# ATTACHMENT 2

Duke Power Company
Oconee Nuclear Station

UFSAR Chapter 15 Transient
Analysis Methodology

DPC-NE-3005
Revision 1

January 1999

Nuclear Engineering Division
Nuclear Generation Department
Duke Power Company

related failures caused by external events, in particular earthquakes and tornadoes, were found to be significant contributors to the total Oconee CDF as indicated by the following results reported in the IPEEE submittal:

a, Seismically-induced loss of on-site power coupled with loss of the SSF contribute about 68 percent of the seismic CDF.

b. Twenty percent of the seismically-induced failure of on-site power are due to a Jocassee dam failure.

c. Tornado-induced degradation of on-site power contributes about 67 percent of the tornado CDF.

d. The major contributing sequences to the tornado CDF (about 40 percent) involve a tornado-induced failure of the Keowee units to provide power to the plant combined with random SSF failures.

In addition, severe weather-induced LOOP events are the largest contributor to the internal event SBO CDF. The uncertainties associated with these external events were not required to be explicitly addressed in licensee's IPEEE. Since external event and severe weather event uncertainties can be large, the staff suggests that weather conditions be taken into consideration when making decisions that challenge the availability of the Oconee emergency ac power system.

## 8.5 CONSEQUENTIAL ECCS ACTUATION FOLLOWING A LOOP

During preparation of the draft version of this report, a question was raised regarding the response of the three Oconee units to a complete LOOP that could lead to the trip of the three reactors and a potential overcooling transient. Such a scenario could lead to a consequential ECCS actuation on one or all units. The staff believed that the loading scenario from a consequential ECCS actuation following a simultaneous LOOP on all three Oconee units could exceed that previously analyzed by Duke and further challenge the Oconee emergency power system. Duke was, therefore, asked to respond to this concern.

Although Duke stated they did not believe an overcooling event that results in an ECCS actuation would occur following a three unit LOOP (because of prompt operator action), their responses also provided a discussion of what would occur if the overcooling transient did result in an ECCS actuation. The responses indicated that only one additional HPI pump on each of the three Oconee units would start in this case, at some time subsequent to the initial LOOP loading of the units. They indicated that, for both the Keowee overhead and underground paths, the additional steady-state and transient electrical loading of these motors is bounded by other previously performed analyses that showed acceptable results. This information resolved the staff's concern on this issue.

concerning how the Keowee PRA should be used in the future.

During review of the Keowee PRA, the staff noted that a large amount of the plant-specific data was obtained from grid generation experience. In the draft report, the staff was concerned that this data would be questionable for the eight components (such as the voltage regulator and the field flash circuit breaker) where subtle differences exist in operation between grid generation and emergency operation. Many of the emergency start failures (listed in Table C.1-1 of the Keowee PRA) involve these components.

In addition, the staff noted that the failure of Keowee Unit 1 to achieve rated voltage following an emergency start signal on June 20, 1997, was caused by subcomponent interactions in the field flash circuit breaker control circuitry that would not have been manifested during a grid generation start. A setpoint for the overvoltage relay (in the field flash circuit breaker control circuitry ) was changed outside the licensee's plant modification process, and no post-modification test was specified or performed.

The staff has concluded that the following actions concerning testing and operation have the potential to increase the reliability of the two Keowee units and/or provide additional assurance of the availability of important components and, as such, are worthy of consideration by Duke.

a. Performance of monthly start tests with the autosynchronizer turned off (both voltage adjust and the base adjust functions would be available during the test).

b. Verification of the base adjust setting in the monthly normal start test procedure.

c. Performance of post-modification tests consisting of at least one emergency start, and evaluation of the impact of the results on the emergency start function.

Keowee reliability during dual-unit grid generation is very dependent upon certain specific component reliabilities. Therefore, the staff has identified the following recommendations that have the potential to increase the reliability of Keowee when both units are generating power to the grid and, as such, are worthy of consideration by Duke. From past experience, dual unit generation only occurs approximately 3 percent of the time; but may, for design considerations, occur for up to 30 percent of the time.

a. Monitoring the reliability of the ACBs and maintaining the reliability values assumed for these components in the Keowee PRA (particularly ACBs 3 and 4 that connect Keowee Units 1 and 2 to the underground path).

b. Performing periodic hot start tests of the Keowee units.

## 8.4 OCONEE EXTERNAL EVENTS ANALYSIS

Based on the staff's preliminary review, external events dominate the total Oconee CDF. Duke reported that the CDF from fires, tornados, seismic and external flooding events contribute approximately 72 percent of the total CDF of 8.4 E-5 per year. Seismic events and tornados are the major external event contributors (contribute almost 60 percent of the total CDF). Keowee-

With regard to the 10-minute initiation concern, the Operations and Training Departments at Oconee have developed and implemented a program to provide added assurance that the licensed operators are qualified to activate and operate the SSF systems within the required time constraints. More recent drills have shown an increase in proficiency and acceptable results. The staff finds that this concern has been adequately addressed.

## 8.3 DUKE'S KEOWEE RELIABILITY ANALYSIS (KEOWEE PRA)

The result (top gate) of the Keowee PRA is the failure of either Keowee unit to supply emergency power to Oconee Unit 3 through Oconee transformer CT 3 (the overhead path through the switchyard) or Oconee transformer CT 4 (the underground path). The base case result of the Keowee PRA was reported to be 7.4 E-3. The base case solution used Bayesian-updated data and included operator recovery actions. The equivalent failure probability without accounting for operator recovery actions increased to 1.0 E-2.

In response to staff's concerns about the use of plant-specific Bayesian-updated data, the licensee performed an additional uncertainty analysis to determine the failure probability distribution for either Keowee unit supply emergency power to CT 3 or CT 4 using generic data (except for the 50 out of 1135 events where generic data was not available). The estimated mean increased to 1.05 E-2.

Dominant contributors to the results include dual-unit Keowee unavailability due to maintenance, overhead path unavailability due to maintenance, failures involving components of the auxiliary ac power system (most notably ACBs 5 thru 8), voltage regulator failures, common cause failures of auxiliary ac power breakers, and clogging of the common intake header of the generator cooling water strainers (with failure of the operator to clean the strainers).

Ignoring the pathways to the Oconee emergency buses and just considering the Keowee units, the failure probability of a Keowee unit to start and run for 24 hours (not including maintenance unavailability) was calculated to be 2.0 E-2. This failure probability is comparable to an EDG failure probability to start and run. Therefore, the reliability of a single hydro unit is comparable to the reliability of a single EDG (with regard to internal event LOOP initiators). However, the high unavailability of the overhead path and the dual-unit maintenance configuration reduce the overall reliability of the Keowee system in comparison to an EDG system with typical pathways to emergency buses and no allowance (or need) for dual-unit maintenance.

When Duke integrated the Keowee PRA with the IPE, the CDF at Oconee Unit 3 for loss of ac power events was calculated to be 1.0 E-6/yr. The severe weather LOOP had the greatest impact on the calculated loss of ac power CDF in both the original IPE and the Keowee PRA integration. Following a severe weather LOOP, power from the CT 3 transformer (the overhead path) and the CT 5 transformer (which can be powered by the Lee Combustion turbines or the Central switchyard) is assumed not to be available. This SBO CDF estimate also includes failure of the SSF to provide inventory to the steam generators and RCP seal cooling.

Based on the staff's review of the Keowee PRA, the staff identified several recommendations for Duke's consideration and that implementation of these recommendations would support the availability results reported in the Keowee PRA. The staff also made recommendations

allow the Keowee underground path unit to accelerate closer to its final nominal frequency and voltage prior to loading. The negative effects of the time delay, however, such as how the logic would perform or the effects on the motors (multiple starts, etc.) and the hydraulics (water hammer, etc.) have not been determined. With regard to motor multiple starts, the staff notes that in the test procedure for the integrated tests performed in January 1997, Duke placed a limitation on the allowed number of motor successive starts that varied from one to three, depending on the motor and its initial temperature. Therefore, there may be some vulnerability in this area to a LOCA/degraded voltage event. The staff has issued IN 93-17, Revision 1 on the sequential occurrence of a LOCA and LOOP and is pursuing the need to address these scenarios generically (Generic Issue 171). As a result, the staff finds this course of action acceptable and will not pursue it for this report.

With regard to the SBO scenario, the Oconee SBO-induced CDF meets the Commission's expectations relative to implementation of the SBO Rule if the targeted reliability and/or availability of the Lee gas turbines are achieved during plant operation. Duke has also satisfactorily addressed staff concerns relative to operation of the SSF, which would be used during an SBO event. Because of this, and the dual means of coping with an SBO event at Oconee (for at least some minimum period of time) using the turbine driven EFW pump or SSF, the staff finds there is no need to further pursue the question of the adequacy of the implementation of the SBO rule at Oconee.

## 8.2 STANDBY SHUTDOWN FACILITY

Over the years a number of concerns have been raised by both the staff and the licensee regarding the SSF. These concerns have been resolved and a number of changes have occurred as a result of this action.

The last remaining unresolved concerns relative to the SSF, as reported in the staff's interim report, were the SSF makeup pump's marginal capacity (which results in a required initiation time of 10 minutes) and the lack of integrated testing of the makeup pump's ability to supply balanced seal flow to all four RCPs for a unit. The balanced flow concern is related to the marginal capacity and is that one or more RCPs could be starved for flow (or have flow below the minimum required for adequate seal cooling), thereby causing seal heatup and inducing increased seal leakage (beyond the capacity of the makeup pump) and possible seal failure during an event where the SSF is used to supply seal water. Both of these concerns have been resolved by the licensee by performing acceptable integrated makeup pump testing.

As reported in the draft and interim reports, the staff had concerns that the flow testing, as originally proposed, would not be adequate to provide sufficient data to verify adequate seal cooling flow to each pump during actual SSF makeup pump injection. However, the licensee revised the test procedure to be more representative of actual system operating conditions, and the results of the revised integrated flow tests demonstrated adequate flow balance to assure the minimum required flow to each RCP. This balanced flow also demonstrated that the capacity of the SSF makeup pump is adequate for the system to perform its function. (See Duke letters dated April 29 and August 25, 1998.)

larger number of Keowee periodic emergency starts from the standby condition. Duke maintained that their one-time black-start tests, in combination with battery service tests, provided sufficient assurance of the Keowee black-start capability. The licensee also maintained that the existing number of periodic emergency starts from standby, in combination with non-emergency starts from standby, provide adequate assurance of Keowee's ability to start from standby under emergency conditions. While the staff believes that a larger number of periodic emergency starts from standby, and a periodic black start test (as routinely conducted on typical DG plants), would be beneficial in detecting synergistic and other types of failures, it is the staff's judgement that it would be extremely difficult to provide the quantitative analysis necessary to support a backfit consistent with the requirements of 10 CFR 50.109(a)(3). Therefore, the staff considers these issues to be resolved.

During periods when both Keowee units are generating to the grid for commercial generation purposes, they are both potentially susceptible to common-mode, grid-related perturbations such as electrical faults. These events might increase the common cause actuation of Keowee generator lockout probability to a degree that both units generating to the grid would be found to be slightly less reliable, rather than slightly more reliable, as concluded in the sensitivity study done for dual-unit generation in the Keowee PRA. However, because the occurrence of such faults and events involving tripping of generator loss-of-excitation relays is not considered significant by the staff, these particular events have not been pursued further. The staff continues to find that dual unit operation is acceptable within the constraints provided in the TS, as documented in Amendment Nos. 210, 210, and 207 for Units 1, 2, and 3, respectively, dated August 15, 1995.

A failure of a Keowee or Lee gas turbine voltage regulator or governor that results in an out-of-tolerance voltage or frequency, could expose the redundant safety equipment of the three Oconee units to that voltage and frequency. Duke has provided a commitment to install protection for the out-of-tolerance voltage and frequency conditions that might occur on the Keowee or Lee generators. As proposed, the protection will consist of both over- and under-voltage and frequency relays in a 2 of 3 configuration. Appropriate time delays to allow for loading transients will be incorporated in the logic. The staff considers this matter resolved pending completion of the modification.

Relative to the above concern on out-of-tolerance voltage and frequency, Duke committed to modify the Keowee loading permissives. The intended permissives would not allow loading of either Keowee unit unless the voltage and frequency were between approximately +/-10 percent of nominal values. Because these permissives provide both an upper as well as lower limit on voltage and frequency, they would not allow a frequency overshoot (or voltage overshoot for that matter) in excess of 10 percent to be seen by the Oconee loads on initial energization, as speculated in the draft report. In the interim report, the staff found this approach for the permissives to be acceptable. Duke, however, has subsequently indicated that they may not eliminate the Keowee early loading feature, depending on the results of the tests that were performed in November 1998. The analysis of the test results will provide the technical basis for Duke's final position on this issue. The staff finds this process to be satisfactory.

For some LOCA/LOOP scenarios, the Oconee emergency loads could be energized by a degraded offsite system before they are transferred to the Keowee generators. This delay might

The integrated tests that were performed in January 1997 were successful as one-time tests by demonstrating the capability of the Oconee emergency power system to perform its intended functions. The test data, however, indicated that there is a relatively large Keowee speed overshoot for scenarios when the Keowee units are started from standby. During these events, as opposed to load rejection scenarios, the Keowee units carry the Oconee emergency loads during the overspeed transient so that the emergency loads are subject to an overfrequency transient. The licensee has recognized that, due to its design limitations, the CYME computer model cannot predict the magnitude or elapsed time of the overfrequency transient. Therefore, that staff has suggested that this should be considered by Duke in the event that modifications are planned in the future that could affect these parameters. The effect of a larger overfrequency transient from that seen in the 1997 tests would have to be evaluated because the larger transient, and its resulting poorer V/Hz ratio, may result in stalling of Oconee or Keowee motor-driven emergency equipment.

The staff found that the CYME computer model generally provides an acceptable means of analyzing motor-driven emergency loads under the various Keowee starting and loading scenarios, provided the limitations of the model are understood and considered in the analysis. In some cases, this would require that analyses separate from the CYME analyses be performed to substantiate the CYME results or provide values to be used in the CYME calculations. Two such limitations were discussed earlier in this report (CYME cannot predict the magnitude of an overfrequency transient on standby starts and is incapable of modeling the Keowee early loading scenario). The CYME model also under predicts the Keowee frequency overshoot experienced following load rejection from the grid and the current inrush experienced by the Keowee main step-up and Oconee startup transformers following energization. These last two are not a problem if the CYME model is limited to analysis of emergency loading capability.

Prior to the conduct of the integrated tests performed by Duke in January 1997, questions arose regarding how MOVs would be affected by the low voltages expected following initial load energization on a Keowee hydroelectric generator or a Lee combustion turbine generator. The low voltages result from the simultaneous loading of the large block of Oconee emergency loads onto the Keowee or Lee generators during emergency events with no offsite power available. The staff, therefore, reviewed the integrated test results and pursued some questions with Duke relative to the tests and MOV operability. The staff concluded from its review of the January 1997 integrated test data and the responses provided by Duke to its questions, that the integrated testing results do not invalidate the conclusions reached in the GL 89-10 program relative to MOV operability caused by degraded voltage.

It was not practical in the Oconee design to provide a periodic integrated test for each possible combination and permutation of emergency power sources, feeder paths, initial state of emergency power sources, and transfer combinations. More reliance, therefore, must be placed on component-specific tests, overlapping tests, partial integrated tests, and analyses. The action Duke was taken to respond to GL 96-01, "Testing of Safety Related Logic Circuits," provided increased assurance that all individual logic components in the Oconee emergency ac power system design were being tested. Since any related issues have been reviewed by this program, the staff has not pursued this aspect of the testing issue in this report.

The staff did, however, discuss with Duke the need for a Keowee periodic black-start test and a

units would load onto the underground path (which has a higher impedance than the overhead path) in approximately 31 seconds. The staff was concerned that the higher impedance of the underground path would result in additional unacceptable voltage drop as compared to the overhead path. In this regard, Duke indicated that the conclusions given above for the overhead path are no different from those related to the underground path.

The staff was also concerned that the delay of approximately 31 seconds to load onto the underground path, as compared to 15 seconds on the overhead path, could potentially allow additional time for the overcooling transient to cause actuation of ES Channels 1 and 2 prior to loading of the Oconee units. This would result in the simultaneous loading of the additional HPI pumps with other Oconee loads, rather than the delayed loading of these pumps assumed by Duke. In response to this concern, Duke performed an analysis to determine if the resultant overcooling decreases RCS pressure to the HPI setpoint within 31 seconds of the LOOP event. To perform this analysis Duke used the Oconee RETRAN0-02 plant simulation model that is detailed in Duke Topical Report DPC-NE-3000, dated November 1988, and was approved by the staff on August 8, 1994. Duke has concluded from its evaluation that the HPI actuation setpoint (1600 psig) would not be reached for more than three minutes based on conservative assumptions. The staff has performed a confirmatory calculation that supports this conclusion. The staff judged Duke's conclusion to be reasonable. This resolved the staff's remaining concern on this subject.

## 8.0 **SIGNIFICANT FINDINGS AND RECOMMENDATIONS**

Following is a synopsis of the significant findings and recommendations from this report.

### 8.1 OCONEE EMERGENCY AC ELECTRICAL SYSTEM

During certain LOCA/LOOP and LOOP scenarios, the Keowee underground path unit will pick up Oconee electrical loads while the Keowee generator is still accelerating during the emergency startup sequence and has not yet reached full nominal frequency and voltage. As reported in the draft and interim reports, the staff was concerned that this scenario had not been adequately analyzed. Subsequently, in January 1997, Duke ran a series of integrated tests on the Oconee emergency ac electrical system. Test number 3 of those tests successfully demonstrated, on a one time basis, the capability of a Keowee unit to perform in this manner. Review of the test data reported by Duke, however, revealed some potential concerns with a low V/Hz ratio on load energization, and a small time margin between load energization and Keowee voltage regulator transfer to automatic. The CYME computer model used by Duke to analyze the Oconee emergency ac electrical system is also incapable of analyzing the Keowee early loading scenario. Instead, Duke is analyzing this scenario by simulating the energization of the Oconee loads (using the CYME model) following a small simulated load rejection from 60 Hz on the Keowee units. The staff generally agrees (with some small departures) with Duke's explanations regarding the test results and the CYME analyses. Duke is reviewing the early loading issue and will make a decision regarding the early loading feature, depending on their evaluation of the results of tests that were performed in November 1998. This analysis will provide the technical basis for Duke's final position on the issues. The staff has finds this process to be acceptable.

The following is derived from the data:

1. The number of LERs involving human performance and the number of human performance items in the IRs for the Oconee plants are less than the average.

2. At Oconee, there are downward trends in the number of LERs and items in the IRs from past years to present.

The memorandum accompanying the data indicated that the information provided is somewhat subjective in nature and should only be used for insights, or to validate information from other sources. Since the data did not appear to validate a conclusion of human performance weaknesses at Oconee, the staff did not further pursue a more in-depth analysis in this area for this report.

## 7.3 CONSEQUENTIAL ECCS ACTUATION FOLLOWING A LOOP

During management review of the draft version of this report a question was raised regarding the response of the three Oconee units to a complete LOOP that could lead to the trip of the three reactors and a potential overcooling transient. Such a scenario could lead to a consequential ECCS actuation at one or all units. The staff believed that the loading scenario from a consequential ECCS actuation following a simultaneous LOOP of all three Oconee units could exceed that previously analyzed by Duke and further challenge the Oconee emergency power system. Duke was, therefore, asked to respond to this concern and did so in letters dated October 31, 1996; May 22, 1997; and March 17, 1998. In those responses Duke stated that they did not believe that an overcooling event that results in an ECCS actuation would occur following a three unit LOOP, and provided their rationale for that conclusion that credited prompt operator action.

Duke also provided a discussion of what would occur if the overcooling transient did result in an ECCS actuation. They indicated that following a simultaneous LOOP on all three Oconee units, each unit would receive auxiliary power via the overhead path in approximately 15 seconds. At that time the motor-driven EFW pumps, two HPI pumps, and essential loads that were previously running would start at each Oconee unit. It was indicated that if an ECCS actuation should subsequently occur, only ES Channels 1 and 2 would actuate, which would bring up only one additional HPI pump in each unit. Duke stated that from a steady-state load perspective, the additional load of one HPI pump per unit to the three LOOP units is bounded by the previously analyzed loading of a three unit LOOP and LOCA, which includes actuation of ES Channels 1 through 8. With regard to the transient loading capability related to the starting of the additional HPI pumps, Duke indicated that the existing analysis showed that acceptable results existed for a loading in excess of approximately 3000 hp (a LOOP unit equivalent load) to a Keowee unit that is already supplying Oconee loads. The additional load of one HPI pump per unit is only approximately 1800 hp (i.e., 3 X 600 hp). This information resolved the staff's concern related to this particular scenario identified by Duke; however, the staff was still concerned about the 3-unit LOOP scenario involving the loss or unavailability of the overhead path.

If the overhead path were not available during the three unit LOOP scenario the three Oconee

was reviewed. The current UFSAR (December 31, 1994 Version) indicated that, for a SBLOCA, "the worst single failure for SBLOCA remains the loss of one bus of emergency power" resulting in one LPI pump and one HPI pump operating, with half of the flow being diverted through the break. For the LBLOCA case, a more limiting single failure was identified. The UFSAR states, "With the assumed LOOP, this single failure results in a 48-second delay until ECCS fluid is delivered to the RCS." This single failure is the failure of transformer CT 4 and the larger 48-second (up from 35-second) delay is the time associated with the second hydro unit to become available to power both trains of ECCS. It should be noted that the 48 second delay case results in a higher peak clad temperature than the 35 second case, even though both trains of ECCS equipment are available after the 48-second delay. The increased delay time (from 35 seconds to 48 seconds) was transmitted to the staff in an attachment to the normal 10 CFR 50.46 reporting requirements, with no description of the change other than the ECCS acceptance criteria continued to be met. A brief review of the docketed correspondence did not show that this change was formally reviewed by the staff.

Although the staff did not perform a comprehensive review of the ECCS design for this report, based on a limited review of the docketed correspondence including the current UFSAR, it appears that there is no reason to believe that Oconee does not continue to be in compliance with the requirements of 10 CFR 50.46 and 10 CFR 50, Appendix K. With regard to single failure, Oconee uses a plant-specific definition. The original staff review of the ECCS for compliance with 10 CFR 50.46 and 10 CFR 50, Appendix K checked for single failure vulnerabilities in the piping system. It ultimately concluded that the plant should be analyzed assuming the limiting single failure was the same as the generic B&W analysis that assumed the loss of an emergency bus (actually a DG). The emphasis of the ECCS rulemaking, and the individual reviews at the time, was on the thermal hydraulic and physical treatment of LOCA analysis models in addition to the acceptance criteria, not on the electrical design or the basis of the single failure criterion. Plants licensed after 10 CFR 50, Appendix A, were required to meet requirements of GDC 17 for electrical systems (onsite and offsite) that encompass any single failure requirements on electrical systems from 10 CFR 50, Appendix K or GDC 35. Because Oconee was not licensed to 10 CFR 50, Appendix A, the plant-specific single failure definition for Oconee remains valid and in effect with no additional requirements on the electrical power systems as a result of 10 CFR 50.46 or 10 CFR 50, Appendix K.

## 7.2 HUMAN PERFORMANCE

To gain some insights into human performance at Oconee, the staff reviewed data summarized for use at the NRC senior management prebriefings (reference Memorandum to Steven Varga, et al from Bruce Boger, Director Division of Reactor Controls and Human Factors, dated February 14, 1996). The information included tabulations of the number of LERs and IR items involving human performance aspects at each NRC regulated plant. It did not, however, provide assessment of the significance of the items. The data was examined for this report to gain some perspective on the number of reported human performance problems at Oconee as compared to other plants.

A = Available, relatively weak correlation between ground acceleration and equipment failure.
D = Degraded, increasing correlation between ground acceleration and equipment failure.
F = Failed, very high conditional probability of equipment failure due to ground acceleration.
GF= Guaranteed Failure, transformer fails due to failure of its power supply.

## 7.0 **OTHER ISSUES**

### 7.1 OCONEE COMPLIANCE WITH 10 CFR 50.46 AND 10 CFR 50, APPENDIX K

In response to questions raised about Oconee's conformance to 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors," the following discussion is provided. The ECCS at Oconee, which was reviewed by the staff in 1976, was determined to meet the requirements of 10 CFR 50.46. However, Oconee was licensed prior to the requirements of 10 CFR 50.46 being established. The original Oconee ECCS design was reviewed and approved by the staff and documented in the staff's SER. The report stated that the design met the requirements of the Interim Policy Statement (36 FR 12247), using the interim acceptance criteria for ECCS. After 10 CFR 50.46 and 10 CFR 50, Appendix K was finalized and became the new ECCS acceptance criteria, the staff issued an Order to Oconee on December 27, 1974, to reevaluate the ECCS with an acceptable ECCS model that conforms to 10 CFR 50.46.

On July 9, 1975, the licensee responded to the Order with an analysis based on an approved B&W methodology, BAW-10103, "ECCS Evaluation of B&W's 177 FA Lowered Loop NSS." The staff review of this model, documented in two status reports, stated that historically, "the single failure which was assumed to degrade the ECCS the most during a LOCA was a failure of a diesel subsequent to a LOOP." The review also described how containment pressure should be handled with regard to single failure. In Section 3.5, "Single Failure," of the July 9, 1975, submittal the licensee stated, "The single failure used in this analysis is identical to that presented in Section 4.6 of BAW-10103," and that Oconee was in compliance with 10 CFR 50.46 and 10 CFR 50, Appendix K. Staff review was documented in an SE dated January 16, 1976, which stated that, with regard to the single failure criterion, "Babcock and Wilcox ... assumed the loss of one diesel to minimize ECCS cooling" and concluded, after discussing some other failures, that the single failure criterion would be satisfied.

On March 10, 1976, the licensee submitted a letter stating that the worst single failure identified in BAW-10103 and the Oconee-specific analysis, was the loss of a diesel following the loss of off-site power, which results in the operation of only one LPI pump and one HPI pump. The letter also stated that Oconee emergency power system uses two hydro-electric generating units rather than diesels and, "a single failure of one of these sources will have no effect on ECCS performance." The letter concluded that the previous analysis remained valid because, "there is no possibility of a common mode failure that will result in the loss of more than one 4160 volt switchboard" that would result in the operation of less than one LPI pump and one HPI pump. A brief review of the docket file did not show that this letter was formally reviewed or approved.

Although there is considerable docketed correspondence regarding the Oconee ECCS, no other substantive information regarding single failure, 10 CFR 50.46 and 10 CFR 50, Appendix K,

## TABLE 6-1
## OCONEE AC AND SSF FUNCTIONS CREDITED DURING EXTERNAL EVENTS ANALYSIS

| INITIATING EVENT | | Off-Site Power | | Keowee under-ground path | | Power from Lee/CT 5 | | SSF | Comments |
|---|---|---|---|---|---|---|---|---|---|
| | | Power lines | CT 3 | Dam | CT 4 | Power lines | CT 5 | | |
| SEISMIC | | | | | | | | | |
| 2% | a < .2g | A | A | A | A | A | A | A | SBO and CD frequency low and dominated by relay chatter |
| 20% | .2g < a < .4g | D | A | A | A | D | A | A | Recoverable relay chatter losses dominance |
| 55% | .4g < a < .8g | F | GF | D | A | F | GF | D | At 0.6g about 60% chance of SBO with 4% from Relays |
| 23% | a > .8g | F | F | F | GF | F | F | F | High conditional CDF given seismic event |
| EXTERNAL FLOODS | | | | | | | | | |
| 80% | depth < 5ft | Failed | | Failed | | Failed | | Available | Flood from Jocassee dam break leaves only the SSF |
| 20% | depth > 5ft | Failed | | Failed | | Failed | | Failed | Flood from Jocassee dam break floods everything |
| FIRE | | Failed | | Failed | | Failed | | Available | SSF is the only RCM and only ASW available. |
| TORNADOS | | | | | | | | | |
| 60% | W/O SBO | Failed | | Available | | Failed | | Available | SSF backup RCM and ASW source. |
| 40% | With SBO | Failed | | Failed | | Failed | | Available | Keowee supply failed by the tornado, SSF only RCM and ASW source. |

both Keowee units or the underground power. This staff finds this response to be acceptable.

The Oconee IPEEE submittal is under separate review by the staff in accordance with GL 88-20, Supplement 4. Therefore, conclusions on the adequacy of the Oconee design will be addressed by that review and not by this report.

Based on the information provided in the IPEEE, the staff created Table 6-1 of this report, which summarizes the capability of the SSF and the Oconee ac power system to withstand an external event.

pumps. Aside from the relatively minor failures of the individual RCM pumps to run, these core damage sequences represent a 3-unit core damage event. The SSF was modeled as a recovery action following a fire (e.g., there are no fire events or fault trees in the IPEEE).

### 6.5.4 Results and Preliminary Findings

The total fire CDF was estimated to be 5.0 E-6/yr, about 6 percent of the total CDF of 8.4 E-5/yr. However, the fire cutset list total was 5.8 E-6/yr.

Since the only mitigating system is the SSF, its failure contributes to 100 percent of the CDF. As defined by the initiating event, failure of ac was given following the fire and can also be considered to contribute to 100 percent of the CDF.

Fire is specified as a severe turbine building oil fire. The frequency of such fires of 1.7 E-4/yr was developed from the Chi-squared variate at the 50 percent cumulative level and zero observed large turbine fires in United States plants. Although there was no discussion of Oconee specific fire data, the LER's indicate that Oconee has had at least two electrical fires.

## 6.6 CONCLUSIONS

Based on the staff's preliminary review, external events dominate the total Oconee CDF. Duke reported that the CDF from fires, tornados, seismic and external flooding events contribute approximately 72 percent of the total CDF of 8.4 E-5 per year. Seismic events and tornados are the major external event contributors (contribute almost 60 percent of the total CDF).

Keowee-related failures caused by external events, in particular earthquakes and tornadoes, were found to be significant contributors to the total Oconee CDF, as indicated by the following results reported in the IPEEE submittal:

1. Seismically-induced loss of on-site power, coupled with loss of the SSF, contribute about 68 percent of the seismic CDF.

2. 20 percent of the seismically-induced failure of on-site power are due to a Jocassee dam failure.

3. Tornado-induced degradation of on-site power contributes about 67 percent of the tornado CDF.

4. The major contributing sequences to the tornado CDF (about 40 percent) involve a tornado-induced failure of the Keowee units to provide power to the plant combined with random SSF failures.

In addition, severe weather-induced LOOP events is the largest contributor to the internal event SBO CDF. The uncertainties associated with these external events were not required to be explicitly addressed in Duke's IPEEE. Since external event and severe weather event uncertainties can be large, the staff believes that these uncertainties should be taken into consideration when making decisions regarding the availability Oconee emergency ac power system. In their response to the draft Oconee ac power report dated October 31, 1996, Duke stated that severe weather was considered when scheduling outages longer than one shift of

contributor (28 percent of internal flooding) is a large flood with successful SSF secondary side cooling but failure of primary RCM pumps.

The total external flood CDF was estimated to be 7.0 E-6/yr, about 8 percent of the total plant CDF.

The CDF from a flood that also floods the SSF was estimated as 2.6 E-6/yr, which represents 37 percent of the total external flooding CDF. Following the less severe floods, the SSF is the only available mitigating system. Failure of the RCM function of the SSF contributed 14 percent of the total flooding CDF. Failure of the SSF ASW function contributes about 12 percent, and failure of both RCM and SSF ASW contributes 36 percent.

## 6.5 FIRES

### 6.5.1 Methodology and Assumptions

Fires in the cable shaft and turbine building were considered in more detail. Cable shaft fires were quantitatively screened out (CDF less than 1.0 E-9). This screening included extensive credit for low levels of combustibles and the SSF. The primary SSF failure mode (operator error failing to correctly start the system) was not deemed applicable to the cable shaft fires. In the screening analysis, the operators were assumed to have much more than 15 minutes to start the system and, thus, a failure probability of 6.0 E-3, instead of 1.0 E-1 was used.

Fire in the turbine building was quantified. EFW from an unaffected unit is assumed to be used to mitigate a fire induced transient unless all three units were damaged. Therefore, only a fire that spread to all 3 units was included in the final calculation.

In the PRA, the frequency of turbine generator oil fires was estimated to be 1.0 E-3/yr based on a simple evaluation of historical data. Using statistical estimation based on the Chi-squared variate at a 50 percent cumulative level (see Keowee PRA Section B.3), the initiating event frequency of large turbine building fires was reduced from 1.0 E-3/yr in the PRA to 1.7 E-4/yr in the IPEEE study.

As in the PRA, the licensee assumed that 10 percent of the fires will not be contained by the automatic sprinkler system and manual actions. Therefore, the frequency of having a large turbine building fire that affects all three units was estimated to be (0.1)(1.7 E-4/yr) or 1.7 E-5/yr.

### 6.5.2 Electric Power

No credit was taken for an electrical supply from any source following a fire that involved all three units' turbine hall. The on-site ac distribution network was assumed to be completely disabled leaving only the SSF as the mitigating system.

### 6.5.3 Safe Shutdown Facility

The SSF was not affected by a turbine building fire. Based on the assumption that this fire involved all 3 units, the SSF was the only mitigating system available. Therefore, the SSF was required to supply feedwater to the steam generators and supply power to the individual RCM

## 6.4 FLOODS

### 6.4.1 Methodology and Assumptions

External floods arising from failure of the Jocassee dam were modeled in the PRA. Excessive precipitation and river floods were evaluated and not considered credible. The frequency of random failure of the Jocassee dam was estimated in the PRA to be 1.6 E-5/yr, but a value of 2.5 E-5/yr was used in the quantification. In the IPEEE study this error was corrected and added the time span from 1988 to 1993 with no new dam failures. These actions decreased the initiating event frequency to 1.3 E-5/yr.

The PRA assumed that the SSF would not be directly effected by any flood. The IPEEE notes, however, that a flood higher than 5 feet would flood and fail equipment located in the SSF building. A probability that a flood would be higher then 5 feet (0.2 per flood) is used in the IPEEE study. This change causes the external flooding CDF in the IPEEE to be higher than the PRA, even though the initiating event frequency is a factor of two smaller.

### 6.4.2 Electric Power

Failure of equipment due to internal floods is dominated by submerged equipment. Examination of the internal fault trees indicated the potential for crediting the Keowee or Lee power sources through the link to the internal events electric power fault trees. It is assumed that these power supplies were included but unclear what, if any, impact they had on the results.

External flooding due to failure of the Jocassee Dam was assumed to fail all power at the plant leaving the SSF as the sole remaining mitigating system.

### 6.4.3 Safe Shutdown Facility

The SSF is credited as a recovery source following internal turbine building flooding. The SSF system is housed in a separate building and not affected by such floods. If a turbine building flood exceeds a first critical level, normal feedwater and EFW are assumed to fail. As a result, the SSF ASW function would be required. If the flood exceeds a second critical level, and other independent backup systems fail, the SSF RCM function would be required. In the event of turbine building flooding, the operators are instructed to isolate all CCW pump discharge valves in an attempt to control the floods. This action will disable the siphon feeding of the CCW inlet line that is the supply for the SSF ASW. This event requires the use of the portable pump in the SSF to refill the inlet lines.

The SSF building is raised above and bunkered against a 5 foot external flood. Floods greater than this are assumed to fail the SSF. Less significant floods were assumed to have no impact on the SSF operability.

### 6.4.4 Results and Preliminary Findings

The total internal flood CDF was estimated to be 5.5 E-6/yr, about 7 percent of the total plant CDF of 8.4 E-5. The major contributor (54 percent of internal flooding total) is a large or medium flood followed by failure of the SSF to supply secondary side cooling. The next major

through CT 4, to both the 4160 V switchgear on the turbine building ground level, as well as alternative 4160 V switchgear in the basement.

The 4160 V switchgear on the ground level of the turbine building powers the HPI pump. A probability of 3.8 E-1 was assigned to loss of power in this switchgear room following a Category F2 to F5 tornado. The pump itself is in the basement of the auxiliary building. A tornado specific recovery action is to run a temporary power cable from an alternative switchgear in the auxiliary building's basement (now powered by the Keowee unit) to the HPI pump. This switchgear also powers an ASW pump that provides both secondary feedwater and HPI cooling. A probability of 1.0 E-1 per demand was assigned to the failure of the operators to correctly align this power path following failure of the switchgear.

The Keowee underground path via hardened transformer CT 4, assumed available in the PRA, was assigned a magnitude dependent failure probability in the IPEEE.

### 6.3.3 Safe Shutdown Facility

The SSF building is constructed of reinforced concrete. The licensee expects the SSF to withstand the wind effects from any tornado. Failure of the operator to align the ASW (0.1 per demand) or RCM (0.25 per demand) were included in the fault trees. Other random failures of SSF equipment were not included. Although the SSF building is not expected to fail, failure of the East and West penetration room wall is included as 0.17 per demand for tornados of Category F4 or F5. If these walls fail, both RCM and SSF ASW functions fail.

The IPE PRA did not consider tornado induced failures of the Keowee units. In the IPEEE study, the tornado induced loss of Keowee power source was included in the logic. Failure of Keowee becomes the principal tornado failure mode that fails both the normal and auxiliary switchgear. Consequently, the failure of the SSF changed from a relatively negligible contributor in the PRA, to a relatively major contributor in the IPEEE.

### 6.3.4 Results and Preliminary Findings

The total tornado CDF is estimated to be 1.3 E-5/yr, about 15 percent of the total CDF of 8.4 E-5/yr.

The tornado-induced degradation of on-site power contributes about 67 percent of the tornado CDF. The major contributing sequence (about 40 percent) involves a tornado-induced failure of the Keowee units to provide power to the plant and SSF failures. The remaining 27 percent contribution arises from a tornado-induced failure of the on-site 4160 V bus, operator failure of power the HPI and ASW from the auxiliary bus, and failure of the SSF.

Failure of the SSF is dominated (40 percent contribution to tornado CDF) by failure to provide RCM flow on time. The next largest SSF failure contribution is the structural failure of the west penetration room walls (20 percent). Failure to provide the ASW SSF function is a minor contributor. The remaining 30 percent includes mostly structural failures coupled most often with relief valves failing to re-seat, which disables the SSF.

### 6.2.4 Results and Preliminary Findings

The total seismic CDF was estimated to be 3.6 E-5/yr, 43 percent of the total CDF of 8.4 E-5/yr.

Seismically-induced loss of on-site power coupled with loss of the SSF contribute about 68 percent of the seismic CDF. Twenty percent of these power failures were due to a Jocassee dam failure and a resulting flood of less then 5 feet. Cutsets involving the auxiliary building and the SSF building surrogate events contribute 23 percent and 25 percent, respectively.

The licensee stated that existing in-structure response spectra for the Turbine Building relay capacity versus demand screening were found to be very conservative and penalizing. Many of the relays had been preliminarily labeled as outliers awaiting more detailed reviews. Evaluation of the two IPEEE relay chatter basic events indicated that these represent relays in the auxiliary building. The IPEEE stated that an addendum to the IPEEE will be submitted if it is eventually concluded that excess margin exist in the relay chatter fragilities.

### 6.2.5 Progress and Revised Schedule for Resolution of USI A-46

By letter dated October 3, 1995, Duke informed the staff of its progress to resolve USI A-46, "Verification of Seismic Adequacy of Mechanical and Electrical Equipment." Duke stated that the current implementation status is in accordance with Revision 2 of the GIP-2 and that over 95 percent of the more than 1,750 SSE items have been walked down. These walkdowns have not identified any safety significant issues that would challenge the current licensing basis. Based on the justification provided in the October 3, 1995, letter the staff determined that Duke's proposed rescheduling was acceptable. This review has not yet been completed.

## 6.3 TORNADO

### 6.3.1 Methodology and Assumptions

Tornados are modeled as discrete frequency and magnitude events. The characterizing wind strength and initiating event frequency changed slightly between the PRA and the IPEEE. The new frequencies in Categories[8] F2 to F4 all increased by about a factor of two above the PRA frequencies. The F5 frequency was recalculated with the Chi-squared estimate due to no observed occurrences in 44 years. It decreased by a factor of two below the PRA estimate. The logic models for tornados events included only tornado caused structure and system failures, several operator actions, and failure of relief valves to re-close.

### 6.3.2 Electric Power

Power components at ground level or higher in the turbine building are susceptible to damage from flying debris if the wind loadings on the turbine building metal walls cause them to buckle and structurally fail. It was assumed that the only source of power would be the Keowee units,

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[8]Fujita tornado scale for damaging winds:

| | | |
|---|---|---|
| F2 | Wind speed 113 to 157 mph | 5.4 E-5/yr probability |
| F3 | Wind speed 158 to 206 mph | 4.1 E-5/yr probability |
| F4 | Wind speed 206 to 260 mph | 3.6 E-5/yr probability |
| F5 | Wind speed greater than 206 mph | 1.7 E-6/yr probability |

event has a HCLPF[7] of 0.17g. The SSF building surrogate event has a HCLPF of 0.24g. From the modeling logic of fault trees, it appears that the auxiliary building surrogate event would cause an SBO, while the SSF surrogate event appears to cause an SSF diesel failure.

### 6.2.2 Electric Power

The loss of the offsite power is directly represented by the fragility of an event called the "Off-site Power Line Insulators." This event has a HCLPF of 0.08g. The companion failure mode, loss of CT 3 transformer, had its HCLPF recalculated from 0.08g in the IPE PRA to 0.27g in the IPEEE study.

The underground line from Keowee through CT 4 was credited in the PRA model. However, the overhead line was not credited. Failure of the Keowee units was represented by the failure of the Keowee dam or failure of CT 4. The random failure probability of the power supply from the Keowee units, estimated to be 7.0 E-3 per demand in the internal events analysis, was represented in the seismic analysis as a 6.0 E-3 per demand unavailability due to maintenance. The HCLPF for failure of the dam is 0.20g and was unchanged between the IPE PRA and the IPEEE. The companion failure mode, loss of the CT 4 transformer, had its HCLPF recalculated from 0.20g to 0.41g in the IPEEE study.

The power supply from the Lee station through CT 5 was credited. Loss of this path was represented by loss of the overhead line from the Lee combustion turbines or loss of the CT 5 transformer. The loss of the overhead line from Lee was quantified as LOOP power line insulators, with the HCLPF of 0.08g. The companion failure mode, loss of the CT 5 transformer, had its HCLPF recalculated from 0.08g to about 0.23g in the IPEEE study.

### 6.2.3 Safe Shutdown Facility Building

The SSF building is a Class 1 seismically qualified structure. Both seismic and random failures were included in the models. Seismic failures of the diesel and diesel support systems, the transformer, and some piping and piping supports were modeled. Seismic failures of the SSF ASW and RCM pumps were not included in the models. They have a median failure acceleration greater than 2.0g and were screened out.

The "weakest" component appears to be the SSF 600 V/208 V ac transformer, which has a HCLPF of 0.2g. Failure of this transformer fails the RCM pump electrical supply but does not fail the SSF ASW function. Other SSF components are relatively robust with HCLPF generally larger than 0.4g.

The SSF can also fail due to failure of the Jocassee dam and a resulting flood that exceeds the 5 foot SSF flood barrier. The HCLPF for the dam failure is 0.20g, and the probability that the resulting flood exceeds the flood barrier is given as 0.4 per flood.

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[7]HCLPF is measured in units of acceleration of gravity. For example, if a ceramic insulator had a HCLPF value of 0.2g, it means that there is a 95 percent confidence that the failure probability of the insulator is less that 5 E-2 when the insulator is exposed to a peak ground acceleration of 0.2g.

External events dominate the Oconee CDF. The CDF from fires, tornado, seismic and external flooding, is estimated as 6.1 E-5/yr, 72 percent of the total CDF of 8.4 E-5/yr. The IPE PRA indicated that external event initiators also dominate the risk profile of the plant. The IPEEE submittal did not provide consequence information, but the staff believes that external events would be dominant contributors to offsite risk.

### 6.1.2 Discussion of the External Event Results

The IPEEE provided CDF estimates for seismic, external floods, fire, and tornado external events. Each of these events is discussed below. Internal flooding is discussed in the PRA and some information is provided in this report for comparison purposes.

A screening discussion of transportation and nearby facility accidents was included in the IPEEE study. The IPEEE study concluded that due to very low occurrence frequency, physical or administrative limits on amounts, and some on-site mitigating features, the risk from these types of initiating events was negligible.

A table in the IPEEE submittal briefly discussed the full range of natural and man-made external initiating events and documented the external events screening analysis. None of these events were applicable to the Oconee site.

## 6.2 SEISMIC ANALYSIS

### 6.2.1 Methodology and Assumptions

The SSE for Oconee Unit 3 is 0.1g. The Oconee IPEEE appears to have used the screening and walk down guidance provided by EPRI's Seismic Margin Methodology (EPRI NP-6041) as a first step. However, instead of employing the Seismic Margin Methodology, fragility curves for those component and structures not screened were developed. A more comprehensive seismic PRA was then performed.

The seismic hazard for Oconee was taken from the EPRI seismic hazard study. As requested in GL 88-20, Supplement 4, the IPEEE submittal also included calculations based on the hazard curve generated by LLNL in 1989. Duke concluded that the results were comparable using the two curves and did not add or change any insights from the analysis.

The median spectral shape used in the IPEEE fragility analysis was also updated from NUREG/CR-0098 to that in NUREG-1407. The IPEEE stated that, due to the decrease in the lower frequency accelerations, "most of the existing Oconee structural fragilities...are conservatively defined." It was noted, however, that major equipment failure contributors (primarily SSF equipment, the transformers, and the standby busses) had their fragilities adjusted upward - sometimes substantially - with table notes indicating that the change was due to the new spectrum or to reevaluation. The net effect was a decrease in the seismically-related CDF.

The staff used the fragility curve parameters reported in the IPEEE submittal and calculated HCLPF values. The IPEEE added an auxiliary building and an SSF building surrogate basic events. These events represented the many components in these two buildings that were screened out during the walkdown and anchorage review. The auxiliary building surrogate

Based on TS amendments issued on August 15, 1995, the Oconee TS required annual testing of the ACBs to close automatically to the underground path. Based on a TS amendment issued on March 20, 1997, to ensure that the Keowee units were operable during period of commercial power generation, the ability of the Keowee units to supply emergency power from the initial conditions of commercial power generation was tested every 18 months. This surveillance tests the operation of the ACBs and their new logic. Also, the reliability of the ACBs are tracked under the Maintenance Rule.

Based on staff review of the Keowee PRA and its integration with the Oconee IPE, the staff did not identify any vulnerabilities in the design or operation of the Keowee units that would require corrective action. As discussed above, this report made some recommendations concerning the testing and operation of the Keowee units to ensure that reported Keowee PRA results would be maintained. This report also made some recommendations regarding future use of the Keowee PRA to ensure that operational data would be reflected in future Keowee reliability estimates. Much of the testing performed for Keowee and many of the assumptions in the Keowee PRA are not included in TS, and therefore, can be changed without NRC approval. Changes in the test frequency have the potential to impact the results of PRA analysis.

## 6.0 **OCONEE EXTERNAL EVENTS ANALYSIS**

### 6.1 BACKGROUND

As discussed earlier, the Keowee PRA was coupled with the existing model of the Oconee ac power system from the IPE. In this study, only internal events including severe weather were evaluated. The impact of external events on the Oconee's emergency electrical system were not within the scope of the Keowee PRA project. Duke submitted their IPEEE on December 31, 1995, but the staff had not completed their review of the Oconee IPEEE in time for this report. The staff, however, did review the results of Duke's IPEEE. This section identifies key assumptions and conclusions from Duke's IPEEE concerning the ability of Oconee's Electrical Power System and the SSF to withstand an external event. These assumptions and conclusions come directly from Duke's IPEEE. The IPEEE is currently under staff review.

#### 6.1.1 Status of the Oconee IPE and IPEEE

Duke submitted an IPE for its Oconee Nuclear Station, Units 1, 2, and 3 on November 30, 1990. A three volume Oconee Unit 3 PRA with external events accompanied the IPE submittal. By letter dated April 1, 1993, the NRC notified Duke that the staffs' review of the completeness and the quality of the IPE submittal found that it met the intent of GL 88-20 for the Oconee Nuclear Station.

Oconee's IPEEE study (submitted by letter dated December 30, 1995) reported the total CDF from external events to be 6.1 E-5/yr. The CDF from external events reported in the IPE PRA is 8.4 E-5/yr. This reduction is primarily due to revised data used in the IPEEE study. The most important change in the results due to such revision, is a decrease in the fire-induced CDF by a factor of three. This change arises from a modified calculation that yields a factor of 10 decrease in the initiating event frequency for large turbine building fires, moderated by an increase in the failure probability of the SSF diesel and SSF ASW pump to start and run.

With no credit for the SSF, the ac power CDF increases by a factor of six. Therefore, the ac power CDF for internal events is very sensitive to the availability of the SSF. The unavailability of the SSF is dominated by human errors rather than hardware failures. The two dominant human errors are (a) failure of the operator to establish RCP seal injection within 10 minutes, and (b) failure of the operator to establish ASW to the steam generators if the EFW System fails. The staff considers the SSF testing issues concerning the Oconee ac power model to be resolved.

The failure modes associated with the implementation of the NSM-ON-52966 modification and dual-unit grid generation were modeled in the Keowee PRA as a sensitivity analysis. If Keowee were to continue to operate with only one unit generating to the grid at a time, the modifications under NSM-ON-52966 would not have been necessary to meet single failure criteria. Although the modifications eliminated the single failures associated with dual-unit grid generation, they add complexity such as additional ACB operations and the logic necessary for their actions.

Qualitatively, dual-unit grid generation is a tradeoff between greater ACB switching action and complexity and less generator excitation breaker action coupled with increased reliability of those components that are tested daily during dual-unit generation.

The quantification of these tradeoffs is minimized by the small fraction of the time that dual grid generation occurs. Based on historical data, dual-unit grid generation occurs approximately 3.4 percent of the time. Although historical data suggests future dual-unit grid generation will occur approximately 3.4 percent of the time, this is not a requirement. Changing this percentage can effect the reliability results, as shown in Figure 5-2 of this report.

A sensitivity study showed that Keowee reliability during dual-unit grid generation is affected by the probabilities used for a governor failure to position wicket gates during a hot start and a unit turbine failure during a hot start. When the Keowee PRA was being developed, no specific hot start test was required to be performed on Keowee. (Oconee TS now require a hot start test every 18 months). These failure probabilities were generated by arbitrarily increasing the corresponding cold start failure probabilities by an order of magnitude and applying these as screening values. In the draft report, the staff was initially concerned that the Duke PRA analysts did not have adequate data to statistically determine these failure probabilities. The staff recommends that future use of the Keowee PRA should carefully evaluate the hot start test results to ensure that failure probabilities assumed for (a) the governor failing to position the wicket gates correctly during a hot start, and (b) unit turbine failure during a hot start are consistent, recognizing the test occurs once every 18 months.

Therefore, whether there is an increase or a decrease in the overall Keowee reliability for dual-unit grid generation is very dependent upon certain specific component reliabilities. To assure that there was no deterioration in the reliability of Keowee when both units were allowed to generate power to the grid (up to 30 percent of the time), the staff identified the following actions:

1. Monitoring the reliability of the ACBs and maintaining the reliability values assumed for these components in the Keowee PRA (particularly ACBs 3 and 4, which connect Keowee Units 1 and 2 to the underground path).

2. Performance of periodic hot start testing of the Keowee units.

Oconee emergency ac power system.

In the draft report, the staff concluded that the unavailability of the Lee gas turbines during a grid-related LOOP was potentially underestimated. Duke assumed that all three gas turbines would be available to start, even though only one gas turbine has the capability to black start. In response to the draft report, Duke performed a sensitivity study (submitted October 31, 1996) using a 0.5 failure probability for Lee to operate following failure of the grid. The increase in CDF was small (6.0 E-7 per year). These results occur since (a) severe weather events dominate risk, and (b) credit was given CT 5 being energized by the Central switchyard following losses of offsite power caused by switchyard failures. Recognizing these results, the staff recommends that future use of the Keowee PRA should only credit the black start turbine as being able to provide power to CT 5 following a grid related LOOP.

Due to the importance of the Lee station in the emergency ac power system of all three Oconee units, the staff requested that Duke establish reliability goals for the CT 5 power components, and performance should be tracked and monitored under the Maintenance Rule. In a letter dated January 31, 1996, the licensee committed to including the Lee/Central Power system in the Maintenance Rule as a risk significant system.

Since CT 5 and the associated 100 kV line are not hardened against severe weather, planned dual maintenance of Keowee is performed during periods of favorable weather conditions. The probability of a LOOP during periods of severe weather with both Keowee units in maintenance was reduced by a factor of 10 in the Keowee PRA to account for maintenance being scheduled for mild weather periods. In the draft report, the staff concluded that this modeling assumption is reasonable provided that a program is referenced in the administrative controls section of the Oconee TS. This program would stipulate that pre-planned maintenance should be avoided and terminated (and equipment restored to operable status) when severe weather is imminent. To justify not placing a Keowee severe weather outage program in TS, Duke reviewed Keowee procedures that would remove the underground path or both Keowee units from service longer than one shift. Two procedures were identified. The staff finds Duke's response acceptable. However, if any future procedures are developed that require dual-unit maintenance or maintenance on the underground path for more than one shift, the staff suggests that Duke add a review of the severe weather potential to the procedure. Also, the staff acknowledges that dual-unit maintenance is the dominant risk contributor to failure of Keowee to provide emergency power. Therefore, future use of the Keowee PRA should include a review of recent dual-unit maintenance hours to ensure that the dual-unit maintenance hours estimated in the Keowee PRA are consistent with current operating history.

When Duke integrated the Keowee PRA with the IPE, the CDF at Oconee Unit 3 for loss of ac power events was calculated to be 1.0 E-6/yr. The severe weather LOOP had the greatest impact on the calculated ac power CDF in both the original IPE and the Keowee PRA integration. Other dominant risk contributors include failure to recover offsite power, failure to deploy the SSF within the necessary time, and CT 4 (underground transformer) failure.

Because of the risk importance of CT 4, the staff recommended in the draft report that Duke consider an additional TS to pre-align Lee during any CT 4 maintenance activity, as is stipulated for dual Keowee maintenance activities. Duke agreed that it is reasonable to require Lee to energize the standby buses if the underground path will be unavailable for greater than 24 hours. This resolved the staff's concern.

specialist is optimistic. However, Duke assigned failure probabilities of 0.5 or higher for the three non-proceduralized recovery actions credited in the Keowee PRA. Therefore, increasing the assumed failure probabilities for the three DHEs will not significantly change the failure for Keowee to start and run. Thus, the staff's concerns are resolved.

Errors of commission are not normally included in a reliability analysis because of the difficulty in identifying and quantifying such errors. The more complex a system, the greater its susceptibility to human errors of commission. Because the Keowee system and logic is complex, Keowee may have a higher susceptibility to errors of commission than most nuclear plants with standard EDGE. However, present PRAs are limited in their ability to identify and quantify these types of human errors. Therefore, the staff recommends that Duke require a technical specialist to be physically present during periods when severe weather is predicted to occur.

Duke classified certain basic events as "undeveloped events." For these basic events, Duke could not find applicable generic data. Therefore, the undeveloped event failure rates were calculated using Keowee plant-specific data only and remained at their plant-specific values for the base case (Bayesian-updated case) and the generic data sensitivity study. Because of this, the generic data result is not a completely generic data assessment. There are approximately 64 undeveloped basic events (of 1135 basic events total).

The Keowee failure probabilities, as reported in the Keowee PRA and shown in the first row of Table 5-2 of this report, are meaningful when considering a grid-related LOOP only. The failure probability of the Keowee system given either a plant-centered LOOP or a severe weather LOOP is equal to the failure probability of the underground path and its aligned Keowee unit. This failure probability was calculated to be 3.0 E-2 (using Bayesian updated data and without applying recoveries). When the recovery action of aligning the Keowee unit designated to the overhead path to the underground path is included, the Keowee failure probability is 8.6 E-3.

Ignoring the pathways to the Oconee emergency buses and just considering the Keowee units, the failure probability of a Keowee unit to start and run for 24 hours (not including maintenance unavailability) was calculated to be 2.0 E-2. This failure probability is comparable to an EDG failure probability to start and run. Therefore, the reliability of a single hydro unit is comparable to the reliability of a single EDG (with regard to internal event LOOP initiators). However, the overhead pathway to Oconee's emergency buses and the dual-unit maintenance configuration reduce the overall reliability of the Keowee system in comparison to an EDG system with typical pathways to emergency buses and no allowance (or need) for dual-unit maintenance.

Although the scope of the project was limited to Keowee reliability, a study was included in the Keowee PRA that coupled the Keowee PRA with the existing model of the Oconee ac power system from the IPE. For the integration with the IPE, Duke calculated the probability of losing all ac power for Oconee Unit 3 to be 6.35 E-5/yr (for internal events including severe weather).

Without credit for power from CT 5, the loss of ac power frequency increases by over a factor of 10; whereas, without credit for power from the overhead path from Keowee, the loss of ac power frequency increases only by a factor of 1.01. From these results, the staff concluded that power from CT 5 is a very important part of the Oconee emergency power system, much more so than the Keowee overhead power path. Because of the importance of power from CT 5, decreases in the reliability of this power source will have a large impact on the reliability of

rejected by the staff. The staff finds the use of one degree of freedom in the Chi-squared formula to be inappropriate for the estimate of a failure probability in the case of zero observed failures, when the intended use of the result is to demonstrate that something is acceptably safe. For the draft report, the licensee did perform a sensitivity study using the 50 percent upper confidence interval values obtained from the Chi-squared distribution with two degrees of freedom as specified in statistical text books. The base case solution only increased a modest amount. However, the staff recommends that for future use of the Keowee PRA, especially when conducting sensitivity studies, the Chi-squared variate with two degrees of freedom be used.

The top gate of the Keowee PRA, "Oconee Transformers CT 3 and CT 4 Fail to Receive Power From Keowee," has a failure probability of 7.4 E-3. The base case solution used Bayesian-updated data and included operator recovery actions. The equivalent failure probability without accounting for operator recovery increases to 1.0 E-2.

In response to staff's concerns about the use of plant-specific Bayesian-updated data, Duke performed an additional uncertainty analysis to determine the failure probability distribution for either Keowee unit supply emergency power to CT 3 or CT 4 using generic data (except for the 50 out of 1135 events where generic data was not available). The estimated mean increased to 1.05 E-2.

The Keowee PRA was also requantified using generic data and assuming no credit for operator recovery. For this sensitivity study, the top gate failure probability was estimated to be 1.3 E-2. Because the KEOWTOP event is dominated by Keowee unit maintenance unavailability, the impact in the overall result is smaller by 31 percent. These probabilities are depicted in Table 5-2 of this report.

Dominant contributors to the base case results include dual-unit Keowee maintenance unavailability, overhead path maintenance unavailability, failure of components in the auxiliary ac power system (most notably ACBs 5 thru 8), failures of the voltage regulator, common cause failures of auxiliary ac power breakers, and clogging of the common intake header of the generator cooling water strainers (including failure of the operator to clean the strainers).

In general, the common cause analysis in the Keowee PRA was found to be thorough and reasonable. Common cause failures played an important role in Keowee unreliability, contributing 11.7 percent to the total Keowee failure probability after recoveries were applied, and 35 percent before applying recoveries.

When operator recovery of equipment was included, the Keowee overall failure probability was reduced by approximately 27 percent, from 1.0 E-2 to 7.4 E-3. (Human recovery does not have a large impact on the overall result since the overall result is dominated by Keowee maintenance.) Important operator recovery actions include recovering the underground supply by aligning the overhead Keowee unit to the underground path, recovering the Keowee auxiliary power breakers by manual control, and recovering clogged common cooling water filters. Some enhancements to the alarm response procedure and the Keowee emergency start procedure were recommended based on this analysis.

Given weather conditions severe enough to cause a loss of the switchyard and simultaneous loss of power from CT 5, the staff believes that the time allotted for the on-call technical

diagrams that the staff reviewed and the actual plant configuration.

The base case model assumes that operation is restricted to allowing one Keowee unit to generate power to the grid at a time. The unit allowed to generate to the grid is aligned to the overhead path, and the standby unit is aligned to the underground path.

The analysis of the base case model assumes that the unit aligned to the overhead path is operated daily, while the unit aligned to the underground path (stand-by unit) is start tested every 7 days. This 7-day test frequency has been the operating practice; however, it is not a requirement in the Oconee TS. Changes in the test frequency have the potential to impact the results of PRA analysis.

During review of the Keowee PRA, the staff found that a large amount of the plant-specific data was obtained from grid generation experience. In the draft report and the interim report, the staff was concerned that this data would be questionable for the eight components where there are subtle differences in operation between grid generation and emergency operation, such as the voltage regulator and the field flash circuit breaker. The staff also found that many of the emergency start failures listed in Table C.1-1 of the Keowee PRA involved these eight components. The staff was also concerned about the validity of this data since there were approximately 6000 normal starts versus 113 emergency starts reported in the Keowee PRA.

Considering this information, the staff evaluated the failure of Keowee Unit 1 to achieve rated voltage following an emergency start signal on June 20, 1997. The AIT team found that the failure of Keowee Unit 1 was caused by subcomponent interactions in the field flash circuit breaker control circuitry that would not have been manifested during an normal start. A setpoint for the overvoltage relay (in the field flash circuit breaker control circuitry) was changed outside of Duke's plant modification process, and no post-modification test was specified or performed. This explanation resolved this concern.

Actions concerning testing and operation that would assure the reliability of the two Keowee units to provide power to CT 3 or CT 4 following an emergency start demand are discussed below:

1. Performance of monthly start tests with the autosynchronizer turned off (both voltage adjust and the base adjust functions would be available during the test).

2. Verification of the base adjust setting in the monthly normal start test procedure.

3. Performance of post-modification tests consisting of at least one emergency start, and evaluation of the impact of the results on the emergency start function.

For components that had not experienced a failure, Duke used the Chi-squared variate at the 50 percent cumulative probability level from an equation specified in the ALWRURD. This equation actually produced a probability at the 20 percent confidence level, not at the 50 percent confidence level indicated by the ALWRURD and the Keowee study. After review of this equation and discussion with statisticians at the NRC, the staff concluded in the draft report that the referenced equation is not appropriate with respect to the number of degrees of freedom that it specifies for the Chi-squared distribution (one versus two degrees of freedom). In response to staff concerns, Duke responded with several arguments that were reviewed and

faulted MFB can be approximated using the following scenario:

> An electrical fault on one of six normally energized MFB when the Standby buses are energized for a mission time of 24 hours,
>
> AND
>
> MFB input breaker fails to open (the breaker has two redundant signals to actuate the trip coils, bus lock-out and overcurrent across the breaker)

Based on values from IEEE 500, the likelihood of losing a standby bus from a faulted MFB is estimated at less than 1.0 E-8.

The staff also considered the likelihood of losing one of the two standby buses from an undetected fault. As described above, these buses are normally de-energized and are tested quarterly.

If the standby failure rate can be reasonably approximately by the hourly failure rate, then the likelihood of an undetected electrical fault on one of two standby buses is determined by the mathematical expression:

> (The standby failure rate) times (Testing Frequency) times (2 buses)
>
> which is:
>
> (1.2 E-7/hr)(2160 hrs/2)(2) = 3 E-4

Based on values from IEEE 500, the likelihood of an undetected electrical fault on one of the two standby buses was found to be approximately 3 E-4. As stated earlier, additional breaker failures would be necessary to occur before the other standby bus would be impacted.

Assuming common cause failures and using a conservative beta factor of 0.1 (for lack of data), the likelihood of losing both standby buses was estimated to be approximately 1E-5.

These two scenarios were compared to the likelihood of Keowee failing to provide power to CT 4 during a severe weather LOOP (the overhead path is assumed to be unavailable). This likelihood was estimated to be 8.6 E-3, as shown in Table 2.

Based on these results, the staff does not believe that electrical system interactions among the three units should significantly decrease the availability of emergency power among the three units. This conclusion was reached assuming that failure of the Oconee emergency ac power system is more likely from the Keowee station itself than unisolated electrical faults from one of the three units. This conclusion assumed that the breaker coordination among these buses is designed and operated correctly.

## 5.3 CONCLUSIONS, INSIGHTS, AND RECOMMENDATIONS

The fault tree models of the systems and subsystems of Keowee were constructed with an appropriate level of detail. Furthermore, the models appeared to be consistent with the Keowee

It is important to note that these results represent the base case with plant-specific Bayesian-updated data and operator recovery actions. This base case applies to grid-related LOOP events only, where both underground and overhead paths are considered to be available. Therefore, these results do not apply to plant centered or severe weather LOOP events, where only the underground path is assumed to be available. Since the uncertainty analysis was performed with plant-specific Bayesian-updated data, this analysis does not encompass the staff concerns with this data.

In their response dated October 31, 1996, Duke performed an uncertainty analysis to determine the probability distribution for the Keowee PRA top gate, KEOWTOP, using generic data (except for the 64 out of 1135 events where generic data was not available). The estimated mean increased to 1.05 E-2. The 5th and 95th percentile increased to 4.4 E-3 and 2.11 E-2, respectively. This distribution, based on generic data, was not significantly different from the probability distribution based on plant-specific data. Duke also requantified the Oconee ac power core damage model with generic data. The LOOP CDF increased from 1.0 E-6 per year to 1.9 E-6 per year.

5.2.10 Electrical System Interactions

The Keowee PRA does not address electrical system interactions from Oconee Units 1 and 2 that could affect the availability of emergency power to Unit 3. Therefore, the staff briefly reviewed this issue to determine if electrical system interactions from Oconee Units 1 and 2 could significantly decrease the availability of emergency power to Unit 3.

The emergency ac distribution system for the three Oconee units are electrically connected only when the two common 4160 V Standby buses are supplying power to the three units. These Standby buses are energized when Keowee is supplying power to Oconee through transformer CT 4 (underground path) or when transformer CT 5 is energized (from the Lee stations or the 100 kV Central Substation). These two standby buses feed two separate MFBs for each unit (six MFBs total). These two MFBs, in turn, feed three separate 4160 V ES Buses for each units (9 ES Buses total). Each of the 4160 V ES buses are energized from both standby buses simultaneously. Therefore, should one standby bus have an uncleared fault, the other standby bus can energize the 9 ES buses. With respect to testing, the two standby buses are energized quarterly, as required by a Selected Licensee Commitment contained in Chapter 16 of the Oconee FSAR. Both MFBs for each unit are always energized either from the Unit Main Generator, the switchyard, CT 4, or CT 5.

In order for an electrical fault on one unit to affect the other units, the standby buses must have an uncleared fault. Failure of the standby buses to remain energized for 24 hours is modeled explicitly (irrespective of the source of the fault) in the Oconee Unit 3 ac power model. However, failure of a switchgear on one of the three units could fail the standby bus if the protective relaying failed to isolate the fault or the necessary circuit breakers failed to open.

For example, should a fault develop on one of the six MFBs when they are being energized by the standby buses, a bus lockout signal would be generated to isolate the faulted MFB. This signal would cause the input breaker and the three output breakers of the faulted bus to open. Should the input breaker fail to open, the standby bus could be faulted. Should one of the three output breakers fail to open, additional failures would have to occur for the redundant standby bus to be affected. Based on the example, the likelihood of losing one standby bus from a

against common cause failures from the frequent starting of the units for grid generation or just modeling and data uncertainty.

TABLE 5-5
COMPARISON OF SYSTEM LEVEL VERSUS
COMPONENT LEVEL COMMON CAUSE FAILURE PROBABILITIES

| | Start Failure Probability | Run Failure Probability | Total CCF Probability |
|---|---|---|---|
| System Level Modeling (Generic Beta) | 4.50 E-4 | 6.20 E-4 | 1.07 E-3 |
| System Level Modeling (Keowee Beta) | 4.05 E-5 | 3.05 E-3 | 3.09 E-3 |
| Component Level Modeling (Unrecovered) | 1.50 E-4 | 3.36 E-3 | 3.51 E-3 |
| Component Level Modeling (Recovered) | 1.46 E-4 | 7.23 E-4 | Not reported |

Note: System Level Independent Failure Rate was based on actual operating data.

5.2.8.6 Human Reliability Sensitivity Studies

5.2.8.6.1 Latent Human Error Importance

Latent human errors involve the improper post maintenance restoration of equipment. LHEs were modeled in the Keowee PRA. The importance of LHEs in the calculated failure probability was evaluated by setting these basic events to zero. The Keowee base case failure probability decreased from 7.4 E-3 to 7.2 E-3, less than 3 percent by eliminating LHEs.

5.2.8.6.2 Human Error Probabilities That Existed Prior to the October 1992 LOOP Event

This study was performed to judge the effects on Keowee reliability of changes made to procedures since October 1992. The two errors of commission that occurred in the 1992 LOOP event were modeled and values for some of the LHEs, DHEs, and RHEs were changed. The results showed no change from the base case Keowee reliability value.

5.2.9 <u>Uncertainty Analysis</u>

The licensee performed an uncertainty analysis to determine the probability distribution for the Keowee PRA top gate, KEOWTOP. The analysis was performed by adding error factor and distribution type information to the basic event database in CAFTA. The CAFTA Uncertainty Analysis Utility was used to evaluate the cutsets.

Using a 5000 sample simulation, the estimated mean value was 7.32 E-3. The 5th and 95th percentiles were estimated to be 2.93 E-3 and 1.53 E-2, respectively. The overall error factor for KEOWTOP was approximately 2.3.

### 15.3.1.1.3 Physics Parameters

Moderator Temperature Feedback

A table of reactivity as a function of moderator density is input to account for moderator reactivity effects. The consequences of a steam line break accident are more severe at EOC due to the more negative moderator temperature coefficient. The most negative EOC moderator temperature feedback curve is used in the analysis.

Doppler Temperature Feedback

A table of reactivity as a function of fuel temperature is input to model Doppler reactivity effects. The most negative Doppler curve is used in the analysis. However, the most negative Doppler curve will also result in the largest negative feedback during any return-to-power. Since the boron injected by the HPI system and CFTs limits the return-to-power (rather than the negative reactivity due to Doppler feedback) it is conservative to assume a most negative Doppler curve.

Reactivity Weighting

Beta-effective and Neutron Lifetime

A small value of $\beta_{eff}$ and prompt neutron lifetime are chosen to maximize the power decrease on reactor trip. Small values of these parameters will also enhance any return-to-power. EOC decay constants and delayed neutron precursor fractions are also assumed.

Break Opening Time

A break opening time of 0.1 seconds is assumed. Based on sensitivity studies performed, shorter break opening times do not significantly alter the initial secondary side depressurization.

Reactor Coolant Pump Modeling

The RETRAN two-phase flow degradation model is used for the RCPs since significant voiding is predicted in the unaffected loop. The RCPs in the unaffected loop are tripped at 100 seconds to avoid a code error associated with pressure oscillations in this loop due to two-phase pump performance. Tripping the RCPs in the unaffected loop has a conservative impact on the cooldown of the RCS since there is reverse heat transfer taking place in the steam generator.

Turbine Stop Valves

A slow turbine stop valve stroke time (1.0 second) is assumed to isolate the unaffected steam generator from the affected steam generator. This maximizes the overcooling.

Main Steam Safety Valves

The main steam safety valves are modeled using conservative assumptions for drift, blowdown and valve capacity that maximize relief flow and minimize the secondary pressure response in the unaffected steam generator. A lower pressure will minimize the reverse primary-to-secondary heat transfer in this steam generator, and maximize the RCS cooldown.

Extraction Steam

To maximize the cooldown of the RCS, it is conservative to model the steam loads on the isolated steam generator. A conservatively high extraction steam flow rate is assumed.

Decay Heat

To maximize the RCS cooldown, a low decay heat power level assuming a multiplier of 0.9 is applied to the 1979 ANS Standard 5.1 decay heat power.

Single Failure

The analysis examines a single failure of the EFW control valve to the affected steam generator or a single failure of the Engineered Safeguards that results in only one train of HPI.

RCS and shut down the reactor if a return-to-power occurs. Sensitivity studies have been performed and have determined that a low initial RCS pressure is the most limiting assumption.

Pressurizer Level

A low initial pressurizer level minimizes the volume of relatively hot water that drains into the RCS upon pressurizer outsurge, thereby maximizing the RCS cooldown and any return-to-power. Thus, nominal pressurizer level less uncertainty is assumed.

RCS Temperature

The ICS controls the average coolant temperature at a constant value whenever power is greater than 15%. For the steam line break accident, a lower initial average coolant temperature will result in a greater cooldown of the primary system. This will result in more positive reactivity addition due to the negative moderator temperature coefficient, and thus maximize any return-to-power. Thus, nominal RCS average temperature less uncertainty is assumed.

RCS Flow

Since this transient is being evaluated for minimum DNBR, a low initial RCS flow is used.

Core Bypass Flow

High core bypass flow is assumed which minimizes core flow and is conservative for DNB.

Fuel Temperature

A low initial fuel temperature is used to minimize the stored energy in the fuel. A conservatively low EOC fuel temperature is assumed.

Steam Generator Mass

A conservatively high steam generator mass is assumed to maximize the overcooling.

15.3.1.1.2 Boundary Conditions

The key boundary conditions for the steam line break with offsite power are as follows:

## 15.3 Transient Analysis

The steam line break analysis presented herein is divided into two sections. The first section assumes that offsite power is available, and is concerned with the potential for a post-trip return-to-power and DNB. The second section assumes that offsite power is lost coincident with the opening of the break, and is concerned with the flow coastdown and primary system depressurization effects on DNB.

### 15.3.1 With Offsite Power

#### 15.3.1.1 RETRAN-02 Analysis

##### 15.3.1.1.1 Initial Conditions

The initial conditions for the steam line break analysis with offsite power are selected to maximize the RCS cooldown and depressurization, and thereby maximize the potential for a post-trip return-to-power and DNB. Since the SCD methodology does not cover the range of RCS pressures expected for the cases that assume offsite power is available, a deterministic approach will be utilized in the selection of the initial conditions.

Power Level

Full rated power plus uncertainty is assumed. High initial power level maximizes the initial steam generator inventory and feedwater flow rate, both of which will maximize the primary-to-secondary heat transfer once the break occurs. A steam line break accident from hot zero power (HZP) is not analyzed. At HZP, feedwater is aligned through the startup feedwater control valves, which results in a much lower feedwater flow rate than at full power. Sensitivity studies have been performed and have determined that the steam line break from HZP is bounded.

RCS Pressure

A low initial pressure minimizes the time to reactor trip. An earlier trip reduces the integrated energy deposition into the RCS, leading to lower RCS temperatures. A lower initial pressure is also conservative with respect to DNB. However, a lower initial pressure results in an earlier actuation of the Engineered Safeguards Systems (HPI and CFTs) which inject boron into the

[ ] The modeling of conservative factors, direct moderator heating, flow correlations, and other correlations is identical to that described in Reference 15-2. The subcooled and bulk void correlations are different than those in Reference 15-2, and are described in Section 15.3.1.2.3. The critical heat flux (CHF) correlations used to evaluate the DNBR are the Westinghouse W-3S (Reference 15-3, Appendix D) for the Mk-B10 or Mk-B11 fuel types, and the BWU (References 15-7 and 15-8) correlations for Mark-B11 fuel.

For the without offsite power analysis, the [ ] channel VIPRE-01 model described in Reference 15-2 is used to calculate the transient local coolant properties and DNBR. The BWC (Reference 15-6) and BWU CHF correlations are used to perform the DNBR calculations for the Mk-B10T and Mk-B11 fuel assembly types, respectively. The VIPRE-01 analysis employs the SCD methodology for the offsite power lost case.

### 15.2.3 SIMULATE-3P

SIMULATE-3P is used to generate safety analysis physics parameters and three-dimensional core pin power distributions. The system transient response during a steam line break accident is sensitive to core temperature feedback. The moderator reactivity versus temperature and the Doppler reactivity versus fuel temperature curves are selected such that the most limiting conditions, which occur at end-of-cycle (EOC), are predicted.

The asymmetric conditions for the with offsite power analysis require non-uniform core inlet temperatures to be input to SIMULATE-3P. The maximum worth stuck rod is conservatively assumed to be in the cold half of the core which will increase the local reactivity and power. A 10% reduction in the worth of the remaining control rods is also assumed. These assumptions result in a conservative reactivity calculation and power distribution at the limiting RETRAN statepoint. The SIMULATE-3P reactivity prediction is used to verify that the RETRAN kinetics model is conservative. The SIMULATE-3P pin power distribution at the limiting RETRAN statepoint is then input to VIPRE for the DNBR analysis.

For the without offsite power analysis, the stuck rod is conservatively assumed to be in the colder half of the core since this will increase the local reactivity and power. SIMULATE-3P is used to calculate the pin power distribution which is used to compare to the MARP limits generated in the VIPRE analysis.

15.2.1.6 Break Model

The break is modeled by dividing the ruptured main steam line into two volumes with a connecting junction, and by adding the two break junctions. The full cross-sectional area of the 34" main steam line is 6.3 $ft^2$. Thus, the double-ended break of the 34" main steam line results in a total initial break flow area of 12.6 $ft^2$.

[ ]

15.2.2 VIPRE-01

The VIPRE-01 code is used for the steam line break core thermal-hydraulic analyses. VIPRE-01 thermal-hydraulic boundary conditions (core exit pressure, core inlet temperature, core inlet flow, and heat flux) are obtained from the RETRAN-02 system transient simulation. Since the

[ ]

nozzle junction, which is reasonable given the high steam velocities. The choking option is turned off at the feedwater nozzle junction, which will result in more feedwater entering the faulted steam generator. The isoenthalpic expansion choked flow option is utilized for Junctions 126, 134, 225, 226 and 234. This avoids junction enthalpy errors when the enthalpy decreases below 170 Btu/lbm (Moody limit). In addition, dynamic slip is modeled in Junctions 136 and 137. This is done in an attempt to minimize the liquid carried into the steam line.

15.2.1.5 Steam Generator Water Carryout Control

Water carryout during blowdown of the affected steam generator can have the effect of reducing the rate of overcooling, since water that does not boil in the tube bundle region will not absorb the heat of vaporization. A secondary concern with water carryout in a steam line break analysis is that the break flow with two-phase conditions will be considerably less on a volumetric basis than single-phase steam flow, and will thus slow the rate of steam generator depressurization. This in turn slows the decrease in steam generator saturation temperature and the primary-to-secondary heat transfer rate, which is non-conservative. However, with uncontrolled main and/or emergency feedwater flow, steam generator overfill will eventually occur. Water carryout at that time is realistic. Possible unrealistic or non-conservative water carryout is addressed in the model.

[ ]

15.2.1.2 Transport Delay Model

Results indicate that reverse heat transfer in the unaffected steam generator causes significant voiding in the RCS loop associated with this generator. The voiding is severe enough to cause degraded reactor coolant pump (RCP) performance which leads to brief periods of reverse flow in the isolated loop. Since reverse flow can cause anomalous predictions when the transport delay model is used, this model is deleted from the primary system piping volumes.

15.2.1.3 Condensate/Feedwater System Model

A Condensate/Feedwater System model is added to the RETRAN base deck to accurately predict the feedwater flow boundary condition during the steam line break accident. The Condensate/Feedwater System model contains fill tables to simulate the condensate booster pumps and the D heater drain pumps. Homologous pump curves are included to accurately model the main feedwater pumps. Non-conducting heat exchangers are used to model all of the feedwater heaters.

15.2.1.4 Steam Generator Model

Low steam generator tube plugging will maximize the transient primary-to-secondary heat transfer. The assumption of low steam generator tube plugging also maximizes the RCS volume, which slightly increases the overall heat capacity of the RCS. Sensitivity studies have been performed and have determined that the impact of the tube plugging on the heat transfer area is the dominant effect. Based upon plant data, a lower bound of 1% tube plugging is modeled.

The vertical junction option is used for the aspirator junctions to smooth the enthalpy and mass flow rate predictions through the aspirator port during the accident. This is necessary due to the reverse flow predicted through these junctions during the accident. The inertia for these junctions is also increased in order to minimize the rate of change in flow through the aspirator ports. The choking option (Extended Henry and Moody) is turned on at the steam generator exit

## 15.2 Simulation Codes and Models

### 15.2.1 RETRAN-02

The RETRAN-02 Oconee base model described in Section 2.2.1 of Reference 15-2 is utilized for the steam line break analysis except as described below. The steam line break model has been previously submitted (Reference 15-5) and approved by the NRC for the Oconee steam line break accident mass and energy release modeling.

#### 15.2.1.1 Nodalization of Reactor Vessel

The steam line break analysis is performed assuming a stuck control rod, a single failure in the Engineered Safety Features or the Emergency Feedwater System, and with consideration of both offsite power maintained and offsite power lost. Fuel failure will be assumed for any fuel pin that exceeds the DNBR limit.

### 15.1.3 Analytical Approach

The steam line break transient requires a limiting set of physics parameters to be determined for use as initial and boundary conditions. These parameters are input to the Oconee RETRAN-02 model (References 15-1 and 15-2) for the system thermal-hydraulic analysis. The with offsite power RETRAN-02 analysis generates the transient core thermal-hydraulic boundary conditions (core heat flux, core inlet flow, core inlet temperature and core exit pressure). The steam line break with offsite power is a severe overcooling transient which results in a return-to-power condition. The affected loop cold leg temperatures are much colder than the unaffected loop and cause asymmetric core inlet temperature conditions. To simulate this asymmetric condition properly, a [ ] channel VIPRE-01 (Reference 15-3) model is used (Figure 15-1). A statepoint DNBR calculation is performed since the return-to-power during the steam line break accident is slow and a statepoint analysis provides conservative DNBR results. The RETRAN-02 thermal-hydraulic statepoint is analyzed using the SIMULATE-3P (Reference 15-4) code to determine a detailed core power distribution including a stuck rod. The detailed core power distribution and the statepoint conditions are then analyzed with the VIPRE-01 code to determine the minimum DNBR.

For the without offsite power case, the core thermal-hydraulic boundary conditions from the RETRAN-02 analysis are input to the Oconee VIPRE-01 [ ] channel model (Reference 15-2) to determine the DNBR statepoint. The VIPRE-01 model is then utilized to calculate a set of maximum allowable radial peaking (MARP) limits such that DNB will not occur. The MARP limits are compared against the SIMULATE-3P core power distribution to determine the number of fuel pins exceeding the DNB limit and therefore assumed to fail.

# 15.0 STEAM LINE BREAK

## 15.1 Overview

### 15.1.1 Description

The steam line break accident initiates with a double-ended rupture of one of the two main steam lines. Since the two steam lines are connected in the steam chest between the turbine stop valves and the control valves, the break initially results in a rapid blowdown of both steam generators. The steam generator depressurization initiates a rapid Reactor Coolant System (RCS) cooldown leading to a reactor trip on low RCS pressure or variable low RCS pressure within the first few seconds of the accident. The reactor trip causes the turbine stop valves to close, isolating the affected steam generator from the unaffected steam generator. Main feedwater flow to each steam generator will be controlled by the Integrated Control System (ICS) by maintaining a minimum post trip steam generator level. If main feedwater is available and controlling steam generator level to the ICS setpoint, emergency feedwater will not be actuated. If main feedwater is lost, or if the ICS fails to control feedwater flow to the affected steam generator, emergency feedwater is likely to be actuated. The affected steam generator continues to depressurize, while the pressure in the isolated steam generator repressurizes and is controlled by the turbine bypass valves and possibly the main steam safety valves. Auxiliary steam loads may also depressurize the isolated steam generator. The cooldown of the RCS continues, resulting in reverse heat transfer in the isolated steam generator. The cooldown of the RCS caused by the continued addition of main and/or emergency feedwater to the depressurized steam generator may lead to a loss of shutdown margin and a return-to-power. Any return-to-power is eventually shut down by the boron injected from the High Pressure Injection (HPI) System and core flood tanks (CFTs).

### 15.1.2 Acceptance Criteria

The acceptance criteria for the steam line break accident are as follows:

- The core will remain intact for effective core cooling, assuming minimum tripped rod worth with a stuck rod.
- Doses will be within 100% of 10CFR100 limits.

Table 14-5

Rod Ejection Accident

Reload Cycle Key Parameter Checklist

| Parameter | | BOC | | | EOC | | |
|---|---|---|---|---|---|---|---|
| | | 4 RCP | 3 RCP | HZP | 4 RCP | 3 RCP | HZP |
| Max Ejected Rod Worth, $ | ≤ | 0.345 | 0.690 | 1.38 | 0.408 | 0.816 | 1.63 |
| MTC, pcm / °F | ≤ | -3.00 | -2.20 | +7.00 * | -25.0 | -25.0 | -15.0 |
| DTC, pcm / °F | ≤ | -1.25 | -1.30 | -1.65 | -1.35 | -1.38 | -1.75 |
| F Δh (at full power) | ≤ | 1.80 | 1.80 | 1.80 | 1.80 | 1.80 | 1.80 |
| Fq (at peak power) | ≤ | 4.17 | 6.30 | 8.01 | 4.03 | 6.20 | 13.8 |
| Fuel Failures, % | ≤ | *** | *** | N/A** | *** | *** | N/A** |

* At ARO conditions

** The HZP cases are non-limiting in terms of fuel failure and do not need to be checked unless any of the other key parameters are violated

*** The percentage of fuel failures must be less than the percentage assumed in the dose analysis.

Table 14-3

SIMULATE-3K Rod Ejection Results

| Parameter | BOC | | | EOC | | |
|---|---|---|---|---|---|---|
| | 4 RCP | 3 RCP | HZP | 4 RCP | 3 RCP | HZP |
| Initial Ejt Rod Position, %WD | 58 | 38 | 0 | 58 | 38 | 0 |
| Begin Rod Ejection, sec | 0 | 0 | 0 | 0 | 0 | 0 |
| End Rod Ejection, sec | 0.063 | 0.093 | 0.150 | 0.063 | 0.093 | 0.150 |
| Maximum Core Power, %FP | 140 | 194 | 1841 | 137 | 214 | 1752 |
| Time of Max Core Power, sec | 0.076 | 0.109 | 0.288 | 0.081 | 0.117 | 0.277 |
| Peak Assembly Power | 2.29 | 2.93 | 4.17 | 2.25 | 3.00 | 4.33 |
| Peak Nodal Power | 3.14 | 4.20 | 6.40 | 3.09 | 4.81 | 10.5 |
| Trip Signal Generation, sec | 0.054 | 0.082 | 0.248 | 0.057 | 0.083 | 0.245 |
| Begin Scram Rod Motion, sec | 0.454 | 0.482 | 0.648 | 0.457 | 0.483 | 0.645 |
| End Scram Rod Motion, sec | 2.854 | 2.882 | 3.048 | 2.857 | 2.883 | 3.045 |

Table 14-4

Total Pins Achieving DNB During Rod Ejection Accident (ARROTTA)

| Transient | BOC | EOC |
|---|---|---|
| 4 RCP | 40.6% | 27.6% |
| 3 RCP | 39.2% | 36.3% |
| HZP | <1% | 2.1% |

Table 14-1

Rod Ejection Accident Parameters

| Parameter | BOC | | | EOC | | |
|---|---|---|---|---|---|---|
| | 4 RCP | 3 RCP | HZP | 4 RCP | 3 RCP | HZP |
| Initial Core Power, %FP | 102 | 82 | 1E-7 | 102 | 82 | 1E-7 |
| Initial Core Avg TMOD, °F | 581 | 581 | 540 | 581 | 581 | 540 |
| Reactor Pressure, psia | 2200 | 2200 | 2200 | 2200 | 2200 | 2200 |
| Core Flow, gpm X $10^{+5}$ | 3.71 | 2.73 | 1.73 | 3.71 | 2.73 | 1.73 |
| Delayed Neutron Fraction | 0.0058 | 0.0058 | 0.0058 | 0.0049 | 0.0049 | 0.0049 |
| MTC, pcm / °F | -3.00 | -2.20 | +7.00 * | -25.0 | -25.0 | -15.0 |
| DTC, pcm / °F | -1.25 | -1.30 | -1.65 | -1.35 | -1.38 | -1.75 |
| Ejected Rod Worth, pcm | 200 | 400 | 800 | 200 | 400 | 800 |

* At ARO conditions

Table 14-2

ARROTTA Rod Ejection Results

| Parameter | BOC | | | EOC | | |
|---|---|---|---|---|---|---|
| | 4 RCP | 3 RCP | HZP | 4 RCP | 3 RCP | HZP |
| Initial Ejt Rod Position, %WD | 58 | 38 | 0 | 58 | 38 | 0 |
| Begin Rod Ejection, sec | 0 | 0 | 0 | 0 | 0 | 0 |
| End Rod Ejection, sec | 0.063 | 0.093 | 0.150 | 0.063 | 0.093 | 0.150 |
| Maximum Core Power, %FP | 144 | 195 | 2098 | 148 | 223 | 1918 |
| Time of Max Core Power, sec | 0.076 | 0.106 | 0.270 | 0.079 | 0.112 | 0.262 |
| Peak Assembly Power | 2.38 | 3.01 | 4.28 | 2.45 | 3.12 | 4.51 |
| Peak Nodal Power | 3.33 | 4.37 | 6.66 | 3.44 | 4.77 | 9.99 |
| Trip Signal Generation, sec | 0.054 | 0.082 | 0.248 | 0.057 | 0.083 | 0.245 |
| Begin Scram Rod Motion, sec | 0.454 | 0.482 | 0.648 | 0.457 | 0.483 | 0.645 |
| End Scram Rod Motion, sec | 2.854 | 2.882 | 3.048 | 2.857 | 2.883 | 3.045 |

## 14.5 Reload Cycle-Specific Evaluation

The failed fuel pin census results from Section 14.3.4 are used in the determination of the offsite dose consequences. In addition to the calculated pin census results, a maximum allowable number of failed pins is determined in the offsite dose calculation. Each reload core design then verifies that this maximum allowable limit is not exceeded. A cycle- specific check will be made for those key physics parameters which most significantly determine the response of the rod ejection transient. These key physics parameters are listed in Table 14-5.

## 14.6 References


14-1 ASME Boiler and Pressure Vessel Code, Section III, "Nuclear Power Plant Components", ASME

14-2 ARROTTA: Advanced Rapid Reactor Operational Transient Analysis, EPRI, August 1993

14-3 SIMULATE-3 Kinetics Theory and Model Description, SOA-96/26, Studsvik of America, April 1996

14-4 SIMULATE-3: Advanced Three-Dimensional Two-Group Reactor Analysis Code, STUDSVIK/SOA-92/01, Studsvik of America, April 1992

14-5 VIPRE-01: A Thermal-Hydraulic Code for Reactor Cores, EPRI NP-2511-CCM, Revision 3, EPRI, August 1989

14-6 RETRAN-02: A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI NP-1850-CCM, Revision 4, EPRI, November 1988

14-7 BWC Correlation of Critical Heat Flux, BAW-10143P-A, B&W, April 1985

versus assembly axial peak and location. Representative MARP curves are presented in Figures 14-12 through 14-14 for BOC conditions, with the HZP cases assuming 2 RCPs in operation when 3 RCPs could have been credited. EOC conditions yield similar, though higher, MARP curves which translates into fewer pin failures. When the radial power peak of the fuel pin exceeds the MARP during the transient, DNB is assumed to occur and the cladding fails. The fuel pin census results resulting from the use of these MARP curves are given in Table 14-4.

14.4.1.3 Coolant Expansion Rate

The BOC 3 RCP rod ejection transient results in the highest coolant expansion rate. Figure 14-15 shows the instantaneous core coolant expansion rate in ft$^3$/sec as a function of transient time. The initial expansion rate corresponds to the full power initial condition and the resulting decrease in coolant density due to sensible heating in the core. The result shows that a peak expansion rate of [ ] sec, the expansion rate has nearly decreased back to its initial value as power decreases due to reactor trip.

14.4.2 RETRAN Peak Primary Pressure Analysis

14.4.2.1 Initial Conditions

The RETRAN model pressure response to the rod ejection transient is primarily a function of the coolant expansion rate, which is input as a boundary condition. Most parameters such as initial primary temperature have little impact on the pressure response due to the [ ] which results in minimizing temperature transport effects. However, since the results of these initializations are used to generate the initial conditions for the VIPRE analyses, the transient is evaluated as if temperature transport effects do play an important role in the pressurization. Each initial condition is discussed below.

Only the maximum power levels at 4 and 3 RCP conditions are analyzed for the peak primary pressure.

Main Feedwater System

The main feedwater subsystem of the ICS is assumed to be in automatic control prior to reactor trip. This will throttle main feedwater to the ruptured steam generator due to the break flow entering it. Main feedwater flow is assumed to be terminated after reactor trip. This minimizes the secondary inventory available to mix with and dilute primary-to-secondary leakage. This also reduces the ability to cool the unit down.

Turbine Control

The turbine control subsystem of the ICS is assumed to be in automatic to prevent steam generator pressure from increasing before the reactor is tripped. This will maximize primary-to-secondary leakage.

Emergency Feedwater System

EFW initiation occurs on the loss of MFW with a long delay. A single failure of the EFW control valve on the intact steam generator to open results in the ruptured steam generator providing all post-trip heat removal until operator action corrects the problem. Minimum flow rates are assumed to minimize primary-to-secondary heat transfer.

## 13.6 Results

The thermal-hydraulic response resulting from this event is provided as input to a separate analysis which determines the fission product release to the environment.

## 13.7 Reload Cycle-Specific Evaluation

The reload physics parameter that must be checked is a minimum boron worth.

## 13.8 References

13-1 Thermal-Hydraulic Transient Analysis Methodology, DPC-NE-3000, Duke Power Company, July 1987

## 13.4 Physics Parameters

Credit for pre-trip negative reactivity addition from HPI System boron injection using the generalized transport model and a conservatively low value of differential boron worth is credited in the methodology. The analysis presented in this report does not include the pre-trip effect of boron injection.

## 13.5 Control, Protection, and Safeguards Systems

Reactor Control

Reactor power does not change prior to reactor trip, thus the reactor control subsystem of the Integrated Control System (ICS) is assumed to be in manual.

Reactor Trip

The Reactor Protective System is assumed to trip the reactor 20 minutes after the tube rupture occurs.

RCS Pressure Control

Pressurizer heaters are assumed to be operable during this event. Pressurizer spray is also assumed to be operable since it is the limiting means of minimizing the RCS subcooled margin after identification of the tube rupture.

Pressurizer Level Control

ECCS injection is manually throttled after the tube rupture occurs to control pressurizer level to a high setpoint.

ECCS Injection

Maximum ECCS injection flow is assumed to be available coincident with the tube rupture. This maximizes primary-to-secondary leakage and lengthens the time to reactor trip. [

]

- RCS subcooled margin is minimized after identification of the tube rupture. This is accomplished by using pressurizer spray to depressurize the RCS. An operator action delay time of 12 minutes following identification of the tube rupture is assumed.

- One RCP per loop is tripped off after the RCS has cooled down to 532°F. A 10 minute operator action delay time is assumed for this after reaching 532°F.

- A shift changeover delay of one hour is assumed. The RCS is held at a stable condition during this time.

- Cooldown of the RCS to 450°F occurs after shift changeover is completed. An operator action delay time of 5 minutes is assumed.

- Cooldown of the RCS is halted upon reaching 450°F . The RCS boron concentration is determined at this time. An operator action delay time of 90 minutes is assumed.

- Boration of the RCS is performed to reach the cold shutdown boron concentration requirement. An operator action delay time of 30 minutes is assumed.

- Cooldown to decay heat removal conditions resumes after the cold shutdown boron concentration has been achieved. An operator action delay time of 5 minutes is assumed.

- During the cooldown the ruptured steam generator is periodically steamed to the atmosphere and/or drained to prevent water from entering the steam lines. A conservatively low steam generator level setpoint corresponding to an elevation below that of the steam line is assumed for this action.

- A delay time is assumed to align the decay heat removal system. An operator action delay time of 45 minutes is assumed.

Ruptured Steam Generator Level Control

After operators isolate the ruptured steam generator, break flow will gradually fill the ruptured steam generator. Upon reaching a high level setpoint which is below the elevation at which water will spill into the main steam lines, operators will control the level by steaming to the atmosphere and/or draining.

Single Failure

The single failure identified for maximizing offsite dose is the failure of the emergency feedwater (EFW) control valve on the intact steam generator to open following reactor trip. This results in the ruptured steam generator providing all post-trip heat removal until operator action corrects the problem.

Manual Operator Actions

- Immediate action to initiate flow from the High Pressure Injection (HPI) System.

- Identify the failed-closed position of the EFW control valve and restore EFW to the intact steam generator. An operator action delay time of 23 minutes after reactor trip is assumed.

- Identification of the ruptured steam generator is determined by the EFW flow imbalance between the intact steam generator and the ruptured steam generator. An operator action delay time of 10 minutes after flow has been restored to the intact steam generator is assumed.

- An operator action delay time is assumed from the time the ruptured steam generator is identified to the time a cooldown of the RCS to 532°F begins. Operator action delay times of 5 minutes for control room actions, and 40 minutes for local action are assumed.

- Isolate the ruptured steam generator after reaching 532°F. This includes isolation of steam loads and isolation of EFW to this steam generator. An operator action delay time of 10 minutes after reaching 532°F is assumed.

to small differences in the predicted critical flow through the main steam safety valves between RETRAN-02 and RETRAN-3D. The critical flow at a junction is a function of the pressure and enthalpy of the fluid. These properties are calculated in slightly different ways in RETRAN-02 and RETRAN-3D. Both calculation methods are appropriate approximations based on known local fluid properties. These small differences are insignificant considering the much greater effect of the numerous conservatisms included in the turbine trip analysis, and the large margin to the acceptance criterion.

## 12.4 Reload Cycle-Specific Evaluation

The key parameters that are checked for each reload core are:

- Moderator temperature coefficient
- Doppler temperature coefficient
- Minimum scram worth curve

## 12.5 References


12-1 RETRAN-02 - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI-NP-1850-CCM, Revision 4, EPRI, November 1988

12-2 Thermal-Hydraulic Transient Analysis Methodology, DPC-NE-3000, Duke Power Company, July 1987

12-3 RETRAN-3D - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI NP-7450, Revision 3, EPRI, September 1998

- Doppler temperature coefficient
- Minimum scram worth curve
- Maximum withdrawable Group 7 control rod worth curve

## 11.2 Statically Misaligned Rod

The statically misaligned rod event considers the situation where a control rod is misaligned from the remainder of its bank. A rod misalignment may produce an increase in core peaking which decreases the margin to DNB. Steady-state three-dimensional power peaking analyses are performed with SIMULATE-3P to confirm that the asymmetric power distributions resulting from the rod misalignment will not result in DNB. There is no system transient associated with the analysis of the statically misaligned rod case. The reactor is assumed to remain at its initial power level.

The statically misaligned rod evaluation is performed at nominal hot full power conditions. Axial shapes allowed by the power dependent axial offset limits are considered in the evaluation. Two specific cases are analyzed which characterize the worst case misalignments. The first case considers the full insertion of any one rod within Group 7 positioned anywhere within the full power rod insertion limits. The second case considers the misalignment of a single Group 7 rod at its fully withdrawn position, with the remainder of Group 7 positioned at the full power rod insertion limit. A rod position uncertainty of 2% is considered.

The results of the generic evaluation of the statically misaligned rod event show that this event is bounded by the dropped rod event. Therefore, power distributions from the statically misaligned rod accident are not analyzed for each reload core.

## 11.3 References


11-1 RETRAN-02 - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI-NP-1850-CCM, Revision 4, EPRI, November 1988

11-2 VIPRE-01: A Thermal-Hydraulic Code for Reactor Cores, EPRI NP-2511-CCM-A, Revision 3, EPRI, August 1989

Main Feedwater System

The main feedwater (MFW) subsystem of the ICS is assumed to be in automatic control. The ICS will adjust the MFW flow to the steam generators according to changes in the demand signal.

Turbine Control

The turbine control subsystem of the ICS is assumed to be in automatic. The ICS will attempt to maintain steam line pressure by opening or closing the turbine control valves. This action will tend to minimize temperature decreases, and maximize primary-to-secondary heat transfer and limit RCS heatup.

### 11.1.6 VIPRE-01 Analysis

The forcing functions necessary to perform the DNB analysis (core average heat flux, core inlet flow and temperature, core exit pressure) are obtained from the RETRAN-02 analysis results and input to VIPRE-01. The VIPRE-01[ ]channel model (Reference 11-4) is then used to determine the time of the minimum DNBR statepoint for the transient conditions analyzed. At these statepoint conditions a set of maximum allowable radial peak (MARP) curves is developed for determining if the DNBR limit is exceeded.

### 11.1.7 Results

The peak power levels for a dropped rod transient as predicted by RETRAN are 116.6% for the four-pump initial condition, and 93.6% for the three-pump initial condition. The results of the DNBR analysis have demonstrated that the power peaking will remain below the DNBR limit. The results of the CFM analysis have demonstrated that the maximum linear heat rate is less than the CFM limit.

### 11.1.8 Reload Cycle-Specific Evaluation

Physics parameters that are checked for each reload core are:

- Moderator temperature coefficient

The analog ICS has been replaced by an advanced digital ICS. The same modeling philosophy presented for the analog ICS will be used in analyzing the plant response to a dropped rod event with the digital ICS.

The transient response is analyzed with the RETRAN-02 code (Reference 11-1). The DNB analysis is performed with the VIPRE-01 code (Reference 11-2). The core power distribution is analyzed with the SIMULATE-3P code (Reference 11-3). The acceptance criteria for this analysis are to ensure that the minimum DNBR remains above the DNBR limit, the CFM limits are not exceeded, and that the pressure in the Reactor Coolant System (RCS) remains below 110% of design pressure. The minimum DNBR is determined using the statistical core design (SCD) methodology. Based on the analysis results, peak RCS pressure is not a concern during this event. The initial conditions and boundary conditions chosen for this analysis are therefore those that will result in the lowest DNBR and the highest linear heat rates.

### 11.1.1 Nodalization

This transient is analyzed using the Oconee two-loop RETRAN model (Reference 11-4). This permits the evaluation of cases with both three and four-pump operation. A junction is added to the base model to connect the steam lines since an asymmetric steam generator response will occur during cases with three-pump operation.

### 11.1.2 Initial Conditions

Core Power Level

A high initial power level for both three and four RCP operation maximizes the primary system heat flux. The uncertainty for this parameter is incorporated in the SCD methodology.

RCS Pressure

Low initial RCS pressure is conservative for DNBR. The SCD accounts for instrument uncertainty in the pressure indication, but does not account for a controller deadband bias. Nominal pressure less the controller deadband bias is therefore assumed for the initial RCS pressure.

## 11.0 CONTROL ROD MISALIGNMENT ACCIDENT

### 11.1 Dropped Control Rod

Control rods are normally grouped into patterns which maintain a symmetric core power distribution. A mechanical or electrical failure can cause a control rod to drop partially or fully into the core. The resulting transient causes a rapid reduction in power and moderator temperature which is followed by an increase in power due to the negative moderator temperature coefficient. If control rods are withdrawn by the Integrated Control System (ICS) during the transient response, they will add to the increase in power. The magnitude of the power increase may exceed the initial power level. This elevated power level, with consideration for the asymmetric power distribution, has the potential for the DNBR and centerline fuel melt (CFM) limits to be exceeded.

The general response of the analog ICS to a dropped rod event is as follows, assuming no credit for the asymmetric rod indication generating either an ICS runback signal or a control rod withdrawal inhibit signal. This conservative assumption is in addition to the normal assumption that control systems either function as designed or do not respond, whichever results in the worst transient response. The plant is assumed to be initially at 100% full power conditions with the ICS in automatic. The initiating event is a control rod dropping into the core. The negative reactivity inserted into the core causes an immediate drop in core power and is assumed to produce a significant quadrant tilt. The difference between the reactor demand and indicated core power signals (neutron error) causes the Group 7 control rods to be withdrawn. A neutron cross limit signal is generated when the neutron error signal reaches 5%, causing the unit to go into tracking mode. In tracking mode, the ULD follows generated megawatts. Turbine control will try to maintain turbine header pressure at its nominal setpoint of 885 psig. The neutron cross limit will also impact the feedwater demand signal to keep core power and feedwater flow coordinated. As Group 7 is withdrawn, actual core power may increase above the initial power level resulting in an increase in steam pressure. The turbine control response will be to open the turbine control valves to maintain header pressure. If the assumed quadrant tilt is large enough, the unit will remain in track for the duration of the transient. If no quadrant tilt is assumed, the unit will come out of track when the neutron cross limit clears and will hold at the then current demand set value.

| Operating Conditions | % of Fuel Pins Experiencing DNB |
|---|---|
| 4 RCP operation | 0 |
| 3 RCP operation | 0 |

## 10.4 Reload Cycle-Specific Evaluation

Physics parameters that are checked for each reload core are:

- Moderator temperature coefficient
- Doppler temperature coefficient
- Minimum scram worth curve

## 10.5 References


10-1 RETRAN-02: A Program for transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI NP-1850-CCM, Revision 4, EPRI, November 1988

10-2 Thermal-Hydraulic Transient Analysis Methodology, DPC-NE-3000, Duke Power Company, July 1987

10-3 VIPRE-01 : A Thermal-Hydraulic Code for Reactor Cores, EPRI NP-2511-CCM-A, Revision 3, August 1989

10-4 BAW-10143-PA, BWC Correlation of Critical Heat Flux, April 1985

10-5 BAW-10199-PA, The BWU Critical Heat Flux Correlation, April 1996

10-6 DPC-NE-1004A, Duke Power Company Nuclear Design Methodology Using CASMO-3/SIMULATE-3P, November 1992

10-7 TACO-3, Fuel Pin Thermal Analysis Code, BAW-10162P-A, BWFC, November 1989

# 10.0 LOCKED ROTOR

## 10.1 Overview

### 10.1.1 Description

The locked rotor accident is the result of an instantaneous seizure of one reactor coolant pump (RCP) rotor. Coolant flow in that loop rapidly decreases, causing the Reactor Protective System (RPS) to initiate a reactor trip on flux/flow/imbalance. The mismatch between power generation and heat removal capability due to the degraded flow condition causes a heatup of the primary system. The major concern in the locked rotor accident is departure from nucleate boiling (DNB). Based on the analysis results, peak RCS pressure is not a concern during this event.

### 10.1.2 Acceptance Criteria

The acceptance criteria for the locked rotor accident are:

- Any fuel damage calculated to occur must be of a sufficiently limited extent that the core will remain in place and intact with no loss of core cooling capability.
- Peak RCS pressure remains below 110% of design pressure
- Any activity release must be such that the calculated doses at the site boundary are less than 100% of the 10 CFR Part 100 guidelines.

### 10.1.3 Analytical Approach

The locked rotor accident requires a limiting set of physics parameters along with conservative initial and boundary conditions. These parameters are input to the Oconee RETRAN-02 model (References 10-1 and 10-2) for the system thermal-hydraulic analysis. The RETRAN-02 analysis generates the transient forcing functions to be input to the Oconee VIPRE-01 (Reference 10-3) model. The VIPRE-01 model calculates the maximum allowable radial peaking (MARP) limits during the transient such that DNB will not occur. The MARP results are used to determine the number of fuel pins in the core exceeding the DNB limit, which are considered to be failed fuel pins.

## 6.3 VIPRE-01 Analysis

The forcing functions necessary to perform the DNB analysis (core average heat flux, core inlet flow and temperature, core exit pressure) are obtained from the RETRAN-02 analysis results and input to VIPRE-01. The VIPRE-01 14 channel model (Reference 6-4) is then used to determine the time of the minimum DNBR statepoint for the transient conditions analyzed. At these statepoint conditions a set of maximum allowable radial peak (MARP) curves is developed for determining if the DNBR limit is exceeded.

## 6.4 Results

The peak primary pressure reached in the limiting case is approximately 2600 psig. This is well below the acceptance criterion of 2750 psig. The results of the DNBR analysis have demonstrated that the power peaking predicted by SIMULATE-3P will remain below the DNBR limits.

## 6.5 Reload Cycle-Specific Evaluation

Physics parameters that are checked for each reload core are:

- Moderator temperature coefficient
- Doppler temperature coefficient
- Minimum scram worth curve
- Minimum and maximum reactivity insertion rates
- Maximum allowable radial peak limits

## 6.6 References

6-1 RETRAN-02 - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI-NP-1850-CCM, Revision 4, EPRI, November 1988

6-2 VIPRE-01: A Thermal-Hydraulic Code for Reactor Cores, EPRI NP-2511-CCM-A, Revision 3, EPRI, August 1989

RCS Temperature

Between 15% and 100% FP, the Integrated Control System controls the RCS average temperature indication to a constant value. The instrument uncertainty associated with RCS T-ave is included in the DNB limit (SCD).

RCS Flow

Low flow is conservative with respect to DNB. Since the uncertainty in the RCS flow indication is accounted for in the SCD limit, the actual RCS flow is assumed to be equal to the minimum indicated value.

Core Bypass Flow

A high core bypass flow is assumed to minimize the coolant flow along the fuel rods.

Fuel Temperature

Sensitivity cases are analyzed using both high and low initial fuel temperatures to determine whether high or low initial fuel temperature is more conservative. The more conservative initial temperature is then assumed.

Steam Generator Mass

A high initial steam generator mass maximizes the available heat sink which should slow the primary system pressurization.

Steam Generator Tube Plugging

The minimum actual SG tube plugging is assumed. Low tube plugging will lessen the rate of RCS heatup/pressurization and delay reactor trip on high pressure. Following reactor trip, the lower tube plugging will help the Turbine Bypass System minimize the RCS pressurization. Both of these effects are conservative with respect to DNB.

6.2.3 Boundary Conditions

Control Rod Group Withdrawal Rate

Sensitivity cases are performed on the withdrawal rate between the physical limits such that the most severe challenge to the acceptance criterion is obtained. Nominal assumptions are made for

Steam Generator Tube Plugging

A high SG tube plugging percentage will degrade primary-to-secondary heat transfer and also minimize RCS inventory. Both of these effects will maximize the RCS pressure increase.

### 6.1.3 Boundary Conditions

Control Rod Group Withdrawal Rate

Sensitivity cases are performed on the withdrawal rate between the physical limits such that the most severe challenge to the respective acceptance criterion is obtained. Nominal assumptions are made for control rod speed, overlap and withdrawal sequence.

Pressurizer Safety Valves

The pressurizer code safety valves are modeled using conservative assumptions for drift, blowdown and valve capacity that minimize relief flow.

Main Steam Safety Valves

The main steam safety valves are modeled using conservative assumptions for drift, blowdown and valve capacity that minimize relief flow and maximize the secondary side pressure response. The increased secondary side temperatures associated with the higher pressure will yield reduced primary-to-secondary heat transfer, which is conservative for peak primary pressure.

Pressurizer Inter-Region Heat Transfer Coefficient

For this analysis, a conservatively low pressurizer inter-region heat transfer coefficient is assumed. This will maximize the rate of RCS pressurization and worsen the approach to the high pressure acceptance criterion.

Single Failure

No credible single failure has been identified which adversely impacts the results of the cases initiated from four-pump operation.

- Minimum scram curve worth
- Maximum reactivity insertion rate

## 5.5 References


5-1 RETRAN-02 - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI NP-1850-CCM, Revision 4, EPRI, November 1988

5-2 VIPRE-01: A Thermal-Hydraulic Code for Reactor Cores, EPRI NP-2511-CCM-A, Revision 3, EPRI, October 1989

5-3 Thermal-Hydraulic Transient Analysis Methodology, DPC-NE-3000, Duke Power Company, July 1987

flux/flow imbalance trip functions. However, preliminary analyses indicate that the reactor trip functions that rely on an indicated flux signal will not occur. This is because of the large control rod shadowing effect and the large nuclear instrumentation calibration errors potentially present at HZP. Therefore, only the high pressure trip function is credited in this analysis. Conservative setpoints are assumed for all credited trip functions with the appropriate conservative trip delay times.

RCS Pressure Control

The pressurizer spray and PORV are assumed inoperable, and the pressurizer heaters are assumed to be operable.

Pressurizer Level Control

No charging/letdown flow is modeled. It is assumed there would be no affect on the results of the analysis if charging/letdown was explicitly modeled due to the short duration of the transient.

### 5.3.5 Results

The startup accident models three reactor coolant pumps in operation and a maximum reactivity addition rate of 11.5 pcm/sec. Table 5-1 gives the sequence of events for this case. Figure 5-2 shows the neutron and thermal power as a function of time. Neutron power does not begin to appreciably increase until the inserted reactivity begins to approach $1. This occurs approximately 45 seconds into the rod withdrawal. Reactor trip occurs on high RCS pressure at 51.9 seconds with neutron power at approximately 125 % FP. After reactor trip, neutron power decreases rapidly as the control rods are inserted, and then decreases slowly due to delayed neutron fissions. The shape of the core thermal power response is similar to the neutron power response, but lags the neutron power peak by approximately 0.5 seconds. The core thermal power rises to a peak value of 73 % FP at 52 sec. Since the peak core thermal power is below the permissible power level with three RCPs in operation, DNB is not a concern for this transient and no VIPRE analysis is required for the assumed core physics parameters.

Figure 5-3 shows the kinetics response for this case. The reactivity insertion due to rod withdrawal is linear with time until reactor trip, when rod withdrawal ceases. Fuel heatup causes negative reactivity insertion due to the negative Doppler temperature feedback until reactor trip,

5.2.2 VIPRE-01

Should a DNB analysis become necessary, the VIPRE-01 code is used to calculate the minimum DNBR for the startup accident. VIPRE thermal-hydraulic boundary conditions (core heat flux, core inlet flow, core inlet temperature and core exit pressure) are obtained from the RETRAN simulation. The[ ]channel VIPRE model described in Section 2.3 of Reference 5-3 is used to calculate the limiting statepoint local properties and DNBR. The VIPRE analysis will employ the SCD methodology for the startup accident.

5.2.3 SIMULATE-3P

SIMULATE-3P is a core neutronics code used to generate safety analysis physics parameters and three-dimensional core pin power distributions for the startup accident. The conservatism of the physics parameters will be confirmed each cycle as described in Section 5.4 SIMULATE-3P will also be used to calculate the pin power distributions for the accident conditions if a DNBR analysis is necessary. The pin power distributions will then be used to determine if any fuel failures occur.

5.3 <u>Peak Primary System Pressure and Core Cooling Capability Analysis</u>

The startup accident analysis presented herein is concerned with maximizing the core heat flux, which therefore maximizes the RCS pressure response. If the predicted heat flux for the peak RCS pressure analysis does not exceed the allowable steady-state heat flux for three-pump operation, then DNB is not of concern for this event. Otherwise a VIPRE-01 analysis is performed to calculate the minimum DNBR.

5.3.1 Initial Conditions

<u>Power Level</u>
An initial critical power level of 1E-9 of the nominal full power level is assumed. This very low initial power level maximizes the power excursion.

Table 4-2
Current RPS and ESPS Actuation Setpoints

| Safety Function | Nominal Setpoint | Uncertainty Adjusted Setpoint | Maximum Response Time * |
|---|---|---|---|
| **RPS:** | | | |
| High Flux | 105.5 %FP | 106.5 %FP | 0.4 sec |
| High Pressure | 2355 psig | 2362 psig | 0.5 sec |
| Low Pressure | 1800 psig | 1793 psig | 0.5 sec |
| Variable Low Pressure-Temperature | trip if: (P is psig) P<11.14(Thot)-4706 | trip if: (P is psig) P<11.14(Thot)-4716 | 0.7 sec |
| Flux/Flow | trip if: $\phi$>109.4 x Fm ** | trip if: $\phi$>109.4 x Fm + 2.2 %FP | 1.2 sec |
| High Temperature | 618 °F | 618.85 °F | 0.7 sec |
| Pump Monitor | NA | NA | 0.6 sec |
| | | | |
| **ESPS:** | | | |
| HPI | 1590 psig | 1480 psig #<br>1400 psig ## | 15 sec (no-LOOP)<br>38 sec (LOOP) |
| CFT *** | 2.0 psid | + 6.5 psid (CFT A) ###<br>- 2.5 psid (CFT B) | NA |

* Note that the RPS trip response times include a minimum 0.14 sec delay for the control rod gripper coils to de-energize.

** Fm is measured flow. 109.4 is in units %FP/flow

*** The nominal actuation setpoint is based on a ΔP across the CFT check valve. The RETRAN values assume the nominal value, but account for the RETRAN modeling to obtain the nominal ΔP. Since this is a passive safety system, no response times are applicable.

\# Includes 50 psi uncertainty and 60 psi margin

\## For large steam line break only due to harsh containment environment allowance

\### These setpoints are adjusted to account for elevation differences

Table 3-1 (continued)

| Report Section | Transient or Accident | FSAR Section | Key Parameters | Conservative Direction |
|---|---|---|---|---|
| 16.0 | Small Steam Line Break | 15.17 | • MTC<br>• DTC | - Bound BOC to EOC<br>- Least negative |

## 2.8 References


2-1 RETRAN-02 - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI NP-1850-CCM, Revision 4, EPRI, November 1988

2-2 Letter, M. J. Virgilio (NRC) to C. R. Lehman (PP&L), April 12, 1994 (SER for RETRAN-02/MOD 5.1)

2-3 Thermal-Hydraulic Transient Analysis Methodology, DPC-NE-3000, Duke Power Company, July 1987

2-4 Letter, L. A. Wiens (NRC) to M. S. Tuckman (Duke), August 8, 1994 (SER for DPC-NE-3000 - ONS sections)

2-5 SIMULATE-3 Kinetics Theory And Model Description, SOA-96/26, Studsvik of America, April 1996

2-6 SIMULATE-3: Advanced Three-Dimensional Two-Group Reactor Analysis Code, Studsvik/SOA-92/01, Studsvik of America, April 1992

2-7 RETRAN-3D - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI NP-7450, Revision 3, EPRI, September 1998

2-8 VIPRE-01: A Thermal-Hydraulic Code for Reactor Cores; EPRI NP-2511-CCM, Revision 3, EPRI, August 1989

2-9 Letter from C. E. Rossi (NRC) to J. A. Blaisdell (UGRA), "Acceptance for Referencing of Licensing Topical Report, VIPRE-01: A Thermal-Hydraulic Analysis Code for Reactor Cores," EPRI-NP-2511-CCM, Vol. 1-5, May 1986

2-10 Multidimensional Reactor Transients and Safety Analysis Physics Parameters Methodology, DPC-NE-3001, Duke Power Company, January 1990

[ ]. The justification for using this simplified [ ] channel model is given in DPC-NE-3000. The thermal-hydraulic modeling techniques and correlations utilized are also consistent with DPC-NE-3000. The [ ] is used as a boundary condition.

In addition to the [ ] channel model described above, a [ ] channel model (Figure 2-5) is constructed for the VIPRE-01 analysis. This [ ] channel model simulates the thermal-hydraulic conditions in [ ] in the reactor core, and will be utilized for the transients requiring a [ ] calculation. In the [ ] channel model, the [ ] channel model. A similar model has also been approved and utilized for the McGuire and Catawba [ ] analysis as described in Section 4.2.2.3 of Reference 2-10.

A [ ] channel model that simulates a [ ] is also constructed for two specific VIPRE-01 analyses. This [ ] channel model will be utilized for the rod ejection [ ] calculation and for some transient DNBR calculations as described in Chapter 14 of this report. The special SLB VIPRE model is described in Section 15.2.2.

2.3.3 Validation of Code and Model

In DPC-NE-3000, the validation of the VIPRE-01 code is performed by comparing the steady-state and transient results with COBRA-IIIC/MIT (Reference 2-11). The basic structure and computational philosophy of the VIPRE-01 code are derived from COBRA-IIIC (Reference 2-12). Therefore, it is appropriate to compare the steady-state as well as transient results calculated by these two codes. An identical COBRA [ ] channel model was constructed for the comparison purpose. Sections 2.3.5.4 and 2.3.5.5 of DPC-NE-3000 show that VIPRE-01 and COBRA-IIIC/MIT [ ] channel models generate essentially identical MDNBR and thermal-hydraulic property results for different steady-state operating conditions and during transients. The simplified [ ] channel model is also validated in DPC-NE-3000 by performing sensitivity studies (Reference 2-13). These sensitivity studies include the radial noding sensitivity, axial

different transient inlet temperatures, flow rates, heat flux transients, and even different transient assembly and pin radial powers or axial flux shapes can be modeled.

The version of the VIPRE-01 code currently used in the analyses is a Duke version of VIPRE-01/MOD2. The Duke version of the code includes additional features and editorial changes so that the constitutive equations, correlations, and solution schemes of the VIPRE-01/MOD2 code have been preserved. These additional features and editorial changes are described below:

- Add the following critical heat flux (CHF) correlations:
    1. BWC CHF correlation
    2. BWCMV CHF correlation
    3. BWU-Z and BWU-N CHF correlations
- Add the ability to print the friction, form loss elevation, acceleration and cross flow pressure drops for specified channels
- Add the option to allow the user to use either a linear interpolation or spline fit for the input nodal axial power profile
- Add the option to generate a summary file of the minimum DNBR value
- Add the option to allow the user to input the power hot channel factor ($F_q$) and the local heat flux hot channel factor ($F_q$") to a subchannel in order to conservatively calculate the DNBR in that subchannel
- Enhance the logic used when VIPRE-01 is utilized to iterate on a parameter, such as radial power, to converge to a MDNBR limit

### 2.3.2 Simulation Models

The NRC has approved the VIPRE-01 models described in DPC-NE-3000 (Reference 2-3) for Oconee core thermal-hydraulic analyses. The simplified[ ]channel model described in Section 2.3.2.1 of the same reference will be utilized for the transients requiring a DNBR evaluation. The[ ]channel model (Figure 2-4) is constructed such that[

]

1-22 Nuclear Design Methodology Using CASMO-3 / SIMULATE-3P, DPC-NE-1004, Duke Power Company, November 1992

1-23 Letter, A. C. Thadani (NRC) to H. B. Tucker (Duke), November 23, 1992 (SER for DPC-NE-1004)

1-24 SIMULATE-3: Advanced Three-Dimensional Two-Group Reactor Analysis Code, STUDSVIK/SOA-92/01, Studsvik of America, April 1992

1-25 ARROTTA: Advanced Rapid Reactor Operational Transient Analysis, EPRI, August 1993

1-26 SIMULATE-3 Kinetics, Studsvik of America, December 1995

1-27 Letter, W. O. Parker, Jr. (Duke), to Robert W. Reid (NRC), March 21, 1981

1-28 Letter, Robert W. Reid (NRC,) to all B&W Licensees, January 14, 1981

1-29 Letter, Philip C. Wagner (NRC), to W. O. Parker, Jr. (Duke), April 21, 1982

1-30 Letter, M. S. Tuckman (Duke) to NRC Document Control Desk, August 9, 1994 (Thermal-Hydraulic Transient Analysis Methodology, DPC-NE-3000, Revision 1)

1-31 Letter, M. S. Tuckman (Duke) to NRC Document Control Desk, December 23, 1997 (Thermal-Hydraulic Transient Analysis Methodology, DPC-NE-3000, Revision 2)

1-32 Letter, D. E. LeBarge (NRC) to W. R. McCollum (Duke), October 14, 1998 (SER for DPC-NE-3000, Rev. 2)

1-11 FSAR Chapter 15 System Transient Analysis Methodology, DPC-NE-3002, Duke Power Company, August 1991

1-12 Letter, T. A. Reed (NRC) to H. B. Tucker (Duke), November 15, 1991 (SER for DPC-NE-3001, Rev. 0)

1-13 Letter, T. A. Reed (NRC) to H. B. Tucker (Duke), November 15, 1991 (SER for DPC-NE-3002, Rev. 0)

1-14 Letter, R. E. Martin (NRC) to M. S. Tuckman (Duke), December 28, 1995 (SER for DPC-NE-3002, Rev. 1)

1-15 Letter, H. N. Berkow (NRC) to M. S. Tuckman (Duke), April 26, 1996 (SER for DPC-NE-3002 regarding safety valve opening characteristics)

1-16 Letter, M. J. Virgilio (NRC) to C. R. Lehman (PP&L), April 12, 1994 (SER for RETRAN-02/MOD 5.1)

1-17 Letter, L. A. Wiens (NRC) to M. S. Tuckman (Duke), March 15, 1995 (SER for DPC-NE-3003)

1-18 Mass and Energy Release and Containment Response Methodology, DPC-NE-3003, Duke Power Company, August 1993

1-19 RETRAN-3D - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI NP-7450, Revision 3, EPRI, September 1998

1-20 Letter, C. E. Rossi (NRC) to J. A. Blaisdell (UGRA), May 1, 1986 (VIPRE-01 SER)

1-21 CASMO-3: A Fuel Assembly Burnup Program User's Manual, STUDSVIK/NFA-88/48, Studsvik of America, September 1988

## 1.5 References


1-1 Letter, P. C. Wagner (NRC) to W. O. Parker, Jr. (Duke), July 29, 1981 (SER for NFS-1001)

1-2 Reload Design Methodology Technical Report, NFS-1001, Revision 3, Duke Power Company, April 1981

1-3 Thermal-Hydraulic Transient Analysis Methodology, DPC-NE-3000, Duke Power Company, July 1987

1-4 Licensee Qualification for Performing Safety Analyses in Support of Licensing Actions (Generic Letter No. 83-11), NRC, February 8, 1983

1-5 RETRAN-02 - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI NP-1850-CCM, Revision 4, EPRI, November 1988

1-6 VIPRE-01: A Thermal-Hydraulic Code for Reactor Cores, EPRI NP-2511-CCM, Revision 3, EPRI, August 1989

1-7 Letter, T. A. Reed (NRC) to H. B. Tucker (Duke), November 15, 1991 (SER for DPC-NE-3000 - MNS/CNS sections)

1-8 Letter, L. A. Wiens (NRC) to M. S. Tuckman (Duke), August 8, 1994 (SER for DPC-NE-3000 - ONS sections)

1-9 Letter, R. E. Martin (NRC) to M. S. Tuckman (Duke), December 27, 1995 (SER for DPC-NE-3000, Rev. 1)

1-10 Multidimensional Reactor Transients and Safety Analysis Physics Parameters Methodology, DPC-NE-3001, Duke Power Company, January 1990

Replacement Integrated Control System

The analyses presented in this report model the original analog Integrated Control System that has been replaced with a digital system. None of the analyses are adversely affected by this control system upgrade. Some of the UFSAR transient and accident analyses will be revised to incorporate the upgraded digital Integrated Control System. The modeling philosophy regarding control systems will remain the same in future reanalysis.

Single Failure and Loss of Offsite Power Assumptions

A limiting active single failure in the Reactor Protective System or in the Engineered Safeguards is assumed. A single failure in the Emergency Feedwater System is also considered. A failure of the manual atmospheric dump valves is not considered. Offsite power is assumed to be lost at time zero for those UFSAR Chapter 15 events which already include that assumption, which are limited to the steam line break accident.

For those transients and accidents for which detailed results are included, the results of each computer code used, the sequence of events, the plant response, and figures of key parameter trends are presented. The results are then compared to the applicable acceptance criteria. The process for evaluating each event for each reload core design is then stated. In general, the UFSAR analyses will remain valid as long as the key safety analysis parameters remain valid. Otherwise a reanalysis using revised and bounding parameters will be performed or the core will be redesigned.

## 1.4 Summary

The methodology presented in this report describes a conservative approach to performing the UFSAR Chapter 15 analyses for Oconee with modern thermal-hydraulic and nuclear analysis codes. These methods will be used to revise the existing UFSAR analyses which date to the early 1970s. The transient and accident analysis results presented are typical of those that will be used to update the UFSAR. Once implemented in the UFSAR, the revised analyses will enable a complete understanding of what the licensing basis analyses assume in terms of plant systems and component responses. This process will enhance the capability of Duke Power to review and assess plant operations and design in order to ensure compliance with regulations, to ensure consistency with Technical Specifications, and to ensure safe operation.

modeling philosophy on control systems, and the situations where non-safety components and systems are credited in the analyses: 1) In the dropped rod event, the Integrated Control System will respond by initiating a plant runback to a reduced power level. Since this plant runback assists in the mitigation of the dropped rod event, no credit is taken for this control system design feature. This assumption is an additional conservatism that is not required by the methodology philosophy. 2) For a loss of all reactor coolant pumps without a loss of the Main Feedwater System, the Integrated Control System is credited for raising steam generator levels to the natural circulation setpoint. This design feature is implicitly credited in the loss of coolant flow event, and involves non-safety equipment. A failure of this design function would be mitigated manually by operator action to start the Emergency Feedwater (EFW) System. 3) The moderator dilution accident credits the non-safety high-flux-at-shutdown alarm and the control rod insertion limit alarm to alert the operator that a boron dilution event is in progress. Both of these alarms rely on non-safety equipment. The rod insertion alarm relies on the plant computer. 4) Many of the transient and accident analyses involve control rod movement. These analyses credit the normal withdrawal sequence, overlap, and rod speed, which are controlled by non-safety control systems. 5) For certain failures in the safety-grade EFW System, credit is taken for realigning EFW flow through the non-safety MFW System. This design aspect has been reviewed and approved by the NRC. 6) Steaming of the steam generators with manual non-safety atmospheric dump valves is credited. 7) The turbine trip circuitry has two channels, one with a one second response time, and one with a fifteen second response time. The faster response time is credited in the current UFSAR Chapter 15 analyses and will be credited in the methodology. A station modification is planned to upgrade the second channel to a one second response time. The turbine trip circuitry is not completely safety-grade. 8) The capability to remotely throttle certain valves is credited. Some of the controls required to remotely throttle these valves are not safety-grade. 9) Electrical bus voltage and frequency control are credited. These are controlled by non-safety components. 10) The steam generator secondary drains are credited in the SGTR analysis to control level in the ruptured steam generator to prevent overfill. These drains are not safety-grade.

Main Feedwater Isolation

The large and small steam line break analyses do not credit automatic isolation of main feedwater by the main steam line break detection and main feedwater isolation instrumentation.

scope, and contents of this report were discussed in a meeting with the NRC staff on August 15, 1995. During this meeting the NRC staff indicated that the proposed contents were reasonable.

For each analysis methodology described in Chapters 5 through 16 the discussion includes acceptance criteria, model nodalization, initial conditions, boundary conditions, physics parameters, control systems, protection systems, safeguards systems, and operator response modeling. Additional discussion on the approach taken for some of these parts of the methodology are as follows:

Acceptance Criteria

Some of the acceptance criteria in the UFSAR have been updated, such as replacing the peak power level acceptance criterion with the industry standard criterion based on a DNBR limit. The updated acceptance criteria are typical of those used in the industry.

Model Nodalization

The RETRAN models and some VIPRE models (Reference 1-3) have been previously approved by the NRC (References 1-8, 1-9, 1-32). The specific application of these models for UFSAR Chapter 15 transient and accident reanalysis has required some changes to these approved models, and some additional VIPRE models. All of the changes and new models are described in this report. For example, the steam line break analysis requires a more detailed RETRAN nodalization of the reactor vessel and a special VIPRE model.

Initial Conditions

The initial conditions for many transient and accident analyses include allowances for uncertainty for parameters such as power, flow, pressure, and temperature. For analyses using the statistical core design approach some of the key initial condition uncertainties are already included in the statistical DNBR limit, and do not need to be included in the thermal-hydraulic analyses.

Credit for Control Systems and Non-Safety Components and Systems

Control systems are generally assumed to respond as designed or remain in manual control (inactive), whichever assumption is more conservative. Non-safety components and systems are generally not credited in the analyses. The following are specific exceptions to the general

VIPRE-01: The core thermal-hydraulic and fuel pin analyses use VIPRE-01/MOD2, which has been reviewed generically by the NRC (Reference 1-20) and approved for use provided plant-specific methods have also been submitted for review. The Oconee VIPRE model used for most of the UFSAR Chapter 15 analyses was approved by the NRC in References 1-8, 1-9, and 1-32. This report includes additional VIPRE models required for specific analyses. The application of VIPRE-01 for Oconee Chapter 15 analyses closely follows that submitted by Duke and approved by the NRC for application to McGuire and Catawba.

CASMO-3: Nuclear constants are generated with the Studsvik of America code CASMO-3 (Reference 1-21). This code is used in Oconee reload design (Reference 1-22), and was approved by the NRC in Reference 1-23. CASMO-3 is also used in the McGuire and Catawba UFSAR Chapter 15 methodology. CASMO-3 is used for generating data used as input to the core models listed below.

SIMULATE-3P: Nuclear parameters and core power distributions are generated with the Studsvik of America code SIMULATE-3P (Reference 1-24). This code is used in Oconee reload design (Reference 1-22), and was approved by the NRC in Reference 1-23. SIMULATE-3P is also used in the McGuire and Catawba UFSAR Chapter 15 methodology.

ARROTTA/1.10: The EPRI code ARROTTA (Reference 1-25) is used for transient three-dimensional (3-D) modeling of the rod ejection accident. This code has been approved by the NRC for analysis of the rod ejection accident for Duke Power's McGuire and Catawba Nuclear Stations (Reference 1-12). The application for Oconee closely follows the methodology developed for McGuire/Catawba.

SIMULATE-3K: The Studsvik of America code SIMULATE-3K (Reference 1-26) is also used for transient 3D modeling of the rod ejection accident. SIMULATE-3K provides the same neutronics solution to steady-state 3-D calculations as SIMULATE-3P. Duke Power intends to use SIMULATE-3K as an equivalent code for any of the steady-state applications in this report that are stated as being analyzed with SIMULATE-3P. Additional features include the time-dependent equations necessary to solve transient 3-D problems. This is the first submittal of this version of the SIMULATE family of codes for NRC approval. It is Duke Power's intent to

# 1.0 INTRODUCTION AND SUMMARY

## 1.1 Overview

This report describes the methodologies to be used by Duke Power Company to perform the analyses of the UFSAR Chapter 15 non-LOCA transients and accidents for the Oconee Nuclear Station. The Oconee Nuclear Station is a three-unit, 2568 MWt pressurized water reactor of the Babcock &Wilcox (B&W) 177 fuel assembly lowered-loop design. Units 1 and 2 began commercial operation in 1973, and Unit 3 in 1974. Duke Power received NRC approval to perform core reload design analyses for Oconee in 1981, when the Safety Evaluation Report (SER) (Reference 1-1) for the "Reload Design Methodology" topical report NFS-1001 (Reference 1-2) was issued. The safety analysis methodology approved as part of the NFS-1001 topical report consists of a review of the key safety analysis physics parameters for each reload to confirm that the existing safety analyses in the UFSAR remain valid. These parameters originated primarily from the analyses performed by B&W during the original licensing of Oconee in the early 1970s. Most of these parameters have remained bounding during the history of the plant, thereby enabling the use of a review process rather than reanalysis. However, future reload core designs will require reanalysis of the UFSAR Chapter 15 transients and accidents due to advanced fuel assembly designs, longer fuel cycles, increased steam generator tube plugging, and more efficient core designs. In addition, the need for detailed knowledge of the licensing basis analyses in order to perform accurate and thorough safety reviews necessitates a reanalysis effort to update the 1970s vintage analyses in the UFSAR.

In September 1987 Duke Power submitted topical report DPC-NE-3000, "Thermal-Hydraulic Transient Analysis Methodology" (Reference 1-3) to address the requirements of NRC Generic Letter 83-11, "Licensee Qualification for Performing Safety Analyses in Support of Licensing Actions" (Reference 1-4). This report describes the transient analysis simulation models and validation analyses for the Oconee, McGuire, and Catawba Nuclear Stations, using the Electric Power Research Institute's (EPRI) RETRAN-02 (Reference 1-5) and VIPRE-01 (Reference 1-6) computer codes. The McGuire/Catawba sections of DPC-NE-3000 received an SER from the NRC in November 1991 (Reference 1-7). The Oconee sections of DPC-NE-3000 received an SER from the NRC in August 1994 (Reference 1-8). Revision 1 to DPC-NE-3000 and its SER are References 1-30 and 1-9. Revision 2 to DPC-NE-3000 and its SER are References 1-31 and 1-32. The application of these models for UFSAR Chapter 15 non-LOCA analyses for McGuire

LIST OF FIGURES (cont'd)

(List of Changes (cont.))

| | | |
|---|---|---|
| 31. | 10-11 | Deleted Section 10.3.4 Offsite Dose Analysis Results |
| 32. | 11-1 | Added centerline fuel melt as a fuel damage criterion for the dropped rod accident |
| 33. | 11-2 | Revised to note that the digital ICS has been installed |
| 34. | 11-2 | Added centerline fuel melt as a fuel damage criterion |
| 35. | 11-6 | Added results of centerline fuel melt analysis |
| 36. | 11-7 | Reference 11-2 updated to Revision 3 |
| 37. | 12-7 | Reference 12-3 updated to Revision 3 |
| 38. | 13-4 | Revised "maximize ECCS injection" to "initiate flow from the High Pressure Injection (HPI) System" |
| 39. | 13-4 | Deleted operator action to manually trip the reactor for SGTR |
| 40. | 13-5 | Revised to state that the cooldown to 450°F occurs after shift changeover is completed (rather than after one RCP per loop is tripped off) |
| 41. | 13-5 | Revised to include steam generator draining as an operator action to be consistent with the preceeding text |
| 42. | 13-6 | Revised to state that the Reactor Protective System is assumed to trip the reactor at 20 minutes (rather than manual trip) |
| 43. | 13-7 | Deleted statement regarding the results of the offsite dose analysis |
| 44. | 14-19 | Deleted Section 14.4.1.3 Offsite Dose Analysis Results, renumbered Section 14.4.1.4 |
| 45. | 14-23 | Reference 14-5 updated to Revision 3 |
| 46. | 14-25 | Added a footnote to Table 14-1 |
| 47. | 14-25 | Corrected some rod ejection analysis results in Table 14-2 |
| 48. | 14-26 | Corrected some rod ejection anlaysis results in Table 14-3 |
| 49. | 14-27 | Corrected some rod ejection analysis results in Table 14-5 and added some details and footnotes for clarity |
| 50. | 15-1 to -43 | Large steam line break with offsite power reanalyzed to not credit main feedwater isolation. New VIPRE model for DNBR analysis described. The entire steam line break section including unrevised pages is included for continuity. The offsite dose analysis results are deleted. |
| 51. | 16-1 to –7 | Small steam line break reanalyzed to not credit main feedwater isolation. The offsite dose acceptance criterion was revised to 10% of 10 CFR Part 100. The offsite dose analysis results are deleted. |

Scram Curve and Worth

The control rods are inserted when the reactor trips. For this analysis, a top-peaked scram curve and a lower bound on the rod insertion time are assumed. These assumptions minimize the post-trip energy addition to the RCS, leading to a greater cooldown. A scram worth is selected which maintains a reactivity margin between the RETRAN-02 and SIMULATE-3P reactivity predictions at the limiting RETRAN statepoint.

Boron Reactivity

[ ]

Differential Boron Worth

A differential boron worth is used to model the reactivity addition from the boron injected by the HPI pumps and the CFTs. A low differential boron worth (% Δk/k/ppm) is conservative in that it will minimize the negative reactivity added by these systems.

15.3.1.1.4 Control, Protection, and Safeguards Systems

Reactor Control

Following the steam line break, the combined effect of decreasing turbine header pressure and T-ave would result in an increase in reactor demand to the high limit. Since a reactor trip will occur within the first few seconds of the accident, it is reasonable to make the simplifying assumption that the control rods are in manual control.

Reactor Trip

An early reactor trip is conservative in that it minimizes the integrated energy transferred into the RCS, leading to a more severe cooldown. Thus, the variable low pressure trip and low RCS pressure trip setpoints are adjusted to ensure an early reactor trip occurs. A lower bound on the delay time for both trip functions is used.

RCS Pressure Control

No credit is taken for pressurizer heater operation. Due to the rapid depressurization of the RCS, the pressurizer sprays, PORV, and safety valves are not actuated.

Pressurizer Level Control

No credit is taken for the automatic operation of makeup and letdown to attempt to maintain pressurizer level. The makeup and letdown flows are assumed to isolate simultaneously and to be balanced prior to isolation. Not taking credit for the makeup and letdown is conservative for the evaluation of minimum DNBR.

Emergency Core Cooling System

Minimum HPI flow is conservative for the steam line break, since the injected borated water from this system helps to prevent or terminate any return-to-power as well as repressurize the RCS. The HPI system is simulated using fill tables that model the A and B HPI pumps injecting through the A train and the C HPI pump injecting through the B train. Sensitivity studies have examined the effect of a failure in the 4160V switchgear or the failure of the EFW control valve to the affected steam generator. For the cases that assume an EFW control valve single failure, three HPI pump minimum flow is credited. Since reverse flow is established in the unaffected loop, the A and B pump flow is injected in the unaffected loop. This maximizes the flowpath the injected boron must take to reach the core inlet, which delays the boron negative reactivity addition. For cases that assume the failure of one of the three available 4160V switchgear, the A train of HPI is assumed to be lost. This results in the C pump injecting through the B train for the first 10 minutes. The C pump injected flow occurs in the unaffected loop to maximize the delay in the boron negative reactivity addition. The presence of any unborated water initially in the HPI piping is modeled. A conservative minimum boron concentration is also assumed.

Similarly, the boron concentration in the CFTs is assumed to be a conservative minimum value. Lower bounds on the initial CFT inventory, pressure and temperature are also assumed. These assumptions will delay CFT injection, minimize the available inventory of borated water and maximize the RCS cooldown.

Main Feedwater System

Since a reactor trip occurs within the first few seconds of the accident, changes in feedwater control over this period of time will have a negligible impact on the accident. Following reactor trip, the ICS rapidly decreases feedwater demand to zero, and then feedwater flow is restored when steam generator level drops below the minimum level control setpoint. With the ICS in manual MFW flow will continue and, assuming no credit for ICS control or operator action, steam generator overfill will occur. The limiting assumption with respect to maximizing the overcooling and reactivity addition has been determined by analysis to be the case with the ICS controlling MFW to the minimum steam generator level setpoint including uncertainty.

Emergency Feedwater System

The three emergency feedwater (EFW) pumps automatically start upon a loss of both main feedwater pumps, and the two motor-driven pumps also start on a low steam generator level. Low main feedwater pump discharge pressure (ATWS Mitigation System Actuation Circuit) can also result in actuation of all three EFW pumps. If the ICS is functioning to throttle MFW flow by controlling on steam generator level, EFW is not modeled. For the cases that assume the ICS does not throttle MFW flow, EFW is actuated when the low MFW pump discharge pressure setpoint plus uncertainty is satisfied. Maximum EFW flow is assumed to maximize the

cooldown. Nominally, the EFW flow is controlled to maintain a minimum steam generator level. The analysis assumes the EFW level control setpoint is higher and includes uncertainty. For the cases assuming a single failure in the EFW System, the EFW control valve to the affected steam generator is assumed to fail full-open. A conservatively low temperature is assumed for the EFW.

Main Steam Line Break Detection and Main Feedwater Isolation Instrumentation

This instrumentation is not credited in the analysis.

Turbine Control

The steam line break causes a rapid decrease in steam generator pressure. Thus, the ICS will attempt to close the turbine control valves in order to restore turbine header pressure to its setpoint. Since steam flow to the turbine is maximized if the turbine control valves remain open, it is conservative to assume that turbine control is in manual.

Turbine Bypass System

The Turbine Bypass System is assumed operable to limit the post-trip pressure in the unaffected steam generator, thereby minimizing the secondary-to-primary heat transfer from the unaffected steam generator to the RCS. This is conservative for maximizing the RCS cooldown.

15.3.1.1.5 With Offsite Power Results

The steam line break with offsite power analysis assumes the ICS controls the post-trip SG level to an uncertainty adjusted setpoint of 100 inches. The single failure is assumed to be a train of Engineered Safety Features that results in only one train of HPI for the first 10 minutes. Table 15-1 gives the sequence of events for this case.

The steam line break initially causes the pressure to decrease in both steam generators (Figure 15-3). Break flowrates (Figure 15-4) for both steam generators rapidly increase. After the turbine stop valves close, break flow from the unaffected steam generator stops. Beyond this point, break flow from the affected steam generator decreases with decreasing pressure, and the unaffected steam generator repressurizes and opens the turbine bypass valves and the first bank of main steam safety valves for a short period of time. The unaffected steam generator gradually

depressurizes due to reverse heat transfer and extraction steam loads. Both steam generators are nearly fully depressurized by the end of the simulation.

The cooldown in the affected loop is initially much more severe than in the unaffected loop, as shown in the cold leg and hot leg temperature responses (Figure 15-5). The cold leg temperature in the unaffected loop increases once the turbine stop valves close. A fairly large ΔT initially develops in the affected loop. The ΔT in the affected loop decreases over the course of the simulation as the RCS is cooled. The unaffected loop ΔT remains fairly small until this loop begins to void and the flow degrades. At about 30 seconds the unaffected loop cold leg temperature exceeds the hot leg temperature. This is the result of reverse heat transfer in the unaffected loop and the beginning of flow degradation in the unaffected loop. At approximately 140 seconds, the unaffected loop hot leg temperature exceeds the unaffected loop cold leg temperature. This is a result of the RCP trip in the unaffected loop at 100 seconds. After the RCPs coast down, the flow reverses in the unaffected loop. Due to flow stagnation and the injection of cold HPI inventory, the unaffected loop cold leg temperature falls below the affected loop cold leg temperature at approximately 170 seconds. The bulk of the RCS has cooled to approximately 270 °F by the end of the simulation.

The total, moderator, Doppler, boron and control rod reactivities are presented in Figure 15-6. The negative reactivity insertion at the beginning of the transient is due to the reactor trip and control rod insertion. The cooldown causes positive reactivity insertion due to the negative moderator and Doppler coefficients. The core returns to a critical condition at approximately 140 seconds. Injected boron from the HPI system and the CFTs reaches the core at approximately 160 seconds. The negative reactivity inserted by the boron returns the core to a subcritical condition by approximately 200 seconds. Subcriticality is maintained for the remainder of the simulation.

The reactor power (Figure 15-7) decreases rapidly on reactor trip. The thermal power generally follows the neutron power response. The fluctuations in the heat flux are caused by flow surges in the core which result from flow degradation due to two-phase conditions in the unaffected loop. A peak return-to-power of 13.09 %FP heat flux occurs at approximately 160 seconds. RCS pressure (Figure 15-8) rapidly decreases until the affected loop and reactor vessel head

begin to saturate at approximately 4 seconds. After this time, RCS pressure continues to decrease for the remainder of the simulation.

Core inlet mass flow (Figure 15-9) initially increases with time following the steam line break. Since the reactor coolant pumps provide essentially constant volumetric flow, the decreasing RCS temperatures initially result in an increase in mass flow. However, as the unaffected loop begins to void and RCP performance degrades as predicted by the RETRAN two-phase pump degradation model, core inlet flow decreases to approximately half of the initial flow. After the RCPs in the unaffected loop are tripped at 100 seconds, the flow oscillations diminish.

15.3.1.2 VIPRE-01 Analysis

15.3.1.2.1 Initial and Boundary Conditions

The RETRAN-02 analyses provide the limiting statepoint core exit pressure, core inlet temperature, core inlet flow rate, and core average heat flux [ ] These boundary conditions are input to VIPRE-01 as steady state boundary conditions.

15.3.1.2.2 Axial and Radial Power Distributions

Axial Power Distributions

[ ]

Radial Power Distributions

The maximum pin radial power peak in the hot assembly is calculated explicitly by SIMULATE. Also, utilizing the hot assembly pin radial power distributions as described in Reference 15-2, the hot assembly pin radial power distributions for the return-to-power situation can be derived. For [ ] For

[ ]

15.3.1.2.3 Flow Correlations

For the steam line break with offsite power case, subcooled and bulk voids are modeled with the [ ] Sensitivity studies have shown that using this combination of void correlations results in an acceptable prediction of DNBR.

15.3.1.2.4 Conservative Factors

Conservative factors described in Reference 15.2 are applied to the [ ] channel VIPRE-01 model. These conservative factors are the hot channel area reduction factors (2% for the hot unit subchannel and 3% for the hot instrumentation subchannel), the engineering hot channel factor ($F_q$) of 1.013, and the core inlet flow maldistribution factor. Based on the vessel model flow test and Oconee core pressure drop measurement, the core inlet flow maldistribution is conservatively modeled as a reduction in the hot assembly flow. Since in the with offsite power RETRAN-02 analysis two RCPs are assumed to trip, the hot assembly flow reduction factor for the VIPRE-01 DNB analysis is therefore [ ] as described in Section 9.3.2.3.

15.3.1.2.5 Critical Heat Flux Correlation

The W-3S CHF correlation is used for the with offsite power steam line break DNBR analysis. The historical range of applicability for the W-3S correlation is (Reference 15-3):

| | |
|---|---|
| Pressure (psia) | 1000 to 2300 |
| Mass flux ($10^6$ lbm/hr-ft$^2$) | 1.0 to 5.0 |
| Quality (equilibrium) | -0.15 to 0.15 |

The W-3S CHF correlation has been approved by the NRC for analysis with system pressures as low as 500 psia and mass flux as low as 0.5 x $10^6$ lbm/hr-ft$^2$ (References 15-9 and 15-10).

15.3.1.2.6 Results

Using the limiting statepoint from the RETRAN-02 analysis discussed in Section 15.3.1.1.5, together with the power distributions discussed in Section 15.3.1.2.2, the VIPRE-01[ ]channel model is used to calculate the core local fluid properties and MDNBR. For the with offsite power analysis the MDNBR predicted by the W-3S CHF correlation is 3.28, which is much greater than 1.45. Therefore, the acceptance criterion discussed in Section 15.1.2, is met.

15.3.1.3 SIMULATE-3P Analysis

The limiting RETRAN statepoint conditions for the steam line break analysis with offsite power are input to SIMULATE-3P. The SIMULATE analysis demonstrates that a reactivity margin is maintained between the RETRAN prediction and the SIMULATE prediction. Therefore, the RETRAN reactivity prediction is conservative. The SIMULATE core power distribution at the limiting RETRAN statepoint (Figure 15-10) is input to VIPRE for the DNBR analysis.

15.3.2 Without Offsite Power

15.3.2.1 <u>RETRAN-02 Analysis</u>

15.3.2.1.1 Initial Conditions

The initial conditions for the steam line break analysis without offsite power are selected to maximize the RCS depressurization and maximize the post-trip core power response. The steam line break analysis without offsite power is very similar to a loss of coolant flow analysis (Chapter 9.0). Thus, sensitivity study results from the loss of coolant flow analysis are utilized to select appropriate initial conditions. The transient RCS conditions for the steam line break without offsite power are within the ranges covered by the statistical core design (SCD) approach. Therefore, the analysis will utilize the SCD approach.

Power Level

Nominal full power will be assumed since the uncertainty in power is accounted for in the SCD limit.

RCS Pressure

Low initial pressure is generally conservative for DNB calculations. The SCD limit accounts for the uncertainty in indicated pressure.

Pressurizer Level

Sensitivity studies have concluded that initial pressurizer level is not an important parameter with respect to DNB for the steam line break with offsite power lost analysis.

RCS Temperature

Nominal RCS average temperature will be assumed. The indication uncertainty and ICS deadband associated with T-ave are accounted for in the SCD limit.

RCS Flow

A low initial flow rate is conservative with respect to DNB calculations. The uncertainty in RCS flow is accounted for in the SCD limit.

Core Bypass Flow

A high core bypass flow is assumed to minimize the coolant flow along the fuel rods.

Fuel Temperature

A high initial fuel temperature is conservative with respect to DNB calculations for loss of flow analyses. Since BOC kinetics parameters are assumed, a maximum BOC fuel temperature is assumed.

Steam Generator Mass

A conservatively high steam generator mass is assumed to maximize the overcooling.

15.3.2.1.2 Boundary Conditions

For a steam line break with coincident loss of offsite power, the reactor will trip and the RCPs will begin to coast down. For this scenario the accident resembles a loss of flow accident with a coincident depressurization. For a loss of flow accident, the minimum DNBR statepoint is expected within the first few seconds of the RCP coastdown. Therefore, detailed modeling of many boundary conditions that would not occur until after the limiting statepoint are unnecessary. The boundary conditions for the steam line break with offsite power lost which differ from the with offsite power case are as follows:

Loss of Offsite Power

The loss of offsite power occurs coincident with the break. The control rods are assumed to lose power coincident with the loss of offsite power. Upon losing power, control rod insertion is delayed to account for gripper coil release delay. The loss of offsite power also initiates a coastdown of the RCPs.

Decay Heat

A decay heat multiplier curve is applied to the 1979 ANS Standard 5.1 decay heat power to ensure that the RETRAN prediction of decay heat is conservatively maximized. Maximum decay heat is conservative for loss of flow DNB analyses.

Single Failure

No single failure could be identified which affects the results.

15.3.2.1.3 Physics Parameters

Moderator Temperature Coefficient

Reactivity insertion curves as a function of temperature are used to model moderator temperature feedback. BOC least negative values are conservative. This assumption minimizes the negative feedback associated with any core moderator heatup that occurs with a loss of flow.

Doppler Temperature Coefficient

Reactivity insertion curves as a function of temperature are used to model Doppler temperature feedback. BOC least negative values are conservative. This assumption minimizes the negative feedback associated with any fuel heatup that occurs with a loss of flow.

Beta-effective and Neutron Lifetime

A large $\beta_{eff}$ and prompt neutron lifetime are chosen to slow the core power decrease on control rod insertion. BOC decay constants and delayed neutron precursor fractions are also utilized.

Scram Curve and Worth

The control rods are inserted when offsite power is lost. For this analysis, a bottom-peaked scram curve and an upper bound on the rod insertion time are assumed. These assumptions maximize the post-trip energy addition, which is conservative for the DNB prediction. A minimum trippable worth (not to exceed a 1% $\Delta$/k subcritical margin), including an allowance for the most reactive rod stuck out of the core, is utilized in the analysis.

15.3.2.1.4 Control, Protection, and Safeguards Systems

Main Feedwater System

On a loss of offsite power, the hotwell pumps and condensate booster pumps will trip, resulting in a trip of the main feedwater pumps on low suction pressure. With the suction head diminishing, the MFW pumps will rapidly coastdown. A maximum coastdown time is assumed for the MFW pumps.

Emergency Feedwater System

The Emergency Feedwater System cannot start and deliver flow in the short duration of this analysis and is not modeled.

Steam Line Break Detection and Mitigation Circuitry

The steam line break detection and mitigation circuitry is not credited in the analysis.

15.3.2.1.5 Results

The steam line break without offsite power case assumes offsite power is lost coincident with the opening of the steam line break. Thus, an RCS flow coastdown also begins with the opening of the break. Table 15-2 gives the sequence of events for this case.

The steam line break initially causes the pressure to decrease in both steam generators (Figure 15-11). Once the turbine stop valves close, the unaffected steam generator repressurizes and opens the turbine bypass valves. The affected steam generator has depressurized to about 400 psig by the end of the simulation. The break flow response is similar to what has been discussed for the with offsite power analysis. The cooldown in the affected loop is much more severe than in the unaffected loop, as shown in the cold leg temperature response (Figure 15-12). The affected loop hot leg temperature is slightly higher than the unaffected loop hot leg temperature due to the outsurge of hot liquid from the pressurizer. The slight increase in hot leg temperatures from 2 to 5 seconds can be attributed to the RCS flow coastdown.

The RCS volumetric flow decreases for the duration of the simulation (Figure 15-13). This is the result of the loss of offsite power. The loss of offsite power also results in control rod insertion, which drives the core kinetics response (Figure 15-14). Due to control rod insertion, the core average fuel temperature begins to decrease. However, due to the relatively slow changes in the moderator and fuel temperatures, and given that the time period of interest for DNB is within the first 1-2 seconds of the flow coastdown, the moderator and Doppler feedback for the offsite power lost analysis are generally negligible.

The reactor power decreases rapidly on reactor trip (Figure 15-15). The core thermal power also decreases after reactor trip, but does not decrease as fast as neutron power. RCS pressure (Figure 15-16) initially decreases due to the effects of the steam line break and control rod insertion. As flow and primary-to-secondary heat transfer begin to degrade, the RCS pressure increases briefly between 2 to 5 seconds. The brief RCS pressure increase is also a result of the closure of the turbine stop valves. After this time, RCS pressure decreases for the remainder of the simulation.

### 15.3.2.2 VIPRE-01 Analysis

#### 15.3.2.2.1 Initial and Boundary Conditions

The RETRAN analyses provide the transient core exit pressure, core inlet temperature, core inlet flow rate, and core average heat flux for both core halves of the split reactor vessel model. For the without offsite power analysis, both core halves have identical transient boundary conditions for the duration of the analysis. These boundary conditions are input to VIPRE as transient forcing functions.

#### 15.3.2.2.2 Axial and Radial Power Distributions

For the SCD statepoint analysis, the axial power distribution is a chopped cosine shape with an axial peak of [ ] peaked at X/L = [ ], and the radial power distribution is the base model radial power distribution with a hot pin radial power of [ ] (Reference 15-3). For the maximum allowable radial peak (MARP) analyses, a set of axial power shapes are analyzed. The magnitude and elevation of the axial shape is varied to cover the full range of shapes resulting from the nuclear design analysis.

#### 15.3.2.2.3 Conservative Factors

Since the SCD methodology is utilized for predicting the DNBR, the SCD limit accounts for most of the uncertainties in key parameters. Based on the vessel model flow tests and Oconee core pressure drop measurement, the core inlet flow maldistribution is conservatively modeled as a reduction in the hot assembly flow. The hot assembly flow reduction factor for four-pump operation is 5%.

#### 15.3.2.2.4 Critical Heat Flux Correlation

The BWC critical heat flux (CHF) correlation is used for the steam line break transient DNBR analysis for the results presented. The range of applicability for the BWC CHF correlation is:

| | |
|---|---|
| Pressure (psia) | 1600 to 2600 |
| Mass flux (Mlbm/hr-sqft) | 0.43 to 3.8 |
| Quality | -0.20 to 0.26 |

The BWC CHF correlation SCD limit for the steam line break transient is determined utilizing the minimum DNBR statepoint boundary conditions described in Section 15.3.2.2.5.

15.3.2.2.5 Results

The transient VIPRE DNBR results are shown in Figure 15-17, with a minimum DNBR of 1.51 at 1.90 seconds. This statepoint is used to determine the SCD limit for the steam line break transient. The MARP results are shown in Figure 15-18.

15.3.2.3 <u>Fuel Pin Census</u>

The MARPs are used for the fuel pin census. When the radial power peak of the fuel pin exceeds the MARP limit during the transient, DNB and cladding failure are assumed to occur. The fuel pin census is performed to determine the number of failed fuel pins during the steam line break accident. The results of the fuel pin census indicate that no peaks exceed the MARP limits, and therefore no cladding failure occurs for the steam line break accident. Based on this result the core will remain intact for effective core cooling.

15.3.3 Without Offsite Power (Using The RETRAN Point and 1-D Kinetics Models)

15.3.3.1 <u>RETRAN-02 Analysis</u>

The large steam line break accident without offsite power case, as described in Section 15.3.2, is simulated using both the RETRAN point kinetics and the RETRAN 1-D kinetics models in a consistent manner in order to demonstrate the 1-D kinetics methodology and to demonstrate the ability to modify reactivity feedback effects and control rod reactivity via cross section adjustments.

For both cases the initial and boundary conditions are as specified in Sections 15.3.2.1.1 and 15.3.2.1.2, respectively, with the following exceptions. In the point kinetics case the minimum control rod worth is allowed to be inserted (as opposed to limiting the inserted worth to not exceed a 1% $\Delta k/k$ subcritical margin). In addition, core power fraction and reactivity weighting are changed to be bottom peaked to be consistent with the power shape that was used to generate

the scram curve used in this model. In the 1-D kinetics case adjustments are made to cross sections to yield the same initial physics parameters (i.e. least negative moderator and Doppler temperature coefficients and the minimum scram worth) assumed in the point kinetics analysis case. The cross sections are generated using a bottom peaked core, thus yielding a conservative bottom peaked scram curve consistent with the point kinetics case. In addition, the cross sections include the effect of the most reactive rod stuck out of the core. A bottom-peaked scram curve and an upper bound on the rod insertion time maximizes the post-trip energy addition, which is conservative for the DNB prediction.

### 15.3.3.2 Results

In general the system thermal-hydraulic response of the 1-D kinetics case is very similar to the system response of the point kinetics case. The small difference in the neutron power shape (which is influenced by the scram curve shape) is attributed to the spatial effect that is captured by the 1-D kinetics model and not by the point kinetics case. The neutron power decreases rapidly on reactor trip (Figure 15-19). The core thermal power also decreases after reactor trip, but does not decrease as fast as neutron power.

The loss of offsite power also results in control rod insertion, which drives the core kinetics response (Figure 15-20). The core reactivity response of the 1-D kinetics case is very similar to the core reactivity response of the point kinetics case except for the scram curve shape as explained above. Due to control rod insertion, the core average fuel temperature begins to decrease. However, due to the relatively slow changes in the moderator and fuel temperatures, and given that the time period of interest for DNB is within the first 1-2 seconds of the flow coastdown, the moderator and Doppler feedback for the without offsite power analysis are generally negligible.

The comparison of the point and 1-D kinetics analyses of the steam line break without offsite power illustrates that the methodology for developing cross sections for the RETRAN 1-D model compares well with the point kinetics model. The spatial effect of control rod insertion as simulated with the 1-D model is well-predicted, while the components of the total reactivity effect are maintained with the cross section adjustments.

## 15.4 Reload Cycle-Specific Evaluation

To verify that the steam line break analysis is being performed conservatively, a reactivity margin which includes the maximum worth stuck rod and a 10% reduction in scram worth will be maintained between the RETRAN model and the SIMULATE-3P model at the limiting RETRAN statepoint for the with offsite power analysis. Each reload cycle also confirms the following core physics parameters are bounded.

- Moderator temperature coefficient (without offsite power)
- Doppler temperature coefficient (with and without offsite power)
- Minimum scram worth curve (without offsite power)
- Differential boron worth (with offsite power)

## 15.5 References


15-1 RETRAN-02: A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI NP-1850-CCM, Revision 4, EPRI, November 1988

15-2 Thermal-Hydraulic Transient Analysis Methodology, DPC-NE-3000, Revision 1, Duke Power Company, July 1987

15-3 VIPRE-01: A Thermal-Hydraulic Code for Reactor Cores, EPRI NP-2511-CCM-A, Revision 3, EPRI, August 1989

15-4 Nuclear Design Methodology Using CASMO-3/SIMULATE-3P, DPC-NE-1004, Duke Power Company, November 1992

15-5 Mass and Energy Release and Containment Response Methodology, DPC-NE-3003, Duke Power Company, August 1993

15-6 BWC Correlation of Critical Heat Flux, BAW-10143P-A, April 1985

15-7 BAW-10199-PA, The BWU Critical Heat Flux Correlations, Addendum 1, September 1996

15-8 Letter, D. E. LaBarge (NRC) to W. R. McCollum (Duke), SER on topical report DPC-NE-3000-PA, Revision 2, October 14, 1998

15-9 Letter, A. S. Thadani (NRC) to W. J. Johnson (Westinghouse), SER on WCAP-9226-P, Reactor Core Response to Excessive Secondary Steam Releases", January 31, 1989

15-10 Letter, T. A. Reed (NRC) to H. B. Tucker (Duke), SER on topical report DPC-NE-3001, November 15, 1991

REVISED

Table 15-1

Sequence of Events

Steam Line Break - With Offsite Power

| Event | Time (sec) |
|---|---|
| Break opens | 0.0 |
| Reactor trip on variable low pressure-temperature | 0.7 |
| Control rod insertion begins | 0.8 |
| Third CBP starts | 1.5 |
| Turbine stop valves closed<br>Control rods fully inserted | 1.8 |
| MSSV opens on unaffected SG | 6.9 |
| HPI actuates | 20.8 |
| MSSV closes on unaffected SG | 26.9 |
| Boron injection from HPI begins | 103.4 |
| CFT injection begins | 131.5 |
| Boron from CFT B starts | 152.0 |
| Boron from CFT A starts | 157.2 |
| Peak return-to-power occurs | 160.0 |
| Simulation ends | 600.0 |

Table 15-2

Sequence of Events

Steam Line Break - Without Offsite Power

| Event | Time (sec) |
|---|---|
| Break Opens, LOOP Occurs | 0.0 |
| RCPs Begin Coastdown | |
| Condensate Booster and D Heater Drain Pumps Begin Coastdown | |
| MFW Pumps Begin Coastdown | |
| Control Rod Insertion Begins | 0.14 |
| Turbine Stop Valves Closed | 1.76 |
| Control Rods Fully Inserted | 2.54 |
| MFW Pumps Stop | 5.0 |
| Condensate Booster and D Heater Drain Pumps Stop | 10.0 |
| Simulation Ends | 10.1 |

Table 15-3

Sequence of Events

Steam Line Break - Without Offsite Power (1-D Kinetics)

| Event | Time (sec) |
|---|---|
| Break Opens, LOOP Occurs | 0.0 |
| RCPs Begin Coastdown | |
| Condensate Booster and D Heater Drain Pumps Begin Coastdown | |
| MFW Pumps Begin Coastdown | |
| Control Rod Insertion Begins | 0.14 |
| Turbine Stop Valves Closed | 1.72 |
| Control Rods Fully Inserted | 2.54 |
| MFW Pumps Stop | 5.0 |
| Condensate Booster and D Heater Drain Pumps Stop | 10.0 |
| Simulation Ends | 10.1 |

Figure 15-1
Large Steam Line Break
[ ] Channel VIPRE-01 Model

Figure 15-2
Large Steam Line Break
Split Core Reactor Vessel Model

**REVISED**

Figure 15-3

LARGE STEAM LINE BREAK

WITH OFFSITE POWER

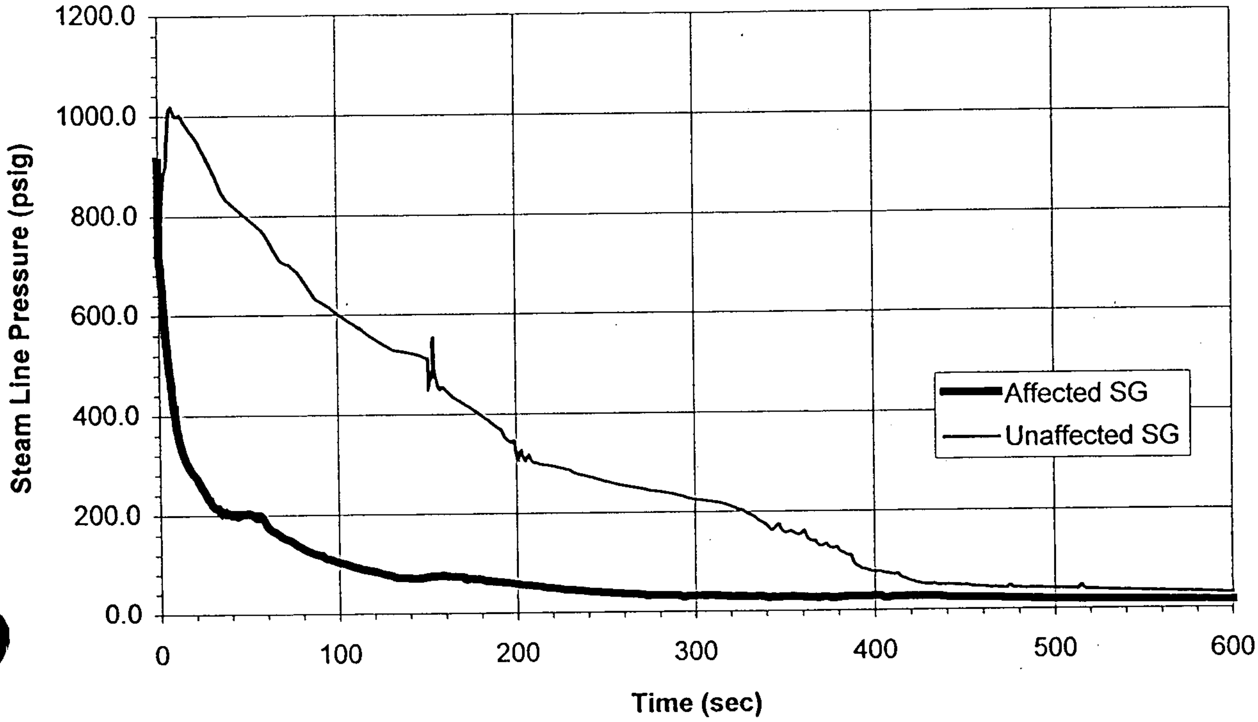
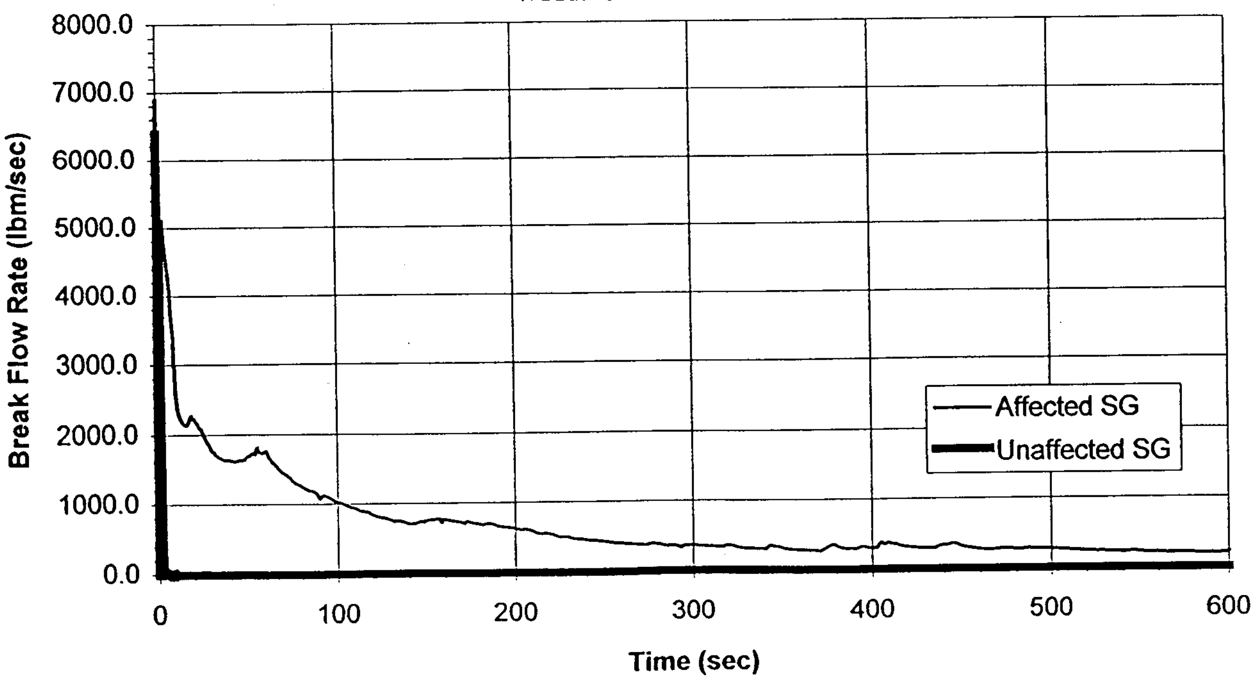



Figure 15-4

LARGE STEAM LINE BREAK

WITH OFFSITE POWER



REVISED

Figure 15-5

LARGE STEAM LINE BREAK

WITH OFFSITE POWER

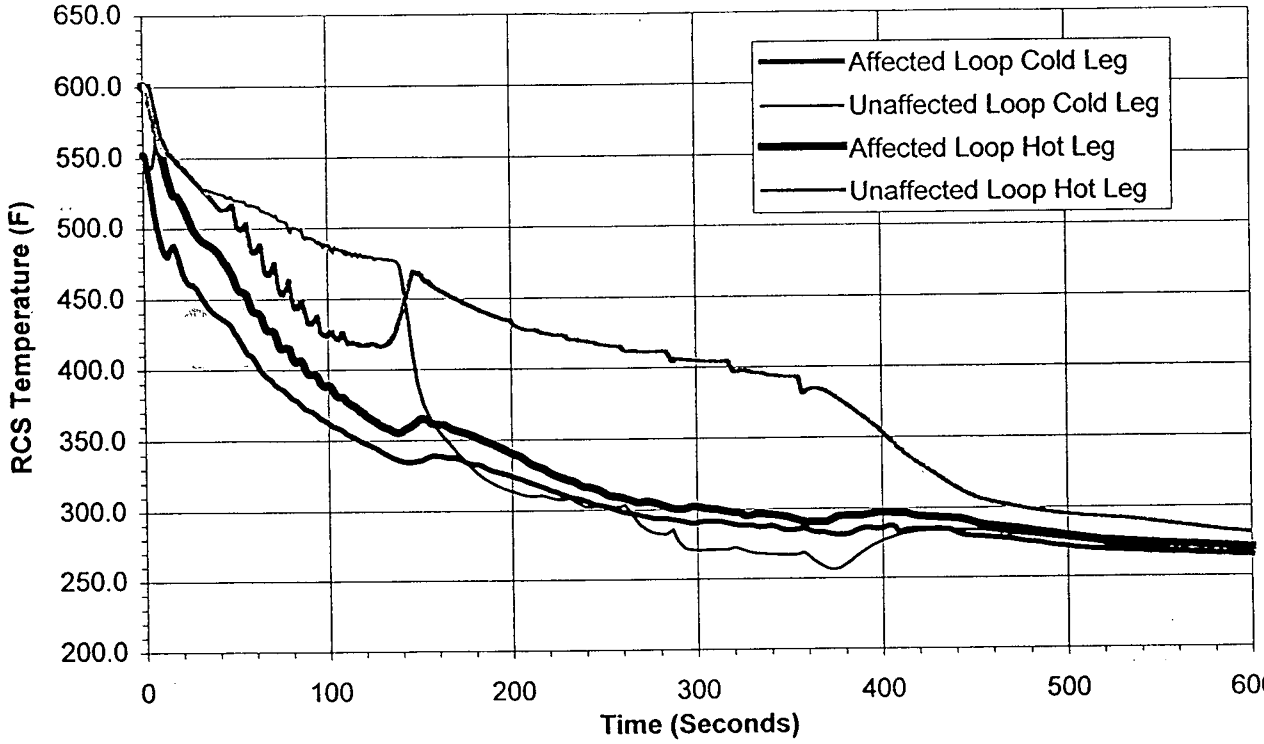
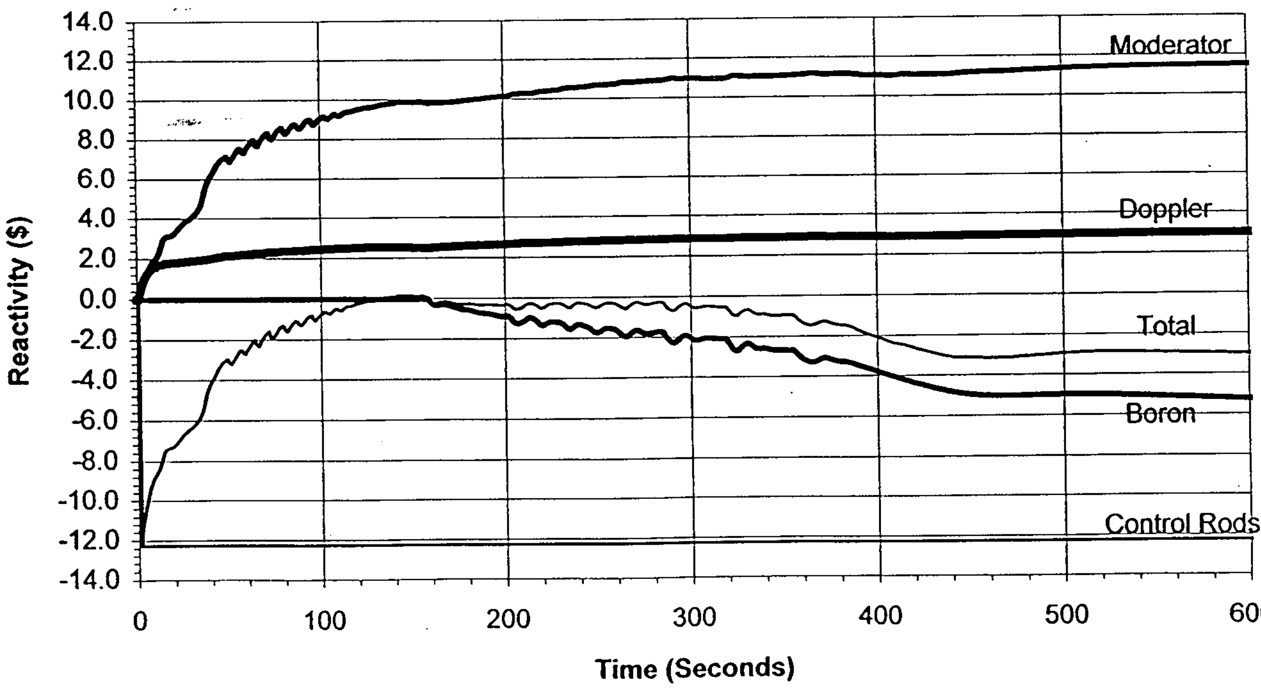



Figure 15-6

LARGE STEAM LINE BREAK

WITH OFFSITE POWER



REVISED

Figure 15-7

LARGE STEAM LINE BREAK

WITH OFFSITE POWER

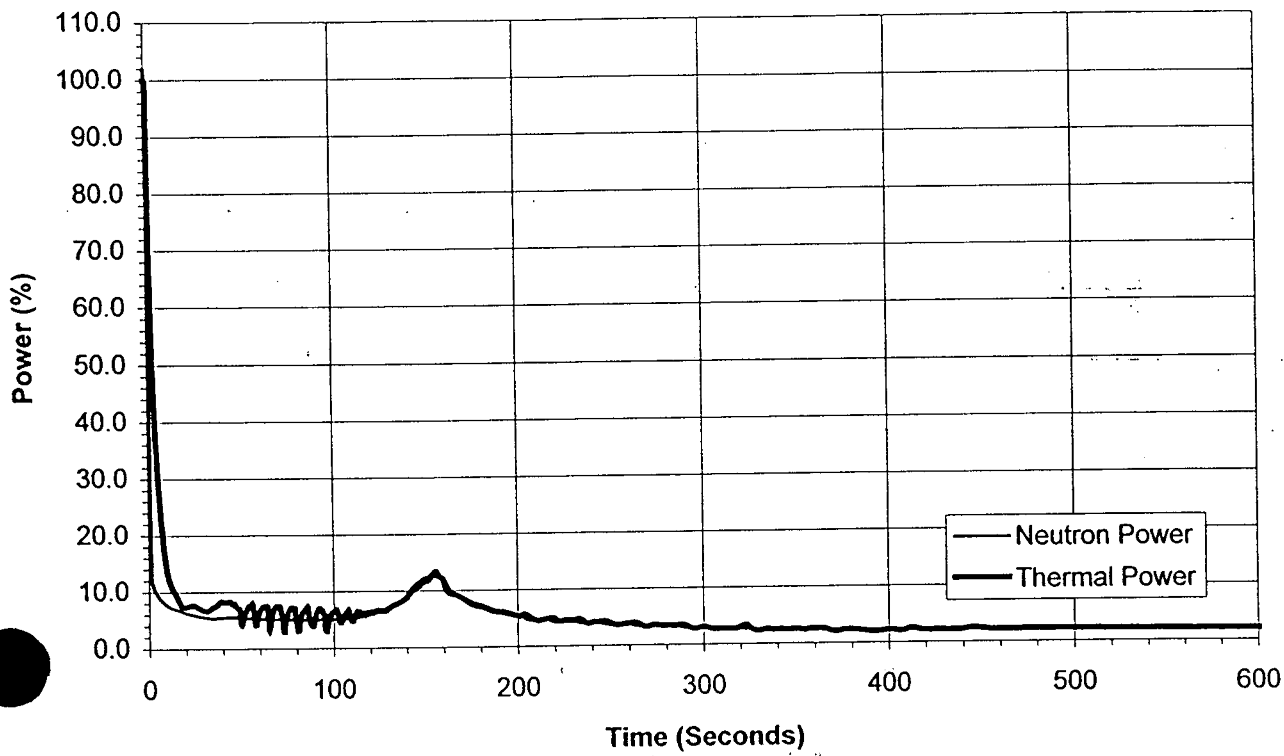
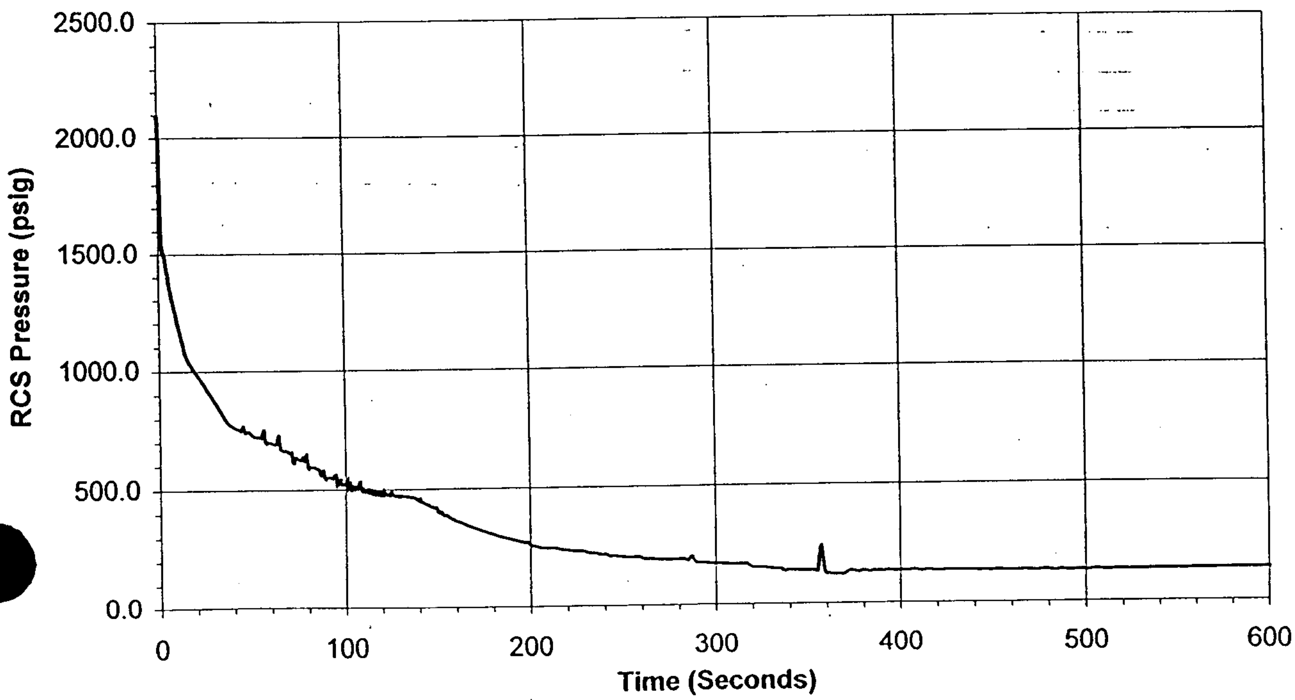



Figure 15-8

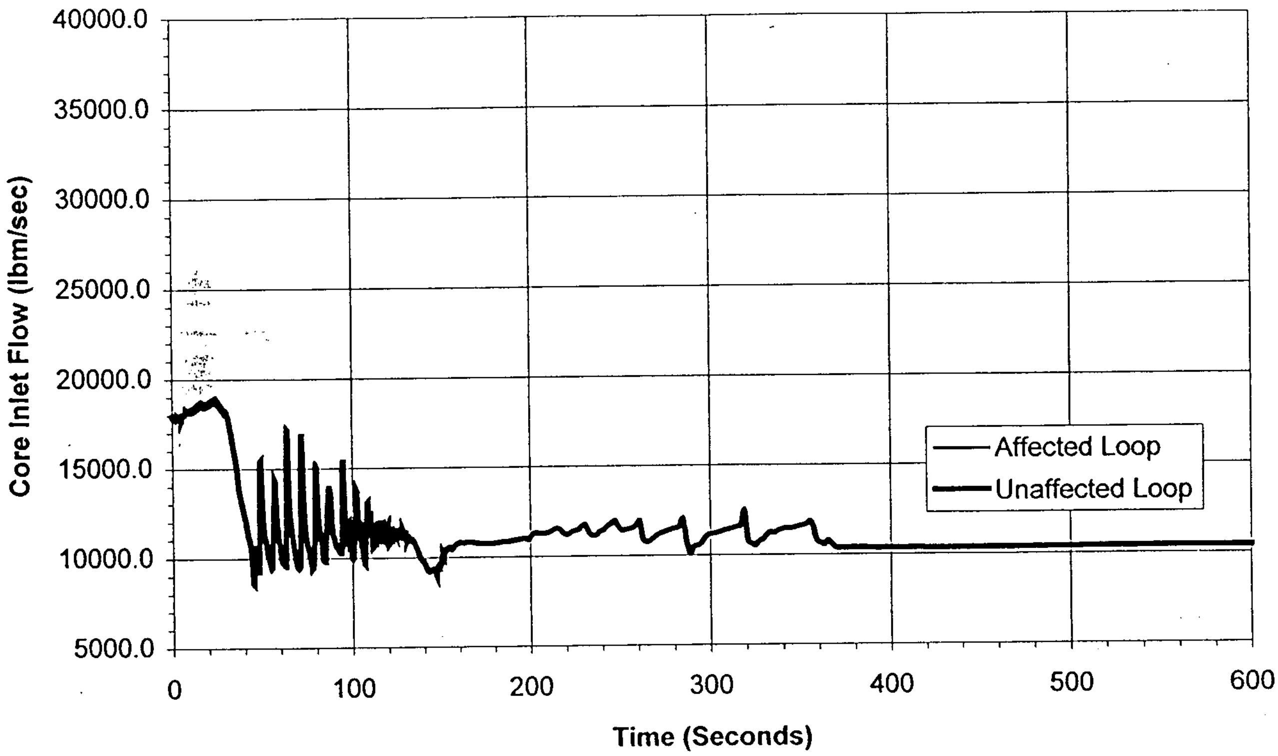
LARGE STEAM LINE BREAK

WITH OFFSITE POWER



REVISED

Figure 15-9
LARGE STEAM LINE BREAK
WITH OFFSITE POWER



Radial Assembly Power Distribution

| ** | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | ** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | | | | | | 0.124 | 0.180 | 0.193 | 0.202 | 0.150 | | | | | | A |
| B | | | | 0.201 | 0.249 | 0.290 | 0.521 | 0.327 | 0.597 | 0.368 | 0.347 | 0.300 | | | | B |
| C | | | 0.284 | 0.617 | 0.413 | 0.681 | 0.404 | 0.610 | 0.480 | 0.903 | 0.593 | 0.942 | 0.452 | | | C |
| D | | 0.201 | 0.616 | 0.460 | 0.765 | 0.664 | 0.662 | 0.351 | 0.817 | 0.915 | 1.140 | 0.735 | 1.027 | 0.346 | | D |
| E | | 0.249 | 0.413 | 0.765 | 0.470 | 0.667 | 0.354 | 0.425 | 0.451 | 0.969 | 0.758 | 1.323 | 0.745 | 0.465 | | E |
| F | 0.124 | 0.290 | 0.682 | 0.665 | 0.667 | 0.295 | 0.443 | 0.291 | 0.592 | 0.472 | 1.192 | 1.262 | 1.357 | 0.615 | 0.277 | F |
| G | 0.180 | 0.521 | 0.405 | 0.662 | 0.354 | 0.443 | 0.253 | 0.340 | 0.369 | 0.805 | 0.720 | 1.431 | 0.928 | 1.248 | 0.443 | G |
| H | 0.194 | 0.327 | 0.611 | 0.351 | 0.425 | 0.291 | 0.340 | 0.247 | 0.552 | 0.622 | 1.061 | 0.948 | 1.692 | 0.920 | 0.547 | H |
| K | 0.202 | 0.598 | 0.480 | 0.818 | 0.452 | 0.593 | 0.369 | 0.551 | 0.638 | 1.434 | 1.347 | 2.651 | 1.588 | 1.950 | 0.650 | K |
| L | 0.150 | 0.368 | 0.904 | 0.916 | 0.971 | 0.472 | 0.805 | 0.622 | 1.436 | 1.232 | 3.215 | 3.400 | 3.439 | 1.384 | 0.538 | L |
| M | | 0.348 | 0.595 | 1.142 | 0.759 | 1.193 | 0.721 | 1.062 | 1.348 | 3.218 | 2.824 | 5.266 | 2.825 | 1.596 | | M |
| N | | 0.300 | 0.944 | 0.736 | 1.324 | 1.263 | 1.433 | 0.948 | 2.652 | 3.402 | 5.270 | 5.505 | 5.369 | 1.585 | | N |
| O | | | 0.453 | 1.028 | 0.745 | 1.359 | 0.929 | 1.693 | 1.589 | 3.441 | 2.827 | 5.374 | 2.547 | | | O |
| P | | | | 0.346 | 0.466 | 0.616 | 1.248 | 0.921 | 1.953 | 1.385 | 1.597 | 1.587 | | | | P |
| R | | | | | | 0.277 | 0.442 | 0.548 | 0.652 | 0.539 | | | | | | R |
| ** | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | ** |

Peak Pin Power Distribution

| ** | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | ** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | | | | | | 0.259 | 0.294 | 0.310 | 0.330 | 0.306 | | | | | | A |
| B | | | | 0.360 | 0.386 | 0.527 | 0.610 | 0.504 | 0.725 | 0.652 | 0.532 | 0.538 | | | | B |
| C | | | 0.484 | 0.737 | 0.683 | 0.797 | 0.609 | 0.673 | 0.782 | 1.093 | 0.961 | 1.122 | 0.771 | | | C |
| D | | 0.360 | 0.736 | 0.614 | 0.847 | 0.723 | 0.767 | 0.518 | 1.002 | 1.012 | 1.256 | 0.985 | 1.230 | 0.619 | | D |
| E | | 0.386 | 0.683 | 0.847 | 0.646 | 0.780 | 0.582 | 0.498 | 0.779 | 1.133 | 1.132 | 1.491 | 1.263 | 0.747 | | E |
| F | 0.259 | 0.527 | 0.798 | 0.723 | 0.780 | 0.452 | 0.503 | 0.429 | 0.705 | 0.728 | 1.427 | 1.389 | 1.564 | 1.146 | 0.596 | F |
| G | 0.293 | 0.611 | 0.609 | 0.768 | 0.582 | 0.502 | 0.362 | 0.400 | 0.575 | 0.919 | 1.140 | 1.586 | 1.257 | 1.481 | 0.731 | G |
| H | 0.316 | 0.506 | 0.674 | 0.516 | 0.499 | 0.427 | 0.394 | 0.427 | 0.797 | 1.076 | 1.439 | 1.560 | 1.981 | 1.524 | 0.943 | H |
| K | 0.331 | 0.727 | 0.783 | 1.003 | 0.780 | 0.707 | 0.573 | 0.785 | 1.182 | 2.010 | 2.596 | 3.438 | 2.752 | 2.541 | 1.075 | K |
| L | 0.307 | 0.654 | 1.095 | 1.014 | 1.136 | 0.728 | 0.920 | 1.070 | 2.014 | 2.219 | 4.301 | 4.022 | 4.513 | 2.474 | 1.047 | L |
| M | | 0.533 | 0.962 | 1.258 | 1.127 | 1.428 | 1.142 | 1.440 | 2.596 | 4.307 | 4.707 | 6.057 | 5.092 | 2.719 | | M |
| N | | 0.539 | 1.125 | 0.986 | 1.492 | 1.391 | 1.589 | 1.553 | 3.439 | 4.024 | 6.065 | 6.029 | 6.695 | 2.883 | | N |
| O | | | 0.772 | 1.231 | 1.264 | 1.566 | 1.259 | 1.981 | 2.753 | 4.515 | 5.097 | 6.699 | 4.595 | | | O |
| P | | | | 0.620 | 0.748 | 1.147 | 1.481 | 1.531 | 2.542 | 2.475 | 2.721 | 2.886 | | | | P |
| R | | | | | | 0.596 | 0.730 | 0.963 | 1.077 | 1.049 | | | | | | R |
| ** | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | ** |

Figure 15-10
LARGE STEAM LINE BREAK
WITH OFFSITE POWER
Core Power Distribution

Figure 15-11
LARGE STEAM LINE BREAK
WITHOUT OFFSITE POWER

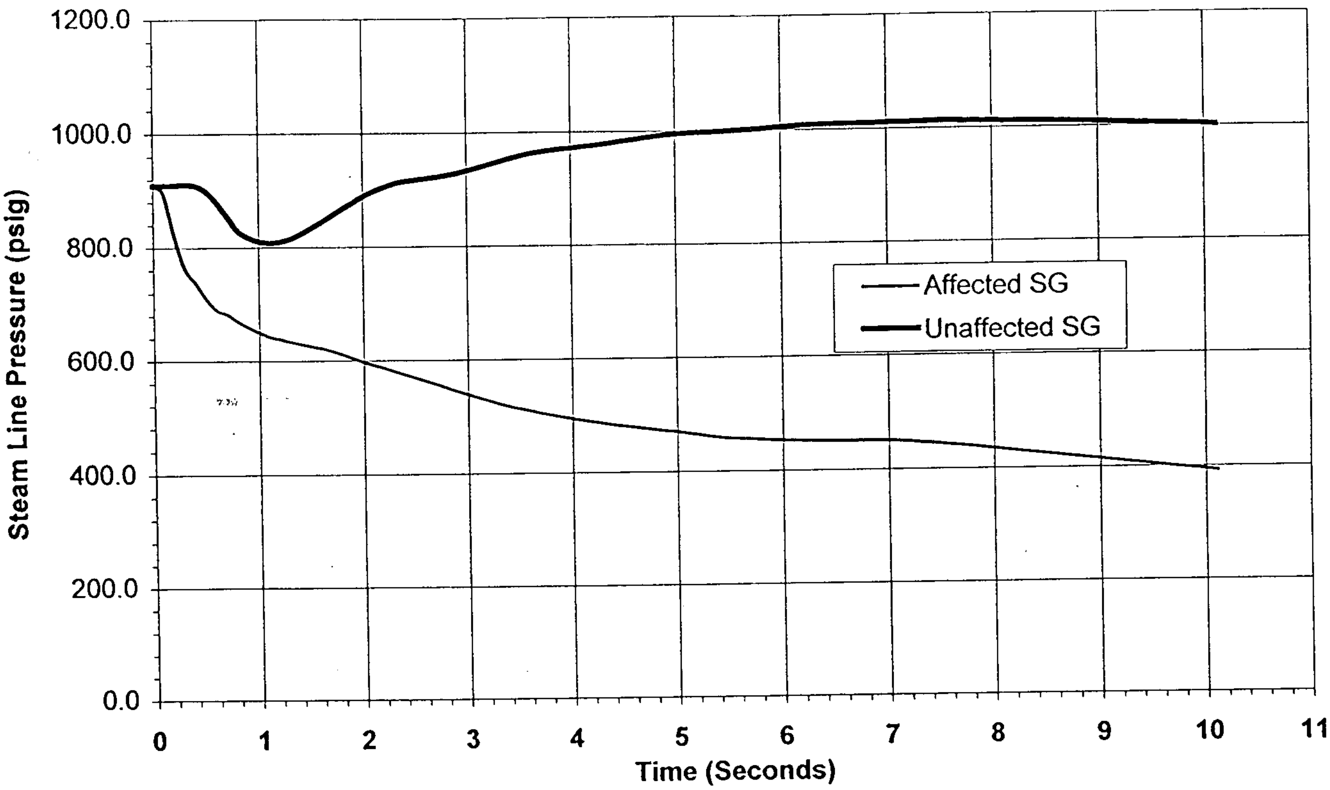



Figure 15-12
LARGE STEAM LINE BREAK
WITHOUT OFFSITE POWER

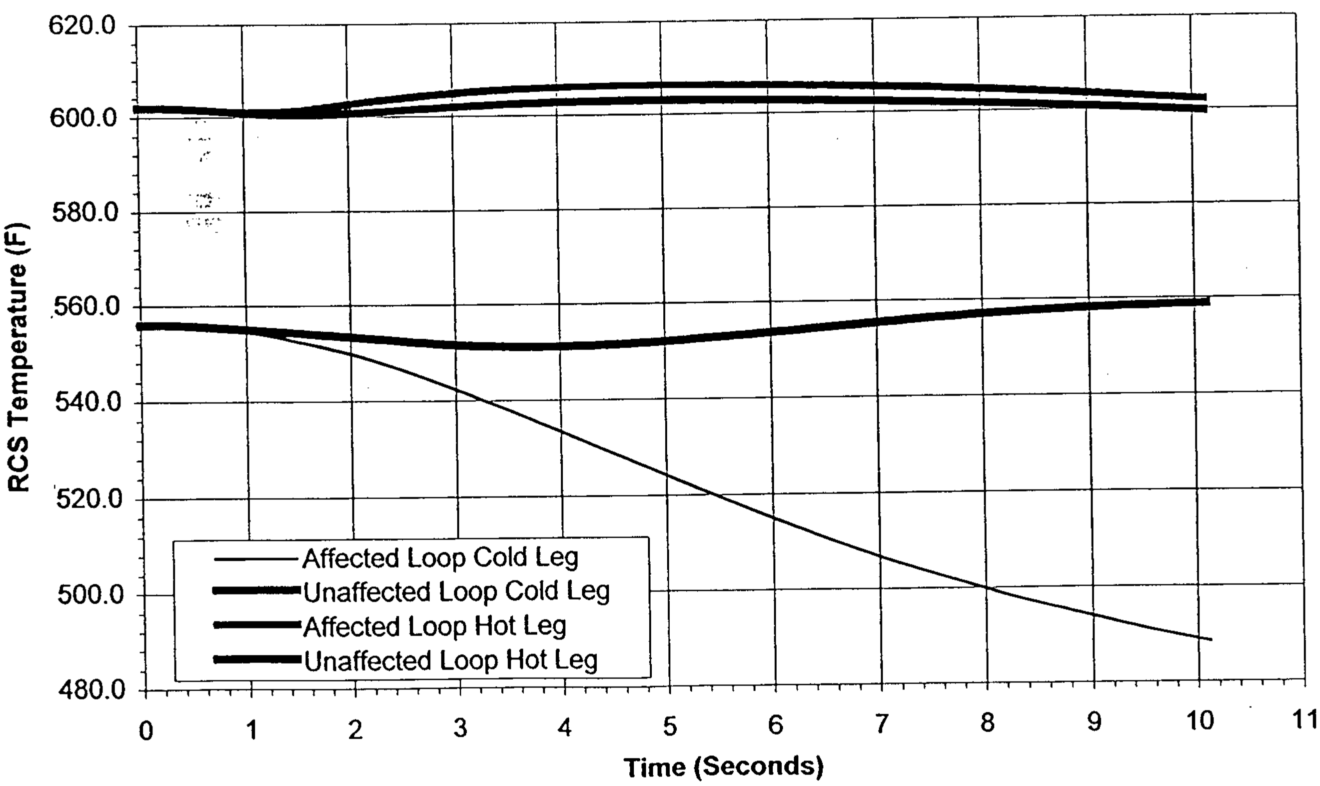


Figure 15-13

# LARGE STEAM LINE BREAK

WITHOUT OFFSITE POWER

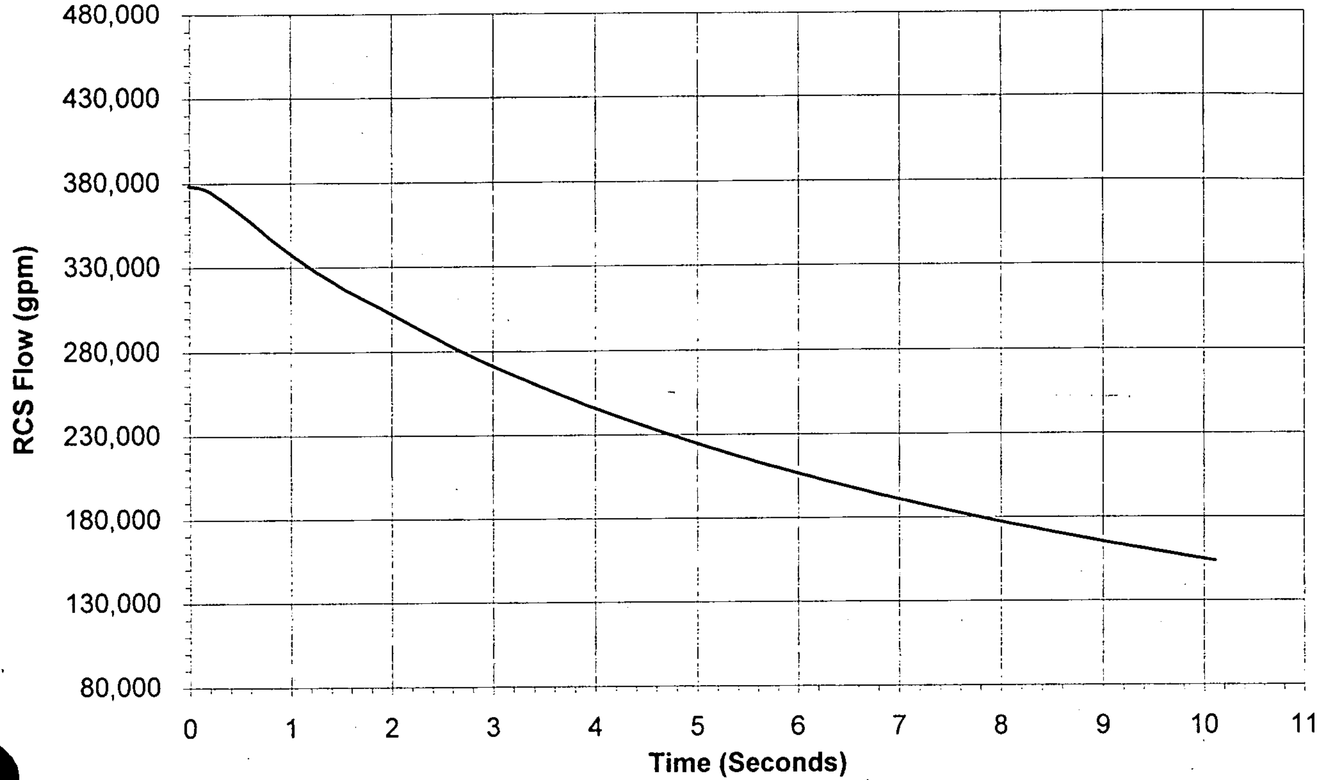



Figure 15-14

# LARGE STEAM LINE BREAK

WITHOUT OFFSITE POWER

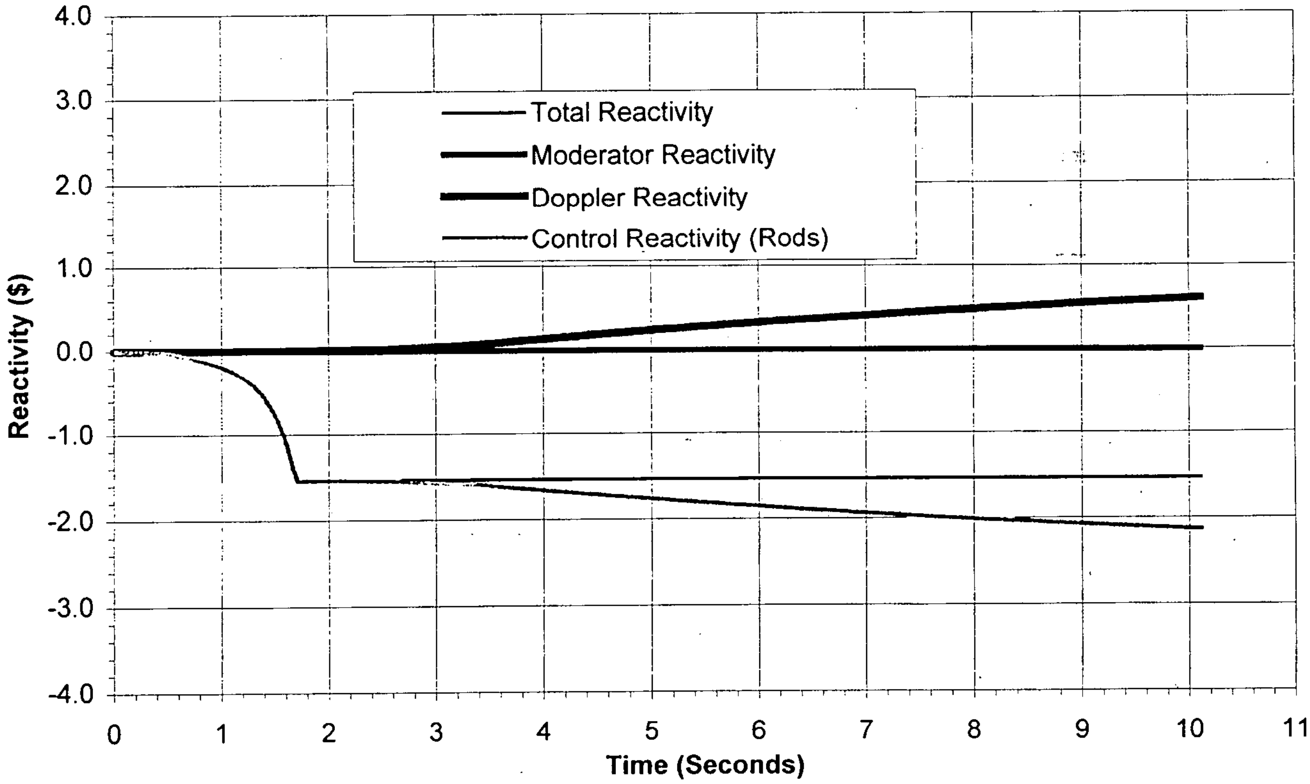


Figure 15-15

LARGE STEAM LINE BREAK

WITHOUT OFFSITE POWER

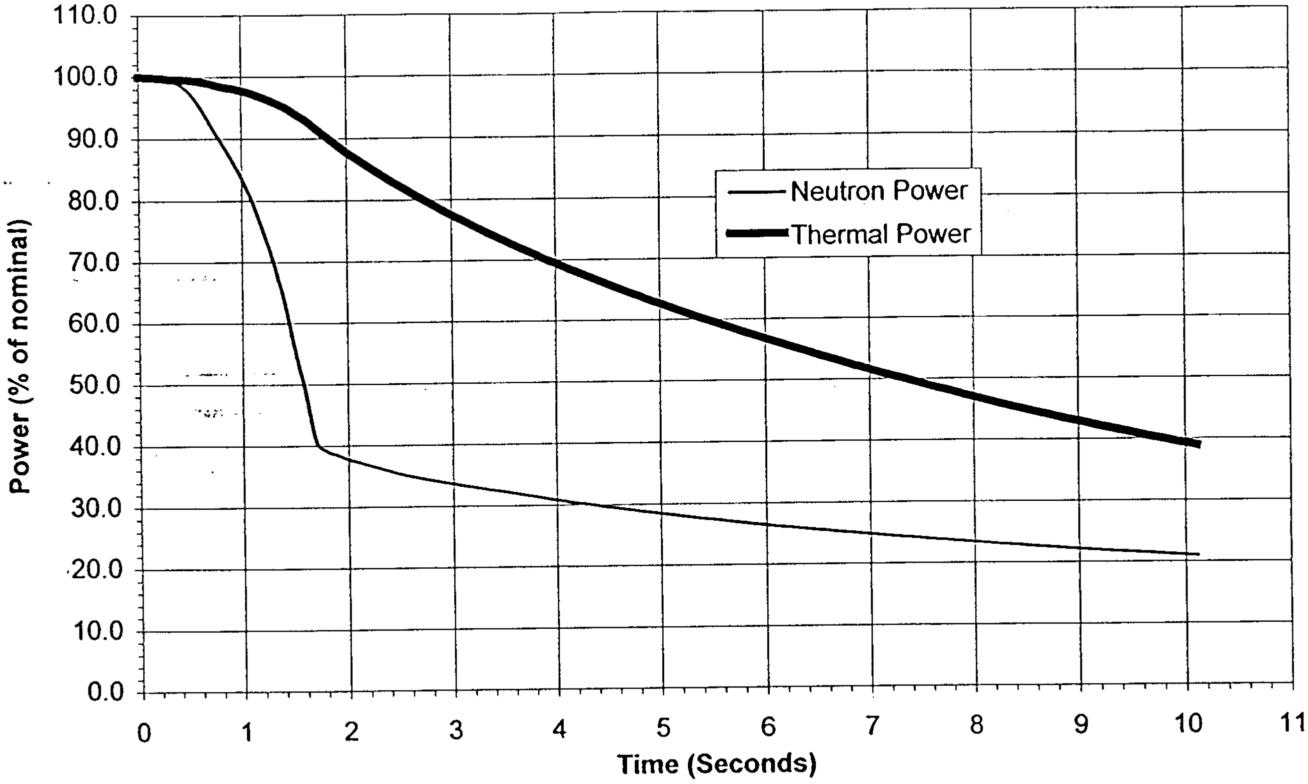



Figure 15-16

LARGE STEAM LINE BREAK

WITHOUT OFFSITE POWER

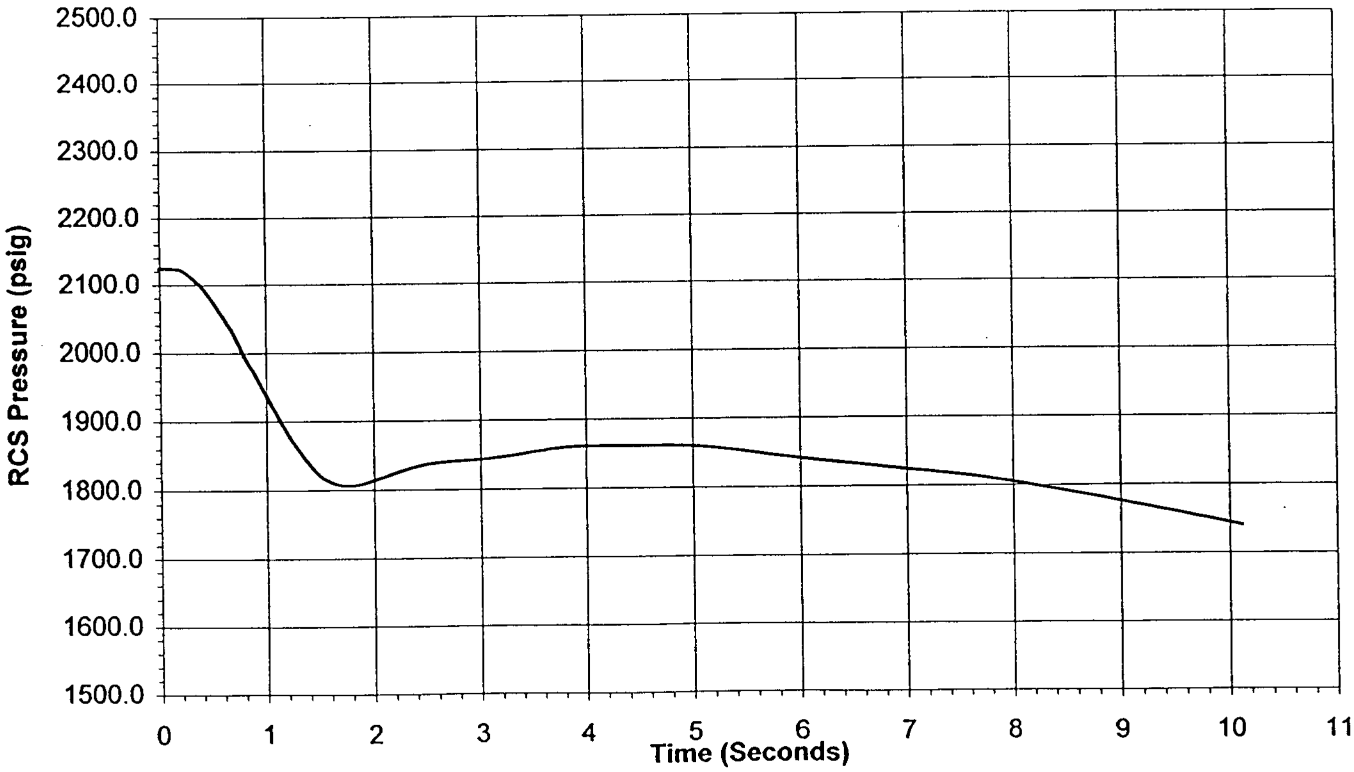


Figure 15-17
LARGE STEAM LINE BREAK
WITHOUT OFFSITE POWER

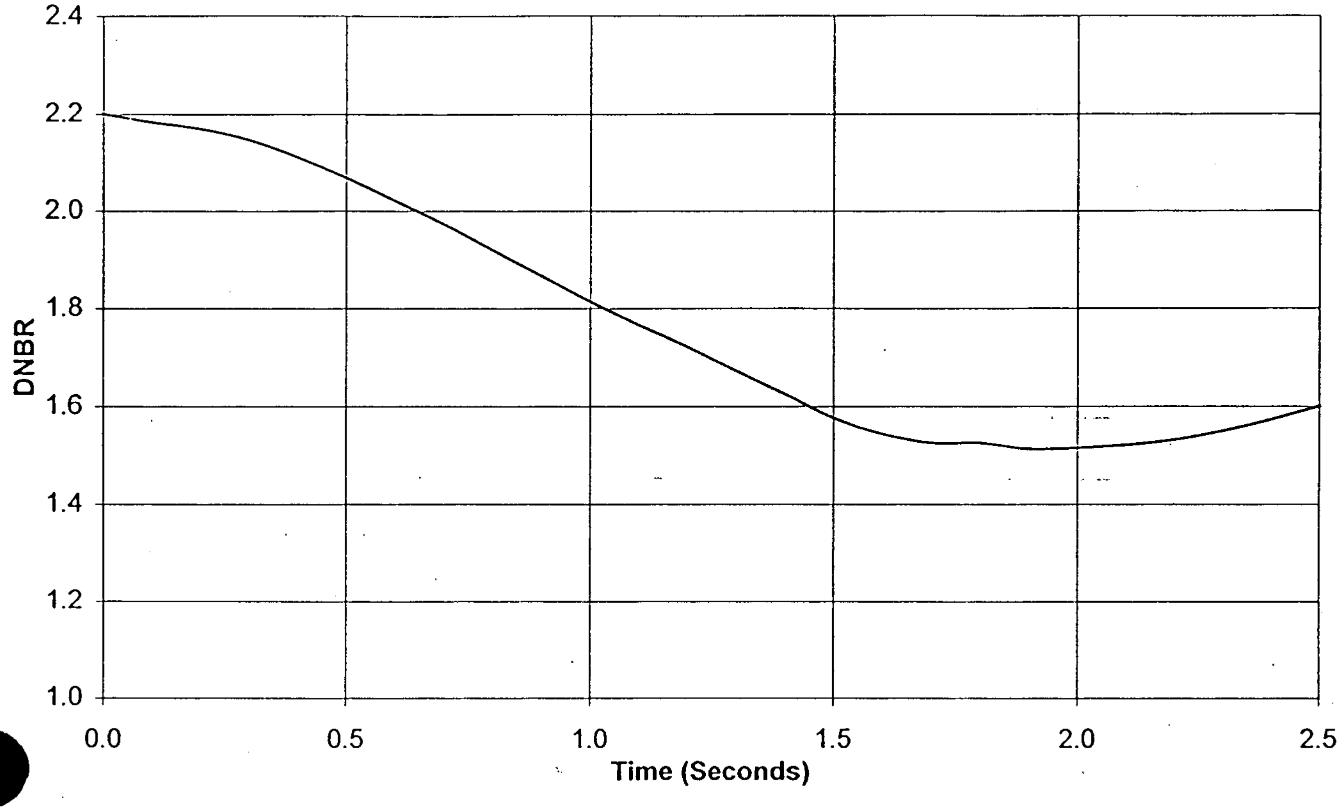



Figure 15-18
LARGE STEAM LINE BREAK
WITHOUT OFFSITE POWER

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Figure 15-19
LARGE STEAM LINE BREAK
WITHOUT OFFSITE POWER

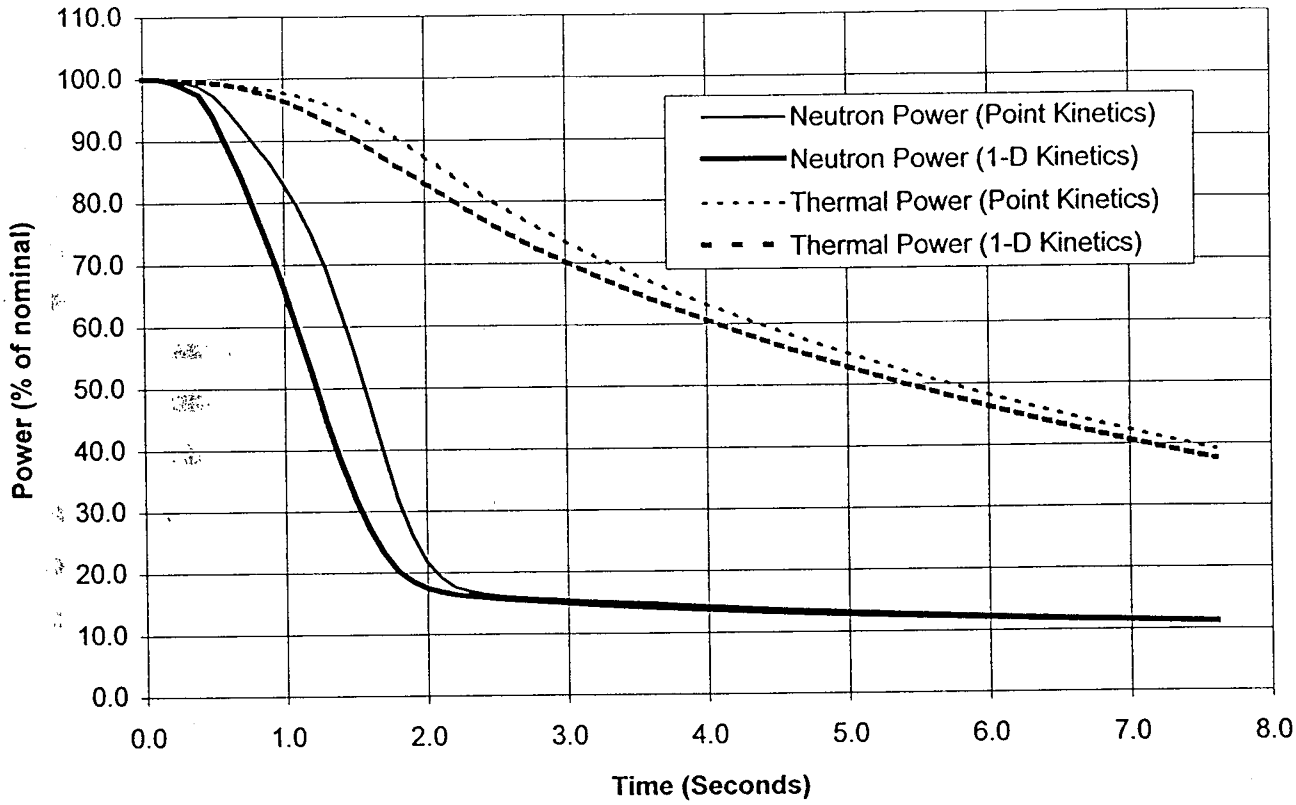
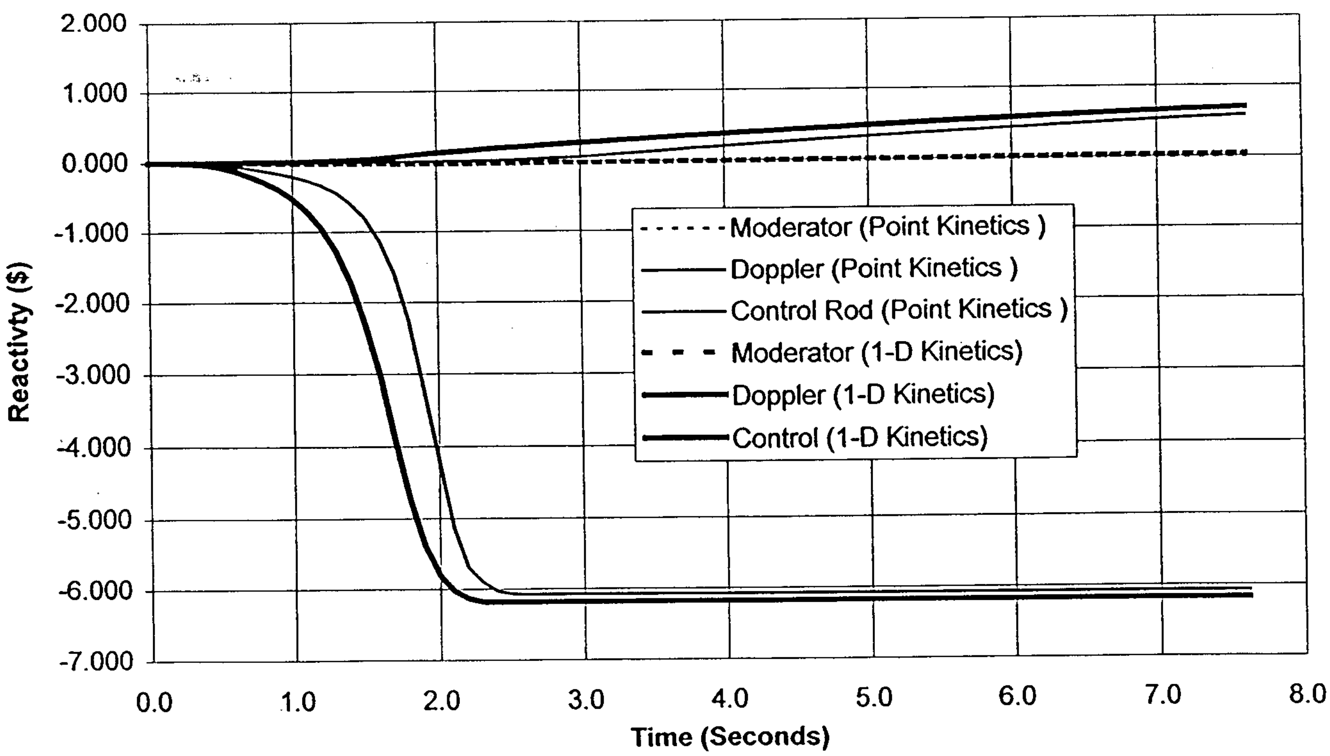



Figure 15-20
LARGE STEAM LINE BREAK
WITHOUT OFFSITE POWER



## 16.0 SMALL STEAM LINE BREAK

A small steam line break can be initiated by either a control system failure in which valves in the main steam line fail open or a mechanical failure of the steam line piping itself. Regardless of which type of failure occurs, the increased steam flow will cause both steam generators to depressurize until they are separated by turbine stop valve closure on turbine trip. The transient response is an overcooling event that results in an increase in power level. The system response is determined by the break size, the moderator temperature coefficient, and the Integrated Control System (ICS) assumption (manual or automatic). The most adverse combination of these conditions is analyzed to determine the worst RCS overcooling and power excursion, which should be the limiting case for DNB and centerline fuel melt (CFM). The limiting cases do not result in a reactor trip due to the reduction in reactor vessel downcomer temperature affecting the excore flux channels. Without a reactor trip a new steady-state condition at an elevated power level will result. The system response is simulated with RETRAN-02 (Reference 16-1). Both full power four-pump and part-power three-pump cases are analyzed. The RETRAN analysis provides the input for the DNB and CFM analyses.

The acceptance criteria for this analysis are to ensure that acceptable fuel damage limits are not exceeded, and that the offsite doses will be within 10% of the 10CFR100 limits. The fuel damage evaluation includes both DNB and CFM. The minimum DNBR is determined using the Statistical Core Design (SCD) methodology and the VIPRE-01 core thermal-hydraulic code (Reference 16-2).

### 16.1 RETRAN-02 Analysis

#### 16.1.1 Nodalization

For the four-pump operating condition, the system response is symmetric and can be analyzed using either the single-loop or two-loop RETRAN-02 Oconee base model (Reference 16-3). The three-pump operating condition is asymmetric and requires the use of the two-loop RETRAN-02 Oconee base model. A steam chest junction is added to the two-loop base model to connect the steam lines upstream of the turbine for modeling the simultaneous depressurization of both generators prior to turbine trip. This junction closes on turbine trip when the turbine stop valves

close. [

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### 16.1.2 Initial Conditions

Power Level

A high initial power level for four- and three-pump operation maximizes the primary system heat flux. The uncertainty for this parameter is incorporated in the SCD limit.

RCS Pressure

Low initial RCS pressure is conservative. The uncertainty for this parameter is incorporated in the SCD limit.

Pressurizer Level

Sensitivity cases are performed to ensure that a conservative pressurizer level is assumed for the conditions analyzed.

RCS Temperature

High initial average temperature is conservative with the uncertainty for this parameter incorporated in the SCD limit.

RCS Flow

Low initial flow is conservative. The uncertainty associated with this parameter is incorporated in the SCD limit.

Core Bypass Flow

A high core bypass flow is assumed to minimize the coolant flow along the fuel rods.

Fuel Temperature

A low initial fuel temperature will result in a higher gap conductivity which will result in a higher heat flux. Maximizing heat flux is conservative for both DNB and CFM.

Steam Generator Mass

A low initial steam generator mass is assumed to allow more cold MFW to enter the generators thereby maximizing RCS overcooling.

Steam Generator Tube Plugging

Low steam generator tube plugging is assumed to maximize primary-to-secondary heat transfer.

### 16.1.3 Boundary Conditions

Break Size

A range of break sizes is analyzed in combination with a range of moderator temperature coefficients to determine the most severe RCS overcooling transient which does not result in a reactor trip. This set of analyses will determine the limiting cases for DNB and CFM.

Excore Flux Detector Error Due To Overcooling

As the steam generators depressurize, the saturation temperature decreases and causes excessive primary-to-secondary heat transfer. The resulting decrease in cold leg temperature upon entering the reactor vessel downcomer attenuates the neutron flux leakage exiting the reactor. This attenuation effect reduces the flux incident on the excore neutron detectors, thereby creating an error in the indicated flux value (indicated excore detector power less than true reactor power). A conservative attenuation factor is assumed as a function of the change in reactor vessel downcomer temperature.

Pressurizer Inter-Region Heat Transfer Coefficient

Sensitivity cases are performed to ensure that a conservative inter-region heat transfer coefficient is assumed for the conditions analyzed.

Single Failure

No single failure has been identified which adversely affects this transient.

### 16.1.4 Physics Parameters

Moderator Temperature Coefficient

A full range of moderator temperature coefficients are considered from the BOC most positive value to the EOC most negative value.

Doppler Temperature Coefficient

The EOC least negative Doppler temperature coefficient value is assumed. This conservatively minimizes the negative reactivity feedback resulting from the fuel heatup during the power increase.

Beta-Effective and Neutron Lifetime

$\beta_{eff}$ affects both the moderator and Doppler reactivity feedback during the transient. However, since the moderator temperature coefficient assumption is variable, $\beta_{eff}$ is conservatively chosen to minimize the Doppler feedback. Thus, an EOC maximum value is assumed. The prompt neutron lifetime associated with the maximum $\beta_{eff}$ value is assumed. The delayed neutron fractions and decay constants are insensitive parameters. Therefore, typical EOC values are used.

Scram Curve and Worth

Since the critical point of this transient occurs during steady-state operation at elevated power levels, the scram curve and worth are unimportant.

### 16.1.5 Control, Protection, and Safeguards Systems

Reactor Control

The reactor control subsystem of the ICS is assumed to be in manual. A power increase would result in the ICS inserting rods to maintain the initial power level, so the ICS is not credited.

Reactor Trip

All RPS trip functions are credited during this transient to identify which analyses do not result in a reactor trip. Conservative trip delay times are assumed. A penalty for a reduction in the excore flux signal due to a decrease in the reactor vessel downcomer temperature is modeled.

RCS Pressure Control

Generally, minimizing RCS pressure is conservative for DNB. However, sensitivity cases on pressurizer heaters and spray are performed to ensure that a conservative result is obtained for the conditions analyzed.

Pressurizer Level Control

Sensitivity cases are performed on net makeup/letdown to ensure that a conservative result is obtained for the conditions analyzed.

Main Feedwater System

The main feedwater subsystem of the ICS is assumed to be in manual control. As the SGs depressurize the feedwater flowrate increases. Also, as steam is lost out the break, there is less steam flow to the turbine, less steam flow to the feedwater heaters, and a reduction in feedwater temperature. These assumptions are conservative for maximizing the overcooling of the RCS and the increase in power level.

Turbine Control

The turbine control subsystem of the ICS is assumed to be in manual. As the steam generators depressurize, the turbine control valves would normally close to raise steam line pressure back to the controlling setpoint. Since it is conservative to maximize the depressurization of the steam generators, the initial turbine control valve position is unchanged for the duration of the transient.

Main Steam Line Break Detection and Main Feedwater Isolation Instrumentation

This instrumentation is not credited in the analysis.

16.2 VIPRE-01 Analysis

The forcing functions necessary to perform the DNB analysis (core average heat flux, core inlet flow and temperature, core exit pressure) are obtained from the RETRAN-02 analysis results and input to VIPRE-01. The VIPRE-01[ ]channel model (Reference 16-3) is then used to determine the time of the minimum DNBR statepoint for the transient conditions analyzed. At these statepoint conditions a set of maximum allowable radial peak (MARP) curves is developed for determining if the DNBR limit is exceeded.

16.3 Results

The peak power levels predicted by RETRAN are 126% for the full power initial condition, and 113% for the three-pump initial condition. These power levels are in excess of the RPS high flux and flux/flow/imbalance trip setpoints due to the attenuation of the flux signal by the cooldown of the reactor vessel downcomer water. The results of the analyses show that the core power peaking and core thermal-hydraulic conditions at these power levels will not exceed the DNB or CFM limits.

16.4 Reload Cycle-Specific Evaluation

Physics parameters that are checked for each reload core include the following:

- Moderator temperature coefficient
- Doppler temperature coefficient
- Maximum allowable radial peak limits
- Centerline fuel melt limits

## 16.5 References

16-1 RETRAN-02: A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI NP-1850-CCM, Revision 4, EPRI, November 1988

16-2 VIPRE-01: A Thermal-Hydraulic Code for Reactor Cores, EPRI NP-2511-CCM-A, Revision 3, EPRI, August 1989

16-3 Thermal-Hydraulic Transient Analysis Methodology, DPC-NE-3000, Duke Power Company, July 1987