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SECTION 13

CONDUCT OF OPERATIONS

13.1 ORGANIZATION STRUCTURE

Public Service Electric and Gas Company (PSE&G), a subsidiary of Public Service Enterprise Group, is an investor-owned public utility which provides reliable generation, transmission, and sale of gas and electric energy in the State of New Jersey. In meeting these responsibilities to its customers, PSE&G, now PSEG Nuclear LLC, has developed experience and expertise in the design, construction, startup, and operation of both fossil and nuclear generation facilities. In continuing these commitments, PSEG Nuclear LLC is dedicated to the safe, reliable, and efficient operation of Salem Generating Station (SGS). The organization chart shown on Figure 13.1-1 depicts the relationship between PSEG Nuclear LLC and Public Service Enterprise Group.

13.1.1 Management and Technical Support Organization

Management of the nuclear program is provided by the President and Chief Nuclear Officer - PSEG Nuclear LLC (P/CNO). The P/CNO is the senior nuclear manager onsite and is responsible for overseeing the direction, development and implementation of the nuclear program. As shown on Figure 13.1-1, the P/CNO reports directly to PSEG Power LLC. Reporting to the P/CNO are the Senior Vice President & Chief Administrative Officer (SVP & CAO), the Vice President - Operations (VP-O), the Vice President - Maintenance (VP-M), the Vice President - Technical Support (VP-TS), the Vice President - Plant Support (VP-PS), and the Director - Nuclear Quality, Nuclear Training and Emergency Preparedness (Director - Quality NT and EP).

Technical support for the nuclear stations is provided by PSEG Nuclear LLC under the direction of the P/CNO. The PSEG Nuclear LLC organization is discussed in Section 13.1.1.2. Table 13.1-1 provides a comparison between PSEG Nuclear LLC organization titles in the UFSAR and the corresponding position titles included in Section 6.0 of the Salem Technical Specifications.

13.1.1.1 Design and Operating Responsibilities

For the Salem projects, PSE&G and Westinghouse Electric Corporation jointly participated in the design and construction of each unit. The SGS is operated by PSEG Nuclear LLC.

PSE&G, now PSEG Nuclear LLC, provided an experienced and trained staff for the SGS to support hot functional testing, core load, and power ascension testing programs. The P/CNO continues to provide an experienced and trained staff to support the continued safe, reliable, and efficient commercial operation of the SGS.

13.1.1.2 Organizational Arrangement

PSE&G dedicated PSEG Nuclear LLC to operate and support the operation of the company's nuclear generating stations. The functional responsibilities of the various positions within PSEG Nuclear LLC are described in the following sections.

13.1.1.2.1 President and Chief Nuclear Officer - PSEG Nuclear LLC (P/CNO)

The P/CNO is responsible for the leadership, direction, management, and control of PSEG Nuclear LLC. The organization chart for the office of the P/CNO is shown on Figure 13.1-2. The P/CNO has direct reports to assist in fulfilling the responsibilities of the position. The responsibilities of each direct report and their respective organizations are discussed in the following sections.

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13.1.1.2.1.1 Vice President - Operations

The Vice President - Operations (VP-O) is responsible for the safe, efficient, and reliable operation of both Salem and Hope Creek stations and reports directly to P/CNO. The VP-O is responsible for maintaining compliance with the operating license and for assuring the prompt reporting of unusual station events and the implementation of effective corrective actions. The VP-O evaluates plant safety-related activities and assures that required support is available. The VP-O develops the station operating budget, administers cost controls, analyzes manpower needs, and provides the administrative procedures required to support station operations.

The Operations organization is shown on Figures 13.1-3 and 13.1-4. A detailed description of the functional responsibilities within the Operations organization is provided in Section 13.1.2.

13.1.1.2.1.2 Vice President - Maintenance

The Vice President - Maintenance manages, directs and controls all maintenance and related programmatic activities for the Salem and Hope Creek Stations and other PSEG Nuclear LLC facilities in accordance with the facility licenses and applicable regulations. The Vice President - Maintenance is responsible for ensuring that department personnel accomplish their work safely and efficiently in support of plant availability and reliability. Specific responsibilities of the Maintenance Department include:

1. performing electrical, mechanical, and instrument and controls maintenance

2. implementing and managing plant modification installation and testing activities

3. performing facilities and yard maintenance

4. providing measuring and test equipment repair and calibration services

5. managing related programs, including:
   - preventative maintenance program
   - predictive maintenance program
   - valve programs
   - Nuclear Repair Program
   - Maintenance Engineering Support

   The Code Assurance Specialist shall review and approve specifications for Code Q-Listed materials, equipment and services to ensure they meet QA program requirements.

6. developing and approving maintenance procedures

7. ensuring that maintenance personnel are properly trained and qualified

8. providing monitoring and oversight of PSEG Nuclear LLC maintenance activities

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13.1.1.2.1.3 Vice President - Technical Support

The Vice President - Technical Support (VP-TS) is responsible for providing technical support, engineering and design services required to support the operating nuclear generating facilities. This includes establishing equipment design and performance standards, appropriate construction standards, and obtaining contractors to support plant betterment activities. Additionally, the SVP-NE is responsible for the performance of safety evaluations on major plant modifications and abnormal plant occurrences. The Vice President - Technical Support is responsible for:

- Designating the "Engineer in Charge" as described in Section 4.6.1 of ANSI/ANI 3.1-1981.
- Engineering and design plant modifications.
- Control and maintenance of design basis for the operating nuclear facilities.
- Resolution of procurement issues.
- Timely and effective engineering support to ensure plant system readiness.
- Providing system management, tracking and trending.
- Coordination of systems maintenance, surveillance and engineering activities.
- Preparation and revision of technical reports and procedures, maintenance support and nonconformance resolution.
- Reactor Engineering and technical support associated with Technical Specification testing and surveillance.
- Responding to operational experience documents as appropriate.
- The development of nuclear physics, thermal hydraulics, and safety and transient analysis expertise to ensure the safe and economical use of nuclear fuel.
- Formulates operating strategies and schedules for nuclear units, provides technical assistance for plant operations pertaining to the reactor core, develops mathematical computer models and evaluates core performance.
- The evaluation of nuclear fuel performance, verifies core design with nuclear fuel vendors.
- Preparation of design data, specifications, and analysis required for core reload licensing.
- Procurement of nuclear fuel and ultimate disposal of spent nuclear fuel.
- Analysis and resolution of steam generator issues at Salem.

The Vice President-Technical Support is responsible for: (Continued)

- Overall management of licensing and regulatory activities associated with the PSEG Nuclear LLC operating facilities.
- Managing the preparation, review and approval of licensing documents.
- Coordinating PSEG Nuclear LLC involvement with regulatory agencies.
- Monitoring and trending of overall system performance.
- Preparation and update of detailed engineering and design documents, including drawings and specifications, for all systems, components and structures.
- Specifying applicable codes, standards, regulatory and quality requirements, acceptance standards, and other design input in design documents.
- Identifying systems, components and structures that are covered by the QA program.
- Performing design verification for systems, components and structures covered by the QA program.
- Performing safety evaluations of proposed design changes, as required.
- Applying generic 10CFR50.59 Safety Evaluation, as required, to configuration changes that impact the SAR.
- Preparing documents for procurement of equipment, materials and components.
- Recommending engineering consultants and laboratories for procurement services and coordinating their activities.
- Reviewing design documents submitted by suppliers (including the Nuclear Steam Supply System (NSSS) supplier) and contractors.
- Specifying, or approving, as required, inspections and/or tests.
- Designating whether they will seek the services of other qualified engineering organizations.
- Thermal Performance Program.
- Inservice Inspection Program.
- Inservice Testing Program.
- Maintenance Rule Program.
- Probabilistic Safety Assessment Program.

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13.1.1.2.1.4 Director - Quality, Nuclear Training and Emergency Preparedness

The Director - Quality, NT and EP provides management direction and control of functions that assess the safe operation of the nuclear stations, quality of work performed by support personnel, and compliance of all departments with Quality Assurance Program and nuclear safety requirements, company policies, regulatory commitments, and other governmental regulations. The Director - Quality NT and EP advises PSEG Nuclear LLC management regarding the overall quality and safety of plant operations and makes recommendations for improvement, as appropriate.

The Director - Quality, NT and EP is responsible for coordinating, managing, and directing all departmental training programs offered through the Nuclear Training Center. The Director develops, implements, and evaluates training programs in accordance with management objectives, NRC guidelines, and industry standards and practices. In addition the Director oversees the conduct of site access training. The Director provides comprehensive training programs for personnel assigned to the operating stations and the Nuclear Operations Services department. The Director also provides services to support the stations in the areas of Health Physics, Dosimetry, Instrumentation and Chemistry. The Nuclear Training Program is briefly described in Section 13.2 of the UFSAR.

The Director is responsible for managing the Emergency Preparedness program by ensuring that it meets all NRC regulatory requirements, management objectives, and industry standards. The Director is responsible for ensuring Emergency Plan implementing procedures which potentially decrease the effectiveness of the Emergency Plan in accordance with 10CFR50.54 (q) are presented to SORC. The Emergency Plan is briefly described in Section 13.3 of the UFSAR.

The Director is responsible for providing support to ensure the Nuclear Review Board (NRB) can perform its function and provide management oversight of onsite and offsite review activities within PSEG Nuclear LLC.

The Quality, Nuclear Training and Emergency Preparedness Departments are shown on Figure 17.2-1. A detailed description of the PSEG Nuclear LLC Operational Quality Assurance Program is provided in Section 17.2. A brief functional description of the departmental positions reporting to the Director - Quality, NT and EP is provided below.

1. The Program Manager - Nuclear Review Board

The Program Manager - NRB is responsible for providing NRB support and management oversight of the NRB subcommittees. The Program Manager is also responsible for reviewing industry operating experiences and disseminating that information to the appropriate departments.

2. Manager - Emergency Preparedness and Instructional Technology (Manager - EP & IT)

The Manager - EP & IT provides the functional responsibility for the Emergency Preparedness and the Instructional Technology Programs. The Manager will provide overall direction, monitoring and oversight of the combined groups. The Manager will direct and supervise the activities of Emergency Preparedness and the Instructional Technologists. The Manager will be responsible for developing and maintaining programs and providing station support in the two areas.

The Manager will be responsible for providing leadership, guidance and facilitation of station work teams on evaluating and improving training programs. These improvements will be accomplished by receiving, analyzing and dispositioning operating experience and trends information related to Emergency Preparedness and Training, thereby increasing individual and workplace performance.

Additional responsibilities for directing the Emergency Preparedness program are described in the approved Emergency Plan.

3. Supervisor - Corrective Action

The Supervisor - CA will provide direction, monitoring and oversight of the Corrective Action Group activities. Additional responsibilities for for corrective action are described in Section 17.2.1.1.1.

4. Manager - Quality Assessment

The Manager - Quality Assessment, is responsible for implementation of the independent assessment program at the Salem/Hope Creek stations, including the audit, assessment, programmatic controls and Quality Verification (QV) functions.

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5. Manager - Employee Concerns

The Manager - Employee Concerns is responsible for coordinating the Employee Concerns Program (ECP). The Manager - Employee Concerns is responsible for the evaluation and resolution of employee concerns brought to the ECP pertaining to nuclear safety, nuclear quality, or harassment or intimidation issues.

6. The Nuclear Training Manager is responsible for promoting and overseeing the development, design and implementation of operator and technical/ maintenance training programs for both Hope Creek and Salem Generating Stations' personnel. The manager is responsible for the training programs under the control of the Technical Training/Services Manager and the Operations Training Manager as described below.

7. Technical Training/Services Manager

The Technical Training/Services Manager is responsible for the Technical Training programs for PSEG Nuclear LLC, managing major training projects such as INPO accreditation, managing the Technical Training staff, and for providing technical services involving areas of health physics, dosimetry, instrument calibration and chemistry for both stations.

8. Operations Training Manager

The Operations Training Manager is responsible for the Operator Training programs for Salem and Hope Creek, managing major training projects such as INPO accreditation and simulator testing and managing the operations training staff and training consultants.

13.1.1.2.1.5 Director - Business Support

Nuclear Business Support is responsible for providing support services to PSEG Nuclear LLC. Included within this support are direct services to departments within PSE Nuclear LLC and services to the corporation and external stakeholders on behalf of PSEG Nuclear LLC. Responsibilities include: project management, purchasing and materials management, procurement quality functions, integrated site planning, external affairs including co-owner activities, industry and community affairs, supporting rate counsel and legal affairs, and internal and external communication; financial services including capital, operating and maintenance, and co-owner's budgets; strategic planning, financial planning, cost analysis and control. The Director Business Support reports to the Senior Vice President & Chief Administrative Officer.

13.1.1.2.1.6 Nuclear Human Resources Manager

The Nuclear Human Resources Manager (NHRMGR) directs and controls various human resources program and administrative services functions necessary to support PSEG Nuclear LLC. The Nuclear Human Resources Manager (NHRMGR) reports directly to the Senior Vice President & Chief Administrative Officer.

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The NHRMGR advises management on the interpretation and administration of labor agreements and assures consistent department-wide adherence to company/union agreements and good labor relations practices. The NHRMGR also provides assistance and support for succession planning, personnel development, staffing, performance management, compensation, and other administrative functions.

13.1.1.2.1.7 (This Section has been deleted)
13.1.1.2.1.8 (This Section has been deleted)

13.1.1.2.1.9 Senior Vice President & Chief Administrative Officer (SVP & CAO)
The SVP & CAO is responsible for providing directions to and oversight of Business Support (administrative support services), Nuclear Fuels, SAP/Business Process Redesign and Plant Projects. Also, provides the key interface with PSEG Nuclear LLC supporters from outside PSEG Nuclear LLC from Corporate Information Technology services and PSEG Environmental group functions. The SVP & CAO reports directly to the P/CNO.

13.1.1.2.1.10 Vice President - Plant Support (VP-PS)
The VP-PS is responsible for directing those departments needed to support the day-to-day functioning of the operating nuclear units. The responsibilities include Station and outage planning, work management and providing oversight of contract maintenance services. The VP-PS is responsible for implementation of the Fire Protection and Industrial Safety programs to meet NRC and other regulatory requirements. The VP-PS is also responsible for implementing and maintaining the Nuclear Security Program as well as the Site Access Program including badging, fitness-for-duty qualification and background investigation. The VP-TS reports directly to P/CNO.

13.1.2 Operating Organization
The Vice President - Operations (VP-O) is responsible for all plant organizational activities. As the senior manager located at the station, the VP-O provides management direction and control of plant operations. In the event of an unexpected contingency, the succession of authority and responsibility for the overall operation is in the following order:

1. Designated Operations Manager

2. Operations Superintendent - Assistant Operations Manager

3. Operations Superintendent - Staff

4. Manager - Plant Maintenance

The Salem Operations organization is shown on Figures 13.1-3 and 13.1-4.

13.1.2.1 <u>Station Management</u>

The VP-O reports directly to the P/CNO and is responsible for the overall management, direction, and control of station activities. In fulfilling these responsibilities this individual ensures the safe and efficient operation of SGS and Hope Creek stations. These functions include, but are not limited to, general administration, liaison activities with regulatory and other agencies, approving and implementing programs and procedures, and acting on matters pertaining to Company policies and practices. The VP-O may designate an individual or group to manage special projects. The VP-O is responsible for ensuring compliance with the requirements of the Technical Specifications, facility operating license, and all other applicable government regulations. The VP-O also ensures the station's commitment to the QA Program by maintaining a close liaison with the Manager - Quality Assessment.

13.1.2.2 <u>Operations Department</u>

The Operations Department is responsible for safe and efficient plant operation. The Operations Managers report to the Vice President - Operations and are responsible for managing, directing, and controlling department activities. Each Operations Manager ensures that plant operation complies with the facility operating license, Technical Specifications, and all government regulations and company policies. Reporting to the Operations Manager are the Operations Superintendent - Assistant Operations Manager, Operations Superintendent - Work Management and Operations Superintendent - Staff. The Operations Manager ensures that a properly trained licensed and nonlicensed staff is available to provide safe and efficient operations. Responsibilities ~~of~~ the Operators assigned to radwaste include the following:

1. Completing checkoff lists, logs, and other shift data associated with radwaste operations to provide continuous surveillance of the equipment assigned

2. Manipulating controls, valves, and equipment to support liquid radwaste processing and storing

3. Initiating immediate actions necessary to maintain radwaste equipment in a safe condition during normal, abnormal, and emergency operations

Shift electrician, instrumentation and control (I&C) technicians, chemistry technicians and radiation protection technicians are assigned to shift schedule and report to the Operations Superintendent. These personnel perform support functions associated with electrical, I&C, chemistry and radiation monitoring disciplines. During normal operation, they are available to perform surveillance, preventive and corrective maintenance. When periods of emergency or abnormal operating conditions exist, they are available as part of the plant emergency preparedness program for emergency response and technical assistance.

13.1.2.3 Maintenance Department

The Nuclear Maintenance Organization is described in Section 13.1.1.2.1.2. Although the Maintenance Organization will not report directly to the Vice President - Operations, the Vice President - Operations will maintain control over those activities necessary for safe operation and maintenance of the plant.

13.1.2.4 Chemistry Department

The Manager Chemistry reports to the Vice President - Operations and is responsible for implementing programs to ensure plant chemistry, radiochemistry, and plant effluents monitoring are in accordance with the facility license and government regulations. Reporting to the Manager Chemistry are the Chemistry Superintendent - Salem, Chemistry Superintendent - Hope Creek and Chemistry Superintendent - Support.

The Chemistry Department is responsible for the development and implementation of the chemistry, radiochemistry, environmental and liquid effluent monitoring programs. They are also responsible for operation of the condensate demineralizers, demineralized water makeup plant, service water chlorination, non-radioactive liquid waste disposal system, oil-water separator and post accident sampling system.

The Chemistry Department is also responsible for the sampling and analysis of plant fluid systems, chemistry results reporting, calibration of chemistry instrumentation, evaluation of laboratory and chemical systems operation and techniques, operation of deep bed demineralizers, plant water and chemical control systems, and maintaining the plant fluid systems and liquid effluents within established limits.

13.1.2.5 Radiation Protection Department

The Radiation Protection Manager reports to the Vice President - Operations and is responsible for ensuring that the conduct of the radiological safety and radiological material control program is in accordance with the facility license, government regulations, and the NBU radiation protection plan. These programs require that personnel exposure to radiation and releases of radioactive material to the environment meet ALARA requirements. The radiation protection program, organization, and various responsibilities of the Radiation Protection Department are described in Section 12. The Radiation Protection Department organization is shown on Figure 13.1-8e.

13.1.2.6 (This section has been deleted)

13.1.2.7 Nuclear Security

The Nuclear Security Manager reports to the Vice President - Plant Support. Nuclear Security responsibilities and organization are addressed in the Salem - Hope Creek Security Plan.

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13.5 Plant Procedures

13.5.1 Administrative Procedures

Administrative procedures define processes and programs that provide for the control of nuclear operations, and in turn incorporate regulatory requirements and commitments. There are three types of administrative procedures: 1) Nuclear Administrative Procedures (NAPs); 2) Station Administrative Procedures (SAPs); and 3) Department Administrative Procedures (DAPs).

Nuclear Administrative Procedures (NAPs) are written to provide direction in the areas that are common to all station departments as well as other organizations within the NBU. NAPs are prepared using a standard format and content, and a writers guide, which provides human factors and style guidance. NAPs are approved by the Vice President - Operations.

Station Administrative Procedures (SAPs) are written to govern station specific programs and processes. SAPs are approved by the General Manager - Salem Operations and comply with all applicable requirements specified in the NAPs.

Department Administrative Procedures (DAPs) provide direction for the administrative control of specific activities that are within a department's functional area of responsibility or between departments with the same functional responsibility or that control administrative functions between a limited number of departments in the NBU. Department - specific procedures are approved by the individual department managers for Salem and comply with all applicable requirements specified in the NAPs.

Additional topics for administrative procedures may be addressed as required, and material may be shifted between specific procedures as needed.

A list of topics for NBU administrative procedures is listed below:

- Action Request Process
- Nuclear Procedure System
- Nuclear Department Organization
- Document Control Program
- Station Operations Review Committee
- Station Operating Practices
- Corrective Action Program

Control of Design and Configuration Changes, Tests and Experiments

- Work Control Process
- Preventive Maintenance Program
- Records Management Program
- Technical Specification Surveillance Requirements
- Control of Temporary Modifications
- Training, Qualification and Certification
- Safety Tagging
- Monitoring the Effectiveness of Maintenance
- Minor Modification Process
- Material Control Program
- Procurement of Materials and Services
- System Cleanliness
- Measuring & Test Equipment, Lifting & Rigging and Tool Control
- Scaffolding Program
- Radiological Protection Program
- Fire Protection
- Nuclear Mutual Limited/Boiler and Machinery Insurance Program
- Inservice Inspection Program
- Code Job Packages
- Commitment Management Program

- Inspection/Housekeeping Program
- Nuclear Security Program
- Nuclear Licensing and Reporting
- Environmental Control
- Chemical Control Program
- Service Water Reliability Program
- Lubricant Program
- Fitness for Duty Program
- Vendor Information Program
- Stations Aids and Labels
- Respiratory Protection Program
- Station Performance and Reliability
- Refueling Management
- Station Testing Program
- Plant Chemistry Control
- Operating Experience Feedback Program
- Outage Management
- 10CFR50.59 Reviews and Safety Evaluations
- Repairs to Presure Relief Devices

- Environmental Qualification Program
- Software and Micro-processor Based Systems (Digital Systems)
- Control of Special Processes
- Control of On-Site Contractor Personnel
- Inservice Testing Program
- Fuel Integrity Program
- Nuclear Fuel Program
- Special Nuclear Material Control Program
- Valve Programs
- Independent Review Program
- Transient Loads
- Conduct of Infrequently Performed Tests and Evolutions

13.5.2 Station Department Manuals

Various departments within the station have manuals which contain their own pertinent operating guidelines and instructions.

The Operations Department has two manuals: the Station Plant Manual and the Operations Directives Manual. The Station Plant Manual contains the Operations Department procedures. The Operations Directives Manual contains general information, organization and responsibility guidelines, administrative and operations directives.

The Chemistry Department maintains Administrative Procedures, implementing procedures, guidelines which detail department organization and responsibilities, training, general work practices, laboratory quality control, and procedure generation and control instructions.

The Radiation Protection Department Manual contains Administrative Procedures, guidelines detailing functions and responsibilities, general work practices, training instructions and requirements, as well as department procedures.

Nuclear Maintenance administrative guidelines describe department functions and responsibilities. Nuclear Maintenance procedures contain instructions for the performance of maintenance.

Nuclear Engineering administrative guidelines describe department functions and responsibilities. Nuclear Engineering procedures contain instructions for performing engineering functions. Reactor Engineering procedures contain instructions for testing various reactor parameters.

Written Test Procedures issued for special test are not incorporated into these manuals due to their one-time nature.

Other manuals used in the station include the following: the System Descriptions, which describe the characteristics of the various Primary, Secondary, and Electrical Systems; and the Emergency Plan Implementing Procedures.

13.5.3 Operating Instructions

All operating instructions are included in the Station Plant Manual and provide initial conditions and precautions on the subject system and, where applicable, surveillance requirements.

13.5.4 Emergency Instructions

The Station Plant Manual includes those emergency instructions, with the exception of fire and medical emergency response procedures, (which are located in the Fire and Medical Emergency Response Manual), necessary to ensure that proper action is taken to handle any malfunction that may occur at either of the Salem units.

13.5.5 Preventive Maintenance

A Preventive Maintenance Program has been in effect since the initiation of plant operation and is reviewed and improved continuously. Preventive maintenance activities are based upon Technical Specification Requirements, Nuclear Regulatory Commission and other regulatory requirements, equipment vendor and motors. These parameters are checked periodically. The component is surveyed for excessive vibration and readings are recorded.

Public Service Electric & Gas believes that testing in accordance with the program described above provides a realistic basis for determining maintenance requirements and, as such, ensures continued system capabilities, including reliability, equal to those established in the original criteria.

14.4.5 Safety Precautions

The test operations during low power and power escalation were similar to normal station operation at power, and normal safety precautions were observed. Those tests which required special operating conditions were accomplished using test procedures which prescribed necessary limitiations and precautions.

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SECTION 15

ACCIDENT ANALYSIS

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2. Leakage from fuel with cladding defects

3. Activity in the reactor coolant

    a. Fission products
    b. Corrosion products
    c. Tritium

4. Operation with steam generator leaks up to the maximum allowed by Technical Specifications

Operational Transients

1. Plant heatup and cooldown (up to 100°F/hour for the Reactor Coolant System; 200°F/hour for the pressurizer)

2. Step load changes (up to ±10 percent)

3. Ramp load changes (up to 5 percent/minute)

4. Load rejection up to and including design load rejection transient

15.1.1 Optimization of Control Systems

A setpoint study has been performed to simulate performance of the Reactor Control and Protection Systems. Emphasis is placed on the development of a control system which will automatically maintain prescribed conditions in the plant even under the most conservative set of reactivity parameters with respect to both system stability and transient performance.

For each mode of plant operation, a group of optimum controller setpoints is determined. In areas where the resultant setpoints are different, compromises based on the optimum overall performance are made and verified. A consistent set of control system parameters is derived satisfying plant operational requirements throughout the core life and for power levels between 15 and 100 percent. The study comprises an analysis of the following control systems: rod cluster assembly control, steam dump, steam generator level, pressurizer pressure and pressurizer level.

15.1.2 Initial Power Conditions Assumed in Accident Analyses

15.1.2.1 Power Rating

Table 15.1-1 lists the principal power rating values which are assumed in analyses performed in this section. The guaranteed Nuclear Steam Supply System (NSSS) thermal power output includes the thermal power generated by the reactor coolant pumps.

Where initial power operating conditions are assumed in accident analyses, the "guaranteed NSSS thermal power output" plus allowance for errors in steady state power determination is assumed. The thermal power values for each transient analyzed are given in Table 15.1-2.

15.1.2.2 Initial Conditions

For accident evaluation, the initial conditions are obtained by adding maximum steady state errors to rated values. The following steady state errors are considered for events not analyzed with Revised Thermal Design Procedure (RTDP):

1.	Core power	± 2 percent allowance calorimetric error
2.	Average Reactor Coolant System (RCS) temperature	± 5°F allowance for deadband and measurement error
3.	Pressurizer pressure	± 50 psi allowance for steady state fluctuations and measurement error

Initial values for core power, average RCS temperature and pressurizer pressure are selected to minimize the initial departure from nucleate boiling ratio (DNBR) unless otherwise stated in the sections describing specific accidents.

The outer surface of the fuel rod at the hot spot operates at a temperature of approximately 660°F for steady state operation at rated power throughout core life due to the onset of nucleate boiling. Initially (beginning of life), this temperature is that of the cladding metal outer surface. During operation over the life of the core, the buildup of oxides and crud on the fuel rod surface causes the cladding surface temperature to increase. Allowance is made in the fuel center melt evaluation of this temperature rise. Since the thermal-hydraulic design basis limits departure from nucleate boiling (DNB), adequate heat transfer is provided between the fuel cladding and the reactor coolant so that the core thermal output is not limited by considerations of the cladding temperature. Figure 4.4-4 shows the axial variation of average cladding temperature for a typical rod (17 x 17 fuel assembly) both at beginning of life (BOL) and end of life (EOL).

End of life is after three typical cycles of operation (approximately 20,000 effective full-power hours). These temperatures are calculated using the Westinghouse fuel rod model (1) which has been reviewed and approved by the Nuclear Regulatory Commission (NRC).

15.1.2.3 Power Distribution

The transient response of the reactor system is dependent on the initial power distribution. The nuclear design of the reactor core minimizes adverse power distribution through the placement of control rods and operation instructions. The power distribution may be characterized by the radial factor $F_{\Delta H}$ and the total peaking factor F_q. The peaking factor limits are given in the Technical Specifications.

For transients which may be DNB limited, the radial peaking factor is of importance. The radial peaking factor increases with decreasing power level due to rod insertion. This increase in $F_{\Delta H}$ is included in the core limits illustrated on Figure 15.1-1. All transients that may be DNB limited are assumed to begin with a $F_{\Delta H}$ consistent with the initial power level defined in the Technical Specifications.

The axial power shape used in the DNB calculation is the chopped cosine as discussed in Section 4.4.3.2.

For transients which may be overpower limited, the total peaking factor F_q is of importance. The value of F_q may increase with decreasing power level such that full power hot spot heat flux is not exceeded, i.e., F_q Power = design hot spot heat flux. All transients that may be overpower limited are assumed to begin with a value of F_q consistent with the initial power level as defined in the Technical Specifications.

The value of peak kW/ft can be directly related to fuel temperature as illustrated on Figures 4.4-1 and 4.4-2. For transients which are slow 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 (CRDM). The loss of power to the mechanism coils causes the mechanisms to release the rod cluster control assemblies (RCCA) 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 coil release of the rods by the mechanisms. The coil release of the rods is conservatively assumed to be 0.15 second. The total delay to trip is defined as the time from when the monitored parameter exceeds its trip setpoint at the channel sensor to the time when the rods begin to drop. 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 on Figure 15.1-1.

The overtemperature ΔT setpoints shown on Figure 15.1-1 along with all other evaluated DNBRS 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 startup tests, it will be demonstrated that actual instrument errors and time delays are equal to or less than the assumed values.

Public Service Electric & Gas, in its letter dated February 25, 1985, addressed NRC concerns regarding the replacement of the existing RCS resistance temperature detectors (RTD) with environmentally qualified RTDs. The new RTDs have a slower response time than the originally installed RTDs, and, therefore, a review of the accidents in which these RTDs are relied upon was performed. The review determined that reanalysis was only required for the uncontrolled RCCA bank withdrawal at power accident described in Section 15.2.2. The reanalysis was performed using the same methodology and inputs as the original analysis except that a 7-second delay was assumed for the overtemperature ΔT trip. It was concluded that a lower DNBR than originally calculated would be reached; however, in no case would the minimum DNBR fall below the limit value.

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 higher 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 RCCAs 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, after the total delay to trip (defined in Section 15.1.3), the insertion time from beginning of rod motion to dashpot entry is 2.7 seconds. The RCCA position versus time assumed in accident analyses is shown on 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 RCCA bank had already traveled some distance after trip. This lower curve is used as input to all point kinetics core models used in transient analyses.

There is inherent conservatism in the use of this curve in that it is based on a skewed distribution which would exist relatively infrequently. For cases other than those associated with xenon oscillations significant negative reactivity would have been inserted due to the more favorable axial distribution existing prior to trip.

The normalized RCCA negative reactivity insertion versus time is shown on Figure 15.1-4. The curve shown on this figure was obtained from Figures 15.1-2 and 15.1-3. A total negative reactivity insertion following trip of 4 percent Δk is assumed in the transient analyses except where specifically noted otherwise. This assumption is conservative with respect to the calculated trip reactivity worth available as shown in Table 4.3-3.

The normalized RCCA negative reactivity insertion versus time curve for an axial power distribution skewed to the bottom (Figure 15.1-4) is used in transient analyses. Where special analyses require use of three-dimensional or axial one-dimensional core models, the negative reactivity insertion resulting from reactor trip is calculated directly by the reactor kinetic code and is not separable from other reactivity feedback effects. In this case, the RCCA position versus time on Figure 15.1-2 is used as code input.

15.1.6 Reactivity Coefficients

The transient response of the Reactor System is dependent on reactivity feedback effects, in particular the moderator temperature coefficient and the Doppler power coefficient. These reactivity coefficients and their values are discussed in detail in Section 4.

In the analysis of certain events, conservatism requires the use of large reactivity coefficient values whereas, in the analysis of other events, conservatism requires the use of small reactivity coefficient values. Some analyses such as loss of reactor coolant from cracks or ruptures in the RCS do not depend on reactivity feedback effects. The values used are given in Table 15.1-2; reference is made in that table to Figure 15.1-5 which shows the current lower and upper Doppler only power coefficient, as a function of power used in the transient analysis respectively. The basis for the revised most negative Doppler curve is the safety analysis performed for the Salem Unit 1 Cycle 6 reload design.(22) Those incidents found to be sensitive to the revised Doppler coefficient were reanalyzed. Table 15.1-7 gives a list of accidents presented in this FSAR and denotes those events reanalyzed for a new coefficient. The results of the analysis showed that the revised most negative Doppler curve can be accommodated with ample margin to the applicable FSAR safety limits.

2.	Uncontrolled RCCA Bank Withdrawal At Power	15.2.2
3.	Rod Cluster Control Assembly Misalignment	15.2.3
4.	Uncontrolled Boron Dilution	15.2.4
5.	Partial Loss of Forced Reactor Coolant Flow	15.2.5
6.	Loss of External Electrical Load and/or Turbine Trip	15.2.7
7.	Loss of Normal Feedwater	15.2.8
8.	Loss of Offsite Power to The Station Auxiliaries	15.2.9
9.	Excessive Heat Removal due to Feedwater System Malfunctions	15.2.10
10.	Excessive Load Increase Incident	15.2.11
11.	Accidental Depressurization of The RCS	15.2.12
12.	Accidental Depressurization of Main Steam Systems	15.2.13
13.	Spurious Operation of the Safety Injection System (SIS) at Power	15.2.14

<u>Condition III Events</u>

1.	Complete Loss of Forced Reactor Coolant Flow	15.3.4
2.	Single RCCA Withdrawal at Full power	15.3.5

Condition IV Events

1. Major Reactor Coolant System Pipe Ruptures (Loss of Coolant Accident) 15.4.1

2. Major Secondary System Pipe Rupture 15.4.2

3. Major Rupture of a Main Feedwater Line 15.4.3

4. Steam generator Tube Rupture 15.4.4

5. Single Reactor Coolant Pump Locked Rotor and Reactor Coolant Pump Shaft Break 15.4.5

6. Fuel Handling Accident 15.4.6

7. Rupture of a Control Rod Drive Mechanism Housing (RCCA Ejection) 15.4.7

8. Containment Pressure Analysis 15.4.8

15.1.7 Fission Product Inventories

15.1.7.1 Activities in the Core

The fission product inventories which are important from a health hazards point of view consider inhalation dose and external dose due to immersion. The bases for the total core iodine (inhalation dose) and noble gas (external dose) inventories are described in Section 11.1.1. These inventories are given in Table 11.1-1.

15.1.7.2 Activities in the Fuel Pellet Cladding Gap

The fraction of core activity assumed to be in the gap can vary depending on the specific application. Gap activity is the primary source term for the locked rotor, rod ejection and fuel handling accidents. The gap activity basis is discussed as part of the assumptions described in the specific accident section of Chapter 15.

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15.1.8 Residual Decay Heat (ANS-1979)

Residual heat in a subcritical core consists of:

1. Fission product decay energy,

2. Decay of neutron capture products, and

3. Residual fissions due to the effect of delayed neutrons.

These constituents are discussed separately in the following paragraphs.

If the outside radius of the expanded pellet is smaller than the inside radius of the expanded clad, there is no fuel-clad contact and the gap conductance is calculated on the basis of the thermal conductivity of the gas contained in the gap. If the pellet outside radius so calculated is larger than the clad inside radius (negative gap), the pellet and the clad are pictured as exerting upon each other a pressure sufficiently important to reduce the gap to zero by elastic deformation of both. This contact pressure determines the gap heat transfer coefficient.

FACTRAN is further discussed in Reference 12.

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5.1.9.2 LOFTRAN

The LOFTRAN program is used for studies of transient response of a pressurized water reactor system to specified perturbations in process parameters. LOFTRAN simulates a multi-loop system by a lumped parameter single loop model containing reactor vessel, hot and cold leg piping, steam generator (tube and shell sides) and the pressurizer. The pressurizer heaters, spray, relief and safety valves are also considered in the program. Point model neutron kinetics, and reactivity effects of the moderator, fuel, boron and rods are included. The secondary side of the steam generator utilizes a homogeneous, saturated mixture for the thermal transients and a water level correlation for indication and control. The Reactor Protection System is simulated to include reactor trips on neutron flux, overpower and overtemperature reactor coolant ΔT, high and low pressure, low flow, and high pressurizer level. Control systems are also simulated including rod control, steam dump, feedwater control, and pressurizer pressure control. The Safety Injection System, including the accumulators, is also modeled.

LOFTRAN is a versatile program which is suited to both accident evaluation and control studies as well as parameter sizing.

LOFTRAN also has the capability of calculating the transient value of DNB ratio based on the input from the core limits illustrated on Figure 15.1-1. The core limits represent the minimum value of DNBR as calculated for typical or thimble cell.

LOFTRAN is further discussed in Reference 15.

15.1.9.3 PHOENIX-P

PHOENIX-P is a two-dimensional, multi-group transport theory computer code. The nuclear cross-section library used by PHOENIX-P contains cross-section data based on a 70 energy group structure derived from ENDF/B-VI files. PHOENIX-P performs a 2D 70 group nodal flux calculation which couples the individual subcell regions (pellet, cladding, and moderator) as well as surrounding rods via a collision probability technique. This 70 group solution is normalized by a coarse energy group flux solution derived from a discrete ordinates calculation. PHOENIX-P is capable of modeling all cell types needed for PWR core design application.

PHOENIX-P calculates macroscopic cross-sections as a function of burnup, fuel type, and temperature for ANC (Section 15.1.9.4).

PHOENIX-P is further discussed in Reference 16.

15.1.9.4 ANC

ANC is an advanced nodal code capable of two-dimensional and three-dimensional neutronics calculations. ANC is the reference model for certain safety analysis calculations, power distributions, peaking factors, critical boron concentrations, control rod worths, reactivity coefficients, etc. In addition, three-dimensional ANC validates one-dimensional and two-dimensional results and provides information about radial (x-y) peaking factors as a function of axial position. It can calculate discrete pin powers from nodal information as well.

ANC is further discussed in Reference 17.

15.1.9.5 TWINKLE

The TWINKLE program is multi-dimensional spatial neutron kinetics code, which was patterned after steady-state codes presently used for reactor core design. The code uses an implicit finite-difference method to solve the two-group transient neutron diffusion equations in one, two, and three dimensions. The code uses six delayed neutron groups and contains a detailed mutli-region fuel-clad-coolant heat transfer model for calculating pointwise Doppler and moderator feedback effects. The code handles up to 2000 spatial points, and performs its own steady state initialization. Aside from basic cross-section data and thermal-hydraulic parameters, the code accepts as input basic driving functions such as inlet temperature, pressure, flow, boron concentration, control rod motion, and others. Various edits provide channelwise power, axial offset, enthalpy, volumetric surge, pointwise power, fuel temperatures, and so on.

The TWINKLE code is used to predict the kinetic behavior of a reactor for transients which cause a major perturbation in the spatial neutron flux distribution.

TWINKLE is further described in Reference 18.

15.1.9.6 THINC

The THINC code is described in Section 4.4.3.1.

15.1.10 References for Section 15.1

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16. Nguyen, T. Q., et al, "Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores", WCAP-11596, June 1988.

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21. Liden, E. A., PSE&G to Varga, S. A., USNRC, "Supplemental Information Request for Amendment, Salem Generating Station Unit Nos. 1 and 2, Docket Nos. 50-272 and 50-311," February 25, 1985.

22. Letter from T. R. Croasdaile (Westinghouse) to J. T. Boettger (PSE&G), Subject: Safety Analysis for PSE&G Proposed Doppler Curve (Proprietary Document), June 28, 1984; 84PS*-G-058, NFUI 84-366.

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3. The reactor is assumed to be at hot zero power. This assumption is more conservative than that of a lower initial system temperature. The higher initial system temperature yields a larger fuel-water heat transfer coefficient, larger specific heats, and a less negative (smaller absolute magnitude) Doppler coefficient all of which tend to reduce the Doppler feedback effect thereby increasing the neutron flux peak. The initial effective multiplication factor is assumed to be 1.0 since this results in maximum neutron flux peaking.

4. Reactor trip is assumed to be initiated by power range high neutron flux (low setting). The most adverse combination of instrument and setpoint errors, as well as delays for trip signal actuation and RCCA release, is taken into account. A 10-percent increase is assumed for the power range flux trip setpoint raising it from the nominal value of 25 percent to 35 percent. Previous results, however, show that rise in the neutron flux is so rapid that the effect of errors in the trip setpoint on the actual time at which the rods are released is negligible. In addition, the reactor trip insertion characteristic is based on the assumption that the highest worth RCCA is stuck in its fully withdrawn position. See Section 15.1.5 for RCCA insertion characteristics.

5. The maximum positive reactivity insertion rate assumed is equal to that for the simultaneous withdrawal of the combination of the two control banks having the greatest combined worth at maximum speed (45 inches per minute). Control rod drive mechanism design is discussed in Section 3.2.3.

6. The initial power level was assumed to be below the power level expected for any shutdown condition. The combination of highest reactivity insertion rate and lowest initial power produces the highest peak heat flux.

15.2.1.3 Results

Figures 15.2-1 and 15.2-2 show the transient behavior for the indicated reactivity insertion rate with the accident terminated by reactor trip at 35 percent nominal power. This insertion rate is equal to that for the two highest worth control banks, both assumed to be in their highest incremental worth region.

Figure 15.2-1 shows the neutron flux transient. The neutron flux overshoots the full power nominal value but this occurs for only a very short time period. Hence, the energy release and the fuel temperature increases are relatively small. The thermal flux response, of interest for DNB considerations, is also shown on Figure 15.2-1. The beneficial effect on the inherent thermal lag in the fuel is evidenced by a peak heat flux less than the full power nominal value. There is a large margin to departure from nucleate boiling (DNB) during the transient since the rod surface heat flux remains below the design value, and there is a high degree of subcooling at all times in the core. Figure 15.2-2 shows the response of the average fuel and cladding temperature. The average fuel temperature increases to a value lower than the nominal full power value. The minimum DNBR at all times remains above the design limit.

15.2.1.4 Conclusions

In the event of a RCCA withdrawal accident from the subcritical condition, the core and the RCS are not adversely affected, since the combination of thermal power and the coolant temperature result in a departure from nucleate boiling ratio (DNBR) well above the design limit. Thus, no fuel or clad damage is predicted as a result of DNB.

15.2.2 Uncontrolled Rod Cluster Control Assembly Bank Withdrawal At Power

15.2.2.1 Identification of Causes and Accident Description

Uncontrolled RCCA bank withdrawal at power results in an increase in the core heat flux. Since the heat extraction from the steam generator lags behind the core power generation until the steam generator pressure reaches the relief or safety valve setpoint, there is a net increase in the reactor coolant temperature. Unless terminated by manual or automatic action, the power mismatch and resultant coolant temperature rise would eventually result in DNB. Therefore, in order to avert damage to the cladding the RPS is designed to terminate any such transient before the DNBR falls below the limit value.

The automatic features of the RPS which prevent core damage following the postulated accident include the following:

1. Power range neutron flux instrumentation actuates a reactor trip if two out of four channels exceed an overpower setpoint.

2. Reactor trip is actuated if any two out of four ΔT channels exceed an overtemperature ΔT setpoint. This setpoint is automatically varied with axial power imbalance, coolant temperature and pressure to protect against DNB.

ensure that the allowable heat generation rate (kw/ft) is not exceeded.

4. A high pressurizer pressure reactor trip actuated from any two out of four pressure channels which is set at a fixed point. This set pressure is less then the set pressure for the pressurizer safety valves.

5. A high pressurizer water level reactor trip actuated from any two out of three level channels which is set at a fixed point.

In addition to the above listed reactor trips, there are the following RCCA withdrawal blocks:

1. High neutron flux (one out of four)

2. Overpower ΔT (two out of four)

3. Overtemperature ΔT (two out of four)

The manner in which the combination of overpower and overtemperature ΔT trips provide protection over the full range of RCS conditions is described in Section 7. This includes a plot (also shown as Figure 15.1-1) presenting allowable reactor coolant loop average temperature and ΔT for the design power distribution and flow as a function of primary coolant pressure. The boundaries of operation defined by the overpower ΔT trip and the overtemperature ΔT trip are represented as "protection lines" on this diagram. The protection lines are drawn to include all adverse instrumentation and setpoint errors so that under nominal conditions trip would occur well within the area bounded by these lines. The utility of this diagram is in the fact that the limit imposed by any given DNBR can be represented as a line. The DNB lines represent the locus of conditions for which the DNBR equals the limit value. All points below and to the left of a DNB line for a given pressure have a DNBR greater than the limit value. The diagram shows that

DNB is prevented for all cases if the area enclosed with the maximum protection lines is not traversed by the applicable DNBR line at any point.

The area of permissible operation (power, pressure and temperature) is bounded by the combination of reactor trips: high neutron flux (fixed setpoint); high pressure (fixed setpoint); low pressure (fixed setpoint); overpower and overtemperature ΔT (variable setpoints).

15.2.2.2 Method of Analysis

This transient is analyzed by the LOFTRAN (4) code. This code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level. The core limits as illustrated on Figure 15.1-1 are used as input to LOFTRAN to determine the minimum DNBR during the transient.

In order to obtain conservative values of DNBR the following assumptions are made:

1. Initial conditions of maximum core power and reactor coolant average temperatures and minimum reactor coolant pressure, resulting in the minimum initial margin to DNB.

2. Reactivity Coefficients - Two cases are analyzed:

    a. Minimum Reactivity Feedback. A zero moderator coefficient of reactivity is assumed corresponding to the beginning of core life. A variable Doppler power coefficient with core power is used in the analysis. A conservatively small (in absolute magnitude) value is assumed.

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 RCCA 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 RCCA.

The effect of RCCA 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 nuclear power, pressurizer pressure, core average temperature, and DNBR to a rapid (75 pcm/sec) RCCA 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 nuclear power, pressurizer pressure, core average temperature, and DNBR for a slow (3 pcm/sec) control rod assembly withdrawal from full power is shown on Figures 15.2-6 and 15.2-7. Reactor trip on overtemperature ΔT occurs after a longer period and the rise in temperature is consequently larger than for rapid RCCA 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 the limit value.

Figures 15.2-9 and 15.2-10 show the minimum DNBR as a function of reactivity insertion rate for RCCA 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 the limit value.

15.2.2.4 Conclusions

The high neutron flux, high pressurizer pressure, 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 the limit value.

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15.2.3 Rod Cluster Control Assembly Misalignment

15.2.3.1 Identification of Causes and Accident Description

Rod cluster control assembly misalignment accidents include:

1. A dropped full-length assembly (single or multiple dropped rods)

2. A dropped full-length assembly bank

3. Statically misaligned assembly

Each RCCA has a position indicator channel which displays position of the assembly. The displays of assembly positions are grouped for the operator's convenience. Fully inserted assemblies are further indicated by a rod bottom light. Group demand position is also indicated. The full length assemblies are always moved in preselected banks and the banks are always moved in the same preselected sequence.

A dropped assembly or assembly banks are detected by:

1. Sudden drop in the core power level as seen by the Nuclear Instrumentation System

2. Asymmetric power distribution as seen on out of core neutron detectors or core exit thermocouples

3. Rod bottom lights(s)

4. Rod deviation alarm

5. Rod position indication

Misaligned assemblies are detected by:

1. Asymmetric power distribution as seen on out of core neutron detectors or core exit thermocouples

2. Rod deviation alarm

3. Rod position indicators

The resolution of the rod position indicator channel is ±5 percent of span (±7.2 inches). For Unit 1, deviation of any assembly; from its group by 10.4 percent of span (5 inches or 24 steps) will not cause power distributions worse than the design limits. For Unit 2, deviation of any assembly; from its group by 10.4 percent of span above 85 percent RTP (24 steps) of 13 percent of span (30 steps) at or below 85 percent RTP, will not cause power distributions worse than the design limits (Reference 16). The deviation alarm alerts the operator to rod deviation with respect to group demand position in excess of 5 percent of span. If the rod deviation alarm is not operable, the operator is required to log the RCCA positions in a prescribed time sequence to confirm alignment.

If one or more rod position indicator channels should be out of service, detailed operating instructions shall be followed to assure the alignment of the non-indicated assemblies. These operating instructions call for the use of moveable in-core neutron detectors to determine assembly misalignment within a prescribed time and following significant motion of the non-indicating assemblies.

15.2.3.2 Analysis of Effects and Consequences

15.2.3.2.1 Method of Analysis

A. One or More Dropped RCCAs from the Same Group

The LOFTRAN computer code (Reference 4) calculates the transient system response for the evaluation of the dropped RCCA event. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

Transient reactor coolant system state points (temperature, pressure, and power) are calculated by LOFTRAN. Nuclear models are used to obtain a hot channel factor consistent with the primary system conditions and reactor power. By incorporating the primary conditions from the transient analysis and the hot channel factor from the nuclear analysis, the DNB design basis is shown to be met using the THINC code. The transient response analysis, nuclear peaking factor analysis, and performance of the DNB design basis confirmation are performed in accordance with the methodology described in Reference 15. Note that the analysis does not take credit for the power-range negative flux rate reactor trip.

B. Dropped RCCA Bank

A dropped RCCA bank results in a symmetric power change in the core. As discussed in Reference 15, assumptions made in the dropped RCCA(s) analysis provide a bounding analysis for the dropped RCCA bank.

C. Statically Misaligned RCCA

Steady-state power distributions are analyzed using appropriate nuclear physics computer codes. The peaking factors are then used as input to the THINC code to calculate the DNBR. The analysis examines the following cases:

1. With the reactor initially at full power, the worst rod is withdrawn with bank D inserted at the insertion limit,
2. With the reactor initially at full power, the worst rod is dropped with bank D inserted at the insertion limit, and
3. With the reactor initially at full power, the worst rod is dropped with all other rods out.

The analysis assumes this incident to occur at beginning of life since this results in the least-negative value of the moderator temperature coefficient. This assumption maximizes the power rise and minimizes the tendency of the most-negative moderator temperature coefficient to flatten the power distribution. An analysis was performed to confirm that BOL bounds EOL conditions.

15.2.3.2.2 Results

A. One or More Dropped RCCAs

Single or multiple dropped RCCAs within the same group result in a negative reactivity insertion. The core is not adversely affected during this period since power is decreasing rapidly. Either reactivity feedback or control bank withdrawal will reestablish power.

The plant will establish a new equilibrium condition following a dropped rod event in manual rod control. Without control system interaction, a new equilibrium is achieved at a reduced power level and reduced primary temperature. Thus, the limiting case has automatic rod control.

For a dropped RCCA event with automatic rod control, the rod control system detects the drop in power and initiates control bank withdrawal. Power overshoot may occur due to this action by the automatic rod controller after which the control system will insert the control bank to restore nominal power. Figure 15.2-11 Sheet 1 and Sheet 2 developed in accordance with Reference 15, show a typical transient response to a dropped RCCA (or RCCAs) in the automatic rod control mode. In all cases, the minimum DNBR remains above the limit value.

Following plant stabilization, the operator may manually retrieve the RCCA(s) by following approved operating procedures.

B. Dropped RCCA Bank

A dropped RCCA bank results in a negative reactivity insertion greater than 500 pcm. The core is not adversely affected during the insertion period since power is decreasing rapidly. The transient will proceed as described in Part A. However, the return to power will be less due to the greater worth of the entire bank. The power transient for a dropped RCCA bank is symmetric. Following plant stabilization, normal procedures are followed.

C. Statically Misaligned RCCA

The most severe misalignment situations with respect to DNBR at significant power levels occur when one RCCA is fully inserted with either all rods out or bank D in at its insertion limit, or when bank D is inserted to its insertion limit with one RCCA fully withdrawn. Multiple independent alarms, including a bank insertion limit alarm, alert the operator well before the transient approaches the postulated conditions. The bank can be inserted to its insertion limit with any one assembly fully withdrawn or inserted without the DNBR falling below the limit value.

Insertion limits in the Technical Specifications may vary from time to time depending on several limiting criteria. The full-power insertion limits on control bank D must be above that position which meets the minimum DNBR and peaking factors. The full-power insertion limit is usually defined by other criteria. Detailed results will vary from cycle depending on fuel arrangements.

For this RCCA misalignment with bank D inserted to its full-power insertion limit and one RCCA fully withdrawn, the DNBR does not fall below the limit value. The analysis of this case assumes that the initial reactor power, pressure, and the RCS temperature are at the nominal values with uncertainties and an increased radial peaking factor associated with the misaligned RCCA(s).

For RCCA misalignment with one RCCA fully inserted, the DNBR does not fall below the limit value. The analysis of this case assumes that initial reactor power, pressure, and RCS temperatures are at the nominal values with uncertainties and an increased radial peaking factor associated with the misaligned RCCA(s).

DNB does not occur for the single RCCA misalignment incident; thus, there is no reduction in the ability of the primary coolant to remove heat from the fuel rod. The peak fuel temperature corresponds to a linear heat generation rate based on the radial peaking factor penalty associated with the misaligned RCCA and the design axial power distribution. The resulting linear heat generation rate is well below that which would cause fuel melting.

After identifying an RCCA group misalignment condition, the operator must take action as required by the plant Technical Specifications and operating instructions.

15.2.3.3 Conclusions

For cases of dropped RCCAs or dropped banks, the DNBR remains greater than the limit value. Therefore, the DNB design criterion is met and the event does not result in core damage. For all cases of any single RCCA fully inserted, or bank D inserted to its rod insertion limits with any single RCCA in that bank fully withdrawn (static misalignment), the DNBR remains greater than the limit value. Thus, the RCCA misalignments do not result in core damage.

15.2.4 Uncontrolled Boron Dilution

15.2.4.1 Malfunction of the Reactor Makeup System: Causes and Accident Description

Reactivity can be added to the core by feeding primary grade water into the RCS via the reactor makeup portion of the Chemical and Volume Control System (CVCS). Boron dilution is a manual operation under strict administrative controls with procedures calling for a limit on the rate and duration of dilution. A boric acid blend system is provided to permit the operator to match the boron concentration of reactor coolant makeup water during normal charging to that in the RCS. The CVCS is designed to limit, even under various postulated failure modes, the potential rate of dilution to a value which, after indication through alarms and instrumentation, provides the operator sufficient time to correct the situation in a safe and orderly manner.

The opening of the primary water makeup control valve provides makeup to the RCS which can dilute the reactor coolant. Inadvertent dilution from this source can be readily terminated by closing the control valve. In order for makeup water to be added to the RCS at pressure, at least one charging pump must be running in addition to a primary makeup water pump.

The rate of addition of unborated makeup water to the RCS when it is not at pressure is limited by the capacity of the primary water supply pumps. The maximum addition rate in this case is 300 gpm with both pumps running. The 300 gpm reactor makeup water delivery rate is based on a pressure drop calculation comparing the pump curves with the system resistance curve. This is the maximum delivery based on the unit piping layout. Normally, only one charging pump is operating.

The boric acid from the boric acid tank is blended with primary grade water in the blender and the composition is determined by the preset flow rates of boric acid and primary grade water on the control board.

In order to dilute, two separate operations are required:

1. The operator must switch from the automatic makeup mode to the dilute mode, and

2. The start button must be depressed.

Omitting either step would prevent dilution.

Information on the status of the reactor coolant makeup is continuously available to the operator. Lights are provided on the control board to indicate the operating condition of the pumps in the CVCS. Alarms are actuated to warn the operator if boric acid or demineralized water flow rates deviate from preset values as a result of system malfunction.

15.2.4.1.1 Method of Analysis

To cover all phases of the plant operation, boron dilution during refueling, startup, and power operation are considered in this analysis. Table 15.2-1 contains the time sequence of events for this accident.

Dilution During Refueling

During refueling, the following conditions exist:

1. One residual heat removal (RHR) pump is operating to ensure continuous mixing in the reactor vessel.

2. The seal injection water supply to the reactor coolant pumps is isolated.

3. The valves on the suction side of the charging pumps are adjusted for addition of concentrated boric acid solution.

4. The boron concentration in the refueling water is approximately 2000 ppm, corresponding to a shutdown margin of at least 5 percent $\Delta k/k$ with all RCCAs in; periodic sampling ensures that this concentration is maintained.

5. Neutron sources are installed in the core and the source range detectors outside the reactor vessel are active and provide an audible count rate. During initial core loading BF_3 detectors are installed inside the reactor vessel and are connected to instrumentation giving audible count rates to provide direct monitoring of the core.

A minimum water volume in the RCS of 3468 cubic feet is considered. This corresponds to the volume necessary to fill the reactor vessel above the nozzles to ensure mixing via the RHR loop. A maximum dilution flow of 300 gpm, limited by the capacity of the two primary water makeup pumps, and uniform mixing is assumed.

The operator has prompt and definite indication of any boron dilution from the audible count rate instrumentation. High count rate is alarmed in the reactor containment and the Control Room.

In addition a high source range flux level is alarmed in the Control Room. The count rate increase is proportional to the subcritical multiplication factor.

Dilution During Startup

Prior to startup the RCS is filled with borated (1618 ppm assumed) water from the refueling water storage tank (RWST).

Core monitoring is by external BF_3 detectors. Mixing of the reactor coolant is accomplished by operation of the reactor coolant pumps. High source range flux level and all reactor trip alarms are effective.

In the analysis, a maximum dilution flow of 300 gpm limited by the capacity of the two primary water makeup pumps is considered. The volume of the reactor coolant is assumed to be 9432 cubic feet, which is the active volume of the RCS excluding the pressurizer.

Dilution at Power

With the unit at power and the RCS at pressure, the dilution rate (236 gpm) is limited by the capacity of the charging pumps.

15.2.4.1.2 Conclusions

For dilution during refueling

At the beginning of the core life, equilibrium cycle core, the boron concentration must be reduced from 2000 ppm to approximately 1400 ppm before the reactor will go critical. This would take 30 minutes. This is ample time for the operator to recognize a high count rate signal and isolate the reactor makeup water source by closing valves and stopping the primary water supply pumps.

For dilution during startup

The minimum time required to reduce the reactor coolant boron concentration to 1450 ppm where the reactor would go critical with all RCCAs in, is 19 minutes. Once again this should be more than adequate time for the operator to recognize the high count rate signal and terminate the dilution flow.

For dilution during full power operation

With the reactor in automatic control at full power, the power and temperature increase from boron dilution results in the insertion of the RCCAs and a decrease in shutdown margin. Continuation of dilution and RCCA insertion would cause the assemblies to reach the minimum limit of the rod insertion monitor. Before reaching this point, however, two alarms would be actuated to warn the operator of the accident condition. The first of these, the low insertion limit alarm, alerts the operator to initiate normal boration. The other, the low-low insertion limit alarm alerts the operator to follow emergency boration procedures. The low alarm is set sufficiently above the low-low alarm to alarm normal boration without the need for emergency procedures. If dilution continues after reaching the low-low alarm, there will be 18.7 minutes available for operator action before the total shutdown margin (assuming 1.3 percent) is lost due to dilution. Therefore, adequate time is available following the alarms for the operator to determine the cause, isolate the primary grade water source, and initiate reboration.

With the reactor in manual control and if no operator action is taken, the power and temperature rise will cause the reactor to reach the overtemperature ΔT trip setpoint. The boron dilution accident in this case is essentially identical to a RCCA withdrawal accident at power. The maximum reactivity insertion rate for boron dilution at power (1.16 pcm/sec) is within the range of insertion rates analyzed for a RCCA withdrawal accident. Prior to the overtemperature ΔT trip, an overtemperature ΔT alarm and turbine runback would be actuated. There are 17.2 minutes after a reactor trip for the operator to determine the cause of dilution, isolate the primary grade water sources and initiate reboration before the reactor can return to criticality assuming a 1.3 percent shutdown margin at the beginning of dilution.

15.2.4.2 Miscellaneous Malfunctions: Causes, Accident Descriptions, and Analyses

An analysis was conducted for the CVCS and other interconnecting systems for the various modes of reactor operation. Attention was directed towards identification of possible paths for an inadvertent boron dilution of the RCS to occur. Each path was analyzed as to the required modes of failure, if any, and the likelihood of occurrence.

Tube failures of heat exchangers located in the CVCS and other interconnecting (RHR, SI, etc.) systems was evaluated. It was found that the seal water heat exchanger has seal water return flowing at a lower pressure than that of the component cooling water. The postulated mode of a failure for this heat exchanger was a single tube failure. Should this occur the total quantity of component cooling water leaking into the RCS would not cause a sharp drop in boron concentration, thereby initiating a sudden increase in reactivity. The low level alarm in the component cooling surge tank or a high level of chromates in the RCS would notify the operators of the problem. A total tube rupture was considered to be extremely unlikely and was not evaluated. All other heat exchangers are designed such that the primary system pressure is greater than the cooling water system pressure, thus precluding boron dilution from occurring.

Unborated water can enter the CVCS while flushing resins from the ion exchange demineralizers. This process involves a total of 600 to 1,000 gallons of primary water to be flushed with spent resins to the spent resin storage tank. The only possible path of entry of this water into the CVCS would be the failure to close the process outlet valve located in the discharge line of each demineralizer. The CVCS pressure at this point is slightly less than the flushing water pressure. The majority of water used to flush the spent resin would, therefore, flow through the demineralizers to the spent resin storage tank (this being the path of least resistance). The amount of primary water capable of entering the CVCS would be a small percentage of the total available volume of water. In order to postulate the worst possible case it was assumed that all 1,000 gallons enter the CVCS via the letdown line flowing to the Volume Control Tank (VCT). The amount of primary water flowing into the VCT depends upon the existing level in the tank. A three-way valve diverts letdown flow to the CVCS holdup tanks on high level signals in the VCT. The portion of water flowing into the VCT enters as a spray mixing with approximately 1,000 to 2,000 gallons of borated water present in the tank. One charging pump normally takes suction from the VCT to provide water for charging and for RCP seals. Total charging flow into the RCS runs as high as 100 gpm. This enters via the reactor coolant pump seals (20 gpm for all four pumps) and through the charging line to the RCS (55 to 80 gpm). Therefore, a situation could occur where there is 100 gpm of unborated water entering the RCS. In order for this to occur, all 1,000 gallons of primary water must flow into the VCT with a minimum amount of mixing with the borated water already present. The probability of this occurring is extremely low. Nevertheless, if the situation

15.2.5.2 Method of Analysis

The following case has been analyzed:

1. Four loops initially operating, two pumps coasting down

The transient is analyzed by three digital computer codes. First the LOFTRAN (4) code is used to calculate the loop and core flow during the transient, the time of reactor trip, and the nuclear power transient following reactor trip. The FACTRAN code is then used to calculate the heat flux transient based on the nuclear power and flow from LOFTRAN. Finally the THINC code is used to calculate the minimum DNBR during the transient based on the heat flux from FACTRAN and flow from LOFTRAN. The DNBR transient presented represents the minimum of the typical or thimble cell for fuel assemblies with and without intermediate flow mixing grids (IFMs).

15.2.5.3 Initial Conditions

Initial operating conditions assumed are the most adverse with respect to the margin to DNB, i.e., maximum steady state power level, minimum steady state pressure, and maximum steady state coolant average temperature. This event is analyzed with the Revised Thermal Design Procedure (RTDP) (Reference 21). Initial reactor power, pressurizer pressure, and RCS temperature are assumed to be at their nominal values. See Section 15.1.2 for explanation of initial conditions.

Reactivity Coefficients

A conservatively large absolute value of the Doppler-only power coefficient is used (See Table 15.1-2). The total integrated Doppler reactivity from 0 to 100 percent power is assumed to be 0.0185 Δk.

The lowest absolute magnitude of the moderator temperature coefficient (0.0 $\Delta k/^{\circ}F$) is assumed since this results in the maximum hot-spot heat flux during the initial part of the transient when the minimum DNBR is reached.

Flow Coastdown

The flow coastdown analysis is based on a momentum balance around each reactor coolant loop and across the reactor core. This momentum balance is combined with the continuity equation, a pump momentum balance and the pump characteristics and is based on high estimates of system pressure losses.

15.2.5.4 Results

The calculated sequence of events is shown in Table 15.2-1 for the case analyzed. Figures 15.2-13 through 15.2-15 show the loop coastdowns, the core flow coastdowns, the nuclear power coastdowns and the average and hot-channel heat flux coastdowns for each of the two cases. The minimum DNBR for fuel assemblies with and without IFMs is not less than the design limit.

15.2.5.5 Conclusions

The analysis shows that the DNBR will not decrease below the limiting value at any time during the transient. Thus no core safety limit is violated.

15.2.6 Startup of an Inactive Reactor Coolant Loop

The Technical Specifications require that all four reactor coolant pumps are operating for reactor power operation and, therefore, operation with an inactive loop is precluded. This event was originally included in the FSAR licensing basis when operation with a loop out of service was considered. Based on the current Technical Specifications which deleted all references to three-loop operation, this event has been deleted from the FSAR.

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15.2.7 Loss of External Electrical Load and/or Turbine Trip

15.2.7.1 Identification of Causes and Accident Description

Major load loss on the plant can result from loss of external electrical load or from a turbine trip. For either case, offsite power is available for the continued operation of plant components such as the reactor coolant pumps. The case of loss of all offsite ac power is analyzed in Section 15.2.9.

For a turbine trip, the reactor would be tripped directly (unless below approximately 50-percent power) from a signal derived from the turbine autostop oil pressure (Westinghouse turbine) and turbine stop valves. The automatic Steam Dump System would accommodate the excess steam generation. Reactor coolant temperatures and pressure do not significantly increase if the Steam Dump System and Pressurizer Pressure Control System are functioning properly. If the turbine condenser were not available, the excess steam generation would be dumped to the atmosphere. Additionally, main feedwater flow would be lost if the turbine condenser were not available. For this situation, feedwater flow would be maintained by the Auxiliary Feedwater System.

For a loss of external electrical load without subsequent turbine trip, no direct reactor trip signal would be generated. The plant would be expected to trip from the RPS. A continued steam load of approximately 5 percent would exist after total loss of external electrical load because of the steam demand of plant auxiliaries.

In the event the steam dump valves fail to open following a large loss of load, the steam generator safety valves may lift and the reactor may be tripped by the high pressurizer pressure signal, the high pressurizer water level signal, the low-low steam generator water level signal, the overpower ΔT signal, or the overtemperature ΔT signal. The steam generator shell side pressure and reactor coolant temperatures will increase rapidly. The pressurizer safety valves and steam generator safety valves are, however, sized to protect the RCS and steam generator against overpressure for all load losses without assuming the operation of the Steam Dump System, pressurizer spray, pressurizer power-operated relief valves, automatic rod cluster control assembly control, or direct reactor trip on turbine trip.

The steam generator safety valve capacity is sized to remove the steam flow at the engineered safeguards design rating (~105 percent of steam flow at rated power) from the steam generator without exceeding 110 percent of the steam system design pressure. The pressurizer safety valve capacity is sized based on a complete loss of heat sink with the plant initially operating at the maximum calculated turbine load along with operation of the steam generator safety valves. The pressurizer safety valves are then able to maintain the RCS pressure within 110 percent of the RCS design pressure without direct or immediate reactor trip action.

A more complete discussion of overpressure protection can be found in Reference 8.

15.2.7.2 Method of Analysis

The total loss of load transients is analyzed by employing the detailed digital computer program LOFTRAN. The program simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The program computes pertinent plant variables including temperatures, pressures, and power level.

In this analysis, the behavior of the unit is evaluated for a complete loss of steam load from 102 percent of full power without direct reactor trip to show the adequacy of the pressure relieving devices and from 100 percent of full power to demonstrate core protection margins.

Typical assumptions are the following:

1. Initial Operating Conditions - For the cases analyzed to demonstrate that core protection margins are maintained (Cases 1 and 2), the Loss of Load accident is analyzed using the Revised Thermal Design Procedure. For these cases, initial core power, reactor coolant temperature, and reactor coolant pressure are assumed to be at their nominal values consistent with steady-state full power operation. Uncertainties in initial conditions are included in the departure from nucleate boiling ratio (DNBR) limit described in WCAP-11397 (Reference 21). For the cases analyzed to demonstrate the adequacy of the pressure relieving devices (Cases 3 and 4), the Loss of Load accident is analyzed using the Standard Thermal Design Procedure. For these cases, initial core power, reactor coolant temperature, and reactor coolant pressure are assumed at their maximum values consistent with steady-state full power operation including allowances for calibration and instrument errors. This results in the maximum power difference for the load loss.

2. Moderator and Doppler Coefficients of Reactivity - The total loss of load is analyzed for both the beginning of life and end of life conditions. Moderator temperature coefficients of zero at beginning of life and a large (absolute value) negative value at end of life are used. A conservatively large (absolute value) Doppler power coefficient is used for all cases.

3. Reactor Control - From the standpoint of the maximum pressures attained it is conservative to assume that the reactor is in manual control.

4. Steam Release - No credit is taken for the operation of the Steam Dump System or steam generator power-operated relief valves. The steam generator pressure rises to the safety valve setpoints where steam release through safety valves limits secondary steam pressure at the setpoint values.

5. <u>Pressurizer Spray and Power-Operated Relief Valves</u> - Two cases for both the beginning and end of life are analyzed:

   a. Full credit is taken for the effect of pressurizer spray and power-operated relief valves in reducing or limiting the coolant pressure.

   b. No credit is taken for the effect of pressurizer spray and power-operated relief valves in reducing or limiting the coolant pressure.

6. <u>Feedwater Flow</u> - Main feedwater flow to the steam generators is assumed to be lost at the time of turbine trip. No credit is taken for auxiliary feedwater flow since a stabilized plant condition will be reached before auxiliary feedwater initiation is normally assumed to occur. However, the auxiliary feedwater pumps would be expected to start on a trip of the main feedwater pumps. The auxiliary feedwater flow would remove core decay heat following plant stabilization.

Reactor trip is actuated by the first RPS trip setpoint reached with no credit taken for the direct reactor trip on the turbine trip.

15.2.7.3 <u>Results</u>

Figures 15.2-20 through 15.2-22 show the transient response for the total loss of steam load from 100 percent full power operation at beginning of life with zero moderator temperature coefficient assuming full credit for the pressurizer spray and pressurizer power-operated relief valves. No credit is taken for steam dump. The reactor is tripped by the overtemperature ΔT trip channel. This case was analyzed to demonstrate that adequate protection of the core thermal limits exists. The minimum DNBR remains well above the limit value.

Figures 15.2-23 through 15.2-25 show the transient response for the total loss of load accident from 102 percent full power operation at beginning of life with zero moderator temperature coefficient with no credit taken for pressurizer spray, pressurizer power-operated relief valves, or steam dump. This case was analyzed to demonstrate the adequacy of the pressure relieving devices. The reactor is tripped on the high pressurizer pressure signal. The neutron flux remains constant at 102 percent of full power until the reactor is tripped. The primary and secondary pressures increase such that the pressurizer safety and main steam safety valves are actuated.

The figures presented for this event are taken from explicit calculations performed for the Unit 1 replacement steam generators. Unit 2 analysis results are similar in nature to those presented here, and the conclusions presented below apply to both sets of analyses.

15.2.7.4 Conclusions

Results of the analyses show that the plant design is such that a total loss of external electrical load without a direct or immediate reactor trip presents no hazard to the integrity of the RCS or the Main Steam System. Pressure relieving devices incorporated in the two systems are adequate to limit the maximum pressures to within the design limits.

The integrity of the core is maintained by operation of the RPS, i.e., the DNBR will be maintained above the limit value. Thus there will be no cladding damage and no release of fission products to the RCS.

15.2.8 Loss of Normal Feedwater

15.2.8.1 Identification of Causes and Accident Description

A loss of normal feedwater (from pump failures, valve malfunctions, or loss of offsite ac power) results in a reduction in capability of the secondary system to remove the heat generated in the reactor core. If the reactor were not tripped during this accident, core damage would possibly occur from a sudden loss of heat sink. If an alternative supply of feedwater were not supplied to the plant, residual heat following reactor trip would heat the primary system water to the point where water relief from the pressurizer occurs. Significant loss of water from the RCS could conceivably lead to core damage. Since the plant is tripped well before the steam generator heat transfer capability is reduced, the primary system variables never approach a DNB condition.

The following provides the necessary protection against a loss of normal feedwater:

1. Reactor trip on low-low water level in any steam generator.

2. Two motor-driven auxiliary feedwater pumps which are started on:

   a. Low-low level in any steam generator

   b. Trip of all main feedwater pumps

   c. Any safety injection signal

   d. Loss of offsite power

   e. Manual actuation

3. One turbine-driven auxiliary feedwater pump which is started on:

   a. Low-low level in any two steam generators, or

   b. Undervoltage on any two reactor coolant pump buses

   c. Manual actuation

The motor-driven auxiliary feedwater pumps are supplied by the diesels if a loss of offsite power occurs and the turbine-driven pump utilizes steam from the secondary system. Both type pumps are designed to start within one minute even if a loss of offsite power occurs simultaneously with loss of normal feedwater. The turbine exhausts the secondary steam to the atmosphere. The auxiliary pumps take suction from the auxiliary feedwater storage tank for delivery to the steam generators.

The analysis shows that following a loss of normal feedwater, the Auxiliary Feedwater System is capable of removing the stored and residual heat thus preventing either over-pressurization of the RCS or loss of water from the reactor core.

15.2.8.2 Method of Analysis

A detailed analysis using the LOFTRAN Code is performed in order to obtain the plant transient following a loss of normal feedwater. The simulation describes the plant thermal kinetics, RCS including the natural circulation, pressurizer, steam generators and Feedwater System. The digital program computes pertinent variables including the steam generator mass, pressurizer water volume, and reactor coolant average temperature.

Major assumptions are:

1. Reactor trip occurs on low-low steam generator water level at 0% narrow range span.

2. The plant is initially operating at 102 percent of the NSSS power rating.

3. A conservative core residual heat generation based on the 1979 version of ANS 5.1-1979 plus two standard deviations.

4. Two motor-driven auxiliary feedwater pumps are available one minute after reactor trip.

5. Auxiliary feedwater total flow of 880 gpm is delivered to all steam generators.

6. Secondary system steam relief is achieved through the self-actuated safety valves. Note that steam relief will, in fact, be through the power-operated relief valves or condenser dump valves for most cases of loss of normal feedwater. However, for the sake of analysis these have been assumed unavailable.

7. The initial reactor coolant average temperature is 5°F higher than the nominal value since this results in a greater expansion of RCS water during the transient and, thus, in a higher water level in the pressurizer.

8. The initial pressurizer pressure is 50 psi higher than the nominal value.

15.2.8.3 Results

Figure 15.2-28A through 15.2-28C show plant parameters following a loss of normal feedwater.

Following the reactor and turbine trip from full load, the water level in the steam generators falls due to the reduction of steam generator void fraction and because steam flow through the safety valves continues to dissipate the stored and generated heat. One minute following the initiation of the low-low level trip, the auxiliary feedwater pumps are automatically started, reducing the rate of water level decrease.

The capacity of the auxiliary feedwater pumps are such that the water level in the steam generators does not recede below the lowest level at which sufficient heat transfer area is available to dissipate core residual heat without the pressurizer filling, or water relief from the RCS relief or safety valves.

The figures presented for this event are taken from explicit calculations performed for the Unit 1 replacement steam generators. Unit 2 analysis results are similar in nature to those presented here, and the conclusions presented below apply to both sets of analyses.

15.2.8.4 Conclusions

Results of the analysis show that a loss of normal feedwater does not adversely affect the core, the RCS, or the steam system since the auxiliary feedwater capacity is such that the reactor coolant water is not relieved from the pressurizer relief or safety valves.

15.2.9 Loss of Offsite Power to The Station Auxiliaries

15.2.9.1 Identification of Causes and Accident Description

In the event of a complete loss of offsite power and a turbine trip, there will be a loss of power to the plant auxiliaries, i.e., the reactor coolant pumps, condensate pumps, etc.

The events following a loss of ac power with turbine and reactor trip are described in the sequence listed below:

1. Plant vital instruments are supplied by emergency power sources.

2. As the steam system pressure rises following the trip, the steam system power-operated relief valves are automatically opened to the atmosphere. Steam dump to the condenser is assumed not to be available. If the steam flow rate through the power relief valves is not available, the steam generator self-actuated safety valves may lift to dissipate the sensible heat of the fuel and coolant plus the residual heat produced in the reactor.

3. As the no load temperature is approached, the steam system power relief valves (or the self-actuated safety valves, if the power relief valves are not available) are used to dissipate the residual heat and to maintain the plant at the hot standby condition.

4. The emergency diesel generators started on loss of voltage on the plant emergency buses begin to supply plant vital loads.

The Auxiliary Feedwater System is started automatically as discussed in the loss of normal feedwater analysis. The steam-driven auxiliary feedwater pump utilizes steam from the secondary system and exhausts to the atmosphere. The motor driven auxiliary feedwater pumps are supplied by power from the diesel generators. The pumps take suction directly from the auxiliary feedwater storage tank for delivery to the steam generators.

Upon the loss of power to the reactor coolant pumps, coolant flow necessary for core cooling and the removal of residual heat is maintained by natural circulation in the reactor coolant loops.

15.2.9.2 Method of Analysis

A detailed analysis using the LOFTRAN Code is performed in order to obtain the plant transient response following a loss of offsite power. The simulation describes the plant thermal kinetics, RCS including the natural circulation, pressurizer, steam generators and Feedwater System. The digital program computes pertinent variables including the steam generator mass, pressurizer water volume, and reactor coolant average temperature.

The following major assumptions are made. These assumptions are similar to the loss of normal feedwater (section 15.2.8) assumptions except that power is assumed to be lost at the time of reactor trip.

1. Reactor trip occurs on steam generator low-low water level at 0% of narrow range span.

2. The plant is initially operating at 102% of the NSSS rated power.

3. A conservative core residual heat generation is used based on the 1979 version of ANS 5.1 plus two standard deviations.

4. Two motor-driven auxiliary feedwater pumps are available one minute after reactor trip. The pumps are assumed to deliver a total of 880 gpm to all steam generators.

5. Secondary system steam relief is achieved through the safety valves. Steam relief through the power-operated relief valves or condenser dump valves is assumed to be unavailable.

6. After normal steam generator level is established, auxiliary feedwater flow is controlled to maintain the water level.

7. The initial reactor coolant average temperature is 5°F lower than the nominal value.

8. The initial pressurizer pressure is 50 psi higher than the nominal value.

15.2.9.3 Results

Figures 15.2-28D through 15.2-28F show the plant parameters following a loss of power to the station auxiliaries event. The sequence of events is provided in

Table 15.2-1. The natural circulation flow as a function of residual reactor power is presented in Table 15.2-3.

Following the reactor and turbine trip from full load, the water level in the steam generators will fall due to the reduction of steam generator void fraction and because steam flow through the safety valves continues to dissipate the stored and generated heat. One minute following the low-low steam generator water level trip, the auxiliary feedwater pumps deliver flow, reducing the rate of the water level decrease. The capacity of the auxiliary feedwater pumps is such that the water level in the steam generators does not recede below the level at which sufficient heat transfer area is available to dissipate core residual heat without pressurizer filling or water relief from the RCS relief or safety valves.

The results of the analysis show that the natural circulation flow available is sufficient to provide adequate core decay heat removal following reactor trip and RCP coastdown.

The figures presented for this event are taken from explicit calculations performed for the Unit 1 replacement steam generators. Unit 2 analysis results are similar in nature to those presented here, and the conclusions presented below apply to both sets of analyses.

15.2.9.4 Conclusions

Results of the analysis show that a loss of power to the station auxiliaries does not adversely affect core, the RCS, or the steam system since the auxiliary feedwater capacity is such that the reactor coolant water is not relieved from the pressurizer relief or safety valves.

The RCS is not overpressurized and no water relief will occur through the pressurizer relief or safety valves. Thus, there will be no cladding damage and no release of fission products to the RCS.

15.2.10 Excessive Heat Removal Due to Feedwater System Malfunctions

15.2.10.1 Identification of Causes and Accident Description

Reductions in feedwater temperature or excessive feedwater flow additions are means of increasing core power above full power. Such transients are attenuated by the thermal capacity of the secondary plant and of the reactor coolant system (RCS). The overpower/overtemperature protection (high neutron flux, overtemperature ΔT, and overpower ΔT trips) prevents any power increase that could lead to a departure from nucleate boiling ratio (DNBR) less than the safety analysis limit.

An example of excessive feedwater flow would be a full opening of one or more feedwater control valves due to a feedwater control system malfunction or an operator error. At power, this excess flow causes a greater load demand on the RCS due to increased subcooling in the steam generators. With the plant at no-load conditions, the addition of cold feedwater may cause a decrease in RCS temperature and thus, a reactivity insertion due to the effects of the negative moderator temperature coefficient of reactivity. Continuous excessive feedwater flow addition is prevented by the steam generator high-high level trip which closes all feedwater control and isolation valves, trips the main feedwater pumps, and trips the turbine.

A second example of excess heat removal is the transient associated with the accidental opening of the low pressure feedwater heater bypass valve that diverts flow around the low pressure feedwater heaters. The function of this valve is to maintain net positive suction head on the main feedwater pump in the event that the heater drain pump flow is lost--e.g., following a large load decrease. At power, this increased subcooling will create a greater load demand on the RCS.

15.2.10.2 Method of Analysis

The excessive heat removal due to a feedwater system malfunction transient is analyzed with the LOFTRAN and THINC computer codes. LOFTRAN simulates a multi-loop system, neutron kinetics, the pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and main steam safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level as well as a conservative DNBR calculation. If appropriate, statepoints are then transferred to THINC for a more rigorous DNBR calculation.

The system is analyzed to show acceptable consequences in the event of a feedwater system malfunction. Feedwater temperature reduction due to low-pressure heater bypass valve actuation with an inadvertent trip of the heater drain pump is considered. Additionally, excessive feedwater flow addition due to a control system malfunction or operator error that allows one or more feedwater control and feedwater control bypass valves to open fully is considered.

Eight excessive feedwater flow cases are analyzed as follows:

1. Zero Power, Single Loop, Manual Rod Control Case - Accidental opening of one feedwater control valve (FCV) and one feedwater control bypass valve (FCBV) with the reactor just critical at zero-load conditions assuming a conservatively large moderator density coefficient characteristic of end of life (EOL) conditions with the reactor in manual rod control.

2. Zero Power, Single Loop, Automatic Rod Control Case - Accidental opening of one FCV and one FCBV with the reactor just critical at zero-load conditions assuming a conservatively large moderator density coefficient characteristic of EOL conditions with the reactor in automatic rod control.

3. Full Power, Single Loop, Manual Rod Control Case - Accidental opening of one FCV (with the corresponding FCBV open) with the reactor in manual control at full power.

4. Full Power, Single Loop, Automatic Rod Control Case - Accidental opening of one FCV (with the corresponding FCBV open) with the reactor in automatic control at full power.

5. Zero Power, Multi-Loop, Manual Rod Control Case - Accidental opening of four FCVs and four FCBVs with the reactor just critical at zero-load conditions assuming a conservatively large moderator density coefficient characteristic of EOL conditions with the reactor in manual rod control.

6. Zero Power, Multi-Loop, Automatic Rod Control Case - Accidental opening of four FCVs and four FCBVs with the reactor just critical at zero-load conditions assuming a conservatively large moderator density coefficient characteristic of EOL conditions with the reactor in automatic rod control.

7. Full Power, Multi-Loop, Manual Rod Control Case - Accidental opening of four FCVs (with their corresponding FCBVs open) with the reactor in manual control at full power.

8. Full Power, Multi-Loop, Automatic Rod Control Case - Accidental opening of four FCVs (with their corresponding FCBVs open) with the reactor in automatic control at full power.

The transient response due to a feedwater system malfunction is calculated with the following assumptions:

1. This accident is analyzed with the Revised Thermal Design Procedure as described in WCAP-11397-P-A (Reference 21). Therefore, initial reactor power, pressure, and RCS temperatures are assumed to be at their nominal values. Uncertainties in initial conditions are included in the limit DNBR calculated using the methodology described in Reference 16.

2. For the single loop accidents at full power, one FCV and one FCBV are assumed to malfunction resulting in a step increase in nominal full load feedwater flow to one steam generator.

3. For the single loop accidents at zero load, the malfunction results in an increase in feedwater flow to one steam generator.

4. For the multi-loop accidents at full power, four FCVs and four FCBVs are assumed to malfunction resulting in a step increase in nominal full load feedwater flow to each of the four steam generators.

5. For the multi-loop accidents at zero load, the malfunction results in an increase in feedwater flow to each of the four steam generators.

6. The initial water level in all steam generators is at a conservatively low level.

7. No credit is taken for the heat capacity of the RCS and steam generator thick metal in attenuating the resulting plant cooldown.

8. No credit is taken for the heat capacity of the steam and water in the unaffected steam generators.

9. The feedwater flow resulting from the malfunction is terminated by the steam generator high-high water level signal. This signal closes all FCVs, FCBVs and feedwater isolation valves and trips the main feedwater pumps and turbine generator (tripping the main feedwater pumps causes valves in the pump discharge line to automatically close).

10. MS10 valves are assumed to fail open concurrently with the feedwater malfunction.

15.2.10.3 Results

Opening of a low pressure feedwater heater bypass valve and tripping the heater drain pumps causes a reduction in the feedwater temperature that increases the thermal load on the primary system. The increased thermal load caused by the opening of the low pressure heater bypass valve and the heater drain pump trip results in a transient very similar (but of reduced magnitude) to that of the Excessive Load Increase event. Therefore, results for this event are not presented here.

Of the full power cases, the multi-loop feedwater malfunction cases result in the closest approach to the safety analysis limit DNBR. A turbine trip and reactor trip is actuated when the steam generator level reaches the high-high level setpoint.

For the zero power feedwater malfunction cases, the primary intent of the event is to determine the maximum equivalent reactivity insertion rate that would be experienced for the given failure scenario. This reactivity insertion rate is compared to the reactivity insertion rate assumed in the RCCA Bank Withdrawal from a Subcritical Condition (UFSAR Section 15.2.1). Although the zero power feedwater malfunction reactivity insertion rate conservatively assumes reactivity parameters representative of EOL core conditions, the DNB analysis for UFSAR Section 15.2.1 assumes conditions representing beginning of life, which is conservative with respect to the DNB analysis. If the reactivity insertion rate assumed in the UFSAR Section 15.2.1 analysis bounds the reactivity insertion rate calculated for the zero power feedwater malfunction cases, then the DNB transient will also be bounded.

The calculated maximum reactivity insertion rate for all of the zero power feedwater malfunction cases is indeed bounded by the reactivity insertion rate assumed in the UFSAR Section 15.2.1 analysis. The results for the DNB analysis for UFSAR Section 15.2.1 show that the DNBR remains above the safety analysis limit value. Thus, the DNB results for the zero power feedwater malfunction cases, although not explicitly calculated, are bounded by the DNB results calculated for UFSAR Section 15.2.1 and remain above the safety analysis limit value.

For all cases of excessive feedwater flow, continuous addition of cold feedwater is prevented by automatic closure of all feedwater control valves, closure of all feedwater bypass valves, a trip of the feedwater pumps, and a turbine trip on high-high steam generator water level. Following a turbine trip, the reactor will automatically be tripped, either directly due to the turbine trip or due to one of the reactor trip signals discussed in UFSAR Section 15.2.7, Loss of External Electrical Load and/or Turbine Trip.

Transient results for both the full-power, single-loop, manual rod-control case and the full-power, multi-loop, automatic rod-control case are shown in Figures 15.2-29a through f.

These figures show the core heat flux, pressurizer pressure, average temperature, DNBR, increase in nuclear power and loop ΔT associated with the described accident. The steam generator water level rises until the feedwater flow addition is terminated by the high-high steam generator level trip. In all cases, the DNBR stays above the safety analysis limit value.

Since the power level rises during this event, the fuel temperature will also rise until the reactor trip occurs. The core heat flux lags behind the neutron flux due to the fuel rod thermal time constant and, as a result, the peak core heat flux value does not exceed 118 percent of nominal. Thus, the peak fuel melting temperature will remain well below the fuel melting point.

The sequence of events for the limiting single loop and multi-loop cases are shown in Table 15.2-1.

The figures presented for this event are taken from explicit calculations performed for Unit 2. Explicit analysis results for the Unit 1 replacement steam generators are similar in nature to those presented here, and the conclusions presented below apply to both sets of analyses.

15.2.10.4 Conclusions

The decrease in the feedwater temperature transient due to an opening of the low-pressure feedwater heater bypass valve is less severe than the Excessive Load Increase event (see UFSAR Section 15.2.11). Based on the results presented in UFSAR Section 15.2.11, applicable acceptance criteria for the decrease in feedwater temperature event have been met.

For the excessive feedwater flow at full power transient, the results show that the DNBRs encountered are above the safety analysis limit value; therefore, no fuel damage is predicted. Additionally, an analysis at hot zero power demonstrates that the minimum DNBR remains above the safety analysis limit for a maximum reactivity insertion rate conservatively bounding an excessive feedwater addition at no-load conditions.

15.2.11 Excessive Load Increase Incident

15.2.11.1 Identification of Causes and Accident Description

An excessive load increase incident is defined as a rapid increase in the steam flow that causes a power mismatch between the reactor core power and the steam generator load demand. The Reactor Control System is designed to accommodate a 10-percent step load increase or a 5 percent per minute ramp load increase in the range of 15 to 100 percent of full power. Any loading rate in excess of these values may cause a reactor trip actuated by the RPS.

This accident could result from either an administrative violation such as excessive loading by the operator or an equipment malfunction in the steam dump control or turbine speed control.

During power operation, steam dump to the condenser is controlled by reactor coolant condition signals; i.e., high reactor coolant temperature indicates a need for steam dump. A single controller malfunction does not cause steam dump; an interlock is provided which blocks the opening of the valves unless a large turbine load decrease or a turbine trip has occurred.

Protection against an excessive load increase accident is provided by the following RPS signals:

1. Overpower ΔT
2. Overtemperature ΔT
3. Power range high neutron flux

15.2.11.2 Method of Analysis

This accident is analyzed using the LOFTRAN Code. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

Four cases are analyzed to demonstrate the plant behavior following a 10-percent step load increase from rated load. These cases are as follows:

1. Manually controlled reactor at beginning-of-life (BOL)
2. Manually controlled reactor at end-of-life (EOL)
3. Reactor in automatic control at BOL

4. Reactor in automatic control at EOL

At BOL the core has the least negative moderator temperature coefficient of reactivity and therefore the least inherent transient capability. At EOL the moderator temperature coefficient of reactivity has its highest absolute value. This results in the largest amount of reactivity feedback due to changes in coolant temperature.

A conservative limit on the turbine valve opening is assumed, and all cases are studied without credit being taken for pressurizer heaters. Initial operating conditions are assumed at nominal values. Operational uncertainties and DNBR correlation statistics are considered in the generation of the limiting DNBR (Section 15.1.2).

15.2.11.3 <u>Results</u>

Figures 15.2-30 through 15.2-33 illustrate the transient with the reactor in the manual control mode. As expected, for the BOL case there is a slight power increase, and the average core temperature shows a large decrease. This results in a DNBR which increases above its initial value. For the EOL manually controlled case there is a much larger increase in reactor power due to the moderator feedback. A reduction in DNBR is experienced, but DNBR remains above the limit value.

Figures 15.2-34 through 15.2-37 illustrate the transient assuming the reactor is in the automatic control mode. Both the BOL and the EOL cases show that core power increases, thereby reducing the rate of decrease in coolant average temperature and pressurizer pressure. For both the BOL and EOL cases, the minimum DNBR remains above the limit value.

15.2.11.4 Conclusions

It has been demonstrated that for an excessive load increase the minimum DNBR during the transient will not be below the limit value.

15.2.12 Accidental Depressurization of The Reactor Coolant System

15.2.12.1 Identification of Causes and Accident Description

The most severe core conditions resulting from an accidental depressurization of the RCS are associated with an inadvertent opening of a pressurizer safety valve. The event results in a rapidly decreasing RCS pressure. The effect of the pressure decrease is a decrease in the neutron flux via the moderator density feedback, but the Reactor Control System (if in the automatic mode) functions to maintain the power and average coolant temperature until reactor trip occurs. The pressurizer level increases initially due to expansion caused by depressurization and then decreases following reactor trip.

The reactor will be tripped by the following RPS signals:

1. Pressurizer low pressure

2. Overtemperature ΔT

15.2.12.2 Method of Analysis

The accidental depressurization transient is analyzed by employing the detailed digital computer code LOFTRAN. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

In calculating the DNBR, the following conservative assumptions are made:

1. The accident is analyzed using the Revised Thermal Design Procedure. Initial core power, reactor coolant average temperature, and RCS pressure are assumed to be at their nominal values consistent with steady-state full-power operation. Uncertainties in initial conditions are included in the DNBR limit described in Reference 21.

2. A zero moderator coefficient of reactivity conservative for BOL operation in order to provide a conservatively low amount of negative reactivity feedback due to changes in moderator temperature. The spatial effect of void due to local or subcooled boiling is not considered in the analysis with respect to reactivity feedback or core power shape.

3. A high (absolute value) Doppler coefficient of reactivity such that the resultant amount of positive feedback is conservatively high in order to retard any power decrease due to moderator reactivity feedback.

It should also be noted that in the analysis power peaking factors are kept constant at the design values while, in fact, the core feedback effects would result in considerable flattening of the power distribution. This would significantly increase the calculated DNBR; however, no credit is taken for this effect.

15.2.12.3 Results

Figure 15.2-38 illustrates the nuclear power transient following the accident. Reactor trip on overtemperature ΔT occurs as shown on Figure 15.2-38. The pressure decay transient following the accident is given on Figure 15.2-38. The resulting DNBR never goes below the limit value as shown on Figure 15.2-39.

15.2.12.4 Conclusions

The pressurizer low pressure and the overtemperature ΔT RPS signals provide adequate protection against this accident, and the minimum DNBR remains in excess of the limit value.

15.2.13 Accidental Depressurization of The Main Steam System

15.2.13.1 Identification of Causes and Accident Description

The most severe core conditions resulting from an accidental depressurization of the MSS are associated with an inadvertent opening of a single steam dump, relief or safety valve. The analyses performed assuming a rupture of a main steam pipe are given in Section 15.4.2.

The steam release as a consequence of this accident results in an initial increase in steam flow which decreases during the accident as the steam pressure falls. The energy removal from the RCS causes a reduction of coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in a reduction of core shutdown margin.

The analysis is performed to demonstrate that the following criterion is satisfied: assuming a stuck RCCA, with or without offsite power, and assuming a single failure in the Engineered Safety Features, there will be no consequential fuel damage after reactor trip for a steam release equivalent to the spurious opening, with failure to close, of the largest of any single steam dump, relief or safety valve. This criterion is satisfied by verifying that the DNB design basis is met.

The following systems provide the necessary protection against an accidental depressurization of the MSS:

1. SIS actuation from any of the following:

a. Two out of three channels of low pressurizer pressure.

system break accident will not lead to a more adverse condition than the case analyzed.

2. A negative moderator coefficient corresponding to the EOL rodded core with the most reactive RCCA in the fully withdrawn position. The variation of the coefficient with temperature and pressure is included. The k_{eff} versus temperature at 1000 psi corresponding to the negative moderator temperature coefficient used plus the Doppler temperature effect is shown on Figure 15.2-41.

3. Minimum capability for injection of boric acid solution corresponding to the most restrictive single failure in the SIS. The injection curve used is shown on Figure 15.2-42. This corresponds to the flow delivered by one charging pump delivering its full contents to the cold leg header. No credit has been taken for the low concentration boric acid which must be swept from the safety injection lines downstream of the refueling water storage tank (RWST) prior to the delivery of boric acid (2300 ppm) to the reactor coolant loops. The BIT concentration was assumed to be 0 ppm.

4. The case studied is an initial total steam flow of 1,100,000 lbs/hr at 1000 psia from one steam generator with offsite power available. This is the maximum capacity of any single steam dump or safety valve. Initial hot shutdown conditions at time zero are assumed, since this represents the most pessimistic initial condition.

Should the reactor be just critical or operating at power at the time of a steam release, the reactor will be tripped by the normal overpower protection signals when power level reaches a trip setpoint. Following a trip at power, the RCS contains more stored energy than at no load, the average coolant temperature is higher than at no load, and there is appreciable energy stored in the fuel.

Thus, the additional stored energy is removed via the cooldown caused by the steam line break before the no load conditions of RCS temperature and shutdown margin assumed in the analyses are reached. After the additional stored energy has been removed, the cooldown and reactivity insertions proceed in the same manner as in the analysis, which assumes no load condition at time zero. However, since the initial steam generator water inventory is greatest at no load, the magnitude and duration of the RCS cooldown are less for steam line breaks occurring at power.

5. In computing the steam flow, the Moody Curve for fL/D = 0 is used.

6. Perfect moisture separation in the steam generator is assumed.

15.2.13.3 Results

The results presented are a conservative indication of the events which would occur assuming a secondary system steam release, since it is postulated that all of the conditions described above occur simultaneously.

Figures 15.2-43A through 15.2-43C show the transients arising as the result of a steam release having an initial steam flow of 1,100,000 lbs/hr at 1000 psia with steam release from one turbine bypass valve. The assumed steam release is the maximum capacity of any single steam dump or safety valve. In this case, safety injection is initiated automatically by low pressurizer pressure. Operation of one centrifugal charging pump is considered. Boron solution at 2300 ppm enters the RCS, providing sufficient negative reactivity to assure no fuel damage. A DNB analysis was performed for this case, and the minimum DNBR was above the design DNBR limit. The reactivity transient for the case shown on Figures 15.2-43A through 15.2-43C is more severe than that of a failed steam generator safety or relief valve which would be terminated by safety injection actuated on high steam line differential pressure, or a failed condenser steam dump valve which would be terminated by safety injection actuated on low pressurizer pressure. The transient is quite conservative with respect to cooldown, since no credit is taken for the energy stored in the system metal other than that of the fuel elements or the energy stored in the other steam generators. Since the transient occurs over a period of about 10 minutes, the neglected stored energy is likely to have a significant effect in slowing the cooldown.

15.2.13.4 Conclusions

The analysis has shown that the criteria stated earlier in this section are satisfied, since a DNBR less than the design DNBR limit does not occur.

15.2.14 Spurious Operation of The Safety Injection System at Power

15.2.14.1 Accident Description

The Spurious Operation of the Safety Injection System (SIS) at Power is caused by either an operator error or a false electrical actuating signal.

When the SIS is actuated, charging pump suction is diverted from the Volume Control Tank to the RWST, and boric acid is pumped from the RWST to the cold leg of each reactor coolant loop. The safety injection pumps are also started automatically; but they cannot develop the head necessary to pump borated water into the reactor coolant loops when the RCS is at normal operating pressure.

The Spurious Operation of the SIS at Power is classified as a Condition II event, a fault of moderate frequency. The acceptance criteria for analysis of this event are:

1. Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the applicable DNBR limit.

2. Pressure in the reactor coolant and main steam systems should be maintained below 110% of the design values.

3. A Condition II must not escalate into, or cause a more serious fault (e.g., a Condition III or Condition IV event) without other faults occurring independently.

15.2.14.2 Method of Analysis

The first criterion, that fuel cladding integrity be maintained, is shown to be satisfied by means of a safety evaluation (see Case 1 below). The remaining criteria, that the RCS and main steam system pressure limits are not exceeded, and that the event would not lead to a more serious event, are demonstrated by means of an accident analysis (see Case 2 below).

Case 1. Safety Evaluation to show that fuel cladding integrity is maintained.

If no reactor trip signal is assumed to be generated by the SI signal, then borated water from the SIS would cause core reactivity and power level to drop, and consequently, the calculated DNB ratio to rise. The calculated DNBR would increase throughout the transient, without ever approaching its safety analysis limit value. Therefore, the Spurious Operation of the SIS at Power could not lead to any fuel damage.

Case 2. Accident Analysis to show that RCS and main steam system pressure limits are not exceeded, and that the event would not lead to a more serious event.

During a Spurious Operation of the SIS at Power event, the addition of borated water from the SIS, into the RCS, can fill the pressurizer and eventually lead to the discharge of water through the pressurizer safety valves. Since the pressurizer safety valves have not been qualified for water relief, one or more of the valves might fail to reseat completely, and thereby create an unisolatable leak from the RCS. Such a situation would be an escalation of a Condition II event into a more serious event (a small break LOCA), a violation of the third acceptance criterion.

The Spurious Operation of the SIS at Power is analyzed using the LOFTRAN [4] code. LOFTRAN simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, feedwater system, steam generator, steam generator safety valves, and the effects of the SI system. The code computes pertinent plant variables, including temperatures, pressures and power level.

The following basic assumptions were used to define and evaluate this event:

a. Initial reactor power is at its maximum value (+2%). Uncertainties are deducted from the initial RCS temperature and pressure (-5^{o}F and -50 psi). Assuming lower values of initial T_{avg} and pressure tends to reduce the time predicted to fill the pressurizer.

b. The SI signal causes the reactor to trip. Core residual decay heat generation is based upon long term operation at the initial power level.

c. Two centrifugal charging pumps and one positive displacement charging pump are in operation, with the miniflow valves open. Full SI flow begins immediately.

d. The pressurizer sprays and heaters operate at their maximum capacity. The pressurizer sprays limit the RCS pressure, permitting a higher SI delivery rate, which fills the pressurizer sooner. The heaters add energy to pressurized fluid, causing it to expand, and thus fill the pressurizer at an increased rate.

e. Either the pressurizer PORV block valves are open, or they are opened by the operators before the pressurizer safety valves open.

f. One of the pressurizer PORVs opens, and relieves water. The PORVs and downstream piping are qualified for this safety-related application [17,18].

15.2.14.3 Results

Fuel Cladding Integrity (evaluation)

If the SI signal does not trip the reactor and turbine, then nuclear power would decrease as borated water is added to the core. Since steam flow would be maintained, the mismatch between nuclear power and load would cause T_{avg}, pressurizer pressure, and pressurizer water volume to decrease until the low pressurizer pressure reactor trip setpoint is reached. The DNB ratio would increase, due mainly to the decrease in power and T_{avg}, and always remain above its safety limit value. Therefore, this event would not pose a challenge to fuel clad integrity.

Pressure Limits and Escalation into a More Serious Event (accident analysis)

An analysis was performed using the LOFTRAN code. The resulting transient response plots are depicted in Figures 15.2-44 and 15.2-45.

Nuclear power, T_{avg}, pressurizer pressure, and pressurizer water volume decrease, and steam pressure increases, as the result of the reactor and turbine trips demanded by the spurious SI signal. Pressurizer pressure and pressurizer water volume begin to increase as water is added to the RCS by the SIS and the pressurizer sprays and heaters operate. Pressurizer pressure stabilizes as the pressurizer spraying limits the pressurizer pressure to within about 40 psi above its initial value. The action of the pressurizer sprays, in limiting the pressure, allows more SI water to be added to the reactor coolant system, which surges into the pressurizer. It is assumed that the operators open the PORV block valves, if they are closed, before the pressurizer safety valves open. After the pressurizer becomes water-solid, the pressure rapidly increases to the PORV opening setpoint (conservatively assumed to be only 100 psi above the initial pressure, or 2300 psia). Only one of the two PORVs is assumed to open and relieve water.

After ten minutes, the transient equilibrates to a relatively stable condition, wherein T_{avg} is fairly constant, the pressurizer is water-solid, and pressure is maintained at or near the PORV setpoint, as water is relieved through repeated cycling of the pressurizer PORV. The event is ultimately ended by the operators, who stop the SIS flow and re-establish normal letdown flow, as per the emergency operating procedures.

The operators will ensure that the PORV block valves are open before the pressurizer safety valves open, ten minutes after the initiation of the event. This action assures the availability of the PORVs to open automatically when their opening setpressure is reached.

The results of the accident analysis indicate that opening one PORV will limit the pressurizer pressure to a level that will not cause any of the pressurizer safety valves to open. As the pressurizer safety valves will not open, the event cannot escalate to a more serious event (e.g., a small break LOCA, due to the failure of a pressurizer safety valve to reseat completely).

The figures presented for this event are taken from explicit calculations performed for the Unit 1 replacement steam generators. Unit 2 analysis results are similar in nature to those presented here, and the conclusions presented below apply to both sets of analyses.

15.2.14.4 Conclusions

The results of the Spurious Operation of the SIS at Power evaluation and analysis demonstrate that:

(1) Pressures in the reactor coolant and main steam systems are limited to less than 110% of the design values. Operating one PORV limits the pressurizer pressure to about the PORV opening setpressure, which is well below the RCS design pressure.

(2) Fuel cladding integrity is maintained. This is based upon an evaluation (Case 1), which predicts that the DNBR would always remain above the DNBR safety analysis limit value.

(3) A more serious fault would not result from the Spurious Operation of the SIS at Power event. The Case 2 analysis results show that an open pressurizer PORV will limit the pressurizer pressure to a level that will not cause any of the pressurizer safety valves to open, and thereby preclude the possibility that one or more of these valves would generate a more serious event by opening and failing to re-seat properly.

15.2.15 Turbine Generator Accidents

The likelihood of a turbine generator failure in which missiles are generated is remote. Westinghouse turbine generator units have never experienced a major structural failure of a rotating part that resulted in missiles leaving the turbine casing. A review of the records of all Westinghouse turbine generator units in operation from 1938 to 1969 is presented in Reference 14.

Catastrophic failure of turbines reported in the Appendix fall into one of two categories:

1. Failure by overstressing arising from accidental and excessive overspeed

2. Fracture because of defects in the material at speeds under the design overspeed

Contributing factors in the Westinghouse record of never having had a turbine generator run away to destructive overspeed are redundancy in the control system and routine testing of the main steam valves and the mechanical emergency overspeed protective system while the unit is carrying load. The overspeed control system for the turbine generator is described in detail in Sections 10.2.2.3 and 10.2.2.4.

The overspeed protective controller calls for fully closed main governing valves and interceptor valves at 103 percent of rated speed. In the event the turbine speed continues to increase past 103 percent of rated speed, the turbine stop and reheat stop valves, and also the main governing valves and interceptor valves will be tripped closed by both the mechanical overspeed weight and a backup electrical trip. When these valves are tripped, the turbine speed will continue to increase due to the finite valve closure time and the steam which is trapped in the turbine and piping downstream of the tripped valves. The turbine speed, however, will not exceed the design overspeed (120 percent of rated speed).

The likelihood of a failure in the second category, resulting from material defects, at speeds below design overspeed, is very small. There have been no failures of this nature in the United States since 1956. This has been attributed to improvements in design, inspection and manufacturing techniques

15.2.16 References For Section 15.2

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15.3 CONDITION III - INFREQUENT FAULTS

By definition, Condition III occurrences are faults which may occur very infrequently during the life of the station. They will be accommodated with the failure of only a small fraction of the fuel rods although sufficient fuel damage might occur to preclude resumption of the operation for a considerable outage time. The release of radioactivity will not be sufficient to interrupt or restrict public use of those areas beyond the exclusion radius. A Condition III fault will not, by itself, generate a Condition IV fault or result in a consequential loss of function of the Reactor Coolant System (RCS) or containment barriers. For the purposes of this report the following faults have been grouped into this category:

1. Loss of reactor coolant, from small ruptured pipes or from cracks in large pipes, which actuates the Emergency Core Cooling System (ECCS)

2. Minor Secondary System pipe breaks

3. Inadvertent loading of a fuel assembly into an improper position

4. Complete loss of forced reactor coolant flow

5. Single rod cluster control assembly (RCCA) withdrawal at full power

6. Accidental release of waste gases

7. Accidental release of radioactive liquids

The time sequence of events during applicable Condition III faults of Categories 1 and 4 above are shown in Tables 15.3-1 and 15.3-4.

15.3.1 Loss of Reactor Coolant from Small Ruptured Pipes or from Cracks in Large Pipes which Actuates the Emergency Core Cooling System

15.3.1.1 Identification of Causes and Accident Description

A loss-of-coolant accident (LOCA) is defined as a rupture of the RCS piping or of any line connected to the system. Ruptures of small cross section will cause expulsion of the coolant at a rate which can be accommodated by the charging pumps which would maintain an operational water level in the pressurizer, permitting the operator to execute an orderly shutdown. The coolant which would be released to the containment contains the fission products existing in it.

The maximum break size for which the normal makeup system can maintain the pressurizer level is obtained by comparing the calculated flow from the RCS through the postulated break against the charging pump makeup flow at normal RCS pressure, i.e. 2,250 psia. A makeup flow rate from one centrifugal charging pump is typically adequate to sustain pressurizer level for a break through an 0.375-inch diameter hole at 2,250 psia. This break results in a loss of approximately 17.5 lb/sec.

Should a larger break occur, depressurization of the RCS causes fluid to flow to the RCS from the pressurizer, resulting in a pressure and level decrease in the pressurizer. Reactor trip occurs when the pressurizer low pressure trip setpoint is reached. The Safety Injection System (SIS) is actuated when the appropriate setpoint is reached. The consequences of the accident are limited in two ways:

1. Reactor trip and borated water injection complement void formation in causing rapid reduction of nuclear power to a residual level corresponding to the delayed fission and fission product decay.

2. Injection of borated water insures sufficient flooding of the core to prevent excessive clad temperatures.

After the small break LOCA is initiated, reactor trip occurs due to a pressurizer low pressure reactor trip signal. For this analysis the safety injection actuation signal is generated due to a pressurizer low-pressure safety injection signal. Safety injection systems consist of gas pressurized accumulator tanks and pumped injection systems. The small break LOCA analysis assumed nominal accumulator water volume with an assumed cover gas consistent with the minimum pressure allowed by the Technical Specifications minus uncertainties. Minimum emergency core cooling system availability is assumed for the analysis, and pumped ECCS is conservatively assumed to be at the maximum RWST temperature. Assumed pumped safety injection characteristics as a function of RCS pressure used as boundary conditions in the analysis are shown in Figure 15.3-3. The safety injection flow rates presented are based on pump performance curves degraded from the design head (7% for High Head Safety Injection (HHSI), 10% for Intermediate Head Safety Injection (IHSI)) and an assumed charging system branch line imbalance of 10.5 gpm for HHSI, 12 gpm for IHSI. The effect of flow from the RHR pumps is not considered in the small break LOCA analyses since the shutoff head is lower than the RCS pressure during the time portion of the transient considered here. Safety injection and reactor trip response times used in the analyses are consistent with Technical Specification requirements.

On the secondary side, main feedwater isolation is assumed to be initiated by the low pressurizer pressure setpoint, with signal delay and valve closure times consistent with the Technical Specifications. The auxiliary feedwater pumps (one turbine driven pump and two motor driven pumps) are assumed to indirectly start from the low pressurizer pressure signal and deliver full flow consistent with the Technical Specifications. The auxiliary feedwater enthalpy is assumed to be that of the main feedwater until all warmer main feedwater has been purged from the lines.

The time sequence of events for the small break LOCA analysis is shown in Table 15.3-1.

Results

This section presents results of the SBLOCA analysis in terms of highest peak clad temperature. Refer to Table 15.3-2 for the input parameters used in the SBLOCA Analysis. The worst break size (small break) is a 2-inch diameter break, with the high T_{avg} being the limiting reactor coolant system average temperature. Refer to Table 15.3-3 for SBLOCA results. The depressurization transient for this break is shown in Figure 15.3-4. The extent to which the core is uncovered is shown on Figure 15.3-5.

The maximum hot spot clad temperature calculated during the transient is 1580°F including the effects of fuel densification as described in Reference 6. The peak clad temperature transient is shown on Figure 15.3-6 for the worst break size (2-inch) i.e, the break with the highest peak clad temperature. The steam flow rate for the worst break is shown on Figure 15.3-7. When the mixture level drops below the top of the core, the steam flow computed in NOTRUMP provides cooling to the upper portion of the core. The rod film coefficients for this phase of the transient are given on Figure 15.3-8. The hot spot fluid temperature for the worst break is shown of Figure 15.3-17. The cold leg break mass flow for the worst break is shown on Figure 15.3-18. The ECCS pumped safety injection for the worst break is shown on Figure 15.3-19.

Identical plot sequences for the 4-, 3-, and 1.5-inch break cases at high T_{avg} are included in Figures 15.3-20 through 15.3-43. Additionally a 2-inch break case at low T_{avg} is included in Figures 15.3-44 through 15.3-51.

The core power (dimensionless) transient following the accident (relative to reactor scram time) is shown on Figure 15.3-52.

The reactor shutdown time is equal to the reactor trip signal time plus rod insertion time. During this rod insertion period, the reactor is conservatively assumed to operate at rated power.

15.3.1.3 Conclusions

The analysis presented in this section shows that the combined high head portion of the ECCS provides sufficient core flooding to maintain the calculated peak clad temperature and any additional penalties compensating for model errors no greater than the required limits of 10CFR50.46. Hence, adequate protection is afforded by the ECCS in the event of a small break LOCA.

15.3.2 Minor Secondary System Pipe Breaks

15.3.2.1 Identification of Causes and Accident Description

Included in this grouping are ruptures of secondary system lines which would result in steam release rates equivalent to a 6-inch diameter break or smaller.

15.3.2.2 Analysis of Effects and Consequences

Minor secondary system pipe breaks must be accommodated with the failure of only a small fraction of the fuel elements in the reactor. Since the results of analysis presented in Section 15.4.2 for a major secondary system pipe rupture also meet this criteria, separate analysis for minor secondary system pipe breaks is not required.

The analysis of the more probable accidental opening of a secondary system steam dump, relief or safety valve is presented in Section 15.2.13. The analysis is illustrative of a pipe break equivalent in size to a single valve opening.

15.3.2.3 Conclusions

The analysis presented in Section 15.4.2 demonstrates that the consequences of a minor secondary system pipe break are acceptable since the calculated departure from nucleate boiling ratio (DNBR) is greater than the design DNBR limit for a more critical major secondary system pipe break.

15.3.3 Inadvertent Loading of a Fuel Assembly into an Improper Position

15.3.3.1 Identification of Causes and Accident Description

Fuel and core loading errors related to inadvertent loading of one or more fuel assemblies into improper positions, loading a fuel rod during manufacture with one or more pellets of the wrong enrichment, or the loading of a full fuel assembly during manufacture with pellets of the wrong enrichment will lead to increased heat fluxes if the error results in placing fuel in core positions calling for fuel of lesser enrichment. Also included among possible core loading errors is the inadvertent loading of one or more fuel assemblies requiring burnable poison rods into a new core without burnable poison rods.

Any error in enrichment, beyond the normal manufacturing tolerances, can cause power shapes which are more peaked than those calculated with the correct enrichments. The in-core system of moveable flux detectors, which is used to verify power shapes at the start of life, is capable of revealing any assembly enrichment error or loading error which causes power shapes to be peaked in excess of the design value.

To reduce the probability of core loading errors, each fuel assembly is marked with an identification number and loaded in accordance with a core loading diagram. During core loading the identification number will be checked before each assembly is moved into the core. Serial numbers read during fuel movement are

Fuel assembly loading errors are prevented by administrative procedures implemented during core loading. In the unlikely event that a loading error occurs, analyses in this section confirm that resulting power distribution effects will either be readily detected by the in-core moveable detector system or will cause a sufficiently small perturbation to be acceptable within the uncertainties allowed between nominal and design power shapes.

15.3.4 Complete Loss of Forced Reactor Coolant Flow

(Text has been deleted)

15.3.4.1 Accident Description

A complete loss of forced reactor coolant flow may result from a simultaneous loss of electrical supplies to all reactor coolant pumps. If the reactor is at power at the time of the accident, the immediate effect of loss-of-coolant flow is a rapid increase in the coolant temperature. This increase could result in departure from nucleate boiling (DNB) with subsequent fuel damage if the reactor were not tripped promptly. The following provides necessary protection against a loss-of-coolant flow accident:

1. Undervoltage or underfrequency on reactor coolant pump power supply buses

2. Low reactor coolant loop flow

3. Pump circuit breaker opening

The reactor trip on reactor coolant pump bus undervoltage is provided to protect against conditions which can cause a loss of voltage to all reactor coolant pumps, i.e., loss of offsite power. This function is blocked below approximately 10 percent power (Permissive 7).

The reactor trip on reactor coolant pump underfrequency is provided to open the reactor coolant pump breakers and trip the reactor for an underfrequency condition, resulting from frequency during the transient, the time of reactor trip, and the nuclear power transient following reactor trip. The FACTRAN (13) code is then used to calculate the heat flux transient based on the nuclear power and flow from LOFTRAN. Finally the THINC code is used to calculate the minimum DNBR during the transient based on the heat flux from FACTRAN and flow from LOFTRAN. The DNBR transients presented represent the minimum of the typical or thimble cell for fuel assemblies with and without IFM's.

Two cases are analyzed:

1. Complete loss of flow transient due to an undervoltage condition; and
2. Complete loss of flow transient due to an underfrequency condition.

The method of analysis and the assumptions made regarding initial operating conditions and reactivity coefficients are identical to those discussed in Section 15.2.5, except that, following the loss of supply to all pumps at power, a reactor trip is actuated by the undervoltage or underfrequency signals.

15.3.4.3 Results

Figures 15.3-14 and 15.3-15 illustrate the transient response for the complete loss of flow (undervoltage) for a loss of power to all four reactor coolant pumps with four loops in operation. Figure 15.3-15 shows that the DNBR remains above the limit value. The undervoltage complete loss of flow minimum DNBR is greater than the more limiting underfrequency event.

Figures 15.3-16A and 15.3-16B illustrate the transient response to a complete loss of flow (underfrequency) with a frequency decay of all four reactor coolant pumps with four loops in operation. Figure 15.3-16B shows that the DMBR remains above the limit value. The calculated sequence of events for both cases are shown in Table 15.3-4.

15.3.4.4 Conclusions

The analysis performed has demonstrated that for the complete loss of forced reactor coolant flow, the DNBR does not decrease below the design limit during the transient and thus no core safety limit is violated.

15.3.5 Single Rod Cluster Control Assembly Withdrawal at Full Power

15.3.5.1 Accident Description

No single electrical or mechanical failure in the Rod Control System could cause the accidental withdrawal of a single RCCA from the inserted bank at full power operation. The operator could deliberately withdraw a single RCCA in the control bank. This feature is necessary in order to retrieve an assembly should one be accidentally dropped. In the extremely unlikely event of simultaneous electrical failures which could result in single RCCA withdrawal, rod deviation and rod control urgent failure would both be displayed on the plant annunciator, and the rod position indicators would indicate the relative positions of the assemblies in the bank. The urgent failure alarm also inhibits automatic rod motion in the group in which it occurs. Withdrawal of a single RCCA by operator action, whether deliberate or by a combination of errors, would result in activation of the same alarm and the same visual indications.

Each bank of RCCAs in the system is divided into two groups of four mechanisms each (except Group 2 of Bank D which consists of five mechanisms). The rods comprising a group operate in parallel through multiplexing thyristors. The two groups in a bank move sequentially such that the first group is always within one step of the second group in the bank. A definite schedule of actuation and deactuation of the stationary gripper, movable gripper, and lift coils of the mechanism is required to withdraw the RCCA attached to the mechanism. Since the four stationary grippers, moveable gripper, and lift coils associated with the four RCCAs of a rod group are driven in parallel, any single failure which would cause rod withdrawal would affect a minimum of one group, or four RCCAs. Mechanical failures are either in the direction of insertion or immobility.

In the unlikely event of multiple failures which result in continuous withdrawal of a single RCCA, it is not possible, in all cases, to provide assurance of automatic reactor trip such that core safety limits are not violated. Withdrawal of a single RCCA results in both positive reactivity insertion tending to increase core power, and an increase in local power density in the core area "covered" by the RCCA.

15.3.5.2 Method of Analysis

Power distributions within the core are calculated by the ANC Code (Reference 10) based on macroscopic cross sections generated by the PHOENIX-P Code (Reference 9). The peaking factors are then used by THINC to calculate the minimum DNBR for the event. The case of the worst rod withdrawn from Bank D inserted at the insertion limit, with the reactor initially at full power, was analyzed. This incident is assumed to occur at beginning of life, since this results in the minimum value of the moderator density coefficient. This maximizes the power rise and minimizes the tendency of increased moderator temperature to flatten the power distribution.

15.3.5.3 Results

Two cases have been considered as follows:

1. If the reactor is in the manual control mode, continuous withdrawal of a single RCCA results in both an increase in core power and coolant temperature, and an increase in the local hot channel factor in the area of the failed RCCA. In terms of the overall system response, this case is similar to those presented in Section 15.2.2; however, the increased local power peaking in the area of the withdrawn RCCA results in lower minimum DNBRs than for the withdrawn bank cases. Depending on

initial bank insertion and location of the withdrawn RCCA, automatic reactor trip may not occur sufficiently fast to prevent the minimum core DNBR from falling below the limit value. Evaluation of this case at the power and coolant conditions at which the overtemperature ΔT trip would be expected to trip the plant shows that an upper limit for the number of rods with a DNBR less than the limit value is 5 percent.

2. If the reactor is in automatic control mode, withdrawal of a single RCCA will result in the immobility of other RCCAs in the controlling bank. The transient will then proceed in the same manner as Case 1 described above. For such cases as above, a trip will ultimately ensue, although not sufficiently fast in all cases to prevent a minimum DNBR in the core of less than the limit value.

15.3.5.4 Conclusions

For the case of one RCCA fully withdrawn with the reactor in the automatic or manual control mode, and initially operating at full power with Bank D at the insertion limit, an upper bound of the number of fuel rods experiencing DNBR < the limit value is 5 percent of the total fuel rods in the core.

For both cases discussed, the indicators and alarms mentioned would function to alert the operator to the malfunction before DNB could occur. For Case 2 discussed above, the insertion limit alarms (both low and low-low alarms) would also serve in this regard.

15.3.6 Accidental Release of Waste Gases

15.3.6.1 Situations Considered

Gaseous activity which could be released in the unlikely event of a tank rupture will result in an offsite whole body and inhalation dose well below 10CFR100 limits. The main sources of gaseous

Periodically, the contents of the waste holdup tanks and the laundry tanks are analyzed and, if the radioactive level is within discharge limits, the liquid is transferred to the waste monitor tanks. Before liquid from these tanks is discharged to the river, a sample is taken and analyzed. If the analysis indicates that the waste fluid can be released, a normally locked closed valve in the waste liquid discharge line is opened. Upstream of this valve a radiation monitor provides an additional safeguard. Should the radioactive level as monitored be above prescribed limits, an alarm sounds and the valve in the discharge line automatically closes, preventing accidental release of radioactive fluids.

Distillate from the Chemical and Volume Control System boric acid evaporator is discharged to monitor tanks. The contents of these tanks are analyzed before being pumped to the primary water storage tanks. Occasionally, it may be necessary to dispose of some of the boric acid distillate for tritium control. If analysis of the contents of the monitor tank is within prescribed limits for discharge to the environment, the liquid is pumped directly to the waste liquid discharge line after the normally closed valve in this line is opened. The radiation monitor downstream prevents discharge of fluids above prescribed levels, as explained in the preceding paragraph.

Therefore, to release radioactive liquid waste to the river inadvertently, samples of the fluid to be discharged must be analyzed incorrectly, the normally closed valve in the discharge line opened, and a malfunction of the radiation monitor or the valve in the discharge line must occur. This series of events is not considered credible.

15.3.8 References for Section 15.3

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14. (This text was deleted)

15.4.2 Major Secondary System Pipe Rupture

15.4.2.1 Identification of Causes and Accident Description

The steam release arising from a rupture of a main steam pipe would result in an initial increase in steam flow which decreases during the accident as the steam pressure falls. The energy removal from the RCS causes a reduction of coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in a reduction of core shutdown margin. If the most reactive RCCA is assumed stuck in its fully withdrawn position after reactor trip, there is an increased possibility that the core will become critical and return to power. A return to power following a steam pipe rupture is a potential concern mainly because of the high power peaking factors which exist assuming the most reactive RCCA to be stuck in its fully withdrawn position. The core is ultimately shutdown by the boric acid injection delivered by the SIS.

The analysis of a main steam pipe rupture is performed to demonstrate that the following criteria are satisfied:

1. Assuming a stuck RCCA with or without offsite power, and assuming a single failure in the engineered safeguards there is no consequential damage to the primary system and the core remains in place and intact.

2. Energy release to containment from the worst steam pipe break does not cause failure of the containment structure.

Although DNB and possible clad perforation following a steam pipe rupture are not necessarily unacceptable, the following analysis, in fact, shows that no DNB occurs for any rupture assuming the most reactive assembly stuck in its fully withdrawn position.

The following safety functions provide the necessary protection against a steam pipe rupture:

1. Safety Injection System actuation from any of the following:

    a. Two-out-of-three channels of low pressurizer pressure.

    b. High differential pressure signals between steam lines.

    c. High steam line flow in two main steam lines (one-out-of-two per line) in coincidence with either low-low RCS average temperature or low steam line pressure in any two lines.

    d. Two-out-of-three high containment pressure.

2. The overpower reactor trips (neutron flux and ΔT) and the reactor trip occurring in conjunction with receipt of the safety injection signal.

3. Redundant isolation of the main feedwater lines: Sustained high feedwater flow would cause additional cooldown. Therefore, in addition to the normal control action which will close the main feedwater valves, a safety injection signal will rapidly close all feedwater control valves, trip the main feedwater pumps, and close the feedwater pump discharge valves.

4. Trip of the fast acting main steam isolation valves (MSIVs) (assumed to isolate within 12 seconds including instrumentation delays) on:

a. High steam flow in two main steam lines in coincidence with low steam line pressure in any two lines.

b. High-high containment pressure.

For breaks downstream of the MSIVs, closure of all valves would completely terminate the blowdown. For any break, in any location, no more than one steam generator would blow down even if one of the isolation valves fails to close. A description of steam line isolation is included in Section 10.

Steam flow is measured by monitoring dynamic head in nozzles inside the steam pipes. The nozzles, which are of considerably smaller diameter than the main steam pipe, are located inside the containment near the steam generators and also serve to limit the maximum steam flow for any break further downstream.

15.4.2.2 Method of Analysis

The analysis of the steam pipe rupture has been performed to determine the following:

1. The core heat flux and RCS temperature and pressure resulting from the cooldown following the steam line break. The LOFTRAN (27) code has been used.

2. The thermal and hydraulic behavior of the core following a steam line break. A detailed thermal and hydraulic digital-computer code, THINC, has been used to determine if DNB occurs for the core conditions computed in Item (1) above.

The following conditions were assumed to exist at the time of a main steam line break accident.

1. End-of-life (EOL) shutdown margin at no load, equilibrium xenon conditions, and the most reactive assembly stuck in its fully withdrawn position: Operation of the control rod banks during core burnup is restricted in such a way that addition of positive reactivity in a steam line break accident will not lead to a more adverse condition than the case analyzed.

2. The negative moderator coefficient corresponding to the EOL rodded core with the most reactive rod in the fully withdrawn position: The variation of the coefficient with temperature and pressure has been included. The k_{eff} versus temperature at 1000 psi corresponding to the negative moderator temperature coefficient used is shown on Figure 15.2-41. The effect of power generation in the core on overall reactivity is shown on Figure 15.4-49.

   The core properties associated with the sector nearest the affected steam generator and those associated with the remaining sector were conservatively combined to obtain average core properties for reactivity feedback calculations. Further, it was conservatively assumed that the core power distribution was uniform. These two conditions cause under-prediction of the reactivity feedback in the high power region near the stuck rod. To verify the conservatism of this method, the reactivity as well as the power distribution were checked. These core analyses considered the Doppler reactivity from the high fuel temperature near the stuck RCCA, moderator feedback from the high water enthalpy near the stuck RCCA, power redistribution and nonuniform core inlet temperature effects. For cases in which steam generation occurs in the high flux regions of the core, the effect of void formation was also included. It was determined that the reactivity employed in the kinetics analysis was always larger than the reactivity calculated for all cases. These results verified conservatism; i.e., underprediction of negative reactivity feedback from power generation.

3. Minimum SIS capability for the injection of borated flow into the RCS is assumed in the analysis. Due to single failure considerations, injection flow is assumed to be delivered by only a single charging pump. The modeling of the SIS in LOFTRAN is described in Reference 27.

   A conservatively bounding total time delay is modeled in the analysis to account for the delay between the time that the ESF actuation setpoint is reached and the time that SIS flow is capable of being pumped from the RWST into the RCS cold leg header. For cases where offsite power is assumed, the total time delay assumed in the analysis is 22 seconds. This 22 second assumption was selected to conservatively bound the sum of the following time delay components:

   a. Instrumentation, logic and signal transport time delay associated with generation and transport of the SI signal, and

   b. The following actions which occur in parallel:
      1. SIS suction valve alignment (opening of RWST valves followed by closure of VCT valves), and
      2. High Head SI/Charging Pump starting and attaining full speed.

For cases where offsite power is not assumed, the total time delay assumed in the analysis is 42 seconds. This bounds the sum of the following time delay components:

   a. Instrumentation, logic and signal transport time delay associated with generation and transport of the SI signal,
   b. Diesel startup and output breaker closure, and
   c. The following actions which occur in parallel:
      1. SEC sequencing delay and SIS suction valve alignment (opening of RWST valves followed by closure of VCT valves), and
      2. SEC sequencing delay and High Head SI/Charging Pump starting and attaining full speed.

In addition, the analysis conservatively assumes that the SIS lines between the RWST and the RCS initially contain unborated water. After the appropriate total time delay described above, the analysis takes into account the purging of this unborated water prior to crediting the injection of broated flow from the RWST into the RCS.

4. Four combinations of break sizes and initial plant conditions have been considered in determining the core power and RCS transients:

    a. Complete severance of a pipe outside the containment, downstream of the steam flow measuring nozzle, with the plant initially at no load conditions, full reactor coolant flow with offsite power available.

    b. Complete severance of a pipe inside the containment at the outlet of the steam generator with the plant initially at no load conditions with offsite power available.

    c. Case (a) above with loss of offsite power simultaneous with the initiation of the safety injection signal. Loss of offsite power results in coolant pump coastdown.

    d. Case (b) above with the loss of offsite power simultaneous with the initiation of the safety injection signal.

5. Power peaking factors corresponding to one stuck RCCA and nonuniform core inlet coolant temperatures are determined at end of core life. The coldest core inlet temperatures are assumed to occur in the sector with the stuck rod. The power peaking factors account for the effect of the local void in the region of the stuck control assembly during the return to power phase following the steam line break. This void, in conjunction with the large negative moderator coefficient, partially offsets the effect of the stuck assembly. The power peaking factors depend upon the core power, temperature, pressure, and flow, and, thus, are different for each case studied.

All the cases above assume initial hot shutdown conditions at time zero since this represents the most pessimistic initial condition. Should the reactor be just critical or operating at power at the time of a steam line break, the reactor will be tripped by the normal overpower protection system when power level reaches a trip point. Following a trip at power, the RCS contains more stored energy than at no load, the average coolant temperature is higher than at no load, and there is appreciable energy stored in the fuel. Thus, the additional stored energy is removed via the cooldown caused by the steam line break, before the no load conditions of RCS temperature and shutdown margin assumed in the analyses are reached. After the additional stored energy has been removed, the cooldown and reactivity insertions proceed in the same manner as in the analysis, which assumes no load condition at time zero.

However, since the initial steam generator water inventory is greatest at no load, the magnitude and duration of the RCS cooldown are less for steam line breaks occurring at power.

6. In computing the steam flow during a steam line break, the Moody Curve (25) for fL/D = 0 is used.

7. Perfect moisture separation in the steam generator is assumed. The assumption leads to conservative results since, in fact, considerable water would be discharged. Water carryover would reduce the magnitude of the

temperature decrease in the core and the pressure increase in the containment.

15.4.2.3 Results

The results presented are a conservative indication of the events which would occur assuming a steam line rupture, since it is postulated that all of the conditions described above occur simultaneously.

15.4.2.4 Core Power and Reactor Coolant System Transient

Figures 15.4-50A through 15.4-50C show the RCS transient and core heat flux following a main steam pipe rupture (complete severance of a pipe) outside the containment, downstream of the flow measuring nozzle at initial no load condition (Case a). The break assumed is the largest break which can occur anywhere outside the containment either upstream or downstream of the MSIVs. Offsite power is assumed available such that full reactor coolant flow exists. The transient shown assumes an uncontrolled steam release from only one steam generator. Should the core be critical at near zero power when the rupture occurs, the initiation of safety injection by high differential pressure between any steam line and the remaining steam lines, or by high steam flow signals in coincidence with either low-low RCS temperature or low steam line pressure will trip the reactor. Steam release from more than one steam generator will be prevented by automatic trip of the fast action isolation valves in the steam line by the high steam flow signals in coincidence with either low-low RCS temperature or low steam line pressure.

The steam flow on Figures 15.4-50B, 15.4-51B, 15.4-52B, and 15.4-53B represent total steam flow. All steam generators were assumed to discharge through the break until steam line isolation had occurred.

As shown on Table 15.4-1, the core attains criticality with the RCCAs inserted (with the design shutdown assuming one stuck assembly) before boron solution at 2300 ppm enters the RCS from the SIS. The delay time consists of the time to receive and actuate the safety injection signal and the time to completely open valve trains in the safety injection lines. The safety injection pumps are then ready to deliver flow. At this stage, a further delay time is incurred before 2300 ppm boron solution can be injected to the RCS due to low concentration solution being purged from the safety injection lines. A peak core power well below the nominal full power value is attained.

The calculation assumes the boric acid is mixed with and diluted by the water flowing in the RCS prior to entering the reactor core. The concentration after mixing depends upon the relative flow rates in the RCS and in the SIS. The variation of mass flow rate in the RCS due to water density changes is included in the calculation as is the variation of flow rate from the SIS and the accumulator due to changes in the RCS pressure.

The SIS flow calculation includes the line losses in the system as well as the pump head curve. The accumulators provide the additional source of borated water if the RCS pressure decreases below 592.2 psia. The core boron concentration for each of the four cases analyzed is shown on Figures 15.4-50C, 15.4-51C, 15.4-52C and 15.4-53C.

Figures 15.4-51A through 15.4-51C show Case b, a steam line rupture at the exit of a steam generator at no load. The sequence of events is similar to that described above for the rupture outside the containment, except that criticality is attained earlier due to more rapid cooldown and a higher peak core average power is attained.

Figures 15.4-52A through 15.4-52C and 15.4-53A through 15.4-53C show the RCS transient and core heat flux for Cases c and d which correspond to the cases discussed above, with additional loss of offsite power at the time the safety injection signal is generated. In each case, criticality is achieved later, and the core power increase is slower than in the similar case with offsite power available. The ability of the emptying steam generator to extract heat from the RCS is reduced by the decreased flow in the RCS. For both these cases the peak core power remains well below the nominal full power value.

It should be noted that, following a steam line break, only one steam generator blows down completely. Thus, the remaining steam generators are still available for dissipation of decay heat after the initial transient is over. In the case of loss of offsite power, this heat is removed to the atmosphere via the steam line safety valves, which have been sized to cover this condition.

The sequence of events is shown in Table 15.4-1.

The figures presented for this event are taken from explicit calculations performed for Unit 2. Explicit analysis results for the Unit 1 replacement steam generators are similar in nature to those presented here, and the conclusions presented below apply to both sets of analyses.

15.4.2.5 Margin to Critical Heat Flux

A DNB analysis was performed for the case most critical to DNB. It was found that all cases had a minimum DNBR greater than the design DNBR limit.

15.4.2.6 Offsite Doses

The analysis is performed for two cases of iodine concentrations in the primary coolant, resulting from:

1) A pre-accident iodine spike and
2) An accident-initiated concurrent iodine spike.

The pre-accident iodine spike concentrations are assumed to result from a reactor transient which raises the primary coolant concentrations to the maximum values identified in the Technical Specifications and is based on the pre-accident iodine spike activity level of 60 μCi/g of dose-equivalent I-131 with the initial primary coolant noble gas activity based on 1% fuel defects.

The activities leaked to the secondary system via a primary-to-secondary leak of 1 gpm are mixed with the existing activities in the steam generators (initial iodine activity is the Technical Specification limit of 0.1 μCi/g of dose equivalent I-131) and are released to the environment via a steam release.

Offsite power is assumed lost and the main steam condensers are not available for heat removal via a steam dump. Steam is released directly to the environment through the steam generator safety relief valves from the generators isolated from the steam line break. Noble gases from the leaked reactor coolant are released directly to the environment with no retention in the steam generators (SGs). Iodine activity is released from the SGs to the environment in proportion to the steam release rate and the partition coefficient. The iodine partition coefficient during the steaming process is conservatively assumed to be 0.01 for the unaffected steam generators and 1.0 for the unisolable generator. Thirty-two hours after the accident, the Residual Heat Removal System is assumed to start operation to cool down the plant and no steam is released to the environment after this time.

The accident-initiated or concurrent iodine spike is modeled by assuming that the iodine release rates from the fuel rods into the primary coolant exceed 500 times the equilibrium release rates for a period of two hours.

Other assumptions, parameters, mass transfer rates, and initial activity inventories used in the analysis are listed in Table 15.4-7 with the consequences listed in Table 15.4-7A.

The radiological consequences for the postulated main steam line break accident assuming either a pre-accident iodine spike or a concurrent iodine spike are within a small fraction of the guideline values described in 10 CFR 100.

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15.4.3 MAJOR RUPTURE OF A MAIN FEEDWATER LINE

15.4.3.1 Accident Description

A major feedwater line rupture is defined as a break in a feedwater pipe large enough to prevent the addition of sufficient feedwater to the steam generators to maintain shell-side fluid inventory in the steam generators. If the break is postulated in a feedline between the check valve and the steam generator, fluid from the steam generator may also be discharged through the break. Further, a break in this location could preclude the subsequent addition of auxiliary feedwater (AFW) to the affected steam generator. (A break upstream of the feedline check valve would affect the Nuclear Steam Supply System (NSSS) only as a loss of feedwater. (This case is covered by the evaluation in Section 15.2.8).

Depending upon the size of the break and the plant operating conditions at the time of the break, the break could cause either a Reactor Coolant System (RCS) cooldown (by excessive energy discharge through the break) or a RCS heatup. Potential RCS cooldown resulting from a secondary pipe rupture is evaluated in the section, "Major Rupture of a Main Steam Line." Therefore, only the RCS heatup effects are considered for a feedline rupture analysis. A main feedwater line rupture is classified as an ANS Condition IV event.

A feedline rupture reduces the ability to remove heat from the RCS generated by the core. First, feedwater to the steam generators is reduced. Also, inventory in the steam generators may be discharged through the break and would then not be available for decay heat removal. Finally, the break may be large enough to prevent the addition of any main feedwater after the trip.

An AFW System is provided to assure that adequate feedwater is supplied to the steam generators for decay heat removal. Reactor trip and AFW assure that no overpressurization of the RCS or Main Steam System occur (equivalent to 110% of their respective design pressures) and that sufficient liquid in the RCS will be maintained. No bulk boiling should occur in the primary coolant system following a feedline rupture prior to the time that the heat removal capability of the intact steam generators, being fed AFW, exceeds the NSSS heat generation.

The severity of the feedwater line rupture transient depends on a number of parameters including break size, initial reactor power, and credit for various control and safety systems. A number of cases have been analyzed. Results of these analyses show that the most limiting feedwater line ruptures are the double-ended rupture of the largest feedwater line at full power, with and without offsite power available.

The following provides the necessary protection against a main feedwater rupture:

1. A reactor trip on any of the following conditions:
    a. High pressurizer pressure,
    b. Overtemperature delta-T,
    c. Low-low steam generator water level in any steam generator,
    d. Safety injection signals from any of the following:
        1. High steam flow coincident with low steam line pressure
        2. High containment pressure
        3. High steam line differential pressure
        4. Low pressurizer pressure
        5. High steam flow coincident with low-low T_{avg}

        (Refer to Chapter 7 for a description of the actuation system.)

2. An AFW System that starts on a low-low steam generator water level signal to provide an assured source of feedwater to the steam generators for decay heat removal. (Refer to Chapter 10 for a description of the AFW System.)

3. Main steam line isolation from any of the following signals:
    a. High-high containment pressure
    b. High steam flow coincident with low-low T_{avg}
    c. High steam flow coincident with low steam line pressure
    d. Operator action

18. The intact loop with the steam generator being fed by both motor- and turbine-driven AFW pumps was assumed to be 5% low and the remaining loops were assumed to each be 1.667% high to maintain the same total reactor coolant flow.

No reactor control systems are assumed to function except the pressurizer power operated relief valves. The only engineered safety features assumed to function are the AFW and Safety Injection Systems.

15.4.3.3 Results

Calculated plant parameters following a major feedwater pipe rupture for the limiting case, where offsite power is available, are presented in Figures 15.4-60A through 15.4-60C. Results for the case without offsite power are presented in Figures 15.4-60D through 15.4-60F. The calculated sequence of events for these cases are listed in Table 15.4-1. The results show that pressures in the RCS and main stem system remain below 110% of their respective design pressures and that the RCS hot legs remain subcooled.

Feedline Rupture with Offsite Power Available

Reactor Coolant System pressure, temperature, and pressurizer water volume initially decrease due to the increased secondary side heat removal as steam from the three unfaulted steam generators flows to the depressurizing, faulted steam generator. The secondary side inventory reduction then leads to a primary system heatup, so RCS pressure, temperature, and pressurizer water volume all increase. Ten minutes after reactor trip, the main steam isolation valves are assumed to close at about which time the steam generators begin to repressurize with the addition of relatively cold AFW. The heat removal capability of the secondary side becomes sufficient to remove the core decay heat from the RCS at approximately 920 seconds. The results show that the core remains covered at all times and that no hot leg saturation occurs.

The pressurizer water volume increases in response to the heatup, but the steam bubble in the pressurizer is maintained throughout the transient. Pressurizer filling is not predicted in either case (with or without offsite power). Therefore, no water relief through the pressurizer relief or safety valves occurs.

Feedline Rupture without Offsite Power

The system response following a feedwater line rupture without offsite power available is similar to the case with offsite power available. However, due to the loss of offsite power (assumed to occur at the time of reactor trip), the reactor coolant pumps coast down. This results in a reduction in RCS heat generation equal to the amount produced by pump operation. Hence, this case is less limiting than the case where offsite power is available. The results show that the core remains covered at all times and that no hot leg saturation occurs.

The figures presented for this event are taken from explicit calculations performed for Unit 2. Explicit analysis results for the Unit 1 replacement steam generators are similar in nature to those presented here, and the conclusions presented below apply to both sets of analyses.

15.4.3.4 Conclusion

Results of the analysis show that for the postulated feedline rupture, the assumed AFW System capacity is adequate to remove decay heat, to prevent overpressurization of the RCS and Main Steam System, and to prevent hot leg saturation.

15.4.4 Steam Generator Tube Rupture

15.4.4.1 General

The accident examined is the complete severance of a single steam generator tube. The accident is assumed to take place at power with the reactor coolant contaminated with fission products corresponding to continuous operation with a limited amount of defective fuel rods. The accident leads to an increase in contamination of the secondary system due to leakage of radioactive coolant from the RCS. In the event of a coincident loss of offsite power or failure of the condenser dump system, discharge of activity to the atmosphere takes place via the steam generator safety and/or power-operated relief valves.

In view of the fact that the steam generator tube material is Inconel 600 and is a highly ductile material, it is considered that the assumption of a complete severance is somewhat conservative. The more probable mode of tube failure would be one or more minor leaks of undetermined origin. Activity in the Steam and Power Conversion System is subject to continual surveillance and an accumulation of minor leaks which exceed the 1-gpm total primary-to-secondary leakage through all steam generators and 500 gallons per day through any one steam generator is not permitted during the unit operation.

The main objective of the operator is to determine that a steam generator tube rupture has occurred, and to identify and isolate the faulty steam generator on a restricted time scale in order to minimize contamination of the secondary system and ensure termination of radioactive release to the atmosphere from the faulty unit. The recovery procedure can be carried out on a time scale which ensures that break flow to the secondary system is terminated before water level in the affected steam generator rises into the main steam pipe. Sufficient indications and controls are provided to enable the operator to carry out these functions satisfactorily.

Consideration of the indications provided at the control board, together with the magnitude of the break flow, leads to the conclusion that the isolation procedure can be completed within the time requirements set forth in this analysis.

15.4.4.2 Description of Accident

Assuming normal operation of the various plant control systems the following sequence of events is initiated by a tube rupture:

1. Pressurizer low pressure and low level alarms are actuated and, prior to plant trip, charging pump flow increases in an attempt to maintain pressurizer level. On the secondary side there is a steam flow/feedwater flow mismatch before trip as feedwater flow to the affected steam generator is reduced due to the additional break flow which is now being supplied to that unit.

2. Continued loss of reactor coolant inventory leads to falling pressure and level in the pressurizer until a reactor trip signal is generated by low pressurizer pressure or overtemperature ΔT. Resultant plant cooldown following reactor trip leads to a rapid decrease in pressurizer level, and the safety injection signal, initiated by low pressurizer pressure, follows soon after the reactor trip. The safety injection signal automatically terminates normal feedwater supply and initiates auxiliary feedwater addition on low steam generator level.

3. The steam generator blowdown liquid monitor and the condenser offgas radiation monitor will alarm, indicating a sharp increase in radioactivity in the secondary system. The steam generator blowdown liquid monitor will automatically terminate steam generator blowdown.

4. The reactor trip automatically trips the turbine and if offsite power is available the steam dump valves open permitting steam dump to the condenser. In the event of a coincident loss of offsite power, the steam dump valves would automatically close to protect the condenser. The steam generator pressure would rapidly increase resulting in steam discharge to the atmosphere through the steam generator safety and/or power-operated relief valves.

5. The following sequence of operator actions is initiated to terminate steam release from the faulted steam generator and primary to secondary leakage:

   a. Identification of the faulted steam generator (A primary indication of a steam generator tube rupture event is steam generator water level increasing in an uncontrolled manner.)

   b. Isolation of the faulted steam generator

   c. Cooldown of the RCS using the non-faulted steam generator to assure 20°F subcooling at the faulted steam generator pressure

   d. Controlled depressurization of the RCS to the faulted steam generator pressure

   e. Subsequent termination of safety injection flow

Sufficient indications and controls are provided at the control board to enable the operator to complete these functions satisfactorily within the time requirements set forth in this analysis.

15.4.4.3 Method of Analysis

In estimating the mass transfer from the RCS through the broken tube, the following assumptions are made:

1. Reactor trip occurs automatically as a result of low pressurizer pressure.

2. Following the initiation of the safety injection signal, all centrifugal charging pumps are actuated and continue to deliver flow until the rupture flow has been terminated. Pump flow is secured procedurally.

3. After reactor trip the break flow reaches equilibrium at the point where incoming safety injection flow is balanced by outgoing break flow as shown on Figure 15.4-61.

4. The steam generators are controlled at the safety valve setting rather than the power-operated relief valve setting. Mass and energy balance calculations are performed to determine primary to secondary mass release and to determine amount of steam vented from each of the steam generators.

15.4.4.4 Results

Figure 15.4-61 illustrates the flow rate that would result through the ruptured steam generator tube. Also plotted on Figure 15.4-61 is the delivered safety injection flow rates considering maximum performance from the centrifugal charging pumps and safety injection pumps. The contribution from the RHR pumps is not included since RCS pressure will remain above their shutoff head during a steam generator tube rupture accident transient. The previous assumptions lead to a conservative upper limit estimate of 137,250 lb for the total amount of reactor coolant transferred to the secondary side of the faulty steam generator as a result of a tube rupture accident.

An evaluation (Reference 72) with respect to the operator action time assumption for isolation of the faulted steam generator has been applied to this analysis. The current licensed method used to calculate the mass released from the faulted steam generator, as has been used for this event analysis, has been shown to be conservative with respect to mass released over an assumed 30-minute operator action time. The amount of mass released, as predicted by the current licensed method, from the faulted steam generator over the 30-minute assumed operator action time is much larger than expected mass release if the transient was to be modeled explicitly. An explicit modeling method was used to evaluate the equivalent amount of operator action time that would be available that yields an equivalent mass release to that calculated by using a 30-minute operator action time with the current licensed method. This time was found to be 55 minutes. Since the operator is able to isolate the faulted steam generator within 50 minutes from event initiation, the amount of mass released is not expected to exceed that calculated using a 30-minute isolation time with the current licensed method. Therefore, the 30-minute assumption used in the current licensed analysis for the time to isolate the faulted steam generator is conservative since it results in a bounding mass release calculation.

15.4.4.5 Environmental Consequences of a Tube Rupture

These analyses incorporate one percent defective fuel clad, and steam generator leakage prior to the release for a time sufficient to establish equilibrium-specific activity levels in the secondary system.
he analysis is performed for two cases of iodine concentrations in the primary coolant, resulting from:

1) A pre-accident iodine spike
2) An accident-initiated concurrent iodine spike

The pre-accident iodine spike concentrations are assumed to result from a reactor transient which raises the primary coolant concentrations to the maximum values identified in the Technical Specifications.

The initial primary coolant iodine activity is based on the pre-accident iodine spike activity level of 60 μCi/g of dose equivalent I-131 with the initial primary coolant noble gas activity based on 1% fuel defects. The activities leaked to the secondary system via a primary-to-secondary leak are mixed with the existing activities in the steam generators (initial iodine activity is the Technical Specification limit of 0.1 μCi/g of dose equivalent I-131) and are released to the environment via a steam release.

Offsite power is assumed lost and the main steam condensers are not available for heat removal via a steam dump. Steam is released directly to the environment through the steam generator safety relief valves for the intact steam generators. Noble gases from the leaked reactor coolant are released directly to the environment with no retention in the Steam Generators (SGs). Iodine activity is released from the SGs to the environment in proportion to the steam release rate and the partition coefficient. The iodine partition coefficient during the steaming process is conservatively assumed to be 0.1. Thirty-two hours after the accident, the Residual Heat Removal System is assumed to start operation to cool down the plant and no steam is released to the environment after this time from the intact steam generators. The faulted steam generator is assumed to be isolated within an acceptable operator action time.

The accident-initiated or concurrent iodine spike is modeled assuming that the iodine release rates from the fuel rods into the primary coolant are 500 times the equilibrium release rates for a period of two hours.

Other assumptions, parameters, mass transfer rates, and initial activity inventories used in the analysis are listed in Table 15.4-7B with the consequences listed in Table 15.4-7C.

15.4.4.6 Conclusions

A steam generator tube rupture will cause no subsequent damage to the RCS or the reactor core. An orderly recovery from the accident can be completed even assuming simultaneous loss of offsite power. Offsite dose consequences may be calculated based on a conservative estimate of 137,250 lb of reactor coolant transferred to the secondary side of the faulty steam generator following the accident are a small fraction of the guideline values described in 10 CFR 100.

15.4.5 Single Reactor Coolant Pump Locked Rotor and Reactor Coolant Pump Shaft Break

15.4.5.1 Identification of Causes and Accident Description

The events postulated are an instantaneous seizure of a reactor coolant pump rotor and a reactor coolant pump shaft break. Following either event, flow through the affected reactor coolant loop is rapidly reduced, resulting in the initiation of a reactor trip on a low flow signal and subsequent turbine trip.

Following initiation of reactor trip, heat stored in the fuel rods continues to be transferred to the coolant, causing the coolant to expand. At the same time, heat transfer to the shell side of the steam generator in the faulted loop is reduced. This reduction in primary heat removal capability is initially caused by the decrease in primary coolant flow, which reduces the tube side film coefficient. Following turbine trip, primary heat removal is further impaired as the shell side temperature in all steam generators increases. Rapid expansion of the coolant in the reactor core, caused by flow reduction and degraded primary-to-secondary heat removal, results in an insurge into the pressurizer and an RCS pressure increase.

The insurge into the pressurizer sequentially compresses the steam volume, actuates the Automatic Spray System, opens the power-operated relief valves, and opens the pressurizer safety valves. The power-operated relief valves are designed for reliable operation and would be expected to function properly during the accident. However, for conservatism, their pressure-reducing effect, as well as the pressure-reducing effect of the spray, is not included in the analysis.

The consequences of a reactor coolant pump shaft break are similar to those that follow a locked rotor event. With a broken shaft, the impeller is free to spin, as opposed to its being fixed in position during the locked rotor event. Therefore, the initial rate of reduction in core flow is greater during a locked rotor event than in a pump shaft break event because the fixed shaft causes greater resistance than a free spinning impeller early in the transient, when flow through the affected loop is in the positive direction. As the transient continues, the flow direction through the affected loop is reversed. If the impeller is able to spin free, the flow to the core will be less than that available with a fixed shaft during periods of reverse flow in the affected loop. Because the peak pressure, clad temperature, and maximum number of fuel rods in DNB occur very early in the transient, before periods of any appreciable reverse flow, the reduction in core flow during the period of forward flow in the affected loop dominates the severity of the results. Therefore, the bounding results for the locked rotor transients also are applicable to the reactor coolant pump shaft break.

The locked rotor accident is an ANS Condition IV event and, as such, is analyzed to demonstrate that the peak RCS pressure reached during the transient is less than that which would cause stresses to exceed the faulted condition stress limits and compromise the integrity of the primary coolant system. In addition, it must be demonstrated that the core will remain intact, with no loss of core cooling capability, and that radioactive releases do not exceed acceptable levels.

15.4.5.2 Method of Analysis

Two digital computer codes are used to analyze this transient. The LOFTRAN code calculates the resulting loop and core flow transients following the event, the time of reactor trip based on loop flow transients, and the nuclear power following reactor trip and determines the peak pressure. Thermal behavior of the fuel located at the core hot spot is investigated with the FACTRAN code, using the core flow and nuclear power calculated by LOFTRAN. The FACTRAN code includes the use of a film boiling heat transfer coefficient.

The case of all loops operating and one locked rotor is analyzed as follows. At the beginning of the postulated event, i.e., when the shaft in one of the reactor coolant pumps is assumed to seize, the plant is assumed to be in operation under the most adverse steady-state operating conditions, with respect to the margin to DNB. These conditions include maximum steady-state power level (including 2-percent uncertainty), thermal design flow, minimum steady-state pressure, and maximum steady-state coolant average temperature.

There is no postulated single failure which will increase the severity of the consequences following this event.

When the peak pressure is evaluated, the initial pressure is conservatively estimated to be 50 psi above the nominal pressure of 2250 psia to allow for errors in the pressurizer pressure measurement and control channels. This is done to obtain the highest possible rise in coolant pressure during the transient. The pressurizer pressure and peak RCS pressure responses for the case analyzed are shown on Figures 15.4-68 and 15.4-70.

Evaluation of Pressure Transient

After pump seizure, the neutron flux is rapidly reduced by control rod insertion. Rod motion begins 1 second after flow in the affected loop reaches 87 percent of nominal flow. Offsite power is assumed to be lost immediately at reactor trip, resulting in a coastdown of the other three reactor coolant pumps. No credit is taken for the pressure reducing effect of the pressurizer relief valves, pressurizer spray, or steam dump.

Although these operations are expected to occur and would result in a lower RCS peak pressure, an additional degree of conservatism is provided by ignoring their effects.

The pressurizer safety valves are assumed to initially open at 2575 psia and achieve rated flow at 2650 psia. This analysis assumed an initial pressurizer pressure of 2300 psia.

Evaluation of DNB in the Core During the Accident

For this accident, DNB is assumed to occur in the core; therefore, an evaluation of the consequences with respect to fuel rod thermal transients is performed. Two DNB-related analyses are performed. The first incorporates the assumption of rods going into DNB as a conservative initial condition to determine the clad temperature and zirconium water reaction. This analysis assumed an initial pressurizer pressure of 2200 psia. Result obtained from the analysis of this hot-spot condition represent the upper limit with respect to clad temperature and zirconium water reaction. In this analysis, the rod power at the hot spot is assumed to be 3.0 times the average rod power (i.e., F_Q = 3.0) at the initial core power level.

The second analysis is performed to determine what percentage of rods, if any, is expected to be in DNB during the transient. Analyses to determine this percentage for the locked rotor and shaft break accidents use three digital computer codes. In addition to the LOFTRAN and FACTRAN codes, the THINC code is used to calculate DNBR during the transient, based on flow calculated by LOFTRAN and heat flux calculated by FACTRAN. Consistent with RTDP (Reference 76), initial reactor power, RCS pressure, and RCS temperature are assumed to be at their nominal values.

Film Boiling Coefficient

The film boiling coefficient is calculated in the FACTRAN code using the Bishop-Sandburg-Tong film boiling correlation. The fluid properties are evaluated at film temperatures (average between wall and bulk temperatures). The program calculates the film coefficient at every time step, based upon the actual heat transfer conditions at the time. Neutron flux, system pressure, bulk density, and mass flow rate as a function of time are used as program inputs.

For this analysis, the initial values of pressure and bulk density are used throughout the transient, since they are the most conservative with respect to clad temperature response. For conservatism, DNB was assumed to start at the beginning of the accident.

Fuel Clad Gap Coefficient

The magnitude and time dependence of the heat transfer coefficient between fuel and clad (gap coefficient) have a pronounced influence on thermal results. The larger the value of the gap coefficient, the more heat is transferred between pellet and clad. Based on investigations on the effect of the gap coefficient upon the maximum clad temperature during the transient, the gap coefficient was assumed to increase from a steady-state value consistent with the initial fuel to 10,000 BTU/hr-ft-°F at the initiation of the transient. Thus, the large amount of energy stored in the fuel is released to be clad at the initiation of the transient because of the small gap coefficient initially assumed.

Zirconium-Steam Reaction

The zirconium-steam reaction can become significant above clad temperatures of 1800°F. In order to take this phenomenon into account, the Baker-Just parabolic rate equation shown below is used to define the rate of the zirconium-steam reaction.

$$d(w^2)/dt = 33.3 \times 10^6 \times \exp - [(45,000)/1.986T]$$

where: w = amount reacted, mg/cm^2

t = time, sec

T = temperature, °K

The reaction heat is 1510 cal/gm.

15.4.5.3 Locked Rotor Results

The locked rotor/shaft break analysis is performed to demonstrate that the peak RCS pressure reached during the transient is less than that which would cause the stresses to exceed the faulted condition stress limits. In addition, it must be shown that a coolable core geometry is maintained and that the radioactive release is within acceptable levels.

To demonstrate that the above conditions are met following a locked rotor/shaft break event, the following criteria are used:

1. RCS maximum pressure ≤ 110-percent design (2750 psia) (110-percent design pressure < faulted condition stress limit).

2. Peak clad temperature ≤ 2700°F.

3. Maximum zirconium-water reaction ≤ 16 percent.

4. Offsite radiological release within 10CFR100 limits.

The transient response of the reactor coolant system during the locked rotor/shaft break incidents analyzed is shown on Figures 15.4-68 through 15.4-70. The peak RCS pressure occurs at the pump outlet. The pump outlet pressure transient is shown on Figure 15.4-70. The clad temperature transient calculated is shown on Figure 15.4-69. The maximum RCS pressure, maximum clad temperature, amount of zirconium-water reaction, and percent of fuel in DNB are listed in Table 15.4-6. The calculated sequence of events is shown in Table 15.4-1.

The results of the locked rotor/shaft break analysis demonstrate that the peak pressure reached is less than that which would cause the faulted condition stress limits to be exceeded. In addition, it was determined that the peak clad surface temperature calculated for the hot spot is less than 2700°F, and the maximum number of fuel rods which undergo DNB will not exceed 5 percent of the total fuel rods.

An analysis of the radiological dose consequences of this event, assuming 10 percent of the fuel rods in the core experienced clad failure (rod perforation), demonstrated that the maximum dose that the general public could receive would be less than 10 percent of the 10CFR100 guidelines.

15.4.5.4 Conclusions

1. The integrity of the primary coolant system is not endangered since the peak RCS pressure reached during any of the transients is less than that which would cause stresses to exceed the faulted condition stress limits.

2. The core will remain in place and intact with no loss of core cooling capability since the peak clad surface temperature calculated for the hot spot during the worst transient remains considerably less than 2700°F (the temperature at which clad embrittlement may be expected) and the amount of zirconium-steam reacted is small.

3. The maximum dose that the general public could receive from this event would be a small fraction (<10 percent) of the 10CFR100 guidelines, since less than 10 percent of the fuel rods were calculated to have a DNB ratio less than the design limit.

15.4.6 Fuel Handling Accident

15.4.6.1 Identification of Causes and Accident Description

The accident is defined as dropping of a spent fuel assembly onto the spent fuel pit floor in the fuel handling building or inside containment resulting in the rupture of the cladding of all the fuel rods in the assembly despite many administrative controls and physical limitations imposed on fuel handling operations. All refueling operations are conducted in accordance with prescribed procedures under direct surveillance of a supervisor.

15.4.6.2 Analysis of Effects and Consequences

During the design phase of the reracking which was implemented in 1994, the potential radiological consequences resulting from a Fuel Handling Accident were evaluated. In performing this evaluation the following documents were used as a reference.

1. Safety Guide 25, Assumptions used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in The Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors, 1972.

2. NUREG/CR-5009, Assessment of the Use of Extended Burnup Fuel in Light Water Reactors, 1988.

3. ORNL Isotope Generation and Depletion, ORNL/TM-7175, Oak Ridge National Laboratory, 1980.

Method of Analysis

Evaluation of this accident in the fuel handling building was based on the following data and assumptions:

1. The reactor was assumed to have been operating at 3600 Mw thermal power prior to shutdown, with an average specific power of 40.45 kw/kgU.

2. Initial enrichment of fuel considered is 4.5 wt% and burned to 65,000 Mwd/mtU.

3. The failed fuel cooling time considered prior to accident was 168 hours.

4. The fuel handling accident was assumed to result in the release of the gaseous fission products contained in the fuel/cladding gaps of all the 264 fuel rods in a peak-power fuel assembly (radial peaking factor of 1.70).

5. Gap inventories of fission products available for release were estimated using the release functions identified in Safety Guide 25 except for I-131. The release fraction for I-131 was increased 20% in accordance with NUREG/CR-5009.

6. Core specific fission product inventories (curies per metric ton of uranium) were estimated using the ORIGEN-2 Code. See Table 15.4-10.

7. The fission product gap inventory in a fuel assembly used in the thyroid dose calculation is I-131, 12%; other iodine, 10%; Kr-85, 30%; other krypton, 10%; xenon, 10%. The iodine gap inventory is 99.75% inorganic and 0.25% organic.

8. The pool decontamination factor for iodine used is 133 for inorganic iodine and 1 for organic iodine. The pool decontamination factor for noble gases is 1.

9. The filter decontamination factor for noble gases is 1. The filter iodine removal efficiency is 90% for inorganic species and 70% for organic species.

10. The atmospheric diffusion factor used is 1.30×10^{-4} s/m^3 and breathing rate used is 3.47×10^{-4} m^3/s.

11. It is conservatively assumed that 25% of the radioactive effluent escapes unfiltered from the fuel handling building following postulated failure of one exhaust fan.

12. The values of average energy per disintegration, and dose conversion factors used are listed in Table 15.4-5A.

The following additional information relates to an evaluation of a fuel handling accident inside containment:

1. An instantaneous puff release of noble gases and radioiodine from the gap and plenum of failed fuel rods is assumed.

2. All airborne activity reacing the containment atmosphere is assumed to exhaust to the environment within 2 hours without filtration.

3. Offsite doses are computed using the TACTS computer code from the HABIT computer code package (Reference 71).

15.4.6.3 Conclusions

15.4.6.3.1 Radiation Doses

The doses at the Salem Exclusion Area Boundary (EAB) from the specified fuel handling accidents are listed below. The doses are based on the release of all gaseous fission product activity in the gaps of all 264 fuel rods in the highest-power assembly.

For a fuel handling accident in the fuel handling area:

Thyroid dose, rem	= 10.4
Whole-body dose, rem	= 0.2

For a fuel handling accident inside containment:

Thyroid dose, rem	= 28.7
Whole-body dose, rem	= 0.2

These potential doses are "well within" the exposure guideline values of 10CFR part 100, paragraph 11.

15.4.6.3.2 Solid Radwaste

A significant increase in the volume of solid radioactive wastes is not expected as a result of expanded storage capacity.

15.4.6.3.3 Gaseous Releases

Gaseous releases from the fuel storage area are combined with other plant exhausts. Normally, the contribution from the fuel storage area is negligible compared to the other releases; therefore, significant increases are not expected as a result of the expanded storage capacity.

15.4.6.3.4 Personnel Exposures

No increase in radiation exposure to operating personnel is expected as a result of the expanded storage capacity; thus, neither the current radiation protection program nor the area monitoring system requires modification.

15.4.7 Rupture of a Control Rod Drive Mechanism Housing (Rod Cluster Control Assembly Ejection)

15.4.7.1 Identification of Causes and Accident Description

This accident is defined as the mechanical failure of a control rod mechanism pressure housing resulting in the ejection of a RCCA and drive shaft. The consequence of this mechanical failure is a rapid reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage.

Design Precautions and Protection

Certain features of the Salem Plants are intended to preclude the possibility of a rod ejection accident, or to limit the consequences if the accident were to occur. These include a sound, conservative mechanical design of the rod housings, together with a thorough quality control (testing) program during assembly, and a nuclear design which lessens the potential ejection worth of RCCAs and minimizes the number of assemblies inserted at power.

Mechanical Design

The mechanical design is discussed in Section 3.2. Mechanical design and quality control procedures intended to preclude the possibility of a RCCA drive mechanism housing failure sufficient to allow a RCCA to be rapidly ejected from the core are listed below:

1. Each full-length CRDM housing is completely assembled and shop tested at 4100 psi.

2. The mechanism housings are individually hydrotested as they are attached to the head adapters in the reactor vessel head, and checked during the hydrotest of the completed RCS.

3. Stress levels in the mechanism are not affected by anticipated system transients at power, or by the thermal movement of the coolant loops. Moments induced by the design earthquake can be accepted within the allowable primary working stress range specified by the ASME Code, Section III, for Class 1 components.

4. The latch mechanism housing and rod travel housing are each a single length of forged Type-304 stainless steel.

This material exhibits excellent notch toughness at all temperatures which will be encountered.

A significant margin of strength in the elastic range together with the large energy absorption capability in the plastic range gives additional assurance that gross failure of the housing will not occur. The joints between the latch mechanism housing and head adapter, and between the latch mechanism housing and rod travel housing, are threaded joints reinforced by canopy-type rod welds. Administrative regulations require periodic inspections of these (and other) welds.

Nuclear Design

Even if a rupture of a RCCA drive mechanism housing is postulated, the operation of a plant utilizing chemical shim is such that the severity of an ejected RCCA is inherently limited. In general, the reactor is operated with the RCCAs inserted only far enough to permit load follow. Reactivity changes caused by core depletion and xenon transients are compensated by boron changes. Further, the location and grouping of control rod banks are selected during the nuclear design to lessen the severity of a RCCA ejection accident. Therefore, should a RCCA be ejected from its normal position during high power operation, only a minor reactivity excursion, at worst, could be expected to occur.

However, it may be occasionally desirable to operate with larger than normal insertions. For this reason, a rod insertion limit is defined as a function of power level. Operation with the rod cluster control assemblies above this limit guarantees adequate shutdown capability and acceptable power distribution. The position of all RCCAs is continuously indicated in the Control Room. An alarm will occur if a bank of RCCAs approaches its insertion limit or if one assembly deviates from its bank. There are low and low-low level insertion monitors with visual and audio signals. Operating instructions require boration at low level alarm and emergency boration at the low-low alarm.

Reactor Protection

The reactor protection in the event of a rod ejection accident has been described in Reference 29. The protection for this accident is provided by the power range high neutron flux trip (high and low setting) and high rate of neutron flux increase trip. These protection functions are described in detail in Section 7.

Effects on Adjacent Housings

Disregarding the remote possibility of the occurrence of a RCCA mechanism housing failure, investigations have shown that failure of a housing due to either longitudinal or circumferential crack-ing is not expected to cause damage to adjacent housings leading to increased severity of the initial accident.

Limiting Criteria

Due to the extremely low probability of a RCCA ejection accident, limited fuel damage is considered an acceptable consequence.

Comprehensive studies of the threshold of fuel failure and of the threshold of significant conversion of the fuel thermal energy to mechanic energy, have been carried out as part of the SPERT project by the Idaho Nuclear Corporation (30). Extensive tests of UO_2 zirconium clad fuel rods representative of those in pressurized water reactor-type cores have demonstrated failure thresholds in the range of 240 to 257 cal/gm. However, other rods of a slightly different design have exhibited failures as low as 225 cal/gm. These results differ significantly from the TREAT (31) results, which indicated a failure threshold of 280 cal/gm. Limited results have indicated that this threshold decreases by 10 percent with fuel burnup. The clad failure mechanism appears to be melting for zero burnup rods and brittle fracture for irradiated rods. Also important is the conversion ratio of thermal to mechanical energy. This ratio becomes marginally detectable above 300 cal/gm for unirradiated rods and 200 cal/gm for irradiated rods; catastrophic failure, (large fuel dispersal, large pressure rise) even for irradiated rods, did not occur below 300 cal/gm.

In view of the above experimental results, conservative criteria are applied to ensure that there is little or no possibility of fuel dispersal in the coolant, gross lattice distortion, or severe shock waves. These criteria are:

1. Average fuel pellet enthalpy at the hot spot below 225 cal/gm for unirradiated fuel and 200 cal/gm for irradiated fuel.

2. Peak reactor coolant pressure less than that which would cause stresses to exceed the faulted condition stress limits.

3. Fuel melting will be limited to less than 10 percent of the fuel volume at the hot spot even if the average fuel pellet enthalpy is below the limits of Criterion 1 above.

(This text has been deleted)

15.4.7.2 Analysis of Effects and Consequences

Method of Analysis

The analysis of the RCCA ejection accident is performed in two stages, first an average core nuclear power transient calculation and then a hot spot heat transfer calculation. The average core calculation is performed using spatial neutron kinetics methods to determine the average power generation with time including the various total core feedback effects, i.e., Doppler reactivity and moderator reactivity. Enthalpy and temperature transients in the hot spot are then determined by multiplying the average core energy generation by the hot-channel factor and performing a fuel rod transient heat transfer calculation. The power distribution calculated without feedback is pessimistically assumed to persist throughout the transient.

A detailed discussion of the method of analysis can be found in Reference 32.

Average Core Analysis

The spatial kinetics computer code, TWINKLE (33), is used for the average core transient analysis. This code uses cross sections generated by LEOPARD (34) to solve the two group neutron diffusion theory kinetic equations in one, two or three spatial dimensions (rectangular coordinates) for six delayed neutron groups and up to 2000 spatial points. The computer code includes a detailed multi-region, transient fuel-clad-coolant heat transfer model for calculating pointwise Doppler and moderator feedback effects.

In this analysis, the code is used as a one-dimensional axial kinetics code since it allows a more realistic representation of the spatial effects of axial moderator feedback and RCCA movement and the elimination of axial feedback weighting factors. However, since the radial dimension is missing, it is still necessary to employ very conservative methods (described below) of calculating the ejected rod worth and hot-channel factor. Further description of TWINKLE appears in Section 15.1.9.7.

Hot Spot Analysis

The average core energy addition, calculated as described above, is multiplied by the appropriate hot-channel factors, and the hot spot analysis is performed using the detailed fuel and clad transient heat transfer computer code, FACTRAN (28). This computer code calculates the transient temperature distribution in a cross section of a metal clad UO_2 fuel rod, and the heat flux at the surface of the rod, using as input the nuclear power versus time and local coolant conditions. The zirconium-water reaction is explicitly represented, and all material properties are represented as functions of temperature. A parabolic radial power generation is used within the fuel rod.

FACTRAN uses the Dittus-Boelter or Jens-Lottes correlation to determine the film transfer before DNB, and the Bishop-Sandburg-Tong correlation (35) to determine the film changes were compared and effective weighting factors determined. These weighting factors take the form of multipliers which when applied to single channel feedbacks correct them to effective whole core feedbacks for the appropriate flux shape. In this analysis, since a one-dimensional (axial) spatial kinetics method is employed, axial weighting is not used. In addition, no weighting is applied to the moderator feedback. A conservative radial weighting factor is applied to the transient fuel temperature to obtain an effective fuel temperature as a function of time accounting for the missing spatial dimension. These weighting factors were shown to be constructive compared to three dimensional analysis.

Moderator and Doppler Coefficient

The critical boron concentrations at the beginning-of-life (BOL) and EOL were adjusted in the nuclear code in order to obtain moderator density coefficient curves which are conservative compared to actual design conditions for the plant. As discussed above, no weighting factor is applied to these results.

The Doppler reactivity defect is determined as a function of power level using the one-dimensional steady state computer code with a Doppler weighting factor of 1.0. The resulting curve is conservative compared to design predictions for this plant. The Doppler weighting factor should be larger than 1.0 (approximately 1.3), just to make the present calculation agree with design predictions before ejection. This weighting factor used in the analysis is presented in Table 15.4-12.

Delayed Neutron Fraction

Calculations of the effective delayed neutron fraction (β_{eff}) typically yield values of 0.70 percent at BOL and 0.50 percent at EOL for the first cycle. The accident is sensitive to β if the ejected rod worth is nearly equal to or greater than β as in zero power transients. In order to allow for future fuel cycles, pessimistic estimates for β of 0.48 percent at beginning of cycle and 0.40 percent at end of cycle were used in the analysis.

Trip Reactivity Insertion

The trip reactivity insertion is assumed to be 4 percent from hot full power and 2 percent from hot zero power, including the effect of one stuck rod in each case. The analyses assume that the start of rod motion occurs 0.5 second after the high neutron flux trip point is reached. The analyses also assume a total rod insertion time of 2.7 seconds, from the start of rod motion to the entrance of the dashpot. This conservative insertion rate includes over a 1 second delay from when the trip setpoint is reached until significant shutdown reactivity is inserted into the core. This conservatism is particularly important for accidents occurring during hot full power. Reactivity insertion versus time assumptions are discussed in Section 15.1.5.

15.4.7.3 Results

The values of the parameters used in the analysis, as well as the results of the analysis, are presented in Tables 15.4-1 and 15.4-12 and discussed below.

Beginning of Cycle, Full Power

Control bank D was assumed to be inserted to its insertion limit. The worst ejected rod worth and hot channel factor were conservatively assumed to be 0.20 percent Δk and 7.4, respectively. The peak hot spot fuel pellet enthalpy remained below 200 cal/g. The peak hot spot fuel centerline temperature reached melting at 4900°F; however, melting was restricted to less than ten percent of the pellet.

Beginning of Cycle, Zero Power

For this condition, control bank D was assumed to be fully inserted and C was at its insertion limit. Assuming the worst ejected rod worth of 0.77 percent Δk and a hot channel factor of 14.2 resulted in the peak fuel pellet enthalpy below 200 cal/g. The peak pellet centerline temperature remained below the melting temperature of 4900°F.

End of Cycle, Full Power

Control bank D was assumed to be inserted to its insertion limit. The worst ejected rod worth and hot channel factor were conservatively assumed to be 0.21 percent Δk and 8.2, respectively. The resulting peak hot spot fuel pellet enthalpy remained below 200 cal/g. The peak hot spot fuel centerline temperature reached melting at 4800°F; however, melting was restricted to less than ten percent of the pellet.

End of Cycle, Zero Power

For this condition, control bank D was assumed to be fully inserted and C was at its insertion limit. Assuming the worst ejected rod worth of 0.90 percent Δk and and a hot channel factor of 20.5 resulted in the peak pellet enthalpy below 200 cal/g. The peak pellet centerline temperature remained below the melting temperature of 4800°F.

A summary of the cases presented above is given in Table 15.4-12. The nuclear power and hot spot fuel and clad temperature transients for the worst cases are presented on Figures 15.4-76 through 15.4-78B.

Fission Produce Release

It is assumed that fission products are released from the gaps of all rods having a DNB ratio of less than the design limit. In all cases would therefore be a negative feedback. It can be concluded that no conceivable mechanism exists for a net positive feedback resulting from lattice deformation. In fact, a small negative feedback may result. The effect is conservatively ignored in the analyses.

15.4.7.4 Conclusions

Even on a pessimistic basis, the analyses indicate that the described fuel limits are not exceeded. It is concluded that there is no danger of sudden fuel dispersal into the coolant. Since the peak pressure does not exceed that which would cause stresses to exceed the faulted condition stress limits, it is concluded that there is no danger of further consequential damage to the primary circuit. The analyses have demonstrated that upper limit in fission product release as a result of a number of fuel rods entering DNB amounts to 10 percent.

15.4.8 Containment Pressure Analysis

The containment pressure response to a spectrum of RCS and steam line breaks have been analyzed. The containment response to minor reactor coolant leakage and the loss of normal containment cooling have also been evaluated. Finally, a subcompartment analysis is provided to permit evaluation of the blowdown loads on the structure.

15.4.8.1 Reactor Coolant System Breaks

15.4.8.1.1 Method of Analysis

Calculation of containment pressure and temperature transients is accomplished by use of the digital computer code, COCO. The analytical model is restricted to the containment volume and structure.

For analytical rigor and convenience, the containment air-steam-water mixture is separated into two systems. The first system consists of the air-steam phase, while the second is the water phase. Sufficient relationships to describe the transient are provided by the equations of conservation of mass and energy as applied to each system, together with appropriate boundary conditions. As thermodynamic equations of state and conditions may vary during the transient, the equations have been derived for all possible cases of superheated or saturated steam, and subcooled or saturated water. Switching between states is handled automatically by the code. The following are the major assumptions made in the analysis:

1. At the break point, the discharge flow separates into steam and water phases. The saturated water phase is at the total containment pressure, while the steam phase is at the partial pressure of the steam in the containment.

2. Homogeneous mixing is assumed. The steam-air mixture and the water phase each have uniform properties. More specifically, thermal equilibrium between the air and steam is assumed. This does not imply thermal equilibrium between the steam-air mixture and the water phase.

3. Air is taken as an ideal gas, while compressed water and steam tables are employed for water and steam thermodynamic properties.

During the transient, there is energy transfer from the steam-air and water systems to the internal structures and equipment within the shell.

Provision is made in the computer analysis for the effects of several engineered safeguards, including internal spray, fan coolers, and recirculation of sump water. The heat removal from containment steam-air phase by internal spray is determined by allowing the spray water temperature to rise to the steam-air temperature.

15.4.8.1.2 Mass and Energy Releases from the Reactor Coolant System

Discharge mass and energy flow rates through the RCS break are established from the coolant blowdown and core thermal transient analysis.

The methods, assumptions and computer codes used to calculate the mass and energy releases to the containment are identical to those given in Reference 36. Mass and energy releases were recalculated as part of the Fuel Upgrade Margin Recovery Program (Reference 73). Changes from the earlier design basis analyses described in the following sections are annotated where appropriate.

For the Preliminary Safety Analysis Report (PSAR) the mass and energy releases to the containment from the RCS during the blowdown were calculated using the FLASH-R code. The SATAN-V code was used to calculate the blowdown mass and energy releases for the Final Safety Analysis Report (FSAR). The SATAN-V code provides a detailed model of the RCS. This alone results in a different mass and energy release. The conservatively high core heat transfer coefficients used in the SATAN analysis result in a conservatively high addition to the reactor coolant which is ultimately discharged through the break to the containment.

All the initial core stored energy and the power generated by the core during blowdown is available for transfer to the coolant and hence to the containment. The initial metal sensible energy is transferred to the coolant by a time-dependent temperature difference calculation. It should be emphasized that the energy transferred from the core to the coolant for the containment evaluation far exceeds that transferred for the core thermal evaluation. That is to say a conservatively high core heat transfer coefficient is used for the containment evaluation, while a conservatively low coefficient is used during core thermal evaluation.

Any energy addition resulting from a $Zr\text{-}H_2O$ reaction is also considered. The reaction energy reaches the containment by transfer to coolant, while the combination energy of the H_2 generated in the reaction is added directly to the steam-air mixture in the containment. The hydrogen is assumed to burn as it is produced. For the containment analyses performed as part of the Marging Recovery Program (Reference 73), Zr-H_2O reaction heat was not considered since the cladding temperature did not rise high enough for the rate of zirconium-water heat generation be to of any significance.

The following are some conservative assumptions used in the analysis:

1. The reactor power is based on operation at the maximum calculated power of 3570 MWt (for Unit 2) which is 4.3 percent greater than the application at 3423 MWt. The Margin Recovery Program analyses were performed at the actual Salem rated power level of 3411 MWth (with a 2% allowance for calorimetric error). As described in Reference 74, the core stored energy was recalculated to bound the new core configuration and conservatively used peak fuel average temperatures. However, due to newer developments in the models used to calculate the stored energy, other conservatisms were removed. The final value of core stored energy used in the Margin Recovery Program analysis is 4.23 full power seconds, which includes a 15% uncertainty allowance to account for manufacturing and thermal model uncertainties.

2. The decay heat is based on power operation for an infinite time. The Margin Recovery Program analyses assumed three years of operation time prior to shutdown.

3. Coolant temperatures are the maximum levels attained in steady state operation, including allowance for instrument error and deadband.

4. Gross system volumes are calculated from component dimensions, to which is added a 3-percent margin.

5. Pressurizer liquid inventory at the nominal full power level plus an appropriate margin for instrument error and deadband.

Analytical methods were used to calculate the free volume of the containment at the design pressure of 47 psig. The volumes of the equipment and structures located inside the containment were hand calculated using the applicable geometric expressions for the various configurations as shown on Public Service Electric & Gas (PSE&G) and vendor drawings. The aggregate (empty) volume of the containment was calculated in a similar manner. The containment free volume was derived by subtracting the sum of all the equipment and structure volumes from the aggregate volume of the containment. The containment net free volume was calculated to be 2.62×10^6 cubic feet.

There are no tests planned to verify the analytically derived free volume of the containment.

Pump suction breaks yield the highest energy flow rate during the post blowdown period. This is because of the following: for the cold leg break, all of the fluid leaving the top of the core passes through the steam generators and may become superheated. However, the flooding rate is limited to a relatively low value by the resistance of the pump in the broken loop. For a hot leg break, the flooding rate is not so restricted but the majority of the fluid leaving the top of the core bypasses the steam generators and is not superheated. Thus the steam generators add much less energy. The pump suction break, on the other hand, has the relatively high flooding rate combined with all of the fluid passing through the primary side of the steam generators.

The calculational model may be divided into four parts: blowdown, when the system pressure drops from 2250 psia to containment pressure; refill, when the vessel inventory is increased to the bottom of the core; and reflood, where the water level moves into the core; and post-reflood.

The Margin Recovery Program utilized the SATAN-VI code to determine the mass and energy releases during blowdown transient and the WREFLOOD code to compute these for the reflood transient as described in Reference 73.

<u>BLOWDOWN</u> The model for blowdown is similar to that used in the ECCS analysis. The SATAN code is used to simulate breaks in the various locations. All accumulators inject for breaks other than the cold leg.

The steam generator is modeled using several well known heat transfer correlations. When the heat flow in the steam generators is from primary to secondary, the heat transfer coefficient on the tube side is calculated using the Dittus Boelter (37) correlation for subcooled forced convection, while the shell side uses the well known Jens-Lottes (38) correlation for nucleate boiling. For secondary to primary heat flow, the tube side heat transfer coefficient is calculated using the Jens-Lottes correlation for nucleate boiling. This calculation will be bypassed if the tubes experience DNB. The DNB ratio is calculated using Macbeth's (39) correlation of the critical heat flux. When the value of this ratio drops below an input value, the Dougall-Rohsenow (40) film boiling correlation is used. Should the fluid in the steam generator tubes become superheated, the superheat forced convection correlation developed by McEligot (41) is used. In the present model the heat transfer coefficient on the shell side when heat flow is from secondary to primary is calculated using McAdam's (42) recommended correlation for turbulent boundary layers on vertical surfaces. Table 15.4-13 lists all of the heat transfer correlations.

The fluid volume contained in the primary system reflects the correct system volume, calculated from component dimensions, plus 1.6 percent to account for thermal expansion and 1.4 percent to account for uncertainties.

The initial fluid energy is also based on coolant temperatures which are the maximum levels attained in steady state operation including allowance for instrument error and deadband. The stored energy has been evaluated using a detailed temperature model of the pellet, clad and gap. The temperature distribution within the fuel pellet is predominantly a function of the local power density and the UO_2 thermal conductivity. However, the computation of radial fuel temperature distributions combines crud, oxide, clad, gap and pellet conductances. The factors which influence these conductances, such as gap size (or contact pressure), internal gas pressure, gas composition, pellet density, and radial power distribution within the pellet, etc., have been combined into a semiempirical thermal model. This thermal model has been incorporated into a computer code to enable the determination of these factors and their net effects on temperature profiles. The temperature predictions of the code have been compared to in-pile fuel temperature measurements and melt radius data with good results. Table 15.4-14 presents the results of a sensitivity study on core stored energy, in full power seconds above average coolant temperature, varying the following parameters:

1. Average Power Level

2. Number of nodes assumed in the pellet

3. Effect of fuel densification.

A conservative value of 7.9 (6.6 x 1.2) full power seconds, which includes fuel densification and additional margin, was used in this analysis. Moreover, core stored energy was based on a conservative value of 102 percent of the engineered safeguards design rating power level, 3570 MWt. The Margin Recovery Program utilized 102% of the actual Salem rated power level of 3411 MWt.

The margins cited above clearly indicate that the values employed in this analysis represent a conservative upper bound of the core stored energy.

The amount of heat released from the core over blowdown is modified to agree with an average channel analysis using the LOCTA code.

REFILL The calculations in this period have been minimized by making the conservative assumption that the bottom of core recovery occurs immediately after the end of blowdown.

Description of the Core Reflooding Model

The SATAN calculations are performed until the completion of a blowdown. In this context the end of blowdown is defined as the time at which zero break flow is first computed. At this time, the normal blowdown transient calculations are terminated and the reflooding calculations are performed.

The reflooding calculations are done in the following two steps:

1. Calculate the core inlet mass flowrate and the fraction of the inlet mass flowrate that leaves the top of the core. This hydraulic calculation yields core flooding rate and entrainment fraction.

2. Calculate the core exit conditions due to the addition of various energy sources. Also perform calculations of the thermal conditions on the primary and secondary side of the steam generators. This step is an energy balance calculation.

Hydraulic Model

The REFLOOD code consists of a fixed vessel model, two variable - geometry loops, and models for accumulators and pumped injection. In the vessel model, water levels in both the downcomer and core are calculated from the mass balance and momentum equations and the Westinghouse entrainment correlation for liquid carry over from the core. REFLOOD includes the effect of inertia in the core-downcomer liquid, and the pressure drop due to the elevation head of two-phase liquid above the core water front.

The model used for each of the coolant loops (broken and lumped unbroken loops) is very general. Each of the loops may have a maximum of 29 series resistance elements. A typical schematic is shown on Figure 15.4-79. Provision is made for pressure drops within each element due to friction (f.L/D), form-factor (commonly called K-factors) and the dynamic pressure drop due to density change. The dynamic pressure drop due to area change is included at the interface between loop elements (and at the interface between the first element of each loop and the core). In the REFLOOD code, the density of fluid flowing in each resistance element is determined from the local pressure and enthalpy. The loops are assumed to be quasi-static. There is no provision for mass buildup in any loop element.

The REFLOOD code currently provides the following models and features:

1. The pressure at the top of the downcomer can be specified as the pressure of any element in either loop, or as containment back pressure.

2. In each loop, any element can be specified as the steam generator element. (The local enthalpy changes to that of superheated steam at the steam generator secondary side temperature at the inlet of the steam generator element).

3. Pumped injection may be specified as a tabular head-flow curve, with delivery pressure specified as the pressure in any loop flow element, or containment back pressure.

4. Accumulator injection may be specified as a linear ramp in time. The core flooding rate is limited by the pressure in the core caused by the generation of steam when the reflood water is heated up by the hot fuel rods. Any steam generated in the core region must be vented through the intact and broken loops via the resistive paths of elements shown on Figure 15.4-79.

Steam which flows through the intact steam generator must encounter the injected water in the cold legs of the broken and intact loops. During the accumulator injection phase, an equilibrium calculation indicates that the amount of water available is sufficient to condense this steam, thus reducing the flow to the containment. Moreover, preliminary results from steam-water mixing experiments performed by Westinghouse indicate that the heat transfer between the steam and injected liquid is quite high, and justify an equilibrium calculation. This effect was not included in the present calculations, but steam-water mixing is included in the Margin Recovery Program core reflood model.

The pressure drops along the two paths include friction from losses and dynamic pressure drops due to area and density changes. The pressure drop across the pump is calculated by assuming that the rotor is locked.

The fraction of calculated core flooding rates that is vaporized and entrained is calculated using the Westinghouse entrainment correlation obtained from the FLECHT results. The core inlet temperature during reflood is assumed to change with time, starting at saturated conditions and decreasing with time, based on separate energy balances on the fluid in the lower plenum and the downcomer. The energy balance includes the effect of the correct distribution of hot metal heating the fluid in the lower plenum and downcomer. Figure 15.4-80 presents the transient core inlet temperature that is used in the entrainment correlation to calculate the carryout fraction.

The FLECHT Data given on Figure 15.4-81 shows that by the time the quench front reaches the 8-foot core elevation, the 10-foot elevation has already been quenched. Hence the design case for the Salem plant conservatively assumes that entrainment ceases at the 8-foot level. In addition to this case, additional analyses have been performed for the case where entrainment is arbitrarily extended until the quench front reaches the 10-foot level to define margin in this calculation.

The resulting transient values of core flooding rate and the entrainment fraction for the double ended pump suction break are presented on Figure 15.4-82. These results are used in the energy balance model to calculate mass and energy release rates to the containment for calculation of the containment pressure transient.

Energy Balance Model

The energy balance model consists of three reference elements which represent the core, the steam generator in the broken loop, and the steam generator in the intact loop. Figure 15.4-83 presents a diagram of the model where the variables shown are defined as follows:

m	=	mass flow rate into the core (lbm/sec)
$(mh)_{in}$	=	energy flow rate into the core (Btu/sec)
$(mh)_{exit}$	=	energy flow rate out of the core (Btu/sec)
m_1	=	mass flow rate to the broken loop steam generator (lbm/sec)
m_2	=	mass flow rate to the intact loop steam generator (lbm/sec)
m_{hout1}	=	energy flow from broken loop steam generator out into containment (Btu/sec)
m_{hout2}	=	energy flow rate from intact loop steam generator out into containment (Btu/sec)
q_{heat}	=	sum of heat sources to the core fluid (Btu/sec)
h_f	=	saturated liquid enthalpy (Btu/lbm)
q_{SG1}	=	heat flow rate from the broken loop steam generator (Btu/sec)
q_{SG2}	=	heat flow rate from the unbroken loop steam generator (Btu/sec)

An energy balance is performed on the fluid entering and leaving the core in order to determine core exit conditions:

$$(mh)_{in} + q_{heat} = (mh)_{exit} + (m_{in} - m_{exit})h_f$$

The mass flow rate of fluid entering the core is identical to the calculated flooding rates times the product of the core area and liquid density. This fluid is taken to be at injection conditions. The heat source term is added to the fluid in the core and is the sum of the following:

1. Decay heat

2. Thick metal (reactor vessel) heat

3. Core stored energy left at end of blowdown

4. Thin metal energy reamining at end of blowdown

Decay heat is calculated using the Westinghouse standard decay heat curve. The Margin Recovery Program unitlized the 1979 ANSI/ASN decay heat standard with 2 sigma uncertainty applied to the fission product decay. The core stored and thin metal energy that are remaining at end of blowdown are brought out at a constant rate over the period between the bottom of core recovery (end of blowdown) and the termination of entrainment. The thick metal decays exponentially with a time constant of 0.0032^{-1} second.

The mass flow rate leaving the core is equal to the inlet flow rate times the entrainment fraction calculated from the hydraulic mode. The difference between inlet and outlet flow represents the fluid which remains in the core, and this is heated to saturated liquid enthalpy.

The above considerations provide sufficient information to determine the core exit enthalpy.

The flow split between the unbroken loop and the broken loop steam generators is determined in the hydraulic model described earlier. Separate energy balances are performed on the broken loop and intact loop steam generators. Fluid which enters the primary side of the steam generator is assumed to be heated instantaneously to the shell side temperature. This sets the outlet enthalpy; the steam generator inlet enthalpy is equal to the core exit enthalpy.

Hence the energy addition from the steam generators to the fluid entering the containment is determined.

This energy flow results in a decrease in internal energy for the shell side of the steam generator. Metal heat on the secondary side is included in the internal energy calculation. The steam generator secondary side fluid mass (and hence density) is taken as constant and temperature can be found directly from the internal energy. Feedwater addition is not considered in the present analysis; this effect would reduce steam temperature; hence, omission is conservative.

The fluid which leaves the steam generator primary side is assumed to flow directly into the containment. No credit is taken for the quenching effect of the accumulator water which spills to containment.

The mass and energy releases for the blowdown and reflood phases of the double-ended pump suction break are given in Tables 15.4-15 and 15.4-16. For the Margin Recovery Program mass and energy releases from the blowdown and reflood phases of the double ended pump suction break are provided in Reference 73. This is the size and location which resulted in the highest calculated containment pressure. The energy release for the 10-foot entrainment case is presented in Table 15.4-17.

At the end of the reflooding phase of the accident, the entire core has been quenched, and the only remaining sources of energy in the vessel are core decay heat and vessel thick metal energy. In the reactor coolant loops, the secondary sides of the steam generators may contain energy, but the release of this energy is limited by the flow rate through the steam generator tubes.

In the case of a break in the hot leg of a reactor coolant loop, the majority of the flow leaving the core bypasses the steam generators while venting to the containment. Furthermore, all safety injection flow which enters the RCS at the loop cold legs must pass through the core before spilling out through the break. With this flow configuration, all the heat released from the core and vessel metal will be absorbed by the safety injection water, and the release of steam to the containment will be terminated shortly after the end of the reflooding transient. The flow through the steam generators will be only a small fraction of the steam generated in the vessel, and therefore there is no mechanism for the release of substantial amounts of energy from the secondary sides at the steam generators.

For breaks in the pump suction line or the cold leg, the potential for continued energy release from the steam generator sides exists, since all flow which leaves the vessel through the hot legs must pass through the steam generators in either the broken or unbroken loops. Moreover, safety injection flow need not flow through the core while passing to the break, and continued boiling of fluid in the core will occur. For such breaks, the steam generated in the core is expected to separate rapidly from the liquid so that dry steam enters the steam generator tubes. The steam flowing through the tubes will become superheated, thus providing a relatively slow mechanism for transfer of steam generator secondary side energy to the containment. This expected case is presented in the next section. Also, a second case, where the two-phase mixture is postulated to enter the steam generator tubes, is presented in the following section.

Post Reflood Model (Dry Steam)

The hydraulic model used for this analysis is a simplified form of the model used during reflooding. The amount of fluid leaving the core is calculated from the rate of release of vessel metal energy and decay heat, assuming that the core exit flow consists of dry steam. The amount of fluid entering the bottom of the core is assumed to be equal to the amount leaving the core, and is taken at the enthalpy of injection water. Since the flow rates in broken and unbroken loops are low, we assume pressure equilibrium throughout the RCS, and take the flow split between the broken and unbroken loops to be the same as that which occurred during reflooding. No credit is taken for condensation of the steam in the intact or broken loop.

Table 15.4-18 presents a summary of the flow resistances in the broken loop and unbroken loop used for this analysis.

Two-Phase Post Reflood Results

A double-ended pump suction (DEPS) break with minimum safeguards safety injection flow (585 lb/sec.) during post reflood was analyzed. For this case the release rates are based on a reference temperature for heat stored in the steam generator secondary fluid equal to saturation temperature corresponding to reference containment design pressure. The table below presents a summary of the available secondary side energy for the broken loop and intact loop for this case.

Break	DEPS
Safety injection assumption	Minimum
Available energy* of secondary mass for broken loop steam generator (10^6 Btu)	7.5
Available energy* of secondary mass for intact loop steam generators (10^6 Btu)	135.8
Total available steam generator energy*	143.3

*Referenced to saturation temperature at containment design pressure

The calculated two-phase phase reflood data is presented in Table 15.4-19. For the Margin Recovery Program the two-phase mass and energy releases data for the double ended pump suction break with minimum sfety injection is provided in Reference 73.

15.4.8.1.3 Heat Sinks

Energy is absorbed from the containment atmosphere during the transient by heat sinks in the containment. Heat sinks include the containment structure, fan coolers and sprays.

Containment Structures

Provision is made in the containment pressure transient analysis for heat transfer through, and heat storage in, both interior and exterior walls.

The structural heat sink model includes a thermal resistance between the steel and concrete layers. The interface resistance is represented by a conservatively low heat transfer coefficient between the steel and concrete of 10 Btu/hr-°F-ft^2. If an incredible postulation of a 0 Btu/hr-°F-ft^2 heat transfer coefficient between the steel and concrete was made, it has been shown for a similar four-loop plant that the peak pressure of the design basis case would rise only 0.1 psi.

The different layers of each heat sink structure are subdivided into thin sublayers. The sublayer thickness is related to the conductivity and thickness of the layer. There are four types of layers: paint topcoat, primer paint, steel and concrete. The paint topcoat is 5 mils thick and is modelled with five interior layers and two surface layers. The primer paint is 3 mils thick and is represented with three interior nodes and two surface nodes. The steel layers are from one-eighth inch to one inch thick. The number of sublayers varies from three interior sublayers and two surface sublayers for the thickest steel layers. The concrete is modelled as slabs of either 1 or 1 1/2 feet in thickness. The number of sublayers used in the concrete model varies from 19 interior nodes and 2 surface nodes to 29 interior

The parabolic increase to the peak value is given by:

$$h_s = h_{max}\sqrt{\frac{t}{t_p}} \qquad \text{for } 0 \leqq t \leqq t_p \qquad (2)$$

where:

h_s = heat transfer coefficient for steel (Btu/hr-°F-ft^2)

t = time from start of accident (sec)

The exponential decrease of the heat transfer coefficient is given by:

$$h_s = h_{stag} + (h_{max} - h_{stag})e^{-.05(t-tp)} \qquad \text{for } t > t_p \qquad (3)$$

where:

$h_{stag} = 2 + 50\chi$ for $0 \leqq \chi \leqq 1.4$

h_{stag} = h for stagnant conditions (Btu/hr-°F-ft^2)

χ = steam to air weight ratio in containment

For concrete, the heat transfer coefficient is taken as 40 percent of the value calculated for steel.

Containment Fan Coolers

The ability of the containment fan coolers to function properly in an accident environment is periodically demonstrated by cooler testing in accordance with Salem commitments to NRC Generic Letter 89-13. Fan cooler capability is demonstrated by measuring cooler performance under normal conditions (inlet and outlet temperatures, flows, etc.) in order to calculate the existing coil fouling factor. Fouling factor is calculated using a computer based heat transfer model which has been benchmarked against a prototype version of the Salem containment fan cooler units. Using the calculated fouling factor, input parameters in the computer model are then set to the postulated accident conditions (e.g., containment accident pressure, temperature, and humidity, minimum accident service water flow, maximum expected service water temperature, etc.) and the accident heat duty is computed. The cooler is found acceptable if this calculated heat duty exceeds the heat duty assumed in the accident analyses plus margin. Margin is included to account for instrument errors during the test and also to provide for estimated cooler degradation during the interval between tests.

Coolers which do not meet test acceptance criteria are declared inoperable, initiating action in accordance with technical specifications. Such coolers are cleaned and restored to operable status following successful testing as described above.

With an assumed design basis fouling factor of 0.0015, containment fan cooler unit design basis performance is given below:

Containment Accident Temperature	271°F Btu/hr-°F-ft^2)
Containment Accident Pressure	61.09 psia
Containment Relative Humidity	100%
Service Water Flow	2500 gpm
Service Water Temperature	90°F
Cooler Air Flow Rate	39,000 cfm
Fouling Factor	0.0015
Heat Duty or Capacity	87.0 x 10^6 Btu/hr
LOCA/MSLB Analysis Assumption	65.0 x 10^6 Btu/hr

The fan cooler heat removal rate as a function of steam temperature provided in Figure 15.4-96 is applicable for LOCA and steam line rupture events.

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Containment Spray

When a spray drop enters the hot saturated steam-air environment, the vapor pressure of the water at its surface is much less than the partial pressure of the steam in the atmosphere. Hence, there will be diffusion of steam to the drop surface and condensation on the drop. This mass flow will carry energy to the drop. Simultaneously the temperature difference between the atmosphere and the drop will cause a heat flow to the drop. Both of these mechanisms will cause the drop temperature and vapor pressure to rise. The vapor pressure of the drop will eventually become equal to the partial pressure of the steam and the condensation will cease. The temperature of the drop will be essentially equal to the temperature of the steam-air mixture.

P_s = Steam partial pressure

P_v = Droplet vapor pressure

Pr = Prandtl number

q = Heat flow rate

Re = Reynolds number

Sc = Schmidt number

T = Droplet temperature

T_s = Steam temperature

t = Time

u = Droplet external energy

V = Velocity

ρ = Droplet density

ρ_m = Steam-air mixture density

15.4.8.1.4 Containment Pressure Response Results

The containment pressure was originally calculated for a spectrum of break sizes including the largest cold leg and hot leg breaks (reactor inlet and reactor outlet) and a range of pump suction breaks from 3.0 square feet up to the largest. The break locations analyzed as part of the Margin Recovery Program (Reference 73) and the fan cooler delay time increase (Reference 75) are the double-ended pump suction guillotine break (10.48 ft^2) and the double-ended hot leg guillotine break (9.12 ft^2). Pump suction break mass and energy releases have been calculated for the blowdown, reflood, and post-reflood phases of the LOCA and the hot leg break mass and energy releases have been calculated for only the blowdown phase.

The double ended hot leg guillotine has been shown in previous studies to result in the highest blowdown mass and energy release rates. Although the core flooding rate would be highest for this break location, the amount of energy released from the steam generator secondary is minimal because the majority of the fluid which exits the core bypasses the steam generator in venting to containment. As a result, the reflood mass and energy releases are reduced significantly as compared to either the pump suction or cold leg break locations where the core exit mixture must pass through the steam generators before venting through the break. For the hot break, there is no reflood peak as determined by generic studies. Therefore, the reflood (and subsequently, post-reflood) releases are not calculated for a hot leg break. As such, this break was not considered for the analysis performed to support the increased fan cooler delay time. The cold leg break location has also been found in previous studies to be much less limiting in terms of the overall containment peak pressure. The cold leg blowdown is faster than that of the pump suction break, and more mass is released into the containment. However, the core heat transfer is greatly reduced, and this results in considerably lower energy release into containment. Studies have determined that the blowdown transient is less limiting than the pump suction break. During the reflood, the flooding rate is greatly reduced and the energy release rate into the containment is reduced. Therefore, the cold leg break was not included in the containment analysis performed as part of the Margin Recovery Program containment analysis (Reference 73).

The pump suction break combines the effects of the relatively high core flooding rate, as in the hot leg break, and the addition of the stored energy in the steam generators. As a result, the pump suction break yields the highest energy flow rates during the post-blowdown period by including all of the available energy of the Reactor Coolant System in calculating the releases to containment.

An analysis of the effects of the single failure criteria has been performed on the mass and energy release rates for the double ended pump suction break. An inherent assumption in the generation of mass and energy releases is that offsite power is lost. This results in the actuation of the emergency diesel generators, required to power the safety injection system. This is not an issue for the blowdown period which is limited by the double ended hot leg break.

The loss of an emergency diesel generator results in the loss of one pumped safety injection train (minimizing safety injection flow) and the containment safeguards (one spray pump and two fan coolers will fail to operate) on that diesel. The analysis further considers the safety injection pump head curves to be degraded by 5%.

Figures 15.4-86 and 15.4-87 give the containment pressure transients for several break sizes and locations for the design basis case as analyzed prior to the Margin Recovery Program. Additional margin cases assuming entrainment continues up to the 10-foot core level were analyzed with results presented on Figures 15.4-88 and 15.4-89. Since the entrainment cases were originally shown to be less limiting than the double ended pump suction break, they were not considered for the Margin Recovery Program containment analysis.

Structural heat transfer coefficients as a function of time are indicated on Figure 15.4-90.

The parameters for the containment fan coolers and spray pumps are presented in Table 15.4-24.

The DEPS results are shown on Figure 15.4-91. The cases that are presented in Figures 15.4-86 through 89 were not reanalyzed for these sensitivities because the DEPS is the most limiting case.

The primary-side volume, secondary-side volume, primary-side metal properties and secondary-side metal properties of the Model F steam generator differ from those of a Model 51. Therefore, the limiting LOCA transients were analyzed specifically for Unit 1 with the Model F steam generators to demonstrate that the peak calculated pressure and temperature did not exceed the containment design requirements (Reference 73). Each of the Unit 1 LOCA cases resulted in less limiting pressure and temperature values than the corresponding current design basis cases (based on the Series 51 steam generators). Therefore, the transient results and conclusions presented in this section remain bounding for both Salem Unit 1 and Unit 2.

15.4.8.2 MASS AND ENERGY RELEASES TO CONTAINMENT FOLLOWING A STEAMLINE RUPTURE

15.4.8.2.1 Accident Description

A steamline rupture results in an increased steam flow from one or more steam generators. The increased steam flow causes an increase in the heat extraction rate from the Reactor Coolant System, resulting in a reduced primary coolant temperature and pressure. The core power will increase due to negative moderator temperature and Doppler fuel temperature reactivity coefficients, assuming no intervention of control, protection, or engineered safety features. The rate of the power increase level that matches the steam flow is greatest when the moderator reactivity coefficients are the most negative, which corresponds to end-of-life conditions. The mass and energy release to containment following a steamline rupture is considered a Condition IV event.

Steamline ruptures occurring inside a reactor containment structure may result in significant releases of high energy fluid to the containment environment that could possibly result in high containment temperatures and pressures. High containment temperatures and pressures may result in failure of equipment that is not qualified to perform its function in an adverse environment. This environment could degrade the effectiveness of the protection system in mitigating the consequences of the steamline rupture. Thus, it is necessary to demonstrate that the conditions that can exist inside the containment during a steamline rupture do not violate the existing environmental qualification envelopes. In addition, the containment structure is designed to withstand limited internal pressure. To ensure containment integrity, the analyses must also demonstrate that the containment design pressure is not exceeded.

The safety features that provide the necessary protection to limit the mass and energy releases to containment are reactor trip, safety injection, feedline isolation, and steamline isolation. Reactor trip may be provided during a steamline break from OPΔT, safety injection (from any source), low pressurizer pressure, or high containment pressure. A safety injection signal (which will also isolate main feed water) can be generated on any of the following functions.

a. Low Steamline Pressure Coincident with High Steamline Flow
b. Low-Low T_{avg} Coincident with High Steamline Flow
c. High Steamline Differential Pressure
d. Low Pressurizer Pressure
e. High Containment Pressure

Steamline isolation can be generated on any of the following functions.

a. Low Steamline Pressure Coincident with High Steamline Flow

b. Low-Low T_{avg} Coincident with High Steamline Flow

c. High-high Containment Pressure

15.4.8.2.2 Method of Analysis

The steamline break analysis performed utilized the Westinghouse containment model developed for the IEEE Standard 323-1971 Equipment Qualification Program. These models and their justification (experimental and analytical) are detailed in References 56 through 60. Some major points of the model are as follows:

a. The saturation temperature corresponding to the partial pressure of the containment vapor is used in the calculation of condensing heat transfer to the passive heat sinks and the heat removal by containment fan coolers.

b. The Westinghouse containment model utilizes the analytical approaches described in References 6 and 60 to calculate the condensate removal from the condensate film. Justification of this model is provided in References 6, 56, 59, and 60. (For large breaks, 100% revaporization of the condensate is used, and a calculated fractional revaporization due to convective heat flux is used for small breaks.)

c. The small steamline break containment analyses utilized the stagnant Tagami correlation, and the large steamline break analyses utilized the blowdown Tagami correlation with an exponential decay to the stagnant Tagami correlation. The details of these models are given in Reference 38. Justification of the use of heat transfer coefficients has been provided in References 58, 59, and 61.

A complete analysis of main steamline breaks inside containment has been performed using the LOFTRAN code and the Westinghouse containment computer code, COCO[6]. All blowdown calculations with the LOFTRAN code assumed the reactor coolant pumps were running (i.e., offsite power available), because this increases the primary to secondary heat transfer and therefore maintains higher blowdown flow rates (Reference 63, Section 3.1.7). Although this assumption is inconsistent with the delay times assumed in containment fan cooler and spray initiations, where loss of offsite power it assumed, the combined effect of these assumptions provides extra conservatism in the calculated containment conditions.

Single Failure Assumptions

Several failures can be postulated which would impair the performance of various steamline break protection systems and therefore would change the net energy releases from a ruptured line. Four different single failures were considered for each break condition resulting in a limiting transient. These were:

a. failure of a main feed regulating valve,
b. failure of a main steam isolation valve,
c. failure of the auxiliary feed water (AFW) runout protection equipment, and
d. failure of a containment safeguards train.

Details about each of the single failures and their major assumptions follow.

Feed Water Flow

There are two valves in each main feedline that serve to isolate main feed water flow following a steamline break. One is the main feed water regulator valve, which receives dual, separate train trip signals from the Plant Protection System on any safety injection signal and closes within 10 seconds (including instrument delays). The second is the feed water isolation valve that also receives dual, separate train trip signals from the reactor protection system following a safety injection signal. This valve closes within 32 seconds (including instrument delays). Additionally, the main feed water pumps receive dual, separate train trips from the protection system following a steamline break. Thus, the worst failure in this system is a failure of the main feed water regulator valve to close. This failure results in an additional 22 seconds during which feed water from the Condensate Feed System may be added to the faulted steam generator. Also, since the feed water isolation valve is upstream of the regulator valve, failure of the regulator valve results in additional feedline volume that is not isolated from the faulted steam generator. Thus, water in this portion of the lines can flash and enter the faulted steam generator.

The feed water regulating valves (main and bypass) and main feed water isolation valves, which are relied upon to terminate main feed flow to the steam generators, are exempt from seismic requirements (thus classified as Seismic Category 3). However, each valve has safety-related performance requirements, and as such receives dual, independent, safety grade, trip close signals from the protection system following a steamline rupture event. The feed water regulating valves are air-operated, fail close design, whereas the feed water isolation valves are motor operated. Since the assumed pipe break occurs inside containment in a Seismic Category I pipe, the steamline rupture is not assumed to be initiated by a seismic event. There is no requirement to assume a coincident seismic event with the hypothetical pipe rupture. Thus a seismic classification for the main feed water regulating and isolation valves is not necessary to ensure closure following a steamline break inside containment. Also, since the feed water isolation valves are only credited in the event of a single failure of the regulating valves to close, additional failure of these valves does not need to be considered.

Feed water flow to the faulted steam generator from the Main Feed Water System is calculated using the hydraulic resistances of the system piping, head/flow curves for the main feed water pumps, and the steam generator pressure decay as calculated by the LOFTRAN code. In the calculations performed to match these systems' variables, a variety of assumptions is made to maximize the calculated flows. These include:

a. No credit is taken for extra pressure drop in the feedlines due to flashing of water.
b. Feed water regulator valves in the intact loops do not change position prior to a trip signal.
c. All feed water pumps are running at maximum speed.

Calculation of feed water flashing is performed by the LOFTRAN code as described in Reference 27, Section 4.1.5 For the Salem units, conservative maximum purge volumes (water available to flash) are considered for both the case without a main feed water regulator valve failure and the case with a feed water regulator valve failure.

Main Steam Isolation

Since all main steam isolation valves have closing times of no more than 12 seconds after receipt of signal (including the instrument delays), failure of one of these valves affects only the volume of the main steam and turbine steam piping which cannot be isolated from the pipe rupture.

Steam contained in the unisolatable portions of the steamlines and turbine plant was considered in the containment analyses in two ways. For the large double-ended ruptures (DERs), steam in the unisolatable steamlines is released to containment as part of the reverse flow. This is accomplished by having the reverse flow begin at the time of the break at the Moody critical flow rate for steam as established by the cross-sectional area of the steamline and the initial steam pressure. The flow is held constant at this rate for a period sufficient to purge the entire unisolated portion of the steamlines. Enthalpy of the flow is also held constant at the initial steam enthalpy. Following this period of constant flow representing purging of the steamlines, flow from the intact steam generators, as calculated by LOFTRAN, is added to the containment and continues until steamline isolation is complete.

When considering split ruptures, steam in the steamlines is included in the analysis by adding the total mass in the lines to the initial mass of steam in the faulted steam generator. This is necessary because, unlike DERs, the total break area of a split is unchanged by steamline isolation; only the source of the blowdown effluent is changed. Thus, steam flow from the piping in the intact loops is indistinguishable from steam leaving the faulted steam generator. However, by adding the water mass in the piping to the faulted steam generator mass and by having dry steam blowdowns, the steamline inventory is included in the total blowdown.

Auxiliary Feed Water Flow

The AFW System is actuated shortly after the occurrence of a steamline break. The mass addition to the faulted steam generator from the AFW System was conservatively determined by using the following assumptions.

a. The entire AFW System is assumed to be actuated at the time of the break and instantaneously pumping at a conservatively high capacity dependent upon the specific configuration.
b. AFW flows are conservatively determined based upon a fluids model for the AFW system that includes the AFW pump flow/head curves, component and line resistances, control valve modeling (runout protection failure), and steam generator pressures.
c. Separate AFW flow input values are used for the faulted and non-faulted steam generators since the steam generator pressures are potentially different. Flow to the faulted steam generator is assumed to exist from the time of rupture until realignment of the system is complete.
d. The failure of the AFW runout control equipment is considered as one of the four single failures. For this failure, one of the four AF21 control valves downstream of the two AFW motor pumps fails in a fully open position.

The AFW System in manually realigned by the operator 10 minutes into the transient. Therefore, the analysis assumes a conservatively high AFW flow to the depressurizing faulted steam generator for a full 10 minutes. In the event a postulated main steamline break occurs, AFW to the faulted steam generator must be terminated manually. Present design criteria allow 10 minutes for the operator to recognize the postulated event and perform the necessary actions. However, it is anticipated the operator would terminate AFW flow to the faulted steam generator in much less time due to the amount of Class 1E indication provided to monitor plant conditions.

A single failure of the AFW isolation valve to close was not considered since the failure would not occur until the operator attempted to close the valve after ten minutes. At that time, the operator can simply trip the respective AFW pump as an alternative.

Heat Sinks

The worst effect of a containment safeguards failure is the loss of a spray pump; this reduces containment spray flow by 50%. In all analyses, the times assumed for initiation of containment sprays and fan coolers are 85 and 60 seconds, respectively, following the appropriate initiating trip signal. These times are based on the assumption of a loss of offsite power, and the delays are consistent with Tech Spec limits. The delay time for spray delivery includes the time required for the spray pumps to reach full speed and the time required to fill the spray headers and piping.

The saturation temperature corresponding to the partial pressure of the vapor in the containment is conservatively assumed for the temperature in the calculation of condensing heat transfer to the passive heat sinks. This temperature is also conservatively assumed for the calculation of heat removal by the containment fan coolers. The fan cooler heat removal rate as a function of containment temperature is presented on Figure 15.4-96.

Other major assumptions included in this analysis are shown below.

a. A shut down margin of 1.3% Δk
b. Minimum steam generator tube plugging
c. Maximum T_{avg}
d. A revised moderator density coefficient for the post-trip reactivity transient
e. The 1979 ANS Decay Heat Model
f. Containment Spray Setpoint of 17 psig
g. Containment Fan Cooler Setpoint of 6 psig (Analysis for Salem Unit 1 assumes 5.5 psig)

The mass and energy releases for the most limiting cases along with the resulting containment pressures and temperatures are plotted as follows:

a. Highest Containment Pressure (4.6 ft^2 DER, 30% power, FW reg valve failure): Figures 15.4-97 and -98.

b. Highest Containment Temperature (0.6 ft^2 DER w/o entrainment, 102% power, MSIV failure): Figures 15.4-99 and -100.

The main steam line break containment integrity transients were reviewed for potential effects from the steam generator replacement of Salem Unit 1. The most limiting case with respect to containment pressure responseis the 4.6 ft^2 double ended rupture at 30% power with a failure of the feedwater regulator valve and the limiting containment temperature case is the 0.6 ft^2 double ended rupture at 102% power with a failure of a main steam isolation valve.

Since the Model F steam generators have integral flow restrictors, the 4.6 ft^2 Double ended rupture case no longer applicable for Salem Unit 1. Therefore, other break sizes and single failure scenarios were analyzed (Reference 73) for Salem Unit 1, to determine potentially limiting containment pressure response. The results presented in Reference 73 demonstrate that the current design basis cases presented here result in the limiting containment pressure and temperature. Therefore, the transient results and conclusions presented in this section remain bounding for both Salem Unit 1 and Unit 2.

15.4.8.2.4 Conclusions

The results provided in the steam line break analysis demonstrate sufficient margin available below the containment design pressure and equipment qualification temperature. Similarly, the containment temperature response demonstrates sufficient margin below the required equipment qualification temperature as described in Reference 67.

15.4.8.3 Subcompartment Pressure Analysis

Reference 64 presents the containment subcompartment pressure analysis using an 18-node containment model and the latest version of the TMD computer code.

15.4.8.4 Miscellaneous Analysis

15.4.8.4.1 Minor Reactor Coolant Leakage

The High Containment Pressure signal actuates engineered safety features. Since the setpoint for this signal is 4 psig, the maximum containment pressure caused by leakage is restricted to this value. The containment response to such leakage would be a gradual pressure and temperature rise which would reach a pressure peak of slightly less than 4 pounds gauge. At this point, energy removal due to structural heat sinks and operating fan coolers would match the energy addition due to the leakage and other sources.

Since the containment atmosphere for this case would consist of saturated steam and air, the maximum containment temperature is established by the maximum steam partial pressure. In order to determine the maximum steam partial pressure for this case, an initial containment atmosphere of saturated steam and air at 120°F should be assumed. This assumption results in a partial steam pressure of 1.69 psi before consideration of leakage. In addition, it is conservative to assume that the entire differential (2 psi) between the initial pressure and the setpoint is due to an increase in steam pressure. Since some of the increase in pressure will be due to added air pressure, this will give a conservatively high steam pressure. Finally, a 0.3 psi margin is added to allow for the possibility of an initial low containment pressure. The maximum steam partial pressure is thus 1.69 + 2.00 + 0.30 = 3.99 psia. The temperature which corresponds to this pressure is 153°F. This is far below the containment design temperature.

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their QA/QV programs. The Operational QA Program verifies that requirements necessary to assure quality are properly included or referenced in procurement documents. In addition, these suppliers' procurement documents include applicable PSE&G quality assurance requirements for items and services provided by their suppliers.

17.2.1 Organization

The Operational QA Program, referred to hereafter as the QA Program, assures that adequate administrative and management controls are established for safe operation of the station.

Implementation is assured by ongoing review, monitoring, assessment and audit under the direction of the Director - Quality, Nuclear Training and Emergency Preparedness (Director - Quality, NT and EP), who reports to the Chief Nuclear Officer and President - Nuclear Business Unit (CNO/PNBU).

Implementation for the non-QA areas under the control of the Director - Quality, NT and EP is assured by the Manager - Quality Assessment.

Company organization is shown on Figures 13.1-1 through 13.1-9 and 17.2-1. Responsibilities for activities affecting quality are described in the following sections.

17.2.1.1 Nuclear Business Unit

The Chief Nuclear Officer and President - Nuclear Business Unit (CNO/PNBU) is responsible for managing and directing the nuclear activities of the company. Overall duties and responsibilities of the Nuclear Business Unit (NBU) are provided in Section 13.1. Vice Presidents and Directors reporting to the CNO/PNBU are responsible for implementation of QA requirements by their staff. These QA requirements are contained in the Nuclear Administrative Procedures Manual and individual department documents.

The CNO/PNBU regularly assesses the scope, status, adequacy, and compliance of the QA program to 10CFR50, Appendix B, through:

1. Frequent contacts in staff meetings, QA audit reports, audits by independent auditors, NRC inspection reports, department status reports.

2. An annual assessment of the QA program that is preplanned and documented. This assessment addresses the scope, status, and adequacy of the QA program. Corrective action is identified and tracked.

17.2.1.1.1 Quality Assurance

The Director - Quality, NT and EP is responsible for defining, formulating, implementing, and coordinating the QA program. The Director has been delegated the authority and has the independence to interpret quality requirements, identify quality problems and trends, and provide recommendations or solutions to quality problems for all areas except those non-QA areas under his control. The Director is responsible for approval of the QA/NSR Department Manual used during the operations phase of the nuclear stations. The Director also is responsible for verifying compliance with established requirements for the QA program through document review, inspection, monitoring, assessments and audits for all areas except those non-QA areas under his control. QA provides a centralized coordinating function for QA/QV activities applied to the operations phase.

The Director - Quality, NT and EP has the authority and responsibility to stop work, through the issuance of a Stop Work Order, when significant conditions adverse to quality require such action.

The PSE&G policies and organization structure assure that the Director - Quality, NT and EP has sufficient organizational freedom and independence to carry out his responsibilities.

The full attention of the Director will be in support of QA activities and will take precedence over his non-QA activities. In the event of a conflict, the Director will delegate all QA authority to the Manager - Quality Assurance, if necessary. The Manager - Quality Assessment has the authority to report directly to the CNO/PNBU for these matters.

The Procurement Assessment (PA) Manager, who reports to the Director - Nuclear Business Support, is responsible for the Quality Services activities provided by the PA group. The PA activities of the Director - Nuclear Business Support will take precedence over his non-PA activities. In the event of a conflict, he will delegate all authority in the area of PA to the PA Manager if necessary.

1. The authority and responsibility to stop work, through the issuance of a Stop Work Order, when significant conditions adverse to quality requires such action.

2. The freedom and authority to directly access the Manager - Quality Assurance if the need for such access exists for any issue under his responsibility. In the event of a conflict concerning the implementation of the QA program between NP&MM and PA, the reporting line will be direct from PA to the Manager - Quality Assessment.

3. Review of engineering documents such as equipment specifications for inclusion of QA requirements.

4. Review and approves specifications for Q-listed materials, equipment and services.

5. Review of procurement documents for insertion of QA requirements.

6. Conduct of Supplier surveys audits and surveillances.

7. Evaluation of prospective and existing Supplier QA programs.

8. Monitoring/auditing of nuclear fuel fabrication.

9. Review of NBU fuel specifications for inclusion of QA requirements.

10. Perform material evaluation activities on items subject to the QA program.

Responsibilities of the Manager - Emergency Preparedness and Instructional Technology (Manager - EP & IT) are described in Section 13.1.1.2.1.4.2.

Responsibilities of the Supervisor - Corrective Action include the following:

1. Administration of the Corrective Action program.

2. Overall management of the trending of Corrective Action reports, related to human, organizational and programmatic performance.

3. Providing trend data reports to management.

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The Director - Quality, NT and EP fulfills the above qualifications with the addition of the following:

1. Knowledge and experience in quality assurance and safety.
2. High level of leadership, with the ability to command the respect and cooperation of company personnel, suppliers, and construction forces.
3. Initiative and judgment to establish related policies to attain high achievements and economy of operations.

17.2.1.1.2 Operational Review

All programs and procedures required by Technical Specifications and changes thereto, will be reviewed in accordance with Section 17.2.1.1.2.1 or 17.2.1.1.2.2 below. Three advisory groups, the Station Operations Review Committee (SORC), the Nuclear Review Board (NRB), and Quality Assessment (QA) (onsite independent review), are responsible for reviewing and evaluating items related to nuclear safety. The overall responsibilities of these groups are described below. Quality Assessment is expected to be represented at SORC meetings.

As part of its offsite independent review function, the NRB is responsible for selected preplanned, independent audits of plant operations. These audits are generally conducted by QA under NRB cognizance.

17.2.1.1.2.1 Technical Review and Control

ACTIVITIES - Procedures and programs required by Technical Specifications 6.8 and other procedures which affect nuclear safety as determined by the plant manager, other than editorial or typographical changes should be reviewed as follows:

PROCEDURE RELATED DOCUMENTS - Procedures, programs and changes thereto shall be reviewed as follows:

1. With the exception of procedures and changes reviewed by SORC, each newly created procedure, program or change thereto shall be independently reviewed by an individual knowledgeable in the subject area other than the individual who prepared the procedure, program or procedure change. Procedures other than the Station Administrative procedures will be approved by the appropriate Department Manager or by the plant manager. Each Department Manager shall be responsible for a predesignated class of procedures. The Vice President - Operations shall approve Station Administrative procedures, Security Plan implementing procedures and Emergency Plan implementing procedures.

2. On-the-spot changes to procedures which clearly do not change the intent of the approved procedures shall be approved by two members of the plant management staff, at least one of whom holds a Senior Reactor Operator License. Revisions to procedures which may involve a change in intent of the approved procedures shall be reviewed in accordance with Item 1 above.

3. Individuals responsible for reviews performed in accordance with Item 1 above shall be approved by the SORC chairman and designated as Station Qualified Reviewers. A system of Station Qualified Reviewers, each of whom shall possess qualifications that meet or exceed the requirements of Section 4.4 of ANSI N18.1-1971, shall be maintained by the SORC chairman. Each review shall include a written determination of whether or not additional cross-disciplinary review is necessary. If deemed necessary, such review shall be performed by the appropriate designated review personnel.

4. If the Department Manager determines that the documents involved require a 10 CFR 50.59 safety evaluation, the documents shall be forwarded for SORC review and also to the Nuclear Review Board for an independent review to determine whether or not an unreviewed safety question is involved. Pursuant to 10 CFR 50.59, NRC approval of items involving unreviewed safety questions or Technical Specification changes shall be obtained prior to implementation.

NON-PROCEDURE RELATED DOCUMENTS - Tests or experiments and changes to equipment or systems shall be forwarded for SORC review and also to the Nuclear Review Board for an independent review to determine whether or not an unreviewed safety question is involved. The results of the Nuclear Review Board reviews will be provide to SORC. Recommendations for approval are made by SORC to the plant manager. Pursuant to 10 CFR 50.59, NRC approval of items involving unreviewed safety questions or requiring Technical Specification changes shall be obtained prior to implementation.

RECORDS AND REPORTS - Written records of reviews performed in accordance with item 1 above, including recommendations for approval or disapproval, shall be maintained.

17.2.1.1.2.2 Station Operations Review Committee (SORC)

FUNCTION - The Station Operations Review Committee shall function to advise the plant manager on operational matters related to nuclear safety.

COMPOSITION - The Station Operations review Committee (SORC) shall be chaired by the plant manager and shall be composed of regular members from the Salem Generating Station staff, Nuclear Engineering, Nuclear Maintenance and from the Quality Assessment organization having experience in each of the following areas:

1. Plant Operations
2. Engineering
3. Maintenance
4. Chemistry
5. Radiation Protection
6. Quality Assessment
7. Licensing

The member having experience in the area of Radiation Protection shall meet the qualification requirements of Regulatory Guide 1.8, September 1975. The member having experience in Quality Assessment shall meet the requirements of ANSI/ANS 3.1-1981. All other members shall meet the requirements of ANSI N18.1-1971 for the appropriate discipline. All members shall be appointed in writing by the plant manager. The Vice Chairmen shall be drawn from the SORC members and shall be appointed in writing by the plant manager.

ALTERNATES - All alternate members shall be appointed in writing by the SORC Chairman. Only the designated Vice Chairmen or the plant manager may act as Chairman of a SORC meeting. No more than two alternates to members shall participate as voting members in SORC activities at any one meeting. Alternates for members will not make up part of the voting quorum when the member the alternate represents is also present.

MEETING FREQUENCY - The SORC shall meet at least once per calendar month and as convened by the SORC Chairman or his designated alternate.

QUORUM - The minimum quorum of the SORC necessary for the performance of the SORC responsibility and authority provisions of this section shall consist of the Chairman or his designated alternate and four members including alternates.

RESPONSIBILITIES - The Station Operations Review Committee shall be responsible for:

1. Review of: (1) Upper tier administrative procedures within the scope of Regulatory Guide 1.33 (2/78), and changes thereto; and (2) Newly created procedures or changes to existing procedures that require a 10 CFR 50.59 safety evaluation as described in Section 17.2.1.1.2.1.

2. Review of all proposed tests and experiments that affect nuclear safety.

3. Review of all proposed changes to Appendix "A" Technical Specifications.

4. Review of all proposed changes or modifications to plant systems or equipment that affect nuclear safety.

5. Review of the safety evaluations that have been completed under the provisions of 10 CFR 50.59.

6. Investigation of all violations of the Technical Specifications including the reports covering evaluation and recommendations to prevent recurrence.

7. Review of all REPORTABLE EVENTS.

8. Review of facility operations to detect potential nuclear safety hazards.

9. Performance of special reviews, investigations or analyses and reports thereon as requested by the plant manager.

10. Review of the Fire Protection Program and implementing procedures and changes thereto that require a 10 CFR 50.59 safety evaluation.

The NRB shall meet twice a year as a minimum, or more often as determined by the Chairman.

The NRB may appoint, in writing (such as in Board meeting minutes), subcommittees for the purposes of performing reviews or studies in areas requiring particular expertise or for performing special investigations. NRB subcommittee members shall meet or exceed the qualifications described in Section 4.7 of ANS 3.1-1981. The chairperson of an NRB subcommittee shall be an NRB member.

The NRB or subcommittees/organizations appointed by the NRB shall review:

a. The safety evaluations for changes to procedures, equipment, or systems and tests or experiments completed under the provision of 10CFR50.59, to verify that such actions did not constitute an unreviewed safety question. The results of the Nuclear Review Board reviews will be provided to SORC.

b. Proposed changes to procedures, equipment, or systems, and tests or experiments that involve an unreviewed safety question as defined in 10CFR50.59.

c. Proposed changes to Technical Specifications or Facility Operating Licenses.

d. Violations of applicable statutes, codes, regulations, orders, Technical Specifications, license requirements, or of internal procedures or instructions having nuclear safety significance.

e. Significant operating abnormalities or deviations from normal and expected performance of plant equipment that affect nuclear safety.

f. Reportable events required by 10CFR50.73.

g. All recognized indications of an unanticipated deficiency in some aspect of design or operation of structures, systems, or components that could affect nuclear safety.

h. Reports and meeting minutes of the SORC.

The NRB will utilize as necessary, the operating experience feedback (OEF) program to review current plant and industry concerns and perform special studies and investigations.

Assessments/audits shall be performed by QA or by specially selected groups or individuals, including independent consultants, who have no immediate responsibility for the activity they assess and do not, while performing the assessment, report to a management representative who has immediate responsibility for the activity being assessed. Final audit reports shall be reviewed by the NRB.

The audits shall include:

a. The conformance of facility operation to provisions contained within Technical Specifications and applicable license conditions.

b. The performance, training, and qualifications of the entire facility staff.

c. The results of actions taken to correct deficiencies occurring in facility equipment, structures, systems, or method of operation that affect nuclear safety.

d. The performance of activities required by the Operational Quality Assurance Program to meet the Criteria of Appendix B to 10CFR50.

e. Any other area of facility operation considered appropriate by the Director - Quality, NT and EP or the CNO/PNBU.

f. The facility Fire Protection Program and implementing procedures.

g. An assessment of the Fire Protection and Loss Prevention Program implementation using an outside independent fire protection consultant.

h. The radiological environmental monitoring program and the results thereof.

i. The Offsite Dose Calculation Manual and implementing procedures.

j. The Process Control Program and implementing procedures for processing and packaging of radioactive wastes.

k. The performance of activities required by the Quality Assurance Program for effluent and environmental monitoring.

The audit plans shall be reviewed at least annually by the NRB to ensure that they are being performed in accordance with this section of the UFSAR.

14. Regulatory Guide 1.137, Fuel-Oil Systems for Standby Diesel Generators.

15. Regulatory Guide 1.144, Auditing of Quality Assurance Programs for Nuclear Power Plants.

16. Regulatory Guide 1.146, Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants.

17. BTP 9.5-1, Appendix A, Guidelines for Fire Protection for Nuclear Plants Docketed Prior to July 1, 1976.

Commitments to Regulatory Guides, with respect to revision level, exceptions, etc, are contained in Section 3, Appendix 3A.

The code QA requirements are used for the procurement of systems, components, and structures covered by ASME Boiler and Pressure Vessel Code B31.1 and B31.7 or evaluated to be an acceptable replacement. The standard QA program controls apply to Q-Listed code items following receipt at the station. In addition, applicable requirements of Regulatory Guide 1.38 are applied to ASME Code procurements where necessary to assure safe shipment.

Substantive changes to the QA program described herein will be submitted to the NRC within 30 days of implementation. Nonsubstantive changes will be identified in the annual UFSAR updates.

Each station has instituted and will maintain a station administrative procedures (SAP) manual.

Regulatory Guide 1.33 requires that plant activities affecting quality-related items and services be conducted in accordance with written administrative controls prepared by management. The procedures and instructions by which plant activities are performed are prepared by the responsible organization as required by the Nuclear Administrative Procedures Manual, reviewed by the organization responsible for the activity, reviewed as required by QA and SORC, and approved by the department manager. Nuclear Administrative Procedures (NAPs) and station APs and all subsequent revisions thereto are reviewed by QA and SORC and are approved by the station General Manager. Procedures cannot be implemented unless the review/approval process is accomplished. The Nuclear Administrative Procedures Manual provides a means to accommodate on-the-spot changes to subtier implementing procedures. The routine practice for revising a procedure is to repeat the original review and approval sequence.

Implementation of the QA program is verified by means of independent inspections, assessments, monitoring, and audits conducted by QA.

QA and PA review and analyze problems affecting quality that occur during the operational phase. Items subject to review include:

1. Documented nonconformances occurring at the supplier's facility and those identified during receiving, storage, installation, test, and operation, e.g., Deficiency Reports, Nonconformance Reports, Work Orders, Licensee Event Reports, etc.

2. Documented corrective actions taken on conditions adverse to quality and actions to prevent recurrence on significant conditions adverse to quality.

3. NRC inspection findings, notifications, bulletins, etc.

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materials, and accessibility for inservice inspection, maintenance, and repair.

Issuance of new drawings and revisions to existing drawings require the implementation of a design change. The term design change, as used throughout this document, shall apply to both design and configuration changes.

Nuclear Engineering procedures provide implementation guidance for the intent of Regulatory Guide 1.64, "Quality Assurance Requirements for the Design of Nuclear Power Plants." QA will conduct periodic engineering process assessments which include procedures contained within Nuclear Engineering.

The Vice President - Technical Support has overall responsibility for the design control program. Specific responsibilities are identified in Section 13.1.1.2.1.3.

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 documents.

3. Identify systems, components, and structures that are covered by the quality assurance program.

4. Perform design verification for systems, components, and structures covered by the QA Program.

5. Perform safety evaluations of proposed design changes, as required.

5a. Apply Generic 10CFR 50.59 Safety Evaluation, as required, to configuration changes that impact the SAR.

6. Prepare documents for procurement of equipment, materials, and components.

testing will be deferred, but not beyond the point when the installation would be irreversible.

3. Tests will be performed under conditions that simulate the most adverse design conditions, as determined by analysis.

New drawings or revisions to existing drawings are prepared for inclusion into a design/configuration change by, or under the supervision of, a designer from information received from the responsible engineer, manufacturer's drawings, etc. After implementation, approved design/configuration change information is transferred onto permanent drawings by a designer or drafter and peer reviewed and initialed as being checked by another designer or responsible design supervisor. New drawings or revisions to existing drawings receive final approval by the responsible design supervisor or authorized designee.

Specifications and changes thereto for items covered by the QA program are prepared by Nuclear Engineering, and are reviewed by PA for QA content.

PA review assures that the documents are prepared, reviewed, and approved in accordance with company procedures and that the documents contain the necessary QA requirements, such as inspection and test requirements, acceptance requirements, and the extent of documenting inspection and test results.

The Station Operations Review Committee (SORC) reviews proposed changes affecting nuclear safety and makes recommendations concerning implementation of the change to the station general manager. The design change process provides for signoff of the design change by the appropriate department head for the purpose of identifying required procedure change. 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 Nuclear Review Board (NRB) for a determination of its safety implication before a license change request is submitted for NRC approval.

During the preparation of design changes, Nuclear Business Support assigns a project manager, as necessary. The project manager leads a project team. The project team consists of members of various organizations, both internal and external to Nuclear Engineering. The project team members are responsible for providing technical and administrative input to the entire design change process, which consists of design, installation, testing, and closeout phases. The technical and administrative input is guided by the requirements of those organizations which comprise the project team. The project manager ensures that the specific requirements of each organization on the project team are considered to ensure the overall quality of the product.

For design changes important to safety, the QA representative on the project team provides input and assures that design changes include quality assurance requirements such as inspection and test requirements, acceptance requirements, test result documentation, and project team compliance with company procedures during preparation, review, and approval of design changes.

Updating of records, including drawings, blueprints, instructions technical manuals, and specifications resulting from design changes, is the responsibility of the Vice President - Technical Support. Design change procedures provide for the timely update of affected drawings following design change implementation to reflect as-built configuration.

17.2.4 Procurement Document Control

Procurement documents and changes thereto for the purchase of Q-Listed material, equipment, or services are reviewed and approved by PA prior to issuance by the Purchasing Department to the prospective supplier. PA review assures that spare and replacement parts are procured using controls which are commensurate with current QA program requirements.

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 PA or its agents.

4. Provide for required supplier documentation to be submitted to PSE&G or maintained by the supplier, as appropriate.

5. Provide for PSE&G review and approval of critical procedures prior to fabrication, as appropriate.

Procurement documents require suppliers and contractors of other than commercial-grade items to provide services or components in accordance with a QA program that complies with applicable parts of 10CFR50, Appendix B. The requirement for notifying PSE&G of procurement requirements that have not been met is conveyed to the supplier through the standard warranty provision contained in each purchase order. In addition, where 10CFR21 is imposed, suppliers are required to comply with applicable reporting requirements.

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 require detailed procedures. The designation of those activities requiring detailed procedures is made by cognizant department heads and, as a minimum, complies with applicable requirements of Regulatory Guide 1.33.

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 appropriate Vice President or director is responsible for assuring that procedures are prepared, approved, and implemented in compliance with the Nuclear Administrative Procedures Manual. Documents affecting nuclear safety are reviewed by the SORC for technical content, by QA for QA requirements, and are approved by the responsible station department manager or his designee.

The Director - Nuclear Business Support is responsible for issuing specifications, drawings, blueprints, procedures and administrative and technical manuals associated with structures, systems, and components covered by the QA Program. Approved and implemented modifications and design changes are incorporated in these reference documents for the life of the station. Master lists of current editions or revisions of these documents are maintained by Nuclear Business Support and are available at the station to assure that only current and approved referenced documents are used.

QA reviews and approves selected procedures that implement the QA program, including testing, calibration, maintenance, modification, rework, and repair. Changes to these documents are also reviewed and approved. In addition, QA is responsible for review and approval of selected specifications, test procedures, and results of testing.

item or service. Dependent upon the evaluation, additional audits or corrections by the supplier/contractor may be required. Supplier's certificates of conformance are periodically evaluated by audit, inspection, or test to assure that they are valid. Results of these audits, inspections, or tests are documented.

Where feasible, replacement parts adhere to the original design criteria (such as Nuclear Steam Supply System (NSSS) components in accordance with NSSS documentation and other code components in accordance with AWWA, AISC, SPCC, and ASME B&PV Code, editions and addenda as applicable to the component or system). This provides the intended level of safety and does not result in redesign of the system.

The requirement for appropriate supplier documentation of conformance to applicable code, standard, specification, or other quality requirements is provided by the procurement document. The supplier-provided documentation is reviewed either at the supplier's facility during source surveillance, or by Material Compliance Group during material evaluation activities. A data review checkoff is used to document the acceptability of the supplier-provided data and to identify discrepancies.

Evaluation of supplier equipment, material and services is conducted by qualified personnel to verify correct identification, appropriate documentation, and to verify that the item is acceptable and can be released for storage, installation, or use.

Nonconforming items identified by the Material Compliance Group 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 Materials, Parts, and Components

Procurement document controls provide assurance that materials, parts, and components received can be properly identified. The identification is directly marked on the item or on records traceable to the item. 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 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 also is provided.

Material identification and traceability is maintained for rework, repairs, and modifications throughout operation.

Identification and control of materials, parts and components are the responsibility of Nuclear Maintenance, Nuclear Engineering and Nuclear Business Support. Procurement document controls are the responsibility of PA. Receipt, storage, installation, inspection and test activities are the responsibility of Nuclear Business Support, QA, PA and Nuclear Maintenance.

17.2.9 Control of Special Processes

Special process controls provide for the use of qualified procedures, equipment, personnel, and documentation of satisfactory completion of an activity. Special processes are generally those processes where direct inspection is impossible or disadvantageous.

Procedures have been established for special processes such as welding, brazing, soldering, concreting, protective coating, cleaning, heat treating, and nondestructive examination (NDE) to assure compliance with codes and design specifications. The Vice President - Technical Support is responsible for preparing special process procedures such as concreting, protective coating and cleaning, while the

Vice President - Maintenance is responsible for preparing specifications for processes such as welding, brazing, soldering, and heat treating. Nuclear Engineering is responsible for preparing specifications for nondestructive examination (NDE). These specifications are reviewed and approved by the Nuclear Maintenance Code Assurance Code Specialist for necessary QA program requirements. QA monitoring assessments and audits assure that qualification of special processes, equipment, and personnel have been satisfactorily performed.

Procedures for implementing the requirements of the specifications are prepared either by the NBU or by supplier personnel and are reviewed by a qualified specialist with the exception of special process procedures prepared by code suppliers holding a valid certificate of authorization. A qualified specialist is a person who has certified proficiency in the area of review (e.g., personnel reviewing NDE procedures are required to have Level III certification in the subject NDE area, and personnel reviewing other procedures or reports are required to be qualified in accordance with PSE&G's Engineering Support Personnel Program).

Qualification records of procedures, equipment, and personnel associated with special processes are retained as stated in Section 17.2.17.

17.2.10 Inspection

A planned inspection program is conducted and documented 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 item's or activity's importance to safety.

The inspection program for maintenance and modification activities is based upon the following three important levels of inspection:

1. Worker Checks - Quality cannot be achieved unless the worker performs the activity in a quality manner. The worker is the individual best able to control the quality of work being performed. Work steps that contain elements impacting plant equipment or systems have provisions for signoff by the worker. This worker signoff establishes accountability for the activity and is

acknowledgement that the activity has been performed as specified in the work step.

2. Supervisory Inspection - Although the work supervisor may have overall responsibility for the conduct and performance of the work activity, certain conditions at the work location require supervisory inspection to increase confidence that work activities are completed as specified through familiarity of the work activity, work group, or past experience. Supervisory inspections are established in the appropriate work procedure and accomplished through direct observation of the work activity.

3. Independent Inspection - Independent inspections are not intended to dilute or replace the responsibility of the worker check or supervisory inspection for quality of work. Independent inspections provide the maximum confidence attainable that the work activity has been performed in accordance with the overall objective. Typical guidelines for establishing independent inspections include conditions similar to the following:

   - Work activity affecting redundant equipment or potentially causing cascading failure.

   - Retest will not verify the applicable attribute.

   - Establishing a baseline in a new process or procedure.

   - It is deemed necessary to maintain confidence in the work process.

This guidance is considered by the responsible QA organization in the establishment of inspection activities.

procedures control the application and removal of tags and are designed to prevent operation of valves and/or switches that 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

Organizations involved in material receipt, installation, test, design modification, and other operating activities are responsible for identifying and documenting nonconformances. Nonconforming materials, where practical, are segregated to prevent installation or use until proper approvals are obtained. Materials, parts, or components that have failed in service are identified and, where practical, segregated. Procedures control the application and removal of tags.

Documentation of the nonconformance includes a description of the nonconformance, review by Operations Superintendent/Control Room Supervisor OS/CRS for Limiting Condition for Operation (LCO) applicability when appropriate and the disposition and inspection or retest requirements, as appropriate. The responsible Engineer dispositions each nonconformance report. Dispositions for repair or "use-as-is" are required to be reviewed and approved by QA prior to implementation. Rework or repair of nonconforming material, parts, or components is inspected or retested, or both, in accordance with specified test and inspection requirements established by the responsible engineering representative, based on applicable requirements. QA or PA shall verify the satisfactory completion of the disposition of nonconformances.

QA and other organizations in the NBU review nonconformance reports for quality problems, including adverse quality trends, 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 implement corrective action for significant conditions adverse to quality and conditions adverse to quality identified within their scope of activity. Such conditions are documented and controlled by the issuance of an action request. The QA Corrective Action Group reviews responses to action requests for adequacy and monitors these action requests through periodic summary and status reports 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 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.

For significant conditions adverse to quality, such as LERs and NRC/INPO/CMAP findings, the QA Corrective Action Group is involved in the review of such conditions and provides oversight to assure timely followup and closeout.

Items 3 and 4 are optional for conditions adverse to quality.

Proper implementation of corrective action is verified through surveillance inspection assessment or audit, as appropriate.

The appropriate Vice President or director 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 that govern station activities covered by the QA program provide for the timely discovery and correction of nonconformances. 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 are 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.

QA closely monitors station conditions requiring corrective action.

Repetitive deficiencies, procedure or process violations at the station that are not classified as operational incidents or reportable occurrences, or nonconformances under the QA program are documented via the issuance of an action request. This request provides 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 are identified and maintained in accordance with Regulatory Guide 1.88, as noted in Section 17.2.2. Records shall be considered valid only when authenticated by authorized personnel. Record types, as a minimum, comply with applicable technical specification requirements and include operating logs, maintenance and modification procedures and related inspection results and reportable occurrences.

The NBU is responsible for the permanent storage of station records. The retention period for records; 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 designated location for retention.

17.2.18 Audits

Audits of PSE&G and supplier organizations that implement the QA program are performed by QA and PA to verify compliance with the applicable portions of the program, through personnel interview, observation of activities in process, and review of applicable documents and records as required. Performance based assessment should be an integral part of the auditing program and should evaluate activities on the basis of their effect on the safe and reliable operation of the facility. An audit plan is developed to identify the audits to be performed and their frequency. A dominant factor in audit plan development is performance in the subject area. The audit plans are revised so that weak or declining areas receive increased audit coverage and strong areas receive less, consistent with the audit frequency requirements of the Code of Federal Regulations and the UFSAR. Audits of the selected aspects of operational phase activities are performed with a frequency commensurate with safety significance and in a manner to assure that at least biennial (2 year) audits of safety related activities are performed. A list of operational phase activities subject to the audit program is provided in Section 17.2.1.1.2.3 and in Table 17.2-1.

Audits are conducted by audit teams comprised of a certified lead auditor, certified auditors, and technical specialists (when deemed necessary).

Audits are conducted using preestablished written procedures and checklists. Areas of deficiency revealed by audits are reviewed with management and are corrected in a timely manner. Required corrective action is documented and verified. Followup action, including reaudit of deficient areas, is performed.

The audit program conducted by QA 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 and requisition documents, instructions, procedures, and drawings.

The areas of the plant affected by post LOCA sources are shown in Tables A-4 and A-5. These zones are identified by TRIS zone number and are assigned a radiation zone based on the following key:

Zone	Dose Rate
I	≤ 15 mrem/hr
II	≤ 100 mrem/hr
III	≤ 1 rem/hr
IV	≤ 5 rem/hr
V	≤ 50 rem/hr
VI	≤ 500 rem/hr
VII	≤ 5000 rem/hr
VIII	> 5000 rem/hr

Separate zone ratings are presented for one hour, one day and one week following the accident. The following is a discussion of the accessibility of specific areas of the plant.

Residual Heat Removal System -
Elevation 45 Feet and 55 Feet Auxiliary Building

1. The RHR pump compartments on elevation 45 feet (Location Code # 01045002, 12045002, 01045006, 12045006) in the Auxiliary Building would be a zone VIII during pump operation one hour after the accident and would not be accessible.

2. The dose rate in the adjacent RHR compartment will be zone III (See Note 5 on Tables A-4 and A-5). This compartment is accessible for limited periods of time while the other RHR system is operating.

3. The radiation zone on elevation 55 feet from the operating RHR System below (Location Code # 01055002, 12055002, 01055005, 12055005) is zone V at one hour post accident. This drops to zone III after 1 week of decay. Six inches of lead was installed to shield an exposed portion of RHR suction pipe.

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Safety Injection System

1. The safety injection pump compartment (Location Code # 01084005, 12084005, 01084006, 12084006) is inaccessible while operating.

2. Radiation zones in adjacent areas, such as the spent fuel pool heat exchanger area (Location Code # 01084004, 12084004) and component cooling heat exchanger compartments (Location Code # 01084009, 12084009) are as high as zone V at contact with the pipe chase and pump compartment shield wall surfaces. This dose rate drops off substantially several feet from the walls. Limited access is afforded to these areas and no additional permanent shielding is planned.

Charging Pump Compartments

1. The radiation zone in the vicinity of these pumps (Location Code # 01084035, 12084035, 01084036, 12084036, 01084037, 12084037) may be as high as zone VIII, thus precluding access while the pumps are operating.

2. The dose rate through the wall separating the pump compartments produces a radiation zone V (Location Code # 01084041, 12084041).

3. The radiation zone outside the charging pump compartments is zone IV (e.g., Location Code # 01084025, 12084025); therefore, access to the components in the general area is available.

Chemical and Volume Control - Demineralizer Area

1. Dose rates from the demineralizers would not have a significant effect on access.

2. The dose rates from piping and valves located behind valve aisle shield walls would be the major source of radiation and result in radiation zone IV in the operating aisles (Location Code # 01084024, 12084024). This would be reduced by decay and will afford sufficient access to the area for limited valve operations.

Reactor Coolant and Seal Water Filters

1. The dose rates from these filters do not present a problem since the elements are replaced at predetermined radiation levels rather than high pressure drop. Post accident radiation levels in this area will not preclude access to this area. Each filter is located in an individual shielded compartment.

Primary Sample Lab

1. Use of the Primary Sample Lab will not be required for post accident sampling (see the response to item 2.1.8a).

Counting Room

1. Direct dose rates in the Counting Room are not significantly affected by accident radiation source terms due to the location of the Counting Room. If high background dose rates preclude use of this area, alternate facilities are available.

Fuel Handling Building

1. Dose rates in the Fuel Handling Building due to direct radiation from the containment will not be significantly affected. The only exception to this is streaming from the elevation 130 feet containment personnel hatch and through the doorway into the Fuel Handling Building at elevation 130 feet.

2. The dose rates at the spent fuel pool heat exchanger and pump area in the Auxiliary Building (Location Code # 01084004, 12084004) produce a radiation zone V at one hour, thus affording limited access to this area.

Areas to Which Access May be Required Following an Accident

The areas discussed below are considered vital areas, i.e., areas to which access may be required following an accident. Accessibility is based on direct radiation levels due to contained radiation sources.

Control Room

The Control Room is located on elevation 122 feet and is sufficiently shielded from systems containing highly radioactive fluids. The radiation levels in the Control Room due to direct dose rates from the systems that may be required to operate after an accident are in the millirem per hour range.

Technical Support Center

The Technical Support Center is located in the Clean Facilities Building, and the doses due to the systems that will be operating in the Auxiliary Building are negligible. The doses to individuals in this building over the course of an accident are mainly due to the cloud dose from plant releases. With installed shielding, the whole body dose would be less than 3 rem. The Emergency Plan Implementing Procedures identify alternate facilties that are available if access to the TSC is limited.

Areas in the Auxiliary Building That do not Contain Highly Radioactive Sources of Radiation but May Require Access

These areas include:

Diesel generator compartments

Diesel oil supply tank compartments

Electrical relay and switchgear rooms

Analysis shows that sufficient shielding exists between these areas and adjacent compartments that contain radiation sources such that access to these areas is not precluded.

Access to Areas in the Auxiliary Building Which May Contain Highly Radioactive Sources

The hydrogen purge controls and containment isolation valve reset controls are operated from the Control Room. Access to other areas of the Auxiliary Building related to this equipment is unnecessary.

Chemistry Lab

The Chemistry Lab (Location Code # 01100005) is located on elevation 100 ft in the Auxiliary Building. If there is a LOCA in Unit 1, there will be a localized high dose rate area (zone V at one hour) in the south end of the room. Otherwise it is sufficiently shielded such that the major contribution to the dose rate in the lab is due to streaming from the containment personnel hatch which produces a zone II. Alternate chemistry facilities are available if access to the Chemistry Lab is limited.

Gaseous Radwaste Control Center

The valve operating station for the gas decay tanks is accessible.

Liquid Radwaste Control Station (Valve Areas)

Liquid radwaste is processed by the Portable Liquid Radwaste System located on elevation 103 ft of the Truck Bay of the Auxiliary Building. Before processing post accident radwaste, appropriate radiological controls will be put in place to reduce potential exposures. After processing, the liquid waste is stored and sampled in the Waste Hold-up Tanks or Waste Monitor Hold-up Tank. The valves used to divert flow are remotely operated at the 104 panel located on elevation 64 ft in the Auxiliary Building. Remaining manual valves are located on elevation 84 ft of the Auxiliary Building in accessible areas.

Component Cooling Pump and Auxiliary Feedwater Pump and Valve Areas

These areas are located on elevation 84 feet (Location Code # 01084016, 12084016). The dose rates from shielded sources adjacent to this area produce a radiation zone III. This does not preclude access to this area.

Boric Acid Evaporator Room

These rooms (Location Code # 01100008, 12100008) are located on elevation 100 ft and contain the PASS sample lines and coolers. The post accident radiation zone in the east side of the room due to the safety injection pumps below is zone IV, which would allow limited access, in the BAE room for the unit in which the LOCA occurs. The dose rate in the west part of the room near the door will be much lower (zone I). Once PASS sampling is initiated, these areas become radiation zone VII due to the presence of the PASS sample lines. If the LOCA is in Unit 1, both rooms will be affected by the PASS sample lines. For a LOCA in Unit 2, only the Unit 2 room is affected by the PASS sample lines.

Electrical Penetration Areas

The areas adjacent to the containment on elevation 78 (Location Code # 02078001, 02078012, 13078001, 13078012) contain electrical busses that may require access for long term recovery. The radiation zone in these areas is zone V at one hour after the accident due to activity in containment, which drops to zone III by one day. When PASS sampling is initiated, a localized high dose rate area will exist on the west end of the penetration in the vicinity of the PASS valves. The dose rate due to these valves also produces a zone V in one hour, which drops to a zone IV at one day.

TABLE 2.3-9

PERCENTAGE FREQUENCY

OF

LAPSE RATES

Lapse Rate Group ($t_{300} - t_{33°F}$)

Month	≤ -1.7	-1.6 to -0.5	-0.4 to +0.5	+0.6 to +1.5	-1.6 to +2.5	+2.6 to +3.5	+3.6 to +4.5	≥ +4.6
Jan	18	46	11	8	5	5	2	5
Feb	18	37	14	10	6	6	3	6
Mar	20	47	14	6	4	3	2	4
Apr	19	45	12	7	5	6	0	6
May	30	27	10	8	6	7	5	7
*Jun	32	40	12	6	4	3	1	2
*Jul	25	45	13	7	5	3	1	1
*Aug	30	32	14	8	9	4	2	1
*Sep	24	32	18	9	7	5	3	2
*Oct	19	33	20	10	7	4	2	5
*Nov	13	43	20	8	6	3	3	4
Dec	18	57	15	5	3	1	<1	1
Annual	22	40	14	8	6	4	2	4

*2 months of data

TABLE 2.3-10

RELATION BETWEEN LAPSE RATES
AND
TURBULENCE CLASSES
(percent)

Turbulence Class	Temperature Difference, T300-T33 Ft (°F)							
	≤-1.7	-1.6 to -0.5	-0.4 to -0.5	0.6 to 1.5	1.6 to 2.5	2.6 to 3.5	3.6 to 4.5	≥4.6
I	5.6	3.2	0.5	0.1	0.1	0.1	0.1	0.1
II	15.4	26.4	7.3	3.1	1.6	0.9	0.4	0.6
III	0.7	5.9	2.8	1.0	0.6	0.4	0.1	0.2
IV	1.0	3.7	4.5	3.8	3.6	2.7	1.5	2.4

TABLE 2.3-13

PERCENTAGE FREQUENCY OF WIND SPEED CLASSES

33ft Wind Speed

Turbulence Class	Calm	2-3	4-7	8-12	13-18	19+	All
I	0.6	2.5	4.4	1.7	0.3	0.0	9.5
II	0.7	4.1	20.9	20.0	8.6	1.8	56.1
III	0.0	0.3	2.6	5.3	2.6	0.7	11.4
IV	1.4	4.2	11.3	5.0	0.9	0.1	22.9
All	2.8	11.1	39.2	32.0	12.3	2.6	100.0

300-ft Wind Speed (mph)

Turbulence Class	Calm	2-3	4-7	8-12	13-18	19+	All
I	0.7	1.9	4.1	2.1	0.6	0.2	9.6
II	0.2	1.1	7.2	18.0	18.6	11.4	56.5
III	0.0	0.0	0.1	0.9	4.8	6.0	11.8
IV	0.4	1.0	3.8	7.1	6.8	3.1	22.2
All	1.3	4.0	15.2	28.1	30.8	20.8	100.0

TABLE 2.3-14

MEAN ANNUAL WIND SPEEDS
AT
VARIOUS LEVELS
(mph)

Turbulence Class	33 ft	300 ft
I	5.0	6.0
II	8.0	13.0
III	10.0	19.0
IV	5.0	12.0
All Hours	7.0	13.0

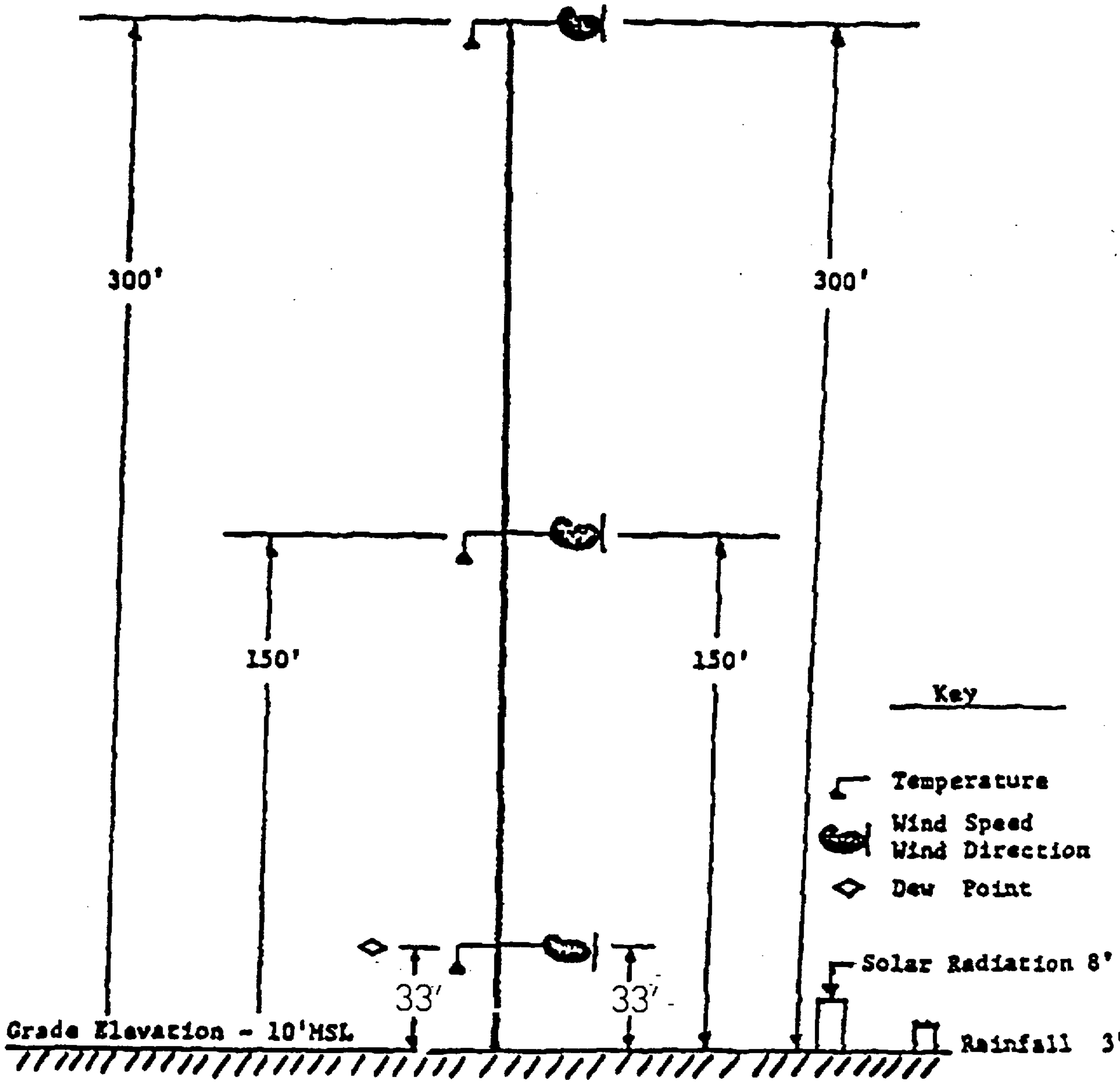
TABLE 2.3-15

WIND DATA RECOVERY

JUNE 1969 - MAY 1970

(percent)

Month	33-ft Level	300-ft Level
Jun 1969	85	85
Jul	67	67
Aug	92	85
Sep	64	65
Oct	96	97
Nov	86	96
Dec	93	94
Jan 1970	89	99
Feb	86	86
Mar	78	78
Apr	90	23
May	98	84
Annual	86	81



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station METEOROLOGICAL TOWER SCHEMATIC
	Updated FSAR — Figure 2.3-7

TABLE 3.6-1

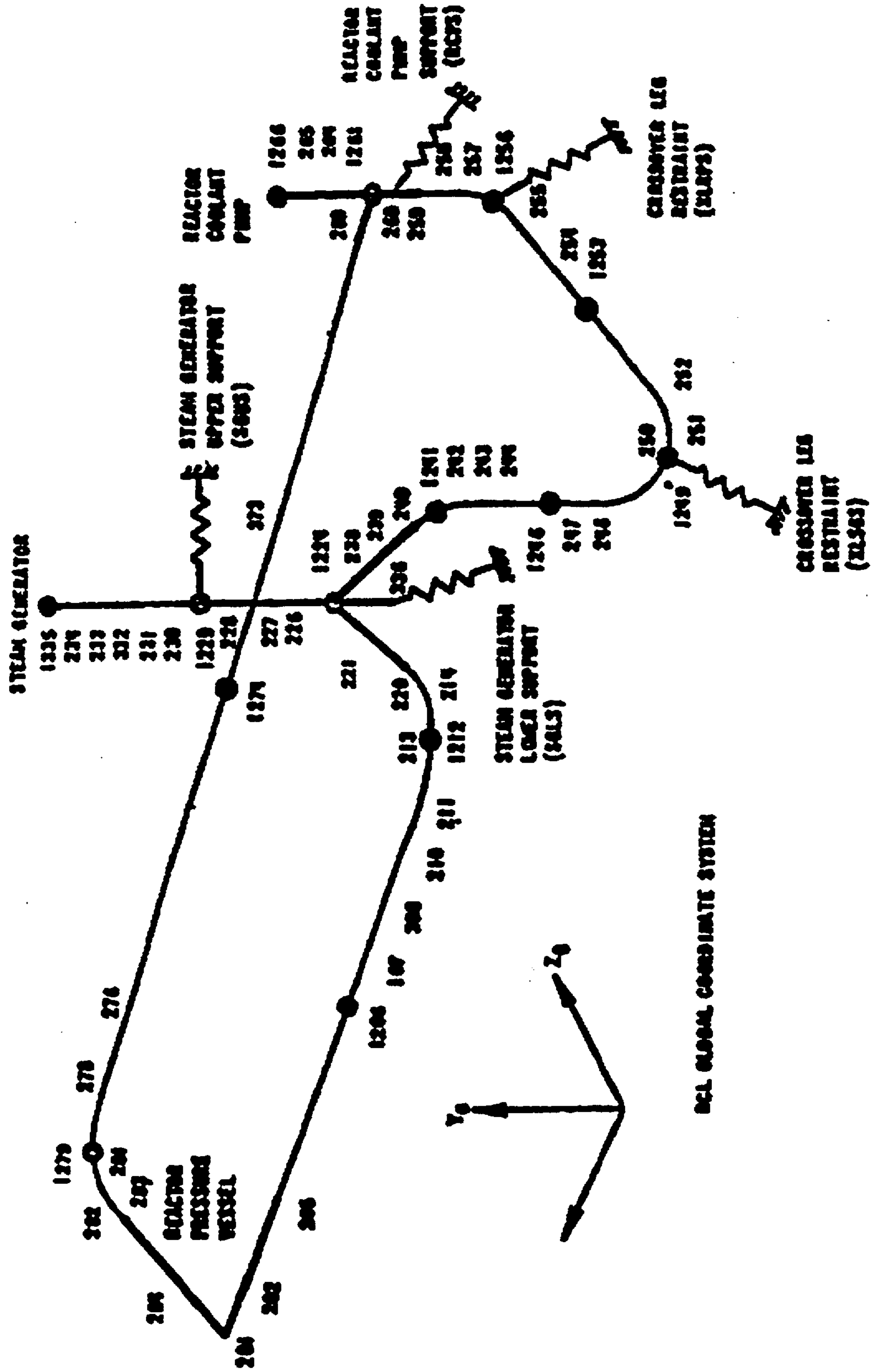
POSTULATED REACTOR COOLANT SYSTEM PIPE RUPTURES

Designation	Description
1. HLHZ	DEC(1) at center of hot leg straight run
2. SGIL	DEC at steam generator inlet nozzle
3. SGOL	DEC at steam generator outlet nozzle
4. XLVT	DEC at steam generator outlet vertical run
5. XLHZ	DEC at center of crossover leg straight run
6. XLPS	DEC at reactor coolant pump suction
7. CLHZ	DEC at center of cold leg straight run
8. S12TRCP	SEL(2) at hot leg elbow, horizontal jet force in positive Z-direction
9. S12ARCP	SEL at hot leg elbow, horizontal jet force in negative Z-direction
10. S41TRCP	SEL at steam generator outlet elbow, maximum +Z component of split force
11. S41ARCP	SEL at steam generator outlet elbow, maximum -Z component of split force

The breaks listed above were considered in the original design basis analysis of the Unit 1/Unit 2 RCS. See Appendix 3B for a listing of the RCS pipe breaks considered in the analysis of the Unit 1 RCS with replacement steam generators.

Notes: (1)DEC: double-ended circumferential rupture

(2)SEL: single-ended longitudinal rupture



See Appendix 3B for descriptions and/or figures detailing the RCS structural and hydraulics models used in the analysis of the Unit 1 RCS with replacement steam generators

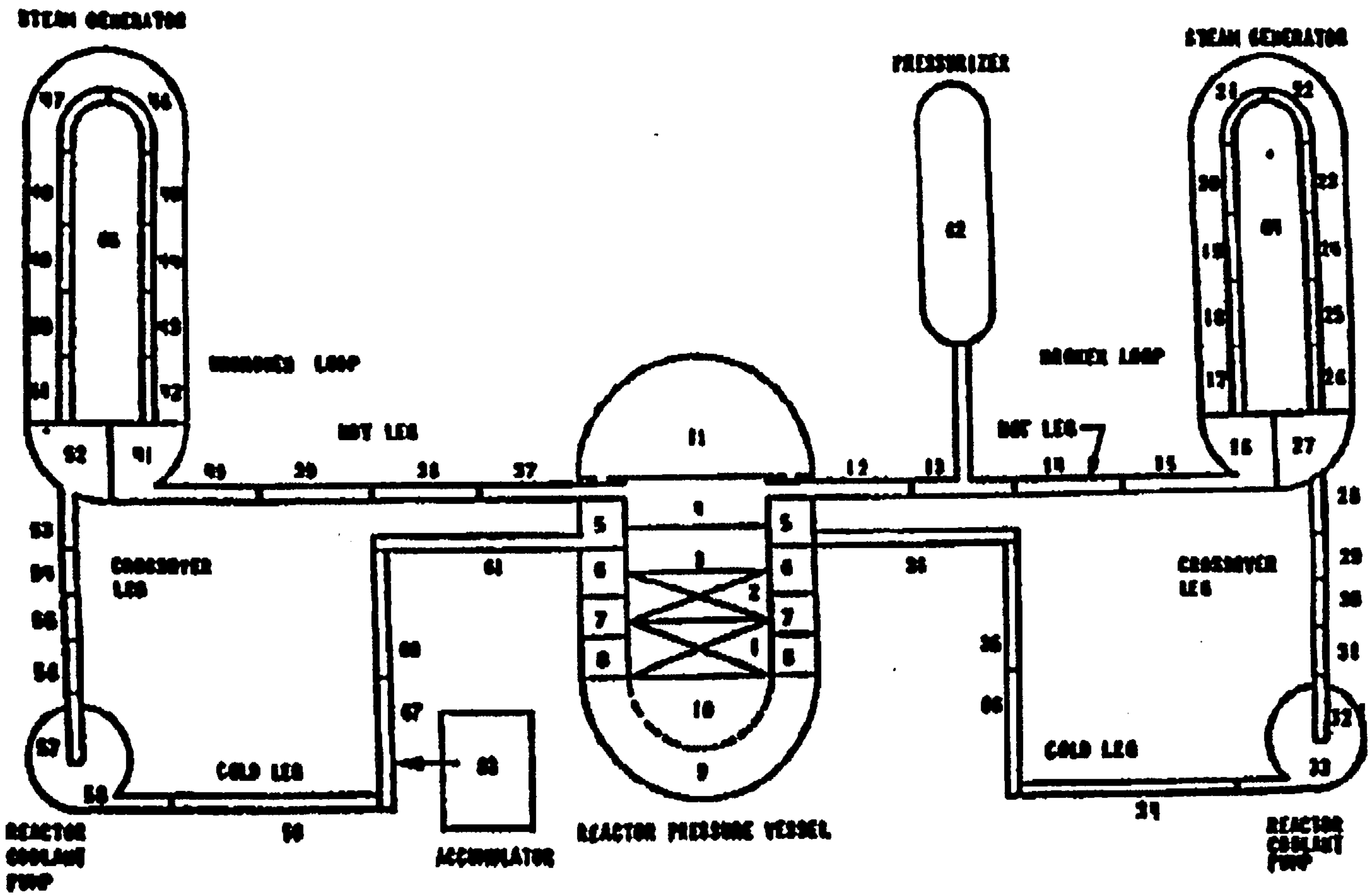
The structural model depicted here was used in the original design basis analysis of the Unit1/Unit2 RCS

Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station REACTOR COOLANT LOOP MODEL
	Updated FSAR — Figure 3.6-2

The hydraulics model depicted in this figure was used in the original design basis analysis of the Unit1/Unit2 RCS

See Appendix 3B for descriptions and/or figures detailing the RCS structural and hydraulics models used in the analysis of the Unit 1 RCS with replacement steam generators

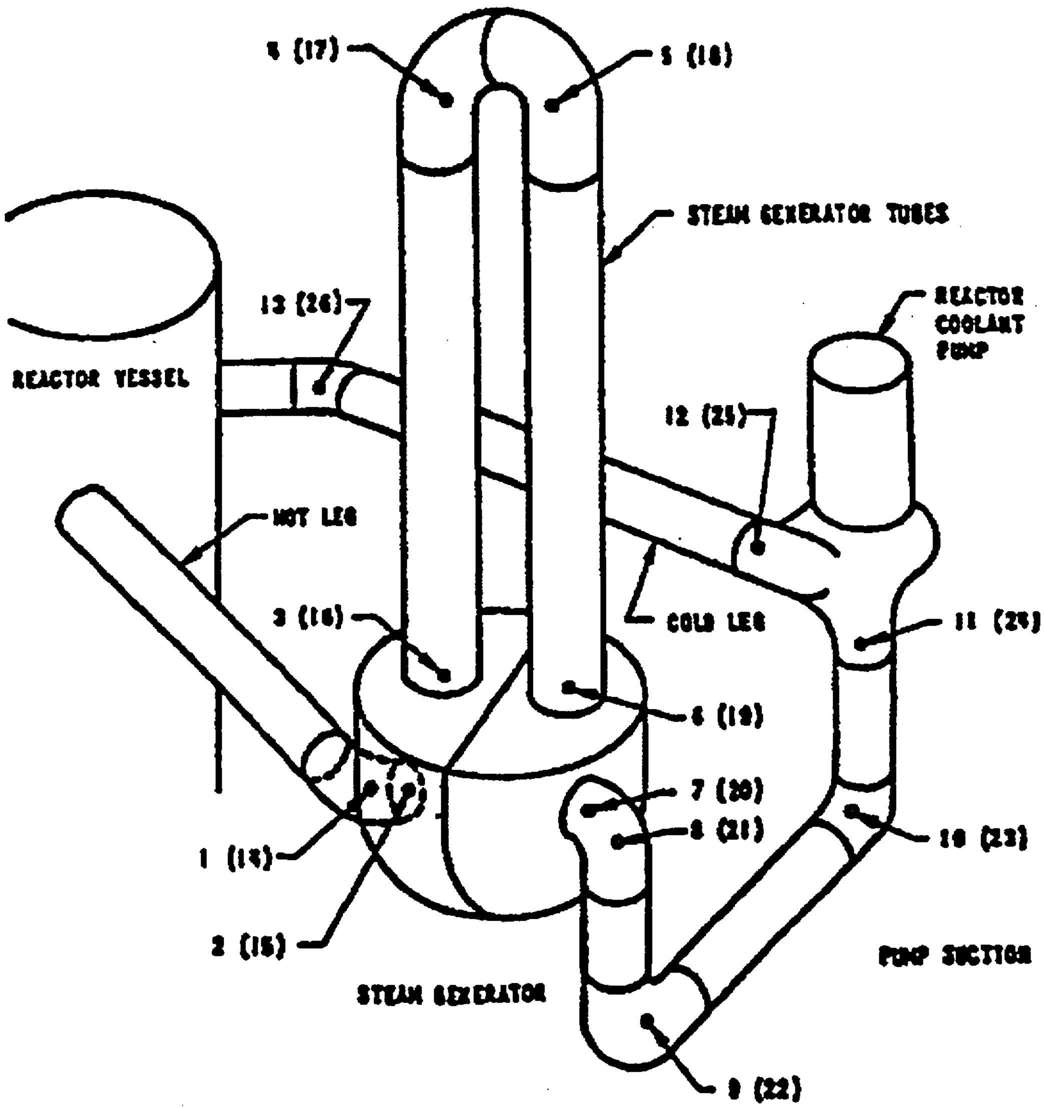


Note: Large bore primary piping breaks are eliminated from the structural design basis for Salem Units 1 and 2 based on approval of Leak-Before-Break (LBB) analyses (Ref. 4).

Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station SATAN-STHRUST REACTOR COOLANT LOOP MODEL
	Updated FSAR — Figure 3.6-4

See Appendix 3B for descriptions and/or figures detailing the RCS structural and hydraulics models used in the analysis of the Unit 1 RCS with replacement steam generators

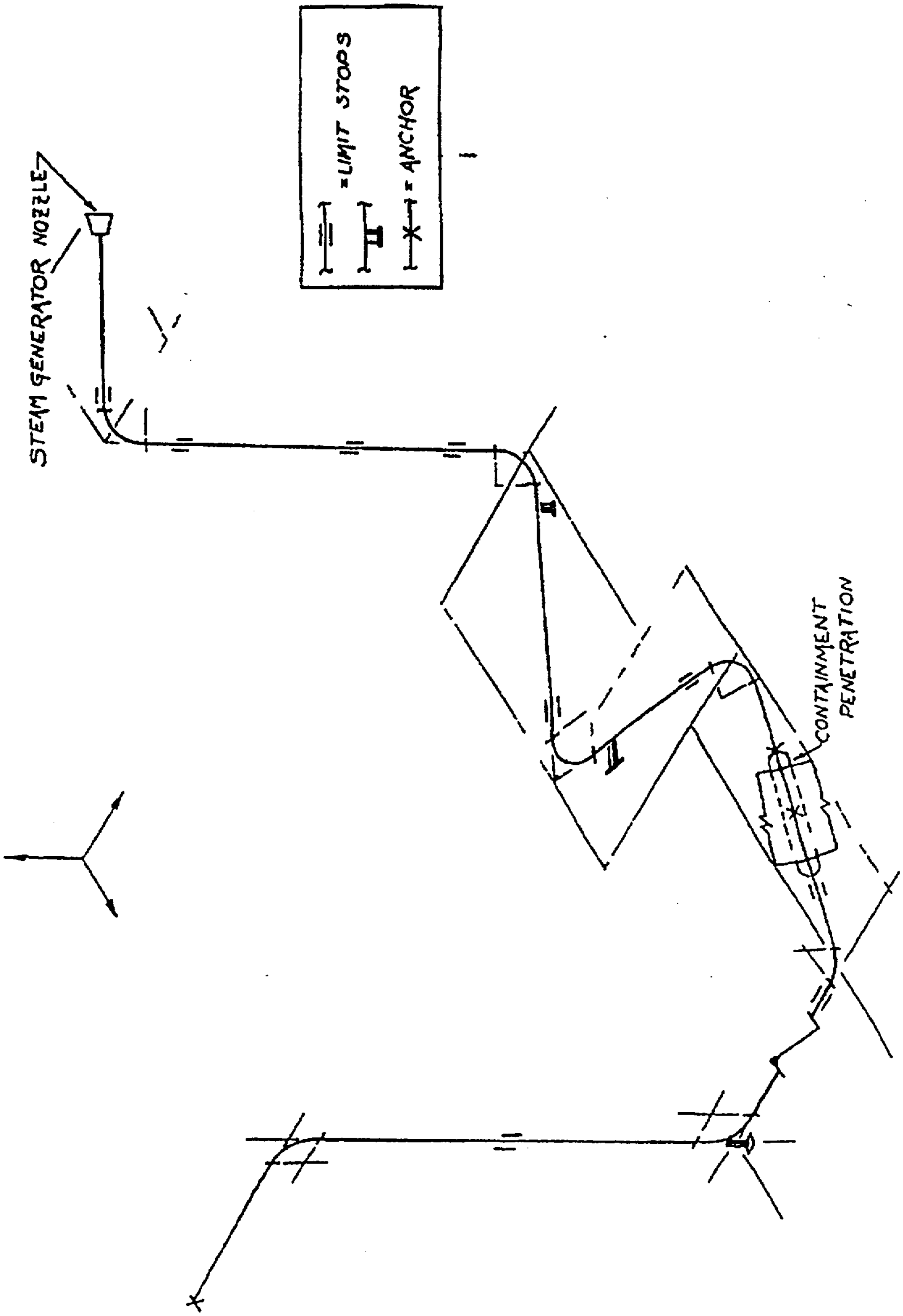


X - BROKEN LOOP FORCE NODES
(X) - UNBROKEN LOOP FORCE NODES

Note. Large bore primary piping breaks are eliminated from the structural design basis for Salem Units 1 and 2 based on approval of Leak-Before-Break (LBB) analyses (Ref. 4)

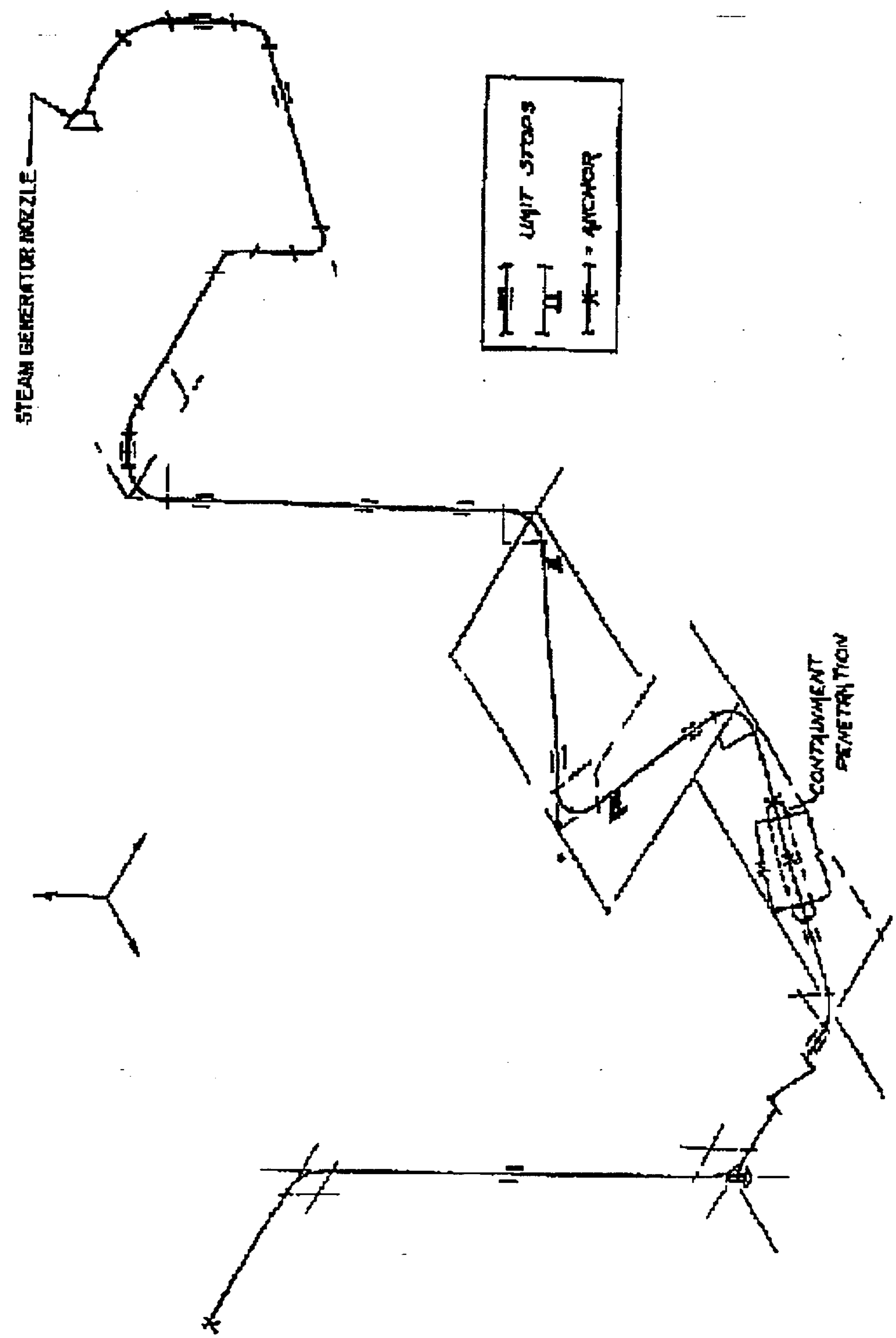
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station REACTOR COOLANT LOOP MODEL SHOWING HYDRAULIC FORCE LOCATION
	Updated FSAR — Figure 3.6-5



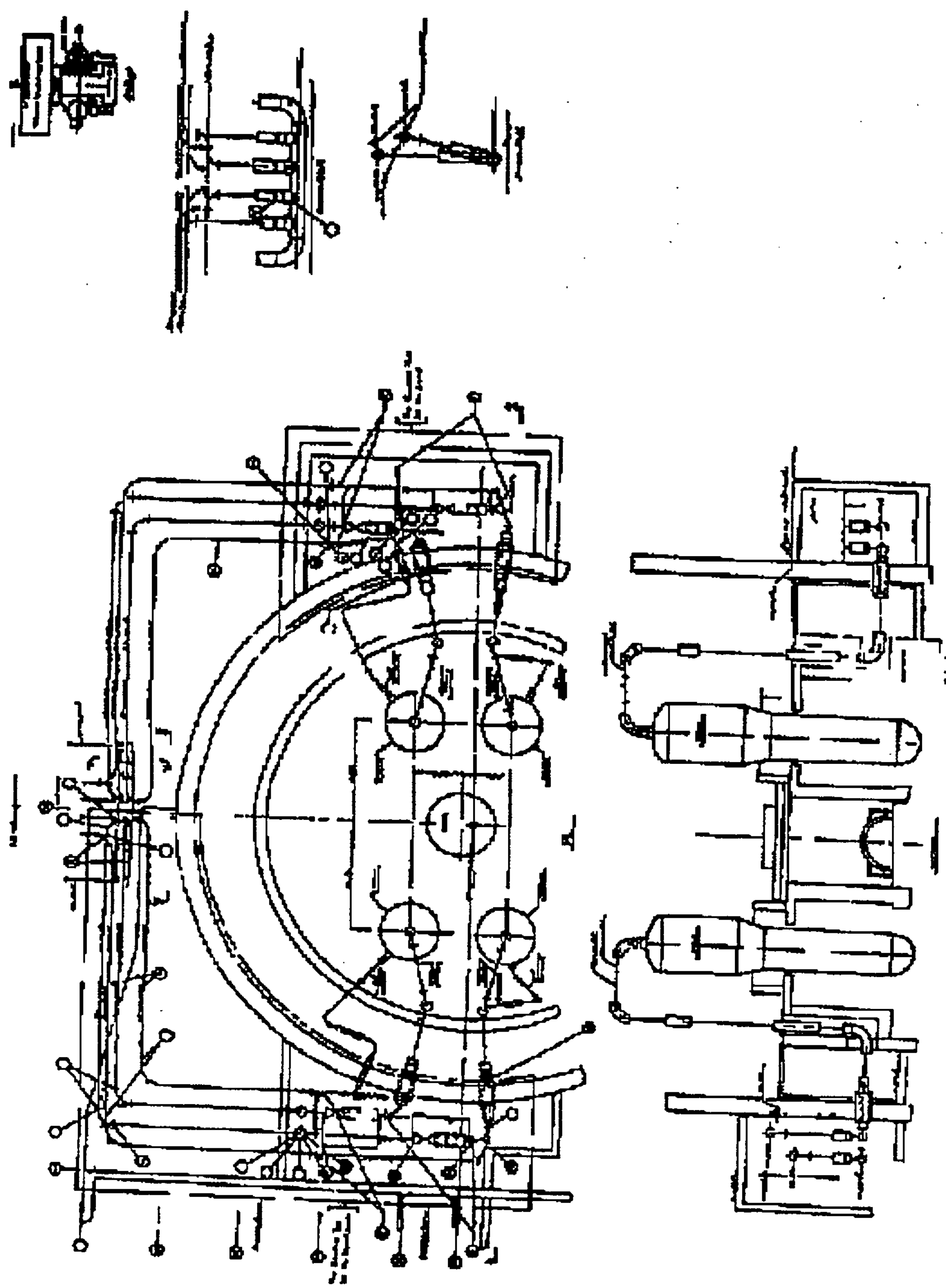
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station PIPEWHIP RESTRAINT LOCATIONS-TYPICAL STEAM GENERATOR FEEDWATER PIPE UNIT 2 ONLY
	Updated FSAR Figure 3.6-8



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station PIPEWHIP RESTAINT LOCATIONS-TYPICAL STEAM GENERATOR FEEDWATER PIPE UNIT 1 ONLY
	Updated FSAR — Figure 3.6-8A



Revision 18, April 26, 2000

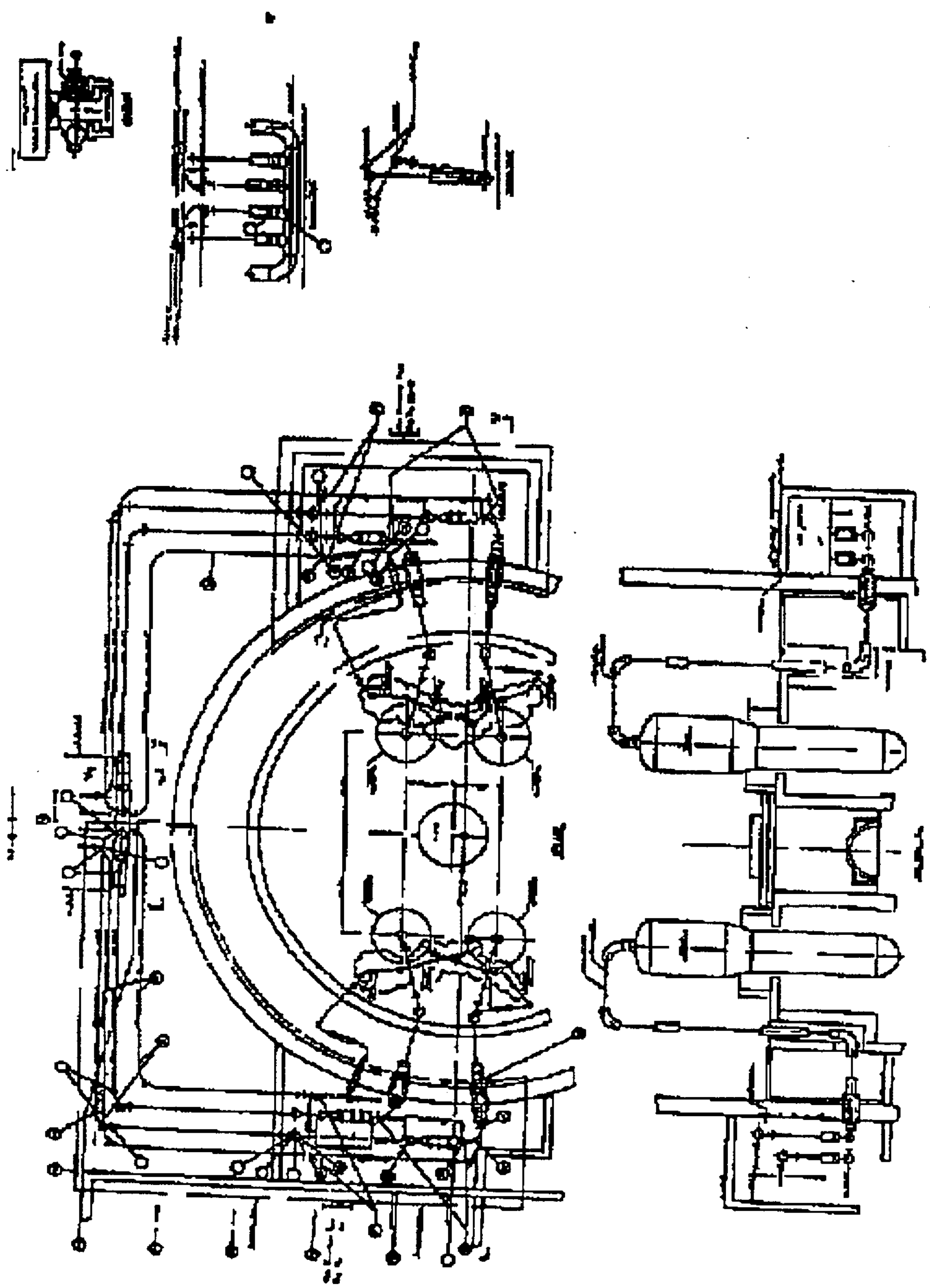
PSEG Nuclear, LLC

SALEM NUCLEAR GENERATING STATION

Salem Nuclear Generating Station
PIPING ARRANGEMENT
MAIN STEAM AND FEEDWATER-UNIT 2 ONLY

Updated FSAR

Figure 3.6-10



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station PIPING ARRANGEMENT MAIN STEAM AND FEEDWATER PIPE-UNIT 1 ONLY
	Updated FSAR — Figure 3.6-10A

THIS FIGURE HAS BEEN DELETED

Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station SEISMIC DYNAMIC MODEL
	Updated FSAR Figure 3.9-1

TABLE 3B.7-1

RCS QUALIFICATION METHOD AND REFERENCES

ITEM	SUB-ITEM	STRESS CALC'S	LOAD COMPARISONS	LOAD COMPARISONS WITH SELECTED STRESS CALC'S
RV	Primary Nozzles			X
SG Model F	Primary Nozzles			X
	Support Ring			X
	Shell @ Upper Support		X	
RCP	Primary Nozzles			X
	Support Lug			X
	Support Lug Attachment Weld	X		
RCS Piping	Straights, Elbows, Attachment Welds	X		
	LBB			X
RV Support	Plates, Bolts, Concrete			X

TABLE 3B.7-1 (Cont'd)

RCS QUALIFICATION METHOD AND REFERENCES

ITEM	SUB-ITEM	STRESS CALC'S	LOAD COMPARISONS	LOAD COMPARISONS WITH SELECTED STRESS CALC'S
SG Lower Support	Beams/Columns	X		
	Beam-to-Column Welds	X		
	Modified Columns	X		
	Modified Column Welds	X		
	Misc. Steel (cross braces, side plates, stiffeners, scab plates, etc.), Welds		X	
	Embedments		X	
SG Upper Support	Snubbers, Bumpers, Belly Band, Welds		X	
	Upper Support Modifications	X		
RCP Support	Beams/Columns	X		
	Beam-to-Column Welds	X		
	Embedments		X	

TABLE 3B.7-2

MAXIMUM SG LOWER SUPPORT STRESS RATIOS

LOAD COMBINATION	MODEL SECTION NUMBER	COMPONENT SECTION NUMBER	ADJUSTED STRESS RATIO
DW+TH(Ehot)+PEX	528	L80	0.38
	622	L80	0.38
	434	L80	0.38
	716	L80	0.38
	483	L35	0.34
	577	L35	0.34
	389	L35	0.33
	671	L35	0.33
	529	L81	0.31
	623	L81	0.31
DW+TH(Ehot)+OBE+PEX	622	L80	0.38
	716	L80	0.37
	528	L80	0.35
	434	L80	0.35
	577	L35	0.32
	671	L35	0.32
	483	L35	0.31
	389	L35	0.30
	623	L81	0.29
	717	L81	0.29
DW+TH(Ehot)+SSE+PEX	622	L80	0.41
	716	L80	0.41
	528	L80	0.38
	434	L80	0.38
	577	L35	0.34
	671	L35	0.34
	483	L35	0.33
	389	L35	0.33
	623	L81	0.31
	717	L81	0.31
DW+TH(Ehot)+PEX+SRSS(SLB,SSE)	622	L80	0.61
	716	L80	0.55
	671	L35	0.43
	434	L80	0.41
	577	L35	0.40
	528	L80	0.39
	717	L81	0.39
	623	L81	0.37
	1042	L102	0.34
	483	L35	0.34

TABLE 3B.7-2 (Cont)

LOAD COMBINATION	MODEL SECTION NUMBER	COMPONENT SECTION NUMBER	ADJUSTED STRESS RATIO
DW+TH(Ehot)+PEX+SRSS(14RLB,SSE)	622	L80	0.55
	716	L80	0.53
	434	L80	0.52
	528	L80	0.44
	577	L35	0.42
	671	L35	0.41
	389	L35	0.41
	623	L81	0.38
	717	L81	0.37
	483	L35	0.37
DW+TH(Ehot)+PEX+SRSS(6RLB,SSE)	622	L80	0.44
	528	L80	0.43
	716	L80	0.39
	434	L80	0.39
	577	L35	0.36
	483	L35	0.36
	671	L35	0.34
	389	L35	0.34
	623	L81	0.33
	529	L81	0.32
DW+TH(Ehot)+PEX+SRSS(SILB,SSE)	716	L80	0.56
	622	L80	0.50
	671	L35	0.44
	717	L81	0.40
	528	L80	0.39
	577	L35	0.39
	434	L80	0.39
	623	L81	0.35
	483	L35	0.33
	389	L35	0.32

TABLE 3B.7-2 (Cont)

LOAD COMBINATION	MODEL SECTION NUMBER	COMPONENT SECTION NUMBER	ADJUSTED STRESS RATIO
DW+TH(Ehot)+PEX+SRSS(MSLB,SSE)	716	L80	0.64
	671	L35	0.53
	717	L81	0.48
	434	L80	0.42
	718	L82	0.40
	622	L80	0.39
	528	L80	0.38
	673	L37	0.36
	389	L35	0.35
	577	L35	0.34
DW+TH(Ehot)+PEX+SRSS(FWLB,SSE)	716	L80	0.43
	528	L80	0.39
	622	L80	0.39
	671	L35	0.38
	434	L80	0.38
	483	L35	0.35
	717	L81	0.34
	389	L35	0.34
	577	L35	0.33
	1049	L101	0.30
DW+TH(Ehot)+PEX+SRSS(ISLB,SSE)	622	L80	0.60
	716	L80	0.56
	577	L35	0.43
	671	L35	0.42
	434	L80	0.41
	528	L80	0.40
	717	L81	0.38
	623	L81	0.38
	389	L35	0.36
	483	L35	0.34

TABLE 3B.7-3

MAXIMUM RCS PIPING STRESS RATIOS

A. **NORMAL (PRESSURE + DEADWEIGHT)**

PIPE SECTION	SECTION	NODE	STRESS (PSI)	ALLOWABLE STRESS (PSI)	STRESS RATIO
HOT LEG STRAIGHT	319	306 - 380	10682.38	16940	0.63
	301	206 - 280	10682.38	16940	0.63
HOT LEG ELBOW	306	(284 - 2100)	8095.06	15280	0.53
	324	(384 - 3100)	8095.06	15280	0.53
XOVER LEG STRAIGHT	290	151 - 152	9205.49	17155	0.54
	344	451 - 452	9205.49	17155	0.54
XOVER LEG ELBOW	293	(154 - 1315)	8364.14	15653	0.53
	347	(454 - 4315)	8364.14	15653	0.53
COLD LEG STRAIGHT	296	191 - 192	8781.85	17155	0.51
	350	491 - 492	8781.85	17155	0.51
COLD LEG ELBOW	295	(116 - 191)	7403.36	15653	0.47
	349	(416 - 491)	7403.36	15653	0.47

B. **UPSET (PRESSURE + DEADWEIGHT + OBE)**

PIPE SECTION	SECTION	NODE	STRESS (PSI)	ALLOWABLE STRESS (PSI)	STRESS RATIO
HOT LEG STRAIGHT	319	306 - 380	11262.38	20328	0.55
HOT LEG ELBOW	324	(384 - 3100)	8789.64	18336	0.48
XOVER LEG STRAIGHT	308	251 - 252	9476.45	20586	0.46
XOVER LEG ELBOW	347	(454 - 4315) (RCP end)	8542.55	18784	0.45
COLD LEG STRAIGHT	318	295 - 2305	9150.79	20586	0.44
COLD LEG ELBOW	349	(416 - 491)	7615.18	18784	0.41

TABLE 3B.7-3(Cont)

C. **THERMAL EXPANSION (THERMAL, PIPE E @ 70° F)**

PIPE SECTION	SECTION	NODE	STRESS (PSI)	ALLOWABLE STRESS (PSI)	STRESS RATIO
HOT LEG STRAIGHT	301	206 - 280	14030.07	27710	0.51
HOT LEG ELBOW	306	(284 - 2100)	9108.02	25695	0.35
XOVER LEG STRAIGHT	290	151 - 152	3741.74	27726	0.13
	344	451 - 452	3741.74	27726	0.13
XOVER LEG ELBOW	293	(154 - 1315)	7194.42	25788	0.28
	347	(454 - 4315)	7194.42	25788	0.28
COLD LEG STRAIGHT	318	295 - 2305	3044.85	27726	0.11
COLD LEG ELBOW	313	(216 - 291)	2586.41	25788	0.10

D. **NORMAL + THERMAL EXPANSION (THERMAL, PIPE E @ 70° F)**

PIPE SECTION	SECTION	NODE	STRESS (PSI)	ALLOWABLE STRESS (PSI)	STRESS RATIO
HOT LEG STRAIGHT	301	206 - 280	24505.45	44800	0.55
HOT LEG ELBOW	306	(284 - 2100)	17097.10	40975	0.42
XOVER LEG STRAIGHT	290	151 - 152	12911.37	44881	0.29
	344	451 - 452	12911.37	44881	0.29
XOVER LEG ELBOW	293	(154 - 1315)	15487.67	41441	0.37
	347	(454 - 4315)	15487.67	41441	0.37
COLD LEG STRAIGHT	300	195 - 1305	11305.14	44881	0.25
	354	495 - 4305	11305.14	44881	0.25
COLD LEG ELBOW	295	(116 - 191)	9880.77	41441	0.24
	349	(416 - 491)	9880.77	41441	0.24

E. **ENVELOPED FAULTED (PRESSURE + DEADWEIGHT) + (SSE or SRSS(SSE + LOCA/HELBA))**

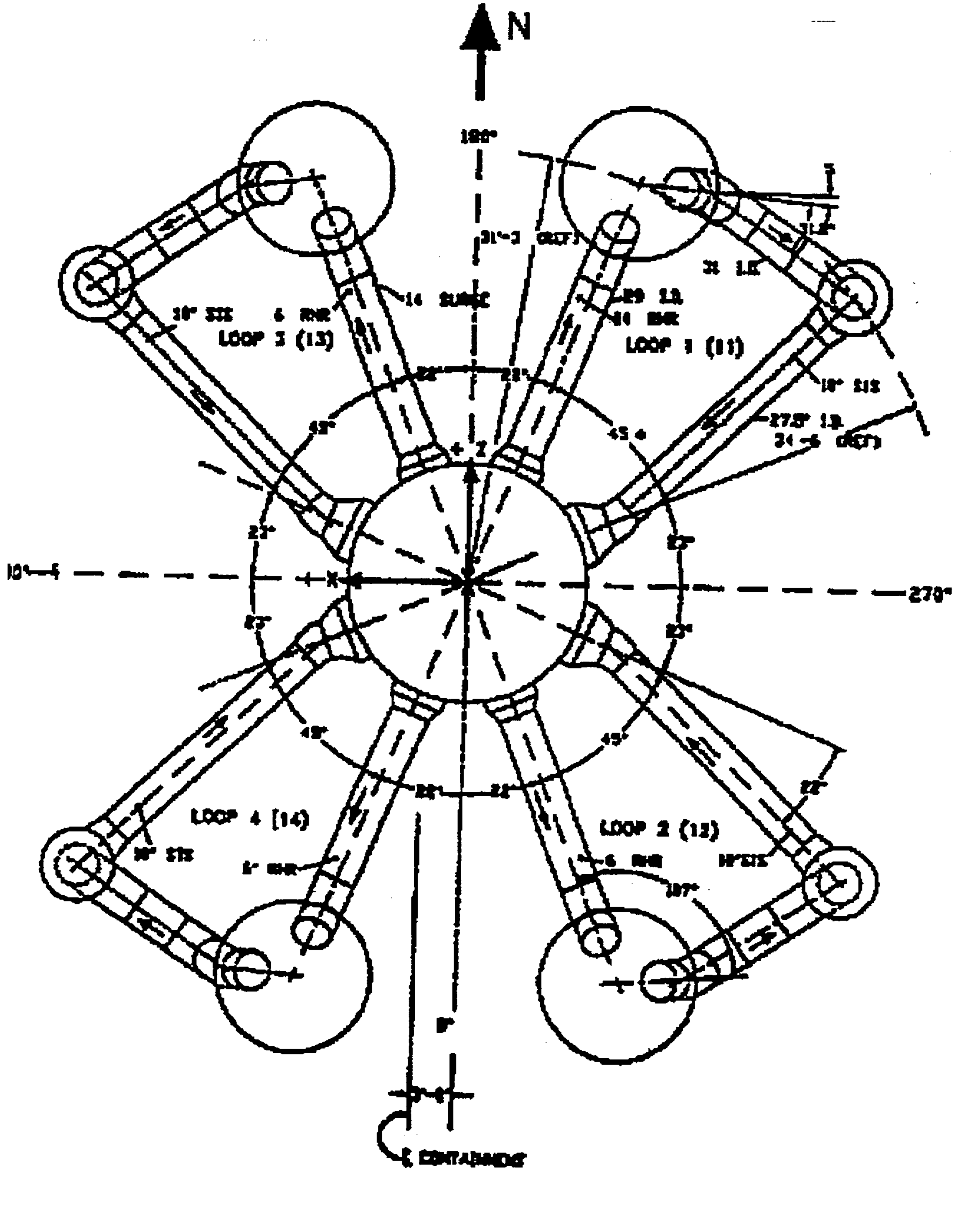
PIPE SECTION	SECTION	NODE	STRESS (PSI)	ALLOWABLE STRESS (PSI)	STRESS RATIO
HOT LEG STRAIGHT	319	306 - 380	17074.72	30492	0.56
HOT LEG ELBOW	324	(384 - 3100)	12495.57	27504	0.45
XOVER LEG STRAIGHT	326	351 - 352	12825.99	30879	0.42
XOVER LEG ELBOW	325	(3195 - 351)	12740.46	28175	0.45
COLD LEG STRAIGHT	354	495 - 4305	12817.67	30879	0.42
COLD LEG ELBOW	349	(416 - 491)	11441.28	28175	0.41

TABLE 3B.7-4

MAXIMUM RCP SUPPORT STRESS RATIOS

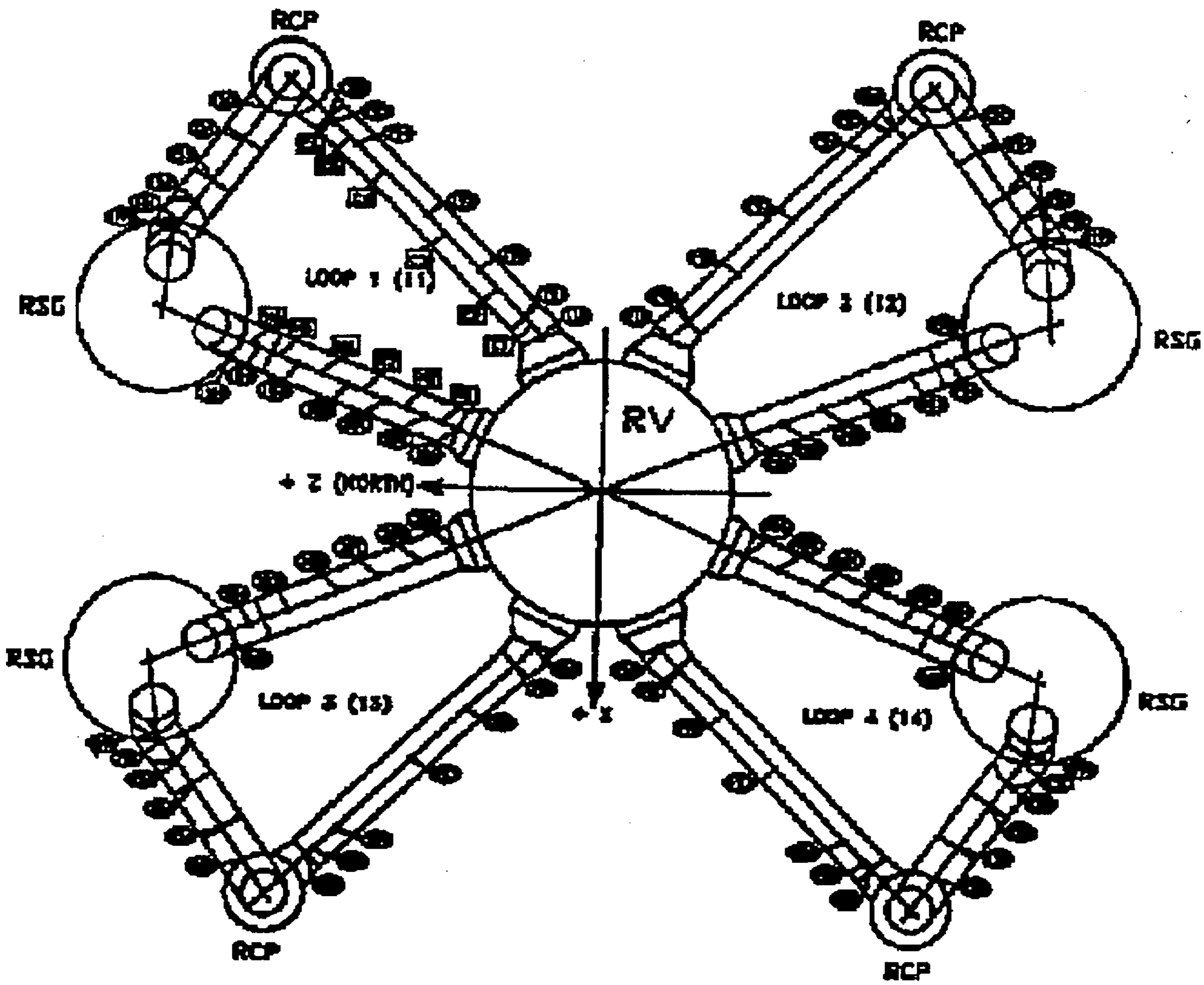
NORMAL CONDITION		UPSET CONDITION		FAULTED CONDITION	
Westinghouse Member Number	Combined Stress Ratio	Westinghouse Member Number	Combined Stress Ratio	Westinghouse Member Number	Combined Stress Ratio
21	0.29	21	0.46	21	1.00
43	0.16	35	0.32	40	0.87
40	0.12	40	0.32	35	0.84
13	0.11	43	0.31	36	0.72
35	0.11	36	0.31	41	0.65
41	0.10	41	0.26	43	0.58
36	0.10	34	0.24	34	0.57
39	0.09	39	0.21	39	0.52
34	0.08	13	0.17	13	0.32
38	0.07	7	0.14	7	0.31

NOTE: The stresses for the RCP support are conservatively calculated, particularly for the faulted condition where loads from all eight faulted cases are enveloped across all four loops and without regard to time. The stress ratios shown are therefore artificially high.



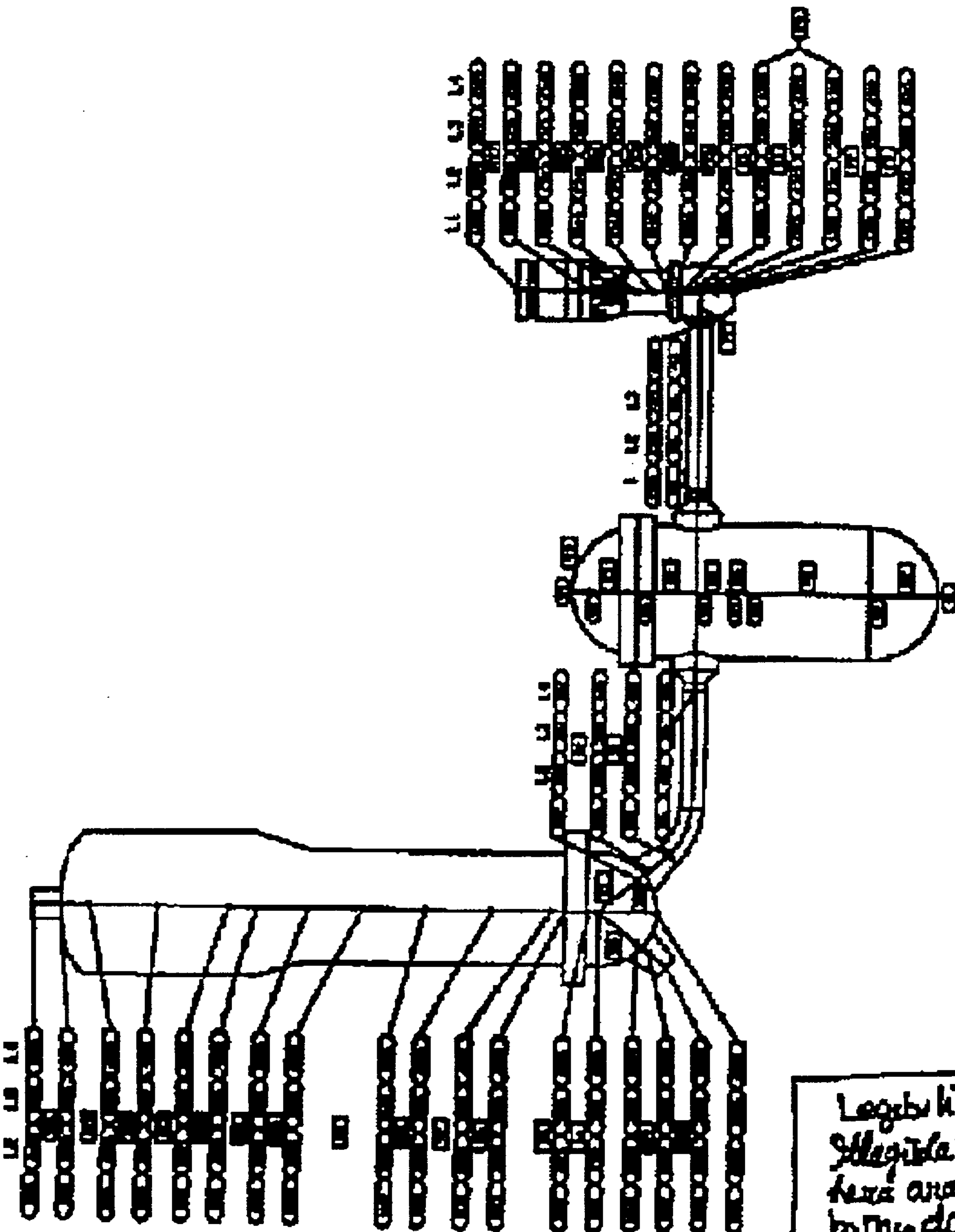
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station PLAN VIEW OF SALEM RCS
	Updated FSAR — Figure 3B-1



Revision 18, April 26, 2000

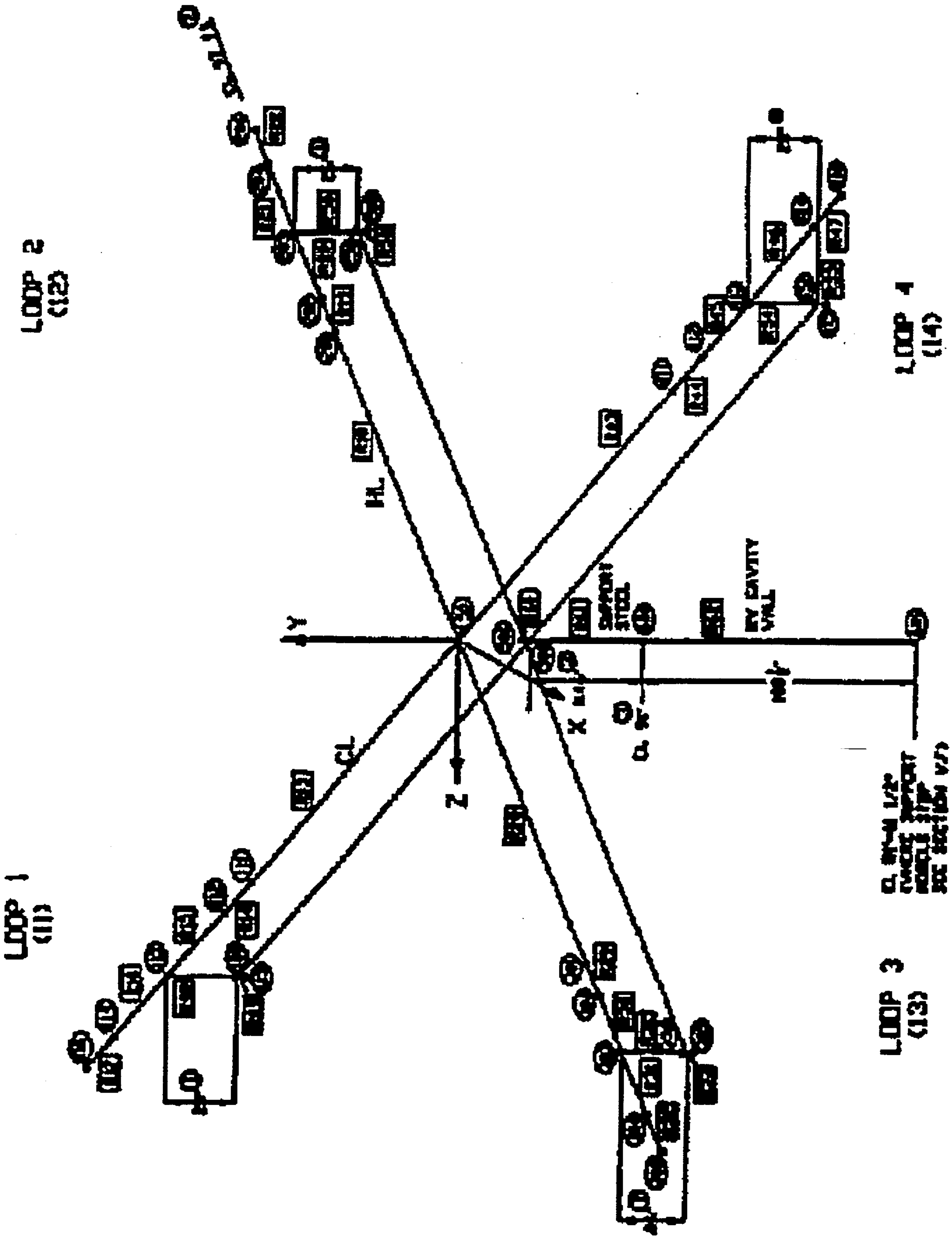
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station PLAN VIEW OF RCS MODEL Updated FSAR — Figure 3B-2



Legibility note
Illegible numbers here are irrelevant to this document

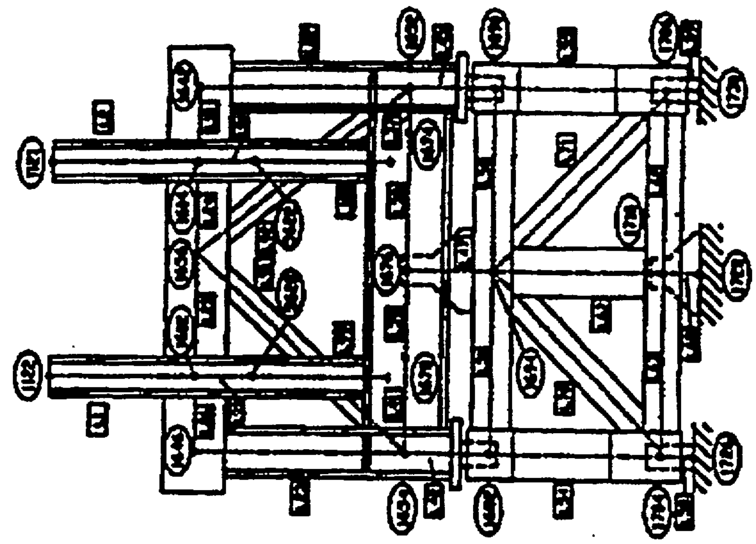
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station ELEVATION VIEW OF RCS MODEL
	Updated FSAR — Figure 3B-3

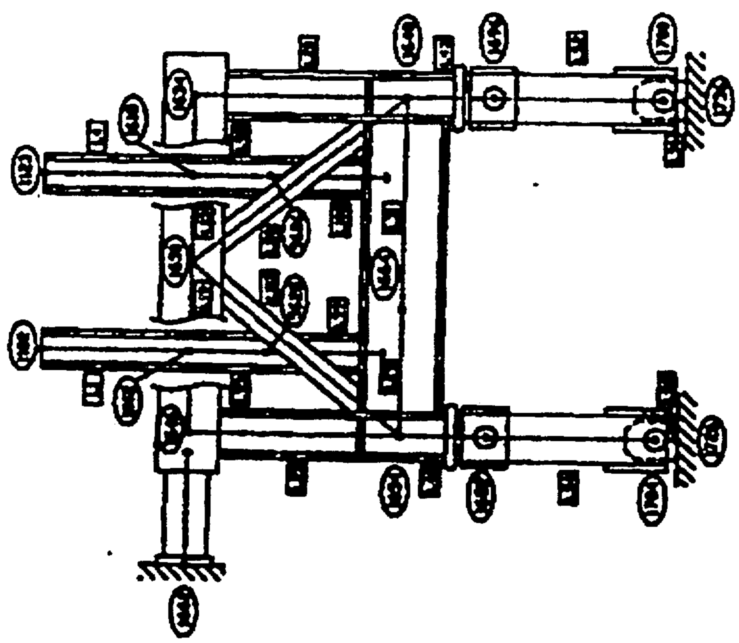


Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station ISOMETRIC VIEW OF RV SUPPORT MODEL
	Updated FSAR — Figure 3B-4



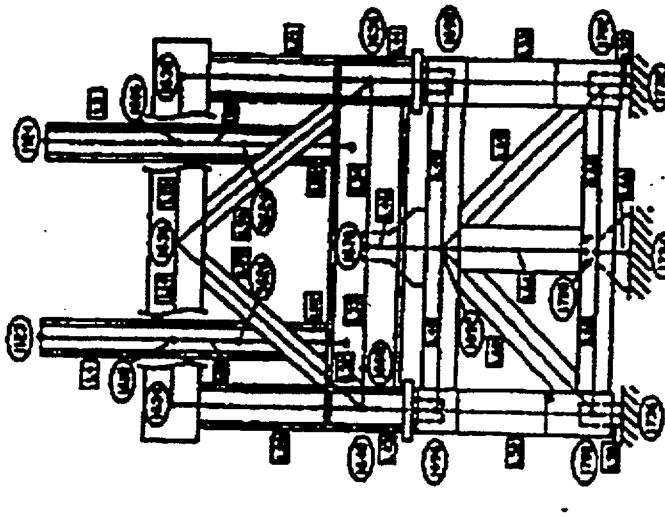
SECTION D-D



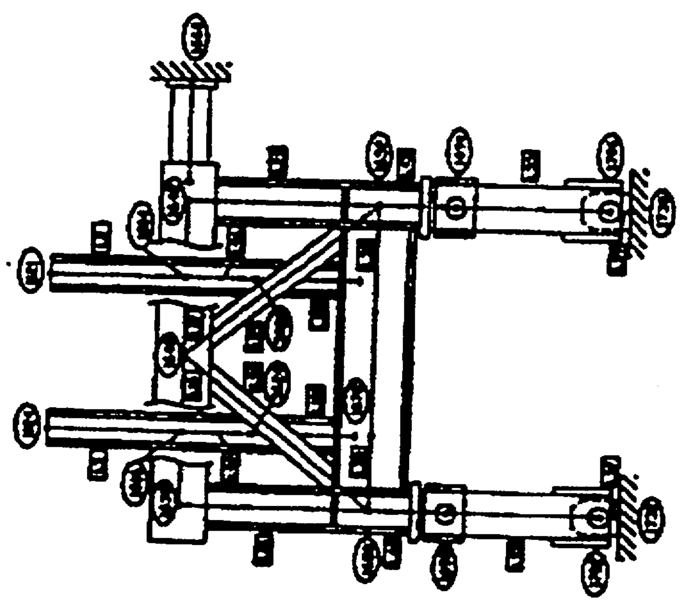
SECTION C-C

Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station ELEVATION VIEW OF RSG SUPPORT MODEL, SHEET1
	Updated FSAR — Figure 3B-5



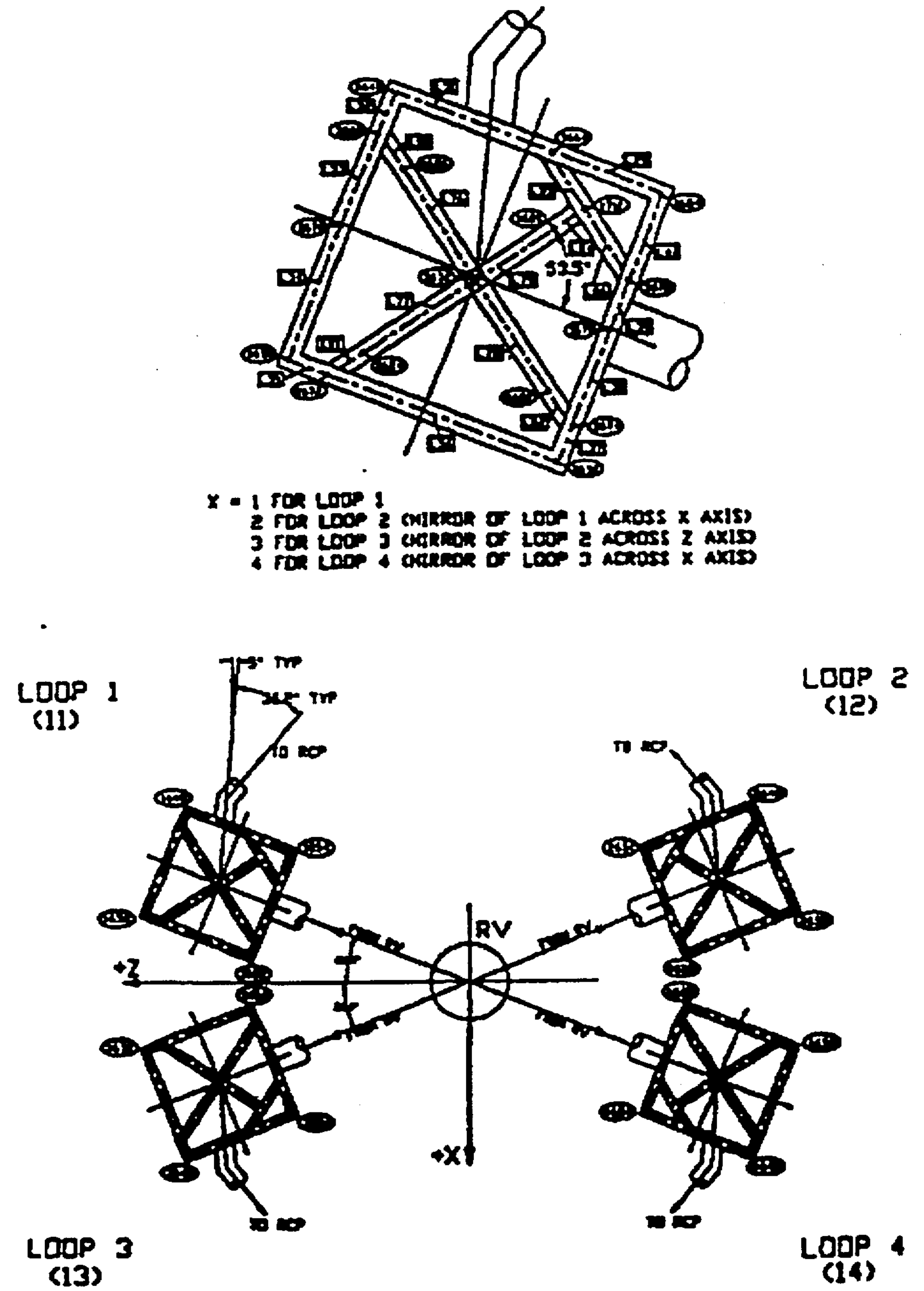
SECTION E–E



SECTION C'–C'

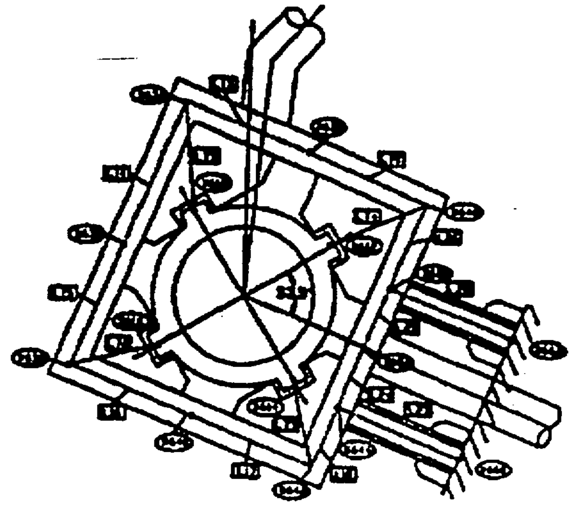
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station ELEVATION VIEW OF RSG SUPPORT MODEL,SHEET 2
	Updated FSAR — Figure 3B-6

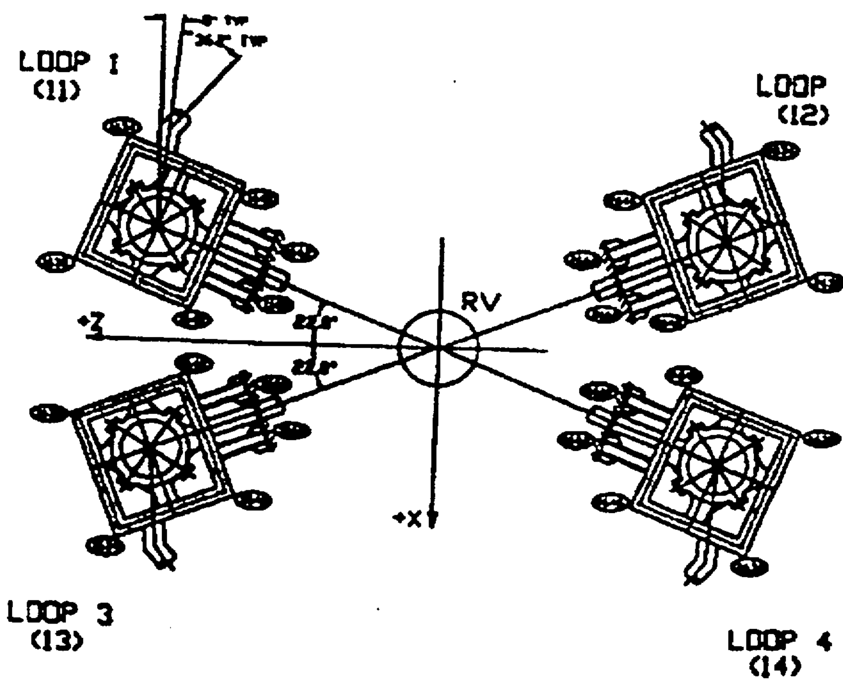


Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station PLAN VIEW OF RSG SUPPORT MODEL AT EL. 94'-1"
	Updated FSAR — Figure 3B-7

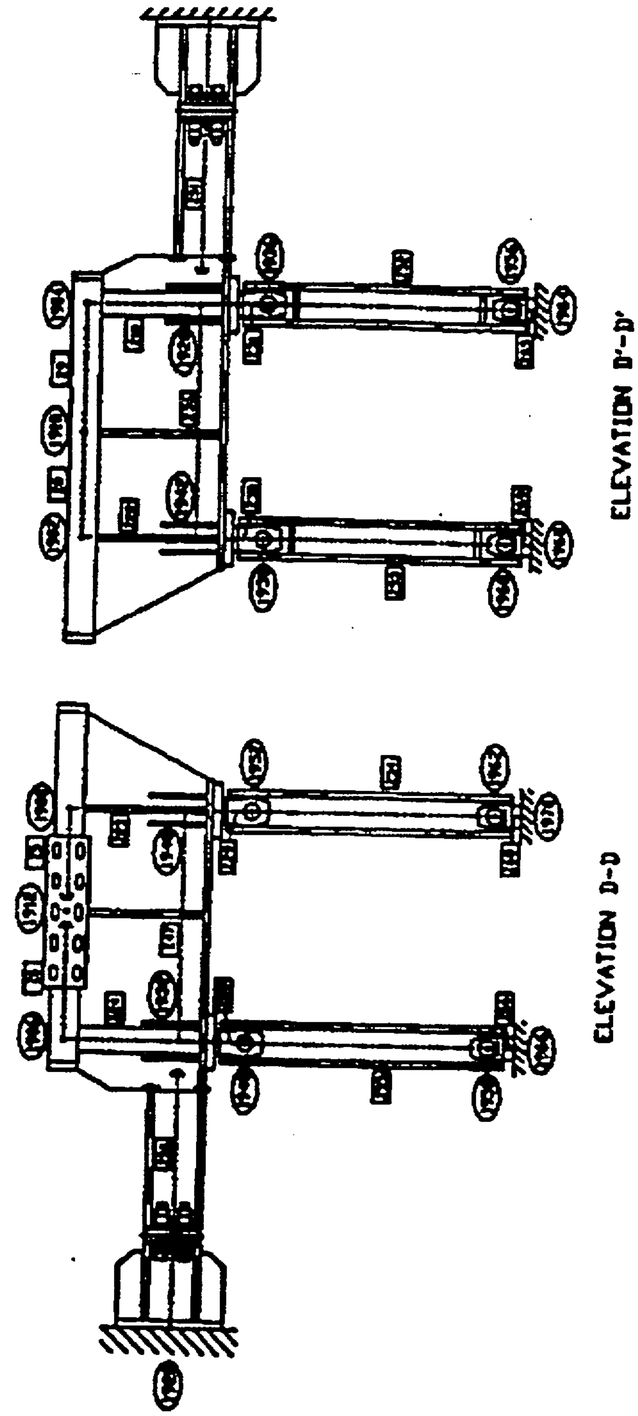


X = 1 FOR LOOP 1
2 FOR LOOP 2 (MIRROR OF LOOP 1 ACROSS X AXIS)
3 FOR LOOP 3 (MIRROR OF LOOP 2 ACROSS Z AXIS)
4 FOR LOOP 4 (MIRROR OF LOOP 3 ACROSS X AXIS)



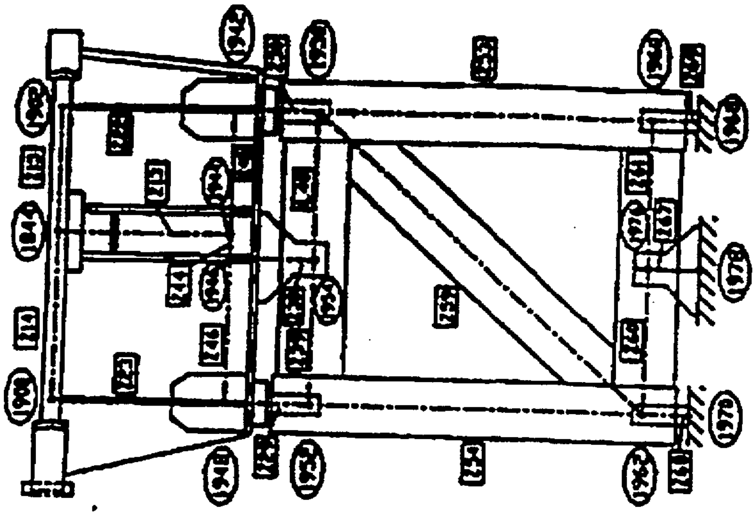
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station PLAN VIEW OF RSG SPRT MODEL AT EL. 100'-8 1/4"
	Updated FSAR — Figure 3B-8

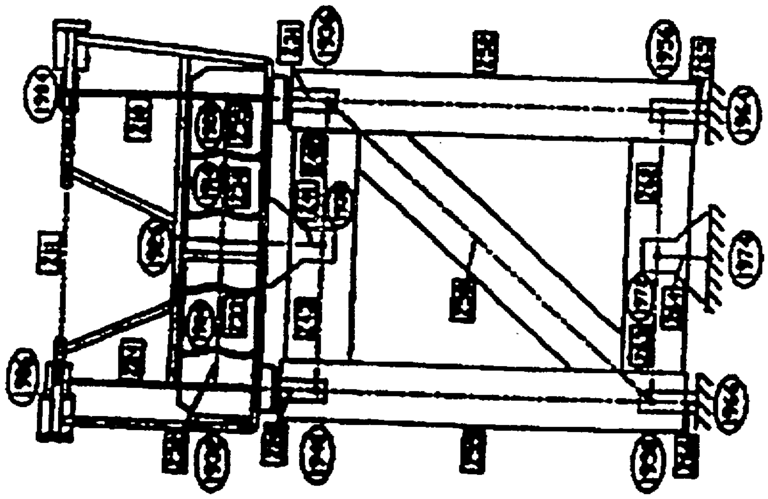


Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station ELEVATION VIEW OF RCP SUPPORT MODEL, SHEET 1
	Updated FSAR — Figure 3B-9



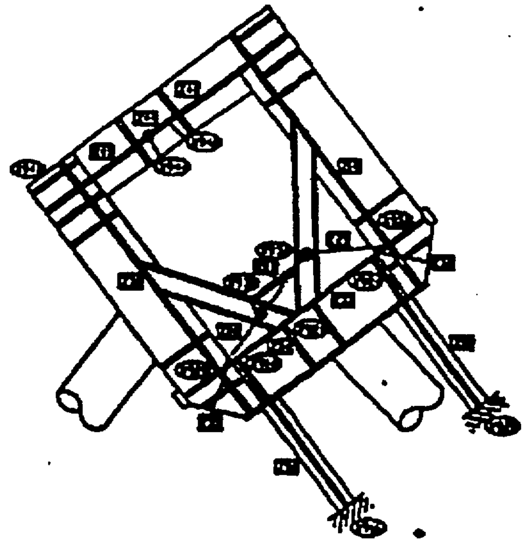
SECTION F-F



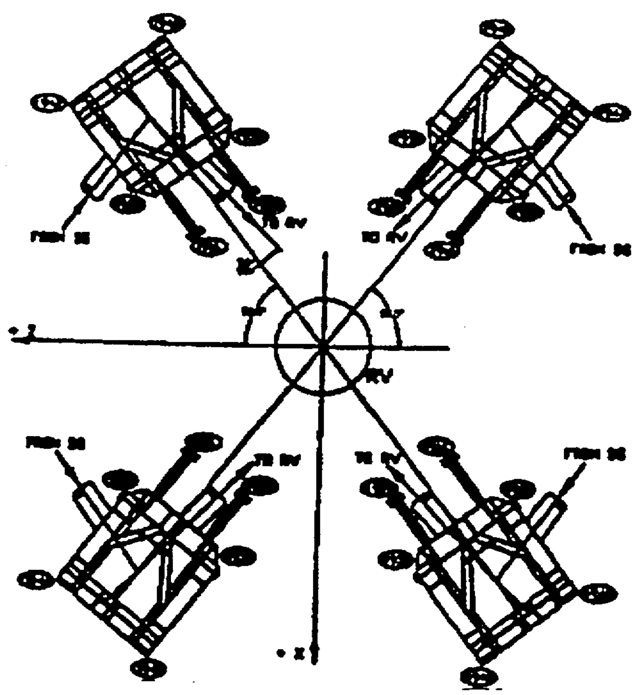
SECTION E-E

Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station ELEVATION VIEW OF RCP SUPPORT MODEL, SHEET 2
	Updated FSAR — Figure 3B-10

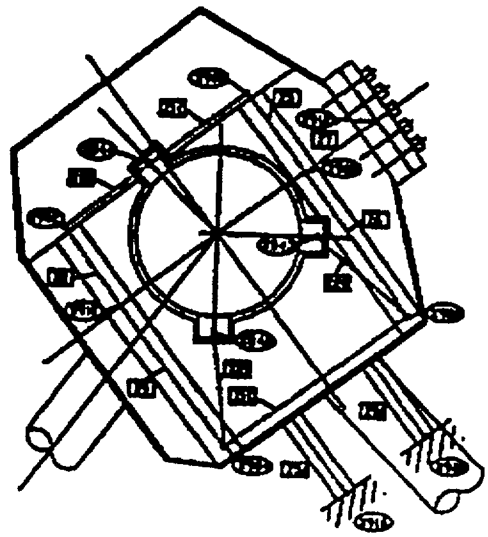


X = 1 FOR LOOP 1
2 FOR LOOP 2 (MIRROR OF LOOP 1 ACROSS X AXIS)
3 FOR LOOP 3 (MIRROR OF LOOP2 ACROSS Z AXIS)
4 FOR LOOP 4 (MIRROR OF LOOP 3 ACROSS X AXIS)

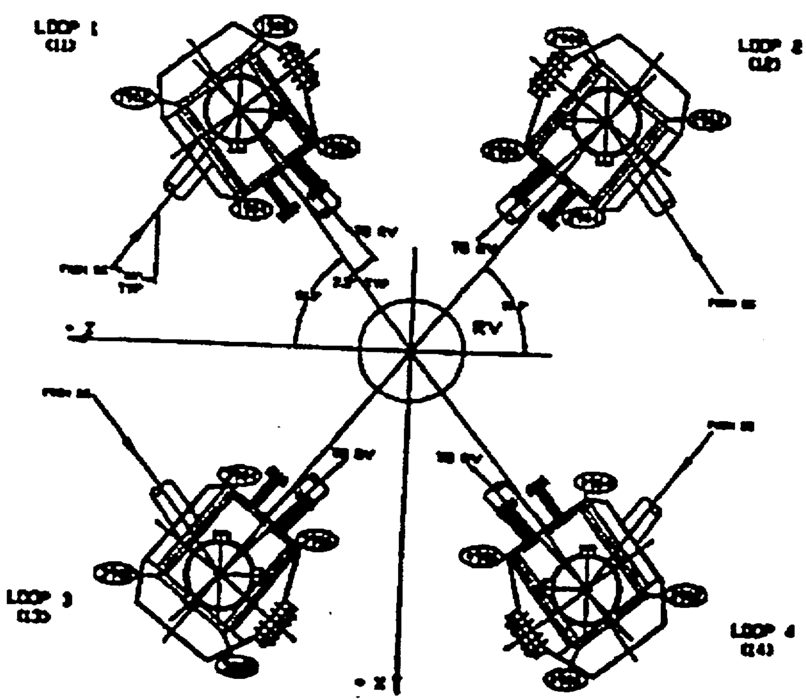


Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station PLAN VIEW OF RCP SPRT MODEL AT 93'- $0\frac{1}{2}$"
	Updated FSAR — Figure 3B-11



X = 1 FOR LOOP 1
2 FOR LOOP 2 (MIRROR OF LOOP 1 ACROSS X AXIS)
3 FOR LOOP 3 (MIRROR OF LOOP 2 ACROSS Z AXIS)
4 FOR LOOP 4 (MIRROR OF LOOP 3 ACROSS X AXIS)



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station PLAN VIEW OF RCP SPRT MODEL AT EL 97'- 0"
	Updated FSAR — Figure 3B-12

TABLE 4.1-1
THERMAL AND HYDRAULIC DESIGN

Reactor Core Heat Output, MWt	3411	
Reactor Core Heat Output, 10^6 Btu/hr	11,642	
Heat Generated in the Fuel, %	97.4	
Nominal System Pressure, psia	2250	
Assumed Initial System Pressure for DNB Transients, psia	2220	(STDP[1])
	2250	(RTDP[2])
Minimum DNBR for Design Transients	STD	1.30 (STDP[1])
	V-5H[3]	1.36 (STDP[1])
	V-5H[4]	1.24 (RTDP[2])
	RFA[7]	1.25[8] (RTDP[2])
DNB Correlation	STD	W-3 "R" Grid
	V-5H[3]	WRB-1
	RFA[7]	WRB-2
Coolant Flow		
Total Thermal Design Flow Rate, 10^6 lb/hr	125.2[5]	
	127.2[6]	
Effective Flow Rate for Heat Transfer, 10^6 lb/hr	116.2[5]	
	118.0[6]	
Effective Flow Area for Heat Transfer, ft^2	STD	51.1
	V-5H[3]	51.3
	RFA	51.1
Average Velocity Along Fuel Rods, ft/sec	STD	14.2
	V-5H[3]	14.1
	RFA	14.2
Average Mass Velocity, 10^6 lb/hr-ft^2	2.27[5]	
	2.30[6]	

TABLE 4.1-1 (Continued)
THERMAL AND HYDRAULIC DESIGN

Fuel Assemblies	
Design	RCC Canless
Number of Fuel Assemblies	193
UO_2 Rods per Assembly	264
Rod Pitch, in	0.496
Overall Dimension, in	8.426 x 8.426
Weight of Fuel (as UO_2) in Core, lbs	STD, V5H, V+ 222,739 RFA(9) 217,565
Weight of Zircaloy in Core, lbs	All STD 50913 All V5H,V+ 52541 All RFA 53847
Number of Grids per Assembly	STD 8 Inconel V5H 2 Inconel (Top & Bottom) 6 Zircaloy-4 (Mid Grids) V+ 2 Inconel (Top & Bottom) 6 Zirlo™ (Mid Grids) RFA 2 Inconel (Top & Bottom) 1 Inconel (Protective Grid) 6 Zirlo™ (Mid Grids) 3 Zirlo™ (Intermediate Flow Mixing Grids)
Loading Technique	3 Region Non-uniform
Fuel Rods	
Number in Core	50,952
Outside Diameter, in	0.374
Diametral Gap, in	0.0065
Clad Thickness, in	0.0225
Clad Material	STD, V5H Zircaloy-4 V+,RFA Zirlo™

Fuel Pellets	
Material	UO_2 Sintered
Density, % of Theoretical	95
Diameter, in	0.3225 [10]
RFA Annular Pellet I.D., in	0.155 [11]
Length, in	STD 0.530 V-5H [3] 0.387 RFA Solid 0.387 RFA Annular 0.462
Rod Cluster Control Assemblies	
Neutron Absorber	Ag-In-Cd
Cladding Material	Type 316L Ionnitride Surface
Clad Thickness, in	0.0185
Number of Clusters	53
Number of Absorbers per Cluster	24
Core Structure	
Core Barrel, ID / OD, in	148.0 / 152.5
Thermal Shield, ID / OD, in	158.5 / 164.0
Nuclear Design Parameters:	
Structure Characteristics	
Core Diameter, in (Equivalent)	132.7
Core Average Active Fuel Height, in	143.7

TABLE 4.1-1 (Continued)

THERMAL AND HYDRAULIC DESIGN

Reflector Thickness and Composition	
Top - Water Plus Steel, in	~10
Bottom - Water Plus Steel, in	~10
Side - Water Plus Steel, in	~15
H_2O/U, Molecular Ratio, Lattice (cold)	2.41

---

(1) Standard Thermal Design Procedure.

(2) Revised Thermal Design Procedure.

(3) Also valid for V+ assemblies without Intermediate Flow Mixing Grids.

(4) To offset the effects of rod bow and provide some generic margin, this has been conservatively increased to a DNBR Safety Limit value of 1.34 for typical channels and 1.33 for thimble channels.

(5) For analyses where high average core temperature is bounding.

(6) For analyses where low average core temperature is bounding.

(7) With Intermediate Flow Mixing Grids.

(8) To provide generic margin, this has been conservatively increased to a DNBR Safety Limit of 1.65 for typical channels and 1.62 for thimble channels.

(9) With annular axial blankets.

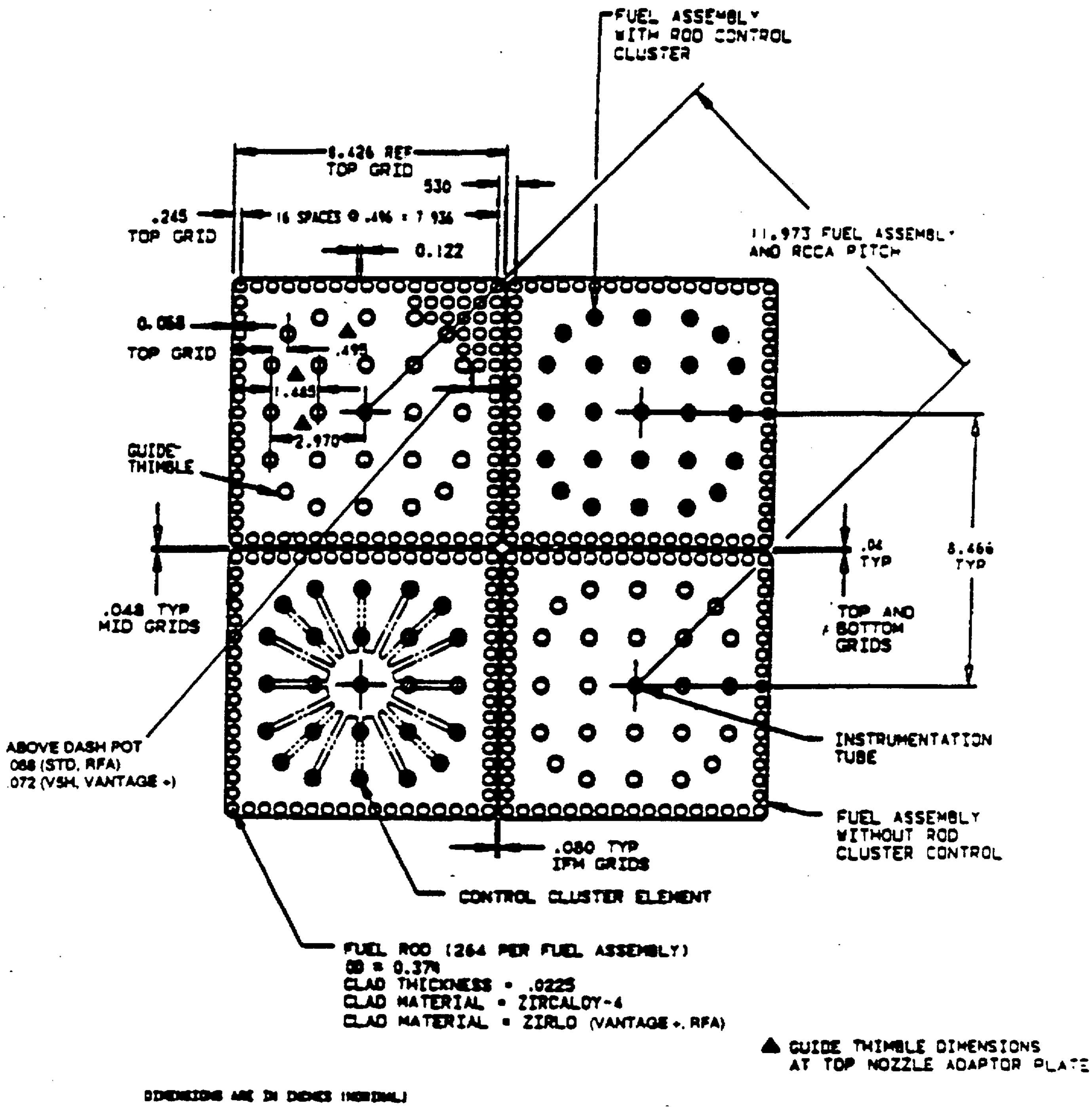
(10) Applicable to solid or annular pellets.

(11) Top and bottom 6" of RFA fuel stack height.

TABLE 4.2-2

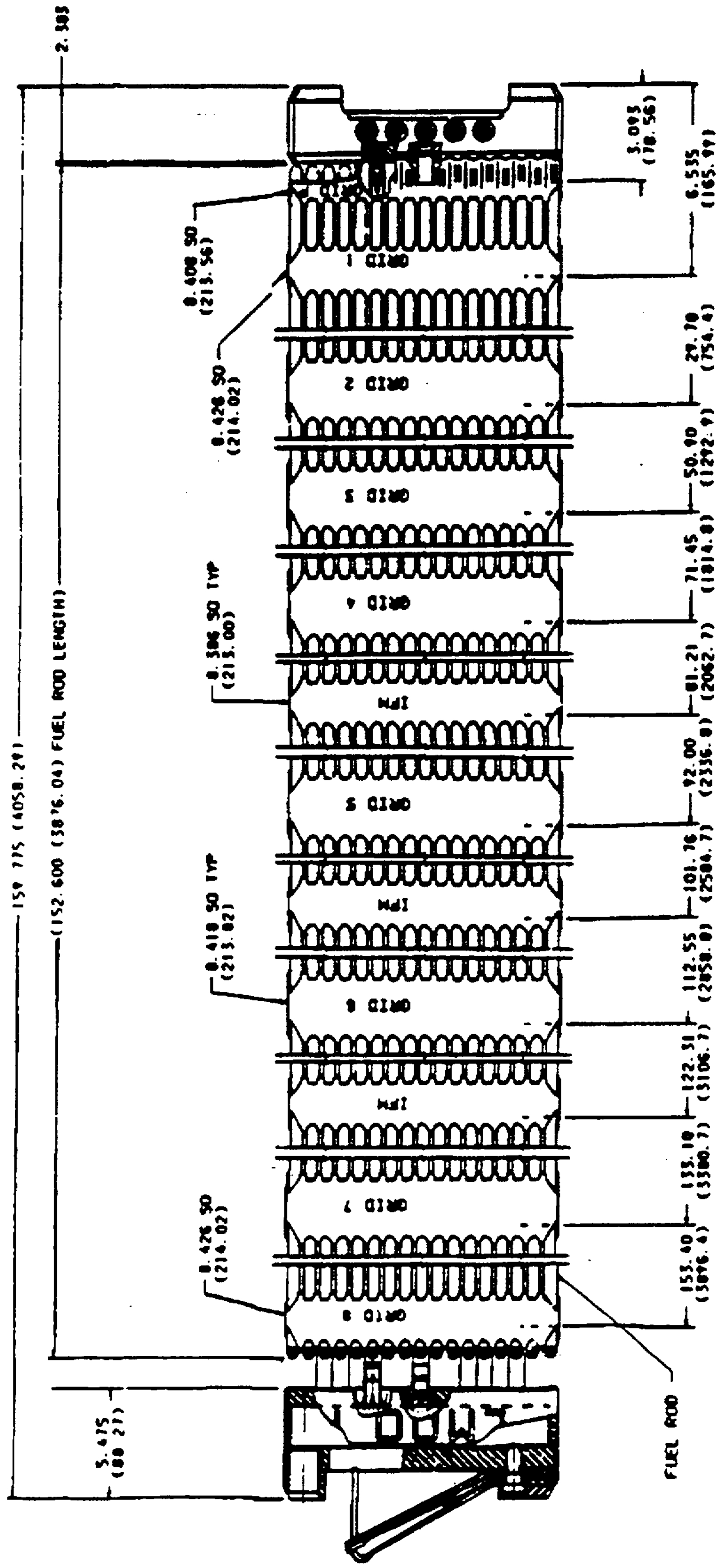
COMPARISON OF SINGLE AND DOUBLE ENCAPSULATED SECONDARY SOURCE DESIGNS

PARAMETER	SINGLE ENCAPSULATED	DOUBLE ENCAPSULATED
Number of rodlets	4	6
Outer Clad OD, in.	0.381 +/- 0.001	0.381 +/- 0.001
Outer Clad ID, in.	0.344 +/- 0.0005	0.344 +/- 0.0005
Inner Clad OD, in.	N/A	0.344 +/- 0.001
Inner Clad ID, in.	N/A	0.297 +/- 0.0005
Pellet OD, in.	0.338 +0.002/-0.001	0.292 +/- 0.001
Pellet Stack Length, in.	88.00	88.00
Pellet Stack Weight, grams	500/535	338 +/- 10
Spring Clip Material	Carbon steel - plated	410 Stainless steel
Outer Pressurization, psig	625 +/- 50	625 +/- 50
Inner Pressurization, psig	N/A	250 +/- 20



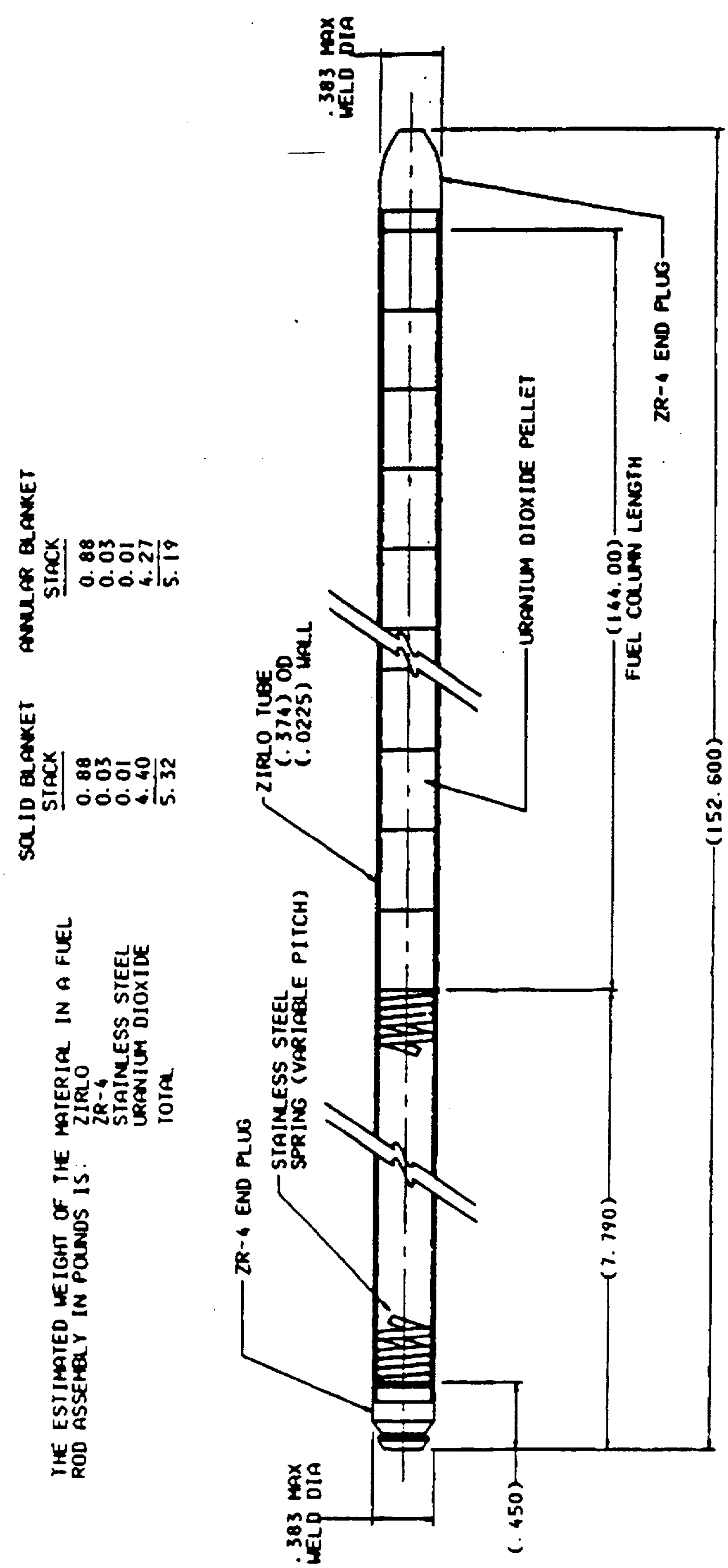
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station FUEL ASSEMBLY CROSS SECTION 17x17
	Updated FSAR — Figure 4.2-1



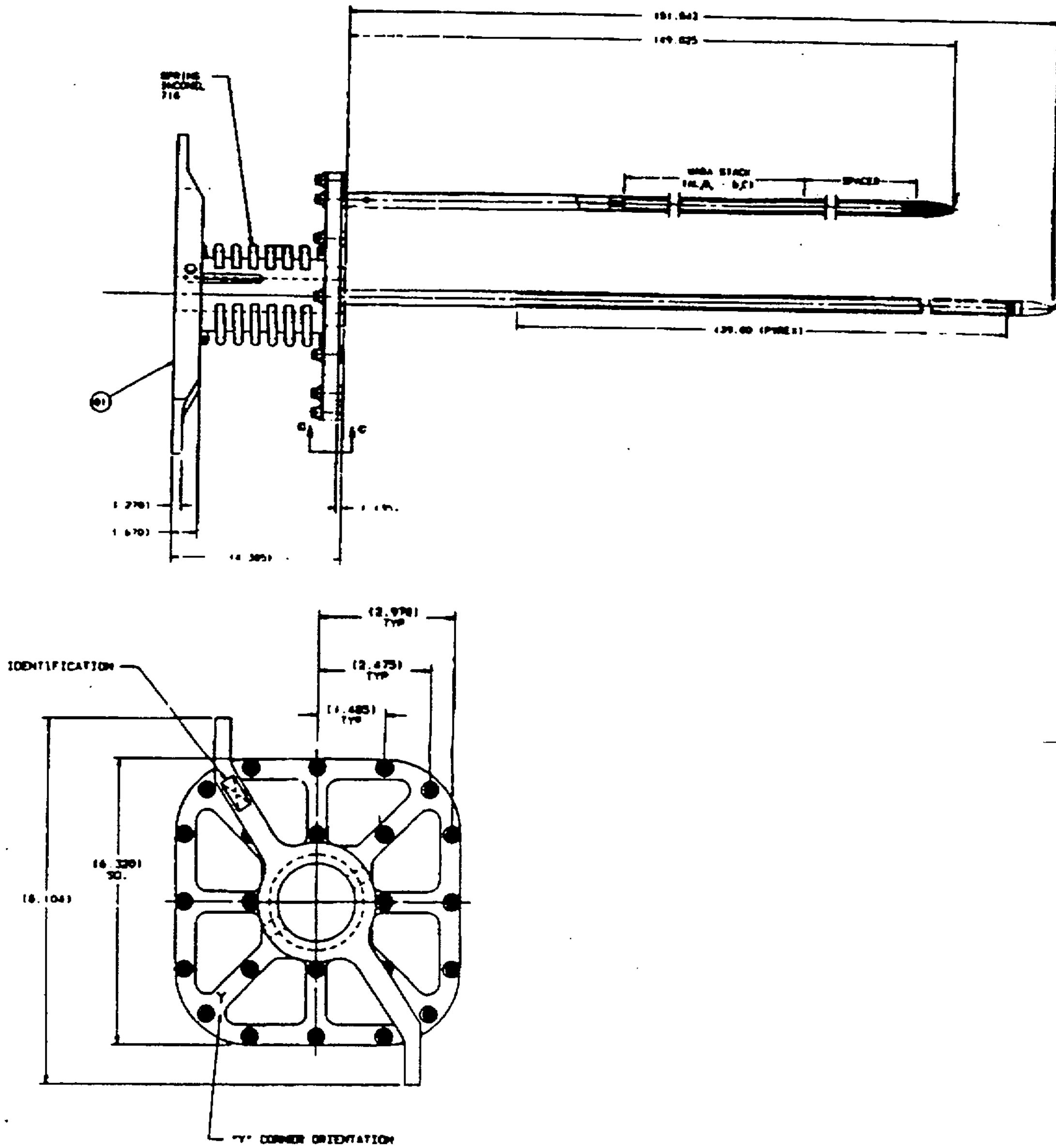
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station STANDARD ROBUST ASSEMBLY OUTLINE 17x17
	Updated FSAR — Figure 4.2-2B



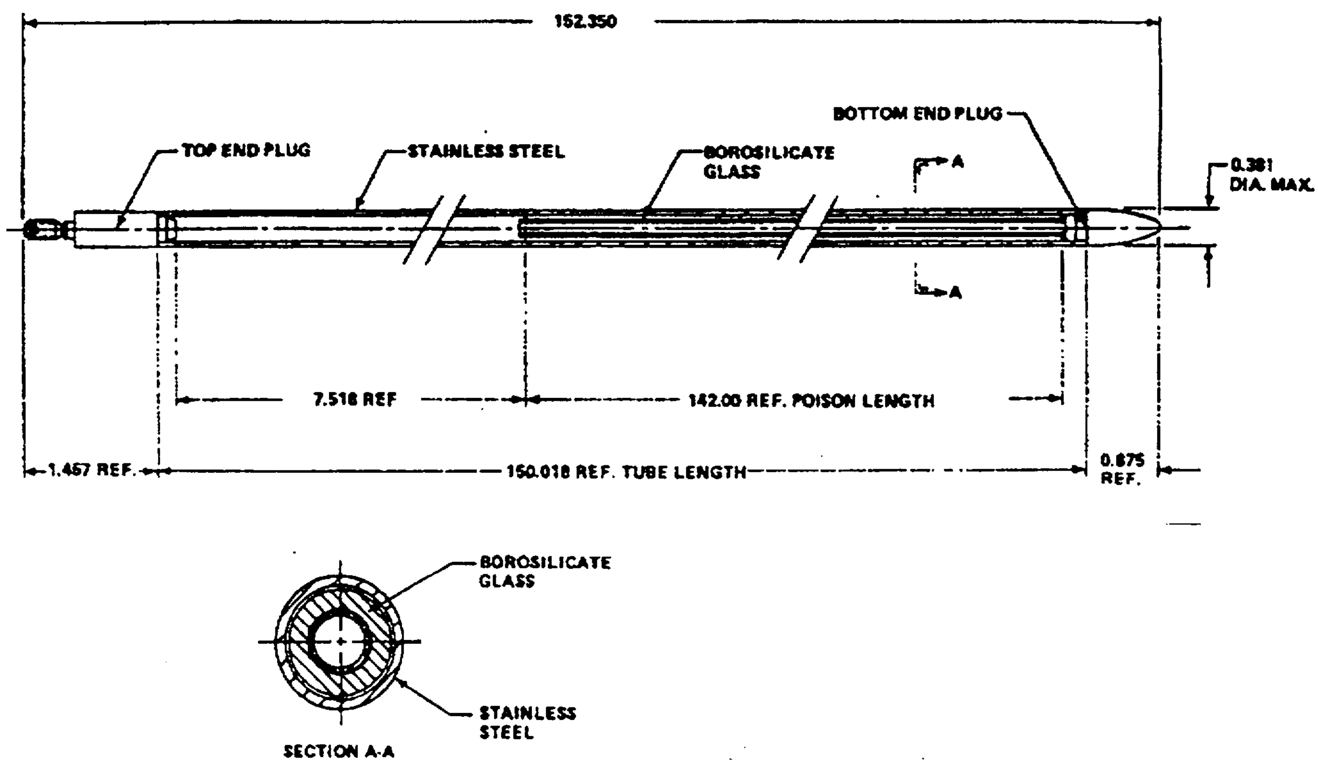
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station STANDARD RFA FUEL ROD SCHEMATIC 17x17 Updated FSAR Figure 4.2-3B



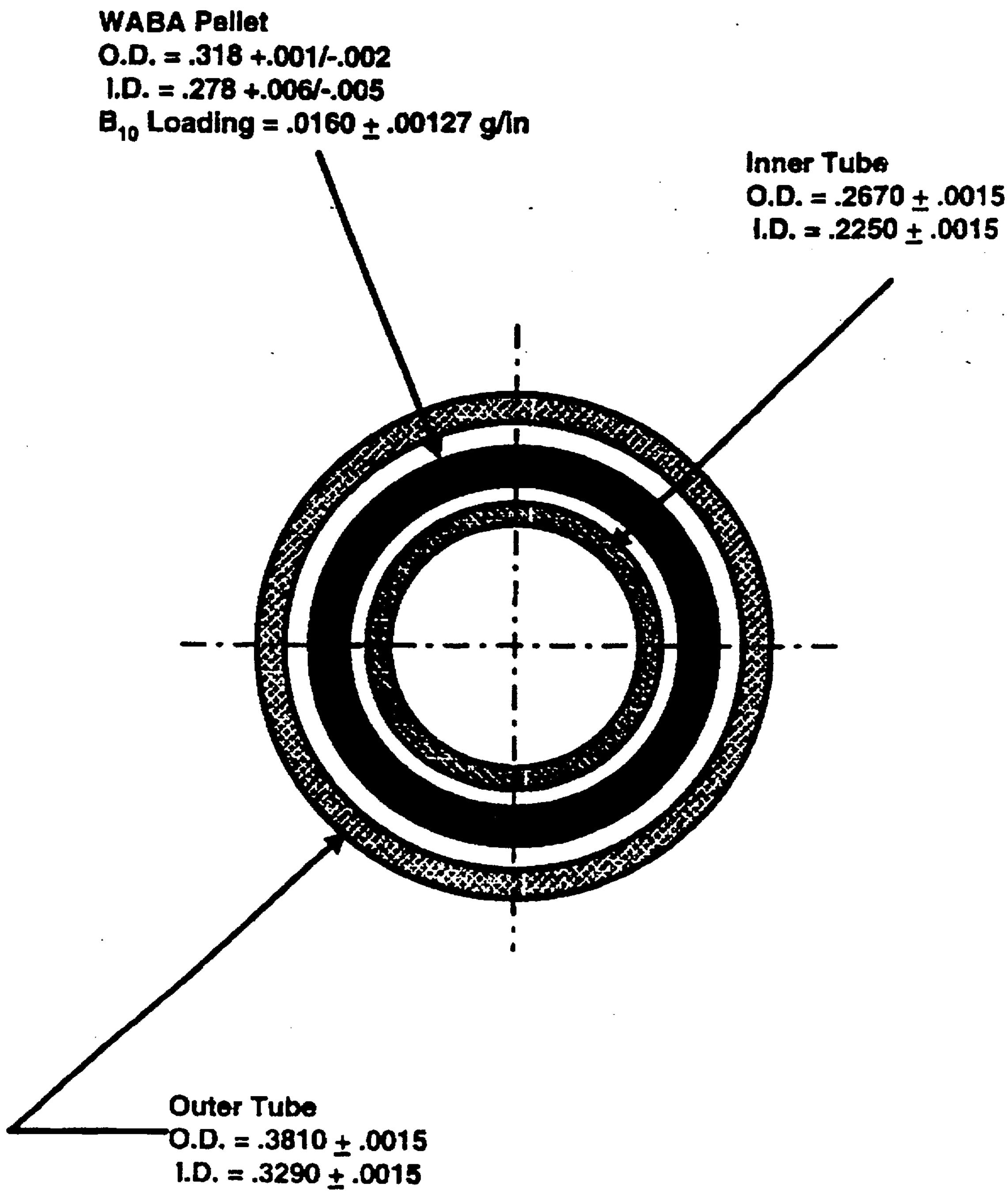
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station BURNABLE ABSORBER ASSEMBLY
	Updated FSAR — Figure 4.2-16



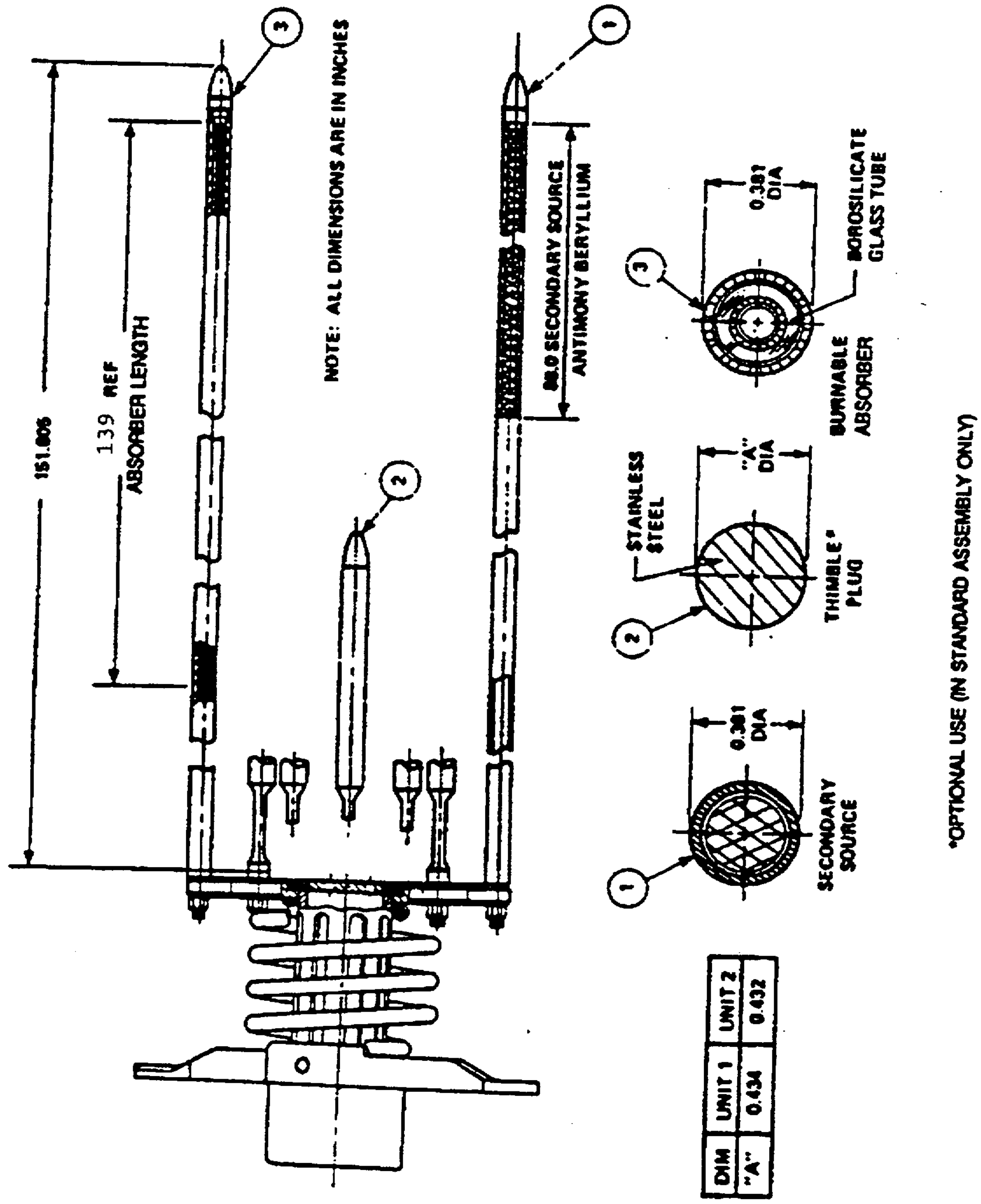
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station PYREX BURNABLE POISON ROD CROSS SECTION
	Updated FSAR — Figure 4.2-17



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station WABA ROD CROSS SECTION
	Updated FSAR — Figure 4.2-17A



DIM	UNIT 1	UNIT 2
"A"	0.434	0.432

Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station SINGLE ENCAPSULATED SECONDARY SOURCE
	Updated FSAR Figure 4.2-19

TABLE 4.3-1

REACTOR CORE DESCRIPTION

Active Core	
Equivalent Diameter, in.	132.7
Core Average Active Fuel Height, First Core (Hot), in.	143.7
Height-to-Diameter Ratio	1.09
Total Cross Section Area, ft^2	96.06
H_2O/U Molecular Ratio, Lattice (Cold)	2.41
Reflector Thickness and Composition	
Top - Water plus Steel, in.	~10
Bottom - Water plus Steel, in.	~10
Side - Water plus Steel, in.	~15
Fuel Assemblies	
Number	193
Rod Array	17 x 17
Rods per Assembly	264
Rod Pitch, in.	0.496
Overall Transverse Dimensions, in.	8.426 x 8.426
Fuel Weight (as UO_2), lb	222,739(V5H,V+ 217,565 (RFA)
Zircaloy Weight, lb	53,142(V5H, V+) 53,847 (RFA)
Number of Grids per Assembly	V5H 2 Inconel (Top & Bottom) 6 Zircaloy-4 (Mid Grids) V+ 2 Inconel (Top & Bottom) 6 Zirlo^{TM} (Mid Grids) RFA 2 Inconel (Top & Bottom) 1 Inconel (Protective Grid) 6 Zirlo^{TM} (Mid Grids) 3 Zirlo^{TM} (Intermediate Flow Mixing Grids)
Weight of Grids (Effective in Core), lb	2324 (V5H, V+) 3248 (RFA)
Number of Guide Thimbles per Assembly	24
Composition of Guide Thimbles	Zircaloy-4 (V5H) Zirlo^{TM} (V+, RFA)

Dia. of Guide Thimbles (upper part), in.	0.442 ID x 0.474 OD (V5H, V+) 0.442 ID x 0.482 OD (RFA)
Dia. of Guide Thimbles (lower part), in.	0.397 ID x 0.429 OD V5H, V+) 0.397 ID x 0.439 OD (RFA)
Dia. of Instrument Guide Thimbles, in.	0.442 ID x 0.474 OD V5H, V+) 0.442 ID x 0.482 OD (RFA)
Fuel Rods	
Number	50,952
Outside Diameter, in.	0.374
Diameter Gap, in.	0.0065
Clad Thickness, in.	0.0225
Clad Material	Zircaloy-4 (V5H) Zirlo^{TM} (V+, RFA))
Fuel Pellets	
Material	UO_2 Sintered
Density[1]	95.5
Region 1	4.0
Fuel Enrichments w/o[1]	Typical Reload
Region 2	4.4
Region 3A	4.0
Region 3B	4.4
Diameter, in.	0.3225
RFA Annular Pellet I.D., in.[2]	0.155
Length, in.	0.530 (STD) 3.387 (V5H, V+) 3.387 (RFA solid)[2] 3.387 (RFA annular)[2]
Mass of UO_2 Per Foot of Fuel Rod, lb/ft	0.364 (V5H, V+) 0.355 (RFA)
Rod Cluster Control Assemblies	
Neutron Absorber	Ag-In-Cd
Composition, percent	80, 15, 5
Diameter, in.	0.381
Density, lb/in.	0.367
Clad Material	Type 316L, Ionnitride Surface
Clad Thickness, in.	0.0185
Number of Clusters, full length	53
Number of Absorber Rods per Cluster	24
Full Length Assembly Weight (dry), lb	149
Burnable Absorber Rods[1]	
Material (PYREX)	Borosilicate Glass
Outside Diameter, in.	0.381
Inner Tube, OD, in.	0.1815

Clad Material	Stainless Steel
Inner Tube Material	Stainless Steel
Boron Loading (w/o B_2O_3 in glass rod)	12.5
Weight of Boron - 10 per foot of rod, lb/ft	0.00419
Material (WABA)	Al_2O_3 - B_4C Compound
B_4C Density (Fraction of Theoretical)	0.7
Absorber I.D., in.	0.278
Absorber O.D., in.	0.318
BA Clad Material	Zirc-4
Inner Clad Thickness, in.	0.021
Inner Clad O.D., in.	0.267
Outer Clad Thickness, in.	0.026
Outer Clad O.D., in.	0.381
Gap Material	Helium
Integral Fuel Burnable Absorber	
Material	ZrB_2
Content	1.570 to 2.350 mg B^{10}/in. ~~(1)~~
Excess Reactivity	
Maximum Core Reactivity (Cold, Zero Power, Beginning of Cycle)(3)	1.200

(1) Typical reload values. Current values are given in the appropriate NDR (See Section 4.5).

(2) Robust Fuel Assembly (RFA) uses annular pellets at the top & bottom 6" of the fuel stack height. Middle 132" of fuel stack height is solid pellets.

(3) Typical reload value. This parameter is cycle-specific and is a function of energy requirements and number of burnable absorbers used.

TABLE 4.4-1

REACTOR THERMAL AND HYDRAULIC DESIGN PARAMETERS

Reactor Core Heat Output, MWt	3411
Reactor Core Heat Output, BTU/hr	$11,642 \times 10^6$
Heat Generated in Fuel	97.4
System Pressure, Nominal psia	2250
System Pressure, Minimum Steady State psia	220 (STDP[1] only)
<u>Coolant Flow</u>	
Total Thermal Flow Rate, lb/hr	125.2×10^6
Effective Flow Rate for Heat Transfer, lb/hr	116.2×10^6
Effective Flow Area for Heat Transfer, ft^2	STD 51.1
	V-5H, V+ 51.3
	RFA[2] 51.1
Average Velocity Along Fuel Rods, ft/sec	STD 14.2
	V-5H, V+ 14.1
	RFA 14.2
Average Mass Velocity, lb/hr-ft^2	STD 2.42×10^6 (STDP)
	V-5H,V+ 2.265×10^6 (STDP)
	V-5H,V+ 2.343×10^6 (RTDP[3])
	RFA 2.274×10^6 (STDP)
	RFA 2.352×10^6 (RTDP)
<u>Coolant Temperature</u>	
Nominal Inlet, deg-F	545.0 (STDP)
	543.2 (RTDP)
Average Rise in Vessel, deg-F	65.8 (STDP)
	69.4 (RTDP)
Average Rise in core, deg-F	69.9 (STDP)
	74.2 (RTDP)

TABLE 4.4-1 (Cont.)

Average in Core, deg-F	581.8 (STDP) 582,3 (RTDP)
Average in Vessel, deg-F	577.9
Heat Transfer	
Active Heat Transfer Surface Area, ft^2	59,700
Average Heat Flux, BTU/hr-ft^2	189,800
Maximum Heat Flux,	
For normal operation, BTU/hr-ft^2	45,500[4]
Average Thermal Output, kW/ft	5.45
Maximum Thermal Output,	
For normal operation, kW/ft	13.1[4]
Peak Linear Power for determination	
of protection setpoints, kW/ft	21.1[5]
Peak at Thermal Output Maximum	
for maximum Overpower Trip, deg-F	<4700
Pressure Drop Across Core, psi	Full core STD 23.7[6] Full core V-5H,V+ 22.2[7] Full core RFA 24.7[7]
Minimum DNBR at Normal Conditions	
Typical Flow Channel	STD 2.12 (STDP) V-5H,V+ 2.32 (STDP) V-%H,V+ 2.23 (RTDP) RFA[1] 2.71 (RTDP)
Thimble (Cold Wall) Flow Channel	STD 1.75 (STDP) V-5H,V+ 2.19 (STDP) V-5H,V+ 2.14 (RTDP) RFA 2.55 (RTDP)

TABLE 4.4-1 (Cont.)

DNBR Margin Summary

DNBR Correlation	STD W-3 V-5H,V+ WRB-1 RFA WRB-2
DNBR Correlation Limit	W-3 1.30 WRB-1 1.17 WRB-2 1.17
DNBR Design Limit	W-3 1.30 WRB-1 1.17 (STDP) WRB-1 1.24 (RTDP, Typ) WRB-1 1.24 (RTDP,Thm) WRB-2 1.25 (RTDP, Typ) WRB-2 1.23 (RTDP, Thm)
DNBR Safety Limit	W-3 1.376 WRB-1 1.36 (STDP) WRB-1 1.34 (RTDP, Typ) WRB-1 1.33 (RTDP, Thm) WRB-2 1.65 (RTDP, Typ) WRB-2 1.62 (RTDP, Thm)

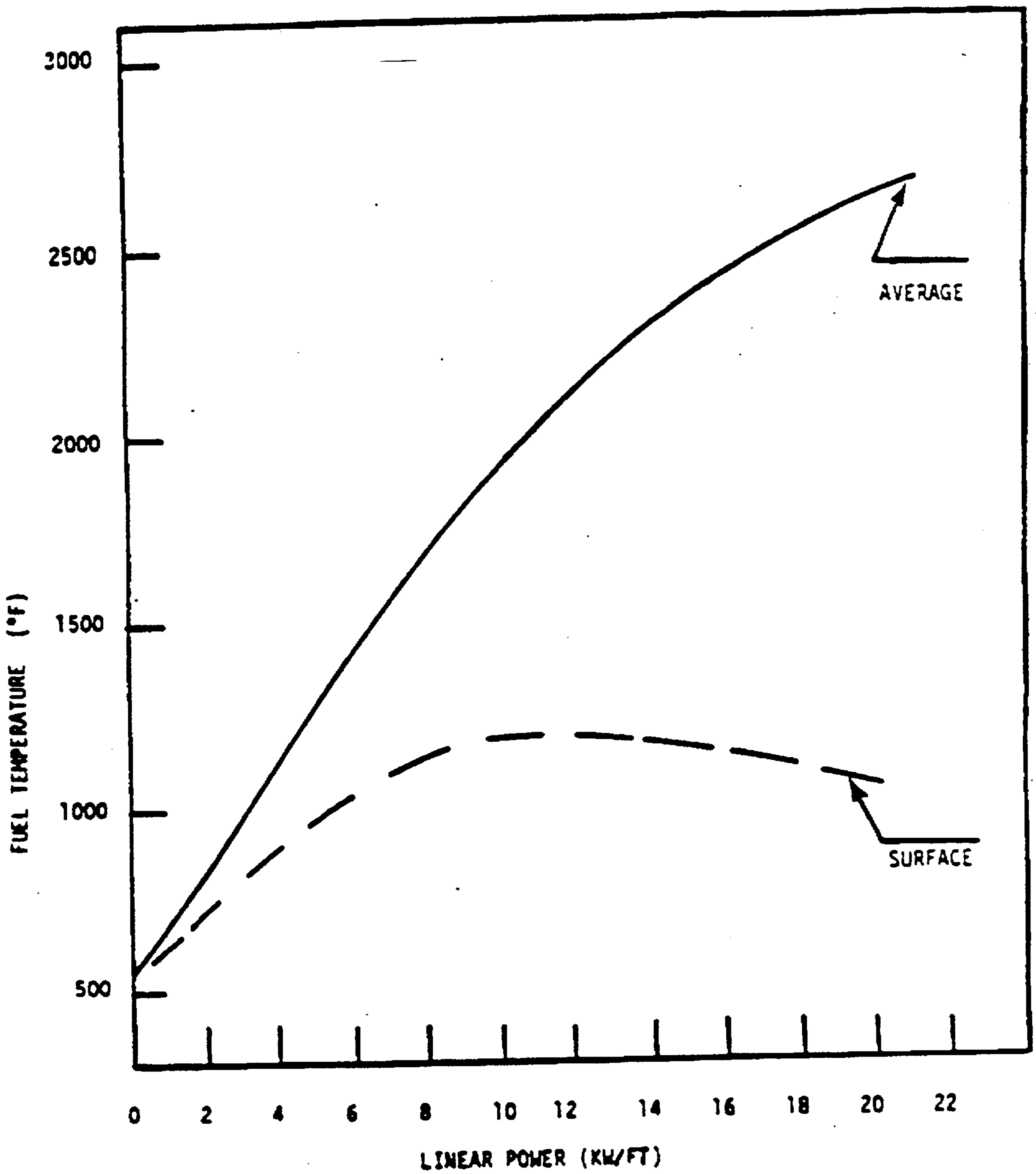
Notes:

1) Standard Thermal Design Procedure
2) All Parameters for RFA include Intermediate Flow Mixing (IFM) grids
3) Revised Thermal Design Procedure
4) Associated with F_Q limit of 2.40
5) See Section 4.3.2.2.6
6) Based on a best estimate reactor flow rate of 95,600 gpm/loop
7) Based on a best estimate reactor flow rate of 93,300 gpm/loop

TABLE 4.4-2

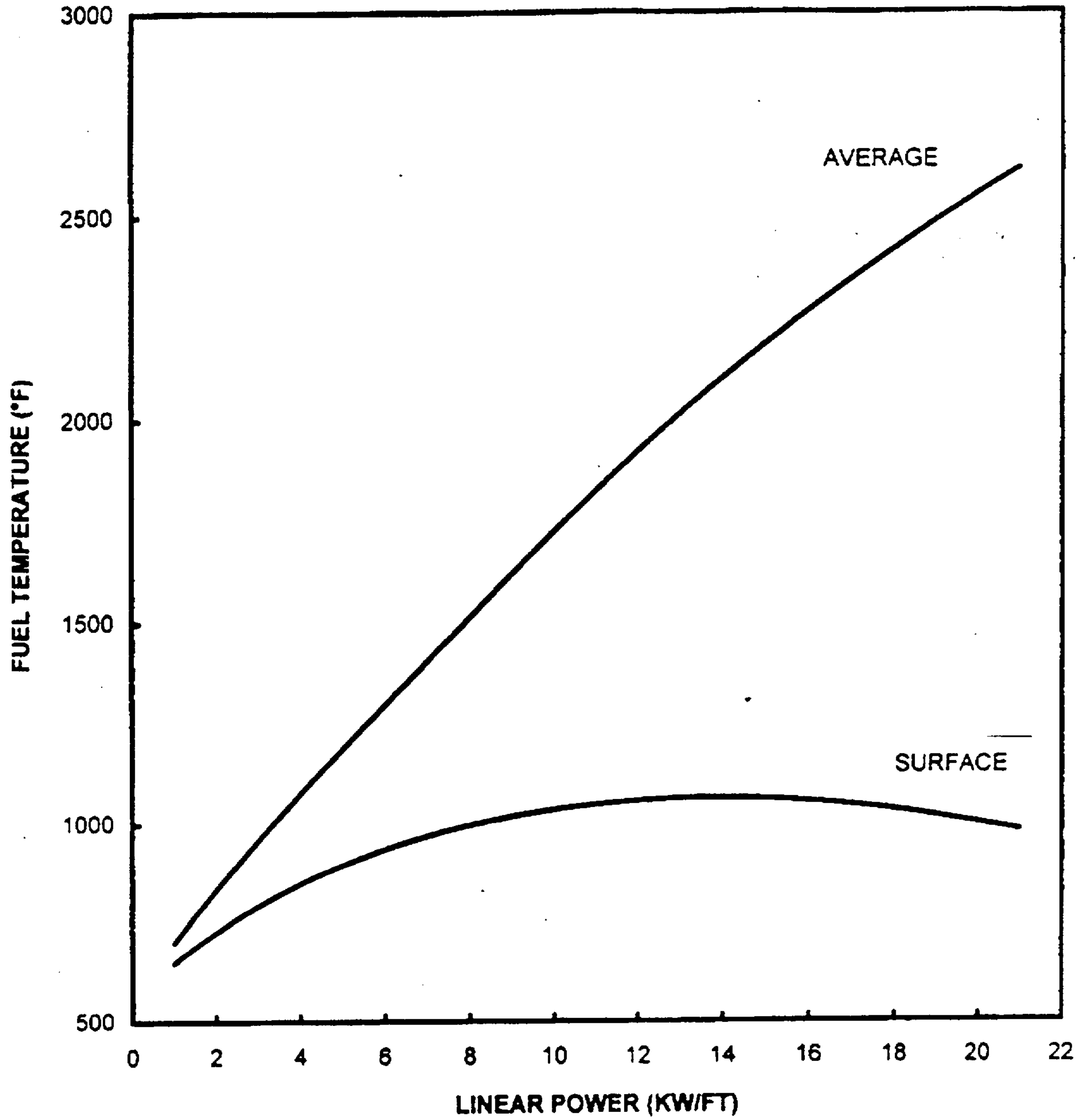
THERMAL-HYDRAULIC DESIGN PARAMETERS FOR
ONE OF FOUR COOLANT LOOPS OUT OF SERVICE

(This Table has been deleted)



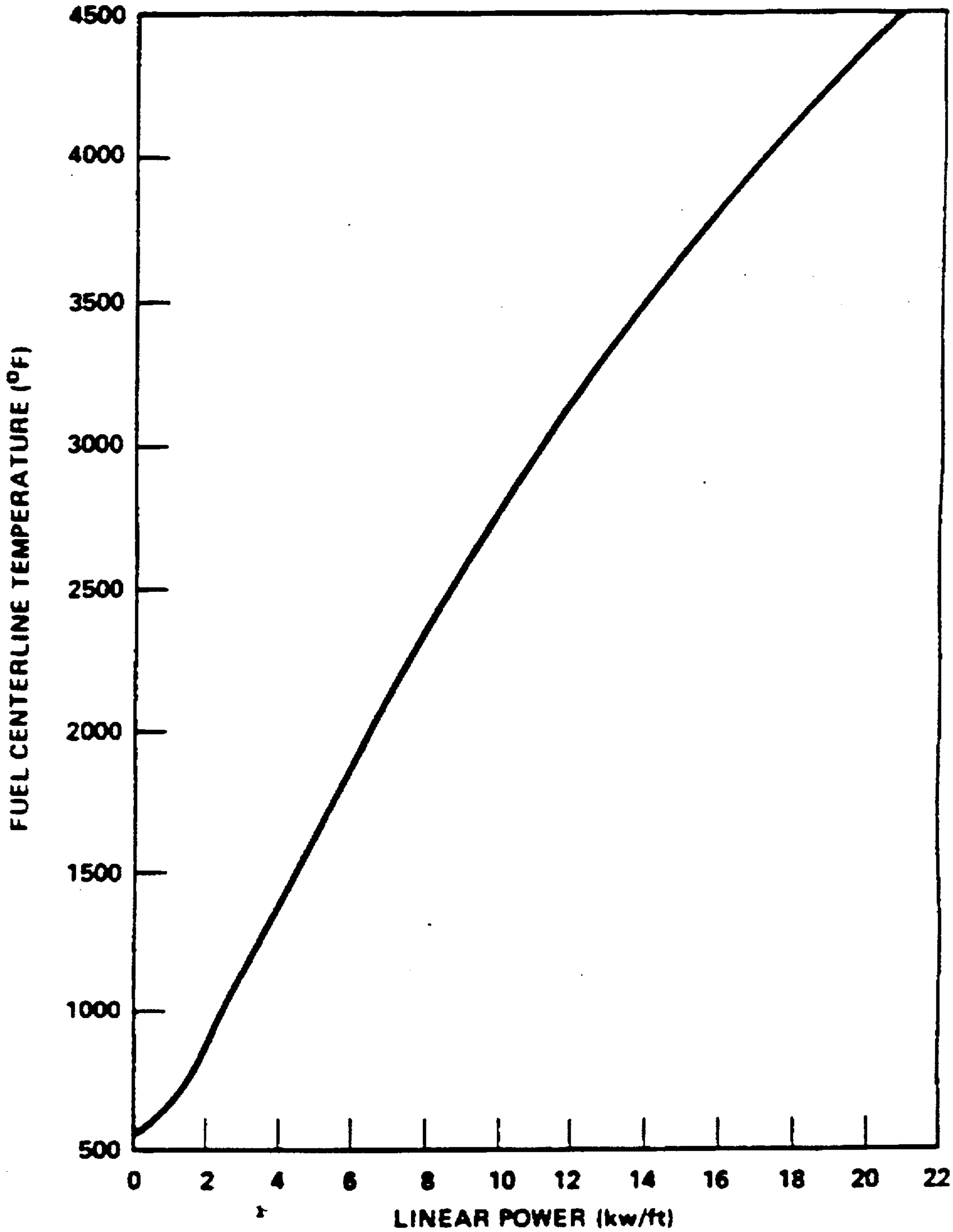
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station PEAK FUEL AVERAGE AND SURFACE TEMPERATURES DURING FUEL ROD LIFETIME VS. LINEAR POWER FOR STANDARD FUEL
	Updated FSAR — Figure 4.4-1



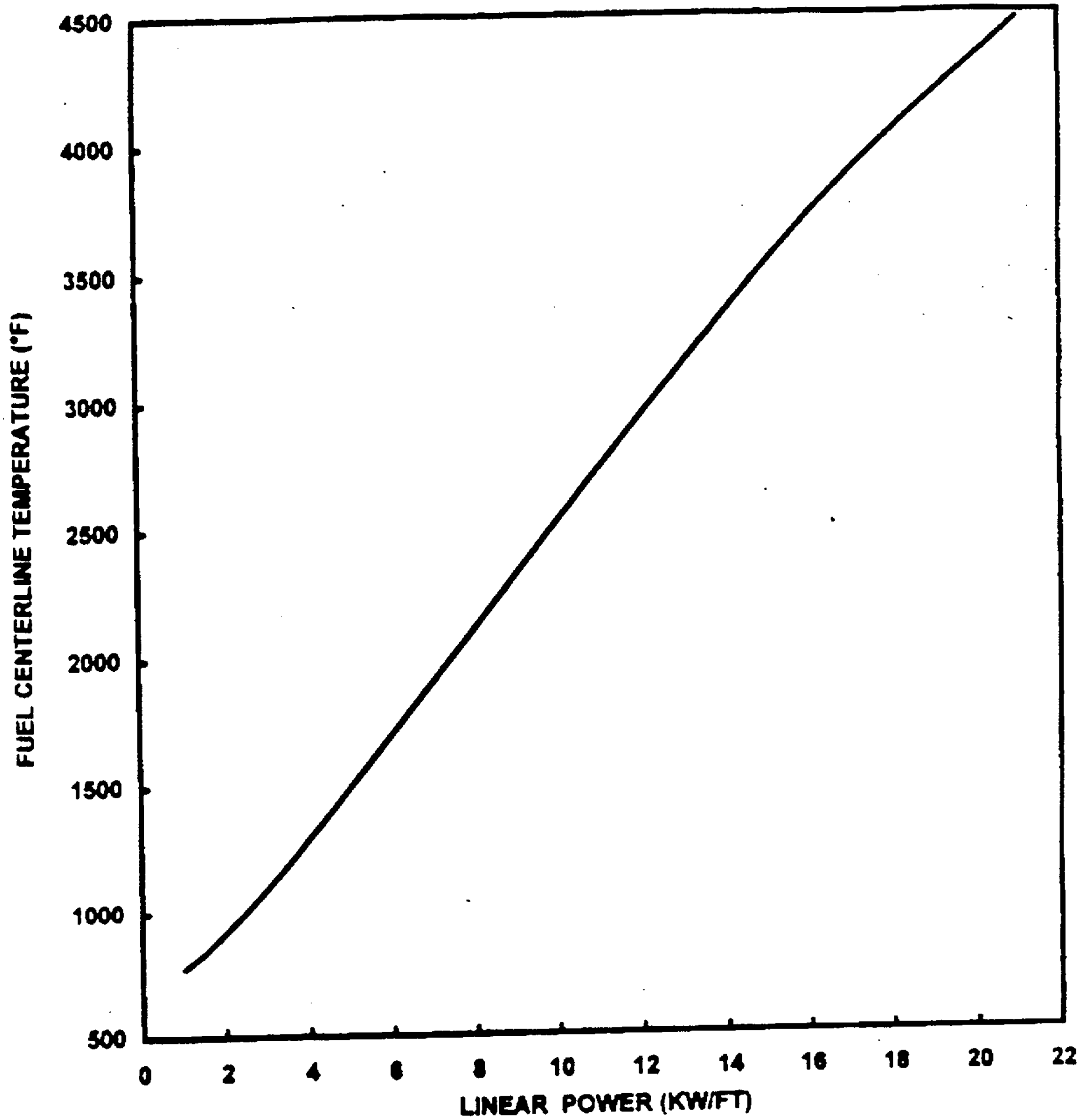
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station PEAK FUEL AVERAGE AND SURFACE TEMPERATURES DURING FEUL ROD LIFETIME VS LINEAR POWER FOR VANTAGE-5H FUEL
	Updated FSAR — Figure 4.4-1A



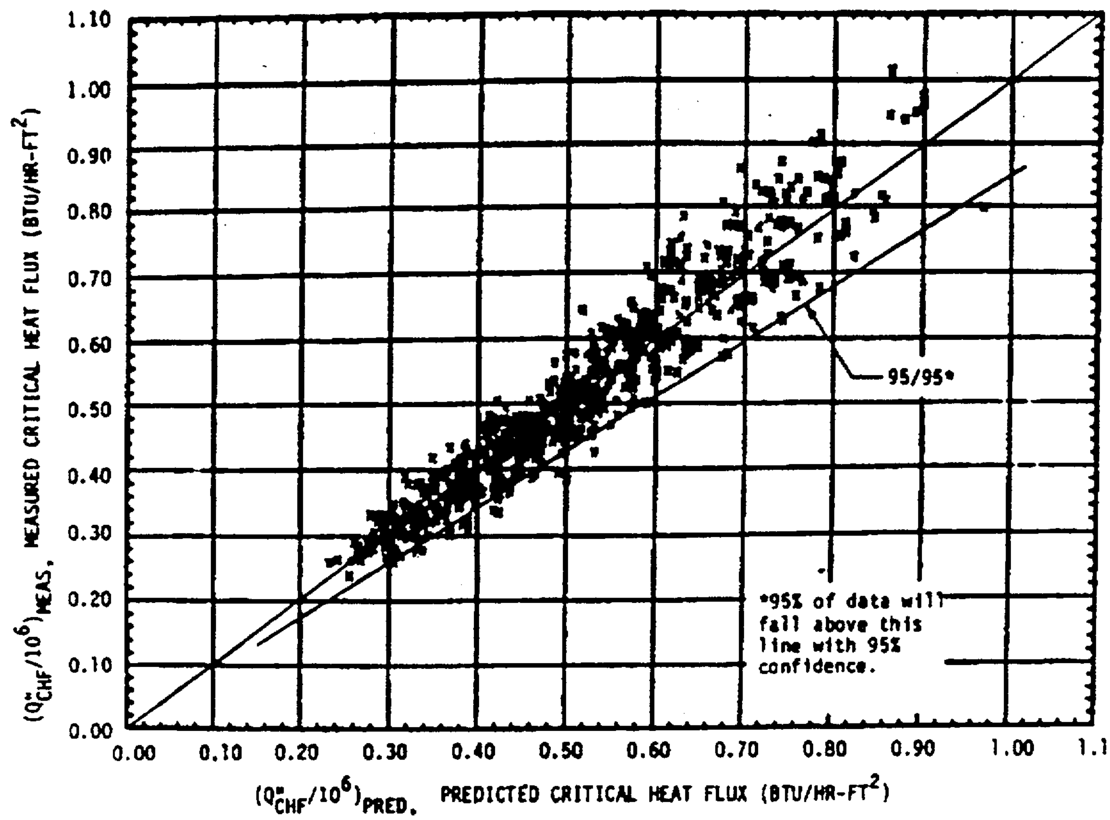
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station PEAK FUEL CENTERLINE TEMPERATURE DURING FUEL ROD LIFETIME VS. LINEAR POWER FOR STANDARD FUEL
	Updated FSAR — Figure 4.4-2



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station PEAK FUEL CENTERLINE TEMPERATURE DURING FUEL ROD LIFETIME VS. LINEAR POWER FOR VANTAGE-5H FUEL
	Updated FSAR Figure 4.4-2A



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station MEASURED VS. PREDICTED CRITICAL HEAT FLUX WRB-2 CORRELATION
	Updated FSAR — Figure 4.4-5C

TABLE 4.5-1

SALEM UNIT 1
RSE, COLR, AND NDR REFERENCE LIST

Cycle	RSE [(1)]	COLR [(2)]	NDR [(3)]
1			NFVD-WW-97012-00 WCAP-8458
2	NFVD-WW-97008-00		NFVD-WW-97017-00/01 WCAP-9497
3			NFVD-WW-97014-00 WCAP-9827
4	NFVD-WW-97009-00		NFVD-WW-97015-00 WCAP-10017
5	NFVD-WW-97010-00		NFVD-WW-97016-00 WCAP-10242
6	NFVD-WW-97011-00		NFVD-WW-97013-00 WCAP-10597
7	NFU-VTDWW 86-004-01		NFU-VTDWW 86-006-003 WCAP-11077
8	NFU-VTDWW 87-014-00		NFU-VTDWW 87-015-00 WCAP-11616
9	NFU-VTDWW 89-028-01		NFU-VTDWW 89-029-00 WCAP-12198
10	NFU-VTDWW 91-042-01		NFU-VTDWW 91-043-00 WCAP-12838
11	NFU-VTDWW 92-064-00		NFU-VTDWW 92-060-00 WCAP-13380
12	NFU-VTDWW 93-073-01		NFU-VTDWW 93-074-00 WCAP-13873
13	NFU-VTDWW 97-018-02	NFS-0163	NFU-VTDWW 97-020-01 WCAP-14997
14	NFVD-WW-99005-02	NFS-0177	NFVD-WW-1999-007-00

(1) PSE&G issued document number. Not available for Cycles 1 and 3.

(2) Prior to Cycle 13, PFLR was issued instead of COLR.

(3) PSE&G issued document number and vendor document number (for cross-reference purposes only).

TABLE 4.5-2

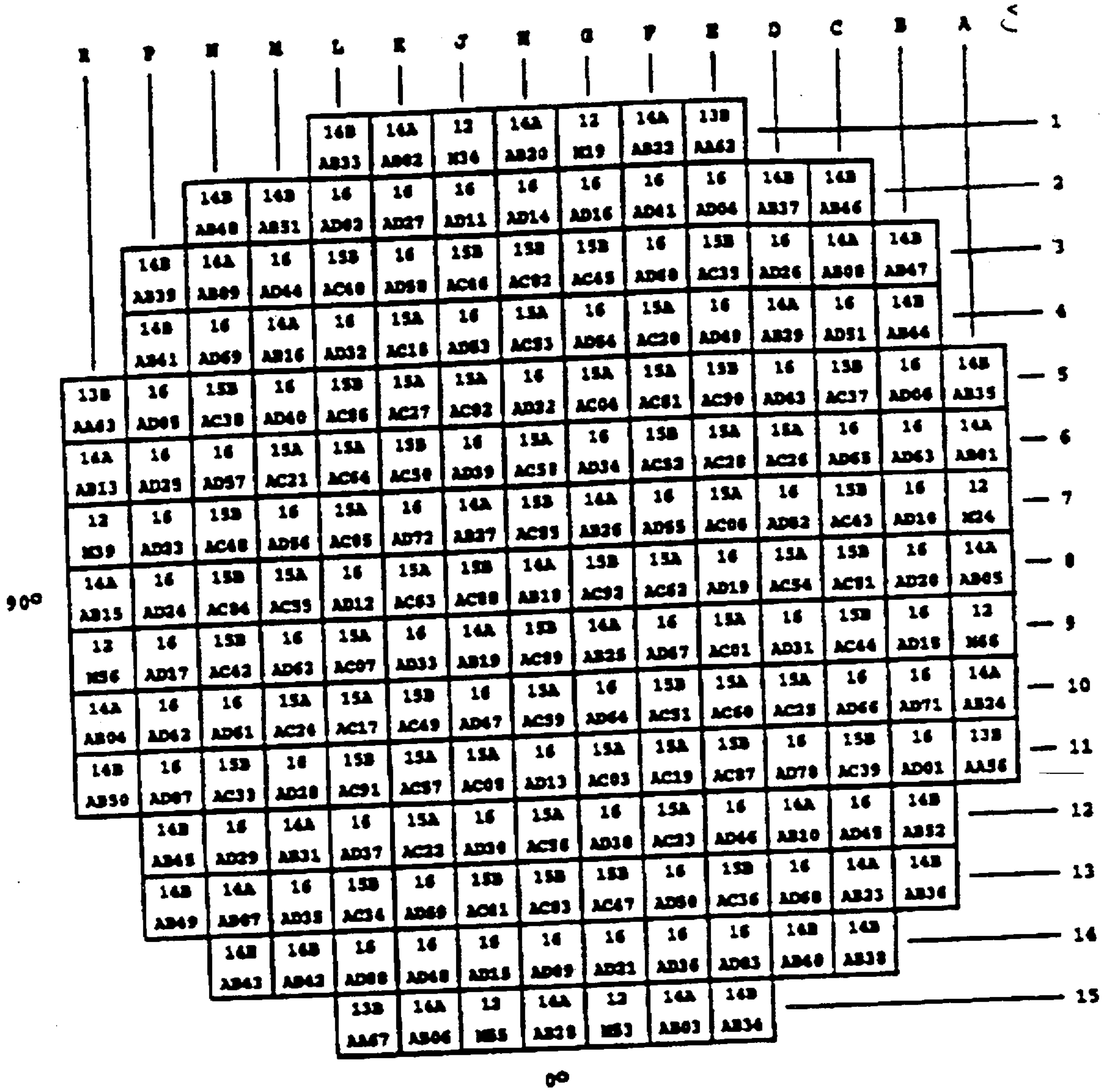
SALEM UNIT 2
RSE, COLR, AND NDR REFERENCE LIST

Cycle	RSE (1)	COLR (2)	NDR (3)
1			NFVD-WW-97005-00 WCAP-9374
2	NFVD-WW-97003-00		NFVD-WW-97006-00 WCAP-10248
3	NFVD-WW-97004-00		NFVD-WW-97007-00 WCAP-10790
4	NFU-VTDWW 86-008-01		NFU-VTWW86-009-00 WCAP-11218
5	NFU-VTDWW 88-022-02		NFU-VTDWW 88-024-00 WCAP-11920
6	NFU-VTDWW 90-034-00		NFU-VTDWW 90-036-00 WCAP-12534
7	NFU-VTDWW 92-059-00		NFU-VTDWW 92-057-00 WCAP-13214
8	NFU-VTDWW 93-068-00		NFU-VTDWW 93-070-00 WCAP-13739
9	NFU-VTDWW 94-100-00		NFU-VTDWW 94-109-00 WCAP-14199
10	NFU-VTDWW 96-151-02		NFUVD-WW 97001-01 WCAP-14669
11	NFVD-WW-99001-01	NFS-0174	NFVD-WW-99003-01

(1) PSE&G issued document number. Not available for Cycle 1.

(2) Prior to Cycle 11, PFLR was issued instead of COLR.

(3) PSE&G issued document number and vendor document number (for cross-reference purposes only).



LEGEND

R	Region Identifier
ID	Fuel Assembly Identifier

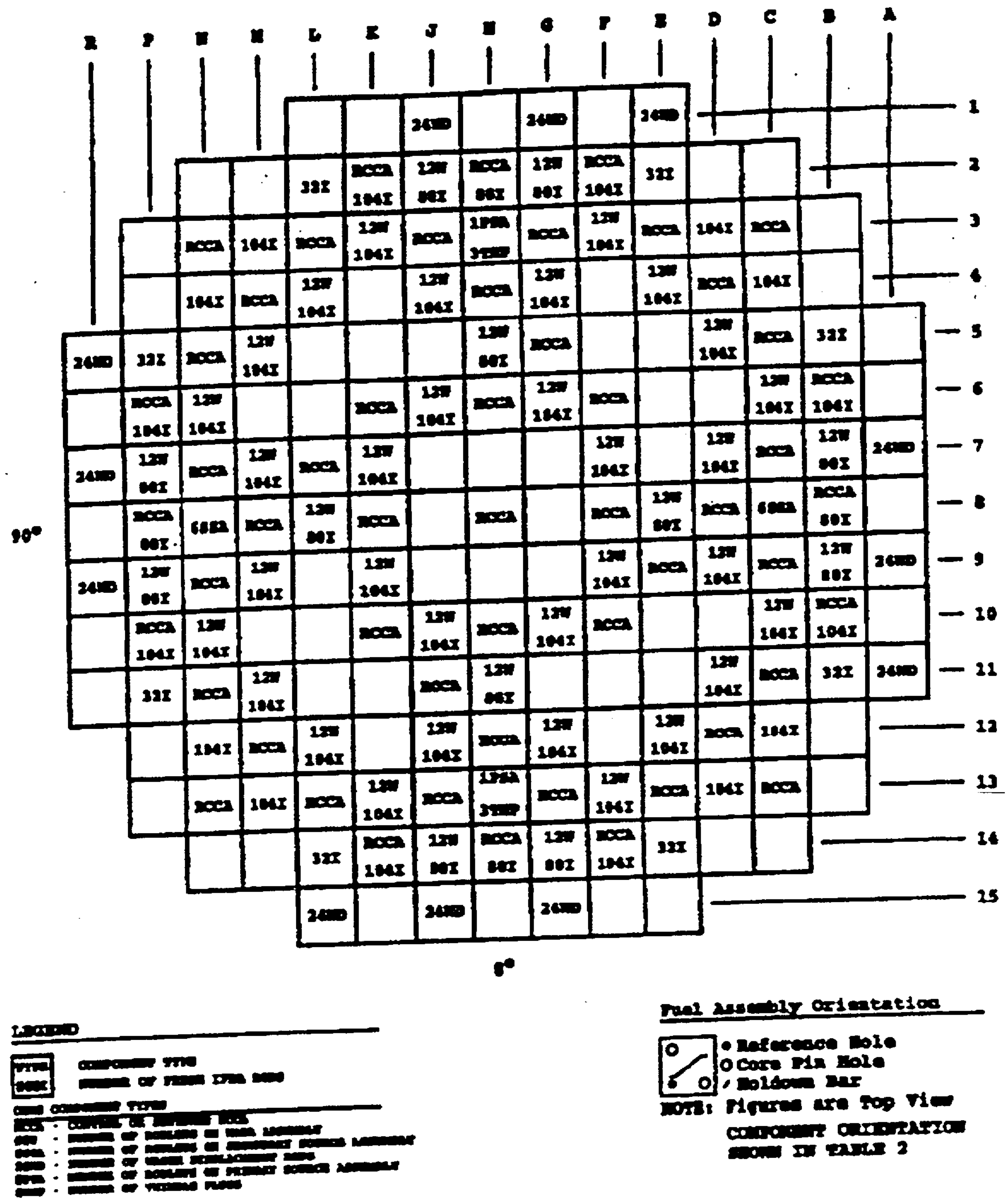
* Reconstituted Assembly

Fuel Assembly Orientation

● Reference Hole
○ Core Pin Hole
/ Holdown Bar
NOTE: Figures are Top View

Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station SALEM UNIT 1 CYCLE 14 LOADING PATTERN
	Updated FSAR Figure 4.5-1



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station SALEM UNIT 1 CYCLE 14 BURNABLE ABSORBER CONFIGURATION
	Updated FSAR — Figure 4.5-2

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1					10B W32	10B W43	11A Y35	11A Y21	11A Y44	10B W36	10B W27				
2			9B V17	11A Y17	13B MM46	13A MM02	13B MM54	13B MM62	13B MM56	13A MM04	13B MM48	11A Y09	10B W53		
3		10B W47	10B W37	13B MM64	11A Y16	13A MM10	15XA AC09	11A Y49	15XA AC15	13A MM12	11A Y05	13B MM65	10B W48	10B W46	
4		11A Y10	13B MM70	11B Y64	13A MM34	11A Y29	13A MM19	15XA AC67	13A MM22	11A Y61	13A MM36	11B Y62	13B MM71	11A Y12	
5	10B W30	13B MM49	11A Y08	13A MM37	15XA AC71	15XB AC74	11B Y54	11A Y28	11B Y56	15XB AC76	15XA AC72	13A MM42	11A Y07	13B MM50	10B W29
6	10B W49	13A MM05	13A MM13	11A Y30	15XB AC77	11A Y02	13A MM24	15XA AC31	13A MM30	11A Y01	15XB AC78	11A Y43	13A MM14	13A MM06	10B W56
7	11A Y33	13B MM57	15XA AC13	13A MM31	11B Y57	13A MM18	11A Y50	13A MM43	11A Y67	13A MM32	11B Y58	13A MM20	15XA AC14	13B MM58	11A Y39
8	11A Y22	13B MM61	11A Y52	15XA AC65	11A Y04	15XA AC32	13A MM33	10A W24	13A MM44	15XA AC29	11A Y03	15XA AC68	11A Y48	13B MM72	11A Y15
9	11A Y32	13B MM59	15XA AC16	13A MM27	11B Y59	13A MM28	11A Y46	13A MM35	11A Y51	13A MM25	11B Y53	13A MM26	15XA AC11	13B MM53	11A Y42
10	10B W42	13A MM07	13A MM15	11A Y38	15XB AC79	11A Y11	13A MM21	15XA AC30	13A MM23	11A Y18	15XB AC73	11A Y37	13A MM09	13A MM01	10B W51
11	10B W25	13B MM51	11A Y13	13A MM40	15XA AC69	15XB AC80	11B Y60	11A Y27	11B Y55	15XB AC75	15XA AC70	13A MM41	11A Y14	13B MM45	10B W31
12		11A Y06	13B MM63	11B Y63	13A MM38	11A Y31	13A MM17	15XA AC66	13A MM29	11A Y34	13A MM39	11B Y61	13B MM68	11A Y26	
13		10B W50	10B W40	13B MM69	11A Y19	13A MM16	15XA AC12	11A Y65	15XA AC10	13A MM11	11A Y24	13B MM66	10B W55	10B W33	
14			10B W52	11A Y20	13B MM52	13A MM08	13B MM60	13B MM67	13B MM55	13A MM03	13B MM47	11A Y25	9B V24		
15					10B W26	10B W38	11A Y40	11A Y23	11A Y36	10B W41	10B W28				

90°

0°

LEGEND

R
ID

R: Region Identifier
ID: Fuel Assembly Identifier

Fuel Assembly Orientation

• Reference Hole
○ Core Pin Hole
/ Holdown Bar

NOTE: Figures are Top View

Revision 18, April 26, 2000

PSEG Nuclear, LLC
SALEM NUCLEAR GENERATING STATION

Salem Nuclear Generating Station
SALEM UNIT 2 CYCLE 11 LOADING PATTERN

Updated FSAR

Figure 4.5-3

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1					24WD	24WD				24WD	24WD				
2			24WD		32I	104I	8P 80I	104I	8P 80I	104I	32I		24WD		
3		24WD	24WD	104I		12P 104I		4SSA		12P 104I		104I	24WD	24WD	
4			104I		8P 128I		4P 128I		4P 128I		8P 128I		104I		
5	24WD	32I		8P 128I								8P 128I		32I	24WD
6	24WD	104I	12P 104I				4P 128I		4P 128I				12P 104I	104I	24WD
7		8P 80I		4P 128I		4P 128I		8P 128I		4P 128I		4P 128I		8P 80I	
8 (90°)		104I					8P 128I		8P 128I					104I	
9		8P 80I		4P 128I		4P 128I		8P 128I		4P 128I		4P 128I		8P 80I	
10	24WD	104I	12P 104I				4P 128I		4P 128I				12P 104I	104I	24WD
11	24WD	32I		8P 128I								8P 128I		32I	24WD
12			104I		8P 128I		4P 128I		4P 128I		8P 128I		104I		
13		24WD	24WD	104I		12P 104I		4SSA		12P 104I		104I	24WD	24WD	
14			24WD		32I	104I	8P 80I	104I	8P 80I	104I	32I		24WD		
15					24WD	24WD				24WD	24WD				

0°

TYPE	TOTAL
#P...(NUMBER OF PYREX RODLETS)..............	320
#I...(TOTAL NUMBER OF FRESH IFBA RODS)......	7392
#WD..(NUMBER OF WATER DISPLACEMENT RODS)....	672
#SSA..(NUMBER OF SECONDARY SOURCE RODLETS)...	8

Revision 18, April 26, 2000

PSEG Nuclear, LLC

SALEM NUCLEAR GENERATING STATION

Salem Nuclear Generating Station
SALEM UNIT 2 CYCLE 11 BURNABLE ABSORBER CONFIGURATION

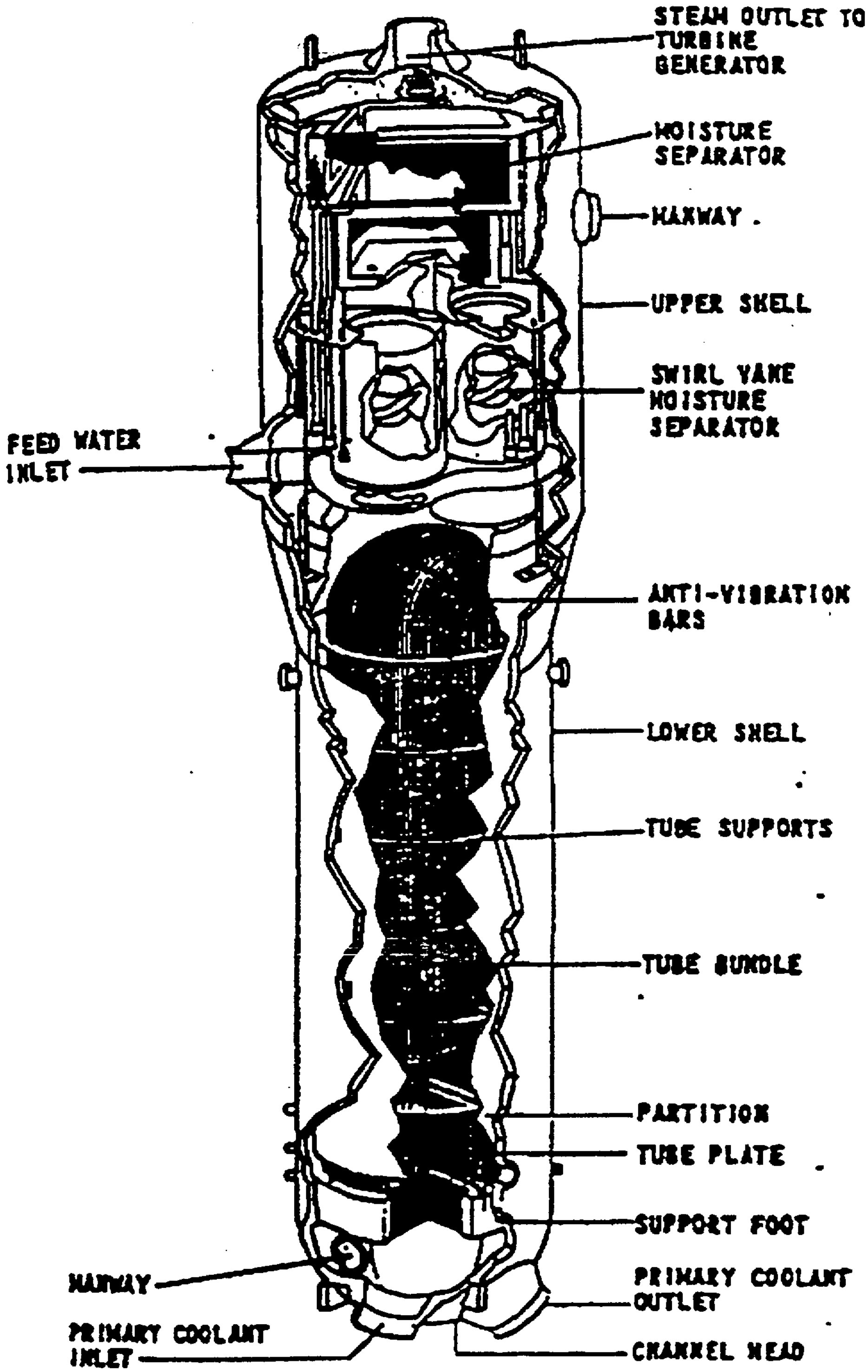
Updated FSAR

Figure 4.5-4

TABLE 5.1-1

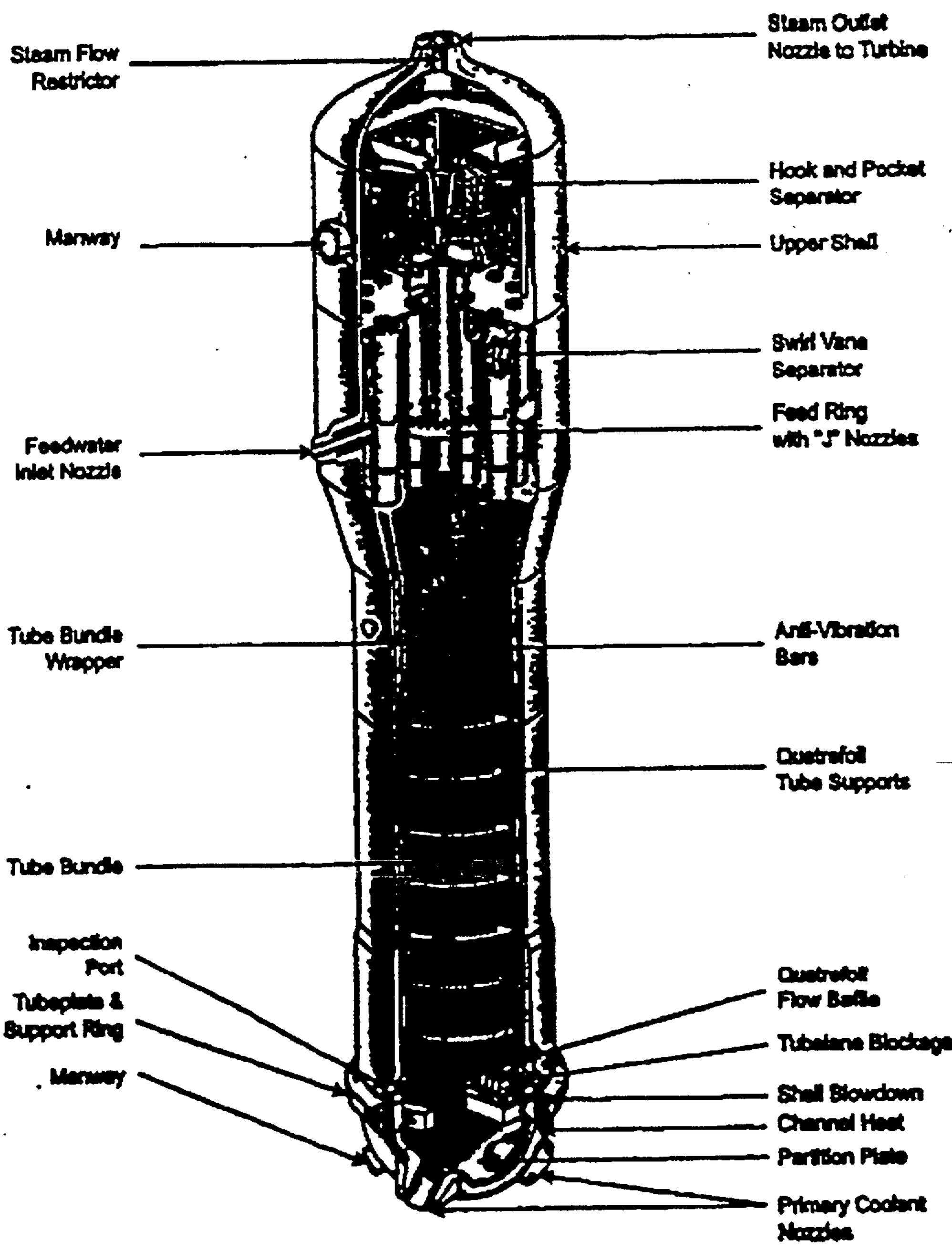
SYSTEM DESIGN AND OPERATING PARAMETERS

Plant design life, years	40
Number of heat transfer loops	4
Design pressure, psig	2485
Nominal operating pressure, psig	2235
Total system volume including pressurizer and surge line (ambient conditions), ft^3	12,076 (Unit 1) 12,612 (Unit 2)
System liquid volume, including pressurizer and surge line (ambient conditions), ft^3	11,356 (Unit 1) 11,892 (Unit 2)
Total heat output (100 percent power), Btu/hr	$11,680 \times 10^6$
Reactor vessel coolant temperature at full power:	
Inlet, nominal, °F	545.0
Outlet, °F	610.2
Coolant temperature rise in vessel at full power, avg, °F	65.2
Total coolant flow rate, lb/hr	132.2×10^6 (Unit 1) 130.9×10^6 (Unit 2)
Steam pressure at full power, psia	829 (Unit 1) 805 (Unit 2)



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station STEAM GENERATOR UNIT 2 ONLY
	Updated FSAR — Figure 5.1-3



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station STEAM GENERATOR (UNIT 1)
	Updated FSAR — Figure 5.1-3A

TABLE 5.2-2

REACTOR COOLANT SYSTEM DESIGN PRESSURE DROP

	Pressure Drop, psi (estimated)
Unit 2	
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
Unit 1	
Across Pump Discharge Leg	1.5
Across Vessel, Including Nozzles	52.0
Across Hot Leg	1.9
Across Steam Generator	35.67
Across Pump Suction Leg	1.8
Total Pressure Drop	92.87

TABLE 5.2-3 (Cont.)

Lower Head Thickness, min., in. (base metal)	5-3/8
Vessel Belt-Line Thickness, min., in. (base metal)	8.5
Closure Heat Thickness, in.	7
Reactor Coolant Inlet Temperature, °F	545.0
Reactor Coolant Outlet Temperature, °F	610.2
Reactor Coolant Flow, lb/hr	132.2×10^6 (Unit 1) 130.9×10^6 (Unit 2)
Total Water Volume Below Core, ft^3	1050
Water Volume in Active Core Region, ft^3	665
Total Water Volume to Top of Core, ft^3	2164
Total Water Volume to Coolant Piping Nozzles Centerline, ft^3	2959
Total Reactor Vessel Water Volume, (with core and internals in place), ft^3	4945
Total Reactor Coolant System Volume, ft^3	12,076 (Unit 1)
Total Reactor Coolant System Volume, ft^3	12,612 (Unit 2)

TABLE 5.2-5

STEAM GENERATOR DESIGN DATA*
(Model 51) - Unit 2 Only

Number of Steam Generators	4
Design Pressure (Reactor coolant/steam), psig	2485/1085
Reactor Coolant Hydrostatic Test Pressure (tube side-cold), psig	3107
Design Temperature (reactor coolant/steam), °F	650/600
Reactor Coolant Flow, lb/hr	33.05×10^6
Total Heat Transfer Surface Area, ft^2	51,500
Heat Transferred, Btu/hr	2920×10^6
Steam Conditions at Full Load, Outlet Nozzle:	
Steam Flow, lb/hr	3.74×10^6
Steam Temperature, °F	519
Steam Pressure, PSIA	805
Maximum Moisture Carryover, wt percent	0.25
Feedwater, °F	435
Overall Height, ft-in.	67-8
Shell OD (upper/lower), in.	175-3/4 / 135
Number of U-tubes	3388
U-tube OD, in.	0.875
Tube Wall Thickness (minimum), in.	0.050
Number of Manways/ID, in.	4/16
Number of handholes/ID, in.	2/6

*Quantities are for each steam generator

TABLE 5.2-5 (Cont)

STEAM GENERATOR DESIGN DATA*
(Model 51) - Unit 2 Only

	Rated Load	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 5.2-5a

STEAM GENERATOR DESIGN DATA*
(Model F) - Unit 1 Only

Number of Steam Generators	4
Design Pressure (Reactor coolant/steam), psig	2485/1185
Reactor Coolant Hydrostatic Test Pressure (tube side-cold), psig	3107
Design Temperature (reactor coolant/steam), °F	650/600
Reactor Coolant Flow, lb/hr	35.5×10^6
Total Heat Transfer Surface Area, ft^2	55,050
Heat Transferred, Btu/hr	2922×10^6
Steam Conditions at Full Load, Outlet Nozzle:	
Steam Flow, lb/hr	3.73×10^6
Steam Temperature, °F	544.6
Steam Pressure, PSIA	1000
Maximum Moisture Carryover, wt percent	0.25
Feedwater, °F	440
Overall Height, ft-in.	67-8
Shell OD (upper/lower), in.	176.25 / 135.42
Number of U-tubes	5626
U-tube OD, in.	0.688
Tube Wall Thickness (minimum), in.	0.041
Number of Inspection Openings/ID, in.	4/2.7
Number of Manways/ID, in.	4/16
Number of handholes/ID, in.	6/6
Reactor coolant Volume, ft^3 (Rated Load)	966.1
Reactor coolant Volume, ft^3 (No Load)	966.1

*Quantities are for each steam generator

TABLE 5.2-8 (Cont.)

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

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 5.2-9A

UNIT 1 REACTOR COOLANT SYSTEM - CODES

Component	Code	Date & Addenda	Code Cases
Reactor Vessel	ASME III	1965 & all thru Winter 1965	All applicable in effect prior to 4/26/66
Steam Generator*	ASME III	1971 & all thru Summer 1973	All applicable in effect prior to 1971, 1484-3, 1528-3 & N474-1
P/L CRDMs	ASME III	1968 (no addenda)	1337-2
F/L CRDMs	ASME III	1965 & all thru Summer 1966	--
RC Pump	No Code	(Design per ASME III, Article 4)	--
Pressurizer	ASME III	1965 & all thru Winter 1966	All applicable in effect at the time
Przr Relief Tank	ASME III	1968 & all thru Summer 1968	All applicable in effect at the time
Przr Safety Valves	ASME III	1968 & all thru Summer 1968	--
RC Piping	ASA B31.1	1955	Applicable portions of ASA N-7 and N-10

TABLE 5.2-9A

UNIT 1 REACTOR COOLANT SYSTEM - CODES

Component	Code	Date & Addenda	Code Cases
Sys Ppg & Fittings	ASA B31.1	1955	Applicable portions of ASA N-7 and N-10
System Valves	ASA B16.5, or	1964	Applicable portions of N-10
	MSS-SP-66, or	1964	--
	ASME III	1968	--

* The steam generators were procured and installed in accordance with NRC GL 89-09 to meet ASME III Section III Class 1 requirements. Lower narrow range level taps conform to 1989 ASME Section III Class 1 reconciled to the original construction code. The tube side and the shell side conform to the requirements of ASME Section III for Class 1 vessels. The steam generators were NPT stamped by the manufacturer prior to hydrostatic testing. The tube side and the shell side were subsequently hydrostatic pressure tested prior to installation at Unit 1. The primary piping to steam generator primary inlet and outlet welds conform to the requirements of the 1989 Edition of the ASME Code Section III for Class 1 piping. Applicable Code Cases are N-416-1 and N-389.

TABLE 5.2-10

DESIGN THERMAL AND LOADING CYCLES*
Series 51 SG - Unit 2

		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
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

TABLE 5.2-10 (Cont)

DESIGN THERMAL AND LOADING CYCLES*
Series 51 SG - Unit 2

		Design Cycles**
13.	Steady State Fluctuations - the reactor 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

* The ASME Section III Nuclear Power Plant Components Code is inapplicable to the Salem Station; 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 5.2-10a

DESIGN THERMAL AND LOADING CYCLES*
Model F SG - Unit 1

		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	13,200***
	Unit Unloading at 5 Percent of Full Power/Min	13,200***
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
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

TABLE 5.2-10a (Cont)

DESIGN THERMAL AND LOADING CYCLES*
Model F SG - Unit 1

		Design Cycles**
13.	Steady State Fluctuations - the reactor 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

* The ASME Section III Nuclear Power Plant Components Code is inapplicable to the Salem Station; 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.

*** Model F steam generators on Unit 1 are designed to 13,200 cycles.

TABLE 5.2-16

STRESS DUE TO MAXIMUM STEAM GENERATOR TUBE SHEET PRESSURE DIFFERENTIAL (2485 PSIG)
Series 51 SG - Unit 2

Stress	(660°F) Computed Value	Allowable Value
Primary Membrane Stress	24,356 psi	37,000 psi ($.9\ S_y$)
Primary Membrane plus Primary Bending Stress	54,946 psi	55,600 psi ($1.35\ S_y$)

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
Series 51 SG - Unit 2

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
Series 51 SG - Unit 2

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 Limit Outer Surface Stress
7	Jct of Short	3 S_m	80,100	-10,063 psi
	Cyl with	S_m	26,700	+ 8,597 psi
	Tubesheet	3 S_m	80,100	+27,247 psi
8	1/2 Through	3 S_m	80,100	+ 9,514 psi
	Short Cyl	S_m	26,700	+ 8,597 psi
	Discontinuity	3 S_m	80,100	+ 7,670 psi
9	Jct of Short	3 S_m	80,100	+10,740 psi
	Cyl with	S_m	26,700	+ 8,597 psi
	Shell	3 S_m	80,100	6,443 psi
10	On Shell	3 S_m	80,100	+10,269 psi
		S_m	26,700	+ 8,597 psi
		3 S_m	80,100	+ 6,912 psi
11	On Shell	3 S_m	80,100	+ 9,746 psi
		S_m	26,700	+ 8,597 psi
		3 S_m	80,100	+ 7,435 psi
12	Jct of Pri	3 S_m	80,100	+58,701 psi
	Short Cyl with	S_m	26,700	+14,518 psi
	Tube Plate	3 S_m	80,100	-29,646 psi

TABLE 5.2-19

STEAM GENERATOR PRIMARY-SECONDARY COMPONENTS
Series 51 SG - Unit 2

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	$0.9\ S_y$	45,000	0 psi
8	1/2 Through Short Cyl Discontinuity	$0.9\ S_y$	45,000	0 psi
9	Jct of Short Cyl With Shell	$0.9\ S_y$	45,000	0 psi
10	On Shell	$0.9\ S_y$	45,000	0 psi
11	On Shell	$0.9\ S_y$	45,000	0 psi
12	Jct of PRI Short Cyl With Tube Plate	$0.9\ S_y$	45,000	18,158 psi
13	1/2 Through Prim Short Cyl Discon.	$0.9\ S_y$	45,000	18,158 psi
14	Jct of PRI Short Cyl With Head	$0.9\ S_y$	45,000	18,158 psi

TABLE 5.2-20

STEAM GENERATOR PRIMARY-SECONDARY BOUNDARY COMPONENTS
Series 51 SG - Unit 2

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	$0.9\ S_y$	45,000	13,169 psi
8	1/2 Through Short Cyl Discontinuity	$0.9\ S_y$	45,000	13,169 psi
9	Jct of Short Cyl with Shell	$0.9\ S_y$	45,000	13,169 psi
10	On Shell	$0.9\ S_y$	45,000	13,169 psi
11	On Shell	$0.9\ S_y$	45,000	13,169 psi
10	Jct of Pri Short Cyl With Tube Plate	$0.9\ S_y$	36,000	0 psi
11	1/2 Through Prim Short Cyl Discon.	$0.9\ S_y$	36,000	0 psi
12	Jct of Pri Short Cyl With Head	$0.9\ S_y$	36,000	0 psi

TABLE 5.2-21

STEAM GENERATOR PRIMARY - SECONDARY BOUNDARY COMPONENTS
Series 51 SG - Unit 2

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 5.2-24
TUBE SHEET STRESS ANALYSIS RESULTS
FOR 51,500 SQ. FT. STEAM GENERATORS
Series 51 SG - Unit 2

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 Indicates 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 5.2-26
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		
1.6.7a	Instrument Connections (Unit 2) (primary and secondary).				yes	
1.6.7b	Instrument Connections (Unit 1) (secondary) for lower NR level taps. No primary connections.	yes		yes	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 (weld deposit)	yes		yes		
2.	Pressurizer					
2.1	Heads					
2.1.1	Casting	yes			yes	
2.1.2	Cladding			yes		

TABLE 5.2-26 (Cont)

Component		RT*	UT*	PT*	MT*	ET*
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		
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			

TABLE 5.2-27

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 Rods	Type 308, 309, or 312
	O-Ring Head Seals	Inconel - 718
	CRDM Housings	SA-183 Type 304
	Lower Tube	SB-167
	Studs	SA-540 Grade B-23
	Instrumentation Nozzles	Inconel SB 167
	Insulation	Stainless Steel
Steam Generator Unit 2 - Series 51	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, 3081,or 309
	Cladding for Tube Sheets	Inconel
	Tubes	Inconel - 600
	Channel Head Castings	ASTM A-216 Grade WCC
Steam Generator Unit 1 - Model F	Shell Material	SA-533 Class 2
	Forgings	SA-508 Class 2a
	Cladding for Heads,	Type 308 or 309 SS
	Stainless Weld Rod	Type 308L or 309L
	Cladding for Tube Sheets	Inconel
	Tubes	Inconel SB-163, Code Case 1484-3
	Channel Head Castings	SA-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
	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.
Dissolved Oxygen*, ppm, max.	0.10 (Steady State) 1.00 (Transient)
Chloride, ppm, max	0.15 (Steady State) 1.50 (Transient)
Fluoride, ppm, max.	0.15 (Steady State) 1.50 (Transient)
Hydrogen, cc (STP)/kg H_2O	25-50
Total Suspended Solids, ppm, max.	1.0
pH Control Agent (Li^7OH)	Up to 2.35 mg/ℓ Li7, in accordance with Station Lithium Program
Boric Acid as ppm B	Variable from 0 to ~4000

*Limit not applicable with $T_{avg} \leq 250°F$

TABLE 5.2-33

STRESS RESULTS OF UNIT 1 TUBESHEET AND SHELL JUNCTIONS ANALYSIS

MODEL F SG

Thin Cast Head Model

	LOCATION (1)				
	1	3	4	6	7
CONDITION:					
Design	0.11 (2) 1.0 (4)(7)	0.41 (3) -	0.43 (3) -	0.40 (3) -	0.28 (2) 0.61 (4)
Normal and Upset Fatigue Usage	(6) <0.71	0.97 (5) <0.38	(6) <0.41	0.71 (5) <0.25	0.65 (5) <0.25
Emergency	0.05 (2) 0.72 (4)	0.28 (3) -	0.51 (3) -	0.23 (3) -	0.10 (2) 0.25 (4)
Faulted	0.03 (2) 0.77 (4)	0.27 (3) -	0.34 (3) -	0.33 (3) -	0.14 (2) 0.61 (4)
Test	0.07 (2) 0.95 (4)	0.37 (3) -	0.65 (3) -	0.29 (3) -	0.08 (2) 0.23 (4)

Notes:
(1) See Figure 5.2-22

(2) P_M/Allowable

(3) P_L/Allowable

(4) $(P_L + P_b)$/Allowable

(5) $(P_L + P_b + Q)$/Allowable

TABLE 5.2-33 (Cont)

Notes (Cont):

(6) The $3S_M$ limit on $P_L + P_b + Q$ stress intensity range was exceeded. However, the provisions of Paragraph NB-3228.3 (Simplified elastic-plastic analysis) of Reference 1 were satisfied.

(7) Satisfied 2/3 the lower bound collapse load of NB-3228.2 of Reference 1.

TABLE 5.2-34

UNIT 1 SECONDARY SHELL AND TRANSITION CONE STRESS RESULTS

MODEL F SG

SECTIONS (Figure 5.2-23)

CONDITION:		A-A	B-B	C-C	D-D	E-E	p + d[1]
Design		0.94[2]	0.33[3]	0.94[2]	0.78[3] 0.76[5]	0.94[2]	0.72[4] 0.64[5]
Normal &[6] Upset	Inside	0.41	0.47	0.68	0.78	0.71	-
	Outside	0.44	0.57	0.85	(7)	0.87	0.87
Fatigue	Inside	<0.01	<0.03	<0.01	<0.03	<0.01	<0.03
	Outside	<0.01	<0.01	<0.01	<0.02	<0.01	-
Emergency		0.48[2]	0.17[3]	0.47[2]	0.40[3]	0.48[2]	-
Faulted		0.47[2]	0.16[3]	0.47[2]	0.39[3] 0.77[5]	0.47[2]	0.88[4] 0.76[5]
Test		0.63[2]	0.22[3]	0.63[2]	0.53[3]	0.63[2]	-

Notes: (1) At Upper Lateral Load Pad location. Not shown in Figure 5.2-23.

(2) P_M/Allowable

(3) P_L/Allowable

(4) $(P_M + P_b)$/Allowable

(5) $(P_L + P_b)$/Allowable

(6) $(P_L + P_b + Q)$/Allowable

(7) The maximum primary + secondary stress intensity range exceeds the allowable stress limit. Therefore, a simplified elastic-plastic analysis was performed. This analysis is reflected in the cumulative usage factor calculations.

TABLE 5.2-35

UNIT 1 STRESS RESULTS OF TUBE ANALYSIS

MODEL F SG

CONDITION:	LOCATION[1] A-A	B-B	C-C	D-D	E-E
Design	0.60[2]	0.62[2]	0.88[3]	0.997[3]	0.60[2]
Normal/Upset	0.96	0.92[4]	0.85[4]	0.67[4]	0.84
Fatigue Usage	0.88	0.53	0.46	0.22	0.22
Emergency	0.67[2]	0.69[2]	0.74[2]	0.80[2]	0.67[2]
Faulted (LOCA + SSE)	0.17[2]	0.17[2]	0.99[3]	0.96[3]	0.17[2]
Faulted (FLB + SSE)	0.47[2]	0.48[2]	0.51[3]	0.55[3]	0.47[2]
Test	0.91[2]	0.94[2]	0.99[2]	0.68[2]	0.91[2]

Notes: (1) See Figure 5.2-24

(2) P_M/Allowable

(3) $(P_M + P_b)$/Allowable

(4) $(P_L + P_b + Q)$/Allowable

Table 5.2-36

UNIT 1 TUBE ANALYSIS FOR EXTERNAL PRESSURE

MODEL F SG

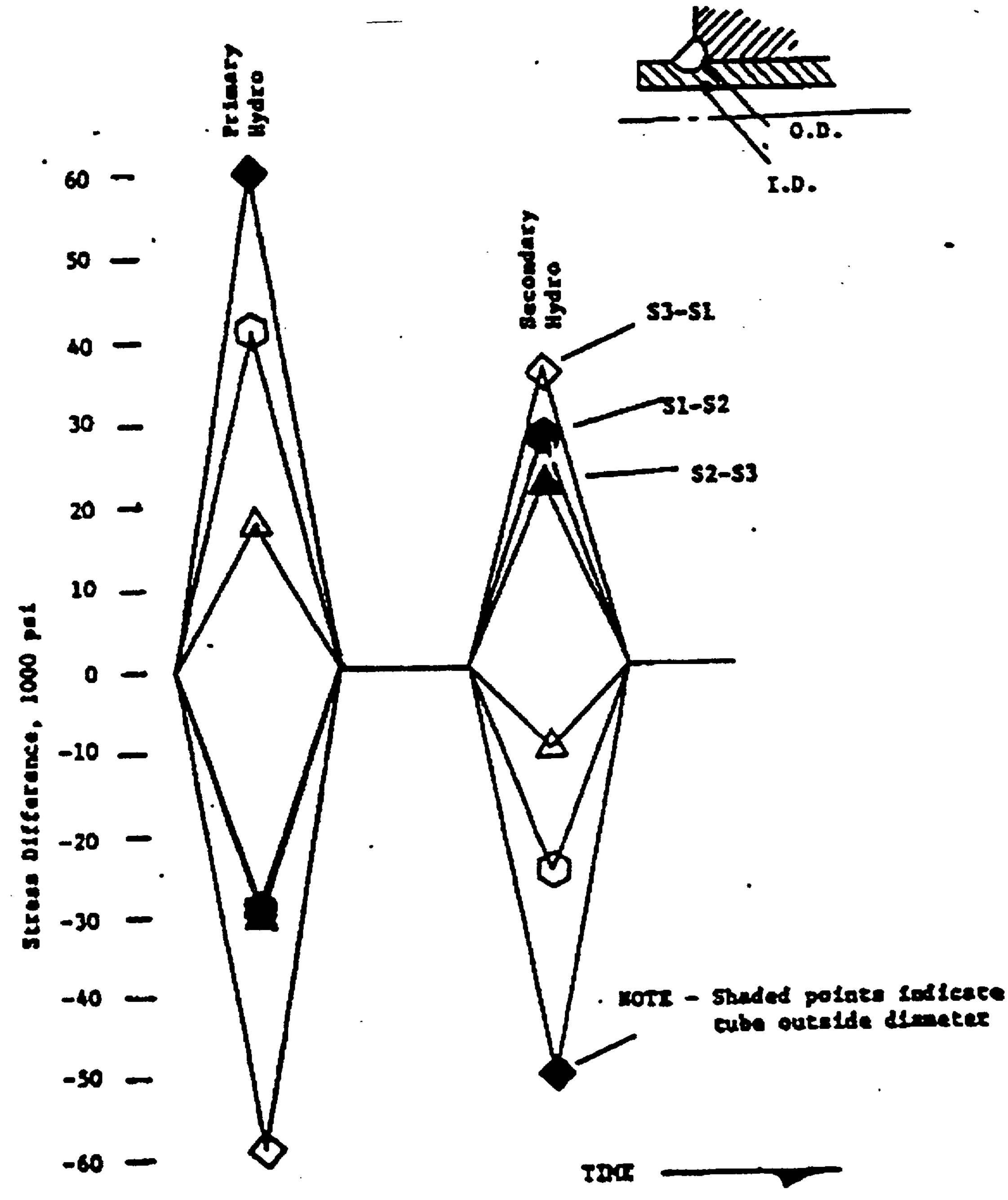
CONDITION	σ_y (ksi)	Actual ΔP (psi)	Criteria Used	Allowable Pressure Differential, psi at these Sections[1] A-A	B-B	C-C	D-D	E-E
Design	-	670	P_a	780	780	780	780	780
Emergency	-	537[2]	$1.2P_a$	936	936	936	936	936
Faulted	35.3	985[3]	$0.9P_c$	2602	2523	2424	1531	2602
Test	38.9	1481[4]	$0.8P_c$	2549	2471	2374	1500	2549

Notes: (1) See Figure 5.2-24

(2) Small LOCA

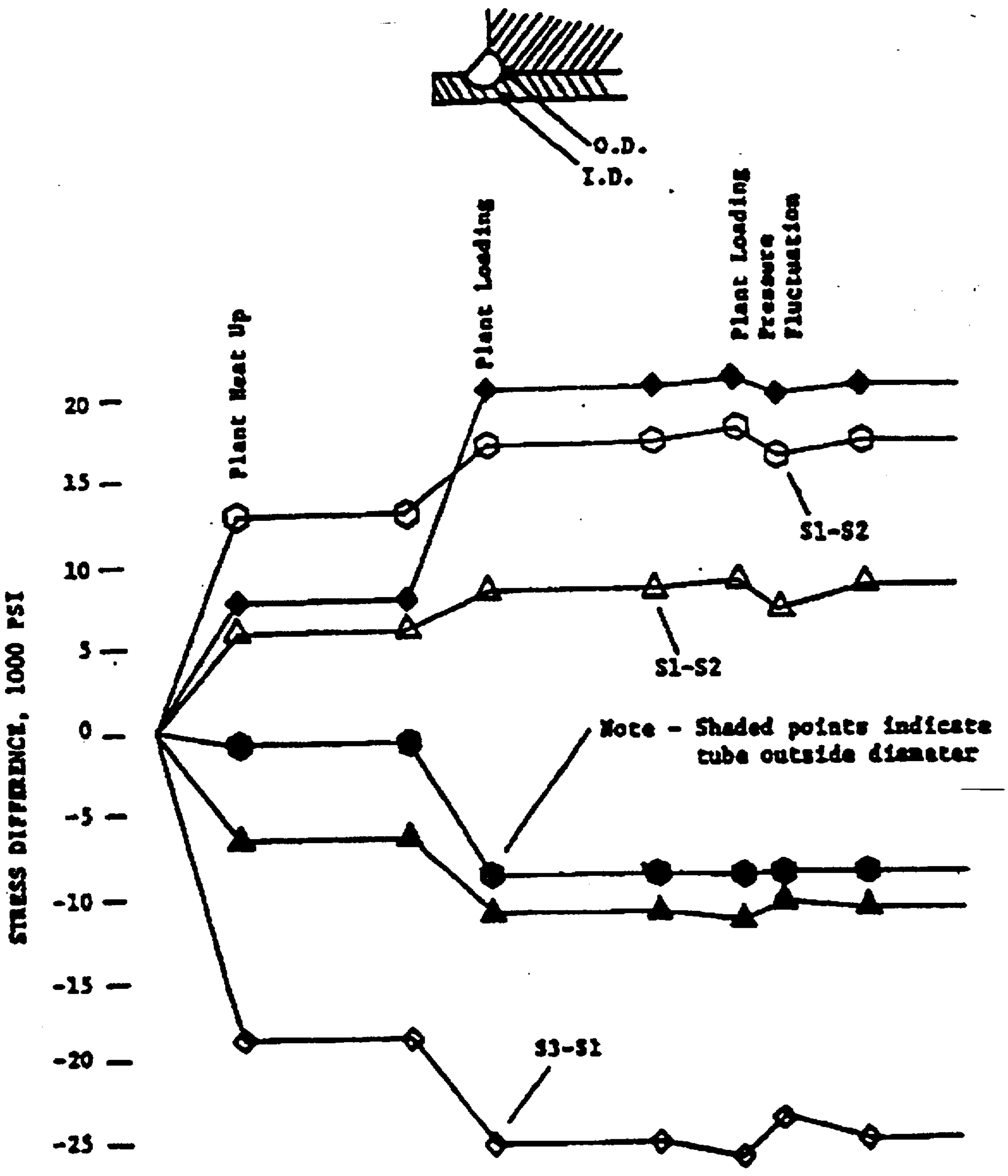
(3) Large LOCA

(4) Secondary Hydrotest



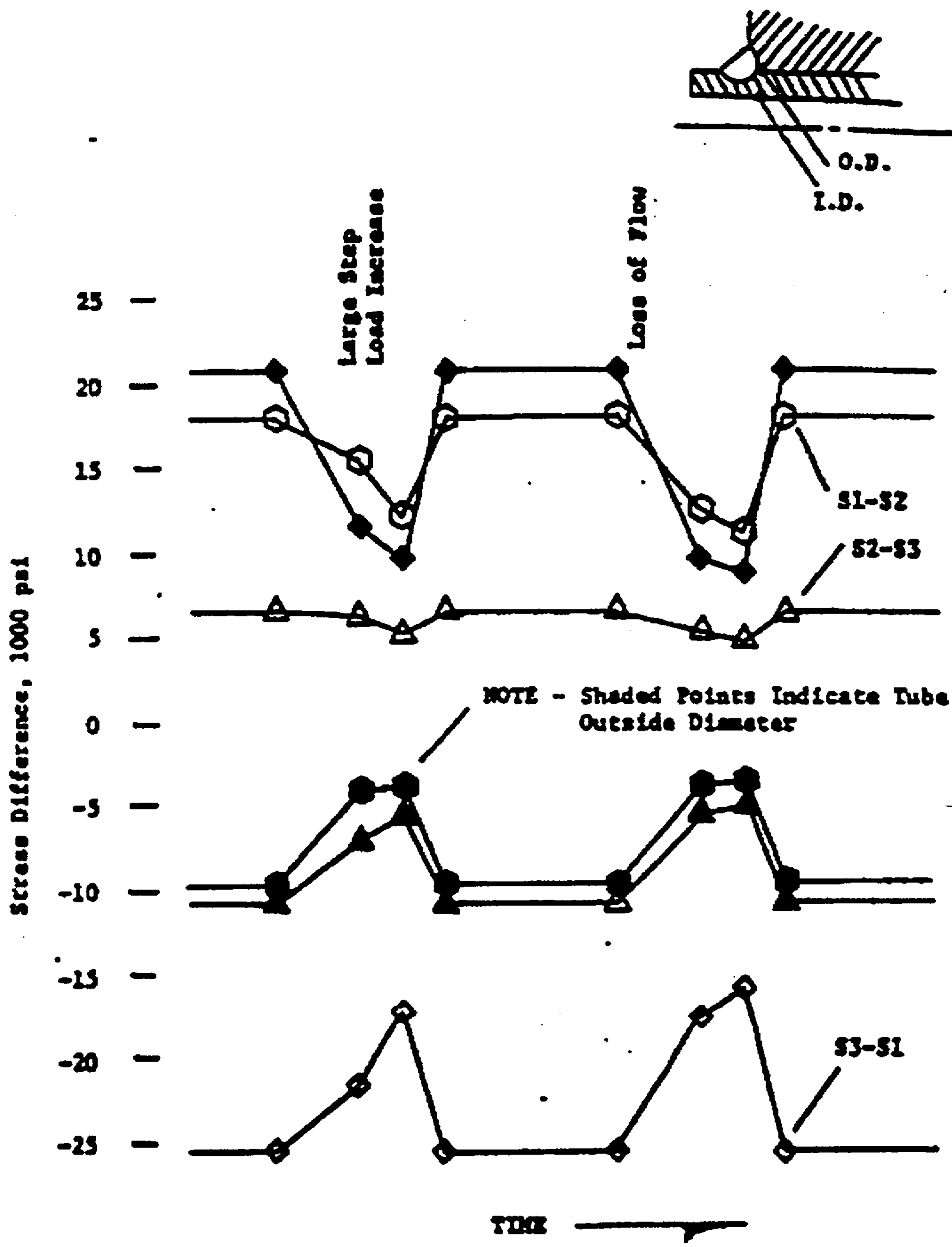
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station PRIMARY AND SECONDARY HYDROSTATIC TEST STRESS HISTORY FOR THE CENTER HOLE LOCATION SERIES S1SG (UNIT 2 ONLY)
	Updated FSAR Figure 5.2-7



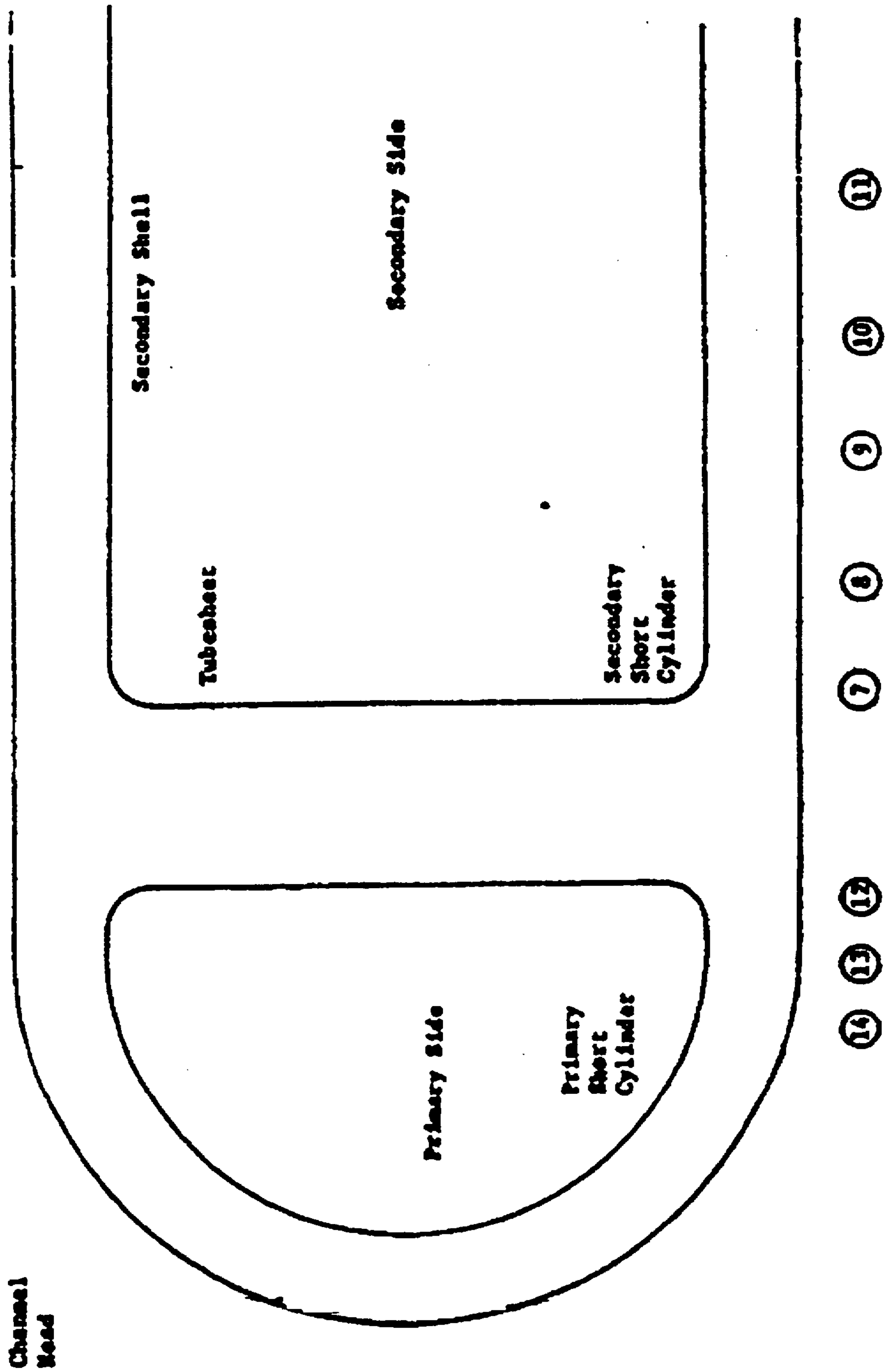
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station PLANT HEATUP AND OPERATIONAL LOADING TRANSIENTS (WITH STEADY-STATE PLATEAU) STRESS HISTORY FOR THE HOT SIDE CENTER HOLE LOCATION SERIES S1SG (UNIT 2 ONLY)
	Updated FSAR — Figure 5.2-8



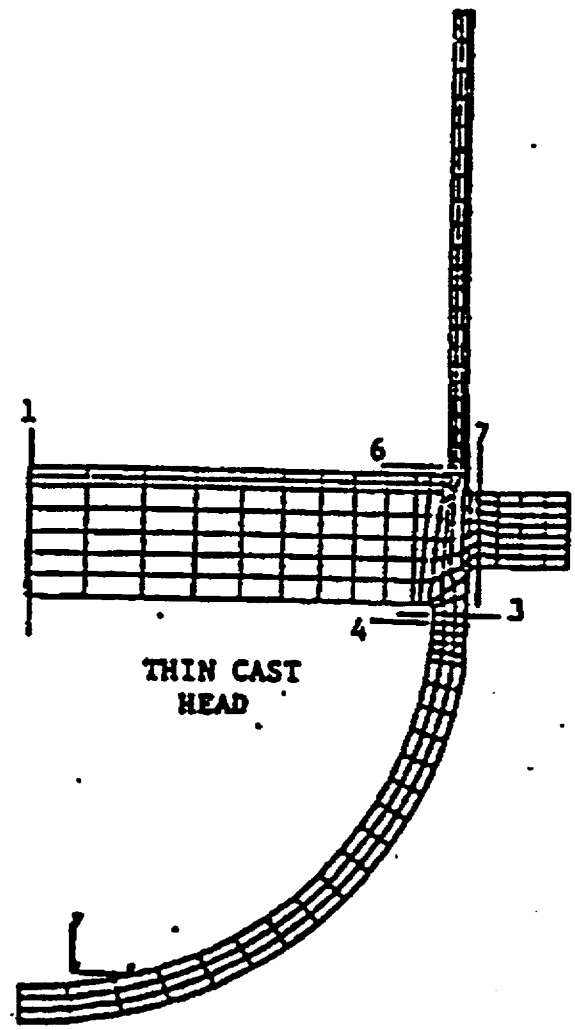
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station LARGE STEP LOAD DECREASES AND LOSS OF FLOW STRESS HISTORY OF THE HOT SIDE CENTER HOLE LOCATION SERIES S1 SG (UNIT 2 ONLY)
	Updated FSAR Figure 5.2-9



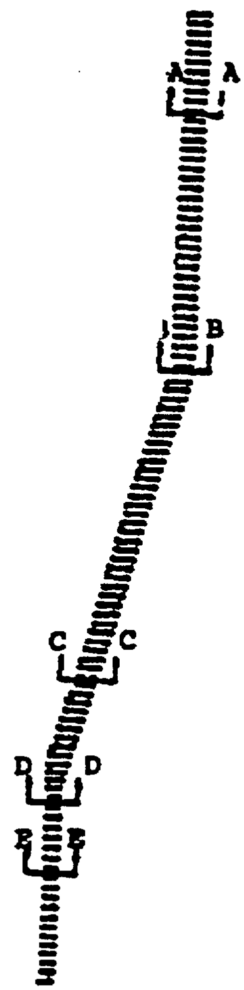
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station PRIMARY AND SECONDARY BOUNDRY COMPONENTS SHELL LOCATIONS OF STRESS INVESTIGATIONS SERIES S1 SG (UNIT 2 ONLY)
	Updated FSAR — Figure 5.2-10



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station TUBSHEET AND SHELL JUNCTIONS IMPORTANT STRESS LOCATIONS UNIT 1 MODEL FSG
	Updated FSAR — Figure 5.2-22



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station SECONDARY SHELL AND TRANSITION CONE IMPORTANT LOCATIONS UNIT 1 MODEL FSG
	Updated FSAR — Figure 5.2-23

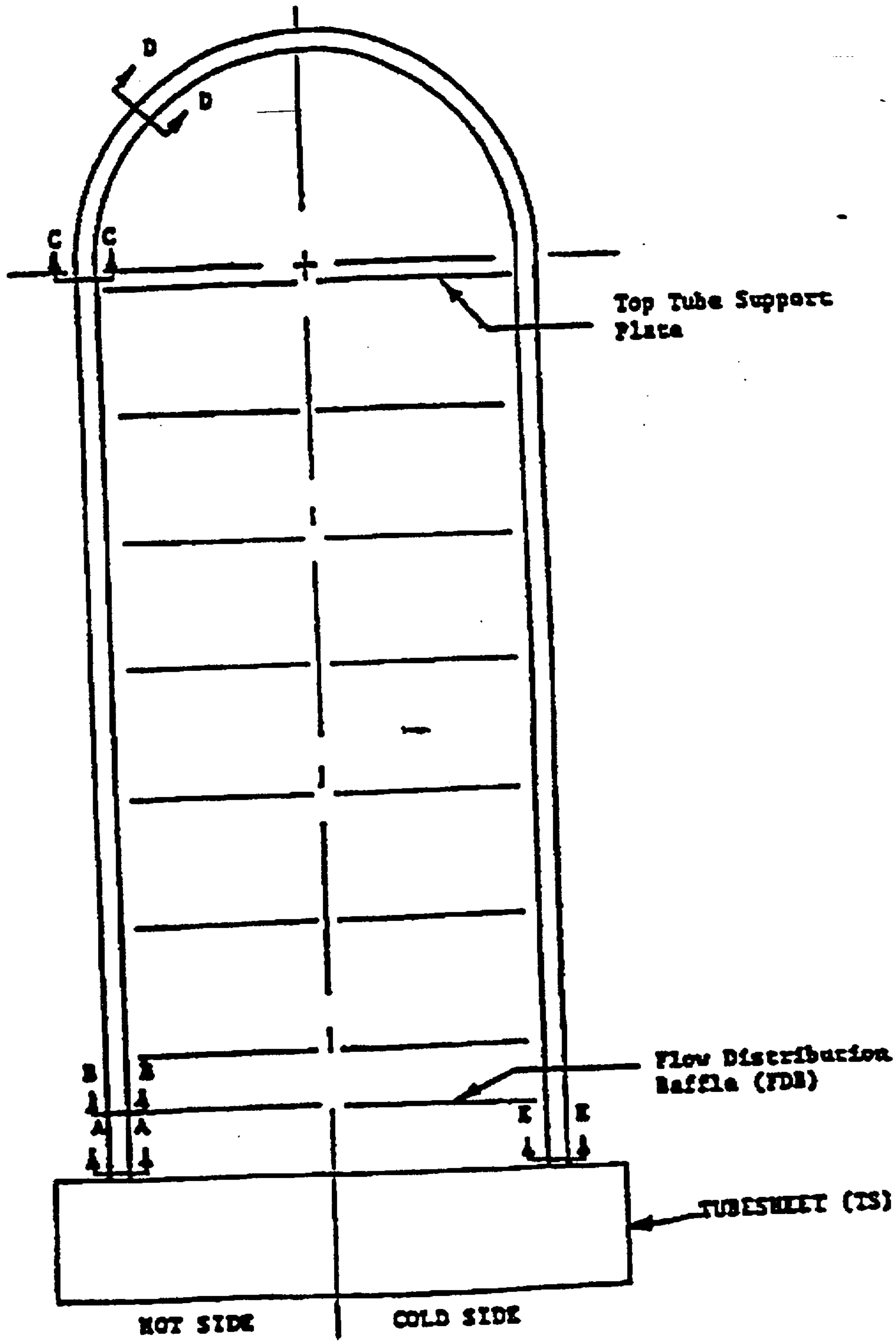


FIGURE 5 2-24 Tubes, Important Stress Locations - Unit 1

Model F SG

Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station TUBES, IMPORTANT STRESS LOCATIONS UNIT 1 MODEL FSG
	Updated FSAR Figure 5.2-24

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	Fails to operate as required	Five RCFC units are provided. A failure of one valve to operate as required will result in no more than one RCFC becoming inoperable. Evaluations have demonstrated that three RCFC units in operation and one Containment Spray Pump operating, provide sufficient cooling during the injection phase of a LOCA event.

TABLE 6.2-10 (Continued)

Figure	Service	Class	Status N	Status S	Status I	Inside Containment Valve(s)	Inside Containment Type	Inside Containment Pwr-Signal		Outside Containment Valve(s)	Outside Containment Type	Outside Containment Pwr-Signal		Auto Isol. Time (Sec)	Fluid	Temp.
6.2-37	Pressure Vacuum Relief Inlet and Outlet	B	If needed	If needed	Closed	1VC6 #	Auto-trip	C	CV	1VC5 #	Auto-trip	B	CV	≤ 2	Gas	Cold
6.2-37	Purge Air Inlet (Containment)	B	Closed	If needed	Closed	1VC2 #	Auto-trip	A	CV	1VC1 #	Auto-trip	B	CV	≤ 2	Gas	Cold
6.2-37	Purge Air Outlet (Containment)	B	Closed	If needed	Closed	1VC3 #	Auto-trip	A	CV	1VC4 #	Auto-trip	B	CV	≤ 2	Gas	Cold
6.2-38	Demineralized Water Supply to Flushing Conn.'s	B	Closed	If needed	Closed	1DR30 #	Non-return	-	-	1DR29 #	Auto-trip	A	T	≤10	Liquid	Cold
6.2-38	Service Air	B	Closed	If needed	Closed	1SA119 #	Non-return	-	-	1SA118 #	Manual	N/A	N/A	N/A	Air	Cold
6.2-38	Instrument Air	B	Open Open	Open Open	Closed Closed	11CA360 # 12CA360 #	Non-return	-	-	11CA330 # 12CA330 #	Auto-trip	A B	T T	≤10	Air	Cold
6.2-39	Service Water to Fan Coil Units	C	Open Open Open Open Open	If needed If needed If needed If needed If needed	Open Open Open Open Open	Closed System	-	-	-	11SW58 12SW58 13SW58 14SW58 15SW58	Rem Manual	A B C B C	N/A N/A N/A N/A N/A	Note 14	Liquid	Cold
6.2-39	Service Water from Fan Coil Units	C	Open Open Open Open Open	If needed If needed If needed If needed If needed	Open Open Open Open Open	Closed System	-	-	-	11SW72 12SW72 13SW72 14SW72 15SW72	Rem Manual	A B C B C	N/A N/A N/A N/A N/A	Note 14	Liquid	Cold

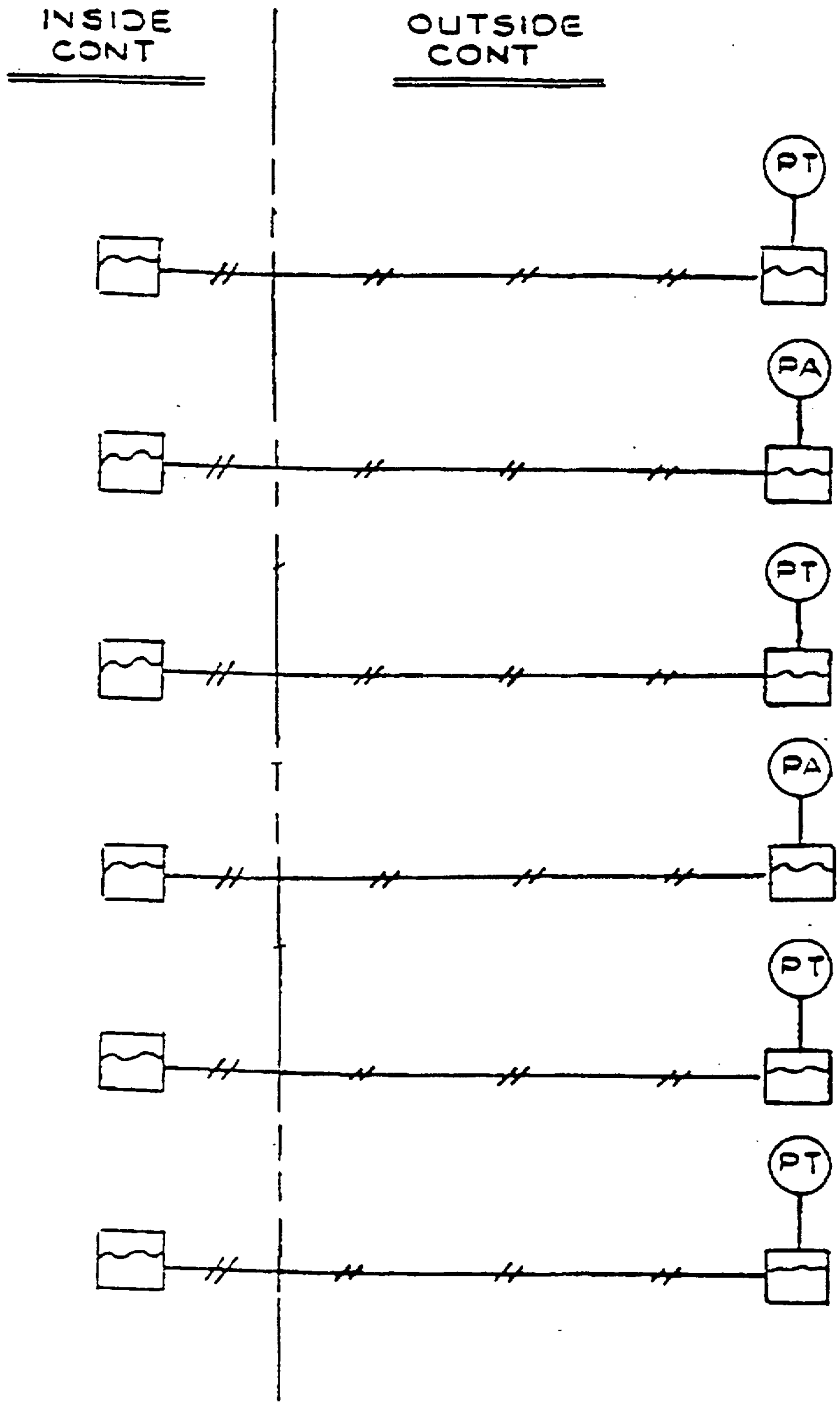
TABLE 6.2-10 (Continued)

Figure	Service	Class	Status N	Status S	Status I	Inside Containment Valve(s)	Inside Containment Type	Inside Containment Pwr-Signal		Outside Containment Valve(s)	Outside Containment Type	Outside Containment Pwr-Signal		Auto Isol. Time (Sec)	Fluid	Temp.
6.2-45B	Post LOCA RCS Sample	B	Closed	Closed	Int.	13SS184 #	Rem. Manual	C	N/A	13SS185 #	Rem. Manual	C	N/A	Note 14	Gas	Cold
		B	Closed	Closed	Int.	13SS182 #	Rem. Manual	C	N/A	13SS181 #	Rem. Manual	C	N/A	Note 14	Gas	Cold
		B	Closed	Closed	Int.	11SS182 #	Rem. Manual	A	N/A	11SS181 #	Rem. Manual	A	N/A	Note 14	Gas	Cold
		B	Closed	Closed	Int.	11SS188 #	Rem. Manual	A	N/A	11SS189 #	Rem. Manual	A	N/A	Note 14	Gas	Cold
6.2-45C	Fill Line for Cont. Press. Inst.	B	Closed	Closed	Closed	1CS900 # 1CS901 #	Manual Manual	N/A N/A	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
		B	Closed	Closed	Closed	1SA267 #	Manual	N/A	N/A	1SA265 #	Manual	N/A	N/A	N/A	Gas	Cold
		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 - 100'	C	Closed	Closed	Closed	Airlock Door Seal	Note 8	-	-	1CA1714 #	Manual	N/A	N/A	N/A	Air	Cold
6.2-45E	Cont. Airlock Seal Test - 130'	C	Closed	Closed	Closed	Airlock Door Seal	Note 8	-	-	1CA1715 #	Manual	N/A	N/A	N/A	Air	Cold

Status Codes
- N: Normal
- S: Shutdown
- I: Incident
- Int: Intermittent

Isolation Signals
- P: Tripped by Containment Isolation Signal - Phase B
- T: Tripped by Containment Isolation Signal - Phase A
- MSI: Main Steam Isolation
- SI: Closes on Safety Injection signal
- CV: Containment ventilation isolation

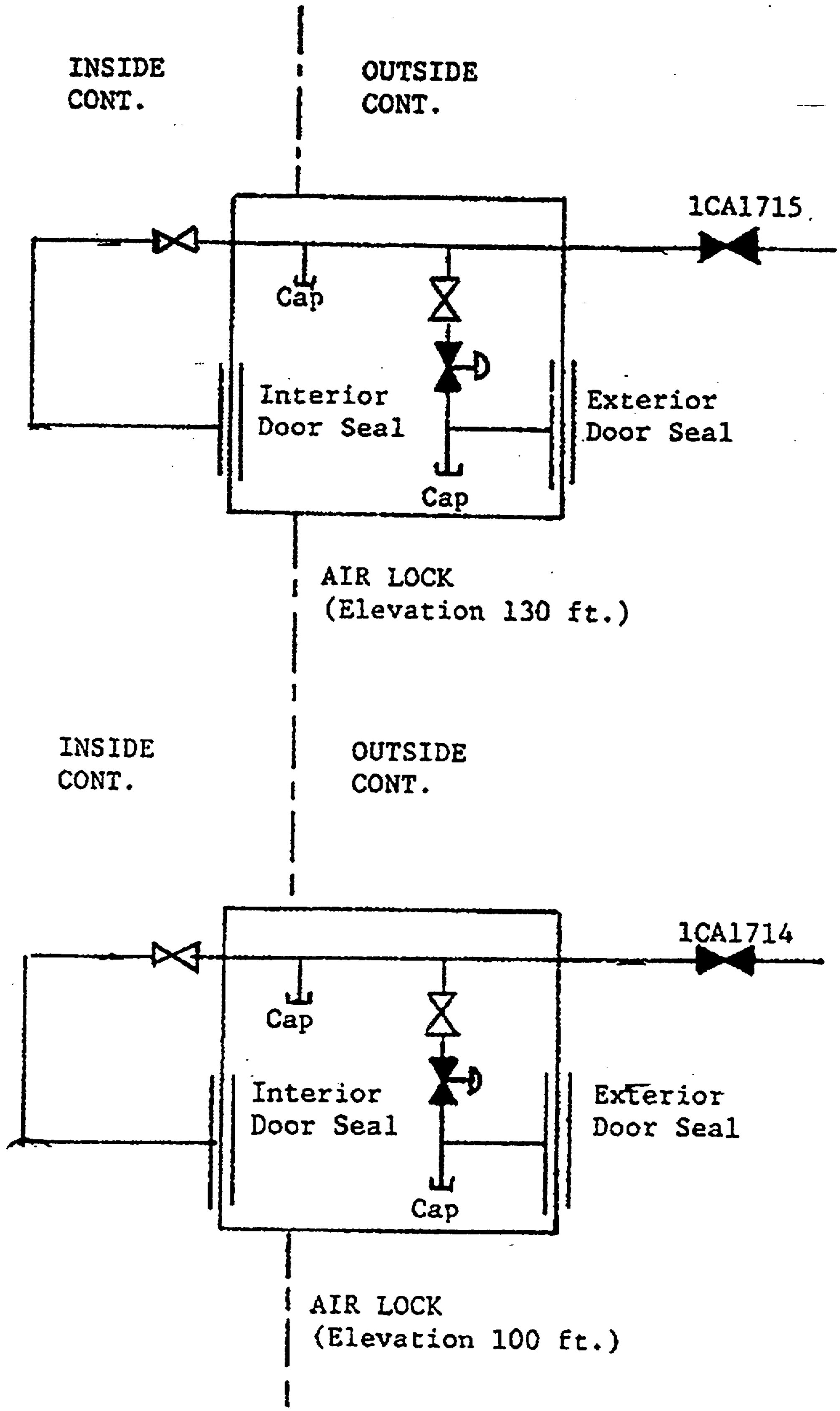
Other Information
- #: Valve required to be local leak rate tested
- $: See Note 13
- ϕ: See Note 17



SEALED SYSTEM

Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station CONTAINMENT ISOLATION CONTAINMENT PRESSURE INSTRUMENTATION
	Updated FSAR — Figure 6.2-35



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station CONTAINMENT ISOLATION CONTAINMENT AIRLOCK TEST INSTRUMENTATION
	Updated FSAR — Figure 6.2-45E

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	560	675	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 centrifugal	Vertical single-stage centrifugal
Material	Stainless steel clad carbon steel (pumps 21, 22) (pumps 11 & 12 are entirely stainless steel)	Stainless steel	Stainless steel

* During the recirculation modes, higher flows can occur depending on system failure assumption.

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 (GPM)	Brake Horsepower Required (HP)	Specified Full Load Horsepower (HP)	Service Factor	Service Factor Rating (HP)(3)	Nema Temperature Limit for Service Factor Rating of 1.15
Centrifugal Charging	5800	150	500	1400	560	625(6)	600	1.15	690	(7)
Safety Injection	---	---	---	2500(1)	425	360	400	1.15	460	(7)
				1500(2)	675	390				
Residual Heat Removal	350	3000	340	300	4500(4)	400(5)	400(5)	1.15	460	(7)

Note: (1) Design Flow Condition of Pump
(2) Runout Condition of Pump
(3) (Full Load HP) X (Service Factor) = Service Factor Rating
(4) During the recirculation modes, higher flows can occur depending on system failure assumption. [See Table 6.3-13]
(5) During the recirculation modes, a maximum 425 HP load can occur.
(6) Horsepowers range from 625 to approximately 650, depending on pump.

(7) Refer to NEMA MG1

TABLE 7.5-1

MAIN CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR

Parameter	Channel Available	Range	Accuracy	Indicator/ Recorder	Purpose
OPERATIONAL OCCURRENCES					
1. Tcold or Thot (measured, wide range	1Thot 1Tcold/ Loop	0-700°F	±4% of full range	All channels are recorded	Ensure maintenance of proper cooldown rate and to ensure maintenance of proper relation-temperature NDTT considerations.
2. Pressurizer water level	3	Entire distance between taps (528"approx)	±4.2% of span level 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	±5.5% 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)	±5.5% 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	±5.5% 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.

Parameter	Channels Available	Range	Accuracy	Indicator/ Recorder	Purpose
ACCIDENT CONDITIONS (Cont.)					
3. Steam generator water level (narrow range)	3/steam generator	0-100%	Refer to Applicable Loop Accuracy Calculation	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.
4. Steam generator water level (wide range)	1/steam generator	0-100%	Refer to Applicable Loop Accuracy Calculation	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	±7.5% 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 (528" Approx)	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	1-107R/hr		Both channels are recorded	NUREG 0737

TABLE 7.5-2 (Cont.)

Parameter	No. of Channels Available	Range	Accuracy	Indicator/ Recorder	Notes
REACTOR COOLANT SYSTEM (Cont.)					
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 T Setpoint	1/loop	0-75°F	±4% of full power ΔT	All channels indicated. One channel is selected for recording.	
5. Pressurizer Pressure	4	1700 to 2500 psig	±51.0 psi	All channels indicated One channel is selected for recording.	
6. Pressurizer Level	3	Entire distance between taps 0-100%	±4.2% span 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	±5.5%	All channels indicated and recorded.	

TABLE 8.3-2

SCN 97-090

DIESEL GENERATOR LOADING SEQUENCE
FOR BLACKOUT WITH ACCIDENT

UNIT NO. 1

STEP NO.	LOAD DESCRIPTION	DIESEL 1A TIME SEC	DIESEL 1B TIME SEC	DIESEL 1C TIME SEC
0	230 V 460 V Vital Buses	00	00	00
1	Safety Inj Chrg Pmp		01	01
2	Safety Injection Pmp	01		05
3	Residual Heat Removal Pmp	05	05	
4	Containment Spray Pmp	09-10;30(1)		09-10;26(1)
5	Service Water Pump	13	09	13
5	Alt S/Wtr Pmp, if fail	18	14	18
6	CFCUs (Low Speed)	22	18	22
7	Aux Feedwater Pmp	26	22	
8	Control Rm A/C (Chillers)	30	26	26
9	Emergency Control Air Comp			26
10	Aux Building Exh and Sup Fans	30	26	26
11	Switchgear Rm Supply Fans	30	26	26

UNIT NO. 2

STEP NO.	LOAD DESCRIPTION	DIESEL 2A TIME SEC	DIESEL 2B TIME SEC	DIESEL 2C TIME SEC
0	230 V 460 V Vital Buses	00	00	00
1	Safety Inj Chrg Pmp		01	01
2	Safety Injection Pmp	01		05
3	Residual Heat Removal Pmp	05	05	
4	Containment Spray Pmp	09-10;30(1)		09-10;26(1)
5	Service Water Pump	13	09	13
5	Alt S/Wtr Pmp, if fail	18	14	18
6	CFCUs (Low Speed)	22	18	22
7	Aux Feedwater Pmp	26	22	
8	Control Rm A/C (Chillers)	30	26	26
9	Emergency Control Air Comp			26
10	Aux Building Exh and Sup Fans	30	26	26
11	Switchgear Rm Supply Fans	30	26	26

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 (2750 kw) of the diesel generator.

(1) A one (1) second containment spray pump start permissive is established followed by an end of sequence permissive.

TABLE 8.3-6

125-VDC Battery Load Profile
SGS - Unit No. 1

Time Interval (Minutes)	Total Load Cycle (Amperes) Battery 1BTRY1ADC No. 1A	Battery 1BTRY1BDC No. 1B	Battery 1BTRY1CDC No. 1C
0 - 1	565.27	667.38	579.24
1 - 30	237.17	299.46	381.74
30 - 60	238.22	300.91	381.61
60 - 120	238.22	300.91	381.61

125-VDC Battery Load Profile
SGS - Unit No. 2

Time Interval (Minutes)	Total Load Cycle (Amperes) Battery 2BTRY2ADC No. 2A	Battery 2BTRY2BDC No. 2B	Battery 2BTRY2CDC No. 2C
0 - 1	561.34	659.02	539.25
1 - 30	249.10	297.02	340.85
30 - 60	250.15	298.47	340.78
60 - 120	250.15	298.47	340.83

TABLE 9.1-2

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	1.25×10^6
Design inlet temperature, °F	99	124
Design outlet temperature, °F	107	113.5
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		2500
Minimum developed head, ft		125
Temperature of pumped fluid, °F		80 - 180
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 - 180
Fluid		Spent fuel pool water
NPSH, ft		15
Material		Austenitic Stainless Steel

Feedwater Heaters		
First Stage Feedwater Heaters		
Number of Shells	3	
Flow Rate per Shell	3,792,475 lb/hr	
Temperature, In	92.6°F	
Temperature, Out	164°F	
Flow is directed through tube side of exchanger		
Number of Passes	2	
Pressure Drop	12 psi	
Design Pressure	700 psig	
Tube Channel Material	A-515-70	
Tubes:		
Material	304 SS A-249	
Number	1659	
O.D.	5/8 in.	
Gauge	0.035 Ave Wall	
Length	43 feet 0 inches	
Second Stage Heaters		
Number of Shells	3	
Flow Rate per Shell	3,792,475 lb/hr	
Temperature, In	164°F	
Temperature, Out	202°F	
Number of Passes	2	
Pressure Drop	19 psi	
Design Pressure	700 psig	
Tube Channel Material	A-515-70	
Tubes:		
Material	304 S.S. A-249	
Number	1,119	
O.D.	5/8 in.	
Gauge	0.035 Ave Wall	
Length	37 feet 11 inches	
Third Stage Feedwater Heaters	Unit 1	Unit 2
Number of Shells	3	3
Flow Rate per Shell	3,792,475 lb/hr	3,792,475 lb/hr
Temperature, In	202°F	202°F
Temperature, Out	256.7°F	256.7°F
Flow is directed through tube side of exchanger		
Number of Tube Passes	2	2
Pressure Drop	12.8	13.5
Design Pressure	700 psig	800 psi
Tube Channel Material	A-515-70	SA-516-70

	Unit 1	Unit 2
Tubes:		
Material	304 S.S. A-249	SA-688-TP316L
Number	896	840
O.D.	3/4 in.	¾ in.
Gauge	0.035 Avg Wall	0.035 in. Avg. Wall
Length	43 feet 5 inches	43 feet 8 inches

Fourth Stage Feedwater Heaters	Unit 1	Unit 2
Number of Shells	3	3
Flow Rate per Shell	3,792,475 lb/hr	3,792,475 lb/hr.
Temperature, In	256.7°F	256.7°F
Temperature, Out	309.3°F	309.3°F
Flow is directed through tube side of exchanger		
Number of Tube Passes	2	2
Pressure Drop	16.0 psig	17 psig
Design Pressure	700 psig	800 psig
Tube Channel Material	A-515-70	SA-516-70
Tubes:		
Material	304 SS A-249	SA688 TP 316L
Number	782	726
O.D.	3/4 in.	¾ in.
Gauge	0.035 Ave Wall	0.035 Avg. Wall
Length	43 feet 3 inches	43 feet 11 inches

Fifth Stage Feedwater Heaters	
Number of Shells	3
Flow Rate per Shell	3,792,475 lb/hr
Temperature, In	309.3°F
Temperature, Out	369.4°F
Flow is directed through tube side of Exchanger	
Number of Tube Passes	2
Pressure Drop	13.6 psig
Design Pressure	700 psig
Tube Channel Material	A-515-70
Tubes:	
Material	304 SS A-249
Number	845
O.D.	3/4 in.
Gauge	0.035 Ave Wall
Length	43 feet 7 inches

TABLE 10.4-3

ASSUMPTIONS USED IN BLOWDOWN WATER TRANSIT TIME CALCULATIONS

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TABLE 10.4-4

BLOWDOWN TRANSIT TIMES

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TABLE 10.4-5

POSTULATED RELEASE OF LIQUID ACTIVITY THROUGH BLOWDOWN SYSTEM

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TABLE 10.4-6

POSTULATED RELEASE OF GASEOUS ACTIVITY THROUGH CONDENSER AIR REMOVAL SYSTEM

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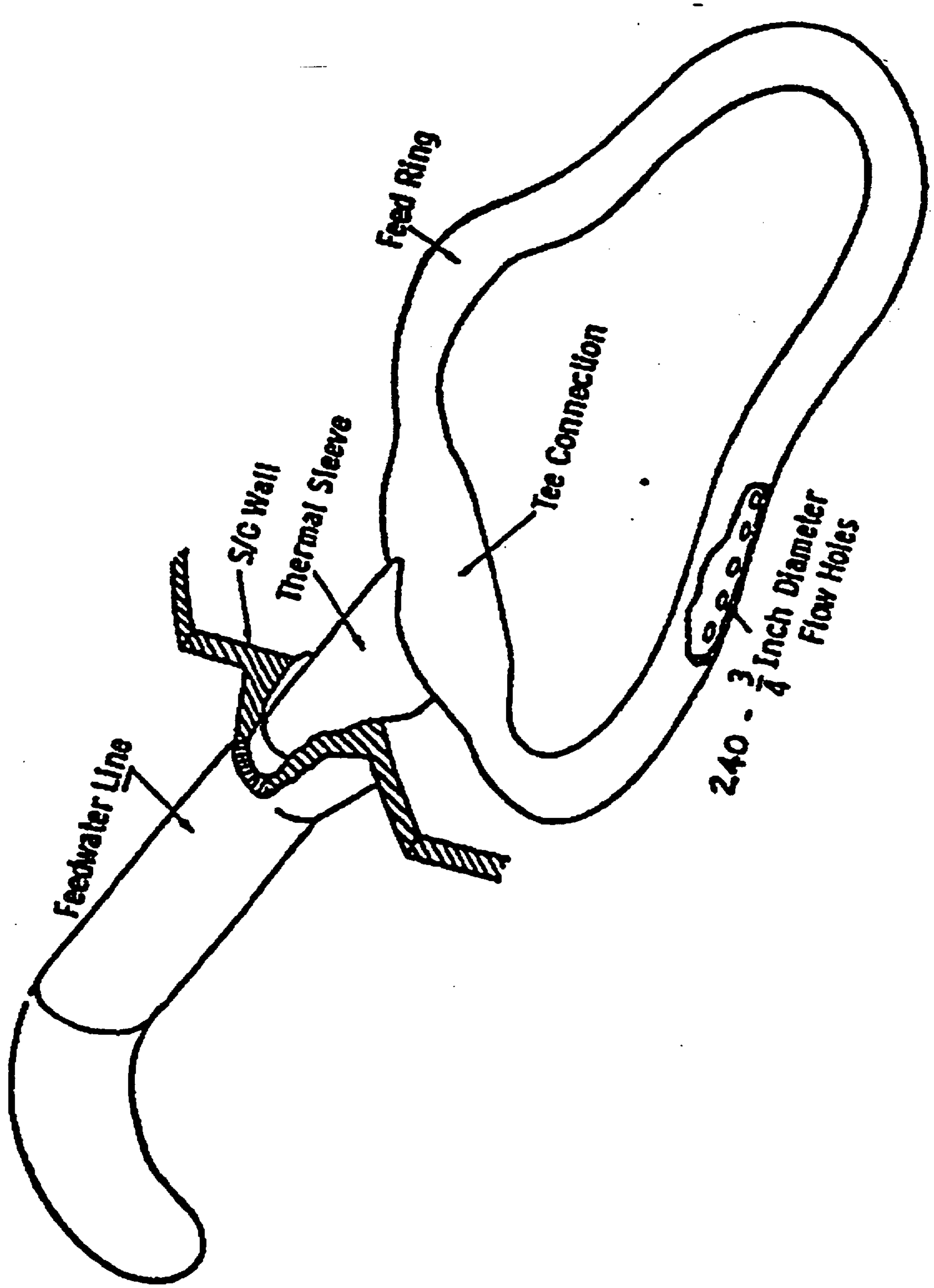
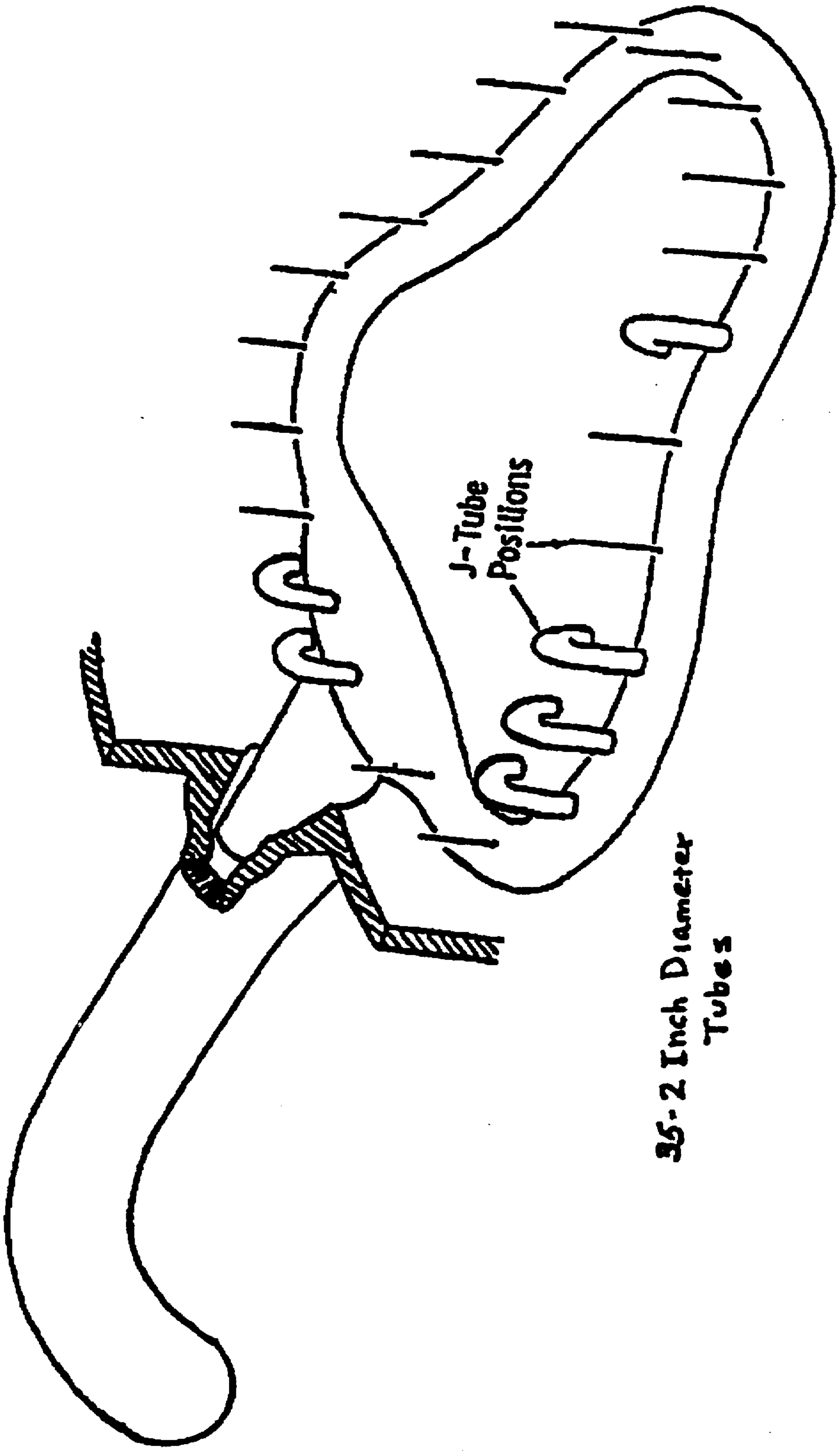


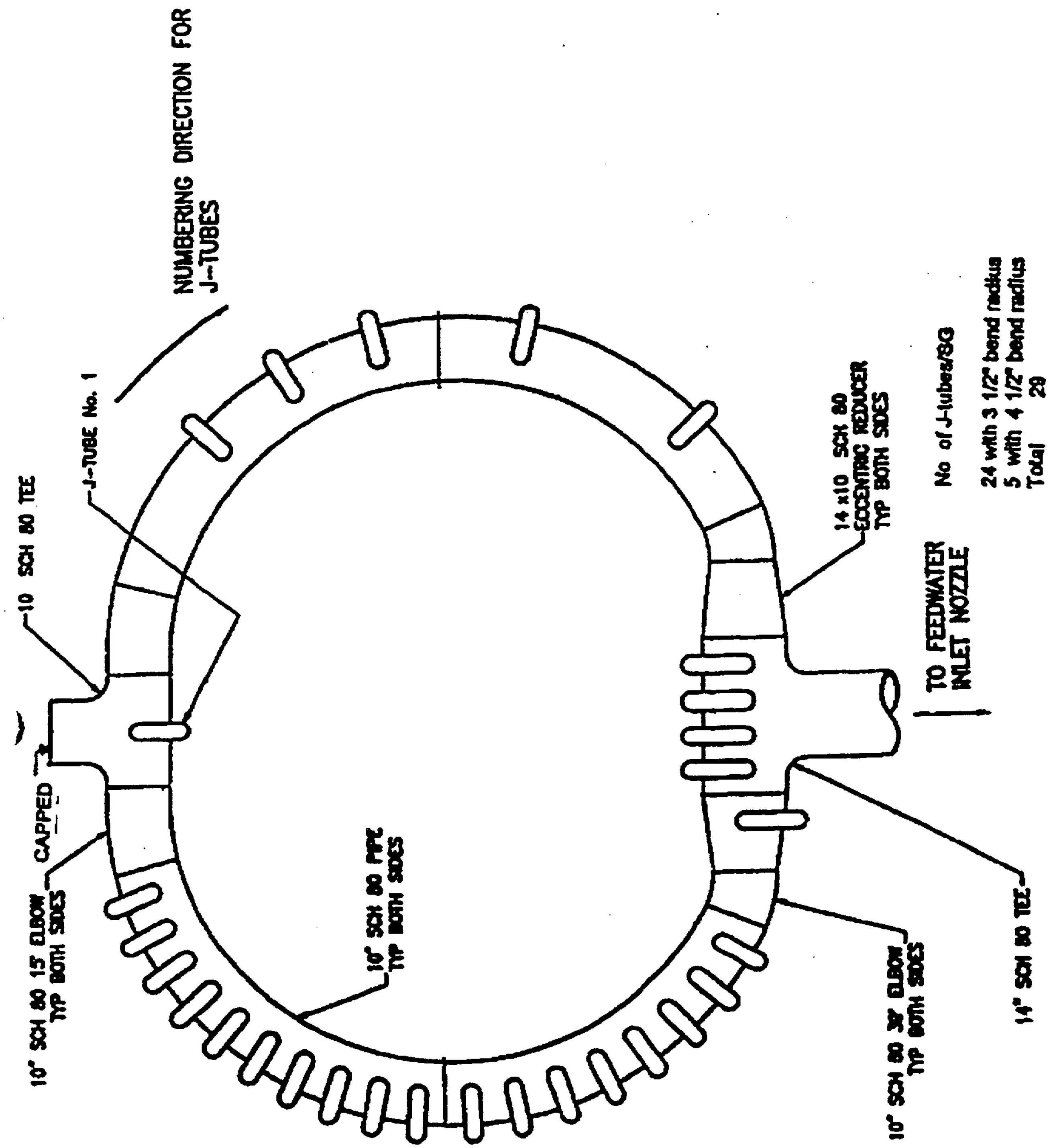
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station CONVENTIONAL SERIES 51 FEED RING ASSEMBLY APPLICABLE TO UNIT 2 ONLY
	Updated FSAR Figure 10.4-7



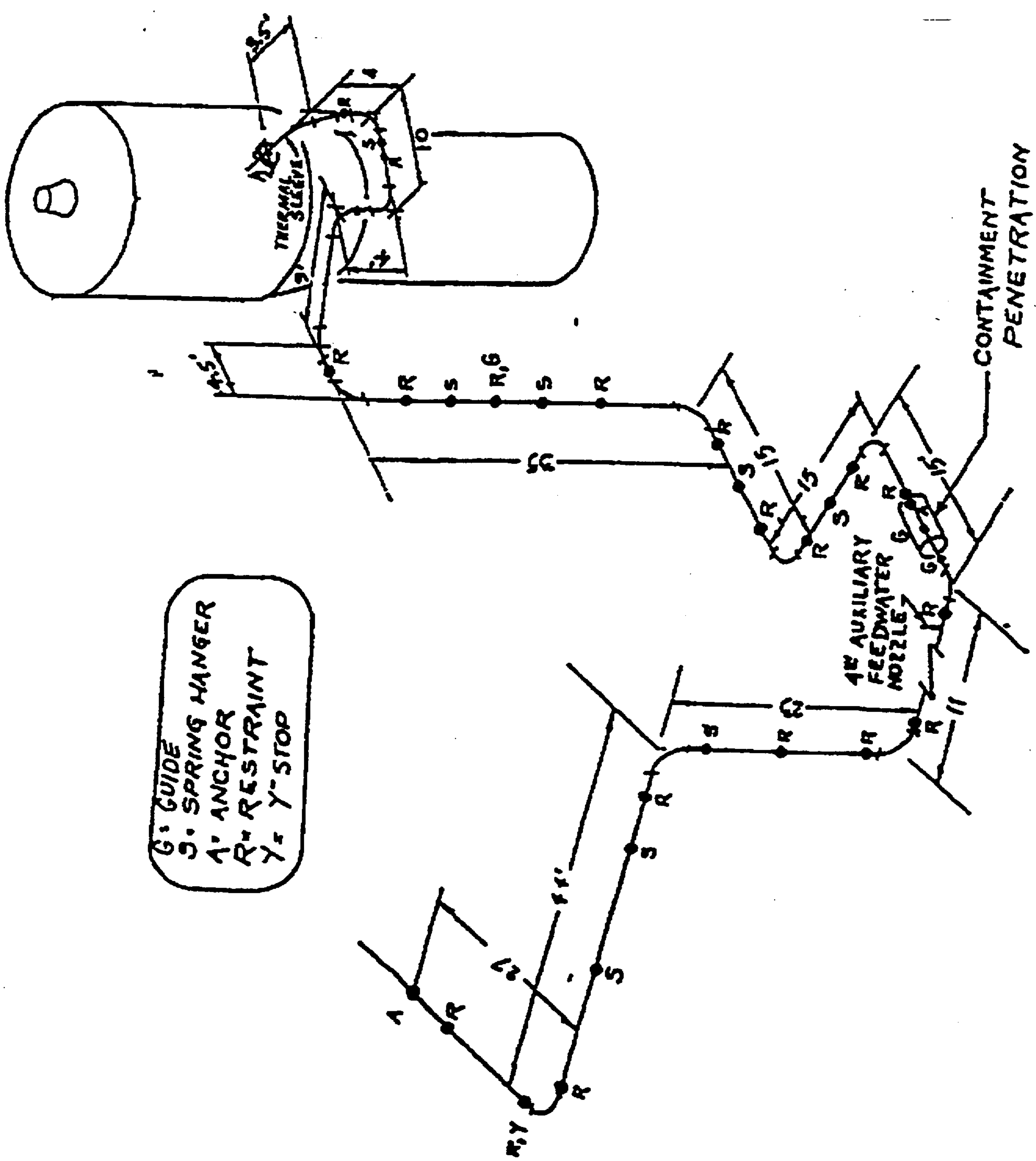
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station SIMPLIFIED J-TUBE FEED RING CONFIGURATION APPLICABLE UNIT 2 ONLY
	Updated FSAR Figure 10.4-8



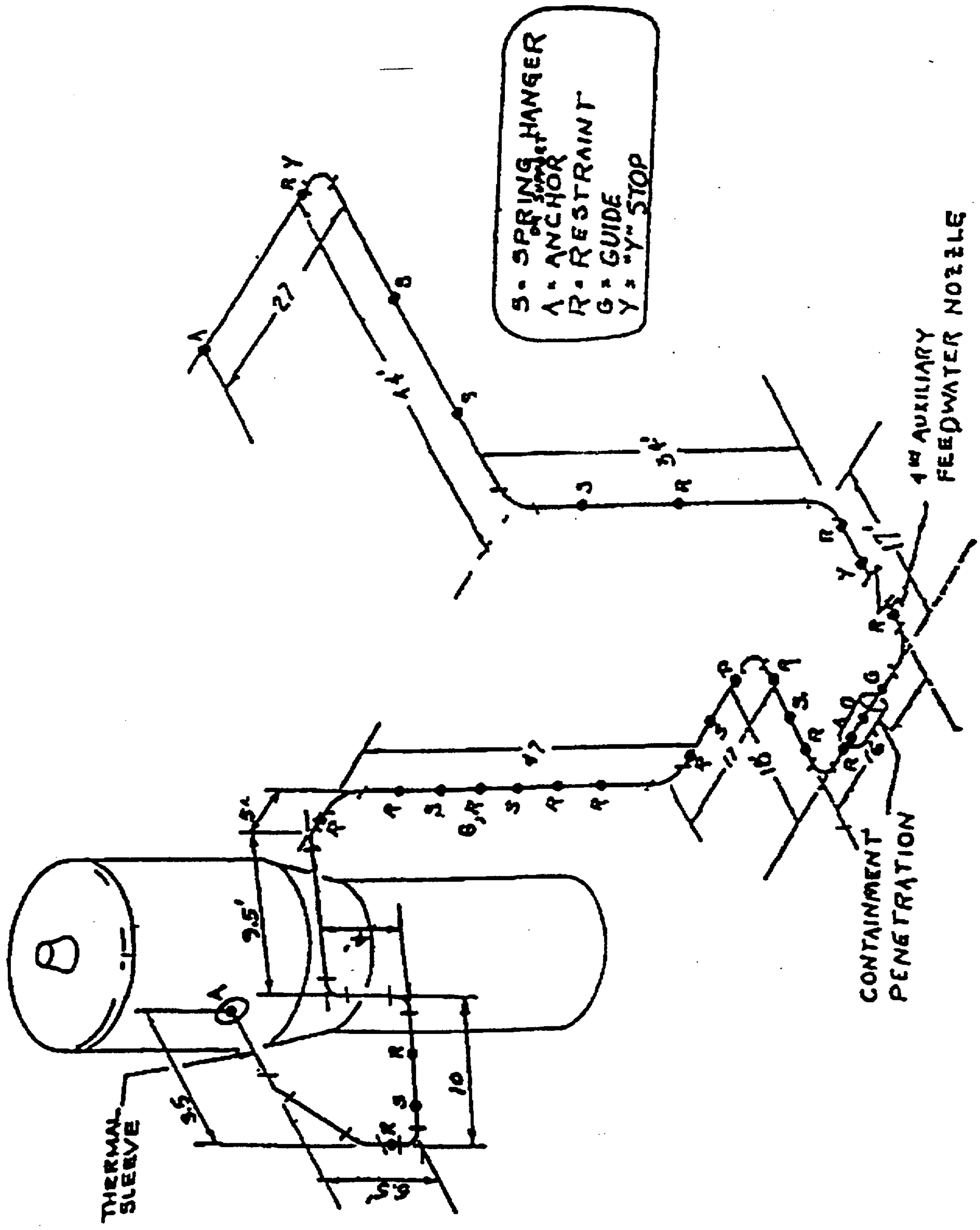
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station TYPICAL FEED RING CONFIGURATION UNIT 1 MODEL FSG
	Updated FSAR — Figure 10.4-8A



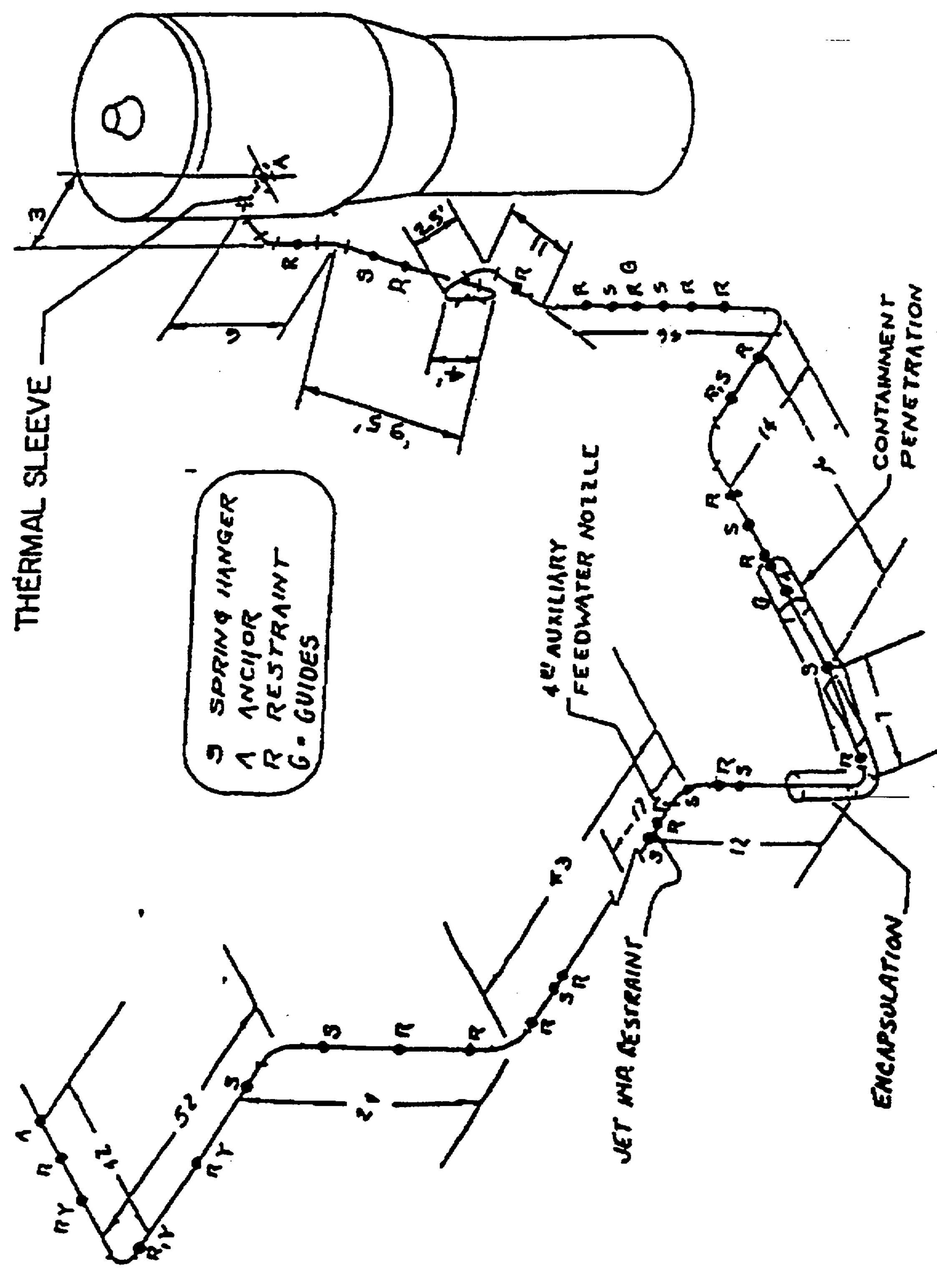
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station ISOMETRIC DIAGRAM-FEEDWATER PIPING NO.11 STEAM GENERATOR-UNIT 1 ONLY
	Updated FSAR — Figure 10.4-9



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station ISOMETRIC DIAGRAM-FEEDWATER PIPING NO. 12 STEAM GENERATOR-UNIT 1 ONLY Updated FSAR — Figure 10.4-10



Revision 18, April 26, 2000

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NO. 13 STEAM GENERATOR-UNIT 1 ONLY</td></tr>
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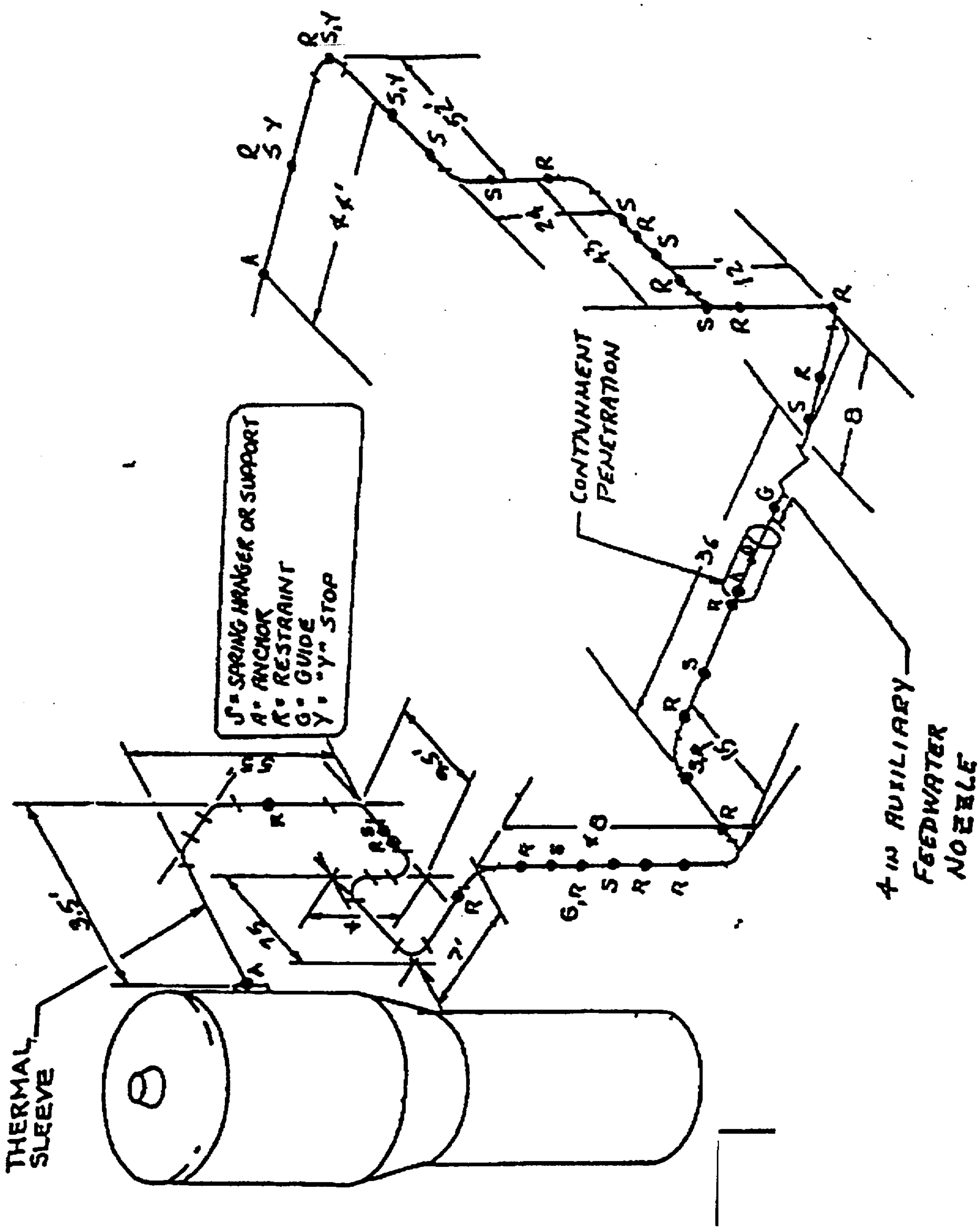
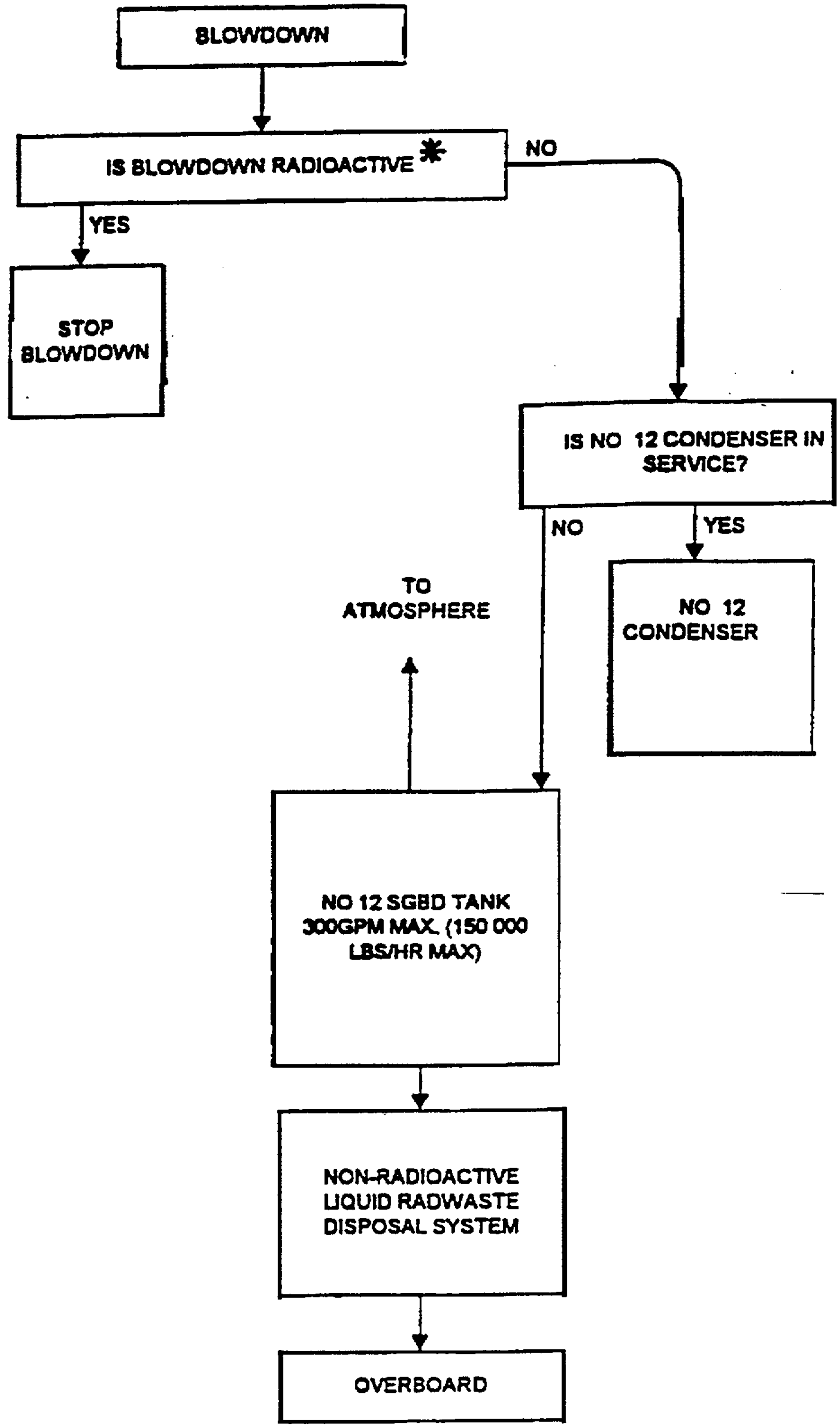


Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station ISOMETRIC DIAGRAM-FEEDWATER PIPING NO.14 STEAM GENERATOR-UNIT 1 ONLY
	Updated FSAR Figure 10.4-12



* (in excess of the radiation monitor setpoint)

Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station STEAM GENERATOR BLOWDOWN LOGIC DIAGRAM
	Updated FSAR Figure 10.4-19

TABLE 11.1-1

CORE ACTIVITIES

Assumptions: Operation at 3600 MWt for 497 days (equilibrium cycle)

Isotope	Curies in the Core ($X 10^7$)
I-131	9.9
I-132	14.0
I-133	20.0
I-134	22.0
I-135	19.0
Xe-131m	0.07
Xe-133	20.0
Xe-133m	2.9
Xe-135	5.0
Xe-135m	4.0
Xe-138	16.0
Kr-85	0.11
Kr-85m	2.6
Kr-87	4.7
Kr-88	6.7

TABLE 11.1-7

PARAMETERS USED IN THE CALCULATION OF REACTOR COOLANT FISSION PRODUCT ACTIVITIES

1.	Core thermal power, max. calculated, MWt	3600
2.	Fraction of fuel containing clad defects	0.01
3.	Reactor coolant liquid volume, ft^3	10,892 (1)
4.	Reactor coolant average temperature, °F	568
5.	Purification flow rate (normal), gpm	77
6.	Effective cation demineralizer flow, gpm	7.5
7.	Volume control tank volumes	
	a. Vapor, ft^3	200
	b. Liquid, ft^3	200
8.	Fission product escape rate coefficients:	
	a. Noble gas isotopes, sec^{-1}	6.5×10^{-8}
	b. Br, I, and Cs isotopes, sec^{-1}	1.3×10^{-8}
	c. Te isotopes, sec^{-1}	1.0×10^{-9}
	d. Mo isotopes, sec^{-1}	2.0×10^{-9}
	e. Sr and Ba isotopes, sec^{-1}	1.0×10^{-11}
	f. Y, La, Ce, Pr isotopes, sec^{-1}	1.6×10^{-12}
9.	Mixed bed demineralizer decontamination factors:	
	a. Noble gases and Cs-134, 136, 137, Y-90, 91 and Mo-99	1.0
	b. All other isotopes	10.0
10.	Cation bed demineralizer decontamination factor for CS-134, 236, 237, Y-90, 91, and Mo-99	10.0

---

(1) Conservatively bounds 20% tube plugging in Series 51 steam generator and 10% tube plugging in Model-F steam generator.

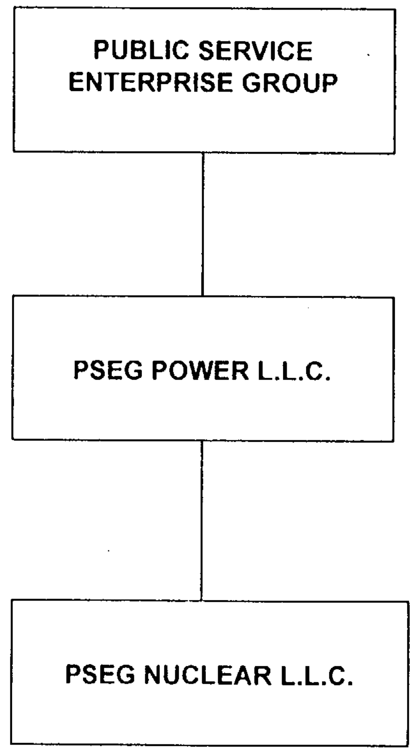
11.	Fraction of ternary tritium diffusing through zirconium cladding	
	a. Design value	0.30
	b. Expected value	0.01

Note: Although Unit 1 has Model-F steam generators, the radioactivity values of Unit 1 are bounded by the values shown in this Table. The Unit 1 primary volume is lower than that of Unit 2. This Table is based on Series 51 steam generators.

Table 13.1-1

Comparison of UFSAR Position Titles and Salem Technical Specifications
Section 6.0 Organization Titles - Listed by Exception

UFSAR Title	Technical Specification Title
President and Chief Nuclear Officer	Senior Corporate Nuclear Officer
Vice President - Operations	Plant Manager
Operations Superintendent	Senior Nuclear Shift Supervisor
Control Room Supervisor	Nuclear Shift Supervisor
Reactor Operator and Plant Operator	Nuclear Control Operator
Nuclear Equipment Operator or Utility Operator	Equipment Operator or Utility Operator
Radiation Protection Manager	Radiation Protection Manager
Radiation Protection Supervisor	Senior Supervisor - Radiation Protection
Director - Quality, Nuclear Training and Emergency Preparedness	Director - Nuclear Training and Radiological Safety
Director - Quality, Nuclear Training and Emergency Preparedness	Senior Management Position with responsibility for Independent Nuclear Safety Assessment and Quality Program oversight
Chemistry Superintendent	Chemistry Manager



PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

RELATIONSHIP WITH PUBLIC SERVICE ENTERPRISE GROUP

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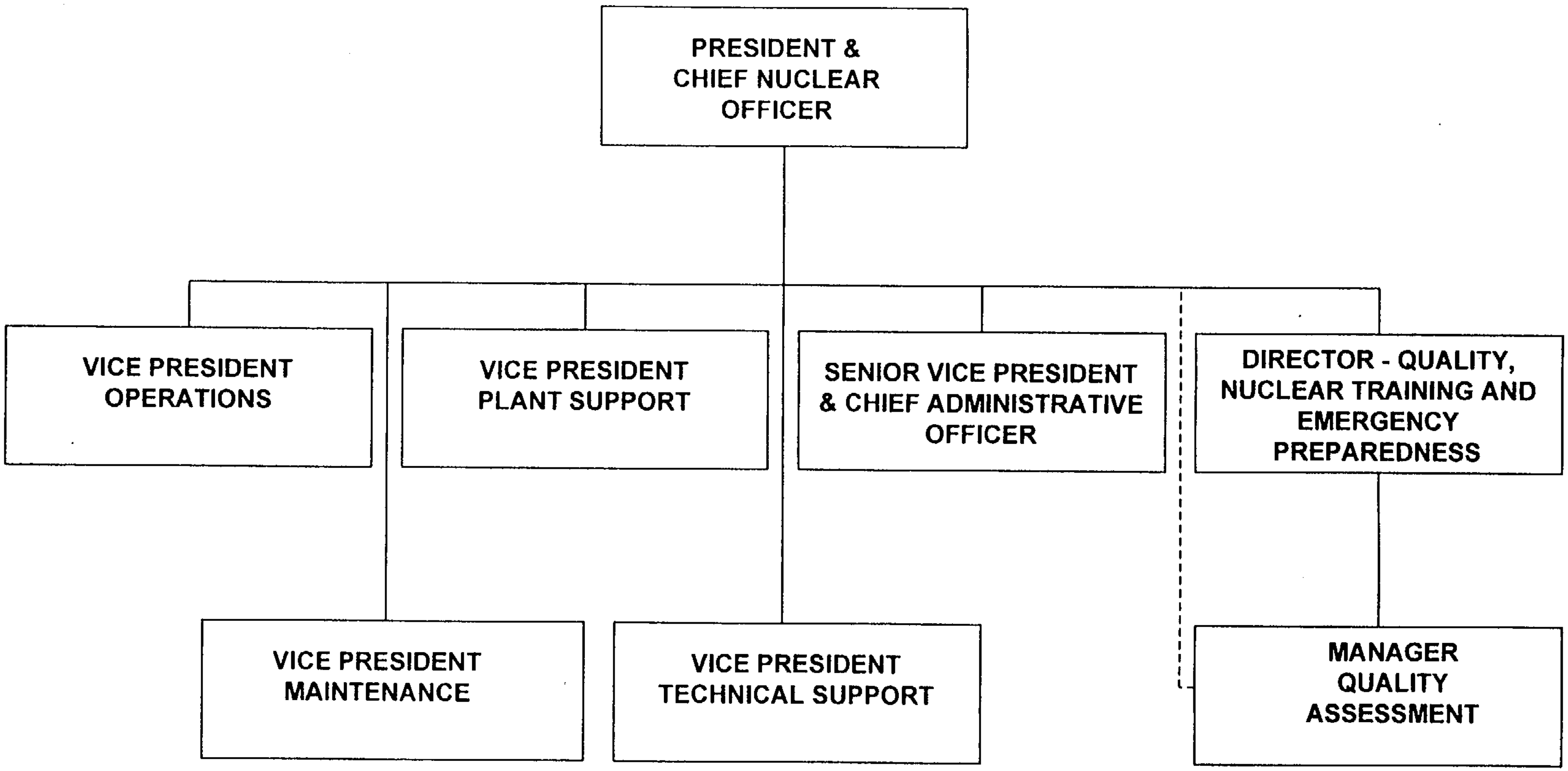

PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

NUCLEAR ORGANIZATION

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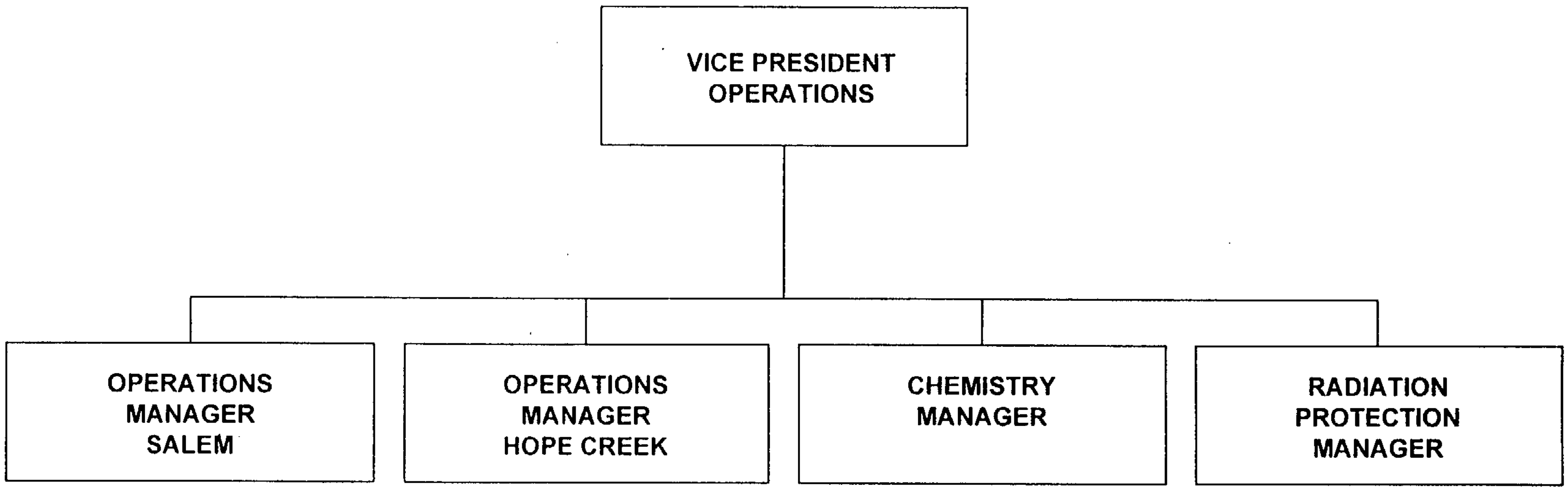

PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

OPERATIONS ORGANIZATION

SALEM UFSAR – REV 18 SHEET 1 OF 1

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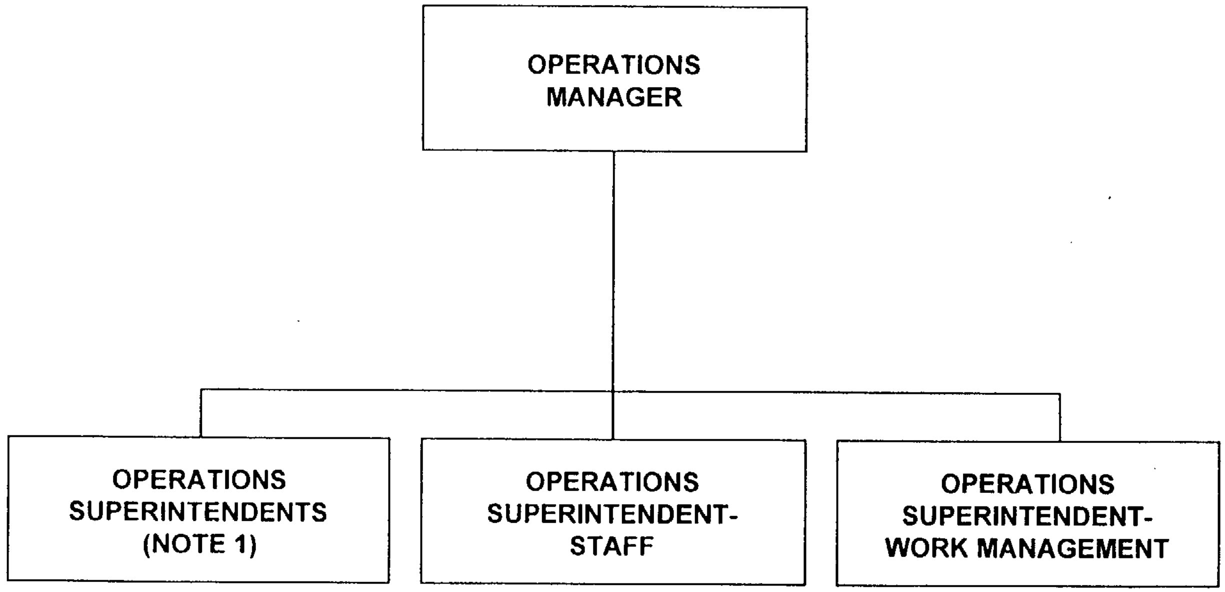

NOTE (1) ONE OF THE SHIFT SUPERINTENDENTS WILL BE DESIGNATED AS THE OPERATIONS SUPERINTENDENT-ASSISTANT OPERATIONS MANAGER TO FULFILL TECHNICAL SPECIFICATION FUNCTIONS.

PSEG NUCLEAR L.L.C. SALEM GENERATING STATION	
STATION OPERATIONS DEPARTMENT	
SALEM UFSAR – REV 18	SHEET 1 OF 1
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PSEG NUCLEAR L.L.C. SALEM GENERATING STATION	
SALEM OPERATIONS UNITS 1 & 2	
SALEM UFSAR - REV 18	SHEET 1 OF 1
APRIL 26, 2000	F13.1-8a

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PSEG NUCLEAR L.L.C. SALEM GENERATING STATION
RADIATION PROTECTION DEPARTMENT
SALEM UFSAR - REV 18   SHEET 1 OF 1 APRIL 26, 2000   F13.1-8e

TABLE 15.1-1

NUCLEAR STEAM SUPPLY SYSTEM POWER RATINGS

Guaranteed Nuclear Steam Supply System thermal power output	3423 MWt
The Engineered Safety Features design rating (maximum calculated turbine rating)	3577 MWt
Thermal power generated by the reactor coolant pumps (nominal)	12 MWt
Guaranteed Core Thermal Power	3411 MWt

TABLE 15.1-2

SUMMARY OF INITIAL CONDITIONS AND COMPUTER CODES USED

Faults	Computer Codes Utilized	Reactivity Coefficients Assumed: Moderator Temperature(1) ($\Delta k/°F$)	Moderator Density(1) ($\Delta k/gm/cc$)	Doppler(2)	Initial NSSS Thermal Power Output Assumed (MWt)
CONDITION II					
Uncontrolled RCC Assembly Bank Withdrawal from a Subcritical Condition	TWINKLE, FACTRAN THINC	$+ 5 \times 10^{-5}$	---	Lower	0
Uncontrolled RCC Assembly Bank Withdrawal at Power	LOFTRAN	---	0 and 0.43	Lower and upper	3423
RCC Assembly Misalignment	THINC, ANC, LOFTRAN	---	0	Upper	3423
Uncontrolled Boron Dilution	NA	NA	NA	NA	0 and 3423
Partial Loss of Forced Reactor Coolant Flow	LOFTRAN THINC, FACTRAN	---	0	Upper	3431
Start-up of an Inactive Reactor Coolant Loop	---	---	---	---	---
Loss of External Electrical Load and/or Turbine Trip	LOFTRAN	---	0 and 0.43	Lower and Upper	3431
Loss of Normal Feedwater	LOFTRAN	---	NA	NA	3423

TABLE 15.1-2 (Cont)

Faults	Computer Codes Utilized	Reactivity Coefficients Assumed Moderator Temperature(1) (Δk/°F)	Moderator Density(1) (Δk/gm/cc)	Doppler(2)	Initial NSSS Thermal Power Output Assumed (MWt)
CONDITION II (cont'd)					
Loss of Offsite Power to the Plant Auxiliaries	LOFTRAN	---	NA	NA	3423
Excessive Heat Removal Due to Feedwater System Malfunctions	LOFTRAN	---	0.43	Lower	0 and 3423
Excessive Load Increase	LOFTRAN	---	0 and 0.43	Lower	3423
Accidental Depressurization of the Reactor Coolant System	LOFTRAN	---	0	Upper	3423
Accidental Depressurization of the Main Steam System	LOFTRAN	---	Function of Moderator Density (See Sec 15.2.13) (Fig 15.2-41)	Fig. 15.4-49	0 (Subcritical)
Inadvertent Operation of ECCS During Power Operation	LOFTRAN	---	0	Lower	3423

Reactivity Coefficients

Faults	Computer Codes Utilized	Assumed Moderator Temperature(1) (Δk/°F)	Moderator Density(1) (Δk/gm/cc)	Doppler(2)	Initial NSSS Thermal Power Output Assumed (MWt)
CONDITION III					
Loss of Reactor Coolant from Small Ruptured Pipes or from Cracks in Large Pipe which Actuate Emergency Core Cooling	NOTRUMP, SBLOCTA				3479
Inadvertent Loading of a Fuel Assembly into an Improper Position	PHOENIX-P, ANC	---	NA	NA	3423
Complete Loss of Forced Reactor Coolant Flow	LOFTRAN THINC, FACTRAN	---	0	Upper	3431
Waste Gas Decay Tank Rupture	NA	---	NA	NA	3577
Single RCC Assembly Withdrawal at Full Power	ANC, THINC PHOENIX-P	---	NA	NA	3423
CONDITION IV					
Major rupture of pipes containing reactor coolant up to and including double-ended rupture of the largest pipe in the Reactor Coolant System (Loss of Coolant Accident)	SATAN BASH COCO LOCBART	Function of Moderator Density (See Section 15.4.1)		Function of Fuel Temp. (See Section 15.4.1)	3579

TABLE 15.1-2 (Cont)

Faults	Computer Codes Utilized	Reactivity Coefficients Assumed: Moderator Temperature(1) (Δk/°F)	Reactivity Coefficients Assumed: Moderator Density(1) (Δk/gm/cc)	Doppler(2)	Initial NSSS Thermal Power Output Assumed (MWt)
CONDITION IV (cont)					
Major Secondary System Pipe Rupture, up to and Including Double-Ended Rupture (Rupture of a Steam Pipe)	LOFTRAN, THINC	Function of Moderator Density (See Section 15.2.13) (Fig. 15.2-41)		Fig. 15.4-49	0 (Subcritical)
Steam Generator Tube Rupture	NA	NA	NA	NA	3577
Single Reactor Coolant Pump Locked Rotor and Reactor Coolant Pump Shaft Break	LOFTRAN THINC, FACTRAN	---	0	Upper	3431
Fuel Handling Accident	NA	NA	NA		3577
Rupture of a Control Rod Mechanism Housing (RCCA Ejection)	TWINKLE, FACTRAN PHOENIX-P	-0 pcm/°F BOL -26 pcm/°F EOL	---	Consistent with lower limit shown on Fig 15.1-5	0 and 3423

NOTES:

(1) Only one is used in an analysis, i.e., either moderator temperature or moderator density coefficient.
(2) Reference Figure 15.1-5 for Doppler power coefficients.
See UFSAR Section 4.5 for the applicable station reload analysis.

TABLE 15.1-3

TRIP POINTS AND TIME DELAYS TO TRIP ASSUMED IN ACCIDENT ANALYSIS

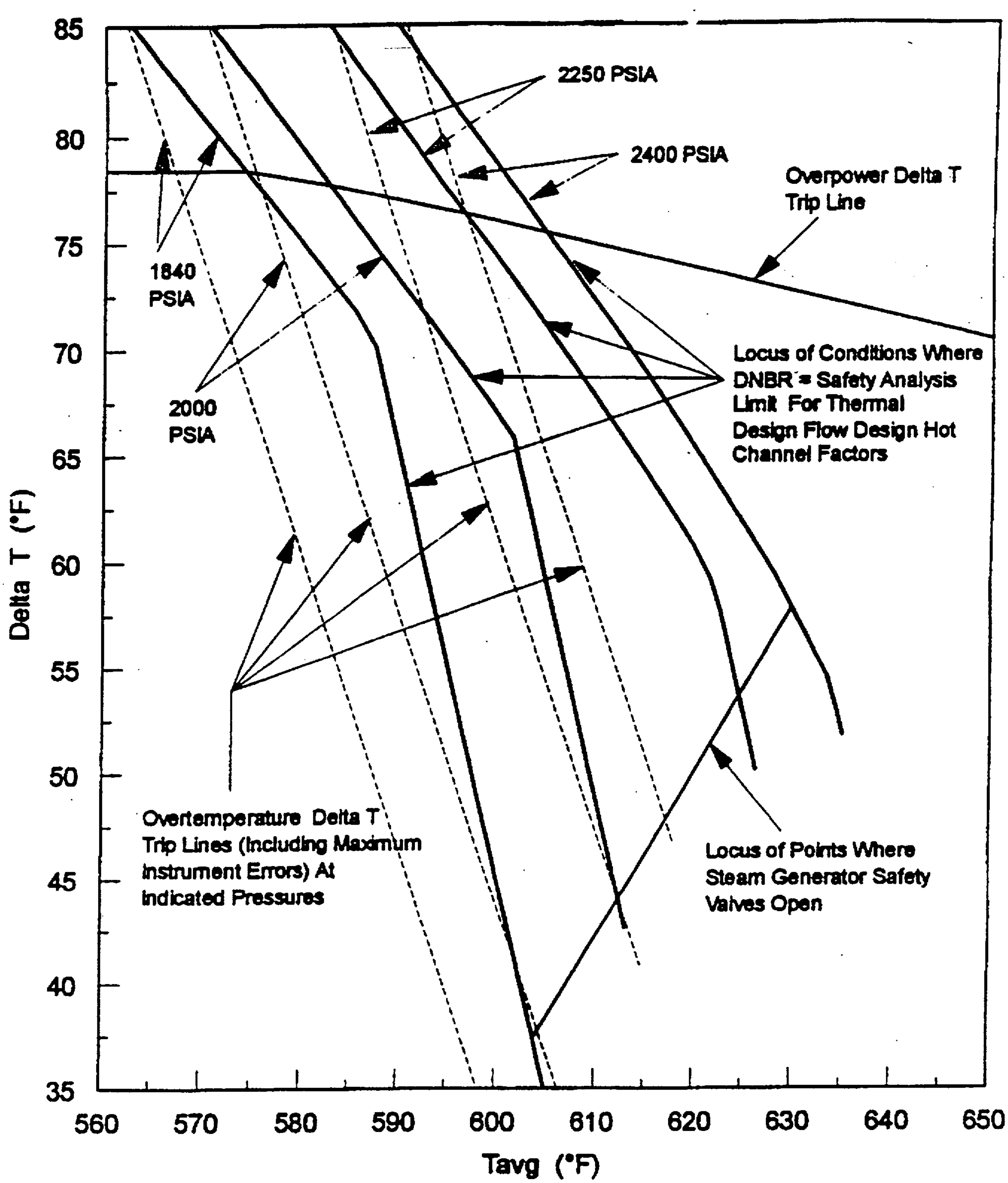
Trip Function	Limiting Trip Point Assumed In Analyses	Time Delay (sec)
Power range high neutron flux, high setting	118 percent	0.5
Power range high neutron flux, low setting	35 percent	0.5
Overtemperature ΔT	Variable, see Figure 15.1-1	7.0(1) (Ref.21)(2)
Overpower ΔT	Variable, see Figure 15.1-1	7.0(1) (Ref.21)
High pressurizer pressure	2425 psig	2.0
Low pressurizer pressure	1825 psig	2.0
Low reactor coolant flow (from loop flow detectors)	87-percent loop flow	1.0
Undervoltage trip	68 percent nominal	1.5
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 feedwater pumps and closure of feedwater system valves, and turbine trip	73 percent of Narrow Range Level Span	2.0
Underfrequency trip	53.9 Hz	0.6
Loss of offsite power time delay	Not Applicable	1.5 (3)

NOTES:

(1) Total time delay (including RTD response time and trip circuit channel electronics delay) from the time the temperature difference in the coolant loops exceeds the trip setpoint at the channel sensor until the rods begin to drop.

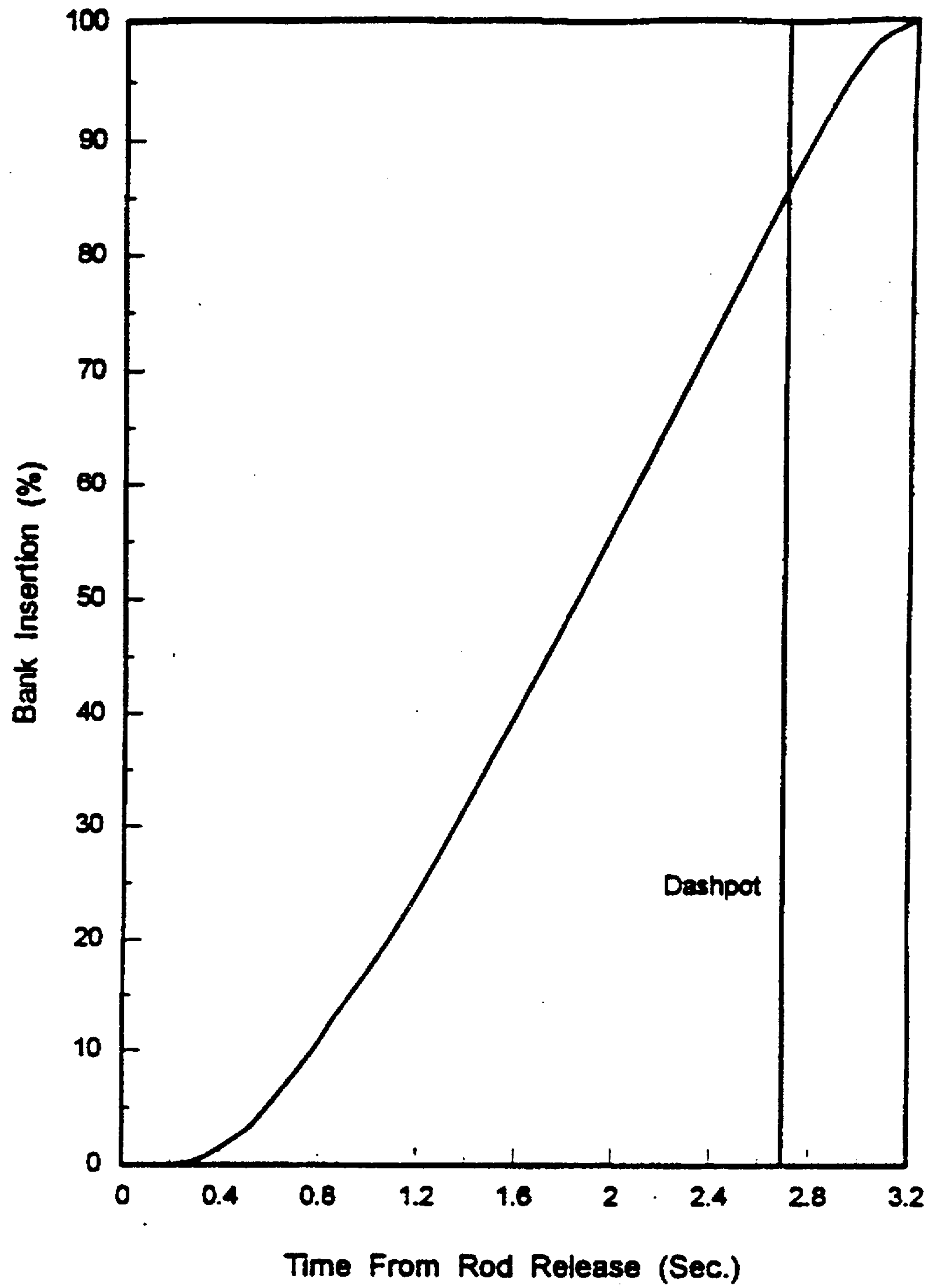
(2) See Reference 21, Section 15.1.10.

(3) From rod motion



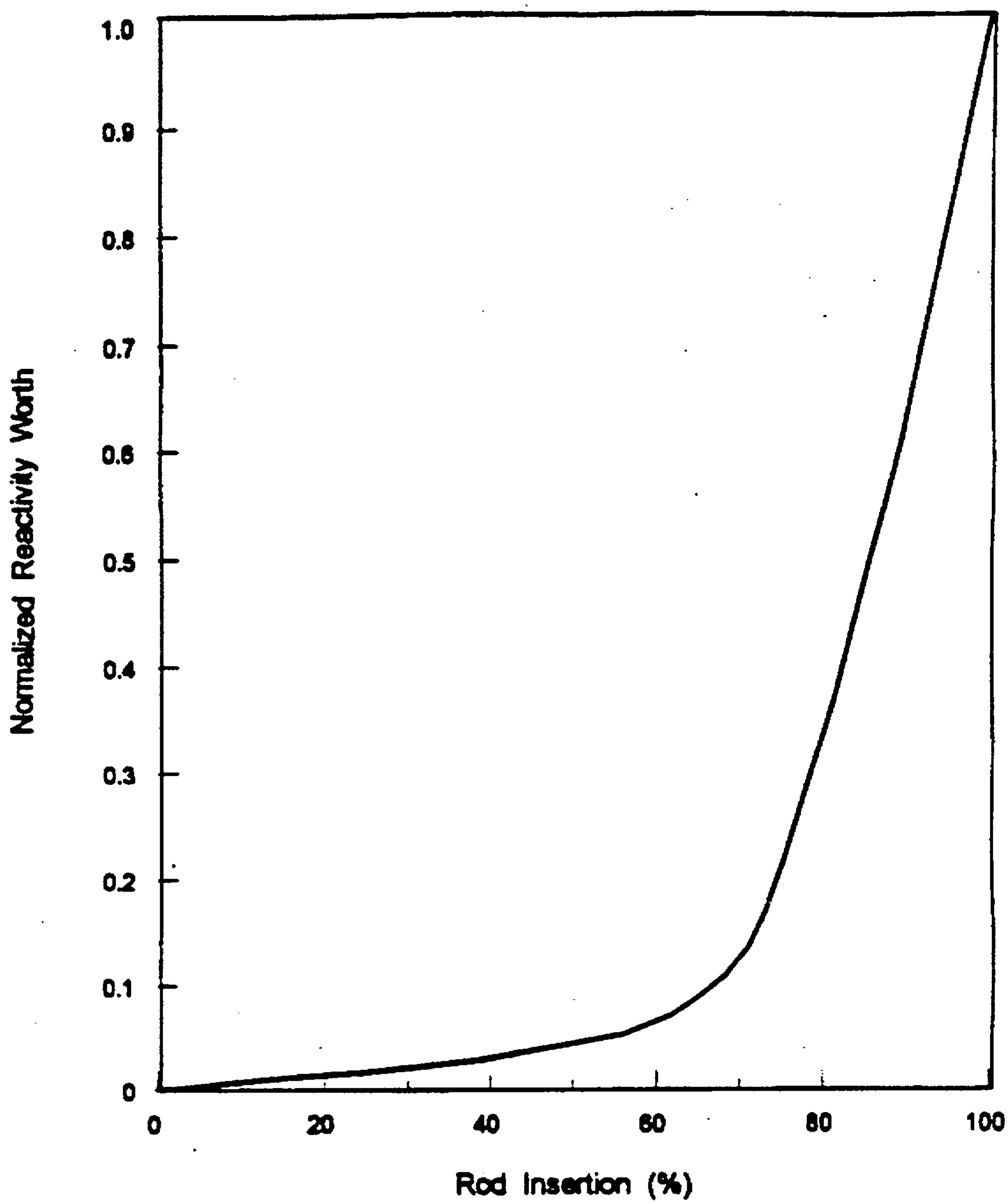
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station ILLUSTRATION OF OVERTEMPERATURE AND OVERPOWER ΔT PROTECTION
	Updated FSAR Figure 15.1-1



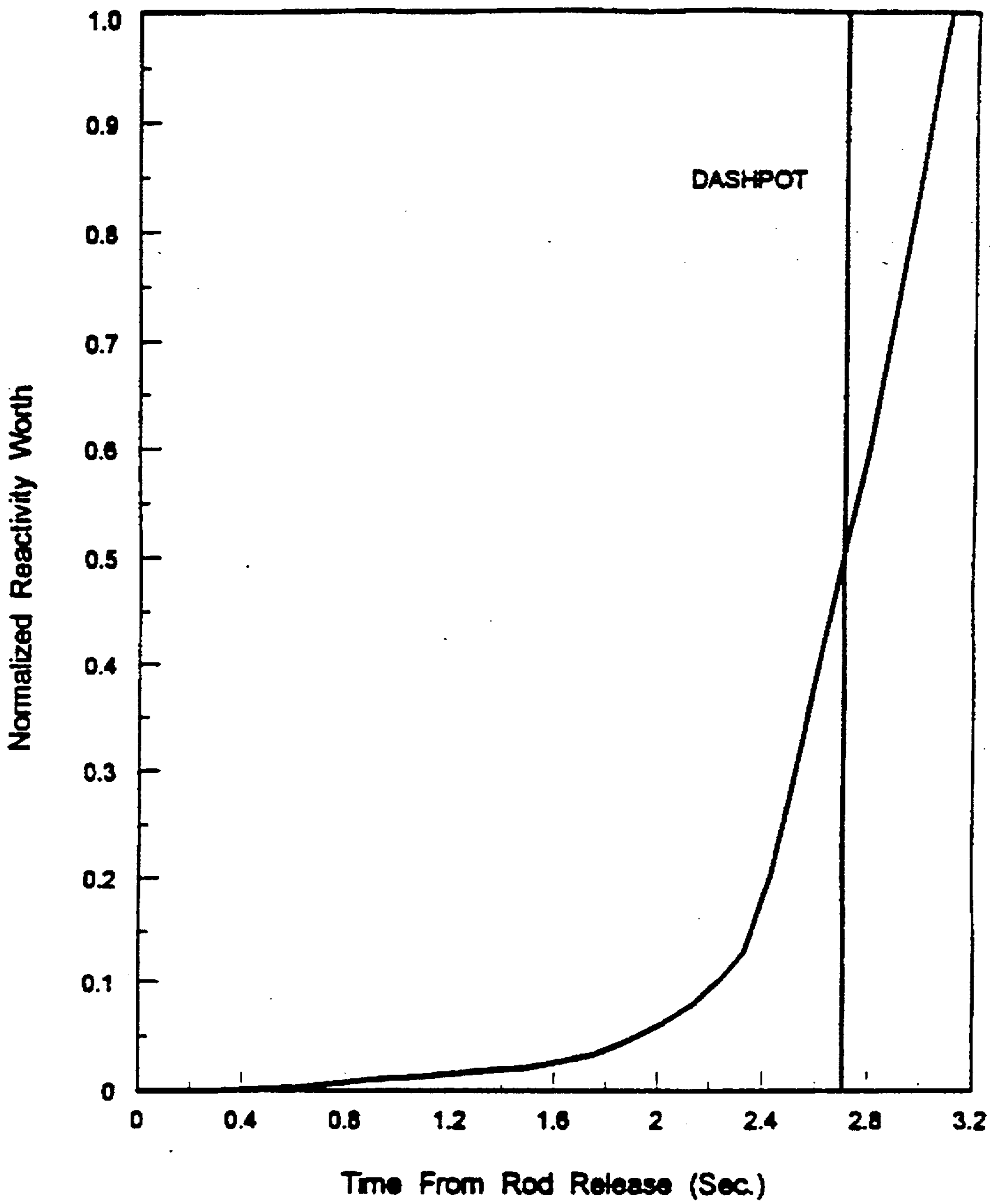
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station ROD POSITION VERSUS TIME ON REACTOR TRIP
	Updated FSAR — Figure 15.1-2



Revision 18, April 26, 2000

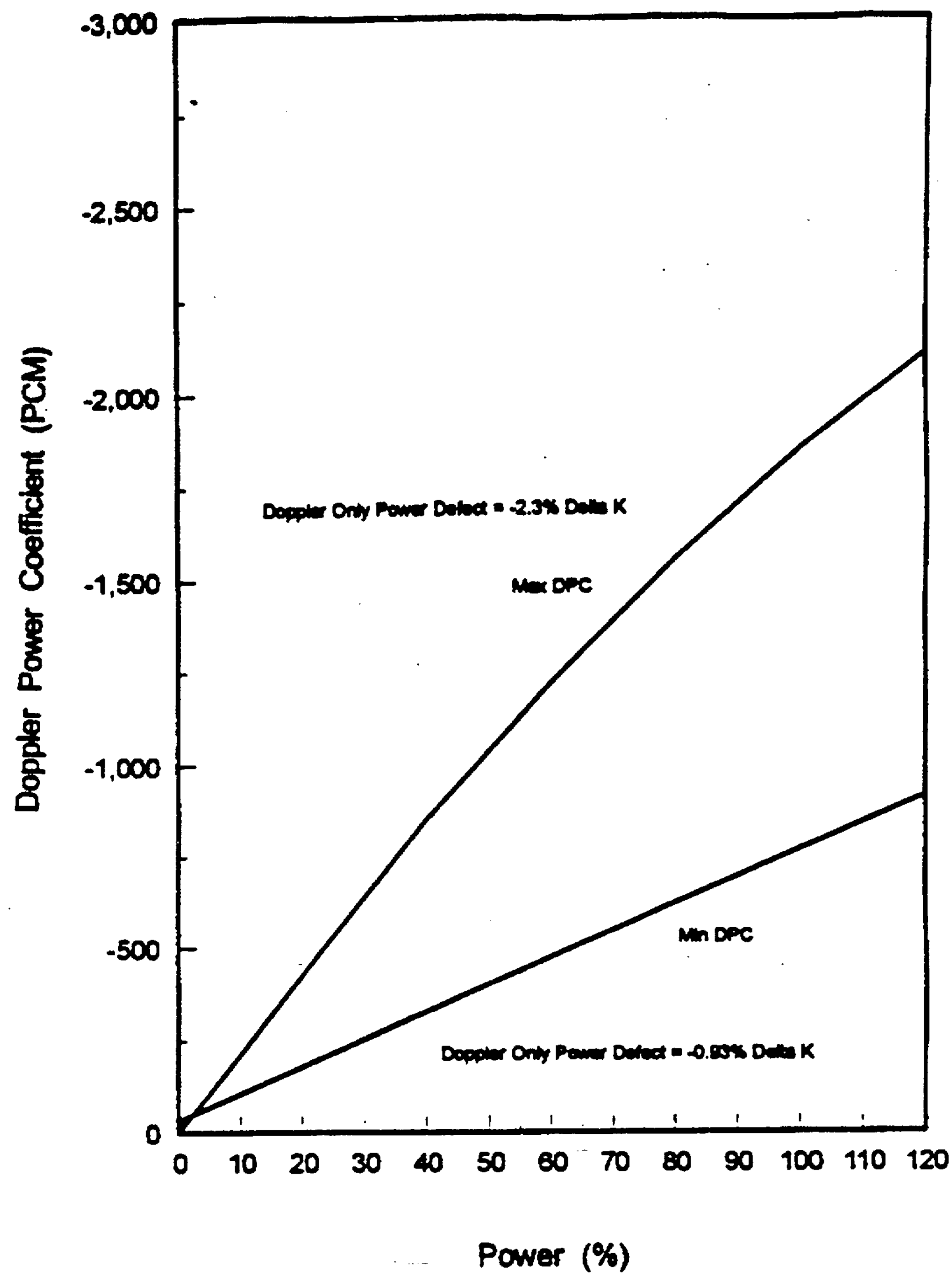
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station NORMALIZED RCCA REACTIVITY WORTH VERSUS PERCENT INSERTION
	Updated FSAR Figure 15.1-3



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station NORMALIZED RCCA REACTIVITY WORTH VERSUS TIME AFTER REACTOR TRIP
	Updated FSAR Figure 15.1-4

SCN 00-004



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station INTEGRATED DOPPLER POWER COEFFICIENT USED IN ACCIDENT ANALYSIS
	Updated FSAR Figure 15.1-5

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PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

SALEM UFSAR - REV 18	SHEET 1 OF 1
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PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

SALEM UFSAR - REV 18

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APRIL 26, 2000

F15.1-9

TABLE 15.2-1

TIME SEQUENCE OF EVENTS FOR CONDITION II EVENTS

Accident	Event	Time (sec)
Uncontrolled RCCA Withdrawal from a Subcritical Condition	Initiation of uncontrolled rod withdrawal (7.5×10^{-5} ΔK/sec reactivity insertion rate from 10^{-9} of nominal power)	0.0
	Power range high neutron flux low setpoint reached	10.4
	Peak nuclear power occurs	10.6
	Rods begin to drop	10.9
	Peak heat flux occurs	12.7
	Peak average clad temperature occurs	13.5
	Minimum DNBR occurs	12.7
	Peak average fuel temperature occurs	14.2
Uncontrolled RCCA Withdrawal at Power	Initiation of uncontrolled RCCA withdrawal at maximum reactivity insertion rate	

Accident	Event	Time (sec)
1. Case A	(7.5×10^{-4} ΔK/sec)	0
	Power range high neutron flux high trip point reached	6.6
	Rods begin to drop	7.1
	Minimum DNBR occurs	7.4
2. Case B	Initiation of uncontrolled RCCA withdrawal at a small reactivity insertion rate (3.0×10^{-5} ΔK/sec)	0
	Overtemperature ΔT reactor trip signal initiated	472.3
	Rods begin to drop	473.8
	Minimum DNBR occurs	474.1
Uncontrolled Boron Dilution		
1. Dilution during refueling and startup	Dilution begins	0
	Operator isolates source of dilution; minimum margin to criticality occurs	>1800
2. Dilution during Startup	Dilution begins	0
	Operator isolates source of dilution: minimum margin to criticality occurs	>900

TABLE 15.2-1 (Cont)

Accident	Event	Time (sec)
2. Dilution during full power operation		
a. Automatic reactor control	Dilution begins	0
	1.3 percent shutdown margin lost	>900
b. Manual reactor control	Dilution begins	0
	Overtemperature ΔT reactor trip signal initiated	89
	Rods begin to drop	91
	1.3 percent shutdown is lost (if dilution continues after trip)	>900
Partial Loss of Forced Reactor Coolant Flow		
1. All loops operating; two pumps coasting down	Coastdown begins	0
	Low-flow reactor trip	1.6
	Rods begin to drop	2.6
	Minimum DNBR occurs	3.9

TABLE 15.2-1 (Cont)

Accident	Event	Time (sec)
Loss of External Electrical Load		
1. With pressurizer control (BOL)	Loss of electrical load	0
	Initiation of steam release from steam generator safety valves	7.6
	Peak RCS pressure occurs	10.6
	Overtemperature ΔT reactor trip signal initiated	12.8
	Rods begin to drop	14.3
	Minimum DNBR occurs	15.6

TABLE 15.2-1 (Cont)

Accident	Event	Time (sec)
2. Without pressurizer control (BOL)	Loss of electrical load	0
	High pressurizer pressure reactor trip point reached	5.6
	Initiation of steam release from steam generator safety valves	6.4
	Rods begin to drop	7.6
	Minimum DNBR occurs	(1)
	Peak RCS pressure occurs	8.6

TABLE 15.2-1 (Cont)

Accident	Event	Time (sec)
Loss of normal feedwater	Low-low steam generator water level reactor trip	50
	Rods begin to drop	52
	Peak water level in pressurizer occurs	55
	All steam generators begin to receive auxiliary feed from motor-driven pumps	110
Loss of Power to the Station Auxiliaries	Reactor coolant pumps begin to coast	2
	Low-low steam generator water level reactor trip	52
	Rods begin to drop	54
	Peak pressurizer water level occurs	57
	All steam generators begin to receive auxiliary feed from motor-driven pumps	112

TABLE 15.2-1 (Cont)

Accident	Event	Time (sec)
Excessive feedwater at full load (single loop)	One feedwater control valve and one feedwater bypass valve fail fully open	0
	High-high steam generator water level setpoint reached	32.0
	Turbine trip	34.5
	Minimum DNBR	35.0
	Rods begin to drop (reactor trip on turbine trip)	36.5
	Feedwater flow isolated due to high-high steam generator water level	64.0
Excessive feedwater at full load (multi-loop)	Four feedwater control valves and four feedwater bypass valves fail fully open	0
	Minimum DNBR	44.0
	High-high steam generator water level setpoint reached	119.7
	Turbine trip	122.2
	Rods begin to drop (reactor trip on turbine trip)	124.2
	Feedwater flow isolated due to high-high steam generator water level	151.7

TABLE 15.2-1 (Cont)

Accident		Event	Time (sec)
Excessive Load Increase			
1.	Manual Reactor Control (BOL)	10% step load increase	0.0
		Peak pressurizer pressure occurs	0.1
		Minimum DNBR occurs	5.1
		Peak nuclear power occurs	165.0
2.	Manual Reactor Control (EOL)	10% step load increase	0.0
		Peak pressurizer pressure occurs	0.1
		Peak nuclear power occurs	48.2
		Minimum DNBR occurs	117.0
3.	Automatic Reactor Control (BOL)	10% step load increase	0.0
		Peak pressurizer pressure occurs	9.0
		Minimum DNBR occurs	43.0
		Peak nuclear power occurs	43.3
4.	Automatic Reactor Control (EOL)	10% step load increase	0.0
		Peak pressurizer pressure occurs	12.7
		Peak nuclear power occurs	20.7
		Minimum DNBR occurs	58.0

TABLE 15.2-1 (Cont)

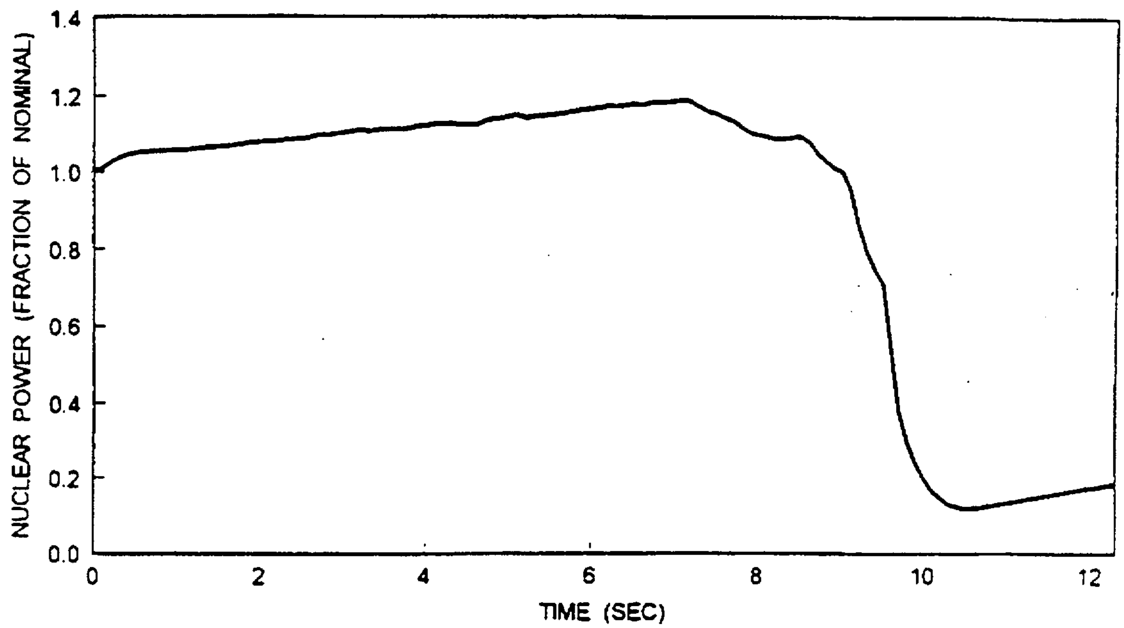
Accident	Event	Time (sec)
Accidental Depressurization of the Reactor Coolant System	Inadvertent opening of one RCS safety valve	0.0
	Overtemperature ΔT reactor trip setpoint reached	35.0
	Rod motion begins	36.5
	Minimum DNBR occurs	37.0

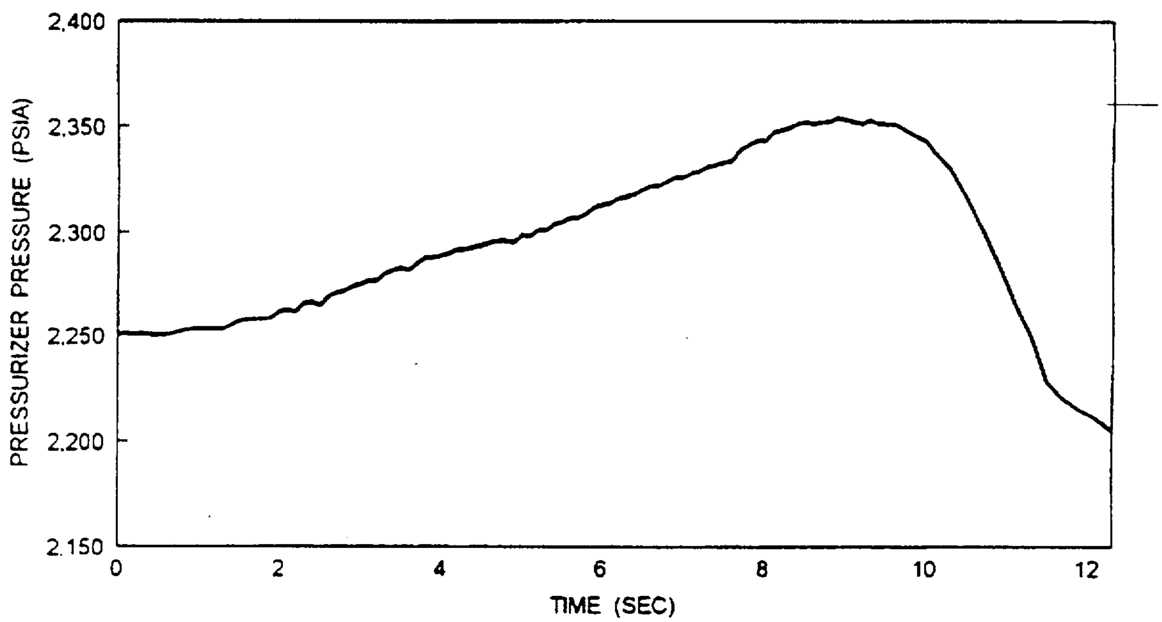
TABLE 15.2-1 (Cont)

Accident	Event	Time (sec)
Accidental Depressurization of the Main Steam System	Inadvertent opening of one main steam safety or relief valve	0
	Safety injection actuation on high steamline differential pressure	78
	Isolation of main feed water	88
	Pressurizer empties	196
	2300 ppm boron reaches RCS loops	283
Spurious Operation of the SIS at Power	Charging pumps begin injecting borated water (reactor/turbine trip on SI signal)	0.0
	Pressurizer becomes water-solid	588.8
	Time by which PORV must be open to prevent water relief through the PSVs	623.0
	Manual procedures to terminate the event are completed	≤2700.0

NOTE:

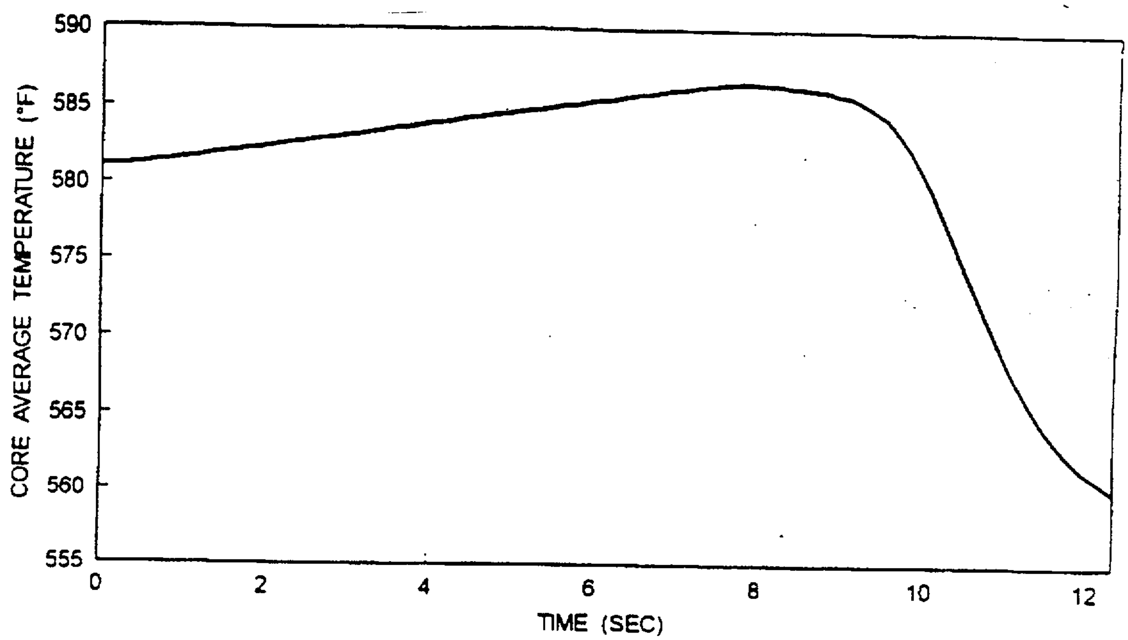
(1) DNBR does not decrease below its initial value.

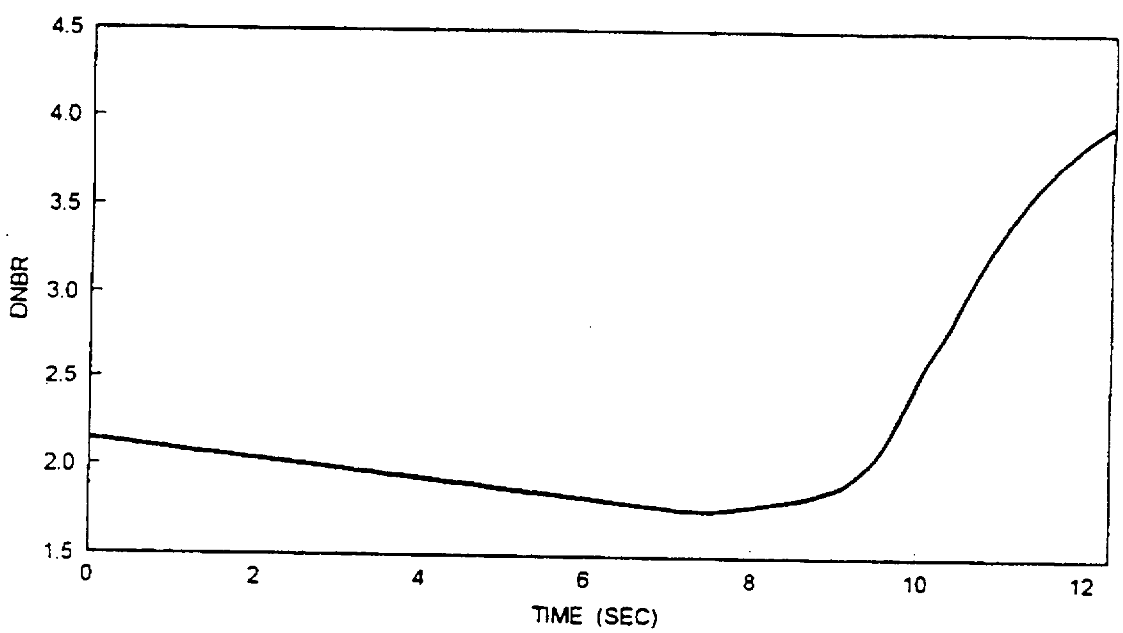




Revision 18, April 26, 2000

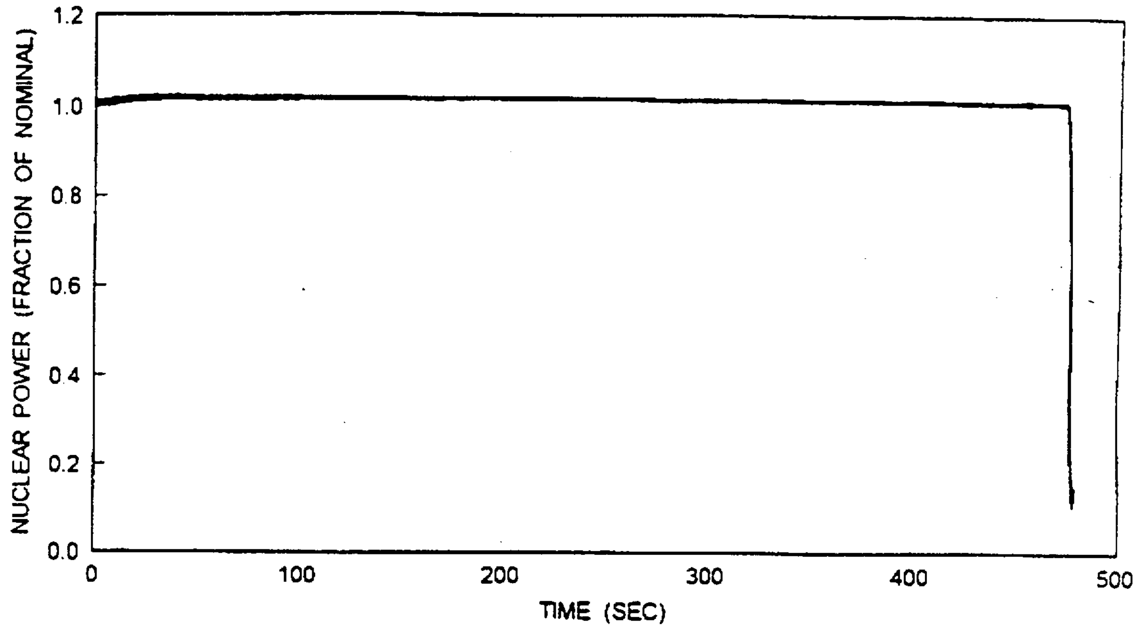
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station TRANSIENT RESPONSE FOR UNCONTROLLED ROD WITHDRAWAL FROM FULL POWER TERMINATED BY HIGH NEUTRON FLUX TRIP (75 pcm/sec)
	Updated FSAR — Figure 15.2-4

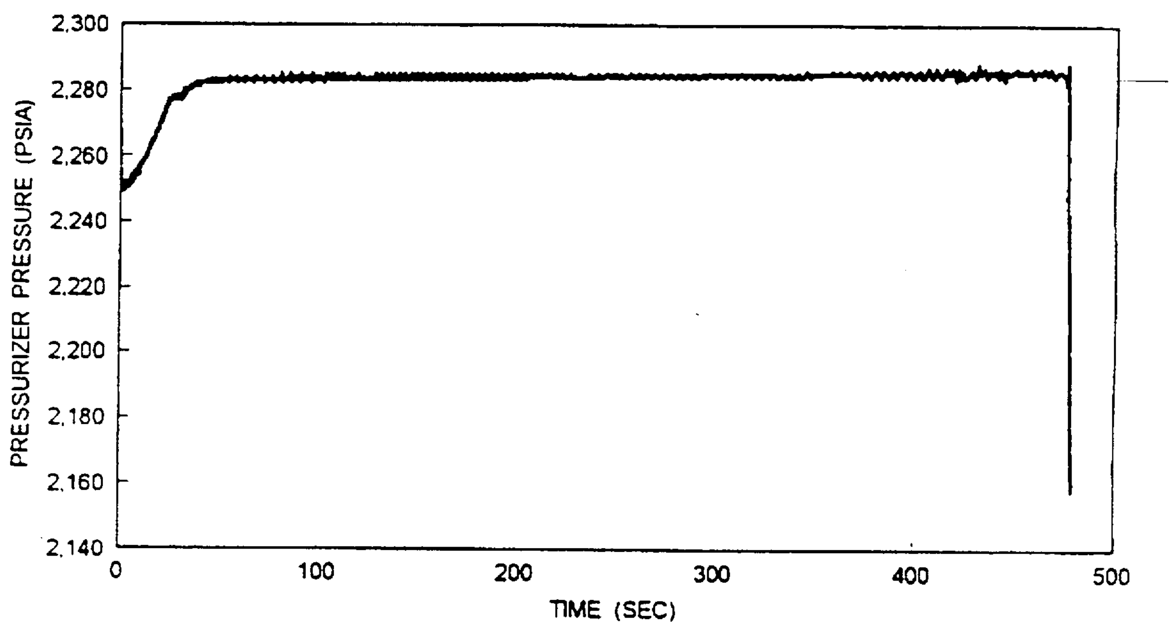




Revision 18, April 26, 2000

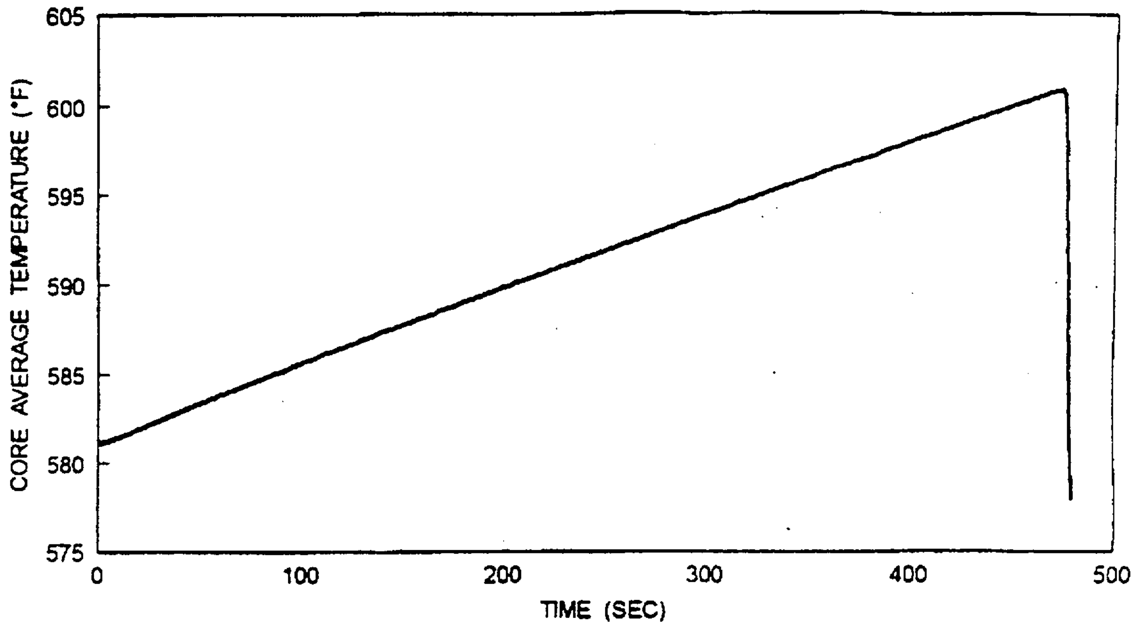
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station TRANSIENT RESPONSE FOR UNCONTROLLED ROD WITHDRAWAL FROM FULL POWER TERMINATED BY HIGH NEUTRON FLUX TRIP (75pcm/sec)
	Updated FSAR Figure 15.2-5

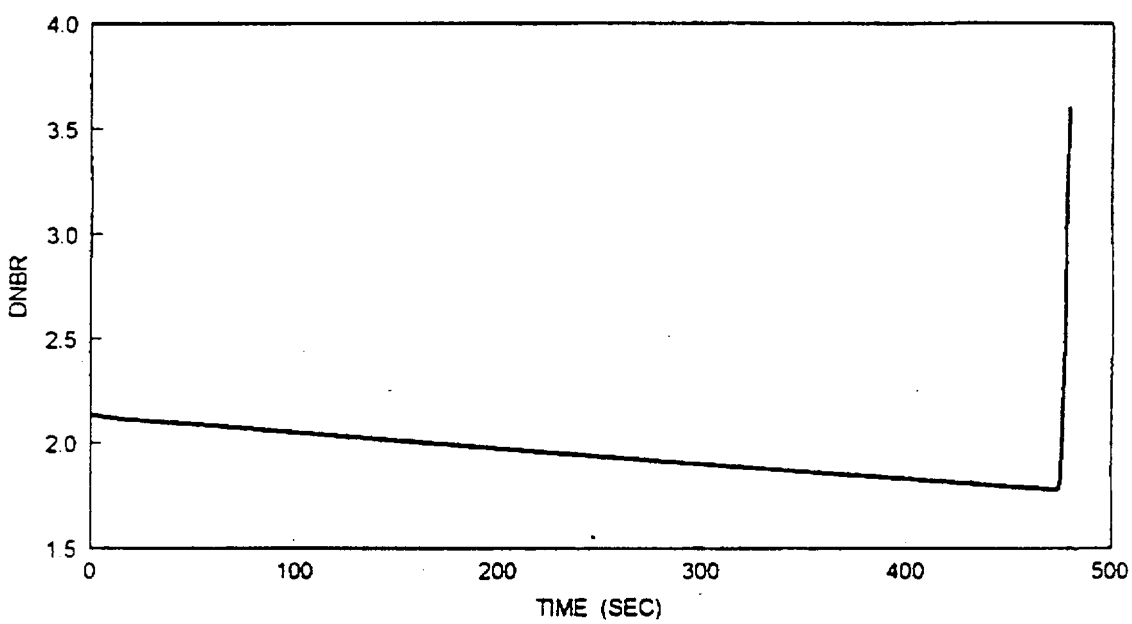




Revision 18, April 26, 2000

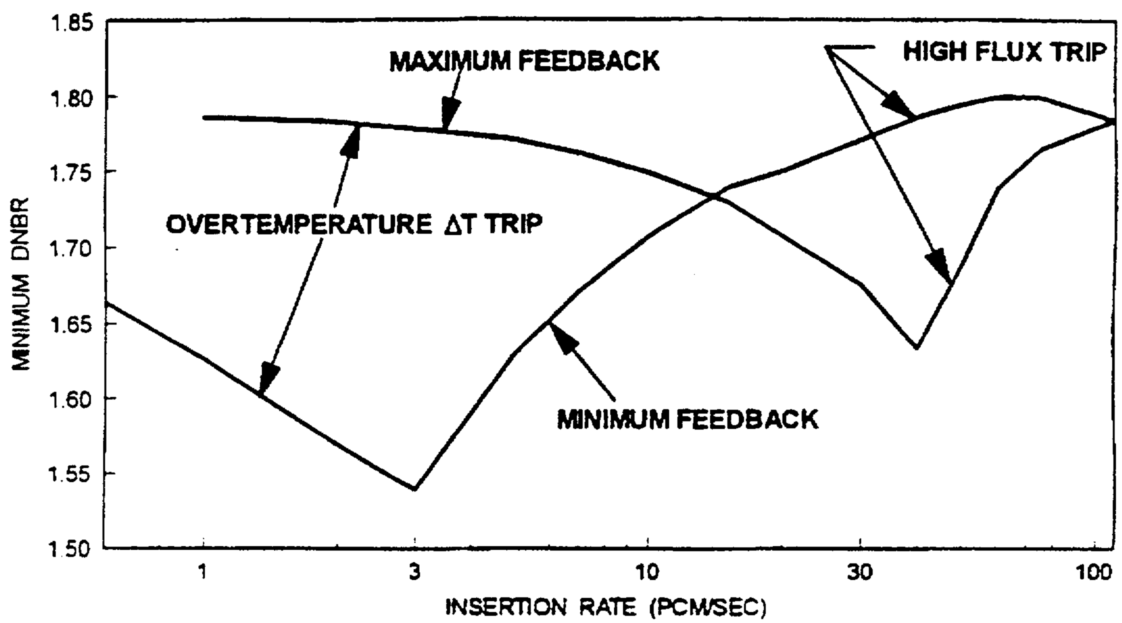
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station TRANSIENT RESPONSE FOR UNCONTROLLED ROD WITHDRAWAL FROM FULL POWER TERMINATED BY OVERTEMPERATURE ΔT TRIP(3pcm/sec)
	Updated FSAR Figure 15.2-6





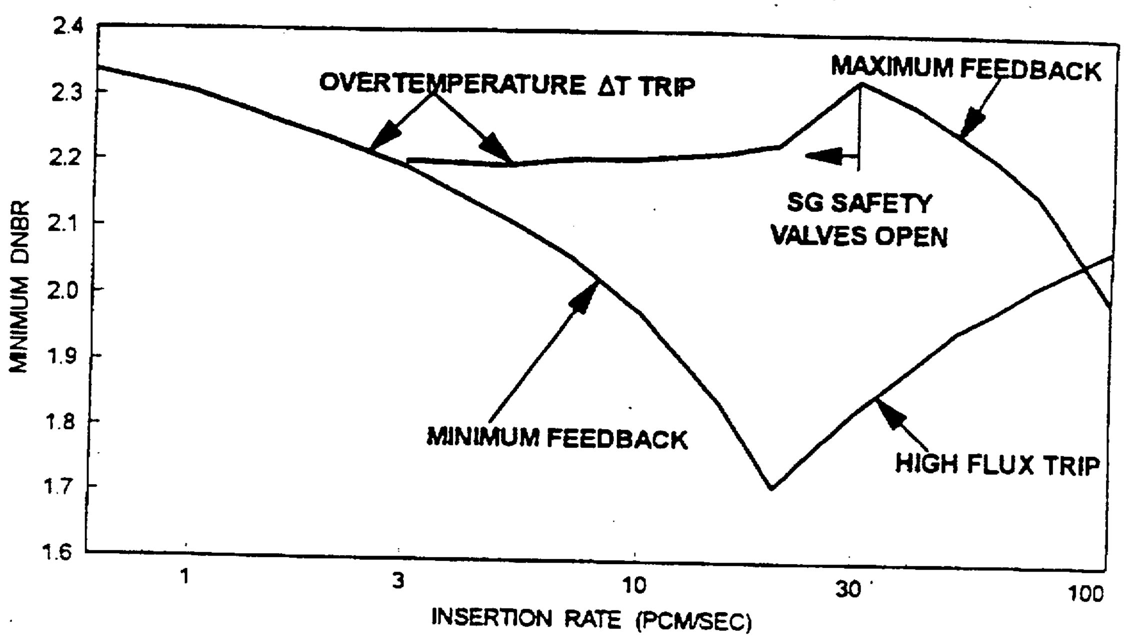
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station TRANSIENT RESPONSE FOR UNCONTROLLED ROD WITHDRAWAL FROM FULL POWER TERMINATED BY OVERTEMPERATURE ΔT TRIP(3pcm/sec)
	Updated FSAR — Figure 15.2-7



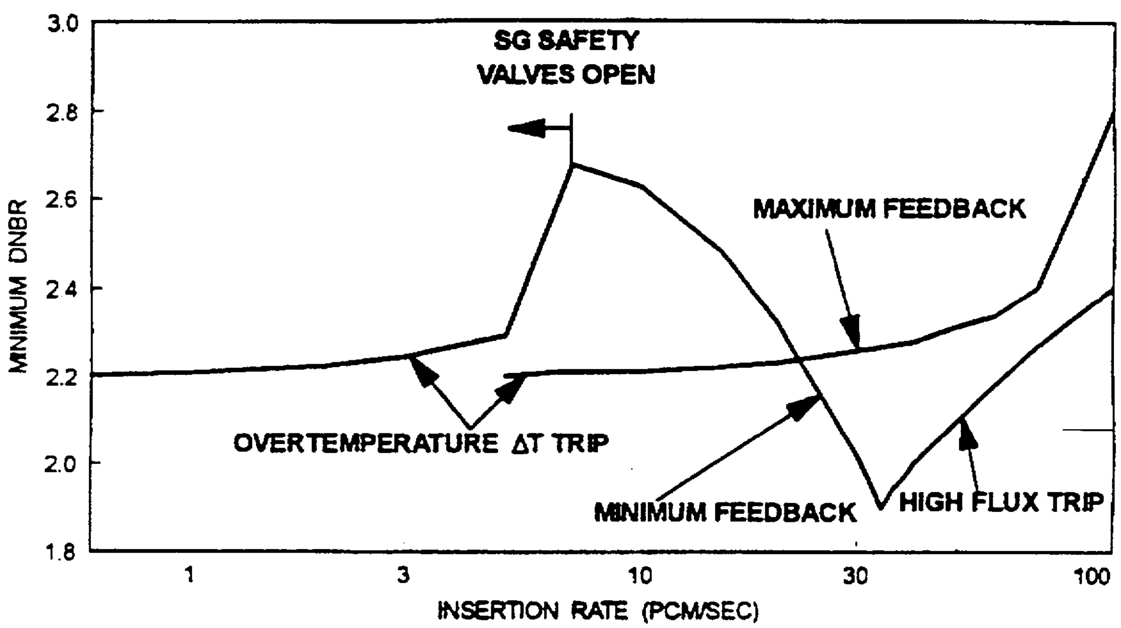
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station EFFECT OF REACTIVITY INSERTION RATE ON MINIMUM DNBR FOR A ROD WITHDRAWAL ACCIDENT FROM 100% POWER
	Updated FSAR Figure 15.2-8



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station EFFECT OF REACTIVITY INSERTION RATE ON MINIMUM DNBR FOR A ROD WITHDRAWAL ACCIDENT FROM 60% POWER
	Updated FSAR Figure 15.2-9



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station EFFECT OF REACTIVITY INSERTION RATE ON MINIMUM DNBR FOR A ROD WITHDRAWAL ACCIDENT FROM 10% POWER
	Updated FSAR — Figure 15.2-10

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PSEG NUCLEAR L.L.C. SALEM GENERATING STATION	
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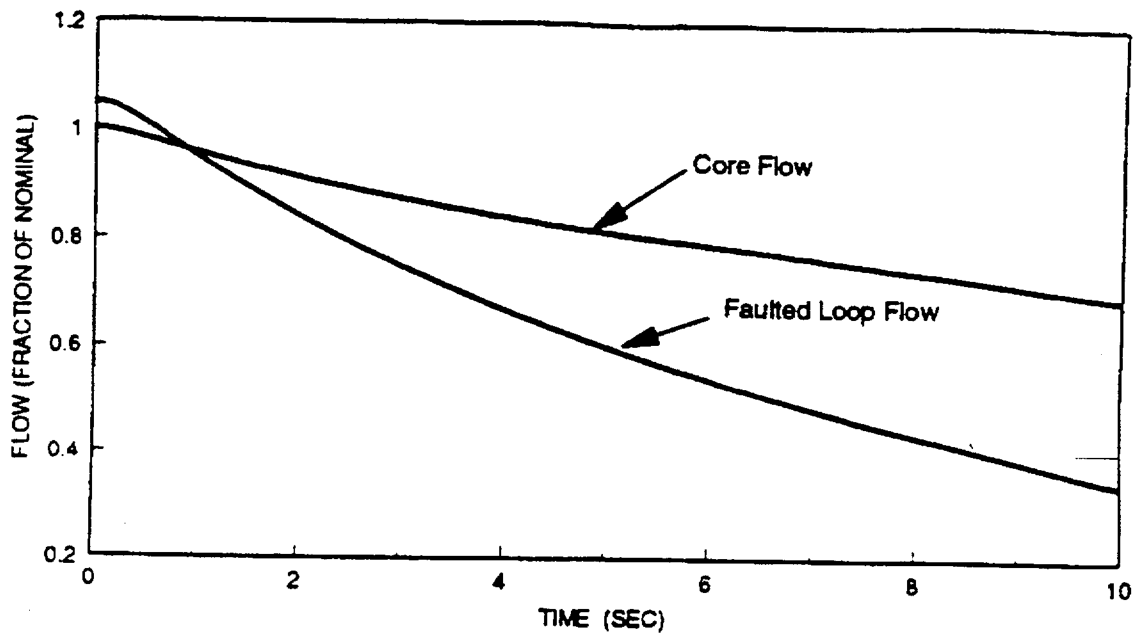
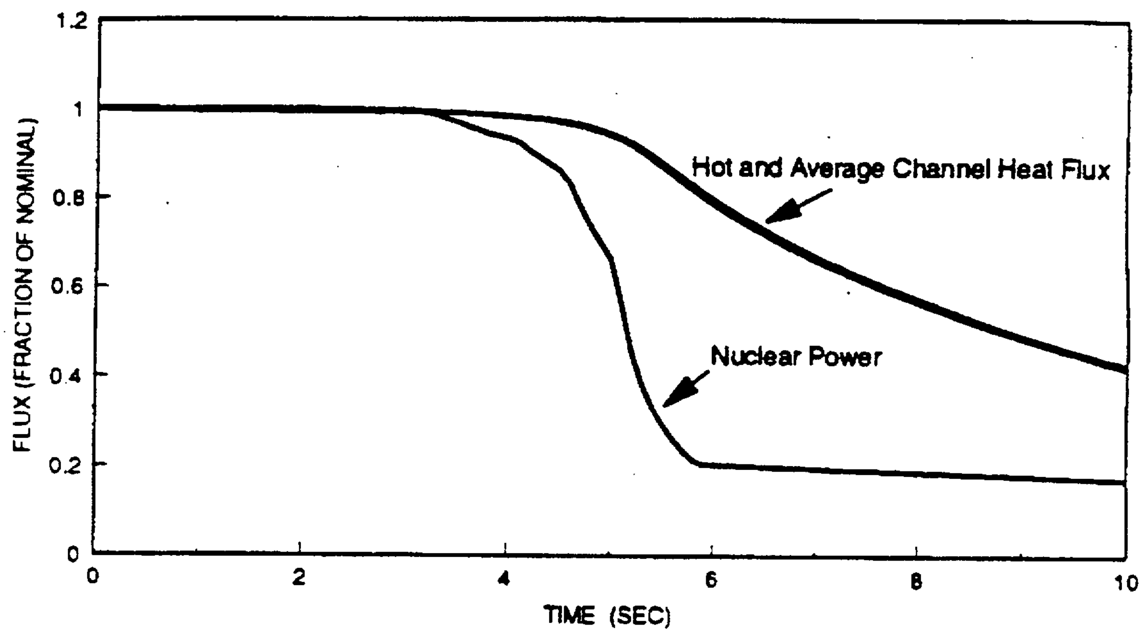


Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station ALL LOOPS OPERATING TWO LOOPS COASTING DOWN
	Updated FSAR — Figure 15.2-13



Revision 18, April 26, 2000

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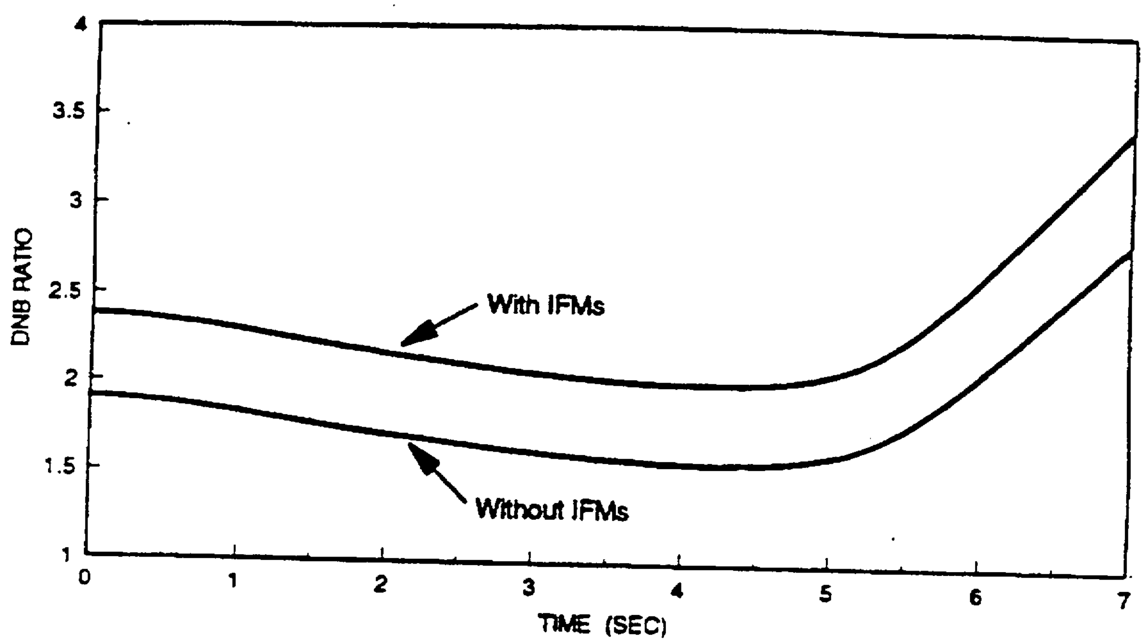
	Updated FSAR — Figure 15.2-14



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station ALL LOOPS OPERATING TWO LOOPS COASTING DOWN
	Updated FSAR — Figure 15.2-15

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C. SALEM GENERATING STATION	
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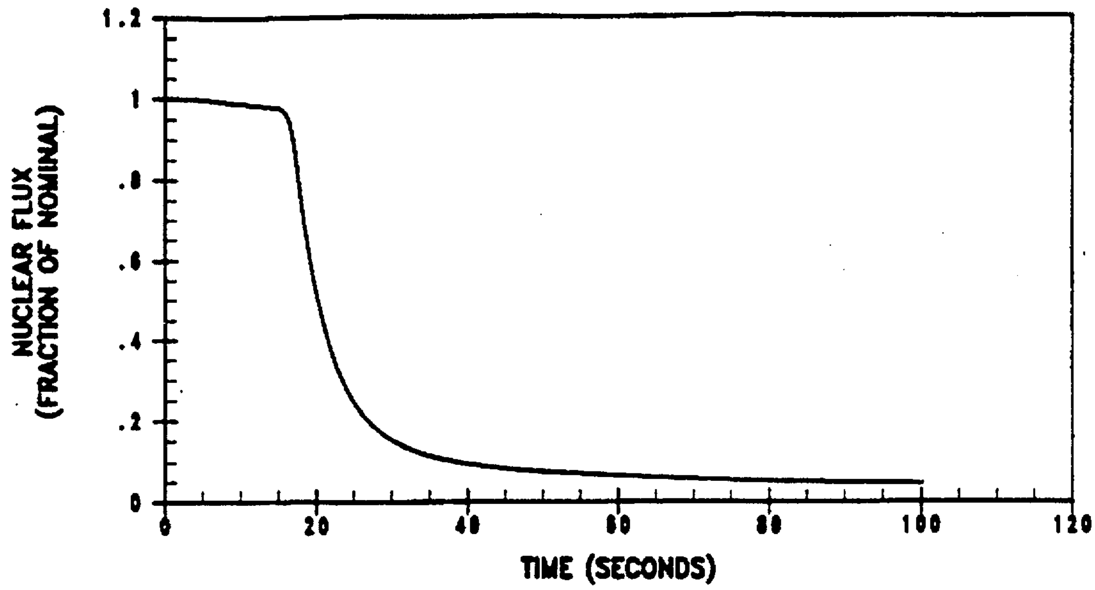
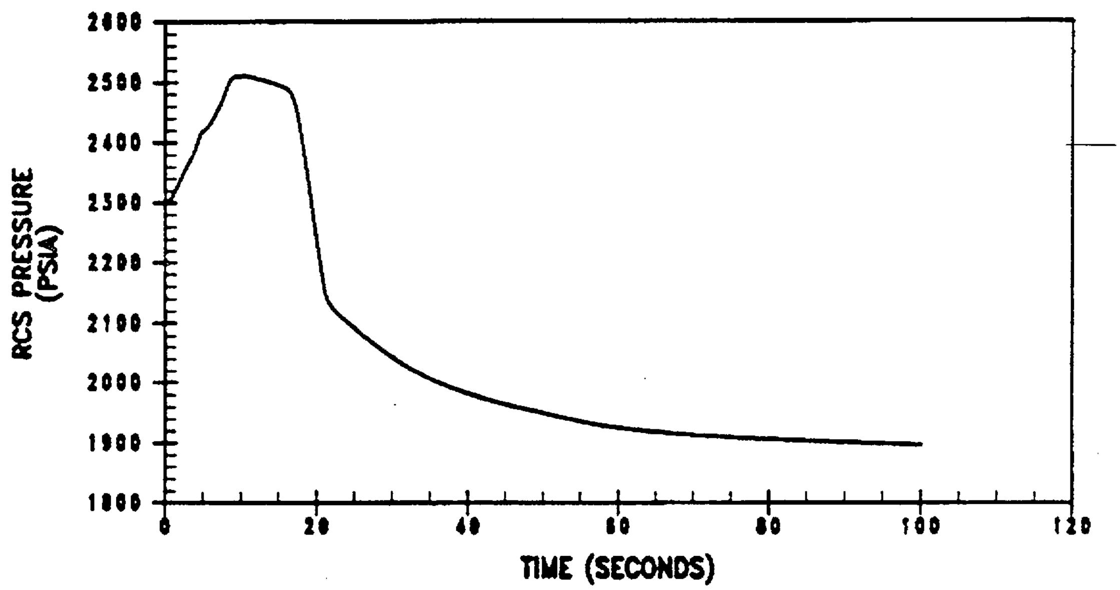
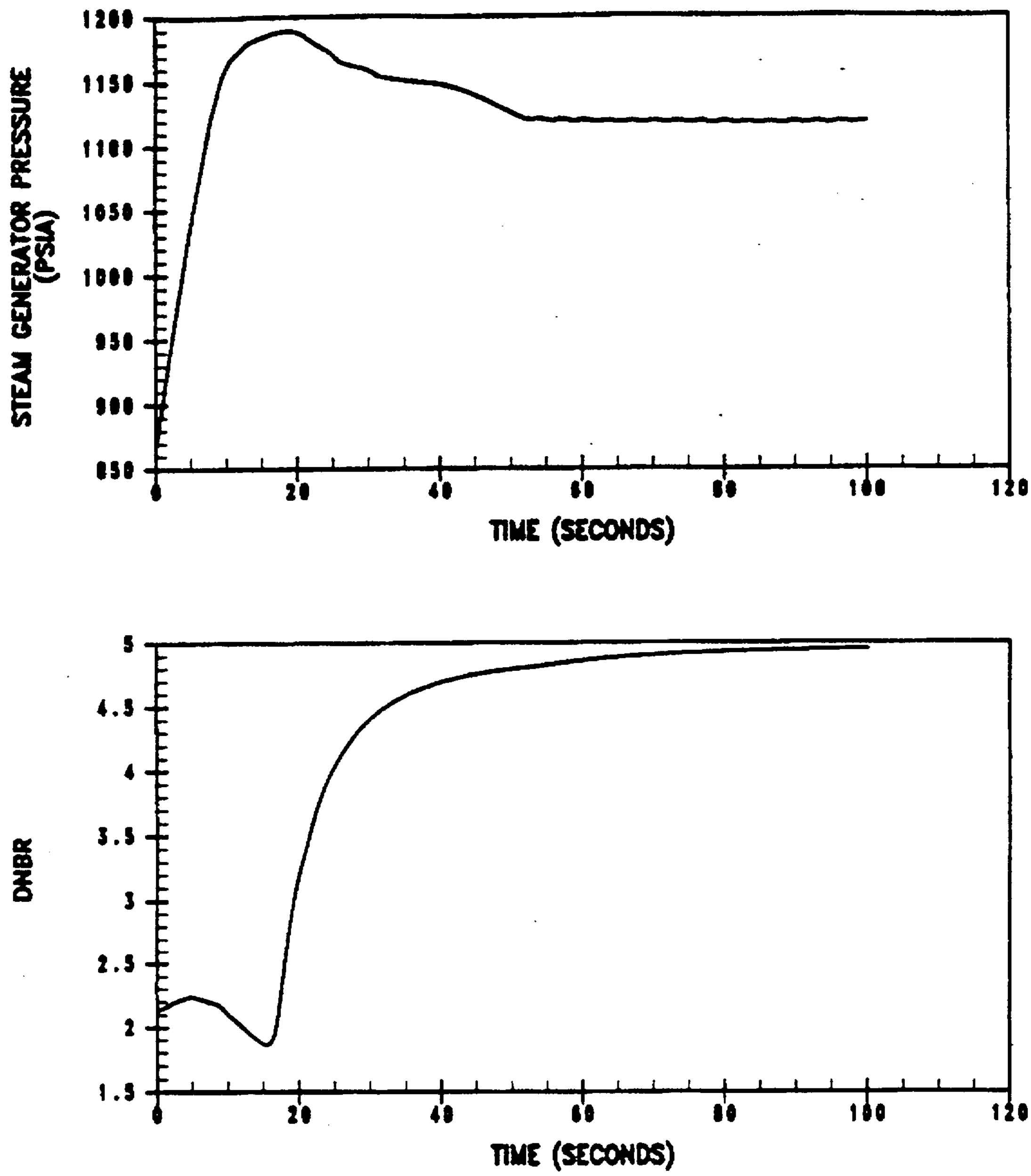
APRIL 26, 2000	F15.2-19





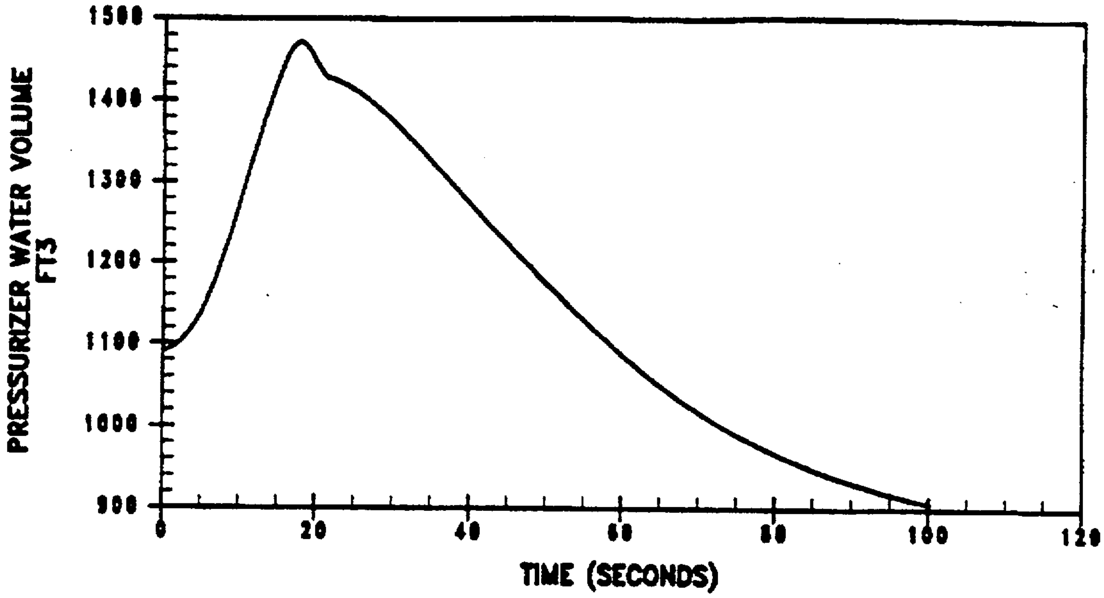
Revision 18, April 26, 2000

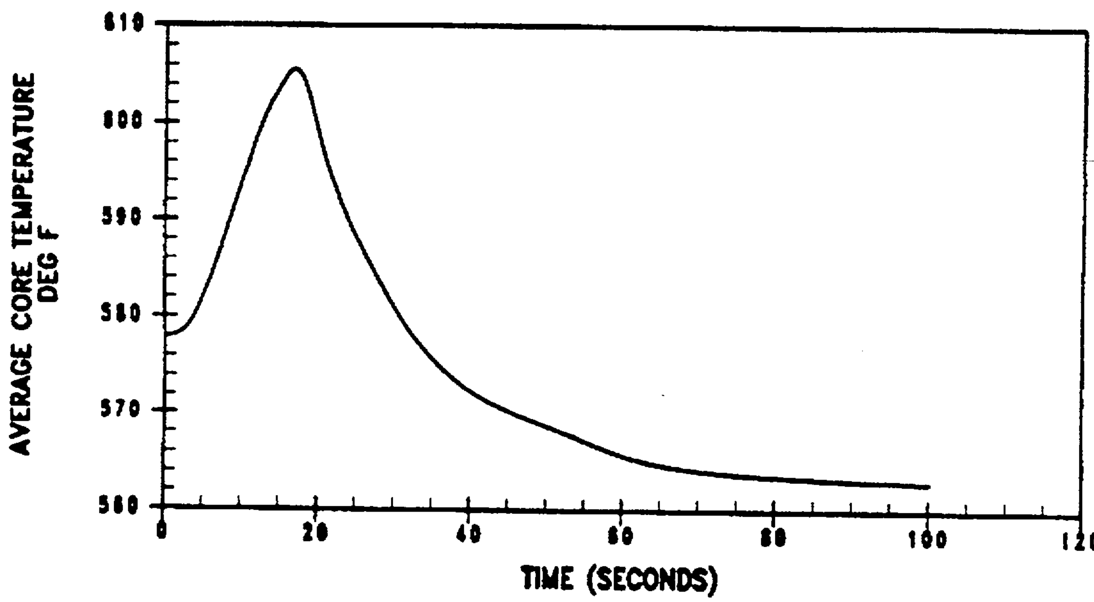
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station LOSS OF LOAD WITH AUTOMATIC PRESSURE CONTROL MINIMUM FEEDBACK(BOL)
	Updated FSAR — Figure 15.2-20



Revision 18, April 26, 2000

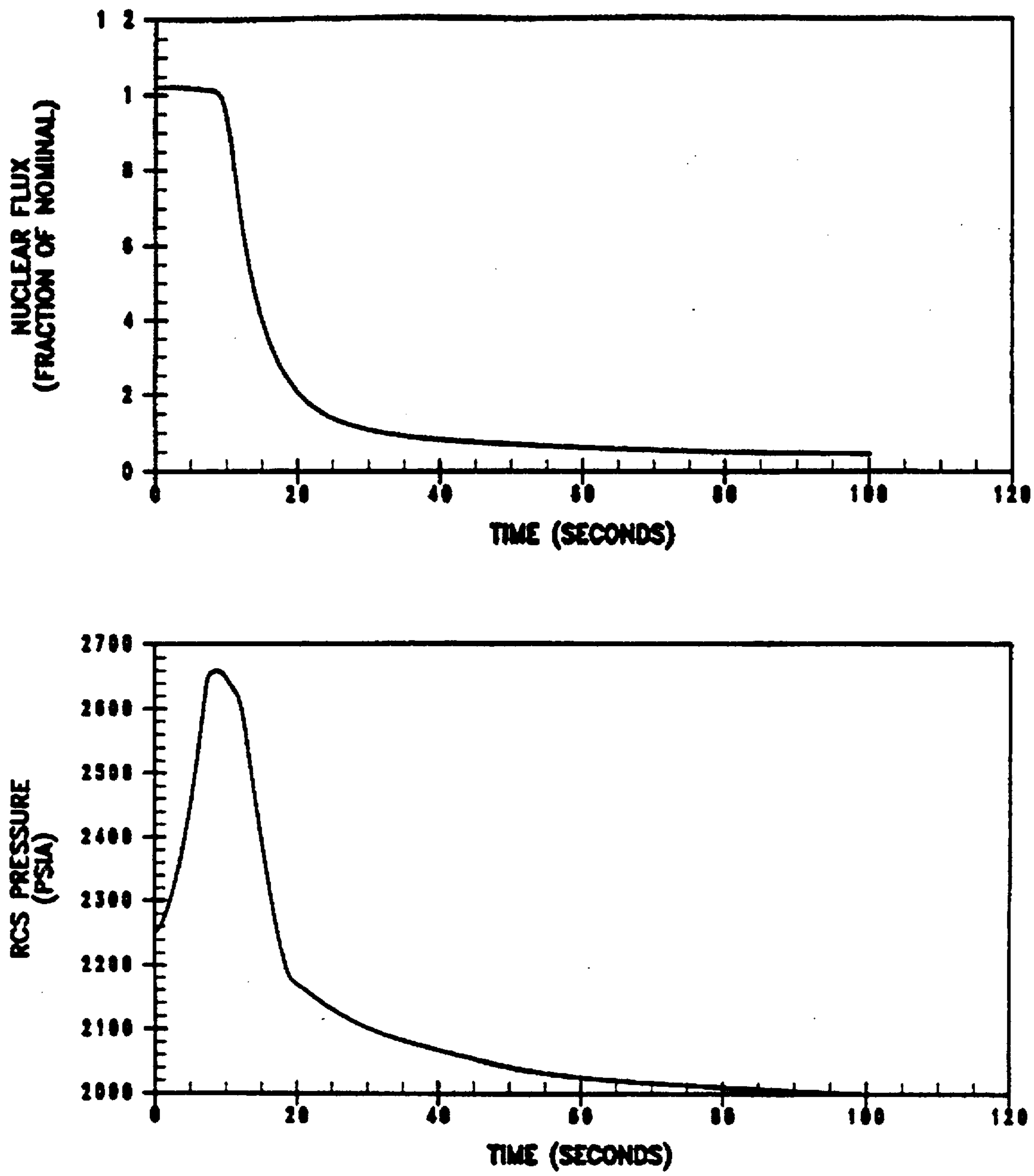
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station LOSS OF LOAD WITH AUTOMATIC PRESSURE CONTROL MINIMUM FEEDBACK(BOL)
	Updated FSAR Figure 15.2-21





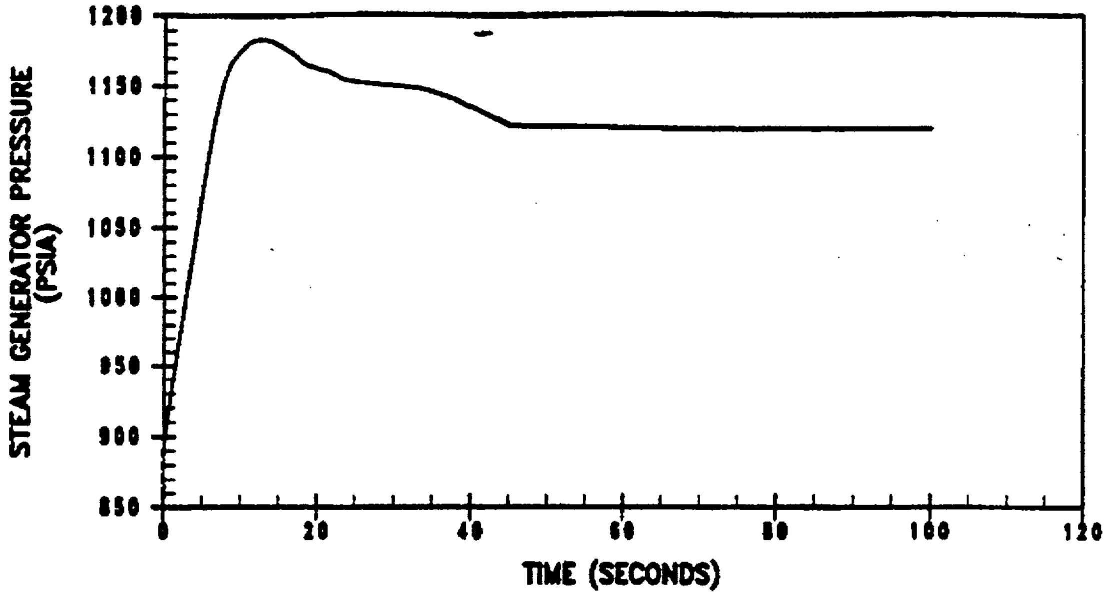
Revision 18, April 26, 2000

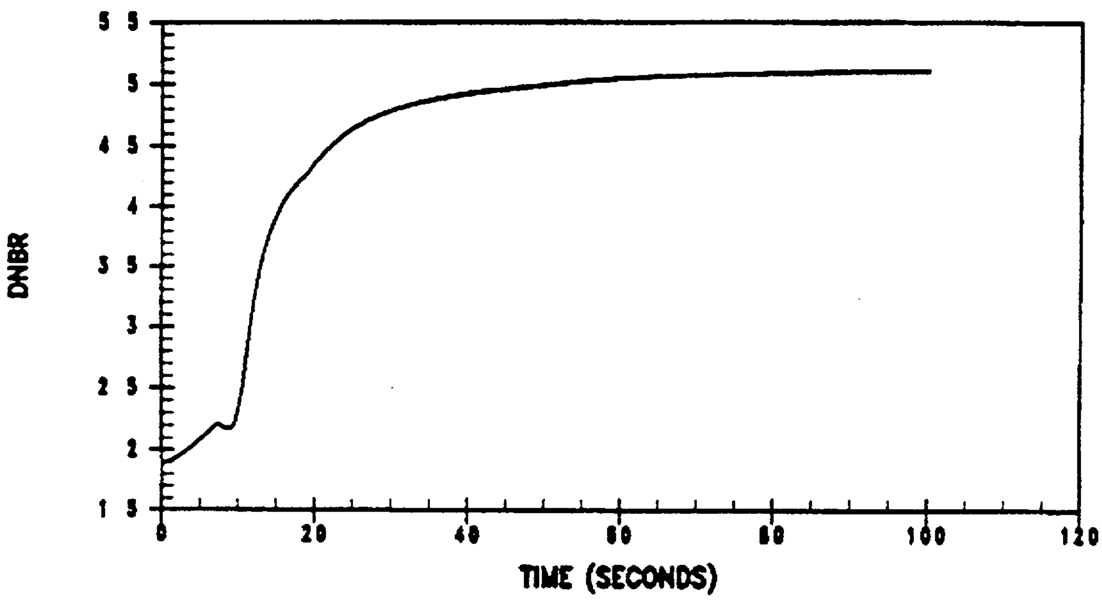
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station LOSS OF LOAD WITH AUTOMATIC PRESSURE CONTROL MINIMUM FEEDBACK (BOL)
	Updated FSAR — Figure 15.2-22



Revision 18, April 26, 2000

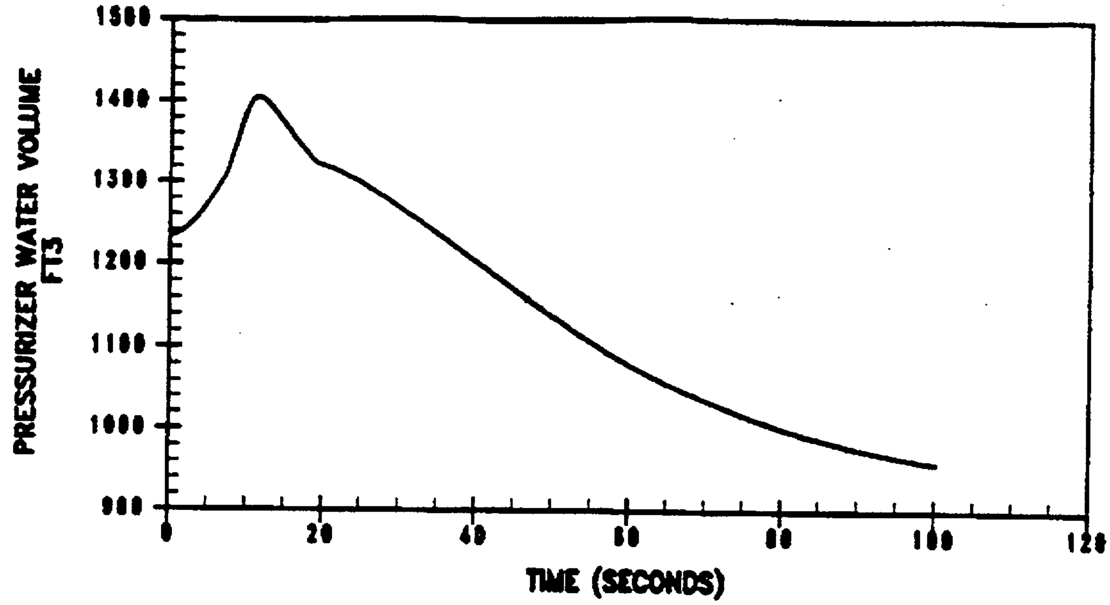
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station LOSS OF LOAD WITHOUT AUTOMATIC PRESSURE CONTROL MINIMUM FEEDBACK (BOL)
	Updated FSAR Figure 15.2-23

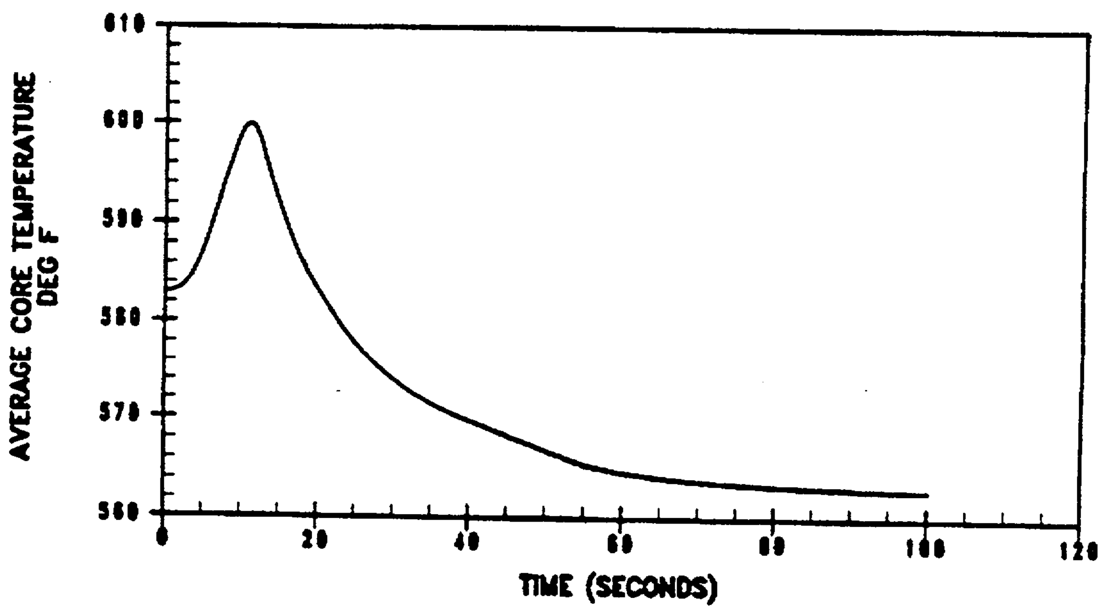




Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station LOSS OF LOAD WITHOUT AUTOMATIC PRESSURE CONTROL MINIMUM FEEDBACK (BOL)
	Updated FSAR — Figure 15.2-24





Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station LOSS OF LOAD WITHOUT AUTOMATIC PRESSURE CONTROL MINIMUM FEEDBACK (BOL)
	Updated FSAR Figure 15.2-25

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PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

SALEM UFSAR - REV 18 SHEET 1 OF 1
APRIL 26, 2000 F15.2-26

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PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

SALEM UFSAR - REV 18 SHEET 1 OF 1

APRIL 26, 2000 F15.2-27

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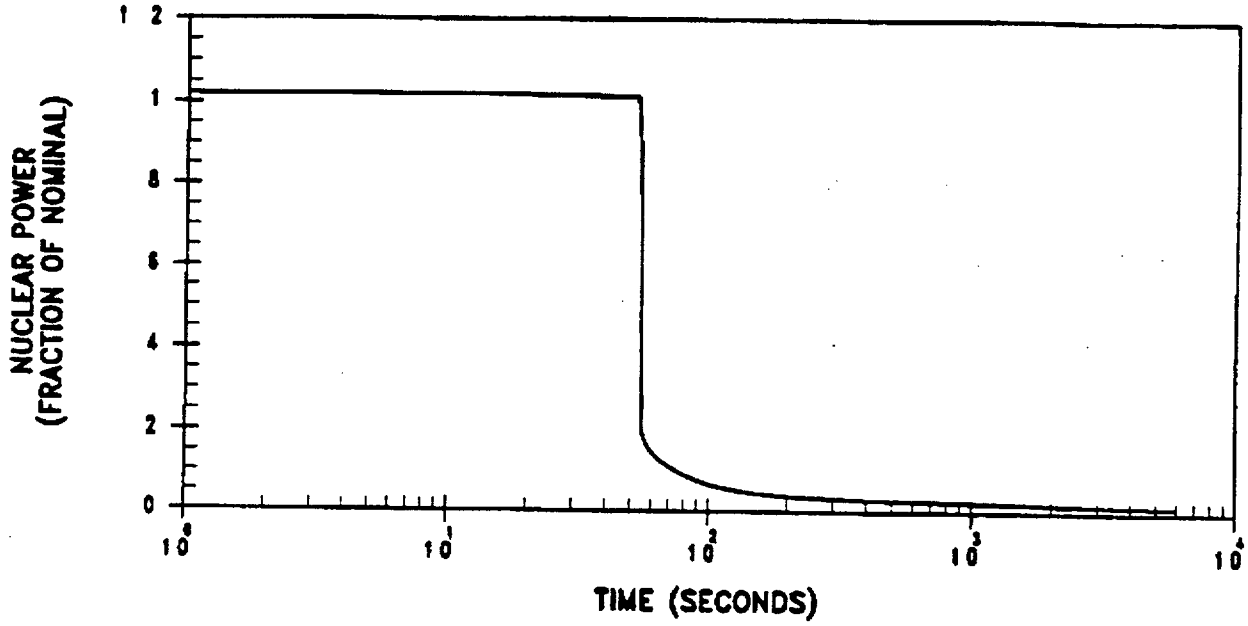
PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

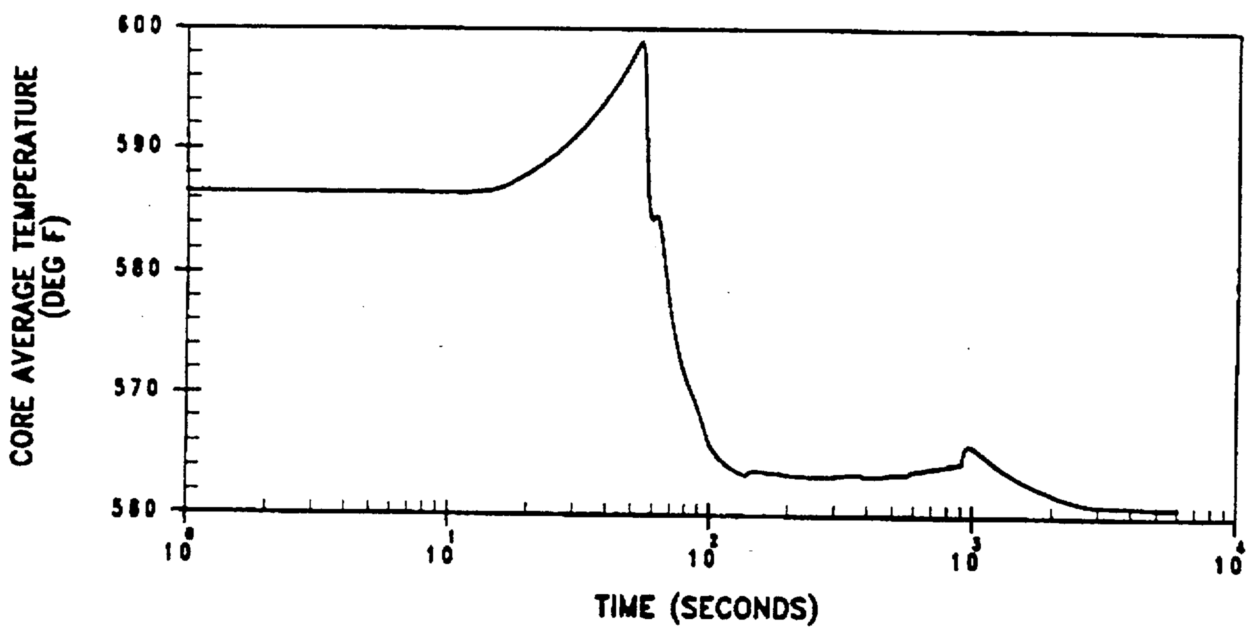
SALEM UFSAR - REV 18

APRIL 26, 2000

SHEET 1 OF 1

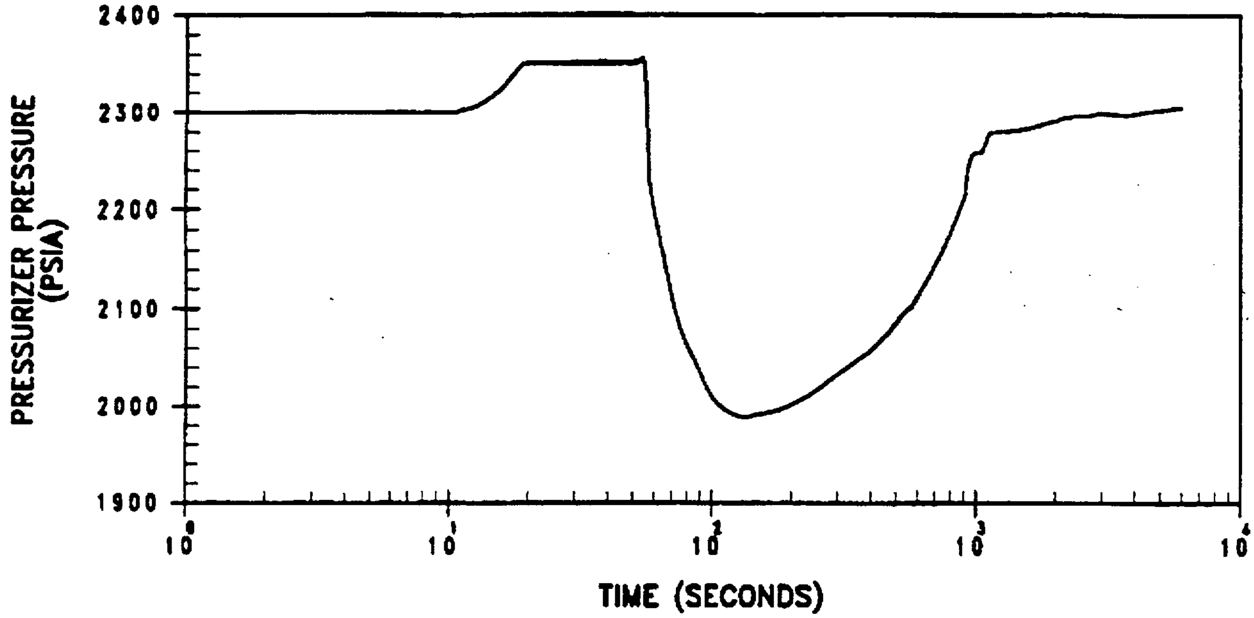
F15.2-28

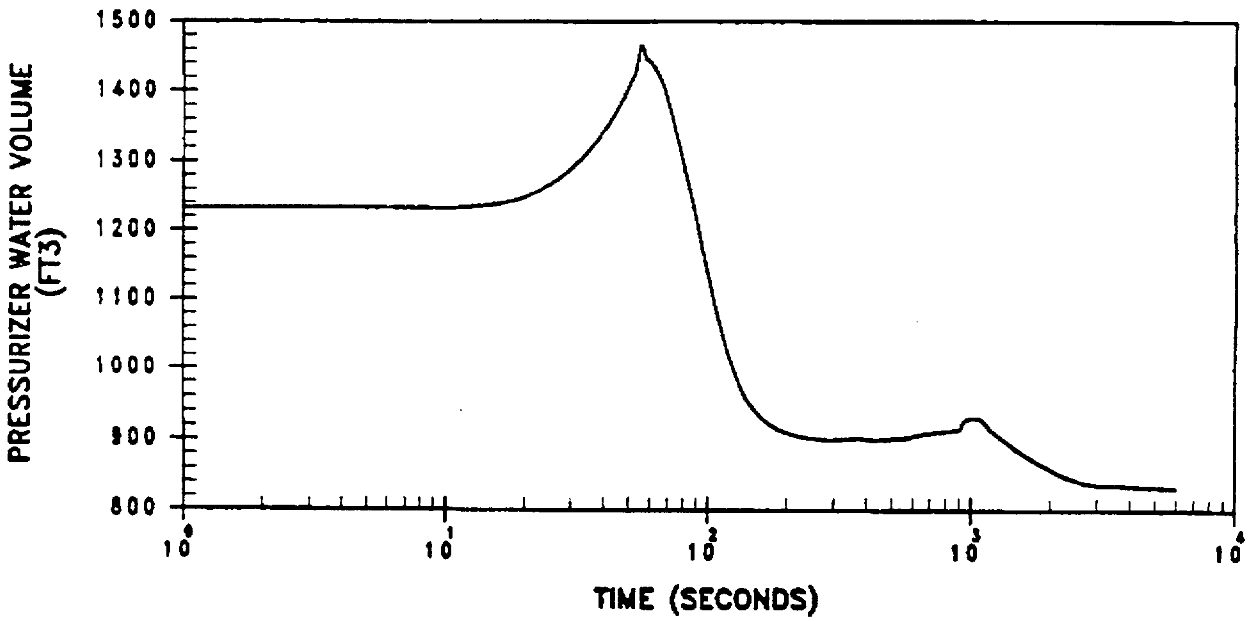




Revision 18, April 26, 2000

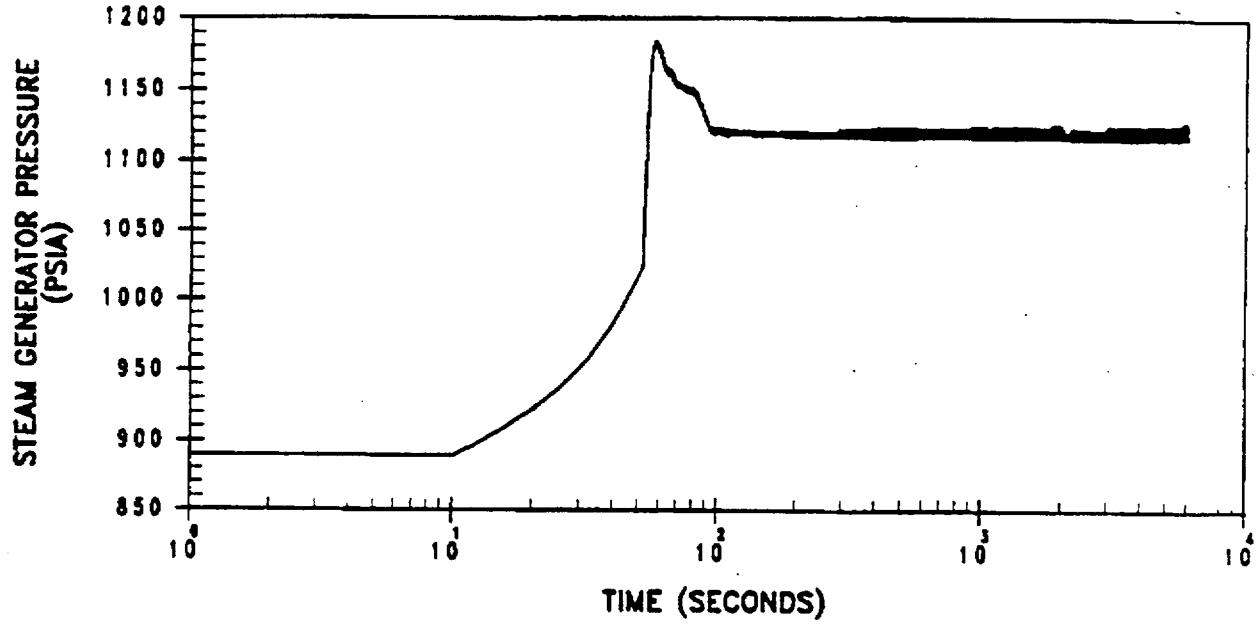
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station LOSS OF NORMAL FEEDWATER
	Updated FSAR — Figure 15.2-28A

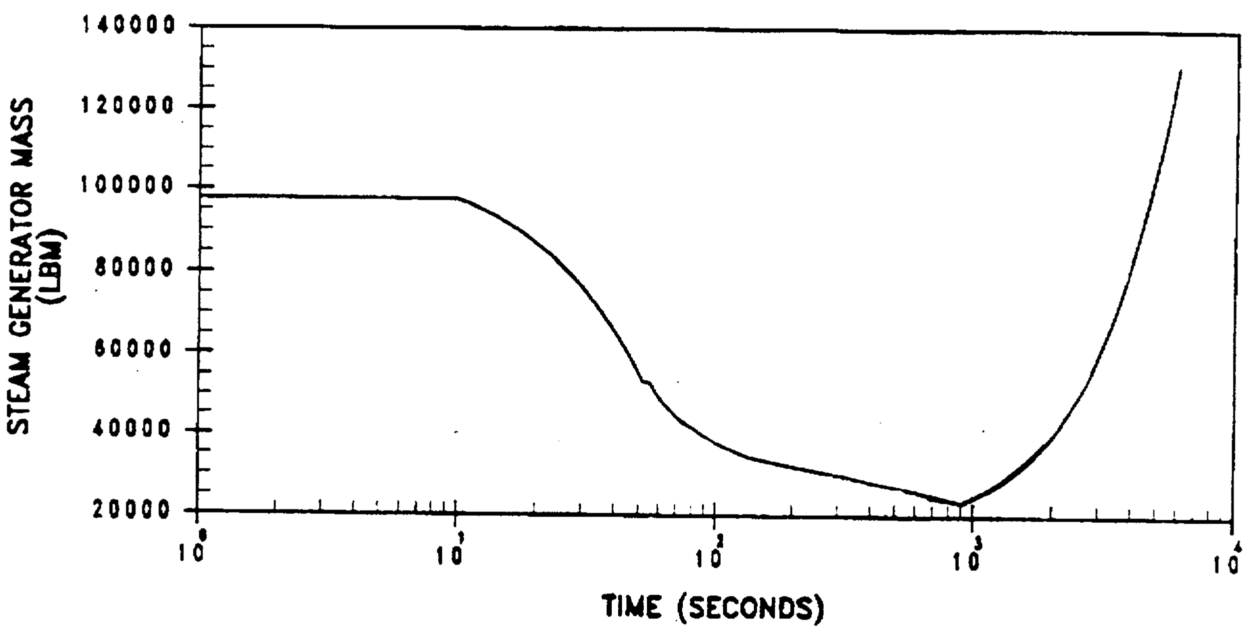




Revision 18, April 26, 2000

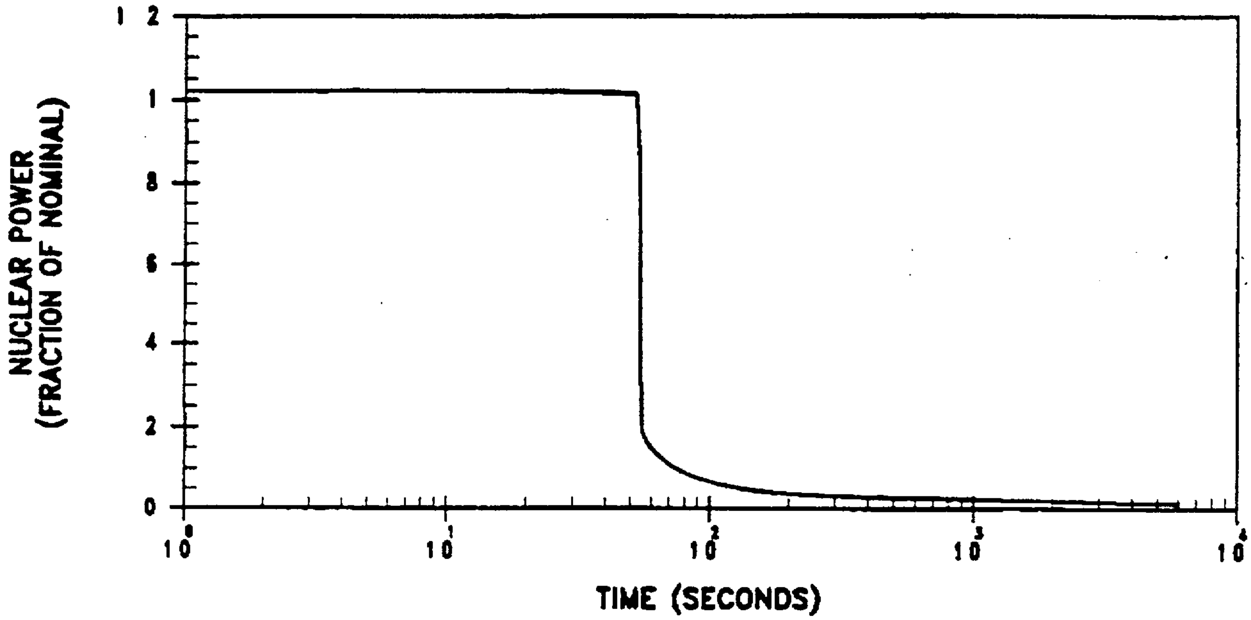
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station LOSS OF NORMAL FEEDWATER
	Updated FSAR — Figure 15.2-28B

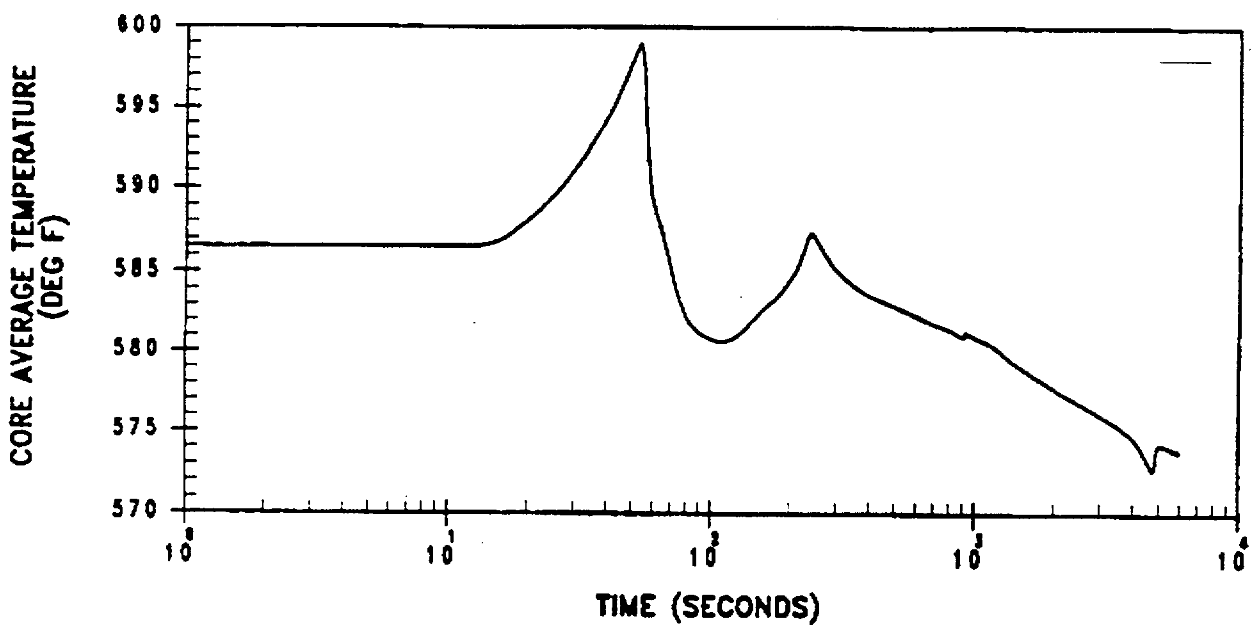




Revision 18, April 26, 2000

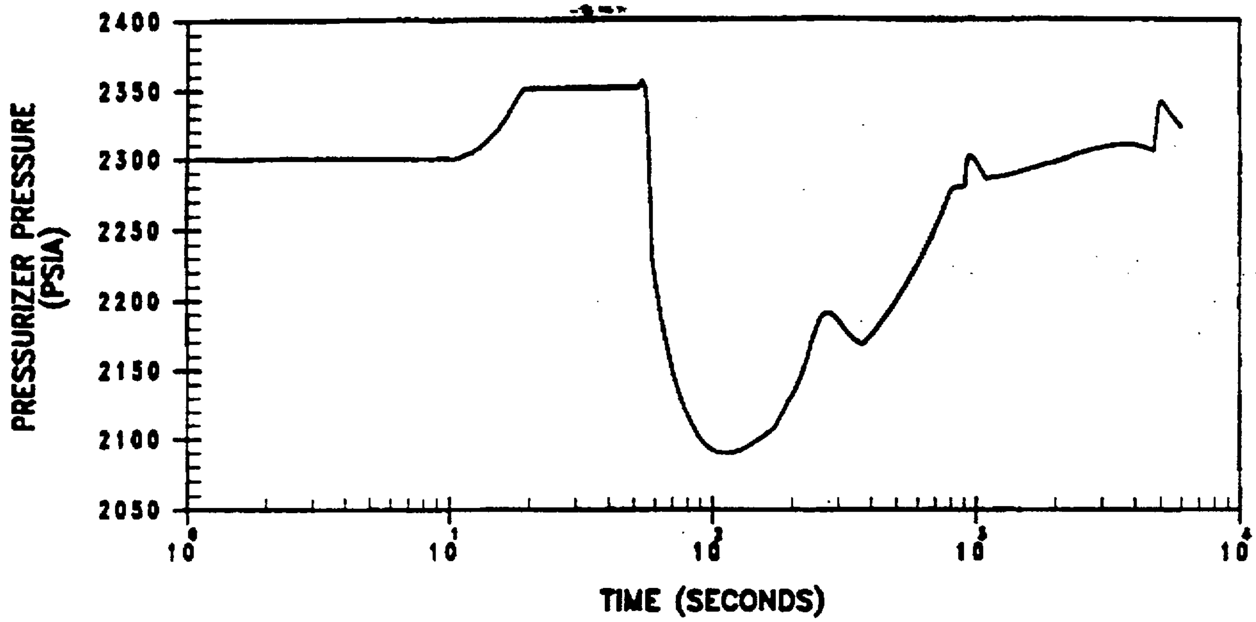
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station LOSS OF NORMAL FEEDWATER
	Updated FSAR Figure 15.2-28C

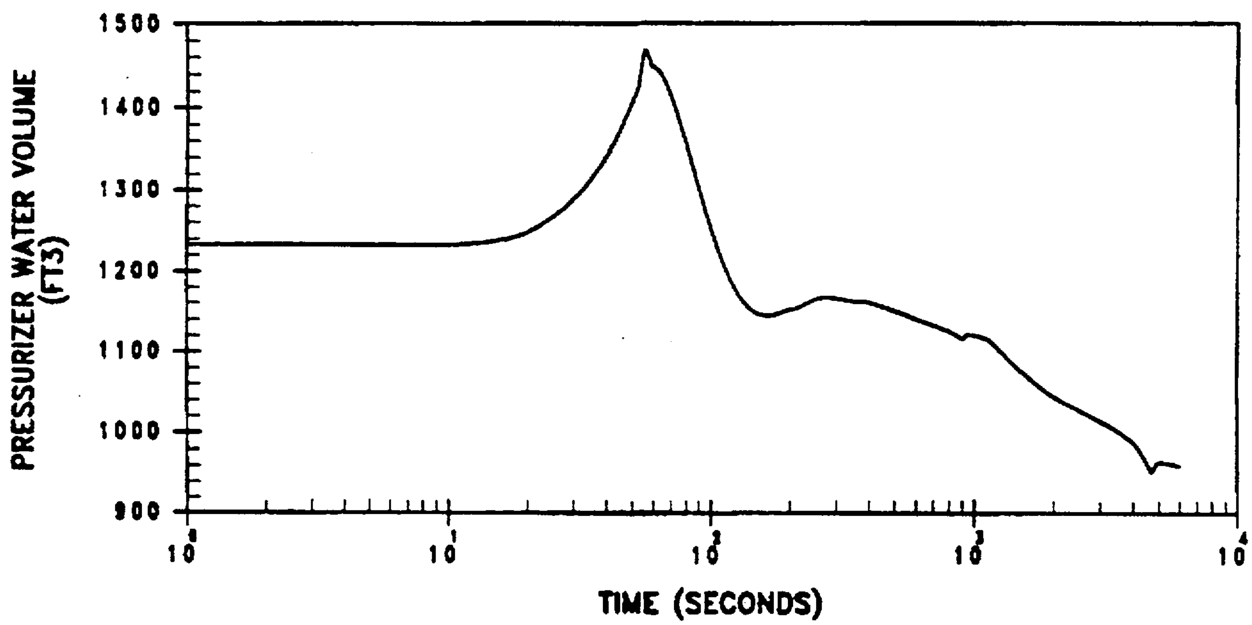




Revision 18, April 26, 2000

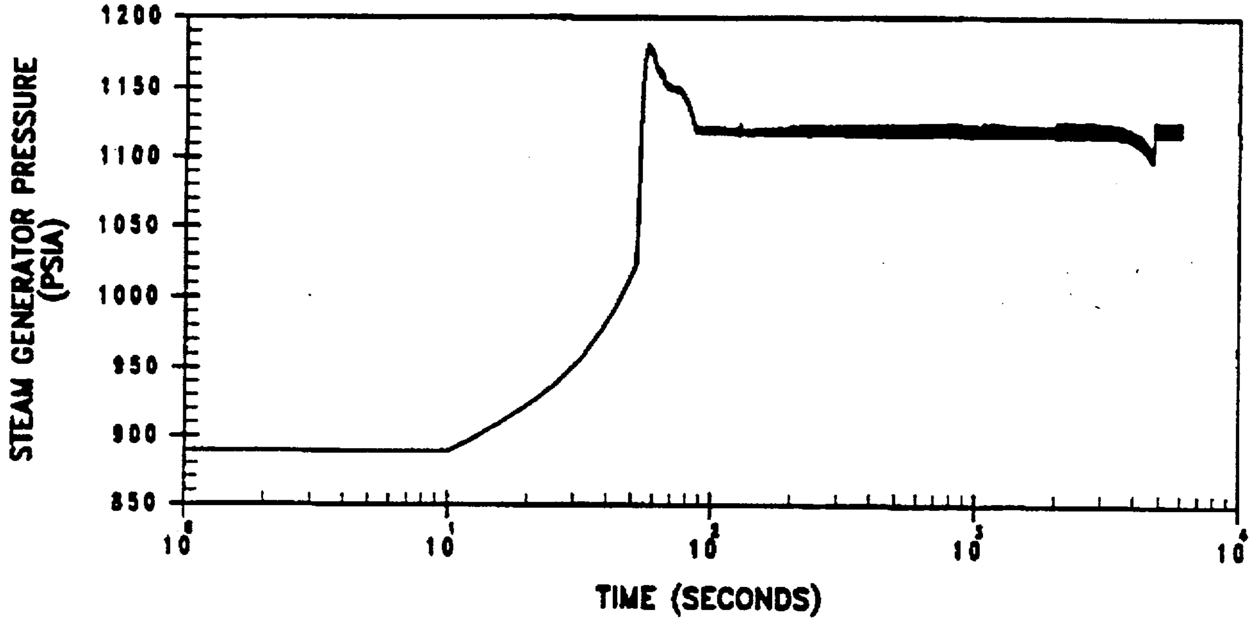
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station LOSS OF POWER TO THE STATION AUXILIARIES
	Updated FSAR — Figure 15.2-28D

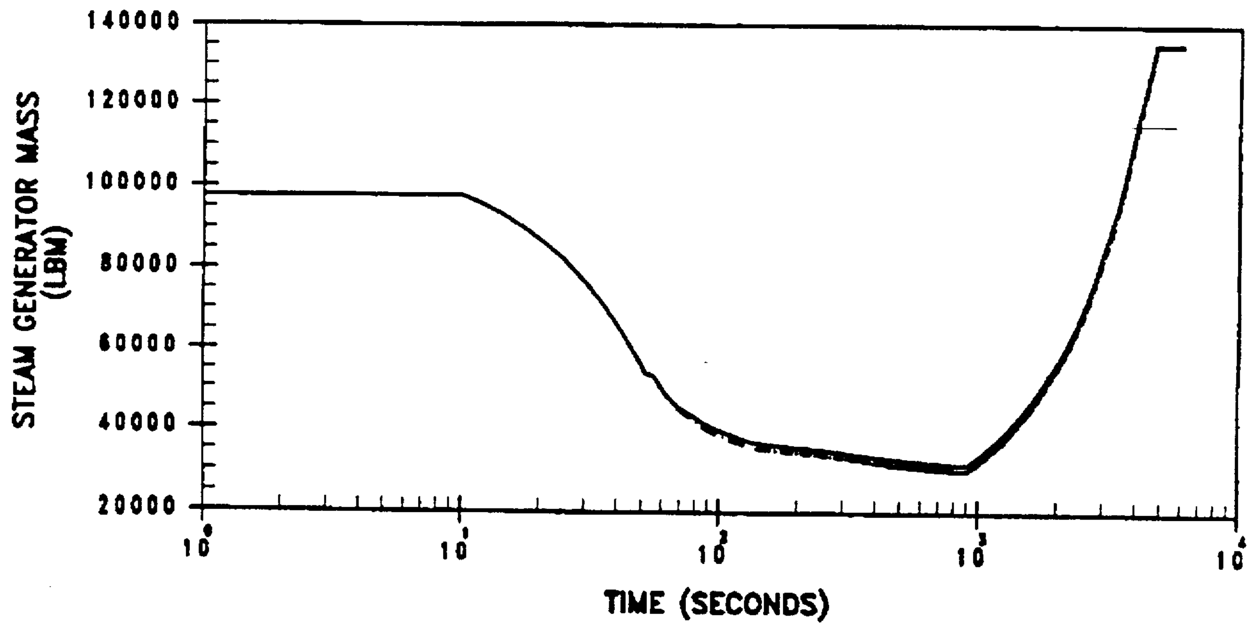




Revision 18, April 26, 2000

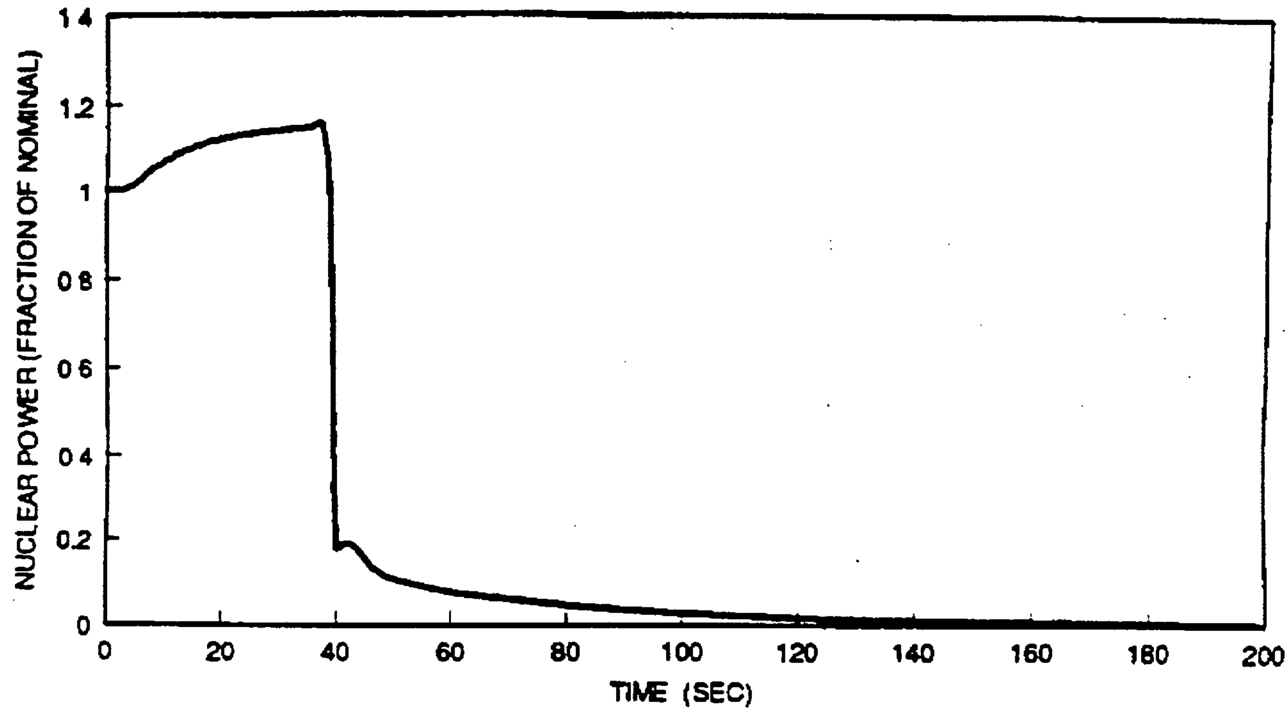
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station LOSS OF POWER TO THE STATION AUXILIARIES
	Updated FSAR Figure 15.2-28E

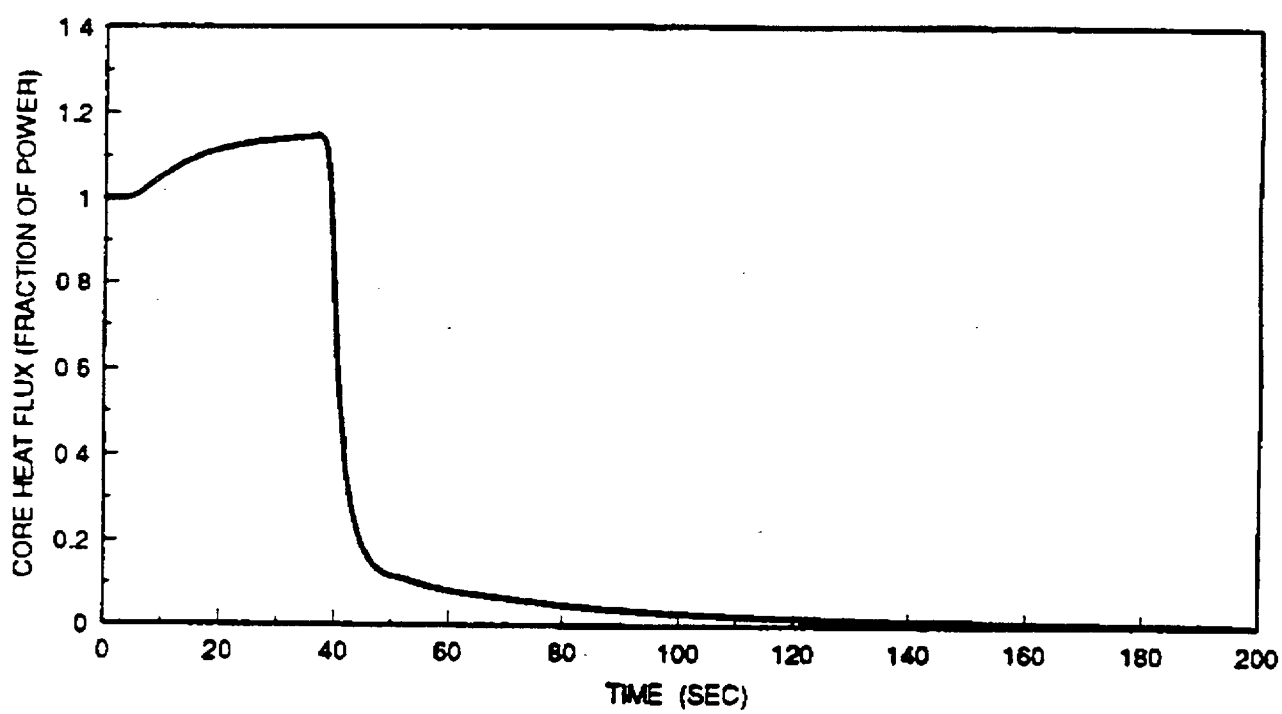




Revision 18, April 26, 2000

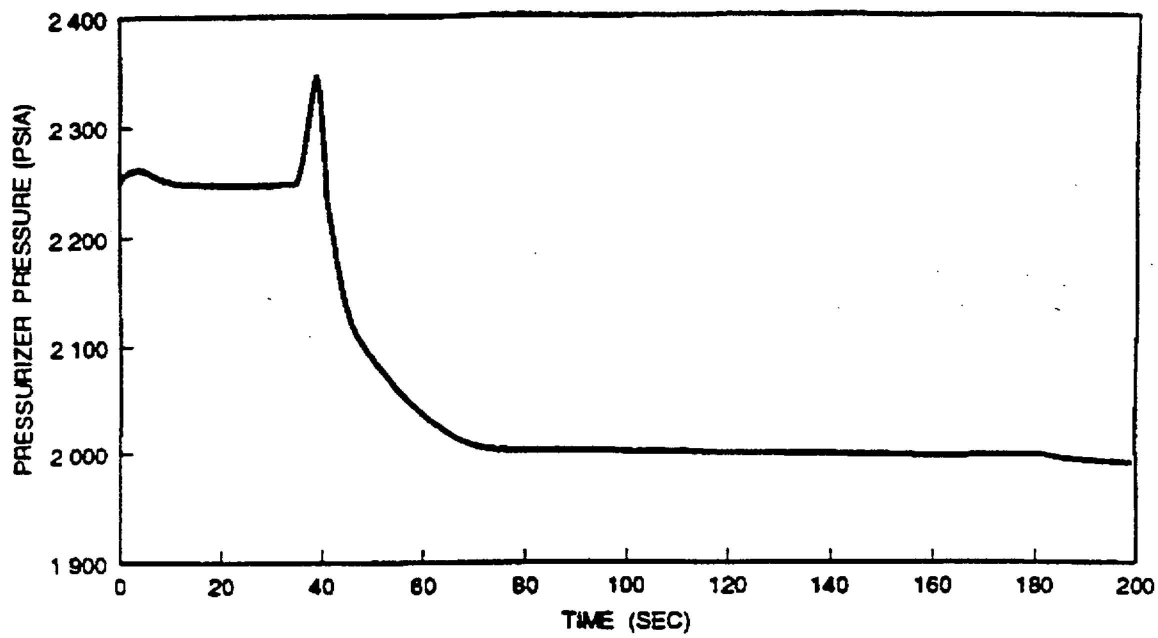
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station LOSS OF POWER TO THE STATION AUXILIARIES
	Updated FSAR Figure 15.2-28F

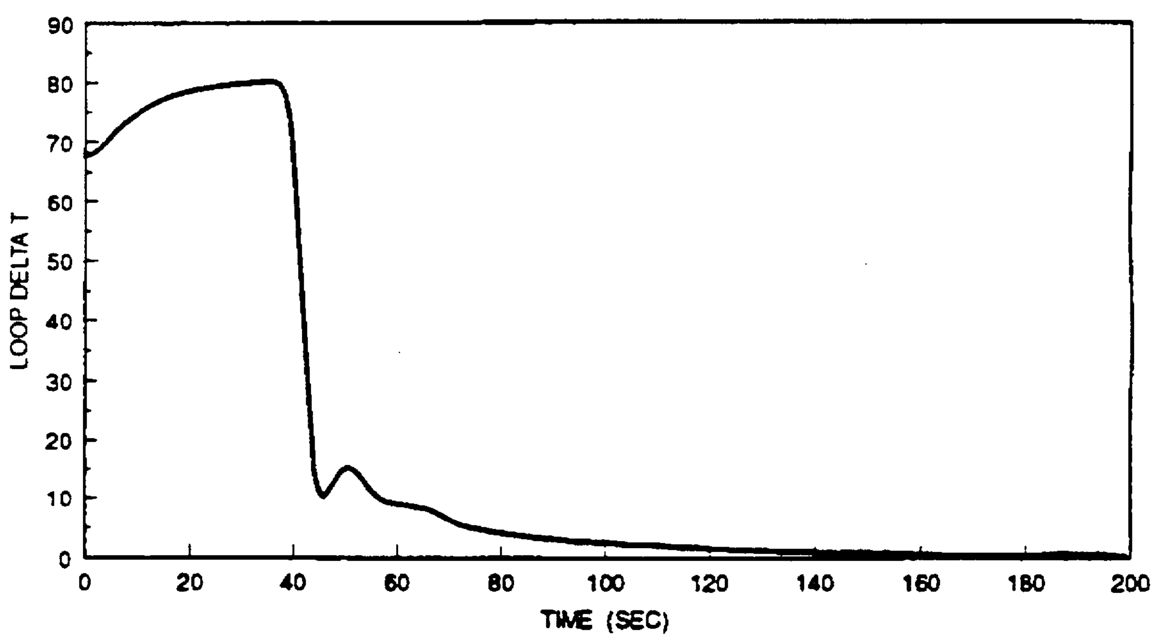




Revision 18, April 26, 2000

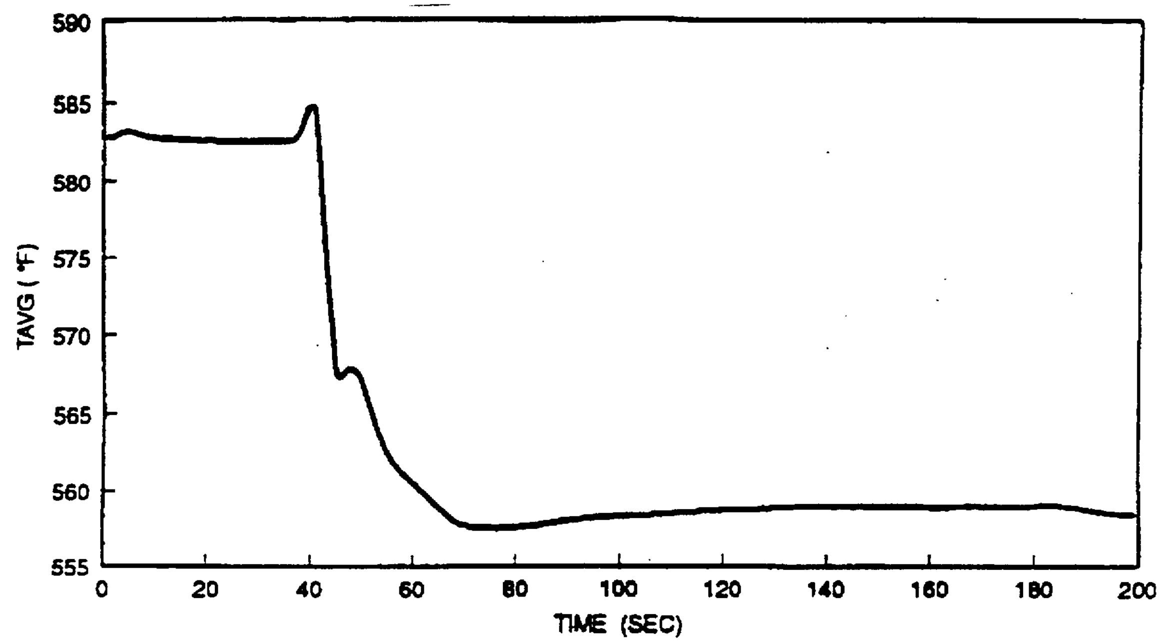
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station SINGLE-LOOP FEEDWATER CONTROL VALVE MALFUNCTION FROM HOT FULL POWER CONDITIONS WITH MANUAL ROD CONTROL
	Updated FSAR — Figure 15.2-29A

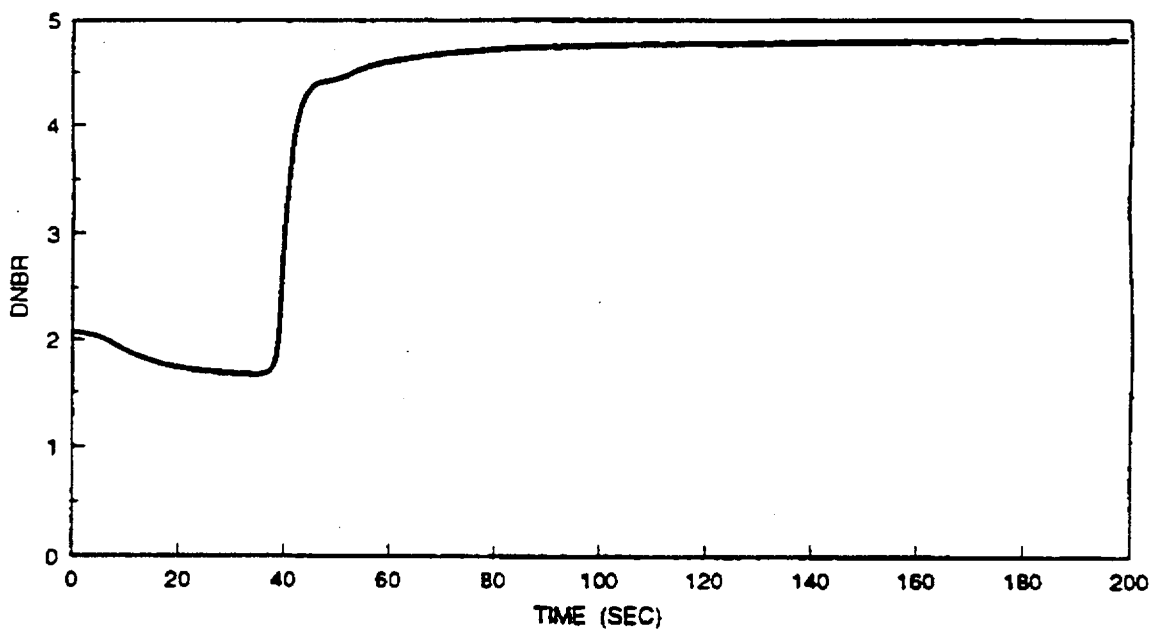




Revision 18, April 26, 2000

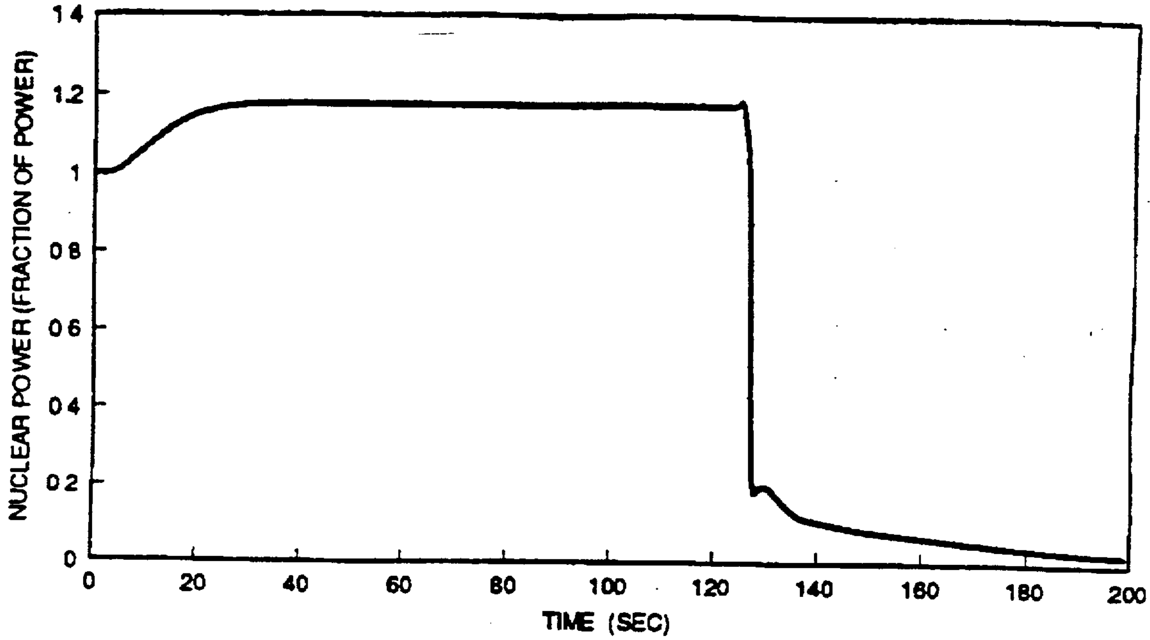
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station SINGLE-LOOP FEEDWATER CONTROL VALVE MALFUNCTION FROM HOT FULL POWER CONDITIONS WITH MANUAL ROD CONTROL
	Updated FSAR Figure 15.2-29B

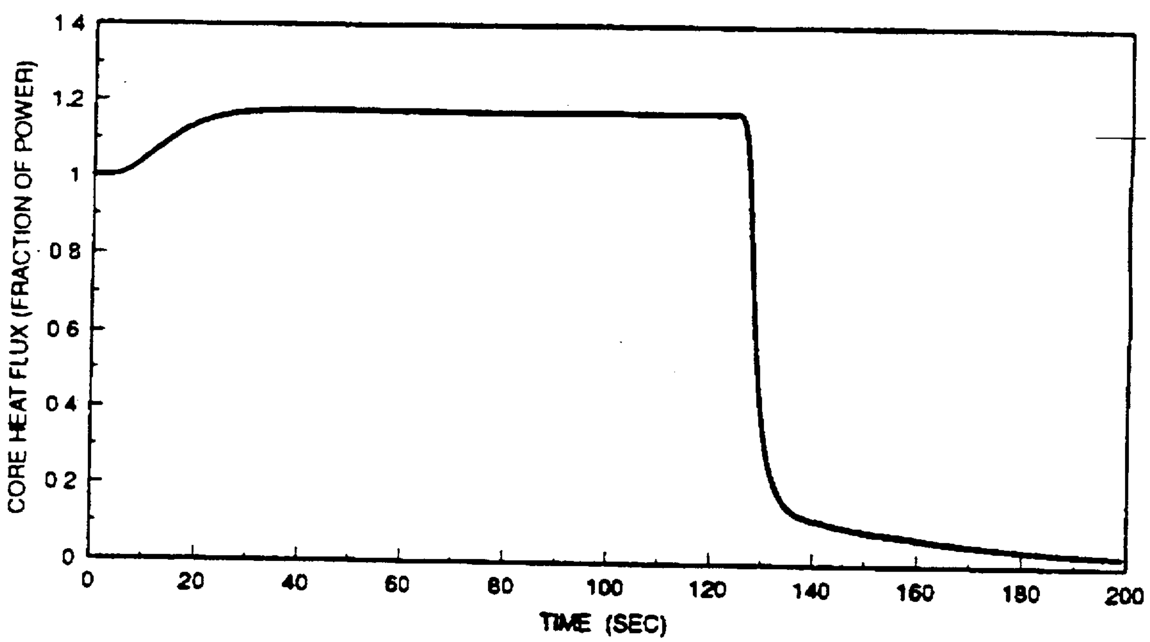




Revision 18, April 26, 2000

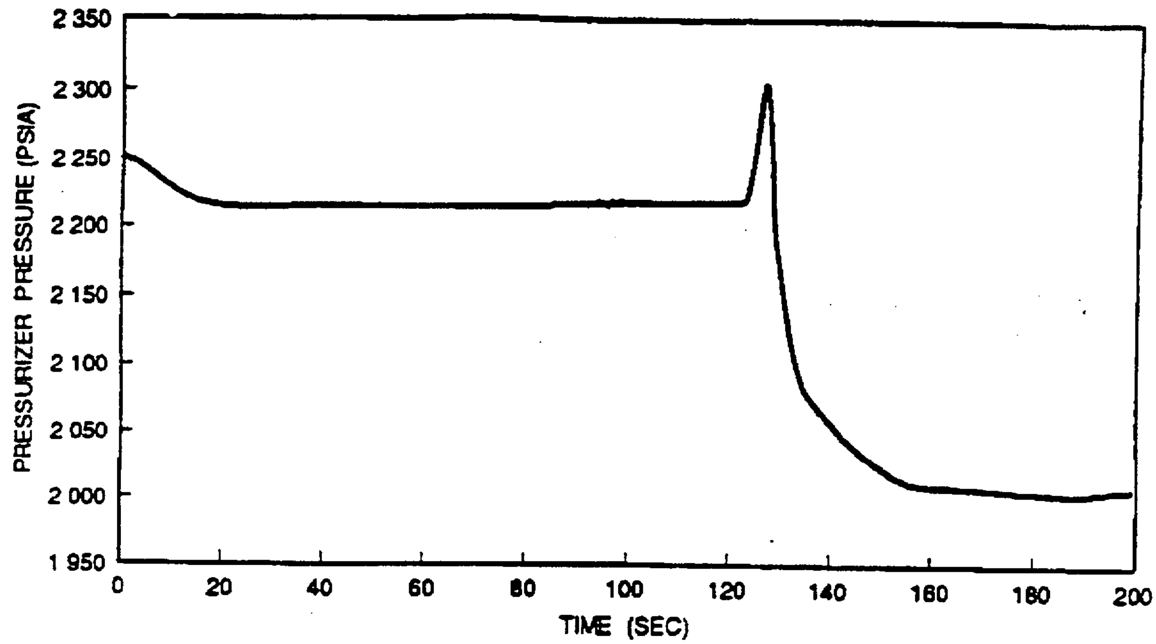
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station SINGLE-LOOP FEEDWATER CONTROL MALFUNCTION FROM HOT FULL POWER CONDITIONS WITH MANUAL ROD CONTROL
	Updated FSAR Figure 15.2-29C

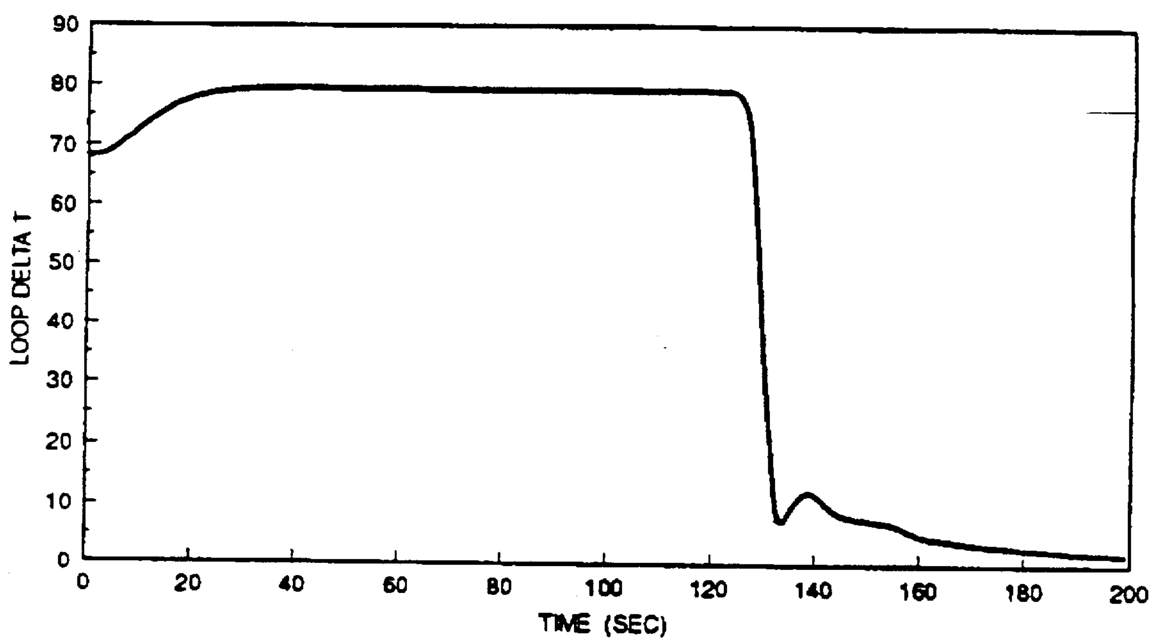




Revision 18, April 26, 2000

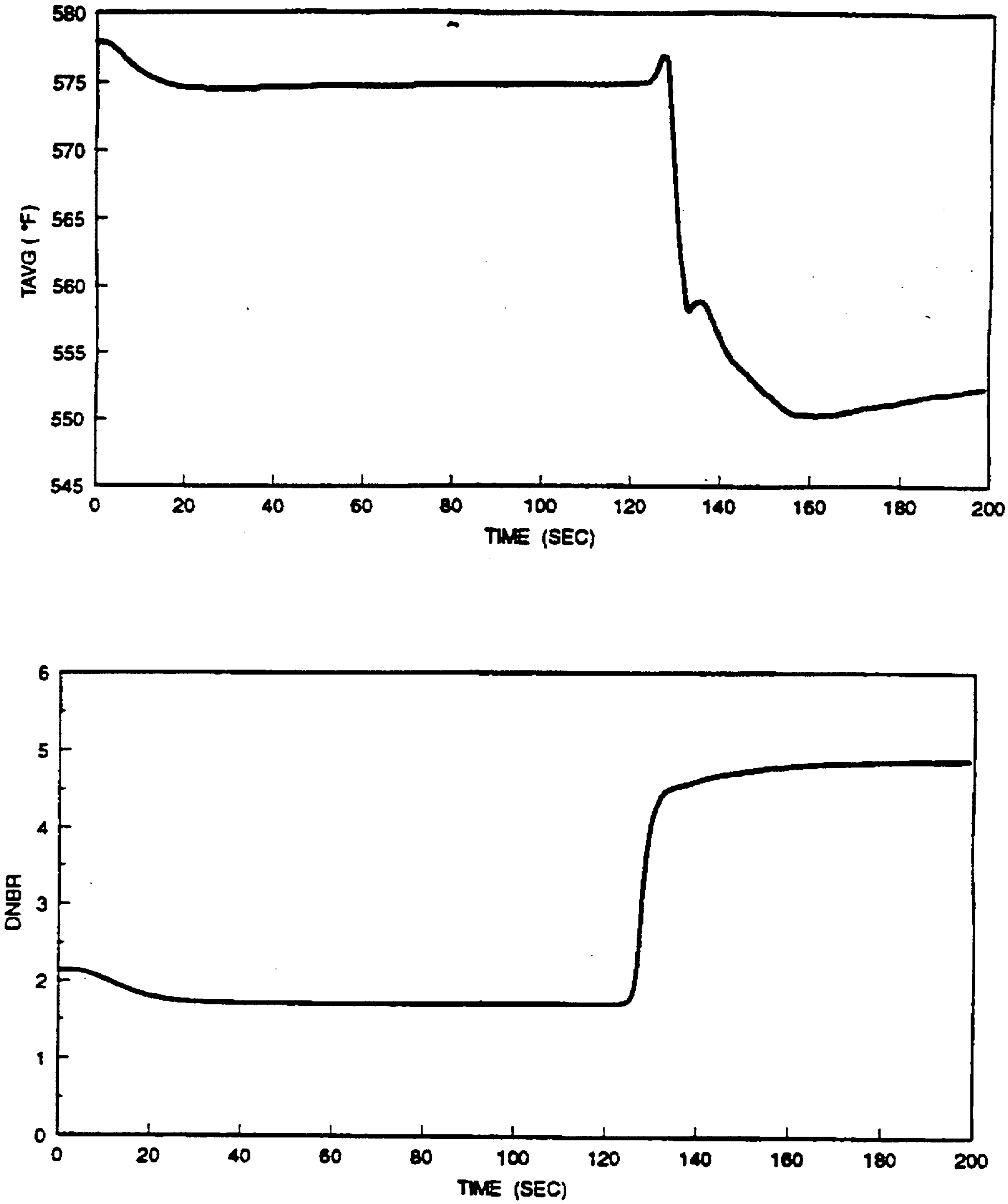
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station SINGLE-LOOP FEEDWATER CONTROL VALVE MALFUNCTION FROM HOT FULL POWER CONDITIONS WITH MANUAL ROD CONTROL
	Updated FSAR — Figure 15.2-29D





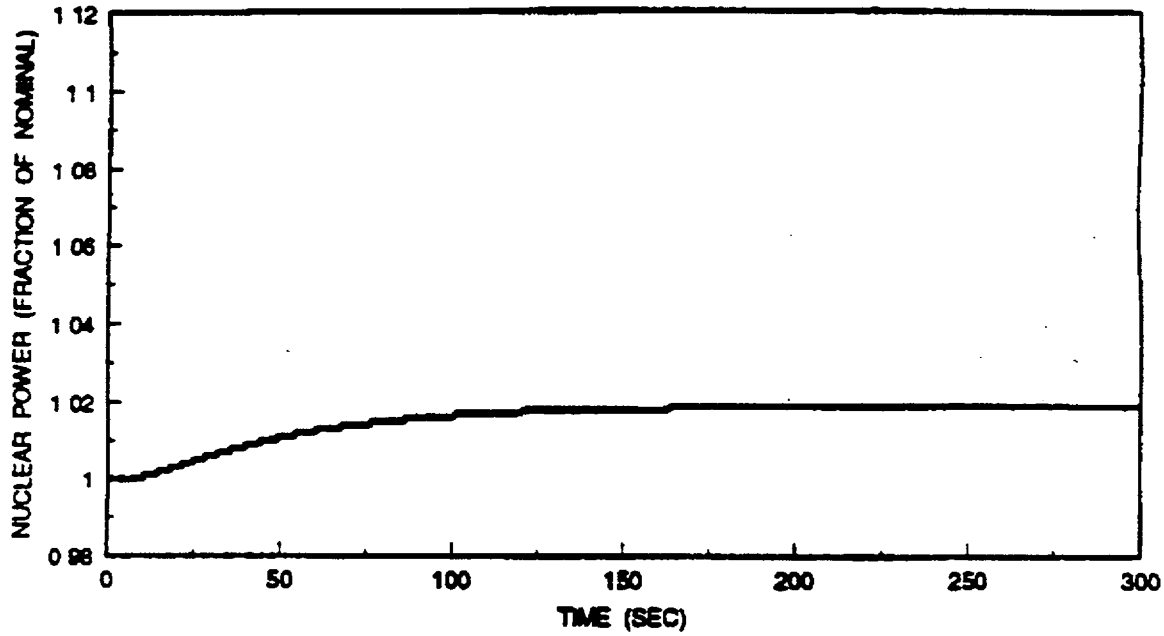
Revision 18, April 26, 2000

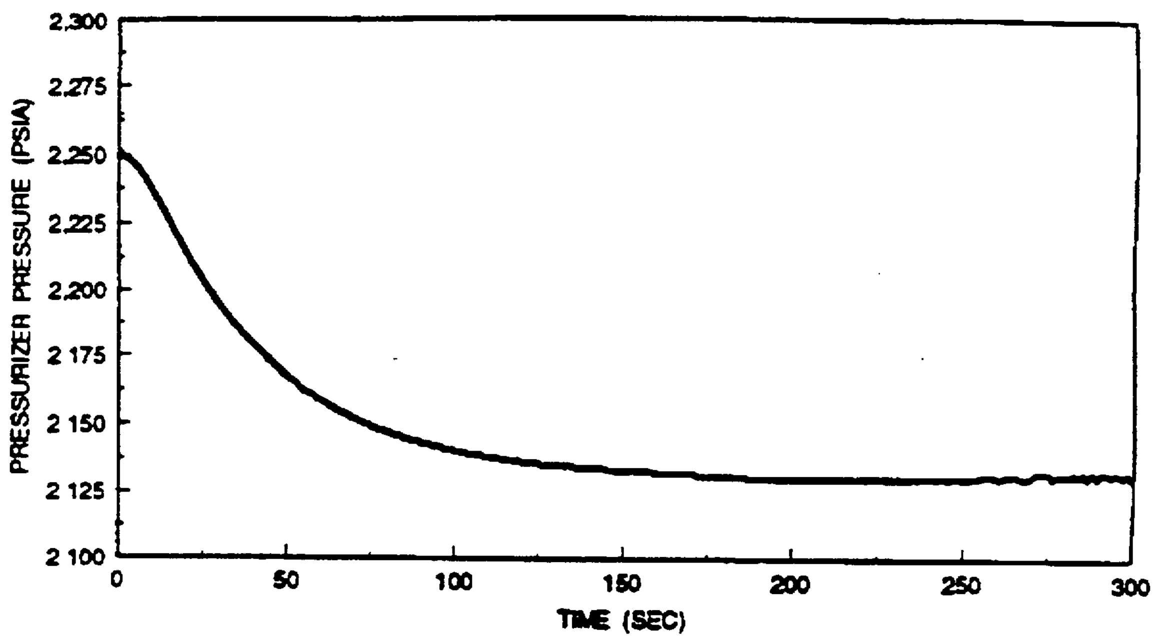
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station MULTI-LOOP FEEDWATER CONTROL VALVE MALFUNCTION FROM HOT FULL POWER CONDITIONS WITH MANUAL ROD CONTROL
	Updated FSAR Figure 15.2-29E



Revision 18, April 26, 2000

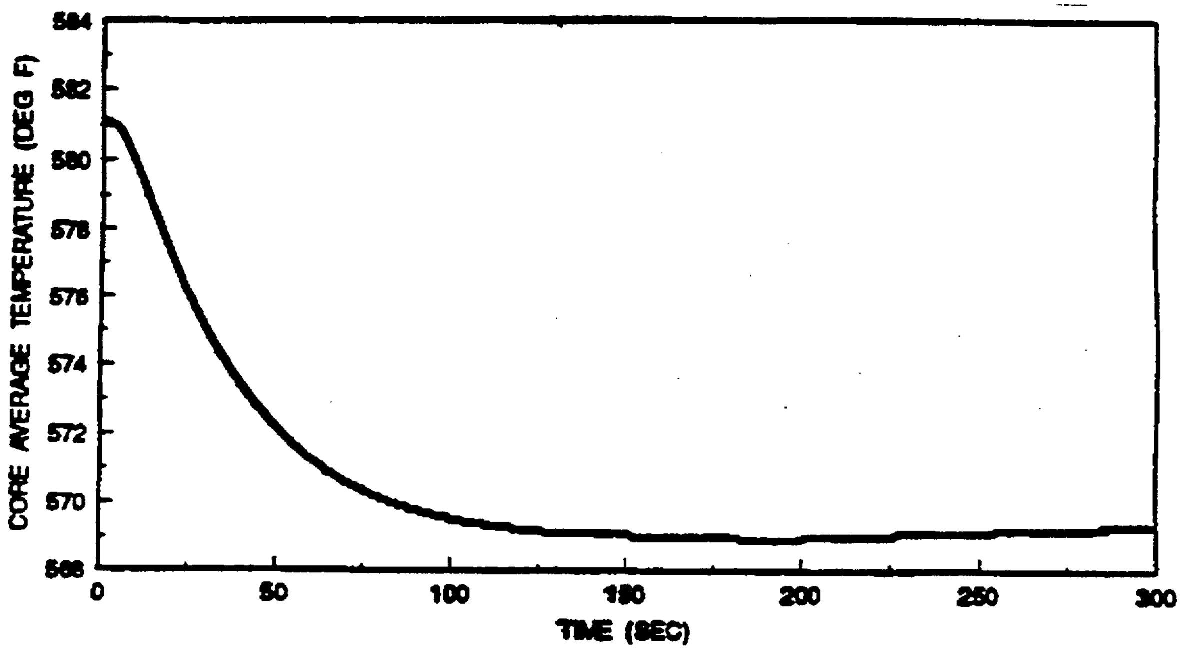
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station MULTI-LOOP FEEDWATER CONTROL VALVE MALFUNCTION FROM HOT FULL POWER CONDITIONS WITH MANUAL ROD CONTROL
	Updated FSAR Figure 15.2-29F

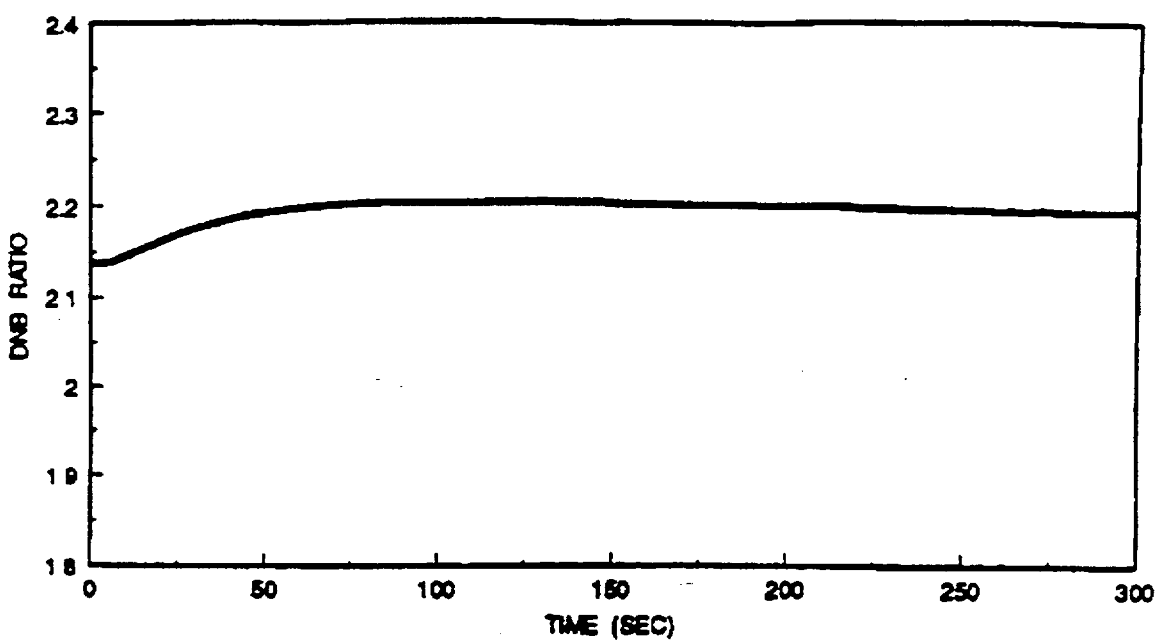




Revision 18, April 26, 2000

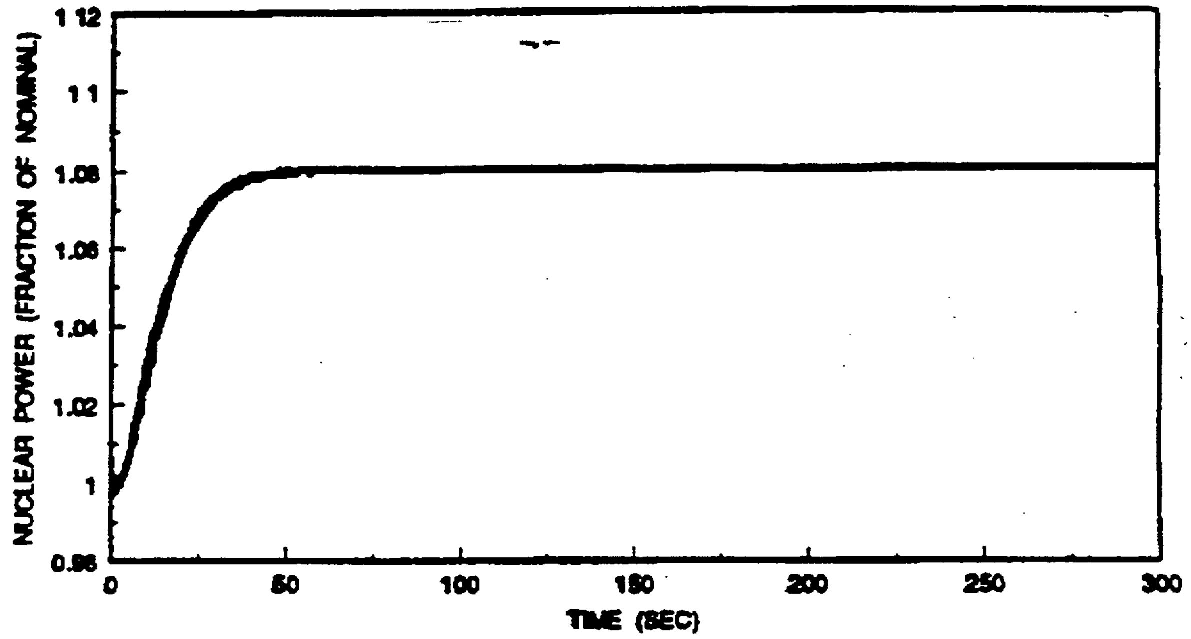
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station EXCESSIVE LOAD INCREASE WITHOUT CONTROL ACTION BEGINNING OF LIFE
	Updated FSAR — Figure 15.2-30

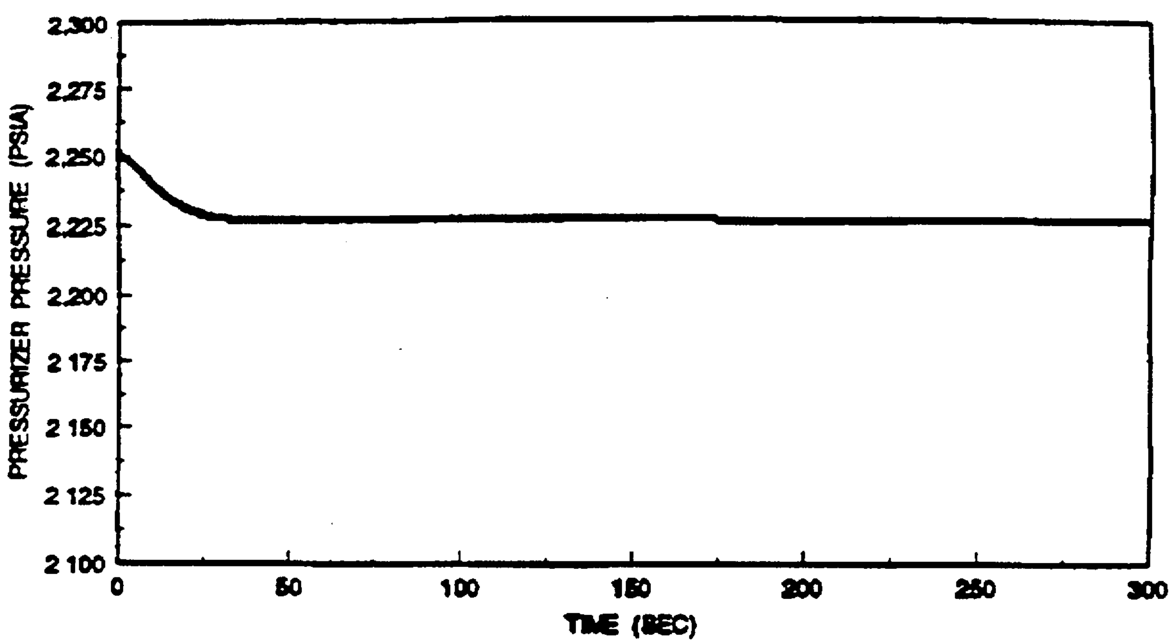




Revision 18, April 26, 2000

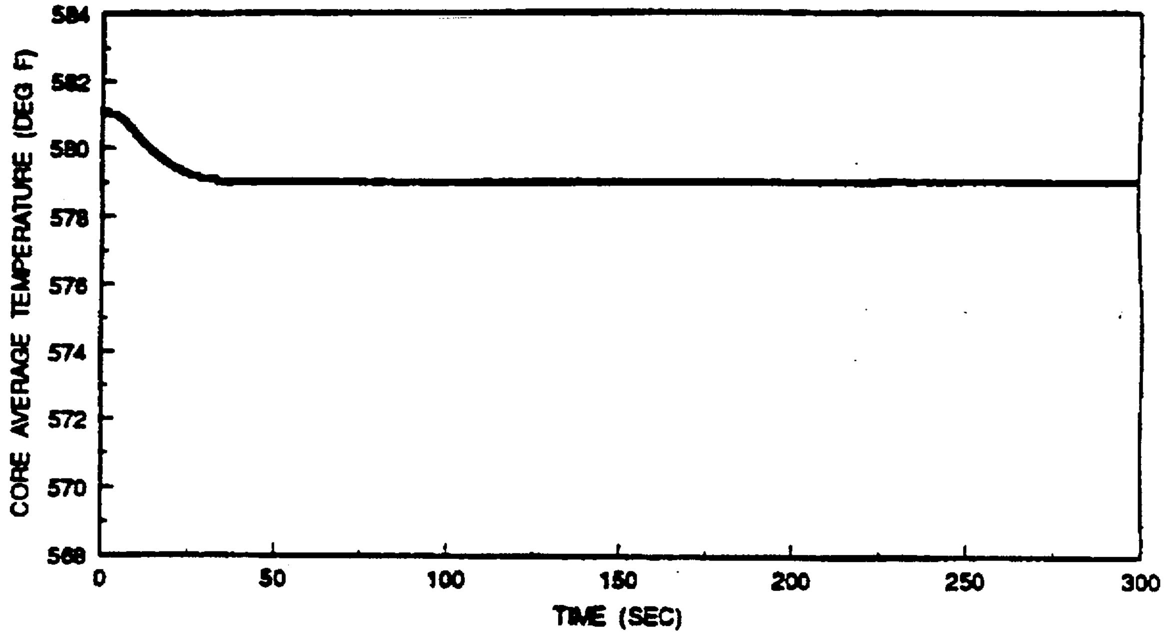
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station EXCESSIVE LOAD INCREASE WITHOUT CONTROL ACTION BEGINNING OF LIFE
	Updated FSAR Figure 15.2-31

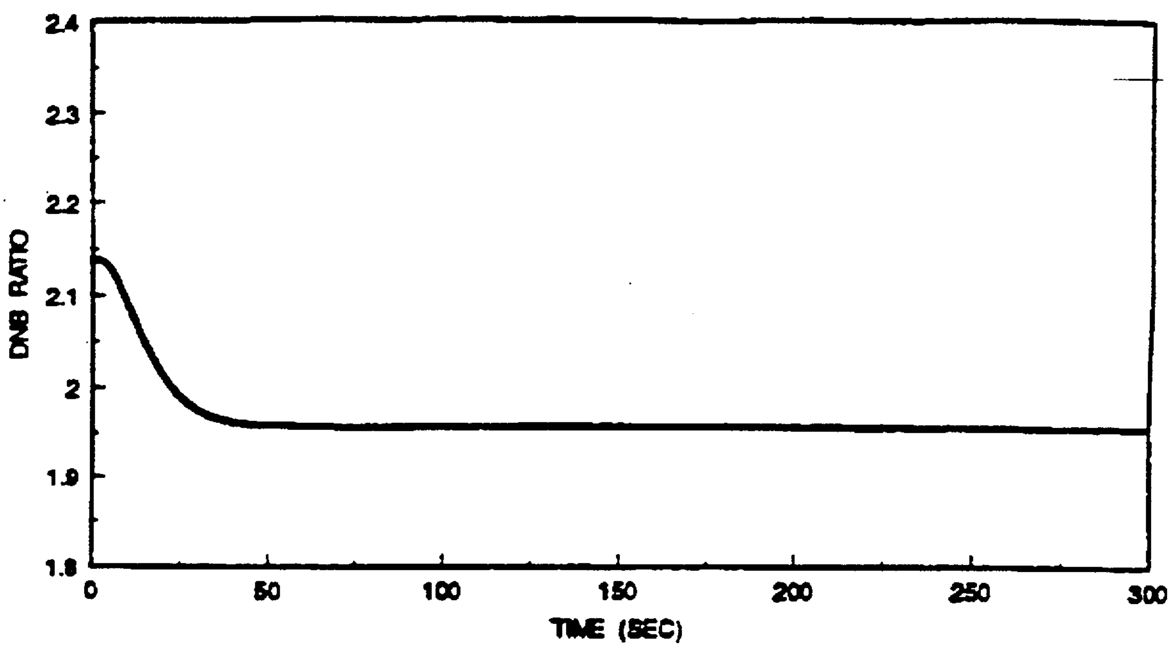




Revision 18, April 26, 2000

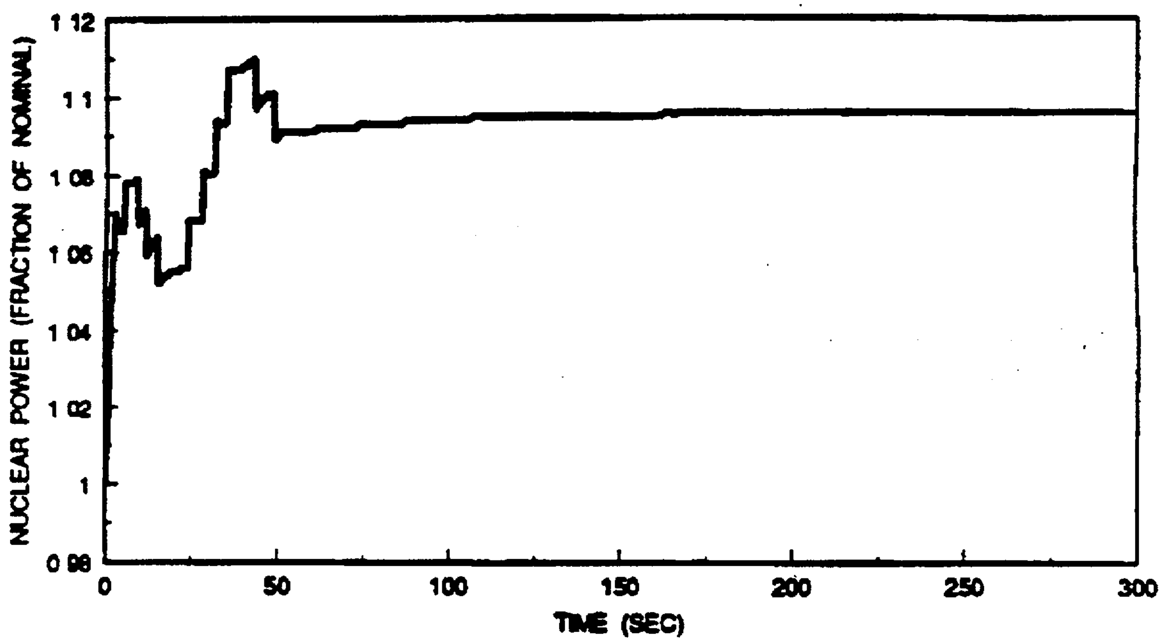
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station EXCESSIVE LOAD INCREASE WITHOUT CONTROL ACTION END OF LIFE
	Updated FSAR — Figure 15.2-32

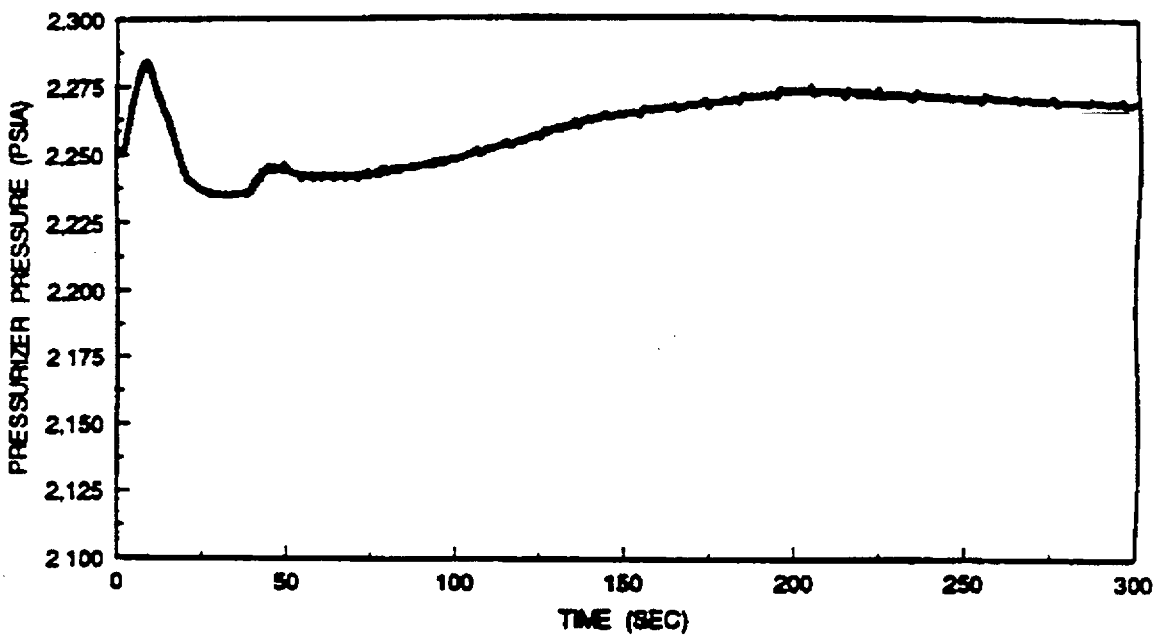




Revision 18, April 26, 2000

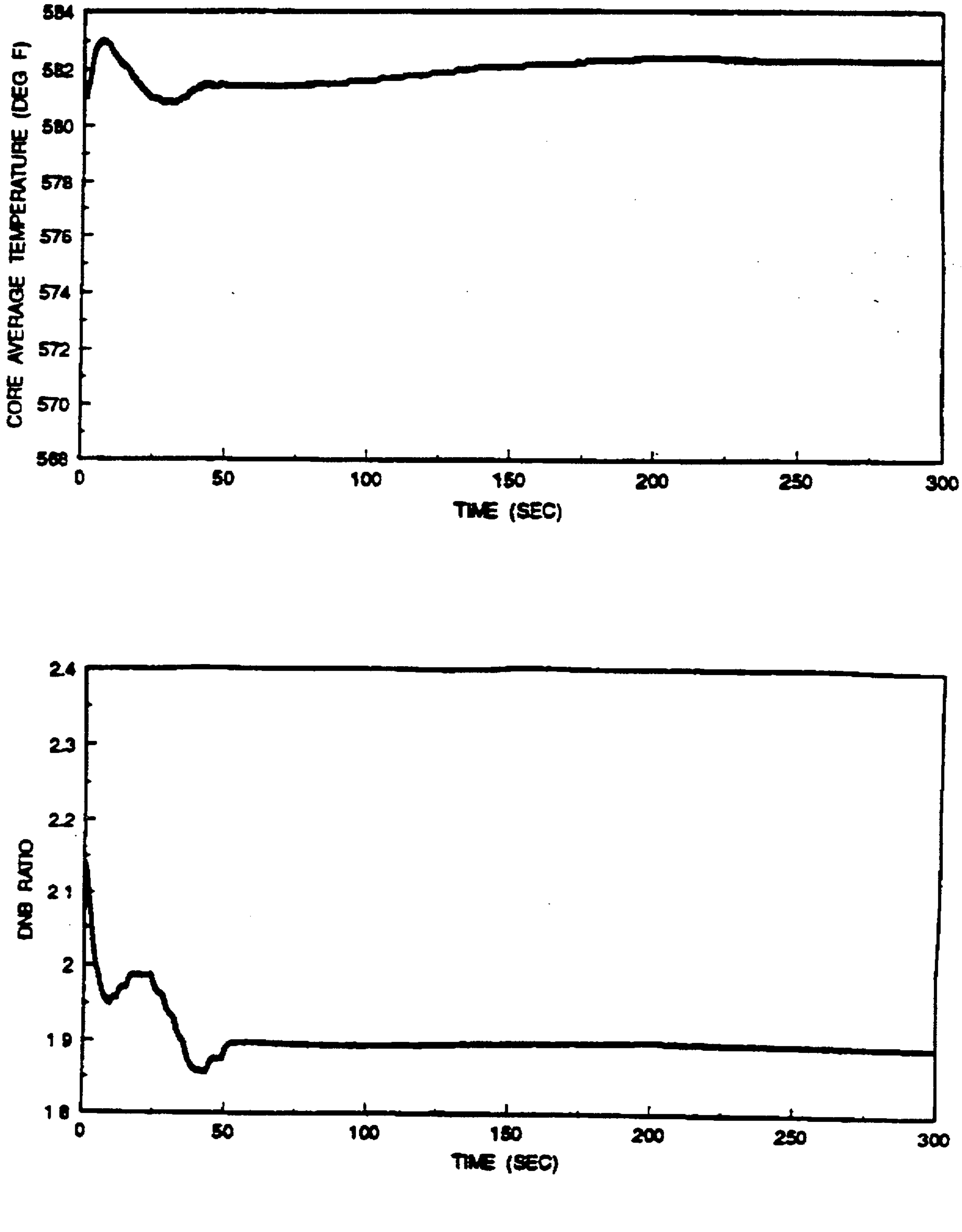
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station EXCESSIVE LOAD INCREASE WITHOUT CONTROL ACTION END OF LIFE
	Updated FSAR — Figure 15.2-33





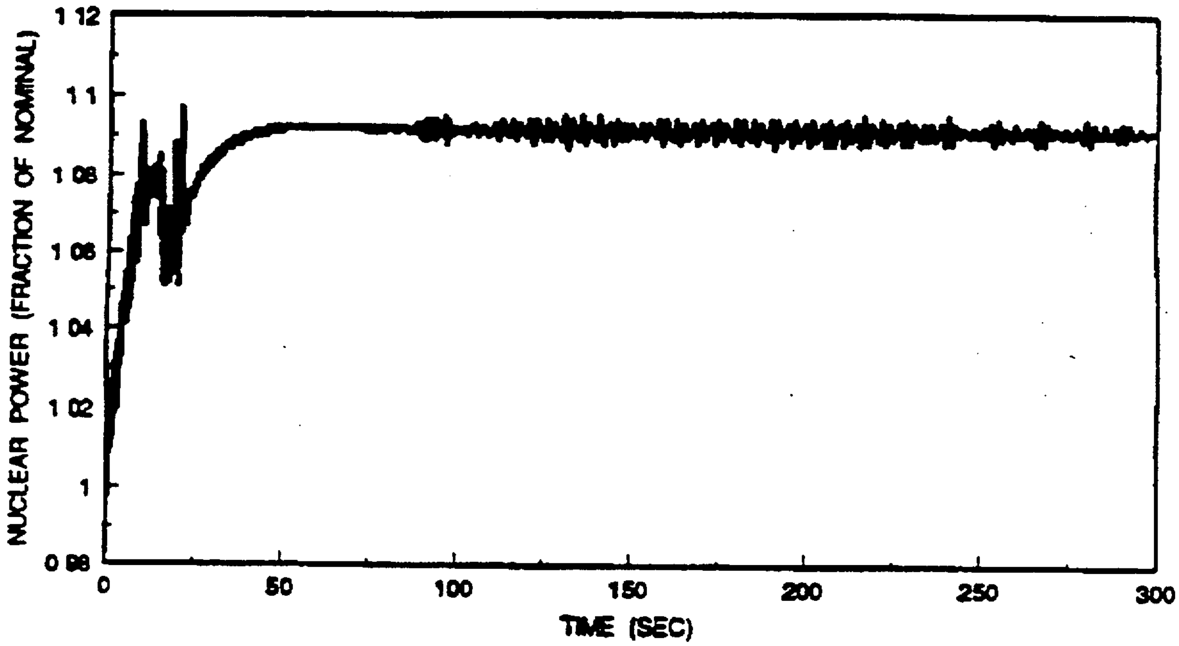
Revision 18, April 26, 2000

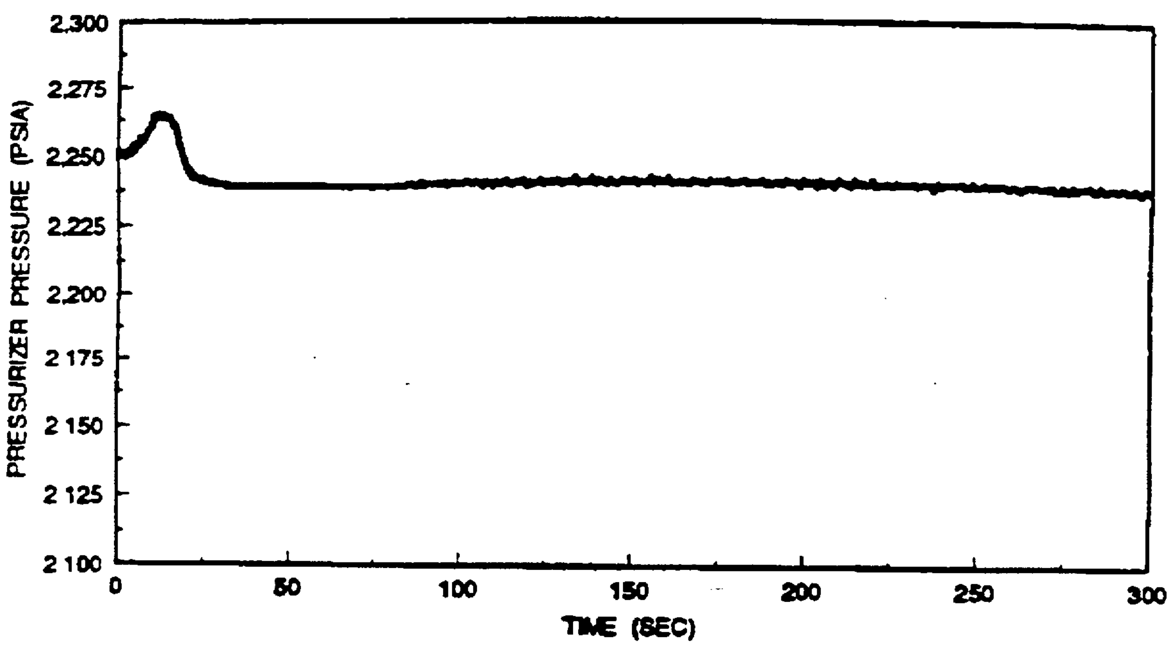
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station EXCESSIVE LOAD INCREASE WITH REACTOR CONTROL BEGINNING OF LIFE
	Updated FSAR — Figure 15.2-34



Revision 18, April 26, 2000

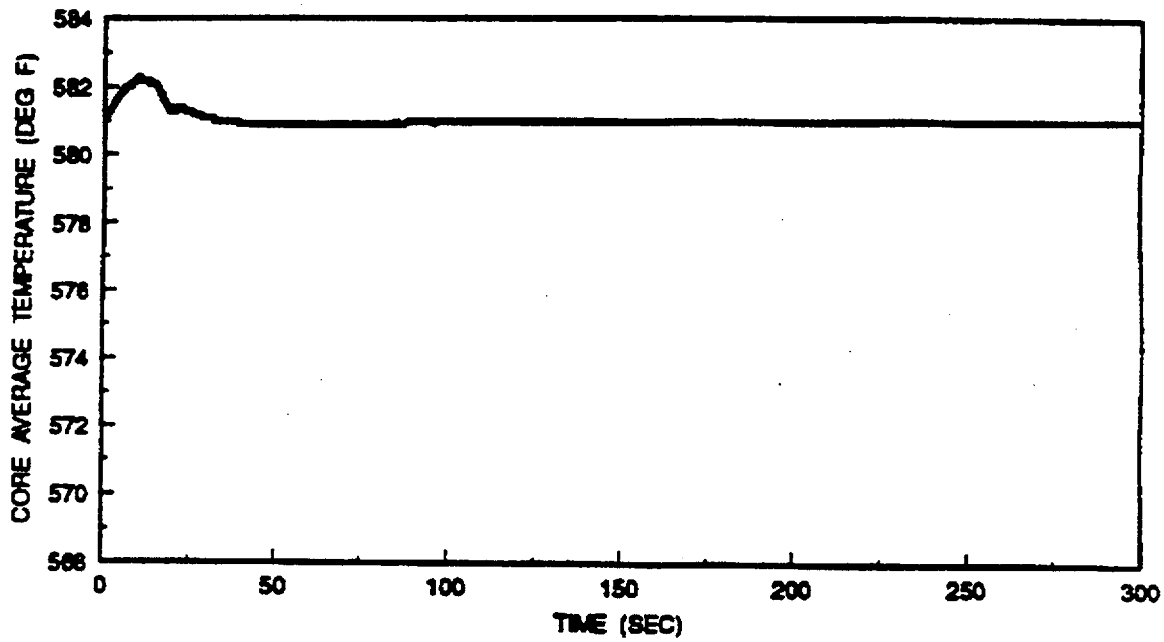
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station EXCESSIVE LOAD INCREASE WITH REACTOR CONTROL BEGINNING OF LIFE Updated FSAR — Figure 15.2-35

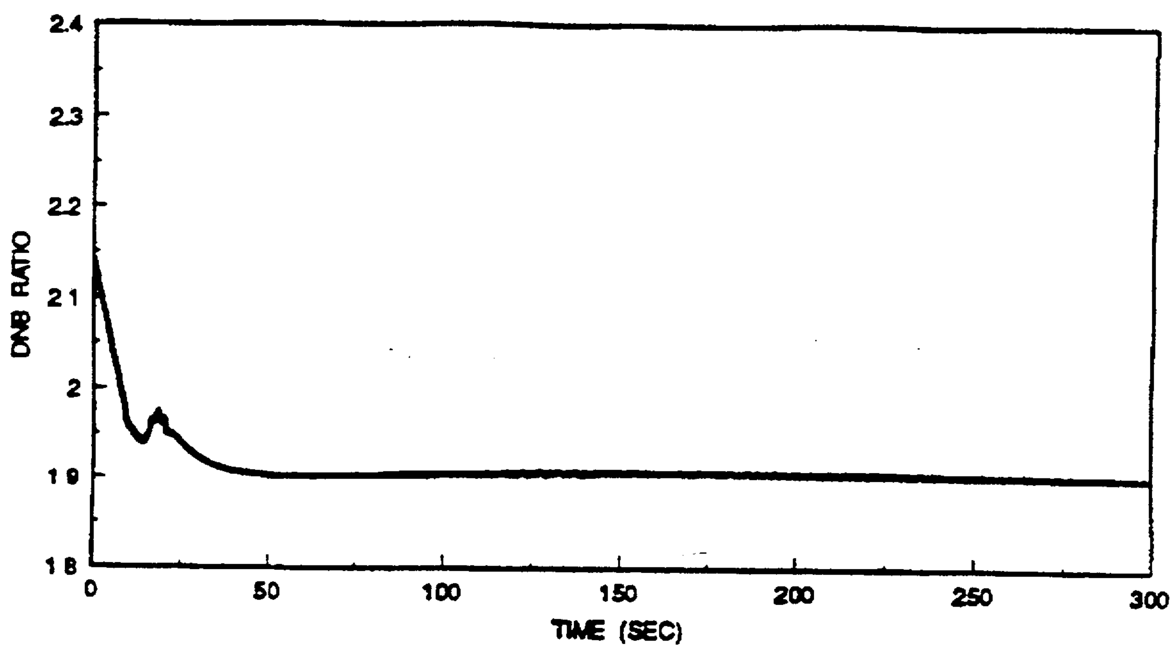




Revision 18, April 26, 2000

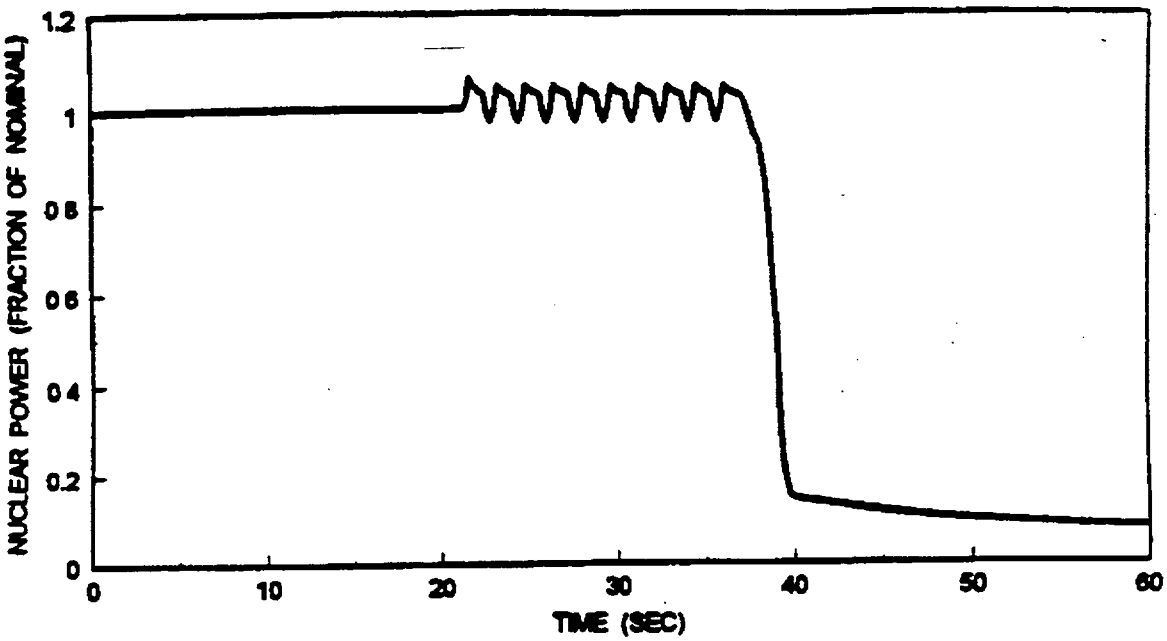
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station EXCESSIVE LOAD INCREASE WITH CONTROL ACTION END OF LIFE
	Updated FSAR Figure 15.2-36

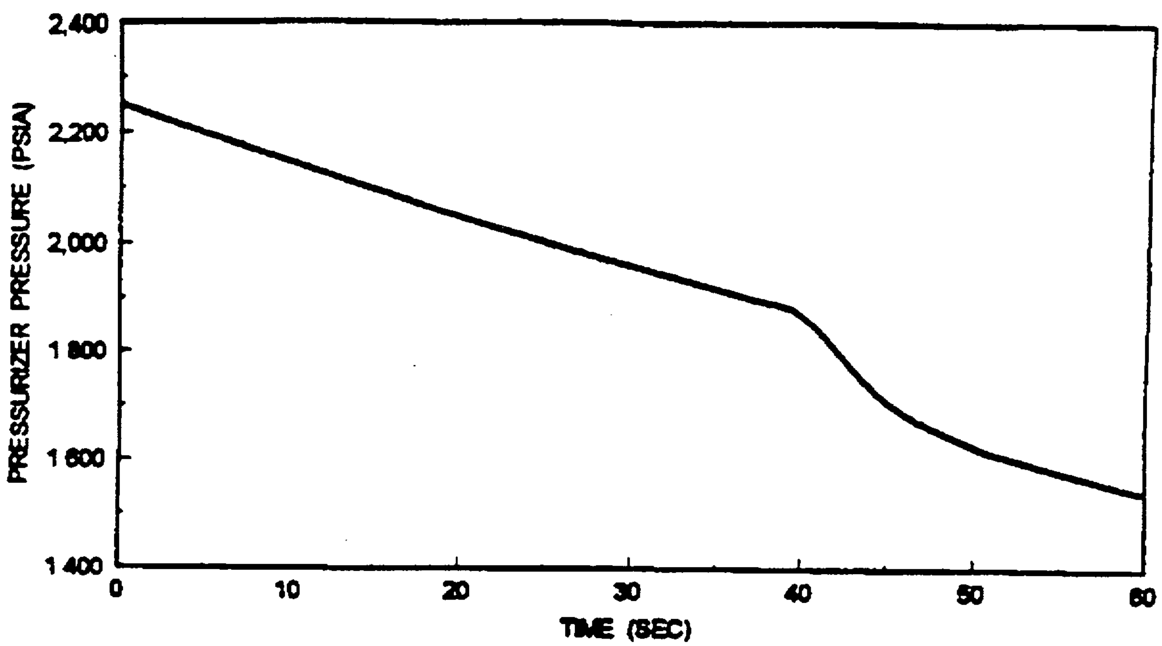




Revision 18, April 26, 2000

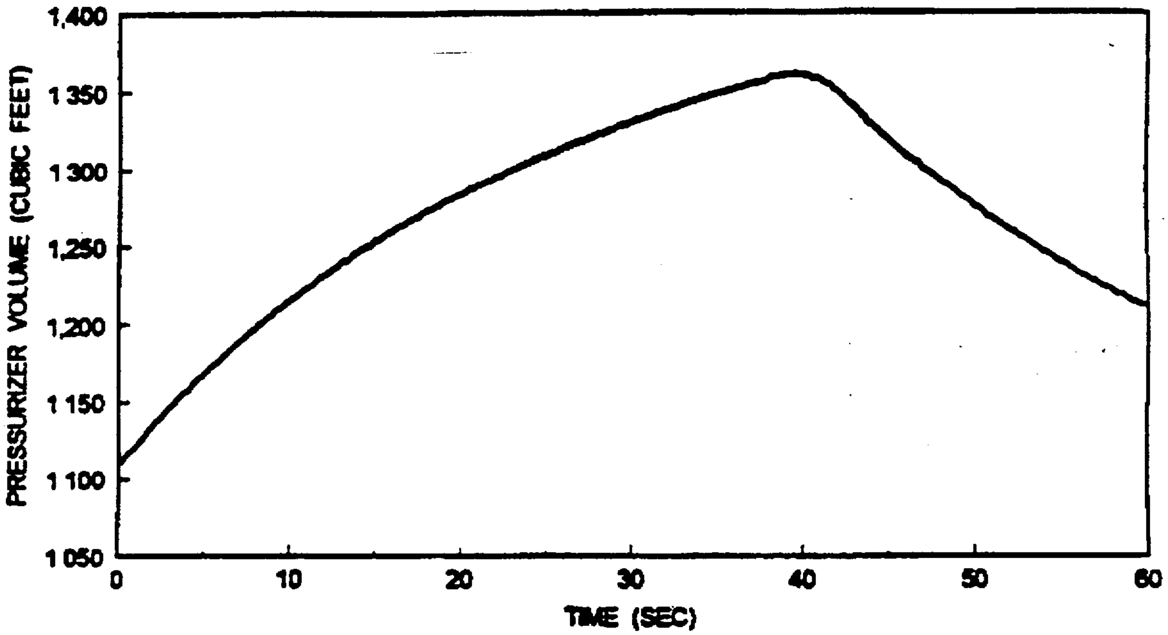
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station EXCESSIVE LOAD INCREASE WITH CONTROL ACTION END OF LIFE
	Updated FSAR — Figure 15.2-37

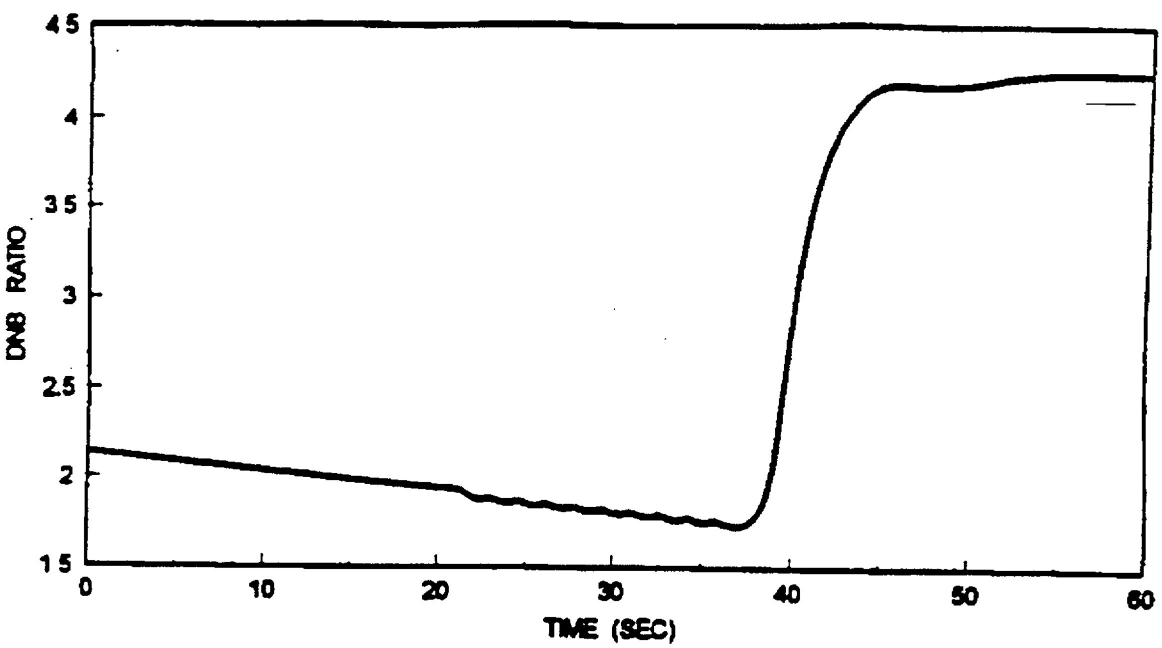




Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station ACCIDENTAL RCS DEPRESSURIZATION Updated FSAR — Figure 15.2-38





Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station ACCIDENTAL RCS DEPRESSURIZATION Updated FSAR Figure 15.2-39

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PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

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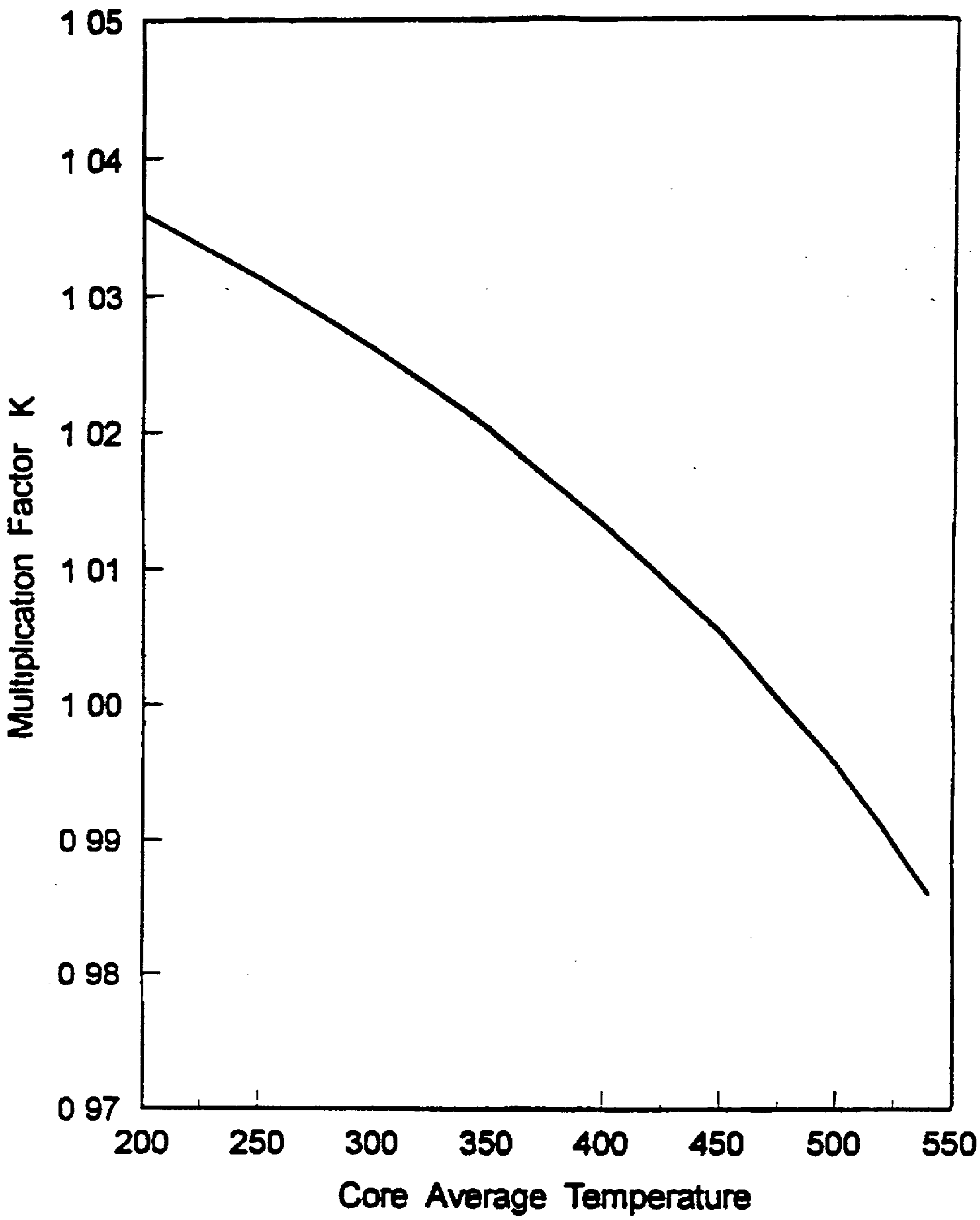
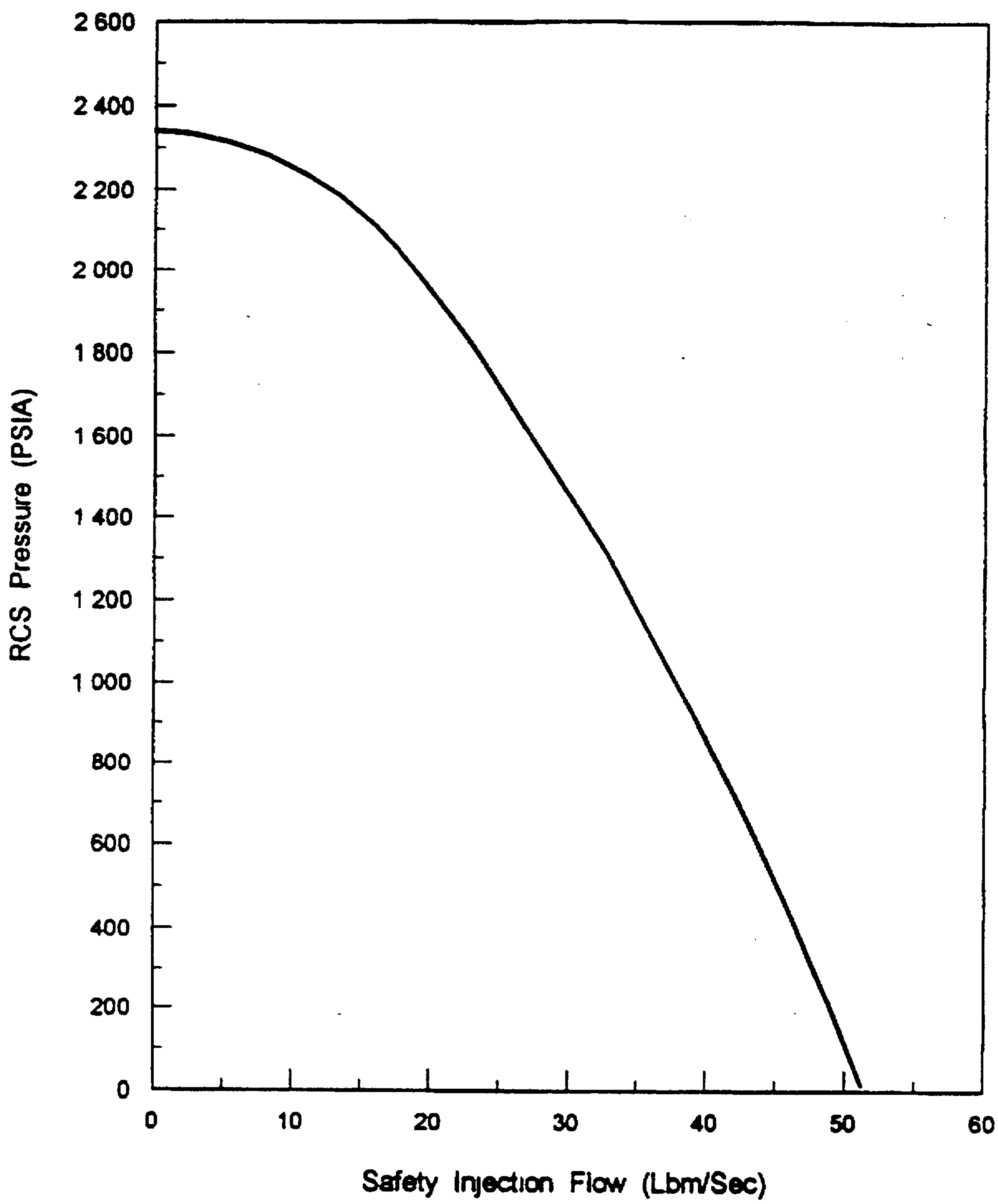


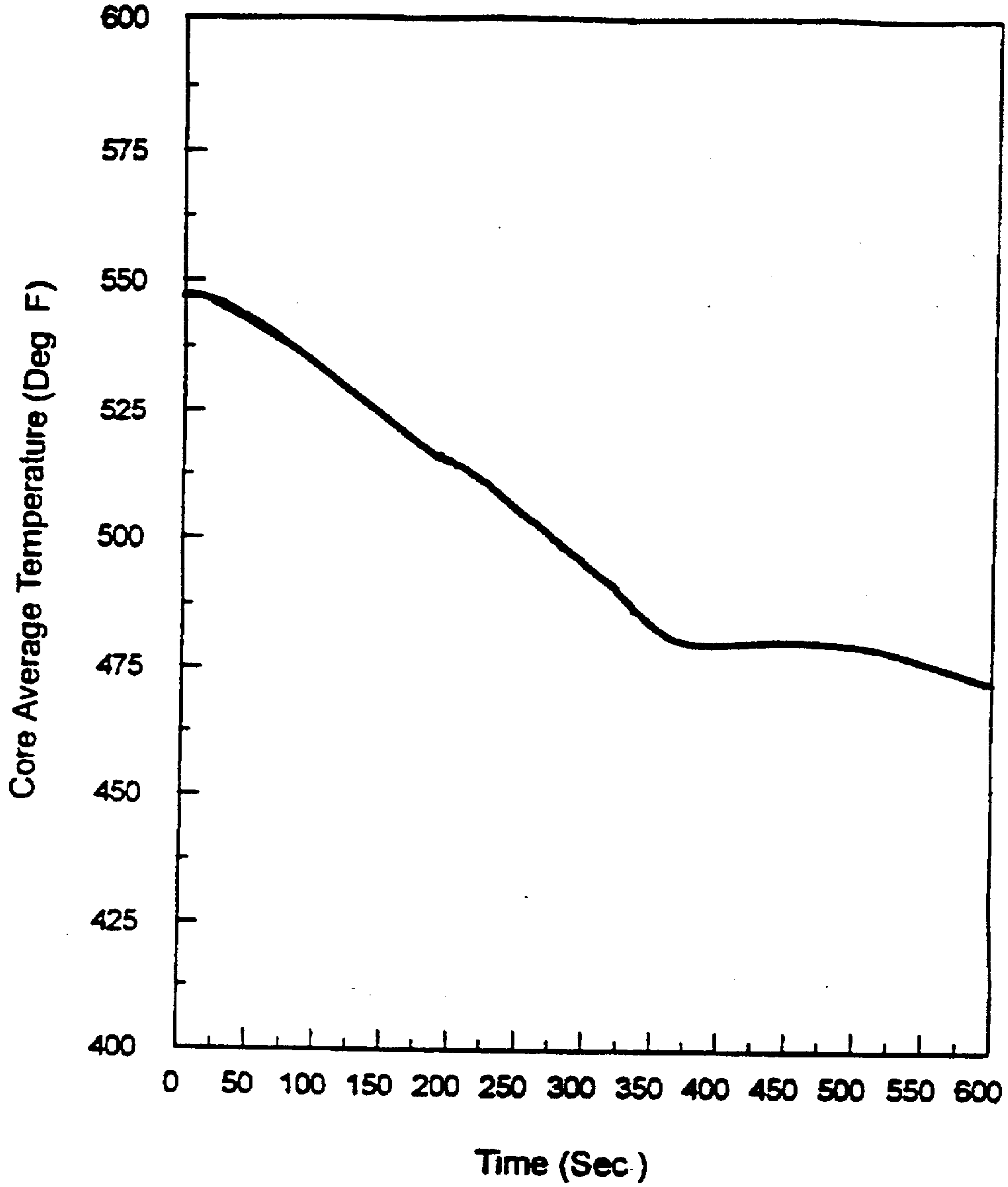
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station VARIATION OF Keff WITH CORE TEMPERATURE
	Updated FSAR — Figure 15.2-41



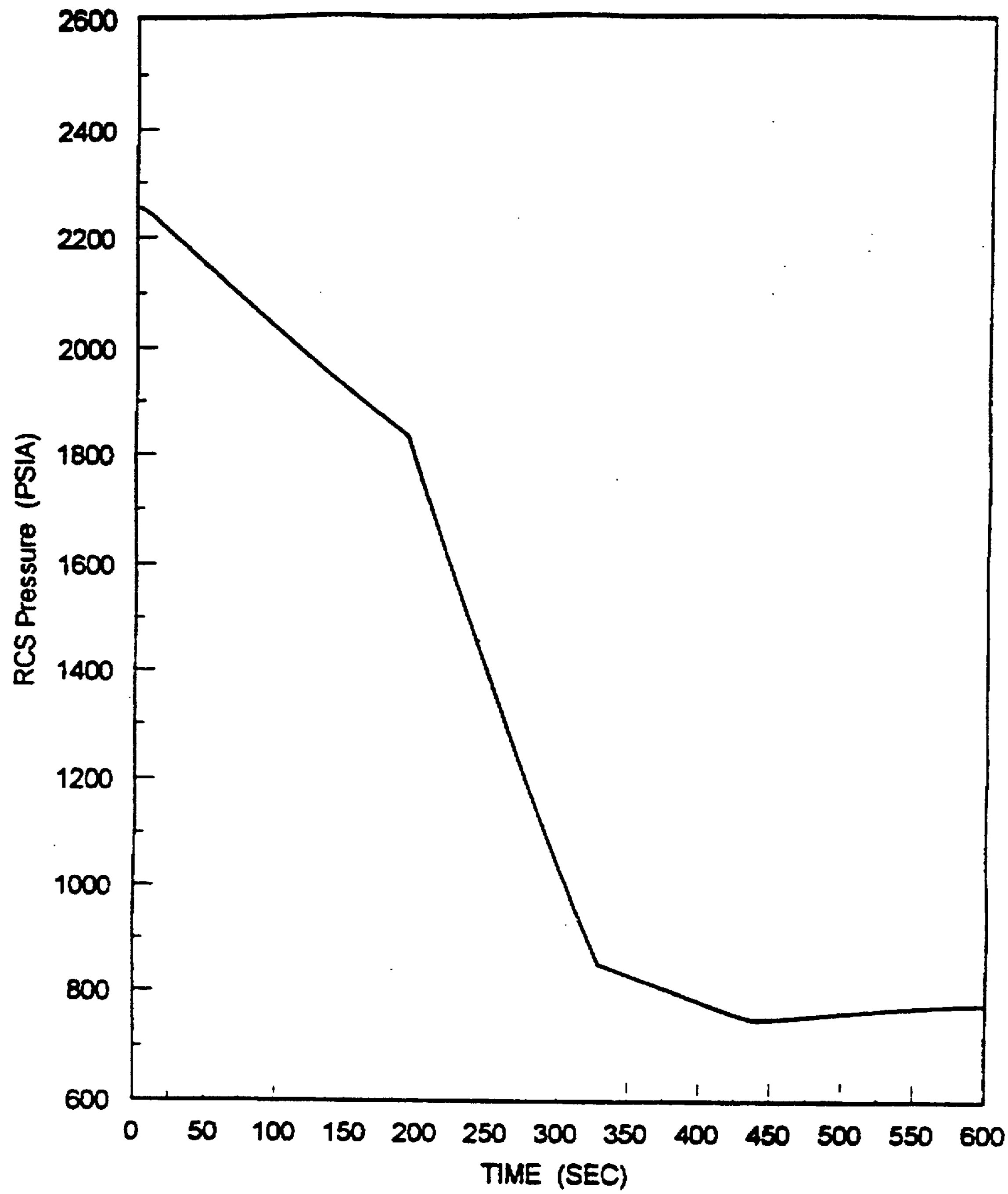
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station SAFETY INJECTION CURVE
	Updated FSAR Figure 15.2-42



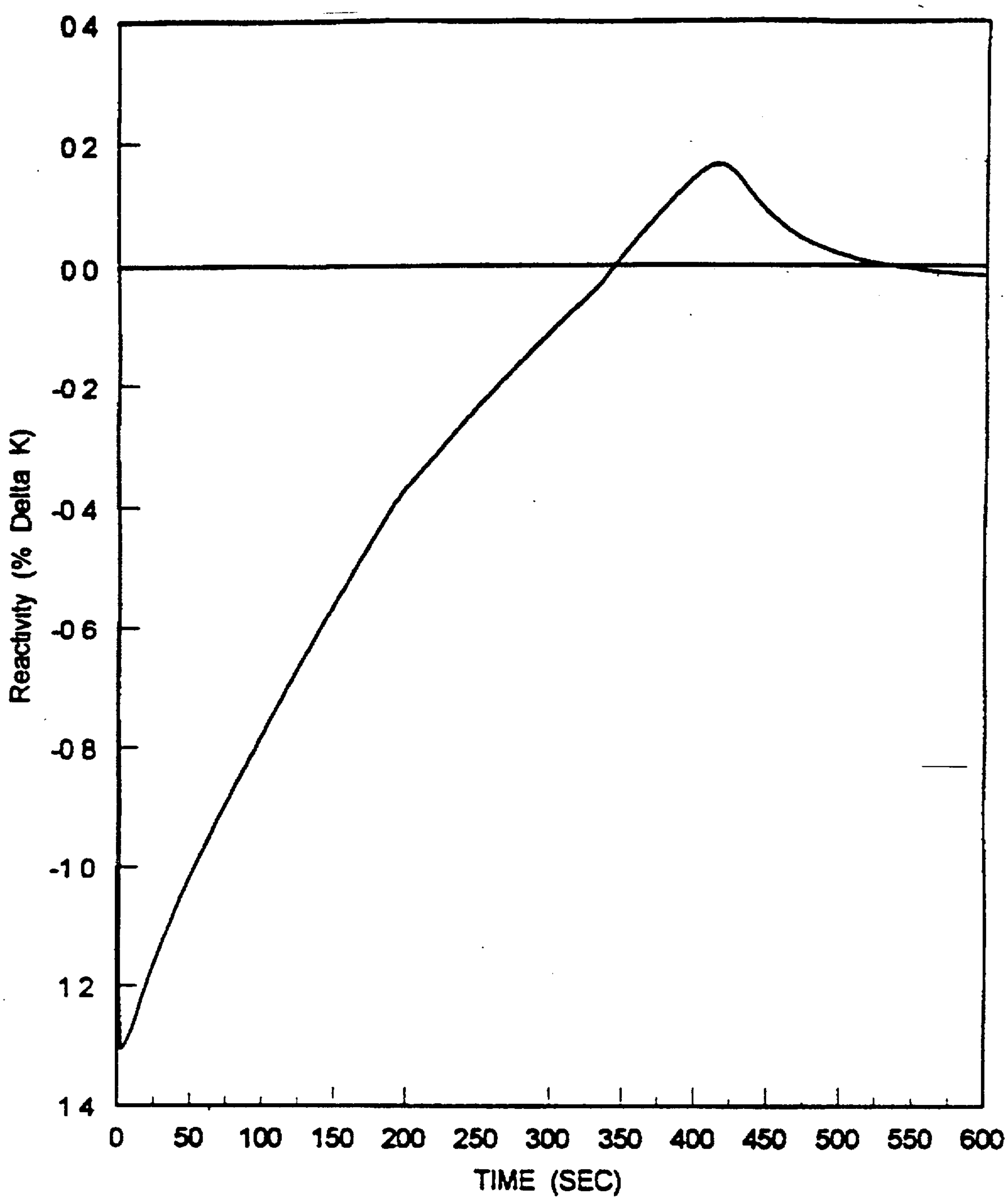
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station ACCIDENTAL MSS DEPRESSURIZATION
	Updated FSAR Figure 15.2-43A



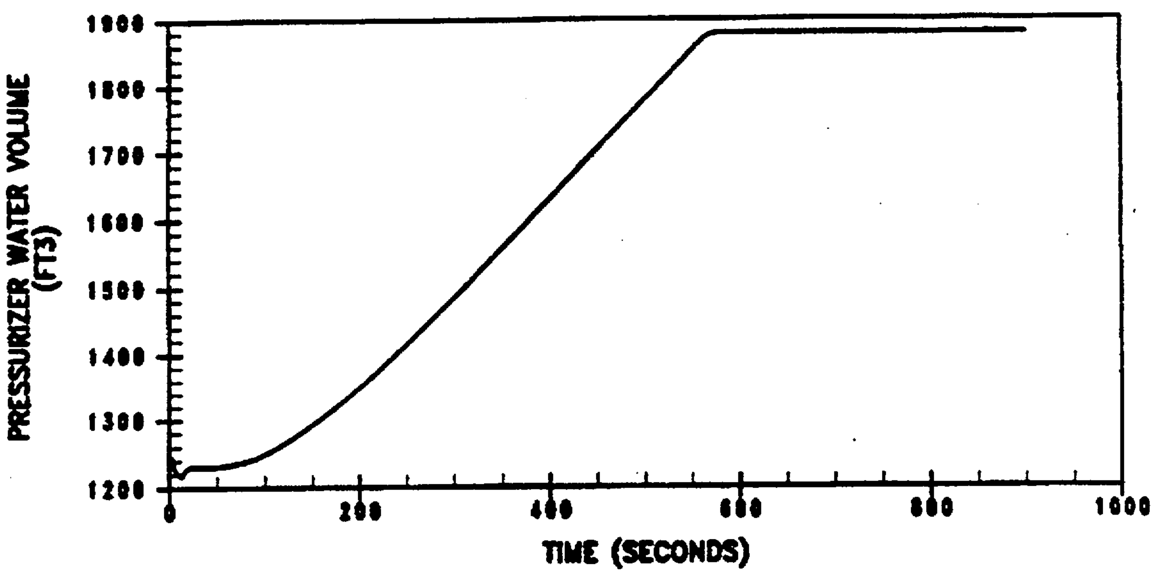
Revision 18, April 26, 2000

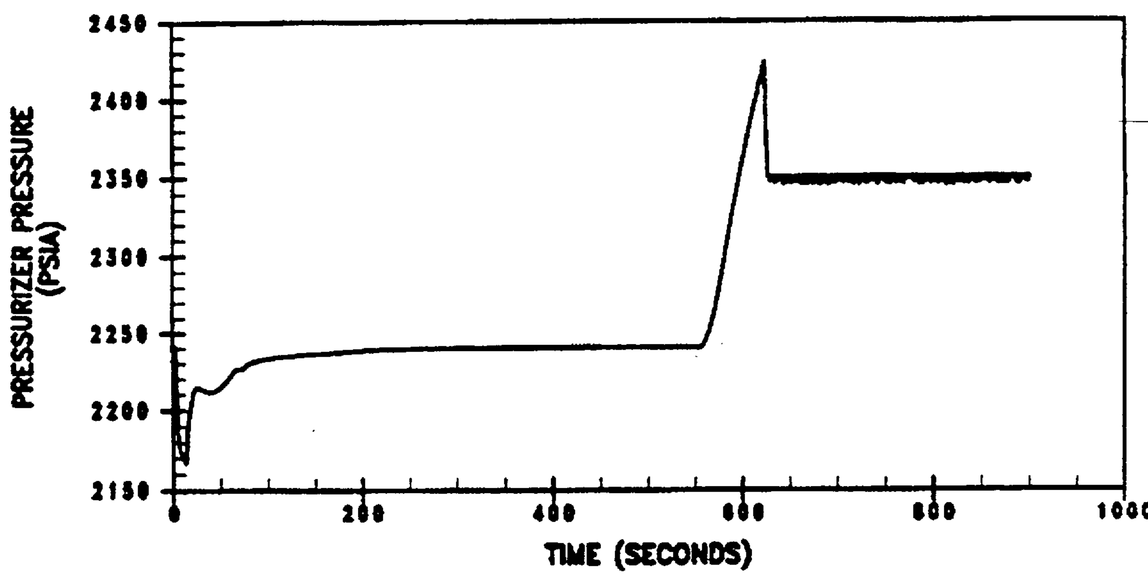
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station ACCIDENTAL MSS DEPRESSURIZATION
	Updated FSAR Figure 15.2-43B



Revision 18, April 26, 2000

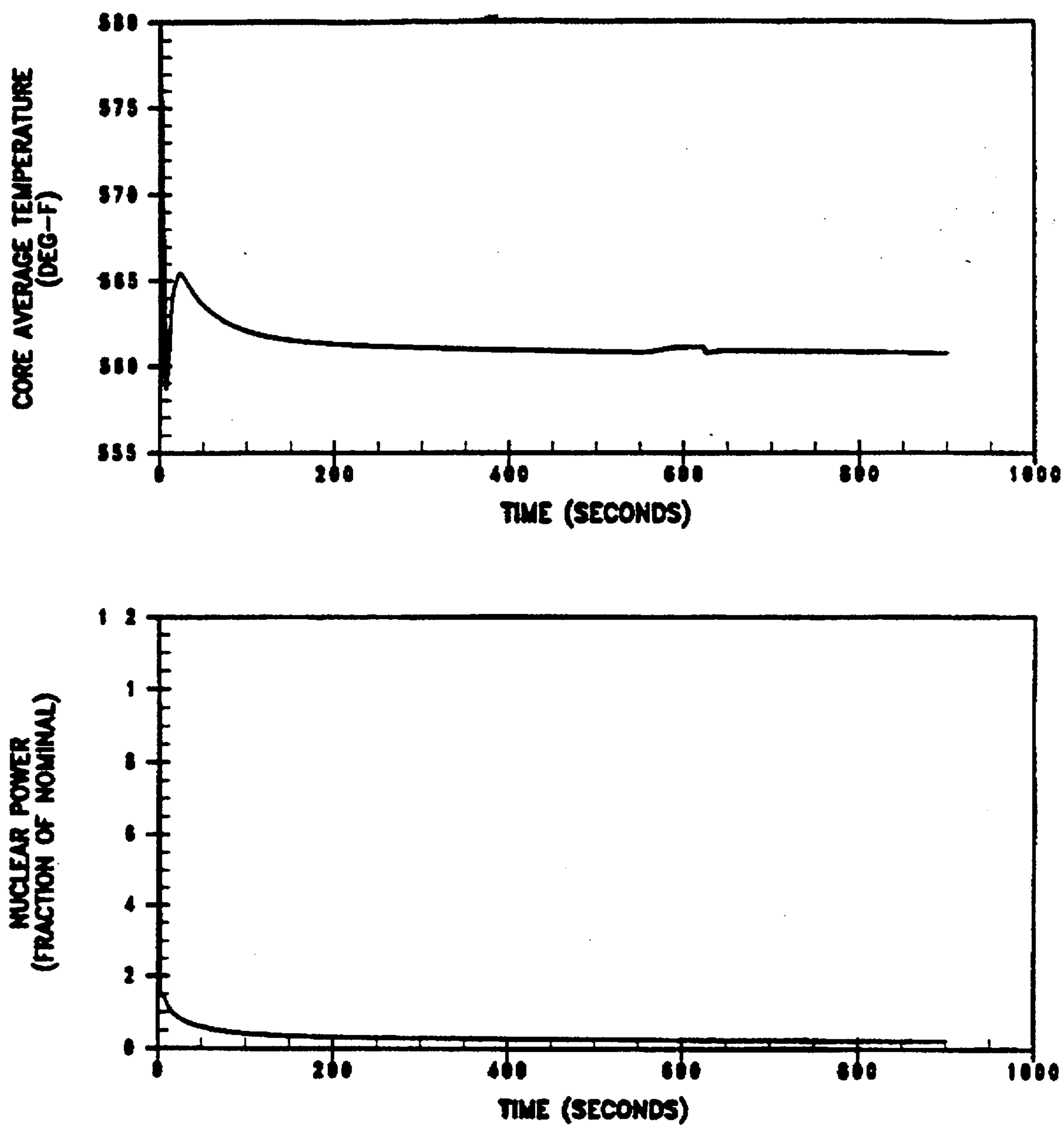
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station ACCIDENTAL MSS DEPRESSURIZATION
	Updated FSAR — Figure 15.2-43C





Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station SPURIOUS OPERATION OF THE SAFETY INJECTION SYSTEM AT POWER
	Updated FSAR — Figure 15.2-44



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station SPURIOUS OPERATION OF THE SAFETY INJECTION SYSTEM AT POWER
	Updated FSAR — Figure 15.2-45

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C. SALEM GENERATING STATION	
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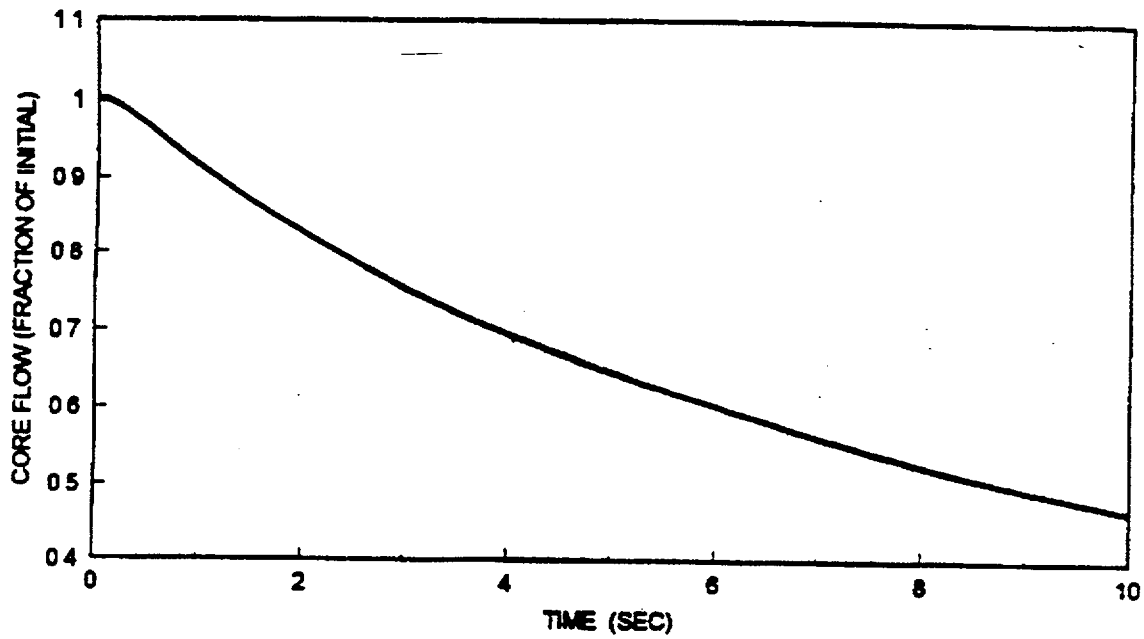
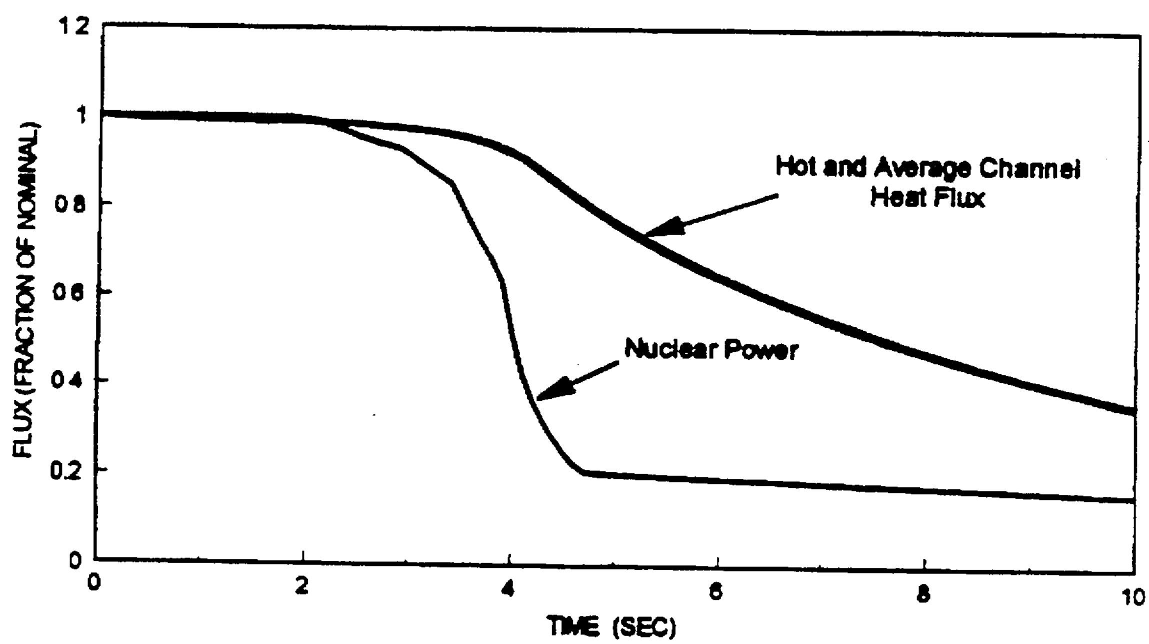
TABLE 15.3-4

TIME SEQUENCE OF EVENTS FOR COMPLETE LOSS OF FLOW EVENTS

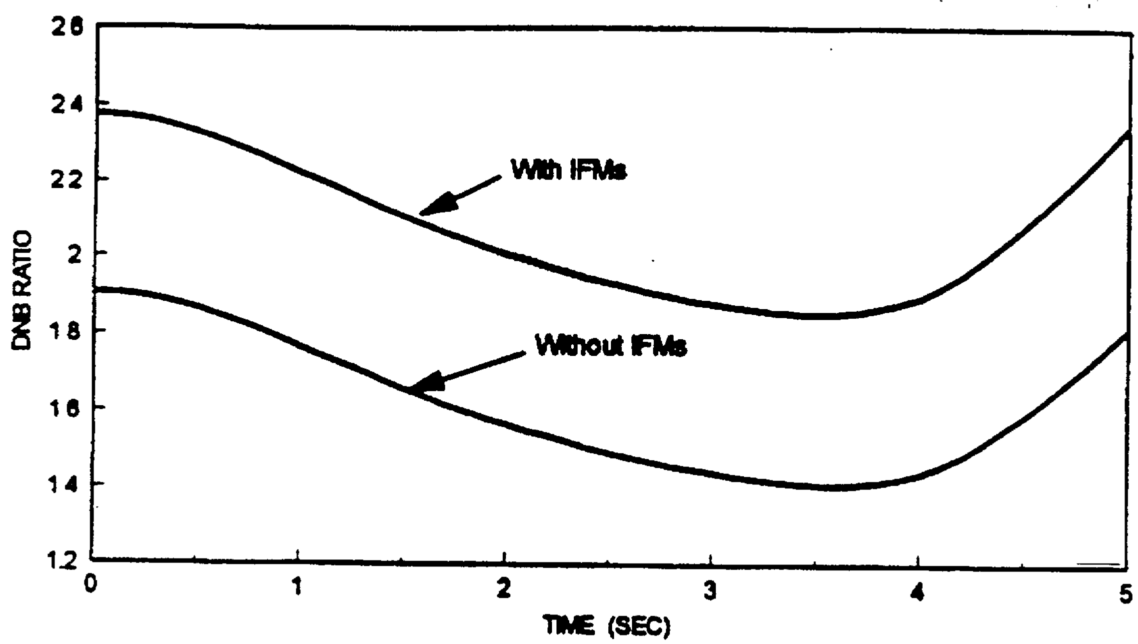
Accident	Event	Time(sec)
Undervoltage Event	All reactor coolant pumps begin to coast	0.0
	Undervoltage reactor trip	0.0
	Rods begin to drop	1.5
	Minimum DNBR occurs	3.4
Underfrequency Event	Frequency decay begins and RCS flow is reduced	0.0
	Underfrequency reactor trip	1.2
	Rods begin to drop	1.8
	Minimum DNBR occurs	3.9





Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station COMPLETE LOSS OF FLOW UNDERVOLTAGE EVENT
	Updated FSAR — Figure 15.3-14



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station COMPLETE LOSS FLOW UNDERVOLTAGE EVENT
	Updated FSAR — Figure 15.3-15

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

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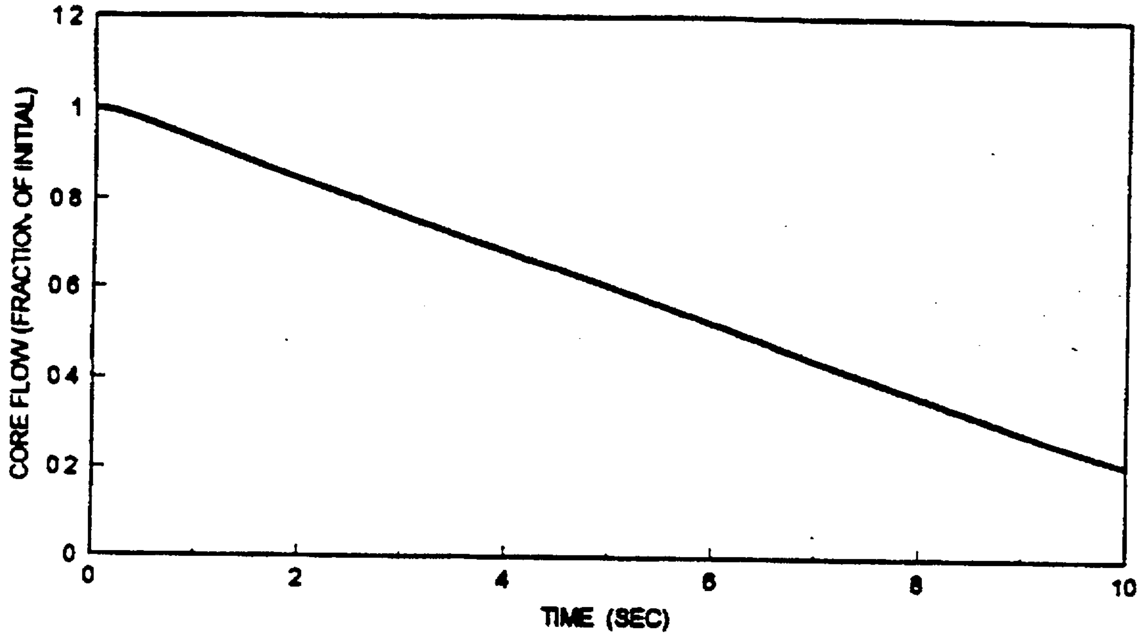
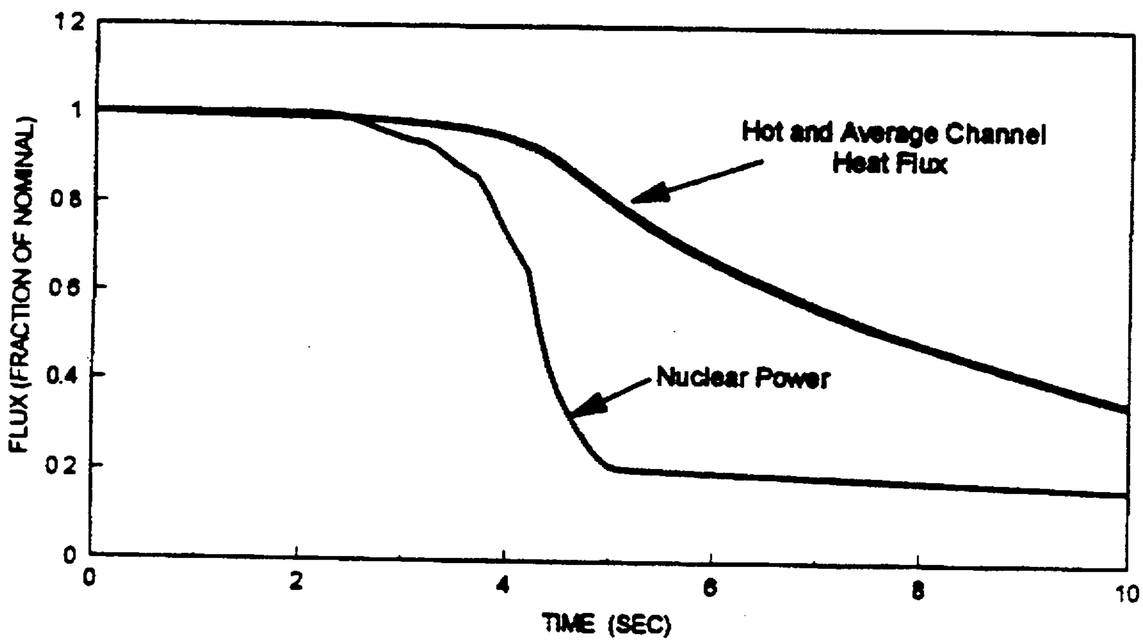
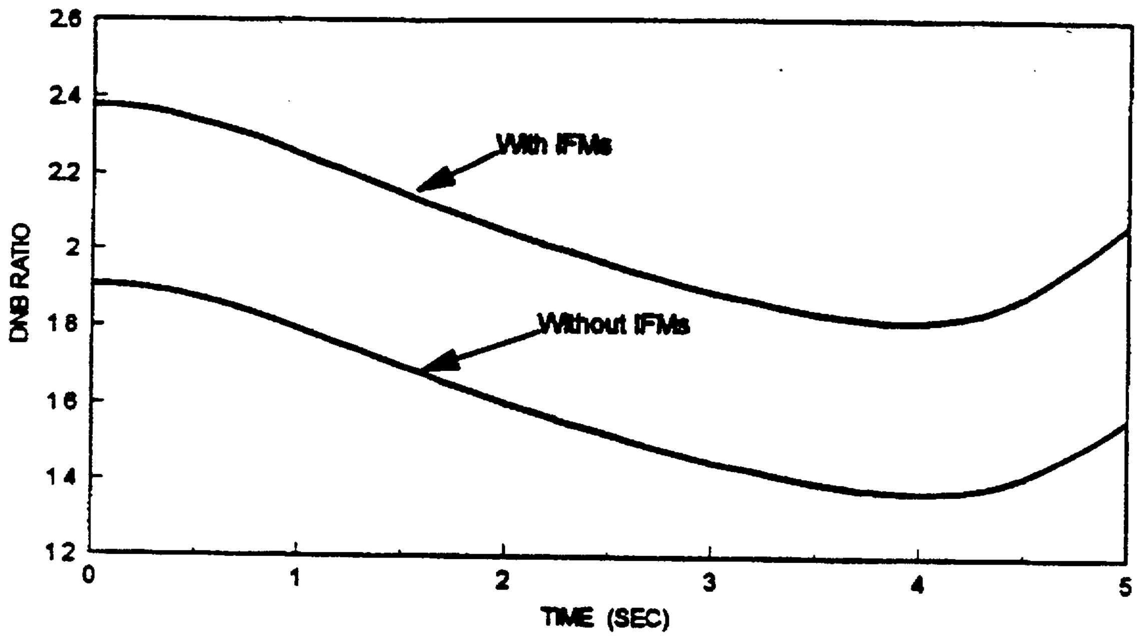




Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station COMPLETE LOSS OF FLOW UNDERFREQUENCY EVENT
	Updated FSAR Figure 15.3-16A



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station COMPLETE LOSS OF FLOW UNDERFREQUENCY EVENT
	Updated FSAR — Figure 15.3-16B

Table 15.4-1 (Cont.)

Accident	Event	Time (secs)
Major Rupture of a Main Feedwater Pipe (With Offsite Power Available)	Feedwater pipe rupture occurs	10
	Reactor trip set point reached for low-low steam generator water level	14
	Rod motion begins	16
	Safety injection actuation on low pressurizer pressure	72
	Auxiliary feedwater system begins flow delivery	74
	Peak steam relief from pressurizer relief valves	539
	Steamline isolation valves actuated and faulted auxiliary feedwater line isolated	614
	Cold auxiliary feedwater reaches the three intact steam generators	656
	Peak core average temperature occurs	920
	Minimum margin to hot leg saturation occurs	1120
Major Rupture of a Feedwater Pipe (With-Out Offsite Power Available)	Feedwater pipe rupture occurs	10
	Reactor trip setpoint reached for low-low steam generator water level	14
	Rod motion begins and reactor coolant Pumps begin coastdown	16
	Auxiliary feedwater flow initiated	74
	Safety injection actuation on low Pressurizer pressure	109

Table 15.4-1 (continued)

Peak steam relief from pressurizer relief Valves	417
Steamline isolation valves actuated and Faulted auxiliary feedwater line isolated	614
Peak core average temperature occurs	664
Minimum margin to hot leg saturation occurs	1036

TABLE 15.4-1 (Cont)

Accident	Event	Time (Sec)
Major Secondary System Pipe Rupture		
1. Case a	Steam line ruptures	0.0
	Pressurizer empties	12.6
	Criticality attained	26.2
	2300 ppm boron reaches loops	128.4
2. Case b	Steam line ruptures	0.0
	Pressurizer empties	13.8
	Criticality attained	18.2
	2300 ppm boron reaches loops	128.0
3. Case c	Steam line ruptures	0.0
	Pressurizer empties	13.6
	Criticality attained	30.2
	2300 ppm boron reaches loops	134.0
4. Case d	Steam line ruptures	0.0
	Pressurizer empties	15.4
	Criticality attained	24.2
	2300 ppm boron reaches loops	135.2
Locked Rotor	Rotor on one pump locks	0.0
	Low flow reactor trip setpoint reached	0.03
	Rod Motion begins	1.03
	Reactor coolant pumps coastdown	2.53
	Peak RCS pressure occurs	3.5
	Peak clad temperature occurs	3.7

TABLE 15.4-1 (Cont)

RCCA Ejection, Beginning of Life, Hot Full Power	Rupture of CRDM housing	0.0
	High neutron flux (high) reactor trip setpoint reached	0.05
	RCCA is fully ejected from core	0.1
	Peak nuclear power occurs	0.13
	Rods begin to drop	0.55
	Maximum fuel pellet enthalpy occurs	2.36
	Peak clad temperature occurs	2.48
	Maximum fuel melt occurs	2.82
RCCA Ejection, Beginning of Life, Hot Zero Power	Rupture of CRDM housing	0.0
	RCCA is fully ejected from core	0.1
	High neutron flux (low) reactor trip setpoint reached	0.25
	Peak nuclear power occurs	0.30
	Rods begin to drop	0.75
	Maximum fuel pellet enthalpy occurs	2.61
	Peak clad temperature occurs	2.55
	Maximum fuel melt occurs	N/A
RCCA Ejection, End of Life, Hot Full Power	Rupture of CRDM housing	0.0
	High neutron flux (high) reactor trip setpoint reached	0.04
	RCCA is fully ejected from core	0.1
	Peak nuclear power occurs	0.13
	Rods begin to drop	0.54
	Maximum fuel pellet enthalpy occurs	2.42
	Peak clad temperature occurs	2.50

TABLE 15.4-1 (Cont)

	Maximum fuel melt occurs	2.65
RCCA Ejection, End of Life, Hot Zero Power	Rupture of CRDM housing	0.0
	RCCA is fully ejected from core	0.1
	High neutron flux (low) reactor trip setpoint reached	0.17
	Peak nuclear power occurs	0.20
	Rods begin to drop	0.67
	Maximum fuel pellet enthalpy occurs	1.98
	Peak clad temperature occurs	1.79
	Maximum fuel melt occurs	N/A

TABLE 15.4-6

SUMMARY OF RESULTS FOR LOCKED ROTOR/RCP SHAFT BREAK TRANSIENTS
(FOUR LOOPS OPERATING INITIALLY)

Maximum Reactor Coolant System Pressure (psia)	2590
Maximum Clad Temperature (°F) Core Hot Spot	2038
Amount of $Zr-H_2O$ at Core Hot Spot (% by Weight)	0.72
Maximum Number of Fuel Rods-in-DNB (Most Limiting Fuel Assembly)	< 5%

TABLE 15.4-7

MAIN STEAM PIPE RUPTURE PARAMETERS AND ASSUMPTIONS

Parameter	Value	
RCS Volume	10,892 ft^3	
Initial RCS Activity	Table 15.4-8	
(1% FF Noble Gas with Pre-Accident Iodine Spike)		
RCS Activity Accident-Initiated Iodine Rate Spike	Table 15.4-8	
Duration of Spike	2 hrs	
Secondary Side Pre-Accident Iodine Activity	Table 15.4-8	
Plant Status		
Offsite Power	Not Available	
Main Condensers	Not Available	
Activity Release Duration		
Affected Steam Generator	30 days	
Intact Steam Generators	32 hours	
Release Pathway		
Affected Steam Generator	Break Point	
Intact Steam Generators (3)	Safety & Relief Valves	
Primary-to-Secondary Leakage		
Affected Steam Generator	0.35 gpm (175 lb/hr)	
Intact Steam Generators (3)	0.65 gpm (325 lb/hr)	
Partition Coefficients	Iodine	Noble Gas
Affected Steam Generator	1.0	1.0
Intact Steam Generators (3)	0.01	1.0
Steam Releases (lbs)	Affected SG	Intact SC
0-2 hr.	106,860	499,500
2-8 hr.	-	452,000
8-32 hr.	-	1,807,800
Mass of Secondary Coolant in intact SG (lbs)	106,860	
Onsite χ/Qs (s/m³)	Table 2.3-21	
Breathing Rates (m³/s)	Table 15.4-9	

TABLE 15.4-7B

STEAM GENERATOR TUBE RUPTURE PARAMETERS AND ASSUMPTIONS

Parameter	Value	
RCS Volume	10,892 ft^3	
Initial RCS Activity	Table 15.4-8	
(1% FF Noble Gas with Pre-Accident Iodine Spike)		
RCS Activity Accident-Initiated Iodine Rate Spike	Table 15.4-8	
Duration of Spike	2 hrs	
Secondary Side Pre-Accident Iodine Activity	Table 15.4-8	
Plant Status		
Offsite Power	Not Available	
Main Condensers	Not Available	
Release Duration		
Faulted Steam Generator	30 min. *	
Intact Steam Generators	32 hours	
Release Pathway		
Faulted Steam Generator	Safety & Relief Valves	
Intact Steam Generators (3)	Safety & Relief Valves	
Primary-to-Secondary Flow		
Faulted Steam Generator (0 to 30 min. *)	137,250 lbs	
Intact Steam Generators	0.65 gpm (325 lb/hr)	
Partition Coefficients	Iodine	Noble Gas
Affected Steam Generator	0.1	1.0
Intact Steam Generators (3)	0.1	1.0
Steam Releases (lbs)	Affected SG	Intact Sg
0-30 min. *	56,460	-
0-2 hr.	-	465,130
2-8 hr.	-	1,055,210
8-32 hr.	-	2,130,600
Mass of Post Accident Steam Generator Liquid in SG (lbs)	106,860/SG	
Onsite χ/Qs (s/m^3)	Table 2.3-21	
Breathing Rates m^3/s)	Table 15.4-9	

* See Section 15.4.4.4 regarding allowable operator action times with respect to isolation of the faulted steam generator.

TABLE 15.4-12

PARAMETERS USED IN THE ANALYSIS OF THE ROD CLUSTER CONTROL ASSEMBLY EJECTION ACCIDENT

Beginning in Life	Full Power	Zero Power
Initial Power Level (%)	102	0
Ejected RCCA Worth (%Δk)	0.20	0.77
Delayed Neutron Fraction	0.0048	0.0048
Reactivity Feedback Weighting	1.6	2.398
Trip Reactivity, (%Δk)	4.0	2.0
F_q Before Ejection	2.544	N/A
F_q After Ejection	7.4	14.2
Number of RCPs Operating	4	2
Max. Fuel Pellet Enthalpy (Cal/g)	188.4	154.8
Max. Fuel Melted (%)	8.60	N/A
Peak Clad Temperature, (°F)	2691	2933

End of Life	Full Power	Zero Power
Initial Power Level (%)	102	0
Ejected RCCA Worth, (%Δk)	0.21	0.90
Delayed Neutron Fraction	0.0040	0.0040
Reactivity Feedback Weighting	1.6	3.55
Trip Reactivity, (%Δk)	4.0	2.0
F_q Before Ejection	2.544	N/A
F_q After Ejection	8.2	20.5
Number of RCPS Operating	4	2
Max. Fuel Pellet Enthalpy (cal/g)	183.5	149.4
Max. Fuel Melted (%)	9.04	N/A
Peak Clad Temperature, (°F)	2628	2894

TABLE 15.4-21 (Cont)

Description	Material Type	Thickness	Sides Exposed	Surface (sq ft)
Refueling Canal	Stainless Steel 304	1/4 in.	1	7,942.0
	Concrete	51 in.	1	7,290.0
Crane Wall	Reinforced Concrete	36 in.	2	13,707.0
	Paint (primer)	10 mils	1	26,414.0
	Paint (finish)	4 mils	1	26,414.0
Operating Deck at El 130 ft-0 in.	Reinforced Concrete	41 in.	2	4,960.0
	Paint (primer)	10 mils	1	9,920.0
	Paint (primer)	8 mils	1	9,920.0
Shield Walls Above El 130 ft-0 in.	Reinforced Concrete	36 in.	2	2,956.0
	Paint (primer)	10 mils	1	5,912.0
	Paint (finish)	4 mils	1	5,912.0
Main Steam/ Feedwater Stops	Steel A-441	5/32 in.	2	224.0
		5/16 in.	2	19.0
		1/4 in.	2	302.0
		3/8 in.	2	1563.0
		1/2 in.	2	6,592.0
		5/8 in.	2	639.0
		3/4 in.	2	3,039.0
		7/8 in.	2	461.0
		1 in.	2	1,981.0
		1 1/4 in.	2	1,006.0
		1 1/2 in.	2	14.0
	Paint (primer)	2.5 mils	1	29,802.0
	Paint (finish)	5.0 mils	1	29,802.0

TABLE 15.4-21 (Cont)

Description	Material Type	Thickness	Sides Exposed	Surface (sq ft)
Steam Generator	Steel A-36	1/2 in.	2	95.75
Supports and	Steel A-441	5/8 in	2	337.5
Manway Cover		3/4 in.	2	180.0
Platforms		7/8 in.	2	434.0
(Units 1 & 2)		1 in.	2	1,803.7
		1 1/4 in.	2	1,124.7
		1 3/8 in.	2	258.5
		1 1/2 in.	2	752.0
		1 7/8 in.	2	282.0
		2 in.	2	714.5
		2 1/4 in.	2	1,296.0
		2 3/4 in.	2	625.0
		3 in.	2	142.5
		4 in.	2	195.5
SGRP(1)	Steel A-36			
(Unit 1 only)	Steel A-441			
	Steel A-572	1.89 in.		934.4
	Paint (primer)	2.5 mils	1	16,764.0
	Paint (finish)	5.0 mils	1	16,764.0
Reactor Coolant	Steel A-36	3/16 in.	2	960.0
Pump Supports		1/4 in.	2	507.0
and Pump		3/8 in.	2	630.0
Access Plate				

NOTE 1: The modifications to the Lower Steam Generator Supports increased the metal volume by 147.5 ft^3 and the surface area by 934.4 square feet. The thickness listed in the table above is the average material thickness calculated from the added volume and surface area (reference PSBP 323462).

TABLE 15.4-21 (Cont)

Description	Material Type	Thickness	Sides Exposed	Surface (sq ft)
RHR and SI Piping with 1 1/2 in. Insulation	Stainless Steel	1.125 in.	1	534.0
Miscellaneous Small Bore Piping Bare Piping	Steel	0.145 in.	1	7,455.0
Control Trays, Panels, and Tubing	Steel	0.202 in.	2	6,083.0
Insert Steel	Steel A-36	5/6 in.	1	2,928.0
Hanger Steel	Steel A-36	1/8 in.	2	3.4
		3/16 in.	2	40.5
		1/4 in.	2	925.4
		1/4 in.	1	106.8
		3/8 in.	2	2,568.4
		3/8 in.	1	106.8
		1/2 in.	1	1.16
		1/2 in.	2	52.0
Pipe Restraints and Hangers (Large Pipes)	Steel A-36	1/4 in.	2	218.0
		3/8 in.	1	108.0
		3/8 in.	2	480.7
		1/2 in.	2	35.2
Supplementary Steel		1/2 in.	1	4.2
		3/4 in.	1	1,154.8
		3/4 in.	2	84.5
		7/8 in.	2	137.0
		1 in.	1	106.0
		1 in.	2	226.0
		1 1/4 in.	1	25.0
		1 1/4 in.	2	14.0
		1 3/8 in.	2	122.75
		1 1/2 in.	1	82.86
		1 1/2 in.	2	92.5
		1 3/4 in.	2	69.88
		2 in.	1	166.0
		2 in.	2	14.1
		3 in.	1	11.6
		4 and 4 1/2 in.	2	111.0
		7/8 in.	1	9.0

TABLE 15.4-21 (Cont)

Description	Material Type	Thickness	Sides Exposed	Surface (sq ft)
Springs and Spring Box for Hangers	Steel	3/16 in.	1	734.7

HEAT TRANSFER PROPERTIES

Material	Thermal Conductivity ($Btu/ft^3-°F$)	Volumetric Heat Capacity ($Btu/hr-ft-°F$)
Steel (carbon)	28.0	58.8
Stainless Steel	8.5	58.8
Concrete	1.04	23.4
Insulation	0.024	3.94
Paint	0.083-0.292	30.86-52.8

TABLE 15.4-22

PEAK PRESSURE

(This Table has been deleted)

TABLE 15.4-23

(This table has been deleted)

TABLE 15.4-24

SPRAY SYSTEM/FAN COOLER/INITIATION TIMES/SETPOINTS

Spray System

Number of Spray Trains	2
Number of Spray Trains Operating in Minimum Safeguards Analysis	1
Spray Flow Rate per Spray Train	2600 gpm

Fan Coolers

Number of Fan Coolers	5
Number of Fan Coolers Operating in Minimum Safeguards Analysis	3

Initiation Times/Setpoints

System	Containment Setpoint Used	Delay after Trip Signal (w/o offsite power available)
Spray	17.0 psig	85
Fan Coolers	6.0 psig (5.5 psig, Unit 1)	60

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SALEM GENERATING STATION

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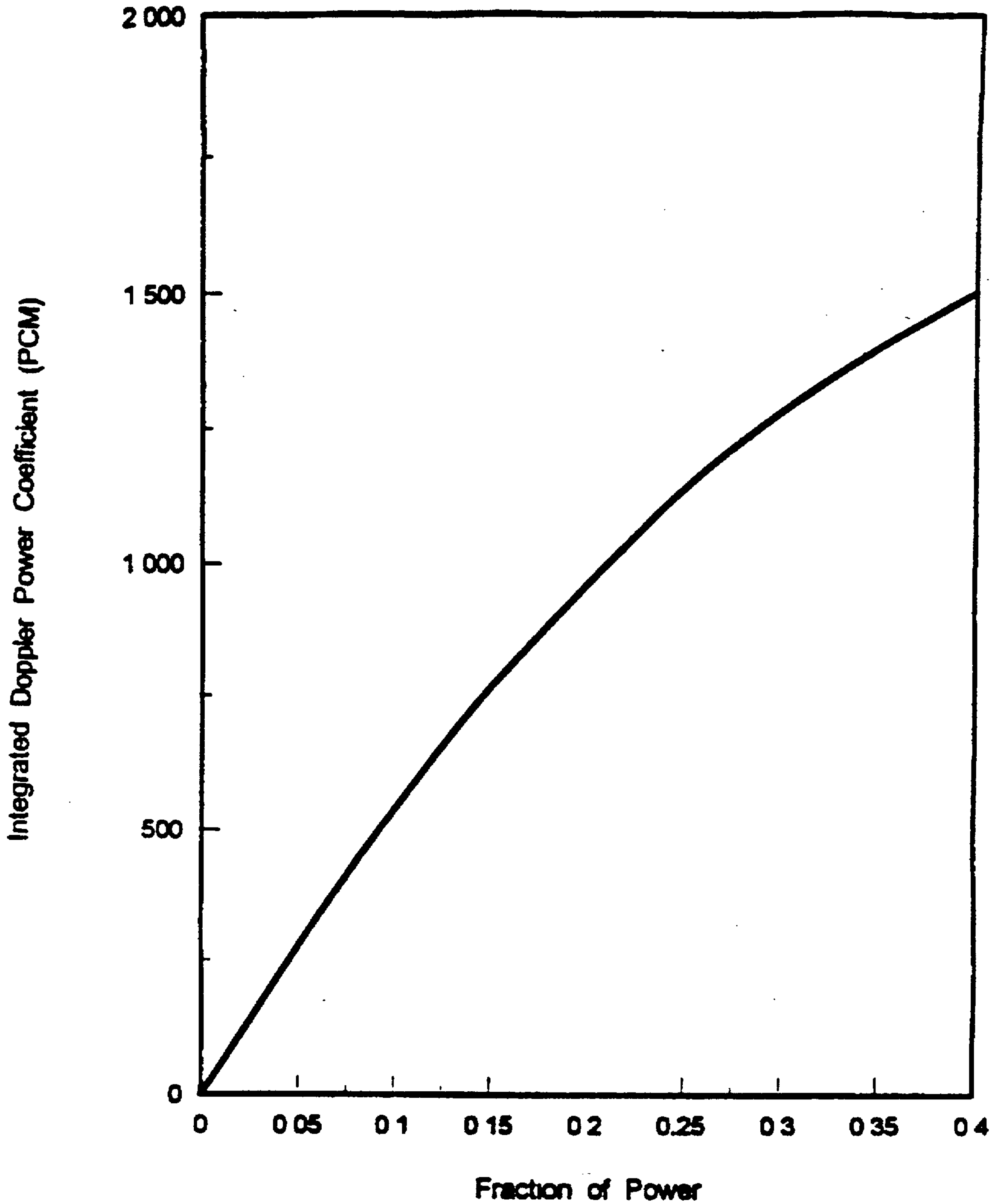
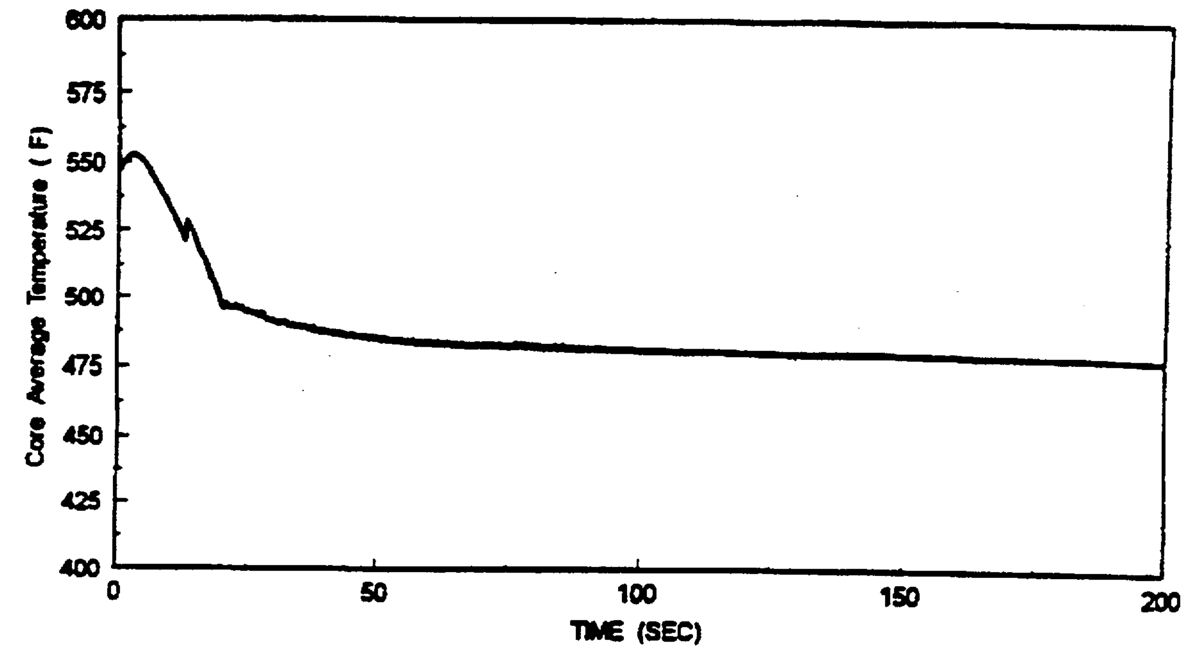
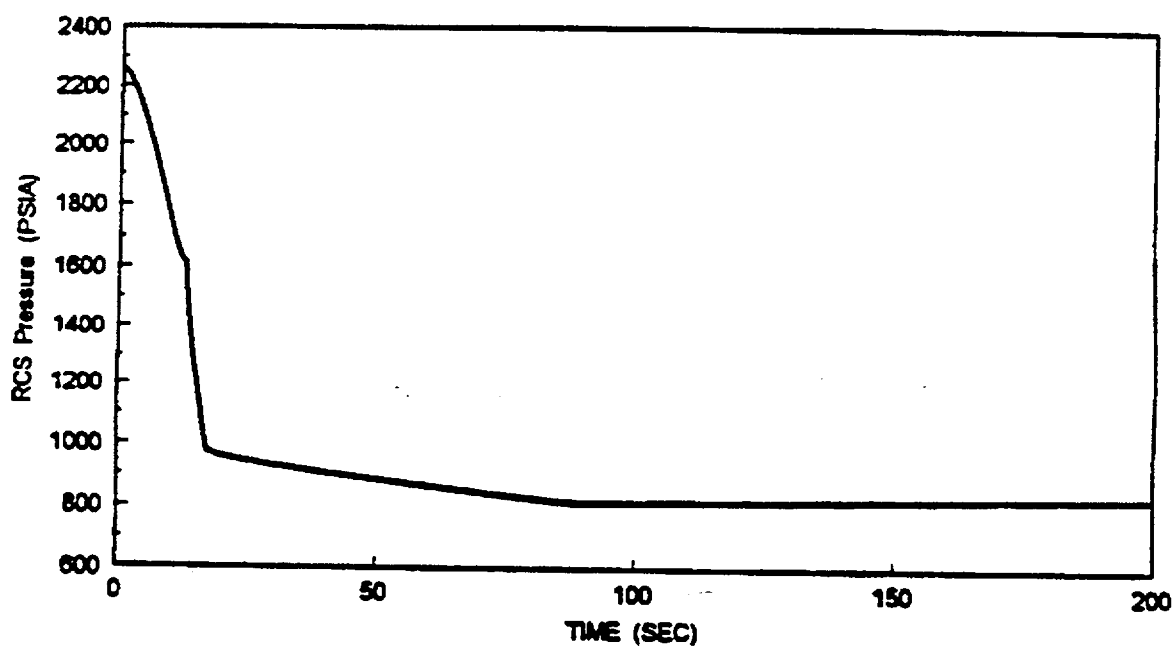


Revision 18, April 26, 2000

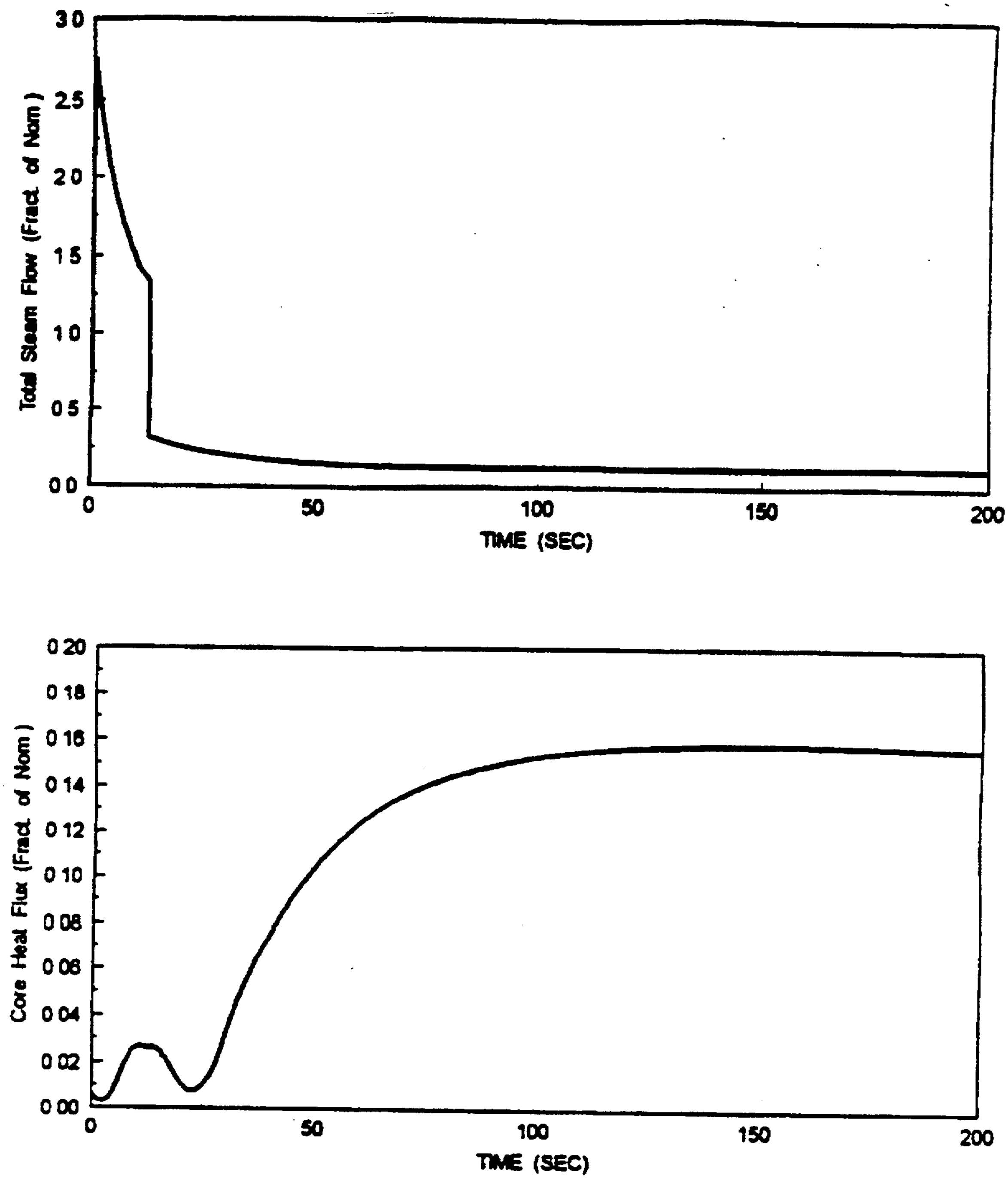
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station VARIATION OF REACTIVITY WITH POWER AT CONSTANT CORE AVERAGE TEMPERATURE
	Updated FSAR — Figure 15.4-49





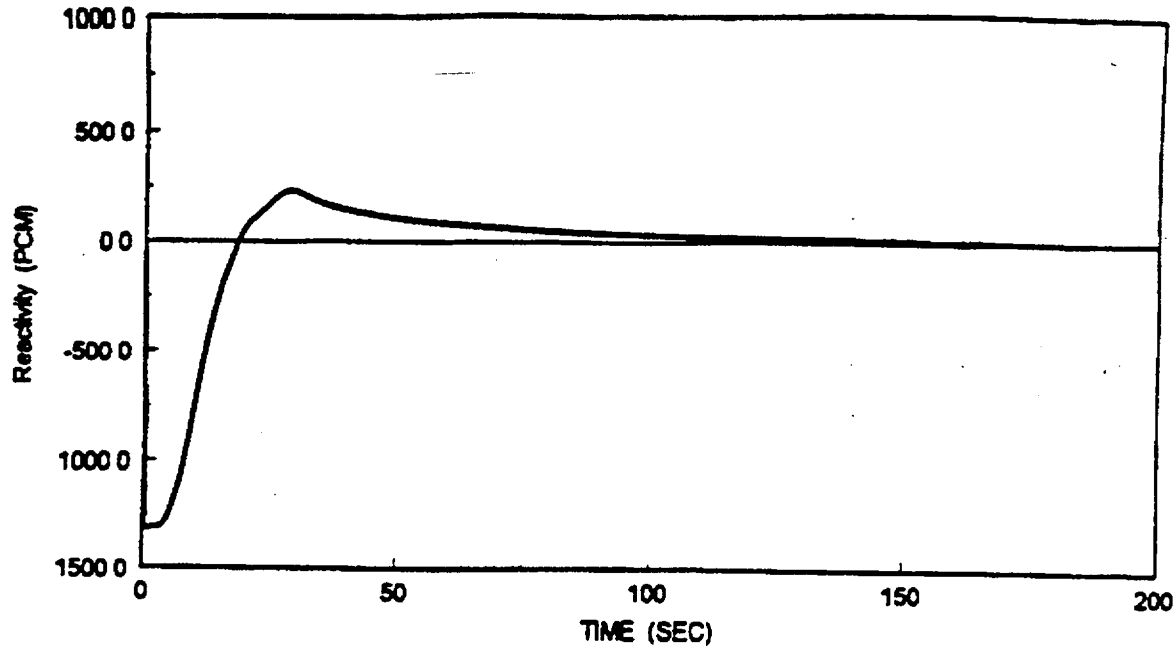
Revision 18, April 26, 2000

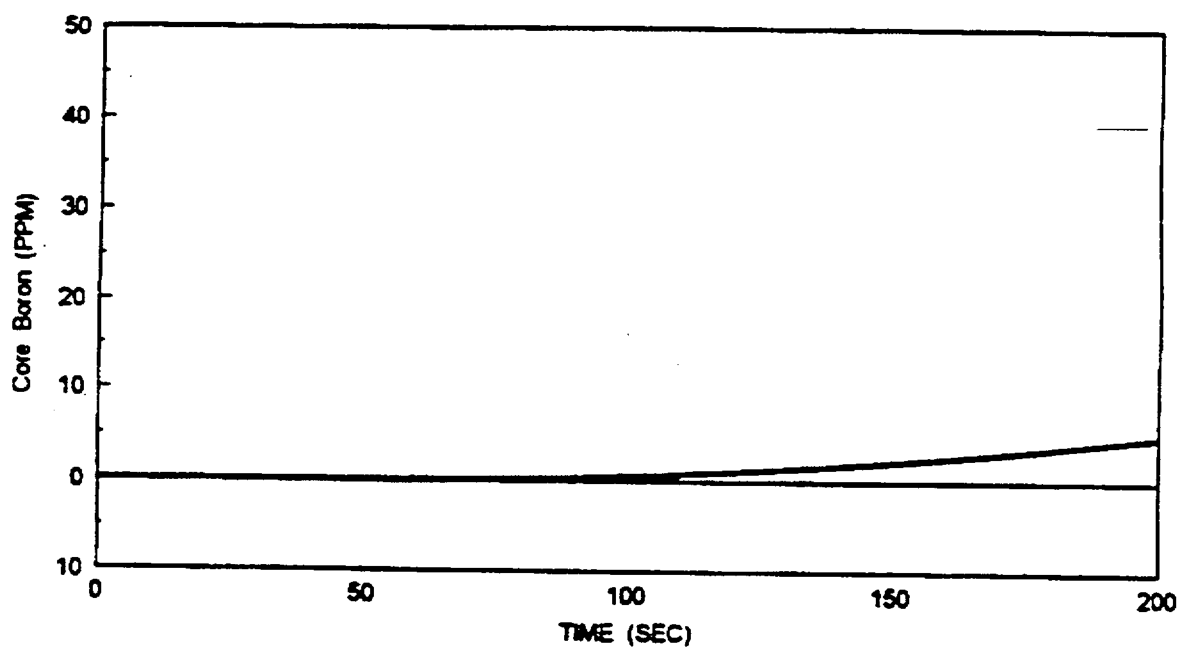
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station STEAMLINE BREAK DOWNSTREAM OF FLOW MEASURING DEVICES WITH OFFSITE POWER(CASE A)
	Updated FSAR — Figure 15.4-50A



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station STEAMLINE BREAK DOWNSTREAM OF FLOW MEASURING DEVICES WITH OFFSITE POWER(CASEA)
	Updated FSAR — Figure 15.4-50B





Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station STEAMLINE BREAK DOWNSTREAM OF FLOW MEASURING DEVICES WITH OFFSITE POWER (CASE A)
	Updated FSAR Figure 15.4-50C

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PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

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PSEG NUCLEAR L.L.C. SALEM GENERATING STATION	
SALEM UFSAR - REV 18	SHEET 1 OF 1
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PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

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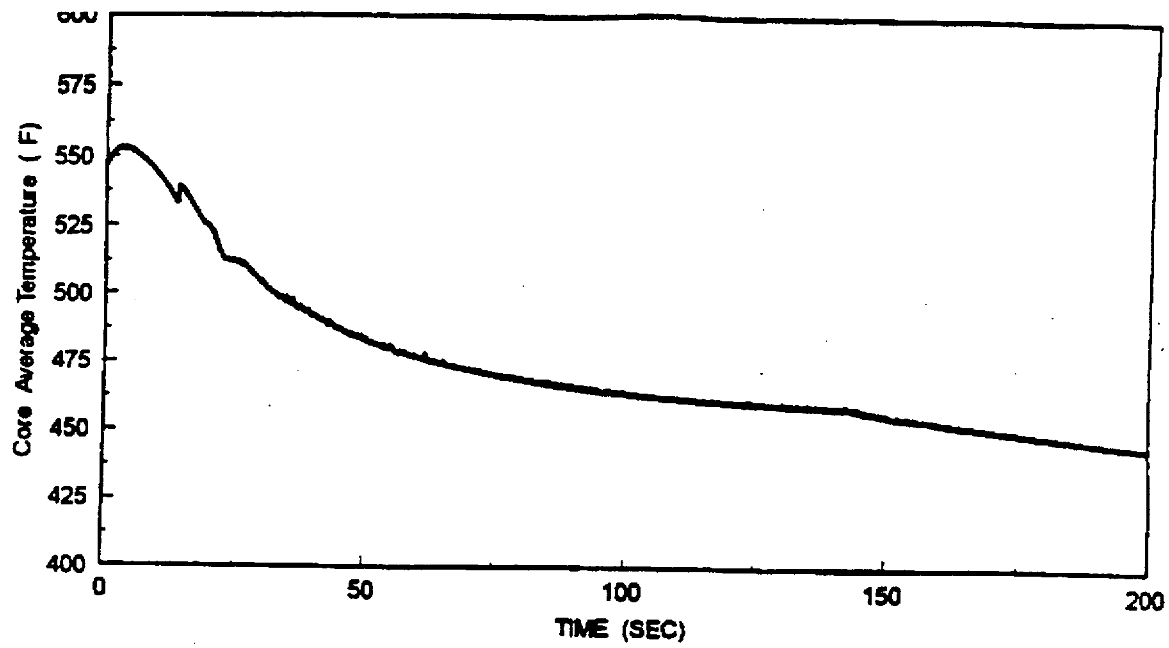
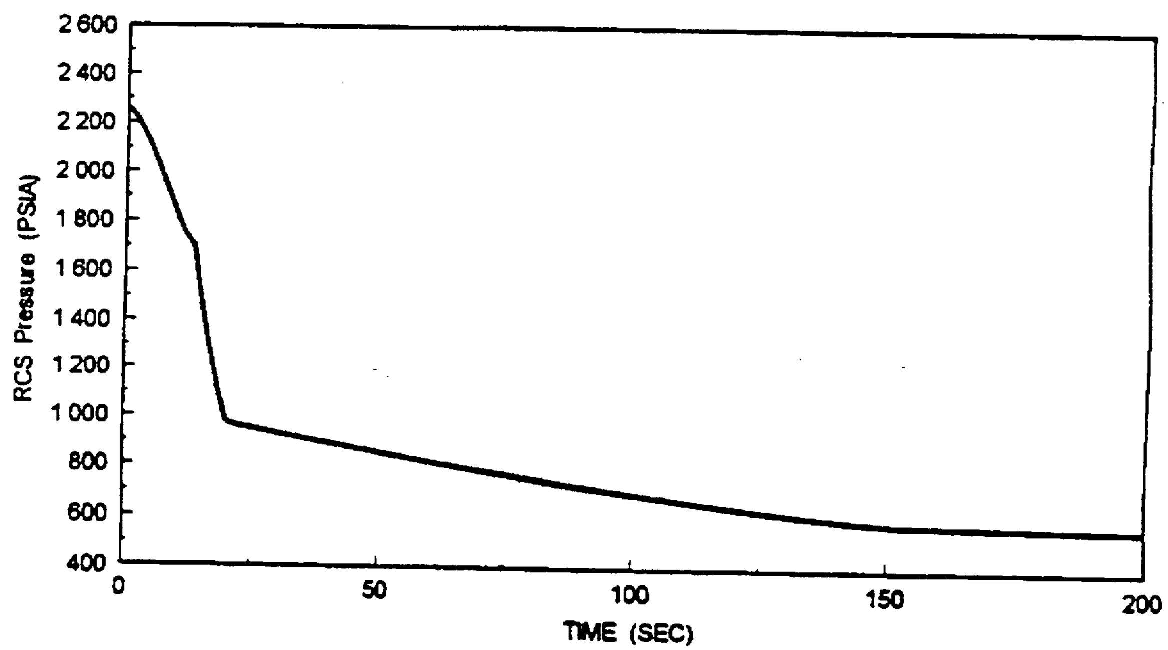
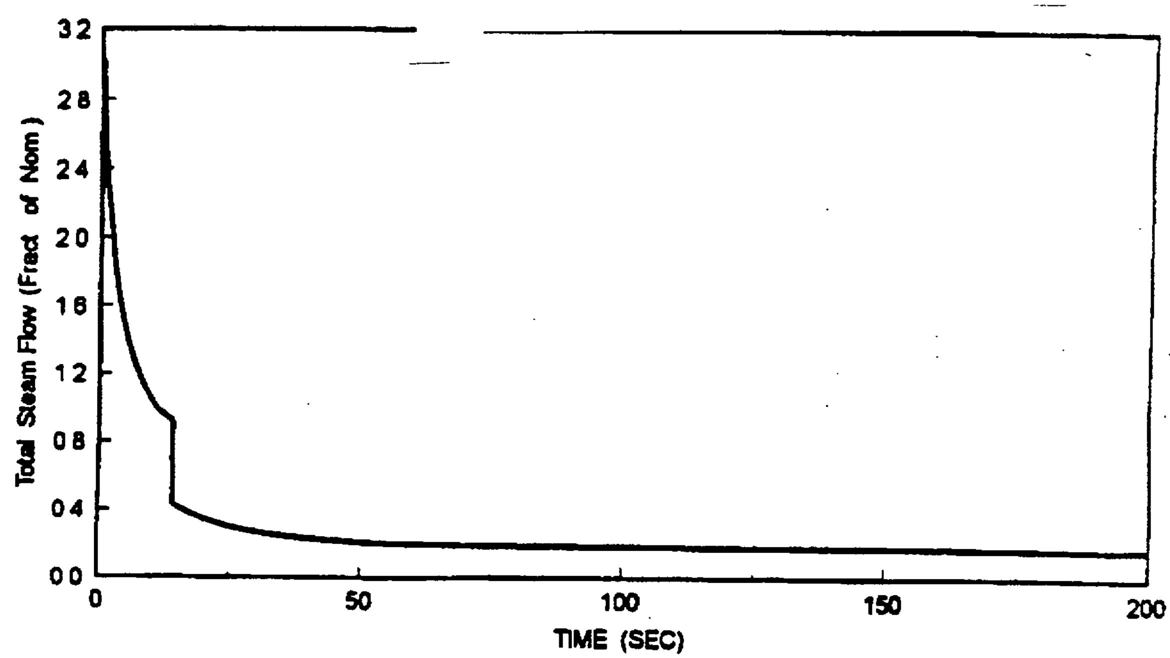
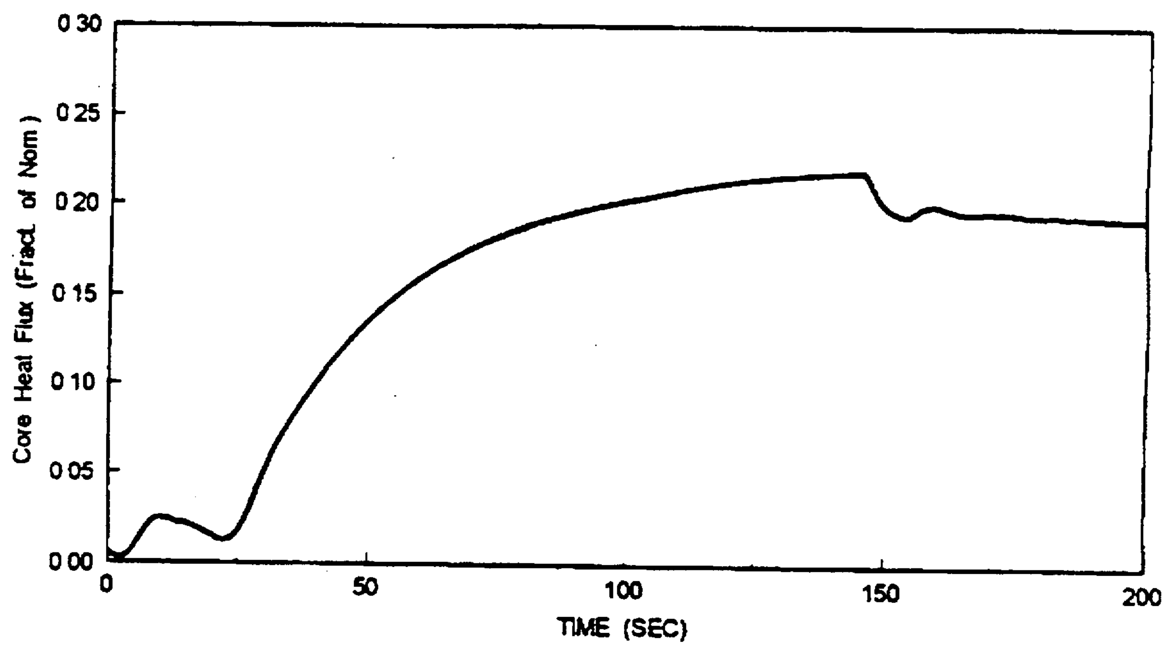




Revision 18, April 26, 2000

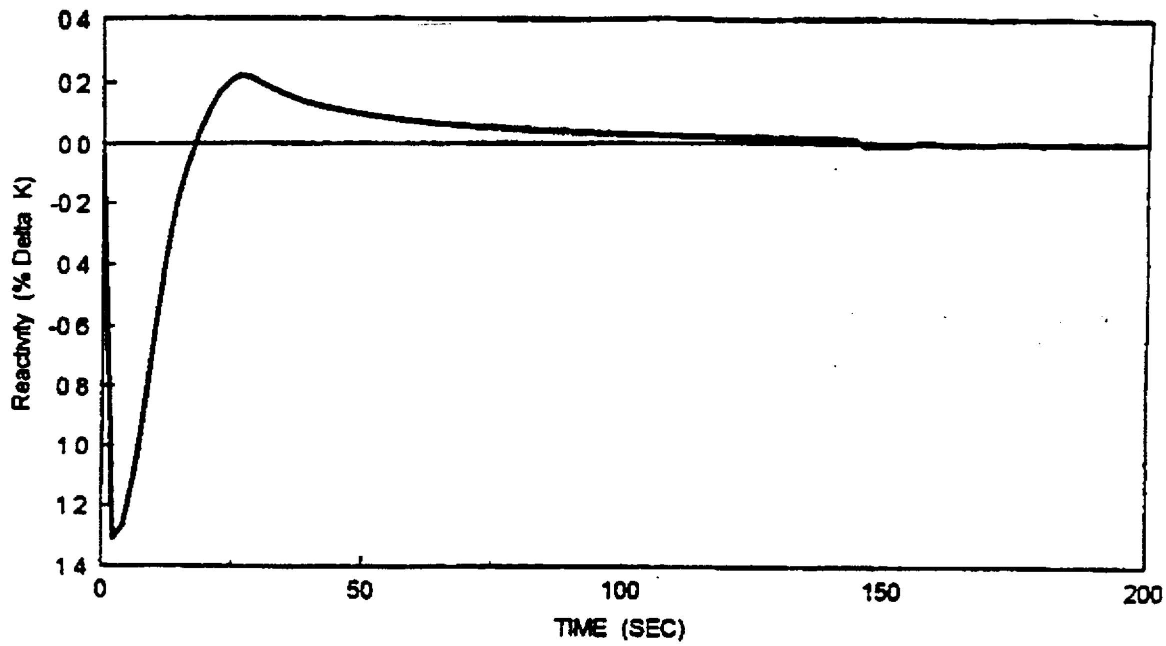
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station STEAMLINE BREAK AT EXIT OF STEAM GENERATOR WITH OFFSITE POWER (CASE B)
	Updated FSAR — Figure 15.4-51A

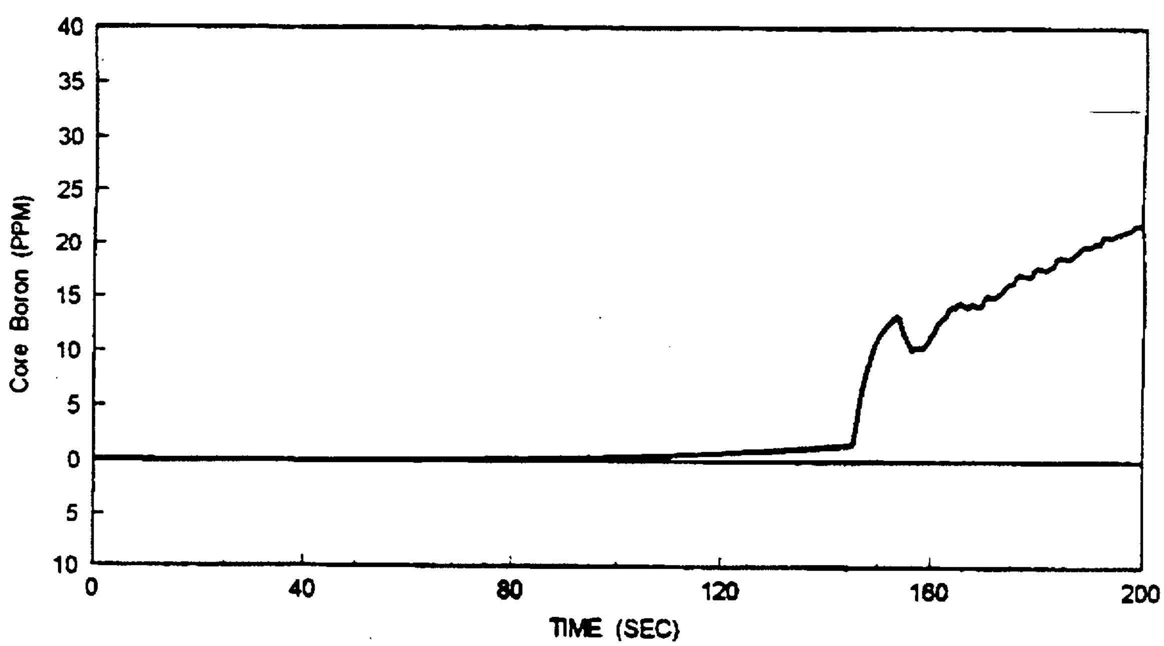




Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station STEAMLINE BREAK AT EXIT OF STEAM GENERATOR WITH OFFSITE POWER (CASE B)
	Updated FSAR — Figure 15.4-51B





Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station STEAMLINE BREAK AT EXIT OF STEAM GENERATOR WITH OFFSITE POWER (CASE B)
	Updated FSAR Figure 15.4-51C

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C. SALEM GENERATING STATION	
SALEM UFSAR - REV 18	SHEET 1 OF 1
APRIL 26, 2000	F15.4-51D

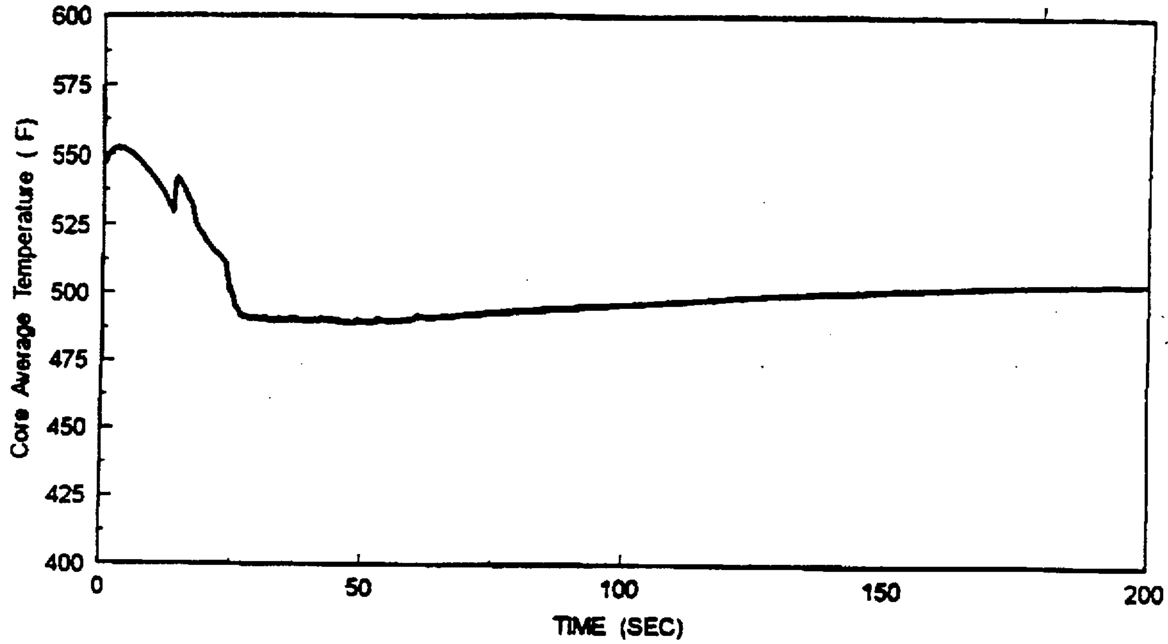
THIS FIGURE HAS BEEN DELETED

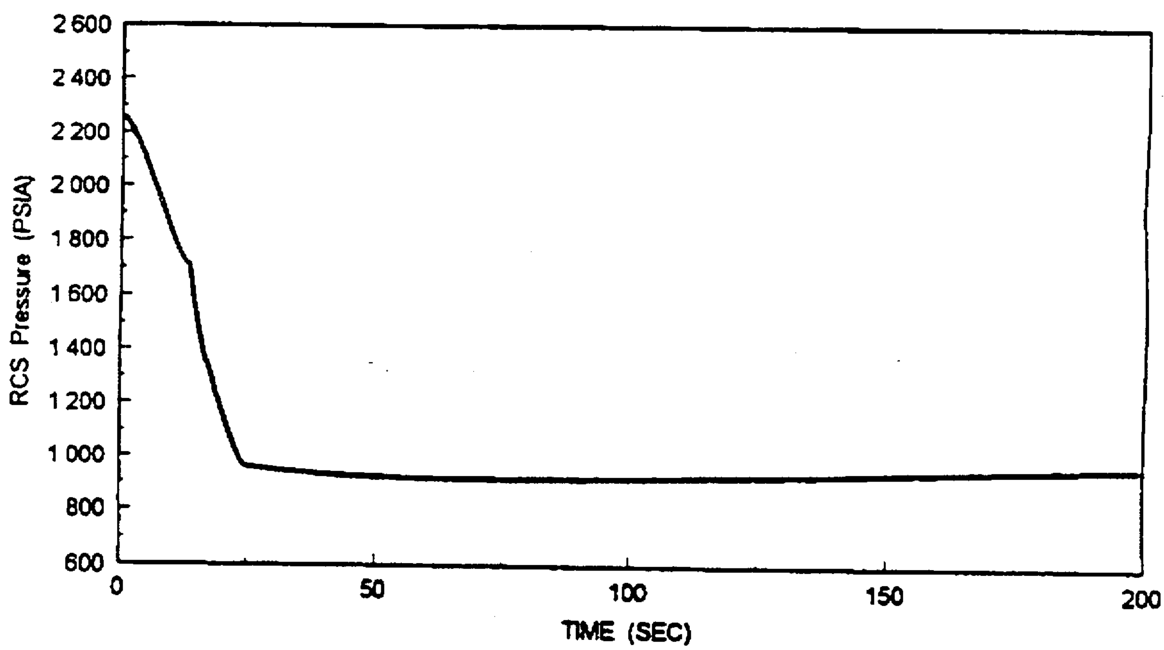
PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

SALEM UFSAR - REV 18	SHEET 1 OF 1
APRIL 26, 2000	F15.4-51E

THIS FIGURE HAS BEEN DELETED

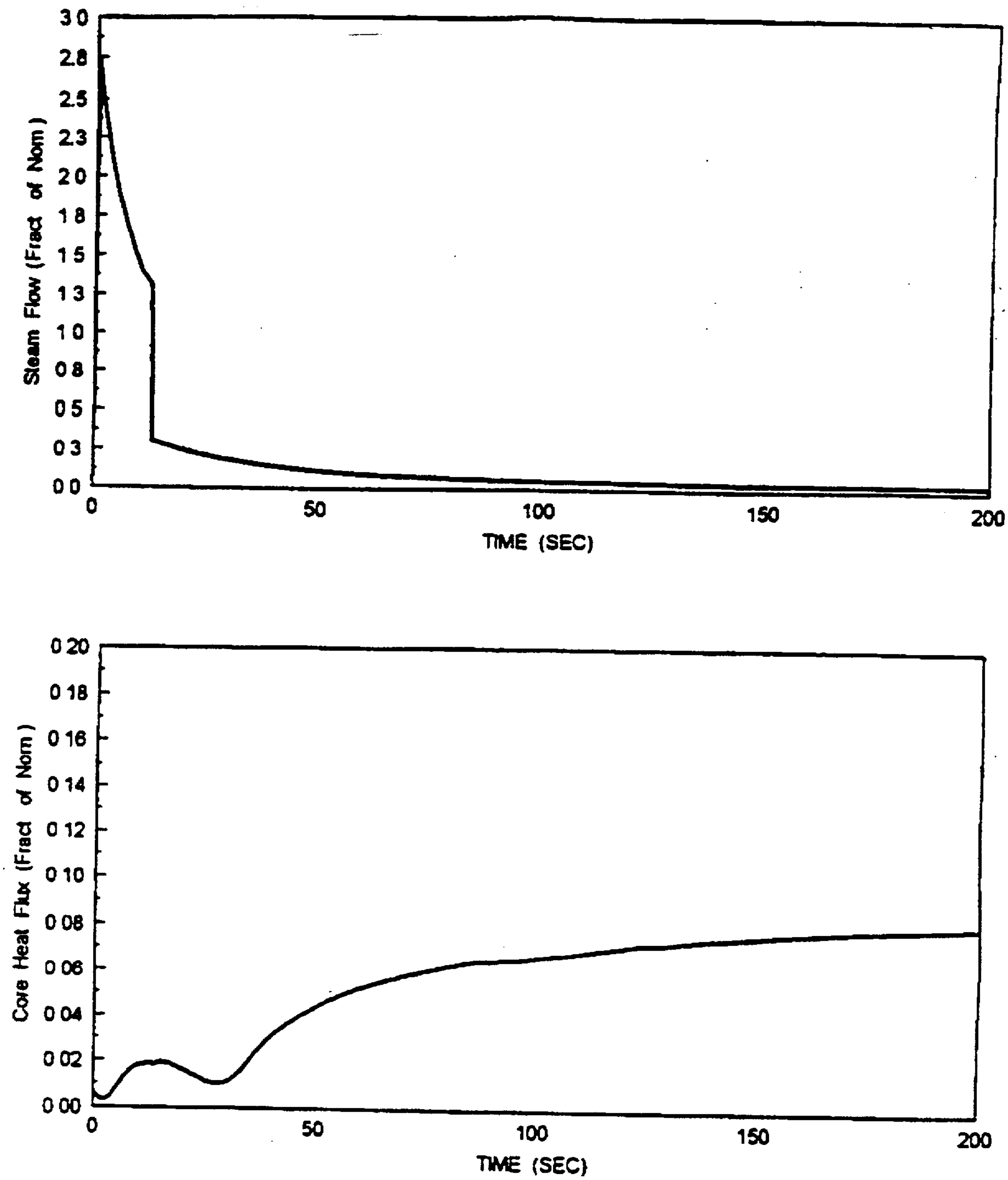
PSEG NUCLEAR L.L.C. SALEM GENERATING STATION	
SALEM UFSAR - REV 18	SHEET 1 OF 1
APRIL 26, 2000	F15.4-51F





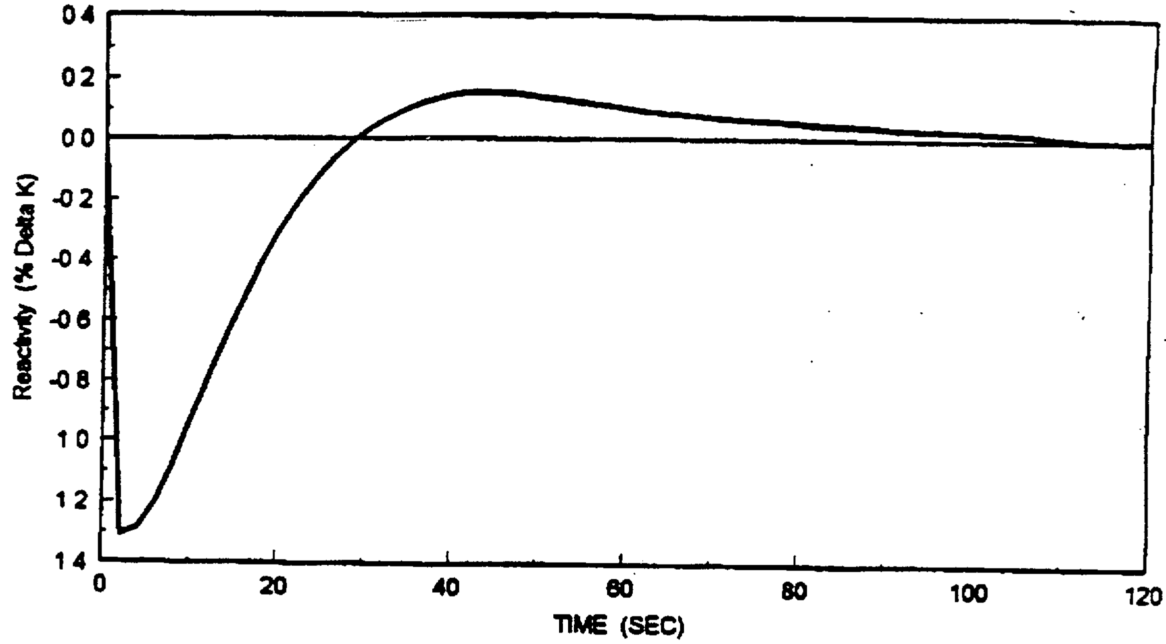
Revision 18, April 26, 2000

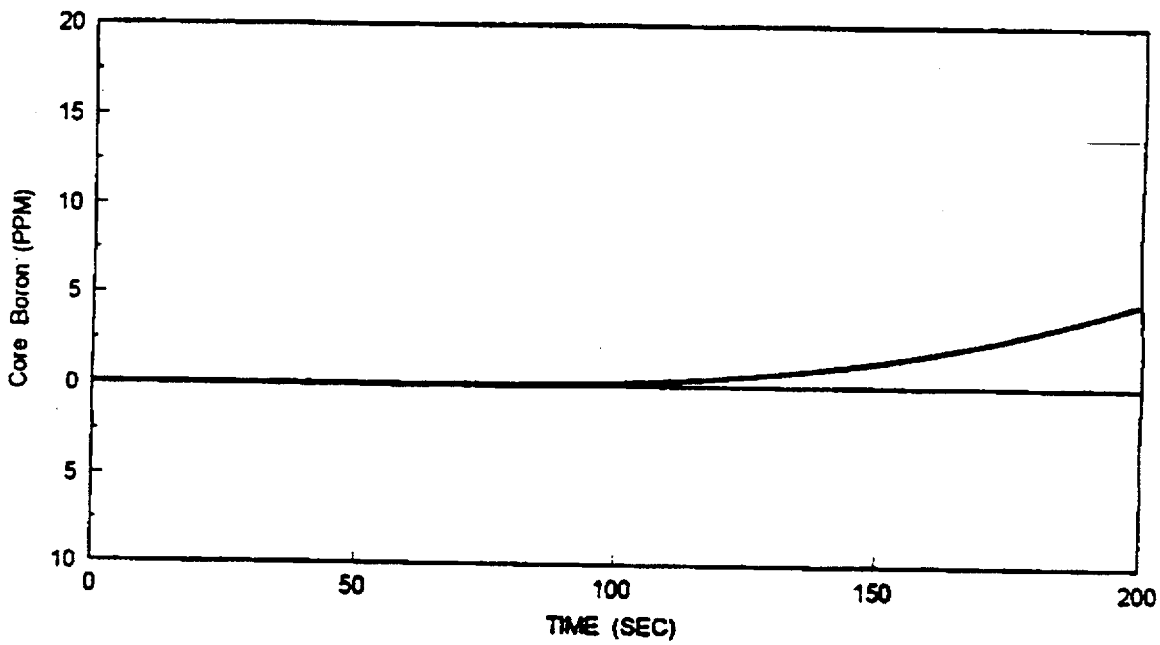
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station STEAMLINE BREAK DOWNSTREAM OF THE FLOW MEASURING DEVICE WITHOUT OFFSITE POWER (CASE C)
	Updated FSAR — Figure 15.4-52A



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station STEAMLINE BREAK DOWNSTREAM OF THE FLOW MEASURING DEVICE WITHOUT OFFSITE POWER (CASE C)
	Updated FSAR — Figure 15.4-52B





Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station STEAMLINE BREAK DOWNSTREAM OF THE FLOW MEASURING DEVICE WITHOUT OFFSITE POWER (CASE C)
	Updated FSAR — Figure 15.4-52C

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

SALEM UFSAR - REV 18	SHEET 1 OF 1
APRIL 26, 2000	F15.4-52D

THIS FIGURE HAS BEEN DELETED

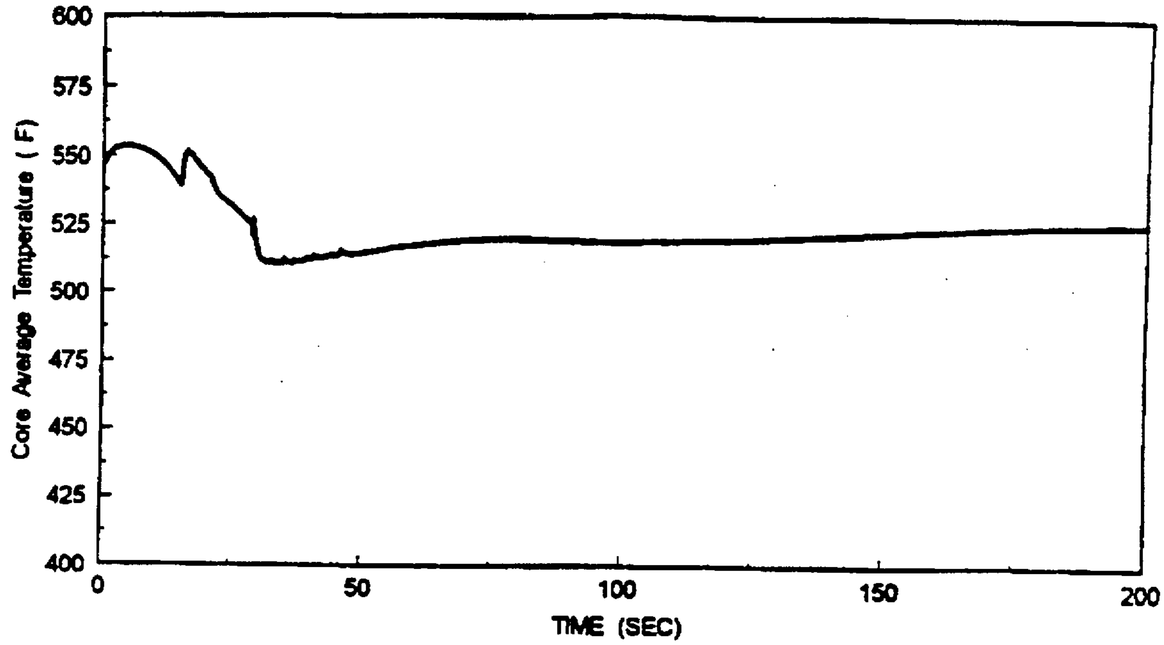
PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

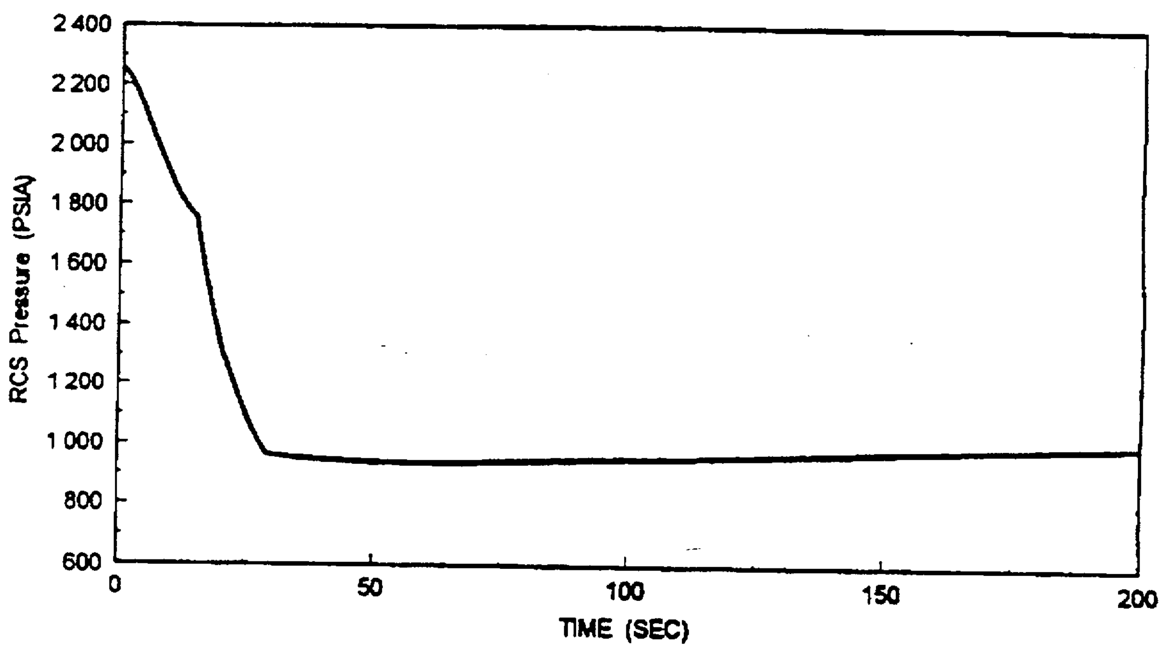
SALEM UFSAR - REV 18	SHEET 1 OF 1
APRIL 26, 2000	F15.4-52E

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

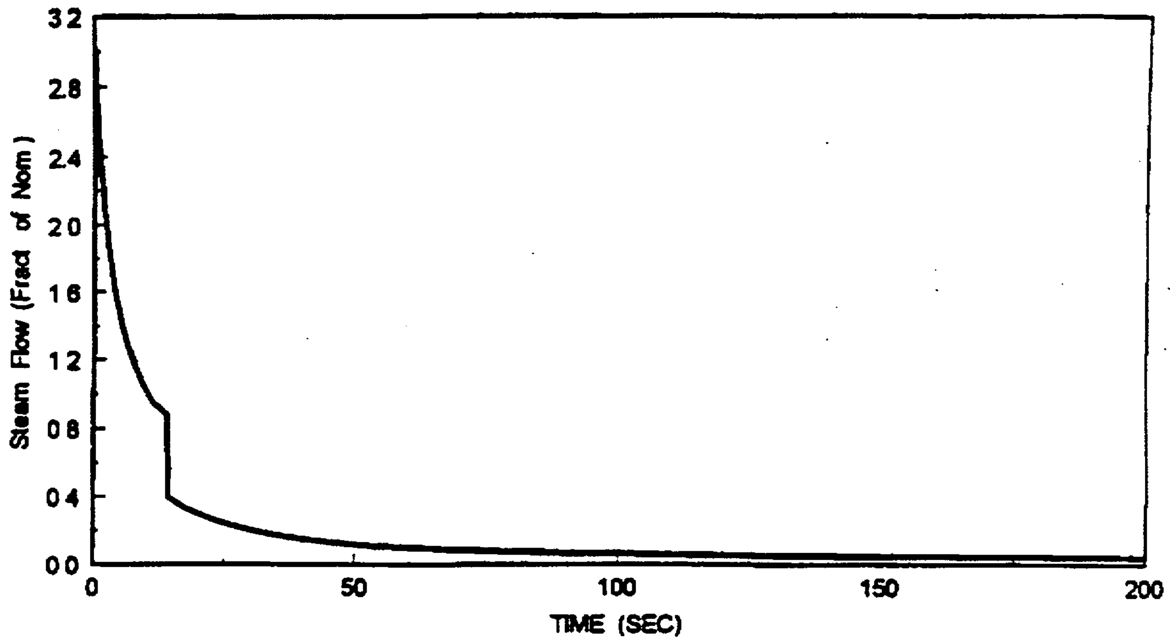
SALEM UFSAR - REV 18	SHEET 1 OF 1
APRIL 26, 2000	F15.4-52F

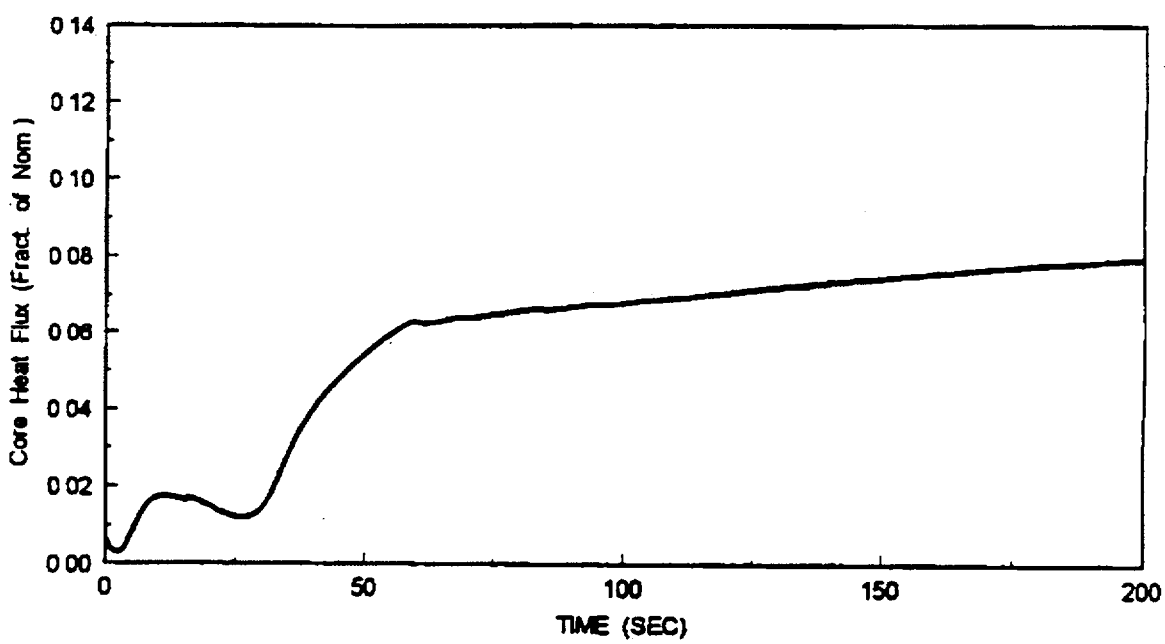




Revision 18, April 26, 2000

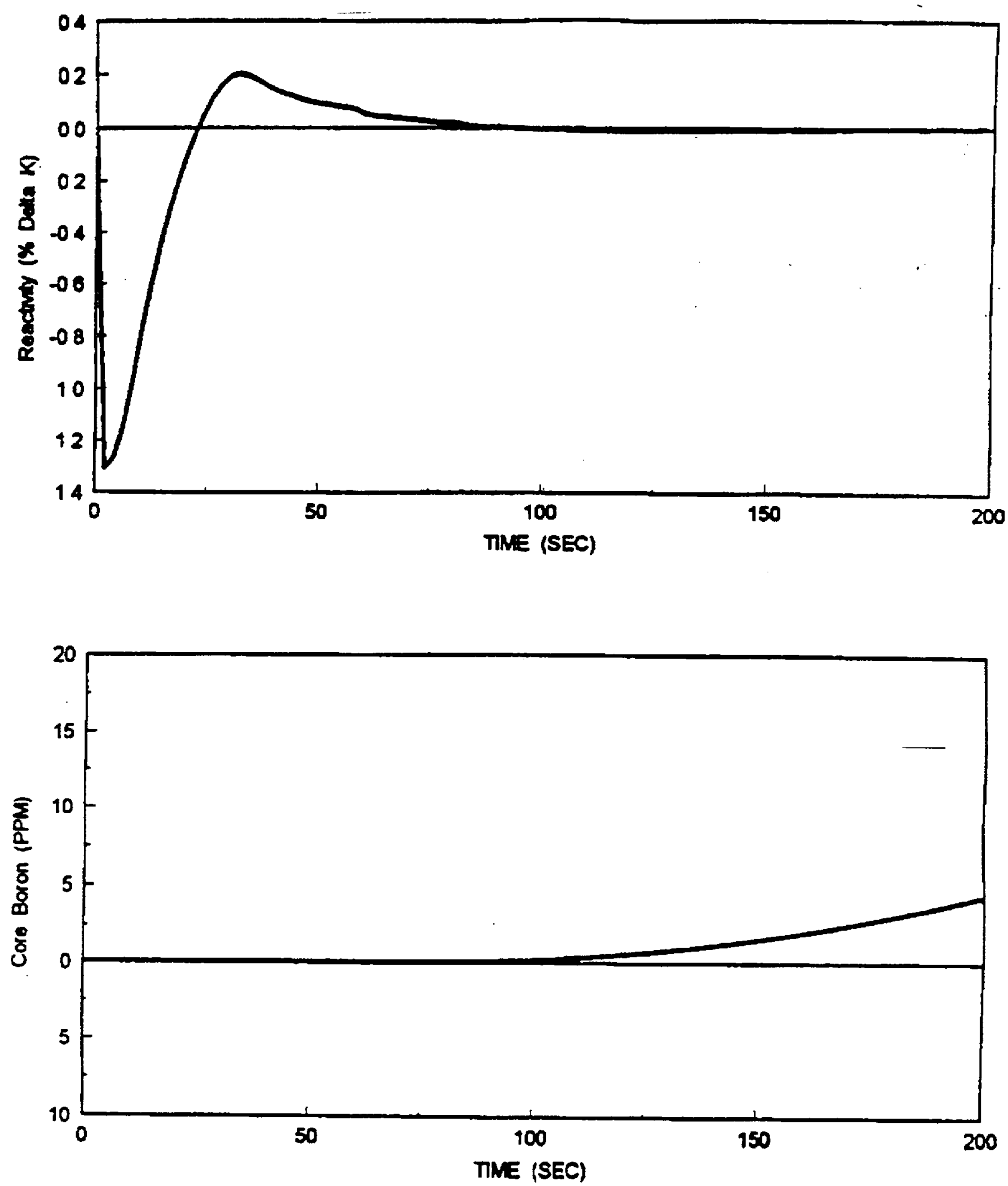
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station STEAMLINE BREAK AT THE EXIT OF THE STEAM GENERATOR WITHOUT OFFSITE POWER (CASE D)
	Updated FSAR Figure 15.4-53A





Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station STEAMLINE BREAK AT THE EXIT OF THE STEAM GENERATOR WITHOUT OFFSITE POWER (CASE D)
	Updated FSAR Figure 15.4-53B



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station STEAMLINE BREAK AT THE EXIT OF THE STEAM GENERATOR WITHOUT OFFSITE POWER (CASE D)
	Updated FSAR Figure 15.4-53C

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C. SALEM GENERATING STATION	
SALEM UFSAR - REV 18	SHEET 1 OF 1
APRIL 26, 2000	F15.4-53D

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

SALEM UFSAR - REV 18	SHEET 1 OF 1
APRIL 26, 2000	F15.4-53E

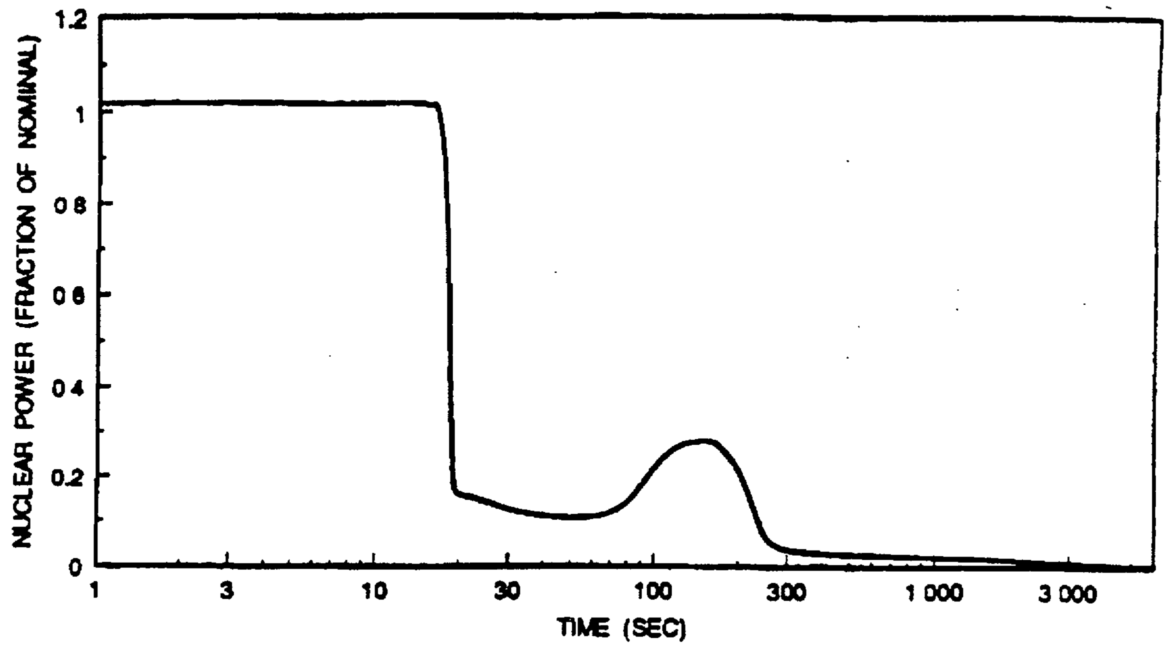
THIS FIGURE HAS BEEN DELETED

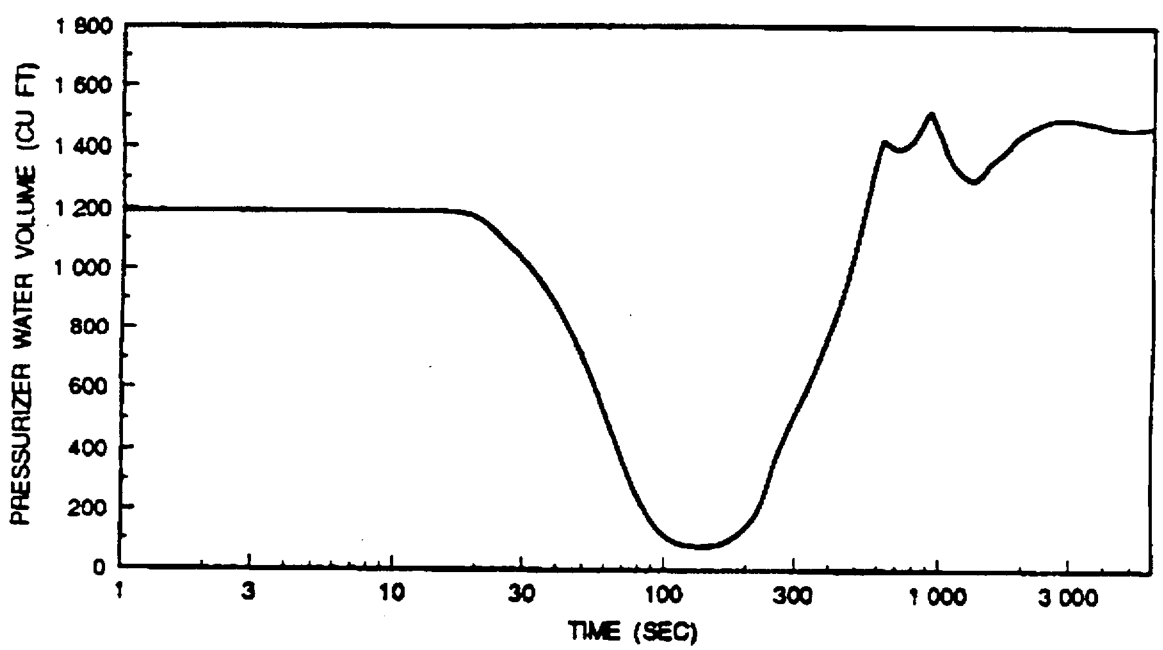
PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

SALEM UFSAR - REV 18	SHEET 1 OF 1
APRIL 26, 2000	F15.4-53F

THIS FIGURE HAS BEEN DELETED

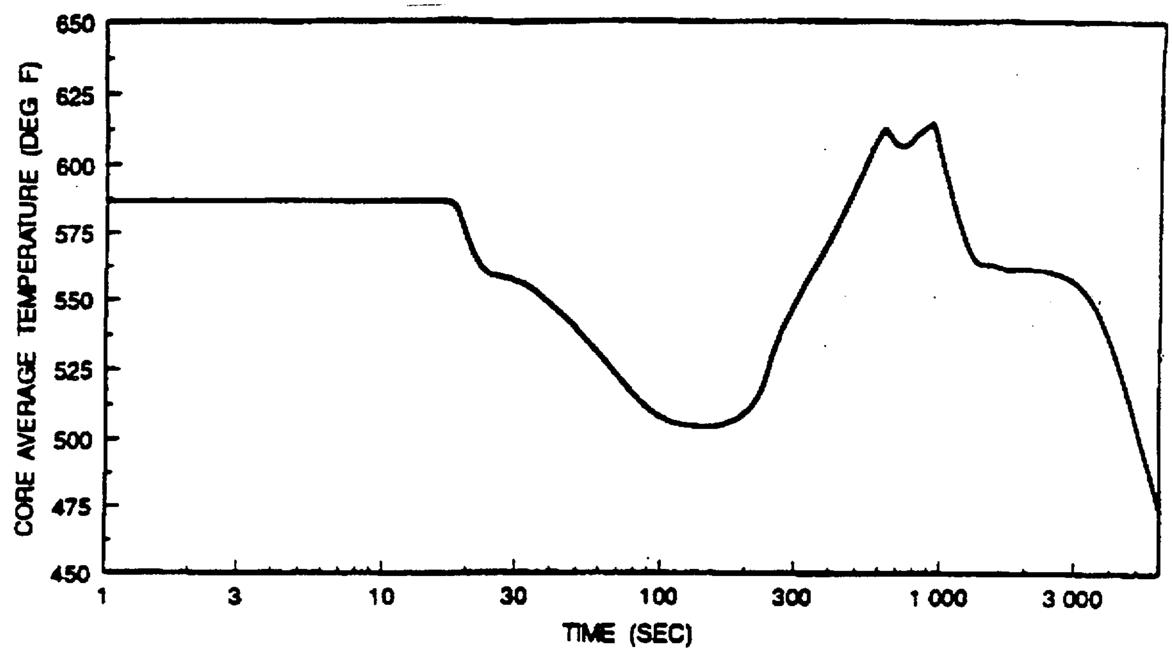
PSEG NUCLEAR L.L.C. SALEM GENERATING STATION	
SALEM UFSAR - REV 18	SHEET 1 OF 1
APRIL 26, 2000	F15.4-54

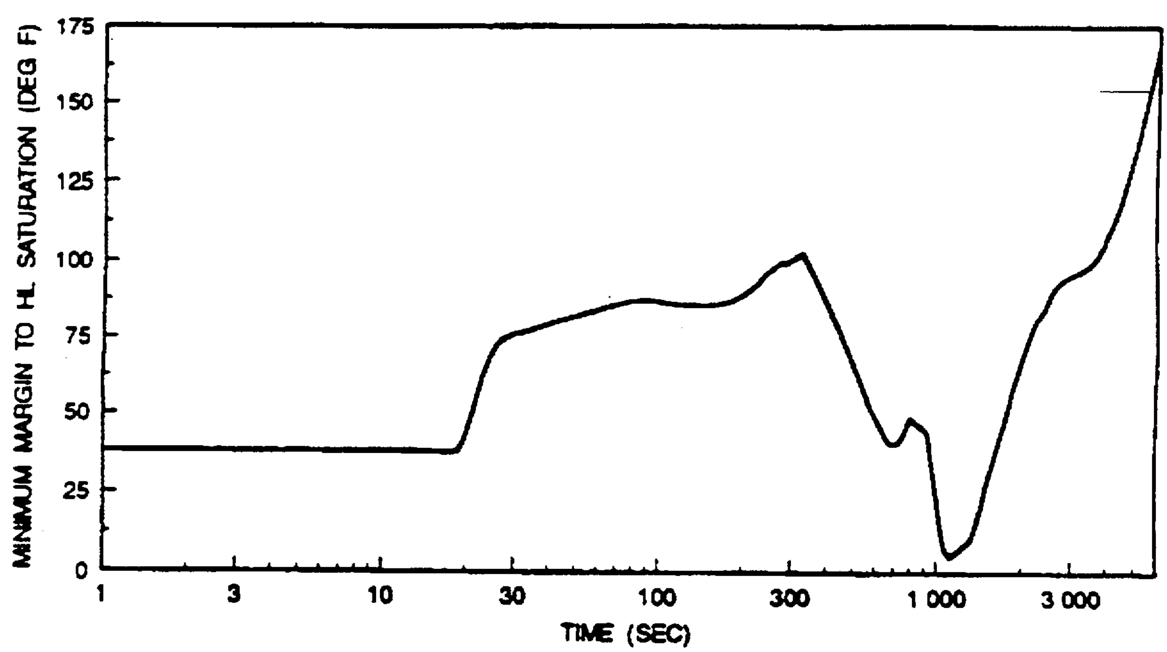




Revision 18, April 26, 2000

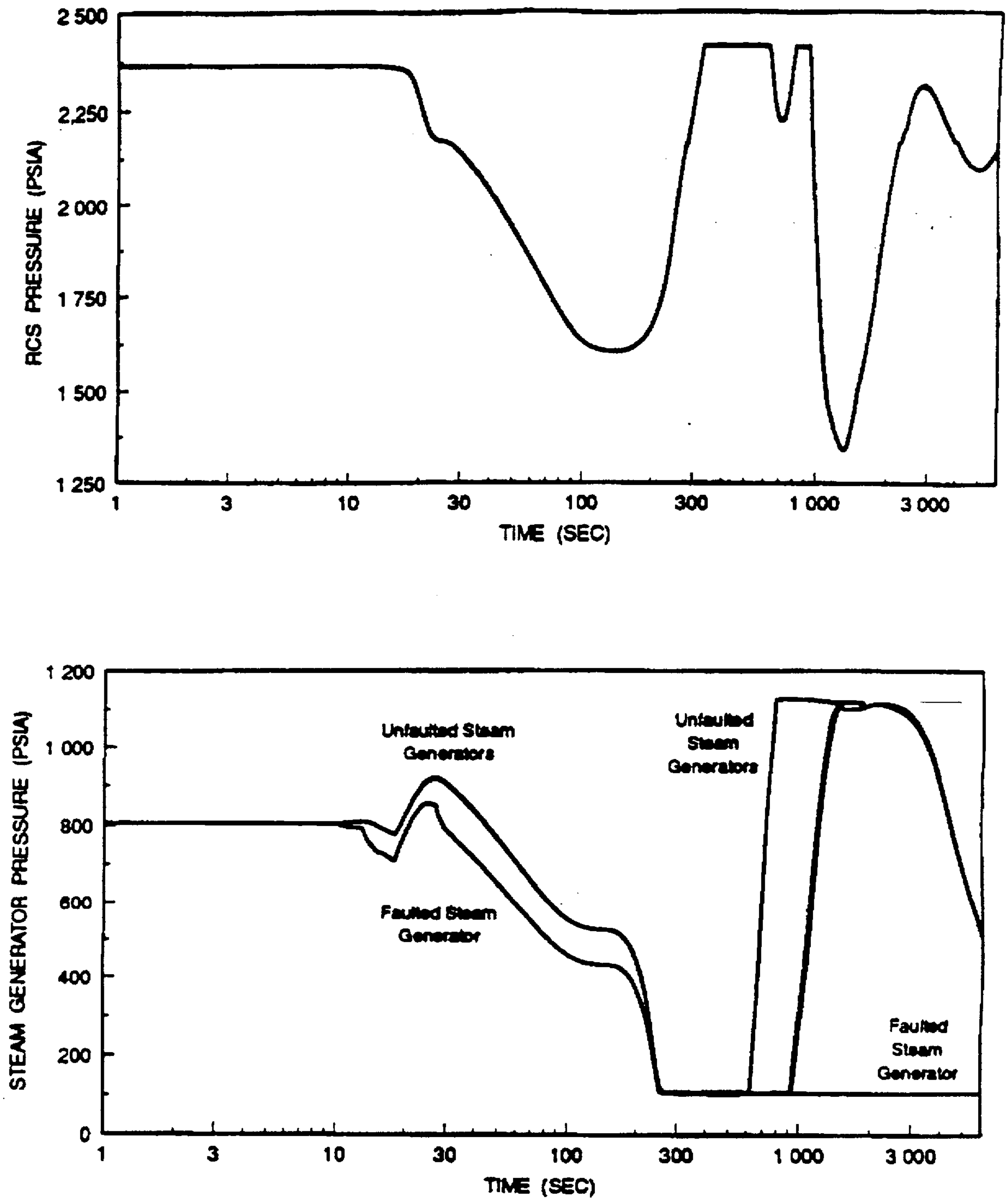
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station MAJOR RUPTURE OF A MAIN FEEDWATER PIPE WITH OFFSITE POWER
	Updated FSAR — Figure 15.4-60A





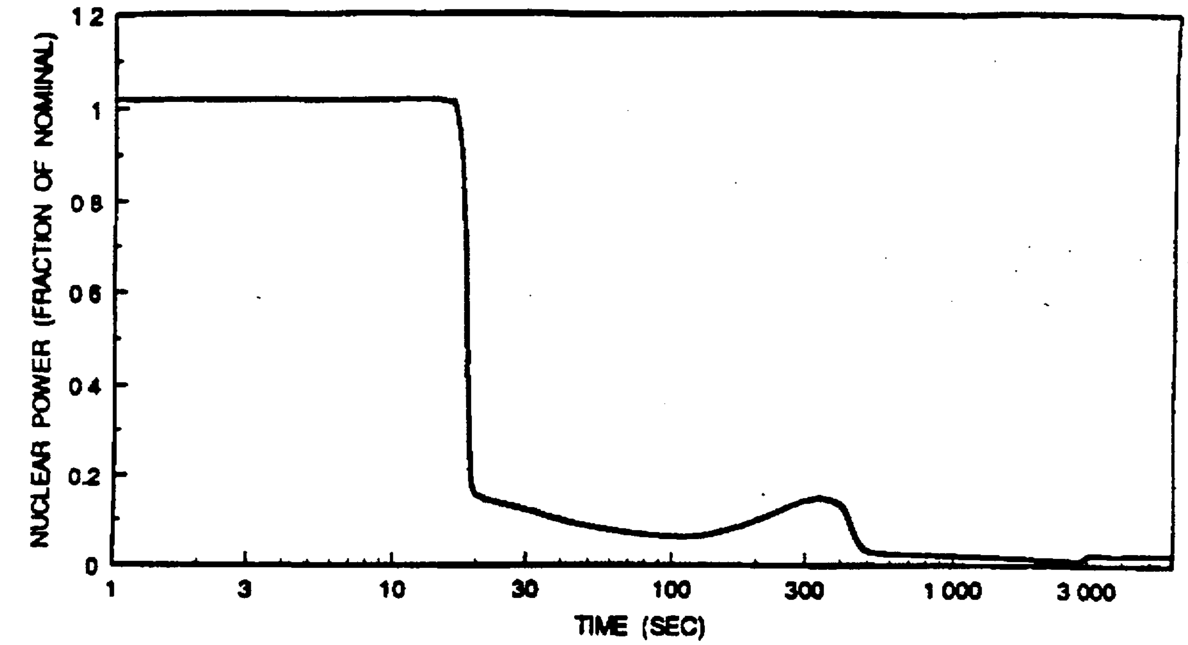
Revision 18, April 26, 2000

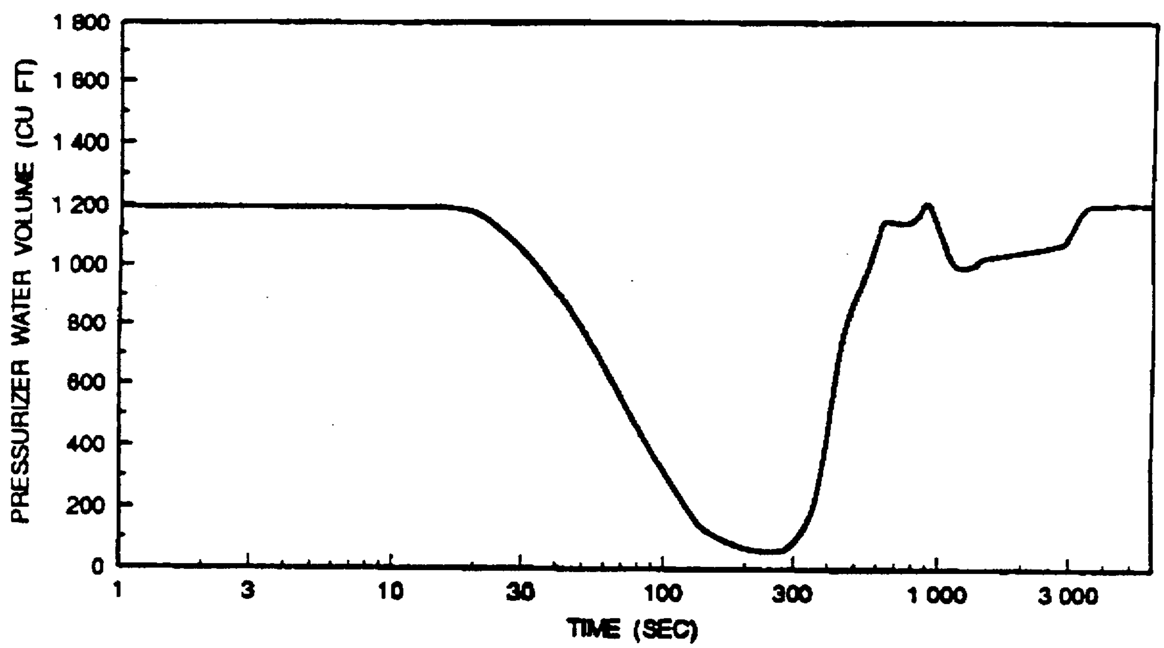
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station MAJOR RUPTURE OF A MAIN FEEDWATER PIPE WITH OFFSITE POWER
	Updated FSAR — Figure 15.4-60B



Revision 18, April 26, 2000

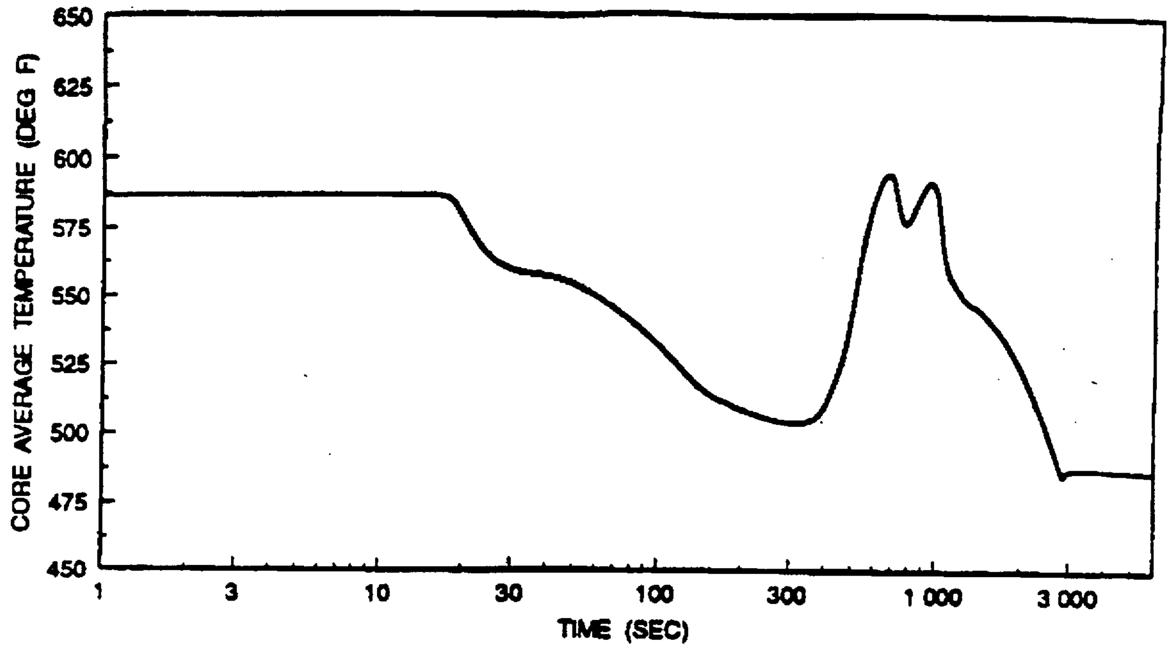
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station MAJOR RUPTURE OF A MAIN FEEDWATER PIPE WITH OFFSITE POWER
	Updated FSAR — Figure 15.4-60C

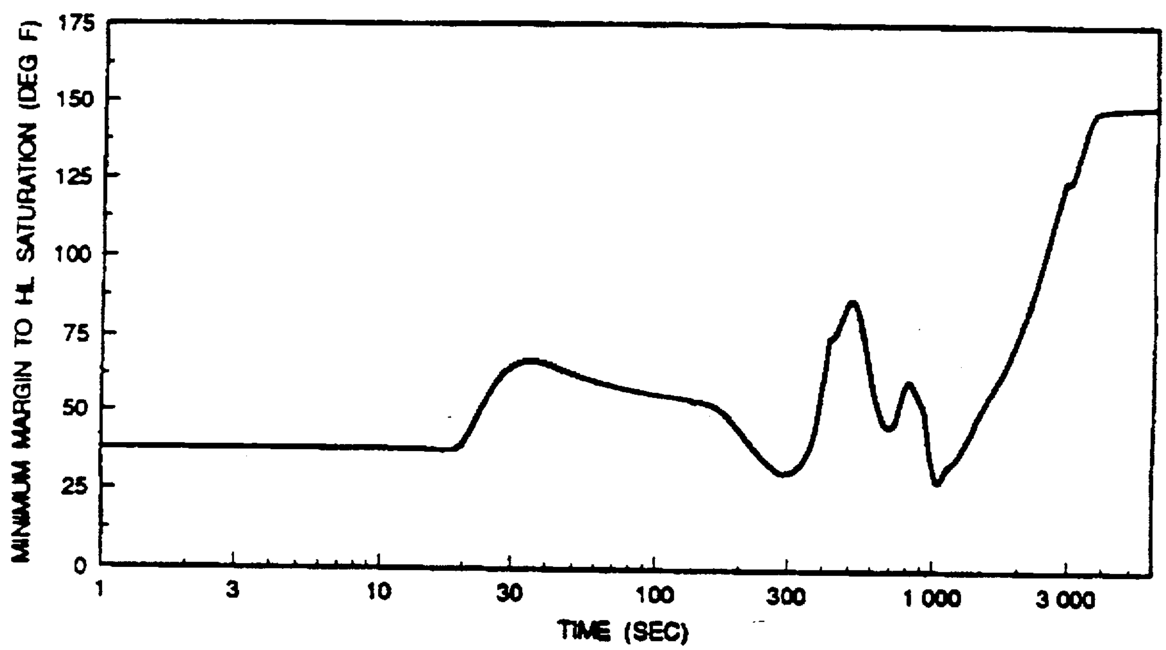




Revision 18, April 26, 2000

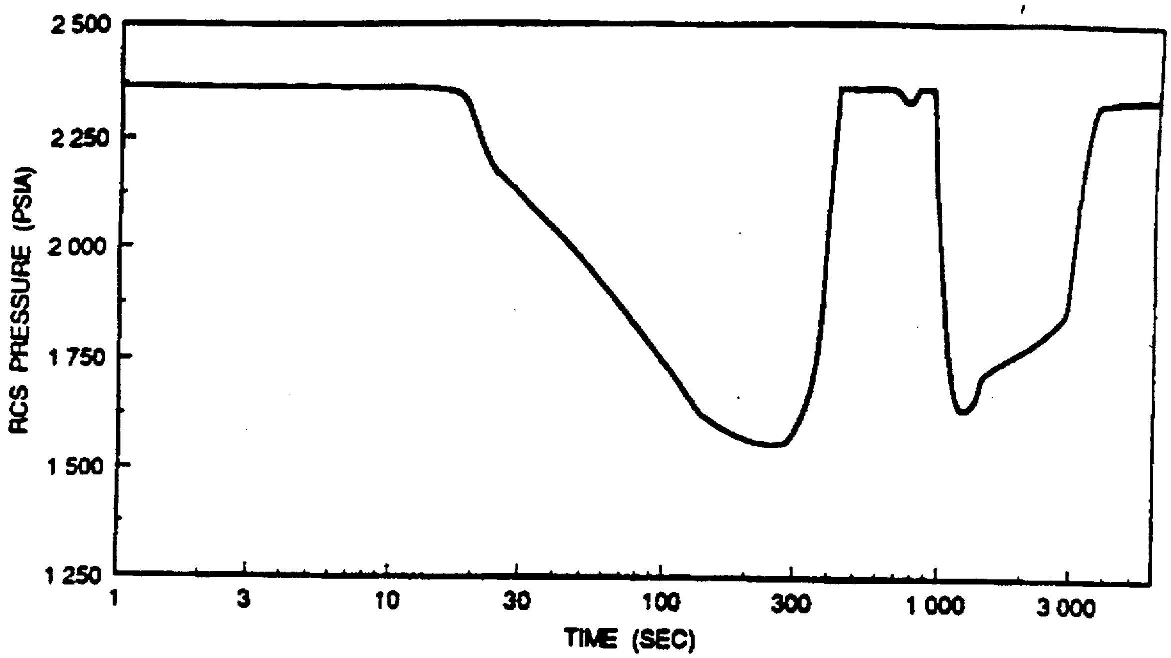
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station MAJOR RUPTURE OF A MAIN FEEDWATER PIPE WITHOUT OFFSITE POWER
	Updated FSAR — Figure 15.4-60D

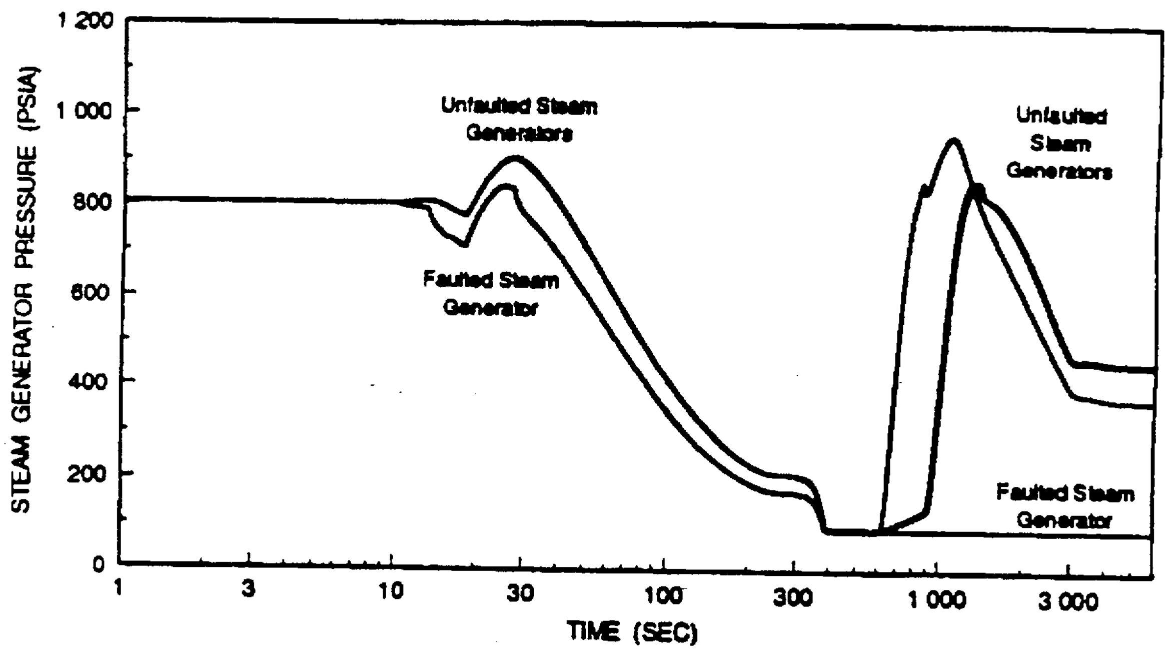




Revision 18, April 26, 2000

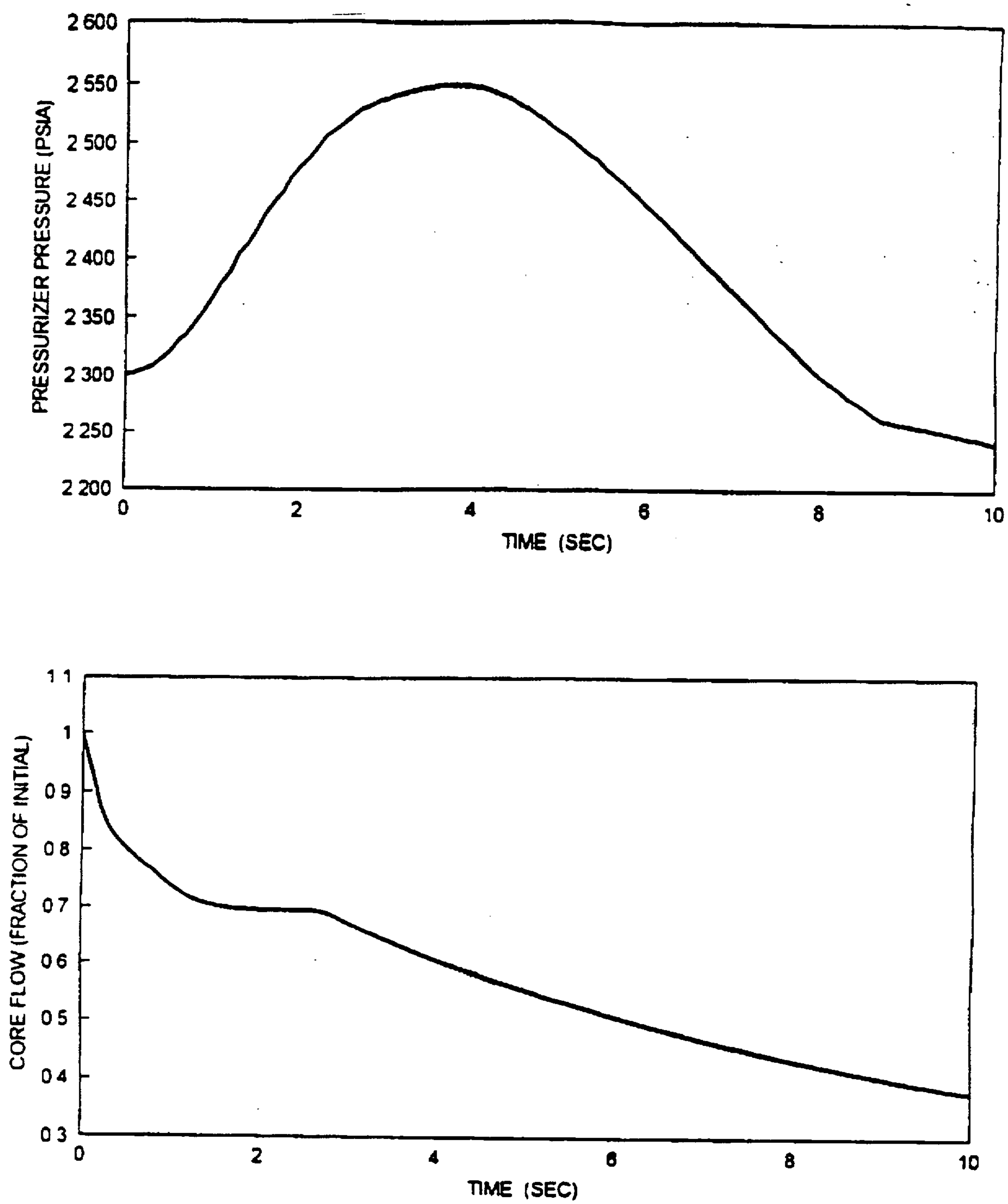
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station MAJOR RUPTURE OF A MAIN FEEDWATER PIPE WITHOUT OFFSITE POWER
	Updated FSAR — Figure 15.4-60E





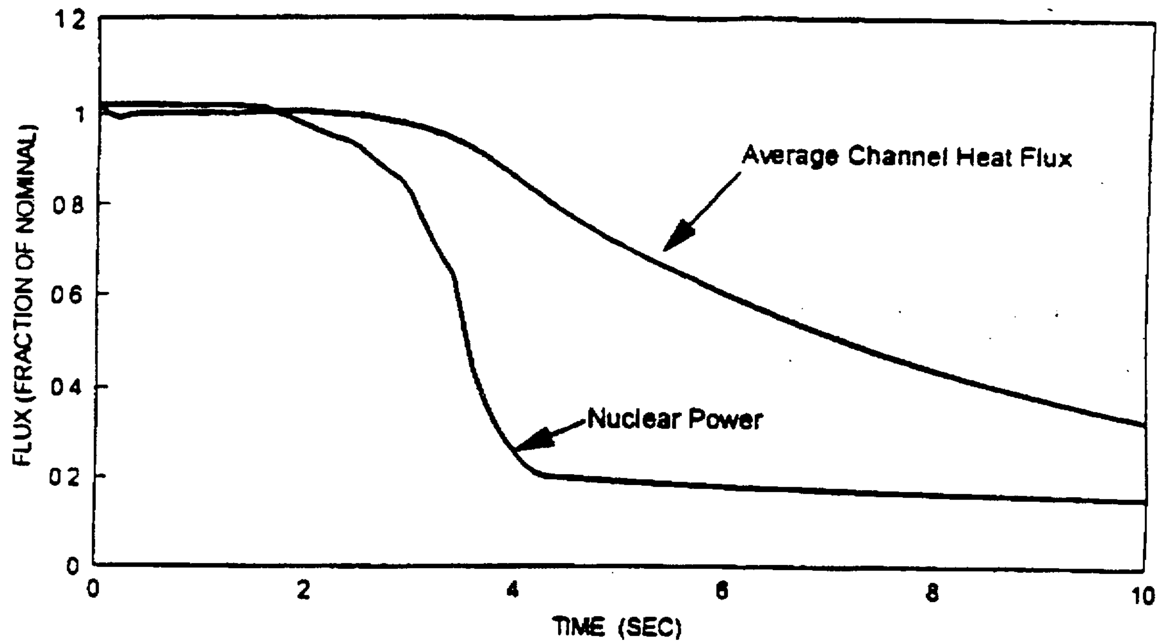
Revision 18, April 26, 2000

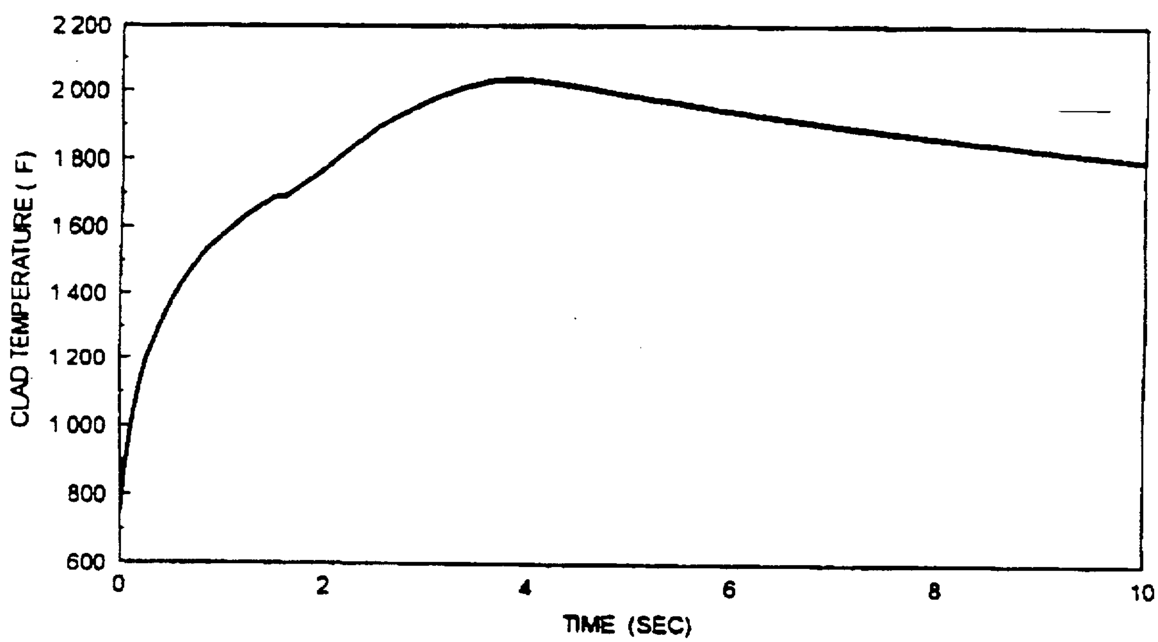
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station MAJOR RUPTURE OF A MAIN FEEDWATER PIPE WITHOUT OFFSITE POWER
	Updated FSAR Figure 15.4-60F



Revision 18, April 26, 2000

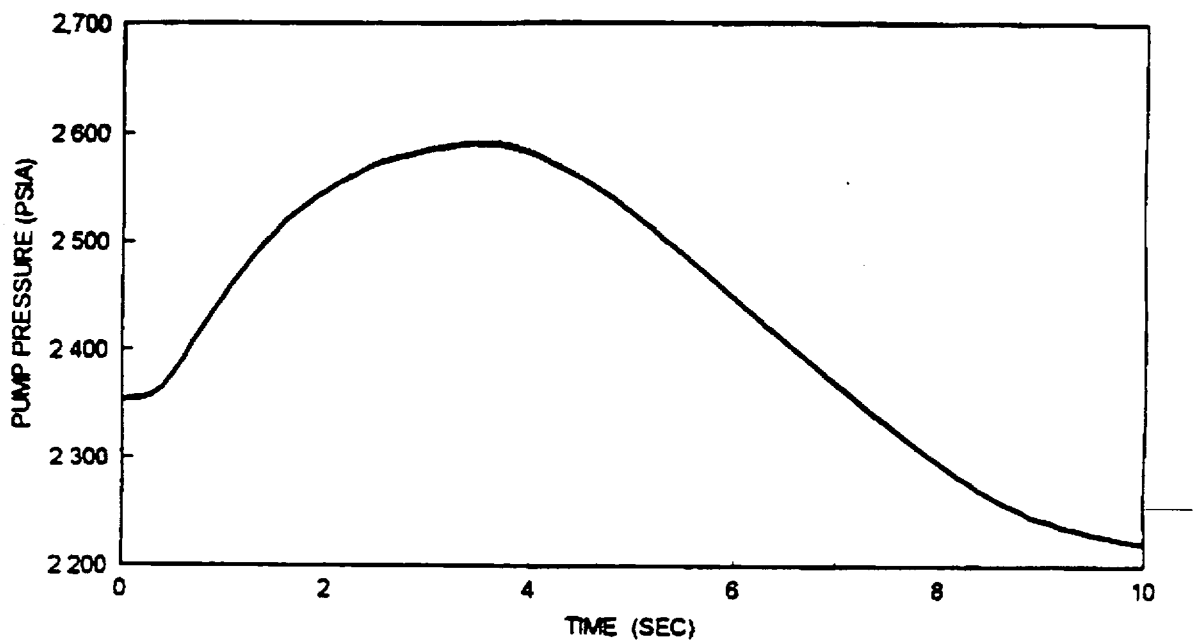
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station SINGLE REACTOR COOLANT PUMP LOCKED ROTOR
	Updated FSAR Figure 15.4-68





Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station SINGLE REACTOR COOLANT PUMP LOCKED ROTOR
	Updated FSAR Figure 15.4-69



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station SINGLE REACTOR COOLANT PUMP LOCKED ROTOR
	Updated FSAR — Figure 15.4-70

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

SALEM UFSAR - REV 18	SHEET 1 OF 1
APRIL 26, 2000	F15.4-71

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

SALEM UFSAR - REV 18

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SHEET 1 OF 1

F15.4-72

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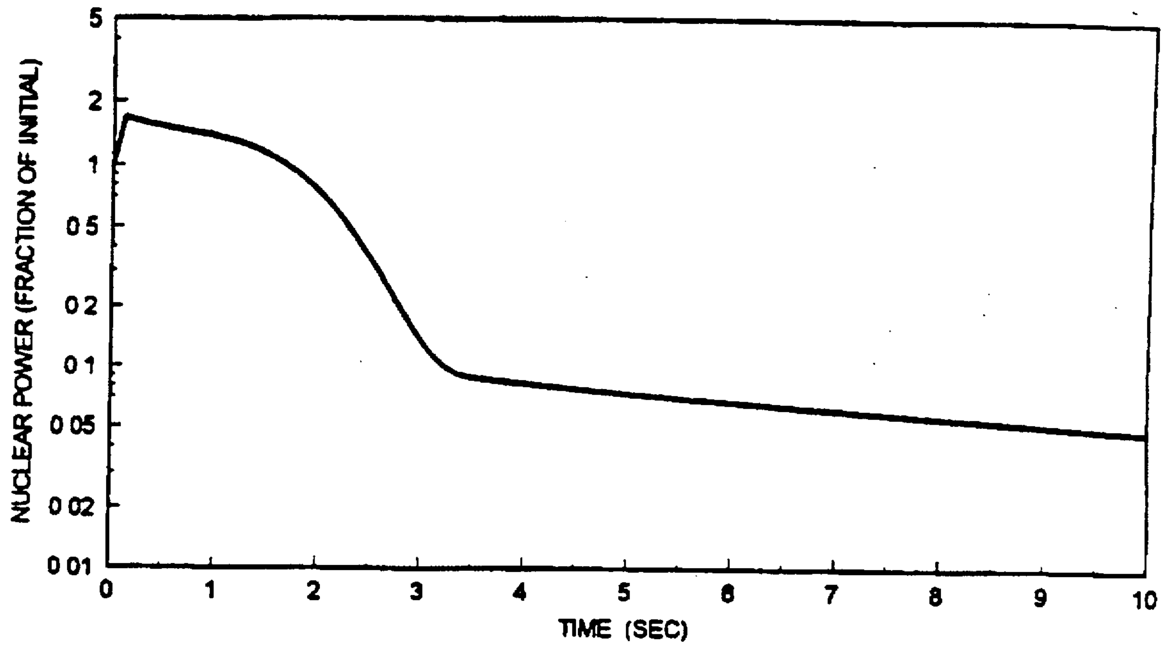
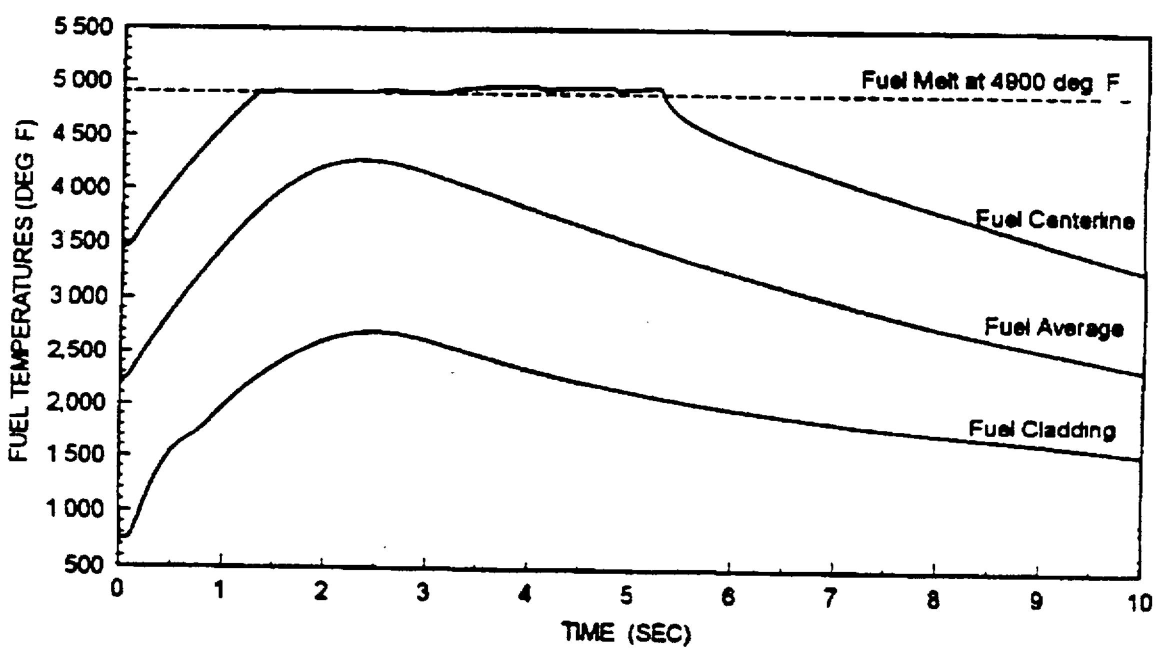
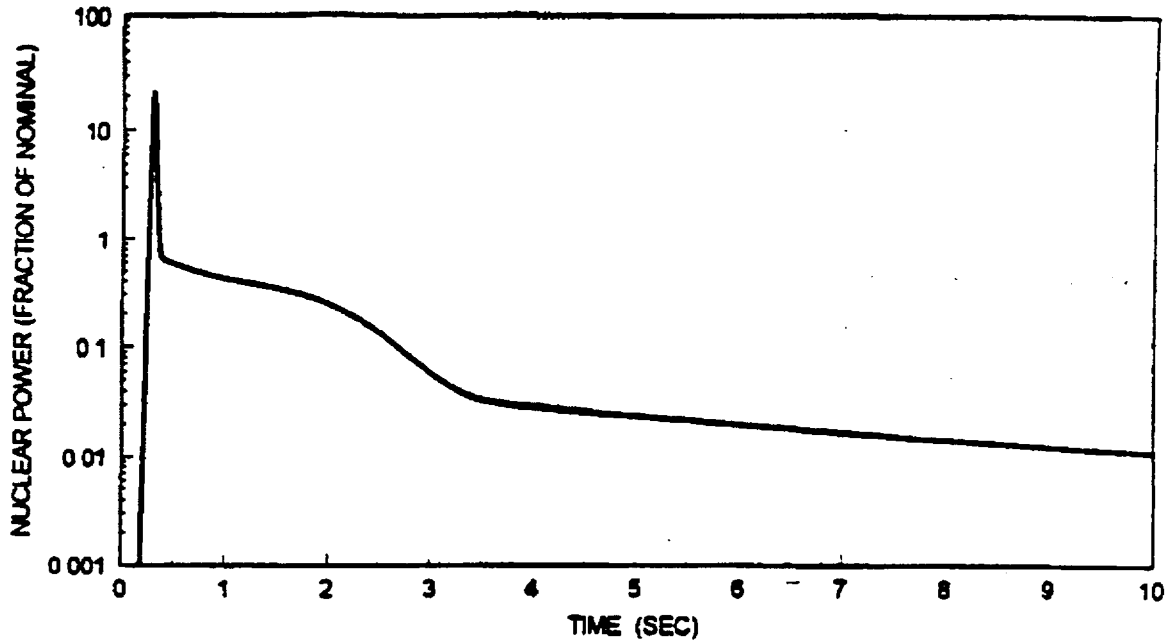
PSEG NUCLEAR L.L.C. SALEM GENERATING STATION
SALEM UFSAR - REV 18 SHEET 1 OF 1 APRIL 26, 2000 F15.4-75

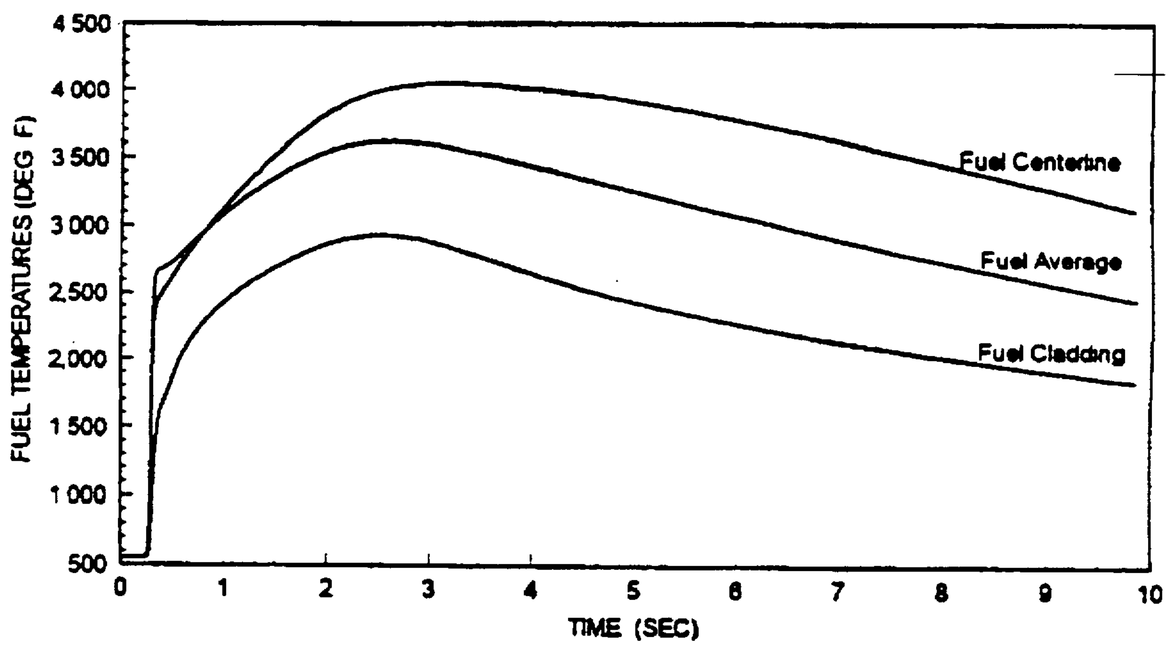




Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station RCCA EJECTION ACCIDENT BEGINNING OF LIFE, HOT FULL POWER
	Updated FSAR — Figure 15.4-76





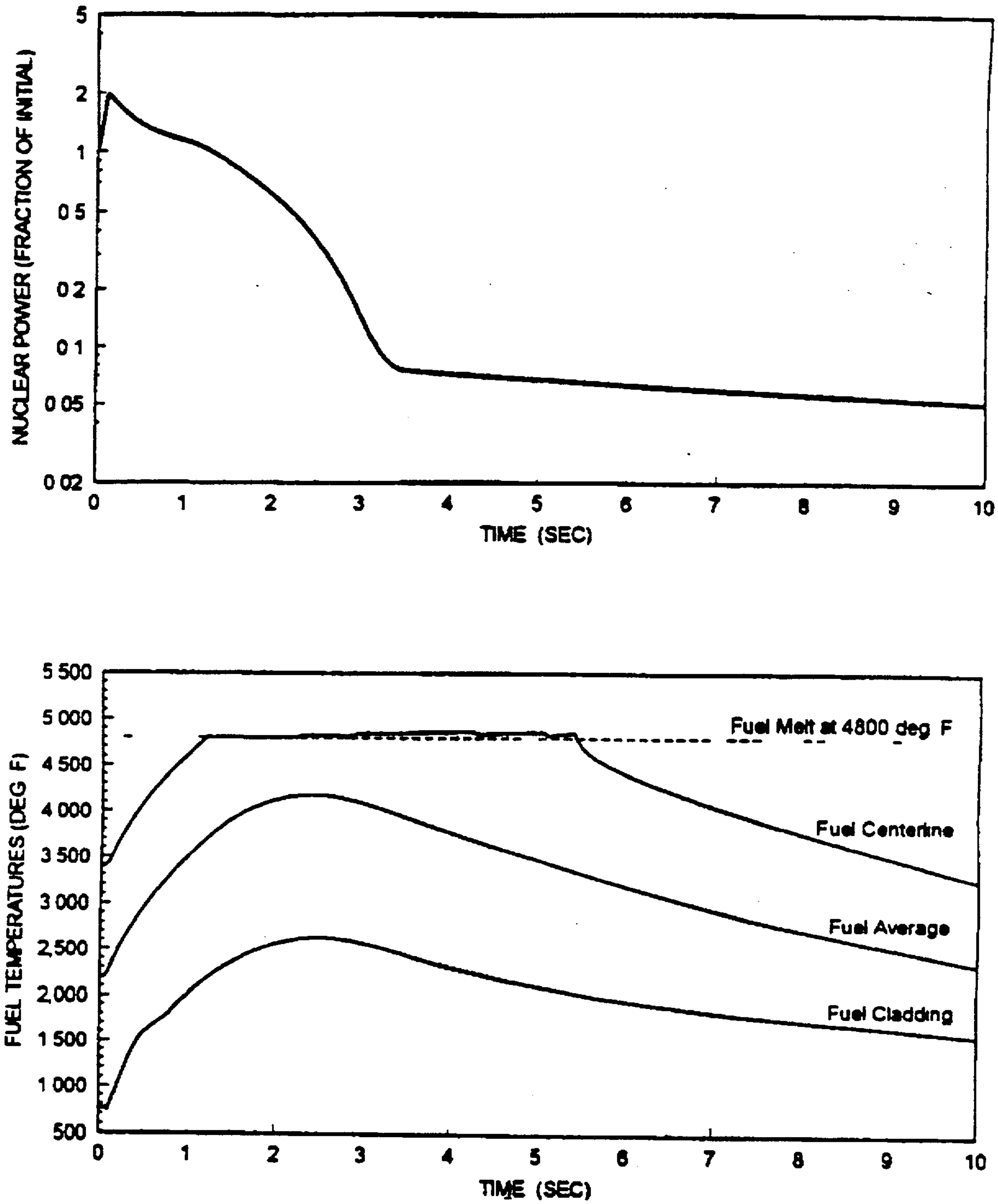
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station RCCA EJECTION ACCIDENT BEGINNING OF LIFE, HOT ZERO POWER Updated FSAR — Figure 15.4-77

THIS FIGURE HAS BEEN DELETED

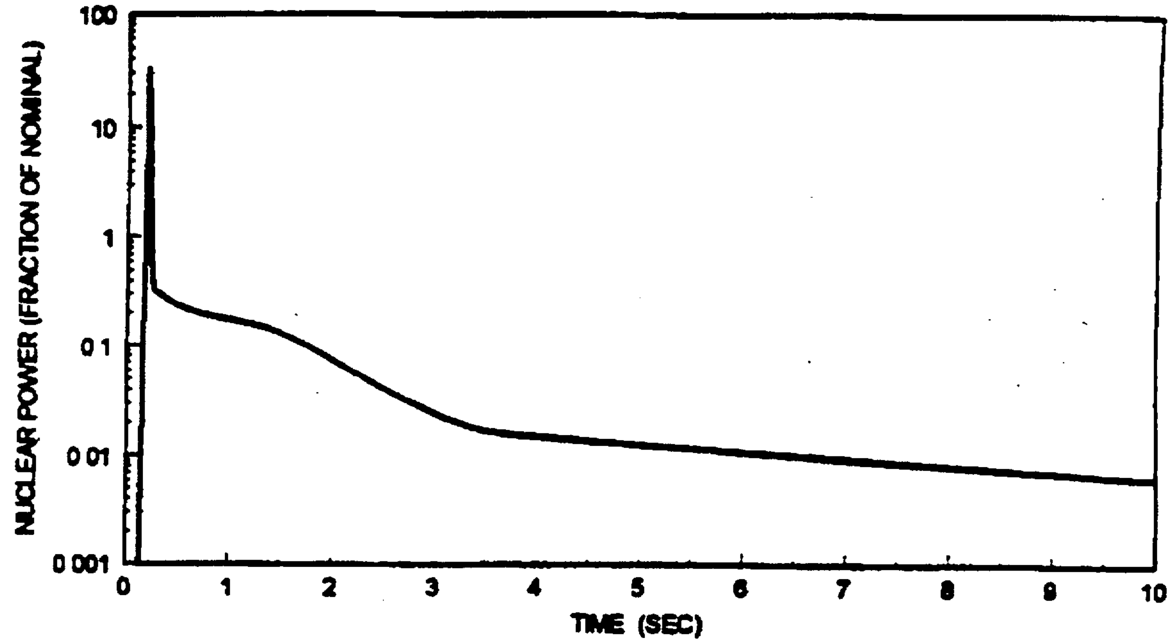
PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

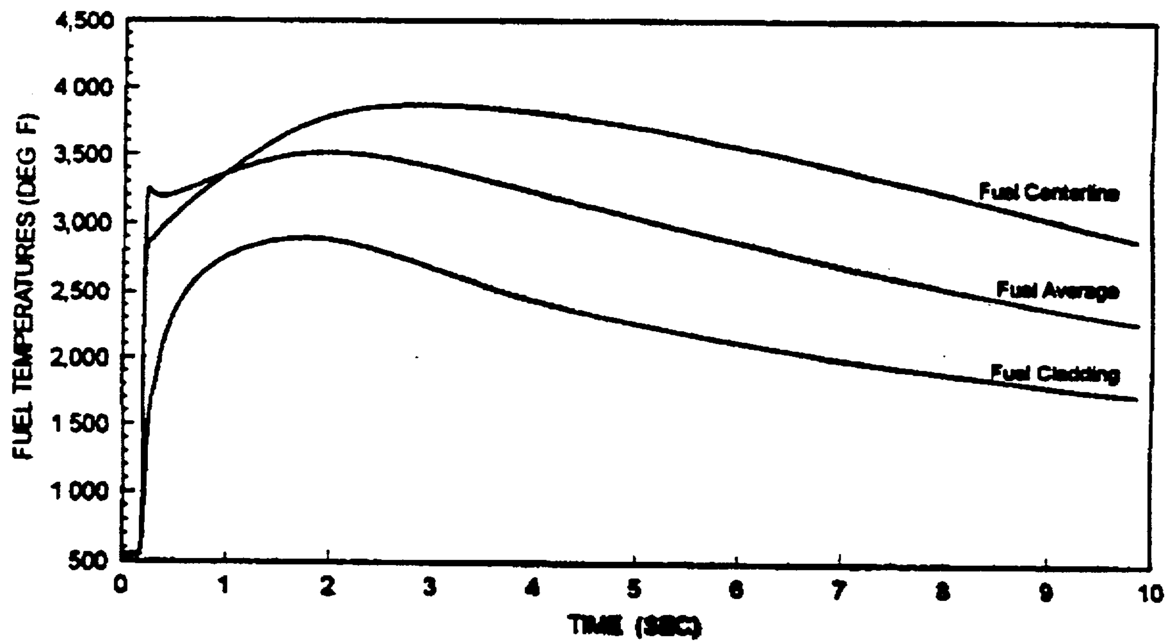
SALEM UFSAR - REV 18	SHEET 1 OF 1
APRIL 26, 2000	F15.4-78



Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station RCCA EJECTION ACCIDENT END OF LIFE, HOT FULL POWER
	Updated FSAR — Figure 15.4-78A



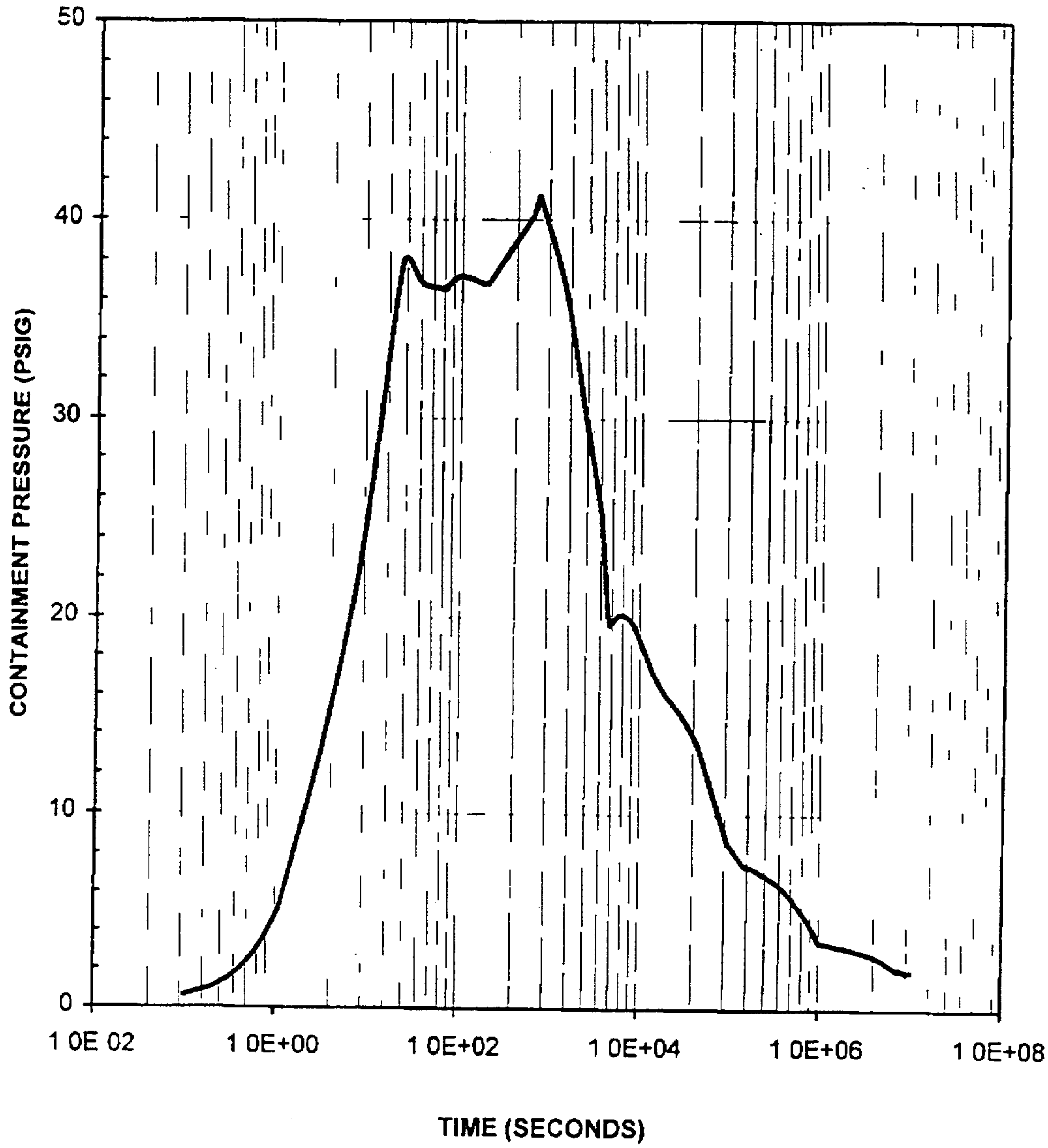


Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station RCCA EJECTION ACCIDENT END OF LIFE, HOT ZERO POWER
	Updated FSAR Figure 15.4-78B

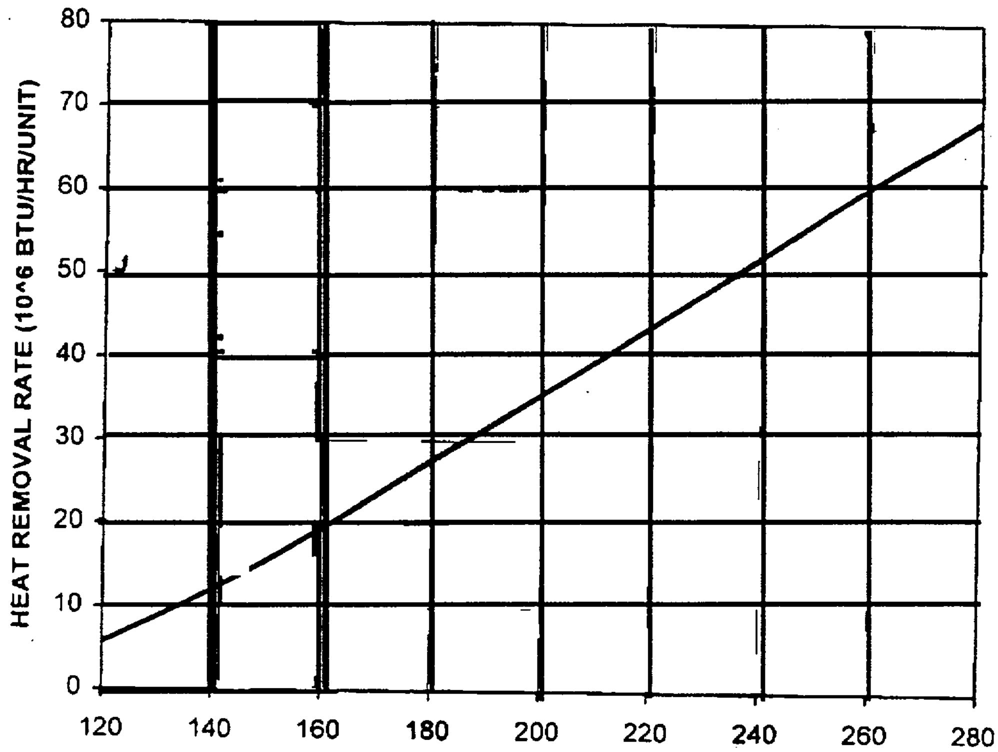
THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C. SALEM GENERATING STATION	
SALEM UFSAR - REV 18	SHEET 1 OF 1
APRIL 26, 2000	F15.4-85



Revision 18, April 26, 2000

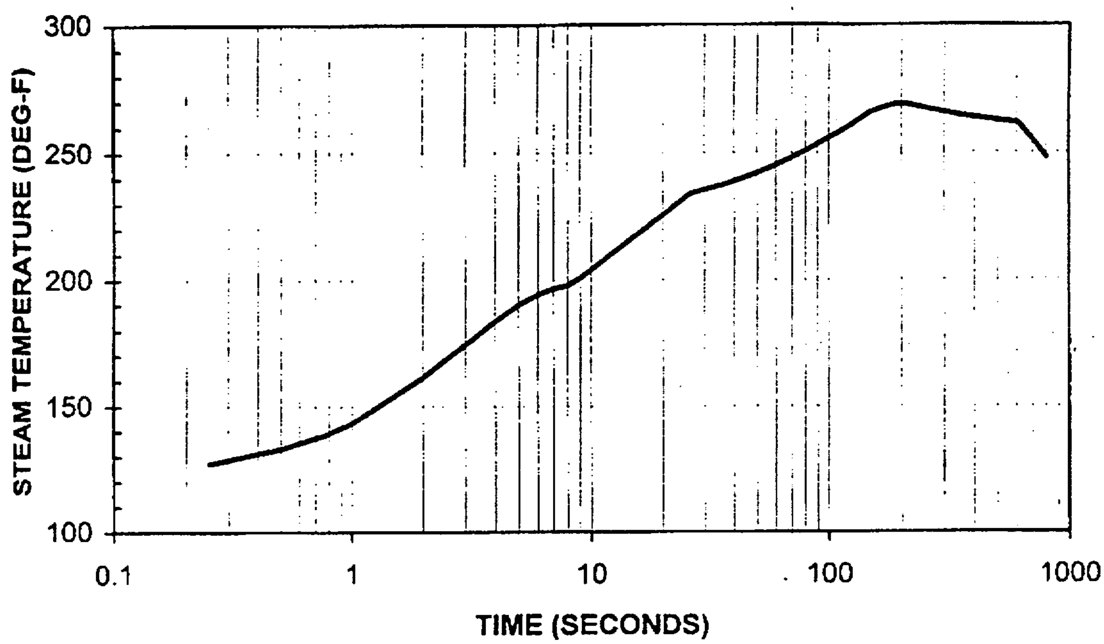
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station CONTAINMENT PRESSURE VS. TIME DOUBLE ENDED PUMP SUCTION BREAK
	Updated FSAR — Figure 15.4-91

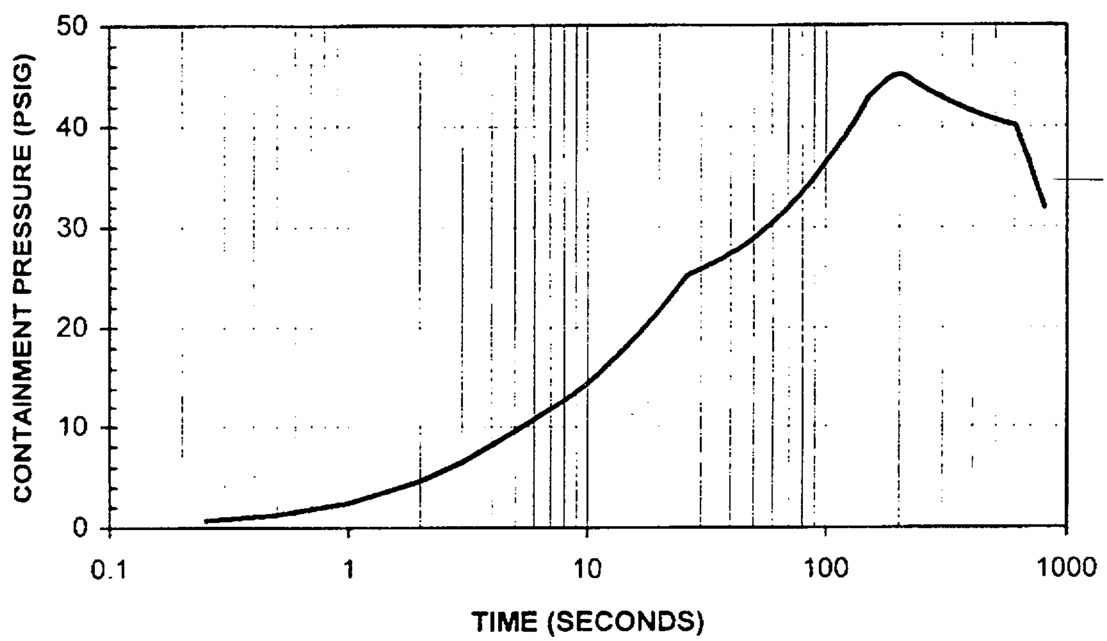


Note These heat removal rates are assumed to be degraded by 10% for the initial 120 seconds of diesel powered fan operation due to nitrogen that could be in solution from the service water system accumulators that are part of the resolution to Generic Letter 96 06

Revision 18, April 26, 2000

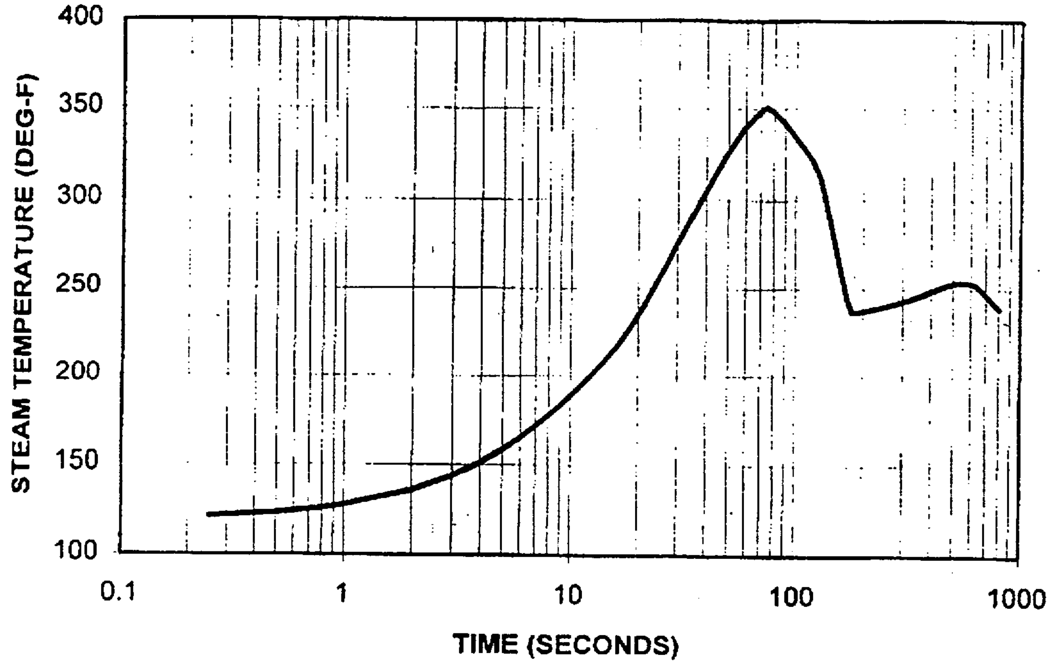
PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station FAN COOLER HEAT REMOVAL RATE
	Updated FSAR — Figure 15.4-96

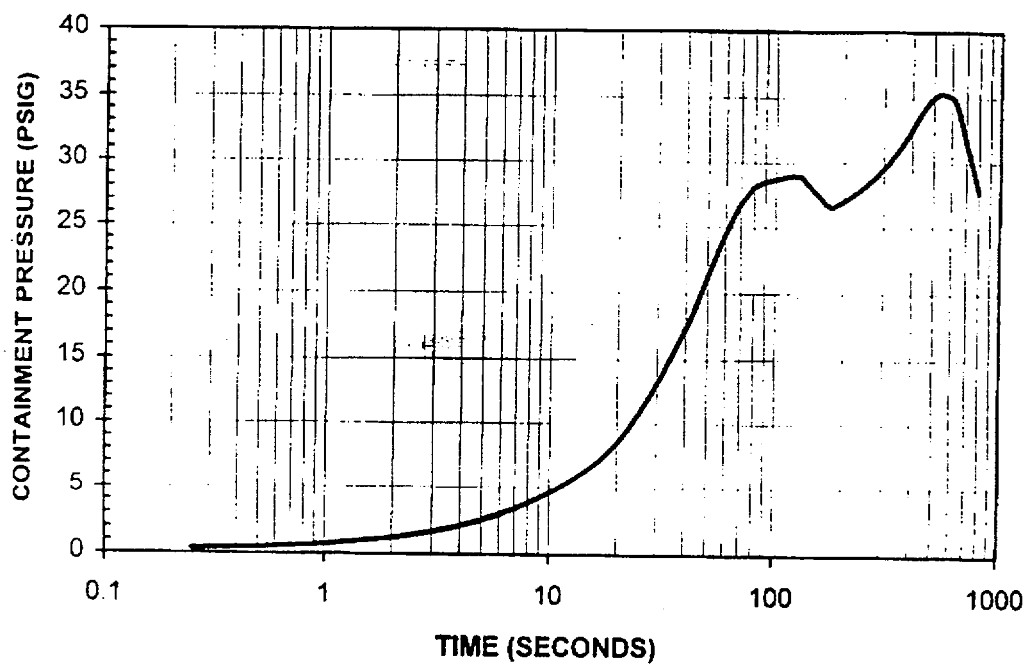




Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station CONTAINMENT RESPONSE TO STEAM LINE RUPTURE 30% POWER, 4.6FT^2 DER, FEEDWATER CONTROL VALVE FAILURE
	Updated FSAR Figure 15.4-98





Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station CONTAINMENT RESPONSE TO STEAM LINE RUPTURE 102% POWER, 0.6 FT2 SMALL DER, MAIN STEAM ISOLATION VALVE FAILURE
	Updated FSAR Figure 15.4-100

Table 17.2-1 (Cont)

2.1.11 Containment (including penetrations, concrete shielding, interior structures, air locks, equipment hatch, outage equipment hatch)

a. Containment Polar Crane

2.1.12 Containment Pressure - Vacuum Relief System

2.1.13 Control Area Air Conditioning System

2.1.14 Control Panels - Class 1E circuits

2.1.15 Electrical Cable Tunnels

2.1.16 Emergency Power for Pressurizer Heaters

2.1.17 Emergency Power Supply System

a. DC Power Supply System

b. Diesel Generator Area Ventilation System

c. Diesel Generators (including associated fuel oil, lube oil, starting auxiliary systems, fuel storage and day tanks, jacket cooling, governor, voltage regulation and excitation systems, piping and valves)

d. Control Boards and Motor Control Centers

e. Control equipment, facilities and lines required for above items

f. Power distribution lines to equipment required for emergency transformers and switchgear supplying Engineered Safety Features (includes 4-kV, 460-V and 230-V vital buses)

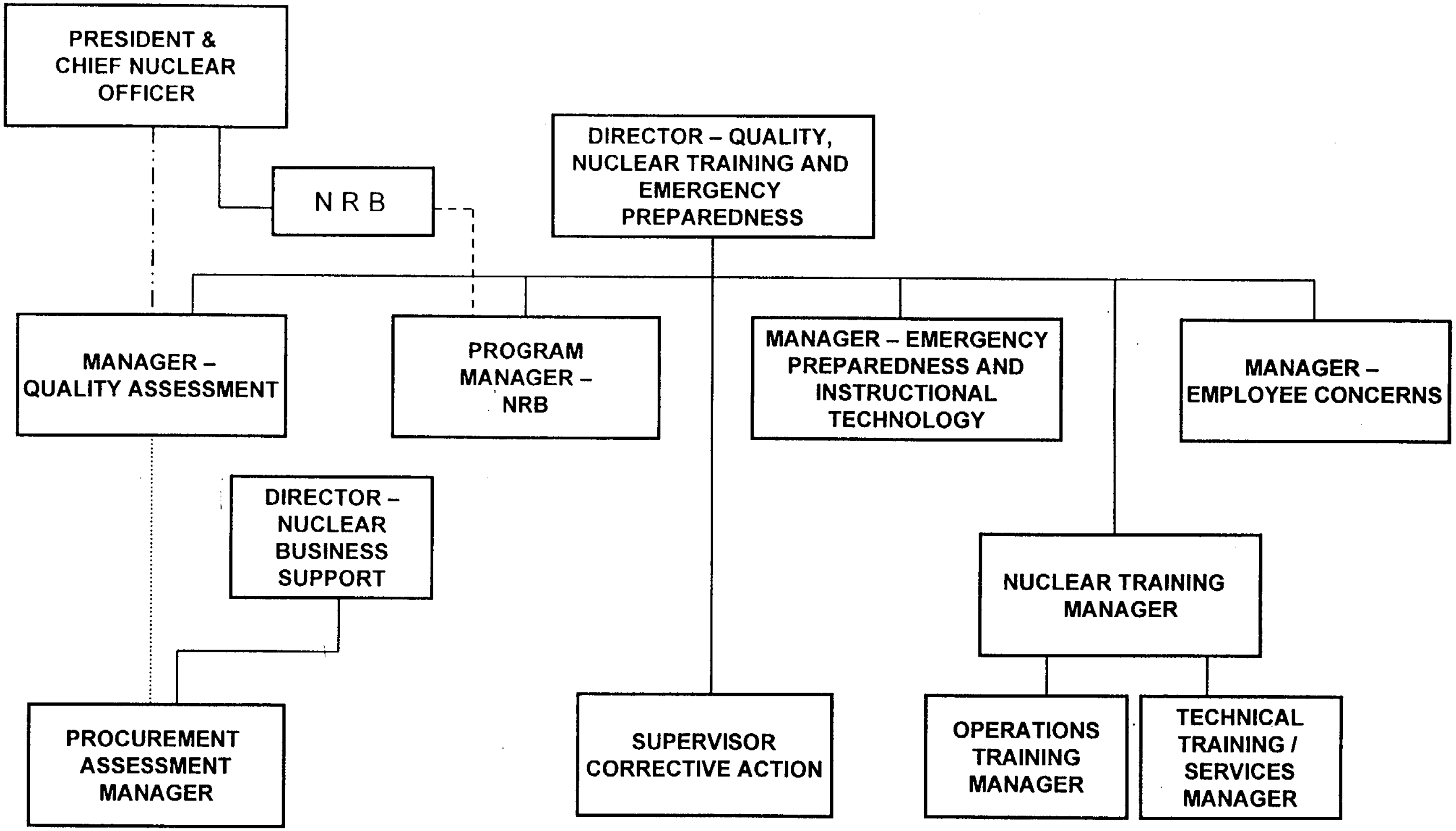
2.1.18 Emergency Response Facilities (NUREG-0737, Supplement 1; document control and verification of functionality only)

2.1.19 Engineered Safety Features

a. Containment Spray System (including spray pumps, spray header, spray additive tank, connecting piping and valves)

b. Containment Ventilation System (including fan coolers, distribution ducts, dampers, HEPA filters, and moisture separators)

c. ECCS (including Safety Injection and RHR pumps, RWST, Accumulators, RHR heat exchangers, containment sump, sump screen vortex suppression devices, and connecting pipes and valves)



LEGEND

— · · — · · —	REPORTS TO P/CNO ON ISSUES INVOLVNG NON-QA AREAS UNDER THE RESPONSIBILITY OF THE DIRECTOR
- - - - - - -	COORDINATION
....	PROCUREMENT ASSESSMENT DOTTED LINE RELATIONSHIP WITH QA WILL BECOME SOLID WITH CONFLICTS CONCERNING QA ISSUES.

PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

QUALITY, NUCLEAR TRAINING & EMERGENCY PREPAREDNESS

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