REACTOR ENGINEERING

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DESIGN BASIS ANALYSIS OF A POSTULATED STEAM GENERATOR TUBE RUPTURE EVENT FOR COMANCHE PEAK STEAM ELECTRIC STATION, UNIT 1

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ABSTRACT

In response to NRC requests, TU Electric has re-examined the postulated, design-basis, Steam Generator Tube Rupture Event (SGTR). The SGTR event is unique among the design-basis accidencs in that timely and correct operator intervention is required to terminate the event. Hence, using the CPSES control room simulator, extensive evaluations of the responses and response times required for termination of the postulated event were performed using CPSES reactor operators trained to follow the CPSES Emergency Response Guidelines. The equipment required for termination of the postulated event was identified, and the safety classification of this equipment was verified.

A transient-specific RETRAN02 model of CPSES was developed in accordance with an approved Quality Assurance program. A representative SGTR analysis was simulated for comparison with a similar analysis performed for the Westinghouse Owners' Group. Conservative initial conditions were identified and included in the model. The effects of a number of postulated active failures were evaluated to determine which failure would result in the most severe transient. The active failure analyses resulted in the formulation of two design-basis scenarios. One scenario included the failure of an auxiliary feedwater throttling valve and resulted in the least margin to overfill of the ruptured steam generator. The second scenario included the failure of an atmospheric relief valve on the ruptured steam generator to close and resulted in the most severe postulated radiological consequences.

The analyses of these two scenarios demonstrated that sufficient time was available for the reactor operators to terminate the primary-to-secondary leakage from a postulated SGTR accident prior to overfill of the faulted steam generator. In addition, the offsite doses received at the Exclusion Area Boundary and the Low Population Zone boundary were calculated to be within the limits of 10CFR100.11.

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CHAPTER 1

INTRODUCTION

The evaluation of the safety of a nuclear power plant includes analyses of the plant response to postulated disturbances in process variables and to postulated malfunctions or failures of equipment. One such postulated failure which is included in the safety evaluation of Comanche Peak Steam Electric Station, Unit 1 (CPSES1) is the complete severance of a single steam generator U-tube. The postulated Steam Generator Tube Rupture (SGTR) event is classified as an ANS Condition IV fault - an occurrence that is not expected to take place, but is postulated because of the potential release of significant amounts of radioactive material.

The Steam Generator Tube Rupture analysis currently in the Final Safety Analysis Report (FSAR) of the Comanche Peak Steam Electric Station is based on the assumption that the primary-to-secondary leakage to the ruptured steam generator can be terminated by appropriate operator actions within 30 minutes. However, SGTR events experienced by two operating plants (Ginna and Prairie Island) required a significantly longer period of time to terminate the break flow rate by equalizing the primary and secondary system pressures. If the primary-to-secondary leakage from a SGTR event were to persist over a sufficiently long period of time, the liquid inventory in the ruptured steam generator would also increase. The subsequent overfill of the ruptured steam generator into the main steamlines could threaten the integrity of the steamlines and the associated supports and could result in increased releases of radioactive material.

In 1984, the Nuclear Regulatory Commission (NRC) requested additional information from TU Electric concerning the SGTR analysis [1]. The following information was requested:

a) an evaluation of operator actions necessary to effect pressure equalization, and a conservative time estimate for each action, including initial delay time;

b) an evaluation of whether liquid can enter the main steamlines as a result of a tube rupture, and the consequential effects on the integrity of the steam piping and supports; and,

c) verification that all components credited in the analysis to mitigate the consequences of the SGTR event are classified as safety related, or justification for the use of any non-safety related component credited in the analysis.

In response to these requests by the NRC, TU Electric elected to participate in the Westinghouse Owners Group (WOG), SGTR subgroup program which attempted to address these concerns on a generic basis. Extensive analyses of the revised SGTR scenario, based on a "bounding" reference plant design, were submitted to the NRC [2, 3, 4]. The NRC issued two Safety Evaluation Reports (SERs), accepting the analysis approach and generic conclusions [5, 6]. However, because of the numerous differences between plant designs and equipment, operating procedures, and operator training, the NRC required each utility to perform plant-specific analyses of the postulated SGTR event.

TU Electric has opted to perform the additional analyses required for resolution of the SGTR issue in-house. This report describes the plant-specific, design-basis analyses of the postulated Steam Generator Tube Rupture Event performed by TU Electric for the Comanche Peak Steam Electric Station, Unit 1.

The RETRAN02MOD004 [7] computer code was used with a detailed model of CPSES1 to simulate the postulated SGTR event. With this model, a "Nominal" SGTR scenario was executed for comparison with a similar analysis performed by the WOG, SGTR subgroup, which was based on the reference plant design. This comparison provided sufficient assurance that all key parameters were addressed in the plant-specific analysis, in addition to providing qualitative assurance of the adequacy of the CPSES1-SGTR model.

An evaluation of the CPSES1 operator responses to the postulated event and the timing of those responses was performed using the results of numerous simulator exercises. In addition, these simulator exercises facilitated the identification of the plant equipment required for the termination of the postulated event.

Using a plant-specific, "Nominal" model of CPSES1 and the plant-specific operator response times, evaluations were performed to identify conservative assumptions concerning equipment availability and initial conditions. After incorporating these conservative assumptions into a "Conservative" RETRAN02 model of CPSES1, evaluations were performed to identify the single active failure which results in the most severe event with respect to the possibility of overfilling the ruptured steam generator and the single active failure which results in the most severe offsite radiological dose consequences. These evaluations resulted in the identification of the design-basis event scenarios.

Detailed thermal-hydraulic descriptions of the two design-basis steam generator tube rupture events are provided in this report as well as a discussion of the radiological consequence assessment methodology and the calculated radiological results.

The discussion of the RETRAN02MOD004 computer code and its adequacy for use in the analysis of SGTR events may be found in Chapter 2. The RETRAN02 base plant model of CPSES1 is described in Chapter 3. The SGTR scenario, including a discussion of the operator responses required to terminate the postulated event, is contained in Chapter 4. Chapter 5 contains a description of the SGTR-specific RETRAN02 model of CPSES1, followed by the justification of the adequacy of this model in Chapter 6. A detailed discussion of the operator responses to a postulated SGTR and the timing of those responses may be found in Chapter 7. Chapter 8 contains the evaluation of the conservative initial conditions incorporated in the analysis of the SGTR event. The equipment required to be available to the operators to terminate the postulated SGTR event is discussed in Chapter 9, as are the effects of potential failures of this equipment.

The analysis of the design-basis SGTR event which minimizes the margin to overfill of the ruptured steam generator is presented in Chapter 10. The thermal-hydraulic analysis of the design-basis SGTR event which results in the most severe radiological consequences is presented in Chapter 11, followed by an assessment of the radiological consequences in Chapter 12. Finally, the conclusions drawn from these analyses are described in Chapter 13.

CHAPTER 2

USE OF RETRAN02MOD004 FOR SGTR ANALYSES

The reanalysis of the design-basis SGTR was performed with the RETRAN02MOD004 computer code. The RETRAN code was developed by Energy, Inc. (now EI Services) under the sponsorship of the Electric Power Research Institute (EPRI). RETRAN02 is a one-dimensional, best-estimate, transient, thermal-hydraulic computer code, capable of simulating most boiling water and pressurized water reactor transients, exclusive of those events where the primary coolant system becomes heavily voided [7]. RETRAN02 is widely used throughout the nuclear industry by over 25 domestic and foreign licensees.

In 1981, the Utility Group for Regulatory Action (UGRA) submitted RETRAN02MOD002 to the NRC for review. The NRC issued a Safety Evaluation Report (SER) in 1984, conditionally approving RETRAN02MOD002, with error corrections, for use in performing transient analyses of non-Appendix K (non-LOCA) events [8].

The NRC approved RETRAN02 for use in the analysis of non-LOCA Transients. Among the transients specifically approved was the steam generator tube rupture (SGTR) event. The capability of RETRAN02 to adequately simulate SGTR transients has been demonstrated by analyses performed by the staffs of the Institute of Nuclear Power Operations (INPO) [9] and the EPRI-sponsored Nuclear Safety Analysis Center (NSAC) [10]. The Prairie Island and Ginna tube rupture events were extensively analyzed using RETRAN02. These analyses were "best-estimate" analyses, i.e., no conservative assumptions were deliberately used. These analyses demonstrated that RETRAN02 may be used to predict transient system responses which compare favorably with recorded plant responses. As concluded in a NSAC report [11] describing parametric studies performed with the RETRAN02 model used to benchmark the Prairie Island event [10], "... RETRAN is a capable thermal-hydraulic code for steam generator tube rupture analysis."

In 1985, RETRAN02MOD003 was released by EPRI. RETRAN02MOD003 contained the corrections to the errors identified subsequent to the release of RETRAN02MOD002, including those identified during the NRC review. The current version of RETRAN02 is RETRAN02MOD004. RETRAN02MOD004 contains error corrections to RETRAN02MOD003 plus two new models. These error corrections and model enhancements were made in accordance with the Quality Assurance programs of EPRI and EI Services. One of the two new models is an improved control rod model for use with 1-D kinetics. The 1-D kinetics option was not used by TU Electric in SGTR analyses. The second model, which was not used by TU Electric in SGTR analyses, is an option to allow the computer code to edit the initial values of the control blocks. Neither the use nor the omission of this option affects the SGTR analyses.

RETRAN02MOD004 is the most recently released version of RETRAN02 and contains corrections to those code errors identified prior to the time of its release. It is appropriate that this version of the code be used for the CPSES1 simulation of the postulated SGTR event.

CHAPTER 3

THE RETRAN BASE PLANT MODEL OF CPSES1

The Comanche Peak Steam Electric Station consists of two Westinghouse Pressurized Water Reactors. The analyses presented in this report are applicable only to Unit 1 (CPSES1).

CPSES1 is a four-loop plant with a rated thermal power of 3411 MWt. The steam generators are the Westinghouse Model D-4. With the exception of the Nitrogen-16 (N-16) temperature synthesis control system, CPSES1 does not have any features not found in similar vintage Westinghouse four-loop PWRs. The N-16 system synthesizes an average Reactor Coolant System (RCS) temperature based on the measured cold leg temperature and a normalized N-16 power measurement. The N-16 system is used in lieu of the more standard Delta-Temperature systems employed at similar Westinghouse plants.

TU Electric has adopted a "Base Model" approach to control the computer models used for transient analyses. The Base Model consists of a detailed, best-estimate, CPSES1 plant model, including all NSSS-related control systems and most of the balance-of-plant control systems. The Base Model was developed, approved, and controlled in accordance with the Quality Assurance program for the Reactor Engineering Department. All transient-specific models, either licensing or best-estimate, are derived from the approved Base Model in accordance with the procedures outlined in the Quality Assurance Program. Hence, a discussion of the specific model for the SGTR analysis requires a discussion of the best-estimate Base Model.

A quality-assured, two-loop, best-estimate model of CPSES1 was developed and issued by TU Electric in early 1985. This model was developed from as-built drawings, plant-specific design documents, etc. The model has been used for a variety of analyses, both best-estimate and quasi-best-estimate, in support of operational concerns at the plant. These analyses provided opportunities to extensively examine the qualitative performance of all portions of the model.

Among the analyses performed were several Emergency Drill scenarios, which included SGTRs in conjunction with other severe events. Other activities using the CPSES1 model included the performance of a long-term, natural circulation, plant cooldown analysis and analyses to support the optimization of several non-safety-related, plant control system parameters. The RETRAN02 model of CPSES1 was also used to simulate eleven transients, including a Steam Generator Tube Rupture, for use as a basis for evaluating the adequacy of the CPSES1 plant simulator.

The RETRAN02, CPSES1 model was the subject of a Technical Review performed in 1985 by the RETRAN code developer, EI Services. The purpose of the review was to ensure that the raw, plant design data had been correctly interpreted and formulated for proper use in RETRAN02, and that appropriate code options and models were selected. In addition, four transients were simulated with this original base plant model to test the model as an integral system. These transients were also reviewed by EI Services to qualitatively evaluate the accuracy of the results. EI Services based their evaluation of the transient results on numerous internal analyses performed for similar plants.

The current, best-estimate, plant model was issued in mid-1987 and addressed all concerns identified in the Technical Review performed by EI Services. In addition, many of the component models were improved, and several of the control systems were enhanced or added to the base model. The quality of the documentation describing the model was also significantly upgraded. The Steam Generator Tube Rupture model was derived from this Base Model of CPSES1.

CHAPTER 4

STEAM GENERATOR TUBE RUPTURE SCENARIO DESCRIPTION

Prior to discussing the SGTR-specific model, it is important to describe the postulated SGTR scenario. The following discussion outlines the "routine" scenario and operator responses with no active failures assumed.

The postulated, design-basis Steam Generator Tube Rupture event is initiated by a complete severance of a single steam generator U-tube. The initial indications of the event are decreasing pressurizer pressure and level and a steam flow - feed flow mismatch. Other indications include increased charging flow, slight transients in steam generator water level indications, and a turbine runback as the RCS pressure reduction forces the Overtemperature N-16 setpoint to within 3% of the calculated Overtemperature N-16 signal. In addition, radiation monitors on the main steamlines, steam generator blowdown header, and condenser offgas system will detect increased radiation levels, and an alarm will sound, providing an early, unique indication of a steam generator tube rupture. In accordance with Abnormal Conditions Procedures [12], following receipt of an alarm on 5% pressurizer level deviation, the reactor operators will isolate the 45 gpm letdown orifice, and start the first and then the second centrifugal charging pump. If the pressurizer level continues to fall, the reactor operators will manually actuate Safety Injection, thus causing a reactor trip, turbine trip, and auxiliary feedwater initiation.

Immediately following reactor trip, the Shift Supervisor will open the Emergency Response Guidelines (ERGs) [13]. These procedures provide specific guidance to the reactor operators for the diagnosis of the cause of the reactor trip and the stabilization of the plant. After the event is diagnosed, transient-specific Emergency Operating

Procedures (EOPs) are provided within the ERGs to mitigate the effects of the transient and to stabilize the plant.

Following reactor trip, the event would be diagnosed as a SGTR based on a marked difference in narrow range level indications between the intact and ruptured steam generators. The narrow range level indication is provided by a safety-grade system. Other non-safety systems available for use in diagnosing the tube rupture include the radiation monitors described above; however, because the radiation monitors are not safety-grade components, credit was not taken in licensing-basis analyses for the proper operation of these monitors.

Following the diagnosis of the event as a SGTR and the identification of the ruptured steam generator, the EOPs direct the operators to isolate the ruptured steam generator. This isolation would be achieved by throttling auxiliary feedwater to the ruptured steam generator, closing the main steam isolation valve (MSIV) on the steamline from the ruptured steam generator, and raising the setpoint pressure of the power-operated, atmospheric relief valve (ARV) on the steamline from the ruptured steam generator. The setpoint pressure of the ARV would be raised, but would remain below the lowest setpoint pressure of any of the main steam safety valves. Procedural contingency actions are provided if any of the above actions can not be completed.

Upon isolation of the ruptured steam generator, the RCS would be cooled such that a subcooling margin would be maintained when the RCS is depressurized. If the steam dump (turbine bypass) valves were available, they would be used to cool the RCS. If offsite power were unavailable, the air-operated steam dump valves would not be available; hence, the RCS would be cooled by relieving steam through the ARVs on the intact steam generators. The target temperature for the RCS cooldown corresponds to a specified subcooling margin at the pressure of the ruptured steam generator.

Once the RCS had been cooled, and the subcooling margin at the ruptured steam generator pressure had been obtained, the RCS would be depressurized to terminate the break flow. If the reactor coolant pumps were operating, the pressurizer sprays would be used to conserve RCS inventory. If offsite power were unavailable, the RCPs would also be unavailable; thus, one pressurizer power-operated relief valve (PORV) would be used to depressurize the system. The depressurization would be terminated when the RCS pressure was less than the pressure in the ruptured steam generator, when a maximum pressurizer level was exceeded, or when the RCS subcooling margin limit was approached.

The final significant operator action required to terminate the event is to stop the Emergency Core Cooling System (ECCS) pumps. When the RCS is at low pressures, the capacity of these pumps is relatively high; thus, the RCS would repressurize quickly if they were not stopped.

After the ECCS pumps are stopped, the RCS and ruptured steam generator pressures would become equal due to flow through the ruptured tube, thereby removing the driving force behind the leakage flow and terminating the break flow. Additional operator actions, discussed below, would be required to prevent the primary-to-secondary break flow from becoming reestablished while taking the plant to cold shutdown conditions.

Immediately following the termination of the ECCS flow, the RCS pressure would increase slowly due to the addition of decay heat and the lack of any active heat removal process (no steam relief from intact steam generators); hence, the break flow rate would tend to be reestablished. Additional procedural guidance has been provided to the reactor operators to prevent the flow of a significant amount of RCS fluid into the ruptured steam generator.

Following the termination of the ECCS flow, the reactor operators would continuously maintain equal RCS and ruptured steam generator pressures, using the pressurizer sprays, a pressurizer PORV, or the auxiliary spray if letdown has been reestablished. Following the initiation of a controlled cooldown to bring the plant to cold shutdown conditions, the

RCS would be maintained at a pressure lower than the ruptured steam generator pressure, thus backfilling the RCS with the ruptured steam generator fluid. This process would continue as the plant is cooled to cold shutdown conditions, thus preventing the liquid volume in the ruptured steam generator from increasing significantly at any time during the recovery following the event.

Because the steam generators have a finite volume, the break flow must be terminated in a timely manner to prevent overfill of the ruptured steam generator. Overfill of the ruptured steam generator could lead to filling of the main steamlines with liquid, thereby increasing the likelihood of several consequential events. If the steamlines are structurally adequate, the filling and pressurization of the steamline could result in opening of a main steam safety valve. Because these valves are not designed for water-relief, it may be postulated that these valves would fail to close, resulting in a prolonged release directly to the atmosphere. If the steamlines are not structurally adequate, a consequential main steamline break may also be postulated. In either case, the overfill of the ruptured steam generator could lead to unacceptable consequences, and hence, must be avoided.

CHAPTER 5

STEAM GENERATOR TUBE RUPTURE BASE MODEL DESCRIPTION

5.1 General

As indicated in Chapter 3, the RETRAN02 models used for the simulation of the design-basis steam generator tube rupture event were derived from the plant-specific, best-estimate model of CPSES1. During the development of the final SGTR model, several "intermediate" models were developed for use in the evaluation of conservative assumptions and effects from postulated active failures. The use of the intermediate models in the development of the design-basis models is illustrated in Figure 5-1.

In the following discussions, the "Nominal Base Case" is that model derived directly from the best-estimate model. Few conservatisms were incorporated into this model. The Nominal Base Case was used to simulate the postulated transient using a similar set of initial conditions and assumptions as was used for the generic tube rupture analysis performed by the Westinghouse Owners Group [2]; a comparison of the two analyses is presented in Chapter 6. In addition, this Nominal Base Case was used to identify critical parameters and to determine conservative values for these parameters to be used in the design-basis SGTR analyses.

The set of conservative assumptions was then incorporated into the Nominal Base Case to derive the "Conservative Base Model". The Conservative Base Model contains all of the conservative assumptions to be included in the design-basis models, with the exception of the single active failures. The Conservative Base Model was then used to evaluate the effects of the postulated active failures to determine which single failure would result in the least margin to overfill of the ruptured steam generator and which single failure would result in the most severe radiological consequences.

5.2 Physical Description of the CPSES1-SGTR Model

The noding of the CPSES1 steam generator tube rupture model (Figure 5-2) is similar to the noding described in NSAC 47 [10], wherein the Prairie Island event was analyzed. The best-estimate models of the Prairie Island [11] and Ginna plants [9] used multi-node steam generator models. The use of a single node steam generator in the CPSES1 model will be addressed in Section 5.3.

In addition to a more detailed steam generator secondary model, the best-estimate model of Ginna employed greater detail in the upper head region of the reactor vessel. The detail in the reactor vessel upper head of the Ginna RETRAN model was considered necessary for the detection of suspected void formation in the upper head region. Because analysis indicated no upper head voiding occurs during the course of the CPSES1 recovery simulations, a single volume representation of the upper head was determined to be adequate.

The Nominal Base Case Steam Generator Tube Rupture model for CPSES1 contained 48 fluid volumes and 80 junctions. Plant loops designated as Loop 1, 2, and 3 were combined into model Loop 1. Plant Loop 4 was modeled separately and included a non-equilibrium pressurizer model. The hot legs, intermediate legs, reactor coolant pumps, and cold legs were each represented as single volumes. In the reactor vessel, the upper head, upper plenum, downcomer, lower head, and core bypass regions were individually modeled as single volumes. The fluid region of the core was modeled as three equi-volume regions.

On the primary side of the steam generators, the inlet and outlet plena were each represented by single volumes. The U-tube region was modeled with six fluid volumes per modeled steam generator. The secondary sides of the steam generators were modeled with a single separated fluid volume. The main steamlines and the main steam header were explicitly modeled.

The model included 38 heat conductors; three for the core region, six in each steam generator U-tube region, and 21 to represent the thermal storage capacity of the thick metal masses of the RCS vessel and piping, the pressurizer walls, and the steam generator vessel walls. To maintain conservatively high primary temperatures and pressures, and hence, a high primary-to-secondary break flow, no heat transfer to the containment though the RCS piping, vessel walls, pressurizer walls, or through the steam generators walls was modeled.

5.3 Single-Node Steam Generator Model

A single-node steam generator model is adequate for relatively long, slow transients where the steam generator mass and pressure are the important parameters and for transients where there is little time for significant feedback from the secondary to the core. For these types of transients, the use of a single-node steam generator model can provide similar results to those obtained with a multi-node model and with a significant savings of computer resources. The main drawback to using the single-node steam generator is its inability to allow direct prediction of the indicated water level.

The level indication in a U-tube steam generator is greatly influenced by the "manometer" effects between the tube bundle region and the downcomer. In a single-node steam generator model, these regions are lumped with other parts of the steam generator into a single region; thus, no detail is available from which the level indication may be directly predicted. However, there are parameters upon which a level prediction may be derived.

Derivation of a level indication from the steam generator mixture volume is the principal mechanism used. This mechanism is particularly useful when the void fraction is small, and the steam generator circulation ratio is small. For these conditions, the manometer effect between the downcomer and tube bundle regions is small and the mixture volume allows a reasonable prediction of the steam generator level. The level indication from the mixture volume is approximate when there is a rapid change in the void fraction of the mixture due to a change in the heat removal or addition rates to the mixture.

In the single-node steam generator model, the preheater section is not explicitly modeled; therefore, the overall calculated heat transfer coefficients must be adjusted in order to transfer the correct amount of heat from the RCS to the steam generator. This adjustment was made in RETRAN by adjusting the heat transfer area of the U-tubes to remove the correct amount of heat. The adjustment is reasonable during steady or slowly changing flow conditions, but less reasonable during rapidly changing flow conditions when the preheater may be bypassed by a different flow fraction.

Use of a single-node steam generator for the SGTR analysis is conservative in that the pressure difference used to determine the break flow is based on the average steam generator pressure. For an actual cold leg, tubesheet surface, SGTR, the local steam generator pressure would be greater than the average pressure. The higher local pressure is due in part to the geometry of the steam generator flow distribution plates and in part to the overall static head of the steam generator fluid. The fluid at the cold leg tubesheet surface consists primarily of relatively dense, main feedwater injected into the preheater box and slightly subcooled recirculation flow. After the main feedwater flow is isolated, the importance of this effect is reduced.

The transient thermal-hydraulic characteristics of the single-node steam generator following the injection of cold auxiliary feedwater also conservatively affect the postulated SGTR event. Due to the simplicity of the model, the auxiliary feedwater is injected directly into the steam generator boiling region, thus causing a rapid collapse of any voids. In turn, the collapse of the voids results in a lower steam generator pressure. Because the primary-to-secondary break flow increases as the primary-to-secondary pressure difference increases, the rapid void collapse is conservative for this event.

5.4 Steam Generator Narrow Range Level Indication

At CPSES1, the Narrow Range Level Indication is derived from a differential pressure transmitter; hence, the collapsed liquid volume is the most reasonable fluid volume parameter to be used for the level calculation. The appropriate collapsed liquid volume to use is that volume between the lower and upper level taps. However, this region is lumped with the rest of the steam generator, it is not possible to obtain only the liquid volume between the level taps and outside the primary separators.

The use of the mixture volume for the level indication is the other alternative. Use of the mixture volume provides a good indication of the steam generator fluid shrink and swell, if the change in the level or heat transfer rate is relatively slow. However, if there is a rapid change, e.g., a reactor trip, the use of the mixture volume does not compensate for the lack of detail in the single-node model; thus, the change in the level is overpredicted. Following reactor trip, when the void fraction in the steam generator is relatively small, use of the mixture volume and the collapsed liquid volume provide essentially the same results. The mixture volume reflects the shrink and swell effects due to pressure changes, and thus, given the coarseness of the steam generator model, is the preferred parameter upon which to base the single-node steam generator level calculation.

Based upon drawings of the Model D-4 steam generators at CPSES1, a table of the indicated steam generator water level as a function of mixture volume was developed for use in calculating an approximate narrow range level. Due to the coarseness of the steam generator model, the dynamic characteristics of the level indication are not expected to be extremely accurate; however, the trends and relative changes between steam generators are expected to be reasonably indicative of actual level behavior.

5.5 Break Flow Model

As will be discussed more thoroughly below, the primary-to-secondary pressure difference and the fluid density have the most impact on the break flow rate. Even though the primary-to-secondary pressure difference is less on the cold leg side of the steam generator than on the hot leg side, the increased fluid density on the cold leg side results in the greater break flow rate. Thus, the SGTR break location which results in the greatest flow is on the cold leg side of the steam generator.

The RETRAN control systems and positive and negative fills (leakage paths) were used to calculate the flow rate through the ruptured U-tube. The mass flow rates from both sides of the tube were conservatively calculated based on the steam generator outlet plenum enthalpy and pressure. The mass removed from the steam generator inlet and outlet plena was added to the steam generator fluid volume through a positive fill. The energy removed from both sides of the ruptured tube was averaged (using flow rate weighting) and added to the steam generator volume through the positive fill.

Because flow out of the "long" tube will be resistance-limited, the shorter the tube, the greater the flow rate. Therefore, the shortest U-tube was assumed to break. In order to maximize flow out of the "short" tube, the break was assumed to occur at the surface of the steam generator tube sheet. Because the frictional resistance to flow for the short tube is relatively small, flow out of the short tube may initially be choked.

Because actual choked flow conditions are not expected to exist for significant periods of time, the resistance-limited flow equation (Equation 5-1) was conservatively utilized to calculate the break flow rate. The friction factor and form loss coefficients which were used resulted in a very conservative calculation of the resistance-limited flow.

$$W = ([2g_c \cdot \rho \cdot A_T^2 \cdot 144 \cdot dP] \div [K_T + fL/D])^{1/2} \qquad (5\text{-}1)$$

where: W = mass flow rate out one end of the tube;

g_c = gravitational constant;

ρ = fluid density;

A_T = cross-sectional flow area of the tube;

dP - primary-to-secondary pressure differential;

K_T = total form loss coefficient for tube entrance and exit; and,

fL/D = frictional loss term.

Use of only the resistance-limited flow equation simplified the model because the choked flow rate did not have to be calculated and compared with the resistance-limited flow rate in order to obtain the break flow rate. In addition, because choked flow was not credited, use of the resistance-limited flow rate resulted in a conservative calculation of the break flow rate. Note also that choking was not allowed to occur at the entrances to the U-tubes, nor at the break locations. In addition, the tube ends were assumed to discharge fluid into an "infinite" plenum; thus the local pressure at the break location was minimized. As previously discussed, no credit was taken for flow distribution plates in the steam generator, or for the higher preheater pressure, both of which would have increased the local pressure.

From Equation (5-1), it is noted that smaller values of form losses and frictional losses result in larger flow rates. The form losses, K_T, consist of the entrance, exit, and direction change losses for the long tube section and entrance and exit losses for the short section. For conservatism, only entrance and exit form losses were modeled, using sharp-edged contraction/expansion geometries. To provide an added measure of conservatism, the exit loss coefficient was reduced by 15%

to bound those postulated cases where the break geometry could be slightly less restrictive to flow.

Because L/D is fixed by geometry considerations, the frictional losses were minimized by using a conservatively small friction factor, f. The friction factor was calculated for a smooth pipe and a conservatively large Reynolds number. The calculated value was then reduced for conservatism.

5.6 Model Options

The Combined Forced/Natural Convection Heat Transfer Map Option selected in the base plant model was also used in the SGTR base model. The slip model was not used for the SGTR licensing-basis analysis because the effects of a slip model in the steam generators would not be evident with a single-node steam generator model.

5.7 Reactor Trip System

A reactor trip signal was assumed to be generated only on low pressurizer pressure. The validity of this assumption will be discussed in Chapter 8.

5.8 Point Kinetics Reactivity Parameters

Licensing-basis, End-of-Life (EOL) reactivity parameters were used as input to the point kinetics model used in the CPSES1-SGTR model. EOL reactivity parameters were chosen because the moderator density coefficient is most positive (moderator temperature coefficient is more negative) than at Beginning-of-Life. A "most positive" moderator density coefficient retards the cooldown of the primary system. Because the SGTR is not an overpower-, overpressurization-, or a criticality-restricted event, this event is rather insensitive to the reactivity parameters selected. Furthermore, a multiplier of 1.2 was used to provide a conservative value for the decay heat assumed in the analysis (120% of 1971 ANS Decay Heat curves).

A relatively large (absolute) Doppler defect was conservatively utilized in the SGTR analysis in order to maximize the positive reactivity during the cooldown.

The time dependent scram reactivity worth was based on a 4% dk/k scram worth, a conservative 3.30 second rod drop time, EOL reactivity parameters, and a conservative value for rod worth as a function of rod position. The 4% dk/k scram worth is conservative with respect to the total rod worth less the most reactive rod, which was assumed to be stuck out of the core.

The moderator density coefficient for CPSES1 will be positive at operating conditions; hence, if the moderator density decreases, the reactivity will decrease. When selecting an appropriate MDC, the goal is to cause the primary pressure and temperature to be maximized during the depressurization, hence a MDC should be selected which results in the greatest addition of positive reactivity as the moderator density increases. Therefore, a conservative moderator density coefficient of 0.43 (delta-ρ)/(delta-gm/cc) was used.

5.9 Steam Generator ARV Control System

The control system for the steam generator ARV was also modified for the SGTR model. It is conservative in the SGTR event for the steam generator ARV to function normally to maintain steam generator pressure below the setpoint pressure of the main steam safety valves following a reactor/turbine trip. Thus, the ARV control system for the ruptured steam generator was allowed to function normally.

In order to maximize the RCS temperature, the ARVs in the intact steam generators was placed in the manual mode of control, and the pressure in the intact steam generators was allowed to rise toward the setpoint pressure of the main steam safety valves. Later in the transient, the ARVs on the intact loops were used in the manual mode to effect the RCS cooldown.

5.10 Boron Transport

Following the initiation of the ECCS flow, borated water is injected into each cold leg. A simple, but conservative, method of modeling the reactivity effects of the injected boron was used for the SGTR model. In this model, the RCS was considered to be a single volume, or "pot". Following a delay time to allow for the borated water to traverse through the cold leg to the top of the core, the ECCS flow was assumed to mix instantaneously with the entire primary volume. Mixing of this type is conservative, because the primary fluid would have a more dilute concentration of boron than if the ECCS fluid were to mix only with the cold leg fluid.

For the SGTR event, the precise time when the injected boron reaches the core is not of vital importance; therefore, the total delay time was estimated in a conservative manner.

A conservative boron worth of 9.0 pcm/ppm was used to determine the total boron reactivity. The boron concentration in the ECCS fluid was 2000 ppm, which is the minimum concentration allowed by the Technical Specifications in the Refueling Water Storage Tank (RWST). For consistency with other EOL conditions, an initial boron concentration of 14 ppm was assumed.

5.11 Summary of Conservatisms in the SGTR Nominal Base Model

The CPSES1-SGTR model described above is used as the Nominal Base Case for the comparative analysis discussed in Chapter 6. As previously stated, relatively few conservatisms have been incorporated into this base model. Those conservative assumptions which are included in this model are summarized below.

1) A single-node steam generator model was used.

2) Choked flow through the ruptured tube, at either entrance to the ruptured tube, and at either exit of the ruptured tube was neglected. Only resistance limited (inertial) flow was considered. The density and pressure assumed for calculation of the resistance-limited break flow were those of the steam generator outlet plenum.

3) Conservative End-of-Life reactivity coefficients and point kinetics were used to provide the reactivity feedback. Boron from the ECCS was modeled in a conservative fashion. Reactivity control was not an immediate concern for the simulated portions of the SGTR event.

4) Only the Low Pressurizer Pressure signal was assumed to generate a reactor trip.

5) The pressure in the ruptured steam generator was limited to the setpoint pressure of the atmospheric relief valve, rather than that of the main steam safety valve. The pressures in the intact steam generators were allowed to rise to the setpoint pressure of the main steam safety valves.

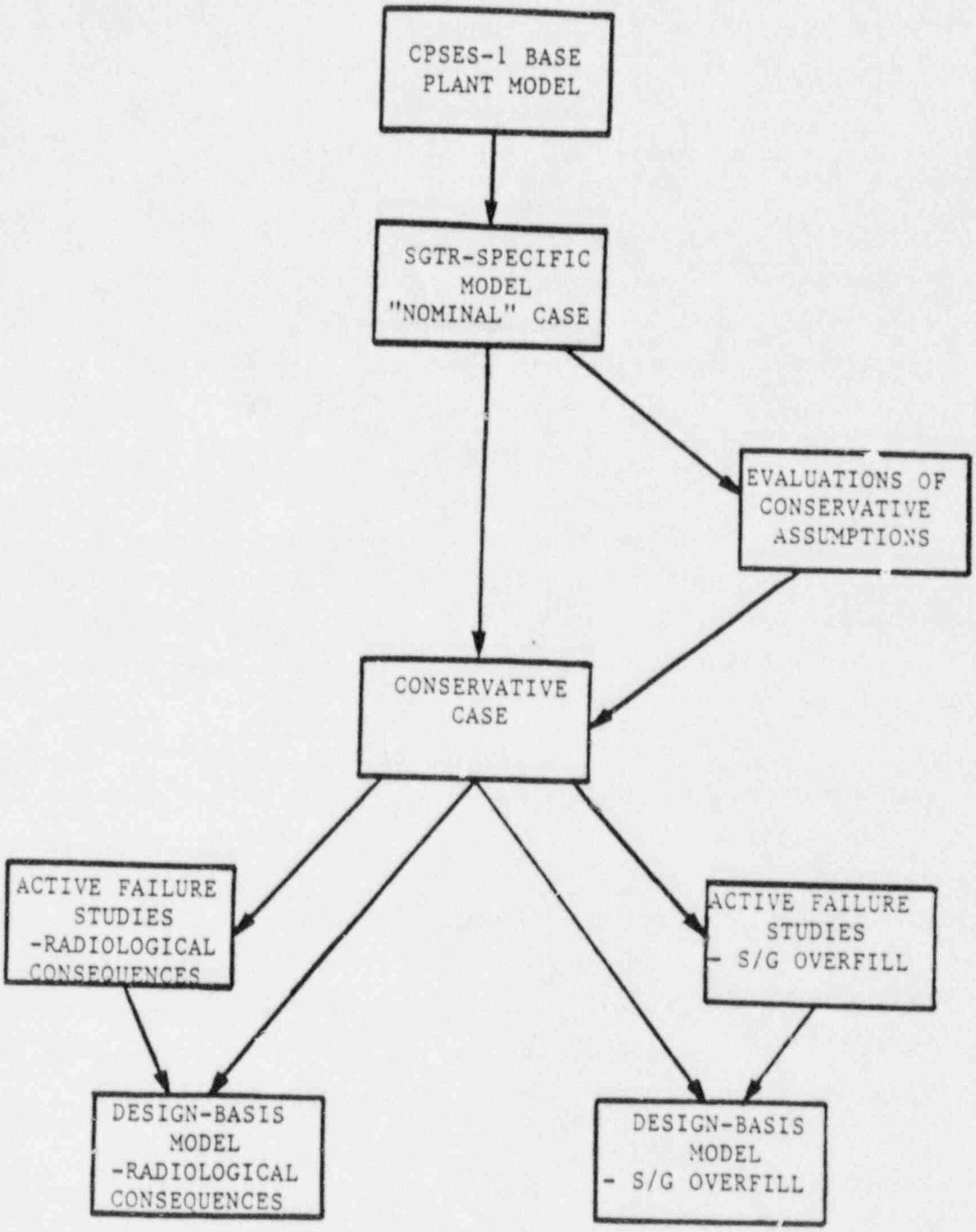


FIGURE 5-1. CPSES1-SGTR Model Flow Chart

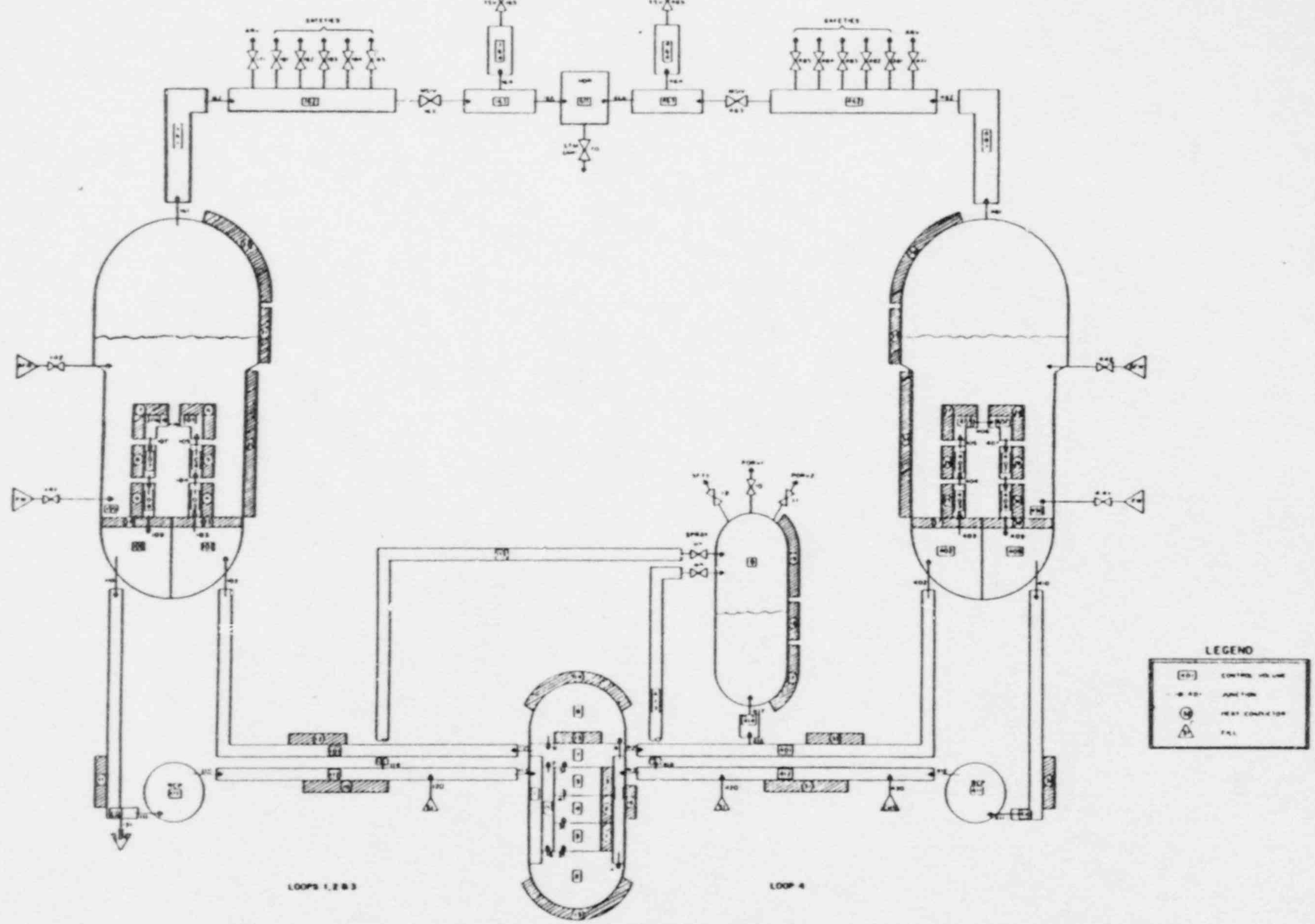


FIGURE 5-2. SGTR Base Deck Noding Diagram for CPSES-1

CHAPTER 6

JUSTIFICATION OF THE ADEQUACY OF THE CPSES1-SGTR MODEL

The adequacy of the CPSES1-SGTR model was assessed by comparison with a similar analysis performed by the WOG, SGTR subgroup for a "Reference Plant" design. In this chapter, a comparison of the input assumptions used for the two analyses as well as a detailed discussion of the analysis results will be presented. In addition, significant differences between the two analyses will be traced to specific plant differences, specific analysis assumptions, or known modeling differences.

During the development of their design-basis models, the WOG, SGTR subgroup developed a "Nominal" base model for the SGTR event into which relatively few conservative assumptions were incorporated [2]. A fairly complete description of the analysis inputs and results was provided in the analysis reports submitted to the NRC by the subgroup. This WOG analysis was selected for a comparison with the results of the RETRAN02 model of CPSES1. A comparison between the WOG analysis and a similar, CPSES1-specific analysis was useful for providing qualitative assurance of the adequacy of the CPSES1-specific model for the analysis of the SGTR event.

Both of the previously discussed analyses were performed using nominal plant conditions; however, the generic SGTR analysis performed by the WOG, SGTR subgroup was based on a Westinghouse [ ]^{a,c} plant with [ ]^{a,c} steam generators. This design differs from the CPSES1 design in many respects which affect the severity of the postulated SGTR event. A discussion of many of the analysis assumptions follows, and a list of specific values used for the two analyses is shown in Table 6-1.

6.1 Nominal Case Initial Conditions/Equipment Availability

Assumptions concerning equipment availability and performance for the "Nominal" base case analyses by both the WOG and TU Electric are shown below:

1) Initial core power was [ ]^{a,c} of nominal full power.

2) Loss-of-offsite power was assumed to occur at the time of the reactor trip.

3) Pressurizer heaters were [ ]^{a,c} for consistency with the WOG analysis.

4) Prior to the reactor trip, the steam generator water level was controlled by the steam generator water level control system.

5) For consistency with the WOG analysis, the main feedwater flow was isolated on the safety injection signal.

6) For consistency with the WOG analysis, [the turbine runback/rod control system was not modeled]^{a,c} and the reactor trip on the Overtemperature N-16 reactor trip signal was not credited.

7) The CPSES1 auxiliary feedwater (AFW) system consists of two motor driven pumps and one turbine driven pump. For consistency with the WOG analysis, all auxiliary feedwater pumps were assumed to deliver auxiliary feedwater to all steam generators on the safety injection actuation signal.

8) The charging and letdown flow systems were not modeled.

9) The operator response times used[ ]a,c were:

a) Identify and isolate ruptured S/G
b) Begin RCS cooldown
c) Begin RCS depressurization
d) Terminate ECCS flow

[ ]a,c

These assumptions were used only for comparison of the "Nominal" analysis by TU Electric with the Reference Plant analysis. The applicability of these assumptions to the CPSES1, design-basis analyses are evaluated in Chapter 8.

6.2 Operator Response Times

The operator response times listed above were used only if plant conditions met a minimum set of conditions specified in the Emergency Response Guidelines (ERGs). Those minimum plant conditions are discussed below. [ ]a,c

6.2.1 Isolation of the Ruptured Steam Generator

Consistent with the WOG analysis, the isolation of the ruptured steam generator was assumed to occur at [ ]a,c or when the water level reached [ ]a,c of the narrow range span, whichever was longer. Because the Model D-4 steam generators at CPSES1 have an extended narrow range span, following a reactor trip, the steam generator narrow range level does not normally fall below approximately 30% of span. Thus, for the CPSES1 analysis, the ruptured steam generator was isolated at [ ]a,c following the initiation of the tube rupture. Isolation was accomplished by closing the main steam isolation valve on the ruptured steam generator, raising the setpoint pressure for opening of the atmosphere relief valve on the ruptured steam generator and terminating auxiliary feedwater to the ruptured steam generator. For the Reference Plant analysis [2], the time when the narrow range level exceeded [ ]a,c span, 666 seconds, was used to isolate the ruptured steam generator.

6.2.2 Cooldown of the Reactor Coolant System

The cooldown of the reactor coolant system was initiated [ ]a,c after the isolation of the steam generator. Steam was discharged through the atmospheric relief valves (ARVs) on the intact steam generators until a sufficient RCS subcooling margin was established at the pressure of the ruptured steam generator.

6.2.3 Depressurization of Reactor Coolant System

[ ]a,c after the completion of the RCS cooldown, the primary system was depressurized by opening a power-operated relief valve (PORV) on the pressurizer to reduce the pressure differential between the primary and secondary systems. In accordance with the CPSES1 ERGs, the PORV was closed when any of the following criteria was satisfied:

a. The ruptured steam generator pressure was higher than that of the RCS, and the pressurizer level was greater than 20%; or,

b. Pressurizer level was greater than 78%; or,

c. RCS subcooling margin was less than 15°F.

For the Reference Plant analysis, using Revision 1 of the generic Westinghouse ERGs, the criteria for the completion of the depressurization were:

a. The RCS pressure was less than the ruptured steam generator pressure, and the pressurizer level was greater than 3%; or,

b. The pressurizer level was greater than 77%; or,

c. The RCS subcooling was less than 30°F.

For both analyses, the PORV was closed when the [ ]^{a,c} criterion was satisfied.

6.2.4 Termination of Safety Injection

In accordance with the ERGs, the ECCS flow could not be terminated unless the RCS pressure was stable or increasing. For the CPSES1 analysis, this criterion was satisfied within [ ]^{a,c} following the end of the depressurization. For the Reference Plant analysis, this criterion was assumed to be satisfied more than [ ]^{a,c} after the end of the depressurization when the RCS pressure had risen to 50 psi greater than the ruptured steam generator pressure.

6.3 Analysis Results

The analysis results are discussed in this section. A description of the responses of each of the significant parameters, as calculated by the CPSES1-SGTR model, is followed by a discussion of the differences between the CPSES1 analysis and the Reference Plant analysis.

A sequence of events for the CPSES1 analysis is provided in Table 6-2. The reactor was tripped on low pressurizer pressure, followed by turbine trip and a loss of offsite power. When the low pressurizer pressure setpoint for safety injection was exceeded, the safety injection actuation signal (SIAS) caused the isolation of the normal feedwater flow and the actuation of the auxiliary feedwater system. The ruptured steam generator was isolated at [ ]^{a,c} followed by the initiation of the RCS cooldown at 900 seconds. The RCS depressurization was started [ ]^{a,c} after the termination of the RCS cooldown and was stopped when the RCS pressure was less than the ruptured steam generator pressure and the pressurizer level exceeded 20% span. The ECCS flow was terminated [ ]^{a,c} following the end of the depressurization.

Also shown in Table 6-2 are the times of the significant events calculated for the Reference Plant. As discussed below, the differences in the calculated times may be attributed either to specific design features (e.g., safety injection flow rate, auxiliary feedwater flow rate, pressurizer size, etc.) and/or specific modeling differences (e.g., stroke times for steam generator ARVs). Also, the plant-specific ERGs have some impact on the calculated results.

Significant parameters from both the Reference Plant analysis and the CPSES1-specific analysis are plotted in Figures 6-1 through 6-7. A key to the symbols used in the figures is provided in Table 6-3. Discussions of specific aspects of the analysis follow.

6.3.1 General Description

As may be observed in Figures 6-1 through 6-7, following initiation of the SGTR, the RCS pressure and level decreased linearly until the low pressurizer pressure reactor trip setpoint was exceeded. A turbine trip and a loss of offsite power occurred simultaneously with the reactor trip. When the low pressurizer pressure setpoint for the SIAS was reached, ECCS flow was initiated, and the main feedwater isolation valves were closed, followed by the initiation of auxiliary feedwater. Following the turbine trip, the steam generator pressure rose rapidly. The ruptured steam generator ARV opened to relieve the pressure. After auxiliary feedwater was initiated, the steam generator pressure was determined by the amount of cold auxiliary feedwater entering the steam generators.

Following the manual isolation of steam flow from the ruptured steam generator, the pressure in the intact steam generators was maintained at the ARV setpoint pressure. The RCS pressure fell off sharply when the RCS cooldown was initiated. The cooldown was initiated by opening the ARVs on the intact steam generators and was terminated when the required RCS subcooling margin at the ruptured steam generator pressure was obtained. [ ][a,c] later, the RCS was depressurized by opening the pressurizer PORV. In accordance with the CPSES1 ERGs, the depressurization was terminated when the RCS pressure became lower than the ruptured steam generator pressure, and the pressurizer level was greater than 20% span. [ ]^{a,c} later, the ECCS flow was secured, marking the termination of the event.

6.3.2 <u>RCS (Pressurizer) Pressure</u>

<u>CPSES1 Analysis</u>

As shown in Figure 6-1, the RCS pressure decreased linearly with time until the low pressurizer pressure reactor trip setpoint was exceeded. The turbine was assumed to trip simultaneously with the reactor; however, since the turbine stop valves closed faster than the control rods fell into the reactor core, there was a brief spike in the pressure prior to the sharp drop-off following reactor trip.

Following reactor trip, the pressure continued to fall toward the setpoint for the generation of a SIAS on low pressurizer pressure. The pressure decrease was momentarily stopped as the cold leg temperature, and therefore the hot leg temperature increased following the loss of main feedwater flow, but then continued to fall as the RCS was drained through the ruptured steam generator tube. The pressure stabilized after the ECCS was initiated, and then began to rise after the ruptured steam generator was isolated, and the ECCS flow rate adjusted to match the break flow rate. The pressure fell rapidly during the initial portions of the cooldown, but stabilized as the cooldown rate decreased with the depressurization of the steam generators. The slight increase in pressure near 1150 seconds was caused by the throttling of the auxiliary feedwater to the intact steam generators. The pressure decrease stopped after the pressurizer emptied at 1240 seconds. This change was attributable to the use of a non-separated, homogeneous volume in the surge line, which acted as the liquid region of the pressurizer. The fluid in the surge line was drained from the pressurizer, and was, therefore, hotter than elsewhere in the RCS. Thus, the RCS was maintained at the saturation pressure corresponding to the fluid temperature in the surge line. Because this effect resulted in conservatively high RCS pressures, continued use of this model was deemed acceptable.

After the cooldown was terminated, the pressurizer began to refill as the RCS fluid volume addition, due to the ECCS flow, exceeded the reduction due to RCS shrinkage and flow through the ruptured tube. The pressure increased more rapidly as the pressurizer was refilled and the steam bubble was compressed. When the PORV was opened, the pressure fell sharply until the RCS pressure became less than the ruptured steam generator pressure. At this point, fluid from the ruptured steam generator backfilled into the RCS. Because the fluid in the ruptured steam generator was hotter than that in the RCS, a portion of the steam generator fluid flashed in the U-tubes and collected in the upper tube regions. This collection of fluid acted as a homogeneous pressurizer volume, much as the surge line had behaved earlier in the event. Thus, the rate of RCS pressure decrease was significantly reduced when backfill occurred.

After the RCS depressurization was completed, the RCS pressure increased, and the voids in the U-tubes were collapsed due to the pressurization and temperature reduction attributable to the high ECCS flow. After the voids were collapsed, the pressurizer pressure increased more rapidly as the pressurizer level increased and the steam bubble was compressed.

Following the termination of the ECCS flow, the pressure continued to increase, but at a slower rate, toward an "equilibrium" condition where the decrease in fluid volume through the break was compensated by the expansion of the fluid as decay heat was deposited in the RCS. The pressure remained at a slightly higher pressure than the ruptured steam generator pressure until operator actions were taken to reduce the pressures in both systems. As will be discussed in Chapter 7, these operator actions could have taken the form of either initiating a controlled cooldown of the RCS or using the pressurizer PORV to reduce the RCS pressure.

Reference Plant Differences

Because of the larger break flow rate and the smaller RCS and pressurizer volumes, the Reference Plant initially depressurized at a faster rate than CPSES1. Following reactor trip, the Reference Plant continued to depressurize until the equilibrium pressure was reached. Again, due to the larger break size, this pressure was significantly lower than for CPSES1. Because the Reference Plant had a smaller pressurizer, the pressurizer emptied significantly sooner. The effects of isolating the ruptured steam generator, as seen in the plot of the Reference Plant analysis (Figure 6-1), were masked in the CPSES1 analysis due to the presence of a water level in the pressurizer. The increase in the pressure immediately prior to the RCS depressurization was not as sharp as in the CPSES1 analysis. There were two primary contributing factors to the slower rate of repressurization: 1) the pressurizer in the Reference Plant analysis was still empty; and, 2) the break flow in the Reference Plant was larger, indicating that the repressurization attributable to the ECCS flow was less than for the CPSES1 analysis.

Following the termination of the ECCS flow, the pressure in the Reference Plant analysis stabilized almost immediately, whereas the pressure in the CPSES1 analysis increased to a new, stable pressure. Again, this difference in "equilibrium" pressures was primarily attributable to the larger tube diameter (larger break flow rate) in the Reference Plant.

6.1.3 Pressurizer Level

CPSES1 Analysis

The pressurizer level, shown in Figure 6-2, decreased linearly with time following the initiation of the SGTR. At the time of reactor trip, the level fell sharply and then stabilized as the ECCS acted to maintain level. When the auxiliary feedwater to the intact steam generators was throttled after 900 seconds, the level increased as the

RCS temperatures rose. Shortly after the start of the RCS cooldown, the level fell offscale low. The pressurizer actually emptied 150 seconds later. The pressurizer level returned on-scale during the depressurization of the RCS. Following the end of the RCS depressurization, the level remained steady while the voids formed in the U-tube region of the ruptured steam generator during the depressurization were collapsed. The level then increased more rapidly until the ECCS flow was terminated.

As the RCS heated up, the RCS inventory expanded, further increasing both pressure and level. The volumetric expansion of the RCS fluid forced subcooled fluid into the pressurizer. The resultant reduction in steam volume forced the steam to become superheated. Thus, a condition existed where there was superheated steam over a subcooled fluid. Hence, even though the pressurizer level decreased when the break flow exceeded the volumetric expansion caused by the addition of decay heat, the interphase mass transfer in the pressurizer acted to maintain and even increase the pressurizer pressure. This effect continued until the temperatures of the two phases in the pressurizer equalized.

Following operator actions to recover from the event (discussed in Chapter 7), the level would be maintained by occasional depressurization of the RCS.

Reference Plant Differences

The pressurizer level plots for the Reference Plant analysis show similar trends. The most significant difference is due to the smaller pressurizer volume and larger break flow rate which caused the pressurizer level to fall off-scale low following the reactor trip. In addition, because the break flow rate was greater than the ECCS capacity, the level did not return on-scale until the RCS was depressurized to refill the pressurizer.

It is suspected that the ratio of decay heat to the RCS volume was significantly less for the Reference Plant than for CPSES1. This assumption is consistent with the lack of pressure increase in the Reference Plant analysis following the termination of the ECCS flow. In addition, the larger diameter U-tubes may have allowed sufficient primary-to-secondary flow such that the primary pressure did not significantly increase as the RCS expanded due to the decay heat addition.

6.3.4 RCS Temperatures

CPSES1 Analysis

As shown in Figure 6-3, following the initiation of the SGTR, the RCS temperatures decreased very slightly as the reactor power decreased. The power reduction was due to the effects of the moderator density coefficient. As the RCS depressurized, the fluid density, and hence, the power generated in the core also decreased, resulting in a lower hot leg temperature and a corresponding reduction in the cold leg temperature. The density decrease due to the depressurization was partially offset by the increase in density due to the lower temperatures. Following the reactor trip, turbine trip, and the subsequent loss of main feedwater flow, the cold leg temperatures increased rapidly toward the steam generator saturation temperature. The cold leg temperature increase was terminated by the opening of the ARVs and the addition of large amounts of AFW to the steam generators. Following reactor trip, the hot leg temperature initially fell, but then increased slightly as the RCS flow coasted down and the cold leg temperatures increased. A hot-to-cold leg temperature difference corresponding to natural circulation quickly developed, thus maintaining the hot leg temperature approximately 30°F above the core inlet average temperature. This natural circulation flow was maintained by steam release through the ARV. Due to the relatively long loop transit times in natural circulation, the hot leg temperature response lagged behind the cold leg response by at least 60 seconds. Thus, the increased cold leg temperature due to the throttling of auxiliary feedwater to the intact loops was not seen in the hot leg temperature response until after the RCS cooldown had been initiated. As the steam generators were depressurized, the cold leg temperatures, and hence, the hot leg temperatures, also decreased; however, the transient hot-cold leg temperature difference was slightly larger than before due to the long loop transit times. Following the completion of the RCS cooldown, the cold leg temperature began to rise; however, the hot leg temperature continued to decrease for a longer period of time than could be accounted for by the loop transit times. The hot leg temperature was based on the core inlet temperature, which is an average of the cold leg temperatures. At this point in the transient, the cold leg temperature of the ruptured loop was relatively cool due to the large proportion of ECCS fluid mixed with the almost stagnant RCS fluid. Thus, even though the intact loop cold leg temperature was increasing, the core inlet temperature and the corresponding hot leg temperature, continued to fall for several seconds.

Following the termination of the ECCS flow, the cold leg temperature increased. Because the plot shown in Figure 6-3 actually shows the steam generator outlet temperature rather than the cold leg temperature, the temperature increase, due to the termination of the ECCS flow, was delayed by one loop transit time.

Reference Plant Analysis

With few exceptions, the plots of the intact loop temperatures follow essentially the same trend as those in the CPSES1 analysis. Following the initiation of the event, the reactor power was held constant. The RCS temperatures increased slightly as the core flow rate was reduced and the heat transfer in the steam generators decreased. After the reactor trip, the hotter pressurizer fluid flowed into the hot leg as the RCS inventory was drained through the break, and thus caused an increase in the hot leg temperatures on the pressurizer loop. The slight increase in hot leg temperature caused the steam generator pressure to increase, which acted to stabilize the cold leg temperature.

In addition, as described in Section 6.3.3, it is surmised that the ratio of decay heat to RCS volume was significantly less for the Reference Plant than for CPSES1. This assumption is consistent with the decrease in RCS temperatures seen in the Reference Plant analysis prior to the initiation of the RCS cooldown. The effect of the reduced decay heat/RCS volume ratio was most obvious after the pressurizer emptied, thus ending the heat addition due to the relatively hot pressurizer fluid.

It may also be postulated that the primary-to-secondary heat transfer was greater in the Reference Plant analysis. The increased heat transfer rate is consistent with the increased primary cooldown rate and the relatively high steam generator pressures (Section 6.3.7).

Another significant difference was the sharp increase in hot leg temperature during the RCS depressurization. The obvious reason for the temperature increase was the mixing of the influx of saturated fluid from the ruptured steam generator with the RCS fluid. However, because of the timing of the temperature increase and the consideration of the loop transit times, the backfill of the hotter steam generator fluid did not appear to be the correct reason.

6.3.5 Break Flow Rate

CPSES1 Analysis

Following the initiation of the event, the break flow rate (Figure 6-4) decreased as the RCS pressure decreased. After the reactor and turbine were tripped, and the ensuing RCS pressure decrease and steam generator pressure increase, the break flow rate dropped sharply. As the ECCS flow rate caused the RCS pressure to rise, and the auxiliary feedwater flow decreased the steam generator pressure, the break flow rate gradually increased. The initiation of auxiliary feedwater caused the break flow rate to increase briefly as the steam generator pressures were reduced. The rate of increase fell sharply as the ruptured steam generator pressure increased following the isolation of auxiliary feedwater. When auxiliary feedwater to the intact steam generators was throttled, the resultant RCS pressure increase caused the break flow rate to increase. The flow rate followed the RCS pressure trend during the cooldown of the RCS; however, the magnitudes of changes in the break flow rate due to changes in RCS pressure were partially offset by the increased break fluid density. Following the initiation of the RCS depressurization, the break flow again fell sharply. The break flow rate momentarily increased when a slug of cool ECCS fluid entered the steam generator outlet plenum. The cooler ECCS fluid entered the outlet plenum when the flow in the ruptured loop briefly reversed during the depressurization (recall that a higher density fluid results in a higher break flow rate).

When the RCS was depressurized with the pressurizer PORV, the break flow rate fell sharply until the RCS pressure became less than the ruptured steam generator pressure. Due to the lower RCS pressure, the break flow became negative, i.e., the flow direction changed due to backfill from the ruptured steam generator into the RCS. Following the end of the depressurization and the termination of ECCS flow, the break flow rate increased toward a stabilized value of approximately 30 lbm/sec. This relatively high break flow rate was due to the increases in RCS pressure discussed in Section 6.3.2. Additional operator actions, described in Chapter 7, would be required to continue the RCS cooldown or to reduce the RCS pressure to terminate the break flow.

Reference Plant Analysis

Prior to the termination of the ECCS flow, the break flow rate followed the RCS pressure predictions for the Reference Plant. The ruptured steam generator pressure in the Reference Plant analysis was held essentially constant throughout the event, thus only the RCS pressure and the RCS average density affected the break flow rate. Following the termination of ECCS flow, the break flow rate gradually decreased as the RCS and secondary pressures tended to equalize. The pressure equalization was hastened by operator actions taken to initiate a controlled RCS cooldown in accordance with recovery guidelines.

6.3.6 Steam Generator Narrow Range Level Response

CPSES1 Analysis

The transient response of the steam generator narrow range level indication is shown in Figure 6-5. After the SGTR begins, the void fraction in the ruptured steam generator was increased due to flashing of the RCS coolant; hence, there was an increase in the level indication. In addition, the increased steam generator mass, due to the break flow, caused the level to increase before the Steam Generator Water Level Control System could act to maintain the indicated level at its setpoint. The steam generator water level controller acted to maintain the level near the nominal value. Following the reactor and turbine trips and the initiation of auxiliary feedwater, the level fell off sharply as the heat from the primary required for void generation was lost. Because of the extended narrow range span on the Model D-4 steam generators, the level did not fall off-scale following a reactor trip. The level began to rise when the ARVs were opened, but fell again as the reactor heat generation rate fell and the cold auxiliary feedwater collapsed the voids in the steam generator mixture.

Throughout the remainder of the event, there was relatively little voiding in the ruptured steam generator, thus the level increase was primarily due to mass addition into the steam generator through the ruptured tube. Inflection points in the plot of the ruptured steam generator level are due to the isolation of the ruptured steam generator (including auxiliary feedwater isolation) and the opening of the ARV on the ruptured steam generator as the pressure rose following the isolation. The level continued to rise until the RCS was depressurized, at which point, the level stabilized as the RCS was backfilled from the ruptured steam generator. Following the pressure increase, due to the RCS heatup after the termination of the ECCS flow, the level again began to increase. Additional reactor operator recovery actions would be required to initiate a controlled cooldown and take the plant to cold shutdown conditions.

The indicated levels in the intact steam generators remained constant until the time of reactor and turbine trip. As in the ruptured steam generator plot (Figure 6-5), the levels increased as the ARVs were opened allowing increased void formation and then fell as the cold auxiliary feedwater collapsed the voids in the steam generators. Operator actions were modeled to throttle the auxiliary feedwater to maintain the intact steam generator levels to between 10% and 50% span; ergo, the levels were maintained near a value of 45% span. When the RCS cooldown began, the levels in the intact steam generators rose due to the rapid void formation resulting from the sharp pressure reduction. The levels then began to fall as the inventory was depleted, but were prevented from falling much below 45% span by the addition of auxiliary feedwater. There was a sharp drop in the levels when the ARVs were closed, resulting from an increase in the steam generator pressure, a rapid void collapse, and a corresponding reduction in the mixture volume. The levels were maintained near 45% span for the remainder of the event.

Reference Plant Analysis

The trends shown in the plots of narrow range level are similar to those of the CPSES1 analysis. Following the initiation of the event, the level began to decrease in all steam generators. This decrease is believed to be due to the slight increase in RCS temperature and corresponding increase in steam generator pressures discussed in Section 6.3.4. The level in the ruptured steam generator was slightly greater than that in the intact generators.

The level fell offscale following the reactor trip. As expected, because of the increased mass addition, the level returned on-scale in the ruptured steam generator before the intact steam generators. The inflection points identified in the CPSES1 analysis are also noticeable in the plot of the ruptured steam generator level. As will be discussed in Section 6.3.7, no inflection point is observed when the ruptured steam generator pressure rose to the ARV setpoint pressure as in the CPSES1 model.

The plot of the level in the intact steam generator is similar to the corresponding plot from the CPSES1 analysis. Because the narrow range span for the Reference Plant's [ ]^{a,c} steam generator was less than the span for CPSES1, the magnitudes of the level variations were magnified. The effects of initiating a controlled cooldown to again terminate the break flow were seen in the level response near 2200 seconds. This specific operator action to recover from the event was not explicitly modeled in the CPSES1 analysis.

6.3.7 Steam Generator Pressure Response

CPSES1 Analysis, Common Responses

The steam generator pressure response is shown in Figure 6-6. Because they are connected through the main steam header, the pressure responses of the steam generators were approximately the same prior to isolation of the ruptured steam generator. Following the initiation of the SGTR, the pressures in the steam generator decreased slightly due to the corresponding reduction in core power. Because the steam dumps were not modeled, the steam generator pressures rose sharply following turbine trip. The pressure leveled off as the ARVs were opened, then fell following the initiation of auxiliary feedwater flow.

CPSES1 Analysis, Ruptured Steam Generator Response

Following the closure of the MSIV on the ruptured steam generator and the termination of AFW to that steam generator, the ruptured steam generator pressure increased toward the ARV setpoint. Because this pressure increase was driven primarily by the compression of the steam bubble as the steam generator liquid volume was increased due to the break flow, the rate of increase was relatively slow. The pressure was maintained at the ARV set pressure until the RCS cooldown was initiated, at which time, the steam generator pressure very slowly drifted downward. Some of the pressure decrease, caused by the RCS cooldown, was counteracted by the pressure increase caused by the steam compression in the steam dome. During the RCS depressurization, the RCS pressure became less than that in the ruptured steam generator pressure, thus reducing the ruptured steam generator pressure. The pressure reduction was terminated when the pressurizer PORV was closed, ending the RCS depressurization.

Even though the RCS pressure increased following the termination of the ECCS flow, the steam generator pressure decreased at a very slow rate. This pressure decrease was due to the addition of cooler RCS fluid and reverse heat transfer from the steam generator to the cooler RCS fluid. The degree of the pressure decrease was offset somewhat by the compression of the steam bubble caused by the addition of the RCS fluid through the ruptured tube. The ruptured steam generator would be depressurized through the RCS as the reactor operators recovered from the SGTR event.

CPSES1 Analysis, Intact Steam Generator Response

After the AFW to the intact steam generators was throttled, the intact steam generator pressure also increased as the cold auxiliary feedwater in the generators was heated by the hotter RCS fluid. The RCS cooldown, effected by opening the ARVs on the intact steam generators, caused a rapid decrease in the steam generator pressure. As expected, as the steam generator pressure decreased, the rate of change decreased; thus, the temperature reduction was more rapid at the start than toward the end of the cooldown period. Subsequent to the termination of the cooldown, the pressure began to recover, increasing toward the saturation pressure corresponding to the RCS temperature.

Reference Plant Analysis

Prior to the reactor trip, the steam generator pressure increased due to the increase in the RCS temperatures and the injection of hotter RCS fluid into the secondary. Following reactor trip, the pressure in the Reference Plant analysis quickly rose to the setpoint pressure of the ARVs. The differences in the predicted pressure between the CPSES1 analysis and the Reference Plant analysis are attributed to differences in the valve and steam generator models used. In the CPSES1 model, the valve was modeled to modulate open in response to a pressure error signal. The maximum stroke time was used to prevent the valves from "popping" open or closed in an unrealistic manner. In the Reference Plant analysis, however, the amount of inventory required to maintain the volume pressure at the valve setpoint pressure was instantaneously removed from the system (up to the maximum rated flow through the valve). Thus, because the "relief valves" responded instantaneously, the pressure response from the Reference Plant is expected to be smoother than the CPSES1 response when the steam pressure was being maintained at the ARV setpoint. In addition, when the RCS cooldown was initiated, the initial rate of depressurization was expected to be somewhat greater.

The effects of initiating the controlled cooldown near 2200 seconds can be seen in the plot (Figure 6-6) of the intact steam generator pressure. The remaining portions of the pressure plots are similar to those of the CPSES1 analysis.

6.3.8 Ruptured Steam Generator Liquid Volume

CPSES1 Analysis

The collapsed liquid volume (Figure 6-7) was used to determine the margin to overfill of the ruptured steam generator. Due to the action of the Steam Generator Water Level Control System, the liquid volume in the ruptured steam generator remained approximately constant until the reactor and turbine were tripped. At that time, the volume increased sharply until the main feedwater pumps were tripped. The volume fell slightly as some inventory was released through the ARV to maintain pressure. The addition of large amounts of auxiliary feedwater continued to cause the steam generator liquid volume to increase, but at a much slower rate. Following the isolation of auxiliary feedwater to the ruptured steam generator, the rate of volume increase, now a function of the SGTR break flow rate, was again reduced. The volume in the ruptured steam generator fell slightly when the RCS was depressurized to a lower pressure. Following the end of the depressurization and the termination of the ECCS flow, the liquid volume in the ruptured steam generator rose until the recovery actions were taken to initiate the controlled RCS cooldown.

Reference Plant Analysis

The trends displayed in the plot of ruptured steam generator water volume (Figure 6-7) are similar to those predicted by the CPSES1 analysis. Due to the magnitude of both the break flow and the auxiliary feedwater flow of the Reference Plant, the volume increased more rapidly in the Reference Plant analysis than that for the CPSES1 analysis. Notice that the auxiliary feedwater capacity of the Reference Plant [ ][a,c] was roughly the same as the capacity of CPSES1 (four steam generators). The stable water volume following 2200 seconds was due to the controlled cooldown initiated in the recovery phase of the event.

6.4 Summary

The results of the analysis of the "Nominal" postulated steam generator tube rupture event performed using RETRAN02MOD004 and the CPSES1-specific model have been compared with a similar analysis performed for the WOG, SGTR subgroup and approved by the NRC [6]. With the exception of an unexpected increase in the hot leg temperature discussed in Section 6.3.5, all significant differences between the two analyses have been attributed to known modeling differences or to differences between the designs of the Reference Plant and CPSES1. The one unexplained difference does not affect the conclusion that the CPSES1.RETRAN02MOD004 model is well-suited for simulating a postulated SGTR event.

TABLE 6-1

Nominal Base Case -
Assumptions and Plant Differences Between
the Reference Plant and CPSES1

	Reference Plant [a,c]	CPSES1
Initial RCS pressure, psia		2250
Initial pressurizer water volume, ft**3		1080
Steam Generator Tube Inner Diameter, inches		0.664
Pressurizer Pressure for Reactor Trip, psia		1925
Pressurizer Pressure for SI, psia		1844
SG ARV Set Pressure, psia		1140
SIS Pump Delay, sec		22
AFW Delay, sec		60
AFW Flow Rate (total gpm)		2218
AFW Temperature (°F)		120
Decay Heat (1971 ANS Decay Heat Curve)		100%

TABLE 6-2

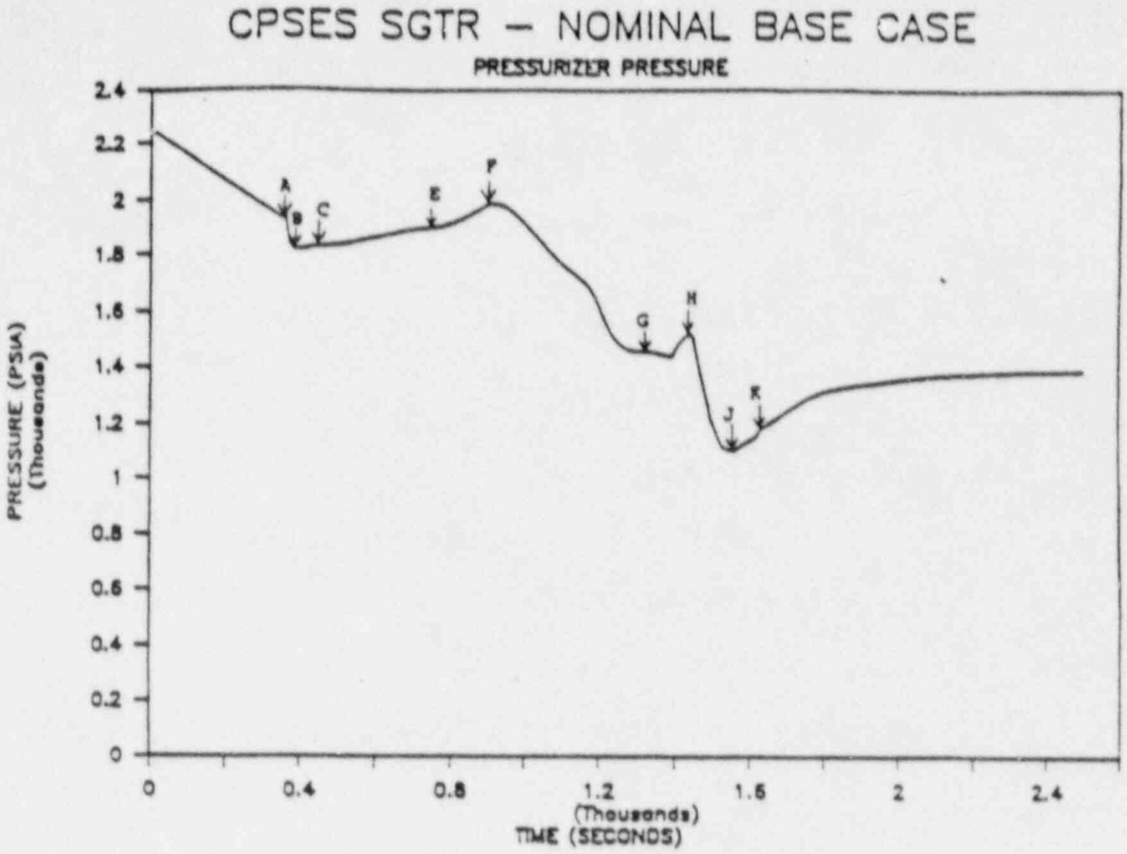
Nominal Base Case -
Sequence of Events

Event	Time (sec) Reference Plant	CPSES1
Tube Failure	0	0
Reactor Trip	259	357
Turbine Trip	259	358
Safety Injection Signal	285	372
Safety Injection	---	394
AFW Actuation	346	432
Isolation of Ruptured SG	[ ]^{a,c}	[ ]^{a,c}
Start Cooldown		901
Pressurizer Emptied		1240
Complete Cooldown		1326
Pressurizer Refilled		1400
Start Depressurization		[ ]^{a,c}
Complete Depressurization		1563
Terminate SI		[ ]^{a,c}

TABLE 6-3

Nominal Base Case -
Key to Figures 6-1 through 6-7

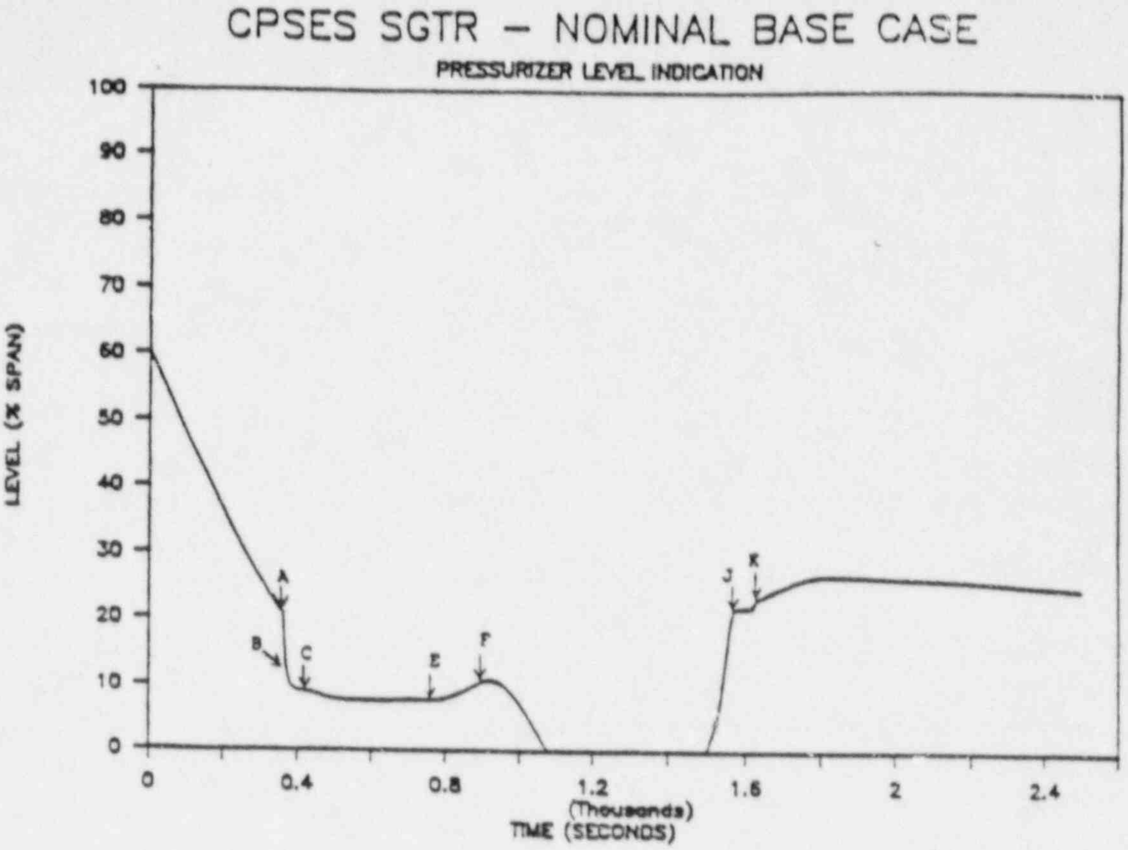
Point	Event
A	Reactor Trip
B	Safety Injection Actuation Signal
C	AFW Actuation
D	Isolation of Ruptured Steam Generator
E	Throttle AFW to Intact Steam Generators
F	Start Cooldown
G	Complete Cooldown
H	Start Depressurization
J	Complete Depressurization
K	Terminate Safety Injection



REFERENCE PLANT

a,c

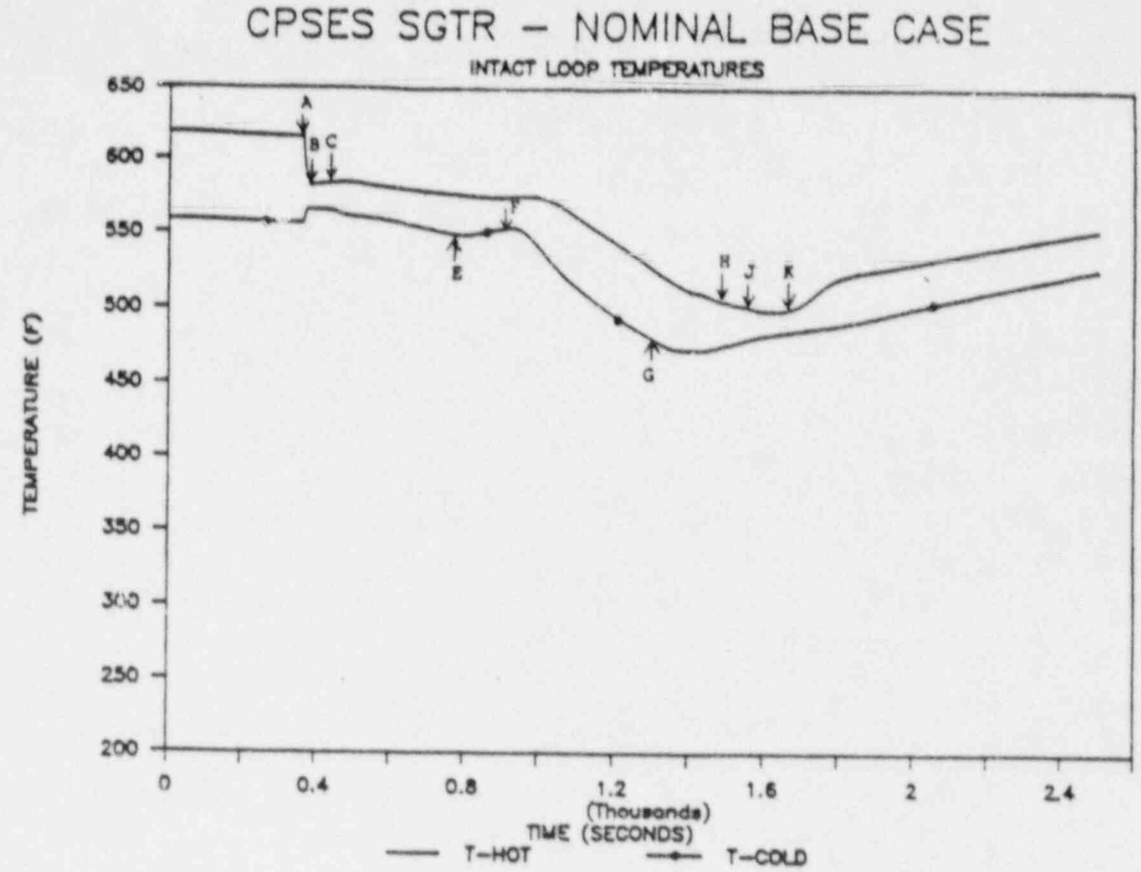
FIGURE 6-1. Nominal Base Case Comparison - Pressurizer Pressure



REFERENCE PLANT

a,c

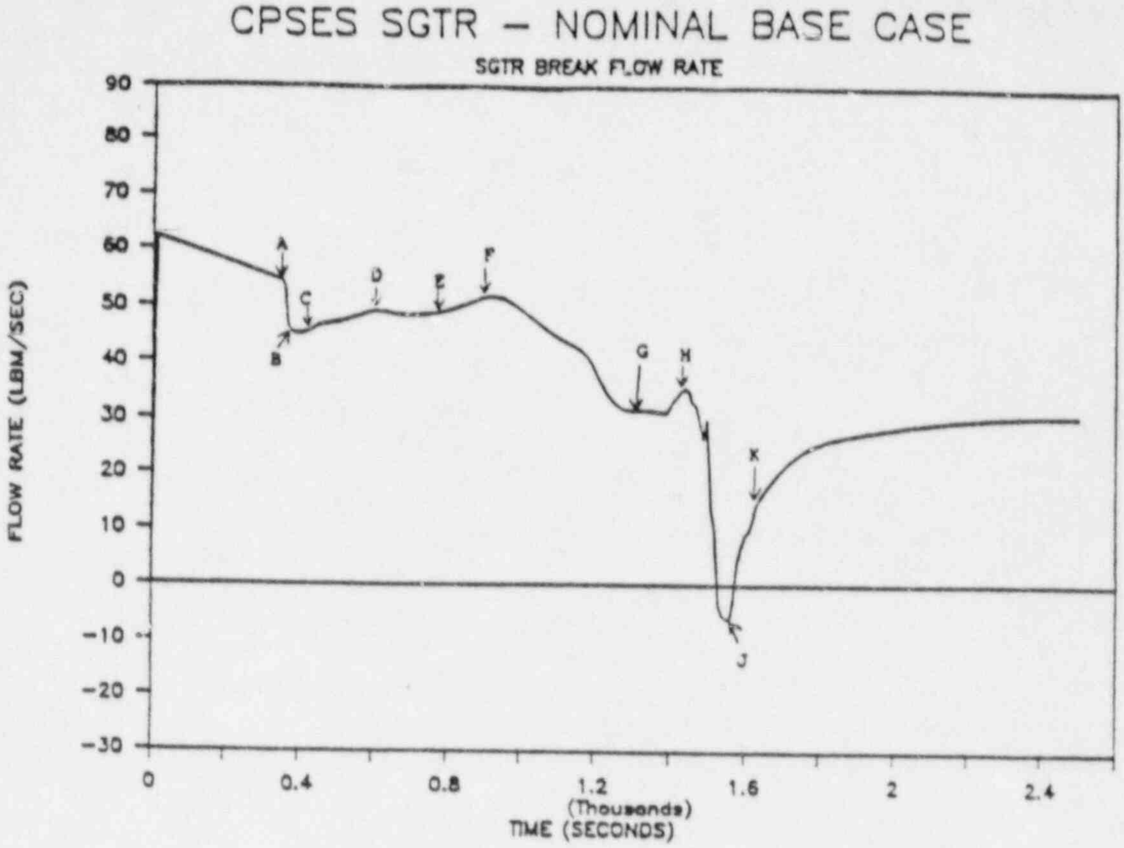
FIGURE 6-2. Nominal Base Case Comparison - Pressurizer Level



REFERENCE PLANT

a,c

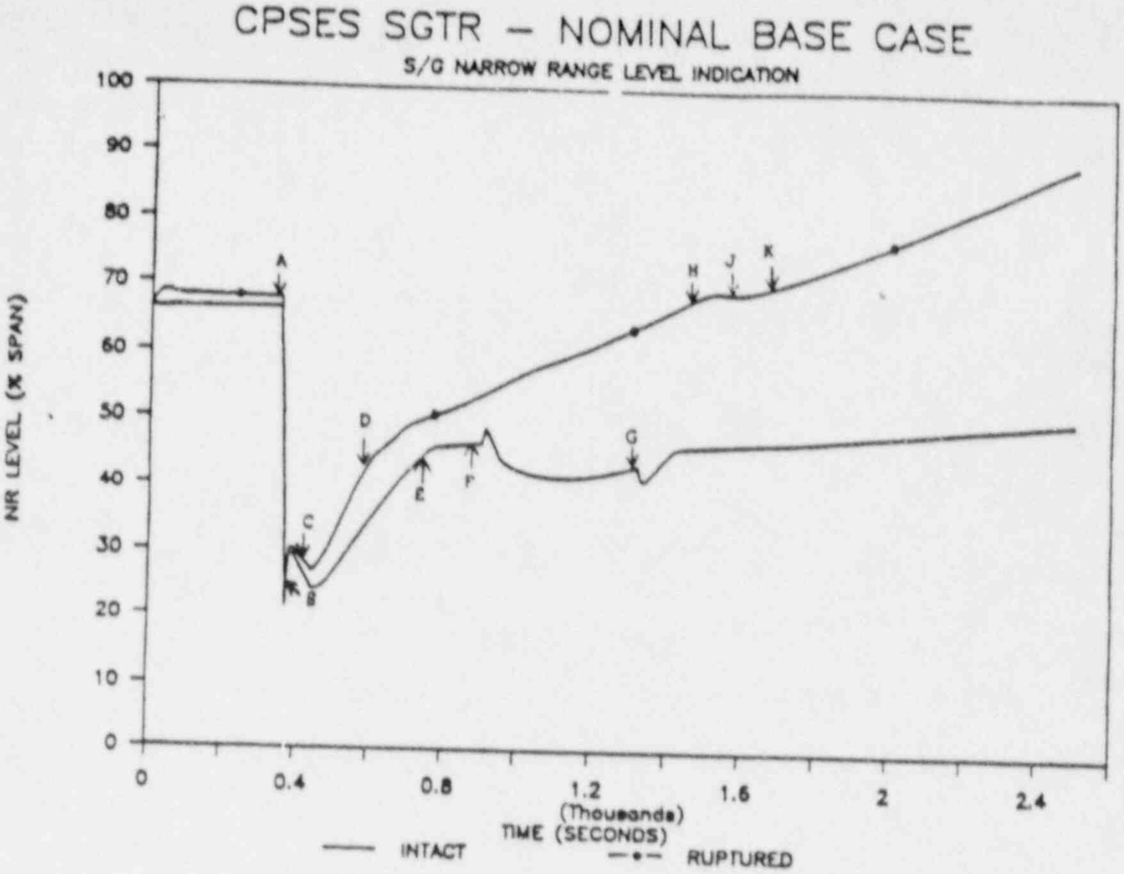
FIGURE 6-3. Nominal Base Case Comparison - Intact Loop Temperature



REFERENCE PLANT

a,c

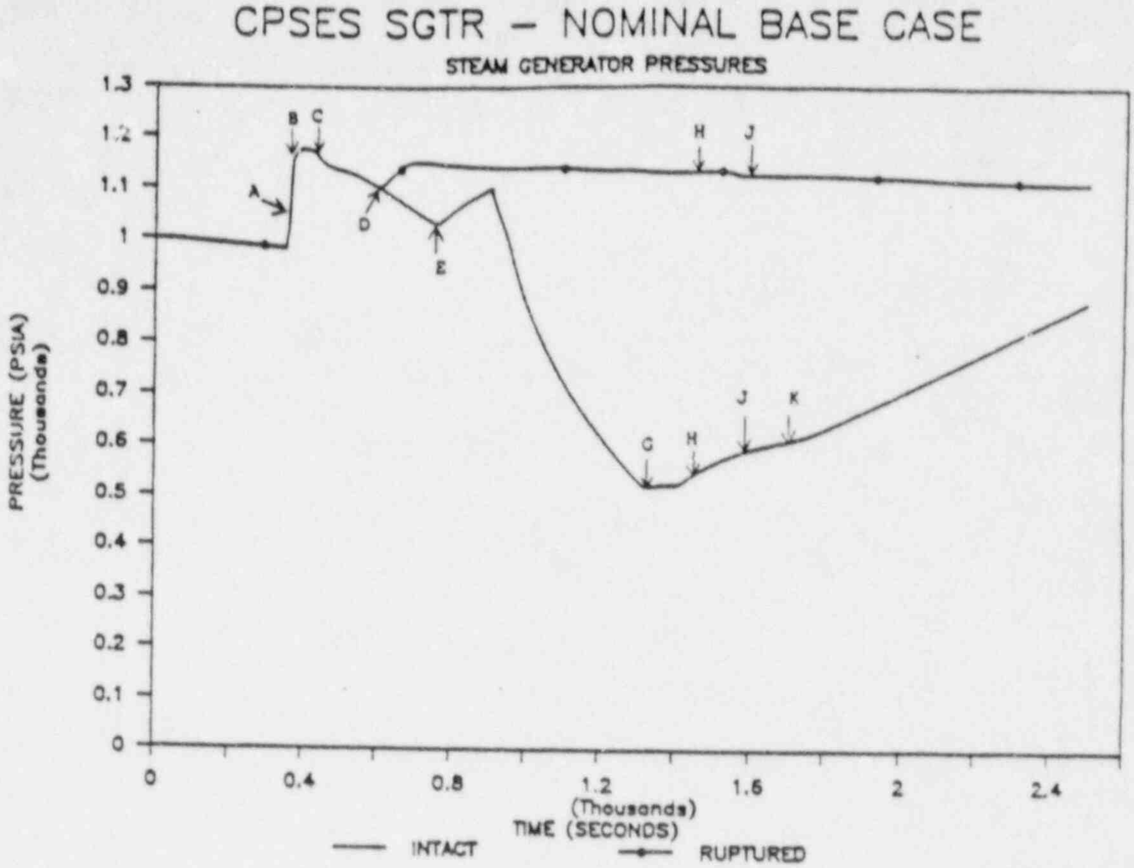
FIGURE 6-4. Nominal Base Case Comparison - SGTR Break Flow Rate



REFERENCE PLANT

a,c

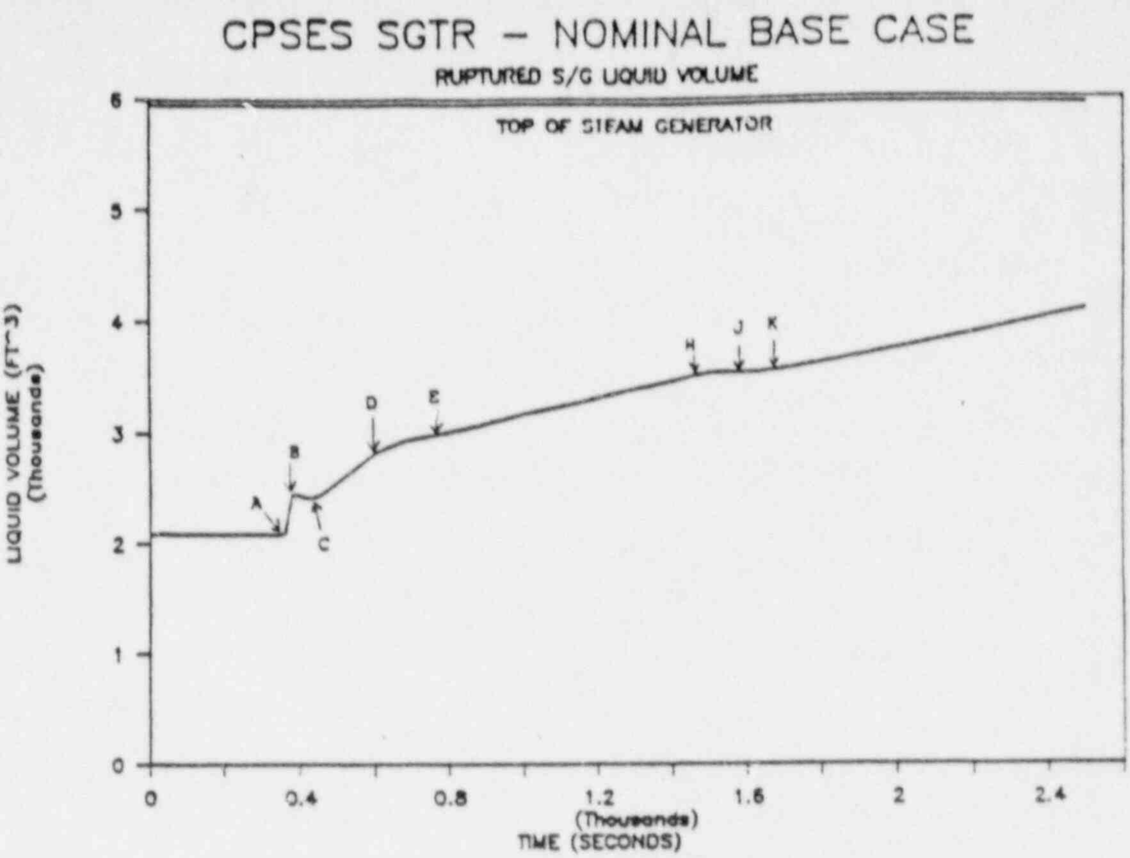
FIGURE 6-5. Nominal Base Case Comparison - Steam Generator Levels



REFERENCE PLANT

[ ] a,c

FIGURE 6-6. Nominal Base Case Comparison - Steam Generator Pressures



REFERENCE PLANT

a,c

FIGURE 6-7. Nominal Base Case Comparison - Rupture S/G Liquid Volume

CHAPTER 7

OPERATOR RESPONSE TIME EVALUATION

The steam generator tube rupture event must be terminated by actions of the reactor operators. The plant-specific analysis required the use of operator response times which were consistent with plant-specific equipment, procedures, and training. In order to determine these response times for CPSES1, a SGTR event using design-basis assumptions regarding equipment availability, but without any active failures, was included as one of the simulator exercises during the Licensed Operators Requalification Training in August and September of 1987.

The scenario used for the simulator exercises included an initial primary-to-secondary leak rate representative of a complete severance of a U-tube. The radiation monitors were assumed to be inoperable. Other failures, designed to simulate the design-basis event, included the failure of all automatic reactor trips and a loss of all offsite power coincident with the manual reactor trip. The turbine and control rods were placed in manual control. In addition, the N-16 related alarms and turbine runback alarms were defeated.

The timing of the first few operator responses following the initiation of the event have the most impact on the final severity of the postulated SGTR. These responses concern the identification and isolation of the ruptured steam generator and the initiation of the cooldown of the RCS. The operator response times for these actions were measured directly from observations of several simulator exercises. The operator response times for the remaining actions were estimated from examination of the CPSES1 procedural guidelines and discussions with CPSES1 reactor operators concerning the difficulty in carrying out these actions.

As discussed in Chapters 4 and 6, the first significant operator action following the postulated SGTR is the isolation of the ruptured steam generator. In accordance with the CPSES1 ERGs, the initial operator responses following the generation of a reactor trip signal are intended to ensure that the control rods had entered the core and that the required safety systems were operating. Subsequent actions are directed toward the diagnosis of the event and then the identification of the ruptured steam generator. Following the isolation of the ruptured steam generator, additional operator actions are required to ensure that the required equipment is available and to prepare to initiate a cooldown of the RCS. The initiation of a maximum rate cooldown is the second significant operator response.

A summary of the response times for these two significant responses, as recorded during the simulator exercises, is provided in Table 7-1. Each exercise used one-half the personnel on a regular control room shift. Use of the "half-shift" was consistent with the minimum number of licensed operators required to be in the control room at any given time. Although ten exercises were executed, only nine were used to determine the plant specific operator response times.

Insufficient data was collected during Run 9 to allow determination of the timing of the operator responses. Also, no confirmatory plots of critical parameters were available for Run 7 due to equipment problems; however, the manually recorded operator response times were included. In addition, that portion of the exercise following the isolation of the ruptured steam generator from the Run 4 exercise was not used. The simulator model of the instrument air reset sequence did not accurately reflect the plant hardware. An action by the simulator instructor in response to directions from the shift supervisor was required to re-establish instrument air; the instructor was occupied elsewhere at the critical time, and the initiation of the RCS cooldown was delayed by several minutes.

As discussed previously, the response of the simulator made the direct measurement of the operator response times following the initiation of the RCS cooldown difficult. Thus, the response times required for the operators to prepare for and to initiate the depressurization of the

RCS were derived from limited observations and discussions with operators. The procedural steps and the ease of performing these steps were considered. The required response time for the termination of the ECCS flow following the end of the RCS depressurization was similarly estimated. Through these discussions and observations, it was determined that a two minute time period was a conservative estimate of the time required to initiate the depressurization of the RCS following the end of the cooldown. Similarly, the time required to terminate the ECCS flow following the end of the RCS depressurization was conservatively estimated as one minute.

For conservatism, the maximum operator response time that was required to identify and isolate the ruptured steam generator was used as the plant-specific identification and isolation time. Similarly, the maximum time between the steam generator isolation and the beginning of the cooldown was used as the plant-specific time for the beginning of the cooldown. These maximum times as well as the estimated times for the initiation of the depressurization of the RCS and the termination of the ECCS flow, are summarized in Table 7-2.

In summary, based on observations of several "half-shifts" of licensed reactor operators responding to a severe Steam Generator Tube Rupture event, the operator action times presented below were determined to be applicable to CPSES1. These response times were based on procedures which have since been updated to clarify guidance for decisions based on the judgement of the Shift Supervisor. More revisions, based on a generic revision of the Westinghouse ERGs, are forthcoming. Because most of the procedural steps which call for operator judgement will be clarified, it is anticipated that these procedural changes will reduce the overall time required for termination of a SGTR event as well as make the response times from different shifts more uniform. Continuous training emphasis on the need to prevent steam generator overfill during a SGTR also will assure appropriate and timely operator responses to a Steam Generator Tube Rupture event.

TABLE 7-1

SGTR Operator Response Times from Simulator Exercises

	DELTA-TIME (minutes) SGTR - SG ISOLATION	DELTA-TIME (minutes) SG ISOLATION - START COOLDOWN
Run 1	10.84	4.66
Run 2	4.20	3.80
Run 3	12.00	3.00
Run 4	8.25	----
Run 5	12.84	1.83
Run 6	10.00	2.84
* Run 7	9.50	3.83
Run 8	7.50	4.75
Run 10	12.75	4.00

* - No confirmatory plots available

TABLE 7-2

Conservative Operator Response Times Assumed
for the CPSES1 Design-Basis SGTR Analyses

SGTR initiation - SG isolation	13.0 minutes
SG isolation - initiation of RCS cooldown	5.0 minutes
Termination of RCS cooldown - Initiation of RCS depressurization	2.0 minutes
Termination of RCS depressurization - Termination of ECCS flow	1.0 minute

CHAPTER 8

EVALUATIONS OF CONSERVATIVE ASSUMPTIONS

Following the creation of the Nominal Base Case, preliminary analyses and evaluations of the SGTR scenario were performed to identify critical parameters and to determine the conservative direction with respect to overfill of the ruptured steam generator for each of these parameters. Conservative assumptions for this set of critical parameters were then incorporated into the Nominal Base Case to create the "Conservative" base model. As stated previously, this Conservative base model is the same as the design-basis models with the exception of the postulated single active failures.

For the least margin to overfill of the ruptured steam generator, it is conservative to maximize the liquid mass in the ruptured steam generator; therefore, the initial conditions and other assumptions are selected to maximize this mass.

8.1 Offsite Power Availability

An evaluation of the effects of the loss of offsite power and of the timing of a postulated loss of offsite power was performed. For the design-basis analysis, it was determined that offsite power should be assumed to be available prior to reactor trip and lost as a result of the turbine trip coincident with reactor trip.

In the unlikely event that offsite power were to be lost coincidently with the initiation of the SGTR, the ensuing reactor trip would cause an immediate decrease in RCS pressure, thus reducing the break flow rate. In addition, no turbine runback would occur; hence, there would be no increase in the steam generator mass prior to reactor trip. Assuming the reactor operators require a constant amount of time to complete the actions outlined in the ERGs, the identification and isolation of the ruptured steam generator and the initiation of the RCS cooldown would occur over a time period shorter than that assumed for the design-basis scenario. This relatively early isolation time would result in essentially the same amount of auxiliary feedwater injection, no increase in mass due to a possible turbine runback, a shorter event duration, and thus, a lower integrated break flow into the ruptured steam generator. Furthermore, there is no credible event which would cause a simultaneous steam generator tube rupture and a loss of offsite power.

The primary effect of assuming no loss of offsite power following reactor trip would be the improved primary-to-secondary heat transfer during the RCS cooldown due to the continued operation of the reactor coolant pumps. Assuming offsite power was available after reactor trip, the pressurizer pressure decrease would be mitigated by the pressurizer heaters, thus delaying the initiation of ECCS flow and auxiliary feedwater. Delaying the initiation of these systems would be non-conservative with respect to overfill. However, the pressure, and therefore, the break flow rate would be maintained at a slightly higher value until the heaters shut off on low pressurizer level. Even though the RCPs (and pressurizer heaters) would be adding heat to the system, the improved heat transfer due to the higher flow rate would allow a very rapid cooldown to be performed. The net result would be a quicker termination of the break flow, resulting in a greater margin to overfill.

In addition, if offsite power were available, the preferred equipment for cooling and depressurizing the RCS would also be available. Thus, the operator response times would be slightly less.

8.2 Timing of the Reactor Trip

Many of the conservative assumptions are concerned with the timing of the reactor trip and its effect on the ruptured steam generator mass. The level in the ruptured steam generator would not significantly increase significantly prior to reactor trip due to the action of the main feedwater controller. Following reactor trip, the auxiliary feedwater, which does not have any steam generator level control system, would be initiated, and the steam generator level would rise unchecked by any automatic control.

The auxiliary feedwater to the ruptured steam generator would be isolated by the first credited operator response which would occur at a fixed time following the initiation of the event. Therefore, it is conservative for the auxiliary feedwater to be initiated earlier, resulting in more auxiliary feedwater injected into the ruptured steam generator prior to steam generator isolation.

In addition, for the evaluation of the operator response times, the CPSES1 plant simulator was configured to maximize the time of reactor trip after the SGTR was initiated; however, the initial operator response time was measured from the time of SGTR initiation. Thus, the initial operator response time represents a minimum time between reactor trip and steam generator isolation. However, in the SGTR analyses, the initial operator response time was assumed to occur at a fixed time following the initiation of the tube rupture. In general, because of the auxiliary feedwater flow, maximizing the time between the reactor trip and the initial operator response is conservative. Therefore, it is conservative for the other analysis assumptions to result in an early reactor trip, thus maximizing the time between reactor trip and steam generator isolation.

8.3 Initial Thermal-Hydraulic Conditions

8.3.1 Power

Due to an increased void fraction in the steam generators, a higher core power would result in a lower steam generator mass. Because the conservative assumption should result in a higher steam generator mass, a "lower" core power should be used. A competing effect is the fact that the decay heat would be greater if the reactor was tripped from a higher power. A higher decay heat would result in a higher RCS pressure (and thus greater break flow), as well as an extended cooldown period.

Both of the effects of a change in the initial power were accounted for in the model. The initial steam generator mass was increased to bound the cases where a lower reactor power would result (e.g., due to a turbine runback), and 100% full power was used to maximize the decay heat following the reactor trip. As an additional conservatism, a 20% uncertainty was added to the decay heat (discussed in Chapter 7); thus, no additional penalties on the core power were included in the model, and nominal full power (3411 MWt) was used.

Zero Power Considerations

As indicated above, a lower reactor power would result in a greater steam generator mass. Thus, the limiting case, zero power, must also be considered. Assuming the plant was at hot zero power conditions, auxiliary feedwater (under manual control) would be used to maintain the steam generator levels.

Following the reactor trip alarm, most of the immediate operator actions would not be applicable because the plant would already be tripped. Because the steam generator level would be controlled manually, the increase in level resulting from a tube rupture would be noticed relatively quickly and compensated by the throttling of the auxiliary feedwater to that steam generator. Thus, the time required for identification and isolation of a ruptured steam generator would be greatly reduced from that required at power. At hot zero power, the steam generator would be maintained at a higher pressure than at full power, thus the initial break flow would be less. In addition, the detrimental effects of a postulated turbine runback would not have to be factored into the analysis. Furthermore, at hot zero power, the average RCS temperature would be significantly less, resulting in a reduced time requirement for the RCS cooldown.

The pressurizer level would be lower at zero power; thus, the pressurizer would empty sooner. However, because the initial steam volume would be larger and the RCS shrinkage following the reactor trip would not be as severe as for the full power case, the rate of depressurization would be slower, thus delaying the initiation of ECCS flow. Because the ECCS flow would cause the RCS pressure to increase, delaying the initiation of the ECCS flow would result in a lower break flow rate.

As will be discussed in Section 8.3.7, the initial steam generator mass for the full power case was increased to the mass corresponding to approximately 40% power. In addition, the initial conditions used in the RCS and core corresponded to 100% power. This combination of conditions resulted in a greater potential for overfilling the ruptured steam generator than an analysis initiated at zero power with consistent initial conditions, event sequences, and operator response times.

8.3.2 RCS Pressure

A reduced initial pressurizer pressure would result in an earlier reactor trip (on low pressurizer pressure), thereby causing the auxiliary feedwater to be initiated at an earlier time. For accident analysis, the error band on the initial pressurizer pressure is ± 30 psi. Considering this uncertainty, the initial pressurizer pressure was assumed to be 2220 psia.

8.3.3 Initial RCS Temperature

In order to maximize the integral break flow, the primary-to-secondary pressure differential and the cold leg (steam generator outlet plenum) fluid density should be large, and the pressure differential should be maintained at a high value for as long as possible. With respect to the RCS temperatures, the break flow rate is maximized by a low T-cold in conjunction with a high T-avg. The low T-cold increases the fluid density while the high T-avg prolongs the cooldown period.

Assuming the reactor power and RCS flow rate are constant, an increase in T-cold must be accompanied by a corresponding increase in T-avg. Thus, changing the initial RCS temperature (typically changed $\pm$ 5.5°F) would result in competing effects on the margin to overfill. Lower RCS temperatures would result in a higher break flow rate, but would shorten the time required for cooldown of the RCS. Conversely, higher RCS temperatures would result in a lower break flow rate, but would lengthen the time required for the cooldown of the RCS. Because the difference in density for a 5.5°F temperature difference is relatively small, and the break flow rate is proportional to the square root of the density, the effect of the density on the break flow rate is relatively small. However, because the proposed change in RCS temperature is a relatively large fraction of the total temperature difference during cooldown (~70°F), the higher T-avg has a much greater effect on the margin to overfill than a reduced T-cold.

The nominal cold leg temperature was used for conservatism with respect to the fluid density. The cooldown time was prolonged by cooling to a temperature at least 5°F less than required by the ERGs to conservatively account for the RCS average temperature uncertainties. Further conservatism was achieved because the cooldown rate at the end of the cooldown period is less than that at the start of the cooldown period, thus prolonging the cooldown period. The smaller cooldown rate was due to a lower steam generator pressure, and thus, a reduced steam flow rate from the intact steam generators.

8.3.4 RCS Flow Rate

As discussed above, the RCS average temperature should be maximized in order to prolong the required time for the RCS cooldown. This temperature increase was effected through the use of the thermal design flow rate rather than the best-estimate RCS loop flow rate. Use of the thermal design flow rate resulted in a higher RCS average temperature for a given cold leg temperature.

8.3.5 Steam Generator Pressure

The nominal steam generator pressure corresponding to the nominal cold leg temperature was used in order to maintain thermal-hydraulic consistency within the model.

8.3.6 Steam Generator Mass

An increase in steam generator mass would result in a decrease in the margin to overfill of the ruptured steam generator. Thus, the initial mass was increased to account for any mass additions to the system which were not explicitly modeled. The most significant mass additions are due to the postulated turbine runback, either manually or initiated by the Overtemperature N-16 (OTN-16) control system, and to an early OTN-16 reactor trip.

From the Nominal Base Case SGTR simulation (Chapter 6), it may be seen that an automatic turbine runback would be initiated at approximately 138 seconds due to the approach of the OTN-16 signal to within 3% of the OTN-16 setpoint. Assuming that the turbine runback prevented the reactor from tripping on the OTN-16 system, the reactor would trip on low pressurizer pressure at 357 seconds. This time difference corresponds to 219 seconds of turbine runback. At CPSES1, the turbine would be runback at an average rate of 10%/minute. Using the average runback rate, the turbine (and reactor) power at the time of reactor trip would be transitioning toward 63% of nominal. It was also assumed that the level was maintained in the ruptured steam generator as the power was reduced, thus causing an increase in the steam generator mass.

The turbine runback, with automatic rod control action, was designed to prevent a reactor trip on OTN-16; therefore, with a depressurization rate similar to a SGTR event and automatic rod control action to reduce reactor power and maintain the appropriate average temperature, the OTN-16 reactor trip setpoint would not be reached, and the reactor would not trip on OTN-16 prior to the low pressurizer pressure trip.

Assuming no turbine runback occurs, the reactor would be tripped on OTN-16 (at 233 seconds for the Nominal Base Case). Using conservative assumptions discussed elsewhere, auxiliary feedwater would be initiated immediately. Thus, the additional auxiliary feedwater injected in the ruptured steam generator due to an early OTN-16 reactor trip must be included in the initial steam generator mass.

For conservatism, the additions to the ruptured steam generator initial mass due to both the potential early reactor trip scenario and the turbine runback case were used. Therefore, the initial mass was increased over the nominal full power mass. If turbine runback were to occur, the steam generator mass would be 10,500 lbm greater than nominal at the time of reactor trip calculated for the Nominal Case. If no turbine runback were to occur, and the reactor were to trip on OTN-16, the steam generator mass would be 12,000 lbm greater than nominal at the time of the reactor trip calculated for the Nominal Case. To conservatively bound both postulated scenarios, a total of 22,500 lbm was added to the nominal initial steam generator mass. Note that increasing the initial steam generator mass by 22,500 lbm results in an initial steam generator mass corresponding to a steady-state power of approximately 40%.

An early, manual reactor trip would not result in a more severe event with respect to the margin to overfill. Due to a lack of information (alarms, etc.), the reactor operators would certainly not trip the reactor prior to the OTN-16 turbine reactor trip signal. The initial steam generator mass has conservatively been increased to bound postulated scenarios which result in an early reactor trip and the associated increase in integrated auxiliary feedwater flow.

8.4 Protection System Setpoints and Delay Times

8.4.1 Reactor Trip Delay

Because the time for the initial operator action following the start of the SGTR was fixed through the simulator exercises, the earlier the reactor is tripped, the greater the integrated auxiliary feedwater flow into the ruptured steam generator. Therefore, no delay time was used between the time the trip signal was generated and the time the rods began to fall into the core.

8.4.2 Turbine Trip Delay

Since continued steam flow would decrease the steam generator mass and cool the RCS, the turbine is assumed to trip simultaneously with the reactor, with no time delay.

8.4.3 Steam Generator Atmospheric Relief Valve Operability

The break flow would be maximized if the ruptured steam generator pressure is minimized. A minimum steam generator pressure would be attained if the steam generator ARV were used to maintain pressure in the ruptured steam generator rather than the safety relief valves. The minimum pressure would result in a greater primary-to-secondary pressure differential, and hence, a greater break flow rate. Therefore, the ARV on the ruptured steam generator was used to control the steam generator pressure rather than the main steam safety valves.

In order to maximize the RCS temperature and pressure, the ARVs were not used to control the pressure in the intact steam generators. The intact ARVs were used to "cooldown" the RCS later in the transient.

8.4.4 Low Pressurizer Pressure for Reactor Trip

As noted above, the earlier the reactor trips, the less the margin to overfill. The nominal setpoint for a reactor trip on low pressurizer pressure is 1910 psig. The uncertainties associated with the pressure measurement are 4.5% of the 800 psi span. For conservatism, an additional 1% of span was used to determine the low pressurizer pressure setpoint to be used in the SGTR analyses. Thus, a maximum setpoint pressure of 1969 psia was used.

8.4.5 Reactor Trip on Overtemperature N-16

As discussed in Section 8.3.6, the effects of an early reactor trip on Overtemperature N-16 were bounded by the increase in initial steam generator mass. Therefore, the reactor trip on OTN-16 was not modeled.

8.4.6 Low Pressurizer Pressure for ECCS Actuation

An earlier actuation of the ECCS would result in the least depressurization of the primary, and hence, the greatest break flow rate. The nominal setpoint for generation of a SIAS on Low Pressurizer Pressure is 1829 psig, or 1844 psia. Because no adverse containment conditions were anticipated during the SGTR event, the total uncertainties used for the low pressurizer pressure reactor trip setpoint were used for the low pressurizer pressure SIAS setpoint. Therefore, the low pressurizer pressure setpoint for generation of an SIAS on low pressurizer pressure was 1888 psia.

8.4.7 Main Feedwater Isolation

Main feedwater flow would be lost following the loss of offsite power due to a variety of reasons. The feedwater regulating valves are air-operated and fail closed when the control solenoids are de-energized. Following the loss of offsite power, the feedwater regulating valves would fail closed when the control solenoids were de-energized. In addition, the valves would drift closed as the instrument air pressure decayed following the loss of offsite power. During normal operation, the main feedwater pumps draw steam from the moisture separator-reheater (MSR), which in turn draws steam from the high pressure turbines. After the turbine stop valves close following reactor trip, there would be no steam supply to the MSR, and thus, the main feedwater pumps would begin to coast down.

Furthermore, there is a check valve located downstream of the feedpumps, and upstream of the feedwater isolation valve; thus, as soon as the feedwater pump discharge pressure fell below the pressure of the steam generator (anticipated to occur very quickly, on the order of a few seconds), the check valve would prevent fluid from flowing out of the steam generator. Thus, the main feedwater flow would effectively be isolated from the ruptured steam generator.

To conservatively model the loss of main feedwater, the main feedwater flow rate was assumed to be ramped down to zero flow linearly over a five second period, beginning five seconds following the loss of offsite power.

8.4.8 Auxiliary Feedwater System Initiation Delay

In order to maximize the ruptured steam generator mass, the motor-driven and turbine-driven auxiliary feedwater pumps were assumed to deliver fluid to the steam generators simultaneously with the loss of offsite power. The time required to start and load the diesel generators was conservatively neglected.

8.4.9 Safety Injection Initiation Delay

In order to maximize the RCS pressure, the centrifugal charging pumps were assumed to start immediately following the generation of a SIAS. The time required to start and load the diesel generators was neglected.

8.5 System Capacities

8.5.1 ECCS Flow Rates

The ECCS flow rates were conservatively based on the design pump output plus 10% and included best-estimate frictional loss, elevation heads, etc.

8.5.2 Auxiliary Feedwater Flow Rates

The turbine-driven and motor-driven auxiliary feedwater pumps were automatically started following the loss-of-offsite-power. The auxiliary feedwater flow rates from these pumps to the steam generators were maximized, based on design pump characteristics and the most conservative control valve configuration. Because the reactor operators would throttle the auxiliary feedwater flow into the intact steam generators to maintain level, the flow rate into these steam generators is not especially critical, as long as sufficient flow was available to cool the primary and not enough flow was added to initiate an overcooling event. The ERGs require that the narrow range level be maintained between 10% and 50%. In addition, the flow to the intact steam generators would be manually throttled during much of the SGTR analysis.

The flow rate to the ruptured steam generator, on the other hand, is more crucial. For the conservative model, in which there are no single active failures, the auxiliary feedwater flow to the ruptured steam generator was essentially the same as that to the intact steam generators prior to the isolation of the ruptured steam generator.

8.6 Control Systems

8.6.1 Pressurizer Pressure and Level Control

Use of the pressurizer heaters prior to reactor trip would delay the reactor trip on low pressurizer pressure. Therefore, the pressurizer heaters were not modeled. The sprays would not be used during a depressurization event. Therefore, the pressure control system was not used in the conservative model.

The operation of the level control system prior to reactor trip would increase the time until the reactor would trip on low pressure. These systems would not be available after the loss of offsite power and initiation of the SIAS (Phase A Isolation). Because an delay in the time to reactor trip is non-conservative, the pressurizer level control system is not modeled.

8.6.2 Steam Generator Water Level Control

The steam generator water level control system was assumed to be in the automatic mode. The assumption of automatic feedwater control prior to reactor trip is conservative because a constant steam generator level until the time of reactor trip would increase the time required for identification of the ruptured steam generator. If the feedwater controller were in manual, the steam generator water level would be under close observation, particularly during transient conditions (such as a sharp decrease in pressurizer pressure and level). The effect on the steam generator mass prior to reactor trip would be slight; however, the ruptured steam generator would be identified early in the transient, conceivably prior to reactor trip.

8.6.3 Turbine Runback/Automatic Rod Control

Because of the depressurization of the RCS, the Overtemperature N-16 control systems would act to reduce the setpoint of the Overtemperature N-16 reactor trip. A turbine runback would be automatically initiated when the setpoint neared the N-16 power. In addition, the automatic rod control would reduce reactor power (and consequently, the N-16 power signal) to maintain the appropriate average temperature. If offsite power were available, the steam dumps could open to further reduce the average RCS temperature. The feedwater control system would adjust the main feedwater flow rate to maintain a constant steam generator level. The net result would be that the mass in the steam generator at the time of reactor trip would be increased. Therefore, the assumption that turbine runback occurs is conservative with respect to the margin to overfill.

The turbine runback, and ensuing reactor power reduction, have a negligible effect on the primary parameters used to maximize break flow. The pressure in the RCS could vary somewhat due to the reduced steam flow followed by actuation of the automatic rod control to maintain RCS average temperature; however, the magnitude of the fluctuations would be relatively small. The decrease in RCS average temperature due to the lower core power would have only a marginal effect on the break flow rate and the cooldown time. No other significant effects were anticipated.

A turbine runback was not explicitly simulated in the SGTR analysis; however, the effects of the turbine runback were conservatively accounted for as described in the previous discussions concerning the initial steam generator mass (Section 8.3.7).

8.7 Decay Heat

Since continued heat addition from the core retards the depressurization of the RCS, the inclusion of a 1.20 multiplier on the 1971 ANS decay heat curves is conservative.

8.8 Summary

Evaluations of those parameters other than active equipment failures have been performed in order to determine conservative values of the parameters for the postulated SGTR event. The conservative values will be used in the evaluations of the postulated active failures (Chapter 9) and in the design-basis analyses described in Chapters 10 and 11.

TABLE 8-1

Summary of Conservative Assumptions

Critical Parameter	Design-Basis Assumption
Offsite Power	Lost on Reactor Trip
Initial Power	100% RTP
Initial RCS Pressure	2220 psia
Initial Pressurizer Water Level	70% span
Initial Cold Leg Temperature	Nominal
RCS Flow Rate	Thermal Design
Initial Steam Generator Pressure	Nominal
Initial Steam Generator Mass	+ 22,500 lbm
Reactor Trip Delay	None
Turbine Trip Delay	None
Steam Generator Atmospheric Relief Valve	Ruptured Loop Only
Low Pressurizer Pressure for Reactor Trip	1969 psia
Reactor Trip On OTN-16	Bounded
Low Pressurizer Pressure for ECCS Actuation	1888 psia
Main Feedwater Isolation	On Reactor Trip
Auxiliary Feedwater System Initiation Delay	None
Safety Injection Initiation Delay	None
ECCS Flow Rates	Maximum
Auxiliary Feedwater Flow Rates	Maximum
Pressurizer Pressure and Level Control	None
Steam Generator Water Level Control	Prior to Rx Trip
Turbine Runback	Bounded
Decay Heat	120% 1971 ANS

CHAPTER 9

REQUIRED EQUIPMENT AND ACTIVE FAILURE EVALUATIONS

The following discussions concern the equipment and instrumentation which has been identified as being required for the successful termination of a postulated design-basis steam generator tube rupture. Because this equipment is required for termination of the tube rupture event, the effects of the postulated failure of this equipment must be considered. In the discussions that follow, the required equipment is described, followed by a evaluation of the effects of an active failure of that component or system. In general, the required equipment (components and systems) is required to control the auxiliary feedwater flow, isolate the ruptured steam generator, and cool and depressurize the RCS. The postulated failures of these components were evaluated to determine the effect on the margin to overfill of the ruptured steam generator, the effect on the radiological dose consequences, and the effect on the operator response times described in Chapter 8.

As described in Chapter 4, the SGTR scenario includes a reactor trip, turbine trip, and safety injection actuation. A loss of offsite power is assumed to occur simultaneously with the turbine trip. Automatic signals to start all of the auxiliary feedwater pumps and the safety injection pumps will occur following the station blackout signal due to the loss of offsite power. By design, these trip and actuation systems are fully safety-grade systems and single failure proof; thus, no single active failure will prevent the reactor and turbine from tripping, nor the auxiliary feedwater and safety injection actuation signals from being generated.

9.1 Auxiliary Feedwater Throttling Valve

The throttling valves between the turbine-driven auxiliary feedwater pump and the steam generator are locked fully open; thus, a fully open failure of any of these valves is of no consequence. The throttling valves between a motor-driven auxiliary feedwater pump and its associated steam generators are normally at some position less than fully open. In addition, these valves automatically throttle to maintain a set discharge pressure from the motor-driven auxiliary feedwater pumps. If one valve were to fail fully open, the other would throttle closed to maintain the discharge pressure, thus further increasing the amount of auxiliary feedwater flow through the fully open valve. The maximum flow is obtained when the throttling (control) valve to the ruptured steam generator from the motor-driven pump fails fully open. In addition, based on the proximity of the isolation valve controls and the auxiliary feedwater pump controls to the throttling valve control and the valve position indication, it has been conservatively estimated that two minutes are required to identify that the throttling valve has not closed and to close the isolation valve or to stop the appropriate auxiliary feedwater pump.

The failure of this throttling valve results in a reduction in the margin to overfill of the ruptured steam generator. An analysis was performed to quantify the effect on the margin to overfill of the ruptured steam generator for this active failure. This failure has only a negligible effect on the radiological consequences of a postulated tube rupture.

9.2 Main Feedwater Isolation Valve

During normal power operation, the steam supply to the main feedwater pump turbines comes from the moisture separator-reheater, which obtains its steam supply from the main turbines. Assuming that the turbine trips following reactor trip, the steam supply for the main feedwater pump turbines would be lost and the feedwater pumps would quickly begin to coastdown. As soon as the main feedwater pumps begin to coastdown, the discharge pressure of the pumps falls below the pressure of the steam generator; thus, significant quantities of main feedwater will not enter the steam generators following the reactor and turbine trips.

In addition, the feedwater regulating valve is a fail-closed, air-operated valve. This non-safety grade valve will close due to de-energizing of the control circuit due to a loss of offsite power. Following the loss of instrument air, this valve will drift closed. This valve will also close on low T-avg coincident with reactor trip.

Therefore, the postulated failure to close of the feedwater isolation valve following the generation of a SIAS has no significant effect on the tube rupture event.

9.3 Miscellaneous Secondary Steam Isolation Valves

The blowdown isolation valves and the process sampling valves are protected by redundant valves. The main steam drippot isolation valves, and some process sampling valves are downstream of the MSIVs. The drippot isolation valves are not qualified as active valves and no credit is taken for their proper operation. The turbine-driven auxiliary feedwater pump steam admission valves are qualified as active valves. The steam flow rate through any of these valves is bounded by the steam flow rate through a stuck open ARV and would not have any significant impact on the operator response times assumed in the SGTR analyses.

9.4 Steam Generator Safety Valves

Analysis indicates that these valves do not open during a steam generator tube rupture event; thus failure of the code safety valves is not a concern.

9.5 Steam Generator Atmospheric Relief Valves (ARVs)

The steam generator ARVs are used for two distinct purposes in the termination of the SGTR event - 1) Isolation of the ruptured steam generator, and 2) cooldown of the RCS.

It was assumed that all ARV block valves are open at the time of the event in accordance with CPSES1 administrative controls. The ARVs are classified as active valves and may be manually operated from the control room. The ARVs are air-operated valves and are equipped with air accumulators should offsite power be lost. The block valves are not currently classified as active and are only operable locally with a handwheel.

For Case 1), the ARV on the ruptured steam generator is postulated to fail open, thus maximizing the amount of radioactive steam released to the atmosphere. The block valves for the ARVs have manual operators which must be operated locally. Due to the postulated environment in the room where the block valves are located, it cannot be assured that these valves would be closed should an ARV fail to close. Thus, the failure of an ARV to close would result in the complete blowdown of that steam generator. A significant number of operator responses is required to terminate the primary-to-secondary break flow; thus, the recovery from this event scenario will require a considerable period of time. Based on the amount of radioactive steam released, this failure would result in a significant increase in the severity of the radiological consequences. Due to the long times required for termination of the event, it may be postulated that this failure could adversely affect the margin to overfill as well.

For Case 2), an ARV on an intact steam generator was assumed to fail to open. This fault will prolong the time required to cool the RCS, thus decreasing the margin to overfill. An analysis was performed to quantify the effect on the margin to overfill of the ruptured steam generator for this active failure.

9.6 Main Steam Isolation Valves

The failure of a main steam isolation valve (MSIV) on an intact loop to close does not pose any problems, because the valves are not required to close to terminate the event. On the other hand, the failure of the MSIV on the ruptured loop to close will make termination of event more difficult. Downstream of the MSIVs and upstream of the turbine stop valves are a number of relatively small branch steam lines with non-nuclear safety-related isolation valves. Most of the isolation valves fail open following the loss of instrument air, thus providing a relatively large steam flow path from the ruptured steam generator. The steam flow path allows the ruptured steam generator to depressurize in an uncontrolled manner. However, because the total steam leakage is less than the flow rate through a steam generator ARV, this potential failure is bounded by the failure of a steam generator ARV.

9.7 Pressurizer Power-Operated Relief Valve (PORV)

One pressurizer PORV is required to depressurize the primary to terminate the SGTR break flow. Should the PORV fail to close, the PORV block valve may be closed to terminate the primary depressurization with little impact on the operator response time. In addition, since only one PORV (and open block valve) is required for depressurization, the failure of one PORV (or block valve) has no effect on the margin to overfill or on the offsite dose. Also, these is only a negligible effect on the operator response times.

The pressurizer PORVs and block valves are active valves and may be operated manually from the control room in the event of a loss of offsite power. In addition, the PORVs are equipped with nitrogen accumulators to provide a motive force should offsite power not be available.

9.8 Pressurizer Safety Valve

These valves never open during the postulated SGTR event.

9.9 ECCS Pump Stop Switches

After the RCS has been depressurized to terminate the SGTR break flow, timely operator action is required to stop the ECCS pumps in order to prevent the break flow from restarting. To stop the ECCS pumps, the operator normally turns the appropriate pump stop switch to "OFF". Should this fail to stop the pumps, the switch may be overridden by the "Pull-to-Lock" feature to manually stop the ECCS pumps. A negligible amount of additional time is required to terminate ECCS flow should the pump stop switches fail.

9.10 SI Reset Device

This device resets all components and systems "initiated" by the SIAS. Because the operators manually reset those components and systems required for termination of the SGTR event, no significant effects or time delays are anticipated.

9.11 Electrical Failures

A loss of offsite power is assumed to occur coincidently with the reactor trip. If one of the diesel generators were to fail to start, one train of ESF were unavailable, and the total ECCS flow rate would be significantly reduced. The reduced ECCS flow rate would allow the RCS to depressurize to a lower equilibrium pressure where ECCS matches break flow and result in a lower break flow rate.

9.12 Instrumentation Failures

Sufficient redundancy (number of channels) exists such that the single failure of an instrument channel has a negligible effect on the recovery from a postulated tube rupture event.

9.13 Summary

9.13.1 Margin to Overfill

Using the CPSES1-SGTR model described in Chapter 5 and the conservative assumptions identified in Chapter 8, analyses were performed to quantify the effect on the margin to overfill of two of the postulated single active failures. The failure of the throttling valve between a motor-driven auxiliary feedwater pump and the ruptured steam generator was determined to have a greater impact on the margin to overfill than the postulated failure to open of an ARV on an intact steam generator. Therefore, the fully open failure of the auxiliary feedwater throttling valve was the worst, single active failure with respect to overfill of the ruptured steam generator.

9.13.2 Radiological Consequences

The failure of the ARV on the ruptured steam generator to close resulted in the most steam released directly to the atmosphere from the ruptured steam generator; thus, this failure was the worst, single active failure with respect to the offsite radiological dose.

CHAPTER 10

DESIGN-BASIS SGTR EVENT
FOR THE WORST CASE FOR STEAM GENERATOR OVERFILL

As discussed in Chapter 9, it was determined that the failure of the throttling valve between the motor-driven auxiliary feedwater pump and the ruptured steam generator would result in the least margin to overfill of the ruptured steam generator at the time of event termination. The Nominal Base Case discussed in Chapter 5 was modified to include the conservative assumptions discussed in Chapter 8 and the worst single active failure identified in Chapter 9 to develop the overfill design-basis model. A complete description of the SGTR analysis inputs and the results using the overfill design-basis model is provided in this chapter.

A description of the effects of the single active failure on the operator actions and response times discussed in Chapter 7 is found in Section 10.1. Section 10.2 contains a description of the modifications to the conservative base model required to incorporate the single active failure. The analysis results are described in the remaining sections.

10.1 Operator Actions and Response Times

The failure resulting in the fully open throttling valve between the motor-driven auxiliary feedwater pump and the ruptured steam generator would most likely not be noticed until the reactor operator was directed by the Emergency Response Guidelines (ERGs) to throttle the auxiliary feedwater to the ruptured steam generator in order to maintain the level to between 10% and 50% of the narrow range span. If the level exceeded 50% span, the operators would completely close the throttling valve, thus effectively terminating the auxiliary feedwater flow to the ruptured steam generator. It was assumed in the design-basis analysis that the operator would notice that the throttling valve had failed fully open when, in accordance with the ERGs, he was directed to throttle auxiliary feedwater to the ruptured steam generator. In addition, it was conservatively assumed that the operator would require two minutes to realize what had happened and to terminate auxiliary feedwater to the ruptured steam generator. To terminate auxiliary feedwater to the ruptured steam generator, the operators could close the appropriate isolation valve, or should those valves also fail, the operators could stop the motor-driven auxiliary feedwater pump. The controls for these actions are all grouped together on the same control panel, such that the time required to terminate auxiliary feedwater to the ruptured steam generator is minimal.

The ERGs direct the reactor operators to first isolate steam flow from the ruptured steam generator and then control/isolate the auxiliary feedwater to the ruptured steam generator. Therefore, it was assumed that the MSIV on the ruptured steam generator was closed at the same time as in the conservative base model, i.e., at thirteen minutes. In addition, no credit was taken for the operator action to raise the setpoint pressure of the ARV on the ruptured steam generator. By neglecting this action, the ruptured steam generator was maintained at a lower value, thus increasing the primary-to-secondary break flow rate. Two additional minutes were assumed to allow time for the operator to close the appropriate auxiliary feedwater isolation valve; hence, the auxiliary feedwater was assumed to be isolated at fifteen minutes following the start of the SGTR event. As in the conservative base model, five minutes were allowed between the time the ruptured steam generator was isolated and the start of the RCS cooldown. Therefore, the RCS cooldown was assumed to start twenty minutes following the start of the SGTR.

Two minutes following the termination of the RCS cooldown, the RCS was depressurized using one pressurizer PORV. One minute after the RCS depressurization had been completed, the ECCS pumps were stopped and placed in standby, marking the end of the event.

Post-Event Operator Responses

Immediately following the termination of the event, the RCS pressure would increase slowly due to the addition of decay heat and the lack of any active heat removal process (no steam relief from intact steam generators); hence, the break flow rate would tend to be re-established. Therefore, additional procedural guidance has been provided to the reactor operators to prevent the flow of a significant amount of RCS fluid into the ruptured steam generator. Following the termination of the ECCS flow, the reactor operators would continuously maintain equal pressures in the RCS and in the ruptured steam generator using the auxiliary spray, if letdown had been re-established by this time, or the pressurizer PORV. Following the initiation of a controlled cooldown to bring the plant to cold shutdown conditions, the RCS pressure would be lower than the ruptured steam generator pressure, thus again backfilling the RCS with the ruptured steam generator fluid. This process would be continued as the plant was cooled to cold shutdown conditions, thus preventing the liquid volume in the ruptured steam generator from increasing significantly at any time during the post-Steam Generator Tube Rupture event recovery.

10.2 Auxiliary Feedwater Flow Rates

In order to maximize the amount of auxiliary feedwater injected into the ruptured steam generator, an analysis was performed using the auxiliary feedwater valve arrangement which results in the maximum auxiliary feedwater flow rate to the ruptured steam generator. For this valve arrangement, the throttling valves from the turbine-driven auxiliary feedwater pump to the steam generators were fully open. The throttling valve from the motor-driven auxiliary feedwater pump to the ruptured steam generator was assumed to fail fully open. The throttling valve to the other steam generator which is served by the motor-driven auxiliary feedwater pump, partially closed automatically in order to prevent pump runout. The auxiliary feedwater flow rates were thus calculated to be a total of 1337 gpm at a back pressure of

1200 psia to the intact steam generator and 614 gpm at a back pressure of 1200 psia to the ruptured steam generator. The auxiliary feedwater model was pressure-dependent; hence, as the steam generator pressures decrease, the auxiliary feedwater flow rates increase and vice versa.

10.3 Results

Using the auxiliary feedwater flow rates and operator response times discussed above, a simulation of the postulated tube rupture event was performed using the RETRAN02 code. A sequence of events timeline is provided in Table 10-1. Time-dependent plots of the critical parameters are shown in Figures 10-1 through 10-10. A key to the symbols used in the figures is provided as Table 10-2. Detailed discussions of the plotted parameters are provided below.

10.3.1 General Description

As may be observed in Figures 10-1 through 10-10, following initiation of the SGTR, the RCS pressure and level decreased linearly until the low pressurizer pressure reactor trip setpoint was reached 5.4 minutes later. Turbine trip, loss of offsite power, and the initiation of auxiliary feedwater flow all occurred simultaneously with the reactor trip. The main feedwater flow was isolated 10.0 seconds later (5.0 second delay with a 5.0 second closure time). The SIAS setpoint on low pressurizer pressure was exceeded 1.9 minutes after the reactor trip. Following the turbine trip, the steam generator pressures rose rapidly, and the ruptured steam generator ARV opened to relieve the pressure. After auxiliary feedwater flow was initiated, the steam generator pressure was determined by the amount of cold auxiliary feedwater flow entering the steam generators.

Following the isolation of steam flow from the ruptured steam generator at 13.0 minutes, the pressure in the intact steam generators rose somewhat due to the loss of the steam relief path, although the magnitude of the increase was small due to the depressurization caused by the cold auxiliary feedwater. The pressure in the ruptured steam generator continued to fall until the auxiliary feedwater flow to the ruptured steam generator was isolated at 15.1 minutes. The pressure then rose to and was controlled at the set pressure of the ARV. The RCS pressure began to rise as the ECCS flow initially matched and then exceeded the break flow. This pressure increase was terminated when the RCS cooldown began at 20.1 minutes. The cooldown was initiated by opening the ARVs on the intact steam generators and was terminated when a RCS subcooling margin of at least 15°F at the ruptured steam generator pressure was obtained. Two minutes later, the RCS was depressurized by opening the pressurizer PORV. In accordance with the ERGs, the depressurization was terminated when:

1) the RCS pressure was lower than the ruptured steam generator pressure, and the pressurizer level was greater than 20% span; or,

2) when the subcooling margin was less than 15°F; or,

3) when the pressurizer level was greater than 78% span.

For this analysis, the reduced RCS pressure criterion was modeled to be satisfied when the RCS pressure was 100 psi less than the ruptured steam generator pressure. Because the ruptured steam generator pressure began to decrease when the RCS pressure was less the steam generator pressure, this 100 psi pressure difference was not attained, and the depressurization was terminated on high pressurizer level. One minute later, the ECCS pumps were secured, marking the termination of the event. The analysis was extended, with no additional operator responses modeled, until 46.7 minutes.

10.3.2 RCS (Pressurizer) Pressure

As shown in Figure 10-1, the RCS pressure decreased linearly with time until the low pressurizer pressure reactor trip setpoint was exceeded. The turbine was assumed to trip simultaneously with the reactor; however, since the turbine stop valves closed faster than the control rods fell into the reactor core, there was a brief spike in the pressure prior to the sharp drop-off following reactor trip.

Following reactor trip, the pressure briefly leveled off and even increased as the cold leg, and therefore, the hot leg temperatures, increase following the turbine trip and loss of main feedwater. The pressure then resumed its decrease as the break flow drained the RCS until the SIAS setpoint on low pressurizer pressure was reached. The pressure stabilized as the ECCS was initiated and then began to rise after the ruptured steam generator was isolated, and the ECCS flow rate adjusted to match the break flow rate. The pressure fell rapidly during the initial portions of the cooldown due to the RCS inventory shrinkage, but stabilized when the cooldown rate decreased as the steam generators depressurized. After the cooldown was terminated, the pressure again increased because the ECCS flow rate was greater than the break flow rate. When the PORV was opened, the pressure fell sharply until the RCS pressure became less than the ruptured steam generator pressure. Until the PORV was closed, the pressure continued to decrease, but at a much slower rate. This change was caused by the backfill and depressurization of the ruptured steam generator through the RCS. The small pressure increase following the end of depressurization was again caused by the ECCS flow into the RCS.

Because the volumetric expansion of the RCS due to deposition of decay heat compensated for the RCS mass lost through the break, the pressure was relatively stable following the termination of the ECCS flow. The pressure would remain at a slightly higher pressure than the ruptured steam generator until operator actions were taken to reduce the pressures in both systems.

10.3.3 Pressurizer Level

As shown in Figure 10-2, the pressurizer level decreased linearly with time following the initiation of the SGTR. At the time of reactor trip, the level fell sharply, began to recover from the drop until the heat removed by the secondary exceeded the heat addition in the primary and then continued to decrease as the break flow continued. After the initiation of the ECCS flow, the level stabilized, and then, following the isolation of the ruptured steam generator, began to rise as the ECCS flow rate exceeded the break flow rate. The level fell due to shrinkage during the RCS cooldown and went off-scale (low) toward the end of the cooldown period. When the pressurizer PORV was opened, the level rose very rapidly due in part to the "swell" effect caused by the depressurization; however, a more important cause was the sharp rise in ECCS flow as the RCS was depressurized. After the RCS depressurization was terminated, the level briefly stabilized. After the ECCS flow was terminated, the level fell again, but at a significantly slower rate. The level would stabilize as the break flow was terminated and could rise slightly due to the deposition of decay heat into the RCS fluid from the reactor core.

10.3.4 Reactor Power Response

Prior to reactor trip, the core power decreased slightly as the RCS pressure decreased. The power reduction was due to the moderator density coefficient, which introduced negative reactivity into the core as the RCS became slightly less dense. Subsequent to reactor trip, the reactor power was 120% of the 1971 ANS decay heat curve and was essentially unaffected by the SGTR transient. Boron injected though the ECCS prevented the core from becoming critical as the RCS was cooled.

10.3.5 Steam Generator Pressure Response

Common Responses

As shown in Figure 10-3, the pressure responses of the steam generators were approximately the same prior to isolation of the ruptured steam generator. This effect is due to the fact that the steam generators are connected through the pressure-equalizing, main steam header.

Following the initiation of the tube rupture, the pressures in the steam generators decreased slightly due to the corresponding reduction in core power. The pressure increased sharply following the turbine trip; however, due to the opening of the ARV and the immediate injection of large amounts of cold auxiliary feedwater flow into the steam generators (Figure 10-7), the steam generator pressure did not reach the actuation pressure of any of the main steam safety valves. Primarily because of the cold auxiliary feedwater flow, the steam generator pressure decreased until the MSIV on the ruptured steam generator was closed. After the ruptured steam generator was isolated from the intact steam generators, the pressure responses of the steam generators diverged.

Ruptured Steam Generator Response

Following the termination of auxiliary feedwater to the ruptured steam generator, the ruptured steam generator pressure increased toward the ARV setpoint. Because this pressure increase was driven primarily by the compression of the steam bubble as the steam generator liquid volume was increased due to the break flow, the rate of increase was relatively slow. The pressure was maintained at the ARV set pressure until the RCS cooldown was initiated, at which time, the steam generator pressure very slowly drifted downward. Some of the pressure decrease due to the RCS cooldown was counteracted by the pressure increase caused by the steam compression in the steam dome. During the RCS depressurization, the RCS pressure became lower than the ruptured steam generator pressure, thus reducing the ruptured steam generator pressure. The pressure reduction was terminated when the pressurizer PORV was closed, ending the RCS depressurization. At that time, the steam generator pressure stabilized at the RCS pressure. The ruptured steam generator would be depressurized through the RCS as the reactor operators recover from the postulated tube rupture event.

Intact Steam Generator Response

After the auxiliary feedwater to the intact steam generators was throttled, the intact steam generator pressure stabilized. The RCS cooldown, effected by opening the ARVs on the intact steam generators, caused a rapid decrease in the steam generator pressure. As expected, as the pressure decreased, the rate of change decreased; thus, the temperature reduction was more rapid at the start than toward the end of the cooldown period. Subsequent to the termination of the cooldown, the pressure began to recover, increasing toward the saturation pressure corresponding to the RCS temperature throughout the remainder of the event.

10.3.6 Break Flow Rate

As shown in Figure 10-5, following the initiation of the event, the break flow decreased as the RCS pressure decreased. After the reactor and turbine were trips and the ensuing RCS pressure decrease and steam generator pressure increase, the break flow rate dropped sharply. As the ECCS flow rate caused an increase in the RCS pressure and the cold auxiliary feedwater flow caused a decrease in the steam generator pressure, the break flow rate gradually increased. The RCS cooldown and resultant depressurization then caused the break flow rate to decrease; however, the magnitude of the decrease was reduced due to the increase in the density of the break fluid.

When the RCS was depressurized with the pressurizer PORV, the break flow rate fell sharply until the RCS pressure became less than the ruptured steam generator pressure (Figure 10-6). Due to the lower RCS pressure, the break flow became negative, i.e., the flow direction changed as the ruptured steam generator backfilled into the RCS. Note that at this time, the flow rate in the RCS loop with the ruptured steam generator was essentially stagnant, with occasional periods of forward or reverse flow. During the periods of reverse flow, the fluid in the steam generator outlet plenum contained a high percentage of cold ECCS fluid, thus the density was relatively high, causing erratic changes in the SGTR break flow rate. Following the end of the depressurization and the termination of the ECCS flow, the break flow rate increased toward a stable flow rate of approximately 7 lbm/sec.

This positive flow was due to the slightly higher RCS pressure (primarily due to decay heat).

Operator actions in accordance with recovery procedures would be required to continue the RCS cooldown to prevent the break flow from becoming re-established.

10.3.7 Auxiliary Feedwater Flow Rates

The time-dependent auxiliary feedwater flow rates are shown in Figure 10-7. Prior to isolation or throttling of the auxiliary feedwater, the flow rates increased as the respective steam generator pressures decreased, and vice versa. Because auxiliary feedwater was assumed to start instantaneously following reactor trip, the initial flow rate was high due to the relatively low steam generator pressure. However, because the turbine trip occurred simultaneously with the initiation of auxiliary feedwater, the duration of the high flow rate was very short as the steam generator pressure rapidly increased. The flow rate decreased and then began to increase again as the pressures in the steam generators fell due to the opening of the ARV on the ruptured steam generator and the cooling effect of the auxiliary feedwater.

The auxiliary feedwater to the intact steam generators was throttled beginning at 13.0 minutes. Thereafter, the flow rates were manually controlled to maintain a level of approximately 35% of span.

As described above, no operator responses to control auxiliary feedwater to the ruptured steam generator were credited until two additional minutes had elapsed. Thus, the auxiliary feedwater to the ruptured steam generator continued unthrottled until 15.08 minutes following the initiation of the tube rupture.

10.3.8 RCS Temperatures

The temperature responses at the core exit and in the RCS cold legs following the postulated steam generator tube rupture event are shown in Figure 10-8.

The core exit temperature is a function of the average core flow rate, the average core inlet temperature, and the power generation rate in the core. Note that due to the higher flow rates and greater number of intact loops, the impact of the ruptured loop on the average core inlet temperature is significantly less than that of the intact loops.

Core Exit Temperature

Following the start of the SGTR event, the core exit temperature decreased slightly due to the reduction in core power caused by the positive moderator density coefficient. Because the turbine trip was conservatively assumed to occur simultaneously with the reactor trip, the temperature briefly spiked prior to the insertion of a significant amount of negative reactivity into the core from the reactor trip. Following reactor trip, the core exit temperature fell as the power generation rate was sharply reduced, but began to rise again as the core flow rate dropped after offsite power was lost and the core inlet temperature increased following the loss of main feedwater. This increase was reversed after the injection of cold ECCS fluid, which reduced the core inlet temperature somewhat. The core exit temperature then began to drift slowly downward as the natural circulation flow was established. The temperature increased slightly following the isolation of auxiliary feedwater to the ruptured steam generator.

As ruptured loop flow rate decreased and eventually reversed, the temperature difference between the hot and cold legs increased due to the lower core flow rate. Following the termination of the ECCS flow, the core exit temperature rose fairly rapidly as the core inlet temperature increased. Once natural circulation flow conditions were restored, the core exit temperatures tracked the cold leg temperatures.

Cold Leg Temperatures

Following the start of the tube rupture event, the cold leg temperatures decreased slightly as the hot leg temperatures decreased due to the reduced core power. After the reactor trip, turbine trip, loss of main feedwater and coolant pump coastdown, the cold leg temperatures increased. The injection of auxiliary feedwater and the opening of the ARV stopped the cold leg temperature increase. Following the initiation of the ECCS flow, the cold leg temperatures decreased as the cold ECCS fluid mixed with the warmer RCS fluid. Because the RCS flow rates were small, the ECCS flow had a more pronounced effect on cold leg temperatures than if the RCPs were operating. The cold leg temperature in the ruptured loop diverged from those in the intact loops after the auxiliary feedwater to the intact steam generators was throttled.

Following the complete isolation of the ruptured steam generator, the cold leg temperatures of the intact loops were stable due to the stable pressure in the intact steam generators. The cold leg temperature in the ruptured loop fell as the pressure in the ruptured steam generator continued to decrease due to the blowdown through the open ARV. The temperature then increased following the termination of auxiliary feedwater to that steam generator. After the RCS cooldown was initiated, the cold leg temperature in the intact loop fell as expected. The temperature rose again following the end of the cooldown as the steam generator pressure increased. Following the termination of the ECCS flow and hence the loss of relatively large amounts of cold ECCS fluid, the calculated cold leg temperatures rose sharply toward the saturation temperature of their respective steam generators. The temperature then began to rise slowly as the decay heat from the core was added to the RCS.

Following the termination of auxiliary feedwater to the ruptured steam generator, the cold leg temperature of the ruptured loop rose as the ruptured steam generator pressure increased toward the setpoint pressure of the ARV. After the RCS cooldown began, the flow rate in the ruptured loop fell. As the loop flow rate fell, the relative contribution of the ECCS fluid to the average cold leg temperature increased, thus the ruptured loop cold leg temperature continued to decrease as the loop flow rate decreased.

Near the end of the RCS cooldown, reverse flow was established in the ruptured loop. Due to the influx of a greater amount of RCS fluid relative to ECCS fluid, the cold leg temperature began to rise; however, this increase was again reversed when the RCS cooldown was terminated and the flow rate into the ruptured loop again approached zero. During the depressurization, the cold leg temperature increased or dropped in accordance with the relative amount of RCS flow in the ruptured loop. Following the termination of the ECCS flow, the cold leg temperature increased toward the cold leg temperature of the intact loops.

10.3.10 RCS Loop Flow Rates

As shown in Figure 10-9, the loss of offsite power causes the RCS flow rates to decrease toward flow rates consistent with natural circulation conditions. After the MSIV on the ruptured steam generator was closed and auxiliary feedwater to the intact steam generators was throttled, the flow rate in the intact loop stabilized at approximately 5% of full flow. The flow rates in the ruptured loop remained higher than those in the intact loops due to the continued addition of auxiliary feedwater. Following the termination of auxiliary feedwater to the the ruptured steam generator, the ruptured loop flow rate decreased slightly to a stable value. This flow was held constant by the small steam relief through the ARV on the ruptured steam generator. The flow rate in the intact loops was maintained by the addition of auxiliary feedwater to the intact steam generators.

Following the initiation of the RCS cooldown, the flow rate in the intact loop increased slightly as the natural circulation driving head was increased due to the increased steaming in the intact steam generators.

Because of the asymmetric cooldown, the flow rate in the ruptured loops fell toward zero and eventually reversed direction. This flow reversal was stopped following the end of the RCS cooldown. The RCS depressurization resulted in a slight disruption of the natural circulation flow due to the effects on the driving pressure head, which included voiding in the U-tubes of the ruptured steam generator. The RCS depressurization also caused several erratic changes in the flow direction of the ruptured loop flow. The direction changes corresponded to the backfill of saturated fluid from the ruptured steam generator. Because this fluid was warmer than the RCS fluid, the RCS fluid density decreased, resulting in the formation of voids which collected in the U-tubes. The formation of the voids changed the pressure distributions and the loop flow rate. The new flow rate allowed colder ECCS fluid into the steam generator outlet plenum, which lowered the pressure, and increased the break flow rate. This cycle was then repeated.

Following the termination of the ECCS flow, natural circulation flow continued in the intact loops, with a small reverse flow rate in the ruptured loop.

10.3.10 Ruptured Steam Generator Liquid Volume

The collapsed liquid volume (Figure 10-10) was used to determine the margin to overfill of the ruptured steam generator. Due to the action of the Steam Generator Water Level Control System, the liquid volume in the ruptured steam generator remained approximately constant until the reactor and turbine were tripped. At that time, the volume increased sharply until main feedwater was lost. The addition of large amounts of auxiliary feedwater continued the volume increase, but at a much slower rate. Following the isolation of the auxiliary feedwater to the ruptured steam generator, the rate of volume increase was again reduced and became a function of the break flow rate. A slight perturbation in the level increase was caused when the ARV opened slightly beginning at 14 minutes and continued to relieve small amounts of steam for approximately 10 minutes.

The volume in the ruptured steam generator decreased briefly when the RCS was depressurized to a lower pressure. Following the end of the depressurization and the termination of the ECCS flow, the liquid volume in the ruptured steam generator stabilized and the event was terminated.

The analysis was stopped after the ECCS flow was terminated. The additional operator responses, discussed in Chapter 7, ensure that the liquid volume would not have increased significantly, and would in fact decrease as the plant was brought to cold shutdown conditions.

10.3.12 Available Margin to Overfill

The total steam generator volume is 5954 ft^3. The maximun liquid volume in the rupture steam generator was 5634 ft^3, resulting in a margin to overfill of 320 ft^3.

10.4 Summary

The postulated design-basis steam generator tube rupture event was analyzed using conservative operator response times, a conservative set of initial conditions, conservative assumptions concerning equipment availability, and the single active failure which resulted in the least margin to overfill of the ruptured steam generator.

Despite the consideration of all of these conservative assumptions, the analysis results indicate that approximately 320 ft^3 of steam space is available prior to the overfill of the ruptured steam generator.

TABLE 10-1

Design-Basis SGTR - Steam Generator Overfill
Event Timeline

Time		Event
5.00	sec.	Begin SGTR
5.05	min.	Reactor trip on low pressurizer pressure, turbine trip, AFW initiation, loss of offsite power
5.13	min.	Begin Main FW isolation
6.96	min.	Low pressurizer pressure - SIAS
13.08	min.	Operator Action - Close MSIV, Loop 4 Throttle AFW, Loop 1
15.08	min.	Isolate AFW, Loop 4
20.08	min.	Begin Maximum rate RCS cooldown
31.38	min.	End Maximum rate RCS cooldown
33.38	min.	Begin RCS depressurization to refill pressurizer
36.67	min.	End RCS depressurization to refill pressurizer
37.67	min.	Terminate ECCS flow
40.00	min.	End transient simulation

TABLE 10-2

Design-Basis SGTR - Steam Generator Overfill
Key to Figures 10-1 through 10-10

Point	Event
A	Reactor trip on low pressurizer pressure, turbine trip, AFW initiation, loss of offsite power
B	Low pressurizer pressure - SIAS
C	Operator Action - Close MSIV, Loop 4, Throttle AFW, Loop 1
D	Isolate AFW, Loop 4
E	Begin maximum rate RCS cooldown
F	End maximum rate RCS cooldown
G	Begin RCS depressurization to refill pressurizer
H	End RCS depressurization to refill pressurizer
J	Terminate ECCS flow
K	End transient simulation

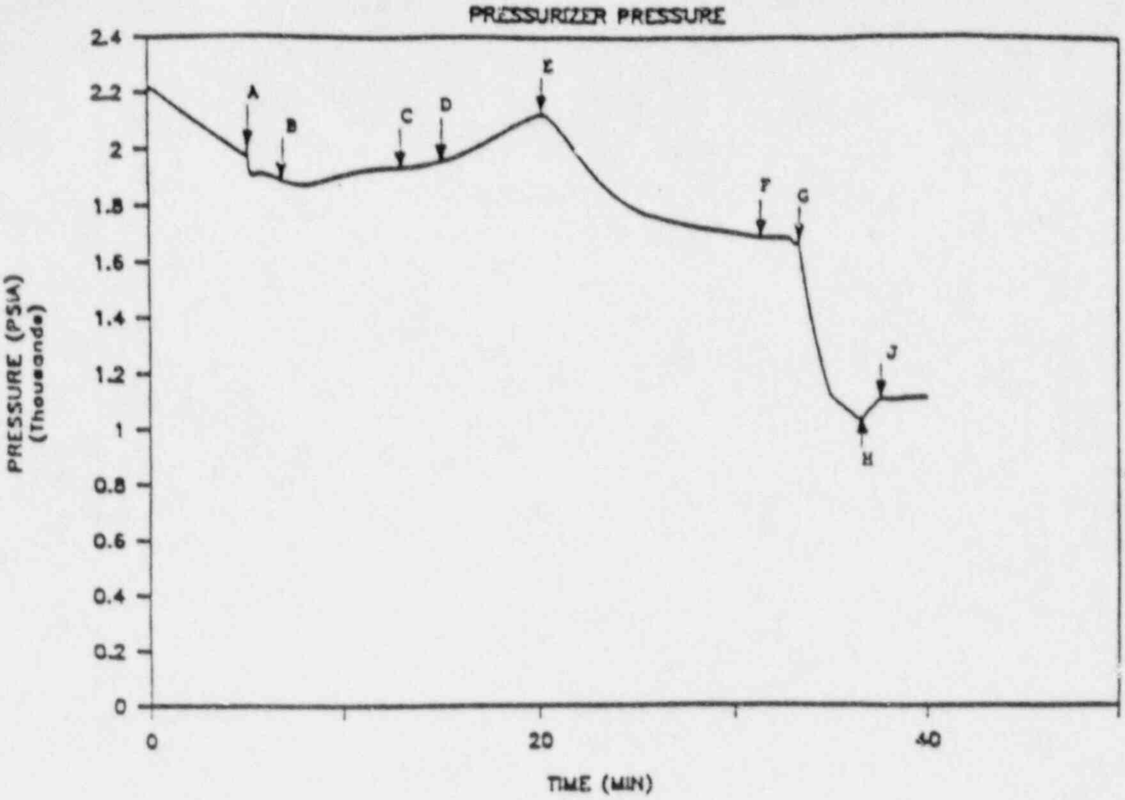


FIGURE 10-1. CPSES1 Design-Basis SGTR, Overfill - Pressurizer Pressure

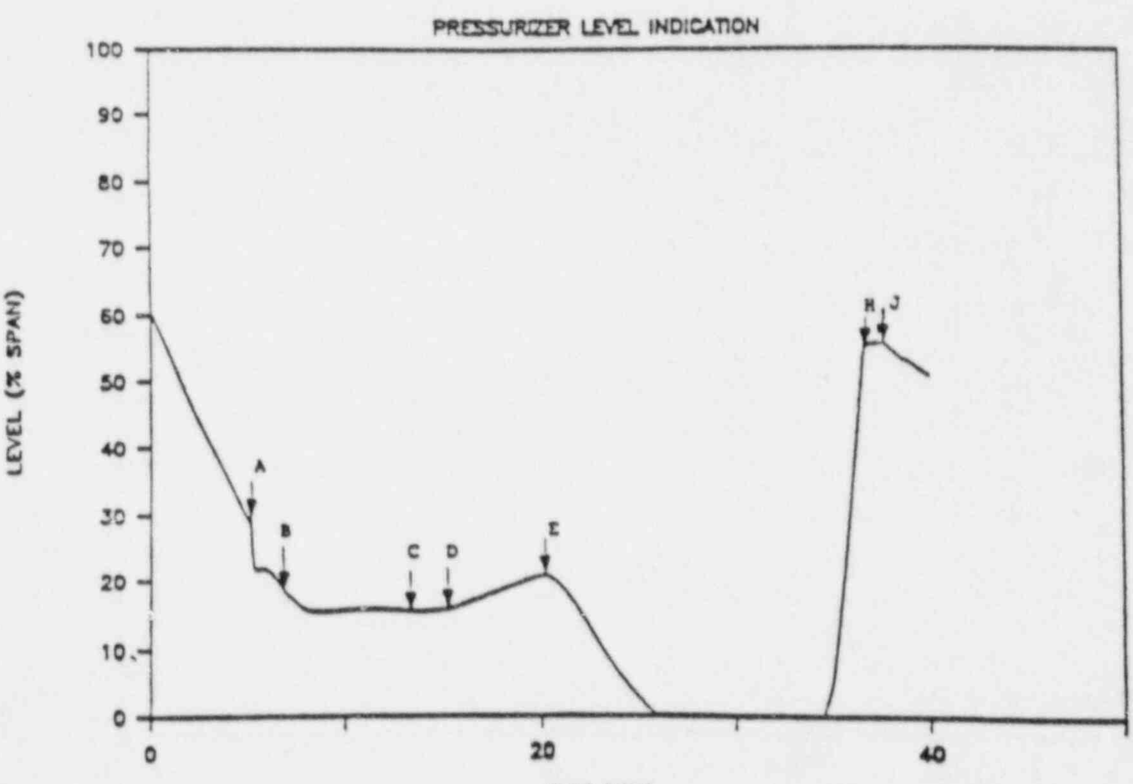


FIGURE 10-2. CPSES1 Design-Basis SGTR, Overfill - Pressurizer Level

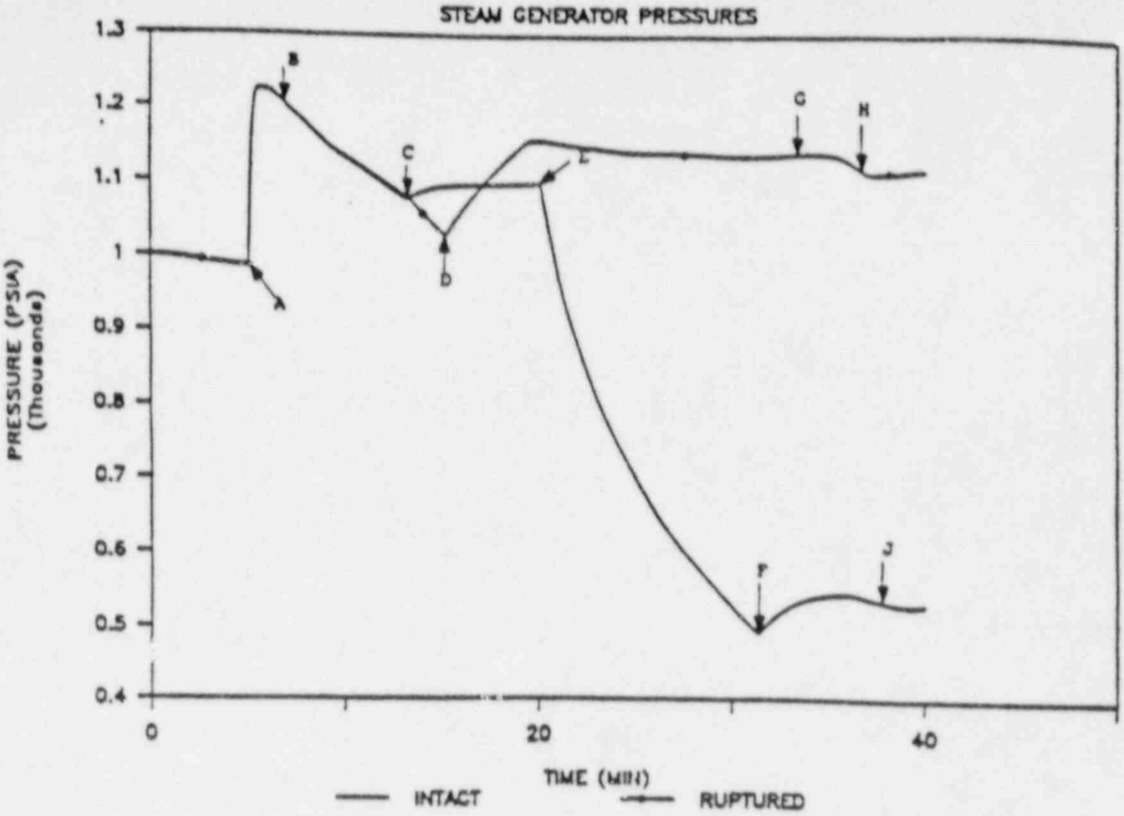


FIGURE 10-3. CPSES1 Design-Basis SGTR, Overfill - SG Pressures

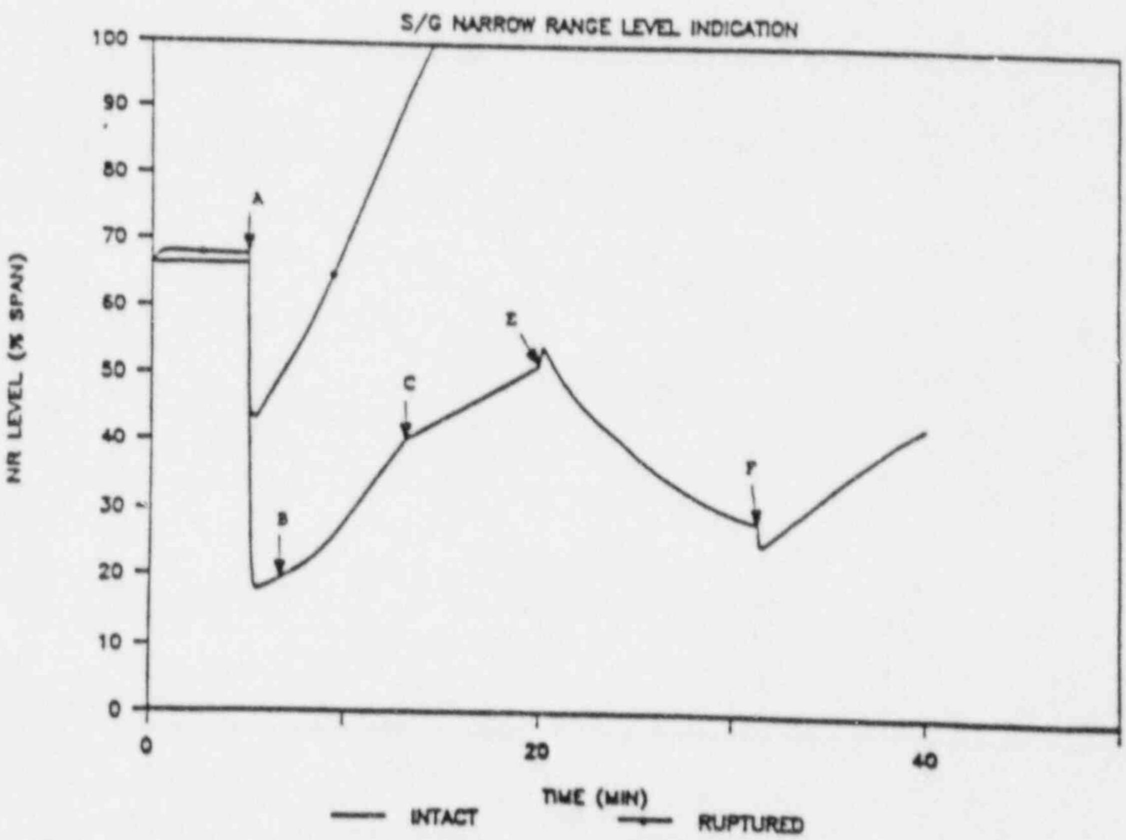


FIGURE 10-4. CPSES1 Design-Basis SGTR, Overfill - SG Levels

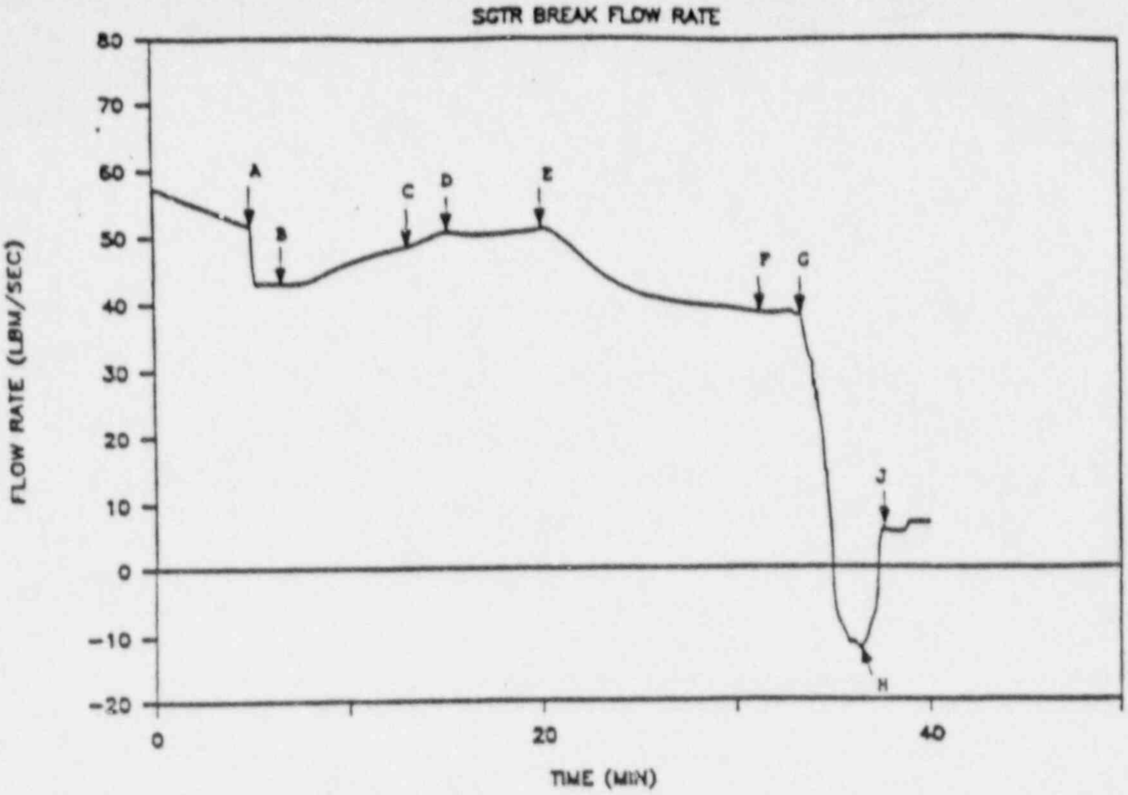


FIGURE 10-5. CPSES1 Design-Basis SGTR, Overfill - SGTR Break Flow Rate

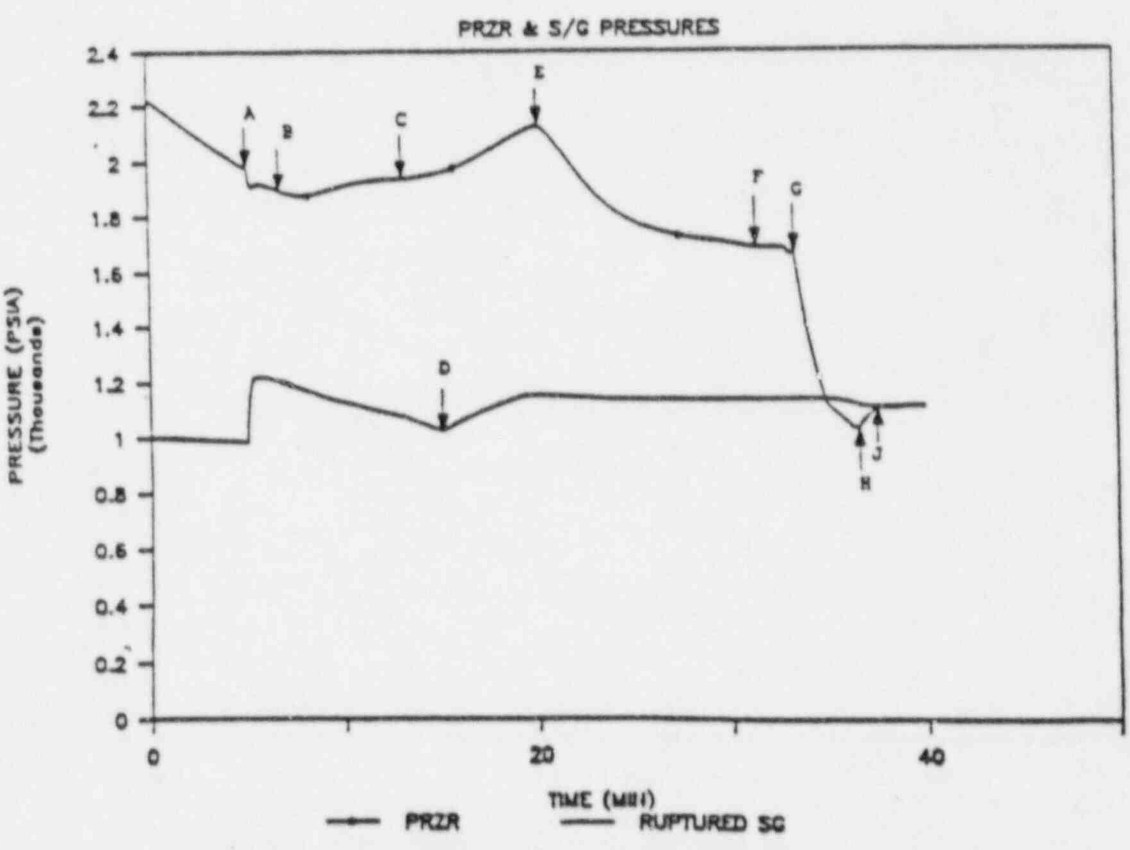


FIGURE 10-6. CPSES1 Design-Basis SGTR, Overfill - Przr and SG Pressures

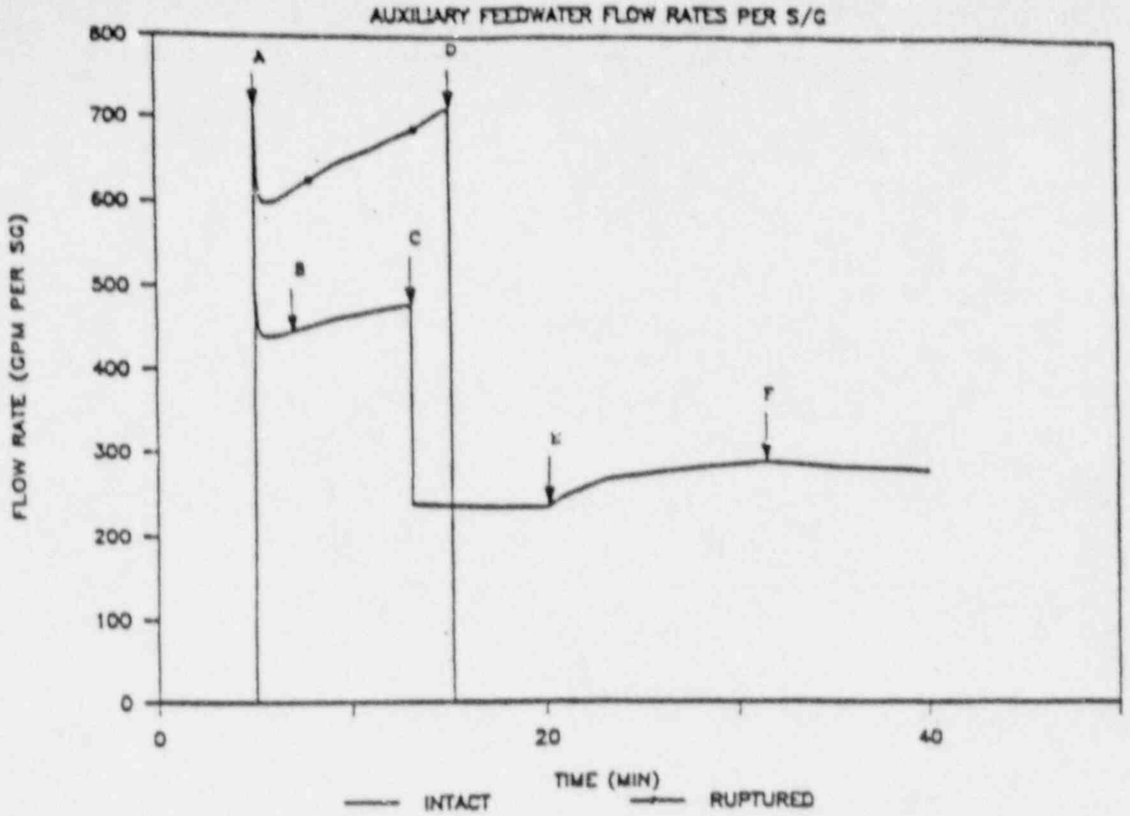


FIGURE 10-7. CPSES1 Design-Basis SGTR, Overfill - Aux FW Flow Rate

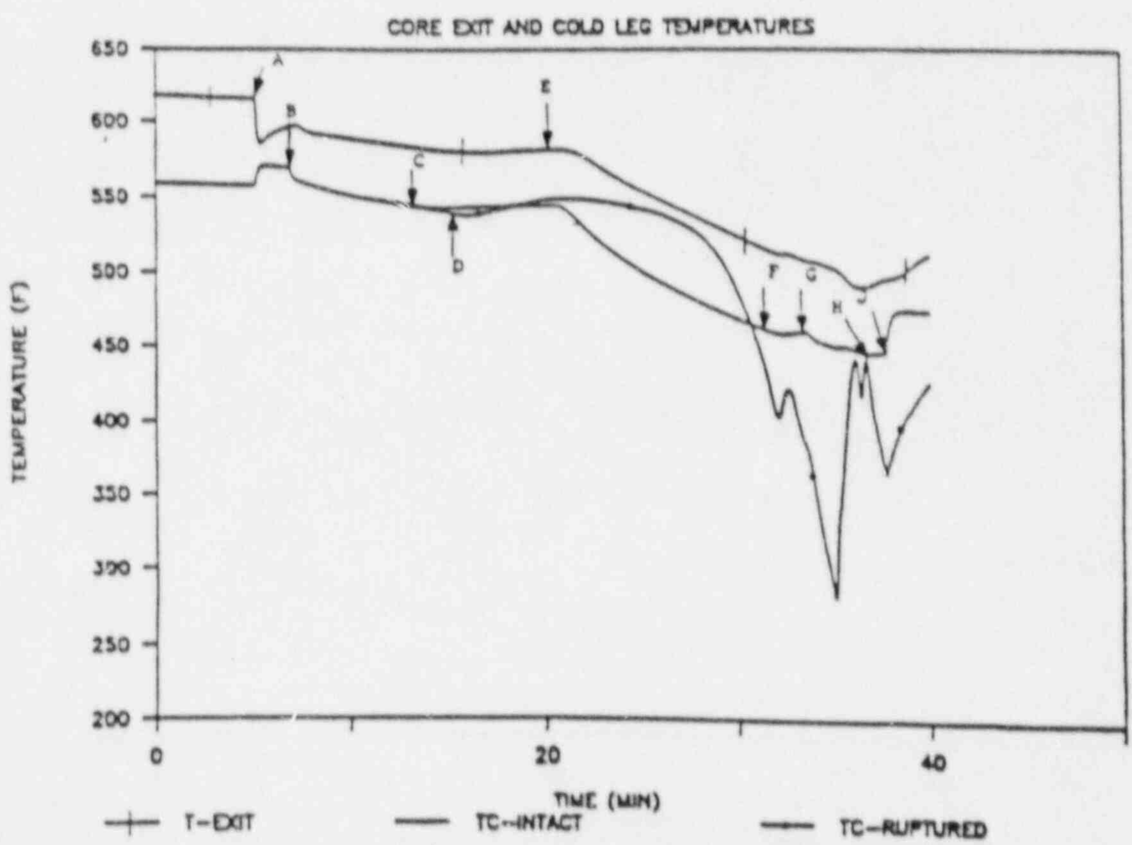


FIGURE 10-8. CPSES1 Design-Basis SGTR, Overfill - RCS Temperatures

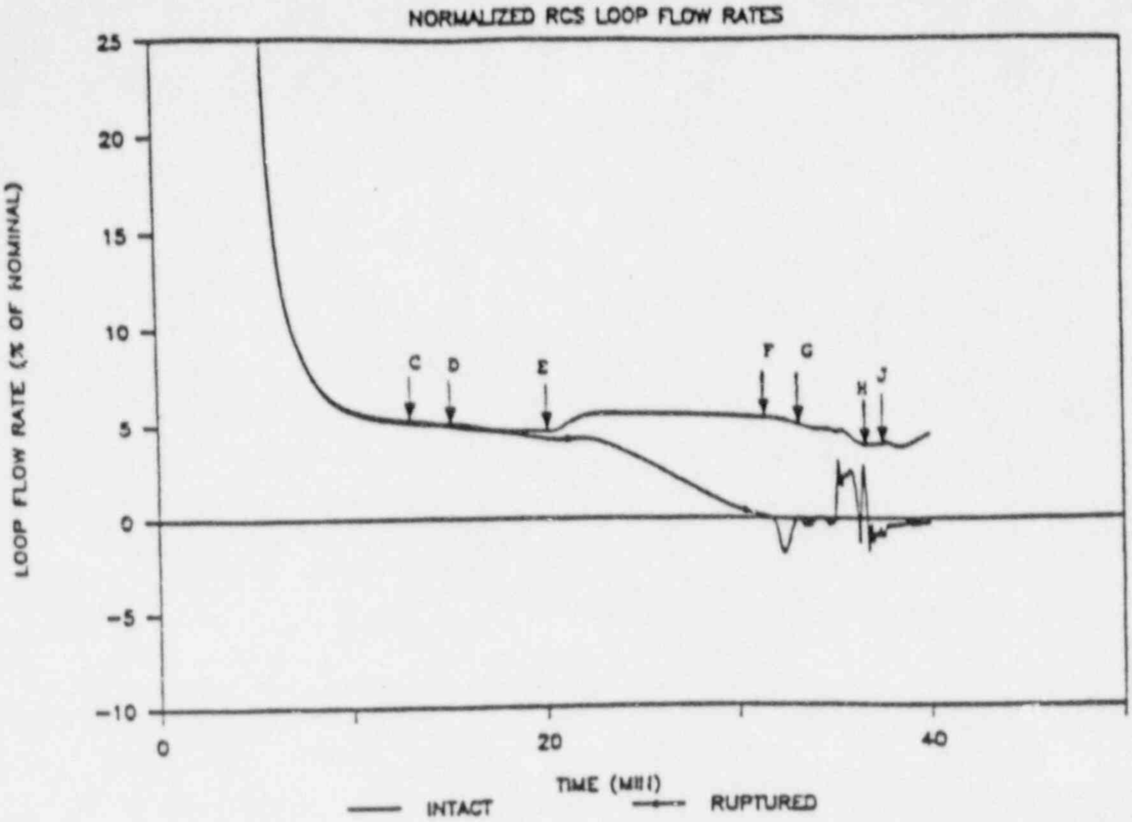


FIGURE 10-9. CPSES1 Design-Basis SGTR, Overfill - RCS Loop Flow Rates

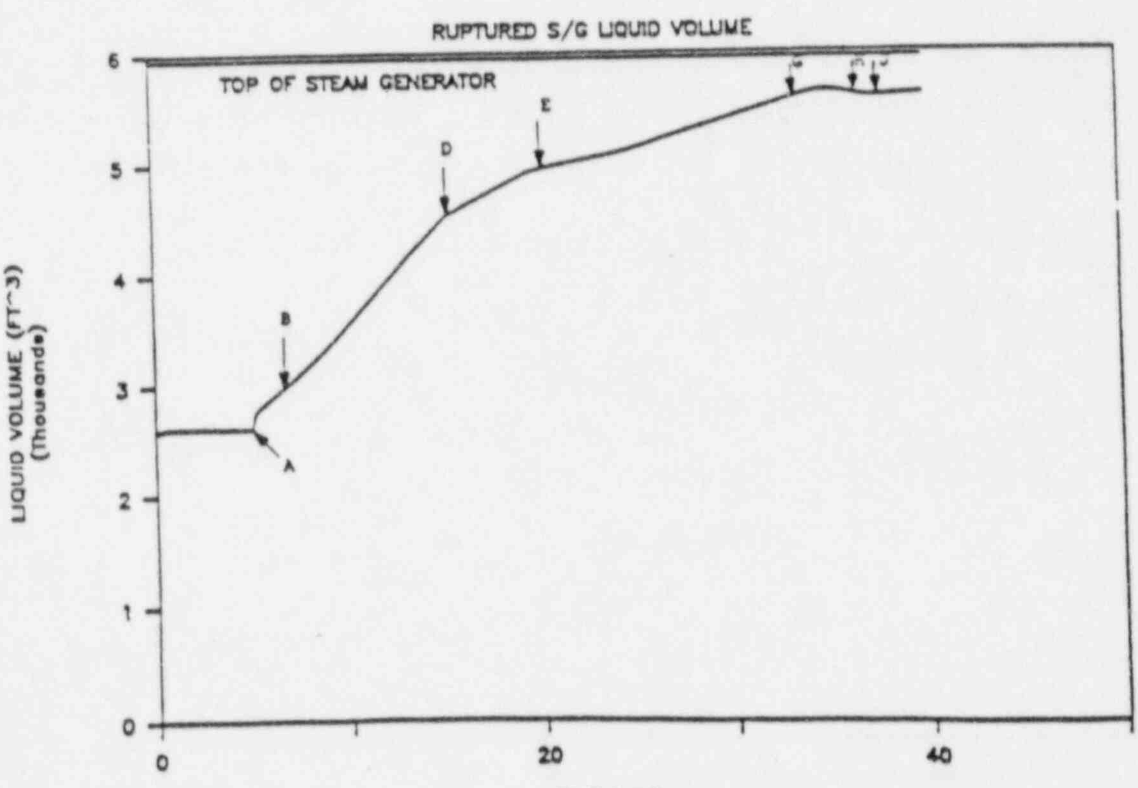


FIGURE 10-10. CPSES1 Design-Basis SGTR, Overfill - Ruptured SG Volume

CHAPTER 11

DESIGN-BASIS SGTR
FOR THE WORST CASE FOR RADIOLOGICAL DOSES

As discussed in Chapter 9, it was determined that the failure of the atmospheric relief valve on the ruptured steam generator results in the worst offsite radiological dose consequences. The thermal-hydraulic aspects of the postulated event are discussed below. The radiological dose consequences from this event are presented in Chapter 12.

A discussion of the conservative assumptions, as applicable to the dose consequences analysis, is presented in Section 11.1. Section 11.2 describes the effects of the single active failure on the operator actions and response times discussed in Chapter 7. The thermal-hydraulic analysis results are described in Section 11.3.

11.1 Conservative Assumptions with Respect to Radiological Doses

Because the objective of this analysis was to maximize the radioactive release to the atmosphere, the conservative assumptions incorporated into the conservative model, were reevaluated to ensure that those assumptions remained valid when the radiological consequences were to be maximized.

As stated previously, the failure to close of the atmospheric relief valve on the ruptured steam generator has been identified as the single active failure which results in the greatest amount of steam release to the atmosphere from the ruptured steam generator. The ARV is assumed to remain open until the plant is brought to cold shutdown conditions. Thus, the conservative directions for plant parameters should ensure that the primary-to-secondary break flow is maximized and that the maximum amount of steam is relieved to the atmosphere. An implication of this latter goal is that the ruptured steam generator mass should be such that long periods of steam relief may be sustained. Thus, the criteria used to determine the conservative directions of initial conditions for the design-basis case for radiological doses are the same as those used for the design-basis case for margin to overfill. Hence, the assumptions concerning initial conditions and equipment availability in the conservative base model (which minimized the margin to overfill) are applicable for the design-basis case for radiological dose.

11.2 Operator Actions and Response Times

11.2.1 Actions

Standard SGTR Recovery Responses (0 to 40 minutes)

Due to the failure of the ARV to close, the operator actions required to terminate this tube rupture event would be considerably different from the standard event termination procedure discussed in Chapter 4. The ARV failure to close would not be noticed by the reactor operators until after the ruptured steam generator had been identified and isolated; however, recognition at this stage would be contingent upon the steam generator pressure being less than the setpoint pressure of the ARV. Because the ruptured steam generator would be isolated from the other steam generators, and the hot RCS fluid would continue to leak into this steam generator, it can not be assured that the pressure would be less than the ARV setpoint pressure at the time of isolation; however, because the ARV would be fully open, the pressure could not be maintained for long solely by the break flow. Thus, the failure of the ARV to close should be readily identifiable by the reactor operators shortly after the ruptured steam generator is isolated.

To conservatively prolong the assumed response times, the assumption was made that the valve position indications were inaccurate or went unnoticed by the operators. The CPSES1 Emergency Response Guidelines (ERGs) [13] specifically direct the operators to look for a faulted steam generator by verifying that the steam generator pressure in any steam generator is not decreasing in an uncontrolled manner.

Because the pressure in the ruptured steam generator would be decreasing, ostensibly without reason, the Shift Supervisor would transition to the FAULTED STEAM GENERATOR ISOLATION procedure. The first steps either require a cursory review of selected plant parameters or would have been performed in earlier procedures. The "Response Not Obtained" action is to dispatch an operator to locally close valves or block valves. Personnel from CPSES Operations have indicated that because of the potentially adverse environment created by the steam release through the ARVs, operators would not be sent into the steam tunnels to locally isolate the valves; hence, no action would be taken to isolate the failed ARV. Because the event had already been identified as a SGTR, the operators would then return to the STEAM GENERATOR TUBE RUPTURE procedure.

In the SGTR Emergency Operating Procedure (EOP), the operators check the ruptured steam generator pressure. If the pressure in the ruptured steam generator is less than 605 psig, the transition is made to a contingency action procedure. Analyses have indicated that at this time (approximately 23 minutes), the ruptured steam generator pressure would be significantly greater than 605 psig; therefore, no transition would be made, and the reactor operators would initiate a cooldown of the RCS at the maximum rate using the ARVs on the intact steam generators. This RCS cooldown would be terminated when the core exit temperature reached was approximately 460°F. Based on the continuing pressure decrease in the ruptured steam generator, the operators would then transition to an alternate recovery procedure, SGTR WITH LOSS OF REACTOR COOLANT - SUBCOOLED RECOVERY REQUIRED.

Subcooled Recovery Contingency Responses (40 - 90 minutes)

After the transition to the subcooled recovery EOP, the operators would begin a controlled cooldown of the RCS at a maximum rate of 100°F/hr in the intact loop cold legs. The ARVs on the intact steam generators would again be used for the cooldown. After the controlled cooldown was initiated, the operators would depressurize the RCS to refill the pressurizer to at least 20% span. The EOP then instructs the operators to determine if a centrifugal charging pump (CCP) and a safety injection pump (SIP) could be stopped.

Following the rapid repressurization of the RCS due to the ECCS flow, the subcooling requirements for stopping one CCP and then one SIP would be satisfied shortly after the RCS depressurization. The procedures require that one CCP be stopped, the pressure allowed to stabilize, and then the SIP be stopped. In order to maximize the break flow, it was assumed that both pumps were stopped simultaneously at the estimated time the SIP would have been stopped. The operators would then cycle back through this procedure, maintaining a minimum pressurizer level, until a sufficient subcooling margin had been established, which would allow an additional SIP to be stopped. The controlled RCS cooldown and depressurization would be continued until the conditions required for placing the Residual Heat Removal System (RHRS) in service were established or until the plant parameters became such that other contingency procedures were required.

<u>Saturated Recovery Contingency Responses (after 90 minutes)</u>

The Shift Supervisor would transition from the Subcooled Recovery EOP when the ruptured steam generator narrow range level exceeded 98% span. In accordance with the procedure, when the narrow range level in the ruptured steam generator exceeded 98% span, the Shift Supervisor should consult with the Technical Support Center and transition to another alternate recovery procedure, SGTR WITH LOSS OF REACTOR COOLANT - SATURATED RECOVERY REQUIRED. This contingency procedure is designed to reduce the SGTR break flow rate by reducing the number of CCPs and SIPs in operation and by intentionally depressurizing the primary to the saturation pressure at the core exit temperature.

In accordance with this procedure, it would then be determined that the subcooling requirements for stopping the second SIP were satisfied at the time of the transition. After the second SIP was stopped, the pressurizer PORV would then be opened to depressurize the RCS to the saturation pressure at the core exit temperature. The depressurization would be stopped if the pressurizer level exceeded 78% of span, or when the saturation pressure was attained. The remaining procedural steps require the operators to continually assess the plant conditions as the cooldown continues. The pressurizer PORV would be opened at intervals to maintain the RCS at the saturation pressure at the core exit temperature.

When the RCS conditions were suitable, the RHRS could be placed in service; however, because the RHRS would allow cooldown of the RCS at the maximum allowable rate and because steam relief from the intact steam generators was not in itself sufficient to maintain the 100°F/hr cooldown rate, no credit was taken for the initiation of the RHRS until two hours following the initiation of the tube rupture. Operation of the RHRS was credited for maintaining the maximum cooldown rate after two hours.

11.2.2 Response Times

The major operator responses are included with the event timeline presented in Table 11-1.

To ensure that reasonably conservative operator response times were used, it was assumed that following the isolation of the ruptured steam generator, five minutes were required for the Shift Supervisor to transition to the FAULTED STEAM GENERATOR procedure, return to the STEAM GENERATOR TUBE RUPTURE procedure, and then to begin the maximum rate RCS cooldown. This five minutes was added to the five minutes shown in Chapter 7 to be required following the isolation of the ruptured steam generator and prior to the initiation of the RCS cooldown. Following the completion of the RCS cooldown, it was conservatively assumed that an additional five minutes would be required for the transition to the first contingency recovery procedure and for the initiation of the controlled cooldown. Two minutes were assumed to elapse prior to the initial RCS depressurization, and then, a minimum of two minutes between consecutive depressurizations was assumed. If the pressurizer level had not fallen below 10% span, no depressurization would be modeled. Finally, it was assumed that one CCP and one SIP were stopped five minutes after the start of the initial depressurization.

The transition into the second contingency recovery procedure was modeled by stopping the second SIP at ninety minutes into the event. Analysis indicated that the ruptured steam generator level went offscale high at approximately 80 minutes; however, for conservatism, it was assumed that the transition was not made until 90 minutes. The initial depressurization to saturate the primary was conservatively assumed to occur five minutes later, at 95 minutes.

11.3 Results

A time sequence of events is shown in Table 11-1. Plots of critical parameters are shown in Figure 11-1 through Figure 11-8, and a key to the symbols used in these figures is shown in Table 11-3.

As discussed in Section 11.1, because of the myriad of operator responses and the operational goals for the particular phases of the event, the discussion of the critical transient parameters is divided into three phases:

1) Standard SGTR Termination Responses (0 to 40 minutes);

2) Subcooled Recovery Contingency Responses (40 to 90 minutes); and,

3) Saturated Recovery Contingency Responses (after 90 minutes).

11.3.1 General Description

Standard SGTR Termination Responses (0 to 40 minutes)

Following the reactor trip and ensuing turbine trip, the ARV on the ruptured steam generator was modulated fully open on a pressure error signal. The steam relief and the large amounts of relatively cold auxiliary feedwater acted to quickly reduce the secondary pressure. Normally, the ARV would close as the pressure fell below the setpoint pressure of the ARV; however, for this case, it was assumed to remain open. Thus the secondary pressure continued to fall. After the reactor operator actions to close the MSIV on the ruptured steam generator and throttle auxiliary feedwater to the intact steam generator are completed, the intact steam generator pressure began to rise as the cold auxiliary feedwater was warmed (level swell), thus compressing steam bubble in the steam generator. After the MSIV on the ruptured loop was closed, only the ruptured steam generator continued to depressurize and at a slightly faster rate than before. The narrow range level in the ruptured steam generator, which had been rising due to the overfeeding of the steam generator by the auxiliary feedwater, fell off sharply as the inventory being steamed away exceeded that being added through the ruptured steam generator tube. The level in the intact steam generator was maintained near 35% of span (the EOPs direct the operators to maintain the level between 10% and 50% narrow range span).

The transition from Phase 1 to Phase 2 was considered to be made during the five minutes between the end of the maximum rate RCS cooldown and the beginning of the controlled rate cooldown.

Subcooled Recovery Contingency Responses (40 to 90 minutes)

This phase of the SGTR termination began when the Shift Supervisor transitioned from the STEAM GENERATOR TUBE RUPTURE procedure to the SGTR WITH LOSS OF REACTOR COOLANT - SUBCOOLED RECOVERY REQUIRED procedure. This transition was the first significant deviation from the standard SGTR termination responses and occurred between the end of the maximum rate RCS cooldown at 39.97 minutes and the start of the controlled rate RCS cooldown at 44.97 minutes. As described previously, the first operator response was to initiate a controlled cooldown of the RCS using the intact ARVs. Ideally, the ARVs would have been modeled to modulate to the position which would relieve sufficient steam to maintain a 100°F/hr cooldown rate. However, because of the long lag between the time a modification of the ARV open area was made and the time a change in the cold leg temperature cooldown rate could be observed, the ARV control model developed for this event modulated the ARV from essentially full open to full closed. Because the continuous modulation is not realistic from an operations viewpoint, a minimum value of 65% open was arbitrarily set beginning at 60 minutes. The ARV control model then modulated the valve as necessary to maintain the cooldown rate.

Once the controlled cooldown was initiated, the procedures direct the operators to depressurize the RCS to refill the pressurizer to greater than 20% span. After the pressurizer was refilled, the one CCP and then one SIP was stopped. The reduced ECCS flow resulted in a lower equilibrium pressure; hence, the RCS pressure trended toward this new pressure. Because the steam generator pressures were relatively low, the 100°F/hr cooldown rate could not be sustained. As the ruptured steam generator pressure continued to decrease (but at a much slower rate), the equilibrium pressure described above was easily maintained. Due to the relatively low steaming rate from the ruptured steam generator, and the higher SGTR break flow rate, the steam generator level indication increased significantly during this period, eventually going off-scale (high) at approximately 80 minutes. Once the level had exceeded 98% span, the contingency procedures directed the Shift Supervisor to transition to the Saturated Recovery procedure, thus ending this phase of the transient.

Saturated Recovery Contingency Responses (after 90 minutes)

The final phase of the SGTR termination began when the Shift Supervisor transitioned from the subcooled recovery procedure to the saturated recovery procedure. The transition was made when the narrow range level indication in the ruptured steam generator became greater than 98% span. Even though the analysis indicated that the level exceeded 98% span at approximately 80 minutes, for conservatism, the transition was not made until 90 minutes. The operational goal in the saturated recovery procedure was to minimize the break flow rate by minimizing the primary-secondary pressure differential. The pressure minimization was accomplished by reducing the ECCS capacity and depressurizing the RCS to near saturation. The subcooling criteria provided in this procedure for stopping ECCS pumps less stringent than in the subcooled recovery procedure, thus an additional SIP was stopped at 90 minutes. After the second SIP was stopped, the break flow rate was greater than the capacity of the single operating CCP, thus the pressure and level immediately began to fall as a new equilibrium pressure was sought. Five minutes after the SIP was stopped, the pressurizer PORV was re-opened to depressurize the primary to the saturation pressure at the temperature indicated by the core exit thermocouples. The depressurization was halted when the desired pressure was attained. This procedure was repeated until RHRS entry conditions were satisfied. Even though the RHRS entry conditions were satisfied at approximately 110 minutes, for conservatism, no credit for its operation was taken until after 120 minutes.

11.3.2 RCS (Pressurizer) Pressure

Standard SGTR Termination Responses (0 to 40 minutes)

Following the initiation of the tube rupture, the pressurizer pressure (Figure 11-1) decreased linearly due to the steam bubble expansion as the RCS was drained through the steam generator tube. The pressure dropped sharply following the reactor trip on low pressure; however, there was a brief pressure spike prior to the decrease. This spike was due to the quicker response of the turbine stop valve closure relative to control rod motion following the simultaneous reactor and turbine trips. Following the post-trip drop, the pressure rose slightly as the cold leg temperature rose, thus raising the hot leg temperature and pressurizer pressure. The continued SGTR break flow caused the pressurizer pressure to continue to fall, but at a slower rate. The break flow rate decreased following the post-trip RCS pressure drop and the steam generator pressurization, but as the steam generators depressurized due to the open ARV and the auxiliary feedwater, the break flow increased, thus increasing the rate of RCS depressurization. With the initiation of the ECCS flow, the net rate of inventory loss from the RCS was greatly reduced, resulting in a reduced rate of depressurization. One additional cause for the change in the depressurization rate was the effect of the growth of the pressurizer steam bubble, which caused a given change in the RCS inventory to become less apparent.

Following the closure of the MSIV on the ruptured loop and the throttling of the auxiliary feedwater flow to the intact steam generators, the RCS pressure decrease was halted. The cold leg temperature increase in the intact loops, due to increases in the intact steam generator saturation temperature, counteracted the continued temperature decrease in the ruptured loop cold leg temperature; hence, the hot leg temperature stabilized as the core inlet temperature stabilized. In addition, the average RCS temperature and density were also stabilized. Because less ECCS fluid was required to make up for RCS shrinkage and there was more ECCS fluid injected than was lost through the ruptured steam generator tube, the pressurizer pressure tended to increase toward the pressure at which the ECCS flow rate equaled the SGTR break flow rate.

This pressure increase continued until the RCS cooldown was initiated at 23 minutes. At the beginning of the cooldown, the mass flow rate required to compensate for the RCS shrinkage plus the mass lost through the ruptured steam generator tube was greater than that being added through ECCS injection; however, when the RCS pressure had fallen to below 1400 psia, the RCS backpressure had become low enough that the higher capacity safety injection pumps (SIPs) could contribute significant amounts of fluid to the total ECCS flow. This additional fluid caused the pressurizer, which had completely emptied at approximately 30 minutes, to refill. The compression of the steam bubble in the pressurizer caused a sharp pressure increase. The pressure continued to rise toward that pressure (slightly less than 1600 psia) where the ECCS fluid compensated for the RCS shrinkage and the mass lost through the break. Following the end of the maximum rate cooldown at 39.97 minutes, the ECCS capacity was no longer required to make up for the RCS shrinkage; therefore, the pressure climbed toward a new "equilibrium" pressure.

Subcooled Recovery Contingency Responses (40 to 90 minutes)

Near the end of the maximum rate RCS cooldown, the pressurizer pressure (Figure 11-1) began trending toward an equilibrium pressure where the ECCS flow rate was approximately the same as the SGTR break flow rate plus that mass required to compensate for shrinkage of the RCS during the cooldown. Immediately following the start of the controlled cooldown, and with the continuance of the RCS shrinkage, the rate of pressure increase slowed significantly. The operator action to refill the pressurizer by opening one PORV resulted in a rapid depressurization. Because the pressure at the end of the depressurization was low (approximately 700 psia), the ECCS flow rate was relatively large, which resulted in a rapid repressurization of the RCS. Following the end of the depressurization, one CCP and one SIP were stopped, thus reducing the ECCS flow rate by one-half. Because the ECCS flow rate was lower, a lower equilibrium pressure was established. This pressure was maintained throughout the remainder of this phase of the transient.

Notice the small indentations on the plot of pressurizer pressure (Figure 11-1) after sixty minutes. These indentations represent brief periods of minor depressurizations which followed the brief injections of auxiliary feedwater into the intact steam generator as the nominal steam generator level was maintained. When the auxiliary feedwater injections occurred, the RCS temperatures became slightly lower, resulting in the depressions in the pressure plots.

Saturated Recovery Contingency Responses (after 90 minutes)

Following the termination of the SIP, leaving only a single CCP operating, the pressurizer pressure began to fall. Because the SGTR break flow was greater than the capacity of the single CCP, the pressure decreased as the pressurizer was drained. A new, equilibrium pressure would eventually be reached at which the break flow rate equaled the CCP flow rate. However, prior to the arrival at the new equilibrium pressure, the pressurizer PORV was opened at 95 minutes, resulting in a rapid decrease in pressure.

The RCS depressurization was procedurally allowed to continue until the RCS was saturated or until the pressurizer level exceeded 78% span. For this analysis, the core exit saturation pressure was not attained in the pressurizer before the PORV was closed due to high pressurizer level at 115.28 minutes. Because of the high level, the RCS could not be further depressurized. In addition, because of the low RCS pressure, the capacity of the single CCP was such that the pressure began to increase as the pressurizer was filled. This pressure increase would have continued until the reactor operators re-established charging and letdown to control level. The addition of the RHRS would also be used to control the pressurizer level (and hence, the pressure as well).

Because the pressurizer pressure was lower than elsewhere in the RCS, no voiding in the RCS was predicted. During the depressurization, when the saturation pressure of the pressurizer was approached, the rate of depressurization changed, following the saturation pressure of the pressurizer throughout the remainder of the event.

11.3.3 Pressurizer Level

Standard SGTR Termination Responses (0 to 40 minutes)

Following the start of the SGTR, the pressurizer level (Figure 11-2) fell linearly until the reactor trip. Subsequent to the expected post-trip drop, the level briefly stabilized as the hot and cold leg temperatures increased. The level then continued to fall due to the RCS shrinkage and the continued break flow. The pressurizer level plot mirrors the pressure plot (Figure 11-1) until the RCS cooldown was initiated. The level then fell offscale low because the ECCS flow could not make up for both the RCS shrinkage and the SGTR break flow. The pressurizer emptied at approximately 30 minutes and began to refill at approximately 32 minutes.

Subcooled Recovery Contingency Responses (40 to 90 minutes)

Beginning at 46.97 minutes, one pressurizer PORV was opened in order to hasten the refilling of the pressurizer. The PORV was closed when the level was greater than 20% span. However, because the RCS had been depressurized to a relatively low pressure, the ECCS flow rate was quite large, thus the pressurizer refilled to a level greater than 20% span. The large ECCS flow rates continued until an equilibrium pressure was approached; thus, the pressurizer level similarly continued to increase until the equilibrium pressure was approached. The bumps apparent in the level plot (Figure 11-2) are due to the sporadic addition of auxiliary feedwater to the intact steam generators, which was discussed in Section 11.3.2.

Saturated Recovery Contingency Responses (after 90 minutes)

Following the stoppage of the SIP, the level began to fall as the RCS was drained through the ruptured tube. When the PORV was opened at 95 minutes, the level initially rose as the pressurizer and RCS fluid expanded due to the lower pressure. However, because the break flow was greater than the ECCS flow, the level began to decrease. The effects of primary coolant expansion at lower pressures, decreased the break flow rates and increased ECCS flow rates at the lower pressures, were sufficient to overcome the reduction in level due to the break flow. Thus, the pressurizer level increased slowly throughout the remainder of the simulation.

11.3.4 Reactor Power Response

Prior to reactor trip, the core power decreased slightly as the RCS pressure decreased. The power reduction was due to the moderator density coefficient, which introduced negative reactivity into the core as the RCS became slightly less dense. Subsequent to reactor trip, the reactor power was 120% of the 1971 ANS decay heat curve, and was essentially unaffected by the SGTR transient. Boron injected though the ECCS prevented the core from becoming critical as the RCS was cooled.

11.3.5 RCS Temperatures

Standard SGTR Termination Responses (0 to 40 minutes)

Following the initiation of the SGTR, the RCS temperatures (Figure 11-3) decreased very slightly as the reactor power decreased. The power reduction was due to the effects of the moderator density coefficient described in Section 11.3.4. As the RCS depressurized, the fluid density in the core also decreased, resulting in a lower hot leg temperature and an ensuing reduction in the cold leg temperature. The pressure spike discussed previously caused a similar spike in the hot leg temperature. This spike was not seen in the cold leg temperature due to the masking effect of the temperature increase following the loss of main feedwater. Following reactor trip, turbine trip and the subsequent loss of main feedwater, and the loss of forced circulation in the RCS, the cold leg temperatures increased rapidly. The cold leg temperature increase was terminated by the opening of the ARV on the ruptured steam generator and the addition of large amounts of auxiliary feedwater to the steam generators.

Following reactor trip, the hot leg temperature initially fell, but then increased as the RCS flow coasted down due to the loss of offsite power. A hot-to-cold leg temperature difference corresponding to natural circulation quickly developed, thus maintaining the hot leg temperature approximately 30°F above the core inlet average temperature. This natural circulation flow was maintained in all loops by steam release through the ARV on the ruptured steam generator. As the steam generators were depressurized, the cold leg temperatures, and thus the hot leg temperatures, also decreased. When the MSIV was closed, the heat removal capacity from the intact loops was sharply reduced. The cold leg temperatures in the intact loops then rose toward the saturation pressures of the intact steam generators. Because steam relief from the ruptured steam generator continued, the cold leg temperature in the ruptured loop continued to decline. The cold leg temperature was expected to fall at a faster rate following the isolation of the ruptured steam generator; however, the increase and stabilization of the hot leg temperatures counteracted much of this effect.

Once the maximum rate cooldown had been initiated, the cold leg temperature in the ruptured loop began to decrease at a significantly sharper rate. Note that the inflection point on the ruptured loop cold leg temperature plot lagged behind the start of the RCS cooldown by approximately one loop transit time (on the order of 300 seconds). This delay was due to the time required for the reduced intact loop cold leg temperatures to be transmitted through the RCS loop to cause a lower hot leg temperature, and assuming the hot-to-cold leg temperature difference was approximately the same, to cause a lower cold leg temperature in the rupture loop.

As the steam generators depressurized, the rate of temperature decrease was reduced. Another system action which affected the RCS temperature was the control system which simulated the operator actions to maintain level at approximately 35% span in the intact steam generator and caused the auxiliary feedwater to be sporadically throttled. The flatter portions of the temperature plot (Figure 11-3) correspond to throttling of the auxiliary feedwater, whereas the continuation of the temperature decrease corresponds to periods of injection of the cold auxiliary feedwater.

The RCS cooldown was terminated at approximately 41 minutes. Because there was no further steaming, the steam generator level remained near 35%, hence no additional auxiliary feedwater was added. The combined effects of the termination of the steam flow and auxiliary feedwater flow caused the RCS temperature cooldown to cease, and the temperatures began to increase as the steam generator saturation temperature began to rise. In addition, because the RCS flow rate was also reduced, the hot leg temperature began to increase.

Subcooled Recovery Contingency Responses (40 to 90 minutes)

Following the end of the maximum rate cooldown, the ARVs on the intact steam generators were closed and the auxiliary feedwater to the intact steam generators was drastically throttled; therefore, the cold leg temperatures on the intact loops began to rise. The rise in the cold leg temperature resulted in an increase in the hot leg temperature as well.

The controlled rate RCS cooldown was initiated at 45.23 minutes. As expected, the cold leg temperatures, followed by the hot leg temperatures, began to fall. The decrease was interrupted by the depressurization of the RCS, which temporarily impeded the natural circulation flow. Following the end of the depressurization, one SIP and one CCP were stopped.

The stoppage of the pumps is readily distinguished in Figure 11-3 by the sharp increases in both the cold and hot leg temperatures. The cold leg volumes used in the RETRAN model are homogeneous volumes, thus the temperature of the entire volume is influenced by the mixture of the cold ECCS fluid. When the ECCS flow was reduced by half, the average enthalpy in the cold legs became more influenced by the RCS fluid and less by the ECCS fluid; hence, the cold leg temperatures were expected to rise. The hot leg temperature also rose as the hot-to-cold leg temperature difference was maintained.

Following the reduction of the ECCS flow by one-half, the cooldown of both the cold legs continued. The hot leg temperatures followed the cold leg temperatures, maintaining a nearly constant temperature difference. As before, the cold leg temperature in the loops with the intact steam generators varied slightly as auxiliary feedwater was injected and then throttled. Because a minimum valve open area was specified for the ARVs after 60 minutes, the effect of the cycling of the ARVs became less pronounced. The throttling of the auxiliary feedwater flow was also evident in the hot leg temperature response; however, because the hot leg temperature depended on the average core inlet temperature, and perfect mixing in the lower plenum was assumed, the variations in the temperature were less pronounced.

Saturated Recovery Contingency Responses (after 90 minutes)

When the SIP was stopped, the cold leg temperatures rose immediately. This temperature rise was due to the reduction of flow into the cold leg volume which was attributable to the cold ECCS fluid. Again, because the core exit temperature reacted to a change in the core inlet average temperature, the core exit temperature also increased. Recall that the controlled cooldown was still in progress; however, the reduction in the pressure in the intact steam generators was such that the target cooldown rate of 100°F/hr could not be maintained. Thus, the cooldown rate was slowed to approximately 30°F/hr. The effects of the periodic injection of auxiliary feedwater continued to be noticeable in the intact cold leg and core exit temperature responses. Note that the ARVs on the intact steam generators were not constantly fully open, as would be expected. This inconsistency was due to the control system being used to control the cooldown. An instantaneous 10-second average was used to determine the cooldown rate. When auxiliary feedwater was injected into the intact steam generators, the cold leg temperature momentarily decreased at a rate greater than

$100^{\circ}F/hr$; hence, the ARVs were modeled to partially close. When the auxiliary feedwater was throttled, the RCS cooldown rate became much less than $100^{\circ}F/hr$; thus, the ARVs rapidly opened fully.

11.3.6 Steam Generator Pressure Response

Standard SGTR Termination Responses (0 to 40 minutes)

Because the steam generators are connected through the main steam headers, the pressure responses of the steam generators were very nearly the same prior to isolation of the ruptured steam generator at 13.08 minutes.

Following the initiation of the SGTR, the pressures in the steam generators decreased slightly due to the corresponding reduction in core power and RCS temperatures. Because the steam dumps were not modeled and only the ARV on the ruptured steam generator was assumed available, the steam generator pressure rose sharply following turbine trip. Due to the opening of the ARV and the immediate injection of large amounts of cold auxiliary feedwater, the steam generator pressures did not reach the accumulation pressure of any of the main steam safety valves. Primarily due to the cold auxiliary feedwater, the steam generator pressures decreased until the ruptured steam generator was isolated, and the auxiliary feedwater flow to the intact steam generators was throttled. After isolation, the pressure responses of the intact and ruptured steam generators diverged.

After the auxiliary feedwater to the intact steam generators was throttled, the intact steam generator pressure rose toward the typical no-load pressure (~1100 psia). The RCS cooldown, effected by opening the ARVs on the intact steam generators, caused a rapid decrease in the steam generator pressure. As would be expected, as the pressure decreased, the rate of pressure decreased; thus the pressure reduction was more rapid at the start than toward the end of the cooldown period. The pressure was noticeably affected by the periods of throttling auxiliary feedwater flow; the pressure increased when the auxiliary feedwater was throttled and decreased when injection continued.

Following the closure of the MSIV on the ruptured steam generator and the isolation of auxiliary feedwater flow to this steam generator, the pressure in this steam generator continued to fall. As the hot leg temperature stabilized (see Section 11.3.4), the rate of pressure decrease in the ruptured steam generator became significantly slower. An equilibrium state was reached where the pressure rise due to the SGTR break flow was offset by the release of steam through the ARV. Following the start of the RCS cooldown, and the ensuing decrease in the hot leg temperatures, the ruptured steam generator pressure again fell off smoothly as the the steam generator depressurized. Because of the buffering effect of the RCS, the ruptured steam generator was essentially unaffected by the cycling of auxiliary feedwater to the intact steam generators.

Subcooled Recovery Contingency Responses (40 to 90 minutes)

Following the termination of the maximum rate cooldown at approximately 40.23 minutes, the pressure in the intact steam generators began to rise. This pressure increase was primarily due to the level swell as the cold auxiliary feedwater warmed and compressed the steam bubble. Once the controlled RCS cooldown was initiated by periodically opening the ARVs at 44.97 minutes, the intact steam generator pressure again began to fall. Throughout the remainder of this phase of the transient, the intact steam generator pressures increased when the ARVs were fully or partially closed or when the auxiliary feedwater was throttled, and decreased when the ARVs were opened or when the auxiliary feedwater flow rate was increased. As the pressure fell, decreasing the differential pressure between the steam generators and the atmosphere, the steam flow rate through the ARVs also decreased. Therefore, the steam pressure tended to level out as the atmospheric pressure was asymtotically approached.

Similarly, the rate of depressurization in the ruptured steam generator also decreased as the atmospheric pressure was approached. Another factor, which acted to maintain the pressure, was the addition of the warmer RCS fluid through the ruptured tube. Some of the fluid flashed to steam immediately, while the remainder acted to maintain the steam pressure by compressing the steam bubble as the steam generator liquid volume increased.

Saturated Recovery Contingency Responses (after 90 minutes)

The steam generators had virtually depressurized by the start of this phase of the transient. There was less than 150 psi of pressure difference driving the steam relief rate; hence, the complete depressurization of the steam generators was approached very slowly. After the RCS had been depressurized to near saturation pressure, the break flow had become relatively small. The added pressure in the ruptured steam generator due to steam bubble compression and primary coolant flashing was compensated by steam relief through the ARVs. The effects of the periodic injections of auxiliary feedwater into the intact steam generators can be seen in the plot of intact steam generator pressure (Figure 11-4).

11.3.7 Steam Generator Narrow Range Level Response

The steam generator level response is shown in Figure 11-5. As discussed in Section 5.3, only a qualitative discussion the steam generator level response is possible. Thus, while the absolute level predicted during the SGTR simulation may not be exactly accurate, the indicated trends are correct. In addition, for this conservative case, the differences in the indicated levels may be misleading. The void fraction in the ruptured steam generator was reduced in order to obtain a desired initial steam generator mass. When the reactor and turbine tripped, the voids were collapsed, but because there initially were fewer voids in the ruptured steam generator, the mixture volume did not decrease as much as in the intact steam generators.

Ruptured Steam Generator

Standard SGTR Termination Responses (0 to 40 minutes)

After the SGTR began, liquid from the break flow was added to the steam generator, and the void fraction in the mixture region of the ruptured steam generator was increased due to flashing of the RCS coolant. The increased void fraction resulted in an increase in the steam generator level indication; however, the steam generator water level controller acted to maintain the level near the nominal value.

Following the reactor and turbine trips and the initiation of auxiliary feedwater, the level rose linearly until the MSIV was closed and the auxiliary feedwater was isolated. The isolation of the ruptured steam generator from the intact steam generators caused an increase in the amount of flow through the ARV on the ruptured steam generator; therefore, the mixture void fraction was increased and the level indication responded appropriately. However, the loss of auxiliary feedwater and the continued steaming caused the ruptured steam generator inventory to decrease, thus the indicated level decreased. As expected, there was a slight change in the rate of decrease during the period where the RCS hot leg temperatures stabilized, and the equilibrium between the SGTR break flow and the ARV break flow was attained. During this period, the SGTR break flow rate increased, and the RCS flow rate in the ruptured loop decreased, resulting in an increase in the mixture void fraction and a change in the rate of level decrease.

Following the start of the RCS cooldown, the rate of level decrease again rose and then fell until the cooldown was completed. Note that the rate of depressurization had dropped sharply from the original rate of depressurization, thus the mass release rate through the ARV had become significantly less. The increase in the RCS pressure caused the SGTR break flow rate to increase. The increase in the break flow rate coupled with the decrease in mass release through the ARV caused the level indication to increase. Because nothing occurred to halt the process until the break flow was terminated, the indicated level in the ruptured steam generator continued to increase throughout the remainder of the event.

Intact Steam Generators

Standard SGTR Termination Responses (0 to 40 minutes)

The indicated level in the intact steam generators remained constant until the time of reactor and turbine trip. The post-trip dropoff was turned around by the addition of large amounts of auxiliary feedwater from both the turbine- and motor-driven auxiliary feedwater pumps. When operator action was modeled at 13 minutes to throttle the auxiliary feedwater to maintain level between 10% and 50% of span, the indicated level was greater than the average value of 35% span used by the auxiliary feedwater controller to simulate operator control of the auxiliary feedwater. Thus, auxiliary feedwater to the intact steam generator was essentially stopped until the level indication fell to below 35% span. The reduction of the auxiliary feedwater flow caused the indicated level to increase slowly as the cold auxiliary feedwater warmed to the saturation temperature of the intact steam generator (level swell). When the RCS cooldown was initiated, the level spiked briefly due to the increased voids at the lower pressure, then fell rapidly as the steam generator inventory was depleted. The effects of the throttling of the auxiliary feedwater to these steam generators is seen in Figure 11-5 between 25 and 40 minutes. The indicated level increased when the auxiliary feedwater was injected and fell when the auxiliary feedwater was throttled. Note that the level swell was not enough to overcome the effects of a decrease in the steam generator inventory, thus the level fell when the auxiliary feedwater was throttled.

Subcooled Recovery Contingency Responses (40 to 90 minutes)

The indicated levels increased immediately when the ARVs were opened further. The level increase was due to an increase in the amount of voiding, which in turn affected the mixture volume upon which the level indication was based. Following the initial level increase when the ARVs were opened, the level fell as the steam generator inventory was depleted. The reduction in the ARV area caused an immediate decrease in level due to the void collapse as the pressure increased. Overlaid onto this pattern were the effects of the throttled auxiliary feedwater. As auxiliary feedwater was added to the intact steam generators, the level began to rise. The rate of level increase due to an injection of auxiliary feedwater was essentially the same every time the feedwater flow rate was increased, facilitating the identification of periods of auxiliary feedwater injection.

The level in the ruptured steam generator is a function of the break flow rate through the ruptured U-tube. When the RCS was depressurized near 47 minutes, the break flow rate was decreased, and the rate of level increase was lessened. This change in the level increase can be seen in the plot (Figure 11-5) of the ruptured steam generator narrow range level near 50 minutes. Following the repressurization of the RCS due to the ECCS flow, the rate of level increase continued until it was predicted to go offscale (high) at approximately 80 minutes.

Saturated Recovery Contingency Responses (after 90 minutes)

The level indications in the intact steam generators during this phase of the transient behaved as in the previous phases, with the effects of the ARV modulations and auxiliary feedwater flow rate adjustments obvious in the level plot.

11.3.8 Break Flow Rate

Standard SGTR Termination Responses (0 to 40 minutes)

Following the initiation of the event, the break flow rate (Figure 11-6) decreased as the RCS pressure decreased. After the reactor and turbine tripped and the ensuing RCS pressure decrease and steam generator pressure increase occurred, the break flow rate dropped sharply. As the ECCS flow caused the RCS pressure to increase, and the auxiliary feedwater flow caused the ruptured steam generator pressure to decrease (Figure 11-7), the break flow rate gradually increased. After the ruptured steam generator was isolated, the ruptured steam generator continued to depressurize while the RCS began to repressurize; thus, the SGTR break flow rate increased. The rate of increase in the flow rate changed as the RCS temperatures and pressure approached equilibrium values. The RCS cooldown and resultant depressurization caused the break flow rate to decrease; however, the magnitude of the decrease was reduced due to the increase in the density of the break fluid.

Near 30 minutes, when the ECCS flow rate was greater than the break flow rate and the RCS began to repressurize, the break flow rate again began to increase. This increase in flow rate continued as the pressurizer repressurized and the ruptured steam generator depressurized through the stuck open ARV.

Subcooled Recovery Contingency Responses (40 to 90 minutes)

The break flow rate (Figure 11-6) was primarily a function of the primary-to-secondary pressure differential. By the start of this phase of the transient, the secondary pressure had essentially leveled out and was decreasing fairly slowly; thus, the break flow rate followed the same general trend as the RCS pressure. However, because the fluid density also affected the flow rate, the magnitude of any change was dampened relative to the pressure change.

Saturated Recovery Contingency Responses (after 90 minutes)

Following the termination of the SIP flow, the break flow rate decreased as the pressurizer pressure fell off. When the pressurizer PORV was opened to depressurize the RCS to saturation, the break flow rate fell sharply as the primary-secondary pressure difference decreased (see Figure 11-7). Thereafter, the break flow rate trended in the same manner as the RCS pressure. Note that the RCS continued to be at a slightly greater pressure than the ruptured steam generator; however, the differential pressure was relatively small. Because the RCS density was high, the mass flow rate through the break continued to be significant, even though the driving pressure differential was small.

Note that after the final RCS depressurization, the break flow began to increase. This increase was caused by the continued influx of ECCS flow from one CCP and would continue until the reactor operators aligned the charging and letdown system and initiated RHR cooling.

11.3.9 Ruptured Steam Generator Liquid Volume

Standard SGTR Termination Responses (0 to 40 minutes)

The collapsed liquid volume (Figure 11-8) is used to determine the margin to overfill of the ruptured steam generator. Due to the action of the Steam Generator Water Level Control System, the liquid volume in the ruptured steam generator remained approximately constant until the reactor and turbine were tripped. At that time, the volume increased sharply until the main feedwater flow was lost. The addition of large amounts of auxiliary feedwater caused the liquid volume to increase, but at a much slower rate. Following the isolation of auxiliary feedwater to the ruptured steam generator, the rate of volume change became a function of the SGTR break flow rate and the ARV steam flow rate. Because the steam flow rate out the stuck open ARV was significantly greater than the break flow rate, the liquid volume decreased. As the ruptured steam generator pressure decreased and the break flow rate increased, particularly near the end of the RCS cooldown, the flow rate out the ARV became less than the incoming fluid. Thus the liquid volume began to increase and continued to increase throughout the remainder of the event.

Subcooled Recovery Contingency Responses (40 to 90 minutes)

Due to the steady break flow rate throughout this phase of the transient, the ruptured steam generator liquid volume steadily increased. At the time the RCS was depressurized to refill the pressurizer, reducing the break flow rate, the rate of volume increase was changed; however, the rapid repressurization renewed the volume increase.

Saturated Recovery Contingency Responses (after 90 minutes)

The liquid volume in the ruptured steam generator continued to increase until the primary was depressurized until the saturation pressure corresponding to the core exit temperature was reached in the pressurizer. At this point, the primary-to-secondary leakage had become relatively small and was essentially offset by the steam flow through the ARV, thus effectively terminating the SGTR event. The final volume was approximately 5140 ft^3, well below maximum steam generator volume of 5954 ft^3.

11.4 Thermal-Hydraulic Input for the Dose Consequences Calculation

In order to calculate the radiological doses received at the exclusion area boundary and low population zone boundary following a postulated SGTR event, the following parameters were required for two distinct time periods, 0 - 2 hours and 2 - 8 hours following the initiation of the event:

1) Time dependent primary coolant flashing fraction;

2) Time dependent break flow;

3) Total mass released from the ruptured steam generator (to atmosphere);

4) Total mass released from the intact steam generators (to atmosphere); and,

5) Total mass released to the condenser.

Because the steam generator secondary was at a lower pressure than the primary fluid, a fraction of the relatively hot primary fluid would flash into steam as the primary coolant leaked into the secondary. This fraction is referred to as the flashing fraction.

Time-dependent values of the above parameters for the 0 - 2 hour period were calculated explicitly as discussed in Section 11.3. The integral steam releases and integral break flow (Figure 11-9 through Figure 11-11) were calculated from the time-dependent values calculated during the simulation of the event. The time dependent flashing fraction for the 0 - 2 hour period is shown in Figure 11-12.

It was conservatively assumed that the entire 6 hour period from 2 - 8 hours was required to terminate the offsite release. The values of the required parameters at two hours were then extrapolated in a conservative manner to determine the integral releases for the 2 - 8 hour period. Furthermore, it was assumed that the steam flow rates decreased linearly with time. The break flow rate was conservatively assumed to remain constant throughout the 2 - 8 hour period. In reality, the mass flows would approach zero asymtotically. The flashing fraction was also assumed to remain constant throughout the 2 - 8 hour period.

The integral mass releases shown in Table 11-2 were calculated for use in assessing the radiological dose consequences following the postulated steam generator tube rupture event.

11.5 Summary

The design-basis scenario of the postulated steam generator tube rupture event has been analyzed in order to obtain steam release rates to be used to assess the radiological dose consequences of this event. In the scenario, it was assumed that the atmospheric relief valve on the ruptured steam generator failed to close. Because of a potentially adverse environment, the reactor operators could not assure that this valve would be closed; hence, it was necessary to simulate the SGTR transient until the Residual Heat Removal System could be placed in service at two hours. The required thermal-hydraulic parameters for the dose assessment calculation were then derived from this transient simulation.

TABLE 11-1

Design-Basis SGTR - Radiological Consequences
Event Timeline

Time		Event
0.08	min	Begin SGTR
5.05	min	Reactor trip on Low Pressurizer Pressure, Turbine Trip, Aux FW initiation, Loss of Offsite Power
5.13	min	Begin Main FW Isolation
6.77	min	Low Pressurizer Pressure - SIAS
13.08	min	Operator Action - Close MSIV, Loop 4, Isolate AFW, Loop 4, throttle AFW, Loop 1
23.08	min	Begin Maximum rate RCS cooldown
39.97	min	End Maximum rate RCS cooldown
44.97	min	Begin Controlled RCS cooldown
46.97	min	Begin RCS depressurization to refill Przr
49.92	min	End RCS depressurization to refill Przr
51.94	min	Stop one CCP and one SI pump
90.00	min	Stop one additional SI pump
95.00	min	Open Przr PORV to saturate RCS
115.80	min	Close Przr PORV on high Przr Level
120.00	min	End transient simulation

TABLE 11-2

Design-Basis SGTR - Radiological Consequences

Summary of Integral Mass Releases

Steam Released from Intact Steam Generators

0-2 hours	
Condenser	992,000 lbm
Atmosphere	370,000 lbm
2-8 hours	
Atmosphere	423,000 lbm

Steam Released from Ruptured Steam Generator

0-2 hours	
Condenser	331,000 lbm
Atmosphere	259,000 lbm
2-8 hours	
Atmosphere	144,000 lbm

Leakage from RCS to Ruptured Steam Generator through the SGTR

0-2 hours	352,000 lbm
2-8 hours	584,000 lbm

TABLE 11-3

Design-Basis SGTR - Radiological Consequences
Key To Figures 11-1 through 11-12

Point	Event
A	Reactor trip on Low Pressurizer Pressure, Turbine Trip, Aux FW initiation, Loss of Offsite Power
B	Low Pressurizer Pressure - SIAS
C	Operator Action - Close MSIV4, Isolate AFW4, throttle AFW1
D	Begin Maximum rate RCS cooldown
E	End Maximum rate RCS cooldown
F	Begin Controlled RCS cooldown
G	Begin RCS depressurization to refill Przr
H	End RCS depressurization to refill Przr
J	Stop one CCP and one SI pump
K	Stop one additional SI pump
L	Open Przr PORV to saturate RCS
M	Close Przr PORV on high Przr Level

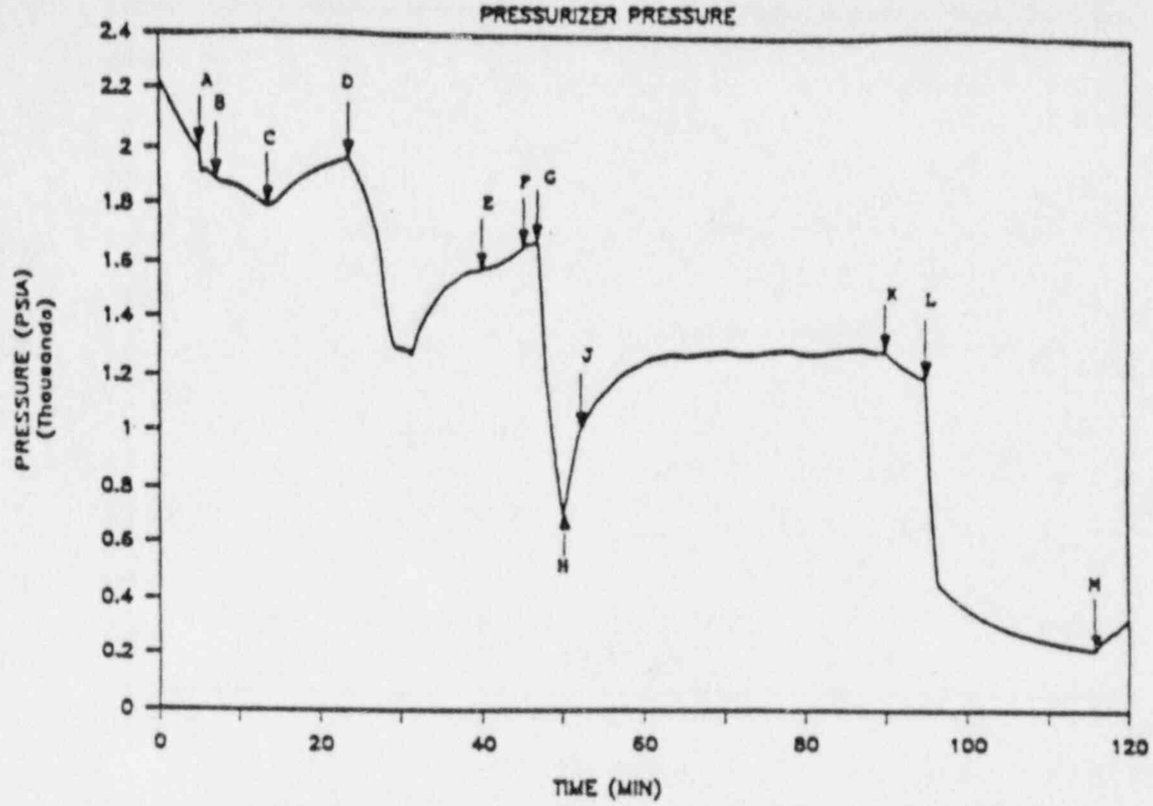


FIGURE 11-1. CPSES1 Design-Basis SGTR, Doses - Pressurizer Pressure

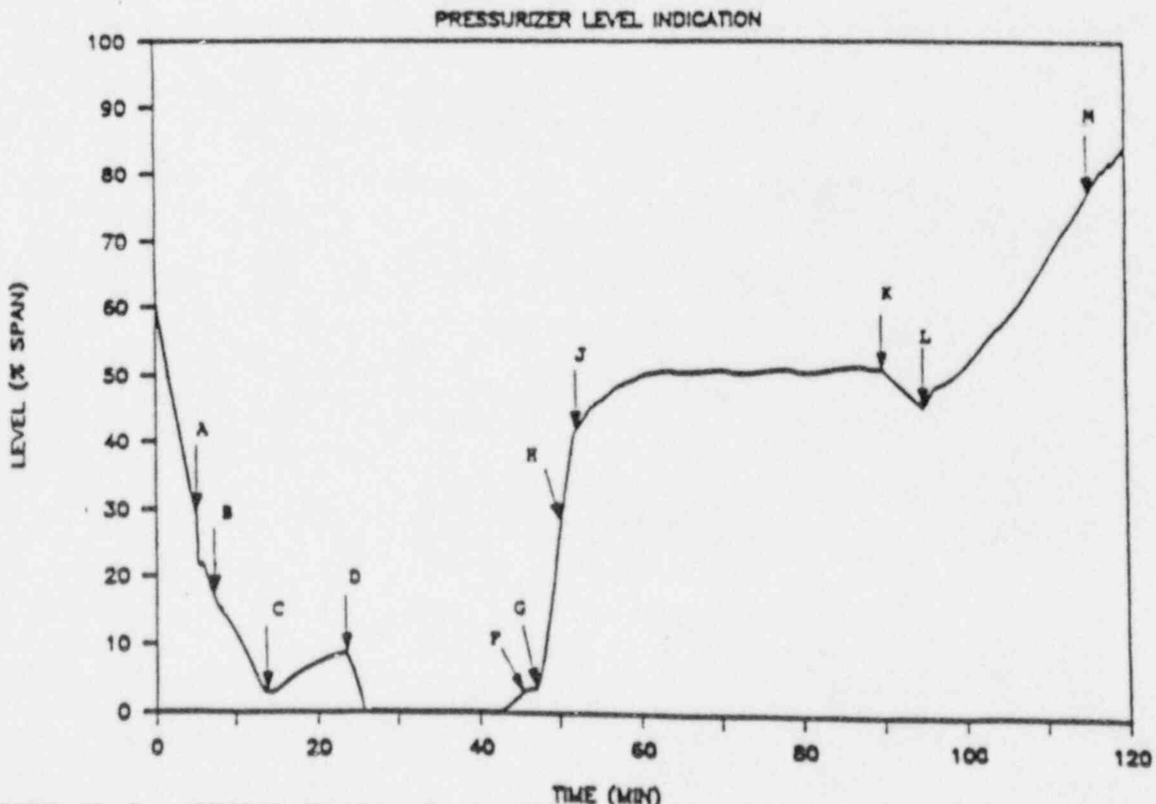


FIGURE 11-2. CPSES1 Design-Basis SGTR, Doses - Pressurizer Level

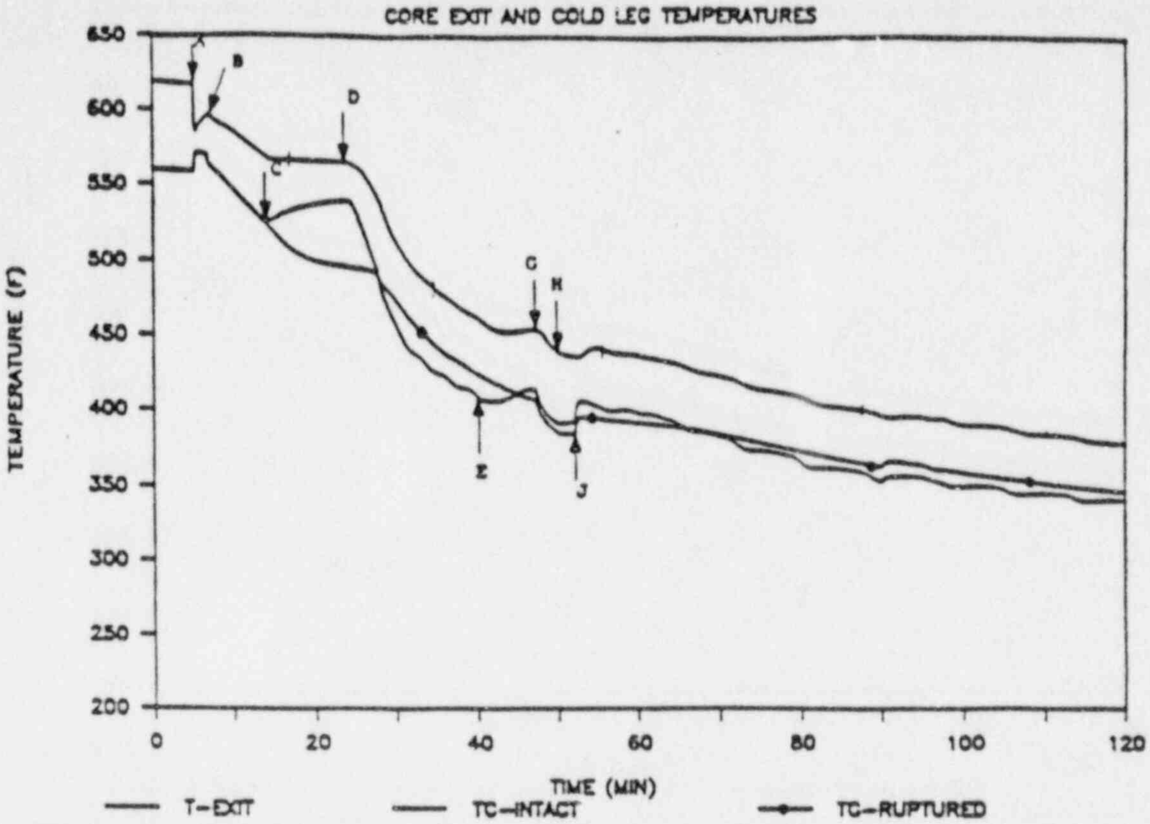


FIGURE 11-3. CPSES1 Design-Basis SGTR, Doses - RCS Temperatures

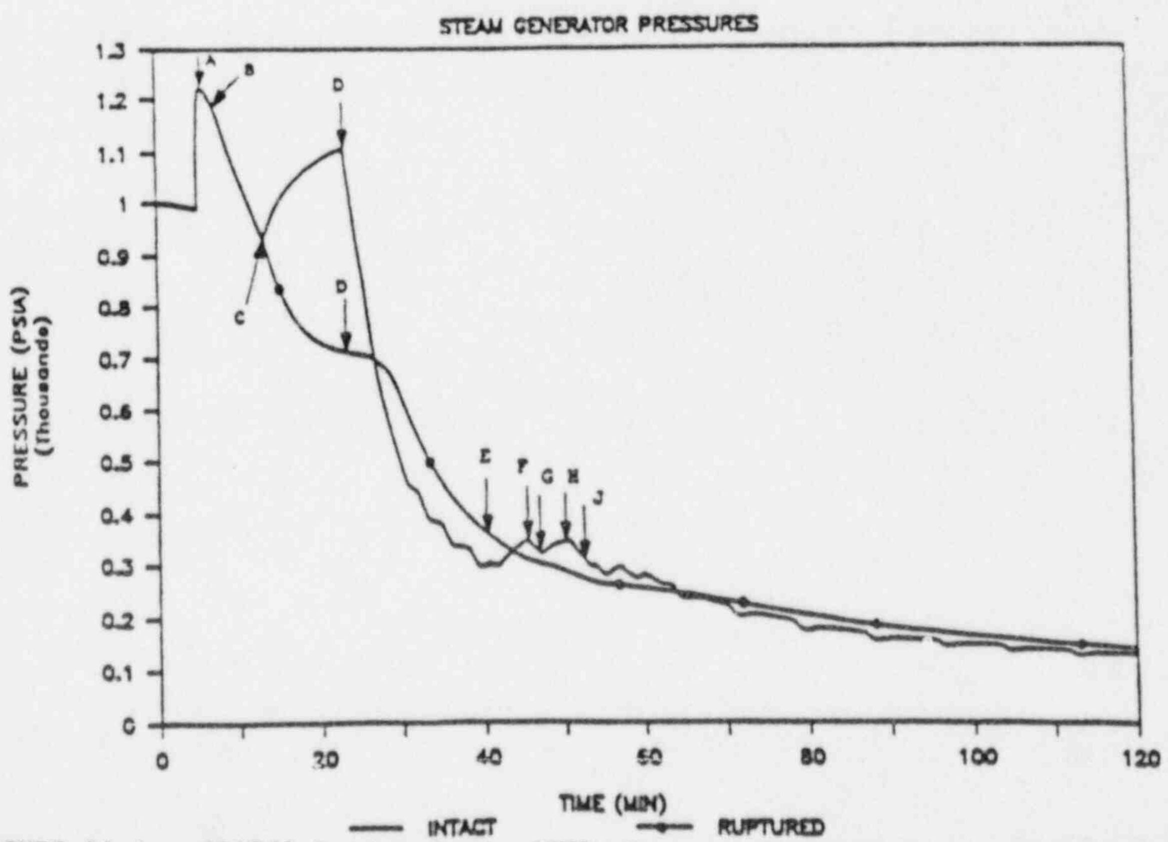


FIGURE 11-4. CPSES1 Design-Basis SGTR, Doses - Steam Generator Pressures

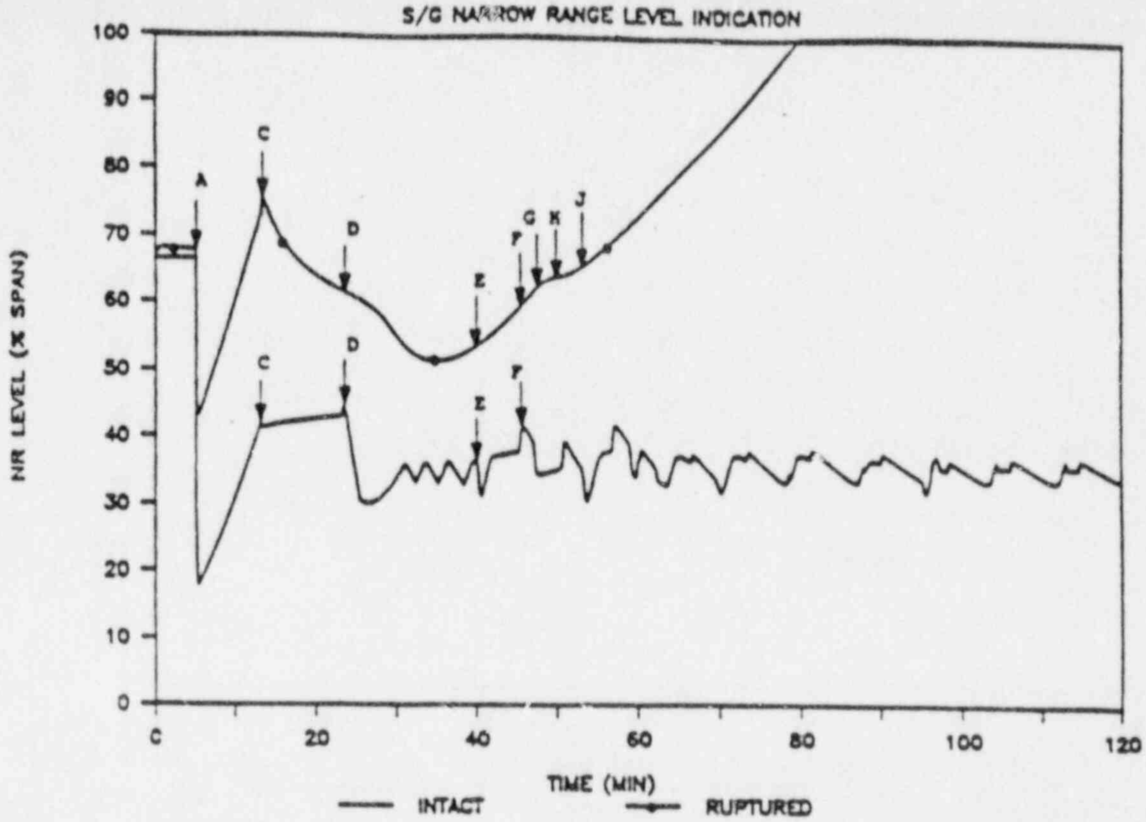


FIGURE 11-5. CPSES1 Design-Basis SGTR, Doses - Steam Generator Levels

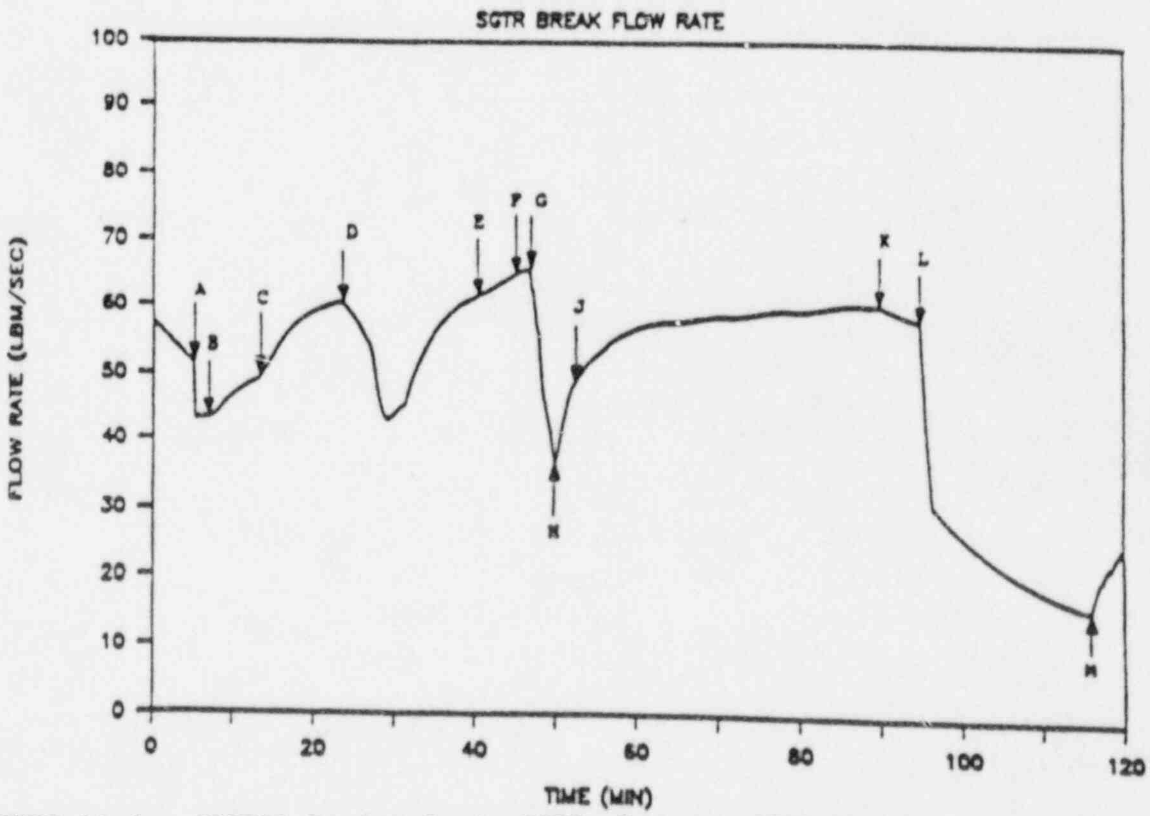


FIGURE 11-6. CPSES1 Design-Basis SGTR, Doses - SGTR Break Flow Rate

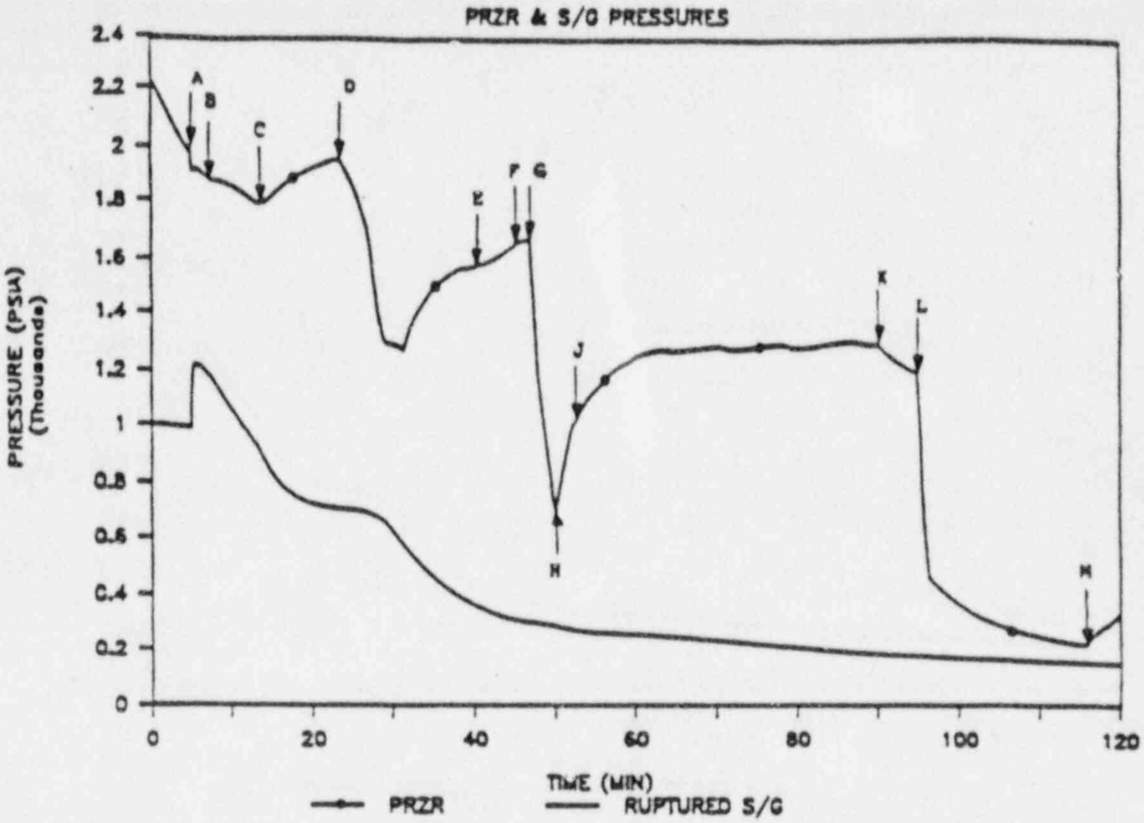


FIGURE 11-7. CPSES1 Design-Basis SGTR, Doses - Przr and SG Pressures

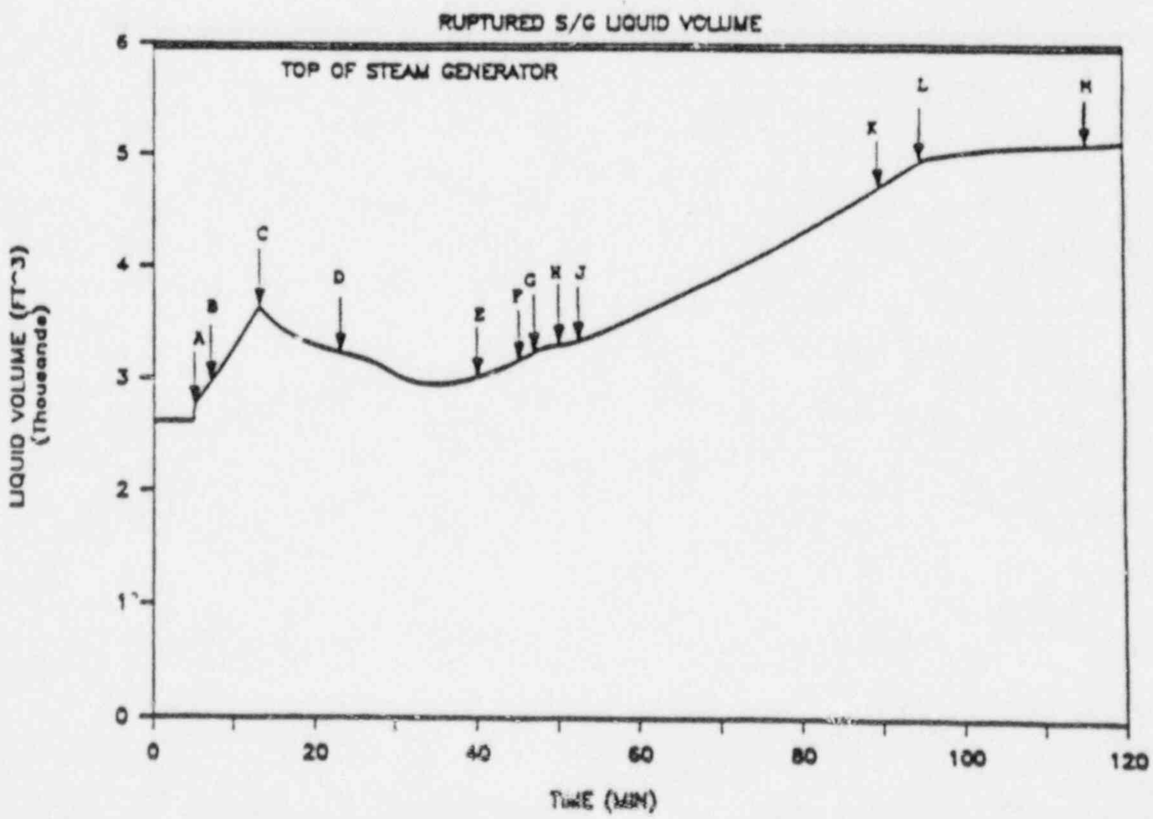


FIGURE 11-8. CPSES1 Design-Basis SGTR, Doses - Ruptured SG Liquid Volume

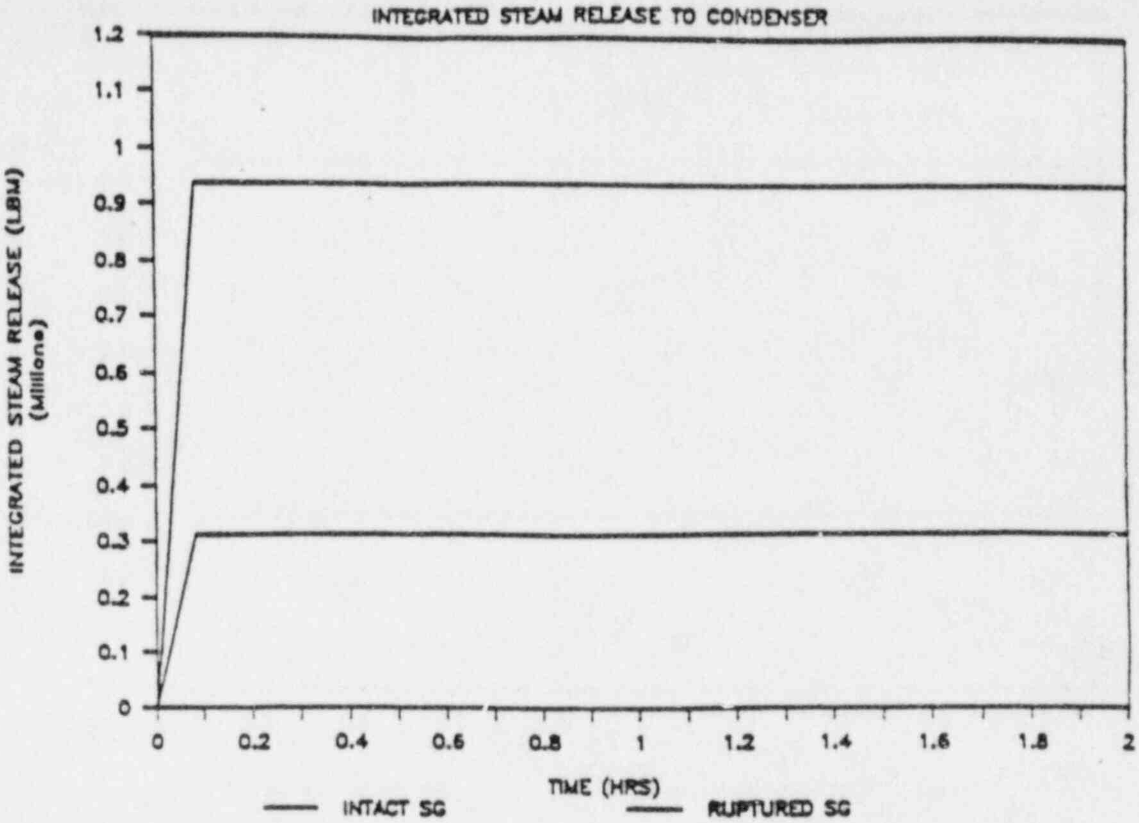


FIGURE 11-9. CPSES1 Design-Basis SGTR, Doses - Integrated Steam Releases to Condenser

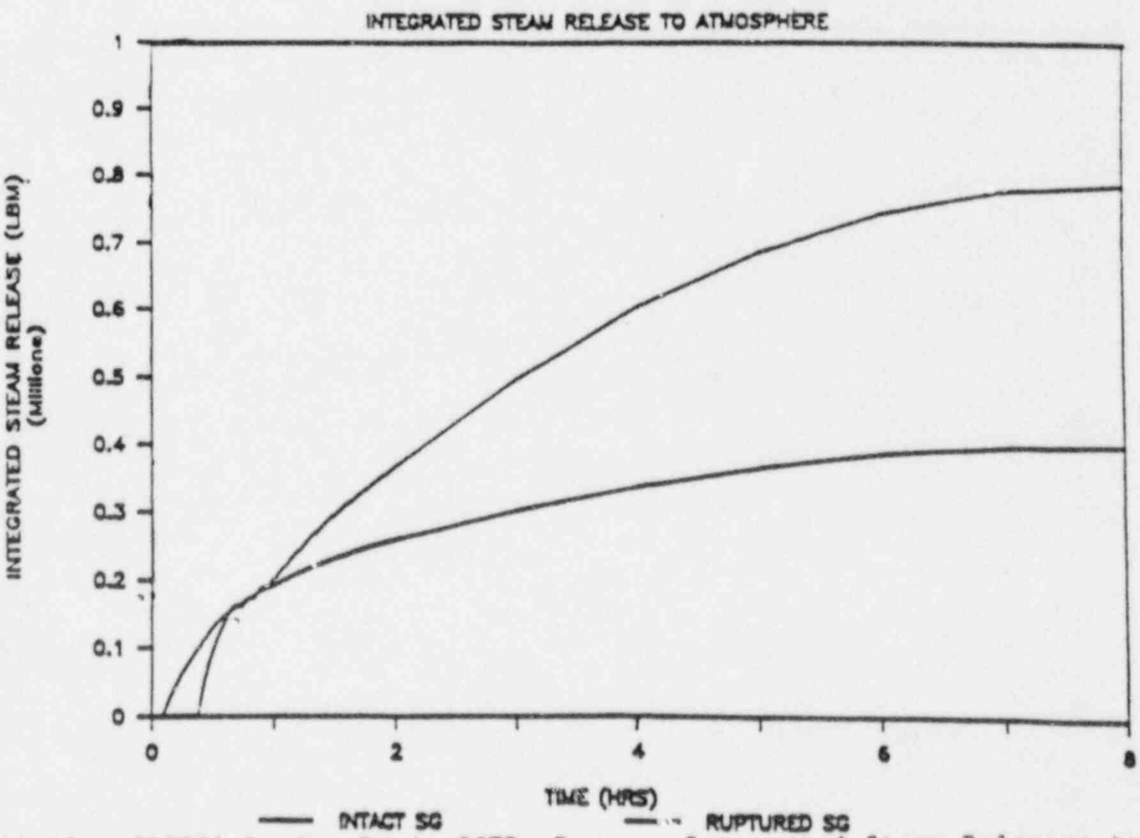


FIGURE 11-10. CPSES1 Design-Basis SGTR, Doses - Integrated Steam Releases to Atmosphere

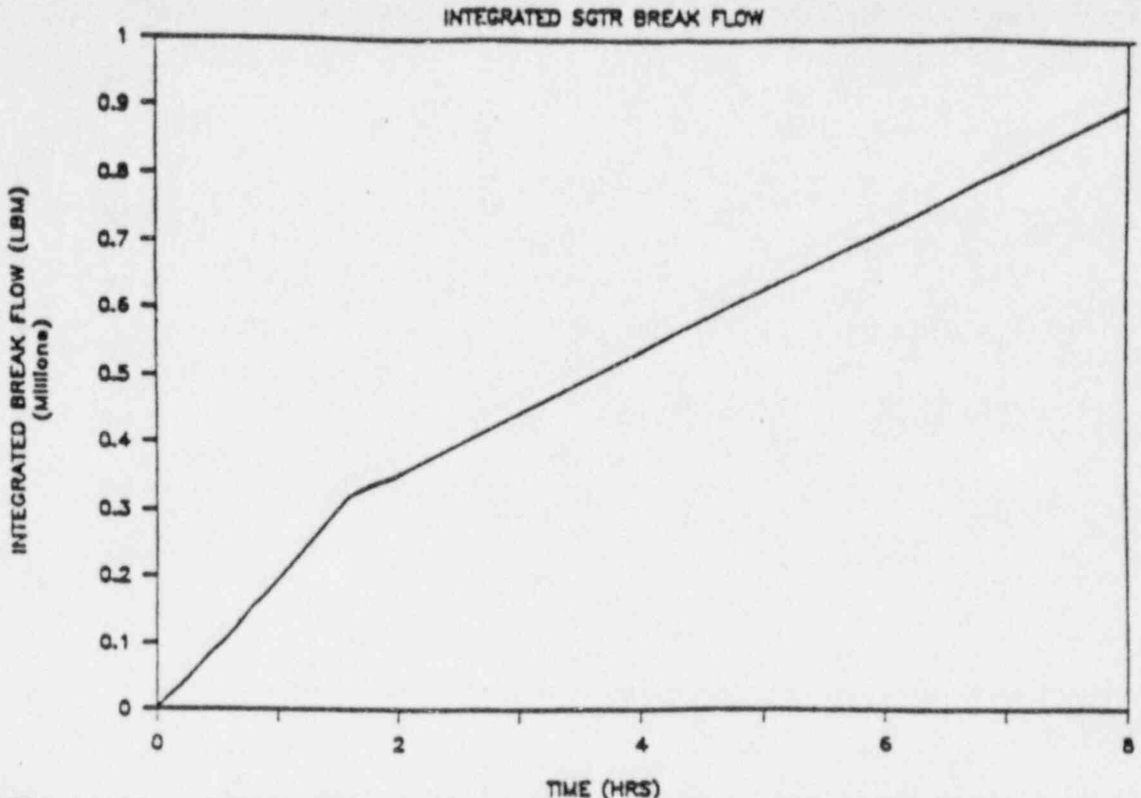


FIGURE 11-11. CPSES1 Design-Basis SGTR, Doses - Integrated Break Flow

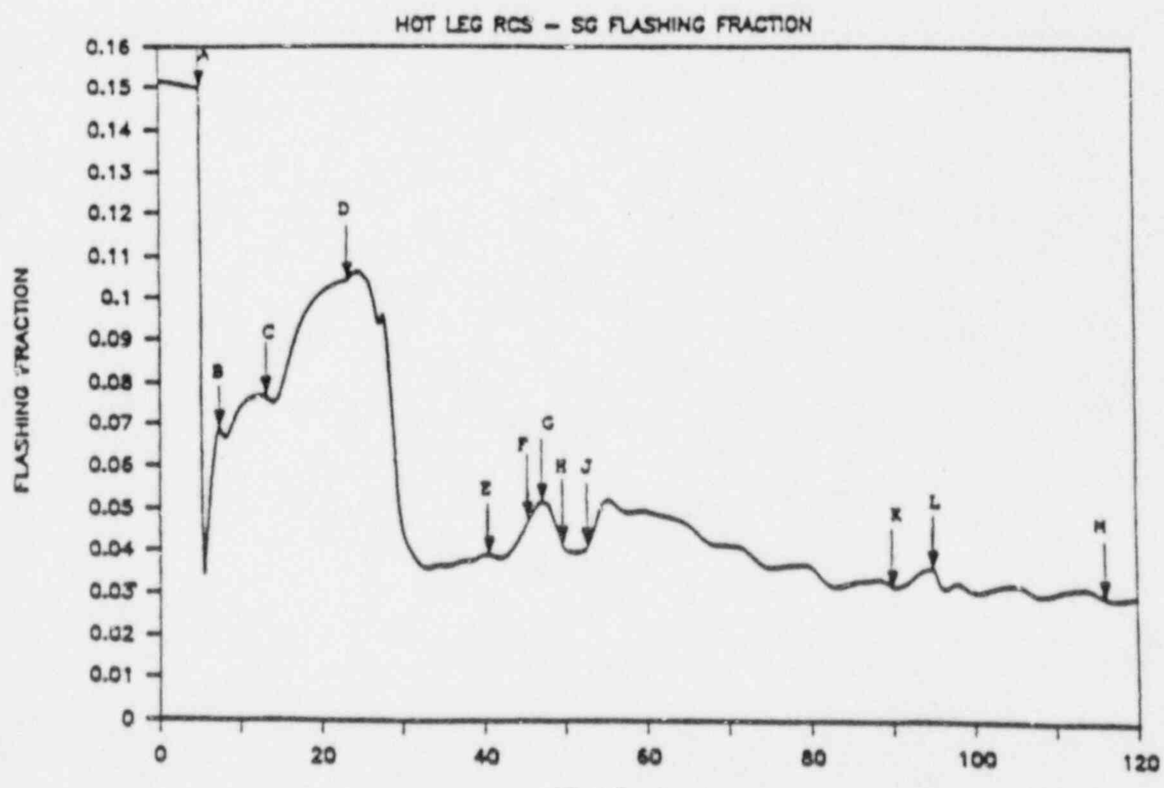


FIGURE 11-12. CPSES1 Design-Basis SGTR, Doses - Hot Leg Flashing Fraction

CHAPTER 12

RADIOLOGICAL DOSE ASSESSMENT

For the design-basis SGTR event for the Worst Case, Radiological Consequences, a calculation was performed to evaluate the whole body and thyroid inhalation doses to an individual located at the exclusion area boundary (EAB, 1544 m) and the low population zone boundary (LPZ, 4 miles). The results were used to show that the distances to the EAB and the LPZ were sufficient to provide reasonable assurance that the calculated radiological consequences of a postulated steam generator tube rupture did not exceed: (a) the exposure guidelines set forth in 10CFR100, Chapter 11 for the accident with an assumed preaccident iodine spike and (b) ten percent of the 10CFR100.11 exposure guidelines for the accident with an assumed concurrent iodine spike.

Two separate iodine spikes were considered:

> Case I: A reactor transient had occurred prior to the tube rupture which raised the primary coolant iodine concentration to 60 uCi/gm dose equivalent iodine-131 (DEQ I-131).
>
> Case II: The reactor trip or primary system depressurization associated with the postulated accident created an iodine spike in the primary system. The spike was assumed to increase the iodine appearance rate (inleakage from the defective fuel rods to the primary coolant) to 500 times the equilibrium appearance rate.

The assumptions listed below were used to determine the initial primary and secondary activities and to calculate the activity released and the offsite doses for the postulated steam generator tube rupture. The dose calculational method and dose conversion assumptions are consistent with those contained in Regulatory Guide 1.109 [14].

1) The initial primary coolant iodine activity was assumed to be at the Stan[illegible] [illegible]hnical Specification limit (STS 3/4.4.8 Specific Activity f 1. [illegible]Ci/gm DEQ I-131 .

2) The primary coolant activity had been leaking into the secondary side for a period of time long enough to establish equilibrium activity concentrations in the steam generators. The magnitude of the leakage, 1 gpm, was the STS limit (3/4.4.6.2 Reactor Coolant System Leakage) for primary to secondary leakage.

3) All noble gas activity was transported from the primary system to the secondary system and the noble gas activity in the steam region of the steam generators was immediately released to the environment.

4) Due to the pressure differential between the primary and secondary sides, a fraction of the primary coolant leaked to the defective steam generator was assumed to flash to steam. This flashed fraction was assumed not to mix with the steam generator water, and therefore, was not subjected to any iodine removal process in the steam generator.

5) No credit was taken for decay of the radionuclides prior to their release to the environment.

6) A ground level release was assumed. No credit was taken for radioactive decay or cloud depletion due to ground deposition during the plume transport.

7) Worst case, five percentile atmospheric dispersion factors were assumed.

8) A breathing rate of 3.47E-04 m^3/s was assumed.

9) Conservative iodine partition factors of 0.01 were used in the steam generator and condenser to account for that fraction of

iodine present in the steam generator and condenser fluids which is carried with the fluid as it is converted to steam.

The integral mass releases shown in Table 11-2 were calculated from the thermal-hydraulic analysis of the Design-basis Event - Worst Case Radiological Consequences, described in Chapter 11, and were used as input for the radiological dose assessment calculation. The integral mass releases for the 2 - 8 hour period were based on extrapolations from the 2 hour values. The steam release rates were conservatively assumed to linearly decrease to zero at 8 hours. The primary to secondary leakage and the flashing fraction were conservatively assumed to be constant at their 2 hour value throughout the 2 - 8 hour period.

The calculated radiological doses are shown in Table 12-1. All of the calculated doses are well within the 10CFR100.11 limits of 300 Rem to the thyroid and 25 rem to the whole body.

TABLE 12-1

Radiological Dose Consequences of a Postulated SGTR

	Minimum EAB (0-2 hrs)		LPZ (0-8 hrs)	
	Whole Body (Rem)	Thyroid (Rem)	Whole Body (Rem)	Thyroid (Rem)
Case I - Preaccident Spike				
Calculated Dose:	5.37×10^{-2}	68.7	1.26×10^{-2}	11.4
10CFR100.11 Limits:	25.0	300.0	25.0	300.0
Case II - Accident-Initiated Spike				
Calculated Dose:	5.37×10^{-2}	27.7	1.26×10^{-2}	13.5
10CFR100.11 Limits:	2.5	30.0	2.5	30.0

CHAPTER 13

CONCLUSIONS

In response to NRC requests, TU Electric has re-examined the postulated, design-basis, Steam Generator Tube Rupture Event. The SGTR event is unique among the design-basis accidents in that timely and correct operator intervention is required to terminate the event and prevent filling the ruptured steam generator with liquid. The overfill of the ruptured steam generator could threaten the integrity of the main steamlines and associated supports and could result in increased releases of radioactive material. Hence, using the CPSES control room simulator, extensive evaluations of the reactor operator responses and response times required for termination of the postulated event were performed using CPSES reactor operators trained to follow the CPSES Emergency Response Guidelines. The equipment required for termination of the postulated event was identified, and the safety classification of this equipment was verified.

A transient-specific RETRAN02 model of CPSES1 was developed in accordance with the TU Electric, Reactor Engineering Quality Assurance program and a representative SGTR analysis was simulated for comparison with a similar analysis performed for the Westinghouse Owners Group. This comparison provided assurance of the adequacy of the CPSES1 Steam Generator Tube Rupture model. Conservative initial conditions were identified and included in the model. The effects of a number of postulated active failures were evaluated to determine which failure would result in the most severe transient. The active failure analyses resulted in the development of two design-basis scenarios. One scenario included the failure of an auxiliary feedwater throttling valve and resulted in the least margin to overfill of the ruptured steam generator. The second scenario included the failure to close of an atmospheric relief valve on the ruptured steam generator, which resulted in the most severe postulated radiological consequences.

For the design-basis Steam Generator Tube Rupture Event - Margin to Overfill, the margin to overfill of the ruptured steam generator was calculated to be 320 ft^3.

For the design-basis Steam Generator Tube Rupture Event - Worst Case Radiological Consequences, the offsite doses received at the exclusion area boundary and the low population zone boundary were calculated to be well within the limits of 10CFR100.11.

CHAPTER 14

REFERENCES

1. Nuclear Regulatory Commission letter to Texas Utilities Generating Company, Docket Nos. 50-445 and 50-446, "Request for Additional Information Regarding the Steam Generator Tube Rupture Accident Event for Comanche Peak Steam Electric Station (Units 1 and 2)", April 9, 1984.

2. R. N. Lewis, et al., "SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill", WCAP-10698-P-A, Westinghouse Electric Corporation.

3. R. N. Lewis, et al., "Evaluation of Offsite Radiation Doses for a Steam Generator Tube Rupture Event", Supplement 1 to WCAP-10698-P-A, Westinghouse Electric Corporation.

4. R. N. Lewis, et al., "Evaluation of Steam Generator Overfill due to a Steam Generator Tube Rupture Event", WCAP-11002, Westinghouse Electric Corporation.

5. Nuclear Regulatory Commission letter to Westinghouse Owners Group, SGTR Subgroup, "Acceptance for Referencing of Licensing Topical Report WCAP-10698, Supplement 1, 'Evaluation of Offsite Radiation Doses for a Steam Generator Tube Rupture Accident'", December 17, 1985.

6. Nuclear Regulatory Commission letter to Westinghouse Owners Group, SGTR Subgroup, "Acceptance for Referencing of Licensing Topical Report WCAP-10698 "SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill", December, 1984", March 30, 1987.

7. J. H. McFadden, et al., "RETRAN-02, A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems", NP-1850-CCM-A, Revision 3, Electric Power Research Institute, June 1987.

8. J. H. McFadden, et al., "RETRAN-02, A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems", NP-1850-CCM-A, Revision 3, Appendix A, Electric Power Research Institute, June 1987.

9. "A Thermal-Hydraulic Analysis of the Ginna Steam Generator Tube Rupture Event of January 25, 1982", INPO 84-009, Institute of Nuclear Power Operations, February 1984.

10. J. Chao, et al., "Using RETRAN-02 and DYNODE-P to Analyze Steam Generator Tube Breaks", NSAC-47, Nuclear Safety Analysis Center, May, 1982.

11. C. E. Peterson, et al., "Response of a W Two-Loop Plant to Steam Generator Tube Ruptures", NSAC-77, Nuclear Safety Analysis Center, July, 1984.

12. "Abnormal Conditions Procedures Manuals", Revision 37, Comanche Peak Steam Electric Station.

13. "Emergency Response Guidelines Manual, E Series", Revision 3, Comanche Peak Steam Electric Station.

14. "Calculation of Annular Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I", Revision 1, Regulatory Guide 1.109, Nuclear Regulatory Commission, October, 1977.