperature has exceeded 85°F (going as high as 90°F). An analysis performed on the system based on a temperature of 90°F indicates that the heat removal requirements during worst case conditions (LOCA) will still be met. Therefore, if the 85°F design temperature is exceeded, there will be no affect on safety and no further action will be required by operating personnel. This temperature places no limitation on normal plant operation and affects only the time required for plant cooldown and the number of component-cooling heat exchangers in use during the various plant operations.

9.2.2.2 Codes and Classifications

All piping and components of the Component Cooling System will be designed to the applicable codes and standards listed in Table 9.2-2. Component cooling water contains a corrosion inhibitor to protect the carbon steel

9.2.2.3 System Description

The System consists of three component cooling pumps, two component cooling heat exchangers, a component cooling surge tank, cooling lines to various components being cooled, and associated piping, valves, and instrumentation. The component coolant flows from the pumps, through the shell side of the component cooling heat exchangers, shell and tube type, or through the component cooling water side of the component cooling heat exchangers, plate type, through the components being cooled, and back to the pumps. The surge tank is connected to the suction side of the component cooling pumps. Makeup water is supplied to the loop near the surge tank.

During normal full power operation, one or two component cooling pumps and one component cooling heat exchanger accommodate the heat removal loads. The standby pump and the standby heat exchanger provide backup during normal operation. Operation of all component cooling pumps and both component cooling heat exchangers is required for removing residual and sensible heat during a normal plant shutdown. Failure of one of these components increases the time required for shutdown but does not affect the safe operation of the plant.

In the event of a loss-of-coolant accident, one pump and one heat exchanger are capable of fulfilling system requirements. Three main cooling headers are provided: two isolable headers which supply cooling water to essential safety equipment, and one header which supplies cooling water to the other plant auxiliaries. With this arrangement, long-term cooling of the Engineered Safety Features under accident conditions is assured considering an active component failure or the development of excessive leakage in one header in the Component Cooling System. Cooling water for the component cooling heat exchangers is supplied from the Service Water System insuring a continuous source of cooling under all conditions.

Component cooling is provided for the following heat sources:

1. Residual heat exchangers
2. Reactor coolant pump motor bearing oil coolers and thermal barriers
3. Letdown heat exchanger
4. Excess letdown heat exchanger
5. Seal water heat exchanger
6. Spent fuel pool heat exchanger
7. Sample heat exchangers (Unit #1 Component Cooling System serves the sample heat exchangers for both units.)
8. Boric acid evaporator condenser and condensate cooler
9. Cooling for residual heat removal, safety injection, and charging pumps
10. Waste disposal system components

Design flow rates under various conditions are tabulated in Table 9.2-3.

All components served are arranged in three main headers with parallel flow circuits from each header. Cooling water is normally available to all components served by the system, even though one or more of the components may be isolated. Motor operated valves are used to provide the residual heat exchangers with cooling water should it become necessary to place these components in service under loss-of-coolant accident conditions. At the reactor coolant pump, component cooling water removes heat from both the motor bearing oil and the thermal barrier.

The Component Cooling System is considered an Engineered Safeguards System, since it is required for post-accident removal of decay heat from the reactor. For that reason, it is designed to meet the single active or passive failure criteria. Two completely independent, parallel trains are available, each consisting of one pump and one component cooling heat exchanger. A third pump is available as a standby. Each train includes 50 percent of the equipment which must be cooled in a post-accident situation. The surge tank is also separated into two parts by a baffle, thereby essentially providing separate surge volume for each of the two trains. During normal operation, the two trains are interconnected, but when an accident occurs, motor operated valves are available to establish the two separate cooling trains within a short period of time. Each of these cooling trains provides cooling water to one of the two residual heat removal trains.

Since the heat is transferred from the component cooling water to the service water, the Component Cooling System serves as an intermediate system between the Reactor Coolant and the Service Water Systems and insures that any leakage of radioactive fluid from the components being cooled is contained within the plant. The surge tank accommodates expansion, contraction, and in-leakage of water and insures a continuous component cooling water supply until a leaking cooling line can be isolated. Radiation monitors are provided on the component cooling heat exchanger discharge lines. The monitors actuate alarms and close the surge tank vent valve when the radiation level reaches a preset level above the normal background.

Water chemistry control of the Component Cooling System is accomplished by chemical additions to the surge tank and by addition of demineralized water to the system through two lines connected to the suction header of the pumps.

The operation of the system is monitored with the following instrumentation:

1. Temperature detectors in the inlet and outlet lines for each component cooling heat exchanger.

2. Pressure detectors on the pump discharge headers.

3. A temperature indicator in the outlet line from each heat exchanger.

4. A radiation monitor in each component cooling heat exchanger discharge line.

5. A level indicator and alarm on each side of the surge tank.

9.2.2.4 Components

Component Cooling System component design data are listed in Table 9.2-4.

9.2.2.4.1 Component Cooling Heat Exchangers

Two component cooling heat exchangers are provided for each unit. Unit No. 1 has one tube and shell type heat exchanger and one plate-type heat exchanger; Unit No. 2 has two(2) tube and shell-type heat exchangers. Service water circulates through the cold side while component cooling water circulates through the hot side.

Each component-cooling heat exchanger is designed to remove one-half of the heat load occuring at 20 hours after plant shutdown. Each heat exchanger is also capable of removing one-half of the maximum heat removal load occurring when the Residual Heat Removal System is first placed in operation during a plant cooldown operation. The heat removal load during normal full-power operation is transferred by one component-cooling heat exchanger with the additional exchanger providing 100 percent standby capacity.

The provision of two component-cooling heat exchangers assures that heat-removal capacity is only partially lost if one exchanger fails or becomes inoperative, and allows maintenance or replacement of one exchanger while the other unit is in service.

9.2.2.4.2 Component Cooling Pumps

The three component cooling pumps which circulate component cooling water through the Component Cooling System are horizontal, centrifugal units of standard commercial construction. The pump motors receive electric power from the 4160 volt vital buses.

The component-cooling flow requirement during full-power operation is normally met by operation of two component-cooling pumps; the third pump provides standby capacity. During plant cooldown all three pumps are operated and each pump circulates one-third of the total Component cooling flow.

9.2.2.4.3 Component Cooling Surge Tank

The surge tank, in addition to the piping connections, has a flanged opening at the top for additions of chemical corrosion inhibitor to the Component Cooling System. For the purpose of homogenizing this chemical with the rest of the system, a recirculation line from the pump discharge is provided.

Normally the tank is open to the atmosphere, but if high radiation is detected in the recirculating system the vent line is automatically closed. The tank is connected to the system by two lines, both equipped with locked-open valves.

The tank has an internal baffle divider to provide two separate surge volumes. This arrangement provides redundancy for a passive failure during recirculation following a loss of coolant accident.

9.2.2.4.4 Valves

Since the component cooling water is not normally radioactive, special features to prevent leakage from the valves to the atmosphere are not provided. Self-actuated spring loaded relief valves are provided for lines and components that could be pressurized to their design pressure by improper operation or malfunction.

9.2.2.4.5 Piping

All Component Cooling System piping is carbon steel with welded joints and connections except at components which might require removal for maintenance. The piping is of carbon steel since the coolant contains a corrosion inhibitor.

9.2.2.5 Design Evaluation

9.2.2.5.1 Availability and Reliability

Inside the containment, most of the piping, valves, and instrumentation are located outside the crane wall at an elevation above the water level in the bottom of the containment at post accident conditions. In this location the portions of the system within the containment are protected against credible missiles and from flooding during post accident operations. This location also provides radiation shielding which permits maintenance and inspection to be performed during power operation. (The exceptions are the cooling lines for the reactor coolant pumps which are isolated following a postulated loss-of-coolant accident).

The component cooling pumps, heat exchangers, and associated valves, piping and instrumentation are located outside of the containment and are therefore available for maintenance and inspection during power operation. Replacement of a pump or heat exchanger is practicable while the other components are in service. Sufficient cooling capacity is provided to fulfill all system requirements under normal and accident conditions. Adequate safety margins are included in the size and number of components to preclude the possibility of a component malfunction adversely affecting operation of safeguards equipment.

Power is supplied to each of the component cooling pumps from separate 4160 volt buses. These buses are normally supplied from separate diesel generators in the event of loss of off-site power. Upon power failure coincident with a loss-of-coolant accident, the component cooling pumps are manually loaded on the vital buses. During a loss-of-coolant accident not coincident with loss of off-site power, the diesels will start but will not be loaded and power to the component cooling water pumps is not interrupted.

9.2.2.6 Leakage Provisions

To minimize the possibility of leakage from piping, valves, and equipment, welded construction is used wherever possible. The component cooling water could become contaminated with radioactive water due to one of the following conditions:

1. A leak in any heat exchanger tube in the Chemical and Volume Control System, Sampling System, Residual Heat Removal System, or Spent Fuel Pool Cooling System or a cooling coil for the thermal barrier cooler on a reactor coolant pump.

2. A leak in the residual heat exchangers following an accident. (Tube or coil leaks in components being cooled are detected by radiation monitors located on the component cooling heat exchanger outlet headers.)

The relief valves on the cooling water lines downstream of the sample, letdown, excess letdown, seal water, spent fuel pool and residual heat exchangers are sized to relieve the volumetric expansion occurring if the exchanger shell side is isolated and high temperature coolant flows through the tube side. The set pressure equals the design pressure of the shell side of the heat exchangers.

The relief valve on the component cooling surge tank is sized to relieve the maximum flow rate of water which enters the surge tank following a rupture of a reactor coolant pump thermal barrier cooling coil. The set pressure is less than the design pressure of the component cooling surge tank. The discharge of this valve is directed to the waste holdup tank. The relief valve on the plant auxiliaries header is sized to relieve the volumetric expansion from all components on that header should it be isolated from the surge tank.

9.2.2.7 Incident Control

The portion of the Component Cooling System located inside the containment can be isolated following a loss-of-coolant accident. The lines to and from the excess letdown heat exchanger are isolated in phase A isolation and the lines to and from the reactor coolant pumps in phase B. The cooling water supply line to the reactor coolant pumps contains a check valve inside and remote operated valves outside the containment wall. Each return line from the pumps has remote operated valves inside and outside the containment wall. The cooling water supply line to the excess letdown heat exchanger contains a check valve inside the containment wall and both supply and return lines have valves outside the containment wall which can close automatically to isolate that portion of the system. Except for the normally closed makeup line and equipment vent and drain lines, there are no direct connections between the cooling water and other systems. The equipment vent and drain lines outside the containment have manual valves which are normally closed unless the equipment is being vented or drained for maintenance or repair operations.

The Component Cooling System instrumentation provides the required signals for safe, reliable, and efficient operation and control of the system. All alarms are located in the control room.

9.2.2.8 Reactor Coolant Pump/Motor Cooling

9.2.2.8.1 Description

Component cooling water is provided to the reactor coolant pump thermal barrier heat exchanger, as well as to the upper and lower motor bearing oil coolers. In addition, seal injection flow is supplied to the pumps from the chemical and volume control system. These cooling supplies are discussed in the following paragraphs and are shown schematically in Figure 9.2-5.

The thermal barrier is a welded assembly consisting of a flanged cylindrical shell, a series of concentric stainless steel cans, a heat exchanger coil assembly, and three flanged water connections.

Component cooling water enters the thermal barrier through a flanged connection on the thermal barrier flange (See Figure 9.2.6). The cooling water flows through the inside of the coiled stainless steel tubing in the heat exchanger and exits through another flanged connection on the thermal barrier flange.

During normal operation, the thermal barrier limits the heat transfer from the reactor coolant to the pump internals. If a loss of seal injection flow should occur, the heat exchanger in the thermal barrier assembly cools the reactor coolant before it enters the radial bearing and the shaft seal area. Conversely, if a loss of component cooling water to the thermal barrier heat exchanger should occur, the seal injection flow is sufficient to prevent damage to the seals.

The upper bearing assembly contains an oil-coolded pivoted-pad radial guide bearing (upper guide bearing), as well as a double acting oil-cooled Kingsbury-type thrust bearing (see Figure 9.2.7. The thrust bearing shoes are positioned above and below a common runner to accommodate thrust in both directions. The shoes are mounted on equalizing pads, which distribute the thrust load equally to all the shoes.

The oil is circulated through and cooled by component cooling water in an external oil-to-water shell and tube heat exchanger (oil cooler).

The lower guide bearing is a pivoted-pad radial bearing, similar to the upper guide bearing.

The entire lower guide bearing assembly is located in the lower oil resevoir, which contains an integral oil-to-water coil type heat exchanger (See Figure 9.2-7).

As discussed above, component cooling water is provided to the reactor coolant pump thermal barrier heat exchanger, as well as to the upper and lower motor bearing oil coolers. Should a loss of component cooling water to the reactor coolant pumps occur, the Chemical and Volume Control System continues to provide seal injection flow to the reactor coolant pumps; the seal injection flow is sufficient to prevent damage to the seal with a loss of thermal barrier cooling. However, the loss of component cooling water to the motor bearing oil coolers will result in an increase in oil temperature and a corresponding rise in motor bearing metal temperature. It has been demonstrated by testing, discussed below, that the reactor coolant pumps will incur no damage as a result of a component cooling water flow interruption of ten minutes.

Two reactor coolant pump motors have been tested with interruped component cooling water these tests were conducted at the Westinghouse Electro Mechanical Division. In both bases, the reactor coolant pumps were operated to achieve "hot" (2230 psia, 552°F) equilibrium conditions. After the bearing temperatures stablized, the cooling water flow to the upper and lower motor bearing oil coolers was terminated and bearing (upper thrust, lower thrust, upper guide and lower guide) temperatures were monitored. A bearing metal temperature of 185°F was established as the maximum test temperature. When that temperature was reached, the cooling water flow was restored.

In both tests, the upper thrust bearing exhibited the limiting temperatures. Figure 9.2.8 shows the upper thrust bearing temperature versus time. In both cases, 185°F was reached in approximately ten minutes.

The maximum test temperature of 185°F is also the suggested alarm setpoint temperature and the suggested trip temperature is 195°F. It should be noted that the melting point of the babbitt bearing metal exceeds 400°F. The information presented above constitutes the basis of the RCP qualification for ten minute operation without component cooling water with no resultant damage.

9.2.2.8.2 Operating Procedures

PSE and G Operating Procedures for Salem Unit 1 and 2 have been revised to address the loss of component cooling water to the reactor coolant pumps in sufficient detail to cover the concerns expressed. Upon a low component cooling flow alarm to any reactor coolant pump, the operator will trip the reactor and reactor coolant pumps within five minutes if flow cannot be restored to the reactor coolant pumps. This action will be performed prior to the motor bearing reaching its design operating temperature.

9.2.2.8.3 Analysis of Simultaneous Multiple Pump Seizure Probability

As discussed above, a loss of component cooling water to the motor bearing oil coolers will result in an increase in oil temperature and a corresponding rise in motor bearing temperature. Westinghouse contends that the loss of component cooling water to the reactor coolant pumps will not result in an instantaneous seizure of two pumps simultaneously is not a credible ultimate consequence.

Instead, it is Westinghouse's technical opinion that a more realistic ultimate consequence will be an abbreviated coastdown. If a limiting condition of the babbitt metal is considered, an increasing coefficient of friction, as well as an increasing retarding torque is expected. However, in view of the large rotational inertia of the pump/motor assembly, Westinghouse maintains that an instantaneous seizure will not result.

Because an initial seizure is not expected, it is not possible to define a precise point in time at which a sequential seizure would be anticipated. Therefore, for the purpose of defining the time expected between sequential seizures, the following discussion is presented in terms of ¨equential occurrences of reaching a "high"bearing temperature. As discussed above, the upper thrust bearing exhibits the limiting temperature. Therefore, an upper thrust bearing temperature of 240°F has been chosen arbitrarily as the "high temperature. It should be noted tht the use of this value does not imply pump seizure at this temperature.

Variables affecting the steady state operating temperature of the bearings include the following:

1. Surface finish of the bearing and runner

2. Bearing (and oil pumping mechanism) clearances

3. Inlet temperature of water to heat exchanger (oil cooler)

4. Condition of oil-to-water heat exchanger (oil cooler), i.e., extent of fouling

5. Condition of oil

6. Amount of oil in oil pot

7. Oil temperature

These variables would be expected to interact concurrently in a manner which individualizes the performance of the bearings during actual steady state plant operation. In order to quantify the resultant variation in performance, Westinghouse has collected data from an operating four-loop plant. This data demonstrates that the upper thrust bearings operate at different steady state temperatures, (i.e., 128°F, 132°F, 135°F, and 145°F.)

Using these actual steady state operating values (A-128°F, B-132°F, C-135°F, D-145°F) and assuming a conservative 5°F/minute linear heatup rate after a loss of component cooling water sequential occurrences of reaching the "high" bearing temperature could be expected at the time intervals tabulated below: (See Figures 9.2-9 and 9.2-10)

Sequential Motors	Operating Temperature (°F)	Time Interval (minutes)
A and B	4	0.85
B and C	3	0.65
C and D	10	2.875
A and C	7	1.5
B and D	13	2.525
A and D	17	3.375

To summarize, two bearings sequentially reaching a temperature of 240°F could be expected a a minimum time interval of 0.65 minutes and at a maximum time interval of 3.375 minutes.

Westinghouse has obtained motor bearing heatup data, as discussed previously. These test data show actual values of bearing temperatures following a loss of component cooling water. The test data presented in Figure 9.2-8 will be examined relative to the above discussion. The test runs, which were performed at different times using different motors, demonstrate similar heatup rates. This fact supports the assumption of identical linear heatup rates made in the previous discussion. In addition, the average heatup rates evidenced in the test data are less than 3.3°F/minute, which substantiates the use of 5°F/minute as a conservative value. The actual test data, although limited, is supportive of the assumptions posed in defining the time intervals tabulated above.

In conclusion, Westinghouse contends that a single or multiple pump seizure as the result of a loss of component cooling water to the reactor coolant pumps is not a credible event. However, in our judgment and based on the above discussion, two reactor coolant pump motor upper thrust bearings could sequentially reach a "high" bearing temperature of 240°F at a minimum time interval of 0.65 minutes (or approximately 40 seconds).

9.2.2.8.4 Definition of core damage and pressure transients as a result of two seqwuential locked rotors

Chapter 15 presents the analysis of a single reactor coolant pump locked rotor. It should be pointed out that the analysis assumes an instantaneous seizure of a reactor coolant pump rotor on a non-mechanistis basis.

As discussed above, Westinghouse contends that a postulated mechanistic instantaneous seizure of a pump rotor due to a loss of component cooling water to the reactor coolant pump will not occur and is not a credible event.

However, in response to the NRC's request, the results of a second non-mechanistic instantaneous seizure occurring at 40 seconds (defined previously) after a first non-mechanistic instantaneous seizure have been evaluated. Although an FSAR approach was utilized to evaluate this situation, Westinghouse does not recognize a postulated mechanistic instantaneous locked rotor as a credible consequence of the loss of component cooling water to the reactor coolant pumps.

Assuming that a second pump seizure occurs 40 seconds after a first pump seizure, no noticeable change is seen in the Reactor Coolant System pressure and the clad temperature transients. Furthermore, even if the time interval between the sequential seizures is reduced to 10 seconds, no noticeable change is seen in the Reactor Coolant System pressure and the clad temperature transients.

The hypothetical seizure of one reactor coolant pump results in a low flow reactor trip approximately one second after the initial of the event. As a result of the fast reactor trip and the consequential decrease in core heat flux, the reactor coolant system pressure and the clad temperature reach the peak values at about 2.5 seconds and then start to decrease.

Because the core has been shut down, at 40 seconds, or even 10 seconds, after a pump seizure, the Reactor Coolant System pressure and the clad temperature transients have decreased to a point at which a second pump seizure results in no noticeable change in the transients.

9.2.2.6.5 Single Failure Criteria Related to Electrical Power Requirements

An audit of the electrical design involved in the redundant supplies of cooling water to the reactor coolant pump seals has been performed to verify the ability of control and motive power sources to meet the single failure criterion.

The result of this audit shows that there are no credible single electrical failures capable of causing a total loss of cooling water to any reactor coolant pump. The equipment and controls analyzed are the following (Unit No. 1 numbers are used - Unit No. 2 analysis is identical).

CVCS

Isolation valves ICV116 and ICV284
RCP Seal Leakoff valves CV104 (11-14)

Component Cooling

Cooling water supply valves ICC117 and ICC118
Bearing water return valves ICC136 and ICC187
Thermal barier water return valves ICC131 and ICC190

All the valves identified except the CV104 valves are 230 V.A.C. motor operated valves. The CV104 valves are 125 VDC solenoid operated valves.

The CV104 valves have been designed to fail into the open position upon loss of control power or air. Each valve control circuit has been assigned to a separate control grouping which insures physical separation of all involved control devices. All credible failures result in an open valve. An individual valve "hot-short" could potentially cause a loss of seal water flow to only one pump. Such a failure could not cause the coincident loss of component cooling flow.

The motor-operated valves perform the safety function of containment isolation, and are separated among the three vital 230V AC busses. All of these valves are normally open and remain open unless signalled to close by containment isolation logic. One half of the component cooling valves would close upon receipt of a containment isolation signal (phase B) from protection Train A. The other half would close upon the same signal from Train B. The Chemical and Volume Control System valves would be closed upon receipt of containment isolation (phase A) signals from their respective protection Trains. There are no credible failures capable of causing both of these events to coincide. A design basis loss-of-coolant accident would result in closure of all valves to comply with containment isolation criteria.

piping. All motive power and control circuits have been analyzed for potential failures. The results of this analysis indicate that no credible failure mechanism can cause loss of all cooling flow to the reactor coolant pumps.

9.2.2.9 Malfunction Analysis

The malfunction analysis of pumps, heat exchangers, and valves is presented in Table 9.1-5.

9.2.2.10 Tests and Inspections

Active components of the Component Cooling System are either in continuous or intermittent use during normal plant operation. Surveillance requirements for in service inspection and testing of components is in accordance with the Technical Specifications.

9.2.3 DEMINERALIZED WATER MAKE-UP SYSTEM

Make-up water required for the high purity water systems in the station is produced from three trains of fully automatic ion exchange demineralizers. A vacuum degasifier is also provided to remove any dissolved or evolved gases from the water. The plant is designed to produce a maximum of 650 gpm of demineralized water with two demineralizer trains in service. Water from wells on the station property is used as make-up to the demineralizer system. Two 500,000 gallon outdoor demineralized water storage tanks are provided. The demineralized water make-up system is shown in Figures 9.2-11A and B.

9.2.4 POTABLE WATER SYSTEMS

The potable water systems use a combination of deep ground water (sub-surface) wells as the supply source in sufficient capacity for all of the plant requirements which includes potable, process make-up, fire protection, and sanitary uses.

Three fresh water wells, located in the Mt. Laurel-Wenonah formation (approx. 300' deep) and one fresh water well, located in the upper Raritan formation (approx. 800' deep) supply through well pumps a total of 1000 gpm of fresh water to two 350,000-gallons of water are reserved for fire protection use, or the auxiliary feedwater system and the upper 50,000 gallons (hereafter referred to as "plant" water) are used for potable, sanitary, and process make-up purposes. The plant water is pumped from the storage tanks to the plant's process water equipment through an 8-inch main, and to all sanitary and potable water equipment through a 4-inch main by a constant pressure pumping system consisting of three automatically-operated pumps and one manual standby pump which maintain a constant 70 psig discharge pressure.

If, for some reason, the fresh water systems fail to operate, it will not affect any safety related equipment on a short term basis as each of the safety related systems store sufficient quantities of water to enable that system to perform its functions.

The following design criteria prevent any radioactivity source in the plant from contaminating the potable water system:

1. Each fresh water supply well is approximately 300 feet deep (or more) and has two impervious clay formations between the ground surface and the source of water supply. Also, the wells are double cased and cement grouted from the bottom of the gravel pack to grade which prevents seepage of surface waters. The source of water is thereby protected from any outside contamination.

2. The fresh water system does not enter any radioactive area nor does it supply any radioactive equipment, directly or indirectly.

3. The water supplies to potentially radioactive areas, such as the "hot" machine shop and the monitoring area, and the demineralizers, are protected from contamination by the use of backflow preventers, of the type approved by the New Jersey department of Health, on all such pipelines.

4. The water storage tanks are enclosed and are 250 feet from any potential radioactive building.

TABLE 9.2-1

SERVICE WATER SYSTEM FLOWS AND HEAT LOADS (PER UNIT)

	Mode of Operation					
	Start-up	Normal	Normal Shutdown	Blackout No Accident	Injection Phase	Recirculation Phase
No. of pumps required	4	4	3	2(4)	2(4)	3
Flow required for services, gpm						
Service Water Intake	2,736	1,486	777	768	1,720	2,280
Turbine Services	15,857	26,613	3,754	0	0	0
Nuclear Services	21,924(1)	13,798	21,570	16,885	12,450	30,600
Total Flow (5)	40,517	41,897	26,101	21,013	14,170	32,880
Estimated Heat Loads, Btu/hr x 10^6						
Turbine Services	71.7	117.85	17.34	14.28	0	0
Nuclear Services	123.18	58.92	279.26(3)	66.62	389.6	422.5
Total Estimated Heat Load	194.88	176.77	296.60	80.90	389.6	422.5

Notes:

(1) Remove one of two component cooling heat exchangers from service prior to feeding service water to second Turbine Auxiliaries Cooling System heat exchanger.

(3) First four hours following shutdown

(4) Assume only two diesel generators running

(5) At service water temperature of 85°F.

TABLE 9.2-2

COMPONENT COOLING SYSTEM CODE REQUIREMENTS

Component Cooling Heat Exchangers (Shell/Tube Type)	ASME Sect. VIII
Component Cooling Heat Exchangers (Plate Type)	ASME Sect. III Class 3
Component Cooling Surge Tank	ASME Sect. VIII
Component Cooling Loop Piping	ANSI B31.1.0*
Component Cooling Valves	ANSI B31.7**

*Used for design

**For piping not supplied by the NSSS supplier, material inspection, fabrication and quality control conform to ANSI B31.7. Where not possible to comply with ANSI B31.7, the requirements of ASME III-1971, which incorporated ANSI B31.7, were adhered to.

TABLE 9.2-3

COMPONENT COOLING SYSTEM
MINIMUM FLOW REQUIREMENTS - ONE UNIT
(GPM)

	Normal	Loss of Coolant Accident (Recirculation Phase)	Cooldown
Waste evap. distillate cooler	150	-	150
Boric Acid evap. distillate cooler	600	-	-
Residual heat exchangers	-	4,000	10,000
Reactor coolant pumps	780	-	780
Seal water heat exchanger	210	-	210
Sample heat exchangers (both units)	220 (max)	-	220 (max)
Letdown heat exchanger	1,000	-	300
Spent fuel pool heat exchanger	3,000	-	-*
Residual heat removal pumps	20	20	20
Safety injection pumps	40	40	40
Charging pump (Reciprocating)	100	-	100
Waste evap. condenser	600	-	600
Boric acid evap. condenser	1,240	-	-
Vent Condenser	56	-	-
Waste gas compressors	40	-	40
Excess letdown heat exchanger	230	-	-
TOTAL	8,286	4,060	12,460
Number of pumps required	2	1	3
Number of pumps in service	2	1	3
Number of pumps installed	3		

Pump capacity (ea) - 4,600 gpm
Pump head - 200 ft. TDH

*Based on refueling shutdown

TABLE 9.2-4 (Sheet 1 of 2)

COMPONENT COOLING SYSTEM
COMPONENT DESIGN DATA

Component Cooling Pumps

Quantity	3
Type	Horizontal Centrifugal
Rated capacity, gpm	4600
Rated head, ft H_2O	200
Design pressure, psig	150
Design temperature, °F	200
Available NPSH, ft	25
Material	Carbon steel

Component Cooling Heat Exchangers (Shell and Tube Type)

	Shell	Tube
Number		2
Design heat transfer, Btu/hr		44.2×10^6
Design pressure, psig	150	150
Design temperature, °F	200	200
Design flow rate, lb/hr	3.41×10^6	4.99×10^6
Design inlet temperature, °F	107.9	85
Design outlet temperature, °F	95	93.9
Fluid	Component cooling water	Service Water
*Material	Carbon steel	90-10 copper-nickel alloy for No. 21. Titanium for No. 22 and No. 11.

*At the conclusion of the Unit 2 third outage, all tube material will be titanium.

TABLE 9.2-4 (Sheet 2 of 2)

COMPONENT COOLING SYSTEM
COMPONENT DESIGN DATA

Component Cooling Heat Exchanger (Plate Type)

Number	1[a]	
Design Heat Transfer, BTU/hr	44.2×10^6	
	Component Cooling Water Side	Service Water Side
Design Pressure, psig	150	150
Design Temperature, °F	200	200
Design Flow Rate, lbs/hr	4.6×10^6	5.26×10^6
Design Inlet Temperature, °F	107.9	85
Design Outlet Temperature, °F	95	97
Material	Titanium	Titanium

Component Cooling Surge Tank

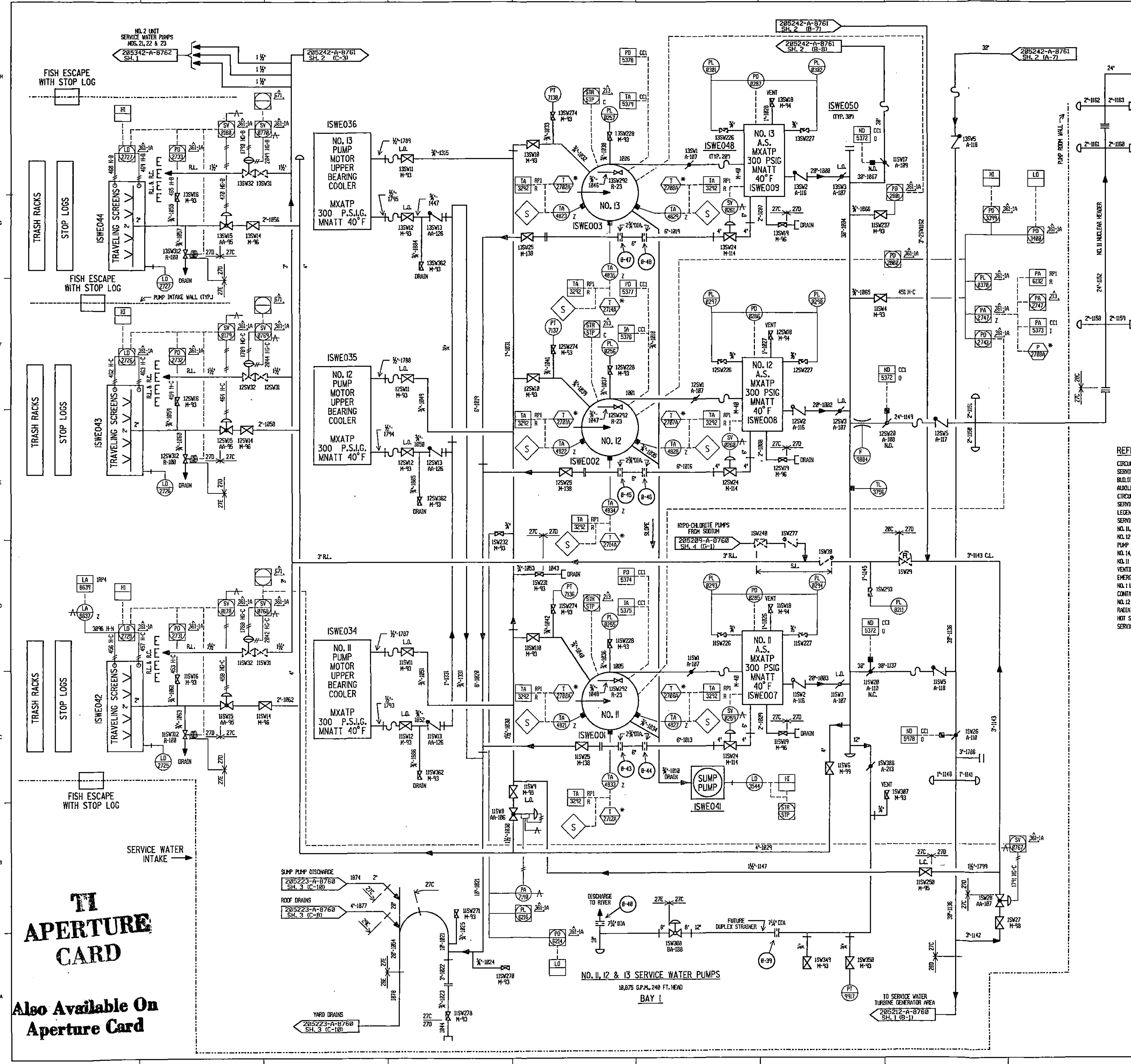
Number	1
Type	Horizontal, with divider plate
Design pressure: Internal, psig	100
External, psig	Vacuum breaker provided
Design temperature, °F	200
Normal Operating pressure, psig	Atmospheric
Total volume, gal	2000
Normal water volume, gal.	1000
Fluid	Component cooling water
Material	Carbon Steel

(a) Unit 1 has one shell and tube type and one plate type heat exchanger. Unit 2 has two shell and tube type heat exchangers.

TABLE 9.2-5

COMPONENT COOLING SYSTEM - MALFUNCTION ANALYSIS

	Component	Malfunction	Comments and Consequences
1.	Component cooling water pumps	Rupture of pump casing	The casing and shell are designed for 150 psi and 200°F which exceeds maximum operating conditions. Pump is inspectable and protected against credible missiles. Rupture is not considered credible.
2.	Component cooling water pumps	Pump fails to start	One operating pump will supply sufficient flow. Redundancy is sufficient to provide ample flow for any condition.
3.	Component cooling water pumps	Manual valve on a pump suction line closed	This will be prevented by prestartup and operational checks. Further, during normal operation, each pump will be checked on a periodic basis which would show that a valve was closed.
4.	Component cooling water pump	Stop valve on discharge line closed or check valve sticks closed	Stop valve will be checked open by prestartup and operational checks. The stop valve and the check valve will be checked by periodic operation of the pumps during normal operation.
5.	Component cooling heat exchanger	Tube or shell rupture	Rupture is considered incredible because of low operating pressures.
6.	Component cooling heat exchanger vent or drain valve	Left open	This will be prevented by prestartup and operational checks. During normal operation such a situation would be readily assessed by observation of level in the component cooling surge tank.



NOTES:

1. PIPING SCHEDULE DESIGNATIONS SHOWN ONLY FOR SEISMIC AND/OR NUCLEAR PIPING.
2. FOR DESIGN, PRESSURE & TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE & TEMPERATURE PARAMETERS AT THE ORIGINAL SOURCE HEADER.
3. ALL PIPING NUMBERS SHALL HAVE THE PREFIX "1SW" (I.E. 1SW1000, ETC.) EXCEPT WHERE OTHERWISE NOTED.
4. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051
5. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200. THE PIPING SCHEDULE AND GROUP NOS. ARE AS NOTED ON THIS DRAWING AND PREFIXED WITH "1S".
6. VALVE INSTALLED, NOT HOOKED UP TO PANEL.

DESIGN				
	CLASSIFICATION			
BOUNDARY *	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S27B	YES	I	III	YES
1S27C	YES	I	III	YES
1S27D	NO	III	NONE	NO
1S27E	NO	III	NONE	NO
1S28B	YES	I	III	YES
1S28C	YES	I	III	YES
1S28D	NO	III	NONE	NO
1S29	NO	III	NONE	NO
1S27A	YES	I	II	YES

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (I.E. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

REFERENCE DRAWINGS:

CIRCULATING WATER NUMBER 1 UNIT ____ 205209-A-8760
SERVICE WATER TURBINE AREA ____ 205212-A-8760
BUILDING & EQUIPMENT DRAINS CONVENTIONAL ____ 205223-A-8760
AUXILIARY FEED WATER ____ 205236-A-8760
CIRCULATING WATER NUMBER 2 UNIT ____ 205309-A-8762
SERVICE WATER NUMBER 2 UNIT ____ 205342-A-8763
LEGEND SHEET ____ 600658-A-8727
SERVICE WATER PUMPS ____ INSTR. SCH. __ 232309-B-9608-13
NO. 11, 12 & 13 TRAVELING SCREENS ____ INSTR. SCH. __ 223125-B-9556-15
NO. 12 HEADER NUCLEAR AREA (SERVICE WATER) ____ INSTR. SCH. __ 223129-B-9556-16
PUMP ROOMS VENTILATION ____ INSTR. SCH. __ 207500-B-9491-13
NO. 14, 15 & 16 TRAVELING SCREENS ____ INSTR. SCH. __ 223126-B-9556-14
NO. 11 HEADER NUCLEAR AREA (SERVICE WATER) ____ INSTR. SCH. __ 211232-B-9508-15
VENTILATION & AIR CONDITIONING CHILLED WATER ____ INSTR. SCH. __ 226931-B-9581-21
EMERGENCY CONTROL AIR COMPRESSOR ____ INSTR. SCH. __ 211322-B-9508-12
NO. 1 UNIT RADIATION MONITORING LIQUID EFFLUENT DISCHARGES ____ INSTR. SCH. __ 239078-B-9639-2
CONTAINMENT VENTILATION ____ INSTR. SCH. __ 211293-B-9507-12
NO. 12 HEADER NUCLEAR AREA ____ INSTR. SCH. __ 600682-B-9478-0
RADIATION MONITORING SYSTEM CABINETS 110,109,75,113,114,120 ____ ARRANGT. __ 233048-A-1399
HOT SHUTDOWN STATION PNL. 213 ____ ARRANGT. __ 219456-A-8933
SERVICE WATER SCREEN WASH CONTROL PNL. 361-1A ____ ARRANGT. __ 211782-A-8870

205242-A-8761 SHEET 1 ____ NO. 11, 12, & 13 SERVICE WATER PUMPS
SHEET 2 ____ NO. 14, 15, & 16 SERVICE WATER PUMPS
SHEET 3 ____ NO. 11 RHR PUMP ROOM COOLER
SHEET 3 ____ NO. 12 SAFETY INJECTION PUMP LUBE OIL COOLER
SHEET 3 ____ NO. 12 CHARGING PUMP LUBE & GEAR OIL COOLERS
SHEET 3 ____ NO. 12 CHARGING PUMP ROOM COOLER
SHEET 3 ____ NO. 11 CONTAINMENT SPRAY PUMP ROOM COOLER
SHEET 3 ____ NO. 11 COMPONENT COOLING PUMP ROOM COOLER
SHEET 3 ____ NO. 11 AUXILIARY FEED WATER PUMP ROOM COOLER
SHEET 3 ____ NO. 11 COMPONENT COOLING HEAT EXCHANGER
SHEET 3 ____ NO. 1A, 1B, & 1C DIESEL GEN. JACKET & LUBE OIL COOLERS
SHEET 4 ____ NO. 12 COMPONENT COOLING HEAT EXCHANGER
SHEET 4 ____ NO. 12 COMPONENT COOLING PUMP ROOM COOLER
SHEET 4 ____ NO. 12 RHR PUMP ROOM COOLER
SHEET 4 ____ NO. 11 CHARGING PUMP LUBE & GEAR OIL COOLERS
SHEET 4 ____ NO. 11 CHARGING PUMP ROOM COOLERS
SHEET 4 ____ NO. 11 SAFETY INJECTION PUMP LUBE OIL COOLER
SHEET 4 ____ NO. 1 SAFETY INJECTION PUMP ROOM COOLER
SHEET 4 ____ NO. 12 CONTAINMENT SPRAY PUMP ROOM COOLER
SHEET 4 ____ NO. 13 CHARGING PUMP ROOM COOLER
SHEET 5 ____ NO. 1A & 1B STEAM GEN. BLOW DOWN HEAT EXCHANGERS
SHEET 5 ____ NO. 11, 12, & 13 CHILLER CONDENSERS
SHEET 5 ____ NO. 1 EMERGENCY CONTROL AIR COMPRESSOR INTER, CYL, AND AFTER COOLERS
SHEET 6 ____ NO. 11, 12, 13, 14, & 15 CONTAINMENT FAN COIL UNIT

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Ref. Dwg. 205242-A-8761-36

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Service Water System - Nuclear Area
Unit 1

Updated FSAR Sheet 1 of 6
Fig 9.2-1A

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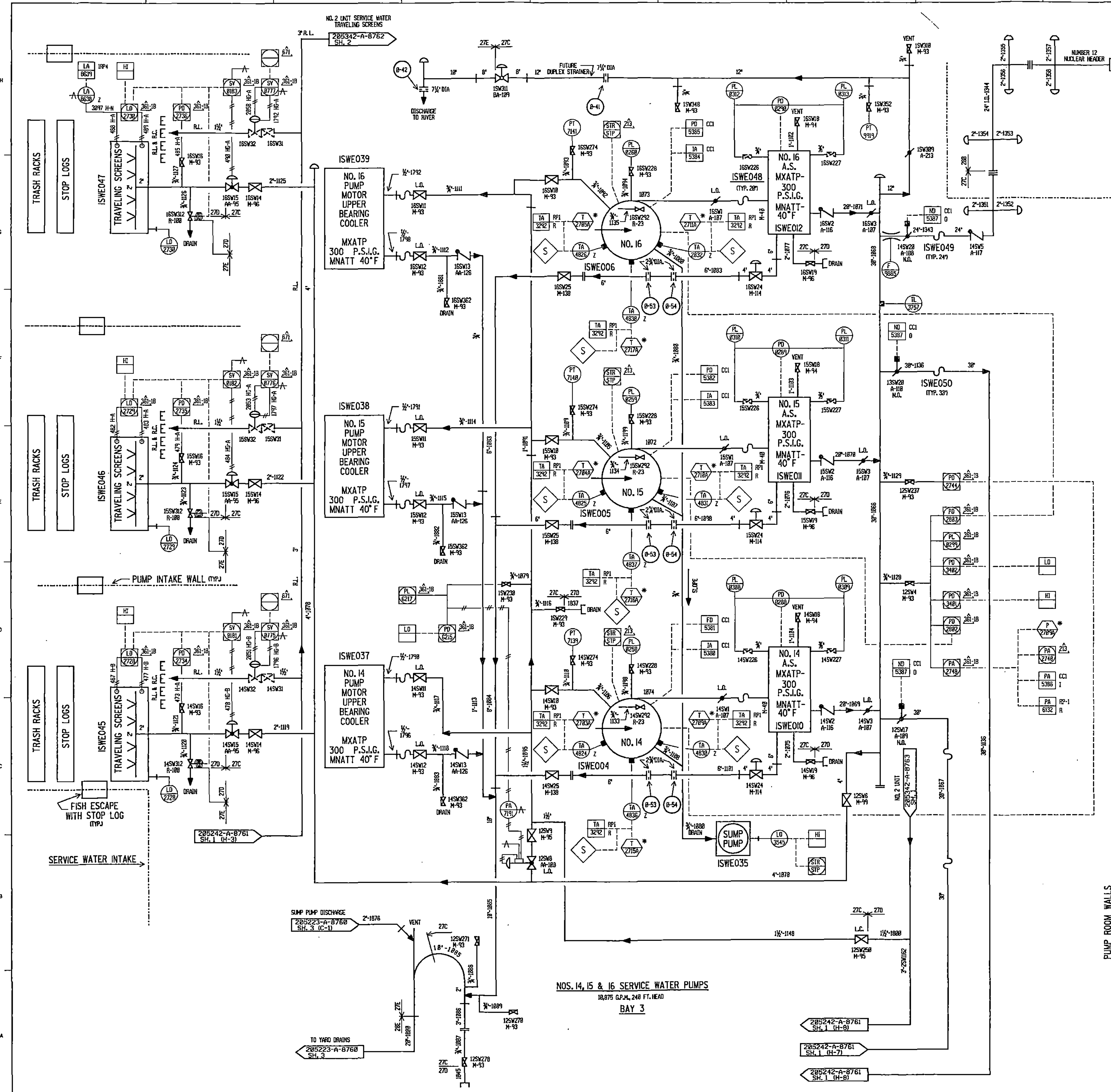

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Service Water System - Nuclear Area
Unit 1

Updated FSAR Sheet 2 of 6
Fig 9.2-1A

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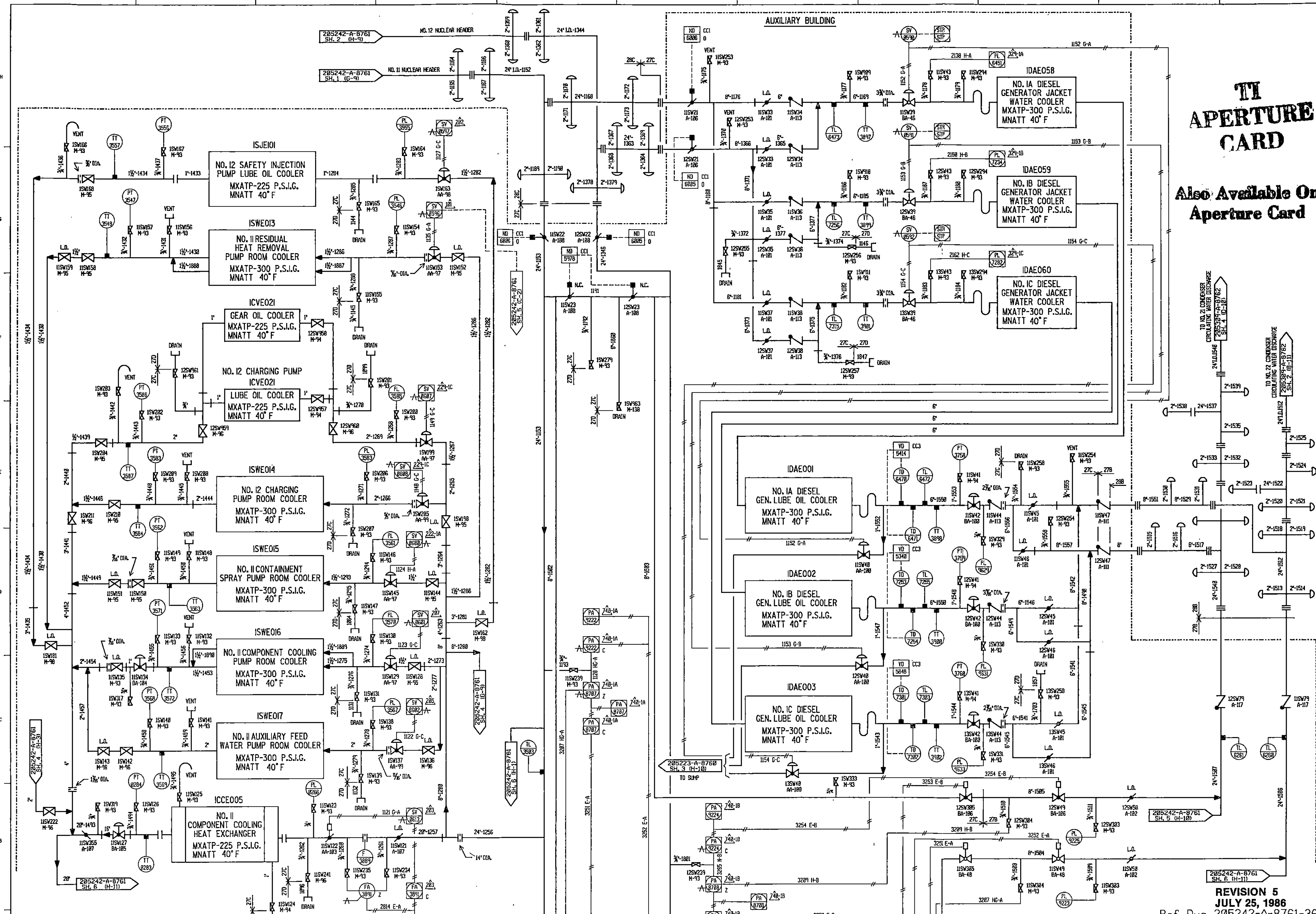

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Service Water System - Nuclear Area
Unit 1

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Fig 9.2-1A

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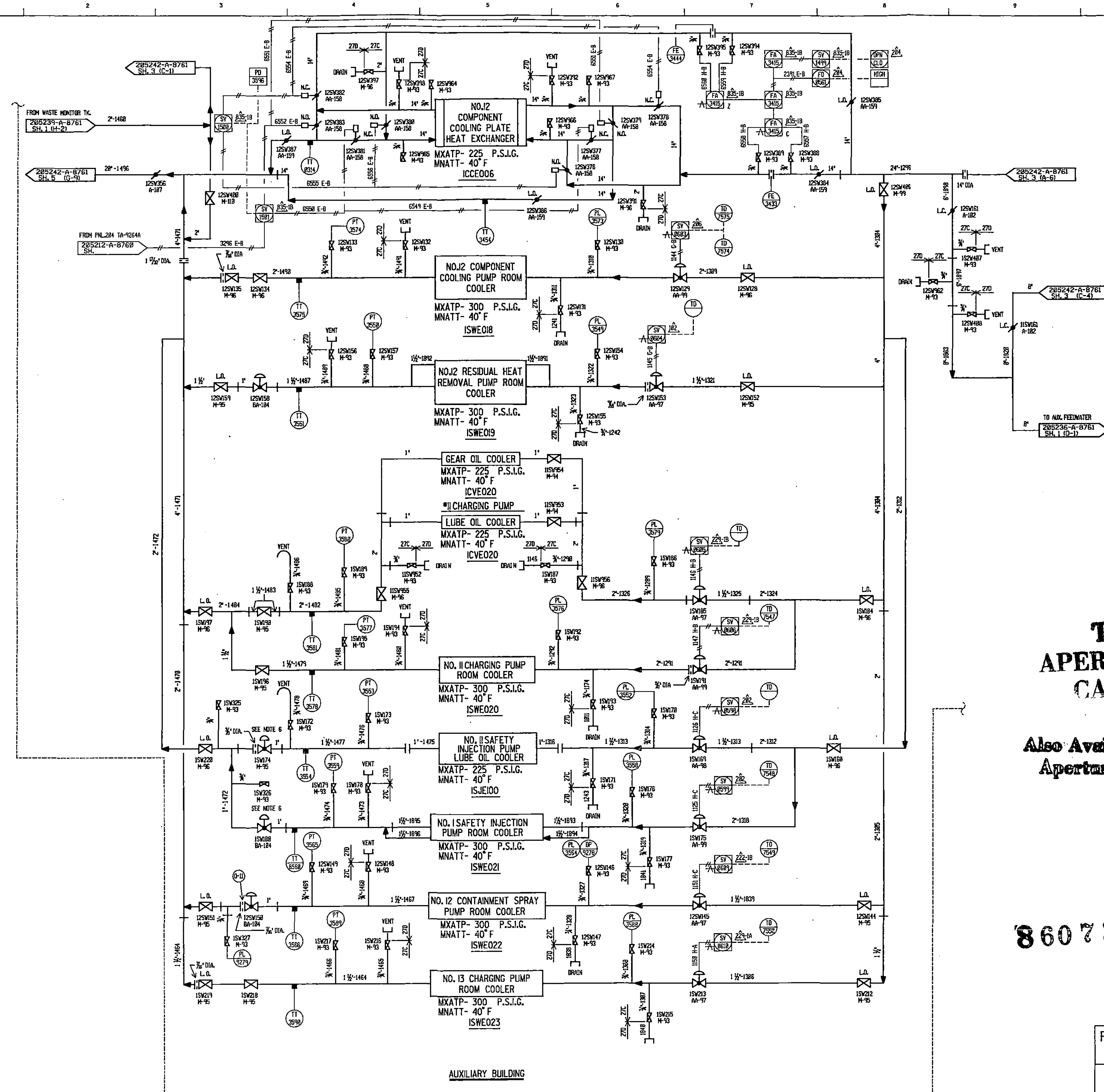

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Service Water System - Nuclear Area
Unit 1

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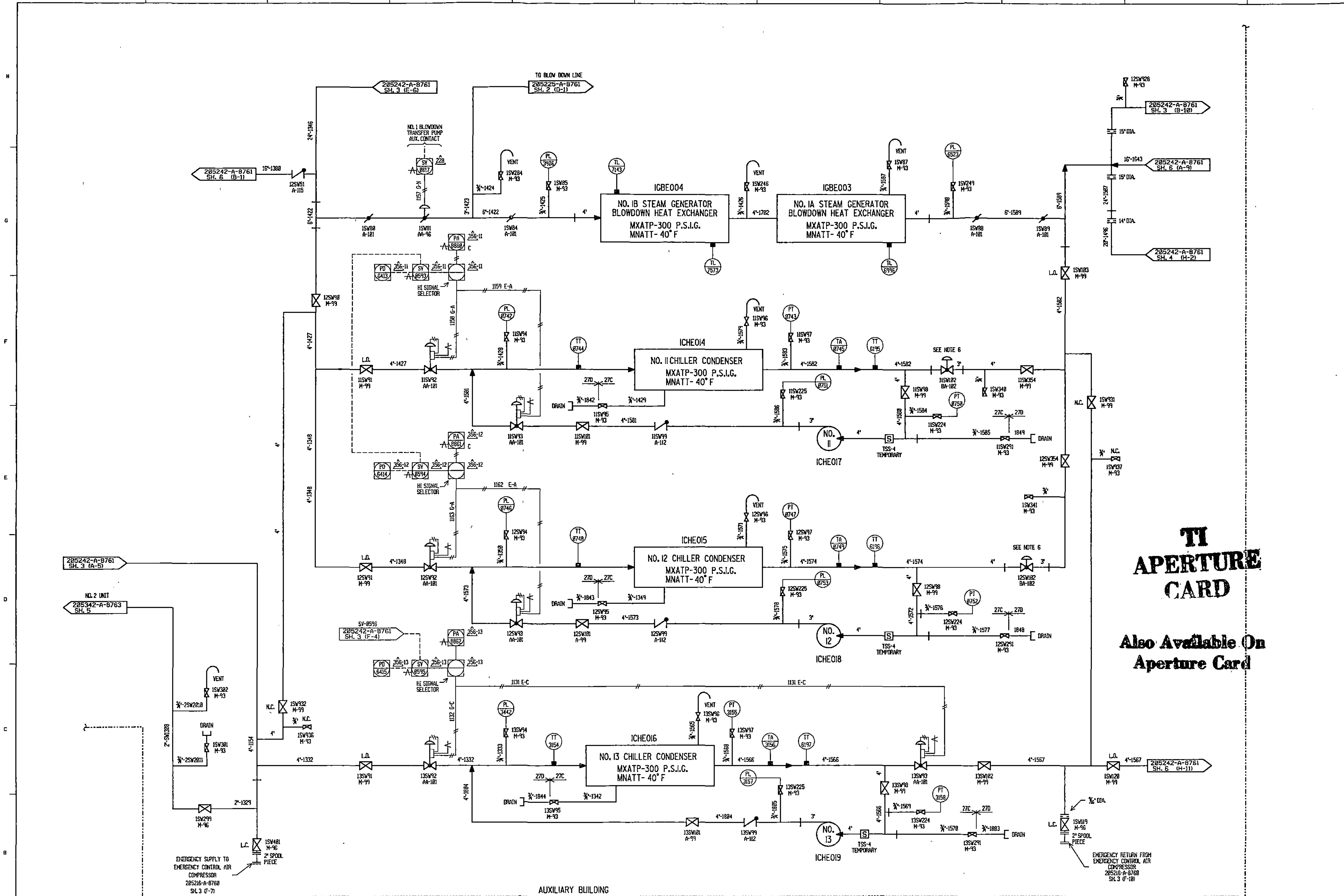
Fig 9.2-1A



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Service Water System - Nuclear Area
Unit 1

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Fig 9.2-1A

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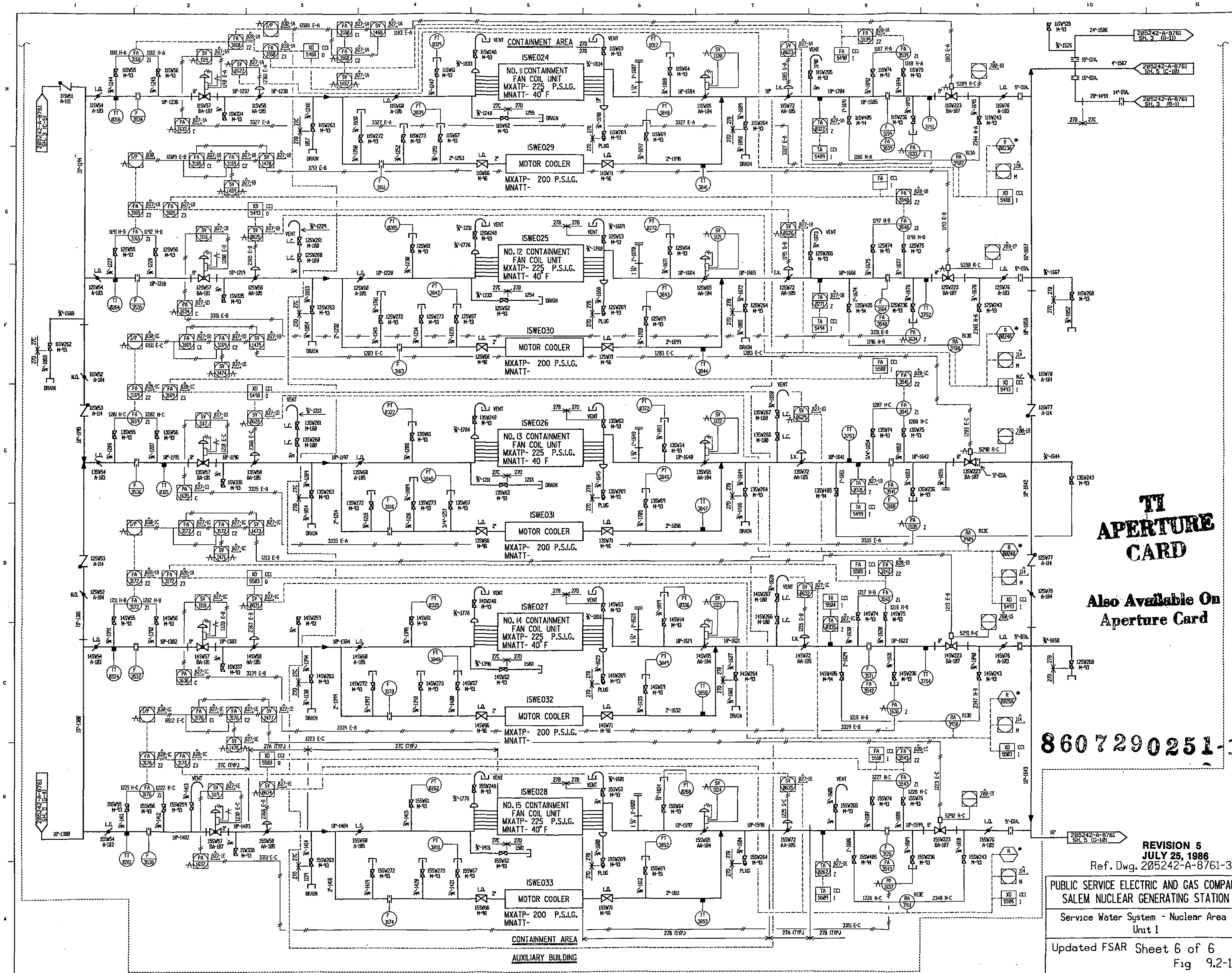

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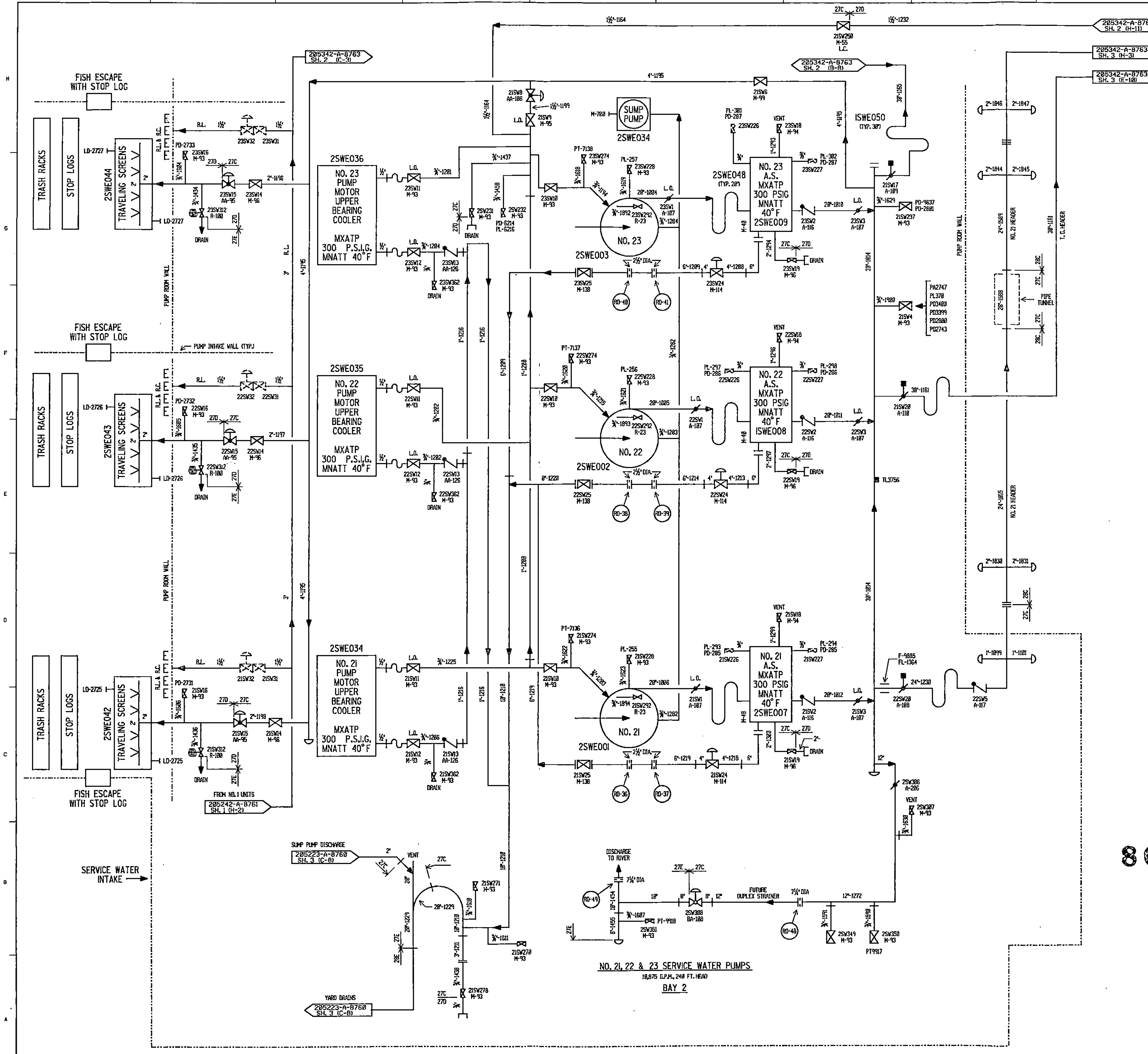
SALEM NUCLEAR GENERATING STATION

Service Water System - Nuclear Area
Unit 1

Updated FSAR Sheet 6 of 6
Fig 9.2-1A



NOTES:

1. ALL PIPING NUMBERS SHALL HAVE THE PREFIX "2SW" (I.E. 2SW1000, ETC.) EXCEPT WHERE OTHERWISE NOTED.
2. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A920-MFD-051
3. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200. THE PIPING SCHEDULE AND GROUP NO'S ARE 1S27 & 1S28 EXCEPT AS OTHERWISE NOTED.

DESIGN				
BOUNDARY *	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S27B	YES	I	III	YES
1S27C	YES	I	III	YES
1S27D	NO	III	NONE	NO
1S27E	NO	III	NONE	NO
1S28B	YES	I	III	YES
1S28C	YES	I	III	YES
1S28D	NO	III	NONE	NO
1S29	NO	III	NONE	NO
1S27A	YES	I	II	YES

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX '1S' (I.E. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

REFERENCE DRAWINGS:

VALVE LIST ______ 206766L
STEAM GENERATOR DRAINS & BLOWDOWN ______ 205325-A-8763
RECIRCULATING WATER NUMBER ______ 205309-A-8762
SERVICE WATER TURBINE AREA ______ 205312-A-8762
WASTE DISPOSAL LIQUID ______ 205339-A-8763
AUXILIARY FEED WATER ______ 205336-A-8763
SERVICE WATER NUCLEAR (NO. 1 UNIT) ______ 205242-A-8761
SERVICE WATER NUMBER 1 UNIT ______ 205212-A-8760
LEGEND SHEET ______ 600658-A-8727

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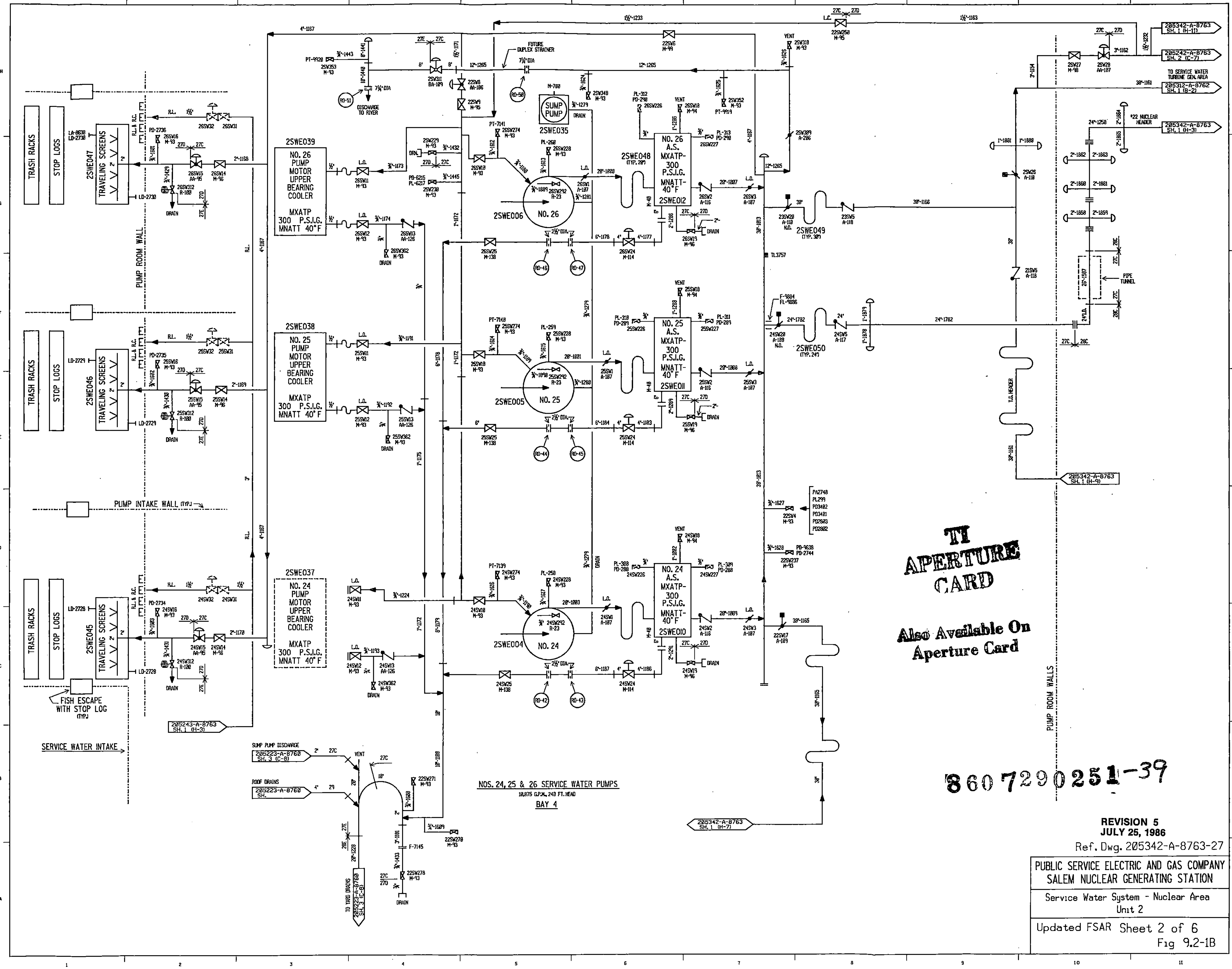
SALEM NUCLEAR GENERATING STATION

Service Water System - Nuclear Area
Unit 2

Updated FSAR Sheet 1 of 6
Fig 9.2-1B



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Service Water System - Nuclear Area
Unit 2

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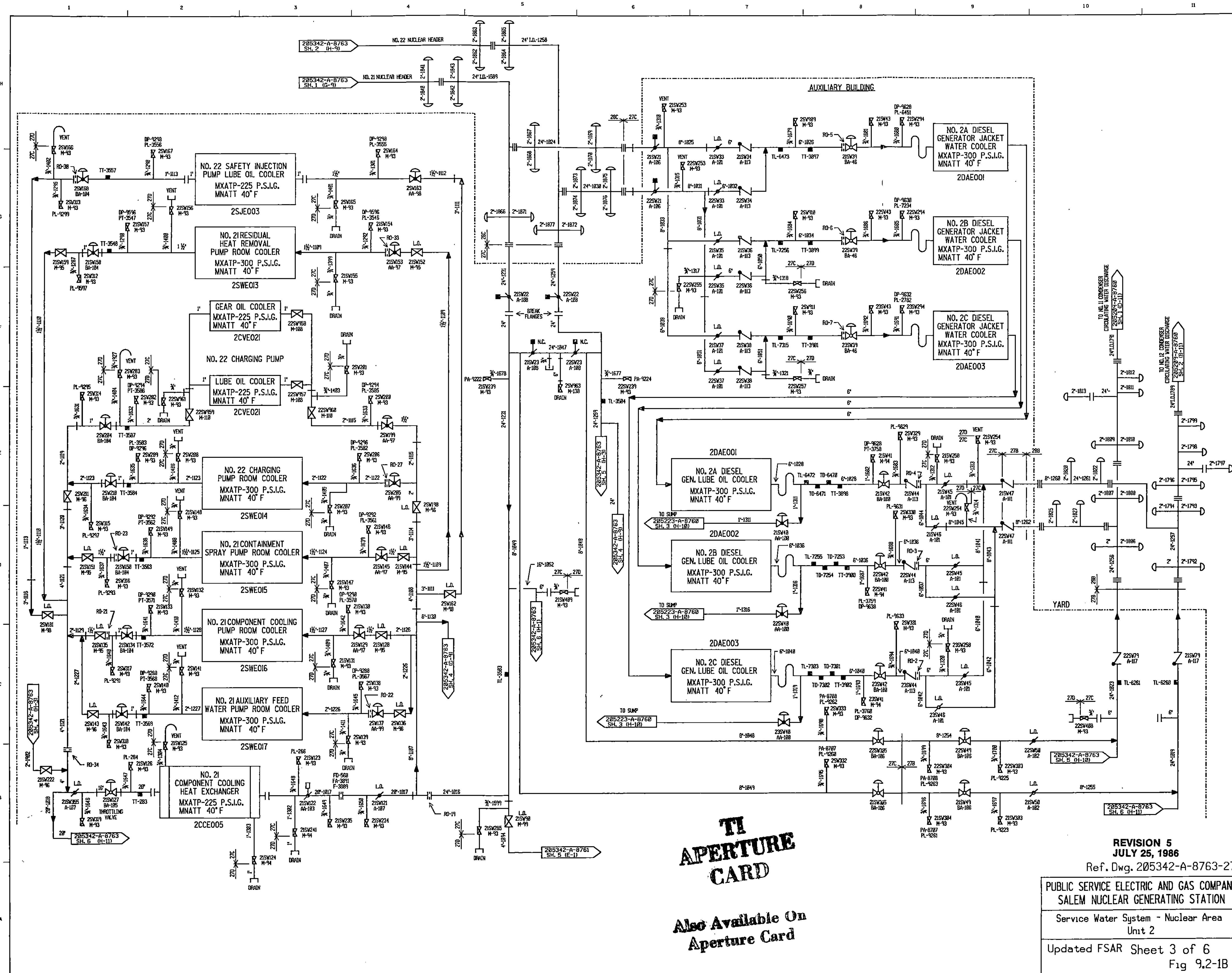
Fig 9.2-1B



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Service Water System - Nuclear Area
Unit 2

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Fig 9.2-1B

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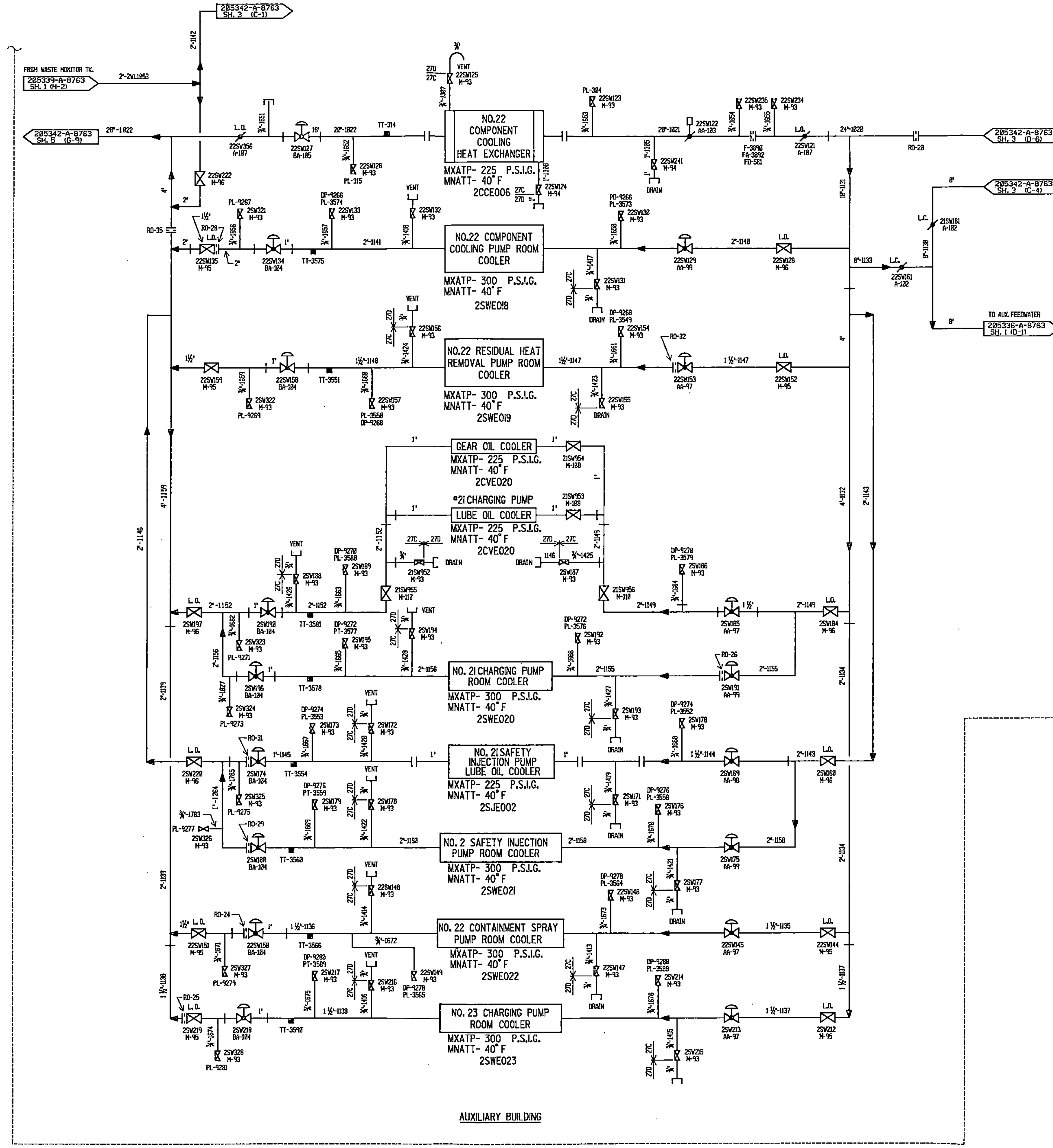

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SALEM NUCLEAR GENERATING STATION

Service Water System - Nuclear Area
Unit 2

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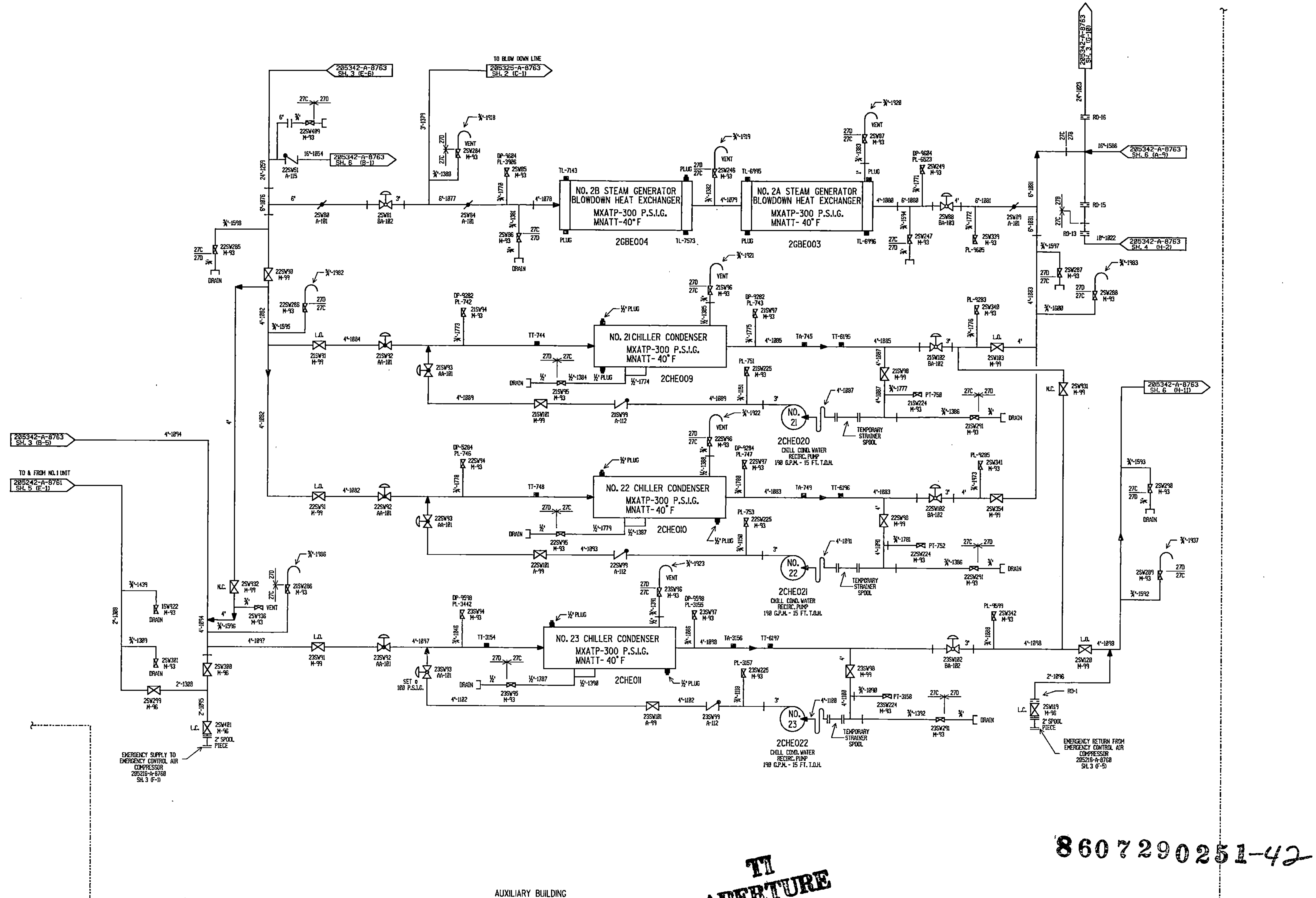
Fig 9.2-1B



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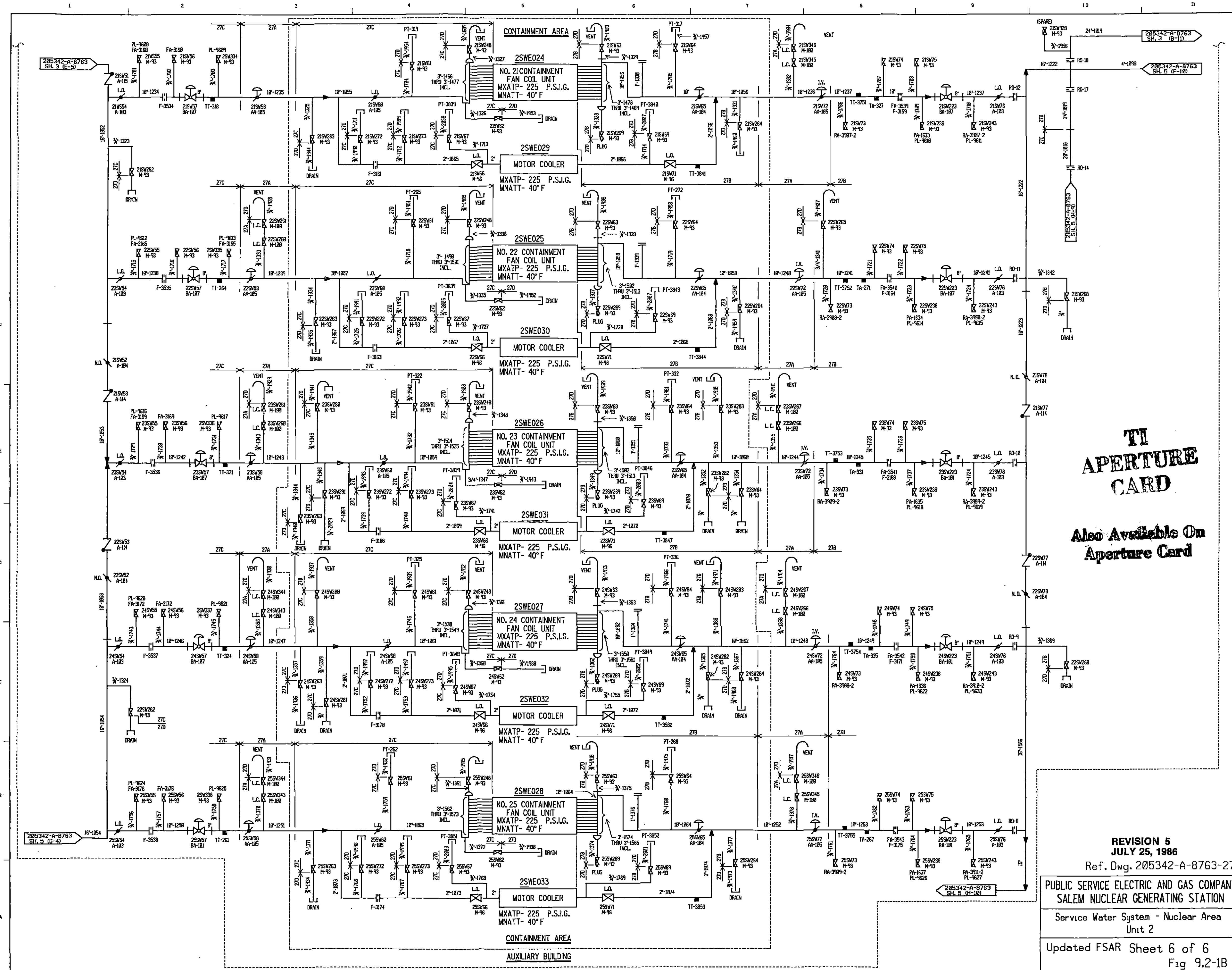
SALEM NUCLEAR GENERATING STATION

Service Water System - Nuclear Area
Unit 2

Updated FSAR Sheet 5 of 6
Fig 9.2-1B



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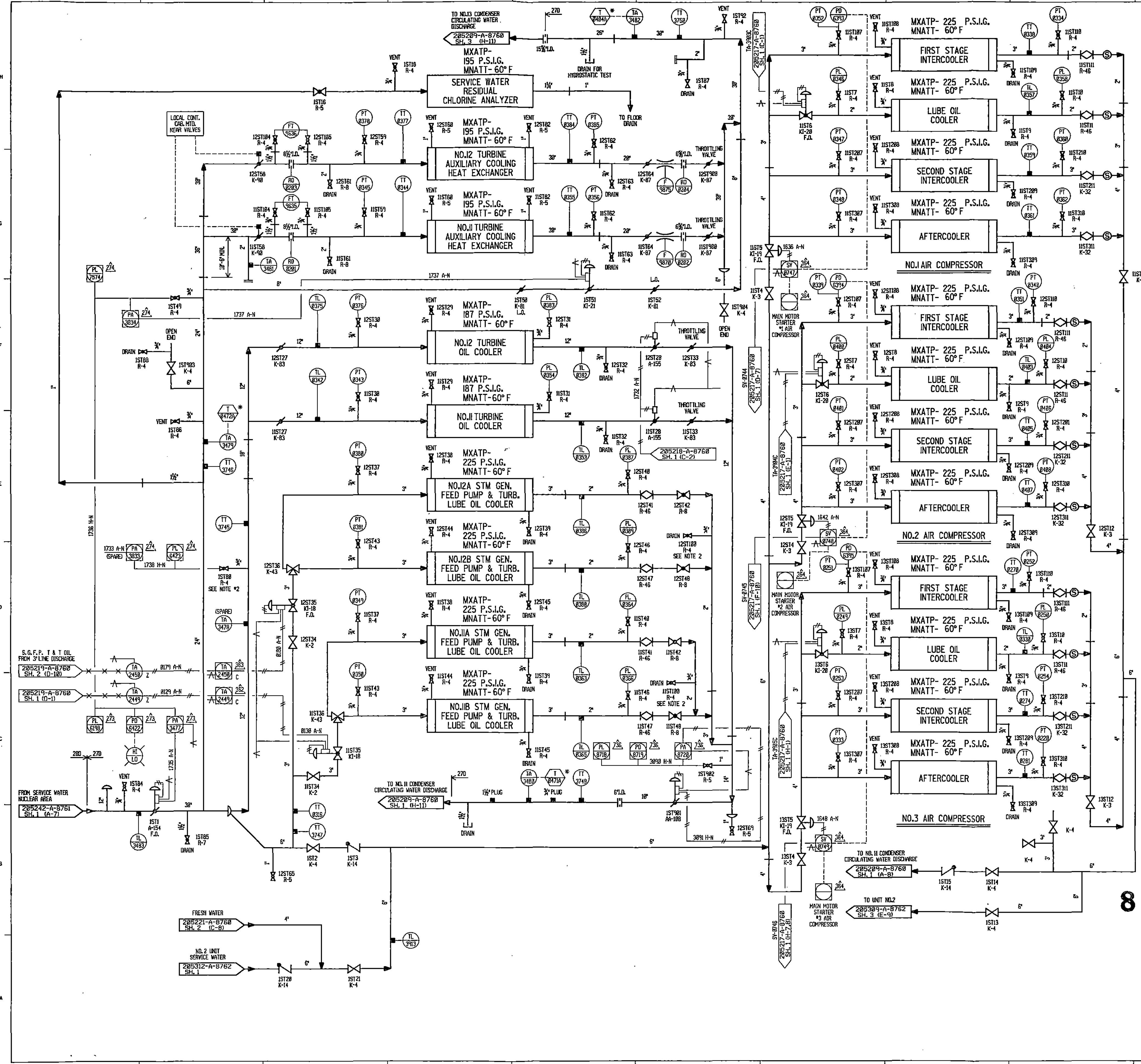
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Service Water System - Nuclear Area
Unit 2

Updated FSAR Sheet 6 of 6
Fig 9.2-1B

8607290251-43



TI APERTURE CARD

Also Available On Aperture Card

REFERENCE DRAWINGS

VALVE LIST		206766-L
CIRCULATING WATER PIPING DIAGRAM		205209-A-8760
SERVICE WATER NUCLEAR AREA PIPING DIAGRAM		205242-A-8760
SERVICE WATER TURBINE AREA PIPING DIAGRAM (#2 UNIT)		205312-A-8760
NO. 1 UNIT GENERATOR LUBE OIL & TURBINE TRIP	INSTR. SCH.	226947-B-9581-12
NO. 1 UNIT NO. 11 STM. GEN. FEED PUMP, TURBINE LUBE & CONTROL OIL	INSTR. SCH.	207525-B-9491-18
NO. 1 UNIT NO. 12 STM. GEN. FEED PUMP, TURBINE LUBE & CONTROL OIL	INSTR. SCH.	207538-B-9492-15
STATION AIR COMPRESSORS AND CONTROL AIR DRYERS	INSTR. SCH.	211319-B-9508-11
LEGEND SHEET		600658-A-8727

INSTRUMENT SCHEMATIC	211291-B-9507-8
INSTRUMENT PANEL 274	232321-B-9608
INSTRUMENT PANEL 273	232320-B-9608
INSTRUMENT PANEL 736	207509-B-9491
INSTRUMENT PANEL 364	205396-A-8772

NOTES:

1. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
2. NOT PRESENTLY INSTALLED.

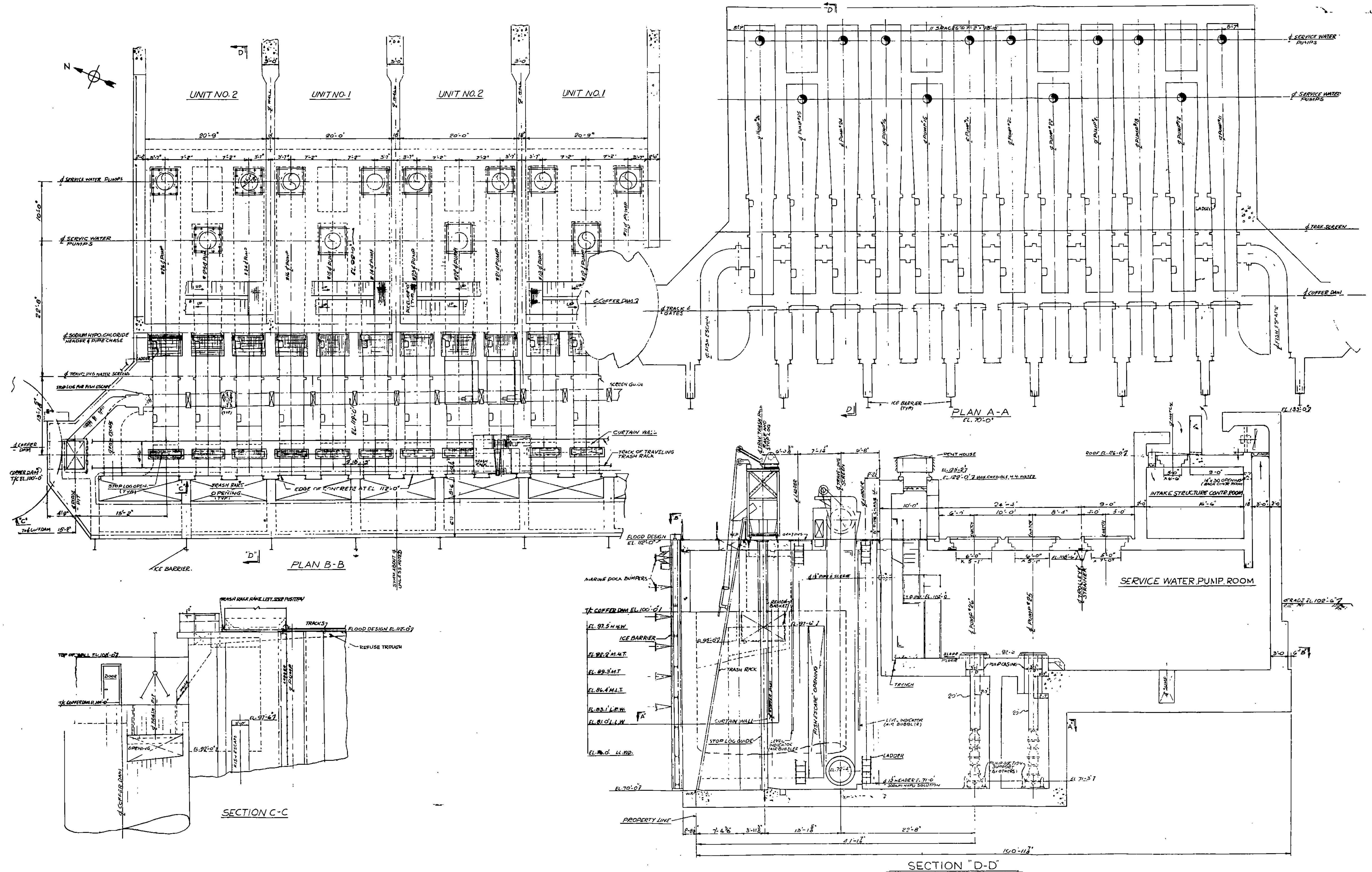
8607290251-44

REVISION 5
JULY 25, 1986
Ref. Dwg. 205212-A-8760-20

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Service Water System - Turbine Area
Unit 1

Updated FSAR Sheet 1 of 1
Fig 9.2-2



Revision 0
July 22, 1982

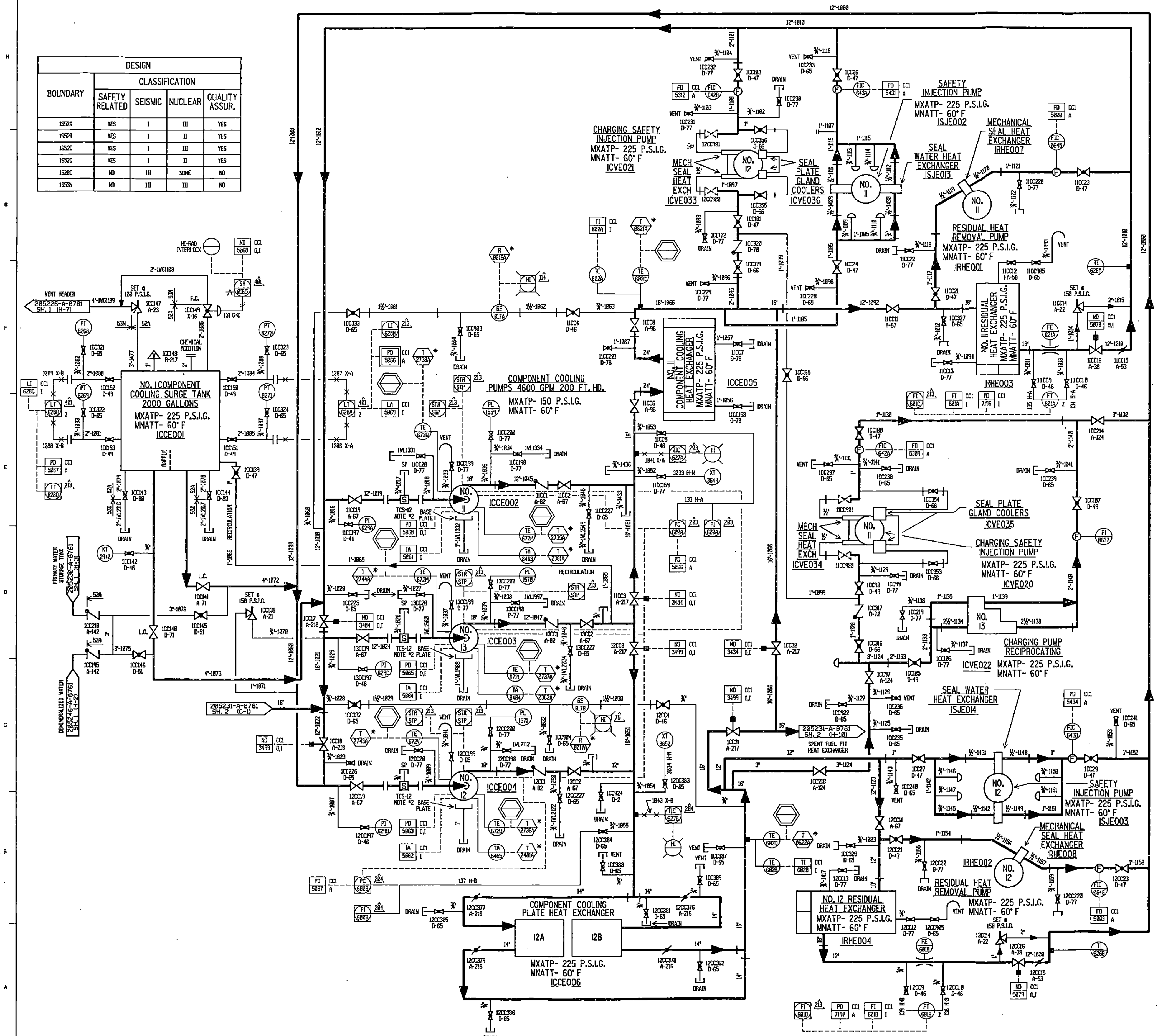
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Service Water Intake

Updated FSAR

Figure 9.2-3

DESIGN				
BOUNDARY	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S52A	YES	I	III	YES
1S52B	YES	I	II	YES
1S52C	YES	I	III	YES
1S52D	YES	I	II	YES
1S20C	NO	III	NONE	NO
1S53N	NO	III	III	NO



TI APERTURE CARD

Also Available On Aperture Card

NOTES

1. THESE VALVES TO BE LOCATED OUTSIDE RADIATION SHIELD.
2. TEMPORARY STRAINER TO BE PLACED IN SPOOL PIECE DURING INITIAL FLUSHING OPERATION. STRAINER MUST BE REMOVED BEFORE PLANT START UP.
3. IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX '1S' (I.E. 1S44A, ETC.) UNLESS OTHERWISE NOTED.
4. ALL PIPING SPECIFICATIONS 52A UNLESS OTHERWISE NOTED.
5. ALL VALVES SHOWN WITH CAPS OR HOSE CONNECTIONS SHALL HAVE PIPE SPEC. END AT VALVE - i.e. 52A
6. FOR PRESSURE AND TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE AND TEMPATURE PARAMETES AT THE ORIGINATING SOURCE HEADER.
7. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX '1CC' (i.e. 1CC1000 ETC.) EXCEPT WHERE OTHERWISE NOTED.
8. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051

REFERENCE DRAWINGS

VALVE LIST		206766-L
REACTOR COOLANT DIAGRAM		205201-A-8761
CVC OPERATION DIAGRAM		205228-A-8761
CVC PRIMARY WATER RECOVERY DIAGRAM		205230-A-8761
RESIDUAL HEAT REMOVAL DIAGRAM		205232-A-8761
SPENT FUEL COOLING DIAGRAM		205233-A-8761
WASTE DISPOSAL - LIQUID DIAGRAM		205239-A-8761
WASTE DISPOSAL - GAS DIAGRAM		205240-A-8761
SAMPLING - DIAGRAM		205244-A-8761
DEMINERALIZED WATER-RESTRICTED AREAS DIAGRAM		205246-A-8761
NO. 1 UNIT LIQUID RADWASTE EVAPORATOR	INSTR.SCH.	246878-B-9719-0
NO. 1 UNIT, COMP. COOL'G. SH.1	INSTR.SCH.	207516-B-9491-16
NO. 1 UNIT, COMP. COOL'G. SH.2	INSTR.SCH.	207537-B-9492-9
SPENT FUEL PIT HX OUT FLOW IND. PNL. 201	ARRGT.	205699-A-8939
NO. 11 COMP. COOL'G WATER HT. EXCH. PNL. 203	ARRGT.	211789-A-8870
NO. 12 COMP. COOL'G WATER HT. EXCH. PNL. 204	ARRGT.	205402-A-8939
LETDOWN HT. EXCH. CONTROL PNL. 210	ARRGT.	218994-A-8920
HOT SHUTDOWN STATION PNL. 213	ARRGT.	219456-A-8933
COMP. COOL'G SURGE TANK PNL. 401	ARRGT.	231162-AB-3686
WASTE EVAP. CONDENSER PNL. 315	ARRGT.	205581-AB-3592
BORIC ACID EVAP. COND PNL. 313	ARRGT.	205580-AB-3592
R.C. PUMP LETDOWN FLOW PNL. 311	ARRGT.	205690-A-8939
NO. 11 RCP. SEAL D/P INJ. FLOW PNL. 237	ARRGT.	205691-A-8939
NO. 12 RCP. SEAL D/P INJ. FLOW PNL. 232	ARRGT.	205399-A-8772
NO. 13 RCP. SEAL D/P INJ. FLOW PNL. 241	ARRGT.	233036-A-1399
NO. 14 RCP. SEAL D/P INJ. FLOW PNL. 240	ARRGT.	205692-A-8939
RCP. BRG. COOLANT & THER. BAR. PNL. 220	ARRGT.	226964-A-1290
LEGEND SHEET		600658-A-8727

205231-A-8761 SH. 1	NO. 1 COMPONENT COOLING SURGE TANK, NO. 11, 12, 13 COMPONENT COOLING HEAT EXCHANGER, NO. 11, 12, 13 CHARGING SAFETY INJECTION PUMPS, NO. 11, 12 SAFETY INJECTION PUMP, NO. 13 CHARGING PUMP RECIPROCATING, NO. 11, 12 RESIDUAL HEAT EXCHANGER, NO. 11, 12 RESIDUAL HEAT REMOVAL PUMP
205231-A-8761 SH. 2	SPENT FUEL PIT HEAT EXCHANGER. BORIC ACID EVAPORATOR, DISTILLER, AND VENT CONDITIONERS. CONDITIONING VENT GAS COOLERS, LET DOWN HEAT EXCHANGER, SEAL WATER HEAT EXCHANGE, NO. 11 AND NO. 12 WASTE GAS COMPRESSOR HEAT EXCHANGER. STEAM SAMPLE HEAT EXCHANGERS, STEAM GENERATORS.
205231-A-8761 SH. 3	EXCESS LET DOWN HEAT EXCHANGER. NO. 11, 12, 13 & 14 REACTOR COOLANT PUMPS.

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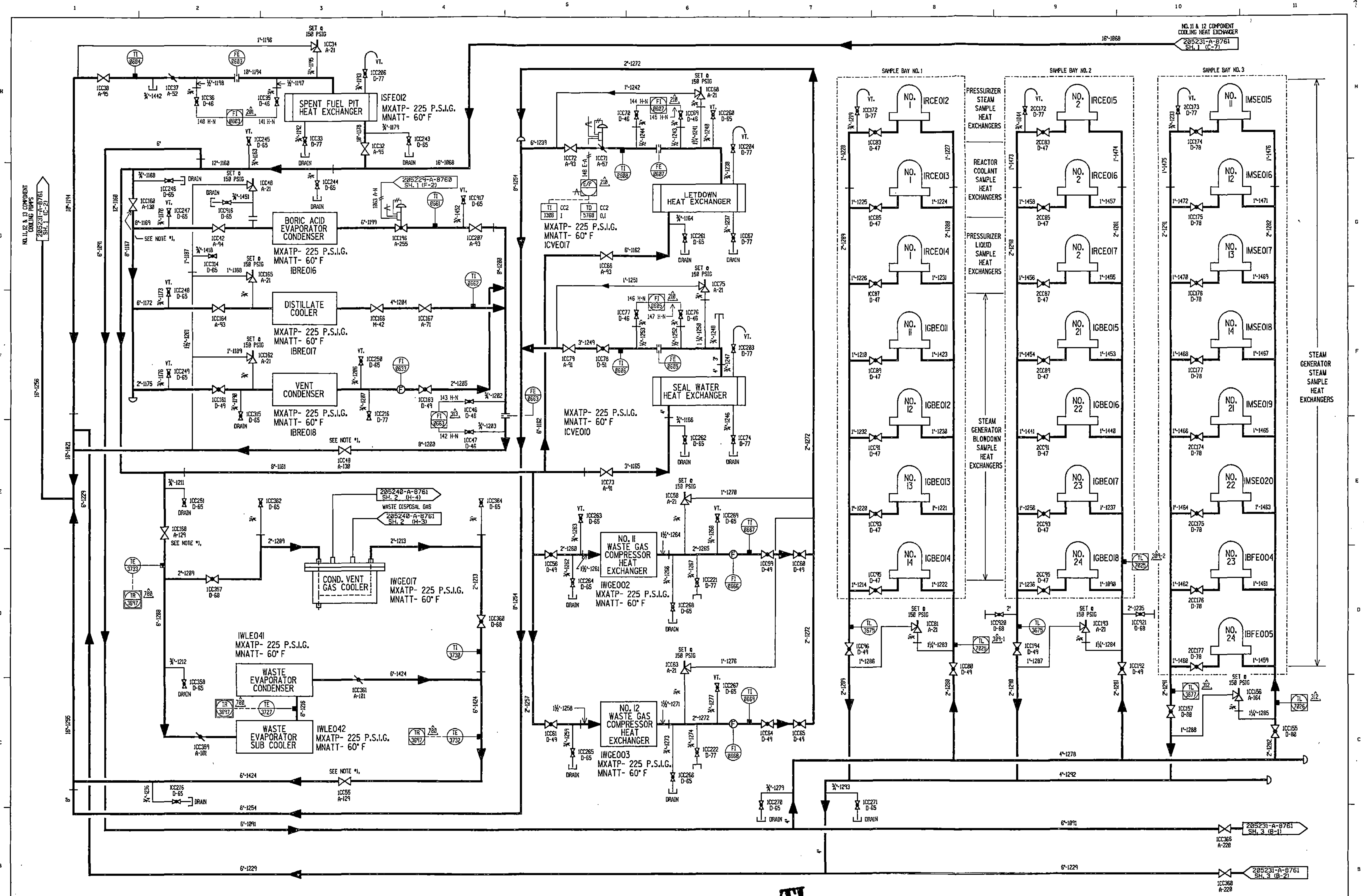
Ref. Dwg. 205231-A-8761-30

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Component Cooling System
Unit 1

Updated FSAR Sheet 1 of 3
Fig 9.2-4A

8607290251-45



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Also Available On Aperture Card

8607290251-46

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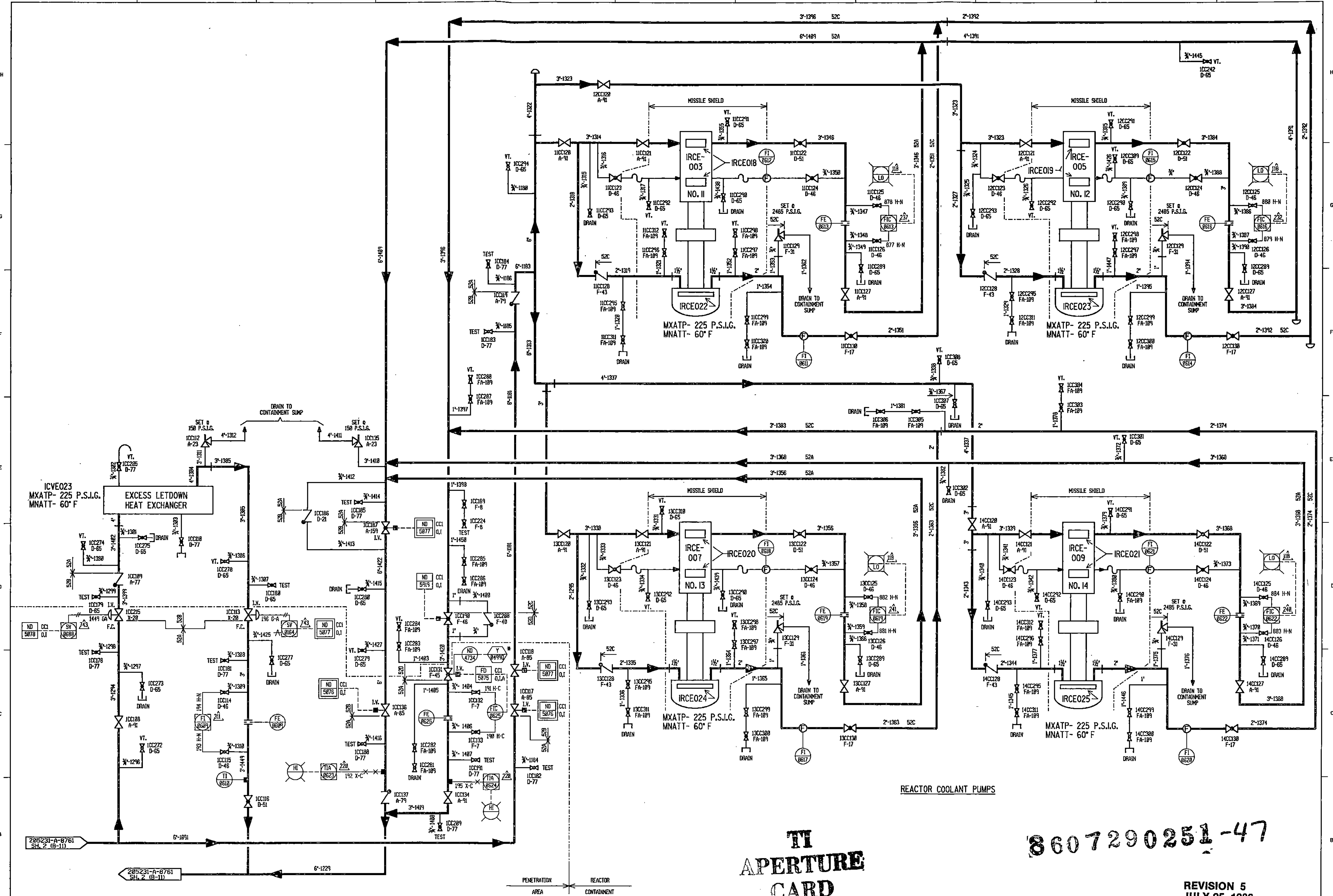
Ref. Dwg. 205231-A-8761-30

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Component Cooling System
Unit 1

Updated FSAR Sheet 2 of 3
Fig 9.2-4A



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Also Available On Aperture Card

8607290251-47

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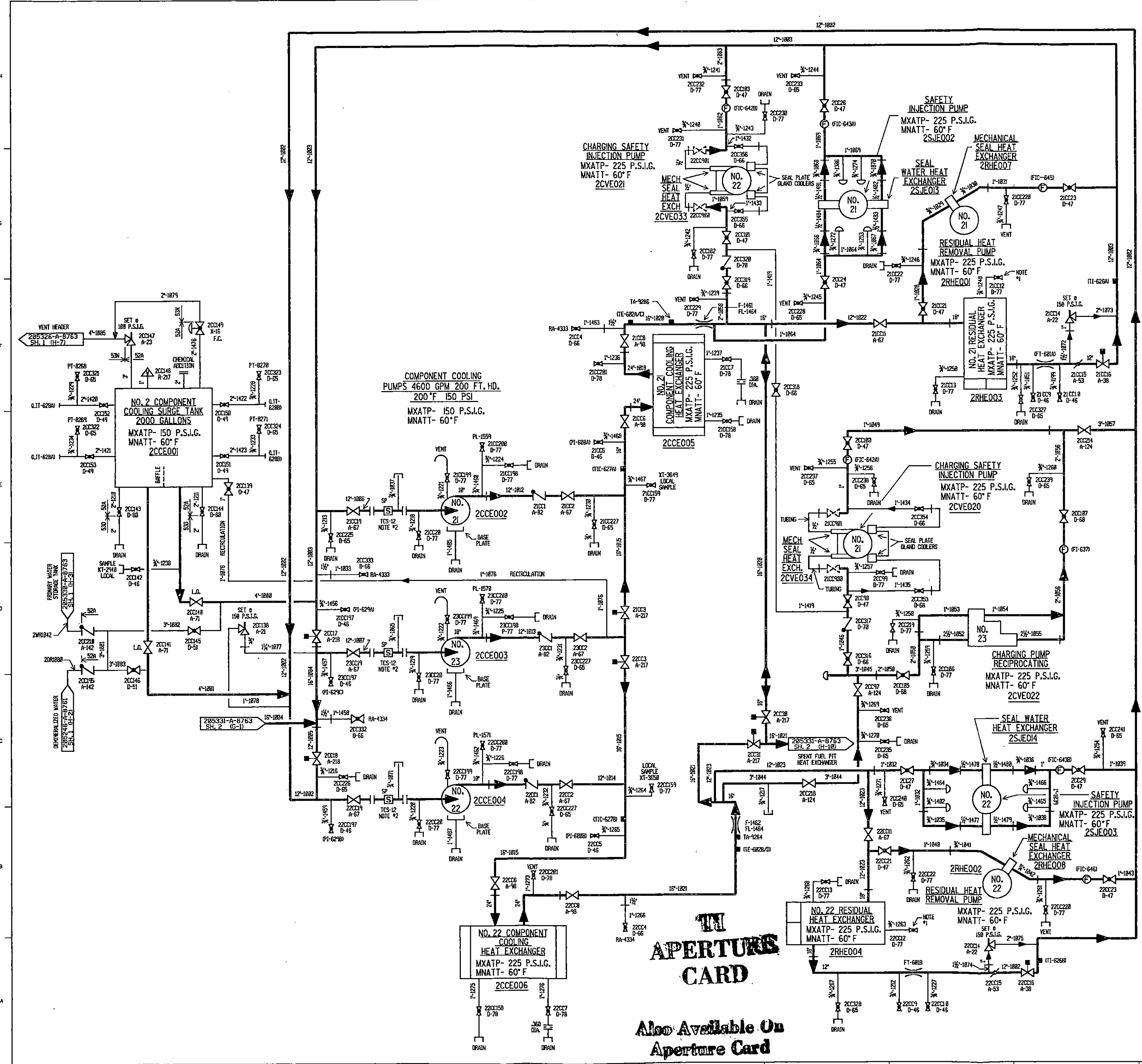
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Component Cooling System
Unit 1

Updated FSAR Sheet 3 of 3
Fig 9.2-4A



DESIGN				
BOUNDARY (NOTE #3)	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S52A	YES	I	III	YES
1S52B	YES	I	II	YES
1S52C	YES	I	III	YES
1S52D	YES	I	II	YES
1S20C	NO	III	NONE	NO
1S53N	NO	III	III	NO

NOTES

1. THESE VALVES TO BE LOCATED OUTSIDE RADIATION SHIELD.
2. TEMPORARY STRAINER TO BE PLACED IN SPOOL PIECE DURING INITIAL FLUSHING OPERATION. STRAINER MUST BE REMOVED BEFORE PLANT START UP.
3. IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (I.E. 1S44A, ETC.) UNLESS OTHERWISE NOTED.
4. ALL PIPING SPECIFICATIONS 52A UNLESS OTHERWISE NOTED.
5. ALL VALVES SHOWN WITH CAPS OR HOSE CONNECTIONS SHALL HAVE PIPE SPEC. END AT VALVE - i.e. 52A
6. FOR PRESSURE AND TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE AND TEMPATURE PARAMETES AT THE ORIGINATING SOURCE HEADER.
7. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2CC" (i.e. 2CC1000 ETC.) EXCEPT WHERE OTHERWISE NOTED.
8. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051

REFERENCE DRAWINGS

VALVE LIST ______ 206766-L
REACTOR COOLANT DIAGRAM ______ 205301-A-8763
CVC OPERATION DIAGRAM ______ 205328-A-8763
CVC PRIMARY WATER RECOVERY DIAGRAM ______ 205330-A-8763
RESIDUAL HEAT REMOVAL DIAGRAM ______ 205332-A-8763
SPENT FUEL COOLING DIAGRAM ______ 205333-A-8763
WASTE DISPOSAL - LIQUID DIAGRAM ______ 205339-A-8763
WASTE DISPOSAL - GAS DIAGRAM ______ 205340-A-8763
SAMPLING - DIAGRAM ______ 205344-A-8763
DEMINERALIZED WATER-RESTRICTED AREAS DIAGRAM ______ 205246-A-8761
INSTRUMENT SCHEMATIC "POST-LOCA SAMPLING SYSTEM" ______ 207510-B-9491
LEGEND SHEET ______ 600658-A-8727

205331-A-8763 SH. 1 ______ NO. 2 COMPONENT COOLING SURGE TANK, NO. 21, 22, 23 COMPONENT COOLING HEAT EXCHANGER, NO. 21, 22, 23 CHARGING SAFETY INJECTION PUMPS, NO. 21, 22 SAFETY INJECTION PUMP, NO. 23 CHARGING PUMP RECIPROCATING, NO. 21, 22 RESIDUAL HEAT EXCHANGER, NO. 21, 22 RESIDUAL HEAT REMOVAL PUMP

205331-A-8763 SH. 2 ______ SPENT FUEL PIT HEAT EXCHANGER, BORIC ACID EVAPORATOR, DISTILLER, AND VENT CONDITIONERS. CONDITIONING VENT GAS COOLERS, LET DOWN HEAT EXCHANGER, SEAL WATER HEAT EXCHANGE, NO. 21 AND NO. 22 WASTE GAS COMPRESSOR HEAT EXCHANGER. STEAM SAMPLE HEAT EXCHANGERS, STEAM GENERATORS.

205331-A-8763 SH. 3 ______ EXCESS LET DOWN HEAT EXCHANGER, NO. 21, 22, 23 & 24 REACTOR COOLANT PUMPS.

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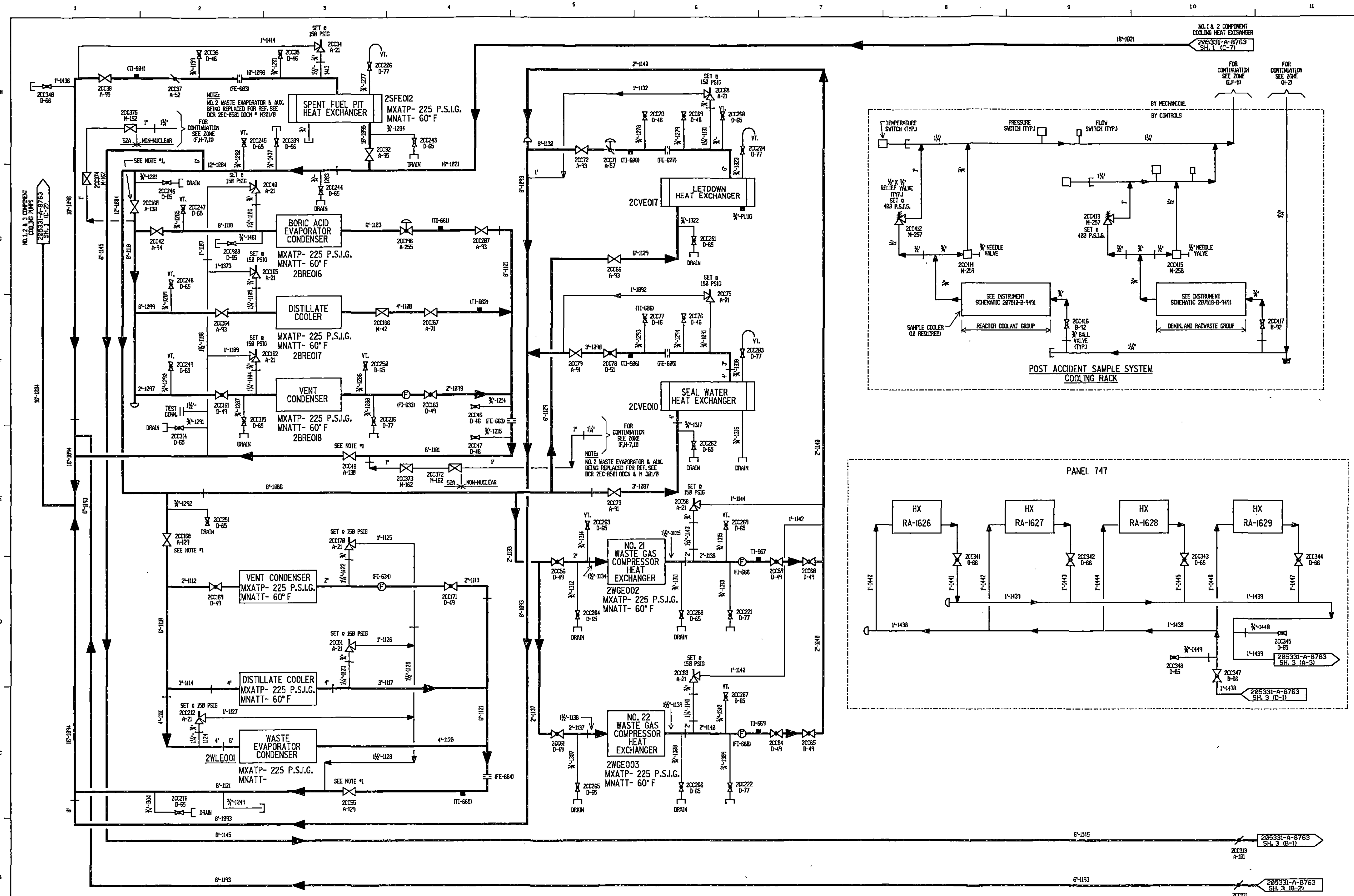
Ref. Dwg. 205331-A-8763-25

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Component Cooling System
Unit 2

Updated FSAR Sheet 1 of 3
Fig 9.2-4B

8607290251-48



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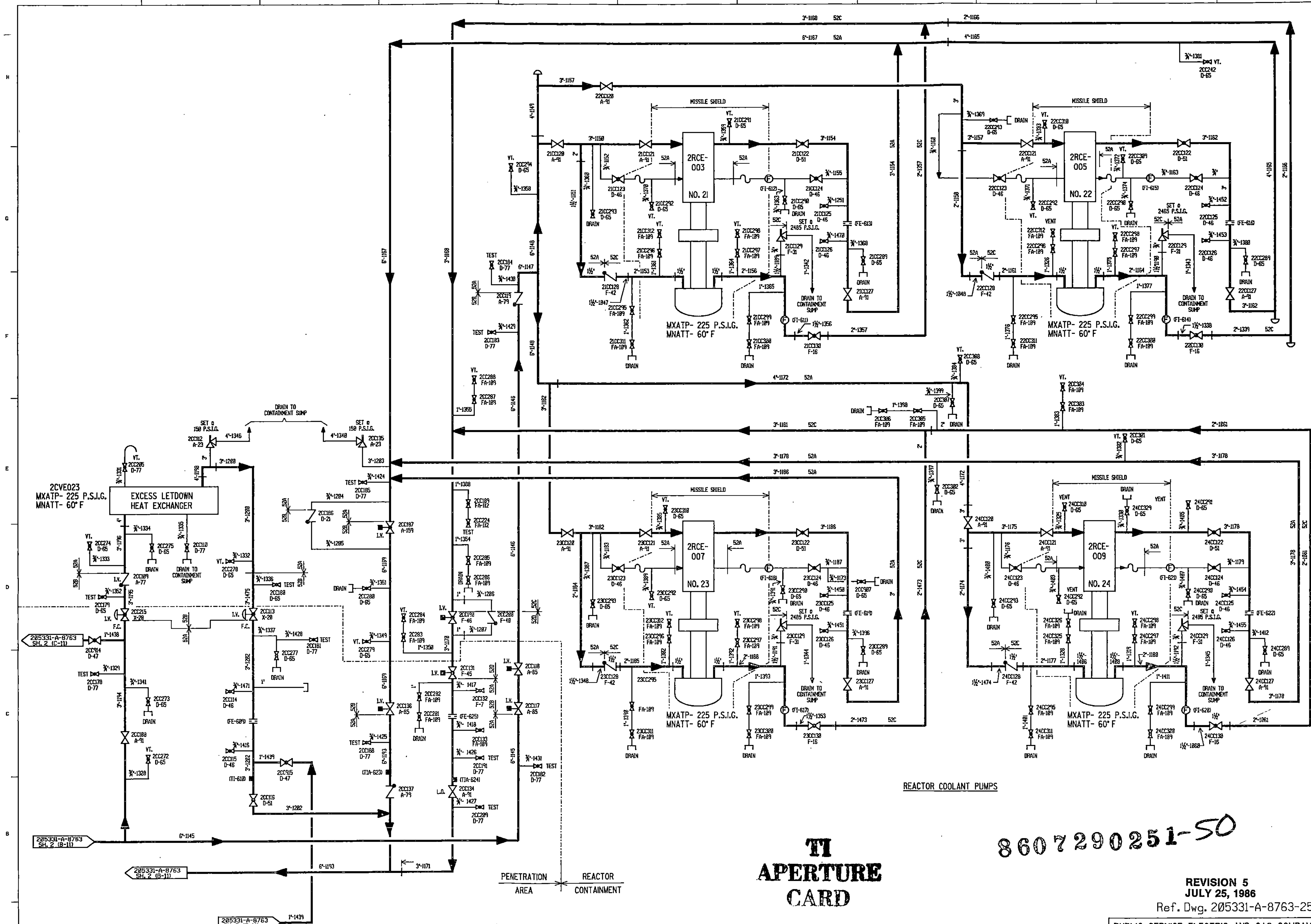
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Component Cooling System
Unit 2

Updated FSAR Sheet 2 of 3
Fig 9.2-4B

Also Available On Aperture Card



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CARD

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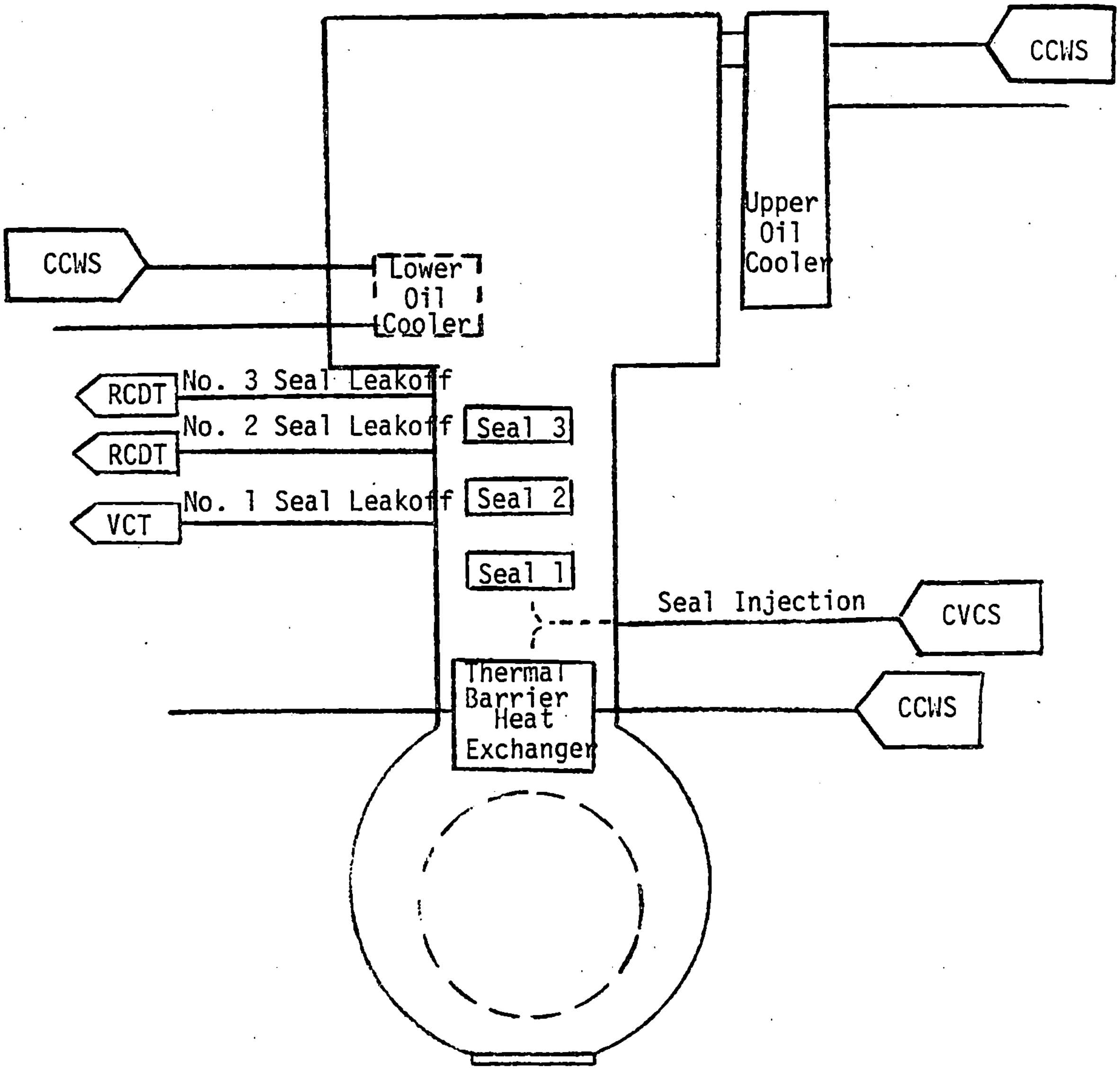
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

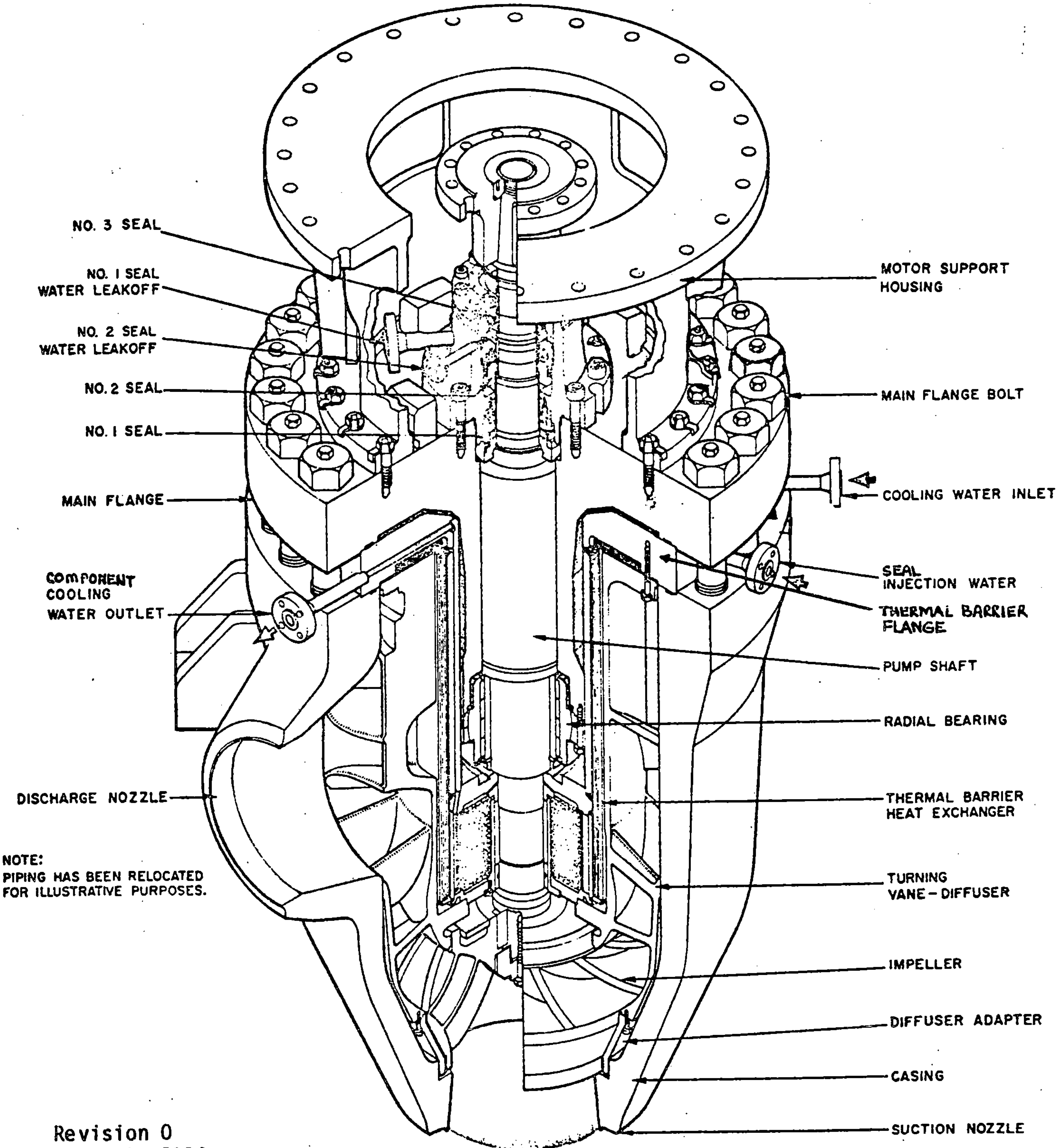
Component Cooling System
Unit 2

Updated FSAR Sheet 3 of 3
Fig 9.2-4B



Revision 0
July 22, 1982

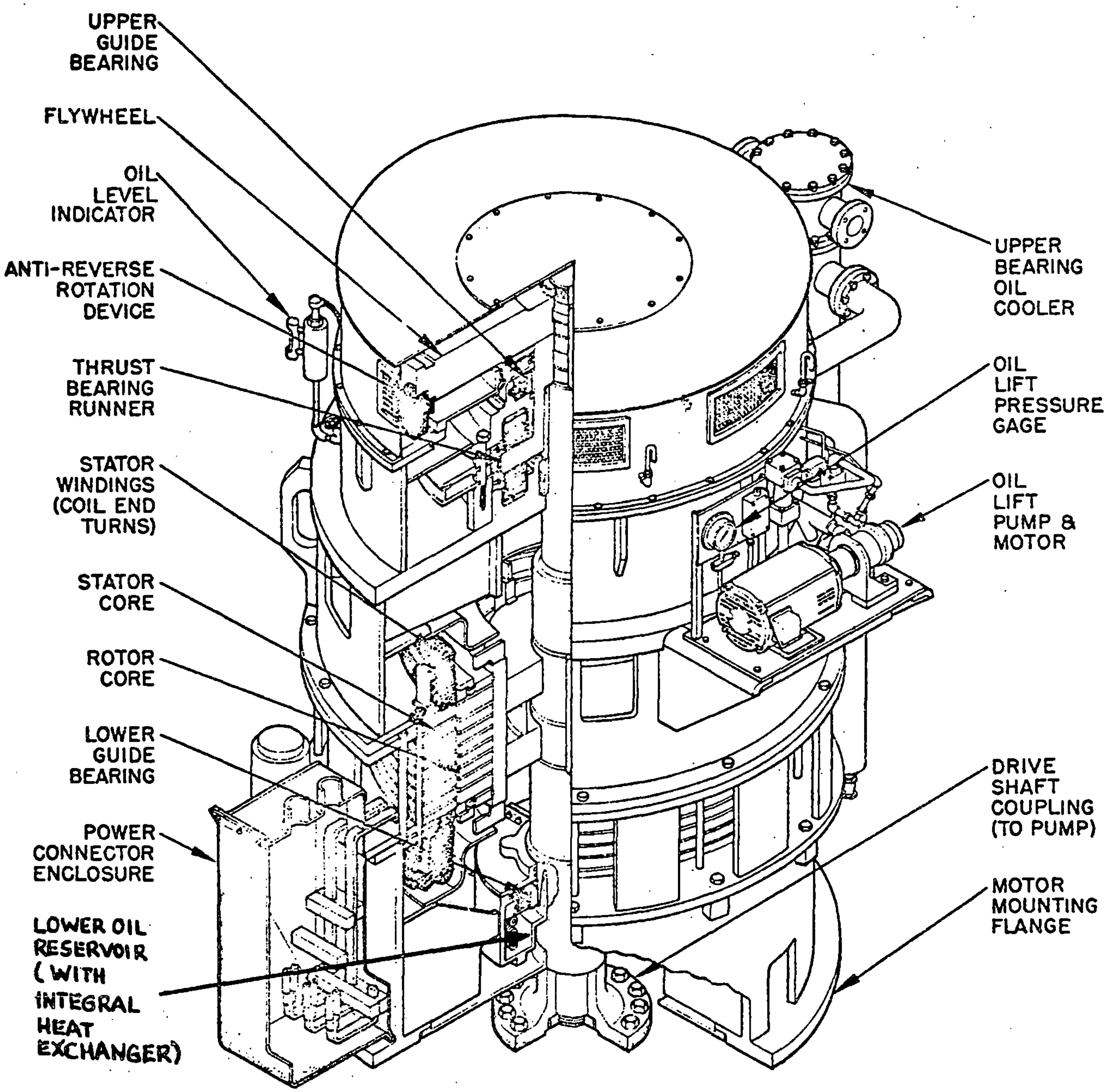
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	**RCP Cooling Supplies** Updated FSAR — **Figure 9.2-5**



NOTE:
PIPING HAS BEEN RELOCATED FOR ILLUSTRATIVE PURPOSES.

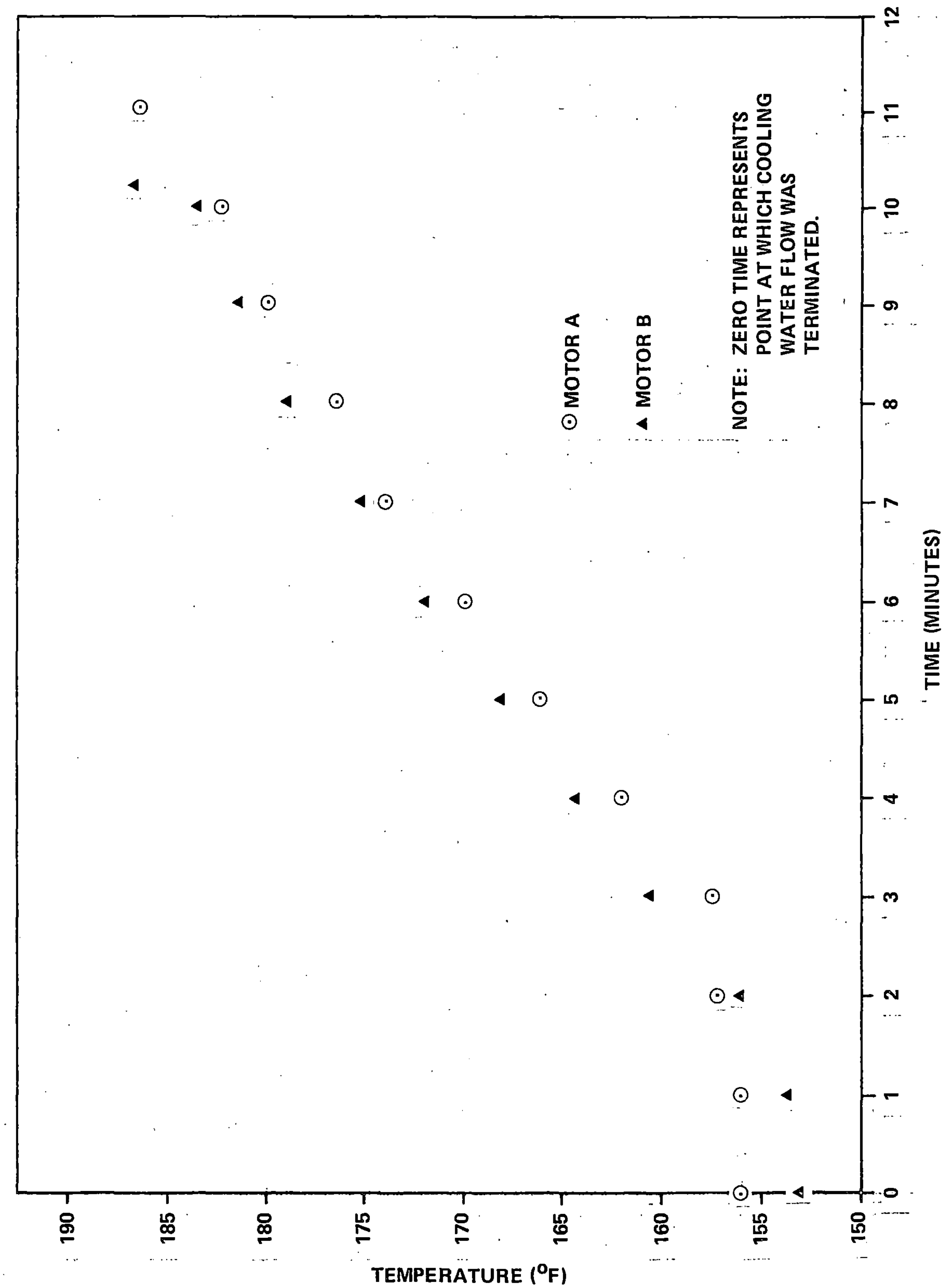
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Coolant Pump
	Updated FSAR Figure 9.2-6



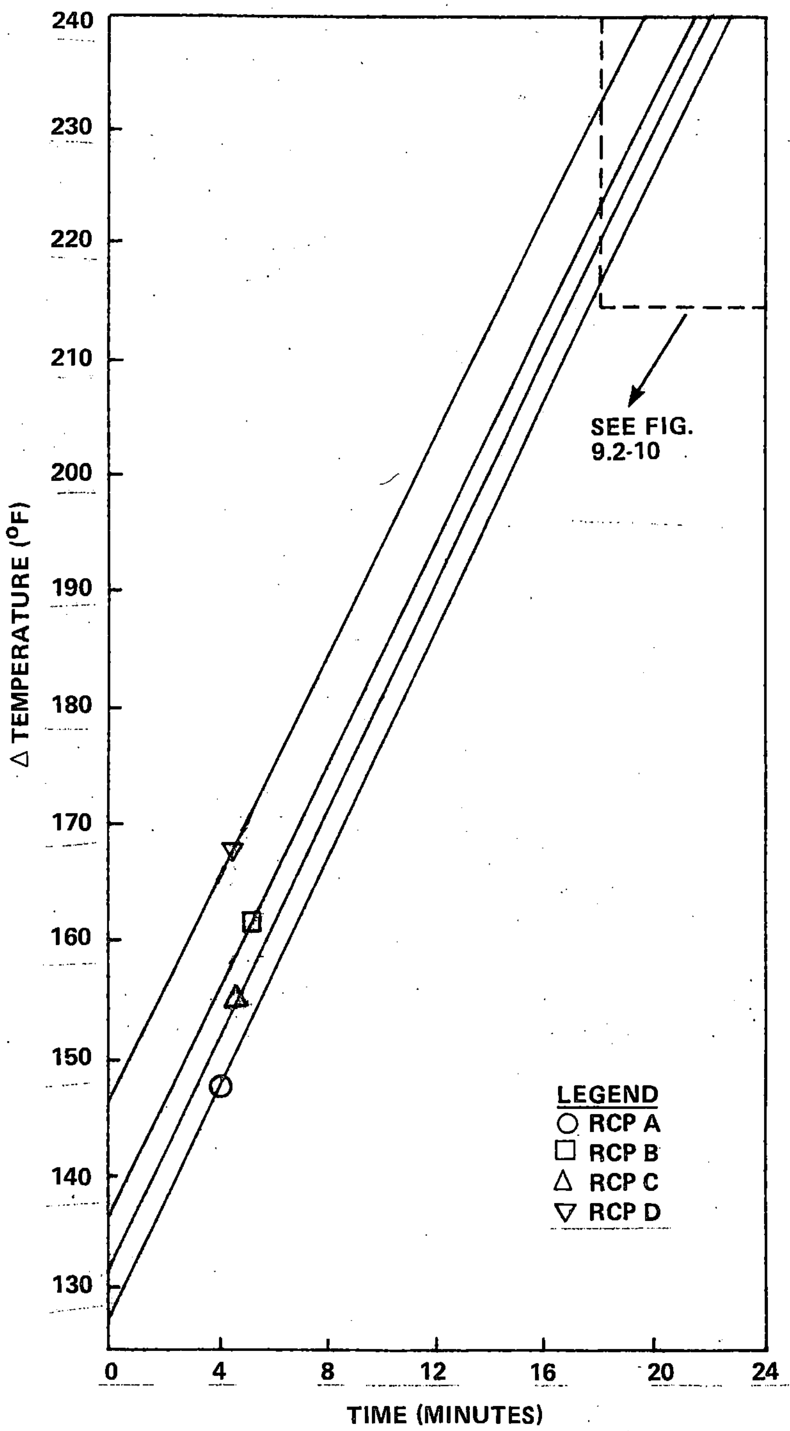
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Coolant Pump Motor
	Updated FSAR — Figure 9.2-7



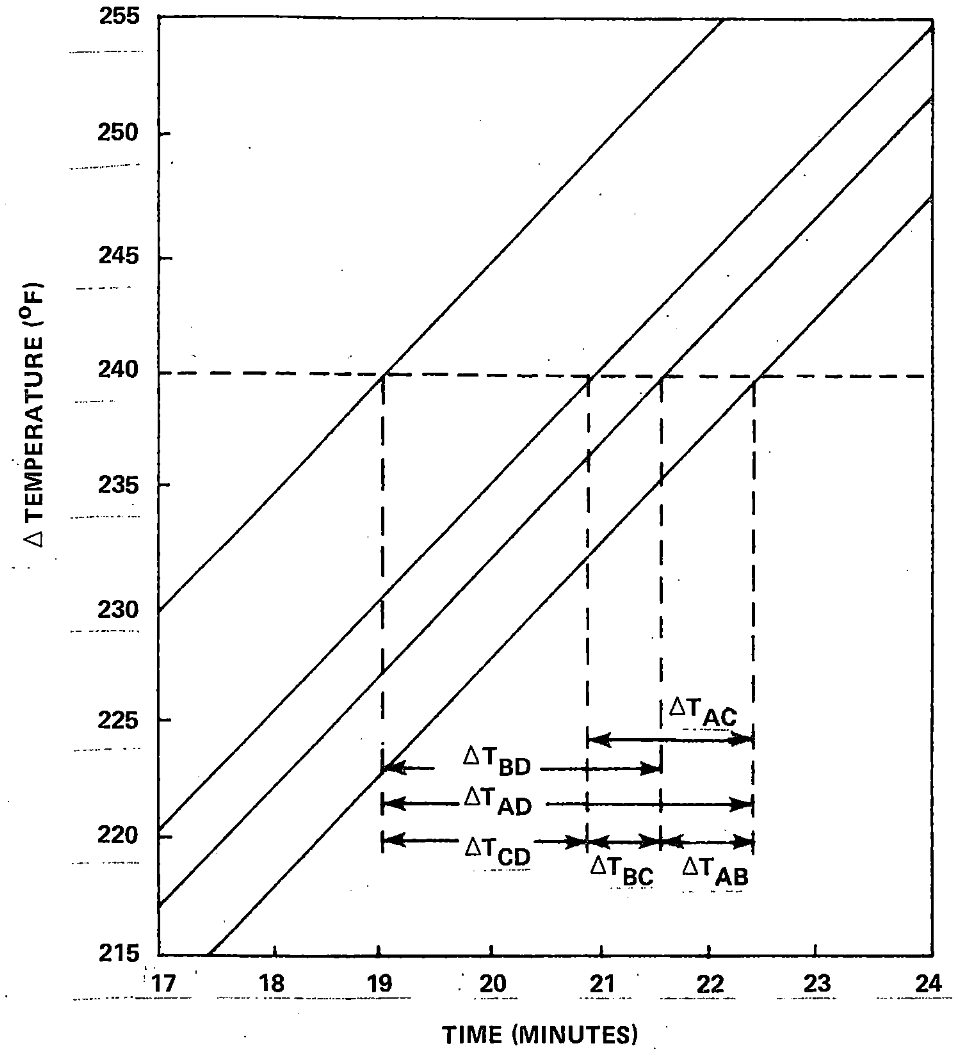
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Motor Upper Thrust Bearing Temperatures After Termination of CCW Flow	
	Updated FSAR	Figure 9.2-8



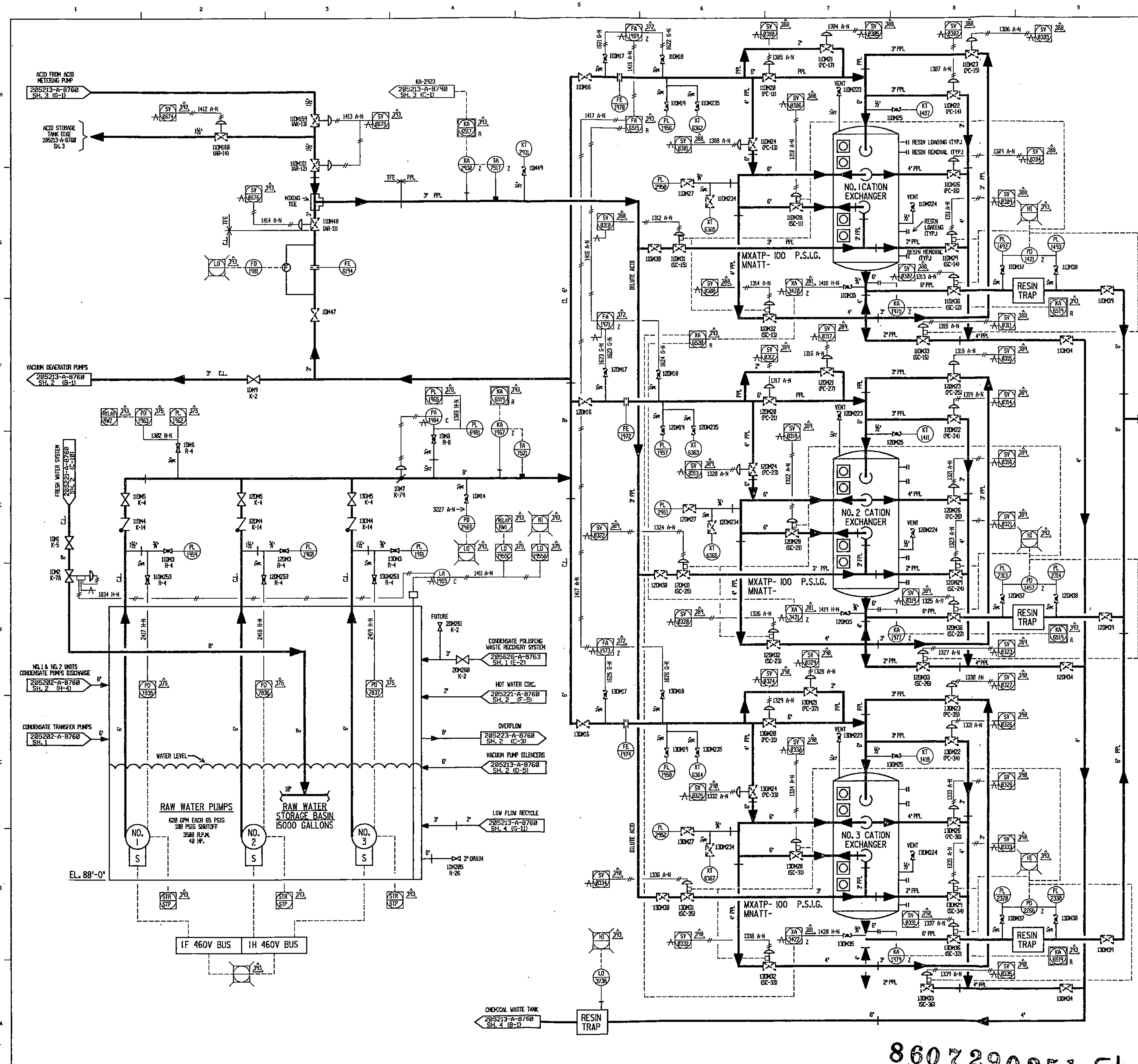
Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Coolant Pump Temperature Time Transients
	Updated FSAR — Figure 9.2-9



Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Reactor Coolant Pump Temperature Time Transients
	Updated FSAR — Figure 9.2-10



VACUUM DEAERATOR
205213-A-8760 SH. 2 (D-11)

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NOTES

1. TEMPORARY STRAINER IS PLACED IN LINE DURING INITIAL FLUSHING. CAPPED LINE IS CONNECTED TO PRESSURE GAGE AT THIS TIME.
2. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY, HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
3. ALL VALVES WITH 0 AROUND THE VALVE NUMBERS ARE COCHRANE VALVES.

REFERENCE DRAWINGS

VALVE LIST		206766-L
STEAM GENERATOR FEED & CONDENSATE	DIAG.	205202-A-8760
FEEDWATER CHEMICAL TREATMENT	DIAG.	205214-A-8760
HEATING WATER	DIAG.	205215-A-8760
FRESH WATER	DIAG.	205221-A-8760
CHEMICAL VOLUME CONTROL OPERATION	DIAG.	205228-A-8761
AUXILIARY FEED WATER	DIAG.	205236-A-8761
DEMINERALIZED WATER-RESTRICTED AREA	DIAG.	205246-A-8761
NO.2 UNIT STEAM GEN. FEED & COND.	DIAG.	205302-A-8763
NONRADIOACTIVE LIQUID WASTE DISPOSAL	DIAG.	205313-A-8763
RAW WTR. & CATION EXCH.	INSTR. SCH.	226925-B-9581-9
VACUUM DEAERATOR & ANION EXCH.	INSTR. SCH.	226926-B-9581-7
MIXED BED EXCH. & D.M. WTR. TKS.	INSTR. SCH.	226927-B-9581-11
ACID & CAUSTIC REGEN. SYS.	INSTR. SCH.	226928-B-9581-7
LEGEND SHEET		600658-A-8727
DEMIN. WTR. SYS.-RAW WTR. STORAGE BASIN PNL. 375	ARRGT. & W.D.	211795-A-8870
DEMIN. WTR. TRANSFER PUMPS PNL. 336	ARRGT. & W.D.	219468-A-8933
DEMIN. WTR. SODIUM & SILICA ANALYLER PNL. 381	ARRGT.	219471-A-8933
DEMIN. WTR. STORAGE TKS. PNL. 384	ARRGT.	219473-A-8933
DEMIN. WTR. MAKE-UP MAIN PNL. 393	ARRGT.	226171-A-1237
NO. 1, 2 & 3 CATION SOL. VA. CABINET PNLS. 388, 389 & 390	ARRGT.	226933-B-9581
NO. 1, 2 & 3 MIXED BED SOL. VA. CABINET PNLS. 397, 398 & 399	ARRGT. & INT. W.D.	226935-B-9581
DEMIN. M/U TO NO. 12 & 22 CONDS. PNL. 374	ARRGT. & W.D.	226963-A-1290

205213-A-8760

SH. 1	RAW WATER PUMPS AND NO. 1, 2 & 3 CATION EXCHANGERS
SH. 2	VACUUM DEAERATOR TANK AND PUMPS
SH. 3	ACID & CAUSTIC STORAGE TANKS AND PUMPS, REGENERATION WATER PUMPS
SH. 4	NO. 1, 2 & 3 ANION AND MIXED BED EXCHANGERS, NO. 1 CHEMICAL WASTE TANK
SH. 5	DEMINERALIZED WATER TRANSFER PUMPS

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Demineralized Water Makeup System
Unit 1 & 2

Updated FSAR Sheet 1 of 7
Fig 9.2-11

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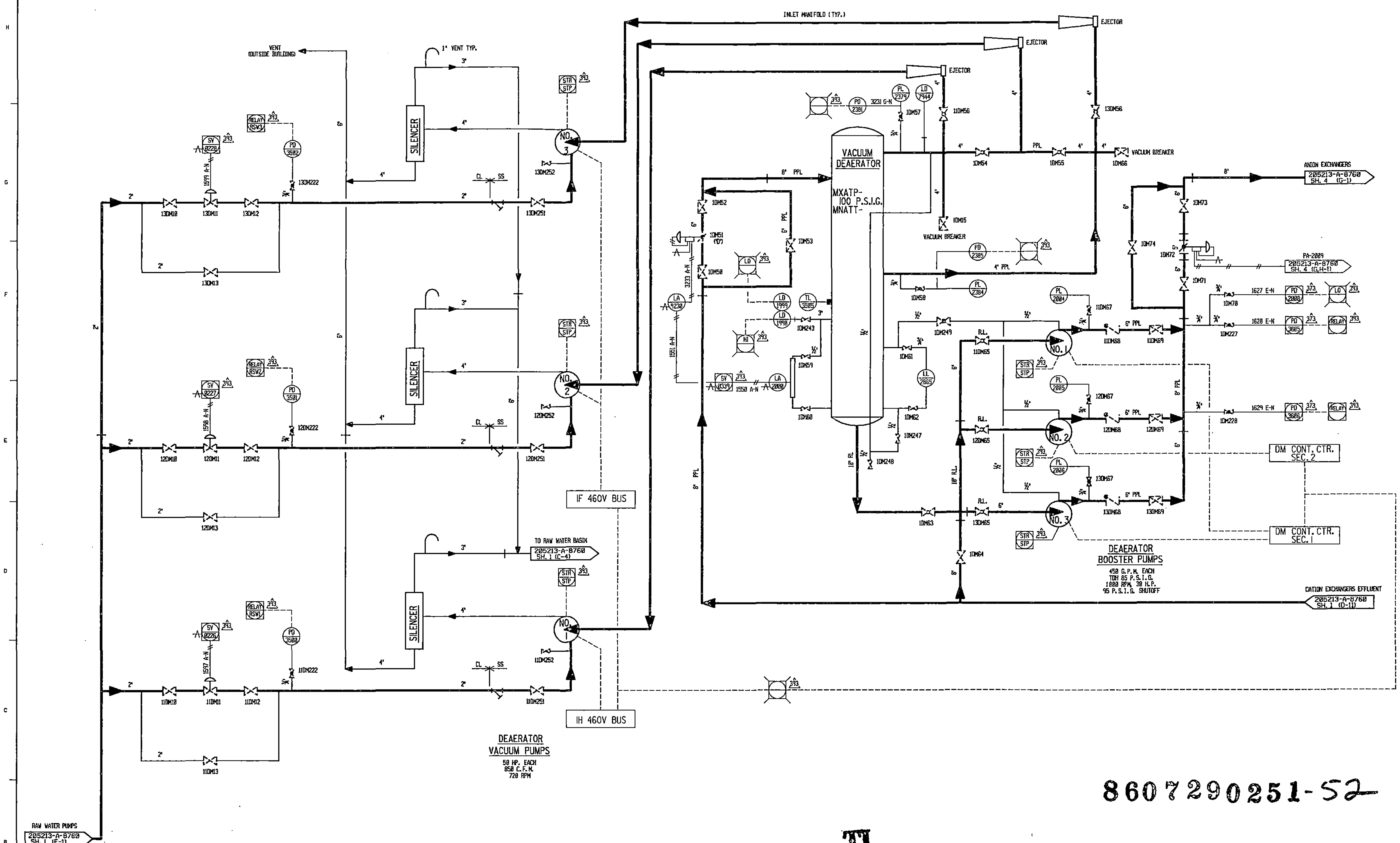

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Also Available On Aperture Card

NOTE:
ALL VALVES BY OTHERS

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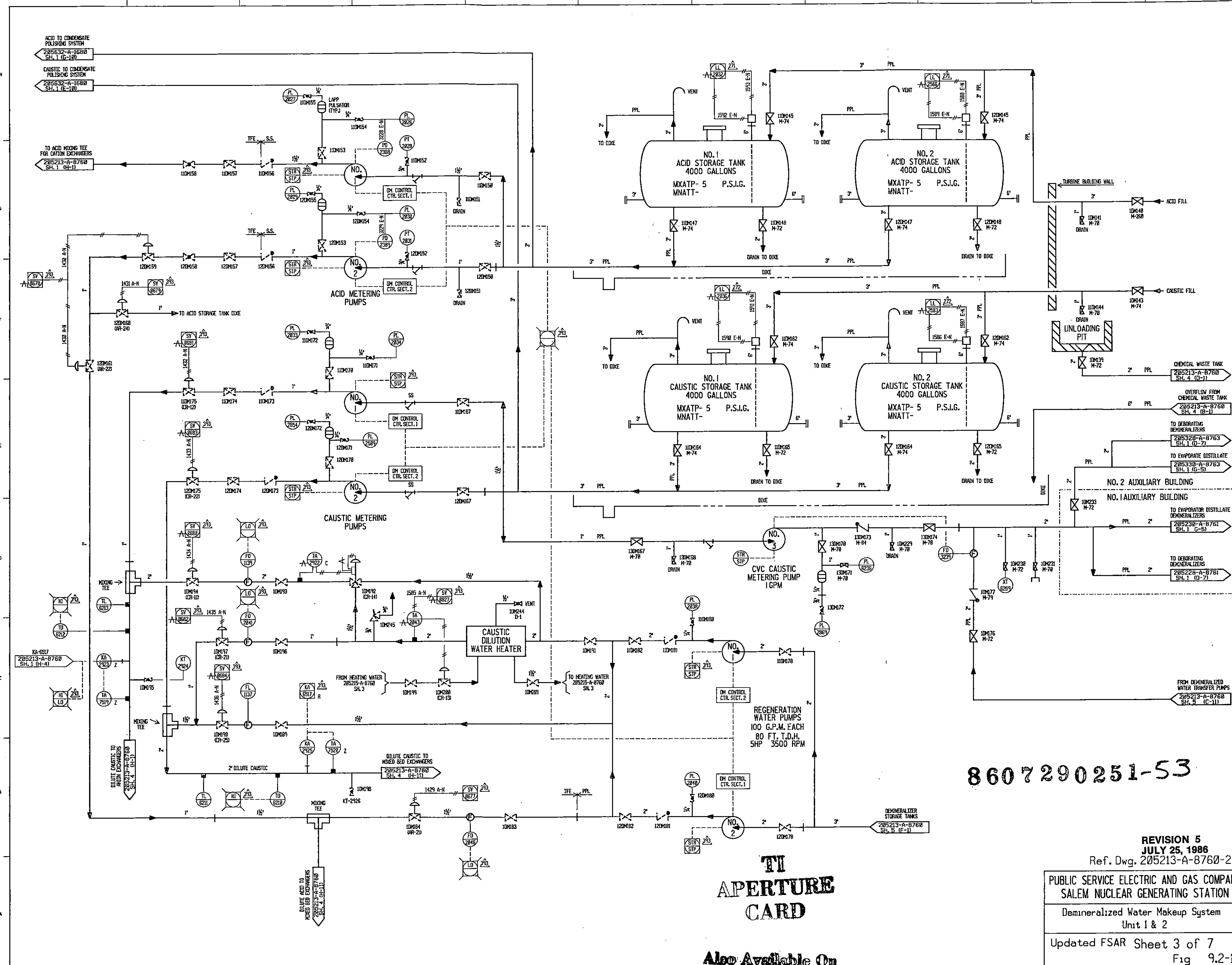
JULY 25, 1986
Ref. Dwg. 205213-A-8760-24

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Demineralized Water Makeup System
Unit 1 & 2

Updated FSAR Sheet 2 of 7
Fig 9.2-11



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JULY 25, 1986
Ref. Dwg. 205213-A-8760-24

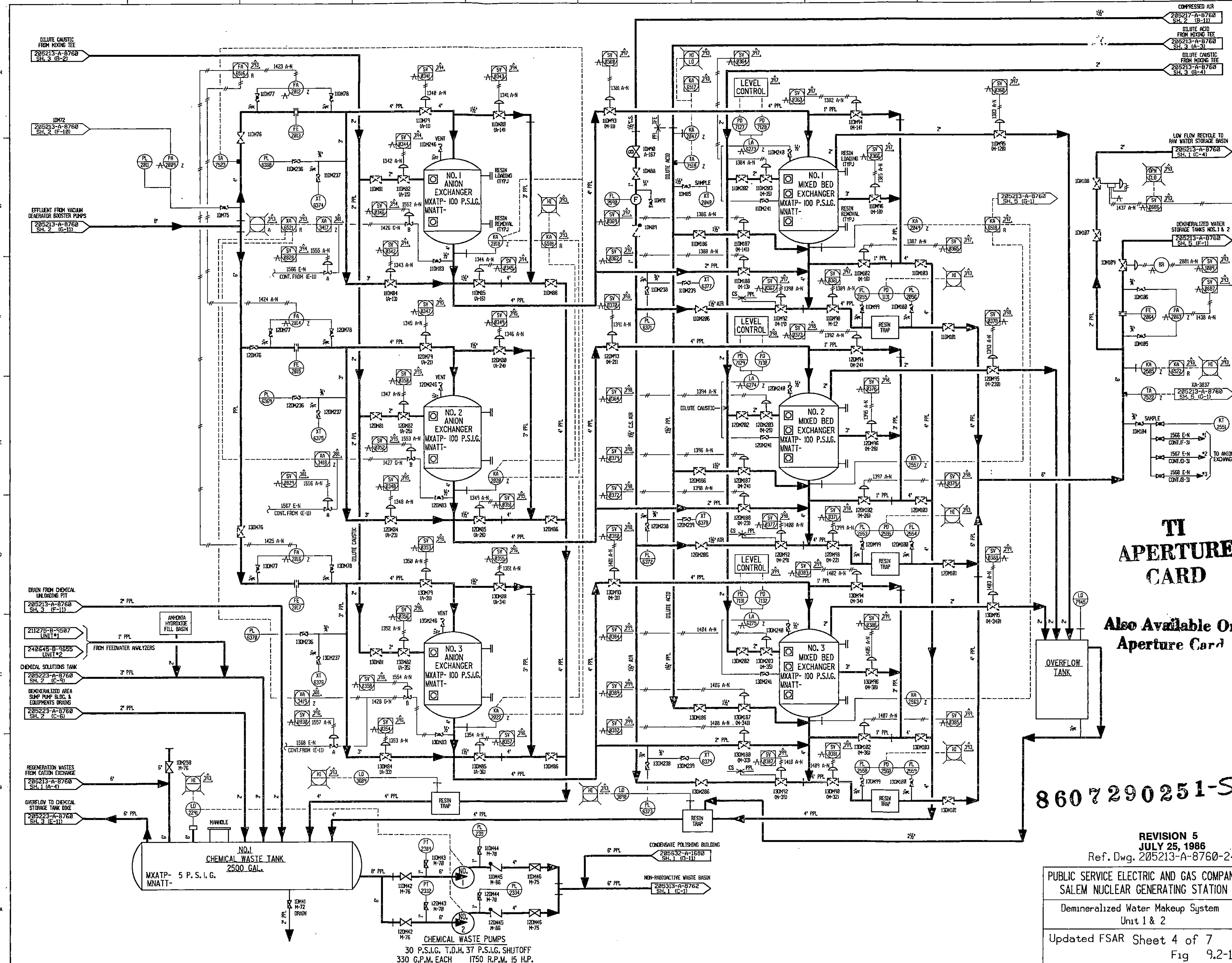
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Demineralized Water Makeup System
Unit 1 & 2

Updated FSAR Sheet 3 of 7
Fig 9.2-11

TI APERTURE CARD

Also Available On Aperture Card



TI APERTURE CARD

Also Available On Aperture Card

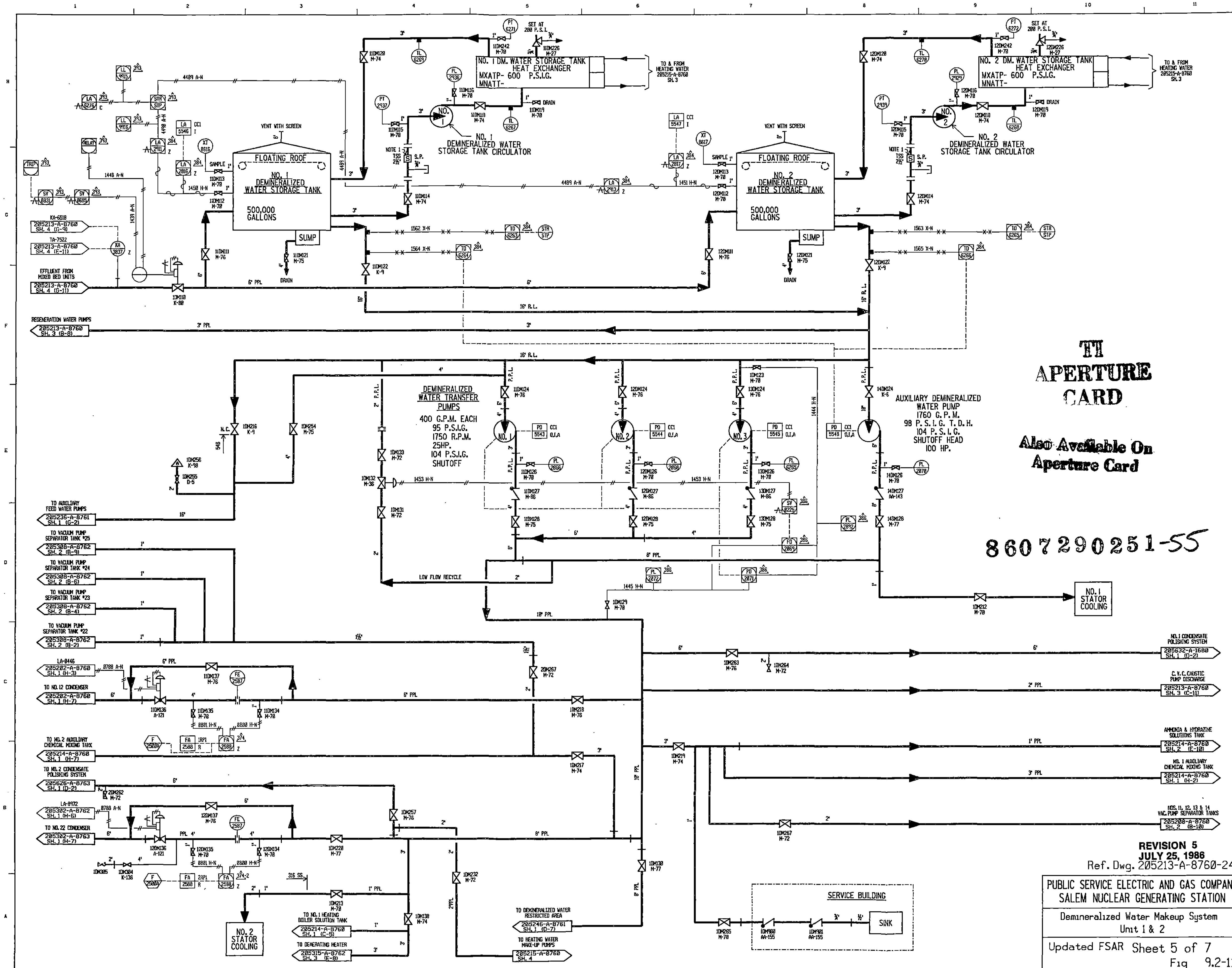
8607290251-54

REVISION 5
JULY 25, 1986
Ref. Dwg. 205213-A-8760-24

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Demineralized Water Makeup System
Unit 1 & 2

Updated FSAR Sheet 4 of 7
Fig 9.2-11



TI APERTURE CARD

Also Available On Aperture Card

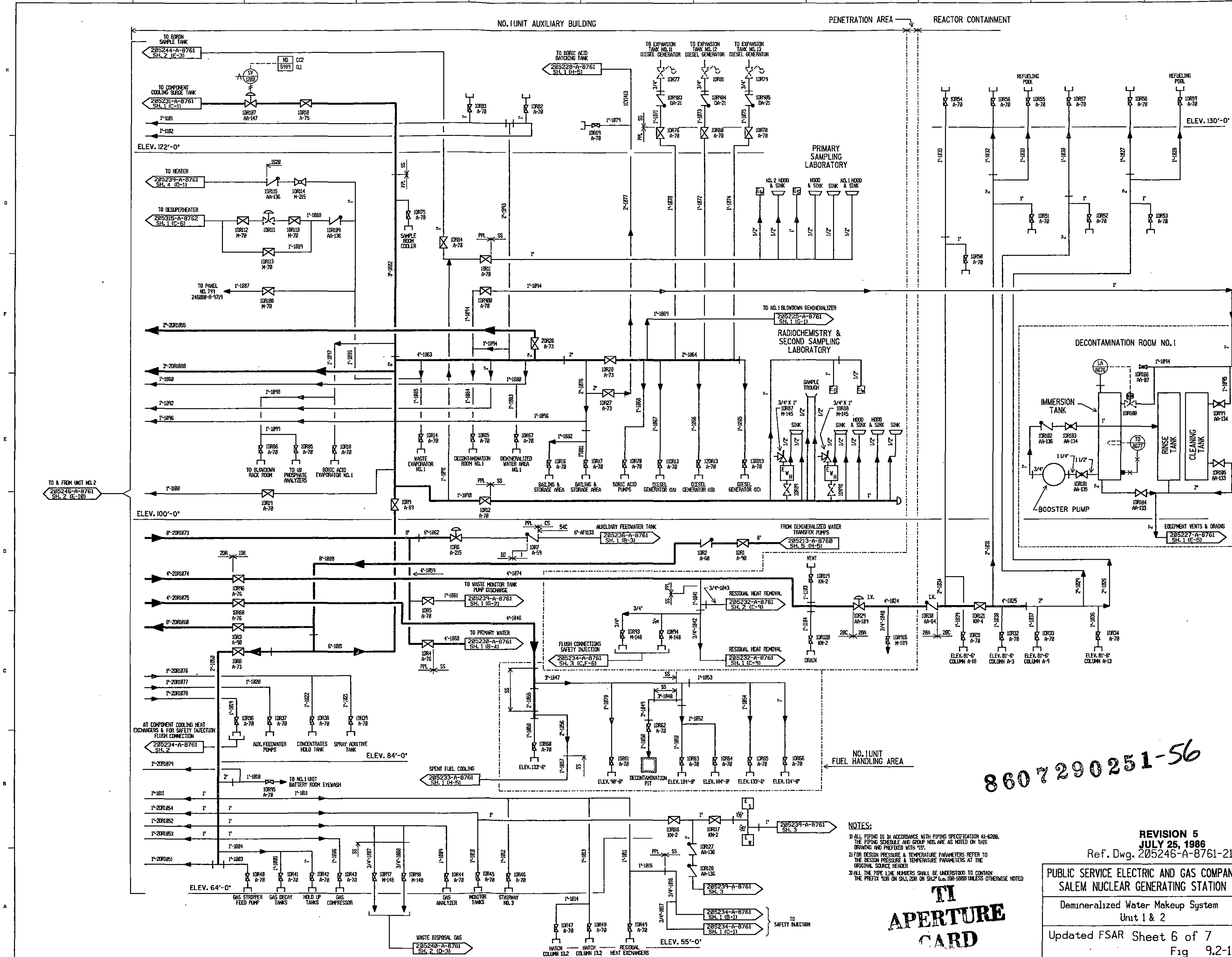
8607290251-55

REVISION 5
JULY 25, 1986
Ref. Dwg. 205213-A-8760-24

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Demineralized Water Makeup System
Unit 1 & 2

Updated FSAR Sheet 5 of 7
Fig 9.2-11



NOTES:

1) ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200. THE PIPING SCHEDULE AND GROUP NOS. ARE AS NOTED ON THIS DRAWING AND PREFIXED WITH "1S".

2) FOR DESIGN PRESSURE & TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE & TEMPERATURE PARAMETERS AT THE ORIGINAL SOURCE HEADER

3) ALL THE PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1DR ON SH.1, 2DR ON SH.2" (i.e. 1DR-1000) UNLESS OTHERWISE NOTED

TI APERTURE CARD

REVISION 5
JULY 25, 1986
Ref. Dwg. 205246-A-8761-21

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Demineralized Water Makeup System
Unit 1 & 2

Updated FSAR Sheet 6 of 7
Fig 9.2-11

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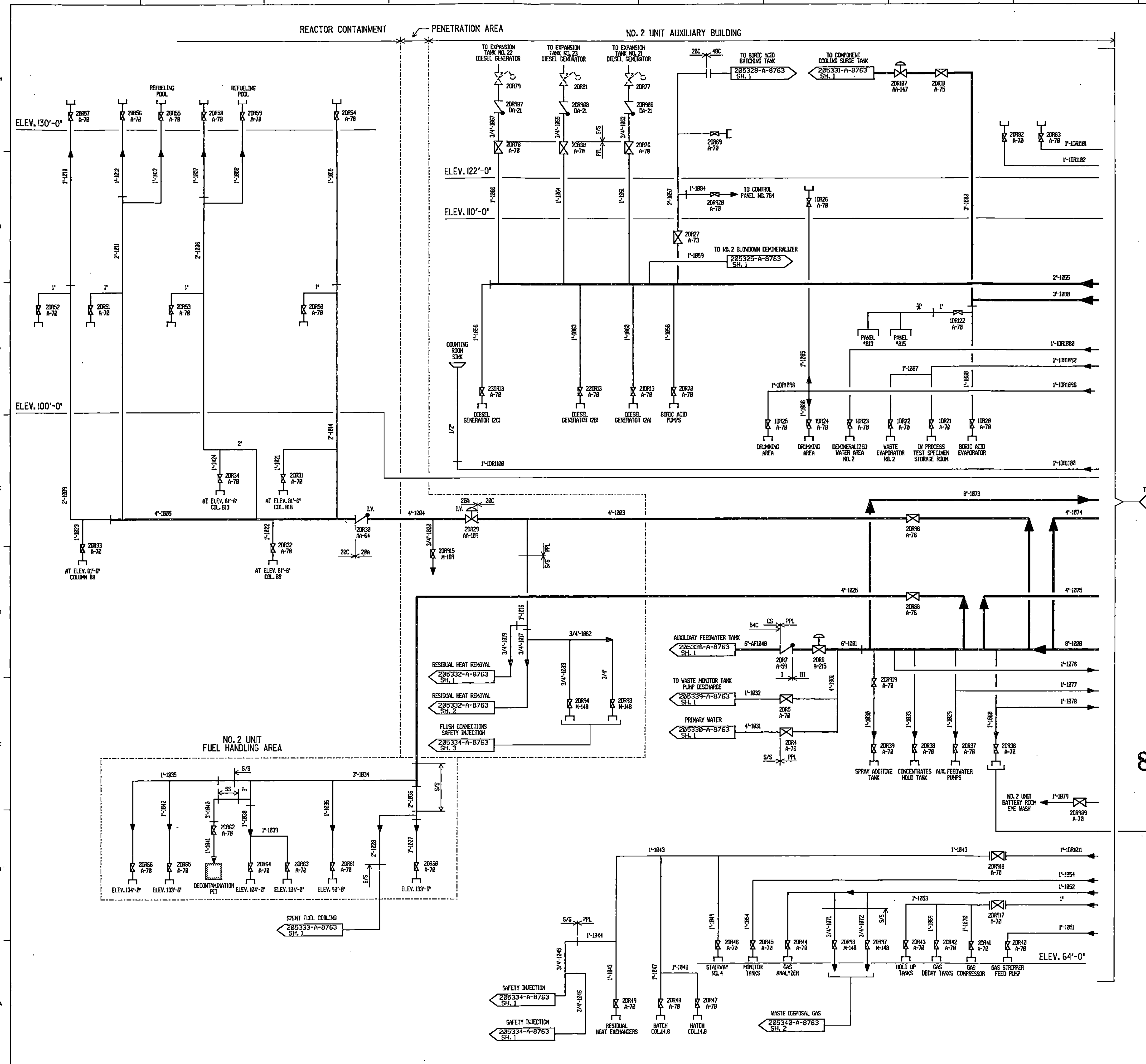

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Demineralized Water Makeup System
Unit 1 & 2

Updated FSAR Sheet 7 of 7
Fig 9.2-11

9.3 PROCESS AUXILIARIES

9.3.1 COMPRESSED AIR SYSTEM

The Compressed Air System provides the station with a reliable supply of clean, oil free air which is directed to various locations for services as required. The system is illustrated on Figures 9.3-1A and B.

9.3.1.1 Design Bases

The system provides a reliable supply of clean, oil free, dry air at temperatures and pressures suitable for use as control air and for containment penetration cooling, as well as for miscellaneous services and maintenance.

The Compressed Air System is designed such that any single failure will not result in loss of function.

9.3.1.2 System Description

9.3.1.2.1 General

The Compressed Air System is supplied by three motor driven, oil free, centrifugal compressors which draw air from the atmosphere. The intakes of the air compressors are located to avoid drawing in toxic or corrosive gases. Each compressor has a capacity of 4000 scfm at 110 psig discharge pressure. Two compressors are operated to satisfy the normal requirements of station air and control air for both units as well as to supply containment penetration cooling air for both units. A third compressor serves as standby. Each compressor is furnished with a 1000 hp motor, intake filter-silencer, blow-off silencer and total closure controls, intercoolers, aftercooler, and moisture separator. The compressors discharge into two independent service air headers, with an air receiver tied to each header.

The station air header for each unit is supplied from either of the two service air headers. This station air header provides operating and service requirements at various locations.

The containment penetration cooling system for each unit is furnished with two supply lines. The normal supply is taken from the station air header and the backup supply from either of the two service air headers.

9.3.1.2.2 Control Air

The control air system for each unit consists of a dual header arrangement as shown on Figures 9.3-2A and B. This control air for each unit is supplied through two distinct parallel paths. One path is supplied from the unit one station air system and the other is supplied from the unit two station air system. Control air for the safety related portions is automatically backed up by an emergency control air compressor. Control air is fed from the station air system through heatless, desiccant type air dryers.

The dual station service air headers are fed by three 100 percent capacity air compressors, any one of which can supply the total service and control air requirements for both units.

In addition to the normal air supply from the service air headers, each system has an emergency control air compressor complete with its own dryer and accessories to supply the safety related headers. The emergency control air for either system may be directed to supply air for the opposite system through a valved connection. Each emergency control air compressor motor is energized from the standby ac power supply. The emergency control air system is designated Class I (seismic) and is located in a Class I (seismic) structure.

Each emergency control air compressor has a capacity of 500 scfm at 110 psig and is driven by a 125 hp motor. Accessory equipment includes an independent heatless desiccant type air dryer, intake filter, silencer, intercooler, aftercooler, moisture separator, inlet control valve, relief valve and automatic condensate trap and drain. The emergency control air compressors with teflon piston rings and stainless steel cylinder liners. Cooling of the emergency control air compressors is provided from the safety-related chilled water system. In the event that the chilled water system is not available, the service water system serves as a backup.

Operational or test data that verify the functional reliability of the emergency control air compressors were not initially available although stress analysis calculations by the manufacturer indicated that the compressor could withstand both operational and seismic loadings simultaneously.

The parallel control air headers for each unit include air receivers of sufficient capacity to dampen pressure surges and act as a momentary reservoir of air to permit switching of air supply sources without cycling the system.

9.3.1.3 Design Evaluation

Reserve air storage of sufficient capacity to minimize pressure fluctuation is provided by means of air receivers in each control air header.

The control air system is designed to supply the required air during normal and abnormal conditions. Any single component failure will not result in a loss of function. A total loss of control air to all systems and equipment is therefore not considered credible.

Redundant safety-related air users are provided with independent single air supplies from the control air header system. The redundant system instruments have control air supplied from independent air headers.

Separate and redundant headers, backed up by emergency control air compressors energized from the standby power system and preservation of header independence assure that air is available during normal as well as abnormal plant conditions. A single failure within the system would not result in total loss of air supply to redundant equipment. The following are failures considered and the resultant action.

Failure	Action
Loss of a station air compressor	The spare air compressor automatically supplies the total requirements for both units.
Loss of all station air compressors	Each emergency control air compressor, energized from its standby a-c power supply, will supply all control air requirements for its safety related headers.
Loss of off-site power and emergency compressor fails to start	Emergency air receivers on each control air header supply enough capacity to maintain header pressure. The second emergency air compressor can provide the safety related control air requirements for both units.

9.3.1.4 Tests and Inspections

Prior to plant operation, the compressed air system was inspected and tested to verify correct installation and operation. During plant operation the system is in operation on a continuous basis, except for the emergency control air compressors which can be tested to verify automatic starting and operability.

9.3.1.5 Instrumentation and Control

9.3.1.5.1 Station Air Compressors

The compressor control circuits are designed to protect the compressor against the following hazards:

1. Low oil pressure

2. High air temperature

3. Low/High oil temperature

4. Low cooling water pressure

5. Excessive vibration

9.3.1.5.2 Control Air

The Emergency Control Air Compressors may be operated in three modes:

1. Remote manual operation from the Control Room,

2. Local manual operation from the "Hot Shut-down panel, or

3. Automatic start-stop operation

Normally, the emergency air compressors are in the automatic mode. The compressor motors are started by either tripping of all three station air compressors or decay of control air header pressure below 85 psig, as sensed by a pressure switch in the respective control air header.

9.3.2 SAMPLING SYSTEM

9.3.2.1 Design Bases

The sampling system provides a means for obtaining fluid and gas samples for laboratory analysis of chemistry and radiochemistry conditions of the Reactor Coolant and other systems. The system is designed to permit the taking of samples during reactor operations and during cooldown without requiring access to the containment. The system has no emergency function, nor is it required to take action to prevent an emergency condition. In the event of a loss-of-coolant accident, the system is isolated at the containment boundary.

Sampling system discharge flows are limited under normal and anticipated fault conditions (malfunctions or failure) to preclude any fission product release beyond the 10CFR20 limit. Adequate safety features are provided to protect laboratory personnel and prevent the spread of contamination from the sampling room when samples are being drawn. Each unit has an identical sampling system and only the boron analyzer is shared between units. The description contained herein is equally applicable to either unit.

System component code requirements are given in Table 9.3-1.

9.3.2.2 System Description

9.3.2.2.1 General

The Sampling System, shown in Figures 9.3-3A and B, provides the representative samples for laboratory analysis. Analysis results provide guidance in the operation of the Reactor Coolant, Residual Heat Removal, Component Cooling, Chemical and Volume Control, Main Steam, and Steam Generator Blowdown Systems. Analysis shows both chemical and radiochemical conditions. Typical information obtained includes reactor coolant boron and chloride concentrations, fission product radioactivity level, hydrogen, oxygen, and fission gas content, conductivity, pH, corrosion product concentration, and chemical additive concentration. The information is used in regulating boron concentration adjustments, evaluating fuel element integrity and mixed bed demineralizer performance, and regulating additions of corrosion controlling chemicals to the systems. The Sampling System is designed to be operated manually, on an intermittent basis except for steam generator blowdown which is continuously analyzed. Samples can be withdrawn under conditions ranging from full power to cold shutdown.

Samples are drawn from the following locations:

Inside Containment

1. The pressurizer steam space

2. The pressurizer liquid space

3. Hot legs of reactor coolant loops 1 and 3

4. The Safety Injection System accumulators

5. Steam generator blowdown

Outside Containment

1. The mixed bed demineralizer inlet header

2. The mixed bed demineralizer outlet header

3. Each Residual Heat Removal System heat exchanger outlet

4. The volume control tank gas space

5. Main Steam

Local sample connections are provided at various locations outside the containment. These connections are shown on the respective flow diagrams and are not considered part of the Sampling System.

Samples originating from locations within the containment flow through lines to the sampling room in the auxiliary building. Each line is equipped with a manual isolation valve close to the source; a remote, air-operated valve immediately downstream of the isolation valve; containment boundary isolation/trip valves located inside and outside the containment, except for blowdown sample lines which have an isolation/trip valve outside the containment only. Manual valves are located inside the sampling room for component isolation, sample flow control and routing. High temperature sample lines also contain a sample heat exchanger.

In addition the high-pressure reactor coolant sample line contains sufficient length to provide at least a 60-second sample transit time within the containment. An additional 20-second transit time from the reactor containment to the sampling hood is provided by the sampling line. This allows for decay of the short-lived isotope, N-16, to a level that permits normal access to the sampling room.

All sample lines, whether originating from locations outside the containment or inside, are provided with manual isolation valves. The Residual Heat Removal System also has a remote, air-operated sampling valve.

Samples are drawn in an enclosed room with controlled ventilation and drainage to confine the spillage of radioactivity. The sample flows are limited to preclude the release of radioactivity above 10CFR20 limits in the event of a system failure.

9.3.2.2.2 Operation

Sampling System equipment is located inside the auxiliary building with most of it in the sampling room. All sample lines from inside the containment have remotely operable valves.

Reactor coolant loop liquid, pressurizer liquid, pressurizer steam and steam generator blowdown samples originate inside the containment and flow through separate sample lines to the sampling room. A delay is provided by the length of the reactor coolant sample lines to provide sufficient elapsed time for N-16 decay. The samples pass through the containment to the auxiliary building, and into the sampling room, where they are cooled (pressurizer steam samples condensed and cooled) in the sample heat exchangers. The sample stream pressure is reduced by a manual throttling valve located downstream of each sample pressure vessel. The sample stream is purged to the volume control tank in the Chemical and Volume Control System until sufficient volume has passed to permit collection of a representative sample. After sufficient purging, the sample pressure vessel is isolated for laboratory analysis of the contents or degassed, depending on the analysis required.

Alternately, these liquid samples may be collected by bypassing the sample pressure vessels. After sufficient volume has passed to the volume control tank to permit collection of a representative sample, a portion of the sample flow is diverted to the sample sink where the sample is collected.

Samples from the accumulators in the Safety Injection System pass through the containment, to the auxiliary building, and into the sampling room. The sample stream is purged to the volume control tank in the Chemical and Volume Control System until sufficient volume has passed to permit collection of a representative sample. After sufficient purging, samples are obtained by diverting a portion of the flow to the sample sink.

The reactor coolant samples originating from the Residual Heat Removal System have remote operated, normally closed air operated sampling valves located close to the sample sources. The sample lines from these sources are connected to the sample lines coming from the reactor coolant loops at a point upstream of the sample heat exchanger. Samples from this source can be collected either in the sample pressure vessel or at the sample sink as with reactor coolant loop samples.

Liquid samples originating at the Chemical and Volume Control System letdown line at the mixed bed demineralizer inlet and outlet headers are purged directly to the volume control tank. Samples are obtained by diverting a portion of the flow to the sample sink. If the pressure is low in the letdown line, the purge flow is directed to the Waste Disposal System.

The sample line from the gas space of the volume control tank delivers gas samples to the volume control tank sample pressure vessel in the sampling room. Purge flow for these samples is discharged to the vent header in the Waste Disposal System.

The steam generator blowdown samples originate from locations inside the containment, flowing through lines to the sampling area in the Auxiliary Building. Each line is equipped with a manual valve close to the source, a remote air operated valve downstream of the manual valve, an automatic containment boundary isolation valve located outside the containment and manual valves located inside the sampling area for component isolation, flow control and routing. These sample lines also contain a sample heat exchanger for cooling. A blowdown sample from each steam generator is reduced in pressure and is continuously monitored for radioactivity level, pH and conductivity.

The steam generator samples originate from locations outside the containment, flowing through lines to the sampling area in the Auxiliary Building. Each line is provided with a manual valve close to the source and manual valves located inside the sampling area for component isolation and flow control. These sample lines also contain a sample heat exchanger for condensing and cooling.

The sample sink, which is located in the sampling room, contains a drain line to the Waste Disposal System.

9.3.2.2.3 Components

A summary of principal component data is given in Table 9.3-2.

Sample Heat Exchangers

Eleven sample heat exchangers are installed in the system. Each heat exchanger is designed to cool the sample flow to a maximum of 127°F before the sample reaches the sample vessel or sample sink.

The sample heat exchangers are of the shell and coil tube type. Sample flow circulates through the tube side, while component cooling water circulates through the shell. The tubes and other surfaces in contact with sample flow are austenitic stainless steel while the shell is carbon steel. The inlet and outlet tube sides have socket-welded joints for connections to the high pressure sample lines.

Sample Pressure Vessel

The sample vessel is designed to receive liquid or gas samples at Reactor Coolant System design pressure and temperature. The sample vessel is sized to contain sufficient gas to perform a radiochemical analysis on the volume control tank gas space constituents or sufficient reactor coolant for dissolved hydrogen and fission gas analyses.

Integral isolation valves are furnished with the sample vessel.

Sample Sink

The sample sink is located in a hooded enclosure which is equipped with an exhaust ventilator. The work area around the sink and the enclosure is large enough for sample collection and storage for radiation monitoring equipment. The sink perimeter has a raised edge to contain any spilled liquid. The enclosure is penetrated by sample lines and by a demineralized water line, all of which discharge into the sink.

Piping and Fittings

All liquid and gas sample lines are austenitic stainless steel tubing and are designed for high pressure service. Lines are so located as to protect them from accidental damage during routine operation and maintenance.

Valves

Stop valves within the containment are remotely operated from the sampling room. They are used to isolate all sampling points and to route sample fluid flow. The remotely operated isolation valve used for sampling from the Residual Heat Removal System is provided so that the operator does not have to enter a possibly high radiation area following a loss-of-coolant accident.

Stop valves are provided for component isolation and flow path control at all Sampling System locations which are normally accessible. A check valve in the sample line prevents accidental overpressurization of the Residual Heat Removal System by preventing back flow from the Reactor Coolant System, should both the air-operated sample valves be open.

Two isolation valves are provided, one inside and one outside the containment on all sample lines leaving the containment except for the steam generator blowdown lines which have one isolation valve outside the containment on each line. The valve trip closed upon actuation of the containment isolation signal.

All valves in the system are constructed of austenitic stainless steel or equivalent corrosion resistant material.

9.3.2.3 System Evaluation

The sampling system is not required to function during an emergency, nor is it required to taken action to prevent any emergency condition.

Samples are collected under a hood provided with a vent to the building exhaust ventilation system. Liquid leakage in the sample sink is collected in the sink and drained to the Waste Disposal System. Any leakage from the system inside of the containment (i.e., valve stem leakage) is collected in the containment sump.

The sampling room and the sample hood are ventilated to reduce the potential for airborne radioactive exposure of operating personnel.

Sufficient length is provided in the reactor coolant sample line to reduce personnel exposure from short-lived radionuclides. Shielding is provided as necessary to reduce personnel exposures. The Operating Procedures will specify the precautions to be observed when purging and drawing samples.

The system is designed to be operated on an intermittent basis under administrative control except for steam generator blowdown sampling which is a continuous operation. The system is normally closed with no flow, except for the steam generator blowdown samples. Sample lines penetrating the containment are equipped with remote-operated isolation valves which close on receipt of a containment isolation signal.

In the event of a loss-of-coolant accident, the malfunctions or failures presented in Table 9.3-3 could occur without loss of integrity of the containment.

9.3.2.4 Tests and Inspection

System operation is verified by normal, periodic collection of samples.

9.3.2.5 Instrumentation and Control

Local instrumentation is provided to permit manual control of sampling operations and to ensure that the samples are at suitable temperatures and pressures before diverting flow to the sample sink.

9.3.3 EQUIPMENT AND FLOOR DRAINAGE SYSTEM

9.3.3.1 Design Bases

Equipment and floor drains are provided to drain radioactivity contaminated water into sumps for transfer to the Liquid Waste Disposal System (See Section 11.2). In many cases equipment drainage is provided by permanently installed lines which eliminate (or reduce) surface and airborne contamination. Permanently piped equipment vents are also provided to enable various mechanical components to be vented to the respective building ventilation system to preclude the direct release of potentially radioactive gases to the building atmosphere.

9.3.3.2 System Description

The Contaminated Equipment Vents and Drains flow diagrams are shown in Figures 9.3-4A and B and 9.3-5A and B.

All liquid drains originating in the Containment and Auxiliary Buildings are considered potentially radioactive and are therefore drained to the Liquid Waste Disposal System. The drain connections on nearly all components within these areas are permanently piped to the equipment drain system. Exceptions include the Component Cooling System and certain portions of the Chemical and Volume Control System containing 12 percent boric acid. Hose connections are provided where it is impractical to have a permanently piped drain in which case equipment drains can be temporarily connected by hose to a local floor drain. These provisions eliminate or reduce the possibility of inadvertently allowing radioactive drains to contaminate concrete floor areas and the building atmosphere.

In the Auxiliary Building the floor drains at Elevations 84, 100 and 122 are piped to the waste holdup tanks. Elevation 64 drains are piped to the waste holdup tanks via the auxiliary building sump tanks and sump tank pumps. All drains below the elevation of the auxiliary building sump tank drain to the waste holdup tank via the auxiliary building sump and the auxiliary building sump pump.

A floor drain, 4 inches in diameter, in the immediate vicinity of each charcoal filter bank, directs the drainage or deluge water to the waste holdup tanks, either directly or via sump pumps. The drain piping system is welded, Schedule 10, ASTM A312, Grade TP 304 or TP 304 L stainless steel pipe having certificates of compliance. The entire drainage system is tested in accordance with ANSI B31.1-1967.

In the containment building all equipment drains to the Waste Disposal System from the containment sump.

In the Fuel Handling Building the equipment drains are piped to the Waste Disposal System via a fuel handling area sump.

With the exception of Nuclear Steam Supply System tanks that are blanketed with nitrogen, all tanks containing potentially contaminated waste are permanently vented to the suction side of the auxiliary building exhaust fans. This insures that the tanks are maintained at a slight negative pressure to eliminate the possiblity of introducing airborne contamination to the auxiliary building atmosphere.

9.3.4 CHEMICAL AND VOLUME CONTROL SYSTEM

The Chemical and Volume Control System is used to a) adjust the concentration of boric acid, i.e., the chemical neutron absorber for reactivity control, b) maintain the proper water inventory in the Reactor Coolant System, c) provide the required seal water flow for the reactor coolant pump shaft seals, d) process reactor coolant letdown for reuse of boric acid and reactor makeup water, e) maintain the proper concentration of corrosion inhibiting chemicals in the reactor coolant, f) maintain the reactor coolant activities to within design limits, and g) provide borated water for safety injection. The system is also used to fill and hydrostatically test the Reactor Coolant System.

During normal operation, this system also has provisions for supplying the following chemicals:

1. Regenerant chemicals to the evaporator condensate and deborating demineralizers.

2. Hydrogen to the volume control tank.

3. Nitrogen as required for purging the volume control tank.

4. Hydrazine and lithium hydroxide as required via the chemical mixing tank to the charging pumps suction.

9.3.4.1 Design Bases

9.3.4.1.1 Redundancy of Reactivity Control

Two independent reactivity control system, preferably of different principles, shall be provided.

In addition to the reactivity control achieved by the rod cluster control assemblies as detailed in Chapters 7 and 4, reactivity control is provided by the Chemical and Volume Control System which regulates the concentration of boric acid solution neutron absorber in the Reactor Coolant System.

9.3.4.1.2 Reactivity Hold-Down Capability

The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public.

Normal reactivity shutdown capability is provided by control rods with boric acid injection used to compensate for the long term xenon decay transient and for plant cooldown. Any time that the plant is at power, the quantity of boric acid retained in the boric acid tanks and ready for injection always exceeds that quantity required for the normal cold shutdown. This quantity always exceeds the quantity of boric acid required to bring the reactor to hot shutdown and to compensate for subsequent xenon decay.

The system is designed to allow for concurrent mixing and subsequent injection of boric acid solution. Thus the Chemical and Volume Control System provides extended reactivity hold-down capability.

9.3.4.1.3 Reactivity Hot Shutdown Capability

The reactivity control systems provided shall be capable of making and holding the core subcritical from any hot standby or hot operating condition.

The reactivity control systems provided are capable of making and holding the core subcritical for any hot standby or hot operating condition, including those resulting from power changes.

The chemical shim control serves to provide hot shutdown for the reactor as backup to the rod cluster control assemblies.

9.3.4.1.4 Reactivity Shutdown Capability

The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public.

The sizing of the Chemical and Volume Control System components and redundance of its components and flow paths determines the Chemical and Volume Control System reactor shutdown capability.

The boric acid solution is transferred from the boric acid tanks by boric acid transfer pumps to the suction of the charging pumps which inject boric acid into the Reactor Coolant system. Any charging pump and any boric acid transfer pump can be operated from diesel generator power on loss of primary power.

On the basis of the above, the injection of boric acid is shown to afford backup shutdown reactivity capability, independent of control rod clusters which normally serve this function in the short term situation. Shutdown for long terms and reduced temperature conditions can be accomplished with boric acid injection using redundant components.

9.3.4.1.5 Codes and Classifications

All pressure retaining components (or compartments of components) of the Chemical and Volume Control System which are exposed to reactor coolant comply with the following codes:

1. System pressure vessels - ASME Boiler and Pressure Vessel Code, Section III, Class C.

2. System valves, fittings and piping - ANSI B31.1 (for design). For piping not supplied by the NSSS supplier, material inspections, fabrication and quality control conform to ANSI B31.7. Where not possible to comply with ANSI B31.7, the requirements of ASME III-1971, which incorporated ANSI B31.7, were adhered to.

System integrity is assured by conformance to applicable codes listed in Table 9.3-4, and by the use of austenitic stainless steel or other corrosion resistant materials in contract with both reactor coolant and boric acid solutions.

The regenerative heat exchanger and the tube side of the excess letdown heat exchanger are designed as ASME III, Class C. This designation is based on the following considerations:

1. Each exchanger can be isolated from the Reactor Coolant System.

2. Each is located inside the reactor containment, and

3. Both exchangers are protected by a missile barrier.

Accordingly, the designation of "Class C" for these exchangers is justifiable and does not lead to any public hazard.

9.3.4.2 System Design and Operation

The Chemical and Volume Control System shown in Figures 9.3-6A and B, 9.3-7A and B, and 9.3-8A and B provides a means for injection of soluble neutron adsorber in the form of boric acid solution, chemical additions for corrosion control and reactor coolant cleanup and degasification. This system also provides a means to add makeup water to the Reactor Coolant System, reprocesses water letdown from the Reactor Coolant System, provide seal water injection to the reactor coolant pump seals, and fill and hydrostatically test the Reactor Coolant System.

System components whose design pressure and temperature are less than the Reactor Coolant System design limits are provided with overpressure protective devices.

System discharge from overpressure protective devices and system leakages are directed to closed systems. Effluents removed from such closed systems are monitored and discharged under controlled conditions.

System design enables post-operational hydrostatic testing to test pressure required by the codes listed in Table 9.3-4.

9.3.4.2.1 System Description

During plant operation, reactor coolant flows through the letdown line from one of the reactor coolant loop cold legs on the suction side of the reactor coolant pump and is returned through the charging line to the cold leg of another loop. An alternate return path is provided to the cold leg of a different loop. (See Figures 9.3-6A and B.) An excess letdown line is also provided as an alternate in case the normal letdown circuit is inoperative or it can be used to supplement maximum letdown during final stages of heatup.

Each of the Chemical and Volume Control System connections to the Reactor Coolant System has an isolation valve. In addition, a check valve is located downstream of each charging line isolation valve. Reactor coolant entering the Chemical and Volume Control System flows through the shell side of the regenerative heat exchanger where its temperature is reduced. The coolant then flows through a letdown orifice which reduces the coolant pressure. The cooled, low pressure water leaves the reactor containment and enters the auxiliary building where it undergoes a second temperature reduction in the tube side of the letdown heat exchanger followed by a second pressure reduction by the low pressure letdown valve. After passing through one of the mixed bed demineralizers, where ionic impurities are removed, coolant flows through the reactor coolant filter and enters the volume control tank through a spray nozzle.

Hydrogen is automatically supplied, as determined by pressure control, to the vapor space in the volume control tank, which is predominantly filled with hydrogen and water vapor. The hydrogen within the tank is, in turn, the supply source to the reactor coolant. Fission gases are removed from the system by venting the volume control tank to the Waste Disposal System prior to a cold or refueling shutdown.

To enter the Reactor Coolant System the coolant flows from the volume control tank to the charging pumps which raise the pressure above that in the Reactor Coolant System. The coolant then enters the containment, passes through the tube side of the regenerative heat exchangers, and returns to the Reactor Coolant System. A portion of the high pressure charging flow is filtered and injected into the reactor coolant pumps between the pump impeller and the shaft seal so that the seals are not exposed to particulate matter in the reactor coolant. Part of the flow cools the lower radial bearing and enters the Reactor Coolant System through a labyrinth seal on the pump's shaft. The remainder, which is the shaft seal leakage flow, is filtered, cooled in the seal water heat exchanger and returned to the suction of the charging pumps. An alternate path provides means for returning seal water to the volume control tank.

Coolant injected through the reactor coolant pump labyrinth seals joins with the reactor coolant. An equal amount of reactor coolant returns to the volume control tank by the normal letdown flow path through the regenerative heat exchanger. When the normal letdown route is not in service, this reactor coolant letdown returns to the suction of the charging pumps through the excess letdown and seal water heat exchangers.

The cation bed demineralizer, located downstream of the mixed bed demineralizers, is used intermittently to control cesium activity in the coolant and also to remove excess lithium which is formed from the B^{10} (n, α) Li^7 reaction.

Boric acid is dissolved in hot water in the batching tank to a concentration of approximately twelve weight percent. The batching tank is jacketed to permit heating of the batching tank solution with low pressure steam. One of two boric acid transfer pumps is used to transfer the batch to the boric acid tanks. Small quantities of boric acid solution are metered from the discharge of an operating boric acid transfer pump for blending with the water supplied to makeup for normal leakage, or for increasing the reactor coolant boron concentration during normal operation. Electric immersion heaters maintain the temperature of the solution in the boric acid tanks high enough to prevent precipitation.

During plant startup, normal operation, load reductions and shutdowns, liquid effluents containing boric acid flow from the Reactor Coolant System through the letdown line and are collected in the holdup tanks or the Volume Control Tank. As liquid enters the holdup tanks, the nitrogen cover gas is displaced to the gas decay tanks in the Waste Disposal System through the waste vent header. The concentration of boric acid in the holdup tanks varies throughout core life from the refueling concentration to essentially zero at the end of the core cycle. A recirculation pump is provided to transfer liquid from one holdup tank to another.

Liquid effluent in the holdup tanks is processed through a recycle processing train. This liquid is pumped by the gas stripper feed pumps through the evaporator feed ion exchangers which primarily remove lithium and long-lived cesium. The liquid then flows through the ion exchanger filter, and into the gas stripper section of the combined boric acid evaporator-gas stripper package where dissolved gases are removed from the liquid. These gases are vented to the Gaseous Waste Disposal System.

The liquid effluent from the gas stripper section enters the boric acid evaporator.

The vapor produced in the boric acid evaporator leaves the evaporator condenser and is pumped through a condensate cooler where the distillate is cooled to the operating temperature of the evaporator distillate demineralizers. After non-volatile evaporator carry over is removed by one of the two evaporator distillate demineralizers, the distillate then flows through the distillate filter and accumulates in one of the two monitor tanks. The evaporator bottoms left behind in the boric acid evaporator are concentrated to approximately twelve weight percent boric acid.

Subsequent handling of the condensate is dependent on the results of sample analysis of the monitor tank contents. Discharge from the monitor tanks may be pumped by either of the two monitor tank drain pumps to the primary water storage tank, recycled through the evaporator distillate deminerlizers, returned to the holdup tanks for reprocessing in the evaporator train or, if the sample analysis of the monitor tank contents indicates sufficiently low levels, the contents may be discharged to the environment via the Waste Disposal System (Chapter 11).

Boric acid evaporator bottoms are discharged through a concentrates filter to the concentrates holding tank. Solutions collected in the concentrates holding tank are sampled, and if analysis indicates that it meets specifications for use as boric acid makeup, it is then pumped by one of two shared concentrates holding tank transfer pumps to the boric acid tanks. Otherwise, concentrates are returned to the holdup tanks for reprocessing by the evaporator train.

The concentrated solution can also be pumped from the evaporator to the Waste Disposal System waste evaporator for additional reprocessing before being placed in containers. These containers can then be stored at the plant site for ultimate shipment off-site for disposal.

The deborating demineralizers can be used intermittently to remove boron from the reactor coolant near the end of core life when boron concentration is low. When the deborating demineralizers are in operation, the letdown stream passes through the mixed bed demineralizers and then through the deborating demineralizers and into the volume control tank after passing through the reactor coolant filter.

During plant cooldown when the residual heat removal loop is operating and the letdown orifices are not in service, a flow path is provided to remove fission products, corrosion products and other impurities. A portion of the flow leaving the residual heat exchangers passes through the letdown heat exchanger, mixed bed demineralizers, reactor coolant filter and volume control tank. The fluid is then pumped via the charging pump through the tube side of the regenerative heat exchanger into the Reactor Coolant System.

9.3.4.2.2 Expected Operating Conditions

Tables 9.3-5 and 9.3-6 list the system performance requirements and data for individual system components respectively.

9.3.4.2.3 Reactor Coolant Activity Concentration

The parameters used in the calculation of the reactor coolant fission product inventory, including the expected coolant cleanup flow rate and the demineralizer effectiveness, are presented with the results of the calculations in Appendix I. In these calculations the defective fuel rods are assumed to be present at core loading uniformly distributed throughout the core. The fission product escape rate coefficients are therefore based upon an average fuel temperature.

Tritium is produced in the reactor from ternary fission in the fuel, irradiation of boron in the burnable poison rods (during initial fuel cycle only), irradiation of boron in the control rods, and irradiation of boron, lithium and deuterium in the coolant.

9.3.4.2.4 Reactor Makeup Control Modes

The reactor makeup control is designed to operate from the Control Room by manually pre-selecting makeup compositon to the charging pump suction header or the volume control tank in order to maintain the desired operating fluid inventory in the volume control tank and to adjust the reactor coolant boron concentration for reactivity control. The operator can stop the makeup operation at any time in any operating mode by remotely closing the makeup stop valves or depressing the makeup mode selector stop pushbutton.

Makeup water to the Reactor Coolant System is provided by the Chemical and Volume Control System from the following sources:

1. The primary water storage tank, which provides water for dilution when the reactor coolant boron concentration is to be reduced.

2. The boric acid tanks, which supply concentrated boric acid solution when the reactor coolant boron concentration is to be increased.

3. The refueling water storage tank which supplies borated water for emergency makeup.

4. The chemical mixing tank, which is used to inject small quantities of solution when additions of hydrazine of pH control chemical (Li^7OH) are necessary.

Makeup for normal plant leakage is regulated by the reactor makeup control which is set by the operator to blend water from the primary water storage tank with concentrated boric acid to match the reactor coolant boron concentration. Makeup is added automatically if the volume control tank level falls below a preset point.

Automatic Makeup

The "automatic makeup" mode of operation of the reactor primary water makeup control provides boric acid solution present to match the boron concentration in the Reactor Coolant System. The automatic makeup compensates for minor leakage of reactor coolant without causing significant changes in the coolant boron concentration.

The operator sets the following equipment in the automatic position:

1. Either primary water makeup pump.

2. Either boric acid transfer pump.

3. Boric acid flow control valve.

4. Primary water flow control valve.

5. Charging suction makeup valve.

6. Makeup mode selector.

By depressing the start pushbutton of the makeup mode selector, the following actions occur when a low level signal is received from the volume control tank:

1. The boric acid transfer pump is switched to high speed and the primary water makeup pump is switched on.

2. The boric acid flow control valve is switched to its respective flow controller.

3. The primary water flow control valve is unblocked.

4. The charging suction makeup valve is open.

The flow controllers then blend the makeup stream according to the pre-sent concentration. Makeup addition to either the charging pump suction header or the spray line to the volume control tank causes the water level in the volume control tank to rise. After the level in the volume control tank is restored, the primary water flow control valve closes, the boric acid transfer pump is returned to low speed operation, the boric acid flow control valve returns to the full open position and the charging suction makeup valve closes.

Dilution

The "dilute" mode of operation permits the addition of a pre-selected quantity of reactor primary water makeup at a pre-selected flow rate to the Reactor Coolant System. The operator sets the following equipment in the automatic position:

1. Either primary water makeup pump.

2. The primary water flow control valve.

3. The volume control tank makeup valve.

He then selects the setpoint for the primary water makeup flow rate and the total quantity of makeup water desired on the primary water flow register. By depressing the "dilute" and start pushbuttons on the makeup mode selector, the following actions are initiated:

1. The primary water makeup pump is switched on.

2. The primary water flow control valve is unblocked.

3. The boric acid flow control valve is closed if it is in the automatic position.

4. The volume control tank makeup valve is opened.

This provides a regulated supply of unborated primary water to the volume control tank which subsequently goes to the charging pump suction header. When the preset quantity of primary water makeup has been added, the primary water flow register causes the primary water makeup pump to stop, the primary water flow control valve to close, and the volume control tank makeup valve to close.

The volume control tank level is controlled by a three way valve which normally modulates flow between the volume control tank and the hold-up tanks with a level controller. In the event the level becomes abnormally high, the entire flow is diverted to the hold-up tanks.

Alternate Dilution

The "alternate dilute" mode of operation provides a more rapid reduction of boric acid concentration than the "dilute" mode. This is accomplished by opening both the charging suction makeup valve and the volume control tank makeup valve. The operation is the same as described for the "dilute" mode except the operator must have the charging suction makeup valve in the automatic position in addition to the equipment listed for the "dilute" mode, and he must depress the "alternate dilute" pushbutton of the makeup mode selector instead of the "dilute" pushbutton.

Boration

The "borate" mode of operation permits the addition of a pre-selected quantity of concentrated boric acid solution at a pre-selected flow rate to the Reactor Coolant System. The operator sets the following equipment in the automatic position:

1. Either boric acid transfer pump.

2. The charging suction makeup valve.

3. The boric acid control valve.

He then selects the setpoint for the concentrated boric acid flow rate and the total quantity of concentrated boric acid desired on the boric acid flow register. By depressing the "borate" and start pushbuttons of the makeup mode selector the following actions are initiated:

1. The boric acid transfer pump is switched to high speed.

2. The boric acid flow control valve is switched to its respective flow controller.

3. The charging suction makeup valve is opened.

This provides a regulated supply of twelve weight percent boric acid solution to the charging pump suction header. The total quantity added in most cases will be so small that it will have only a minor effect on the volume control tank level. When the present quantity of concentrated boric acid solution has been added, the boric acid flow register causes the boric acid transfer pump to return to low speed operation and closes the charging suction makeup valve and returns the boric acid flow control valve to the full open position. In the event of a volume control tank low-low level signal, the suction of the charging pumps is automatically aligned to take suction from the refueling water storage tank.

The maximum rate of boration of the primary system with the 75 gpm discharge of a boric acid transfer pump directed to the charging pump suction is 24.0 ppm/minute, which compensates for a cooldown rate of 6°F/minute at the end of core life when the moderator temperature coefficient is most negative.

The maximum rate of boration with the two centrifugal charging pumps delivering water from the refueling water storage tank at a concentration of 2000 ppm boron is 9 ppm/minute. This compensates for a cooldown rate of 2°F/minute at the end of core life when the moderator temperature coefficient is most negative. By comparison, normal cooldown rates are about 0.8°F/minute.

Deviation of reactor primary water makeup flow rate from the control set point and deviation of concentrated boric acid flow rate from the control set point are alarmed on the main control board.

9.3.4.2.5 Charging Pump Control

Positive Displacement Charging Pump

The positive displacement charging pump has a variable speed drive and supplies charging flow to the Reactor Coolant System.

The speed of this pump can be controlled manually, or automatically by pressurizer level. During load changes the pressurizer level set point varies automatically with T_{avg}, compensating partially for the expansion or contraction of reactor coolant associated with T_{avg} changes. Charging pump speed will not change rapidly with pressurizer level controller. If the pressurizer level increases, the speed of the pump decreases; conversely, if the level decreases, the speed increases. If the positive displacement charging pump reaches the high speed limit, it becomes necessary to place a centrifugal pump in operation to provide the higher flow capacity.

To ensure that the charging pump flow is always sufficient to meet the seal water flow requirements of the reactor coolant pumps, the pump has a low-speed stop which prevents pump flow lower than the specified minimum.

Centrifugal Charging Pumps

The centrifugal pumps are constant speed pumps with flow control accomplished by a modulating valve in the pump discharge line. When the positive displacement pump is in operation, this control valve is in the wide open position.

A flow transmitter on the charging line upstream of the regenerative heat exchanger transmits a signal to a controller which regulates a modulating valve in the charging line to maintain a preset charging flow. A pressurizer water level error signal resets the charging flow set point to take corrective action. The response of the charging line modulating valve to changes in the flow control signal is normally maintained slow to reduce charging flow fluctuations due to short term pressurizer level transients.

9.3.4.2.6 Components

A summary of principal component data is given in Table 9.3-6.

Regenerative Heat Exchanger

The regenerative heat exchanger is designed to recover heat from the letdown flow by reheating the charging flow, to eliminate reactivity effects due to insertion of cold water, and to reduce thermal shock on the charging penetrations into the reactor-coolant-loop piping.

The design also considers the limit of difference in temperature which occurs during periods when letdown flow exceeds charging flow by a greater margin than at normal letdown conditions.

The letdown stream flows through the shell of the regenerative heat exchanger and the charging stream flows through the tubes. The unit is made of austenitic stainless steel, and is of all welded construction. It is a multi-shell U tube type heat exchanger using three shells.

Letdown Orifices

One of the three letdown orifices controls flow of the letdown stream during normal operation and reduces the pressure to a value compatible with the letdown heat exchanger design. Two of the letdown orifices are designed to pass normal letdown flow. The third orifice is designed to be used in conjunction with one normal letdown flow orifice to maintain maximum purification flow at normal Reactor Coolant System operating pressure. The orifices are placed in and taken out of service by remote manual operation of their respective isolation valves. The standby orifice may be used in parallel with the normally operating orifice in order to increase letdown flow when the Reactor Coolant System pressure is below normal. This arrangement provides a full standby capacity for control of letdown flow. Each orifice is an austenitic pipe containing a bored corrosion and erosion resistant insert.

Letdown Heat Exchanger

The letdown heat exchanger cools the letdown stream to the operating temperature of the mixed bed demineralizers. Reactor coolant flows through the tube side of the exchanger while component cooling water flows through the shell. The letdown stream outlet temperature is automatically controlled by a temperature control valve in the component cooling water outlet stream. The unit is a multiple-tube-pass heat exchanger. All surfaces in contact with the reactor coolant are austenitic stainless steel, and the shell is carbon steel.

Mixed Bed Demineralizers

Two flushable mixed bed demineralizers assist in maintaining reactor coolant purity. A Li^7 cation resin bed and a hydroxyl form anion resin are charged into the demineralizers. Both forms of resin remove fission and corrosion products. The resin bed is designed to reduce concentration of ionic isotopes in the purification stream except for cesium, yttrium and molybdenum, by a minimum factor of 10. The anion resin rapidly converts in service to a borate form and thereafter does not remove boron from the reactor coolant.

Each demineralizer is sized to accommodate the maximum letdown flow. One demineralizer serves as a standby unit for use if the operating demineralizer becomes exhausted during operation.

The demineralizer vessels are provided with suitable connections to facilitate resin replacement when required. The vessels are equipped with a resin retention screen. Each demineralizer has sufficient capacity for approximately one core cycle with one percent defective fuel rods.

Cation Bed Demineralizer

A flushable cation resin bed in the hydrogen form is located downstream of the mixed bed demineralizers and is used intermittently to control the concentration of Li^7 which builds up in the coolant from the B^{10} (n, α) Li^7 reaction. The demineralizer also has sufficient capacity to maintain the cesium-137 concentration in the coolant below 1.0 μc/cc with 1 percent defective fuel. The demineralizer is used intermittently to control cesium.

The demineralizer vessel is provided with suitable connections to facilitate resin replacement when required. The vessel is equipped with resin retention screens. The cation bed demineralizer has sufficient capacity for approximately one core cycle with one percent defective fuel rods.

Resin Fill Tank

The resin fill tank is mobile and is used to charge fresh resin to the demineralizers. The line from the conical bottom of the tank is fitted with a valve and a flexible hose spool piece that may be connected to any one of the demineralizer fill lines. The demineralizer water and resin slurry can then be sliced into the demineralizer by opening the valve.

Reactor Coolant Filter

The filter collects resin fines and particulates from the letdown stream. The vessel is provided with connections for draining and venting. The nominal flow capacity of the filter is equal to the maximum purification flow rate. Disposable synthetic filter elements in a cage assembly are used.

Volume Control Tank

The volume control tank is an operating surge volume compensating in part for reactor coolant releases from the Reactor Coolant System as a result of level changes. The volume control tank also acts as a head tank for the charging pumps and a reservoir for the leakage from the reactor coolant pump controlled leakage seal. Overpressure of hydrogen gas is maintained in the volume control tank to control the hydrogen concentration in the reactor coolant at 25 to 35 cc per kg of water (STP).

A spray nozzle is located inside the tank on the inlet line from the reactor coolant filter. This spray nozzle provides intimate contact to equilibriate the gas and liquid phases. A remotely operated vent valve discharging to the Waste Disposal System permits removal of gaseous fission products which are stripped from the reactor coolant and collected in the tank.

Charging Pumps

Three charging pumps are provided for injection coolant into the Reactor Coolant System. Two are centrifugal pumps and the third is a positive displacement pump equipped with variable speed drive. All parts in contact with the reactor coolant are fabricated of austenitic stainless steel or other material of adequate corrosion resistance. The centrifugal pump packing glands and positive displacement pump stuffing box are provided with leakoffs to collect reactor coolant before it can leak to the outside atmosphere. Pump leakage is piped to the drain header for disposal. The pump design prevents lubricating oil from contaminating the charging flow. The integral discharge valves on the positive displacement pump act as check valves.

The positive displacement pump is designed to provide the full charging flow and the reactor coolant pump seal water supply during normal seal leakage and normal letdown. The centrifugal pumps have a higher flow capacity and are used during periods of maximum letdown or purification flow. Each pump is deisgned to provide rated flow against a pressure equal to the sum of the Reactor Coolant System normal maximum pressure (existing when the pressurizer power operated relief valve is operating) and the piping, valve and equipment pressure losses at the design charging flows. Vibration dampers are installed on the suction and discharge of the positive displacement pumps.

The positive displacement charging pump is used to hydrotest the Reactor Coolant System.

Under normal conditions, either the positive displacement charging pump or a centrifugal charging pump will take suction from the volume control tank and discharge to the normal charging and reactor coolant pump seal water injection paths. If the positive displacement pump is not used, one of the centrifugal charging pumps is operated. The flow paths remain the same but flow control is accomplished by a modulating valve on the discharge side of the centrifugal pumps. For periods when maximum letdown or purification flow is required, a centrifugal pump is operated to provide the necessary flow. The centrifugal charging pumps also serve as safety injection pumps in the Emergency Core Cooling System (Chapter 6).

Chemical Mixing Tank

The primary use of the chemical mixing tank is in the preparation of caustic solutions for pH control and hydrazine for oxygen scavenging.

The capacity of the chemical mixing tank is determined by the quantity of 35 percent hydrazine solution necessary to increase the hydrazine concentration in the reactor coolant by 10 ppm. This capacity is more than sufficient to prepare solution of pH control chemical for the Reactor Coolant System.

Excess Letdown Heat Exchanger

The excess letdown heat exchanger cools an amount of reactor coolant letdown equal to the nominal injection rate through the reactor coolant pump labyrinth seal, if letdown through the normal letdown path is not usable. The unit is designed to reduce the letdown stream temperature from the cold leg temperature to 195°F. The letdown stream flows through the tube side and component cooling water is circulated through the shell side. All surfaces in contact with the reactor coolant are austenitic stainless steel and the shell is carbon steel. All tube joints are welded.

Seal Water Heat Exchanger

The seal water heat exchanger removes heat from several sources; the reactor coolant pump seal water returning to the volume control tank, the reactor coolant discharge from the excess letdown heat exchanger and the centrifugal charging pump by-pass flow. Reactor coolant flows through the tubes and component cooling water is circulated through the shell side. The tubes are welded to the tube sheet to prevent leakage in either direction and undesirable contamination of the reactor coolant or component cooling water. All surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel.

The unit is designed to cool the excess letdown flow, the pump seal water flow and the centrifugal charging pump by-pass flow to the temperature normally maintained in the volume control tank.

Seal Water Filter

This filter collects particulates from the reactor coolant pump seal water return and from the excess letdown heat exchanger flow. The filter is designed to pass the sum of the excess letdown flow and the maximum design leakage from the reactor coolant pump seals. The vessel is provided with connections for draining and venting. Disposable synthetic filter elements in a cage assembly are used.

Seal Water Injection Filters

The filter collects particulates from the reactor coolant pump seal water inlet. Two filters are provided in parallel, each sized for the maximum design pump seal flow rate. The vessel is provided with connections for draining and venting. Disposable synthetic filter elements in a cage assembly are used.

Boric Acid Filter

The boric acid filter collects particulates from the boric acid solution being pumped to the charging pump suction line or boric acid blender. The filter is designed to pass the design flow of two boric acid transfer pumps operating simultaneously. The filter elements are disposable synthetic cartridges in a cage assembly. Provisions are included for venting and draining the filter.

Boric Acid Tanks

The boric acid tanks, taken together, hold enough boric acid for cold shutdown and refueling without the need for mixing additional boric acid solution. Each tank holds 8000 gallons of boric acid solution at a concentration of 11-1/2 to 13 percent by weight (20,000 ppm to 22,500 ppm). Approximately 5100 gallons of this solution are required to meet cold shutdown requirements with the most reactive RCCA not inserted and about twice this amount is required to achieve refueling concentration of 2000 ppm. Therefore, about 15,000 gallons of boric acid are required for both evolutions, which is less than the 16,000 gallon combined volume of the two boric acid tanks. The Technical Specifications state the minimum amount of boric acid required to be available. It is likely that additional boric acid solution would be prepared following either of these evolutions (cold shutdown or refueling shutdown).

Periodic manual sampling and corrective action, if necessary, insures that these limits are maintained. As a consequence, measured amounts of boric acid solution can be delivered to the reactor coolant to control the chemical poison concentration. The combination overflow and breather vent connection has a water loop seal to minimize vapor discharge during storage of the solution.

Batching Tank

The batching tank is sized to hold one week's makeup supply of boric acid solution for transfer to the boric acid tanks. The basis for makeup is an arbitrary reactor coolant leakage of 1/2 gpm at beginning of core life. The tank may also be used for solution storage.

A local sampling point is provided for verifying the solution concentration prior to transferring it to the boric acid tank or for draining the tank. The tank is provided with an agitator to improve mixing during batching operations. The tank is provided with a steam jacket for heating the boric acid solution to 165°F.

Boric Acid Tank Heaters

Each of two electric immersion heaters in each boric acid tank is designed to maintain the temperature of the boric acid solution at 165°F with ambient air temperature of 40°F, thus ensuring a temperature in excess of the solubility limit (for 12 percent boric acid solution, this is approximately 130°F). The heaters are sheathed in austenitic stainless steel.

Boric Acid Transfer Pumps

Two horizontal, centrifugal, two speed pumps with mechanical seals are supplied. Normally one pump is aligned with one boric acid tank and runs continuously at low speed to provide recirculation of the boric acid system, boric acid tank, and boron injection tank in the Safety Injection System. The second pump is aligned with the second boric acid tank and is then considered as a standby pump, with service being transferred as operation requires. This second pump also intermittently circulates fluid through the second tank. Manual or automatic initiation of the Reactor Coolant Makeup System will activate the running pump to the higher speed to provide normal makeup of boric acid solution as required. For emergency boration, supplying of boric acid solution to the suction of the charging pump can be accomplished by manually choosing either fast or slow speed and actuating either or both pumps. The transfer pumps also function to transfer boric acid solution from the batching tank to the boric acid tanks.

The design capacity of each pump is equal to the normal letdown flow with the capacity of both pumps being equivalent to the normal design capacity of one centrifugal charging pump. The design discharge pressure is sufficient to overcome any pressures which may exist in the suction manifold of the charging pumps (volume control tank relief valve setting). In addition to the automatic actuation by the makeup control system, and manual actuation from the main control board, these pumps may also be controlled locally.

The pumps are heat traced to prevent crystallization of the boric acid solution. All parts in contact with the solution are of austenitic stainless steel. Connections are provided to enable the use of these pumps to flush the equipment and piping with primary water.

Each boric acid transfer pumps is powered by a separate 460 V. vital bus which is capable of being supplied by the associated diesel generator in the event of loss of off-site power.

Each boric acid transfer pump can pump from either boric acid tank. Operator action to place the plant in a cold shutdown condition with one boric acid tank unavailable would consist merely of using the other tank.

Boric Acid Blender

The boric acid blender promotes thorough mixing of boric acid solution and primary water makeup for the reactor coolant makeup circuit. The blender consists of a conventional pipe fitted with a perforated tube insert. The blender decreases the pipe length required to homogenize the mixture for taking a representative local sample.

Holdup Tanks

Three holdup tanks contain radioactive liquid which enters the tanks from the letdown line. The liquid is released from the Reactor Coolant System during startup, shutdowns, load changes and from boron dilution to compensate for burnup. The contents of one tank are normally being processed by the gas stripper boric acid evaporator packages while another tank is being filled. The third tank is available for storage as required.

The total liquid storage capacity of the three holdup tanks is equal to two Reactor Coolant System volumes. The tanks are constructed of austenitic stainless steel. The cover gas used in these tanks is nitrogen.

Holdup Tank Recirculation Pump

The recirculation pump is used to mix the contents of a holdup tank for sampling or to transfer the contents of a holdup tank to another holdup tank. The wetted surface of this pump is constructed of austenitic stainless steel.

Gas Stripper Feed Pumps

The two gas stripper feed pumps supply feed to the gas stripper-boric acid evaporator train from the holdup tanks. The capacity of each pump is equal to the capacity of a gas stripper-evaporator. The non-operating pump is a standby and is available for operation in the event the operating pump malfunctions. These canned centrifugal pumps are constructed of austenitic stainless steel.

Evaporator Feed Ion Exchangers

Four flushable evaporator feed ion exchangers remove cations (primarily cesium and lithium) from the holdup tank effluent.

The design flow rate is equal to the gas stripper-boric acid evaporator processing rate. The demineralizer vessels are contructed of austenitic stainless steel and are provided with suitable connections to facilitate resin replacement when required. The vessels are equipped with resin retention screens.

Ion Exchanger Filters

These filters collect resin fines and particulates from the evaporator feed ion exchangers. The vessels are made of austenitic stainless steel and are provided with connections for draining and venting. Disposable synthetic filter elements in a cage assembly are used. The maximum design flow capacity is equal to the boric acid evaporator flow rate.

Gas Stripper - Boric Acid Evaporator Package

One gas stripper-boric acid evaporator package is provided. The package will process 30 gpm of dilute radioactive boric acid and produce distillate and approximately 12 weight percent of concentrated boric acid, both stripped of the radioactive gases. Radioactive gas stripping is achieved by passing heated feed through packed towers employing stripping steam which removes nitrogen, hydrogen and fission gases from the feed and is designed to reduce the influent gas concentration by a factor of 10^5.

After stripping, the feed enters the evaporator where it is evaporated by a submerged steam tube bundle. The vapors leaving the boiling pool are stripped of entrained liquid and volatile boron by passing through an absorption tower. Pure vapors are then condensed in the condenser section and pumped from the system. When the desired concentration is reached in the boiling pool, the concentrates are pumped from the system. The solids decontamination factor between the condensate and bottoms is approximately 10^6. All evaporator equipment is constructed of austenitic stainless steel.

A boric acid solution is fed from the holdup tanks through the ion exchangers to the gas stripper evaporator packages at a temperature of 50 to 130°F. The feed then passes through a heat exchanger where condensing steam raises its temperature to about 215°F. The feed then passes into the top of the stripping column. Radioactive and other gases are stripped off as the feed passes over the packing in the tower. After stripping, the feed is introduced into the evaporator as make-up. Radioactive gases and other non-condensables are discharged from the system into the waste disposal vent header.

Heating for the evaporator is provided by steam in a submerged tube bundle. Steam to the feed pre-heater is taken from the same system. A constant vapor pressure is maintained in the evaporator by a pressure control valve on the steam supply line.

A cooling water supply for condensing the distillate is passed through a tube bundle in the condenser.

Some of the distillate produced in the evaporator passes through the absorption tower. This reduces ionic carryover and volatile boron carryover to less than 10 ppm. Condensed distillate is pumped from the system by a distillate pump. Conductivity measurement causes an automatic dump system to return contaminated distillate to the evaporator. Distillate is cooled to 120°F by passing through the distillate cooler heat exchanger.

The concentration of boric acid is determined by sampling and chemical analysis. The boric acid concentrates pump continuously draws a concentrated solution from the evaporator and through use of hand valves the operator can either return the concentrates to the evaporator or pump it to the concentrates holding tank. A concentrate sample connection is provided at the discharge of the boric acid concentrates pump.

The operating output of the system can be adjusted by manual (board mounted control) positioning of the distillate condenser flow control valve. Adjustment of cooling water flow controls the temperature/pressure of condensing distillate in the vapor section of the evaporator. Vapor temperature automatically controls steam input to the submerged tube heating bundle. Thus when the operator manually increases cooling water flow, the vapor temperature is lowered and the steam flow control valve automatically opens to compensate and maintain vapor temperature at the set point. When equilibrium is again reached, the overall operating output of the system is increased. Other control circuits such as concentrate level, feed temperature, distillate level, etc., will automatically follow the system conditions and maintain their set point.

In case of a low evaporator level, caused by feed failure, etc. an alarm will sound; the operator can open a manual distillate return valve which will return all distillate produced to the evaporator. This coupled with manual return of the blowdown will stop any loss of liquid or vapor from the system until level is returned to normal.

A low temperature in the evaporator, caused by failure of the automatic steam control valve, etc., would sound an alarm on the panel and the operator can open a manual steam bypass valve to raise the temperature.

All lines and miscellaneous equipment in the system containing concentrated boric acid are electric heat traced to prevent boric acid precipitation at low temperatures. Figure 9.3-_ shows two lines discharging from the Boric Acid Evaporator. The lines which is heat traced transfers the evaporator bottoms to the Concentrates Holding Tank. This line is heat traced due to high boron concentrates (21000 ppm). The line which is not heat traced is used as the stripping medium in the Gas Stripper. The line runs from the evaporator overhead (steam) and enters the bottom of the packed stripping column of the Gas Stripper. The steam contains low boron concentrates (approximately 100 ppm). Heat tracing is therefore not necessary.

The batching tank has a steam jacket to heat the boric acid solution. The source of steam heating for the batching tank is from the house heating boilers and/or one of the main turbines, either of which has a capacity of 140,000 lbs/hr. The batching tank steam jacket requires only 150 lbs/hr. The design, materials, testing and inspection of the batching tank are in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII.

Evaporator Distillate Demineralizers

Two anion demineralizers remove any boric acid contained in the evaporator distillate. Hydroxyl based ion-exchange resin is used to produce evaporator distillate of high purity by releasing a hydroxyl ion when a borate ion is absorbed. Facilities are provided for regeneration of the resin. When regeneration is no longer feasible, the resin is flushed to the spent resin storage tank. Each demineralizer is sized for a flow rate equal to the evaporator flow rate. The demineralizer vessel is made of all-welded austenitic stainless steel, and is equipped with a resin retention screen.

Distillate Filter

The filter collects resin fines and particulates from the boric acid evaporator condensate stream. The vessel is made of austenitic stainless steel, and is provided with connections for draining and venting. Disposable synthetic filter elements in a cage assembly are used. The design flow capacity of the filter is equal to the total installed gas stripper-boric acid evaporator flow rate.

Monitor Tanks

Two monitor tanks permit continuous operation of the evaporator train. When one tank is filled, the contents are analyzed and either reprocessed, discharged to the Waste Disposal System or pumped to the primary water storage tank.

Each of the tanks has sufficient capacity to hold the condensate produced during 12 hours of operation from an evaporator at full output.

The tanks are fitted with a nylon, rubber-coated membrane to prevent absorption of oxygen by the water stored in the tank. The portion of the tank above the membrane is vented to the auxiliary building atmosphere.

Monitor Tank Pumps

Two monitor tank pumps discharge water from the monitor tanks. Each pump is sized to empty a monitor tank is approximately 3 hours. The pumps are constructed of austenitic stainless steel.

Deborating Demineralizers

When required, two anion demineralizers remove boric acid from the Reactor Coolant System fluid. The demineralizers are provided for use near the end of a core cycle, but can be used at any time when boron concentration is low. Hydroxyl based ion-exchange resin is used to reduce Reactor Coolant System boron concentration by releasing hyroxyl ion when a borate ion is absorbed. Facilities are provided for regeneration. When regeneration is no longer feasible, the resin is flushed to the spent resin storage tank.

Each demineralizer is sized to remove the quantity of boric acid that must be removed from the Reactor Coolant System to maintain full power operation near the end of core life should the holdup tanks be full.

Concentrates Filter

A disposable synthetic cartridge type filter removes particulates from the evaporator concentrates. Design flow capacity of the filter can accomodate the total installed boric acid evaporator capacity. The vessel is provided with connections for draining and venting. Disposable synthetic filter elements in a cage assembly are used.

Concentrates Holding Tank

The concentrates holding tank is sized to hold approximately the production of concentrates from one batch from the evaporator. The tank is supplied with an electrical heater which prevents boric acid precipitation.

Concentrates Holding Tank Transfer Pump

Two holding tank transfer pumps discharge boric acid solution from the concentrates holding tank to the boric acid tanks. The canned centrifugal pumps are sized to approximately match the capacity of the boric acid evaporator concentrates pumps or to pump out the contents of the tank in approximately 1 hour. The wetted surfaces are constructed of austenitic stainless steel.

Electrical Heat Tracing

Electrical heat tracing is installed under the insulation on all piping, valves, line-mounted instrumentation, and components normally containing concentrated boric acid solution. The heat tracing is designed to prevent boric acid precipitation due to cooling, by compensating for heat loss. The heat tracing is considered to be a vital load and is operable from the diesel generators.

Exceptions are:

1. Lines which may occasionally transport concentrated boric acid but are subsequently flushed with reactor coolant or other liquid of low boric acid concentration during normal operation.

2. The boric acid tanks which are provided with immersion heaters.

3. The batching tank which is provided with a steam heated jacket.

4. The concentrates holding tank, which is provided with an immersion heater.

Power failures in the heat tracing system can be detected by:

1. Loss of AC power failure alarm in each distribution panel, if power source to the distribution panel fails. This alarm is indicated in the control room.

2. Low temperature, high temperature and loss of a normal heating circuit are alarmed in the control room. Alarm indication remains until corrective action has been completed.

Each heat traced pipe has duplicate heat tracing cable. Each cable is fed from separate sources which are connected to the vital bus system. In the event of a loss of all off-site power, the diesel generators will supply the power requirements for the heat tracing system.

Lines which are provided with heat tracings are shown in Figures 9.3-4A and B, 9.3-5A and B, and 9.3-6A and B.

Valves

Valves that perform a modulating function are equipped with two sets of packing and an intermediate leakoff connection that discharges to the Waste Disposal System. Valves are normally installed such that, when closed, pressure is not on the packing. Basic material of construction is stainless steel for all valves.

Isolation valves are provided for all connections to the Reactor Coolant System. Lines entering the reactor containment also have check valves inside the containment to prevent reverse flow from the containment.

Relief valves are provided for lines and components that might be pressurized above design pressure by improper operation or component malfunction. Pressure relief for the tube side of the regenerative heat exchanger is provided by a locked open valve and a 250 psi spring loaded check valve bypassing the charging isolation valves.

Piping

All Chemical and Volume Control System piping handling radioactive liquid is austenitic stainless steel. All piping joints and connections are welded, except where flanged connections are required to facilitate equipment removal for maintenance and hydrostatic testing.

Primary Water Storage Tank

The tank is provided with a high level alarm and the overflow line is piped to the diked area around the No. 13 Chemical and Volume Control holdup tank, from where any overflow can be pumped to the Liquid Waste Disposal System. The overflow line includes a collection pot which is also provided with a high level alarm. Both alarms are indicated in the control room.

9.3.4.3 System Design Evaluation

9.3.4.3.1 Availability and Reliability

A high degree of functional reliability is assured in the Chemical and Volume Control System by providing standby components where performance is vital to safety and by assuring fail-safe response to the most probable mode of failure. Special provisions include duplicate heat tracing with alarm protection of lines, valves, and components normally containing concentrated boric acid and required for boric acid control.

The Chemical and Volume Control System has three high pressure charging pumps, which are capable of supplying the required reactor coolant pump seal and makeup flow.

Aside from those components that are also part of the Emergency Core Cooling System (Chapter 6), the Chemical and Volume Control System is not required to function during a loss-of-coolant accident.

The generation of a safety injection signal automatically closes the motor-operated valves in the outlet line of the volume control tank and in the normal charging line thus isolating the Chemical and Volume Control System from the safety injection path. The letdown line and reactor coolant pump seal water return line are isolated at the containment boundary by a valve which automatically closes as a result of high containment pressure caused by a loss-of-coolant accident. The centrifugal charging pumps are also automatically started and commence pumping into the Reactor Coolant System immediately.

9.3.4.3.2 Control of Tritium

The Chemical and Volume Control System is also used to control the concentration of tritium in the Reactor Coolant System. Essentially all of the tritium is in chemical combination with oxygen as a form of water. Therefore, any leakage of coolant to the containment atmosphere carries tritium in the same proportion as it exists in the coolant. Thus, the level of tritium in the containment atmosphere, when it is sealed from outside air ventilation, is a function of tritium level in the reactor coolant, the dew point temperature of the air, and the presence of leakage other than reactor coolant as a source of moisture in the containment air.

There are two major considerations with regard to the presence of tritium in the reactor coolant:

1. Possible plant personnel hazard during access to the containment must be limited. Leakage of reactor coolant during operation with a closed containment causes an accumulation of tritium in the containment atmosphere.

2. Undue public hazard due to release of tritium to the plant environment must be avoided.

Both of these criteria are met in this plant. The concentration of tritium in the reactor coolant is maintained at a level which precludes personnel hazard during access to the containment. This can be achieved by discharging part of the distillate from the primary water recovery process to the Waste Disposal System (Chapter 11).

Essentially all of the tritium in the reactor coolant will eventually be released via the Radwaste System (Chapter 11) to the plant discharge stream. In the plant discharge stream, the tritium (and other liquid radwastes) is mixed with the plant effluent water flow.

9.3.4.3.3 Leakage Provisions

Quality control of the material and installation of the Chemical and Volume Control System valves and piping which are designated for radioactive service is provided, in order to essentially eliminate leakage to the atmosphere.

The components designated for radioactive service are provided with welded connections to prevent leakage to the atmosphere. However, flanged connections are provided on each charging pump suction and discharge, on each boric acid pump suction and discharge, on the relief valves inlet and outlet, on three-way valves and on the flow meters to permit removal for maintenance.

The positive displacement charging pump stuffing box is provided with a leakoff to collect reactor coolant before it can leak to the atmosphere. All valves which are larger than 2 inches and which are designated for radioactive service at an operating fluid temperature normally above 212°F are provided with a stuffing box and lantern leakoff connections. All control valves are either provided with stuffing box and leakoff connections or are totally enclosed. Leakage to the atmosphere is essentially zero for these valves.

Diaphragm valves are provided where the operating pressure is 200 psi or below and the operating temperature is 200°F or below. Leakage to the atmosphere is essentially zero for these valves.

9.3.4.3.4 Incident Control

The letdown line and the reactor coolant pumps seal water return line penetrate the reactor containment. The letdown line contains three air-operated valves inside the reactor containment and one air-operated valve outside the reactor containment which are automatically closed by the containment isolation signal. The reactor coolant pumps seal water return line contains one motor-operated isolation valve outside the reactor containment and one motor-operated valve inside the containment which are automatically closed by the containment isolation signal.

The four seal water injection lines to the reactor coolant pumps and the charging line are inflow lines penetrating the reactor containment. Each line contains a check valve inside the reactor containment to provide isolation of the reactor containment should a break occur in these lines outside the reactor containment.

In the event of an accidental release of a radioactivity in the area housing the Chemical and Volume Control System, personnel safety equipment is available and will be used to protect operating personnel. For example, equipment such as respirators, appropriate protective clothing, and radiation survey meters would be used to guard against inhalation of possible airborne activity, personnel containmination, and exposure to possibly high radiation levels. Immediately after the accidental release of a radioactive source, entry into the building housing the Chemical and Volume Control System will be through an access control point under the supervision of health physics trained personnel. The required equipment, outlined above, will be available in the vicinity of the control point. This area also contains a monitoring and clothing change area, a personnel decontamination washroom and showers, and a first aid room.

Radiation levels outside of a shielded compartment where such a release has occurred will not be severly affected. The dose rates outside the shield wall could rise from 2.5 MR/hr to approximately 4.0 MR/hr until cleanup procedures have been initiated. This higher dose rate is based on a leak large enough to result in all inner compartment surfaces being covered with radioactive liquid, and that the excess liquid that drains from the surfaces runs into the floor drains. The liquid activity is assumed to be that associated with 1 percent failed fuel. If the excess liquid did not flow into the floor drains and was contained within the compartment, the dose rate outside the shield wall could rise to approximately 25 MR/hr.

If a demineralizer ruptured releasing all its resin into the shielded compartment, the dose rates outside the compartment would not be significantly affected since each demineralizer tank is in a cell which is completely isolated from personnel and separated from the operating aisle by a valve gallery shield wall. Further, no credit for the thickness of the demineralizer wall was taken in the design of the concrete shield wall.

9.3.4.3.5 Malfunction Analysis

To evaluate system safety, failures or malfunctions were assumed concurrent with a loss-of-coolant accident, and the consequences analyzed, see Table 9.3-7 and Chapter 15.

If a rupture takes place between the reactor coolant loop and the first isolation valve or check valve, an uncontrolled loss of reactor coolant occurs. The analysis of the loss-of-coolant accident is discussed in Chapter 15.

Should a rupture occur in the Chemical and Volume Control System outside the containment, or at any point beyond the first check valve or remotely operated isolation valve, actuation of the valve would limit the release of coolant and assure continued functioning of the normal means of heat dissipation from the core. For the general case of rupture in the CVCS outside the containment, the largest source of radioactive gases and fluid subject to release is the contents of the volume control tank. The consequences of such a release are considered in Chapter 15.

When the reactor is subcritical, i.e., during cold or hot shutdown, refueling and approach to criticality, the relative reactivity status (neutron source multiplication) is continuously monitored and indicated by BF_3 counters and count rate indicators. Any appreciable increase in the neutron source multiplication, including that caused by the maximum physical boron dilution rate, is slow enough to give ample time to start corrective action (boron dilution stop and emergency boron injection) to prevent the core from becoming critical. This case is analyzed in Chapter 15.

At least two separate and independent flow paths are available for reactor coolant boration; i.e., the charging line, or the reactor coolant pumps labyrinths. The malfunction or failure of one component does not result in the inability to borate the Reactor Coolant System. An alternate flow path is always available for emergency boration of the reactor coolant. As backup to the boration system, the operator can align the refueling water storage tank outlet to the suction of the charging pumps.

Boration during operation to compensate for power changes will be indicated to the operator from a combination of two sources: (a) the control rod movement and (b) the flow indicator in the boric acid transfer pump discharge line. When the emergency boration path is used, four indications to the operator are available. The primary indication is a flow indicator in the emergency boration line. The charging line flow indicator will indicate boric acid flow since the charging pump suction is aligned to the boric acid transfer pump suction for this mode of operation. The change in boric acid tank level and control rod motion are other indications of boric acid injection.

On loss of seal injection water to the reactor coolant pump seals, seal water flow may be reestablished by manually rerouting the flow or starting a standby charging pump. Even if the seal water injection flow is not reestablished, the plant can be operated indefinitely since the thermal barrier cooler has sufficient capacity to cool the reactor coolant flow which would pass through the thermal barrier cooler and seal leakoff from the pump volume.

It can be concluded that proper consideration has been given to station safety in the design of the system.

9.3.4.3.6 Galvanic Corrosion

The only types of materials which are in contact with each other in borated water are stainless steels, Inconel, Stellite valve materials and Zircaloy fuel element cladding. Those materials have been shown to exhibit only an insignificant degree of galvanic corrosion when coupled to each other.

For example, the galvanic corrosion of Inconel versus 304 stainless steel resulting from high temperature tests (575°F) in lithiated, boric acid solution was found to be less than -20.9 mg/dm^2 for the test period of 9 days. Further galvanic corrosion would be trivial since the cell currents at the conclusion of the tests were approaching polarization. Zircaloy versus 304 stainless steel was shown to polarize at 180°F in lithiated, boric acid solution in less than 8 days with a total galvanic attack of -3,0 gm/dm^2. Stellite versus 304 stainless steel was polarized in 7 days at 575°F in lithiated boric acid solution. The total galvanic corrosion for this couple was -0.97 gm/dm^2.

As can be seen from the tests, the effects of galvanic corrosion are insignificant to systems containing borated water.

9.3.4.4 Tests and Inspections

Those portions of the Chemical and Volume Control System associated with the Emergency Core Cooling System will be subject to the same type of inspections required for those systems as outlined in Chapter 6. Special tests and inspections for the remainder of the Chemical and Volume Control System are not required because the system is in daily operation. Routine maintenance during refueling can be performed on system components.

The contents of the Boric Acid Tanks will be sampled at least once per week to assure required boric acid concentrations.

9.3.5 FAILED FUEL DETECTION SYSTEM

9.3.5.1 Design Basis

The gross failed fuel detection system consists of equipment designed to indicate gross fuel failure by monitoring the delayed neutron activity in the reactor coolant.

9.3.5.2 System Description

The gross failed fuel detector is connected to the hot leg of a primary coolant loop (Figure 9.3-9). The coolant sample passes through a cooler and then into a coil encompassing a neutron detector and moderator, then to a connection upstream of the mixed bed demineralizers after which it flows back into the volume control tank. The delay time depends on the length of tubing used. A transmitting flowmeter is installed for periodic checks of the flow rate. A sensor monitors the sample cooler outlet temperature.

Figure 9.3-10 shows the block diagram of the gross failed fuel detector channel. The detector, preamp, sample coolers, and associated flow indication are located outside the containment. The signal processing equipment and readout are mounted in a rack located in the control room.

The delayed neutron signal of the detector is displayed on a recorder located in the rack. The response time for the gross failed fuel detector is on the order of 60 seconds.

9.3.5.3 Safety Evaluation

The gross failed fuel detection system does not perform a safety related function, and is not designed to satisfy any specific safety criteria. As shown on Figure 9.3-9, the gross failed fuel detector is outside of the containment and is installed in the primary coolant hot leg sample line. It is isolated from the containment by means of the sample system isolation valves. The safety evaluation of the sampling system, including the isolation valve, is discussed in Section 9.3.2.

A confirmatory radiochemical analysis for failed fuel in the primary system would be performed and would require approximately 1-1/2 hours of sampling, preparation, counting and calculations. In the event that personnel to perform analysis is not on site, an additional 2 hours will be required for notification and travel time.

The system measures gamma radiation in a continuously flowing sample of primary coolant. It is designed to monitor the coolant for gross gamma activity and specific nuclides simultaneously. This is accomplished by using a common gamma scintillation detector coupled to two ratemeters.

In addition to continuous indication of the reactor coolant activity, abnormal conditions are alarmed in the Control Room.

The detector is capable of measuring up to 1 x 10^7 cpm. Provision is made for desensitizing the system by two or more decades to compensate for permanent activity buildup resulting from long-term normal operation. This is accomplished by insertion of a lead spacer between the sensitive end of the detector and the sample line.

In addition to using separate ratemeters for monitoring the gross gamma and I^{131}, a separate recorder and an associated ratiometer which records and indicates the ratio of iodine to gross gamma at all times is provided. Changes in activity in the letdown sample line from any cause other than failed fuel will result in proportionate changes in the I^{131} and gross gamma readings. A rise in activity caused by a fuel failure would result in a proportionately greater rise in the I^{131} than in the gross gamma. Therefore, the ratio between the readings of the two ratemeters (I^{131} and gamma) would remain constant, except after a fuel failure.

With the plant operating with reactor coolant activity corresponding to one percent failed fuel, the concentration of all isotopes in the coolant will be about 226 uCi/cc.

Assuming that "gross" fuel failure has occurred, the action that would be taken is a function of both the magnitude of reactor coolant activity and the rate of change. For the case where activity is higher than previous values, but below Technical Specification limits, the following action would be taken:

1. Increase purification flow to maximum.

2. Calculate coolant activity in uCi/cc and new E if greater than predetermined change in activity has occurred.

3. Increase sampling frequency to a minimum of once per day until trends are clearly established.

4. If coolant activity is increasing and approaching Technical Specification limits, reduce power and attempt to establish equilibrium.

5. Verify reactor power distribution to assure that rod patterns and flux shapes are within normal values.

In the event that coolant activity is increasing rapidly to the Technical Specification limit or has reached that limit, the plant would be shut down and cooled to 500°F or less.

The above actions would be initiated promptly following confirmatory radiochemical analysis. Most of these actions can be initiated upon receipt of the failed fuel alarm, except for trending, which will require several samples.

In the event the failed fuel monitoring system is inoperable, the gross radioiodine analysis of the reactor coolant system will be increased to 5 days per week with not longer than 72 hours between sampling intervals.

9.3.5.4 Tests and Inspection

The gross failed fuel detection system is equipped with a test oscillator in the pre-amplifier and a test oscillator in the electronics drawer, each of which can be used to test the proper operation of the signal processing circuitry.

9.3.5.5 Instrument Applications

Instrumentation associated with the gross failed fuel detection system is described in Section 9.3.5.2.

9.3.6 POST-ACCIDENT SAMPLING SYSTEM

9.3.6.1 Design Basis

The functional and design requirements for the Post-Accident Sampling System are contained in NUREG-0737 Item II.B.3 and in Regulatory Guide 1.97. The seismic design and quality group classification of the sampling lines and components conforms to the classification of the system to which each sampling line is connected. Seismic design is not required for components and piping downstream of the second isolation valve in the Post-Accident Sampling System.

The Post Accident Sampling System (PASS) provides the capability to obtain, under accident conditions, a containment air grab sample, reactor coolant grab sample (diluted and undiluted) and to perform various analyses using in-line instrumentation. Grab samples are used to determine isotopic concentrations of reactor coolant and containment air, boron concentration of reactor coolant and hydrogen concentration containment air. The in-line instrumentation provides analysis of dissolved hydrogen, dissolved oxygen, chlorides, conductivity and pH for reactor coolant. Acquisition and analysis of these samples can be performed in a manner which limits radiation exposure to personnel to 5 rem/year whole body and 75 rem/year to the extremities.

9.3.6.2 System Description

Sample Lines and Sample Points

Two redundant sample loops are utilized per unit (two separate channels). Reactor coolant sample lines connect into the 11, 13, 21, and 23 hot legs. Sample return lines are routed to the containment sump.

Containment atmosphere samples are tied into the Radiation Monitoring System sample supply lines. Samples are returned to containment.

Sampling lines inside containment and the containment isolation valves are designed to Nuclear Class II, Seismic Class I requirements. Sampling lines downstream of the second containment isolation valve are designed to Nuclear Class III, Seismic Class I requirements.

Sample lines are designed to minimize crud traps and dead legs. The lines are separated to provide assurance that a single pipe break will not render both loops inoperative.

Heat tracing of the containment air sample lines is provided from the penetration area to the sample room to minimize iodine plateout. Heat tracing is not required for lines inside containment or the sample return lines.

Penetrations are cooled with compressed air to limit the temperature of the containment wall surrounding the penetrations from exceeding 150°F.

Shielding is provided on the Unit 1 sampling lines where the lines cross the access corridors on the 100 Ft. elevation of the Auxiliary Building. All other sampling lines pass through shielded areas of the Auxiliary Building. Where feasible, lines are run along floors to facilitate the use of lead blankets should the need arise.

Analysis Equipment

The following sampling system equipment processes the reactor coolant and containment air samples.

The Liquid Sampling Panel (LSP) routes reactor coolant samples to the Chemical Analysis Panel (CAP) for on-line gas and liquid analysis.

The LSP also captures gases stripped from pressurized reactor coolant for isotopic analysis; depressurized, reactor coolant for boron and isotopic analysis; and depressurized, diluted reactor coolant for boron and isotopic analysis.

The CAP provides the capability for on-line determination of the pH, specific conductivity, oxygen content, and chloride content of a liquid sample. In addition, the gas chromatograph permits determination of the hydrogen content of the gas stripped from the reactor coolant.

The Containment Air Sampling Panel (CASP) collects grab samples.

The CASP Control Panel is used to select, start and monitor the CASP sample exercises. Once the operator has started the CASP, a programmer automatically performs the exercise.

Both the CASP Control Panel and the CAP Monitor Panel are separated from the LSP, CASP, and CAP by shielding to minimize operator exposure while operating the equipment.

The shielding in the panels limits the maximum dose from the panel to an operator per sampling exercise to 100 mrem.

Analytical equipment for isotopic analysis is located in the Counting Room on the 100 Ft elevation on the Unit 2 side of the Auxiliary Building. Sample preparation and boron analysis equipment are located in the Chemistry Lab on the 100 Ft elevation on the Unit 1 side of the Auxiliary Building. This equipment serves both Units 1 and 2.

The sampling room cooler maintains an environment that is satisfactory for both personnel and equipment operation.

Analysis equipment is not seismically qualified.

Interfaces

Piping connections to other fluid systems are designed consistent with the safety class and seismic category of the interfacing system. In particular interfaces with non-seismic portions are designed in such a way that failure of non-seismic portions of the Post-Accident Sampling System will not degrade the interfacing system performance.

Ten gallons per minute of component cooling water is supplied to the sample cooler rack to cool reactor coolant samples.

Redundant control air is provided for pneumatic operation of the containment isolation valves.

Demineralized water is provided for flushing the sample lines and analysis equipment after a sampling operation.

Nitrogen is provided for purging the containment air sampling lines and for the nitrogen-operated eductor which induces the flow of air from the containment to the CASP and back to containment.

9.3.6.3 Design Evaluation

Electric power is supplied from the 1E vital bus. Heat tracing is supplied with redundant power. Consequently the Post-Accident Sampling System is expected to remain operable during accidents concurrent with loss of offsite power. The Post-Accident Sampling System is not designed to operate following certain single failures, e.g., failure of sampling analysis equipment.

REFERENCES FOR SECTION 9.3.4

1. Sammarone,D. G., "The Galvanic Behavior of Materials in Reactor Coolants," WCAP 1844, August, 1961.

TABLE 9.3-1

SAMPLING SYSTEM CODE REQUIREMENTS

Primary sample heat exchanger	ASME III*, Class C, tube side ASME VIII, shell side
Sample pressure vessels	ASME III*, Class C
Piping and Valves	ANSI B31.1.0** ANSI B31.7***
Steam generator blowdown sample and steam sample heat exchangers	ASME III*, Class C, tube side ASME VIII, shell side

* ASME III - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III, Nuclear Vessels.

** ANSI B31.1.0 - Code for Power Piping, used for design.

*** For piping not supplied by the NSSS supplier, material inspection, fabrication and quality control conform to ANSI B31.7. Where not possible to comply with ANSI B31.7, the requirements of ASME III-1971, which incorporated ANSI B31.7, were adhered to.

TABLE 9.3-2 (Sheet 1 of 2)

SAMPLING SYSTEM COMPONENTS

Primary System Sampling Heat Exchanger

General

Number	3	
Type	Shell and coiled tube	
	Shell	Tube
Design pressure, psig	150	2485
Design temperature, °F	350	680
Design flow, gpm	14.1	.42
Temperature, in, °F	95	652.7 (max.)
Temperature, out, °F	125	127 (max.)
Material	Carbon steel	Austenitic Stainless Steel
Fluid	Component cooling water	Sample

Steam Generator Blowdown Sampling Heat Exchanger

General

Number	8	
Type	Shell and coiled tube	
Design pressure, psig	150	1500
Design temperature, °F	650	550
Design flow, gpm	6	0.40
Temperature, in, °F	95	550 (max.)
Temperature, out, °F	125	127 (max.)

TABLE 9.3-2 (Sheet 2 of 2)

SAMPLING SYSTEM COMPONENTS

	Shell	Tube
Material	Carbon steel	Austenitic Stainless Steel
Fluid	Component cooling water	Sample
Sample Pressure Vessels		
Number, total	1	
Volume, ml.	75	
Design pressure, psig	2485	
Design temperature, °F	680	
Material	Austenitic Stainless Steel	
Piping		
Design pressure, psig	2485	
Design temperature, °F	680	

TABLE 9.3-3

MALFUNCTION ANALYSIS OF SAMPLING SYSTEM

Component	Malfunction or Failure	Consequence
Pressurizer Sample Lines or Reactor Coolant Sample Lines	An isolation valve fails to close on containment isolation signal	The second isolation valve closes on containment isolation signal maintaining containment integrity
Any of the above Sample Lines	Break in line downstream of isolation valves	Isolation valves close on containment isolation signal
Sample Heat Exchangers	Loss of cooling water	Sample lines can be isolated at the containment. Cooling of samples is not required

TABLE 9.3-4

CHEMICAL AND VOLUME CONTROL SYSTEM CODE REQUIREMENTS

Regenerative heat exchanger	ASME III*, Class C
Letdown heat exchanger	ASME III, Class C, Tube Side, ASME VIII, Shell Side
Mixed bed demineralizers	ASME III, Class C
Reactor coolant filter	ASME III, Class C
Volume control tank	ASME III, Class C
Seal water heat exchanger	ASME III, Class C, Tube Side, ASME VIII, Shell Side
Excess letdown heat exchanger	ASME III, Class C, Tube Side, ASME VIII, Shell Side
Cation bed demineralizer	ASME III, Class C
Seal water injection filters	ASME III, Class C
Boric acid filter	ASME III, Class C
Evaporator condensate demineralizers	ASME III, Class C
Concentrates filter	ASME III, Class C
Evaporator feed ion exchangers	ASME III, Class C
Ion exchanger filter	ASME III, Class C
Condensate filter	ASME III, Class C
Piping and valves	ANSI B31.1** ANSI B31.7***

* ASME III - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III, Nuclear Vessels.

** ANSI B31.1 - Code for Power Piping, used for design.

*** For piping not supplied by the NSSS supplier, material inspection, fabrication, and quality control conform to ANSI B31.7. Where not possible to comply with ANSI B31.7, the requirements of ASME III-1971, which incorporated ANSI B31.7, were adhered to.

TABLE 9.3-5

CHEMICAL AND VOLUME CONTROL SYSTEM

DESIGN PARAMETERS

General

Plant design life, years	40
Seal water supply flow rate:	
Normal, gpm	32
Maximum, gpm	113
Seal water return flow rates:	
Normal, gpm	12
Maximum, gpm	93
Letdown flow:	
Normal, gpm	75
Minimum, gpm	45
Maximum, gpm	120
Charging flow:	
Normal, gpm	55
Minimum, gpm	25
Maximum, gpm	100
Temperature of letdown reactor coolant entering system, °F	547
Centrifugal pump miniflow, gpm	60 (each)
Temperature of charging flow directed to Reactor Coolant System, °F	495
Temperature of effluent directed to holdup tanks, °F	127

(volumetric flow rates in gpm are based upon 130°F and 2350 psig)

TABLE 9.3-6 (Sheet 1 of 17)

PRINCIPAL COMPONENT DATA SUMMARY

Regenerative Heat Exchanger

Number	1
Heat transfer rate at design conditions, Btu/hr	10.28×10^6

Shell Side

Design pressure, psig	2485
Design temperature, °F	650
Fluid	Borated reactor coolant
Material of construction	Austenitic stainless steel

	Normal (Design)	Maximum Purification	Heatup
Flow, lb/hr	37,050	59,280	59,280
Inlet temperature, °F	555	555	547
Outlet temperature, °F	298	294	369

Tube Side

Design pressure, psig	2735
Design temperature, °F	650
Fluid	Borated reactor coolant
Material of construction	Austenitic stainless steel

	Normal (Design)	Maximum Purification	Heatup
Flow, lb/hr	27,170	49,400	29,640
Inlet temperature, °F	130	130	130
Outlet temperature, °F	495	466	520

TABLE 9.3-6 (Sheet 2 of 17)

Letdown Orifice

Design pressure, psig	2485	
Design temperature, °F	650	
Normal operating inlet pressure, psig	2185	
Normal operating temperature, °F	290	
Material of construction	Austenitic stainless steel	
	45 gpm	75 gpm
Number	1	2
Design flow, lb/hr	22,230	27,050
Differential pressure at design flow, psig	1900	1900

Letdown Heat Exchanger

Number	1
Heat transfer rate at design conditions (heatup), Btu/hr	14.8×10^6

Shell Side

Design pressure, psig	150
Design temperature, °F	250
Fluid	Component cooling water
Material of construction	Carbon steel

	Normal	Heatup (Design)	Maximum Purification
Flow, lb/hr	203,000	492,000	320,000
Inlet temperature, °F	95	95	95
Outlet temperature, °F	125	125	125

Tube Side

Design pressure, psig	600
Design temperature, °F	400
Fluid	Borated reactor coolant
Material of construction	Austenitic stainless steel

	Normal	Heatup (Design)	Maximum Purification
Flow, lb/hr	37,050	59,280	59,280
Inlet temperature, °F	290	380 (max.)	380 (max.)
Outlet temperature, °F	127	127	127

Mixed Bed Demineralizers

Number	2
Type	Flushable
Vessel design pressure:	
Internal, psig	200
External, psig	15
Vessel design temperature, °F	250
Resin volume, each, ft^3	30
Vessel volume, each, ft^3	43
Design flow rate, gpm	120
Minimum decontamination factor	10
Normal operating temperature, °F	127
Normal operating pressure, psig	150
Resin type	Cation and anion
Material of construction	Austenitic stainless steel

Resin Fill Tank

Number	1
Capacity, ft^3	8
Design pressure	Atmospheric
Design temperature, °F	200
Normal operating temperature	Ambient
Material of construction	Austenitic stainless steel

Reactor Coolant Filter

Number	1
Type	Cage assembly
Design pressure, psig	200
Design temperature, °F	250
Flow rate:	
Nominal, gpm	120
Maximum, gpm	150
Retention of 25 micron particles	98 percent
Material of construction	Austenitic stainless steel

Volume Control Tank

Number	1
Internal volume, ft^3	400
Design pressure:	
Internal, psig	75
External, psig	15
Design temperature, °F	250
Operating pressure range, psig	0 - 60
Normal operating pressure, psig	15
Spray nozzle flow (maximum), gpm	120
Material of construction	Austenitic stainless steel

TABLE 9.3-6 (Sheet 5 of 17)

Centrifugal Charging Pumps

Number	2
Type	Horizontal centrifugal
Design pressure, psig	2800
Design temperature, °F	300
Shutoff head, psi	2670
Normal suction temperature, °F	127
Design flowrate, gpm	150
Design head, ft	5800
Required NPSH at 150 gpm, ft	10
Material	Austenitic stainless steel

Positive Displacement Charging Pump

Number	1
Type	Positive displacement with variable speed drive
Design head, ft	5800
Design temperature, °F	250
Design pressure, psig	3200
Design flow rate*, gpm	98
Suction temperature, °F	127
Discharge pressure at 130°F, psig	2500
Material of construction	Austenitic stainless steel
Maximum operating pressure, psia	3125

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* At 130°F, 2500 psig

TABLE 9.3-6 (Sheet 6 of 17)

Chemical Mixing Tank

Number	1
Capacity, gal	5
Design pressure, psig	150
Design temperature, °F	200
Normal operating temperature	Ambient
Material of construction	Austenitic stainless steel

Boric Acid Tank

Number	2
Capacity (each), gal	8000
Design pressure	Atmospheric
Design temperature, °F	250
Normal operating temperature, °F	150 - 170
Material of construction	Austenitic stainless steel

Boric Acid Tank Electric Immersion Heater

Number (two per tank)	4
Heat transfer rate, each, KW	7.5
Material of construction	Austenitic stainless steel sheath

Batching Tank and Batching Tank Heater Jacket

Number	1
Type	Cylindrical with steam panel coils
Capacity, gal	400
Design pressure	Atmospheric
Design temperature, °F	300
Steam temperature, °F	250

Batching Tank and Batching Tank Heater Jacket (continued)

Initial ambient temperature, °F	32
Final fluid temperature, °F	165
Heatup time, hrs	~3
Tank material of construction	Austenitic stainless steel
Panel coils, material of construction	Carbon steel

Batching Tank Agitator

Number	1
Fluid handled, boric acid, wt percent	12
Service	Continuous
Tank volume, gal	400
Operating temperature, °F	165
Operating pressure	Atmospheric
Material of construction	Austenitic stainless steel

Excess Letdown Heat Exchanger

Number	1	
Heat transfer rate at design conditions, Btu/hr	4.61×10^6	
	Shell Side	Tube Side
Design pressure, psig	150	2485
Design temperature, °F	250	650
Design flow rate, lb/hr	115,000	12,380
Inlet temperature, °F	95	545
Outlet temperature, °F	135	195
Fluid	Component cooling water	Borated reactor coolant
Material of construction	Carbon Steel	Austenitic stainless steel

Seal Water Heat Exchanger

Number	1	
Heat transfer rate at design conditions, Btu/hr	2.49×10^6	
	Shell Side	Tube Side
Design pressure, psig	150	150
Design temperature, °F	250	250
Design flow rate, lb/hr	99,500	160,600
Design operating inlet temperature, °F	95	143
Design operating outlet temperature, °F	120	127
Fluid	Component cooling water	Borated reactor coolant
Material of construction	Carbon steel	Austenitic stainless steel

Seal Water Filter

Number	1
Type	Cage assembly
Design pressure, psig	200
Design temperature, °F	250
Maximum flow rate, gpm	325
Retention of 25 micron particles	98 percent
Vessel material of construction	Austenitic stainless steel

Boric Acid Filter

Number	1
Type	Cage assembly
Design pressure, psig	200
Design temperature, °F	250
Design flow, gpm	150
Retention of 25 micron particles	98 percent
Vessel material of construction	Austenitic stainless steel

Boric Acid Transfer Pump

Number	2
Type	Two-speed horizontal centrifugal
Design flow rate, each, gpm	75
Design pressure, psig	150
Design discharge head, ft	235
Design temperature, °F	250
Temperature of pumped fluid, °F	170
Required NPSH at 75 gpm, ft	6
Material of construction	Austenitic stainless steel

Boric Acid Blender

Number	1
Design pressure, psig	150
Design temperature, °F	250
Material of construction	Austenitic stainless steel

TABLE 9.3-6 (Sheet 10 of 17)

Cation Bed Demineralizer

Number	1
Type	Flushable
Vessel design pressure:	
Internal, psig	200
External, psig	15
Vessel design temperature, °F	250
Normal operating temperature, °F	127
Normal operating pressure, psig	150
Design flow, gpm	75
Resin type	Cation
Material of construction	Austenitic stainless steel

Chemical Mixing Tank Orifice

Number	1
Design pressure, psig	150
Design temperature, °F	200
Design flow, gpm	2
Material of construction	Austenitic stainless steel

Boric Acid Tank Orifice

Number	2
Design pressure, psig	150
Design temperature, °F	200
Design flow, gpm	3
Material of construction	Austenitic stainless steel

Deborating Demineralizers

Number	2
Type	Regenerable
Vessel design pressure:	
Internal, psig	200
External, psig	15
Vessel design temperature, °F	250
Normal flow, gpm	127
Normal operating temperature, °F	127
Normal operating pressure, psig	150
Resin type	Anion
Material of construction	Austenitic stainless steel

Seal Injection Filters

Number	2
Design pressure, psig	2735
Design temperature, °F	200
Design flow, gpm	80
Particle retention	98 percent above 5 micron
Fluid	Reactor coolant containing up to 5 percent boric acid
Material of construction, vessel	Austenitic stainless steel
Type	Disposable synthetic cartridge, cage assembly

No. 1 Seal By-Pass Orifice

Number	4
Design pressure, psig	2485
Design temperature, °F	250
Design flow, gpm	1.0
Differential pressure at design flow, psi	300

Holdup Tanks

Number	3
Design temperature, °F	200
Design pressure, psig	15
Volume, each, ft^3	8,500
Normal operating pressure, psig	3
Normal operating temperature, °F	130
Material of construction	Austenitic stainless steel

Recirculation Pump

Number	1
Type	Centrifugal
Design flow, gpm	500
Design head, ft	100
Design pressure, psig	75
Design temperature, °F	200
Normal operating temperature, °F	115
Material of construction	Austenitic stainless steel

Gas Stripper Feed Pumps

Number	2
Type	Canned
Design flow, gpm	30
Design head (TDH), ft	320
Design pressure, psig	150
Design temperature, °F	200
Normal fluid temperature, °F	115
Material of construction	Austenitic stainless steel

Gas Stripper and Evaporator Package Unit

Number of Units	1
Design flow/unit; gas stripper feed, gpm	30
Evaporator condensate, gpm	30
Evaporator concentrates (batch flow), gpm	40
Decontamination factors (design):	
Gas stripper	Approx. 10^5 (for gas)
Evaporator	Approx. 10^6 (for liquid)
Concentration of concentrates, boric acid, wt percent	12
Concentration of distillate	<10 ppm boron as H_3BO_3 <0.1 ppm oxygen Conductivity <2.0 μmhos/cm pH = 6.0 to 8.0
Material of construction	Austenitic stainless steel

Evaporator Distillate Demineralizers

Number	2
Type	Regenerable
Design temperature, °F	250
Design pressure:	
Internal, psig	200
External, psig	15
Design flow, gpm	30
Normal operating pressure, psig	50
Normal operating temperature, °F	130
Resin type	Anion
Material of construction	Austenitic stainless steel

Monitor Tanks

Number	2
Type	Diaphragm
Volume, each, gal	21,600
Design pressure	Atmospheric
Design temperature, °F	150
Material of construction	Stainless steel

Monitor Tank Pumps

Number	2
Type	Centrifugal
Design flow, gpm	150
Design head, ft	200
Design pressure, psig	150
Design temperature, °F	200
Material of construction	Austenitic stainless steel
NPSH, ft	15

Evaporator Feed Ion Exchangers

Number	4
Type	Flushable
Design temperature, °F	250
Design pressure:	
Internal, psig	200
External, psig	15
Minimum decontamination factor for ions removed	10
Design flow, gpm	30
Normal operating temperature, °F	130
Normal operating pressure, psig	75
Resin type	Cation
Material of construction	Austenitic stainless steel

Concentrates Filter

Number	1
Type	Cage type
Design pressure, psig	200
Design temperature, °F	250
Design flow rate, gpm	35
Retention for 25 micron particles	98 percent
Material of construction (vessel)	Austenitic stainless steel

Concentrates Holding Tank

Number	1
Type	Cylindrical, heated
Volume, gal	1000
Design pressure	Atmospheric
Design temperature, °F	250
Normal operating temperature, °F	150
Material of construction	Austenitic stainless steel

Concentrates Holding Tank Transfer Pump

Number	2
Type	Centrifugal canned
Design flow rate, gpm	40
Design head, ft	150
Design temperature, °F	250
Design pressure, psig	100
Required NPSH at 40 gpm, ft	8
Material of construction	Austenitic stainless steel

TABLE 9.3-6 (Sheet 16 of 17)

Concentrates Holding Tank Electric Heater

Number	1
Heat transfer rate, KW	3.0
Material of construction	Austenitic stainless steel

Ion Exchanger Filter

Number	1
Type	Cage assembly
Design pressure, psig	200
Design temperature, °F	250
Design flow rate, gpm	35
Retention of 25 micron particles	98 percent
Material of construction	Austenitic stainless steel

Distillate Filter

Number	1
Type	Cage assembly
Design pressure, psig	200
Design temperature, °F	250
Design flow rate, gpm	35
Retention of 25 micron particles	98 percent
Material of construction	Austenitic stainless steel

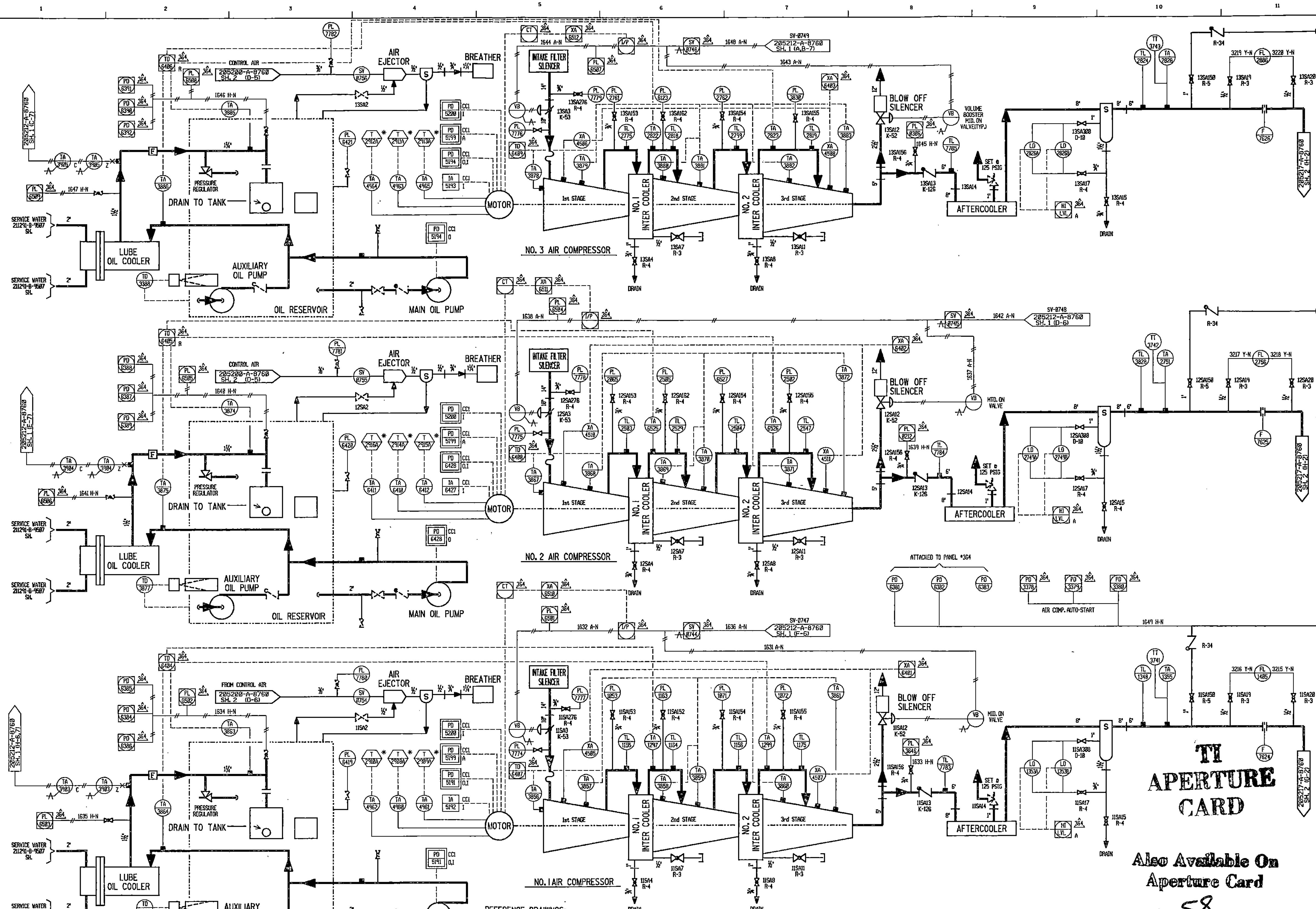
TABLE 9.3-6 (Sheet 17 of 17)

Relief Valves	No.	Fluid Discharged	Fluid Inlet Temperature °F	Set Pressure psig	Back Pressure, psig Constant	Back Pressure, psig Buildup	Capacity gpm
Letdown line (HP)	1	Water-Steam Mixture	385 (max.)	600	3	50	98,000 lb/hr
Seal water return line	1	Water	150	150	3	50	225
Charging pump's discharge	1	Water	130	2735	15	75	100
Letdown line (LP)	1	Water	127	200	15	12	200
Volume control tank	1	Hydrogen, nitrogen, or water	130	75	3	12	350
Boric acid batch tank heater	1	Steam	250	20	0	0	320 lb/hr
Holdup tanks	3	Nitrogen, water	130	12	3	3	235

TABLE 9.3-7

FAILURE ANALYSIS OF THE CHEMICAL AND VOLUME CONTROL SYSTEM

	Component	Failure	Comments and Consequences
a)	Letdown Line	Rupture in the line inside the reactor containment	The two remote air-operated valves located near the main coolant loop are closed on low pressurizer level to prevent supplementary loss of coolant through the letdown line rupture. The containment isolation valves in the letdown line are automatically closed by the containment isolation signal. The closure of these valves prevents any leakage of the reactor containment atmosphere outside the reactor containment.
b)	Normal and Alternate Charging Line	See above.	The check valves located near the main coolant loops prevent supplementary loss of coolant through the line and isolate the Reactor Coolant System from the rupture. The check valve located at the boundary of the reactor containment prevents any leakage of the reactor containment atmosphere outside the reactor containment. The two motor-operated valves outside the containment are automatically closed by the containment isolation signal.
c)	Seal Water Return Line	See above.	The motor-operated isolation valves located inside and outside the containment are automatically closed by the containment isolation signal. The closure of these valves prevents any leakage of the reactor containment atmosphere outside the reactor containment.



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8607290251-58

REFERENCE DRAWINGS:

VALVE LIST		206766-L
DEMINERALIZED WATER MAKE-UP	DIAG.	205213-A-8760
CONTROL AIR	DIAG.	205200-A-8760
NO. 1 AND 2 UNITS NON RADIOACTIVE LIQUID WASTE DISPOSAL		205213-A-8762
NO. 2 UNIT COMPRESSED AIR	DIAG.	205317-A-8762
NO. 2 UNIT CONTROL AIR	DIAG.	205300-A-8762
WASTE DISPOSAL SOLID		205349-A-8763
LEGEND SHEET		600658-A-8727
STATION AIR COMPRESSORS AND CONTROL AIR DRYERS	INSTR. SCH.	211319-B-9508-11
TURB. GEN. AREA CONTROL AIR	INSTR. SCH.	237102-A-1468-4
NO. 1 & 2 UNITS T.G.A. NO. 1, 2, 3, AIR COMPRESSORS PNL. 364	ARRGT.	205396-A-8772

205217-A-8760

SH. 1	NO. 1, 2 & 3 COMPRESSORS
SH. 2	NO. 1 & 2 SERVICE & CIRCULATING WATER INTAKE, CLEAN FACILITIES BUILDING, TURBINE AREA, PENETRATION AREA & PERF. DEPT
SH. 3	NO. 1 & 2 SERVICE & CIRCULATING WATER INTAKE, AUXILIARY BUILDING, TURBINE AREA PENETRATION AREA, PERF. DEPT., CONTAINMENT AND FUEL HANDLING BUILDING

NOTES:

1. VALVES TO BE LOCKED OPEN AFTER ENTIRE SYSTEM IS COMPLETED.
2. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
3. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200. THE PIPING SCHEDULE AND GROUP NOS. ARE AS NOTED ON THIS DRAWING AND PREFIXED WITH "1S".

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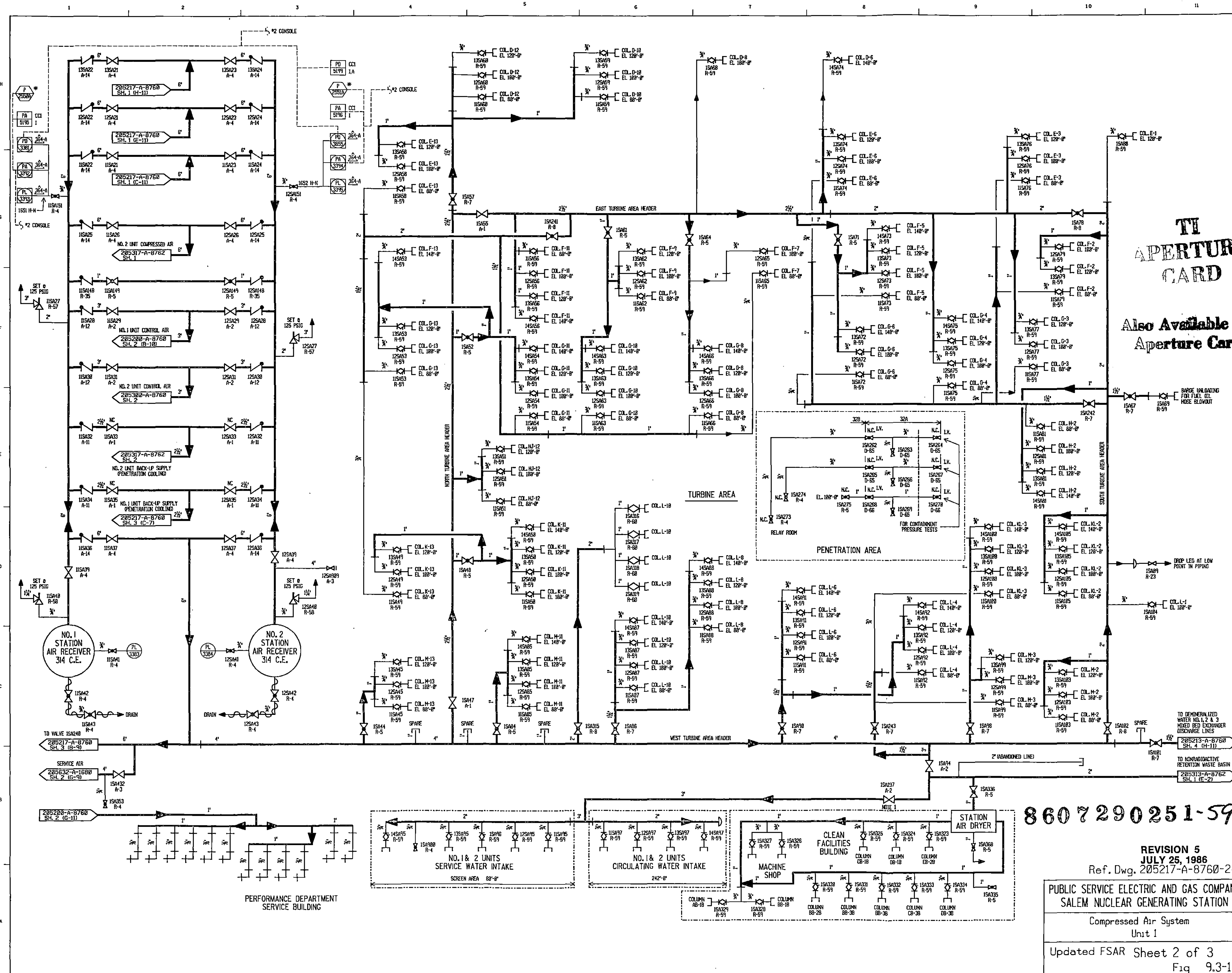
Ref. Dwg. 205217-A-8760-24

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Compressed Air System
Unit 1

Updated FSAR Sheet 1 of 3

Fig. 9.3-1A



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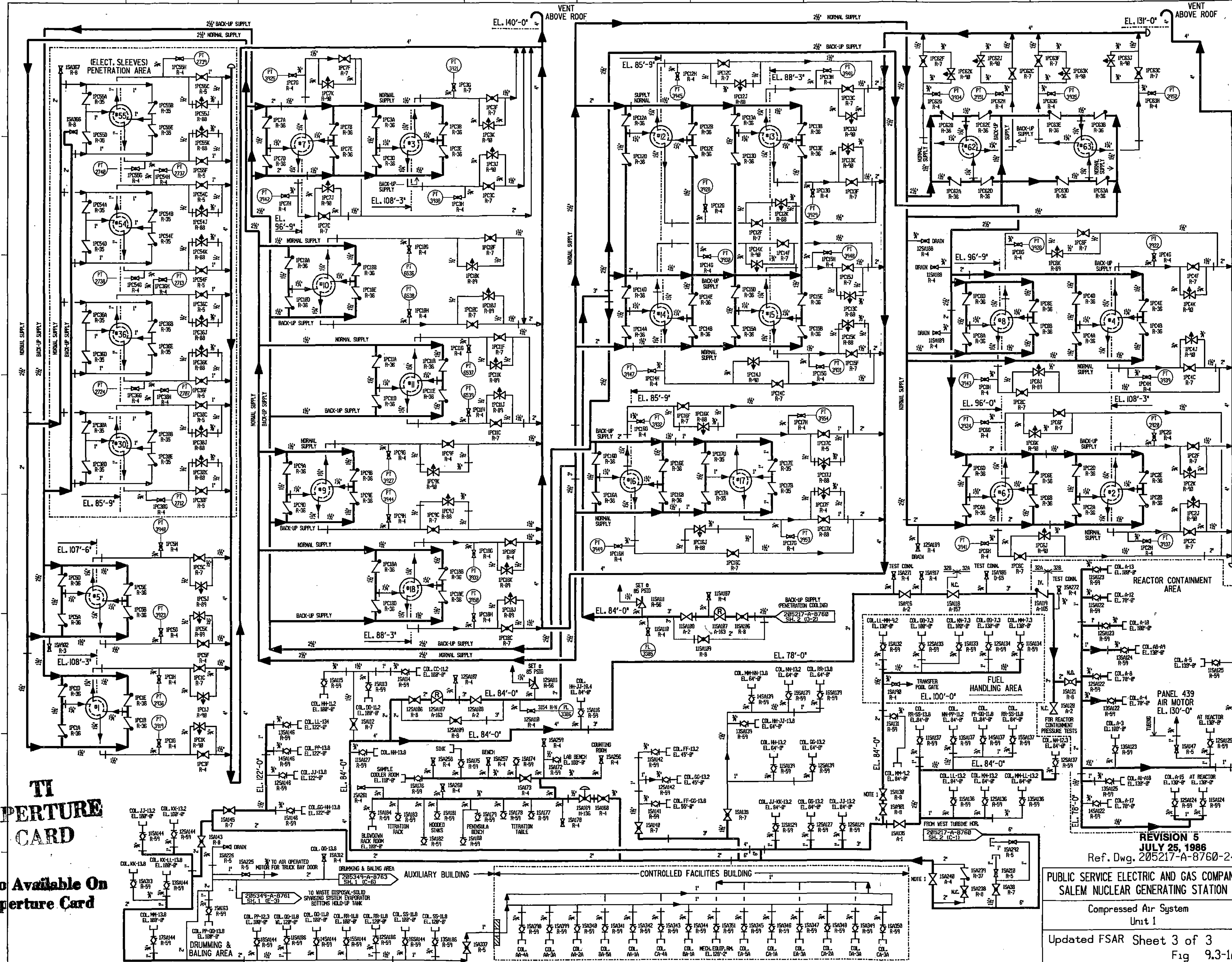
SALEM NUCLEAR GENERATING STATION

Compressed Air System
Unit 1

Updated FSAR Sheet 2 of 3
Fig 9.3-1A



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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Compressed Air System
Unit 1

Updated FSAR Sheet 3 of 3
Fig 9.3-1A

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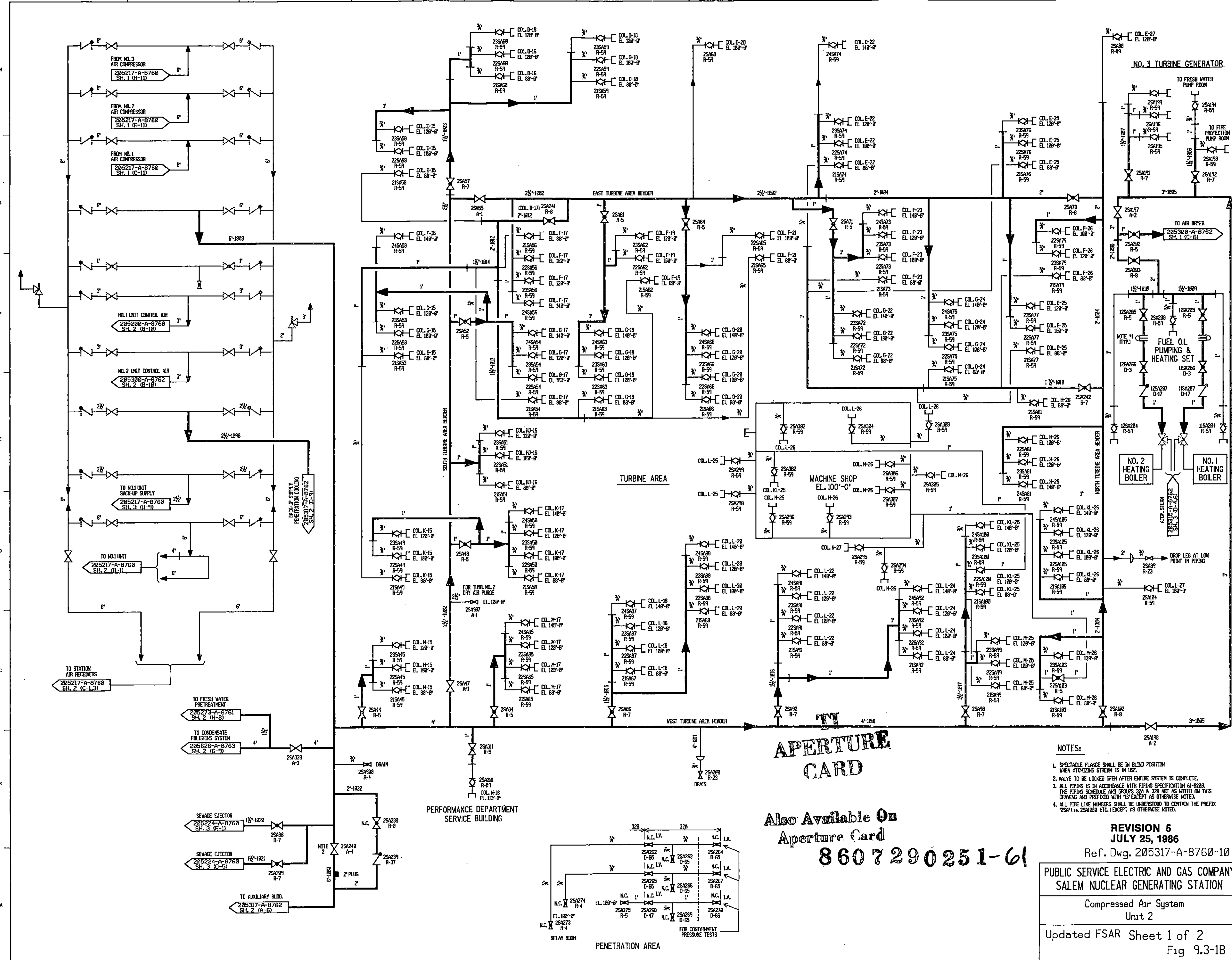

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8607290251-61

NOTES:

1. SPECTACLE FLANGE SHALL BE IN BLIND POSITION WHEN ATOMIZING STREAM IS IN USE.
2. VALVE TO BE LOCKED OPEN AFTER ENTIRE SYSTEM IS COMPLETE.
3. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6280. THE PIPING SCHEDULE AND GROUPS 32A & 32B ARE AS NOTED ON THIS DRAWING AND PREFIXED WITH '15' EXCEPT AS OTHERWISE NOTED.
4. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX '2SA' (i.e. 2SA1000 ETC.) EXCEPT AS OTHERWISE NOTED.

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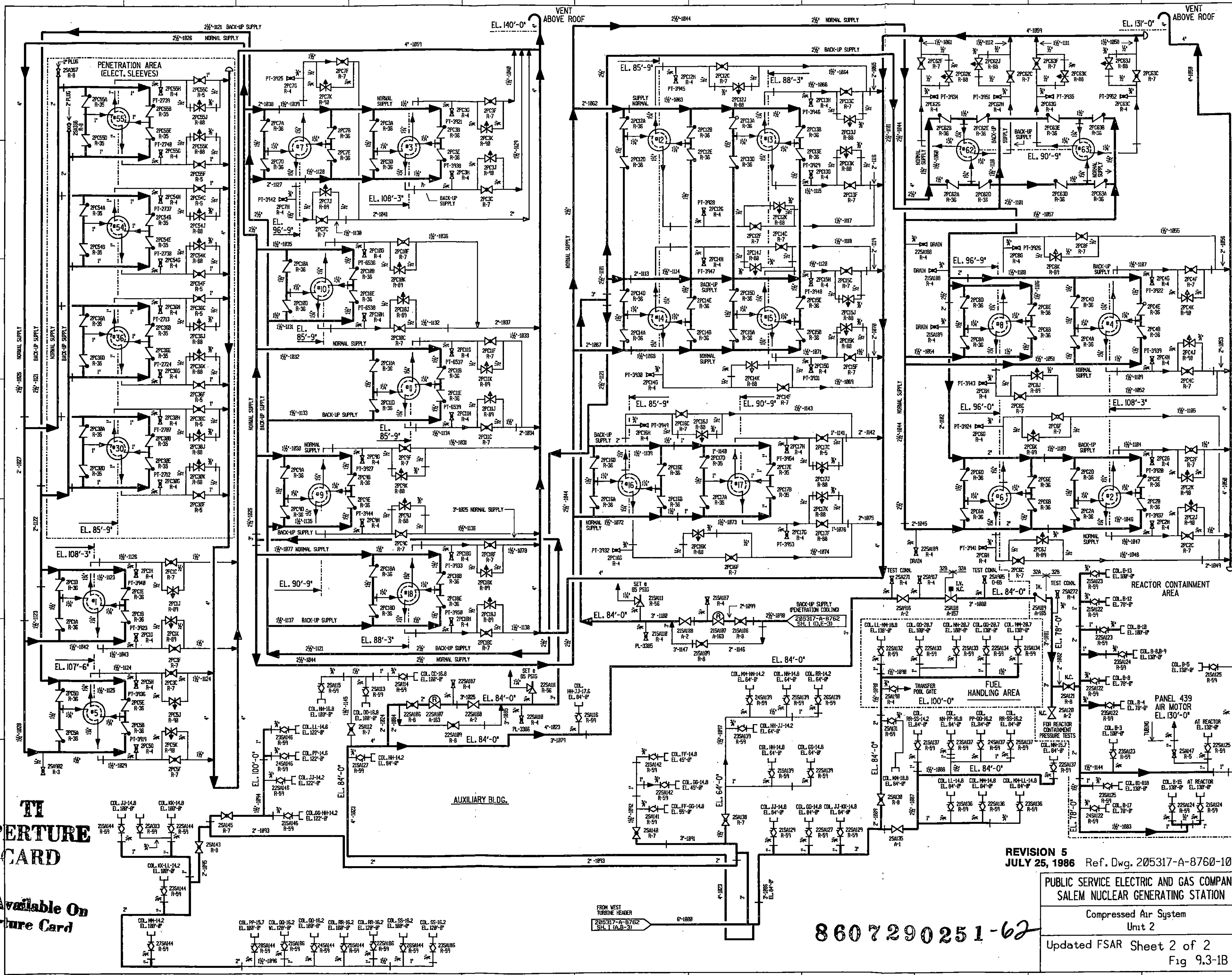
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Compressed Air System
Unit 2

Updated FSAR Sheet 1 of 2
Fig 9.3-1B



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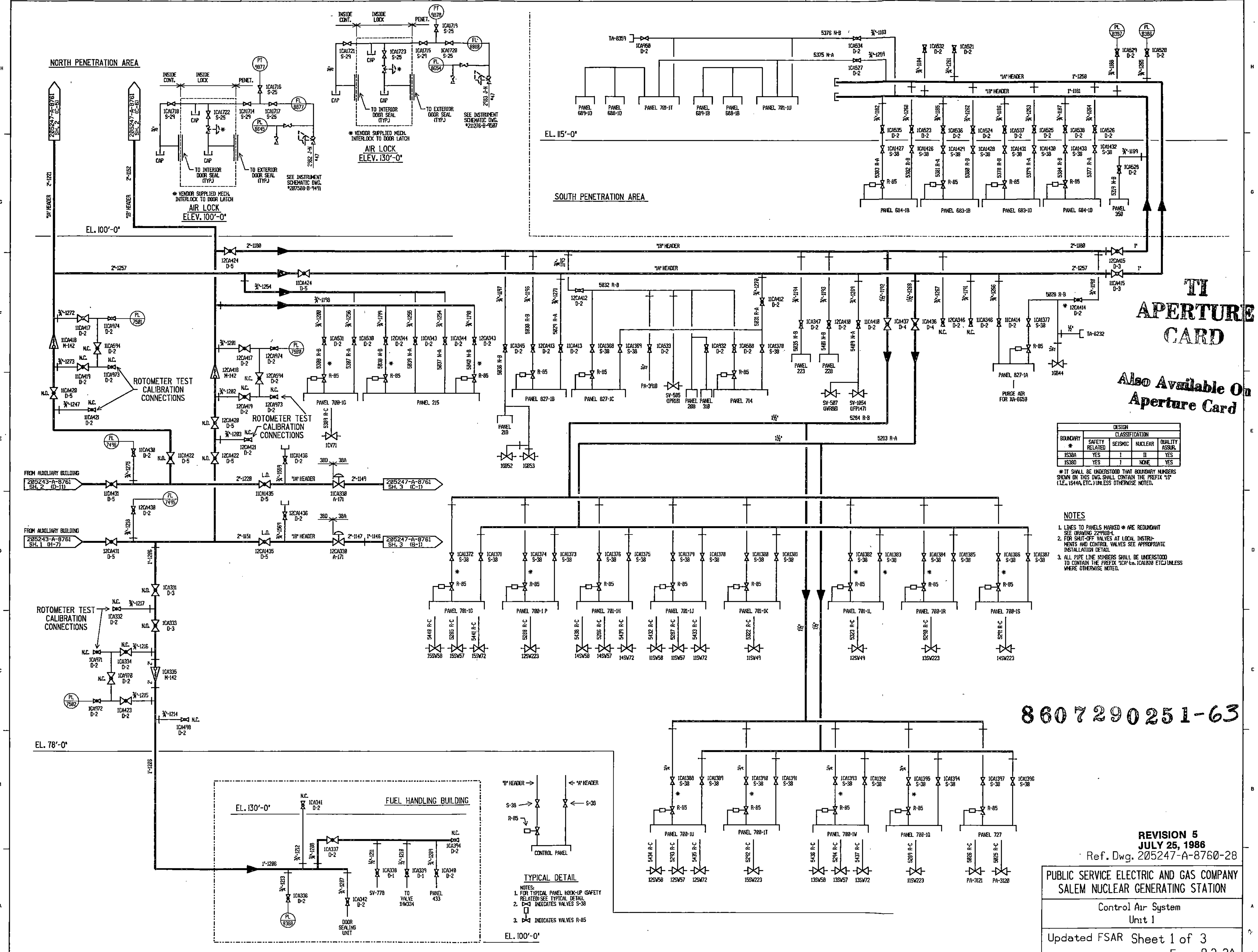
SALEM NUCLEAR GENERATING STATION

Compressed Air System
Unit 2

8607290251-62

Updated FSAR Sheet 2 of 2
Fig 9.3-1B



BOUNDARY *	DESIGN CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S38A	YES	I	II	YES
1S38D	YES	I	NONE	YES

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DWG. SHALL CONTAIN THE PREFIX "1S" (I.E., 1S44A, ETC.) UNLESS OTHERWISE NOTED.

NOTES

1. LINES TO PANELS MARKED * ARE REDUNDANT SEE DRAWING 229988-L
2. FOR SHUT-OFF VALVES AT LOCAL INSTRUMENTS AND CONTROL VALVES SEE APPROPRIATE INSTALLATION DETAIL
3. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1CA" (i.e. 1CA1000 ETC.) UNLESS WHERE OTHERWISE NOTED.

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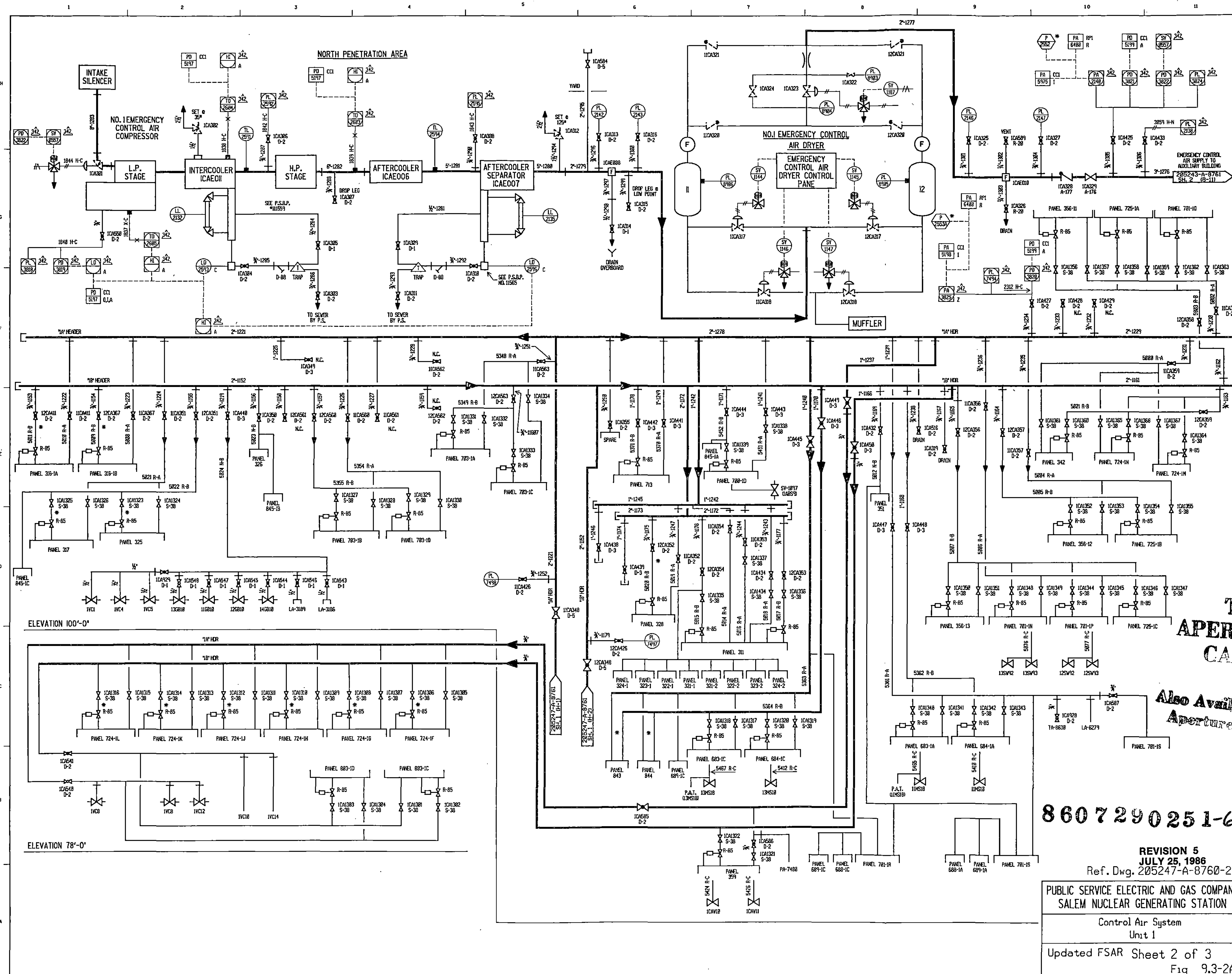
Ref. Dwg. 205247-A-8760-28

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Control Air System
Unit 1

Updated FSAR Sheet 1 of 3
Fig 9.3-2A



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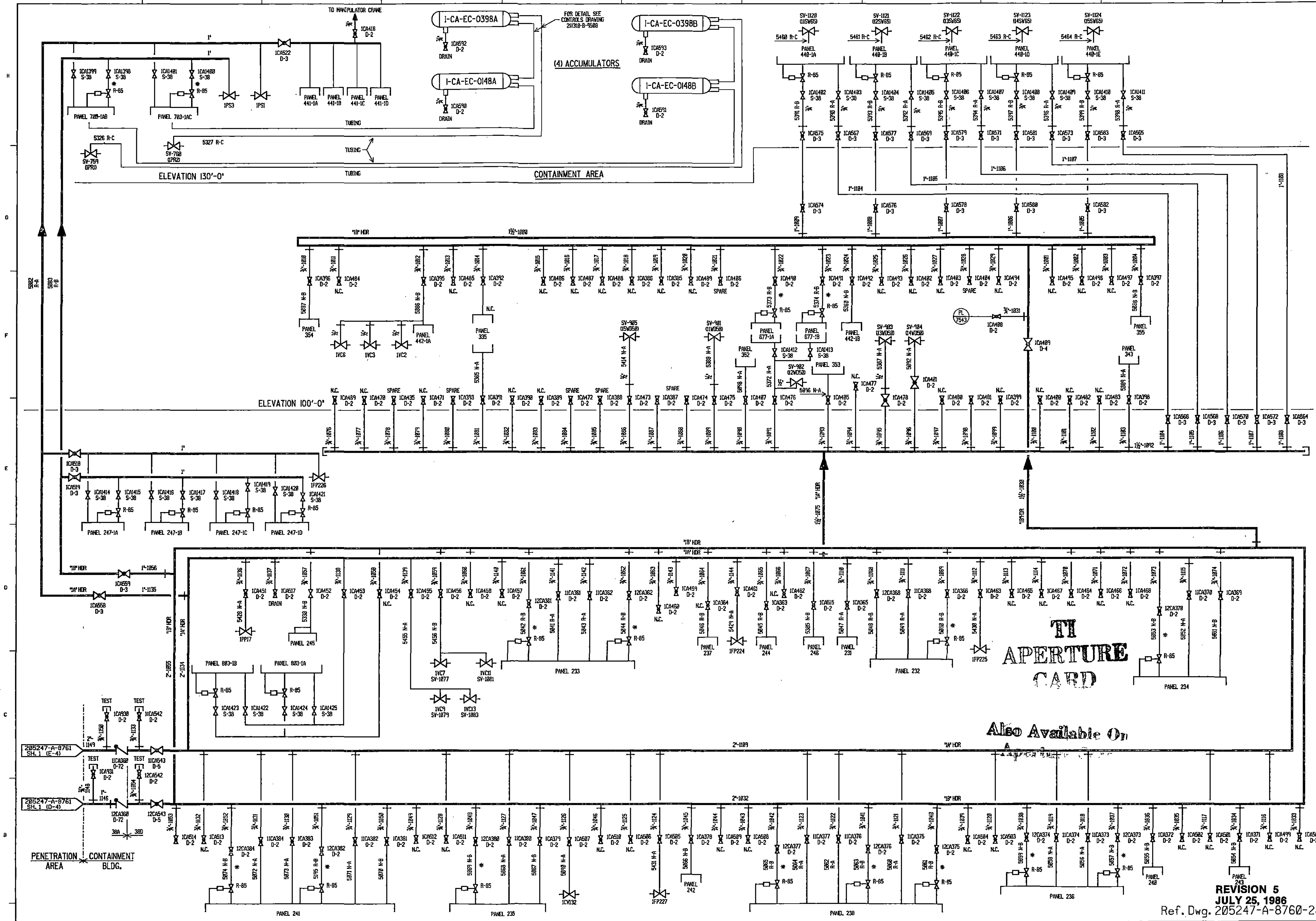
SALEM NUCLEAR GENERATING STATION

Control Air System
Unit 1

Updated FSAR Sheet 2 of 3
Fig 9.3-2A



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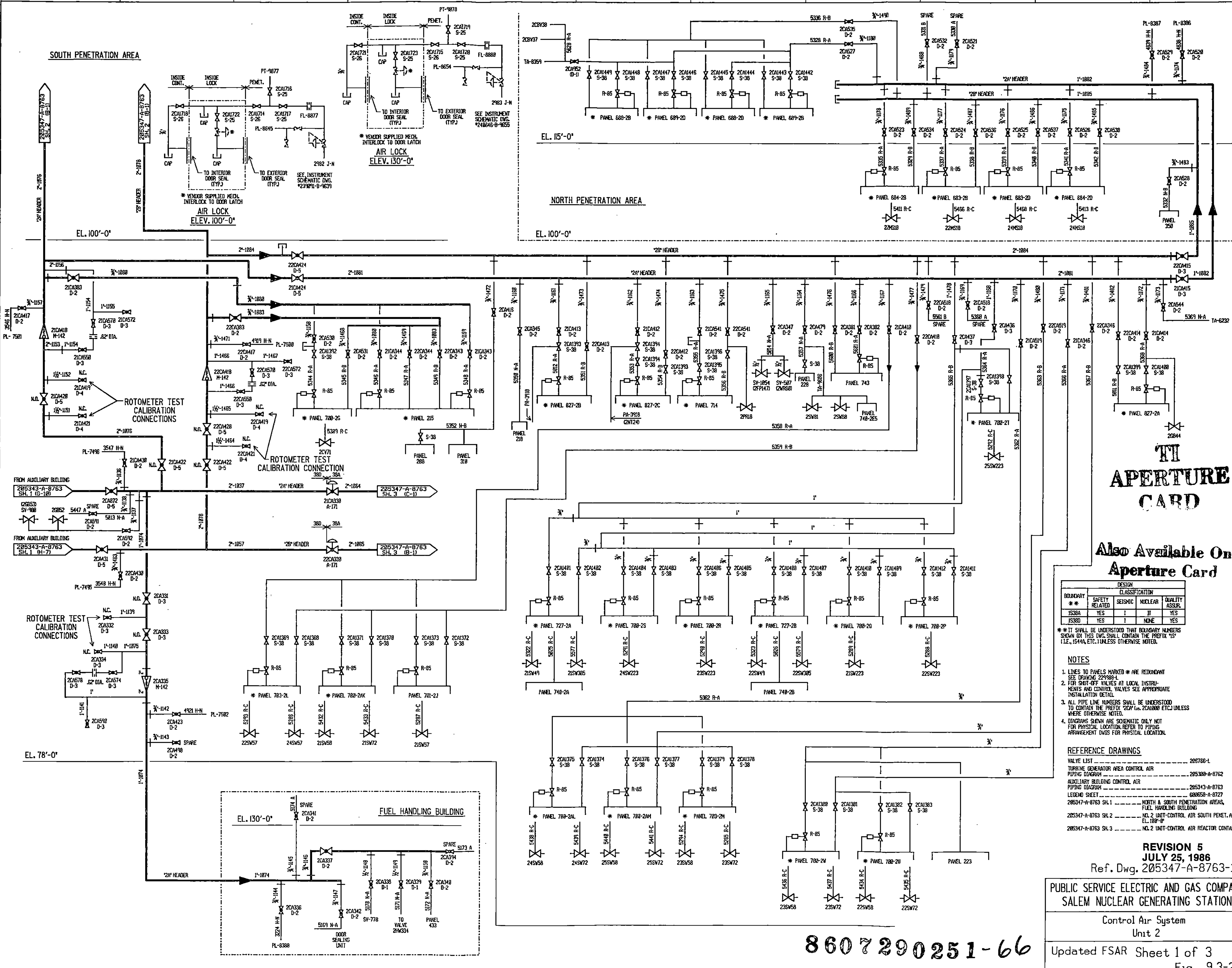
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Control Air System
Unit 1

Updated FSAR Sheet 3 of 3
Fig 9.3-2A

8607290251-65



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BOUNDARY **	DESIGN CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S38A	YES	I	II	YES
1S38D	YES	I	NONE	YES

** IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DWG. SHALL CONTAIN THE PREFIX "1S" (I.E., 1S44A, ETC.) UNLESS OTHERWISE NOTED.

NOTES

1. LINES TO PANELS MARKED * ARE REDUNDANT SEE DRAWING 229988-L
2. FOR SHUT-OFF VALVES AT LOCAL INSTRUMENTS AND CONTROL VALVES SEE APPROPRIATE INSTALLATION DETAIL
3. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX '2CA' (i.e. 2CA1000 ETC.) UNLESS WHERE OTHERWISE NOTED.
4. DIAGRAMS SHOWN ARE SCHEMATIC ONLY NOT FOR PHYSICAL LOCATION. REFER TO PIPING ARRANGEMENT DWGS FOR PHYSICAL LOCATION.

REFERENCE DRAWINGS

VALVE LIST ____________________ 206766-L
TURBINE GENERATOR AREA CONTROL AIR PIPING DIAGRAM ____________________ 205320-A-8762
AUXILIARY BUILDING CONTROL AIR PIPING DIAGRAM ____________________ 205343-A-8763
LEGEND SHEET ____________________ 600658-A-8727
205347-A-8763 SH. 1 ______ NORTH & SOUTH PENETRATION AREAS, FUEL HANDLING BUILDING
205347-A-8763 SH. 2 ______ NO. 2 UNIT-CONTROL AIR SOUTH PENET. AREA EL. 100'-0"
205347-A-8763 SH. 3 ______ NO. 2 UNIT-CONTROL AIR REACTOR CONTAINMENT

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Ref. Dwg. 205347-A-8763-16

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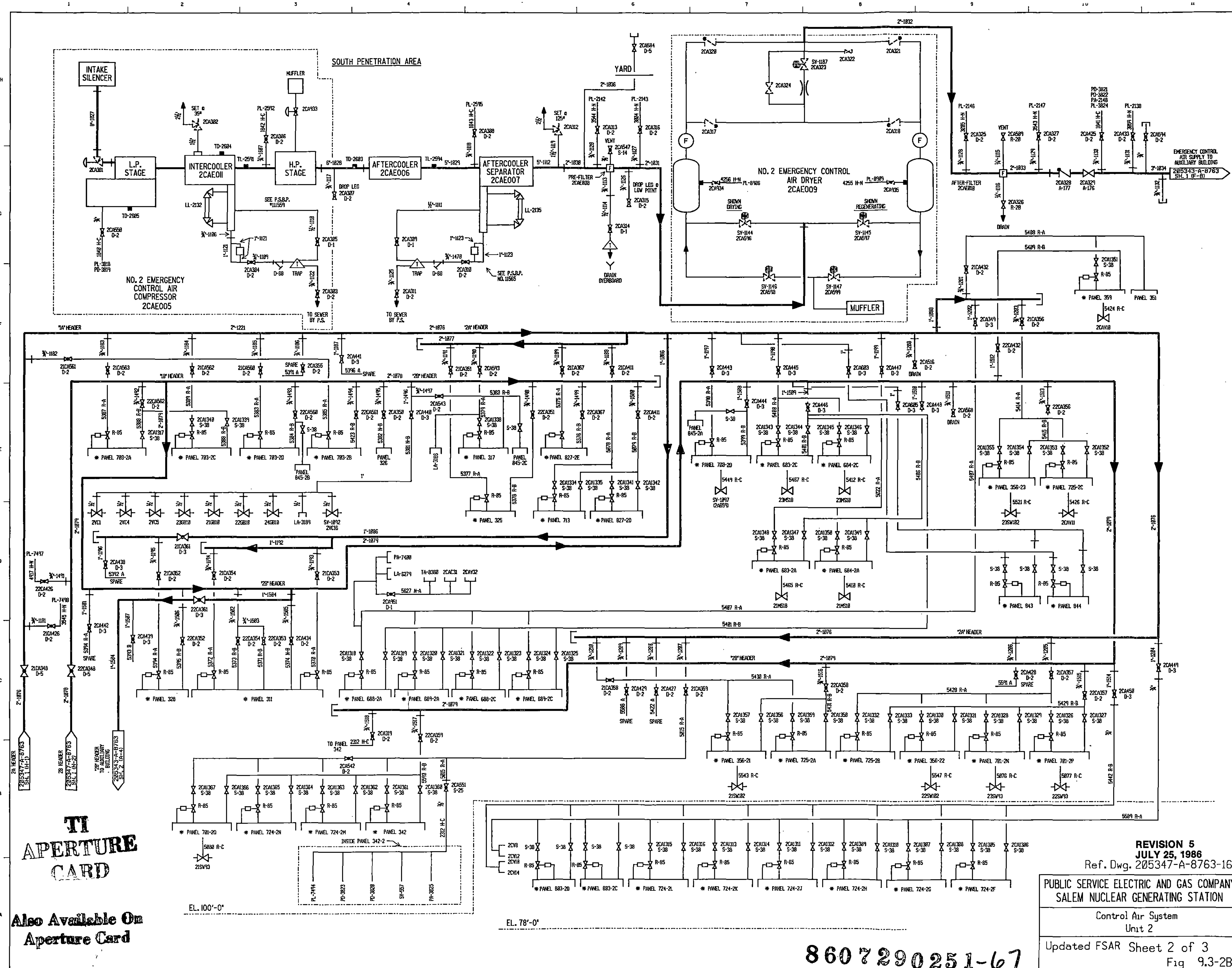
SALEM NUCLEAR GENERATING STATION

Control Air System
Unit 2

8607290251-66

Updated FSAR Sheet 1 of 3
Fig 9.3-2B



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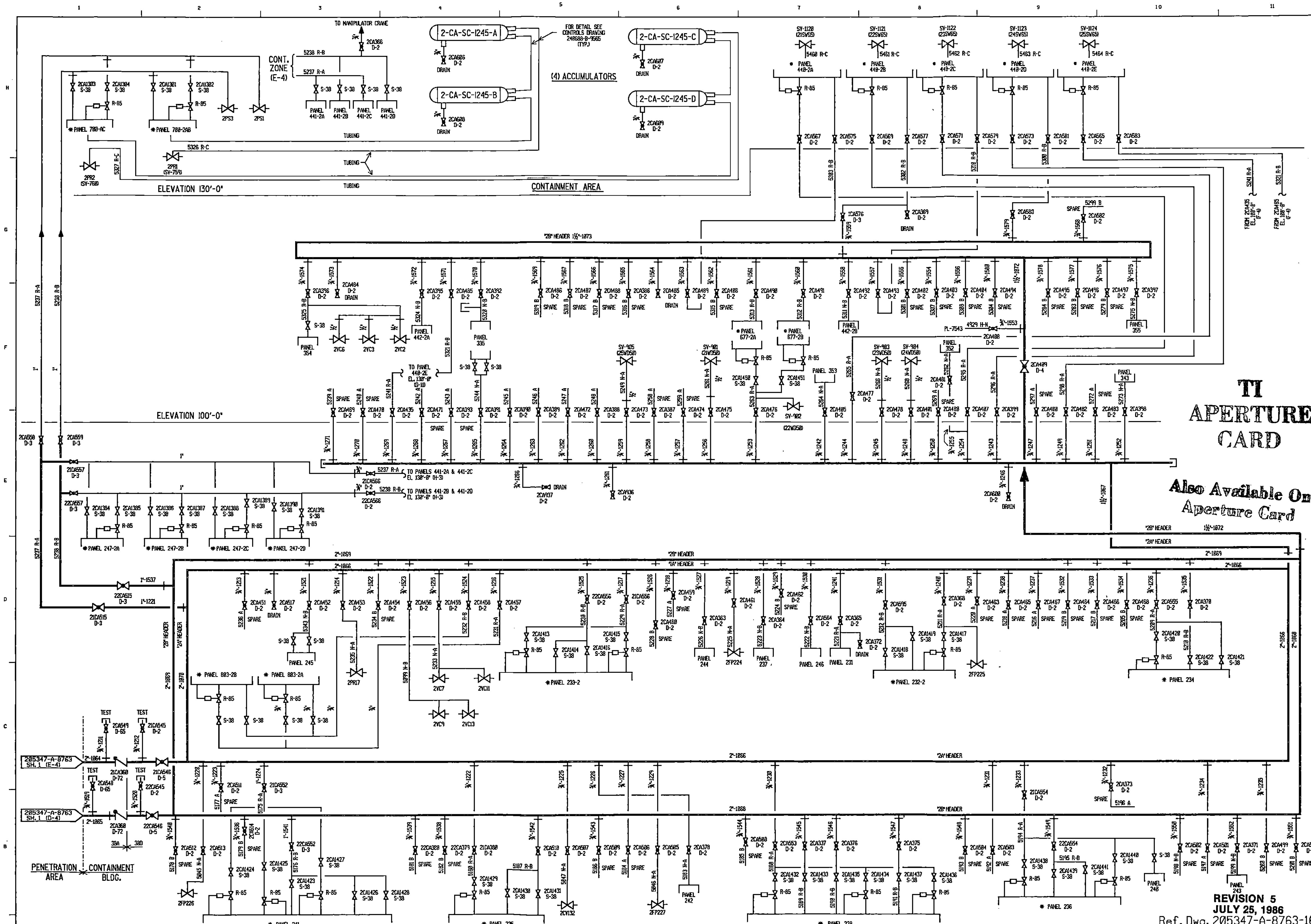
Control Air System
Unit 2

Updated FSAR Sheet 2 of 3
Fig 9.3-2B

8607290251-67



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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
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Control Air System
Unit 2

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Updated FSAR Sheet 3 of 3
Fig 9.3-2B

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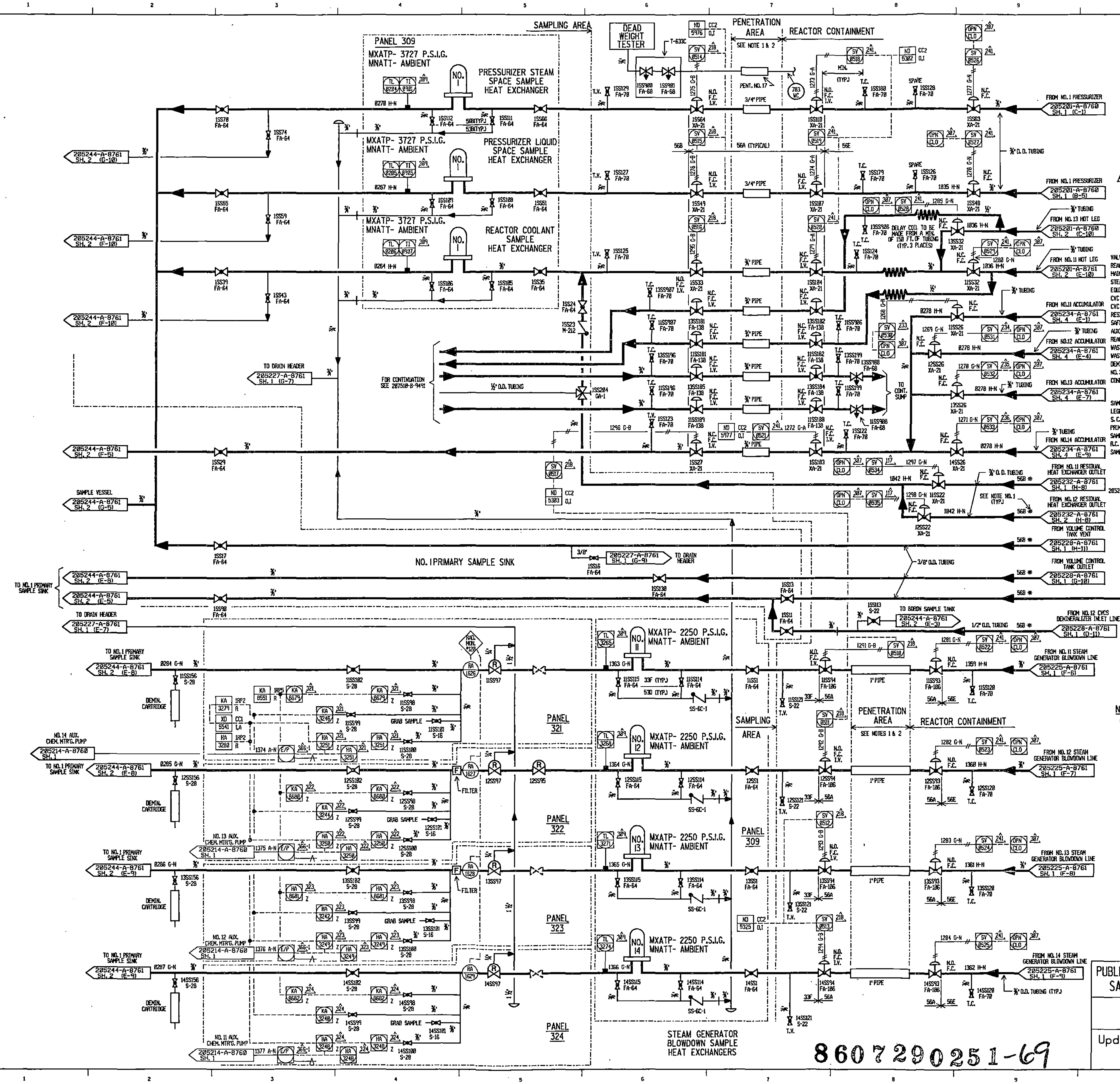

REFERENCE DRAWINGS

VALVE LIST		206765-L
REACTOR COOLANT	DIAG.	205201-A-8760
MAIN STEAM	DIAG.	205203-A-8760
STEAM GENERATOR DRAINS & BLOWDOWN	DIAG.	205225-A-8761
EQUIPMENT VENTS & DRAINS-CONTAMINATED	DIAG.	205227-A-8761
CVC OPERATION	DIAG.	205228-A-8761
CVC BORIC ACID RECOVERY	DIAG.	205229-A-8761
RESIDUAL HEAT REMOVAL	DIAG.	205232-A-8761
SAFETY INJECTION	DIAG.	205234-A-8761
AUXILIARY BUILDING - VENTILATION	DIAG.	205237-A-8761
REACTOR CONTAINMENT - VENTILATION	DIAG.	205238-A-8761
WASTE DISPOSAL LIQUID	DIAG.	205239-A-8761
WASTE DISPOSAL GAS	DIAG.	205240-A-8761
DEMINERALIZED WATER	DIAG.	205246-A-8761
NO. 2 UNIT SAMPLING SYSTEM	DIAG.	205344-A-8763
CONDENSATE FEEDWATER & STEAM ANALYSIS	INSTRUMENT SCHEMATIC	211275-B-9507
	INSTRUMENT SCHEMATIC	211284-B-9507-10
SAMPLING SYSTEM	INSTRUMENT SCHEMATIC	211311-B-9508-10
LEGEND SHEET		600658-A-8727
S.C. BLOWDOWN ANALYSIS PNLS. 321, 322, 323, & 324		211798-A-8878-10
PRIMARY SAMPLE ROOM VLV. PNL. 1		228921-AB-3653-6
SAMPLE SYSTEM ISO. VLV. SOL. PNL. 218	ARRGT.	223872-A-1212-7
R.C. WIDE RANGE S.S. PNL. 241-1	ARRGT.	205394-A-8772-20
SAMPLE HEAT EXCH. PNL. 309-1	ARRGT.	205680-A-8939-10

205244-A-8761 ——— SAMPLING

SHEET 1 ——— REACTOR CONTAINMENT, PENETRATION AREA STEAM GENERATOR SAMPLE HEAT EXCHANGERS, REACTOR CONTAINMENT SAMPLE HEAT EXCHANGER, PRESSURIZER LIQUID SPACE SAMPLE HEAT EXCHANGER PRESSUERIZER STEAM SPACE SAMPLE HEAT EXCHANGER PANELS - 321, 322, 323 & 324

SHEET 2 ——— NO. 1 PRIMARY & SECONDARY SAMPLE SINK, SAMPLE VESSEL, BORON SAMPLE TANK & STEAM GENERATOR STEAM SAMPLE HEAT EXCHANGERS

NOTES:

(✱) 1. FOR PRESSURE & TEMPERATURE DESIGN PARAMETERS REFER TO THE DESIGN PARAMETERS AT THE ORIGINATING SOURCE HEADER

2. ALL PIPING PENETRATION TO BE AS PER PIPING SPEC 1547
3. 1" PIPE TO BE DOUBLE EXTRA STRONG ASTM A376 GRADE TP316
4. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051
5. MXATP INDICATED IS FOR THE TUBE SIDE OF THE SAMPLE HEAT EXCHANGERS.

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Ref. Dwg. 205244-A-8761-19

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Sampling System
Unit 1

Updated FSAR Sheet 1 of 2
Fig 9.3-3A

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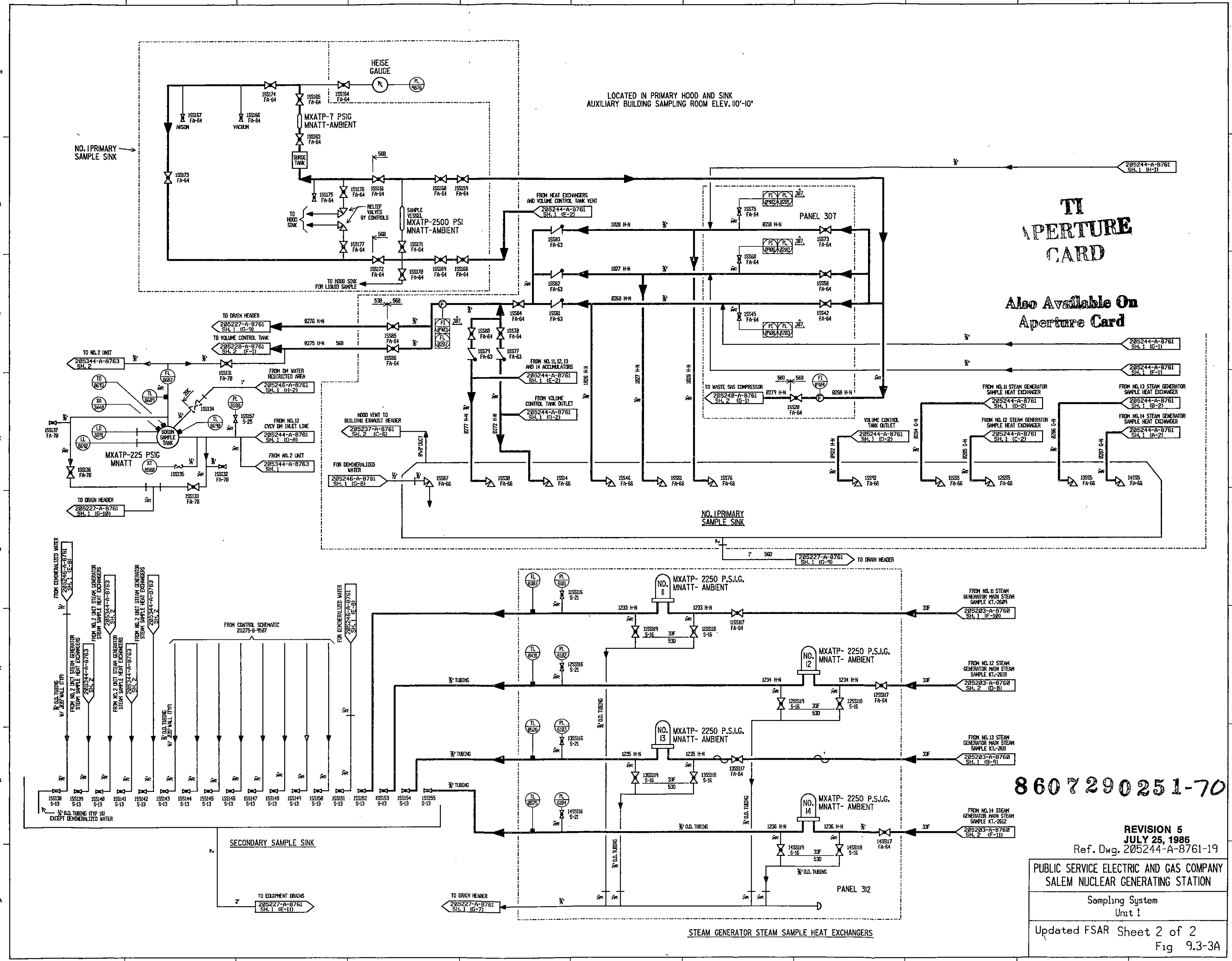

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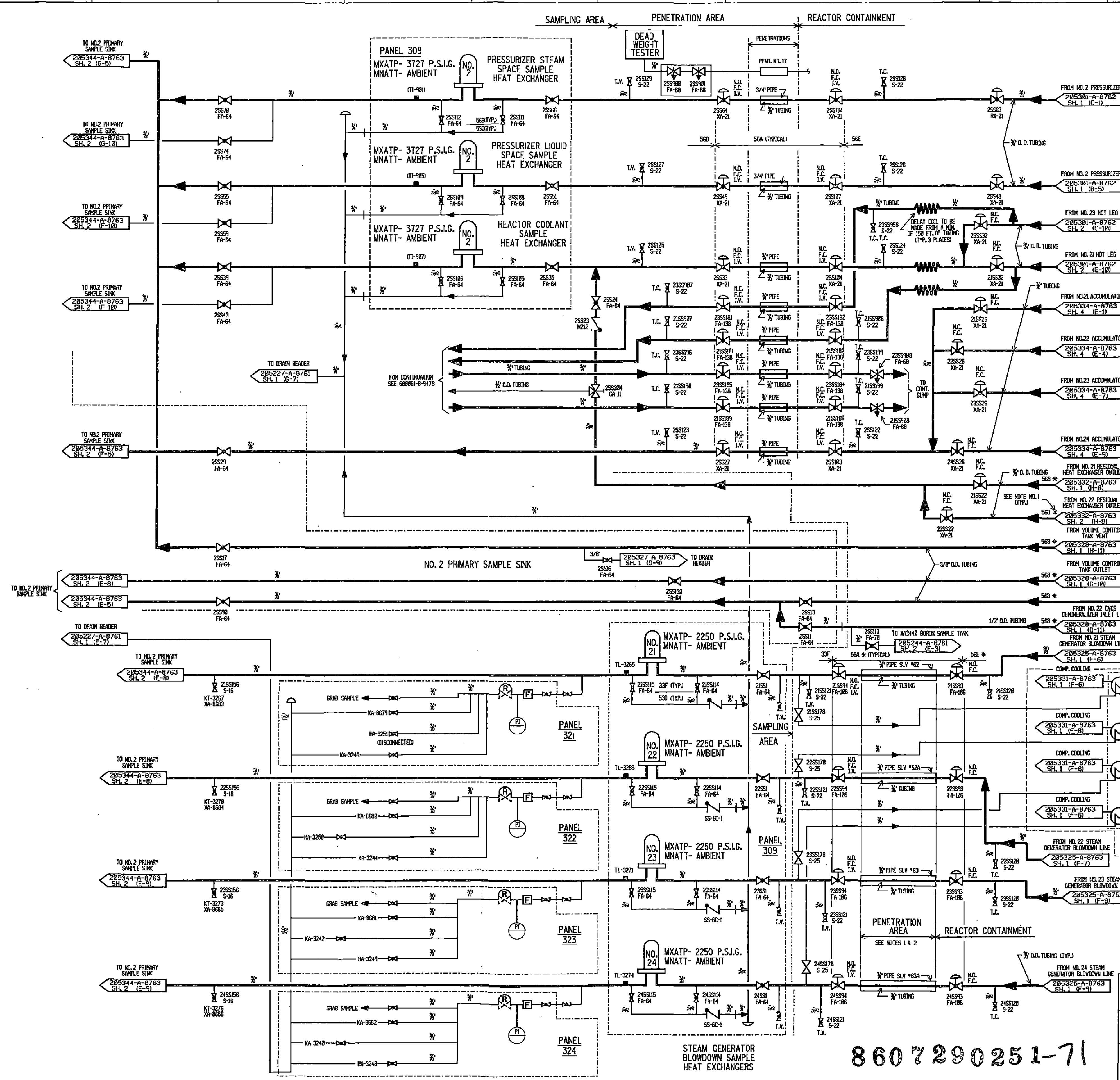
JULY 25, 1986
Ref. Dwg. 205244-A-8761-19

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Sampling System
Unit 1

Updated FSAR Sheet 2 of 2
Fig 9.3-3A



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NOTES:

(*) 1. FOR PRESSURE & TEMPERATURE DESIGN PARAMETERS REFER TO THE DESIGN PARAMETERS AT THE ORIGINATING SOURCE HEADER

2. ALL PIPING PENETRATION TO BE AS PER PIPING SPEC 1547

3. ¾" PIPE TO BE DOUBLE EXTRA STRONG ASTM A376 GRADE TP316

4. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051

5. ALL PIPING IS IN ACCORDANCE WITH PIPING SPEC. 61-6200 PIPING SCHEDULE AND GROUP NOS. 1SS6A & 1SS6B EXCEPT OTHERWISE NOTED.

6. DELAY COIL TO BE MADE FROM A MINIMUM OF 150 FEET TO TUBING.

REFERENCE DRAWINGS

VALVE LIST		206756-L
REACTOR COOLANT	DIAG.	205301-A-8762
WASTE DISPOSAL GAS	DIAG.	205303-A-8763
STEAM GENERATOR DRAINS & BLOWDOWN	DIAG.	205325-A-8763
EQUIPMENT VENTS & DRAINS-CONTAMINATED	DIAG.	205327-A-8763
CVC OPERATION	DIAG.	205328-A-8763
CVC BORIC ACID RECOVERY	DIAG.	205329-A-8763
RESIDUAL HEAT REMOVAL	DIAG.	205332-A-8763
SAFETY INJECTION	DIAG.	205334-A-8763
REACTOR CONTAINMENT - VENTILATION	DIAG.	205338-A-8763
WASTE DISPOSAL LIQUID	DIAG.	205339-A-8763
DEMINERALIZED WATER	DIAG.	205246-A-8761
CONDENSATE FEEDWATER & STEAM ANALYSIS	INSTRUMENT SCHEMATIC	211275-B-9507
SAMPLING SYSTEM	INSTRUMENT SCHEMATIC	211371-B-9528
LEGEND SHEET		600650-A-8727

SHEET 1 — REACTOR CONTAINMENT, PENETRATION AREA STEAM GENERATOR SAMPLE HEAT EXCHANGERS, REACTOR CONTAINMENT SAMPLE HEAT EXCHANGER, PRESSURIZER LIQUID SPACE SAMPLE HEAT EXCHANGER PRESSUERIZER STEAM SPACE SAMPLE HEAT EXCHANGER PANELS - 321, 322, 323 & 324

SHEET 2 — NO. 2 PRIMARY & SECONDARY SAMPLE SINK, SAMPLE VESSEL, BORON SAMPLE TANK & STEAM GENERATOR STEAM SAMPLE HEAT EXCHANGERS

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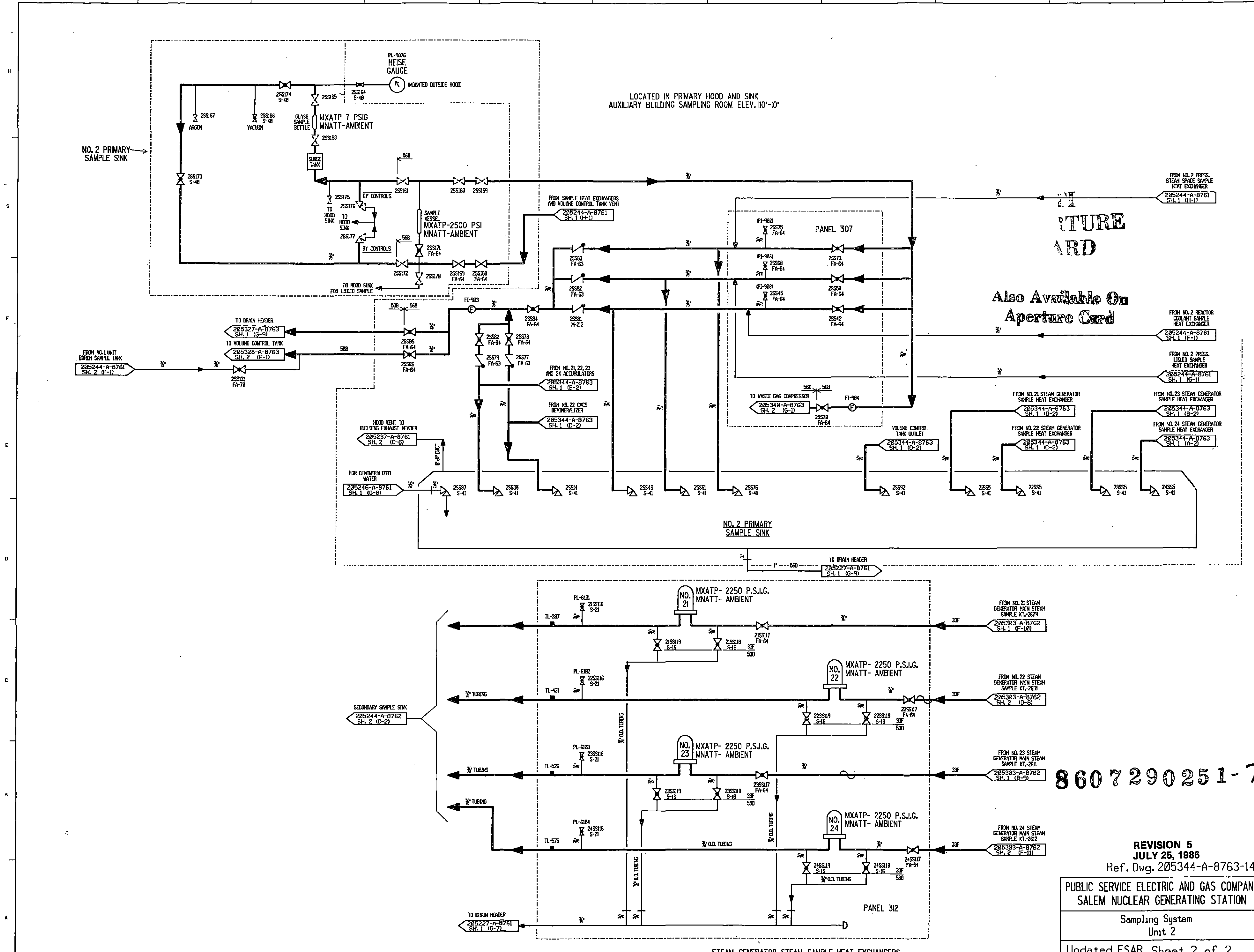
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Sampling System
Unit 2

Updated FSAR Sheet 1 of 2
Fig 9.3-3B

8607290251-71



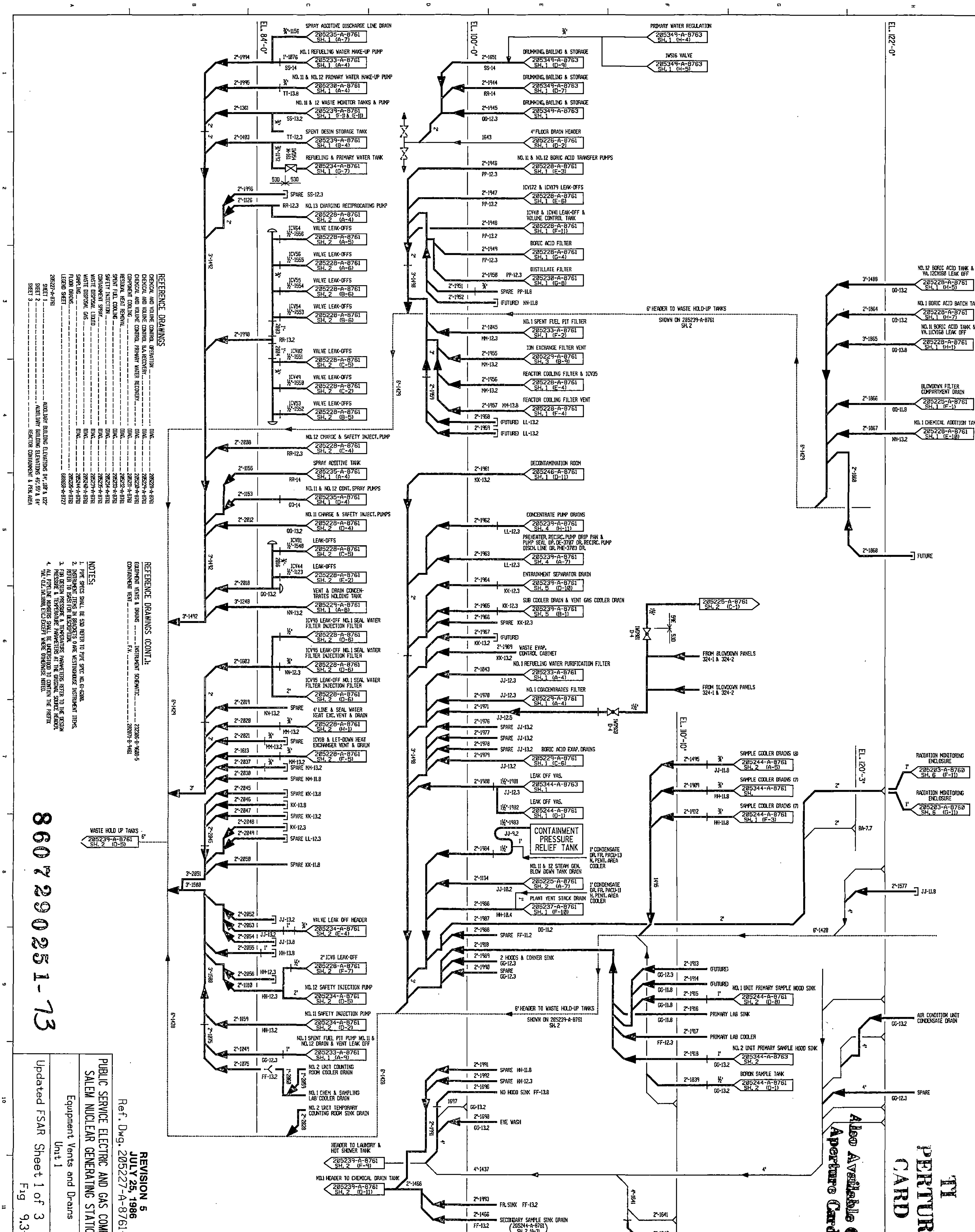
8607290251-72

REVISION 5
JULY 25, 1986
Ref. Dwg. 205344-A-8763-14

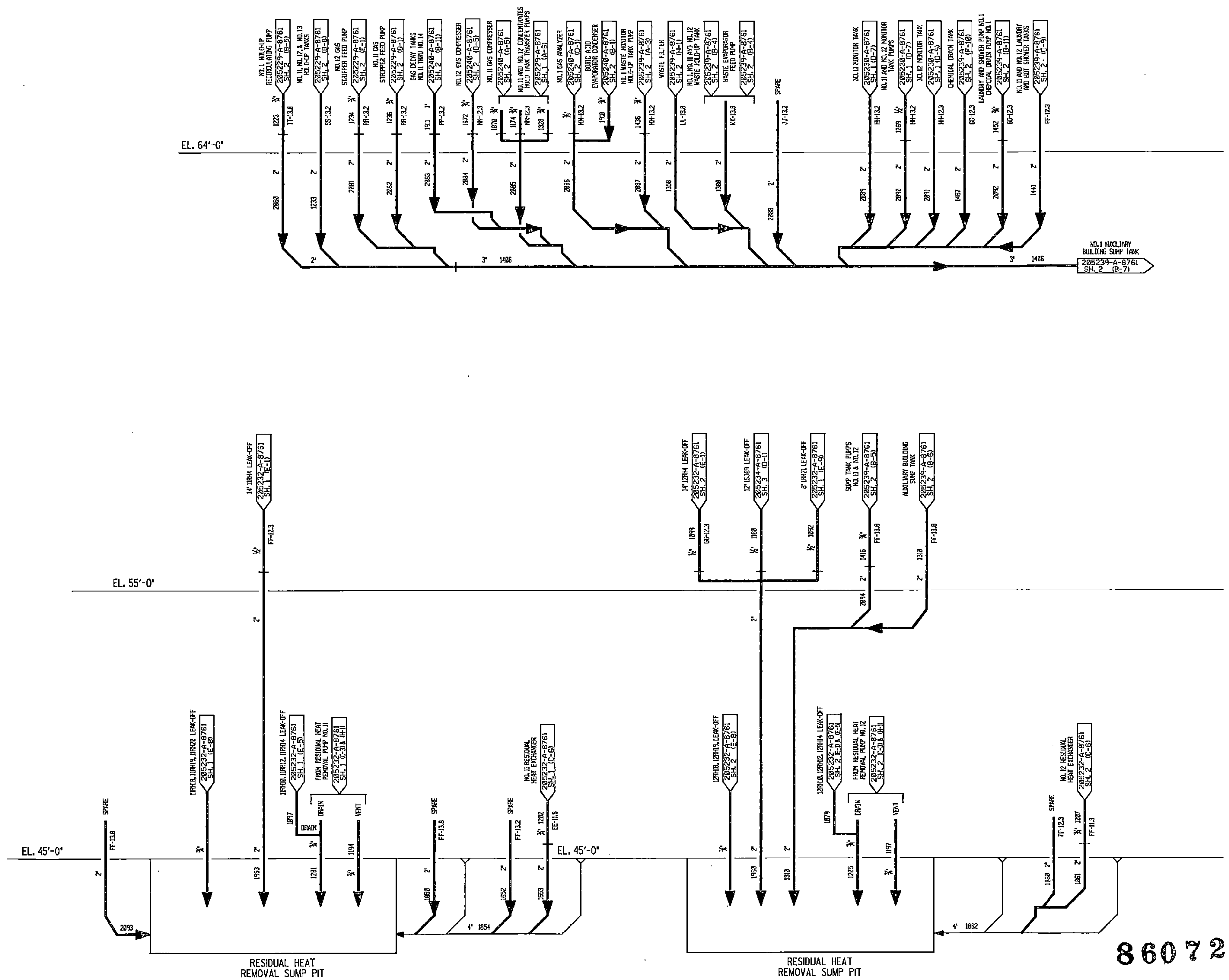
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Sampling System
Unit 2

Updated FSAR Sheet 2 of 2
Fig 9.3-3B



EL. 84'-0"
EL. 100'-0"
EL. 110'-10"
EL. 120'-3"
EL. 122'-0"
CONTAINMENT PRESSURE RELIEF TANK
WASTE HOLD UP TANKS 205239-A-8761 SH. 2 (D-5)
REFERENCE DRAWINGS
NOTES:
8607290251-73
TI APERTURE CARD
Also Available On Aperture Card
REVISION 5
JULY 25, 1986
Ref. Dwg. 205227-A-8761-18
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION
Equipment Vents and Drains
Unit 1
Updated FSAR Sheet 1 of 3
Fig 9.3-4A



TI APERTURE CARD

Also Available On Aperture Card

8607290251-74

REVISION 5
JULY 25, 1986
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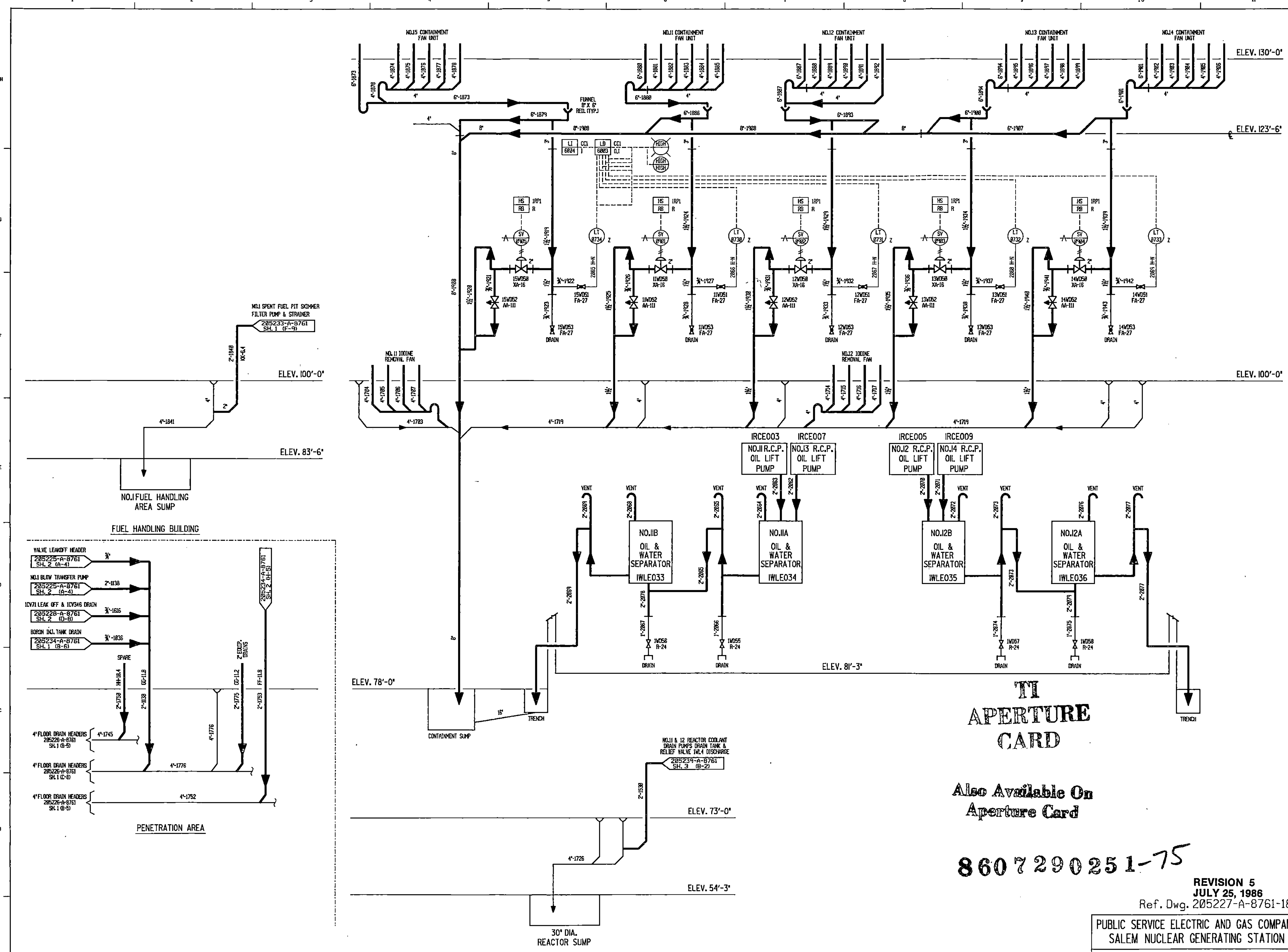
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Equipment Vents and Drains
Unit 1

Updated FSAR Sheet 2 of 3
Fig 9.3-4A



TI APERTURE CARD

Also Available On Aperture Card

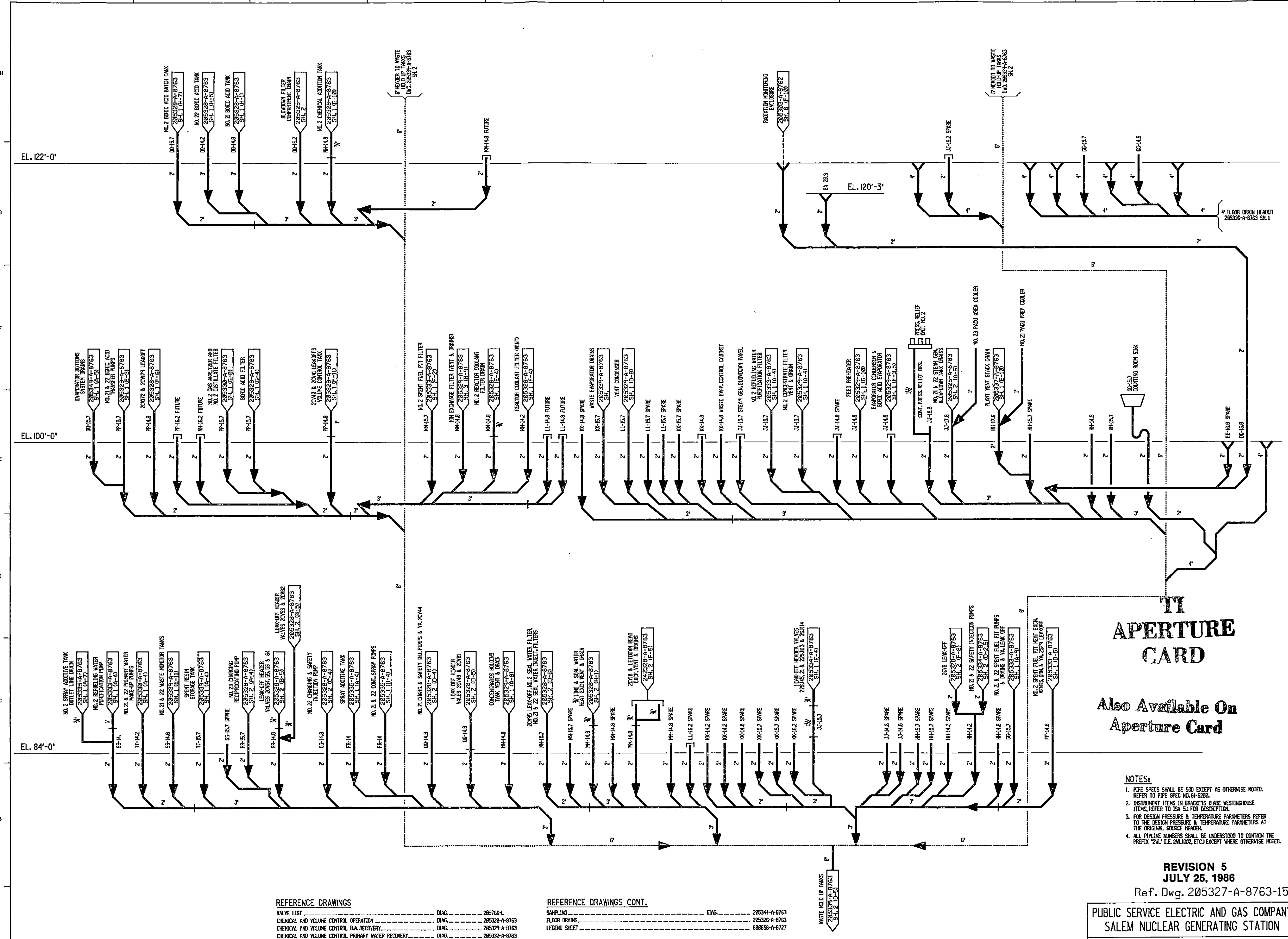
8607290251-75

REVISION 5
JULY 25, 1986
Ref. Dwg. 205227-A-8761-18

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Equipment Vents and Drains
Unit 1

Updated FSAR Sheet 3 of 3
Fig 9.3-4A



TI
APERTURE
CARD

Also Available On
Aperture Card

NOTES:

1. PIPE SPECS SHALL BE 530 EXCEPT AS OTHERWISE NOTED. REFER TO PIPE SPEC NO. 61-6200.
2. INSTRUMENT ITEMS IN BRACKETS 0 ARE WESTINGHOUSE ITEMS, REFER TO ISA 5.1 FOR DESCRIPTION.
3. FOR DESIGN PRESSURE & TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE & TEMPERATURE PARAMETERS AT THE ORIGINAL SOURCE HEADER.
4. ALL PIPLINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2WL" (I.E. 2WL1030, ETC.) EXCEPT WHERE OTHERWISE NOTED.

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Ref. Dwg. 205327-A-8763-15

REFERENCE DRAWINGS

VALVE LIST	DIAG.	205766-L
CHEMICAL AND VOLUME CONTROL OPERATION	DIAG.	205328-A-8763
CHEMICAL AND VOLUME CONTROL B.A. RECOVERY	DIAG.	205329-A-8763
CHEMICAL AND VOLUME CONTROL PRIMARY WATER RECOVERY	DIAG.	205330-A-8763
COMPONENT COOLING	DIAG.	205331-A-8763
RESIDUAL HEAT REMOVAL	DIAG.	205332-A-8763
SPENT FUEL COOLING	DIAG.	205333-A-8763
SAFETY INJECTION	DIAG.	205334-A-8763
CONTAINMENT SPRAY	DIAG.	205335-A-8763
WASTE DISPOSAL LIQUID	DIAG.	205339-A-8763
WASTE DISPOSAL GAS	DIAG.	205340-A-8763

REFERENCE DRAWINGS CONT.

SAMPLING	DIAG.	205344-A-8763
FLOOR DRAINS		205326-A-8763
LEGEND SHEET		600658-A-8727

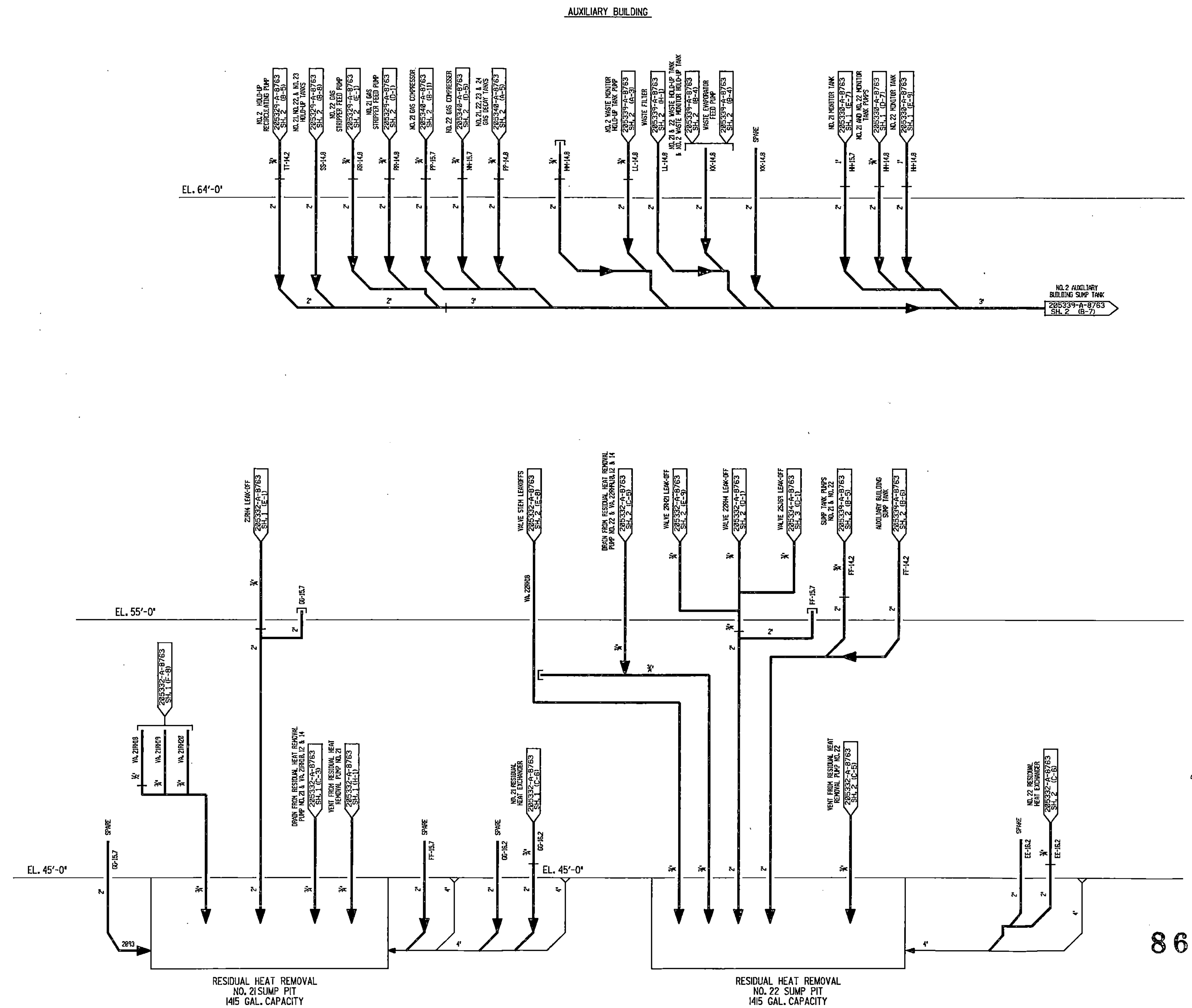
205327-A-8763
SHEET 1 — AUXILIARY BUILDING ELEVATIONS 84', 100' & 122'
SHEET 2 — AUXILIARY BUILDING ELEVATIONS 45', 55' & 64'
SHEET 3 — REACTOR CONTAINMENT & PEN. AREA

8607290251-76

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Equipment Vents and Drains
Unit 2

Updated FSAR Sheet 1 of 3
Fig 9.3-4B



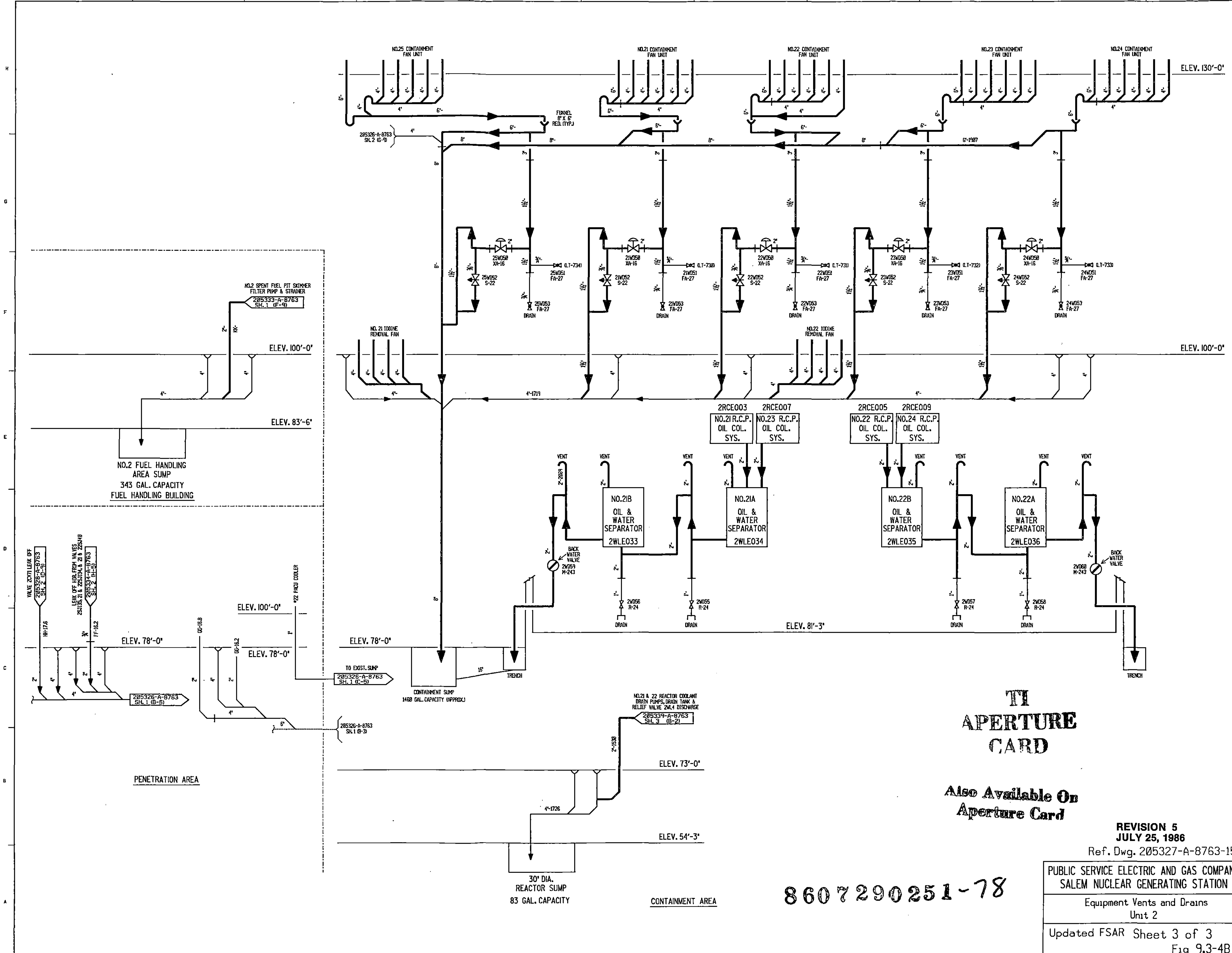
TI
APERTURE
CARD

Also Available On
Aperture Card

8607290251-77

REVISION 5
JULY 25, 1986
Ref. Dwg. 205327-A-8763-15

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION
Equipment Vents and Drains Unit 2
Updated FSAR Sheet 2 of 3 Fig 9.3-4B



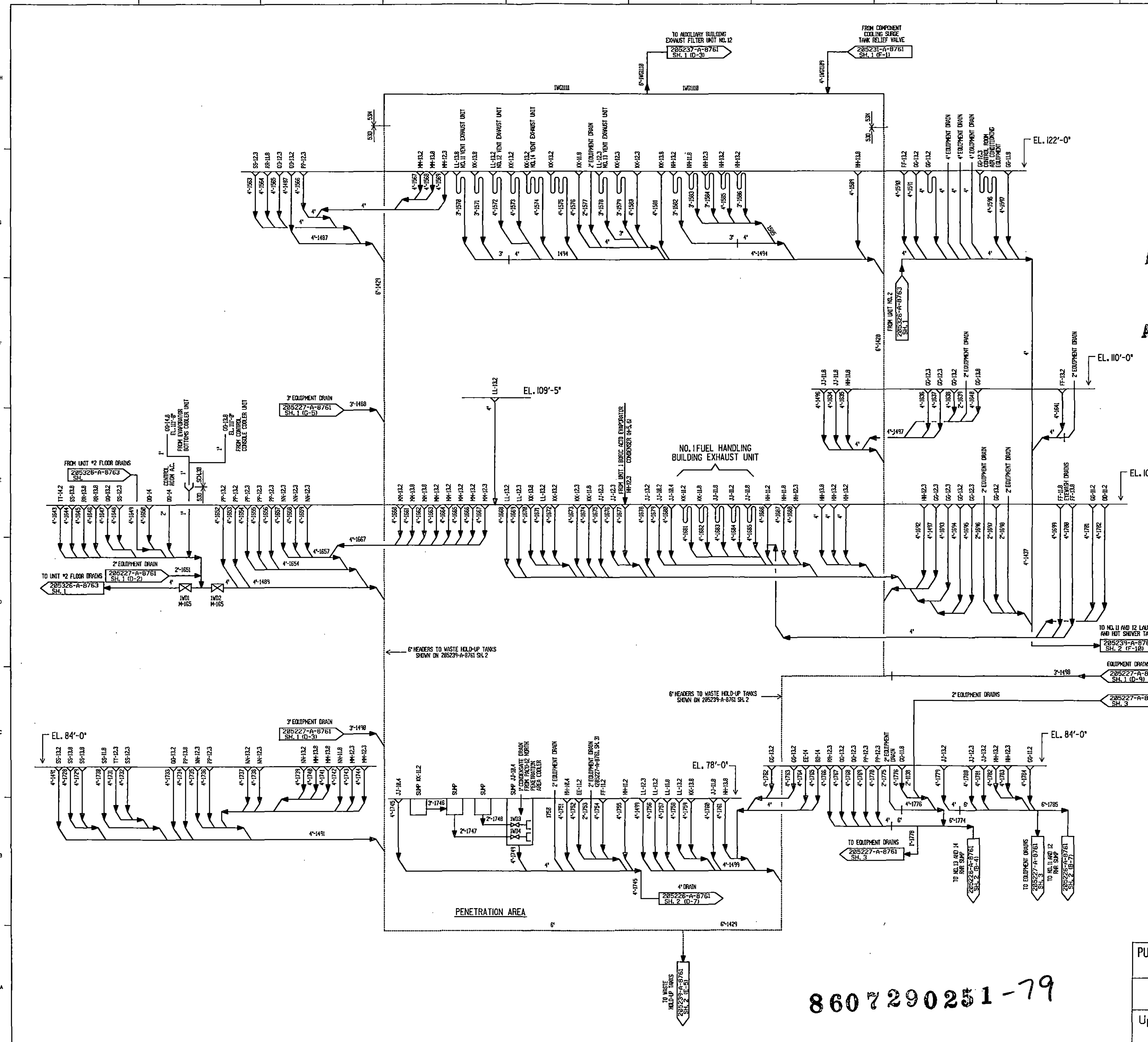
REVISION 5
JULY 25, 1986

Ref. Dwg. 205327-A-8763-15

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Equipment Vents and Drains
Unit 2

Updated FSAR Sheet 3 of 3
Fig 9.3-4B



REFERENCE DRAWINGS

EQUIPMENT VENTS AND DRAINS CONTAMINATED DIAGRAM _____ 205227-A-8761

WASTE DISPOSAL - GAS ____ DIAGRAM _____ 205239-A-8761

SUMP & FLOOR PUMPS CONTAMINATED INSTR.SCH. ____ 233621-B-9611-8

AUXILIARY ANNUNCIATOR SYSTEM CAB. #33 ____ WIRING DIAG. ____ 220478-A-1320

LEGEND SHEET ________________ 600658-A-8727

205226-A-8761 __ SH. 1 __ AUX. BLDG. & PEN. AREA EL. 84', 100', 110' & 122'

SH. 2 __ CONT., F.H.BLDG. & AUX.BLDG. EL. 45', 55' & 64'

NOTES

1. PIPE SPECIFICATIONS SHALL BE 53D REFER TO PIPE SPECIFICATION NO. 61-6200.
2. FOR DESIGN PRESSURE AND TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE AND TEMPERATURE PARAMETERS AT THE ORIGINAL SOURCE HEADERS.
3. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX 1WL (IE: 1WL1000, ETC.) EXCEPT WHERE OTHERWISE NOTED.

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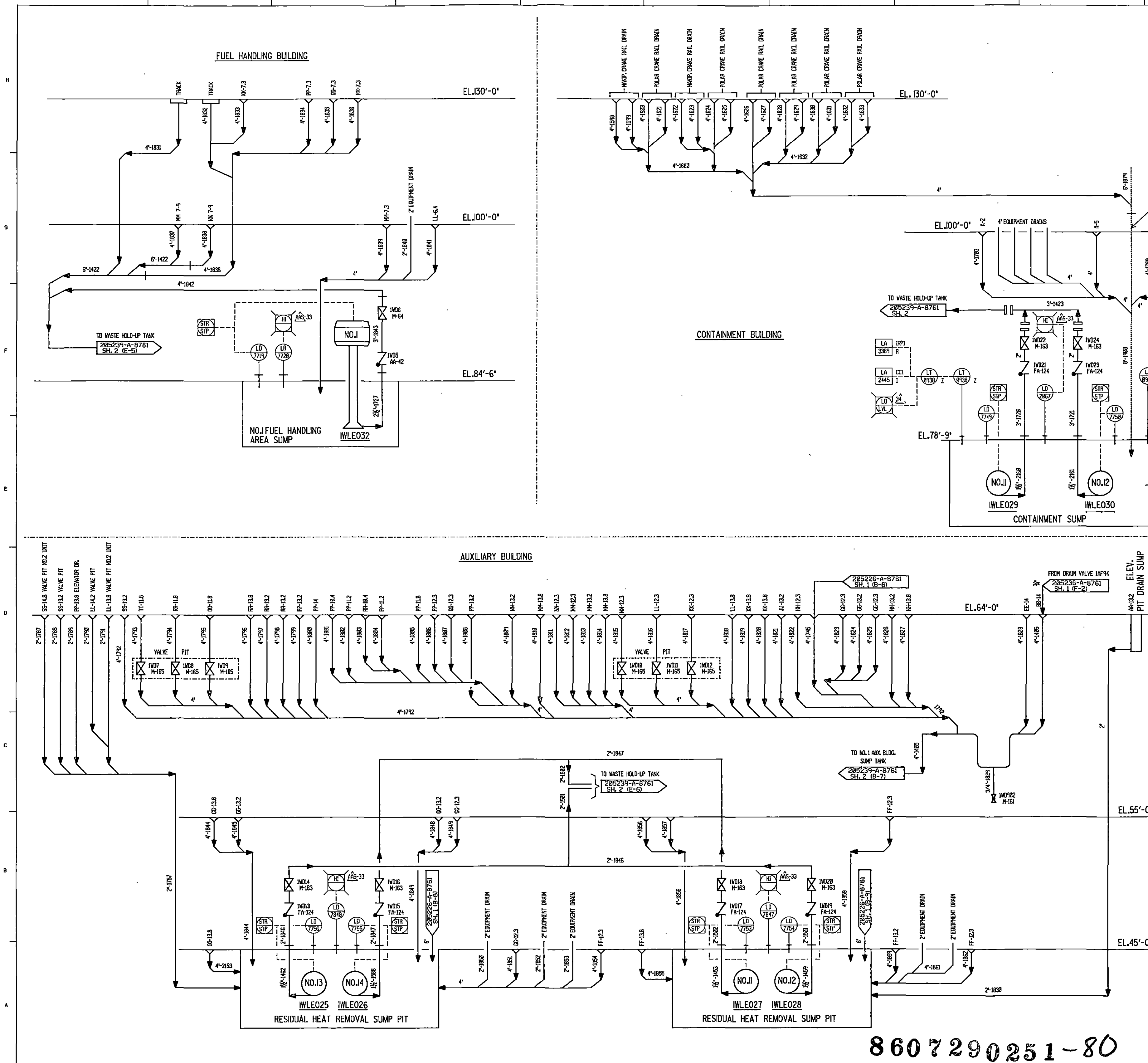
Ref. Dwg. 205226-A-8761-20

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Floor Drains
Unit 1

Updated FSAR Sheet 1 of 2
Fig 9.3-5A

8607290251-79



TI APERTURE CARD

Also Available On Aperture Card

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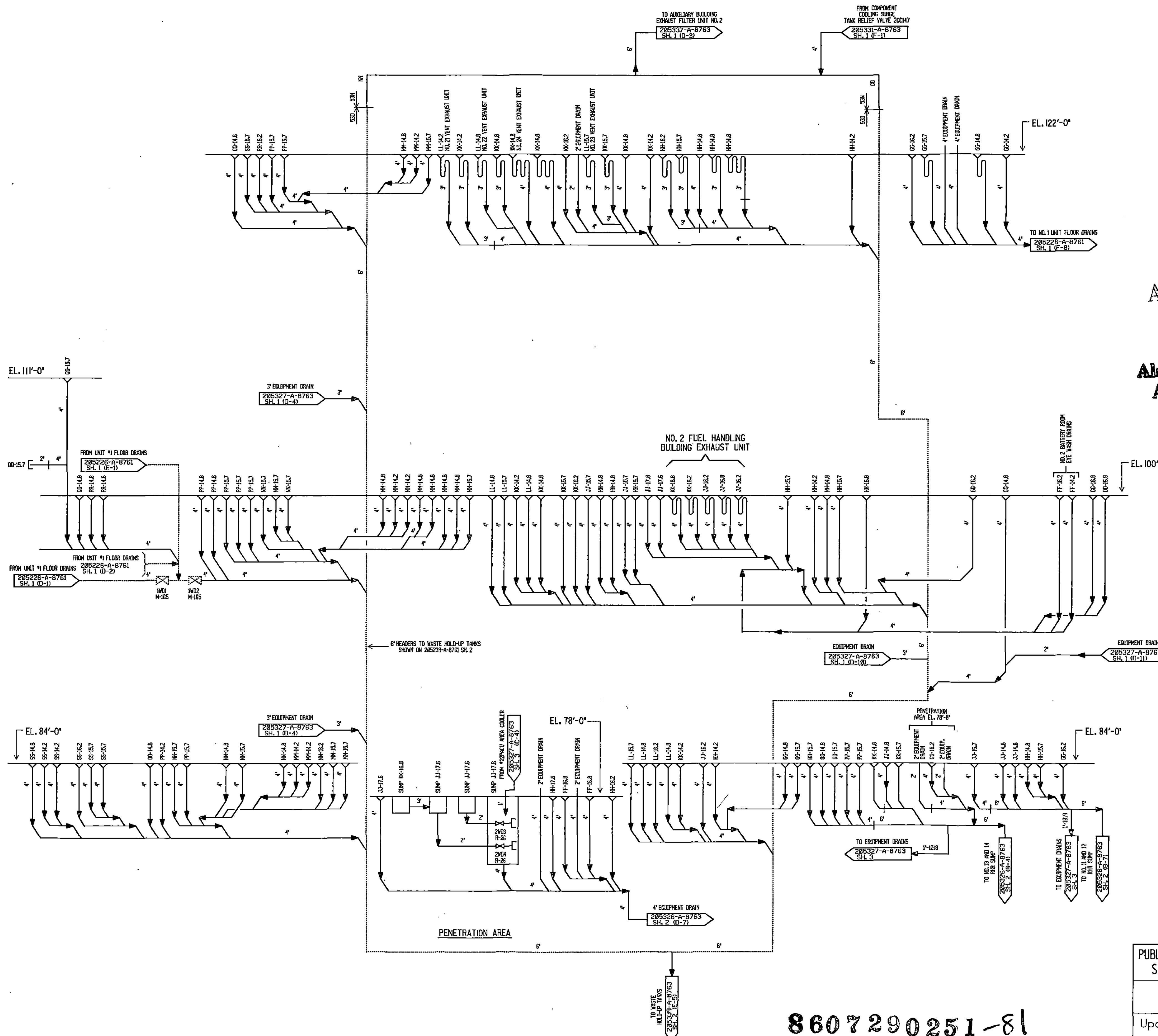
JULY 25, 1986
Ref. Dwg. 205226-A-8761-19

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Floor Drains
Unit 1

Updated FSAR Sheet 2 of 2
Fig 9.3-5A

8607290251-80



REFERENCE DRAWINGS

VALVE LIST	206766-L
EQUIPMENT VENTS AND DRAINS CONTAMINATED DIAGRAM	205327-A-8763
WASTE DISPOSAL - LIQUID DIAGRAM	205339-A-8763
NO. 2 UNIT AUX. BLDG. VENTILATION	205337-A-8763
NO. 1 UNIT FLOOR DRAINS - CONTAMINATED	205226-A-8761
LEGEND SHEET	600658-A-8727

NOTES

1. PIPE SPECIFICATIONS SHALL BE 530 REFER TO PIPE SPECIFICATION NO. 61-6200.
2. FOR DESIGN PRESSURE AND TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE AND TEMPERATURE PARAMETERS AT THE ORIGINAL SOURCE HEADERS.
3. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX 2WD (IE: 2WD1000, ETC.) EXCEPT WHERE OTHERWISE NOTED.

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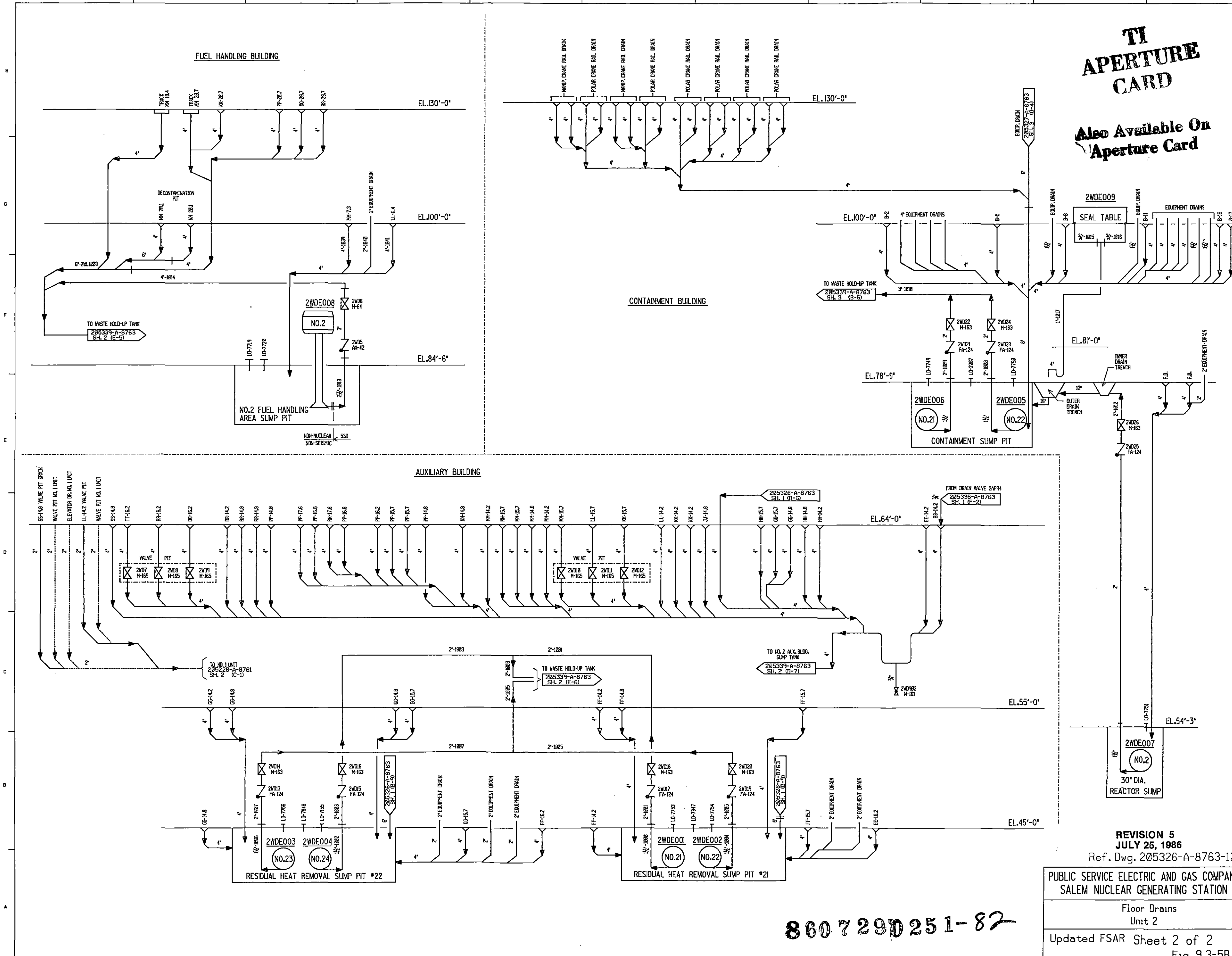
JULY 25, 1986
Ref. Dwg. 205326-A-8763-12

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Floor Drains
Unit 2

Updated FSAR Sheet 1 of 2
Fig 9.3-5B

8607290251-81



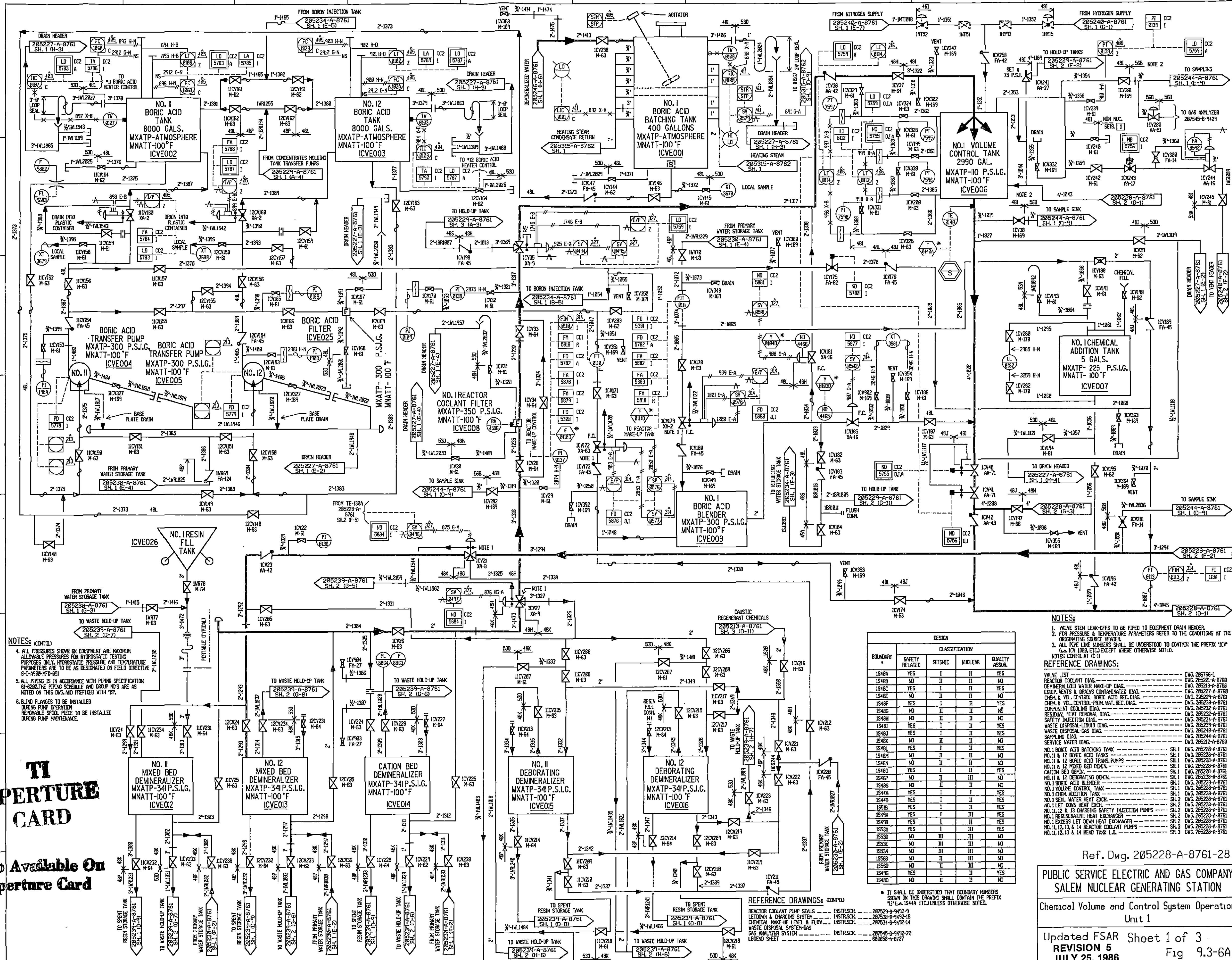
REVISION 5
JULY 25, 1986
Ref. Dwg. 205326-A-8763-12

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Floor Drains
Unit 2

Updated FSAR Sheet 2 of 2
Fig 9.3-5B

8607290251-82



NOTES:

1. VALVE STEM LEAK-OFFS TO BE PIPED TO EQUIPMENT DRAIN HEADER.
2. FOR PRESSURE & TEMPERATURE PARAMETERS REFER TO THE CONDITIONS AT THE ORIGINATING SOURCE HEADER.
3. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1CV" (i.e. 1CV 1030, ETC.) EXCEPT WHERE OTHERWISE NOTED.

NOTES CONT'D. AT (C-1)

NOTES: (CONT'D.)

4. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPURATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051
5. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200. THE PIPING SCHEDULE AND GROUP NO'S ARE AS NOTED ON THIS DWG. AND PREFIXED WITH '1S'.
6. BLIND FLANGES TO BE INSTALLED DURING PUMP OPERATION
REMOVABLE SPOOL PIECE TO BE INSTALLED DURING PUMP MAINTENANCE.

DESIGN				
BOUNDARY *	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S48A	YES	I	II	YES
1S48B	NO	II	II	NO
1S48C	YES	I	II	YES
1S48E	NO	II	II	NO
1S48F	YES	I	II	YES
1S48G	NO	II	II	NO
1S48H	NO	II	II	NO
1S48I	YES	I	II	YES
1S48J	YES	I	II	YES
1S48K	NO	II	II	NO
1S48L	YES	I	II	YES
1S48M	NO	II	II	NO
1S48N	NO	II	II	NO
1S48O	YES	I	II	YES
1S46P	NO	II	III	NO
1S48S	NO	II	II	NO
1S44A	YES	I	I	YES
1S44D	YES	I	II	YES
1S51B	YES	I	II	YES
1S49A	YES	I	III	YES
1S49B	YES	I	II	YES
1S53A	YES	I	III	YES
1S53D	NO	III	III	NO
1S53E	NO	III	III	NO
1S53N	NO	III	III	NO
1S56B	NO	II	III	NO
1S56D	NO	II	III	NO
1S49G	YES	I	II	YES
1S48D	NO	II	II	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "L" (i.e. 1S44A ETC.) UNLESS OTHERWISE NOTED.

REFERENCE DRAWINGS:

VALVE LIST ---------- DWG. 206766-L
REACTOR COOLANT DIAG. ---------- DWG. 205201-A-8760
DEMINERALIZED WATER MAKE-UP DIAG. ---------- DWG. 205213-A-8760
EQUIP. VENTS & DRAINS CONTAMINATED DIAG. ---------- DWG. 205227-A-8760
CHEM. & VOL. CONTROL BORIC ACID REC. DIAG. ---------- DWG. 205229-A-8761
CHEM. & VOL. CONTROL-PRIM. WAT. REC. DIAG. ---------- DWG. 205230-A-8761
COMPONENT COOLING DIAG. ---------- DWG. 205232-A-8761
RESIDUAL HEAT REMOVAL DIAG. ---------- DWG. 205232-A-8761
SAFETY INJECTION DIAG. ---------- DWG. 205234-A-8761
WASTE DISPOSAL-LIQUID DIAG. ---------- DWG. 205239-A-8761
WASTE DISPOSAL-GAS DIAG. ---------- DWG. 205240-A-8761
SAMPLING DIAG. ---------- DWG. 205244-A-8761
SERVICE WATER DIAG. ---------- DWG. 205212-A-8760

NO. 1 BORIC ACID BATCHING TANK ---------- SH. 1 DWG. 205228-A-8761
NO. 11 & 12 BORIC ACID TANKS ---------- SH. 1 DWG. 205228-A-8761
NO. 11 & 12 BORIC ACID TRANS. PUMPS ---------- SH. 1 DWG. 205228-A-8761
NO. 11 & 12 MIXED BED DEMIN. ---------- SH. 1 DWG. 205228-A-8761
CATION BED DEMIN. ---------- SH. 1 DWG. 205228-A-8761
NO. 11 & 12 DEBORATING DEMIN. ---------- SH. 1 DWG. 205228-A-8761
NO. 1 BORIC ACID BLENDER ---------- SH. 1 DWG. 205228-A-8761
NO. 1 VOLUME CONTROL TANK ---------- SH. 1 DWG. 205228-A-8761
NO. 1 CHEM. ADDITION TANK ---------- SH. 1 DWG. 205228-A-8761
NO. 1 SEAL WATER HEAT EXCH. ---------- SH. 2 DWG. 205228-A-8761
NO. 1 LET DOWN HEAT EXCH. ---------- SH. 2 DWG. 205228-A-8761
NO. 11, 12 & 13 CHARGING SAFETY INJECTION PUMPS ---------- SH. 2 DWG. 205228-A-8761
NO. 1 REGENERATIVE HEAT EXCHANGER ---------- SH. 2 DWG. 205228-A-8761
NO. 1 EXCESS LET DOWN HEAT EXCHANGER ---------- SH. 2 DWG. 205228-A-8761
NO. 11, 12, 13, & 14 REACTOR COOLANT PUMPS ---------- SH. 3 DWG. 205228-A-8761
NO. 11, 12, 13 & 14 HEAD TANK L.O. ---------- SH. 3 DWG. 205228-A-8761

REFERENCE DRAWINGS: (CONT'D.)

REACTOR COOLANT PUMP SEALS ---- INSTR. SCH. ---- 207529-B-9492-9
LETDOWN & CHARGING SYSTEM ---- INSTR. SCH. ---- 207530-B-9492-16
CHEMICAL MAKE-UP LEVEL & FLOW ---- INSTR. SCH. ---- 207534-B-9492-14
WASTE DISPOSAL SYSTEM-GAS
GAS ANALYZER SYSTEM ---- INSTR. SCH. ---- 207545-B-9492-22
LEGEND SHEET ---------- 600658-A-8727

TI APERTURE CARD

Also Available On Aperture Card

Ref. Dwg. 205228-A-8761-28

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

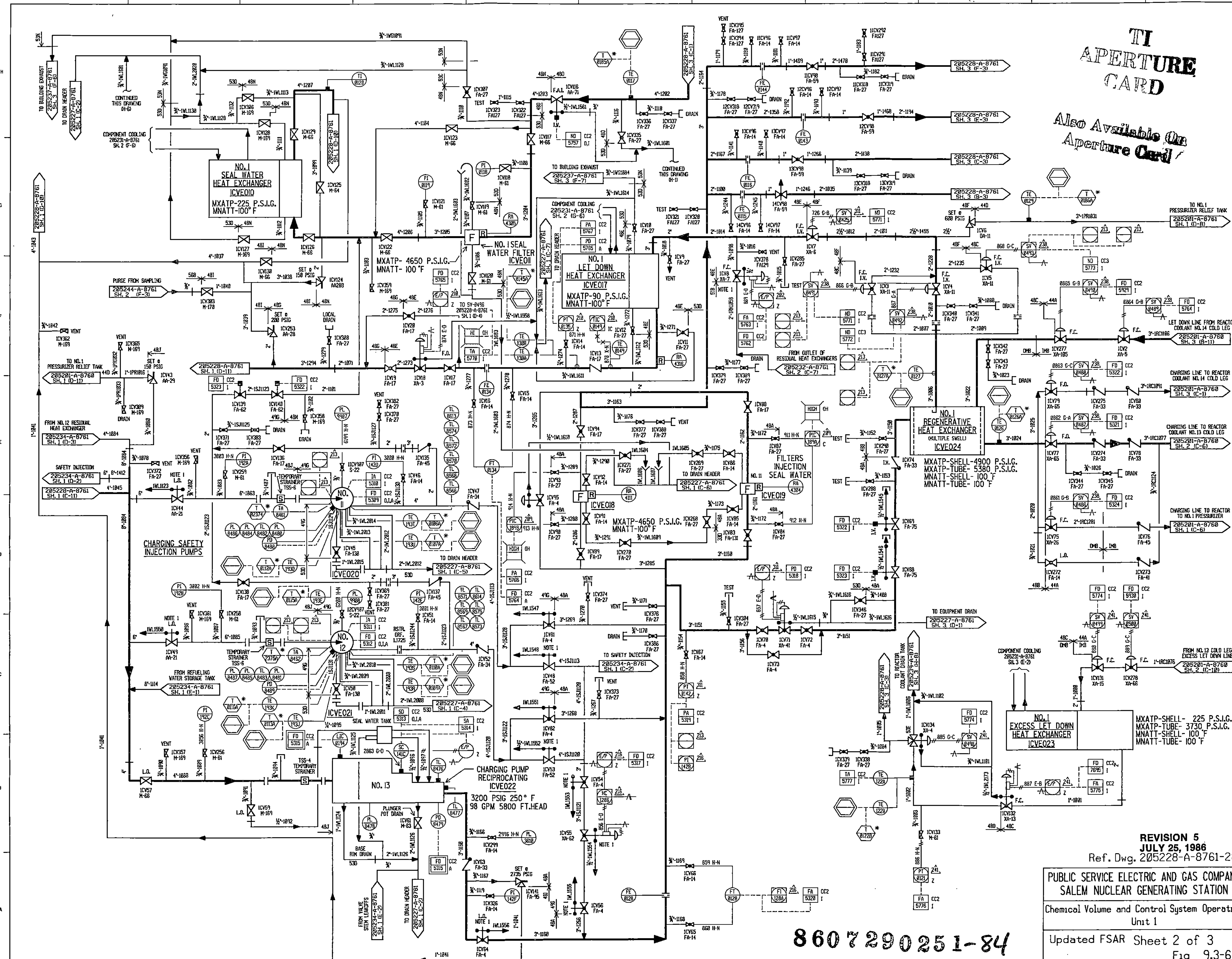
Chemical Volume and Control System Operation
Unit 1

Updated FSAR
REVISION 5
JULY 25, 1986

Sheet 1 of 3

Fig 9.3-6A

8607290251-83

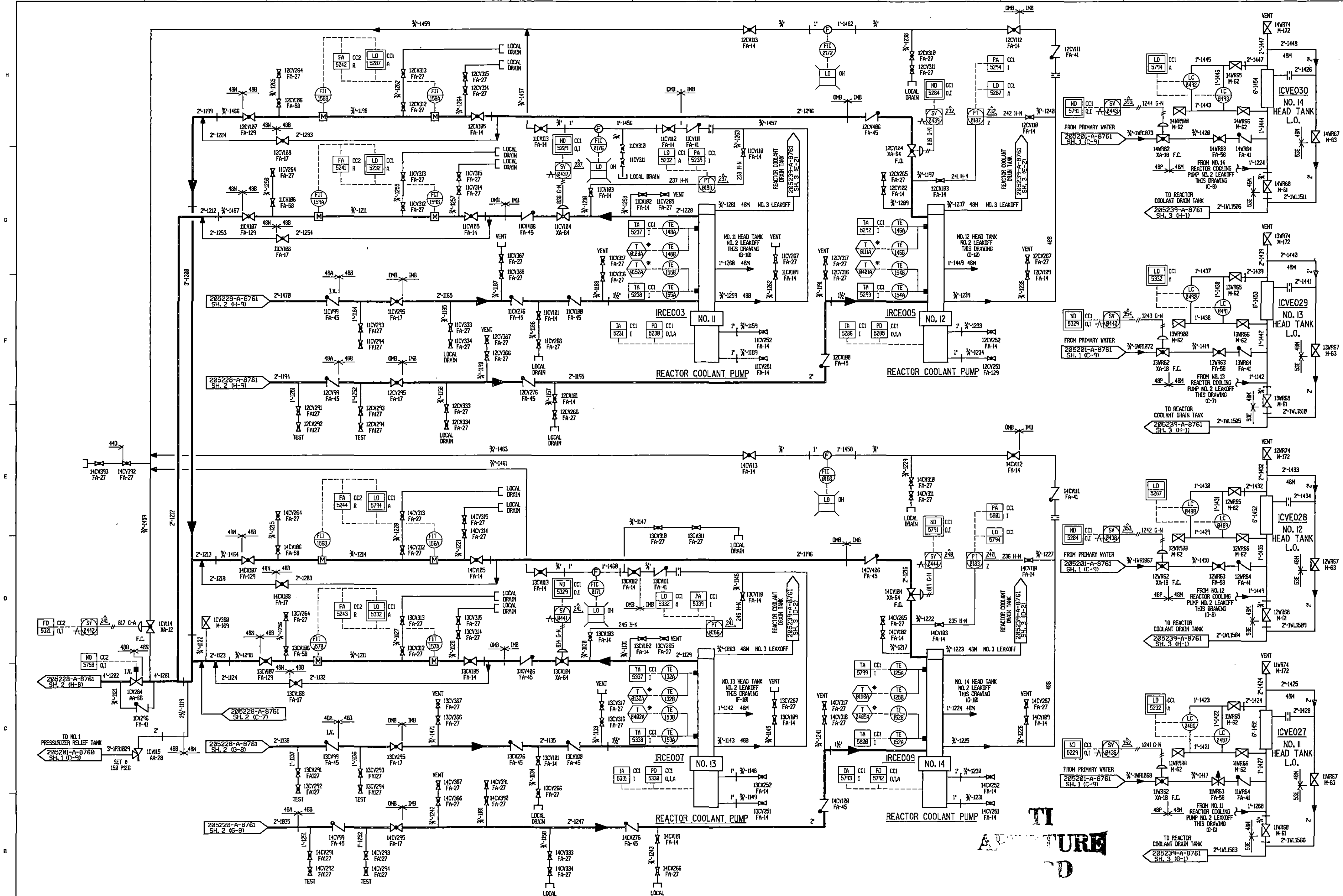


REVISION 5
JULY 25, 1986
Ref. Dwg. 205228-A-8761-28

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Chemical Volume and Control System Operation
Unit 1

Updated FSAR Sheet 2 of 3
Fig 9.3-6A



Also Available On Aperture Card

8607290251-85

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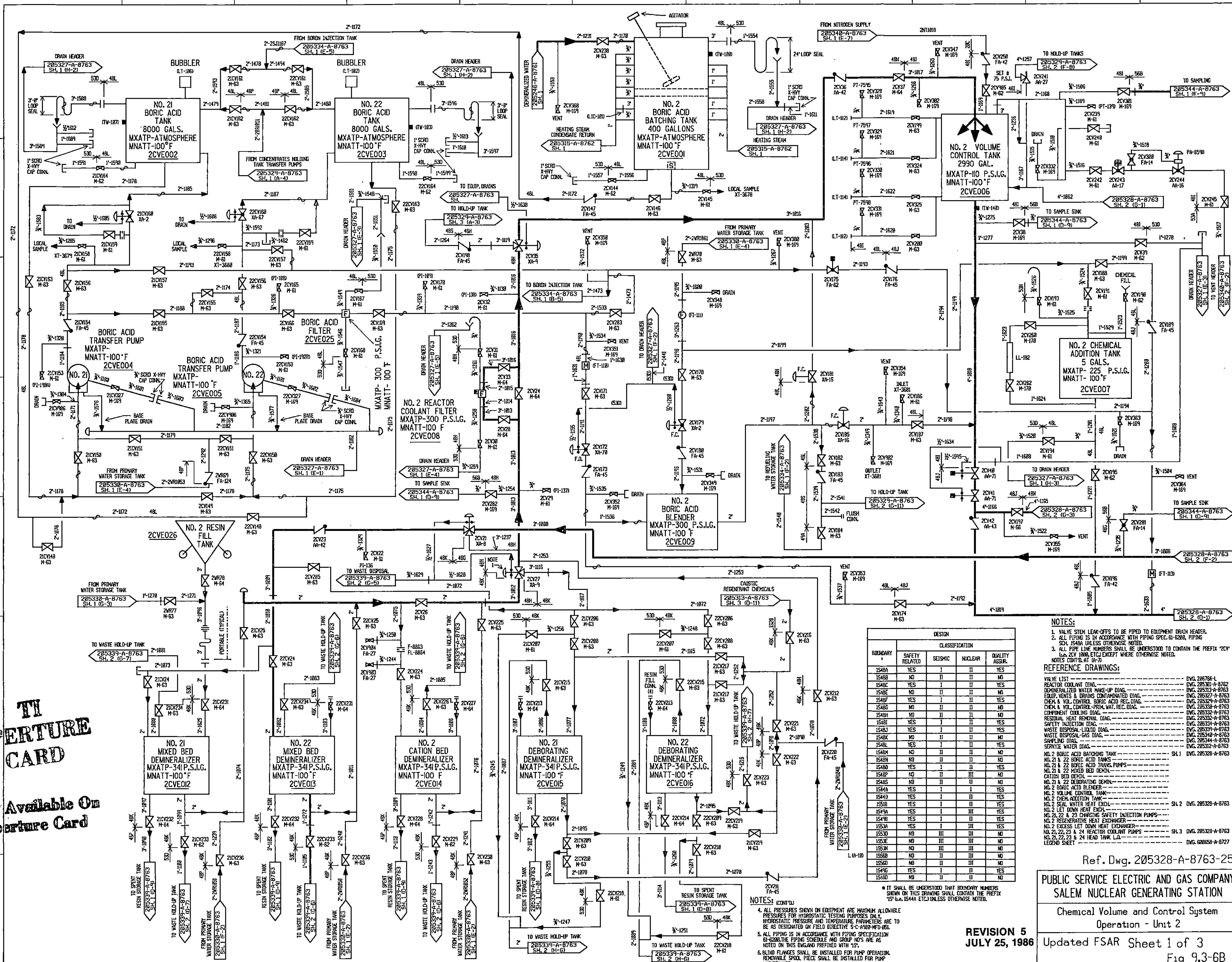
JULY 25, 1986
Ref. Dwg. 205228-A-8761-28

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Chemical Volume and Control System Operation
Unit 1

Updated FSAR Sheet 3 of 3
Fig 9.3-6A



NOTES:

1. VALVE STEM LEAK-OFFS TO BE PIPED TO EQUIPMENT DRAIN HEADER.
2. ALL PIPING IS IN ACCORDANCE WITH PIPING SPEC. 61-6200, PIPING SCH. 1S48A UNLESS OTHERWISE NOTED.
3. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2CV" (i.e. 2CV 1000, ETC.) EXCEPT WHERE OTHERWISE NOTED.

NOTES CONT'D. AT (A-7)

REFERENCE DRAWINGS:

VALVE LIST ---------- DWG. 206766-L
REACTOR COOLANT DIAG. ---------- DWG. 205301-A-8762
DEMINERALIZED WATER MAKE-UP DIAG. ---------- DWG. 205313-A-8763
EQUIP. VENTS & DRAINS CONTAMINATED DIAG. ---------- DWG. 205327-A-8763
CHEM. & VOL. CONTROL BORIC ACID REC. DIAG. ---------- DWG. 205329-A-8763
CHEM. & VOL. CONTROL-PRIM. WAT. REC. DIAG. ---------- DWG. 205330-A-8763
COMPONENT COOLING DIAG. ---------- DWG. 205332-A-8763
RESIDUAL HEAT REMOVAL DIAG. ---------- DWG. 205332-A-8763
SAFETY INJECTION DIAG. ---------- DWG. 205334-A-8763
WASTE DISPOSAL-LIQUID DIAG. ---------- DWG. 205339-A-8763
WASTE DISPOSAL-GAS DIAG. ---------- DWG. 205340-A-8763
SAMPLING DIAG. ---------- DWG. 205344-A-8763
SERVICE WATER DIAG. ---------- DWG. 205312-A-8763

NO. 2 BORIC ACID BATCHING TANK ---------- SH. 1 DWG. 205328-A-8763
NO. 21 & 22 BORIC ACID TANKS ----------
NO. 21 & 22 BORIC ACID TRANS. PUMPS ----------
NO. 21 & 22 MIXED BED DEMIN. ----------
CATION BED DEMIN. ----------
NO. 21 & 22 DEBORATING DEMIN. ----------
NO. 2 BORIC ACID BLENDER ----------
NO. 2 VOLUME CONTROL TANK ----------
NO. 2 CHEM. ADDITION TANK ----------
NO. 2 SEAL WATER HEAT EXCH. ---------- SH. 2 DWG. 205328-A-8763
NO. 2 LET DOWN HEAT EXCH. ----------
NO. 21, 22 & 23 CHARGING SAFETY INJECTION PUMPS ----------
NO. 2 REGENERATIVE HEAT EXCHANGER ----------
NO. 2 EXCESS LET DOWN HEAT EXCHANGER ----------
NO. 21, 22, 23 & 24 REACTOR COOLANT PUMPS ---------- SH. 3 DWG. 205328-A-8763
NO. 21, 22, 23 & 24 HEAD TANK L.O. ----------
LEGEND SHEET ---------- DWG. 600658-A-8727

DESIGN				
BOUNDARY •	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S48A	YES	I	II	YES
1S48B	NO	II	II	NO
1S48C	YES	I	II	YES
1S48E	NO	II	II	NO
1S48F	YES	I	II	YES
1S48G	NO	II	II	NO
1S48H	NO	II	II	NO
1S48I	YES	I	II	YES
1S48J	YES	I	II	YES
1S48K	NO	II	II	NO
1S48L	YES	I	II	YES
1S48M	NO	II	II	NO
1S48N	NO	II	II	NO
1S48O	YES	I	II	YES
1S48P	NO	II	III	NO
1S48S	NO	II	II	NO
1S44A	YES	I	I	YES
1S44D	YES	I	II	YES
1S51B	YES	I	II	YES
1S49A	YES	I	III	YES
1S49B	YES	I	II	YES
1S53A	YES	I	III	YES
1S53D	NO	III	III	NO
1S53E	NO	III	III	NO
1S53N	NO	III	III	NO
1S56B	NO	II	III	NO
1S56D	NO	II	III	NO
1S49G	YES	I	II	YES
1S48D	NO	II	II	NO

• IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A ETC.) UNLESS OTHERWISE NOTED.

NOTES: (CONT'D.)

4. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
5. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200. THE PIPING SCHEDULE AND GROUP NO'S ARE AS NOTED ON THIS DWG. AND PREFIXED WITH "1S".
6. BLIND FLANGES SHALL BE INSTALLED FOR PUMP OPERATION. REMOVABLE SPOOL PIECE SHALL BE INSTALLED FOR PUMP MAINTENANCE.

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Ref. Dwg. 205328-A-8763-25

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

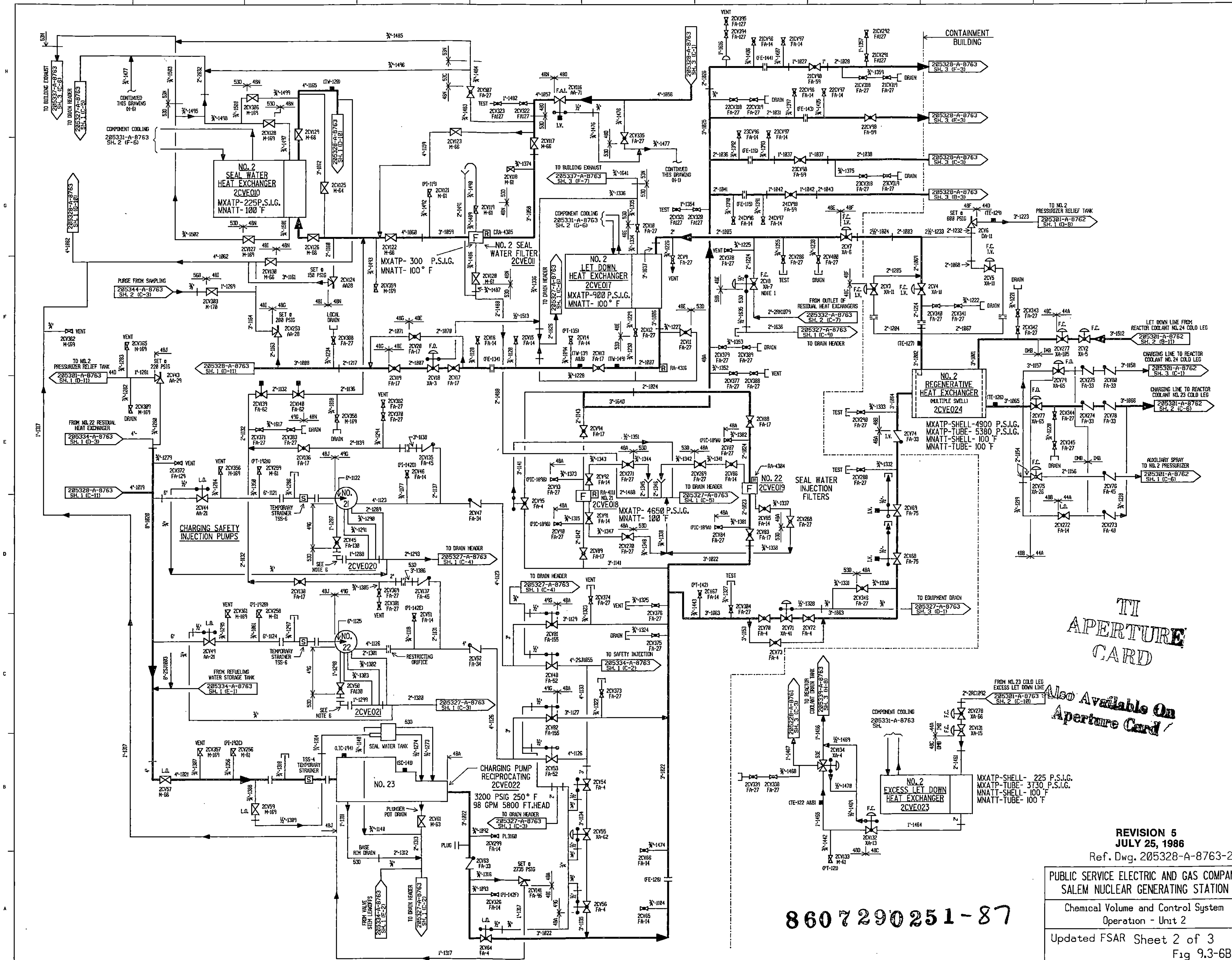
Chemical Volume and Control System Operation - Unit 2

REVISION 5
JULY 25, 1986

Updated FSAR Sheet 1 of 3

Fig 9.3-6B

8607290251-86



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JULY 25, 1986

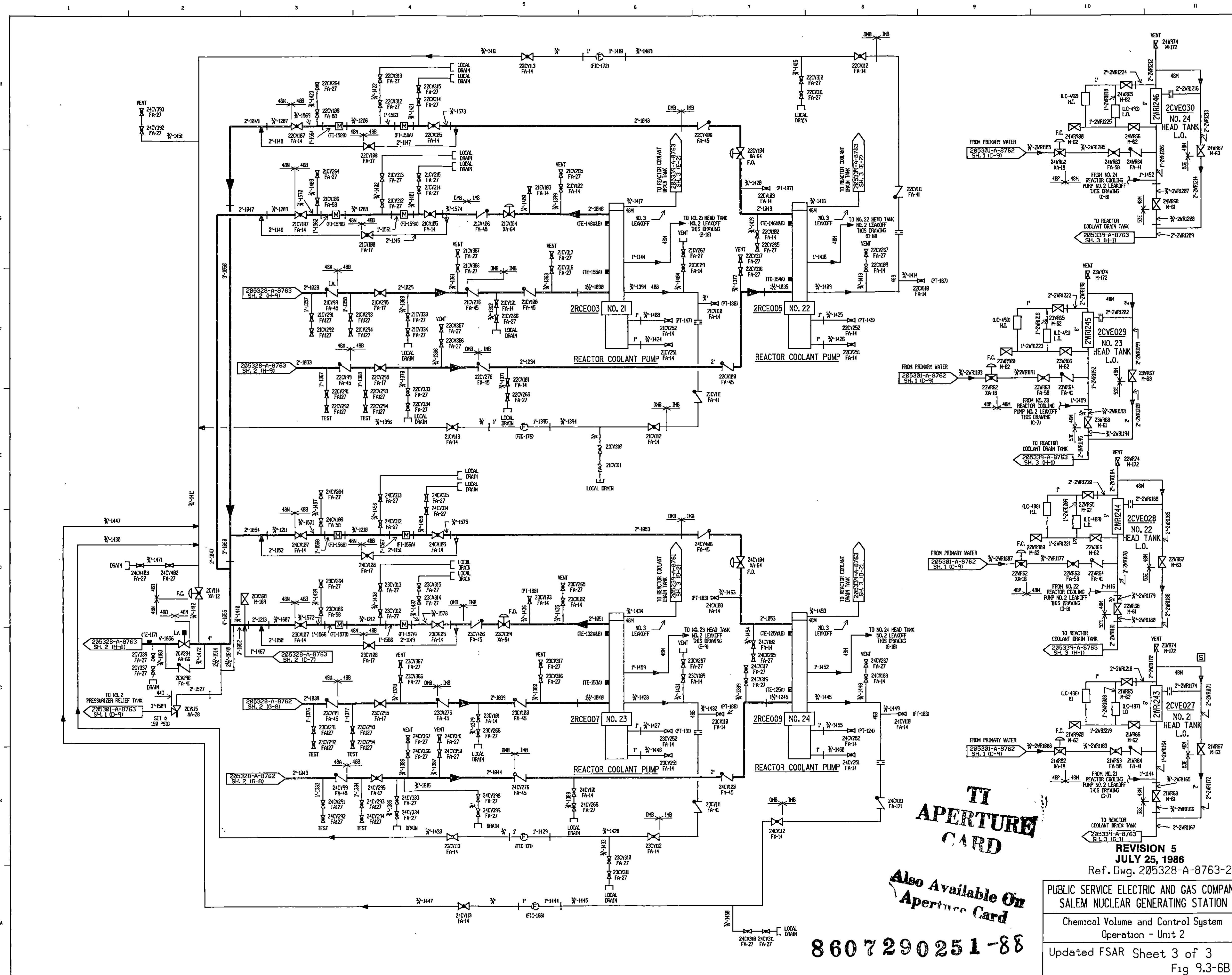
Ref. Dwg. 205328-A-8763-25

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Chemical Volume and Control System
Operation - Unit 2

Updated FSAR Sheet 2 of 3
Fig 9.3-6B

8607290251-87



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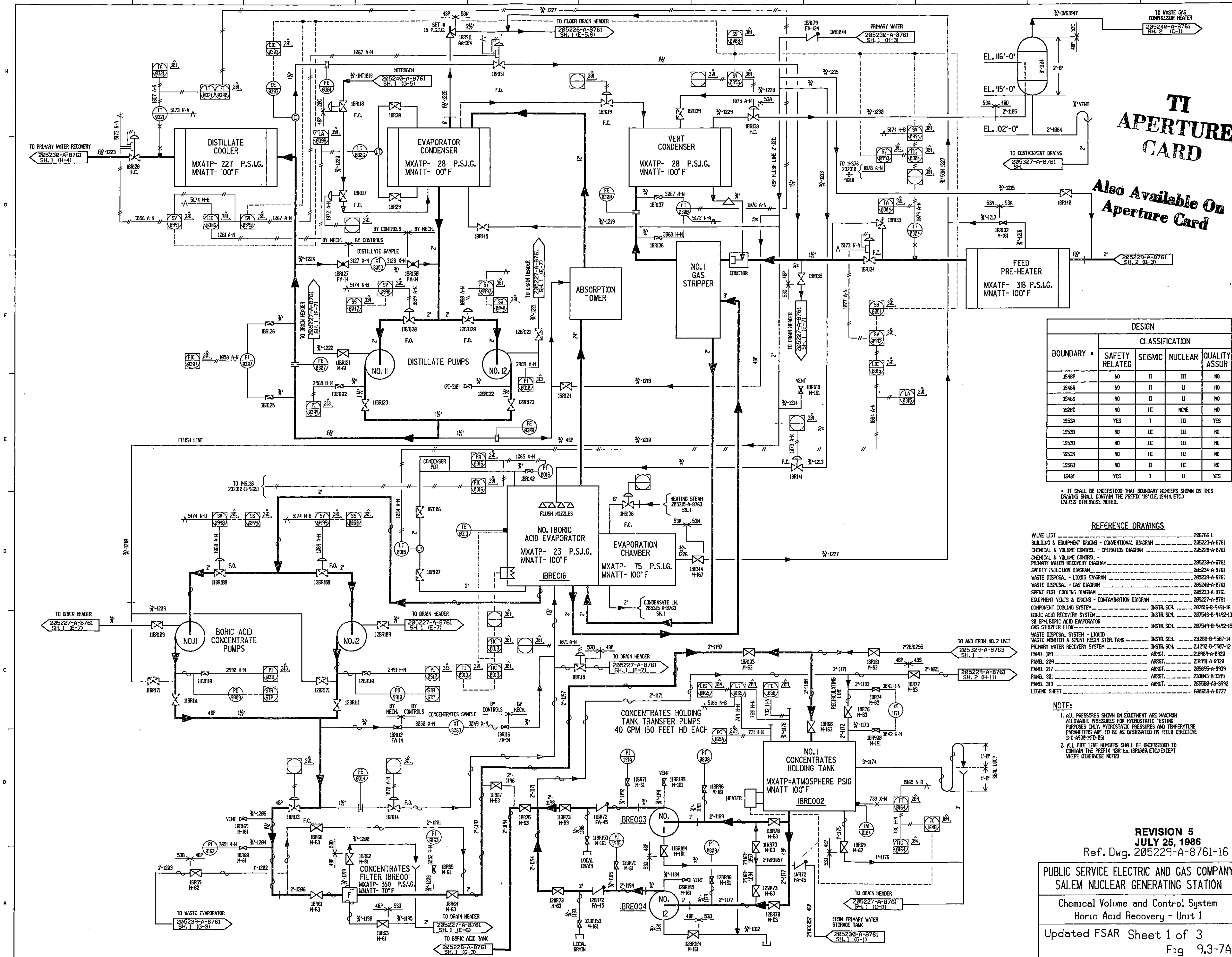
JULY 25, 1986
Ref. Dwg. 205328-A-8763-25

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Chemical Volume and Control System
Operation - Unit 2

Updated FSAR Sheet 3 of 3
Fig 9.3-6B

8607290251-88



BOUNDARY *	DESIGN CLASSIFICATION: SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR
1S48P	NO	II	III	NO
1S48R	NO	II	II	NO
1S48S	NO	II	II	NO
1S20C	NO	III	NONE	NO
1S53A	YES	I	III	YES
1S53B	NO	III	III	NO
1S53D	NO	III	III	NO
1S53N	NO	III	III	NO
1S56D	NO	II	III	NO
1S48I	YES	I	II	YES

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX '1S' (I.E. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

REFERENCE DRAWINGS

VALVE LIST		206766-L
BUILDING & EQUIPMENT DRAINS - CONVENTIONAL DIAGRAM		205223-A-8761
CHEMICAL & VOLUME CONTROL - OPERATION DIAGRAM		205228-A-8761
CHEMICAL & VOLUME CONTROL - PRIMARY WATER RECOVERY DIAGRAM		205230-A-8761
SAFETY INJECTION DIAGRAM		205234-A-8761
WASTE DISPOSAL - LIQUID DIAGRAM		205239-A-8761
WASTE DISPOSAL - GAS DIAGRAM		205240-A-8761
SPENT FUEL COOLING DIAGRAM		205233-A-8761
EQUIPMENT VENTS & DRAINS - CONTAMINATION DIAGRAM		205227-A-8761
COMPONENT COOLING SYSTEM	INSTR. SCH.	207516-B-9491-16
BORIC ACID RECOVERY SYSTEM	INSTR. SCH.	207546-B-9492-13
30 GPM BORIC ACID EVAPORATOR GAS STRIPPER FLOW	INSTR. SCH.	207549-B-9492-15
WASTE DISPOSAL SYSTEM - LIQUID WASTE MONITOR & SPENT RESIN STOR. TANK	INSTR. SCH.	211288-B-9507-14
PRIMARY WATER RECOVERY SYSTEM	INSTR. SCH.	211292-B-9507-12
PANEL 109	ARRGT.	218989-A-8920
PANEL 209	ARRGT.	218991-A-8920
PANEL 217	ARRGT.	205695-A-8939
PANEL 301	ARRGT.	233043-A-1399
PANEL 313	ARRGT.	205580-AB-3592
LEGEND SHEET		600658-A-8727

NOTE:

1. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051
2. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX '1BR' (i.e. 1BR1000, ETC.) EXCEPT WHERE OTHERWISE NOTED

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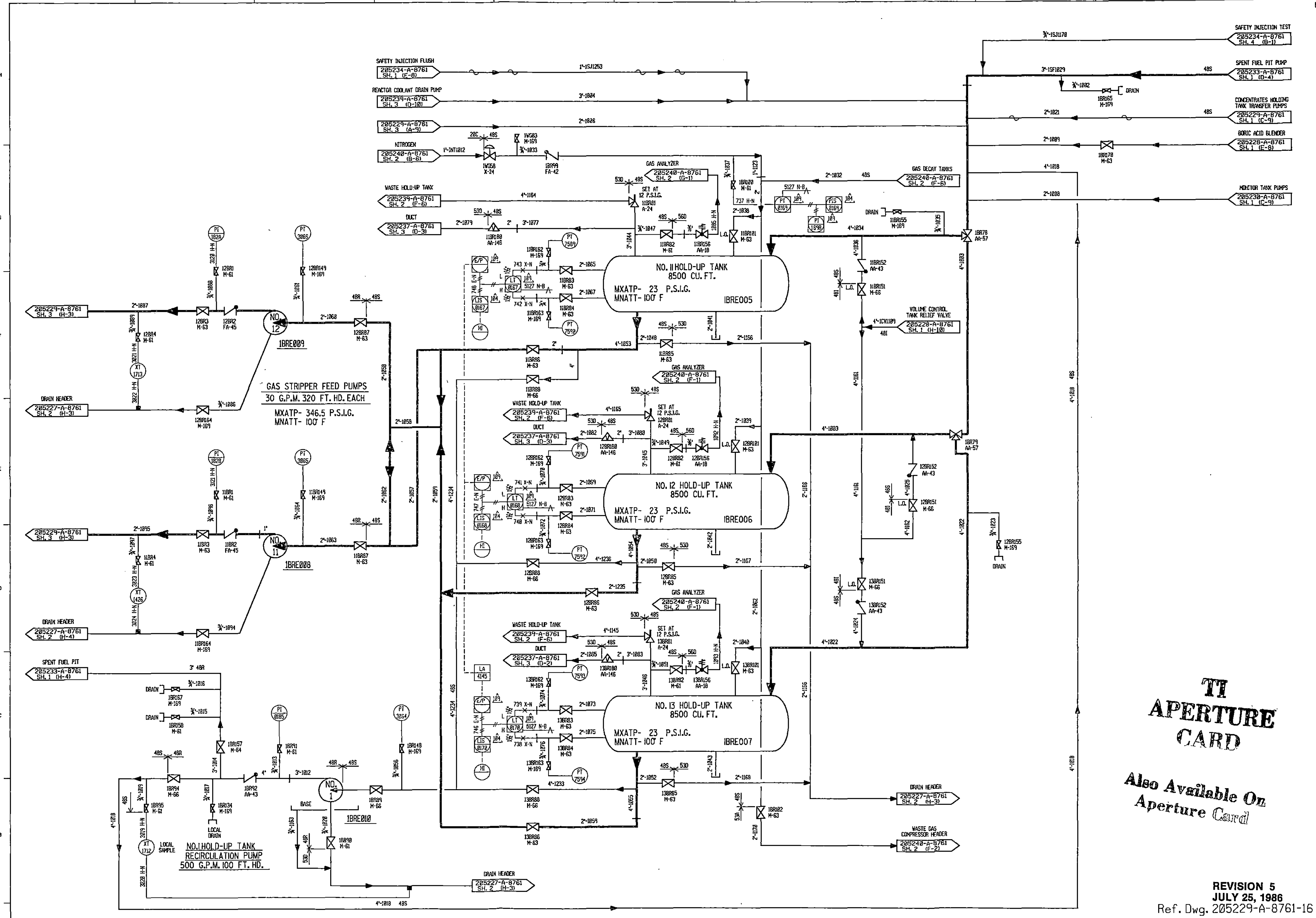
JULY 25, 1986
Ref. Dwg. 205229-A-8761-16

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Chemical Volume and Control System
Boric Acid Recovery - Unit 1

Updated FSAR Sheet 1 of 3
Fig 9.3-7A

8607290251-89



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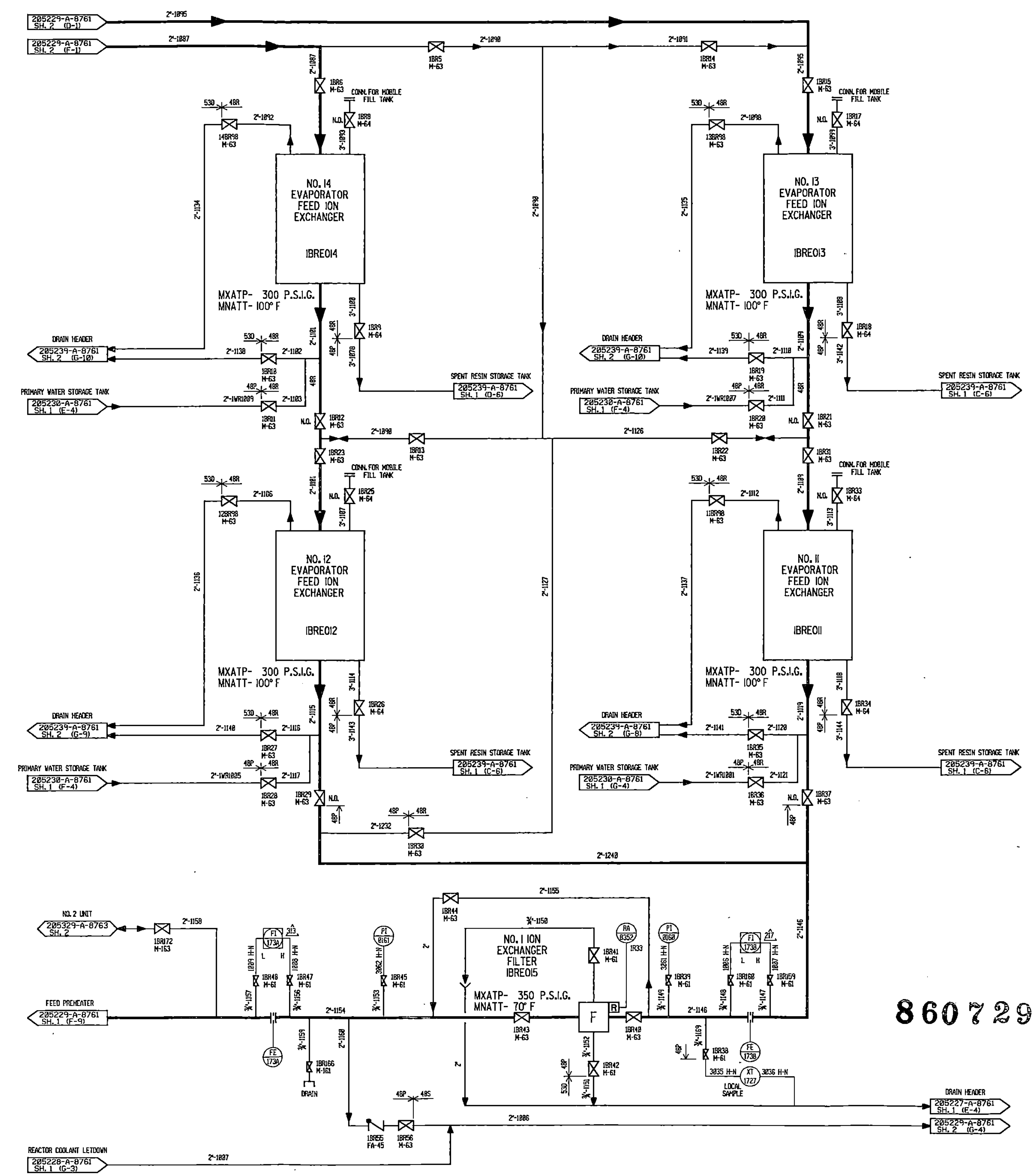
Ref. Dwg. 205229-A-8761-16

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Chemical Volume and Control System
Boric Acid Recovery - Unit 1

Updated FSAR Sheet 2 of 3
Fig 9.3-7A

8607290251-90



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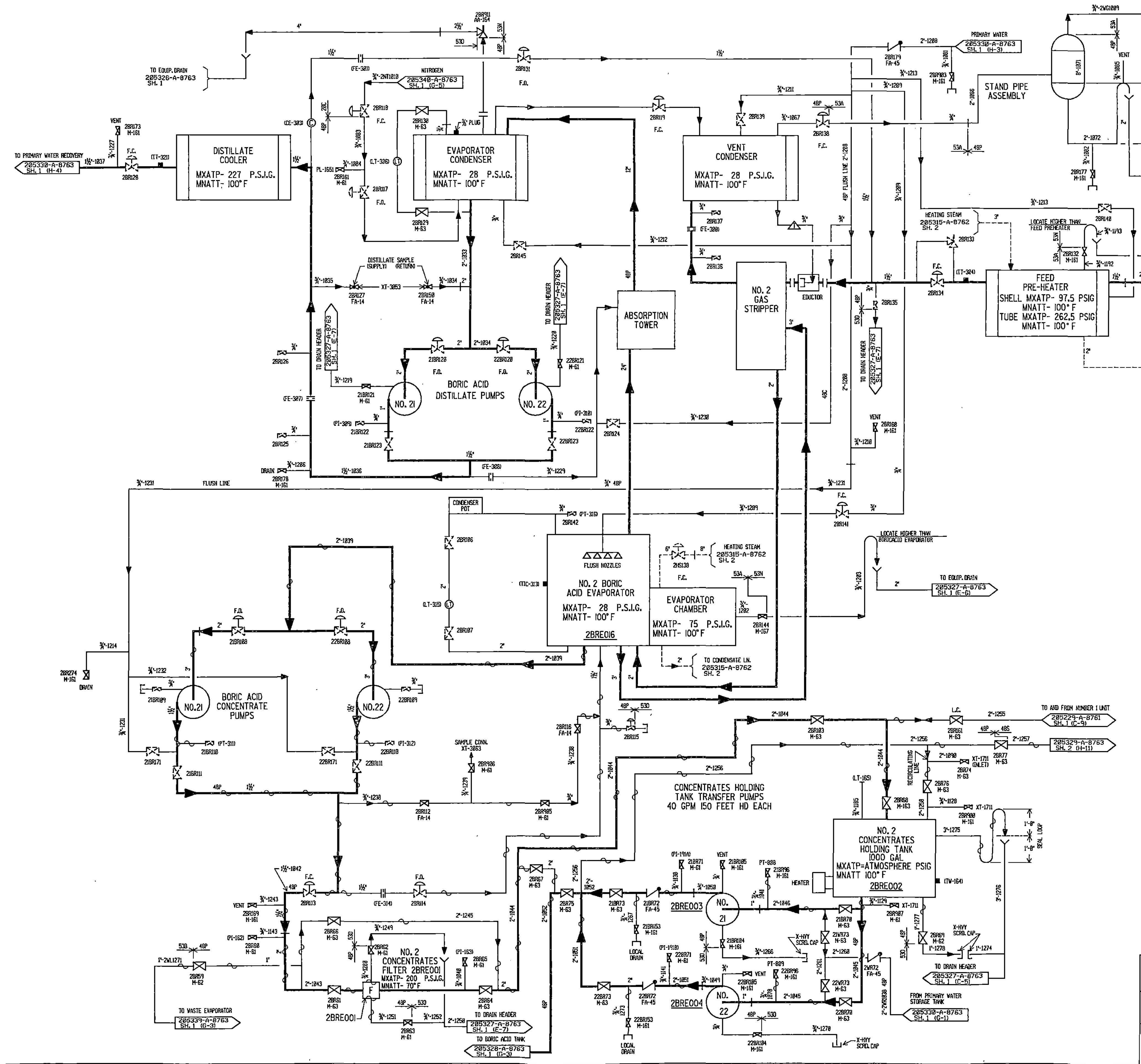
JULY 25, 1986
Ref. Dwg. 205229-A-8761-16

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Chemical Volume and Control System
Boric Acid Recovery - Unit 1

Updated FSAR Sheet 3 of 3
Fig 9.3-7A



BOUNDARY *	DESIGN CLASSIFICATION: SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR
1S48P	NO	II	III	NO
1S48R	NO	II	II	NO
1S48S	NO	II	II	NO
1S20C	NO	III	NONE	NO
1S53A	YES	I	III	YES
1S53B	NO	III	III	NO
1S53D	NO	III	III	NO
1S53N	NO	III	III	NO
1S56D	NO	II	III	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (I.E. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

REFERENCE DRAWINGS

- VALVE LIST — DRAWING *206766-L
- BUILDING & EQUIPMENT DRAINS - CONVENTIONAL DIAGRAM — DRAWING *205323-A-8763
- CHEMICAL & VOLUME CONTROL - OPERATION DIAGRAM — DRAWING *205328-A-8763
- CHEMICAL & VOLUME CONTROL - PRIMARY WATER RECOVERY DIAGRAM — DRAWING *205330-A-8763
- SAFETY INJECTION DIAGRAM — DRAWING *205334-A-8763
- WASTE DISPOSAL - LIQUID DIAGRAM — DRAWING *205339-A-8763
- WASTE DISPOSAL - GAS DIAGRAM — DRAWING *205340-A-8763
- SPENT FUEL COOLING DIAGRAM — DRAWING *205333-A-8763
- EQUIPMENT VENTS & DRAINS - CONTAMINATION DIAGRAM — DRAWING *205327-A-8763
- LEGEND SHEET — DRAWING *600658-A-8727

NOTE:

1. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051
2. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2BR" (i.e. 2BR1000, ETC.) EXCEPT WHERE OTHERWISE NOTED
3. ALL PIPING IS IN ACCORDANCE WITH SPEC. NO. 61-6200 THE PIPING SCHEDULE AND GROUP NUMBERS ARE AS NOTED ON THIS DRAWING AND PREFIXED WITH "1S" IN THE PIPE SPEC.

REVISION 5
JULY 25, 1986

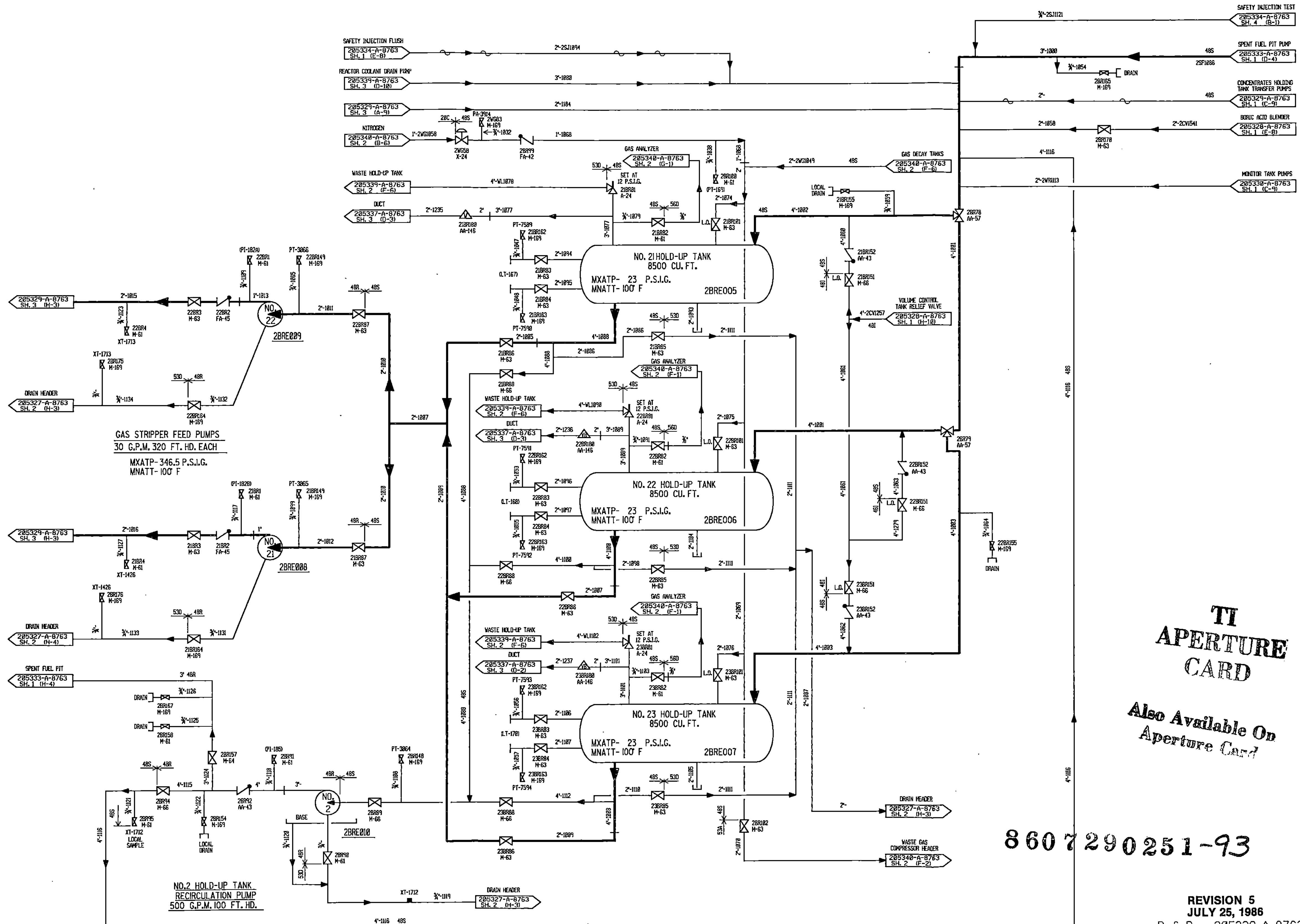
Ref. Dwg. 205329-A-8763-15

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Chemical Volume and Control System
Boric Acid Recovery - Unit 2

Updated FSAR Sheet 1 of 3

Fig 9.3-7B



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JULY 25, 1986
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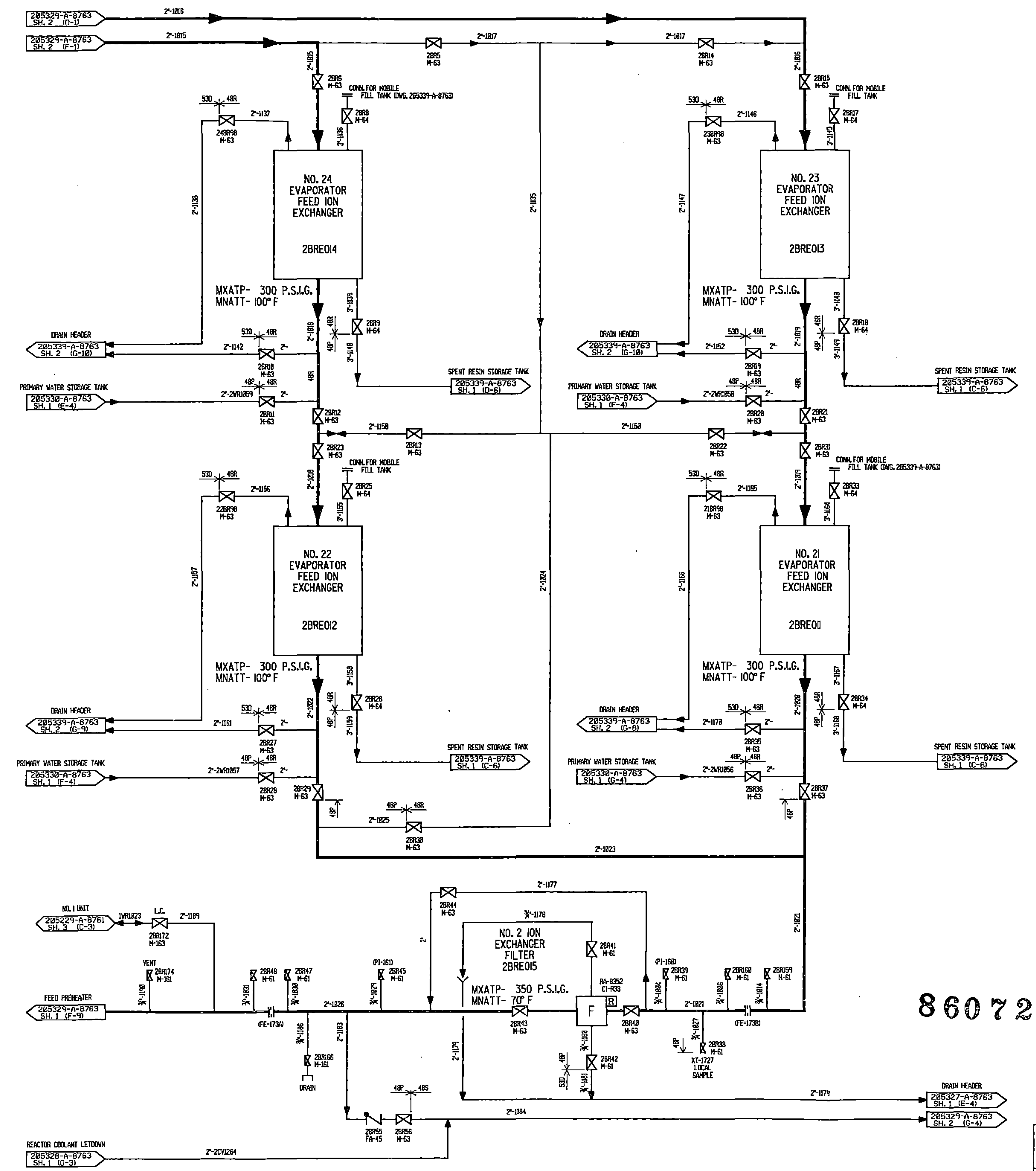
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Chemical Volume and Control System
Boric Acid Recovery - Unit 2

Updated FSAR Sheet 2 of 3
Fig 9.3-7B



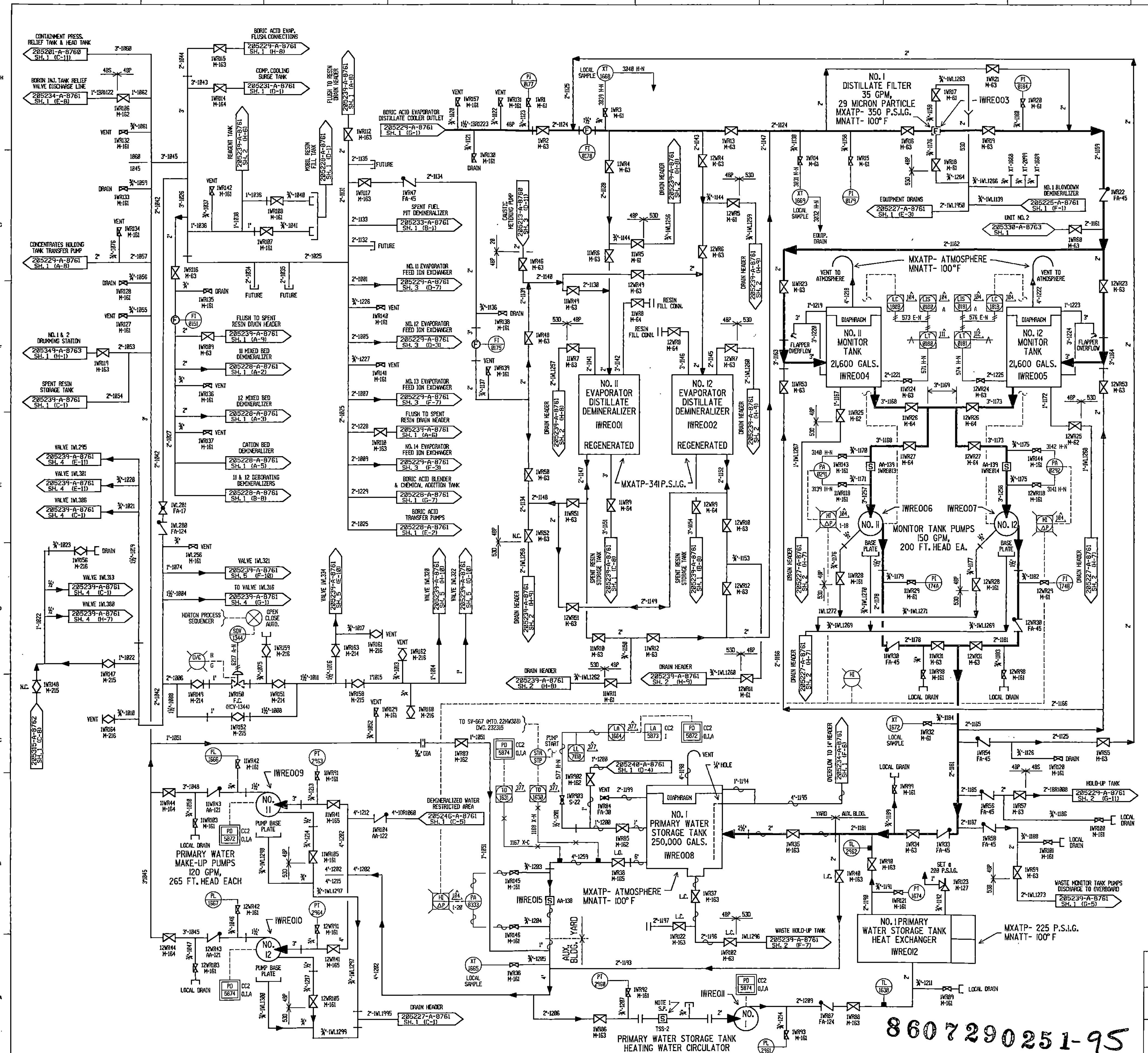
8607290251-94

REVISION 5
JULY 25, 1986
Ref. Dwg. 205329-A-8763-15

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Chemical Volume and Control System
Boric Acid Recovery - Unit 2

Updated FSAR Sheet 3 of 3
Fig 9.3-7B



8607290251-95

NOTES:

1. TEMPORARY STRAINER IS PLACED IN LINE DURING INITIAL FLUSHING-CAPPED CONN. IS FOR A TEMPORARY PRESSURE GAGE AT THIS TIME.
2. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051
3. FOR DESIGN PRESSURE AND TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE AND TEMPERATURE PARAMETERS AT THE ORIGINAL SOURCE HEADER.
4. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1WR" (i.e. 1WR1020, ETC.) EXCEPT WHERE OTHERWISE NOTED.
5. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200. THE PIPING SCHEDULE AND GROUP NOS. ARE AS NOTED ON THIS DRAWING AND PREFIXED WITH "1S".

REFERENCE DRAWINGS:

VALVE LIST ____ 206776-L
REACTOR COOLANT DIAGRAM ____ 205201-A-8760
DM WATER MAKE-UP DIAGRAM ____ 205213-A-8760
EQUIP. VENTS & DRAINS-CONTAMINATED DIAGRAM ____ 205227-A-8761
CVC OPERATION DIAGRAM ____ 205228-A-8761
CVC BORIC ACID RECOVERY DIAGRAM ____ 205229-A-8761
COMPONENT COOLING DIAGRAM ____ 205231-A-8761
SPENT FUEL COOLING DIAGRAM ____ 205233-A-8761
SAFETY INJECTION DIAGRAM ____ 205234-A-8761
WASTE DISPOSAL-LIQUID DIAGRAM SH. 1 ____ 205239-A-8761
SAMPLING DIAGRAM ____ 205244-A-8761
HEATING WATER ____ 205215-A-8761
WASTE DISPOSAL LIQUID DIAGRAM SH. 2 ____ 246909-A-1704
NO. 1 PRIMARY WTR. REC. ____ INSTR. SCH. ____ 211292-B-9507-12
NO. 1 UNIT LIQUID RADWASTE EVAPORATOR ____ INSTR. SCH. ____ 246878-B-9719-0
WASTE DISPOSAL ____ PNL. 104 __ ARRGMT. ____ 223851-A-1212
NO. 11 MONITOR TK. ____ PNL. 111 __ ARRGMT. ____ 218988-A-8920
NO. 12 MONITOR TK. ____ PNL. 112 __ ARRGMT. ____ 218988-A-8920
PRI. WATER STOR. TK. LVL. __ PNL. 377 __ ARRGMT. ____ 223873-A-1212
LEGEND SHEET ____ 600658-A-8727

DESIGN				
*BOUNDARY	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
IS20C	NO	III	NONE	NO
IS48P	NO	II	III	NO
IS48S	NO	II	II	NO
IS53B	NO	III	III	NO
IS53D	NO	III	III	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "IS" (i.e. IS44A, ETC.) UNLESS OTHERWISE NOTED.

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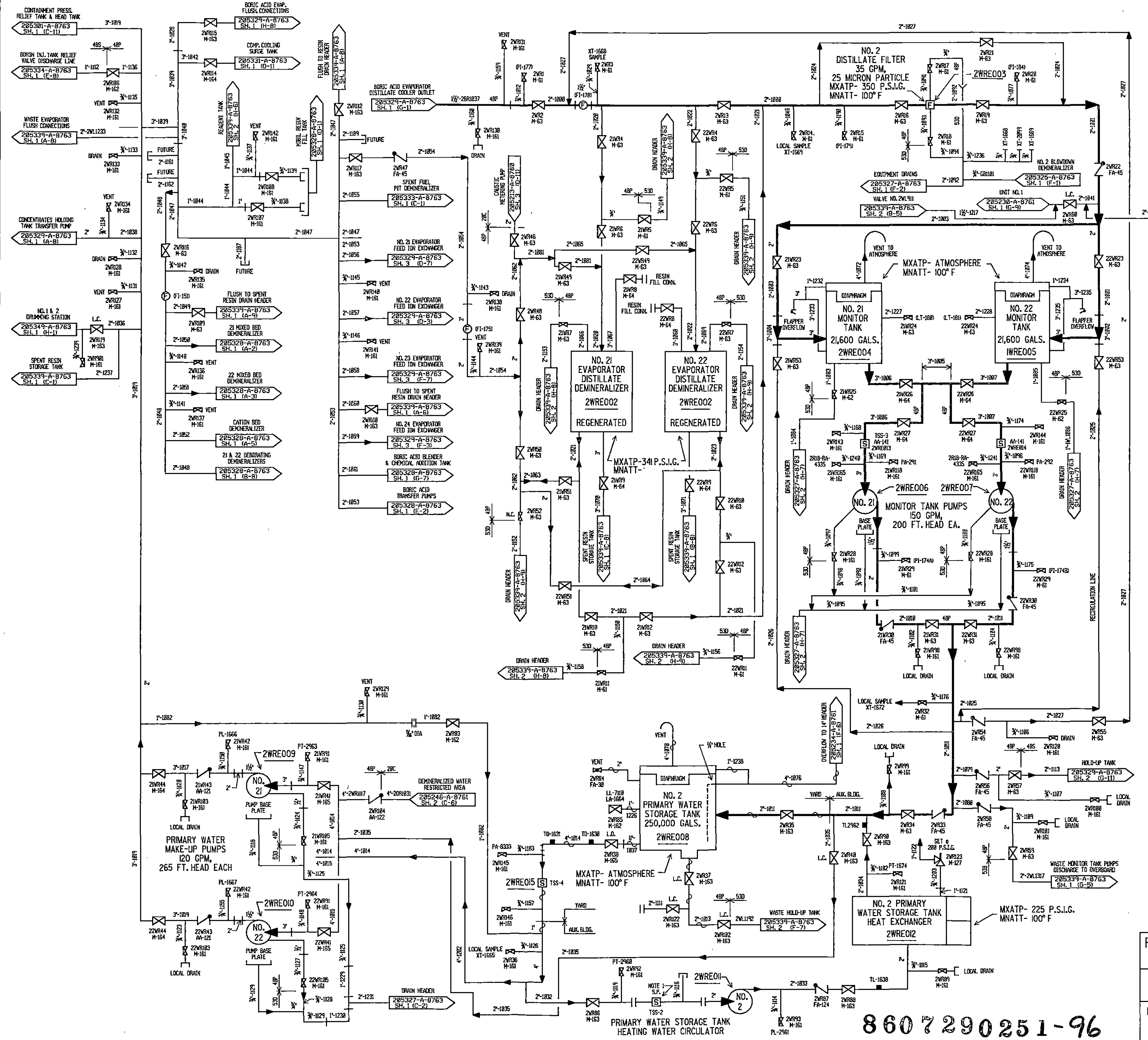
JULY 25, 1986
Ref. Dwg. 205230-A-8761-17

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

CVC System - Primary Water Recovery
Unit 1

Updated FSAR Sheet 1 of 1
Fig 9.3-8A



NOTES:

1. TEMPORARY STRAINER IS PLACED IN LINE DURING INITIAL FLUSHING-CAPPED CONN. IS FOR A TEMPORARY PRESSURE GAGE AT THIS TIME.
2. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051
3. FOR DESIGN PRESSURE AND TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE AND TEMPERATURE PARAMETERS AT THE ORIGINAL SOURCE HEADER.
4. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2WR" (i.e. 2WR1000, ETC.) EXCEPT WHERE OTHERWISE NOTED.
5. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200, PIPING SCHEDULE AND GROUP NO. 1S48P EXCEPT AS OTHERWISE NOTED.

REFERENCE DRAWINGS:

VALVE LIST 206776-L
REACTOR COOLANT DIAGRAM 205301-A-8762
DM WATER MAKE-UP DIAGRAM 205213-A-8760
EQUIP. VENTS & DRAINS-CONTAMINATED DIAGRAM 205327-A-8763
CVC OPERATION DIAGRAM 205328-A-8763
CVC BORIC ACID RECOVERY DIAGRAM 205329-A-8763
COMPONENT COOLING DIAGRAM 205331-A-8763
SPENT FUEL COOLING DIAGRAM 205333-A-8763
SAFETY INJECTION DIAGRAM 205334-A-8763
WASTE DISPOSAL-LIQUID DIAGRAM 205339-A-8763
SAMPLING DIAGRAM 205344-A-8763
HEATING WATER 205215-A-8760
LEGEND SHEET 600658-A-8727

DESIGN				
BOUNDARY	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
IS20C	NO	III	NONE	NO
IS48P	NO	II	III	NO
IS48S	NO	II	II	NO
IS53B	NO	III	III	NO
IS53D	NO	III	III	NO

• IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "IS" (i.e. IS44A, ETC.) UNLESS OTHERWISE NOTED.

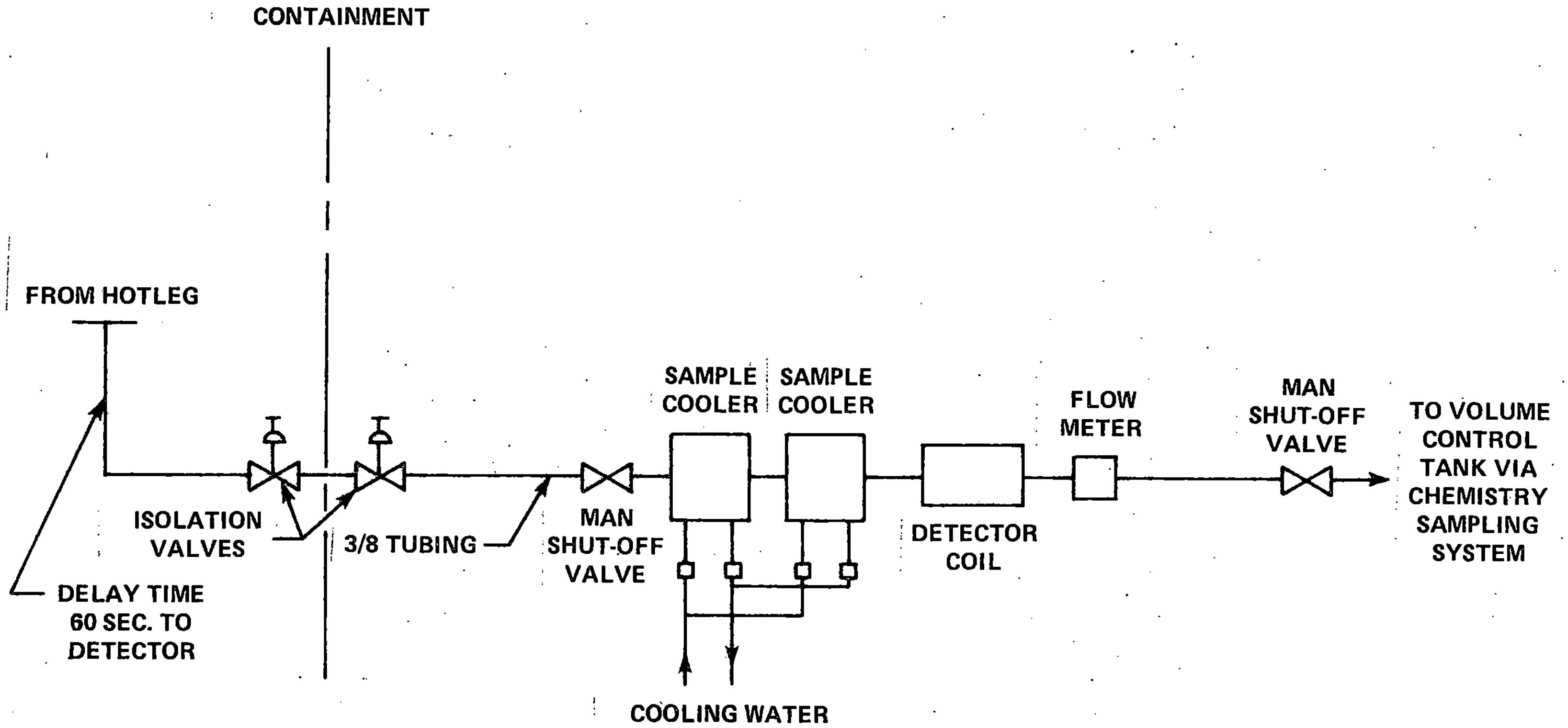
REVISION 5
JULY 25, 1986
Ref. Dwg. 205330-A-8763-10

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Chemical Volume and Control System
Primary Water Recovery - Unit 2

Updated FSAR Sheet 1 of 1
Fig 9.3-8B

8607290251-96



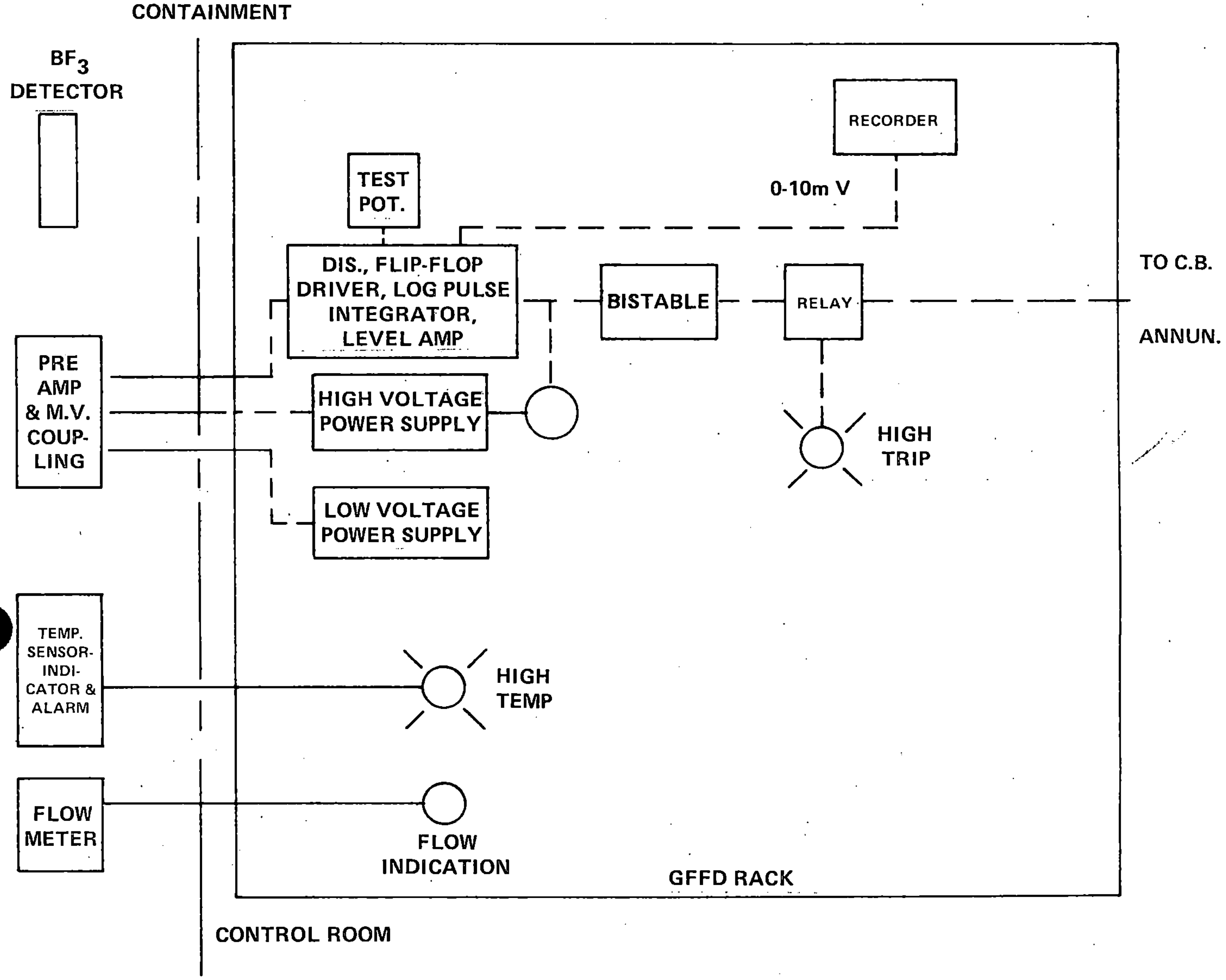
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Updated FSAR

Gross Failed Fuel Detector
Flow Diagram

Figure 9.3-9

Revision 0
July 22, 1982



Revision 0
July 22, 1982

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Gross Failed Fuel Detector Electronics Diagram
	Updated FSAR — Figure 9.3-10

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50-311

SALEM GENERATING STATION

UNITS 1 AND 2

UPDATED FINAL SAFETY ANALYSIS REPORT

Volume 5

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9.4 HEATING, VENTILATION AND AIR CONDITIONING SYSTEMS

9.4.1 CONTROL AREA AIR CONDITIONING SYSTEM

9.4.1.1 Design Basis

The Control Area Air Conditioning System (CAACS) is designed to maintain room temperatures within limits required for operation, maintenance and testing of plant controls and uninterrupted safe occupancy during post-accident conditions.

The CAACS maintains a temperature of 76°F dry bulb and a maximum of 50 percent relative humidity. The design is based on outside temperatures ranging from 0°F winter dry bulb to 95°F summer dry bulb and 78°F summer wet bulb. The system operates during normal or emergency conditions as required.

The Control Room is protected from infiltration of air from other rooms in the control area and the entire control area is protected from infiltration of fire, smoke or airborne radioactivity from other areas of the Auxiliary Building by minimum leakage penetrations, weather stripped doors, absence of outside windows and maintenance of a positive air pressure in the rooms during normal operation.

CAACS equipment is designed to Class I (seismic) criteria and will therefore remain operable during a design basis seismic event coincident with a loss-of-coolant acccident. The Control Room is therefore available at all times to permit attaining and maintaining a safe shutdown of the reactor from there.

9.4.1.2 System Description

9.4.1.2.1 General Description

The control area for each unit consists of the unit Control Room, adjacent offices, a data logging room, a control equipment room and a toilet area on elevation 122'-0". Normal access to the control area is attained through the Auxiliary and Service Buildings. The control area is enclosed in a Class I (seismic) structure. The air conditioning equipment for each control area is housed in an equipment room adjacent to its respective control room. The CAACS is shown in Figures 9.4-1A and B.

The CAACS consists of a filter enclosure equipped with medium and low efficiency filters, three vane-axial fans (one standby), a multi-zone coil unit with three cooling coils and one heating coil, air distribution ducts and electrically or pneumatically operated dampers (with manual backup operators).

Since the Control Room is to be occupied continuously under all operating conditions, a portion of the CAACS, designated the Emergency Air Conditioning System (EACS), supplies cooled HEPA and charcoal filtered air to the Control Room (the Control Room and adjacent offices for Unit 1 and only the Control Room for Unit 2) and the corridor between the Unit 1 and unit 2 Control Room upon actuation of the safeguards systems. The EACS consists of a filter enclosure equipped with low efficiency, HEPA and charcoal filters, a cooling coil, two vane-axial fans (one standby), supply and return ducts to the Control Room, and electrically or pneumatically operated dampers (with manual backup operators).

The multi-zone fan unit cooling coils are supplied with chilled water from a chilled water system, its condensers and pumps. The condensers are cooled from the Service Water System. All equipment has ample capacity to cool the above areas. The air conditioning equipment is designed to Class I (seismic) criteria and can be energized from the Standby AC Power Supply.

The dampers in the CAACS are pneumatically controlled and have position indication in the Control Room. The dampers required to operate during abnormal conditions are designed to fail in the preferred position upon loss of control air or power. These dampers receive actuating signals from the Solid State Protection System and the Radiation Monitoring System. All vital dampers can also be operated manually at the damper.

Control power for the dampers is taken from the station 125V d-c system. Redundance is provided where required to insure proper system operation in the event of a single failure of a damper or power supply.

9.4.1.2.2 System Operation

Two CAACS fans are normally operated, with the third serving as a spare. The EACS is isolated during normal operation. The CAACS normally operates with varying amounts of outside air according to the season, but means are provided to enable the operator to select one of the following modes of operation:

Mode	Condition	Air Path
1	Normal	Mixture of outside air and recirculated air to maintain design temperature conditions. EACS is isolated.
2	Fire in Control Area	Manual Action - Supply all outside air and exhaust all return air to the outside. EACS is isolated.
3a	Safeguards Actuation	Automatic Action - Outside air supply shut off; all control room air recirculated through EACS; remainder of control area air recirculated through CAACS.
3b	Fire Outside	Manual Action - Same as 3a.
4	Safeguards Actuation	Manual Action - Mixture of 4 percent outside air supply and 96 percent control room return air recirculated through EACS; remainder of control area air recirculated through CAACS.

Smoke and combustibles detection devices located in the air conditioning unit ducts provide warning so that steps can be taken to minimize any hazard by operating the system in the proper mode.

Radiation detectors with alarms in the Control Room provide warning of abnormal radiation levels which may affect the Control Room environment. High radiation will automatically initiate Mode 3A operation of the CAACS. Recirculation of air in the Control Room can be maintained until the radiation source is isolated and safe conditions are restored.

When operating in mode 3, the carbon dioxide buildup with all outside air makeup shut off (and no in-leakage) will not exceed the allowable concentration of 1 percent by volume in 10 hours, assuming there are 20 persons in the Control Room. After 10 hours of operation in this mode, the EACS will be operated in mode 4 for one hour to reduce the carbon dioxide concentration in the Control Room air to normal levels.

In the event of a loss-of-coolant accident in either unit the CAACS for each unit will automatically shift to operating mode 3. The operator can manually change operating modes as required.

The ductwork and all contained equipment is of Class I (seismic) construction, except for the secondary men's room, janitor's closet and corridor subsystem.

9.4.1.3 Design Evaluation

The control areas and their respective air conditioning equipment rooms are directly adjacent to each other in the east end of the Auxiliary Building, a seismic Class I structure. All other areas in the vicinity of the control area, such as the remainder of the Auxiliary Building, Service Building and Turbine Building are ventilated by systems which are completely independent of the CAACS, thus fire or smoke generated in such other areas would not impair the integrity or accessibility of the Control Room. The CAACS (including the EACS) is an excess capacity system with four isolable cooling coils, three 50 percent capacity chillers, two 100 percent capacity chilled water pumps, three 50 percent and two 100 percent capacity fans provided for each control area.

Damper operators are spring-loaded to their fail-safe positions. This, together with redundant dampers (A* and C* on Figure 9.4-1) on outside air intake and discharge ducts, assures isolation of the Control Room from the outside environment. Manual operators are also provided for backup.

Failure of the other dampers to operate as desired would have no immediate effect on the Control Room environment. The position indicators would alert the operator, who would then correctly position the dampers with the manual operators provided.

9.4.1.4 Tests and Inspections

The systems are inspected, tested and balanced upon installation. Normal operation serves as a continuous check on system operation. The EACS equipment is tested after installation and periodically during the life of the plant. Automatic initiation of operation mode 3 and EACS operation is verified during testing of the safeguards systems.

9.4.2 AUXILIARY BUILDING VENTILATION SYSTEM

9.4.2.1 Design Bases

The Auxiliary Building Ventilation System is designed for long-term continuous operation to provide consistent levels of temperature, cleanliness, and negative pressure within the building. Standby equipment is included in the system to assure the maintenance of design conditions within the building and thus preclude the uncontrolled release of radioactivity to the environs. Containment purging, however, is an intermittent operation performed in accordance with the requirements of 10CFR20. The standby equipment in the Auxiliary Building is available to purge the containment during normal power operation, normal reactor shutdown, and the last stages of post-loss-of-coolant accident cleanup.

The total capacity of fans and filters, including standby equipment, is designed for the maximum required ventilation rate. That is, total capacity is based on summertime ventilation of the Auxiliary Building during normal power operation (approximately 45,000 cfm) concurrent with the maximum containment purge rate of 0.8 air changes per hour (approximately 35,000 cfm). This operating mode is designed to limit the average temperature of the Auxiliary Building to 105°F or less, and to allow personnel access to the containment within 2 to 6 hours after a normal reactor shutdown.

The Auxiliary Building Ventilation System is designed to maintain a year-round range of temperature within the Auxiliary Building of 60 - 105°F. Hot water coils in the supply air units are designed to provide 60°F air to the Auxiliary Building in winter and no less than 45°F air to the Containment Building. The design basis outdoor temperature is 0°F (winter), and 95°F (summer). Both values satisfy more than 99 percent of the conditions experienced at the site area annually.

A standby, 21,400 cfm capacity charcoal filter is included in the exhaust air system to remove gaseous radioactivity, especially iodine, from the exhaust effluent. This filter is designed to absorb at least 90 percent of the elemental and methyl iodines contacted at rated flow. The charcoal filter is capable of treating 1) all the effluent from areas served having the highest potential for radioactive contamination during any loss-of-coolant accident, 2) all the effluent from the remainder of the Auxiliary Building up to 53 percent of the design maximum ventilation rate, and 3) all of the effuent from the containment purging operation up to 43 percent of the design maximum rate. With regard to item (2), the charcoal filter could not be subjected to 100 percent humidity conditions because of the dilution effects of drier air from such places as the pipe penetration area (4000 cfm), pipe chase (2000 cfm), normal operating charging pump room (500 cfm), and the spent resin pump and storage rooms (400 cfm). On this basis, it has been calculated that the charcoal filter would be subjected to no more than 75 percent RH when the residual heat removal, safety injection and charging pump areas (or any combination of areas totaling 13,400 cfm of ventilation air) are at saturated conditions. This result does not take credit for any moisture condensation that would occur in the sheet metal ducts and filter enclosures, nor for any excess room cooler capacity above design values. We therefore anticipate no loss of charcoal filter efficiency during a loss-of-coolant accident. Each of these three capabilities is separate and independent, not coincident, and always preceded by HEPA filtration.

Individual room coolers, in conjunction with the once-through ventilation air, are designed to limit the ambient temperature at the vital pumping equipment to the following values:

Residual Heat Removal, Component Cooling, Auxiliary Feedwater, Positive Displacement Charging Pump	110°F
Containment Spray Pumps	115°F
Safety Injection, Centrifugal Charging Pump	120°F

These temperatures help to assure long-term and reliable operation of the pumps, motors, controls and instrumentation and accessability to this equipment for maintenance as required.

The fan-filter units in the Auxiliary Building Ventilation System and their controls are designed to seismic Class I criteria. They can be powered from the Standby AC Power Supply during a loss of off-site power. The distribution ductwork for the system is designed to seismic Class II criteria. Room coolers are seismic Class I and powered from the Standby AC Power System.

The design arrangement of the HEPA and charcoal filter exhaust units provides various filtering modes for ventilating the Auxiliary Building continuously and purging the containment intermittently. In order to purge the containment, standby equipment must be available.

All the filtering modes are designed to satisfy the requirements of normal power operation, normal reactor shutdown, refueling, loss-of-coolant accident, post-loss-of-coolant accident cleanup and any minor contamination problems. The functional capabilities of the filtering modes are:

1. HEPA filtration of the effluent from the emergency equipment area in the Auxiliary Building at the design maximum flow rate.

2. Same as 1 above, but with charcoal filtration.

3. HEPA filtration of the effluent from the remainder of the Auxiliary Building at the design maximum flow rate.

4. HEPA and charcoal filtration for the remainder of the Auxiliary Building, but at 67 percent of the design maximum flow rate.

5. HEPA filtration of the effluent purged from the containment at the design maximum purge rate.

6. HEPA filtration of the purged containment effluent at 63 percent of the design maximum purge rate.

7. HEPA and charcoal filtration of the purged containment effluent at 43 percent of the design maximum purge rate.

9.4.2.2 System Description

9.4.2.2.1 General Description

The Auxiliary Building Ventilation System is a once-through heating and ventilating system for each unit, with no connection or sharing between units, except for the drumming and boiling area and the auxiliary building elevator shaft. The Auxiliary Building Ventilation System is shown in Figures 9.4-2A and B. The Control Room and its associated areas are provided with a separate heating, ventilating and air conditioning system as described in Section 9.4.1. Ventilation of the diesel generator area and Fuel Handling Building are described in Section 9.4.3 and 9.4.5. The post-accident sampling room is located in the Unit 2

Auxiliary Building and is served by the Unit 2 Auxiliary Building Ventilation system. A local booster fan is provided for exhausting air from the post-accident sampling room.

The auxiliary building is a multi-level compartmented structure containing the auxiliary nuclear equipment and systems required for the normal, shutdown and emergency modes of unit operation. The Auxiliary Building Ventilation System operates continuously during these modes of operation to perform the following functions:

1. Provide satisfactory ambient temperatures within the building.

2. Direct air flow within the building always from the clean areas to the heat producing, contaminated, or potentially contaminated areas.

3. Control the release of particulate and gaseous contamination from the building in accordance with 10CFR20 limits.

4. Purge the containment building at selected intervals, utilizing the standby fan and filter equipment as required.

The Auxiliary Building Ventilation System is comprised of supply and exhaust air systems and a network of individual room coolers. The supply air system consists of two 100 percent capacity fan-filter units, hot water heating coils, controls, instrumentation and distribution ductwork. The exhaust air system consists of three 50 percent capacity fans, three HEPA filter units, one standby charcoal filter unit, controls, instrumentation and distribution ductwork. The room coolers are packaged fan cooler units supplied with service water and mounted locally near vital pumping equipment (Residual Heat Removal, Safety Injection, Component Cooling, Auxiliary Feed, Charging, and Containment Spray Pumps).

Supply air taken from outdoors is delivered primarily to the clean aisles and walkways although some air is supplied directly to the Residual Heat Removal pump pits at the base of the building. Exhaust air is extracted from each room and compartment, and delivered to the unit vent along side the containment building. The unit vent effluent is continually monitored for radioactivity. The room coolers recirculate air around the equipment in the room when required. One branch of the exhaust ductwork is used exclusively for those rooms and compartments that would have the highest potential for radioactivity during loss-of-coolant accident in the containment (Residual Heat Removal, Safety Injection and Charging Pump rooms; Main Pipe Chase; Spent Resin Rooms; and the Containment Piping Penetration Area). In the event of such an accident, an increased rate of exhaust air flow is effected through this branch ductwork.

The Auxiliary Building Ventilation System maintains the building at a slight negative pressure with respect to outdoors. This is performed continuously whether or not standby fan and filter capability is being used for containment purging.

The starting, stopping, and mode of operation of the system is manually controlled from the Control Room. After being placed in operation, the system automatically maintains building temperature and pressure within satisfactory limits. System performance and building conditions are monitored from the Control Room.

9.4.2.2.2 System Operation

Automatic controls are provided to maintain the building within the design values of pressure and temperature. A temperature controller modulates total fan capacity between 2/3 and full as the average building temperature varies from 60°F in winter to 105°F in summer. Simultaneously, a differential pressure controller maintains the building at a normal 0.1-inch w.g. negative pressure. This temperature and pressure control for the auxiliary building continues to operate even when containment purging is required.

In the event of a loss-of-coolant accident, any purging of the containment is automatically terminated (isolation valves closed) and the auxiliary building ventilation equipment continues to operate in its normal mode. That is:

1. One of the two supply air units modulates filtered air to the building in response to building exhaust air temperatures.

2. Two of the three HEPA filter units and exhaust fans modulate filter effluent to the plant vent in response to building negative pressure.

The Control Room operator will activate the charcoal filter to the effluent emanating from the potentially radioactive safeguard areas during the recirculation phase. This is accomplished by actuating controls in the control room. Activation of the charcoal filter is confirmed by Control Room indication which indicates that the necessary air diversion dampers are in the correct position. If proper operation is not indicated within a few seconds, the dampers can be manually positioned.

The following operations occur automatically:

1. Equipment room increased flowrate exhaust air dampers open for the Residual Heat Removal, containment spray, charging, and safety injection pumps.

2. Room coolers energize to operate continuously at full capacity in response to the above-normal ambient temperatures that develop as the Residual Heat Removal, containment spray, charging, safety injection, component cooling, and auxiliary feedwater pumps are started. However, in the event that vital power is being provided by the diesel-generators, the room coolers for the Residual Heat

Removal, charging, and containment spray pumps will be delayed for up to 20 minutes.

3. Containment purging is terminated.

Thereafter, operator action is required only if trouble or failure alarms sound in the Control Room:

1. The standby supply air unit can be energized if the operating unit signals low air flow, high or low supply air temperature, or a break in the hot water heating coil.

2. The standby HEPA filter exhaust unit can be placed in service if either of the other two operating units experience high differential pressure. In this event, the charcoal filter can be repositioned simultaneously with another HEPA filter unit if necessary.

3. The standby exhaust fan can be energized if either of the other two operating fans experience low air flow.

The damper at the outlet of the charcoal filter will actually consist of two individual operating sections, each with redundant operators. Damper blades are designed to fail safe (open) in the event that control air or electric control power is lost. In addition, each damper section can be manually positioned to the required position.

9.4.2.3 Design Evaluation

The Auxiliary Building Ventilation System can maintain design conditions in the Auxiliary Building with one of the two 100 percent capacity fan-filter supply air units, two of the three 50 percent capacity exhaust fans, and two of the three HEPA filter exhaust air units operating. The charcoal filter exhaust air unit is normally at standby. Exhaust fans take suction from a common plenum at the outlet side of the HEPA and charcoal filter units, which permits changes in the exhaust filter operating mode without affecting fan operation and vice versa. The system is normally operated from the Control Room.

Supply air to the Auxiliary Building and to the containment is filtered at an efficiency of 80 percent. This high quality filtration significantly reduces the inventory of particulates that could become contaminated and lessens the loading on the more vital exhaust air filters.

All exhaust air from the Auxiliary Building and Containment is processed through HEPA filters which remove at least 99 percent of all particles 0.3 microns and larger in size.

In the event of a loss-of-coolant accident, any purging of the containment is terminated automatically (isolation valves close) and no change is required in the operating mode in effect for the auxiliary building. However, if there is indication of excessive radiation levels in the Auxiliary Building, the charcoal filter can be placed in one of the two effluent paths as required.

During any loss-of-coolant accident, the effluent path most affected by the loss-of-coolant accident handles a flow rate greater than normal because the ventilation rate for the Residual Heat Removal, Safety Injection and Charging Pump Rooms is increased. Also, the room coolers for pumps listed in Section 9.4.2.1 are automatically energized (the fan motor starts and a service water supply valve opens) to operate at full capacity continuously. In the event that the temperature in a pump room exceeds its specified upper limit, an alarm is sounded in the control room. A failure mode and effects analysis is presented in Section 9.4.2.2.2.

In general, ventilation air is supplied to the areas having the least potential for contamination and exhausted from the areas of potentially higher contamination. Those areas having the potential for the greatest contamination are exhausted at a higher rate during a loss-of-coolant accident than during normal power operation. The entire Auxiliary Building is designed to be at a slight negative pressure continuously with respect to the outdoors. These design considerations satisfy the basic criterion for preventing the uncontrolled release of radioactivity.

Standby fan and filter capacity is included in the Auxiliary Building Ventilation System to assure that the design pressure, temperatures and air flow patterns for the building are controlled continuously for maintenance, testing or in the event of an active component failure. Even if there is a failure when all components are energized for containment purging, the Auxiliary Building can be maintained at a negative pressure automatically with up to 70 percent of the design maximum ventilation rate. The system, therefore, provides a wide range of available capacity. Similarly, because of the standby equipment, the system arrangement provides numerous filtering modes. This flexibility in capacity and mode ensures that the system can maintain the Auxiliary Building at satisfactory conditions.

Rigorous filtration of the supply air from outdoors is designed to minimize the inventory of airborne particulates within the Auxiliary Building and the containment. This reduces the potential hazard of irradiated particles being transported throughout the building and reduces the loading on the exhaust filters. The HEPA type exhaust filters, in turn, continuously minimize the release of particulate radioactivity to the environment while the standby charcoal filter is available to adsorb gaseous contamination. The design capability of a 3-part high level filtration train ensures that all exhausted emissions from the Auxiliary Building and the containment are within the requirements of 10CFR20.

The design exhaust flow from each local area within the Auxiliary Building is based on the heat generated in the area, or six air changes per hour, whichever is the greater requirements.

Availability of the Auxiliary Building supply and exhaust ventilation equipment is ensured by connection to the Standby AC Power Supply.

The room coolers located near vital pumping equipment are single capacity units. The total capacity of the room cooler(s) in a given area, in conjunction with the exhaust air flow rate, is designed to limit the area temperature to the design values even if all pumping equipment in the area is operated continuously.

9.4.2.4 Tests and Inspections

All components of the Auxiliary Building Ventilation System are subjected to a test and inspection program. This program is similar to that described for the Containment Ventilation System (Section 9.4.4), except the resistance to loss-of-coolant accident pressure and temperature transients is not applicable to the Auxiliary Building equipment.

9.4.3 FUEL HANDLING AREA VENTILATION

9.4.3.1 Design Bases

The ventilation system is designed to exhaust the spent fuel pool area at 60 air changes an hour within a 10 foot height above the pool during design conditions for spent fuel storage. Out of a system operating capacity of 20,000 cfm, 15,000 cfm is exhausted from the spent fuel pool area (10,000 of which is extracted right at the pool surface) and the remaining 5,000 cfm of system capacity ventilates other parts of the building.

Because of the potential for radioactive releases from the spent fuel, defective fuel cladding or a fuel handling mishap, the building is maintained at a slight negative pressure to assure in-leakage of air rather than out-leakage.

The total capacity of the ventilation system is designed to maintain the building between 60°F and 105°F. Although there is no direct control of the humidity in the building, and there can be instances of 100 percent relative humidity around the spent fuel pool when the outdoor air is damp, the relative humidity under design conditions is expected to be less than 70 percent.

The exhaust filter units, fans and controls are designed to Class I (seismic) criteria. The discharge ductwork from the fuel handling area to the plant vent is also designed to Class I (seismic) criteria. The supply air equipment is served by the normal AC power system only, whereas the exhaust air equipment can be energized from the standby AC power system in the event of a loss of offsite power.

9.4.3.2 System Description

9.4.3.2.1 General Description

The fuel handling area is a structure separate from other unit structures and is provided with its own ventilation system. This system is a once-through filtered air system that continuously ventilates the normal operating areas (fuel pools, decontamination pit, electrical equipment room and sump tunnel), and also ventilates the shipping bay when fuel casks are being loaded or unloaded. The shipping bay, at all other times, is exhausted to the outdoors by a standard wall type vent fan as required. The Fuel Handling Area Ventilation System is shown in Figures 9.4-3A and B.

The ventilation system consists of the following equipment:

1. One 100 percent capacity supply air unit with particulate filters at about 80 percent cleaning efficiency and a heating coil for winter-time tempering of the supply air.

2. Two 50 percent capacity exhaust fans.

3. One 100 percent capacity HEPA filter exhaust unit with one 100 percent capacity HEPA-and-charcoal filter exhaust unit available for standby.

4. Controls and instrumentation.

5. Distribution ductwork.

All exhaust effluent is diverted to the standby HEPA-and-charcoal exhaust unit in the event that radioactivity levels within the building become excessive. Control of the system and surveillance of building conditions are accomplished from the Control Room. Air is distributed with overhead ducts for supply and exhaust, as well as embedded exhaust ducts around the spent fuel pool.

Supply air enters the building at the cask storage area, flows through the building to the spent fuel pool area, and is exhausted to the unit vent where the total plant effluent is continually monitored for radioactivity. The ventilation system maintains the building under a slight negative pressure, and exhausts the heat and humidity emitted from the spent fuel pool.

9.4.3.2.2 System Operation

Normally the supply air unit, both exhaust fans and the HEPA exhaust filter unit operate continuously. A temperature control modulates the total quantity of ventilation air from 100 percent capacity to 2/3 capacity as the building temperature varies between 105°F and 60°F. A differential pressure controller maintains a 0.1-inch w.g. negative pressure in the building. When the building temperature reduces to 60°F, the heating coil and controls at the supply air unit are energized to maintain the building at approximately 60°F.

In the event that a local radiation monitor detects excessive radioactivity in the building and alarms in the Control Room, the operator can divert the building effluent from the HEPA exhaust unit to the standby HEPA-and-charcoal exhaust unit.

Additional alarms in the Control Room will signal adverse operating conditions: low or high supply air temperature, low air flow from the supply or exhaust fans, clogged HEPA filters and insufficient negative pressure in the building.

9.4.3.3 Design Evaluation

The heating and ventilating of the fuel handling area is based on outdoor design conditions of 0°F in winter, 93°F dry bulb and 79°F wet bulb in summer. These values satisfy 99 percent of the weather conditions experienced annually at the Salem site and offer a high degree of assurance that satisfactory temperature conditions will be maintained.

Directing the air flow from areas of least contamination to areas of higher contamination is accomplished in two ways. First, the building is maintained at a negative pressure such that outdoor air leaks into the building rather than building air leaking out. Secondly, air flow within the building is from the cask storage area to the spent fuel pool area.

Efficient filtration of the supply air minimizes the inventory of airborne particulates within the building. This reduces the rate of dirt buildup on the HEPA filter exhaust units and extends their useful life. Whereas the supply air filters can be replaced easily and safely as required, the HEPA exhaust filters are potentially radioactive and less maintenance is desirable.

The heat, humidity and potential radioactivity in the building is confined to the spent fuel pool area. Seventy-five percent of the building exhaust occurs in that area, and the 60 air changes per hour over the pool is a rapid exhaust rate. Two-thirds of this exhaust rate takes place just inches above the pool water through numerous, high velocity (2000 fpm) exhaust ports spaced around the pool periphery. These ports act to vacuum the surface of the pool and effect early capture of pool emissions.

The exhaust portion of the ventilation system includes two 100 percent capacity filter units, two 50 percent fans and redundant sources of electrical power. The system can sustain a failure of an active component without losing the capability of maintaining the building under negative pressure and of filtering all the effluent.

The charcoal filter train is normally at standby and is inspected and tested periodically for availability, especially prior to refueling. This administrative control will assure the preparedness of the filter train and clogging of the train during the relatively short period of refueling or during a fuel handling accident is not anticipated.

An analysis was made of the heat loading on the filters if all the iodines released, using Safety Guide No. 25 assumptions, were absorbed on the filters. The resultant heat loading was approximately 1 Btu/hr. Hence, overheating is not expected to occur due to radioiodine loading.

The exhaust ductwork and exhaust fan-filter units leading from the fuel handling structure to the plant vent are seismic Class I design. Exposed ductwork along the walls within the structure is seismic Class II. The supply air unit, located below the fuel handling operating floor, is of non-seismic standard construction.

In the event of a seismic disturbance or a fuel handling accident that causes the failure of non-Class I equipment, the primary function of the ventilation system will still be maintained. That is, the seismic Class I portion of the exhaust system will continue to operate, creating a negative pressure within the structure, and pass the exhaust through HEPA and charcoal filters. There would be no increase in building differential pressure and, therefore, radioactivity would be contained within the building.

9.4.3.4 Tests and Inspections

All components of the Fuel Handling Area Ventilation System are subjected to a program of tests and inspections. This program is similar to that described for the Containment Ventilation System (Section 9.4.4.5) except that resistance to loss-of-coolant accident pressure and temperature transients is not applicable to the Fuel Handling Area.

9.4.4 CONTAINMENT VENTILATION SYSTEM

9.4.4.1 Design Bases

Containment ventilation is sub-divided into a number of independently controlled systems which perform specific functions for the containment during normal power generation, the design basis loss-of-coolant accident and a loss of offsite power. The systems are the following:

1. Containment Fan Cooler System
2. Containment Iodine Removal System
3. Rod Drive Ventilation System
4. Reactor Nozzle Support Ventilation System
5. Reactor Shield Ventilation System
6. Pressure - Vacuum Relief System
7. Containment Purge System

The Containment Ventilation flow diagram is shown in Figures 9.4-4A and B.

Except for the Pressure - Vacuum Relief System and the Containment Purge System, both of which connect the containment atmosphere to the environment at controlled intervals, all systems are of the recirculation type; completely contained within the containment, which have sufficient redundancy to perform their required functions.

9.4.4.1.1 Fan Cooler System

The Containment Fan Cooler System is an engineered safeguard that is designed to operate during normal power generation and "blackout" situations as well as during the design basis loss-of-coolant accident. The system is described in detail in Section 6.2.2.2.

This system removes heat from the containment atmosphere to limit the average temperature to 120°F during normal power operation, shutdown conditions and blackout situations.

9.4.4.1.2 Iodine Removal System (Internal Cleanup)

Two iodine removal units are provided within the containment. Each unit is designed to remove gaseous iodine and particulate radioactivity from the containment atmosphere as required to minimize airborne activity concentrations for containment access during normal operation.

9.4.4.1.3 Rod Drive Ventilation System

Four 1/3 capacity ventilation fans remove heat continuously from the control rod drive mechanism shroud during normal power operation. The air flow rate is sufficient to maintain a satisfactory ambient temperature around the electro-magnetic positioning coils of the rod drive mechanisms.

9.4.4.1.4 Reactor Nozzle Support Ventilation System

The four reactor nozzle supports are cooled by two sets of two fans. Each pair of full capacity fans cools two of the four nozzle supports. This system operates during normal power operation to assure that concrete surfaces in contact with the structural steel supports do not exceed the design temperature of 150°F. The fans are powered from the Standby AC Power System to cool the concrete during a loss of offsite power.

9.4.4.1.5 Reactor Shield Ventilation System

Two 100 percent capacity fans provide continuous ventilation for the reactor cavity to assure that the ambient temperature within the shield and around the neutron monitoring instrumentation cables does not exceed the design value of 135°F during normal power operation. The fans are powered from the Standby AC Power System to provide reactor cavity cooling during a loss of offsite power.

The air delivered by the reactor shield ventilation system is exhausted primarily through the reactor nozzle support ventilation system, with the balance of the air forced up and out of the cavity.

9.4.4.1.6 Pressure-Vacuum Relief System

The Pressure-Vacuum Relief System is a normally isolated system which can be used during power and hot standby operations as required to maintain containment pressure in the range of -1.5 to +0.3 psig. One exhaust effluent filter unit and one supply air filter unit are connected to a common penetration to relieve containment pressure or vacuum during normal power operation. The supply air filter unit can be manually energized in the event of a negative pressure in the containment. The exhaust filter unit can be manually energized for pressure relief if the containment pressure exceeds the ambient pressure. All exhaust is directed to the plant vent where it is monitored to assure that releases to the environment are within the limits specified in 10CFR20. The design pressure differentials inherently provide the motive power to restore the containment to an equilibrium pressure, and so no fan power is provided in the system.

9.4.4.1.7 Containment Purge System

The Containment Purge System is normally isolated. One supply air penetration and one exhaust penetration are provided for purging the containment atmosphere during normal power operation and normal plant shutdown. These purging modes are designed to perform the following functions:

1. Refresh the containment atmosphere as required to maintain doses to operating personnel within acceptable limits during in-service and shutdown maintenance and/or inspections.

2. Minimize the accumulation in containment of any long-lived radio-isotopes, such as tritium, which may be produced as a result of normal power operation.

All exhaust is directed to the plant vent where it is monitored to assure that releases to the environment are within the limits specified in 10CFR20. One pair of supply and exhaust fans and filters is normally available in the Auxiliary Building Ventilation System to perform the containment purging functions.

9.4.4.2 <u>System Description</u>

9.4.4.2.1 Fan Cooler Units

The information is presented in Section 6.2.2.2.

9.4.4.2.2 Purging System

The containment purging system is a normally closed, deactivated system that is manually energized as required to perform the functions described in Section 9.4.4.1. The supply and exhaust air equipment used for the various purging modes are the standby fan and filter units installed in the Auxiliary Building Ventilation System.

Purging air is supplied by one 35,000 cfm unit consisting of fan and motor, hot water heating coil, 80 percent efficiency filters, shut-off dampers, controls and instrumentation and a supply duct. The heating coil is designed to temper the air during winter to 60°F maximum. A low limit temperature alarm is provided in the control room to alert the operator in the event the supply air temperature approaches the freezing point. Two pneumatically operated, quick-closing, butterfly type isolation valves are installed in series, one on each side of the containment wall. Each valve is designed to withstand the 47 psig, 271°F atmosphere following a design basis loss-of-coolant accident and to close automatically on a safety injection signal or on a high radiation signal from the radiation monitoring devices discussed in Chapter 11. The filters remove most of the atmospheric dust and dirt that would otherwise enter the containment.

Purging air is exhausted by energizing the 35,000 cfm capacity standby exhaust fan and a standby HEPA filter unit which are normally available in the auxiliary building ventilation system. Operation of the standby fan in addition to two other 35,000 cfm exhaust fans provides the dual capability of purging the containment and exhausting the auxiliary building. The output of each exhaust fan is controlled such that the rate of containment purging can be varied from .57 to 0.80 air changes per hour as required, while maintaining the auxiliary building at design conditions. The HEPA filters remove 99 percent of particles 0.3 microns and larger from the containment exhaust and are preceded by roughing filters to prolong the life of the HEPA filters.

A 24,000 cfm capacity charcoal filter unit on standby in the Auxiliary Building Ventilation System can be placed in series with the containment purging HEPA filter exhaust unit. The charcoal filter is designed to absorb gaseous contaminants, particularly iodine, and when in use will afford a purging rate of 0.57 air changes per hour. During a reactor shutdown period when a different HEPA filter exhaust unit is available in the auxiliary building system for containment purging, but without the charcoal filter, the purging rate can be increased to 0.80 air changes per hour.

The purging exhaust duct that penetrates the containment is provided with two isolation valves in series as described previously in this section for the purging supply duct.

The exhaust air is combined with the Auxiliary Building exhaust air and directed to the plant vent where the total flow is monitored for radiation.

All penetrations, exhaust equipment and exhaust ductwork are designed to Class I (seismic) criteria. All supply equipment and supply ductwork are Class II (seismic) design. Purging system compliance with Branch Technical position CSB 6-4 is discussed in Section 9.4.4.3.2.

9.4.4.2.3 Pressure - Vacuum Relief System

The pressure-vacuum relief system is a normally closed deactivated system that is manually energized as required to equalize the containment with outdoor pressure during normal power operation. The system is designed for 2400 cfm capacity.

The exhaust air (pressure relief) filter unit consists of roughing, HEPA and charcoal filters, shut off dampers, backdraft preventer, and a water spray fire protection system for the charcoal filters.

The HEPA filters are designed to collect not less than 99 percent of particles 0.3 microns and larger, while the charcoal filters are designed to absorb not less than 90 percent of gaseous iodine.

The supply air (vacuum relief) filter unit consists of 80 percent efficiency filters, shut off damper and a backdraft preventer. The filters remove most of the atmosphere dust and dirt that would otherwise enter the containment.

The common duct from the containment to the supply and exhaust air filter units is provided with two isolation valves in series, one on each side of the containment wall.

The supply air filter unit is of standard construction. The exhaust air unit and all ductwork are designed and constructed to seismic Class I criteria. Pressure-Vacuum Relief System Compliance with Branch Technical Position CSB 6-4 is discussed in Section 9.4.4.3.2.

9.4.4.2.4 Containment Iodine Removal System (Internal Cleanup)

The containment iodine removal system consists of two fan and filter units located on Elevation 100 of the containment building outside the polar crane wall. Either of the units can be manually energized depending upon the need to reduce the level of particulate and gaseous radioactivity. The level of activity within the containment can be continually monitored by gaseous and particulate air monitors. Neither unit is required to be operated during a design basis loss-of-coolant accident.

Each 8,000 cfm capacity iodine removal unit is comprised of a single-speed fan, roughing, HEPA and charcoal filters, shut off dampers, and a water spray fire protection system for the charcoal filters. The HEPA filters are designed to collect 99 percent of particles 0.3 microns and larger, while the charcoal filters are designed to adsorb 90 percent of the gaseous iodine. Source air to each iodine removal unit is supplied through a duct connected to the large duct header of the fan cooler system.

All equipment and materials comprising the containment iodine removal system are designed and constructed to satisfy Class II seismic criteria.

9.4.4.2.5 Control Rod Drive Cooling

Control rod drive cooling is performed by the rod drive ventilation system, which consists of four one-third capacity fans connected to the control rod drive cooling shroud by ducts. Three of the four 23,000 cfm fans operate during normal power operation to remove 2.6×10^6 Btu/hr from the control rod drive mechanism and discharge the heat above operating floor (Elevation 130). This heat is then removed from the containment by the cooling coils in the fan cooler system.

The rod drive ventilation fans are located above the reactor head shield at Elevation 130. All the fans and ducts are designed and constructed to be removed for refueling activities and to satisfy Class II seismic criteria. Each fan is monitored for vibration and a control room alarm is provided.

9.4.4.2.6 Reactor Vessel Cooling

Cooling of the reactor vessel is performed by the reactor shield ventilation system in conjunction with the reactor nozzle support ventilation system. Both systems can be powered by the Standby AC Power System, and are designed to Class II seismic criteria.

The reactor shield ventilation system consists of two 100 percent capacity 18,000 cfm fans located outside the polar crane wall at elevation 100, each with its own duct system. The fans draw filtered, cooled air from the large duct header of the fan cooler system and deliver it to the neutron monitoring instrumentation cable space under the reactor. The system is designed to maintain the cable space at 135°F or less, provide 16,000 cfm through the annular space around the reactor to the nozzle support ventilation system, and provide 2,000 cfm upward to the reactor head.

The reactor nozzle support ventilation system consists of two identical sub-systems, each comprised of two 8,000 cfm fans (one spare) connected to common ductwork embedded in the reactor shield to cool two of the four reactor nozzle supports. The system draws air from the annular space around the reactor and through each of the nozzle supports to maintain the concrete bearing surfaces at 150°F or less. Source air is supplied to the annulus by the reactor shield ventilation system. All fans are located outside the reactor shield on floor Elevation 81 and discharge in the vicinity of the steam generators.

9.4.4.2.7 Penetrations

Each ventilation duct penetration in the containment building is equipped with two pneumatically operated, quick closing, butterfly type isolation valves in series, one on each side of the containment wall. Each isolation valve is part of a sealed penetration assembly, designed to Class I seismic criteria, to withstand the 47 psig, 271°F, saturated steam-air mixture resulting from a design basis loss-of-coolant accident. Complete closure of at least one valve in each pair satisfies the containment isolation criteria.

All ventilation isolation valves that require remote-manual actuation to open are of the fail closed type. The valve operator is a dual acting, piston type, pneumatic operator, controlled by a solenoid type air supply valve.

In the event of a loss of control air pressure and/or electric control power, a spring assembly integral with each isolation valve is designed to return the valve to the closed position.

Each ventilation isolation valve is equipped with a permanently bonded rubber seat for the butterfly disc, and low leakage bushings on the butterfly shaft. This construction limits leakage from each valve to 5.0 cc per hour per inch of valve diameter when subjected to 47 psig saturated steam in the closed position.

9.4.4.2.8 Instrumentation and Control

Instrumentation and controls for starting, stopping and monitoring the performance of the Containment Ventilation System are located in the Control Room. Additional instrumentation is also provided locally for inspection, test and maintenance.

The instrumentation and controls provided in the Control Room includes the following:

1. START and STOP pushbuttons for fans and fan coolers.

2. Low air flow alarms.

3. OPEN-CLOSE indication for the air control dampers in each fan cooler. (The normal positioning of the dampers is interlocked with the starting of the fan at its higher speed, while the post-accident positioning of the dampers and the lower fan speed are interlocked with a safety injection signal.)

4. High differential air pressure alarms for filters.

5. High temperature alarms for the fan cooler motor bearings and windings, air leaving each fan cooler, air discharged from the control rod drive mechanisms and reactor nozzle supports, ambient air around the neutron monitoring instrumentation cables, and the ambient air at numerous locations throughout the containment.

6. Control equipment to manually select ventilation filtration paths and service water isolation valve position indicating lights. (Ventilation duct isolation valves are interlocked to close automatically on a safety injection signal or in the event of a high radiation signal from the containment. Service water isolation valves close automatically in the event of high radiation in their respective lines.)

7. Service water temperature and flow indication and flow differential mismatch alarms at cooling coils.

8. Fire alarms to signal any ignition of a charcoal filter bank. (The ignition detection automatically actuates a water deluge system for the affected charcoal filter.)

9. High radiation alarms for service water leaving the fan coolers. These monitors are located outside the containment.

10. An overhead annunciator alarm is received whenever containment ventilation isolation is reset in the presence of an isolation actuation signal.

The instrumentation provided locally includes the following:

1. Manometers for indication of pressure drop across each bank of HEPA and charcoal filters, and each bank of roughing filters outside the containment.

2. Position indicators for each air control damper, water control valve, and isolation valve.

3. Pressure test-taps or gages in service water lines to each water cooled fan motor in the fan cooler safeguard system.

9.4.4.3 Design Evaluation

9.4.4.3.1 General

During the final design review of Unit No. 2 the NRC requested verification that adequate torque was available to shut isolation valves in the Containment Vacuum Relief and Purge System. Public Service evaluated this matter based on a conservatively assumed differential pressure of 60 psi, and it was determined that the actuator torque values were not sufficient to move the valves from the full open (90°) position to the closed position (0). With a differential pressure of between 18 to 24 psi, which is the calculated actual differential, the actuator torque values were marginal. Corrective action was therefore taken as follows:

1. For the 36" purge valves, administrative controls were implemented to keep the valves closed in all operating modes except cold shutdown and refueling.

2. The 10" valves were modified by the vendor. The modification consisted of reworking the actuator and a realignment of the actuator and valve shaft such that the full open position will correspond to 60° open instead of the original 90° open. This significantly reduced the required closing torque with a 60 psi differential to a value well below the available actuator torque. The new required closing torque with a 60 psi differential is 4,572 in-lbs., whereas the actuator torque available is 9,100 in-lbs., (spring force only, with no air assist).

Detailed valve information is contained in correspondence dated February 18, 1982 (Liden to Varga).

The Containment Fan Cooler System is required to remove approximately 8×10^6 Btu per hour during normal power operation. The design operating capacity of the system is greater than 12×10^6 Btu per hour. A 50 percent operating margin of 4×10^6 Btu per hour is ample capacity to account for miscellaneous loads during normal conditions. Additional evaluation is presented in Section 6.2.2.2.

The design of all the other mechanical ventilation systems within the containment (iodine removal, reactor shield ventilation, reactor nozzle support ventilation, and control rod drive ventilation) includes at least one standby unit with its own power, controls and instrumentation. Physical separation and redundancy of the power and control sources enhances the reliability of these systems. The failure of a single component or unit, therefore, will not prevent these systems from performing their design function. Additionally, the design operating capacity of the reactor shield, reactor nozzle, and rod drive ventilation systems exceeds the minimum performance requirements.

Ventilation ductwork penetrating the containment consists of two 36 inch diameter ducts for containment purging and one 10 inch diameter duct for containment pressure-vacuum relief. Redundant isolation valves in each duct, one inside and one outside the containment, assure the closing of at least one of each pair of valves to prevent the release of radioactivity from the containment environment. Each of the isolation valves is designed to withstand the effects of any loss-of-coolant accident. Failure of a single component or unit will not prevent these isolation valves from performing their function.

The control rod drive mechanism (CRDM), reactor vessel supports and the out-of-core nuclear instrumentation are provided cooling air by separate, independently controlled ventilation systems. They are the rod drive ventilation system (Section 9.4.4.2.12), reactor nozzle support ventilation system and the reactor shield ventilation system (Section 9.4.4.2.13).

Loss of cooling air to the CRDM's, the vessel supports, or the nuclear instrumentation will be detected via high air temperature alarms and/or low air flow alarms for the respective ventilation systems serving this equipment. Temperature and flow instrumentation is provided for each of the ventilation systems as shown in Figure 9.4-4A and B. An alarm is annunciated in the control room on indication of low air flow or high air temperature for an individual vent fan unit of the ventilation systems. The operation of the vent fan units (start-stop) is also monitored in the control room.

The CRDM coils have a design operating temperature of 392°F. Should this temperature be exceeded over a period of time, the life of the mechanism coils would be affected. The reactor vessel support concrete surfaces have a design operating temperature of 150°F. The out-of-core nuclear instrumentation and cabling have a design operating temperature of 135°F. The containment ventilation systems have been designed with spare capacity fans, physical separation, and redundant power and control sources so that a single component or unit failure will not affect the operation of these systems and ensure that these design temperatures are not exceeded.

An average ambient temperature of 120°F in the containment is maintained by the containment fan coolers. Under these normal conditions, 3 of the 4 rod drive vent fans operating will maintain the temperature of the CRDM's at approximately 160°F. The reactor vessel supports will have sufficient cooling air from 2 of the 4 reactor nozzle support fans (1 from each pair) so that the design temperature of 150°F is not exceeded. The operation of 1 of the 2 reactor shield vent fans will keep the out-of-core instrumentation below the design operating temperature of 135°F. The temperature alarms will annunciate when the normal operating temperatures are exceeded.

The ventilation system alarms will warn the operator if the cooling air for the CRDM's, reactor vessel supports or the out-of-core instrumentation areas has exceeded the temperature limits or do not have sufficient cooling air flow. The operator will then manually actuate the spare fan units for the affected system. These actions should restore normal cooling air flow and temperatures to the above mentioned equipment and areas and return the alarmed condition to normal.

It is considered highly unlikely that a complete loss of cooling air from the containment ventilation systems would occur because of the system design and use of multiple fans. In the unlikely event that high temperature and/or low air flow alarms are annunciated and the spare capacity fans and coolers are incapable of supplying the required ventilation to maintain design conditions, the plant will be shut down to prevent equipment damage and to effect repairs to the ventilation systems.

9.4.4.3.2 Conformance to Branch Technical Position CSB 6-4

This section addresses conformance of Containment Purge and the Pressure-Vacuum Relief Systems to Branch Technical Position CSB 6-4. The item numbers below correspond to the numbering employed in Section 5 of CSB 6-4.

1a. The purge and pressure-vacuum relief line isolation valves were purchased, manufactured and factory tested prior to the issuance of the NRC Branch Technical Position MEB-2, "Pump and Valve Operability Assurance Program". The appropriate design, environmental and leakage parameters were adequately specified for these isolation valves. The valves have undergone testing to verify leak tightness and operability during seismic events. The appropriate quality documentation was provided for the valves. The valves will be tested periodically for operability and leakage in accordance with the Technical Specifications. Although not specifically referenced, the design and testing of the purge and pressure-vacuum relief isolation valves meet the intent of Branch Technical Position CSB 6-4.

1b. Each unit has two purge lines and one pressure-vacuum relief line penetrating the containment.

1c. The purge vent lines are 36 inches in diameter and the pressure-vacuum relief line is 10 inches in diameter. The 36 inch lines, however, are not used for routine station operation. The operability of the 10" pressure/vacuum relief valves was assessed with respect to the stresses induced by the valve-to-operator interfacing hardware under operating loads during a LOCA. This analysis demonstrates that the 10" pressure/vacuum relief valves (VC5 and VC6) will operate in the event of a LOCA. Technical Specifications allow the valves, normally maintained shut in MODES 1, 2, 3, and 4, to be intermittently opened under administrative control for safety purposes during all applicable modes of operation. The accident analysis (see item 5a, below) yields doses well within 10CFR100 guidelines.

1d. The isolation valves and control system provisions for isolation meet the appropriate safety-related criteria consistent with containment isolation. Containment purge system isolation is actuated by Phase A and high radiation signals.

1e. Instrumentation and control systems are independent and actuated by diverse parameters.

1f. The purge and pressure-vacuum relief isolation valves are designed to close within 2 seconds. The valves were tested at the factory and will be tested periodically in accordance with the Technical Specifications. Total isolation time, including the 2 second valve closure, will not exceed 5 seconds if initiated by a high containment pressure signal (based on a design basis double ended cold leg rupture). Isolation time will not exceed 10 seconds if initiated by a high containment radiation signal. Isolation is also initiated by a safety injection signal.

1g. To ensure isolation valve closure, the design, which includes the type, location, orientation, and configuration of valves and piping/ducting of the penetration and ventilation system, considers the potential problem of debris becoming entrained in the escaping air and steam. Where the containment purge and pressure-vacuum relief penetrations are not connected directly to a filtered ventilation system and are terminated in the free containment atmosphere, the openings are faced down to preclude debris from entering the system. All the valves are either contained within the piping/duct lines or have a 1-inch expanded metal mesh basket around them.

2. The Containment Purge System is not intended for humidity and temperature control within the containment, but was designed to perform the functions previously described.

3. The Containment Ventilation System utilizes fan coolers for temperature and humidity control. The Iodine Removal System (internal cleanup) is used to remove gaseous iodine and particulate activity from the containment atmosphere.

4. The isolation valves are testable for operability and leakage in accordance with the Technical Specifications.

5a. The dose analysis for a loss-of-coolant accident during containment purge is presented in Chapter 15. This analysis utilizes very conservative assumptions, including an iodine spike. The analysis results in doses well within 10CFR100 guideline values.

5b. The system design includes provisions to protect structures and safety-related equipment. All equipment necessary to perform automatic isolation of the containment purge and pressure-vacuum relief lines is external to the containment (except the inboard isolation valves) and would not be affected by a loss-of-coolant accident.

5c. The analysis of a double-ended pipe rupture (see Chapter 15) indicates less than 0.2 percent of the Reactor Coolant System mass would be released from the containment prior to isolation. This will not adversely affect Emergency Core Cooling System performance.

5d. The allowable leak rate is specified in the Technical Specifications.

Based on the above, it is concluded that the design of the Containment Purge and Pressure-Vacuum Relief Systems satisfies the requirements of BTP CSB 6-4.

9.4.4.4 Tests and Inspections

All components of the containment ventilation system are subjected to a test and inspection program. The performance of unitized equipment, such as fans, filters, cooling coils, isolation valves, dampers, etc., is verified through manufacturers' tests and inspections. The performance of field-erected sections, such as filter enclosures and duct work, is verified mainly through post-erection tests and inspections. After installation, all unitized equipment and field-erected sections are inspected, tested and adjusted to assure performance of their design function. During plant operation, periodic tests and inspections are performed to ensure the integrity and performance of all components. All components are inspected when delivered to the site to assure compliance with specifications.

All components of the containment fan cooler system are designed to withstand normal and loss-of-coolant accident conditions without loss of function. When it is impractical to subject components to full scale testing, conservative calculations and/or prototype tests are performed to demonstrate capability to resist loss-of-coolant accident and seismic effects.

The pressure-vacuum relief system for the containment building is expected to be used intermittently during normal operations. When energized, the system will operate for at least 15 minutes to relieve a 0.3 psi positive pressure or 1.5 psi negative pressure in the containment.

Station personnel can read local manometers at the equipment during system startup to see if filter pressure drops are approaching their design limits. Also, a sample of the charcoal filter will be available in the pressure relief unit for removal and testing to determine the efficiency of the charcoal filter.

9.4.5 DIESEL GENERATOR AREA VENTILATION

9.4.5.1 Design Bases

The ventilation systems are designed to limit the temperature of each room to 110°F in the summer with equipment in the room operating. The unit heaters are designed to limit the temperature in the rooms to 60°F minimum in the winter. This range of room temperature (60 to 110°F) is an adequate environment for reliable operation and maintenance of the diesel generator, their controls and instrumentation.

The ventilation capacity for each diesel generator compartment (20,000 cfm) and Control Room (1200 cfm) is based on the waste heat released to the space. The ventilation capacity for the fuel oil storage area (2800 cfm) provides 5 air changes per hour.

The ventilation equipment and controls for the diesel generator compartments and control rooms can be powered from the Standby AC Power System and is designed to seismic Class I criteria. The fuel oil storage area ventilation is powered by the normal ac power system and is designed to seismic Class II criteria.

9.4.5.2 System Description

9.4.5.2.1 General Description

The Diesel Generator Area Ventilation System is shown in Figures 9.4-5A and B. The diesel generator area for each plant consists of three diesel generator compartments, three diesel generator control rooms and a fuel oil storage area. Each of these spaces is provided with an independent, once-through ventilation system. The use of independent systems enhances the effectiveness of the carbon dioxide flooding system in the event of a fire, permitting selective flooding into a given space without affecting other spaces. In the event carbon dioxide is delivered to a space, the ventilation for that space is automatically terminated.

The diesel generator area ventilation systems are designed to start automatically and limit the maximum room temperature when the diesel generators are operating. Provisions are available to permit starting or testing individual systems during normal plant conditions when the diesel generators are not running.

The ventilation system for the fuel storage area normally operates continuously to avoid concentrating oil fumes in the area. A local ON-OFF switch is provided.

The ventilation system for each of the spaces consists of (1) an exhaust fan discharging to the outdoors and (2) a supply air duct which supplies outdoor air to the room.

Local unit heaters assure an adequate minimum temperature in the spaces during cold weather.

9.4.5.2.2 System Operation

Normally the fuel oil storage area ventilation system is the only system that operates continuously. The diesel generator and control room systems are normally operated in an automatic mode. They are energized only when diesel generators are started. These ventilation systems can be started independently of the diesels, however, for testing and maintenance.

The ventilation system for all spaces operate similarly. The single speed exhaust fan discharges to the outdoors, and supply air from the outdoors is modulated by room temperature to provide the design room temperature. When a system is shut down, its exhaust fan stops and the supply air damper returns by spring action to the closed position.

Each system will automatically shut down if carbon dioxide fire protection flooding is initiated for the space.

If the ambient temperature in a diesel generator compartment or control room exceeds 110°F or goes below 40°F, the condition is alarmed in the Unit Control Room.

9.4.5.3 Design Evaluation

The heating and ventilating of the diesel generator area is predicated on outdoor temperature limits of 0°F in winter and 95°F in summer. For the Salem site, these values satisfy more than 99 percent of the conditions experienced annually. There is, therefore, a conservative margin in the heating and ventilating systems to assure that the design temperatures for the spaces can be maintained. Heaters are provided on the after cooler, in the lube oil system and in the jacket water system to assure each diesel generator is maintained at a temperature at which it can be started in 10 seconds. This conditions is satisfied for an outside temperature of 0°F and an inside ambient temperature of 40°F.

The ventilation systems for the diesel generator areas are independent, physically separated and powered from separate sources. Each system is provided with its own controls.

In the event of a fire in one space, the ventilation system for that space is automatically de-energized and does not feed air to the fire. The other diesel generators are available with full ventilation.

9.4.5.4 Tests and Inspections

All equipment and components of the diesel generator area ventilation systems are subject to a program of tests and inspections.

9.4.6 SWITCH GEAR ROOM VENTILATION SYSTEM

9.4.6.1 Design Basis and Criteria

The switch gear ventilation system is designed for continuous operation to maintain safe levels of temperature and cleanliness in the rooms served. Standby equipment is included in the system to assure the maintenance of these design conditions. The system is seismic Class I. The ventilation system is designed to maintain a year-round range of temperatures between 65 - 105°F within the areas served.

9.4.6.2 System Description

9.4.6.2.1 General Description

A separate ventilation system is provided for each unit's switch gear rooms which are located on Elevation 84 and 64 of the Auxiliary Building. The ventilation system consists of a supply air roll filter and enclosure, supply air fans, exhaust fans, recirculation duct, supply and exhaust ducts and control dampers. Most of the equipment is located in the penetration areas at Elevation 100 of each unit. It also ventilates the electrical penetration areas located at Elevation 78 and the switch gear ventilation equipment room. All ventilated areas and equipment are enclosed in seismic Class I structures. The switch gear ventilation system is shown on Figures 9.4-6A and B.

9.4.6.2.2 System Operation

The ventilation system for each unit consists of the following equipment:

1. One 100 percent capacity supply-air filtering unit having 70 - 82 percent ASHRAE Weight Arrestance efficiency to filter the outside and recirculated air.

2. Three 50 percent capacity fans to supply filtered air through supply ducts to the various areas.

3. Six return (or exhaust) air fans to exhaust air out of the switch gear rooms.

4. Two exhaust fans for the ventilation equipment room and penetration area (Elevation 100) and electrical penetration area (Elevation 78).

5. Three recirculation cooling units serve the north (mechanical) penetration area at Elevation 100, each consisting of a filter, cooling coil and fan.

6. Control and instrumentation.

7. Distribution ductwork and dampers for the supply air, exhaust air or recirculation air.

Normally two of the three supply fans are operated, with the third as a standby. Modulating dampers in the recirculation duct and the fresh air inlet duct control in the supply air temperature and thus maintain design air flow.

The three fans on Elevation 84 and three fans on Elevation 64 operate to exhaust the switch gear rooms to the return duct.

The exhaust from the ventilation equipment room and the penetration areas (Elevation 100 and Elevation 78) is directed to the return duct by two vane-axial fans connected in parallel.

If operation of the CO_2 fire protection system for one of these areas is initiated, a damper in the duct supplying air to that area is closed. However, the exhaust fans from that particular affected area continue to run, permitting the air displaced by the CO_2 to escape. All other areas served by the ventilating system continue to operate as usual except that the main recirculating dampers close and the system supplies 100 percent fresh air. This prevents the tripping of other smoke detectors by recirculated smoky air. It also provides a means for purging smoke from the fire area as soon as air supply is re-established.

9.4.6.3 Design Evaluation

The ventilation equipment for the switch gear rooms, equipment rooms, and electrical penetration area is enclosed in a seismic Class I structure. The equipment room is directly accessible from the relay room of the control area. All other areas in the vicinity of the switch gear rooms are ventilated by systems which are completely independent of the switch gear ventilation system and thus fire and smoke generated in such other areas would not impair the integrity or accessibility of the switch gear rooms.

9.4.6.4 Tests and Inspections

The systems are inspected, tested and balanced upon installation. Normal operation serves as a continuous check on system operation.

Operation of the dampers associated with initiation of the CO_2 fire protection system can be checked periodically.

9.4.7 SERVICE WATER INTAKE STRUCTURE VENTILATION

9.4.7.1 Design Bases

The ventilation systems are designed to limit the temperature of each compartment and/or control room to 110°F during ambient conditions of 95°F with all equipment operating. The unit heaters are designed to limit the temperature in the areas to 60°F minimum in the winter during ambient condition of 0°F. This range of room temperature (60 to 110°F) is an adequate environment for reliable operation and maintenance of the service water pumps, their controls and instrumentation.

The ventilation capacity for each service water intake structure compartment and control room is based on the calculated waste heat released.

The exhaust fans (12,000 and 32,000 cfm capacity) and their controls and instrumentation are designed to Class I (seismic) criteria and can be powered from the Standby AC Power System. The air intake penthouse, supply and exhaust dampers are of nonseismic construction.

9.4.7.2 System Description

9.4.7.2.1 General Description

The service water intake structure (SWIS) for both units consists of four service water intake compartments, each with its own control room. Each of these compartments is provided with an independent, once-through ventilation system.

The service water intake structure ventilation systems are designed to start automatically and limit the maximum room temperature when the service water pumps are operating.

The ventilation system for each compartment consists of an outside air intake penthouse, power operated intake and exhaust dampers and two exhaust fans discharging to the outdoors.

Local unit heaters assure an adequate minimum temperature in the spaces during cold weather when no pumps are in operation.

9.4.7.2.2 System Operation

The service water intake structure ventilating systems operate automatically in response to compartment and/or Control Room temperatures.

The ventilation systems operate as follows: On a small rise in temperature, the smaller of two exhaust fans starts and discharges to the outdoors. The supply air from the outdoors is modulated by room thermostats to provide the design compartment or control room temperature. On a greater rise in temperature, the larger fan starts, its intake damper opens and more air is induced to flow through the compartments. When a system is shut down, its exhaust fans stop and the supply and exhaust air dampers return by spring action to their closed positions.

If the ambient temperature in compartments or control rooms exceeds 110°F or goes below 40°F, the condition is alarmed in the Control Room.

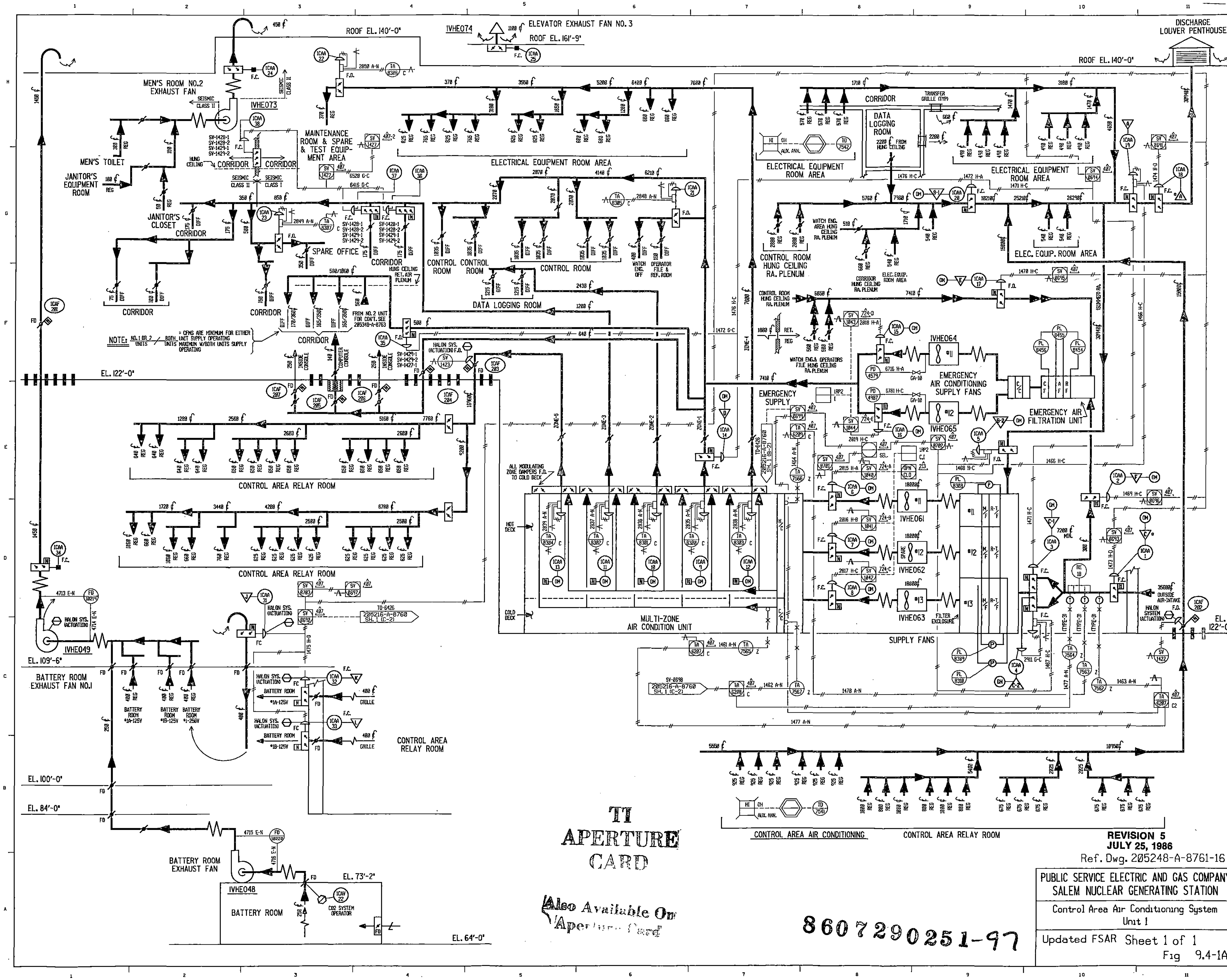
9.4.7.3 Design Evaluation

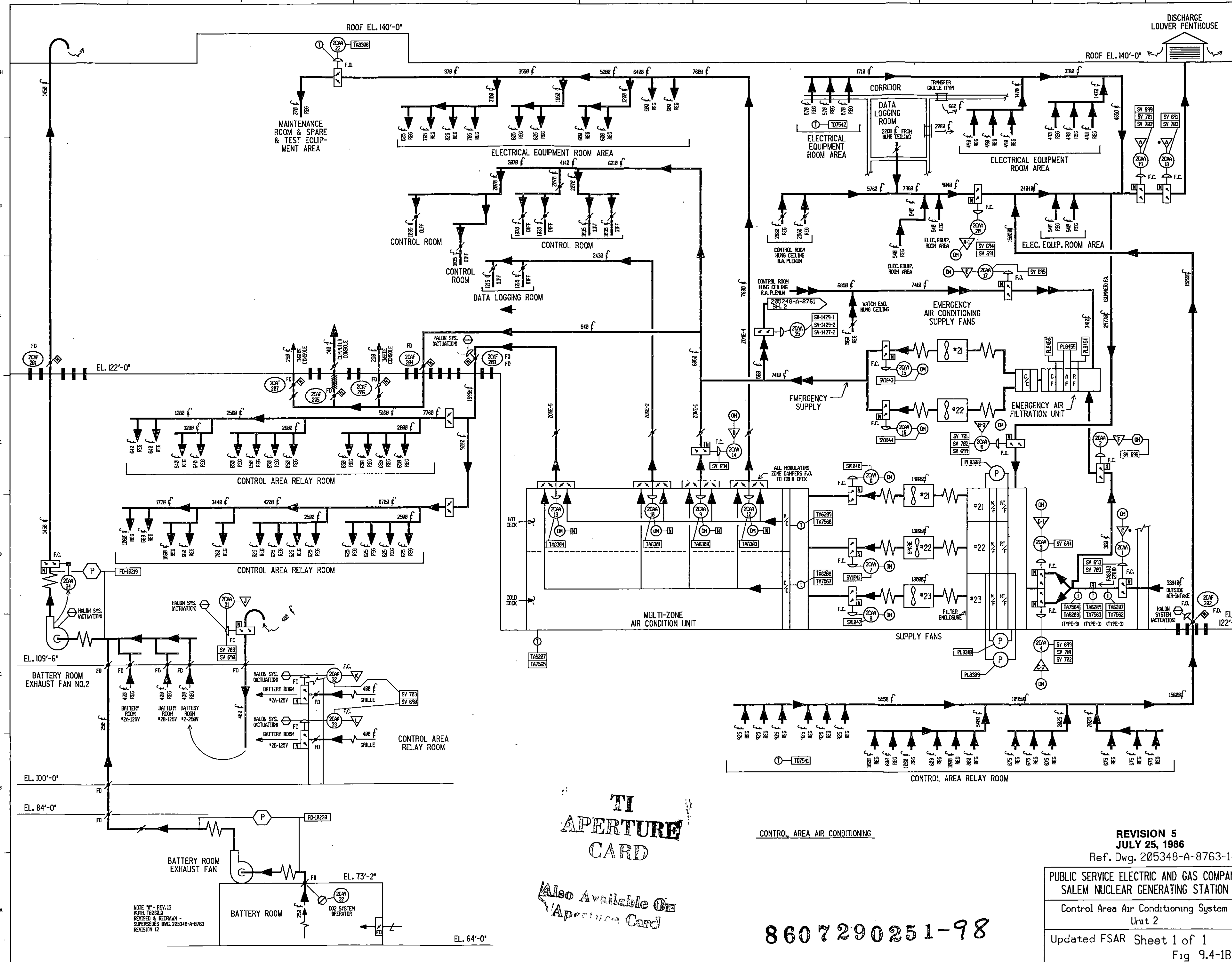
The heating and ventilating of the service water intake structure area is predicated on outdoor temperature limits of 0°F in winter and 95°F in summer. For the Salem site, these values satisfy more than 99 percent of the conditions experienced annually. This is, therefore, a conservative margin in the heating and ventilating systems to assure that the design temperatures for the spaces can be maintained.

The ventilation systems for the service water intake structure compartment use two fans which are physically separated and powered from separate sources. Each system is provided with its own controls, can be started manually or automatically, and can be tested independently to assure its availability. Failure of the non-seismic ventilating equipment (dampers and intake penthouse) would not interfere with the ability of the exhaust fans to perform their design function. The dampers fail open or loss of air or electric power.

9.4.7.4 Tests and Inspections

The system is inspected and tested upon installation. Normal operation serves as a continuous check on system operation.


ELEVATOR EXHAUST FAN NO. 3
IVHE074
ROOF EL. 161'-9"
ROOF EL. 140'-0"
DISCHARGE LOUVER PENTHOUSE
MEN'S ROOM NO.2 EXHAUST FAN
IVHE073
MEN'S TOILET
JANITOR'S EQUIPMENT ROOM
JANITOR'S CLOSET
MAINTENANCE ROOM & SPARE & TEST EQUIPMENT AREA
CORRIDOR
SPARE OFFICE
ELECTRICAL EQUIPMENT ROOM AREA
CONTROL ROOM
DATA LOGGING ROOM
DATA LOGGING ROOM
CONTROL ROOM HUNG CEILING RA. PLENUM
ELEC. EQUIP. ROOM AREA
EMERGENCY AIR CONDITIONING SUPPLY FANS
IVHE064
IVHE065
EMERGENCY AIR FILTRATION UNIT
EMERGENCY SUPPLY
EL. 122'-0"
CONTROL AREA RELAY ROOM
MULTI-ZONE AIR CONDITION UNIT
HOT DECK
COLD DECK
IVHE061
IVHE062
IVHE063
SUPPLY FANS
FILTER EXCLOSURE
OUTSIDE AIR INTAKE
NOTE: NO. 1 OR 2 UNITS / BOTH UNITS = CFMS ARE MINIMUM FOR EITHER UNIT SUPPLY OPERATING / MAXIMUM W/BOTH UNITS SUPPLY OPERATING
BATTERY ROOM EXHAUST FAN NO.1
IVHE049
EL. 109'-6"
EL. 100'-0"
EL. 84'-0"
BATTERY ROOM EXHAUST FAN
IVHE048
EL. 73'-2"
BATTERY ROOM
CO2 SYSTEM OPERATOR
EL. 64'-0"
CONTROL AREA RELAY ROOM
CONTROL AREA AIR CONDITIONING
CONTROL AREA RELAY ROOM
TI APERTURE CARD
Also Available On Aperture Card
8607290251-97
REVISION 5
JULY 25, 1986
Ref. Dwg. 205248-A-8761-16
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION
Control Area Air Conditioning System Unit 1
Updated FSAR Sheet 1 of 1
Fig 9.4-1A



TI APERTURE CARD

Also Available On Aperture Card

CONTROL AREA AIR CONDITIONING

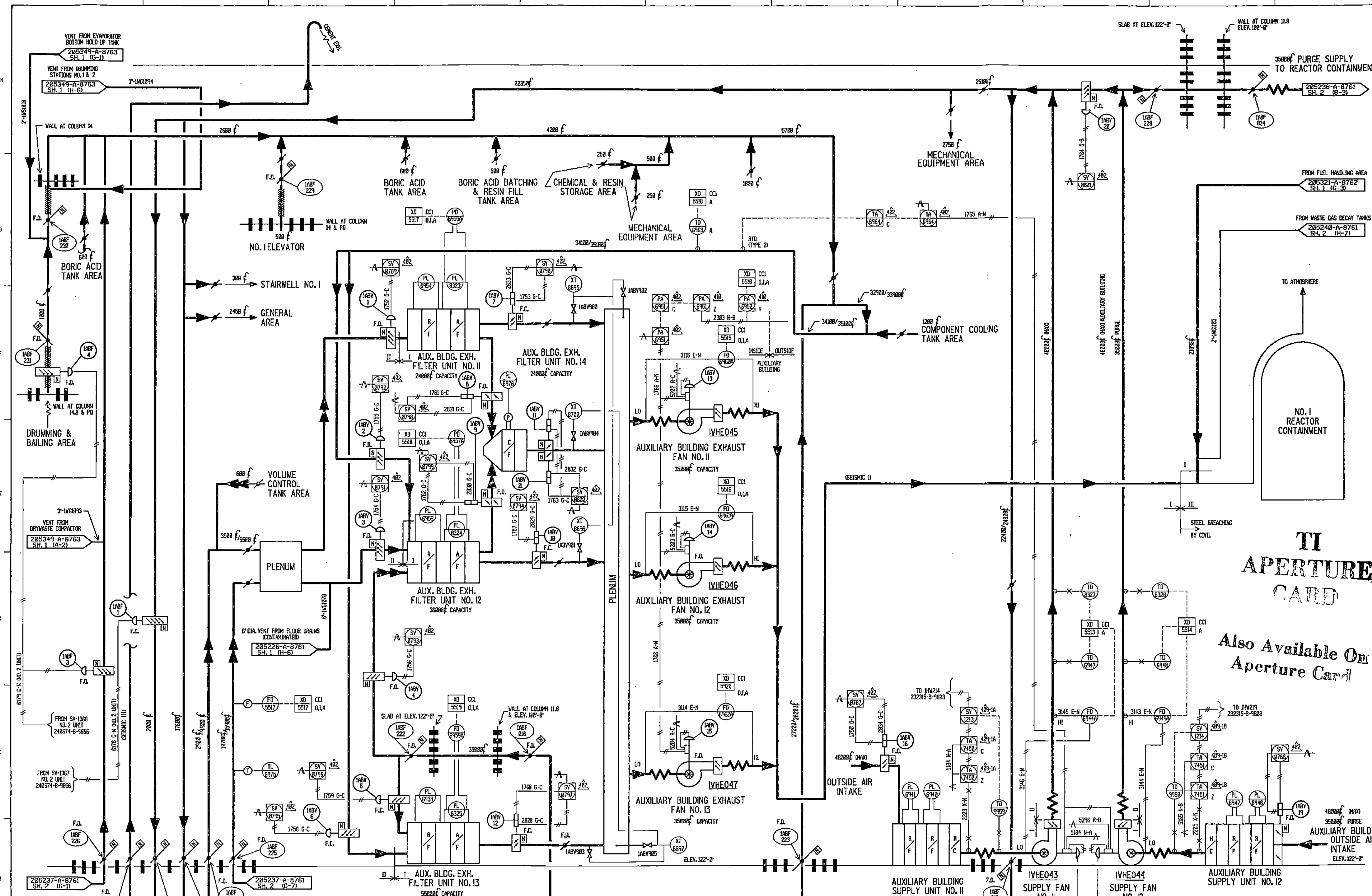
8607290251-98

REVISION 5
JULY 25, 1986
Ref. Dwg. 205348-A-8763-14

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Control Area Air Conditioning System
Unit 2

Updated FSAR Sheet 1 of 1
Fig 9.4-1B



REFERENCE DRAWINGS

NO. 1 UNIT - FLOOR DRAINS-CONTAMINATED	DIAG.	205226-A-8761
NO. 1 UNIT-REACTOR CONTAINMENT-VENTILATION ELEVATION 78', 100', & 130'-0"	DIAG.	205238-A-8761
NO. 1 UNIT WASTE DISPOSAL - GAS	DIAG.	205240-A-8761
NO. 1 UNIT - AUX. BLDG. DIESEL GEN. & FUEL HANDLING AREA - VENTILATION	DIAG.	205321-A-8762
NO. 1 & 2 UNITS WASTE DISPOSAL - SOLID	DIAG.	205349-A-8763
VENTILATION SYSTEM	INSTR. SCH.	211320-B-9508-20
PUMP ROOMS VENTILATION	INSTR. SCH.	207508-B-9491-14
PNL. 119	ARRGT.	232322-B-9608
PNL. 222	ARRGT.	232305-B-9608
PNL. 402	ARRGT.	223865-A-1212
PNL. 409	ARRGT.	232318-B-9608
LEGEND SHEET		600658-A-8727

205237-A-8761 ——— DIAG. ——— NO. 1 UNIT-AUXILIARY BUILDING-VENTILATION
SHEET 1 ——— ELEVATION 122'-0"
SHEET 2 ——— ELEVATION 100'-0"
SHEET 3 ——— ELEVATION 45', 55', 64' & 84'-0"

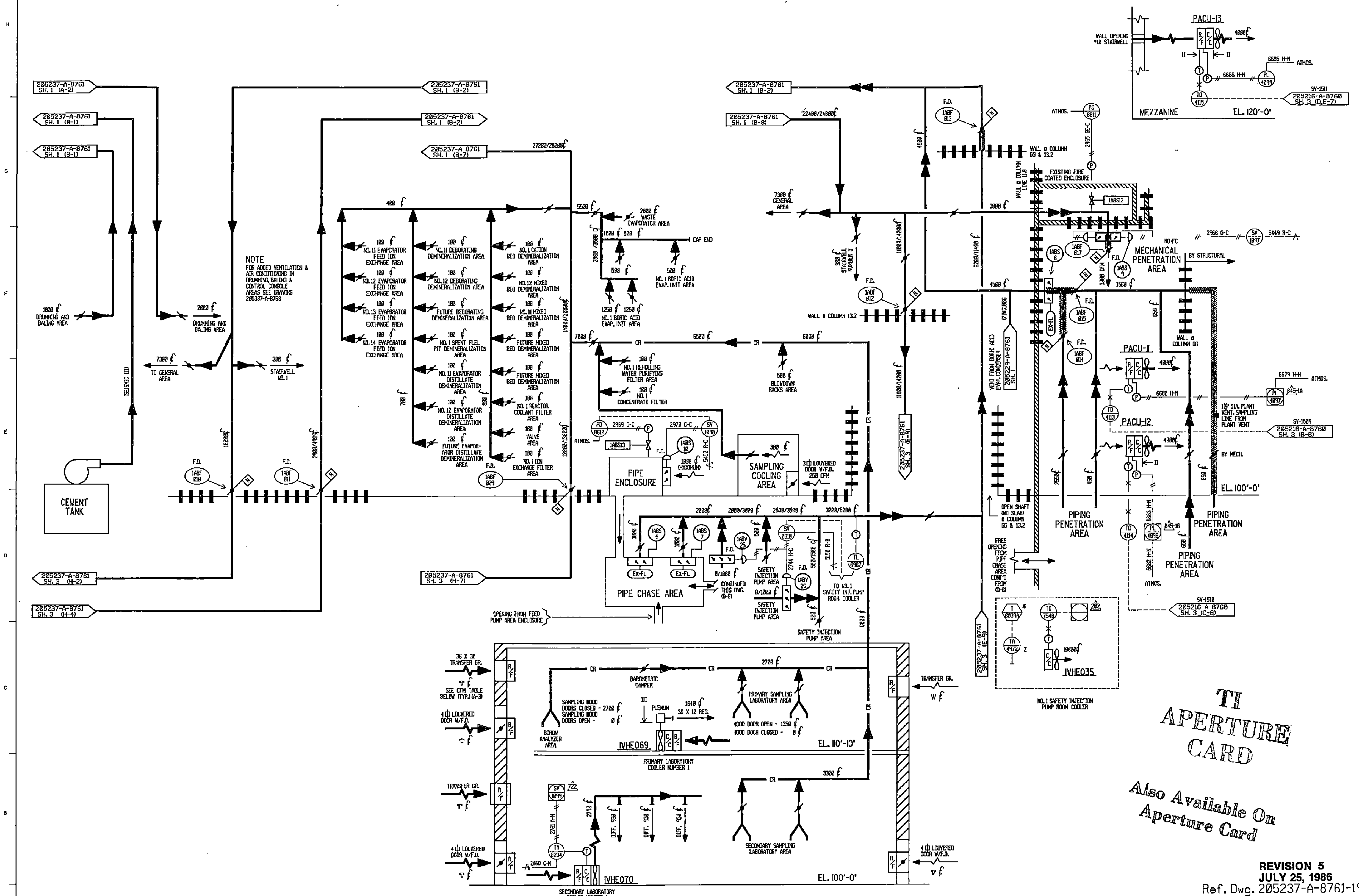
REVISION 5
JULY 25, 1986
Ref. Dwg. 205237-A-8761-19

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Auxiliary Building Ventilation System
Unit 1

Updated FSAR Sheet 1 of 3
Fig 9.4-2A

8607290251-99



ROOM SUPPLY	CFM
'A'	200 MAXIMUM
'B' + 'C'	2500 MAXIMUM
'D'	2000 MINIMUM
'E' + 'F'	1300 MAXIMUM

* NOTE: 'E' + 'F' = 3300 - 'D'
SET 'D' AS HIGH AS POSSIBLE

TI APERTURE CARD

Also Available On Aperture Card

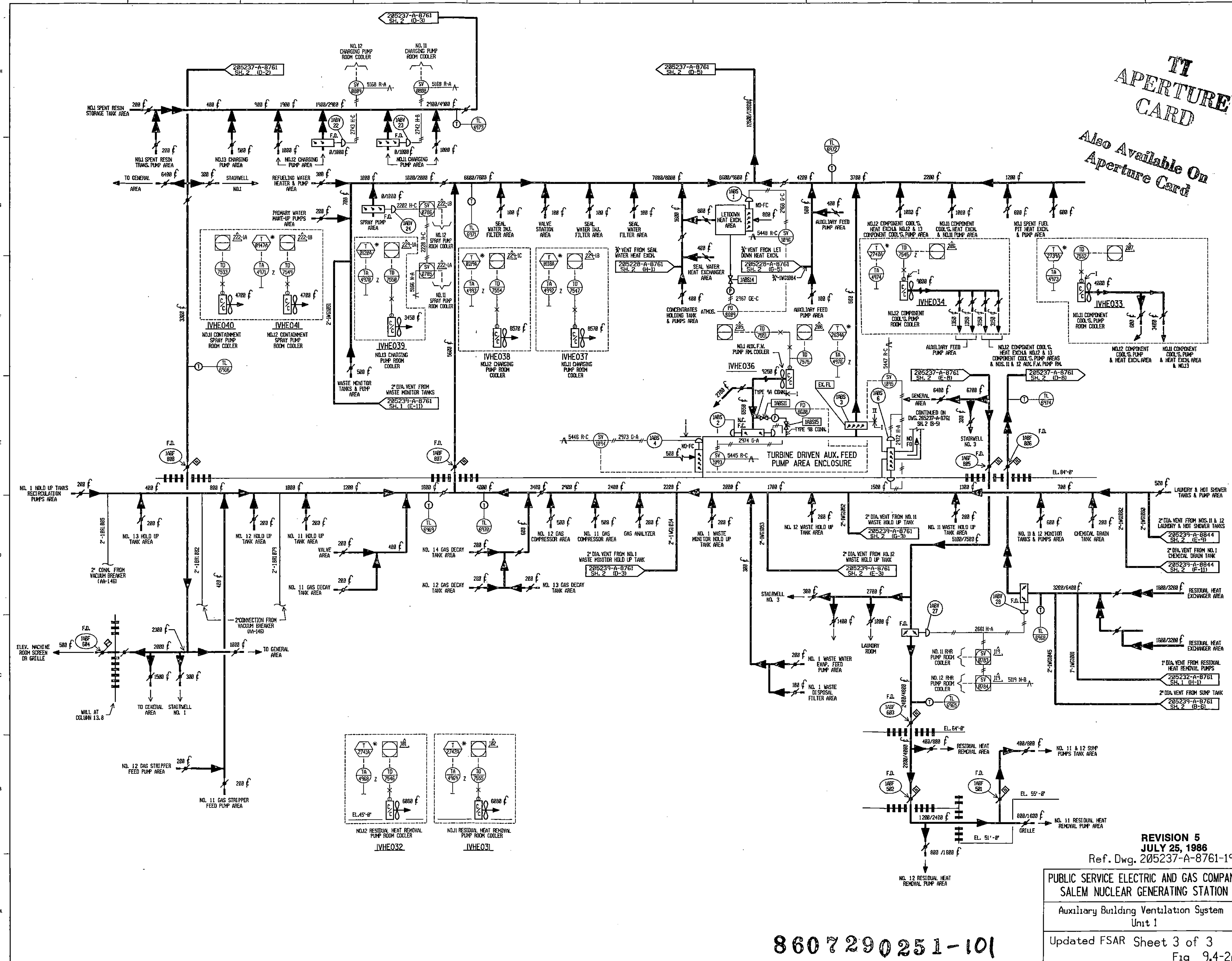
REVISION 5
JULY 25, 1986
Ref. Dwg. 205237-A-8761-19

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Auxiliary Building Ventilation System
Unit 1

Updated FSAR Sheet 2 of 3
Fig 9.4-2A

8607290251-100



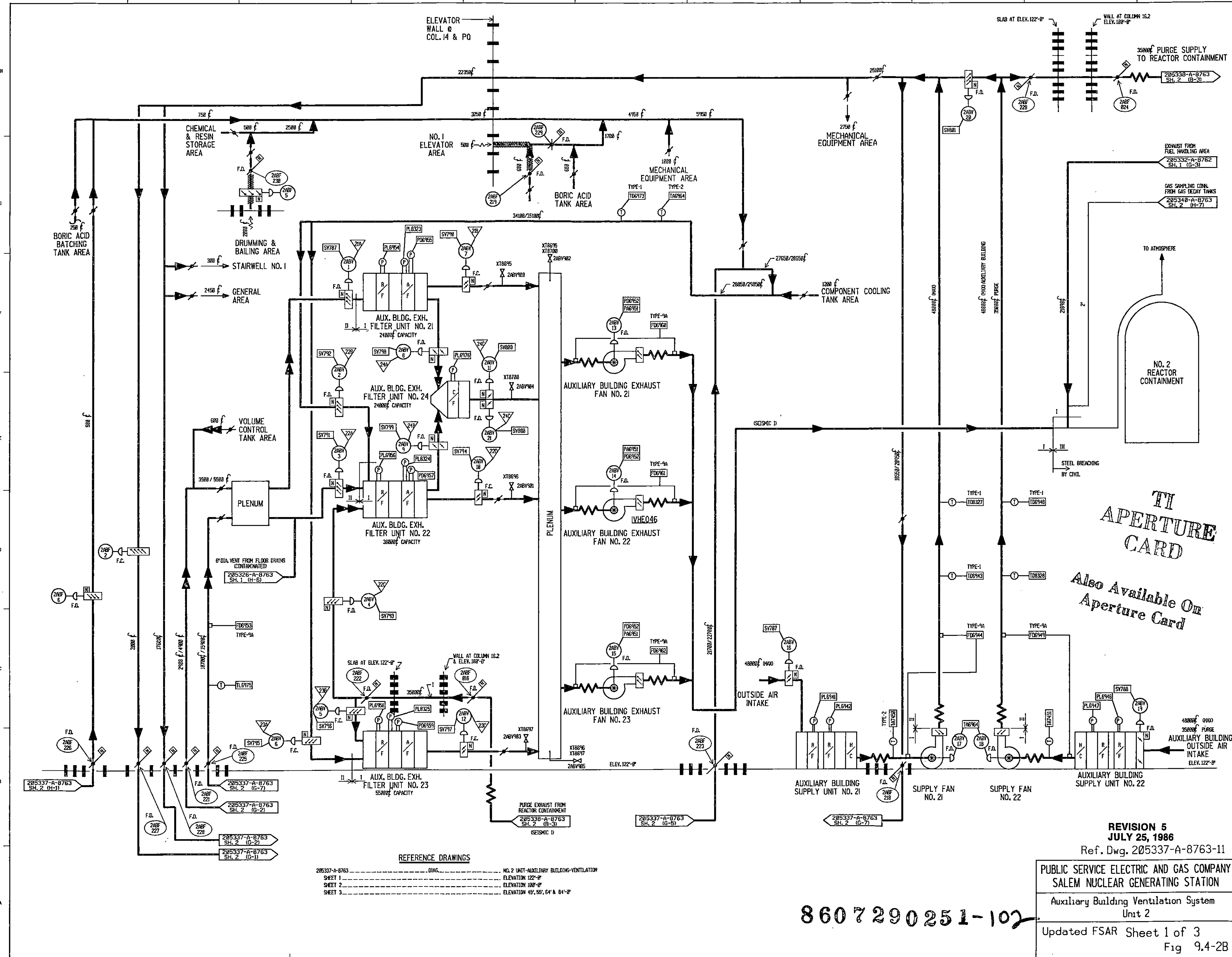
REVISION 5
JULY 25, 1986
Ref. Dwg. 205237-A-8761-19

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Auxiliary Building Ventilation System
Unit 1

Updated FSAR Sheet 3 of 3
Fig 9.4-2A

8607290251-101



REFERENCE DRAWINGS

205337-A-8763	DIAG.	NO. 2 UNIT-AUXILIARY BUILDING-VENTILATION
SHEET 1		ELEVATION 122'-0"
SHEET 2		ELEVATION 100'-0"
SHEET 3		ELEVATION 45', 55', 64' & 84'-0"

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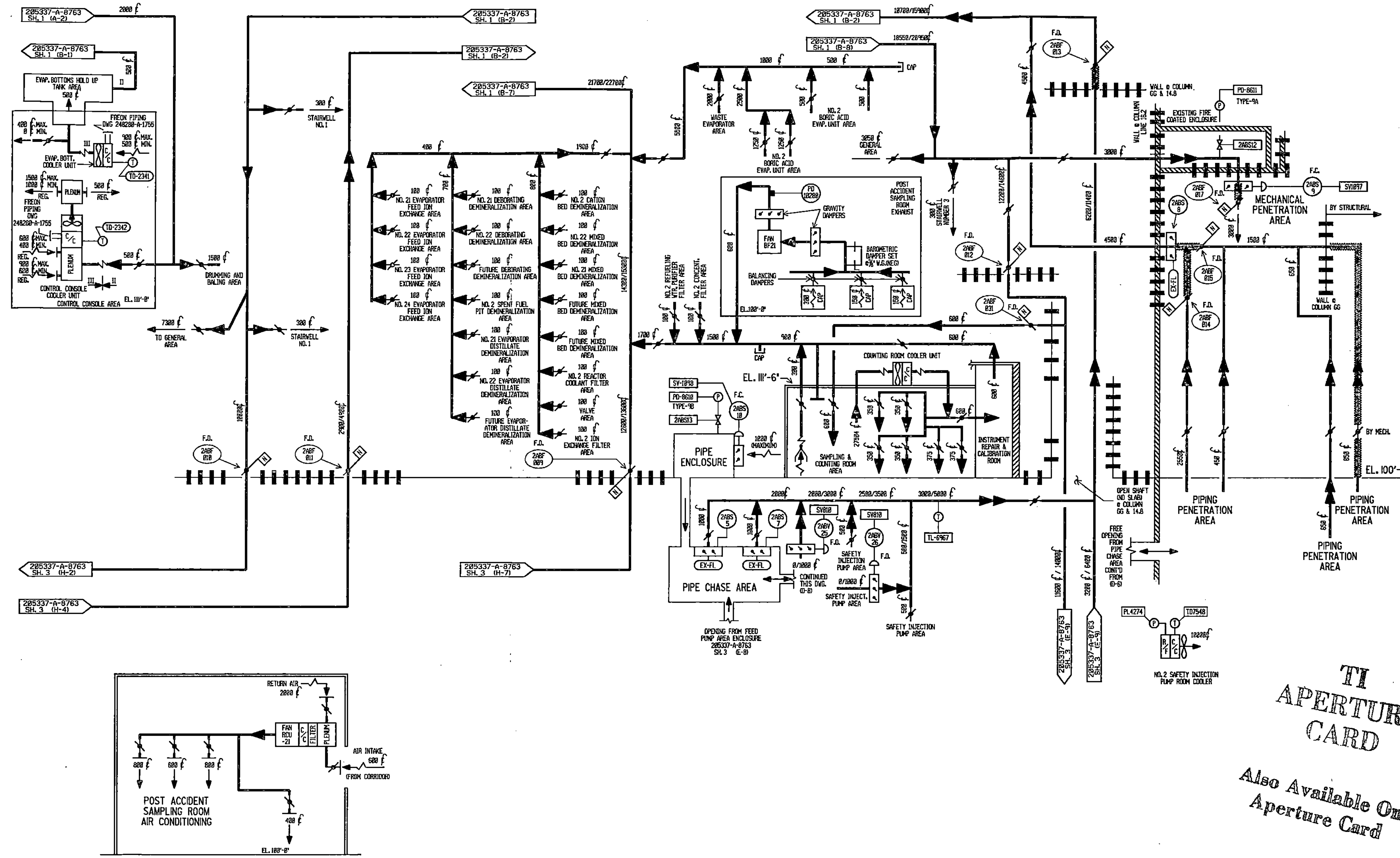
Ref. Dwg. 205337-A-8763-11

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Auxiliary Building Ventilation System
Unit 2

8607290251-102

Updated FSAR Sheet 1 of 3
Fig 9.4-2B



REVISION 5
JULY 25, 1986

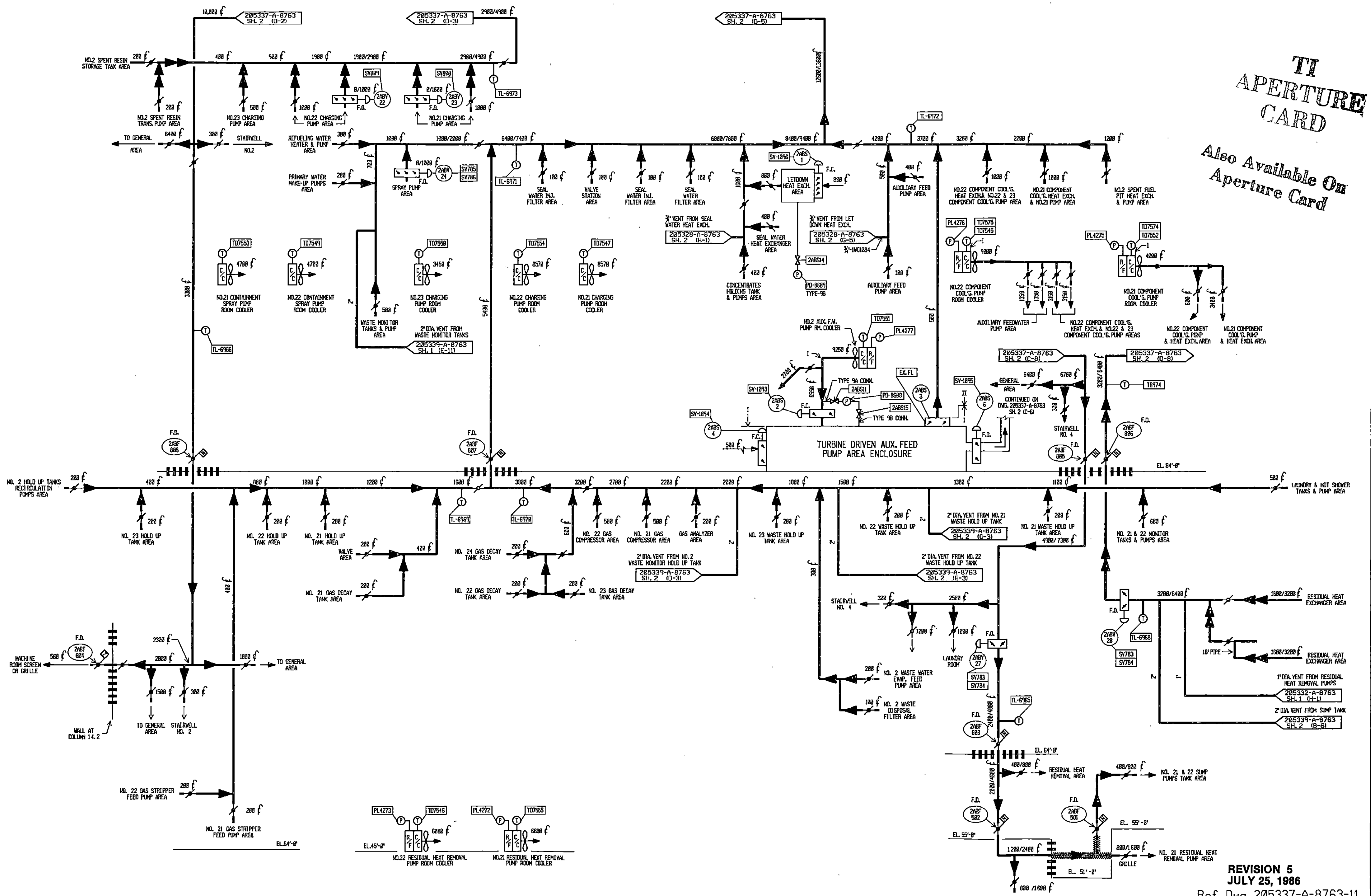
Ref. Dwg. 205337-A-8763-11

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Auxiliary Building Ventilation System
Unit 2

Updated FSAR Sheet 2 of 3
Fig 9.4-2B

8607290251-103



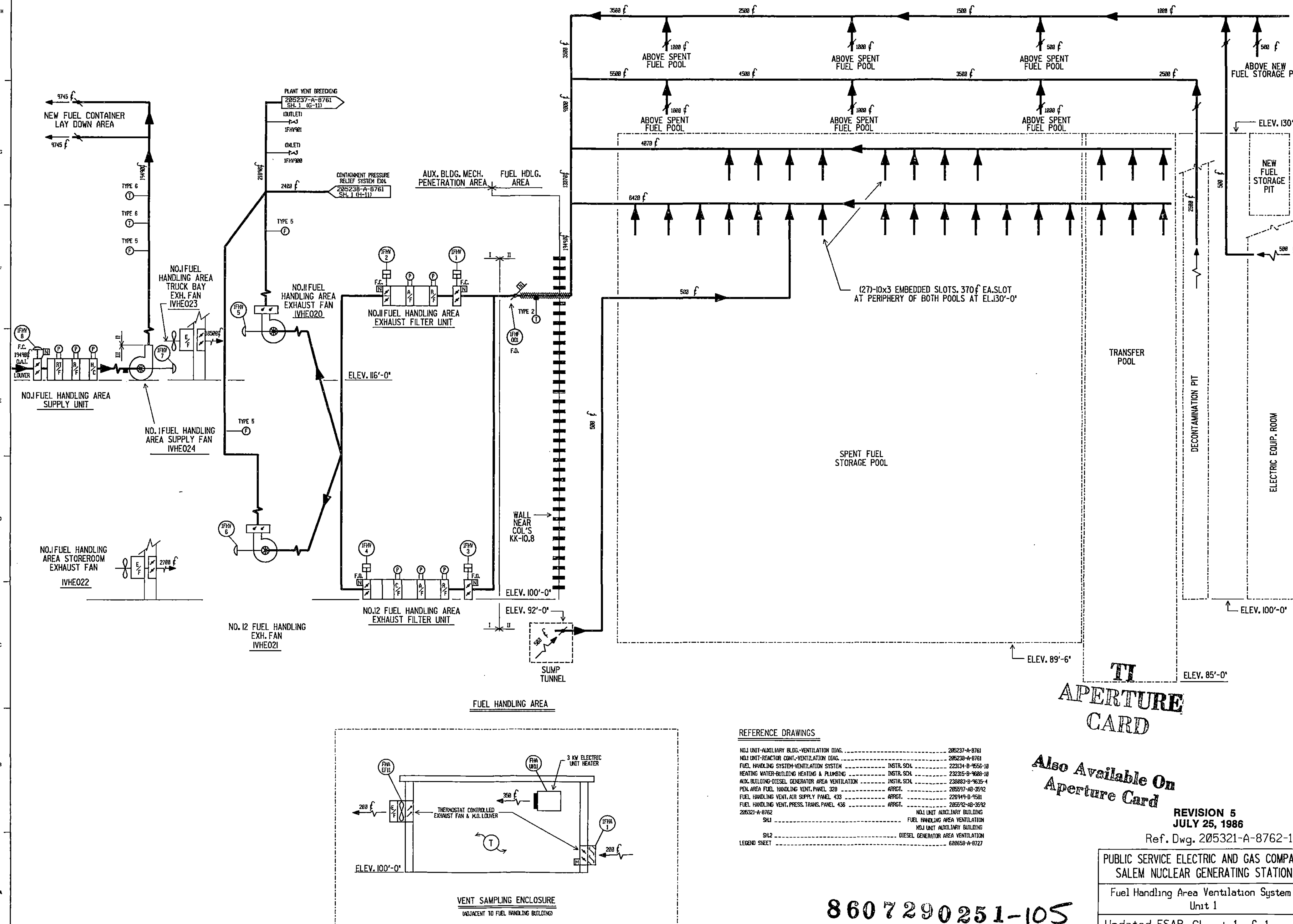
REVISION 5
JULY 25, 1986
Ref. Dwg. 205337-A-8763-11

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Auxiliary Building Ventilation System
Unit 2

Updated FSAR Sheet 3 of 3
Fig 9.4-2B

8607290251-104



REFERENCE DRAWINGS

NO.1 UNIT-AUXILIARY BLDG.-VENTILATION DIAG.		205237-A-8761
NO.1 UNIT-REACTOR CONT.-VENTILATION DIAG.		205238-A-8761
FUEL HANDLING SYSTEM-VENTILATION SYSTEM	INSTR. SCH.	223134-B-9556-10
HEATING WATER-BUILDING HEATING & PLUMBING	INSTR. SCH.	232315-B-9608-10
AUX. BUILDING-DIESEL GENERATOR AREA VENTILATION	INSTR. SCH.	238083-B-9635-4
PEN. AREA FUEL HANDLING VENT. PANEL 328	ARRGT.	205597-AB-3592
FUEL HANDLING VENT. AIR SUPPLY PANEL 433	ARRGT.	226949-B-9581
FUEL HANDLING VENT. PRESS. TRANS. PANEL 436	ARRGT.	205592-AB-3592
205321-A-8762		
SH.1		NO.1 UNIT AUXILIARY BUILDING FUEL HANDLING AREA VENTILATION
SH.2		NO.1 UNIT AUXILIARY BUILDING DIESEL GENERATOR AREA VENTILATION
LEGEND SHEET		600658-A-8727

TI APERTURE CARD

Also Available On Aperture Card

REVISION 5
JULY 25, 1986

Ref. Dwg. 205321-A-8762-11

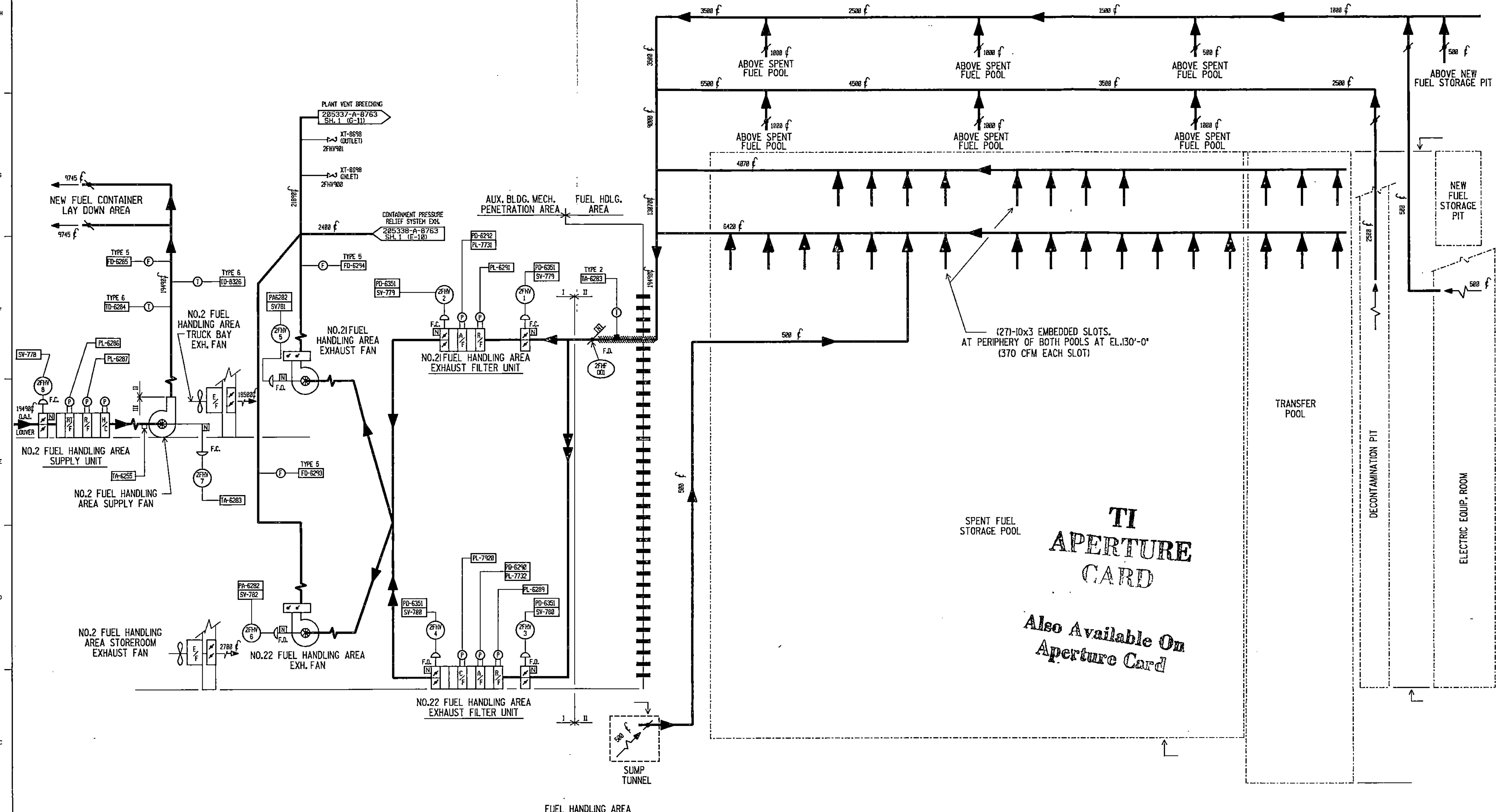
8607290251-105

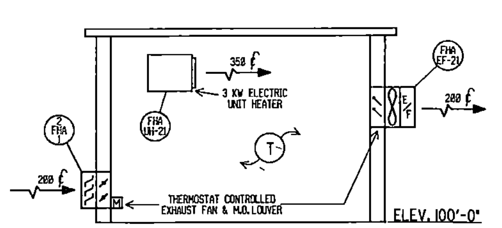
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Fuel Handling Area Ventilation System
Unit 1

Updated FSAR Sheet 1 of 1

Fig 9.4-3A





VENT SAMPLING ENCLOSURE
(SEISMIC CLASS III)

REFERENCE DRAWINGS

NO.2 UNIT-AUXILIARY BLDG.-VENTILATION DIAG.	205337-A-8763
NO.2 UNIT-REACTOR CONT.-VENTILATION DIAG.	205338-A-8763
LEGEND SHEET	600658-A-8727
205322-A-8762 SH.1	NO.2 UNIT AUXILIARY BUILDING FUEL HANDLING AREA VENTILATION VENT SAMPLING ENCLOSURE EL.100'-0"
205322-A-8762 SH.2	NO.2 UNIT AUXILIARY BUILDING DIESEL GENERATOR AREA VENTILATION

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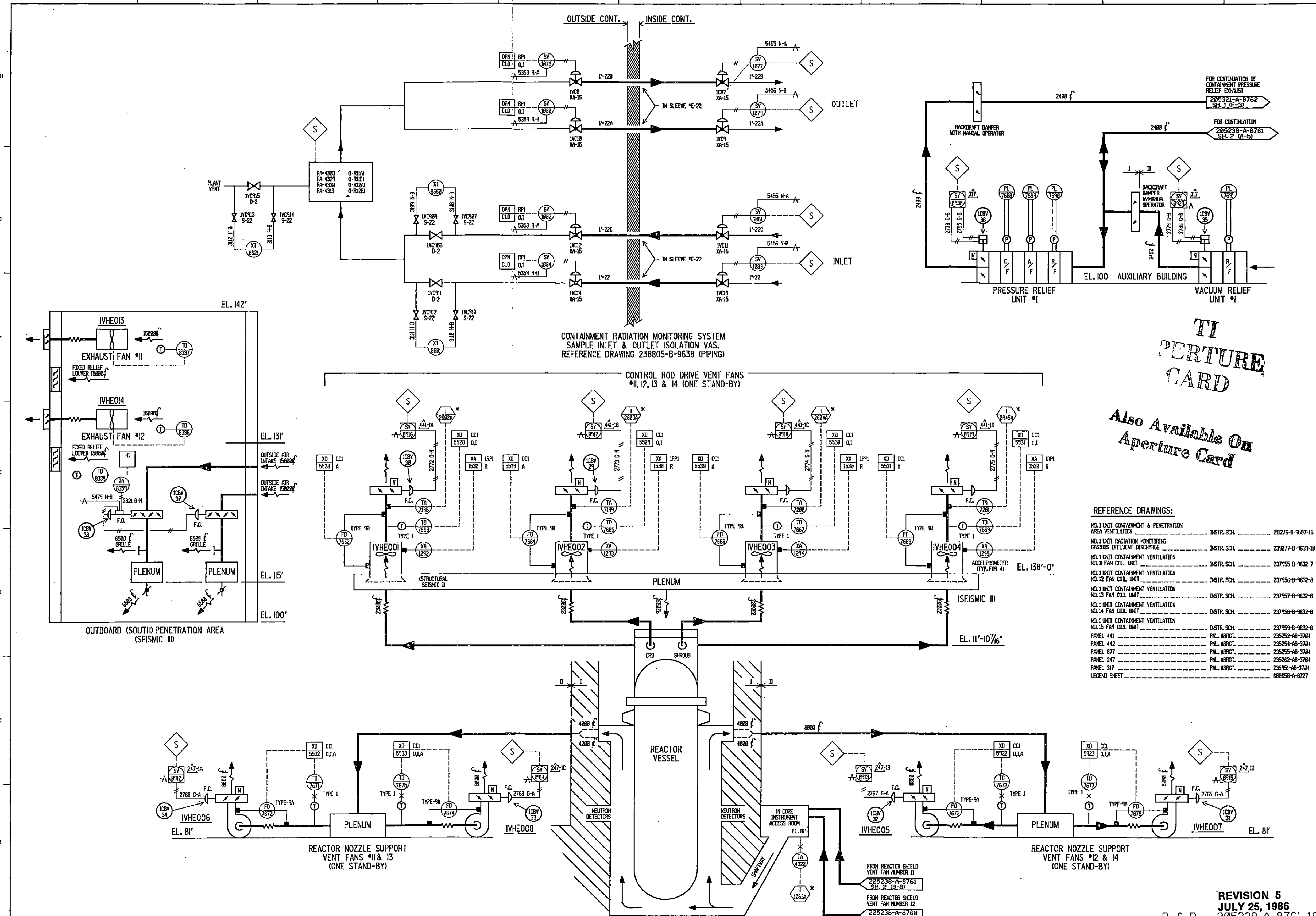
Ref. Dwg. 205322-A-8763-10

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Fuel Handling Area Ventilation System
Unit 2

Updated FSAR Sheet 1 of 1
Fig 9.4-3B

8607290251-106



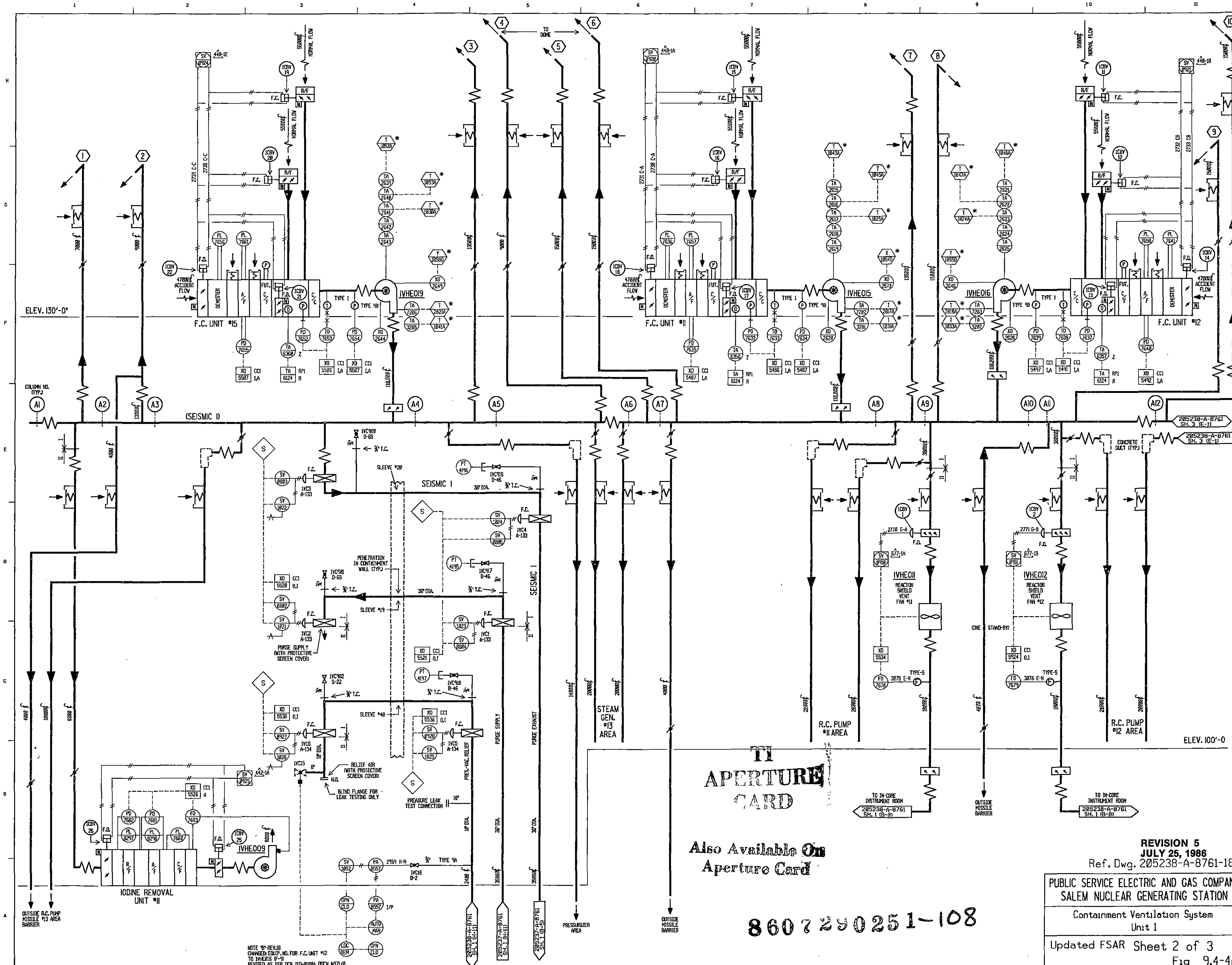
REVISION 5
JULY 25, 1986
Ref. Dwg. 205238-A-8761-18

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Containment Ventilation System
Unit 1

Updated FSAR Sheet 1 of 3
Fig 9.4-4A

8607290251-107



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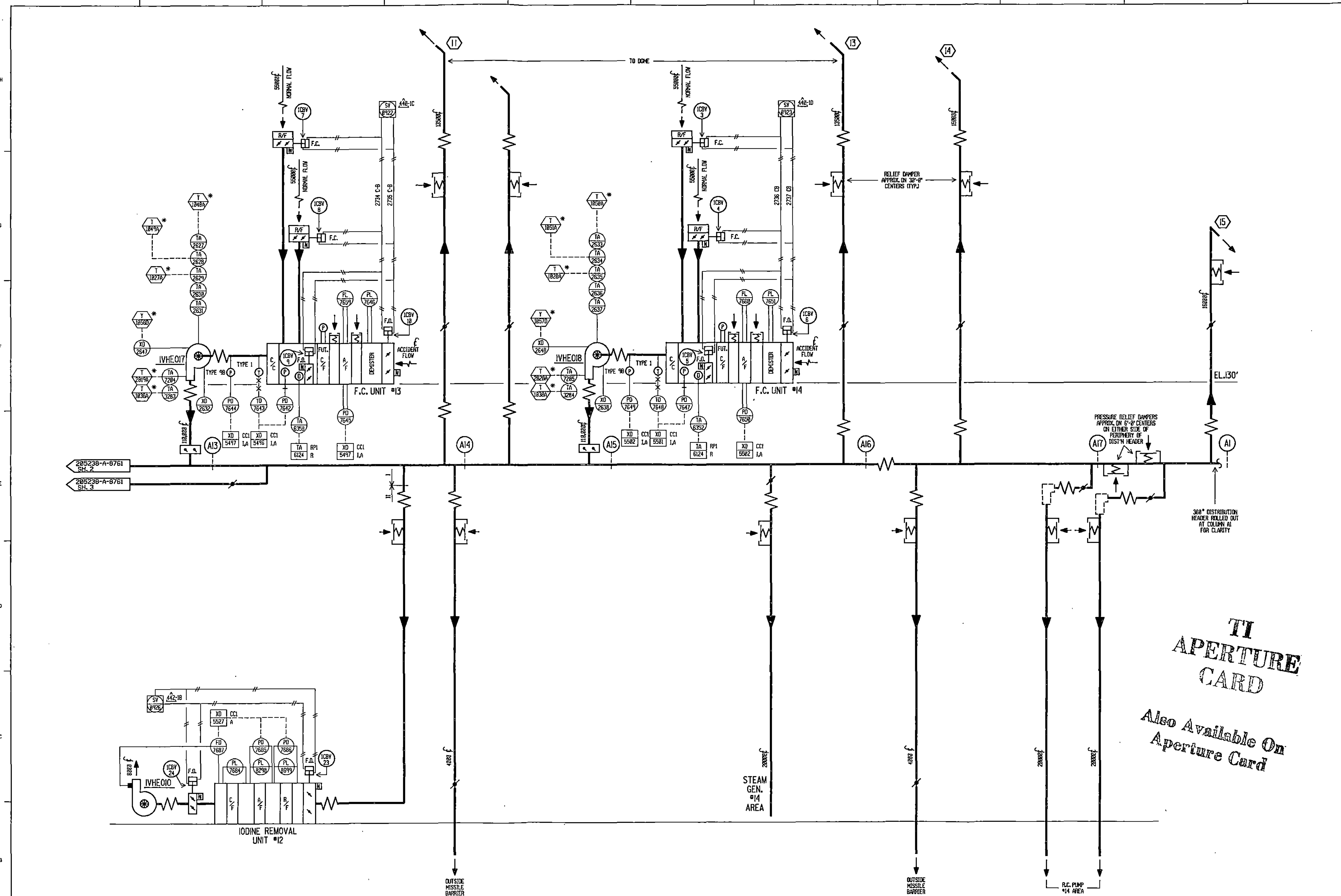
8607290251-108

REVISION 5
JULY 25, 1986
Ref. Dwg. 205238-A-8761-18

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Containment Ventilation System
Unit 1

Updated FSAR Sheet 2 of 3
Fig 9.4-4A



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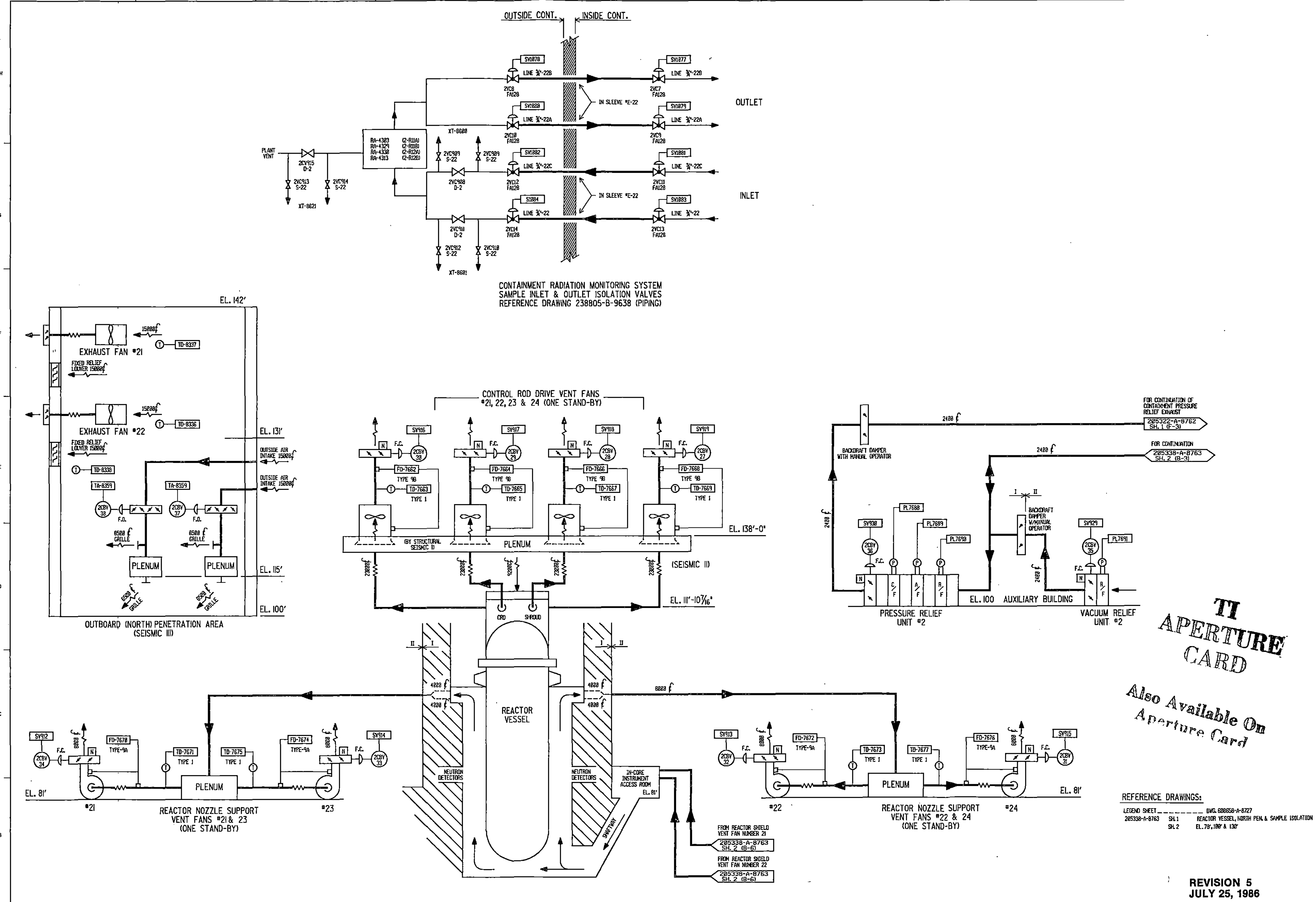
REVISION 5
JULY 25, 1986
Ref. Dwg. 205238-A-8761-18

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Containment Ventilation System
Unit 1

Updated FSAR Sheet 3 of 3
Fig 9.4-4A

8607290251-109



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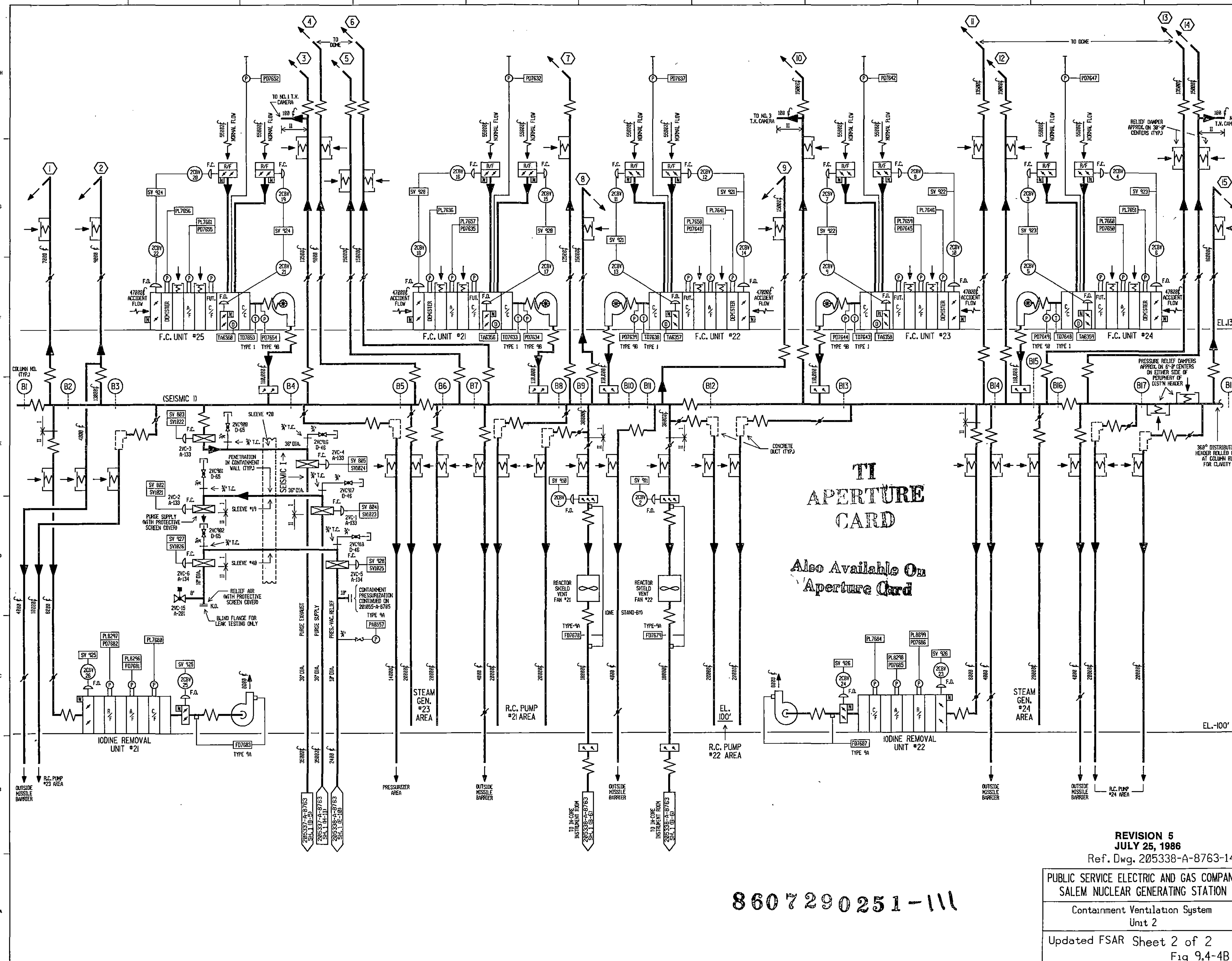
JULY 25, 1986
Ref. Dwg. 205338-A-8763-14

8607290251-110

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Containment Ventilation System
Unit 2

Updated FSAR Sheet 1 of 2
Fig 9.4-4B

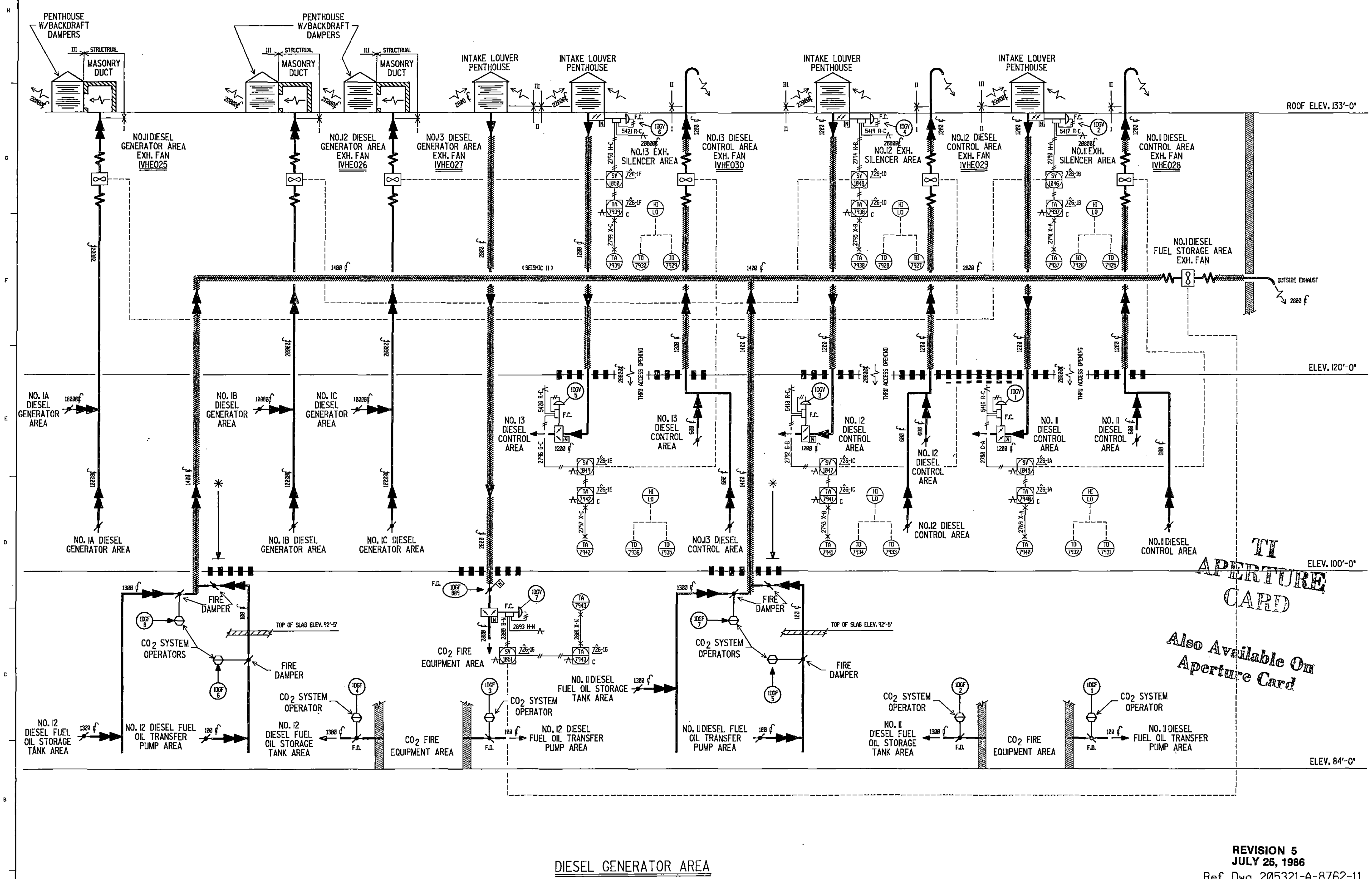


REVISION 5
JULY 25, 1986
Ref. Dwg. 205338-A-8763-14

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Containment Ventilation System
Unit 2

Updated FSAR Sheet 2 of 2
Fig 9.4-4B



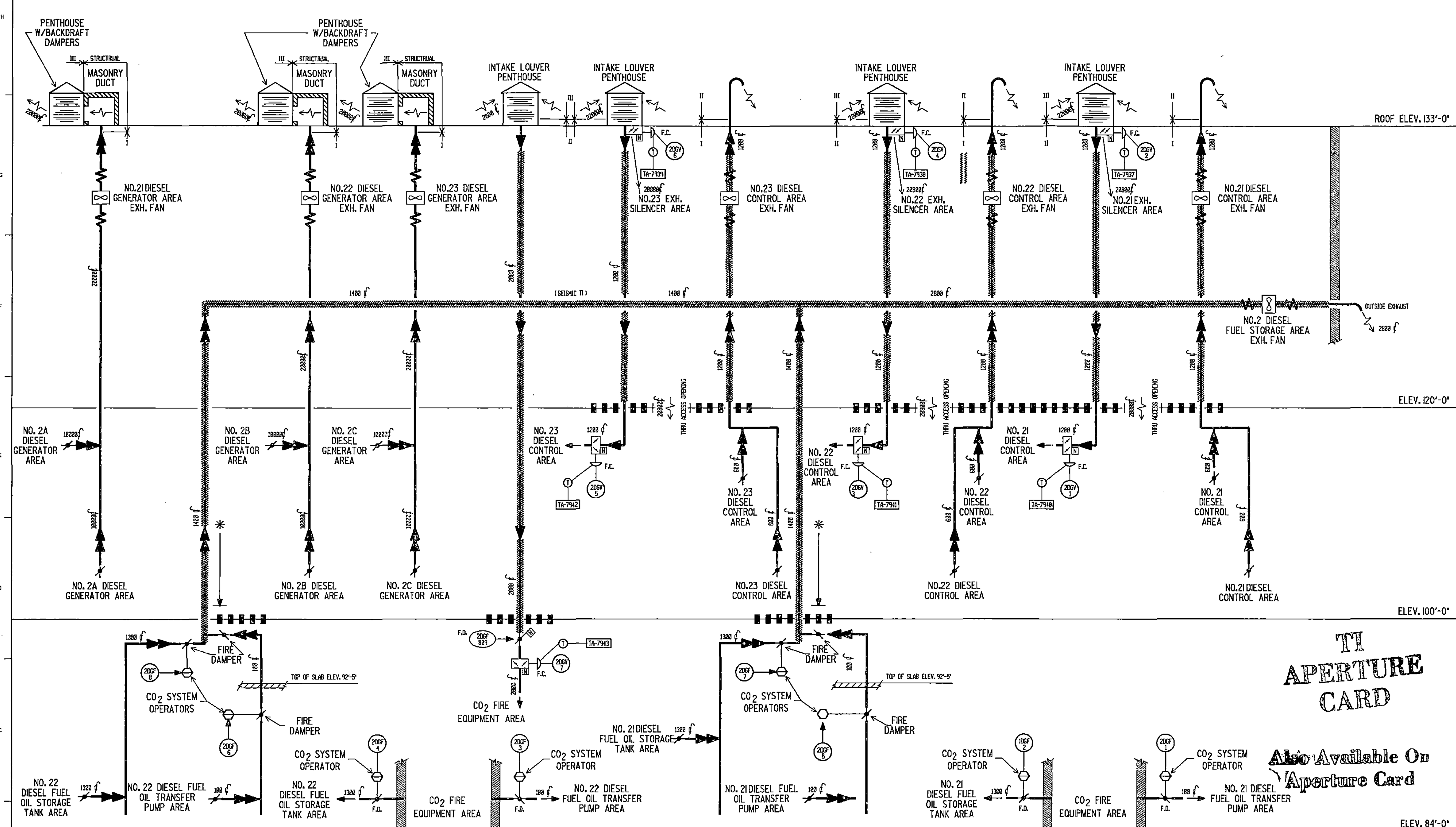
REVISION 5
JULY 25, 1986
Ref. Dwg. 205321-A-8762-11

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Diesel Generator Rooms Ventilation
Unit 1

Updated FSAR Sheet 1 of 1
Fig 9.4-5A

8607290251-112



TI APERTURE CARD

Also Available On Aperture Card

DIESEL GENERATOR AREA

* FIRE COATING ON THESE DUCTS ARE INSTALLED FROM FLOOR ELEV. 100'-0" & UP, BUT IS NOT REQUIRED BY FIRE SAFETY EVALUATIONS

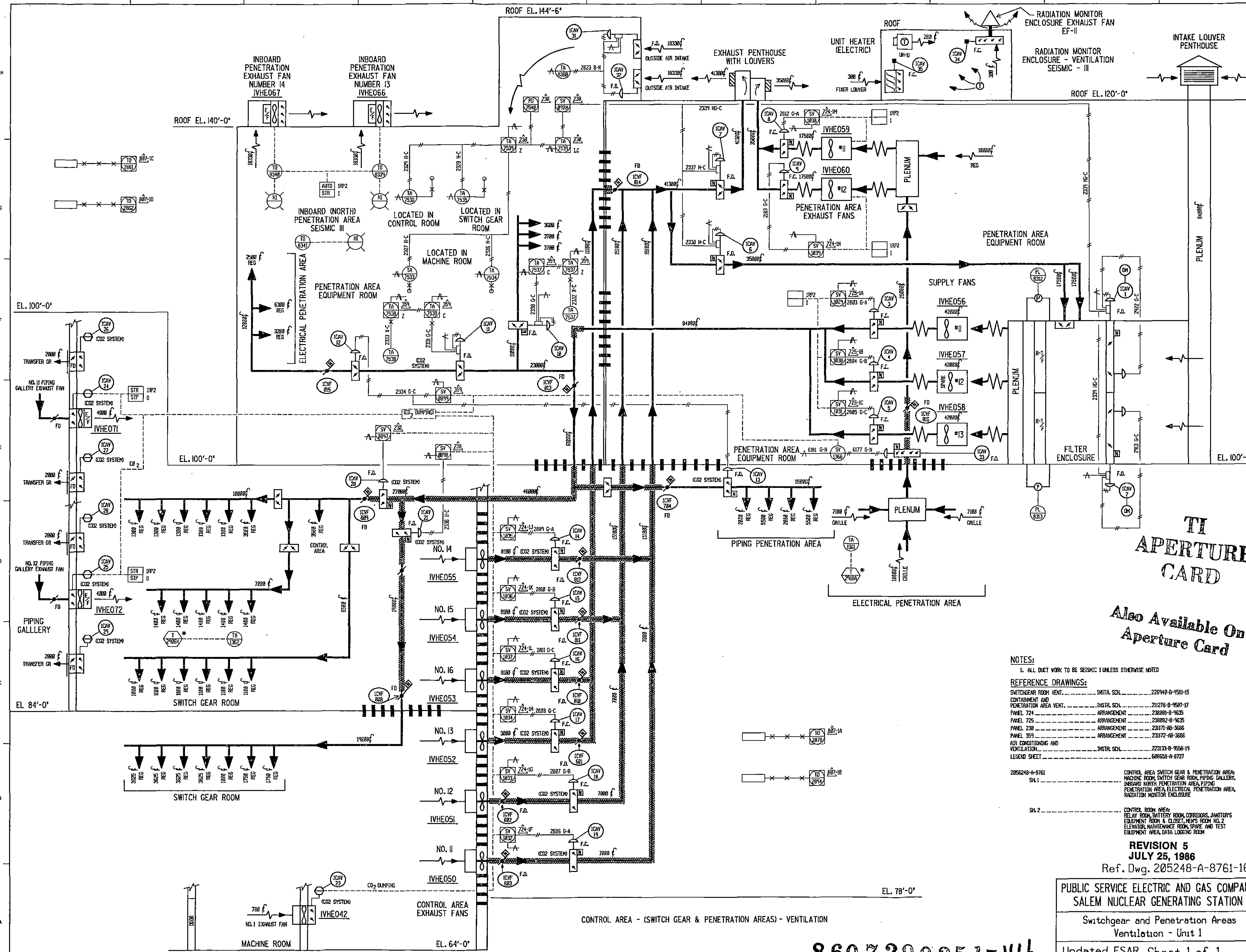
8607290251-113

REVISION 5
JULY 25, 1986
Ref. Dwg. 205322-A-8762-10

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Diesel Generator Rooms Ventilation System - Unit 2

Updated FSAR Sheet 1 of 1
Fig 9.4-5B



CONTROL AREA - (SWITCH GEAR & PENETRATION AREAS) - VENTILATION

TI APERTURE CARD

Also Available On Aperture Card

NOTES:

1. ALL DUCT WORK TO BE SEISMIC I UNLESS OTHERWISE NOTED

REFERENCE DRAWINGS:

SWITCHGEAR ROOM VENT.	INSTR. SCH.	226940-B-9581-15
CONTAINMENT AND PENETRATION AREA VENT.	INSTR. SCH.	211276-B-9507-17
PANEL 724	ARRANGEMENT	238081-B-9635
PANEL 725	ARRANGEMENT	238082-B-9635
PANEL 230	ARRANGEMENT	231171-AB-3686
PANEL 359	ARRANGEMENT	231172-AB-3686
AIR CONDITIONING AND VENTILATION	INSTR. SCH.	223133-B-9556-19
LEGEND SHEET		600658-A-8727

205248-A-8761

SH. 1 — CONTROL AREA SWITCH GEAR & PENETRATION AREA: MACHINE ROOM, SWITCH GEAR ROOM, PIPING GALLERY, INBOARD NORTH PENETRATION AREA, PIPING PENETRATION AREA, ELECTRICAL PENETRATION AREA, RADIATION MONITOR ENCLOSURE

SH. 2 — CONTROL ROOM AREA: RELAY ROOM, BATTERY ROOM, CORRIDORS, JANITOR'S EQUIPMENT ROOM & CLOSET, MEN'S ROOM NO. 2 ELEVATOR, MAINTENANCE ROOM, SPARE AND TEST EQUIPMENT AREA, DATA LOGGING ROOM

REVISION 5
JULY 25, 1986

Ref. Dwg. 205248-A-8761-16

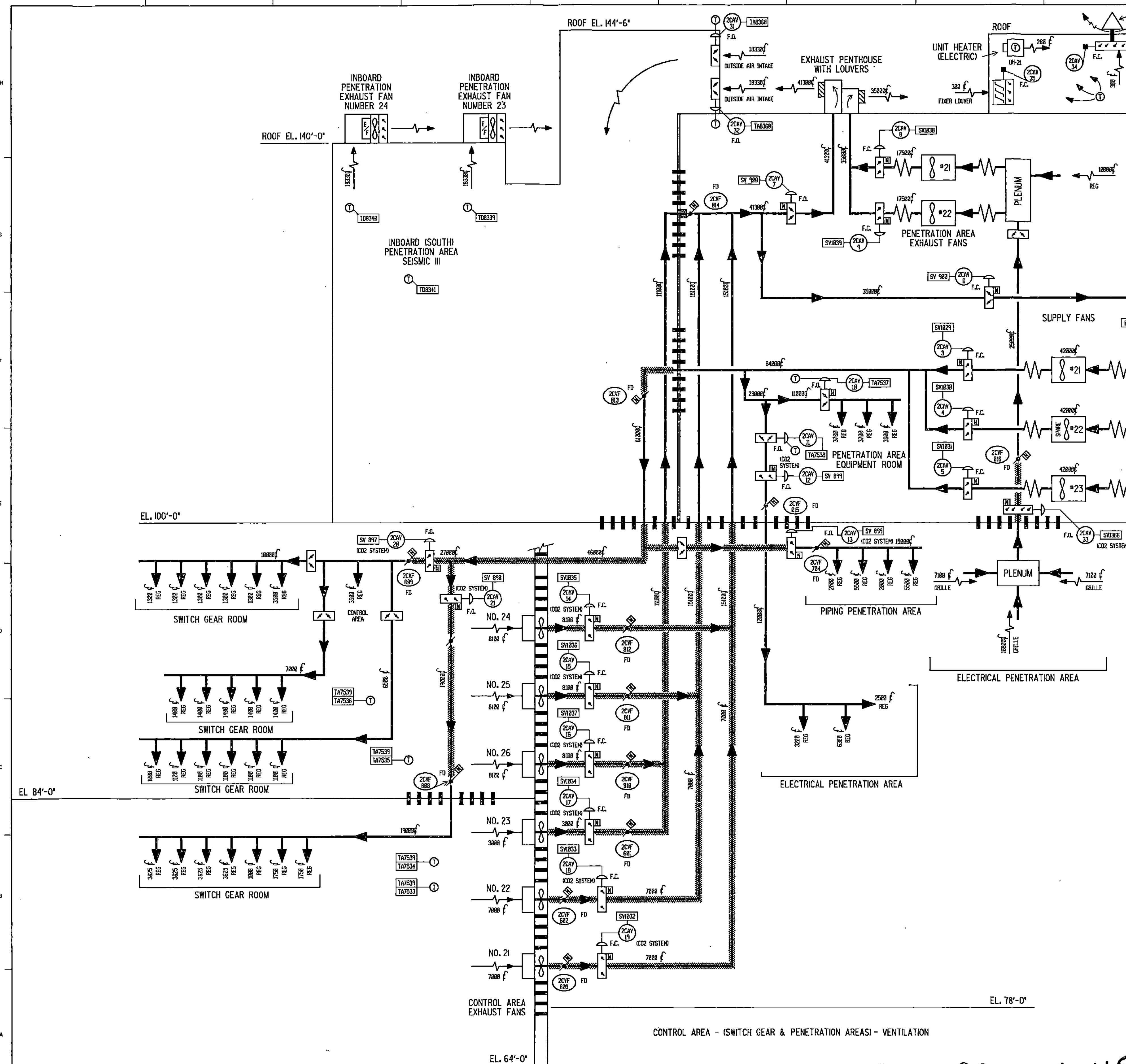
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Switchgear and Penetration Areas Ventilation - Unit 1

Updated FSAR Sheet 1 of 1

Fig 9.4-6A

8607290251-114



TI APERTURE CARD

Also Available On Aperture Card

NOTES:

1. ALL DUCT WORK TO BE SEISMIC I UNLESS OTHERWISE NOTED

REFERENCE DRAWINGS:

LEGEND SHEET 220658-A-8727

205348-A-8763

SH.1 .... CONTROL AREA SWITCH GEAR & PENETRATION AREA: SWITCH GEAR ROOM, PIPING GALLERY, INBOARD NORTH PENETRATION AREA, PIPING PENETRATION AREA, ELECTRICAL PENETRATION AREA, RADIATION MONITOR ENCLOSURE

SH.2 .... CONTROL AREA: EQUIPMENT ROOM & CLOSET, MEN'S ROOM NO.2 RELAY ROOM, BATTERY ROOM, CORRIDORS MAINTENANCE ROOM, SPARE AND TEST EQUIPMENT AREA, DATA LOGGING ROOM, ELECTRICAL EQUIPMENT ROOM.

REVISION 5
JULY 25, 1986

Ref. Dwg. 205348-A-8763-14

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Switchgear and Penetration Areas Ventilation - Unit 2

Updated FSAR Sheet 1 of 1
Fig 9.4-6B

8607290251-115

9.5 OTHER AUXILIARY SYSTEMS

9.5.1 FIRE PROTECTION SYSTEM

9.5.1.1 Design Basis

The Fire Protection Systems are designed to achieve the following objectives:

1. Provide automatic extinguishing capability using water spray, carbon dioxide or foam wherever lubricating oil or diesel fuel is stored or used.

2. Provide manually operated extinguishing equipment, either water or chemical, throughout the station.

3. Provide detection equipment in areas and locations where combustible material is concentrated and a fire would not be detected sooner by other means, and automatic protection is not provided.

4. Provide standard automatic sprinkler systems in all areas where hazardous materials are stored.

c. Comply with the Standards of the National Fire Protection Association.

6. Indicate to station personnel the location of a fire.

7. Provide protection for structures, systems, and components important to safety so that a fire will not prevent the safe shutdown of the plant.

The following Standards of the National Fire Protection Association (NFPA) have been used as guidance in the design of the Fire Protection System:

1. NFPA 10 for selection of type, the number, and the location of portable fire extinguishers, throughout the Station.

2. NFPA 11 for design of the fixed foam system for the bulk fuel oil storage tank.

3. NFPA 12 for design of the carbon dioxide systems.

4. NFPA 13 and NFPA 15 for design of sprinkler and water spray systems.

5. NFPA 20 for the design of the Fire Pump House and piping and selection of the Fire Pump. (The pump manufacturer also certified compliance with the same standard in the design and manufacture of the pumps.)

6. NFPA 12A for Halon Suppression Systems.

Where NFPA standards were not explicit, Nuclear Mutual Limited (NML) was considered to be the authority having jurisdiction and their interpretations were used.

The components, piping, and pump house for the FPS are designed to Class III (seismic) standards.

9.5.1.2 System Description

9.5.1.2.1 Water Supply Distribution System

The water supply consists of four deep wells and two storage tanks which provide a source for two fire pumps which discharge into an underground distribution system and interior headers. The Water Supply Distribution System Fire Protection Diagram is shown in Figure 9.5-1.

Two deep wells have tested capacities of 200 gpm with a 30 hp pump. One deep well (No. 5) has a tested capacity of 800 gpm. The No. 6 deep well has a tested capacity of 600 gpm. The pumps discharge into a header which is piped to the two storage tanks. Each Fresh Water Storage Tank has a capacity of 360,000 gallons of which 50,000 gallons is available for process use, and the remainder is reserved for fire protection. The tanks are interconnected by valved, 16 in. cement lined steel piping arranged so that either fire pump can take suction from either or both tanks. The tanks are of steel construction and pad mounted at grade. They are equipped with thermostatically controlled heaters and automatic level controls which are monitored in the Control Room.

Each of the two fire pumps discharge separately through 12 inch piping to an underground distribution header which encircles the station. One 6 inch and four 8 inch connections from the underground distribution main enter the Turbine and Auxiliary Buildings to supply an 8 inch header at the perimeter of the Turbine-Generator area at Elevation 88 feet and a 6 inch header through the center of the Auxiliary Building at Elevation 95 feet (approx.). The pipe is sectionalized by valves which permit the use of selected lengths in the event any section of piping is damaged.

The piping is cement lined carbon steel. The sections of pipe that are buried in the ground are coated with "X-Tru-Coat" for corrosion protection.

The 12 inch underground header also supplies five hydrants spaced at approximately 400 feet. Each hydrant is provided with a hose house containing 250 feet of 2-1/2 inch Underwriter-approved hose, appropriate accessories and a maintenance shut-off valve.

The 8 inch inside header at elevation 88 feet supplies 18 standpipes located throughout the Turbine-Generator area and Service Building. A six inch header running through the Auxiliary Building, fed from each end, supplies five standpipes in the Auxiliary Building and four inch lines to two standpipes in each containment. Valved connections with hose reels, nozzles and hose are provided on these standpipes at various levels so that all parts of the above areas are within reach of a hose stream.

If a section of distribution piping is not available, or damaged so that the most direct route of water from fire pumps is obstructed, there are 29 sectional control valves which provide one or more alternate paths to the fire. All interior control valves are monitored as to position. The distribution piping is all Schedule 40 steel, cement lined or coal tar lined, with welded steel fittings. No cast iron pipe or fittings are used.

Flow occurring anywhere in the Fire Protection System to the Auxiliary Building or the Containment areas will be alarmed on the Control Room overhead annunciator. During an actual fire this water flow alarm will be accompanied by a coded fire alarm over the station PA System, a fire alarm on the Control Room Overhead Annunciator, and a zone indicating light on the Control Room Recorder Panel 1RP5. Thus, if the water flow alarm occurs subsequently to, or simultaneously with a station fire alarm, a pipe break in the FPS is not considered; however, if the water flow alarm occurs with no corresponding station fire alarms, this is considered to be an indication of a possible pipe break in that area. The operator may then close the Auxiliary Building or Containment isolation valves remotely from the Control Room.

Each of the two fire pumps has a rated discharge of 2500 gpm at 135 psi or 3000 gpm at 125 psi. Each pump is driven by a 282 hp diesel engine mounted on a structural steel base and controlled by a combined manual and automatic panel. A pressure of 105-125 psig is maintained on the entire water distribution system by a 5 hp electric centrifugal booster pump. When a water demand reduces the normal pressure to 100 psig, one pump will start automatically and run until manually shut off. If one pump is unable to maintain pressure, the second pump will start when the pressure drops to 70 psig. If one fire pump fails to operate, the second pump is started automatically and is capable of supplying the maximum credible demand.

Fuel for each fire pump is supplied from an 8 hour day tank located in the Pump House. The 20,000 barrel fuel oil storage tank supplies fuel to the day tanks. It is protected by a mechanical foam system with a fixed discharge cone mounted in the tank. The system is supplied from a foam generator located in an adjacent enclosure. The system is manually operated, with the isolation valve monitored for open position. The system is under pressure at all times and positive operation is assured as long as the distribution piping is pressurized by the fire pumps. This system is backed up by hose lines from hydrants in the yard.

9.5.1.2.1.1 Water Protected Facilities and Areas

The following components of the lubricating oil systems are protected by water spray deluge sprinkler systems:

1. Turbine lubricating oil makeup tank.

2. Turbine lubricating oil storage tank.

3. Turbine lubricating oil reservoir, coolers and conditioner.

4. Seal oil unit.

5. Feedwater pump turbine lubricating oil coolers and tank.

6. Turbine and inboard generator bearing housings.

7. Station air compressors.

8. Reactor coolant pump lubricating oil systems.

The Generator Main Transformer banks, 25-4 kV Auxiliary Power Transformers and 13-4 kV Station Power Transformers are also protected by water deluge sprinkler systems.

Automatic recycling water spray deluge systems are provided for the following charcoal filter banks:

1. Control room emergency air conditioning system.

2. Auxiliary building exhaust - emergency filter bank.

3. Containment pressure-vacuum relief system.

4. Fuel handling ventilation system.

5. Iodine removal system (internal cleanup).

These systems operate on detection of a fire and shut down when the charcoal is cooled. They will restart if the fire re-ignites. These deluge systems have redundant operating solenoid valves; either of which will operate the system.

Automatic wet pipe sprinkler systems are provided for areas under the Turbine Generator where lubricating oil might spill or drip from pipe leaks. These systems extend from below Elevation 140 feet to below Elevation 100 feet at the sides and ends of the Turbine Generator.

Wet pipe systems are also provided for the Fire Pump House, Heating Boiler House and the Auxiliary and Service Building storage areas.

All systems are provided with alarms in the Control Room which sound any time a system operates. All principal gate valves used to shut off these systems are locked in their normal positions and are monitored in the Control Room.

No flooding is anticipated because the calculated discharge at any point of the Fire Protection System is well below the drainage capacity.

In Containment there are two (2) deluge water spray systems; one for the charcoal filter banks; the other for the oil lubrication systems of the reactor coolant pumps. Accidental flooding of the Containment; due to rupture of the water supply, is prevented by Class I (seismic) valves located inside and outside the containment wall. The water used for fire fighting in the Auxiliary and Containment buildings may become radioactively contaminated. In these areas, the largest charcoal filter bank deluge system discharges 100 gallons per minute and is arranged to shut off one minute after the fire detector resets. A floor drain, 4 inches in diameter, in the immediate vicinity of each charcoal filter bank, directs the drainage or deluge water to the waste hold-up tanks, either directly or via sump pumps. The drain piping system is welded, Schedule 10, ASTM A312, Grade TP 304 or TP 304 L stainless steel pipe having certificates of compliance. The entire drainage system is tested in accordance with ANSI B31.1-1967.

The reactor coolant pump deluge systems discharges 100 gpm and must be shut off manually. The discharge from these systems is directed to two 275 gallon reactor coolant pump oil drain tanks that are designed to act as oil skimming tanks. These tanks retain the oil and allow the water to drain to the containment sumps. From there it is pumped by one of two 100 gpm sump pumps to one of two 25,000 gallon waste holdup tanks. Assuming that a tank is half full when a system starts to operate, it would take two hours for the tank to be filled. The sump pump discharge can then be diverted to the other holdup tank, or the supply can be shut off remotely at the containment wall.

Water suppression is provided for the charging pumps. Redundant Water Suppression Systems are provided for the auxiliary feedwater pumps.

9.5.1.2.1.2 Water Protected Facilities Detection Systems

All deluge systems (except those in charcoal filter banks) are actuated by a detection system using fusible pilot line sprinkler heads. These are used alternately with thermostatically operated releases in some locations. Except for the reactor coolant pump oil lift pump fire protection which is an interior system and is air operated, all the pilot lines are water operated on interior systems and air operated on exterior systems. The operation of any sprinkler or thermostat releases the water or air pressure and trips the deluge valve.

Automatic wet pipe sprinklers are actuated by individually fused heads.

In charcoal filter banks, timed recycling deluge systems are used in order to minimize total water discharge. Continuous thermistor strip fire detection tubing is used in these systems and is self-resetting when the heat source is removed. When the thermistor strip resets, the valve resets, stopping water discharge after a present minimum time. If the fire re-ignites, the system will operate again. A manual control can override automatic operation if necessary.

The charcoal filter fire detection and water spray actuation circuits are supervised by zone and a trouble alarm will occur if there is a malfunction in a circuit. Each charcoal filter is assigned to a separate zone and therefore, a failure of a circuit in one zone will not affect the operation of the fire provisions for the charcoal filters in other zones.

The arrangement of the charcoal filter banks offers easy access for manual fire fighting in the event that deluge water should be unavailable. Self-contained breathing apparatus is also readily available.

9.5.1.2.1.3 Manual Fire Protection (Water)

Manual fire protection equipment is provided for the following areas and facilities:

1. Hydrants and fire hose are available in the yard surrounding the plant for use on any equipment, and as back-up for the water spray systems on transformers, sprinkler systems in the Pump House and Heating Boiler House and the foam system on the Bulk Fuel Oil Storage Tank. These hydrants are accessible at all times.

2. The manually-controlled foam system on the Bulk Fuel Oil Storage Tank is located in the yard, away from all buildings and is accessible at all times.

3. The manually-operated hose stations located in all levels of the Turbine-Generator Area are accessible at all times to back up the protected equipment and to provide fire protection for any temporarily located combustible material in areas which normally contain no combustibles.

4. The manually-operated hose stations in the Service Building are accessible at all times to provide back-up for this area.

The manually-operated hose stations in the Auxiliary Building are accessible for back-up of the automatic sprinklers in the Baling and Storage areas and for protection against fire in any packing materials, etc. not normally present in this building.

There are manually-operated hose stations in the containment. These can be used for back-up for deluge systems in the Charcoal Filter Banks and the oil systems of the reactor coolant pumps. There are no other combustibles normally present in the containment.

9.5.1.2.2 Carbon Dioxide Supply Distribution System

Carbon dioxide for each section of the Auxiliary Building is stored in a 10 ton refrigerated storage tank located near the diesel oil storage tanks at Elevation 84 feet. One 750 lb. tank is provided for the generator exciter enclosure on each unit. The Bulk CO_2 storage capacity is sufficient to flood the largest zone twice. A diesel compartment or a diesel fuel storage room could be flooded 4 or more times.

The operating and design pressures of the CO_2 storage tanks in the FPS are 300 psi and 363 psi, respectively. The CO_2 storage tanks have multiple safety devices: In the event of failure of the refrigeration compressors, an alarm sounds when the tank pressure rises to 325 psi. A bleeder relieves the pressure when it rises to 341 psi, causing the tank to self-refrigerate by boiling off and will lose its charge intermittently for a number of days until the charge is exhausted. If the pressure continues to rise beyond the capacity of the bleeder valve a safety valve (one of two) will open at 357 psi. A low pressure alarm is received at 290 psi. The storage tanks are designed and constructed in accordance with the ASME Unfired Pressure Vessel Code.

Diesel oil storage tanks are protected from any CO_2 tank missiles by reinforced concrete walls 2 feet thick and the transfer pumps are protected by 1 foot thick walls.

A 4 ton tank, used for generator purging, is not connected to any fire protection system. This tank also also has a design/operating pressure of 363/300 psi.

A 2 ton tank is provided for fire protection in the structure housing the gas turbine unit.

9.5.1.2.2.1 Carbon Dioxide Protected Facilities

Automatic CO_2 systems are installed in the diesel-generator rooms, diesel fuel tank rooms, fuel transfer pump rooms and the generator exciter enclosures. Each of these spaces is provided with an independent, once-through ventilation system. The use of independent systems enhances the effectiveness of the carbon dioxide flooding system in the event of a fire, permitting selective flooding into a given space without affecting other spaces. In the event carbon dioxide is delivered to a space, the ventilation for that space is automatically terminated.

The three diesel generators, three diesel engine control rooms and two diesel fuel tanks and their pumping units for each unit are in compartments separated by fire walls. Each engine compartment and its associated control room are on a common fire zone and have a separate line and actuating valve from the carbon dioxide supply.

The exciter housing on each unit houses the end bearing of the generator and is protected by a small carbon dioxide supply unit located below it at Elevation 120 feet.

Manual CO_2 systems are installed in the switchgear room and electrical penetration areas and activation of CO_2 discharge is by positive action valves. Notification of fire in these rooms is by combustion products detectors installed in supervised circuits. Failure in the circuit results in notification of trouble. Hose and hand chemical extinguishers are provided for backup.

Carbon dioxide is dispersed into protected areas with wide diffuser nozzles. The velocity of the CO_2 exiting the nozzles is low, even in near proximity to the nozzle. Nozzles are located along the ceiling or several feet below the ceiling, well above the equipment being protected. Thus, the effect of CO_2 impinging upon the equipment is negligible. In addition, electrical equipment is located in cabinets further protecting the internals from any direct CO_2 impingement.

9.5.1.2.2.2 Carbon Dioxide Protected Facilities Detection Systems

Electrically operated thermal rate-of-rise thermostats are used to actuate the total flooding carbon dioxide systems in the compartments housing the diesel generators, their control rooms and fuel tanks. The thermostats are wired on a supervised circuit. The exciter enclosures are similarly protected. The rate-of-rise element is backed up by a fixed temperature element. Failure of the circuit results in notification of trouble. Failure of the automatically operated CO_2 valves leaves manual operation possible. Manual CO_2 operation is backed up by hand-held chemical extinguishers and hose.

All CO_2 protected areas are monitored by ionization type combustion product detectors. These detectors alarm in the Control Room, but do not actuate the carbon dioxide system.

9.5.1.2.3 Halon 1301 Supply Distribution System

The Halon 1301 Fire Extinguisher Systems provide an effective and reliable means of extinguishing fires in the Relay Rooms of Units No. 1 and No. 2 while minimizing the effect on equipment and hazard to personnel.

Each Relay Room has an independent extinguishing system capable of total discharge of either main or reserve charges of fire extinguishing agent within approximately ten seconds of activation. The main and reserve charges are of equal size and each consists of eight Halon cylinders, divided equally into an east and west bank. Discharge of the selected charge results in an initial Halon 1301 concentration of 7% by volume. The reserve charge is provided to supplement the main charge for the purpose of maintaining a minimum Halon concentration of 5% over a minimum time period of twenty minutes. The time-concentration capability provides a considerable margin of safety in extinguishing difficult electrical fires in the Relay Rooms.

The Halon systems are designed to be activated either automatically or manually. Automatic actuation occurs upon receipt of a coincident signal from both zones of a cross-zone Fire Detection System. Manual actuation is accomplished by using the remote pull station, located near the Relay Room entrance from the Service Building (Elevation 113 ft. or 100 ft.), or by utilizing the STRIKE button on the front cover of the Halon control panel, located in the corridor between Relay Rooms (Elevation 100 ft.). Also, individual discharge of each Halon cylinder, located in the corridor between Relay Rooms (Elevation 100 ft.), can be affected by depressing the pushbutton on the actuator of the cylinder discharge valves.

Primary components of the Halon 1301 systems are the main and reserve Halon storage cylinders with discharge valves and actuators, Halon discharge nozzles, and interconnecting piping. Control panels, housing and nitrogen actuation cartridges are located near the storage cylinders in the corridor between the Relay Rooms (Elevation 100 ft.). Piping between the control panels and the cylinder valve actuators carries the pneumatic signal that discharges the cylinders. Sample stations (one for each Relay Room) located in this same corridor provide the capability to withdraw room air samples for measurement of Halon concentration following system discharge.

9.5.1.2.3.1 Halon 1301 Protected Facilities

The Halon 1301 is installed within the Relay Rooms for Units No. 1 and No. 2.

9.5.1.2.3.2 Halon 1301 Protected Facilities Detection Systems

The Halon System is activated by a contact from the cross-zone Fire Detection System processed through the Fire Protection System logic cabinets. Upon receipt of coincident signals from both zones of the detection system, nitrogen actuation gas is released from cartridges located within the Halon control panels. The nitrogen pressure actuates the Halon cylinder discharge valves and allows Halon to discharge from the cylinders and out through the nozzles located within the Relay Rooms. The determination of which charge, main or reserve, is released, is made by the position of the MAIN/RESERVE switch located near the Halon control panel. A pressure switch located in the nitrogen piping leading to the Halon cylinder discharge valves provides a signal, upon Halon system actuation, to close air conditioning dampers 1CAA-31, 1CAA-32, 1CAA-33, 1CAA-34, 1CAF-202, and 1CAF-203, for No. 1 Unit and 2CAA-31, 2CAA-32, 2CAA-33, 2CAA-34, 2CAF-202, and 2CAF-203 for No. 2 Unit, thereby isolating the Relay Room to prevent outleakage of discharging Halon gas. This pressure switch signal is also used to shut down the battery exhaust fan and to illuminate the warning signs at each entrance to the Relay Room and the "CO_2/HALON DISCHARGE" light on the Fire Protection System Panel.

9.5.1.2.4 Fire Separation and Detection Features

Where possible, equipment is separated to prevent a single fire from damaging both trains of redundant equipment. For example, the two Residual Heat Removal pumps are in separate concrete enclosed rooms so that a fire in one room cannot progress beyond the room boundary. Also, the two motor driven auxiliary feedwater pumps are totally separated from the steam turbine driven auxiliary feedwater pump.

Smoke detectors are placed throughout the plant as required by fire hazards analysis. For example, smoke detectors are in the area of power feeds to the redundant diesel generators; also in the Control Room, and the Relay Room.

9.5.1.2.5 Control Room Area Fire Safety Features

In order to minimize the potential of fire in the Control Room, Relay Room or other electrical equipment rooms, the following safety features are provided:

1. Ionization type smoke detectors are located in the Relay Room, Control Room Console and Control Room ceiling void space. Also, all peripheral rooms within the control room complex (within the 3 hr. fire rated walls) have automatic smoke detectors.

2. The Control Room Console is of steel construction and contains low voltage (28 Volt dc) control modules, primarily.

3. Fire-resistant, flame retardant cable of teflon or ethylene-propylene rubber, jacketed with neoprene, are employed in the Control Room console.

4. The Control Room is protected from infiltration of air from other rooms in the control area and the entire control area is protected from infiltration of fire, smoke or airborne radioactivity from other areas of the Auxiliary Building by minimum leakage penetrations, weather stripped doors, absence of outside windows and maintenance of a positive air pressure in the rooms during normal operation.

5. Smoke and combustibles detection devices located in the air conditioning unit ducts provide warning so that steps can be taken to minimize any hazard by operating the system in the proper mode.

6. Control areas contain a minimum amount of combustible material. Physical separation of the equipment and redundant cable paths minimize damage in the unlikely event of a fire. Cabling provisions related to fire protection are further discussed in Chapter 8.

9.5.1.2.6 Structure Fire Protection

The plant is constructed entirely of noncombustible materials. Floors and walls are reinforced concrete and columns are structural steel. Suspended ceilings are noncombustible and suspended by steel hangars.

The two units are separated by a 3-hour rated fire wall (except between the control rooms on elevation 122') and the two containment structures are 172 feet apart on their nearest point. Other areas separated by 3-hour rated fire walls are:

1. Administration and Service Buildings from Turbine Generator area.

2. Service Building from Auxiliary Building.

3. Auxiliary Building from Containment.

4. Fuel Handling Building from Containment.

5. Diesel Generator rooms from each other and from Auxiliary Building.

Walls rated at 2-hours separate the Turbine-Generator Area from the main and auxiliary transformers, and the individual transformers.

The house heating boiler house is protected by sprinklers. It is 33 feet from the fire protection and domestic water storage tanks and 240 feet from the turbine generator area.

The bulk fuel oil storage tank is 290 feet from the nearest facility and the demineralized water tanks, and 400 feet from the turbine generator area.

9.5.1.2.7 Reactor Coolant Pump Oil Drain Tank

A seismically qualified lube oil collection system is provided to drain reactor coolant pump lube oil to a contained location away from the pump. Thus, accumulations of oil near the Reactor Coolant System pressure boundary, with the consequent fire hazard, is prevented.

9.5.1.2.8 Fire Protection System Power Supply

1. Fixed Water Spray Fire Protection Systems: 115 Volt AC, backed up by static inverters.

2. Ionization Detection System: 115 Volt AC, backed up static inverters.

3. Carbon Dioxide Storage Tank Refrigeration Compressor: 10 ton capacity unit, 460 Volt AC.

4. Carbon Dioxide Storage Tank Refrigeration Compressor: 750 lb. capacity unit, 115 Volt AC inverter backed up by 230 Volt AC vital bus with step down transformer.

5. Control Room Annunciators: 115 Volt AC, backed up by static inverters.

6. Carbon Dioxide Flooding Control Systems: 115 Volt AC inverter backed up by 230 Volt AC vital bus with step down transformer.

9.5.1.3 Design Evaluation

A reliable water supply of 600,000 gallons is provided and piped to all levels of all buildings, with the supply lines sectionalized by valves for isolation in the event of damage to any section of the line. The components, piping, and pump house for the Fire Protection System (FPS) are designed to Class III (seismic) standards. Water spray systems are provided at high-hazard locations, with hand hoses available at all other points.

Operation of the FPS does not cause flooding in any Class I (seismic) structure, system or component because the calculated discharge of any FPS system is well below the capacity of the drainage facilities available. In the Containment, there are two types of deluge water spray systems; one for the charcoal filter banks and the other for the Reactor Coolant Pump. System operation is indicated in the control room. Any one of the systems in the containment discharges no more than 100 gpm, which is accomodated by the drainage system. Accidental flooding of the containment due to rupture of the water supply is prevent by Class I (seismic) valves located inside and outside the containment wall.

In addition to the hand hoses available throughout, an adequate complement of wheeled and hand held extinguishers are provided, both carbon dioxide and dry chemical, as applicable.

In areas where carbon dioxide flooding systems are installed, warning signs are placed at entrances, and self-contained breathing equipment is readily available.

The actuation valves in water spray deluge systems are operated by venting either air or water from the top of the valve operator through a detector head, thus providing a reliable means of operation.

Water spray deluge systems, except the recycling systems on the charcoal filters, are equipped with means to operate the system on failure or damage to the actuating system. In the event of failure of a deluge valve, an alarm is initiated and the fire can be attacked manually with hoses.

The recycling deluge systems on the charcoal filters have reduntant operating solenoid valves, either of which will operate the system. Failure of both valves to operate is extremely improbable but if such should occur, the activating system alarm will alert personnel so that the fire can be attacked manually with hoses.

Water spray deluge systems in the Turbine-Generator Building have surrounding adjacent wet pipe sprinkler systems which will operate to prevent the spread of fire.

Detection systems are provided in conjunction with the protection and in areas where no automatic protection is provided. The station buildings and grounds are divided into fire protection zones with each zone equipped with fire detectors and/or manual fire alarm stations. Coded fire alarms will sound over the public address system upon detection of a fire or a pulled fire alarm to alert station personnel. The operator will also have zone indication alarms available in the Control Room.

The separate detection circuits provided for each fire protection zone are supervised and will alarm in the Control Room in the event of detection circuit malfunction. The failure of a detection circuit will not affect the detection circuits of other zones. All areas are equipped with manually-actuated fire alarm stations in addition to the automatic detectors. Malfunction of a manual fire alarm station circuit may actuate a fire alarm signal in the control room.

A failure in the audible alarm circuitry will cause inoperability of the coded fire alarm signals which are heard on the public address system. However, zone indication will still be available to the operator in the Control Room. Conversely, loss of zone indication alarms in the Control Room will not affect the coded fire alarm signals.

The station fire brigade will receive periodic instruction in fire-fighting techniques and fire drills will be held periodically. The fire brigade will have portable radios with necessary repeater stations to assist in communications. Manual access for fire fighting is provided by exhaust ventilation systems which provide for smoke and heat removal.

9.5.1.4 Compliance With 10CFR50 Appendix R

Appendix R to 10CFR50 requires certain features to be backfitted into the FPS, even if the FPS had been previously approved by the NRC. The Salem FPS was approved in the Fire Protection Safety Evaluation Report dated November 20, 1979. The provisions of Appendix R which apply to Salem are the following:

1. Fire Protection of Safe Shutdown Capability (Appendix R III.G).

2. Emergency Lighting (Appendix R III.J).

3. Oil Collection System for Reactor Coolant Pump (Appendix R III.O).

Public Service has complied with these requirements as noted in the following sections.

9.5.1.4.1 Fire Protection for Safe Shutdown

In order to determine that the Salem Plant's safe shutdown capability is protected from fire, an analysis was performed and documented in a report titled "Safe Shutdown and Interaction Analyses" dated September 1981 and in a report supplement dated June 1982. As well as documenting the evaluation of the fire protection features, the report also documented a number of design changes which would be made in order to enhance safe shutdown capability. These changes include installing fire barriers and radiant energy shields, where appropriate, to provide separation of the safe shutdown redundant trains where required. Another design change provides alternate shutdown capability. This includes procedural measures and installation of new instrumentation to monitor plant shutdown from outside the relay room and control room. Separate power supplies and signal conditioners are also installed exclusively for the alternate shutdown capability.

In a letter dated March 19, 1981, concerning compliance with fire protection backfit items, PSEG requested four exemptions from the requirements of 10CFR50, Appendix R, Section III.G. One of these requests regarding fire protection for the auxiliary feedwater pump room was later withdrawn. The following requests were approved in a commission order dated September 16, 1982:

1. Use of fire doors and/or fire dampers rated for 1-1/2 hours rather than a three hour fire barrier as required by Item III.G.2a.

2. Substitution of portable fire extinguishers for a fixed fire suppression system in the control room area as required by Item III.G.3.

The final exemption request is for the use of one hour fire barriers in some areas without an automatic fire suppression system as required by Item III.G.2c. To support this request, a (final) report entitled, "Fire Protection Program - Area by Area Analyses to Support Exemption Request," was submitted by letter dated April 29, 1982. Supplemental information was submitted by letter dated November 1, 1982.

In a letter dated March 19, 1981, concerning compliance with fire protection backfit items, PSEG requested four exemptions from the requirements of 10CFR50, Appendix R, Section III.G. One of these requests regarding fire protection for the auxiliary feedwater pump room was later withdrawn. The following requests were approved in a commission order dated September 16, 1982:

1. Use of fire doors and/or fire dampers rated for 1-1/2 hours rather than a three hour fire barrier as required by Item III.G.2a.

2. Substitution of portable fire extinguishers for a fixed fire suppression system in the control room area as required by Item III.G.3.

The final exemption request is for the use of one hour fire barriers in some areas without an automatic fire suppression system as required by Item III.G.2c. To support this request, a (final) report entitled, "Fire Protection Program - Area by Area Analyses to Support Exemption Request," was submitted by letter dated April 29, 1982. Supplemental information was submitted by letter dated November 1, 1982. This exemption request was approved in a Commission letter dated June 17, 1983.

In Generic Letter 83-33 the NRC Staff took an interpretation of Appendix R which deviated significantly from the definitions used by PSEG up to that point. Plant-specific definitions used by PSEG had been developed following the criteria used by the Staff in their earlier review of the Salem fire protection program. As a result, additional exemptions were requested in a letter dated January 31, 1984, (Liden to Varga). The requested exemptions are of the following general types and seek relief from the explicit wording of Appendix R as interpreted in Generic Letter 83-33:

A. Use of area wide automatic suppression and/or detection system.

B. Certain area boundaries not 3-hour rated.

C. Less than 20 foot separation between major pumps.

D. Use of manually-actuated suppression system.

E. One hour barriers and/or extent of cubicle separation between components.

During January 1984 the NRC Staff and its consultants performed a comprehensive inspection of Unit 1 to assess compliance with Appendix R. In a letter dated January 27, 1984 (Liden to Varga) PSEG responded to concerns identified by the review team and concluded that none represented a significant degradation of the fire protection program.

9.5.1.4.2 Emergency Lighting

The required features are described in Section 9.5.3.

9.5.1.4.3 Reactor Coolant Pump Oil Collection System

The required features are described in Section 9.5.1.2.

9.5.1.5 Tests and Inspections

All open head deluge systems are tested manually and automatically at full flow when installed. Systems are tested annually thereafter, with every valve being tripped at least once.

Fire pumps are initially tested at rated capacity and 150 percent of rated capacity with flow monitored at discharge nozzles and calibrated orifice meters simultaneously. Subsequent tests are performed with water recirculating to the tanks rather than discharging outside. Fire pumps are tested weekly, using recording gages to monitor the operation.

Carbon dioxide systems are tested at full flow at installation. Tank levels are monitored in the Control Room.

All of the fire detection systems are of the supervised circuit type. In this way a continuous check is made of the operability of all circuits.

9.5.2 COMMUNICATIONS SYSTEM

The plant communications systems provide an effective means to coordinate activities during conditions of normal operation, maintenance and accidents.

9.5.2.1 Page-Party System

The Page-Party system is a completely transistorized voice communication system which is capable of operation in extreme environmental conditions such as dust, moisture, heat and noise. The system consists of two separate and independently wired communication channels are provided for page and party.

The page channel is connected to all plant loudspeakers and may be used to call personnel or issue plantwide instructions. Also, a multi-tone generator provides procedural and alarm signals which can be broadcast throughout the plant. Examples of such signals are start and stop whistles, lunch, fire, and radiation alert. The page channel can also be used for direct communication between individual personnel at separate handset locations, however, this conversation will be heard over all unsilenced speakers.

The party line is used to carry on conversations which can be heard by anyone picking up a heandset. While the party line is in used others can utilize the page channel. Simultaneous conversations can take place, one on each channel.

Closed channel communication is provided between fuel loading areas (Reactor Containment, Fuel Handling Building and Control Room) by means of separately wired page and party line connected between these locations for closed circuit communications.

Power for the communication system is 120 volt A. C., inverted from a D. C. source. This is to insure the continuous availability of plant wide communications during a power failure and to provide uninterruptable communications with the Newark Load Dispatcher. If the inverter fails, power will be derived from a 230 V AC vital bus.

9.5.2.2 Telephone System

Three telephones are located in each Control Room. Two of them are direct lines to the Load Dispatcher and the other is a house phone. Direct lines are also provided in the Aministration Building Conference Room and tie in directly to the New Jersey Bell Telephone Company. These lines are for emergency use and insure communications between the Conference Room and the Telephone Company.

In addition, an interface amplified assembly is provided to permit the Newark Load Dispatcher to transmit voice instructions directly over the station page line, via a telephone link to the plant.

9.5.2.3 Closed Circuit Television System

A closed circuit TV system provides intermittant television monitoring of equipment inside containment. Portable underwatr television equipment is provided for the Fuel Handling Building and for scanning the inside of large vessels.

Each containment building has three television cameras mounted on the containment liner, 120 degrees apart, at an elevation of approximately 205 feet. Each containment camera has a zoom lens and a pan and tilt control unit. Each containment camera is provided with a 14 inch television monitor in the Control Room. Below each television monitor there is a control panel for operating the television camera, the zoom lens and the pan and tilt unit. Also, adjacent to the T. V. monitors there is a switch for turning the lights in the containment on and off.

Underwater equipment consists of four underwater cameras each with its own zoom lens, pan and tilt unit and 9 inch monitor. Two sets of portable lights are provided for underwater illumination. Monitors and camera controls are mounted on a movable T. V. table

Video tape recorders are provided with any of the T. V. cameras.

9.5.2.4 Radio Repeater System

A system of portable transceivers and fixed repeaters is provided for the fire brigade.

9.5.3 LIGHTING SYSTEM

The lighting system provides necessary illumination for day-to-day plant operation and adequate illumination for safe shutdown and personnel safety.

9.5.3.1 Emergency Lighting

Power for emergency lighting within the plant is distributed by Lighting Distribution Panels (LDP) 1ELD and 1ELC (2ELD and 2ELC for Unit 2). LDP 1ELD (2ELD for Unit 2) contains two separate distribution buses. One bus within LDP 1ELD (2ELD) is supplied either from Lighting Inverter 11 (21) or from 2309 volt AC vital bus 1A (2A) through a lighting transformer. A bus transfer switch in the output of inverter 11(21) automatically switches from the inverter output to AC vital bus 1A (2A) if a loss of inverter output power is sensed. Lighting Inverter 11(21) is powered by battery 1A (2A). The second bus within LDP 1ELD (2ELD) is supplied in a similar manner from Lighting Inverter 12 (22), 230 volt AC vital bus 1B (2B), battery 1B (2B) and a bus transfer switch. LDP 1ELC (2ELC) is powered from lighting inverter 13 (23) and 230 volt AC vital bus 1B (2B), with automatic switchover accomplished by a bus transfer switch in the same way as described above. Inverter 13 (23) receives power from an auctioneering rectifier circuit which is powered from battery 1A (2A) or 230 volt AC vital bus 1C (2C).

Areas of the plant requiring operator access for safe shutdown are provided with self-contained emergency lights. These units are battery powered and have an 8 hour capacity. The battery supports are designed to withstand seismic forces.

9.5.3.2 Normal Lighting

Power for normal lighting within the plant is distributed through 12 lighting distribution panels (LDP) and 61 lighting panel boards (LP). Normal lighting LDPs in the main plant receive power from 4 KV buses 1H and 1F (2H and 2F for Unit 2) and substations 1HL and 1FL (2HL and 2FL for Unit 2). One Lighting Panelboard in the reactor area of each unit is cross fed from the opposite unit substation (1FL for Unit 2 and 2FL for Unit 1). Most of the LPs are fed from LDPs; however, LPs serving the following areas receive power from local motor control centers: Service Water Intake Area, Circulating Water Intake Area, Fire Pump House, Heating Boiler House, Guardhouse and Guardhouse Extension.

In most area where mercury vapor or fluorescent lighting is used, such as in the Turbine Building and Auxiliary Building, lighting is switched directly from the LP's. However, in the Reactor Containments, Fuel Handling Areas, Service Building, and Administration Building, special switching arrangements have been provided.

Containment Area Lighting is controlled by lighting contractors located on Elevation 64 in the Auxiliary Building. These contractors can be switched from personnel hatches and from the Control Rooms. Remote switching is provided because of the inaccessibility of the Containment Areas while the Reactors are in operation and the occasional need for closed circuit TV surveillance.

Lighting in Fuel Handling Areas (which are normally unoccupied) is controlled from a panel located in the electrical equipment room on Elevation 100. Lighting for building access is controlled from switches located near the equipment room doors and at the door on Elevation 130 entering staircase No. 10 (No. 1 Unit) and staircase No. 11 (No. 2 Unit).

Conventional commericial building switching arrangements are employed in office and laboratory areas such as those located in the Administration and Service Buildings.

9.5.4 DIESEL GENERATOR FUEL STORAGE AND TRANSFER SYSTEM

The diesel fuel oil system stores and supplies the diesel generators with No. 2 diesel fuel. The system flow diagram is shown in Figure 9.5-2, and also includes other portions of the fuel oil system. The diesel generator fuel oil system is Seismic Class 1.

The 30,000 gallon Fuel Oil Storage tanks per unit are the source of fuel oil supply for the diesel generators. These tanks can be filled from the 20,000 barrel Fuel Oil Storage tank or via the emergency truck connection provided in the diesel generator area. Each 30,000 gallon fuel oil storage tank can supply one diesel with enough oil to run it for seven days at full load.

Each diesel draws fuel from its own 550 gal. diesel day tank located above the engine on the 120 ft. elevation of the Auxiliary Building. Day tanks are accessible only by ladder from the diesel engine room.

Two fuel oil transfer pumps per unit are used to transfer fuel oil to the diesel day tanks from four 30,000 gal. storage tanks located on the 84 feet level of the Auxiliary Building. Each of the fuel oil transfer pumps has a REGULAR-BACKUP selector switch and an OFF-AUTO-MAN selector switch. Level switches in each day tank start one of the two fuel transfer pumps when oil level in any day tank falls below one-third full. The transfer pump continues to operate until all three day tanks are full. Should the transfer pump fail to operate and level drops to one-fourth capacity, another level switch will give a "FUEL OIL DAY TANK LEVEL LOW" alarm and start the backup fuel transfer pumps. Should the pump fail to shut off when all tanks are full or should oil in one tank reach the tank overflow, a level switch will stop the transfer pump and give a "Fuel Oil Day Tank Level High" alarm. A gage glass is also installed on the side of each day tank.

Fuel oil is supplied by gravity to the engine mounted fuel oil booser pump by two parallel lines which join at the inlet to the primary duplex filter. The pump discharges 5 gpm at 40 to 45 psi and a relief valve on the discharge will bypass fuel to the inlet of the pump if pressure exceeds 75 psia. From the pump the fuel is filtered again by the secondary duplex filter and is supplied to the individual fuel oil injection pumps. A pressure regulator maintains fuel oil pressure in the engine fuel oil header. The regulator diverts oil to the day tank if header pressure exceeds 45 psi.

Local pressure gages are provided to read pressure drop across the primary and secondary filters, fuel oil header pressure, and both fuel transfer pump discharges.

Measures have been taken to satisfy the intent of the fuel oil quality asurance requirements of Regulatory Guide 1.137, Position C.2.b. In addition to classifying diesel fuel as a safety-related material within the Salem quality assurance program, the following procedural requirements have been specified:

1. A fuel oil sample is taken from each truck delivering fuel oil to Salem, except when several trucks arrive at once, a minimum of 1 in 4 trucks is sampled.

2. All newly received fuel oil is pumped into the 20,000 barrel Fuel Oil Storage Tank. Fuel Oil in third tank is sampled at least once every 30 days.

3. Fuel oil in each of the four 30,000 gallon Diesel Fuel Oil Storage Tanks is sampled as required by the Salem Technical Specifications.

4. All fuel oil samples taken in items 1-3 above are sent to an independent laboratory within 48 hours of the time the sample was taken. The analysis performed by the laboratory will be consistent

with Regulatory Guide 1.137 and the analysis report is submitted to the Salem Station within 30 days of receipt of the sample at the laboratory. If reports indicate that fuel oil quality is not within acceptable limits, appropriate action will be taken to restore it to within acceptable limits.

5. Fuel oil deliveries, samples taken and related analysis reports will be logged at the station.

9.5.5 DIESEL GENERATOR JACKET WATER COOLING SYSTEM

The jacket cooling water system controls the operating temperature of the diesel engine by removing diesel engine heat. The jacket water cooling system is Seismic Class 1.

Thw engine driven jacket water pump circulates cooling water through the engine manifold and turbocharger, to a 3-way thermostatically controlled valve. The 3-way valve is set to maintain engine water temperature at 170°F. If water temperature sensed at the suction to the jacket water pump is high, the valve automatically directs the system water through the jacket water heat exchanger where it is cooled by the Service Water System. If the water temperature is low, the valve automatically bypasses the jacket water heat exchanger. Temperature switches are provided at the manifold outlet to give a "Jacket Water High Temperature:" alarm if water temperature exceeds 175°F and to trip the diesel if water temperature exceeds 195°F.

Make-up water to the jacket cooling water system is suplied to the expansion tank from the station demineralized water system. Control of the make-up water flow is provided by a ball-float valve mounted inside the expansion tank. A gage glass and a level switch for an "Expansion Tank and a level switch for an "Expansion Tank Hi-Lo Level" alarm are provided.

Immersion heaters are installed in the engine water manifold to maintain water temperature near 120°F. The heaters are controlled by a temperature switch that energizes the heaters when water temperature drops below 90°F and deenergizes the heaters when the temperature exceeds 120°F. A second temperature switch gives a "Jacket Water Heater Failure" alarm if the water temperature falls below 80°F or exceeds 130°F with the diesels in a shut-down conditions. The jacket water system is also supplied with an after-cooler heater. This 2 Kw thermostatically controlled heater maintains water temperature in after-cooler piping when engines are not in operation.

9.5.6 DIESEL GENERATOR STARTING AIR SYSTEM

The starting air system supplied compressed air to the diesel engine air starting motors. The starting air system is seismic class 1.

The starting air system for each diesel generator consists of two motor driven air compressors and two starting air receiver tanks. Each receiver is sized to hold sufficient air for three cold diesel starts. Compressors are designed for automatic unloading at start-up and can operate either in the manual mode or in the automatic mode with unloading controlled by air pressure in the receiver tanks.

A pressure switch located at the compressor discharge starts the compressor when receiver air pressure falls below 225 psig and stops the compressor when pressure reaches 250 psig. The discharge line is protected by a relief valve set at 275 psi and the receivers are protected by relief valves set at 260 psi.

Each diesel generator is equipped with four air start motors all of which in an emergency can be supplied by a single receiver In additon, receivers are interconnected so that they can be filled by either or both compressors. If necessary, the diesel can be started by any two motors.

Air from the receivers is fed through regulator valves, which reduce pressure to 150 psig, to the air system solenoid valves. At the initiation of a start, the solenoid valves open, supplying air to the motors. The air supply is shut off after ignition has been sensed by pressure switches located on the discharge of the jacket water pump.

Testing provisions include the capability to test, individually, the air-start solenoid valves and the turbo-boost solenoid valves.

Low pressure in the air receivers is sensed by pressure switches mounted on the starting air header and an "Air Receiver Pressure Low: alarm is generated at 90 psig.

9.5.7 DIESEL GENERATOR LUBE OIL SYSTEM

The lubricating oil system circulates, cools and filters lubricating oil for each diesel generator engine. An engine-driven lube oil pump takes suction from the lube oil sump tank in the engine and discharges through the lube oil filter to a 3-way thermostatically controlled valve. The 3-way valve is designed to maintain the lube oil temperature at about 180°F. If lube oil temperature is higher than 180°F, the valve automatically directs the lube oil through the lube oil heat exchanger where it is cooled by the Service Water System. If lube oil temperature is lower than 180°F, the valve automatically by-passes the lube oil cooler. A temperature switch, at the discharge of the engine driven lube oil pump gives a "LUBE OIL HIGH TEMPERATURE" alarm if oil temperature exceeds 190°F and trips the engine if oil temperature exceeds 205°F.

From the 3-way valve, lube oil passes through a duplex strainer before reentering the engine and supercharger. Once the lube oil has completed its path through the engine, it is collected in the lube oil sump tank.

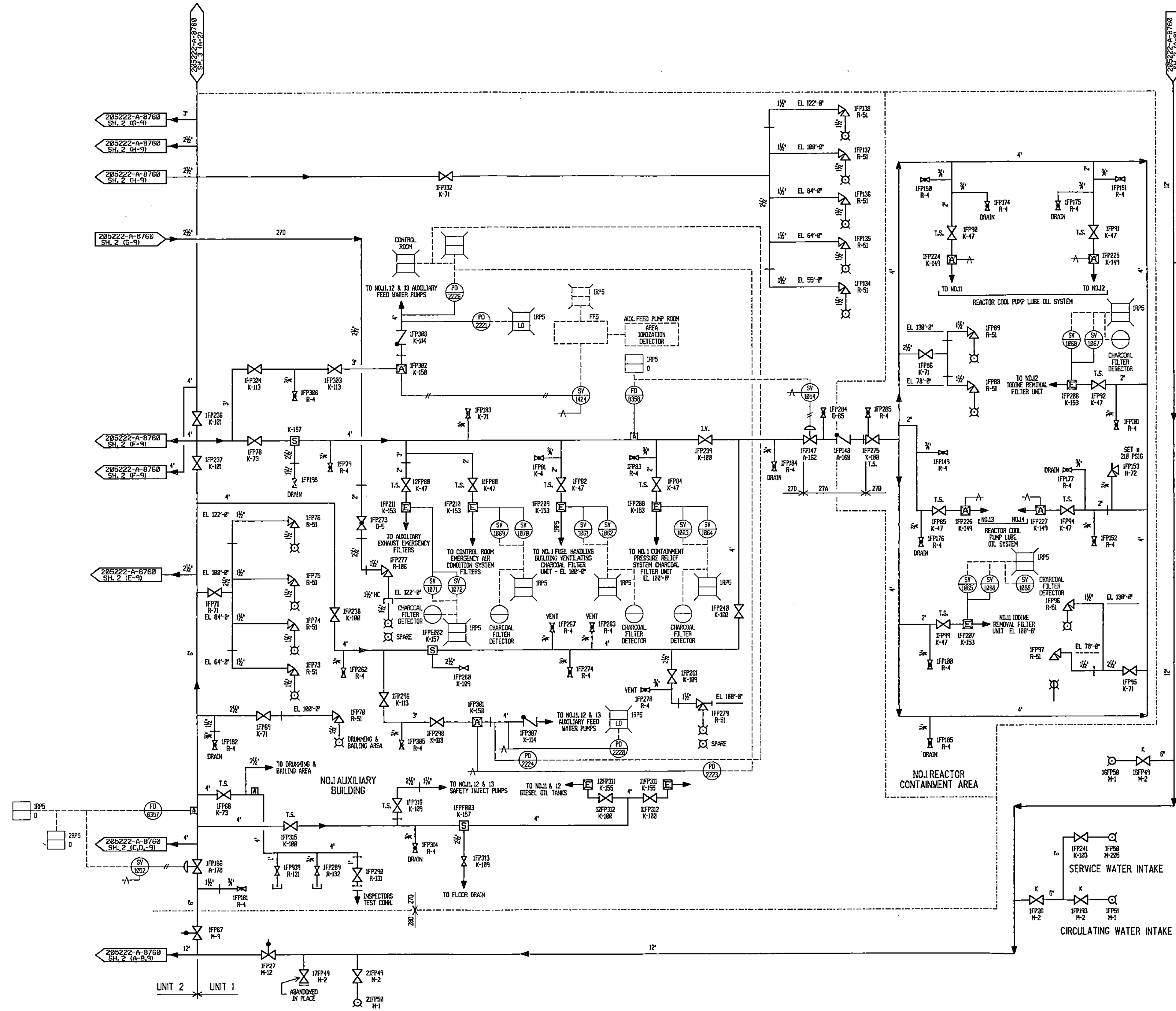
A relief valve on the discharge of the main lube oil pump is designed to protect the pump in case of a line restriction by relieving oil to the engine if discharge pressure exceeds 130 psi.

A motor-driven pre-lube pump provides backup to the main shaft driven pump. A pressure switch located in the main engine lube oil inlet header energizes the pre-lube pump if header pressure falls below 60 psi. An additional pressure switch gives a "LOW ENGINE LUBE OIL HEADER PRESSURE" alarm. If the pre-start pump malfunctions and pressure continues to fall, two parallel pressure switches trip the engine if either senses that oil pressure has dropped below 40 psi.

The primary purpose of the pre-start lube pump is to circulate lube oil through the system after the diesel has been shutdown to cool off the oil. Another function of the pre-lube pump is to provide oil pressure during periodic testing of the diesel. This permits oil to coat the critical parts of the engine prior to starting, thus reducing wear. When the diesel is started, the pre-lube pump automatically cuts out as soon as the engine boosts the lube oil pressure to its normal operating pressure.

Lube oil heaters are supplied to maintain lube oil temperature at 120°F for easier starting when engines are in standby condition. A temperature switch located at the inlet to the lube oil filter energizes the heater when lube oil temperature drops below 90°F and shuts off when lube oil temperature rises above 120°F. An additional temperature switch gives a "Lube Oil Heater Failure" alarm if lube oil temperature falls below 80°F or rises above 130°F.

Two level switches provide an alarm when crankcase oil level falls to a low level or rises to a high level.



TI APERTURE CARD

Also Available On Aperture Card

NOTES:

1. FOR TEMPORARY CONSTRUCTION PIPING SEE DRAWING 207574-A-8802.
2. WET PIPE SPRINKLER SYSTEMS COVER AREAS AROUND TURBINE GENERATOR AT ELEVATIONS INDICATED.
3. ½" STANDARD SPRINKLER HEAD MODIFIED FOR INSPECTORS TEST CONN.

REFERENCE DRAWINGS:

VALVE LIST		206766-L
AUXILIARY FEED WATER		205236-A-8761
FRESH WATER		205221-A-8760
FIRE PROTECTION SYSTEM CO 2	INSTR. SCH.	226942-B-9581-5
FIRE PROTECTION	INSTR. SCH.	239079-B-9639-5
NO. 2 UNIT FIRE PROTECTION	INSTR. SCH.	240673-B-9656-3
LEGEND SHEET		600658-A-8727

205222-A-8760	SHEET 1	NO. 1 UNIT - AUXILIARY BUILDING, DRUMMING AREA, CONTAINMENT, YARD & INTAKE STRUCTURE.
	SHEET 2	NO. 2 UNIT - AUXILIARY BUILDING, CONTAINMENT & YARD.
	SHEET 3	NO. 1 UNIT - T.G.A., SERVICE BUILDING, ADMINISTRATION BUILDING, SWITCH YARD, FOAM TANK HOUSE & CLEAN FACILITIES BUILDING.
	SHEET 4	NO. 2 UNIT - T.G.A., SERVICE BUILDING, ADMINISTRATION BUILDING, SWITCH YARD, COND. POLISHING BUILDING, HEATING BOILER HOUSE & FIRE PUMP HOUSE.

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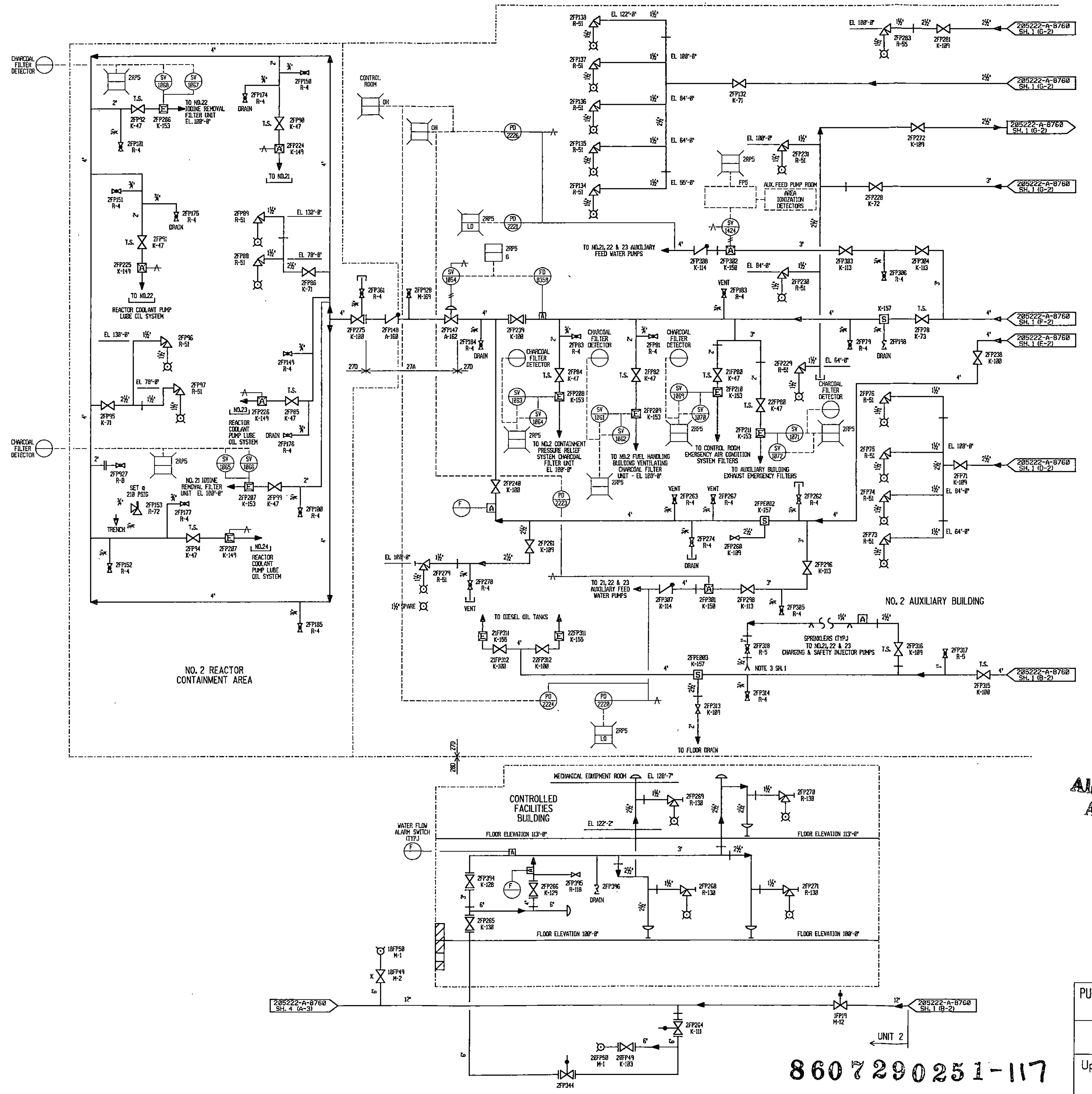
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Fire Protection System
Unit 1 & 2

Updated FSAR Sheet 1 of 4
Fig 9.5-1

8607290251-116



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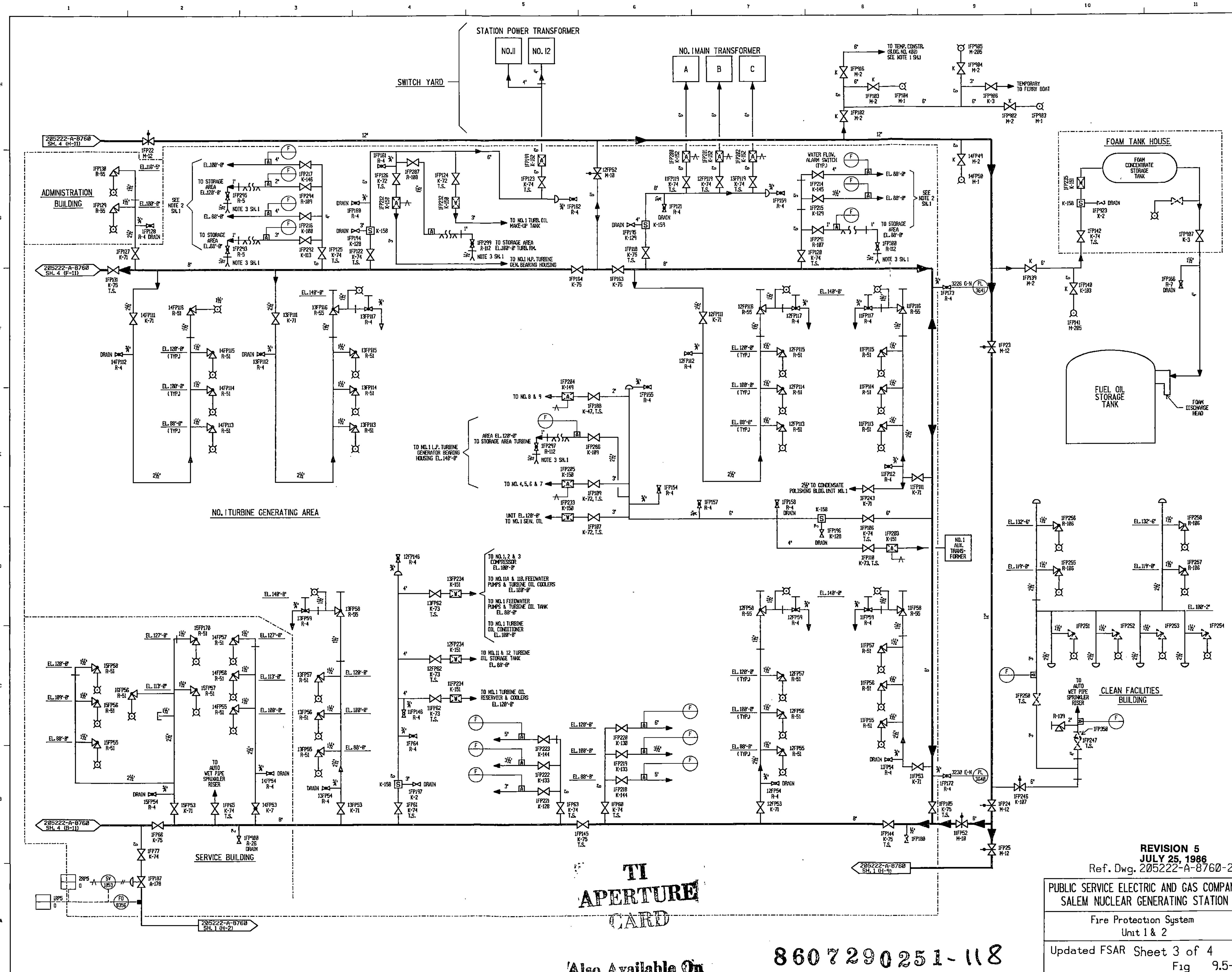
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Fire Protection System
Unit 1 & 2

Updated FSAR Sheet 2 of 4
Fig 9.5-1

8607290251-117



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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Fire Protection System
Unit 1 & 2

Updated FSAR Sheet 3 of 4
Fig 9.5-1

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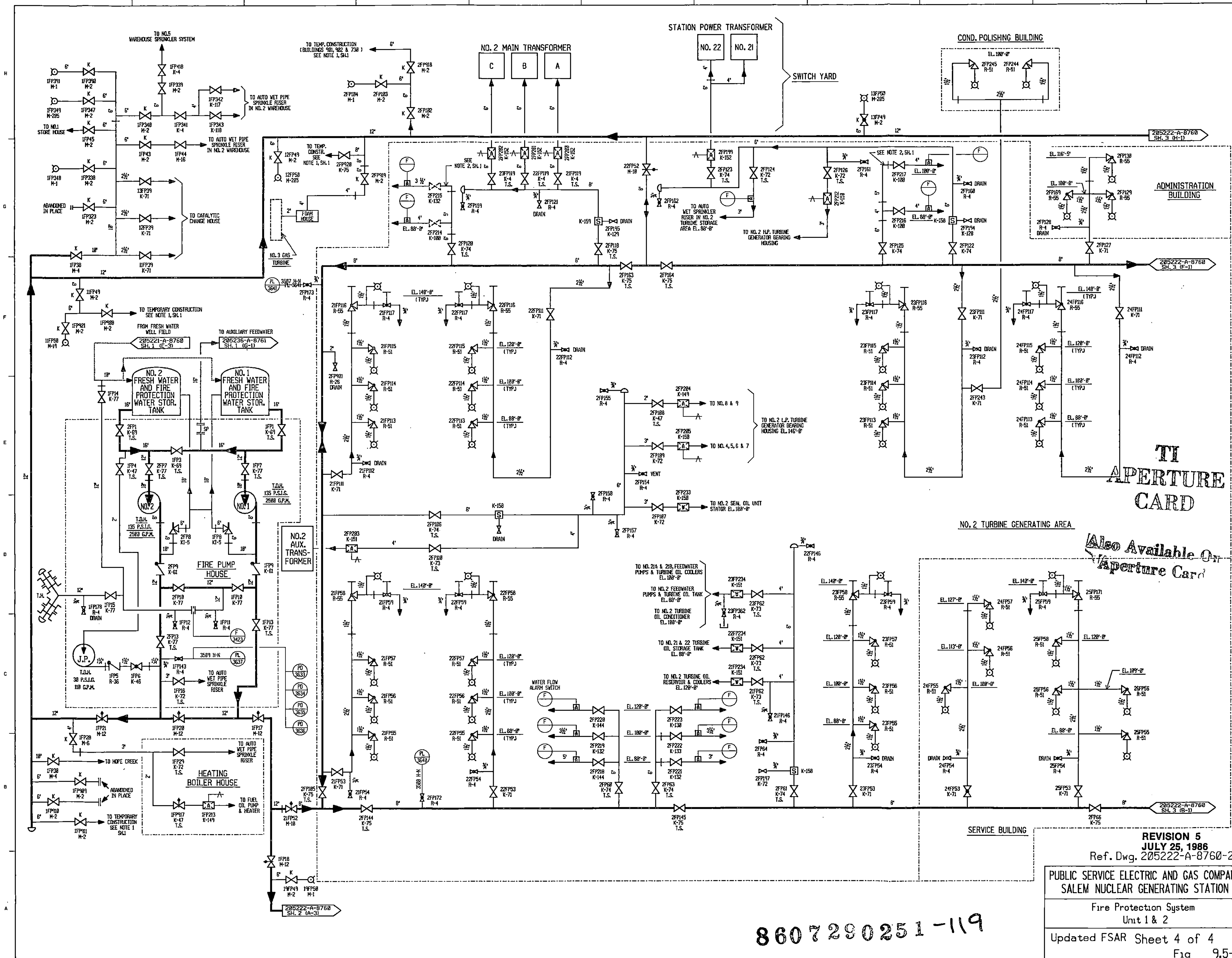
8607290251-118



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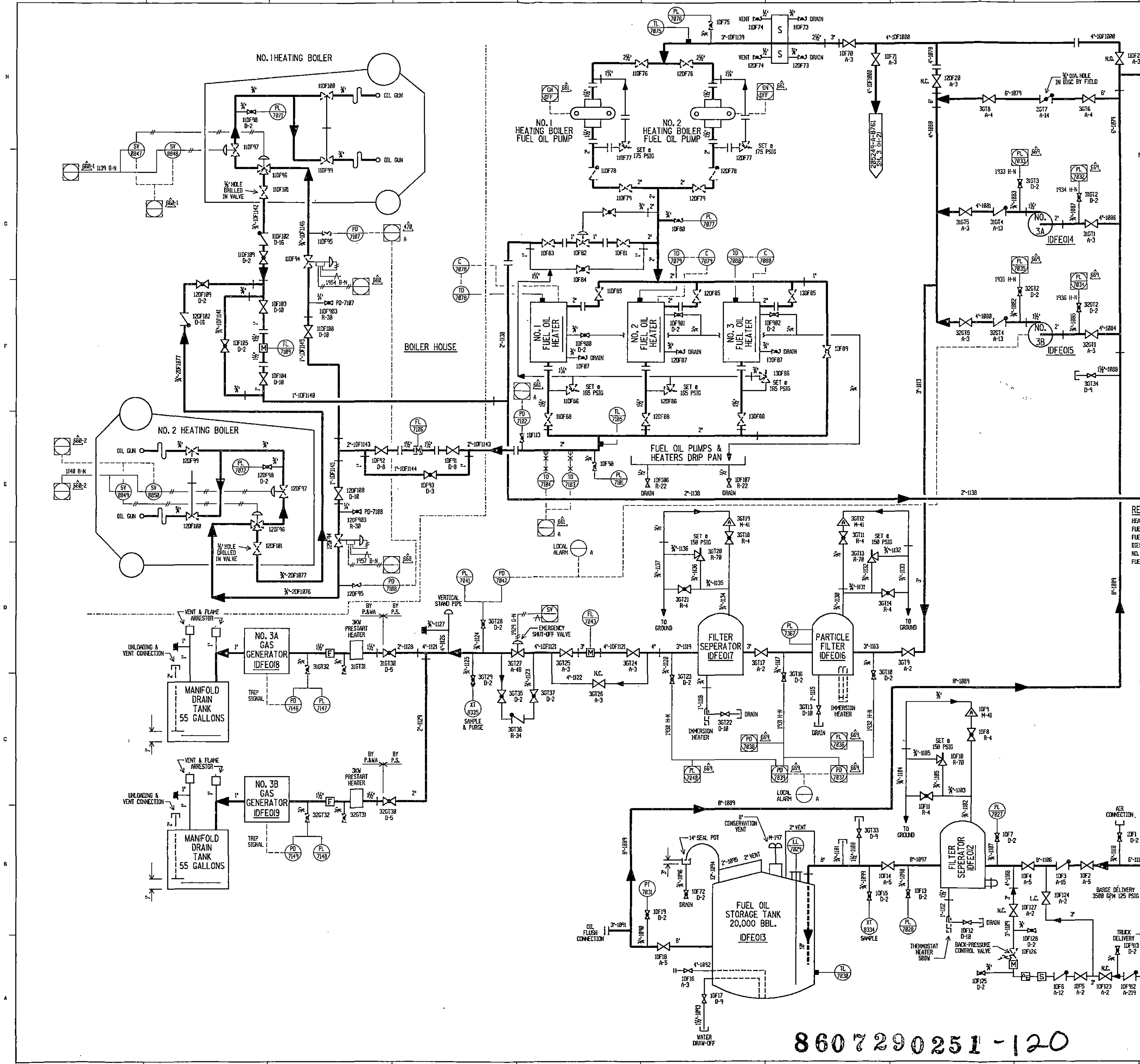
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Fire Protection System
Unit 1 & 2

Updated FSAR Sheet 4 of 4
Fig 9.5-1

8607290251-119



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REFERENCE DRAWINGS:

HEATING BOILERS-FEEDWATER AND STEAM ______ INSTR. SCH. _____ 211312-B-9508-6
FUEL OIL ______ INSTR. SCH. _____ 211306-B-9508-7
FUEL OIL ______ INSTR. SCH. _____ 211307-B-9508-8
DIESEL GEN. GAUGE PNLS. 329-1A, 1B, 1C, 2A, 2B, 2C ___ ARRGT. _______ 229955-A-1355
NO. 1 & 2 HEATING BOILERS ______ PNL. 660 ARRGT. ___ 205586-AB-3592
FUEL OIL ______ PNL. 669 ARRGT. ___ 217727-AB-3653

205249-A-8761
SH. 1 ______ NO. 1 & 2 HEATER BOILER, NO. 1, 2 & 3 FUEL OIL HEATERS, NO. 3A & 3B GAS GENERATORS, MANIFOLD DRAIN TANKS, FILTER SEPERATOR, AND PARTICLE FILTER.
SH. 2 ______ NO. 1A, 1B & 1C DIESEL FUEL TANKS, NO. 1A, 1B & 1C DIESEL GENERATOR, NOS. 11 & 12 DIESEL FUEL OIL STORAGE TANK.
SH. 3 ______ NO. 2A, 2B & 2C DIESEL FUEL TANKS, NO. 2A, 2B & 2C DIESEL GENERATORS, NOS. 21 & 22 DIESEL FUEL OIL STORAGE TANK, NOS. 1 & 2 FIRE PUMP DIESEL ENGINE, NOS. 1 & 2 FIRE PUMP DAY TANK.

LEGEND SHEET ______ 600658-A-8727

DESIGN				
	CLASSIFICATION			
BOUNDARY •	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSURANCE
24/-A	YES	I	NONE	YES
24/-B	NO	III	NONE	NO

NOTE: • IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX '1S' (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

NOTES:

1. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200, SCHEDULE AND GROUP 24 EXCEPT AS OTHERWISE NOTED.
2. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051
3. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1DF" (i.e. 1DF1002, ETC.) EXCEPT WHERE OTHERWISE NOTED.

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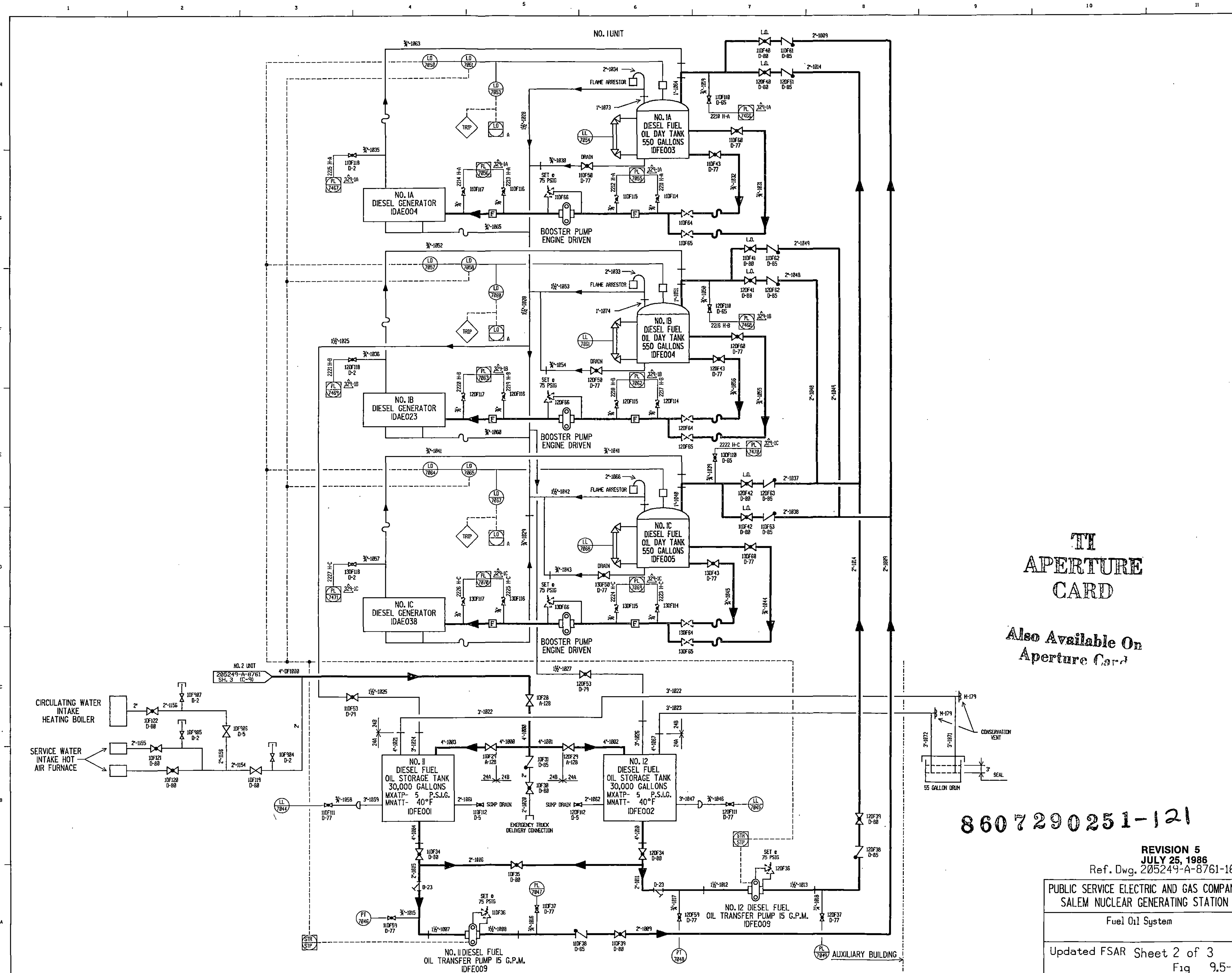
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Fuel Oil System

8607290251-120

Updated FSAR Sheet 1 of 3
Fig 9.5-2



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8607290251-121

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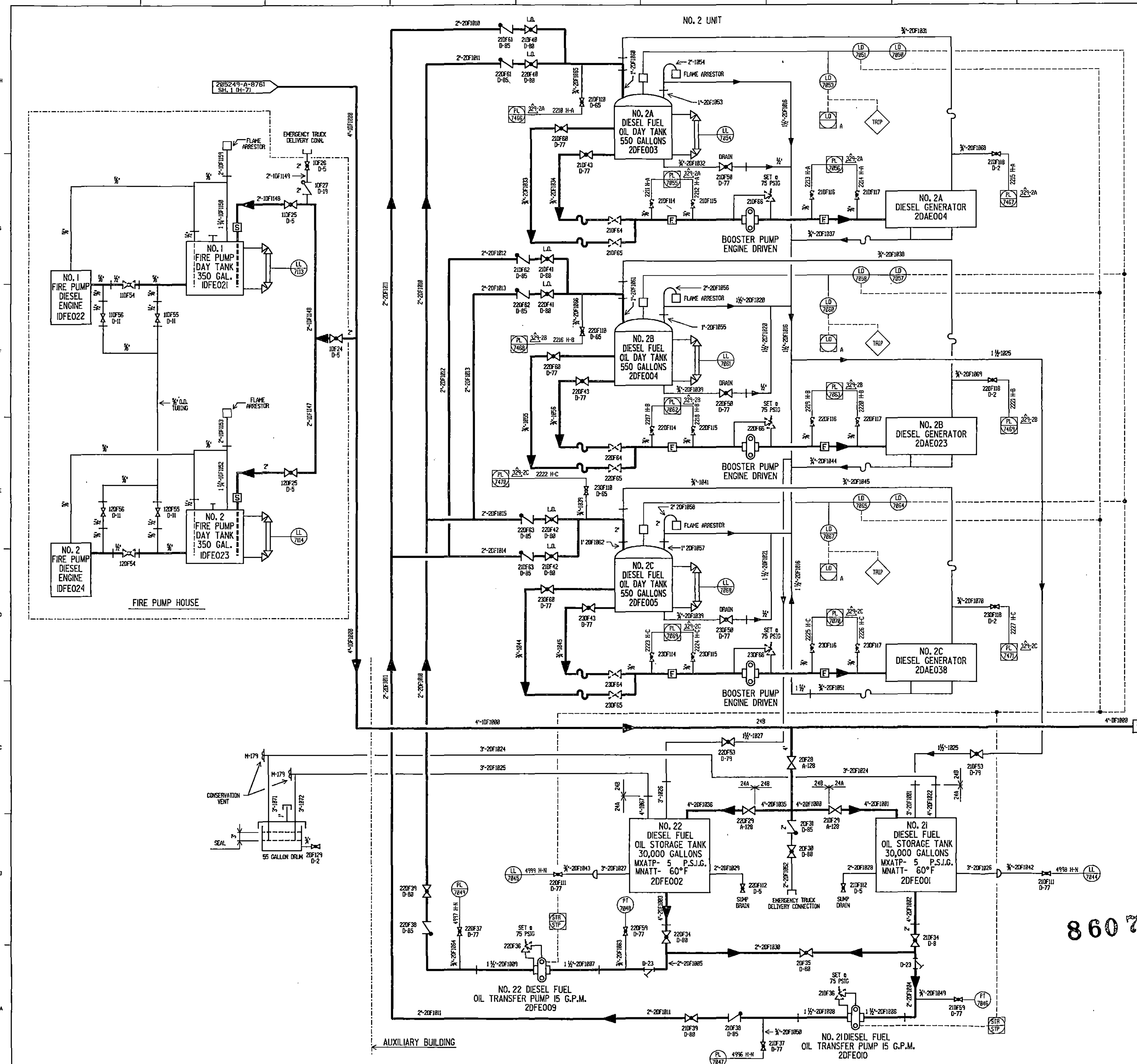
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Fuel Oil System

Updated FSAR Sheet 2 of 3
Fig 9.5-2



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8607290251-122

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Fuel Oil System

Updated FSAR Sheet 3 of 3
Fig 9.5-2