6.4 Steam Generator Tube Rupture Transient

6.4.1 Thermal-Hydraulic Analysis for Offsite Radiological Consequences

In support of the Indian Point Unit 3 (IP3) stretch power uprate (SPU), a steam generator tube rupture (SGTR) thermal-hydraulic analysis to calculate the radiological consequences has been performed. The analysis was performed using the Nuclear Steam Supply System (NSSS) design parameters for a power uprate to a nominal core power of 3216 MWt.

The major hazard associated with an SGTR event is the radiological consequences resulting from the transfer of radioactive reactor coolant to the secondary side of the ruptured steam generator and subsequent release of radioactivity to the atmosphere. The primary thermal-hydraulic parameters that affect the calculation of doses for an SGTR include the amount of reactor coolant transferred to the secondary side of the ruptured steam generator, the amount of primary-to-secondary break flow that flashes to steam and the amount of steam released from the ruptured steam generator to the atmosphere. The radiological consequences analysis will be discussed in subsection 6.11.9 of this report.

6.4.1.1 Input Parameters and Assumptions

The accident analyzed is the double-ended rupture of a single steam generator tube. It is assumed that the primary-to-secondary break flow following an SGTR results in depressurization of the Reactor Coolant System (RCS), and that reactor trip and safety injection (SI) are automatically initiated on low-pressurizer pressure. Loss-of-offsite power (LOOP) is assumed to occur at reactor trip resulting in the release of steam to the atmosphere via the steam generator atmospheric relief valves (ARVs) and/or safety valves. After plant trip and SI actuation, it is assumed that the RCS pressure stabilizes and the break flow equilibrates at the point where incoming SI flow is balanced by outgoing break flow as shown in Figure 6.4-1. The equilibrium primary-to-secondary break flow is assumed to persist until 30 minutes after the initiation of the SGTR, at which time it is assumed that the operators have completed the necessary actions to terminate the break flow and the steam releases from the ruptured steam generator.

The current analysis does not require that the operators demonstrate the ability to terminate break flow within 30 minutes from the start of the event. It is recognized that the operators may not be able to terminate break flow within 30 minutes for all postulated SGTR events. As discussed in the following paragraphs, the LOFTTR2 analysis supports operator actions to terminate break flow at 60 minutes. The purpose of the calculation is to provide conservatively high mass-transfer rates for use in the radiological consequences analysis. This is achieved by assuming a constant break flow at the equilibrium flow rate, with a constant flashing fraction that does not credit the plant cooldown, for a relatively long time period. Thirty minutes was selected for this purpose. This modeling is consistent with the SGTR analysis presented in Section 14.2.4 of the current *Updated Final Safety Analysis Report* (UFSAR) (Reference 1).

In addition to the previously discussed licensing basis analysis, a supplemental plant response to the event was modeled using the LOFTTR2 computer code with conservative assumptions of break size and location, and condenser availability. The analysis methodology includes the simulation of the operator actions for recovery from an SGTR based on the IP3 Emergency Operating Procedures (EOPs), which are based on the Westinghouse Owners Group (WOG) Emergency Response Guidelines (ERGs). Conservative operator action times were assumed for analysis purposes and are not intended to serve as a basis for actual operator action times in procedures or training.

The LOFTTR2 analyses were performed for the time period from the SGTR initiation until the primary and secondary pressures were equalized (break flow termination at 60 minutes). The water volume in the secondary side of the ruptured steam generator was calculated as a function of time to demonstrate that overfill does not occur. The primary-to-secondary break flow and steam releases to the atmosphere from both the ruptured and intact steam generators were calculated for use in determining the activity released to the atmosphere. The mass releases were calculated with the LOFTTR2 program from the initiation of the event until termination of the break flow. The mass release information was compared to the licensing basis analysis to verify that the licensing basis analysis modeling break flow for only 30 minutes is limiting with respect to offsite and control room doses.

After 30 minutes, it is assumed in the licensing basis analysis that steam is released only from the intact steam generators to dissipate the core decay heat and to subsequently cool the plant down to the Residual Heat Removal System (RHRS) operating conditions. It is assumed that the RHRS is capable of removing core decay heat within 29 hours after the SGTR initiation, and that steam releases are terminated at that time. A primary and secondary side mass and energy (M&E) balance is used to calculate the steam release for the intact steam generators from 0 to 2 hours, from 2 to 8 hours, and from 8 to 29 hours.

The following analysis assumptions and input parameters were used.

- Analysis methodology is consistent with current UFSAR analysis.
- LOOP is assumed to occur concurrent with the reactor trip.
- The core power is 3216 MWt.

- The RCS average temperature range is 549.0° to 572.0°F.

- The steam generator tube plugging (SGTP) range is 0 to 10 percent.

- The main feedwater temperature range is 390° to 433.6°F

- The low-pressurizer pressure SI actuation setpoint is 1734.7psia.

- The lowest steam generator safety valve reseat pressure is 885.4 psia. This includes an 18-percent main steam safety valve (MSSV) blowdown, which covers the -3-percent safety valve setpoint tolerance.

- The maximum high-head safety injection (HHSI) flow rates from all 3 HHSI pumps are shown below:

RCS Pressure (psia)	HHSI Flow Rate (gpm)
1014.7	834.9
1214.7	656.9
1414.7	420.6
1614.7	0.0

- In addition to the HHSI flow, the analysis models a charging flow of 108 gpm per pump for a total of 324 gpm from 3 pumps.

- The time the RHR is capable of removing all decay heat (termination of steam releases) is less than 29 hours after event initiation.

- The break-flow flashing fraction is calculated based on the initial hot leg temperature (603.0°F) for the pre-reactor trip break-flow flashing fraction. Following reactor trip, the break-flow flashing fraction is based upon a hot leg temperature equal to the saturation temperature of the RCS pressure where the break-flow rate equals SI flow rate (T_{sat}(1600 psia) = 604.9°F).

- The break-flow to the ruptured steam generator and steam releases from the ruptured steam generator is assumed to be terminated at 30 minutes.

- The minimum total auxiliary feedwater (AFW) flow rate supplied to the plant is 600 gpm.

6.4.1.2 Description of Analyses and Evaluations

The SGTR analysis supports an average temperature (T_{avg}) window range of 549.0°F up to 572.0°F. Plant secondary side conditions (for example, steam pressure, flow, and temperature) are based on high and low tube plugging (0-percent up to 10-percent average/peak) to bound all possible conditions. Four separate cases have been analyzed as follows:

1. T_{avg} = 549.0°F and SGTP = 0 percent
2. T_{avg} = 549.0°F and SGTP = 10-percent average/peak
3. T_{avg} = 572.0°F and SGTP = 0 percent
4. T_{avg} = 572.0°F and SGTP = 10-percent average/peak

In total, four cases were considered in the SGTR thermal-hydraulic analysis to bound the operating conditions for the uprate. Note that these four cases are individually analyzed to determine the limiting steam release and limiting break flow between 0 and 30 minutes (break-flow termination) for the radiological consequences calculation.

A portion of the break flow will flash directly to steam upon entering the secondary side of the ruptured steam generator. Since a transient break-flow calculation is not performed for IP3, a detailed time-dependent flashing fraction that incorporates the expected changes in primary side temperatures cannot be calculated. Instead, a conservative calculation of the flashing fraction is performed using the limiting conditions from the break-flow calculation cases. Two time intervals are considered, as in the break-flow calculations: pre- and post-reactor trip (SI initiation occurs concurrently with reactor trip). Since the RCS and steam generator conditions are different before and after the trip, different flashing fractions would be expected.

The flashing fraction is based on the difference between the primary side fluid enthalpy and the saturation enthalpy on the secondary side. Therefore, the highest flashing will be predicted for the case with the highest primary side temperatures. For the flashing-fraction calculations, it is conservatively assumed that all of the break flow is at the hot leg temperature (T_{hot}) (the break is assumed to be on the hot-leg side of the steam generator). Similarly, a lower secondary side pressure maximizes the difference in the primary and secondary enthalpies, resulting in more flashing. The highest possible pre-trip flashing fraction, based on the range of operating conditions covered by this analysis, is for a case with a T_{hot} of 603.0°F, an initial RCS pressure of 2250 psia, and an initial secondary pressure of 567 psia. All cases consider the same post-trip RCS pressure of 1600 psia and post-trip steam generator pressure of 885.4 psia. The post-trip flashing fraction is based on a hot leg temperature at saturation conditions with the RCS at the equilibrium pressure of 1600 psia.

A single calculation is performed to determine long-term steam releases from the intact steam generators for the time interval from the start of the event (0 hours) to 2 hours, 2 hours to 8 hours, and from 8 hours to RHR conditions at 29 hours. The 0- to 2-hour calculations use the 0- to 30-minute intact steam generators' steam release results from the case that resulted in the highest intact steam generators' steam flow rates.

A simple mass and energy (M&E) balance is assumed in the calculation of the break flow and steam releases. The energy balance is based on the following assumed conditions at 30 minutes:

- The RCS fluid is at the equilibrium pressure and no-load temperature.
- The pressurizer fluid and steam generator secondary fluid for both the ruptured and intact steam generators is at saturation conditions at the no-load temperature.
- The fuel and clad, primary system metal, pressurizer metal, and steam generator secondary metal are at no-load temperature. Since the RCS fluid is not at a consistent energy state with the ruptured steam generator and the remainder of the primary and secondary systems, energy must be dissipated to reduce the RCS fluid from equilibrium pressure and no-load temperature to saturation at no-load temperature.

It is assumed that the plant is then maintained stable at the no-load temperature until 2 hours, and that steam will be released from only the intact steam generators to dissipate the energy from the reduction in the RCS fluid energy state and the core decay heat from 30 minutes to 2 hours.

After 2 hours, it is assumed that plant cooldown to RHR cut-in conditions is initiated by releasing steam from only the intact steam generators. It is assumed that cooldown to RHR cut-in conditions is completed within 8 hours after the SGTR since the cooldown should be accomplished within this time period. However, at 8 hours the RHRS may not be capable of removing all the residual decay heat. Therefore, between 8 and 29 hours steam is released from the intact steam generators to remove the residual decay heat. After the RHR is capable of removing all decay heat, it is assumed that further cooldown is performed using the RHRS, and that the steam release from the intact steam generators is terminated. The energy to be dissipated from 2 to 8 hours and 8 to 29 hours is calculated from an energy balance for the primary and secondary systems between no-load conditions at 2 hours, and the RHR entry conditions at 8 hours, plus the core decay heat load from 2 to 8 hours and 8 to 29 hours. The amount of steam released from the intact steam generators is calculated from an M&E balance for the intact steam generators.

6.4.1.3 Acceptance Criteria

There are no criteria associated with the thermal-hydraulic calculations. The results of the calculations are used in the determination of the offsite and control room dose. Acceptance criteria for offsite and control room doses are discussed in subsection 6.11.9 of this report.

6.4.1.4 Results

The tube rupture break flow and ruptured steam generator atmospheric steam releases from 0 to 30 minutes for the four different SGTR cases (discussed in subsection 6.4.1.2 of this report) are summarized in Table 6.4-1. Based on the results of these four SGTR cases, bounding values for break flow and steam releases are provided in Table 6.4-2, along with the long-term steam releases, and steam generator water mass data to be used in radiological consequences analysis. For an SGTR event, the amount of radioactivity released to the atmosphere is highly dependent on the amount of steam released through the safety valves associated with the ruptured steam generator. Therefore, the worst radiological consequences result from the SGTR case with the greatest amount of steam released. Likewise, a greater break flow results in greater radiological contamination of the secondary side that, in turn, results in a greater amount of activity released along with the steam. Maximum break flow and steam release, therefore, represent bounding values that are conservative for an offsite and control room dose evaluation. An additional 10-percent margin has been added to the primary-to-secondary break flow and steam releases to allow for design changes.

The results of the radiological consequences analysis of an SGTR are discussed in subsection 6.11.9 of this document.

6.4.1.5 Conclusions

The SGTR thermal-hydraulic analysis to be used in the radiological consequences calculation has been completed in support of the IP3 SPU. Subsection 6.11.9 of this report presents the offsite and control room dose consequences based in the thermal-hydraulic data in Table 6.4-2.

6.4.2 References

1. *Indian Point Nuclear Generating Unit No.3, Updated Final Safety Analysis Report*, Docket No. 50-286.

Table 6.4-1 Case-Specific SGTR Thermal-Hydraulic Results[1]	
Tube Rupture Break Flow for 0 - 30 min.	
T_{avg} = 549.0°F, 0% SGTP	124,901 lbm
T_{avg} = 549.0°F, 10% SGTP	125,118 lbm
T_{avg} = 572.0°F, 0% SGTP	122,401 lbm
T_{avg} = 572.0°F, 10% SGTP	123,213 lbm
Steam Release from Ruptured Steam Generator for Reactor Trip - 30 min.[2]	
T_{avg} = 549.0°F, 0% SGTP	51,922 lbm
T_{avg} = 549.0°F, 10% SGTP	50,768 lbm
T_{avg} = 572.0°F, 0% SGTP	65,192 lbm
T_{avg} = 572.0°F, 10% SGTP	62,002 lbm

Notes:

1. No margin added.
2. Prior to reactor trip, the steam flow rate is unaffected by the SGTR.

Table 6.4-2 Bounding SGTR Thermal-Hydraulic Results for Radiological Dose Analysis[1]	
Reactor Trip, SI Actuation, and LOOP	392 seconds
Pre-Trip (less than 392 sec)	
Tube Rupture Break Flow[1]	38,500 lbm
Percentage of Break Flow which Flashes	21.0%
Steam Release Rate to Condenser[1]	1070.21 lbm/sec for each steam generator
Post-Trip (after 392 sec)	
Tube Rupture Break Flow[1]	99,500 lbm
Percentage of Break Flow which Flashes	15.0%
Steam Release from Ruptured Steam Generator up to 30 minutes[1]	72,000 lbm
Steam Release from Intact Steam Generators up to 2 Hours[1]	526,000 lbm
Steam Release from Intact Steam Generator from 2 - 8 Hours[1]	1,160,000 lbm
Steam Release from Intact Steam Generator from 8 - 29 Hours[1]	1,580,000 lbm
Steam Generator Maximum Mass	90,000 lbm/steam generator
Steam Generator Minimum Mass	63,500 lbm/steam generator

Note:

1. 10-percent margin added on break flow and steam releases.

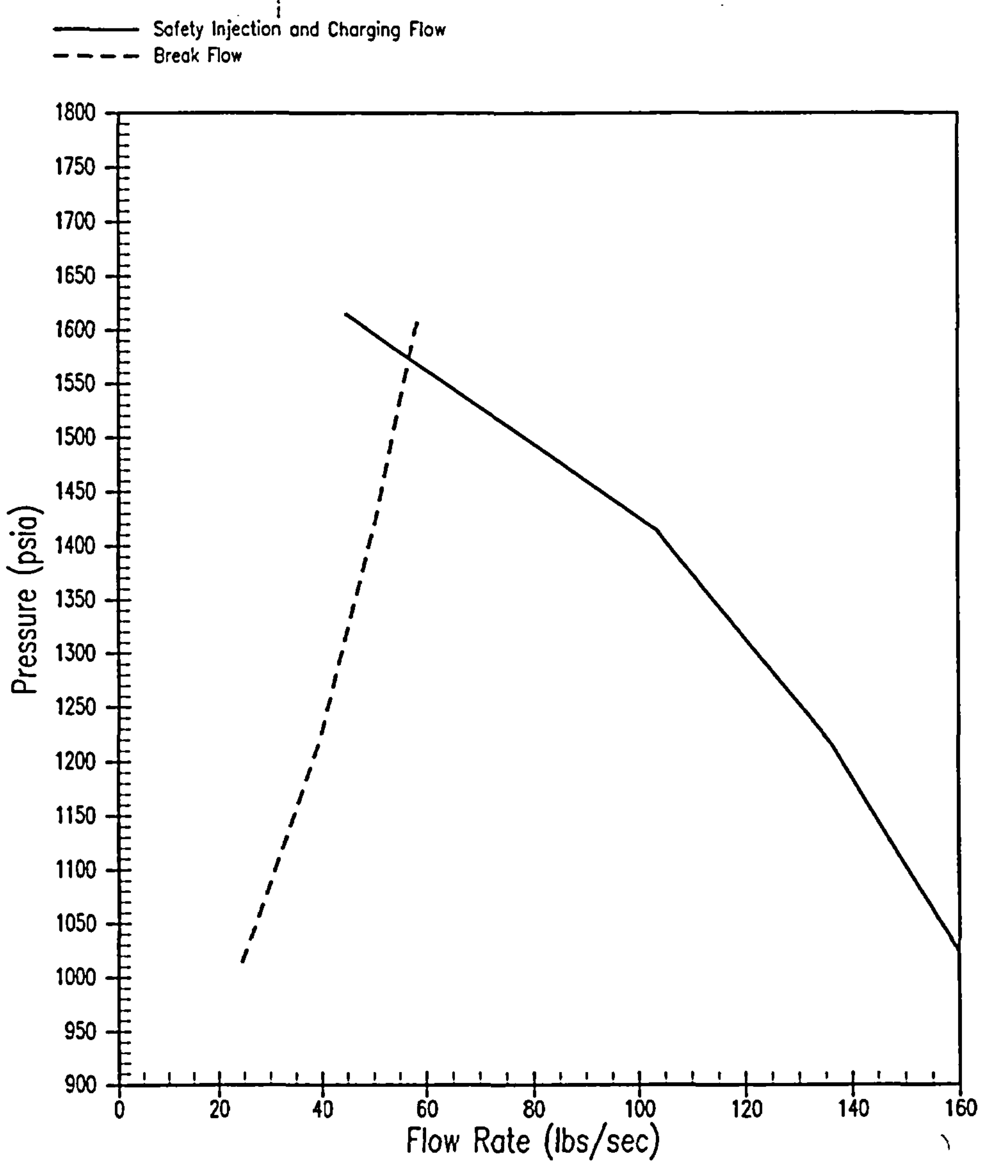

Figure 6.4-1

SI and Charging Flow and Break Flow versus RCS Pressure

6.5 Loss-of-Coolant Accident Containment Integrity

The uncontrolled release of pressurized high-temperature reactor coolant, termed a loss-of-coolant accident (LOCA), will result in release of steam and water into the containment. This, in turn, will result in increases in the local subcompartment pressures and an increase in the global containment pressure and temperature. Both the long-term and short-term effects on containment resulting from a postulated LOCA were considered for the stretch power uprate (SPU) at Indian Point Unit 3 (IP3).

To demonstrate the acceptability of the containment safeguards systems to mitigate the consequences of a hypothetical large-break LOCA (LBLOCA), the long-term LOCA mass and energy (M&E) releases were analyzed to approximately 10^7 seconds and used as input to the containment integrity analysis. The containment safeguards systems must be capable of limiting the peak containment pressure to less than the design pressure and to limit the temperature excursion to less than the Environmental Qualification (EQ) acceptance limits. In addition, the integrated leak rate test (ILRT) limit must not be exceeded. For this program, Westinghouse generated the M&E releases using the March 1979 model, described in WCAP-10325-P-A and WCAP-10326-A (Reference 1), which include the NRC review and approval letter. This methodology has previously been applied to IP3 and has also been used and approved on many plant-specific dockets. Subsection 6.5.1 of this report discusses the long-term LOCA M&E releases generated for this program. The results of this analysis were used in the containment integrity analysis (see subsection 6.5.3).

The short-term LOCA-related M&E releases are used as input to the subcompartment analyses, which are performed to ensure that the walls of a subcompartment can maintain their structural integrity during the short pressure pulse (generally less than 3 seconds) accompanying a high-energy-line pipe rupture within that subcompartment. The subcompartments evaluated include the steam generator compartment, loop compartments, and the pressurizer compartment. The fact that IP3 is approved for leak-before-break (LBB) methodology was used to qualitatively demonstrate that any changes associated with the SPU are offset by the LBB benefit of using the smaller Reactor Coolant System (RCS) nozzle breaks, thus demonstrating that the current licensing bases for these subcompartments remain bounding. Any changes associated with the SPU will be offset by the LBB benefit and the *IP3 Updated Final Safety Analysis Report* (UFSAR) (Reference 2) will not change. Subsection 6.5.2 discusses the short-term evaluation conducted for this program.

6.5.1 Long-Term LOCA M&E Releases

The revised M&E release rates described in this section were used as input for the containment pressure calculations discussed in subsection 6.5.3. The M&E releases were revised using the *Westinghouse LOCA Mass and Energy Release Model for Containment Design, March 1979 Version* (Reference 1). The long-term LOCA M&E releases are provided for the hypothetical double-ended pump suction (DEPS) rupture and double-ended hot leg (DEHL) rupture cases for IP3 at the SPU conditions.

6.5.1.1 Input Parameters and Assumptions

The M&E release analysis is sensitive to the assumed characteristics of various plant systems, in addition to other key modeling assumptions. Where appropriate, bounding inputs were used and instrumentation uncertainties were included. For example, the RCS operating temperatures were chosen to bound the highest average coolant temperature range of all operating cases, and a temperature uncertainty allowance of +7.5°F was then added. Nominal parameters were used in certain instances. For example, the RCS pressure in this analysis was based on a nominal value of 2250 psia, plus an uncertainty allowance (+49 psi). All input parameters were consistent with accepted analysis methodology.

Some of the most critical items were the RCS initial conditions, core decay heat, safety injection (SI) flow, and primary and secondary metal mass and steam generator heat release modeling. Specific assumptions concerning each of these items are discussed below. Tables 6.5-1 through 6.5-3 present key data assumed in the analysis.

The core-rated power of 3216 MWt was used in the analysis. The core-rated power uncertainty used in the long-term LOCA M&E analysis is 2 percent. As previously noted, RCS operating temperatures bounding the highest average coolant temperature range were used in the analysis. The use of higher temperatures is conservative because the initial fluid energy is based on coolant temperatures, which are at the maximum levels attained in steady-state operation. Additionally, an allowance to account for instrument error and deadband was reflected in the initial RCS temperatures. As previously discussed, the initial RCS pressure in this analysis was based on a nominal value of 2250 psia, plus an allowance that accounts for the measurement uncertainty on pressurizer pressure. The selection of 2299 psia as the limiting pressure is considered to affect the blowdown phase results only, since this represents the initial pressure of the RCS. The RCS rapidly depressurizes from this value to the point at which it equilibrates with containment pressure.

The rate at which the RCS blows down is initially more severe at the higher RCS pressure. Additionally, the RCS has a higher fluid density at the higher pressure (assuming a constant temperature) and subsequently has a higher RCS mass available for releases. Thus, 2250 psia plus uncertainty was selected for the initial pressure as the limiting case for the long-term M&E release calculations.

The selection of the fuel design features for the long-term M&E release calculation is based on the need to conservatively maximize the energy stored in the fuel at the beginning of the postulated accident (that is, the core-stored energy). The core stored energy used is 4.90 full power seconds.

The RCS volume is increased by 3 percent, which is composed of a 1.6-percent allowance for thermal expansion and a 1.4-percent allowance for uncertainty.

A uniform steam generator tube plugging (SGTP) level of 0 percent was modeled. This assumption maximized the reactor coolant volume and fluid release by including the RCS fluid in all steam generator tubes. During the post-blowdown period, the steam generators are active heat sources since significant energy remains in the secondary metal and secondary mass that has the potential to be transferred to the primary side. The 0-percent SGTP assumption maximized heat transfer area and, therefore, the transfer of secondary heat across the steam generator tubes. Additionally, this assumption reduced the reactor coolant loop (RCL) resistance, which reduced the ΔP upstream of the break for the pump suction breaks and increased break flow. Thus, the analysis very conservatively modeled the effects related to SGTP.

The M&E release analyses modeled configurations and failure assumptions that conservatively bound alignments for SI flows. The minimum safeguards case that has a single failure of a diesel generator (DG) 32 (two high-head safety injection [HHSI] pumps and one low-head safety injection [LHSI] pump available). The maximum safeguards case has a single failure of one containment spray pump (three HHSI pumps and two LHSI pumps available).

The following assumptions were used to ensure that the M&E releases were conservatively calculated, thereby maximizing energy release to containment.

- Maximum expected operating temperature of the RCS (100 percent, full-power conditions)
- Allowance for RCS temperature uncertainty (+7.5°F)
- Margin in RCS volume of 3 percent (which is composed of a 1.6-percent allowance for thermal expansion, and 1.4 percent for uncertainty)

- Core-rated power of 3216 MWt

- Conservative heat transfer coefficient (that is, steam generator primary-to-secondary heat transfer and RCS metal heat transfer)

- Allowance in core-stored energy for the effect of fuel densification

- An allowance for RCS initial pressure uncertainty (+49 psi)

- A maximum containment backpressure equal to design pressure (61.7 psia)

- Minimum RCS loop flow (88,600 gpm/loop)

- Main feedwater addition following a signal to close the flow control valve

- SGTP leveling (0 percent uniform)

  — Maximizes reactor coolant volume and fluid release

  — Maximizes heat transfer area across the steam generator tubes

  — Reduces coolant loop resistance, which reduces the ΔP upstream of the break for the pump suction breaks, and increases break flow

Based on these conditions and assumptions, a bounding analysis of IP3 was made for the release of M&E from the RCS for a postulated LOCA at the SPU core power of 3216 MWt.

6.5.1.2 Description of Analyses

The evaluation model (EM) used for the long-term LOCA M&E release calculations is the March 1979 model described in WCAP-10325-P-A (Reference 1). This EM has been reviewed and approved generically by the NRC. The approval letter is included with WCAP-10325-P-A. This model has previously been applied to IP3, and also has been used and approved on the plant-specific dockets for other Westinghouse pressurized water reactors (PWRs).

This report section presents the long-term LOCA M&E releases generated in support of the IP3 SPU. These M&E releases were used in the containment integrity analysis discussed in subsection 6.5.3.

6.5.1.3 LOCA M&E Release Phases

The containment system receives M&E releases following a postulated rupture in the RCS. These releases continue over a time period that, for the LOCA M&E analysis, is typically divided into four phases.

1. **Blowdown** - the period of time from accident initiation (when the reactor is at steady-state operation) to the time that the RCS and containment reach an equilibrium state.

2. **Refill** - the period of time when the lower plenum is being filled by accumulator and Emergency Core Cooling System (ECCS) water. At the end of blowdown, a large amount of water remains in the cold legs, downcomer, and lower plenum. To conservatively consider the refill period for the purpose of containment M&E releases, it is assumed that this water is instantaneously transferred to the lower plenum along with sufficient accumulator water to completely fill the lower plenum. This allows an uninterrupted release of M&E to containment because the lower plenum is not filled over time. Thus, the refill period is conservatively neglected in the M&E release calculation because there is an instantaneous rather than mechanistic transfer of water to the lower plenum.

3. **Reflood** - begins when the water from the lower plenum enters the core and ends when the core is completely quenched.

4. **Post-Reflood (FROTH)** - the period following the reflood phase. For the pump suction break, a two-phase mixture exits the core, passes through the hot legs, and is superheated in the steam generators prior to exiting the break as steam. After the broken-loop steam generator cools, the break flow becomes two-phase.

6.5.1.4 Computer Codes

The M&E release evaluation model in WCAP-10325-P-A (Reference 1) comprises M&E release versions of the following codes: SATAN VI, WREFLOOD, FROTH, and EPITOME. These codes were used to calculate the long-term LOCA M&E releases for IP3.

SATAN VI calculates blowdown; the first portion of the thermal-hydraulic transient following break initiation, including pressure, enthalpy, density, M&E flowrates; and energy transfer between primary and secondary systems as a function of time.

The WREFLOOD code addresses the portion of the LOCA transient in which the core reflooding phase occurs after the primary coolant system has depressurized (blowdown) due to the loss of water through the break and water supplied by the ECCS refills the reactor vessel and provides cooling to the core. The most important feature of WREFLOOD is the steam/water mixing model (see subsection 6.5.1.8.2 of this report).

FROTH models the post-reflood portion of the transient. The FROTH code is used for the steam generator heat addition calculation from the broken-loop and intact-loop steam generators.

EPITOME continues the FROTH post-reflood portion of the transient from the time at which the secondary equilibrates to containment design pressure to the end of the transient. It also compiles a summary of data on the entire transient, including formal instantaneous M&E release tables and M&E balance tables with data at critical times.

6.5.1.5 Break Size and Location

Generic studies have been performed to determine the limiting postulated break size for LOCA M&E releases. The double-ended guillotine break has been determined to be limiting due to larger mass flow rates during the blowdown phase of the transient. During the reflood and post-reflood phases, the break size has little effect on the releases.

Three distinct locations in the RCS loop can be postulated for pipe rupture for any release purposes:

- Hot leg (between vessel and steam generator)
- Cold leg (between pump and vessel)
- Pump suction (between steam generator and pump)

The break locations analyzed for the SPU are the DEPS rupture (10.48 ft^2), and the DEHL rupture (9.18 ft^2). Break M&E releases have been calculated for the blowdown, reflood, and post-reflood phases of the LOCA for the DEPS cases. For the DEHL case, the releases were calculated only for the blowdown. The following information provides a discussion for each break location.

The DEHL rupture has been shown in previous studies to result in the highest blowdown M&E release rates. Although the core flooding rate would be the highest for this break location, the amount of energy transferred from the steam generator secondary side is minimal because the majority of the fluid that exits the core vents directly to containment, bypassing the steam generators. As a result, the reflood M&E releases were reduced significantly as compared to either the pump suction or cold leg break locations for which the core exit mixture must pass through the steam generators before venting through the break. For the hot leg break, generic studies have confirmed that there is no reflood peak (that is, from the end of the blowdown period the containment pressure would continually decrease). Therefore, only the M&E releases for the hot leg break blowdown phase were calculated and presented in this section of the report.

The cold leg break location has also been determined in previous studies to be much less limiting in terms of the overall containment energy releases. The cold leg blowdown is faster than that of the pump suction break, and more mass is released into the containment. However, the core heat transfer is greatly reduced, and this results in a considerably lower energy release into containment. Studies have determined that the blowdown transient for the cold leg is, in general, less limiting than that for the pump suction break. During reflood, the flooding rate is greatly reduced and the energy release rate into the containment is reduced. Therefore, the cold leg break is bounded by other breaks and no further evaluation is necessary.

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

6.5.1.6 Application of Single-Failure Criterion

An analysis of the effects of the single-failure criterion has been performed on the M&E release rates for each break analyzed. An inherent assumption in the generation of the M&E release is that offsite power is lost. This results in the actuation of the emergency diesel generators (DGs), which are required to power the Safety Injection System (SIS). This is not an issue for the blowdown period, which is limited by the DEHL break.

Two cases have been analyzed to assess the effects of a single failure. The first case assumes minimum ECCS SI flow based on the postulated single failure of a DG. This results in the loss of one train of safeguards equipment. The other case assumes maximum ECCS SI flow based on no postulated failures that would affect the amount of ECCS flow; one containment spray pump is failed. The analysis of these two cases provides confidence that the effect of credible single failures is bounded.

6.5.1.7 Acceptance Criteria for Analyses

An LBLOCA is classified as an American Nuclear Society (ANS) Condition IV event—an infrequent fault. Although IP3 is not a *Standard Review Plan* (SRP) plant, for completeness, the SRP long-term cooling criterion is also examined. To satisfy the NRC acceptance criteria presented in the SRP, Section 6.2.1.3, the relevant requirements are as follows:

- 10CFR50, Appendix A (Reference 3)
- 10CFR50, Appendix K, paragraph I.A (Reference 4)

To meet these requirements, the following must be addressed:

- Sources of energy
- Break size and location
- Calculation of each phase of the accident

6.5.1.8 M&E Release Data

6.5.1.8.1 Blowdown M&E Release Data

The SATAN-VI code is used for computing the blowdown transient. The code uses the control volume (element) approach with the capability for modeling a large variety of thermal fluid system configurations. The fluid properties are considered uniform and thermo-dynamic equilibrium is assumed in each element. A point kinetics model is used with weighted feedback effects. The major feedback effects include moderator density, moderator temperature, and Doppler broadening. A critical flow calculation for sub-cooled (modified Zaloudek), two-phase (Moody), or superheated break flow is incorporated into the analysis. The methodology for the use of this model is described in WCAP-10325-P-A (Reference 1).

Table 6.5-4 presents the calculated M&E release for the blowdown phase of the DEHL break. For the hot leg break M&E release tables, break path 1 refers to the M&E exiting from the reactor vessel side of the break, and break path 2 refers to the M&E exiting from the steam generator side of the break. Table 6.5-5 presents the mass balance for the DEHL break. Table 6.5-6 presents the energy balance for the DEHL break.

Table 6.5-7 presents the calculated M&E releases for the blowdown phase of the DEPS break with minimum ECCS flows. Table 6.5-8 presents the calculated M&E releases for the blowdown phase of the DEPS break with maximum ECCS flows. For the pump suction breaks, break path 1 in the M&E release tables refers to the M&E exiting from the steam-generator side of the break; break path 2 refers to the M&E exiting from the pump side of the break.

6.5.1.8.2 Reflood M&E Release Data

The WREFLOOD code is used for computing the reflood transient. The WREFLOOD code consists of two basic hydraulic models: one for the contents of the reactor vessel, and one for the coolant loops. The two models are coupled through the interchange of the boundary conditions applied at the vessel outlet nozzles and at the top of the downcomer. Additional transient phenomena, such as pumped SI and accumulators, reactor coolant pump (RCP) performance, and steam generator releases are included as auxiliary equations that interact with the basic models as required. The WREFLOOD code permits the capability to calculate variations during the core reflooding transient of basic parameters, such as core flooding rate, core and downcomer water levels, fluid thermo-dynamic conditions (pressure, enthalpy, density) throughout the primary system, and mass flow rates through the primary system. The code permits hydraulic modeling of the two flow paths available for discharging steam and entrained water from the core to the break; that is, the path through the broken loop and the path through the unbroken loops.

A complete thermal equilibrium mixing condition for the steam and ECCS injection water during the reflood phase has been assumed for each loop receiving ECCS water. This is consistent with the use and application of the M&E release evaluation model (Reference 1) in recent analyses, for example, D. C. Cook Docket (Reference 5). Even though the WCAP-10325-P-A (Reference 1) model credits steam/water mixing only in the intact loop and not in the broken loop, the justification, applicability, and NRC approval for using the mixing model in the broken loop has been documented (Reference 5). Moreover, this assumption is supported by test data and is further discussed below.

The model assumes a complete mixing condition (that is, thermal equilibrium) for the steam/water interaction. The complete mixing process, however, is made up of two distinct physical processes. The first is a two-phase interaction with steam condensation by cold ECCS water. The second is a single-phase mixing of condensate and ECCS water. Since the steam release is the most important influence to the containment pressure transient, the steam condensation part of the mixing process is the only part that must be considered. (Any spillage directly heats only the sump.)

The most applicable steam/water mixing test data have been reviewed for validation of the containment integrity reflood steam/water mixing model. These data were generated in 1/3-scale tests (Reference 6) and are the largest scale data available and, thus, most clearly simulate the flow regimes and gravitational effects that would occur in a PWR. These tests were designed specifically to study the steam/water interaction for PWR reflood conditions.

A group of 1/3-scale tests corresponds directly to containment integrity reflood conditions. The injection flowrates for this group cover all phases and mixing conditions calculated during the reflood transient. The data from these tests were reviewed and discussed in detail in WCAP-10325-P-A (Reference 1). For all of these tests, the data clearly indicate the occurrence of very effective mixing with rapid steam condensation. The mixing model used in the containment integrity reflood calculation is, therefore, wholly supported by the 1/3-scale steam/water mixing data.

Additionally, the following justification is also noted. The post-blowdown limiting break for the containment integrity peak pressure analysis is the DEPS rupture. For this break, there are two flow paths available in the RCS by which M&E can be released to containment. One is through the outlet of the steam generator, the other via reverse flow through the RCP. Steam that is not condensed by ECCS injection in the intact RCS loops passes around the downcomer and through the broken-loop cold leg and pump-in venting to containment. This steam also encounters ECCS injection water as it passes through the broken-loop cold leg, where complete mixing occurs, and a portion of it is condensed. It is this portion of steam, which is condensed, that is credited in this analysis. Based upon the postulated break location and the actual physical presence of the ECCS injection nozzle, this assumption is justified. A description of the test and the test results are contained in WCAP-10325-P-A and EPRI 294-2 (References 1 and 6).

Tables 6.5-9 and 6.5-10 present the calculated M&E releases for the reflood phase of the DEPS minimum ECCS and maximum ECCS cases, respectively.

The transient response of the principal parameters during reflood are given in Tables 6.5-11 and 6.5-12 for the DEPS cases.

6.5.1.8.3 Post-Reflood M&E Release Data

The FROTH code (Reference 7) is used for computing the post-reflood transient. The FROTH code calculates the heat release rates from the steam generator metal and secondary side water to the two-phase mixture present in the steam generator tubes. The M&E releases that occur during this phase are typically superheated due to the depressurization and equilibration of the broken-loop and intact-loop steam generators. During this phase of the transient, the RCS has equilibrated with the containment pressure, but the steam generators contain a secondary inventory at an enthalpy that is much higher than the primary side, therefore, a significant amount of reverse heat transfer occurs. Steam is produced in the core due to core decay heat. For a pump suction break, a two-phase fluid exits the core, flows through the hot legs and becomes superheated as it passes through the steam generator. Once the broken loop cools, the break flow becomes two-phase. In the FROTH calculation, ECCS injection is addressed for both the injection phase and the recirculation phase. The FROTH code calculation stops when the secondary side equilibrates to the saturation temperature (T_{sat}) at the containment design pressure. After this point, the EPITOME code completes the steam generator depressurization (see subsection 6.5.1.8.5 of this document for additional information).

The methodology for the use of this model is described in WCAP-10325-P-A (Reference 1). The M&E release rates are calculated by FROTH and EPITOME until the time of containment depressurization. After containment depressurization (14.7 psia), the M&E release available to containment is generated directly from core boil off/decay heat.

Tables 6.5-13 and 6.5-14 present the two-phase post-reflood M&E release data for the DEPS cases, minimum and maximum ECCS assumptions, respectively.

6.5.1.8.4 Decay Heat Model

On November 2, 1978, the Nuclear Power Plant Standards Committee (NUPPSCO) of the ANS approved ANS Standard 5.1 (Reference 8) for the determination of decay heat. This standard was used in the M&E release. Table 6.5-15 lists the decay heat curve used in the M&E release analysis, post-blowdown, for the IP3 SPU.

Significant assumptions in the generation of the decay heat curve for use in the LOCA M&E releases analysis include the following:

- Decay heat sources considered are fission product decay and heavy element decay of U-239 and Np-239.
- Decay heat power from fissioning isotopes other than U-235 is assumed to be identical to that of U-235.
- Fission rate is constant over the operating history of maximum power level.
- The factor accounting for neutron capture in fission products has been taken from Equation 11 up to 10,000 seconds and from Table 10, both of ANSI/ANS-5.1 (Reference 8), beyond 10,000 seconds.
- The fuel has been assumed to be at full power for 10^8 seconds.
- The number of atoms of U-239 produced per second has been assumed to be equal to 70 percent of the fission rate.

- The total recoverable energy associated with one fission has been assumed to be 200 MeV/fission.

- Two-sigma uncertainty (two times the standard deviation) has been applied to the fission product decay.

Based upon the NRC staff review as indicated in the *Safety Evaluation Report* (SER) of WCAP-10325-P-A (Reference 1), use of the ANS Standard-5.1, November 1979 decay heat model was approved for the calculation of M&E releases to the containment following a LOCA.

6.5.1.8.5 Steam Generator Equilibration and Depressurization

Steam generator equilibration and depressurization is the process by which secondary side energy is removed from the steam generators in stages. The FROTH computer code calculates the heat removal from the secondary mass until the secondary temperature is the saturation temperature (T_{sat}) at the containment design pressure. After the FROTH calculations, the EPITOME code continues the calculation for steam generator cooldown by removing steam generator secondary energy at different rates (that is, first and second stage rates). The first stage rate is applied until the steam generator reaches T_{sat} at the user-specified intermediate equilibration pressure, when the secondary pressure is assumed to reach the actual containment pressure. Then, the second stage rate is used until the final depressurization, when the secondary reaches the reference temperature of T_{sat} at 14.7 psia, or 212°F. The heat removal of the broken-loop and intact-loop steam generators are calculated separately.

In the FROTH calculations, steam generator heat removal rates were calculated using the secondary side temperature, primary side temperature, and a secondary side heat transfer coefficient determined using a modified McAdam's correlation. Steam generator energy is removed during the FROTH transient until the secondary side temperature reaches the saturation temperature at the containment design pressure (61.7 psia). The constant heat removal rate used during the first heat removal stage is based on the final heat removal rate calculated by FROTH. The steam generator energy available to be released during the first stage interval is determined by calculating the difference in secondary energy available at the containment design pressure, and that at the (lower) user-specified intermediate equilibration pressure, assuming saturated conditions. This energy is then divided by the first stage energy removal rate, resulting in an intermediate equilibration time. At this time, the rate of energy release drops substantially to the second stage rate. The second stage rate is determined as the fraction of the difference in secondary energy available between the intermediate equilibration and final depressurization at 212°F, and the time difference from the time of the intermediate equilibration to the user-specified time of the final depressurization at 212°F. With the current methodology, all of the secondary energy remaining after the intermediate equilibration is conservatively assumed to be released by imposing a mandatory cooldown and subsequent depressurization down to atmospheric pressure at 3600 seconds, that is, 14.7 psia and 212°F.

6.5.1.8.6 Sources of M&E

The sources of mass considered in the LOCA M&E release analysis are given in Tables 6.5-5, 6.5-16, and 6.5-17. These sources are the RCS, accumulators, and pumped SI.

The energy inventories considered in the LOCA M&E release analysis are given in Tables 6.5-6, 6.5-18, and 6.5-19. The energy sources include:

- RCS water
- Accumulator water (all four inject)
- Pumped SI water
- Decay heat
- Core-stored energy
- RCS metal (includes steam generator tubes)
- Steam generator metal (includes transition cone, shell, wrapper, and other internals)
- Steam generator secondary energy (includes fluid mass and steam mass)
- Secondary transfer of energy (feedwater into and steam out of the steam generator secondary; feedwater pump coastdown after the signal to close the flow control valve)

Energy reference points are the following:

- Available energy: 212°F, 14.7 psia
- Total energy content: 32°F, 14.7 psia

The M&E inventories are presented at the following times, as appropriate:

- Time zero (initial conditions)
- End-of-blowdown time
- End-of-refill time
- End-of-reflood time
- Time of broken-loop steam generator equilibration to pressure setpoint
- Time of intact-loop steam generator equilibration to pressure setpoint
- Time of full depressurization (3600 seconds)

In the M&E release data presented, no zirconium-water reaction heat was considered because the clad temperature is assumed not to rise high enough for the zirconium-water reaction heat to be of any significance.

The sequence of events for the LOCA transients are shown in Tables 6.5-20 through 6.5-22.

6.5.1.8.7 Conclusions

The consideration of the various energy sources in the long-term M&E release analysis provides assurance that all available sources of energy have been included in this analysis. Thus, the review guidelines presented in SRP Section 6.2.1.3 have been satisfied. The results of this analysis are used in the containment integrity analysis, as shown in subsection 6.5.3.

6.5.2 Short-Term LOCA M&E Releases

6.5.2.1 Purpose

An evaluation was conducted to determine the effect of the IP3 SPU on the short-term LOCA-related M&E releases that support subcompartment analyses discussed in the IP3 UFSAR (Reference 2). IP3 has been licensed for the application of LBB technology (Reference 9).

6.5.2.2 Discussion and Evaluation

The subcompartment analysis is performed to ensure that the walls of a subcompartment can maintain their structural integrity during the short pressure pulse (generally less than 3 seconds) that accompanies a high-energy line pipe rupture within the subcompartment. The magnitude of the pressure differential across the walls is a function of several parameters, which include the blowdown M&E release rates, the subcompartment volume, vent areas, and vent flow behavior. The blowdown M&E release rates are affected by the initial RCS temperature conditions. Since short-term releases are linked directly to the critical mass flux, which increases with decreasing temperatures, the short-term LOCA releases would be expected to increase due to any reductions in RCS coolant temperature conditions. Short-term blowdown transients are characterized by a peak M&E release rate that occurs during a sub-cooled condition; thus, the Zaloudek correlation, which models this condition, is currently used in the short-term LOCA M&E release analyses with the SATAN computer program.

This calculation was used to conservatively evaluate the effect of the changes in RCS temperature conditions due to the SPU conditions on the short-term releases. This was accomplished by maximizing the reservoir pressure and minimizing the RCS inlet and outlet temperatures for the original Analysis of Record (AOR), and by minimizing the RCS inlet and outlet temperatures for the SPU data. Since this maximizes the change in short-term LOCA M&E releases, data representative of the lowest inlet and outlet temperatures with uncertainty subtracted were used for the SPU evaluation of short-term M&E releases.

For this evaluation, an RCS pressure of 2299 psia, a vessel/core inlet temperature of 511.8°F, and a hot leg temperature of 574.8°F were used.

Current Licensing Basis Analyses

IP3 is approved for LBB (Reference 9) for the primary loop, and LBB eliminates the dynamic effects of these pipe ruptures from the design basis. This means that the current RCL breaks no longer have to be considered for subcompartment short-term effects. Since these breaks have been eliminated, the next largest branch nozzles must be considered for design verification. The LBB cases that have been evaluated for IP3 are a hot leg break, a cold leg break, a surge line break, an accumulator line break or a residual heat removal (RHR) line break. The evaluations determined that the increase in subcompartment pressurization due to the lower SPU RCS temperatures resulted in at least 72.9-percent margin to the current AOR.

6.5.2.3 Results and Conclusion

The short-term LOCA-related M&E releases discussed in Chapter 14.3 of the UFSAR (Reference 2) have been reviewed to assess the effects associated with the SPU conditions for IP3. Since IP3 is approved for LBB, the decrease in M&E releases associated with the smaller RCS branch line breaks, as compared to the larger RCS pipe breaks, more than offsets the effects associated with the IP3 SPU conditions.

6.5.3 Long-Term LOCA Containment Response

6.5.3.1 Accident Description

The IP3 containment systems are designed such that for all LOCA break sizes, up to and including the double-ended severance of a reactor coolant pipe, the containment peak pressure remains below the design pressure and the ILRT limit. This section discusses the containment response subsequent to a hypothetical LOCA. The containment response analysis uses the long-term M&E release data from subsection 6.5.1 of this document.

The containment response analysis demonstrates the acceptability of the containment safeguards systems to mitigate the consequences of a LOCA inside containment. The effect of LOCA M&E releases on the containment pressure is addressed to assure that the containment pressure remains below its design pressure and the ILRT limit at the SPU conditions. In support of equipment design and licensing criteria (for example, qualified operating life), long-term containment pressure and temperature transients for post-accident environmental conditions are generated to conservatively bound the potential post-LOCA containment conditions.

6.5.3.2 Input Parameters and Assumptions

An analysis of containment response to the rupture of the RCS must start with knowledge of the initial conditions in the containment. The pressure, temperature, and humidity of the containment atmosphere prior to the postulated accident are specified for the analysis as shown in Table 6.5-23.

Values for the initial temperature of the service water (SW) and refueling water storage tank (RWST) water have been specified, along with containment spray (CS) pump flowrate and reactor containment fan cooler (RCFC) heat removal performance. These values (shown in Tables 6.5-23 and 6.5-24) are chosen conservatively. Long-term sump recirculation is addressed via Residual Heat Removal System (RHRS) heat exchanger performance. The primary function of the RHRS is to remove heat from the core by using the ECCS. Table 6.5-23 provides the RHRS parameters assumed in the analysis.

A series of cases were performed for the LOCA containment response. Subsection 6.5.1 documented the M&E releases for the minimum and maximum ECCS cases for a DEPS break and the releases from the blowdown of a DEHL break.

For the maximum ECCS DEPS case, the failure of a containment spray pump was assumed as the single failure, which leaves available as active heat removal systems one containment spray pump and five RCFCs. Table 6.5-25 provides the performance data for one spray pump in operation. Emergency safeguards equipment data are given in Table 6.5-23.

The minimum ECCS DEPS case was based upon a diesel train failure, DG 32, (which leaves available as active heat removal systems one containment spray pump and four RCFCs). The failure of each DG (31, 32 and 33) was analyzed to determine the most limiting case; the single failure of DG 32 resulted in the highest peak pressure, so the single failure of DG 32 was used in all of the minimum ECCS cases.

Due to the duration of the DEHL transient (that is, blowdown only), no containment safeguards equipment is modeled.

The calculations for the DEPS minimum ECCS and maximum ECCS cases were performed for 10^7 seconds (approximately 115 days). The DEHL cases were terminated soon after the end of the blowdown. The sequence of events for each of these cases is shown in Tables 6.5-26 through 6.5-28.

The following are the major assumptions made in the analysis.

- The M&E released to the containment for LOCA are described in subsection 6.5.1 of this document.

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

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

- For the blowdown portion of the LOCA analysis, the discharge flow separates into steam and water phases at the breakpoint. The saturated water phase is at the total containment pressure, while the steam phase is at the partial pressure of the steam in the containment. For the post-blowdown portion of the LOCA analysis, steam and water releases are input separately.

- The saturation temperature at the partial pressure of the steam is used for heat transfer to the heat sinks and the containment fan coolers.

6.5.3.3 Description of COCO Model

Calculation of containment pressure and temperature is accomplished by use of the digital computer code COCO (Reference 10). COCO is a mathematical model of a generalized containment; the proper selection of various options in the code allows the creation of a specific model for particular containment design. The values used in the specific model for different aspects of the containment are derived from plant-specific input data. The COCO code has been used and determined to be acceptable to calculate containment pressure transients for many dry containment plants, most recently including Vogtle Units 1 and 2, Turkey Point Unit 3, Salem Units 1 and 2, Diablo Canyon Units 1 and 2, IP3, and Indian Point Unit 2 (IP2). Transient phenomena within the RCS affect containment conditions by means of convective M&E transport through the pipe break.

For analytical rigor and convenience, the containment air-steam-water mixture is separated into a water-phase and a steam-air phase. Sufficient relationships to describe the transient are provided by the equations of conservation of M&E as applied to each system, together with appropriate boundary conditions. As thermodynamic equations of state and conditions may vary during the transient, the equations have been derived for possible cases of superheated or saturated steam, and subcooled or saturated water. Switching between states is handled automatically by the code.

Passive Heat Removal

The significant heat removal source during the early portion of the transient is the containment structural heat sinks. Provision is made in the containment pressure response analysis for heat transfer through, and heat storage in, both interior and exterior walls. Each wall is divided into a large number of nodes. For each node, a conservation of energy equation expressed in finite-difference form accounts for heat conduction into and out of the node and temperature rise of the node. Table 6.5-29 is the summary of the containment structural heat sinks used in the analysis. The thermal properties of each heat sink material are shown in Table 6.5-30.

The heat transfer coefficient to the containment structure for the early part of the event is calculated based primarily on the work of Tagami (Reference 11). From this work, it was determined that the value of the heat transfer coefficient can be assumed to increase parabolically to a peak value. In COCO, the value then decreases exponentially to a stagnant heat transfer coefficient that is a function of steam-to-air-weight ratio. The heat transfer coefficient (h) for stagnant conditions is based upon Tagami's steady state results.

Tagami presents a plot of the maximum value of the heat transfer coefficient, (h), as function of "coolant energy transfer speed," defined as follows:

$$h = \frac{\text{total coolant energy transferred in to containment}}{(\text{containment volume})(\text{time interval to peak pressure})}$$

From this, the maximum heat transfer coefficient of steel is calculated:

$$h_{max} = 75\left(\frac{E}{t_p V}\right)^{0.60} \qquad \text{(Equation 1)}$$

where:

h_{max} = maximum value of h (Btu / hr ft^2 °F)

t_p = time from start of accident to end of blowdown for LOCA and steam line isolation for secondary breaks (sec)

V = containment net free volume (ft^3)
E = total coolant energy discharge from time zero to t_p (Btu)
75 = material coefficient for steel

(Note: Paint is addressed by the thermal conductivity of the material [paint] on the heat sink structure, not by an adjustment on the heat transfer coefficient.) The basis for the equations is a Westinghouse curve fit to the Tagami data.

The parabolic increase to the peak value is calculated by COCO according to the following equation:

$$h_s = h_{max}\left(\frac{t}{t_p}\right)^{0.5}, 0 \le t \le t_p \qquad \text{(Equation 2)}$$

where:

h_s = heat transfer coefficient between steel and air/steam mixture (Btu / hr ft^2 °F)
t = time from start of event (sec)

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

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

$$h_s = h_{stag} + (h_{max} - h_{stag})e^{-0.05(t-t_p)} \qquad t > t_p \qquad \text{(Equation 3)}$$

where:

h_{stag} = $2 + 50X,\ 0 < X < 1.4$
h_{stag} = h for stagnant conditions (Btu / hr ft^2 °F)
X = steam-to-air weight ratio in containment

Active Heat Removal

For a large break, the engineered safety features (ESFs) are quickly brought into operation. Because of the brief period of time required to depressurize the RCS or the main steam system, the containment safeguards are not a major influence on the blowdown peak pressure;

however, they reduce the containment pressure after the blowdown and maintain a low, long-term pressure and a low, long-term temperature.

RWST, Injection

During the injection phase of post-accident operation, the ECCS pumps water from the RWST into the reactor vessel. Since this water enters the vessel at RWST temperature, which is less than the temperature of the water in the vessel, it is modeled as absorbing heat from the core until the saturation temperature is reached. SI and CS can be operated for a limited time, depending on the RWST capacity.

RHR, Sump Recirculation

After the supply of refueling water is exhausted, the recirculation system is operated to provide long term cooling of the core. In this operation, water is drawn from the sump, cooled in an RHR heat exchanger then pumped back into the reactor vessel to remove core residual heat and energy stored in the vessel metal. The heat is removed from the RHR heat exchanger by the component cooling water (CCW). The RHR heat exchangers and CCW heat exchangers are coupled in a closed-loop system, for which the ultimate heat sink (UHS) is the SW cooling to the CCW heat exchangers.

Containment Spray

CS is an active removal mechanism, which is used for rapid pressure reduction and for containment iodine removal. During the injection phase of operation, the CS pumps draw water from the RWST and spray it into the containment through nozzles mounted high above the operating deck. As the spray droplets fall, they absorb heat from the containment atmosphere. Since the water comes from the RWST, the entire heat capacity of the spray from the RWST temperature to the temperature of the containment atmosphere is available for energy absorption. During the recirculation phase, the spray is provided by diverting some of the LHSI to the spray rings. However, no credit was taken for recirculation spray in calculating the peak containment pressure.

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

The equations describing the temperature rise of a falling droplet are as follows:

$$\frac{d}{dt}(Mu) = mh_g + q \qquad \text{(Equation 4)}$$

where:

M	=	droplet mass (lbm)
u	=	internal energy (Btu)
m	=	diffusion rate (lbm/sec)
h_g	=	steam enthalpy (Btu/lbm)
q	=	heat flow rate (Btu/sec)
t	=	time (sec)

Note that

$$\frac{d}{dt}(M) = m \qquad \text{(Equation 5)}$$

where:

q	=	$h_c A * (T_s - T)$
q	=	heat flow rate (Btu/hr)
m	=	$k_g A * (P_s - P_v)$
m	=	mass flow rate (lbm/hr)
A	=	drop surface area (ft^2)
h_c	=	coefficient of heat transfer (Btu / hr ft^2 °F)
k_g	=	coefficient of mass transfer (lbm / hr ft^2 psi)
T	=	droplet temperature (°F)
T_s	=	steam temperature (°F)
P_s	=	steam partial pressure (psi)
P_v	=	droplet vapor pressure (psi)

The coefficients of heat transfer (h_c) and mass transfer (k_g) are calculated from the Nusselt number for heat transfer, Nu, and the Nusselt number for mass transfer, Nu'.

Both Nu and Nu' may be calculated from the equations of Ranz and Marshall (Reference 12).

$$Nu = 2 + 0.6(Re)^{1/2}(Pr)^{1/3} \qquad \text{(Equation 6)}$$

where:

Nu	=	Nusselt number for heat transfer
Pr	=	Prandtl number
Re	=	Reynolds number

$$Nu' = 2 + 0.6(Re)^{1/2}(Sc)^{1/3} \qquad \text{(Equation 7)}$$

where,

Nu'	=	Nusselt number for mass transfer
Sc	=	Schmidt number

Thus, Equations 4 and 5 can be integrated numerically to find the internal energy and mass of the droplet as a function of time as it falls through the atmosphere. Analysis shows that the temperature of the (mass) mean droplet produced by the spray nozzles rises to a value within 99 percent of the bulk containment temperature in less than 2 seconds. Detailed calculations of the heatup of spray droplets in post-accident containment atmospheres by Parsly (Reference 13) show that droplets of the size encountered in the containment spray reach equilibrium in a fraction of their residence time in a typical PWR containment. These results confirm the assumption that the containment spray will be 100-percent effective in removing heat from the atmosphere.

RCFC

The RCFCs are another means of heat removal. Each RCFC has a fan that draws in the containment atmosphere from the upper volume of the containment via a return air riser. The RCFCs are cooled by the SW. The steam/air mixture is routed through the enclosed RCFC unit past essential SW cooling coils. The RCFC then discharges the air through ducting containing a check damper. The discharged air is directed at the lower containment volume. See Table 6.5-24 for the assumed RCFC heat removal capability for the containment response analyses.

6.5.3.4 Acceptance Criteria

A LOCA is an ANS Condition-IV event—an infrequent fault. The relevant requirements for the containment response for containment integrity to a design-basis LOCA are shown below.

- General Design Criteria (GDC) 10 (7/11/67) and GDC 49 (7/11/67) from the UFSAR (Reference 2), Chapter 5.1 requires that the peak calculated containment pressure does not exceed the containment design pressure of 47 psig.

- GDC 52 (7/11/67) from the UFSAR (Reference 2), Chapter 9.1 requires modeling of an active single failure to determine the response of the active heat removal systems.

- The UFSAR (Reference 2), Chapter 14.3 requires that the calculated pressure at 24 hours is less than 50 percent of the peak calculated pressure.

6.5.3.5 Analysis Results

The containment pressure, steam temperature, and water (sump) temperature profiles for the DEPS LOCA cases are shown in Figures 6.5-1 through 6.5-4. The results of the DEHL break are shown in Figures 6.5-5 through 6.5-6. Tables 6.5-31 through 6.5-33 provide detailed results for the analyses.

6.5.3.5.1 DEPS Break with Minimum ECCS

This analysis assumes a loss-of-offsite power (LOOP) in coincidence with a DEPS rupture. The associated single-failure assumption is the failure of a diesel to start, resulting in one train of ECCS and containment safeguards equipment being available. This combination results in a minimum set of safeguards equipment being available. Furthermore, LOOP delays the actuation times of the safeguards equipment due to the time required for diesel startup after receiving the SI signal.

The postulated RCS break results in a rapid release of M&E to the containment with a resulting rapid rise in the containment pressure and temperature. This rapid rise in containment pressure results in the generation of a fan cooler initiation signal at 1 second, and a containment spray initiation signal at 8 seconds. The containment pressure continues to rise rapidly in response to the release of M&E, reaching the peak blowdown pressure of 38.9 psig at 24 seconds, and then decreasing slightly as the end of blowdown occurs at 27.2 seconds (pressure = 38.5 psig). The end of blowdown marks a time when the initial inventory in the RCS has been exhausted and a slow process of filling the RCS downcomer in preparation for reflood has begun. During the reflood period, the RCFCs start at approximately 49 seconds. Since the M&E release during this period is low and the RCFCs are removing heat, the pressure decreases slightly to 36.1 psig at approximately 67 seconds, the time at which the intact loop accumulators have emptied. The pressure then starts to slowly rise in response to the loss of steam condensation in the RCS loops and the introduction of the accumulator nitrogen gas to the containment.

CS initiation occurs at approximately 68 seconds. Reflood continues at a reduced flooding rate due to the buildup of mass in the RCS core, which offsets the downcomer head. This reduction in flooding rate and the continued action of the RCFCs and CS leads to a slowly decreasing pressure as the end of reflood is reached at 182.1 seconds. At this time in the transient simulation, by design of the WCAP-10325-P-A (Reference 1) model, energy removal is initiated from the steam generator secondary side at a very increased rate, resulting in a rise in containment pressure from 182.1 seconds until sufficient energy has been removed from the steam generators to bring the intact loops' steam generator secondary pressure down to 20 psi below the containment design pressure of 47 psig. The steam generator secondary energy release results in a peak containment pressure of 42.00 psig at 1118 seconds. After this peak is reached, the M&E release is reduced since the large energy removal from the steam generators has been accomplished.

Containment pressure slowly decreases until the cold leg recirculation time is reached at 1623.8 seconds. After the RHRS is realigned for cold leg recirculation, an increase in the SI temperature (due to water delivery from the hot sump and reduction in steam condensation) results in an increase in containment pressure. Containment spray is terminated at 3355 seconds. By 3600 seconds, the steam generator secondary energy has been reduced to a low value and the containment pressure begins a steady decline. This trend continues until the end of the transient at 10^7 seconds (approximately 115 days).

6.5.3.5.2 DEPS Break with Maximum ECCS

The DEPS break with maximum ECCS has a transient history similar to the minimum ECCS case discussed in subsection 6.5.3.5.1 of this report. Table 6.5-27 provides the key sequence of events and Table 6.5-34 shows that a peak pressure of 38.94 psig was calculated at 23.7 seconds.

6.5.3.5.3 DEHL Break

This analysis assumes a LOOP in coincidence with a DEHL rupture. The associated single failure assumption is the component failure of one CS pump. Furthermore, LOOP delays the actuation times of the safeguards equipment due to the time required for diesel startup after receipt of the SI signal.

The postulated RCS break results in a rapid release of M&E to the containment with a resulting rapid rise in both the containment pressure and temperature. This rapid rise in containment pressure results in the generation of a fan cooler initiation signal at 1 second and a containment spray initiation signal at 8 seconds. The containment pressure continues to rise rapidly in response to the release of M&E, reaching the peak blowdown pressure of 40.38 psig at 24.2 seconds and then decreasing slightly as the end of blowdown occurs at 25.6 seconds. The end of blowdown marks a time when the initial inventory in the RCS has been exhausted, and the process of filling the RCS downcomer in preparation for reflood has begun. Since the reflood for a hot leg break is very fast due to the low resistance to steam venting posed by the broken hot leg, Westinghouse terminates hot leg break M&E release transients at the end of blowdown. The basis for this is further developed in References 1 and 7.

6.5.3.6 Conclusions

LOCA containment response analyses have been performed as part of the IP3 SPU. The analyses included long-term pressure and temperature profiles for the DEPS minimum and maximum ECCS flow cases. As illustrated in Table 6.5-34, the analyzed design cases resulted in a peak containment pressure that was less than the containment design pressure of 47 psig and less than the ILRT limit of 42.42 psig. The long-term pressures are well below 50 percent of the peak value within 24 hours. Based on these results, the applicable LOCA criteria for IP3 have been met. Thus, all typical design accident (that is, NUREG-0800) and IP3 UFSAR analysis criteria have been met at SPU conditions.

6.5.4 References

1. WCAP-10325-P-A (Proprietary) and WCAP-10326-A (Nonproprietary), *Westinghouse LOCA Mass and Energy Release Model for Containment Design,March 1979 Version*, March 1983.

2. *Indian Point Nuclear Generating Unit No. 3, Updated Final Safety Analysis Report*, Docket No. 50-286, Rev. 10, January 6, 2001.

3. 10CFR50, Appendix A, *General Design Criteria for Nuclear Power Plants.*

4. 10CFR50, Appendix K, *ECCS Evaluation Models.*

5. Amendment No. 126, *Facility Operating License No. DPR-58 (TAC No. 7106), for D. C. Cook Nuclear Plant Unit 1*, Docket No. 50-315, June 9, 1989.

6. EPRI 294-2, *Mixing of Emergency Core Cooling Water with Steam; 1/3-Scale Test and Summary*, (WCAP-8423), Final Report, June 1975.

7. WCAP-8264-P-A (Proprietary) and WCAP-8312-A (Non-proprietary), *Topical Report Westinghouse Mass and Energy Release Data For Containment Design*, Rev. 1, August 1975.

8. ANSI/ANS-5.1-1979, *American National Standard for Decay Heat Power in Light Water Reactors*, The American Nuclear Society Standards Institute, Inc., LaGrange Park, Illinois, August 1979.

9. *NRC Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Elimination of Large Primary Loop Ruptures as a Design Basis, Power Authority of the State of New York, Indian Point Nuclear Generating Unit No. 3,* Docket No. 50-286, March 10, 1986.

10. WCAP-8327 (Proprietary) and WCAP-8326 (Nonproprietary), *Containment Pressure Analysis Code (COCO),* July 1974.

11. *Interim Report on Safety Assessments and Facilities Establishment Project in Japan for Period Ending June 1965,* No. 1, Takashi Tagami.

12. *Chemical Engineering Progress, 48,* "Evaporation for Drops," pp.141-146, D. W. Ranz and W. R. Marshall, Jr., March 1952.

13. ORNL-TM-2412 Part VI, *Design Consideration of Reactor Containment Spray System. Part VI, The Heating of Spray Drops in Air-Steam Atmospheres,* L. F. Parsly, January 1970.

Table 6.5-1

System Parameters Initial Conditions for IP3 SPU

Parameters	Value SPU
Core Thermal Power Without Uncertainty (MWt)	3216
RCS Total Flow Rate (lbm/sec)	37,444.4
Vessel Outlet Temperature With Uncertainty (°F)	610.5
Core Inlet Temperature With Uncertainty (°F)	548.5
Vessel Average Temperature Without Uncertainty (°F)	572.0
Initial Steam Generator Steam Pressure (psia)	787.0
SGTP (%)	0
Initial Steam Generator Secondary Side Mass (lbm)	100,668.7
Assumed Maximum Containment Backpressure (psia)	61.7
Accumulator Water Volume Per Accumulator Including Line Volume (ft^3) N_2 Cover Gas Pressure (psia) Temperature (°F)	 807.2 555 130
Total SI Delay From Beginning of Event (sec)	27.8

Table 6.5-2

SI Flow Rate
Minimum ECCS for IP3 SPU

RCS Pressure (psia)	Total Flow (gpm)
Injection Mode (reflood phase)	
14.7	5252.3
24.7	5115.1
34.7	4975.2
44.7	4832.7
54.7	4687.2
64.7	4536.1
74.7	4367.1
84.7	4192.8
94.7	4012.4
104.7	3825.0
114.7	3630.0
Injection Mode (post-reflood phase)	
61.7	4581.4
Cold Leg Recirculation Mode	
61.7	2080
Hot Leg Recirculation Mode	
61.7	717

Table 6.5-3 SI Flow Rate Maximum ECCS for IP3 SPU	
RCS Pressure (psia)	Total Flow (gpm)
Injection Mode (reflood phase)	
14.7	7815.6
34.7	7479.7
54.7	7129.7
74.7	6745.8
94.7	6330.8
114.7	5885.9
134.7	5403.6
154.7	4866.3
174.7	4215.0
194.7	3414.7
214.7	2180.4
234.7	1332.7
314.7	1290.1
414.7	1234.6
Injection Mode (post-reflood phase)	
61.7	6995.3
Cold Leg Recirculation Mode	
61.7	4160

Table 6.5-4

DEHL Break
Blowdown M&E Releases for IP3 SPU

Time	Break Path No. 1(1)		Break Path No. 2(2)	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
0.0	0.0	0.0	0.0	0.0
0.001	43,216.1	27,017.6	43,213.1	27,014.4
0.002	44,433.6	27,779.4	44,164.6	27,604.0
0.1	45,538.9	28,778.8	25,444.9	15,873.6
0.2	32,791.7	21,154.0	22,595.2	14,017.6
0.3	32,084.8	20,646.9	20,305.9	12,441.9
0.4	31,280.4	20,117.6	19,120.5	11,538.7
0.5	31,012.0	19,936.5	18,348.2	10,908.8
0.6	30,970.6	19,912.6	17,786.9	10,431.7
0.7	30,879.0	19,877.0	17,343.9	10,051.4
0.8	30,588.4	19,730.6	17,023.3	9762.1
0.9	30,227.7	19,552.0	16,732.0	9505.9
1.0	29,827.8	19,360.2	16,560.6	9329.1
1.1	29,559.7	19,264.0	16,444.0	9194.1
1.2	29,306.8	19,187.0	16,442.2	9130.6
1.3	29,048.7	19,106.1	16,506.8	9108.9
1.4	28,718.0	18,974.1	16,618.7	9118.1
1.5	28,330.4	18,796.2	16,751.8	9144.7
1.6	27,926.6	18,603.7	16,900.6	9184.9
1.7	27,555.8	18,429.8	17,051.8	9232.4
1.8	27,184.5	18,255.6	17,199.2	9282.7
1.9	26,773.1	18,050.8	17,332.3	9330.3
2.0	26,314.9	17,808.3	17,447.9	9372.9
2.1	25,851.9	17,556.4	17,543.1	9408.5
2.2	25,391.2	17,303.5	17,619.5	9437.1
2.3	24,938.1	17,054.4	17,679.3	9459.3
2.4	24,496.9	16,809.6	17,722.1	9474.5
2.5	24,046.1	16,552.9	17,750.4	9483.7
2.6	23,573.2	16,273.0	17,766.3	9487.6
2.7	23,114.2	15,997.0	17,771.4	9486.7
2.8	22,689.1	15,743.8	17,768.4	9482.3
2.9	22,284.5	15,500.2	17,756.4	9473.7
3.0	21,875.4	15,243.8	17,734.3	9460.2
3.1	21,492.2	15,000.3	17,702.9	9442.1
3.2	21,129.3	14,765.0	17,663.7	9420.1
3.3	20,779.2	14,529.5	17,615.8	9393.8
3.4	20,470.4	14,319.2	17,561.3	9364.3
3.5	20,180.8	14,117.6	17,501.0	9331.9
3.6	19,903.1	13,914.9	17,434.1	9296.3

Table 6.5-4 (Cont.) DEHL Break Blowdown M&E Releases for IP3 SPU				
	Break Path No. 1[(1)]		Break Path No. 2[(2)]	
Time	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
3.7	19,644.4	13,720.7	17,361.0	9257.8
3.8	19,414.0	13,544.5	17,283.1	9216.9
3.9	19,194.4	13,368.4	17,199.0	9173.1
4.0	19,004.3	13,209.8	17,109.4	9126.7
4.2	18,688.3	12,931.8	16,914.7	9026.8
4.4	18,436.2	12,689.9	16,696.0	8916.1
4.6	18,246.3	12,490.3	16,458.1	8797.2
4.8	18,184.6	12,385.8	16,197.0	8668.2
5.0	18,242.3	12,349.7	15,914.4	8530.2
5.2	18,416.6	12,359.7	15,630.4	8393.8
5.4	18,634.4	12,390.6	15,313.5	8240.9
5.6	18,872.2	12,431.3	14,943.5	8059.9
5.8	19,167.6	12,503.3	14,553.8	7868.7
6.0	19,546.1	12,605.6	14,202.2	7697.4
6.2	11,596.1	9053.2	13,865.2	7532.8
6.4	14,615.2	10,424.6	13,543.6	7374.6
6.6	14,498.6	10,297.0	13,191.7	7197.4
6.8	14,631.6	10,261.7	12,824.2	7009.7
7.0	14,823.9	10,328.0	12,479.4	6833.2
7.2	15,043.6	10,422.7	12,161.2	6669.8
7.4	15,250.0	10,436.2	11,845.6	6506.1
7.6	15,449.4	10,476.1	11,532.8	6342.4
7.8	15,635.7	10,580.4	11,228.3	6182.3
8.0	15,575.1	10,451.1	10,941.3	6031.2
8.2	15,901.5	10,556.6	10,677.6	5892.1
8.4	16,217.3	10,658.8	10,419.5	5755.5
8.6	16,550.9	10,772.6	10,167.7	5621.8
8.8	16,971.8	10,933.5	9920.2	5490.0
9.0	17,728.7	11,275.9	9678.6	5361.3
9.2	18,541.3	11,698.2	9442.1	5235.5
9.4	18,929.1	11,866.3	9206.6	5110.3
9.6	19,223.8	11,965.3	8971.5	4985.4
9.8	18,854.0	11,651.4	8726.2	4855.0
10.0	17,951.0	11,023.8	8481.1	4725.3
10.2	14,860.8	9376.5	8233.4	4595.0
10.2	14,840.4	9366.2	8231.4	4594.0
10.4	14,303.8	9059.4	8004.6	4475.3
10.6	14,418.5	9086.4	7784.8	4361.1
10.8	14,561.4	9141.4	7592.6	4262.5

Table 6.5-4 (Cont.) DEHL Break Blowdown M&E Releases for IP3 SPU				
	Break Path No. 1(1)		Break Path No. 2(2)	
Time	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
11.0	14,722.8	9210.1	7417.9	4172.7
11.2	14,873.7	9265.9	7245.6	4083.2
11.4	15,060.7	9333.2	7079.6	3997.0
11.6	15,358.1	9452.3	6918.4	3913.3
11.8	15,822.0	9672.5	6752.4	3827.3
12.0	15,709.9	9570.8	6587.3	3742.1
12.2	15,462.5	9384.3	6419.7	3656.1
12.4	14,575.9	8878.8	6246.4	3567.5
12.6	12,813.6	7956.4	6076.2	3481.5
12.8	12,586.2	7813.6	5909.8	3398.4
13.0	12,574.0	7785.1	5753.6	3321.3
13.2	12,565.4	7764.9	5614.8	3253.7
13.4	12,544.7	7740.0	5481.0	3188.0
13.6	12,502.3	7704.5	5356.4	3126.3
13.8	12,413.7	7644.8	5235.4	3066.3
14.0	12,248.4	7546.3	5115.8	3007.0
14.2	11,967.8	7389.8	4998.4	2949.2
14.4	11,490.4	7165.4	4884.3	2893.4
14.6	10,863.9	6930.2	4767.2	2836.4
14.8	10,495.2	6789.9	4653.9	2781.9
15.0	10,225.7	6678.1	4544.9	2729.6
15.2	9956.4	6553.4	4433.8	2676.3
15.4	9643.3	6398.4	4323.8	2623.7
15.6	9288.3	6219.5	4213.7	2571.5
15.8	8937.9	6045.4	4099.8	2517.7
16.0	8619.6	5891.9	3979.2	2461.0
16.2	8322.4	5755.6	3846.8	2399.1
16.4	8019.5	5624.2	3698.2	2330.8
16.6	7695.6	5489.8	3534.0	2256.5
16.8	7342.7	5348.1	3358.3	2177.1
17.0	6962.8	5199.8	3179.0	2094.7
17.2	6557.4	5045.0	3004.6	2012.0
17.4	6136.6	4886.9	2844.0	1932.3
17.6	5701.0	4725.1	2700.7	1857.7
17.8	5260.7	4562.3	2576.3	1789.8
18.0	4822.8	4398.4	2470.4	1729.7
18.2	4368.6	4198.7	2379.7	1677.0
18.4	3966.3	3932.9	2297.4	1628.2
18.6	3702.8	3715.2	2224.0	1584.6

Table 6.5-4 (Cont.)

DEHL Break

Blowdown M&E Releases for IP3 SPU

Time	Break Path No. 1[1]		Break Path No. 2[2]	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
18.8	3502.0	3553.9	2156.6	1544.8
19.0	3337.0	3431.7	2092.0	1508.1
19.2	3175.6	3312.9	2028.2	1473.8
19.4	3006.4	3193.8	1964.2	1441.4
19.6	2833.6	3074.0	1899.5	1410.3
19.8	2659.6	2943.8	1832.2	1378.9
20.0	2476.5	2810.7	1765.5	1348.9
20.2	2279.9	2650.6	1697.5	1319.2
20.4	2105.3	2493.7	1626.0	1289.3
20.6	1969.1	2360.6	1546.6	1258.6
20.8	1835.2	2217.8	1461.5	1230.8
21.0	1703.9	2071.2	1370.8	1202.4
21.2	1582.3	1933.8	1282.9	1171.9
21.4	1471.4	1809.0	1209.5	1142.4
21.6	1373.0	1697.9	1151.9	1116.0
21.8	1298.2	1615.2	1107.2	1095.8
22.0	1257.9	1571.0	1068.6	1074.2
22.2	1194.9	1500.0	1040.6	1054.5
22.4	1119.7	1408.8	1019.6	1036.8
22.6	1047.1	1319.4	1004.2	1019.2
22.8	976.8	1232.5	995.6	1003.8
23.0	928.8	1170.9	988.5	990.1
23.2	860.1	1086.8	975.4	980.3
23.4	770.3	973.1	938.3	975.2
23.6	704.9	893.0	853.3	973.8
23.8	641.7	813.7	661.6	802.7
24.0	588.2	746.7	574.4	703.1
24.2	548.1	696.1	579.4	709.1
24.4	518.7	658.7	512.3	627.2
24.6	500.9	636.1	371.8	456.9
24.8	487.5	618.7	319.8	394.3
25.0	475.6	603.1	247.6	305.8
25.2	54.2	69.9	199.2	247.1
25.4	0.0	0.0	95.2	118.9
25.6	0.0	0.0	0.0	0.0

Notes:

1. M&E exiting from the reactor-vessel side of the break
2. M&E exiting from the steam-generator side of the break

Table 6.5-5 DEHL Break Mass Balance for IP3 SPU				
Time (sec)		0.00	25.60	25.60
		Mass (thousand lbm)		
Initial	In RCS and accumulators	732.01	732.01	732.01
Added Mass	Pumped injection	0.00	0.00	0.00
	Total added	0.00	0.00	0.00
Total Available		732.01	732.01	732.01
Distribution	Reactor coolant	527.21	61.26	88.21
	Accumulator	204.80	158.37	131.42
	Total contents	732.01	219.63	219.63
Effluent	Break flow	0.00	512.36	512.36
	ECCS spill	0.00	0.00	0.00
	Total effluent	0.00	512.36	512.36
Total Accountable		732.01	731.98	731.98

Table 6.5-6 DEHL Break Energy Balance for IP3 SPU				
Time (sec)		0.00	25.60	25.60
		Energy (million Btu)		
Initial Energy	In RCS, accumulators and steam generators	775.34	775.34	775.34
Added Energy	Pumped injection	0.00	0.00	0.00
	Decay heat	0.00	7.72	7.72
	Heat from secondary	0.00	9.96	9.96
	Total added	0.00	17.68	17.68
Total Available		775.34	793.02	793.02
Distribution	Reactor coolant	305.75	15.57	18.25
	Accumulator	20.35	15.73	13.06
	Core stored	26.87	10.59	10.59
	Primary metal	166.23	156.28	156.28
	Secondary metal	40.98	40.06	40.06
	Steam generator	215.15	227.53	227.53
	Total contents	775.34	465.77	465.77
Effluent	Break flow	0.00	326.77	326.77
	ECCS spill	0.00	0.00	0.00
	Total effluent	0.00	326.77	326.77
Total Accountable		775.34	792.53	792.53

Table 6.5-7 DEPS Break Minimum ECCS Blowdown M&E Releases for IP3 SPU				
	Break Path No. 1[1]		Break Path No. 2[2]	
Time	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
0.0	0.0	0.0	0.0	0.0
0.001	81,761.8	44,233.2	40,576.0	21,912.8
0.1	40,368.4	21,885.1	19,793.9	10,677.7
0.2	45,306.7	24,772.6	22,451.3	12,124.9
0.3	45,415.9	25,096.5	23,512.5	12,704.7
0.4	45,055.9	25,215.1	23,517.2	12,711.4
0.5	44,009.1	24,945.6	22,969.5	12,420.5
0.6	44,256.3	25,378.4	22,403.5	12,120.2
0.7	43,600.3	25,252.0	22,049.2	11,934.2
0.8	42,230.5	24,671.9	21,887.5	11,851.0
0.9	40,998.0	24,158.5	21,772.1	11,792.1
1.0	39,954.5	23,761.7	21,676.2	11,742.9
1.1	38,791.7	23,329.2	21,567.5	11,686.1
1.2	37,322.5	22,738.0	21,464.4	11,631.9
1.3	35,681.4	22,020.7	21,381.4	11,588.1
1.4	34,261.3	21,372.7	21,325.8	11,558.9
1.5	33,185.6	20,878.9	21,311.8	11,552.2
1.6	32,347.7	20,502.1	21,335.1	11,565.8
1.7	31,543.5	20,137.7	21,256.7	11,523.4
1.8	30,691.4	19,737.1	21,078.4	11,426.5
1.9	29,771.4	19,286.1	20,897.8	11,328.4
2.0	28,806.8	18,796.0	20,735.0	11,240.3
2.1	27,794.9	18,268.3	20,582.8	11,158.0
2.2	26,813.6	17,759.7	20,406.0	11,062.5
2.3	25,407.1	16,959.1	20,198.9	10,950.3
2.4	23,314.1	15,671.6	19,979.5	10,831.5
2.5	21,428.3	14,504.8	19,781.6	10,724.5
2.6	21,061.3	14,354.1	19,588.9	10,620.6
2.7	20,375.5	13,940.6	19,405.6	10,521.9
2.8	19,647.9	13,490.3	19,200.4	10,411.3
2.9	19,327.9	13,315.2	19,003.6	10,305.3
3.0	18,990.9	13,110.6	18,809.5	10,201.0
3.1	18,936.7	13,103.3	18,599.8	10,088.1
3.2	18,708.8	12,965.8	18,359.2	9958.3
3.3	18,376.1	12,765.8	18,107.3	9822.4
3.4	18,036.8	12,557.7	17,873.1	9696.2

Table 6.5-7 (Cont.)

DEPS Break Minimum ECCS
Blowdown M&E Releases for IP3 SPU

Time	Break Path No. 1[1]		Break Path No. 2[2]	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
3.5	17,593.9	12,267.4	17,641.1	9571.4
3.6	17,069.3	11,917.1	17,408.8	9446.3
3.7	16,489.9	11,528.9	17,177.4	9321.8
3.8	15,903.3	11,135.1	16,954.4	9202.0
3.9	15,363.2	10,772.2	16,746.0	9090.1
4.0	14,881.1	10,447.4	16,551.1	8985.8
4.2	14,051.8	9886.3	16,181.4	8787.9
4.4	13,368.7	9425.1	15,844.1	8607.7
4.6	12,849.6	9066.2	15,533.4	8442.0
4.8	12,412.2	8757.6	15,247.7	8289.7
5.0	12,013.1	8465.4	14,999.3	8157.8
5.2	11,703.6	8224.2	14,763.6	8032.5
5.4	11,586.3	8094.8	14,554.2	7921.5
5.6	11,514.6	7994.2	14,351.2	7813.7
5.8	11,482.1	7922.8	14,628.1	7971.2
6.0	11,522.2	7898.5	14,747.6	8037.3
6.2	12,194.7	8296.4	14,583.2	7949.9
6.4	12,141.3	8354.3	14,758.0	8049.7
6.6	10,307.9	7832.3	14,611.9	7971.5
6.8	9121.4	7303.9	14,448.4	7884.8
7.0	9073.9	7243.1	14,317.3	7815.8
7.2	9131.3	7217.0	14,150.0	7726.8
7.4	9251.8	7207.9	13,997.8	7646.3
7.6	9481.4	7234.9	13,888.3	7588.7
7.8	9840.4	7325.9	13,772.0	7525.2
8.0	10,359.8	7518.4	13,588.0	7423.3
8.2	11,037.7	7812.7	13,409.2	7324.2
8.4	11,803.6	8167.7	13,241.4	7231.2
8.6	12,593.0	8547.8	13,064.4	7133.0
8.8	13,245.7	8851.5	12,873.9	7027.5
9.0	13,483.0	8908.3	12,687.9	6924.7
9.2	13,276.1	8712.1	12,523.4	6834.0
9.4	12,965.9	8476.1	12,374.3	6751.5
9.6	12,574.6	8194.2	12,222.6	6667.2
9.8	11,645.6	7582.1	12,081.1	6588.6
10.0	10,593.6	6936.8	12,004.7	6546.0

Table 6.5-7 (Cont.) DEPS Break Minimum ECCS Blowdown M&E Releases for IP3 SPU				
	Break Path No. 1(1)		Break Path No. 2(2)	
Time	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
10.2	10,208.2	6743.1	11,946.2	6512.7
10.4	9933.1	6606.9	11,771.6	6414.9
10.6	9558.0	6412.6	11,662.9	6354.9
10.8	9363.2	6333.5	11,584.3	6312.0
11.0	9110.8	6193.7	11,405.8	6213.9
11.2	8843.7	6050.6	11,321.2	6168.3
11.4	8611.3	5935.8	11,207.4	6105.7
11.6	8331.5	5791.9	11,060.1	6024.8
11.8	8094.4	5682.6	10,972.5	5976.9
12.0	7841.1	5558.8	10,793.8	5878.6
12.2	7631.1	5453.0	10,669.0	5810.9
12.4	7447.7	5345.9	10,550.1	5746.4
12.6	7300.3	5249.1	10,397.4	5663.0
12.8	7176.9	5155.0	10,272.0	5594.7
13.0	7066.5	5061.5	10,136.2	5520.5
13.2	6964.1	4969.2	10,003.1	5447.9
13.4	6860.9	4873.9	9867.7	5374.1
13.6	6756.5	4776.9	9730.9	5299.6
13.8	6652.7	4679.5	9599.0	5227.9
14.0	6551.1	4582.4	9463.3	5154.1
14.2	6454.6	4487.7	9332.5	5083.2
14.4	6364.5	4396.4	9204.0	5013.5
14.6	6286.8	4312.4	9088.1	4950.7
14.8	6229.3	4241.5	8991.4	4898.8
15.0	6169.6	4171.4	8866.3	4830.2
15.2	6106.1	4106.5	8779.1	4783.6
15.4	6042.3	4043.3	8675.6	4727.6
15.6	5976.8	3981.7	8590.2	4682.1
15.8	5911.6	3925.6	8496.0	4631.6
16.0	5840.4	3870.9	8414.4	4588.8
16.2	5773.5	3823.7	8339.7	4550.2
16.4	5698.8	3775.3	8193.0	4472.2
16.6	5626.7	3739.9	8057.1	4403.0
16.8	5544.7	3720.5	7908.6	4327.8
17.0	5421.2	3692.9	7741.4	4242.5
17.2	5275.7	3658.2	7585.2	4161.0
17.4	5130.3	3623.8	7425.0	4062.6

Table 6.5-7 (Cont.)

DEPS Break Minimum ECCS
Blowdown M&E Releases for IP3 SPU

Time	Break Path No. 1(1)		Break Path No. 2(2)	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
17.6	4987.5	3591.5	7279.3	3956.0
17.8	4848.1	3560.2	7149.2	3845.8
18.0	4712.0	3529.8	7046.1	3743.0
18.2	4578.9	3500.4	6951.5	3642.4
18.4	4447.5	3473.6	6860.8	3545.2
18.6	4317.2	3448.0	6736.5	3434.4
18.8	4184.1	3423.5	6572.9	3308.7
19.0	4049.4	3401.2	6399.0	3183.7
19.2	3911.0	3380.1	6214.5	3060.8
19.4	3769.8	3361.2	6034.1	2949.3
19.6	3623.5	3344.6	5864.7	2853.8
19.8	3472.5	3330.4	5695.8	2768.6
20.0	3285.7	3291.4	5492.9	2673.1
20.2	3023.0	3191.9	5043.3	2439.6
20.4	2764.3	3072.7	4849.5	2304.6
20.6	2543.6	2957.3	4656.1	2205.9
20.8	2393.5	2873.4	4365.2	2058.6
21.0	2180.7	2661.6	4194.5	1968.7
21.2	2028.5	2492.3	3842.0	1786.4
21.4	1885.9	2325.5	3636.1	1644.4
21.6	1764.8	2182.2	3508.4	1551.5
21.8	1659.9	2056.6	3113.1	1339.6
22.0	1549.0	1922.8	2768.0	1141.4
22.2	1453.0	1806.5	2485.3	983.1
22.4	1366.4	1701.7	2269.9	866.9
22.6	1282.0	1598.2	2098.7	777.9
22.8	1194.9	1492.1	2020.9	728.2
23.0	1119.7	1399.9	2062.5	723.2
23.2	1045.0	1307.9	2203.1	754.1
23.4	958.1	1200.9	2404.8	807.2
23.6	868.4	1089.6	2598.9	859.2
23.8	786.1	987.3	2745.0	896.0
24.0	701.2	881.4	2904.0	935.2
24.2	614.4	772.9	3064.9	971.6
24.4	528.0	664.7	3199.8	997.3
24.6	446.8	562.9	3189.0	977.5
24.8	370.2	466.8	2986.6	903.0

Table 6.5-7 (Cont.) DEPS Break Minimum ECCS Blowdown M&E Releases for IP3 SPU				
	Break Path No. 1[(1)]		Break Path No. 2[(2)]	
Time	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
25.0	301.9	380.8	2789.6	834.7
25.2	239.4	302.3	2590.3	768.5
25.4	183.9	232.4	2383.7	702.3
25.6	142.6	180.4	2177.3	637.8
25.8	127.2	161.1	1969.4	574.5
26.0	105.9	134.2	1761.3	512.4
26.2	58.4	74.2	1556.4	452.4
26.4	0.0	0.0	1339.4	389.5
26.6	0.0	0.0	1082.8	315.5
26.8	0.0	0.0	724.1	211.6
27.0	0.0	0.0	25.5	7.5
27.2	0.0	0.0	0.0	0.0

Notes:

1. M&E exiting from the steam-generator side of the break
2. M&E existing from the pump side of the break

Table 6.5-8

DEPS Break Maximum ECCS
Blowdown M&E Releases for IP3 SPU

Time	Break Path No. 1(1)		Break Path No. 2(2)	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
0.0	0.0	0.0	0.0	0.0
0.0	81,761.8	44,233.2	40,576.0	21,912.8
0.1	40,368.4	21,885.1	19,793.9	10,677.7
0.2	45,306.7	24,772.6	22,451.3	12,124.9
0.3	45,415.9	25,096.5	23,512.5	12,704.7
0.4	45,055.9	25,215.1	23,517.2	12,711.4
0.5	44,009.1	24,945.6	22,969.5	12,420.5
0.6	44,256.3	25,378.4	22,403.5	12,120.2
0.7	43,600.3	25,252.0	22,049.2	11,934.2
0.8	42,230.5	24,671.9	21,887.5	11,851.0
0.9	40,998.0	24,158.5	21,772.1	11,792.1
1.0	39,954.5	23,761.7	21,676.2	11,742.9
1.1	38,791.7	23,329.2	21,567.5	11,686.1
1.2	37,322.5	22,738.0	21,464.4	11,631.9
1.3	35,681.4	22,020.7	21,381.4	11,588.1
1.4	34,261.3	21,372.7	21,325.8	11,558.9
1.5	33,185.6	20,878.9	21,311.8	11,552.2
1.6	32,347.7	20,502.1	21,335.1	11,565.8
1.7	31,543.5	20,137.7	21,256.7	11,523.4
1.8	30,691.4	19,737.1	21,078.4	11,426.5
1.9	29,771.4	19,286.1	20,897.8	11,328.4
2.0	28,806.8	18,796.0	20,735.0	11,240.3
2.1	27,794.9	18,268.3	20,582.8	11,158.0
2.2	26,813.6	17,759.7	20,406.0	11,062.5
2.3	25,407.1	16,959.1	20,198.9	10,950.3
2.4	23,314.1	15,671.6	19,979.5	10,831.5
2.5	21,428.3	14,504.8	19,781.6	10,724.5
2.6	21,061.3	14,354.1	19,588.9	10,620.6
2.7	20,375.5	13,940.6	19,405.6	10,521.9
2.8	19,647.9	13,490.3	19,200.4	10,411.3
2.9	19,327.9	13,315.2	19,003.6	10,305.3
3.0	18,990.9	13,110.6	18,809.5	10,201.0
3.1	18,936.7	13,103.3	18,599.8	10,088.1
3.2	18,708.8	12,965.8	18,359.2	9958.3
3.3	18,376.1	12,765.8	18,107.3	9822.4
3.4	18,036.8	12,557.7	17,873.1	9696.2

Table 6.5-8 (Cont.) DEPS Break Maximum ECCS Blowdown M&E Releases for IP3 SPU				
	Break Path No. 1[(1)]		Break Path No. 2[(2)]	
Time	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
3.5	17,593.9	12,267.4	17,641.1	9571.4
3.6	17,069.3	11,917.1	17,408.8	9446.3
3.7	16,489.9	11,528.9	17,177.4	9321.8
3.8	15,903.3	11,135.1	16,954.4	9202.0
3.9	15,363.2	10,772.2	16,746.0	9090.1
4.0	14,881.1	10,447.4	16,551.1	8985.8
4.2	14,051.8	9886.3	16,181.4	8787.9
4.4	13,368.7	9425.1	15,844.1	8607.7
4.6	12,849.6	9066.2	15,533.4	8442.0
4.8	12,412.2	8757.6	15,247.7	8289.7
5.0	12,013.1	8465.4	14,999.3	8157.8
5.2	11,703.6	8224.2	14,763.6	8032.5
5.4	11,586.3	8094.8	14,554.2	7921.5
5.6	11,514.6	7994.2	14,351.2	7813.7
5.8	11,482.1	7922.8	14,628.1	7971.2
6.0	11,522.2	7898.5	14,747.6	8037.3
6.2	12,194.7	8296.4	14,583.2	7949.9
6.4	12,141.3	8354.3	14,758.0	8049.7
6.6	10,307.9	7832.3	14,611.9	7971.5
6.8	9121.4	7303.9	14,448.4	7884.8
7.0	9073.9	7243.1	14,317.3	7815.8
7.2	9131.3	7217.0	14,150.0	7726.8
7.4	9251.8	7207.9	13,997.8	7646.3
7.6	9481.4	7234.9	13,888.3	7588.7
7.8	9840.4	7325.9	13,772.0	7525.2
8.0	10359.8	7518.4	13,588.0	7423.3
8.2	11037.7	7812.7	13,409.2	7324.2
8.4	11803.6	8167.7	13,241.4	7231.2
8.6	12593.0	8547.8	13,064.4	7133.0
8.8	13245.7	8851.5	12,873.9	7027.5
9.0	13483.0	8908.3	12,687.9	6924.7
9.2	13276.1	8712.1	12,523.4	6834.0
9.4	12965.9	8476.1	12,374.3	6751.5
9.6	12574.6	8194.2	12,222.6	6667.2
9.8	11645.6	7582.1	12,081.1	6588.6
10.0	10593.6	6936.8	12,004.7	6546.0

Table 6.5-8 (Cont.)

DEPS Break Maximum ECCS
Blowdown M&E Releases for IP3 SPU

Time	Break Path No. 1(1)		Break Path No. 2(2)	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
10.2	10208.2	6743.1	11,946.2	6512.7
10.4	9933.1	6606.9	11,771.6	6414.9
10.6	9558.0	6412.6	11,662.9	6354.9
10.8	9363.2	6333.5	11,584.3	6312.0
11.0	9110.8	6193.7	11,405.8	6213.9
11.2	8843.7	6050.6	11,321.2	6168.3
11.4	8611.3	5935.8	11,207.4	6105.7
11.6	8331.5	5791.9	11,060.1	6024.8
11.8	8094.4	5682.6	10,972.5	5976.9
12.0	7841.1	5558.8	10,793.8	5878.6
12.2	7631.1	5453.0	10,669.0	5810.9
12.4	7447.7	5345.9	10,550.1	5746.4
12.6	7300.3	5249.1	10,397.4	5663.0
12.8	7176.9	5155.0	10,272.0	5594.7
13.0	7066.5	5061.5	10,136.2	5520.5
13.2	6964.1	4969.2	10,003.1	5447.9
13.4	6860.9	4873.9	9867.7	5374.1
13.6	6756.5	4776.9	9730.9	5299.6
13.8	6652.7	4679.5	9599.0	5227.9
14.0	6551.1	4582.4	9463.3	5154.1
14.2	6454.6	4487.7	9332.5	5083.2
14.4	6364.5	4396.4	9204.0	5013.5
14.6	6286.8	4312.4	9088.1	4950.7
14.8	6229.3	4241.5	8991.4	4898.8
15.0	6169.6	4171.4	8866.3	4830.2
15.2	6106.1	4106.5	8779.1	4783.6
15.4	6042.3	4043.3	8675.6	4727.6
15.6	5976.8	3981.7	8590.2	4682.1
15.8	5911.6	3925.6	8496.0	4631.6
16.0	5840.4	3870.9	8414.4	4588.8
16.2	5773.5	3823.7	8339.7	4550.2
16.4	5698.8	3775.3	8193.0	4472.2
16.6	5626.7	3739.9	8057.1	4403.0
16.8	5544.7	3720.5	7908.6	4327.8
17.0	5421.2	3692.9	7741.4	4242.5
17.2	5275.7	3658.2	7585.2	4161.0
17.4	5130.3	3623.8	7425.0	4062.6

Table 6.5-8 (Cont.) DEPS Break Maximum ECCS Blowdown M&E Releases for IP3 SPU				
	Break Path No. 1[(1)]		Break Path No. 2[(2)]	
Time	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
17.6	4987.5	3591.5	7279.3	3956.0
17.8	4848.1	3560.2	7149.2	3845.8
18.0	4712.0	3529.8	7046.1	3743.0
18.2	4578.9	3500.4	6951.5	3642.4
18.4	4447.5	3473.6	6860.8	3545.2
18.6	4317.2	3448.0	6736.5	3434.4
18.8	4184.1	3423.5	6572.9	3308.7
19.0	4049.4	3401.2	6399.0	3183.7
19.2	3911.0	3380.1	6214.5	3060.8
19.4	3769.8	3361.2	6034.1	2949.3
19.6	3623.5	3344.6	5864.7	2853.8
19.8	3472.5	3330.4	5695.8	2768.6
20.0	3285.7	3291.4	5492.9	2673.1
20.2	3023.0	3191.9	5043.3	2439.6
20.4	2764.3	3072.7	4849.5	2304.6
20.6	2543.6	2957.3	4656.1	2205.9
20.8	2393.5	2873.4	4365.2	2058.6
21.0	2180.7	2661.6	4194.5	1968.7
21.2	2028.5	2492.3	3842.0	1786.4
21.4	1885.9	2325.5	3636.1	1644.4
21.6	1764.8	2182.2	3508.4	1551.5
21.8	1659.9	2056.6	3113.1	1339.6
22.0	1549.0	1922.8	2768.0	1141.4
22.2	1453.0	1806.5	2485.3	983.1
22.4	1366.4	1701.7	2269.9	866.9
22.6	1282.0	1598.2	2098.7	777.9
22.8	1194.9	1492.1	2020.9	728.2
23.0	1119.7	1399.9	2062.5	723.2
23.2	1045.0	1307.9	2203.1	754.1
23.4	958.1	1200.9	2404.8	807.2
23.6	868.4	1089.6	2598.9	859.2
23.8	786.1	987.3	2745.0	896.0
24.0	701.2	881.4	2904.0	935.2
24.2	614.4	772.9	3064.9	971.6
24.4	528.0	664.7	3199.8	997.3
24.6	446.8	562.9	3189.0	977.5
24.8	370.2	466.8	2986.6	903.0

Table 6.5-8 (Cont.) DEPS Break Maximum ECCS Blowdown M&E Releases for IP3 SPU				
	Break Path No. 1[1]		Break Path No. 2[2]	
Time	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
25.0	301.9	380.8	2789.6	834.7
25.2	239.4	302.3	2590.3	768.5
25.4	183.9	232.4	2383.7	702.3
25.6	142.6	180.4	2177.3	637.8
25.8	127.2	161.1	1969.4	574.5
26.0	105.9	134.2	1761.3	512.4
26.2	58.4	74.2	1556.4	452.4
26.4	0.0	0.0	1339.4	389.5
26.6	0.0	0.0	1082.8	315.5
26.8	0.0	0.0	724.1	211.6
27.0	0.0	0.0	25.5	7.5
27.2	0.0	0.0	0.0	0.0

Notes:

1. M&E exiting the steam-generator side of the break
2. M&E exiting the pumpside of the break

Table 6.5-9

DEPS Break Minimum ECCS
Reflood M&E Releases for IP3 SPU

Time	Break Path No.1[1]		Break Path No. 2[2]	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
27.2	0.0	0.0	0.0	0.0
27.8	0.0	0.0	0.0	0.0
27.9	0.0	0.0	0.0	0.0
28.1	0.0	0.0	157.7	12.3
28.2	0.0	0.0	157.7	12.3
28.2	0.0	0.0	157.7	12.3
28.3	46.8	55.1	157.7	12.3
28.4	31.0	36.5	157.7	12.3
28.6	12.5	14.8	157.7	12.3
28.7	13.3	15.7	157.7	12.3
28.8	15.5	18.2	157.7	12.3
28.9	25.2	29.7	157.7	12.3
29.0	29.2	34.4	157.7	12.3
29.1	35.0	41.2	157.7	12.3
29.2	39.6	46.7	157.7	12.3
29.3	43.8	51.6	157.7	12.3
29.4	47.8	56.4	157.7	12.3
29.5	51.3	60.5	157.7	12.3
29.6	54.5	64.2	157.7	12.3
29.7	58.1	68.5	157.7	12.3
29.8	60.3	71.0	157.7	12.3
29.8	61.1	71.9	157.7	12.3
29.9	63.8	75.2	157.7	12.3
30.0	66.4	78.3	157.7	12.3
30.1	69.0	81.3	157.7	12.3
30.2	71.5	84.3	157.7	12.3
30.3	73.9	87.1	157.7	12.3
31.3	95.3	112.3	157.7	12.3
32.3	113.0	133.1	157.7	12.3
33.3	128.2	151.1	157.7	12.3
34.3	141.8	167.2	157.7	12.3
34.8	147.5	173.9	157.7	12.3
35.3	154.0	181.6	157.7	12.3
36.3	255.5	301.7	2311.3	359.4
37.3	364.4	431.1	3697.8	614.5
38.3	367.7	435.0	3727.8	628.4

Table 6.5-9 (Cont.)

DEPS Break Minimum ECCS Reflood M&E Releases for IP3 SPU

Time	Break Path No.1[1]		Break Path No. 2[2]	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
39.3	362.5	428.8	3670.1	622.1
40.0	358.5	424.1	3626.2	616.7
40.3	356.8	422.1	3607.3	614.3
41.3	351.3	415.5	3545.2	606.6
42.3	345.9	409.0	3484.4	598.9
43.3	340.6	402.8	3425.0	591.4
44.3	335.6	396.8	3367.3	584.1
45.3	330.7	391.0	3311.1	576.9
46.1	327.0	386.6	3267.2	571.3
46.3	326.0	385.5	3256.4	569.9
47.3	321.5	380.1	3203.3	563.1
48.3	317.1	374.9	3151.7	556.5
49.3	312.9	369.8	3101.4	550.0
50.3	308.8	365.0	3052.5	543.7
51.3	304.9	360.3	3004.9	537.6
52.3	301.0	355.8	2958.5	531.6
53.0	298.4	352.7	2926.7	527.5
53.3	297.3	351.4	2913.3	525.7
54.3	293.8	347.1	2869.2	520.0
55.3	290.3	343.0	2826.1	514.4
56.3	286.9	338.9	2784.1	509.0
57.3	283.6	335.1	2743.1	503.6
58.3	280.4	331.3	2703.0	498.4
59.3	242.9	286.7	2184.4	434.4
60.3	240.6	284.0	2153.4	430.1
60.6	239.9	283.2	2144.2	428.9
61.3	238.3	281.3	2123.1	425.9
62.3	236.1	278.8	2093.5	421.9
63.3	234.0	276.3	2064.5	417.8
64.3	232.0	273.8	2036.1	413.9
65.3	229.9	271.4	2008.3	410.0
66.3	228.0	269.1	1981.1	406.2
67.3	458.8	543.7	349.1	256.1
68.3	468.5	555.3	353.1	262.1
69.3	460.9	546.2	349.5	257.2
70.3	452.9	536.7	345.8	252.2

Table 6.5-9 (Cont.)

DEPS Break Minimum ECCS
Reflood M&E Releases for IP3 SPU

Time	Break Path No.1[1]		Break Path No. 2[2]	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
71.3	445.0	527.3	342.0	247.2
72.3	437.1	517.8	338.3	242.1
73.3	429.2	508.3	334.6	237.2
74.3	421.9	499.6	331.2	232.6
74.7	419.0	496.2	329.9	230.8
75.3	414.7	491.1	327.9	228.2
76.3	407.6	482.6	324.6	223.8
77.3	400.7	474.3	321.4	219.5
78.3	393.8	466.2	318.3	215.3
79.3	387.1	458.1	315.2	211.2
80.3	380.5	450.2	312.2	207.2
81.3	373.9	442.5	309.2	203.2
82.3	367.5	434.8	306.3	199.4
83.3	361.3	427.4	303.5	195.6
84.3	355.1	420.1	300.7	192.0
85.3	349.1	412.9	298.0	188.4
86.3	343.3	406.0	295.4	185.0
87.3	337.6	399.2	292.9	181.6
88.3	332.0	392.5	290.4	178.4
89.4	326.0	385.4	287.7	174.9
90.3	321.3	379.8	285.7	172.2
92.3	311.2	367.8	281.2	166.3
94.3	301.7	356.5	277.1	160.9
96.3	292.7	345.9	273.2	155.8
98.3	284.4	336.0	269.6	151.2
100.3	276.6	326.7	266.2	146.8
102.3	269.3	318.1	263.1	142.8
104.3	262.6	310.1	260.3	139.1
106.3	256.3	302.6	257.6	135.6
107.8	251.9	297.4	255.8	133.2
108.3	250.5	295.8	255.2	132.5
110.3	245.1	289.4	252.9	129.6
112.3	240.2	283.6	250.9	126.9
114.3	235.7	278.2	249.0	124.5
116.3	231.5	273.3	247.3	122.3
118.3	227.7	268.8	245.7	120.3
120.3	224.3	264.7	244.3	118.5

Table 6.5-9 (Cont.)

DEPS Break Minimum ECCS

Reflood M&E Releases for IP3 SPU

Time	Break Path No.1(1)		Break Path No. 2(2)	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
122.3	221.1	261.0	243.0	116.8
124.3	218.3	257.6	241.8	115.3
126.3	215.7	254.5	240.8	114.0
128.3	213.3	251.7	239.8	112.7
130.2	211.3	249.4	239.0	111.7
130.3	211.2	249.2	239.0	111.6
132.3	209.3	247.0	238.2	110.7
134.3	207.6	245.0	237.5	109.8
136.3	206.1	243.2	236.9	109.0
138.3	204.8	241.6	236.4	108.3
140.3	203.6	240.2	235.9	107.7
142.3	202.6	239.0	235.5	107.2
144.3	201.7	237.9	235.1	106.7
146.3	200.9	237.0	234.8	106.3
148.3	200.2	236.2	234.5	105.9
150.3	199.6	235.5	234.3	105.6
152.3	199.1	235.0	234.1	105.4
154.3	198.7	234.5	233.9	105.1
155.3	198.5	234.2	233.8	105.0
156.3	198.4	234.1	233.7	105.0
158.3	198.1	233.7	233.6	104.8
160.3	197.9	233.5	233.5	104.7
162.3	197.8	233.3	233.5	104.6
164.3	197.7	233.2	233.4	104.5
166.3	197.6	233.2	233.4	104.5
168.3	197.6	233.2	233.4	104.5
170.3	197.7	233.2	233.4	104.5
172.3	197.8	233.3	233.4	104.5
174.3	197.9	233.4	233.4	104.6
176.3	198.0	233.6	233.5	104.6
178.3	198.2	233.8	233.5	104.7
180.3	198.4	234.1	233.6	104.8
182.1	198.6	234.3	233.7	104.9

Notes:

1. M&E exiting from the steam-generator side of the break
2. M&E existing from the pump side of the break

Table 6.5-10

DEPS Break Maximum ECCS
Reflood M&E Releases for IP3 SPU

Time	Break Path No. 1[1]		Break Path No. 2[2]	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
27.2	0.0	0.0	0.0	0.0
27.8	0.0	0.0	0.0	0.0
27.9	0.0	0.0	0.0	0.0
28.1	0.0	0.0	241.1	18.8
28.2	0.0	0.0	241.1	18.8
28.2	0.0	0.0	241.1	18.8
28.3	74.4	87.6	241.1	18.8
28.4	22.8	26.8	241.1	18.8
28.5	15.2	17.9	241.1	18.8
28.6	17.3	20.3	241.1	18.8
28.7	22.7	26.7	241.1	18.8
28.8	27.1	31.9	241.1	18.8
28.9	31.9	37.5	241.1	18.8
29.0	37.6	44.3	241.1	18.8
29.1	42.3	49.8	241.1	18.8
29.2	46.5	54.8	241.1	18.8
29.3	50.7	59.7	241.1	18.8
29.5	54.1	63.8	241.1	18.8
29.6	57.9	68.2	241.1	18.8
29.7	61.0	71.9	241.1	18.8
29.8	63.9	75.3	241.1	18.8
29.9	66.7	78.5	241.1	18.8
30.0	69.4	81.7	241.1	18.8
30.1	72.0	84.8	241.1	18.8
30.2	74.5	87.8	241.1	18.8
30.3	77.0	90.8	241.1	18.8
31.3	99.4	117.1	241.1	18.8
32.3	117.4	138.4	241.1	18.8
33.3	133.1	156.9	241.1	18.8
34.3	147.3	173.7	241.1	18.8
34.6	151.0	178.0	241.1	18.8
35.3	159.9	188.6	241.1	18.8
36.3	357.7	423.0	3654.2	570.9
37.3	393.9	466.2	4034.5	656.1
38.3	390.1	461.7	3992.6	653.5
39.3	384.2	454.7	3930.0	646.0

Table 6.5-10 (Cont.)

DEPS Break Maximum ECCS
Reflood M&E Releases for IP3 SPU

Time	Break Path No. 1[1]		Break Path No. 2[2]	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
39.6	382.5	452.6	3911.0	643.6
40.3	378.4	447.8	3866.8	638.1
41.3	372.7	441.0	3804.6	630.3
42.3	367.2	434.4	3743.9	622.6
43.3	361.9	428.1	3684.7	615.1
44.3	356.7	422.0	3627.1	607.7
45.3	351.8	416.0	3571.2	600.6
45.4	351.3	415.5	3565.7	599.9
46.3	347.0	410.3	3516.8	593.6
47.3	342.3	404.8	3463.9	586.8
48.3	337.9	399.5	3412.5	580.2
49.3	333.6	394.4	3362.5	573.8
50.3	329.4	389.4	3313.9	567.5
51.3	325.4	384.6	3266.6	561.4
52.0	322.6	381.4	3234.2	557.3
52.3	321.4	380.0	3220.5	555.5
53.3	317.7	375.5	3175.6	549.7
54.3	314.0	371.1	3131.8	544.0
55.3	310.4	366.9	3089.0	538.5
56.3	307.0	362.8	3047.4	533.0
57.3	303.6	358.8	3006.6	527.7
58.3	300.3	354.9	2966.9	522.6
59.3	285.7	337.7	2725.6	502.8
59.3	266.9	315.4	2402.0	470.9
60.3	259.8	306.8	2436.2	457.3
61.3	257.4	304.0	2406.0	453.2
62.3	255.2	301.3	2376.5	449.2
63.3	252.9	298.7	2347.6	445.2
64.3	250.8	296.1	2319.4	441.3
65.3	248.7	293.6	2291.7	437.5
66.3	246.6	291.1	2264.6	433.7
67.3	244.6	288.7	2238.1	430.1
68.3	363.1	429.6	374.8	189.2
69.3	363.0	429.4	375.5	189.1
70.3	362.8	429.1	376.5	188.9
71.3	362.5	428.9	377.5	188.7

Table 6.5-10 (Cont.) DEPS Break Maximum ECCS Reflood M&E Releases for IP3 SPU				
	Break Path No. 1[1]		Break Path No. 2[2]	
Time	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
72.3	362.3	428.5	378.6	188.5
73.3	362.0	428.2	379.6	188.4
74.3	361.7	427.9	380.7	188.2
74.5	361.6	427.8	380.9	188.1
75.3	361.4	427.5	381.8	188.0
76.3	361.0	427.1	382.9	187.8
77.3	360.7	426.7	384.0	187.6
78.3	360.3	426.2	385.2	187.4
79.3	359.9	425.7	386.4	187.1
80.3	359.5	425.2	387.7	186.9
81.3	359.0	424.7	389.0	186.7
82.3	358.5	424.1	390.3	186.5
83.3	358.0	423.5	391.7	186.2
84.3	357.4	422.8	393.2	186.0
85.3	356.8	422.1	394.7	185.8
86.3	356.2	421.4	396.2	185.5
87.3	355.6	420.6	397.8	185.2
88.3	354.9	419.8	399.5	185.0
88.9	354.4	419.2	400.5	184.8
90.3	353.4	418.0	403.0	184.5
92.3	351.7	416.0	406.7	183.9
94.3	349.9	413.9	410.6	183.3
96.3	348.0	411.5	414.7	182.8
98.3	345.9	409.0	419.0	182.2
100.3	343.6	406.3	423.5	181.6
102.3	341.2	403.4	428.2	181.0
104.3	338.6	400.4	433.1	180.5
104.4	338.5	400.2	433.3	180.5
106.3	335.9	397.2	438.1	179.9
108.3	333.1	393.8	443.3	179.4
110.3	330.1	390.3	448.7	178.9
112.3	327.0	386.6	454.3	178.4
114.3	323.8	382.8	460.0	177.9
116.3	320.4	378.8	465.9	177.5
118.3	316.9	374.6	472.0	177.1
120.3	313.3	370.3	478.3	176.7
121.3	311.4	368.1	481.5	176.6

Table 6.5-10 (Cont.)

DEPS Break Maximum ECCS
Reflood M&E Releases for IP3 SPU

Time	Break Path No. 1[1]		Break Path No. 2[2]	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
122.3	309.5	365.8	484.7	176.4
124.3	305.6	361.1	491.3	176.1
126.3	301.5	356.3	498.2	175.9
128.3	297.3	351.3	505.2	175.7
130.3	292.9	346.1	512.4	175.6
132.3	288.3	340.7	519.8	175.5
134.3	283.6	335.0	527.5	175.5
136.3	278.7	329.2	535.4	175.5
138.3	273.6	323.1	543.5	175.6
140.3	268.3	316.9	551.9	175.8
140.5	267.7	316.2	552.8	175.8
142.3	262.8	310.3	560.6	176.0
144.3	257.0	303.5	569.6	176.4
146.3	251.0	296.4	578.8	176.8
148.3	244.8	289.0	588.4	177.3
150.3	238.3	281.3	598.3	177.9
152.3	231.4	273.2	608.7	178.6
154.3	224.2	264.7	619.5	179.4
156.3	216.7	255.7	630.7	180.4
158.3	208.7	246.3	642.5	181.5
160.3	200.4	236.4	654.7	182.8
162.3	191.5	225.9	667.6	184.2
163.7	185.0	218.2	677.0	185.3

Notes:

1. M&E exiting the steam-generator side of the break
2. M&E exiting the pumpside of the break

Table 6.5-11

DEPS Break Minimum ECCS
Principle Parameters During Reflood for IP3 SPU

Time (sec)	Flooding Temp (°F)	Flooding Rate (in/sec)	Carryover Fraction	Core Height (ft)	Downcomer Height (ft)	Flow Fraction	Injection Total (lbm/sec)	Injection Accumulator (lbm/sec)	Injection Spill (lbm/sec)	Injection Enthalpy (Btu/lbm)
27.2	185.8	0.000	0.000	0.00	0.00	0.250	0.0	0.0	0.0	0.00
28.1	184.0	21.923	0.000	0.77	1.04	0.000	6394.7	5763.9	0.0	97.24
28.2	183.6	22.509	0.000	0.95	1.05	0.000	6374.0	5743.2	0.0	97.24
28.2	183.4	22.418	0.126	1.05	1.06	0.225	6353.4	5722.6	0.0	97.23
28.6	183.1	2.305	0.095	1.31	1.49	0.203	6278.0	5647.2	0.0	97.20
28.8	183.1	2.493	0.117	1.34	1.90	0.217	6248.5	5617.7	0.0	97.19
28.9	183.2	2.442	0.147	1.36	2.15	0.270	6209.7	5578.9	0.0	97.18
29.1	183.3	2.475	0.186	1.40	2.56	0.295	6171.6	5540.8	0.0	97.17
29.8	183.5	2.375	0.298	1.50	3.96	0.329	6043.0	5412.1	0.0	97.12
30.3	183.8	2.321	0.364	1.57	5.01	0.339	5946.7	5315.9	0.0	97.09
34.8	185.8	2.601	0.613	2.00	13.40	0.359	5290.4	4659.6	0.0	96.80
37.3	187.2	3.915	0.675	2.24	16.11	0.536	4542.5	3949.9	0.0	96.56
39.3	188.3	3.760	0.698	2.44	16.12	0.535	4327.0	3734.5	0.0	96.43
40.0	188.7	3.703	0.703	2.50	16.12	0.533	4268.6	3675.2	0.0	96.38
46.1	192.7	3.364	0.727	3.01	16.12	0.518	3829.7	3228.9	0.0	96.00
53.0	197.5	3.127	0.735	3.51	16.12	0.503	3434.8	2827.8	0.0	95.58
60.6	203.0	2.748	0.738	4.00	16.12	0.459	2559.2	1940.3	0.0	94.19
66.3	207.2	2.655	0.740	4.34	16.12	0.450	2374.9	1754.0	0.0	93.77
67.3	208.0	4.011	0.748	4.41	16.02	0.599	566.8	0.0	0.0	78.00
68.3	209.0	4.043	0.748	4.49	15.84	0.600	562.2	0.0	0.0	78.00
69.3	210.0	3.980	0.748	4.58	15.66	0.600	564.3	0.0	0.0	78.00
74.7	215.5	3.642	0.749	5.01	14.79	0.595	575.5	0.0	0.0	78.00
82.3	223.3	3.234	0.750	5.55	13.87	0.587	588.1	0.0	0.0	78.00

Table 6.5-11 (Cont.)

DEPS Break Minimum ECCS
Principle Parameters During Reflood for IP3 SPU

Time (sec)	Flooding Temp (°F)	Flooding Rate (in/sec)	Carryover Fraction	Core Height (ft)	Downcomer Height (ft)	Flow Fraction	Injection Total (lbm/sec)	Injection Accumulator (lbm/sec)	Injection Spill (lbm/sec)	Injection Enthalpy (Btu/lbm)
89.4	230.5	2.910	0.750	6.01	13.28	0.579	597.2	0.0	0.0	78.00
98.3	238.4	2.589	0.750	6.51	12.85	0.568	605.5	0.0	0.0	78.00
107.8	246.3	2.341	0.750	7.00	12.66	0.556	611.3	0.0	0.0	78.00
120.3	252.8	2.130	0.751	7.58	12.72	0.544	615.8	0.0	0.0	78.00
130.2	257.7	2.028	0.753	8.00	12.91	0.537	617.7	0.0	0.0	78.00
144.3	263.8	1.947	0.757	8.58	13.32	0.531	619.1	0.0	0.0	78.00
155.3	267.9	1.915	0.760	9.00	13.70	0.529	619.6	0.0	0.0	78.00
170.3	272.8	1.895	0.765	9.57	14.26	0.529	619.7	0.0	0.0	78.00
182.1	276.2	1.891	0.770	10.00	14.72	0.530	619.6	0.0	0.0	78.00

Table 6.5-12

DEPS Break Maximum ECCS
Principle Parameters During Reflood for IP3 SPU

Time (sec)	Flooding Temp (°F)	Flooding Rate (in/sec)	Carryover Fraction	Core Height (ft)	Downcomer Height (ft)	Flow Fraction	Injection Total (lbm/sec)	Injection Accumulator (lbm/sec)	Injection Spill (lbm/sec)	Injection Enthalpy (Btu/lbm)
27.2	185.5	0.000	0.000	0.00	0.00	0.250	0.0	0.0	0.0	0.00
28.1	183.5	23.012	0.000	0.78	1.06	0.000	6770.0	5805.3	0.0	96.31
28.2	18.9	24.009	0.000	1.08	1.07	0.000	6728.0	5763.3	0.0	96.29
28.5	182.6	2.385	0.100	1.31	1.54	0.235	6653.8	5689.1	0.0	96.25
29.0	182.8	2.522	0.190	1.40	2.60	0.306	6550.3	5585.6	0.0	96.21
29.7	183.0	2.420	0.293	1.50	3.98	0.333	6428.3	5463.6	0.0	96.15
30.3	183.2	2.360	0.369	1.58	5.23	0.342	6321.1	5356.4	0.0	96.09
34.6	185.2	2.652	0.614	2.00	13.80	0.360	5670.4	4705.8	0.0	95.72
37.3	186.5	4.078	0.680	2.27	16.12	0.550	4803.5	3892.8	0.0	95.30
39.3	187.6	3.880	0.701	2.47	16.12	0.547	4615.3	3702.1	0.0	95.13
39.6	187.8	3.854	0.704	2.50	16.12	0.546	4590.1	3676.5	0.0	95.10
45.4	191.4	3.513	0.727	3.00	16.12	0.533	4164.4	3242.1	0.0	94.62
52.0	195.9	3.272	0.736	3.50	16.12	0.519	3778.0	2848.2	0.0	94.10
67.3	206.8	2.742	0.741	4.49	16.12	0.467	2656.4	1708.4	0.0	91.73
68.3	207.6	3.443	0.747	4.56	16.12	0.548	918.5	0.0	0.0	78.00
69.3	208.4	3.437	0.747	4.63	16.12	0.548	918.5	0.0	0.0	78.00
74.5	213.2	3.406	0.749	5.01	16.12	0.550	919.0	0.0	0.0	78.00
82.3	221.0	3.351	0.752	5.55	16.12	0.552	919.9	0.0	0.0	78.00
88.9	228.0	3.292	0.755	6.00	16.12	0.553	922.9	0.0	0.0	78.00
98.3	237.6	3.188	0.759	6.62	16.12	0.555	922.9	0.0	0.0	78.00
104.4	243.1	3.110	0.760	7.01	16.12	0.555	924.6	0.0	0.0	78.00
114.3	250.7	2.967	0.763	7.60	16.12	0.554	927.8	0.0	0.0	78.00
121.3	255.4	2.856	0.765	8.00	16.12	0.553	930.5	0.0	0.0	78.00

Table 6.5-12 (Cont.)

DEPS Break Maximum ECCS
Principle Parameters During Reflood for IP3 SPU

Time (sec)	Flooding Temp (°F)	Flooding Rate (in/sec)	Carryover Fraction	Core Height (ft)	Downcomer Height (ft)	Flow Fraction	Injection Total (lbm/sec)	Injection Accumulator (lbm/sec)	Injection Spill (lbm/sec)	Injection Enthalpy (Btu/lbm)
132.3	261.7	2.665	0.768	8.60	16.12	0.547	935.4	0.0	0.0	78.00
140.5	265.6	2.507	0.769	9.00	16.12	0.538	939.6	0.0	0.0	78.00
152.3	270.4	2.250	0.771	9.54	16.12	0.517	946.7	0.0	0.0	78.00
163.7	274.2	1.950	0.771	10.00	16.12	0.476	954.8	0.0	0.0	78.00

Table 6.5-13

DEPS Break Minimum ECCS
Post-Reflood M&E Releases for IP3 SPU

Time	Break Path No. 1(1)		Break Path No. 2(2)	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
182.2	263.5	324.2	367.2	149.7
187.2	262.8	323.3	368.0	149.5
192.2	262.4	322.9	368.3	149.2
197.2	261.9	322.3	368.8	149.0
202.2	260.9	321.0	369.9	148.9
207.2	260.3	320.3	370.4	148.6
212.2	260.1	320.0	370.7	148.3
217.2	264.3	325.1	366.5	150.5
222.2	263.8	324.6	366.9	150.2
227.2	263.1	323.7	367.7	150.0
232.2	262.5	322.9	368.3	149.7
237.2	262.0	322.3	368.8	149.4
242.2	261.4	321.6	369.3	149.2
247.2	260.8	320.8	370.0	148.9
252.2	259.9	319.8	370.8	148.7
257.2	259.5	319.2	371.3	148.4
262.2	258.5	318.1	372.2	148.3
267.2	257.9	317.3	372.9	148.0
272.2	257.4	316.6	373.4	147.7
277.2	256.7	315.8	374.1	147.5
282.2	255.9	314.8	374.8	147.3
287.2	255.1	313.9	375.6	147.0
292.2	254.5	313.1	376.3	146.8
297.2	253.9	312.3	376.9	146.5
302.2	93.7	115.3	537.0	188.4
434.5	93.7	115.3	537.0	188.4
434.6	93.5	114.5	537.2	183.2
437.2	93.4	114.4	537.3	183.0
1114.8	93.4	114.4	537.3	183.0
1114.9	76.5	88.0	554.3	48.2
1623.8	69.7	80.2	561.1	49.4
1623.9	69.7	80.2	208.3	48.4
3600.0	56.7	65.3	221.2	50.8
3600.1	49.3	56.7	228.7	39.7
3916.2	47.5	54.7	230.5	40.0
3916.3	47.8	55.0	100.2	17.9

Table 6.5-13 (Cont.)

DEPS Break Minimum ECCS
Post-Reflood M&E Releases for IP3 SPU

Time	Break Path No. 1[1]		Break Path No. 2[2]	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
10,000.0	36.0	41.5	112.0	20.0
100,000.0	19.3	22.2	128.7	23.0
1,000,000.0	8.3	9.5	139.8	25.0
10,000,000.0	2.6	3.0	145.4	26.0

Notes:

1. M&E exiting from the steam-generator side of the break
2. M&E existing from the pump side of the break

Table 6.5-14 DEPS Break Maximum ECCS Post-Reflood M&E Releases for IP3 SPU				
	Break Path No. 1[1]		Break Path No. 2[2]	
Time	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
163.8	158.0	193.6	806.7	207.2
168.8	157.6	193.1	807.1	206.8
173.8	157.7	193.2	807.0	206.4
178.8	157.7	193.2	807.0	206.0
183.8	157.2	192.7	807.5	205.7
188.8	157.2	192.6	807.5	205.3
193.8	157.2	192.6	807.5	204.8
198.8	156.7	192.0	808.0	204.5
203.8	156.8	192.2	807.8	204.1
208.8	156.6	191.9	808.1	203.7
213.8	156.8	192.1	807.9	206.8
218.8	156.5	191.8	808.2	206.5
223.8	156.2	191.4	808.5	206.1
228.8	156.3	191.6	808.4	205.6
233.8	156.0	191.2	808.7	205.3
238.8	156.1	191.3	808.6	204.8
243.8	156.2	191.4	808.5	204.3
248.8	155.8	190.9	808.9	204.0
253.8	155.8	190.9	808.9	203.5
258.8	155.8	190.9	808.9	203.1
263.8	155.8	190.9	808.9	202.6
268.8	155.7	190.8	809.0	202.2
273.8	155.6	190.7	809.1	201.8
278.8	155.5	190.6	809.2	201.3
283.8	155.4	190.4	809.3	200.9
288.8	155.2	190.2	809.5	200.5
293.8	155.0	189.9	809.7	200.1
298.8	155.2	190.1	809.5	203.0
303.8	154.9	189.8	809.8	202.6
308.8	154.9	189.8	809.8	202.1
313.8	154.6	189.4	810.1	201.7
318.8	154.5	189.4	810.2	201.2
323.8	154.4	189.2	810.2	200.8
328.8	154.3	189.1	810.4	200.3

Table 6.5-14 (Cont.) DEPS Break Maximum ECCS Post-Reflood M&E Releases for IP3 SPU				
	Break Path No. 1(1)		Break Path No. 2(2)	
Time	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
333.8	154.4	189.2	810.3	199.8
338.8	154.1	188.9	810.5	199.3
343.8	154.1	188.9	810.6	198.8
348.8	154.0	188.7	810.7	198.4
353.8	153.8	188.5	810.9	197.9
358.8	153.9	188.5	810.8	197.4
363.8	153.8	188.4	810.9	196.9
368.8	153.5	188.1	811.2	199.7
373.8	153.4	188.0	811.3	199.2
378.8	153.5	188.0	811.2	198.7
383.8	153.3	187.8	811.4	198.2
388.8	153.1	187.6	811.6	197.7
393.8	153.2	187.7	811.5	197.1
398.8	152.9	187.4	811.8	196.7
403.8	153.0	187.5	811.7	196.1
408.8	152.8	187.2	811.9	195.6
413.8	152.9	187.3	811.8	195.1
418.8	152.8	187.2	811.9	197.7
423.8	152.6	187.0	812.0	197.2
428.8	152.5	186.9	812.2	196.6
433.8	152.4	186.7	812.3	196.1
438.8	144.5	177.1	820.2	197.6
443.8	86.1	105.5	878.6	212.4
798.1	86.1	105.5	878.6	212.4
798.2	83.7	102.0	881.0	204.6
798.8	83.7	102.0	881.0	204.6
1033.6	83.7	102.0	881.0	204.6
1033.7	78.5	90.4	886.1	73.4
1172.7	76.6	88.1	888.1	73.8
1172.8	76.6	88.1	474.6	105.6
3119.9	60.4	69.5	490.7	108.5
3120.0	60.4	69.5	233.4	59.3
3600.0	57.7	66.3	236.1	59.7
3600.1	50.5	58.1	243.3	47.9

Table 6.5-14 (Cont.)

DEPS Break Maximum ECCS

Post-Reflood M&E Releases for IP3 SPU

Time	Break Path No. 1[1]		Break Path No. 2[2]	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
10,000.0	36.7	42.2	257.1	50.6
100,000.0	19.6	22.6	274.1	53.9
1,000,000.0	8.4	9.7	285.4	56.1
10,000,000.0	2.6	3.0	291.1	57.3

Notes:

1. M&E exiting the steam-generator side of the break
2. M&E exiting the pumpside of the break

Table 6.5-15

LOCA M&E Release Analysis
for Core Decay Heat Fraction

Time (sec)	Decay Heat Generation Rate (Btu/Btu)
1.00E+01	0.053876
1.50E+01	0.050401
2.00E+01	0.048018
4.00E+01	0.042401
6.00E+01	0.039244
8.00E+01	0.037065
1.00E+02	0.035466
1.50E+02	0.032724
2.00E+02	0.030936
4.00E+02	0.027078
6.00E+02	0.024931
8.00E+02	0.023389
1.00E+03	0.022156
1.50E+03	0.019921
2.00E+03	0.018315
4.00E+03	0.014781
6.00E+03	0.013040
8.00E+03	0.012000
1.00E+04	0.011262
1.50E+04	0.010097
2.00E+04	0.009350
4.00E+04	0.007778
6.00E+04	0.006958
8.00E+04	0.006424
1.00E+05	0.006021
1.50E+05	0.005323
4.00E+05	0.003770
6.00E+05	0.003201
8.00E+05	0.002834
1.00E+06	0.002580
1.00E+07	0.000808

Table 6.5-16

DEPS Break Minimum ECCS Mass Balance
IP3 SPU

		Mass Balance						
Time (sec)		0.00	27.20	27.20	182.14	434.58	1114.84	3600.00
		Mass (thousand lbm)						
Initial	In RCS and accumulators	732.01	732.01	732.01	732.01	732.01	732.01	732.01
Added Mass	Pumped injection	0.00	0.00	0.00	94.02	253.21	682.29	1552.63
	Total added	0.00	0.00	0.00	94.02	253.21	682.29	1552.63
Total Available		732.01	732.01	732.01	826.03	985.21	1414.29	2284.64
Distribution	Reactor coolant	527.21	40.55	67.50	134.67	134.67	134.67	134.67
	Accumulator	204.80	159.14	132.19	0.00	0.00	0.00	0.00
	Total contents	732.01	199.70	199.70	134.67	134.67	134.67	134.67
Effluent	Break flow	0.00	532.30	532.30	691.35	850.53	1279.61	2149.98
	ECCS spill	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total effluent	0.00	532.30	532.30	691.35	850.53	1279.61	2149.98
Total Accountable		732.01	731.99	731.99	826.01	985.20	1414.28	2284.64

Table 6.5-17

DEPS Break Maximum ECCS Mass Balance
IP3 SPU

		Mass Balance						
Time (sec)		0.00	27.20	27.20	163.73	798.20	1033.63	3600.00
		Mass (thousand lbm)						
Initial	In RCS and accumulators	732.01	732.01	732.01	732.01	732.01	732.01	732.01
Added Mass	Pumped injection	0.00	0.00	0.00	126.74	738.74	965.85	2314.17
	Total added	0.00	0.00	0.00	126.74	738.74	965.85	2314.17
Total Available		732.01	732.01	732.01	858.74	1470.74	1697.86	3046.18
Distribution	Reactor coolant	527.21	40.55	66.31	137.06	137.06	137.06	137.06
	Accumulator	204.80	159.14	133.38	0.00	0.00	0.00	0.00
	Total contents	732.01	199.70	199.70	137.06	137.06	137.06	137.06
Effluent	Break flow	0.00	532.30	532.30	721.67	1333.67	1560.78	2909.14
	ECCS spill	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total effluent	0.00	532.30	532.30	721.67	1333.67	1560.78	2909.14
Total Accountable		732.01	731.99	731.99	858.73	1470.73	1697.84	3046.20

Table 6.5-18

DEPS Break Minimum ECCS Energy Balance
IP3 SPU

		Energy Balance						
Time (sec)		0.00	27.20	27.20	182.14	434.58	1114.84	3600.00
		Energy (million Btu)						
Initial Energy	In RCS, accumulators and steam generators	775.34	775.34	775.34	775.34	775.34	775.34	775.34
Added Energy	Pumped injection	0.00	0.00	0.00	7.33	19.75	53.22	173.60
	Decay heat	0.00	7.65	7.65	25.09	47.82	98.19	235.35
	Heat from secondary	0.00	10.72	10.72	10.72	10.72	10.72	10.72
	Total added	0.00	18.37	18.37	43.15	78.29	162.14	419.68
Total Available		775.34	793.71	793.71	818.49	853.63	937.48	1195.02
Distribution	Reactor coolant	305.75	9.37	12.05	36.23	36.23	36.23	36.23
	Accumulator	20.35	15.81	13.13	0.00	0.00	0.00	0.00
	Core stored	26.87	14.68	14.68	3.95	3.78	3.55	2.71
	Primary metal	166.23	158.03	158.03	127.92	94.29	70.05	53.31
	Secondary metal	40.98	40.83	40.83	36.70	30.14	20.07	15.24
	Steam generator	215.15	232.85	232.85	205.85	165.18	106.47	80.08
	Total contents	775.34	471.57	471.57	410.65	329.61	236.37	187.56
Effluent	Break flow	0.00	321.67	321.67	400.48	516.66	698.75	1008.11
	ECCS spill	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total effluent	0.00	321.67	321.67	400.48	516.66	698.75	1008.11
Total Accountable		775.34	793.23	793.23	811.13	846.27	935.11	1195.67

Table 6.5-19

DEPS Break Maximum ECCS Energy Balance
IP3 SPU

		Energy Balance						
Time (sec)		.00	27.20	27.20	163.73	798.20	1033.63	3600.00
		Energy (million Btu)						
Initial Energy	In RCS, accumulators and steam generators	775.34	775.34	775.34	775.34	775.34	775.34	775.34
Added Energy	Pumped injection	0.00	0.00	0.00	9.89	57.62	75.34	321.96
	Decay heat	0.00	7.65	7.65	23.26	76.05	92.67	235.26
	Heat from secondary	0.00	10.72	10.72	10.72	10.72	10.72	10.72
	Total added	0.00	18.37	18.37	43.87	144.40	178.73	567.95
Total Available		775.34	793.71	793.71	819.21	919.74	954.07	1343.29
Distribution	Reactor coolant	305.75	9.37	11.93	37.02	37.02	37.02	37.02
	Accumulator	20.35	15.81	13.25	0.00	0.00	0.00	0.00
	Core stored	26.87	14.68	14.68	3.95	3.78	3.69	2.71
	Primary metal	166.23	158.03	158.03	127.18	79.50	71.49	53.32
	Secondary metal	40.98	40.83	40.83	36.27	23.54	20.26	15.22
	Steam generator	215.15	232.85	232.85	203.11	125.58	107.48	80.01
	Total contents	775.34	471.57	471.57	407.52	269.40	239.93	188.27
Effluent	Break flow	0.00	321.67	321.67	404.33	642.97	698.44	1144.08
	ECCS spill	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total effluent	0.00	321.67	321.67	404.33	642.97	698.44	1144.08
Total Accountable		775.34	793.23	793.23	811.85	912.38	939.37	1332.35

Table 6.5-20 DEHL Break Sequence of Events for IP3 SPU	
Time (sec)	**Event Description**
0.0	Break occurs, LOOP is assumed
0.6	Reactor trip on low-pressurizer pressure of 1748.7 psia
4.0	Low-pressurizer pressure SI setpoint at 1648.7 psia reached in blowdown
15.2	Broken-loop accumulator begins injecting water
15.5	Intact-loop accumulator begins injecting water
25.6	End-of-blowdown phase

Table 6.5-21

DEPS Break Minimum ECCS
Sequence of Events for IP3 SPU

Time (sec)	Event Description
0.0	Break occurs, and LOOP is assumed
0.66	Reactor trip on low-pressurizer pressure of 1748.7 psia
4.0	Low-pressurizer pressure SI setpoint 1648.7 psia reached in blowdown
16.0	Main feedwater flow control valve closed
16.9	Broken-loop accumulator begins injecting water
17.5	Intact-loop accumulator begins injecting water
27.2	End-of-blowdown phase
27.8	SI begins
58.4	Broken-loop accumulator water injection ends
66.5	Intact-loop accumulator water injection ends
182.1	End of reflood phase
1623.8	Cold leg recirculation begins
23,400.0	Hot leg recirculation begins
1.0E+07	Transient modeling terminated

Table 6.5-22 DEPS Break Maximum ECCS Sequence of Events for IP3 SPU	
Time (sec)	**Event Description**
0.0	Break occurs, and LOOP are assumed
0.66	Reactor trip on low-pressurizer pressure of 1748.7 psia
4.0	Low-pressurizer pressure SI setpoint 1648.7 psia reached in blowdown
16.9	Broken-loop accumulator begins injecting water
17.5	Intact-loop accumulator begins injecting water
27.2	End-of-blowdown phase
27.8	SI begins
59.2	Broken-loop accumulator water injection ends
67.4	Intact-loop accumulator water injection ends
163.7	End-of-reflood phase
1172.7	Cold leg recirculation begins
1.0E+07	Transient modeling terminated

Table 6.5-23 IP3 LOCA Containment Response Analysis Parameters	
SW Temperature (°F)	95
RWST Water Temperature (°F)	110
Initial Containment Temperature (°F)	130
Initial Containment Pressure (psia)	17.2
Initial Relative Humidity (%)	20
Net-Free Volume (ft^3)	2.61E+06
Reactor Containment Air Recirculation Fan Coolers	
Total	5
Minimum ECCS	4
Maximum ECCS	5
Fan Cooler Initiation Setpoint (psig)	5.12
Delay Time (sec)	48.21
Containment Spray Pumps	
Total	2
Minimum ECCS	1
Maximum ECCS	1
Flow Rate (gpm) Injection Phase Recirculation Phase	 see Table 6.5-25 970
Containment Spray Initiation Setpoint (psig)	24.63
Delay Time (sec)	60
ECCS Recirculation Switchover (sec) Minimum ECCS Maximum ECCS	 1623.4 1172.7
Containment Spray Termination (sec) Minimum ECCS Maximum ECCS	 3355 3119.9

Table 6.5-23 (Cont.) IP3 LOCA Containment Response Analysis Parameters	
ECCS Flow Rates	
Minimum ECCS	
Injection Alignment (gpm)	2871.2
Recirculation Alignment (gpm)	1864.0
Maximum ECCS	
Injection Alignment (gpm)	5394.5
Recirculation Alignment (gpm)	6320.5
Residual Heat Removal System	
RHR Heat Exchangers	
Total	2
Minimum ECCS	1
Maximum ECCS	2
UA (million Btu / hr °F Hx)	0.62
CCW Flow Through RHR Heat Exchanger (gpm/Hx)	1096
CCW Heat Exchangers	
Total	3
Minimum ECCS	2
Maximum ECCS	3
UA (million Btu / hr °F Hx)	1.44
Total CCW Flow Through CCW Heat Exchangers (gpm)	3710
Total SW Flow Through CCW Heat Exchangers (gpm)	7221
Additional Heat Loads on CCW Heat Exchanger (Btu/hr)	18.85E+06

Table 6.5-24 IP3 RCFC Performance	
Containment Temperature (°F)	Heat Removal Rate (Btu/hr/RCFC)
271	46,952,250
250	39,551,200
230	31,810,100
210	24,063,770
190	19,528,450
170	14,984,710
150	10,516,890
130	6,253,162
110	2,426,960

Table 6.5-25 IP3 Minimum Containment Spray Assumed	
Containment Pressure (psig)	Containment Spray Flow Rate (gpm)
0	2750.8
10	2656.8
20	2558.0
25	2507.4
35	2403.8
45	2296.5
50	2237.9

Table 6.5-26

DEPS Break Minimum ECCS IP3 SPU Sequence of Events

Time (sec)	Event Description
0.0	Break occurs, reactor trip and LOOP power are assumed
0.66	Reactor trip on low-pressurizer pressure of 1748.7 psia
1	Fan cooler initiation pressure setpoint reached
4	Low-pressurizer pressure SI setpoint 1648.7 psia reached in blowdown
8	Containment spray initiation pressure setpoint reached
16	Main feedwater flow control valve closed
16.9	Broken-loop accumulator begins injecting water
17.5	Intact-loop accumulator begins injecting water
27.2	End-of-blowdown phase
27.8	SI begins
48.74	RCFCs actuate
58.4	Broken-loop accumulator water injection ends
66.5	Intact-loop accumulator water injection ends
67.81	Containment spray pump starts
182.1	End of reflood
1118	Peak pressure and temperature occur
1623.8	RHR/HHSI alignment for recirculation
3355	Containment spray is terminated
23,400	Hot leg recirculation
1.0E+07	Transient modeling terminated

Table 6.5-27 DEPS Break Maximum ECCS IP3 SPU Sequence of Events	
Time (sec)	**Event Description**
0.0	Break occurs, reactor trip and LOOP power are assumed
0.66	Reactor trip on low pressurizer pressure of 1748.7 psia
1	Fan cooler initiation pressure setpoint reached
4	Low-pressurizer pressure SI setpoint 1648.7 psia reached in blowdown
8	Containment spray initiation pressure setpoint reached
16	Main feedwater flow control valve closed
16.9	Broken-loop accumulator begins injecting water
17.5	Intact-loop accumulator begins injecting water
27.2	End-of-blowdown phase
27.3	Peak pressure and temperature occur
27.8	SI begins
48.74	RCFCs actuate
59.2	Broken-loop accumulator water injection ends
67.4	Intact-loop accumulator water injection ends
67.81	Containment spray pump starts
163.7	End of reflood
1172.7	RHR/HHSI alignment for recirculation
3119.9	Containment spray is terminated
1.0E+07	Transient modeling terminated

Table 6.5-28 DEHL Break IP3 SPU Sequence of Events	
Time (sec)	**Event Description**
0.0	Break occurs, reactor trip and LOOP are assumed
0.6	Reactor trip on low pressurizer pressure of 1748.7 psia
1	Fan cooler initiation pressure setpoint reached
4	Low-pressurizer pressure SI setpoint =1695 psia reached
8	Containment spray initiation pressure setpoint reached
15.2	Broken-loop accumulator begins injecting water
15.5	Intact-loop accumulator begins injecting water
24.2	Peak pressure and temperature occur
25.6	End-of-blowdown phase
25.6	Transient modeling terminated

Table 6.5-29

IP3 Containment Heat Sinks

No.	Material	Heat Transfer Area (ft^2)	Thickness (ft)
1.	Paint	41,302	0.000625
	Steel		0.03125
	Concrete		1.0
2.	Paint	28,613	0.000625
	Steel		0.04167
	Concrete		1.0
3.	Paint	15,000	0.000625
	Concrete		1.0
4.	Stainless Steel	10,000	0.03125
	Concrete		1.0
5.	Paint	61,000	0.000625
	Concrete		1.0
6.	Paint	68,792	0.000625
	Steel		0.0417
7.	Paint	81,704	0.000625
	Steel		0.03125
8.	Paint	27,948	0.000625
	Steel		0.02083
9.	Paint	69,800	0.000625
	Steel		0.015625
10.	Paint	3000	0.000625
	Steel		0.01042
11.	Paint	22,000	0.000625
	Steel		0.01152
12.	Paint	10,000	0.000625
	Steel		0.0052

Table 6.5-30 IP3 Thermo-Physical Properties of Containment Heat Sinks		
Material	**Thermal Conductivity (Btu / hr ft °F)**	**Volumetric Heat Capacity (Btu / ft^3 °F)**
Paint	0.2083	36.86
Steel	26.0	56.35
Stainless Steel	8.6	56.35
Concrete	0.8	28.8

Table 6.5-31 DEPS Break Minimum ECCS IP3 SPU			
Time (sec)	Pressure (psig)	Steam Temperature (°F)	Sump Temperature (°F)
0.001	2.5	130.0	130.0
0.5	5.0	149.4	189.9
1	7.4	167.5	204.2
2	11.8	194.5	216.5
3	15.2	210.3	222.9
4	17.9	219.4	227.1
5	20.0	223.9	230.2
6	21.8	226.1	232.8
7	23.5	227.8	235.1
8	25.1	228.6	237.0
9	26.8	232.6	239.1
19	37.4	253.7	250.6
29	38.1	254.9	252.2
39	36.9	252.8	249.9
49	36.5	252.1	245.9
59	36.3	251.6	243.6
69	36.2	251.4	243.3
79	36.6	252.1	243.4
89	37.0	252.7	243.5
99	37.2	253.0	243.7
109	37.3	253.1	243.8
119	37.4	253.2	244.0
129	37.5	253.3	244.1
139	37.5	253.3	244.3
149	37.6	253.3	244.4
159	37.6	253.3	244.5
169	37.6	253.4	244.7
179	37.7	253.4	244.8
189	37.8	253.7	245.0
199	38.0	254.1	245.2
299	40.5	258.2	247.3
399	40.2	257.6	250.0
499	40.2	257.6	252.1
599	40.3	257.8	253.9
699	40.6	258.2	255.3
799	40.9	258.7	256.6
899	41.2	259.2	257.7
999	41.6	259.8	258.7
1999	35.3	248.9	239.7
2999	29.4	237.0	241.6
3999	27.9	233.7	240.5

Table 6.5-31 (Cont.) DEPS Break Minimum ECCS IP3 SPU			
Time (sec)	Pressure (psig)	Steam Temperature (°F)	Sump Temperature (°F)
4999	27.3	232.3	238.6
5999	26.7	230.8	236.8
6999	26.0	229.2	235.0
7999	25.3	227.3	233.4
8999	24.5	225.3	231.8
9999	23.7	223.2	230.3
99,999	12.0	181.6	197.2
199,999	10.7	174.9	191.7
299,999	10.3	172.0	191.7
399,999	10.1	168.2	189.8
499,999	9.4	164.3	187.0
599,999	8.9	160.6	185.2
699,999	8.4	157.5	183.8
799,999	7.9	153.4	181.7
899,999	7.4	149.8	180.5
999,999	7.0	146.1	179.0
10,000,000	4.4	127.4	170.7

Table 6.5-32

DEPS Break Maximum ECCS
IP3 SPU

Time (sec)	Pressure (psig)	Steam Temperature (°F)	Sump Temperature (°F)
0.001	2.5	130.0	130.0
0.5	5.0	149.4	189.9
1	7.4	167.5	204.2
2	11.8	194.5	216.5
3	15.2	210.3	222.9
4	17.9	219.4	227.1
5	20.0	223.9	230.2
6	21.8	226.1	232.8
7	23.5	227.8	235.1
8	25.1	228.6	237.0
9	26.8	232.6	239.1
19	37.4	253.7	250.6
29	38.1	254.9	252.2
39	37.0	252.9	249.3
49	36.6	252.2	244.6
59	36.3	251.7	241.8
69	36.2	251.4	240.9
79	36.3	251.6	241.2
89	36.6	252.0	241.5
99	36.8	252.4	241.8
109	37.1	252.7	242.1
119	37.3	253.0	242.5
129	37.5	253.3	242.8
139	37.6	253.4	243.2
149	37.7	253.5	243.6
159	37.7	253.5	244.1
169	37.6	253.3	244.6
179	37.4	253.0	245.1
189	37.3	252.8	245.6
199	37.2	252.6	246.1
299	36.5	251.3	249.6
399	36.3	250.9	251.7
499	35.6	249.7	253.0
599	34.7	247.9	254.0
699	33.9	246.4	254.8
799	33.2	245.0	255.3
899	32.5	243.7	255.3
999	31.9	242.4	255.2
1999	25.5	228.1	243.7
2999	21.0	215.6	241.2
3999	22.3	219.4	238.8

Table 6.5-32 (Cont.) DEPS Break Maximum ECCS IP3 SPU			
Time (sec)	Pressure (psig)	Steam Temperature (°F)	Sump Temperature (°F)
4999	22.4	219.7	235.9
5999	22.2	219.3	233.5
6999	21.9	218.3	231.4
7999	21.5	217.0	229.5
8999	20.9	215.2	228.0
9999	20.2	213.3	226.5
99,999	11.5	179.1	204.1
199,999	10.8	175.0	201.9
299,999	10.3	172.4	200.7
399,999	9.9	169.8	199.4
499,999	9.5	167.1	198.1
599,999	9.1	164.5	197.0
699,999	8.7	161.9	195.9
799,999	8.3	159.4	194.8
899,999	7.9	156.8	193.7
999,999	7.6	154.1	192.6
10,000,000	6.0	141.1	186.9

Table 6.5-33

DEHL Break
IP3 SPU

Time (sec)	Pressure (psig)	Steam Temperature (°F)	Sump Temperature (°F)
0.001	2.5	130.0	130.0
0.5	5.1	149.8	182.5
1.0	7.1	165.0	197.7
2.0	10.9	188.7	212.6
3.0	14.3	205.2	221.1
4.0	17.2	216.0	226.9
5.0	19.8	222.9	231.5
6.0	22.2	227.7	235.3
7.0	24.2	229.9	238.1
8.0	26.0	231.1	240.6
9.0	27.8	234.9	242.9
10.0	29.7	238.9	245.2
11.0	31.2	242.1	246.9
12.0	32.6	244.9	248.6
13.0	33.9	247.3	250.0
14.0	35.0	249.4	251.3
15.0	36.1	251.3	252.3
16.0	37.0	252.9	253.2
17.0	37.8	254.3	253.8
18.0	38.5	255.5	254.2
19.0	39.1	256.5	254.5
20.0	39.6	257.3	254.6
21.0	39.9	257.8	254.7
22.0	40.2	258.2	254.7
23.0	40.3	258.5	254.7
24.0	40.4	258.6	254.8
25.0	40.4	258.6	254.8
25.6	40.3	258.4	254.8

Table 6.5-34

LOCA Containment Response Results for IP3 SPU

Case	Peak Pressure (psig)	Peak Steam Temperature (°F)	Pressure at 24 hours (psig)	Steam Temperature at 24 hours (°F)
DEPS Minimum ECCS	42.00 at 1118 sec	260.4 at 1118 sec	13.27	187.8
DEPS Maximum ECCS	38.94 at 23.7 sec	256.2 at 23.7 sec	12.40	183.6
DEHL	40.38 at 24.2 sec	258.6 at 24.2 sec	N/A	N/A

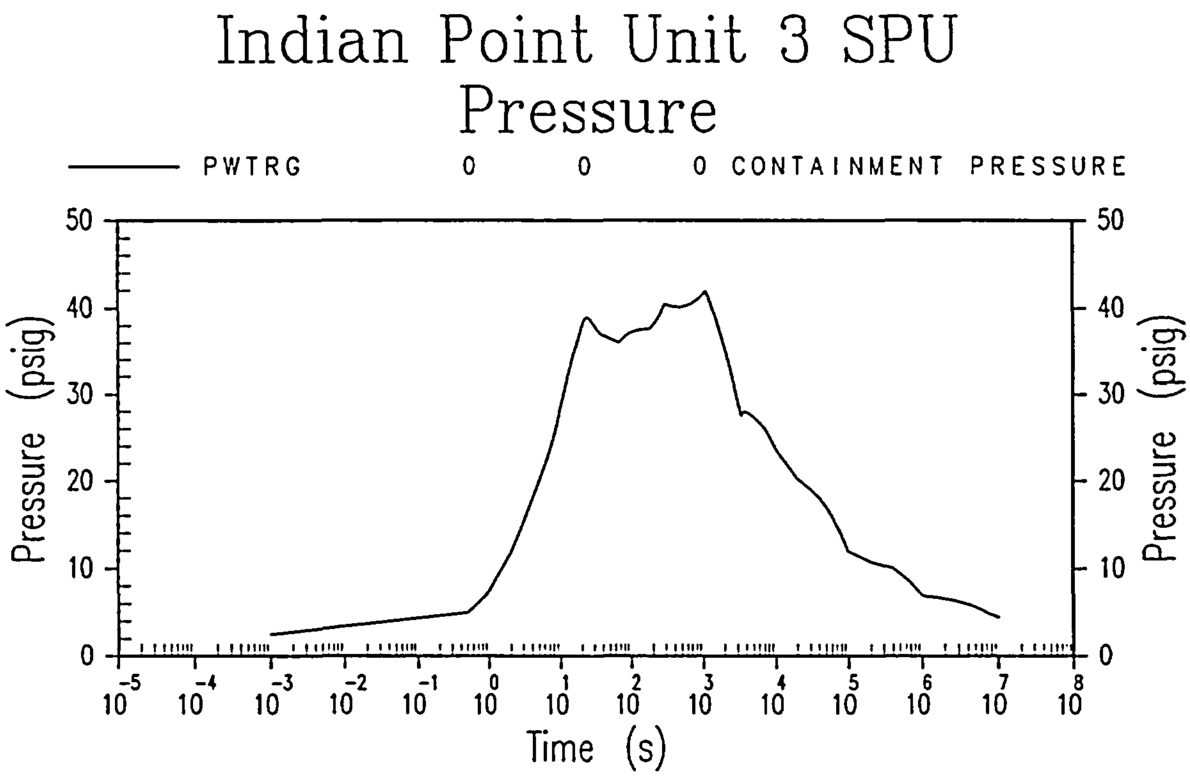

Figure 6.5-1

DEPS Break Minimum ECCS - Containment Pressure

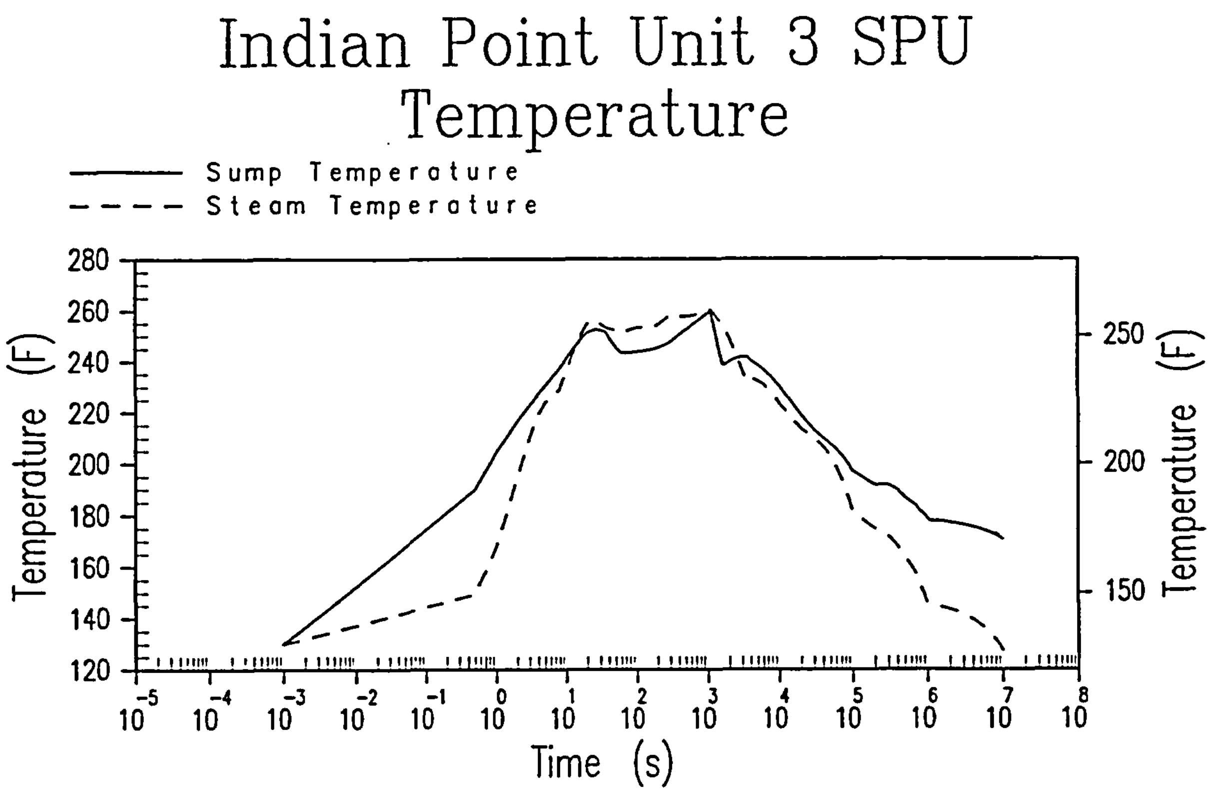

Figure 6.5-2

DEPS Break Minimum ECCS - Containment Temperature

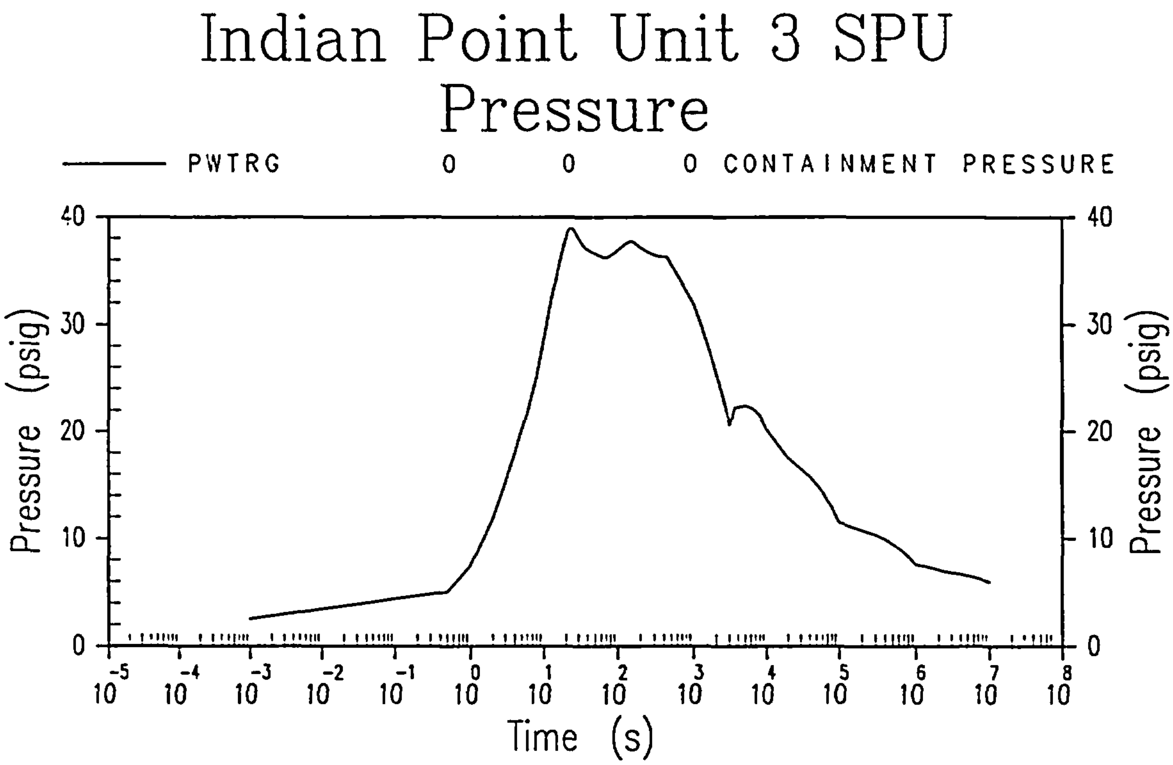

Figure 6.5-3

DEPS Break Maximum ECCS - Containment Pressure

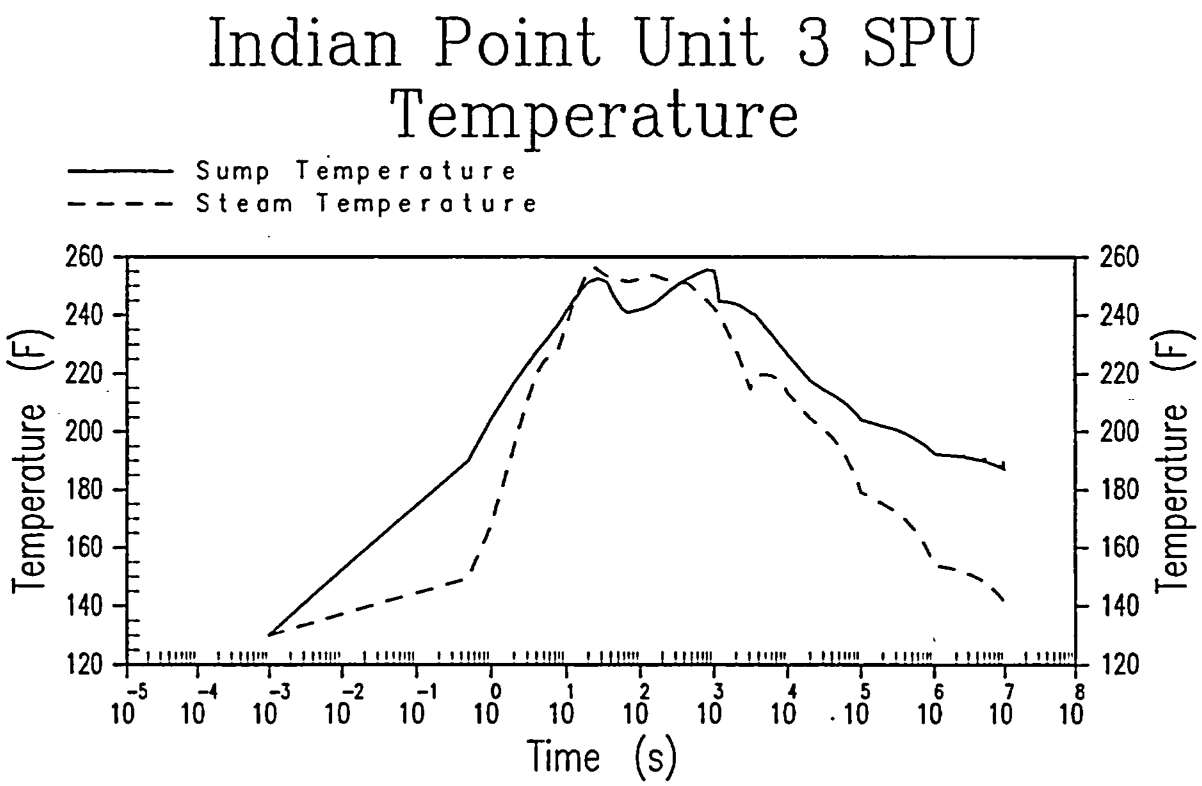

Figure 6.5-4

DEPS Break Maximum ECCS - Containment Temperature

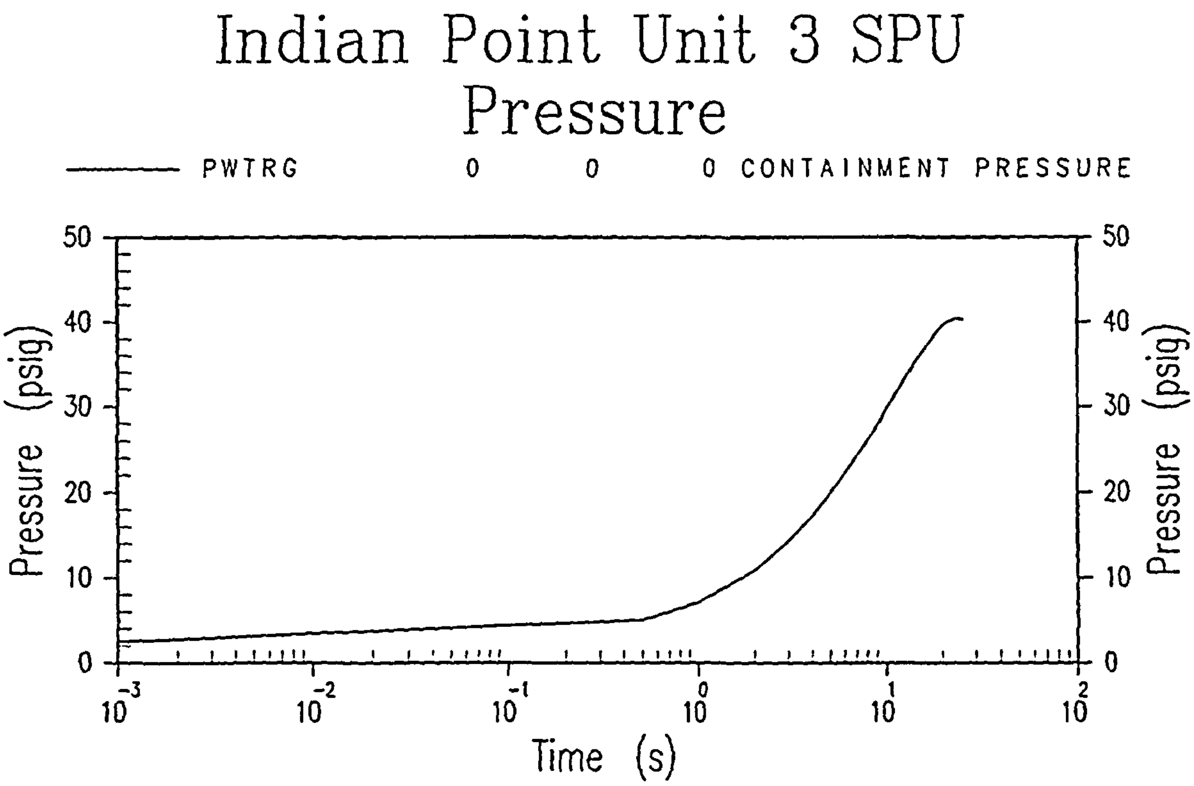

Figure 6.5-5

DEHL Break - Containment Pressure

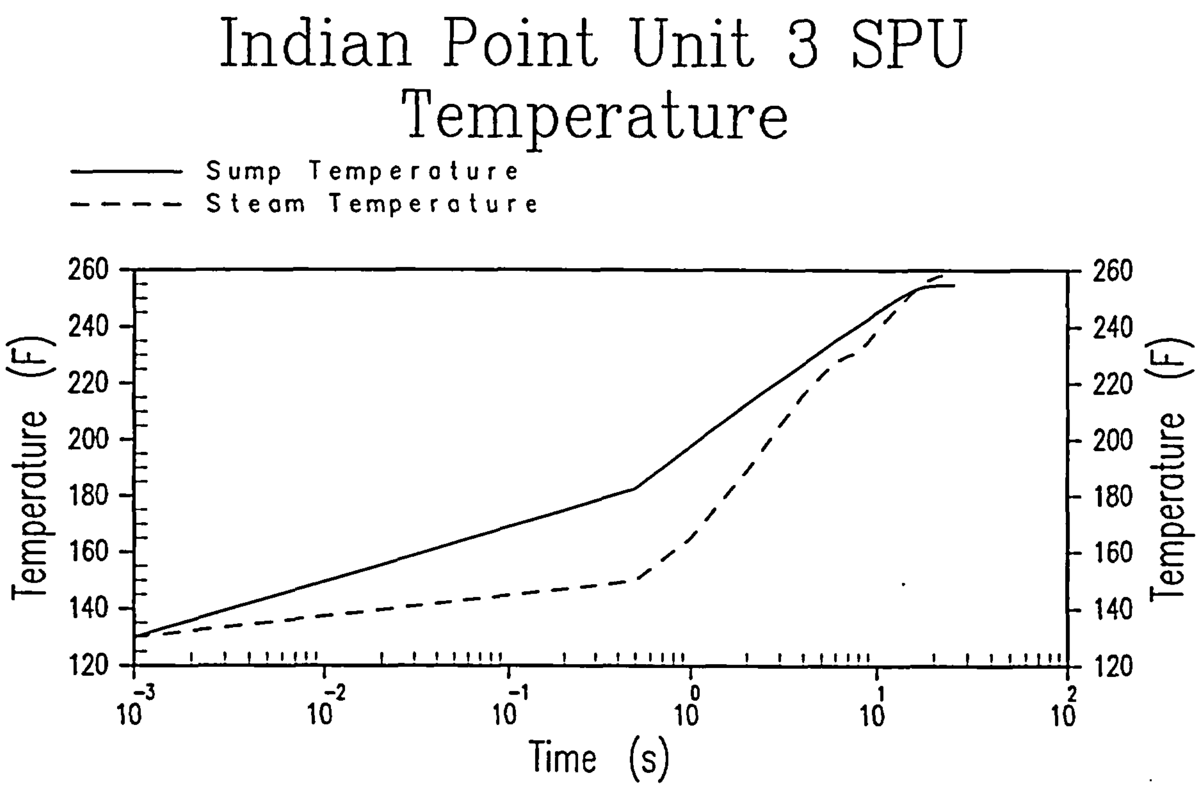

Figure 6.5-6

DEHL Break - Containment Temperature

6.6 Main Steamline Break Inside and Outside Containment

6.6.1 MSLB M&E Releases Inside Containment

6.6.1.1 Introduction

Steamline ruptures occurring inside a reactor containment structure may result in significant releases of high-energy fluid to the containment environment, possibly resulting in high containment temperatures and pressures. The quantitative nature of the releases following a steamline rupture is dependent upon the plant operating conditions, the size of the rupture, the configuration of the plant steam system, and containment building design. The analysis considers a postulated pipe break with limiting consequences, thereby encompassing wide variations in plant operation, safety system performance, and break size in determining the main steamline break (MSLB) mass and energy (M&E) releases for use in containment integrity analysis.

6.6.1.2 Input Parameters and Assumptions

To assess the effects of the M&E releases from a ruptured steamline, the limiting rupture of the main steamline has been evaluated. This analysis returns to the assumption of a 2-percent power uncertainty by assuming 102 percent of Nuclear Steam Supply System (NSSS) power as the initiating condition for the MSLB event. At a plant power level of 102-percent nominal full-load power, a full double-ended rupture (DER) has been analyzed based on the results of the analyses presented in Section 14 of the *IP3 Updated Final Safety Analysis Report* (UFSAR) (Reference 1).

The DER is postulated in one steamline downstream of the steam generator flow restrictor. Note that a DER is defined as a rupture in which the steam pipe is severed and the ends of the break completely displace from each other. The effective break area for IP3 (with Westinghouse Model 44F steam generators) is 1.4 ft^2 because the flow from the steam generator is limited by the steam generator flow restrictor.

The important plant conditions and features that were assumed for the stretch power uprate (SPU) analysis case are discussed in the following paragraphs.

Initial Power Level

This analysis returns to the assumption of a 2-percent power uncertainty by assuming 102 percent of NSSS power as the initiating condition for the MSLB event. Full-power conditions have been investigated for IP3 as presented in the UFSAR (Reference 1).

NSSS power is used in this analysis since the reactor coolant pumps (RCPs) continue to run during the event. Net heat addition is conservatively modeled at 20 MWt (see Table 6.6-1). For the MSLB analysis, it has been demonstrated that the containment response at SPU conditions does not exceed the containment pressure limit of 42.42 psig, as delineated in the *Technical Specifications.*

Initial Plant Conditions

In general, plant initial conditions are assumed to be at their nominal values corresponding to the initial power for that case, with appropriate uncertainties included. Tables 6.6-1 and 6.6-2 identify the values assumed for Reactor Coolant System (RCS) pressure, RCS vessel average temperature, pressurizer water volume, steam generator water level, and feedwater enthalpy at 102-percent uprated power. Steamline break M&E releases assuming an RCS average temperature at the high end of the T_{avg} window are conservative with respect to similar releases at the low end of the T_{avg} window.

Single-Failure Assumptions

The analyzed case considered a single failure of the feedwater control valve (FCV) in the faulted loop. If the FCV in the feedwater line to the faulted steam generator is assumed to fail in the open position, there is a longer period of pumped feedwater flow and the unisolatable volume of feedwater piping is increased. The fluid inventory in this additional unisolatable feedwater piping is available to flash, entering the steam generator as the feedline depressurizes.

Main Feedwater System

The rapid depressurization that occurs following a steamline rupture typically results in large amounts of water being added to the faulted steam generator through the Main Feedwater System. The FCV is a rapid-closing valve that can limit this effect. However, as noted above, it is postulated to fail open in this analysis.

Following initiation of the MSLB, main feedwater flow is conservatively modeled as increasing in response to the decreasing steam pressure. This maximizes the total mass addition prior to feedwater isolation. Following the safety injection (SI) signal, the main feedwater pumps trip. However, condensate pumps continue to run, pumping a reduced feedwater flowrate into the faulted steam generator until the main feedwater pump discharge (BFD-2) valves close 122 seconds after the SI signal.

Following the termination of pumped feedwater, as the steam generator pressure decreases, the fluid in the feedwater lines downstream of the BFD-2 valves will flash when saturated conditions are reached in the feedwater piping. The flashing decreases the density of the feedwater, causing it to enter the faulted steam generator. This additional source of fluid is limited by the closure of the BFD-5 valve in the loop-specific feedline 125 seconds after the SI signal. The BFD-5 valve closure reduces the unisolatable feedline volume and thus limits the additional feedwater mass that enters the faulted steam generator.

Auxiliary Feedwater System

Addition of auxiliary feedwater (AFW) to the steam generators will increase the secondary mass available for release to containment and increase the heat transferred to the secondary fluid. Within the first minute following a steamline break, the Auxiliary Feedwater System (AFWS) is initiated on any one of several protection system signals. The AFW flow to the faulted and intact steam generators has been assumed to be a constant value, based on maximum AFW pump performance. A higher AFW flowrate to the faulted loop steam generator is assumed, consistent with a depressurizing steam generator. Conversely, a lower AFW flowrate to the intact steam generators is assumed, consistent with the intact-loop steam generators remaining at a pressurized condition.

Steam Generator Secondary Side Fluid Mass

A maximum initial steam generator mass in the faulted-loop steam generator was used in the analyzed case. The use of a high faulted-loop initial steam generator mass maximizes the steam generator inventory available for release to containment. The initial mass was calculated as the value corresponding to the programmed level +10-percent narrow-range span (NRS) and assuming 0-percent steam generator tube plugging (SGTP), plus an uncertainty on steam generator water mass.

Steam Generator Reverse Heat Transfer

Once the steamline isolation is complete, the steam generators in the intact loops become sources of energy, which can be transferred to the steam generator with the broken line. This energy transfer occurs via the primary coolant. When the RCS fluid temperature decreases below the secondary side intact steam generator fluid temperature, energy is returned to the primary coolant. This energy is then available for transfer to the steam generator with the broken steamline. The effects of reverse steam generator heat transfer are included in the results.

Break Flow Model

Piping discharge resistances were not included in the calculation of the releases resulting from the steamline ruptures (Moody Curve for an f [L/D] = 0 was used).

Steamline Volume Blowdown

The contribution to the M&E releases from the secondary plant steam piping was included in the M&E release calculations. For the analyzed case, the steamline check valves were credited to prevent break flow from the intact steam generators. Therefore, the M&E available for release from the secondary plant steam piping is limited to that contained in the volume between the faulted steam generator and the steamline check valve. The flowrate was determined using the Moody critical mass flow model.

Main Steamline Isolation

Steamline isolation is not considered, as the steamline check valve in the faulted loop is credited to prevent blowdown from the three intact steam generators.

Protection System Actuations

The protection systems available to mitigate the effects of a MSLB accident inside containment include reactor trip, safety injection, steamline isolation, and feedwater isolation. (Subsequent analysis of the containment response to the MSLB models the operation of the emergency fan coolers and containment spray.) The protection system actuation signals and associated setpoints that were modeled in the analysis are identified in Table 6.6-3. The setpoints used are conservative with respect to the IP3 plant-specific values presented in the *Technical Specifications* (Reference 2).

For the DER MSLB for IP3 at 102-percent power, the first protection system signal actuated is high-1 containment pressure, which initiates safety injection; the SI signal produces a reactor trip signal. Feedwater system isolation occurs as a result of the SI signal.

Safety Injection System

Minimum Emergency Core Cooling System (ECCS) flowrates corresponding to the failure of one ECCS train were assumed in this analysis. A minimum ECCS flow is conservative since the reduced boron addition maximizes a return to power resulting from RCS cooldown. The higher power generation increases heat transfer to the secondary side, maximizing steam flow out of the break. The delay time to start ECCS pumps was assumed to be 16 seconds for this analysis with offsite power available. A coincident loss-of-offsite power (LOOP) is not assumed for the analysis since the assumed LOOP would reduce the M&E releases. This is due to the loss-of-forced reactor coolant flow, which results in a consequential reduction in primary-to-secondary heat transfer.

RCS Metal Heat Capacity

As the primary side of the plant cools, the temperature of the reactor coolant drops below the temperature of the reactor coolant piping, the reactor vessel, and the RCPs. As this occurs, the heat stored in the metal is available to be transferred to the steam generator with the broken line. Stored metal heat does not have a major effect on the calculated M&E releases. The effects of this RCS metal heat are included in the results using conservative thick-metal masses and heat-transfer coefficients.

Core Decay Heat

Core decay heat generation assumed in calculating the steamline break M&E releases was based on the 1979 American National Standard (ANS) decay heat with 2σ uncertainty model (Reference 3).

Rod Control

The Rod Control System was conservatively assumed to be in manual operation for all steamline break analyses. Rods in automatic control would step into the core prior to reactor trip, due to the increased steam flow. This would reduce nuclear power and core heat flux, reducing the primary-to-secondary heat transfer.

Core Reactivity Coefficients

Conservative core reactivity coefficients corresponding to end-of-cycle (EOC) conditions were used to maximize the reactivity feedback effects resulting from the steamline break. Use of maximum reactivity feedback results in higher power generation if the reactor returns to criticality, thus maximizing heat transfer to the secondary side of the steam generators.

6.6.1.3 Description of Analysis

The break flows and enthalpies of the steam release through the steamline break inside containment are analyzed with the LOFTRAN computer code (Reference 4). Blowdown M&E releases determined using LOFTRAN include the effects of core power generation, main and

AFW additions, engineered safeguards systems, RCS thick metal heat storage, and reverse steam generator heat transfer.

The IP3 NSSS is analyzed using LOFTRAN to determine the transient steam M&E releases inside containment following a steamline break event. The M&E releases are used as input conditions to the analysis of the containment response.

The licensing-basis cases of the MSLB inside containment that have been analyzed for the SPU are the full DER at 102-percent power and the full DER at 70-percent power, both with the FCV in the faulted loop assumed to be failed open. Selection of these cases was based on the results of the analyses presented in the IP3 UFSAR, Section 14 (Reference 1).

For the DER cases, the forward-flow cross-sectional area from the faulted-loop steam generator is limited by the integral flow restrictor area of 1.4 ft^2 for IP3 (Model 44F steam generators). Reverse flow from the three intact steam generators is prevented by the steamline check valve located downstream of the break site.

6.6.1.4 Acceptance Criteria

The MSLB is classified as an ANS Condition IV event—an infrequent fault. Additional clarification of the ANS classification of this event is presented in subsection 6.3.11 of this report, which discusses the core response to a steamline break event. The acceptance criterion associated with the steamline break event resulting in an M&E release inside containment is not based on the M&E analysis itself. It is based on an analysis for containment response that provides sufficient conservatism to ensure that the containment design margin is maintained. The containment response analysis is discussed in subsection 6.6.2.

The specific criterion applicable to this analysis is related to the assumptions regarding power level, stored energy, the break flow model including entrainment, main and auxiliary feedwater flow, steamline and feedwater isolation, and single failure such that the containment peak pressure and temperature are maximized. These analysis assumptions have been included in this steamline break M&E release analysis as discussed in Reference 5 and subsection 6.6.1.2 of this report.

The M&E release data for each of the MSLB cases were used as input to a containment response calculation to confirm the design parameters of the IP3 containment structure.

6.6.1.5 Results

Using the UFSAR (Reference 1) as a basis, including parameter changes associated with the SPU, the M&E release rates for the MSLB case noted in subsection 6.6.1.3 were developed for use in containment pressure and temperature response analysis. The containment pressure response was, in turn, used for evaluation of containment integrity. Table 6.6-4 provides the sequence of events for IP3, for the large DER at 102-percent power and 70-percent power with feedwater control valve failure assumed.

6.6.1.6 Conclusions

The M&E releases from the MSLB case have been analyzed at the SPU power conditions. The assumptions discussed in subsection 6.6.1.2 have been included in the MSLB analysis such that the applicable acceptance criteria are met. The M&E releases discussed in this section have been provided for use in the containment response analysis (see subsection 6.6.2) in support of the IP3 SPU.

6.6.2 Steamline Break Containment Response Evaluation

6.6.2.1 Introduction

The IP3 containment systems are designed such that for all steamline break sizes, up to and including the double-ended severance of a steamline, the containment peak pressure remains below the design pressure. This section details the containment response subsequent to a hypothetical steamline break. The containment response analysis uses the long-term M&E release data from subsection 6.6.1.5.

6.6.2.2 Input Parameters and Assumptions

The pressure, temperature, and humidity of the containment atmosphere prior to the postulated accident are specified in the analysis as shown in Table 6.6-5.

Also, values for the refueling water storage tank (RWST) temperature have been specified, along with containment spray (CS) pump flowrate and reactor containment fan cooler (RCFC) heat removal performance. These values are chosen conservatively, as shown in Tables 6.6-5, 6.6-6 and 6.6-7. The heat sink modeling is specified in Tables 6.6-8 and 6.6-9, and is consistent with the values used for the LOCA containment response analysis, as documented in Section 6.5 of this document.

Subsection 6.6.1.5 discusses the M&E releases for the SPU MSLB case. The M&E release analysis includes the single failure of the faulted-loop FCV, as discussed in subsection 6.6.1.2. Since a single failure is included in the M&E release analysis, no single failure is modeled in the containment response analysis.

6.6.2.3 Description of Analysis

Calculation of containment pressure and temperature is accomplished by using the computer code COCO (Reference 6). COCO is a mathematical model of a generalized containment; the proper selection of various options in the code allows the creation of a specific model for a particular containment design. The values used in the specific model for different aspects of the containment are derived from plant-specific input data. The COCO code has been used and found acceptable to calculate containment pressure and temperature transients for previous IP3 containment response analyses.

6.6.2.4 Acceptance Criteria

The design basis MSLB is an ANS Condition IV event—an infrequent fault. To satisfy the NRC acceptance criteria presented in the IP3 UFSAR, Revision 18 (Reference 1) for long-term containment response, the relevant General Design Criteria (GDC) (Reference 7) requirements are listed below.

GDC 16, Containment Design

To satisfy the requirements of GDC 16, the peak calculated containment pressure must be less than the containment design pressure of 47 psig for IP3. Additionally, the peak containment pressure must be less than the integrated leak rate test (ILRT) limit of 42.42 psig.

GDC 38, Containment Heat Removal

To satisfy the requirement of GDC 38, the calculated pressure at 24 hours must be less than 50 percent of the peak calculated value.

6.6.2.5 Analysis Results

The peak containment pressure is listed in Table 6.6-10 uprated full-power case with offsite power available. The containment pressure curves for 102- and 70-percent power steamline break are provided in Figures 6.6-1 and 6.6-2.

6.6.2.6 Conclusions

An evaluation of the MSLB containment pressure response has been performed as part of the IP3 SPU. The analysis included the long-term pressure profile for the limiting case. The analyzed case results in a peak containment pressure that is less than the containment design pressure of 47 psig, as well as below the ILRT limit of 42.42 psig. The long-term pressures are well below 50 percent of the peak value within 24 hours. Based on these results, the GDC criteria for IP3 have been met.

6.6.3 MSLB M&E Releases Outside Containment Responses

6.6.3.1 Introduction

MSLBs outside the Containment Building were considered for the IP3 SPU to define conditions for equipment qualification (EQ) for electrical equipment that is needed to mitigate the consequences of high-energy line breaks (HELBs) and is located near the steam and feed penetration area.

Steamline ruptures occurring outside the reactor containment structure may result in significant releases of high-energy fluid to the structures surrounding the steam systems. Superheated steam blowdowns following the steamline break have the potential to raise compartment temperatures outside containment. Early uncovery of the steam generator tube bundle maximizes the enthalpy of the superheated steam that is released. The effect of the steam release depends on the plant configuration at the time of the break, plant response to the break, and the size and location of the break. Because of the interrelationship among many of the factors that influence steamline break M&E releases, an appropriate determination of a single limiting case with respect to M&E releases cannot be made. Therefore, it was necessary to analyze the steamline break event outside containment for a range of conditions. The resulting M&E releases were used as input to the Auxiliary Building temperature analysis (see subsection 6.5.2.7) for equipment environmental qualification (see subsection 10.9.3 of this document).

6.6.3.2 Input Parameters and Assumptions

To determine the effects of NSSS power level and break area on M&E releases from a ruptured steamline, spectra of both variables were evaluated as part of the methodology development program documented in WCAP-10961 (Reference 8). At 102 and 70 percent of NSSS power levels, various break sizes were analyzed, ranging from 0.1 ft^2 to 4.6 ft^2.

A full-break spectrum at both power levels (102 and 70 percent) has been analyzed at the SPU conditions for IP3. Other assumptions regarding important plant conditions and features are discussed in the following paragraphs.

Initial Power Level

The initial power assumed for steamline break analyses outside containment affects the M&E releases and steam generator tube bundle uncovery in two ways. First, the steam generator mass inventory increases with decreasing power levels. This will tend to delay uncovery of the steam generator tube bundle, although the increased steam pressure at lower power levels will cause faster blowdown at the beginning of the transient. Second, the amount of stored energy and decay heat, as well as feedwater temperature, are less for lower power levels. This will result in lower primary temperatures and less primary-to-secondary heat transfer during the steamline break event.

Therefore, the following power levels were analyzed:

- Full power - maximum NSSS power (3230 MWt based on 3216 MWt plus 14 MWt for RCP heat addition) plus uncertainty, that is, 102 percent of rated NSSS power
- Near full-power - 70 percent of maximum NSSS power

For this IP3 SPU analysis, the power levels and steamline break sizes are noted in subsection 6.6.3.3 of this report.

In general, plant initial conditions were assumed to be the nominal values corresponding to the initial power for that case, with appropriate uncertainties included. Table 6.6-11 lists nominal 100-percent power NSSS conditions. Table 6.6-12 lists initial plant condition assumptions for the cases analyzed.

Steamline break mass releases and superheated steam enthalpies assuming an RCS average temperature at the high end of the T_{avg} window are conservative with respect to similar releases at the low end of the T_{avg} window. At the high end, the calculated values of the superheated steam enthalpy available for release outside containment are larger than at the low end. The thermal design flowrate has been used for the RCS flow input. This is consistent with the assumptions documented in Reference 5 and with other MSLB analysis assumptions related to nonstatistical treatment of uncertainties and RCS thermal-hydraulic inputs related to pressure drops and rod drop time.

Uncertainties on the initial conditions assumed in the analysis for the SPU have been applied only to RCS average temperature (7.5°F), steam generator mass (10-percent NRS), and power fraction (2 percent) at full power. Nominal values are adequate for the initial pressurizer pressure and water level. Uncertainty conditions were only applied to those parameters that could increase the enthalpy of superheated steam discharged from the break.

Single-Failure Assumptions

The steamline break analyses outside containment were designed to encompass the failure of one AFW pump and an additional conservative failure of the main steamline isolation valve (MSIV) in the loop with the faulted steamline.

The first single failure is one AFW pump resulting in minimum AFW flow to the steam generators. Variations in AFW flow can affect steamline break M&E releases in a number of ways, including break mass flowrate, RCS temperature, tube bundle uncovery time, and steam superheating. The minimum AFW flow used in the analysis was conservatively based on only one motor-driven AFW pump.

The second failure is the MSIV in the loop with the faulted steamline. This permits blowdown of the entire mass inventory of the steam generator in the loop with the faulted steamline. This failure was limited to the steamline with the postulated break.

Main Feedwater System

The rapid depressurization that occurs following a steamline rupture results in large amounts of water being added to the steam generators through the Main Feedwater System. However, main feedwater flow has been conservatively modeled by assuming no increase in feedwater flow in response to the increased steam flow following the steamline break. This minimizes total mass addition and the associated cooling effects in the steam generators, which causes the earliest onset of superheated steam released from the break.

Isolation of main feedwater flow was conservatively assumed to be coincident with reactor trip, irrespective of the function that produced the trip signal. This assumption reduces the total mass addition to the steam generators. The main feedwater flow isolation valves were assumed to close instantaneously with no consideration of associated signal processing or valve stroke time.

Auxiliary Feedwater System

Within the first few minutes following a steamline break, AFW is initiated on one of several protection system signals. Addition of AFW to the steam generators will increase the secondary mass available to cover the tube bundle and reduce the amount of superheated steam produced. For this reason, AFW flow is minimized while the actuation delay is maximized to accentuate depletion of the initial secondary side inventory.

The volume of the AFW piping up to the isolation valve closest to the steam generator was maximized and purging of the AFW piping was assumed. This maximizes the amount of preheated water resident in the AFW piping and ensures that this preheated water was injected into the steam generator first. The less dense resident AFW decreases initial mass addition to the faulted-loop steam generator. The large volume also delays the introduction of colder AFW into any steam generator, which reduces the cooldown effect on the primary side of the RCS. AFW assumptions used in the analysis are presented in Table 6.6-13.

Steam Generator Fluid Mass

A minimum initial fluid mass in all steam generators has been used in each of the analyzed cases. This minimizes the capability of the heat sink afforded by the steam generators and leads to earlier tube bundle uncovery. The initial mass has been calculated as that corresponding to the programmed water level, minus 10-percent NRS, minus a mass uncertainty. All steam generator fluid masses were calculated assuming 0-percent SGTP. This assumption is conservative with respect to the RCS cooldown through the steam generators resulting from the steamline break.

Steam Generator Reverse Heat Transfer

Once steamline isolation is complete, the steam generators in the intact loops become sources of energy that can be transferred to the steam generator with the broken steamline via the primary coolant. When the RCS fluid temperature decreases below the secondary side intact steam generator fluid temperature, energy is returned to the primary coolant. This energy is then available to be transferred to the steam generator with the broken steamline. When applicable, the effects of reverse steam generator heat transfer were included in the results.

Break Flow Model

The flow rate from the break is maximized by assuming a critical flow rate for saturated steam based on the Moody correlation for f[L/D]=0. The upstream pressure is based on the steam generator pressure, with no credit for line losses or piping discharge resistance. The downstream pressure is assumed to be atmospheric throughout the blowdown.

Steamline Volume Blowdown

There is no contribution to M&E releases from the steam in the secondary plant loop piping and header because the initial volume is saturated steam. With the focus of the MSLB analysis outside containment on maximizing superheated steam enthalpy, it is presumed that the saturated steam in the loop piping and header has no adverse effects on the results. The blowdown of steam in this volume serves to delay the time of tube uncovery in the steam generators and is conservatively ignored.

Main Steamline Isolation

Steamline isolation was assumed to terminate blowdown from the intact-loop steam generators for the header break cases. The main steamline isolation function was accomplished via the closure of the MSIVs on the intact loops. The MSIV actuation signal is generated if the following setpoints are reached in at least two loops:

- Low steamline pressure coincident with high steam flow, or
- Low-low T_{avg} coincident with high steam flow.

A delay time of 7 seconds, accounting for delays associated with signal processing plus MSIV stroke time, has been assumed. Unrestricted steam flow through the valve during valve stroke has been assumed. Operator action to close MSIVs is credited at 600 or 900 seconds if the setpoints for steamline isolation are not reached. The Analysis of Record assumed an operator action time of 600 seconds.

For loop break cases, the faulted-loop steamline check valve was assumed to prevent blowdown from the three intact steam generators. Closure of the MSIVs does not have an impact on the loop break cases in the analysis.

Protection System Actuations

The protection systems available to mitigate the effects of a MSLB outside containment include reactor trip, SI, steamline isolation, and AFW injection. The protection system actuation signals and associated setpoints that were modeled in the analysis are identified in Table 6.6-14. The setpoints are conservative values with respect to the plant-specific values delineated in the IP3 *Technical Specifications* (Reference 2).

Tables 6.6-15 through 6.6-22 provide the protection system actuation times for the various steamline break sizes for IP3, at 102- and 70-percent NSSS power.

In all cases, the turbine stop valve was assumed to close instantly following the reactor trip signal.

Safety Injection System

Minimum ECCS flowrates corresponding to failure of one ECCS train have been assumed in this analysis. Minimum ECCS flow is conservative since the reduced boron addition maximizes a return to power resulting from RCS cooldown. The return to power increases heat transfer to the secondary side, maximizing steam flow from the break. The delay time to achieve full SI flow was assumed to be 15 seconds for this analysis with offsite power available. A coincident LOOP was not assumed for the analysis since the M&E releases would be reduced due to loss-of-forced reactor coolant flow, resulting in less primary-to-secondary heat transfer.

RCS Metal Heat Capacity

As the primary side of the plant cools, the reactor coolant temperature drops below that of the reactor coolant piping, reactor vessel, RCPs, and steam generator thick-metal mass and tubing. As this occurs, the heat stored in the metal is available to be transferred to the steam generator with the broken line. Stored metal heat does not have a major effect on the calculated M&E releases, but the effects were included in the results using conservative thick-metal masses and heat transfer coefficients.

Core Decay Heat

Core decay heat generation assumed in calculating steamline break M&E releases was based on the 1979 ANS decay heat with 2σ uncertainty model (Reference 3).

Rod Control

The Rod Control System was conservatively assumed to be in manual operation for all steamline break analyses. Rods in automatic control would step in prior to reactor trip due to the increase in steam flow, reducing nuclear power and core heat flux. However, sensitivity analyses performed when WCAP-10961 (Reference 8) was written, investigating the effects on steamline break M&E releases of manual versus automatic rod control, have shown negligible effect on calculated results.

Core Reactivity Coefficients

Conservative core reactivity coefficients corresponding to EOC conditions were used to maximize reactivity feedback effects resulting from the steamline break. This results in higher power generation should the reactor return to criticality, thus maximizing heat transfer to the secondary side of the steam generators.

6.6.3.3 Description of Analysis

The system transient that provides the break flows and enthalpies of the steam release through the steamline break outside containment has been analyzed with the LOFTRAN (Reference 4) computer code. Blowdown M&E releases determined using LOFTRAN include the effects of core power generation, main feedwater and auxiliary feedwater additions, engineered safeguards systems, RCS thick-metal heat storage, and reverse steam generator heat transfer. The use of the LOFTRAN code for analysis of the MSLB with superheated steam M&E releases is documented in Supplement 1 of WCAP-8822 (Reference 5), which has been reviewed and approved by the NRC for use in analyzing MSLBs. LOFTRAN was also used in WCAP-10961 (Reference 8) for MSLBs outside containment.

The IP3 NSSS has been analyzed to determine the transient mass releases and associated superheated steam enthalpy values outside containment following a steamline break event. The resulting tables of mass flowrates and steam enthalpies were used as input conditions to the calculation of outside-containment compartment conditions (see subsection 6.6.4) for the environmental evaluation of safety-related electrical equipment.

The following cases of the MSLB outside containment were analyzed at the noted conditions for the SPU.

- At 102-percent power, break sizes of 4.6, 2.0, 1.4, 1.2, 1.0, 0.9, 0.8, 0.7, 0.6, 0.5, 0.4, 0.3, 0.2, and 0.1 ft^2
- At 70-percent power, break sizes of 4.6, 2.0, 1.4, 1.2, 1.0, 0.9, 0.8, 0.7, 0.6, 0.5, 0.4, 0.3, 0.2, and 0.1 ft^2

Each MSLB outside containment was represented as a non-mechanistic split rupture (crack area). The largest break was postulated as a crack area equivalent to a single-ended pipe rupture. The break flowrate was limited by the total cross-sectional flow area of the steam pipe;

the maximum break size was limited to the header break size of 4.6 ft^2. Prior to steamline isolation, the break area was represented by the spectrum noted above. After steamline isolation, the break area was limited by the area of the integral steam generator flow restrictor (1.4 ft^2).

6.6.3.4 Acceptance Criteria

The acceptance criteria associated with the steamline break event resulting in an M&E release outside containment are based on an analysis that provides sufficient conservatism to ensure that the equipment remains qualified for the temperature and pressure profiles from the compartment analyses. The specific criteria applicable to this analysis are related to the assumptions regarding power level, stored energy, break flow model, steamline and feedwater isolation, and main and auxiliary feedwater flow such that superheated steam resulting from tube bundle uncovery in the steam generators is accounted for and maximized. These assumptions have been included in this steamline break M&E release analysis as discussed in subsection 6.6.3.2 of this report. The tables of mass flowrates and steam enthalpy values for each of the steamline break cases analyzed were used as input to calculation of outside-containment compartment conditions (see subsection 6.6.4) for the environmental evaluation of safety-related electrical equipment.

6.6.3.5 Results

Using the MSLB analysis methodology documented in WCAP-10961 (Reference 8) as a basis, including parameter changes associated with the SPU, the M&E release rates for each steamline break case have been developed for use in calculating outside-containment compartment conditions for the environmental evaluation of safety-related electrical equipment. Tables 6.6-15 through 6.6-22 provide the sequences of events for the various steamline break sizes for IP3, at 102- and 70-percent NSSS power.

6.6.3.6 Conclusions

The mass releases and associated steam enthalpy values from the spectrum of steamline break cases outside containment have been analyzed at the conditions defined by the IP3 SPU. The assumptions discussed in subsection 6.6.3.2 have been included in the analysis such that conservative M&E releases were calculated. The resulting mass releases and associated steam enthalpy values have been provided for use in the calculation of outside-containment compartment conditions (see subsection 6.6.4) for the environmental evaluation of safety-related electrical equipment outside containment in support of the IP3 SPU.

6.6.4 MSLB Outside Containment Compartment Response

6.6.4.1 Introduction

This section of the report presents the results of a study to determine the effects of superheated steam releases, during postulated main steamline ruptures, on outside containment equipment qualification for IP3. For this study, the compartment temperature profiles for the steam and feed penetration area were calculated as required by 10CFR50.49 (Reference 9).

NRC IE Information Notice 84-90, *Main Steam Line Break Effect on Environmental Qualification of Equipment*, (Reference 10) informed licensees of potential issues related to the release of superheated steam following a postulated MSLB. Specifically, such superheated blowdowns have the potential to raise the compartment temperatures and, therefore, the equipment surface and internal temperatures, above those originally used for the environmental qualification of such equipment needed to mitigate the consequences of HELBs.

The report describes the methods and assumptions used in modeling the IP3 compartments in the steam and feed penetration area. The M&E releases from the postulated MSLBs were discussed in subsections 6.6.3.1 through 6.6.3.6. The results from these calculated compartment temperature profiles are discussed here.

6.6.4.2 Input Parameters and Assumptions

This study used MSLB M&E releases (see subsections 6.6.3.1 through 6.6.3.6) in calculations of the outside containment compartment temperatures resulting from those releases. The RCS conditions used for determining the steamline break M&E releases were described in subsection 6.6.3.2. The compartment model was developed for the GOTHIC code (Reference 11) from engineering drawings and plant information.

Some ventilation louvers in the steam and feed penetration area are closed and covered during winter conditions. Because of this difference and because of the different temperature and humidity conditions for winter and summer, cases were divided into winter and summer conditions. Table 6.6-23 provides the GOTHIC initial conditions for the winter and summer cases.

6.6.4.3 Description of Analysis

This analysis of the temperature and pressure response in the steam and feed penetration area was performed with the GOTHIC code. The M&E releases for loop breaks at 102- and 70-percent power and header breaks at 102- and 70-percent power were provided by the analysis discussed in subsections 6.6.3.1 through 6.6.3.6 at the SPU conditions. The compartment response was determined for two sets of initial temperature conditions, winter and summer. In addition to the initial temperature and relative humidity, the cases for the winter and summer conditions also modeled several louvers differently. The louvers were modeled as closed for both the winter and summer conditions, but for the winter, Entergy covers the louvers in order to reduce the possibility of freezing in the compartment. The compartment response for limiting breaks was calculated for a period of 30,000 seconds. This duration was sufficient to ensure that the compartment and component (thermal lag) temperatures decrease to below the initial conditions.

6.6.4.4 Acceptance Criteria

The acceptance criteria for the outside containment compartment temperature evaluation was defined for the EQ program at IP3 as the qualification limits for each piece of equipment because each piece of equipment has its own qualification conditions. The peak temperature in the compartment and the duration at elevated temperatures are of interest for the EQ program. (Refer to subsection 10.9.3 of this report for the EQ discussion.)

6.6.4.5 Results

The M&E releases for IP3 were provided by the analysis in subsections 6.6.3.1 through 6.6.3.6 at the SPU conditions.. These cases were analyzed for IP3 at initial conditions for winter and initial conditions for summer.

The computer simulations performed for the M&E release analysis were run assuming operator action times of 600 and 900 seconds to terminate AFW flow and close the MSIVs. The limiting winter break was a 1.2-ft^2 header break at 102-percent power, which generated a peak area temperature of about 481°F and the limiting summer break was a 1.4-ft^2 header break at 102-percent power, which generated a peak area temperature of about 484°F. The area temperatures returned to near initial conditions within 4 hours for the bounding winter case, and 3 hours for the bounding summer case.

6.6.4.6 Conclusions

Since these results were used for EQ, the temperature and pressure profiles for each case were provided for the EQ evaluations.

The limiting temperature profile and corresponding pressure profiles for the 600-second (10-minute) operator action time are provided in Figures 6.6-3 and 6.6-4 for winter and summer conditions. The limiting temperature profile and corresponding pressure profile for the 900-second (15-minute) operator action time are provided in Figures 6.6-5 and 6.6-6 for winter and summer conditions. Section 10.9.3 of this report uses the individual case profiles to address the qualification of the equipment for IP3 at the SPU conditions.

6.6.5 Steam Releases for Radiological Dose Analysis

The vented steam releases have been calculated for the locked rotor and steamline break events. Table 6.6-24 summarizes the vented steam releases from the operable steam generators as well as auxiliary feedwater flows for the 0- to 2-hour time period, and the 2- to 29-hour time period for each of these events.

The steam releases discussed in this section have been provided as inputs to the radiological dose analyses (see subsection 6.11.9) in support of the IP3 SPU.

6.6.6 References

1. *Indian Point Nuclear Generating Unit No. 3, Updated Final Safety Analysis Report*, Rev. 18, Docket No. 50-286.

2. *Indian Point Unit 3 Technical Specifications, Amendment 205.*

3. ANSI/ANS-5.1-1979, *American National Standard for Decay Heat Power in Light Water Reactors*, The American Nuclear Society Standards Institute, Inc., LaGrange Park, Illinois, August 1979.

4. WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Nonproprietary), *LOFTRAN Code Description*, T. W. T. Burnett, et al., April 1984.

5. WCAP-8822 (Proprietary) and WCAP-8860 (Nonproprietary), *Mass and Energy Releases Following a Steam Line Rupture*, September 1976; WCAP-8822-S1-P-A (Proprietary) and WCAP-8860-S1-A (Nonproprietary), *Supplement 1 – Calculations of Steam Superheat in Mass/Energy Releases Following a Steam Line Rupture*, September 1986; WCAP-8822-S2-P-A (Proprietary) and WCAP-8860-S2-A (Nonproprietary), *Supplement 2 – Impact of Steam Superheat in Mass/Energy Releases Following a Steam Line Rupture for Dry and Subatmospheric Containment Designs*, September 1986.

6. WCAP-8327 (Proprietary), WCAP-8326 (Nonproprietary), *Containment Pressure Analysis Code (COCO), July 1974.*

7. 10CFR50 Appendix A, *General Design Criteria for Nuclear Power Plants.*

8. WCAP-10961 (Proprietary), *Steamline Break Mass/Energy Releases for Equipment Environmental Qualification Outside Containment, Report to the Westinghouse Owners Group High Energy Line Break/Superheated Blowdowns Outside Containment Subgroup*, Rev. 1, October 1985.

9. 10CFR50.49, *Environmental Qualification Of Electric Equipment Important To Safety For Nuclear Power Plants*, 66FR64738, December 14, 2001.

10. NRC IE Information Notice 84-90, *Main Steam Line Break Effect on Environmental Qualification of Equipment*, December 07, 1984.

11. NAI 8907-02, *GOTHIC Containment Analysis Package User Manual*, Version 7.1, Rev. 14, January 2003.

Table 6.6-1

Nominal Plant Parameters for IP3 SPU[1]
(MSLB M&E Releases Inside Containment)

Nominal Conditions	IP3
NSSS Power, MWt	3230
Core Power, MWt	3216
Net Heat Addition, MWt	20[2]
Reactor Coolant Flow (total), gpm	354,400
Pressurizer Pressure, psia	2250
Core Bypass, %	5.5 – 7.5
Reactor Coolant Temperatures, °F	
Core Outlet	607.5
Vessel Outlet	603.0
Core Average	575.8
Vessel Average	572.0
Vessel/Core Inlet	541.0
Steam Generator	
Steam Temperature, °F	516.3
Steam Pressure, psia	787
Steam Flow (total), 10^6 lbm/hr	14.01
Feedwater Temperature, °F	433.6

Note:

1. Noted values correspond to plant conditions defined for 0% SGTP and the high end of the RCS T_{avg} window.
2. 14 MWt RCP heat addition was used for MSLB M&E analyses to determine NSSS power. A net heat addition of 20 MWt is conservatively assumed as additional energy that must be released through the faulted steam generator.

Table 6.6-2 IP3 Initial Condition Assumptions for SPU[1]	
MSLB M&E Releases Inside Containment	
Parameter	**Value**
NSSS Power (% Nominal Uprated)	102
RCS Average Temperature (°F)	579.5
RCS Flowrate (gpm)	354,400
RCS Pressure (psia)	2250
Pressurizer Water Volume (ft^3)	916.7 (102% Power) 777.23 (70% Power)
Feedwater Enthalpy (Btu/lbm)	412.3 (102% Power) 377.3 (70% Power)
SG Water Level (% span)	55

Note:

1. Noted values correspond to plant conditions defined for 0% SGTP and the high end of the RCS T_{avg} window; the temperature includes the applicable calorimetric uncertainties.

Table 6.6-3 Protection System Actuation Signals and Safety System Setpoints for IP3 SPU Analysis	
MSLB M&E Releases Inside Containment	
Safety Injection High-1 Containment Pressure: 5.12 psig	Conservatively high value used SI signal results in reactor trip, feedwater isolation, and actuation of the RCFCs
Containment Sprays High-High Containment Pressure: 24.62 psig	Conservatively high value used

Table 6.6-4 1.4 ft² MSLB With FCV Failure Assumed Sequence of Events for IP3 SPU		
Time (sec)		**Event Description**
102% Power	**70% Power**	
0.0	0.0	MSLB occurs
4.0	3.8	SI setpoint reached on high-1 containment pressure
5.0	5.0	SI setpoint (high-1 containment pressure) credited in mass/energy calculation Start of AFW
7.0	7.0	Rod motion starts (high containment pressure actuates SI, which initiates reactor trip) Intact loop FCVs close
12.0	12.0	Main feedwater pumps trip
22.0	22.0	MFW pumps stopped; continued flow from condensate pumps
42.2	42.0	Fan coolers start
129.0	129.0	BFD-2 feedwater pump discharge valve closes (following SI signal)
132.0	132.0	BFD-5 feedwater block valve closes (following SI signal)
144.4	150.7	Containment sprays start (high-2 containment pressure of 24.62 psig)
248.2	254.0	Secondary side of steam generator tubes start to uncover in faulted steam generator
271.0	294.5	Peak containment pressure
1800.0	1800.0	Operator terminates AFW to faulted steam generator
1803.0	1803.0	Break releases stop

Table 6.6-5

MSLB Containment Response Analysis Initial Containment Conditions and Parameters

RWST Water Temperature (°F)	110
Initial Containment Temperature (°F)	130
Initial Containment Pressure (psia) Maximum	 17.2
Initial Relative Humidity (%)	20
Net-Free Volume (ft^3)	2.61×10^6
Number of Containment Air Recirculation Fan Coolers	5
Number of Containment Spray Pumps	2

Table 6.6-6 Reactor Containment Fan Cooler Performance	
Containment Temperature (°F)	**Heat Removal Rate [Btu/sec] Per RCFC**
110	674
130	1737
150	2921
170	4162
190	5425
210	6684
230	8836
250	10986
271	13042

Table 6.6-7 Containment Spray Performance	
Containment Pressure (psig)	**Spray Flow Rate (gpm)**
5.0	4819.4
10.0	4735.0
20.0	4561.8
30.0	4375.0
35.0	4278.6
40.0	4180.2
45.0	4080.2
50.0	3977.8

Table 6.6-8

Containment Heat Sinks

No.	Material	Thickness (ft)	Surface Area (ft^2)
1	Carbon Steel Concrete	0.03125 1.0	41302
2	Carbon Steel Concrete	0.04167 1.0	28613
3	Concrete	1.0	15000
4	Stainless Steel Concrete	0.03125 1.0	10000
5	Concrete	1.0	61000
6	Carbon Steel	0.0417	68792
7	Carbon Steel	0.03125	81704
8	Carbon Steel	0.02083	27948
9	Carbon Steel	0.015625	69800
10	Carbon Steel	0.01042	3000
11	Carbon Steel	0.0115	22000
12	Carbon Steel	0.0052	10000
Coatings	Paint	0.000625	Equal to carbon steel surface area

Table 6.6-9

Thermo-physical Properties of Containment Heat Sinks

Material	Thermal Conductivity (Btu/hr-ft - °F)	Volumetric Heat Capacity (Btu/ft^3 - °F)
Paint	0.2083	36.86
Carbozinc	0.9	28.8
Carbon Steel	26.0	56.35
Stainless Steel	8.6	56.35
Concrete	0.8	28.8

Table 6.6-10 MSLB Peak Containment Pressure for IP3		
Break	**Single Failure**	**Peak Pressure @ Time (sec)**
Full DER, 102% Power	FCV	38.14 psig @ 271.0 sec
Full DER, 70% Power	FCV	39.2 psig @ 304.2 sec

Table 6.6-11

Nominal Plant Parameters for SPU[1]
(MSLB M&E Releases Outside Containment)

Nominal Conditions	
NSSS Power, MWt	3230.0[2]
Core Power, MWt	3216.0
Net Heat Addition, MWt	20[2]
Reactor Coolant Flow (total), gpm TDF	322,800
Pressurizer Pressure, psia	2250
Core Bypass, %	6.5
Reactor Coolant Vessel Average Temperature, °F	572.0[1]
Steam Generator	
Steam Temperature, °F	516.3
Steam Pressure, psia	787
Steam Flow, 10^6 lbm/hr (plant total)	14.01
Feedwater Temperature, °F	433.6
Zero-Load Temperature, °F	547

Notes:

1. Noted values correspond to plant conditions defined by 0% SGTP and the high end of the RCS T_{avg} window.
2. 14 MWt RCP heat addition was used for MSLB M&E analyses to determine NSSS power. A net heat addition of 20 MWt is conservatively assumed as additional energy that must be released through the faulted steam generator.

Table 6.6-12 Initial Condition Assumptions for SPU[1] (MSLB M&E Releases Outside Containment)		
Initial Conditions	**102% Power**	**70% Power**
RCS Average Temperature (°F)	579.5[1]	572[1]
RCS Flowrate (gpm TDF)	354,400	354,400
RCS Pressure (psia)	2250	2250
Pressurizer Water Volume (ft^3)	916.7	777.23
Feedwater Enthalpy (Btu/lbm)	412.2	377.2
Steam Generator Pressure (psia)[2]	787	787
Steam Generator Water Level (% NRS)	35	35

Notes:

1. Noted values correspond to plant conditions defined by 0% SGTP and the high end of the RCS T_{avg} window; temperatures include applicable calorimetric uncertainties.
2. The noted steam generator pressures were determined at the steady-state conditions defined by the RCS average temperatures, including applicable uncertainties.

Table 6.6-13 **Main and AFWS Assumptions for SPU (MSLB M&E Releases Outside Containment)**	
Main Feedwater System	
Flowrate – Both Power Levels (102% and 70%)	Nominal flow to all loops
Unisolable Volume from Steam Generator Nozzle to MFIV (all loops)	None assumed
AFW	
One motor-driven pump split evenly between faulted steam generator and one intact steam generator (Other MD AFW pump assumed to fail; no AFW to other two steam generators)	343 gpm
Manual Isolation Assumption	600 and 900 seconds (1)
Temperature (maximum value)	120°F
Piping Volume (faulted loop)	268.8 ft^3
Actuation Delay Time	60 seconds

Note:
1. See subsection 6.6.4.5 for discussion of use of 600 or 900 seconds.

Table 6.6-14

Protection System Actuation Signals and Safety System Setpoints for SPU (MSLB M&E Releases Outside Containment)

Reactor Trip

Low-Low Steam Generator Water Level in any loop – 0% NRS

Low-Pressurizer Pressure – 1748.7 psia

Overtemperature ΔT $K_1 = 1.42$ $K_2 = 0.022$ $K_3 = 0.00070$

Dynamic Compensation lead – 25 seconds
lag – 3 seconds

Overpower ΔT $K_4 = 1.164$ $K_5 = 0.0$ $K_6 = 0.0015$

Dynamic Compensation rate lag – 10 seconds

Safety Injection

Low-Pressurizer Pressure – 1648.7 psia
Low-Steamline Pressure in any Loop – 435 psia

Steamline Isolation

Low-Steamline Pressure in any Loop – 435 psia coincident with High Steam Flow

Feedwater Isolation

Reactor Trip (conservative assumption)

AFW Initiation

Low-Low Steam Generator Water Level in any Loop – 0% NRS
SI

Table 6.6-15

Summary of System Actuations for IP3 MSLB Outside Containment Header Breaks, Full Power

Break Size (ft^2, before/ after steamline isolation)	Reactor Trip		SI[1]		MSIV Closure		AFW			Time-Faulted Steam Generator Tubes Uncover (sec)	Time-Break Releases Stop (sec)
	Signal	Time Rod Motion Starts (sec)	Signal	Time of Signal (sec)	Signal	Time Fully Closed (sec)	Signal	Time Flow Starts (sec)	Time Flow Stops (sec)		
0.1 / 0.1	LSGWL	247	HSΔP	745	Manual	600.0	LSGL	305	600.0	701	984
0.2 / 0.2	LSGWL	128	LPP	513	Manual	600.0	LSGL	186	600.0	414[2]	761
0.3 / 0.3	LSGWL	88	LPP	307	Manual	600.0	LSGL	146	600.0	301[2]	652
0.4 / 0.4	LSGWL	67	LPP	222	Manual	600.0	LSGL	125	600.0	238[2]	620
0.5 / 0.5	OPΔT	31	LPP	151	Manual	600.0	LSGL	105	600.0	201[2]	613
0.6 / 0.6	OPΔT	25	LPP	123	Manual	600.0	LSGL	99	600.0	173[2]	609
0.7 / 0.7	OPΔT	22	LPP	104	Manual	600.0	LSGL	94	600.0	153[2]	607
0.8 / 0.8	OPΔT	20	LPP	91	Manual	600.0	LSGL	90	600.0	137[2]	605
0.9 / 0.9	OPΔT	19	LPP	80	Manual	600.0	LSGL	88	600.0	125[2]	605
1.0 / 1.0	OPΔT	18	LPP	72	Manual	600.0	LSGL	86	600.0	116[2]	604
1.2 / 1.2	OPΔT	16	LPP	60	Manual	600.0	LSGL	82	600.0	101[2]	603
1.4 / 1.4	OPΔT	15	LPP	52	Manual	600.0	LSGL	80	600.0	91[2]	603
2.0 / 1.4	OPΔT	13	HSF/L	33	HSF/L	40	LSGL	75	600.0	64	601
4.6 / 1.4	OPΔT	11	LPP	24	HSF/L	31	LSGL	71	600.0	50[2]	601

<u>Key</u> LPP ≡ low-pressurizer pressure
HSΔP ≡ high-steamline differential pressure
HSF/LT_{avg} ≡ high-steam flow + low T_{avg}
LSGL ≡ low-low steam generator water level
OPΔT ≡ overpower ΔT

1. The SI signal is generated, but the RCS pressure remains too high for delivery of SI flow.
2. The intact steam generator tubes also uncover and contribute superheated steam out the break.

Table 6.6-16

Summary of System Actuations for IP3 MSLB Outside Containment Header Breaks, 70% Power

Break Size (ft^2, before/ after steamline isolation)	Reactor Trip		SI[1]		MSIV Closure		AFW			Time-Faulted Steam Generator Tubes Uncover (sec)	Time-Break Releases Stop (sec)
	Signal	Time Rod Motion Starts (sec)	Signal	Time of Signal (sec)	Signal	Time Fully Closed (sec)	Signal	Time Flow Starts (sec)	Time Flow Stops (sec)		
0.1 / 0.1	LSGWL	203	HSΔP	853	Manual	600.0	LSGL	261	600.0	785	1070
0.2 / 0.2	LSGWL	105	LPP	460	Manual	600.0	LSGL	163	600.0	598	802
0.3 / 0.3	LSGWL	72	LPP	374	Manual	600.0	LSGL	130	600.0	385[2]	684
0.4 / 0.4	LSGWL	55	LPP	258	Manual	600.0	LSGL	113	600.0	295[2]	627
0.5 / 0.5	LSGWL	45	LPP	190	Manual	600.0	LSGL	103	600.0	244[2]	614
0.6 / 0.6	LSGWL	38	LPP	152	Manual	600.0	LSGL	96	600.0	208[2]	610
0.7 / 0.7	LSGWL	33	LPP	127	Manual	600.0	LSGL	91	600.0	183[2]	608
0.8 / 0.8	LSGWL	30	LPP	109	Manual	600.0	LSGL	88	600.0	163[2])	606
0.9 / 0.9	LSGWL	27	LPP	96	Manual	600.0	LSGL	85	600.0	149[2]	605
1.0 / 1.0	LSGWL	25	LPP	85	Manual	600.0	LSGL	83	600.0	137[2]	604
1.2 / 1.2	LSGWL	21	LPP	69	Manual	600.0	LSGL	79	600.0	119[2]	604
1.4 / 1.4	LSGWL	19	LPP	58	Manual	600.0	LSGL	77	600.0	107[2]	603
2.0 / 1.4	LSGWL	14	HSF/L	30	HSF/L	37	LSGL	72	600.0	64	601
4.6 / 1.4	LSGWL	8	HSF/L	19	HSF/L	26	LSGL	66	600.0	42	600

<u>Key</u> LPP ≡ low-pressurizer pressure; LSGL ≡ low-low steam generator water level; HSΔP ≡ high-steamline differential pressure; OPΔT ≡ overpower ΔT; HSF/LT_{avg} ≡ high-steam flow + low T_{avg}

1. *The SI signal is generated, but the RCS pressure remains too high for delivery of SI flow.*
2. The intact steam generator tubes also uncover and contribute superheated steam out the break.

Table 6.6-17

Summary of System Actuations for IP3 MSLB Outside Containment Loop Breaks, Full Power

Break Size (ft^2)	Reactor Trip		SI[1]		AFW			Time-Faulted Steam Generator Tubes Uncover (sec)	Time-Break Releases Stop (sec)
	Signal	Time Rod Motion Starts (sec)	Signal	Time of Signal (sec)	Signal	Time Flow Starts (sec)	Time Flow Stops (sec)		
0.1	LSGWL	207	HSΔP	397	LSGL	265	600.0	335	726
0.2	LSGWL	106	HSΔP	135	LSGL	164	600.0	188	636
0.3	LSGWL	72	HSΔP	88	LSGL	130	600.0	137	618
0.4	LSGWL	54	HSΔP	66	LSGL	112	600.0	113	610
0.5	OPΔT	31	HSΔP	40	LSGL	94	600.0	94	606
0.6	OPΔT	24	HSΔP	32	LSGL	87	600.0	82	604
0.7	OPΔT	21	HSΔP	28	LSGL	84	600.0	74	604
0.8	OPΔT	20	HSΔP	25	LSGL	82	600.0	68	603
0.9	OPΔT	18	HSΔP	23	LSGL	80	600.0	63	603
1.0	OPΔT	17	HSΔP	22	LSGL	78	600.0	60	602
1.2	OPΔT	16	HSΔP	19	LSGL	74	600.0	53	601
1.4	LSGWL	13	HSΔP	15	LSGL	71	600.0	47	601

<u>Key</u> LPP ≡ low-pressurizer pressure; LSGL ≡ low-low steam generator water level

HSΔP ≡ high-steamline differential pressure; OPΔT ≡ overpower ΔT

HSF/LT_{avg} ≡ high-steam flow + low T_{avg}

1. The SI signal is generated, but the RCS pressure remains too high for delivery of SI flow.
2. The intact steam generator tubes also uncover and contribute superheated steam out the break.

Table 6.6-18

Summary of System Actuations for IP3 MSLB Outside Containment Loop Breaks, 70% Power

Break Size (ft^2)	Reactor Trip		SI(1)		AFW			Time-Faulted Steam Generator Tubes Uncover (sec)	Time-Break Releases Stop (sec)
	Signal	Time Rod Motion Starts (sec)	Signal	Time of Signal (sec)	Signal	Time Flow Starts (sec)	Time Flow Stops (sec)		
0.1	LSGWL	184	HSΔP	436	LSGL	242	600.0	371	758
0.2	LSGWL	94	HSΔP	130	LSGL	152	600.0	211	637
0.3	LSGWL	64	HSΔP	84	LSGL	122	600.0	155	618
0.4	LSGWL	49	HSΔP	63	LSGL	107	600.0	126	611
0.5	LSGWL	40	HSΔP	50	LSGL	98	600.0	109	607
0.6	LSGWL	30	HSΔP	37	LSGL	88	600.0	93	605
0.7	LSGWL	21	HSΔP	27	LSGL	79	600.0	80	604
0.8	LSGWL	17	HSΔP	21	LSGL	75	600.0	75	604
0.9	LSGWL	14	HSΔP	17	LSGL	72	600.0	71	603
1.0	LSGWL	12	HSΔP	14	LSGL	70	600.0	66	603
1.2	LSGWL	10	HSΔP	11	LSGL	68	600.0	59	601
1.4	LSGWL	8	HSΔP	8	LSGL	66	600.0	53	601

<u>Key</u> LPP ≡ low-pressurizer pressure; LSGL ≡ low-low steam generator water level

HSΔP ≡ high-steamline differential pressure; OPΔT ≡ overpower ΔT

HSF/LT$_{avg}$ ≡ high-steam flow + low T$_{avg}$

1. The SI signal is generated, but the RCS pressure remains too high for delivery of SI flow.
2. The intact steam generator tubes also uncover and contribute superheated steam out the break.

Table 6.6-19

Summary of System Actuations for IP3 MSLB Outside Containment Header Breaks, Full Power

Break Size (ft^2, before/after steamline isolation)	Reactor Trip		SI[1]		MSIV Closure		AFW			Time-Faulted Steam Generator Tubes Uncover (sec)	Time-Break Releases Stop (sec)
	Signal	Time Rod Motion Starts (sec)	Signal	Time of Signal (sec)	Signal	Time Fully Closed (sec)	Signal	Time Flow Starts (sec)	Time Flow Stops (sec)		
0.1 / 0.1	LSGWL	247	HSΔP	996	Manual	900.0	LSGL	305	900.0	788	1251
0.2 / 0.2	LSGWL	128	LPP	513	Manual	900.0	LSGL	186	900.0	414[2]	979
0.3 / 0.3	LSGWL	88	LPP	307	Manual	900.0	LSGL	146	900.0	301[2]	932
0.4 / 0.4	LSGWL	67	LPP	222	Manual	900.0	LSGL	125	900.0	238[2]	921
0.5 / 0.5	OPΔT	31	LPP	151	Manual	900.0	LSGL	105	900.0	201[2]	915
0.6 / 0.6	OPΔT	25	LPP	123	Manual	900.0	LSGL	99	900.0	173[2]	911
0.7 / 0.7	OPΔT	22	LPP	104	Manual	900.0	LSGL	94	900.0	153[2]	909
0.8 / 0.8	OPΔT	20	LPP	91	Manual	900.0	LSGL	90	900.0	137[2]	907
0.9 / 0.9	OPΔT	19	LPP	80	Manual	900.0	LSGL	88	900.0	125[2]	906
1.0 / 1.0	OPΔT	18	LPP	72	Manual	900.0	LSGL	86	900.0	116[2]	905
1.2 / 1.2	OPΔT	16	LPP	60	Manual	900.0	LSGL	82	900.0	101[2]	904
1.4 / 1.4	OPΔT	15	LPP	52	Manual	900.0	LSGL	80	900.0	91[2]	904
2.0 / 1.4	OPΔT	13	HSF/L	33	HSF/L	40	LSGL	75	900.0	64	903
4.6 / 1.4	OPΔT	11	LPP	24	HSF/L	31	LSGL	71	900.0	50[2]	903

<u>Key</u>
LPP ≡ low-pressurizer pressure
LSGL ≡ low-low steam generator water level
HSΔP ≡ high-steamline differential pressure
OPΔT ≡ overpower ΔT
HSF/LT$_{avg}$ ≡ high-steam flow + low T$_{avg}$

1. The SI signal is generated, but the RCS pressure remains too high for delivery of SI flow.
2. The intact steam generator tubes also uncover and contribute superheated steam out the break.

Table 6.6-20

Summary of System Actuations for IP3 MSLB Outside Containment Header Breaks, 70% Power

Break Size (ft^2, before/after steamline isolation)	Reactor Trip		SI[1]		MSIV Closure		AFW			Time-Faulted Steam Generator Tubes Uncover (sec)	Time-Break Releases Stop (sec)
	Signal	Time Rod Motion Starts (sec)	Signal	Time of Signal (sec)	Signal	Time Fully Closed (sec)	Signal	Time Flow Starts (sec)	Time Flow Stops (sec)		
0.1 / 0.1	LSGWL	203	HSΔP	1144	Manual	900.0	LSGL	261	900.0	1058	1345
0.2 / 0.2	LSGWL	105	LPP	460	Manual	900.0	LSGL	163	900.0	598	1030
0.3 / 0.3	LSGWL	72	LPP	374	Manual	900.0	LSGL	130	900.0	385[2]	935
0.4 / 0.4	LSGWL	55	LPP	258	Manual	900.0	LSGL	113	900.0	295[2]	922
0.5 / 0.5	LSGWL	45	LPP	190	Manual	900.0	LSGL	103	900.0	244[2]	915
0.6 / 0.6	LSGWL	38	LPP	152	Manual	900.0	LSGL	96	900.0	208[2]	912
0.7 / 0.7	LSGWL	33	LPP	127	Manual	900.0	LSGL	91	900.0	183[2]	910
0.8 / 0.8	LSGWL	30	LPP	109	Manual	900.0	LSGL	88	900.0	163[2]	908
0.9 / 0.9	LSGWL	27	LPP	96	Manual	900.0	LSGL	85	900.0	149[2]	907
1.0 / 1.0	LSGWL	25	LPP	85	Manual	900.0	LSGL	83	900.0	137[2]	906
1.2 / 1.2	LSGWL	21	LPP	69	Manual	900.0	LSGL	79	900.0	119[2]	904
1.4 / 1.4	LSGWL	19	LPP	58	Manual	900.0	LSGL	77	900.0	107[2]	904
2.0 / 1.4	LSGWL	14	HSF/L	30	HSF/L	37	LSGL	72	900.0	64	902
4.6 / 1.4	LSGWL	8	HSF/L	19	HSF/L	26	LSGL	66	900.0	42	901

Key
LPP ≡ low-pressurizer pressure
LSGL ≡ low-low steam generator water level
HSΔP ≡ high-steamline differential pressure
OPΔT ≡ overpower ΔT
HSF/LT_{avg} ≡ high-steam flow + low T_{avg}

1. The SI signal is generated, but the RCS pressure remains too high for delivery of SI flow.
2. The intact steam generator tubes also uncover and contribute superheated steam out the break.

Table 6.6-21

Summary of System Actuations for IP3 MSLB Outside Containment Loop Breaks, Full Power

Break Size (ft^2)	Reactor Trip		SI[1]		AFW			Time-Faulted Steam Generator Tubes Uncover (sec)	Time-Break Releases Stop (sec)
	Signal	Time Rod Motion Starts (sec)	Signal	Time of Signal (sec)	Signal	Time Flow Starts (sec)	Time Flow Stops (sec)		
0.1	LSGWL	207	HSΔP	397	LSGL	265	900.0	335	1002.
0.2	LSGWL	106	HSΔP	135	LSGL	164	900.0	188	941
0.3	LSGWL	72	HSΔP	88	LSGL	130	900.0	137	922
0.4	LSGWL	54	HSΔP	66	LSGL	112	900.0	113	913
0.5	OPΔT	31	HSΔP	40	LSGL	94	900.0	94	908
0.6	OPΔT	24	HSΔP	32	LSGL	87	900.0	82	906
0.7	OPΔT	21	HSΔP	28	LSGL	84	900.0	74	905
0.8	OPΔT	20	HSΔP	25	LSGL	82	900.0	68	904
0.9	OPΔT	18	HSΔP	23	LSGL	80	900.0	63	904
1.0	OPΔT	17	HSΔP	22	LSGL	78	900.0	60	903
1.2	OPΔT	16	HSΔP	19	LSGL	74	900.0	53	903
1.4	LSGWL	13	HSΔP	15	LSGL	71	900.0	47	902

<u>Key</u> LPP ≡ low-pressurizer pressure; LSGL ≡ low-low steam generator water level
HSΔP ≡ high-steamline differential pressure; OPΔT ≡ overpower ΔT
HSF/LT_{avg} ≡ high-steam flow + low T_{avg}

1. The SI signal is generated, but the RCS pressure remains too high for delivery of SI flow.
2. The intact steam generator tubes also uncover and contribute superheated steam out the break.

Table 6.6-22

Summary of System Actuations for IP3 MSLB Outside Containment Loop Breaks, 70% Power

Break Size (ft^2)	Reactor Trip		SI[1]		AFW			Time-Faulted Steam Generator Tubes Uncover (sec)	Time-Break Releases Stop (sec)
	Signal	Time Rod Motion Starts (sec)	Signal	Time of Signal (sec)	Signal	Time Flow Starts (sec)	Time Flow Stops (sec)		
0.1	LSGWL	184	HSΔP	436	LSGL	242	900.0	371	1005
0.2	LSGWL	94	HSΔP	130	LSGL	152	900.0	211	941
0.3	LSGWL	64	HSΔP	84	LSGL	122	900.0	155	922
0.4	LSGWL	49	HSΔP	63	LSGL	107	900.0	126	914
0.5	LSGWL	40	HSΔP	50	LSGL	98	900.0	109	909
0.6	LSGWL	30	HSΔP	37	LSGL	88	900.0	93	907
0.7	LSGWL	21	HSΔP	27	LSGL	79	900.0	80	906
0.8	LSGWL	17	HSΔP	21	LSGL	75	900.0	75	905
0.9	LSGWL	14	HSΔP	17	LSGL	72	900.0	71	904
1.0	LSGWL	12	HSΔP	14	LSGL	70	900.0	66	904
1.2	LSGWL	10	HSΔP	11	LSGL	68	900.0	59	903
1.4	LSGWL	8	HSΔP	8	LSGL	66	900.0	53	902

<u>Key</u> LPP ≡ low-pressurizer pressure; LSGL ≡ low-low steam generator water level

HSΔP ≡ high-steamline differential pressure; OPΔT ≡ overpower ΔT

HSF/LT_{avg} ≡ high-steam flow + low T_{avg}

1. The SI signal is generated, but the RCS pressure remains too high for delivery of SI flow.
2. The intact steam generator tubes also uncover and contribute superheated steam out the break.

Table 6.6-23

IP3 Outside Containment
Steam & Feed Penetration Area Initial Conditions

	Pressure (psia)	Temperature (°F)	Relative Humidity (%)
Winter			
Inside	14.7	110.0	100.0
Outside	14.7	84.0	70.0
Summer			
Inside	14.7	125.0	100.0
Outside	14.7	100.0	90.0

Table 6.6-24

Vented Steam Releases from Operable Steam Generators and AFW Flows for the 0-to-2 and 2-to-29 Hr Time Periods

Event	Vented Steam Release		AFW Injection	
	0-2 hours	2-29 hours	0-2 hours	2-29 hours
Locked Rotor	405,229 lbm	2,303,229 lbm	586,953 lbm	2,380,773 lbm
Steamline Break	401,945 lbm	2,273,538 lbm	538,238 lbm	2,331,696 lbm

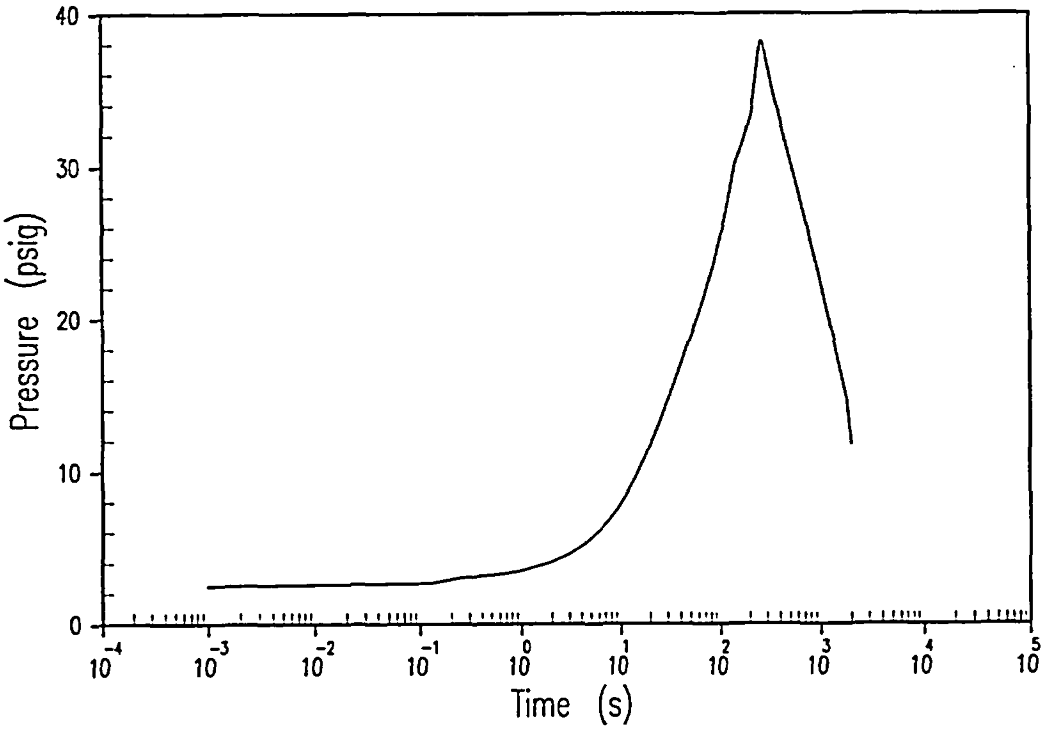

Figure 6.6-1

Containment Pressure Curve for 102% Power MSLB for IP3

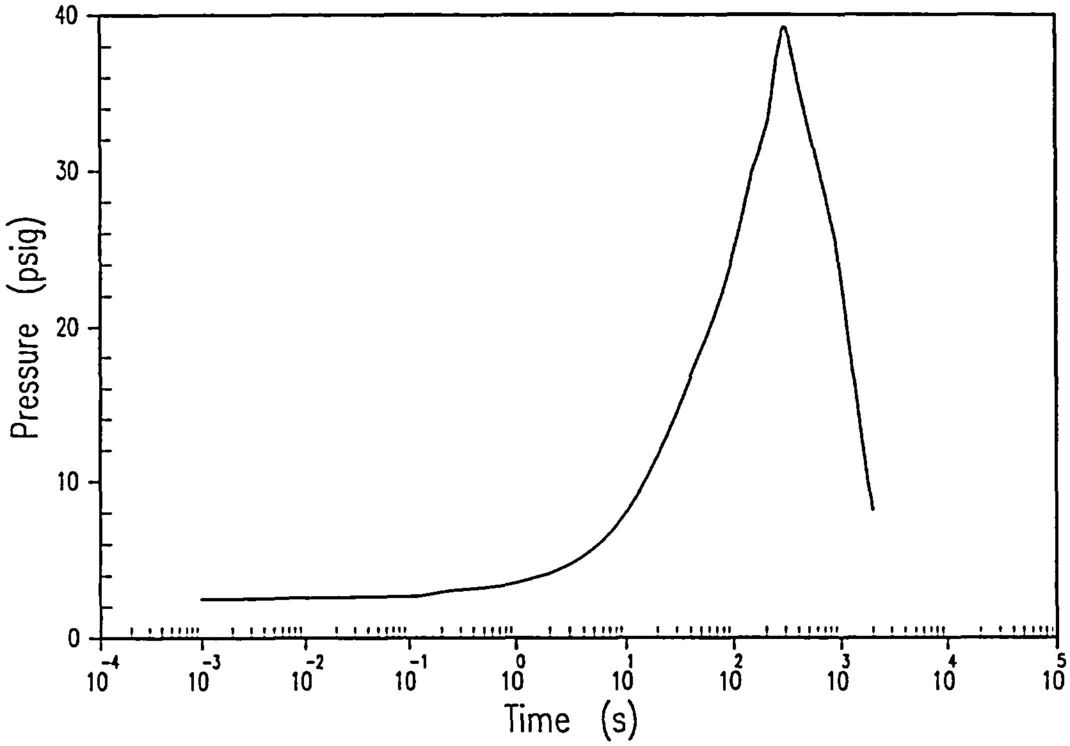

Figure 6.6-2

Containment Pressure Curve for 70% Power MSLB for IP3

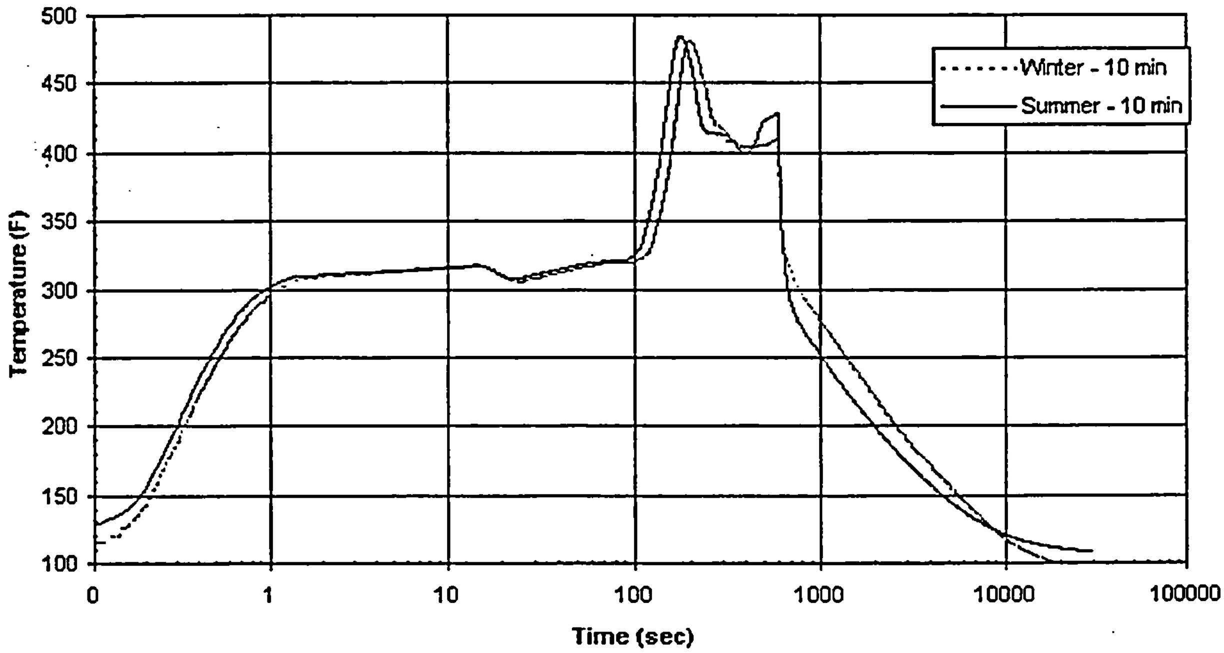

Figure 6.6-3

IP3 MSLB Outside Containment Limiting Break Temperature Profiles

(10-minute operator action time)

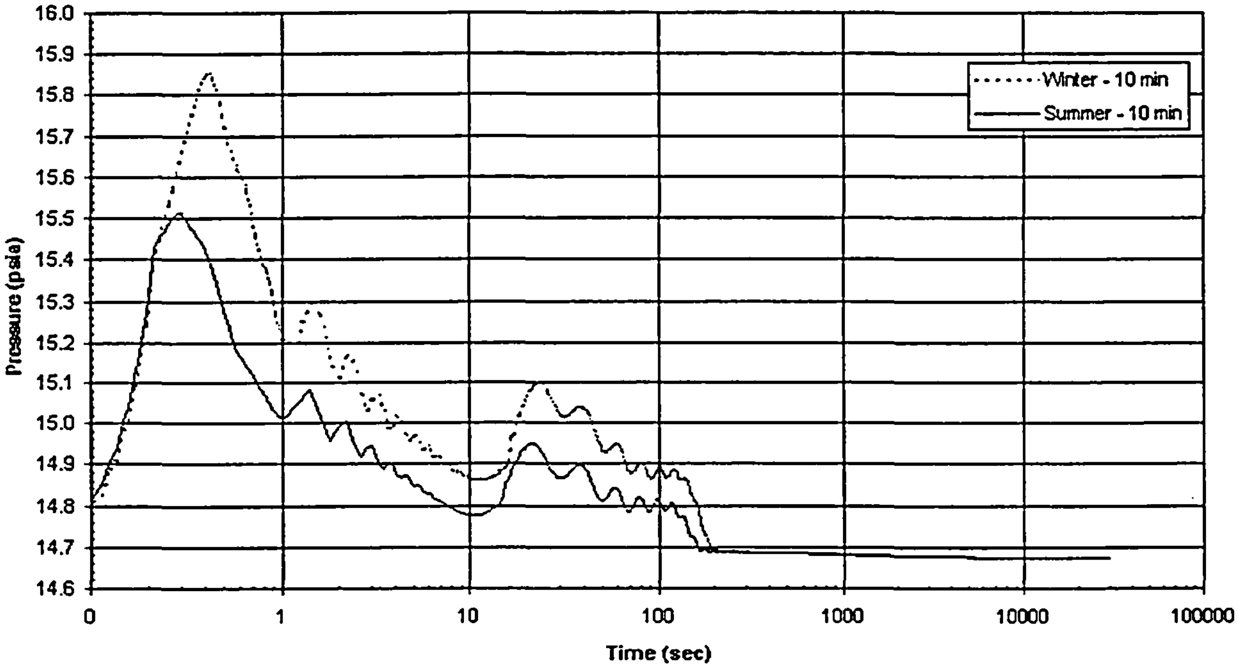

Figure 6.6-4

IP3 MSLB Outside Containment Limiting Break Pressure Profiles

(10-minute operator action time)

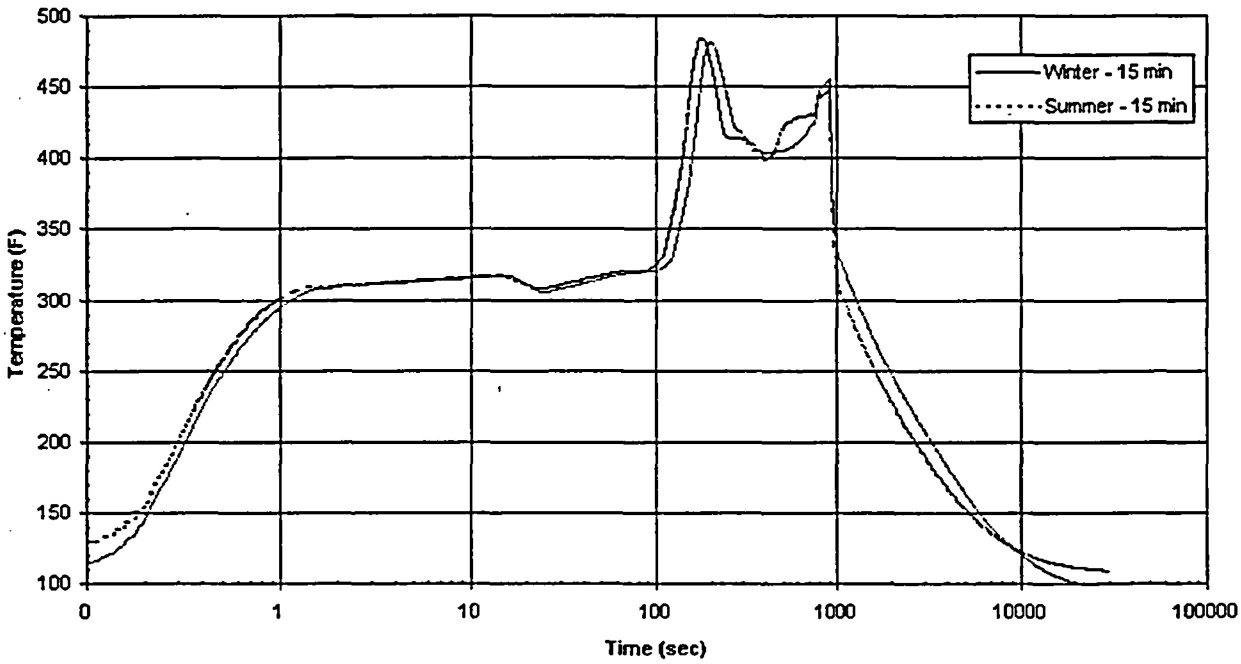

Figure 6.6-5

IP3 MSLB Outside Containment Limiting Break Temperature Profiles

(15-minute operator action time)

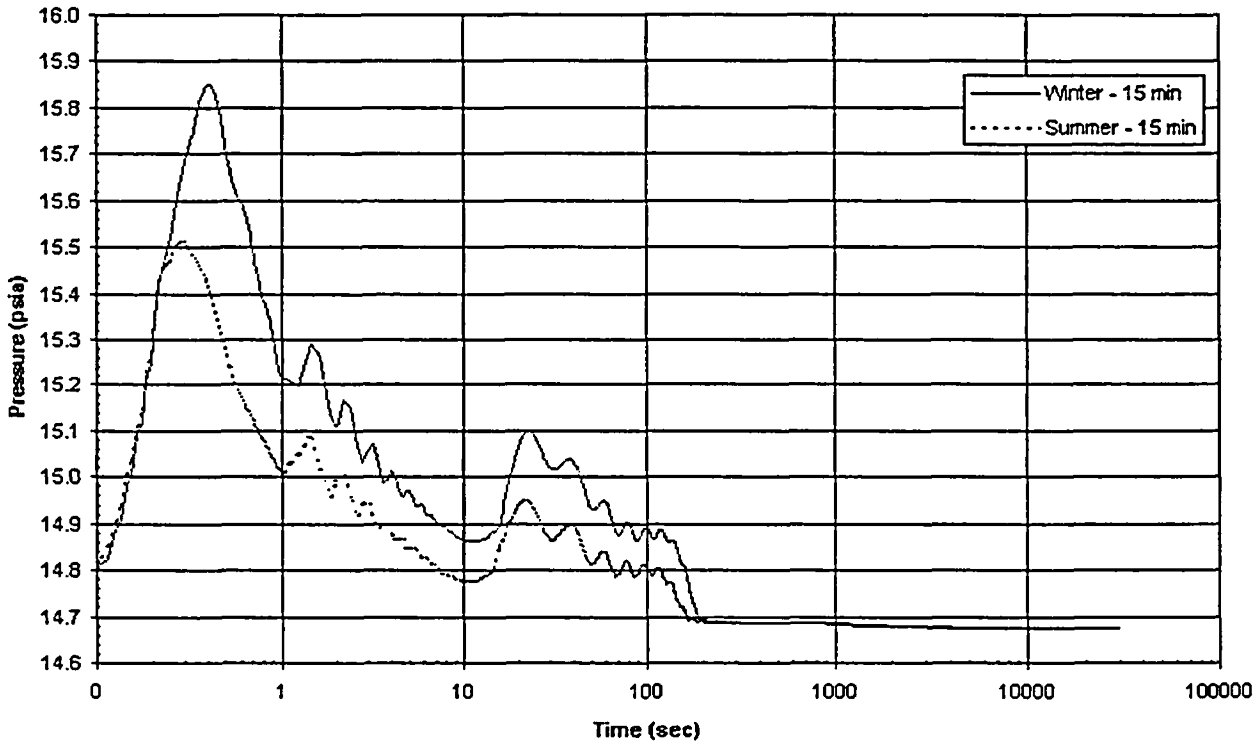

Figure 6.6-6

IP3 MSLB Outside Containment Limiting Break Pressure Profiles

(15 minute operator action time)

6.7 Loss-of-Coolant Accident Hydraulic Forces

6.7.1 Introduction

The loss-of-coolant accident (LOCA) hydraulic forces analysis generates the hydraulic forcing functions that would act on Reactor Coolant System (RCS) components as a result of a postulated LOCA. The LOCA hydraulic forces were calculated for conditions consistent with minimum thermal design flow and maximum RCS power. The Indian Point Unit 3 (IP3) stretch power uprate (SPU) used the advanced beam model version of MULTIFLEX (3.0) (Reference 1) in accordance with methodology approved by the NRC in WCAP-15029-P-A and WCAP-15030-NP-A (Reference 2).

6.7.2 Input Parameters and Assumptions

To conservatively calculate LOCA hydraulic forces for IP3, the following operating conditions were considered in establishing the limiting temperatures and pressures:

- Initial RCS conditions associated with a minimum thermal design flow of 88,600 gpm per loop
- Uprated core power of 3216 MWt (Nuclear Steam Supply System [NSSS] power of 3230 MWt)
- A nominal RCS hot full power (HFP) T_{avg} range of 549.0° to 572.0°F. This provides an RCS T_{cold} range of 517.3° to 541.0°F (see Table 2.1-2 of Section 2).
- An RCS temperature uncertainty of ±7.0°F. (The minimum analyzed T_{cold} was 510.3°F.)
- A feedwater temperature range of 390.0° to 433.6°F
- A nominal RCS pressure of 2250 psia
- A pressurizer pressure uncertainty of ±75 psi

General Design Criterion 4 (GDC-4) (Reference 3) allows main coolant piping breaks to be "...excluded from the design basis when analyses reviewed and approved by the Commission demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping." This exemption is generally referred to as leak-before-break (LBB). The technical justification for application of LBB to IP3 is documented in WCAP-8228 Vol. 1, Rev. 1 (Reference 4).

LBB licensing allows RCS components to be evaluated for LOCA integrity considering the next most limiting auxiliary line breaks, that for IP3, are the accumulator line, the pressurizer surge line, and the residual heat removal line.

6.7.3 Description of Evaluation

LOCA forces were generated with a focus on the component of interest; loop, vessel, steam generator, or rod control cluster assembly (RCCA) guide tubes using the advanced beam model version of MULTIFLEX (3.0) (Reference 1), assuming a conservative break-opening time (BOT) of 1 millisecond (msec).

Generally, this improved modeling results in lower, more realistic, but still conservative hydraulic forces on the core barrel.

The MULTIFLEX computer code calculated the thermal-hydraulic transient within the RCS and considers subcooled, transition, and early two-phase (saturated) blowdown regimes. The code used the method of characteristics to solve the conservation laws, assuming one-dimensional (1-D) flow and a homogeneous liquid-vapor mixture. The RCS was divided into subregions in which each subregion was regarded as an equivalent pipe. A complex network of these equivalent pipes was used to represent the entire primary RCS.

For the reactor pressure vessel (RPV) and specific vessel internal components, the MULTIFLEX code generated the LOCA thermal-hydraulic transient that was input to the LATFORC and FORCE2 post-processing codes (Reference 5). These codes, in turn, were used to calculate the actual forces on the various components.

These forcing functions for horizontal and vertical LOCA hydraulic forces, combined with seismic, thermal, and system-shaking loads, were used by the cognizant structural groups to determine the resultant mechanical loads on the RPV and vessel internals.

The loop forces analysis use the THRUST post-processing code to generate the X, Y, and Z directional component forces during a LOCA blowdown from the RCS pressure, density, and mass flux calculated by the MULTIFLEX code. The THRUST code is described and documented in WCAP-8252 (Reference 6).

The hydraulic transient time-history data were extracted directly from the MULTIFLEX output for steam generator and some reactor vessel internal components, such as baffle bolts or RCCA guide tubes.

6.7.4 Acceptance Criteria

LOCA hydraulic forces were provided as input to structural qualification analyses, and as such, had no independent regulatory acceptance criteria.

6.7.5 Results

For the IP3 SPU, all relevant LOCA hydraulic forces analyses were performed directly at the uprated power operating conditions using models specific to the IP3 NSSS design. These analyses included reactor vessel internals and fuel, loop piping, steam generator, and RCCA guide tube forces. The results of these analyses were then used as input to the structural analyses for component qualification.

6.7.6 Conclusions

LOCA hydraulic forces were generated for IP3 for the SPU conditions specified in subsection 6.7.2 of this document. These LOCA hydraulic forcing functions are used in the structural analyses in Section 5 of this report.

6.7.7 References

1. WCAP-9735, Rev. 2 (Proprietary) and WCAP-9736, Rev. 1, (Nonproprietary), *MULTIFLEX 3.0 A FORTRAN IV Computer Program for Analyzing Thermal-Hydraulic-Structural System Dynamics Advanced Beam Model*, K. Takeuchi, et al., February 1998.

2. WCAP-15029-P-A (Proprietary) and WCAP-15030-NP-A (Nonproprietary), *Westinghouse Methodology for Evaluating the Acceptability of Baffle-Former-Barrel Bolting Distributions Under Faulted Load Conditions*, R. E. Schwirian, et al., January 1999.

3. 10CFR50, Appendix A, *General Design Criteria for Nuclear Power Plants.*

4. WCAP-8228, Volume 1, (Proprietary), *Structural Evaluation of Reactor Coolant Loop/Support System for Indian Point Nuclear Generating Station, Unit No. 3*, D. C. Bhowmick, et al., Rev. 1, April 1997.

5. WCAP-8708-P-A (Proprietary) and WCAP-8709-A (Nonproprietary), *MULTIFLEX A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics*, K. Takeuchi, et al., September 1977.

6. WCAP-8252 (Nonproprietary), Documentation of Selected Westinghouse Structural Analysis Computer Codes, K. M. Vashi, Rev. 1, May 1977.

6.8 Anticipated Transients without Scram

6.8.1 Introduction

For Westinghouse-designed pressurized water reactors (PWRs), the licensing requirements related to anticipated transients without scram (ATWS) are specified in the Final ATWS Rule, 10CFR50.62(c) (Reference 1). The requirement set forth in 10CFR50.62(c) is that all Westinghouse-designed PWRs must install AMSAC (ATWS Mitigation System Actuation Circuitry) and, in compliance with this, AMSAC has been installed and implemented at Indian Point Unit 3 (IP3).

As documented in SECY-83-293 (Reference 2), the analytical bases for the Final ATWS Rule are the generic ATWS analyses for Westinghouse PWRs generated by Westinghouse in 1979. These generic ATWS analyses were formally transmitted to the Nuclear Regulatory Commission (NRC) via letter NS-TMA-2182 (Reference 3), and were performed based on the guidelines provided in NUREG-0460 (Reference 4). The generic ATWS analysis assumed nominal conditions consistent with the requirements outlined by the NRC. In consideration of the low probability of an ATWS, the NRC permitted nominal initial conditions, nominal system parameters, and the availability of all system functions except reactor trip to be assumed.

The generic ATWS analyses that are documented in NS-TMA-2182 (Reference 3) were performed with the LOFTRAN computer code and addressed the various American Nuclear Society (ANS) Condition II events (that is, anticipated transients), considering various Westinghouse PWR configurations applicable at that time. These analyses addressed two-, three-, and four-loop PWRs with various steam generator models. For IP3, the generic ATWS analyses applicable at that time were those for a four-loop PWR with Model 44 steam generators and a core power of 3025 MWt. These conditions are summarized in Table 3-1-d of NS-TMA-2182 (Reference 3). For this plant configuration, the peak Reactor Coolant System (RCS) pressure reported in NS-TMA-2182 for the limiting loss-of-load ATWS event is 2979 psia.

The generic ATWS analyses documented in NS-TMA-2182 (Reference 3) also support the analytical basis for the NRC-approved generic AMSAC designs generated for the Westinghouse Owners Group (WOG), as documented in WCAP-10858-P-A, Revision 1 (Reference 5). For the purpose of these AMSAC designs, the generic ATWS analyses for the four-loop PWR configuration with Model 51 steam generators were used to conservatively represent all of the various Westinghouse PWR configurations contained in NS-TMA-2182. For IP3, WCAP-10858P-A AMSAC Logic 2, AMSAC actuation on low main feedwater flow was used.

As prescribed by NUREG-0460 (Reference 4), the 1979 generic ATWS analyses for Westinghouse PWRs documented in NS-TMA-2182 (Reference 3) assumed a full-power moderator temperature coefficient (MTC) of -8 pcm/°F. A sensitivity analysis including the use of an MTC of -7 pcm/°F was also provided as prescribed by NUREG-0460. In 1979, the MTC values of -8 pcm/°F and -7 pcm/°F represented MTCs that Westinghouse PWRs would be more negative than for 95 and 99 percent of the cycle, respectively. The base case of 95 percent represents a 95-percent confidence limit on favorable MTC for the fuel cycle. For IP3, the *Technical Specification* requirement on MTC is limited to < 0 pcm/°F at all power levels. The current MTC *Technical Specification* for IP3 remains the same as that which was applicable for most Westinghouse PWRs in 1979. Therefore, the reactivity feedback for IP3 remains sufficiently negative to be comparable to the generic Westinghouse ATWS analyses presented in NS-TMA-2182.

Relative to the other conditions important to the ATWS analyses, the pressurizer power-operated relief valve (PORV) relief capacity, safety valve relief capacity, and auxiliary feedwater (AFW) capacity are unaffected by the stretch power uprate (SPU). The design capacities of both of the IP3 pressurizer PORVs (179,000 lbm/hr) are consistent with the relief capacities assumed in the 1979 generic ATWS analysis for this plant configuration. The design capacity of each of the three IP3 pressurizer safety relief valves is 420,000 lbm/hr. This capacity is greater than the pressurizer safety valve relief capacity of 408,000 lbm/hr assumed in the 1979 generic ATWS analysis for this plant configuration. As such, this would result in an overall peak pressure benefit when compared to peak RCS pressure calculated for the generic limiting ATWS events.

The design capacities of the IP3 AFW pumps are as follows.

- Motor-driven AFW pump - 400 gpm
- Turbine-driven AFW pump - 800 gpm

The IP3 Auxiliary Feedwater System (AFWS) has two motor-driven AFW pumps (MDAFWPs) (each pump aligned to two steam generators) and a turbine-driven AFW pump (TDAFWP) that requires operator action to initiate flow to all four steam generators. Since operator action is required at IP3 to deliver TDAFWP flow to the steam generators, IP3 can only credit AFW flow from the two MDAFWPs. Based on the safety analysis AFW flows of 343 gpm from each MDAFWP, the total AFW flow at IP3 would be 686 gpm. This lower AFWS flow would result in an overall peak pressure penalty when compared to the total AFWS capacity of 1760 gpm, assumed in the 1979 generic ATWS analyses for the Westinghouse four-loop plant configuration with Model 44 steam generators (as documented in Table 3-1-d of NS-TMA-2182 [Reference 3]).

For the IP3 SPU, the two most limiting RCS overpressure transients reported in NS-TMA-2182 (Reference 3), the loss-of-normal feedwater (LONF) and loss-of-load (LOL) transients, were analyzed at the SPU conditions to ensure that the basis for the final ATWS rule continues to be met.

The primary inputs to the LONF and LOL ATWS analyses performed in support of the IP3 SPU are the four-loop reference LONF and LOL ATWS models with Model 44 steam generators supporting NS-TMA-2182 (Reference 3). The nominal and initial conditions were updated to reflect an NSSS power of 3230 MWt corresponding to the SPU, as well as a total AFW flow of 686 gpm.

6.8.2 Acceptance Criteria and Conclusions

To remain consistent with the basis of the Final ATWS Rule (Reference 1) and the supporting analysis reported in NS-TMA-2182 (Reference 3), the peak RCS pressure for the ATWS events for IP3 at an NSSS power level of 3230 MWt corresponding to the SPU shall not exceed the ASME Boiler and Pressure Vessel Level C service limit stress criterion of 3200 psig (3215 psia).

The results of the LONF and LOL ATWS analyses performed at an SPU NSSS power level of 3230 MWt with Model 44 steam generators are provided in Table 6.8-1. The results show that assuming the IP3 plant-specific AFW flow of 686 gpm results in higher peak RCS pressures than what were calculated based on the AFW flow rate of 1760 gpm from NS-TMA-2182 (Reference 3). However, the results do not exceed the ASME Boiler and Pressure Vessel Code Level C service limit stress criterion of 3200 psig (3215 psia). In fact, the peak RCS pressures are significantly less than the limit value of 3215 psia.

For the LONF and LOL cases analyzed at the SPU power level of 3230 MWt, the calculated peak RCS pressures of 2814 psia and 2862 psia, respectively, are less limiting than the corresponding peak pressures of 2857 psia and 2979 psia obtained for the LONF and LOL cases, respectively, in the 1979 ATWS analyses for four-loop Model 44 steam generators (Reference 3). The lower RCS pressures are attributed to the lower initial steam generator steam temperature associated with the IP3 SPU. For the SPU, the initial steam temperature is ~17°F lower than what was assumed in the 1979 ATWS analysis (Reference 3).

Furthermore, these analyses results do not credit the overall peak pressure benefit associated with the higher pressurizer safety valve relief capacity for IP3.

In conclusion, operation of IP3 at an SPU NSSS power of 3230 MWt remains in compliance with the Final ATWS Rule, 10CFR50.62(c) (Reference 1).

6.8.3 References

1. 10CFR50.62, *Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants,* July 29, 1996.

2. SECY-83-293, *Amendments to 10CFR50 Related to Anticipated Transients Without Scram (ATWS) Events,* W. J. Dircks, July 19, 1983.

3. Letter NS-TMA-2182, T. M. Anderson (Westinghouse) to S. H. Hanauer (NRC), *ATWS Submittal,* December 30, 1979.

4. NUREG-0460, *Anticipated Transients Without Scram for Light Water Reactors,* December 1978.

5. WCAP-10858-P-A, *AMSAC Generic Design Package, Westinghouse Topical Report,* Rev. 1, M. R. Adler, July 1987.

Table 6.8-1 LONF and LOL ATWS Analyses Results		
AFW Flow (gpm)	Peak RCS Pressure (psia)	
	LONF	LOL
1760 gpm (Ref. 3 flow)	2783	2836
686 gpm	2814	2862

6.9 Natural Circulation Cooldown Capability

6.9.1 Introduction

Certain initiating events, such as a loss-of-offsite power (LOOP) can cause a reactor trip with loss of forced circulation. As the reactor coolant pumps (RCPs) coast down, a coolant density difference is established between the Reactor Coolant System (RCS) hot-leg and cold-leg sides that causes flow to circulate, allowing residual heat to be transferred to and removed by the steam generators. This process of natural circulation cooling has been observed in Westinghouse-designed pressurized water reactors (PWRs) in startup tests as well as actual events. In addition, Diablo Canyon Unit 1, a four-loop PWR similar to Indian Point Unit 3 (IP3), has performed a test to demonstrate capability to cooldown the RCS to residual heat removal (RHR) initiation conditions (below 350°F and ~400 psig) via this natural circulation cooling process. The recovery guidance used for this test as well as the IP3 plant-specific Emergency Operating Procedures (EOPs) has been based on the Westinghouse Owners Group Emergency Response Guidelines (ERGs), specifically ES-0.2, *Natural Circulation Cooldown.*

To demonstrate that the stretch power uprate (SPU) does not adversely affect the natural circulation cooling capability of the IP3 plant, a short-term (20-minute) analysis simulation was performed. A comparison to the Indian Point Unit 2 (IP2) scenario was then made to evaluate the longer term portion. In addition to providing or supporting the technical basis for the EOPs, this simulation plus comparison has helped demonstrate the following:

- The maximum temperature differential ($T_{hot} - T_{cold}$) and maximum hot-leg temperatures are bounded by full power operation.
- The capacity of the steam generator atmospheric relief valves (ARVs) does not limit the capability to cooldown to RHR cut-in conditions (350°F, 400 psig).

6.9.2 Analysis Methods and Inputs

The IP3 EOPs, which are based on the ERGs, were reviewed in performing the long-term comparison and also the short-term simulation using the TREAT computer code. This analysis and comparison were performed in a conservative manner using realistic time delays and equipment limitations. For example, the simulation assumed a "locked rotor" RCP hydraulic resistance following RCP coastdown. The longer term portion included a 4-hour delay at hot standby to allow boration to cold shutdown, a natural circulation cooldown rate of 20°F/hr (versus a maximum 25°F/hr allowed for a T_{hot} upper-head plant), and an 8-hour delay to allow the upper head to cool or "soak" before depressurizing to the RHR cut-in pressure. As per the ERG generic analysis, this upper-head soak delay is included to allow the upper-head region sufficient time to cool due to the assumed loss of control rod drive mechanism (CRDM) fans. If the CRDM fans were operating, the upper-head region would cool down at a rate comparable to the rest of the RCS and this 8-hour delay to preclude steam void formation in the upper head would not be necessary.

Other important assumptions were:

- Decay heat rate is approximately the same as the ANSI/ANS-5.1-1979 standard (Reference 1), including +2 sigma uncertainty, with full-power operation at 3288.4 MWt core power for an extended period of time (3.2 years average fuel exposure). (This power level bounds 102 percent of 3216 MWt.)

- There is a total capacity for all 4 steam generator ARVs = 2,503,612 lbm/hr at the valve inlet pressure of 1020 psig = 1035 psia.

6.9.3 Simulation Results

For the short-term maximum temperature response, the decay heat is approximately 3 percent of full power by the time the RCPs coast down and the core/hot-leg side heats up to quasi steady-state conditions. This condition occurs approximately 5 minutes after the RCPs and the reactor trip. Results calculated for this situation are the following:

- Hot-leg/core exit temperature = 593°F
- Hot- to cold-leg Delta-T = 40°F
- Cold-leg temperature = 553°F
- Core flow rate ≅ 6.15 x 10^6 lbm/hr (approximately 4.5 percent of nominal)

For this maximum temperature condition, the cold-leg temperatures are assumed to be controlled by the lowest main steam safety valve (MSSV) pressure set-point (1080 psia, T_{sat} = 554°F). Soon after reactor trip, the operator would control this temperature to no-load (547°F), as instructed in the EOPs, by operation of the steam generator ARVs. Thus, the above temperatures for T_{hot} and T_{cold} would be reduced accordingly by about 5 to 10°F. The above hot-leg/vessel-outlet temperature is approximately 10°F less than the maximum Performance Capability Working Group (PCWG) temperature of (603°F). Since the RCS is initially controlled to ~2100 to 2250 psia (T_{SAT} = 643 to 653°F), it would typically be subcooled by more than 50°F at the core exit/hot-legs at this maximum temperature condition.

For the comparison portion, it is noted that the IP2 and IP3 EOP actions taken would be the same, apart from differences in certain EOP setpoint values. These differences would have minor impact on the cooldown scenario. Both EOPs limit the RCS cooldown rate to 25°F/hr and assume an 8-hour upper head "soak" delay if CRDM fans are not in service. IP3 performs this upper head "soak" delay in two pieces because of pressure-temperature limitations, but the overall impact on the scenario longer term response would not be significant.

6.9.4 Conclusion

By performing the short-term analysis for IP3 and making a comparison of IP3 parameters to IP2, it is concluded that the SPU will not adversely impact the natural circulation cooldown capability of the plant.

6.9.5 References

1. ANSI/ANS-5.1-1979, American *National Standard for Decay Heat Power in Light Water Reactors*, August 1979.

2. WCAP-16157, *Indian Point Nuclear Generating Unit No. 2 - Stretch Power Uprate NSSS and BOP Licensing Report*, January 2004. (Section 6.9)

6.10 Reactor Trip System/Engineered Safety Feature Actuation System Setpoints

6.10.1 Introduction

The Reactor Trip System (RTS)/Engineered Safety Feature Actuation System (ESFAS) nominal trip setpoints (NTSs) and *Technical Specifications* (Reference 1) allowable values (AVs) have been reviewed for operation at the stretch power uprate (SPU) conditions. As a result of this review, several NTS and AV changes have been identified.

6.10.2 Description of Analyses and Evaluations

The setpoint analysis uses the square-root-sum-of-the-squares (SRSS) technique to combine the uncertainty components of an instrument channel in an appropriate combination of those components, or groups of components, that are statistically independent. Those uncertainties that are not independent arithmetically summed to produce groups that are independent of each other, which can then be statistically combined. The method used for determining NTSs and AVs for the Indian Point Unit 3 (IP3) stretch power uprate (SPU) is defined in IP3 Engineering Standard IES-3B, Revision 0 (Reference 2) and is the same as used for the recently NRC-approved 1.4-percent measurement uncertainty recapture (MUR). However, where *Technical Specifications* (Reference 1) AVs were affected, these were recalculated in accordance with both the above-referenced engineering standard, which utilizes ISA 67.04 Method 3, and the methodology described in for the Indian Point Unit 2 (PU Licensing Amendment Request (LAR) package, which imposes ISA 67.04 Method 2 requirements for determining AVs. As a result, the changed AVs shown in the Reactor Protection System (RPS)/ESFAS *Technical Specification* markups (included as Attachment II of the IP3 LAR package) conservatively bound the AVs determined via both of the identified methods.

In accordance with requirements issued by the NRC, for implementation of surveillance frequency extensions for RPS/ESFAS instrument components, IP3 instituted a component drift Performance Monitoring Program. This program, which includes the performance tracking of over 1000 instrument components, benchmarks expected drift characteristics of each device in the program.

Recorded As-Found/As-Left data sets, collected during the field calibrations/surveillances, are screened for resultant drift magnitude and compared to the benchmark values, which are the basis for drift allowances in the RPS/ESFAS uncertainty calculations. Components, whose observed drift magnitude exceeds the benchmark values, are posted on a "Degraded Instruments Watch List" (assuming they can be successfully be brought into required As-Left tolerance). Subsequent surveillance results are specifically reviewed for these instruments and determinations are made relative to cause and appropriate corrective actions, which can be the following:

- Increase surveillance frequency (to collect more data)
- Repair/Replace the device (where observed degradation is confirmed)
- Revise surveillance procedural steps (where inappropriate steps are inducing observed degradation)
- Review/Revise the uncertainty calculation drift allowances (where benchmark values are determined to be inappropriate)

The IP3 RTS/ESFAS uncertainty calculations were evaluated based on operation at the SPU operating conditions, along with the plant-specific instrumentation and plant calibration procedures, and any revisions to the safety analysis limits (SALs) values that were required to support operation at the SPU conditions. Several setpoint calculations were affected due to revised SALs or changes in instrumentation hardware and scaling/calibration.

6.10.3 Acceptance Criteria and Results

The setpoint methodology defines the distance between the limiting *IP3 Updated Final Safety Analysis Report* (UFSAR) (Reference 3) SAL and the NTS as the channel uncertainty (CU), plus any setpoint margin that may have been applied. Margin is defined as the difference between the calculated limiting NTS (SAL plus or minus CU) and the implemented NTS. The acceptance criterion for the RTS/ESFAS setpoints is that margin is greater than or equal to zero.

Setpoint calculations were performed for the affected RTS/ESFAS parameters. Table 6.10-1 summarizes the most limiting SALs, NTS, and *Technical Specifications* AVs for the parameters that were affected by the IP3 SPU. Incorporation of these AVs and NTS changes will support operation at SPU conditions in a manner consistent with the UFSAR (Reference 3) assumptions. Functions not listed in Table 6.10-1 were not affected by the IP3 SPU. The steam generator water level uncertainty calculations included the resolution of the generic uncertainty issues (References 4 through 7), which are unrelated to the SPU.

6.10.4 Conclusions

With the setpoint and allowable value changes as shown on Table 6.10-1, all of the RTS/ESFAS functions have acceptable margins and, therefore, are acceptable for operation at the uprated core power of 3216 MWt.

6.10.5 References

1. Appendix A to Facility Operating License DPR-64 for Entergy Nuclear Indian Point 3, LLC and Entergy Nuclear Operations, Inc., *Indian Point Nuclear Generating Plant Unit No. 3 Docket No. 50-286 Technical Specifications and Bases.*

2. IP3 Engineering Standard IES-3B, *Instrument Loop Accuracy and Setpoint Calculation Methodology*, Rev. 0

3. *Indian Point Nuclear Generating Unit No. 3 – Updated Final Safety Analysis Report*, Rev. 18, Docket No. 50-286.

4. NSAL-02-03, *Steam Generator Mid-deck Plate Pressure Loss Issue*, Rev. 1, April 2002.

5. NSAL-02-04, *Maximum Reliable Indicated Steam Generator Water Level*, Rev. 0, February 2002.

6. NSAL-02-05, *Steam Generator Water Level Control System Uncertainty Issue*, Rev. 1, April 2002.

7. NSAL-03-09, *Steam Generator Water Level Uncertainties*, Rev. 0, September 2003.

Table 6.10-1 IP3 SPU Summary of RTS/ESFAS Setpoint Calculations			
Protection Function	**NTS**	**SAL Value**	**Tech. Spec. AV**
Nuclear Instrumentation System (NIS) Power Range Reactor Trip High Setpoint	≤108% rated thermal power (RTP)	118% RTP	≤111% RTP
Overtemperature ΔT Reactor Trip			
K_1 Max		1.42	
K_1 Nominal	≤1.22		≤1.26
K_2	0.022 /°F	0.022 /°F	
K_3	0.00070 /psi	0.00070 /psi	
Overpower ΔT Reactor Trip			
K_4 Max		1.164	
K_4 Nominal	≤1.074		≤1.10
K_5 (decreasing T_{avg})	0	0	
K_5 (increasing T_{avg})	0.0175/°F	0.0175/°F	
K_6 ($T \geq T''$)	0.0015/°F	0.0015/°F	
K_6 ($T < T''$)	0	0	
Pressurizer Pressure Low (Reactor Trip)	1930 psig	1850 psia	1900 psig
Pressurizer Pressure Low (SI Initiation)	1780 psig	1648.7 psia	1710 psig
Steam Flow in Two Steamlines – High (SI/SL actuation)	≤43% full flow between 0 and 20% load, increasing linearly to ≤110% full flow at 100% load	78% full flow between 0 and 20% load, increasing linearly to 144% full flow at 100% load (1)	≤54% full flow between 0 and 20% load, increasing linearly to ≤120% full flow at 100% load
T_{avg} – Low Coincidence with High Steam Flow (SI/SL actuation)	≥542°F	535°F (1)	≥540.5°F

Note:

1. Although the SAL is beyond the instrument range, the uncertainty calculation confirmed that all uncertainties subject to saturation can be accommodated between the NTS and the instrument span limit.

6.11 Radiological Assessments

6.11.1 Introduction

This section addresses the radiological effects of the stretch power uprate (SPU) at Indian Point Unit 3 (IP3). The current licensing basis core power level is 3067.4 MWt. The SPU core power level is 3216 MWt (that is, an increase of approximately 4.85 percent with respect to the current power level).

The SPU was evaluated for its effect on the following radiological areas:

- Normal operation dose rates and shielding
- Normal operation annual radwaste effluent releases
- Radiological environmental doses for equipment qualification (EQ)
- Post-loss-of-coolant-accident (LOCA) access to vital areas
- Post-accident offsite and control room doses

In accordance with regulatory guidance, radiological evaluations for accident-related issues are assessed at a core power level of 3216 MWt plus 2 percent to address power measurement uncertainties (for a total of 3280.3 MWt). Installation of improved feedwater measurement instrumentation used for calorimetric power calculation allows for instrument error to be reduced from the traditional 2 percent as recommended in Regulatory Guide (RG) 1.49 (Reference 1). The reduction of the uncertainty allowance for calorimetric thermal power measurement to 0.6 percent was approved by the NRC in its *Safety Evaluation Report* (SER) for License Amendment No. 213 for IP3 (Reference 2). However, IP3 has decided to return to the use of the traditional 2 percent uncertainty.

Except as noted, radiological evaluations for normal-operation-related issues were assessed for the SPU at a core power level of 3216 MWt. In accordance with regulatory guidance, the radwaste effluent assessment assumed a core power level of 3280.3 MWt, but used flow rates and coolant masses at the Nuclear Steam Supply System (NSSS) power level of 3230 MWt.

The SPU evaluations discussed in this section associated with normal operation dose rate/shielding adequacy, normal operation radwaste effluents, environmental levels for equipment qualification, and vital access are based on scaling techniques. The scaled increase in radiation levels also includes the effect of the change in fuel cycle length and the use of current computer codes, methodology, and nuclear data in developing the uprated core and reactor coolant inventory, versus the methodology computer tools, and nuclear data used in the development of the original licensing basis core/reactor coolant inventory. Note that for the most part, the percentage of the estimated increase that can be attributed directly to the power uprate is approximately the percentage of the core uprate.

The radiological consequences for the following design-basis accidents (DBAs) were re-analyzed to support the SPU:

- Main steamline break (MSLB)
- Locked reactor coolant pump (RCP) rotor
- Rod ejection
- Steam generator tube rupture (SGTR)
- Small-break LOCA (SBLOCA)
- Large-break LOCA (LBLOCA)
- Waste gas decay tank (GDT) rupture
- Volume control tank (VCT) rupture
- Holdup tank (HT) failure
- Fuel-handling accident (FHA)

As holder of an operating license issued prior to January 10, 1997, and in accordance with 10CFR50.67 (Reference 3) and *Standard Review Plan* (SRP) 15.0.1 (Reference 4), the accident source terms used in the IP3 SPU design-basis offsite and control room dose analyses have been revised to reflect the full implementation of alternative source terms (ASTs) as detailed in RG 1.183 (Reference 5).

The first use of the AST for IP3 involved only the postulated fuel handling accident and was reviewed and approved by the NRC in its SER for Operating License (OL) Amendment No. 215 (Reference 6). Subsequently, the radiological consequences analyses for all accidents included in the IP3 licensing basis have been revised to incorporate the AST and have been submitted to the NRC (Reference 7).

The analyses performed for the SPU have also followed the methodology outlined in RG 1.183 (Reference 5) and have utilized input assumptions consistent with the proposed nominal core power of 3216 MWt and are presented in subsection 6.11.9 of this document.

6.11.2 Regulatory Approach

Summarized below are the regulatory acceptance criteria that were used for the SPU assessments.

6.11.2.1 Normal Operation Assessments

The regulatory commitments currently associated with normal operation assessments are not affected by this application and remain applicable for the SPU assessment:

- Normal operation onsite dose rates and available shielding will meet the requirements of 10CFR20 (Reference 8) as it relates to allowable operator exposure and access control.

- Normal operation offsite releases and doses will meet the requirements of 10CFR20 and 10CFR50, Appendix I (Reference 9). Performance and operation of installed equipment as well as reporting of offsite releases and doses will continue to be controlled by the requirements of the *Technical Specifications* (Reference 10) and the *Offsite Dose Calculation Manual* (Reference 11).

6.11.2.2 Accident Assessments

The regulatory commitments associated with accident assessments are summarized below:

- Offsite doses:

  The acceptance criteria for the exclusion area boundary (EAB) and low-population zone (LPZ) doses are based on 10CFR50.67 (Reference 3) and Table 6 of RG 1.183 (Reference 5) (also noted in Table 1 of SRP 15.0.1 [Reference 4]):

  — An individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release should not receive a radiation dose in excess of the accident-specific total effective dose equivalent (TEDE) value noted in RG 1.183 (Reference 5), Table 6.

  — An individual located at any point on the outer boundary of the LPZ who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage) should not receive a radiation dose in excess of the accident-specific TEDE value noted in RG 1.183 (Reference 5), Table 6.

  — The GDT rupture, VCT rupture, and HT failure are not specifically addressed in RG 1.183 (Reference 5). The acceptance criterion used for these events is assumed to be 0.5 rem consistent with the guidance of RG 1.26 (Reference 12). The criterion is applied as 0.5 rem TEDE to be consistent with an AST application.

- Control Room Dose: The acceptance criterion for the control room dose is based on 10CFR50.67 (Reference 3).

  — Adequate radiation protection is provided to permit occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) TEDE for the duration of the accident.

- Equipment Qualification:

  The SPU EQ assessment takes into consideration the effect of a core power uprate using scaling techniques and TID-14844 source terms (Reference 13). This approach is acceptable, based on Section 1.3.5 of RG 1.183, which indicates that though EQ analyses affected by plant modifications should be updated to address the effects, no plant modification is required to address the effect of the difference in source term characteristics (that is, AST versus TID-14844) on EQ doses.

- Vital Area Access Doses:

  The vital area access dose assessment for the SPU takes into consideration the effect of core power uprate using scaling techniques and TID-14844 (Reference 13) source terms. This approach is acceptable based on the bench-marking study reported in SECY-98-154 (Reference 14), which concluded that results of analyses based on TID-14844 would be more limiting earlier in the event.

  The SPU assessment took into consideration the IP3-specific regulatory commitments associated with post-LOCA vital area access. In accordance with NUREG-0737, Item II.B.2 (Reference 15), each power reactor licensee was required to perform a radiation and shielding design review of spaces around systems that may, as a result of an accident, contain highly radioactive material. Additionally, each licensee was required to provide for adequate access to vital areas and protection of safety equipment by design changes, increased permanent or temporary shielding, or post-accident procedure controls.

6.11.3 Computer Codes

The Quality Assurance (QA) Category 1 computer code used by Westinghouse to support this application is *ORIGEN2, Isotope Generation and Depletion Code – Matrix Exponential Method* (Reference 16). The referenced computer code has been used extensively to support nuclear power plant design.

6.11.4 Radiation Source Terms

6.11.4.1 Introduction

This section describes the input parameters and methodology used in the calculation of radiation source terms applicable to the IP3 SPU. Radiation source terms for several different accident- and normal-operating conditions were determined for the SPU conditions. These source terms were used as input to dose and balance-of-plant (BOP) analyses. The re-analyzed areas included the following:

- Core inventory and FHA fission product activities
- Reactor Coolant System (RCS) design basis sources
- Volume control tank sources
- Tritium sources
- Control room direct dose following a large-break LOCA
- Normal primary and secondary coolant source

Each of these source term calculations is discussed in subsequent subsections.

6.11.4.2 Core Inventory and Fuel-Handling Accident Sources

6.11.4.2.1 Input Parameters and Assumptions

The assumptions and input parameters used in the determination of the total core inventory are summarized in Tables 6.11-1 and 6.11-2.

6.11.4.2.2 Description of Analysis

Fuel burnup and fission product production were modeled using the ORIGEN2 code (Reference 16). ORIGEN2 is a versatile point-depletion and radioactive decay code for use in simulating nuclear fuel cycles and calculating the nuclide concentration and characteristics of materials contained therein. The code considers the transmutation of isotopes in the material. For the relatively high fluxes in the core region of the reactor, burn in and burn out of isotopes can have an important effect. This is particularly true for fuel cycle designs with high-burnup regions. These important effects are modeled in the ORIGEN2 calculations.

For the transition to cycles with the SPU power level, the core inventory calculation was performed for Cycles 14 through 16. The core inventory for these three cycles differed very little. For the IP3 SPU, Cycle 16 operating at the SPU power conditions was modeled in the

ORIGEN2 calculations as the base case, the case from which results were taken. The characteristics of Cycle 16 are provided in Tables 6.11-1 and 6.11-2.

The ORIGEN2 analysis for the SPU modeled a single fuel assembly from each region of the core. Burnup calculations that reflect each of the appropriate power histories were performed, and the total inventory for each region at the end of the transition cycle was then determined by multiplying the individual assembly isotopic inventory by the number of assemblies in the respective regions. Finally, the results for each region of the core were summed to produce the total core inventory.

To accommodate variations in fuel design and fuel management, a multiplier of 1.04 was applied to the core inventory of Cycle 16. A decay time of 84 hours after shutdown was used for the FHA source term. The inventory for one average fuel assembly can be obtained by dividing the core inventory by 193 assemblies.

6.11.4.2.3 Acceptance Criteria

There are no specific acceptance criteria since this is an input to various radiological evaluations.

6.11.4.2.4 Results

The total core inventories of actinide and fission product activities for use in radiological evaluations are presented in Table 6.11-3.

6.11.4.3 RCS Fission Product Activities

6.11.4.3.1 Input Parameters and Assumptions

Based on the core loading parameters in Tables 6.11-1 and 6.11-2, the parameters used in the calculation of the reactor coolant fission product concentrations, including pertinent information concerning the expected coolant cleanup flow rate, are presented in Table 6.11-4. In the RCS activity calculations, fission product escape rate coefficients were used to model a 1-percent level of small cladding defects (that is, 1 percent of the power that is being produced by fuel rods that have cladding defects) in all fuel regions for the fuel cycle.

6.11.4.3.2 Description of Analysis

The fission product inventory in the reactor coolant during operation of the fuel cycle with a 1-percent level of small cladding defects was computed. No credit was taken for fission product removal due to purge of the VCT. Furthermore, in determining the RCS inventory for individual isotopes, the maximum activity occurring at any time during the fuel cycle was documented in each case. Therefore, the total set of fission product concentrations did not represent any particular time during the fuel cycle, but rather, a composite of the maximum activity concentration exhibited by each isotope. This overall approach provided a conservative treatment of the RCS.

For fission products, effects of the following variations were estimated and included conservatively in the calculation of RCS activities:

- Lower-than-expected letdown flow
- Application of a 1.04 multiplier to calculated specific activities
- Core power increased by 2 percent for power determination uncertainty
- Low RCS mass

Tritium and corrosion product values, which are not directly related to reactor power, were taken as the greater of standard Westinghouse values or nominal values from ANSI/ANS-18.1-1999 (Reference 17).

6.11.4.3.3 Acceptance Criteria

There are no specific acceptance criteria since this is an input to radiological evaluations that are presented in subsection 6.11.9 of this report.

6.11.4.3.4 Results of Analyses

The RCS-fission product and corrosion-product specific activities are given in Table 6.11-5 and were provided as input to radiological evaluations.

6.11.4.4 Volume Control Tank Inventory

6.11.4.4.1 Input Parameters and Assumptions

The input and methods for calculating the VCT inventory are the same as those used in the RCS source calculations except that the VCT purification flow rate is based on the maximum flow rate (132 gpm) as opposed to the nominal flow rate (45 gpm) that was used in the RCS calculations.

In addition, for Kr-85, it is assumed the Kr-85 in the VCT was in equilibrium with the RCS in accordance with Henry's Law.

6.11.4.4.2 Description of Analyses

Radiological inventories for the VCT were based on the calculation of RCS and VCT nuclide concentrations with the maximum letdown flow of 132 gpm. As with RCS activities, a multiplier of 1.04 is applied.

Values for the gas inventory in the VCT are based on a vapor volume of 266 ft^3.

6.11.4.4.3 Acceptance Criteria

There are no specific acceptance criteria since this is an input to radiological evaluations that are presented in subsection 6.11.9.

6.11.4.4.4 Results of Analyses

The VCT radionuclide inventory is given in Table 6.11-6.

6.11.4.5 Tritium Sources

6.11.4.5.1 Input Parameters and Assumptions

Tritium generation is based on the cycle design described in Tables 6.11-1 and 6.11-2; tritium release fractions to the reactor coolant are given in Table 6.11-7.

6.11.4.5.2 Description of Analysis

Tritium generation is based on a calculation of tritium generation in the active core (fuel rods and coolant water) from ternary fissions, soluble boron and lithium in the coolant, and deuterium reactions in the coolant during normal operation.

The tritium generation calculations use the reactor power level, a set of groupwise neutron fluxes, groupwise neutron reaction cross sections, and water masses in the active core region, to predict the tritium generation. The design value of release of tritium from ternary fissions to the coolant is 10 percent of generation; the expected value is 2 percent.

6.11.4.5.3 Acceptance Criteria

The results of the tritium source analysis are used to evaluate plant tritium generation and release. There are no acceptance criteria for these stand-alone calculations.

6.11.4.5.4 Results of Analyses

The calculated tritium generation and release to the reactor coolant is provided for evaluation of plant tritium releases. A summary of the results of this tritium generation and release analysis is given in Table 6.11-7.

6.11.4.6 LOCA DBA Direct Control Room Dose

6.11.4.6.1 Input Parameters and Assumptions

The assumptions and input parameters used in determining the total core inventory are summarized in Tables 6.11-1 and 6.11-2.

Other input parameters for this analysis include the reactor containment vessel and Containment Shield Building dimensions, the control room location relative to the Reactor Containment Building, the location and dimensions of selected Auxiliary Building walls and floors, and the time at which removal of gaseous activity starts. These are discussed below:

- The containment dome is a 67.5-foot radius hemisphere with a thickness of 3.5 feet of concrete.

- The cylindrical portion of the containment is treated as a 67.5-foot radius cylindrical shell with a thickness of 4.5 feet of concrete. The height of the cylinder is considered to be 145 feet.

- The containment liner has a thickness of ¼ inch of steel.

- The crane support wall has a thickness of 3 feet of concrete and is 49 feet in height.

- The shielding afforded by the control room walls and structures is equivalent to 2 feet of concrete.

- Removal of non-gaseous activity occurs at 4.0 hours (for the control room direct dose applications only).

6.11.4.6.2 Description of Analyses

The gamma radiation source within containment following a LOCA DBA is based on the RG 1.183 methodology (Reference 5) and is calculated using the ORIGEN2 computer code. Source strength is reported in units of MeV/sec and MeV, respectively.

The gamma radiation going directly from the containment into the control room was calculated using the ORIGEN2 computer code. In the calculation, the containment volume was treated as two separate source regions, that is, the containment dome and the cylindrical section of the containment. The results from these two sources were then summed to give the total normalized dose rate.

The detector point was placed at a point just inside the control room location.

6.11.4.6.3 Acceptance Criteria

The calculation provided a radiation source to be used as input to other calculations. As such, there are no specific criteria for this portion of calculated results.

6.11.4.6.4 Results of Analyses

Containment gamma radiation source strength per unit time and integrated source strength for the LOCA DBA are given in Figures 6.11-1 and 6.11-2, respectively.

The 1-month calculated direct dose in the control room is 0.273 mrem. Applying an additional 4 percent for fuel management variations gave a control room dose of 0.284 mrem.

Dose rate and dose are illustrated in Figure 6.11-3.

6.11.5 Normal Operation Dose Rates and Shielding

6.11.5.1 Introduction

Cubicle wall thickness is specified not only for structural and separation requirements, but also, to provide radiation shielding in support of radiological EQ, and to reduce operator exposure during all modes of plant operation, including maintenance and accidents.

Conservative estimates of the radiation sources in plant systems and components form the bases of normal operation plant shielding and radiation zoning. These radiation source terms are primarily derived from conservative estimates of the reactor core and RCS isotopic inventory and are referred to as "design basis" source terms. The SPU will affect the isotopic inventory in the core. In addition, since the design basis RCS source term is based on 1-percent fuel defects, the SPU will result in an increase in the design basis RCS concentration.

The "expected" radiation source terms in the coolant will also be affected by core SPU. Expected source terms are less than those allowable by the plant *Technical Specifications* and are usually significantly less than the design basis source terms.

The effects of the SPU on the normal operation dose rates and the adequacy of existing shielding were evaluated to ensure continued safe operation within regulatory limits. The effect of the SPU on the normal operation component of the total integrated dose used for radiological environmental qualification is discussed in subsection 6.11.8.

6.11.5.2 Description of Analysis and Evaluations

The core SPU from 3067.4 MWt to an analyzed power level of 3216 MWt will increase the activity inventory of fission products in the core by approximately the percentage of the SPU. The radioactivity levels in the primary coolant, secondary coolant, and other radioactive process systems and components will also be affected.

The original shielding design for IP3 was based on a core power level of 3216 MWt, a traditional one-year fuel cycle and a design RCS source term based on 3216 MWt and 1-percent failed fuel. To reflect SPU conditions, new radiological source terms were developed for the core and the RCS. The SPU core inventory is based on 3280.3 MWt and a 24-month fuel cycle. The SPU design RCS source term is based on 3280.3 MWt with 1-percent failed fuel, a 24-month fuel cycle, a conservative purification flow, and an additional multiplier of 1.04 to accommodate fuel management variations. The inclusion of the 24-month fuel cycle will serve to increase the inventory of the long-lived isotopes.

The assessment of the effect of the SPU and the use of a 24-month fuel cycle on normal operation plant radiation levels as well as radiation zoning and shielding adequacy addresses the following four areas:

- Areas near the reactor vessel where the dose rate is dominated by the reactor core neutron flux during power operation and gamma radiation from the irradiated fuel and neutron activated sources during shutdown
- Areas in containment that are not in proximity to the reactor but are adjacent to the RCS sources, where the dose rate is dominated by the high-energy gammas associated with Nitrogen-16 (N-16)

- Areas near spent fuel assemblies where the dose rate is dominated by the gamma radiation from the irradiated fuel

- Areas outside the containment, where the dose rate is determined by radiation sources derived from primary coolant activity

The evaluation of the effect of the SPU on the normal operation plant radiation levels is focused on the change in the expected radiation source terms in the areas discussed above.

Since plant shielding is designed to encompass all modes of operation, including anticipated operational occurrences, the evaluation of the effect of SPU on radiation zoning and shielding adequacy is based on the change in design radiation source terms. The original design RCS activity concentration, the gamma energy emission rate, and the resulting dose rates are compared to the uprate design RCS activity concentration, the gamma energy emission rate, and the resulting dose rates. The limitations imposed by the plant *Technical Specification* on the allowed reactor coolant activity concentrations are included in the evaluation.

6.11.5.2.1 Plant Radiation Levels

For the same source-shield-detector configuration, the dose rate at a given detector point is directly proportional to the neutron/gamma flux leaking out of the source region or the volumetric gamma source strength in the source region. This flux or activity increase factor for a given radiation source is the SPU scaling factor for the expected dose rate due to that source. Note that this portion of the assessment takes into consideration that the current in-plant radiation levels already reflect the 24-month fuel cycle.

<u>Dose Rates near Reactor Vessel</u>: During normal operation, the radiation source in the reactor core is primarily made up of neutron and gamma fluxes, which are approximately proportional to the core power level.

The radiation sources during shutdown are the gamma fluxes in the core due to decay and the activation activities in the reactor internals, pressure vessel, and primary system piping walls, which also vary approximately in proportion to the core power.

Therefore, the SPU from the current licensed core power of 3067.4 MWt to the analyzed core power level of 3216 MWt is expected to increase the normal operation radiation levels in areas near the reactor vessel by a factor of approximately 1.05; that is, 3216/3067.4.

In-Containment Areas Adjacent to the RCS: During normal operation, the major radiation source in the RCS components located within containment is the high energy, short half-life, gamma emitter N-16. N-16 is produced as the oxygen (of the water moderator) is exposed to the fast neutron flux present in the reactor core. The amount of activation is defined by the fast flux level (or power density) of the core and the amount of time the moderator is resident in the core. After the moderator exits the core (and neutron field), decay of the N-16 will occur.

During shutdown, the major radiation sources in the RCS components located within containment are the deposited corrosion products on the internal surfaces and the primary coolant activity without N-16.

With the SPU, the fast neutron flux is expected to increase by approximately the percentage of uprate, that is, 5 percent. The coolant residence time in the core and the transit time are not expected to change significantly due to the SPU. Therefore, the appropriate uprate scaling factor for the areas subjected to the N-16 source is 1.05.

The deposited corrosion product activity depends on RCS chemistry and cobalt impurity in RCS and steam generator components. Assuming the water chemistry remains the same, the SPU will increase the neutron flux by approximately the percentage of uprate (5 percent) and, therefore, the equilibrium corrosion product activity and the associated shutdown dose rate is also expected to increase by 5 percent.

Areas Near Irradiated Fuels and Other Irradiated Objects: These areas include the refueling canal, the spent fuel pit, the incore instrumentation drive assembly area, and other areas housing neutron-irradiated materials. The radiation source is the gamma rays from the fission products and activation products, which are determined by the fission rate, neutron flux level and the irradiation time associated with the referenced irradiated fuels and objects.

Since both the fission products and the activation products associated with the irradiated fuels and other objects are expected to increase by approximately the percentage increase in core power, the SPU scaling factor for the areas subjected to irradiated fuels and other irradiated sources is 1.05.

Areas Outside Containment where the Radiation Source is Derived from the Primary Coolant Activity: In most areas outside the reactor containment, the radiation sources are either the primary coolant itself or down-stream sources originating from the primary coolant activity. The reactor coolant activity is dominated by the fission products, which vary approximately in proportion to the reactor power. The neutron activated corrosion products (Co-60, Co-58, etc.) are also important radionuclides in the filters. The deposited activity of corrosion products on the pipe internal surface is a major dose contributor during the shutdown maintenance. If everything remains the same after the SPU, the RCS corrosion product concentration and the equilibrium deposited corrosion product are expected to increase by approximately the same percentage as the SPU due to the increased neutron flux level.

Since both the fission products and the activated corrosion products are expected to increase by approximately 5 percent for a core power increase from 3067.4 MWt to the analyzed power level of 3216 MWt, the SPU scaling factor for the areas outside containment where the radiation source is derived from the primary coolant activity is 1.05.

6.11.5.2.2 Radiation Zoning and Shielding Adequacy

Shielding is used to reduce radiation dose rates in various parts of the station to acceptable levels consistent with operational and maintenance requirements, and also below the limits specified in 10CFR20 (Reference 8). The shielding is designed to encompass all modes of operation, including anticipated operational occurrence. The original IP3 shielding design was based upon generalized occupancy requirements in various radiation zones of the station, and upon conservative radiation source terms in various plant systems. The occupancy requirements are not affected by the SPU. The layout and configuration of systems containing radioactivity are assumed unchanged in this SPU evaluation. This evaluation focuses on comparisons of the radiation source terms used in the original plant shielding design, (as documented in the *Updated Final Safety Analysis Report* (UFSAR) (Reference 18) Section 11.2 and its supporting documentation), to the corresponding SPU source terms.

Reactor Primary Shield: The primary shield is a reinforced concrete structure that surrounds the reactor vessel. The primary function is to attenuate the neutron and gamma fluxes leaking out of the reactor vessel. The IP3 primary shield was designed for a reactor power of 3216 MWt. It was designed to reduce the exiting thermal neutron flux to less than 10^6 n/cm^2-sec during full power operation and the exiting gamma dose rate to less than 15 mrem/hr during shutdown.

Area dose rates during normal plant operation at 100-percent power bound those expected during all other modes of operation including shutdown and are, therefore, the basis of the dose estimates used for environmental qualification and shielding. Since the dose rates near the reactor vessel at 100-percent power are dominated by neutron and gamma fluxes from the core fission process, the effect of the 24-month fuel cycle is insignificant.

The original calculations of neutron and gamma ray leakage fluxes from the IP3 reactor were based on a design basis core configuration that included fresh fuel (generally higher power) on the core periphery, providing the greatest contribution to neutron and gamma leakage. Review of recent IP3 fluence calculations confirms that the original design remains bounding for SPU conditions. With continued use of low leakage fuel management in the SPU design, the existing primary shielding remains adequate and the dose rates adjacent to the reactor vessel/primary wall are within the design objective.

Reactor Secondary Shielding: The secondary shield is a reinforced-concrete structure that surrounds the RCS pipes, pumps and steam generators. The secondary shield also includes the reactor containment structure and the concrete operating floor over the primary coolant loops. The primary function is to attenuate the N-16 source, which emits high-energy gammas. The secondary shield was designed to limit the full power dose rate outside the containment building to less than 0.75 mrem/hr. The original design basis reactor coolant N-16 activity is based on a core power level of 3216 MWt.

Area dose rates during normal plant operation at 100-percent power bound those expected during all other modes of operation including shutdown and are, therefore, the basis of the dose estimates used for environmental qualification and shielding. Note that due to its short half-life, the N-16 activity level is not affected by the use of 24-month fuel cycle.

Since the reactor power for the original N-16 design activity is at the analyzed SPU power of 3216 MWt, the current secondary shield is adequate for continued safe operation at the SPU power.

Fuel Handling Shielding: This shielding provides protection during all phases of removal and storage of spent fuel and control rod cluster. The design basis for refueling shielding is presented in UFSAR (Reference 18) Section 11.2.2 and Table 11.2-5, and is based on 193 fuel assemblies (for a total reactor power of 3216 MWt), a maximum full power exposure of 1000 days, and a minimum fuel removal delay time of 56 hours. The fuel handling shield was designed to insure a calculated maximum dose rate in the areas adjacent to the spent fuel pit of less than 0.75 mrem/hr.

The 24-month fuel cycle will increase the long-lived isotopes in the irradiated fuel. It will also increase the activity of those isotopes for which the thermal neutron activation production mode is important, (such as Cs-134m, Cs-134, Cs-136, Rb-86, I-130, and Sm-153), due to increased thermal neutron flux toward the end of the fuel cycle. However, this is not a significant concern as the dose rates near the refueling canal and the spent fuel pit are dominated by the shorter half-life isotopes in the freshly discharged spent fuel assemblies and the gamma source from the above-mentioned neutron activation isotopes constitutes only a small percentage of the total source. It is, therefore, concluded that the current spent fuel shielding is adequate for continued safe operation at the SPU power and with a 24-month fuel cycle.

Outside Containment Shielding: In support of shielding provided outside the containment, where the radiation sources are either the reactor coolant itself or down-stream sources originating from coolant activity, a review was performed of the SPU design primary coolant source terms (fission and activation products) versus the original design basis primary coolant source terms. A comparison was performed of the gamma energy emission rates by energy group for the SPU versus the original primary coolant source terms. The sources included total primary coolant, degassed primary coolant and the primary coolant noble gas source. Due to the change in isotopic compositions and gamma energy spectrum between the original and the uprated RCS fluid, the comparison was based on the dose rate shielded by 0, 1, 2, and 3 feet of concrete for representative source geometry. The SPU evaluation reflects the change in fuel cycle length, difference in computer codes used in generating the source terms, and the difference in nuclear libraries. The evaluation takes into consideration the conservative simplified modeling typically employed in shielding design and considers the operation limits imposed by the plant *Technical Specification* on the primary coolant activity.

The dose rate ratios resulting from comparison of the SPU source to the pre-SPU source for the various design basis source term and shielding configurations discussed above ranged from 1.1 to 3.3. However, since the design basis SPU primary coolant activity is a very conservative source term (that is, based on 1-percent failed fuel, a very small purification flow, a 2-percent margin for power uncertainty and an additional 4-percent margin for fuel management schemes), credit is taken for a more realistic but limiting upper bound primary coolant activity based on the plant *Technical Specification* (Reference 10).

Due to similarity in the effectiveness of removal mechanisms such as demineralizers and filters, the *Technical Specification* on the iodine concentration will control both the iodines as well as the non-gaseous radionuclides in the reactor coolant with similar effectiveness. The *Technical Specification* limit on the gross activity levels (which are dominated by noble gases and their daughters), will control the level of noble gases in the reactor coolant.

The SPU assessment indicates that the *Technical Specifications* will limit the uprated RCS and degassed RCS to less than 80 percent of the original design basis source terms. In addition, the *Technical Specification* limits on the reactor coolant gross activity will maintain the SPU RCS gas activity at approximately the original design basis source terms.

Therefore, taking into consideration the limits on reactor coolant concentrations imposed by the plant *Technical Specifications* and the conservatism in the SPU design source terms, it is concluded that the shielding design based on the original design basis primary coolant activity remains valid at the SPU condition.

6.11.5.3 Acceptance Criteria

Following the SPU, normal operation dose rates and available shielding must continue to meet those requirements of 10CFR20 (Reference 8) related to allowable operator exposure and access control.

6.11.5.4 Results and Conclusions

The SPU will affect the radiation source terms in the core and the expected radiation source terms in the coolant. Expected source terms are less than those allowable by the plant *Technical Specifications* and are usually significantly less than the design basis source terms.

Since the plant is already operating with a 24-month fuel cycle, the normal operation radiation levels are expected to increase by approximately 5 percent, that is, by the percentage of core SPU. The exposure to plant personnel and to the offsite public is also expected to increase by the same percentage.

The increase in expected radiation levels will have no significant effect on plant normal operation radiation zones and shielding adequacy. This is because the increase is offset by the:

- Conservative analytical techniques typically used to establish shielding requirements,
- Conservatism in the original design basis RCS source terms used to establish the radiation zones, and
- Plant *Technical Specifications* that limit the RCS concentrations to levels below or equal to the original design basis source terms.

Individual worker exposures will be maintained within regulatory limits by the site As-Low-As-is-Reasonably-Achievable (ALARA) Program, which controls access to radiation areas.

6.11.6 Normal Operation Annual Radwaste Effluent Releases

6.11.6.1 Introduction

Liquid and gaseous effluents released to the environment during normal plant operations contain small quantities of radioactive materials.

Liquid Radioactive Waste: Liquids from reactor process systems, or liquids that have become contaminated with these process system liquids, are considered liquid radioactive waste. These wastes are then processed according to their purity level (boron concentration, conductivity, insoluble solids content, organic content, and activity) before being recycled within the plant, discharged to the environment, or reprocessed through the Radioactive Waste System for further purification until the dose guidelines of 10CFR50, Appendix I (Reference 9) are met.

Gaseous Radioactive Waste: Airborne particulates and gases vented from process equipment as well as the building ventilation exhaust air are considered gaseous radioactive waste. The major source of gaseous radioactive waste (processing the reactor coolant by the gas stripper and the cover gas system) is continuously decayed using separate pressurized decay tanks. It is then filtered and monitored prior to release to ensure that the dose guidelines of 10CFR50 Appendix I are not exceeded.

The design of the liquid and gaseous radwaste systems must be such that the plant is capable of maintaining normal operation offsite releases and doses within the requirements of 10CFR20 and 10CFR50, Appendix I. (Note that actual performance and operation of installed equipment, and reporting of actual offsite releases and doses continues to be controlled by the requirements of the *IP3 Offsite Dose Calculation Manual* [Reference 11].)

The SPU does not change existing radioactive waste systems (gaseous and liquid) design, operating procedures, or waste inputs. Consequently, a comparison of releases can be made based on inventories/coolant concentrations in the RCS, and secondary side steam and water inventories and concentrations. As a result, the effect of the SPU on radwaste releases and Appendix I doses can be estimated using scaling techniques.

Based on an existing licensed core power level of 3067.4 MWt and an analyzed SPU core power level of 3216 MWt, it is expected that the radioactive effluents and consequent offsite doses will increase by approximately the percentage increase in core power, that is, approximately 5 percent.

The conservatively performed SPU analysis considered:

- The plant core power operating history during the years 1998 to 2002
- The reported effluent and dose data during that period
- NUREG-0017 (Reference 19) assumptions
- Conservative methodology

The analysis estimated the effect of operation at the analyzed core power level of 3280.3 MWt (3216 MWt plus instrument uncertainty) over that of current operation (based on the 5-year data) on radioactive effluents and consequent offsite doses.

6.11.6.2 Description of Analyses and Evaluations

The SPU will increase the activity level of radioactive isotopes in the primary and secondary coolant. Due to leakage or process operations, fractions of these fluids are transported to the liquid and gaseous radwaste systems where they are processed prior to discharge. As the activity levels in the primary and secondary coolant are increased, the activity level of radwaste inputs are proportionately increased. Regulatory guidance relative to methodology to be utilized to establish whether the radwaste effluent releases from a pressurized water reactor (PWR) meet the requirements of 10CFR20 (Reference 8) and 10CFR50 Appendix I (Reference 9) is provided in NUREG-0017 (Reference 19), Rev. 1.

The methodology utilized in NUREG-0017 is independent of the fuel cycle length in that, in determining the nominal coolant activities provided in NUREG-0017, isotopic concentrations from a number of plants and power levels were combined and adjusted to yield a dataset with a resulting range of uncertainty. Adjustment factors were provided to address facilities outside a nominal range in which coolant activities could be used without adjustment. The core power levels addressed for the IP3 base and SPU cases are within the range of applicability and input data that was used to develop NUREG-0017.

The IP3 annual radioactive effluent release reports for 1998 through 2002 demonstrate that the current gaseous and liquid radwaste releases from the site are well within the release/dose limits set by 10CFR20 and 10CFR50, Appendix I. The effect of the SPU on these releases was evaluated to ensure continued operation within regulatory limits.

The licensed reactor core power level of IP3 during the 1998 to 2002 time frame was 3025 MWt. The SPU assessment addresses a core power level of 3280.3 MWt. The system parameters for SPU conditions reflect the flow rates and coolant masses at an NSSS power level of 3228.5 MWt. For the pre-SPU condition, the evaluation utilized offsite doses based on an average five-year set of organ and whole body doses calculated from effluent reports for the years 1998 through 2002, including the associated average annual core power level extrapolated to 100-percent availability. Releases occurring during periods of IP3 shutdown were conservatively lumped with operational releases and included in the doses scaled for 100-percent availability.

Using the methodology and equations found in NUREG-0017 (Reference 19) with the plant-specific parameters for the SPU case, the percentage change for activity classes in the reactor coolant and secondary coolant (water and steam) were calculated. Relative changes in the noble gas activity inventory in the reactor coolant were also calculated; this was necessary for those releases that are based on coolant inventory such as noble gas released during shutdown operations. To estimate an upper bound effect on offsite doses, the highest factor found for any chemical group of radioisotopes pertinent to the release pathway was applied to the average doses previously determined as representative of operation at pre-SPU conditions (at 100-percent availability). This was used to estimate the maximum potential increase in effluent doses due to the SPU, and to demonstrate that the estimated offsite doses following SPU, although increased, continue to remain below the regulatory limits.

6.11.6.3 Acceptance Criteria

The liquid and gaseous radwaste systems' design must be such that the plant is capable of maintaining normal operation offsite releases and doses within the requirements of 10CFR20 (Reference 8) and 10CFR50, Appendix I (Reference 9) following the SPU. (Note that actual performance and operation of installed equipment as well as reporting of actual offsite releases and doses continue to be controlled by the requirements of the *Technical Specifications* [Reference 10] and the *IP3 Offsite Dose Calculation Manual* [Reference 11].) If the resulting doses estimated after the SPU are still a small fraction of the 10CFR50 Appendix I limits, then it is reasonable to conclude that the IP3 Radioactive Waste Systems and operating procedures will meet the design objectives of 10CFR50 Appendix I.

6.11.6.4 Results and Conclusions

Results

As indicated earlier, based on an existing licensed core power level of 3067.4 MWt, and an SPU core power level of 3216 MWt, it is expected that the radioactive effluents and consequent off-site doses will increase by approximately the percentage increase in core power, that is, approximately 5 percent.

Using NUREG-0017 (Reference 19) assumptions and conservative methodology, the SPU analysis results summarized below utilize the plant operating history to estimate the effect of the

SPU on radioactive effluents and consequent offsite doses, by comparing plant operation at the SPU core power level of 3280.3 MWt (which includes margin for power uncertainty) to plant operation at 2956.15 MWt (the effective core power level during the period 1998 through 2002). The estimated doses following the SPU are presented in Table 6.11-9.

6.11.6.4.1 Expected Reactor Coolant Source Terms

Based on a comparison of base versus SPU input parameters, and the methodology outlined in NUREG-0017 (Reference 19), the maximum expected increase in the reactor coolant source is approximately 12.1 percent for noble gases and 11 percent for other long half-life activity. The above change is primarily due to the estimated decrease in RCS mass (~1 percent) and increase in effective core power level (~11 percent, that is, 3280.3 MWt [uprate power level]/2956.15 MWt [average power level during 1998 - 2002) between pre- and post-SPU conditions. Considering the accuracy and error bounds of the operational data used in NUREG-0017, this percentage is well within the uncertainty of the existing NUREG-0017-based expected reactor coolant isotopic inventory used for radwaste effluent analyses.

6.11.6.4.2 Liquid Effluents

As discussed above, there is a maximum 11-percent increase in the liquid releases as input activities are based on long-term RCS activity (the relative increase of I-131 in the RCS is limiting—the maximum increase of cesiums and other nuclides is 11 percent), which is proportional to the SPU percentage increase, and on waste volumes that are essentially independent of power level within the applicability range of NUREG 0017. Tritium releases in liquid effluents are assumed to increase approximately 11 percent (corresponding to the effective core SPU percent), since the analysis identifies changes in an existing facility's power rating without changing its mode of operation.

6.11.6.4.3 Gaseous Effluents

For all noble gases, there will be a bounding maximum 12.1-percent increase in effluent releases due to the effective core SPU percentage increase. Gaseous effluents have two components: one is based on RCS inventory and results in an 11-percent increase and the other is based on concentration (due primarily to differences in RCS masses and the increase in effective core power level between the pre- and post-SPU conditions), which would result in a 12.1-percent increase. The limiting increase will be used for this evaluation, that is, 12.1 percent.

In actuality, gaseous releases of Kr-85 will increase by approximately the percentage of power increase (~11 percent). Gaseous isotopes with shorter half-lives will have increases slightly greater than the effective percentage increase in power level up to a bounding value of 12.1 percent.

Tritium releases in the gaseous effluents increase in proportion to their increased production, which is directly related to core power and is allocated in this analysis in the same ratio as pre-SPU releases.

The effect of the SPU on iodine releases is approximated by the effective power level increase and calculated increase in I-131 RCS concentration of 11 percent.

For particulates, the methodology of NUREG-0017 (Reference 19) specifies the release rate per year per unit per building ventilation system. This is not dependent on power level within the range of applicability. Particulates released via the Turbine Building from main steam leaks and air ejector exhaust are generally considered to be a small fraction of total particulate releases. Thus, minimal change would be expected for the SPU operations. However, a conservative approach is dictated by the fact that the annual effluent release reports do not delineate the "source" of particulates or iodines released. In addition, tritium is included in the category of iodines and particulates. On the secondary side, moisture carryover (MCO) is a major factor in determining the non-volatile activity in the steam. The multiplier applicable to the particulates released via the Turbine Building due to main steam leaks and air ejector exhaust is higher than the percentage of the SPU (primarily due to an estimated five-fold increase in MCO due to the SPU, coupled with an 11-percent increase in coolant concentration). However, the contribution of particulates to the "Iodine and Particulate" category was insignificant to the dose contribution from iodine or tritium. For these two species, iodine had the greater increase due to the addition of MCO to that of the volatile component resulting in a 12.3-percent increase in steam activity, while the tritium increase was bounded by the increase in power. Thus, the scaling factor for the entire category was conservatively estimated at 12.3 percent.

6.11.6.4.4 Solid Radioactive Waste

Though solid radwaste is not specifically addressed in 10CFR50, Appendix I (Reference 9), for completeness relative to radwaste assessments, the effect of SPU on solid radwaste generation is summarized below.

For a new facility, the estimated volume and activity of solid waste is linearly related to the core power level. However, for an existing facility that is undergoing power uprate, the volume of solid waste is not expected to increase proportionally, since the power uprate neither appreciably affects installed equipment performance, nor does it require drastic changes in system operation or maintenance. Only minor, if any, changes in waste generation volume are expected. However, it is expected that the activity levels for most of the solid waste would increase proportionately to the increase in long half-life coolant activity bounded by the effective increase in core power, that is, 11 percent.

Thus, while the total long-lived activity contained in the waste is expected to be bounded by the percentage, 11 percent, for SPU, the increase in the overall volume of waste generation resulting from the SPU is expected to be minor.

Conclusion

As discussed in subsection 6.11.6.3, under Acceptance Criteria, the commitment is to both 10CFR20 (Reference 8) and 10CFR50 Appendix I (Reference 9), however, 10CFR50 Appendix I is more limiting. 10CFR20 does have a release rate criteria that does not exist in 10CFR50 Appendix I, but as noted in subsection 6.11.6.3, the plant *Technical Specifications* (Reference 10) and the *IP3 Offsite Dose Calculation Manual* (Reference 11) control actual performance and operation of installed equipment and releases thus maintaining compliance with that aspect of 10CFR20.

In summary, and as documented in Table 6.11-9, the estimated doses due to annual radwaste effluent releases following the SPU remain a small percentage of the allowable 10CFR50 Appendix I limits. Therefore, it is concluded that, following the SPU, the liquid and gaseous radwaste effluent treatment system will remain capable of maintaining normal operation offsite doses within the requirements of 10CFR50, Appendix I.

6.11.7 Post-Accident Access to Vital Areas

6.11.7.1 Introduction

In accordance with NUREG-0578, 2.1.6.b (Reference 20) and NUREG-0737, II.B.2 (Reference 15), vital areas are those areas within the station that will or may require access or occupancy to support accident mitigation or recovery following a LOCA. In accordance with the above regulatory documents, all vital areas and access routes to vital areas, must be designed such that operator exposure remains within regulatory limits. NUREG 0737, II.B.3 identifies NRC requirements relative to operator exposure while performing post-accident sampling.

This section focuses on areas that may require infrequent access following a LOCA. Areas that require continuous occupancy, such as the control room and Technical Support Center, are addressed later in subsection 6.11.9 of this report.

The vital access shielding review that supports IP3 licensing basis relative to post-LOCA accessibility is documented in United Engineers & Constructors (UE&C) Report, *Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems which May Be Used in Post Accident Conditions*, (Reference 21). Post-LOCA accessibility based on the estimated radiation levels versus time was evaluated for about sixteen areas in the plant. This assessment was conservatively based on a power level of 3216 MWt and a traditional 1-year fuel cycle length. The NRC review of the referenced UE&C Report and plant modifications is documented in the NRC Inspection Report 50-286/83-05 (Reference 22). NRC acceptance of the IP3 actions taken or planned for post-accident vital area access is documented in SER, NUREG-0737, Item II.B.2. (Reference 23).

A finalized report (Report No. 6604-182-S-D-001, Revision 1), reflecting revised accessibility assessments resulting from the installation of some of the proposed modifications was issued by UE&C in August 1985 (Reference 24). As a result of the plant modifications/procedure updates, operator access requirements were reduced from the previous sixteen to eight locations. In accordance with NUREG 0737 II.B.2 (Reference 23), the evaluation focused on the de-pressurized LOCA.

Subsequent to the issuance of the final UE&C Report, and as a result of other plant modifications, additional operator access requirements have been identified and operator exposure resulting from these access requirements have been analyzed. These analyses are based on a power level of 3025 MWt. The core activity used for the containment airborne source is based on a fuel irradiation period of 830 days. The sump water source is based on a 24-month fuel cycle.

In addition, per the NRC SER related to Amendment No 210 (Reference 25), the need to have, maintain, and utilize the post-accident sampling system to support emergency response decision-making has been eliminated. Consequently, the IP3 licensing basis no longer includes areas associated with post-LOCA sampling and analyses as vital areas that need post-accident access.

The above documents were reviewed to assess the effect of operation at an analyzed SPU core power level of 3280.3 MWt and a 24-month fuel cycle on post-LOCA accessibility. In addition, and as part of the SPU evaluation, the above composite list of vital access requirements were reviewed against the Emergency Operations Procedures (EOPs) to develop a current validated list of vital area access requirements essential for accident mitigation and safe shutdown.

The SPU assessment addresses the impact on operator doses due to changes in the required time for the ECCS switchover to hot-leg recirculation following a LOCA. The current IP3 design allows all recirculating sump fluids to remain inside containment until T=14hours, which is the current time for ECCS switchover to hot-leg recirculation. The above change, which is caused by the use of an updated methodology at IP3 for boron precipitation evaluations, will result in sump fluids being recirculated outside containment starting from T=6.5 hours, instead of from T=14 hours.

The vital access dose assessment for SPU uses scaling techniques and TID-14844 (Reference 13) source terms.

6.11.7.2 Description of Analysis and Evaluations

The effect of the SPU on the radiation doses received while accessing or occupying vital areas during post-LOCA conditions is evaluated based on a comparison of the original design basis source terms to the SPU source terms.

The SPU post-LOCA gamma radiation dose rates at IP3 are compared to the gamma source terms based on the original core inventory used to develop the post-LOCA dose rates at IP3. The approach uses scaling techniques based on a source term comparison, rather than developing new dose rate estimates at the various locations, using the new core inventory.

The SPU will increase the activity level in the core by the percentage of the uprate. The estimated radiation source terms in equipment and structures containing post-accident fluids, and the corresponding post-LOCA environmental dose rates, will increase by the percentage of the SPU relative to the power level used in the analyses of record. Additional factors that can affect the equilibrium core inventory and consequently, the estimated operator dose are fuel enrichment and burnup. Theoretically, with all things being equal, the post-LOCA environmental gamma dose rates and the operator dose per identified mission should increase, as a worst case, by approximately 13 percent, that is:

$$3280.3 \text{ MWt} \times 1.04 / 3025 \text{ MWt}, = 1.13$$

Note: The multiplier of 1.04 was applied to the SPU inventory as a factor to account for variation in fuel design parameters.

However, because the uprated core reflects extended burnup and the more advanced fuel burnup modeling/libraries used in development of the uprated core, as compared to the computer code used in the original analyses, the calculated SPU scaling factor (SF) values will deviate from the core power ratio.

Radiological source terms for both the pre-SPU and SPU cases were developed for the following post accident sources discussed in the

- Final UE&C report documenting the original licensing basis:
  - Containment atmosphere, sprays not credited (100-percent noble gases and 25-percent halogens)
  - Sump water (50-percent halogens and 1-percent remainder solids)
- Subsequent analyses supporting additional assess requirements:
  - Containment atmosphere, sprays credited (the most limiting mixture that ranges from 100-percent noble gas and 50-percent halogens to 100-percent noble gas, and ~1-percent halogens)
  - Filters (halogens only)
  - Sump water (50-percent halogens and 1-percent remainder solids)

For the "unshielded" case, the factor effects on post-accident gamma dose rates were estimated by ratioing the gamma energy release rates weighted by the flux-to-dose-rate conversion factor, as a function of time, for the SPU power level, to the corresponding weighted source terms based on the pre-SPU power level. To address outside containment locations, the unshielded values included the shielding effect of a pipe wall thickness associated with a 2-inch nominal diameter pipe. This ensures that the results are not skewed by photons at energies less than 25 Kev, which will be substantially attenuated by any piping sources.

To evaluate the factor effect of the SPU on post-LOCA gamma dose rates (versus time) in areas that are shielded, the pre-SPU and SPU source terms discussed above were weighted by the concrete shielding factors for each energy group. The concrete shielding factors, for 1 and 3 feet of concrete, provided a basis for comparison of the post-LOCA spectrum hardness of source terms with respect to time for both original design and SPU cases.

The original licensing basis assessment documented in the UE&C Report conservatively did not credit the delay in the ECCS switchover to hot-leg recirculation. However, credit was taken for this delay in the subsequent vital access assessments. The impact of the change in time of ECCS switchover to hot-leg recirculation on the unshielded post-accident radiation dose rates and operator dose estimates in the subsequent analyses is developed by ratioing the total gamma energy release rates (weighted by the energy-specific flux-to-dose rate conversion factor) for the SPU sump fluids at the time of interest (for example, 6.5 hrs) to the weighted SPU sump water source terms at 14 hours multiplied by the estimated dose rate at T=14 hours. To address the impact of shielding, the source terms discussed above are weighted by the concrete shielding factors for each energy group and summed across all energy groups. The concrete shielding factors for 1 and 3 feet of concrete provide a basis for comparison of the post-LOCA spectrum hardness of source terms with respect to time.

6.11.7.3 Acceptance Criteria

- In some cases, the vital area assessment establishes expected operator mission doses. For those cases, the SPU acceptance criterion is to demonstrate continued compliance with the operator exposure dose limits of 5 rem noted in NUREG 0737, II.B.2 following SPU.

- For other cases, the vital area assessment establishes radiation levels in the area, but does not develop operator mission doses. For these cases, the SPU analysis will provide the estimated radiation levels following SPU. There are no acceptance criteria for this case. The licensing bases for such cases is availability of the radiation dose rate information such that the licensee can factor this information into any post-accident access planning.

6.11.7.4 Results and Conclusions

Results

Provided below is the effect of SPU including initiation of ECCS switchover to hot-leg recirculation at 6.5 hrs.

- Operator exposure during vital area access: At IP3, vital area access is required during the time period of T=30 mins to T=6.5 hrs (that is, prior to initiation of ECCS switchover to hot-leg recirculation). The bounding scaling factor for post-LOCA dose rates was used in the SPU assessment. The operator exposure during these vital missions will remain within the regulatory limit of 5-rem whole body following SPU.

- Post-LOCA accessibility in the PAB determined via radiation dose rate maps versus time. These post-LOCA radiation dose rate zone maps can be used for planning purposes relative to post-accident vital area access. Each zone represents a range of dose rates covering a decade (for example, 10E2 to 10E3 mrem/hr). These zone maps will not be affected by the SPU, since the percentage increase in source terms between the currently analyzed basis (power level of 3280 MWt with sump water sources, based on a 24-month fuel cycle and the remaining sources based on a fuel irradiation cycle of 830 days), and the uprated power level (3280.3 MWt and a 24-month fuel cycle), is considered to be well within the error margin of the radiation dose rate zones depicted in the maps. The T=12 hour radiation dose rate map is impacted due to the change in time for ECCS switchover to hot-leg recirculation from T=14 hours to T=6.5 hours. The remaining radiation dose rate maps are not impacted since there are no other radiation dose rate maps within this time interval.

Conclusions

It is concluded that following SPU and change in time for ECCS switchover to hot-leg recirculation, the post-LOCA vital area operator dose estimates will remain within the regulatory limit of 5-rem whole body listed in NUREG-0737 II.B.2.

6.11.8 Radiological Environmental Qualification

6.11.8.1 Introduction

In accordance with 10CFR50.49 (Reference 26) safety-related electrical equipment must be qualified to survive the radiation environment at their specific location during normal operation and during an accident.

The effect of SPU on the normal operation and post-accident radiation environmental dose estimates supporting environmental qualification is summarized in this section.

Post-accident environmental doses are usually developed based on the equilibrium core inventory assuming full-power operation at the licensed power level plus margin, source term guidance available from regulatory documents relative to post-accident core releases, and plant-specific mitigation system design features and layout. The SPU affects the equilibrium core inventory and, therefore, the post-accident radiological source terms. Additional factors that can affect the equilibrium core inventory are fuel enrichment and burnup.

The SPU assessment addresses the impact on post-LOCA radiological environmental levels due to changes in the required time for ECCS switchover to hot-leg recirculation following a LOCA. The current IP3 design allows all recirculating sump fluids to remain inside containment until T=14 hours, which is the current time for ECCS switchover to hot-leg recirculation. The above change, which is caused by the use of an updated methodology at IP3 for boron precipitation evaluations, will result in sump fluids being recirculated outside containment starting from T=6.5 hours, instead of from T=14 hours.

For purposes of equipment qualification, IP3 is divided into various environmental zones. The radiological environmental conditions noted for these zones are the maximum conditions expected to occur and are representative of the whole zone. The normal operation doses represent 40 years of operation. The accident environmental doses in areas that are considered harsh from a radiological standpoint are based on a LOCA. Integrated doses are provided up to a period of one year after the accident.

Accident Environments

The post-accident dose rate and integrated dose information relative to both the gamma and beta radiation environments inside and outside containment are based on a power level of 3280 MWt. The core activity used for the containment airborne source is based on a fuel irradiation period of 830 days. The sump water source is based on a 24-month fuel cycle.

The radiation sensitive portions of safety-related electrical equipment located outside containment are contained in leak tight enclosures, are shielded, or are enclosed in such a way that the beta dose contribution from airborne radioactivity is negligible. Based on this, post-LOCA beta environments are not applicable outside containment.

Normal Operation Environments

The normal operation gamma radiation dose rate and 40-year integrated dose are based on survey data.

6.11.8.2 Description of Analysis and Evaluation

Post-Accident Radiological Environments

The SPU will increase the activity level in the core by the percentage of the uprate. The estimated radiation source terms in equipment and structures containing post-accident fluids, and the corresponding post-LOCA environmental dose rates, will increase by the percentage of the uprate relative to the power level used in the analyses of record. However, because the SPU core reflects extended burnup and the more advanced fuel burnup modeling/libraries used in development of the uprated core, as compared to the computer code used in the original analyses, the calculated uprate scaling factor values will deviate from the core power ratio.

Radiological source terms for both the pre-SPU and the SPU cases were developed for the various post-accident sources addressed in the IP3 analyses of record supporting radiological equipment qualification.

The following core release fractions were considered in developing SPU scaling factors:

- The most limiting mixture that ranges from 100-percent noble gas and 50-percent halogens to 100-percent noble gas and ~1-percent halogens.
- Halogens only
- 50-percent halogens and 1-percent remainder solids

For the "unshielded" case, the post-LOCA gamma dose rate scaling factors were estimated by ratioing the gamma energy release rates (Mev/sec) weighted by the flux-to-dose-rate conversion factor, as a function of time, for the SPU power level, to the corresponding weighted source terms based on the pre-SPU power level. To address outside containment locations, the unshielded values included the shielding effect of a pipe wall thickness associated with a 2-inch nominal diameter pipe. This ensures that the results are not skewed by photons at energies less than 25 Kev, which will be substantially attenuated by any piping sources.

The post-LOCA gamma dose rate scaling factors (versus time) in areas that are shielded, were determined by weighting the pre-SPU and the SPU source terms discussed above by the concrete shielding factors for each energy group. The concrete shielding factors, for 1 and 3 feet of concrete provided a basis for comparison of the post-LOCA spectrum hardness of source terms with respect to time for both original design and SPU cases.

Similar calculations were performed to estimate the gamma dose scaling factors, that is, unshielded scaling factors were estimated by ratioing the integrated gamma energy release (Mev-hr/sec) weighted by the flux to dose rate conversion factor, as a function of time, for the SPU power level, to the corresponding weighted source terms based on the pre-SPU power level; whereas the shielded scaling factors were determined by weighting the pre-SPU and the SPU integrated gamma energy release discussed above by the concrete shielding factors for each energy group.

The impact of the change in the time of ECCS switchover to hot-leg recirculation on the post-accident integrated doses is developed as follows. The SPU sump water activity (curies) is integrated from 6.5 hours and from 14 hours to 1-year post-LOCA, and converted to cumulative energy releases (Mev-hr/sec) versus time for the two integration sets. The two sets of energy releases are multiplied by weighting factors per energy group for a no-shield, moderately shielded, and heavily shielded source to detector geometry, and summed across all energy groups. The weighted cumulative energy release that begins at 6.5-hours after the LOCA is divided by the weighted cumulative energy release that begins at 14 hours after the LOCA for each time interval. The ratio at each interval that results in the maximum value for the three conditions (that is, no-shield, moderately shielded, and heavily shielded source to detector geometry), is then conservatively chosen as the integrated dose-scaling factor for that interval.

The beta dose/dose rate scaling factor was simply a ratio of the dose or dose rate developed with the SPU core activity and the dose or dose rate developed with the pre-SPU core activity as a function of time after a LOCA.

Normal Operation Radiation Environments

New surveys performed by Entergy in each of the zones confirmed the continued validity of the existing data for uprated conditions.

6.11.8.3 Acceptance Criteria

The equipment in the IP3 EQ Program must be qualified to actively function, and/or not impair other equipment relied on to perform an active safety function in the radiation environment to which they are exposed during normal operation as well as for the duration of the accident. This section establishes the new radiation environments following SPU.

6.11.8.4 Results and Conclusions

The existing normal operation radiation environmental levels remain valid at SPU conditions.

To qualify for post-accident radiological environments, IP3 utilizes the 1-year integrated dose. The current one-year integrated doses in TSP-011 are increased by 10 percent as a result of the SPU and the earlier ECCS switchover to hot-leg recirculation.

6.11.9 Radiological Consequences Evaluations (Doses)

6.11.9.1 Introduction

The radiological consequences for the following DBAs were re-analyzed to support the SPU:

- Main steamline break (MSLB)
- Locked RCP rotor
- Rod ejection
- Steam generator tube rupture (SGTR)
- Small-break LOCA (SBLOCA)
- Large-break LOCA (LBLOCA)
- Waste gas decay tank (GDT) rupture

- Volume control tank (VCT) rupture
- Holdup tank (HT) failure
- Fuel-handling accident (FHA)

The accident source terms used in the IP3 SPU design-basis offsite and control room dose analyses reflect the full implementation of ASTs as detailed in RG 1.183 (Reference 5).

The first use of the AST for IP3 involved only the postulated fuel handling accident and was reviewed and approved by the NRC in its SER for Operating License (OL) Amendment No. 215 (Reference 6). Subsequently, the radiological consequences analyses for all accidents included in the IP3 licensing basis have been revised to incorporate the AST and have been submitted to the NRC (Reference 7).

The analyses performed for the SPU follow the methodology outlined in RG 1.183 (Reference 5). The analyses have been updated using input assumptions consistent with the proposed nominal core power of 3216 MWt and are presented in this section.

For each accident, the TEDE doses are determined at the site boundary (SB) for the limiting 2-hour period, at the LPZ boundary for the duration of the accident, and in the control room for 30 days.

6.11.9.1.1 General Input Parameters and Assumptions

The assumptions and inputs described in this section are common to various analyses discussed in the following sections. These assumptions and inputs are consistent with those submitted to the NRC (Reference 7) except as revised to reflect plant operation at the SPU power. Each accident and the specific input assumptions are described in detail in subsections 6.11.9.2 through 6.11.9.11.

The TEDE dose is equivalent to the committed effective dose equivalent (CEDE) from inhalation and the deep dose equivalent (DDE) from external exposure. Effective dose equivalent (EDE) is used in lieu of DDE in determining the contribution of external dose to the TEDE consistent with RG 1.183 (Reference 5) guidance. The dose conversion factors (DCFs) used in determining the CEDE dose are from the Environmental Protection Agency (EPA) Federal Guidance Report No. 11 (Reference 27). The DCFs used in determining the EDE dose are from the EPA Federal Guidance Report No. 12 (Reference 28). The nuclide decay constants are derived from half-lives reported in EPA Federal Guidance Report No. 11 (Reference 27). The nuclide data are listed in Table 6.11-10.

The offsite breathing rates and the offsite atmospheric dispersion factors used in the offsite radiological calculations are provided in Table 6.11-11.

Parameters modeled in the control room personnel dose calculations are provided in Table 6.11-12. These parameters include normal operation flow rates, emergency operation flow rates, control room volume, filter efficiencies, and control room operator breathing rates. Atmospheric dispersion factors are event-dependent and are listed together with the assumptions for each accident. The control room dose acceptance limit from 10CFR50.67 (Reference 3) is 5-rem TEDE.

Subsection 6.11.4 of this report describes the calculation of the core and coolant activity. The core fission product activity modeled in the radiological consequences analyses for the locked rotor, rod ejection, SBLOCA, and LBLOCA is provided in Table 6.11-13, and was calculated by modeling the third transition cycle. To accommodate variations in fuel design and fuel management, a multiplier of 1.04 was applied to the core inventory. The core activity data in Table 6.11-13 include this multiplier. The nominal reactor coolant activity based on 1-percent fuel defects is provided in Table 6.11-14. A 1.04 multiplier was applied to the coolant activity. The reactor coolant and secondary coolant iodine activities modeled in the radiological consequences analyses, based on the *Technical Specification* limits for dose equivalent I-131 (DE I-131), are provided in Table 6.11-15.

6.11.9.1.2 Iodine Spiking Models

A number of accident analyses take iodine spiking into consideration (for example, MSLB and SGTR).

For the pre-existing iodine spike, it was assumed that a reactor transient occurs prior to the accident and raises the primary coolant iodine concentration to 60 μCi/gm of DE I-131. (This is the *Technical Specification* limit for transient elevated iodine activity in the primary coolant.) For the accident-initiated iodine spike, it was assumed that the reactor trip associated with the accident creates an iodine spike, which increases the iodine release rate from the fuel to the reactor coolant. The spike iodine release rate is a multiple of the maximum equilibrium release rate (where the equilibrium release rate is that rate corresponding to maintaining a primary coolant concentration of 1.0 μCi/gm of DE I-131, which is the maximum concentration allowed by the *Technical Specifications* for continuous operation). RG 1.183 (Reference 5) requires a spike multiplier of 500 for the steamline break, and allows a multiplier of 335 for the SGTR.

The primary coolant iodine concentrations associated with a pre-existing iodine spike are provided in Table 6.11-15, and the iodine appearance rates associated with an accident-initiated iodine spike are provided in Table 6.11-16.

6.11.9.2 Main Steamline Break Radiological Consequences

In this analysis, a complete severance of a main steamline outside containment is assumed to occur. The affected steam generator rapidly depressurizes and releases iodine activity initially contained in the secondary coolant and primary coolant activity (iodines and noble gases) transferred via steam generator tube leaks, directly to the outside atmosphere. A portion of the iodine activity initially contained in the intact steam generators and the activity transferred to the secondary coolant due to tube leakage is released to the atmosphere through either the atmospheric relief valves (ARVs) or the safety valves. The steamline break outside containment bounds any break inside containment since the outside containment break provides a means for direct release to the environment. This section describes the assumptions and analyses performed to determine the offsite and control room doses resulting from the release of activity associated with this event.

6.11.9.2.1 Input Parameters and Assumptions

The major assumptions and parameters used in this analysis are itemized in Table 6.11-17.

The analytical methods and assumptions outlined in RG 1.183 (Reference 5) were used in the analysis of the MSLB radiological consequences. The activity available for release to the environment included the iodine assumed to be initially present in the secondary coolant and the activity in the primary coolant (both iodine and noble gases) that could leak into the secondary coolant due to steam generator tube leakage.

Source Term

The iodine activity concentration of the secondary coolant at the time an MSLB occurs was assumed to be equivalent to the *Technical Specification* (Reference 10) limit of 0.10 μCi/gm of DE I-131.

The MSLB event was analyzed for two iodine spiking cases: one in which there is a pre-existing iodine spike resulting in elevated primary coolant activity, and the other in which an iodine spike is assumed to be initiated by the accident. For the pre-accident iodine spike case, it was assumed that a reactor transient occurs prior to the MSLB and raises the RCS iodine concentration to the *Technical Specification* limit for a transient of 60 μCi/gm of DE I-131. For the accident-initiated iodine spike case, the reactor trip associated with the MSLB creates an iodine spike in the RCS that increases the iodine release rate from the fuel to the RCS to a value 500 times greater than the release rate corresponding to a maximum equilibrium RCS concentration of 1.0 μCi/gm of DE I-131. The duration of the accident-initiated iodine spike is limited by the amount of activity available in the fuel-cladding gap. Based on having 8 percent of the iodine in the fuel-cladding gap, the gap inventory is depleted within 3 hours, and the accident-initiated spike is terminated at that time.

The noble gas activity concentration in the RCS at the time the accident occurs is based on operation with a fuel defect level of 1.0 percent.

Release Pathway

The primary-to-secondary steam generator tube leakage rate was assumed to be at the *Technical Specification* limit of 432 gpd for any one steam generator, and a total of 1440 gpd for all steam generators combined.

The steam generator connected to the broken steamline was assumed to boil dry within 5 minutes following the MSLB. The entire liquid inventory of this steam generator was assumed to be steamed off and all of the iodine that was initially in this steam generator was assumed to be released to the environment. Also, iodine carried over to the faulted steam generator by tube leakage was assumed to be released directly to the environment, with no credit taken for iodine retention in the steam generator.

An iodine partition factor in the intact steam generators of 0.01 (curies [Ci] iodine/gm steam)/(Ci iodine/gm water) was used. Prior to reactor trip and concurrent loss-of-offsite power (LOOP), an iodine removal factor of 0.01 could be taken for steam released to the condenser, but this was conservatively ignored.

All noble gas activity carried over to the secondary side through steam generator tube leakage was assumed to be immediately released to the outside atmosphere.

At 29 hours after onset of the accident, the Residual Heat Removal System (RHRS) was assumed to remove all decay heat, and there were no further steam releases to the atmosphere from the intact steam generators.

Within 72 hours after the event, analysis showed that the RCS had been cooled to below 212°F, and there were no further steam releases to the atmosphere from the faulted steam generator.

No fuel failure (departure from nucleate boiling [DNB] or melt) was calculated to occur for the MSLB event.

Control Room Isolation

In the event of an MSLB, the low steamline pressure safety injection (SI) setpoint will be reached almost immediately after event initiation. The SI signal causes the control room heating, ventilation, and air conditioning (HVAC) to switch from the normal-operation mode to the emergency-operation mode. It was conservatively assumed that the control room HVAC would not fully enter the emergency mode of operation until 1 minute after event initiation.

6.11.9.2.2 Acceptance Criteria

The offsite dose limit for an MSLB with a pre-accident iodine spike is 25-rem TEDE per RG 1.183 (Reference 5), which is also the guideline value of 10CFR50.67 (Reference 3). For an MSLB with an accident-initiated iodine spike, the offsite dose limit is 2.5-rem TEDE per RG 1.183. This is 10 percent of the guideline value of 10CFR50.67. The limit for the control room dose is 5-rem TEDE per 10CFR50.67 for both iodine spiking cases.

6.11.9.2.3 Results and Conclusions

The calculated doses due to the MSLB with a pre-existing iodine spike are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
Pre-Accident Iodine Spike – SB	0.2	25
Pre-Accident Iodine Spike – LPZ	0.3	25
Pre-Accident Iodine Spike - Control Room	0.6	5

The calculated doses due to the MSLB with an accident-initiated iodine spike are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
Accident-Initiated Iodine Spike - SB	0.5	2.5
Accident-Initiated Iodine Spike - LPZ	0.8	2.5
Accident-Initiated Iodine Spike - Control Room	2.1	5

The acceptance criteria are met.

The SB doses reported are for the worst 2-hour period. This period is from 0 to 2 hours for the pre-accident iodine spike and from 3 to 5 hours for the accident-initiated iodine spike.

6.11.9.3 Locked Rotor Accident

In this analysis, an instantaneous seizure of an RCP rotor is assumed to occur, which rapidly reduces flow through the affected reactor coolant loop (RCL). Fuel cladding damage could be predicted as a result of this accident. Due to the pressure differential between the primary and secondary systems and assumed steam generator tube leakage, fission products transfer from the primary into the secondary system. A portion of this radioactivity is released to the outside atmosphere through either the ARVs or safety valves. In addition, iodine activity is contained in the secondary coolant prior to the accident, and some of this activity is assumed to be released to the atmosphere as a result of steaming from the steam generators following the accident.

6.11.9.3.1 Input Parameters and Assumptions

The major assumptions and parameters used in the analysis are itemized in Table 6.11-18.

The analysis of the locked-rotor radiological consequences was performed using the analytical methods and assumptions outlined in RG 1.183 (Reference 5).

Source Term

The analysis of the locked-rotor radiological consequences assumed an iodine concentration of 1.0 μCi/gm of DE I-131 in the primary coolant prior to the accident.

The noble gas and alkali metal activity concentration in the primary coolant when the postulated accident occurs is based on a fuel defect level of 1 percent. The iodine activity concentration of the secondary coolant when the locked rotor occurs is assumed to be 0.10 μCi/gm of DE I-131. The alkali metal activity concentration of the secondary coolant at the time the locked rotor occurs is assumed to be 10 percent of the primary side concentration.

The transient analysis performed for the SPU (subsection 6.3.14 of this report) shows that no rods in DNB are calculated for the locked-rotor event. However, it was conservatively assumed that 5 percent of the fuel rods in the core suffered damage sufficient that all of their gap activity was released to the RCS. Eight percent of the total I-131 core activity, 10 percent of the total Kr-85 core activity, 5 percent of the total core activity for other noble gases and other iodines, and 12 percent of the total core activity for alkali metals were assumed to be in the fuel-cladding gap and released into the primary coolant. In the calculation of the activity releases from the failed fuel, the maximum radial peaking factor of 1.7 was applied.

Release Pathway

Activity is released to the environment by way of primary-to-secondary leakage and steaming from the secondary side to the environment. The primary-to-secondary steam generator tube leakage rate was assumed to be at the *Technical Specification* limit of 1440 gallons per day.

The RHRS was assumed to remove all decay heat 29 hours into the accident, with no further releases to the environment after that time.

An iodine partition factor in the steam generators of 0.01 (Ci iodine/gm steam)/(Ci iodine/gm water) was used. Prior to reactor trip and concurrent loss-of-offsite-power (LOOP), an iodine removal factor of 0.01 could have been taken for steam released to the condenser, but this was conservatively ignored.

The release of non-volatile activity from the steam generators is limited by MCO. The bounding value for MCO is 0.10 percent, therefore, an alkali metal partition factor in the steam generators of 0.001 (Ci alkali metal/gm steam)/(Ci alkali metal/gm water) was used.

All noble gas activity carried over to the secondary side through steam generator tube leakage was assumed to be immediately released to the outside atmosphere.

Control Room Isolation

It was assumed that the control room HVAC System begins in normal-operation mode, and as activity builds up in the control room, a high-radiation signal is generated. It was conservatively assumed that there is a 20-minute operator action time to switch the control room HVAC to the emergency mode of operation after the high radiation signal. For this analysis, this was modeled at 32 minutes.

6.11.9.3.2 Acceptance Criteria

The offsite dose limit for a locked rotor accident is 2.5-rem TEDE per RG 1.183 (Reference 5). This is 10 percent of the guideline value of 10CFR50.67 (Reference 3). The limit for the control room dose is 5-rem TEDE, per 10CFR50.67.

6.11.9.3.3 Results and Conclusions

The calculated doses due to the locked rotor event are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
SB	1.1	2.5
LPZ	1.4	2.5
Control Room	2.5	5

The acceptance criteria are met.

The SB dose reported is for the worst 2-hour period, determined to be from 27 to 29 hours after event initiation.

6.11.9.4 Rod Ejection Accident

For this analysis, it is assumed that a control rod drive mechanism (CRDM) pressure housing mechanical failure occurs, resulting in the ejection of a rod cluster control assembly (RCCA) and drive shaft. As a result of the accident, some fuel cladding damage and a small amount of fuel melting (pellet centerline) are assumed to occur. Due to the pressure differential between the primary and secondary systems, radioactive primary coolant is assumed to leak from the primary into the secondary system. A portion of this radioactivity is released to the outside atmosphere through the main condenser, the ARVs, or the safety valves. Also, iodine and alkali metal group activity is contained in the secondary coolant prior to the accident, and some of this activity is released to the atmosphere as a result of steaming from the steam generators following the postulated accident. Finally, radioactive primary coolant is discharged to the containment via spill from the opening in the reactor vessel head. A portion of this radioactivity is released through containment leakage to the environment.

6.11.9.4.1 Input Parameters and Assumptions

Separate calculations were performed to calculate the dose resulting from the release of activity to containment and subsequent leakage to the environment and the dose resulting from the leakage of activity to the secondary system and subsequent release to the environment. The total offsite and control room doses are the sum of the doses resulting from each of the postulated release paths.

A summary of input parameters and assumptions is provided in Table 6.11-19.

The analysis of the rod ejection radiological consequences was performed using the analytical methods and assumptions outlined in RG 1.183 (Reference 5).

Source Term

The assumption is that less than 10 percent of the fuel rods in the core undergo DNB as a result of the rod ejection accident. In determining the offsite doses following a rod ejection accident, it was conservatively assumed that 10 percent of the fuel rods in the core suffer sufficient damage so that all of their gap activity is released. Ten percent of the total core activity of iodine and noble gases and 12 percent of the total core activity for alkali metals were assumed to be in the fuel-cladding gap. In the calculation of activity released from the failed/melted fuel, the maximum radial peaking factor of 1.7 was applied.

A small fraction of the fuel in the failed fuel rods was assumed to melt as a result of the rod ejection accident. This amounts to 0.25 percent of the core, with the melting assumed to take place in the centerline of the affected rods. Of the rods that entered DNB, 50 percent were assumed to experience some fuel melting (5.0 percent of the core). Of the rods that experience melting, 50 percent of the axial length of the rod was assumed to melt (2.50 percent of the core). It was further assumed that only 10 percent of the radial portion of the rod melts (0.25 percent of the total core).

For both the containment leakage release path and the primary-to-secondary leakage release path, it was assumed that all noble gas and alkali metal activity released from the failed fuel (both gap activity and melted fuel activity) was available for release. For the containment leakage release path, it was assumed that all of the iodine released from the gap of failed fuel and 25 percent of the activity released from melted fuel was available for release from containment. For the primary-to-secondary leakage release path, it was assumed that all of the iodine released from the gap of failed fuel and 50 percent of the activity released from melted fuel was available for release from the RCS.

Prior to the postulated accident, the iodine activity concentration of the primary coolant was assumed to be 1.0 µCi/gm of DE I-131. The noble gas and alkali metal activity concentrations in the RCS when the rod ejection accident was postulated to occur were based on operation with a fuel defect level of 1 percent. Further, the iodine activity concentration of the secondary coolant was assumed to be equivalent to 0.10 µCi/gm of DE I-131, and the alkali metal activity concentration of the secondary coolant was assumed to be 10 percent of the primary side concentration.

Iodine Chemical Form

Iodine in containment was assumed to be 4.85-percent elemental, 0.15-percent organic, and 95-percent particulate. Iodine released from the secondary system was assumed to be 97-percent elemental and 3-percent organic.

Release Pathways

When determining the offsite doses due to containment leakage, all of the RCS iodine, noble gas, and alkali metal activity (from prior to the accident and resulting from the accident) was assumed to be in the containment.

The containment was assumed to leak at the design leak rate of 0.1 percent per day for the first 24 hours of the accident, and then to leak at half that rate (0.05 percent per day) for the remainder of the 30-day period considered in the analysis.

When determining the doses due to the primary-to-secondary steam generator tube leakage, all of the RCS iodine, noble gas, and alkali metal activity (from before the accident and resulting from the accident) was assumed to be in the primary coolant.

Primary-to-secondary tube leakage and steaming from the steam generators continue until the RCS pressure drops below the secondary side pressure. Bounding times of 1 hour of leakage and 2 hours of steaming were selected for this analysis, although the analysis showed that leakage and releases would stop before these times.

The primary-to-secondary steam generator tube leakage rate was assumed to be at the *Technical Specification* limit of 1440 gallons per day. Although the primary-to-secondary pressure differential drops throughout the event, a constant leakage rate was assumed.

Removal Coefficients

An iodine partition factor in the steam generators of 0.01 (Ci iodine/gm steam)/(Ci iodine/gm water) was used. Prior to reactor trip and concurrent LOOP, an iodine removal factor of 0.01 could be taken for steam released to the condenser, but this was conservatively ignored.

The release of non-volatile activity from the steam generators is limited byMCO. The bounding value for MCO is 0.10 percent. Therefore, an alkali metal partition factor in the steam generators of 0.001 (Ci alkali metal/gm steam)/(Ci alkali metal/gm water) was used.

All noble gas activity carried over to the secondary side through steam generator tube leakage was assumed to be immediately released to the outside atmosphere.

For the containment leakage pathway, no credit was taken for plateout onto containment surfaces or for containment spray operation that would remove airborne particulates and elemental iodine. Removal of iodine and alkali metal particulates in containment by the fan cooling unit (FCU) filters was credited, with a removal efficiency of 0.90 and a filtered flow of 8000 cfm for each of the three FCUs assumed to be in operation. No credit was taken for the charcoal filters on the FCUs.

Control Room Isolation

The low-pressurizer pressure SI setpoint would be reached in approximately 71 seconds from event initiation. The SI signal causes the control room HVAC to switch from the normal-operation mode to the emergency operation mode. It was conservatively assumed that the control room HVAC would not fully enter the emergency mode of operation until 140 seconds after event initiation.

6.11.9.4.2 Acceptance Criteria

The offsite dose limit for a rod ejection is 6.3-rem TEDE, per RG 1.183 (Reference 5). This is ~25 percent of the guideline value of 10CFR50.67 (Reference 3). The limit for the control room dose is 5-rem TEDE, per 10CFR50.67.

6.11.9.4.3 Results and Conclusions

The calculated doses due to the rod ejection accident are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
SB	4.4	6.3
LPZ	2.2	6.3
Control Room	0.9	5

The acceptance criteria are met.

The SB dose reported is for the worst 2-hour period, determined to be from 0 to 2 hours.

6.11.9.5 SGTR Accident

The discussion of the thermal-hydraulic analysis for the SGTR event is given in Section 6.4 of this document.

6.11.9.5.1 Input Parameters and Assumptions

The major assumptions and parameters used in this analysis are itemized in Table 6.11-20.

The analysis of the SGTR radiological consequences was performed using the analytical methods and assumptions outlined in RG 1.183 (Reference 5). The activity available for release to the environment included the iodine assumed to be initially present in the secondary coolant and the activity in the primary coolant (both iodine and noble gases) that could leak into the secondary coolant due to steam generator tube leakage.

The SGTR event was analyzed for two iodine spiking cases: one in which there is a pre-existing iodine spike resulting in elevated primary coolant activity, and the other in which an iodine spike is assumed to be initiated by the accident. For the pre-accident iodine spike case, it was assumed that a reactor transient occurs prior to the SGTR and raises the RCS iodine concentration to the *Technical Specification* limit for a transient of 60 μCi/gm of DE I-131. For the accident-initiated iodine-spike case, it was assumed that the reactor trip associated with the SGTR creates an iodine spike in the RCS, which increases the iodine release rate from the fuel to the RCS to a value 335 times greater than the release rate corresponding to a maximum equilibrium RCS concentration of 1.0 μCi/gm of DE I-131. The duration of the accident-initiated iodine spike is limited by the amount of activity available in the fuel-cladding gap. Based on having 8 percent of the iodine in the fuel-cladding gap, the gap inventory would be depleted within 4 hours, and the accident-initiated spike was terminated at that time.

The noble gas activity concentration in the RCS at the time the SGTR accident occurs was based on operation with a fuel defect level of 1 percent. The iodine activity concentration of the secondary coolant at that time was assumed to be equivalent to the *Technical Specification* limit of 0.10 μCi/gm of DE I-131.

Release Pathway

Break-flow flashing fractions and steam release rates from the intact and ruptured steam generator were calculated. The amount of break flow that flashes to steam was conservatively calculated assuming that all break flow is from the hot-leg side of the break and that the primary temperatures remain constant.

The break flow, flashed break flow, and steam release data presented in Table 6.4-2 of Section 6.4 of this document were used for the dose analysis.

The intact steam generator primary-to-secondary steam generator tube leakage rate was assumed to be at the *Technical Specification* limit of 432 gpd per steam generator for each of the intact steam generators.

An iodine partition factor in the steam generators of 0.01 (Ci iodine/gm steam)/(Ci iodine/gm water) was used. Prior to reactor trip and concurrent LOOP, an iodine removal factor of 0.01 was taken for steam released to the condenser.

All noble gas activity carried over to the secondary side through steam generator tube leakage was assumed to be immediately released to the outside atmosphere.

At 29 hours after the accident, the RHRS was assumed to be placed into service for heat removal and there was no further steam release to the atmosphere from the secondary system.

Control Room Isolation

The low-pressurizer pressure SI setpoint would be reached at 6.53 minutes from event initiation. The SI signal causes the control room HVAC to switch from the normal operation mode to the emergency mode of operation. It was conservatively assumed that the control room HVAC would not fully enter the emergency mode of operation until 7.53 minutes after event initiation.

6.11.9.5.2 Acceptance Criteria

The offsite dose limit for a SGTR with a pre-accident iodine spike is 25-rem TEDE per RG 1.183 (Reference 5), which is also the guideline value of 10CFR50.67 (Reference 3). For an SGTR with an accident-initiated iodine spike, the offsite dose limit is 2.5-rem TEDE per RG 1.183 (Reference 5). This is 10 percent of the guideline value of 10CFR50.67. The limit for the control room dose is 5-rem TEDE, per 10CFR50.67.

6.11.9.5.3 Results and Conclusions

The calculated doses due to the SGTR with a pre-existing iodine spike are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
SB	4.9	25
LPZ	1.9	25
Control Room	2.2	5

The calculated doses due to the SGTR with an accident-initiated iodine spike are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
SB	1.9	2.5
LPZ	0.8	2.5
Control Room	0.9	5

The acceptance criteria are met.

The SB doses reported are for the worst 2-hour period, determined to be from 0 to 2 hours.

6.11.9.6 Small-Break LOCA

An abrupt failure of the primary coolant system was assumed to occur and it was assumed that the break would be small enough that the containment spray system would not be actuated by high containment pressure, but that the core would experience substantial cladding damage such that the fission product gap activity of all fuel rods would be released. Activity that is released to the containment is assumed to be released to the environment due to the containment leaking at its design rate. There is also a release path through the steam generators (primary-to-secondary leakage) until the primary system becomes depressurized to below the secondary system pressure.

6.11.9.6.1 Input Parameters and Assumptions

Separate calculations were performed to determine the doses resulting from the release of activity to containment and subsequent leakage to the environment and the doses resulting from the leakage of activity to the secondary system and subsequent release to the environment. The total offsite and control room doses are the sum of the doses resulting from each of the postulated release paths.

A summary of input parameters and assumptions is provided in Table 6.11-21.

The analysis of the SBLOCA radiological consequences was performed using the analytical methods and assumptions credited in RG 1.183 (Reference 5).

Source Term

In determining the offsite doses following an SBLOCA, it was assumed that all of the fuel rods in the core suffer sufficient damage so that their gap activity was released and no fuel in the core melts. Five percent of the total core activity of iodines, noble gases, and alkali metals were assumed to be in the fuel-cladding gap.

It was assumed that for both the containment leakage release path and the primary-to-secondary leakage release path all iodine, noble gas, and alkali metal activity in the failed fuel gap was available for release.

Prior to the accident, it was assumed that the iodine activity concentration of the primary coolant was 60 μCi/gm of DE I-131. The noble gas and alkali metal activity concentrations in the RCS when the postulated accident occurs were based on operation with a fuel defect level of 1 percent.

Iodine Chemical Form

Iodine in containment was assumed to be 4.85-percent elemental, 0.15-percent organic, and 95-percent particulate. Iodine released from the secondary system was assumed to be 97-percent elemental and 3-percent organic.

Release Pathways

When determining the offsite doses due to containment leakage, all of the RCS iodine, noble gas, and alkali metal activity (from prior to the accident and resulting from the accident) was assumed to be in the containment.

The containment was assumed to leak at the design leak rate of 0.1 percent per day for the first 24 hours of the accident, and then to leak at half that rate (0.05 percent per day) for the remainder of the 30-day period considered in the analysis.

When determining the doses due to the primary-to-secondary steam generator tube leakage, all of the RCS iodine, noble gas, and alkali metal activity (from before the accident and resulting from the accident) was assumed to be in the primary coolant.

Primary-to-secondary tube leakage and steaming from the steam generators were assumed to continue until the RCS pressure drops below the secondary pressure. Bounding times of 1 hour of leakage and 2 hours of steaming were selected for this analysis, although the analysis shows that leakage and releases would stop before then.

The primary-to-secondary steam generator tube leakage rate was assumed to be at the *Technical Specification* limit of 1440 gallons per day. Although the primary-to-secondary pressure differential drops throughout the event, a constant leakage rate was assumed.

Removal Coefficients

An iodine partition factor in the steam generators of 0.01 (Ci iodine/gm steam)/(Ci iodine/gm water) was used. Prior to reactor trip and concurrent LOOP, an iodine removal factor of 0.01 could be taken for steam released to the condenser, but this was conservatively ignored.

The release of non-volatile activity from the steam generators is limited by the MCO. The bounding value for MCO is 0.10 percent. Therefore, an alkali metal partition factor in the steam generators of 0.001 (Ci alkali metal/gm steam)/(Ci alkali metal/gm water) was used.

All noble gas activity carried over to the secondary side through steam generator tube leakage was assumed to be immediately released to the outside atmosphere.

For the containment leakage pathway, no credit was taken for plateout onto containment surfaces or for containment spray operation that would remove airborne particulates and elemental iodine. Deposition removal of elemental iodine was not credited. Removal of iodine and alkali metal particulates in containment by the FCU filters was credited, with a removal efficiency of 0.90 and a filtered flow of 8000 cfm for each of the three FCUs assumed to be in operation. No credit was taken for the charcoal filters on the FCUs.

Control Room Isolation

The low-pressurizer pressure SI setpoint would be reached approximately 71 seconds after event initiation. The SI signal causes the control room HVAC to switch from the normal operation mode to the emergency mode of operation. It was conservatively assumed that the control room HVAC would not fully enter the emergency mode of operation until 140 seconds after event initiation.

6.11.9.6.2 Acceptance Criteria

The offsite dose limit for a LOCA is 25-rem TEDE, per RG 1.183 (Reference 5). The limit for the control room dose is 5-rem TEDE, per 10CFR50.67 (Reference 3).

6.11.9.6.3 Results and Conclusions

The calculated doses due to the SBLOCA are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
SB	11.0	25
LPZ	5.5	25
Control Room	2.2	5

The acceptance criteria are met.

The SB dose reported is for the worst 2-hour period, determined to be from 0 to 2 hours.

6.11.9.7 Large-Break LOCA

In this analysis, an abrupt failure of a reactor coolant pipe was assumed to occur, and it was also assumed that the emergency core cooling features would fail to prevent the core from experiencing significant degradation (that is, melting). This sequence cannot occur unless there are multiple failures, and thus goes beyond the typical DBA that considers a single active failure. Activity from the core is released to the containment and then to the environment by containment leakage or leakage from the Emergency Core Cooling System (ECCS) as it recirculates sump solution outside the containment.

6.11.9.7.1 Input Parameters and Assumptions

The input parameters and assumptions are listed in Table 6.11-22.

The analysis of the LBLOCA radiological consequences was performed using the analytical methods and assumptions outlined in RG 1.183 (Reference 5).

The analysis considered the release of activity from the damaged core to the containment via containment leakage. In addition, it was assumed that once external recirculation of the ECCS was established, activity in the sump solution would be released to the environment by means of leakage from ECCS equipment outside containment in the Auxiliary Building. The total offsite and control room doses are the sum of the doses resulting from each of the postulated release paths. The following sections address topics of significant interest in the analysis.

Source Term

The reactor coolant activity was assumed to be insignificant compared with the release from the core and was not included in the analysis.

Of the total core activity provided in Table 6.11-13, the following portions were assumed to be released to the containment atmosphere and available for release to the environment via containment leakage:

- 100 percent of the noble gases (Xe, Kr)
- 40 percent of the iodines
- 30 percent of the alkali metals (Cs, Rb)
- 5 percent of the tellurium metals (Te, Sb)
- 2 percent of the barium and strontium
- 0.25 percent of the noble metals (Ru, Rh, Mo, Tc)
- 0.05 percent of the cerium group (Ce, Pu, Np)
- 0.02 percent of the lanthanides (La, Zr, Nd, Nb, Pr, Y, Cm, Am)

The release of activity to containment is assumed to occur over a 1.8-hour interval. The gap activity is released in the first 30 minutes (starting at 30 seconds), and the fraction of the core activity that is released due to fuel melt does so over the next 1.3 hours. A gap fraction of 5 percent of core activity was assumed for iodines, noble gases, and alkali metals. Gap activity of the other nuclides is not assumed in the RG 1.183 (Reference 5) source term. With the exception of the iodines and noble gases, all activity released to containment was modeled as particulates. The iodine in containment was modeled as 4.85-percent elemental, 0.15-percent organic, and 95-percent particulate. For ECCS leakage considerations, the iodine activity that became airborne after being released by the leakage was modeled as 97-percent elemental and 3-percent organic.

For the containment leakage analysis, all activity released from the fuel was assumed to be in the containment atmosphere until removed by sprays, sedimentation, radioactive decay, or leakage from the containment. No credit was taken for removal of activity by the FCU filters. For the ECCS leakage analysis, all iodine activity released from the fuel was assumed to be in the sump solution until removed by radioactive decay or leakage from the ECCS.

Containment Modeling

The containment was modeled as two discrete volumes that considered hold-up, removal, and decay. The two volumes were the sprayed containment, which accounted for 80 percent of the free volume, and the unsprayed containment. Mixing between the two volumes was provided by the fan coolers. The analysis credited three fan coolers starting 60 seconds after event initiation.

The containment was assumed to leak at the design leak rate of 0.1 percent per day for the first 24 hours of the accident, and then to leak at half that rate (0.05 percent per day) for the remainder of the 30-day period considered in the analysis.

Activity Removal from the Containment Atmosphere

Only containment sprays and radioactive decay were credited for removal of elemental iodine from the containment atmosphere. Containment sprays, sedimentation, and radioactive decay were credited for removing particulates from the containment atmosphere. The noble gases and the organic iodine were subject to removal only by radioactive decay. No credit was taken for the HEPA and charcoal filters on the FCUs.

One train of the Containment Spray System (CSS) was assumed to operate following the LOCA. Injection spray was credited with a 67-second startup delay. Earlier spray actuation is conservative since it results in earlier spray injection phase termination. There would be little activity in the containment at the time the sprays start. When the refueling water storage tank (RWST) drains to a predetermined setpoint level, the operators switch to sump liquid recirculation to provide a source for the sprays. Injection spray was credited for approximately 44 minutes. There is a 3-minute period with no spray flow during the switchover to the spray recirculation phase. The analysis assumed that the recirculation sprays would operate until 4.0 hours into the accident. Retention of iodine in the sump solution is ensured by adjusting the sump solution to a pH greater than or equal to 7.0.

Containment Spray Removal of Elemental Iodine

The SRP 6.5.2 (Reference 29) identifies a methodology to determine spray removal of elemental iodine. The removal rate constant is determined by:

$$\lambda_s = 6K_g\,TF/VD$$

where:

λ_s = Elemental iodine removal rate constant due to spray removal, hr^{-1}
K_g = Gas phase mass transfer coefficient, ft/min
T = Time of fall of the spray drops, min
F = Volume flow rate of sprays, ft^3/hr
V = Containment sprayed volume, ft^3
D = Mass-mean diameter of the spray drops, ft

The upper limit specified for this model is 20 hr^{-1}.

The parameters listed below were chosen to bound the current plant configuration:

K_g = 9.84 ft/min
T = 10 sec
F = 2200 gpm
V = 2.088E6 ft^3
D = 0.112 cm

These parameters and appropriate conversion factors were used to calculate the elemental spray removal coefficients. The upper limit of 20 hr^{-1} specified for this model was applied in the analysis in place of the calculated value of 22.7 hr^{-1}.

The elemental iodine removal rate during recirculation spray operation can be calculated by multiplying the injection spray removal rate (22.7 hr^{-1}) by the ratio of the recirculation spray flow rate (1050 gpm) to the injection spray flow rate (2200 gpm). The recirculation spray removal rate is then 10.8 hr^{-1}. However, during recirculation, the spray solution would gradually become loaded with elemental iodine that will limit the capacity of the spray to remove airborne iodine. As the DF approaches its defined limit, the removal coefficient would be only a small fraction of its original value. This was approximated by setting the removal coefficient at approximately one half of the calculated value (5.0 hr^{-1}).

Removal of elemental iodine from the containment atmosphere was assumed to be terminated when the airborne inventory (including both sprayed and unsprayed regions) dropped to 0.5 percent of the total elemental iodine released to the containment (this is a DF of 200). With the RG 1.183 (Reference 5) source term methodology, this was interpreted as being 0.5 percent of the total inventory of elemental iodine that was released to the containment atmosphere over the duration of gap and in-vessel release phases. In the analysis, this occurred at 2.765 hours.

Containment Spray Removal of Particulates

Particulate spray removal was determined using the model described in the SRP 6.5.2 (Reference 29).

The first order spray removal rate constant for particulates is written as follows:

$$\lambda_p = 3hFE/2VD$$

where:

λ_p = Particulate removal rate constant due to spray removal, hr^{-1}
h = Drop fall height, ft
F = Spray flow rate, ft^3/hr
V = Volume sprayed, ft^3
E = Single drop collection efficiency
D = Average spray drop diameter, ft

The parameters listed below were chosen to bound the current plant configuration:

h = 118.5 ft
F = 2200 gpm
V = 2.088E6 ft^3

The E/D term depends upon the particle size distribution and spray drop size. It is conservative to use 10 m^{-1} for E/D until the point is reached when the inventory in the atmosphere is reduced to 2 percent of its original (DF of 50). With the RG 1.183 (Reference 5) source term methodology, this is interpreted as being 2 percent of the total inventory particulate iodine that is released to the containment atmosphere over the duration of gap and in-vessel release phases.

These parameters and the appropriate conversion factors were used to calculate the particulate spray removal coefficients. A value of 4.6 hr^{-1} was used in the analysis during the spray injection phase. The recirculation spray particulate removal rate used was 2.2 hr^{-1} corresponding with the reduction in the spray flow rate (2200-gpm injection reduced to 1050 gpm for recirculation). Recirculation sprays were assumed to be terminated at 4.0 hours. The DF of 50 was not reached by 4.0 hours, so no reduction in the spray removal coefficient for particulates was modeled.

Sedimentation Removal of Particulates

During spray operation, no credit was taken for sedimentation removal of particulates in the sprayed region, although it would take place. It was assumed that containment spray operation would be terminated at 4.0 hours. Credit was taken for sedimentation removal of particulates in the sprayed region after spray termination. Sedimentation was credited in the unsprayed region from the start of the event. The analysis assumed a sedimentation coefficient of 0.1 hr^{-1}.

Emergency Core Cooling System Leakage

Initially, the ECCS recirculation would be internal to the containment and there would be no potential for leakage outside containment. However, the switch to external recirculation was assumed to occur at 6.5 hours because of the need to switch from cold-leg recirculation mode to hot-leg recirculation mode. With external ECCS recirculation established following the LOCA, leakage was assumed to occur from ECCS equipment outside containment. The leakage goes into the Auxiliary Building and no filtration or holdup was credited for this release. The ECCS leakage was modeled as 4.0 gallons per hour which, consistent with RG 1.183 (Reference 5), is double the plant allowable leakage value of 2.0 gallons per hour. The leakage was assumed to continue for the 30-day period considered in the analysis. Based on the sump solution pH, the temperature of the leaked solution, and the ventilation provided in the Auxiliary Building, a bounding value for the iodine partition coefficient was determined to be 0.027.

Control Room Isolation

In the event of an LBLOCA, the low-pressurizer pressure SI setpoint will be reached shortly after event initiation. The SI signal causes the control room HVAC to switch from the normal operation mode to the emergency mode of operation. It was conservatively assumed that the control room HVAC would not fully enter the emergency mode of operation until 1 minute after event initiation.

6.11.9.7.2 Acceptance Criteria

The offsite dose limit for a LOCA is 25-rem TEDE per RG 1.183 (Reference 5). This is the guideline value of 10CFR50.67 (Reference 3). The limit for the control room dose is 5-rem TEDE, per 10CFR50.67.

6.11.9.7.3 Results and Conclusions

The calculated total offsite and control room doses due to the LBLOCA are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
SB	23.4	25
LPZ	11.2	25
Control Room	4.4	5

The acceptance criteria are met.

The SB dose reported is for the worst 2-hour period, determined to be from 0.6 to 2.6 hours.

Subsection 6.11.4.6 of this report discusses the calculation of the direct and skyshine control room dose. The calculated dose for the 30-day duration considered in this analysis was 0.284 mrem. This dose was included in the control room dose reported above.

6.11.9.8 GDT Rupture Radiological Consequences

For the GDT rupture analysis, there is assumed to be a failure that results in the release of the contents of one GDT.

6.11.9.8.1 Input Parameters and Assumptions

The input parameters and assumptions are listed in Table 6.11-23.

Consistent with the UFSAR analysis, the tank contents were assumed to be at the administratively controlled limit of 50,000 Curies of dose equivalent Xe-133. Dose equivalent Xe-133 is the amount of Xe-133 that results in the same gamma radiation dose as a given mixture of noble gases. A failure in the Gaseous Waste Processing System (GWPS) was assumed to result in release of a single tank inventory with a release duration of 5 minutes.

Control Room Isolation

It is assumed that the control room HVAC System is manually switched over from the normal-operation mode to the emergency mode of operation after a high radiation alarm is actuated.

6.11.9.8.2 Acceptance Criteria

The offsite dose limit for a GDT rupture is 0.5-rem TEDE. This is consistent with the guidance of RG 1.26 (Reference 12), which specifies 0.5-rem whole body or equivalent to any part of the body and of RG 1.183 (Reference 5), which specifies that doses will be determined as TEDE. The limit for the control room dose is 5-rem TEDE, per 10CFR50.67 (Reference 3).

6.11.9.8.3 Results and Conclusions

The calculated doses due to the GDT rupture are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
SB	0.32	0.5
LPZ	0.12	0.5
Control Room	0.1	5

The acceptance criteria are met.

The SB dose reported is for the worst 2-hour period, determined to be from 0 to 2 hours.

6.11.9.9 VCT Rupture

For the VCT rupture, a failure was assumed that results in the release of the tank contents, plus the noble gases and a fraction of the iodines from the letdown flow until the letdown path is isolated.

6.11.9.9.1 Input Parameters and Assumptions

The input parameters and assumptions are listed in Table 6.11-24.

The inventory of gases in the tank was based on continuous operation with 1.0-percent fuel defects and without any purge of the gas space. The inventory of iodine in the tank was based on operation of the plant with 1.0 μCi/gram Dose-Equivalent (DE) I-131 in the primary coolant and with 90 percent of the iodine removed by the letdown demineralizer.

As a result of the accident, all of the noble gas in the tank and 1.0 percent of the iodine in the tank liquid were assumed to be released to the atmosphere over a period of 5 minutes.

After event initiation, letdown flow to the VCT was assumed to continue at the maximum flow rate of 132 gpm (maximum letdown flow plus 10-percent uncertainty) for 30 minutes when the letdown line was assumed to be isolated. The primary coolant noble gas activities were based on operation with 1-percent fuel defects. The primary coolant iodine activity was assumed to be at the equilibrium operation *Technical Specification* limit of 1.0 µCi/gram DE I-131, which was reduced by 90 percent by the letdown demineralizer. All of the noble gas and 10 percent of the iodine in the letdown flow were assumed to be released to the environment.

Control Room Isolation

It was assumed that the control room HVAC System is manually switched over from the normal operation mode to the emergency mode of operation after a high radiation alarm is actuated.

6.11.9.9.2 Acceptance Criteria

The offsite dose limit for a VCT rupture is 0.5-rem TEDE. This is consistent with the guidance of RG 1.26 (Reference 12), which specifies 0.5-rem whole body or equivalent to any part of the body and of RG 1.183 (Reference 5), which specifies that doses will be determined as TEDE. The limit for the control room dose is 5-rem TEDE, per 10CFR50.67 (Reference 3).

6.11.9.9.3 Results and Conclusions

The calculated doses due to the VCT rupture are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
SB	0.42	0.5
LPZ	0.16	0.5
Control Room	0.08	5

The acceptance criteria are met.

The SB dose reported is for the worst 2-hour period, determined to be from 0 to 2 hours.

6.11.9.10 Holdup Tank Failure

During normal plant operation water is added to the HTs periodically as the primary coolant is diluted during the fuel cycle to provide reduction in the primary coolant boron concentration. As water enters the HT, gases (the nitrogen cover gas and the noble gas and hydrogen that evolve out of solution from the water entering the tank) are displaced to the GWPS. For the HT failure, a failure is assumed that results in the release of the contents of the tank.

6.11.9.10.1 Input Parameters and Assumptions

The input parameters and assumptions are listed in Table 6.11-25.

The inventory of gases in the tank was based on letdown of primary coolant to fill the HT in a 24-hour period without any purge of the tank gas space. The primary coolant noble gas concentration was based on operation with 1.0 percent fuel defects and without any fission gas removal other than by decay. The inventory of iodine in the tank was based on operation with a primary coolant concentration at the equilibrium concentration *Technical Specification* limit of 1.0 μCi/gram of DE I-131 and with 90 percent of the iodine removed by the letdown demineralizer.

As a result of the HT failure, all of the noble gas in the tank and 1.0 percent of the iodine in the tank liquid were assumed to be released to the atmosphere over a period of 5 minutes.

<u>Control Room Isolation</u>

It was assumed that the control room HVAC System is manually switched over from the normal-operation mode to the emergency mode of operation after a high radiation alarm is actuated.

6.11.9.10.2 Acceptance Criteria

The offsite dose limit for an HT failure is 0.5-rem TEDE. This is consistent with the guidance of RG 1.26 (Reference 12), which specifies 0.5-rem whole body or equivalent to any part of the body and of RG 1.183 (Reference 5), which specifies that doses will be determined as TEDE. The limit for the control room dose is 5-rem TEDE, per 10CFR50.67 (Reference 3).

6.11.9.10.3 Results and Conclusions

The calculated doses due to the HT failure are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
SB	0.38	0.5
LPZ	0.14	0.5
Control Room	0.10	5

The acceptance criteria are met.

The SB dose reported is for the worst 2-hour period, determined to be from 0 to 2 hours.

6.11.9.11 Fuel-Handling Accident

This accident assumes that a fuel assembly is dropped and damaged during refueling. Analysis of the accident was performed with assumptions selected so that the results would be bounding for the accident occurring either inside containment or in the Fuel Handling Building. Activity released from the damaged assembly was assumed to be released to the outside atmosphere through either the Containment Purge System or the Fuel Pit Ventilation System.

6.11.9.11.1 Input Parameters and Assumptions

The input parameters and assumptions are listed in Table 6.11-26.

The analysis of the FHA radiological consequences was performed using the analytical methods and assumptions outlined in RG 1.183 (Reference 5). This analysis allowed fuel movement 84 hours after shutdown.

All activity released from the water pool was assumed to be released to the atmosphere in 2 hours, using a linear release model (this is the release model used in the existing licensing basis for this event). No credit was taken for operating the Spent Fuel Pit Ventilation System in the Fuel-Handling Building. No credit was taken for isolating containment for the FHA in containment. Since the assumptions and parameters for an FHA inside containment are identical to those for a FHA in the Fuel-Handling Building, the radiological consequences were the same regardless of the location of the accident.

Source Term

The calculation of the radiological consequences following an FHA used gap fractions of 12 percent for I-131, 30 percent for Kr-85, and 10 percent for all other nuclides. The value for I-131 was taken from NUREG/CR-5009 (Reference 30). The values for Kr-85 and the other iodines and noble gases were taken from RG 1.25 (Reference 31). There are lower values identified in Table 3 of RG 1.183 (Reference 5), but these were not used because the conditions for their use (specified in footnote 11 in RG 1.183) have not been ensured.

As in the existing licensing basis, it was assumed that all of the fuel rods in the equivalent of one fuel assembly would be damaged to the extent that all of their gap activity would be released. The assembly inventory was based on the assumption that the subject fuel assembly had been operated at 1.7 times the core average power. The activity calculated for the third transition cycle was conservatively increased by 4 percent to bound variations in core average enrichment, core mass, and cycle length (Table 6.11-27).

The decay time used in the analysis was 84 hours.

Iodine Chemical Form

The iodine released from the fuel was assumed to be 95-percent cesium iodide (CsI), 4.85-percent elemental iodine, and 0.15-percent organic iodine. It was assumed that all of the CsI was dissociated in the water and that the iodine re-evolved as elemental iodine. This was assumed to occur instantaneously. Thus, the FHA dose analysis was based on an initial iodine characterization of 99.85-percent elemental iodine and 0.15-percent organic iodine.

Water Scrubbing Removal of Activity

The activity released from the damaged fuel rods was assumed to be contained within gas bubbles that rise up through the water and are released into the atmosphere above the pit. As the bubbles pass through the water column, there is a significant removal of activity. RG 1.183 (Reference 5) identifies a DF of 500 for elemental iodine and no removal for organic iodine and noble gases. The DF of 500 for elemental iodine is based on having a water height of 23 feet or more. (Per the *Technical Specifications*, there are requirements for ≥23 feet of water above the stored spent fuel and above the reactor vessel flange during fuel-handling operations.)

The DF of 500 for elemental iodine is also based on fuel rod pressure of ≤1200 psig. There is the potential for fuel rod pressures to exceed 1200 psig (but remain less than 1500 psig). With this increase in fuel rod pressure, the DF is determined to remain above 400. Using a DF of 400 for elemental iodine and the defined iodine species split of 99.85-percent elemental and 0.15-percent organic, the overall DF would be 250. However, RG 1.183 (Reference 5) also specifies the overall DF for iodine to be 200. The overall DF of 200 has an associated elemental iodine DF of 285, and this value was used in the analysis together with a DF of 1.0 for organic iodine and noble gases.

The cesium released from the damaged fuel rods was assumed to remain in a nonvolatile form and not be released from the water.

The split between elemental and organic iodine being released to the environment had no effect on the analysis since no filtration was credited.

Filtration of Release Paths

No credit was taken for removing iodine by filters, nor was credit taken for isolating release paths.

Although the containment purge would be automatically isolated on a purge line high-radiation alarm, isolation was not modeled in the analysis. The activity released from the damaged assembly was assumed to be released to the outside atmosphere over a 2-hour period. Since no filtration or containment isolation was modeled, this analysis supports refueling operation with the equipment hatch and the personnel air lock remaining open.

Control Room Isolation

It was assumed that the control room HVAC System is manually switched over from the normal operation mode to the emergency mode of operation after a high radiation alarm is actuated.

6.11.9.11.2 Acceptance Criteria

The offsite dose limit for an FHA is 6.3-rem TEDE per RG 1.183 (Reference 5). This is ~25 percent of the guideline value of 10CFR50.67 (Reference 3). The limit for the control room dose is 5-rem TEDE, per 10CFR50.67.

6.11.9.11.3 Results and Conclusions

The calculated doses due to the FHA are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
SB	5.7	6.3
LPZ	2.1	6.3
Control Room	1.4	5

The acceptance criteria are met.

The SB dose reported was for the worst 2-hour period, determined to be from 0 to 2 hours.

6.11.10 References

1. NRC Regulatory Guide 1.49, *Power Levels of Nuclear Power Plants*, Rev. 1, May 1973.

2. Letter from P. Milano (NRC) to M. Kansler (Entergy Nuclear Operations, Inc.), *Indian Point Nuclear Generating Unit No. 3 – RE: Issuance of Amendment RE: 1.4-Percent Power Uprate (TAC NO. MB5297),* License Amendment No. 213, Docket No. 50-286, November 26, 2002.

3. 10CFR50.67, *Accident Source Term*, 64 FR 72001, December 23, 1999.

4. NUREG-0800, *Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants,* 15.0.1, "Radiological Consequence Analyses using Alternative Source Terms," Rev. 0.

5. NRC Regulatory Guide 1.183, *Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors,* Rev. 0, July 2000.

6. Letter from P. Milano (NRC) to M. Kansler (Entergy Nuclear Operations, Inc.), *Indian Point Nuclear Generating Unit No. 3 – RE: Issuance of Amendment Affecting Adoption of Alternate Source Term for the Fuel Handling Accident (TAC NO. MB5382),* Amendment No. 215, Docket No. 50-286, March 17, 2003.

7. Letter from F. Dacimo (Entergy Nuclear Operations, Inc.) to P. Milano (NRC), *Indian Point Nuclear Generating Unit No. 3 – RE: Application of Alternate Source Term for the Radiological Dose Analyses for IP3* Docket No. 50-286, June 2, 2004.

8. 10CFR20, *Standards for Protection Against Radiation*, May 21, 1991.

9. 10CFR50, Appendix I, *Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion As Low As Reasonably Achievable for Radioactive Material in Light Water Cooled Nuclear Power Reactor Effluents*, July 29, 1996.

10. Appendix A to Facility Operating License DPR-64 for Entergy Nuclear Indian Point 3, LLC and Entergy Nuclear Operations, Inc., *Indian Point Nuclear Generating Plant Unit No. 3, Docket No. 50-286, Technical Specifications and Bases.*

11. *IP3 Offsite Dose Calculation Manual.*

12. NRC Regulatory Guide 1.26, *Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants*, Rev. 2, June 1975.

13. TID-14844, *Calculation of Distance Factors for Power and Test Reactor Sites*, 1962.

14. SECY-98-154, *Results of the Revised (NUREG-1465) Source Term Rebaselining for Operating Reactors*, June 30, 1998.

15. NUREG-0737, *Clarification of TMI Action Plan Requirements*, November 1980.

16. RSIC Computer Code Collection CCC-371, *ORIGEN2.1: Isotope Generation and Depletion Code – Matrix Exponential Method*, February 1996.

17. ANSI/ANS-18.1-1999, *Radioactive Source Term for Normal Operation of Light Water Reactors*, The American Nuclear Society Standards Institute, Inc., LaGrange Park, Illinois, September 21, 1999.

18. *Indian Point Nuclear Generating Unit No. 3, Updated Final Safety Analysis Report*, Rev. 18, Docket No. 50-286.

19. NUREG-0017, *Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors*, Rev. 1, April 1985.

20. NUREG-0578, *TMI Lessons Learned Task Force Status Report and Short Term Recommendations*, July 1979.

21. UE&C Report, *Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems which May Be Used in Post Accident Conditions*, July 1981.

22. *NRC Plant Shielding Design Review Inspection Report 50-286/83-05*, May 12, 1983.

23. NUREG-0737, Item 11.B.2.2, *Design Review of Plant shielding – Corrective Actions for Access to Vital Areas, Power Authority of the State of New York, Indian Point Generating Station Unit No. 3*, February 28, 1984.

24. UE&C Report, *Design Review of the Plant Accessibility Environmental Qualification of Equipment for Area/Systems Requiring Occupancy and/or use during Post Delta Pressurized Design Basis Accident Recovery Operations*, August 1985.

25. Letter from P. Milano (NRC) to M. Kansler (Entergy Nuclear Operations, Inc.), *Indian Point Nuclear Generating Unit No. 3 – RE: Issuance of Amendment to Delete Requirements for Post Accident Sampling*, Amendment No. 210, Docket No. 50-286, February 6, 2002.

26. 10CFR50.49, Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants, 66FR64738, December 14, 2001.

27. EPA Federal Guidance Report No. 11, EPA-520/1-88-020, *Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion*, September 1988.

28. EPA Federal Guidance Report No. 12, EPA 402-R-93-081, *External Exposure to Radionuclides in Air, Water and Soil*, September 1993.

29. NUREG-0800, *Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants*, 6.5.2, "Containment Spray as a Fission Product Cleanup System," Rev. 2, December 1988.

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

31. NRC Regulatory Guide 1.25, *Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors*, March 1972.

Table 6.11-1 Input Parameters for Core Inventory Calculations - Cycle 16	
Parameter	**Value**
Core Thermal Power (MWt)	3280.3 (3216*1.02)
Fuel Assembly Type	15 x 15
Uranium Mass (MTU)	86.6
Cycle Length (MWD/MTU)	25,432
Loading Pattern	See Table 6.11-2
Uranium Enrichments (wt % U-235)	Region 16A 4.48 Region 17B 4.80 Region 18B 4.80

Table 6.11-2 Input Parameters for Loading Pattern - Cycle 16			
Region	**No. of Assemblies**	**EOC Burnup (MWD/MTU)**	**Average Relative Power**
Feed Region 18B	93	30,830	1.21
1 x Burned Region 17B	92	51,920	0.85
2 x Burned Region 16A	8	45,990	0.20

Table 6.11-3

Core Inventory with 1.04 Fuel Management Variation Multiplier (core power = 3280.3 MWt)

Nuclide	Inventory at Shutdown (Ci)	Inventory at 84 Hours after Shutdown (Ci)	Nuclide	Inventory at Shutdown (Ci)	Inventory at 84 Hours after Shutdown (Ci)
Noble Gases			Other Isotopes		
KR 85	1.11E+06	1.11E+06	SR 89	8.84E+07	8.43E+07
KR 85M	2.44E+07	5.62E+01	SR 90	8.79E+06	8.79E+06
KR 87	4.69E+07	0.00E+00	SR 91	1.11E+08	2.43E+05
KR 88	6.60E+07	0.00E+00	SR 92	1.20E+08	0.00E+00
XE131M	9.92E+05	9.71E+05	Y 90	9.16E+06	8.94E+06
XE133	1.79E+08	1.36E+08	Y 91	1.14E+08	1.10E+08
XE133M	5.45E+06	2.78E+06	Y 92	1.21E+08	3.66E+01
XE135	4.77E+07	7.86E+05	Y 93	1.39E+08	4.43E+05
XE135M	3.68E+07	4.21E+03	NB 95	1.56E+08	1.55E+08
XE138	1.55E+08	0.00E+00	ZR 95	1.54E+08	1.49E+08
Halogens			ZR 97	1.55E+08	4.94E+06
I130	3.78E+06	3.41E+04	MO 99	1.75E+08	7.23E+07
I131	9.10E+07	6.90E+07	TC 99M	1.53E+08	6.97E+07
I132	1.33E+08	6.38E+07	RU103	1.39E+08	1.31E+08
I133	1.88E+08	1.17E+07	RU105	9.58E+07	1.99E+02
I134	2.06E+08	0.00E+00	RU106	4.84E+07	4.81E+07
I135	1.76E+08	2.63E+04	RH105	8.83E+07	1.98E+07
Rb and Cs			SB127	9.89E+06	5.34E+06
RB 86	2.36E+05	2.07E+05	SB129	2.97E+07	4.21E+01
CS134	2.05E+07	2.04E+07	TE127	9.83E+06	6.36E+06
CS136	5.96E+06	4.95E+06	TE127M	1.28E+06	1.27E+06
CS137	1.19E+07	1.19E+07	TE129	2.92E+07	2.60E+06
CS138	1.72E+08	0.00E+00	TE129M	4.28E+06	4.00E+06
CS138M	8.09E+06	0.00E+00	TE131M	1.33E+07	1.93E+06
Actinides			TE132	1.30E+08	6.20E+07
PU238	4.11E+05	4.14E+05	BA139	1.68E+08	0.00E+00
PU239	3.50E+04	3.53E+04	BA140	1.60E+08	1.32E+08
PU240	5.21E+04	5.21E+04	LA140	1.65E+08	1.48E+08
PU241	1.17E+07	1.17E+07	LA141	1.53E+08	6.13E+01
NP239	1.87E+09	6.71E+08	LA142	1.48E+08	0.00E+00
AM241	1.44E+04	1.46E+04	CE141	1.52E+08	1.42E+08
CM242	3.47E+06	3.44E+06	CE143	1.43E+08	2.46E+07
CM244	3.70E+05	3.70E+05	CE144	1.20E+08	1.19E+08
			PR143	1.37E+08	1.25E+08
			ND147	6.07E+07	4.88E+07

Note:

1. Curie values less than 1.0 are not significant and are assigned a value of zero.

Table 6.11-4

Input Parameters for RCS Activity and VCT Inventory Calculations

Parameter	Value
Core Thermal Power (MWt)	3280.3 (3216*1.02) 3216 for tritium
Cycle Length (full-power days)	685
Maximum Boron Concentration (ppm)	1238
Mixed-Bed Demineralizer Resin Volume (ft^3)	30
Failed Fuel Fraction (%)	1.0
Reactor Coolant Mass (lbm)	4.82×10^5
Purification System Flow Rate, Normal (gpm)	45
Purification System Flow Rate, Maximum (gpm)	132
VCT Liquid Volume (ft^3)	134
VCT Vapor Volume (ft^3)	266
VCT Temperature (°F)	130
Tritium Release Fraction from Fuel Rods Design Basis Expected	 0.1 0.02
RCS Lithium Concentration (ppm)	3

Table 6.11-5

Reactor-Coolant-Fission and Corrosion-Product-Specific Activities (core power = 3280.3 MWt)

Nuclide	Activity uCi/g	Nuclide	Activity uCi/g	Nuclide	Activity uCi/g
Kr-83m	5.04E-01	Mn-54	1.60E-03	Ag-110m	8.70E-03
Kr-85m	2.03E+00	H-3	3.5 (max)	Te-125m	2.01E-03
Kr-85	1.37E+01	Cr-51	5.50E-03	Te-127m	6.48E-03
Kr-87	1.30E+00	Mn-56	2.00E-02	Te-127	2.16E-02
Kr-88	3.81E+00	Fe-55	2.00E-03	Te-129m	1.96E-02
Kr-89	1.03E-01	Fe-59	5.20E-04	Te-129	2.08E-02
Xe-131m	3.23E+00	Co-58	1.56E-02	Te-131m	3.80E-02
Xe-133m	3.52E+00	Co-60	1.98E-03	Te-131	1.67E-02
Xe-133	2.46E+02	Rb-86	6.92E-02	Te-132	4.68E-01
Xe-135m	6.25E-01	Rb-88	4.48E+00	Te-134	3.28E-02
Xe-135	9.56E+00	Rb-89	2.06E-01	Ba-137m	4.19E+00
Xe-137	1.97E-01	Sr-89	7.43E-03	Ba-140	7.14E-03
Xe-138	7.14E-01	Sr-90	4.90E-04	La-140	2.95E-03
Br-83	1.10E-01	Sr-91	7.34E-03	Ce-141	1.10E-03
Br-84	5.10E-02	Sr-92	1.43E-03	Ce-143	7.48E-04
Br-85	5.86E-03	Y-90	1.68E-04	Pr-143	1.07E-03
I-127 (a)	2.62E-10	Y-91m	4.09E-03	Ce-144	4.92E-04
I-129	1.45E-07	Y-91	9.91E-04	Pr-144	4.92E-04
I-130	9.60E-02	Y-92	1.36E-03		
I-131	4.67E+00	Y-93	4.87E-04		
I-132	3.18E+00	Zr-95	1.09E-03		
I-133	6.28E+00	Nb-95	1.09E-03		
I-134	6.82E-01	Mo-99	1.23E+00		
I-135	3.05E+00	Tc-99m	1.15E+00		
Cs-134	8.82E+00	Ru-103	1.09E-03		
Cs-136	5.46E+00	Rh-103m	1.08E-03		
Cs-137	4.43E+00	Ru-106	5.71E-04		
Cs-138	1.08E+00	Rh-106	5.71E-04		

Notes:

1. (a) Grams of I-127 per gram of coolant.
2. Mn-54 is from the ANSI/ANS-18.1-1999.
3. Calculated specific activities have been multiplied by 1.04.
4. Operation with defects in fuel which generates 1% of core power.
5. RCS purification of 45 gpm at 130F and 40.0 psia.
6. No VCT purging.
7. RCS mass – 2.19E+08 g.

Table 6.11-6

Nuclide Inventories for Noble Gases and Iodine in the VCT (total of gas and liquid phases)

VCT Isotope	Inventory (curies)
Kr-83m	2.93E+01
Kr-85m	1.61E+02
Kr-85	2.24E+02
Kr-87	4.96E+01
Kr-88	2.40E+02
Kr-89	2.33E-01
Xe-131m	3.95E+02
Xe-133m	4.18E+02
Xe-133	3.04E+04
Xe-135m	7.54E+01
Xe-135	9.57E+02
Xe-137	5.36E-01
Xe-138	6.68E+00
I-127[1]	3.34E-11
I-129	1.85E-08
I-130	1.97E-02
I-131	6.29E-01
I-132	9.61E-01
I-133	1.14E+00
I-134	2.33E-01
I-135	7.38E-01

Note:

1. g I-127/g water

Table 6.11-7

Reactor Coolant Tritium Activity
(curies per cycle)

Tritium Source	Total Produced (curies)	Released to the Coolant	
		Design Value (curies)	Expected Value (curies)
Ternary Fissions	22280	2228	446
Soluble Poison Boron	1013	1013	1013
Burnable Poisons	4245	425	85
Li-7 Reaction	37	37	37
Li-6 Reaction	286	286	286
Deuterium Reaction	5	5	5
Total - Equilibrium Cycle	27866	3994	1872

Table 6.11-8

ANSI/ANS 18.1 – 1999 Normal Source Input Parameters

Parameter	Symbol	Value	Units
Core Thermal Power	P	3.216E+03	MWt
Weight of Water in RCS	WP	8.06E+04	gal
Reactor Coolant Letdown Flow Rate (purification)	FD	7.50E+01	gpm
Reactor Coolant Letdown Flow Rate (yearly average for boron control)	FB	1.52E-01	gpm
Flow through the Purification System Cation Demineralizer	FA	7.50E+00	gpm
Steam Flowrate	FS	1.32E+07	lb/hr
Weight of Secondary Side Water in all Steam Generators	WS	3.40E+05	lb
Steam Generator Blowdown Flowrate (total)	FBD	1.20E+02	gpm
Parameters Used to Calculate the Y Parameter:			
Density of RCS Water	Drcs	4.51E+01	lb/ft^3
VCT Liquid Volume	VOL-L	1.30E+02	ft^3
VCT Vapor Space Volume	VOL-V	2.70E+02	ft^3
VCT Purge Rate	PR	0.00E+00	scfm
Density of VCT Water	Dvct	6.17E+01	lb/ft^3
VCT Temperature	TEMP	1.27E+02	°F
VCT Vapor Pressure	PRESS	2.97E+01	psig

Note:
Values for NB, NA, NBD, NC, NS, and NX are equal to ANSI/ANS 18.1 values.

Table 6.11-9

Estimated Effect of Core SPU on Appendix I Doses

Type of Dose	Appendix I Design Objectives	5 Yr Annual Average Doses (Base Case)*	Scaled Doses (SPU Case)**	Percentage of Appendix I Design Objectives for SPU Case
Liquid Effluents				
Dose to Total Body from all Pathways	3 mrem/yr	1.10E-3 mrem/yr	1.22E-3 mrem/yr	0.041%
Dose to any Organ from all Pathways	10 mrem/yr	2.70E-3 mrem/yr	3.00E-3 mrem/yr	0.03%
Gaseous Effluents				
Gamma Dose in Air	10 mrad/yr	3.34E-04 mrad/yr	3.74E-04 mrad/yr	0.0037%
Beta Dose in Air	20 mrad/yr	6.78E-04 mrad/yr	7.60E-04 mrad/yr	0.0038%
Dose to Total Body of an Individual	5 mrem/yr	Not reported in annual radioactive release report	12.1% increase	As other doses are a small fraction of Appendix I Limits, it is assumed that this dose and consequent increase is also a small fraction of Appendix I.
Dose to Skin of an Individual	15 mrem/yr	Not reported in annual radioactive release report	12.1% increase	As other doses are a small fraction of Appendix I Limits, it is assumed that this dose and consequent increase is also a small fraction of Appendix I.
Radioiodines and Particulates Released to the Atmosphere				
Dose to any organ from all pathways	15 mrem/yr	7.32E-04 mrem/yr	8.22E-04 mrem/yr	0.0055%

Notes:

* Average core power level for the 5-year operation (base case) is 2956.15 MWt.

** Core power level assumed for SPU analysis is 3280.3 MWt.

Table 6.11-10 Nuclide Parameters			
Nuclide	Decay Constant (hr^{-1})	CEDE DCF (rem/Ci inhaled)	EDE DCF (rem· m^3 /Ci · sec)
I-130	5.61E-02	2.64E3	3.848E-01
I-131	3.59E-03	3.29E4	6.734E-02
I-132	3.01E-01	3.81E2	4.144E-01
I-133	3.33E-02	5.85E3	1.088E-01
I-134	7.91E-01	1.31E2	4.810E-01
I-135	1.05E-01	1.23E3	2.953E-01
Kr-85m	1.55E-01	NA	2.768E-02
Kr-85	7.38E-06	NA	4.403E-04
Kr-87	5.45E-01	NA	1.524E-01
Kr-88	2.44E-01	NA	3.774E-01
Xe-131m	2.43E-03	NA	1.439E-03
Xe-133m	1.32E-02	NA	5.069E-03
Xe-133	5.51E-03	NA	5.772E-03
Xe-135m	2.72E+00	NA	7.548E-02
Xe-135	7.63E-02	NA	4.403E-02
Xe-138	2.93E+00	NA	2.135E-01
Cs-134	3.84E-05	4.63E4	2.801E-01
Cs-136	2.20E-03	7.33E3	3.922E-01
Cs-137	2.64E-06	3.19E4	1.066E-01*
Cs-138	1.29E+00	1.01E2	4.477E-01
Rb-86	1.55E-03	6.62E3	1.780E-02
Te-127m	2.65E-04	2.15E4	5.439E-04
Te-127	7.41E-02	3.18E2	8.954E-04
Te-129m	8.60E-04	2.39E4	5.735E-03
Te-129	5.98E-01	8.95E1	1.018E-02
Te-131m	2.31E-02	6.40E3	2.594E-01
Te-132	8.86E-03	9.44E3	3.811E-02
Sb-127	7.50E-03	6.03E3	1.232E-01
Sb-129	1.60E-01	6.44E2	2.642E-01
Sr-89	5.72E-04	4.14E4	2.860E-04
Sr-90	2.72E-06	1.30E6	2.786E-05
Sr-91	7.30E-02	1.66E3	1.277E-01
Sr-92	2.56E-01	8.07E2	2.512E-01
Ba-139	5.03E-01	1.72E2	8.029E-03
Ba-140	2.27E-03	3.74E3	3.175E-02

Table 6.11-10 (Cont.)

Nuclide Parameters

Nuclide	Decay Constant (hr^{-1})	CEDE DCF (rem/Ci inhaled)	EDE DCF (rem· m^3 /Ci · sec)
Ru-103	7.35E-04	8.95E3	8.325E-02
Ru-105	1.56E-01	4.55E2	1.410E-01
Ru-106	7.84E-05	4.77E5	0.00E+00
Rh-105	1.96E-02	9.55E2	1.376E-02
Mo-99	1.05E-02	3.96E3	2.694E-02
Tc-99m	1.15E-01	3.26E1	2.179E-02
Ce-141	8.89E-04	8.95E3	1.269E-02
Ce-143	2.10E-02	3.39E3	4.773E-02
Ce-144	1.02E-04	3.74E5	3.156E-03
Pu-238	9.02E-07	3.92E8	1.806E-05
Pu-239	3.29E-09	4.29E8	1.569E-05
Pu-240	1.21E-08	4.29E8	1.758E-05
Pu-241	5.50E-06	8.25E6	2.683E-07
Np-239	1.23E-02	2.51E3	2.845E-02
Y-90	1.08E-02	8.44E3	7.030E-04
Y-91	4.94E-04	4.88E4	9.620E-04
Y-92	1.96E-01	7.81E2	4.810E-02
Y-93	6.86E-02	2.15E3	1.776E-02
Nb-95	8.22E-04	5.81E3	1.384E-01
Zr-95	4.51E-04	2.36E4	1.332E-01
Zr-97	4.10E-02	4.33E3	3.337E-02
La-140	1.72E-02	4.85E3	4.329E-01
La-141	1.76E-01	5.81E2	8.843E-03
La-142	4.50E-01	2.53E2	5.328E-01
Nd-147	2.63E-03	6.84E3	2.290E-02
Pr-143	2.13E-03	8.10E3	7.770E-05
Am-241	1.83E-07	4.44E8	3.027E-03
Cm-242	1.77E-04	1.73E7	2.105E-05
Cm-244	4.37E-06	2.48E8	1.817E-05

Notes:

CEDE = Committed effective dose equivalent

EDE = Effective dose equivalent

DCF = Dose conversion factor

* This is the DCF for Ba-137m. The DCF for Cs-137 is low; however a significant amount of Ba-137m is produced through decay. This is conservatively addressed by applying the DCF from Ba-137m to Cs-137.

Table 6.11-11 Offsite Breathing Rates and Atmospheric Dispersion Factors	
Time	**Offsite Breathing Rates (m^3/sec)**
0 - 8 hours 8 - 24 hours >24 hours	3.5E-4 1.8E-4 2.3E-4
	Offsite Atmospheric Dispersion Factors (sec/m^3)
SB(1)	1.03E-3
LPZ 0 - 2 hours 2 - 24 hours > 1 day	 3.8E-4 1.9E-4 1.7E-5

Note:

1. This SB atmospheric dispersion factor is conservatively applied during all time intervals in the determination of the limiting 2-hour period.

Table 6.11-12 Control Room Parameters		
Breathing Rate - Duration of the Event	$3.5E-4\ m^3/sec$	
Control Room Volume	$47,200\ ft^3$	
Occupancy Factors		
0 - 24 hours	1.0	
1 - 4 days	0.6	
4 - 30 days	0.4	
Normal Ventilation Flow Rates		
Filtered Makeup Flow Rate	0.0 scfm	
Filtered Recirculation Flow Rate	0.0 scfm	
Unfiltered Makeup Flow Rate	≤1500 scfm	
Unfiltered In-Leakage	≤700 scfm	
Emergency Ventilation System Flow Rates[1]	Option 1	Option 2
Filtered Makeup Air Flow Rate	≥400 scfm	≥1500 scfm
Filtered Recirculation Flow Rate	≥1000 scfm	0 scfm
Unfiltered Makeup Flow Rate	0 scfm	0 scfm
Unfiltered In-leakage	≤700 scfm	≤700 scfm
Filter Efficiencies		
Elemental Iodine	90%	
Organic Iodine	90%	
Particulates	99%	
Radiation Monitor Setpoint	1.0 mrem/hr	
Delay to Initiate Switchover of HVAC from Normal Operation to Emergency Operation after SI Signal	60 seconds	
Delay for Switchover of HVAC from Normal Operation to Emergency Operation after Receiving a High Alarm Signal (radiation monitor) Based on Manual Action	20 minutes	
Control Room Shielding	2 feet concrete	

Note:

1. The analyses are performed addressing each of the two options for control room HVAC operation in the emergency mode. The doses reported bound the two alternatives.

Table 6.11-13 Core Total Fission Product Activities Based on 3280.3 MWt (102% of 3216 MWt)	
Isotope	Activity (Ci)
I-130	3.78E+06
I-131	9.10E+07
I-132	1.33E+08
I-133	1.88E+08
I-134	2.06E+08
I-135	1.76E+08
Kr-85m	2.44E+07
Kr-85	1.11E+06
Kr-87	4.69E+07
Kr-88	6.60E+07
Xe-131m	9.92E+05
Xe-133m	5.45E+06
Xe-133	1.79E+08
Xe-135m	3.68E+07
Xe-135	4.77E+07
Xe-138	1.55E+08
Cs-134	2.05E+07
Cs-136	5.96E+06
Cs-137	1.19E+07
Cs-138	1.72E+08
Rb-86	2.36E+05
Te-127m	1.28E+06
Te-127	9.83E+06
Te-129m	4.28E+06
Te-129	2.92E+07
Te-131m	1.33E+07
Te-132	1.30E+08
Sb-127	9.89E+06
Sb-129	2.97E+07

Table 6.11-13 (Cont.) Core Total Fission Product Activities Based on 3280.3 MWt (102% of 3216 MWt)	
Isotope	**Activity (Ci)**
Sr-89	8.84E+07
Sr-90	8.79E+06
Sr-91	1.11E+08
Sr-92	1.20E+08
Ba-139	1.68E+08
Ba-140	1.60E+08
Ru-103	1.39E+08
Ru-105	9.58E+07
Ru-106	4.84E+07
Rh-105	8.83E+07
Mo-99	1.75E+08
Tc-99m	1.53E+08
Ce-141	1.52E+08
Ce-143	1.43E+08
Ce-144	1.20E+08
Pu-238	4.11E+05
Pu-239	3.50E+04
Pu-240	5.21E+04
Pu-241	1.17E+07
Np-239	1.87E+09
Y-90	9.16E+06
Y-91	1.14E+08
Y-92	1.21E+08
Y-93	1.39E+08
Nb-95	1.56E+08
Zr-95	1.54E+08
Zr-97	1.55E+08
La-140	1.65E+08
La-141	1.53E+08
La-142	1.48E+08
Nd-147	6.07E+07
Pr-143	1.37E+08
Am-241	1.44E+04
Cm-242	3.47E+06
Cm-244	3.70E+05

Table 6.11-14

RCS Coolant Concentrations
Based on 1% Fuel Defects[1]

Nuclide	Activity (μCi/gm)
I-130	0.096
I-131	4.67
I-132	3.18
I-133	6.28
I-134	0.682
I-135	3.05
Kr-85m	2.03
Kr-85	13.7
Kr-87	1.30
Kr-88	3.81
Xe-131m	3.23
Xe-133m	3.52
Xe-133	246
Xe-135m	0.625
Xe-135	9.56
Xe-138	0.714
Cs-134	8.82
Cs-136	5.46
Cs-137	4.43
Cs-138	1.08
Rb-86	0.0692

Note:

1. Plant *Technical Specification* limits primary coolant iodine coolant concentration to 1.0 μCi/gm dose equivalent I-131. These coolant concentrations are provided in Table 6.11-15.

Table 6.11-15 Iodine Specific Activities (µCi/gm)			
	Primary Coolant		Secondary Coolant
Nuclide	1 µCi/gm[1]	60 µCi/gm	0.10 µCi/gm
I-130	0.0161	0.97	0.0016
I-131	0.7849	47.09	0.0785
I-132	0.5345	32.07	0.0535
I-133	1.0555	63.33	0.1056
I-134	0.1146	6.88	0.0115
I-135	0.5126	30.76	0.0513

Note:

1. Iodine concentrations are converted to DE I-131 using the CEDE DCFs in Table 6.11-10.

Table 6.11-16 Iodine Spike Appearance Rates (Curies/Minute)[1]						
	I-130	I-131	I-132	I-133	I-134	I-135
335 Times the Equilibrium Rate (SGTR)	4.2	146.1	314.6	239.0	143.6	165.8
500 Times the Equilibrium Rate (MSLB)	6.2	218.0	469.6	356.7	214.3	247.5

Note:

1. Calculated based on the RCS concentration of 1.0 µCi/gm DE I-131, letdown flow of 120 gpm + 10% with perfect cleanup and RCS leakage of 11 gpm.

Table 6.11-17

Assumptions Used for Steamline Break Dose Analysis

Source Term	
Nuclide Parameters	See Table 6.11-10
Primary Coolant Noble Gas Activity prior to Accident	Based on operation with 1.0% Fuel Defects (See Table 6.11-14)
Primary Coolant Iodine Activity prior to Accident	
Pre-Existing Spike	60 µCi/gm of DE I-131 (See Table 6.11-15)
Accident-Initiated Spike	1.0 µCi/gm of DE I-131 (See Table 6.11-15)
Primary Coolant Iodine Appearance Rate Increase Due to the Accident-Initiated Spike	500 times equilibrium rate (See Table 6.11-16)
Duration of Accident-Initiated Spike	3.0 hours
Secondary Coolant Iodine Activity prior to Accident	0.10 µCi/gm of DE I-131 (See Table 6.11-15)
Iodine Chemical Form after Release to Atmosphere	
Elemental	97%
Organic	3%
Particulate (cesium iodide)	0%
Release Modeling	
Faulted Steam Generator Tube Leak Rate during Accident	432 gpd
Intact Steam Generator Tube Leak Rate during Accident	1008 gpd
Steam Generator Iodine Steam/Water Partition Coefficient	
Intact Steam Generator	0.01
Faulted Steam Generator	1.0
Time for RHR to take over cooling	29 hours
Time to Cool RCS Below 212°F and Stop Releases from Faulted Steam Generator	72 hours
Steam Release from Intact Steam Generators to Environment	
0-2 hours	402,000 lbm
2-29 hours	2,273,500 lbm
Steam Release from Faulted Steam Generator to Environment (during first 5 minutes)	142,400 lbm
Primary Coolant Mass	1.96E8 gm

Table 6.11-17 (Cont.)

Assumptions Used for Steamline Break Dose Analysis

Intact Steam Generator Secondary Mass	70,400 lbm/SG
Faulted Steam Generator Secondary Mass	142,400 lbm
Offsite Atmospheric Dispersion Factors	See Table 6.11-11
Offsite Breathing Rates	See Table 6.11-11
Control Room Model	See Table 6.11-12
Time to Start Crediting Emergency Control Room HVAC	*1 minute*
Control Room Atmospheric Dispersion (χ/Q) Factors	
Intact SG Releases:	
0 - 2 hours	1.19E-3 sec/m^3
2 - 8 hours	1.12E-3 sec/m^3
8 - 24 hours	5.59E-4 sec/m^3
24 - 96 hours	4.27E-4 sec/m^3
96 - 720 hours	3.35E-4 sec/m^3
Faulted SG Releases:	
0 - 2 hours	1.18E-3 sec/m^3
2 - 8 hours	1.06E-3 sec/m^3
8 - 24 hours	5.42E-4 sec/m^3
24 - 96 hours	4.09E-4 sec/m^3
96 - 720 hours	3.27E-4 sec/m^3

Table 6.11-18 Assumptions Used for Locked Rotor Dose Analysis	
Source Term	
Nuclide Parameters	See Table 6.11-10
Core Activity	See Table 6.11-13
Fraction of Fuel Rods in Core Failing	5% of core
Fission Product Gap Fractions	
I-131	8% of core activity
Kr-85	10% of core activity
Other Iodines and Noble Gases	5% of core activity
Alkali Metals	12% of core activity
Radial Peaking Factor	1.7
RCS Iodines	1.0 µCi/gm DE I-131 (See Table 6.11-15)
RCS Noble Gases and Alkali Metals	Based on operation with 1.0% fuel defects (See Table 6.11-14)
Secondary Coolant Iodine Activity at Beginning of Event	0.10 µCi/gm DE I-131 (See Table 6.11-15 values)
Secondary Alkali Metal Activity at Beginning of Event	10% of Table 6.11-14 values
Iodine Chemical Form after Release to Atmosphere	
Elemental	97%
Organic	3%
Particulate (cesium iodide)	0%
Release Modeling	
Primary Coolant Mass	1.96E8 gm
Secondary Coolant Mass	1.277E8 gm (total)
Primary-to-Secondary Leak Rate	1440 gal/day (total)
Steam Released from the Secondary Side	
0 - 2 hr	405,000 lbm
2 - 29 hr	2,303,000 lbm
Steam Generator Iodine Steam/Water Partition Coefficient	0.01
Steam Generator Alkali Metal Steam/Water Partition Coefficient	0.001
Termination of Releases	29 hours

Table 6.11-18 (Cont.) **Assumptions Used for Locked Rotor Dose Analysis**	
Offsite Atmospheric Dispersion Factors	See Table 6.11-11
Offsite Breathing Rates	See Table 6.11-11
Control Room Model	See Table 6.11-12
Time to Start Crediting Emergency Control Room HVAC	32 minutes
Control Room Atmospheric Dispersion (χ/Q) Factors	
Secondary Releases:	
0 - 2 hours	1.19E-3 sec/m^3
2 - 8 hours	1.12E-3 sec/m^3
8 - 24 hours	5.59E-4 sec/m^3
24 - 96 hours	4.27E-4 sec/m^3
96 - 720 hours	3.35E-4 sec/m^3

Table 6.11-19 Assumptions Used for Rod Ejection Accident	
Source Term	
Nuclide Parameters	See Table 6.11-10
Core Activity	See Table 6.11-13
Fraction of Fuel Rods in Core that Fail	10 (% of core)
Radial Peaking Factor	1.7
Fission Product Gap Fractions	
Iodines and Noble Gases	10% of core activity
Alkali Metals	12% of core activity
Fraction of Fuel Melting	0.25% of core
Fraction of Activity Released from Failed Fuel (gap activity)	100% for both containment leakage and steam generator steaming release paths
Fraction of Activity Released from Melted Fuel	
Noble Gases and Alkali Metals	100%
Iodines	25% for containment leakage release path 50% for steam generator steaming release path
RCS Iodines	1.0 µCi/gm DE I-131 (See Table 6.11-15)
RCS Noble Gases and Alkali Metals	Based on operation with 1% fuel defects (See Table 6.11-14)
Secondary Coolant Iodine Activity	0.10 µCi/gm DE I-131 (See Table 6.11-15)
Secondary Alkali Metal Activity	10% of Table 6.11-14 values
Containment Leakage Release Path	
Containment Net Free Volume	2.61E6 ft^3
Containment Leak Rates	
0 - 24 hours	0.1 weight %/day
> 24 hours	0.05 weight %/day
Iodine Chemical Form	4.85% elemental, 0.15% organic, and 95% particulate
Spray Removal in Containment	Not credited
Aerosol Removal by FCU Filters	
Number of FCUs Operating	3
FCU Filtered Flow	8000 cfm/FCU
Filter Efficiency	0.9
Time to Credit FCU Filtration Flow	60 sec.

Table 6.11-19 (Cont.)

Assumptions Used for Rod Ejection Accident

Steam Generator Steaming Release Path	
Primary Coolant Mass	1.96E8 gm
Secondary Coolant Mass	1.277E8 gm (total)
Primary-to-Secondary Leak Rate	1440 gal/day
Duration of Primary-to-Secondary Leakage	1 hr
Steam Released from the Secondary Side	
0 - 2 hours	405,000 lbm
> 2 hours	0 lbm
Iodine Chemical Form after Release to Atmosphere	97% elemental, 3% organic
SG Iodine Steam/Water Partition Coefficient	0.01
SG Alkali Metal Steam/Water Partition Coefficient	0.001
Offsite Atmospheric Dispersion Factors	See Table 6.11-11
Offsite Breathing Rates	See Table 6.11-11
Control Room Model	See Table 6.11-12
Time to Start Crediting Emergency Control Room HVAC	140 seconds
Control Room Atmospheric Dispersion (χ/Q) Factors	
Secondary Releases:	
0 - 2 hours	1.19E-3 sec/m^3
2 - 8 hours	1.12E-3 sec/m^3
8 - 24 hours	5.59E-4 sec/m^3
24 - 96 hours	4.27E-4 sec/m^3
96 - 720 hours	3.35E-4 sec/m^3
Containment Releases:	
0 - 2 hours	3.57E-4 sec/m^3
2 - 8 hours	3.12E-4 sec/m^3
8 - 24 hours	1.24E-4 sec/m^3
24 - 96 hours	1.06E-4 sec/m^3
96 - 720 hours	7.99E-5 sec/m^3

Table 6.11-20

Assumptions Used for SGTR Dose Analysis

Source Term	
Nuclide Parameters	See Table 6.11-10
Primary Coolant Noble Gas Activity prior to Accident	Based on operation with 1.0% fuel defects (See Table 6.11-14)
Primary Coolant Iodine Activity Prior to Accident	
Pre-Existing Spike	60 µCi/gm of DE I-131 (See Table 6.11-15)
Accident-Initiated Spike	1.0 µCi/gm of DE I-131 (See Table 6.11-15)
Primary Coolant Iodine Appearance Rate Increase Due to the Accident-Initiated Spike	335 times equilibrium rate (See Table 6.11-16)
Duration of Accident-Initiated Spike	4.0 hours
Secondary Coolant Iodine Activity Prior to Accident	0.10 µCi/gm of DE I-131 (See Table 6.11-15)
Release Modeling	
Ruptured Steam Generator Steam Releases	See Table 6.4-2
Ruptured Steam Generator Break Flow Rate	See Table 6.4-2
Break-Flow Flashing Fractions	See Table 6.4-2
Intact Steam Generator Tube Leak Rate during Accident	432 gpd per steam generator
Steam Release from Intact Steam Generators to Environment	See Table 6.4-2
Steam Generator Iodine Steam/Water Partition Coefficient	
Ruptured and Intact Steam Generator Steam Release	0.01
Flashed Break Flow	1.0
Primary Coolant Mass	1.96E8 gm
Steam Generator Secondary Mass	2.88E7 gm/SG
Offsite Atmospheric Dispersion Factors	See Table 6.11-11
Offsite Breathing Rates	See Table 6.11-11
Control Room Model	See Table 6.11-12
Time to Start Crediting Emergency Control Room HVAC	7.53 minutes

Table 6.11-20 (Cont.) Assumptions Used for SGTR Dose Analysis	
Control Room Atmospheric Dispersion (χ/Q) Factors	
Secondary releases:	
0 - 2 hours	1.19E-3 sec/m^3
2 - 8 hours	1.12E-3 sec/m^3
8 - 24 hours	5.59E-4 sec/m^3
24 - 96 hours	4.27E-4 sec/m^3
96 - 720 hours	3.35E-4 sec/m^3

Table 6.11-21

Assumptions Used for SBLOCA Analysis

Source Term	
Nuclide Parameters	See Table 6.11-10
Core Activity	See Table 6.11-13
Fraction of Fuel Rods in Core that Fail	100% of core
Gap Fractions	
Iodine, Noble Gases and Alkali Metals	5% of core activity
Fraction of Fuel Melting	0% of core
Fraction of Activity Released from Failed Fuel (Gap Activity)	100%
RCS Noble Gas and Alkali Metal Activity Prior to Accident	Based on operation with 1.0% fuel defects (See Table 6.11-14)
RCS Iodine Activity Prior to Accident	1.0 µCi/gm of DE I-131 (See Table 6.11-15)
Containment Release Path	
Containment Net-Free Volume	2.61E6 (ft^3)
Containment Leak Rates	
0 - 24 hours	0.1 (weight %/day)
> 24 hours	0.05 (weight %/day)
Iodine Chemical Form	4.85% elemental, 0.15% organic and 95% particulate
Spray Removal in Containment	Not Credited
Aerosol Removal by FCU Filters	
Number of FCUs in Operation	3
FCU Filtered Flow	8000 cfm
Filter Efficiency	0.9
Time FCU Filtered Flow Begins	60 sec
Deposition Removal in Containment	Not credited

Table 6.11-21 (Cont.) Assumptions Used for SBLOCA Analysis	
Steam Generator Steaming Release Path	
Primary Coolant Mass	1.96E8 gm
Secondary Coolant Mass	1.277E8 gm (total)
Primary-to-Secondary Leak Rate	1440 gal/day total
Duration of Primary-to-Secondary Leakage	1 hr
Steam Released from the Secondary Side	
0 - 2 hours	405,000 lbm
> 2 hours	0 lbm
Steam Generator Iodine Steam/Water Partition Coefficient	0.01
Steam Generator Alkali Metal Steam/Water Partition Coefficient	0.001
Iodine Chemical Form after Release to Atmosphere	97% elemental, 3% organic
Offsite Atmospheric Dispersion Factors	See Table 6.11-11
Offsite Breathing Rates	See Table 6.11-11
Control Room Model	See Table 6.11-12
Time to Start Crediting Emergency Control Room HVAC	140 seconds
Control Room Atmospheric Dispersion (χ/Q) Factors	
Secondary Releases:	
0 - 2 hours	1.19E-3 sec/m^3
2 - 8 hours	1.12E-3 sec/m^3
8 - 24 hours	5.59E-4 sec/m^3
24 - 96 hours	4.27E-4 sec/m^3
96 - 720 hours	3.35E-4 sec/m^3
Containment Releases:	
0 -2 hours	3.57E-4 sec/m^3
2 - 8 hours	3.12E-4 sec/m^3
8 - 24 hours	1.24E-4 sec/m^3
24 - 96 hours	1.06E-4 sec/m^3
96 - 720 hours	7.99E-5 sec/m^3

Table 6.11-22 Assumptions Used for LBLOCA Analysis	
Source Term	
Nuclide Parameters	See Table 6.11-10
Core Activity	See Table 6.11-13
Activity Release Timing	
Gap Release	Starting at 30 seconds, Ending at 30 minutes
Fuel Melt Release	Starting at 30 minutes Ending at 1.8 hours
Activity Release from the Fuel	
Noble Gases	5% gap, 95% fuel melt (100% total)
Iodines	5% gap, 35% fuel melt (40% total)
Alkali Metals	5% gap, 25% fuel melt (30% total)
Tellurium Metals	0% gap, 5% fuel melt (5% total)
Barium, Strontium	0% gap, 2% fuel melt (2% total)
Noble Metals	0% gap, 0.25% fuel melt (0.25% total)
Cerium Group	0% gap, 0.05% fuel melt (0.05% total)
Lanthanides	0% gap, 0.02% fuel melt (0.02% total)
Iodine Chemical Form in Containment	4.85% elemental, 0.15% organic and 95% particulate
Iodine Chemical Form Released to Atmosphere from ECCS Leakage	97% elemental, 3% organic
Containment Release Path	
Containment Net-Free Volume	2.61E6 ft^3
Sprayed Fraction	0.8
Containment Leak Rates	
0 - 24 hours	0.1 weight %/day
> 24 hours	0.05 weight %/day
Fan Cooler Flow Rate	34,000 cfm/unit
Number of Fan Coolers Credited	3
Time to Start Fan Coolers	1 minute
Fan Cooler Filtration	Not credited

Table 6.11-22 (Cont.)

Assumptions Used for LBLOCA Analysis

Spray Operation	
Time to Initiate Sprays	67 seconds
Spray Injection Duration	43.9 minutes
Delay Between End of Spray Injection Phase and Beginning of Spray Recirculation Phase	3 minutes
Termination of Spray Recirculation	4.0 hours
Injection Spray Flow Rate	2200 gpm
Recirculation Spray Flow Rate	1050 gpm
Spray Fall Height	118.5 feet
Removal Coefficients	
Elemental Iodine Injection Spray Removal	20.0 hr^{-1}
Particulate Injection Spray Removal	4.6 hr^{-1}
Elemental Iodine Recirculation Spray Removal	5.0 hr^{-1}
Particulate Recirculation Spray Removal	2.2 hr^{-1}
Sedimentation Particulate Removal in Unsprayed Region and in Sprayed Region after Spray Termination	0.1 hr^{-1}
DF Limit for Elemental Iodine Removal	200
DF Limit for Particulates Removal	1000
Sump Solution Leakage Release Path	
Credited Sump Mass	3.097E6 lbm
Sump Solution Leak Rate to Auxiliary Building	
0 - 4.0 hours	1 gal/hr
4.0 – 6.5 hours	0 gal/hr
> 6.5 hours	4 gal/hr
Iodine Airborne Fraction for Sump Solution Leakage to Auxiliary Building	
0 - 4 hours	0.10
4 – 6.5 hours	NA
>6.5 hours	0.027
Filtration of Activity Released by ECCS Leakage Outside Containment	Not credited

Table 6.11-22 (Cont.) Assumptions Used for LBLOCA Analysis	
Offsite Atmospheric Dispersion Factors	See Table 6.11-11
Offsite Breathing Rates	See Table 6.11-11
Control Room Model	See Table 6.11-12
Time to Start Crediting Emergency Control Room HVAC	1 minute
Control Room Atmospheric Dispersion (χ/Q) Factors	
Containment Releases:	
0 - 2 hours	3.57E-4 sec/m^3
2 - 8 hours	3.12E-4 sec/m^3
8 - 24 hours	1.24E-4 sec/m^3
24 - 96 hours	1.06E-4 sec/m^3
96 - 720 hours	7.99E-5 sec/m^3
ECCS leakage:	
0 - 2 hours	5.93E-4 sec/m^3
2 - 8 hours	4.92E-4 sec/m^3
8 - 24 hours	2.06E-4 sec/m^3
24 - 96 hours	1.69E-4 sec/m^3
96 - 720 hours	1.26E-4 sec/m^3

Table 6.11-23

Assumptions Used for GDT Rupture Dose Analysis

Nuclide Parameters	See Table 6.11-10
GDT Inventory (Dose Equivalent Xe-133)	50,000 Ci
Duration of Release	5 minutes
Offsite Atmospheric Dispersion Factors	See Table 6.11-11
Offsite Breathing Rates	See Table 6.11-11
Control Room Model	See Table 6.11-12
Control Room Atmospheric Dispersion (χ/Q) factors	
Containment Vent Releases:	
0 - 2 hours	5.93E-4 sec/m^3
Time to Start Crediting Emergency Control Room HVAC	5 minutes

Table 6.11-24 Assumptions Used for VCT Rupture Dose Analysis	
Nuclide Parameters	See Table 6.11-11
VCT Inventory (Ci)	See Table 6.11-6
Duration of Activity Release from Tank	5 minutes
Iodine Partition Coefficient for VCT Liquid	0.01
Primary Coolant Noble Gas Activity	1.0% fuel defect level (See Table 6.11-14)
Primary Coolant Initial Iodine Activity	1.0 μCi/gm of DE I-131 (See Table 6.11-15)
Letdown Flow Rate	132 gpm
Iodine Partition Coefficient for Letdown Releases	0.1
Letdown Line Demineralizer DF for Iodine	10
Time to Isolate Letdown Flow	30 minutes
Offsite Atmospheric Dispersion Factors	See Table 6.11-11
Offsite Breathing Rate	See Table 6.11-11
Control Room Model	See Table 6.11-12
Control Room Atmospheric Dispersion (χ/Q) factors	
Containment Vent Releases:	
0 - 2 hours	5.93E-4 sec/m^3
Time to Start Crediting Emergency Control Room HVAC	5 minutes

Table 6.11-25

Assumptions Used for HT Failure Dose Analysis

Nuclide Parameters	See Table 6.11-10
Duration of Activity Release from Tank	5 minutes
Iodine Partition Coefficient for HT Liquid	0.01
HT Volume	8500 ft^3
HT Full Level	80%
Primary Coolant Noble Gas Activity	1.0% fuel defect level (See Table 6.11-14)
Primary Coolant Initial Iodine Activity	1.0 μCi/gm of DE I-131 (See Table 6.11-15)
Tank Fill Time	24 hours
Letdown Demineralizer DF for Iodines	10
Offsite Atmospheric Dispersion Factors	See Table 6.11-11
Offsite Breathing Rates	See Table 6.11-11
Control Room Model	See Table 6.11-12
Control Room Atmospheric Dispersion (χ/Q) factors	
Containment Vent Releases:	
0 - 2 hours	5.93E-4 sec/m^3
Time to Start Crediting Emergency Control Room HVAC	5 minutes

Table 6.11-26 Assumptions Used for FHA Analysis	
Source Term	
Nuclide Parameters	See Table 6.11-10
Core Total Fission Product Activity (with 84 Hours Decay)	See Table 6.11-27
Number of Fuel Assemblies	193
Radial Peaking Factor	1.70
Fuel Rod Gap Fraction	
I-131	12%
Kr-85	30%
Other Iodines and Noble Gases	10%
Fuel Damaged	One assembly
Time after Shutdown	84 hours
Water Depth	23 feet
Overall Iodine Scrubbing Factor	200
Noble Gases Scrubbing Factor	1
Filter Efficiency	No filtration of releases assumed
Isolation of Release	No isolation of releases assumed
Time to Release All Activity	2 hours
Offsite Atmospheric Dispersion Factors	See Table 6.11-11
Offsite Breathing Rates	See Table 6.11-11
Control Room Model	See Table 6.11-12
Time to Start Crediting Emergency Control Room HVAC	24 minutes
Control Room Atmospheric Dispersion (χ/Q) Factors	
Containment Vent:	
0 - 2 hours	5.93E-4 sec/m^3

Table 6.11-27

Core Fission Product Inventory 84 Hours after Shutdown Based on 3280.3 MWt (102% of 3216 MWt)

	Isotopic Inventory, curies
Iodine	
I-130	3.41E4
I-131	6.90E7
I-132	6.38E7
I-133	1.17E7
I-134	0.00E0
I-135	2.63E4
Noble Gases	
Kr-85m	5.62E1
Kr-85	1.11E6
Kr-87	0.00E0
Kr-88	0.00E0
Xe-131m	9.71E5
Xe-133m	2.78E6
Xe-133	1.36E8
Xe-135m	4.21E3
Xe-135	7.86E5
Xe-138	0.00E0

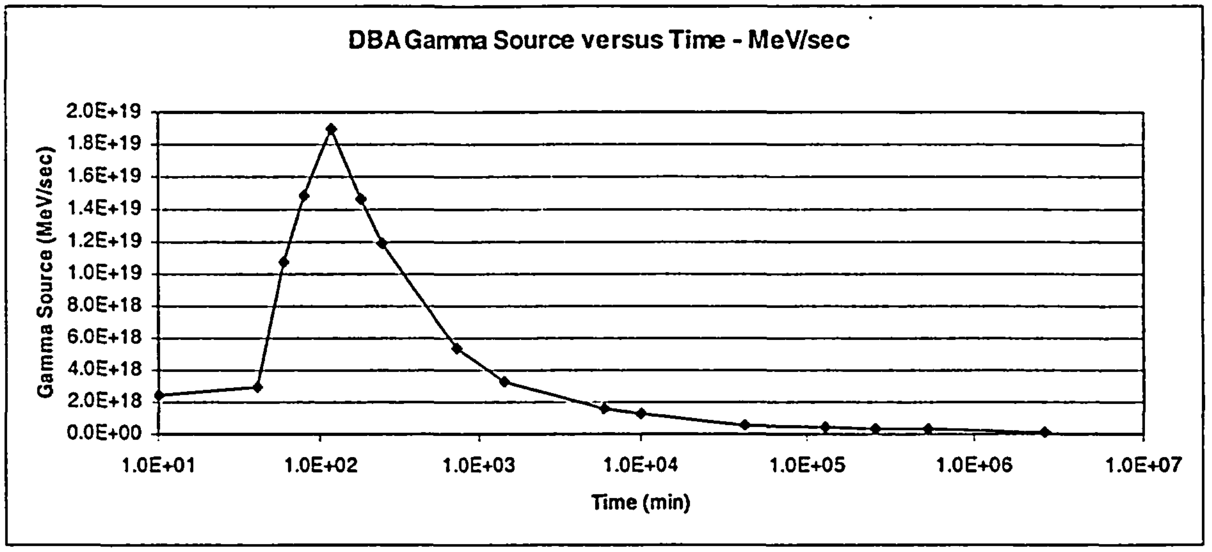

Figure 6.11-1

Containment Gamma Dose Rate vs. Time

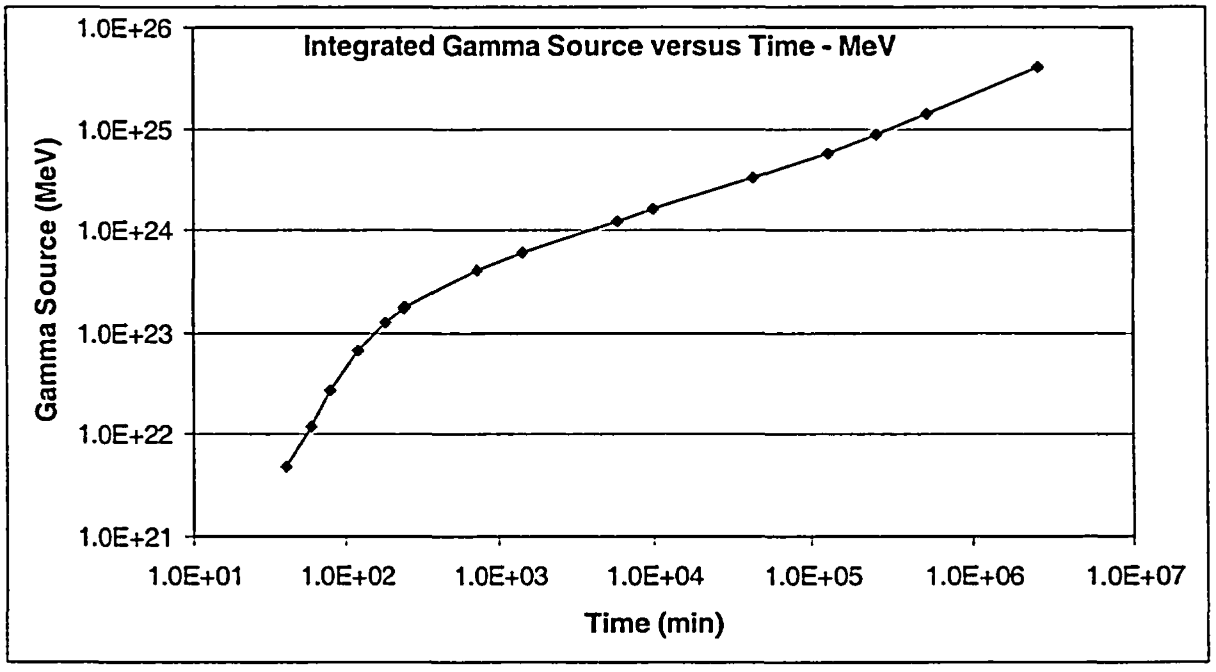

Figure 6.11-2

Integrated Containment Gamma Sources

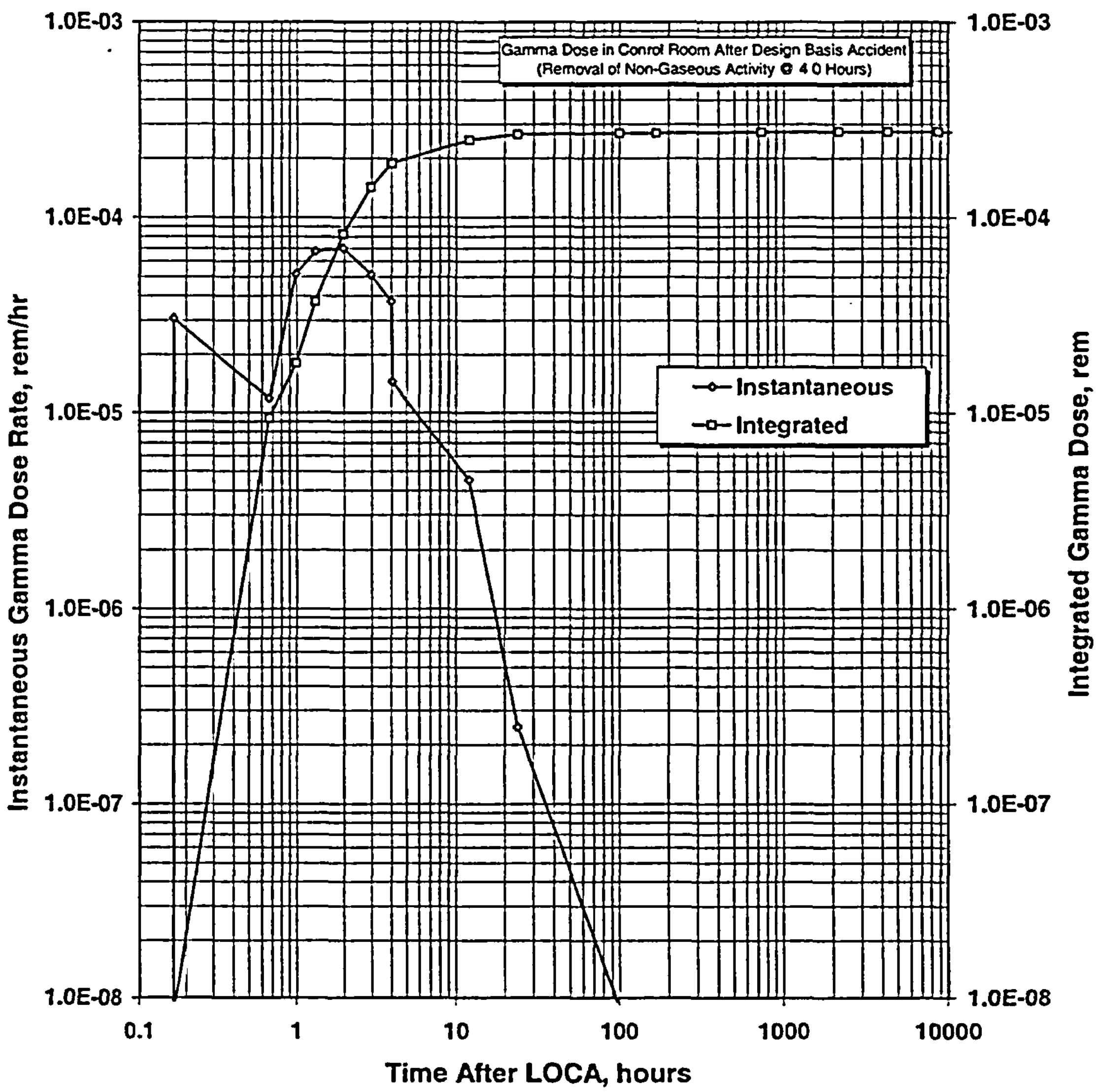

Figure 6.11-3

Direct Gamma Dose Rate and Integrated Dose in the Control Room Following a DBA

6.12 EOPs and EOP Setpoints

As a result of the Indian Point Unit 3 (IP3) stretch power uprate (SPU), the plant operating parameters have changed from the current design parameters. These include parameters that affect analyses and evaluations for plant operations and for plant accident responses. As a result of the parameter revisions, Emergency Operating Procedure (EOP) setpoints specified by the IP3 EOPs were reviewed to determine the potential effect from the changed power uprating parameters. Once this list of EOP setpoints was established, the new EOP setpoint calculations were performed.

To further ensure that the EOP setpoint documentation met the current generic requirements of Westinghouse Owners Group (WOG) Emergency Response Guidelines (ERGs), all relevant ERG Maintenance Direct Work Items (DWs) approved through August 2003 were reviewed, and necessary changes incorporated into the IP3 EOP setpoints and corresponding EOPs.

Based on the identified EOP setpoint changes, the IP3 EOPs were reviewed to identify changes resulting from the changed power uprating parameters and corresponding EOP setpoint changes.

These changes will be incorporated into the IP3 EOPs for use in the operator training program and in plant operations when the SPU is implemented.

6.13 Post-LOCA Hydrogen Generation

6.13.1 Introduction

An evaluation of the hydrogen generation in containment following a loss-of-coolant accident (LOCA) for the Indian Point Unit 3 (IP3) was performed based on updated parameters and assumptions that reflect the power uprate conditions. Westinghouse methodologies and the guidance provided in NRC Regulatory Guide (RG) 1.7 (Reference 1) were used in this assessment.

The hydrogen control strategies presented in the IP3 *Updated Final Safety Analysis Report* (UFSAR) (Reference 2) reflect controlled vent flow and pressurization of containment, with provisions for an external hydrogen recombiner as a third alternative. The projected impact of removal by a recombiner on post-LOCA hydrogen accumulation was addressed in the Westinghouse evaluation. However, in the event of a LOCA design basis accident (DBA), plant personnel would calculate the effects of a release based on the actual conditions at the time of the release. Thus, it is not necessary to re-evaluate the pressurization and venting control methods, since actual plant conditions will be considered in ensuring that the resultant doses are within acceptable limits.

6.13.2 Input Parameters and Assumptions

A listing of the major parameters and assumptions are listed below in Table 6.13-1.

The remaining assumptions are consistent with NRC RG 1.7 (Reference 1).

6.13.3 Description of Analyses

The evaluation consists of the calculation of the production of hydrogen following a LOCA and the associated buildup of the concentration of hydrogen inside the containment. The concentrations are compared to the regulatory limit and the impact of removal of hydrogen by a hydrogen recombiner was determined. The sources of hydrogen that are considered in the analysis are:

- Zirconium water reaction
- Corrosion of materials
- Core and sump solution radiolysis
- Initial Reactor Coolant System (RCS) and containment inventories

The evaluations conducted for the various sources of hydrogen are summarized in the following paragraphs.

Zirconium - Water Reaction

The weight of analyzed zirconium cladding based on the current fuel load is 41,002 lbs. This value is noted to be less than the current IP3 UFSAR (Reference 2) loading of 47,947 lbs. However, the extra mass is based upon the total mass of zirconium cladding in the core (including zirconium outside the active core region that is not required to be analyzed in this event). Per 10CFR50.44 (Reference 3), the Zirc-water reaction involves only the region of the fuel that could exceed the temperature required for the chemical reaction of the cladding with the water or steam to occur (that is, the cladding in the active fuel region).

The amount of zirconium cladding that is assumed to undergo the Zirc-water reaction is 5 percent of the zirc cladding mass in the active core region. The amount of zirconium is mandated by 10CFR50 to be 5 times the fraction calculated in the 10CFR50.46 (Reference 4) ECCS performance criteria assessment. The assumption of 5 percent is an upper limit since 10CFR50 specifies that the calculated fraction not exceed 1 percent of the cladding in the active core region. Thus, 5 percent is 5 times the limiting calculated value and is a conservative and bounding value.

The total hydrogen produced from the Zirc-water reaction based on these conservative assumptions is 16,200 standard cubic feet (scf). This inventory is assumed to be instantaneously released to the containment atmosphere at the beginning of the LOCA.

Corrosion of Materials

The corrosion of materials in containment following a LOCA is a function of the temperature and pH of the solution in contact with the material, as well as the composition and surface area. The relationship of the aluminum corrosion rate with temperature and pH is illustrated in Figure 6.13-1. The default corrosion rates as a function of inverse temperature considered in the analysis is shown in this figure. The relationship used for the default aluminum corrosion rates is based on Oak Ridge National Laboratory (ORNL) measurements at a pH of about 9.5 (Reference 5).

<u>Containment Temperature</u> - The post-LOCA temperature profile used in establishing the material corrosion rates is graphically represented in Figure 6.13-2. The temperature profile is conservatively assumed to be that associated with only one train of safeguards in operation. It should also be noted that the long-term aluminum corrosion rate is maintained at or above 16 $mg/dm^2/hr$ (200 mils/year) regardless of the prevailing temperature. This assumption is consistent with guidance provided in NRC RG 1.7 (Reference 1).

Spray/Sump pH - The pH of the spray and sump water is considered to be in the range of 7.0 to 10.0, per the IP3 UFSAR (Reference 2).

Corrodible Materials - Data relative to the inventory of corrodible materials inside containment (for example, aluminum) are tabulated in Table 6.13-2.

Core and Sump Solution Radiolysis

Hydrogen from sump and core radiolysis are time-dependent quantities that are a function of fission product decay energy. Core and sump radiolysis is calculated based on values of energy deposition in the core and sump solutions that reflect TID-14844 (Reference 6) release assumptions and the associated distribution of fission products, as defined in RG 1.7 (Reference 1). Plant operation with extended fuel cycles prior to a LOCA was considered. The default decay energy data were derived from the ORIGEN2.1 computer code (Reference 7) and bound decay energy data associated with typical Westinghouse fuel design parameters associated with extended (that is, 18- and 24-month) fuel cycles. The decay energies that are considered in the analyses reflect RG 1.7 assumptions relative to the amount of energy available for deposition in the sump and core solutions.

Initial RCS and Containment Inventories

The initial hydrogen inventory in the RCS prior to the LOCA includes hydrogen in the primary coolant as well as in the pressurizer gas space. The amount of hydrogen contained in the RCS is based on a pre-accident RCS hydrogen concentration of 50 cc/kg. This value is conservatively based on the value associated with the upper end of the operating range of 25 to 50 cc/kg that is recommended by Westinghouse and Electrical Power Research Institute (EPRI) (Reference 8). The hydrogen volume in the liquid, V_L, based on the maximum hydrogen concentration of 50 cc/kg, is 415 scf. An additional RCS H_2 inventory of 1059 scf is contained in the pressurizer steam space. This inventory is calculated based on no purge or leakage from the pressurizer, which results in a conservative estimate. Then, the total RCS inventory is:

$$V_{RCS} = V_L + V_P = 415 + 1059 = 1474 \text{ scf}$$

The associated hydrogen inventory is considered to be instantaneously released to the containment atmosphere.

Recombination

Removal from the containment atmosphere is conservatively assumed to be only by operation of a single electric hydrogen recombiner, and post-LOCA containment venting is not credited in the analyses.

The time at which recombination is assumed is at the end of the ninth day after a LOCA.

6.13.4 Acceptance Criteria for Analyses

RG 1.7 (Reference 1) indicates that the containment hydrogen concentration should remain below 4 volume-percent (v/o).

The initiation of recombination at the end of the ninth day satisfies the NRC Standard Review Plan (SRP) criteria for combustible gas control in containment. As stated in NUREG-0800, Section 6.2.5 (Reference 9):

"The proposed operation of the combustible gas control equipment, excluding containment atmosphere dilution (CAD) systems, is acceptable if there is an appropriate margin, e.g., on the order of 0.5 v/o, between the limiting hydrogen concentration limit and the hydrogen concentration at which the equipment would be actuated."

6.13.5 Results

The hydrogen production rates and containment inventories from the various sources of hydrogen are shown in Figures 6.13-3 and 6.13-4. The effects of recombination at various times are illustrated in Figure 6.13-5. The results indicate that, without recombination, a containment concentration of 3.0 v/o hydrogen is reached during the eleventh day after a LOCA, and a containment concentration of 4.0 v/o is reached during the twenty-fourth day after a LOCA. A concentration of 4.1 v/o is reached without recombination during the twenty-sixth day after a LOCA. Figure 6.13-5 shows that with no removal mechanisms in place, the hydrogen concentration builds up to about 4.4 v/o at 30 days following a LOCA. The figure also shows that operation of a single recombiner at a 100-scfm processing rate beginning at the time when the hydrogen concentration reaches 3.0 v/o results in an immediate termination of the buildup of hydrogen inside the containment. The decreasing hydrogen concentration after recombination is initiated indicates that the recombination rate exceeds the production rate.

The assumed minimum time from the beginning of a LOCA to start of recombiner operation is 9 days. As shown in Figure 6.13-5, the start of recombination at this time limits the containment hydrogen concentration to less than 4 v/o for the duration of the accident.

6.13.6 Conclusions

The start of recombination at 9 days after a LOCA limits the containment hydrogen concentration to less than 4 v/o for the duration of the accident. Thus, the regulatory limit is not exceeded.

6.13.7 References

1. NRC Regulatory Guide 1.7, *Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident*, Rev. 3, May 2003.

2. *Indian Point Nuclear Generating Unit No. 3, Updated Final Safety Analysis Report*, Docket No. 50-286, Rev. 10, January 6, 2001.

3. 10CFR50.44, *Combustible Gas Control for Nuclear Power Reactor*, September 16, 2003.

4. 10CFR50.46, *Acceptance Criteria for Emergency Core Cooling Systems for Light Water Cooled Nuclear Power Reactors,* September 16, 2003.

5. Griess, J. C., and Barcarella, A. L., *Design Considerations of Reactor Containment Spray Systems – Part III. Corrosion of Plant Materials in Spray Solutions,* ORNL-TM-2412 (Part III), December 1969.

6. TID-14844, *Calculation of Distance Factors for Power and Test Reactor Sites,* Technical Information Document, Atomic Energy Commission – Division of Technical Information, March 23, 1962.

7. CCC-371, *ORIGEN2.1: Isotope Generation and Depletion Code – Matrix Exponential Method, RSICC Computer Code Collection*, Oak Ridge National Laboratory, February 1996.

8. *PWR Primary Water Chemistry Guidelines: Volume 1*, Revision 4, EPRI, Palo Alto, CA, 199-TR-105714-V1R4.

9. NUREG-0800, Branch Technical Position MTEB 6-1, *pH for Emergency Coolant Water for PWRs,* Rev. 2, July 1981.

Table 6.13-1 Major Parameters and Assumptions – Hydrogen Generation	
Core Thermal Power Rating[1]	3281 MWt
Containment Free Volume	2,610,000 ft^3
Containment Temperature at Accident Initiation	130°F
Fuel Cladding Mass Undergoing Zirc-Water Reaction	5.0%
Total Mass of Zirc in the Core	41,002 lbs.
RCS Hydrogen Concentration during Normal Operation	50 cc/kg
RCS Mass (normal pressurizer level)	518,182 lbs.
Pressurizer Volume	1834.4 ft^3
Pressurizer Level (normal operation)	50%
Hydrogen Recombiner Flow Rate	100 scfm

Note:

1. 3216 MWT multiplied by 1.02 to account for source uncertainties.

Table 6.13-2

Inventory of Aluminum Inside the Containment Building

Item Description	Weight (lbs)	Area (ft^2)
UFSAR Aluminum Sources		
Source, Intermediate, and Power Range Detectors	472	338
Process Instrumentation and Control Equipment	159	31
Paint	58	7480
Valve Parts inside Containment	230	86
Reactor Vessel Foil	269	10000
Flux Mapping Drive System	1950	335
Reactor Coolant Pump Motor Parts	125	12.8
Other Sources Included in Analysis		
CRDM Cooling Fan Blades	800	131.6
RCP conduit boxes	7.2	4
Rod Position Indicators	10.6	3.7
Others (filters, etc.)	25	25
Total Aluminum	4105.8	18447.1

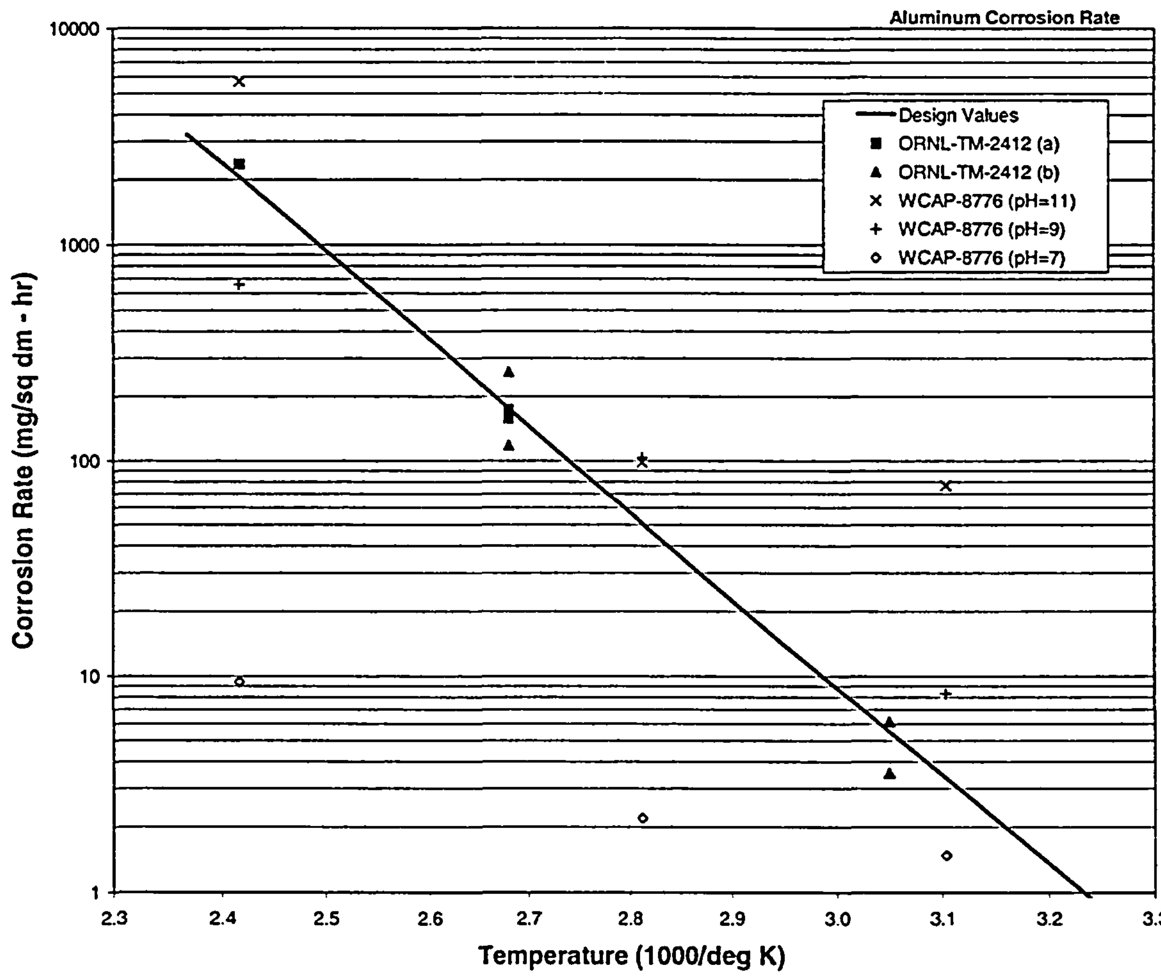

Figure 6.13-1

Aluminum Corrosion Rates in LOCA Environment

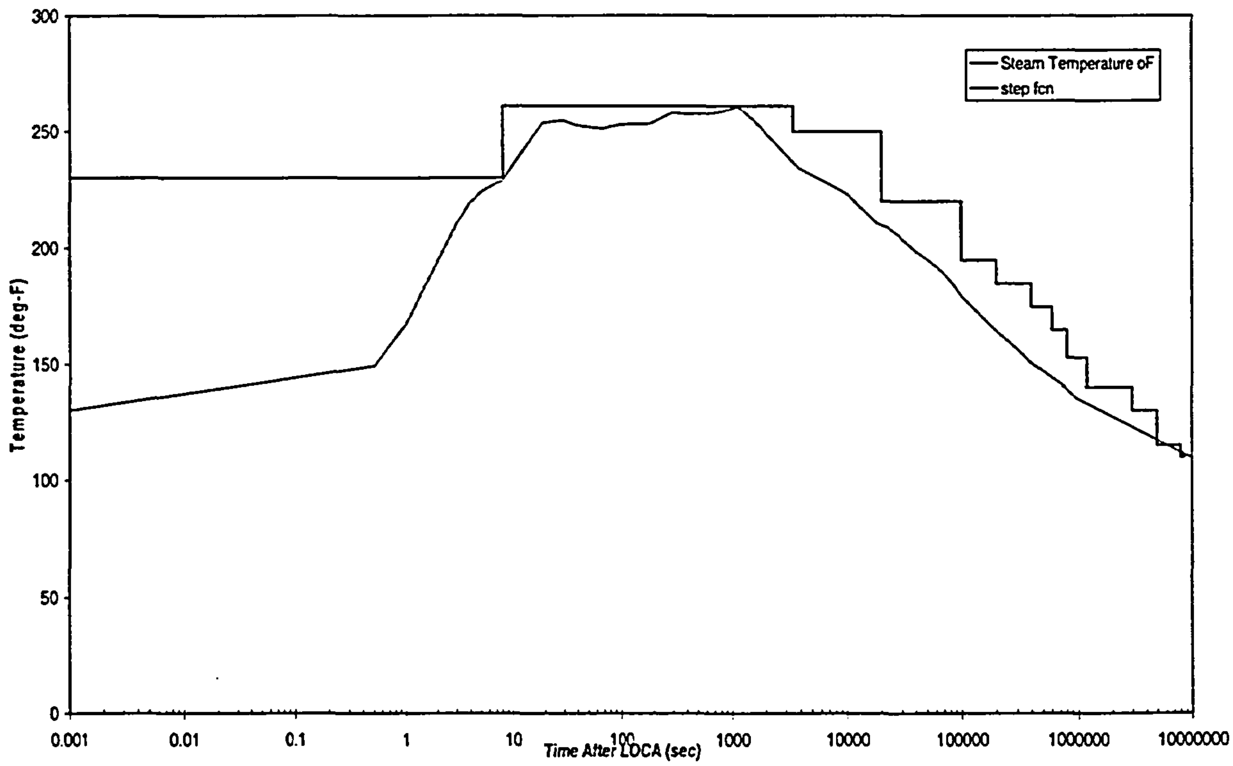

Figure 6.13-2

Post-LOCA Containment Temperatures

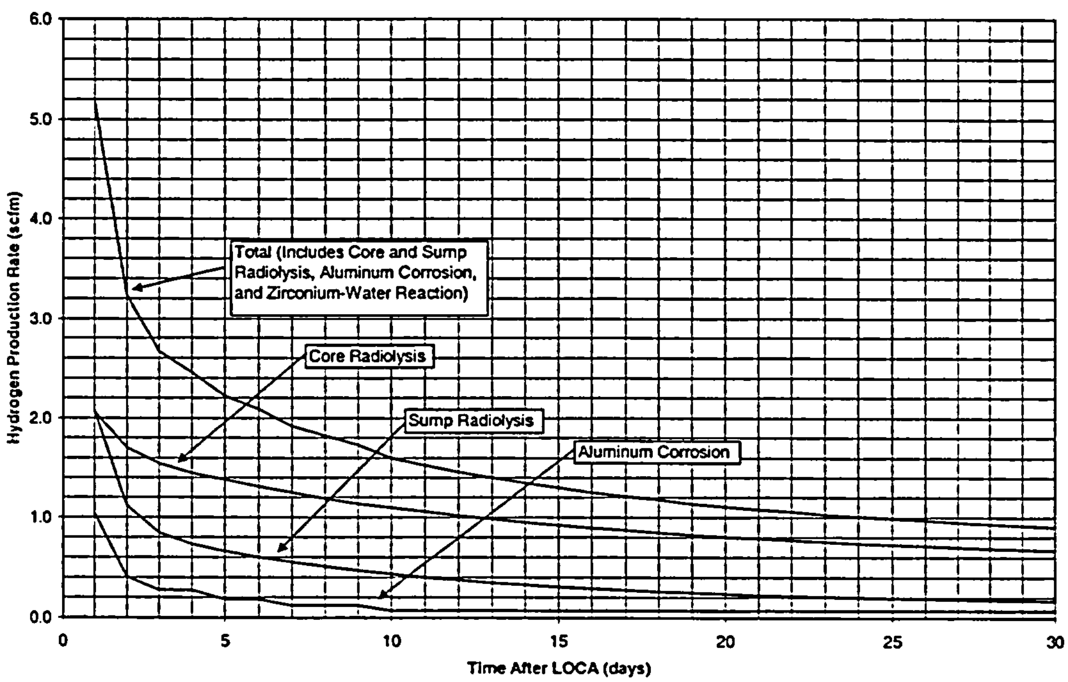

Figure 6.13-3

Containment Hydrogen Production Rate versus Time after LOCA

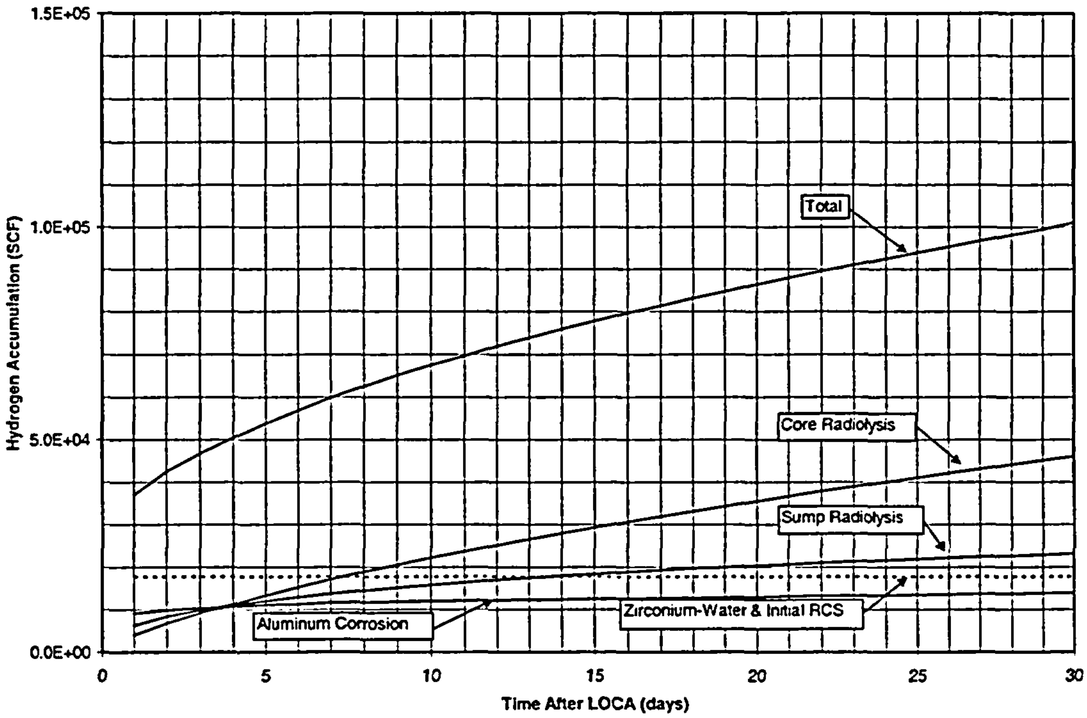

Figure 6.13-4

Hydrogen Accumulation from All Sources versus Time after LOCA

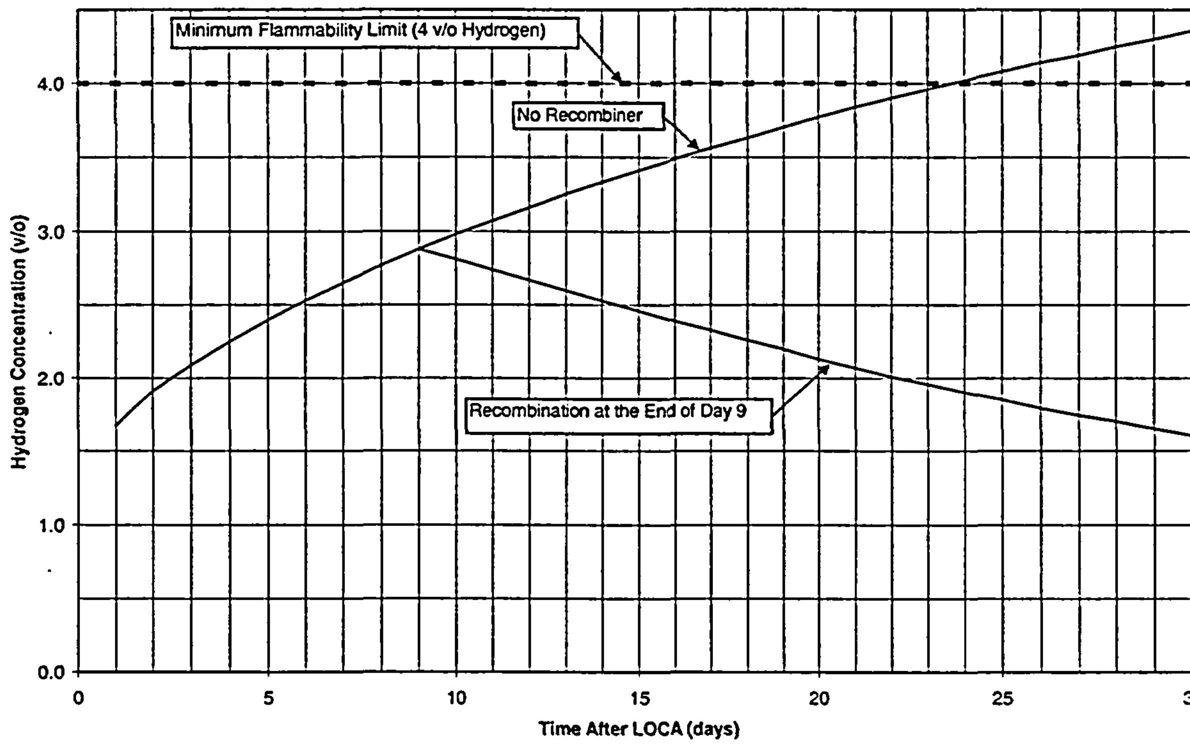

Figure 6.13-5

Containment Hydrogen Concentration versus Time after LOCA

7.0 NUCLEAR FUEL

This chapter discusses the analyses performed in support of the Indian Point Unit 3 (IP3) stretch power uprate (SPU) in the nuclear fuel and fuel-related areas. Specifically, it addresses fuel thermal-hydraulic design, fuel core design, fuel rod performance, neutron fluence, and heat generation rates. The results and conclusions of each analysis can be found within the applicable subsection.

IP3 is currently operating in Cycle 13 with 15 x 15 VANTAGE+ fuel assemblies. Commencing in Cycle 14, it is planned to refuel with a 15 x 15 upgraded fuel assembly with modified fuel rod support surfaces of the mid-grids and intermediate flow mixing (IFM) grids to enhance margin to grid-to-rod fretting. Westinghouse has already notified the NRC of this upgrade by letter LTR-NRC-04-8, dated February 6, 2004, "Fuel Criterion Evaluation Process (FCEP) Notification of the 15 x 15 Upgrade Design (Proprietary/Non-Proprietary)." The FCEP notification letter includes a description of the fuel upgrade. Neither the FCEP notification letter, nor the IP3 SPU License Amendment Request (LAR) requests or requires NRC approval of the subject fuel upgrade. Since the thermal limits of the existing fuel at IP3 are the same as those for the upgrade fuel, the upgraded fuel product is not needed to support the validity of the SPU analyses and implementation of the SPU. However, the upgrade fuel does provide additional margin for grid-to-rod fretting and to reduce the potential for incomplete rod cluster control assembly (RCCA) insertion. A mixed fuel core will exist at IP3 for the Cycle 14 reload; however, this has been addressed in, and bounded by, the various analyses (both for the mixed cores that will exist in transition and the final equilibrium core of the upgrade fuel) that have been performed to support the IP3 SPU (as described in this Licensing Report). The core design of each future cycle at IP will also explicitly consider the consequences of mixed cores that may exist for each cycle. For the purposes of the SPU analysis, fuel-related safety and design parameters have been chosen to bound the current VANTAGE+ fuel and the upgraded fuel assembly. These bounding parameters have been used in the safety and design analyses discussed in this section and in other sections of this report. If Entergy chooses to implement the upgraded fuel design for Cycle 14, licensing of this upgraded design will occur according to the NRC-approved Westinghouse Fuel Criteria Evaluation Process (FCEP) described in WCAP-12488-P-A. Furthermore applicability of the SPU safety analysis for the 15 x 15 upgraded fuel assembly will be evaluated or re-analyzed during the Cycle 14 reload safety evaluation in accordance with the reload safety evaluation methodology described in WCAP-9272-P-A.

Sections 7.1 through 7.4 discuss the results of analyses and evaluations that have been performed to show that the fuel and core designs as represented by the bounding parameters meet the acceptance criteria. The results of these analyses or evaluations will be reviewed and evaluated for each operating cycle as part of the cycle-specific reload safety evaluation in accordance with the reload safety evaluation methodology described in WCAP-9272-P-A. The cycle-specific reload safety evaluation will provide the technical and licensing bases for operation of the specific cycle at the licensed power level.

7.1 Fuel Design Features and Components

Fuel assemblies are designed to perform satisfactorily throughout their lifetime. The combined effects of the design basis loads are considered in evaluating the capability of fuel assemblies and their components to maintain structural integrity. This is necessary so that fuel assembly functional requirements are met while maintaining the core coolable geometry and the ability for reactor core safe shutdown.

The stretch power uprate (SPU) conditions result in changes to temperatures that affect loss-of-coolant accident (LOCA) forces. LOCA force changes result in changes to core plate motions, the effects of which have been incorporated into the analyses for the fuel assemblies. The SPU core power uprating does not increase operating or transient loads such that they will adversely affect fuel assembly functional requirements. Fuel assembly structural integrity is not affected and the core coolable geometry is maintained for the 15 x 15 VANTAGE+ (Zirlo™ with 0.422 rod and debris mitigating features) fuel assembly design and the 15 x 15 upgraded fuel assembly for Indian Point Unit 3 (IP3).

The top nozzle holddown spring analysis verified the fuel assembly holddown spring capability to maintain contact between the fuel assembly and the lower core plate at normal operating conditions. Thus, fuel assembly structural integrity is not affected by the SPU.

Other areas, such as fuel rod fretting, oxidation and hydriding of thimbles and grids, fuel rod growth gap, and guide thimble wear, were determined to be within the limits of the respective design criteria. It is concluded that the fuel assemblies are in conformance with all fuel assembly functional requirements at the SPU conditions.

Fuel Assembly Interface with Fuel Handling Provisions

The subject area of fuel handling has a bearing on nuclear safety because criticality accidents, radioactivity releases resulting from damage to irradiated fuel, and unacceptable personnel radiation exposures must be avoided.

There are no changes to the fuel handling equipment for the SPU. Entergy plans to implement an upgrade to the current fuel design at Indian Point Unit 3 (IP3) starting with Cycle 14. The upgrade basically consists of an enhancement to grid design to provide additional margin for grid-to-rod fretting, and the use of tube-in-tube guide thimbles to reduce the potential for incomplete rod control cluster assembly (RCCA) insertion. (See Section 7.0) There are no planned changes to the fuel assembly characteristics that interface with the fuel handling equipment (that is, the lifting pockets of the top nozzle).

For the SPU, there is no change in the plant provisions for confinement of radioactive material, for shielding for radiation protection, or for criticality prevention. The source terms for normal operation (see subsection 6.11.5) have been evaluated for the nominal increase in SPU power level and determined to have a very small effect on normal operation dose. The dose effects from a fuel handling accident have been evaluated (see subsection 6.11.9.11) and have been determined to meet acceptance criteria. The maximum permissible fuel enrichment and spent fuel pit boron Technical Specification are unchanged. Therefore, the criticality considerations are unchanged.

7.2 Core Thermal-Hydraulic Design

7.2.1 Introduction

This section describes the core thermal-hydraulic analyses and evaluations performed in support of Indian Point Unit 3 (IP3) operation at a stretch power uprate (SPU) core power level of 3216 MWt over a range of Reactor Coolant System (RCS) temperatures (Table 2.1-2 in Section 2 of this report).

7.2.2 Input Parameters and Assumptions

Table 7.2-1 summarizes the thermal-hydraulic design parameters used in the departure from nucleate boiling ratio (DNBR) analyses. The core inlet temperature used in the DNBR analyses is based on the upper bound of the RCS temperature range for the SPU conditions. Use of the upper bound temperature is conservative for the DNBR analyses. The DNBR analyses also assume that the SPU core designs are composed of 15 x 15 VANTAGE+ and 15 x 15 upgraded fuel assemblies.

7.2.3 Description of Analyses and Evaluations

7.2.3.1 Calculation Methods

The thermal-hydraulic design criteria and methods for the SPU remain the same as those presented in the *IP3 Updated Final Safety Analysis Report* (UFSAR) and the 1.4-percent Measurement Uncertainty Recapture (MUR) Report (References 1 and 2). The WRB-1 departure from nucleate boiling (DNB) correlation and the Revised Thermal Design Procedure (RTDP) DNB methodology (Reference 3) continue to be used for the SPU DNB analysis with the 15 x 15 VANTAGE+ and upgraded fuel assemblies. The W-3 DNB correlation is used for events where the conditions fall outside the applicable range of the WRB-1 correlation. The Westinghouse version of the VIPRE-01 (VIPRE) code (Reference 4) is used for DNBR calculations with the WRB-1 and the W-3 DNB correlations. The use of VIPRE for the SPU analysis is in full compliance with the conditions specified in the NRC *Safety Evaluation Report* (SER) in WCAP-14565-P-A (Reference 4).

With the RTDP methodology, uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer codes, and DNB correlation predictions are considered statistically to obtain DNB sensitivity factors. Based on the DNB sensitivity factors, RTDP design limit DNBR values were determined such that there was at least a 95-percent probability at a 95-percent confidence level that DNB would not occur on the most limiting fuel rod during normal operation, operational transients, or transient conditions arising from faults of moderate frequency (Condition I and II events as defined in the IP3 USFAR [Reference 1]).

Uncertainties in plant operating parameters (pressurizer pressure, primary coolant temperature, reactor power, and RCS flow) are considered in the RTDP DNBR analysis. Only the random portion of each plant operating parameter uncertainty is included in the statistical combination for RTDP. Any adverse instrumentation bias is treated either as a direct DNBR penalty or a direct analysis input.

The RTDP design limit DNBR values specified in the 1.4-percent MUR report (Reference 2) for IP3 were revised for the SPU to 1.22/1.23 (for thimble/typical cells).

In addition to the above considerations for uncertainties, DNBR margin was obtained by performing the safety analyses to DNBR limits higher than the design limit DNBR values. Sufficient DNBR margin was conservatively maintained in the safety analysis DNBR limits to offset the rod bow, transition core, and plant operating parameter bias DNBR penalties. The net remaining DNBR margin, after considering penalties, is available for operating and design flexibility.

As noted in the USFAR and in the 1.4-percent MUR Report (References 1 and 2), the Standard Thermal Design Procedure (STDP) is used for those analyses where RTDP is not applicable. The DNBR limit for STDP is the appropriate DNB correlation limit increased by sufficient margin to offset the applicable DNBR penalties.

7.2.3.2 DNB Performance

The current DNBR analyses of record for IP3 are primarily those that were performed to support the SPU using VANTAGE+ fuel. All DNBR analyses performed for the SPU for a core power level of 3216 MWt are bounding for operation using both 15x15 VANTAGE+ and upgraded fuels. A comparison of the current thermal-hydraulic parameters and the SPU parameters is shown in Table 7.2-1.

To support the operation of IP3 at SPU conditions, DNBR reanalysis was required to define new core limits, axial offset limits, and Condition II accident acceptability. The accident DNB analyses to support the SPU are addressed below.

7.2.3.2.1 Loss of Flow

DNB Design Criteria

There will be at least a 95-percent probability that DNB will not occur on the limiting fuel rods during the loss-of-flow (LOF) transient conditions at a 95-percent confidence level. This criterion is met if the minimum DNBR for the LOF evaluation is above the safety analysis limit DNBR.

Evaluations

The DNB analysis of the loss-of-flow accident was performed for SPU conditions. Three cases, including partial-loss-of-flow (PLOF), complete-loss-of-flow (CLOF), and CLOF-under frequency (CLOF-UF) were checked to ensure the limiting scenario was identified. The effect of updated fuel temperatures was included in the analysis of this event (subsection 7.2.3.3). The CLOF-UF case resulted in the lowest minimum DNBR. The minimum DNBRs calculated for each of the three cases were greater than the new safety analysis DNBRs, thereby demonstrating compliance to the DNB design criterion for this event.

7.2.3.2.2 Locked Rotor

DNB Design Criteria

As shown in the radiological consequences analysis (see subsection 6.11.9), the locked rotor (LR) event (Condition IV event) is allowed to have 5-percent fuel rod failure. This criterion is met if there are less than or equal to 5 percent of the rods in DNB for the LR evaluation.

Evaluations

The analysis of the locked rotor accident was performed for SPU conditions. The locked rotor accident is classified as a Condition IV event. To calculate the radiation release as a consequence of the accident, DNB calculations were performed to quantify the inventory of rods that would experience DNB and be conservatively presumed to fail. For IP3, the analysis indicates that there would be no rods in DNB due to the locked rotor accident. The radiological consequences analysis conservatively assumed 5 percent of the fuel rods as failed rods and showed that the site dose limits were met (see subsection 6.11.9 of this report).

7.2.3.2.3 Feedwater Malfunction

The core response for the feedwater malfunction event at hot zero power (HZP) was bounded by the steamline break core response. All DNBR design criteria are met for the feedwater malfunction event at zero power. The feedwater malfunction at hot full power (HFP) conditions is presented in subsection 6.3.9 of this report.

7.2.3.2.4 Dropped Rod

DNB Design Criteria

There will be at least a 95-percent probability that DNB will not occur on the limiting fuel rods during the dropped rod event at a 95-percent confidence level. This criterion is met if the dropped rod limit lines, which would result in the safety analysis limit DNBR being reached, are met.

Evaluations

Dropped rod limit lines were calculated to address the acceptability of the plant's response to this accident scenario. The limit lines were calculated based on the reference power shape. The loci of points that would result in the safety-limit DNBR being reached were defined for a wide span of core conditions (inlet temperature, power, and pressure).

The effects on core conditions, including power distribution, are demonstrated to remain within the bounds represented by the dropped rod limit lines. There was no explicit DNBR calculation performed for the dropped rod event. The SPU core design met the limit lines. Calculation of the effects of the accident on the core was checked cycle-by-cycle, ensuring compliance to the DNB criterion for each cycle.

7.2.3.2.5 Steamline Break

DNB Design Criteria

There will be at least a 95-percent probability that DNB will not occur on the limiting fuel rods during the steamline break (SLB) events at a 95-percent confidence level. This criterion is met if the minimum DNBR for the SLB evaluation is above the safety analysis limit DNBR.

Evaluations

The DNB analysis of the hot zero power (HZP) steamline break event was performed for SPU conditions. The mechanistic STDP methodology was applied in the HZP steamline break analysis. For the STDP application, the W-3 DNBR correlation limit for this transient is 1.45. The calculated minimum DNBR, which is reduced to account for any DNBR penalties applicable at this transient condition, is well above the W-3 DNBR correlation limit of 1.45.

7.2.3.2.6 Rod Withdrawal from Subcritical

DNB Design Criteria

There will be at least a 95-percent probability that DNB will not occur on the limiting fuel rods during the rod withdrawal from subcritical (RWFS) event at a 95-percent confidence level. This criterion is met if the minimum DNBR for the RWFS evaluation is above the safety analysis limit DNBR.

Evaluations

The DNB analysis of the rod withdrawal from subcritical accident was performed for SPU conditions.

By nature of the accident, a bottom-skewed power shape was conservatively applied. A power excursion, due to the removed rod bank, would develop more prominently in the lower part of the core. For this calculation, a conservative generic power shape was applied. To preserve applicability of the critical heat flux correlation, two calculations were required for this accident. For fuel assembly spans below the first mixing vane grid, the W-3 correlation was applied. For fuel assembly spans above the mixing grid, the WRB-1 correlation was applied, consistent with other DNBR confirmation calculations. Also, because of the zero power precondition of this event, the methodology that convolutes uncertainty terms to set limits was not appropriate, so the mechanistic STDP was applied. For the STDP application, the DNBR limit applied was the correlation limit DNBR, since uncertainties were mechanistically applied on the calculation input. For the W-3 correlation, this value was 1.30. For the WRB-1 correlation, this value was 1.17.

Calculations have been completed for each span and the results showed that the predicted DNBR remained above the respective correlation limit DNBR, thereby demonstrating compliance to the DNB design criterion for this event.

7.2.3.3 Fuel Temperatures and Rod Internal Pressures

The fuel temperatures and rod internal pressures for the SPU safety analysis for VANTAGE+ and upgraded fuel were based on ZIRLO™ cladding design. The NRC-approved Westinghouse PAD 4.0 fuel performance models (References 5 and 6) were used in the fuel temperature and rod internal pressure analyses. The integral fuel burnable absorber (IFBA) and non-IFBA fuel temperatures and/or rod internal pressures were used as initial conditions for LOCA and non-LOCA transients. Also, based on the fuel temperature analysis, the linear power limit to preclude fuel centerline melting was determined to be 22.7 kW/ft and was met at the SPU conditions.

7.2.4 Acceptance Criteria

The acceptance criteria are contained in each subsection under subsection 7.2.3.2 of this report.

7.2.5 Results and Conclusions

Core thermal-hydraulic analyses and evaluations were performed in support of IP3 operation at the SPU core power level of 3216 MWt over a range of RCS temperatures. The results showed that the core thermal-hydraulic design criteria listed in subsection 7.2.3.2 and the UFSAR (Reference 1) are satisfied.

7.2.6 References

1. *Indian Point Nuclear Generating Unit No. 3, Updated Final Safety Analysis Report,* Rev. 18, Docket No. 50-286.

2. *Indian Point Nuclear Generating Unit No. 3, 1.4-Percent Measurement Uncertainty Recapture Power Uprate License Amendment Request Package*, Entergy Nuclear Operations, Inc., May 2002.

3. WCAP-11397-A (Nonproprietary) and WCAP-11397-P-A (Proprietary), *Revised Thermal Design Procedure*, A. J. Friedland and S. Ray, April 1989.

4. WCAP-14565-A (Proprietary) and WCAP-15306 (Nonproprietary), *VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis*, Y. X. Sung, et al., October 1999.

5. WCAP-15063-P-A, *Westinghouse Improved Performance Analysis and Design Model (PAD 4.0)*, Foster, Sidener, and Slagle, Rev. 1 with Errata, July 2000.

6. WCAP-12610-P-A, *VANTAGE+ Fuel Assembly Reference Core Report*, S. L. Davidson and T. L. Ryan, April 1995.

Table 7.2-1 Thermal-Hydraulic Design Parameters for IP3		
Thermal-Hydraulic Design Parameters	**Current**	**SPU**
Reactor Core Heat Output, MWt	3067.4	3216
Reactor Core Heat Output, 10^6 Btu/hr	10,468	10,973
Heat Generated in Fuel, %	97.4	97.4
Pressurizer Pressure, Nominal, psia	2250	2250
$F_{\Delta H}$, Nuclear Enthalpy Rise Hot Channel Factor	1.70	1.70
Part Power Multiplier for $F_{\Delta H}$	[1+0.3(1-P)]	[1+0.3(1-P)]
Minimum DNBR at Nominal Conditions (using RTDP)		
Typical Flow Channel	2.62	2.60[1]
Thimble (cold wall) Flow Channel	2.51	2.50[1]
Design Limit DNBR		
Typical Flow Channel	1.23	1.23
Thimble (cold wall) Flow Channel	1.23	1.22
DNB Correlation[2]	WRB-1	WRB-1
Vessel Inlet Minimum Measured Flow Rate, MMF, (including bypass)		
gpm	330,800	364,700
Vessel Inlet Thermal Design Flow Rate, TDF, (including bypass)		
gpm	323,600	354,400
Core Inlet Flow Rate (excluding total bypass, based on TDF)		
gpm	306,800	327,800
Fuel Assembly Flow Area for Heat Transfer, ft^2	51.54	51.54
Core Inlet Mass Velocity (based on TDF), ft/sec	13.3	14.2
Tube plugging level, %	24.0	10.0
Nominal Vessel/Core Inlet Temperature, °F	542.5	541.0
Vessel Average Temperature, °F	574.7	572.0
Core Average Temperature, °F	577.9	575.8
Vessel Outlet Temperature, °F	606.9	603.0
Average Temperature Rise in Vessel, °F	64.4	62.0
Average Temperature Rise in Core, °F	67.5	66.5

Table 7.2-1 (Cont.) Thermal-Hydraulic Design Parameters for IP3		
Thermal-Hydraulic Design Parameters	**Current**	**SPU**
Heat Transfer		
Active Heat Transfer Surface Area, ft^2	52,100	52,100
Average Heat Flux, Btu/hr-ft^2	196,000	205,200
Average Linear Power, kW/ft	6.34	6.64
Peak Linear Power for Normal Operation, kW/ft	15.3[3]	16.6[3]
Temperature Limit for Prevention of Centerline Melt, °F	4700	4700

Notes:

1. The minimum nominal DNBRs are conservatively listed for both VANTAGE+ and upgraded fuel.
2. See subsection 3.2.2.8 of Reference 1 for the use of the W-3 DNB correlation.
3. This power level is based on a peaking factor (F_Q) of 2.5 for SPU conditions and 2.42 for current operating conditions.

7.3 Fuel Core Design

7.3.1 Introduction

The nuclear design portion of the Indian Point Unit 3 (IP3) stretch power uprate (SPU) core analysis determined the effect of the uprate on the key safety parameters. These safety parameters were used as input to the Indian Point Unit 3 *Updated Final Safety Analysis Report* (UFSAR) (Reference 1) Chapter 14 accident analyses.

7.3.2 Input Parameters and Assumptions

The nuclear design analyses demonstrated the acceptability of operation at the SPU core power level of 3216 MWt consistent with parameters in Section 2 of this report.

7.3.3 Description of Analyses and Evaluations

To satisfy these objectives, conceptual models were developed that followed the uprate transition to an equilibrium cycle. Fuel management strategies similar to those used in recent cycles were assumed in developing the models. The SPU assumed a core thermal power level of 3168 MWt during the first transition cycle and 3216 MWt in the second and third transition cycles. Key safety parameters were then evaluated to determine the expected ranges of variation in the parameters. The key safety parameters are those described in the standard reload design methodology (Reference 2). Some of these parameters, such as shutdown margin, were sensitive to the fuel management and loading pattern characteristics.

The observed variation in the parameters that were sensitive to loading patterns at SPU conditions were typical of the normal cycle-to-cycle variations for non-transition fuel reloads. Many of the key safety parameters were dependent on the loading patterns.

7.3.3.1 Methodology

All nuclear design analysis in support of the IP3 SPU was performed using standard Westinghouse core reload methodology described in WCAP-9272-P-A (Reference 2) with the Westinghouse PHOENIX-P and ANC codes described in WCAP-11596-P-A and WCAP-10965-P-A (References 3 and 4). These licensed methods and models have been used for IP3 and other previous Westinghouse reload fuel designs with and without uprating. No changes to the nuclear design philosophy, methods, or models, are necessary due to the SPU.

The reload design philosophy used by Westinghouse includes an evaluation of the reload core key safety parameters that comprises the nuclear-design-dependent input to the reload fuel safety evaluation for each reload cycle. This philosophy is described in WCAP-9272-P-A (Reference 2). These key safety parameters will be evaluated for each IP3 reload cycle. If one or more of the key parameters fall outside the bounds assumed in the safety analyses, the affected transients will be reevaluated and the results documented in the *Reload Safety Evaluation Report* (RSE) for that cycle. The main objective of the uprating core analyses was to determine, prior to the cycle-specific reload design, if the previously used bounds for the key safety parameters remained applicable. The results of these analyses are described below.

7.3.3.2 Physics Characteristics and Key Safety Parameters

Conceptual core loading patterns were constructed to be representative of future IP3 cores. Table 7.3-1 compares the safety parameter ranges considered for the IP3 current designs and for the SPU.

The comparison in Table 7.3-1 shows that the SPU core did not have any marked deviations from the core design at 3067.4 MWt. Of note is a small change in the hot full power (HFP) most-negative- and least-negative-doppler-only power coefficients, which were analyzed over a slightly larger range in order to achieve consistency with the Indian Point Unit 2 (IP2) SPU analysis.

Shutdown margin and maximum boron concentrations are two parameters that are loading-pattern-dependent and the core design must be developed such that these constraints are met. The shutdown margin requirement of 1300 pcm is primarily a function of the power defect from full power to hot zero power (HZP) at the time of trip, and the type of fuel that is placed under control rod locations. The power defect is set by the enrichments required to achieve the design cycle length and the operating temperature. The core design can govern the amount of shutdown margin by increasing the amount of fresh fuel in control rod locations. Since the SPU conditions significantly increase the power defect, the required amount of shutdown margin is a loading pattern constraint that must be met in order to consider the loading pattern acceptable. Maximum boron concentration is a function of the feed enrichment needed to achieve the cycle lifetime but also of the fuel management strategy used for the loading pattern. As the maximum boron concentrations are initial or final conditions, they are also a design constraint that must be considered at the time of loading pattern development.

7.3.3.3 Power Distributions and Peaking Factors

Loading patterns were developed and modeled based on the projected energy requirements for the SPU. These models were not intended to represent limiting loading patterns but were developed with the intent to show that enough margin exists between typical safety parameter values and the corresponding limits to allow flexibility in designing actual reload cores.

7.3.3.4 Radial Power Distribution Effects

Assembly average powers at beginning of life (BOL), middle of life (MOL), and end of life (EOL) were calculated using the SPU core models for different fuel management techniques. The effect on the radial power distribution due to the SPU conditions was small when compared to loading patterns for similar fuel management practices at nominal power conditions. The effects of these radial power distribution differences on rod worths and on off-nominal condition peaking factors were small and were well within normal cycle-to-cycle variation in these parameters.

7.3.3.5 Axial Power Distribution and FQ(z) Effects

The axial power distribution effect of the SPU conditions shows only a small sensitivity to the uprate.

As part of the reload design process, a cycle-specific final acceptance criteria (FAC) analysis based on constant axial offset control (CAOC) operation (Reference 5) check is performed that implicitly includes the axial effects of the uprating. Load follow simulations were performed through the power range to generate axial power shapes that were typical of Condition I operation. The results of the FAC analysis for this report showed that the total peaking factor (FQ) was acceptable. Therefore, it is expected that all reload cores at SPU conditions will also be acceptable.

7.3.4 Conclusions

In summary, implementing the SPU will not cause changes to the current nuclear design bases given in the UFSAR. The effect of the SPU on peaking factors, rod worths, reactivity coefficients, shutdown margin, and kinetics parameters will be well within normal cycle-to-cycle variation of these values or controlled by the core design, and will be addressed on a cycle-specific basis, consistent with the reload safety evaluation methodology (Reference 2). The ranges of key safety parameters as reported in Table 7.3-1 remain valid and bounding for the SPU.

7.3.5 References

1. *Indian Point Nuclear Generating Unit No. 3, Updated Final Safety Analysis Report*, Docket No. 50-286, November 2001.

2. WCAP-9272-P-A, *Westinghouse Reload Safety Evaluation Methodology*, S. L. Davidson et al., July 1985.

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

4. WCAP-10965-P-A, ANC: *A Westinghouse Advanced Nodal Computer Code*, Y. S. Liu et al., September 1986.

5. WCAP-8385 (Proprietary), *Power Distribution Control and Load Following Procedures*, T. Morita et al., September 1974.

7.4 Fuel Rod Design and Performance

7.4.1 Introduction

Fuel rod design analyses were performed to assess the potential effects that the SPU operating conditions for Indian Point Unit 3 (IP3) would have on meeting fuel rod design criteria.

7.4.2 Description of Analyses, Acceptance Criteria, and Results

The fuel rod design analyses modeled 15 x 15, 8-inch annular blanket, 1.25X integral fuel burnable absorber (IFBA), ZIRLO™ clad fuel rods irradiated for up to 4 cycles at SPU conditions.

Based on the history of IP3, operation should be limited to a maximum vessel average temperature of 572.0°F is recommended to avoid potential clad fatigue and rod internal pressure violations for operation at the SPU power level. Representative rod power histories and axial power shapes, generated by the NRC-approved Advanced Nodal Code (ANC) (References 1 and 2) were analyzed. The NRC-approved Westinghouse PAD 4.0 fuel performance models (References 3 and 4) were also used in the analyses. PAD is the main design tool for evaluating fuel rod performance, calculating the inter-related effects of temperature, pressure, clad elastic and plastic behavior, fission gas release, and fuel densification and swelling as a function of time and linear power.

The following sections summarize the effect of the core power uprating on the fuel rod design criteria most affected by the SPU core power. The fuel rod design criteria affected were rod internal pressure, clad corrosion, clad stress, and clad strain criteria. Other fuel rod design criteria were not significantly affected by a core power uprating.

7.4.2.1 Rod Internal Pressure

Design Basis

The fuel system will not be damaged due to excessive fuel rod internal pressure.

Acceptance Limit

The internal pressure of the lead fuel rod in the reactor will be limited to a value below that which could cause the diametral gap to increase due to outward clad creep during steady state operation or cause extensive departure from nucleate boiling (DNB) propagation to occur.

Design Evaluation

The analyses showed that meeting the rod internal pressure criterion was most affected by the SPU increase in core power level. The higher power levels resulted in higher fuel operating temperatures with a potential for increased fission gas release. Analysis of the representative rod power histories indicated that the higher duty fuel rods have this potential for increased fission gas release resulting in higher rod internal pressures. The IFBA loading was reduced from 1.5X to 1.25X to meet the rod internal pressure criterion. The rod internal pressure criterion can be met under uprated core conditions with a maximum vessel average temperature of 572.0°F by appropriate cycle-specific core design.

7.4.2.2 Clad Corrosion

Design Basis

The fuel system will not be damaged due to excessive fuel clad oxidation. The fuel system will be operated to prevent significant degradation of mechanical properties of the clad at low temperatures, due to hydrogen embrittlement caused by formation of zirconium hydride platelets.

Acceptance Limit

The calculated fuel clad temperature (metal-oxide interface temperature) will be less than the license limit [ ]^{a,c} for ZIRLO clad fuel during steady state operation. For Condition II events, the calculated fuel clad temperature will not exceed the license limit [ ]^{a,c} for ZIRLO clad fuel. The hydrogen pickup level in the fuel clad will be less than or equal to the license limit [ ]^{a,c} at the end of fuel operation.

Design Evaluation

The SPU conditions result in increased operating temperatures for the fuel clad due to the increased fuel rod average power rating. Since the corrosion process is a strong function of fuel clad temperature, the SPU will affect meeting these criteria. Analysis of the representative rod power histories indicated that the corrosion design criteria will be satisfied for the higher duty fuel rods at the SPU core conditions.

7.4.2.3 Clad Fatigue

Design Basis

The fuel system will not be damaged due to excessive fuel clad fatigue.

Acceptance Limit

The fatigue life usage factor will be less than 1.0 or, for a given strain range, the number of strain fatigue cycles will be less than those required for failure, considering a minimum safety factor of 2 on the stress amplitude or a minimum safety factor of 20 on the number of cycles, whichever is more conservative.

Design Evaluation

The Westinghouse PAD 4.0 fuel performance models (References 3 and 4) were used to evaluate fuel clad fatigue limits. The evaluation of the fatigue limit assumes conservative load follow scenarios over the life of the fuel rod. Analysis of the representative rod power histories at the SPU conditions resulted in an increase in the clad fatigue levels. The combinations of long cycle lengths, high burnups, and the presence of cut pin penalties proved clad fatigue to be more limiting than previous reload designs. The clad fatigue criterion can be met under SPU core conditions with a maximum vessel average temperature of 572.0°F by appropriate cycle-specific core design.

7.4.2.4 Clad Stress and Strain Design Basis

The fuel system will not be damaged due to excessive fuel clad stress and strain.

Acceptance Limit

The volume-average effective stress calculated with the Von Mises equation, considering interference due to uniform cylindrical fuel pellet-clad contact, caused by fuel pellet thermal expansion, fuel pellet swelling, uniform fuel clad creep, and pressure differences, was less than the 0.2-percent offset yield stress with due consideration to temperature and irradiation effects under Condition II events. The acceptance limit for fuel rod clad strain during Condition II events is that the total tensile strain increase, due to uniform cylindrical fuel pellet thermal expansion during a transient, is less than 1 percent of the pre-transient value.

Design Evaluation

The Westinghouse PAD 4.0 fuel performance models (References 3 and 4) were used to evaluate fuel clad stress and strain limits. The local power duty during Condition II events was a key factor in evaluating the margin to fuel clad stress and strain limits. The fuel duty at the SPU conditions was more limiting, resulting in an increase in the cladding stress and strain levels. However, the fuel analyses results showed that the core power uprating will not affect the fuel's capability to meet the clad stress and strain limits.

7.4.3 Cycle-Specific Analyses

The fuel rod design criteria most affected by a change in core power rating have been evaluated. The evaluations indicated that all fuel rod design criteria can be met at the SPU core conditions with the proper cycle-specific core design.

Cycle-specific core designs and fuel performance analyses are performed for each reload cycle. These cycle-specific analyses are performed to ensure that all fuel rod design criteria will be satisfied for the specific operating conditions of that cycle.

Although the SPU analyses described in this section were performed for ZIRLO-clad fuel, the cycle-specific fuel performance analyses considered each specific fuel region (whether ZIRLO-clad fuel design or older fuel designs with different fuel features) in the core during that cycle. These analyses ensure that all fuel rod design criteria are met for each fuel region.

The cycle-specific fuel performance analyses considered any improved fuel performance models and methods licensed and approved by the NRC available at the time of the specific cycle design. These cycle-specific evaluations support the reload safety evaluation (RSE) performed for each cycle of operation.

7.4.4 Conclusions

The fuel rod design criteria most affected by a change in core power rating have been analyzed. The results indicate that all fuel rod design criteria can be met at the SPU core conditions with the proper cycle-specific core design.

7.4.5 References

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

2. WCAP-10965-P-A, ANC: *A Westinghouse Advanced Nodal Computer Code*, Y. S. Liu et al., September 1986.

3. WCAP-15063-P-A, *Westinghouse Improved Performance Analysis and Design Model (PAD 4.0)*, Foster, Sidener, and Slagle, Rev. 1 with Errata, July 2000.

4. WCAP-12610-P-A, *VANTAGE+ Fuel Assembly Reference Core Report*, S. L. Davidson and T. L. Ryan, April 1995.

7.5 Neutron Fluence

7.5.1 Introduction

In the assessment of the state of embrittlement of light water reactor (LWR) pressure vessels, an accurate evaluation of the neutron exposure of the materials comprising the beltline region of the vessel is required. This exposure evaluation must, in general, include assessments not only at locations of maximum exposure at the inner radius of the vessel, but also as a function of axial, azimuthal, and radial location throughout the vessel wall.

In order to satisfy the requirements of 10CFR50, Appendix G (Reference 1), for the calculation of pressure/temperature limit curves for normal heatup and cooldown of the Reactor Coolant System (RCS), fast neutron exposure levels must be defined at depths within the vessel wall equal to 25 and 75 percent of the wall thickness for each of the materials comprising the beltline region. These locations are commonly referred to as the 1/4t and 3/4t positions in the vessel wall. The 1/4t exposure levels are also used in the determination of upper shelf fracture toughness as specified in 10CFR50, Appendix G. In the determination of values of reference temperature – pressurized thermal shock (RT_{PTS}) for comparison with the applicable PTS screening criterion as defined in 10CFR50.61, *Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events*, (Reference 2) maximum neutron exposure levels experienced by each of the beltline materials are required. These maximum levels occur at the vessel inner radius.

The methodology used to determine the fast neutron (E > 1.0 MeV) exposure of the IP3 pressure vessel derives from the guidance provided in ASTM Standard E853, *Analysis and Interpretation of Light Water Reactor Surveillance Results*, and Regulatory Guide (RG) 1.190, *Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence*, March 2001 (Reference 3). The analytical methodology has received regulatory approval as documented in WCAP-14040-NP-A, *Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Curves*, January 1996 (Reference 4). The Westinghouse methodology has also been documented in WCAP-15557, Qualification of the Westinghouse Pressure Vessel Neutron Fluence Evaluation Methodology, August 2000 (Reference 5).

7.5.2 Description of Analysis/Evaluation and Input Assumptions

A three-dimensional (3-D) assessment of fast neutron exposures for the IP3 reactor geometry was made using discrete ordinates transport techniques. The analysis was based on a two-dimensional/one-dimensional (2D/1D) synthesis of neutron fluxes that were obtained from a series of plant- and cycle-specific forward transport calculations using r-θ, r-z, and r spatial mesh. These transport calculations were subsequently compared against dosimetry results obtained from the in-vessel surveillance capsules withdrawn to date at IP3 in order to demonstrate that the plant-specific analysis meets the 20-percent uncertainty criterion specified in RG 1.190; however, these comparisons only serve to validate the calculational model and are not used in any way to modify the calculational results.

The generalized equation that was used to assess the fast neutron flux in the reactor pressure vessel, which is described in RG 1.190, is given as:

$$\phi_g(r,\theta,z)=\phi_g(r,\theta)\times\frac{\phi_g(r,z)}{\phi_g(r)}$$

where

$\phi_g(r,\theta)$	=	The group g transport solution in r,θ geometry for a representative axial plane, that is, at the core midplane.
$\phi_g(r)$ and $\phi_g(r,z)$	=	The 1-D and 2-D group g flux solutions whose ratio is used to determine a group-dependent axial shape factor.

The fast neutron exposure calculations were carried out using the DORT (DOORS 3.1 code package, Reference 6) discrete ordinates transport code in the forward mode and the BUGLE-96 cross-section library (Reference 7). This suite of codes has been used to support numerous pressure vessel fluence evaluations and are generally accepted by the Nuclear Regulatory Commission (NRC) for deterministic particle transport calculations, for example, neutron exposure and gamma-ray heating rate evaluations. All calculations were based on an S16 order of angular quadrature and a P5 expansion of the scattering cross-sections.

The core power distributions used in the plant-specific analysis were taken from the nuclear design reports for each of the first 13 operating fuel cycles at IP3. For future projections that support the IP3 stretch power uprate (SPU), core power distributions obtained from Westinghouse Core Engineering fuel management studies for Cycles 14 through 16 were used. The fast neutron transport calculations also account for several changes in core power during plant life. Specifically, reactor power increases from 3025 to 3067.4 MWt near the middle of

Cycle 12 and to 3216 MWt at the onset of Cycle 14, were assumed. Future projections beyond the end of Cycle 16 were based on the equilibrium cycle design intended for implementation in Cycle 16 core power distributions.

7.5.3 Acceptance Criteria

There are no specific acceptance criteria for this section. Adequacy of the modeling is tested by comparing the calculated results against dosimetry measurements from surveillance capsules withdrawn from the plant. As long as these comparisons fall within the ± 20-percent criterion specified in RG 1.190, the calculational results are validated, that is, no specific acceptance criteria apply to the calculated values. However, these calculated results are used as input to reactor vessel analysis that is described in subsection 5.1.2 of this report.

7.5.4 Results and Conclusions

Comparisons of the measurement results from the in-vessel surveillance capsules withdrawn from the IP3 reactor versus the corresponding calculated predictions obtained at the measurement locations are presented in Table 7.5-1 for the fast neutron sensor reactions. An examination of the measurement/calculation (m/c) ratios of the fast neutron sensor reaction rates obtained from the surveillance capsule irradiations shows consistent behavior for all reactions at all capsule locations within the constraint of the allowable ± 20-percent (1σ) uncertainty in the final calculated results. Specifically, Table 7.5-1 shows that the average M/C ratios range from 1.02 to 1.20 for the individual capsules and that the overall average M/C ratio for the entire 10 foil data set is 1.08 with an associated sample standard deviation of 9.6 percent. Therefore, these comparisons of calculations with the surveillance capsule dosimetry sets withdrawn to date validate the neutron transport calculations performed to support this program and demonstrate that the uncertainty criterion of ± 20 percent (1σ), as specified by RG 1.190, has been satisfied for the IP3 reactor.

Therefore, based on this validation, the maximum calculated fast neutron fluence and displacement of atom (dpa) exposure values for the IP3 pressure vessel are provided in Table 7.5-2. As presented, these data represent the maximum exposure of the pressure vessel clad/base metal interface at azimuthal angles of 0, 15, 30, and 45 degrees relative to the core cardinal axes. The data tabulation includes the plant-specific calculated fluence at the end of Cycle 12 (EOC 12, the last cycle completed at IP3), the end of Cycle 13 (EOC 13, which is the current operating fuel cycle), and projections for future operation to 23 (EOC 16), 32, 34 and 48 effective full-power years (EFPYs).

Based on the current NRC position of using the calculated values of neutron fluence to specify the neutron exposure for use in materials damage correlations, the calculated exposure values provided in Table 7.5-2 were provided for use in the materials properties assessments of the IP3 pressure vessel at SPU power conditions (see subsection 5.1.2).

7.5.5 References

1. 10CFR50, Appendix G, *Fracture Toughness Requirements.*

2. 10CFR50.61, *Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events, Federal Register,* Volume 60, No. 243, December 19, 1995.

3. Regulatory Guide 1.190, *Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence,* March 2001.

4. WCAP-14040-NP-A, *Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Curves,* January 1996.

5. WCAP-15557, *Qualification of the Westinghouse Pressure Vessel Neutron Fluence Evaluation Methodology,* August 2000

6. RSICC Computer Code Collection CCC-650, *DOORS 3.1, One-, Two-, and Three-Dimensional Discrete Ordinates Neutron/Photon Transport Code System,* August 1996.

7. RSIC Data Library Collection DLC-185, *BUGLE-96, Coupled 47 Neutron, 20 Gamma-Ray Group Cross Section Library Derived from ENDF/B-VI for LWR Shielding and Pressure Vessel Dosimetry Applications,* March 1996.

Table 7.5-1

Comparison of Measured and Calculated Sensor Reaction Rate Ratios for the Fast Neutron Threshold Foil Reactions Obtained from In-Vessel Capsules Removed from Service at IP3

Capsule	M/C Ratio				Average	% Std. Dev.
	$^{63}Cu(n,\alpha)^{60}Co$	$^{54}Fe(n,p)^{54}Mn$	$^{58}Ni(n,p)^{58}Co$	$^{238}U(n,f)^{137}Cs$		
T	1.21	1.23	1.16	---	1.20	3.0
Y	1.10	1.01	0.98	1.09	1.05	5.7
Z	1.13	1.01	0.91	---	1.02	10.8
Average	1.15	1.08	1.02	1.09	**1.08**	**9.6**
% Std. Dev.	5.0	11.7	12.7	N/A		

Note:
The average and percent standard deviation values in boldface type represent the entire 10 sample threshold foil data set.

Table 7.5-2

Summary of Calculated Maximum Pressure Vessel Exposure at the Clad/Base Metal Interface for IP3

Cumulative Operating Time (EFPY)	Neutron Fluence (n/cm^2) (E > 1.0 MeV)			
	0.0 Degrees	**15.0 Degrees**	**30.0 Degrees**	**45.0 Degrees**
15.5 (EOC 12)	2.64e+18	4.01e+18	4.42e+18	5.86e+18
17.4 (EOC 13)	2.87e+18	4.38e+18	4.82e+18	6.30e+18
23.0 (EOC 16)	3.66e+18	5.58e+18	6.17e+18	7.98e+18
32.0	4.95e+18	7.57e+18	8.38e+18	1.07e+19
34.0	5.24e+18	8.01e+18	8.87e+18	1.13e+19
48.0	7.27e+18	1.11e+19	1.24e+19	1.56e+19
	Iron Atom Displacements (dpa)			
15.5 (EOC 12)	4.27e-03	6.42e-03	7.13e-03	9.48e-03
17.4 (EOC 13)	4.65e-03	7.00e-03	7.76e-03	1.02e-02
23.0 (EOC 16)	5.93e-03	8.93e-03	9.93e-03	1.29e-02
32.0	8.02e-03	1.21e-02	1.35e-02	1.73e-02
34.0	8.49e-03	1.28e-02	1.43e-02	1.83e-02
48.0	1.18e-02	1.78e-02	1.99e-02	2.51e-02

7.6 Reactor Internals Heat Generation Rates

7.6.1 Introduction

The presence of radiation-induced heat generation in reactor internals components, in conjunction with the various reactor coolant fluid temperatures, results in thermal gradients within and between the components. These thermal gradients cause thermal stress and thermal growth, which must be considered in the design and analysis of the various components. The primary design considerations are to insure that thermal growth is consistent with the functional requirements of the components, and to insure that the applicable ASME Code requirements are satisfied as part of the components evaluation that is described in Section 5.2 of this report. In order to satisfy these requirements, the reactor internals must be analyzed with respect to fatigue and maximum allowable stress considerations.

The reactor internals components subjected to significant radiation-induced heat generation are the upper and lower core plates, lower core support, core baffle plates, former plates, core barrel, thermal shield, baffle-former bolts and barrel-former bolts. However, due to relatively low heat generation rates in the lower core support and the thermal shield, these components experience little, if any, temperature rise relative to the surrounding reactor coolant.

This section provides a description of the methodology that was used to determine the radiation-induced heat generation rates for the axial core components (the upper and lower core plates) and selected radial reactor internals components (the core baffle plates, core barrel and thermal shield) due to the core power uprate to 3216 MWt. Although design-basis neutron exposure data for the reactor internals components are documented in WCAP-9620, Revision 1 (Reference 1), key core power distribution, fuel product, and methodology differences presently exist such that the axial component data reported in WCAP-9620 are non-conservative. However, as demonstrated in the Indian Point Unit 3 (IP3) plant-specific analysis performed to support the stretch power uprate (SPU), the radial component data from WCAP-9620 remains conservative. Key axial components for the IP3 SPU were addressed using recently developed baseline upper and lower core plate heating rates applicable to IP3 (that is, four-loop design with 2-inch thick core plates).

7.6.2 Key Input Assumptions

For the core plates, baseline gamma heating rates were determined for both long- and short-term conditions since the WCAP-9620 (Reference 1) data was no longer deemed applicable for the reactor internals design calculations of these components. Long-term heat generation rates intended to represent time-averaged behavior are used in component fatigue analyses, whereas the short-term results are intended to provide conservative values for use in calculating maximum temperatures and thermal stresses of components. For the long-term heat generation rate evaluation of the core plates, a reactor power level of 3950 MWt was used in conjunction with a flat axial core power distribution, since these parameters significantly influence the core plate gamma heating rates and the aforementioned conditions conservatively bound the IP3 SPU. (Note: The reactor power level of 3950 MWt was selected since this currently bounds the entire fleet of Westinghouse four-loop plants.) For the short-term heat generation rate evaluation of the upper core plate, the reactor power of 3950 MWt was assumed and a conservative design-basis top-peaked axial power distribution from WCAP-9620 (Reference 1) was used. Analogous conditions were applied in the short-term heating rate evaluation of the lower core plate; however, in this case, the design basis bottom-peaked axial power distribution from Reference 1 was employed for conservatism.

For the radial reactor internals components, only a long-term analysis was performed, since it was anticipated that the current IP3 gamma heating rates would be bounded by the corresponding data reported in WCAP-9620. (This scenario was hypothesized since IP3 has transitioned to low-leakage loading patterns, whereas an out-in loading pattern was assumed in WCAP-9620 (Reference 1). Hence, the long-term case was examined to provide confirmation that the WCAP results remained conservative for the radial components.) Since the long-term radial case of WCAP-9620 was shown to be bounding, the short-term radial case of WCAP-9620 would also remain bounding and, therefore, was not calculated. The long-term heat generation rate evaluation of the core baffle plates, core barrel, and thermal shield was based on the Cycle 13 radial power distribution forecasted for use by IP3 operating at the reactor power level of 3216 MWt, as reported in Table 2.1-2.

Design basis heat generation rates applicable to the IP3 radial internals were obtained from Appendix J of WCAP-9620 (Reference 1). The core power distributions upon which those calculations were based were derived from statistical studies of 23 independent fuel cycles from 10 four-loop reactors. These power distributions represented an upper tolerance limit for beginning-of-cycle (BOC) and end-of-cycle (EOC) power in the peripheral fuel assemblies, based on a 95-percent probability with a 95-percent confidence level. Most of the evaluated fuel cycles were based on an out-in fuel loading strategy (fresh fuel on the periphery) which, when combined with the statistical processing of the data, resulted in a design basis core power distribution that tended to be biased high on the periphery. This high bias on the core periphery was desired by the reactor internals analysts to ensure conservative, but realistic, design calculations for the critical baffle-barrel region of the reactor internals and explains why the WCAP-9620 radial component heating rate results were expected to bound the corresponding IP3 values.

7.6.3 Acceptance Criteria

There are no specific acceptance criteria since this is an input to the reactor internals evaluation that is described in Section 5.2 of this report.

7.6.4 Description of Analysis/Evaluation and Results

The heat generation rate analyses were carried out using the DORT (DOORS 3.1 code package [Reference 2]) two-dimensional (2-D) discrete ordinates transport code in the forward mode and the BUGLE-96 cross-section library (Reference 3). This suite of codes has been used to support numerous pressure vessel fluence evaluations and are generally accepted by the Nuclear Regulatory Commission (NRC) for deterministic particle transport calculations, for example, neutron exposure and gamma-ray heating rate evaluations.

Two different coordinate systems were used in the 2-D heating rate analyses to precisely model the components undergoing evaluation. The core baffle plates were analyzed using a x,y coordinate system, and the core barrel and thermal shield heating rates were determined using a r,θ geometric model.

The results of the radiation-induced heat generation rate calculations were provided as inputs for the reactor internals evaluations described in Section 5.2. The volume-averaged heat generation rates for the core plates and radial reactor internal components that were evaluated as part of this study are summarized in Table 7.6-1. In accordance with WCAP-9620 (Reference 1), this table also segregates the core plate heating rates into two distinct regions. Region A refers to the cylindrical portion of the core plates that are axially adjacent to the active fuel, and Region B refers to the annular portion of the plates that are located radially outboard of the active fuel.

As expected, the revised IP3 zone average gamma heating rates for the core plates tended to be much higher than the corresponding WCAP-9620 (Reference 1) data. As a result, the spatial distributions of long-term and short-term heating rates for the upper and lower core plates that are presented in Tables 7.6-2 through 7.6-5 were also identified for consideration as part of the component evaluation that is described in Section 5.2 of this report.

Table 7.6-1 also shows that the current IP3 zone average gamma heating rates for the core baffle, core barrel, and thermal shield continue to remain bounded by the conservative radial component heating rates that are reported in WCAP-9620 (Reference 1).

7.6.5 References

1. WCAP-9620, *Reactor Internals Heat Generation Rates and Neutron Fluences*, Rev. 1, A. H. Fero, December 1983.

2. RSICC Computer Code Collection CCC-650, *DOORS 3.1, One-, Two-, and Three-Dimensional Discrete Ordinates Neutron/Photon Transport Code System*, August 1996.

3. RSIC Data Library Collection DLC-185, *BUGLE-96, Coupled 47 Neutron, 20 Gamma-Ray Group Cross Section Library Derived from ENDF/B-VI for LWR Shielding and Pressure Vessel Dosimetry Applications*, March 1996.

Table 7.6-1 Reactor Internals Zone Average Gamma Heating Rates		
	Region Average Long-Term Heating Rates (Btu/hr-lbm)	
Location	WCAP-9620-R1 Analysis* (Ref. 1, Appendix J)	New IP3 Analysis
Baffle Plate 18	784	438
Baffle Plate 19	885	526
Baffle Plate 20	821	403
Baffle Plate 21	645	255
Core Barrel	158	76
Thermal Shield	22	11
* Values are scaled down by a factor of 3216/3565 to account for difference in reactor power.		
	Upper and Lower Core Plates Heating Rates (Btu/hr-lbm)	
	WCAP-9620-R1 Analysis (Ref. 1, Appendix E&J)(1)	New Baseline Analysis(2)
Long-Term Heating Rates		
Upper Core Plate A	27.4	246
Upper Core Plate B	5.57	29
Lower Core Plate A	249	903
Lower Core Plate B	52.4	88
Short-Term Heating Rates		
Upper Core Plate A	64.4	265
Upper Core Plate B	15.0	34
Lower Core Plate A	822	1480
Lower Core Plate B	201	167

Note:

1. Based upon 3565 MWt
2. Based upon 3950 MWt

Table 7.6-2

Spatial Distribution of Long-Term Gamma Heating Rates (Btu/hr-lbm) in the Upper Core Plate for IP3

Radial Mesh Midpoint (inches)	Bottom Surface 0.00	Distance through Plate (inches) 0.25	0.75	1.25	1.75	Top Surface 2.00
0.98	472	426	335	269	219	194
2.95	471	425	334	268	218	194
4.92	470	425	333	267	217	193
6.89	469	423	332	266	217	192
8.86	467	422	331	265	216	192
10.83	466	420	330	264	215	191
12.80	464	419	329	263	215	190
14.76	463	418	328	262	214	190
16.73	462	417	327	262	213	189
18.70	461	416	326	261	213	189
20.67	460	415	325	261	213	189
22.64	459	415	325	260	213	189
24.61	459	415	325	261	213	189
26.57	459	415	325	261	213	189
28.54	459	415	326	261	213	189
30.51	459	415	326	261	213	189
32.48	459	415	325	261	213	189
34.45	458	414	325	260	212	188
36.42	457	412	324	259	211	188
38.39	454	410	322	258	210	186
40.35	449	406	319	255	208	184
42.32	443	400	314	252	205	182
44.29	435	393	309	247	201	178
46.26	424	383	301	241	196	174
48.23	409	369	290	232	189	167
50.20	390	352	277	221	180	160
52.17	366	331	260	208	169	150
54.13	338	306	240	192	156	139
56.10	307	277	218	174	142	126
58.07	273	247	194	155	127	112
60.04	239	216	169	136	110	98
62.01	204	184	144	116	94	83
63.78	172	155	122	97	79	70
64.96	150	135	106	84	69	61
65.65	134	121	95	75	61	54
66.15	121	109	86	68	56	49
66.64	90	82	66	53	44	39
67.20	63	58	48	40	33	30
67.89	54	48	37	30	25	23
68.70	53	46	31	24	20	18
69.52	52	45	29	21	17	15
70.33	50	43	27	19	15	13
71.15	47	40	25	17	13	11
71.96	44	37	23	16	12	10
72.78	39	33	21	14	11	9
73.59	35	29	18	12	9	8
74.00	32	27	17	11	8	7

Table 7.6-3

Spatial Distribution of Short-Term Gamma Heating Rates (Btu/hr-lbm) in the Upper Core Plate for IP3

Radial Mesh Midpoint (inches)	Bottom Surface	Distance through Plate (inches)				Top Surface
	0.00	0.25	0.75	1.25	1.75	2.00
0.98	517	467	367	295	241	213
2.95	517	466	366	293	240	213
4.92	516	466	365	292	239	212
6.89	514	464	364	291	238	211
8.86	513	463	363	290	237	211
10.83	512	462	362	290	237	210
12.80	510	460	361	289	236	209
14.76	509	459	360	288	235	209
16.73	507	458	359	287	235	208
18.70	506	457	358	287	234	208
20.67	505	456	357	286	234	208
22.64	504	455	357	286	234	208
24.61	504	455	357	286	234	208
26.57	504	455	357	286	234	208
28.54	504	455	357	286	234	208
30.51	504	455	357	286	234	208
32.48	503	454	357	286	233	207
34.45	502	453	356	285	233	207
36.42	500	451	354	284	232	206
38.39	497	448	352	282	230	204
40.35	492	444	348	279	228	202
42.32	485	438	344	275	225	199
44.29	475	429	337	270	220	195
46.26	463	418	328	263	214	190
48.23	446	403	316	253	206	183
50.20	425	384	301	241	197	174
52.17	399	360	283	226	185	164
54.13	369	333	261	209	171	151
56.10	335	302	237	190	155	138
58.07	298	269	212	170	138	123
60.04	261	235	185	148	121	107
62.01	223	201	158	126	103	91
63.78	188	169	133	106	87	77
64.96	163	147	116	92	75	67
65.65	146	131	103	82	67	59
66.15	131	118	93	75	61	54
66.64	99	90	73	59	49	43
67.20	70	65	54	44	37	34
67.89	62	55	42	34	29	26
68.70	61	53	36	28	23	21
69.52	61	52	34	24	20	17
70.33	59	50	32	23	18	15
71.15	56	48	30	21	16	14
71.96	52	44	28	19	15	12
72.78	47	40	25	17	13	11
73.59	42	35	22	15	11	10
74.00	39	33	21	14	11	9

Table 7.6-4

Spatial Distribution of Long-Term Gamma Heating Rates (Btu/hr-lbm) in the Lower Core Plate for IP3

Radial Mesh Midpoint (inches)	Bottom Surface 0.00	Distance through Plate (inches) 0.25	0.75	1.25	1.75	Top Surface 2.00
0.98	694	782	958	1196	1518	1679
2.95	693	780	956	1196	1522	1684
4.92	693	781	956	1197	1524	1687
6.89	690	778	953	1193	1519	1683
8.86	686	773	946	1185	1507	1668
10.83	680	766	939	1174	1493	1652
12.80	676	761	932	1165	1482	1641
14.76	672	757	927	1159	1474	1631
16.73	670	755	924	1156	1470	1628
18.70	669	753	922	1153	1467	1624
20.67	667	751	919	1150	1463	1619
22.64	665	749	916	1146	1458	1613
24.61	665	748	915	1144	1455	1611
26.57	667	750	918	1148	1460	1616
28.54	670	755	924	1157	1471	1628
30.51	675	760	932	1166	1484	1642
32.48	677	764	936	1173	1492	1651
34.45	678	765	937	1174	1493	1653
36.42	678	764	936	1172	1491	1650
38.39	677	763	935	1171	1490	1649
40.35	678	764	937	1172	1492	1652
42.32	679	766	941	1178	1500	1660
44.29	681	769	945	1185	1508	1670
46.26	679	768	946	1187	1511	1674
48.23	670	759	937	1177	1499	1660
50.20	650	737	912	1146	1460	1617
52.17	616	700	866	1090	1388	1537
54.13	567	644	798	1004	1279	1417
56.10	505	573	708	890	1134	1256
58.07	434	491	604	758	965	1068
60.04	359	405	496	621	788	872
62.01	286	321	391	488	618	683
63.78	224	251	304	377	476	525
64.96	186	207	249	308	386	425
65.65	163	180	216	266	331	363
66.15	144	160	191	236	292	320
66.64	120	133	158	197	253	280
67.20	98	107	127	161	216	244
67.89	79	87	103	134	185	211
68.70	64	71	84	111	157	180
69.52	54	59	70	93	135	156
70.33	45	49	58	79	117	136
71.15	38	42	49	67	102	120
71.96	32	35	42	58	89	105
72.78	26	29	35	49	76	90
73.59	22	24	28	40	64	76
74.00	19	21	25	36	58	69

Table 7.6-5

Spatial Distribution of Short-Term Gamma Heating Rates (Btu/hr-lbm) in the Lower Core Plate for IP3

Radial Mesh Midpoint (inches)	Bottom Surface 0.00	Distance through Plate (inches) 0.25	0.75	1.25	1.75	Top Surface 2.00
0.98	1178	1313	1584	1956	2457	2708
2.95	1174	1310	1581	1957	2464	2717
4.92	1175	1310	1581	1958	2465	2719
6.89	1171	1306	1576	1951	2458	2711
8.86	1163	1297	1565	1938	2440	2690
10.83	1154	1287	1553	1922	2418	2666
12.80	1148	1279	1542	1908	2401	2648
14.76	1142	1273	1534	1898	2388	2633
16.73	1138	1268	1530	1893	2382	2627
18.70	1135	1265	1526	1888	2376	2620
20.67	1132	1262	1522	1883	2370	2613
22.64	1130	1259	1517	1877	2362	2605
24.61	1129	1258	1516	1875	2360	2602
26.57	1133	1262	1521	1881	2367	2610
28.54	1138	1269	1531	1894	2383	2628
30.51	1145	1277	1541	1908	2402	2649
32.48	1149	1282	1549	1918	2414	2662
34.45	1150	1284	1550	1920	2417	2665
36.42	1150	1283	1549	1918	2415	2663
38.39	1149	1282	1548	1917	2414	2662
40.35	1149	1283	1550	1919	2417	2666
42.32	1151	1286	1555	1927	2428	2678
44.29	1151	1288	1561	1935	2439	2690
46.26	1145	1283	1559	1935	2439	2691
48.23	1128	1265	1541	1915	2414	2664
50.20	1092	1227	1497	1863	2348	2591
52.17	1035	1163	1421	1769	2230	2461
54.13	953	1071	1308	1629	2054	2267
56.10	850	954	1162	1446	1824	2012
58.07	732	820	995	1235	1557	1717
60.04	609	680	822	1016	1277	1408
62.01	488	543	652	805	1009	1111
63.78	387	428	511	627	783	861
64.96	324	357	423	517	641	703
65.65	285	313	370	450	554	606
66.15	253	279	330	403	493	539
66.64	214	235	277	342	432	478
67.20	177	193	226	285	377	423
67.89	146	160	188	243	332	376
68.70	122	134	158	208	290	331
69.52	104	114	136	181	257	295
70.33	89	98	117	158	229	265
71.15	76	84	101	138	204	236
71.96	64	72	87	119	179	209
72.78	54	61	73	102	155	181
73.59	45	50	60	83	129	152
74.00	40	44	53	74	116	138

8.0 TURBINE ISLAND ANALYSIS

8.1 Steam Turbine

The currently installed Indian Point Unit 3 (IP3) steam turbine consists of a combination of a Siemens-Westinghouse nuclear turbine generator set and Brown Boveri (Alstom) equipment. The steam turbine is composed of four elements—one double-flow high-pressure (HP) turbine BB96 and three Brown Boveri (Alstom) double-flow, low-pressure (LP) turbines.

In order to optimize the HP efficiency and make it compatible with the higher mass flow at the Stretch Power Uprate (SPU) thermal power, the rotor, including blading and the inner casing of the HP turbine will be exchanged. The existing turbine valves and auxiliary systems were found to be acceptable for the full-power uprate pressure, temperature, and flow conditions. The new HP turbine components were designed so as to not exceed the LP turbine inlet flow and pressure conditions.

The HP turbine will be replaced by the full-arc steam admission turbine during an upcoming refueling outage. This all-reaction turbine is designed to provide 2-percent nominal flow margin at the full-uprate power level throttle valve steam conditions. This design also provides improved full-load performance by eliminating the partial admission control stage and applying current blade path technology.

The major changes associated with the new HP turbines are:

- Elimination of the inlet nozzle blocks that will be replaced with full-arc admission and a new inner casing including a diagonal stage.
- Optimized all-reaction blading
- Improved materials for blade rings (stainless steel)
- Monoblock HP rotor with no through-bore
- Full-arc steam admission at all loads

The existing turbine bearings, gland seals, main lube oil system, hydraulic control system, and gland sealing steam system are acceptable for the uprated conditions. The HP turbine first-stage instrumentation will be adjusted to the new pressure conditions for the reaction turbine.

The BB96 HP turbine retrofit for IP3 was evaluated for the likelihood of missile generation due to HP rotor burst. The study evaluated the likelihood of missile generation resulting from a burst of a fully integral nuclear HP rotor. Three potential failure mechanisms were considered:

- Ductile burst due to overspeed.
- Fracture resulting from high-cycle fatigue cracking.
- Fracture resulting from low-cycle fatigue cracking.

A ductile failure analysis showed that a ductile burst will not occur until the speed of the rotor is increased to greater than 240 percent of rated speed; this is well beyond the design overspeed. A fatigue evaluation showed that the minimum safety factor for the newly designed BB96 HP rotor is two times the safety factor of the original rotor at the limiting location. Since there is no history of high-cycle fatigue issues with the existing HP turbines, the risk of missile generation from this mechanism is negligible. In the case of low cycle fatigue, the failure mechanism is brittle fracture. A calculation of cyclic life assuming a threshold internal flaw at the highest stressed section based on ultrasonic testing (UT) inspection sensitivity showed that the rotor low cycle fatigue life is greater than 10,000 start cycles. Based on the results of this study, there is not a significant likelihood of missile generation for the BB96 HP retrofit.

The LP turbine components were originally dimensioned for 105 percent steam flow. This applies to LP blading, inner casing, and rotors with couplings. These components can therefore be operated at a 5 percent higher steam flow rate; 9900 klb/hr at an LP inlet pressure of 203 psia. The Phase 1 SPU steam conditions remain within the LP turbine original design conditions and were found to have no effect on the validity of the existing turbine missile analyses.

8.1.1 Overspeed

The construction of IP3 predates the use of Intercept valves in nuclear plants, therefore, it uses a LP Steam Dump System for overspeed protection. The current WR^2 of IP3 with BB96-(3) Brown Boveri LP turbines and the generator rotor is 10,163,468 lb-ft^2. The new HP rotor will be approximately 20 percent heavier than the original HP rotor. This will increase the WR^2 approximately 5 percent and the LP dump system will remain acceptable at the SPU conditions because the higher WR^2 requires more steam to spin up the turbine to higher speeds and is, therefore, conservative with respect to the capability of the LP Steam Dump System to provide overspeed protection.

8.1.2 Conclusions

The turbines, turbine valves, and auxiliary systems were found to be acceptable for the Phase 1 full-power SPU pressure, temperature, and flow conditions. The turbine bearings, gland seals, main lube oil system, hydraulic control system, and gland sealing steam system are acceptable for the Phase 1 SPU conditions. The Phase 1 SPU steam conditions were found to have no effect on the validity of the existing turbine missile analyses. Since the Phase 2 modifications to the LP turbines will maintain the design basis for the turbine missile analysis, this analysis will continue to be acceptable at 3216 MWt.

8.2 Heat Balances

Heat balances were generated to identify relevant parameters and design inputs to evaluate balance-of-plant (BOP) systems, structures and auxiliaries at the SPU conditions. Detailed heat balance models were developed and tuned to match plant operational data and extrapolated to SPU conditions. In addition to the guarantee heat balance at full-load conditions at rated condenser pressure, heat balances were also generated for partial-load conditions and for different condenser pressure levels.

These heat balances were used in the BOP evaluations as indicated in Section 9 of this report.

9.0 BOP SYSTEMS

Introduction

To predict the performance of the balance-of-plant (BOP) thermal cycle at the stretch power uprate (SPU) conditions and to determine the corresponding system and equipment operating parameters, heat balances were developed using the PEPSE models.

The SPU heat balances define the bounding parameters for evaluating the BOP system performance at the SPU condition.

Method of SPU Heat Balance Development

To accurately predict BOP system performance during SPU operation, it was first necessary to develop a benchmark heat balance model that represented the current plant performance. This benchmark heat balance model was then used as a basis for developing a variety of SPU cases.

The development of the baseline and SPU models was accomplished as follows:

- The existing PEPSE heat balance model that was based on “as-designed” component parameters was reviewed. Physical data in the model were verified as being representative of the current plant design by a detailed review of plant design documents and physical inspection results.

- Actual operating temperatures, pressures, and flows with the plant operating at 100-percent power were obtained. Using these data, the PEPSE model was tuned to represent the actual performance characteristics of the plant thermal cycle, including the effects of component degradation or modifications that may change their performance from the as-designed characteristics. This tuned heat balance was then established as the “benchmark heat balance.”

- The two sets of SPU heat balance were then run for a range of condenser backpressures (that is, circulating water temperature variations). The first set provided data for an uprate power level of 3168 MWt core power to represent Phase 1 conditions. A 0.5-percent margin was added to each case to provide conservatism. The second set provided data for an uprate power level of 3216 MWt core power to reflect the future thermal power at SPU conditions with an additional 0.5-percent margin for each case to provide conservatism. The BOP plant systems were evaluated to 3216-MWt core power unless otherwise noted.

9.1 Main Steam System

9.1.1 Introduction

Main Steam System (MSS) piping components and equipment, including the main steam safety valves (MSSVs), atmospheric relief valves (ARVs), main steam isolation valves (MSIVs), and condenser steam dump valves, were evaluated for the Indian Point Unit 3 (IP3) SPU conditions.

The MSS transports saturated steam produced in the steam generators to the main turbine for power generation. The steam dump and bypass piping and valves provide alternate flow paths for the generated steam when the turbine is unavailable, or when a plant operational transient requires a reduction in the main turbine power level.

In addition to supplying saturated steam to the main turbine, the MSS also supplies steam to the following users:

- Main boiler feed pump drive turbines
- Moisture separator reheaters (MSRs)
- High-pressure (HP) turbine
- HP turbine gland sealing steam system
- Priming and steam jet air ejectors
- Auxiliary feedwater (AFW) pump drive turbine
- Auxiliary steam system (via reducing valve)

An inadvertent opening, with failure to close, of the largest of any single steam dump, relief, or safety valve will not prevent the safe shutdown of the plant. The maximum capacity of any single MSSV, ARV, or main steam dump valve does not exceed 890,000 lb/hr at 1085 psig inlet pressure. This feature limits the potential uncontrolled blowdown flow rate in the event a valve inadvertently fails or sticks in the open position. This maximum value has not changed for SPU.

9.1.2 Input Parameters and Assumptions

The evaluation of the MSS used conditions predicted by SPU thermal cycle heat balances. The SPU heat balances were developed by first establishing a benchmark heat balance model representative of current plant performance, which was then used as a basis for developing heat balances representative of SPU operation. The 3216 MWt SPU heat balance parameters were used as the bounding values for evaluating the MSS.

9.1.3 Description of Analysis and Evaluations

The MSS piping, valves, and components were evaluated to verify their ability to operate at SPU conditions. Based on SPU heat balances, operation at the higher SPU power level increases the steam flow required from the steam generators to the HP turbine. Additional steam flow is also necessary for other components, which operate at higher loads and use steam as a motive force.

The SPU heat balance parameters were reviewed and compared with original system heat balance parameters as well as the original component design parameters to determine their capability to function adequately at SPU conditions.

The following system design features were reviewed and evaluated:

- Main steam (MS) pressure drop and flow versus required HP turbine inlet conditions
- MS piping pressure/temperature design and flow velocities
- MS component pressure/temperature design
- Design closure time for MSIVs
- Setpoints for ARVs
- Setpoints for MSSVs
- Steam supply flow rates/line sizes/velocities to auxiliary components
- Accident analyses (see Section 6 of this report for the evaluations of specific accidents)

9.1.4 Acceptance Criteria

The following acceptance criteria must be met:

- Steam pressure and flow must satisfy HP turbine throttle inlet conditions required by the SPU heat balances.

- MS piping and component pressure and temperature design must exceed the maximum expected operating pressure and temperature associated with SPU and abnormal and accident conditions.

- MSIVs must be able to close within the required times under SPU conditions and abnormal and accident conditions.

- Increases in MS piping velocities due to the SPU will remain within accepted industry standards for the service conditions and existing pipe material. The current Flow-Accelerated Corrosion (FAC) Program will continue to require that the MS piping be monitored for any lines exceeding program criteria.

- The MSSV setpoints must consider the added piping pressure drop due to increased SPU flows and must be adequate to ensure that the steam generator pressure does not exceed 110 percent of design pressure.

- Sufficient steam flow and pressure must be provided to auxiliary components using MS to meet SPU operating requirements for each component.

9.1.5 Design Criteria

The MSS was designed to meet the intent of the General Design Criteria (GDC), which was published by the Atomic Energy Commission (AEC) in the Federal Register of July 11, 1967. The NRC concluded in the *Safety Evaluation Report* (SER), that the plant design conformed to the intent of the newer criteria. SPU operation does not affect the ability of the MSS to meet these requirements. Therefore the MSS continues to meet the criterion requirements.

In addition to AEC Criterion 2 (*Performance Standards*), New York Power Authority (NYPA) committed to the requirements of Sections III.G, III.J, III.L, and III.O of 10CFR50 Appendix R (Reference 1). Evaluation of IP3 fire protection features against the requirements of Section III.G of Appendix R to 10CFR50 was completed and the report submitted to NRC on August 16, 1984. SPU operation does not affect the ability of the MSS to meet these requirements. Therefore the MSS continues to meet the criterion requirements.

In addition to AEC Criterion 17 (*Monitoring Radioactive Releases*) and 70 (*Control of Radioactive Releases to the Environment*), provisions are included in the MSS design to meet 10CFR20 (Reference 2) limits. The radioactive releases at SPU conditions are within the original design basis of the plant. Therefore, the MSS will continue to meet the criterion requirements.

Environmental qualification (EQ) of MSS electrical equipment important to safety is demonstrated in EQ packages compiled in accordance with the requirements of 10CFR50.49 (Reference 3) and DOR Guidelines (see LAR Section 11, and ER Section 10). The MSS is monitored as a result of the Three Mile Island 2 (TMI-2) accident investigation and the requirements of Regulatory Guide (RG) 1.97 (Reference 4). The MSS is designed with provisions to allow post-accident sampling in accordance with the post-TMI Requirements of NUREG 0578 and 0737 (References 5 and 6) SPU operation does not affect the ability of the MSS to meet these requirements. The Technical Specification requirements for sampling provisions were deleted by Amendment 210, dated February 6, 2002. Therefore the MSS continues to meet the criterion requirements.

9.1.6 Results and Conclusions

Based on the system evaluation discussed in the previous sections, it was determined that the IP3 MSS is capable of performing its design function under SPU conditions. The following sections provide additional details of the evaluation results/conclusions.

9.1.6.1 Flow Restriction Nozzles

The MS header at the outlet of each steam generator contains a venturi-type steam flow restriction nozzle. These flow restriction nozzles are designed to limit the blowdown flow from a downstream rupture in the main steam header, and to provide flow measurement of each steam header via differential pressure connections upstream and downstream. In addition, the model 44F steam generators contain a flow restriction nozzle at the outlet of the steam generators. As described in Sections 4 and 5 of this report, the flow restriction nozzles are acceptable for use under SPU conditions.

9.1.6.2 Main Steam Safety Valves

Each of the four MS headers contains five MSSVs, located outside of the containment, which provide overpressure protection for the steam generators and the MSS inside containment. The safety valves are designed to pass a total of 100-percent of MS flow rate while maintaining the steam generators at or below 110-percent of design pressure. Maximum steam flow rate at 100-percent power under SPU conditions is significantly below the MSSV design capacity. As described in Sections 4 and 5 of this report, the IP3 MSSVs are acceptable for overpressure protection under SPU conditions.

Based on the aggregate capacity of the safety valves, the safety valve setpoints were evaluated to confirm that the existing setpoints do not result in a steam generator pressure greater than 110 percent of the design pressure of 1085 psig. There is no change to the steam generator design pressure due to the SPU. The evaluation determined that the steam generator pressure was well below the 110 percent limit when the existing safety valves were passing the required relieving capacity at SPU conditions.

MSSV setpoints are acceptable for operation under SPU conditions and will maintain the steam generators below their design pressure.

9.1.6.3 Atmospheric Steam Relief Valves

The MSS includes four ARVs. These relief valves are used for controlling Reactor Coolant System (RCS) temperature to maintain hot standby and to cool the RCS prior to initiating residual heat removal (RHR).

To limit the frequency of safety valve lifts, the setpoints of the ARVs are based on plant no-load conditions and the lowest MSSV setpoint. These four valves are designed to pass a total of 10 percent of full-load MS mass flow rate at no-load steam generator outlet pressure. As discussed in subsection 4.2.1 of this document, the IP3 ARVs are adequate to support required steam relief (during a steam generator tube rupture [SGTR] and other cooldown events) under SPU conditions.

Since the no-load steam generator pressure and the lowest set MSSV setpoint are not changed with the implementation of SPU, current setpoints of the ARVs are acceptable and will not change.

9.1.6.4 HP Steam Dump Valves

The HP steam dump valves and associated piping are designed to reduce the transients on the RCS during plant trips and load rejections. Twelve HP steam dump valves, six on each MS auxiliary loads header, are provided to discharge MS directly to the main condenser. The valves have a sizing criteria of a total of 40 percent of full-load MS mass flow at full load T_{avg} (see section 4.2).

The full-load MS flow increases under SPU conditions. As detailed in subsection 4.2.1 of this report, the HP steam dump valves are adequate for operation under SPU conditions.

9.1.6.5 Low-Pressure Steam Dump Valves

The low-pressure (LP) steam dump valves and associated piping are designed to preclude LP turbine overspeed by diverting a portion of the HP turbine exhaust steam from the crossunder lines directly to the main condensers. Six 10-inch diameter dump valves and piping are provided, each of which branches from the crossunder line near the MSR to the condenser. Each dump line contains a motor-operated isolation valve and an air-operated dump valve in series.

The LP steam dump valves are required to pass a total of approximately 25 percent of the MS available to limit overspeed of the turbine following a turbine or generator trip. The full-load MS flow increases under SPU conditions. As detailed in subsection 4.2.1, the IP3 LP steam dump valves are adequate for operation under SPU conditions.

9.1.6.6 MSIVs and Non-Return Valves

The IP3 MSIVs and non-return check valves are located outside of containment (downstream of the MSSVs) and function to prevent uncontrolled blowdown of more than one steam generator. The valves are swing-disc check valves. The isolation valves are reverse-mounted on the MS headers, utilizing a spring-loaded air piston to hold the disc out of the steam flow.

Since the steam generator design pressure and the MSSV setpoints are not changing due to SPU operation, the MSIV and non-return valve design pressure and temperature are not affected.

The MSIVs and non-return valves are required to have the capability of closing in 5 seconds or less in the event of a MS line rupture. Because the MSIVs isolation valves and non-return valves are a check-valve design, reverse steam flow will assist in closing the non-return valves. The MSIVs are reverse mounted check valves with the disk held out of the steam flow by an air operated piston and are assisted in closing by forward steam flow. Therefore under SPU conditions of increased flow, the valves will continue to meet their design capability, including the capability of closing in 5 seconds or less. The MSIVs and non-return valves are acceptable for SPU operation without modification. Piping and support loads relating to rapid valve closure are addressed in Section 9.9 of this report.

9.1.6.7 AFW Pump Drive Turbine Steam Supply

In the event of an abnormal condition and accident, the MSS must supply motive steam to the AFW pump drive turbine. The AFW pump can operate using MS over the entire range of MS pressures from normal operation to very low pressures at startup or shutdown.

The MS supply line of the turbine drive for the AFW pump is designed to provide steam at a range of pressures from 110 to 1118 psig. The turbine drive is designed to operate at a maximum inlet pressure of 600 psig. A pressure control valve on the steam supply line reduces the supply pressure to 600 psig or less. Based on the evaluation under SPU conditions at full load, the pressure of the MS supply upstream of the control valve was 740 psig, thus providing sufficient pressure.

9.1.6.8 Main Feedwater Pump Drive Turbine Steam Supply

The MSS supplies motive steam to the main feedwater pump turbine drives during all modes of pump operation. Initially, during plant startup, steam is provided directly from the MS headers. When sufficient pressure exists in the hot reheat side of the MSR, steam is provided from the "A" MSRs.

Since the full-load main feedwater flow requirements increase relative to SPU operation, the required steam flow for the two feedwater pump turbines also increases. A comparison of the required steam flow to the turbine drives during SPU operation with SPU heat balances confirmed adequate steam flow capacity available under SPU operation.

9.1.6.9 Main Steam Piping

Under SPU operating conditions, the steam generator steam outlet mass flow rate will increase approximately 6 percent above the current operating mass flow rate. This increase will impact MS header piping pressure drops and flow velocities.

The MS piping pressure and temperature design bounds SPU pressure temperature conditions. Piping pressure temperature design is, therefore, acceptable for SPU conditions.

The MS header piping pressure drop at SPU conditions from the steam generators to the HP turbine throttle valve inlet was calculated and compared with original design pressure drop parameters. There was adequate steam flow and pressure to satisfy throttle valve inlet requirements under SPU conditions.

Increased MS piping flow velocities based on SPU conditions in MS piping to normally operating components were evaluated and found acceptable. Velocities in pipelines to infrequently used lines, such as the AFW pump turbines and startup supply line for the main feedwater pump turbines, are also acceptable. Existing FAC monitoring activities will ensure that corrosion remains acceptable.

9.1.7 References

1. 10CFR50, Appendix R, *Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1979,* June 20, 2000.

2. 10CFR20, *Standards for Protection Against Radiation,* May 21, 1991.

3. 10CFR50.49, *Environmental Qualification of Electric Equipment Important To Safety for Nuclear Power Plants*, 66FR64738, December 14, 2001.

4. Regulatory Guide 1.97, *Instrumentation of Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident* (Errata published July 1981) (Draft RS 917-4, Proposed Revision 2, published December 1979) (Rev. 3, ML003740282).

5. NUREG-0578, *TMI Lessons Learned Task Force Status Report and Short Term Recommendations*, July 1979.

6. NUREG-0737, *Clarification of TMI Action Plan Requirements*, November 1980.

9.2 Extraction Steam System

9.2.1 Introduction

The IP3 Extraction Steam (ES) System was evaluated in conjunction with stretch power uprate (SPU) conditions to determine the extent to which system design parameters bound SPU conditions.

The IP3 ES System is designed to transmit steam from high pressure (HP) and low pressure (LP) main turbines to the shell sides of the feedwater heaters to heat feedwater to improve cycle efficiency.

The ES System has no safety function.

9.2.2 Input Parameters and Assumptions

The ES was evaluated using conditions predicted by SPU thermal cycle heat balances. The SPU heat balances were developed by first establishing a benchmark heat balance model representative of current plant performance, which was then used as a basis for developing heat balances representative of SPU operation. The SPU heat balance parameters were used as the bounding values for evaluating the ES system.

9.2.3 Description of Analysis and Evaluations

The ES System was evaluated to verify its ability to operate at the SPU conditions. SPU heat balances were used to establish the SPU parameters with which the turbine cycle system evaluations were performed. A tuned baseline heat balance was also used in these evaluations.

The following ES System design features were reviewed and evaluated:

- The pressure and temperature design of extraction steam piping and valves was compared with SPU pressure and temperature conditions.

- The feedwater heater (FWH) shell pressure and temperature design was compared with SPU pressure and temperature conditions.

- The results of past FWH inspections were reviewed to determine the current physical condition of the heaters.

- Extraction steam piping velocities at the higher flow rates of SPU operating conditions were compared to industry standard criteria for extraction steam service. These velocities were also evaluated to determine whether the SPU flow rates increase the possibility of flow-accelerated corrosion (FAC).

- FWH extraction steam inlet nozzle velocities at SPU operating conditions were compared with standard industry guidelines (Heat Exchange Institute [HEI]) to size FWH nozzles to determine the potential for increased wear and FAC.

- The SPU extraction steam flow rates into the FWHs were evaluated to determine the effects on tube vibration and erosion of internal subcomponents and support structures.

- Extraction steam piping flow regimes were evaluated relative to moisture carryover (MCO) capability.

9.2.4 Acceptance Criteria

The evaluations must demonstrate that design parameters of the existing ES System piping and valves bound the corresponding parameters at SPU conditions. The following criteria must be met:

- The pressure and temperature design of extraction steam piping and valves should envelop the pressure and temperature conditions expected under SPU operation.

- FWH shell pressure and temperature design should envelop the pressure and temperature conditions expected under SPU operation.

- FWH extraction steam inlet nozzle velocities at SPU conditions should not appreciably increase the potential for wear and FAC.

- Extraction steam piping flow velocities due to SPU are within the industry standard values for extraction steam piping of this size, material, and service. The expected velocities at SPU flow rates, when considered with the SPU operating temperatures, should not appreciably increase the potential for FAC.

- FWH level control systems effectively control level without activating high level protection or otherwise adversely affecting thermal efficiency.

- The SPU extraction steam flow rates into the FWHs should not cause destructive tube vibration or the erosion of internal parts such that their function is impaired.

- Relative to extraction steam line flow regimes, system piping flow must exhibit effective MCO and should not exhibit slug flow characteristics.

9.2.5 Design Criteria

The IP3 ES System is designed to transmit steam from HP and LP main turbines to the shell sides of the feedwater heaters to heat feedwater to improve cycle efficiency. The ES System is not safety related. Criterion required to meet SPU conditions are listed in the Acceptance Criteria above.

9.2.6 Results and Conclusions

Based on the system evaluation as discussed in the above sections, it was determined that the IP3 ES System is capable of performing its design function under SPU conditions.

ES System pressure/temperature conditions predicted under SPU conditions are bounded by system component and piping design parameters.

Calculated pipeline velocities under SPU conditions are either bounded by industry standard velocity limits, or the lines are already included in the FAC program and are, therefore, acceptable for SPU operation. FAC associated with these lines under SPU conditions will not significantly increase. FAC Program activities for the extraction lines will be continued during SPU operation.

With the exception of IP3 FWHs 34A, B, and C shell-side temperature, the FWH shells pressure and temperature design envelops the SPU pressure/temperature conditions. For FWHs 34A, B, and C, the maximum shell-side inlet temperature during SPU exceeds the shell design temperature by 29°F. Since the shell material of these heaters is carbon steel SA 516 Grade 70, the shell design can accept the higher SPU temperatures as the maximum allowable stress value of material SA 516 Grade 70 in tension does not change in the temperature range of –20° to 650°F.

With the exception of IP3 FWHs 31A, B, and C and 32A, B, and C, extraction steam inlet nozzle velocities are bound by the HEI standard industry guidelines for FWH nozzles. Current operation of these heaters exceed HEI guidelines. The SPU will decrease the velocities of FWH 31A, B and C by approximately 3 fps, and increase the velocities of FWHs 32A, B and C by approximately 3 fps. The nozzles are already included in the plant FAC Program and will continue to be monitored for future wear.

Horizontal portions of the ES System piping are expected to develop either a semi-annular pattern, or to contain a liquid-phase portion that is small enough to be carried over. Vertical upward flows are expected to develop annular or mist flow patterns so that effective MCO will occur. Void coefficients associated with the vertical downward flowing portions of the system exceed minimum acceptance criteria with enough margin that slug patterns are not expected.

9.3 Heater Drains System

9.3.1 Introduction

The Heater Drains System was evaluated in conjunction with stretch power uprate (SPU) conditions to determine the extent to which system design parameters bound SPU conditions.

The turbine cycle has six stages of feedwater heaters (FWHs). Each stage consists of three strings of heaters.

The drains from the heaters 35 and 36 are collected in the heater drain tank and then pumped by two half-size heater drain pumps to the suction of the main feedwater pumps (MFPs). The drains from heaters 34, 33, 32, and 31 flow cascade from higher pressure to lower pressure heaters. The combined drains in heaters 31 flow to the condenser. Bypass drain lines to the condenser for each heater and the heater drain tank dump drains directly to the condenser on high level are also provided.

As part of the plant's turbine water induction prevention features for events such as a heater tube rupture, a second emergency drain is required for condenser neck heaters 32 and 31 since a non-return valve cannot be provided in the extraction steam lines. On high-high level in these heaters, the emergency lines will open to drain additional flow to the condenser.

Simultaneously, the level control valves (LCVs) on the bypass drain line to condenser will remain open and the cascading drain flow from the preceding heaters will be isolated.

Moisture Separators, Reheaters, and Moisture Pre-Separators Drain System

Each moisture separator drains to its associated moisture separator drain tank. The moisture separator drain tanks flow to the heater drain tank during normal plant operation and to the drain collecting tank during startup, shutdown, or high water level conditions. The drain collecting tank drains to condenser.

Each reheater drains to its associated reheater drain tank. The reheater drain tanks flow to heaters 36. In the abnormal situation of high water level, the reheater drains are diverted to the condensers.

The moisture pre-separators consist of moisture pre-separators (MOPs) combined with special crossunder pipe separators (SCRUPs). The MOPs/SCRUPs drain system starts at the upstream end of the crossunder piping and runs to the heater drain tank. The main feature of the MOPs/SCRUPSs drain system is the separation chamber. The MOPs/SCRUPs drains enter the separation chamber from the bottom. The liquid portion of the drains exits at the side of the separation chamber through a line that is equipped with a manual throttle valve. This line forms a loop-seal. The vapor portion of the drains exits at the top of the separation chamber through a vent line that is equipped with a control station and manual throttle valves. The level of water in the separation chamber can and will be fine-tuned by the operators in response to plant operating conditions.

The MOPs/SCRUPs and reheater drains are returned to the thermal cycle by pumping the heater drain tank into the suction of the feedwater pumps

Normal Operating Vents Lines of Heaters to Condensers

The normally operating vent lines of heaters are directed to the condenser through piping provided with globe valves for isolation or throttling of the flow.

Scavenging Steam to Reheaters

This additional heating steam supplied to the reheater, called scavenging steam, ensures that all reheater tubes are flowing clearly and a vapor space exists over condensed steam. This scavenging steam is directed to FWHs 36 during normal operation and to the condensers during start up.

Heaters Relief Valves

All heaters, with the exception of condenser neck heaters 31 and 32, are equipped with shell-side relief valves for overpressure protection of heater shells in the event of rupture of heater tube. These heaters, 31 and 32, have no isolation valves in their extraction lines from the low-pressure (LP) turbine and, therefore, have no relief valves for the shell.

9.3.2 Input Parameters and Assumptions

A current operating (benchmark) heat balance, tuned to the current plant operating characteristics and SPU heat balances at 1.0-, 1.5-, and 3.0-inch HgA condenser pressures, were used in the evaluation of the system. Additionally, these heat balances included a margin of 0.5 percent as a conservatism for evaluation purposes. Each of these heat balances and the corresponding parameters were reviewed and the most conservative case was chosen for the specific evaluation being performed.

Plant design basis documents, system descriptions, equipment and piping specification, drawings, and calculations provided system and component design parameters.

9.3.3 Description of Analysis and Evaluation

Hydraulic Analysis of Operation of Heater Drain Pumps and Associated Suction and Discharge Piping System

Refer to Section 9.4 of this report for the analysis of heater drain pumps and associated suction and discharge piping at SPU conditions.

FWHs, Moisture Separators, Reheaters, and Heater Drain Tanks Level Control Valves

The change in the flow coefficient (percent C_V difference) of the LCVs at the current operating and SPU conditions has been determined based on the heat balance parameters.

A generic flow characteristic curve has been used to determine the expected change of valve position at SPU conditions based on current valve position and percent C_V difference. The expected change of valve position at SPU conditions has been added to the current opening position to predict the opening position of the normally operated drain valves after SPU.

If the opening position of LCVs exceeds 75 percent at SPU conditions or the change in valve opening position at current and SPU conditions is significantly different, a detailed pressure drop analysis is performed to determine the change of valve position from current and SPU conditions.

The LCVs on bypass lines from heaters to the condenser are closed during normal operation and are opened when the normal drain line is not in service. The design of these bypass lines and valves is the same as the normally operated level control valve for the subject heater and assumed to be adequately sized for SPU conditions when the corresponding normal drain valves are found to be adequate.

The required C_V of heater drain tank bypass and condenser neck heaters emergency dump to condenser LCVs at SPU is expressed in percentage of maximum C_V as 100 x [$C_{V\ UPRATE}/C_{V\ MAX}$]. The expected opening positions of heater drain tank bypass and condenser neck heaters emergency dump to condenser LCVs at SPU conditions have been determined from the generic flow characteristic curve.

FWHs, Moisture Separators, and Reheaters Gravity Drain Lines

The following drain lines are gravity-flow lines, not equipped with control valves, and are evaluated as self-venting or non-self venting:

- FWHs 35 to the heater drain tank, non-self-venting
- Moisture separators to moisture separator drain tanks, self-venting
- Moisture separator drain tanks to heater drain tank, non-self-venting
- Reheaters to reheater drain tanks, non-self-venting

The self-venting gravity-flow drain lines are evaluated to comply with the criteria:

- Froude number (F_N) shall be less than approximately 0.3
- Slope of piping shall be greater than 1/2 inch per foot

The non-self-venting gravity-flow drain lines are properly designed when the static head available exceeds the friction head loss in the lines. If static head is too low, the fluid will back up into the source vessel. If friction head loss is too low, the flow velocities will be excessive and vapor may be entrained in the liquid, causing unstable two-phase flow.

Flow Regimes of Fluid Flow in Piping Downstream of Reheater Drain Tanks LCVs

The reheater drain piping and valves have a lower flow rate during SPU operation than current conditions. Downstream piping of reheater drain tank level control valves, an unstable flow regime, such as slug flow, could develop in long horizontal runs. Flow regime is evaluated by computing Baker parameters B_X and B_Y and applying them to Baker's map for two-phase flow regimes.

Scavenging Steam Vent Chamber Discharge Lines

Each moisture separator reheater (MSR) has a 3-inch vent chamber discharge line designed to accept approximately 26 percent of the reheater steam flow at 7.7 percent quality. These discharge lines are directed to heaters 36 during normal operation and to the condenser during start up. The flow in this 3-inch line is governed by a 3/4-inch control station. To evaluate two-phase choked flow in the control section, critical flow analysis software has been used that is based on the Henry-Fauske model.

Heater Shell-Side Normal Operating Vent System

The heater shell-side normal operating vent system has been analyzed to confirm that the Heat Exchanger Institute (HEI) recommended flow at SPU conditions can be vented (0.5 percent of the steam entering the FWHs at SPU conditions).

Heater Shell-Side and Heater Drain Tank Relief Valves for Overpressure Protection

The FWHs 33, 34, 35, and 36 and the heater drain tank have relief valves for overpressure protection. The set pressure of the heater relief valves should be equal to or less than the design pressure of its shell side. The set pressure of the heater drain tank relief valve should be equal to or less than the heater drain tank design pressure.

The heater shell-side relief valves were evaluated for compliance with the HEI standard industry guidelines that the relief valve is capable of passing the larger of the following flows with 10percent accumulation:

- Minimum of 10 percent of the feedwater flow through the heater at maximum load capability based on average tube-side temperature.

- Flow based on the rupture of one heater tube resulting in two open ends discharging as orifices of a diameter equal to the inside diameter of the tube with an orifice discharge coefficient of 0.9 and a pressure difference across the orifices equal to the difference between the tube and shell design pressures.

The heater drain tank accepts drain flows from heaters 35 and 36, moisture separator drain tanks, and MOP drain tank. The heater drain tank relief valves were evaluated by comparing the total of all drain flows into the tank with the rated capacity of the two valves.

Piping, Valves, and Component Design Pressures and Temperatures

The maximum sustained operating pressures and temperatures of heaters, MOPs/SCRUPs, moisture separators, and reheaters drain/vent system at SPU conditions are compared with the piping, valves, tank, and heater shell design/rated pressures and temperatures.

Flow-Accelerated Corrosion of Drain and Vent Lines

The piping velocities were calculated at SPU conditions and compared to standard industry velocity criteria as a measure of whether there was a greater potential for flow-accelerated corrosion (FAC). The potentially contributing factors to FAC, such as flow path geometry, material composition, flow velocities, fluid temperatures, and flashing service conditions, were evaluated to determine if a particular pipe needed to be added to the current FAC Program.

Drain Inlet and Outlet Nozzle Velocities of Heaters

The drain inlet and outlet nozzle velocities of heaters at SPU conditions were compared with HEI standard industry guidelines for prevention of undue wear of the nozzles and to determine whether any nozzles needed to be added to the present scope of the FAC Program.

Inlet and Outlet Drain Flows – Effects on FWHs Internals

The SPU drain inlet and drain outlet flow rates of the FWHs were evaluated to determine the effects on tube vibration and erosion of internal subcomponents and support structures.

9.3.4 Acceptance Criteria

FWHs, Moisture Separators, Reheaters, and Heater Drain Tank LCVs

The acceptance criteria for the LCV position is that the valve shall be open below 75 percent at full-load SPU operation to provide adequate assurance of long-term control margin and operability.

FWHs, Moisture Separators, and Reheaters Gravity Drain Lines

The drain lines with gravity flow should be self-venting if the liquid Froude Number is less than approximately 0.3 at SPU conditions and slope is greater than 1/2 inch per foot. The satisfactory operation of non-self-venting gravity-flow drain lines is performed when the static head available exceeds the friction head loss in the lines.

Flow Regimes of Fluid Flow in Piping Downstream of Reheater Drain Tanks LCVs

The piping downstream of reheater drain tanks level control valves should not have any unstable flow regime such as slug flow at SPU conditions.

Scavenging Steam Vent Chamber Discharge Lines

The scavenging steam vent chamber discharge line should be adequately sized to pass the required flow at SPU conditions.

Heater Shell-Side Normal Operating Vent System

The existing piping design should be capable of removing the expected non-condensable gases per the HEI standard industry guidelines at SPU conditions.

Heater Shell-Side and Heater Drain Tank Relief Valves for Overpressure Protection

The set pressure of the heater shell-side relief valve should be equal to or less than the associated heater shell design pressure. The set pressure of the heater drain tank relief valve should be equal to or less than the heater drain tank design pressure.

The HEI-standard industry guideline of flow capacity for heater shell-side relief valves should be bounded by design flow capacity of heater shell-side relief valves.

The total incoming flow to the heater drain tank should be bounded by the total design flow capacity of heater drain tank relief valves.

Piping, Valves, and Component Design Pressures and Temperatures

The acceptance criteria is that the maximum sustained system operating pressures and temperatures at SPU conditions be bounded by design or rated pressures, and temperatures of piping and components.

FAC of Drain and Vent Lines

The piping velocities at SPU conditions associated with the single-phase flow of drain lines for the heater, MOPs/SCRUPs, moisture separator, and reheater drain system should be bounded by the standard industry velocity criteria. Other potential FAC influences, such as flow path geometry, material composition, flow velocities, flashing service conditions, and fluid temperature >200°F are also considered.

Drain Inlet and Outlet Nozzle Velocities of Heaters

The drain inlet and outlet nozzle velocities of heaters at SPU conditions should not appreciably increase the potential for wear and FAC.

Inlet and Outlet Drain Flows – Effects on FWHs Internals

The SPU drain inlet and drain outlet flow rates of the FWHs cannot cause destructive tube vibration or the erosion of internal subcomponents and support structures so that their function is impaired.

9.3.5 Design Criteria

The heater drain system is not required for safe shutdown of the reactor, has no safety-related function, and is designed as non-nuclear safety system.

9.3.6 Results and Conclusions

The heater, moisture separator, reheater, and pre-separator drain system are capable of accomplishing their design functions during SPU as discussed in the following paragraphs.

FWHs, Moisture Separators, Reheaters, and Heater Drain Tank LCVs

All normally operating, bypass, and emergency drain line LCVs are capable of transporting the required flows at SPU conditions with the open position below 75 percent.

FWHs, Moisture Separators, and Reheaters Gravity Drain Lines

The gravity-flow lines that satisfy the Froude number criterion for self-venting flow at current conditions will also do so at SPU conditions. The other gravity-flow lines are non-self-venting, but they are not observed to cause problems at current conditions. Based on comparison of flow velocity, they are not expected to exhibit any problem at SPU conditions.

MOPS/SCRUPS Drain Lines

The MOPs/SCRUPs drain system was modified with enough adaptability to accommodate the higher flows resulting from expected 6-percent SPU. The drain and vent throttle valves can be adjusted to accommodate 8.4 percent increased flow at SPU. In addition, there are provisions for condensate fill to sub-cool the drains and manual venting at the high point of the loop seal. The MOPs/SCRUPs drain system is operating in a satisfactory manner at the current conditions and expected to do so at SPU conditions.

Flow Regimes of Fluid Flow in the Piping Downstream of Reheater Drain Tanks LCVs

The flow downstream of the reheater drain control valves is an annular two-phase regime except for a small pipe length that approaches slug flow regime, at SPU conditions. Based on current operating conditions and the decease in flow in these lines of nominally 5 percent under SPU conditions no problems are expected in this section of piping. These lines will be considered under vibration monitoring during SPU power ascension.

Scavenging Steam Vent Chamber Discharge Lines

The mass flow in the scavenging steam vent chamber discharge line at SPU conditions is 9.45-percent lower than current condition. This discharge line is adequately sized for SPU conditions.

Heater Shell-Side Normal Operating Vent System

The evaluation concluded that the existing piping design of the operating vent system from all heaters to condenser is capable of removing the expected non-condensable gases per standard industry guidelines at SPU conditions.

Heater Shell-Side and Heater Drain Tank Relief Valves for Overpressure Protection

Heater shells must not be overpressurized in the event of tube or tubesheet failure because:

- The set pressures of relief valves are equal to or less than the design pressures of associated FWHs.
- The HEI standard industry guideline of maximum flow capacity for relief valves for heaters 33, 34, 35, and 36 is bounded by design flow capacity of the relief valves.

The total incoming flow to heater drain tank (that is, moisture separators drain, MOPs/SCRUPs drain, and heaters 35 and 36 drains) is less than the total relieving flow capacity of heater drain tank relief valves. The set pressures of relief valves are equal to the design pressures of the heater drain tank. Hence, the heater drain tank must not be overpressurized in the extreme event of complete loss of both heater drain pumps and the heater tank emergency drain system to condenser.

Piping, Valves, and Component Design Pressures and Temperatures

The maximum sustained operating pressures and temperatures of the FWHs and moisture separators, reheaters, and separating tanks drain and vent piping systems at SPU conditions are enveloped by the currently operating piping design pressures and temperatures.

The maximum sustained operating pressures and temperatures of heater shells at SPU conditions are enveloped by heater shell design pressures and temperatures except for heaters 36A/B/C. The maximum normal sustained temperatures of heaters 36A/B/C shells exceed the heater design temperature by 29°F. The materials of shells, elliptical heads and channels of the heaters 36A/B/C are carbon steel SA 516 Grade 70. The nozzles are carbon steel SA 105 and SA 516 Grade 70. The shell design can accept the higher SPU temperatures since the maximum allowable stress value of materials does not change in the temperature range of –20° to 650°F.

The maximum sustained operating pressures and temperatures of heater, moisture separator, reheater drain tanks at SPU conditions are enveloped by the tank design pressures and temperatures

FAC of Drain and Vent Lines

All of the piping experiences velocities below the industry standard pipe velocity limit. All of the carbon steel piping with temperatures exceeding 200°F and flashing service are presently in the FAC Program except heaters 32A/B/C operating vent lines. The operating vent lines for heaters 32A/B/C will be added in FAC Program.

Heater Drain Inlet and Outlet Nozzle Velocities of FWHs

The drain inlet and outlet velocities of the FWHs at SPU conditions are below the HEI standard industry guidelines and FAC program screening criteria except for the drain outlet nozzles of heaters 33A/BC, 34A/B/C, 35A/B/C and 36A/B/C and drain inlet nozzles of heaters 32A/B/C and 33A/B/C.

In consideration of this condition, Entergy currently carries all these nozzles in the FAC Program.

Inlet and Outlet Drain Flows – Effects on FWHs Heaters Internals

The SPU drain inlet flow rates are above the existing design values for FWH 36A/B/C. For FWH 33A/B/C, FWH 32A/B/C, and FWH 31A/B/C, the SPU drain inlet flow rates are below the existing design values. The SPU drain outlet flow rates are above the existing design values for FWH 36A/B/C, FWH 34A/B/C, FWH 32A/B/C, and FWH 31A/B/C. For FWH 35A/B/C and FWH 33A/B/C, the SPU drain outlet flow rates are below existing design values. FWH 36A/B/C, FWH 34A/B/C, FWH 32A/B/C, and FWH 31A/B/C will be monitored to determine whether destructive tube vibration or the significant erosion of internal parts will occur at the higher SPU flow rates.

9.4 Condensate and Feedwater System

9.4.1 Introduction

The Condensate and Feedwater System (C&FS) was evaluated in conjunction with stretch power uprate (SPU) conditions to determine the extent to which system design parameters bound SPU conditions.

The Condensate System was designed to transport condensate and low-pressure (LP) heater drains from the condenser hotwell through the Condensate Polishing System (CPS) and five stages of feedwater heating to the suctions of the main feedwater pumps (MFPs). The CPS is installed within the condensate system between the condensate pumps and the first stage of feedwater heaters (FWHs). Normally, five deep-bed polisher vessels and five condensate post-filter vessels are in service, and one polisher vessel and one condensate post-filter vessel are on standby. Three one-third capacity condensate pumps are provided. Three one-half capacity condensate booster pumps are provided to recover the pressure drop induced by the CPS.

Two half-size heater drain pumps are designed to transport the high-pressure (HP) heater drains from the heater drain tank into the condensate header upstream of the MFPs.

The Feedwater System increases the pressure of the condensate/heater drains for delivery to the steam generators. The Feedwater System also provides the final stage of feedwater heating and controls the feedwater flow via the regulating valves and feedwater pump turbine speed control system. This system has two half-size steam turbine-driven MFPs.

9.4.2 Input Parameters and Assumptions

SPU heat balances were developed to define the thermal plant performance at the current operating conditions and at SPU conditions. A current operating (benchmark) heat balance, tuned to the current plant operating characteristics and SPU heat balances at 1.0-, 1.5-, and 3.0-inch HgA condenser pressures, was used to evaluate the system. For evaluation purposes, these heat balances included a margin of approximately 0.5 percent. Each of these heat balances and the corresponding parameters were reviewed and the most conservative case was chosen for the specific evaluation of C&FS.

Plant design basis documents, system descriptions, equipment and piping specifications, calculations, and drawings provided system and component design parameters.

9.4.3 Description of Analysis and Evaluation

Operation at SPU conditions affects a variety of system parameters, such as flow rates and velocities, temperatures and pressures, and the thermal performance of the FWHs. The C&FS was evaluated to confirm its ability to operate successfully at the SPU conditions. The following subsections describe the specific evaluations.

Hydraulic Analysis of Condensate, Feedwater, and Heater Drain Pump Systems

The hydraulic model of the C&FS operation under SPU conditions (including associated portions of the heater drain pumps suction and discharge system) was developed, and included the following scenario cases:

Case 1: Flow analysis for three condensate pumps, two main feedwater pumps. two heater drain pumps, and two condensate booster pumps (CBPs) and CPS in operation at 100-percent power level for the SPU.

Case 2: Flow analysis for three condensate pumps, two main feedwater pumps, and two heater drain pumps in operation at 100-percent power level for the SPU. CPS and CBPs are not in operation.

Case 3: Flow analysis for three condensate pumps, three CBPs, one heater drain pump, and two main feedwater pumps in operation and loss of one heater drain pump resulting from 50-percent load reduction. The pumps must provide 96 percent of full-power feedwater flow for the SPU to steam generators with steam generators' pressure increased by 100 psi above full-power steam generator pressure for the SPU during a 50-percent load reduction. The condensate polisher and post- filter vessels are bypassed but the three CBPs are operational.

Component and Piping Design Pressures and Temperatures

The maximum sustained SPU system operating pressures and temperatures were compared with the piping design/rated pressures and temperatures of piping, valves, flanges, FWH tubes, and pump casings to verify that the design bounds SPU sustained operating conditions.

Velocity and Flow-Accelerated Corrosion of Condensate, Feedwater, and Heater Drain Pump Piping

The piping velocities were calculated at SPU conditions and compared to standard industry velocity criteria as a measure of whether there was a greater potential for flow-accelerated corrosion (FAC). The potential contributing factors to FAC, such as flow path geometry, material composition, flow velocities, fluid temperatures, and service conditions etc., were evaluated to determine if a particular pipe needed to be added to the current FAC Program.

FWHs - Nozzle Velocities, Tube Velocities, and Past Inspection Results

The feedwater inlet and outlet nozzle velocities at SPU conditions were compared to Heat Exchanger Institute (HEI) standard industry guidelines to determine the potential for increased wear and FAC. The FWH tube velocities at SPU conditions were compared with HEI-recommended velocities for FWH tubes.

The FWHs inspection results were evaluated to determine whether the actual operating condition of these components, including any existing degradation in performance or component materials, affected their ability to perform under SPU conditions.

Condensate Booster, Condensate, and Heater Drain Pumps Brake Horsepower

The CBPs, condensate, and heater drain pumps' brake horsepower (bhp) at SPU conditions were compared with CBP, condensate, and heater drain pump motors' rated horsepower for acceptability of operation under SPU conditions.

Condenser Operation with Main Steam Dump Resulting from 50-Percent Turbine Load Reduction

The probability of excessive condenser tube vibration and a condenser pressure increase (that is, loss of vacuum) during a main steam dump following a 50-percent turbine load reduction at SPU conditions was evaluated to ensure that the condenser HP alarm and turbine trip setpoint were not exceeded.

Condenser Hotwell Volume

The volume of the condenser hotwell was evaluated to confirm that there would be sufficient volume to accept the condensate flow at SPU full load with free volume for condensate surge protection and to accommodate system surges during load rejection.

NRC Generic Letter 89-10 MOV Program – Motor-Operated Valve Program Review

The feedwater motor-operated valves (MOVs) BFD-MOV- 2-31, BFD-MOV-2-32, BFD-MOV-5-1, BFD-MOV-5-2, BFD-MOV-5-3, BFD-MOV-5-4, BFD-MOV-90-1, BFD-MOV-90-2, BFD-MOV-90-3, and BFD-MOV-90-4 are included in the Generic Letter (GL) 89-10 MOV Program. The differential pressure calculations were reviewed to evaluate the effects of SPU on the operating parameters for these valves (for example, maximum design basis opening/closing differential pressures/line pressures).

9.4.4 Acceptance Criteria

The C&FS is considered acceptable under SPU conditions provided the criteria in the following paragraphs are met.

Hydraulic Analysis of Condensate, Feedwater, and Heater Drain Pump Systems

The main feedwater pumps, operating in conjunction with condensate pumps, heater drain pumps, and with/without CBPs must be capable of providing the required heat balance flow rate and pressure to steam generators at 100-percent SPU power level and transient conditions.

The CBPs, condensate, main feedwater, and heater drain pumps must have sufficient net positive suction head available (NPSHA) with sufficient margin over net positive suction head required (NPSHR) at all modes of system operation.

Component and Piping Design Pressures and Temperatures

Maximum sustained system operating pressures and temperatures at SPU conditions will be bounded by the piping design and the component rated (or design) pressure and temperature.

Velocity and FAC of Condensate, Feedwater, and Heater Drain Pump Piping

The piping velocities and other potential FAC influences, such as operating temperature >200°F, at SPU conditions in the condensate, feedwater, and heater drain pump systems will not cause the potential for increased FAC.

Feedwater Heaters - Nozzle Velocities, Tube Velocities, and Past Inspection Results

The feedwater inlet and outlet nozzle velocities shall not significantly increase the wear and FAC of the nozzles.

Condensate Booster, Condensate, and Heater Drain Pumps bhp

The CBPs, condensate, and heater drain pumps' bhp at SPU conditions should be bounded by CBP, condensate, and heater drain pump motor-rated horsepower.

Condenser Operation with Main Steam Dump Resulting from 50-Percent Turbine Load Reduction

The condenser HP alarm and turbine trip set point should not be exceeded with main steam dump resulting from a 50-percent turbine load reduction.

The tube support spacing recommended by HEI for prevention of tube vibration at SPU conditions should exceed the existing tube support spacing.

Condenser Hotwell Volume

The condenser hotwell must contain sufficient volume to accept full-condensate flow at SPU conditions for 4 minutes with free volume for condensate surge protection and to accommodate system surges during load rejection.

NRC Generic Letter 89-10 MOV Program – MOV Program Review

The impact of SPU conditions on the maximum design basis opening and closing differential pressures/ line pressures in the MOV differential pressure calculations are evaluated in the station MOV program.

9.4.5 Design Criteria

The C&FS was designed to transport condensed steam and low-pressure (LP) heater drains from the condenser hotwell through condensate polishing system and six stages of feedwater heating for the improved cycle efficiency to the steam generator at the heat balance required pressure and temperature.

The portion of the FCS is nuclear safety-related and required for safe shutdown of the reactor. The remaining portion is not required for safe shutdown of the reactor, has no safety-related function, and is designed as non-nuclear safety system.

The C&FS was designed to meet the intent of the General Design Criteria (GDC), which were published by the Atomic Energy Commission (AEC) in the Federal Register of July 11, 1967. The NRC concluded in the *Safety Evaluation Report* (SER), that the plant design conformed to the intent of the newer criteria. SPU operation does not affect the ability of the C&FS to meet these requirements. Therefore, the C&FS continues to meet the criterion requirements.

In addition to AEC Criterion 2 (*Performance Standards*), New York Power Authority (NYPA) committed to the requirements of Sections III.G, III.J, III.L, and III.O of 10CFR50, Appendix R (Reference 1). Evaluation of IP3 fire protection features against the requirements of Section III.G of Appendix R to 10CFR50 was completed and the report submitted to NRC on August 16, 1984. SPU operation does not affect the ability of the C&FS to meet these requirements. Therefore, the C&FS continues to meet the criterion requirements.

Environmental qualification (EQ) of C&FS electrical equipment important to safety is demonstrated in EQ packages compiled in accordance with the requirements of 10CFR50.49 (Reference 2) and Division of Operating Reactors (DOR) Guidelines (see LAR Section 11, and ER Section 10). Monitoring of the C&FS is provided as a result of the Three Mile Island 2 (TMI-2) accident investigation and the requirements of Regulatory Guide (RG) 1.97 (Reference 3). The C&FS is designed with provisions to allow post-accident sampling in accordance with the post-TMI requirements of NUREGs 0578 and 0737 (References 4 and 5). The Technical Specification requirements for sampling provisions were deleted by Amendment 210, dated February 6, 2002. SPU operation does not affect the ability of the C&FS to meet these requirements. Therefore, the C&FS continues to meet the criterion requirements.

Criterion as it relates to the accident analyses and NSSS/BOP interface can be found in Sections 4 and 5 of this document.

Other criteria required to meet SPU conditions are listed in subsection 9.4.4, of this section.

9.4.6 Results and Conclusions

Specific results of each evaluation are discussed in the following paragraphs.

Hydraulic Analysis of Condensate, Feedwater, and Associated Heater Drain Pump System

The feedwater/condensate/associated heater drain pump system is capable of providing the required heat balance flow rate and pressure to steam generators at 100-percent SPU power level and transient conditions with sufficient margin in control valve open position and feedwater pump turbine speed.

The analysis also confirmed that the CBPs, condensate, feedwater, and heater drain pumps will have sufficient NPSHA with margin over NPSHR in all modes of system operation.

The analysis also confirmed that the feedwater pump suction header pressures are higher than the pump speed runback set pressures with sufficient margin.

Component and Piping Design Pressures and Temperatures

The maximum sustained operating pressures and temperatures for piping at SPU conditions are enveloped by the existing piping design pressures and temperatures, except for the maximum normal sustained operating temperatures for the condensate pump suction piping and DCT outlet piping to condenser (112°F @ 3.0 inch HgA condenser pressure) exceeds design temperature (10°F) by 12°F. The maximum sustained operating temperature for these piping will be 89°F @ 1.5 inch HgA condenser pressure and 77°F @ 1.0 inch HgA condenser pressure respectively. The IP3 operating test data indicates that condensate pressure varies from 1.0 inch HgA to 2.50 inch HgA at current conditions. The maximum sustained operating temperature for these piping will be 104°F @ 2.50 inch HgA condenser pressure. The C&FS has been evaluated based on 3.00 inch HgA condenser pressure heat balance for conservatism and additional margin. The materials of this piping are A155, grade C55, Class 2 for pipe 30-inch-to-54-inch, A53, grade B for 3-inch-to-24-inch and A106, grade B for 2-1/2 inch and smaller. The pipe walls of condensate pumps suction piping from condenser and DCT outlet piping to condenser are acceptable at SPU since the stress value of carbon steel piping material remains unchanged in the temperature range of -20° to 650°F and the existing pipe walls/schedules will remain unchanged based on maximum normal sustained SPU temperature (112°F) and design pressure (30 psig). Also, the rated temperature of the valves and flanges in this piping (that is, –20 to 150°F) bounds the maximum normal sustained temperature (that is, 112°F).

The maximum sustained operating pressures and temperatures at SPU conditions are enveloped by the rated/design pressures and temperatures of valves, flanges, FWH tubes, and pump casings.

Velocity and FAC of Condensate, Feedwater, and Heater Drain Pump Piping

The majority of the piping experiences velocities below the standard industry pipe velocity guideline. The temperature criterion for FAC susceptibility is greater than 200°F. All the piping from feedwater heaters 31A/B/C outlet to steam generators with temperatures exceeding 165°F are presently in the FAC Program. The limited number of pipes with velocities above the applicable guideline are considered susceptible to FAC and are presently in the FAC Program.

The velocity of 54-inch and 30-inch pipes from the common suction header to each condensate pump's suction nozzle exceeds the velocity guideline by a relatively small amount (3.08 ft/sec calculated for 54-inch pipe and 3.31ft/sec for 30-inch pipe versus 3.0 ft/sec guideline). Although, the velocity is exceeded slightly, the condensate pumps have sufficient NPSHA with ample margin over NPSHR (NPSHA = 29 ft versus NPSHR = 14 ft). Hence, the system capability is not impaired. The maximum operating temperatures are in the range of 77°-112°F. Therefore, these pipes are not an FAC concern.

The velocity of 30-inch common suction line (15.96 ft/sec) and the two 24-inch suction pipes (12.94 ft/sec), one to each feedwater pump, exceeds the velocity guideline of 10 ft/sec. Although the velocity guideline is exceeded, the feedwater pumps have sufficient NPSHA with ample margin over NPSHR (NPSHA = 390 ft versus NPSHR = 135 ft). Hence, the system capability is not impaired. These pipes are already part of the FAC Program and will continue to be monitored after SPU implementation.

The velocity of two 18-inch heater drain pump suction lines, one to each pump from the heater drain tank, exceed the velocity guideline (6.16 ft/sec actual velocity versus 4 ft/sec guideline for a saturated drain line). Although the velocity guideline is exceeded, the heater drain pumps have sufficient NPSHA with ample margin over NPSHR (NPSHA = 80 ft versus NPSHR = 28 ft). Hence, the system capability is not impaired. These pipes are already part of the FAC Program and will continue to be monitored after SPU implementation.

The velocity of two 20-inch discharge pipes, one from each feedwater pump discharge to common discharge header exceeds the velocity guideline slightly (20.61 ft/sec versus 20.0 ft/sec guideline). These pipes are already part of the FAC Program and will continue to be monitored after SPU implementation.

The two 4-inch/ 6-inch feedwater pump recirculation lines, one from each pump to the drain collecting tank, significantly exceed the velocity guideline of 20 ft/sec (111 ft/sec in the 6-inch portion and 267 ft/sec in the 4-inch portion). These pipes are in service only during plant startup or shutdown and are normally secured at power levels greater than 50 percent. These pipes are already part of the FAC Program and will continue to be monitored after SPU implementation.

FWHs - Nozzle Velocities and Tube Velocities

The FWH tube velocities at SPU conditions meet the HEI standard guidelines.

Feedwater inlet and outlet nozzle velocities of FWHs 36A/B/C, 35A/B/C, 34A/B/C, 33A/B/C, 32A/B/C, and 31A/B/C exceed HEI standard guidelines as follows:

- Heater 36A/B/C: 14.73 ft/sec versus 10 ft/sec @ 60°F HEI guidelines
- Heater 35A/B/C: 15.94 ft/sec versus 10 ft/sec @ 60°F HEI guidelines
- Heater 34A/B/C: 16.26 ft/sec versus 10 ft/sec @ 60°F HEI guidelines
- Heater 33A/B/C: 16.25 ft/sec versus 10 ft/sec @ 60°F HEI guidelines
- Heater 32A/B/C: 16.25 ft/sec versus 10 ft/sec @ 60°F HEI guidelines
- Heater 31A/B/C: 16.25 ft/sec versus 10 ft/sec @ 60°F HEI guidelines

The current FAC Program includes the outlet nozzles of FWHs 31A/B/C and inlet and outlet nozzles of feedwater heaters 32A/B/C, 33A/B/C, 34A/B/C, 35A/B/C, and 36A/B/C. Although, the velocities in FWHs 31A/B/C condensate inlet nozzles exceed HEI guidelines, the nozzles are part of a single-phase line, which is below the temperature guideline of FAC susceptibility of 200°F. Based on EPRI guidelines and IP3 FAC Program procedure, these nozzles are excluded from the FAC Program. Based on the above information, all heater nozzles are acceptable for SPU conditions.

Condensate Booster, Condensate, and Heater Drain Pumps BHP

The CBPs', condensate, and heater drain pumps' bhp at SPU conditions are enveloped by CBPs, condensate, and heater drain pump motor-rated horsepower.

Condenser Operation with Main Steam Dump Resulting from 50-Percent Turbine Load Reduction

The condenser vacuum will reduce to approximately 25.4-inch Hg vacuum at maximum 95°F circulating water temperature. This is slightly below the condenser low vacuum alarm set point of 26-inch Hg but above the turbine trip set point of 18-inch Hg vacuum. Therefore, the alarm might be actuated at infrequent circulating water temperature of 95°F, but the turbine will not trip in the event of main steam dump resulting from 50-percent turbine load reduction.

The existing condenser tube support spacing is more robust than the HEI requirement and, therefore more structurally adequate to preclude damaging flow-induced vibration.

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The design inputs in the calculations such as condensate pump shutoff head, maximum MFP discharge pressure/minimum MFP suction pressure/minimum MFP speed of MFP speed control system, steam generator pressure at which AFW pump starts, MFP coast down head, condenser high water level set point etc., for maximum design basis opening and closing differential pressures and line pressures of MOVs are not affected by the SPU conditions.

Condenser Hotwell Volume

The condenser hotwell volume of 114,000 gallons provides for more than 5 minutes of storage at SPU that exceeds the 4 minutes requirement to accept full-condensate flow at SPU conditions. Hence, the condenser hotwell will contain free volume for condensate surge protection and to accommodate system surges during load rejection.

Condensate Polishing System

The CPS operates during plant startup and infrequently during normal power operation to maintain the required purity of the condensate for the steam generators. The system is designed for a continuous operation at maximum flow of 24,000 gpm with inlet maximum pressure of 700 psig and temperature of 140°F. The 140°F temperature is based on precluding thermal degradation of the resin. The maximum allowable flow/pressure/temperature of CPS design envelopes the SPU flow/pressure/temperature of 20,328 gpm, 496 psig and 112°F through CPS.

9.4.7 References

1. 10CFR50, Appendix R, *Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1979,* June 20, 2000.

2. 10CFR50.46, *Acceptance Criteria for Emergency Core Cooling Systems for Light Water Cooled Nuclear Power Reactors,* September 16, 2003.

3. NRC Regulatory Guide 1.97, *Instrumentation of Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident* (Errata published July 1981) (Draft RS 917-4, Proposed Revision 2, published December 1979) (Rev. 3, ML003740282).

4. NUREG-0578, *TMI Lessons Learned Task Force Status Report and Short Term Recommendations,* July 1979.

5. NUREG-0737, *Clarification of TMI Action Plan Requirements,* November 1980.

9.5 Steam Generator Blowdown System

9.5.1 Introduction

The Steam Generator Blowdown System (SGBS) is designed to extract blowdown water from the secondary side of the steam generators as a means of removing particulates and dissolved solids to control water chemistry in the steam generators. By maintaining the proper water chemistry, steam generator tube corrosion is reduced, thereby minimizing the likelihood and magnitude of tube leaks. Steam generator blowdown is collected from the steam generator and is normally directed to the blowdown recovery system. Blowdown flow may also be directed to the blowdown flash tank. The blowdown flash tank is used to process large volumes of blowdown from a single steam generator and is vented to the atmosphere and drains to the Service Water System (SWS). The blowdown recovery system consists of four manual control valves (one for each of the blowdown recovery lines from the steam generators), three heat exchangers, and a set of pre-filters, demineralizers, and post-filters with a bypass and pressure control and bypass valve station. The blowdown recovery system transfers SGBS heat to the condensate system and returns the blowdown recovery inventory to the drains collection tank in the condensate system.

The SGBS also provides samples of the secondary side water in the steam generator. These samples are used for monitoring water chemistry and for detecting the amount of radioactive primary coolant leakage through the steam generator tubes. In the event of a high-radiation signal, both isolation valves in the blowdown lines close automatically. The valves also shut on a Phase A containment isolation signal, an automatic start signal for the motor-driven auxiliary feedwater pumps (MDAFWPs), and also fail shut on loss-of-air or electrical power.

The portion of the SGBS from the steam generator connections inside containment, up to and including the containment isolation valves outside containment, are considered a part of the containment boundary and are safety-related.

9.5.2 Input Parameters and Assumptions

The SGBS was designed to accommodate blowdown flows of up to 4 percent of the total feedwater flow rate. This corresponds to a total blowdown flow rate of 960 gpm from all four steam generators. During plant operation, total blowdown flow rates are maintained between 0.2 percent and 1.0 percent of the total feedwater flow.

The SGBS is currently operating with a blowdown flow of 37.5 gpm per steam generator for a total of 150 gpm.

The design of the steam generator permits:

- Continuous normal flow at 230 gpm per steam generator from each of the two steam generator nozzles.
- Flow at 335 gpm per steam generator from each of the two steam generator nozzles for short periods of operation, not to exceed 1 year cumulative over the life of the steam generator.

The blowdown recovery system is designed to process up to 300 gpm but is limited administratively to 265 gpm.

The SGBS piping is designed for 1085 psig and 600°F.

9.5.3 Description of Analysis and Evaluation

The SGBS was evaluated to verify that the required blowdown flow could be processed during stretch power uprate (SPU) conditions. The system design pressure, design temperature, pipe sizing, and flow velocities were reviewed against the SPU operating conditions.

Since the variables that affect blowdown flowrates are not affected by SPU (refer to Section 4.2 of this report), the blowdown flow rate is not affected by the SPU.

Westinghouse indicated that the minimum full-load steam generator steam pressure decreases approximately 26 percent from 762 psia to 567 psia for the SPU. This decrease in blowdown system inlet pressure may affect the required maximum Cv of the blowdown flow control valves. The blowdown control valves (HCV-1, 2, 3, and 4) were reviewed to confirm adequate control capability.

The piping velocities, operating temperatures, piping material, and service time during SPU operation were evaluated for the potential to accelerate pipe corrosion and the need to include these lines in the plant Flow-Accelerated Corrosion (FAC) Program.

9.5.4 Acceptance Criteria for Analysis

The SGBS is considered acceptable under SPU conditions by satisfying the following:

- The piping system can pass the evaluated blowdown flow rate at SPU conditions.

- The SPU maximum pressure and temperature conditions are bound by the piping and valve design pressures and temperatures.

- The flow velocities and/or operating temperatures above 200°F due to SPU conditions will not increase the potential for FAC in the SGBS lines fabricated from carbon steel.

9.5.5 Design Criteria

The SGBS is designed to extract blowdown water from the secondary side of the steam generators as a means of removing particulates and dissolved solids to control water chemistry in the steam generators. The SGBS also provides samples of the secondary side water in the steam generator that are used for monitoring water chemistry and detecting the amount of radioactive primary coolant leakage through the steam generator tubes.

Portions of the SGBS are safety-related. The SGBS was designed to meet the intent of the General Design Criteria (GDC), which were published by the Atomic Energy Commission (AEC) in the Federal Register of July 11, 1967. The NRC concluded in the *Safety Evaluation Report* (SER) that the plant design conformed to the intent of the newer criteria. SPU operation does not affect the ability of the SGBS to meet these requirements, therefore, the SGBS continues to meet the criteria requirements.

In addition to AEC Criterion 2 (*Performance Standards*), New York Power Authority (NYPA) committed to the requirements of Sections III.G, III.J, III.L, and III.O of 10CFR50 Appendix R (Reference 1). Evaluation of IP3 fire protection features against the requirements of Section III.G of Appendix R to 10CFR50 was completed and the report submitted to the NRC on August 16, 1984. SPU operation does not affect the ability of the SGBS to meet these requirements, therefore, the SGBS continues to meet the criterion requirements.

In addition to AEC Criterion 17 (*Monitoring Radioactive Releases*) and 70 (*Control of Radioactive Releases to the Environment*), provisions are included in the SGBS design to meet 10CFR20 (Reference 2) limits. The radioactive releases at SPU conditions are within the original design basis of the plant. Therefore, the SGBS will continue to meet the criteria requirements.

Environmental qualification of SGBS electrical equipment important to safety is demonstrated in Environmental Qualification packages compiled in accordance with the requirements of 10CFR50.49 (Reference 3) and Division of Operating Reactors (DOR) Guidelines (see Licensing of Amendment Request [LAR] Section 11, and Engineering Report [ER] Section 10). Monitoring of the SGBS is provided as a result of the Three Mile Island 2 (TMI-2) accident investigation and the requirements of NRC Regulatory Guide (RG) 1.97 (Reference 4).

The SGBS is designed with provisions to allow post-accident sampling in accordance with the post-TMI requirements of NUREG-0578 (Reference 5) and NUREG-0737 (Reference 6). The requirements for sampling provisions were deleted by Amendment 210, dated February 6, 2002. SPU operation does not affect the ability of the SGBS to meet these requirements. Therefore, the SGBS continues to meet the criterion requirements.

Design criteria related to the accident analyses and Nuclear Steam System Supply (NSSS)/ balance-of-plant (BOP) interface can be found in Sections 4 and 5 of this document. Design criteria required to meet SPU conditions are listed in the acceptance criteria above.

9.5.6 Results

The plant is currently operating with a blowdown flow of 37.5 gpm from each steam generator for a total flow of 150 gpm. The blowdown flow is not affected by SPU (refer to Section 4.2).

For SPU operation, the manual throttle valve on the blowdown recovery line from each steam generator (HCV-1, 2 ,3, and 4) may require repositioning. The throttle valves were evaluated for control capability due to the decrease in minimum full load steam generator pressures for SPU. Each valve has a maximum capacity in excess of power uprate blowdown flow rate (e.g. 240 gpm for each valve) at pressure drops of 100 psid. Backpressure regulator valve PCV-2 is designed to maintain the pressure drop across the HCVs to less than 100 psid. Consequently, these valves will retain adequate control capability at power uprate operation.

The blowdown system continues to be capable of continuous operation for the design life of the steam generator at a flow rate equal to 230 gpm. In addition, a maximum blowdown flow rate equal to 335 gpm is allowed for the equivalent of 1 year operation. These blowdown rates are per steam generator blowdown nozzle.

In regard to FAC, although the normal operating velocities are slow and the maximum velocities only occur for short durations, the portions of the SGBS fabricated from carbon steel (2-inch blowdown lines associated with steam generators 32 and 33) are monitored as part of the IP3 FAC Program, since the temperature is approximately 515°F and the lines can experience flashing flow due to the saturated conditions in the steam generators. The portions of the SGBS fabricated from stainless steel are excluded from the FAC Program.

The steam generator steam outlet temperature and pressure decreases from the original design values of 514.5°F/774.4 psia to 511.6°F/754.8 psia at SPU conditions. This slight decrease (-2.9°F and -19.6 psia) does not affect the main steam safety valve (MSSV) setpoints nor the design pressure (1085 psig) and temperature (600°F) of the steam generators. Therefore, the SGBS design pressure and temperature is not affected.

9.5.7 Conclusions

The design and operation of the IP3 SGBS is not affected by changes in SPU parameters and therefore the SGBS is acceptable for the SPU conditions. Aside from the possible need to reposition the throttle valves controlling blowdown flow rate, no changes are required for SPU operation.

Due to the operating temperature and saturated, potentially flashing process conditions, the blowdown lines fabricated from carbon steel will remain in the existing FAC Program.

9.5.8 References

1. 10CFR50, Appendix R, *Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1979,* June 20, 2000.

2. 10CFR20, *Standards for Protection Against Radiation,* May 21, 1991.

3. 10CFR50.49, *Environmental Qualification of Electric Equipment Important To Safety for Nuclear Power Plants*, 66FR64738, December 14, 2001.

4. NRC Regulatory Guide 1.97, *Instrumentation of Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident* (Errata published July 1981) (Draft RS 917-4, Proposed Revision 2, published December 1979) (Rev. 3, ML003740282).

5. NUREG-0578, *TMI Lessons Learned Task Force Status Report and Short Term Recommendations*, July 1979.

6. NUREG-0737, *Clarification of TMI Action Plan Requirements*, November 1980.

9.6 Essential and Non-Essential Service Water System

9.6.1 Introduction

The Indian Point 3 (IP3) Essential and Non-Essential Service Water System (SWS) is a safety-related system that provides cooling water from the Hudson River to essential components (loads that require cooling water immediately after a loss of power or an accident) and non-essential components (loads that do not require cooling water immediately after a loss of power or an accident) on both the nuclear and conventional sides of the plant. The cooling water removes waste heat from the equipment for all plant operating modes and rejects the waste heat to the Hudson River through a discharge canal. One set of three pumps provides water to the essential header, and the other set of three pumps supplies the non-essential header. Three SW backup pumps are provided that take suction from the Unit 2 discharge canal and discharge into the essential header. The backup pumps were originally provided to provide for a loss of intake structure. SW backup pump 38 was later designated for Appendix R supply to the Component Cooling Water Heat Exchangers in the event of a fire.

Essential SWS loads include:

- Containment recirculation fan cooling coils
- Containment recirculation fan motor cooling coils
- Instrument air cooling water heat exchangers (HXs)
- Diesel generator lube oil coolers and jacket water coolers (Note 1)
- Control room AC units (Note 1)
- Cooling for radiation monitors
- Feedwater pump coolers
- Turbine oil coolers

Non-essential SWS loads include:

- Component cooling water HXs
- Hydrogen coolers
- Exciter coolers
- Iso-phase bus (IPB) HXs
- Steam generator blowdown coolers
- Turbine building closed cooling water HXs
- Circulating water pump shaft seal and bearing cooling

(Note 1: This equipment can be manually fed from the non-essential header)

9.6.2 Input Parameters and Assumptions

The latest system hydraulic analysis provided the basis for the system alignments, valve/equipment controls and operation evaluated. Inputs for cooling flow rates and heat load requirements were provided by Westinghouse or developed based on the latest plant design specifications, drawings, licensing documents, design basis documents, test data and inspection reports and the results of the IP2 SWS SPU evaluation and confirmed with equipment suppliers.

9.6.3 Description of Analysis and Evaluations

The stretch power uprate (SPU) will increase the heat rejection to the SWS.

The latest system hydraulic analysis was evaluated to determine the effects of SPU operation.

The following were evaluated at SPU conditions:

- Heat load removal capability
- Flow adequacy to system components and SWS pump capacity and head
- Effects of higher outlet temperatures versus the existing piping design
- System stress analysis and environmental conditions
- Design pressure and temperature of system piping and components

The results of the IP3 SWS hydraulic analysis including system arrangement, flow requirements, heat load data, etc., and system/equipment requirements for meeting SPU conditions were compared to the IP2 SWS evaluation completed for SPU. Similarities and differences were noted and an evaluation completed.

9.6.4 Acceptance Criteria

The Essential and Non-Essential SWS is considered acceptable under SPU conditions provided the following conditions are met:

- The SWS remains capable of providing the required flow rate for each of its design functions (safety and non-safety) under SPU operating conditions.

- SWS pump operation at SPU flow conditions is within the acceptable margins of pump design parameters (for example, net positive suction head [NPSH], flow and total discharge head [TDH]) for all applicable operating modes.

- The SWS remains capable of performing its heat removal functions (safety and non-safety) specified for each component for all applicable operating modes.

- The design pressure and temperature of the SWS piping and components bound the SPU pressure and temperature conditions. The existing SWS pipe stress bounds SPU conditions and outlet SWS conditions are bound by existing plant environmental conditions.

9.6.5 Design Criteria

The SWS is designed to provide cooling water from the Hudson River to essential components (loads that require cooling water immediately after a loss of power or an accident) and non-essential components (loads that do not require cooling water immediately after a loss of power or an accident) on both the nuclear and conventional sides of the plant to remove waste heat and reject the waste heat to the Hudson River through a discharge canal for all plant operating modes.

Portions of the SWS are safety-related. The SWS was designed to meet the intent of the General Design Criteria (GDC), which were published by the Atomic Energy Commission (AEC) in the Federal Register of July 11, 1967. The NRC concluded in the *Safety Evaluation Report* (SER) that the plant design conformed to the intent of the newer criteria. SPU operation does not affect the ability of the SWS to meet these requirements. Therefore, the SWS continues to meet the criteria requirements.

In addition to AEC Criterion 2 (*Performance Standards*), New York Power Authority (NYPA) committed to the requirements of Sections III.G, III.J, III.L, and III.O of 10CFR50 Appendix R (Reference 1). Evaluation of IP3 fire protection features against the requirements of Section III.G of Appendix R to 10CFR50 was completed and the report submitted to NRC on August 16, 1984. SPU operation does not affect the ability of the SWS to meet these requirements. Therefore, the SWS continues to meet the criterion requirements.

In addition to AEC Criterion 17 (*Monitoring Radioactive Releases*) and 70 (*Control of Radioactive Releases to the Environment*), provisions are included in the SWS design to meet 10CFR20 (Reference 2) limits. The radioactive releases at SPU conditions are within the original design basis of the plant. Therefore, the SWS will continue to meet the criteria requirements.

Environmental qualification of SWS electrical equipment important to safety is demonstrated in Environmental Qualification packages compiled in accordance with the requirements of 10CFR50.49 (Reference 3) and Division of Operating Reactors (DOR) Guidelines (see Licensing of Amendment Request (LAR) Section 11, and Engineering Report (ER) Section 10). Monitoring of the SWS is provided as a result of the Three Mile Island 2 (TMI-2) accident investigation and the requirements of NRC Regulatory Guide (RG) 1.97 (Reference 4). The SWS is designed with provisions to allow post-accident sampling in accordance with the post-TMI Requirements of NUREG-0578 (Reference 5) and NUREG-0737 (Reference 6). The Technical Specification requirements for sampling provisions were deleted by Amendment 210, dated February 6, 2002. SPU operation does not affect the ability of the SWS to meet these requirements. Therefore, the SWS continues to meet the criterion requirements.

Design criteria related to the accident analyses and Nuclear Steam System Supply (NSSS)/ balance-of-plant (BOP) interface can be found in Sections 4 and 5 of this document.

Design criteria required to meet SPU conditions are listed in the acceptance criteria above.

9.6.6 Results and Conclusions

The SPU will increase the heat rejection to the SWS. For the SPU evaluation, the existing SWS hydraulic analysis was used to evaluate the requirements of SPU operation and evaluate flow adequacy to system components and SWS pump capacity and head. The evaluation of the system included analysis of the heat load removal capability, effects of higher outlet temperatures, design pressure and temperature of system piping and components, and developed system stress analysis and environmental conditions. The IP3 hydraulic analysis assumed worst case conditions of low river-water level, design inlet temperature (95°F), and 18-percent degraded pump curves and atmospheric vents where applicable.

Adequate SWS and equipment performance (safety and non-safety) were verified under SPU conditions, including pump net pump suction head (NPSH) requirements, system flashing, strainer backwash capability, etc.

The evaluation verified that the SPU does not affect the flow requirements for any of the safety-related equipment cooled by the SWS. Some turbine plant equipment fed by the non-essential SWS header required increases in flow. Increased heat loads from the equipment were found to be bounded by the original equipment and system design. SWS instrumentation and controls were found to be adequate at SPU conditions.

The SWS remains capable of performing its heat removal functions (safety and non-safety) specified for each component for all applicable operating modes.

Outlet service water temperatures were confirmed to be within the system and equipment design specifications. The SWS piping and components' design pressure and temperature bound the SPU pressure and temperature conditions. The existing SWS pipe stress conditions bound SPU conditions and outlet SWS conditions are bounded by existing plant environmental conditions.

The Ultimate Heat Sink (UHS) for IP3 is the Hudson River. The Circulating Water System (CWS) (refer to Section 9.7 of this report) and Essential and Non-Essential SWS take cooling water from and discharge waste heat to the UHS. The analyses completed for these systems are based on the most conservative SPU heat balances that include a 0.5-percent margin.

The CWS is a non-safety-related, once-through system that uses six CWS pumps to supply water from the Hudson River, circulates it through the main condenser to condense the exhaust steam from the main turbine and other steam/water drains, and returns heated water back to the Hudson River.

Plant operation at the SPU conditions will increase the exhaust steam flow and duty of the main condenser and, therefore, increase the heat load rejected by the CWS to the Hudson River. The existing CWS pumps were not modified for SPU and continue to operate at the same flow rates. Since the CWS inlet temperatures from the Hudson River were not affected by the SPU, the CWS discharge temperature to the Hudson River will increase, but is still within the original discharge permit limits.

As described in Section 11 of this report, the environmental issues associated with the issuance of an operating license for IP3 were originally evaluated in the *IP3 Final Environmental Statement* (FES) (Reference 7) (Volume 1, page I-1 Section I) and addressed plant operation up to a maximum calculated reactor power of 3216 MWt. The AEC, predecessor of the NRC, approved the FES in February 1975. In addition to the FES, the Indian Point State Pollutant Discharge Elimination System (SPDES) restrictions on discharge temperatures and discharge flow rates for the station were evaluated along with the flow limits set forth in IP3 Consent Order. Historic river temperature data (taken from 1993 to the present) were used in the SPU analyses. Increased heat rejection to the CWS and SWS at SPU conditions is expected to result in a nominal calculated increase in discharge temperature to the river. This temperature increase falls within the applicable SPDES permit thermal limits for IP3.

9.6.7 References

1. 10CFR50, Appendix R, Fire *Protection Program for Nuclear Power Facilities Operating Prior to January 1979*, June 20, 2000.

2. 10CFR20, *Standards for Protection Against Radiation*, May 21, 1991.

3. 10CFR50.49, Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants, 66FR64738, December 14, 2001.

4. NRC Regulatory Guide 1.97, *Instrumentation of Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident* (Errata published July 1981) (Draft RS 917-4, Proposed Revision 2, published December 1979) (Rev. 3, ML003740282).

5. NUREG-0578, *TMI Lessons Learned Task Force Status Report and Short Term Recommendations*, July 1979.

6. NUREG-0737, *Clarification of TMI Action Plan Requirements*, November 1980.

7. *Indian Point Unit 3 Final Environmental Statement*, February 1975

9.7 Circulating Water System and Main Condenser

9.7.1 Introduction

The Indian Point 3 (IP3) Circulating Water System (CWS) is a non-safety-related system that provides cooling water for the main condenser of the turbine generator unit. The CWS is a once-through system that uses six CWS pumps to supply water from the Hudson River and circulate it through the main condenser to condense the exhaust steam from the main turbine and other steam/water drains, and returns heated water back to the Hudson River.

The main condenser is a conventional triple-shell, single-pass, divided waterbox, radial-flow surface condenser that condenses and deaerates exhaust steam from each of the three low-pressure (LP) turbines, two boiler feedwater pump turbine exhausts, the Steam Dump System, and other miscellaneous drains. Heat is removed by the CWS, where it is ultimately rejected to the Hudson River.

The Main Condenser Air Removal System is a non-safety-related system that removes non-condensable gasses from the main condenser to help maintain condenser vacuum. The Condenser Air Removal System consists of three hogging and three priming steam jet air ejectors (SJAEs). One hogging or one priming SJAE serves one condenser shell.

9.7.2 Input Parameters and Assumptions

Thermal cycle heat balances were developed to define the thermal plant performance at the current operating conditions and at SPU conditions. The CWS pumps ratings, main condenser data, and the assumptions made for the Main Condenser Air Removal System were used in the evaluation of the CWS and main condenser.

The SPU evaluation assumed the existing CWS pumps and air removal equipment were not modified and would continue to operate at the same flow rates.

9.7.3 Description of Analyses and Evaluations

Plant operation at the SPU conditions will increase the exhaust steam flow and duty of the main condenser and, therefore, increase the heat load rejected by the CWS to the Hudson River. The existing CWS pumps were not modified for the SPU and continue to operate at the same flow rates. Since the CWS inlet temperatures from the Hudson River were not affected by the SPU, the CWS discharge temperature to the Hudson River increased. The SPU resulted in a higher flow of turbine exhaust steam to the condenser, which, in turn, increased the amount of air and non-condensables needed to be removed from the condenser during plant operation. The air removal system was evaluated to verify that it is within original equipment capability.

The increases were evaluated considering the State Pollutant Discharge Elimination System (SPDES) Permit restrictions on discharge temperatures, discharge flow rates, and consent order flows.

The maximum pressure rise in the main condenser was found to result from a main steam dump following a 50-percent load rejection at the turbine while operating at the SPU power level. This abnormal operating condition maximized the incoming steam flow and heat load to the condenser. The potential for excessive vibration of the main condenser tubes and tube supports due to the worst case incoming steam was evaluated in accordance with the recommendations and methods of the Heat Exchange Institute (HEI).

9.7.4 Acceptance Criteria

The CWS design is considered acceptable to support SPU conditions, provided the following criteria are met:

- CWS pressure is bounded by system piping and component design.
- CWS temperature is bounded by system piping and component design and is within the SPDES limitations.
- CWS pumps provide the required flow to ensure condenser duty requirements are met.
- CWS discharge flows are within the SPDES limitations and consent order flows at SPU conditions.
- Remaining CWS equipment is adequate to support SPU conditions.

The main condenser design is considered acceptable to support SPU conditions, provided the following criteria are met:

- Main condenser thermal performance meets the increased heat loads and power output during SPU operation, as required by the SPU heat balances.
- Main condenser pressure with the maximum incoming steam flow and heat load at SPU conditions remains below the main turbine trip setpoint.

- Main condenser tubes and tube support design is adequate to prevent excessive tube vibration with the maximum incoming steam flow at SPU conditions.

- Main condenser auxiliary equipment is adequate to support SPU conditions.

The Condenser Air Removal System must be capable of removing all non-condensables, including air leakages and associated water vapor from the condenser shell, by maintaining a minimum steam condensing pressure. The Condenser Air Removal System is considered acceptable if the SPU requirements are bounded by the system and equipment design capability.

9.7.5 Design Criteria

The CWS provides cooling water for the main condenser of the turbine generator unit. As part of the CWS, the main condenser condenses and deaerates exhaust steam from the LP turbines, the steam dump system and the boiler feedpump turbine exhaust to maintain the required backpressure for improved plant efficiency. The CWS System is not safety related. Criterion required to meet SPU conditions are listed in the Acceptance Criteria above.

9.7.6 Results and Conclusions

The SPU evaluation confirmed that the existing CWS pumps provided sufficient flow for SPU heat removal and that the discharge temperature was within the SPDES limits. Main condenser duty, corresponding CWS discharge temperatures, steam flows, and condenser pressure increases due to SPU conditions were found to be within original design specifications.

The CWS pressure was not affected by operation at SPU conditions. No physical changes are being made to the CWS pumps, main condenser, piping, or auxiliary equipment. Therefore, none of the parameters that affect CWS pressure or inlet operating or design temperatures are affected by operation at SPU conditions.

The main condenser can accept the worst-case steam dump flow without exceeding the turbine trip setpoint and without experiencing excessive tube vibration. (See subsection 9.4.6 for additional discussion)

Other main condenser design factors including deaerating effects, tube cleanliness, tube-side velocity, and tube-side friction losses, will not be affected by SPU conditions.

The SJAEs meet the 1970 version of the HEI Standard. The SJAE capacity envelops the current plant recorded air and non-condensable gas in-leakage to the condenser with sufficient margin such that the SJAEs will operate satisfactorily under SPU conditions. The capability of the priming ejectors is not affected by the SPU since they operate only during plant startup.

9.8 Electrical Systems

9.8.1 AC and DC Plant Electrical Systems

The alternating-current (AC) and direct-current (DC) electrical distribution system and associated equipment were reviewed to evaluate the impact of the SPU on system and equipment performance, capacity and capability. Specifically, the following items were evaluated:

- Main generator
- Iso-Phase bus (IPB) duct
- Main transformers (MTs)
- Unit auxiliary transformer (UAT)
- Station auxiliary transformer (SAT)
- 6900-V power distribution system (including loads and cables)
- Protective relay schemes
- Miscellaneous systems (480-VAC, emergency diesel generators [EDGs], 118-VAC instrument supply systems, and 125-VDC systems)
- Grid stability

The system review also included an evaluation of the station load flow analysis, the station fault analysis, and grid stability studies. The purpose of the review was to determine if the electrical systems and equipment would operate satisfactorily and continue to perform their intended functions under SPU power levels. The results of the evaluation are described in the following sections.

9.8.1.1 Main Generator

9.8.1.1.1 Input Parameters and Assumptions

The main generator is a turbine-driven, hydrogen-cooled, four-pole machine-rated 1125.6 MVA, 22 kV, 0.90 power factor at 75-psig hydrogen pressure. The output of the main generator is delivered to the low-voltage windings of the main transformers (MT31 and MT32) via the IPB duct. An IPB tap bus connects the main generator output to the UAT. Unit operation at SPU conditions will result in increased power output from the unit.

The scope of this review includes an evaluation of the main generator electrical parameters relevant to assessing equipment adequacy at SPU conditions. The review includes an evaluation of the generator operating at 75-psig hydrogen pressure, since this reflects the maximum capability of the machine.

Evaluation of the main generator is based upon the following inputs and assumptions:

- The main generator gross real power output at the reactor thermal power level of 3244 MWt is 1093.5 Mwe, based on a heat balance calculation.

- The value of 3244 MWt is based on a maximum calculated value of 3216 MWt with an additional 0.5-percent flow margin on the main steam supply.

- The value of 3216 MWt is the maximum calculated reactor thermal power given in the *IP3 Updated Final Safety Analysis Report* (UFSAR) (Reference 1), Table 10.2-3.

- The SPU will propose to license IP3 to a maximum calculated reactor thermal power of 3216 MWt, which corresponds to a calculated electrical output of 1093.5 MWe.

- The main generator can presently provide a rated output of 1125.6 MVA when operated from 0.90-lagging power factor up to and including unity (1.0) power factor at 75-psig hydrogen pressure. This capability has been evaluated and will remain the same at SPU.

- The main generator can presently provide a rated output of 1125.6 MVA when operated from 0.950-leading power factor up to and including unity (1.0) power factor at 75-psig hydrogen pressure. This capability has been evaluated in order to accommodate an output of 1093.5 MWe.. The capability has been limited to 1125.6 MVA when operated from 0.996-leading power factor up to and including unity (1.0) power factor at SPU. This reactive power limitation at leading power factor is due to stator core end packs.

- The main generator will operate within the constraints of the new generator capability curve at SPU.

- Generator real and reactive power output capacity at SPU will be determined from the new generator capability curve.

- The generator currently operates at 75-psig hydrogen pressure and will continue to operate at that pressure at SPU conditions.

- IP3 reactive power commitments credited for this SPU Program are 225-MVAR lagging and 100-MVAR leading.

- Generator reactive power requirements for normal power operation typically range from 200-MVAR lagging to 100-MVAR leading.

9.8.1.1.2 Description of Analysis and Evaluation

The nameplate rating of the main generator is 1125.6 MVA based on 75 psig hydrogen, 22 kV, 0.90 lagging power factor, three-phase, 60 Hz, 1800 rpm.

Evaluation of the main generator was based upon a comparison between the generator capability curve and the anticipated operating requirements when the machine operates at SPU conditions. Unit operation at leading and lagging power factor was considered.

9.8.1.1.3 Acceptance Criteria for Analysis

- Generator real power output capability (MW) does not limit turbine output capability at SPU.

- Generator reactive power requirements will not exceed 225-MVAR lagging, and 100-MVAR leading when the unit is operating at SPU conditions and 75-psig hydrogen pressure.

9.8.1.1.4 Evaluation

The main generator is one of the normal sources of power to the plant discussed in the IP3 UFSAR (Reference 1) Sections 8.1 and 8.1.1. The normal source of auxiliary power during plant operation is supplied from both IP3's main generator and offsite power. This SPU increases the main generator's electrical output to 1093.5 MWe. IP3 reactive power commitments credited for this SPU Program are 225-MVAR lagging and 100-MVAR leading. Operation of the generator at the proposed SPU is within the generator's capability curve. Increasing the generator output to 1093.5 MWe and operating the generator within the proposed reactive power limits does not reduce the capacity and capability of any system to perform its intended function during anticipated operational occurrences and accident conditions. The onsite electrical distribution system independence, redundancy, and testability to perform safety functions, assuming a single failure, has not been affected. The onsite and offsite power systems will continue to meet the requirements of General Design Criteria-17 (GDC-17) (Reference 2) following implementation of the proposed SPU.

9.8.1.1.5 Results and Conclusions

The real power output (MW) capability of the main generator exceeds that required when the unit operates at SPU conditions. The generator capability curve shows that the machine is capable of continuous operation at an output of 1013 MW (0.90-lagging power factor) up to and including 1125.6 MW (unity power factor) at 75-psig hydrogen pressure. Maximum required unit output at SPU is 1093.5 MWe. Therefore, the real power output (MW) capability of the main generator is significantly higher than the real power output required at SPU.

The reactive power capability (MVAR) of the main generator from the generator capability curve is 267-MVAR lagging at 75-psig hydrogen pressure when the unit operates at maximum evaluated reactor thermal power. Machine operation at the specified values (1093.5 MW and 267 MVAR) corresponds to a generator lagging power factor of 0.971. Machine leading reactive power capability is 124 MVAR at 75-psig hydrogen pressure when the unit operates at maximum evaluated reactor thermal power. Machine operation at the specified values (1093.5 MW and 124 MVAR) corresponds to a generator leading power factor of 0.993.

The reactive capability of the main generator meets or exceeds the normal power requirement of 200-MVAR lagging and 100-MVAR leading and the IP3 reactive power commitments credited for this SPU of 225-MVAR lagging and 100-MVAR leading at 75-psig hydrogen pressure. The main generator provides these reactive power requirements at SPU conditions.

A review of the generator capability curve confirms that the main generator will support unit operation at SPU load conditions. Additionally, the main generator will support credited agreements regarding machine leading and lagging reactive power requirements.

9.8.1.2 Iso-Phase Bus Duct

9.8.1.2.1 Input Parameters and Assumptions

The output of the main generator is delivered to the low-voltage windings of the main transformers (MTs) (MT31 and MT32) via the IPB duct. An IPB tap bus connects the main generator output to the UAT. Unit operation at SPU conditions will result in increased power output from the unit and an attendant increase in MT and UAT loading. Accordingly, the IPB main and tap bus conductor current will also increase.

The scope of this review includes an evaluation of IPB electrical parameters relevant to assessing equipment adequacy at SPU conditions and at maximum reactor thermal power.

Evaluation of the IPB is based upon the following inputs and assumptions:

- The IPB system is organized into segments. The first segment runs from the generator terminals to the point where the main bus splits into the two segments that run to the two MTs. The segment from the generator has a forced air-cooled rating of 32 kA at 23 kV, 65°C rise. The next segments of the main bus that run from the split to each MT have forced air-cooled rating of 16 kA at 23 kV, 65°C rise. The remaining segment runs from MT32 to the UAT. This tap segment has a self-cooled rating of 1.5 kA at 23 kV. This segment does not have a forced air-cooled rating.

- The transformer test reports show that the two MTs have identical MVA ratings but different impedances. Since the current splits differently between the transformers in proportion to the impedance, current to each MT primary winding will be slightly different.

- The highest IPB loading will occur when the house loads are fed from the UAT. The 16-kA portion of the bus between the MT split and UAT tap is the most limiting since it carries the generator output to one MT plus the UAT load.

- The highest IPB loading will occur when the generator is operating at minimum voltage and maximum generator output. Generator operation was evaluated within a voltage range of ±5 percent from nominal rated voltage.

- The generator is assumed to be operating at 75-psig hydrogen pressure.

Fault current at the IPB is a function of equipment parameters associated with the main generator, MT, auxiliary transformer, etc. Since SPU did not change any relevant equipment parameters, it is assumed that unit operation at SPU will not adversely affect IPB fault duty.

9.8.1.2.2 Description of Analysis and Evaluation

Evaluation of the IPB main and tap buses was based upon a comparison between the maximum anticipated full-load current and the design ratings of the main and tap bus conductors with the generator operating at both lagging and leading power factor. This evaluation is based on house loads being fed from the UAT, since this results in the worst-case IPB loading. Since the IPB main and tap bus short circuit design ratings were adequate prior to SPU and SPU did not adversely affect IPB fault current levels, the IPB main and tap bus short circuit design ratings are adequate for SPU.

9.8.1.2.3 Unit Operation at Lagging Power Factor

The generator capability curve was reviewed to identify gross generator output when the unit operates at SPU conditions with main generator operation at lagging power factor.

Table 9.8-1 shows the IPB loading with the generator operating at the SPU power level, lagging power factor (75-psig hydrogen), and at maximum reactor thermal power.

9.8.1.2.4 Unit Operation at Leading Power Factor

The generator reactive capability curve was reviewed to identify the gross generator output when the unit operates at SPU load conditions with the main generator operation at leading power factor.

Table 9.8-2 shows the IPB loading with the generator operating at the power SPU level, leading power factor (75-psig hydrogen), and at maximum reactor thermal power.

9.8.1.2.5 Tap Bus

Maximum anticipated full-load current for the tap buses results when the connected UAT operates at maximum output load conditions. Based on a review of calculated transformer loading included in the applicable station load flow analysis, the maximum UAT loading occurs when the station is operating at maximum full-load conditions. The calculated UAT loading is identified in Table 9.8-3. The resulting tap bus currents are shown in Tables 9.8-1 and 9.8-2.

9.8.1.2.6 Acceptance Criteria for Analysis

- The continuous current rating of the IPB main bus is equal to or greater than the required IPB bus ampacity at maximum generator output (MVA) and minimum generator voltage (0.95 pu).

- The continuous current rating of the IPB tap bus is equal to or greater than the required bus ampacity at maximum UAT loading.

- Short circuit current ratings of the IPB main and tap buses are equal to or greater than the calculated available fault current at SPU conditions.

9.8.1.2.7 Evaluation

The IPB duct is part of the onsite power system discussed in the IP3 UFSAR (Reference 1) Section 8.1.1. For Phase 1 SPU (1080 MWe, 225-MVAR lagging and 100-MVAR leading), the IPB is capable of operating within its ratings. The Phase 2 SPU increases the main generator's electrical output to 1093.5 MWe. IP3 reactive power commitments credited for this SPU project are 225-MVAR lagging and 100-MVAR leading. Increasing the generator output to 1093.5 MWe and operating the generator within the proposed reactive power limits causes the IPB duct to operate slightly outside its ratings. This load exceedance occurs only during extreme system grid conditions and is controlled by reactive power limits and can be permanently addressed with future Phase 2 modifications to the IPB.

The increased power flow through the IPB duct does not reduce the capacity and capability of any system to perform its intended function during anticipated operational occurrences and accident conditions. The onsite electrical distribution system independence, redundancy, and testability to perform safety functions has not been affected. The onsite and offsite power systems will continue to meet the requirements of GDC-17 (Reference 2) following implementation of the proposed SPU.

9.8.1.2.8 Results and Conclusions

IPB Main Bus (32 and 16 kA sections)

The continuous current rating of the IPB main bus exceeds the anticipated worst-case bus loading for maximum proposed SPU generator output (MWe) and maximum required reactive power (MVAR) except as described below (see Tables 9.8-1 and 9.8-2).

However, when operating the generator at 0.95 pu voltage during the maximum analyzed reactor thermal power and maximum generator reactive power capability (1093.5 MWe, 267-MVAR lag), the 16-kA section of IPB feeding the MT32 and UAT exceeds the IPB rating (16.183-kA operating, 16.0-kA rated).

Since the IPB main bus short circuit design ratings were adequate prior to SPU, and SPU did not adversely affect available fault current levels, the IPB main bus short circuit design ratings are considered adequate for SPU.

IPB Tap Bus (1.5 kA section)

The continuous current rating of the IPB tap bus exceeds the anticipated worst-case bus loading at SPU with substantial margin (that is, 1500 amps versus 1328 amps, see Table 9.8-1).

Since the IPB tap bus short circuit design ratings were adequate prior to SPU, and SPU did not adversely affect available fault current levels, the IPB tap bus short circuit design ratings are considered adequate for SPU.

9.8.1.3 Main Transformers

9.8.1.3.1 Input Parameters and Assumptions

The MTs provide the interface between the main generator and the power system grid. Main generator output power is delivered to the primary windings of the MT at 22 kV nominal. The MT steps up generator output to 345 kV nominal and delivers the output to the 345-kV switchyard. Unit operation at SPU conditions will result in an attendant increase in MT output loading.

The scope of this review includes an evaluation of MT capacity based upon a comparison between transformer nameplate rating and the maximum transformer loading at SPU. The review also includes an evaluation of remaining transformer life expectancy and existing MT cooler capacity.

Evaluation of the MT is based upon the following inputs and assumptions:

- The main generator real power output is 1093.5 MWe during maximum analyzed reactor thermal power of 3216 MWt.
- The generator is assumed to be operating at 75-psig hydrogen pressure.
- The MT will be evaluated using generator reactive power capabilities of 267-MVAR lagging and 124-MVAR leading. These are reactive power capabilities at 1093.5 MWe.
- The unit auxiliary system (house) load will be supplied from the main generator via the UAT and from offsite via the SAT. This is consistent with the normal plant configuration when the unit is operating at full power.
- The load to the UAT is assumed to be 48 MVA at 0.84-lagging power factor based on a review of the normal load flow runs. This includes the distribution system increase in load due to this SPU (Table 9.8-3).

9.8.1.3.2 Description of Analysis and Evaluation

The MT consists of two half-sized generator step-up transformers MT31 and MT32. The nameplate rating for each transformer is 542/607 MVA FOA @ 55°/65°C rise, 20.3 kV primary, 345 kV secondary, three-phase, 60 Hz. MT31 is manufactured by Westinghouse and has been in operation since 1976. MT32 is manufactured by General Electric and has been in operation since 1983.

Evaluation of the MT was based upon a comparison between the applicable transformer design ratings and the anticipated operating requirements when the unit operates at SPU conditions. Unit operation at leading and lagging power factor conditions was considered assuming the main generator operates within the limits previously identified.

9.8.1.3.3 Main Transformer Loading

MT loading at SPU is determined in Tables 9.8-4 and 9.8-5 assuming house loads are supplied either from the UAT or offsite power sources and the main generator real and reactive power requirements previously identified in Section 9.8.1.3.1..

MT loading determined in Table 9.8-4 assumes house loads are supplied from the main generator via the UAT consistent with the normal plant configuration when the unit is operating at full power. Plant operating scenarios, evaluated using load flow analysis, assume the house loads are either supplied from the main generator via the UAT and from offsite via the SAT or completely from offsite power sources via the SAT. Each MT has adequate capacity to support unit operation at proposed SPU conditions even if the house loads are supplied entirely from the SAT. Table 9.8-5 shows that at maximum proposed SPU reactor thermal power, corresponding to 1093.5 MWe and 124-MVAR leading, results in maximum MT loading. Each transformer will operate above its 542-MVA, 55°C rating but below the maximum rating of 607-MVA, 65°C rating.

9.8.1.3.4 Acceptance Criteria for Analysis

MT nameplate ratings of 542/607 MVA FOA @ 55°/65°C rise each will not limit unit operation at SPU conditions.

9.8.1.3.5 Evaluation

The MTs are part of the onsite power system discussed in the IP3 UFSAR Section 8.1.1 (Reference 1). The normal source of auxiliary power during plant operation is supplied from both IP3's main generator and offsite power. The main transformers analyzed in this evaluation connect the main generator, offsite power system, and IP3 distribution system. This SPU increases the main generator's electrical output to 1093.5 MWe. IP3 reactive power commitments credited for this SPU program are 225-MVAR lagging and 100-MVAR leading. Increasing the generator output to 1080 MWe and operating the generator within the proposed reactive power limits does not cause the MTs to operate outside their ratings. The increased power flow through the MTs does not reduce the capacity and capability of any system to perform its intended function during anticipated operational occurrences and accident conditions. The onsite electrical distribution system independence, redundancy, and testability to perform safety functions has not been affected. The onsite and offsite power systems will continue to meet the requirements of GDC-17 (Reference 2) following implementation of the proposed SPU.

9.8.1.3.6 Results and Conclusions

The maximum calculated load for the parallel MTs is 1098 MVA with house load supplied from UAT (see Table 9.8-4). The maximum calculated load for the parallel MTs is 1132 MVA with house load supplied from the offsite power source (see Table 9.8-5). The parallel MT's maximum rating is 1214 MVA at 65°C temperature rise over ambient.

The preceding evaluation confirms that the existing MT nameplate ratings are adequate to support unit operation at SPU conditions when the main generator is operated in accordance with the assumptions previously identified. It is also reasonable to conclude that each MT is adequately sized at its 65°C rating to support unit operation at SPU even if the SAT supplies the entire house load.

9.8.1.4 Unit Auxiliary Transformer

9.8.1.4.1 Input Parameters and Assumptions

Power required for station auxiliaries during normal operation is split between the UAT and the SAT. Power to the auxiliaries (house loads) on 6900-V buses 1 through 4 is supplied by the UAT, which is connected to the main generator via the IPB duct. Unit operation at SPU conditions will result in a slight increase in UAT output loading because the net brake horsepower (bhp) required by several large pump motor drives supplied from 6900-V buses 1 through 4 will increase due to proposed SPU operation.

The scope of this review included an evaluation of UAT design capacity based upon a comparison between transformer nameplate rating and the maximum transformer loading at SPU.

Evaluation of the UAT is based upon the following inputs and assumptions:

- The house load is shared between the UAT and the SAT. This is consistent with the normal plant configuration when the unit is operating at full power.
- IP3 load flow analysis will be used to evaluate the effect of SPU on the electrical distribution system.

9.8.1.4.2 Description of Analysis and Evaluation

The nameplate rating for the UAT is 43.00 MVA FOA @ 55°C rise and 48.16 MVA FOA @ 65°C rise, 22 kV primary, 6900 V secondary winding, three-phase, 60 Hz. The secondary winding supplies power directly to downstream 6900-V buses 1 through 4. The UAT primary is equipped with an automatic load tap changer that regulates voltage to a preset value at the downstream 6900-V normal buses.

9.8.1.4.3 UAT Loading

The station load flow analysis was reviewed to identify maximum calculated UAT loading. The analysis determined UAT loading during normal operation (full-load), hot-shutdown (start-up), cold-shutdown, condensate polisher building, large-break loss-of-coolant accident (LBLOCA), and steam breaks. Review of the calculated results confirmed that worst-case UAT loading occurs during normal operation (full-load). This case was used to evaluate the effect of SPU on the UAT.

The existing IP3 load flow analysis was used as the baseline to evaluate the effect of SPU on the UAT for full-load conditions. The incremental changes in loading due to SPU were added to the baseline and the resulting values were compared to the UAT rating to determine the equipment adequacy for SPU. The incremental changes in loading due to SPU are summarized in Table 9.8-6.

9.8.1.4.4 Acceptance Criteria

UAT nameplate rating of 43.00 MVA FOA @ 55°C rise and 48.16 MVA FOA @ 65°C rise will not limit unit operation at SPU conditions.

9.8.1.4.5 Evaluation

The UAT is part of the onsite power system discussed in the IP3 UFSAR (Reference 1) Section 8.2.2. Although the proposed SPU causes a slight increase in loading on the UAT, the

UAT operation remains within its 48.16 MVA FOA @ 65°C rise rating. The increased power flow through the UAT does not reduce the capacity and capability of any system to perform its intended function during anticipated operational occurrences and accident conditions. The onsite electrical distribution system independence, redundancy, and testability to perform safety functions has not been affected. The onsite and offsite power systems will continue to meet the requirements of GDC-17 (Reference 2) following implementation of the proposed SPU.

9.8.1.4.6 Results and Conclusions

The worst-case total secondary load on the UAT is 44.563 MVA (Table 9.8-6), which is slightly greater than the UAT maximum nameplate rating of 43.00 MVA FOA @ 55°C rise but less than the nameplate rating of 48.16 MVA FOA @ 65°C rise. Accordingly, it is reasonable to conclude that the transformer temperature rise will be within the design ratings and the transformer coolers will be operating within their design capacity when the unit operates at SPU.

The UAT has adequate capacity to support unit operation at SPU conditions, and based on the transformer condition, the UAT will require no modifications to the cooling system to meet SPU conditions.

9.8.1.5 Station Auxiliary Transformer

9.8.1.5.1 Input Parameters and Assumptions

A single SAT serves IP3. Offsite power from the 138-kV switchyard is supplied to the 6900-V buses via the SAT during normal operation, plant start-up, outage, and design bases accident (DBA) conditions. Power required for station auxiliaries (house loads) during normal operation is split between the UAT and the SAT, with house loads on 6900-V buses 5 and 6 supplied by the SAT, which is connected to the 138-kV switchyard via overhead lines. On a unit trip, a transfer scheme ties buses 1 and 2 to bus 5, and buses 3 and 4 to bus 6.

The scope of this review included an evaluation of SAT design capacity based upon a comparison between transformer nameplate rating and the maximum transformer loading at SPU.

The evaluation of the SAT is based upon the following inputs and assumptions:

- The normal source of auxiliary power for 6900-V buses 5 and 6, and standby power required during plant startup, shutdown, and after reactor trip is the SAT.

- The existing IP3 load flow analysis will be used to evaluate the effect of SPU on the electrical distribution system.

- Unit operation at SPU conditions will result in an actual increase in SAT output loading when the house loads are transferred, because the net bhp required by several large pump motor drives supplied from 6900-V buses 1 through 4 will increase due to power SPU. However, the existing load flow calculation has modeled some of the 6.9-kV loads conservatively high. The new KW and KVAR values for the affected motors are based on the actual calculated bhps. Some of the loads have increased, but others have decreased. When UAT loads are transferred to the SAT during certain operating conditions, certain loads are turned off. Analysis of the loads shows a calculated net decrease to the load flow. Therefore, although the actual 6600-V motor bhp requirements have increased, the calculated net effect is a decrease in overall SAT loading based on load flow model calculations.

- Incremental load changes in the 480-V system have not been included in this SAT analysis since conservatism in the existing load flow model bounds any increase in 480-V system loading.

9.8.1.5.2 Description of Analysis and Evaluation

The nameplate rating for the SAT is 43.00 MVA FOA @ 55°C rise and 48.16 MVA FOA @ 65°C rise, 138 kV primary, 6900 V secondary winding, three-phase, 60 Hz. The secondary winding supplies power directly to downstream 6900-V buses 5 and 6. The SAT secondary is equipped with an automatic load tap changer that regulates voltage to a preset value at the downstream 6900-V buses.

9.8.1.5.3 SAT Loading

The IP3 load flow analysis was reviewed to identify maximum calculated SAT loading. The analysis determined SAT loading during normal operation (full-load), hot-shutdown (start-up), cold-shutdown, condensate polisher building, LBLOCA, and steam breaks. Review of the calculated results showed that worst-case steady-state SAT loading occurs during a steam break event with phase B isolation and buses 2A and/or 3A not available.

A baseline for transformer loading was developed using the values in the existing IP3 load flow analysis. The incremental changes in loading due to SPU were added to the baseline and the resulting values were compared to the SAT rating to determine the equipment adequacy for SPU.

The loading on buses 5A and 6A is conservative in the existing IP3 load flow analysis (bus 5A is 731-kVA high, bus 6A is 1788-kVA high). Overall, the existing IP3 load flow analysis has over 7300 kVA of conservatism on buses 2A, 3A, 5A, and 6A. For this reason, any incremental load changes in the 480-V system were not included in this SAT analysis and are bounded by the existing SAT loading analysis.

9.8.1.5.4 Acceptance Criteria for Analysis

SAT nameplate rating of 43.00 MVA FOA @ 55°C rise and 48.16 MVA FOA @ 65°C rise will not limit unit operation at SPU conditions.

9.8.1.5.5 Evaluation

The SAT is part of the onsite power system discussed in the IP3 UFSAR (Reference 1) Section 8.2.2. The changes in power flow through the SAT during the analyzed accident events do not reduce the capacity and capability of any system to perform its intended function during anticipated operational occurrences and accident conditions. The onsite electrical distribution system independence, redundancy, and testability to perform safety functions has not been affected. The onsite and offsite power systems will continue to meet the requirements of GDC-17 (Reference 2) following implementation of the proposed SPU.

9.8.1.5.6 Results and Conclusions

The highest postulated load on the SAT is during a steam break accident. During this event, the total secondary load on the SAT at SPU is calculated to be 49.295 MVA (Table 9.8-7), which is less than the existing modeled load of 49.309 MVA (Table 9.8-8). However, there is conservatism in the existing load flow analysis. Buses 5A and 6A alone include a total of about 2.5 MVA of excess load. Therefore, the existing load on the SAT during peak accident conditions would be decreased to 46.809 MVA and the new SAT load at SPU would be decreased to 46.795 MVA. In both cases, the total SAT load is less than the SAT rating of 48.16 MVA @ 65°C. If the entire 7.3 MVA of approximated excess load on buses 2A, 3A, 5A, and 6A was subtracted from the calculated load flow results, the existing SAT load would be 42.009 MVA and at SPU would be 41.995 MVA. Both are less than the SAT rating of 43.00 MVA @ 55°C.

The normal loading on the SAT at SPU is 8.588 MVA (Table 9.8-7), which is a continuous operating condition. Accordingly, it is reasonable to conclude that the transformer temperature rise will be within the design ratings and the transformer coolers will be operating within their design capacity when the unit operates at SPU.

The SAT has adequate capacity to support unit operation at SPU conditions based on the analyzed normal and accident loading conditions. The incremental BHP changes due to SPU cause a reduction in modeled loading on the SAT. Based on the transformer condition, the SAT will require no modifications to the cooling system to meet SPU conditions.

9.8.1.6 Medium-Voltage, 6900-V System

9.8.1.6.1 Input Parameters and Assumptions

The 6900-V system supplies power for the majority of the safety- and non-safety-related (AC) loads. Large station loads are supplied directly from the system. Smaller low-voltage AC loads (480 V and below) are also supplied from the system via appropriately rated step-down transformers. During normal full-load operation, the system is supplied power from the UAT, and the SAT, with buses 1 through 4 supplied by the UAT, and buses 5 and 6 supplied by the SAT. During plant start-up, shutdown, outage, and plant-accident conditions the system is supplied from the SAT.

Unit operation at SPU conditions will result in increased fluid system flow requirements that will, in turn, increase the bhp load on several medium-voltage pump motor drives supplied from the 6900-V buses. The 6900-V non-segregated phase bus, switchgear, medium-voltage motors, and associated feeder cables affected by SPU are discussed in this section.

The scope of this review included an evaluation of the 6900-V system to confirm adequacy of the applicable switchgear ratings and to confirm that bus voltage levels are adequate to support equipment operation and function when the unit operates at SPU conditions. The review also included an evaluation of motor load requirements at SPU conditions to verify that the affected pump motor drives and associated feeder cables will operate within their rated capability.

Evaluation of the 6900-V system was based on the following inputs and assumptions:

- Loading from the existing station load flow analysis together with incremental changes in loading calculated in the bhp calculation and RCP motor evaluation due to SPU are used to develop the evaluation model.

- Revised load bhp data for balance-of-plant (BOP) 6900-V motor driven pumps is based upon analysis at a reactor thermal power level of 3244 MWt, which is maximum reactor thermal power plus 0.5-percent steam flow rate margin. This analysis determined condensate pumps (CPs), condensate booster pumps (CBPs), and heater drain pumps (HDs) bhp requirements at SPU.

- Revised bhp data for the reactor coolant pumps (RCPs) for SPU conditions
- Cable ampacities are taken from IP3 short-circuit calculations.
- The highest loading for buses 1, 2, 3, and 4 is during normal full-load operation conditions while supplied from the UAT.
- The highest loading for buses 5 and 6 is during a steam break event where loads from buses 1 and 2 are supplied by bus 5 and loads from buses 3 and 4 are supplied by bus 6.

9.8.1.6.2 Description of Analysis and Evaluation

The effect of power operation at SPU on the 6900-V non-segregated phase bus, switchgear buses and breakers, station bus voltage levels, and the 6600-V pump motor drives and associated feeder cables are discussed separately below.

9.8.1.6.3 6900-V Switchgear

The evaluation of the 6900-V non-segregated phase bus, switchgear buses, and breakers was based upon a comparison between the applicable equipment ratings and the anticipated operating requirements at SPU conditions, as determined in the existing IP3 load flow and evaluation model. The continuous current design ratings of the 6900-V non-segregated phase bus, switchgear, and switchgear breakers are potentially affected by unit operation at SPU because of the attendant increase in electrical load flow throughout the system. Conversely, 6900-V equipment short-circuit duty is not expected to be adversely affected because unit operation at SPU conditions does not require any equipment changes, replacements, and/or new installations that could increase the fault current duty at the 6900-V level. Since no new 6900-V loads were added as a part of SPU, the existing switchgear physical arrangement remains unchanged.

6900-V Bus Incoming Supply and Motor Feeder Breaker Continuous Current Ratings

IP3 load flow analysis was reviewed to identify the maximum calculated steady state loading for the 6900-V incoming supply breakers. The analysis determined equipment loading during maximum normal full-load, DBA, and outage load conditions with either the UAT and/or the SAT, as applicable, supplying power for the house loads. Review of the calculated results confirmed that worst-case loading on buses 1, 2, 3, and 4 occurs during normal operation and that worst-case steady-state loading occurs on buses 5 and 6 during a steam break event, where all auxiliary loads on buses 1, 2, 3, and 4 are transferred to the SAT. The incremental loading is combined with the existing loading, and the resulting bus loading is summarized in Table 9.8-9.

A comparison between the expected SPU load conditions, as determined in this evaluation, and the continuous current ratings of the switchgear incoming supply breakers is also provided in Table 9.8-9. Note that the non-segregated bus comprises of segments with ratings of 4000A, 2000A, and 1200A as shown on the 6900-V single-line diagram. The non-segregated bus loading is also provided in Table 9.8-9.

A comparison between the maximum continuous current load at SPU and the design rating of the affected motor feeder breakers is shown in Table 9.8-10. The motor load current was taken from Table 9.8-11.

6900-V Equipment Fault Current Ratings

Short-circuit duty is not adversely affected by equipment load changes associated with unit operation at SPU conditions. This is because the load changes did not require replacement of, or changes to, existing electrical components and equipment (for example, motor drives, power transformers, and feeder cables) that could result in increased equipment fault current duty at the 6900-V buses.

9.8.1.6.4 Medium-Voltage (6600-V) Motors and Motor Feeder Cables

6600-V Motors

Unit operation at SPU conditions will result in a bhp load change on several 6600-V motor-driven pumps. Specifically, the CP, CBP, HP, and RCP motors, all of which are supplied from the 6900-V switchgear buses, will each experience a load change. Evaluation of each affected motor drive was based upon a comparison between the motor nameplate rating (HP) and the required motor bhp at SPU flow conditions. It should be noted that the CP 31, RCPs 31, 32, 33, and 34, and HD 31 motors have been calculated to operate at a bhp during SPU that is less than the presently modeled bhp shown in the current load flow analysis. A summary of the motor nameplate ratings (HP) and SPU bhp data is shown in Table 9.8-12.

All affected BOP motor drives will be operating at less than nameplate rating when the unit operates at SPU.

6600-V Motor Feeder Cables Including the RCP Electrical Penetrations

The existing motor feeder cables were evaluated to confirm that cable ampacity was equal to or greater than motor load current when the associated motor operates at SPU load conditions. The comparison between feeder cable ampacity and motor load current was developed at SPU was developed and shown in Table 9.8-11.

Evaluation of the electrical penetrations associated with the RCP motor feeders was based upon a comparison between motor load current during cold- and hot-loop operation and penetration rated ampacity. Cold-loop values bound normal operating (hot-loop) load current. The penetrations associated with the RCP motor feeders consist of two feed-through conductors per phase each rated 315 amps, continuous, for a total ampacity of 630 amps. RCP motor load current under cold loop conditions, adjusted for motor operation at 90-percent rated voltage, results in motor load current of 634 amps (317 amps/penetration conductor). Although the required ampacity is slightly greater than the rated penetration ampacity, the penetrations are considered adequate since this is a short-time condition and is not continuous. Also, if the actual motor voltage was 91 percent of rated, the load current would be 627 amps, which is within the rated ampacity of the cables. Since cold-loop operation only occurs during startup, where 6600-V motors are operated well above 90 percent of rated voltage, these cables should always operate well within their rated ampacity. Furthermore, the RCPs will be operating at SPU below their existing nameplate horsepower ratings.

9.8.1.6.5 System Voltage Levels

The existing IP3 load flow calculation analyzed a number of load flow (steady-state) scenarios. These included full-load, hot-shutdown (start-up), cold-shutdown, condensate polisher building, large LBLOCA, and steam break conditions. It was determine that the largest loading on the UAT and SAT during normal-operation conditions was at full load.

It was also determined that a steam break event with bus 2A and/or 3A not available had the greatest loading on the SAT.

The estimated bus and motor terminal voltages during normal and accident conditions were evaluated to determine the extent of impact on the 6900-V system. The evaluation, using load flow analysis, shows a worst-case voltage reduction at the 6900-V system level at SPU to be about 1 volt in the system model.

9.8.1.6.6 Acceptance Criteria

For the 6900-V system to be considered acceptable, unit operation at SPU conditions will result in:

- Continuous current or fault current requirements that do not exceed the applicable design ratings of the 6900-V switchgear or circuit breakers.
- Operation of 6600-V motors at loads less than or equal to rated motor horsepower.
- Load current requirements that do not exceed motor feeder cable ampacity or result in excessive cable voltage drop.
- Minimum voltage levels at the 480-V buses that are greater than the voltage required to reset the degraded voltage relays.
- Protective relay requirements that do not exceed the capability of the 6900-V system electrical protection schemes (refer to subsection 9.8.1.7 of this report).

9.8.1.6.7 Evaluation

The 6900-V system is part of the onsite power system discussed in the IP3 UFSAR (Reference 1) Section 8.2.2. The changes to motor loads in the 6900-V system do not reduce the capacity and capability of any system to perform its intended function during anticipated operational occurrences and accident conditions. The onsite electrical distribution system independence, redundancy, and testability to perform safety functions has not been affected. The onsite and offsite power systems will continue to meet the requirements of GDC-17 (Reference 2) following implementation of the proposed SPU.

9.8.1.6.8 Results and Conclusions

9.8.1.6.8.1 6900-V Switchgear

The continuous current design ratings of the 6900-V switchgear incoming supply breakers and buses and the affected motor feeder breakers exceed the SPU load requirement during steady-state normal-loading conditions. However, bus 5 load exceeds its rating during a steam break event peak loading based on the existing load flow model. This bus loading is not considered a continuous operating condition. The SPU bhp changes have increased bus 5 current by only 3 A, from 2099 A to 2102 A, during this accident event. The change is considered insignificant compared to the overall bus 5 load that already existed. Furthermore, removing the conservatism from the 480-V system loading would bring bus 5 well within its continuous rating during a peak accident condition.

Short circuit duty is not adversely affected by equipment load changes associated with unit operation at SPU conditions, because the load changes did not require replacement of, or changes to, existing electrical components and equipment.

9.8.1.6.8.2 6600-V Motors

All affected 6600-V motor drives will operate at less than nameplate rating HP when the associated systems are operating at SPU conditions.

9.8.1.6.8.3 6600-V Motor Feeder Cables Including RCP Electrical Penetrations

The ampacity of the existing 6600-V motor feeder cables exceed the motor load current required when the associated motors operate at normal SPU load conditions (Table 9.8-11). However, the RCP loading exceeds the cable ampacity during cold-loop operating conditions (Table 9.8-11) with terminal voltage at 90 percent of rated voltage. Although the cold-loop current drawn by the RCP marginally exceeds the cable ampacity, this is considered acceptable, that is, ampacity is exceeded by 0.63 percent. The RCP cold-loop current is not continuous and its hot-loop current is less than the cable continuous ampacity. Also, the analyzed load flow cases show the RCP terminal voltages to be well above 90 percent of rated voltage, bringing the RCP load current within the cable ratings.

9.8.1.6.8.4 6900-V System Voltage

The worst-case reduction of 6900-V system voltage levels as a result of SPU is approximately 1 volt (0.01 percent difference). All bus voltages are above 98 percent of their nominal operating voltage. Also, all motor terminal voltages are above 102 percent of their rated voltage. Therefore, the SPU does not significantly change the analyzed operating voltages. Also, the changes in the 6900-V system do not affect the 480-V bus voltages. Therefore, the degraded grid voltage (DGV) relay settings are not affected.

9.8.1.6.8.5 6600-V Motor Protective Relays

6600-V motor protective relays are discussed in subsection 9.8.1.7.4 of this report.

9.8.1.7 Protective Relay Schemes

9.8.1.7.1 Input Parameters and Assumptions

Plant electrical equipment is provided with protective relay schemes designed to prevent or minimize equipment damage and to limit equipment outages to the immediately involved equipment or component during system disturbances. Protective relay schemes associated with systems affected by SPU may, in turn, be affected because of the change in the protected equipment operating point. Accordingly, the scope of this review is limited to an evaluation of affected equipment protection schemes.

The evaluation of the protective relay schemes was based, in part, on the following inputs and assumptions:

- IP3 electrical system description – high voltage
- IP3 electrical system description – medium voltage
- IP3 overall unit protection system description
- Power distribution bus arrangement as shown on the one-line diagrams
- IP3 relay setting calculations
- IP3 design basis document – 480-V electrical distribution system

9.8.1.7.2 Description of Analysis and Evaluation

Protective relay schemes for the main generator, MTs, UATs, and SATs, and those medium-voltage motors affected by SPU were reviewed to evaluate the effects of unit operation at SPU conditions.

9.8.1.7.3 Unit Equipment Protection

Entergy maintains the existing unit equipment protection schemes and associated setpoints. A review was conducted and has confirmed that the schemes and the associated setpoints were unaffected for operation under SPU conditions. The following paragraphs summarize the protective relay scheme review.

Main Generator Protection

The applied main generator protection schemes are intended to limit machine damage for internal fault conditions and to prevent machine damage during abnormal operating or external fault conditions. To accomplish this basic design requirement, the primary and backup generator protection systems are designed to trip the generator and associated feeder breakers for faults that may result in abnormally high currents flowing through the windings of the generator, MTs, or the UAT. A trip signal acts to simultaneously open the generator output breakers (at Buchanan Substation), and open the field supply breaker at the unit. The IP3 main generator is tripped via primary and backup lockout relays, actuated primarily in response to the following parameters:

Primary Protection:

- Generator differential
- MT31 differential
- MT32 differential
- Generator neutral ground overcurrent
- UAT lockout signal
- Turbine trip

Backup Protection (additional functions):

- Generator/MT differential
- Loss of excitation (field)
- Negative sequence
- Backup generator ground

A review of one-line diagrams and the electrical system description confirms that the applied schemes are dependent upon machine ratings, machine design parameters, and the design of the connected system. These schemes are not affected by machine operation at SPU conditions. For example, overlapping differential schemes provide machine protection for both internal (generator differential and unit differential schemes) and external (unit differential scheme) phase fault conditions. The schemes are not affected by load changes within the rated operating range of the generator. Ground fault protection schemes, provided by ground over-voltage relays, are designed and set based upon the system grounding design, and is independent of main generator output. Loss-of-excitation and negative-sequence protection schemes that are included among the remaining main generator protection schemes are similarly unaffected by unit operation at SPU conditions because the machine will be operated within its rated capability.

MT, UAT, and SAT

A review of one-line diagrams, high voltage, and medium-voltage electrical system descriptions, overall unit protection system descriptions, and the relay setting calculation indicates that transformer protection essentially consists of high-speed phase fault protection and ground fault protection.

Main Transformers (MT31 and MT32)

Primary protection of each of the two half-size MTs is provided by three dedicated differential relays. Actuation of either of the differential relays will initiate a generator trip by tripping the primary lockout relay. Back-up protection is provided by three unit differential relays. Both MT secondary windings are 'wye' connected with a grounded neutral leg, each of which is monitored by a current transformer connected to a single neutral ground relay. Actuation of the backup differential and the neutral ground overcurrent will initiate a generator trip by tripping the unit lockout relay. Primary protection CT selection and relay setting are based on maximum MT nameplate rating of 607,040 KVA each (at 65°C temp rise). Backup protection CT selection and relay setting are based on the maximum generator rating of 1,125,600 KVA.

Unit Auxiliary Transformer

The UAT is protected by a dedicated differential relay scheme and three single-phase time overcurrent protection relay scheme for internal phase and ground faults as well as faults within the 6900-V bus sections fed by the transformer. A neutral time overcurrent relay provides ground fault protection to the low voltage winding. Back-up protection is also provided by these unit auxiliary transformer protective relay schemes. CT selection and differential relay setting are based on the maximum UAT rating of 48,160 KVA (FOA @ 65°C temp rise), and the overcurrent relay protection is based on allowing operation of the UAT at 30 percent above its 65°C FOA rating.

Station Auxiliary Transformer

The SAT is protected by a differential relay scheme. Back-up protection is provided by three single-phase overcurrent relays and a ground overcurrent relay. CT selection and differential relay setting are based on the maximum SAT rating of 48,160 KVA (FOA at 65°C temp rise), and the overcurrent relay protection is based on allowing operation of the SAT at 30 percent above its 65°C FOA rating.

Conclusion

Since the existing power transformers (MT31, MT32, UAT, and SAT) will continue in service and operate within their nameplate ratings, the existing electrical protection schemes described above are unaffected when the unit operates at SPU conditions.

9.8.1.7.4 Medium-Voltage Motor Protection

The purpose of the medium-voltage motor and motor feeder protection scheme is to provide electrical protection against the damaging effects of sustained overload, locked rotor, and phase and ground fault conditions. For example, instantaneous overcurrent relays provide phase and ground fault protection, while time overcurrent relays provide motor overload protection. The protection scheme also incorporates thermal overload relays as applicable.

Design of the applied motor protective relay schemes (including setpoints) is based upon motor nameplate ratings, motor design parameters, and feeder ratings. The BOP motors affected by the SPU are listed in Table 9.8-12 of this engineering report.

Since the subject motors will be operated within their respective nameplate rated capabilities, and because none of the affected motor drives will be replaced, operation at SPU conditions will not affect the existing BOP medium-voltage motor protection schemes and setpoints.

9.8.1.7.5 Emergency Diesel Generator

Loading associated with the 480-V EDGs is bounded by operation at SPU conditions as described in subsection 9.8.1.8.2.3 of this report. Since no new EDG-related loads or other changes have been identified, the existing EDG electrical protection schemes and setpoints are similarly unaffected.

9.8.1.7.6 Acceptance Criteria for Analysis

Protective relay schemes and associated setpoints shall not constrain equipment operation at SPU load conditions.

9.8.1.7.7 Evaluation

The protective relays discussed in this report affect the operation of onsite power system equipment described in the IP3 UFSAR (Reference 1) Sections 8.1, 8.1.1, 8.2.1, 8.2.2, and 8.2.3. Review of the protective relaying calculations shows that no changes are required to the existing protective relay settings, since all equipment is operated within previously analyzed constraints used to set the protective devices. There are no changes to the control circuits, power circuits, or auxiliary support systems and features that support safety-related loads. The changes due to this SPU do not reduce the capacity and capability of any system to perform its intended function during anticipated operational occurrences and accident conditions. The onsite electrical distribution system independence, redundancy, and testability to perform safety functions has not been affected. The onsite and offsite power systems will continue to meet the requirements of GDC-17 (Reference 2) following implementation of the proposed SPU.

9.8.1.7.8 Results and Conclusions

The review determined that unit equipment protection schemes (that is, main generator, MTs, UAT, and the SAT), as well as the protective relay schemes associated with the 6900-V equipment are adequate as installed, and that they provide adequate margin to permit unit operation at SPU power levels.

The review concluded that the protection schemes are considered adequate for use at SPU.

9.8.1.8 Miscellaneous Systems

9.8.1.8.1 Input Parameters and Assumptions

This section includes evaluations of various electrical power distribution systems that are either not impacted, or are marginally impacted by SPU. The systems include:

- 480-V system
- 13.8-kV system
- EDG system
- 118-VAC instrument supply system
- 125-VDC system

Relevant inputs and assumptions are identified within the evaluation discussion for the applicable system.

9.8.1.8.2 Description of Analysis and Evaluation

9.8.1.8.2.1 480-V System

The 480-V power distribution system consists of seven bus sections designated 2A, 3A, 5A, 6A, 312, 313, and 3NGY01. Bus sections 5A, 6A, and 2A and 3A are the 480-V safeguard buses, while 312 and 313 supply power to non-safety-related loads. There is also a seventh 480-V bus designated 3NGY01, dedicated to serve the Condensate Polishing Facility. The system supplies 480 V, three-phase power to various essential and non-essential electrical loads via switchgear assemblies and distribution network comprised of a number of motor control centers and distribution panels.

Based on an assessment of the peak EDG loads, the 480-V system loading is potentially affected by operation at SPU power levels when the switchgear buses receive their power from the emergency diesel generators due to changes that affect CR fan loading.

When operating at SPU power levels, the EDG loading under steam break LOCA conditions will still be enveloped by the 2000-kW half-hour rating of the EDG, and therefore meets the requirement.

Based on a review of the other loads on the EDG, no other load changes except for the CR fans are anticipated. Therefore, the EDG loading remains adequate for operation under SPU power levels.

Since the worst-case loading on the EDGs when operating under SPU conditions is bounded by the existing EDG load study, and since no other 480-V load changes are identified, the loading on the EDGs is similarly bounded for operating under SPU conditions.

Based on discussions provided in subsection 9.8.1.5.3, the incremental changes in the 480-V system, for example, CR fans, are bounded by the conservatism in the existing load flow analysis.

480-V System Voltage Levels

Review of the existing IP3 load flow analysis and the evaluation model shows that changes in the 6900-V system did not affect the 480-V system at SPU. The estimated effect on 480-V switchgear voltage levels, resulting from unit operation at SPU conditions with 480-V changes, is provided in Tables 9.8-13 and 9.8-14.

The following two scenarios were evaluated:

- Full-Load Normal Operation (Table 9.8-13)

  All five CR fans are running in existing load flow case during normal operation. There are no changes to the 480-V system loads at SPU. The CR fans have no bhp changes at SPU during normal operating conditions. The 480-V bus voltages were taken directly load flow analysis.

- LBLOCA Conditions (Table 9.8-14)

  Four out of five CR fans are running in the existing load flow case during a LBLOCA event (116 kW/fan). In order to estimate the effects of increased bhp for the CR fans, the highest kW per CR fan demand (161.69 kW/fan) was taken from the SPU evaluation on CR fan operation. All four fan motor loads were increased and the 480-V bus loads were estimated for SPU operation. Voltage drops were extrapolated based on the estimated bus loading. The conservatism in the existing load flow analysis bounds the incremental changes in CR fan loading.

Degraded Voltage Relay Settings

Based on Table 9.8-13, bus 6A has the lowest steady-state bus voltage of 441 V at SPU, which is significantly above the existing degraded voltage relay reset setting of 434.8 V. During accident conditions, the greatest estimated change is on bus 5A in Table 9.8-14, which is only 2-V. However, the voltage is estimated to be 457 V, which is also above the degraded voltage relay reset setting. Therefore, the estimated 480-V bus voltages at SPU do not affect the degraded voltage relay settings.

480-V Equipment Fault Duty

Short circuit duty at the 480-V buses is not adversely affected by equipment load changes associated with unit operation at SPU conditions because the load changes did not require replacement of, or changes to, existing electrical components and equipment.

Low-Voltage (440/460-V) Motors, Motor Feeder Cables, Associated Electrical Penetrations, and Overcurrent Protection

Based on Westinghouse assessment of the peak bhp values affected by SPU, CR fan motor power requirements can be conservatively assumed to reach 161.69 kW/fan (corresponding to 195 bhp/fan when four fans out of five are required to operate). The CR fan motors, nameplate rated at 225 HP each, will operate at less than their nameplate rating, and therefore the existing motors are considered adequate to support SPU. Since these are the only low-voltage motors affected by SPU, the remaining low-voltage motors are considered adequate as well.

Since the bhp of the CR fan motors, when operating under SPU conditions, is bounded by the existing rating, it can be concluded that the feeder cable ampacity, electrical penetrations, and overcurrent trip setpoint associated with CR fan motors are adequate to support unit operation at SPU.

9.8.1.8.2.2 13.8-kV System

The 13.8-kV system provides backup electrical power to the 6900-V buses 5 and 6. Unit operation at SPU conditions does not result in a load change to any equipment supplied from 6900-V buses 5 and 6 other than the CR fan loads described above. Additionally, review of the bus loading included in the load flow/voltage profile analysis indicates that loads supplied from the 13.8-kV system during plant shutdown are unaffected by unit operation at SPU conditions.

9.8.1.8.2.3 EDG System

Three independent EDGs supply emergency power to the engineered safeguards features (ESFs) buses in the event of a loss-of-offsite-AC-auxiliary power. Each EDG is started automatically on a SI signal or upon the occurrence of an under-voltage signal on any safeguards 480-V switchgear bus. Any two diesels have adequate capacity to supply the ESFs loads for the hypothetical design bases accident concurrent with loss-of-offsite power (LOOP). This capacity is adequate to provide a safe and orderly plant shutdown in case of loss-of-offsite-electrical power. The EDG system includes the bus duct connections up to the 480-V switchgear circuit breaker generator-side stabs. The 480-V switchgear buses and associated circuit breakers are included in the 480-V power distribution system.

EDG System Loading

The EDGs ratings are as follows:

- Continuous operation 1750 kW
- 2000-hour operation 1950 kW (peak)
- 2-hour operation 1950 kW
- 30-minute operation 2000 kW

Based on assessment of the peak EDG loads, the 480-V system loading is potentially affected by operation at SPU power levels when the switchgear buses receive their power from the EDGs. Currently, this load is 157.3 kW/fan (maximum load occurring when three out of five CR fans are operating. In accordance with the SPU analysis, the maximum BHP requirements for the equivalent scenario (when three out of five CR fans are operating) under SPU conditions is 154.51 kW/fan (maximum load occurring during a LBLOCA with EDG31 failure.) This represents a decrease in the required kW per fan of approximately 2.8 kW. Since EDG32 supplies only one CR fan, the resulting peak EDG32 load decreases from 1984.8 to 1981.6 kW. This represents an improvement in the existing EDG peak loading for the postulated accident case, when operating under SPU conditions.

Since the loading on the EDGs resulting from SPU is bounded by the existing EDG load study, the loading on the EDG bus ducts is similarly bounded.

9.8.1.8.2.4 118-VAC Instrument Supply System

The 118-VAC instrument power distribution system consists of four bus pairs, 31and 31A, 32 and 32A, 33 and 32A, and 34 and 34A. The 118-VAC power is provided to safeguards and non-safeguards plant instrumentation and controls. Instrument bus power is provided by static inverters, which are in turn supplied from separate 125-VDC buses. Backup power is available from voltage-regulated transformers fed from motor-control centers (MCCs).

Existing 118-VAC power and control schemes supplied from the system are unaffected by SPU. Similarly, no new equipment requiring 118-VAC motive or control power is expected to be added to support SPU. Consequently, the 118-VAC system will not be affected by operation at SPU conditions.

9.8.1.8.2.5 125-VDC System

The 125-VDC power distribution system consists of the following major components that support the 125-VDC safeguards and non-safeguards loads throughout the station:

- (5) Station batteries
- (6) Battery chargers
- (5) Power panels
- (6) Distribution panels

One battery charger is available to each battery so that all batteries are maintained at full charge prior to a postulated loss-of-AC-power incident. The sixth battery charger is an installed spare that could replace any of the safeguards battery charger loads. Battery chargers are fed from respective MCCs and power a distribution panel.

Existing 125-VDC power and control schemes are unaffected by SPU. Similarly, no new equipment requiring 125-VDC motive or control power is expected to be added to support operation under SPU conditions.

Consequently, operation at SPU conditions will not result in load or equipment changes in the 125-VDC system.

9.8.1.8.3 Acceptance Criteria

The objective of this section is to demonstrate that the systems included herein are adequately designed to operate at the SPU power levels. The systems fall into one of two categories:

- Systems that are not affected by any parameter changes associated with SPU or are bounded by existing analysis and are therefore adequate for SPU operation.

- Systems that have small or reduced operating parameter changes and can be easily demonstrated as adequate.

9.8.1.8.4 Evaluation

The 480-V system, 13.8-kV system, EDGs, 118-VAC system, and 125-VDC system are described in the IP3 UFSAR (Reference 1) Sections 8.2.2, 8.2.3, and shown in Figure 8.2-9. The proposed SPU affects the operating BHP of the safety-related CR fan motors. All motors will operate within their nameplate ratings at SPU. EDG loading, including changes due to the CR fans, is bounded within the existing IP3 analysis. The EDGs will operate within their 30-minute rating (2000 kW) during peak accident loading conditions. The changes due to this SPU do not reduce the capacity and capability of any system to perform its intended function during anticipated operational occurrences and accident conditions. The 480-V system has been analyzed to approximate the maximum incremental change in operating voltage due to safety and non-safety-related motor bhp changes. The changes proposed by this SPU marginally affect the 480-V system operating voltages and do not affect the existing degraded voltage relay settings. There are no changes to the 125-VDC or 118-VAC systems as a result of the SPU. There are no changes to the control circuits, power circuits, or auxiliary support systems and features that support safety-related loads. The onsite electrical distribution system independence, redundancy, and testability to perform safety functions has not been affected. The onsite and offsite power systems will continue to meet the requirements of GDC-17 (Reference 2) following implementation of the proposed SPU.

The Emergency Diesel Engine Fuel Oil and Transfer System is not affected by the SPU. The subject area of Emergency Diesel Engine Fuel Oil and Transfer System effect due to the SPU has a bearing on reactor safety because the emergency diesel engine must be able to support the EDG operation throughout its design mission. The evaluation concludes that the loading on the EDGs resulting from SPU remains within the existing EDG load study. The demands on the Emergency Diesel Engine Fuel Oil and Transfer System are based on fuel consumption for the existing load study. Therefore, the Emergency Diesel Engine Fuel Oil and Transfer System will provide sufficient fuel to support diesel requirements at SPU conditions.

9.8.1.8.5 Results and Conclusions

Results are identified within the evaluation discussion for the applicable system.

The system evaluations included in this section concluded that the following systems are not affected by power SPU or are bounded by existing analysis and are considered adequate as installed for operation at SPU conditions:

- 480-V system
- 13.8-kV system
- EDG system
- 118-VAC instrument supply system
- 125-VDC system

The system evaluation included in this section concluded that the 480-V system voltage levels are not affected by power SPU. The evaluation concludes that the SPU will have a marginal effect on 480-V system voltage levels for normal operation and steam break LOCA conditions based on load flow analysis (Tables 9.8-13 and 9.8-14). The evaluation also concluded that all other aspects of the 480-V system are not affected by power SPU or are bounded by existing analyses and are considered adequate as installed for operation at SPU conditions.

9.8.1.9 Grid Stability

9.8.1.9.1 Input Parameters and Assumptions

Grid stability was reviewed to assess the transmission system impact resulting from power SPU at IP3. The purpose of the review was to verify that the transmission system would remain stable under SPU conditions, and to determine stability issues or modifications, if any, that require resolution to support power SPU. The evaluation included herein was based upon system studies performed by PowerGEM (Reference 3).

The studies were conducted to assess the system reliability impact of a power SPU by Entergy of the Indian Point 2 (IP2) and IP3 nuclear power plants. The studies followed the New York Independent System Operator (NYISO) System Reliability Impact Study (SRIS) Criteria and Procedures. The studies evaluated two independent SPU programs—the IP2 SPU from 1042 MW (gross) to 1078 MW and IP3 SPU from 1042 to 1080 MW. (Both units had previously been evaluated to a conservatively high value of 1042 MW.)

The review was based upon the inputs and assumptions identified below.

Interconnection Plan

No changes to the connection of IP2 and IP3 to the bulk power system, or the impedances of the generators of generator step-up transformers, are planned as part of the SPUs.

The study period was summer 2005 and winter 2005/2006. Plant gross MW outputs, which are maximum winter values, were assumed to be the same for both seasons.

The bulk power system of North America's entire eastern interconnection was represented in the study. The study focused on the area of the bulk system in proximity to, and most likely to be affected by the SPUs. This included the area of New York State from Utica, east to and including the New York-New England (NY-NE) interconnections, and from Utica, south to New York City (NYC), including the New York-Pennsylvania-Jersey-Maryland (PJM) interconnections.

9.8.1.9.2 Description of Analysis

The following analyses were conducted:

- Evaluation of impact on transfer limits and transfer capability

  Analyses determined the incremental impact of the SPUs on the normal and emergency transfer limits of transmission interfaces within the study area considering thermal, voltage and stability limitations. The interfaces considered were: Central-East, Total-East, Upper New York-Southeast New York (UPNY-SENY), UPNY-Con Edison, NYC Cable Interface, NYISO-PJM, PJM-NYISO, NYISO-Independent System Operator New England (ISONE), and ISONE-NYISO. Summer and winter peak load conditions were analyzed.

- Thermal Analysis

  Thermal analyses were conducted to evaluate the impact of the SPUs on the thermal transfer limits of the above interfaces, and on the Con Edison Bulk Power Transmission System in the Buchanan area, in accordance with the Con Edison design criteria. The effect of the SPUs on the phase-shifted regulating lines controlling the 1000-MW wheeling contract between Public Service Enterprise Group (PSE&G) and Con Edison were also evaluated.

- Voltage Analysis

  Voltage analyses were conducted to evaluate the impact of the SPUs on the New York bulk power system transmission system, the Con Edison system (emphasis on the Buchanan area), in accordance with NYISO Transmission Planning Guideline No. 2.

- Stability Analysis

  Stability analyses were conducted to assess the stability impact of the SPUs on the bulk transmission system in accordance with NYISO Transmission Planning Guideline No. 3. The stability analyses evaluated the transient stability performance of the system for normal criteria contingencies in accordance with Northeast Power Coordinating Council (NPCC), NYSRC, and NYISO criteria and standards. In addition, the impact of the SPUs on critical clearing times of Con Edison's substations in the area was determined.

- Extreme Contingence Assessment

  Evaluations were performed on significant load flow studies and significant stability studies for pre- and post-SPU system performance for the most severe contingencies as specified in Section 7.0 of NPCC's Basic Criteria, titled "Extreme Contingency Assessment."

- Short Circuit Analysis

  No changes to IP2 or IP3 generator impedances, generator step-up transformer impedances, or interconnections to the bulk power system are anticipated. Thus, there would be no effect of the SPUs on short circuit contributions when calculated in accordance with the NYISO guideline for fault current assessment.

9.8.1.9.3 Acceptance Criteria

Operation under SPU conditions will not adversely affect transmission system stability or existing power system performance.

9.8.1.9.4 Evaluation

The 345 kV offsite power systems discussed in this report are described in the IP3 UFSAR (Reference 1) Sections 8.1.1 and 8.2.1. No changes to the offsite power system are required as a result of the proposed IP3 SPU. Thermal analysis shows no adverse impact on the transmission interfaces to IP3 during increased plant output at SPU. Contingency analysis shows almost no change in voltage behavior at SPU based on the loss of several major transmission circuits or a large generator. Stability analysis shows that the grid remains stable after clearing various postulated faults. This stability analysis shows that the loss of the largest operating unit on the grid will not result in loss of grid stability and availability of offsite power to IP3. Since the IP3 SPU has almost no effect on the power grid, no voltage changes from the grid are seen on the IP3 distribution system that would result in changes to degraded voltage relays. Because the grid remains stable for the conditions analyzed, the 138 kV system will remain available for offsite power feed. The onsite electrical distribution system independence, redundancy, and testability to perform safety functions has not been affected by the grid system stability. The onsite and offsite power systems will continue to meet the requirements of GDC-17 (Reference 2) following implementation of the proposed SPU.

9.8.1.9.5 Results and Conclusions

The results of the analyses described above demonstrated that all applicable NYISO criteria are satisfied, and that no modifications are required for IP3 as a result of the SPUs.

The grid system stability is acceptable, and there are no modifications required as a result of IP3 SPU operation.

9.8.2 References

1. *Indian Point Nuclear Generating Unit No. 3, Updated Final Safety Analysis Report,* Docket No. 50-286.

2. 10CFR50, Appendix A, General Design Criteria for Nuclear Power Plants, Criterion 17

3. System Reliability Impact Study: Extended Power Uprate of IP2 and IP3, Power GEM Study, February 24, 2004

Table 9.8-1 IP3 IPB Duct Loading Generator Lagging Power Factor, (Exporting MVARs) House Loads from UAT(1,2,3)							
MVA	MWe	MVAR	Gen. Voltage (p.u.)	32 kA Bus Load (A)	16 kA Bus to MT31 Load (A)	16 kA Bus to MT32 UAT Load (A)	1.5 kA Tap Bus Load (kA)
1125.6	1093.5	267	0.95	31,095	14,919	16,183	1331
1103	1080	225	0.95	30,475	14,618	15,866	1328

Notes:

1. MVA, MVAR based on review of generator capability curve at SPU.
2. UAT load for normal plant operation from Table 9.8-3.
3. Loads shown in table are based on the evaluation model.

Table 9.8-2 IP3 IPB Duct Loading Generator Leading Power Factor, (Importing MVARs) House Loads from UAT(1,2,3)							
MVA	MWe	MVAR	Gen. Voltage (p.u.)	32 kA Bus Load (A)	16 kA Bus to MT31 Load (A)	16 kA Bus to MT32 UAT Load (A)	1.5 kA Tap Bus Load (kA)
1101	1093.5	-124	0.95	30,400	14,693	15,726	1328
1085	1080	-100	0.95	29,962	14,464	15,516	1327

Notes:

1. MVA, MVAR based on review of generator capability curve at SPU.
2. UAT load for normal plant operation from Table 9.8-3.
3. Loads shown in table are based on the evaluation model.

Table 9.8-3 UAT Load, Primary Winding - Normal Full-load Conditions			
	Primary Winding		
	MW	MVAR	MVA(1)
Existing Load(2)	40.191	26.239	47.998
Load Increase for SPU	0.048	0.041	
Total Load at SPU	40.239	26.280	48.061

Notes:

1. $MVA = (MW^2 + MVAR^2)^{1/2}$
2. Existing UAT primary loading taken from IP3 load flow analysis and used as a baseline for the evaluation model.
3. Load Increase for SPU = Total Load at SPU - Existing Load. This includes the effects of revised bhp values, transformer and cable losses, and voltage effects on constant impedance loads.
4. Total at SPU results are taken directly from the evaluation model and include equipment losses from transformers and cables. The bhp changes at SPU conditions have been included.

Table 9.8-4 MT Output Loading (Approx. 48 MVA UAT Load)							
Main Generator Output[1]				MT Output Load[2]			Max Rated Output Using Both Transformers[3]
MW	MVAR	MVA[4]	PF, %[5]	MW31 Loading MVA[6]	MT32 Loading MVA[6]	Total Plant Output MVA[6,7]	MVA
Unit Operating at Lagging Power Factor (exporting VARs)							
1093.5	267	1125.6	97.1	526.389	526.741	1053.104	1214
Unit Operating at Leading Power Factor (importing VARs)							
1093.5	-124	1101	99.3	548.596	548.990	1097.560	1214

Notes:

1. Main generator output based on discussion given in section 9.8.1.1.1.
2. When house load is supplied via UAT, MT Output Load = Main Generator Output – (UAT load + Main Transformer Losses). When the house load is supplied via the SAT, MT Output Load = Main Generator Output – Main Transformer Losses.
3. MT rated output taken from MT at 65°C rise.
4. $MVA = (MW2 + MVAR2)^{1/2}$.
5. Power Factor (PF), % = $\frac{MW}{MVA} x100$
6. Loads shown in table are from evaluation model load flow results.
7. MT31 and MT32 have different X/R ratios. Therefore, total plant output MVA is taken directly from load flow analysis using the swing bus power absorption.

Table 9.8-5 Main Transformer Output Loading (no UAT load)							
Main Generator Output[1]				MT Output Load[2]			Max Rated Output Using Both Transformers[3]
MW	MVAR	MVA[4]	PF, %[5]	MW31 Loading MVA[6]	MT32 Loading MVA[6]	Total Plant Output MVA[6,7]	MVA
Unit Operating at Lagging Power Factor (exporting VARs)							
1093.5	267	1125.6	97.1	546.674	547.180	1093.828	1214
Unit Operating at Leading Power Factor (importing VARs)							
1093.5	-124	1101	99.3	565.640	566.164	1131.776	1214

Notes:

1. Main generator output based on discussion given in section 9.8.1.1.1.
2. When house load is supplied via UAT, MT Output Load = Main Generator Output – (UAT load + Main Transformer Losses). Otherwise, MT Output Load = Main Generator Output – Main Transformer Losses.
3. MT rated output taken from MT nameplate at 65°C rise.
4. MVA = $(MW2 + MVAR2)^{1/2}$.
5. Power Factor (PF), % = $\frac{MW}{MVA} x100$
6. Loads shown in table are from evaluation model load flow results.
7. MT31 and MT32 have different X/R ratios. Therefore, total plant output MVA is taken directly from load flow analysis using the swing bus power absorption.

Table 9.8-6 UAT Load, Secondary Winding – Maximum Full-Load Conditions				
	Output Loading			Maximum Nameplate Rating MVA @55/65°C
	MW	MVAR	MVA[1]	
Existing Load[2]	39.873	19.782	44.510	43.00 / 48.16
Load Increase for SPU	0.048	0.022	0.053	
Total at SPU	39.921	19.804	44.563	43.00 / 48.16

Notes:

1. $MVA = (MW^2 + MVAR^2)^{1/2}$
2. Existing UAT secondary loading taken from IP3 load flow analysis and used as a baseline for the evaluation model.
3. Load Increase for SPU = Total at SPU – Existing Load. This includes the effects of revised bhp values, transformer and cable losses, and voltage effects on constant impedance loads.
4. Total at SPU results are taken directly from the evaluation model and include equipment losses from transformers and cables. The bhp changes at SPU conditions have been included.

Table 9.8-7 SAT Output Loading Supplying Buses 5 and 6 during Normal Unit Operating Conditions				
	Output Loading			Maximum Nameplate Rating MVA @55/65°C
	MW	MVAR	MVA(1)	
Existing Load(2)	7.483	4.216	8.589	43.00 / 48.16
Load Increase at SPU(3)	-0.001	0.000	-0.001	
Total at SPU(4)	7.482	4.216	8.588	43.00 / 48.16

Table 9.8-8 SAT Output Loading Supplying Buses 1, 2, 3, 4, 5 and 6 during Steam Break Accident Condition				
	Output Loading			Maximum Nameplate Rating MVA @55/65°C
	MW	MVAR	MVA(1,5)	
Existing Load(2)	43.970	22.316	49.309	43.00 / 48.16
Load Increase at SPU(3)	-0.016	0.000	-0.016	
Total at SPU(4)	43.954	22.316	49.295	43.00 / 48.16

Notes:

1. $MVA = (MW^2 + MVAR^2)^{1/2}$
2. Existing SAT secondary loading taken from IP3 load flow analysis and used as a baseline for the evaluation model.
3. Load Increase at SPU = Total at SPU – Existing Load. This includes the effects of revised bhp values, transformer and cable losses, and voltage effects on constant impedance loads.
4. Total at SPU results are taken directly from the evaluation model and include equipment losses from transformers and cables. The bhp changes at SPU conditions have been included.
5. Removing the conservatism from the existing load flow model brings the output loading within the maximum nameplate rating.

Table 9.8-9

6900-V Bus Loading (maximum loading conditions)

Bus	Bus Loading[1]				Bus Voltage KV[3]	Bus Amps[4]	Breaker Rating Amps[5]
	Loading	MW	MVAR	MVA[2]			
1	Existing	10.70	5.36	11.97	6.769	1021	
	Incremental	-0.07	-0.04	-0.08	-1	-7	1200
	Total	10.63	5.32	11.89	6.768	1014	
2	Existing	10.16	5.19	11.41	6.769	973	
	Incremental	0.05	0.02	0.05	-1	5	1200
	Total	10.21	5.21	11.46	6.768	978	
3	Existing	10.67	5.06	11.81	6.770	1007	
	Incremental	-0.07	-0.04	-0.08	-1	-7	1200
	Total	10.60	5.02	11.73	6.769	1000	
4	Existing	8.33	4.14	9.30	6.770	793	
	Incremental	0.14	0.08	0.16	-1	14	1200
	Total	8.47	4.22	9.46	6.769	807	
5	Existing	23.34	11.86	26.18	7.202	2099	
	Incremental	0.03	0.01	0.03	0	3	2000
	Total[6]	23.37	11.87	26.21	7.202	2102	
6	Existing	20.63	10.41	23.11	7.202	1854	
	Incremental	-0.05	-0.02	-0.05	0	-4	2000
	Total[7]	20.58	10.39	23.05	7.202	1850	
7	Existing	2.391	0.972	2.581	6.841	218	
	Incremental	0.080	0.038	0.089	-1	7	2000
	Total[8]	2.471	1.010	2.669	6.840	225	

Notes:

1. Existing bus-loads, incremental loads, and total load at SPU determined from IP3 load flow analysis.
2. MVA = $(MW^2 + MVAR^2)^{1/2}$
3. Bus voltages are taken directly from load flow results, unless noted otherwise.
4. *Non-segregated bus currents are taken directly from load flow results, unless noted otherwise.*
5. The 6900 V incoming supply breaker ratings are taken from one-line diagrams.
6. Loading shown for bus 5 includes loads from buses 1 and 2.
7. Loading shown for bus 6 includes loads from buses 3 and 4.
8. For bus 3NBY01, the total load is calculated directly from the incremental load. Voltage and current results are extrapolated based on the incremental load.

Table 9.8-10 6900-V Motor Feeder Breaker Loading at SPU Conditions		
Description	**Motor Load, Amps(1)**	**Breaker Rating, Amps(2)**
Reactor Coolant Pumps		
RCP31, 32, 33, 34	502/634	1200
Condensate Pumps		
CP31, 32, 33	220	1200
Heater Drain Pumps		
HD31, 32	78	1200
Condensate Booster Pump		
CBP31, 32, 33	58	1200

Notes:

1. Motor load amps taken from Table 9.8-11 of this report.
2. Feeder breaker ratings taken from IP3 single-line diagrams.

Table 9.8-11

Motor Load Current and Feeder Cable Ampacity at Uprate Conditions

Affected Pump Motor Load	Rated HP(1)	SPU Load BHP(2)	Power Factor(1)	Load Flow(3) MW	Load Flow(3) MVAR	Load Current at SPU, Amps(4)	Cable Ampacity(5)
Condensate Pump CP31 CP32 CP33	3000	2610	0.90	2.041	0.988	220	315
Cond Booster Pump CBP31 CBP32 CBP33	700	680	0.90	0.540	0.261	58	315 (Note 6)
Heater Drain Pump HD31 HD32	1000	910	0.90	0.718	0.348	78	315
Reactor Coolant Pump RCP31 RCP32 RCP33 RCP34	6000	5969 (Hot)	0.90	4.722	2.288	510	630
Reactor Coolant Pump RCP31 RCP32 RCP33 RCP34	6000	7425 (Cold)	0.90	5.874	2.846	634 (Note 7)	630

Notes:

1. The rated HP for each motor was taken from the IP3 motor data calculation. The cold loop rating for the RCPs was taken from the EMD Curtis-Wright RCP motor evaluation.
2. SPU load bhp for BOP motors (condensate pumps, condensate booster pumps, and heater drain pumps) were based on analysis at 3244 MWt (3216 MWt with 0.5% margin).
3. Load flow MW and MVAR are taken from load flow analysis at SPU. MW and MVAR for RCPs at cold loop calculated by direct proportion between cold loop and hot loop BHP.
4. Motor full-load current (amps) calculated at 90% rated voltage, as follows:

$$\frac{\sqrt{MW^2 + MVAR^2}}{\sqrt{3} \times 6.6kV \times 0.9} \times 1000$$

5. Minimum feeder cable ampacity based on time-current coordination plots given in IP3 short-circuit calculations.
6. Condensate booster pump cable ampacity could not be confirmed. It is assumed that the cable is a 250kcmil with an ampacity similar to other cables of the same size and voltage rating.
7. Although the cold loop current drawn by the RCP marginally exceeds the cable ampacity at 90% of rated voltage, motor current would be 627 A at 91% of rated voltage. Also, the RCP cold loop current is not continuous and its hot loop current is less than the cable continuous ampacity.

Table 9.8-12 6600-V Motors Affected by SPU Conditions		
Affected Pump Motor Load	Nameplate Rating (HP)[1]	SPU Load (BHP)[2,3]
Condensate Pumps		
CP31	3000	2610
CP32	3000	2610
CP33	3000	2610
Cond. Booster Pump		
CBP31	700	680
CBP32	700	680
CBP33	700	680
Heater Drain Pump		
HD31	1000	910
HD32	1000	910
Reactor Coolant Pumps		
RCP31	6000 7500	5969 (Hot) 7425 (Cold)
RCP32	6000 7500	5969 (Hot) 7425 (Cold)
RCP33	6000 7500	5969 (Hot) 7425 (Cold)
RCP34	6000 7500	5969 (Hot) 7425 (Cold)

Notes:

1. The rated HP for each motor was taken from the IP3 motor data calculation. The cold loop rating for the RCPs was taken from the RCP motor evaluation.
2. SPU Load bhps for BOP motors (condensate pumps, condensate booster pumps, and heater drain pumps) were based on analysis at 3244 MWt (3216 MWt with 0.5% margin).
3. RCP BHP for hot- and cold-loop operation taken from the RCP motor evaluation.

Table 9.8-13 Estimated Voltage at 480-V Switchgear Buses (full-load normal operation)				
	Voltage (V)			
			Delta	
Equipment	Existing[1]	SPU[2]	(V)	(%)
Bus 2A	447	447	0	0
Bus 3A	450	450	0	0
Bus 5A	442	442	0	0
Bus 6A	441	441	0	0
Bus 312	442	442	0	0
Bus 313	453	453	0	0

Note:

1. Existing bus voltages taken from IP3 load flow analysis and used as a baseline for the evaluation model.
2. Bus voltages at SPU taken from the evaluation model. These voltages do not represent actual bus voltages, but only signify the expected voltage change due to SPU.

Table 9.8-14 Estimated Voltage at 480-V Switchgear Buses (LBLOCA condition)				
	Voltage (V)			
			Delta	
Equipment	Existing[1]	SPU[2]	(V)	(%)
Bus 2A	475	474	1	0.2
Bus 3A	480	479	1	0.2
Bus 5A	459	457	2	0.4
Bus 6A	475	475	0	0.0
Bus 312	473	473	0	0.0
Bus 313	483	483	0	0.0

Note:

1. Existing bus voltages taken from IP3 load flow analysis and used as a baseline for the evaluation model.
2. Bus voltages at SPU taken from the evaluation model. These voltages do not represent actual bus voltages, but only signify the expected voltage change due to SPU.

9.9 Piping and Supports

9.9.1 Introduction

The purpose of the piping review is to evaluate piping systems for the effects resulting from stretch power uprate (SPU) conditions to demonstrate design basis compliance in accordance with USAS B31.1-1967, Code for Pressure Piping (Reference 1).

The scope of the Indian Point Unit 3 (IP3) piping that was evaluated for SPU conditions included the following piping systems.

Steam and Power Conversion Systems

- Main steam (MS)
- Extraction steam
- Condensate
- Feedwater
- Heater drains
- Moisture separator, moisture pre-separator (MOP), and reheater drains
- Steam generator blowdown
- Circulating water

Auxiliary Systems

- Auxiliary feedwater (AFW)
- Fuel pit cooling
- Service water (SW)

Miscellaneous Balance-of-Plant (BOP) Systems

- Auxiliary steam

9.9.2 Description of Analysis and Evaluation

System operation at SPU conditions generally results in increased pipe stress levels and pipe support loads due to slightly higher operating temperatures, pressures, and flow rates internal to the piping.

The piping systems affected by SPU were evaluated to the current code of record for IP3 as follows.

Pre-uprate and SPU operating data (operating temperature, pressure, and flow rate) were obtained from heat balance diagrams, calculations, and/or other applicable reference documents.

Change factors were determined, as required, to evaluate and compare the changes in operating conditions. The thermal, pressure, and flow rate change factors were based on the following ratios:

- The thermal change factor was based on the ratio of the SPU to pre-uprate operating temperature. That is, thermal change factor is $(T_{uprate}-70°F)/(T_{pre}$-uprate$-70°F)$.
- The pressure change factor was determined by the ratio of $(P_{uprate}/P_{pre\text{-}uprate})$.
- The flow rate change factor was determined by the ratio of $(Flow_{uprate}/Flow_{pre\text{-}uprate})$.

These thermal, pressure, and flow rate change factors were used in determining the acceptability of piping systems for SPU conditions.

For thermal, pressure, and flow rate change factors less than or equal to 1.0 (that is, the pre-uprate condition envelops or equals the SPU condition), the piping system was concluded to be acceptable for SPU conditions.

For thermal, pressure, and flow rate change factors greater than 1.0, additional evaluations or detailed analyses were performed to address the specific increase in temperature, pressure, and/or flow rate to document design basis compliance.

Applicable rupture postulation criteria and related design basis documents for IP3 were reviewed and changes to piping system stress levels resulting from the SPU were reconciled against these design basis documents. The evaluations performed concluded that the SPU does not result in any new or revised break locations, and the existing design basis for pipe break, jet impingement, and pipe whip considerations remains valid for the SPU.

All impacted piping and supports were evaluated for changes in operating temperatures, pressures, and flow rates resulting from SPU. The results of these evaluations showed that all piping and supports continue to satisfy existing design basis requirements. Piping systems experiencing higher flow rates will be reviewed for flow-induced vibration (FIV) issues as part of the start-up testing program related to the overall implementation of the SPU.

There were no changes to any seismic inputs (amplified response spectra) or loads resulting from the SPU. The existing seismic design basis for all equipment qualification (EQ) remains valid and unaffected by the SPU.

The evaluations reconciling SPU conditions have addressed applicable piping systems for potential increases in steam-hammer or water-hammer loads. The MS piping was evaluated to reconcile the increased loads resulting from a turbine-stop-valve-closure event. The evaluations performed concluded that the MS piping system can withstand the steam-hammer loads associated with SPU conditions.

The results of the piping system evaluations indicate that all piping systems remain acceptable and will continue to satisfy design basis requirements when considering the temperature, pressure, and flow rate effects resulting from SPU conditions.

For those piping systems that required detailed analyses for change factors greater than 1.0, a summary of revised stress levels corresponding to SPU conditions is provided in Table 9.9-1. The results presented include existing stress levels (that is, pre-uprate), revised pipe stress levels for SPU conditions, allowable stress for the applicable loading condition, and the resulting design margin for each piping analysis that was evaluated to reconcile SPU conditions. The design margin provided is based on the ratio of the calculated stress divided by the allowable stress.

Plant Walkdown Summary

To further support the evaluations that were performed on the condensate, feedwater, extraction steam, feedwater heaters vents and drains, and moisture separator and reheater drains systems, a plant walkdown of these power cycle systems was performed to review the piping layouts and support configurations. The purpose of the piping system walkdowns was to assess the adequacy of the installed piping deadweight spans and to review the existing thermal flexibility of the piping systems.

The portion of these piping systems located in the Turbine Building was the focus of the walkdowns performed. The overall assessment from the walkdowns performed concluded that the existing piping that was observed was adequately supported and that it contained adequate flexibility to accommodate the small temperature and pressure changes resulting from SPU. Piping systems were determined to be adequately supported if the piping was supported by vertical supports, rod hangers, or spring hangers, so that piping spans were consistent with the guidance presented in USAS B31.1-1967, Code for Pressure Piping (Reference 1). Piping systems were determined to have adequate flexibility if the following attributes were observed:

- Piping lengths and offsets were consistent with simplified industry methods of determining flexibility (for example, nomographs).

- There were no non-integral or integrally welded piping anchors installed.
- There was a sufficient and reasonable number of piping elbows installed providing thermal flexibility.

9.9.3 Acceptance Criteria

The piping evaluations were performed to demonstrate design basis compliance in accordance with the USAS B31.1–1967, Code for Pressure Piping (Reference 1).

For those piping systems that required detailed analyses, Table 9.9-1 provides a summary of the allowable stress for the applicable loading condition that required evaluation, along with the existing (pre-uprate) stress and revised stress corresponding to SPU conditions.

9.9.4 Results and Conclusions

The piping and pipe support evaluations performed showed that all piping systems remain acceptable and will continue to satisfy design basis requirements when considering the temperature, pressure, and flow rate effects resulting from SPU conditions. The piping evaluations also concluded that the Main Steam System (MSS) can withstand the steam-hammer loads associated with SPU conditions. The piping and support systems will continue to meet their licensing basis and satisfy the requirements of General Design Criterias (GDCs)-1, 2, 4, 14, and 15.

The evaluations also demonstrated that the SPU does not result in any new or revised break locations, and the design basis for pipe break, jet impingement, and pipe whip considerations remain valid for the SPU. Hence, for rupture postulation issues, the piping, and support systems continue to meet their licensing basis and satisfy the requirements of GDC- 4.

There were no changes to any seismic inputs (amplified response spectra) or loads resulting from SPU. The existing seismic design basis for all equipment qualification remains valid and unaffected by the SPU. Therefore, the existing licensing basis for the seismic qualification of equipment remains valid and satisfies the requirements of GDCs-1, 2, 4, 14, and 30.

Lastly, an important element of successful operation of IP3 at SPU conditions is the monitoring and evaluation of piping vibration. Lessons learned from power uprates indicate that increased vibration of components in systems experiencing increased flow rates under uprated conditions has caused fatigue-induced failures, and that these conditions may not be readily identified during the analysis phase of the SPU Program. Accordingly, in support of the SPU, piping vibration will be monitored during the power ascension to the SPU power level.

9.9.5 References

1. *USA Standard Code for Pressure Piping, Power Piping USAS B31.1*, 1967 Edition, The American Society of Mechanical Engineers, New York, NY.

Table 9.9-1 Stress Summary at SPU Conditions					
Piping Analysis Description	**Loading Condition(1)**	**Existing Stress (psi)**	**SPU Stress (psi)**	**Allowable Stress (psi)**	**Stress Ratio(2)**
Main Steamline 1 (inside containment)	DL + LP + TSV	12,410	12,587	21,000	0.60
Main Steamline 2 (inside containment)	DL + LP + TSV	11,833	11,993	21,000	0.57
Main Steamline 3 (inside containment)	DL + LP + TSV	12,812	13,234	21,000	0.63
Main Steamline 4 (inside containment)	DL + LP + TSV	12,649	12,811	21,000	0.61
Main Steamlines 1, 2, 3 and 4 (outside containment)	DL + LP + TSV	18,489	19,171	19,950	0.96
Extraction Steamlines to Inlet of Feedwater Heaters 36A/B/C	Thermal expansion	14,189	14,331	22,500	0.64

Notes:

1. Loading condition "DL + LP + TSV" corresponds to the combination of stresses due to deadweight +. pressure + turbine stop valve effects.
2. Stress Ratio reported is based on the ratio of SPU stress divided by the allowable stress.

9.10 BOP Instrumentation and Controls

A review was performed on the following balance-of-plant (BOP) systems:

- Steam and power conversion systems
- Auxiliary systems
- Miscellaneous BOP systems
- Electrical systems

As a result of the review, it was concluded that the BOP instrument and controls (I&C) systems equipment will accommodate the Indian Point Unit 3 (IP3) stretch power uprate (SPU) operation

It was also determined that the changes in plant process values resulting from SPU conditions do not require re-scaling of any existing BOP instrumentation.

9.11 Area Ventilation (HVAC)

A review of Indian Point Unit 3 (IP3) area heating, ventilation, and air conditioning (HVAC) systems was performed to determine the impact of the stretch power uprate (SPU) on system operation. Systems reviewed were grouped as follows:

- Primary Auxiliary Building (PAB)/Electrical Penetration Tunnels (EPTs)/Emergency Diesel Generator (EDG) Building HVAC Systems
- Fuel-Storage Building (FSB) HVAC System
- Central Control Room (CCR) HVAC System
- Containment Heating, Ventilation, and Heat Removal HVAC System

9.11.1 Introduction

9.11.1.1 HVAC Systems in the PAB, EPT, and EDG Building

The IP3 HVAC systems in the PAB, EPT, and EDG Building are designed to remove heat generated from operating equipment and piping, and to maintain safe ambient operating temperatures for equipment and personnel. The HVAC systems associated with areas containing radioactive material also control airborne radioactive contamination, ensure air flow is from areas of low contamination to areas of higher contamination, provide for controlled cleanup of contaminated air, and provide for safe release to the environment.

9.11.1.2 HVAC System in the Fuel-Storage Building

The primary function of the HVAC system in the FSB is to provide ventilation air to remove heat and moisture buildup generated from spent fuel decay heat and from operating equipment, and to maintain safe ambient operating temperatures for equipment and personnel. The secondary function of this system is to remove potential airborne radioactive contamination from the area during an accident and provide for controlled cleanup of contaminated air for safe release to the environment. Note that Section 6.11.9 takes no credit for filtration in the FSB.

9.11.1.3 Central Control Room HVAC System

The IP3 CCR HVAC system is designed to provide the following functions:

- Maintain the required design temperature and relative humidity inside the CCR during all modes of plant operation.

- Isolate the CCR to prevent infiltration of toxic gases and smoke, and cleanup of airborne radioactive particulates in the outdoor air entering the CCR during high radiation and/or safety injection (SI) conditions.

- Provide slight positive pressure in the CCR during normal and high radiation or SI modes of operation to prevent in-leakage of airborne contamination from adjoining space.

9.11.1.4 Containment Heating, Ventilation, and Heat Removal System

The Containment Heating, Ventilation, and Heat Removal System is designed to accomplish the following functions:

- Remove normal heat loss from equipment and piping to ensure that a maximum ambient temperature of 130°F is not exceeded.

- Provide positive circulation of air across the refueling water surface to ensure personnel access and safety during shutdown.

- Provide containment heating to maintain a minimum containment temperature of 50°F before the reactor is taken above the cold shutdown condition.

- Purge the containment vessel to the plant vent for dispersion to the environment.

- Depressurize the containment vessel following an accident.

- Provide pressure relief via an exhaust system.

The above functions are accomplished in conjunction with the following subsystems:

- Containment recirculation cooling system
- Control rod drive mechanism (CRDM) cooling system
- Containment purge and pressure relief system

9.11.2 Input Parameters and Assumptions

The primary input assumption associated with evaluating the HVAC systems was that the systems are capable of performing their required functions at the current power level. The systems were evaluated based on input parameters resulting from associated SPU operating conditions as compared with HVAC systems design input parameters.

9.11.3 Description of Analysis and Evaluation

The IP3 HVAC systems were evaluated to determine if the existing system design is capable of performing intended functions under conditions associated with plant SPU to 3216 MWt core power. Expected SPU conditions were compared and evaluated against system design conditions.

The need to perform additional analyses and/or modifications necessary to support SPU was taken into consideration as part of the evaluation.

9.11.4 Acceptance Criteria

The overall acceptance criterion is that the HVAC systems remain capable of performing their design function under IP3 SPU operating conditions. System design parameters must bound SPU operating conditions.

The potential radiological exposure to the operators under post-accident conditions is addressed by the accident analyses. The loss-of-coolant accident (LOCA) analysis assumes an SPU core power level of 3216 MWt. The current analysis must bound the SPU conditions.

9.11.3.5 Design Criteria

The HVAC systems are designed to remove heat from normal heat loss from equipment and maintain a regulated ambient temperature and humidity for equipment and personnel. In an accident condition, an HVAC system may be responsible for removing smoke, gas, and other toxins that may enter a safety-related area.

Portions of the HVAC systems are safety-related. The HVAC systems (as applicable) were designed to meet the intent of the General Design Criteria (GDC), which were published by the Atomic Energy Commission (AEC) in the Federal Register of July 11, 1967. The NRC concluded in the *Safety Evaluation Report* (SER), that the plant design conformed to the intent of the newer criteria. SPU operation does not affect the ability of the HVAC Systems to meet these requirements. Therefore the HVAC systems continue to meet the criterion requirements.

In addition to NRC Criterion 2 (*Performance Standards*), New York Power Authority (NYPA) committed to the requirements of Sections III.G, III.J, III.L and III.O of 10CFR50 Appendix R (Reference 1) as applicable. Evaluation of IP3 fire protection features against the requirements of Section III.G of Appendix R to 10CFR50 was completed and the report submitted to NRC on August 16, 1984. SPU operation does not affect the ability of the HVAC Systems to meet these requirements. Therefore the HVAC Systems continues to meet the criterion requirements.

In addition to AEC Criterion 17 (*Monitoring Radioactive Releases*) and 70 (*Control of Radioactive Releases to the Environment*), provisions are included in the HVAC Systems design to meet 10CFR20 (Reference 2) limits as applicable. The radioactive releases at SPU conditions are within the original design basis of the plant. Therefore, the HVAC Systems will continue to meet the criterion requirements.

Environmental qualification (EQ) of HVAC systems electrical equipment important to safety is demonstrated in EQ packages compiled in accordance with the requirements of 10CFR50.49 (Reference 3) and DOR Guidelines as applicable (see LAR Section 11, and ER Section 10). Monitoring of the HVAC systems is provided as a result of the Three Mile Island 2 (TMI-2) accident investigation and the requirements of Regulatory Guide (RG) 1.97 (Reference 4). The HVAC systems are designed with provisions to allow post-accident sampling in accordance with the post-TMI Requirements of NUREG 0578 and 0737 (References 5 and 6). The Technical Specification requirements for sampling provisions were deleted by Amendment 210, dated February 6, 2002. SPU operation does not affect the ability of the HVAC systems to meet these requirements. Therefore, the HVAC systems continues to meet the criterion requirements.

The HVAC systems design criteria (as applicable), as it relates to accident analyses and the NSSS/BOP interface, are described in Sections 4 and 5 of this document. Other criterion required to meet SPU conditions are listed in the acceptance criteria above.

9.11.5 Results and Conclusions

9.11.5.1 HVAC Systems in the PAB, EPT, and EDG Building

Operation at SPU conditions will not increase the heat load in the PAB above the bounding analysis level, and will not affect the potential airborne contamination in the building.

Operation under SPU conditions will not affect the heat load in the EPT or operation of equipment in the EPT.

Operation at SPU conditions will not affect the heat load or operation of equipment in the EDG Building.

Based on the results discussed above, the impact of SPU operating conditions on the PAB, EPT and EDG HVAC systems will not adversely affect the operational ability of these systems. The systems will function as designed under SPU conditions without limitation. No plant modifications to the PAB, EPT, and EDG HVAC systems are required to support SPU.

9.11.5.2 HVAC System in the Fuel-Storage Building

Operation at SPU conditions will not increase the heat load in the FSB above the bounding analysis (that is, analysis bounds SPU operating conditions). Fuel decay heat will increase slightly as a result of SPU operation, but the normal spent fuel pit (SFP) temperature will not be affected by this slight increase.

Based on the results the evaluation, the impact of SPU on the FSB HVAC system does not adversely affect the operational ability of the system. The FSB HVAC system will function as designed under SPU conditions without limitation. No plant modifications to the FSB HVAC system is required to support SPU.

9.11.5.3 Central Control Room HVAC System

Based on the results discussed above, the impact of SPU on the CCR HVAC system does not adversely affect the operational ability of the system. The system will function as designed under SPU conditions without limitation. No plant modifications to the CCR HVAC system is required to support SPU. However, modifications are planned for the CCR HVAC system during R13 outage to improve charcoal filter design.

9.11.5.4 Containment Heating, Ventilation, and Heat Removal System

Results of the SPU evaluation in conjunction with subsystems making up the Containment Heating, Ventilation, and Heat Removal System are provided below. Based on these results, the impact of SPU on the Containment Heating, Ventilation, and Heat Removal System does not adversely affect the operational ability of the system and associated subsystems. The system and associated subsystems will function as designed under SPU conditions without limitation. No plant modifications to the CCR HVAC system are required to support SPU.

- Containment Recirculation Cooling System

  The Containment Recirculation Cooling System and associated filtration systems maintain ambient containment temperature at or below 130°F, remove heat from containment following an accident, and clean up post-accident containment atmosphere. During the normal mode operation under SPU conditions, the containment heat load will increase slightly. However, the fan cooling units (FCUs), in conjunction with station operating procedures, will remain adequate for normal operation to maintain containment temperature below 130°F.

For post-accident conditions, the FCUs cooling capacity performance was evaluated as a part of the accident analysis. The capacity to remove fission products from the containment atmosphere after an accident was also evaluated as part of the accident analysis. Under SPU conditions, the system design remains bounding.

- CRDM Cooling System

The CRDM Cooling System is designed to maintain the control rod drive operating coils stacks at or below their maximum operating temperature of 200°F. Operation under SPU conditions will not significantly affect heat loads or temperature associated with the CRDM. The CRDM Cooling System will continue to meet system functional requirements under SPU operating conditions.

- Containment Purge and Pressure Relief System

Operation under SPU conditions will not affect operation of the Containment Purge and Pressure Relief System. The containment purge and make-up capability are not impacted by SPU, and operation under SPU conditions will not affect pressure build up in containment during reactor power operation, or the operation of the Containment Pressure Relief System. The Containment Purge and Pressure Relief System will continue to meet system functional requirements under SPU operating conditions.

9.11.6 References

1. 10CFR50, Appendix R, *Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1979,* June 20, 2000.

2. 10CFR20, *Standards for Protection Against Radiation,* May 21, 1991.

3. 10CFR50.49, *Environmental Qualification of Electric Equipment Important To Safety for Nuclear Power Plants,* 66FR64738, December 14, 2001.

4. NRC Regulatory Guide 1.97, *Instrumentation of Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident* (Errata published July 1981) (Draft RS 917-4, Proposed Revision 2, published December 1979) (Rev. 3, ML003740282).

5. NUREG-0578, *TMI Lessons Learned Task Force Status Report and Short Term Recommendations*, July 1979.

6. NUREG-0737, *Clarification of TMI Action Plan Requirements*, November 1980.

9.12 Auxiliary Feedwater System

9.12.1 Introduction

The Auxiliary Feedwater System (AFWS) is designed to provide emergency cooling for the reactor by supplying water to the steam generators. The Feedwater System (FWS) provides water to the steam generators during power operation while the AFWS is used at low power when the steam is not available to operate the main feedwater system. The AFWS also operates under the following conditions:

- Loss-of-main feedwater
- Rupture of a main steam line
- Loss-of-coolant accident (LOCA)
- Loss-of-AC power (LOAC)
- Steam generator tube rupture (SGTR)
- Anticipated transient without scram (ATWS)
- Alternate safe shutdown
- Station blackout (SBO)

The AFWS also provides feedwater to the steam generators to support the ability to cool the RCS to the point at which the Residual Heat Removal System (RHRS) may be brought online to complete the cooldown process (during normal-operation or post-accident scenarios).

Auxiliary feedwater (AFW) is supplied by the actuation of two motor-driven AFW pumps (MDAFWPs), which are initiated by any of the following signals.

- Low-low water level in any steam generator
- Automatic trip (not manual) of any main feedwater pump turbine
- Any safety injection (SI) signal
- ATWS mitigating system actuation circuitry (AMSAC) signal
- Loss-of-offsite power (LOOP)
- Manual actuation

In addition, one turbine-driven AFW pump (TDAFWP) starts on any of the following actuation signals, although no automatic delivery of water to the steam generators occurs (the TDAFWP is automatically started, but must be manually aligned by the operator to allow delivery of AFW flow to the steam generators).

- Low-low water level in any two steam generators
- LOOP concurrent with unit trip and no safety injection signal
- AMSAC signal

The MDAFWPs are powered by the emergency diesel generators (EDGs). The pumps take suction from the condensate storage tank (CST) for delivery to the steam generators. Each MDAFWP is designed to supply the minimum required flow within 60 seconds of the initiating signal. Although the TDAFWP is automatically actuated, this pump is not available to deliver flow to the steam generators until operator action is taken to align the TDAFWP.

The AFWS consists of two distinct safety-grade subsystems (that is, two pumping systems using different sources of motive power for their pumps) to ensure reliability of the feedwater supply. The plant original design consisted of a subsystem with two trains, each with a 100-percent capacity MDAFWP designed to deliver flow to two of the four steam generators. The second subsystem consisted of a 200-percent capacity TDAFWP designed to deliver flow to all four steam generators.

There are two independent water supplies available to the AFWS. These two sources are configured so that there are two redundant suction flow paths to each AFW pump. One flow path is a single line from the CST; the second flow path is a single line from the city water storage tank. Only one source is aligned to the pumps at one time.

9.12.2 Input Parameters

The required AFWS flow and capacity are proportional to the amount of decay heat that must be removed from the core during accident conditions. The AFWS functions associated with normal plant startup and shutdown are not dependent on core power and, therefore, are not affected by the stretch power uprate (SPU).

The design capacities of AFW pumps as follows:

- MDAFWP: 400 gpm
- TDAFWP: 800 gpm

The AFW pumps are normally aligned to take suction from the CST for delivery to the steam generators. The limiting transient with respect to CST inventory requirements is the LOAC transient. The IP3 licensing basis requires that, in the event of a LOAC, sufficient CST useable inventory must be available to bring the plant from full-power to hot-standby conditions, and maintain the plant at hot standby for 24 hours. Since the duration of the SBO event is less than 24 hours, it is bounded by maintaining hot standby for 24 hours. (see subsection 4.2.4.1). Technical Specification 3.7.6 requires a minimum CST useable inventory of 360,000 gallons. An alarm and interlock at 20 ft (< or = 385,000 gallons) ensures the compliance with Technical Specification 3.7.6. The interlock closes other users' isolation valves to preserve CST volume for AFWS.

The CST operating water temperature is at the maximum allowable value of 120°F.

The design pressure and temperature of AFW pump discharge piping and components are 1440 psig and 450°F. The design pressure and temperature of AFW pump suction piping and components are 150 psig and 225°F.

9.12.3 Description of Analysis and Evaluation

Evaluation of the AFWS consisted of documenting the current system functional requirements for transients/accidents and the extent to which SPU impacts these AFWS functions.

This evaluation compared the design pressure and temperature of piping and components with the SPU maximum operating pressure and temperature (that is, AFWS functions associated with normal plant startup and shutdown).

The evaluation also considered the extent to which sufficient AFW flow is provided to the steam generators following a design basis accident (DBA), and the extent to which adequate water inventory is available in the CST to satisfy AFWS functional requirements (see subsections 4.2.4.1, 6.3.7, 6.3.8, and 6.8 of this document).

9.12.4 Acceptance Criteria

The design pressure and temperature of piping and components bounds the SPU maximum operating pressure and temperature.

Based on the limiting transient with respect to CST inventory requirements (that is, LOAC as described in subsection 4.2.4.1), sufficient 120°F AFW inventory is available to maintain the plant in hot standby for 24 hours following a reactor trip from full power.

The AFWS must provide sufficient flow at the required head to obtain acceptable results for those licensing basis analyses that require AFW flow for transient or accident mitigation.

Licensing-basis acceptance criteria for the AFWS under SPU conditions include the following:

Loss-of-Normal Feedwater (LONF): Provide sufficient AFW cooling to meet the acceptance criteria for LONF (see subsection 6.3.7).

Rupture of a Main Steam Line: Provide isolation of AFW to the faulted-loop steam generator to meet acceptance criteria for the rupture of a steam pipe and for the main steamline break (MSLB) events (see subsections 6.3.11 and 6.6).

LOCA: Provide sufficient AFW to meet the acceptance criteria for LOCA. AFW has only a minor effect on LOCA analyses (see Section 6.2).

LOAC: Provide sufficient AFW cooling to meet the acceptance criteria for LOAC (see subsection 6.3.8).

SGTR: Provide AFW isolation early enough to prevent exceeding offsite dose limits (see Section 6.4 and subsection 6.11.9).

ATWS: Provide sufficient AFW cooling to prevent exceeding a Reactor Coolant System (RCS) pressure service level C limit of 3215 psia (see Section 6.8).

10CFR50, Appendix R (Reference 1) Safe Shutdown/Alternate Safe Shutdown: Provide sufficient AFW cooling to remove decay heat and to cooldown the RCS to RHR entry conditions. This allows the 10CFR50, Appendix R cooldown analysis to demonstrate that the cooldown can be completed within the required 72 hours (see subsections 4.1.3, 4.1.6, and 10.1).

SBO: Provide sufficient condensate inventory to remove decay heat and to cooldown the RCS to minimize RCS inventory loss (see Sections 4.2 and 10.6).

High-Energy Line Break (HELB): Refer to "Rupture of a Main Steam Line" above.

Three Mile Island (TMI) Action Plan Items: TMI Action Plan items for the AFWS, including system reliability analyses, re-evaluation of system design bases, and implementation of requirements for AFW automatic initiation and flowrate indication, continue to be met for the SPU.

9.12.5 Design Criteria

The AFWS is designed to maintain sufficient water inventory in the steam generators to allow removal of decay heat from the RCS by secondary steam releases in the event that the FWS is inoperable. The AFWS is used for plant startup.

The AFWS is nuclear safety-related and required for safe shutdown of the reactor. The AFWS was designed to meet the intent of the General Design Criteria (GDC), which was published by the Atomic Energy Commission (AEC) in the Federal Register of July 11, 1967. The NRC concluded in the *Safety Evaluation Report* (SER), that the plant design conformed to the intent of the newer criteria. SPU operation does not affect the ability of the AFWS to meet these requirements. Therefore, the AFWS continues to meet the criteria requirements.

In addition to AEC Criterion 2 (*Performance Standards*), New York Power Authority (NYPA) committed to the requirements of Sections III.G, III.J, III.L and III.O of 10CFR50 Appendix R (Reference 1). Evaluation of IP3 fire protection features against the requirements of Section III.G of Appendix R to 10CFR50 was completed and the report submitted to NRC on August 16, 1984. SPU operation does not affect the ability of the AFWS to meet these requirements. Therefore the AFWS continues to meet the criterion requirements.

In addition to AEC Criterion 17 (*Monitoring Radioactive Releases*) and 70 (*Control of Radioactive Releases to the Environment*), provisions are included in the AFWS design to meet 10CFR20 (Reference 2) limits. The radioactive releases at SPU conditions are within the original design basis of the plant. Therefore, the AFWS will continue to meet the criterion requirements.

Environmental qualification (EQ) of AFWS electrical equipment important to safety is demonstrated in EQ packages compiled in accordance with the requirements of 10CFR50.49 (Reference 3) and NRC Guidelines (see Section 10.6). Monitoring of the AFWS is provided as a result of the Three Mile Island 2 (TMI-2) accident investigation and the requirements of NRC Regulatory Guide (RG) 1.97 (Reference 4). The AFWS is designed with provisions to allow post-accident sampling in accordance with the post-TMI requirements of NUREG-0578 (Reference 5) and NUREG-0737 (Reference 6). The *Technical Specification* requirements for sampling provisions were deleted by Amendment 210, dated February 6, 2002. SPU operation does not affect the ability of the AFWS to meet these requirements. Therefore, the AFWS continues to meet the requirements.

Accident analyses acceptance criteria are provided in each subsection in Section 6 for those accidents for which AFW is credited for mitigation. Interface guidelines for the Nuclear Steam Supply Systems (NSSS) and balance-of-plant (BOP) interface are discussed in Section 4.2.

Acceptance criteria required to meet SPU conditions are listed in the subsection 9.12.4.

9.12.6 Results and Conclusions

Since the required CST inventory is a function of plant-rated power and other NSSS design parameters, a new analysis was performed to determine the required inventory for the range of NSSS design parameters approved for the SPU. The analysis concluded that a minimum required useable inventory of 288,500 gallons is required to meet the plant licensing bases for the range of NSSS design parameters approved for the SPU. Thus, considering the unavailable volume and other margins, the design basis requirement remains satisfied by the existing *Technical Specification* CST volume of 360,000 gallons. The volume of water contained in the IP3 CST is adequate to support the SPU (see Sections 4.2 and 10.6).

The AFW pumps can draw from an alternative supply of water to provide for long-term cooling. This alternate supply is from city water storage tank. This alternative supply is manually aligned to the AFW pumps in the event of unavailability of the CST.

The worst single failure modeled in the SPU LONF and LOAC analyses is the loss of one of the two MDAFWPs. This results in the availability of only one MDAFWP automatically supplying a minimum total AFW flow of 343 gpm, distributed equally between two of the four steam generators. Additional flow from a second MDAFWP or the TDAFWP is assumed to be available only following operator action to start a second MDAWFP or align the TDAFWP discharge valves. This operator action is assumed to provide an additional 343 gpm of AFW flow distributed equally to the other two steam generators not receiving AFW automatically, and is assumed to occur at 10 minutes after the reactor trip due to a low-low steam generator water level signal (see subsections 6.3.7 and 6.3.8).

The SPU ATWS analysis assumes normal conditions consistent with the requirements outlined by the NRC. In consideration of the low probability of an ATWS, the NRC permitted normal initial conditions, normal system parameters and the availability of all system functions except reactor trip to be assumed. The SPU ATWS analysis conservatively assumes AFW flow of 343 gpm per pump from two MDAFWPs and no credit for the TDAFWP. The RCS pressure service level C limit of 3215 psia is not exceeded at SPU conditions.

The AFW pumps are capable of providing the required flow and pressure to steam generators during normal plant startup, shutdown, and accident conditions with sufficient net pump suction head (NPSH) available with margin over NPSH required.

The brake horsepower (bhp) requirements of MDAFWPs at the pump flow of 343 gpm and 400 gpm are approximately 440 bhp and 460 bhp, respectively, which are enveloped by horsepower of pump motors designed with a service factor of 1.15 (that is, 400 hp x 1.15 = 460 hp).

AFWS piping and components design pressure and temperature bounds maximum operating pressure and temperature conditions expected under SPU operation. AFWS piping and components are considered acceptable for SPU operation.

The AFWS will provide sufficient flow at the required head to obtain acceptable results for those analyses that require AFW flow for transient or accident mitigation (see subsections 4.1.3, 4.1.6, 6.2, 6.3.7, 6.3.8, 6.8, and 10.1).

AFWS operation under SPU conditions complies with licensing basis acceptance criteria (see subsection 9.12.4).

The AFWS is acceptable for operation under SPU conditions. No system modifications are required.

9.12.7 References

1. 10CFR50, Appendix R, Fire *Protection Program for Nuclear Power Facilities Operating Prior to January 1979*, June 20, 2000.

2. 10CFR20, *Standards for Protection Against Radiation*, May 21, 1991.

3. 10CFR50.49, *Environmental Qualification of Electric Equipment Important To Safety for Nuclear Power Plants*, 66FR64738, December 14, 2001.

4. NRC Regulatory Guide 1.97, *Instrumentation of Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident* (Errata published July 1981) (Draft RS 917-4, Proposed Revision 2, published December 1979) (Rev. 3, ML003740282).

5. NUREG-0578, *TMI Lessons Learned Task Force Status Report and Short Term Recommendations*, July 1979.

6. NUREG-0737, Clarification of TMI Action Plan Requirements, November 1980.

9.13 Structural Analysis

9.13.1 Fuel-Handling Building Structural Analysis

The stretch power uprate (SPU) for Indian Point Unit 3 (IP3) results in fuel with increased radioactivity in the fuel assemblies being transferred from the reactor to the spent fuel pit (SFP) during refueling. The addition of a non-SPU-related effect (the removal of fuel sooner from the reactor after shutdown, that is, 84 hours instead of 100 hours after shutdown), also results in an increased level of radioactivity. The combination of these two conditions may result in the heating of the concrete pit structure by the gamma radiation emanating from the fuel, in the event the fuel is placed in fuel rack cells adjacent to the concrete walls.

The SFP water temperature will be maintained within the limits defined in the system description for the SFP cooling loop. Bounding estimates of the concrete temperature effects can be made with the conservative assumption that as fuel is offloaded it will be immediately placed adjacent to the concrete walls of the pit structure, with no older spent fuel between it and the concrete. The gamma heating is limited to the lower 13 feet of the exterior walls, which are 6-feet, 3-inches thick and in contact with the rock or soil backfill on the outside face, the south wall, which is adjacent to the interior of the Fuel Storage Building, and the 5-foot thick interior fuel transfer canal wall. This 13-foot height comprises the active fuel length (12 feet) and an additional 1 foot to account for the floor of the rack and the lower end of the fuel bundle.

This section describes the analysis made to address the effects of gamma heating on the concrete structure.

9.13.1.1 Input Parameters and Assumptions

The input parameters and the assumptions used in the evaluation of the gamma-heated concrete pit structure are summarized in the following paragraphs.

- The reference temperature, T_{ref}, for the concrete, which is the temperature at which no thermal expansion or contraction occurs, is 70°F.
- The maximum expected SFP water temperature is 120°F during fuel offloading
- The active fuel length in a fuel bundle is 12 feet. This defines the height of the wall above the mat, 13 feet, that is heated by the gamma radiation.

- The non-linear thermal gradient due to gamma heating can be decomposed into a uniform thermal expansion across the section and a linear gradient across the section, producing an equivalent compression and tension and an equivalent bending moment as the nonlinear gradient.

- The volume of the concrete wall affected by gamma heating is approximately equal to the height of the fuel bundle, that is, 13 feet, measured from the SFP floor liner. The thickness of the gamma-heated volume is defined by the gradients calculated for the IP3 SFP. The width of the gamma-heated zone resulting from the radiation from a single fuel bundle is equal to the width of the bundle.

- There is no reduction in the gradient through the wall due to propagation of the heat, away from the gamma-heated volume, obliquely through the wall.

- The temperature of the soil in contact with the SFP mat and lower part of the walls is 50°F.

- The entire SFP is assumed to be exposed to "fresh" fuel, a normal loads condition. The more realistic case, where only specified locations will see fresh fuel, results in local effects that would correspond to an abnormal condition.

9.13.1.2 Description of Analysis and Evaluation

The nonlinear thermal gradient arising from the gamma heating of the concrete structure is converted to a linear gradient producing an equivalent compression and bending moment. The conversion requires the integration of the nonlinear gradient relative to reference temperature, 70°F. This reference temperature is applicable to each face of the concrete walls.

The gamma heating gradients in the concrete walls and mat are developed assuming an SFP water temperature of 120°F at the start of refueling. The equivalent linear gradient for gamma heating is compared to the design basis gradient, a temperature gradient equal to 200°F (the SFP water temperature) less the exterior wall/mat temperature. The comparison is made to demonstrate that the design basis gradients bound the corresponding equivalent linear gradients and that the thermal gradients associated with gamma heating for the SPU refueling condition are, therefore, less limiting.

9.13.1.3 Acceptance Criteria

Equivalent linear gradients derived from the thermal gradients associated with gamma heating for the new SPU refueling condition are bounded by the thermal gradients used in the design basis analysis of the fuel pit.

The peak concrete temperatures determined for the gamma heating condition are less than the maximum value of 200°F used in the design basis analysis for the normal load condition.

9.13.1.4 Design Criteria

American Concrete Institute (ACI) 349-80, "Code Requirements for Nuclear Safety-Related Concrete Structures," provides the design basis criteria by which the thermal stresses in the walls of the SFP resulting from temperature gradients were evaluated.

9.13.1.5 Results and Conclusions

The peak temperature in the 6-foot, 3-inch thick outside walls is 189.2°F.

The peak temperature in the 5-foot thick interior fuel transfer canal wall is 191.4°F.

The analysis has demonstrated that the concrete fuel pit thermal gradients associated with gamma heating for the new SPU refueling condition are less limiting than the corresponding thermal gradients used in the design basis analysis.

The elevated temperatures in the zone of the gamma-heated concrete are acceptable since they are less than the maximum 200°F temperature considered in the design basis analysis.

9.13.2 Auxiliary Boiler Feed Pump Building Structural Analysis

One possible consequence of the SPU is an increase to the outside containment compartment differential pressures due to a high-energy line break (HELB). The compartment differential pressure due to HELB is addressed for the Auxiliary Boiler Feed Pump Building in this section of the report. The Auxiliary Boiler Feed Pump Building includes the "shield wall area" consisting of the steam and feedline penetration area and the auxiliary feed pump room.

A main steam line break (MSLB) or feedline break are the sources of the postulated-accident differential pressure challenging the capacity of the structure, since the smaller breaks do not produce significant differential pressure. Since the postulated break in the auxiliary feed pump room is the double-ended rupture (DER) of a 4-inch diameter steam line to the auxiliary boiler feed pump turbine, the resulting HELB pressure in this compartment is small.

9.13.2.1 Input Parameters and Assumptions

The input parameters for this evaluation are the HELB differential pressure transients in the outside containment compartments for the SPU. Also, the compartment differential pressures for the current licensed power levels are provided in the plant evaluation of harsh environment areas.

The assumption applicable to this section is that the SPU does not result in changes to the locations of existing, postulated pipe-break locations or to the type of break.

9.13.2.2 Description of Analysis and Evaluation

The outside containment HELB pressure due to SPU conditions were compared to the design pressure capacity or the HELB differential pressure for current licensed thermal power conditions for each of the compartments in the Auxiliary Boiler Feed Pump Building. The structural pressure capacity was reviewed to support the conclusions that the SPU does not govern the compartment design for pressurization. For the steam and feedline penetration area, the sheet metal siding is calculated to commence failure at a differential pressure of 0.46 psig and is completely failed at a pressure of 1.26 psig.

9.13.2.3 Acceptance Criteria

The acceptance criteria for the auxiliary feed pump room are the current licensed thermal power HELB differential pressures for each cubicle or the differential pressure used as the design basis for the structure. Pressures below these values are deemed to meet the acceptance criteria.

Since the enclosure of the steam and feedline penetration area of the Auxiliary Boiler Feed Pump Building is assumed to fail at a differential pressure exceeding 0.46 psig, there are no acceptance criteria for this area. Failure of the sheet metal siding is acceptable.

9.13.2.4 Design Criteria

General Design Criterion (GDC) 4, "Environmental and Dynamic Effects Design Basis," is applicable to the design of the Auxiliary Boiler Feed Pump Building. Criterion 4 of the GDC, listed in 10CFR50, Appendix A, (Reference 1) requires that, "Structures, systems and components important to safety shall be designed to accommodate the effects of and be compatible with the environmental considerations associated with normal operation, maintenance, testing and postulated accidents, including loss-of-coolant accidents. These structures, systems and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit."

9.13.2.5 Results and Conclusions

The SPU does not result in HELB pressurization exceeding the structural capacity of the affected compartments. Therefore, the structural capacity of the affected compartments is acceptable under SPU conditions.

9.13.3 Miscellaneous Structures

9.13.3.1 Structural Analysis

The SPU does not affect the Primary Auxiliary Building (PAB). Outside containment HELB is the only PAB structural issue affected by the SPU and no changes result from HELB.

9.13.3.2 Turbine Building Structural Analysis

The SPU does not affect the Turbine Building. Outside containment HELB is the only Turbine Building structural issue affected by the SPU and no changes result from HELB.

9.13.4 References

1. 10CFR50, Appendix A, *General Design Criteria for Nuclear Power Plants.*

10.0 GENERIC ISSUES AND PROGRAMS

The Indian Point Unit 3 (IP3) stretch power uprate (SPU) has the potential to affect plant programs and generic issues that have been developed and implemented at IP3 in compliance with various design, maintenance, and licensing requirements. The plant programs and generic issues listed in Table 10-1 were identified for review and evaluation of the effect of the SPU.

For the programs and generic issues listed in Table 10-1, a review of the documentation was performed and discussions with cognizant station personnel were conducted. Based upon review of this information, the effect of the SPU implementation on the program and generic issue was determined.

Table 10-1 identifies if a program/generic issue is either "affected/potentially affected" or "not affected" by the SPU. Programs/generic issues are "not affected" by the SPU if:

- The SPU does not affect key inputs to the program/generic issue, or
- The program/generic issue is based on information/parameters that bound the conditions that will result from implementation of the SPU, or
- Existing program requirements, procedures, or activities will be utilized or applied in support of implementation of the SPU.

Table 10-1 Effect of SPU on IP3 Generic Issues and Programs			
Section	Program/Generic Issue	Not Affected [*]	Affected/ Potentially Affected [*]
10.1	Fire Protection (10CFR50 Appendix R) Program	X	
10.2	Generic Letter 89-10 Motor-Operated Valve (MOV) Program	X	
10.3	Flow-Accelerated Corrosion (FAC) Program		X
10.4	Flooding	X	
10.5	Probabilistic Safety Assessment		X
10.6	Station Blackout	X	
10.7	In-Service Inspection/In-Service Test Programs	X	
10.8	Electrical Equipment Environmental Qualification Program		X
10.9	Chemistry Program	X	
10.10	Generic Letter 95-07	X	
10.11	Generic Letter 96-06	X	
10.12	Generic Letter 89-13	X	
10.13	Plant Simulator		X
10.14	Containment Leak Rate Testing		X
10.15	Plant Operations		X

10.1 Fire Protection (10CFR50 Appendix R) Program

NRC regulatory/guidance documents applicable to the IP3 Fire Protection Program include:

- 10CFR50, Appendix A, General Design Criterion 3 (Reference 1), as addressed in the *Indian Point Unit 3 Updated Final Safety Analysis Report* (UFSAR) Section 1.3.1, "General Design Criteria, Fire Protection (Criterion 3)," (Reference 2).

- 10CFR50, Section 50.48 (Reference 3)

- 10CFR50, Appendix R (Reference 4)

- Branch Technical Position (BTP) 9.5-1 and Appendix A (Reference 5)

- NRC Generic Letters 81-12 (Reference 6), 85-01 (Reference 7), and 86-10 (Reference 8)

The IP3 10CFR50 Appendix *R Safe Shutdown Analysis Report* (referred to herein as the "Shutdown Analysis") describes the safe shutdown model used in the analysis, and evaluates each plant analysis area to determine compliance with 10CFR50 Appendix R Sections III.G and III.L. In accordance with these sections of Appendix R, if shutdown is accomplished using alternate or dedicated systems, cold shutdown must be achieved within 72 hours. To meet Appendix R performance goals, the shutdown analysis states that certain time critical activities have been established, as follows:

- Establish feedwater flow to steam generators
- Establish reactor coolant pump (RCP) seal cooling
- Maintain pressurizer level (re-establish charging)
- Ensure at least one residual heat removel (RHR) pump is available to achieve cold shutdown

Regarding the shutdown analysis time critical activity of establishing feedwater flow to the steam generators, analysis of IP3 steam generator dryout time shows that the required time period for restoring feedwater flow is bounded under SPU conditions.

The time-critical activities of establishing RCP seal cooling and re-establishing charging to maintain pressurizer level are related to loss of RCS inventory due to leakage through the reactor coolant pump (RCP) seals. RCP seal leakage is assumed as per WCAP-10541 Revision 2 (Reference 9) and is not affected by SPU conditions. In addition, the shutdown analysis indicates that numerous charging paths are available for charging to the RCS following an Appendix R fire. Accordingly, it is concluded that the SPU does not affect these activities.

The IP3 Appendix R cooldown analysis under SPU conditions (3216-MWt core power) shows that IP3 is capable of meeting the Appendix R requirement that cold shutdown be achieved within 72 hours after reactor trip following a fire.

For postulated Appendix R fire scenarios concurrent with a loss-of-off-site power (LOOP), the emergency diesel generators (EDGs) are the preferred power supply for safe shutdown equipment. Fire scenarios that cannot credit the EDGs due to fire-induced failures will utilize the Appendix R Diesel Generator and the associated 6.9-kV switchgear. The Appendix R Diesel Generator load analysis determines the capability of the Appendix R Diesel Generator to provide power requirements during hot shutdown and cold shutdown conditions. Evaluation of Appendix R Diesel Generator load requirements under station blackout (SBO) conditions shows that there are no significant load increases that would affect the conclusions of the existing Appendix R Diesel Generator load analysis.

10.1.1 References

1. 10CFR50, Appendix A, *General Design Criteria for Nuclear Power Plants General Design Criterion 3, Fire Protection*, July 11, 1967.

2. *Indian Point Nuclear Generating Unit No. 3, Updated Final Safety Analysis Report* (UFSAR), Section 1.3.1, General Design Criteria, Fire Protection (Criterion 3).

3. 10CFR50.48, *Fire Protection.*

4. 10CFR50, Appendix R, *Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979.*

5. Branch Technical Position (BTP) 9.5-1 and Appendix A to BTP 9.5-1, Guidelines for Fire Protection for Nuclear Power Plants Docketed Prior to July 1, 1976.

6. NRC Generic Letter 81-12, *Fire Protection Rule* (45 FR 76602, November 19, 1980), February 20, 1981.

7. NRC Generic Letter 85-01, *Fire Protection Policy Steering Committee Report*, January 9, 1985.

8. NRC Generic Letter 86-10, *Implementation of Fire Protection Requirements*, April 24, 1986.

9 WCAP-10541, *WOG Report Reactor Coolant Pump Seal Performance Following a Loss of All AC Power*, Rev. 2, November 1986

10.2 Generic Letter 89-10 Motor-Operated Valve Program

In June 1989, the NRC issued Generic Letter (GL) 89-10 (Reference 1) to address concerns noted in achieving reliable operation of applicable motor-operated valves (MOVs). Generally, safety-related valves and other valves determined to be important to safety are required to be included in this valve program. GL 89-10 requires that safety-related MOVs be analyzed and controlled to ensure they are capable of performing their required functions. IP3 has established a GL 89-10 MOV Program.

Generic Letter 96-05 (Reference 2) supersedes GL 89-10 with respect to MOV periodic verification, and requests licensees verify on a periodic basis that safety-related MOVs continue to be capable of performing their safety functions within the current licensing bases of the facility. The requirements of GL 96-05 are incorporated into the IP3 GL 89-10 MOV Program.

Generic Letter 89-10, Supplement 6 required an evaluation of the potential for pressure locking and thermal binding of motor-operated gate valves. GL 95-07 (Reference 3) expanded the scope to include all power-operated gate valves within the design and licensing basis. This issue is addressed in Section 10.10 of this report.

In conformance with GL 89-10 requirements, a differential pressure calculation has been issued for each MOV in the GL 89-10 MOV Program. The following parameters are determined in these calculations:

- Maximum design basis opening and closing differential pressure
- Maximum design basis opening and closing line pressure

The results of the MOV differential pressure calculations are used as inputs in other GL 89-10 Program MOV calculations, for example, analysis of MOV thrust and torque limits.

The evaluations of MOV motor-torque degradation due to elevated ambient temperatures utilize temperature data from the Electrical Equipment Environmental Qualification (EQ) Program.

Evaluation of the impact of the SPU on the differential pressure calculations for GL 89-10 MOVs in balance-of-plant (BOP) systems shows that the SPU has no impact on the maximum differential pressures/line pressures determined in the current MOV differential pressure calculations for MOVs in the Main Feedwater System (refer to Section 9.4 of this report).

For MOVs in the Nuclear Steam Supply System (NSSS) systems (that is, Reactor Coolant System [RCS], Chemical and Volume Control System [CVCS], Residual Heat Removal System [RHRS], Component Cooling Water System [CCWS], and Safety Injection System [SIS], the changes in system flows, pressures, and temperatures resulting from the SPU have been documented. Changes in NSSS system parameters resulting from the SPU do not affect the conclusions of the MOV Program for MOVs in NSSS Systems.

The impact of the SPU on peak ambient temperatures in plant locations containing environmentally qualified equipment is addressed in Section 10.8 of this report. Review of the environmental data in this section shows that accident peak ambient temperatures under SPU conditions are bounded by the accident peak ambient temperatures under existing (pre-uprate) conditions. Accordingly, the SPU does not affect the results of current evaluations of MOV motor-torque degradation due to elevated ambient temperatures.

The SPU does not impact the schedule for periodic verification of MOV settings per GL 96-05.

10.2.1 References

1. NRC Generic Letter 89-10, *Safety-Related Motor Operated Valve Testing and Surveillance*, June 28, 1989, and supplements.

2. NRC Generic Letter 96-05, *Periodic Verification of Design Basis Capability of Safety-Related Motor-Operated Valves*, September 18, 1996.

3. NRC Generic Letter 95-07, *Pressure Locking and Thermal Binding of Safety-Related Power Operated Gate Valves*, August 17, 1995.

10.3 Flow-Accelerated Corrosion Program

Flow-accelerated corrosion is a form of material degradation that results in thinning the inside pipe wall in carbon steel piping and fittings under certain flow and chemistry conditions. Undetected FAC-induced wall thinning may cause a pipe to leak or rupture, causing personnel injury and/or plant shutdown. For these reasons, and in response to regulatory requirements (References 1 and 2) and *Updated Final Safety Analysis Report* (UFSAR) (Reference 3) commitments, IP3 has developed and implemented a program to monitor and mitigate FAC in plant piping.

For the following large-bore, high-energy piping systems, the Electric Power Research Institute (EPRI) computer program CHECWORKS is used to predict erosion rates for each modeled component within each system. The specific lines and fittings in these systems that are included in the FAC Program are identified in the applicable large bore calculation and report and shown on the applicable isometric drawings.

- Heater drains
- Extraction steam
- Feedwater
- Condensate
- Reheater drains
- Moisture separator drains
- Moisture pre-separator drains

The IP3 Small Bore and Augmented Monitoring Program addresses piping that has not been modeled using CHECWORKS. The majority of these lines are small bore lines (defined as all socket-welded piping, and all butt-welded piping less than or equal to 2 inches nominal pipe size). Also included is a subgroup of large bore lines, which would normally be exempt from modeling using the CHECWORKS criteria. This program identifies lines in the following systems that are recommended for inspection:

- Heater drains and vents
- Moisture separator reheater (MSR) drains and vents
- Feedwater
- Steam generator blowdown
- Main steam
- Extraction steam
- Heater drains
- Gland seal steam
- Condensate

The Auxiliary Feedwater System (AFWS) and Auxiliary Steam System are also currently included within the scope of the FAC Program.

The SPU will result in changes in fluid flow velocities and temperatures in the Main Feedwater and Condensate System, Heater Drains System, Main Steam System (MSS), Extraction Steam System (ESS), and Steam Generator Blowdown System (SGBS). Evaluations of the impact of the SPU on FAC for the piping in these systems were performed. The following are the key elements of these evaluations:

- Calculation and documentation of piping velocities for lines and equipment nozzles in the system, including lines in IP3 FAC Program. Piping velocities under SPU conditions in drain lines were calculated as single-phase (water) flow.
- Comparison of the calculated piping and nozzle velocities with standard industry velocity criteria as a measure of whether there was an increased potential for FAC.
- Evaluation of any effect of calculated operating temperatures under SPU conditions on FAC in pipelines and nozzles.

Major results and conclusions from these evaluations are summarized as follows (details are included in Sections 9.1, 9.2, 9.3, 9.4, and 9.5):

- The majority of piping and nozzle velocities under SPU conditions are within the standard industry criteria. Many of these lines are included in the IP3 FAC Program.
- Most of the pipelines and nozzles that had velocities exceeding the standard industry criteria are included in the IP3 FAC Program or have been removed from the FAC Program due to piping material upgrade.
- The velocities in feedwater heaters 31A, B and C condensate inlet nozzles and heater drain outlet nozzles exceed Heat-Exchange Institute (HEI)-recommended velocities. However, these nozzles are part of single-phase lines that are below the low temperature limit for FAC susceptibility. Therefore, these lines are excluded from the FAC Program.
- Based on a review of changes in operating temperatures due to the SPU, the operating vent lines for feedwater heaters 32A, B, and C will be added to the FAC Program.

The CHECWORKS models will be updated to incorporate flow and thermal performance data at SPU conditions.

10.3.1 References

1. NRC Bulletin No. 87-01, *Thinning of Pipe Walls in Nuclear Power Plants,* July 9, 1987.

2. NRC Generic Letter 89-08, *Erosion/Corrosion – Induced Pipe Wall Thinning.*

3. *Indian Point Nuclear Generating Unit No. 3 – Updated Final Safety Analysis Report,* Rev. 18, Docket No. 50-286, Section 10.4, "Tests and Inspections."

10.4 Flooding

10.4.1 Internal Flooding Outside Containment

In response to an NRC request, IP3, determined if failure of any non-Category I (seismic) equipment could result in a condition that might potentially adversely affect the performance of safety-related equipment required for safe shutdown or for limiting the consequences of an accident (Reference 1). The review consisted of determining the seismic Class III (non-seismic) lines in the Diesel Generator Building, containment, Fuel Handling Building, service water pump area, Control Building, Turbine Hall, Primary Auxiliary Building (PAB), and the auxiliary feedwater pump room, and assessing the flooding potential from each line.

IP3 performed a systems interaction study that addressed flooding from failure of Seismic Class II and III lines in the PAB, Control Building, Diesel Generator Building, and the Auxiliary Feedwater Building. Flooding from failure of Seismic Class II and III lines is also addressed in the UFSAR (Reference 2), Section 16.1.3, "General Seismic Design Criteria and Damping Values, Effects of Failure of Class III Equipment on Safety-Related Equipment."

Evaluation results include the following, along with discussion of the impact of the SPU on results:

Circulating Water System

A barrier is installed at the doorway to the switchgear room to provide protection from flooding up to Elevation 19'. Therefore, flooding from the Circulating Water System (CWS) in the turbine hall could not affect the performance of the 480-V switchgear located in the Control Building at Elevation 15'. Since the CWS is an open system with no valves, and therefore no means of producing a high dynamic head, the probability of a failure is very small. However, to ensure that the 480-V switchgear would not be adversely affected from flooding, redundant level alarm switches were installed in the pipe tunnel at Elevation 3'-3" of the turbine hall. These switches sense high water in the pipe tunnel and have indication in the control room. The operators have time to investigate any flooding problem and take appropriate action by shutting down the circulating water pumps to prevent flooding to Elevation 19'.

There are no CWS flow rate changes or system modifications resulting from the SPU. Therefore, the analysis of flooding from this system in the turbine hall is not affected by the SPU.

Auxiliary Feedwater Pump Room

Evaluation of the auxiliary feedwater pump room, located between the containment and the shield wall, revealed that safety-related equipment would not be affected by failure of the Seismic Class III portion of the MSS. Performance of the auxiliary feedwater (AFW) pumps could be adversely affected if the water reached Elevation 19'-8" in the auxiliary feedwater pump room. To preclude flooding of the AFW pump motors under the worst postulated conditions of main feedwater line failure, modifications were made to the AFW Building exterior doors to provide openings (called "flood control gates") at the bottom of the doors.

Failure of the main feedwater lines, located above and outside of the auxiliary feedwater pump room, would result in water accumulating at the 18'-6" elevation. Feedwater pump flow increases above the current flow at 100-percent power under SPU conditions. However, the following features preclude flooding of the AFW pump motors in the pump room under SPU conditions:

- Flood water from the area adjacent to the auxiliary feedwater pump room containing the feedwater lines would only propagate into the pump room through an interconnecting door with a small gap at the bottom of the door. Flood water would drain to the yard via a door equipped with a flood control gate (approximately 8 inches by 32 inches).

- Flood water in the area containing the feedwater lines would drain to the yard via a door equipped with a flood control gate (approximately 8 inches by 26 inches).

Primary Auxiliary Building

Performance of the residual heat removal (RHR) pumps located at Elevation 15' of the PAB would be affected by flooding only if the water level reached Elevation 19'. Analysis showed that approximately 120,000 gallons of water would be required to cause flooding to this elevation, considering pipe breaks in Seismic Class III lines in the Auxiliary Steam System, SGBS, Waste Disposal System, Auxiliary Coolant System, and City Water System, and Seismic Class II lines in the Primary Water System. Analysis results showed that it would take almost 10 hours for the water level to rise approximately 3.5 feet at the 15' elevation. The major contributors to this result were postulated ruptures in Seismic Class II primary water lines. Although the ten hour time period provides sufficient time for operator action to prevent flooding to Elevation 19' of the PAB, modifications were made to assure there is adequate drainage area to preclude flooding of the RHR pumps in the unlikely event that postulated flooding was not discovered.

The only lines in the PAB flooding evaluation affected by the SPU are the SGBS Seismic Class III lines. The nominal blowdown flow under SPU conditions can increase in proportion to the SPU increase in feedwater flow (approximately 6 percent) to the steam generators. However, this relatively small increase in flow would not significantly affect the conclusions of the evaluation of flooding in the PAB due to failure of non-Seismic Class I piping.

10.4.2 Flooding Inside Containment

The submergence level inside containment resulting from a postulated loss-of-coolant accident (LOCA), documented in the IP3 Environmental Qualification Program, is at Elevation 50'-1.5", which is 4 feet – 1½ inch above the containment floor level.

The SPU does not affect the water inventories of the Reactor Coolant System (RCS), residual water storage tank (RWST), spray additive tank, or safety injection (SI) accumulators. Accordingly, the flood level inside containment documented in the EQ Program Plan will not be impacted by the SPU.

10.4.3 References

1. Letter from Consolidated Edison Co. of NY to the NRC, January 23, 1973.

2. *Indian Point Nuclear Generating Unit No. 3 – Updated Final Safety Analysis Report*, Rev. 18, Docket No. 50-286.

10.5 Probabilistic Safety Assessment

A Probabilistic Safety Assessment (PSA) is a useful tool for a quantitative and qualitative assessment of the likelihood and consequences of damage that could potentially result from events occurring during plant operation.

The model used in the IP3 PSA analyses is maintained and updated in accordance with plant procedures. Plant modifications that have the potential to significantly effect core damage frequency (CDF) or large early release frequency (LERF) are evaluated and incorporated, as appropriate, into the model following implementation of the change.

The effect of the SPU on the IP3 PSA will be evaluated, including the effect of plant modifications due to the SPU. The PSA "levels" to be addressed for the IP3 SPU are in accordance with existing procedures.

10.6 Station Blackout

The SBO Rule, 10CFR50.63 (Reference 1), requires that nuclear power plants be capable of withstanding a total loss-of-offsite AC power and onsite emergency AC power supplies. The NRC issued Regulatory Guide (RG) 1.155 (Reference 2) to provide guidance in responding to the SBO Rule. This RG endorses a publication of the Nuclear Management and Resource Council (NUMARC), NUMARC 87-00 (Reference 3). Regulatory Guide 1.155 and NUMARC 87-00 were utilized in evaluating SBO at IP3.

The Appendix R Diesel Generator serves as the alternate AC (AAC) power source at IP3. The IP3 Appendix R Diesel Generator load analysis determines the capability of the Appendix R Diesel Generator to provide power requirements during hot shutdown above RHR conditions. The AAC power source will be available within 1 hour of the onset of the SBO event. The SBO minimum required coping duration for IP3 is determined to be 8 hours.

Evaluation of Appendix R Diesel Generator load requirements for an SBO event under SPU conditions shows that there are no significant load increases that would affect the conclusions of the current Appendix R Diesel Generator load analysis.

The IP3 SBO coping analysis addresses the following topics:

- Condensate inventory for decay heat removal
- Class 1E battery capacity
- Compressed air
- Effects of loss-of-ventilation
- Containment isolation
- Reactor coolant inventory

The following is a discussion of the effect of the SPU on the plant capabilities for coping with an SBO event for each of these topics.

Condensate Inventory for Decay Heat Removal

The condensate inventory for decay heat removal was determined using the methodology in NUMARC 87-00, which provides a bounding analysis for assessing condensate inventory. The *Technical Specifications* require that a minimum of 360,000 gallons of water must be available in the condensate storage tank (CST) during plant operation above 350°F. For the SPU, the volume of water required for 8 hours of decay heat removal and primary system cooldown was determined; the results show that there is adequate margin between the minimum required volume of water in the CST and the volume of water required for coping with an SBO event.

Class 1E Battery Capacity

Evaluation of plant fluid systems affected by operation at SPU conditions shows that there are no new SBO loads that require 125-VDC control or motive power, and that there is no need to modify existing SBO loads that require 125-VDC control or motive power. Accordingly, the station batteries have sufficient capacity to meet SBO loads for one hour under SPU conditions.

Compressed Air

Based on existing plant SBO analyses and associated NRC safety evaluations:

- Air-operated valves (AOVs) needed to cope with an SBO can either be operated manually or have sufficient backup sources independent of AC power for 1 hour coping duration, at which time the AAC power source will become available.
- The turbine-driven AFW pump steam supply valve can be operated manually. The turbine-driven AFW pump (TDAFWP) speed control valve has nitrogen back-up and can be operated manually.
- The turbine-driven AFW pump flow control valves have nitrogen back-up and can be operated manually. Regarding habitability in the AFW pump room for local operation of these valves, it is expected that AFW flow will be established within a time period such that the temperature rise up to this time is not expected to make habitability a concern.
- The atmospheric relief valves (ARVs) have two back-up supplies: a common nitrogen supply, and dedicated nitrogen bottles, which are lined-up manually. Habitability is not a concern for the short duration required to line up the back-up nitrogen bottles.
- All other AOVs are designed to fail in the correct or safe position.
- The SPU does not affect these evaluation results.

Effects of Loss-of-Ventilation

The AFW pump room was identified as the only dominant area of concern. The temperatures used in the analysis of AFW pump room temperatures after an SBO envelop the steam conditions used as inputs for the SPU analyses associated with the TDAFWP, and therefore the SPU does not affect the current AFW pump room analysis results.

The SPU does not affect the inputs used in the analysis of control room temperatures following an SBO.

Containment Isolation

Based on existing plant SBO analyses and associated NRC safety evaluations:

- A total of 19 containment isolation valves (CIVs) were identified that could not be excluded based on the five criteria given in RG 1.55 (Reference 2), (for example, valves normally locked closed during operation). Rationale was provided for accepting these valves without modification as providing the required containment integrity during an SBO event. All of these valves can be operated independent of the EDGs and have some means of valve position indication independent of the emergency AC power system.

- Except for the containment air lock door equalizing valves, plant procedures provide instructions for closing these CIVs if necessary. Because the inner and outer air lock doors are mechanically interlocked so that only one door will be open at any one time, and the door equalizing valves are interlocked with their respective air lock door, only one air lock door equalizing valve will be open at any one time.

The SPU does not affect these evaluation results.

Reactor Coolant Inventory

IP3 assessed the ability to maintain adequate RCS inventory for the coping duration of the SBO event in accordance with NUMARC 87-00 (Reference 3), Section 2.5.2. The reactor coolant inventory calculation is based on an RCS inventory loss of 25-gpm seal leakage per RCP, 11-gpm *Technical Specification* leakage, and 120-gpm letdown leakage for 10 minutes. The AAC power source, which will be available 1 hour after onset of an SBO, will provide power to a charging pump with a capacity of 98 gpm to offset inventory loss and keep the core covered for the entire 8 hour coping duration.

The SPU does not affect these evaluation results.

In a Safety Evaluation dated December 23, 1991, the NRC stated that the 25-gpm seal leakage per RCP was agreed to between NUMARC and the NRC pending resolution of Generic Issue (GI) 23, "Reactor Coolant Pump Seal Failure," and if the final resolution of GI 23 defined higher RCP leakage rates, the reactor coolant inventory analysis could be affected accordingly. However, in a letter to holders of operating licenses in February 2000 (Reference 4), the NRC stated that the staff concluded that no additional generic requirements should be proposed and licensees should not be required to revise the current deterministic SBO coping analysis assumptions, and that GI 23 is closed.

10.6.1 References

1. 10CFR50.63, *Loss of All Alternating Current Power*, June 21, 1988.

2. NRC Regulatory Guide 1.155, *Station Blackout*, August 1, 1988.

3. NUMARC 87-00, *Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout and Light Water Reactors*, November 1987.

4. NRC Letter, *NRC Regulatory Issue Summary 2000-02, Closure of Generic Safety Issue 23, Reactor Coolant Pump Seal Failure*, February 15, 2000.

10.7 In-Service Inspection/In-Service Testing Programs

10.7.1 In-Service Inspection Program

The following inspection programs, required by the *ASME Boiler and Pressure Vessel Code* (Reference 1), Section XI, are implemented at IP3.

- In-Service Inspection (ISI) Program for inspections of ISI Class 1, 2, and 3 piping systems.
- ISI Containment Program for inspections of ISI Class MC and CC components.

Classification of systems and components as ISI Class 1, 2, 3, MC, and CC is performed in accordance with RG 1.26 (Reference 2), 10CFR50.55a (Reference 3), and NRC rulemaking. Inservice inspection of these systems and components is performed in accordance with ASME Code of Record requirements.

The IP3 "Inservice Inspection Program, Third Ten-Year Interval" details the ISI plan and schedule for ISI Class 1, 2, and 3 components, piping, and their supports. This plan will be conducted in accordance with the *ASME Boiler and Pressure Vessel Code*, Section XI – 1989 Edition with no Addenda (Reference 1), with exceptions as noted in the implementing IP3 document. Augmented inspections are performed as required by 10CFR50.55a (Reference 3), the NRC, or as deemed necessary by the ISI Program.

For modifications required in support of the SPU, the effect of the changes on the ISI Program will be evaluated as part of the engineering change process.

10.7.2 In-Service Testing Program

The purpose of the In-Service Testing (IST) Program is to assess the operational readiness of selected pumps and valves to perform a specific function. The pumps and active/passive valves covered under the program are those which are required to perform a specific function in mitigating the consequences of an accident, or shutting down and maintaining the reactor in a safe shutdown condition.

The IP3 IST Program for pumps and valves is implemented by plant procedures, as required by the *ASME Boiler and Pressure Vessel Code*, Section XI (Reference 1), ASME/ANSI OM Part 6 (Reference 4) and Part 10 (Reference 5), and *Technical Specification* 5.5.7 (Reference 6). The program is applicable to IST of pumps and valves for IP3's third 10-year inspection interval (July 21, 1999 to July 21, 2009). The IST Program is integrated into the IP3 Surveillance

Program and is governed by the scheduling, conduct of testing, and equipment operability review requirements of this program.

For modifications required in support of the SPU, the effect of the changes on the IST Program will be evaluated as part of the engineering change process.

10.7.3 References

1. *ASME Boiler and Pressure Vessel Code*, Section XI, 1989 Edition, The American Society of Mechanical Engineer, New York, NY.

2. NRC Regulatory Guide 1.26, Rev. 3, Quality Group Classifications and Standards for Water, Steam, and Radioactive Waste – Containing Components of Nuclear Power Plants.

3. 10CFR50.55a, *Codes and Standards.*

4. ASME/ANSI Operations and Maintenance Standard, Part 6 (OM-6), *In-Service Testing of Pumps in Light Water Reactor Plants*, 1987 Edition.

5. ASME/ANSI Operations and Maintenance Standard, Part 10 (OM-10), *In-Service Testing of Valves in Light Water Reactor Plants*, 1987.

6. IP3 Technical Specification 5.5.7, *In-Service Testing Program*, Amendment No. 205.

10.8 Electrical Equipment Environmental Qualification Program

10.8.1 Introduction

The electrical equipment that is covered by the Electrical Equipment EQ Program has been reviewed for effects to its qualification as a result of the Indian Point Unit 3 (IP3) stretch power uprate (SPU). The review has been performed primarily by comparison of the new accident temperatures and radiation dose associated with the uprate to environmental conditions in the EQ Program.

The environmental parameters of pressure, humidity and chemical spray, and submergence are also addressed.

10.8.2 Environmental Parameters Inside Containment

The SPU has no effect on the qualification of equipment inside containment with respect to the temperature, but does have an impact with respect to qualifying the radiation dose.

10.8.2.1 Normal Operating Temperature

The temperature during normal operation is unchanged. The qualified life of all EQ equipment inside the containment is unchanged.

10.8.2.2 Accident Temperature

The pre-uprate accident temperature profile used for the EQ Program with a peak of 261.5°F bounds the containment re-analysis temperature profile with a peak of 260.4°F from the LOCA. IP3 does not use the main steamline break (MSLB) inside containment as a basis for EQ since it is licensed to Division of Operating Reactors (DOR) EQ requirements. Therefore, a composite LOCA/MSLB temperature profile is not evaluated for the SPU review of EQ.

The equipment inside containment remains qualified on the existing bases for the temperature conditions associated with the SPU.

10.8.2.3 Accident Pressure

The LOCA pressure inside containment is bounded by the EQ pressure profile.

The equipment inside containment remains qualified on the existing bases for the pressure conditions associated with the SPU.

10.8.2.4 Radiation

The SPU radiation doses have increased as a result of the increased power, the associated allowance for instrument error and the fuel cycle extension to 24 months. The total integrated dose (TID) for 40-year normal operation and accident of 2.01 $x10^7$ rads increases the radiation doses for several equipment types.

An evaluation of the exposure of the critical radiation-sensitive parts was made for selected equipment for the beta dose. It was concluded that the affected equipment remains qualified. This analysis took into account the installation configuration of the equipment with respect to gamma and beta shielding and the construction of the equipment with respect to self-shielding against beta radiation. All equipment was determined to be acceptable for use within the requirements of the EQ program.

10.8.2.5 Submergence

Flood level inside containment is discussed in Section 10.4 of this report. The cables in the EQ Program inside containment are qualified for submergence. Radiation doses to submerged cables increase as a result of the SPU and the fuel cycle change.

To provide the SPU qualification for submergence, a scaling factor was applied for the SPU, and the normal 40-year operating dose for 3216 MWt added. All potentially submerged cables are qualified for the SPU with large margins.

10.8.2.6 Humidity

The normal and accident humidity has not been affected by the SPU.

10.8.2.7 Chemical Spray

The spray and sump water chemistry has been marginally affected by the SPU. The slight change of a fraction of a pH level is within the range of pH values covered in the EQ Program prior to SPU.

10.8.3 Environmental Parameters Outside Containment

The power uprate has little effect on the qualification of equipment outside containment with respect to the temperature, except for equipment in the main steam penetration area. There is also a small increase in the radiation levels for the SPU due to the recirculation of reactor coolant or sump water.

10.8.3.1 Normal Operating Temperature

The temperature during normal operation is unchanged.

10.8.3.2 Accident Temperature

The three bounding high-energy line breaks (HELBs) for EQ equipment outside containment are:

- The MSLB in the steam and feedline penetration area
- The main steam supply line to the turbine drive of the auxiliary feedwater (AFW) pump in the AFW pump room
- The steam generator blowdown line break in the pipe penetration area

Main Steam to Auxiliary Feedwater Pump Turbine HELB

The existing HELB temperature analysis bounds the conditions of the SPU.

Steam Generator Blowdown Line HELB

A check of process conditions was performed to determine the effect of the SPU on the steam generator blowdown line break. The Zaloudek correlation was used to compare the blowdown conditions that have been used for the existing EQ to the conditions that will be present for the SPU.

The critical flow under the SPU conditions is 4.4 percent less than the pre-SPU conditions. The difference in the mass and energy (M&E) release is considered by engineering judgment within the conservatism in the M&E release analysis and, therefore, no change in the accident temperatures is necessary.

All equipment located in the areas that are affected by the steam generator blowdown HELB that were qualified remain qualified.

Equipment in the Primary Auxiliary Building, such as the RHR pumps and the safety injection (SI) pumps, are in areas where there is no HELB effect. The only harsh environmental parameter is the LOCA radiation dose from the recirculated sump or reactor vessel water. The accident temperature is the same as the normal temperature.

MSLBs in Steam and Feedline Penetration Area

A spectrum of MSLBs have been reanalyzed for the SPU (see subsection 6.6.4). The peak accident temperature for the break building area is above the qualification temperatures for the EQ equipment in these areas, however, it is bounded by the pre-SPU HELB temperatures.

The equipment that is required to respond to these HELBs has been re-evaluated using thermal lag analysis of the equipment response to the break environment for the spectrum of breaks. The limiting break for equipment qualification was identified as a 1-ft^2 break. The equipment in the steam and feedline penetration area is qualified considering the thermal lag analysis.

10.8.3.3 Radiation

The SPU effect on radiation outside containment has been evaluated. The beta radiation dose to EQ equipment outside containment is negligible. The radiation sources are inside process equipment and piping. In the event of a LOCA inside containment, the highly radioactive water is recirculated within process equipment and piping in the Primary Auxiliary Building and pipe tunnel. This water has a slightly higher radiation dose than before the SPU, but the effect on EQ is acceptable.

10.8.3.4 Humidity

The SPU does not change the normal operational humidity or the accident humidity outside containment.

10.8.3.5 Flooding

Flooding outside the containment is addressed in Section 10.4 of this document.

10.8.4 SPU Equipment Qualification Evaluation

Equipment Inside Containment

All equipment inside reactor containment is qualified for SPU conditions when the considerations discussed earlier in subsection 10.8.2 are made.

The equipment qualified life and post-accident operability time are not impacted by the SPU.

Equipment Outside Containment

Accident temperatures outside containment in the steam and feedline penetration area have been re-analyzed and result in lower temperatures. All other areas outside containment experience insignificant temperature increases. All equipment outside containment required for accident response has been verified to be qualified.

10.9 Chemistry Program

10.9.1 Primary Chemistry Program

The IP3 Primary Strategic Water Chemistry Plan establishes a site-specific chemical program for minimizing corrosion damage and maintaining system and fuel cladding integrity in the RCS, as well as keeping ex-core dose rates as low as possible. This plan satisfies the requirements for the primary water chemistry component of NEI 97-06, *Steam Generator Program Guidelines* (Reference 1), which directs licensees to comply with the intent of EPRI's, *PWR Primary Water Chemistry Guidelines* (Reference 2).

As addressed in subsection 4.1.2.1 of this report, the IP3 SPU results in relatively small temperature changes in primary and secondary coolant temperatures and these new operating conditions are well within the envelope of conditions used in developing the industry chemistry guidelines. Therefore, the IP3 plant chemistry limits based on industry guidelines are still applicable after the IP3 SPU, and no changes to the Primary Chemistry Program are required for the IP3 SPU.

10.9.2 Secondary Chemistry Program

The goal of the IP3 Secondary Strategic Water Chemistry Plan is to minimize chemically induced corrosion damage and performance degradation in the secondary water system. This plan is required by NEI 97-06, *Steam Generator Program Guidelines* (Reference 1). With respect to the secondary water chemistry component of the Steam Generator Program, NEI 97-06 directs licensees to comply with the intent of EPRI's, *PWR Secondary Water Chemistry Guidelines* (Reference 3). As addressed in IP3 *Technical Specification* 5.5.9 (Reference 4), a specific objective of the Secondary Water Chemistry Program is to provide controls for monitoring secondary water chemistry to inhibit steam generator tube degradation.

The original steam generators at IP3 were replaced in 1989 with Westinghouse Model 44F steam generators containing thermally treated U-tubes fabricated from Alloy 690. Subsection 5.6.7 of this report addresses the impact of the SPU on the potential for stress corrosion cracking (SCC) and pitting of the Alloy 690 tubing.

10.9.3 References

1. Nuclear Energy Institute (NEI) 97-06, Steam *Generator Program Guidelines*, Rev. 1, January 2001.

2. EPRI TR-105714-V1R4, *PWR Primary Water Chemistry Guidelines*, Volume 1, Rev. 4.

3. EPRI TR-102134-R5, Final Report, *PWR Secondary Water Chemistry Guidelines*, Rev. 5.

4. *IP3 Technical Specification*, No. 5.5.9, "Secondary Water Chemistry Program," Amendment No. 205.

10.10 Generic Letter 95-07

In 1995 the NRC issued Generic Letter 95-07 (Reference 1), requesting that certain actions be taken by utilities regarding the susceptibility and evaluation of power-operated gate valves to the phenomena of pressure locking and thermal binding. Power-operated valves include safety-related MOVs and AOVs.

Based on recognition of the potential for pressure locking, a number of motor-operated gate valves were field-modified prior to initial startup to eliminate the potential for pressure locking. Similar modification of additional MOVs was performed after startup. The normal positions of two MOVs were changed utilizing the 10CFR50.59 (Reference 2) process from closed to open to eliminate the potential for pressure locking.

Results of the screening of safety-related motor-operated gate valves identified the MOVs that required detailed evaluations for susceptibility to pressure locking and/or thermal binding. The evaluations considered two types of pressure locking: hydraulically induced pressure locking and thermally induced pressure locking. These detailed evaluations showed that: the MOV actuators have sufficient thrust to open the valves under the prescribed conditions, or based on detailed analysis, pressure locking and/or thermal binding is not a concern or the valves are acceptable in the current condition.

By screening gate valves with attached hydraulic/pneumatic actuators, two AOVs that are potentially susceptible to pressure locking and/or thermal binding were identified. These valves are not susceptible to thermal binding due to valve design. An evaluation of the susceptibility of the AOVs to pressure locking determined that pressure locking is not a concern due to their normal position of open and procedural guidance given in event of their closure.

The impact of the SPU on the pressure locking and thermal binding evaluations of MOVs/AOVs was reviewed. It was determined that the SPU does not introduce any increased challenge for pressure locking and/or thermal binding and does not impact the results and conclusions of the current evaluations.

10.10.1 References

1. NRC Generic Letter 95-07, Pressure Locking and Thermal Binding of Safety-Related Power Operated Gate Valves, August 17, 1995.

2. 10CFR50.59, *Changes, Tests, and Experiments.*

10.11 Generic Letter 96-06

Generic Letter 96-06 (Reference 1) requested that nuclear utilities address the susceptibility of containment air cooler cooling water systems to either water-hammer or two-phase flow conditions during postulated accident conditions, and piping systems that penetrate containment to thermal expansion of fluid such that overpressurization of piping could occur.

In response to GL 96-06, IP3 performed evaluations of:

- Thermally induced overpressurization of isolated water-filled piping sections
- Water-hammer associated with containment fan cooler units (FCUs)
- Two-phase flow conditions associated with the FCUs.

Summary of major results/conclusions of these evaluations and the impact of the SPU on the results/conclusions follows.

Thermally Induced Overpressurization

The containment penetration configurations were evaluated, and the lines and associated CIVs determined to be potentially susceptible to thermal pressurization resulting from containment LOCA and/or PAB HELB conditions were identified. These lines and associated CIVs were determined to be acceptable based on one of the following:

- Line contains AOVs that would self-relieve pressure prior to exceeding design code or UFSAR faulted condition stress limits

- Line/CIVs meet design code normal condition stress acceptance criteria

- Line/CIVs meets faulted condition stress limits allowed by the UFSAR

A generic containment temperature effect evaluation was performed to confirm that CIVs outside containment, and the piping between these valves, would not be significantly affected by elevated containment temperatures.

An evaluation review of the lines and associated CIVs determined to be potentially susceptible to thermal pressurization from containment LOCA and/or PAB HELB conditions for impact of the SPU was performed. the SPU does not affect the results and conclusions of these evaluations, based on the following:

- The maximum temperature utilized for structural evaluation of lines and CIVs subject to containment LOCA conditions envelopes the peak containment temperature for a LOCA under SPU conditions.

- The structural evaluation of lines and CIVs subject to PAB HELB conditions is not affected by the SPU since, as indicated in Section 10.8 of this report the peak temperature in the PAB pipe penetration area resulting from a HELB under SPU conditions is bounded by the peak temperature due to a HELB under existing (pre-uprate) conditions.

Water-Hammer

All Service Water System (SWS) supply and return lines to the five containment FCUs were analyzed for postulated water-hammer loadings. Two type of water-hammer events were determined to occur: column-closure caused by a LOOP event or a simultaneous LOOP and LOCA event, and steam-condensation-induced (void collapse) caused by simultaneous LOOP and LOCA events. Evaluations and assessments encompassed hydraulic system response, system monitoring during a simulated SI test, system walkdowns to visually observe the structural condition of the piping and support system, and structural assessments. Based on the analytical work performed, consideration of actual measured data during a simulated SI, present system condition, and modification of pipe supports, it was concluded that the containment service water (SW) piping and FCUs are capable of withstanding the postulated water-hammers events that can occur either during LOOP, or LOOP with LOCA events within the design basis acceptance criteria in the UFSAR.

The impact of SPU conditions on GL 96-06 SWS water-hammer issues was evaluated. It was concluded that the column closure water-hammer and the steam-condensation-induced (steam bubble or void collapse) water-hammer will not be significantly impacted by the small (less than 1 percent) decrease in accident peak containment temperature and/or the small expected increase in containment FCU cooling water outlet temperature under SPU accident conditions. That is, the velocity (critical parameter) of column closure and the volume (critical parameter) of steam bubble formation are not significantly affected by these small changes in temperatures.

Two-Phase Flow

Based on evaluations, it was concluded that the IP3 SWS and containment FCUs will remain operable and perform their design accident functions with the single failures considered during the original design and licensing with two-phase flow occurring at the manual isolation valves in the SW piping downstream of the FCUs, outside of containment. This two-phase flow condition will result in reduced SW flow to the FCUs. However, the predicted reduction in SW flow will not result in reduced FCU heat removal capability below the design basis accident heat removal requirement. Therefore, there is no challenge to either the SWS or FCU operability.

The impact of the SPU on the current evaluation for two-phase flow was reviewed. The inputs that affect the results of the two-phase flow evaluation include SW temperature and the SW flow requirements for the containment FCUs. The SW temperature is affected by containment peak temperature and containment FCU heat load. Under SPU conditions, the containment LOCA peak temperature decreases slightly (refer to Section 10.8), and the containment FCU heat load is enveloped by the original design basis. The SW flow requirement for the containment FCUs is not changed under SPU conditions. Therefore, the SPU does not impact the conclusions of the current IP3 two-phase flow evaluation.

10.11.1 References

1. NRC Generic Letter 96-06, *Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions*, September 30, 1999, and Supplement, November 13, 1997.

10.12 Generic Letter 89-13

Generic Letter 89-13 (Reference 1) identified a number of concerns affecting safety-related equipment associated with SWSs, and put forth recommended actions in the areas of surveillance, testing, inspection, and maintenance to ensure these systems are in compliance with regulations.

The intake structure, SWS, and the following safety-related (Quality Assurance [QA] Category I) essential heat exchangers cooled by the SWS, including associated piping and valves, are included within the scope of GL 89-13 at IP3:

- Control Room AC condenser units
- Containment FCUs
- Containment FCU motor coolers
- EDG lube oil/jacket water coolers
- CCW heat exchangers (HXs)

The GL 89-13 implementation plan at IP3 addresses the following five areas:

1. Surveillance and control techniques to reduce the incidence of flow blockage as a result of bio-fouling: Activities include inspection of the intake structure, chlorination of the SWS, and implementation of an equipment lay-up program for HXs to minimize microbiologically influenced corrosion.

2. Test program to verify heat transfer capability of all safety-related HXs cooled by SW: IP3 has committed to perform frequent periodic cleaning and inspection of essential SW HXs (identified above) in lieu of testing for degraded performance. This is implemented through preventive maintenance procedures for the applicable HXs.

3. Inspection and maintenance program for SW piping and components: The IP3 Preventive Maintenance Program includes major SWS components, such as the SW pumps, Zurn strainers, and various relief and butterfly valves. A continuing corrosion monitoring program has been established for the SWS. This program involves non-destructive examinations of piping components and valves, and visual inspection of internal pipe surfaces.

4. SWS licensing basis review: The SWS Design Basis Document is in place, and a computer hydraulic model of the SWS has been developed to compute flows through various parts of the system. Walkdown inspections of the accessible portions of the SWS are conducted so that the entire system is inspected on a quarterly basis.

5. Maintenance practices, operating and emergency procedures, and training: The SWS is a risk-significant system and is included in the Maintenance Rule effort. An SWS operating procedure has been established and is updated periodically. Training in the SWS is included in the plant operator re-qualification process.

The SPU does not affect the programs, procedures, and activities in place at IP3 in support of implementation of the requirements of GL 89-13. The impact of the SPU on SWS HX heat loads is addressed in Section 9.6 of this report.

Continued cleaning and inspection of all GL 89-13 HXs post-SPU is recommended to ensure that the performance of these HXs remains acceptable following the SPU.

10.12.1 References

1. Generic Letter 89-13, *Service Water System Problems Affecting Safety-Related Equipment*, July 18, 1989.

10.13 Plant Simulator

IP3 has a unit-specific simulator, which replicates the plant control room. The simulator computer systems provide simulator responses that are intended to match, to the greatest extent possible, actual plant conditions for the simulation of accidents and transients.

Appendix A to 10CFR55 (Reference 1) permits use of simulators for operator training. Regulatory Guide 1.149 (Reference 2), states that the requirements established by ANSI/ANS 3.5, *Nuclear Power Plant Simulators for Use in Operator Training*, for specifying the functional capability of a simulator and for comparing a simulator to its reference plant are acceptable to the NRC, subject to provisions identified in the Regulatory Guide. The IP3 simulator is currently certified to ANSI/ANS 3.5-1985 (Reference 3).

The implementation of the SPU Program will result in changes in plant operating characteristics (software changes). These changes will range from simple changes in process parameters (for example, flow rates) to changes in plant responses to transients and accidents.

Modifications in support of the SPU will be implemented in accordance with the IP3 engineering change process. This process requires review of the impact of modifications on the IP3 simulator.

10.13.1 References

1. 10CFR55, *Operator Licenses.*

2. NRC Regulatory Guide 1.149, *Nuclear Power Plant Simulators for Use in Operator Training*, April 1981.

3. ANSI/ANS 3.5-1985, *Nuclear Power Plant Simulators for Use in Operator Training.*

10.14 Containment Leakage Rate Testing Program

Appendix J to 10CFR50 (Reference 1) requires that the leakage requirements for a reactor containment specified therein be met. IP3 *Technical Specification* 5.5.15 (Reference 2) specifies that a program should be established to implement the leakage rate testing of the containment as required by 10CFR50.54 (Reference 3) section (o) and 10CFR50, Appendix J, Option B, "Performance-Based Requirements," as modified by approved exemptions. *Technical Specification* 5.5.15 also states that this program should be in accordance with the guidelines in RG 1.163 (Reference 4), as modified by the exceptions noted.

Leakage rate testing requirements are addressed in the IP3 *Technical Specifications* and IP3 Containment Leakage Rate Testing Program procedures.

The results of IP3 design basis accident analyses under SPU conditions show that the calculated peak containment pressure for these accidents, (resulting from the LOCA analysis), is less than the minimum test pressure for leakage rate testing identified in the Containment Leakage Rate Testing Program. Accordingly, the SPU does not impose additional requirements on IP3 containment leakage rate testing.

10.14.1 References

1. 10CFR50, Appendix J, *Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors.*

2. *Indian Point Unit 3 Technical Specification* 5.5.15, "Containment Leakage Rate Testing Program," Amendment No. 206.

3. 10CFR50.54, *Conditions of Licenses.*

4. NRC Regulatory Guide 1.163, *Performance-Based Containment Leak-Test Program,* September 1995.

10.15 Plant Operations

Entergy does not expect the changes to plant conditions and operation associated with the SPU to result in significant new or increased challenges to plant operations. Entergy recognizes the importance of this element of plant performance and safety and has taken specific actions to address the areas of potential concern. Operations has participated in the preparation and review of changes to the plant and associated operating procedures. Furthermore, appropriate training and simulator changes will be implemented prior to the SPU to ensure operations personnel are familiar with and prepared for any associated changes to the plant response.

10.15.1 Procedures

Although numerous, no significant changes to plant procedures will be required for the SPU. Changes associated with the SPU will be treated in a manner consistent with any other plant modification. The Emergency Operating Procedure (EOP) changes will be made as necessary to reflect the new power level and setpoint changes. The EOP step for addition of supplemental feedwater to steam generators after a trip already exists and has been demonstrated to be accomplished in less than 10 minutes. This procedure will be revised to provide specificity for the flow and time requirements.

10.15.2 Effect on Operator Actions and Training

Engineered Safety Feature System design and procedural controls have not changed with the SPU. Various setpoint changes will be required. However, the operator response to any event will be insignificantly reduced by a change in rated thermal power. The change in hot leg switchover time from 14 hours to 6.5 hours will also have an insignificant effect on operator action and training.

Before SPU implementation, the Nuclear Instrumentation System (NIS), including alarm setpoints, will be adjusted to satisfy new analysis and *Technical Specification* values contained in this report. The operator response to existing alarms remains unchanged.

The changes in operating procedures and setpoints will be part of operator training to be conducted prior to implementation of the SPU.

10.15.3 Plant-Integrated Computer System

Process parameter setpoint and scaling changes will be made, as required, to the Critical Function Monitoring System (CFMS). There are no other changes to the CFMS from the SPU.

10.15.4 Startup Testing

Startup from the refueling outage when plant modifications will be made to accomplish the SPU will be treated as a special evolution. As in the previous uprate for the 1.4-percent MUR, the power escalation will be controlled by a specific procedure. This procedure will detail controls for power escalation, hold points, and data collection requirements (including radiation surveys). Performance monitoring for plant modifications, such as the new high-pressure turbine, will be accomplished at specified power levels. Setpoint changes will be controlled under plant procedure requirements. Monitoring of NSSS plant performance will include monitoring of margins to activation of alarms and trips such as overpower ΔT and overtemperature ΔT. A vibration monitoring activity will be included to monitor plant response at various power levels. The procedure will be subjected to dry runs on the plant simulator to assure plant responses are as predicted. The results of the startup testing will be documented and maintained as plant records.

The IP3 test plan has been prepared to cover both phases of the planned proper increases from the current power level to 3216. The test plan is designed to demonstrate that systems, structures, and components will perform satisfactorily at the SPU condition. The plan provides assurances that:

- The initial power ascension to the Phase 1 SPU power level condition will be controlled.
- The facility can be operated at the proposed SPU condition in accordance with design requirements and in a manner that will not endanger the health and safety of the public.
- The SPU-related modifications to IP3 have been adequately constructed and implemented.
- The Phase 2 power ascension testing will be conducted in a manner similar to the Phase 2 testing program.

A Temporary Operating Instruction (TOI) will be written to control the sequence and coordination of existing plant startup procedures with new post-modification test procedures. It will ensure that the required modifications, calibrations, and specification requirements are in place to support the ascension to full power. Additionally, during the power ascension, the TOI will be used to callout or to verify the performance of specific test procedures, collection of plant performance data, and documentation of the required reviews. Upon acceptance of plant data and test results, engineering and operations management will document their approval to proceed with the power ascension.

Additionally, post-modification tests (PMTs) for each modification will be performed in accordance with plant design process procedures. The specifics of these PMTs are not detailed herein.

Pre-Startup Activities:

- Material Degradation - Flow-Accelerated Corrosion (FAC) Monitoring Program will be updated for the following areas, affected as a result of SPU:
  - 31ABC and 32ABC FWH
- Additionally, the projected SPU secondary heat balance parameters for temperature, pressures, and velocities will be checked with the CheckWorks FAC Program to ensure that no unanticipated margins are reduced in advance of SPU.

Areas of Increased Monitoring, during Power Ascension

- FWH performance
- Reheat moisture separator drains, potential slug flows/vibrations
- Margin to OP/DT and OT/DT alarm/trip setpoints
- Heater drain pump runout and discharge valve control stability
- Main boiler feed pump speed control circuit:
  - Main feed regulator valve Delta P program circuit
  - Main feed regulator final valve position (lift)
- Flow induced vibration (FIV) on main, reheat, exhaust steam systems
- FIV on condensate/feedwater and heater drain pump systems
- Plant operating control system performance

Piping Vibration Test Plan

In response to feedback from other plants' power uprate efforts, Entergy developed a piping vibration (PV) test plan. This PV plan considered plant condition reports written on piping vibration or support problems and plant piping and support evaluations or calculations for the effects resulting from SPU operating conditions. Based on this review, the following IP3 piping systems, affected by flow increases associated with SPU, were visually observed to determine if any existing pre-uprate vibration concerns exist.

- Main Steam System
- Extraction Steam System
- Feedwater Heater Drains and Vents
- Moisture Separator and Reheater Drains
- Boiler Feedwater System
- Condensate System

As a follow-up to the above pre-uprate visual observations, walkdowns will be conducted during the increase to SPU power. The acceptance criteria to be used during these walkdowns are intended to initially accept piping based on displacement or velocity screening criteria (based on observations of piping systems), and to collect data.

IP3 SPU Test Plan

The following tables describe the testing and data collection for the SPU, related modifications and areas of increased monitoring. The test number to be performed on Table 10-2 is referenced on Table 10-3 at the respective power levels.

10.15.5 References

1. ASME OM-S/G-1994, *Standards and Guides for Operation and Maintenance of Nuclear Power Plants*, 1994.

Table 10-2

Phase 1 IP3 SPU Power Ascension Testing

System/Component	Modification Description	Test
HP Turbine	Replace the HP turbine steam path	1 - Vibration monitoring and harmonic vibration speed determination and turbine differential expansion monitoring. 2 - Over-speed setting test 3 - Demonstration of thermal performance improvements and generator increase.
Turbine Inlet Steam Pressure	Two pressure tap relocations from turbine 1st stage to inlet control stage (downstream of Governor valves)	1 - Post-modification test 2 - Monitoring of turbine inlet steam pressure during ascension versus projection at hold points for plant calorimetric at 90%, 96.8%, and 100%. Engineering evaluate deviations prior to power ascension approval.
LP Turbine	No modification planned	1 - Vibration monitoring and harmonic vibration speed determination and turbine differential expansion monitoring. 2 - Demonstration of thermal performance.
Moisture Separator Reheaters	Replacement of lower separator baskets with counter flow chevron design	1 - Establish as-found base line vibration data at current power level 3067.4 MWt 2- Monitor for flow induced vibrations during power ascension versus as-found. Engineering evaluate deviations prior to power ascension approval. 3 - Monitoring during power ascension steam flow, cross-under; cross-over temperatures and pressures versus projected PEPSE secondary heat balance. Engineering evaluate deviations prior to power ascension approval. 4 - Post-modification test

Table 10-2 (Cont.) Phase 1 IP3 SPU Power Ascension Testing		
System/Component	**Modification Description**	**Test**
Heater Drain System	(mod. not required for SPU)	1 - Monitor HDTP & motors amps; flows and discharge valve lift versus projected. Engineering evaluate deviations prior to power ascension approval. 2 - Monitor for FIVs during power ascension versus as found. Engineering evaluate deviations prior to power ascension approval. 3 - Monitor FWHs levels and terminal drain temperatures versus expected PEPSE heat balance projections.
BOP System Main Steam/Extraction Steam/Reheat Steam/Condensate & Feedwater/ Service Water System	Increase steam and feed flow for Phase 1 power level.	1 - Establish as found base line vibration data at current power level 3067.4 MWt. 2 - Monitor for FIVs during power ascension versus as found. Engineering evaluate deviations prior to power ascension approval. 3 - Monitor for flow induced vibrations post-uprate plus 7 days versus as left. Engineering evaluate deviations and recommend correction as necessary. 4 - Monitor main boiler feed pump speed control; Delta P; feed regulating valve lift, and condensate pump Amps versus expected. Engineering evaluate deviations prior to power ascension approval. 5 - Monitor service water system loads: main turbine generator (MTG) hydrogen coolers, MTG exciter coolers, MTG IPB coolers, temperatures & flows versus established as found base line data at current power level 3114.4 MWt.

Table 10-2 (Cont.) Phase 1 IP3 SPU Power Ascension Testing		
System/Component	**Modification Description**	**Test**
		6 - Monitor FW Hsterminal discharge temperatures versus projected. Engineering evaluate deviations prior to power ascension approval. 7 - Monitor secondary plant oil cooling systems: MBF/CP/HDT/MLO sys. vs. expected and adjust as necessary.
MTG IPB Duct Cooling	No modification planned.	1 - Monitor cooling performance. Engineering evaluate deviations prior to power ascension approval. 2 - *Perform hot spot survey on ducts and* evaluate.
Main Power Transformer Monitoring	Installation of N2 gas monitor	1 - Monitor cooling performance: at minimum and maximum amp/VAR loading versus expected. Engineering evaluate deviations prior to power ascension approval. 2 - Post-modification test for monitoring system.
HHSI Modification	Installation of orifice valves and system re-configuration.	1 - Post-modification test 2 - HHSI system flow balance test
RPS/ESFAS Setpoints	Rescaling transmitters ranges/resetting of NTS	1 - Post-modification test
Control System Setpoints	Rescaling transmitters ranges/resetting of nominal control ranges.	1 - Collect plant data and confirm performance as expected. Evaluate adjustment as required. 2 - Post-modification test
Process Computer	Engineering & alarm value update	1- Perform pre-startup test monitor program functionality during power ascension. 2 - Post-modification test for plant computer update

Table 10-2 (Cont.) Phase 1 IP3 SPU Power Ascension Testing		
System/Component	**Modification Description**	**Test**
Radiation Measurement	Power increase to 100% power level	2 - Monitor and adjust N-16 main steam line radiation monitors. 1 - Perform plant radiation surveys post-power escalation to Phase 1 power level.
Low Pressure Turbine	Rotor blade upgrade	1 - Vibration monitoring and harmonic vibration speed determination and turbine differential expansion monitoring. 2 - Demonstration of thermal performance improvements and generator increase.
MTG Isolated Phase Bus Duct Cooling	Upgrade cooling & air flow fans	1 - Post-modification testing. 2 - Perform high pot of flex links, insulators 3 - Monitor cooling performance. Engineering evaluate deviations prior to power ascension approval. 4 - Perform hot spot survey on ducts and evaluate.

Table 10-3 Phase 1 IP3 SPU Power Ascension Tests vs. Power Levels							
		Rated Thermal Power % 3216 MWt (Allowance +/-.5%)					
Test/Modification	Test Description	Prior to Startup	90	93.4	96.8 Pre-SPU 100%	98.4.	100
Main Turbine	Table 10-1	2					3
Turbine Inlet Steam Pressure	Table 10-1	1	2		2	2	2
Moisture Separator Reheaters	Table 10-1	1	2 3		2 3	2 3	2 3
Heater Drain System	Table 10-1	1	1 3 4		2 3 4		2 3 4
BOP sys. MS / EST / RST / C&FW / SWS	Table 10-1	1	2 4		2 4 5 6 7	2 4 5 6 7	2 3 5 6 7
MTG Isolated Phase Bus Duct cooling	Table 10-1	1 3 4			2	2	1 2 4
Main Transformer Monitoring	Table 10-1	2			1 3		1 3
RPS/ESFAS Setpoints	Table 10-1	1	1		1		1
Control System Setpoints	Table 10-1	1	1	1	1	1	1
Process Computer	Table 10-1	1					1
Radiation Measurement	Table 10-1						1

11.0 ENVIRONMENTAL IMPACTS

11.1 Introduction

The environmental issues associated with the issuance of an operating license for Indian Point Unit 3 (IP3) were originally evaluated in the *IP3 Final Environmental Statement* (FES) (Volume 1, page I-1 Section I) (Reference 1) and addressed plant operation up to a maximum calculated core power of 3216 MWt. The Atomic Energy Agency (AEC), the predecessor of the NRC, approved the FES in February 1975.

The Indian Point State Pollutant Discharge Elimination System (SPDES) restrictions on discharge temperatures and discharge flow rates for the station were evaluated along with the flow limits set forth in IP3 Consent Order.

11.2 Input Parameters and Assumptions

The IP3 FES that was approved by the AEC in February 1975 for a maximum calculated core power of 3216 MWt envelops the SPU condition.

The Indian Point SPDES restrictions on discharge temperatures and discharge flow rates for the station were used in the stretch power uprate (SPU) evaluation along with the flow limits set forth in the IP3 Consent Order.

The SPU evaluation assumes the existing Circulating Water System (CWS) pumps are not modified and continue to operate at the same flow rates. Since the CWS inlet temperatures from the Hudson River are not affected by the SPU, circulating flow is unchanged, and main condenser duty and exhaust flows will increase, the CWS discharge temperature to the Hudson River will increase.

Heat load increases due to SPU in the normal and emergency Service Water System (SWS) will result in an increase in the SWS discharge temperature to the Hudson River.

11.3 Description of Analysis and Evaluations

IP3 operation at the SPU core power level of 3216 MWt will increase the exhaust steam flow and duty of the main condenser and, therefore, increase the heat load rejected by the CWS and discharge temperature to the Hudson River. CWS flows were verified to be within the original design basis.

Heat load increases due to the SPU in the normal and emergency SWS will result in an increase in the original SWS discharge temperature to the Hudson River. SWS flows were verified to be within the design basis.

11.4 Acceptance Criteria

The environmental impacts associated with the proposed changes are acceptable when they are within the existing regulatory release permits.

11.5 Design Criteria

Design criteria are not applicable to the Environmental Impact Statement.

11.6 Results and Conclusions

Increased heat rejection to the CWS and SWS is expected to result in a nominal calculated increase in discharge temperature to the river. This temperature increase falls within the applicable SPDES permit thermal limits for IP3.

11.7 References

1. *Indian Point Unit 3 Final Evaluation Statement*, February 1975.