VALVE INLET FLUID CONDITIONS FOR PRESSURIZER SAFETY AND RELIEF VALVES IN COMBUSTION ENGINEERING-DESIGNED PLANTS

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RESEARCH PROJECT V102-20

(PHASE B)

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Prepared by

COMBUSTION ENGINEERING, INC.

1000 Prospect Hill Road

Windsor, Connecticut 06095

PRINCIPAL INVESTIGATORS

J. Bahr
D. Chari
M. Puchir
S. Weismantel

Prepared for

PARTICIPATING PWR UTILITIES

and

ELECTRIC POWER RESEARCH INSTITUTE

3412 Hillview Avenue

Palo Alto, California 94304

EPRI Project Manager

J. Hosler

Nuclear Power Division

EPRI PERSPECTIVE

PROJECT DESCRIPTION

This report, developed under RPV102-20 in support of the EPRI/PWR Safety and Relief Valve Test Program, presents the expected range of fluid inlet conditions for pressurizer safety valves and power-operated relief valves (PORVs) utilized in PWR units designed by Combustion Engineering. These conditions are determined based on consideration of FSAR, Extended High Pressure Liquid Injection, and Cold Overpressurization events.

PROJECT OBJECTIVE

The objective of this report is to assist PWR utilities with Combustion Engineering plants in demonstrating that the fluid conditions under which their valve designs are tested as part of the aforementioned program, envelop those expected in their unit(s).

PROJECT RESULTS

FSAR events are found to result in challenges to both PORVs and safety valves under steam conditions with valve inlet pressures as high as 2760 psia. Liquid discharge is not predicted for FSAR events.

Extended High Pressure Liquid Injection events result in PORV challenges only in one Combustion Engineering unit (Maine Yankee); if the PORVs are inoperable, safety valve actuation may occur. For this unit, steam followed by liquid discharge is predicted. Based on a qualitative assessment, liquid temperatures are estimated to range from about 467 to 650 degrees Fahrenheit. Surge rates into the pressurizer are expected to range from 0 to 125 gallons per minute.

Cold Overpressurization events challenge only PORVs. Liquid discharge is predicted for these events at pressures ranging from 465 to 870 psia with temperatures ranging from 100 to 417 degrees Fahrenheit.

John Hosler, Project Manager
Nuclear Power Division

ABSTRACT

The purpose of this study is to assemble documented information for C-E designed plants concerning pressurizer safety and power operated relief valve (PORV) inlet fluid conditions during actuation as calculated by conventional licensing analyses. This information is to be used to assist in the justification of the valve inlet fluid conditions selected for the testing of safety valves and PORVs in the EPRI/PWR Safety/Relief Valve Test Program. Available FSAR/Reload analyses and certain low temperature overpressurization analyses were reviewed to identify the pressurization transients which would actuate the valves, and the corresponding valve inlet fluid conditions. In addition, consideration was given to the Extended High Pressure Liquid Injection event. A general description of each pressurization transient is provided. The specific fluid conditions identified and tabulated for each C-E designed plant for each transient are peak pressurizer pressure, pressure ramp rate at actuation, temperature and fluid state.

For all C-E plants (except Maine Yankee), the safety/relief valve inlet fluid state for all transients initiated at normal power operating conditions is saturated steam. For the Maine Yankee plant a potential exists for liquid discharge from the PORVs and safety valves during the High Pressure Injection Event. In those plants where the valves are provided with water seals the saturated steam flow is preceded by a momentary liquid flow as the water seals are voided. Those C-E plants which are provided with PORVs also utilize the PORVs for low temperature overpressure protection (LTOP) in addition to their high pressure relieving function. In the low temperature operating mode pressurizer pressure must be maintained within the limits defined by the plant Pressure/Temperature Limitation curve in order to preclude brittle failures. The plant restrictions that must be invoked to ensure that the PORVs maintain pressurizer pressure within allowable limits during the limiting LTOP transients are described. Since water-solid pressurizer conditions are considered in the LTOP analyses, liquid phase inlet conditions at the PORVs are encountered as well as saturated steam conditions.

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Section 1

INTRODUCTION

This report presents the results of studies performed by Combustion Engineering (C-E) under contract to Electric Power Research Institute (EPRI). The work reported herein applies to Task 2 of the Phase B Extension to EPRI Project V102-20.

1.1 BACKGROUND

In the aftermath of the Three Mile Island (TMI) accident, the Nuclear Regulatory Commission (NRC) has required that utilities operating and constructing Pressurized Water Reactor (PWR) power plants demonstrate the operability of pressurizer safety and relief valves. These requirements were issued in NUREG-0578 (Reference 1) and later clarified in NUREG-0737 (Reference 2). In response to these requirements, EPRI is conducting a comprehensive program to test various types of safety and power-operated relief valves (PORVs) utilized in domestic PWR units. The objective of the test program is to demonstrate valve operability for fluid conditions which are prescribed in conventional licensing analyses.

As a supplement to the test program, EPRI has initiated several supporting studies which are being performed by each Nuclear Steam Supply System (NSSS) vendor. The particular study which is the subject of this report is intended to provide EPRI with supporting data required to demonstrate that the fluid test conditions being used in the EPRI Valve Test Program are applicable to C-E NSSSs.

1.2 OBJECTIVE

The objective of this study is to develop information to assist in the justification of the applicability to C-E designed NSSSs of the inlet fluid conditions selected for the testing of pressurizer and relief valves in the EPRI Valve Test Program. This study is intended to document the fluid conditions under which the safety and relief valves are shown in FSAR/Reload analyses to actuate. Cold pressurizations and High Pressure Injection events are also considered. Cold pressurization events are characterized in this report as Low Temperature Overpressure Protection (LTOP) events.

1.3 SCOPE

The scope of this study is to review the various sources containing information on pressurization events in those C-E designed plants participating in the EPRI PWR Safety and Relief Valve Test Program, and to present the inlet fluid conditions for those events for which safety and/or PORV actuation is calculated to occur.

The major source of information on valve inlet fluid conditions during actuation are plant FSAR safety analyses or the most recent available fuel reload analyses. Table 1-1 presents a tabulation of the specific FSAR/Reload Analyses from which data was obtained. In addition, for those plants provided with PORVs which are used for low temperature overpressure protection (LTOP), the PORV inlet fluid conditions were based on LTOP analyses performed by C-E on behalf of utilities operating C-E designed NSSSs. The Maine Yankee LTOP study was not performed by C-E since this utility was not a member of the C-E LTOP Owners' Group. Therefore, LTOP conditions for Maine Yankee are not presented in this report. Finally, the actuation of the safety valves and/or PORVs as a result of the extended operation of the high pressure safety injection (HPSI) pumps was investigated.

1.4 QUALITY ASSURANCE

The data presented in this report is based on information in the documents referenced in Table 1-1 as well as information from References (4) through (9). The analyses* used to generate the information contained in the above sources were performed in accordance with 10CFR50 Appendix B quality assurance requirements.

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*Since C-E does not perform the current reload safety analyses for Palisades, Maine Yankee, and Fort Calhoun, those licensees should validate that the corresponding fluid conditions noted in this report remain applicable for the current operating cycle.

TABLE 1-1

Data Sources for FSAR/Reload Transients in C-E Designed Plants

Plant	Current Operating Cycle(1)	Start up Date for Current Cycle	Reference Cycle Analysis
Arkansas Nuclear One-Unit 2	2	June, 1981	Cycle 2
Calvert Cliffs Unit 2	5	Jan., 1981	Cycle 5
Calvert Cliffs Unit 2	4	March, 1981	Cycle 4
Maine Yankee	6	July, 1981	FSAR
Millstone Pt. Unit 2	4	Oct., 1980	Cycle 3
Fort Calhoun	6	June, 1980	FSAR and Cycle 5
Palisades	4	May, 1980	FSAR
St. Lucie Unit 1	4	May, 1980	Cycle 4***
San Onofre Units 2&3	**	-	FSAR, Amend. 23
Waterford Unit 3	**	-	FSAR, Amend. 16
St. Lucie Unit 2	**	-	FSAR, Amend. 2
Yellow Creek Units 1&2	**	-	CESSAR FSAR Amend. 5†
WNP Units 3&5	**	-	CESSAR FASR Amend. 5†
Cherokee Units 1,2&3*	**	-	CESSAR FSAR Amend. 5†
Perkins Units 1,2&3*	**	-	CESSAR FSAR Amend. 5†
Palo Verde Units 1,2&3*	**	-	CESSAR FSAR Amend. 5†

* Each unit is a System 80 Standard Plant design.

** Not Operating.

*** The Cycle 4 Stretch Power license amendment was used as the reference cycle.

† CESSAR is the C-E Standard Safety Analysis Report

(1) As of Summer, 1981

Section 2

DESCRIPTION OF C-E DESIGNED NSSSs

2.1 INTRODUCTION

A brief general description of a typical C-E NSSS is provided in Section 2.2. Figure (2-1), a simplified Reactor Coolant System (RCS) flow diagram, is provided to facilitate following the description. The description is generally applicable to all C-E NSSSs, although specific plants may differ in some details. Special features of specific plants that are of particular interest in this study are described in Section 2.3.

2.2 GENERAL DESCRIPTION

2.2.1 Reactor Coolant System

The C-E NSSS contains a reactor core which is the heat source, housed in a reactor vessel, and a Reactor Coolant System (RCS) to transfer the heat generated to the steam generators. The RCS consists of four reactor coolant pumps (RCPs) operating in two loops* with one steam generator in each loop. The steam generators are vertical U-tube heat exchangers with the primary reactor coolant flowing inside the tubes and transferring heat to secondary water outside the tubes. A pressurizer is connected to one hot leg. Shutdown cooling suction nozzles are located on either one or both hot legs. Safety injection nozzles are located in each of the RCP discharge legs. A letdown line nozzle is located at the suction of one RCP and a charging line nozzle is located at the discharge of another RCP.

2.2.2 Overpressure Protection System

RCS overpressure protection is provided by two to four ASME Code spring-loaded safety valves (nominal set pressure of 2500 psia) located at the top of the pressurizer. Safety valve set pressures have an ASME Code allowable tolerance of ± 1%. In some plants the set pressures are staggered. The staggered safety valve set pressures typically range from 2500 psia to 2580 psia.

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* An exception applies to the Maine Yankee plant which is provided with three RCPs operating in three loops, with one steam generator in each loop.

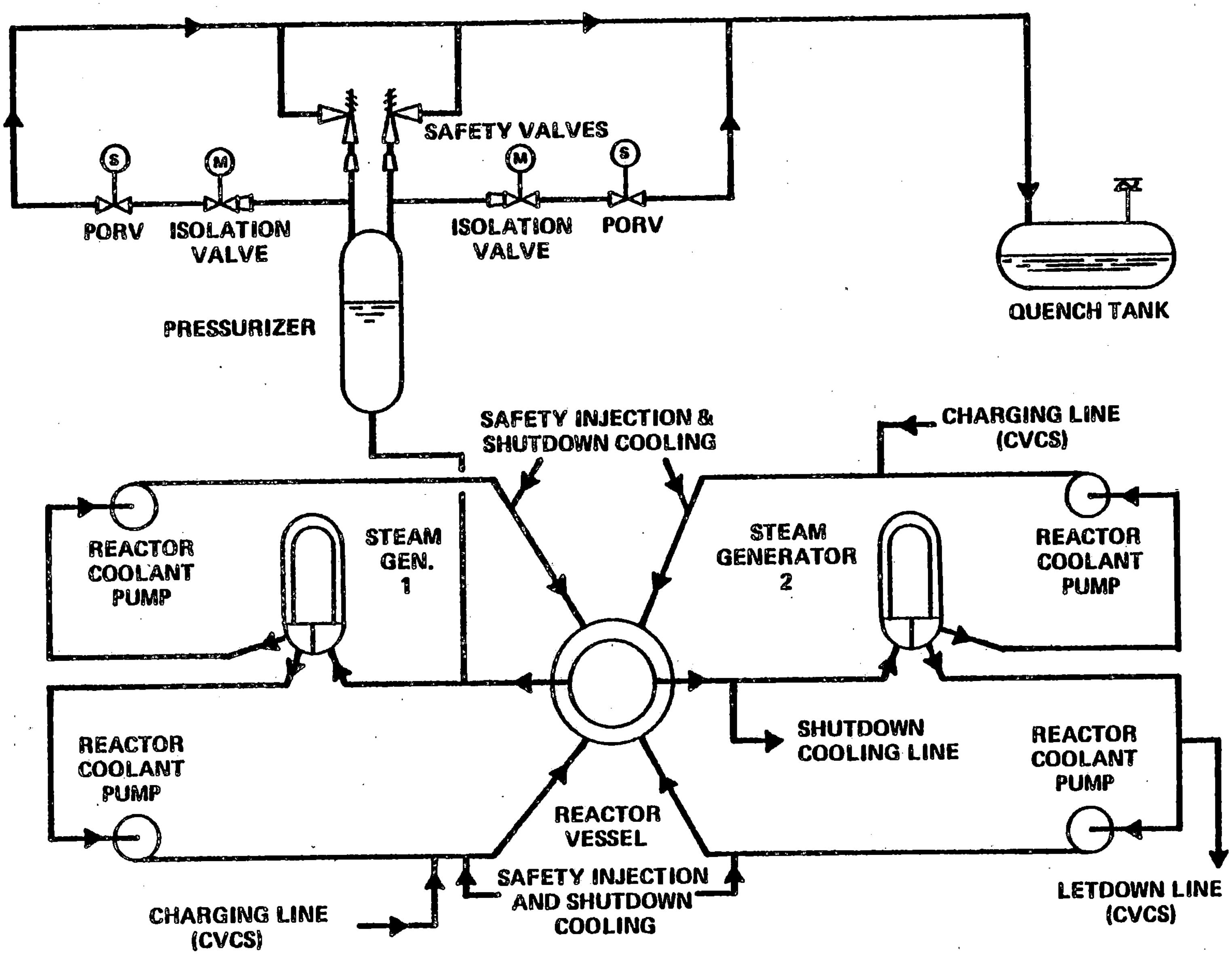

Figure 2-1
TYPICAL REACTOR COOLANT SYSTEM

Earlier C-E plants are also equipped with two power operated relief valves (PORVs) with a set pressure of 2400 psia.The original design function of the PORVs was to prevent unnecessary challenges to the pressurizer safety valves. Subsequently, the PORV function has been extended to provide protection against brittle fracture (during low temperature plant operations) by adding a low pressure setpoint (nominally 465 psia) to the PORV control circuitry.

For later C-E plants, PORVs for overpressure protection during normal power operation were found to be unnecessary and were therefore not provided. For those plants not equipped with PORVs, other means are used to provide low temperature overpressure protection. Section 2.3.1 describes, for each C-E plant, its provisions for LTOP and whether or not it is equipped with PORVs.

2.2.3 Shutdown Cooling System

The Shutdown Cooling System (SCS) is provided for removal of decay and sensible heat for plant cooldown following a reactor shutdown and for maintaining a suitable temperature for refueling and maintenance operations. The system is designed to cool the RCS from about 300°F to refueling temperature (about 130°F). The reactor coolant circulating path is from the RCS hot leg SCS nozzles, through the low pressure safety injection (LPSI) pumps, through the SCS heat exchangers to the low pressure safety injection header, through the cold leg safety injection nozzles into the RCS, and through the core back to the SCS nozzles.

2.2.4 Safety Injection System

The Safety Injection System (SIS) is designed to automatically provide borated cooling water to the core in the event of a loss-of-coolant accident (LOCA). The description of a typical system which follows is not applicable to the Maine Yankee system, which is described in Section 2.3.3. Two or three centrifugal high pressure safety injection (HPSI) and two centrifugal LPSI pumps are actuated by a Safety Injection Acutation Signal (SIAS) to pump borated water from a refueling water storage tank through the safety injection nozzles into the RCS. In addition, four passive pressurized safety injection tanks (SIT) automatically force borated water into the RCS when RCS pressure has decreased below SIT pressure. Actuation of the SIS occurs when pressurizer pressure decreases below the safety injection actuation setpoint value (typically 1750 psia) or when the containment pressure increases above a selected setpoint (typically 5 psig). The pressurizer pressure safety injection actuation setpoint can be varied in order to permit normal plant shutdown and depressurization without unnecessarily actuating the SIS. Shutoff heads for the HPSI pumps vary from the equivalent of 1200 psia for operating plants to about 2000 psia for System 80 plants.

2.2.5 Volume Control System

During normal operation the Chemical and Volume Control System (CVCS) automatically adjusts RCS water volume using a signal from the level instrumentation located on the pressurizer. A pressurizer level control program regulates the letdown flow by adjusting the letdown control valve so that the reactor coolant pump bleedoff plus letdown flow match the input from the operating charging pump(s).

Each plant is provided with three reciprocating charging pumps, except for Maine Yankee, which is equipped with three centrifugal charging pumps. During water-solid RCS conditions* the pressurizer level control program fully opens the letdown control valve. Under this condition primary system pressure is manually regulated by adjusting letdown backpressure control valves to balance the charging pump delivery.

When there is a steam bubble in the pressurizer, charging/letdown imbalances delivering excess inventory to the RCS result in a high pressurizer level alarm if charging input is not controlled. Due to the relatively low capacity of the charging pumps, this alarm provides ample time (more than ten minutes) for operator action to correct the mismatch prior to challenges to the PORVs or safety valves.

2.3 SPECIAL FEATURES OF SPECIFIC PLANTS

2.3.1 Power-Operated Relief Valves

All currently operating C-E plants, with the exception of Arkansas Nuclear One Unit 2 (ANO-2), that is, Palisades, Fort Calhoun, Millstone-2, Calvert Cliffs- 1 &-2, Maine Yankee, and St. Lucie-1, are provided with two PORVs. The PORVs have dual setpoints for overpressure protection during 1) normal power operation, and 2) low temperature operation. No credit is taken in FSAR analyses for the operation of the PORVs in pressurization events occurring during normal power operation.

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* Water-solid conditions normally occur only at low temperatures when the plant is operated in the LTOP mode; e.g. less than 300°F.

ANO-2 is not equipped with PORVs, but employs a pair of spring-loaded relief valves for the LTOP function. These valves have low pressure setpoints ($\sim$ 465 psia) and are mounted on the pressurizer. The valves are double-isolated during power operation. The Maine Yankee plant provides LTOP with both PORVs on the pressurizer and spring-loaded relief valves in the SCS suction line. Spring-loaded relief valves are considered outside the scope of the EPRI program and are not considered in this report.

With the exception of St. Lucie-2, all non-operating C-E plants are not equipped with PORVs. These plants utilize spring-loaded relief valves located in the SCS suction lines for LTOP. St. Lucie-2 is equipped with two PORVs on the pressurizer which are used for overpressure protection during normal power operation, as well as for LTOP.

2.3.2 Safety Valve and PORV Water Seals

With the exception of Millstone-2 and Fort Calhoun, the PORVs (if provided) and safety valves on all C-E designed NSSSs are located at a higher elevation than the valve inlet header. Millstone-2 and Fort Calhoun are provided with water (loop) seals at the PORV and safety valve inlets. The Millstone-2 water seals are insulated and heat-traced to normally maintain the water temperature at 325°F. The Fort Calhoun water seals are not insulated or heat-traced. The safety valves at Fort Calhoun are located within the pressurizer compartment so that the normal water seal temperature is considered to be about 160°F, the estimated pressurizer compartment ambient temperature. The PORVs are located outside of the pressurizer compartment, but within the containment environment; hence, the water seal temperature is considered to be at the containment ambient temperature, in the range of 100 to 120°F. The total volume of water in each of the water seals is less than five gallons.

2.3.3 Maine Yankee Safety Injection System

The Maine Yankee Safety Injection System is similar to the generic C-E Safety Injection System, with some noteworthy differences. In lieu of providing pumps specifically for high pressure safety injection, Maine Yankee utilizes two of their high capacity centrifugal charging pumps as HPSI pumps. These pumps have a relatively high shutoff head (2450 psia) compared to that of the remainder of the C-E designed plants (1200 to 2000 psia).

Section 3

GENERAL APPROACH

3.1 FSAR/RELOAD TRANSIENTS

The general approach to determine the inlet fluid conditions during safety and PORV actuation for C-E designed plants was to survey FSARs and those reload license amendments performed by C-E to identify the design basis events which result in safety valve and/or PORV lift. For the operating Maine Yankee and Palisades plants (for which C-E has not performed recent reload analyses) the survey was limited to the original FSAR analyses. For non-operating C-E plants, the survey included the most recent analyses for which quantitative results have been presented in the FSARs. Valve inlet fluid conditions, including peak pressure and pressure ramp rates during safety valve actuation were extracted directly from the FSAR or reload analyses. The results are conservatively high from a peak pressure and a pressure ramp rate viewpoint since these analyses do not credit PORV operation (for those plants equippped with PORVs) or pressurizer spray to mitigate the transients.

3.2 EXTENDED HIGH PRESSURE INJECTION TRANSIENTS

For typical C-E plants, the Extended High Pressure Injection event is not analyzed in the FSAR since the HPSI pump shutoff head is below the safety valve and PORV set pressures. The Maine Yankee safety injection system provides the only instance for which the HPSI pumps can inject at pressures in the vicinity of the valve set pressures. However, the event was not included in the FSAR analyses originally performed by C-E. Therefore, for Maine Yankee the approach was to perform a qualitative evaluation of the inadvertent actuation of high pressure injection during normal power operation. The head-flow characteristics of the HPSI pumps were considered in the evaluation of this event.

3.3 LOW TEMPERATURE PRESSURIZATION TRANSIENTS

For those C-E plants using PORVs to provide low temperature overpressure protection (LTOP), the design basis events which challenge the PORVs in the low temperature operating mode (i.e., below approximately 300°F) are presented. The conditions for low temperature PORV actuation were extracted from generic and plant-specific reports on studies of low temperature pressurization. The generic study (Reference 4) was sponsored in 1976 by the C-E Operating Plants Owners Group, while plant-specific studies were subsequently sponsored by individual utilities. Plant-specific reports were generated for Fort Calhoun (Reference 5), Millstone-2 (Reference 6), St. Lucie-1 (Reference 7), and Calvert Cliffs-1 & 2 (Reference 8). The Maine Yankee plant was not included in C-E's low temperature pressurization studies since that plant was not a participant in the C-E Operating Plants Owners Group. Also, although Palisades was a participant in the generic study, C-E did not perform a plant-specific study for this unit.

The only non-operating C-E plant equipped with PORVs is St. Lucie-2. Fluid conditions resulting from LTOP events for the St. Lucie-2 PORVs are based on LTOP analyses performed as part of that unit's FSAR (Reference 9).

The generic and plant specific studies, as required by licensing considerations, were based on water-solid pressurizer conditions since the solid condition resulted in the most severe pressurization transients. For the water-solid pressurizer, the PORV inlet fluid will be liquid.

Since a steam bubble may also exist in the pressurizer during low temperature operations, a pressurization event under these conditions could lift the PORVs on steam instead of water. Due to the cushioning effect of the steam in the pressurizer, lifting of the PORVs is much less likely than when the pressurizer is water-solid. The possibility of the PORVs opening on steam during low temperature operation was considered qualitatively in this study.

Section 4

GENERAL DESCRIPTION OF SAFETY/RELIEF VALVE ACTUATING TRANSIENTS

4.1 FSAR/RELOAD PRESSURIZATION TRANSIENTS

A general description of the FSAR/Reload pressurization transients which result in safety valve or PORV actuation is provided in the following subsections. Transients which are closely related are described together in a given subsection.

4.1.1 Loss of Load

The related transients covered in this description are:

a) Loss of Load
b) Turbine Trip
c) Isolation of the Turbine

A Loss of Load event is initiated by a turbine trip without a concurrent reactor trip. This results in the termination of secondary steam flow and causes a heatup of both the primary and secondary systems. On the primary side the RCS pressure and temperatures increase. The core power and heat flux increase prior to reactor trip due to the moderator temperature reactivity feedback assumed in the analysis.

The pressure increase would actuate the pressurizer spray. However, the maximum capacity of the pressurizer spray is not sufficient to terminate the pressure increase. The pressure increases further until the PORVs open (for plants equipped with PORVs) and a reactor trip on high pressurizer pressure is initiated. Since no credit for mitigating the transient by operation of pressurizer spray or the opening of the PORVs is assumed in the FSAR analysis, the pressurizer pressure increases and the pressurizer safety valves open. The increase in the pressurizer level during the event is not sufficient to cause liquid flow through the safety valves (or PORVs, if actuated). The pressure increase is terminated by the steam discharge through the safety valves and the high pressurizer pressure reactor trip.

4.1.2 Loss of Condenser Vacuum

The related transients covered in this description are:

a) Loss of Condenser Vacuum
b) Loss of Condenser Vacuum with Failure of a Pressurizer Level Measurement Channel Associated with Pressurizer Level Control
c) Loss of Condenser Vacuum with Failure to Achieve a Fast Transfer of a 6.9 KV Bus.
d) Loss of Condenser Vacuum with Loss of Offsite Power as a Result of Turbine Trip.

A Loss of Condenser Vacuum event may occur due to the failure of the Circulating Water System, the failure of the Main Condenser Evacuation System to remove non-condensible gases, or the leakage of an excessive amount of air through a turbine gland.

The increase in condenser pressure during the event generates a turbine trip signal which terminates steam flow from the steam generator. The feedwater regulating system receives the turbine trip signal which actuates a feedwater ramp back. The steam generator pressure increases to the main steam safety valves setpoint. The valves then open to remove heat from the RCS. The reduction in steam flow due to turbine trip results in an increase in RCS temperature and pressure. As the RCS pressure increases, the PORVs (for plants so equipped) and the pressurizer safety valves open, discharging steam to the quench tank. A reactor trip on high pressurizer pressure occurs which, along with the pressurizer PORVs, safety valves, and pressurizer spray mitigates the pressure rise. For the purposes of the FSAR analysis, no credit for mitigating the transient is assumed for the operation of pressurizer spray or opening of the PORVS. Pressurizer level increase during this time is not sufficient to cause liquid flow through the safety valves (or PORVs, if actuated).

The Loss of Condenser Vacuum event is similar to the Loss of Load event when the turbine bypass system is assumed to be in the manual mode. Cooldown is accomplished using the atmospheric dump valves.

In cases where a failure in the Pressurizer Level Control System is also assumed, a false pressurizer low level signal results. This causes activation of both standby charging pumps and the closing of the letdown control valve to its minimum flow area. Further compression of the pressurizer steam space results in slightly higher peak pressures. For this case, however, single phase steam flow conditions still prevail.

The effect of a failure to achieve fast transfer is to lose one-half of the non-Emergency Safety Feature (ESF) electrical loads. This results in the loss of two reactor coolant pumps, one main feedwater pump, and one-half of all other non-ESF loads. The reduction in reactor coolant and feedwater flow reduces the primary to secondary heat transfer resulting in a higher peak pressure and prolonged discharge through the pressurizer safety valves. Single phase steam conditions still prevail at the valve inlets.

The effect of a loss of offsite power is to lose all four reactor coolant pumps and all other non-ESF loads. In terms of pressurizer response this results in a greater pressure increase and prolonged valve discharge. However, the safety valve and PORV inlet fluid is still limited to single phase steam.

4.1.3 Control Element Assembly (CEA) Group Withdrawal

The related transients covered in this description are:

a) Sequential CEA Group Withdrawal
b) Uncontrolled Positive Reactivity Insertion with a Loss of Offsite Power as a Result of Turbine Trip
c) Uncontrolled CEA Withdrawal from Subcritical or Low Power Conditions
d) Uncontrolled CEA Withdrawal at Power

A continuous withdrawal of CEAs could result from a malfunction in the reactor regulating system or control element drive mechanism. The CEA withdrawal event can occur over a range of initial power conditions, from subcritical conditions existing during startup to normal full power operating conditions.

The withdrawal of CEA's adds positive reactivity to the core causing the core power and heat flux to increase. Since the heat extraction from the steam generators remains relatively constant, there will be an increase in reactor coolant system temperature and pressure.

The pressure increase would normally actuate pressurizer spray and possibly the PORVs (for plants equipped with PORVs). However, since no credit for spray or opening of PORVs is assumed in the analysis, the pressure will increase until the pressurizer safety valves are opened. The increase in the pressurizer level during the event is not sufficient to cause liquid flow through the safety valves (or PORVs, if actuated).

The pressure increase is terminated by the steam discharge through the safety valves and the reactor trip initiated on high pressurizer pressure, high reactor power, thermal margin low pressure (TM/LP) trip, or Core Protection Calculator (CPC) DNBR trip. The reactor trip which is initiated depends upon the characteristics of the individual plant reactor protection system and the assumed initial conditions.

For the case where loss of offsite power at turbine trip is also considered, normal feedwater and forced reactor coolant flow is lost. This results in a greater mismatch between heat production in the core and heat removal by the steam generators and, thus, results in a higher peak pressure. However, single phase steam conditions still occur at the safety valve and PORV inlets.

4.1.4 CEA Ejection

The related transients covered in this description are:

a) CEA Ejection
b) CEA Ejection with a Fast Transfer Failure

For the postulated CEA Ejection accident, a mechanical failure is assumed such that the reactor coolant system pressure would eject the CEA and drive shaft to the fully withdrawn position. This would require a complete and instantaneous circumferential rupture of the control element drive mechanism (CEDM) housing or of the CEDM nozzle. However, in analyzing this event to determine primary pressure, the FSAR analysis generally assumes that the pressure boundary is not breached.

The CEA ejection will lead to a rapid positive reactivity addition. This results in a rapid power excursion which produces a highly skewed and severely peaked core power distribution. The reactor power rapidly increases in approximately 2 to 3 seconds. This increase is mitigated by the effect of delayed neutrons and the Doppler reactivity feedback. A reactor trip on high power is initiated, which terminates the core power rise.

The increase in core power coupled with the constant secondary power demand causes the RCS temperature and pressure to increase. The pressure increase will normally actuate pressurizer spray and the PORVs, for plants equipped with PORVs. However, since no credit for this equipment is assumed in the FSAR analysis, the pressure continues to increase. Depending on the initial conditions, the pressure increase may open the pressurizer safety valves. The pressure increase is terminated by the steam discharge through the safety valves and/or the high power trip. The increase in pressurizer level is not sufficient to cause liquid flow through safety valves (or PORVs, if actuated).

In cases where a failure to achieve fast transfer is also assumed, the effect is to cause the loss of one half of the non-ESF electrical loads. This results in the loss of two reactor coolant pumps, loss of condenser vacuum, and one-half of all other non-ESF loads. The reduction in reactor coolant and feedwater flow reduces the primary to secondary heat transfer resulting in a higher peak pressure and prolonged safety valve and PORV discharge. However, steam conditions still prevail at the safety valve and PORV inlets.

4.1.5 Pressurizer Level Control System Malfunction

The related transients covered in this description are:

a) Chemical and Volume Control Systems (CVCS) Malfunction
b) Pressurizer Level Control System (PLCS) Malfunction with Failure to Fast Transfer
c) PLCS Malfunction with Loss of Offsite Power at Turbine Trip.

An unplanned increase in RCS inventory may occur as a result of equipment or electrical malfunction or operator error which causes the interruption of letdown flow and the startup of one or more charging pumps. The transient is assumed to occur without changing boron concentration, so a reactivity anomaly does not result.

When in the automatic mode, the PLCS and CVCS respond to changes in pressurizer level by changing the letdown and charging flow to maintain the programmed level. Normally, one or two charging pumps are running with (an) additional pump(s) available when a low level setpoint is reached. If the pressurizer level controller fails low or the level setpoint generated by the reactor regulating system fails high, a low level signal can be transmitted to the controller. In response, the controller would start (an) additional charging pump(s) and close the letdown control valve to its minimum opening. The increase in reactor coolant system inventory produces an increase in pressurizer level, compressing the steam volume and increasing pressurizer pressure. Pressurizer spray is actuated which reduces the rate of pressure increase. Further compression of the steam results in a reactor trip on high pressurizer pressure. The post-trip pressure increase opens the pressurizer and secondary safety valves. Reactor trip occurs prior to filling the pressurizer. The increase in pressurizer level is not sufficient to cause liquid to reach the safety valves (or PORVs for plants so equipped). Therefore, only steam is discharged through the safety valves (or PORVs).

In cases where a failure to achieve fast transfer is also assumed, the effect is the loss of one-half of the non-ESF electrical loads. This results in the loss of two reactor coolant pumps, loss of condenser vacuum, and one-half of all other non-ESF loads. The reduction in reactor coolant and feedwater flow reduces the primary to secondary heat transfer resulting in a higher peak pressure and a longer safety valve opening duration. Valve inlet fluid conditions are as described in the previous paragraph.

The effect of a loss of offsite power is to lose all four reactor coolant pumps and all other non-ESF loads. In terms of pressurizer response this results in a greater pressure increase and additional steam release. In both cases (failure to fast transfer and loss of offsite power) the loss of condenser vacuum results in a loss of the steam bypass. Valve inlet fluid conditions are as described above.

4.1.6 Loss of Offsite Power

The transients covered in this description are:

a) Loss of Offsite Power
b) Loss of All Normal and Preferred AC Power to the Station Auxiliaries.

The Loss of Offsite Power event is defined as the Loss of Offsite (Preferred) AC Power event which results in a turbine-generator trip. The turbine-generator trip terminates the in-house (normal) AC power generation. The transients listed above, though designated differently, are identical.

The loss of offsite power (LOOP) is assumed to occur as a result of a failure in the external grid system. The LOOP causes a loss of power to the start-up transformers and is assumed to result in an immediate turbine trip. Since the start-up transformers are not powered, the plant electrical loads will not be able to fast transfer to them. The onsite loads will lose power, and the plant is assumed to experience a simultaneous loss of feedwater, condenser inoperability, and a four reactor coolant pump coastdown following the turbine trip. Automatic startup of the emergency diesel generators supplies power to all necessary engineered safety features systems and equipment necessary to maintain the plant in a safe shutdown condition.

A reactor trip occurs automatically on either low reactor coolant flow (plants with an analog Reactor Protection System (RPS)) or low DNBR (plants with a digital RPS). Subsequent to reactor trip, stored heat and fission product decay heat must be dissipated. In the absence of forced reactor coolant flow, convective heat transfer through the core is maintained by natural circulation. Prior to reactor trip the steam generator pressure increases to the main steam safety valve (MSSV) setpoint and these valves open and cycle until the operator controls secondary steam flow by opening the atmospheric dump valves. Emergency feedwater is actuated on a low steam generator level signal.

As reactor coolant system pressure increases, the PORVs (for plants equipped with PORVs) and safety valves open, discharging steam to the quench tank. The increase in pressurizer level is not sufficient to cause liquid to pass through either set of valves. The RCS pressure decreases rapidly due to the declining core heat flux in combination with the heat removal from the PORVs and safety valves in the primary system and MSSVs in the secondary system. For the purposes of the FSAR analysis, no credit is assumed for mitigating the transient by the operation of pressurizer spray or the PORVs.

4.1.7 Total Loss of Normal Feedwater Flow

The loss of normal feedwater flow is defined as a reduction in feedwater flow to the steam generators when operating at power without a corresponding reduction in steam flow from the steam generators. The result of this mismatch is a reduction in the water inventory in the steam generators. This can be caused by the loss of all feedwater or condensate pumps, operator error in feedwater regulation or the rupture of the main feedwater header.

The reduction in steam flow from the generators following turbine trip causes an increase in steam generator pressure as heat transfer continues from the primary to the secondary side. As a result of the increase in main steam pressure, reactor coolant temperature increases until reactor trip. The increasing reactor coolant temperature causes a pressurization of the RCS which may result in opening the PORVs (for plants equipped with PORVs) and the pressurizer safety valves for a short period of time. A reactor trip occurs on either low steam generator water level or high pressurizer pressure. Auxiliary feedwater is automatically actuated on low steam generator level preventing the steam generators from drying out. The pressure transient is mitigated by the operation of the high pressurizer pressure trip, pressurizer spray, the PORVs and safety valves. The increase in the pressurizer level does not result in liquid flow through either the PORVs or the safety valves. The decrease in heat generation rate following trip and the re-establishment of normal steam generator water level terminate the pressurization transient. For the purposes of the FSAR analysis, no credit is assumed for mitigating the transient by the operation of pressurizer spray or the actuation of the PORVs.

4.1.8 Feedwater Line Break

The related transients covered in this description are:

a) Feedwater System Pipe Breaks
b) Loss of Feedwater Inventory
c) Loss of Feedwater Inventory with Loss of Offsite Power as a Result of Turbine Trip.

The Feedwater Line Break event is initiated by a break in the main feedwater system piping. Depending on the break size, location, and the response of the main feedwater system, the effects of the break can vary from a rapid heatup to a rapid cooldown of the primary system. The FSAR analysis assumes that the break occurs downstream of the feedwater line reverse flow check valves and that the main feedwater system is rendered inoperable. A saturated liquid discharge through the break is conservatively assumed to minimize steam generator heat removal capability. Such a scenario presents the greatest challenge to the RCS pressure boundary.

The loss of subcooled feedwater flow to both steam generators increases steam generator temperature and decreases liquid inventory. The rising secondary temperature reduces the primary to secondary heat transfer and forces a heatup and subsequent pressurization of the RCS. The heatup becomes more severe as the affected steam generator experiences a further reduction in its heat transfer capabilities due to insufficient liquid inventory as the discharge from the break continues. The RCS pressure increase would actuate pressurizer spray; however, the maximum capacity of the spray is not sufficient to terminate the pressure increase. Eventually the increasing pressure causes the PORVS (for plants so equipped) and the pressurizer safety valves to open. A reactor trip occurs on high pressurizer pressure, low steam generator water level, or high containment pressure, depending on the assumed initial conditions. RCS heatup can continue after trip due to a total loss of heat transfer in the affected steam generator as it empties. The increase in the pressurizer level is not sufficient to cause liquid flow through either the PORVs or the safety valves. Eventually, the decreased core power following reactor trip reduces the core heat rate to the heat removal capacity of the unaffected steam generator, thus terminating the RCS heatup and pressure rise. For the purpose of FSAR analysis, no credit is assumed for mitigating the transient by the operation of pressurizer spray or the actuation of the PORVs.

For cases where a loss of offsite power at turbine trip is also assumed, the major impact on the transient is imposed by the loss of all four reactor coolant pumps and the subsequent decrease in flow. In addition, the Pressurizer Pressure Control System (PPCS) is lost. The unavailability of the RC pumps and the PPCS increases the RCS pressurization and the peak pressure during the event. However, steam conditions still exist at the safety valve and PORV inlets.

4.2 EXTENDED HIGH PRESSURE INJECTION TRANSIENTS

The Extended High Pressure Injection transient is characterized in licensing, terms as an "Increase in Reactor Coolant System Inventory Event" in which the high pressure safety injection pumps are inadvertently actuated to discharge into the RCS during normal power operation. The rate of increase in RCS inventory is dependent upon the head-flow curve for the high pressure safety injection pumps. Except for Maine Yankee, the HPSI pumps shut off heads on C-E designed plants are below normal operating pressure. Therefore, this event is of convern only for Maine Yankee since the HPSI pump shutoff head is near the safety valve setpressure. A possible scenario for this event is described in Section 5.2.

4.3 LOW TEMPERATURE PRESSURIZATION TRANSIENTS

4.3.1 Introduction

During low temperature modes of plant operation, system pressure must be maintained below specific limits to preclude brittle fracture in the reactor coolant pressure boundary. Inadvertent inputs of mass and/or energy into the RCS can result in undesirable pressure increases. Particularly rapid and severe pressure transients can occur when the pressurizer is operated in a water-solid condition (without a volume of steam or gas). The severity of the pressure transient is increased if RCS letdown is in a secured condition and the SCS is isolated.

Overpressurization due to any of several initiating events described in Section 4.3.2 and 4.3.3 can be avoided by:

(1) provision of sufficient relieving capacity,
(2) preclusions of the initiating events by administrative control and/or operating procedures,
(3) a combination of (1) and (2).

Different C-E plants and plant classes have provided specific means for low temperature overpressure protection which are particularly suited to that plant or plant class. In this study, interest is focused primarily on investigating PORVs which are used for a dual relief function, i.e., for high and low pressure relief. Plants using such PORVs are Palisades, Fort Calhoun, Maine Yankee, Millstone-2, St. Lucie-1 & 2, Calvert Cliffs-1 & 2. The evaluation of LTOP conditions for Maine Yankee is not included as part of this study.

The remaining C-E designed plants provide other means for low temperature overpressure protection. ANO-2 is provided with two spring-loaded relief valves on the pressurizer with low pressure setpoints for low pressure protection only. These valves are double-isolated from the pressurizer at system temperatures above 300°F. The remainder of the C-E designed plants (that is, Waterford-3, San Onofre-2 and 3, Palo Verde-1, 2 and 3, Yellow Creek-1 and 2, WNP-3 and 5, Cherokee-1, 2 and 3 and Perkins-1, 2 and 3) are not provided with PORVs and utilize relief valves in the SCS suction lines for LTOP. These valves are not considered within the scope of this study.

4.3.2 Mass Addition Events

The following events increase RCS pressure by mass addition:
(a) Inadvertent starting of a HPSI pump.
(b) Imbalance between RCS charging and letdown.
(c) Spurious safety injection actuation, resulting in two HPSI and two LPSI pumps charging or attempting to charge into the RCS.

The description of a typical mass addition pressurization event follows: The plant is initially shut down, in a low temperature operating mode, (with or without a steam bubble in the pressurizer).The SCS is in operation with pressurizer pressure below 300 psia and RCS temperature below 300°F. A mass addition event causes system pressure to increase (very rapidly if there is no steam bubble in the pressurizer) until the PORVs lift, at the setpoint pressure of 465 psia. In a water-solid plant, when the volumetric addition rate exceeds the PORV relieving capacity at the setpoint pressure, system pressure continues to increase to some equilibrium pressure at which point the PORV discharge rate matches the input rate. If the mass addition rate is less than the PORV relieving capacity at the setpoint pressure, the PORV will lift and then close as the pressure is relieved, and will continue to cyclically open and close until the event is terminated. The event is terminated by operator action terminating the mass addition.

4.3.3 Energy Addition Events

Energy addition events which could increase RCS pressure are:

(a) Energy input from pressurizer heaters.

(b) Energy input from reactor decay heat.

(c) Starting a reactor coolant pump (RCP) at a time when the steam generator secondary temperature exceeds the reactor vessel coolant temperature.

The description of the limiting energy addition pressurization event follows: The event is the reactor coolant pump start at a time when the steam generator fluid temperature exceeds the reactor vessel coolant temperature. The plant is assumed to be in the low temperature operating mode, in a shutdown condition, with or without a steam bubble in the pressurizer. Reactor vessel fluid temperature is less than 300^{o}F and pressurizer pressure is less than 300 psia. The startup of a reactor coolant pump initiates circulation of reactor coolant through the steam generator tubes where the reactor coolant absorbs heat and increases in temperature and also pressure. The pressure increase is extremely rapid when there is no steam bubble in the pressurizer to act as a cushion. When the pressurizer pressure reaches the PORV setpoint pressure, the PORV lifts. The pressure may continue to rise until the PORV's energy discharge rate matches the energy input from the steam generators. As the temperature difference (ΔT) between the steam generator fluid and the reactor vessel fluid decreases due to mixing and transfer of heat, the pressurizer pressure decreases resulting in PORV closure. Continued energy transfer to the RCS causes the pressurizer pressure to increase again. The PORVs cycle open and closed until the ΔT between the steam generator and reactor vessel is dissipated and energy addition to the RCS basically ceases. The duration of PORV cycling and the peak pressure attained varies with the magnitude of ΔT. The peak pressure and frequency of PORV cycling is decreased significantly if there is a steam space in the pressurizer. It should be noted that there is a pressure difference between the pressurizer and the inlet of a discharging PORV due to the flow resistance of the connecting piping. For liquid flow, this pressure difference amounts to roughly 25-50 psi.

Section 5

SAFETY AND RELIEF VALVE INLET CONDITIONS

5.1 FSAR/RELOAD PRESSURIZATION TRANSIENTS

Details of pressurization transients for specific C-E designed plants as presented in the FSAR/Reload analyses are provided in the sections which follow. Included is the sequence of events for the various transients as well as peak pressure, pressure ramp rates, and valve inlet fluid conditions. The specific limiting events analyzed in the FSAR/Reload documents varied among the different plants, depending upon the plant vintage, design details, and specific licensing requirements.

It is noted that the analyses for the various FSAR transients do not take credit for the mitigation of the event by pressurizer spray or the operation of the PORVs, but only for the safety valves. Thus, the calculated peak pressures are conservatively high. The pressure ramp rate presented for the safety valves is estimated at the time that the pressure is in the vicinity of the safety valve setpoint, with the PORVs assumed not to operate. The pressure ramp rate presented for the PORVs is estimated at the time the pressure reaches the vicinity of the PORV opening setpoint (2400 psia).

5.1.1 Arkansas Nuclear One Unit 2

The Design Basis Events which result in peak pressurizer pressure greater than the opening setpressure for the safety valves are:

a) Loss of Load
b) Feedwater Line Break with Concurrent Loss of AC Power
c) Loss of Condenser Vacuum
d) Sequential CEA Group Withdrawal

The valve inlet conditions for each of these events is presented in Table 5-1. The sequence of events for each event is presented in Table 5-2.

As shown in Table 5-1, the highest peak pressure and greatest ramp are 2705 psia and 106 psi/sec, respectively, for the Feedwater Line Break event. The safety valves inlet fluid was steam for all transients.

5.1.2 Calvert Cliffs Units 1 and 2

The Design Basis Events which result in peak pressurizer pressure greater than the opening setpressure for the PORV and safety valves are:

a) Loss of Load
b) Loss of Main Feedwater
c) CEA Ejection
d) Loss of AC

The valve inlet conditions for each of these events is presented in Table 5-3. The sequence of events for each event is presented in Table 5-4. Table 5-3 shows the highest peak pressure was 2538 psia for the Loss of Load event, and the greatest pressure ramp rate was about 64.4 psi/sec for the Loss of AC event. For all transients, the valves inlet fluid was steam.

5.1.3 Maine Yankee

The Design Basis Events which result in peak pressurizer pressure greater than the opening setpressure for the PORVs and safety valves are:

a) Loss of Load
b) CEA Withdrawal

The valve inlet conditions for each of these events is presented in Table 5-5. The sequence of events for each event is presented in Table 5-6. Table 5-5 shows the highest peak pressure was 2500 psia for the CEA Withdrawal event, and the greatest pressure ramp rate was 25 psi/sec for the Loss of Load event. For all transients, the valve inlet fluid was steam.

5.1.4 Millstone Unit 2

The Design Basis Events which result in peak pressurizer pressure greater than the opening setpressure for the PORVs and safety valves are:

a) Loss of Load
b) Loss of Main Feedwater
c) CEA Ejection
d) Loss of AC

The valve inlet conditions for each of these events is presented in Table 5-7. The sequence of events for each event is presented in Table 5-8. Table 5-7 shows the highest peak pressure was 2555 psia for the Loss of Load event, and the greatest pressure ramp rate was 60 psi/sec for the Loss of AC event. The valve inlet fluid was limited to saturated steam after the water seal was discharged in all cases.

5.1.5 Ft. Calhoun

The Design Basis Events which result in peak pressurizer pressure greater than the opening setpressure for the PORVs are:

a) Loss of Load
b) CEA Withdrawal

The valve inlet conditions for each of these events is presented in Table 5-9. The sequence of events for each event is presented in Table 5-10. Table 5-9 shows the highest peak pressure was 2480 psia and the greatest pressure ramp rate was 45 psi/sec for the Loss of Load event. The valve inlet fluid was limited to setam after the water seal was discharged in all cases. The reload analyses do not show actuation of the safety valves.

5.1.6 St. Lucie Unit 1

The Design Basis Events which result in peak pressurizer pressure greater than the opening setpressure for the PORVs and safety valves are:

a) Loss of Load
b) Loss of Main Feedwater
c) CEA Ejection
d) Loss of AC

The valve inlet conditions for each of these events is presented in Table 5-11. The sequence of events for each event is presented in Table 5-12. Table 5-11 shows that the highest peak pressure was 2562 psia for the Loss of Load event, and the greatest pressure ramp rate was 64.4 psi /sec for the Loss of AC event. The valve inlet fluid was limited to steam in all cases.

5.1.7 Palisades

The FSAR shows that the Design Basis Event which results in peak pressurizer pressure greater than the opening setpressure for the PORVs and safety valves is limited to the Loss of Load event. The valve inlet conditions for this event is presented in Table 5-13. The sequence of events for the resulting transient is presented in Table 5-14. Table 5-13 shows that the peak pressure was 2520 psia and the maximum pressure ramp rate was 45 psi/sec. The valve inlet fluid condition is steam in all cases.

5.1.8 San Onofre Units 2 and 3

The Design Basis Events treated in the FSAR which result in peak pressurizer pressure greater than the opening set pressure for the safety valves are:

a) Loss of Condenser Vacuum
b) Loss of Condenser Vacuum with Failure of Pressurizer Level Measurement Channel Associated with the Pressurizer Level Control System
c) Feedwater System Pipe Break
d) Uncontrolled CEA Withdrawal from Subcritical or Low Power Conditions
e) Uncontrolled CEA Withdrawal at Power
f) CEA Ejection

The valve inlet conditions for each of these events is presented in Table 5-15. The sequence of events for each event is presented in Table 5-16. Table 5-15 shows that the highest peak pressure was 2760 psia for the Feedwater System Pipe Break and the greatest pressure ramp rate was 93 psi/sec for the CEA Ejection. The valve inlet fluid was limited to saturated steam in all cases.

5.1.9 Waterford Unit 3

The Design Basis Events treated in the FSAR which result in peak pressurizer pressure greater than the opening set pressure for the safety valves are:

a) Loss of Condenser Vacuum
b) Loss of Condenser Vacuum with Failure of Pressurizer Level Measurement Channel Associated with the Pressurizer Level Control System
c) Feedwater System Pipe Break
d) Uncontrolled CEA Withdrawal from Subcritical or Low Power Conditions
e) Uncontrolled CEA Withdrawal at Power
f) CEA Ejection
g) CVCS Malfunction (Increase in RCS Inventory)

The valve inlet conditions for each of these events is presented in Table 5-17. The sequence of events for each event is presented in Table 5-18. Table 5-17 shows that the highest peak pressure was 2688 psia for the Feedwater System Pipe Break and the greatest pressure ramp rate was 104 psi/sec for the Loss of Condenser Vacuum with Failure of Pressurizer Level Measurement Channel Associated with the Pressurizer Level Control System. In all cases, the safety valve inlet fluid was saturated steam.

5.1.10 St. Lucie Unit 2

The Design Basis Events treated in the FSAR which result in peak pressurizer pressure greater than the opening set pressure for the PORV and safety valves are:

a) Isolation of the Turbine
b) Loss of Condenser Vacuum with Failure to Achieve Fast Transfer of a 6.9 KV Bus
c) Loss of Condenser Vacuum with Loss of Offsite Power as a Result of Turbine Trip
d) Loss of Feedwater Inventory with Loss of Offsite Power as a Result of Turbine Trip (Feedwater Line Break)
e) Loss of Offsite Power
f) Uncontrolled Positive Reactivity Insertion with a Loss of Offsite Power as a Result of Turbine Trip (CEA Withdrawal)

The valve inlet conditions for each of these events is presented in Table 5-19. The sequence of events for each event is presented in Table 5-20. Table 5-19 shows that the highest peak pressure was 2752 psia for the Loss of Feedwater Inventory with Loss of Offsite Power and the greatest pressure ramp rate was 92 psi/sec for the Loss of Condenser Vacuum with Failure to Achieve Fast Transfer. The valve inlet fluid was limited to saturated steam in all cases.

5.1.11 System 80 Plants (Yellow Creek Units 1 and 2, WNP Units 3 and 5, Cherokee Units 1, 2 and 3, Perkins Units 1, 2 and 3, Palo Verde Units 1,2, and 3)

The Design Basis Events treated in the FSAR which result in peak pressurizer pressure greater than the opening set pressure for the safety valves are:

a) Turbine Trip
b) Loss of Condenser Vacuum with a Fast Transfer Failure
c) Sequential CEA Withdrawal
d) CEA Ejection with a Fast Transfer Failure
e) Pressurizer Level Control System Malfunction with a Fast Transfer Failure

f) Pressurizer Level Control System Malfunction with a Loss of Offsite Power at Turbine Trip.

g) Loss of Feedwater Inventory

h) Loss of Offsite Power

i) Total Loss of Normal Feedwater Flow

The valve inlet conditions for each of these events is presented in Table 5-21. The sequence of events for each event is presented in Table 5-22. Table 5-21 shows that the highest peak pressure was 2587 psia for the Loss of Feedwater Inventory event. The greatest pressure ramp rate was 105 psi/sec for the Loss of Condenser Vacuum with Fast Transfer Failure. The valve inlet fluid was limited to saturated steam in all cases.

5.2 EXTENDED HIGH PRESSURE INJECTION TRANSIENT

5.2.1 Maine Yankee

Since the Maine Yankee HPSI pump shutoff heads (approximately 2450 psia) exceed both the normal plant operating pressure (nominally 2250 psia) and the PORV setpoint (nominally 2400 psia) the potential exists for the injection of fluid into the RCS and the lifting of PORVs upon the inadvertent actuation of the HPSI system (refer to Section 4.2). The calculated fluid injection rates into the RCS from one and two HPSI pumps as a function of RCS pressure is shown in Figure 5-1. The figure shows that at normal plant operating pressure, two HPSI pumps would deliver approximately 450 gpm to the RCS. At the PORV setpoint pressure two HPSI pumps would deliver approximately 125 gpm. If tolerances on the HPSI pump head-flow curves and the safety valve setpoint are taken into account, the actual HPSI pump shutoff heads might exceed the safety valve setpoint (nominally 2500 psia). Under these conditions, with the PORVs inoperable, the HPSI pumps could inject fluid into the RCS at a relatively low rate (probably less than 125 gpm) and would present a potential for lifting the safety valves.

The injection of cold borated water into the RCS during this event has opposing effects on system pressure. The volume of the injected water tends to compress the pressurizer steam space and increase pressure. The boron content and low temperature of the injected water tend to reduce reactor coolant temperature and volume, and hence also pressurizer pressure. A wide spectrum of scenarios is possible, depending upon the relative magnitude of the opposing effects, the initial conditions, and the assumptions of the analysis. A study would be required to identify the various scenarios and corresponding PORV inlet conditions. An analysis of this event has not

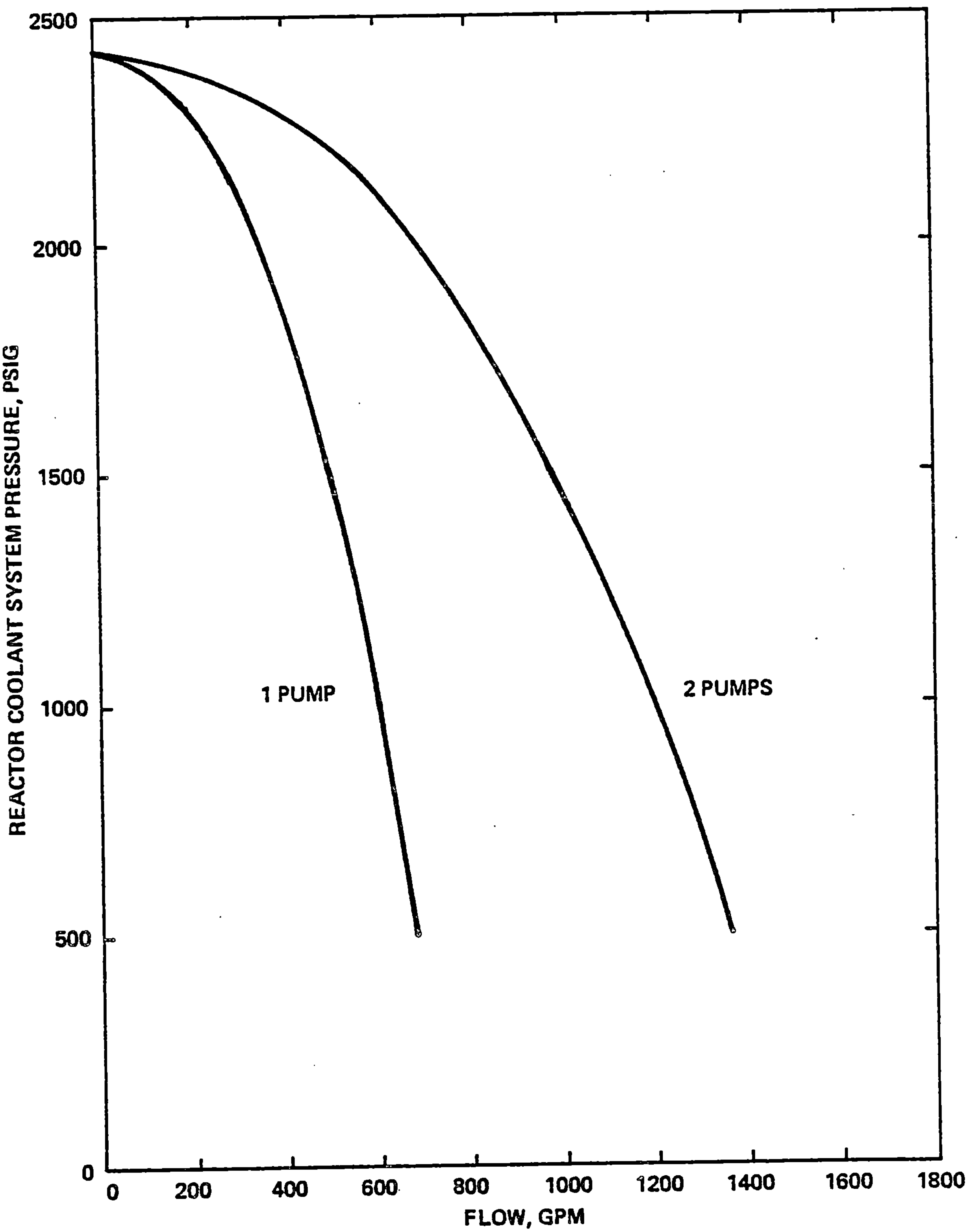

Figure 5-1
MAINE YANKEE HPSI PUMPS FLOW vs RCS PRESSURE

been performed by C-E and is not included in the original Maine Yankee FSAR. Without a quantitative analysis of the event, any postulated scenarios are speculative. However, it is clear that, without corrective action, the Extended High Pressure Injection event eventually results in filling the pressurizer and lifting the PORVs, not necessarily in that order. A speculative scenario resulting in a high degree of subcooling at the PORV inlet is described below.

The event is assumed to initiate from a nominal plant operating pressure of 2250 psia, with the pressurizer containing saturated water at 653°F at the normal operating level. Inadvertent actuation of the HPSI system results in the injection of cold, borated water from the refueling water tank into the RCS via the HPSI pumps, causing reactor coolant temperatures to decrease. It is assumed that the injection of water and the action of the pressurizer heaters prevent reactor trip on low pressurizer pressure, despite the shrinkage resulting from the decreasing reactor coolant temperature. A reactor trip would then eventually be initiated on low steam generator pressure when steam generator pressure decreases to 500 psia. The reactor coolant temperatures would then approach the steam generator secondary temperature corresponding to 500 psia (467°F). The continued injection of water into the RCS causes the pressurizer water level and pressure to increase. Since the HPSI pump shutoff head exceeds the PORV setpressure, the pressurizer pressure would, without corrective action, eventually reach the PORV setpressure. At this time the PORVs would open to relieve steam. Further continued water injection would result in the filling of the pressurizer and discharge of liquid through the PORVs. If the PORVs were inoperable, and if the HPSI pump shutoff head exceeded its nominal value sufficiently, while the safety valve setpoints happened to be below their nominal value, a similar scenario could be postulated, involving the safety valves instead of the PORVs. The pressure ramp rate at safety valve actuation would be relatively low.* During the refill of the pressurizer after reactor trip, the reactor coolant temperature entering the pressurizer could approximate 467°F. The water insurge would mix with the pressurizer water initially at 653°F. This scenario would therefore result in a fluid temperature range of approximately 467°F to 653°F at the inlets to the PORVs and safety valves. It is again noted that these fluid conditions are qualitative estimates; detailed analysis would be needed to more accurately quantify the plant response and resultant fluid conditions.

* For example, based on Reference (4) analyses, a 125 gpm charging rate into a water-solid plant at 130°F would result in a 25 psi/second pressure ramp rate. This ramp rate would decrease with increasing RCS temperature. Figure 5-1 suggests that it is very unlikely that HPSI flow could exceed 125 gpm at the safety valve setpoint pressure.

5.2.2 All C-E Designed Plants Except Maine Yankee

The shut off heads on the HPSI pumps in all C-E designed plants, except for Maine Yankee, range from 1200 psia to 2000 psia. This range is below the range of C-E designed plants' operating pressures of 2010 psia to 2250 psia, as well as below the PORV setpoints of 2400 psia and safety valve setpoints of 2500 psia nominal. Therefore, the Extended High Pressure Injection Transient is not applicable to any C-E designed plant except Maine Yankee.

5.3 LOW TEMPERATURE PRESSURIZATION TRANSIENTS

5.3.1 Generic LTOP Study

5.3.1.1 Introduction

An investigation was performed by C-E (Reference 4) for C-E operating plants to quantitatively assess the various low temperature pressurization initiating events discussed in Section 4.3 and to develop appropriate recommendations for plant protection when operating at low temperature. Since all the C-E operating plants (except for ANO-2) were initially provided with two PORVs for use at high RCS pressure, the use of these valves for low pressure protection by the addition of a low pressure setpoint was further studied. The discussion below briefly describes the C-E generic LTOP efforts and the results which are pertinent to the current EPRI program.

5.3.1.2 Scope of the Generic Effort

In the Reference (4) study, the plant parameters, initial conditions, and assumptions were selected conservatively so as to make the analysis results generally representative of all C-E operating plants with PORVs (except for Maine Yankee). Specifically, the generic study applied to Palisades, Calvert Cliffs-1 and 2, St. Lucie-1, Millstone-2 and Fort Calhoun. Maine Yankee was not included because it was not a member of the sponsoring Owners' Group, and because of significant differences in design from the remainder of the C-E operating plants.

5.3.1.3 Transient Analysis

The system pressure increases due to mass/energy additions to a water-solid RCS were generically evaluated for the various initiating events described in Section 4.3. Conservative design values were assumed in the pressure transient calculations. The initial pressure was assumed as the maximum allowed for SCS operation. The assumed initial temperature values were minimum values which could reasonably be achieved in the SCS mode of operation. In the case of the spurious SIS actuation event, the LPSI pumps were eliminated from consideration since their shutoff heads were insufficient to overpressurize the RCS, as was the safety injection tank pressure.

5.3.1.4 Results of Generic Analyses

The most rapid pressurizations were found to occur during an energy addition and a mass addition event: 1) starting an RCP with a positive ΔT between the steam generators and the reactor vessel (RV), and 2) inadvertent actuation of safety injection. Accordingly, these two events were considered as the limiting events for later plant-specific analyses.

The severity of the transient caused by the RCP start with a positive ΔT between the steam generator and the RV increases with the magnitude of the ΔT. During this transient, in order to avoid violating pressure/temperature (P/T) limits in low temperature operation, a limit must be placed on the allowable ΔT, particularly since credit for the operation of only one of the two existing PORVs can be assumed due to single failure considerations. Figure 5-2, which is a generic curve from Reference (4), illustrates typical pressure limitations which are imposed at various RCS temperatures. The steam generator-to-RV ΔT can be limited to an acceptable value by specifying maximum allowable values in plant Technical Specifications or in administrative controls and operating procedures. The limiting steam generator-to-RV ΔT varies from plant to plant, and is determined by an analysis of the transient, assuming only a single PORV is available, in conjunction with the plant-specific P/T operating curve.

Similarly, for all other potential low temperature pressurization events Technical Specifications, administrative controls, and operating procedures are formulated so that the event cannot occur, or so that the resulting transient, in conjunction with the lifting of a single PORV (assuming a single failure of one PORV) will not result in the violation of P/T limits. For example, the "racking out" of HPSI pumps in operating C-E plants at RCS temperatures below 200°F ensures that a pressurization due to spurious startup of HPSI pumps cannot occur at lower temperatures.

5.3.2 Plant-Specific Studies

5.3.2.1 Introduction

Plant-specific LTOP efforts based on the results of the generic study (see Section 5.3.1) were performed for Fort Calhoun, Millstone-2, St. Lucie-1, and Calvert Cliffs-1 & 2 (References 4-7). A separate effort was performed for St. Lucie-2 to provide data required for the FSAR. The St. Lucie-2 results are presented in Reference (9). The objective of these investigations was to extend the results of the generic study to determine plant-specific low temperature pressurization transient behavior and plant operating limitations for the purpose of formulating appropriate Technical Specifications, administrative controls, and operating procedures.

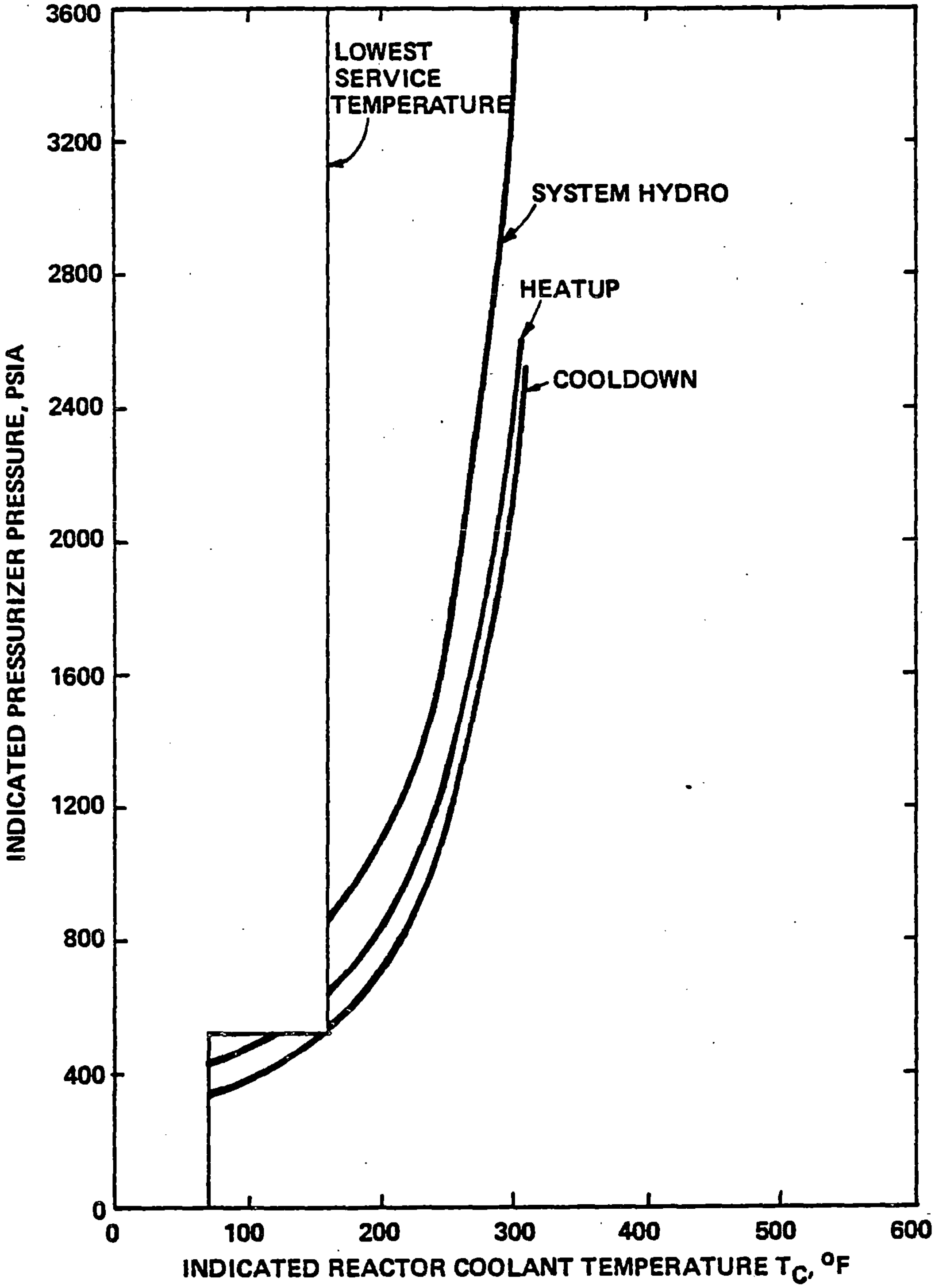

Figure 5-2

REACTOR COOLANT SYSTEM PRESSURE TEMPERATURE LIMITATIONS FOR 2 TO 10 YEARS OF FULL OPERATION

Plant-specific studies were not performed for Maine Yankee and Palisades. However, because of system similarities, it would be expected that the Palisades transient responses for low temperature pressurization events would be similar to those found for the plants for which specific studies were performed.

5.3.2.2 Scope of Plant Specific Efforts

The most severe low temperature pressurization transients as determined in the generic analysis (Reference 4), were considered as design basis events for Fort Calhoun, St. Lucie-1, Calvert Cliffs-1 & 2, and Millstone-2. In the "RCP Start" transient analysis, the energy contribution from the pressurizer heaters, the RCPs, and decay heat were included. Assuming that one PORV was available, the maximum allowable steam generator-to-RV ΔT was determined to ensure that P/T limits were not violated. For the HPSI pump(s) transients, the following cases were considered.

(a) One HPSI and three charging pumps actuated with one PORV available.
(b) Two HPSI and three charging pumps actuated with one PORV available.
(c) One HPSI and three charging pumps actuated with two PORVs available.
(d) Two HPSI and three charging pumps actuated with two PORVs available.

For each of the above cases, energy addition from decay heat and the pressurizer heaters was included.

From the plant-specific analyses, PORV inlet fluid conditions and associated parameters for the design basis transients were abstracted. These are discussed below.

5.3.2.3 Discussion of Plant-Specific Results

Tables 5-23 through 5-27 summarize the pertinent data of specific interest to this study taken from References (4) through (9) for Fort Calhoun, Millstone-2, St. Lucie-1, Calvert Cliffs-1 and 2, and St. Lucie-2. The tables provide PORV inlet fluid data for the design basis mass and energy addition transients. The data includes peak pressurizer pressure, fluid temperature, and pressure ramp rate prior to PORV actuation. Several cases for the safety injection actuation event are included. Table 5-28 provides a brief description of the sequence of events for the design basis energy addition transient.

The data in Tables 5-23 through 5-27 provide various conditions under which the PORVs could be required to operate. With regard to the "RCP Start" transient, the peak pressurizer pressure and pressure ramp rate is a function of the assumed temperature difference between the steam generator and the RV. The steam generator-to-RV ΔT was selected to maintain the peak pressurizer pressure below P/T limits (approximately 520 psia per Figure 5-2). Administrative controls and operating procedures have been imposed limiting the steam generator-to-RV ΔT during low temperature operation to a value which will ensure that the peak transient pressure is below the maximum allowable. Thus, the pressure limits of the P/T curve represent an upper bound to the peak permissible pressurizer pressures for this and all other LTOP transients.

For the "RCP Start" transient, the analyses generally were carried out only just beyond the first pressure peak. However, depending upon the ΔT and the extent of the PORV blowdown, the PORV could cycle a number of times before the transient is self-terminated.

For the inadvertent safety injection transient, detailed transient analyses were not performed. Rather, the equilibrium pressure was calculated when the PORV(s) are open and the HPSI and charging pumps are charging into the RCS. Depending on whether the calculated equilibrium pressure was above or below the PORV setpoint, the PORV would remain open or would cycle between the opening setpressure and the blowdown pressure until the transient was terminated by operator action.

The analyses generally assumed a conservatively high initial pressurizer saturation temperature of 417°F, corresponding to a pressure of 300 psia. The lift pressure of the PORV was assumed as 465 psia, which corresponds to a saturation temperature of 460°F. Therefore, under these conditions the liquid subcooling at the PORV inlet when the valve opens is about 43°F. This subcooling represents a reasonable lower bound to the subcooling expected at the PORV inlet upon actuation during normal low temperature operating conditions. Assuming a minimum pressurizer temperature of 100°F, the potential range of liquid subcooling at the PORV inlet is therefore about 43°F to 360°F.

5.3.2.4 <u>Effect of Vapor Space in the Pressurizer</u>

The data discussed above does not include all the possible fluid regimes which the PORVs could be exposed to during LTOP conditions since only the water-solid plant condition was analyzed. A qualitative discussion of other fluid conditions which could be seen by the PORVs is presented below.

The low temperature pressurization analyses discussed above were performed for the water-solid plant condition, which was expected to result in the most severe transients from the point of view of peak pressure and pressure ramp rate. The water-solid plant results in liquid PORV inlet fluid conditions. However, low temperature plant operation with a steam bubble in the pressurizer is the recommended mode of operation. A steam space in the pressurizer serves as a cushion to greatly reduce the magnitude and rate of the pressure increase during mass and energy addition transients. Depending upon the volume of the pressurizer steam space, the PORVs may not even lift during an RCP start with a steam generator-to-RV ΔT.

If the PORVs lift during a mass or energy addition transient, the initial fluid that is discharged would be steam, unless loop seals were provided at the PORV inlet. For the "RCP Start" transient, the PORV discharge would generally remain as steam until the transient is terminated. For the inadvertent safety injection transient, the continued injection of liquid into the RCS and discharge of steam from the PORVs could, unless terminated by the operator,* eventually result in completely filling the pressurizer with liquid. At this time the PORV inlet fluid would undergo a transition from steam to liquid. The details of the flow transition have not been investigated. During the transient, depending upon the flow-pressure characteristics of the PORV, the PORV could remain open, or could close and open cyclically until the transient is terminated by operator action.

For those plants which have a water seal at the PORV inlet (Millstone-2 and Fort Calhoun) the inlet fluid condition when the PORVs initially lift is subcooled water. Upon valve actuation the water in the seal is emptied and the inlet PORV fluid condition changes to steam if the pressurizer contains a steam bubble. Following water seal discharge, the sequence of events described previously applies for the case of a bubble in the pressurizer.

* Credit for operator action is permissible after 10 minutes.

TABLE 5-1

ARKANSAS NUCLEAR ONE - UNIT 2

Calculated Pressurizer Safety Valve Inlet Fluid Conditions During Pressurization Transients

Pressurization Transient	Peak Pressurizer Pressure (PSIA)	Pressure Ramp Rate (PSI/SEC)	Fluid Condition
Loss of Load	2671	90.0	Steam
Feedline Break*	2705	106.0	Steam
CEA Withdrawal	2662	87.5	Steam
Loss of Condenser Vacuum**	2671	90.0	Steam

* With Loss of AC on Reactor Trip.

** Loss of Condenser Vacuum is the same as Loss of Load.

TABLE 5-2

ARKANSAS NUCLEAR ONE - UNIT 2

Sequence of Events for Pressurization Transients
Which Actuate Safety Valves

TIME, SECONDS

Pressurization Transient

Event During Transient	Loss of Load	Feedline Break*	CEA Withdrawal	Loss of Condenser Vacuum
Event Initiation	0.0	0.0	0.0	0.0
Reactor Trip:				
1. High Power 2. High Pressurizer Pressure 3. TM/LP	5.6	31.4	25.1	5.6
Opening of Safety Valve	6.0	32.0	25.7	6.0
Peak Pressure	9.0	35.5	28.5	9.0
Safety Valve Closing	12.2	42.2	32.9	12.2

* With Loss of AC on Reactor Trip.

TABLE 5-3

CALVERT CLIFFS UNITS 1 AND 2

Calculated Pressurizer Safety and Power Operated Relief Valves
Inlet Fluid Conditions During Pressurization Transients

Pressurization Transient	Valve Type	Peak Pressurizer Pressure (PSIA)	Pressure Ramp Rate (PSI/SEC)	Fluid Condition
Loss of Load	PORV Safety	2538	46.0 52.0	Steam Steam
Loss of Feedwater Flow	PORV Safety	2506	12.0 27.0	Steam Steam
Loss of AC	PORV Safety	2534	52.4 64.4	 Steam
CEA Ejection	PORV	2477	8.0	Steam

TABLE 5-4

CALVERT CLIFFS UNITS 1 AND 2

Sequence of Events for Pressurization Transients Which Actuate Safety and/or Power Operated Relief Valves

TIME, SECONDS

Pressurizer Transient

Event During Transient	Loss of Load	Loss of Feedwater Flow	Loss of AC	CEA Ejection
Event Initiation	0.0	0.0	0.0	0.0
Reactor Trip:				
1. High Power				.2
2. High Pressurizer Pressure	8.3	28.8		
3. Low Flow Trip			.86	
Opening of PORV	7.9	26.9	*	1.53
Opening of Safety Valve	9.8	32.4	5.5	-
Peak Pressure	11.5	32.8	7.4	4.0
Safety Valve Closing	13.4	33.6	12.0	-

* PORVs do not open under Loss of AC conditions

Note: FSAR/Reload analyses assume that PORVs do not operate. The time of PORV opening given in the table corresponds to the time when system pressure increases to 2400 psia, the PORV setpoint.

TABLE 5-5

MAINE YANKEE

Calculated Pressurizer Safety and Power Operated Relief Valves
Inlet Fluid Conditions During Pressurization Transients

Pressurization Transient	Valve Type	Peak Pressurizer Pressure (PSIA)	Pressure Ramp Rate (PSI/SEC)	Fluid Condition
Loss of Load	PORV	2479	25	Steam
CEA Withdrawal	PORV	2500	5.0	Steam

TABLE 5-6

MAINE YANKEE

Sequence of Events for Pressurization Transients Which Actuate Safety and / or Power Operated Relief Valves

TIME, SECONDS

Pressurization Transient

Event During Transient	Loss of Load	CEA Withdrawal
Event Initiation	0.0	0.0
Reactor Trip on High Pressurizer Pressure	8.0	46.0
Opening of PORV	8.0	46.0
Opening of Safety Valve	-	-
Peak Pressure	10.0	70.0
Safety Valve Closing	-	-

Note: FSAR/Reload analyses assume that PORVs do not operate. The time of PORV opening given in the table corresponds to the time when system pressure increases to 2400 psia, the PORV setpoint.

TABLE 5-7

MILLSTONE POINT UNIT 2

Calculated Pressurizer Safety and Power Operated Relief Valves
Inlet Fluid Conditions During Pressurization Transients

Pressurization Transient	Valve Type	Peak Pressurizer Pressure (PSIA)	Pressure Ramp Rate PSI/SEC	Fluid Condition*
Loss of Load	PORV Safety	2555	50.0 53.0	Steam Steam
Loss of Feedwater Flow	PORV	2476	11.0	Steam
Loss of AC	PORV Safety	2549	51.0 60.0	 Steam
CEA Ejection	PORV	2477	8.0	Steam

* The valve inlets are provided with insulated and heat-traced water seals maintained at about 325°F. The safety valve water seals each contain about 3.2 gals. water while the PORV water seals contain about 4 gals. water. Upon valve actuation, this water is first discharged through the valve, followed subsequently by the discharge of steam.

TABLE 5-8

MILLSTONE POINT UNIT 2

Sequence of Events for Pressurization Transients Which Actuate Safety and/or Power Operated Relief Valves

TIME, SECONDS

Pressurization Transient

Event During Transient	Loss of Load	Loss of Feedwater Flow	Loss of AC	CEA Ejection
Event Initiation	0.0	0.0	0.0	0.0
Reactor Trip:				
1. High Power				.2
2. High Pzr Press.	10.8	31.0		
3. Low Flow			1.0	
Opening of PORV	10.3	29.0	*	1.53
Opening of Safety Valve	12.3	-	5.6	-
Peak Pressure	14.3	35.3	8.5	4.0
Safety Valve Closing	16.5	-	16.0	-

* PORVs would not open under Loss of AC conditions

Note: FSAR/Reload analyses assume that PORVs do not operate. The time of PORV opening given in the table corresponds to the time when system pressure increases to 2400 psia, the PORV new setpoint.

TABLE 5-9

FT. CALHOUN

Calculated Pressurizer Safety and Power Operated Relief Valves
Inlet Fluid Conditions During Pressurization Transients

Pressurization Transient	Valve Type	Peak Pressurizer Pressure (PSIA)	Pressure Ramp Rate (PSI/SEC)	Fluid Conditions*
Loss of Load	PORV	2480.0	45.0	Steam
CEA Withdrawal	PORV	2425.0	4.0	Steam

* The valve inlets are provided with uninsulated loop seals which contain water. The safety valve water seals are in the pressurizer compartment and contain approximately 5 gallons each of water at an estimated temperature of about 160°F. The PORV water seals are outside the pressurizer compartment and contain approximately 2.3 gallons each of water at an estimated temperature of 100° to 120°F, the normal operating containment temperature. Upon valve actuation the water seal is first discharged through the valve, subsequently followed by discharge of steam.

TABLE 5-10

FORT CALHOUN

Sequence of Events for Pressurization Transients which Actuate Safety and/or Power Operated Relief Valves

TIME, SECONDS

Pressurization Transient

Event During Transient	Loss of Load	CEA Withdrawal
Event Iniation	0.0	0.0
Reactor Trip on High Pressurizer Pressure	12.0	116.0
Opening of PORV	11.2	116.0
Opening of Safety Valve	-	-
Peak Pressure	14.0	119.0
Safety Valve Closing	-	-

Note: FSAR/Reload analyses assume that PORVs do not operate. The time of PORV opening given in the table corresponds to the time when system pressure increases to 2400 psia, the PORV setpoint.

TABLE 5-11

ST. LUCIE UNIT 1

Calculated Pressurizer Safety and Power Operated Relief Valves
Inlet Fluid Conditions During Pressurization Transients

Pressurization Transient	Valve Type	Peak Pressurizer Pressure (PSIA)	Pressure Ramp Rate (PSI/SEC)	Fluid Conditions
Loss of Load	PORV	2562	60.0	Steam
	Safety		64.0	Steam
Loss of Feedwater Flow	PORV	2506	12.0	Steam
	Safety		27.0	Steam
Loss of AC	PORV	2534	52.4	
	Safety		64.4	Steam
CEA Ejection	PORV	2477	8.0	Steam

TABLE 5-12

ST LUCIE UNIT 1

Sequence of Events for Pressurization Transients Which Actuate Safety and/or Power Operated Relief Valves

TIME, SECONDS

Pressurization Transient

Event During Transient	Loss of Load	Loss of Feedwater Flow	Loss of A/C	CEA Ejection
Event Iniation	0.0	0.0	0.0	0.0
Reactor Trip:				
1. High Pressurizer Pressure	7.75	28.8		
2. Low Flow Trip			.86	
Opening of PORV	7.35	26.9	*	1.53
Opening of Safety Valve	8.95	32.4	5.55	-
Peak Pressure	11.0	32.8	7.4	4.0
Safety Valve Closing	13.4	33.6	12.0	-

* PORVs do not open under Loss of AC conditions

Note: FSAR/Reload analyses assume that PORVs do not operate. The time of PORV opening given in the table corresponds to the time when system pressure increases to 2400 psia, the PORV setpoint.

TABLE 5-13

PALISADES

Calculated Pressurizer Safety and Power Operated Relief Valve Inlet Fluid Conditions During Pressurization Transients

Pressurization Transient	Valve Type	Peak Pressurizer Pressure (PSIA)	Pressure Ramp Rate (PSI/SEC)	Fluid Conditions
Loss of Load (PORV not operable)	Safety	2520	45	Steam
Loss of Load (PORV operable)	PORV	2450	20	Steam

TABLE 5-14

PALISADES

Sequences of Events for Pressurization Transients Which Actuate Safety and Power Operated Relief Valves

TIME, SECONDS

Pressurization Transient

Event	Loss of Load PORV Not Operable	Loss of Load PORV Operable
Event Initiation	0	0
Reactor Trip on High Pressurizer Pressure	13	20
PORV Opens	-	18
Safety Valve Opens	14.7	-
Peak Pressure	16	22
Safety Valve Closes	20.7	-
PORV Closes	-	28

TABLE 5-15

SAN ONOFRE UNITS 2 & 3

Calculated Pressurizer Safety Valve Inlet
Fluid Conditions During Pressurization Transients

Pressurization Transient	Peak Pressurizer Pressure (PSIA)*	Pressure Ramp Rate (PSI/SEC)	Fluid Condition
Loss of Condenser Vacuum (LOCV)	2612	92	Steam
LOCV with Failure of a Pressurizer Level Measurement Channel Associated with the Pressurizer Level Control System	2607	86	Steam
Feedwater System Pipe Breaks	2760	77	Steam
Uncontrolled CEAW from a Subcritical or Low Power Condition	2560	45	Steam
Uncontrolled CEAW at Power	2518	24**	Steam
CEA Ejection	2574	93	Steam

* Assumed safety valve setpoint is 2525 psia.

** Safety valve does not open. Pressure ramp rate is taken at the time pressurizer pressure reaches 2500 psia.

TABLE 5-16

SAN ONOFRE UNITS 2 & 3

Sequence of Events for Pressurization Transients Which Actuate Safety Valves

TIME, SECONDS

Pressurizer Transient

Event During Transient	Loss of Condenser Vacuum	LOCV & SF	Feedwater System Pipe Breaks	Uncontrolled CEAW From Subcritical or Low Power & Condition	Uncontrolled CEAW at Power	CEA Ejection
Event Initiation	0.0	0.0	0.0	0.0	0.0	0.0
Reactor Trip:						
1. High Power	-	-	-	-	-	0.5
2. High Pressurizer Pressure	8.5	8.4	36.1	69.5	-	-
3. DNBR	-	-	-	-	43.5	-
Opening of Safety Valve	10.0	9.7	36.6	72.2	-	2.3
Peak Pressure	12.4	12.2	41.3	73.7	47.2	3.1
Safety Valve Closing	15.5	15.4	46.4	95.7	-	5.0

TABLE 5-17

WATERFORD UNIT 3

Calculated Pressurizer Safety Valve Inlet Fluid Conditions During Pressurization Transients

Pressurization Transient	Peak Pressurizer Pressure (PSIA)	Pressure Ramp Rate (PSI/SEC)	Fluid Condition
Loss of Condenser Vacuum (LOCV)	2555	72	Steam
LOCV with Failure of a Pressurizer Level Measurement Channel Associated with the Pressurizer Level Control System (PLCS)	2557	104	Steam
Feedwater System Pipe Breaks	2688	96	Steam
Uncontrolled CEAW from a Subcritical or Low Power Con-dition	2559	45	Steam
Uncontrolled CEAW at Power	2534	33	Steam
CEA Ejection	2574	93	Steam
CVCS Malfunction (Increase in RCS Inventory)	2539	62	Steam

TABLE 5-18

WATERFORD UNIT 3

Sequence of Events for Pressurization Transients Which Actuate Safety Valves

TIME, SECONDS

Pressurizer Transient

Event During Transient	Loss of Condenser Vacuum	LOCV & SF	Feedwater System Pipe Breaks	Uncontrolled CEAW From Subcritical or Low Power & Condition	Uncontrolled CEAW at Power	CEA Ejection	CVCS Malfunction (Increase in RCS Inventory)
Event Initiation	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reactor Trip:							
1. High Power	-	-	-	-	-	0.5	-
2. High Pressurizer Pressure	8.2	8.1	15.4	69.5	-	-	1641.5
3. DNBR	-	-	-	-	42.8	-	-
Opening of Safety Valve	9.2	9.0	15.9	72.2	45.9	2.3	1643.9
Peak Pressure	10.6	11.0	20.8	73.7	46.6	3.1	1644.2
Safety Valve Closing	13.0	12.8	25.4	95.7	50.0	5.0	1646.4

TABLE 5-19

ST. LUCIE UNIT 2

Calculated Pressurizer Safety and Power Operated Relief Valves Inlet Fluid Conditions During Pressurization Transients

Pressurization Transient	Valve Type	Peak Pressurizer Pressure (PSIA)	Pressure Ramp Rate (PSI/SEC)	Fluid Condition
Isolation of the Turbine	PORV SAFETY	2621	91 84	Steam Steam
LOCV with Failure to Achieve Fast Transfer of a 6.9 KV Bus	PORV SAFETY	2617	92 49	Steam Steam
LOCV with Loss of Offsite Power as Result of Turbine Trip	PORV SAFETY	2663	91 84	Steam Steam
Loss of Feedwater Inventory with Loss of Offsite Power as a Result of Turbine Trip	PORV SAFETY	2752	14 64	Steam Steam
Loss of Offsite Power	PORV SAFETY	2585	66 60	Steam Steam
Uncontrolled Positive Reactivity Insertion with a Loss of Offsite Power as a Result of Turbine Trip	PORV SAFETY	2530	6 44	Steam Steam

TABLE 5-20

ST. LUCIE UNIT 2

Sequence of Events for Pressurization Transients Which Actuate Safety and/or Power Operated Relief Valves

TIME, SECONDS

Pressurizer Transient

Event During Transient	Isolation of the Turbine	LOCV With Failure to Fast Transfer	LOCV With Loss of Offsite Power As a Result of Turbine Trip	LOFW Inventory With Loss of Offsite Power As a Result of Turbine Trip	Loss of Offsite Power	UPRI* With Loss of Offsite Power As a Result of of Turbine Trip
Event Initiation	0.0	0.0	0.0	0.0	0.0	0.0
Reactor Trip:						
1. High Power	-	-	-	-	-	16.1
2. High Pressurizer Pressure	7.7	7.4	7.5	26.0	-	16.1
3. Low RCP Flow	-	7.4	7.5	-	2.45	-
4. Low SG Level	-	-	-	26.0	-	-
Opening of PORV	7.6	6.1	6.0	23.1	1.7	16.0
Opening of Safety Valve	8.1	7.6	7.6	26.4	3.7	18.5
Peak Pressure	10.6	10.6	11.3	31.8	6.0	18.6
Safety Valve Closing	14.6	14.8	17.0	37.8	12.0	20.2

* Uncontrolled Positive Reactivity Insertion

Note: FSAR/Reload analyses assume that PORVs do not operate. The time of PORV opening given in the Table corresponds to the time when system pressure increases to 2400 psia, the PORV setpoint.

TABLE 5-21

SYSTEM 80 PLANTS***

Calculated Pressurizer Safety Valve Inlet Fluid Conditions During Pressurization Transients

Pressurization Transient	Peak Pressurizer Pressure (PSIA)*	Pressure Ramp Rate (PSI/SEC)	Fluid Condition
Turbine Trip	2538	81	Steam
LOCV with Fast Transfer Failure	2547	105	Steam
Sequential CEA Withdrawal	2549	27	Steam
CEA Ejection with a Fast Transfer Failure (FFT)	2539	73	Steam
PLCS Malfunction with FFT	2527	21	Steam
PLCS Malfunction with Loss of Offsite Power at Turbine Trip	2561	83	Steam
Loss of Feedwater Inventory	2587	71	Steam
Loss of Offsite Power	2561	68	Steam
Total Loss of Normal Feedwater Flow	2520	14**	Steam

* Assumed safety valve setpoint is 2525 psia (includes 1% tolerance above normal 2500 psia setpressure).

** Safety valve does not open. Pressure ramp rate is taken at the time pressurizer pressure reaches 2500 psia.

*** The System 80 Plants are Yellow Creek Units 1 and 2, WNP Units 3 and 5, Cherokee Units 1, 2 and 3, Perkins Units 1, 2 and 3, Palo Verde Units 1, 2, and 3.

TABLE 5-22

SYSTEM 80 PLANTS*

Sequence of Events for Pressurization Transients Which Actuate Safety Valves

Pressurizer Transient

Event During Transient	Turbine Trip	LOCV & Fast Transfer Failure	Sequential CEA Withdrawal	CEA Ejection With a Fast Transfer Failure	PLCS Malfunction with Fast Transfer Failure	PLCS Malfunction with a Loss of Offsite Power at Turbine Trip	Loss of Feedwater Inventory	Loss of Offsite Power	Total Loss of Normal Feedwater Flow
Event Initiation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reactor Trip:									
1. High Power	-	-	-	0.13	-	-	-	-	-
2. High Pressurizer Pressure	7.4	5.3	46.5	-	1250.7	1250.7	34.4	-	22.1
3. DNBR	-	-	-	-	-	-	-	0.75	-
4. Low SG Level	-	-	-	-	-	-	34.4	-	-
Opening of Safety Valve	7.8	5.6	48.2	2.5	1254.6	1252.7	34.6	4.65	-
Peak Pressure	8.0	5.7	49.1	2.8	1254.9	1253.2	38.2	5.3	28.1
Safety Valve Closing	11.9	10.8	51.4	5.0	1256.8	1262.3	45.4	10.0	-

* The System 80 Plants are Yellow Creek Units 1 and 2, WNP Units 3 and 5, Cherokee Units 1, 2 and 3, Perkins Units 1, 2 and 3, Palo Verde Units 1, 2, and 3.

TABLE 5-23

FORT CALHOUN

Power Operated Relief Valve Inlet Fluid Conditions During Low Temperature Pressurization Transients

	Pressurization Event	PORVs Available	Fluid State	Inlet Fluid Data Peak Pressure (PSIA)	Range of Temperature (°F)	Pressure Ramp Rate (PSI/SEC)
1	Rep Start With SG-RV $\Delta T = 50°F$	1	Liquid	465	100-417	27
2	SI Actuation					
	a) 2 HPSI + 3 Charging Pumps	1	Liquid	750	100-417	*
	b) 1 HPSI + 3 Charging Pumps	1	Liquid	465	100-417	59
	c) 2 HPSI + 3 Charging Pumps	2	Liquid	465	100-417	*
	d) 1 HPSI + 3 Charging Pumps	2	Liquid	465	100-417	59

NOTE: The peak pressures shown are based on an assumed pressurizer liquid temperature of 417°F (corresponding to a 300 psia saturation pressure) which would result in the minimum flow out of the system and therefore the greatest peak pressures. If the events were initiated with a lower pressurizer liquid temperature the peak pressures would be lower.

* Not analyzed.

TABLE 5-24

MILLSTONE POINT UNIT 2

Power Operated Relief Valve Inlet Fluid Conditions
During Low Temperature Pressurization Transients

			Inlet Fluid Data			
	Pressurization Event	PORVs Available	Fluid State	Peak Pressure (PSIA)	Range of Temperature (°F)	Pressure Ramp Rate (PSI/SEC)
1	RCP Start with SG-RV $\Delta T = 50°F$	1	Liquid	504	100-417	33
2	SI Actuation					
	a) 2 HPSI + 3 Charging Pumps	1	Liquid	800	100-417	*
	b) 1 HPSI + 3 Charging Pumps	1	Liquid	465	100-417	50
	c) 2 HPSI + 3 Charging Pumps	2	Liquid	465	100-417	*
	d) 1 HPSI + 3 Charging Pumps	2	Liquid	465	100-417	50

NOTE: The peak pressures shown are based on an assumed pressurizer liquid temperature of 417°F (corresponding to a 300 psia saturation pressure) which would result in the minimum flow out of the system and therefore the greatest peak pressures. If the events were initiated with a lower pressurizer liquid temperature the peak pressures would be lower.

* Not analyzed

TABLE 5-25

CALVERT CLIFFS UNITS 1 AND 2

Power Operated Relief Valve Inlet Fluid Conditions
During Low Temperature Pressurization Transients

Inlet Fluid Data

	Pressurization Event	PORVs Available	Fluid State	Peak Pressure (PSIA)	Range of Temperature (°F)	Pressure Ramp Rate (PSI/SEC)
1	RCP Start With SG-RV $\Delta T = 50°F$	1	Liquid	521	100-417	34
2	SI Actuation					
	a) 2 HPSI + 3 Charging Pumps	1	Liquid	870	100-417	*
	b) 1 HPSI + 3 Charging Pumps	1	Liquid	540	100-417	50
	c) 2 HPSI + 3 Charging Pumps	2	Liquid	465	100-417	*
	d) 1 HPSI + 3 Charging Pumps	2	Liquid	465	100-417	50

NOTE: The peak pressures shown are based on an assumed pressurizer liquid temperature of 417°F (corresponding to a 300 psia saturation pressure) which would result in the minimum flow out of the system and therefore the greatest peak pressures. If the events were initiated with a lower pressurizer liquid temperature the peak pressures would be lower.

* Not analyzed

TABLE 5-26

ST. LUCIE UNIT 1

Power Operated Relief Valve Inlet Fluid Conditions
During Low Temperature Pressurization Transients

	Pressurization Event	PORVs Available	Fluid State	Peak Pressure (PSIA)	Range of Temperature (°F)	Pressure Ramp Rate (PSI/SEC)
			Inlet Fluid Data			
1	RCP Start With SG-RV	1	Liquid	537	100-417	38
	$\Delta T = 50°F$					
2	SI Actuation					
	a) 2 HPSI + 3 Charging Pumps	1	Liquid	800	100-417	55
	b) 1 HPSI + 3 Charging Pumps	1	Liquid	550	100-417	50
	c) 2 HPSI + 3 Charging Pumps	2	Liquid	470	100-417	55
	d) 1 HPSI + 3 Charging Pumps	2	Liquid	465	100-417	50

NOTE: The peak pressures shown are based on an assumed pressurizer liquid temperature of 417°F (corresponding to a 300 psia saturation pressure) which would result in the minimum flow out of the system and therefore the greatest peak pressures. If the events were initiated with a lower pressurizer liquid temperature the peak pressures would be lower.

TABLE 5-27

ST. LUCIE UNIT 2

Power Operated Relief Valve Inlet Fluid Conditions
During Low Temperature Pressurization Transients

			Inlet Fluid Data		
Pressurization Event	PORVs Available	Fluid State	Peak Pressure (PSIA)	Range of Temperature (°F)	Pressure Ramp Rate (PSI/SEC)
RCP Start With SG-RV ΔT = 100°F	1	Liquid	470	100-417	56
SI Actuation with 2 HPSI + 3 Charging Pumps	1	Liquid	477	100-417	80

NOTE: The peak pressures shown are based on an assumed pressurizer liquid temperature of 417°F (corresponding to a 300 psia saturation pressure) which would result in the minimum flow out of the system and therefore the greatest peak pressures. If the events were initiated with a lower pressurizer liquid temperature the peak pressures would be lower.

TABLE 5-28

Sequence of Events for
RCP Start With SG-RV ΔT = 50°F

	Time, Sec				
Event	Fort Calhoun	Millstone 2	St. Lucie 1	St. Lucie 2*	Calvert Cliffs 1 & 2
Initiation	0	0	0	0	0
PORV Opens	6	6	6	4.4	6
Peak Pressurizer Pressure	6	18	20	4.5	19
PORV Closes	27	50	48.4	22.5	49

*St. Lucie 2 analysis is based on a SG-RV ΔT of 100°F.

Section 6

SUMMARY

6.1 FSAR/Reload Transients

The transients resulting in peak pressurizer pressures or maximum pressure ramp rates, as well as their specific values, vary from plant to plant. These variations exist for a number of reasons. The various plants differ in physical details. In addition, there are variations in control systems, control setpoints, and operating plant parameters. Furthermore, the analyses of the transients may utilize different guidelines, initial conditions, assumptions, models, analysis methods, and computer codes, depending upon the period when the analyses were performed. The details of the analyses can be obtained by reference to the sources indicated in Table 1-1. It should be noted that the valve inlet fluid condition was saturated steam for all cases analyzed, with the exception of two plants having water seals at the valve inlet. For these plants, saturated steam inlet conditions result once the water seal is discharged.

6.2 Extended High Pressure Injection Transient

With the exception of Maine Yankee, the Extended High Pressure Injection transient cannot occur during normal power operation on C-E designed plants due to the relatively low shut off heads of the high pressure safety injection pumps. The Maine Yankee high pressure safety injection pumps have the capability of charging into the Reactor Coolant System at the PORV opening setpoint. Depending upon assumptions regarding plant conditions and equipment or operator failures, the potential exists for lifting the PORVs. Such a transient has not been analyzed by C-E, however. It can be postulated that if the transient were not terminated, the RCS could be charged to a water-solid condition, and the PORVs could actuate on steam followed by transition to liquid. Finally, if the PORVs are isolated initially, the safety valves could be challenged in the same way.

6.3 Low Temperature Pressurization Transients

Tables 5-23 through 5-27 summarize the calculated PORV inlet fluid conditions resulting from inadvertent transients during low temperature plant operation with the RCS in a water-solid condition. During these events, the PORVs lift on subcooled water. It is noteworthy that the peak pressurizer pressure listed in the tables is slightly greater than the actual PORV inlet pressure due to the pressure drop in the inlet piping. For water flow, this pressure difference is about 25 to 50 psi.

During low temperature plant operation, the PORVs are required to maintain the pressurizer pressure below limits defined by the plant Pressure/Temperature curves (see generic Figure 5-2 for example). These curves thus govern allowable PORV peak pressures. At RCS temperatures in the vicinity of refueling temperature, maximum allowable pressurizer pressure is relatively low, in the vicinity of 520 psia. This maximum allowable pressure varies only slightly amongst plants. To avoid overpressurization during the limiting mass and energy addition transients, the pressure rise is limited by invoking appropriate Technical Specifications, administrative controls, and operating procedures. An upper limit is required on the steam generator to reactor vessel ΔT to reduce the severity of transient resulting from an inadvertent reactor coolant pump start. Removal of high pressure safety injection pumps from service by "racking out" at appropriate RCS temperatures will ensure that over-pressurization does not occur as a result of inadvertant safety injection. Thus, maximum PORV inlet pressure for low temperature operation is governed by the plant-specific P/T operating curves.

The low temperature transients with a vapor space in the pressurizer are much less severe than during water-solid plant operation. If the PORVs did lift on an "RCP Start" transient, the inlet fluid would generally be steam until the transient was terminated. For the safety injection actuation transient, the PORV inlet fluid would initially be steam changing to liquid as the pressurizer fills. For both transients, the PORV would remain open or would cycle until the transient is terminated.

For those plants having a water seal (Millstone-2 and Fort Calhoun) the PORV inlet fluid would initially be liquid until the water seal liquid is discharged. Then, if there is a steam space in the pressurizer, the inlet fluid would change to steam. For a safety injection transient that is not terminated, the PORV inlet fluid would change to liquid as the pressurizer fills.

SECTION 7.0

REFERENCES

1. NUREG-0578, TMI-2 Lessons Learned Task Force Status Report and Short Term Recommendations, Nuclear Regulatory Commission, July 1979.

2. NUREG-0737, Clarification of TMI Action Plan Requirements, Nuclear Regulatory Commission, November 1980.

3. EPRI Program Plan for the Performance Testing of PWR Safety and Relief Valves, Revision 1, dated July 1, 1980.

4. Generic Report - Overpressure Protection for Operating C-E NSSSs, December 3, 1976, transmitted by NNECO (D. C. Switzer) letter to NRC (G. Lear), dated December 3, 1976.

5. Low Temperature Overpressure Protection for Fort Calhoun Unit 1, transmitted by OPPD (T. E. Short) letter to NRC (G. Lear), dated May 10, 1977.

6. Low Temperature RCS Overpressure Protection for Millstone Unit No. 2, transmitted by NNECO (D. C. Switzer) letter to NRC (G. Lear), dated June 9, 1977.

7. Low Temperature Reactor Coolant System Overpressure Mitigation for St. Lucie Unit 1, April 10, 1978, transmitted by FP&L (R. E. Uhrig) letter to NRC (V. Stello), dated April 13, 1978.

8. Low Temperature Overpressure Protection for Calvert Cliffs Units 1 and 2, May 13, 1977, transmitted by BG&E (A. E. Lundvall) letter to NRC dated July 21, 1977.

9. Final Safety Analysis Report for Florida Power and Light Co., St. Lucie Plant Unit No. 2.