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Duke Power Company
McGuire Nuclear Station
Catawba Nuclear Station

UFSAR Chapter 15 System
Transient Analysis Methodology

DPC-NE-3002-A
Revision 3

May 1999

Nuclear Engineering Division
Nuclear Generation Department
Duke Power Company

Mr. Gary R. Peterson
Site Vice President
Catawba Nuclear Station
Duke Energy Corporation
4800 Concord Road
York, South Carolina 29745-9635

SUBJECT: CATAWBA NUCLEAR STATION, UNIT 2 - TOPICAL REPORT DPC-NE-3002-A,
REVISION TO ADDRESS LOSS OF NORMAL FEEDWATER (TAC MA3702)

Dear Mr. Peterson:

The accepted version of Duke Energy Corporation topical report DPC-NE-3002-A, "UFSAR
[Updated Final Safety Analysis Report] Chapter 15 System Transient Analysis Methodology,"
Revision 2, was submitted for docketing by letter, M. S. Tuckman to NRC, February 9, 1998.
By letter dated September 25, 1998, you proposed to revise the methodology in that topical
report to permit use of a single-node model, instead of a multi-node model, to represent the
steam generator secondary system for the post-trip phase of the loss of normal feedwater
analysis for Catawba Unit 2.

The staff has completed its review and finds your proposal acceptable for Catawba Unit 2. This
approval is based on the fact that you use previously accepted methodologies for this analysis,
and the proposed modeling change produces conservative results and maintains adequate
margins. Details are set forth in the enclosed safety evaluation.

In accordance with procedures established in NUREG-0390, we request Duke Energy
Corporation to publish an accepted version of the topical report within 3 months of receipt of
this safety evaluation. The accepted version shall incorporate this letter and the enclosed
safety evaluation. I have discussed with Mr. Greg Swindlehurst this schedule and he agreed
that it is reasonable.

This completes the staff's effort on the above TAC number. Please reference TAC numbers
MA3702, M94405, M94406, M94407, and M94408 when you submit the accepted version of
DPC-NE-3002.

Sincerely,

Peter S. Tam, Senior Project Manager
Project Directorate II-2
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Docket No. 50-414

Enclosure: Safety Evaluation

cc w/encl: See next page

Catawba Nuclear Station

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SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

TOPICAL REPORT DPC-NE-3002-A, REVISION 2

DUKE ENERGY CORPORATION

CATAWBA NUCLEAR STATION, UNIT 2

DOCKET NO. 50-414

1.0 Introduction and Background

The accident and transient analyses in Chapter 15 of the Final Safety Analysis Report (FSAR) for the Catawba Nuclear Station were performed by Westinghouse Electric Corporation. Subsequent to completion of FSAR review, Duke Energy Corporation prepared topical reports detailing accident and transient analyses based on methodologies using industry-based computer codes. Topical Report DPC-NE-3002-A, Revision 2, "FSAR Chapter 15 System Transient Analysis Methodology," dated December 1997 (NRC Accession No. 9802170009), details the analytical methodologies that have been reviewed and approved by the NRC for application to the Catawba and McGuire nuclear stations. Section 3.3 of the report describes, among other things, the methodology to analyze the loss of normal feedwater event (Updated Final Safety Analysis Report (UFSAR), Section 15.2.7). The RETRAN computer code used to perform the analysis has been described in Section 3.2 of Topical Report DPC-NE-3000-PA, "Thermal-Hydraulic Transient Analysis Methodology," dated January 27, 1998 (NRC Accession No. 9802170017).

2.0 Discussion and Evaluation

In a meeting held with the NRC staff during October 7-8, 1991 (documented in a letter, H. B. Tucker to NRC, November 5, 1991), Duke Energy Corporation (DEC) demonstrated that representing the steam generator secondary system as a multi-node model produced conservative results for analysis of the loss of normal feedwater accident under most conditions. However, should there be significant post-trip tube bundle uncovery, the model could predict excessive primary-to-secondary heat transfer. Significant tube bundle uncovery was defined as a reduction of water inventory to less than 10 percent of the full power inventory. Specifically, the use of the multi-node steam generator secondary nodalization resulted in underprediction of the cold leg temperatures, which then produced an underprediction of the bulk average temperature, and pressurizer level and pressure. Using a single-node steam generator secondary nodalization was shown to restore the previously calculated margins. The staff agreed with this noted limitation and approved the model and results since water inventory was not expected to reduce to less than 10 percent of the full power inventory during the loss of normal feedwater event.

Enclosure

Performing Catawba Unit 2-specific analyses recently using the methodology of DPC-NE-3002-A, Revision 2, Duke Energy Corporation has found that the loss of normal feedwater event would result in reduction of the steam generator water inventory to less than 10 percent of the full power inventory. These results are nonconservative with regard to primary-to-secondary heat transfer. Duke Energy Corporation has, by letter dated September 25, 1998, requested revision of the approved methodology to permit use of a single volume steam generator secondary model for the post-trip phase of the loss of normal feedwater analysis. The single volume steam generator secondary model has been reviewed and approved for analysis of the uncontrolled control rod bank withdrawal from a subcritical or low power startup condition (UFSAR, Section 15.4.1).

Accordingly, Duke Energy Corporation proposed to revise Section 3.3.3.1 of DPC-NE-3002-A, adding two sentences as highlighted below, to read

3.3.3.1 Nodalization - since the transient response of the loss of normal feedwater event is the same for all loops, the single-loop model described in Section 3.2 of Reference 2 is utilized for this analysis. For Catawba Unit 2 only, the post-trip phase of the analysis uses a single volume steam generator secondary model. This model uses the bubble rise option with the local-conditions heat transfer model applied to the steam generator tube conductors.

The staff finds the proposal to use a single-node (i.e., single volume) model to represent the steam generator secondary system in the loss of normal feedwater accident for Catawba Nuclear Station, Unit 2, acceptable. This approval is based on the fact that Duke Energy Corporation used previously accepted methodologies for this analysis, and the proposed RETRAN modeling change produces conservative results and maintains adequate margins. The staff also approves the revision of Topical Report DPC-NE-3002-A as cited above.

3.0 Conclusion

Duke Energy Corporation's proposal to use a single-node model to represent the steam generator secondary system for the loss of normal feedwater accident is acceptable. In accordance with procedures established in NUREG-0390, "Topical Report Review Status," the staff requests Duke Energy Corporation to publish an accepted version of the topical report within 3 months of receipt of this safety evaluation. The accepted version shall incorporate this safety evaluation and the associated transmittal letter.

Principal Contributor: Ralph Landry

Date: February 5, 1999

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

April 26, 1996

Mr. M. S. Tuckman
Senior Vice President
Nuclear Generation
Duke Power Company
P. O. Box 1006
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SUBJECT: SAFETY EVALUATION ON CHANGE TO TOPICAL REPORT DPE-NE-3002-A ON
OPENING CHARACTERISTICS OF SAFETY VALVES - CATAWBA NUCLEAR STATION,
UNITS 1 AND 2; AND MCGUIRE NUCLEAR STATION, UNITS 1 AND 2
(TAC NOS. M94405, M94406, M94407, AND M94408)

Dear Mr. Tuckman:

On December 19, 1995 and March 15, 1996 you submitted a proposed change to the
analysis methodology in the Duke Power Company (DPC) Topical Report, DPC-NE-
3002-A, "FSAR Chapter 15 System Transient Analysis Methodology" as applicable
to the Catawba and the McGuire Nuclear Stations. The proposed modeling change
addresses the performance of the pressurizer code safety valves and the main
steam code safety valves (MSSV) by using a pop-open modeling approach rather
than a linear ramping open approach.

The NRC staff's letter dated December 28, 1995 transmitted the staff's Safety
Evaluation for the review of DPC-NE-3002, Revision 1. Accordingly, your
letters dated December 19, 1995 and March 15, 1996 are considered to
constitute Revision 2 to report DPC-NE-3002 as discussed recently with
Mr. Scott Gewehr of your staff.

The staff finds DPC-NE-3002, through Revision 2, to be acceptable for
referencing in Catawba and McGuire licensing applications to the extent
specified and under the limitations stated in DPC-NE-3002, through Revision 2
and the associated NRC Safety Evaluations issued on December 28, 1995 and with
this letter. These Safety Evaluations define the basis for accepting this
Topical Report.

When the Topical Report is referenced in a license application, the staff does
not intend to repeat its review of the matters described in the Topical Report
that were found acceptable, except to ensure that the material presented is
applicable to the specific plant involved. Staff acceptance applies only to
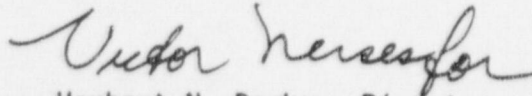the matters described in the report.

In accordance with procedures established in NUREG-0390, DPC must publish
accepted versions of this Topical Report. The accepted versions shall
incorporate this letter and the enclosed Safety Evaluation between the title
page and the abstract. The accepted versions shall include an "A"
(designating accepted) following the Topical Report identification symbol.

Mr. M. S. Tuckman   - 2 -

Should NRC criteria or regulations change so that staff conclusions regarding
the acceptability of the Topical Report are invalidated, DPC will be expected
to revise and resubmit their documentation, or to submit justification for
continued effective applicability of the Topical Report without revision of
their documentation. This completes NRC actions for TAC Nos. M94405, M94406,
M94407, AND M94408.

                              Sincerely,

                              Herbert N. Berkow, Director
                              Project Directorate II-2
                              Division of Reactor Projects - I/II
                              Office of Nuclear Reactor Regulation

Docket Nos. 50-413, 50-414,
            50-369 and 50-370

Enclosure: Safety Evaluation

cc w/encl: See next page

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UNITED STATES

NUCLEAR REGULATORY COMMISSION

WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

DUKE POWER COMPANY

MCGUIRE NUCLEAR STATION

DOCKET NO. 50-369 AND 50-370

CATAWBA NUCLEAR STATION

DOCKET NOS. 50-413 AND 50-414

INTRODUCTION

In its letter of December 19, 1995, Duke Power Company (DPC), licensee for McGuire Nuclear Station, Units 1 and 2, and Catawba Nuclear Station, Units 1 and 2, notified the NRC of a change to an approved analysis methodology for the four nuclear units. DPC submitted additional information in its letter dated March 15, 1996. The change relates to the modeling of accumulation in the lifting of the pressurizer safety valves or the main steam safety valves. These safety valves provide overpressure protection of the primary system. Currently, DPC is involved in steam generator replacements at the McGuire and Catawba stations. During reviews of overpressure protection analyses, DPC identified that increases in the heat transfer area of replacement steam generators result in higher peak secondary pressures following turbine trip. The higher peak pressures would require setpoints of safety valves to be lowered. DPC found, however, that with the change in accumulation modeling, the setpoints of the valves may remain consistent with those setpoints currently in the plant technical specifications.

VALVE INFORMATION

The specific valves are listed below:

McGuire Nuclear Station:

Main Steam Safety Valves

1/2SV 2,3,8,9,14,15,20,21: 6" x 8" Crosby Style HA-65-FN, Built to ASME Section III, 1971 Edition, Winter 1971 Addenda

1/2SV 4,5,6,10,11,12,16,17,18,22,23,24: 6" x 10" Crosby Style HA-65-FN, Built to ASME Section III, 1974 Edition, Winter 1975 Addenda (originally purchased for the Marble Hill Nuclear Plant), and recertified to ASME Section III, 1971 Edition, Winter 1971 Addenda.

ENCLOSURE

2

Pressurizer Safety Valves

Size 6M6 (6" inlet, "M" orifice, 6" outlet) Crosby Style HB-BP-86. Valves originally installed with loop seals, but modified in 1992 to drain the loop seal and modify valve internals for sealing against steam. The valves were built to ASME Section III, 1971 Edition, addenda through the 1972 Addenda.

Catawba Nuclear Station:

Main Steam Safety Valves

Dresser Model 3787, built to ASME Section III, 1974 Edition, Summer 1975 Addenda.

Pressurizer Safety Valves

Dresser Model 31749A, built to ASME Section III, 1974 Edition, Summer 1975 Addenda. These valves do not have loop seals.

MODELING METHODOLOGY

The current Final Safety Analysis Report (FSAR) Chapter 15 analyses that support the McGuire units and the Catawba units are detailed in the topical report DPC-NE-3002-A, "FSAR Chapter 15 System Transient Analysis Methodology." The NRC-approved methodology says that the pressurizer safety valves and the main steam safety valves are modeled with lift, accumulation, and blowdown assumptions which maximize the pressurizer pressure or minimize the secondary (main steam system) pressure. Lift is the actual travel of the valve disc away from the closed position when the valve is relieving. Accumulation is the pressure increase in the system pressure over the actual valve set pressure, frequently referred to as "overpressure," and is usually expressed as a percentage of set pressure. Blowdown is the difference between actual lift pressure of a safety valve and actual reseating pressure, usually expressed as a percentage of set pressure. The requirements of Section III of the American Society of Mechanical Engineers (ASME) *Boiler and Pressure Vessel Code* (the Code), 1971 Edition, and similar in later editions, paragraph NB-7614, gives the operating requirements for Class 1 safety valves (pressurizer safety valves) as follows:

NB-7614.1 Anti-Chattering and Lift Requirements. Safety valves shall be designed and constructed without chattering and to attain full lift at a pressure no greater than 3 percent above their set pressures.

NB-7614.2 Blow Down Requirements. Safety valves shall be set and adjusted to close after blowing down at a pressure not lower than 5 percent of the set pressure. The valves shall be adjusted, sealed and marked by the Manufacturer.

NB-7614.3 Popping-Point Tolerance. The popping-point
tolerance shall not exceed 1 percent, plus or minus, of
the set pressure for pressure over 1000 psi.

The similar design and operating requirements for Class 2 safety valves (main
steam safety valves) given in paragraph NC-7614 are as follows:

NC-7614.1 Lift and Blowdown. Safety valves shall operate
without chattering and to attain full lift at a pressure
no greater than 3 percent above their set pressure. After
blowing down, all valves shall close at pressures not
lower than 95 percent of their set pressures . . .

NC-7614.2 Popping-Pressure Tolerance. (a) The
popping-pressure tolerance (plus or minus) from the set
pressure of safety valves shall not exceed the following:
. . . 1 percent for pressures over 1000 psi.

The approved models assume that lifting of the safety valves is a linear
opening beginning at the setpoint and reaching full open at a pressure
corresponding to the setpoint plus a conservatively assumed accumulation of
one to three percent of the lift pressure setpoint. For example, a
pressurizer safety valve with a setpoint of 2500 psig and three percent
accumulation would reach full open at no higher than 2575 psig. DPC asserts
that the models are conservative, but that the actual valve performance is not
represented. Both sets of safety valves, though different models and
different manufacturer, are best characterized as having a popping-open
response.

MODELING CHANGE

DPC proposes to use a pop-open modeling approach rather than a linear ramping
open approach. The revised modeling assumes that the safety valves pop open
to a full-open position in 0.5 seconds after the drifted lift setpoint is
reached. The assumption is based on testing and a review of tests that DPC
engineering and the valve manufacturers (Crosby and Dresser) conducted.

Pressurizer Safety Valves

The pressurizer safety valves were tested as part of a performance test
program conducted by the Electric Power Research Institute (EPRI) to meet
action item II.D.1, "Performance Testing of Boiling-Water Reactor and
Pressurized-Water Reactor Relief and Safety Valves," of NUREG-0737,
"Clarification of TMI Action Plan Requirements." Multiple tests of Dresser
Model 31709NA and 31739A and Crosby HB-BP-86 6N8 pressurizer safety valves,
varying parameters such as pressurization rate, system media, and ring
settings, indicated opening times of less than 0.1 second. Such a rapid
opening time is characteristic of a popping-open action. The test results
were used by licensees to correlate performance to site-specific similar
valves.

4

Main Steam Safety Valves

DPC tested all of the McGuire Station main steam safety valves at Crosby's high flow test loop to determine unique ring settings for each valve. The tests were to assure blowdown performance within a range less than or equal to ten percent. The test simultaneously recorded (1) inlet pressure, (2) outlet pressure, and (3) spindle position using the Crosby Data Acquisition System. Although determining opening response time was not the purpose of the test, the times were recorded. The opening times ranged from 0.060 second to 0.110 second. Graphs of the opening of several of the valves were included in DPC's letter of March 15, 1996. These graphs show a rapid popping-open action. DPC correlated these tests and the measured opening times with the tests performed by EPRI and concluded that the main steam safety valves would pop open and be fully open within the 0.5 second assumed in the new model for overpressure protection.

The main steam safety valves installed in Catawba Station have not been tested in the same manner as the McGuire Station valves. Therefore, DPC reviewed data for similar valves that were part of the EPRI testing program. Selection of the 0.5 seconds for full opening is over 500 percent slower than the full opening time observed for the pressurizer safety valves. Dresser engineering concurred with the assumption that the Catawba Station Model 3787 main steam safety valves will open in less than 0.5 second.

EVALUATION

Pressure relief valves of various designs can modulate open and closed over the entire or a substantial portion of the lift, or modulate open over only a small portion of the lift and then open suddenly to the fully open position. The pressurizer safety valves and the main steam safety valves installed in the McGuire Station and Catawba Station are of the full-lift type (i.e., they open for a small portion of the lift and then pop open to the full-open position). DPC's determination that the valves will fully open within 0.5 seconds includes conservatism when compared to the test data used to validate the modeling assumption. For safety valve design, the ASME Code, Section III (see above), requires a popping-point tolerance of plus or minus one percent of the setpoint of the valves and requires that the valves be fully open at no greater than three percent above the setpoint.

DPC has demonstrated through testing and correlation of valves not specifically tested that a rapid popping action is characteristic of the valves. For these valves, there will be a short period when the valves first begin to lift where the closing forces are initially greater than the opening forces (i.e., the modulating portion of the lift). As the system pressure continues to act on the disc, the opening forces become greater than the closing forces, and the disc rises sharply. The disc moves to the full open position in a very short period of time, almost instantaneously, by design. Therefore, DPC may use a value of 0.5 second as the time from when the system pressure reaches the setpoint of the valves (adjusted in the model for an assumed drift of three percent) to the full opening and full relieving capacity. In making this change to the model, all requirements of the ASME Code, Section III, must be met.

CONCLUSION

Valve Design Characteristics

An assumption of 0.5 second as the time to reach the full-open position for the pressurizer safety valves and the main steam safety valves is acceptable as it relates to the design characteristics of these valves.

Overpressure Protection Analysis

The licensee stated in its letter dated December 19, 1995, that the proposed change of the safety valve opening characteristics in the methodology for analyzing system transients is needed for McGuire and Catawba plants. The current methodology as documented in DPC-NE-3002-A assumes that the safety valves are opened at their fully open position when the system pressures are corresponding to their lift setpoints plus an accumulation allowance. This is a conservative modeling approach. However, the licensee finds that a change of the safety valve opening characteristics to popping-open of the safety valves at their lift setpoint is needed to accommodate the proposed change of the safety valve allowable setpoint drift and the design of the replacement steam generators at McGuire and Catawba plants. For reasons discussed in the above paragraphs, the staff considers that the proposed change of safety valve opening characteristics in DPC-NE-3002-A is reasonable and acceptable.

Principal Contributor: P. Campbell
                        C. Liang
                        R. Martin

Date: April 26, 1996

December 28, 1995

Mr. M. S. Tuckman
Senior Vice President
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Duke Power Company
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SUBJECT: SAFETY EVALUATION FOR REVISION 1 TO TOPICAL REPORT DPC-NE-3002,
          "FSAR CHAPTER 15 SYSTEM TRANSIENT ANALYSIS METHODOLOGY" MCGUIRE
          NUCLEAR STATION, UNITS 1 AND 2; AND CATAWBA NUCLEAR STATION, UNITS 1
          AND 2 (TAC NOS. M89944, M89945, AND M89946)

Dear Mr. Tuckman:

By letter dated July 18, 1994, Duke Power Company (DPC or licensee) submitted
DPC Topical Report DPC-NE-3002, Revision 1, "FSAR Chapter 15 System Transient
Analysis Methodology," dated June 1994, for NRC review. The report describes
changes to the DPC transient analysis methodology. These changes are due to:
(1) steam generator replacement for the McGuire and Catawba stations, (2)
methodology changes documented in DPC-NE-3000P, Revision 1, and (3) correction
of typographical errors. In the original report, the steam generator tube
rupture (SGTR) transient methodology was not included. However, it has since
been approved and was included in this revision.

The staff finds DPC-NE-3002, Revision 1, to be acceptable for referencing in
McGuire and Catawba licensing applications to the extent specified and under
the limitations stated in DPC-NE-3002, Revision 1, and the associated NRC
Safety Evaluation. The enclosed Safety Evaluation defines the basis for
accepting this Topical Report. The staff was assisted in its review by
International Technical Services (ITS) Inc. The ITS Technical Evaluation
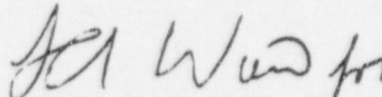Report (TER ITS/NRC/95-5) is also enclosed.

When the Topical Report is referenced in a license application, the staff does
not intend to repeat its review of the matters described in the Topical Report
that were found acceptable, except to ensure that the material presented is
applicable to the specific plant involved. Staff acceptance applies only to
the matters described in the report.

In accordance with procedures established in NUREG-0390, DPC must publish
accepted versions of this Topical Report. The accepted versions shall
incorporate this letter and the enclosed Safety Evaluation between the title
page and the abstract. The accepted versions shall include an -A (designating
accepted) following the Topical Report identification symbol.

Should NRC criteria or regulations change so that staff conclusions regarding the acceptability of the Topical Report are invalidated, DPC will be expected to revise and resubmit their documentation, or to submit justification for continued effective applicability of the Topical Report without revision of their documentation. This completes NRC actions for TAC Nos. M89944, M89945 and M89946.

Sincerely,

Robert E. Martin, Senior Project Manager
Project Directorate II-2
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Docket Nos. 50-369, 50-370
             50-413 and 50-414

Enclosures: 1. Safety Evaluation
             2. Technical Evaluation Report ITS/NRC/95-5

cc w/encls: See next page

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SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

TOPICAL REPORT DPC-NE-3002, REVISION 1, "FSAR CHAPTER 15 SYSTEM

TRANSIENT ANALYSIS METHODOLOGY"

DUKE POWER COMPANY

MCGUIRE NUCLEAR STATION, UNITS 1 AND 2

CATAWBA NUCLEAR STATION, UNITS 1 AND 2

DOCKET NOS. 50-369, 50-370

50-413, AND 50-414

1.0   INTRODUCTION

In Revision 1 of the Topical Report DPC-NE-3002 entitled "FSAR Chapter 15
System Transient Analysis Methodology" dated June 1994 (Reference 1), Duke
Power Company (DPC) documented revisions reflecting changes due to (i)
replacement of steam generators (SGs) for the McGuire Units 1 and 2 and
Catawba Unit 1 stations, and (ii) methodology changes documented in
DPC-NE-3000, Revision 1 (Reference 2). Corrections of typographical errors
were also included. Additional information was provided in Reference 3.

The original Topical Reports DPC-NE-3000 (Reference 4) and DPC-NE-3002
(Reference 5) were reviewed and approved, subject to certain conditions
(References 6 and 7).

Steamline break, rod ejection, dropped rod, and boron dilution events were not
part of this review since these events are documented in DPC-NE-3001
(Reference 8), which has been reviewed and approved.

2.0   REPORT SUMMARY

DPC-NE-3002 (References 1 and 5) contains DPC's qualitative approach to
performance of FSAR Chapter 15 type analysis for the McGuire and Catawba
stations using methodology utilizing the RETRAN and VIPRE-01 computer codes
described in DPC-NE-3000. It does not address justification, qualification,
or demonstration of the approaches taken for the analysis. However, it does
state the process DPC intends to use in determining initial and boundary
conditions, transient assumptions and scenarios, and code models used in
licensing applications for transient analysis.

Revision 1 of DPC-NE-3002 documents changes due to (i) the replacement of
steam generators for McGuire Units 1 and 2 and Catawba Unit 1, and (ii) minor
methodology changes presented in Revision 1 of DPC-NE-3000. Typographical
errors were also corrected. Changes include analysis objectives, pressurizer

and SG models, initial and boundary conditions, transient assumptions in terms of system component availability, and the use of statistical core design (SCD) methodology for DNBR computation.

3.0 EVALUATION

Acceptability of DPC's revisions of RETRAN models and assumptions for thermal-hydraulic calculations of FSAR Chapter 15 transient analysis of its McGuire/Catawba (M/C) plants is discussed below. Only those items which bear analytical or safety significance are discussed. Those items of a non-technical nature are not discussed.

3.1 Changes in McGuire and Catawba RETRAN Methodology

The RETRAN base models for M/C plants were qualified in DPC-NE-3000 and its Revision 1 for both best estimate and licensing-type, non-LOCA applications, subject to limitations described in the Safety Evaluation (SE) (References 6 and 9). Note that DPC's submittal of August 9, 1994, was identified then as Revision 3 to the DPC-NE-3000 report. That submittal has since been renumbered as Revision 1 to the original DPC-NE-3000 report by DPC's letter of September 12, 1995. The approved version of the original DPC-NE-3000 report was issued by DPC on August 8, 1995 (Reference 6). The NRC's SE for Revision 1 to the original DPC-NE-3000 report was issued on December 27, 1995 (Reference 9).

A change which impacted the documentation of DPC-NE-3002 was a change in the pressurizer modeling described in DPC-NE-3000, Revision 1. Thus, all sections that related to the previous modeling description were revised.

Also included in the revision of the RETRAN methodology is modeling of a Babcock & Wilcox (B&W) feedring steam generator (FSG) model. Details of the FSG nodalization and other associated changes due to SG replacement are presented in Reference 2. A significant impact is expected in the Feedwater System Pipe Break analysis results due to the design and location of the main feedwater nozzles, which is discussed in Section 3.3 of this evaluation.

3.2 SCD Transients

The core thermal-hydraulics for most of the transients considered in this Topical Report are analyzed using the DPC-developed and NRC-approved SCD methodology (Reference 10). For these transients, certain initial conditions used in the transient safety analysis are selected to be at nominal conditions, as qualitatively defined in the subject report, since the uncertainty associated with the initial conditions is accounted for in the SCD method.

Of those transients for which a DNBR computation is performed, there remain two transients (startup of an inactive reactor coolant pump at an incorrect temperature and steam line break) for which DNBR calculations are not performed using the SCD methodology. With this revision, DPC stated its intent to use the SCD methodology for reactor coolant pump (RCP) locked rotor, and steam generator tube rupture (SGTR).

Although in the locked rotor analysis the core flowrate is expected to fall below the minimum SCD parameter value, a statistical Monte Carlo propagation is performed to ensure that the statistical design limit remains acceptable. This approach was approved provided that the range of applicability of the critical heat flux (CHF) correlation is not violated. In the SGTR analysis, DPC stated that the range of applicability remained valid for SCD parameters.

3.3 Revised FSAR Transient Analysis

In this section those transient analyses, in which significant revisions are proposed, are highlighted and other revisions are briefly discussed.

3.3.1 Increase in Heat Removal by the Secondary System

Two transients in this category, which incorporated revisions, are (i) Feedwater System Malfunction Causing an Increase in Feedwater Flow, and (ii) Excessive Increase in Secondary Steam Flow. In both cases revisions are minor since the changes are primarily editorial reflecting methodology changes in DPC-NE-3000, Revision 1, and, therefore, are acceptable.

3.3.2 Decrease in Heat Removal by the Secondary System

All four transient analyses are affected by revisions in this category: (i) turbine trip, (ii) loss of offsite power, (iii) loss of normal feedwater, and (iv) feedwater system pipe break. Turbine trip is analyzed with respect to peak RCS and secondary side pressure, and the others are analyzed with respect to peak RCS pressure and DNB and/or long-term core coolability (potential for hot leg boiling).

3.3.2.1 Turbine Trip

A change in the assumption regarding the pressurizer (PZR) level control is introduced. DPC stated that the use of the level control in manual with the PZR heaters locked on will be worse with respect to high primary system pressure than the case when the PZR level control is in automatic. The staff concurs with this assumption.

3.3.2.2 Loss of Offsite Power

In addition to the potential challenges to peak RCS pressure, peak secondary side pressure, and DNB, DPC will analyze this transient with respect to long-term core cooling capability. Therefore, a new section was added to the report describing the analysis to demonstrate that natural circulation can be established after loss of offsite power. Transient assumptions are reasonable. With respect to the other transient objectives, changes introduced are benign.

3.3.2.3 Loss of Normal Feedwater

Assumptions regarding the initial SG inventory were revised. In the new approach, low instead of high SG level is assumed to maximize the secondary pressure. This is expected to cause an earlier reactor trip on the SG low-low

level. The downward adjustment of the initial SG level introduces competing effects with respect to predicted peak primary and secondary pressures and DNBR.

This event is currently not a limiting transient in this category and is bounded by the turbine trip event. Therefore, its analysis is not required. However, DPC stated that an analysis may become necessary in the future due to hardware or methodology changes. In that event, DPC will need to perform sensitivity studies with respect to initial condition selections to ensure conservatism in the analysis.

3.3.2.4   Feedwater System Pipe Break

This transient is significantly impacted by implementation of the feedring steam generators, and requires three major assumption changes as a direct result of the design and location of the main feedwater nozzles. DPC's discussion of assumption changes and the impact of changes in transient results was reviewed and found to be reasonable.

The loss of offsite power coincident with reactor trip is assumed, resulting in RCP trip and delay in the startup of the diesel generators for safety injection. Early main steam isolation valve (MSIV) closure was determined to be conservative in terms of earlier faulted SG dryout. Thus, in the revised assumptions, MSIV closure occurs coincident with turbine trip, which occurs on loss of offsite power. DPC's approach to the analysis of this event is acceptable.

3.3.3 Decrease in Reactor Coolant System Flowrate

Three transients analyzed in this category are: (1) partial loss of forced reactor coolant (RC) flow, (2) complete loss of forced reactor coolant flow, and (3) reactor coolant pump locked rotor.

Revisions to both the complete and partial loss of forced RC flow are editorial changes and are acceptable.

3.3.3.1   Reactor Coolant Pump Locked Rotor

As stated in Section 3.2, DNBR for this event will be analyzed using the SCD methodology. Therefore, affected parameters are initially set to nominal values instead of assuming conservative values. DPC provided the explanation of the applicability of the SCD methodology for this transient (Reference 3) and the staff finds the explanation to be acceptable (see also Section 3.2).

DPC stated that cases with and without loss of offsite power coincident with the turbine trip will be analyzed.

As stated in the SE (Reference 7) for DPC-NE-3002 (Reference 5), the assumption of 120% of design pressure is not an acceptable limit. DPC is required to use 110% of design pressure, as stated in the previous revision.

3.3.4 Reactivity and Power Distribution Anomalies

DPC added the possibility of reactor trip on high pressurizer pressure in addition to the high neutron flux for completeness.

3.3.5 Increased Reactor Coolant Inventory

Inadvertent operation of ECCS during power operation is the only transient analyzed. Although DNB is a primary concern, since a potential for pressurizer overfill exists during this event, DPC added a new section to address that concern for PZR overfill leading to water relief through the PZR Safety Valves (PSVs). The acceptance criterion for this analysis is the minimum water relief temperature to assure PSV operability.

The Standard Review Plan suggests the use of full power unless a lower power can be justified. In Reference 3, DPC assumes zero power in this analysis for conservatism. This is because if overfill occurs at lower initial power, then the water relief temperature is more likely to be less than the acceptance criterion. Therefore, DPC selected the initial and boundary conditions in order to minimize relief temperature. The staff finds this approach to be reasonable and acceptable.

3.3.6 Decrease in Reactor Coolant Inventory

Inadvertent opening of a pressurizer safety or relief valve and steam generator tube rupture events are the two transients analyzed in this category. Proposed revisions to the inadvertent opening of a pressurizer safety or relief valve are editorial changes.

3.3.6.1 Steam Generator Tube Rupture

The steam generator tube rupture (SGTR) event was not part of the original review since the transient methodology documented in DPC-NE-3000, based on the use of the RETRAN computer code, was approved only for non-LOCA applications. This restriction regarding performance of SGTR analysis with RETRAN (Item vii of RETRAN SER (Reference 11)) applies to applications that encounter two-phase flow in the primary loop, which does occur in many SGTR scenarios.

In the limited review documented in Reference 12, DPC received approval for an SGTR analysis of the worst-case offsite dose scenario using RETRAN for Catawba Nuclear Station, Units 1 and 2. Justification was provided in a qualitative manner by DPC (Reference 13) on each of the items cited under restrictions and limitations on the use of RETRAN in its SE. There is assurance that the use of the code for that particular scenario was acceptable since DPC stated that two-phase flow was not encountered in the primary loop.

Although NRC approval was specific to Catawba Units 1 and 2, as considered in DPC-NE-3000, the Catawba and McGuire plants, for the purpose of analysis qualification, are interchangeable. Therefore, DPC stated that NRC approval of the SGTR analysis using RETRAN should be applicable to the McGuire plant analysis (Reference 3). The staff concurs with DPC's statement, so long as

the scenario is essentially the same and no two-phase flow conditions are encountered in the RCS primary loops.

The DNBR will be computed using the SCD methodology (see Section 3.2).

4.0 CONCLUSIONS AND LIMITATIONS

Revision 1 to the DPC Topical Report DPC-NE-3002 and the DPC responses to NRC questions and other supporting documents cited in Section 5.0 were reviewed. Review of these documents focused upon evaluation of acceptability of the proposed changes and the perceived impact of these changes.

As stated earlier, steamline break, rod ejection, dropped rod, and boron dilution events were not part of this review.

Subject to the foregoing, DPC's proposed revision of its approach to FSAR Chapter 15 transient analysis, as documented in Revision 1 of DPC-ME-3002 and its supporting document, was found to be acceptable subject to the following limitations:

1. The acceptability of the use of DPC's approach to FSAR analysis is subject to the conditions of SEs on all aspects of transient analysis and methodologies (DPC-NE-3000, DPC-NE-3001, DPC-NE-3002, DPC-NE-2004, and DPC-NE-2005) as well the SEs on the RETRAN and VIPRE-01 computer codes.

2. There are scenarios in which an SGTR event may result in loss of subcooling and the consequent two-phase flow conditions in the primary system. In such instances, the use of RETRAN is not acceptable without a detailed review of the analysis.

3. In the future, if hardware or methodology changes, selection of limiting transients needs to be reconsidered, and DPC is required to perform sensitivity studies to identify the initial conditions in such a way to avoid conflict between transient objective, such as DNB and worst-case primary pressure.

4. It is emphasized that, when using the SCD methodology to determine DNBR, the range of applicability of the selected critical heat flux correlation must not be violated.

5. DPC's assumption of 120% of design pressure as part of the acceptance criteria for Reactor Coolant Pump Locked Rotor is not acceptable; DPC is required to use 110% of design pressure for that limit.

Principal Contributor: L. Lois

Date: December 28, 1995

5.0 REFERENCES

1. Letter from M. S. Tuckman (DPC) to NRC, dated July 18, 1994, transmitting "FSAR Chapter 15 System Transient Analysis Methodology, DPC-NE-3002," Revision 1, June 1994.

2. Letter from M. S. Tuckman (DPC) to NRC, dated August 9, 1994, transmitting "Duke Power Company, The Thermal-Hydraulic Transient Analysis Methodology Oconee Nuclear Station, McGuire Nuclear Station, Catawba Nuclear Station," DPC-NE-3000-P, redesignated as Revision 1, August 1994.

3. Letter from M. S. Tuckman (DPC) to NRC, "Topical Report DPC-NE-3002, "FSAR Chapter 15 System Transient Analysis Methodology," Responses to NRC Questions," August 18, 1995.

4. Letter from H. B. Tucker (DPC) to NRC, dated September 29, 1987, transmitting "Duke Power Company, The Thermal-Hydraulic Transient Analysis Methodology, DPC-NE-3000, July 1987" for Oconee Nuclear Station, McGuire Nuclear Station, and Catawba Nuclear Station.

5. Letter from H. B. Tucker (DPC) to NRC, dated August 17, 1992 transmitting the approved version of the report "DPC-NE-3002-A, FSAR Chapter 15 System Transient Analysis Methodology."

6. Letter from T. A. Reed (NRC), to H. B. Tucker (DPC), dated November 15, 1991, transmitting "Safety Evaluation on Topical Report DPC-NE-3000, Thermal-Hydraulic Transient Analysis Methodology," as transmitted with the approved version of the report (DPC-NE-3000-PA) by M. S. Tuckman's letter of August 8, 1995.

7. Letter from T. A. Reed (NRC) to H. B. Tucker (DPC), dated November 15, 1991, "Safety Evaluation on Topical Report DPC-NE-3002, FSAR Chapter 15 System Transient Analysis Methodology," as transmitted with the approved version of the report (DPC-NE-3002-A) by H. B. Tucker's letter of August 17, 1992.

8. Letter from H. B. Tucker (DPC), to NRC, dated August 17, 1992, transmitting the approved version of "Multi-dimensional Reactor Transients and Safety Analysis Physics Parameters Methodology," DPC-NE-3001PA, November 1991.

9. Letter from R. E. Martin (NRC), to M. S. Tuckman (DPC), dated December 27, 1995, transmitting "Safety Evaluation for Revision 1 to Topical Report DPC-NE-3000-P, Thermal-Hydraulic Transient Analysis Methodology."

10. Letter from G. M. Holahan (NRC) to H.B. Tucker (DPC), dated February 24, 1995, "Acceptance for Referencing of the Modified Licensing Topical Report, DPC-NE-2005P, Thermal-Hydraulic Statistical Core Design Methodology," as transmitted with M. S. Tuckman's letter of August 8, 1995, "Issuance of Approved Version of DPC-NE-2005P (DPC-NE-2005P-A)."

REFERENCES (continued)

11. Letter from C. O. Thomas (NRC) to T. W. Schnatz (UGRA), "Acceptance for Referencing of Licensing Topical Reports EPRI CCM-5, RETRAN-A Program for One Dimensional Transient Thermal Hydraulic Analysis of Complex Fluid Flow Systems," September 2, 1984.

12. Letter from R. E. Martin (NRC) to M. S. Tuckman (DPC), "Safety Evaluation for the Catawba Nuclear Station, Units 1 and 2, Steam Generator Tube Rupture Analysis," May 14, 1991.

13. Letter from H. B. Tucker (DPC) to NRC, dated December 7, 1987, "Catawba Nuclear Station Steam Generator Tube Rupture Analysis."

TECHNICAL EVALUATION:
FSAR CHAPTER 15 SYSTEM TRANSIENT ANALYSIS METHODOLOGY
DPC-NE-3002 REVISION 1
FOR
DUKE POWER COMPANY

P.B. Abramson
H. Komoriya

ENCLOSURE 2

<u>TECHNICAL EVALUATION:</u>
<u>FSAR CHAPTER 15 SYSTEM TRANSIENT ANALYSIS METHODOLOGY</u>
<u>TOPICAL REPORT DPC-NE-3002 REVISION 1</u>
<u>FOR</u>
<u>DUKE POWER COMPANY</u>
<u>MCGUIRE AND CATAWBA NUCLEAR STATIONS</u>

1.0   INTRODUCTION

In Revision 1 of the topical report entitled "FSAR Chapter 15 System Transient Analysis Methodology," DPC-NE-3002, dated June 1994 (Ref. 1), Duke Power Company (DPC) documented revisions reflecting changes due to (i) replacement of steam generators for the McGuire and Catawba Unit 1 stations and (ii) methodology changes documented in DPC-NE-3000 Rev. 3 (Ref. 2). Corrections of typographical errors were also included.   Additional information was provided in Reference 3.

The original topical reports DPC-NE-3000 (Ref. 4) and DPC-NE-3002 (Ref. 5) were reviewed and approved, subject to certain conditions (Refs. 6 and 7).

DPC-NE-3002 (Refs. 1 and 5) contains DPC's qualitative approach to selection of initial and boundary conditions, transient assumptions and computer code models for use in performing transient analysis of FSAR Chapter 15 accidents for McGuire and Catawba Nuclear Stations. The report does not contain any justification, qualification or demonstration of selections.

Steam line break, rod ejection, dropped rod and boron dilution events were not part of this review since these events are documented in DPC-NE-3001 (Ref. 8) which has been reviewed and approved.

2.0   SUMMARY

DPC-NE-3002 contains DPC's qualitative approach to performance of FSAR Chapter 15-type analysis for the McGuire and Catawba stations using methodology utilizing the RETRAN and VIPRE-01 computer codes described in DPC-NE-3000.   It does not address justification, qualification or demonstration of the approaches taken for analysis. However, it does state the process they intend to use in determining initial and boundary conditions, transient assumptions and scenarios and code models used in licensing-type transient analysis.

Revision 1 of DPC-NE-3002 documents changes due to (i) the replacement steam generators for McGuire and Catawba Unit 1 and (ii) minor methodology changes presented in Revision 3 of DPC-NE-3000.   Typographical errors are also corrected.   Changes include analysis objectives, pressurizer and SG models,

initial and boundary conditions, transient assumptions in terms of system component availability, and the use of statistical core design methodology for DNBR computation.

3.0   EVALUATION

Acceptability of DPC's revisions of RETRAN models and assumptions for thermal-hydraulic calculations of FSAR Chapter 15 transient analysis of its McGuire/Catawba (M/C) plants is discussed below. Only those items which bear analytical or safety significance are discussed. Those items of a non-technical nature are not discussed.

3.1   Changes in McGuire and Catawba RETRAN Methodology

The RETRAN base models for M/C plants were qualified in DPC-NE-3000 and its Revision 3 for both best-estimate and licensing type non-LOCA applications, subject to limitations described in the SER and TER (Refs. 6 and 9).

A change which impacted the documentation of DPC-NE-3002 was a change in PZR modeling described in DPC-NE-3000 Rev. 3. Thus, all sections which related to previous modeling description were revised.

Also included in the revision of the RETRAN methodology is modeling of a B&W feedring steam generator (FSG) Model. Details of the FSG nodalization and other associated changes due to SG replacement are presented in Reference 2. A significant impact is expected in the Feedwater System Pipe Break analysis results due to the design and location of the main feedwater nozzles, which is discussed in Section 3.3. of this report.

3.2   SCD Transients

The core thermal-hydraulics for most of the transients considered in this topical report are analyzed using the DPC developed and NRC approved SCD methodology (Ref. 10). For these transients, certain initial conditions used in the transient safety analysis are selected to be at nominal conditions, as qualitatively defined in the subject report, since the uncertainty associated with the initial conditions is accounted for in the SCD method.

Of those transient for which a DNBR computation is performed, there remain two transients (startup of an inactive reactor coolant pump at an incorrect temperature and steam line break) for which DNBR calculations are not performed using the SCD methodology. With this revision, DPC stated its intent to use the SCD methodology for RCP Locked Rotor and SGTR.

Although in the Locked Rotor analysis the core flowrate is expected to fall below the minimum SCD parameter value, a statistical Monte Carlo propagation is performed to ensure that the statistical design limit remains acceptable. This approach was approved provided that the range of applicability of the critical heat flux (CHF) correlation is not violated.

In the SGTR analysis, DPC stated that the range of applicability remained valid for SCD parameters.

3.3 Revised FSAR Transient Analysis

In this section those transient analyses in which significant revisions are proposed are highlighted and other revisions are briefly discussed.

3.3.1 Increase in Heat Removal by the Secondary System

Two transients in this category which incorporated revisions are (i) Feedwater System Malfunction Causing an Increase in Feedwater Flow and (ii) Excessive Increase in Secondary Steam Flow. In both cases revisions are minor since the changes are primarily editorial reflecting methodology changes in DPC-NE-3000 Rev. 3 and therefore acceptable.

3.3.2 Decrease in Heat Removal by the Secondary System

All four transient analyses are affected by revisions in this category: (i) turbine trip, (ii) loss of offsite power, (iii) loss of normal feedwater, and (iv) feedwater system pipe break. Turbine trip is analyzed with respect to peak RCS and secondary side pressure, and the others are analyzed with respect to peak RCS pressure and DNB and/or long term core coolability (potential for hot leg boiling).

3.3.2.1 Turbine Trip

A change in the assumption regarding the PZR level control is introduced. DPC stated that the use of the level control in manual with the PZR heaters locked on will be worst in order to elevate the primary pressure to a higher value than is obtained when the PZR level control in automatic. We concur.

3.3.2.2. Loss of Offsite Power

In addition to the potential challenges to peak RCS pressure, peak secondary side pressure and DNB, DPC will analyze this transient with respect to long-term core cooling capability. Therefore, a new section was added to the report describing the analysis to demonstrate that natural circulation can be established after loss of offsite power. Transient assumptions are reasonable. With respect to the other transient objectives, changes introduced are benign.

3.3.2.3 Loss of Normal Feedwater

Assumptions regarding the initial SG inventory were revised. In the new approach, low instead of high SG level is assumed, to maximize the secondary pressure. This is expected to cause an earlier reactor trip on the SG low-low level. The downward adjustment of the initial SG level introduces competing effects with respect to predicted peak primary and secondary pressures and DNBR.

This event is currently not a limiting transient in this category and is bounded by the turbine trip event. Therefore, its analysis is not required. However, DPC stated that analysis may become necessary in the future due to

3

hardware or methodology changes. In that event DPC should be required to perform sensitivity studies with respect to initial condition selections to ensure conservatism in the analysis.

3.3.2.4   Feedwater System Pipe Break

This transient is significantly impacted by implementation of the feedring steam generators, and requires three major assumption changes as a direct result of the design and location of the main feedwater nozzles. DPC's discussion of sources of assumption changes and impact of changes in transient results was reviewed and found to be reasonable.

The loss of offsite power coincident with reactor trip is assumed, resulting in RCP trip and delay in the startup of the diesel generators for SI. Early MSIV closure was determined to be conservative in terms of earlier faulted SG dryout. Thus, in the revised assumptions, MSIV closure occurs coincident with turbine trip, which occurs on loss of offsite power.

DPC's approach to analysis of this event is acceptable.

3.3.3   Decrease in Reactor Coolant System Flow Rate

Three transients analyzed in this category are: (1) partial loss of forced reactor coolant flow, (2) complete loss of forced reactor coolant flow, and (3) reactor coolant pump locked rotor.

Revisions to both of the complete and partial loss of forced RC flow are editorial changes and are acceptable.

3.3.3.1   RC Pump Locked Rotor

As stated in Section 3.2, DNBR for this event will be analyzed using the SCD methodology. Therefore, affected parameters are initially set to nominal values instead of assuming conservative values. DPC provided (Ref. 3) the explanation of the applicability of the SCD methodology for this transient and we find the explanation to be acceptable (see also Section 3.2).

DPC stated that cases with and without loss of offsite power coincident with the turbine trip will be analyzed.

As stated in the SER (Ref. 7) for DPC-NE-3002 (Ref. 5), the assumption that 120% of design pressure is not an acceptable limit. DPC is required to use 110% of design pressure.

3.3.4   Reactivity and Power Distribution Anomalies

DPC added the possibility of reactor trip on high pressurizer pressure in addition to the high neutron flux for completeness.

3.3.5   Increased in Reactor Coolant Inventory

Inadvertent operation of ECCS during at-power operation is the only transient

4

analyzed. Although DNB is a primary concern, since a potential for pressurizer overfill exists during this event, DPC added a new section to address that concern for PZR overfill leading to water relief through the PZR Safety Valves (PSVs). The acceptance criterion for this analysis is the minimum water relief temperature to assure PSV operability.

The SRP suggests use of full power unless a lower power can be justified. DPC assumes zero power (Ref. 3) in this analysis for conservatism. This is because if overfill occurs at lower initial power, then the water relief temperature is more likely to be less than the acceptance criterion. Therefore DPC selects the initial and boundary conditions in such a way to minimize relief temperature. We find this approach to be reasonable.

3.3.6 Decrease in Reactor Coolant Inventory

Inadvertent opening of a pressurizer safety or relief valve and steam generator tube rupture (SGTR) events are the two transients analyzed in this category. Proposed revisions to the inadvertent opening of a pressurizer safety or relief valve are editorial changes.

3.3.6.1 Steam Generator Tube Rupture

The steam generator tube rupture (SGTR) event was not part of the original review since the transient methodology documented in DPC-NE-3000 based on the use of the RETRAN computer was approved only for non-LOCA applications. This restriction regarding performance of SGTR analysis with RETRAN (Item vii of RETRAN SER (Ref. 11)) applies to applications which encounter two-phase flow in the primary loop, which does occur in many SGTR scenarios.

In the limited review documented in Reference 12, DPC received approval for an SGTR analysis of the worst offsite dose scenario using RETRAN for Catawba Nuclear Station Units 1 and 2. Justification was provided (Ref. 13) in a qualitative manner by DPC on each of the items cited under restrictions and limitations on the use of RETRAN in its SER. There is assurance that the use of code for that particular scenario was acceptable since DPC stated that two-phase flow was not encountered in the primary loop.

Although NRC approval was specific to Catawba units, as considered in DPC-NE-3000, Catawba and McGuire plants for the purpose of analysis qualification are interchangeable. Therefore DPC stated (Ref. 3) that NRC approval of the SGTR analysis using RETRAN should be applicable to McGuire plant analysis. We concur with DPC's statement, so long as the scenario is essentially the same and no two-phase flow conditions are encountered in the RCS primary loops.

The DNBR will be computed using the SCD methodology (see Section 3.2).

4.0 CONCLUSIONS

Revision 1 to the DPC topical report DPC-NE-3002 and the DPC responses to NRC questions and other supporting documents cited in Section 5.0 were reviewed. Review of these documents focused upon evaluation of acceptability of the

proposed changes and the perceived impact of these changes.

As stated earlier, steam line break, rod ejection, dropped rod and boron dilution events were not part of this review.

Subject to the foregoing, DPC's proposed revision to approach to FSAR Chapter 15 transient analysis, as documented in Revision 1 of DPC-NE-3002 and its supporting document, was found to be acceptable subject to the following conditions:

1. The acceptability of the use of DPC's approach to FSAR analysis is subject to the conditions of SERs on all aspects of transient analysis and methodologies (DPC-NE-3000, DPC-NE-3001, DPC-NE-3002, DPC-NE-2004, DPC-NE-2005) as well the SERs on RETRAN and VIPRE computer codes.

2. There are scenarios in which an SGTR event may result in loss of subcooling and the consequent two-phase flow conditions in the primary system. In such instances, the use of RETRAN is not acceptable without a detailed review of the analysis.

3. In the future if hardware or methodology changes, selection of limiting transients needs to be reconsidered, and DPC is required to perform sensitivity studies to identify the initial conditions in such a way to avoid conflict between transient objective, such as DNB and worst primary pressure.

4. It is emphasized that, when using the SCD methodology to determine DNBR, the range of applicability of the selected CHF correlation must not be violated.

5. DPC's assumption of 120% of design pressure as part of the acceptance criteria for Reactor Coolant Pump Locked Rotor is not acceptable: DPC is required to use 110% of design pressure for that limit.

5.0 REFERENCES

1. Letter from M.S. Tucker (DPC) to USNRC, "FSAR Chapter 15 System Transient Analysis Methodology, DPC-NE-3002," Revision 1, June 1994.

2. "Duke Power Company - The Thermal-Hydraulic Transient Analysis Methodology - Oconee Nuclear Station, McGuire Nuclear Station, Catawba Nuclear Station," DPC-NE-3000, Revision 3, August 1994.

3. Letter from M.S. Tuckman (DPC) to USNRC, "Topical Report DPC-3002, "FSAR Chapter 15 System Transient Analysis Methodology", Responses to NRC Questions," August 18, 1995.

4. "Duke Power Company - The Thermal-Hydraulic Transient Analysis Methodology - Oconee Nuclear Station, McGuire Nuclear Station, Catawba Nuclear Station," DPC-NE-3000, July 1987.

5. "FSAR Chapter 15 System Transient Analysis Methodology," DPC-NE-3002, August 1991.

6. "Safety Evaluation on Topical Report DPC-NE-3000, Thermal-Hydraulic Transient Analysis Methodology," November 15, 1991.

7. Letter from T.A. Reed (USNRC) to H.B. Tucker (DPC), "Safety Evaluation on Topical Report DPC-NE-3002, "FSAR Chapter 15 System Transient Analysis Methodology", " November 15, 1991.

8. "Duke Power Company Multi-dimensional Reactor Transients and Safety Analysis Physics Parameters Methodology," DPC-NE-3001-P, January 1990.

9. "Technical Evaluation Report on Topical Report DPC-NE-3000 Rev. 3, Thermal-Hydraulic Transient Analysis Methodology," ITS/NRC/95-4, September 1995.

10. Letter from G.M. Holahan (USNRC) to H.B. Tucker (DPC), "Acceptance for Referencing of the Modified Licensing Topical Report, DPC-NE-2005P, "Thermal-Hydraulic Statistical Core Design Methodology," February 27, 1995.

11. Letter from C.O. Thomas (USNRC) to T.W. Schnatz (UGRA), "Acceptance for Referencing of Licensing Topical Reports EPRI CCM-5, "RETRAN-A Program for One Dimensional Transient Thermal Hydraulic Analysis of Complex Fluid Flow Systems," and EPRI NP-1850-CCM, "RETRAN-02-A Program for One Dimensional Transient Thermal Hydraulic Analysis of Complex Fluid Flow Systems," September 2, 1984.

12. Letter from R.E. Martin (NRC) to M.S. Tuckman (DPC), "Safety Evaluation Report for the Catawba Nuclear Station Units 1 and 2, Steam Generator Tube Rupture Analysis," May 14, 1991.

13. Letter from H.B. Tucker (DPC) to USNRC, "Catawba Nuclear Station Steam Generator Tube Rupture Analysis," December 7, 1987.

November 15, 1991

Docket Nos. 50-369, 50-370
50-413 and 50-414

Mr. H. B. Tucker, Senior Vice President
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P. O. Box 1007
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Dear Mr. Tucker:

SUBJECT: SAFETY EVALUATION ON TOPICAL REPORT DPC-NE-3002, "FSAR CHAPTER 15
SYSTEM TRANSIENT ANALYSIS METHODOLOGY," (TAC NO. 66850)

The NRC staff with the support of its contractor has reviewed Duke Power
Company Topical Report DPC-NE-3002, "FSAR Chapter 15 System Transient Analysis
Methodology," dated August 30, 1991, as supplemented by letters dated
October 16 and November 5, 1991. The staff has found the topical report to
be acceptable subject to the conditions identified in section 4.0 of the
attached Technical Evaluation Report as modified by Section 2.? of the
attached Safety Evaluation.

This concludes our review activities in response to your submittals regarding
Topical Report DPC-NE-3002.

Sincerely,

Timothy A. Reed, Project Manager
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Office of Nuclear Reactor Regulation

Enclosures:
1. Safety Evaluation
2. Technical Evaluation Report

cc: See next page

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

ENCLOSURE 1

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION
RELATING TO TOPICAL REPORT DPC-NE-3002
"FSAR CHAPTER 15 SYSTEM TRANSIENT ANALYSIS METHODOLOGY"
DUKE POWER COMPANY
MCGUIRE NUCLEAR STATION
CATAWBA NUCLEAR STATION
DOCKET NOS. 50-369, 50-370, 50-413 AND 50-414

1.0 INTRODUCTION

By letter dated August 30, 1991, the Duke Power Company (DPC) submitted
Topical Report DPC-NE-3002, McGuire Nuclear Station and Catawba Nuclear
Station, "FSAR Chapter 15 System Transient Analysis Methodology," describing
modelling assumptions used by DPC in performing analyses of FSAR Chapter 15
events. This report, as supplemented by letters of October 16 and November 5,
1991, is intended to augment Topical Report DPC-NE-3000, "The Thermal-Hydraulic
Transient Analysis Methodology - Oconee Nuclear Station, McGuire Nuclear
Station, Catawba Nuclear Station." DPC-NE-3002 is also related to
DPC-NE-2004, "Duke Power Company McGuire and Catawba Nuclear Stations Core
Thermal-Hydraulic Methodology Using VIPRE-01," and DPC-NE-3001,
"Multidimensional Reactor Transients and Safety Analysis Physics Parameters
Methodology."

2.0 STAFF EVALUATION

The staff performed its evaluation of the methodology reported in DPC-NE-3002
with the technical assistance of International Technical Services, Inc.
(ITS). The evaluation and findings are described in detail in the ITS
technical evaluation report (TER) which is enclosed as part of this report.
As identified in the TER, certain items from DPC-NE-3002 were not included in

this review because they have already been included in the review of one of
the other related DPC topical reports. For instance, steam line break,
control rod misoperation, and rod ejection events are included in the
DPC-NE-3001 review and not repeated herein except as reference.

2.1 Other Items Not Evaluated in TER

2.1.1 Boron Dilution Event

The TER identifies that the review of this event is beyond its scope.
DPC-NE-3002 discusses boron dilution events. However, apart from core physics
aspects of DPC-NE-3001, the DPC methodology for evaluating boron dilution
events does not use the codes described in the related topical reports
identified in Section 1 of this SER. The staff concludes that the finding of
acceptability for the boron dilution event analysis methodology of record
continues to apply.

2.1.2 Steam Generator Tube Rupture (SGTR)

The TER identifies that the review of this event is beyond its scope. DPC-NE-
3002 discusses SGTR events; however, except for any parts of DPC-NE-3001 that
may be found to apply, the DPC methodology for evaluating SGTRs does not use
codes described in the related topical reports identified in Section 1 of this
SER. The staff concludes that the finding of acceptability for the SGTR
analysis methodology of record continues to apply.

2.2 TER CONCLUSIONS

2.2.1 Feedwater Line Break

TER Section 4.0 (Conclusions) recommends that justifications for trip and
actuation times be required when the methodology is applied.

While the staff agrees that trip setpoints and actuation times must be
consistent with the assumptions in FSAR analyses, we find that this

consistency is implemented in the plant technical specifications and is
outside the scope of DPC-3002 and this review.

2.2.2 Power and Reactivity Feedback

TER Section 4.0 recommends that the modelling of power and reactivity feedback
be reviewed and that it be assured that such modelling has no adverse effect
on the other modelling described in the TER. The staff review of DPC-NE-3001
covered these considerations and found them acceptable.

2.2.3 Locked Rotor Event

TER Section 4.0 identifies that DPC has proposed that reactor coolant system
(RCS) pressure of 120% of design pressure be used as a performance acceptance
criterion for locked rotor event analyses replacing the previous 110%
criterion. Based on our review we find that the licensee has not provided
adequate justification for the proposed change, particularly in light of the
credit taken in the DPC methodology for delayed loss of power to the unlocked
reactor coolant pumps. The licensee identifies that its locked rotor event
analyses calculate a peak RCS pressure of less than 110% design pressure. We
find the DPC locked rotor analysis methodology (incorporating the 110% RCS
pressure criterion) and results acceptable.

2.2.4 Parametric Studies

TER Section 4.0 recommends that parameteric studies be required to be presented
when the methodology is applied. The licensee has indicated that it will
perform such studies, as needed. The staff finds this commitment acceptable.

3.0 STAFF CONCLUSIONS

The staff finds the DPC transient analysis methodology acceptable for McGuire
and Catawba analyses.

Date: November 15, 1991

TECHNICAL EVALUATION
OF THE FSAR CHAPTER 15 SYSTEM TRANSIENT ANALYSIS METHODOLOGY
TOPICAL REPORT DPC-NE-3002
FOR THE
DUKE POWER COMPANY
MCGUIRE AND CATAWBA NUCLEAR STATIONS

1.0   INTRODUCTION

The topical report entitled "FSAR Chapter 15 System Transient Analysis Methodology," DPC-NE-3002, dated August 1991 (Ref. 1), documents description of modeling assumptions used by Duke Power Company in performing transient analysis of FSAR Chapter 15 accidents by discussing specific choices for use of the models described and qualified in DPC-NE-3000 using the RETRAN and VIPRE-01 computer codes (Refs. 2 and 3).

DPC documented, for licensing application, the conservative nature of (1) the RETRAN model nodalization, (2) RETRAN control systems, (3) use of the models described in the DPC-NE-3000 (Ref. 4) and (4) selection of initial and boundary conditions.

1.1   Scope of Review

Review of the subject topical report focused upon evaluation of acceptability, for licensing type analyses, of RETRAN models such as: (1) nodalizations for steam generators, core and reactor vessel, including any transient specific modifications; (2) selection of RETRAN internal models/correlations and (3) selection of RETRAN initial and boundary conditions.

The topical report was further reviewed to assure that the application of DPC's DNB methodology was acceptable and consistent with the contents of DPC-NE-2004, DPC-NE-3000 and their supporting documents (Refs. 4 - 8) together

with their respective TERs (Ref. 9 and 10). The review, therefore, included identification of which transients DPC intends to analyze using its statistical core design (SCD) methodology and which they do not, and evaluation of DPC's selection of initial and boundary conditions in the systems analysis which was used to determined the statepoints for the DNB analysis.

Although the subject topical report covered all applicable non-LOCA accident in Sections 15.1 through 15.6 of the FSAR, no review was conducted of the details of the transients which are presented in separate topical reports (steam line break, control rod misoperation, rod ejection and steam generator tube rupture) or those accidents identified by the DPC as: (i) not applicable to M/C plants; (ii) no system analysis deemed necessary; or (iii) those current licensing bases bounded by other analyses.

The following items are beyond the scope of this review: (i) review with respect to the core physics parameters or dose analyses; (ii) review related to the current McGuire 1 Cycle 8 (M1C8) reload analysis submittal; (iii) review of FSAR analyses; (iv) review of the Boron dilution event;(v) review of a statically misaligned control rod; and (vi) review of consistency or satisfaction of current Technical Specifications or proposed changes therein. Therefore, no consistency check was made of DPC's philosophical approach documented in the topical report against the M1C8 reload analyses, FSAR analyses or Technical Specification limits. Furthermore, accuracy of details of the Reactor Protection System, Engineered Safety Features, instrumentation and auxiliary systems and their associated tolerance or uncertainty was not reviewed.

Finally, no technical review was conducted as to the validity of DPC's assumption of 120% of design pressure as an acceptance criterion for the RCP locked rotor analysis.

2.0   SUMMARY

Topical Report DPC-NE-3002 documents DPC's approach to performance of the

2

NSSS primary and secondary system analyses of FSAR Chapter 15 accidents. It covers all applicable non-LOCA accidents in Sections 15.1 through 15.6 of the FSAR except steam line break, dropped rod, and rod ejection, which are addressed in a separate topical report, DPC-NE-3001 (Ref. 11).

DPC-NE-3002 presents brief discussion of specific choices for the use of the RETRAN plant models described in DPC-NE-3000, including nodalization, initial and boundary conditions and modeling of the process instrumentation and control systems. Also presented are assumptions related to the Reactor Protection System, the Engineered Safety Features Actuation System, and availability of other systems and components. Trip actuation is discussed in generality, and thus potential trip functions are presented. However, the report contains no justification for actuation times for reactor trip, safety injection and other actions. Assumptions related to reactivity feedback modeling, power peaking and power distribution are not presented, therefore are not reviewed. Furthermore, although there is mention of intent to perform (or, in some instances, actual performance of) parametric studies to identify conservative scenarios and assumptions, none of such studies were presented.

The topical report contains qualitative, rather than quantitative information, and no the actual RETRAN or VIPRE computed results are presented. Therefore, this report presents DPC's philosophical approaches to performance of FSAR Chapter 15 type analysis.

Nodalization selection is made based upon symmetry or a degree of asymmetry of the expected transient system response. Selection of initial and boundary conditions is designed to result in conservative predictions with respect to the aspect of a transient which the analysis is intended to assess, such as peak primary pressure, peak secondary pressure, short and long term core coolability. With respect to core coolability, selection of initial conditions depends upon the mode of DNBR computation; i.e., the use of the DPC developed SCD methodology SCD or the traditional DNBR methodology.

3.0 EVALUATION

Acceptability of DPC's application of RETRAN models and assumptions for thermal-hydraulic calculations of FSAR Chapter 15 transient analysis of its McGuire/Catawba (M/C) plants is discussed below. In addition, application to licensing type transient analysis of the SCD methodology described in DPC Topical Report DPC-NE-2004 and its supplements was also reviewed.

3.1 McGuire and Catawba RETRAN Plant Model

The RETRAN base models for M/C plants were qualified in DPC-NE-3000 for both best-estimate and licensing type applications, subject to limitations described in the TER (Ref. 10).

DPC developed three different size models of the M/C Plants: a one-loop plant model to be used when all four loops are expected to behave similarly so that there is no asymmetric condition; and a two-loop and a three-loop model to be used when more detail is desirable due to asymmetric conditions expected in the reactor coolant system during the transient.

The steam generator model was examined in detail during review of DPC-NE-3000 for use in licensing analyses, specifically in over-pressurization transients. That review focused upon the ability of the DPC SG model to predict SG tube uncovery and resulting degradation of primary-to-secondary heat transfer. DPC presented results from an extensive sensitivity study to assure that during two transients considered, loss of normal feedwater and feedwater line break, the current modeling is adequate. The finding of that review is documented in the TER for DPC-NE-3000 and imposes certain limitations on use.

Use of certain RETRAN internal models such as the inter-region heat transfer model and local condition heat transfer model was reviewed and found to be acceptable for use in the components and for transients identified by DPC (Ref. 8).

3.2   SCD Transients

The core thermal-hydraulics for most of the transients considered in this topical report is analyzed using the DPC developed SCD methodology. For these transients, certain initial conditions used in the transient safety analysis are selected to be at nominal conditions, as qualitatively defined in Reference 10, since the uncertainty associated with the initial conditions is accounted for in the SCD method. These parameters are: (1) power level, (2) Core flow (RCS flowrate and core bypass flow), (3) Coolant temperature, and (4) RCS pressure. Other parameters necessary for the SCD method are not discussed in this topical report.

Those transient for which DNB is relevant but for which the SCD is not used are; (1) turbine trip, (2) RCP Locked Rotor, (3) startup of an inactive reactor coolant pump at an incorrect temperature, and (4) steam line break. The turbine trip is not analyzed because as postulated, this transient results in a monotonically increasing DNBR which therefore is not an issue. The SCD method is not used for DNBR analysis of steam line break since the primary pressure predicted during the transient is below the range of applicability of the CHF correlation used to develop the response surface equation. Similarly, the other events are outside the range of applicability of the response surface equation.

3.3   Transient Initial Conditions and Assumptions

In this section, initial and boundary conditions such as the transient initiators, reactor coolant pump operation and assumptions related to safety and relief valves are discussed. Control, protection and safeguard system modeling is discussed highlighting which systems are credited or not credited, actuation logic and modeling assumptions.

A summary of assumptions and conditions selected by DPC is shown in Table 8.1 of the topical report as corrected by Reference 8. Definition of the terms used in the table are provided in Reference 8.

5

Deviations from the following common analytical approach are highlighted in the ensuing sections of this TER:

1. For DNB analysis of SCD transients, SCD parameters are set at nominal while non-SCD parameters are set at conservative values.

2. For DNB analysis of non-SCD transients, all key parameters were set at conservative values.

3. For all DNB analyses except those which were initiated by reactivity insertion, the gap conductivity is assumed to be low to maximize the stored energy in the fuel and thereby minimize the change in heat flux out of the fuel during the transient, whereas for the reactivity insertion driven transients, the gap conductivity is assumed to be high because the transient duration is short compared to the fuel's thermal constant. For DNB analysis of transients which depressurize the primary, the pressurizer level is assumed to be at its high limit to maximize the depressurization.

4. Where transients are being analyzed for peak RCS pressure, the primary-to-secondary heat transfer is minimized, the pressurizer is assumed to be initially at the high limit of its operating range to produce the maximum pressure as the vapor region is compressed, and the fuel is assumed to have a high gap conductivity (which is accompanied by a low average fuel temperature) to maximize the energy transferred into the primary fluid.

5. For transients initiated on the primary side which have short duration, it is assumed that the results are insensitive to modeling of the secondary side and primary-to-secondary heat transfer. Therefore, for all such analyses the secondary side and steam generator parameters were set at nominal rather than conservative conditions.

6. Transients with symmetric loop behavior are analyzed with a single loop

6

plant model while asymmetric transients are analyzed with a two loop model.

7. DPC uses the setpoint values and response time of trip function as specified in the Technical Specifications and accounts for uncertainty.

8. Decay heat is computed using the end-of-cycle data based upon ANSI/ANS-5.1-1979 standards plus a two-sigma uncertainty.

9. Availability assumptions on the PZR pressure and level control mechanisms, such as the PZR sprays, PORVs and heaters, and the modes of operation are made in various combination to yield system behavior consistent with the transient being modeled. Steam line PORVs and condenser dump modeling is similar.

3.3.1   Increase in Heat Removal by the Secondary System

Four transients are considered in this category; (1) feedwater (FW) system malfunctions that result in a reduction in feedwater temperature, (2) feedwater system malfunction causing an increase in feedwater flow, (3) excessive increase in secondary steam flow, and (4) inadvertent opening of a steam generator relief or safety valve. As stated earlier review of the steam line break event is beyond of the scope of this review.

The FW temperature reduction event is bounded by the FW flow increase event, which is analyzed. Since inadvertent opening of a SG relief or safety valve is similar to, and bounded by, the steam line break, it is not analyzed, however a small step increase eq   to 10% of licensed core thermal power is presented in the report. Both of these transients are analyzed with respect to DNB using the SCD method.

An additional condition to consider a FW malfunction affecting more than one loop was recently added to the scenario of FW system malfunction event. DPC felt that the most limiting case would involve multi-loop malfunction affecting all loops equally. Therefore, the use of a single-loop model is

7

appropriate.

The pressurizer liquid level is assumed to be high to maximize the primary
pressure decrease. The SG mixture level is assumed to be low for the
feedwater flow increase malfunction in order to maximize the overcooling
before a protection or safeguards actuation. The small step increase in the
steam flow event is not considered to be sensitive to SG level.

A conservatively large step change in main feedwater flow is assumed for the
FW malfunction event. A 10% step increase in steam flow is assumed for the
other event.

In both event analyses, two cases are investigated to assess whether modeling
the rod control system in manual control or automatic control would result in
the worst case. In addition, minimum AFW flow, turbine trip and FW isolation
are credited and expected to trip on SG narrow range level after the
appropriate Technical Specification response time delay.

The input selection and transient assumptions as described in the topical
report for this category of events is acceptable.

3.3.2   Decrease in Heat Removal by the Secondary System

Four transient analyses are performed in this category: (1) turbine trip, (2)
loss of offsite power, (3) loss of normal feedwater, and (4) feedwater system
pipe break. Turbine trip is analyzed with respect to peak RCS and secondary
side pressure, and the others are analyzed with respect to peak RCS pressure
and DNB and/or long term core coolability (r ential for hot leg boiling).

3.3.2.1   Turbine Trip

DNBR analysis is not performed for this transient since this is a rapid
transient in which prior to reactor trip, a significant RCS pressurization
takes place due to the reduction in secondary heat sink offsetting the
increase in core inlet temperature, while the core power and the core flow

8

change very little. Therefore this event does not challenge the DNBR safety margin.

In peak RCS pressure analysis, reactor trip is expected to actuate on either overtemperature delta T (OTDT), overpower delta T (OPDT), or PZR high pressure. MFW is isolated upon turbine trip.

In the peak SG secondary side pressure analysis, RCS flow is assumed to be high to maximize the primary-to-secondary heat transfer. High SG level is assumed, to maximize the secondary pressure. In order to prevent a high PZR pressure reactor trip prior to OTDT trip, PZR PORVs are assumed operable.

3.3.2.2. Loss of Offsite Power

This transient has potential challenges to peak RCS pressure, peak secondary side pressure, and DNB. However, the DNBR results from this event are bounded by the loss of flow event because these two events, as postulated by DPC, differ only in the timing of the insertion of the control rods. In the loss of offsite power (LOOP) event, the rods begin to fall immediately, whereas in the loss of flow event rods fall after an instrumentation delay. Similarly, the peak primary system pressure is bounded by the loss of flow event. The secondary side pressure is bounded by the turbine trip event. For LOOP, the reactor trips prior to the turbine trip, therefore by the time the secondary pressure begins to increase, the primary system is rapidly cooling down. However, in the turbine trip event, reactor trip is after the turbine trip.

Therefore, a quantitative analysis of this transient is not required. Nevertheless, DPC provided the analytical methodology for analysis of this event should it become necessary.

The transient will be analyzed with respect to three different objectives: peak RCS pressure; peak secondary side pressure; and DNB using the SCD method.

9

For peak RCS pressure analysis, all RCPs are tripped as the transient initiating event. Reactor trip and MFW trip are assumed on LOOP. AFW is assumed to actuate on LOOP after a delay. However, in order to minimize the heat removal capability, the minimum AFW flow is assumed.

For peak SG secondary side pressure analysis, DPC assumes high RCS flow to maximize the primary-to-secondary heat transfer. High SG level is assumed, to maximize the secondary pressure.

In order to determine statepoints to be used in DNB analysis using the SCD method, PZR level is assumed to be low to minimize the primary pressure increase. Low SG level is assumed, which minimizes primary-to-secondary heat transfer.

3.3.2.3   Loss of Normal Feedwater

The loss of normal feedwater is bounded by the turbine trip transient. The power to heat sink mismatch is greater for the turbine trip because the reactor trip and turbine trip occur simultaneously for the loss of FW event, while for the turbine trip event, reactor trip occurs after the turbine trip.

Therefore, a quantitative analysis of this transient is not required. Nevertheless, DPC provided the analytical methodology for analysis of this event should it become necessary.

For peak RCS pressure analysis, reactor trip is assumed on the SG low-low level. AFW is assumed to actuate on the SG low-low level; however, in order to minimize the heat removal capability, the minimum AFW flow is ⸰ sumed.

In order to maximize the peak SG secondary side pressure by maximizing the primary-to-secondary heat transfer, high RCS flow is assumed. High SG level is assumed, to maximize the secondary pressure. Reactor trip is assumed on the SG low-low level. AFW is assumed to actuated on the SG low-low level with a minimum flow delivery.

10

In order to determine statepoints to be used in DNB analysis using the SCD method, PZR level is assumed to be low to minimize the primary pressure increase. High SG level is assumed to delay reactor trip on SG low-low level. Reactor trip is assumed on the SG low-low level. AFW is assumed to actuate on SG low-low level with a minimum flow delivery. Turbine trip is assumed on reactor trip.

3.3.2.4   Feedwater System Pipe Break

This transient is analyzed with respect to (1) DNB using the SCD method, and (2) long term core coolability (potential for boiling in the hot leg). The most limiting event assumed by DPC is the double-ended rupture of the largest feedwater line.

The DNB analysis for this transient is analyzed as a complete loss of coolant flow event initiated from an off-normal conditions. It is postulated in this transient that coincident with reactor trip (and turbine trip) loss of offsite power is assumed to occur causing RCP coastdown. Reactor trip is assumed on the OTDT. AFW is assumed to actuate on SG low-low level after a delay with a minimum flow delivery in order to minimize the heat removal capability. Turbine trip is assumed on reactor trip.

Long Term Core Coolability (Hot Leg Boiling)

A three-loop model is used since uneven flow of AFW into the unaffected SGs causes asymmetric loop behavior.

High core power is assumed to maximize the heat flux. PZR pressure assumed to be low, which minimizes the margin to hot leg boiling by lowering the hot leg saturation temperature. A high RCS temperature is assumed, to increase the amount of energy to be removed. Low SG level is assumed to maximize the loss of secondary heat sink. A high fuel temperature is assumed, accompanied by low gap conductivity. High SG tube plugging is assumed to minimize the primary-to-secondary heat transfer.

11

The RCPs are assumed to trip at 15 seconds, which is assumed to precede the time at which the pumps would be manually tripped on high-high containment pressure.

Reactor trip is assumed at 10 seconds into the transient which is after the SI actuation on high containment pressure. SI actuation is assumed on high containment pressure at 10 seconds and terminated at 70 seconds when the emergency procedure criteria for termination are assumed to be met. AFW is assumed to actuate on SI actuation after a delay. However, in order to minimize the heat removal capability, the minimum AFW flow is assumed. AFW is terminated at 120 seconds into the transient. MSIV closure are actuated at 15 seconds and assumed to precede automatic closure on high-high containment pressure. Early closure is conservative in order to initiate the overheating portion of the transient. However, no justification was presented for any of the actuation time assumptions.

The input selection and transient assumptions as described in the topical report for this category of events is acceptable; however, trip actuation times must be justified in any application of this methodology.

3.3.3   Decrease in Reactor Coolant System Flow Rate

Three transient analyzed in this category are: (1) partial loss of forced reactor coolant flow, (2) complete loss of forced reactor coolant flow and (3) reactor coolant pump locked rotor.

3.3.3.1   Loss of Forced RC Flow: Partial and Complete

Due to the similarity of these events, the partial loss of forced flow and complete loss of forced flow events are discussed together.

A single-loop model is used for analysis of the complete loss of forced flow since the transient impacts all loops symmetrically: the two-loop model is used for the partial loss of forced flow event analysis. In both cases, DNB analysis will be performed using the SCD method.

12

For the partial loss of flow, a single reactor coolant pump is assumed to trip, while the other three pumps remain operational for the duration of the transient. For the complete loss of forced flow, all four RCPs are tripped at the initiation of the transient. The pump model is adjusted to yield pump coastdown which is conservative with respect to the flow coastdown test data.

Reactor trip for the partial loss event is assumed on low RCS flow after an appropriate delay time, while for the complete loss event, reactor trip is assumed on RCP undervoltage. Turbine trip is assumed on reactor trip.

3.3.3.2 RC Pump Locked Rotor

This transient is analyzed with respect to both peak RCS pressure and DNB. For both analyses a two-loop model is used for analysis due to the asymmetric nature of the transient.

In presenting its approach to these transients, DPC stated that it used an acceptance criterion of 120% design pressure. Review of this criterion is beyond the scope of this review.

In order to maximize RCS pressure, the RCS flow is assumed at its low initial flow to minimize the heat transfer to the secondary side. A high core bypass flow is assumed to minimize the core flow to maximize the heat-up. The initial RCS average temperature is also assumed at its high level.

The transient initiating event is seizure of the rotor of the RCP in the faulted loop, while the other three pumps trip on bus undervoltage following the loss of offsite power. Offsite power is assumed to be lost coincident with the turbine trip. Reactor trip is assumed on low RCS flow in the affected loop. Turbine trip is assumed on reactor trip.

DNB analysis is performed using the traditional method. Therefore, core power is assumed to be high, while the PZR pressure and level are assumed to be low to minimize the pressure increase. High initial loop average

13

temperature is assumed to maximize the stored energy in the primary which must be removed. Similarly, a high core bypass flow resulting in low core flow is assumed to maximize the heat-up and low RCS flow is chosen to maximize the primary-to-secondary heat transfer.

Offsite power is assumed to be lost coincident with the turbine trip. Similar to the peak RCS pressure case, reactor trip is assumed on low RCS flow in the affected loop. Turbine trip is assumed on reactor trip.

The input selection and transient assumptions as described in the topical report for this category of events is acceptable; however, the assumption that 120% of design pressure is an acceptable limit must be reviewed by the NRC staff.

3.3.4   Reactivity and Power Distribution Anomalies

Seven transients are considered in this category; (1) uncontrolled bank withdrawal from a subcritical or low power startup condition, (2) uncontrolled bank withdrawal at power, (3) statically misaligned control rod (4) single control rod withdrawal, (5) startup of an inactive reactor coolant pump at an incorrect temperature, (6) CVCS malfunction (boron dilution), and (7) inadvertent loading and operation of a fuel assembly in an improper position.

Review of boron dilution event analysis and of inadvertent loading and operation of a fuel assembly in an improper position is beyond the scope of this review. Acceptability of these events should be reviewed by an appropriate branch of NRC.

Each of the two uncontrolled bank withdrawal events is analyzed with respect to both peak RCS pressure and DNB. The single control rod withdrawal and startup of an inactive RCP at in incorrect temperature are analyzed for DNB only. All transients except the startup of an inactive RCP are SCD transients.

14

3.3.4.1 Uncontrolled Bank Withdrawal from a Subcritical or Low Power

The core power is assumed at a critical zero power startup condition.

Peak RCS pressure analysis is performed assuming the RCPs are operational to minimize thermal feedback during the power excursion. Reactor trip is assumed on high power range flux trip.

DNB analysis will be performed using the SCD method except when the potential for bottom-peaked power distributions exists. In such event, since SCD is not applicable, DNBR analysis is performed using the W-3S CHF correlation in the traditional manner accounting for uncertainties explicitly. Thus the input selection criteria described below is only applicable when the SCD method is used.

In order to determine the statepoints to be used in the DNB analysis, the initial conditions for the SCD treated parameters for the cases are set at nominal conditions for this power with three RCPs in operation. To minimize the PZR pressure increase, low initial PZR pressure and level is assumed. Three RCPs, a minimum number required for the modes of operation applicable for this transient, are assumed operational to yield low flow. Reactor trip is assumed on high power range flux trip.

3.3.4.2 Uncontrolled Bank Withdrawal from Power

For peak RCS pressure analysis, in order to avoid trip on high flux, the transient is initiated from low power. The SG level is assumed high and a high amount of SG tube plugging is assumed in order to minimize primary-to-secondary heat transfer.

In order to determine statepoints to be used in DNB analysis using the SCD method, the initial conditions for the SCD treated parameters for the cases are set at the nominal conditions corresponding to each of the power levels, which span the full spectrum, for which this event is analyzed. The steam

15

generator level is assumed to be high in an effort to minimize the primary-to-secondary heat transfer. Analysis is performed with and without PZR sprays and PORVs.

3.3.4.3 Control Rod Misoperation

Transient systems analysis is not performed for the statically misaligned control rod event. Steady-state three-dimensional power peaking analyses are performed to assure that the resulting asymmetric power distribution will not result in DNB.

3.3.4.4 Single Rod Withdrawal

DNB analysis will be performed using the SCD method.

The SG mixture level is assumed high to maximize the secondary pressure and minimize the primary-to-secondary heat transfer. High SG tube plugging is assumed to minimize the primary-to secondary heat transfer.

Reactor trip is assumed on one of four functions; OTDT, OPDT, PZR high pressure and power range high flux. In order to delay reactor trip on high PZR pressure, the PZR heaters is assumed to be in manual. Similarly the PORVs are assumed disabled in order to delay reactor trip on OTDT and high PZR pressure. Feedwater control is in automatic to prevent SG level trip. AFW is assumed disabled. Turbine trip is assumed on reactor trip.

3.3.4.5 Startup of an Inactive RCP at an Incorrect Temperature

DNB analysis will be performed using the traditional method. A two-loop model will be used because of the loop asymmetry.

The initial indicated power level is set to delay or prevent reactor trip from a low flow trip setpoint. The core bypass flow is assumed to be high to minimize the core flow to maximize the heatup. Similarly the RCS flow in the three unaffected loop is the minimum flow allowed by Technical Specification.

16

The three unaffected RCPs are modeled assuming a constant speed through the transient. The RCP that is initially inactive is modeled with a conservative speed vs. time controller.

The SG level control is assumed to be in automatic mode to minimize the probability of trip on low-low SG level. Turbine trip is assumed to be in manual.

The input selection and transient assumptions as described in the topical report for this category of events is acceptable.

3.3.5   Increased in Reactor Coolant Inventory

Inadvertent operation of ECCS during power operation is the only transient analyzed. The DNB results of this transient are bounded by the inadvertent opening of a PZR safety or relief valve transient.

Notwithstanding the qualitative argument provided by DPC for not analyzing this event, DPC nevertheless presented the analytical methodology used for this analysis, should reanalysis become necessary in the future.

DNB analysis will be performed using the SCD method.

A maximum safety injection flowrate with a conservatively high boron concentration is assumed to yield the most limiting transient response because it minimizes power and thereby maximizes the amount of ECCS which can be injected. In order to minimize the delay in the delivery of the borated water, no credit is assumed for the purge volume of unborated water in the injection line.

Reactor trip is assumed on low PZR pressure after an appropriate delay time. The steam line PORVs and condenser steam dump are assumed to be unavailable to maximize secondary side pressurization and minimize the primary-to-secondary heat transfer, also tending to maximize primary fluid volume.

17

Turbine trip is assumed on reactor trip.

The input selection and transient assumptions as described in the topical report for this category of events is acceptable.

3.3.6   Decrease in Reactor Coolant Inventory

Inadvertent opening of a pressurizer safety or relief valve and steam generator tube rupture events are the two transients analyzed in this category. The steam generator tube rupture event is beyond the scope of this review. Therefore, the inadvertent opening of a PZR safety or relief valve was reviewed.

In order to determine statepoints to be used in DNB analysis using the SCD method, the pressurizer liquid level is assumed to be high to maximize the primary pressure decrease, which maximizes the added coolant inventory. Reactor trip is credited. The turbine trip is assumed on reactor trip without delay to minimize post-trip primary-to-secondary heat removal.

The input selection and transient assumptions as described in the topical report for this category of events is acceptable.

4.0   CONCLUSIONS

DPC topical report DPC-NE-3002 and its supporting documents, including the DPC responses to questions, were reviewed.

Review of the subject topical report focused upon evaluation of acceptability of the RETRAN models for the type of analysis generally described on the subject topical report. The topical report was further reviewed to assure that the application of the DPC's DNB methodology was consistent with the contents of DPC-NE-2004 and DPC-NE-3000 and acceptable. The review, therefore, included identification of the SCD transients and evaluation of DPC's selected initial and boundary conditions in the systems analysis which was used to determined the statepoints for the DNB analysis.

18

As stated earlier, steam line break, rod ejection, dropped rod, steam generator tube rupture and boron dilution events were not part of this review (see also Section 1.1).

Subject to the foregoing, DPC's approach to FSAR Chapter 15 transient analysis, as documented in DPC-NE-3002 and its supporting documents, was generally found to be acceptable subject to the following conditions:

1. DPC's Statistical Core Design methodology treat seven state variables as key parameters. Four of these variables were accounted for in this topical report. Of the remaining parameters, the power factors are also input items for systems analysis, which was not presented in the topical report. Similarly, reactivity feedback was not discussed in this report. Both of these parameters can significantly influence the course of the transient. Therefore, when application of the philosophical approach reported in this topical report is made and submitted for NRC review and approval, review should be made of the modeling of power and reactivity feedback, and to assure that such modeling has no adverse impact on the other modeling described herein.

2. Validity of DPC's assumption of 120% of design pressure as part of the acceptance criteria for Reactor Coolant Pump Locked Rotor should be determined by the NRC staff.

3. No justification was presented for trip and actuation times assumed in the Feedwater System Pipe Break event analysis. Such justifications must be presented when this methodology is applied.

4. DPC documented intent to perform parametric studies in order to select conservative scenarios or assumptions throughout the subject topical report. Therefore, such parametric studies must be presented when this methodology is applied.

5.0 REFERENCES (Amended to reflect transmittal dates)

1. Letter, M. S. Tuckman (DPC) to NRC, "FSAR Chapter 15 System Transient Analysis Methodology," DPC-NE-3002, August 30, 1991.

2. Letter, C. O. Thomas (NRC) to T. W. Schnatz (UGRA), September 4, 1984, (Transmittal of RETRAN-02 Safety Evaluation Report).

3. Letter, C. E. Rossi (NRC) to J. A. Blaisdell (UGPA), May 1, 1986, (Transmittal of VIPRE-01 Safety Evaluation Report).

4. Letter, H. B. Tucker (DPC) to NRC, "Thermal-Hydraulic Transient Analysis Methodology," DPC-NE-3000, September 29, 1987.

5. Letter, H. B. Tucker (DPC) to NRC, "Duke Power Company McGuire and Catawba Nuclear Stations Core Thermal-Hydraulic Methodology Using VIPRE-01," DPC-NE-2004, January 9, 1989.

6. Letter, M. S. Tuckman (DPC) to NRC, "Supplemental Information to Assist in Review of Topical Reports DPC-NE-3000 and DPC-NE-2004," August 29, 1991.

7. Letter, H. B. Tucker (DPC) to NRC, "Handouts Presented in the October 7 & 8, 1991 Meeting with NRC Staff and Contract Reviewers," October 16, 1991.

8. Letter, H. B. Tucker (DPC) to NRC, "Final Response to Questions Regarding the Topical Reports Associated with the M1C8 Reload Package," November 5, 1991.

9. Letter, T. A. Reed (NRC) to H. B. Tucker (DPC), Safety Evaluation on Topical Report DPC-NE-2004, "Core Thermal-Hydraulic Methodology Using VIPRE-01," November 15, 1991.

10. Letter, T. A. Reed (NRC) to DPC, Safety Evaluation on Topical Report DPC-NE-3000, "Thermal-Hydraulic Transient Analysis Methodology," November 15, 1991.

11. Letter, T. A. Reed (NRC) to H. B. Tucker (DPC), Safety Evaluation on Topical Report DPC-NE-3001, "Multidimensional Reactor Transients and Safety Analysis Physics Parameters Methodology," November 15, 1991.

Duke Power Company
McGuire Nuclear Station
Catawba Nuclear Station

UFSAR Chapter 15 System
Transient Analysis Methodology

DPC-NE-3002-A
Revision 3

May 1999

Nuclear Engineering Division
Nuclear Generation Department
Duke Power Company

Abstract

This report documents the conservative modeling assumptions used by Duke
Power Company in performing the NSSS primary and secondary system
analyses of UFSAR Chapter 15 accidents. It covers all applicable non-
LOCA accidents in Sections 15.1 through 15.6 of the UFSAR except those
already addressed in Duke Power Company topical report DPC-NE-3001. The
areas discussed are nodalization, initial conditions, boundary
conditions, modeling of the process instrumentation and control systems,
the Reactor Protection System, the Engineered Safety Features Actuation
System, and availability of other important systems and components.

i

UFSAR CHAPTER 15 SYSTEM
TRANSIENT ANALYSIS METHODOLOGY

Table of Contents

1.0   INTRODUCTION

This report documents the conservative modeling assumptions used by Duke Power Company in performing the NSSS primary and secondary system analyses of FSAR Chapter 15 accidents. It covers all applicable non-LOCA accidents in Sections 15.1 through 15.6 of the FSAR except those already addressed in Duke Power Company topical report DPC-NE-3001 (Reference 1), which are steam system piping failure (FSAR Section 15.1.5), control rod misoperation (dropped rod, rod group, or rod bank, FSAR Sections 15.4.3a&b), and rod ejection (FSAR Section 15.4.8). The only accidents categorized as not applicable are those which 1) do not apply to McGuire and Catawba (FSAR Sections 15.2.1, 15.5.3, 15.5.4, and 15.6.6), 2) involve no system thermal-hydraulic analysis (FSAR Section 15.6.2), or 3) the current McGuire and Catawba licensing bases regard as being bounded by another accident (FSAR Sections 15.2.2, 15.2.4, 15.2.5, 15.3.4, and 15.5.2). The assumptions discussed in this report are specific choices about the use of the models described in general in DPC-NE-3000 (Reference 2). The areas discussed are nodalization, initial conditions, boundary conditions, modeling of the process instrumentation and control systems, the Reactor Protection System, the Engineered Safety Features Actuation System, and availability of other important systems and components.

The discussion of the nodalization employed in analyzing a particular accident focuses on two main areas. First, the symmetry of the accident is examined to determine whether it affects all Reactor Coolant System (RCS) loops in approximately the same manner, justifying the use of a single RCS loop model, or whether one or more loops must be modeled separately to conservatively model differential effects of the accident on them. Second, the level of detail of the models described in Reference 2 is examined to determine whether they are appropriate for each analysis. In most cases the modeling described in Reference 2 is appropriate. Any inadequate modeling would be upgraded on an accident specific basis to ensure conservative modeling of the physical phenomena requiring a more detailed model. Modeling regarded as excessively detailed, considering the importance of that area of the system in the particular accident, might be simplified to reduce the computational costs or the effort required to simulate that section of the model.

The analyses covered by this report are intended to be valid, unless stated otherwise, for both the McGuire and Catawba Nuclear Stations. For each analysis, the differences between the two stations and between the two units at a given station, as discussed in Section 3.1.6 of Reference 2, are considered. A bounding "unit" is selected considering how these differences affect the margin to each acceptance criterion of the accident being analyzed. In some cases this is an actual unit, e.g., the use of Catawba Unit 2 because its steam generator inventory as a function of power is different from the other three units. In others it is a superposition of limiting characteristics from more than one unit, e.g., using steam line safety valve banks which correspond to the two lowest setpoint McGuire valves and the three highest setpoint Catawba valves since this artificial bank has a smaller relief capacity than the actual banks at either station. In the future such combined

analyses might be redone separately on a more plant specific basis to gain margin.

The values for relevant plant parameters at the start of each accident are determined through the following process. First, the value for a given parameter is determined considering normal and off-normal plant operation, Technical Specification limits, and mode of parameter control (whether controlled by an automatic system or manually by the operator). Since many of the important parameters are functions of reactor power, some of the parameter value choices are made to be consistent with the initial power level for the accident. Once the parameter value is determined, a method is used to account for uncertainties in this value due to controller tolerance (either manual or automatic) or instrument uncertainty. This method might be an explicit adjustment to the initial value itself or an accounting for the uncertainty in other affected parameters, such as DNBR limits or reactor trip setpoints. Parameters for which an uncertainty adjustment is made are listed in Table 8-1.

The boundary conditions which affect the course of the transient are modeled to ensure a conservative result. Boundary conditions include:

1) Flows to and from plant components not explicitly modeled, e.g., Emergency Core Cooling System (ECCS) flow rate as a function of ECCS configuration, RCS back pressure, ECCS suction source temperature, pressure, and boron concentration, pump motor starting time, and any postulated pump degradation

2) Releases through pipe breaks and open valves, including the effects of critical flow

3) Timing of manual actions

4) Timing of automatic actions, including the effects of setpoints, setpoint tolerances, and the uncertainties in monitored parameter signals

The modeling of boundary conditions is very accident specific and is discussed in detail under each accident.

The plant control systems modeled for accident analyses are described in Sections 3.1.4 and 3.2.4 of Reference 2. Only those control systems which have an important effect on the course of the accident are considered. If the operation of a given control system would make the accident more severe, that system is assumed to function normally. If its operation would make the accident less severe, the system is not assumed to function. The Reactor Protection System (RPS) and the Engineered Safety Features (ESF) are described in Sections 3.1.5 and 3.2.4 of Reference 2. Only those safety systems which have an important effect on the course of the accident are considered. The most limiting single active failure of a component to perform its safety functions is considered in accordance with Appendix A to 10 CFR 50.

In general, no credit is taken for components which are not safety grade, although a penalty for their operation might be taken as

described above. Similarly, the availability of non-safety systems and components, e.g., reactor coolant pumps (RCPs), pressurizer heaters, non-emergency AC power, and instrument air, is only assumed if such availability would make the accident worse.

The list of assumptions for the accidents is summarized in Table 8-1. Each accident description gives the relevant subset of these assumptions applicable for a particular accident and discusses their bases.

2.0   INCREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

2.1   Feedwater System Malfunctions That Result In A Reduction In
           Feedwater Temperature

A Feedwater System malfunction that results in a decrease in feedwater
temperature will cause an increase in core power by decreasing reactor
coolant temperature. Physically, as the cooler feedwater reduces the
reactor coolant temperature, positive reactivity will be inserted due to
the effect of a negative moderator temperature coefficient. Postulating
that the Rod Control System is in automatic control, control rods would
be withdrawn as RCS temperature decreased, inserting additional positive
reactivity. The net effect on the RCS due to a reduction in feedwater
temperature would be similar to the effect of increasing feedwater flow
or increasing secondary steam flow; the reactor will reach a new
equilibrium condition at a power level corresponding to the new steam
generator ΔT.

A Feedwater System malfunction that results in a decrease in feedwater
temperature can be initiated from the following types of events:
spurious actuation of a feedwater heater bypass valve, interruption of
steam extraction flow to a feedwater heater(s), spurious startup of a
single auxiliary feedwater pump, failure of a single feedwater heater
drain pump or failure of all feedwater heater drain pumps. The above
events are examined, with the most limiting determined to be a spurious
actuation of a feedwater heater bypass valve. However, under the
current Duke Power Company method of analysis, this accident is bounded
by quantitative analysis of the increase in feedwater flow event or the
excessive increase in secondary steam flow event. These events bound
the reduction in feedwater temperature event by producing a greater RCS
cooldown. The applicable acceptance criterion is that fuel cladding
integrity shall be maintained by ensuring that the minimum DNBR remains
above the 95/95 DNBR limit based on acceptable correlations.

2.2   Feedwater System Malfunction Causing an Increase in
           Feedwater Flow

The malfunctions considered are 1) the full opening of a single main
feedwater control valve, 2) an increase in the speed of a single main
feedwater pump, 3) the spurious startup of a single auxiliary feedwater
pump, or 4) a malfunction which affects more than one loop. The
limiting scenario from among those listed above is evaluated to
demonstrate that fuel cladding integrity is maintained by ensuring that
the minimum DNBR remains above the 95/95 DNBR limit based on acceptable
correlations using the Statistical Core Design Methodology.

2.2.1   Nodalization

Of the events identified in the previous section, the latter, the multi-loop malfunction, is the most limiting, and is therefore the one that is discussed. This transient affects all loops equally and is therefore analyzed with a single-loop NSSS system model (Reference 2, Section 3.2).

2.2.2   Initial Conditions

Core Power Level
High initial power level maximizes the primary system heat flux. The uncertainty in this parameter is accounted for in the Statistical Core Design Methodology.

Pressurizer Pressure
The nominal pressure corresponding to full power operation is assumed, with the pressure initial condition uncertainty accounted for in the Statistical Core Design Methodology.

Pressurizer Level
Since this accident involves a reduction in RCS volume due to coolant contraction, a positive level uncertainty is applied to the nominal programmed level to minimize the initial pressurizer steam bubble volume and therefore maximize the pressure decrease due to contraction.

Reactor Vessel Average Temperature
The nominal temperature corresponding to full power operation is assumed, with the temperature initial condition uncertainty accounted for in the Statistical Core Design Methodology.

RCS Flow
The Technical Specification minimum measured flow for power operation is assumed since low flow is conservative for DNBR evaluation. The flow initial condition uncertainty is accounted for in the Statistical Core Design Methodology.

Core Bypass Flow
The nominal calculated flow is assumed, with the flow uncertainty accounted for in the Statistical Core Design Methodology.

Steam Generator Level
A negative level uncertainty is assumed to maximize the margin to a high-high steam generator narrow range level reactor trip due to any temporary steam/feedwater flow mismatch. This maximizes the duration of the overcooling before it is ended by feedwater isolation.

Fuel Temperature
A low initial temperature is assumed to maximize the gap conductivity calculated for steady-state conditions and used for the subsequent transient. A high gap conductivity minimizes the fuel heatup and attendant negative reactivity insertion caused by the power increase.

This makes the power increase more severe and is therefore conservative for DNBR evaluation.

Steam Generator Tube Plugging

In order to maximize the effects of the increased secondary system heat removal, no tube plugging is assumed.

2.2.3   Boundary Conditions

Main Feedwater Flow

A conservatively large step change in main feedwater flow to all steam generators is assumed at the initiation of the transient. A step decrease in main feedwater temperature is assumed to account for the increased main feedwater flow rate.

2.2.4   Control, Protection, and Safeguards Systems Modeling

Reactor Trip

The pertinent reactor trip functions are the low-low steam generator level, high flux and overpower ΔT. The safety analysis setpoint or the initial condition for the monitored parameter contains an allowance for measurement instrumentation uncertainty and setpoint setting tolerance.

Pressurizer Level Control

No credit is taken for pressurizer level control system operation to compensate for the depressurization which accompanies RCS volume shrinkage.

Rod Control

This accident will result in a decrease in RCS temperature. The reduced temperature will cause a positive reactivity insertion through the negative moderator temperature coefficient. With the Rod Control System in automatic control, the control rods may insert due to the mismatch between NI power and turbine power and cause a negative reactivity insertion. However, since the reactor vessel average temperature is maintained at a programmed value, the control rods may withdraw in an attempt to maintain this temperature and cause a positive reactivity insertion. Both automatic and manual control of the Rod Control System are analyzed in order to ensure that the worst case is determined.

Turbine Control

The turbine is modeled in the load control mode, which is described in Section 3.2.5.1 of Reference 2. In this mode any decrease in steam pressure, due for example to a shift from latent to sensible heat transfer because of the overfeed, would be compensated for by an opening of the turbine control valves to maintain impulse chamber pressure at the programmed value.

Auxiliary Feedwater

AFW flow would be credited, after the appropriate Technical Specification response time delay, when the safety analysis value of the

low-low steam generator level setpoint is reached. However, the parameter of interest for this transient has reached its limiting value before the appropriate Technical Specification response time delay has elapsed. Therefore, no AFW is actually delivered to the steam generators.

Turbine Trip
Turbine trip is credited, after the appropriate Technical Specification response time delay, on high-high steam generator narrow range level or on reactor trip.

Feedwater Isolation
Feedwater isolation is credited, after the appropriate Technical Specification response time delay, on high-high steam generator narrow range level.

2.3   Excessive Increase in Secondary Steam Flow

The accident analyzed is a step increase in secondary steam flow of a magnitude equal to that for which the Reactor Control System is designed, 10% of licensed core thermal power. Increases of larger magnitude are discussed in Section 2.4 and in Chapter 5 of Reference 1. The accident is analyzed to demonstrate that fuel cladding integrity is maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit based on acceptable correlations. The minimum DNBR is determined using the Statistical Core Design Methodology.

2.3.1   Nodalization

The accident analyzed is an excessive increase in secondary steam flow at power. Flow increases from a zero power initial condition are evaluated in Section 2.4 and in Chapter 5 of Reference 1. Per Reference 3, Section 15.1.4, the power level analyzed for this accident should be 102% of licensed core thermal power for the number of loops initially assumed to be operating. At power, the Technical Specifications require all four loops to be operating. Therefore full power is assumed as the initial condition. An increase in steam flow to the turbine would affect all loops equally, therefore, a single-loop NSSS system model (Reference 2, Section 3.2) is used.

2.3.2   Initial Conditions

Core Power Level
Per Reference 3, Section 15.1.4, the power level analyzed for this accident should be 102% of licensed core thermal power for the number of loops initially assumed to be operating. At power, the Technical Specifications require all four loops to be operating. Therefore full power is assumed as the initial condition. The uncertainty in initial power level is accounted for in the Statistical Core Design Methodology.

Pressurizer Pressure
The nominal pressure corresponding to full power operation is assumed, with the pressure initial condition uncertainty accounted for in the Statistical Core Design Methodology.

Pressurizer Level
Since this accident involves, particularly for the manual Rod Control System operation scenario, a reduction in RCS volume due to coolant contraction, a positive level uncertainty is assumed to minimize the initial pressurizer steam bubble volume and therefore maximize the pressure decrease due to contraction.

Reactor Vessel Average Temperature
The nominal temperature corresponding to full power operation is assumed, with the temperature initial condition uncertainty accounted for in the Statistical Core Design Methodology.

RCS Flow
The Technical Specification minimum measured flow for power operation is assumed since low flow is conservative for DNBR evaluation. The flow initial condition uncertainty is accounted for in the Statistical Core Design Methodology.

Core Bypass Flow
The nominal calculated flow is assumed, with the flow uncertainty accounted for in the Statistical Core Design Methodology.

Steam Generator Level
The results of this transient are not sensitive to the direction of steam generator level uncertainty as long as the transient level response is kept within the range that avoids protection or safeguards actuation.

Fuel Temperature
The results of this transient are not sensitive to initial fuel temperature.

Steam Generator Tube Plugging
In order to maximize the effects of the increased secondary system heat removal, no tube plugging is assumed.

2.3.3   Boundary Conditions

Main Steam Flow
A step change in main steam flow to the turbine equal to 10% of full power flow is assumed at the initiation of the transient.

2.3.4   Control, Protection, and Safeguards Systems Modeling

Reactor Trip
The reactor is not expected to trip for this transient. However, reactor trip is credited, after the appropriate Technical Specification response time delay, if the safety analysis setpoint is exceeded for any reactor trip function.

Pressurizer Level Control
No credit is taken for pressurizer level control system operation to compensate for the depressurization which accompanies RCS volume shrinkage.

Steam Line PORVs and Condenser Steam Dump
While the steam line PORVs and steam dump might be a source of the increased steam flow in this postulated accident, the case analyzed assumes the increased flow exits to the turbine.

Steam Generator Level Control
The results of this transient are not sensitive to the mode of steam generator level control as long as the level is kept within the range that avoids protection or safeguards actuation.

MFW Pump Speed Control
The results of this transient are not sensitive to the mode of MFW pump speed control as long as the steam generator level is kept within the range that avoids protection or safeguards actuation.

Rod Control
This accident will result in a decrease in RCS temperature. With the Rod Control System in manual control, the reduced temperature will cause a positive reactivity insertion through the negative moderator temperature coefficient. With the Rod Control System in automatic control, in which the reactor vessel average temperature is maintained at a programmed value, the control rods will cause a positive reactivity insertion as they are withdrawn in an attempt to maintain this temperature. Both cases are analyzed in order to ensure that the worse one is considered.

Turbine Control
The turbine is modeled as described in Section 3.2.5.1 of Reference 2, with a step increase in flow rate at the beginning of the accident.

Auxiliary Feedwater
AFW flow would be credited, after the appropriate Technical Specification response time delay, when the safety analysis value of the low-low steam generator level setpoint is reached. However, the parameter of interest for this transient has reached its limiting value before the appropriate Technical Specification response time delay has elapsed. Therefore, no AFW is actually delivered to the steam generators.

2.4   Inadvertent Opening of a Steam Generator Relief or Safety
           Valve

This accident is similar in most respects to the steam line break
accident analyzed in Chapter 5 of Reference 1. If the inadvertently
opened valve will not reseat, and cannot be isolated by closing a valve
in series with it, the effect is the same as a pipe break in the same
location and with the same effective flow area. Because the steam line
safety valves and the steam line power-operated relief valves (PORVs)
are located upstream of the MSIVs, a steam line isolation actuation,
with or without a failure of a single MSIV, would result in the
continued blowdown of the steam generator with the failed valve. The
applicable acceptance criterion is that fuel cladding integrity shall be
maintained by ensuring that the minimum DNBR remains above the 95/95
DNBR limit based on acceptable correlations. This criterion is satisfied
by comparison to the DNBR results for the more limiting steam line break
transient. The analytical methodology for the steam line break analysis
(Reference 1) is applied to an analysis of the inadvertent opening of a
steam generator relief or safety valve, with an appropriate adjustment
to the break flow area.

3.0   DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

3.1   Turbine Trip

The turbine trip event causes a loss of heat sink to the primary system.
The mismatch between power generation in the primary system and heat
removal by the secondary system causes temperature and pressure to
increase in the primary and secondary until reactor trip and/or lift of
the pressurizer safety valves and main steam safety valves. The
transient is analyzed to ensure that both the peak Reactor Coolant
System pressure and the peak Main Steam System pressure remain below the
acceptance criterion of 110% of design pressure. Peak RCS pressure and
peak Main Steam System pressure are analyzed separately due to the
differences in assumptions required for a conservative analysis.

3.1.1   Peak RCS Pressure Analysis

3.1.1.1   Nodalization

Since the transient response of the turbine trip event is the same for
all loops, the single-loop model described in Section 3.2 of Reference 2
is utilized for this analysis.

3.1.1.2   Initial Conditions

Core Power Level
High initial power level and a positive power uncertainty maximize the
primary-to-secondary power mismatch upon turbine trip.

Pressurizer Pressure
Positive uncertainty is applied to the initial pressurizer pressure.
High initial pressure reduces the initial margin to the overpressure
limit.

Pressurizer Level
High initial level minimizes the initial volume of the pressurizer steam
space, which maximizes the transient primary pressure response.

Reactor Vessel Average Temperature
High initial temperature maximizes the primary coolant stored energy,
which maximizes the transient primary pressure response.

RCS Flow
Low initial flow minimizes the primary-to-secondary heat transfer.

Core Bypass Flow
Core bypass flow is not an important parameter in this analysis.

Steam Generator Level

High initial level minimizes the initial volume of the steam generator steam space, which maximizes the transient secondary pressure response. Maximum secondary pressurization causes maximum secondary temperature response, which minimizes primary-to-secondary heat transfer.

Fuel Temperature

High fuel temperature, associated with low gap conductivity, minimizes the decrease in the temperature difference across the cladding as moderator temperature increases due to the turbine trip. This maximizes the transient heat flux and thus maximizes primary-to-secondary heat transfer.

Steam Generator Tube Plugging

A bounding high tube plugging value degrades primary-to-secondary heat transfer.

3.1.1.3   Boundary Conditions

Pressurizer Safety Valves

The pressurizer safety valves are modeled with opening and closing characteristics which maximize the pressurizer pressure.

Steam Line Safety Valves

The steam line safety valves are modeled with opening and closing characteristics which maximize transient secondary side pressure and minimize transient primary-to-secondary heat transfer.

3.1.1.4   Control, Protection, and Safeguards System Modeling

Reactor Trip

The pertinent reactor trip functions are the overtemperature ΔT (OTΔT), overpower ΔT (OPΔT), and pressurizer high pressure.

The response time of each of the two ΔT trip functions is the Technical Specification value. The setpoint values of the ΔT trip functions are continuously computed from system parameters using the modeling described in Section 3.2.4.2 of Reference 2. In addition, the ΔT coefficients used in the analysis account for instrument uncertainties.

The response time of the pressurizer high pressure trip function is the Technical Specification value. Since the pressure uncertainty is accounted for in the initial pressurizer pressure, the pressurizer high pressure reactor trip setpoint is the Technical Specification value.

Pressurizer Pressure Control

Pressurizer pressure control is in manual with sprays and PORVs disabled in order to maximize primary pressure.

Pressurizer Level Control
Pressurizer level control is in manual with the pressurizer heaters
locked on in order to elevate primary pressure. Charging/letdown has
negligible impact.

Steam Line PORVs and Condenser Steam Dump
Secondary steam relief via the steam line PORVs and the condenser steam
dump is unavailable in order to maximize secondary side pressurization
and minimize transient primary-to-secondary heat transfer.

Steam Generator Level Control
Feedwater is isolated upon turbine trip. The addition of subcooled
feedwater would tend to subcool the water in the steam generator, and
reduce secondary side pressure.

Rod Control
No credit is taken for the operation of the Rod Control System.
Following turbine trip, the turbine impulse chamber pressure is rapidly
reduced. The corresponding reduction in the Rod Control System
reference temperature would lead to control rod insertion, which would
lessen the severity of the transient.

Auxiliary Feedwater
Auxiliary feedwater is disabled. The addition of subcooled auxiliary
feedwater would tend to subcool the water in the steam generator, and
reduce secondary side pressure.

3.1.2   Peak Main Steam System Pressure Analysis

3.1.2.1   Nodalization

Since the transient response of the turbine trip event is the same for
all loops, the single-loop model described in Section 3.2 of Reference 2
is utilized for this analysis.

3.1.2.2   Initial Conditions

Core Power Level
High initial power level and a positive power uncertainty maximize the
primary-to-secondary power mismatch upon turbine trip.

Pressurizer Pressure
Positive uncertainty is applied to the initial pressurizer pressure. As
long as a high pressurizer pressure reactor trip is avoided, maximum
primary system pressure is conservative in order to delay reactor trip
on OTΔT.

Pressurizer Level
High initial level minimizes the initial volume of the pressurizer steam
space, which maximizes the transient primary pressure response.

Reactor Vessel Average Temperature
High initial temperature maximizes the initial Main Steam System pressure and the primary coolant stored energy.

RCS Flow
High initial flow maximizes the primary-to-secondary heat transfer.

Core Bypass Flow
Core bypass flow is not an important parameter in this analysis

Steam Generator Level
High initial level minimizes the initial volume of the steam generator steam space, which maximizes the transient secondary pressure response.

Fuel Temperature
High fuel temperature, associated with low gap conductivity, minimizes the decrease in the temperature difference across the cladding as moderator temperature increases due to the turbine trip. This maximizes the transient heat flux and thus maximizes primary-to-secondary heat transfer.

Steam Generator Tube Plugging
Zero tube plugging is modeled to maximize primary-to-secondary heat transfer.

3.1.2.3 Boundary Conditions

Pressurizer Safety Valves
The pressurizer safety valves are modeled with opening and closing characteristics which maximize the pressurizer pressure.

Steam Line Safety Valves
The steam line safety valves are modeled with opening and closing characteristics which maximize transient secondary side pressure.

3.1.2 4 Control, Protection, and Safeguards System Modeling

Reactor Trip
The pertinent reactor trip functions are the overtemperature ΔT (OTΔT), overpower ΔT (OPΔT), and pressurizer high pressure.

The response time of each of the two ΔT trip functions is the Technical Specification value. The setpoint values of the ΔT trip functions are continuously computed from system parameters using the modeling described in Section 3.2.4.2 of Reference 2. In addition, the ΔT coefficients used in the analysis account for instrument uncertainties.

The response time of the pressurizer high pressure trip function is the Technical Specification value. The pressurizer high pressure reactor trip setpoint is the Technical Specification value plus an allowance which bounds the instrument uncertainty.

Pressurizer Pressure Control

Pressurizer pressure control is in automatic with sprays and PORVs enabled in order to prevent a high pressurizer pressure reactor trip actuation prior to OTΔT trip actuation.

Pressurizer Level Control

Pressurizer level control is in manual with the pressurizer heaters locked on in order to elevate primary pressure. Charging/letdown has negligible impact.

Steam Line PORVs and Condenser Steam Dump

Secondary steam relief via the steam line PORVs and condenser steam dump is unavailable in order to maximize secondary side pressurization.

Steam Generator Level Control

The addition of subcooled feedwater would tend to subcool the water in the steam generator, and reduce secondary side pressure. However, continued feedwater addition will also tend to slow the heatup of the primary system and delay reactor trip on overtemperature ΔT. Both cases will be analyzed in order to ensure that the limiting boundary condition is selected.

Rod Control

No credit is taken for the operation of the Rod Control System. Following turbine trip, the turbine impulse chamber pressure is rapidly reduced. The corresponding reduction in the Rod Control System reference temperature would lead to control rod insertion, which would lessen the severity of the transient.

Auxiliary Feedwater

Auxiliary feedwater is disabled. The addition of subcooled auxiliary feedwater would tend to subcool the water in the steam generator, and reduce secondary side pressure.

3.2   Loss of Non-Emergency AC Power To The Station Auxiliaries

A loss of non-emergency AC power causes the power supply to all busses not powered by the emergency diesel generators to be lost. This leads to the trip of both the main feedwater pumps and the reactor coolant pumps. A primary system heatup ensues, due to both the coastdown of the reactor coolant pumps and the loss of main feedwater heat removal. As a result of this heatup, the primary concerns for this event are short-term core cooling capability (DNBR), long-term core cooling capability (natural circulation), and primary and secondary system overpressurization.

This transient differs from the complete loss of flow transient only in the timing of the insertion of the control rods. Both transients presume reactor coolant pump and feedwater pump trip as the initiating events. In the loss of flow event, the reactor trips when the reactor coolant pump bus undervoltage setpoint is reached and the rods begin to fall into the core after an instrumentation delay. In the loss of AC power

transient, the control rods begin to fall immediately due to the loss of gripper coil voltage. Therefore, the transient core power response and consequently the short-term core cooling capability result (DNBR) is bounded by the loss of flow event. Long-term core cooling capability is shown by analyzing the transition from forced flow to natural circulation following a loss of non-emergency AC power.

Similarly, the primary system temperature increase and, therefore, the peak primary system pressure is also bounded by the loss of flow event.

Secondary side pressure does not rise significantly until the turbine trip occurs and steam flow is terminated. The magnitude of this pressure increase is largely determined by the amount of heat transferred from the primary system to the secondary once the pressure increase has begun. For this event the reactor trip occurs prior to the turbine trip, such that the primary system heat generation is rapidly decreasing as secondary side pressure is increasing. Therefore, the peak secondary pressure result is bounded by the turbine trip event, in which the reactor trip occurs well after the turbine trip.

Based on the above qualitative evaluation, a quantitative analysis of this transient is not required except for the long-term core cooling capability analysis. Should a reanalysis become necessary, either due to plant changes, modeling changes, or other changes which invalidate any of the above arguments, the analytical methodology employed would be as follows.

Peak RCS pressure, peak Main Steam System pressure and core cooling capability (short-term and long-term) are each analyzed separately due to the differences in assumptions required for a conservative analysis. The short-term core cooling capability analysis demonstrates that fuel cladding integrity is maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit based on acceptable correlations. The minimum DNBR is determined using the Statistical Core Design Methodology. The long-term core cooling capability analysis demonstrates that natural circulation is established.

3.2.1   Peak RCS Pressure Analysis

3.2.1.1   Nodalization

Since the transient response of the loss of offsite power event is the same for all loops, the single-loop model described in Section 3.2 of Reference 2 is utilized for this analysis.

3.2.1.2   Initial Conditions

Core Power Level
High initial power level and a positive power uncertainty maximize the primary-to-secondary power mismatch.

Pressurizer Pressure
Positive instrument uncertainty is applied to the initial pressurizer pressure. High initial pressure reduces the initial margin to the overpressure limit.

Pressurizer Level
High initial level minimizes the initial volume of the pressurizer steam space, which maximizes the transient primary pressure response.

Reactor Vessel Average Temperature
High initial temperature maximizes the initial primary coolant stored energy, which maximizes the transient primary pressure response.

RCS Flow
Low initial flow degrades the primary-to-secondary heat transfer.

Core Bypass Flow
Core bypass flow is not an important parameter in this analysis.

Steam Generator Level
Initial steam generator level is not an important parameter in this analysis.

Fuel Temperature
Low fuel temperature, associated with high gap conductivity, maximizes the transient heat transfer from the fuel to the coolant.

Steam Generator Tube Plugging
A bounding high tube plugging value degrades primary-to-secondary heat transfer.

3.2.1.3   Boundary Conditions

RCP Operation
All four reactor coolant pumps are tripped at the initiation of the transient. The pump model is adjusted such that the resulting coastdown flow is conservative with respect to the flow coastdown test data.

Pressurizer Safety Valves
The pressurizer safety valves are modeled with opening and closing characteristics which maximize the pressurizer pressure.

Steam Line Safety Valves
The steam line safety valves are modeled with opening and closing characteristics which maximize transient secondary side pressure and minimize transient primary-to-secondary heat transfer.

3.2.1.4   Control, Protection, and Safeguards System Modeling

Reactor Trip
The insertion of all control and shutdown banks occurs when the power is lost to the control rod drive mechanism.

Pressurizer Pressure Control
Pressurizer pressure control is in manual with sprays and PORVs disabled in order to maximize primary pressure.

Pressurizer Level Control
Pressurizer level control is in automatic in order to maximize primary pressure. Charging/letdown has negligible impact.

Steam Line PORVs and Condenser Steam Dump
Secondary steam relief via the steam line PORVs and the condenser steam dump is unavailable in order to maximize secondary side pressurization and minimize transient primary-to-secondary heat transfer.

Auxiliary Feedwater
Auxiliary feedwater actuation occurs on the loss of offsite power after an appropriate Technical Specification response time delay. If applicable, a purge volume of hot main feedwater is assumed to be delivered prior to the cold AFW water reaching the steam generators. In order to minimize the post-trip steam generator heat removal, the minimum auxiliary feedwater flow is assumed.

Turbine Trip
Turbine trip occurs on the loss of offsite power.

3.2.2   Peak Main Steam System Pressure Analysis

3.2.2.1   Nodalization

Since the transient response of the loss of offsite power event is the same for all loops, the single-loop model described in Section 3.2 of Reference 2 is utilized for this analysis.

3.2.2.2   Initial Conditions

Core Power Level
High initial power level and a positive power uncertainty maximize the primary-to-secondary heat transfer.

Pressurizer Pressure
Pressurizer pressure is not an important parameter in this analysis.

Pressurizer Level
Since initial level primarily affects the transient primary pressure response, it is not an important parameter in this analysis.

Reactor Vessel Average Temperature
High initial temperature maximizes the initial Main Steam System pressure and the primary coolant stored energy.

RCS Flow
High initial flow maximizes the primary-to-secondary heat transfer.

Core Bypass Flow

Core bypass flow is not an important parameter in this analysis.

Steam Generator Level

High initial level minimizes the initial volume of the steam generator steam space, which maximizes the transient secondary pressure response.

Fuel Temperature

Low fuel temperature, associated with high gap conductivity, maximizes the transient heat transfer from the fuel to the coolant.

Steam Generator Tube Plugging

In order to maximize primary-to-secondary heat transfer, no tube plugging is modeled.

3.2.2.3   Boundary Conditions

RCP Operation

All four reactor coolant pumps trip on undervoltage at the initiation of the loss of offsite power. The pump model is adjusted such that the resulting coastdown flow is conservative with respect to the flow coastdown test data.

Pressurizer Safety Valves

The pressurizer safety valves are modeled with opening and closing characteristics which maximize pressurizer pressure.

Steam Line Safety Valves

The steam line safety valves are modeled with opening and closing characteristics which maximize transient secondary side pressure.

3.2.2.4   Control, Protection, and Safeguards System Modeling

Reactor Trip

The insertion of all control and shutdown banks occurs when the power is lost to the control rod drive mechanism.

Pressurizer Pressure Control

The operation of the pressurizer pressure control system is not important in this analysis.

Pressurizer Level Control

The operation of the pressurizer level control system is not important in this analysis.

Steam Line PORVs and Condenser Steam Dump

Secondary steam relief via the steam line PORVs and condenser steam dump is unavailable in order to maximize secondary side pressurization.

Auxiliary Feedwater

Auxiliary feedwater actuation occurs on the loss of offsite power after
the appropriate Technical Specification response time delay. If
applicable, a purge volume of hot main feedwater is assumed to be
delivered prior to the cold AFW water reaching the steam generators. In
order to minimize the post-trip steam generator heat removal, the
minimum auxiliary feedwater flow is assumed.

Turbine Trip

Turbine trip occurs on the loss of offsite power.

3.2.3   Core Cooling Capability Analysis - Short Term

3.2.3.1   Nodalization

Since the transient response of the loss of offsite power event is the
same for all loops, the single-loop model described in Section 3.2 of
Reference 2 is utilized for this analysis.

3.2.3.2   Initial Conditions

Core Power Level

High initial power level maximizes the primary system heat flux. The
uncertainty in this parameter is accounted for in the Statistical Core
Design Methodology.

Pressurizer Pressure

Nominal full power pressurizer pressure is assumed. The uncertainty in
this parameter is accounted for in the Statistical Core Design
Methodology.

Pressurizer Level

Low initial level increases the volume of the pressurizer steam space
which minimizes the pressure increase resulting from the insurge.

Reactor Vessel Average Temperature

Nominal full power vessel average temperature is assumed. The
uncertainty in this parameter is accounted for in the Statistical Core
Design Methodology.

RCS Flow

Technical Specification minimum measured Reactor Coolant System flow is
assumed. The uncertainty in this parameter is accounted for in the
Statistical Core Design Methodology.

Core Bypass Flow

The nominal calculated flow is assumed, with the flow uncertainty
accounted for in the Statistical Core Design Methodology.

Steam Generator Level
Initial steam generator level is not an important parameter in this analysis.

Fuel Temperature
A high initial temperature is assumed to minimize the gap conductivity calculated for steady-state conditions and used for the subsequent transient. A low gap conductivity minimizes the transient change in fuel rod surface heat flux associated with a power decrease. This makes the power decrease less severe and is therefore conservative for DNBR evaluation.

Steam Generator Tube Plugging
Steam generator tube plugging is not an important parameter in this analysis.

3.2.3.3   Boundary Conditions

Reactor Coolant Pumps
All reactor coolant pumps are assumed to trip on undervoltage at the initiation of the loss of offsite power. The pump model is adjusted such that the resulting coastdown flow is conservative with respect to the flow coastdown test data.

Decay Heat
End-of-cycle decay heat, based upon the ANSI/ANS-5.1-1979 standard plus a two-sigma uncertainty, is employed.

Steam Line Safety Valves
The main steam code safety valves are modeled with opening and closing characteristics which maximize secondary side pressure and minimize primary-to-secondary heat transfer.

3.2.3.4   Control, Protection, and Safeguards System Modeling

Reactor Trip
The insertion of all control and shutdown banks occurs when the power is lost to the control rod drive mechanism.

Pressurizer Pressure Control
Pressurizer sprays and PORVs are assumed to be operable in order to minimize the system pressure throughout the transient.

Pressurizer Level Control
Pressurizer heaters are assumed to be inoperable so that Reactor Coolant System pressure is minimized. Charging/letdown has negligible impact.

Steam Line PORVs and Condenser Steam Dump
Secondary steam relief via the steam line PORVs and the condenser steam dump is unavailable in order to maximize secondary side pressurization and minimize transient primary-to-secondary heat transfer.

Auxiliary Feedwater

Auxiliary feedwater actuation occurs on the loss of offsite power after the appropriate Technical Specification response time delay. If applicable, a purge volume of hot main feedwater is assumed to be delivered prior to the cold AFW water reaching the steam generators. In order to minimize the post-trip steam generator heat removal, the minimum auxiliary feedwater flow is assumed.

Turbine Trip

Turbine trip occurs on the loss of offsite power.

3.2.4   Core Cooling Capability Analysis - Long Term

3.2.4.1   Nodalization

Since the transient response of the loss of offsite power event is the same for all loops, the single loop model described in Section 3.2 of Reference 2 is utilized for this analysis.

3.2.4.2   Initial Conditions

Core Power Level
High initial power level and a positive power uncertainty maximize the primary system heat source.

Pressurizer Pressure
The nominal pressure corresponding to full power operation is assumed since the establishment of natural circulation is independent of initial pressurizer pressure.

Pressurizer Level
The nominal level corresponding to full power operation is assumed since the establishment of natural circulation is independent of initial pressurizer level.

Reactor Vessel Average Temperature
High initial temperature maximizes the amount of stored energy in the primary system that must be removed by the secondary system.

RCS Flow
Technical Specification minimum measured Reactor Coolant System flow is assumed since initial RCS flow has little impact on the final natural circulation flow.

Core Bypass Flow
Core bypass flow is not an important parameter in this analysis.

Steam Generator Level
High initial steam generator level minimizes the initial volume of the steam generator steam space, which maximizes the transient secondary pressure response. Maximum secondary pressurization causes maximum

secondary temperature response, which minimizes primary-to-secondary heat transfer.

Fuel Temperature
Initial fuel temperature is not an important parameter in this analysis.

Steam Generator Tube Plugging
A bounding high tube plugging value degrades primary-to-secondary heat transfer.

3.2.4.3   Boundary Conditions

Reactor Coolant Pumps
All reactor coolant pumps are assumed to trip on undervoltage at the initiation of the loss of offsite power.

Decay Heat
End-of-cycle decay heat, based upon the ANSI/ANS-5.1-1979 standard plus a two-sigma uncertainty, is employed.

Steam Line Safety Valves
The main steam code safety valves are modeled with opening and closing characteristics which maximize secondary side pressure and minimize primary-to-secondary heat transfer.

3.2.4.4   Control, Protection, and Safeguards System Modeling

Reactor Trip
The insertion of all control and shutdown banks occurs when the power is lost to the control rod drive mechanism.

Pressurizer Pressure Control
Pressurizer sprays are lost when the reactor coolant pumps trip. Pressurizer PORVs are lost when offsite power is lost. Therefore, both are inoperable.

Pressurizer Level Control
Pressurizer heaters are assumed to be inoperable since they are lost when offsite power is lost. Charging/letdown has negligible impact.

Steam Line PORVs and Condenser Steam Dump
Secondary steam relief via the steam line PORVs and the condenser steam dump is unavailable due to the loss of offsite power.

Auxiliary Feedwater
Auxiliary feedwater actuation occurs on the loss of offsite power after the appropriate Technical Specification response time delay. In order to minimize post-trip steam generator heat removal, the minimum auxiliary feedwater flow is assumed.

Turbine Trip
Turbine trip occurs on the loss of offsite power.

3.3   Loss Of Normal Feedwater

A loss of normal feedwater flow event could result due to the failure of
both of the main feedwater pumps or a malfunction of the feedwater
control valves. A primary system heatup ensues due to the degradation
of the secondary heat sink. As a result of this heatup, the primary
concerns for this event are core cooling capability and primary and
secondary system overpressurization.

The loss of normal feedwater transient is bounded by the turbine trip
transient. Both transients involve a mismatch between primary heat
source and secondary heat sink, but the mismatch is greater for the
turbine trip. This is mainly due to the reactor trip and turbine trip
occurring simultaneously for the loss of feedwater event, whereas
reactor trip lags the turbine trip during the turbine trip transient.

Based on the above qualitative evaluation, a quantitative analysis of
this transient is not required. Should a reanalysis become necessary,
either due to plant changes, modeling changes, or other changes which
invalidate any of the above arguments, the analytical methodology
employed would be as follows.

Peak RCS pressure, peak Main Steam System pressure and core cooling
capability are each analyzed separately due to the differences in
assumptions required for a conservative analysis. The core cooling
capability analysis demonstrates that the Auxiliary Feedwater System is
capable of returning the plant to a stabilized condition and that fuel
cladding integrity is maintained by ensuring that the minimum DNBR
remains above the 95/95 DNBR limit based on acceptable correlations.
The minimum DNBR is determined using the Statistical Core Design
Methodology.

3.3.1   Peak RCS Pressure Analysis

3.3.1.1   Nodalization

Since the transient response of the loss of normal feedwater event is
the same for all loops, the single-loop model described in Section 3.2
of Reference 2 is utilized for this analysis.

3.3.1.2   Initial Conditions

Core Power Level
High initial power level and a positive power uncertainty maximize the
primary-to-secondary power mismatch.

Pressurizer Pressure
Positive instrument uncertainty is applied to the initial pressurizer
pressure. High initial pressure reduces the initial margin to the
overpressure limit.

Pressurizer Level
High initial level minimizes the initial volume of the pressurizer steam space, which maximizes the transient primary pressure response.

Reactor Vessel Average Temperature
High initial temperature maximizes the initial primary coolant stored energy, which maximizes the transient primary pressure response.

RCS Flow
Low initial flow degrades the primary-to-secondary heat transfer.

Core Bypass Flow
Core bypass flow is not an important parameter in this analysis.

Steam Generator Level
Low initial level is assumed in order to minimize steam generator inventory at the time of reactor trip. The low-low level trip setpoint is adjusted to account for the difference between actual level and indicated level.

Fuel Temperature
Low fuel temperature, associated with high gap conductivity, maximizes the transient heat transfer from the fuel to the coolant.

Steam Generator Tube Plugging
A bounding high tube plugging value degrades primary-to-secondary heat transfer.

3.3.1.3   Boundary Conditions

Pressurizer Safety Valves
The pressurizer safety valves are modeled with opening and closing characteristics which maximize the pressurizer pressure.

Steam Line Safety Valves
The steam line safety valves are modeled with opening and closing characteristics which maximize transient secondary side pressure and minimize transient primary-to-secondary heat transfer.

Decay Heat
End-of-cycle decay heat, based upon the ANSI/ANS-5.1-1979 standard plus a two-sigma uncertainty, is employed.

3.3.1.4   Control, Protection, and Safeguards System Modeling

Reactor Trip
Reactor trip occurs on overtemperature ΔT, pressurizer high pressure, or when the low-low level setpoint is reached in the steam generator.

Pressurizer Pressure Control
Pressurizer pressure control is in manual with sprays and PORVs disabled in order to maximize primary pressure.

Pressurizer Level Control
Pressurizer level control is in automatic in order to maximize primary pressure. Charging/letdown has negligible impact.

Steam Line PORVs and Condenser Steam Dump
Secondary steam relief via the steam line PORVs and the condenser steam dump is unavailable in order to maximize secondary side pressurization and minimize transient primary-to-secondary heat transfer.

Rod Control
No credit is taken for the operation of the Rod Control System for this transient, which results in an increase in RCS temperature. With the Rod Control System in automatic, the control rods would cause a negative reactivity addition as they are inserted in an attempt to maintain RCS temperature at its nominal value.

Turbine Control
The turbine is modeled in the load control mode, which is described in Section 3.2.5.1 of Reference 2.

Auxiliary Feedwater
Auxiliary feedwater actuation occurs on low-low steam generator level after the appropriate Technical Specification response time delay. If applicable, a purge volume of hot main feedwater is assumed to be delivered prior to the cold AFW water reaching the steam generators. In order to minimize the post-trip steam generator heat removal, the minimum auxiliary feedwater flow is assumed.

3.3.2   Peak Main Steam System Pressure Analysis

3.3.2.1   Nodalization

Since the transient response of the loss of normal feedwater event is the same for all loops, the single-loop model described in Section 3.2 of Reference 2 is utilized for this analysis.

3.3.2.2   Initial Conditions

Core Power Level
High initial power level and a positive power uncertainty maximize the primary-to-secondary power mismatch.

Pressurizer Pressure
Pressurizer pressure is not an important parameter in this analysis.

Pressurizer Level
Pressurizer level is not an important parameter in this analysis.

Reactor Vessel Average Temperature
High initial temperature maximizes the initial Main Steam System pressure and the primary coolant stored energy.

RCS Flow
High initial flow maximizes the primary-to-secondary heat transfer.

Core Bypass Flow
Core bypass flow is not an important parameter in this analysis.

Steam Generator Level
Low initial level is assumed in order to minimize steam generator inventory at the time of reactor trip. The low-low level trip setpoint is adjusted to account for the difference between actual level and indicated level.

Fuel Temperature
Low fuel temperature, associated with high gap conductivity, maximizes the transient heat transfer from the fuel to the coolant.

Steam Generator Tube Plugging
Zero tube plugging is modeled to maximize primary-to-secondary heat transfer.

3.3.2.3   Boundary Conditions

Pressurizer Safety Valves
The pressurizer safety valves are modeled with opening and closing characteristics which maximize the pressurizer pressure.

Steam Line Safety Valves
The steam line safety valves are modeled with opening and closing characteristics which maximize transient secondary side pressure.

Decay Heat
End-of-cycle decay heat, based upon the ANSI/ANS-5.1-1979 standard plus a two-sigma uncertainty, is employed.

3.3.2.4   Control, Protection, and Safeguards System Modeling

Reactor Trip
Reactor trip occurs on overtemperature ΔT, pressurizer high pressure, or when the low-low level setpoint is reached in the steam generator.

Pressurizer Pressure Control
The results of this transient are not sensitive to the operation of pressurizer pressure control as long as the pressure is controlled to within the range that avoids protection or safeguards actuation.

3.3.3.4 Control, Protection, and Safeguards System Modeling

Reactor Trip
Reactor trip occurs on overtemperature ΔT, pressurizer high pressure, or when the low-low level setpoint is reached in the steam generator.

Pressurizer Pressure Control
Pressurizer sprays and PORVs are assumed to be operable in order to minimize the system pressure throughout the transient.

Pressurizer Level Control
No credit is taken for pressurizer heater operation so that Reactor Coolant System pressure is minimized. Charging/letdown has negligible impact.

Steam Line PORVs and Condenser Steam Dump
Secondary steam relief via the steam line PORVs and the condenser steam dump is unavailable in order to maximize secondary side pressurization and minimize transient primary-to-secondary heat transfer.

Rod Control
No credit is taken for the operation of the Rod Control System for this transient, which results in an increase in RCS temperature. With the Rod Control System in automatic, the control rods would cause a negative reactivity addition as they are inserted in an attempt to maintain RCS temperature at its nominal value.

Turbine Control
The turbine is modeled in the load control mode, which is described in Section 3.2.5.1 of Reference 2.

Auxiliary Feedwater
Auxiliary feedwater actuation occurs on low-low steam generator level after the appropriate Technical Specification response time delay. If applicable, a purge volume of hot main feedwater is assumed to be delivered prior to the cold AFW water reaching the steam generators. In order to minimize the post-trip steam generator heat removal, the minimum auxiliary feedwater flow is assumed.

Turbine Trip
Turbine trip occurs on reactor trip.

3.4 Feedwater System Pipe Break

The feedwater system pipe break event postulates a rupture of the Main Feedwater System piping just upstream of the steam generator (downstream of the final feedline check valve). Following the blowdown of the faulted generator, there is a mismatch between the heat generation in the reactor and the secondary side heat removal rate. Due to the mismatch, the primary concern for this transient is the capability to effectively cool the reactor core.

Adequate short term and long term core cooling capability are analyzed separately due to the differences in assumptions required for a conservative analysis. The short term core cooling capability analysis demonstrates that fuel cladding integrity is maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit based on acceptable correlations. The minimum DNBR is determined using the Statistical Core Design Methodology. The long term core cooling capability analysis demonstrates that no hot leg boiling occurs.

3.4.1 Short Term Core Cooling Capability

The DNB analysis for this transient is modeled as a complete loss of coolant flow event initiated from an off-normal condition. The loss of flow is assumed to occur coincident with the OTΔT reactor trip caused by the feedline break heatup.

3.4.1.1 Nodalization

Since the complete loss of flow transient is symmetrical with respect to the four reactor coolant loops, a single-loop model (Reference 2, Section 3.2) is utilized for this analysis.

3.4.1.2 Initial Conditions

Core Power Level
High initial power level maximizes the primary system heat flux. The uncertainty in this parameter is accounted for in the Statistical Core Design Methodology.

Pressurizer Pressure
Nominal full power pressurizer pressure is assumed. The uncertainty in this parameter is accounted for in the Statistical Core Design Methodology.

Pressurizer Level
Low initial level increases the volume of the pressurizer steam space which minimizes the pressure increase resulting from the insurge.

Reactor Vessel Average Temperature
Nominal full power vessel average temperature is assumed. The uncertainty in this parameter is accounted for in the Statistical Core Design Methodology.

RCS Flow
Minimum measured Reactor Coolant System flow is assumed. The uncertainty in this parameter is accounted for in the Statistical Core Design Methodology.

Pressurizer Level Control
The results of this transient are not sensitive to the operation of pressurizer level control as long as the level is kept within the range that avoids protection or safeguards actuation.

Steam Line PORVs and Condenser Steam Dump
Secondary steam relief via the steam line PORVs and condenser steam dump is unavailable in order to maximize the transient secondary side pressurization.

Rod Control
No credit is taken for the operation of the Rod Control System for this transient, which results in an increase in RCS temperature. With the Rod Control System in automatic, the control rods would cause a negative reactivity addition as they are inserted in an attempt to maintain RCS temperature at its nominal value.

Turbine Control
The turbine is modeled in the load control mode, which is described in Section 3.2.5.1 of Reference 2.

Auxiliary Feedwater
Auxiliary feedwater actuation occurs on low-low steam generator level after the appropriate Technical Specification response time delay. If applicable, a purge volume of hot main feedwater is assumed to be delivered prior to the cold AFW water reaching the steam generators. In order to minimize the post-trip steam generator heat removal, the minimum auxiliary feedwater flow is assumed.

3.3.3   Core Cooling Capability Analysis

3.3.3.1   Nodalization

Since the transient response of the loss of normal feedwater event is the same for all loops, the single-loop model described in Section 3.2 of Reference 2 is utilized for this analysis. For Catawba Unit 2 only, the post-trip phase of the analysis uses a single-volume steam generator secondary model. This model uses the bubble rise option with the local-conditions heat transfer model applied to the steam generator tube conductors.

3.3.3.2   Initial Conditions

Core Power Level
High initial power level maximizes the primary system heat flux. The uncertainty in this parameter is accounted for in the Statistical Core Design Methodology.

Pressurizer Pressure
Nominal full power pressurizer pressure is assumed. The uncertainty in this parameter is accounted for in the Statistical Core Design Methodology.

Pressurizer Level
Low initial level increases the volume of the pressurizer steam space which minimizes the pressure increase resulting from the insurge.

Reactor Vessel Average Temperature
Nominal full power vessel average temperature is assumed. The uncertainty in this parameter is accounted for in the Statistical Core Design Methodology.

RCS Flow
Minimum measured Reactor Coolant System flow is assumed. The uncertainty in this parameter is accounted for in the Statistical Core Design Methodology.

Core Bypass Flow
The nominal calculated flow is assumed, with the flow uncertainty accounted for in the Statistical Core Design Methodology.

Steam Generator Tube Plugging
A bounding high tube plugging level impairs the ability of the secondary side to remove primary side heat.

Fuel Temperature
A high initial temperature is assumed to minimize the gap conductivity calculated for steady-state conditions and used for the subsequent transient. A low gap conductivity minimizes the transient change in fuel rod surface heat flux associated with a power decrease. This makes the power decrease less severe and is therefore conservative for DNBR evaluation.

Steam Generator Level
Low initial level is assumed in order to minimize steam generator inventory at the time of reactor trip. The low-low level trip setpoint is adjusted to account for the difference between actual level and indicated level.

3.3.3.3   Boundary Conditions

Steam Line Safety Valves
The main steam code safety valves are modeled with opening and closing characteristics which maximize secondary side pressure and minimize primary-to-secondary heat transfer.

Decay Heat
End-of-cycle decay heat, based upon the ANSI/ANS-5.1-1979 standard plus a two-sigma uncertainty, is employed.

<u>Core Bypass Flow</u>
The nominal calculated flow is assumed, with the flow uncertainty
accounted for in the Statistical Core Design Methodology.

<u>Fuel Temperature</u>
A high initial temperature is assumed to minimize the gap conductivity
calculated for steady-state conditions and used for the subsequent
transient. A low gap conductivity minimizes the transient change in
fuel rod surface heat flux associated with a power decrease. This makes
the power decrease less severe and is therefore conservative for DNBR
evaluation.

<u>Steam Generator Level</u>
Initial steam generator level is not an important parameter in this
analysis.

<u>Steam Generator Tube Plugging</u>
For transients of such short duration, steam generator tube plugging
does not have an effect on the transient results.

3.4.1.3   Boundary Conditions

<u>Steam Line Safety Valves</u>
The main steam code safety valves are modeled with opening and closing
characteristics which maximize secondary side pressure and minimize
primary-to-secondary heat transfer.

3.4.1.4   Control, Protection, and Safeguards System Modeling

<u>Reactor Trip</u>
Reactor trip occurs on overtemperature ΔT following the heatup due to
the heat transfer mismatch. Earlier trips on high containment pressure
safety injection and low-low steam generator level are not credited in
order to maximize the primary system heatup.

<u>Pressurizer Pressure Control</u>
Pressurizer sprays and PORVs are assumed to be operable in order to
minimize the system pressure throughout the transient.

<u>Pressurizer Level Control</u>
Pressurizer heaters are assumed to be inoperable so that Reactor Coolant
System pressure is minimized. Charging/letdown has negligible impact.

<u>Steam Line PORVs and Condenser Steam Dump</u>
Secondary steam relief via the steam line PORVs and the condenser steam
dump is unavailable in order to maximize secondary side pressurization
and minimize transient primary-to-secondary heat transfer.

<u>Rod Control</u>
No credit is taken for the operation of the Rod Control System for this
transient, which results in an increase in RCS temperature. With the

Rod Control System in automatic, the control rods would cause a negative reactivity addition as they are inserted in an attempt to maintain RCS temperature at its nominal value.

Turbine Control
The turbine is modeled in the load control mode, which is described in Section 3.2.5.1 of Reference 2.

Auxiliary Feedwater
AFW flow would be credited when the safety analysis value of the low-low steam generator level setpoint is reached. However, the parameter of interest for this transient has reached its limiting value before the appropriate Technical Specification response time delay has elapsed. Therefore, no AFW is actually delivered to the steam generators.

Turbine Trip
The reactor trip leads to a subsequent turbine trip.

3.4.2   Long Term Core Cooling Capability

3.4.2.1   Nodalization

Due to the asymmetry of the auxiliary feedwater flow boundary condition in the feedline break transient, a three-loop model (Reference 2, Section 3.2), with two single loops and one double loop, is utilized for this analysis.

3.4.2.2   Initial Conditions

Core Power Level
High initial power level and a positive power uncertainty maximize the primary system heat load.

Pressurizer Pressure
Low initial pressure causes a corresponding decrease in the hot leg saturation temperature, which minimizes the margin to hot leg boiling and is conservative for demonstrating long term core cooling.

Pressurizer Level
Low initial level increases the volume of the pressurizer steam space which minimizes the pressure increase resulting from the insurge.

Reactor Vessel Average Temperature
High initial temperature increases the stored energy in the primary system which must be removed by the degraded secondary side.

RCS Flow
Low initial flow degrades the primary-to-secondary heat transfer.

Core Bypass Flow
Core bypass flow is not an important parameter in this analysis.

Steam Generator Level
Low initial level in all steam generators decreases the long-term
capability of the secondary system to remove primary system heat.

Fuel Temperature
A conservatively high initial fuel temperature is assumed in order to
maximize the amount of stored energy that must be removed.

Steam Generator Tube Plugging
Tube plugging does not significantly affect the transient results so
long as the minimum Technical Specification RCS flow rate is used.

3.4.2.3   Boundary Conditions

Break Modeling
The feedline break is modeled as a double-ended rupture of the main
feedwater line just upstream of the steam generator (downstream of the
check valve). A bounding flow area of the break junction is assumed in
order to maximize the break flow rate. The break flow rate is
determined by the Henry (subcooled) and Moody (saturated) critical flow
correlations.

Reactor Coolant Pumps
The reactor coolant pumps are lost at the initiation of the loss of
offsite power which occurs coincident with reactor trip.

Offsite Power
Offsite power is assumed to be lost coincident with reactor trip to
delay safety injection and accelerate the post-trip heatup due to the
loss of the reactor coolant pumps.

Pressurizer Safety Valves
The pressurizer safety valves are modeled with opening and closing
characteristics which minimize pressurizer pressure.

Steam Line Safety Valves
The main steam code safety valves are modeled with opening and closing
characteristics which maximize secondary side pressure and minimize
primary-to-secondary heat transfer.

Decay Heat
End-of-cycle decay heat, based upon the ANSI/ANS-5.1-1979 standard plus
a two-sigma uncertainty, is employed.

3.4.2.4   Control, Protection, and Safeguards System Modeling

Reactor Trip
The reactor is tripped 10 seconds into the transient. This is assumed to
be after the occurrence of safety injection actuation on high
containment pressure.

Pressurizer Pressure Control

Since low Reactor Coolant System pressure is conservative and the blowdown pressure of a cycling safety valve is much lower than for a cycling PORV, the PORVs are assumed inoperable. Pressurizer spray is assumed to be operable in order to minimize system pressure.

Pressurizer Level Control

Pressurizer heaters are assumed to be inoperable so that Reactor Coolant System pressure is minimized. Charging/letdown has negligible impact.

Steam Line PORVs and Condenser Steam Dump

Secondary steam relief via the steam line PORVs and the condenser steam dump is unavailable in order to maximize secondary side pressurization and minimize transient primary-to-secondary heat transfer.

Rod Control

No credit is taken for the operation of the Rod Control System for this transient, since the pre-trip RCS temperature change is insufficient to cause rod motion.

Turbine Control

The turbine is modeled in the load control mode, which is described in Section 3.2.5.1 of Reference 2.

Safety Injection

Safety injection actuation occurs at 10 seconds on high containment pressure. Injection begins after the appropriate Technical Specification delay to allow for the startup of the diesel generators on the loss of offsite power. One-train minimum injection flow, as a function of RCS pressure, is assumed to minimize the delivery of cold SI water. Injection is stopped when the emergency procedure SI termination criteria are met.

Auxiliary Feedwater

Auxiliary feedwater actuation occurs on safety injection actuation after the appropriate Technical Specification response time delay. If applicable, a purge volume of hot water is assumed to be delivered prior to the cold AFW water reaching the steam generators. Operator action to isolate AFW flow to the faulted generator occurs with a conservative delay time to minimize the amount of cold AFW flow to the faulted generator. In order to minimize the post-trip steam generator heat removal, the minimum auxiliary feedwater flow is assumed.

MSIV Closure

Early MSIV closure is conservative since it accelerates the heatup portion of the transient due to the faulted SG reaching dryout sooner following MSIV closure. Main steam line isolation occurs on low steam line pressure or high-high containment pressure. Since neither of these setpoints can be reached before reactor trip, it is conservatively assumed that MSIV closure occurs coincident with turbine trip.

4.0   DECREASE IN REACTOR COOLANT SYSTEM FLOW RATE

4.1   Partial Loss of Forced Reactor Coolant Flow

A partial loss of forced reactor coolant flow can result from a
mechanical or electrical failure in a reactor coolant pump, or from a
fault in the power supply to the pump. If the reactor is at power when
such a fault occurs, this could result in DNB with subsequent fuel
damage if the reactor is not tripped promptly. The necessary protection
against a partial loss of coolant flow is provided by the low reactor
coolant flow reactor trip signal.

The acceptance criteria for this analysis are to ensure that there is
adequate core cooling capability and that the pressure in the Reactor
Coolant System remains below 110% of design pressure. The core cooling
capability analysis demonstrates that fuel cladding integrity is main-
tained by ensuring that the minimum DNBR remains above the 95/95 DNBR
limit based on acceptable correlations. The minimum DNBR is determined
using the Statistical Core Design Methodology. The peak RCS pressure
criterion is met through a comparison to the peak pressure results for
the more limiting locked rotor transient. In Section 4.3 of this
report, the locked rotor event is shown to remain below 110% of the RCS
design pressure.

4.1.1   Nodalization

This non-symmetric transient is analyzed using a two-loop model, with a
single loop for the tripped reactor coolant pump and an intact triple
loop.

4.1.2   Initial Conditions

Core Power Level
High initial power level maximizes the primary system heat flux. The
uncertainty for this parameter is incorporated in the Statistical Core
Design Methodology.

Pressurizer Pressure
The nominal pressure corresponding to full power operation is assumed,
with the uncertainty for this parameter incorporated in the Statistical
Core Design Methodology.

Pressurizer Level
Low initial level increases the volume of the pressurizer steam space
which minimizes the pressure increase resulting from the insurge.

Reactor Vessel Average Temperature
The nominal temperature corresponding to full power operation is
assumed, with the uncertainty for this parameter incorporated in the
Statistical Core Design Methodology.

RCS Flow
The Technical Specification minimum measured flow for power operation is assumed since low flow is conservative for DNBR evaluation. The uncertainty for this parameter is incorporated in the Statistical Core Design Methodology.

Core Bypass Flow
The nominal calculated flow is assumed, with the flow uncertainty accounted for in the Statistical Core Design Methodology.

Steam Generator Level
Initial steam generator level is not an important parameter in this analysis.

Fuel Temperature
A high initial temperature is assumed to minimize the gap conductivity calculated for steady-state conditions and used for the subsequent transient. A low gap conductivity minimizes the transient change in fuel rod surface heat flux associated with a power decrease. This makes the power decrease less severe and is therefore conservative for DNBR evaluation.

Steam Generator Tube Plugging
For transients of such short duration, steam generator tube plugging does not have an effect on the transient results.

4.1.3   Boundary Conditions

RCP Operation
A single reactor coolant pump is assumed to trip. The other three reactor coolant pumps remain operating for the duration of the transient. The reactor coolant pump model is adjusted such that the resulting pump coastdown is conservative with respect to the flow coastdown test data.

Steam Line Safety Valves
The main steam code safety valves are modeled with opening and closing characteristics which maximize secondary pressure and minimize primary-to-secondary heat transfer.

4.1.4   Control, Protection, and Safeguards System Modeling

Reactor Trip
A reactor trip signal is generated when flow in the affected loop falls below a setpoint which conservatively bounds the Technical Specification value. A delay time consistent with the Technical Specifications is assumed between receipt of the low flow signal and the initiation of control rod motion.

Pressurizer Pressure Control
Pressurizer sprays and PORVs are assumed to be operable in order to minimize the system pressure throughout the transient.

Pressurizer Level Control
Pressurizer heaters are assumed to be inoperable so that Reactor Coolant System pressure is minimized. Charging/letdown has negligible impact.

Steam Line PORVs and Condenser Steam Dump
Secondary steam relief via the steam line PORVs and the condenser steam dump is unavailable in order to maximize secondary side pressurization and minimize transient primary-to-secondary heat transfer.

Steam Generator Level Control
The results of this transient are not sensitive to the mode of steam generator level control as long as the level is kept within the range that avoids protection or safeguards actuation.

MFW Pump Speed Control
The results of this transient are not sensitive to the mode of MFW pump speed control as long as the steam generator level is kept within the range that avoids protection or safeguards actuation.

Rod Control
No credit is taken for the operation of the Rod Control System for this transient, which results in an increase in RCS temperature. With the Rod Control System in automatic, the control rods would cause a negative reactivity addition as they are inserted in an attempt to maintain RCS temperature at its nominal value.

Turbine Control
The turbine is modeled in the load control mode, which is described in Section 3.2.5.1 of Reference 2.

Auxiliary Feedwater
AFW flow would be credited when the safety analysis value of the low-low steam generator level setpoint is reached. However, the parameter of interest for this transient has reached its limiting value before the appropriate Technical Specification response time delay has elapsed. Therefore, no AFW is actually delivered to the steam generators.

Turbine Trip
The reactor trip leads to a subsequent turbine trip.

4.2   Complete Loss Of Forced Reactor Coolant Flow

A complete loss of forced reactor coolant flow would occur if all four reactor coolant pumps tripped due to either a common mode failure or a simultaneous loss of power to the pump motors. The Reactor Protection System (RPS) senses an undervoltage condition at the pumps and initiates a reactor trip. The decrease in core flow which occurs prior to reactor trip causes a heatup of the Reactor Coolant System.

The acceptance criteria for this analysis are to ensure that there is
adequate core cooling capability and that the pressure in the Reactor
Coolant System remains below 110% of design pressure. The core cooling
capability analysis demonstrates that fuel cladding integrity is main-
tained by ensuring that the minimum DNBR remains above the 95/95 DNBR
limit based on acceptable correlations. The minimum DNBR is determined
using the Statistical Core Design Methodology. The peak RCS pressure
criterion is met through a comparison to the peak pressure results for
the more limiting locked rotor transient. In Section 4.3 of this
report, the locked rotor event is shown to remain below 110% of the RCS
design pressure.

4.2.1   Nodalization

Since the complete loss of flow transient is symmetrical with respect to
the four reactor coolant loops, a single-loop model (Reference 2,
Section 3.2) is utilized for this analysis.

4.2.2   Initial Conditions

Core Power Level
High initial power level maximizes the primary system heat flux. The
uncertainty in this parameter is accounted for in the Statistical Core
Design Methodology.

Pressurizer Pressure
Nominal full power pressurizer pressure is assumed. The uncertainty in
this parameter is accounted for in the Statistical Core Design
Methodology.

Pressurizer Level
Low initial level increases the volume of the pressurizer steam space
which minimizes the pressure increase resulting from the insurge.

Reactor Vessel Average Temperature
Nominal full power vessel average temperature is assumed. The
uncertainty in this parameter is accounted for in the Statistical Core
Design Methodology.

RCS Flow
Minimum measured Reactor Coolant System flow is assumed. The
uncertainty in this parameter is accounted for in the Statistical Core
Design Methodology.

Bypass Flow
The nominal calculated flow corresponding to full power operation is
assumed, with the flow uncertainty accounted for in the Statistical Core
Design Methodology.

Steam Generator Level
Initial steam generator level is not an important parameter in this
analysis.

Fuel Temperature
A high initial temperature is assumed to minimize the gap conductivity
calculated for steady-state conditions and used for the subsequent
transient. A low gap conductivity minimizes the transient change in
fuel rod surface heat flux associated with a power decrease. This makes
the power decrease less severe and is therefore conservative for DNBR
evaluation.

Steam Generator Tube Plugging
For transients of such short duration, steam generator tube plugging
does not have an effect on the transient results.

4.2.3   Boundary Conditions

RCP Operation
All four reactor coolant pumps are tripped at the initiation of the
transient. The pump model is adjusted such that the resulting coastdown
flow is conservative with respect to the flow coastdown test data.

Steam Line Safety Valves
The main steam code safety valves are modeled with opening and closing
characteristics which maximize secondary side pressure and minimize
primary-to-secondary heat transfer.

4.2.4   Control, Protection, and Safeguards System Modeling

Reactor Trip
Reactor trip occurs on reactor coolant pump undervoltage, after an
appropriate instrumentation delay.

Pressurizer Pressure Control
Pressurizer sprays and PORVs are assumed to be operable in order to
minimize the system pressure throughout the transient.

Pressurizer Level Control
Pressurizer heaters are assumed to be inoperable so that Reactor Coolant
System pressure is minimized. Charging/letdown has negligible impact.

Steam Line PORVs and Condenser Steam Dump
Secondary steam relief via the steam line PORVs and the condenser steam
dump is unavailable in order to maximize secondary side pressurization
and minimize transient primary-to-secondary heat transfer.

Steam Generator Level Control
The results of this transient are not sensitive to the mode of steam
generator level control as long as the level is kept within the range
that avoids protection or safeguards actuation.

MFW Pump Speed Control
The results of this transient are not sensitive to the mode of MFW pump
speed control as long as the steam generator level is kept within the
range that avoids protection or safeguards actuation.

Rod Control

No credit is taken for the operation of the Rod Control System for this
transient, which results in an increase in RCS temperature. With the
Rod Control System in automatic, the control rods would cause a negative
reactivity addition as they are inserted in an attempt to maintain RCS
temperature at its nominal value.

Turbine Control

The turbine is modeled in the load control mode, which is described in
Section 3.2.5.1 of Reference 2.

Auxiliary Feedwater

AFW flow would be credited when the safety analysis value of the low-low
steam generator level setpoint is reached. However, the parameter of
interest for this transient has reached its limiting value before the
appropriate Technical Specification response time delay has elapsed.
Therefore, no AFW is actually delivered to the steam generators.

Turbine Trip

The reactor trip leads to a subsequent turbine trip.

4.3   Reactor Coolant Pump Locked Rotor

The postulated accident involves the instantaneous seizure of one
reactor coolant pump rotor. Coolant flow in that loop is rapidly
reduced, causing the Reactor Protection System (RPS) to initiate a
reactor trip on low RCS loop flow. The mismatch between power generation
and heat removal capacity due to the degraded flow condition causes a
heatup of the primary system.

The acceptance criteria for this analysis are to ensure that there is
adequate core cooling capability and that the pressure in the Reactor
Coolant System remains below 110% of design pressure. Peak RCS pressure
and core cooling capability are analyzed separately due to the
differences in assumptions required for a conservative analysis. The
core cooling capability analysis determines to what extent fuel cladding
integrity is compromised by calculating the number of fuel rods that
exceed the 95/95 DNBR limit based on acceptable correlations.

4.3.1   Peak RCS Pressure Analysis

4.3.1.1   Nodalization

Due to the asymmetry of the transient, a two-loop model (Reference 2,
Section 3.2), with a faulted single loop and an intact triple loop, is
utilized for this analysis.

4.3.1.2   Initial Conditions

Core Power Level
High initial power level and a positive power uncertainty maximize the
primary system heat load.

Pressurizer Pressure
High initial pressure yields a smaller margin to overpressurization.

Pressurizer Level
High initial level decreases the volume of the pressurizer steam space
which maximizes the pressure increase resulting from the insurge.

Reactor Vessel Average Temperature
High initial temperature maximizes the initial primary coolant stored
energy, which maximizes the transient primary pressure response.

RCS Flow
Low initial flow minimizes the primary-to-secondary heat transfer.

Core Bypass Flow
High core bypass flow minimizes coolant flow through the core and
exacerbates heatup.

Steam Generator Level
Initial steam generator level is not an important parameter in this
analysis.

Fuel Temperature
 A high initial temperature is assumed to minimize the gap conductivity
calculated for steady-state conditions and used for the subsequent
transient. A low gap conductivity minimizes the transient change in
fuel rod surface heat flux associated with a power decrease. This makes
the power decrease less severe and thus maximizes primary pressure.

Steam Generator Tube Plugging
For transients of such short duration, steam generator tube plugging
does not have an effect on the transient results.

4.3.1.3   Boundary Conditions

Reactor Coolant Pumps
The rotor of the reactor coolant pump in the faulted loop is assumed to
seize at the initiation of the transient. The remaining reactor coolant
pumps trip on bus undervoltage following the loss of offsite power.

Offsite Power
Offsite power is assumed to be lost coincident with the turbine trip.

Pressurizer Safety Valves
The pressurizer safety valves are modeled with opening and closing
characteristics which maximize pressurizer pressure.

Steam Line Safety Valves

The main steam code safety valves are modeled with opening and closing
characteristics which maximize secondary side pressure and minimize
primary-to-secondary heat transfer.

4.3.1.4   Control, Protection, and Safeguards System Modeling

Reactor Trip

Reactor trip occurs on low Reactor Coolant System flow in the locked
loop.

Pressurizer Pressure Control

In order to maximize primary system pressure, no credit is taken for
pressurizer spray or PORV operation.

Pressurizer Level Control

Pressurizer heaters are assumed to be operable in order to maximize
Reactor Coolant System pressure resulting from the insurge/level
increase. Charging/letdown has negligible impact.

Steam Line PORVs and Condenser Steam Dump

Secondary steam relief via the steam line PORVs and the condenser steam
dump is unavailable in order to maximize secondary side pressurization
and minimize transient primary-to-secondary heat transfer.

Steam Generator Level Control

The results of this transient are not sensitive to the mode of steam
generator level control as long as the level is kept within the range
that avoids protection or safeguards actuation.

MFW Pump Speed Control

The results of this transient are not sensitive to the mode of MFW pump
speed control as long as the steam generator level is kept within the
range that avoids protection or safeguards actuation.

Rod Control

No credit is taken for the operation of the Rod Control System for this
transient, which results in an increase in RCS temperature. With the
Rod Control System in automatic, the control rods would cause a negative
reactivity addition as they are inserted in an attempt to maintain RCS
temperature at its nominal value.

Turbine Control

The turbine is modeled in the load control mode, which is described in
Section 3.2.5.1 of Reference 2.

Auxiliary Feedwater

AFW flow would be credited when the safety analysis value of the low-low
steam generator level setpoint is reached. However, the parameter of
interest for this transient has reached its limiting value before the
appropriate Technical Specification response time delay has elapsed.
Therefore, no AFW is actually delivered to the steam generators.

<u>Turbine Trip</u>
The reactor trip leads to a subsequent turbine trip.

4.3.2   Core Cooling Capability Analysis

4.3.2.1   Nodalization

Due to the asymmetry of the transient, a two-loop model (Reference 2,
Section 3.2), with a single (faulted) loop and a triple (intact) loop,
is utilized for this analysis.

4.3.2.2   Initial Conditions

<u>Core Power Level</u>
High initial power level maximizes the primary system heat flux. The
uncertainty in this parameter is accounted for in the Statistical Core
Design Methodology.

<u>Pressurizer Pressure</u>
The nominal pressure corresponding to full power operation is assumed,
with the pressure initial condition uncertainty accounted for the in
Statistical Core Design Methodology.

<u>Pressurizer Level</u>
Low initial level increases the volume of the pressurizer steam space
which minimizes the pressure increase resulting from the insurge.

<u>Reactor Vessel Average Temperature</u>
The nominal temperature corresponding to full power operation is
assumed, with the temperature initial condition uncertainty accounted
for in the Statistical Core Design Methodology.

<u>RCS Flow</u>
The Technical Specification minimum measured flow for power operation is
assumed since low flow is conservative for DNBR evaluation. The flow
initial condition uncertainty is accounted for in the Statistical Core
Design Methodology.

<u>Core Bypass Flow</u>
The nominal calculated flow is assumed, with the flow uncertainty
accounted for in the Statistical Core Design Methodology.

<u>Steam Generator Level</u>
Initial steam generator level is not an important parameter in this
analysis.

<u>Fuel Temperature</u>
A high initial temperature is assumed to minimize the gap conductivity
calculated for steady-state conditions and used for the subsequent
transient. A low gap conductivity minimizes the transient change in
fuel rod surface heat flux associated with a power decrease. This makes

4-9

the power decrease less severe and is therefore conservative for DNBR
evaluation.

Steam Generator Tube Plugging

For transients of such short duration, steam generator tube plugging
does not have an effect on the transient results.

4.3.2.3   Boundary Conditions

Reactor Coolant Pumps

The rotor of the reactor coolant pump in the faulted loop is assumed to
seize at the initiation of the transient. The remaining reactor coolant
pumps trip on bus undervoltage following the loss of offsite power.

Offsite Power

Cases with offsite power maintained as well as with offsite power lost
coincident with the turbine trip are analyzed.

Pressurizer Safety Valves

The pressurizer safety valves are not challenged by this transient.

Steam Line Safety Valves

The main steam code safety valves are modeled with opening and closing
characteristics which maximize secondary side pressure and minimize
primary-to-secondary heat transfer.

4.3.2.4   Control, Protection, and Safeguards System Modeling

Reactor Trip

Reactor trip occurs on low Reactor Coolant System flow in the loop with
the locked rotor.

Pressurizer Pressure Control

Credit is taken for both pressurizer spray and PORV operation in order
to minimize primary system pressure.

Pressurizer Level Control

Pressurizer heaters are assumed to be inoperable so that Reactor Coolant
System pressure is minimized. Charging/letdown has negligible impact.

Steam Line PORVs and Condenser Steam Dump

Secondary steam relief via the steam line PORVs and the condenser steam
dump is unavailable in order to maximize secondary side pressurization
and minimize transient primary-to-secondary heat transfer.

Steam Generator Level Control

The results of this transient are not sensitive to the mode of steam
generator level control as long as the level is kept within the range
that avoids protection or safeguards actuation.

MFW Pump Speed Control
The results of this transient are not sensitive to the mode of MFW pump speed control as long as the steam generator level is kept within the range that avoids protection or safeguards actuation.

Rod Control
No credit is taken for the operation of the Rod Control System for this transient, which results in an increase in RCS temperature. With the Rod Control System in automatic, the control rods would cause a negative reactivity addition as they are inserted in an attempt to maintain RCS temperature at its nominal value.

Turbine Control
The turbine is modeled in the load control mode, which is described in Section 3.2.5.1 of Reference 2.

Auxiliary Feedwater
AFW flow would be credited when the safety analysis value of the low-low steam generator level setpoint is reached. However, the parameter of interest for this transient has reached its limiting value before the appropriate Technical Specification response time delay has elapsed. Therefore, no AFW is actually delivered to the steam generators.

Turbine Trip
The reactor trip leads to a subsequent turbine trip.

4.3.2.5   Other Assumptions

The peak clad temperature calculation employs the fuel conduction model as described in Section 4.2.2 of Reference 2.

5.0   REACTIVITY AND POWER DISTRIBUTION ANOMALIES

5.1   Uncontrolled Bank Withdrawal From a Subcritical or Low Power
           Startup Condition

A malfunction of the Rod Control System can result in an uncontrolled
withdrawal of control rods. Beginning from a low initial power typical
of Modes 2 and 3, the resulting positive reactivity addition causes a
power excursion which is terminated by the high power range flux (low
setpoint) or high pressurizer pressure RPS trip functions. Since the
initial condition requires as few as three reactor coolant pumps in
operation, the minimum DNBR is of concern for peak transient power
levels less than full power. The peak Reactor Coolant System pressure
limit of 110% of design pressure is also of concern due to the mismatch
between core power and the secondary heat sink during the power
excursion. Peak RCS pressure and core cooling capability are analyzed
separately due to the differences in assumptions required for a
conservative analysis. The core cooling capability analysis
demonstrates that fuel cladding integrity is maintained by ensuring that
the minimum DNBR remains above the 95/95 DNBR limit based on acceptable
correlations. The minimum DNBR is determined using the Statistical Core
Design Methodology.

5.1.1   Peak RCS Pressure Analysis

5.1.1.1   Nodalization

The peak RCS pressure transient is analyzed with four reactor coolant
pumps in operation. Since all initial and boundary conditions are
symmetric, a single-loop model or any multi-loop nodalization is
appropriate. The standard model (Reference 2, Section 3.2) is used with
one significant exception. Since this transient initiates at zero power,
and since the duration of the transient is very short, the steam
generator secondary response is not important. Rather than using the
standard steam generator secondary nodalization, a single secondary
volume is used. The single volume uses the bubble rise option with the
local-conditions heat transfer model applied to the steam generator tube
conductors. With this modeling approach the initial condition of zero
power can be obtained, and the primary-to-secondary heat transfer that
occurs following the power excursion can be simulated.

5.1.1.2   Initial Conditions

Core Power Level
A minimum initial power level typical of a critical, zero power startup
condition maximizes the power excursion.

Pressurizer Pressure
High initial pressurizer pressure maximizes the peak transient pressure.

Pressurizer Level

High initial pressurizer level minimizes the volume of the steam bubble and therefore maximizes the pressure increase following an insurge.

Reactor Vessel Average Temperature

Reactor vessel average temperature is not an important parameter in this analysis.

RCS Flow

RCS flow is not an important parameter in this analysis.

Core Bypass Flow

Core bypass flow is not an important parameter in this analysis.

Steam Generator Level

Initial steam generator level is not an important parameter in this analysis.

Fuel Temperature

Due to the zero power initial condition, the initial fuel temperature is equal to T-ave. The fuel-clad gap conductivity is set high to maximize heat transfer from the fuel.

Steam Generator Tube Plugging

A bounding high tube plugging value degrades primary-to-secondary heat transfer.

5.1.1.3   Boundary Conditions

Non-Conducting Heat Exchangers

For initialization purposes, non-conducting heat exchangers are used to remove reactor coolant pump heat since the steam generators are passive at initialization. These are turned off prior to the start of the power excursion.

RCP Operation

Four reactor coolant pumps are in operation to increase the pressure drop around the loop, and to minimize thermal feedback during the power excursion.

Pressurizer Safety Valves

The pressurizer safety valves are modeled with opening and closing characteristics to maximize RCS pressure during the transient.

Steam Line Safety Valves

Although not important for this transient, steam line safety valves are modeled with opening and closing characteristics to minimize primary-to-secondary heat transfer.

5.1.1.4   Control, Protection, and Safeguards System Modeling

Reactor Trip
The pertinent reactor trip functions are the high power range flux (low setpoint) and pressurizer high pressure.

The high power range flux (low setpoint) trip includes a conservative allowance to account for calibration error, and error due to rod withdrawal effects. The response time of the high flux trip function is the Technical Specification value.

The response time of the pressurizer high pressure trip function is the Technical Specification value. Since the pressure uncertainty is accounted for in the initial pressurizer pressure, the pressurizer high pressure reactor trip setpoint is the Technical Specification value.

Pressurizer Pressure Control
Pressurizer spray and PORVs are inoperable to maximize RCS pressure during the transient.

Pressurize Level Control
Due to the short duration of this transient, heaters, makeup and letdown are unimportant.

Steam Line PORVs and Condenser Steam Dump
Steam line PORVs and steam dump to condenser are unimportant for this transient and are inoperable.

5.1.2   Core Cooling Capability Analysis

5.1.2.1   Nodalization

The core cooling capability analysis, which determines the minimum DNBR, is analyzed with three reactor coolant pumps in operation. A two-loop model with one single loop and one triple loop is utilized for this analysis. The standard model (Reference 2, Section 3.2) is used with one significant exception. Since this transient initiates at zero power, and since the duration of the transient is very short, the steam generator secondary response is not important. Rather than using the standard steam generator secondary nodalization, a single secondary volume is used. The single volume uses the bubble rise option with the local-conditions heat transfer model applied to the steam generator tube conductors. With this modeling approach the initial condition of zero power can be obtained, and the primary-to-secondary heat transfer that occurs following the power excursion can be simulated. No main or auxiliary feedwater or initial steam flow is modeled.

5.1.2.2   Initial Conditions

Core Power Level
A minimum initial power level typical of a critical, zero power startup condition maximizes the power excursion.

Pressurizer Pressure
Nominal pressure is assumed, with the pressure initial condition uncertainty accounted for in the Statistical Core Design Methodology.

Pressurizer Level
Low initial pressurizer level minimizes the pressure increase following an insurge.

Reactor Vessel Average Temperature
The nominal temperature corresponding to zero power operation is assumed, with the temperature initial condition uncertainty accounted for in the Statistical Core Design Methodology.

RCS Flow
Nominal three pump flow is assumed since low flow is conservative for DNBR evaluation. The flow initial condition uncertainty is accounted for in the Statistical Core Design Methodology.

Core Bypass Flow
The nominal calculated flow is assumed, with the flow uncertainty accounted for in the Statistical Core Design Methodology.

Steam Generator Level
Initial steam generator level is not an important parameter in this analysis.

Fuel Temperature
Due to the initial zero power condition, the initial fuel temperature is equal to T-ave. The fuel-clad gap conductivity is set high to maximize heat transfer from the fuel.

Steam Generator Tube Plugging
No tube plugging is assumed to maximize the RCS volume and thereby minimize the insurge into the pressurizer.

5.1.2.3   Boundary Conditions

Non-Conducting Heat Exchangers
For initialization purposes, non-conducting heat exchangers are used to remove reactor coolant pump heat since the steam generators are passive at initialization. These are turned off prior to the start of the power excursion.

RCP Operation

Since low flow is conservative for DNBR, the minimum number of reactor coolant pumps (three) required for the modes for which this transient is applicable (Modes 2 and 3) are assumed to be in operation.

Pressurizer Safety Valves

The pressurizer safety valves are modeled with opening and closing characteristics to minimize RCS pressure during the transient.

Steam Line Safety Valves

Although not important for this transient, steam line safety valves are modeled with opening and closing characteristics to maximize primary-to-secondary heat transfer.

5.1.2.4   Control, Protection, and Safeguards System Modeling

Reactor Trip

The pertinent reactor trip functions are the high power range flux (low setpoint) and pressurizer high pressure.

The high power range flux (low setpoint) trip includes a conservative allowance to account for calibration error, and error due to rod withdrawal effects. The response time of the high flux trip function is the Technical Specification value.

The response time of the pressurizer high pressure trip function is the Technical Specification value. The pressurizer high pressure reactor trip setpoint is the Technical Specification value plus an allowance which bounds the instrument uncertainty.

Pressurizer Pressure Control

Pressurizer spray and PORVs are operable to minimize RCS pressure during the transient. Heaters are not energized during the transient.

Steam Line PORVs and Condenser Steam Dump

Steam line PORVs and steam dump to condenser are unimportant for this transient and are inoperable.

5.1.2.5   Other Assumptions

Due to the potential for bottom-peaked power distributions during this transient, and due to the non-applicability of the Statistical Core Design Methodology below the mixing vane grids in the current fuel assembly designs, acceptable DNBRs are confirmed with the W-3S CHF correlation as necessary. Explicit accounting for uncertainties (i.e., non-SCD) is used with the W-3S correlation.

5.2   Uncontrolled Bank Withdrawal at Power

The uncontrolled bank withdrawal at power accident is characterized by an increase in core power level that cannot be matched by the secondary heat sink. The resultant mismatch causes an increase in primary and secondary system temperatures and pressures. The increases in power and temperature, along with a change in the core power distribution, present a DNBR concern. The primary and secondary overpressure limits of 110% of design pressure are also of concern.

Peak RCS pressure and core cooling capability are analyzed separately due to the differences in assumptions required for a conservative analysis. The core cooling capability analysis demonstrates that fuel cladding integrity is maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit based on acceptable correlations. The minimum DNBR is determined using the Statistical Core Design Methodology.

5.2.1   Peak RCS Pressure Analysis

5.2.1.1   Nodalization

Since the transient response of the uncontrolled bank withdrawal event is the same for all loops, the single-loop model described in Section 3.2 of Reference 2 is utilized for this analysis.

5.2.1.2   Initial Conditions

Core Power Level
Initial pressurizer pressure and, thus, initial margin to the overpressurization limit are independent of initial power level. Due to the pressure overshoot during the reactor trip instrumentation delay, maximum pressure is achieved with the maximum pressurization rate. The maximum pressurization rate is achieved with the maximum insertion of reactivity, provided that reactor trip on high flux does not occur prior to significant system heatup. Since the initial margin to the high flux reactor trip is greatest at a low power level, this power level yields the most rapid insertion of reactivity with significant system heatup.

Pressurizer Pressure
Initial pressurizer pressure is the nominal value, and the uncertainty in pressure is accounted for in the high pressure reactor trip setpoint.

Pressurizer Level
High initial level minimizes the initial volume of the pressurizer steam space, which maximizes the transient primary pressure response.

Reactor Vessel Average Temperature
Initial temperature is not an important parameter in this analysis.

RCS Flow
Initial RCS flow rate is not an important parameter in this analysis.

Core Bypass Flow
Core bypass flow is not an important parameter in this analysis.

Steam Generator Level
Initial steam generator level is not an important parameter in this
analysis.

Fuel Temperature
Low fuel temperature, associated with high gap conductivity, maximizes
the transient heat transfer from the fuel to the coolant.

Steam Generator Tube Plugging
A bounding high tube plugging value degrades primary-to-secondary heat
transfer.

5.2.1.3   Boundary Conditions

Pressurizer Safety Valves
The pressurizer safety valves are modeled with opening and closing
characteristics which maximize the pressurizer pressure.

Steam Line Safety Valves
The steam line safety valves are modeled with opening and closing
characteristics which maximize transient secondary side pressure and
minimize transient primary-to-secondary heat transfer.

5.2.1.4   Control, Protection, and Safeguards System Modeling

Reactor Trip
The pertinent reactor trip functions are the overtemperature ΔT (OTΔT),
overpower ΔT (OPΔT), pressurizer high pressure and power range high
flux (high setpoint).

The response time of each of the two ΔT trip functions is the Technical
Specification value. The setpoint values of the ΔT trip functions are
continuously computed from system parameters using the modeling
described in Section 3.2 of Reference 2. In addition, the ΔT coeffi-
cients used in the analysis account for instrument uncertainties.

The response time of the pressurizer high pressure trip function is the
Technical Specification value. The pressurizer high pressure reactor
trip setpoint is the Technical Specification value plus an allowance
which bounds the instrument uncertainty.

The response time of the power range high flux trip function is the
Technical Specification value. The power range high flux trip high
setpoint is the Technical Specification value plus an allowance which

5-7

bounds the instrument uncertainty. The high flux signal is adjusted to account for the effects of bank withdrawal.

Pressurizer Pressure Control
In order to maximize primary system pressure, no credit is taken for pressurizer spray or PORV operation.

Pressurizer Level Control
Pressurizer level control system operation has negligible impact on the results of this analysis.

Steam Line PORVs and Condenser Steam Dump
Secondary steam relief via the steam line PORVs and the condenser steam dump is unavailable in order to maximize secondary side pressurization and minimize transient primary-to-secondary heat transfer.

Steam Generator Level Control
Feedwater control is in automatic to prevent steam generator low-low level reactor trip.

Turbine Control
The turbine is modeled in the load control mode, which is described in Section 3.2.5.1 of Reference 2.

Auxiliary Feedwater
Auxiliary feedwater is disabled. The addition of subcooled auxiliary feedwater would tend to subcool the water in the steam generator, and provide better heat removal capability.

Turbine Trip
Turbine trip upon reactor trip is modeled in order to minimize the post-trip primary-to-secondary heat transfer.

5.2.2   Core Cooling Capability Analysis

5.2.2.1   Nodalization

Since the transient response of the uncontrolled bank withdrawal event is the same for all loops, the single-loop model described in Section 3.2 of Reference 2 is utilized for this analysis.

5.2.2.2   Initial Conditions

Core Power Level
The uncontrolled bank withdrawal event is analyzed with a spectrum of initial power levels which range from low power to full power. Uncertainties in initial power level are accounted for in the Statistical Core Design Methodology.

Pressurizer Pressure
Initial pressurizer pressure is the nominal value, and the uncertainty in pressure is accounted for in the Statistical Core Design Methodology.

Pressurizer Level
Initial pressurizer level is the nominal value which corresponds to the initial power level, and uncertainties are accounted for in the initial value. Low initial level maximizes the initial volume of the pressurizer steam space, which minimizes the transient primary pressure response.

Reactor Vessel Average Temperature
The nominal temperature corresponding to the initial power level is assumed, with the temperature initial condition uncertainty accounted for in the Statistical Core Design Methodology.

RCS Flow
The Technical Specification minimum measured flow for power operation is assumed since low flow is conservative for DNBR evaluation. The flow initial condition uncertainty is accounted for in the Statistical Core Design Methodology.

Core Bypass Flow
The nominal calculated flow is assumed, with the flow uncertainty accounted for in the Statistical Core Design Methodology.

Steam Generator Level
Initial steam generator level is not an important parameter in this analysis.

Fuel Temperature
Initial fuel temperature is the value which corresponds to the initial power level. Low fuel temperature maximizes the transient heat transfer from the fuel to the coolant.

Steam Generator Tube Plugging
The bounding tube plugging assumption (high or low) varies depending on other initial and boundary conditions.

5.2.2.3   Boundary Conditions

Pressurizer Safety Valves
The pressurizer safety valves are modeled with opening and closing characteristics which minimize the pressurizer pressure.

Steam Line Safety Valves
The steam line safety valves are modeled with opening and closing characteristics which maximize transient secondary side pressure and minimize transient primary-to-secondary heat transfer.

5.2.2.4   Control, Protection, and Safeguards System Modeling

Reactor Trip

The pertinent reactor trip functions are the overtemperature ΔT (OTΔT), overpower ΔT (OPΔT), pressurizer high pressure and power range high flux (high setpoint).

The response time of each of the two ΔT trip functions is the Technical Specification value. The setpoint values of the ΔT trip functions are continuously computed from system parameters using the modeling described in Section 3.2 of Reference 2. In addition, the ΔT coefficients used in the analysis account for instrument uncertainties. The response time of the pressurizer high pressure trip function is the Technical Specification value. The pressurizer high pressure reactor trip setpoint is the Technical Specification value plus an allowance which bounds the instrument uncertainty.

The response time of the power range high flux trip function is the Technical Specification value. The power range high flux trip high setpoint is the Technical Specification value plus an allowance which bounds the instrument uncertainty. The high flux signal is adjusted to account for the effects of bank withdrawal.

Pressurizer Pressure Control

A sensitivity study is performed on pressurizer pressure control. Two modes are analyzed, one in which pressurizer pressure control is in manual with sprays and PORVs disabled, and the other in which pressurizer pressure control is in automatic with sprays and PORVs enabled.

Pressurizer Level Control

Pressurizer level control is in manual. Level control has negligible impact on the results of this analysis.

Steam Line PORVs and Condenser Steam Dump

Secondary steam relief via the steam line PORVs and the condenser steam dump is unavailable in order to maximize secondary side pressurization and minimize transient primary-to-secondary heat transfer.

Steam Generator Level Control

Feedwater control is in automatic to prevent steam generator low-low level reactor trip.

Turbine Control

The turbine is modeled in the load control mode, which is described in Section 3.2.5.1 of Reference 2.

Auxiliary Feedwater

Auxiliary feedwater is disabled. The addition of subcooled auxiliary feedwater would tend to subcool the water in the steam generator, and provide better heat removal capability.

Turbine Trip

Turbine trip upon reactor trip is modeled in order to minimize the post-trip primary-to-secondary heat transfer.

5.3   Control Rod Misoperation (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 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 (HFP) conditions. Axial shapes allowed by the power dependent AFD 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 with Control Bank D positioned anywhere within the full power rod insertion limits (RILs). The second case considers the misalignment of a single Control Bank D rod at its fully withdrawn position, with the remainder of Control Bank positioned at the full power rod insertion limit.

Power distributions resulting from Case 1 are not analyzed for each reload core. This is because the thermal conditions (reactor power, pressure and coolant temperature) and power distributions evaluated in the dropped rod transient analysis bound the thermal conditions and power distributions that would occur in the statically misaligned rod event described in Case 1. The asymmetric power distributions resulting from Case 2 are evaluated for each reload core to ensure that the minimum DNBR remains above the 95/95 DNBR limit based on acceptable correlations. The minimum DNBR is determined using the Statistical Core Design Methodology.

The peak linear heat generation rate produced from the rod misalignment is confirmed for each reload core to be less than the linear heat generation rate which would result in fuel melt. The peak linear heat generation rates resulting from rod misalignments do not challenge the fuel melt limit.

5.4   Control Rod Misoperation (Single Rod Withdrawal)

The single rod withdrawal accident is characterized by an increase in the power generation of the primary system, and since the heat removal capability of the secondary system is not increased during the transient, the resultant power mismatch causes an increase in primary and secondary system temperature and pressure.

The acceptance criterion for this event is to ensure that there is adequate core cooling capability. The core cooling capability analysis determines to what extent fuel cladding integrity is compromised by calculating the number of fuel rods that exceed the 95/95 DNBR limit based on acceptable correlations.

5.4.1   Nodalization

Since the transient response of the single rod withdrawal event is the same for all loops, the single-loop model described in Section 3.2 of Reference 2 is utilized for this analysis.

5.4.2   Initial Conditions

Core Power Level
Initial power is the nominal full power value. Uncertainty in power level is accounted for in the Statistical Core Design Methodology.

Pressurizer Pressure
Initial pressurizer pressure is the nominal value. Uncertainty in pressure is accounted for in the Statistical Core Design Methodology.

Pressurizer Level
High initial level minimizes the initial volume of the pressurizer steam space, which maximizes the transient primary pressure response. Up to the limit of the ability of the pressurizer sprays to control pressure, maximum pressure is conservative in order to delay reactor trip on OTΔT.

Reactor Vessel Average Temperature
Initial temperature is the full power nominal value. Uncertainty in this parameter is accounted for in the Statistical Core Design Methodology.

RCS Flow
The Technical Specification minimum measured flow for power operation is assumed since low flow is conservative for DNBR evaluation. The flow initial condition uncertainty is accounted for in the Statistical Core Design Methodology.

Core Bypass Flow
The nominal calculated flow is assumed, with the flow uncertainty accounted for in the Statistical Core Design Methodology.

Steam Generator Level
Initial steam generator level is not an important parameter in this analysis.

Fuel Temperature
Low fuel temperature, associated with high gap conductivity, maximizes the transient heat transfer from the fuel to the coolant.

Steam Generator Tube Plugging
Steam generator tube plugging is not an important parameter in this
analysis.

5.4.3   Boundary Conditions

Pressurizer Safety Valves
The pressurizer safety valves are modeled with opening and closing
characteristics which minimize the pressurizer pressure.

Steam Line Safety Valves
The steam line safety valves are modeled with opening and closing
characteristics which maximize transient secondary side pressure and
minimize transient primary-to-secondary heat transfer.

5.4.4   Control, Protection, and Safeguards System Modeling

Reactor Trip
The pertinent reactor trip functions are the overtemperature ΔT (OTΔT),
overpower ΔT (OPΔT), pressurizer high pressure and power range high
flux (high setpoint).

The response time of each of the two ΔT trip functions is the Technical
Specification value. The setpoint values of the ΔT trip functions are
continuously computed from system parameters using the modeling
described in Section 3.2 of Reference 2. In addition, the ΔT coeffi-
cients used in the analysis account for instrument uncertainties.

The response time of the pressurizer high pressure trip function is the
Technical Specification value. The pressurizer high pressure reactor
trip setpoint is the Technical Specification value plus an allowance
which bounds the instrument uncertainty.

The response time of the power range high flux trip function is the
Technical Specification value. The power range high flux trip high
setpoint is the Technical Specification value plus an allowance which
bounds the instrument uncertainty. The high flux signal is adjusted to
account for the effects of rod withdrawal.

Pressurizer Pressure Control
Pressurizer pressure control is in automatic with sprays enabled and
PORVs disabled in order to delay reactor trip on OTΔT and delay reactor
trip on high pressurizer pressure.

Pressurizer Level Control
Pressurizer level control is in manual with the pressurizer heaters
disabled in order to delay reactor trip on high pressurizer pressure.
Charging/letdown has negligible impact.

<u>Steam Line PORVs and Condenser Steam Dump</u>
Secondary steam relief via the steam line PORVs and the condenser steam dump is unavailable in order to maximize secondary side pressurization and minimize transient primary-to-secondary heat transfer.

<u>Steam Generator Level Control</u>
Feedwater control is in automatic to prevent steam generator low-low level reactor trip.

<u>Auxiliary Feedwater</u>
Auxiliary feedwater is disabled. The addition of subcooled auxiliary feedwater would tend to subcool the water in the steam generator, and reduce secondary side pressure.

<u>Turbine Control</u>
The turbine is modeled in the load control mode, which is described in Section 3.2.5.1 of Reference 2.

<u>Turbine Trip</u>
Turbine trip upon reactor trip is modeled in order to minimize the post-trip primary-to-secondary heat transfer.

5.5   <u>Startup Of An Inactive Reactor Coolant Pump At An Incorrect Temperature</u>

The McGuire and Catawba plant Technical Specifications currently require that all four RCPs be running at power operation. Furthermore, low flow in any RCS loop, coincident with reactor power above the P-8 interlock (currently at 48% of rated thermal power) will cause a reactor trip. Therefore, the only situation in which the subject accident is possible is a trip of one RCP below P-8. For this situation the operator might choose, during allowable at power outage time for the fourth RCP, to attempt a restart of the tripped pump. The accident is analyzed from the most conservative condition allowed by the Reactor Protection System, even though operator error is required for the analyzed scenario to occur. The acceptance criterion is that fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains the above the 95/95 DNBR limit based on acceptable correlations.

5.5.1   Nodalization

Because of the loop asymmetry between the inactive single loop and the three active loops, the double-loop RCS model described in Section 3.2 of Reference 2 is used.

5.5.2   Initial Conditions

<u>Core Power</u>
The inadvertent pump startup event is analyzed assuming that the plant administrative procedure (i.e., lowering the power level to 25% of rated thermal power prior to starting the idle pump) is not followed. Thus,

it is assumed that the plant is operating at the P-8 setpoint of 48% of rated thermal power plus a positive power uncertainty.

Pressurizer Pressure

A pressure initial condition uncertainty including a bias is applied to minimize pressure during the transient since this is conservative for DNBR evaluation.

Pressurizer Level

The heatup of the colder water and the increase in core power will cause an expansion of the reactor coolant and an increase in pressurizer level. A negative level uncertainty is used in order to maximize the size of the pressurizer steam bubble to be compressed, which minimizes the transient pressure response.

Reactor Vessel Average Temperature

A positive temperature uncertainty is used to minimize the margin to DNB.

RCS Flow

In order to minimize core flow, and therefore the margin to DNB, the three pump equivalent of the Technical Specification minimum measured flow is adjusted by a negative flow uncertainty.

Core Bypass Flow

High core bypass flow minimizes coolant flow through the core and therefore minimizes the margin to DNB.

Steam Generator Level

The results of this transient are not sensitive to the direction of steam generator level uncertainty as long as the transient level response is kept within the range that avoids protection or safeguards actuation.

Fuel Temperature

A low initial temperature is assumed to maximize the gap conductivity calculated for steady-state conditions and used for the subsequent transient. A high gap conductivity minimizes the fuel heatup and attendant negative reactivity insertion caused by the power increase. This makes the power increase more severe and is therefore conservative for DNB evaluation.

Steam Generator Tube Plugging

Steam generator tube plugging is not an important parameter in this analysis.

5.5.3   Boundary Conditions

RCP Operation

The RCPs operating prior to the accident are modeled assuming constant speed operation throughout the transient. The RCP that is inactive at the start of the accident is modeled with a conservative speed vs. time controller.

5-15

5.5.4   Control, Protection, and Safeguards Systems Modeling

Reactor Trip
The reactor trip on low RCS flow coincident with reactor power above the P-8 interlock is conservatively assumed to be unavailable.

Pressurizer Pressure Control
The pressurizer sprays and PORVs are assumed to be operable to minimize the pressure increase resulting from the pump restart and power increase.

Pressurizer Level Control
No credit is taken for pressurizer heater operation to compensate for the increase above programmed pressurizer level which occurs due to the power increase. Heater operation would tend to elevate pressure.

Steam Generator Level Control
The results of this transient are not sensitive to the mode of steam generator level control as long as the steam generator level is kept within the range that avoids protection or safeguards actuation.

MFW Pump Speed Control
The results of this transient are not sensitive to the mode of MFW pump speed control as long as the steam generator level is kept within the range that avoids protection or safeguards actuation.

Rod Control
The Rod Control System is assumed to be in automatic when reactor vessel average temperature decreases. The temperature decrease will cause rod withdrawal and an increase in core power.

Turbine Control
The turbine is assumed to be in manual control. In this mode, the valves do not respond to changes in steam line pressure. Therefore, when steam line pressure increases due to increased heat input from the primary system, the steam flow to the turbine will increase. This will retard the core power less than if the turbine control valves closed down and caused steam line pressure and RCS temperatures to increase further.

Auxiliary Feedwater
AFW flow would be credited when the safety analysis value of the low-low steam generator level setpoint is reached. However, the parameter of interest for this transient has reached its limiting value before the appropriate Technical Specification response time delay has elapsed. Therefore, no AFW is actually delivered to the steam generators.

5.6   CVCS Malfunction That Results In A Decrease In Boron Concentration In The Reactor Coolant

A boron dilution occurs when the soluble boric acid concentration of makeup water supplied to the RCS is less than the concentration of the existing reactor coolant. The boron dilution accident postulates that

such a dilution occurs without adequate administrative control such that there was the potential for loss of shutdown margin. This accident is conservatively analyzed to ensure that the dilution is terminated, by manual or automatic means, within appropriate time limits. In accordance with Reference 3, appropriate time is judged to be at least 15 minutes for Modes 3-5 and at least 30 minutes for Mode 6.

The licensing bases for the McGuire and Catawba Nuclear Stations are different. For McGuire, this accident is analyzed for the power operation (Mode 1), startup (Mode 2), and refueling (Mode 6) modes of operation. Manual operation is relied on to terminate the dilution in all three modes. For Catawba, this accident is analyzed for the power operation, startup, hot standby (Mode 3), hot shutdown (Mode 4), cold shutdown (Mode 5), and refueling modes of operation. Automatic operation of the Boron Dilution Mitigation System (BDMS) is relied on to terminate the dilution in hot standby, hot shutdown, cold shutdown, and refueling, with manual operation as substitute means when the BDMS is inoperable. Manual operation is relied on to terminate the dilution in power operation or startup.

The various modes at the two stations are analyzed with two different methods for two different purposes. First, with the BDMS applicable and assumed to be operable, the accident is analyzed to demonstrate that there is adequate time, without restrictions on the flow rates from potential dilution sources, for the BDMS to terminate the dilution prior to criticality. This time consists of two components: 1) the period required to stroke the valves manipulated by the BDMS and 2) the period required, once the unborated water source has been isolated, to purge the remaining unborated water from the piping leading to the RCS. Second, with the BDMS inapplicable or assumed to be inoperable, the accident is analyzed to demonstrate that there is adequate time, possibly with restrictions on the flow rates from potential dilution sources, for the operator to terminate the dilution prior to criticality. Since the BDMS is not used in Modes 1 and 2, the analysis of these modes is similar to the analysis of Modes 3-6 with the BDMS assumed to be inoperable, but without the restrictions on flow rates.

During Mode 6 an inadvertent dilution from the Reactor Makeup Water System is prevented by administrative controls which isolate the RCS from potential sources of unborated makeup water. The results of the accident analysis for this mode are for an assumed dilution event, for which no mechanism or flow path has been identified. The results of the accident analysis are for the dilution flow rates which, assuming the boron concentrations are at the reload safety analysis limits, give exactly the acceptance criteria operator response times. Flow rates are restricted, through Technical Specifications and administrative controls, to values which are less than these analyzed flow rates, thus in practice giving even longer operator response times. Additional margin is provided by the fact there is typically margin between the assumed boron concentrations for a given mode and the actual corresponding concentrations for the reload core.

5.6.1   Initial Conditions

Dilution Volume

A postulated dilution event progresses faster for smaller RCS water volumes. Therefore, the analysis considers the smallest RCS water volume in which the unborated water is actively mixed by forced circulation. For Modes 1-3, the Technical Specifications require that at least one reactor coolant pump be operating. This forced circulation will mix the RCS inventory in the reactor vessel and each of the four reactor coolant loops. The pressurizer and the pressurizer surge line are not included in the volume available for dilution in Modes 1-3. For normal operation in Mode 4, forced circulation is typically maintained, although the Technical Specifications do not require it. The volume available for dilution in Mode 4 is therefore conservatively assumed to not include the upper head of the reactor vessel, a region which has reduced flow in the absence of forced circulation, or the pressurizer and the pressurizer surge line. Since the Technical Specifications do require operability of all four steam generators during Mode 4, all four of the reactor coolant loops, in addition to the remainder of the reactor vessel, are included in the RCS volume available for dilution. For Modes 5 and 6, the reactor coolant water level may be drained to below the top of the main coolant loop piping, and at least one train of the Residual Heat Removal System (RHRS) is operating. The volume available for dilution in these modes is limited to the smaller volume RHRS train plus the portions of the reactor vessel and reactor coolant loop piping below the minimum water level and between the RHRS inlet and outlet connections. The minimum water level used to calculate this volume is corrected for level instrument uncertainty.

Boron Concentrations

The Technical Specifications require that the shutdown margin in the various modes be above a certain minimum value. The difference in boron concentration, between the value at which the relevant alarm function is actuated and the value at which the reactor is just critical, determines the time available to mitigate a dilution event. Mathematically, this time is a function of the ratio of these two concentrations, where a large ratio corresponds to a longer time. During the reload safety analysis for each new core, the above concentrations are checked to ensure that the value of this ratio for each mode is larger than the corresponding ratio assumed in the accident analysis. Each mode of operation covers a range of temperatures. Therefore, within that mode, the temperature which minimizes this ratio is used for comparison with the accident analysis ratio. For accident initial conditions in which the control rods are withdrawn, it is conservatively assumed, in calculating the critical boron concentration, that the most reactive rod does not fall into the core at reactor trip. This assumption is also conservatively applied in Mode 3 when the initial condition is hot zero power. For colder conditions in Modes 3-5, emergency procedures for reactor trip with a stuck rod require that, prior to the initiation of the cooldown, the boron concentration be increased by an amount which compensates for any rods not completely inserted.

5.6.2   Boundary Conditions

In the absence of flow rate restrictions, the dilution flow rate assumed to enter the RCS is greater than or equal to the design volumetric flow rate of both reactor makeup water pumps. In a dilution event, these pumps are assumed to deliver unborated water to the suction of the centrifugal charging pumps. Since the water delivered by these pumps is typically colder than the RCS inventory, the unborated water expands within the RCS, causing a given volumetric flow rate measured at the colder temperature to correspond to a larger volumetric dilution flow rate within the RCS. This density difference in the dilution flow rate is accounted for in the analysis. The above assumption on flow rate is also conservatively used for Mode 6. Any makeup which is required during this mode is borated water supplied from the refueling water storage tank.

5.6.3   Control, Protection, and Safeguards System Modeling

Mitigation of a boron dilution accident is not assumed to begin until an alarm has warned of the abnormal circumstances caused by the event. For Modes 3-6 with the BDMS operable, the alarm function is provided by the measured source range count rate exceeding the BDMS setpoint. For Modes 3-6 with the BDMS inoperable, the alarm function is provided by the source range high-flux-at-shutdown alarm exceeding its setpoint. For Mode 2 and for manual rod control during Mode 1, the alarm function is provided by the earliest reactor trip setpoint reached. Finally, for automatic rod control during Mode 1, the alarm function is provided by the alarm which occurs when the control rods reach their insertion limits.

5.7   Inadvertent Loading and Operation of A Fuel Assembly In An Improper Position

Core loading errors can occur from the improper loading of one or more fuel assemblies in an improper position, from enrichment errors, or from the misloading or omission of burnable absorber rods. The result of these errors is the possibility that core peaking will exceed the peaking calculated for the correct core loading.

Administrative procedures are in place to prevent enrichment errors during fuel fabrication and during core loading. Also, a rigorous startup physics testing program is performed subsequent to each core loading that would detect any credible misloaded fuel assembly. The misloaded fuel assembly analysis confirms that the increase in peaking produced from a loading error or enrichment error would either be detected by the incore flux mapping system, or would be less than the peaking uncertainties included in the analysis of both Condition I and Condition II events.

6.0   INCREASE IN REACTOR COOLANT INVENTORY

6.1   Inadvertent Operation Of ECCS During Power Operation

The inadvertent operation of the Emergency Core Cooling System could be
caused by either operator error or a spurious electrical actuation
signal. Upon receipt of the actuation signal, the centrifugal charging
pumps begin delivering highly borated refueling water storage tank water
to the Reactor Coolant System. The resultant negative reactivity
insertion causes a decrease in core power and, consequently, a decrease
in temperature. Initially, coolant shrinkage causes a reduction in both
pressurizer water level and pressure. Core cooling capability (DNB) is
the primary concern during this time period due to the decrease in
system pressure. Following the initial depressurization, the increase
in reactor coolant inventory causes pressurizer level to increase and
pressurization to occur. Pressurizer level might increase sufficiently
to overfill the pressurizer and cause water relief through the
pressurizer safety valves (PSVs). Water relief through the PSVs could
degrade valve operability and lead to a Condition III event.

The magnitude of the pressure decrease for this transient is no more
severe than that for the inadvertent opening of a pressurizer safety or
relief valve transient, which also trips the reactor on low pressurizer
pressure. Furthermore, the opening of a safety valve does not introduce
the core power and Reactor Coolant System temperature decreases that are
characteristic of the inadvertent ECCS actuation. Neither event
involves any reduction in the Reactor Coolant System flow rate, since
the reactor coolant pumps are not tripped. Therefore, the DNB results
of this transient are bounded by the inadvertent opening of a
pressurizer safety or relief valve transient.

Based on the above qualitative evaluation, a quantitative core cooling
capability analysis of this transient is not required. Should a
reanalysis become necessary, either due to plant changes, modeling
changes, or other changes which invalidate any of the above arguments,
the analytical methodology employed would be as follows.

The core cooling capability analysis demonstrates that fuel cladding
integrity is maintained by ensuring that the minimum DNBR remains above
the 95/95 DNBR limit based on acceptable correlations. The minimum DNBR
is determined using the Statistical Core Design Methodology.

The concern in the pressurizer overfill analysis is that water relief
through the PSVs will degrade valve operability and lead to a Condition
III event. However, even if water relief occurs, valve operability is
not degraded provided that the temperature of the pressurizer water is
sufficiently high. Therefore, the acceptance criterion for this
analysis is the minimum water relief temperature to assure PSV
operability.

6.1.1   Core Cooling Capability Analysis

6.1.1.1   Nodalization

Since the inadvertent ECCS operation transient is symmetrical with
respect to the four reactor coolant loops, a single-loop model
(Reference 2, Section 3.2) is utilized for this analysis.

6.1.1.2   Initial Conditions

Core Power Level
High initial power level maximizes the primary system heat flux. The
uncertainty in this parameter is accounted for in the Statistical Core
Design Methodology.

Pressurizer Pressure
Nominal full power pressurizer pressure is assumed. The uncertainty in
this parameter is accounted for in the Statistical Core Design
Methodology.

Pressurizer Level
High initial level minimizes the volume of the pressurizer steam space
which maximizes the pressure decrease resulting from the outsurge.

Reactor Vessel Average Temperature
Nominal full power vessel average temperature is assumed. The
uncertainty in this parameter is accounted for in the Statistical Core
Design Methodology.

RCS Flow
The Technical Specification minimum measured flow for power operation is
assumed since low flow is conservative for DNBR evaluation. The flow
initial condition uncertainty is accounted for in the Statistical Core
Design Methodology.

Core Bypass Flow
The nominal calculated flow is assumed, with the flow uncertainty
accounted for in the Statistical Core Design Methodology.

Steam Generator Level
Steam generator level is not an important parameter in this analysis.

Fuel Temperature
A high initial temperature is assumed to minimize the gap conductivity
calculated for steady-state conditions and used for the subsequent
transient. A low gap conductivity minimizes the transient change in
fuel rod surface heat flux associated with a power decrease. This makes
the power decrease less severe and is therefore conservative for DNBR
evaluation.

Steam Generator Tube Plugging

Steam generator tube plugging is not an important parameter in this analysis.

6.1.1.3 Boundary Conditions

ECCS Flow

A maximum safety injection flow rate along with a conservatively high boron concentration yields the most limiting transient response. In order to minimize the delay in the delivery of the borated injection water, no credit is taken for the purge volume of unborated water in the injection lines.

Steam Line Safety Valves

The main steam code safety valves are modeled with opening and closing characteristics which maximize secondary side pressure and minimize primary-to-secondary heat transfer.

6.1.1.4 Control, Protection, and Safeguards System Modeling

Reactor Trip

Reactor trip is assumed to occur on low pressurizer pressure, after an appropriate instrumentation delay.

Pressurizer Pressure Control

Pressurizer sprays and PORVs are assumed to be operable in order to minimize the system pressure throughout the transient.

Pressurizer Level Control

Pressurizer heaters are assumed to be inoperable so that Reactor Coolant System pressure is minimized. Charging/letdown has negligible impact.

Steam Line PORVs and Condenser Steam Dump

Secondary steam relief via the steam line PORVs and the condenser steam dump is unavailable in order to maximize secondary side pressurization and minimize transient primary-to-secondary heat transfer.

Steam Generator Level Control

The results of this transient are not sensitive to the mode of steam generator level control as long as the level is kept within the range that avoids protection or safeguards actuation.

MFW Pump Speed Control

The results of this transient are not sensitive to the mode of MFW pump speed control as long as the steam generator level is kept within the range that avoids protection or safeguards actuation.

Rod Control

No credit is taken for the operation of the Rod Control System for this transient, which results in a decrease in RCS temperature. With the Rod Control System in automatic, the control rods would cause a positive reactivity addition as they are withdrawn in an attempt to maintain RCS

6-3

temperature at its nominal value. The resultant power increase would retard the system depressurization.

Turbine Control
The turbine is modeled in the load control mode, which is described in Section 3.2.5.1 of Reference 2.

Auxiliary Feedwater
AFW flow would be credited when the safety analysis value of the low-low steam generator level setpoint is reached. However, the parameter of interest for this transient has reached its limiting value before the appropriate Technical Specification response time delay has elapsed. Therefore, no AFW is actually delivered to the steam generators.

Turbine Trip
The reactor trip leads to a subsequent turbine trip.

6.1.2   Pressurizer Overfill Analysis

6.1.2.1   Initial Conditions

Core Power
Zero power is assumed in this analysis. Reference 3 states that the acceptable initial power for the analysis is the licensed core thermal power, i.e., full power. However, lower power is more limiting in order to minimize the initial RCS temperature. If overfill occurs at lower initial power, then the water relief temperature is more likely to be less than the acceptance criterion.

Pressurizer Pressure
Actual system response to a safety injection (SI) would be an initial pressure drop then subsequent pressurization above initial pressure. During the depressurization phase, SI flow would increase above the initial flow rate, and during the pressurization phase, SI flow would decrease below initial flow rate. Initial pressure is assumed conservatively low to determine the SI flow during the event.

Reactor Vessel Average Temperature
Low initial temperature is conservative in order to minimize pressurizer water temperature.

Steam Generator Tube Plugging
High steam generator tube plugging is assumed in order to decrease the volume of the initial RCS water, which will minimize the RCS water temperature as it mixes with the cold SI water.

6.1.2.2   Boundary Conditions

RCP Operation
For Modes 1-3, the Technical Specifications require at least one reactor coolant pump be operating.

6.1.2.3   Control, Protection, and Safeguards System Modeling

Pressurizer Level Control
The pressurizer heaters are assumed to be in manual and off since heater
operation would increase the temperature of the pressurizer water.
Normal makeup is isolated upon SI, and credit is not taken for letdown.

ECCS Flow
A maximum safety injection flow rate from both centrifugal charging
pumps is assumed. RCS pressure remains above the shutoff head of the
intermediate head and low head safety injection pumps for the duration
of the event.

ECCS Temperature
Minimum injection temperature is conservative in order to minimize
relief temperature.

7.0   DECREASES IN REACTOR COOLANT INVENTORY

7.1   <u>Inadvertent Opening of a Pressurizer Safety or Relief Valve</u>

The loss of inventory through the open valve causes a depressurization
of the RCS. Since the core power, flow, and temperature are relatively
unaffected prior to reactor trip by this depressurization, the
reduction in pressure causes a reduction in DNB margin. The applicable
acceptance criterion is that fuel cladding integrity shall be maintained
by ensuring that the minimum DNBR remains the above the 95/95 DNBR limit
based on acceptable correlations. The minimum DNBR is determined using
the Statistical Core Design Methodology.

7.1.1   Nodalization

Since the valve opening is in the pressurizer, it affects all RCS loops
identically. Therefore a single-loop RCS system model is used.

7.1.2   Initial Conditions

<u>Power Level</u>
Full power is assumed in order to maximize the primary system heat flux.
The uncertainty in this parameter is accounted for in the Statistical
Core Design Methodology.

<u>Pressurizer Pressure</u>
Nominal pressure is assumed, with the pressure initial condition
uncertainty accounted for in the Statistical Core Design Methodology.

<u>Pressurizer Level</u>
Since this accident involves a reduction in RCS volume due to inventory
loss, a negative level uncertainty is assumed to minimize the initial
pressurizer liquid volume and therefore maximize the pressure decrease
due to inventory loss.

<u>Reactor Vessel Average Temperature</u>
The nominal temperature corresponding to full power operation is
assumed, with the temperature initial condition uncertainty accounted
for in the Statistical Core Design Methodology.

<u>RCS Flow</u>
The Technical Specification minimum measured flow for power operation is
assumed since low flow is conservative for DNBR evaluation. The flow
initial condition uncertainty is accounted for in the Statistical Core
Design Methodology.

<u>Core Bypass Flow</u>
The nominal calculated flow is assumed, with the flow uncertainty
accounted for in the Statistical Core Design Methodology.

Steam Generator Level

The results of this transient are not sensitive to the direction of steam generator level uncertainty as long as the transient level response is kept within the range that avoids protection or safeguards actuation.

Fuel Temperature

A high initial temperature is assumed to minimize the gap conductivity calculated for steady-state conditions and used for the subsequent transient. A low gap conductivity minimizes the transient change in fuel rod surface heat flux associated with a power decrease due to moderator density. This makes the power decrease less severe and is therefore conservative for DNBR evaluation.

Steam Generator Tube Plugging

The results of this analysis are not sensitive to the amount of steam generator tube plugging.

7.1.3   Boundary Conditions

Steam Line Safety Valves

The results of this transient are not sensitive to the main steam safety valve modeling as long as the opening of the safety valves occurs after reactor trip.

7.1.4   Control, Protection, and Safeguards Systems Modeling

Reactor Trip

Reactor trip is on either low pressurizer pressure or overtemperature ΔT. The Technical Specification response times are used and the safety analysis setpoints include the effects of uncertainty in the monitored parameter and in the setpoint.

Pressurizer Pressure Control

No credit is taken for pressurizer heater operation to compensate for the decrease in pressurizer pressure which occurs due to the inventory loss. This results in a lower post-trip pressurizer pressure, which is conservative for DNBR evaluation.

Steam Generator Level Control

The results of this transient are not sensitive to the mode of steam generator level control as long as the level is kept within the range that avoids protection or safeguards actuation.

MFW Pump Speed Control

The results of this transient are not sensitive to the mode of MFW pump speed control as long as the steam generator level is kept within the range that avoids protection or safeguards actuation.

Rod Control

Rod control is assumed to be in manual for this transient.

Turbine Control
The turbine is modeled in the load control mode, which is described in Section 3.2.5.1 of Reference 2.

Auxiliary Feedwater
AFW flow would be credited when the safety analysis value of the low-low steam generator level setpoint is reached. However, the parameter of interest for this transient has reached its limiting value before the appropriate Technical Specification response time delay has elapsed. Therefore, no AFW is actually delivered to the steam generators.

Turbine Trip
The turbine is tripped on reactor trip. A conservatively long time delay is assumed since this assumption minimizes the post-trip primary pressure response.

7.2 Steam Generator Tube Rupture

The steam generator tube rupture analyzed is a double ended guillotine break of a single tube. This transient is evaluated in two parts; first to evaluate minimum DNBR, and secondly to provide offsite dose input data for a separate evaluation to determine whether the fission product release to the environment is within the established dose acceptance criteria.

The DNBR analysis for this transient is modeled as a complete loss of coolant flow event initiated from an off-normal condition, using the Statistical Core Design methodology. The loss of flow is assumed to occur subsequent to the OTΔT reactor trip caused by the steam generator tube rupture depressurization.

The initiating event for the offsite dose input analysis is the double-ended guillotine break of a single steam generator tube. This analysis generates the offsite steam release boundary condition for the dose evaluation. The single failure identified for maximizing offsite dose is the failure of the PORV on the ruptured steam generator to close. In this analysis, this valve remains open until operator action is taken to isolate the PORV.

7.2.1 Core Cooling Capability Analysis

7.2.1.1 Nodalization

Since the complete loss of flow transient is symmetrical with respect to the four reactor coolant loops, a single loop model (Reference 2, Section 3.2) is utilized for this analysis.

7.2.1.2   Initial Conditions

Core Power Level
High initial power level maximizes the primary system heat flux. The uncertainty in this parameter is accounted for in the Statistical Core Design Methodology.

Pressurizer Pressure
Nominal pressurizer pressure is assumed. The uncertainty in this parameter is accounted for in the Statistical Core Design Methodology.

Pressurizer Level
Low initial level increases the volume of the pressurizer steam space which minimizes the pressure increase resulting from the insurge.

Reactor Vessel Average Temperature
Nominal vessel average temperature is assumed. The uncertainty in this parameter is accounted for in the Statistical Core Design Methodology.

RCS Flow
Minimum measured Reactor Coolant System flow is assumed. The uncertainty in this parameter is accounted for in the Statistical Core Design Methodology.

Core Bypass Flow
Nominal full power bypass flow is assumed. The uncertainty in this parameter is accounted for in the Statistical Core Design Methodology.

Steam Generator Level
Initial steam generator level is not an important parameter in this analysis.

Fuel Temperature
A high initial temperature is assumed to minimize the gap conductivity calculated for steady-state conditions and used for the subsequent transient. A low gap conductivity minimizes the transient change in fuel rod surface heat flux associated with a power decrease. This makes the power decrease less severe and is therefore conservative for DNBR evaluation.

Steam Generator Tube Plugging
For transients of such short duration, steam generator tube plugging does not have an effect on the transient results.

7.2.1.3   Boundary Conditions

RCP Operation
All four reactor coolant pumps are tripped on the loss of offsite power. The pump model is adjusted such that the resulting coastdown flow is conservative with respect to the flow coastdown test data.

Steam Line Safety Valves

The main steam code safety valves are modeled with opening and closing characteristics which maximize secondary side pressure and minimize primary-to-secondary heat transfer.

Offsite Power

Offsite power is assumed to be lost coincident with turbine trip in order to minimize RCS flow following reactor trip.

7.2.1.4   Control, Protection, and Safeguards System Modeling

Reactor Trip

Reactor trip is assumed to occur on overtemperature ΔT, after an appropriate instrumentation delay.

Pressurizer Pressure Control

Following the tube rupture, RCS pressure continuously decreases through the time at which minimum DNBR occurs. Thus, pressurizer sprays are not activated nor are the pressurizer PORVs challenged during the transient.

Pressurizer Level Control

Pressurizer heaters are assumed to be inoperable so that Reactor Coolant System pressure is minimized. Charging and letdown are assumed to be balanced at all times during the event with no action taken to increase charging flow due to RCS pressure and pressurizer level decreasing. This will maximize the RCS depressurization rate.

Steam Line PORVs and Condenser Steam Dump

The main steam PORVs and condenser dumps valves are assumed to be unavailable during this transient. This maximizes the secondary side pressure and temperature and therefore reduces primary-to-secondary heat transfer.

Steam Generator Level Control

The results of this transient are not sensitive to the mode of steam generator level control as long as the level is kept within the range that avoids protection or safeguards actuation.

MFW Pump Speed Control

The results of this transient are not sensitive to the mode of MFW pump speed control as long as the steam generator level is kept within the range that avoids protection or safeguards actuation.

Rod Control

No credit is taken for the operation of the Rod Control System for this transient, which results in an increase in RCS temperature. With the Rod Control System in automatic, the control rods would cause a negative reactivity addition as they are inserted in an attempt to maintain RCS temperature at its nominal value.

<u>Turbine Control</u>
The turbine is modeled in the load control mode, which is described in
Section 3.2.5.1 of Reference 2.

<u>Auxiliary Feedwater</u>
AFW flow would be credited when the safety analysis value of the low-low
steam generator level setpoint is reached. However, the parameter of
interest for this transient has reached its limiting value before the
appropriate Technical Specification response time delay has elapsed.
Therefore, no AFW is actually delivered to the steam generators.

<u>Turbine Trip</u>
The reactor trip leads to a subsequent turbine trip.

7.2.2   Offsite Dose Calculation Input Analysis

7.2.2.1   Nodalization

Due to the asymmetry of this transient a three-loop model, with two
single loops and a double loop, is utilized for this analysis. The
boundary conditions for the two intact steam generators with operable
steam line PORVs are symmetric. The loop with the tube rupture
requires separate modeling, as does the loop with the inoperable steam
line PORV.

7.2.2.2   Initial Conditions

<u>Core Power Level</u>
High initial core power and a positive uncertainty maximize the primary
system heat load.

<u>Pressurizer Pressure</u>
High initial pressure with a positive uncertainty delays the time of
automatic reactor trip. This retards the primary system cooldown,
extending primary-to-secondary leakage, and therefore maximizing the
offsite dose.

<u>Pressurizer Level</u>
High initial level with a positive uncertainty maximizes primary-to-
secondary leakage and maximizes pressurizer heater operation.

<u>Reactor Vessel Average Temperature</u>
Nominal vessel average temperature with a negative uncertainty is used
to minimize the initial steam generator steam pressure. This maximizes
the initial differential pressure across the steam generator tubes and
therefore maximizes the initial primary-to-secondary leakage. A lower
vessel average temperature also maximizes the initial primary-to-
secondary leakage. If the reactor trip occurs at a fixed time (e.g.,
due to manual safety injection), maximizing the leakage maximizes the
amount of high activity inventory leaked to the steam generators.
However, if an automatic reactor trip occurs, it is because a sufficient

inventory of primary-to-secondary leakage has occurred, and in that case the transient is not sensitive to assumptions which only change the rate of leakage.

RCS Flow
Nominal primary system loop flow with a negative uncertainty is assumed. Low forced circulation flow results in lower natural circulation flow during the post-trip cooldown. This reduces primary-to-secondary heat transfer and extends plant cooldown. Frictional and form losses will also be smaller throughout the RCS, resulting in a higher primary pressure at the break location. This maximizes primary to secondary leakage.

Core Bypass Flow
Core bypass flow is not an important parameter for this transient.

Steam Generator Level
Minimum steam generator level reduces the initial secondary inventory available to mix with and dilute the primary-to-secondary leakage. This also minimizes the secondary side static head at the break location, thus maximizing primary to secondary leakage.

Fuel Temperature
High initial fuel temperature maximizes the stored energy which must be removed during the post-trip natural circulation cooldown.

Steam Generator Tube Plugging
Steam generator tube plugging is not an important parameter in this analysis.

7.2.2.3   Boundary Conditions

Single Failure
The single failure identified for maximizing offsite dose is the failure of the PORV on the ruptured steam generator to close. In this analysis, this valve remains open until operator action is taken to isolate the PORV. Per Reference 4, page 5-7, "The most limiting failure would be the loss of air supply or power which prevents actuation of the (PORVs) from the main control room. The valves could be operated (locally) by manual action to correct for this single failure." This failure is incorporated into the analysis as it prolongs the transient, maximizing the primary-to-secondary leakage.

Pressurizer Safety Valves
The pressurizer code safety valves are not challenged during the course of this transient.

Steam Line Safety Valves
The main steam code safety valves are modeled with opening and closing characteristics which maximize secondary pressure. This delays operator identification of the failed open steam line PORV.

Steam Line PORVs

Only two of the three steam line PORVs on the intact steam generators are assumed to be operable. This lengthens the cooldown time, thereby maximizing the atmospheric steam releases. A negative bias is applied to the ruptured steam generator PORV control signal. This results in an earlier opening time which maximizes atmospheric releases and delays operator identification of the failed open steam line PORV. A positive bias is applied to the intact SG PORV control signals to maximize secondary side post-trip pressurization. This delays operator identification of the failed open steam line PORV.

Decay Heat

End-of-cycle decay heat, based upon the ANSI/ANS-5.1-1979 standard plus a two-sigma uncertainty, is employed.

Offsite Power

Offsite power is assumed to be lost coincident with turbine trip. This isolates steam flow to the condenser, thereby maximizing the atmospheric steam releases.

Break Model

The break is assumed to be a double-ended guillotine break of a single steam generator tube at the tubesheet surface on the steam generator outlet plenum. This location maximizes the mass flow through the break.

RCP Operation

The reactor coolant pumps are assumed to operate normally until offsite power is lost coincident with turbine trip.

ECCS Injection

SI actuation is assumed to occur on low pressurizer pressure at a setpoint with an applied positive uncertainty or on manual operator action. Maximum ECCS injection flow is assumed to maximize the primary-to-secondary leakage.

Main Feedwater

Main feedwater flow is assumed to terminate coincident with the loss of offsite power to minimize the secondary inventory available to mix with and dilute primary-to-secondary leakage.

Charging Flow

A conservatively high charging flow capacity is modeled to delay reactor trip and maximize total primary-to-secondary leakage.

Manual Actions

- Immediate action to maximize charging flow (penalty).

- Immediate action to energize pressurizer heater banks (penalty).

- Operators identify the abnormal condition of the RCS at 20 minutes and manually trip the reactor if not already tripped.

- Identify and isolate ruptured steam generator consistent with assumptions in WCAP-10698 (Reference 5), 15 minute minimum delay (credit).

- Isolate failed open steam line drains upstream of the main steam isolation valves. This action occurs 10 minutes after the ruptured steam generator is identified.

- Isolate the steam supply to the turbine-driven auxiliary feedwater pump from the ruptured steam generator after identification of the ruptured steam generator. An operator action delay time of 30 minutes is assumed (credit).

- Isolate failed open steam line PORV on the ruptured steam generator with an operator action delay time from when it should have closed normally. The delay times assumed are 10 minutes for control room and 30 minutes for local operation (credit).

- Manually control auxiliary feedwater to maintain zero power steam generator levels (nominal).

- Using the steam line PORVs, initiate natural circulation cooldown of the primary system after identification of the ruptured steam generator. Operator action delay times of 15 minutes for control room action and 45 minutes for local action are assumed (credit).

- Initiate depressurization of the primary system using the pressurizer PORVs to terminate break flow 10 minutes after the primary system is 20°F subcooled at the ruptured steam generator pressure (credit).

7.2.2.4   Control, Protection, and Safeguards System Modeling

Reactor Trip
A reactor trip occurs on either low pressurizer pressure or manual operator action at 20 minutes. A negative uncertainty is applied to the low pressurizer pressure trip setpoint to delay reactor trip. The overtemperature ΔT trip function is not credited.

Pressurizer Pressure Control
This control system is assumed to be in manual and therefore is not modeled. Operator action is assumed to energize the pressurizer heaters and control the PORVs. Pressurizer spray is not available for the duration of this transient.

Pressurizer Level Control
This control system is assumed to be in manual and therefore is not modeled. Operator action is assumed to maximize charging flow.

Condenser Steam Dump
The condenser steam dump valves are not assumed to be operable.
Condenser steam dump would nonconservatively minimize offsite doses.

Steam Generator Level Control
This control system is assumed to operate to maintain the initial steam
generator level prior to reactor trip.

Main Feedwater Pump Speed Control
The results of this transient are not sensitive to the mode of MFW pump
speed control as long as the steam generator level is kept within the
range that avoids protection or safeguards actuation.

Rod Control
No credit is taken for the operation of the Rod Control System for this
transient, which results in a slight increase in RCS temperature. With
the Rod Control System in automatic, the control rods would cause a
negative reactivity addition as they are inserted in an attempt to
maintain RCS temperature at its nominal value.

Turbine Control
The turbine is modeled in the load control mode, which is described in
Section 3.2.5.1 of Reference 2. Turbine trip on reactor trip is delayed
by 0.3 seconds to maximize primary to secondary leakage.

Safety Injection
To maximize makeup to the RCS, injection begins after a conservatively
short delay to allow for the startup of the diesel generators on the
loss of offsite power. Two train maximum injection flow, as a function
of RCS pressure, is assumed to maximize RCS pressure and tube leakage.
Injection is stopped when the emergency procedure SI termination
criteria are met.

Auxiliary Feedwater
Auxiliary feedwater initiation occurs after the loss of offsite power
with a delay, consistent with Technical Specifications. If applicable,
a purge volume of hot water is assumed to be delivered before cold
feedwater reaches the steam generators. Minimum flow rates are assumed
to minimize primary-to-secondary heat transfer.

MSIV Closure
Automatic MSIV closure is assumed using a steam line pressure signal.
Early closure maximizes the primary leakage released to the atmosphere
through the failed open steam line PORV.

8.0   SUMMARY

The preceding chapters have described in detail the system analysis
modeling assumptions used by Duke Power Company for the FSAR Chapter 15
accident analyses not documented in Reference 1. Table 8-1 summarizes
these modeling details for each of the analyzed events.

Table 8-1

Accident Analysis Assumptions

FSAR Section	15.1.2	15.1.3	15.2.3	15.2.3	15.2.6	15.2.6	15.2.6	15.2.6	15.2.7	15.2.7
Report Section	2.2	2.3	3.1.1	3.1.2	3.2.1	3.2.2	3.2.3	3.2.4	3.3.1	3.3.2
Power	Nominal	Nominal	High	High	High	High	Nominal	High	High	High
Pzr Pressure	Nominal	Nominal	High	High	High	**	Nominal	**	High	**
Pzr Level	High	High	High	High	High	**	Low	**	High	**
RCS Temp	Nominal	Nominal	High	High	High	High	Nominal	High	High	High
RCS Flow	Nominal	Nominal	Low	High	Low	High	Nominal	High	Low	High
Bypass Flow	Nominal	Nominal	**	**	**	**	Nominal	**	**	**
SG Level	Low	**	High	High	**	High	**	High	Low	Low
Fuel Temp	Low	**	High	High	Low	Low	High	**	Low	Low
SG Tube Plugging	None	None	High	None	High	None	**	High	High	None
Pzr Spray	-	-	OFF	Auto	OFF	**	Auto	OFF	OFF	**
Pzr Heaters	OFF	OFF	On	On	Auto	**	OFF	OFF	Auto	**
Pzr PORVs	-	-	Closed	Auto	Closed	**	Auto	Closed	Closed	**
SM PORVs	-	-	Closed	Closed	Closed	Closed	Closed	Closed	Closed	Closed
Steam Dump	-	-	Closed	Closed	Closed	Closed	Closed	Closed	Closed	Closed
SG Level	-	**	*	*	-	-	**	-	-	-
MFW Pump Speed	-	**	*	*	-	-	High	-	-	-
Rod Control	*	*	Manual	Manual	-	-	-	-	Manual	Manual
Turbine Control	Auto	Auto	-	-	**	**	**	**	Auto	Auto
SI Signal	-	-	-	-	-	-	-	-	-	-
SI Flow	-	-	-	-	-	-	-	-	-	-
SI Delay	-	-	-	-	-	-	-	-	-	-
AFW Signal	**	**	*	*	LOSP	LOSP	LOSP	LOSP	SG Lvl	SG Lvl
AFW Flow	**	**	*	*	Min	Min	Min	Min	Min	Min
AFW Delay	**	**	*	*	TS	TS	TS	TS	TS	TS
Turb Trip Signal	SG Lvl	-	LOSP	LOSP	LOSP	LOSP	LOSP	LOSP	Rx Trip	Rx Trip
Turb Trip Delay	TS	-	None	None	None	None	None	None	None	Rx Trip
Stm Line Isol Signal	-	-	-	-	None	None	None	None	None	None
Stm Line Isol Delay	-	-	-	-	-	-	-	-	-	-
MFW Isol Signal	SG Lvl	-	*	*	-	-	-	-	-	-
MFW Isol Delay	TS	-	*	*	-	-	-	-	-	-

Notes:

* Refer to the text discussion of this transient.

** Results of the transient are insensitive to the choice about this parameter.

- Not applicable, either because the transient does not challenge that control system or because the malfunction of that system might be the cause of the transient.

Table 8-1 (continued)
Accident Analysis Assumptions

FSAR Section	15.2.7	15.2.8	15.2.8	15.3.1	15.3.2	15.3.3	15.3.3	15.4.1	15.4.1	15.4.2
Section	3.3.3	3.4.1	3.4.2	4.1	4.2	4.3.1	4.3.2	5.1.1	5.1.2	5.2.1
Power	Nominal	Nominal	High	Nominal	Nominal	High	Nominal	0	0	*
Pzr Pressure	Nominal	Nominal	Low	Nominal	Nominal	High	Nominal	High	Nominal	High
Pzr Level	Low	Low	Low	Low	Low	High	Low	High	Low	High
RCS Temp	Nominal	Nominal	High	Nominal	Nominal	High	Nominal	**	Nominal	**
RCS Flow	Nominal	Nominal	Low	Nominal	Nominal	High	Nominal	**	Nominal	**
Bypass Flow	Nominal	Nominal	**	Nominal	Nominal	High	Nominal	**	Nominal	**
SG Level	Low	**	Low	**	**	**	**	**	**	**
Fuel Temp	High	High	High	High	High	High	High	Low	Low	Low
SG Tube Plugging	High	**	**	**	**	**	**	High	None	High
Pzr Spray	Auto	Auto	Auto	Auto	Auto	Off	Auto	Off	Auto	Off
Pzr Heaters	Off	Off	Off	Off	Off	Auto	Off	**	Off	**
Pzr PORVs	Auto	Auto	Closed	Closed	Auto	Closed	Auto	Closed	Auto	Closed
SM PORVs	Closed	Closed	Closed	Closed	Closed	Closed	Closed	Closed	Closed	Closed
Steam Dump	Closed	Closed	Closed	Closed	Closed	Closed	Closed	Closed	Closed	Closed
SG Level	-	-	-	**	**	**	**	-	-	Auto
MFW Pump Speed	-	-	-	**	**	**	**	-	-	**
Rod Control	Manual	Manual	Manual	Manual	Manual	Manual	Manual	-	-	-
Turbine Control	Auto	Auto	Auto	Auto	Auto	Auto	Auto	-	-	Auto
SI Signal	-	-	*	-	-	-	-	-	-	-
SI Flow	-	-	Min	-	-	-	-	-	-	-
SI Delay	-	-	TS	-	-	-	-	-	-	-
AFW Signal	SG Lvl	**	SI	**	**	**	**	**	**	*
AFW Flow	Min	**	Min	**	**	**	**	**	**	*
AFW Delay	TS	**	TS	**	**	**	**	**	**	-
Turb Trip Signal	Rx Trip	Rx Trip	Rx Trip	Rx Trip	Rx Trip	Rx Trip	Rx Trip	-	-	Rx Trip
Turb Trip Delay	None	None	None	None	None	None	None	-	-	None
Stm Line Isol Signal	-	-	*	-	-	-	-	-	-	-
Stm Line Isol Delay	-	-	*	-	-	-	-	-	-	-
MFW Isol Signal	-	**	-	**	**	**	**	-	-	**
MFW Isol Delay	-	**	-	**	**	**	**	-	-	**

Notes:
* Refer to the text discussion of this transient.
** Results of the transient are insensitive to the choice about this parameter.
- Not applicable, either because the transient does not challenge that control system or because the malfunction of that system might be the cause of the transient.

8-3

Table 8-1 (continued)
Accident Analysis Assumptions

FSAR Section	15.4.2	15.4.3c	15.4.3d	15.4.4	15.4.6	15.4.7	15.5.1	15.5.1	15.6.1	15.6.3	15.6.3
Section	5.2.2	5.3	5.4	5.5	5.6	5.7	6.1.1	6.1.2	7.1	7.2.1	7.2.2
Power	Nominal	-	Nominal	*	-	-	Nominal	0	Nominal	Nominal	High
Pzr Pressure	Nominal	-	Nominal	Low	-	-	Nominal	Low	Nominal	Nominal	High
Pzr Level	Low	-	High	Low	-	-	High	Low	Low	Low	High
RCS Temp	Nominal	-	Nominal	High	-	-	Nominal	Low	Nominal	Nominal	Low
RCS Flow	Nominal	-	Nominal	Low	-	-	Nominal	-	Nominal	Nominal	Low
Bypass Flow	Nominal	-	Nominal	High	-	-	Nominal	-	Nominal	Nominal	**
SG Level	**	-	**	**	-	**	**	-	**	**	Low
Fuel Temp	Low	-	Low	Low	-	-	High	-	High	High	High
SG Tube Plugging	*	-	**	**	High	-	**	High	**	**	**
Pzr Spray	*	-	Auto	Auto	-	-	Auto	-	-	-	Off
Pzr Heaters	Off	-	Off	Off	-	-	Off	Off	Off	Off	Manual
Pzr PORVs	*	-	Closed	Auto	-	-	Auto	-	-	-	Manual
SM PORVs	Closed	-	Closed	-	-	-	Closed	-	-	Closed	*
Steam Dump	Closed	-	Closed	-	-	-	Closed	-	-	Closed	Closed
SG Level	Auto	-	Auto	**	-	-	**	-	**	**	Auto
MFW Pump Speed	**	-	**	**	-	-	**	-	**	**	**
Rod Control	-	-	-	Auto	-	-	Manual	-	Manual	Manual	Manual
Turbine Control	Auto	-	Auto	Manual	-	-	Auto	-	Auto	Auto	Auto
SI Signal	-	-	-	-	-	-	-	-	**	-	*
SI Flow	-	-	-	-	-	-	Max	Max	**	-	Max
SI Delay	-	-	-	-	-	-	-	-	**	-	Min
AFW Signal	*	-	*	**	-	-	**	-	**	**	LOSP
AFW Flow	*	-	*	**	-	-	**	-	**	**	Min
AFW Delay	*	-	*	**	-	-	**	-	**	**	TS
Turb Trip Signal	Rx Trip	-	Rx Trip	-	-	-	Rx Trip	-	Rx Trip	Rx Trip	Rx Trip
Turb Trip Delay	None	-	None	-	-	-	None	-	Max	None	*
Stm Line Isol Signal	-	-	-	-	-	-	-	-	-	-	*
Stm Line Isol Delay	-	-	-	-	-	-	-	-	-	-	*
MFW Isol Signal	**	-	**	**	-	-	-	-	**	**	LOSP
MFW Isol Delay	**	-	**	**	-	-	-	-	**	**	None

Notes:

* Refer to the text discussion of this transient.

** Results of the transient are insensitive to the choice about this parameter.

\- Not applicable, either because the transient does not challenge that control system or because the malfunction of that system might be the cause of the transient.

9.0 REFERENCES

1. DPC-NE-3001-PA, "Multidimensional Reactor Transients and Safety Analysis Physics Parameters Methodology", Duke Power Company, Revision 0, November 1991.

2. DPC-NE-3000-PA, "Thermal-Hydraulic Transient Analysis Methodology", Duke Power Company, Revision 1, December 1997.

3. NUREG-0800, "U.S.N.R.C. Office of Nuclear Reactor Regulation Standard Review Plan", Revision 3, July 1981.

4. NUREG-0422, SER Related to the Operation of McGuire Nuclear Station, Units 1 and 2, Supplement 4, January 1981.

5. WCAP-10698-P-A. "SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill", R. N. Lewis, et. al., August, 1987.

List of Changes/Errata from Revision 2, December 1997 to Revision 3, May 1999

1. The title page was revised to Revision 3 and was dated May 1999.

2. The Revision 3 SER dated 2/5/99 was included at the front.

3. Section 3.3.3.1: Revised to describe steam generator nodalization change.

4. This page describing the changes from Revision 2 to Revision 3 was added

5. The list of attached docketed correspondence was updated

6. The Duke letter dated 9/25/98 (submitting Revision 3 related to steam generator modeling) was included at the back.

List of Changes/Errata from Revision 1, June 1994 to Revision 2, December 1997

1. The title page was revised to Revision 2 and was dated December 1997.

2. The Revision 1 SER dated 12/28/95 was included at the front.

3. The Revision 2 SER dated 4/26/96 was included at the front.

4. The Duke cover letter dated 7/18/94 (submitting Revision 1 related to replacement steam generators), and the letter dated 8/18/95 (responses to the NRC RIA letter dated 7/25/95) were included at the back.

5. The Duke letter dated 12/19/95 (submitting the minor methodology change for the "pop open" safety valve modeling), and the letter dated 3/15/95 (additional information related to the 12/19/95 submittal) were included at the back.

6. The Duke letter dated 5/16/96 (additional information related to the Duke response dated 8/18/95) was included at the back.

7. Table of contents: Typo; added "Valve" to title for Section 7.1.

8. Multiple sections (3.1.1.3, 3.1.2.3, 3.2.1.3, 3.2.2.3, 3.2.3.3, 3.2.4.3, 3.3.1.3, 3.3.2.3, 3.3.3.3, 3.4.1.3, 3.4.2.3, 4.1.3, 4.2.3, 4.3.1.3, 4.3.2.3, 5.1.1.3, 5.1.2.3, 5.2.1.3, 5.2.2.3, 5.4.3, 6.1.1.3, 7.2.1.3, 7.2.2.3): Revised to reflect the "pop open" modeling for the main steam safety valves and pressurizer safety valves that was approved by NRC SER dated April 26, 1996.

9. Section 1.0: Typo; replaced "9" with "Reference".

10. Section 2.3.2: Revised to state that the results of this transient are insensitive to initial fuel temperature.

11. Section 2.4: Revised to reflect that analyses will be performed using the steam line break methodology rather than relying on the use of the steam line break analysis to bound this event.

12. Section 3.1.1.2: Revised to state that high initial fuel temperature is conservative.

13. Section 3.1.2.2: Revised to state that high initial fuel temperature is conservative.

14. Section 3.1.2.4: Revised the steam generator level control assumption. Sensitivity studies indicate that continued feedwater addition may be more conservative than feedwater isolation on reactor trip. Therefore, both cases will be analyzed to ensure a conservative result.

15. Section 3.3: Editorial; replaced "DNB" with "core cooling capability".

16. Section 3.3: Editorial; added that the core cooling capability analysis confirms that the Auxiliary Feedwater System is capable of returning the plant to a stabilized condition.

17. Section 3.3.1.4: Added overtemperature ΔT and high pressurizer pressure to the list of potential reactor trip signals.

18. Section 3.3.1.4: Clarify that a purge volume of hot auxiliary feedwater will be considered only if applicable. This change was inadvertently omitted from Revision 1 but is essentially the same change that was approved for other transients in the Revision 1 SER dated December 28, 1995.

19. Section 3.3.2.1: Remove sentence regarding pressurizer heat conductor modeling since this is now described in topical report DPC-NE-3000. This change was inadvertently omitted from Revision 1 but is essentially the same change that was approved for other transients in the Revision 1 SER dated December 28, 1995.

20. Section 3.3.2.4: Added overtemperature ΔT and high pressurizer pressure to the list of potential reactor trip signals.

21. Section 3.3.3.4: Added overtemperature ΔT and high pressurizer pressure to the list of potential reactor trip signals.

22. Section 4.3: Changed locked rotor peak RCS pressure acceptance criterion from 120% to 110%. This change is required by the NRC SER for Revision 0 of DPC-NE-3002 dated November 15, 1991.

23. Section 4.3.1.2: Revised to state that high initial fuel temperature is conservative.

24. Section 5.5.2: Revised to initiate the transient from the power level corresponding to the P-8 setpoint. This initial power level combined with the unavailability of the low RCS flow reactor trip function gives a more conservative result.

25. Section 5.5.2: Editorial; clarified that the pressurizer pressure initial condition uncertainty includes a bias.

26. Section 5.5.2: Editorial; reworded core bypass flow assumption for clarification.

27. Section 5.5.4: Added paragraph describing reactor trip assumptions.

28. Section 5.5.4: Revised to state that the results of this analysis are not sensitive to SG level control or MFW pump speed control so long as protection or safeguards actuation is avoided.

29. Section 6.1.2.1: Editorial; replaced "NC system" with "RCS".

30. Section 6.1.2.1: Typo; replaced "an" with "a".

31. Section 7.1.2: Revised to state that low initial pressurizer level is conservative.

32. Section 7.1.3: Revised to state that the main steam safety valves are not challenged during the time period of interest for this transient.

33. Section 7.1.4: Typo; deleted duplicate sections for SG level control and MFW pump speed control.

34. Section 7.1.4: Revised to state that rod control in manual is conservative.

35. Section 7.1.4: Revised to state that a long delay on turbine trip is conservative.

36. Section 7.2: Editorial; deleted sentence concerning SG overfill. Methodology for analyzing SG overfill is not included in DPC-NE-3002. SG overfill is part of the licensing basis for Catawba only and has been handled separately through correspondence with the NRC.

37. Section 7.2.2.2: Editorial; added "automatic" in front of "reactor trip".

38. Section 7.2.2.2: Editorial; added clarification of the rationale for the selection of initial RCS average temperature.

39. Section 7.2.2.4: Typo; replaced "avoid" with "avoids".

40. Section 7.2.2.4: Added a paragraph describing the assumptions made regarding safety injection.

41. Section 7.2.2.4: Deleted reference to dynamically compensated steam line pressure signal. This revision is made to reflect the current plant configuration.

42. Table 8-1, Sections 2.3, 3.1.1, 3.1.2: Revised fuel temperature assumptions for consistency with changes 10, 12, and 13 above.

43. Table 8-1: Typo; replaced "contol" with "control".

44. Table 8-1, Section 4.3.1: Revised fuel temperature assumption for consistency with change 23 above.

45. Table 8-1, Section 7.1: Revised pressurizer level assumption for consistency with change 31 above.

46. Table 8-1, Section 7.1: Revised to state that the SM PORVs and steam dumps are not applicable since they are not challenged during the time period of interest for this transient.

47. Table 8-1, Section 5.5: Revised to state that this transient is not sensitive to the SG level and MFW pump speed control assumptions as described in change 28 above.

48. Table 8-1, Section 7.1: Revised to state that rod control is in manual as described in change 34 above.

49. Table 8-1, Section 7.2.2: Revised SI delay from "None" to "Min". No delay is slightly more conservative; however, a minimum delay that conservatively bounds the plant response time is assumed.

50. Table 8-1, Section 7.1: Revised to state that a maximum turbine trip delay is used as described in change 35 above.

51. Section 9.0: Revised References 1 and 2 to reflect the latest revisions and associated approval dates.

List of Attached Docketed Correspondence

1. 10/30/91 original submittal letter, M. S. Tuckman to NRC

2. 11/5/91 letter responding to NRC questions, H. B. Tucker to NRC

3. 7/18/94 letter submitting Revision 1 (replacement SGs), M. S. Tuckman to NRC

4. 7/25/95 NRC RIA letter on 7/18/94 submittal, R. E. Martin to M. S. Tuckman

5. 8/18/95, letter responding to NRC RIA letter, M. S. Tuckman to NRC

6. 12/19/95 letter submitting Revision 2 ("pop-open" safety valve modeling), M. S. Tuckman to NRC

7. 3/15/96 letter providing additional information related to the 12/19/95 letter, M.S. Tuckman to NRC

8. 5/16/96 letter responding to May 14, 1996 conference call questions, M. S. Tuckman to NRC

9. 9/25/98 letter submitting Revision 3 (SG modeling), G. R. Peterson to NRC

DUKE POWER

August 30, 1991

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D. C. 20555

Subject: McGuire Nuclear Station
         Docket Numbers 50-369 and -370
         Catawba Nuclear Station
         Docket Numbers 50-413 and -414
         FSAR Transient Analysis Methodology;
         Topical Report DPC-NE-3002-P

Attached for your review is Duke Power Company's Topical Report
DPC-NE-3002, "FSAR Chapter 15 System Transient Analysis
Methodology." This report describes Duke's methodology for
conservatively modeling those FSAR Chapter 15 non-LOCA transients
and accidents not previously described in DPC-NE-3000, "Thermal-
Hydraulic Transient Analysis Methodology" and DPC-NE-3001,
"Multidimensional Reactor Transients and Safety Analysis Physics
Parameters Methodology." This report is applicable to the McGuire
and Catawba Nuclear Stations.

The objectives of this report are: 1) to describe the initial and
boundary conditions and input assumptions regarding control and
protective system functions, as used in the analysis of FSAR
Chapter 15 events; and 2) to describe nodalization and/or modeling
differences relative to those analyses previously detailed in DPC-
NE-3000. The rod ejection, steam line break, and dropped rod
methodologies are described in DPC-NE-3001, and are not discussed
in this report. Assumptions regarding safety analysis physics
parameters are also discussed in DPC-NE-3001.

Please note that approval of this Topical Report is needed for
startup of McGuire Unit 1 Cycle 8 following its upcoming refueling
outage. The outage is scheduled to begin in late September, 1991.
Cycle 8 is expected to start up in late November or early December.

U. S. Nuclear Regulatory Commission
August 30, 1991
Page 2

If there are any questions, please call Scott Gewehr at (704) 373-
7581.

Very truly yours,

M. S. Tuckman
cvr3002/sag

cc: Mr. T. A. Reed, Project Manager
     Office of Nuclear Reactor Regulation
     U. S. Nuclear Regulatory Commission
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     Washington, D. C. 20555

     Mr. R.E. Martin, Project Manager
     Office of Nuclear Reactor Regulation
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     Washington, D. C. 20555

     Mr. S. D. Ebneter, Regional Administrator
     U.S. Nuclear Regulatory Commission - Region II
     101 Marietta Street, NW - Suite 2900
     Atlanta, Georgia 30323

     Mr. P. K. Van Doorn
     Senior Resident Inspector
     McGuire Nuclear Station

     Mr. R. C. Jones
     Reactor Systems Branch
     Office of Nuclear Reactor Regulation
     U. S. Nuclear Regulatory Commission
     Washington, D. C. 20555

     Mr. W. T. Orders
     NRC Resident Inspector
     Catawba Nuclear Station

DUKE POWER

November 5,1991

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Wasnington, D. C. 20555

Subject: McGuire Nuclear Station
         Docket Numbers 50-369 and -370
         Catawba Nuclear Station
         Docket Numbers 50-413 and -414
         Oconee Nuclear Station
         Docket Numbers 50-269, -270, and -287
         Final Response to Questions Regarding the Topical Reports
         Associated with the M1C8 Reload Package

References: 1) Letter, H. B. Tucker to NRC, January 9, 1989.
               (DPC-NE-2004 submittal)
            2) Letter, H. B. Tucker to NRC, September 29, 1987.
               (DPC-NE-3000 submittal)
            3) Letter, H. B. Tucker to NRC, January 29, 1990.
               (DPC-NE-3001 submittal)
            4) Letter, M. S. Tuckman to NRC, September 25, 1991.
               (Reaffirmation of Proprietary Affidavit for DPC-NE-
               2004)
            5) Letter, M. S. Tuckman to NRC, September 25, 1991.
               (Reaffirmation of Proprietary Affidavit for DPC-NE-
               3000)

On October 7 and 8, 1991, representatives of Duke Power met with
NRC Staff and contract reviewers to discuss outstanding issues
associated with three Topical Reports (References 1, 2, and 3),
which are currently undergoing review. At this meeting, and during
various telephone conference calls subsequent to the meeting,
questions were identified which required additional information or
clarification. Attached are formal responses to each of the
questions. The attached information should resolve all outstanding
issues related to the review of Topical Reports DPC-NE-2004, -3001,
and -3000.
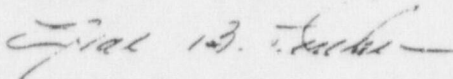
Please note that some of the information is identified as

proprietary, and should be withheld from public disclosure pursuant
to 10 CFR2.790. Affidavits attesting to the proprietary nature of
the information have been provided (References 3, 4, and 5).

Also, please note that while aspects of the referenced Topical
Reports may be applicable to all three of Duke's nuclear stations,
approval of the Reports is required for McGuire Unit 1 Cycle 8;
currently scheduled for startup in early December, 1991.

If there are any questions, please call Scott Gewehr at (704) 373-
7581.

Very truly yours,

H. B. Tucker

cc: Mr. T. A. Reed, Project Manager
      Office of Nuclear Reactor Regulation
      U. S. Nuclear Regulatory Commission
      Mail Stop 14H25, OWFN
      Washington, D. C.   20555

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      Mr. L. A. Wiens, Project Manager
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      Mr. S. D. Ebneter, Regional Administrator
      U.S. Nuclear Regulatory Commission - Region II
      101 Marietta Street, NW - Suite 2900
      Atlanta, Georgia   30323

bxc (w/o attachments):
     R. L. Gill, Jr.
     P. F. Guill
     S. G. Benesole
     P. J. North
     G. B. Swindlehurst
     K. S. Canady
     R. H. Clark
     R. M. Gribble
     GS-801.01

ATTACHMENTS

Attachment 1: A discussion of the adequacy of the McGuire/Catawba steam generator modeling in DPC-NE-3000 with respect to conservative prediction of primary-to-secondary heat transfer for transients which involve U-tube uncovery.

Attachment 2: Responses to informal questions on DPC-NE-3002, as understood by Duke Power, regarding issues that were not adequately addressed at the meeting, that were requested by the NRC to be formally docketed, or that arose in subsequent telephone conversations.

Attachment 3: Responses to informal questions on Chapter 15 markups, as understood by Duke Power, regarding issues that were not adequately addressed at the meeting, that were requested by the NRC to be formally docketed, or that arose in subsequent telephone conversations.

Attachment 4: A response to an additional question on DPC-NE-2004.

Attachment 5: A set of markups to DPC-NE-3001; due to questions asked at the meeting, and other corrections.

Attachment 6: A set of markups to DPC-NE-3002; due to questions asked at the meeting, and other corrections.

Attachment 2

Questions on Topical Report DPC-NE-3002

1. Justify that the results of analyzing the feedwater flow increase transient at zero power will not be more limiting than the full power case, considering the increased peaking factors, reduced RCS flow, and asymmetric inlet temperature and power distributions as a result of a stuck rod and a single loop malfunction.

Response: A power increase due to a feedwater flow increase at zero power would, at worst, reach the high neutron flux reactor trip low setpoint. This setpoint is no higher than 35% RTP. The increased neutron attenuation in cooler downcomer water would affect only the excore flux detector next to the affected loop (at least two detectors must indicate above the setpoint for a trip to occur), and an allowance for this is already included in the 10% RTP margin between the above safety analysis value and the 25% RTP Technical Specification trip setpoint. For the core power distributions at the start of the accident (those permitted by the Technical Specifications), abundant DNB margin exists at 35% RTP with three (see proposed revision to Technical Specification 3.4.1.2) reactor coolant pumps operating. Unlike the steam line break accident, adequate shutdown margin is maintained. Power generation therefore ceases when the control rods fall into the core. The presence of a stuck rod does not therefore perturb the core power distribution during the time of minimum DNBR. Finally, the loss in local DNB margin due to a shift in core power distribution toward the quadrant near the affected loop would be somewhat mitigated by a gain in DNB margin due to reduced core inlet temperatures in that quadrant. It should also be noted that the current justification presented in the McGuire and Catawba FSARs for not analyzing this case, that the reactivity insertion rate for this transient is less than the rate assumed in the uncontrolled RCCA bank withdrawal from zero power, remains valid for the Duke Power Company analytical approach.

2. For the excessive increase in secondary steam flow accident, explain why a low initial pressurizer bubble volume would maximize the pressure decrease due to contraction.

Response: When the coolant contracts the pressurizer steam bubble expands, reducing the pressurizer pressure. The amount of pressure reduction is roughly inversely proportional to the volume of the bubble. Therefore expansion of a smaller bubble will maximize the resulting pressure decrease.

3. For the turbine trip accident, discuss the reasons why a DNB analysis is not required.

Response: The FSAR will be revised to insert the following paragraph into the 15.2.3.2 "Method of Analysis" section:

> For the turbine trip event the reactor power, the core power distribution, and the core flow change very little prior to reactor trip. The RCS pressurization due to the reduction in secondary heat sink more than offsets the increase in core inlet temperature. Therefore significant DNB margin is maintained throughout the transient, and no quantitative DNB analysis is required.

4. Explain why a high initial steam generator level would maximize the transient secondary pressure response for the turbine trip peak RCS pressure and peak secondary pressure analyses.

Response: Initial steam generator (SG) level has a small impact on two competing phenomena during a turbine trip event. First, as secondary pressure increases, the saturated liquid in the SG becomes slightly subcooled, which causes some of the energy transferred from the primary to heat the SG liquid to saturation. The higher the initial SG level, the greater the mass that is subcooled during pressurization, which tends to cause a lower transient SG pressure. The second phenomenon is that the higher the initial SG level, the smaller the initial steam volume, which tends to cause a higher transient SG pressure.

For the peak secondary pressure analysis, a sensitivity study on initial SG level in the turbine trip event was performed in a previous analysis. The sensitivity study demonstrated that a decrease of 8% span from nominal for initial SG level resulted in a decrease of 0.15 psi in peak secondary pressure. This result demonstrates that the effect of reducing initial steam volume dominates the effect of increasing initial SG mass, and high initial SG level is conservative. In addition, this result demonstrates that initial SG level is not a critical parameter. The effect of initial SG level is dominated by other conservatisms such as the drift and accumulation assumptions of the main steam safety valves.

For the peak RCS pressure analysis, the impact of initial SG level on the peak primary pressure analysis is limited to the second order effect of SG level on primary-to-secondary heat transfer. Maximum primary pressure is achieved by minimizing primary-to-secondary heat transfer. Primary-to-secondary heat transfer is less with an increase in the secondary saturation temperature, which increases with an increase in secondary pressure. Therefore, initial SG level is chosen to maximize secondary pressure. As shown above, maximum secondary pressure is achieved with a high initial SG level. In addition, the effect of initial SG level on secondary pressure is dominated by other conservatisms such as the drift and accumulation assumptions of the main steam safety valves and the pressurizer safety valves.

5. For a given high pressurizer pressure reactor trip setpoint, justify that a lower initial indicated pressurizer pressure, i.e., one at the limit of Technical Specification 3.2.5.b, would not give a higher peak RCS pressure result for the turbine trip and uncontrolled RCCA bank withdrawal at power events.

Response: While it is true that Technical Specification 3.5.2.b permits pressurizer pressure to indicate as low as 8.5 psi (at McGuire) less than the nominal value, this does not occur during automatic pressure control. There is no normal operator evolution during manual control at power operation which reduces pressure below the nominal value. Therefore this initial condition is not regarded as a credible one. Nevertheless, there remains sufficient margin in the pressure initial condition uncertainty adjustment to compensate for this 8.5 psi. Therefore the results presented in the McGuire 1 Cycle 8 reload submittal FSAR markups are conservative. In addition, for the uncontrolled RCCA bank withdrawal at power, the initial margin to trip is 45 psi more than for the turbine trip event, thus ensuring further conservatism. The values used in the analyses are as follows:

Parameter	Turbine Trip	UCBW @ Power
Pressure Instrument Uncertainty, psi	20	20
Pressure Uncertainty Allowance, psi	30	45
Initial Actual Pressure, psia	2280	2250
Initial Indicated Pressure, psia	2250	2250
Trip Setpoint, psia	2400	2445
Initial Margin to Trip, psi	150	195
Actual Pressure at Trip, psia	2430	2445

6. One acceptance criterion for the Condition II events is that there should be no water release from the pressurizer safety valves. For the loss of offsite power, loss of normal feedwater, and uncontrolled RCCA bank withdrawal at power accidents, provide analysis assumptions and results for addressing this criterion or justify that the margin to a water solid pressurizer condition for these events could be bounded by another event(s).

Response: Pressurizer overfill is a potential concern during an event in which either safety injection (SI) occurs or RCS heatup due to primary/secondary power mismatch occurs. As shown below, SI is the key factor in pressurizer overfill.

Pressurizer level at the station is determined by the difference in pressure between two elevations in the pressurizer. In addition to the random effects typically associated with a measurement, the use of a DP transmitter to determine pressurizer level introduces the possibility that a difference between actual liquid density and the calibrated density could allow actual pressurizer level to be higher than indicated level. This situation occurs when the actual liquid density is less than the liquid density at calibration conditions. Liquid density is a weak function of liquid pressure, but liquid density is a strong function of liquid temperature. Therefore, actual liquid density less than calibrated liquid density only occurs when actual liquid temperature is greater than the liquid temperature at calibration. The pressurizer level transmitters at the station are calibrated at full power conditions. Since the pressurizer is at saturated conditions at calibration, the temperature of the liquid in the pressurizer at calibration is the saturation temperature at nominal pressure, 2250 psia, which is approximately 653 °F. In order for the density error to cause actual level to be greater than indicated level, the water entering the pressurizer during a transient must be greater than 653 °F, but no transient will achieve this hot leg temperature for a sufficient duration prior to mitigating actions occurring. In addition, since the initial hot leg temperature is less than 653 °F, the initial insurge will decrease the temperature of the pressurizer liquid, causing indicated level to be higher than actual level. Pressurizer level in the McGuire/Catawba RETRAN model is not currently determined by the difference in pressure between two elevations in the pressurizer. As stated in Section 3.2.4.1 of DPC-NE-3000, pressurizer level in this model is determined directly from the liquid volume actually calculated by RETRAN in the node representing the pressurizer. This modeling determines the actual level in the pressurizer during the simulation, and it is not possible for the calculated indicated level to differ from the calculated actual level by more than the uncertainty allowance, and no credit is taken for the density effect described above. Therefore, pressurizer level derived from either DP or liquid level will prevent a pressurizer overfill condition prior to reactor trip.

In the loss of offsite power event (LOOP), SI does not occur. Reactor trip occurs at the initiation of the transient, and no significant post trip degradation of the secondary side cooling ability relative to the primary power generation occurs which could cause a power mismatch and

subsequent pressurizer overfill. Therefore, since SI does not occur, and a significant power mismatch does not occur, pressurizer overfill does not occur for the loss of offsite power event.

In the loss of normal feedwater (LOFW) event, SI does not occur. Pressurizer overfill could not occur prior to reactor trip because of the high pressurizer level reactor trip function. Overfill is most severe in the Condition IV feedwater line break (FWLB) event, and the high pressurizer level in the this event is caused by the addition of SI water to the RCS. Analysis has shown that continued SI causes pressurizer overfill to occur in the FWLB event. In comparison, the LOFW transient is the most severe intact steam generator tube uncovery event, but the power mismatch is not sufficient to cause pressurizer overfill. Therefore, since SI does not occur, and the power mismatch is not sufficiently severe, pressurizer overfill does not occur for the loss of normal feedwater event.

In the uncontrolled RCCA bank withdrawal at power event, SI does not occur. Pressurizer overfill could not occur prior to reactor trip because of the high pressurizer level reactor trip function. There is no post trip degradation of the secondary side cooling ability relative to the primary power generation which could cause a power mismatch and subsequent pressurizer overfill. Therefore, since SI does not occur, and a significant power mismatch does not occur, pressurizer overfill does not occur for the uncontrolled bank withdrawal at power event.

7. For the loss of offsite power, loss of normal feedwater, and feedwater line break accidents, provide a description of the auxiliary flow assumptions used, including number of pumps assumed, capacity, and flow fraction delivered to each steam generator.

Response: The limiting single failure in the Auxiliary Feedwater (AFW) System is assumed for each of these accidents. This assumption will result in no credit being taken for the single AFW pump whose loss would represent the greatest reduction in flow delivered to the intact steam generators. Therefore only two of the three AFW pumps are assumed to be operating for any of these accidents. Pump capacity is conservatively reduced from the manufacturer's head curves. The reduced capacity corresponds to a pump performance level below that which the pump is verified to meet in periodic tests. This additional reduction provides margin for further pump degradation between tests. The flow fraction delivered to each steam generator is calculated based on a model of the AFW pumps and piping layout. The flow fractions vary with 1) the transient backpressure in the steam generators, 2) which station (McGuire or Catawba) is being analyzed, and 3) whether operator action has occurred to realign the AFW System to change which pumps deliver flow to which steam generators. Because of these variabilities, a separate time dependent AFW boundary condition is calculated for each plant for each accident.

8. Justify why only the double-ended feedwater line break is analyzed and not a spectrum of feedwater line breaks. A smaller break, for which the reactor trip occurred on low-low steam generator water level might be limiting compared to the double-ended rupture of the main feedwater line.

Response: The current McGuire FSAR states (p.15.2-15), "...it has been shown that the most limiting feedwater line ruptures are the double-ended rupture of the largest feedwater line..." This assumption was reviewed and approved in the NRC SER for initial startup of McGuire. Duke did not analyze a spectrum of break sizes since it was apparent that the issue of break size

was resolved per the existing FSAR analyses. However, in order to respond to the question, additional investigation into the technical basis for concluding that the double-ended rupture is the limiting break size was performed. The results of this investigation have led to the conclusion that the double-ended rupture is the limiting case. The bases for this conclusion are as follows.

The feedwater line break transient causes a reactor trip on either low-low steam generator level or high containment pressure (~1 psig). The pre-trip transient response is dictated by the break size. For large breaks, the affected steam generator rapidly blows down, and main feedwater flow to all four steam generators is lost out the break. The intact steam generators gradually boil off until auxiliary feedwater delivery begins approximately 60 seconds after reactor trip. Long-term decay heat removal is established via auxiliary feedwater and the intact steam generators. For smaller feedwater line breaks, the affected steam generator blows down more slowly and some main feedwater flow continues to be delivered to the intact steam generators. Main feedwater would only be stopped by assuming a loss of offsite power coincident with reactor trip. For all break sizes, the affected steam generator will blow down to dryout, and will not contribute to long-term decay heat removal. The minimum inventory in the intact steam generators is the key parameter when determining the limiting break size. The inventory in the intact steam generators will change depending on the pre-trip steaming duration, and main feedwater flowrate. Both of these are a function of the break size. For larger breaks the steaming duration is short due to a rapid reactor trip. Larger breaks will also prevent any main feedwater flow from reaching the intact steam generators. For small breaks the steaming duration is longer, but some main feedwater can still reach the intact steam generators. From this argument it follows that an intermediate size break will result in the minimum intact steam generator inventory. It is noted that the auxiliary feedwater flowrate is the same for all break sizes. Therefore, the long-term cooling capability is not affected by the break size. The break size concern is limited to determining if the minimum post-trip heat sink, corresponding to the minimum intact SG inventory case, causes any of the acceptance criteria to be met.

A sensitivity study on break size was performed. The required modifications to the RETRAN model were [

] The effect of these modeling changes is to conservatively predict the minimum main feedwater flow delivered to the intact steam generators. As stated above, for the double-ended rupture this flow will be zero, but as the break size decreases some flow will be delivered. All main feedwater is assumed to be lost on reactor trip due to an assumed loss of offsite power.

In addition to the double-ended rupture break size for which all main feedwater is lost, split breaks of 0.2387, 0.3, and 0.5 ft^2 were analyzed. Due to the feedwater nozzle flow restrictor area [   ] the duration of blowdown and the time of reactor trip is unaffected until the break size approaches the range of sizes analyzed. Within this range of break sizes, the larger sizes predict an earlier reactor trip, less steaming from the intact steam generators, and less main feedwater reaching the generator. Smaller break sizes predict a later reactor trip, more steaming from the intact steam generators, and more delivered main feedwater. The integrated effect of these parameters on the analysis is characterized by the minimum intact steam generator inventory.

Break Size (ft²)	Rx Trip Time (sec)	Minimum SG Mass (lbm/SG)
DE	19.5	[ ]
0.5	[	]
0.3		

The 0.5 ft² break size is significant in that this break size is at the transition where all main feedwater is lost out the break. The 0.3 ft² break has some main feedwater reaching the intact steam generators, which explains the higher minimum mass flow. For breaks larger than 0.5 ft², there is essentially no difference when compared to the double-ended break. The difference in reactor trip time is [   ] second, and the minimum steam generator masses are [   ] Break sizes above 0.5 ft² are the [   ]

Based on the results of the break size sensitivity, the FSAR statement that the double-ended rupture is the limiting case is confirmed. The minimum steam generator inventory in the intact steam generators and the available auxiliary feedwater capacity ensure that the consequences of the limiting feedwater line break are acceptable.

9. The current FSAR analysis of the feedwater line break assumes that the AFW flow to the faulted steam generator is spilled through the break. Justify why this AFW spillage is not assumed in the McGuire 1 Cycle 8 reload submittal analysis of feedwater line break. Justify the operator action time assumed isolate the AFW flow to the faulted steam generator.

Response: The McGuire and Catawba steam generators are of the preheat design with a lower feedwater nozzle entering the preheater region and an upper nozzle entering the upper region of the downcomer. At all but the lowest power levels, the vast majority of the main feedwater flow enters through the lower nozzle. At all conditions the AFW flow enters through the upper nozzle. AFW spillage through a break of a pipe connected to the lower nozzle (main feedwater line) would require failure of a check valve plus closure failure on a second valve which receives a feedwater isolation signal. This is not regarded as credible. Otherwise, the AFW flow entering the faulted steam generator must travel down the downcomer and partially up the tube bundle through the preheater to exit through the lower nozzle before reaching the broken piping. This flow path allows heat to be transferred to this water from the RCS. Since this AFW flow to the depressurized steam generator is a relatively large fraction of the total AFW flow, isolation of it reduces the total AFW flow available for RCS heat removal. Therefore its isolation is conservatively accomplished at two minutes into the transient. This is a very short time for the operator to perform the steps in the emergency procedures preceding isolation of AFW to a faulted steam generator.

10. For a feedwater line break analysis in which reactor trip was actuated by the low-low steam generator water level, a higher initial steam generator water for the faulted steam generator could be more conservative.

Response: Duke agrees. If the low-low steam generator narrow range level reactor trip is credited in the FSAR Section 15.2.8 feedwater line break accident, a high initial condition uncertainty adjustment will be applied to the faulted steam generator narrow range level.

11. Justify the gap heat transfer coefficient used for the partial and complete loss of forced flow events.

Response: A low fuel gap conductivity, which corresponds to a high initial fuel temperature is used in the analyses. The low fuel gap conductivity has three major effects in these events. First, low gap conductivity is conservative due to the higher initial stored energy in the fuel compared to the initial stored energy in the fuel with a high gap conductivity. For a given rate of decrease of the fuel rod surface heat flux, a higher initial stored energy in the fuel causes a higher heat flux during the transient because more energy is available to be transferred to the coolant. Second, low gap conductivity is more conservative because the energy will be retained in the fuel for a longer period of time. Since the energy is retained in the fuel for a longer time period, the heat flux will decrease more slowly, and compared to high gap conductivity, the heat flux will be maintained at a higher value during the flow coastdown. Third, from a reactivity insertion aspect, low gap conductivity is less conservative than high gap conductivity. The fuel Doppler temperature coefficient (DTC) is negative, and a low gap conductivity causes more fuel heatup to occur, which adds more negative reactivity than a high gap conductivity. However, the fuel temperature increase is minimal in these events, and the difference in reactivity insertion due to a low gap conductivity versus a high gap conductivity is insignificant. The higher initial stored energy and the slower heat flux decrease completely dominate the reactivity effect, and low gap conductivity is conservative.

12. The staff's peak RCS pressure acceptance criterion for the locked rotor event is 110% of the design pressure instead of the proposed 120% value.

Response: The Standard Review Plan (NUREG-0800, July 1981) states that the Reactor Systems Branch acceptance criteria for both the feedwater line break and the locked rotor events are based on meeting the relevant requirements of General Design Criteria 31 as it relates to the reactor coolant system being designed with sufficient margin to ensure that the boundary behaves in a nonbrittle manner and that the probability of propagating fracture is minimized. Although the wording is the same for both events, the feedwater line break Standard Review Plan section also gives quantitative acceptance criteria, 110% of design pressure for low probability events and 120% of design pressure for very low probability events. The locked rotor event is characterized as a Condition IV event (limiting fault not expected to occur during the life of the plant) in both the McGuire and Catawba FSARs. The acceptance criterion of 120% of the design pressure is based on assuming that a locked rotor event is of very low probability and therefore that the acceptance criterion adopted for double-ended guillotine feedwater line breaks applies. However, the peak pressure result of the locked rotor event analyzed in the McGuire 1 Cycle 8 reload submittal is within 110% of the Reactor Coolant System design pressure.

13. Discuss whether the locked rotor event will be analyzed assuming coastdown of undamaged pumps coincident with turbine trip if it is more limiting.

Response: The relevant Standard Review Plan instruction concerning this question is as follows:

"This event should be analyzed assuming turbine trip and coincident loss of offsite power and coastdown of undamaged pumps."

As stated in Section 4.3.1.3 of Duke Power Company topical report DPC-NE-3002, offsite power was assumed to be lost coincident with turbine trip. Upon the loss of offsite power, voltage and frequency begin to decay on the four 6900 V busses which supply power to the reactor coolant pump (RCP) motors. Pump motor speed, and therefore pump flow, decrease as the bus frequency decays. After the loss of offsite power the bus voltage decreases to the RCP undervoltage trip setpoint. At this point the RCP motor breakers open and the pumps coast down as controlled by the inertia of their flywheels. It is Duke Power Company's position that this modeling meets the intent of the Standard Review Plan, i.e., the RCP coastdown is caused by the loss of offsite power.

14. Provide and justify the gap heat transfer coefficient used for the locked rotor accident.

Response: See response to question 11, above.

15. Justify the use of a point kinetics model for the uncontrolled RCCA bank withdrawal from zero power and single RCCA withdrawal events. Describe in detail the methodology used to determine the bounding radial and axial power shapes and the uncertainties assumed. Provide and justify the bounding radial and axial power shapes, moderator density coefficients, and trip reactivity used in the DNB analysis.

Response: The uncontrolled bank withdrawal from zero power and the single rod withdrawal events use a point kinetics model to determine the core average power response. The point model employs physics parameters that conservatively bound the core designs. Due to the absence of leakage and spatial effects in a point model relative to a 3-dimensional space-time model, the point model will overpredict reactivity and the transient core average power response. Spatial effects are accounted for by explicit 3-dimensional simulation of the core power distribution. The analytical methodology is as follows. The system thermal-hydraulic analysis is conservatively simulated with the RETRAN code. Transient core thermal-hydraulic boundary conditions from RETRAN are then input to VIPRE to determine DNBR vs. time. The minimum

DNBR limit. These rods are assumed to experience cladding failure and contribute to the source term for the offsite dose calculations.

The moderator density coefficient assumed in the analyses is consistent with the current Technical Specification value.

The conservative normalized trip reactivity vs. normalized drop time given in Figure 15.0.5-3b of the McGuire 1 Cycle 8 reload submittal was used. A rod drop time consistent with Technical Specification 3.1.3.4 was assumed. As stated in Section 2.2 of Duke Power Company topical report DPC-NE-3001, the minimum worth was assumed for the amount of trip reactivity inserted after trip. As described in that report, this worth assumes that the most reactive rod remains in the fully withdrawn position and that the other rods drop from their power dependent insertion limits. [

]

16. The current FSAR high neutron flux trip setpoint uncertainties include a process measurement accuracy term for shielding effects and detector placement. Discuss how this effect is accounted for in the uncontrolled RCCA bank withdrawal accidents.

[

]

17. Specify which of the accidents discussed in DPC-NE-3002 will be analyzed with a non-zero value of the pressurizer interregion heat transfer coefficient.

Response: The methodology for determining whether to model interregion heat transfer was presented in the NRC/ITS/Duke Power meeting on October 7-8, 1991. Of the transients discussed in DPC-NE-3002, [

]

18. Explain what differences, if any, are intended by the use of various descriptions of initial condition assumptions in the text and tables of DPC-NE-3002, both among the text sections for various accidents and between the text and Table 8-1 for a particular accident.

Response: The entries in Table 8-1 of DPC-NE-3002, which are in a standardized format for specification of initial conditions, are intended to be consistent with the text descriptions. Any variation in text descriptions has no significance. In general , the choice of initial conditions is as described in the first full paragraph on page 1-2 of DPC-NE-3002. The specific table entries and their intended meanings are as follows:

"Nominal" means that, for power level, the initial condition is chosen from the range of zero to 100% RTP based on conservative modeling or on consistency with the Standard Review Plan. For pressurizer pressure the initial condition is the plant reference pressure for power operation For reactor vessel average temperature the initial condition is the programmed value for the chosen power level. For core bypass flow the initial condition is the best estimate calculated value. For RCS flow the initial condition is a chosen value at or below the Technical Specification minimum measured flow. Initial condition uncertainties in each of these parameters is accounted for in the statistical DNB limit, only these five parameters are initialized at nominal values, and the specification of "nominal" is used only for DNB analyses.

"High" means that, for power level, the initial condition is chosen as for "nominal" and then increased by the initial condition uncertainty. For pressurizer pressure, the above reference pressure is increased by the initial condition uncertainty. For reactor vessel average temperature, pressurizer level, and steam generator level, the programmed value for the chosen (unadjusted) power level is increased by the respective initial condition uncertainties. For core bypass flow the initial condition is the best estimate calculated value increased by the assumed SCD uncertainty in bypass flow. For steam generator tube plugging the initial condition is a plugging level above that existing at any of the four McGuire and Catawba units. For fuel temperature, a conservatively high core average calculated value is used.

"Low" means that, for power level, pressurizer pressure, reactor vessel average temperature, pressurizer level, steam generator level, and core bypass flow, the initial condition is the same as for "High" except the initial condition uncertainty adjustment is a decrease rather than an increase. For fuel average temperature the initial condition is a nominal core average calculated value.

"None" is used only for steam generator tube plugging and means zero plugged tubes.

"**" means that initial condition uncertainty is unimportant since the results of the transient are insensitive to the exact value of the parameter.

"-" means that the model used to analyze the transient did not have an explicit input for the parameter in question

19. High steam generator level is stated to be conservative for peak RCS pressure for the turbine trip peak primary pressure analysis. Low steam generator level is stated to be conservative for peak RCS pressure for the loss of AC power transient. Explain this discrepancy.

Response: The statement in the loss of AC power transient discussion on p.3-7 is in error. It should be replaced with, "Initial steam generator level is not an important parameter in this analysis." Table 8-1 will also be corrected.

20. For the inadvertent operation of ECCS during power operation transient, high steam generator tube plugging is assumed. Explain this assumption considering that steam generator level is stated as unimportant, and therefore that heat transfer must be unimportant. This discrepancy appears to occur in other transients.

Response: Steam generator tube plugging is unimportant for this transient. The text on p.6-2 and Table 8-1 will be revised accordingly. Based on this question additional review was conducted of the text of DPC-NE-3002 vs. Table 8-1. Marked-up pages are included in Attachment 6. In general, these markups correct inconsistencies between the text and table or in the use of table entries defined in the response to Question 18.

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DUKE POWER

July 18, 1994

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, D. C. 20555

Subject: McGuire Nuclear Station
             Docket Nos. 50-369, -370
             Catawba Nuclear Station
             Docket Nos. 50-413, -414
             FSAR Chapter 15 System Transient Analysis Methodology, DPC-NE-3002

Please find attached revisions to Topical Report DPC-NE-3002, FSAR Chapter 15
System Transient Analysis Methodology. This Topical Report was approved for
Catawba and McGuire on November 15, 1991. The revisions reflect changes due to the
replacement steam generators for McGuire and Catawba Unit 1, corrections to
typographical errors, and minor methodology changes.

Duke Power is requesting review and approval of these changes by July 7, 1995 in
order to support the steam generator replacement schedule for McGuire Nuclear
Station.

If we can be of assistance in your review please call Mary Hazeltine at (704) 382-6111.

Very truly yours,

M. S. Tuckman

M. S. Tuckman

U. S. Nuclear Regulatory Commission
July 18, 1994
Page 2

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

July 25, 1995

Mr. M. S. Tuckman
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SUBJECT: REQUEST FOR ADDITIONAL INFORMATION - DPC-NE-3002, FSAR CHAPTER 15
SYSTEM TRANSIENT ANALYSIS METHODOLOGY - McGUIRE NUCLEAR STATION,
UNITS 1 AND 2; AND CATAWBA NUCLEAR STATION, UNIT 1
(TAC NOS. M89944, M89945, M89946)

Dear Mr. Tuckman:

By letter dated July 18, 1994, you submitted for staff review and approval
Revision 1 of Topical Report DPC-NE-3002, "FSAR Chapter 15 System Transient
Analysis Methodology." Based on our review of your report conducted to date,
the NRC staff has identified a need for additional information as indicated in
the enclosure. Please provide a response within 15 days of receipt of this
letter to enable us to continue our review.

This requirement affects nine or fewer respondents, and therefore, it is not
subject to the Office of Management and Budget review under P.L. 96-511.

Sincerely,

Robert Martin

Robert E. Martin, Senior Project Manager
Project Directorate II-2
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Docket Nos. 50-369, 50-370,
and 50-413

Enclosure:
Request for Additional
Information

cc w/enclosure:
See next page

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Catawba Nuclear Station

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Catawba Nuclear Station

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REQUEST FOR ADDITIONAL INFORMATION

FSAR CHAPTER 15 SYSTEM

TRANSIENT ANALYSIS METHODOLOGY

1. Explain the new sentence in §2.2.3. Is DPC saying that a decrease in MFW temperature is a surrogate for the increased flow or that both are assumed to occur.

2. Explain the reason why DPC's assumption regarding the PZR level control shifted from the automatic to the manual operation for the turbine trip analysis (§3.1.1.4).

3. Clarify the SG level control description for the turbine trip.

4. Explain the qualification on availability of the purge volume of hot MFW for the Loss of Non-Emergency AC Power Event (§3.2.1).

5. Explain why the high instead of low initial SG level is conservative for the ability to establish natural circulation (§3.2.4).

6. §3.2.5.1 of Ref. 2 does not describe the turbine control. Please revise reference.

7. Discuss and justify the timing of reactor trip in §3.3. In addition, DPC should provide demonstration that both the RCS and SG pressure peaks are higher and the DNB is lower with earlier reactor trip with less mass in SG than with delayed trip. Discuss how the low-low level trip setpoint is adjusted.

8. Describe in detail the long-term core coolability analysis of the Feedwater System Pipe Break event with revised transient assumptions and scenario. When and on which signal is the turbine assumed to trip? Furthermore, discuss any impact from planned SG replacement on this transient analysis with respect to transient objectives, assumptions and scenario.

9. The RCP Locked Rotor event is proposed to be analyzed using the SCD methodology. Discuss the applicability of the SCD methodology for this event analysis.

10. Discuss the impact of allowing a possibility of reactor trip on pressurizer high pressure for the analysis of the uncontrolled bank withdrawal from a subcritical or low power startup condition event.

11. Since DPC is taking exception to the RSP guidelines with respect to the pressurizer overfill, DPC should demonstrate that the analysis with the plant at zero power does produce more conservative PZR overfill analysis than does at the full power. Furthermore, discuss DPC's acceptance criterion for this event analysis.

Enclosure

12. Discuss any impact of feedring SG design on the SG Tube Rupture analysis. DPC needs to justify extending the SGTR methodology approved for Catawba on McGuire applications. Provide discussion of the expected primary loop subcooling during the entire time of analysis. Discuss the impact of modified PZR modeling on the PZR pressure. In the plant nodalization, discuss the impact of the PZR on the affected vs. unaffected loops. In addition, DPC should justify the applicability of the SCD methodology for this event analysis.

13. DPC should revise §9.0 in Revision 1.

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Nuclear Generation
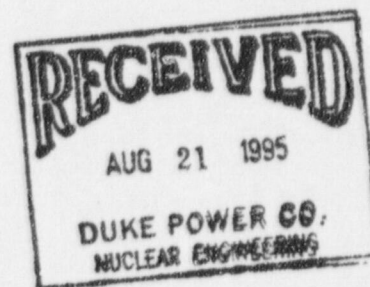(704)382-2200 Office
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DUKE POWER

August 18, 1995

U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Attention: Document Control Desk

Subject: Duke Power Company
McGuire Nuclear Station
Docket Numbers 50-369 and -370
Catawba Nulear Station
Docket Numbers 50-413 and -414
Topical Report DPC-3002, "FSAR Chapter 15 System Transient Analysis Methodology";
Reponse to NRC Questions

On July 18, 1994 Duke Power Company submitted Revision 1 to the subject topical report for review and approval. By letter dated July 25, 1995, the NRC staff requested additional information about the report. Attached are responses to the Staff's questions.

If you have any questions, or need more information, please call Scott Gewehr at (704) 382-7581.

M. S. Tuckman

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U. S. Nuclear Regulatory Commission
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Page 3

bxc: G. A. Copp
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         ELL

Attachment

Question 1

Explain the new sentence in §2.2.3 (increase in feedwater flow). Is DPC saying that a decrease in MFW temperature is a surrogate for the increased flow or that both are assumed to occur.

Response

Both an increase in the main feedwater flow and a corresponding decrease in temperature are assumed to occur. The magnitude of the temperature decrease is conservatively calculated based on maintaining a constant heat addition rate from the feedwater heaters.

Question 2

Explain the reason why DPC's assumption regarding the PZR level control shifted from the automatic to the manual operation for the turbine trip analysis (§3.1.1.4).

Response

This revision corrects a typographical error in the original report. The turbine trip analyses for both the feedring and preheater steam generator designs were performed assuming that the pressurizer heaters are manually locked on. This augments the pressurizer pressure increase which conservatively delays reactor trip on overtemperature ΔT.

Question 3

Clarify the SG level control description for the turbine trip.

Response

This question concerns analysis methodology which has not been revised. In the turbine trip analysis, main feedwater flow is conservatively isolated at the initiation of the transient. If feedwater flow were to continue, a portion of the primary system heat would be expended heating the subcooled feedwater up to saturation conditions as opposed to generating steam. This would act to reduce the secondary system pressure, which is non-conservative for all acceptance criteria.

Question 4

Explain the qualification on availability of the purge volume of hot MFW for the Loss of Non-Emergency AC Power Event (§3.2.1).

Response

As it is used here, "purge volume" refers to the amount of relatively hot main feedwater that must be displaced from the auxiliary feedwater piping before the cold auxiliary feedwater can reach the steam generators. This purge volume is introduced because of the delivery of a small percentage of the main feedwater flow through the auxiliary feedwater piping and associated nozzles during steady-state full power operation. Plant operations staff at McGuire has eliminated this tempering flow practice, while Catawba has not. Therefore, the purge volume modeling is applicable only to Catawba analyses.

Question 5

Explain why the high instead of low initial SG level is conservative for the ability to establish natural circulation (§3.2.4 - loss of non-emergency AC power).

Response

As stated in the report, the high initial level assumption minimizes the volume of the steam space in the steam generator. Following turbine trip, this smaller steam volume yields a greater pressurization rate. The higher steam generator pressure (and saturation temperature) conservatively reduce the primary-to-secondary heat transfer.

Low steam generator level would be conservative only if the primary-to-secondary heat transfer were degraded by tube bundle uncovery prior to the point at which the auxiliary feedwater heat removal capacity exceeds the core decay heat generation. Beyond this point, the transient turns around and primary system temperatures begin to decrease.

In the existing analysis, this transition point is reached approximately 10 minutes after the loss of offsite power. At that time, the steam generator liquid mass has decreased by less than 15,000 lbm from its initial value of approximately 130,000 lbm. At this point in time, there is a large amount of margin to tube bundle uncovery and heat transfer degradation. This conclusion would remain valid even if the initial steam generator level was adjusted low rather than high.

Question 6

§3.2.5.1 of Ref. 2 does not describe the turbine control. Please revise reference.

Response

Automatic turbine control is modeled in RETRAN as a negative fill junction with a constant flow rate, as described in §3.2.5.1 of DPC-NE-3000. This simulates the modulation of the turbine control valves which act to maintain a constant turbine power and, therefore, a constant steam flow rate.

Question 7

Discuss and justify the timing of reactor trip in §3.3 (loss of normal feedwater). In addition, DPC should provide demonstration that both the RCS and SG pressure peaks are higher and the DNB is lower with earlier reactor trip with less mass in SG than with delayed trip. Discuss how the low-low level trip setpoint is adjusted.

Response

The loss of feedwater transient has been determined to be bounded by the turbine trip event and is not routinely analyzed as part of the DPC licensing basis analyses. A reanalysis is performed with the feedring steam generators for the purpose of generating replacement FSAR figures.

Before a discussion of the trip setpoint adjustment can proceed, three basic terms must be defined: nominal, indicated, and actual level. Nominal level is the programmed value at which the plant is intended to operate. Indicated level refers to the control room indication, which may vary within a specified controller deadband around the nominal value. The actual level is

the true water level in the steam generator, which can differ from the indicated level by the measurement uncertainty of the level instrument.

The intent of the downward adjustment to the steam generator level was to promote the uncovery of the tube bundle, as this would potentially degrade the primary-to-secondary heat transfer. If the initial level indication were adjusted upward, reactor trip on low-low steam generator level would be delayed. However, this also introduces competing effects. The delayed reactor trip would extend the RCS heatup but also the core power reduction due to moderator temperature feedback. Since this event is bounded by the turbine trip event, a demonstration of the limiting initial steam generator level condition is not necessary. Were this accident to become potentially limiting in the future, a sensitivity study would be performed on the initial steam generator level assumption to ensure its conservatism.

In the analysis of the loss of feedwater transient, the actual level was initially set 8% below the nominal programmed value. This allowance is a statistical combination of the controller deadband and instrument uncertainties. Although inherent in this assumption is the fact that the indicated level must be lower than nominal, it is conservatively assumed that the indication is at the nominal value - fully 8% above the actual value. Physically, the reactor trips when the indicated value reaches the plant trip setpoint. In this RETRAN simulation however, the trip is modeled as if it occurred on actual level. Therefore, the reactor trip occurs when the actual level reaches a value 8% below the low-low steam generator level trip setpoint.

Question 8

Describe in detail the long-term core cooling analysis of the Feedwater System Pipe Break event with revised transient assumptions and scenario. When and on which signal is the turbine assumed to trip? Furthermore, discuss any impact from planned SG replacement on this transient analysis with respect to transient objectives, assumptions and scenario.

Response

The major impact of the feedring steam generators on this analysis is due to the design and location of the main feedwater nozzles. Since the main and auxiliary feedwater nozzles are now at approximately the same elevation, it is conservatively assumed that the auxiliary feedwater enters and exits the faulted steam generator without passing over the tube bundle and removing primary system heat. This is a significant departure from the preheater steam generator response, where the auxiliary feedwater delivered to the faulted generator must remove a significant amount of heat prior to exiting through the break. Therefore, in the feedring steam generator analysis it is conservative to assume a late operator action time for the isolation of the faulted generator.

In addition, since the main feedwater nozzle is considerably closer to the normal steam generator water level, following a short period of liquid blowdown the broken feedwater line is relieving steam instead of water. This tends to exacerbate the overcooling phase of the feedline break transient, which continues until the faulted generator has blown dry.

A third notable impact of the feedring steam generators is due to the lack of a flow-restricting orifice in the main feedwater nozzle. Because of this design difference, the faulted generator blows dry in roughly two-thirds of the time taken by the preheater steam generator.

In lieu of performing a revised containment response calculation to determine the timing of the high-high containment pressure signal actuation, the following modifications were made to the transient analysis assumptions. A loss of offsite power, which causes the reactor coolant pumps to coast down, is assumed to occur coincident with reactor trip on high containment pressure safety injection. The pumps were previously assumed to be tripped manually on high-high containment pressure. Also, steam line isolation is assumed to occur coincident with turbine trip, which occurs on reactor trip with no response time delay. The superseded analysis methodology assumed that steam line isolation occurred automatically on high-high containment pressure. In both of the above cases the revised assumption is more conservative than that which it replaces. Since, due to the feedring steam generator design, the overheating transient is less limiting, these modifications do not introduce any excessive conservatism.

Question 9

The RCP Locked Rotor event is proposed to be analyzed using the SCD methodology. Discuss the applicability of the SCD methodology for this event analysis.

Response

The approved DPC core thermal-hydraulic statistical core design methodology, including the range of applicability, is described in DPC-NE-2005P-A. Although the core inlet flow for the locked rotor transient falls below the minimum SCD parameter value, a statistical Monte Carlo propagation was performed to ensure that the statistical design limit (SDL) remained acceptable. The details of this statistical propagation methodology are discussed in §2.3 of the topical report. Using the BWCMV CHF correlation, the statistical analysis for the locked rotor transient yields a statepoint DNBR of 1.364, which confirms that the use of this correlation with an SDL of 1.40 is valid for this event.

Question 10

Discuss the impact of allowing a possibility of reactor trip on pressurizer high pressure for the analysis of the uncontrolled bank withdrawal from a subcritical or low power startup condition event.

Response

The subject revision simply includes a potentially applicable reactor trip function that was inadvertently omitted from the original report. The actual analysis methodology for the uncontrolled bank withdrawal from a subcritical or low power startup condition event has not been modified.

Due to the rapid increase in neutron power once prompt criticality is achieved, a high pressure trip is much less likely than a high flux trip. However, if the analysis is performed with a lower reactivity insertion rate, it is possible that the core power increase might be slow enough to allow a high pressure reactor trip.

Question 11

Since DPC is taking exception to the SRP guidelines with respect to the pressurizer overfill (for the inadvertent operation of ECCS during power operation transient), DPC should demonstrate that the analysis with the plant at zero power does produce more conservative PZR overfill analysis than does at the full power. Furthermore, discuss DPC's acceptance criterion for this event analysis.

Response

The Standard Review Plan stipulates that the Condition II inadvertent operation of ECCS during power operation transient not give rise to a more serious Condition III event. A potential escalation scenario that could result in an unisolable small-break LOCA involves the failure of the pressurizer safety valve to reseat following the relief of subcooled liquid.

According to Westinghouse VIL W 93-18, in order to meet the applicable Condition II criterion, the PSV's must either not open or must be capable of closing after release of subcooled water. DPC mechanical maintenance support staff has affirmed that the PSV's will reseat if the liquid relief temperature remains above 500°F. This low temperature limit is therefore chosen as the acceptance criterion for the event.

Zero power is chosen rather than full power as the initial condition for the analysis since the RCS is at a lower average temperature and would therefore have a lower transient temperature response.

Question 12

Discuss any impact of feedring SG design on the SG Tube Rupture analysis. DPC needs to justify extending the SGTR methodology approved for Catawba on McGuire applications. Provide discussion of the expected primary loop subcooling during the entire time of analysis. Discuss the impact of modified PZR modeling on the PZR pressure. In the plant nodalization, discuss the impact of the PZR on the affected vs. unaffected loops. In addition, DPC should justify the applicability of the SCD methodology for this event analysis.

Response

There are three significant effects of the feedring steam generators on the SGTR analysis. First, the feedring steam generator tubes are approximately 10% smaller in diameter, which yields a proportionally lower break flow rate. This introduces the competing effects of slower buildup of activity levels in the faulted steam generator and delayed recovery of the tube bundle. Secondly, the tube bundle in the feedring steam generator is approximately 8 feet taller than the preheater steam generator; therefore there is the potential for a greater period of tube uncovery. Tube bundle uncovery has a direct bearing on the entrainment of the break flow liquid droplets, which significantly impacts the activity of the steam released to the atmosphere. Thirdly, the feedring steam generator liquid mass at full power is approximately 20,000 lbm greater than that in the preheater steam generator. This equates to a larger liquid volume available for mixing with the break flow and diluting the iodine concentration of the steam relief.

The current approved methodology for McGuire is a non-mechanistic calculation which simply postulates 30 minutes of primary-to-secondary break flow with no thermal-hydraulic transient simulation. Applying the methodology which has been approved for Catawba to the McGuire

analysis is both a more physical and more conservative approach. Three of the more significant areas of increased conservatism are: a) the primary-to-secondary break flow continues until the system pressures are equalized, b) the atmospheric release from the secondary system persists until the failed steam line PORV is isolated, and c) tube bundle uncovery is explicitly modeled (as discussed above). Finally, since the McGuire units will be virtually identical to Catawba Unit 1 following the steam generator replacement, the extension of the approved Catawba methodology is technically warranted.

Following the tube rupture, the RCS subcooling margin gradually decreases as RCS pressure decreases until reactor trip occurs. At this point, the RCS is still in a subcooled condition. During the cooldown portion of the transient, the subcooling margin gradually increases since the rate at which the RCS temperature is decreasing more than compensates for the rate at which the RCS is depressurizing. After the operators begin depressurizing the RCS to terminate break flow, the subcooling margin decreases, but always remains above 0°F. Following identification of the ruptured SG, cooldown of the RCS is initiated using the operable SM PORVs on the intact SGs. This cooldown continues until the RCS reaches a 20°F subcooled condition relative to the ruptured SG pressure. 10 minutes after this condition has been reached, operators begin depressurizing the RCS using a single pressurizer PORV until break flow is terminated.

Per §7.1.1, the local conditions heat transfer model was employed in the pressurizer in the original analysis methodology. This sentence is being removed from all of the event-specific discussions since the modeling is now applied generically as discussed in §3.2.3.3 of DPC-NE-3000. However, since this transient mainly consists of a prolonged pressurizer outsurge, the wall conductors do not play a significant role.

Since an outsurge of hot water from the pressurizer will occur as the RCS depressurizes during this event, the pressurizer is assumed to be attached to the lumped intact loops. This will maximize the break flow through the ruptured tube by minimizing the primary inlet temperature entering the ruptured steam generator.

The tube rupture DNBR transient, which is analyzed completely independent from the offsite dose analysis, is essentially a complete loss of reactor coolant flow event initiated from a reduced pressurizer pressure. At the minimum DNBR statepoint, all of the SCD treated parameters: core inlet temperature and flow, core exit pressure and core heat flux are within their respective parameter ranges for SCD applicability (Refer to Appendix B of DPC-NE-2005P-A).

Question 13
DPC should revise §9.0 (References) in Revision 1.

Response
When Revision 3 to DPC-NE-3000 is approved, the references will be updated accordingly.

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DUKE POWER

December 19, 1995

U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Attention Document Control Desk

Subject: Duke Power Company
McGuire Nuclear Station
Docket Numbers 50-369 and -370
Catawba Nuclear Station
Docket Numbers 50-413 and -414
Minor Change to NRC-Approved Methodology

The purpose of this letter is to notify the NRC staff of a minor change to the NRC-approved analysis methodology that Duke Power uses for FSAR Chapter 15 analyses to support the McGuire and Catawba Nuclear Stations. This methodology is detailed in the topical report DPC-NE-3002-A, "FSAR Chapter 15 System Transient Analysis Methodology." The specific modeling change is the assumed performance of the pressurizer code safety valves and the main steam code safety valves. In the licensed methodology it is stated that these valves "are modeled with lift, accumulation, and blowdown assumptions which maximize (or minimize) the pressurizer (or secondary) pressure." The specific minor change is in regard to the concept of accumulation during lift of a safety valve. Accumulation has been modeled as a linear opening of a safety valve beginning at the lift setpoint and reaching full open at a pressure corresponding to the lift setpoint plus an accumulation allowance which is typically 1-3% of the lift pressure setpoint. For example, a pressurizer safety valve with a lift setpoint of 2500 psig and 3% accumulation would reach full open at 2575 psig. Although this is a conservative modeling approach, it does not physically represent the real valve performance, which is best characterized as a popping-open response. The proposed minor change to the approved modeling would be to model the valves as popping open with a conservatively slow response time. For each valve type for which this modeling is to be applied, valve testing data will be researched to determine the actual valve dynamic response. These data will then be conservatively bounded by the new popping-open modeling used in the RETRAN-02 model for McGuire and Catawba.

The need for this modeling change is twofold. Licensing basis analyses assuming +3% valve setpoint drift and the current 3% linear accumulation assumption can result in peak primary or secondary pressures which approach or exceed the overpressure limits. The proposed modeling significantly reduces the predicted peak pressures, thereby adding margin and avoiding other unnecessary and undesirable alternatives such as lowering the valve setpoints. The second cause is
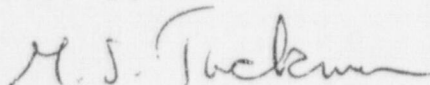
the design of the replacement steam generators which are to be installed at McGuire and Catawba Nuclear Stations, beginning in mid-1996. The increase in steam generator heat transfer area in the replacement steam generators results in higher peak secondary pressures following turbine trip. The analysis results will exceed the secondary overpressure limit unless this modeling change is implemented or the code safety valve setpoints are lowered, which would require a Technical Specification change. Lowering the valve setpoints is not desirable, and any unnecessary Technical Specification revisions should be avoided if possible.

This modeling change was discussed by phone with NRC staff from the Mechanical Engineering and Reactor Systems Branches in May 1995. The conclusions from the discussions were that the proposed modeling approach would be acceptable as long as the modeling was conservative relative to the industry valve testing database. That constraint will be followed with the proposed modeling approach, with a significant amount of conservatism maintained.

NRC concurrence with this proposed modeling change will be necessary to avoid submittal of a topical report revision or a Technical Specification change. The application of this proposed modeling change is necessary to support the Catawba Unit 1 outage with steam generator replacement, which is currently scheduled to start in April 1996.

If you would like to discuss this letter, please call Scott Gewehr at (704) 382-7581.

Very truly yours,

M. S. Tuckman

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        Mr. G. F. Maxwell
        Senior Resident Inspector
        McGuire Nuclear Station

August 29, 1995

Christy Ray
NGD Safety Analysis Group

Re: McGuire Nuclear Station
MSSV Opening Response Time
Tech Spec Submittal

This is to summarize the expected opening response times of the McGuire's Main Steam Safety Valves and to demonstrate that they will open fully within the 0.5 seconds assumed in the Safety Analysis. The following valves were manufactured by Crosby and are the subject of this review.

Style	Size	Set Pressure	Open Time	Tag Nos.
HA-65-FN	6Q8	1170 psig*	0.160 sec	1/2 SV2, 8, 14, 20
HA-65-FN	6Q8	1190 psig*	0.090 sec	1/2 SV3, 9, 15, 21
HA-75-FN	6R10	1205 psig*	0.110 sec	1/2 SV4, 10, 16, 22
HA-75-FN	6R10	1220 psig*	0.060 sec	1/2 SV5, 11, 17, 23
HA-75-FN	6R10	1225 psig	unavailable	1/2 SV6, 12, 18, 24

All valves at McGuire were tested at Crosby's high flow test loop to determined unique ring setting for each valves to assure blowdown performance within a range less than or equal to 10%. The tests simultaneously recorded 1) inlet pressure, 2) outlet pressure and 3) spindle position on Crosby's Data Acquisition System. Although the test was not specifically intended to demonstrate the opening response time for the valves, the data did record the opening time for each valve at test conditions with its own unique ring settings.

Crosby recently provided one set of test curves, for one valve at each set pressure indicated above with an asterisk (*). These curves (Attachment 1) show typical response time for valves installed at McGuire. Crosby has not yet provided curves for all valves but has indicted that these curves should represent the opening response of all MSSV's at McGuire.

Since the Crosby tests were intended primarily to validate ring settings for blowdown performance, the inlet pressure ramp rate was not varied to study its effect on opening times. EPRI, however, conducted extensive tests on Pressurizer Safety Valves as required by NUREG-0737. These test by EPRI on a Crosby style HB-BP-86, size 6N8, demonstrated no appreciable relationship between inlet pressurization rate and opening times. With ramp rates varrying between 2 psi/sec and 325 psi/sec, opening times varied little between 0.018 and 0.021 seconds. See Attachment 2, tables 4-2 and 4-3.

Although the Pressurizer Valve tested by EPRI and the Main Steam Saftey Valves tested at Crosby are different styles, they both have a two-ring internal design and are similar in body size. Tests also demonstrate that both style valves, under varying conditions, open with a rapid "pop" at valve setpoint. We would expect similar inlet pressurization rates to have little effect on the opening time of the MSSV's.

Therefore, the tests performed by Crosby, coupled with those performed by EPRI demonstrate valve opening response times under various inlet conditions, are well within the assumed time of 0.500 seconds.
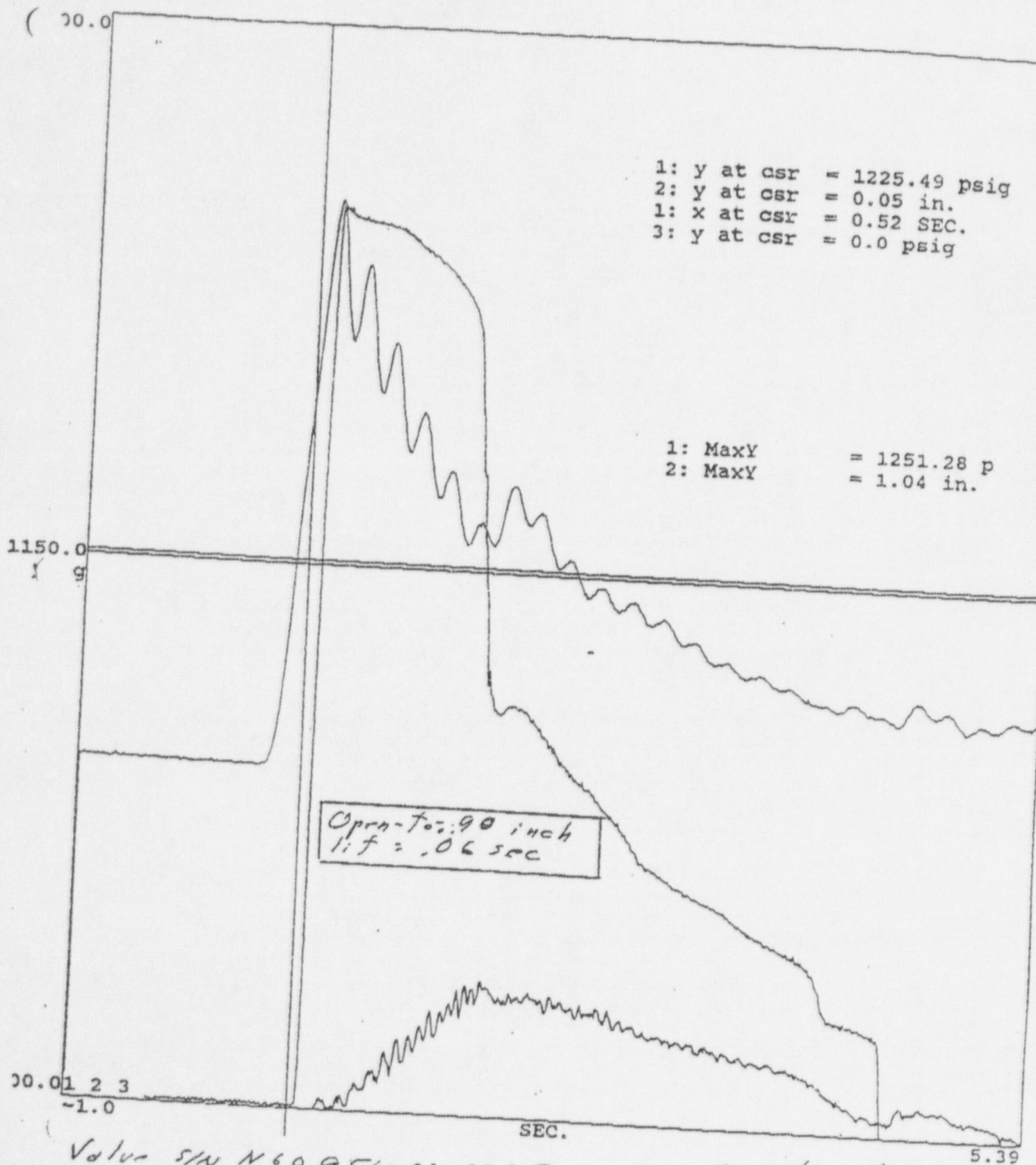
If you wish to discuss this subject further, please contact the undersigned at 875-5627.

Grant Cutri
McGuire Valve Engineering

Attachments (2)

Christy Ray
8/29/95
Attachment 1   sh 2 of 5

1: y at csr = 1225.49 psig
2: y at csr = 0.05 in.
1: x at csr = 0.52 SEC.
3: y at csr = 0.0 psig

1: MaxY   = 1251.28 p
2: MaxY   = 1.04 in.

Open-to-.90 inch
lift = .06 sec

SEC.

Valve S/N N60951-01-0025
6 R 10   Set Pressure = 1220 psig
Sheet 1 of 1

Open-to-close = 3.91 sec

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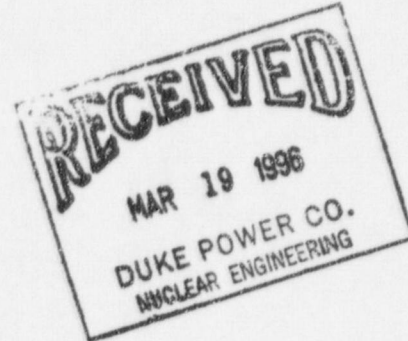   G. B. Swindlehurst
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DUKE POWER

March 15,1996

U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Attention: Document Control Desk

Subject: Duke Power Company
           McGuire Nuclear Station
           Docket Numbers 50-369 and -370
           Catawba Nuclear Station
           Docket Numbers 50-413 and -414
           Safety Valve Modeling

References: 1) November 15, 1995 letter from W. R. McCollum
               (DPC) to NRC, "Proposed Technical
               Specifications (TS) Changes."

            2) December 19, 1995 letter from M. S. Tuckman
               (DPC) to NRC, "Minor Change to NRC-Approved
               Methodology."

The purpose of this letter is to provide additional
information concerning the two submittals referenced above.
The intent of the November 15, 1995 submittal was to pursue
an increase in the main steam code safety relief valve
setpoint tolerance for the current plant configuration. As
such, the transient analyses discussed in the technical
justification section were those based on the existing Model
D steam generator design. This submittal is completely
independent of steam generator replacement, although the
approval of the submittal will affect the replacement steam
generator licensing plan as described below. The
corresponding McGuire submittal was approved by the NRC on
August 2, 1994.

The December 19, 1995 submittal seeks NRC concurrence for a
revision to the pressurizer and main steam safety valve lift
modeling in NRC-approved analysis methodologies. This
revision will use a pop-open modeling approach rather than a
linear ramping open approach. This change was made
necessary primarily by the turbine trip transient, which was
reanalyzed in support of the steam generator replacement.
During the course of this reanalysis, it was discovered that
due to the increased heat transfer area of the replacement
steam generator, the peak secondary pressure case did not

meet the acceptance criterion. Below is a summary of the peak secondary pressure results for the pertinent analysis cases:

Acceptance criterion (110% of 1185 psig)	1303.5 psig
Model D S/G:	
+3% setpoint drift, original lift setpoints, linear ramp model	1295 psig
Replacement S/G:	
+3% setpoint drift, original lift setpoints, linear ramp model	>1311 psig
+3% setpoint drift, reduced lift setpoints, linear ramp model	1295.8 psig
+3% setpoint drift, original lift setpoints, pop-open model	1285.7 psig

The revised modeling assumes that the safety valves pop open to a full open position in 0.5 seconds after the drifted lift setpoint is reached. This assumption is based on the attached documents, in which the valve manufacturers, Crosby and Dresser, and the McGuire/Catawba valve engineering staff concur that this modeling is adequate to conservatively bound the performance of both the pressurizer and main steam safety valves. Approval of the increased setpoint tolerance and NRC concurrence with the revised pop-open modeling approach is requested. No additional Technical Specification changes or engineering effort are necessary to resolve this issue with this approach. There are no NUREG-0737 commitments regarding the transient analysis modeling of the safety valves that conflict with this request.

If the increased setpoint tolerance is approved and the valve pop-open modeling is not, the main steam safety valve setpoints will have to be lowered in conjunction with the steam generator replacement. This will require submittal of additional Technical Specification revisions. If the increased tolerance is not approved, the turbine trip analysis will not necessitate any setpoint or valve modeling changes. However, the consequence of this course of action will be a continuation of licensee reports and engineering evaluations due to the safety valves failing their Technical Specification surveillance and being declared inoperable.

If you would like to discuss this letter further, please call Scott Gewehr at (704) 382-7581.

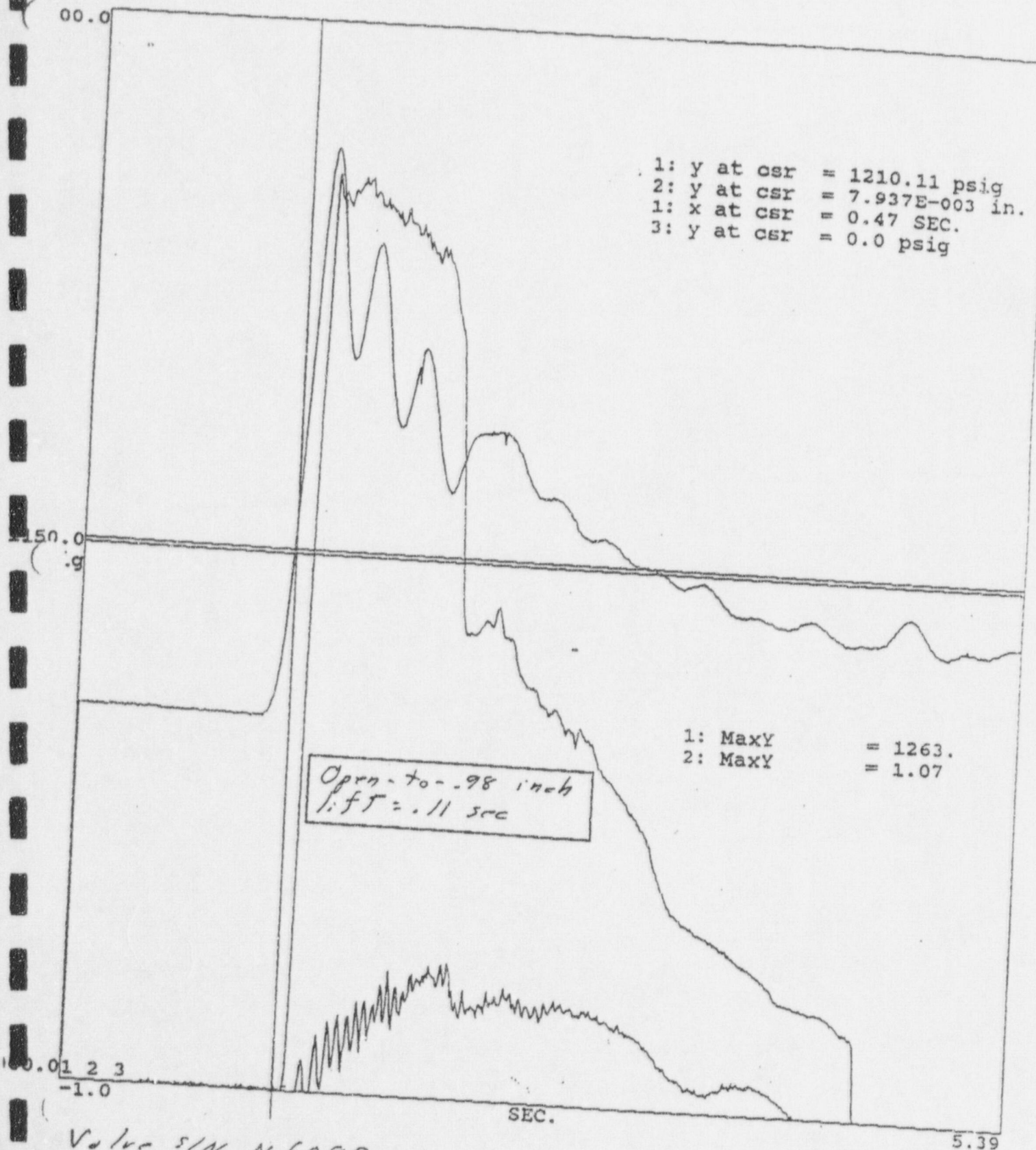Very truly yours,

M. S. Tuckman

M. S. Tuckman

Christy Ray
8/29/95
Attachment 1 sh 3 of 5

1: y at csr = 1210.11 psig
2: y at csr = 7.937E-003 in.
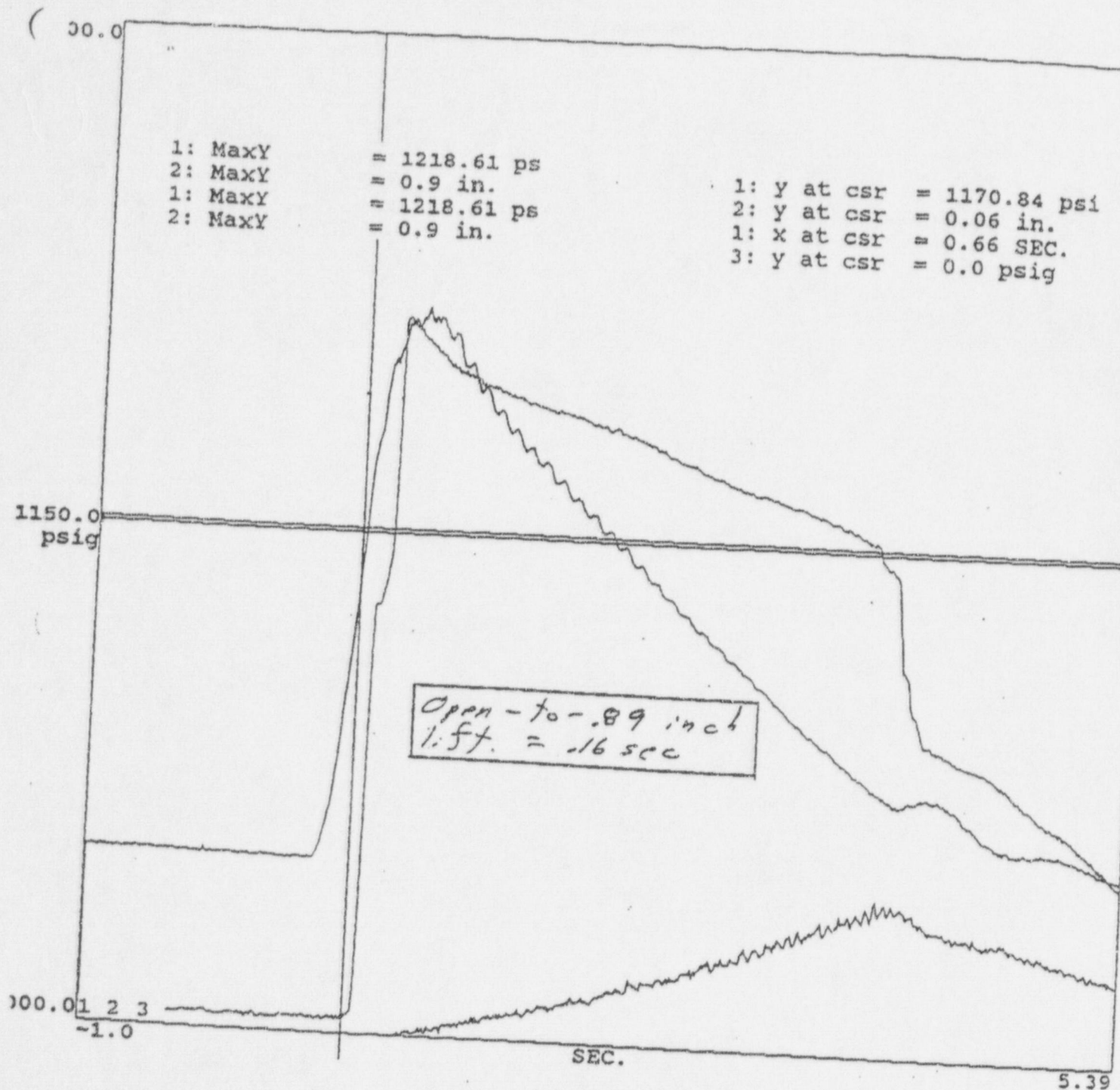1: x at csr = 0.47 SEC.
3: y at csr = 0.0 psig

1: MaxY = 1263.
2: MaxY = 1.07

Open-to-.98 inch
lift=.11 sec

Valve S/N N 60951-01-0034
6 R10   Set Pressure = 1205
Sheet 1 of 1

Open-to-close.= 3.8? sec

Christy Ray
8/29/95
Attachment 1 sh 4 of 5

1: MaxY   = 1218.61 ps
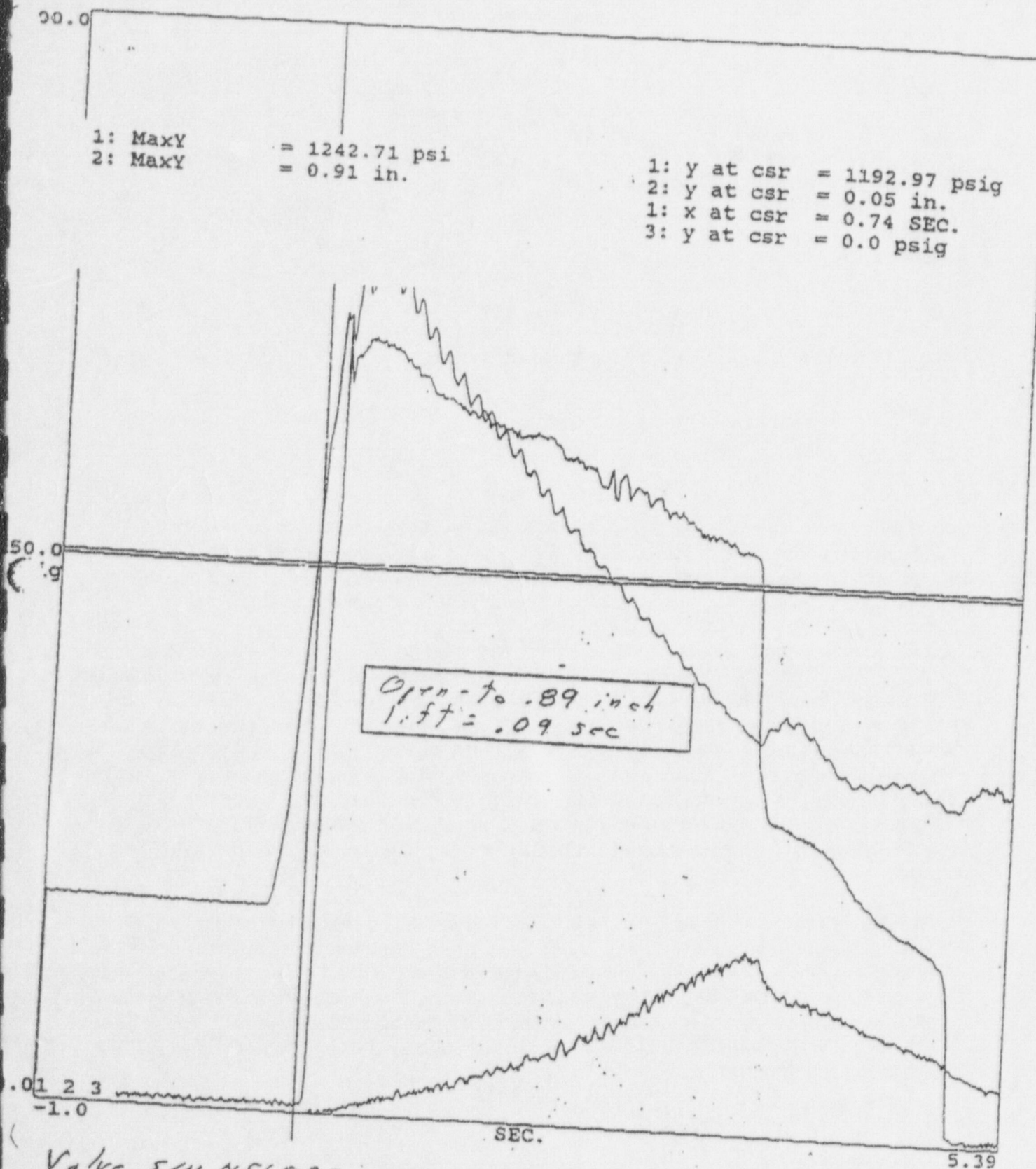2: MaxY   = 0.9 in.
1: MaxY   = 1218.61 ps
2: MaxY   = 0.9 in.

1: y at csr = 1170.84 psi
2: y at csr = 0.06 in.
1: x at csr = 0.66 SEC.
3: y at csr = 0.0 psig

Open - to - .89 inch
lift = .16 sec

1150.0
psig

SEC.

Valve S/N N56937-01-0001,
6 Q 8   Set Pressure = 1170 psig
Sheet 1 of 2

Christy Ray
8/29/95
Attachment 1   sh 5 of 5

00.0

1: MaxY   = 1242.71 psi
2: MaxY   = 0.91 in.

1: y at csr = 1192.97 psig
2: y at csr = 0.05 in.
1: x at csr = 0.74 SEC.
3: y at csr = 0.0 psig

50.0
.g

Open-to .89 inch
lift = .09 sec

.0 1 2 3
-1.0

SEC.

5.39

Valve S/N NS6937-01-0005
6 Q 8 Set Pressure = 1190 psig
Sheet 1 of 1

Open-to-close = 4.28 sec

DUKE POWER

April 12, 1995

Rolland S. Huffman, Senior Engineer
Dresser Industries
PO Box 1430
Alexandria, LA 71309

Subject: MSSV (Dresser Model 3787) Opening Times
File No: CN1205.09

Dear Sir,

Due to a historical trend of Main Steam Safety Valve (MSSV) setpoint drift outside of
+/- 1% and a recent trend of performance outside of +/- 3 %, Catawba has initiated a
comprehensive safety analysis considering the potential impact of MSSV setpoint drift. A
significant contributor to our computer modeled analysis is the valve "opening" time.

Catawba Engineering believes that Duke Power assumed an overly conservative MSSV
Opening Time during the initial safety analysis. Based on review of extensive, well documented
EPRI Safety Relief Valve Test Data performed after TMI, as required by NUREG-0737; the
opening times of Dresser Pressurizer Safety Valves (PSV) was consistently shown to be less
than 0.1 of a second. Multiple tests were performed with Dresser Model 31709na and 31739a
PSV's under varied conditions of pressurization rate, system media, ring positions, etc. and
validate this position. In addition, Crosby spring actuated safety valves of similar design,
model HB-BP-86 6N8, also had opening times of less than 0.1 of a second. The " POP" action
of these safety valves is clearly demonstrated by review of these comprehensive EPRI Test
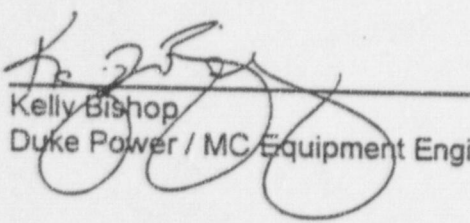Reports.

Attached are excerpts from the EPRI Test Reports representing typical test data and graphical
plots of both stem position and steam flow vs time. These two parameters distinctly define the
valve opening time. A summary of test results are documented on the Test Matrix Table noting
the valve "simmer" time, "POP" time, pressurization rate, test media, etc. for each test run. In
addition, plots for stem movement and steam flow for Dresser test number 603, 606, 611, and
1305 which are typical and notably represent varied conditions of pressurization (from 2.9 to
322 psi/sec) are attached.

The following information is a simple summary of key parameters of stem travel, steam flow, and time which have been recorded from the attached test data/plots.

	Time to Full Stem Travel Simmer + POP Time (Rated lift 0f .588 ")	Time to Maximum Steam Flow (>rated steam flow of 508k lb/hr)	Pressurization Rate (psi/sec)
603	.016 sec	.080 sec	2.9
606	.020 sec	.075 sec	296
611	.024 sec	.072 sec	322
1305	.031 sec	.082 sec	308
1202	.020 sec	not available	2.0
1207	.019 sec	not available	317

Catawba does not have actual full flow test data for the Dresser 3787 MSSV's to support the position of valve opening times of .1 of a second, but CNS Engineering believes that the extensive PSV test data adequately demonstrates the "pop" action of a safety valve of this design and that the MSSV opening times will also be less than .1 seconds. Conservatively, Catawba proposes to model the valves with an opening time of .5 of second or over 500% of the slowest time observed for the PSV.

As per our telephone conversation, please review Catawba's Engineering Evaluation of MSSV opening times and the attached supporting documentation. As the original OEM of Catawba's MSSV's, we need your concurrence of our evaluation that the valves will open in less than .5 seconds. If you concur with the our evaluation please sign below and return ;otherwise, provide comments as to your position and the expected opening time we should assume for our analysis.

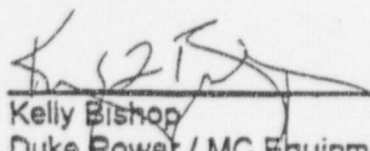Kelly Bishop
Duke Power / MC Equipment Engineer

OEM (Dresser) Engineering Concurrence
R.S. Huffman
Dresser Industries /SR. Engineer

2

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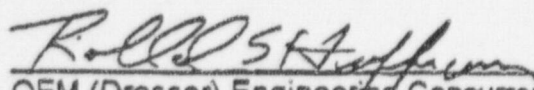
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As per our telephone conversation, please review Catawba's Engineering Evaluation of MSSV opening times and the attached supporting documentation. As the original OEM of Catawba's MSSV's, we need your concurrence of our evaluation that the valves will open in less than .5 seconds. If you concur with the our evaluation please sign below and return :otherwise, provide comments as to your position and the expected opening time we should assume for our analysis.

Kelly Bishop
Duke Power / MC Equipment Engineer

We agree that safety valve 3787 will open in less than .0.5 seconds.

OEM (Dresser) Engineering Concurrence
R.S. Huffman
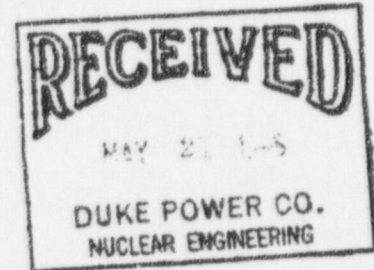Dresser Industries /SR. Engineer

2

M. S. TUCKMAN
Senior Vice President
Nuclear Generation
(704)382-2200 Office
(704)382-4360 Fax

DUKE POWER

May 16, 1996

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC   20555

Subject: Catawba Nuclear Station, Unit 1,
            Docket No. 50-413
            McGuire Nuclear Station, Units 1 and 2,
            Docket Nos. 50-369 and 370

On May 14, 1996, a conference call was held between
representatives of Duke Power Company and the NRC Staff.
The purpose of the conference call was to clarify
discussions of feedwater system pipe breaks that were
provided in a March 15, 1996 Response to an NRC Request for
Additional Information.

Consistent with the NRC-approved transient analysis
methodology (DPC-NE-3002), the feedwater system pipe break
event is analyzed to address two separate acceptance
criteria: short-term core cooling (DNB) and long-term core
cooling (hot leg boiling). Previous analyses have shown the
feedline break event to be non-limiting with respect to the
primary and secondary system pressure limits; therefore, no
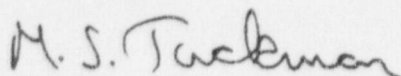explicit peak pressure calculations are performed for this
event.

The results of the long-term core cooling evaluation,
performed in support of the steam generator replacement,
show that the pressurizer pressure reaches a peak of
slightly less than 2250 psig. This is significantly lower
than the corresponding Model D steam generator result. The
primary reasons for this difference are the increased tube
bundle heat transfer area and the elevated feedwater nozzle
of the feedring steam generator design. Both of these tend
to enhance the overcooling phase of the feedline break
transient and thereby reduce the RCS pressurization.

U. S. Nuclear Regulatory Commission
May 16, 1996
Page 2

Since the intent of the above analysis was to minimize the
margin to hot leg boiling, assumptions were made for the
initial and boundary conditions which minimize the RCS
pressure. Were an explicit peak primary system pressure
analysis to be performed, many of these assumptions would be
reversed. The impact of the revised assumptions on the peak
RCS pressure result has not been quantified. However, due
to the large margin to the Standard Review Plan peak primary
system pressure acceptance criterion of 3000 psig, this
additional analysis was deemed to be unnecessary.

If additional information is required, please call Robert
Sharpe at (704) 382-0956.

Very truly yours,

M. S. Tuckman

M. S. Tuckman

Attachments

xc: S. D. Ebneter
      Regional Administrator, Region II
      U. S. Nuclear Regulatory Commission
      101 Marietta Street, NW, Suite 2900
      Atlanta, GA   30323

      R. J. Freudenberger
      Senior Resident Inspector
      Catawba Nuclear Station

      G. F. Maxwell
      Senior Resident Inspector
      McGuire Nuclear Station

      P. S. Tam
      Project Manager, ONRR

      V. Nerses
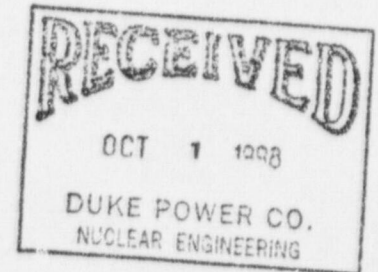   Project Manager, ONRR

Duke Energy

Gary R. Peterson
Vice President

September 25, 1998

RECEIVED

OCT 1 1998

DUKE POWER CO.
NUCLEAR ENGINEERING

U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555

Subject: Duke Energy Corporation
             Catawba Nuclear Station, Unit 2
             Docket Number 50-414
             Topical Report DPC-NE-3002-A
             Notification of Methodology Error

Reference: DPC-NE-3002-A, Revision 2, December 1997, "FSAR
           Chapter 15 System Transient Analysis Methodology"
           SER Dated April 26, 1996.

The purpose of this letter is to notify the NRC that the
referenced computer code nodalization model has recently been
determined to predict the Catawba Unit 2 plant response for the
loss of normal feedwater event in a non-conservative manner. The
loss of normal feedwater transient has been analyzed with a
different nodalization model in order to predict the plant
response conservatively. NRC review of this methodology change
to topical report DPC-NE-3002-A is requested.

Duke Power analyzes the Catawba UFSAR Chapter 15 non-LOCA
transients and accidents with analytical methodologies that have
been reviewed and approved by the NRC. Specifically, topical
report DPC-NE-3002-A, Revision 2, December 1997, "FSAR Chapter 15
System Transient Analysis Methodology", details the methodology
for most of the Chapter 15 events.   Section 3.3 of this topical
report describes the methodology for analyzing the loss of normal
feedwater event, which is the analysis in UFSAR Section 15.2.7.
In Section 3.3.3.1 of the DPC-NE-3002-A topical report, the
computer code nodalization used for the loss of normal feedwater
core cooling capability analysis is identified as the RETRAN
model described in Section 3.2 of the NRC-approved Duke Power
topical report DPC-NE-3000-PA, "Thermal-Hydraulic Transient
Analysis Methodology". (SER dated December 27, 1995)

The RETRAN computer code model used by Duke Power to model UFSAR
Chapter 15 transients and accidents is described in the DPC-NE-
3000-PA topical report. The RETRAN model nodalization includes a
multi-node model of the steam generator secondary. This model
has the potential for predicting excessive primary-to-secondary
post-trip heat transfer during events which significantly uncover
the steam generator tube bundle. This model limitation was
discussed in detail with the NRC during a meeting on October 7 &
8, 1991. During this meeting Duke demonstrated that the model
provided conservative predictions of primary-to-secondary heat
transfer as long as the steam generator water inventory did not
decrease to less than 10% of the full power inventory.

Recently completed analyses of the loss of normal feedwater event
for Catawba Unit 2 have resulted in minimum post-trip steam
generator water inventories of less than 10% of the full power
inventory. These results prompted an evaluation and an
assessment of the analytical methodology and model. As a result
of this evaluation it has been concluded that the methodology for
analyzing the loss of normal feedwater event for Catawba Unit 2
must be revised in order to ensure conservative predictions of
the plant response.

The proposed methodology revision is two additional sentences to
be inserted in Section 3.3.3.1 of the DPC-NE-3002-A topical
report. This revision will require using a single volume steam
generator secondary model for the post-trip phase of the loss of
normal feedwater analysis for Catawba Unit 2. This single volume
steam generator secondary model is already used for analyzing the
uncontrolled bank withdrawal from a subcritical or low power
startup condition transient (UFSAR Section 15.4.1), which is
described in Section 5.1.1.1 of the DPC-NE-3002-A topical report.
Therefore, this model has already been reviewed and approved by
the NRC. This letter is requesting NRC approval to apply an
approved model to a different analysis.

The current Section 3.3.3.1 of the DPC-NE-3002-A topical report
reads as follows:

> "3.3.3.1 Nodalization - Since the transient response of the
> loss of normal feedwater event is the same for all loops,
> the single-loop model described in Section 3.2 of Reference
> 2 is utilized for this analysis."

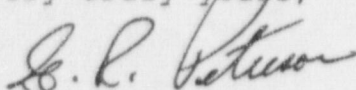U.S. Nuclear Regulatory Commission
Page 3
September 25, 1998

The proposed revision is as follows:

> "3.3.3.1 Nodalization – Since the transient response of the loss of normal feedwater event is the same for all loops, the single-loop model described in Section 3.2 of Reference 2 is utilized for this analysis. For Catawba Unit 2 only, the post-trip phase of the analysis uses a single volume steam generator secondary model. This model uses the bubble rise option with the local-conditions heat transfer model applied to the steam generator tube conductors."

The non-conservative results predicted by the multi-node steam generator secondary model can be characterized as an underprediction of the cold leg temperatures, which then produce an underprediction of bulk average temperature, and pressurizer level and pressure. With the revised model the corrected results maintain a large margin to the acceptance criteria, and therefore no safety significance is associated with this modeling error. The revised analyses will be incorporated into the UFSAR following NRC review and approval of this methodology change to topical report DPC-NE-3002-A. The above revision to Section 3.3.3.1 of the DPC-NE-3002-A topical report will be included in a future revision to the published version.

Should you have any questions concerning this information, please call G.B. Swindlehurst at (704) 382-5176.

Very truly yours,

G.R. Peterson

U.S. Nuclear Regulatory Commission
Page 4
September 25, 1998

xc:

L.A. Reyes
U.S. Nuclear Regulatory Commission
Regional Administrator, Region II
Atlanta Federal Center
61 Forsyth St., SW, Suite 23T85
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D.J. Roberts
Senior Resident Inspector (CNS)
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Catawba Nuclear Station

P.S. Tam
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