Duke Energy Carolinas
McGuire Nuclear Station
Catawba Nuclear Station

UFSAR Chapter 15 System Transient Analysis Methodology

DPC-NE-3002-A
Revision 4b

September 2010

Nuclear Engineering Division
Nuclear Generation Department
Duke Energy Carolinas

STATEMENT OF DISCLAIMER

Table of Contents

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

April 6, 2001

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

SUBJECT: CATAWBA NUCLEAR STATION, UNITS 1 AND 2 RE: REVISION 4 TO THE DUKE ENERGY CORPORATION TOPICAL REPORT DPC-NE-3002-A, "UFSAR CHAPTER 15 TRANSIENT ANALYSIS METHODOLOGY" (TAC NOS. MA8928 AND MA8929)

Dear Mr. Peterson:

The accepted version of Duke Energy Corporation topical report DPC-NE-3002-A, Revision 3, was submitted to the NRC on May 13, 1999. By letter dated April 19, 2000, as supplemented by letters dated August 24 and September 22, 2000, and March 21, 2001, you submitted Revision 4 of the topical report for NRC review. You proposed three changes to the previously approved revision of the topical report. The first change corrects the description of the primary coolant volume that is used in the Updated Final Safety Analysis Report, Section 15.4.6, for boron dilution accident analysis in Mode 4 for Catawba Nuclear Station, Units 1 and 2. The second change involves an increase in the number of operable main steam line power-operated relief valves credited in the steam generator tube rupture analysis for Catawba Nuclear Station, Units 1 and 2. The third change specifies a three-minute operator response time to initiate the depressurization of the primary system and a separate three-minute response time for initiating safety injection termination. Previously, one ten-minute response time was credited for completing both the depressurization initiation and the safety injection termination actions.

The staff concludes that Revision 4 to the Topical Report DPC-NE-3002-A is acceptable. Our safety evaluation is enclosed. However, these changes are not applicable to McGuire, and Revision 4 separates the McGuire and Catawba methodology assumptions as necessary.

Sincerely,

Chandu P. Patel

Chandu P. Patel, Project Manager, Section 1
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket Nos. 50-413 and 50-414

cc w/encl: See next page

Catawba Nuclear Station

cc:

Mr. Gary Gilbert
Regulatory Compliance Manager
Duke Energy Corporation
4800 Concord Road
York, South Carolina 29745

Ms. Lisa F. Vaughn
Legal Department (PB05E)
Duke Energy Corporation
422 South Church Street
Charlotte, North Carolina 28201-1006

Anne Cottingham, Esquire
Winston and Strawn
1400 L Street, NW
Washington, DC 20005

North Carolina Municipal Power
Agency Number 1
1427 Meadowwood Boulevard
P. O. Box 29513
Raleigh, North Carolina 27626

County Manager of York County
York County Courthouse
York, South Carolina 29745

Piedmont Municipal Power Agency
121 Village Drive
Greer, South Carolina 29651

Ms. Karen E. Long
Assistant Attorney General
North Carolina Department of Justice
P. O. Box 629
Raleigh, North Carolina 27602

Elaine Wathen, Lead REP Planner
Division of Emergency Management
116 West Jones Street
Raleigh, North Carolina 27603-1335

North Carolina Electric Membership
Corporation
P. O. Box 27306
Raleigh, North Carolina 27611

Senior Resident Inspector
U.S. Nuclear Regulatory Commission
4830 Concord Road
York, South Carolina 29745

Virgil R. Autry, Director
Division of Radioactive Waste Management
Bureau of Land and Waste Management
Department of Health and Environmental
Control
2600 Bull Street
Columbia, South Carolina 29201-1708

Mr. C. Jeffrey Thomas
Manager - Nuclear Regulatory
Licensing
Duke Energy Corporation
526 South Church Street
Charlotte, North Carolina 28201-1006

Saluda River Electric
P. O. Box 929
Laurens, South Carolina 29360

Mr. Peter R. Harden, IV
VP-Customer Relations and Sales
Westinghouse Electric Company
5929 Carnegie Blvd.
Suite 500
Charlotte, North Carolina 28209

Catawba Nuclear Station

cc:

Mr. T. Richard Puryear
Owners Group (NCEMC)
Duke Energy Corporation
4800 Concord Road
York, South Carolina 29745

Richard M. Fry, Director
Division of Radiation Protection
North Carolina Department of
Environment, Health, and
Natural Resources
3825 Barrett Drive
Raleigh, North Carolina 27609-7721

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

TOPICAL REPORT DPC-NE-3002-A, REVISION 4

DUKE ENERGY CORPORATION

CATAWBA NUCLEAR STATION, UNITS 1 AND 2

DOCKET NOS. 50-413 AND 50-414

1.0 INTRODUCTION

By letter dated April 19, 2000, as supplemented by letters dated August 24 and September 22, 2000, and March 21, 2001, Duke Energy Corporation (DEC/the licensee) requested review of Revision 4 to Topical Report DPC-NE-3002-A, "UFSAR Chapter 15 System Transient Analysis Methodology." The licensee proposed three changes to the previously approved Revision 3 of the topical report. The first change corrects the description of the primary coolant volume that is used in the Updated Final Safety Analysis Report (UFSAR), Section 15.4.6, for boron dilution accident analysis in Mode 4 for Catawba Nuclear Station, Units 1 and 2. The second change involves an increase in the number of operable main steam line power-operated relief valves (PORVs) credited in the steam generator tube rupture (SGTR) analysis for Catawba, Units 1 and 2. The third change specifies a three-minute operator response time to initiate the depressurization of the primary system and a separate three-minute response time for initiating safety injection termination at Catawba, Units 1 and 2. Previously, one 10-minute response time was credited for completing both the depressurization initiation and the safety injection termination actions. These changes are discussed below in more detail.

2.0 DISCUSSION AND EVALUATION

2.1 Change in Dilution Volume for Boron Dilution Analysis

The first change corrects the description of the primary coolant volume that is used in the UFSAR, Section 15.4.6, boron dilution accident analysis in Mode 4 for Catawba Nuclear Station, Units 1 and 2. The current topical report description of the primary coolant volume used in the analysis includes the reactor coolant system excluding the pressurizer, the pressurizer surge line, and the reactor vessel upper head. The licensee later determined that the correct minimum primary coolant volume for the Mode 4 boron dilution analysis should include only those regions of the reactor coolant system that have circulation during the residual heat removal mode. The proposed change reflects the correct minimum mixing volume.

The proposed change will make topical report DPC-NE-3002-A consistent with Revision 6 of the UFSAR. The change in the methodology is a conservative change in that the mixing volume for the Mode 4 boron dilution accident is being revised to a smaller volume. Therefore, the change is acceptable to the staff.

2.2 Steam Line PORVs

The second change involves an increase in the number of operable main steam line PORVs credited in the SGTR analysis for Catawba, Units 1 and 2. The licensee proposed to increase the number of operable PORVs credited in the SGTR analysis from two to three. This change is consistent with the current Technical Specifications which require all four main steam line PORVs to be operable during Modes 1 - 4 when steam generators are being used for decay heat removal. The failure of the PORV to close on the ruptured steam generator is assumed to be the limiting single failure. Therefore, the staff finds the proposed change acceptable.

2.3 Operator Actions

The third change in the proposed revision for Catawba, Units 1 and 2, specifies a three-minute operator response time to initiate the depressurization of the primary system and a separate three-minute response time for initiating safety injection termination. Previously, one 10-minute response time was credited for completing both the depressurization initiation and the safety injection termination actions.

The licensee stated that the proposed change is consistent with that approved by the staff in a safety evaluation (SE) dated April 29, 1997, for a steam generator tube rupture analysis related to steam generator overfill. The staff requested additional information on the differences in conditions between the current and earlier analyses and also requested a current copy of procedure CNS EP/1/A/5000/E-3, "Steam Generator Tube Rupture." By letters dated August 24 and September 22, 2000, and March 21, 2001, the licensee provided additional information.

Normally the staff would use the following guidance to evaluate operator actions: Generic Letter 91-18, "Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability," ANSI/ANS 58.8 (1984), "Time Response Design Criteria for Safety-Related Operator Actions," and Information Notice 97-78, "Crediting of Operator Actions in Place of Automatic Actions and Modification of Operator Actions, Including Response Times." However, in this case the licensee is justifying the time change based on staff's evaluation dated April 29, 1997, in which the same actions were approved using the above guidance. Thus, this evaluation need only verify that the conditions surrounding the current actions are equal to, or are more favorable than, those of the 1997 safety evaluation. As a further check on the revised time intervals, the facility's steam generator tube rupture procedure was reviewed.

For several items, the staff requested that the licensee indicate where the conditions changed from the 1997 SE. The following are the licensee's response to each item:

- Control room conditions (e.g., alarms, peripheral activities being conducted) - the licensee stated that alarms, indications and activities are the same as in the 1997 SE. It is Catawba Nuclear Station practice to clear the control room of any unrelated activity at the onset of any significant event.

- Information required by the operator to initiate each action - the licensee stated that the operators will be responding to the same indication and information as in the 1997 SE.

- Information required to know that the action has been successfully completed - the licensee stated that the information required to know that the action has been successfully completed have not changed since the original submittal.

- Qualified displays providing the above information - the licensee stated that the displays providing the above information are all QA1 qualified instruments.

- Sequence of actions leading up to and to accomplish the intended result - the licensee stated that there is no change to the sequence of actions leading up to initiating depressurization and no technical change to the method of actually initiating the action (see procedural enhancements below). There is no change to terminating safety injection.

- Procedures used to accomplish the actions - the licensee stated that the procedures have been enhanced to reduce operator decision time such that the actions can actually be accomplished faster. Training was conducted on the changes in a recent re-qualification segment.

- Consequence of not accomplishing each action within the 3-minute time frame - the licensee's analysis indicates that increasing the time from three minutes to five minutes increases the expected dose from 15 rem to 16 rem, still well below 10% of the acceptance criteria of 10 CFR Part 100.

- Ability to recover from plausible errors in performance of manual actions and the expected time required to make such a recovery - the licensee stated that each action is accomplished with simple control board devices such as switches and pushbuttons that have direct indication of component status and control board indication of the affected parameters. During these evolutions, these parameters are the direct focus of the control room team, and recognition of an error would be almost immediate. Should an error occur, recovery would be neither difficult nor time consuming.

The staff concludes that conditions surrounding this event are equivalent to, or are more favorable than those surrounding the event evaluated in the SE dated April 29, 1997, in which the three-minute action times were found acceptable. In addition, based on a review of the facility's steam generator tube rupture procedure, the staff found the revised three-minute actions times acceptable. The staff, therefore, finds the revised three-minute action times to initiate depressurization and to initiate safety injection termination acceptable.

3.0 CONCLUSION

Based on the above discussion the staff concludes that the proposed changes in the Topical Report DPC-NE-3002- A, Revision 3 are acceptable for Catawba, Units 1 and 2. However, these changes are not applicable to McGuire, and Revision 4 separates the McGuire and Catawba methodology assumptions as necessary.

Principal Contributors: R. Eckenrode
C. Liang
C. Patel

Date: April 6, 2001

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

February 5, 1999

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

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

cc:

Mr. Gary Gilbert
Regulatory Compliance Manager
Duke Energy Corporation
4800 Concord Road
York, South Carolina 29745

Ms. Lisa F. Vaughn
Legal Department (PB05E)
Duke Energy Corporation
422 South Church Street
Charlotte, North Carolina 28201-1006

J. Michael McGarry, III, Esquire
Winston and Strawn
1400 L Street, NW
Washington, DC 20005

North Carolina Municipal Power
Agency Number 1
1427 Meadowwood Boulevard
P. O. Box 29513
Raleigh, North Carolina 27626

County Manager of York County
York County Courthouse
York, South Carolina 29745

Piedmont Municipal Power Agency
121 Village Drive
Greer, South Carolina 29651

Ms. Karen E. Long
Assistant Attorney General
North Carolina Department of Justice
P. O. Box 629
Raleigh, North Carolina 27602

Elaine Wathen, Lead REP Planner
Division of Emergency Management
116 West Jones Street
Raleigh, North Carolina 27603-1335

North Carolina Electric Membership
Corporation
P. O. Box 27306
Raleigh, North Carolina 27611

Senior Resident Inspector
U.S. Nuclear Regulatory Commission
4830 Concord Road
York, South Carolina 29745

Regional Administrator, Region II
U. S. Nuclear Regulatory Commission
Atlanta Federal Center
61 Forsyth Street, S.W., Suite 23T85
Atlanta, Georgia 30303

Virgil R. Autry, Director
Division of Radioactive Waste Management
Bureau of Land and Waste Management
Department of Health and Environmental
Control
2600 Bull Street
Columbia, South Carolina 29201-1708

L. A. Keller
Manager - Nuclear Regulatory
Licensing
Duke Energy Corporation
526 South Church Street
Charlotte, North Carolina 28201-1006

Saluda River Electric
P. O. Box 929
Laurens, South Carolina 29360

Mr. Steven P. Shaver
Senior Sales Engineer
Westinghouse Electric Company
5929 Carnegie Blvd.
Suite 500
Charlotte, North Carolina 28209

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

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 5.3 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 <u>Conclusion</u>

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
Charlotte, NC 28201

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.

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,

Victor Nerses for

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

Duke Power Company

McGuire Nuclear Station
Catawba Nuclear Station

cc:
Mr. Paul R. Newton
Legal Department (PB05E)
Duke Power Company
422 South Church Street
Charlotte, North Carolina 28242-0001

County Manager of Mecklenburg County
720 East Fourth Street
Charlotte, North Carolina 28202

Mr. J. E. Snyder
Regulatory Compliance Manager
Duke Power Company
McGuire Nuclear Site
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

J. Michael McGarry, III, Esquire
Winston and Strawn
1400 L Street, NW.
Washington, DC 20005

Senior Resident Inspector
c/o U. S. Nuclear Regulatory
Commission
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

Mr. Peter R. Harden, IV
Account Sales Manager
Westinghouse Electric Corporation
Power Systems Field Sales
P. O. Box 7288
Charlotte, North Carolina 28241

Dr. John M. Barry
Mecklenburg County
Department of Environmental
Protection
700 N. Tryon Street
Charlotte, North Carolina 28202

Mr. Dayne H. Brown, Director
Department of Environmental,
Health and Natural Resources
Division of Radiation Protection
P. O. Box 27687
Raleigh, North Carolina 27611-7687

Ms. Karen E. Long
Assistant Attorney General
North Carolina Department of
Justice
P. O. Box 629
Raleigh, North Carolina 27602

Mr. G. A. Copp
Licensing - EC050
Duke Power Company
526 South Church Street
Charlotte, North Carolina 28242-0001

Regional Administrator, Region II
U.S. Nuclear Regulatory Commission
101 Marietta Street, NW. Suite 2900
Atlanta, Georgia 30323

Elaine Wathen
Lead REP Planner
Division of Emergency Management
116 West Jones Street
Raleigh, North Carolina 27603-1335

Mr. T. Richard Puryear
Owners Group (NCEMC)
Duke Power Company
4800 Concord Road
York, South Carolina 29745

Duke Power Company

McGuire Nuclear Station
Catawba Nuclear Station

cc:
Mr. M. S. Kitlan
Regulatory Compliance Manager
Duke Power Company
4800 Concord Road
York, South Carolina 29745

North Carolina Municipal Power
Agency Number 1
1427 Meadowwood Boulevard
P. O. Box 29513
Raleigh, North Carolina 27626-0513

County Manager of York County
York County Courthouse
York, South Carolina 29745

Richard P. Wilson, Esquire
Assistant Attorney General
South Carolina Attorney General's
Office
P. O. Box 11549
Columbia, South Carolina 29211

Piedmont Municipal Power Agency
121 Village Drive
Greer, South Carolina 29651

Saluda River Electric
P. O. Box 929
Laurens, South Carolina 29360

Max Batavia, Chief
Bureau of Radiological Health
South Carolina Department of
Health and Environmental Control
2600 Bull Street
Columbia, South Carolina 29201

North Carolina Electric Membership
Corporation
P. O. Box 27306
Raleigh, North Carolina 27611

Senior Resident Inspector
4830 Concord Road
York, South Carolina 29745

Mr. William R. McCollum
Site Vice President
Catawba Nuclear Station
Duke Power Company
4800 Concord Road
York, South Carolina 29745

Mr. T. C. McMeekin
Vice President, McGuire Site
Duke Power Company
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

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

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.

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

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

December 28, 1995

Mr. M. S. Tuckman
Senior Vice President
Nuclear Generation
Duke Power Company
P. O. Box 1006
Charlotte, NC 28201-1006

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

Duke Power Company

McGuire Nuclear Station
Catawba Nuclear Station

cc:
Mr. Paul R. Newton
Duke Power Company, PB05E
422 South Church Street
Charlotte, North Carolina 28242-0001

County Manager of Mecklenburg County
720 East Fourth Street
Charlotte, North Carolina 28202

Mr. J. E. Snyder
Regulatory Compliance Manager
Duke Power Company
McGuire Nuclear Site
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

J. Michael McGarry, III, Esquire
Winston and Strawn
1400 L Street, NW.
Washington, DC 20005

Senior Resident Inspector
c/o U. S. Nuclear Regulatory
Commission
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

Mr. Peter R. Harden, IV
Account Sales Manager
Westinghouse Electric Corporation
Power Systems Field Sales
P. O. Box 7288
Charlotte, North Carolina 28241

Dr. John M. Barry
Mecklenburg County
Department of Environmental
Protection
700 N. Tryon Street
Charlotte, North Carolina 28202

Mr. Dayne H. Brown, Director
Department of Environmental,
Health and Natural Resources
Division of Radiation Protection
P. O. Box 27687
Raleigh, North Carolina 27611-7687

Ms. Karen E. Long
Assistant Attorney General
North Carolina Department of
Justice
P. O. Box 629
Raleigh, North Carolina 27602

Mr. G. A. Copp
Licensing - EC050
Duke Power Company
526 South Church Street
Charlotte, North Carolina 28242-0001

Regional Administrator, Region II
U.S. Nuclear Regulatory Commission
101 Marietta Street, NW. Suite 2900
Atlanta, Georgia 30323

Elaine Wathen
Lead REP Planner
Division of Emergency Management
116 West Jones Street
Raleigh, North Carolina 27603-1335

Duke Power Company

McGuire Nuclear Station
Catawba Nuclear Station

cc:
Mr. Z. L. Taylor
Regulatory Compliance Manager
Duke Power Company
4800 Concord Road
York, South Carolina 29745

North Carolina Municipal Power
Agency Number 1
1427 Meadowwood Boulevard
P. O. Box 29513
Raleigh, North Carolina 27626-0513

County Manager of York County
York County Courthouse
York, South Carolina 29745

Richard P. Wilson, Esquire
Assistant Attorney General
South Carolina Attorney General's
Office
P. O. Box 11549
Columbia, South Carolina 29211

Piedmont Municipal Power Agency
121 Village Drive
Greer, South Carolina 29651

Saluda River Electric
P. O. Box 929
Laurens, South Carolina 29360

Max Batavia, Chief
Bureau of Radiological Health
South Carolina Department of
Health and Environmental Control
2600 Bull Street
Columbia, South Carolina 29201

North Carolina Electric Membership
Corporation
P. O. Box 27306
Raleigh, North Carolina 27611

Senior Resident Inspector
4830 Concord Road
York, South Carolina 29745

Mr. William R. McCollum
Site Vice President
Catawba Nuclear Station
Duke Power Company
4800 Concord Road
York, South Carolina 29745

Mr. T. C. McMeekin
Vice President, McGuire Site
Duke Power Company
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

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

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-NE-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."

ITS/NRC/95-5

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

P.B. Abramson
H. Komoriya

Prepared for
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555
Under NRC Contract No. NRC-03-90-027
FIN No. L1318

International Technical Services, Inc.
420 Lexington Avenue
New York, NY. 10170

ENCLOSURE 2

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

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

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

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.

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

November 15, 1991

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

Mr. H. B. Tucker, Senior Vice President
Nuclear Generation
Duke Power Company
P. O. Box 1007
Charlotte, North Carolina 28201-1007

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 2.2 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
Project Directorate II-3
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Enclosures:
1. Safety Evaluation
2. Technical Evaluation Report

cc: See next page

cc:

Mr. R. C. Futrell
Regulatory Compliance Manager
Duke Power Company
Catawba Nuclear Site
Clover, South Carolina 29710

Mr. A.V. Carr, Esq.
Duke Power Company
422 South Church Street
Charlotte, North Carolina 28242-0001

J. Michael McGarry, III, Esq.
Winston and Strawn
1400 L Street, N.W.
Washington, DC 20005

North Carolina MPA-1
Suite 600
P.O. Box 29513
Raleigh, North Carolina 27626-513

Mr. Frank Modrak
Project Manager, Mid-South Area
ESSD Projects
Westinghouse Electric Corporation
MNC West Tower - Bay 241
P.O. Box 355
Pittsburgh, Pennsylvania 15230

County Manager of York County
York County Courthouse
York, South Carolina 29745

Richard P. Wilson, Esq.
Assistant Attorney General
S.C. Attorney General's Office
P.O. Box 11549
Columbia, South Carolina 29211

Piedmont Municipal Power Agency
121 Village Drive
Greer, South Carolina 29651

Mr. Alan R. Herdt, Chief
Project Branch #3
U.S. Nuclear Regulatory Commission
101 Marietta Street, NW, Suite 2900
Atlanta, Georgia 30323

North Carolina Electric Membership
Corp.
P.O. Box 27306
Raleigh, North Carolina 27611

Saluda River Electric Cooperative,
Inc.
P.O. Box 929
Laurens, South Carolina 29360

Senior Resident Inspector
Route 2, Box 179N
York, South Carolina 29745

Regional Administrator, Region II
U.S. Nuclear Regulatory Commission
101 Marietta Street, NW, Suite 2900
Atlanta, Georgia 30323

Mr. Heyward G. Shealy, Chief
Bureau of Radiological Health
South Carolina Dept. of Health
and Environmental Control
2600 Bull Street
Columbia, South Carolina 29201

Ms. Karen E. Long
Assistant Attorney General
North Carolina Dept. of Justice
P.O. Box 629
Raleigh, North Carolina 27602

Mr. R. L. Gill, Jr.
Licensing
Duke Power Company
P.O. Box 1007
Charlotte, North Carolina 28201-1007

Duke Power Company

Catawba Nuclear Station
McGuire Nuclear Station

County Manager of Mecklenburg County
720 East Fourth Street
Charlotte, North Carolina 28202

Dr. John M. Barry
Department of Environmental Health
Mecklenburg County
1200 Blythe Boulevard
Charlotte, North Carolina 28203

Mr. R. O. Sharpe
Compliance
Duke Power Company
McGuire Nuclear Site
12700 Hagers Ferry Road
Huntersville, North Carolina 28078-8985

Mr. Dayne H. Brown, Director
Department of Environmental Health
and Natural Resources
Division of Radiation Protection
P. O. Box 27687
Raleigh, North Carolina 27611-7687

Senior Resident Inspector
c/o U.S. Nuclear Regulatory Commission
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

Mr. M. S. Tuckman
Vice President, Catawba Site
Duke Power Company
P. O. Box 256
Clover, South Carolina 29710

Mr. T. C. McMeekin
Vice President, McGuire Site
Duke Power Company
12700 Hagers Ferry Road
Huntersville, North Carolina 28078-8985

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 ana 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

ENCLOSURE 2

ITS/NRC/91-10

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

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 fr-dwater 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, eactor 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.

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

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[illegible] 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

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 <u>Decrease in Heat Removal by the Secondary System</u>

Four transient analyses are performed in this category: (1) turbine trip, (2) loss of offsite power, (3) loss of normal feedwater, anc (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 <u>Turbine Trip</u>

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

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.

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.

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 is 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.

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.

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

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.

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

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.

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.

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.

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 (UGRA), 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 Energy Carolinas
McGuire Nuclear Station
Catawba Nuclear Station

UFSAR Chapter 15 System Transient Analysis Methodology

DPC-NE-3002-A
Revision 4b

September 2010

Nuclear Engineering Division
Nuclear Generation Department
Duke Energy Carolinas

Abstract

This report documents the conservative modeling assumptions used by Duke Energy Carolinas 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 methodology 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.

UFSAR CHAPTER 15 SYSTEM
TRANSIENT ANALYSIS METHODOLOGY

Table of Contents

Revision History

Revision 1

Revision 1 includes methodology revisions associated with the replacement steam generators for McGuire Units 1 & 2 and Catawba Unit 1.

Revision 2

Revision 2 includes methodology revisions associated with safety valve modeling.

Revision 3

Revision 3 includes methodology revisions associated with steam generator modeling for the loss of main feedwater transient for Catawba Unit 2.

Revision 4

Revision 4 includes methodology revisions associated with the mixing volume for the boron dilution accident analysis in Mode 4, the number of steam line PORVS credited in the Catawba SGTR analysis, and two changes in operator action response times for the SGTR analysis.

Revision 4a

This revision consists of numerous editorial and clarification type changes. There are a few error corrections that are made as a result of analyses that demonstrate more conservative results are obtained with assumptions that differ from what was documented in Revision 4. The changes to Section 5.6 are made to maintain consistency with the Technical Specifications. This revision is made under the 10 CFR 50.59 regulation.

Revision 4b

The lone change revises the Fuel Assembly Misload method provided in Section 5.7. The revised method is more comprehensive and conservative than the previous method and consequently is performed under the 10 CFR 50.59 regulation.

1.0 INTRODUCTION

This report documents the conservative modeling assumptions used by Duke 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 methodology report DPC-NE-3001 (Reference 1), which are steam system piping failure (UFSAR Section 15.1.5), control rod misoperation (dropped rod, rod group, or rod bank, UFSAR Sections 15.4.3a&b), and rod ejection (UFSAR Section 15.4.8). The only accidents categorized as not applicable are those which 1) do not apply to McGuire and Catawba (UFSAR Sections 15.2.1, 15.5.3, 15.5.4, and 15.6.6), 2) involve no system thermal-hydraulic analysis (UFSAR Section 15.6.2), or 3) the current McGuire and Catawba licensing bases regard as being bounded by another accident (UFSAR 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 run time 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. It should be noted that uncertainty in this report is described as either positive (actual value > indicated value) or negative (actual value < indicated value). 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 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 turbine trip and feedwater isolation 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 UFSAR 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 UFSAR response time delay has elapsed. Therefore, no AFW is actually delivered to the steam generators.

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

Feedwater Isolation
Feedwater isolation is credited, after the appropriate UFSAR 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

<u>Core Power Level</u>
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.

<u>Pressurizer Pressure</u>
The nominal pressure corresponding to full power operation is assumed, with the pressure initial condition uncertainty accounted for in the statistical core design methodology.

<u>Pressurizer Level</u>
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.

<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>
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.

<u>Fuel Temperature</u>
The results of this transient are not sensitive to initial fuel temperature.

<u>Steam Generator Tube Plugging</u>
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 UFSAR 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 UFSAR 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 UFSAR 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 so long as there are no DNB failures for the 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 the primary system heat up.

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 UFSAR 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 UFSAR 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 and letdown have 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 UFSAR 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 UFSAR 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 and letdown have 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

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

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

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

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

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

<u>RCS Flow</u>
Low initial flow degrades the primary-to-secondary heat transfer.

<u>Core Bypass Flow</u>
Core bypass flow is not an important parameter in this analysis.

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

<u>Fuel Temperature</u>
High initial fuel average temperature is conservative to maximize the transient heat flux and the resultant primary system heat up.

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

3.2.1.3 Boundary Conditions

<u>RCP Operation</u>
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 heaters are assumed to be inoperable since they are lost when offsite power is lost. Charging and letdown have 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 UFSAR response time delay. If applicable, a purge volume of hot main feedwater is assumed to be delivered prior to the cold AFW 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
High initial fuel average temperature is conservative to maximize the transient heat flux and the resultant primary-to-secondary heat transfer.

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 UFSAR response time delay. If applicable, a purge volume of hot main feedwater is assumed to be delivered prior to the cold AFW 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 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 so that Reactor Coolant System pressure is minimized. Charging and letdown have 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 UFSAR response time delay. If applicable, a purge volume of hot main feedwater is assumed to be delivered prior to the cold AFW 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 and letdown have 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 UFSAR 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 peak pressure aspects of the loss of normal feedwater transient are 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 peak RCS pressure and peak Main Steam System pressure 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 (long-term core cooling) and that fuel cladding integrity is maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit based on acceptable correlations (short-term core cooling). 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
High initial fuel average temperature is conservative.

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 and letdown have 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 UFSAR response time delay. If applicable, a purge volume of hot main feedwater is assumed to be delivered prior to the cold AFW 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
High initial level is assumed to delay reactor trip on low-low steam generator level and minimize the steam space following the subsequent turbine trip. The low-low level trip setpoint is adjusted to account for the difference between actual level and indicated level.

Fuel Temperature
High initial fuel average temperature is conservative.

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.

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 UFSAR response time delay. If applicable, a purge volume of hot main feedwater is assumed to be delivered prior to the cold AFW 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 – Short-Term

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.

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.

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 and letdown have 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 UFSAR response time delay. If applicable, a purge volume of hot main feedwater is assumed to be delivered prior to the cold AFW 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.

3.3.4 Core Cooling Capability Analysis – Long-Term

3.3.4.1 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 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.

3.3.4.2 Initial Conditions

Core Power Level
High initial power level plus the power uncertainty maximizes the primary system heat load.

Pressurizer Pressure
Low initial pressurizer pressure causes a corresponding decrease in the hot leg saturation temperature, which minimizes subcooling margin 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 that 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 Tube Plugging
A bounding high tube plugging level impairs the ability of the secondary side to remove primary side 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 Level
Low initial level in all steam generators decreases the long-term capability of the secondary system to remove primary system heat.

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.

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 and letdown have 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 UFSAR response time delay. If applicable, a purge volume of hot main feedwater is assumed to be delivered prior to the cold AFW 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. While it is expected that a feedline break will result in a reactor trip on low-low steam generator level or high containment pressure before reaching the OTΔT trip setpoint, modeling the short-term analysis in this manner precludes having to analyze smaller break sizes that may result in an initial RCS overheating prior to reactor trip. The worst overheating possible is one that trips on OTΔT.

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.

Core Bypass Flow
The nominal calculated flow is assumed, with the flow uncertainty accounted for in the statistical core design methodology.

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

Steam Generator Tube Plugging
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

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.

3.4.1.4 Control, Protection, and Safeguards System Modeling

Reactor Trip
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.

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 and letdown have 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
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 UFSAR 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 Extended 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 and letdown have 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 UFSAR 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 UFSAR response time delay. If applicable, a purge volume of hot water is assumed to be delivered prior to the cold AFW 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 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 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 UFSARs 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 and letdown have 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 UFSAR 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 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 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 and letdown have 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 UFSAR 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 loop with the locked rotor.

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 and letdown have 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 UFSAR 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 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

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 the in 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 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
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.

4.3.2.3 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
It is conservatively assumed that both pressurizer spray and PORVs are in operation to minimize primary system pressure.

Pressurizer Level Control
Pressurizer heaters are assumed to be inoperable so that Reactor Coolant System pressure is minimized. Charging and letdown have 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 UFSAR 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 cladding temperature calculation employs the fuel conduction model as described in Section 4.2.2 of Reference 1.

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
A sensitivity study is performed to determine whether high or low RCS flow is conservative.

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 conservatively 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 UFSAR value.

The response time of the pressurizer high pressure trip function is the UFSAR 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 conservatively 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 UFSAR value.

The response time of the pressurizer high pressure trip function is the UFSAR 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 UFSAR 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 UFSAR 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 UFSAR 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
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
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.

5.2.2.3 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 UFSAR 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 UFSAR 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 UFSAR 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
Low initial level maximizes the initial volume of the pressurizer steam space, which minimizes the transient primary pressure response. Minimizing pressure is conservative for DNBR and also delays reactor trip on high pressurizer pressure.

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 UFSAR 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 UFSAR 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 UFSAR 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 determined via sensitivity studies with different spray and PORVs availability combinations.

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 and letdown have 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 control is in automatic to prevent steam generator low-low level reactor trip.

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.

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

5.5 Startup Of An Inactive Reactor Coolant Pump At An Incorrect Temperature

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

Core Power
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.

5.5.4 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 trip on high-high steam generator level is not credited.

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 if reactor vessel average temperature decreases. If the temperature decreases, rod withdrawal will occur and result in an increase in core power. Control rod insertion is not credited in the analysis until a reactor trip occurs.

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. Turbine trip on high-high steam generator level is not credited.

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 UFSAR 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. The possibility of an inadvertent boron dilution event occurring in Mode 6 is precluded by adherence to the Mode 6 LCO's in Technical Specification 3.9 (specifically, LCO 3.9.2 for McGuire and 3.9.7 for Catawba).

The licensing bases for the McGuire and Catawba Nuclear Stations are different. For McGuire, this accident is analyzed for the power operation (Mode 1) and startup (Mode 2). Manual operation is relied on to terminate the dilution in both modes. For Catawba, this accident is

analyzed for the power operation, startup, hot standby (Mode 3), hot shutdown (Mode 4), and cold shutdown (Mode 5). Automatic operation of the Boron Dilution Mitigation System (BDMS) is relied on to terminate the dilution in hot standby, hot shutdown, and cold shutdown modes, with manual operation as a 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 3-5 with the BDMS assumed to be inoperable, but without the restrictions on flow rates.

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

<u>Dilution Volume</u>
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 allow for only a single train of the Residual Heat Removal System (RHRS) to be in operation, the Mode 4 dilution volume is assumed to be comprised of the reactor vessel (excluding the upper head), the RHR System, and portions of the hot and cold legs between the RHR inlet and outlet connections. For Mode 5, 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 this mode 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.

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 3-5 with the BDMS operable, the alarm function is provided by the measured source range count rate exceeding the BDMS setpoint. For Modes 3-5 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 not result in fuel failures when compared to appropriate DNB peaking limits.

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

<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>
Nominal full power pressurizer pressure is assumed. The uncertainty in this parameter is accounted for in the statistical core design methodology.

<u>Pressurizer Level</u>
High initial level minimizes the volume of the pressurizer steam space which maximizes the pressure decrease resulting from the outsurge.

<u>Reactor Vessel Average Temperature</u>
Nominal full power vessel average temperature is assumed. The uncertainty in this parameter is 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>
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 the power decrease less severe and is therefore conservative for DNBR evaluation.

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

6.1.1.3 Boundary Conditions

<u>ECCS Flow</u>
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.

<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.

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 and letdown have 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 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 UFSAR 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 and maintained there throughout the calculation 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 to 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 Inadvertent Opening of a Pressurizer Safety or Relief Valve

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

Power Level
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.

Pressurizer Pressure
Nominal pressure 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 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.

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
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 UFSAR 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 UFSAR 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. A third acceptance criterion and analysis that pertains to Catawba only, steam generator overfill, has been performed and NRC approved separately from this report.

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 due to hot primary fluid entering the ruptured generator thereby increasing the heat sink 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 UFSAR 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.

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

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

Pressurizer Pressure
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.

Pressurizer Level
High initial level with a positive uncertainty maximizes the static head driving force and subsequent primary-to-secondary leakage and maximizes pressurizer heater operation.

Reactor Vessel Average Temperature
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
For McGuire, two of the three steam line PORVs on the intact steam generators are assumed to be operable. For Catawba, three steam line PORVs on the intact steam generators are assumed to be operable. 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).

- For Catawba, isolate the 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 (Catawba) and 30 minutes for local (McGuire) 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 (Catawba) and 45 minutes for local action (McGuire) are assumed (credit).

- For McGuire, 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). For Catawba, this action is initiated 3 minutes after the primary system is 20°F subcooled (credit).

- Initiate SI termination 3 minutes after completing the depressurization of the primary system (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 in order to delay reactor trip.

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 non-conservatively 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 due to hot primary fluid entering the ruptured generator thereby increasing the heat sink 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 UFSARs. 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 for the UFSAR 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

UFSAR 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	Nominal	High	**
Pzr Level	High	High	High	High	High	**	Low	Nominal	High	**
RCS Temp	Nominal	Nominal	High	High	High	High	Nominal	High	High	High
RCS Flow	Nominal	Nominal	Low	High	Low	High	Nominal	**	Low	High
Bypass Flow	Nominal	Nominal	**	**	**	**	Nominal	**	**	**
SG Level	Low	**	High	High	**	High	**	High	Low	High
Fuel Temp	Low	**	High	High	High	High	High	**	High	High
SG Tube Plugging	None	None	High	None	High	None	**	High	High	None
Pzr Spray	-	-	Off	Auto	Off	**	Off	Off	Off	**
Pzr Heaters	Off	Off	On	On	Off	**	Off	Off	Auto	**
Pzr PORVs	-	-	Closed	Auto	Closed	**	Closed	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	-	**	*	*	-	-	-	-	-	-
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	**	**	*	*	UFSAR	UFSAR	UFSAR	UFSAR	UFSAR	UFSAR
Turb Trip Signal	SG Lvl	-	-	-	LOSP	LOSP	LOSP	LOSP	Rx Trip	Rx Trip
Turb Trip Delay	UFSAR	-	None	None	None	None	None	None	None	None
Stm Line Isol Signal	-	-	-	-	-	-	-	-	-	-
Stm Line Isol Delay	-	-	-	-	-	-	-	-	-	-
MFW Isol Signal	SG Lvl	-	*	*	-	-	-	-	-	-
MFW Isol Delay	UFSAR	-	-	-	-	-	-	-	-	-

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

UFSAR Section	15.2.7	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	3.3.4	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	High	Nominal	High	Nominal	Nominal	High	Nominal	0	0	*
Pzr Pressure	Nominal	Low	Nominal	Low	Nominal	Nominal	High	Nominal	High	Nominal	Nominal
Pzr Level	Low	Low	Low	Low	Low	Low	High	Low	High	Low	High
RCS Temp	Nominal	High	Nominal	High	Nominal	Nominal	High	Nominal	**	Nominal	**
RCS Flow	Nominal	Low	Nominal	Low	Nominal	Nominal	Low	Nominal	*	Nominal	**
Bypass Flow	Nominal	**	Nominal	**	Nominal	Nominal	High	Nominal	**	Nominal	**
SG Level	Low	Low	**	Low	**	**	**	**	**	**	**
Fuel Temp	High	High	High	High	High	High	High	High	*	*	Low
SG Tube Plugging	High	High	**	**	**	**	**	**	High	None	High
Pzr Spray	Auto	Auto	Auto	Auto	Auto	Auto	Off	Auto	Off	Auto	Off
Pzr Heaters	Off	Off	Off	Off	Off	Off	Auto	Off	**	Off	**
Pzr PORVs	Auto	Auto	Auto	Closed	Auto	Auto	Closed	Auto	Closed	Auto	Closed
SM PORVs	Closed	Closed	Closed	Closed	Closed	Closed	Closed	Closed	Closed	Closed	Closed
Steam Dump	Closed	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	Manual	-	-	-
Turbine Control	Auto	Auto	Auto	Auto	Auto	Auto	Auto	Auto	-	-	Auto
SI Signal	-	-	-	*	-	-	-	-	-	-	-
SI Flow	-	-	-	Min	-	-	-	-	-	-	-
SI Delay	-	-	-	UFSAR	-	-	-	-	-	-	-
AFW Signal	SG Lvl	SG Lvl	**	SI	**	**	**	**	**	**	*
AFW Flow	Min	Min	**	Min	**	**	**	**	**	**	*
AFW Delay	UFSAR	UFSAR	**	UFSAR	**	**	**	**	**	**	*
Turb Trip Signal	Rx Trip	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	-	-	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.

Table 8-1 (continued)
Accident Analysis Assumptions

UFSAR 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	0	Nominal	Nominal	High
Pzr Pressure	Nominal	-	Nominal	Low	-	-	Nominal	Low	Nominal	Nominal	High
Pzr Level	Low	-	Low	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	-	**	High	**	**	**
Pzr Spray	*	-	*	Auto	-	-	Auto	-	-	-	Off
Pzr Heaters	Off	-	Off	Off	-	-	Off	Off	Off	Off	Manual
Pzr PORVs	*	-	*	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	-	-	-	*	-	-	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	*	-	*	**	-	-	**	-	**	**	UFSAR
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 Energy Carolinas, Revision 0, December 2000

2. DPC-NE-3000-PA, "Thermal-Hydraulic Transient Analysis Methodology", Duke Energy Carolinas, Revision 3, September 2004

3. NUREG-0800, "U.S.N.R.C. Office of Nuclear Reactor Regulation Standard Review Plan", Revision 3, February 1984.

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.

DPC-NE-3002-A
Revision 4b

List of Changes to DPC-NE-3002-A Revision 4b

The following is the complete list of changes made in the conversion of DPC-NE-3002-A Revision 4a (April 2009) to DPC-NE-3002-A Revision 4b (September 2010). None of the topical report changes are considered to be significant changes, and therefore do not require NRC review (hence the "b" designation in the revision number).

List of Changes from Revision 4a to Revision 4b

1. The title page was revised to Revision 4b and dated September 2010

2. Revision 4b summation added to the revision summation page.

3. The last sentence in Section 5.7 is changed as follows:

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~~ not result in fuel failures when compared to appropriate DNB peaking limits.

List of Changes to DPC-NE-3002-A Revision 4a

The following is the complete list of changes made in the conversion of DPC-NE-3002-A Revision 4 (May 2005) to DPC-NE-3002-A Revision 4a (April 2009). None of the topical report changes are considered to be significant changes, and therefore do not require NRC review (hence the "a" designation in the revision number).

List of Changes from Revision 4 to Revision 4a

1. The title pages were revised to Revision 4a and dated April 2009

2. A statement of disclaimer page was added immediately following the title page.

3. A revision history summation page after the table of contents.

4. "Duke Power Company" was changed everywhere to "Duke Energy Carolinas", or simply "Duke".

5. "FSAR" was changed everywhere to "UFSAR".

6. The table of contents was updated.

7. "topical report" was changed everywhere to "methodology report".

8. A sentence was added in the introduction clarifying what is meant by positive or negative uncertainty.

9. Section 2.2.1, Steam Generator Level discussion was revised as follows "steam generator narrow range level ~~reactor~~turbine trip and feedwater isolation due to any temporary steam/feedwater flow mismatch".

10. "technical specifications" is changed to "UFSAR" everywhere in reference to response times since the response time values have been relocated to the UFSAR.

11. A clarifying statement is added to Section 2.4 as follows "This criterion is satisfied by comparison to the DNBR results for the more limiting steam line break transient so long as there are no DNB failures for the steam line break transient".

12. Section 3.1.1.4, Fuel Temperature discussion was revised as follows "This maximizes the transient heat flux and thus maximizes ~~primary-to-secondary heat transfer~~the primary system heat up."

13. Sections 3.2.1.2 and 3.2.2.2, Fuel temperature discussion were revised as follows "High initial fuel average temperature is conservative to maximize the transient heat flux and the resultant primary system heat up."

14. Section 3.2.1.4, Pressurizer Level Control was revised as follows "Pressurizer heaters are assumed to be inoperable since they are lost when offsite power is lost.~~Pressurizer level control is in automatic in order to maximize primary pressure.~~"

15. Section 3.2.3.4, Pressurizer Pressure Control was revised as follows "Pressurizer sprays are lost when the reactor coolant pumps trip. Pressurizer PORVs are lost when offsite power is lost. Therefore, both are inoperable.~~Pressurizer sprays and PORVs are assumed to be operable in order to minimize the system pressure throughout the transient.~~"

16. Section 3.3 was revised for clarification as follows:

"The peak pressure aspects of the~~The~~ loss of normal feedwater transient ~~is~~ are bounded by the turbine trip transient."

"Based on the above qualitative evaluation, a quantitative peak RCS pressure and peak Main Steam System pressure analysis of this transient is not required."

"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 (long-term core cooling) and that fuel cladding integrity is maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit based on acceptable correlations (short-term core cooling)."

17. Section 3.3.2.2, Steam Generator Level was revised as follows "~~Low initial level is assumed in order to minimize steam generator inventory at the time of reactor trip.~~High initial level is assumed to delay reactor trip on low-low steam generator level and minimize the steam space following the subsequent turbine trip."

18. Section 3.3.3 was updated to reflect the discussion is related to the short-term core cooling analysis only.

"3.3.3 Core Cooling Capability Analysis – Short-Term

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.~~"

19. Section 3.3.4, the loss of main feedwater long-term core cooling analysis discussion was added.

20. A clarifying statement was added to Section 3.4.1 as follows "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. While it is expected that a feedline break will result in a reactor trip on low-low steam generator level or high containment pressure before reaching the OTΔT trip setpoint, modeling the short-term analysis in this manner precludes having to analyze smaller break sizes that may result in an initial RCS overheating prior to reactor trip. The worst overheating possible is one that trips on OTΔT."

21. Section 3.4.2.3, Break flow modeling is revised as follows "The break flow rate is determined by the Extended Henry (subcooled) and Moody (saturated) critical flow correlations."

22. Section 4.3.1.4, Reactor trip is revised to be more descriptive as follows "Reactor trip occurs on low Reactor Coolant System flow in the ~~locked~~ loop with the locked rotor."

23. Section 4.3.2.4, Pressurizer Pressure Control is revised as follows "~~Credit is taken for~~It is conservatively assumed that both pressurizer spray and PORVs are in operation ~~in order~~ to minimize primary system pressure."

24. Section 4.3.2.5, "clad" is changed to "cladding"

25. Section 5.1.1.2, RCS Flow is revised as follows "~~RCS flow is not an important parameter in this analysis.~~A sensitivity study is performed to determine whether high or low RCS flow is conservative."

26. Sections 5.1.1.2 and 5.1.2.2 are revised as follows "The fuel-clad gap conductivity is set conservatively high to maximize heat transfer from the fuel."

27. The Fuel Temperature and Steam Generator Tube Plugging discussions in Section 5.2.2.2 are revised as follows:

    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.~~ Low fuel temperature, associated with high gap conductivity, 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.~~ A bounding high tube plugging value degrades primary-to-secondary heat transfer.

28. Section 5.4.2, Pressurizer Level is revised as follows "~~High~~ Low initial level ~~minimizes~~ maximizes the initial volume of the pressurizer steam space, which ~~maximizes~~minimizes the transient primary pressure response. Minimizing pressure is conservative for DNBR and also delays reactor trip on high pressurizer pressure. ~~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.~~

29. Section 5.4.4, Pressurizer Pressure Control is revised as follows "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~~determined via sensitivity studies with different spray and PORVs availability combinations.

30. Section 5.6 is revised to remove discussion of the Mode 6 analysis since adherence to technical specifications precludes the event from occurring in Mode 6.

31. Section 6.1.2.1, Pressurizer Pressure is revised as follows "Initial pressure is assumed conservatively low and maintained there throughout the calculation to determine the SI flow during the event.

32. Section 7.2 is revised to acknowledge that steam generator overfill is an acceptance criterion for Catawba but that it is beyond the scope of this methodology report. "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. A third acceptance criterion and analysis that pertains to Catawba only, steam generator overfill, has been performed and NRC approved separately from this report."

33. Section 7.2.2.2, Pressurizer Level is revised as follows "High initial level with a positive uncertainty maximizes the static head driving force and subsequent primary-to-secondary leakage and maximizes pressurizer heater operation."

34. Section 7.2.2.4 is revised as follows:

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 in order to delay reactor trip.

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 due to hot primary fluid entering the ruptured generator thereby increasing the heat sink 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.

35. Table 8-1 is revised as a result of the above changes.

DPC-NE-3002-A
Revision 4

List of Changes to DPC-NE-3002-A Revision 3

The following is the complete list of changes made in the conversion of DPC-NE-3002-A Revision 3 (May 1999) to DPC-NE-3002-A Revision 4 (May 2005). The significant methodology changes have been reviewed and approved by the NRC. None of the other topical report changes are considered to be significant changes, and therefore do not require NRC review.

List of Changes from Revision 3 to Revision 4

1. The title pages were revised to Revision 4 and dated May 2005

2. The Revision 4 SER dated April 6, 2001 was included at the front

3. Section 3.2.1.2, Fuel Temperature: Change the text to correct the conservative initial value of the fuel average temperature. (error correction)

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

   To: "High initial fuel average temperature is conservative."

4. Section 3.2.2.2, Fuel Temperature: Change the text to correct the conservative initial value of the fuel average temperature. (error correction)

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

   To: "High initial fuel average temperature is conservative."

5. Section 3.3.1.2, Fuel Temperature: Change the text to correct the conservative initial value of the fuel average temperature. (error correction)

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

   To: "High initial fuel average temperature is conservative."

6. Section 3.3.2.2, Fuel Temperature: Change the text to correct the conservative initial value of the fuel average temperature. (error correction)

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

   To: "High initial fuel average temperature is conservative."

7. Section 5.5.4, Steam Generator Level Control: Clarification added that the high-high steam generator level trip of the main feedwater pumps is not credited. (editorial)

   Insert the following: "MFW pump trip on high-high steam generator level is not credited."

8. Section 5.5.4, Rod Control: Re-worded to avoid potentially misleading statement. (editorial)

   Change: "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."

   To: "The Rod Control System is assumed to be in automatic if reactor vessel average temperature decreases. If the temperature decreases, rod withdrawal will occur and result in an increase in core power. Control rod insertion is not credited in the analysis until a reactor trip occurs."

9. Section 5.5.4, Turbine Control: Clarification added that the turbine trip on high-high steam generator level is not credited. (editorial)

   Insert the following: "Turbine pump trip on high-high steam generator level is not credited."

10. Section 5.6, third paragraph: Revised to reflect the current plant design basis, which no longer relies on the BDMS for mitigation in Mode 6 refueling. (plant design and licensing basis change)

    Change: "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, . . . "

    To: "Automatic operation of the Boron Dilution Mitigation System (BDMS) is relied on to terminate the dilution in hot standby, hot shutdown, and cold shutdown, . . ."

    Change: "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."

    To: "Since the BDMS is not used in Modes 1 and 2, the analysis of these modes is similar to the analysis of Modes 3-5."

11. Section 5.6, fourth paragraph: The fourth paragraph should have only been the first two sentences, with the remainder in a following paragraph (editorial)

12. Section 5.6.1, Dilution Volume: Revise the dilution volume to be consistent with the Technical Specifications. (model revision)

    Change: "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."

To: "Since the Technical Specifications allow for only a single train of the Residual Heat Removal System (RHRS) to be in operation, the Mode 4 dilution volume is assumed to be comprised of the reactor vessel (excluding the upper head), the RHR System, and portions of the hot and cold legs between the RHR inlet and outlet connections."

13. Section 5.6.3: Revised to reflect the current plant design basis, which no longer relies on the BDMS for mitigation in Mode 6 refueling. (plant design and licensing basis change)

    Change: "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, . . . "

    To: "For Modes 3-5 with the BDMS operable, the alarm function is provided by the measured source range count rate exceeding the BDMS setpoint. For Modes 3-5 with the BDMS inoperable, . . . "

14. Section 7.2.2.3, Steam Line PORVs: Revise to clarify the differences between McGuire and Catawba consistent with the current licensing basis analyses. (model revision)

    Change: "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."

    To: "For McGuire, two of the three steam line PORVs on the intact steam generators are assumed to be operable. For Catawba, three steam line PORVs on the intact steam generators are assumed to be operable."

15. Section 7.2.2.3, Manual Actions: Revise to clarify the differences between McGuire and Catawba consistent with the current licensing basis analyses. (model revision)

    Change: "Isolate failed open steam line drains upstream . . . ."

    To: "For Catawba, isolate the failed-open steam line drains upstream . . . ."

16. Section 7.2.2.3, Manual Actions: Revise to clarify the differences between McGuire and Catawba consistent with the current licensing basis analyses. (model revision)

    Change: "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)."

    To: "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 (Catawba) and 30 minutes for local (McGuire) operation (credit)."

17. Section 7.2.2.3, Manual Actions: Revise to clarify the differences between McGuire and Catawba consistent with the current licensing basis analyses. (model revision)

Change: "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)."

To: "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 (Catawba) and 45 minutes for local action (McGuire) are assumed (credit)."

18. Section 7.2.2.3, Manual Actions: Revise to clarify the differences between McGuire and Catawba consistent with the current licensing basis analyses. (model revision)

    Change: "- 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)."

    To: "- For McGuire, 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). For Catawba, this action is initiated 3 minutes after the primary system is 20°F subcooled (credit).

    - Initiate SI termination 3 minutes after completing the depressurization of the primary system (credit)."

19. Table 8-1, Fuel Temp (row), Sections 15.1.3, 15.2.6, and 15.2.7 (columns). The text has errors regarding the conservative direction of the assumption for fuel temperature (error correction)

    Change: Under 15.1.3, "**"
    To: "high"

    Change: Under 15.2.6 (3.2.1), "low"
    To: "high"

    Change: Under 15.2.6 (3.2.2), "low"
    To: "high"

    Change: Under 15.2.7 (3.3.1), "low"
    To: "high"

    Change: Under 15.2.7 (3.3.2), "low"
    To: "high"

20. Revised References 1 and 2 to the current revisions and dates. (editorial)

    1. DPC-NE-3001-PA, "Multidimensional Reactor Transients and Safety Analysis Physics Parameters Methodology", Duke Power Company, Revision 0, December 2000

2. DPC-NE-3000-PA, "Thermal-Hydraulic Transient Analysis Methodology", Duke Power Company, Revision 3, September 2004

21. Revised the list of attached docketed correspondence and included copies.

22. Included this list

DPC-NE-3002-A Revision 3

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.

DPC-NE-3002-A Revision 2

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 DT 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 DT and high pressurizer pressure to the list of potential reactor trip signals.

21. Section 3.3.3.4: Added overtemperature DT 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.

DPC-NE-3002-A
Revision 4

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
10. 4/19/00 letter submitting Revision 4, M. S. Tuckman to NRC
11. 8/4/00 letter response to NRC questions, M. S. Tuckman to NRC
12. 9/22/00 letter response to NRC questions, M. S. Tuckman to NRC
13. 3/21/01 letter submitting SGTR emergency procedure, M. S. Tuckman 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.

If there are any questions, please call Scott Gewehr at (704) 373-7581.

Very truly yours,

M. S. Tuckman

M. S. Tuckman
cvr3002/sag

cc: Mr. T. A. Reed, Project Manager
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 9H3, OWFN
Washington, D. C. 20555

Mr. R.E. Martin, Project Manager
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 9H3, OWFN
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 Company
PO Box

DUKE POWER

November 5,1991

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
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,

Hal B. Tucker

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

Mr. R. E. Martin, Project Manager
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 14H25, OWFN
Washington, D. C. 20555

Mr. L. A. Wiens, Project Manager
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 14H25, OWFN

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 (ft^2)	Rx Trip Time (sec)	Minimum SG Mass (lbm/SG)
DE	19.5	[ ]
0.5	[	]
0.3		

The 0.5 ft^2 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 ft^2 break has some main feedwater reaching the intact steam generators, which explains the higher minimum mass flow. For breaks larger than 0.5 ft^2, 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 ft^2 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.

Duke Power Company
P.O. Box 1006
Charlotte, NC 28201-1006

M. S. Tuckman
Senior Vice President
Nuclear Generation
(704)382-2200 Office
(704)382-4360 Fax

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

cc: Mr. V. Nerses, Project Manager
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 14H25, OWFN
Washington, D. C. 20555

Mr. R. E. Martin, Project Manager (3 copies)
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 14H25, OWFN
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. G. F. Maxwell
Senior Resident Inspector
McGuire Nuclear Station

Mr. R. J. Freudenburger
Senior Resident Inspector
Catawba Nuclear Station

T. E. Collins, Acting Branch Chief
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 8 E23, OWFN
Washington, D. C. 20555

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

July 25, 1995

Mr. M. S. Tuckman
Senior Vice President
Nuclear Generation
Duke Power Company
P. O. Box 1006
Charlotte, NC 28201

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

cc:
Mr. Z. L. Taylor
Regulatory Compliance Manager
Duke Power Company
4800 Concord Road
York, South Carolina 29745

North Carolina Municipal Power
Agency Number 1
1427 Meadowwood Boulevard
P. O. Box 29513
Raleigh, North Carolina 27626-0513

County Manager of York County
York County Courthouse
York, South Carolina 29745

Richard P. Wilson, Esquire
Assistant Attorney General
South Carolina Attorney General's
Office
P. O. Box 11549
Columbia, South Carolina 29211

Piedmont Municipal Power Agency
121 Village Drive
Greer, South Carolina 29651

Saluda River Electric
P. O. Box 929
Laurens, South Carolina 29360

Max Batavia, Chief
Bureau of Radiological Health
South Carolina Department of
Health and Environmental Control
2600 Bull Street
Columbia, South Carolina 29201

North Carolina Electric Membership
Corporation
P. O. Box 27306
Raleigh, North Carolina 27611

Senior Resident Inspector
4830 Concord Road
York, South Carolina 29745

Mr. David L. Rehn
Vice President, Catawba Site
Duke Power Company
4800 Concord Road
York, South Carolian 29745

Mr. T. C. McMeekin
Vice President, McGuire Site
Duke Power Company
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

cc:
A. V. Carr, Esquire
Duke Power Company
422 South Church Street
Charlotte, North Carolina 28242-0001

County Manager of Mecklenberg County
720 East Fourth Street
Charlotte, North Carolina 28202

Mr. J. E. Snyder
Regulatory Compliance Manager
Duke Power Company
McGuire Nuclear Site
12700 Hagers Ferry Road
Huntersville, North Carolina 28078-8985

J. Michael McGarry, III, Esquire
Winston and Strawn
1400 L Street, NW.
Washington, DC 20005

Senior Resident Inspector
c/o U. S. Nuclear Regulatory Commission
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

Mr. T. Richard Puryear
Nuclear Technical Services Manager
Westinghouse Electric Corporation
Carolinas District
2709 Water Ridge Parkway, Suite 430
Charlotte, North Carolina 28217

Dr. John M. Barry
Mecklenberg County
Department of Environmental Protection
700 N. Tryon Street
Charlotte, North Carolina 28202

Mr. Dayne H. Brown, Director
Department of Environmental, Health and Natural Resources
Division of Radiation Protection
P. O. Box 27687
Raleigh, North Carolina 27611-7687

Ms. Karen E. Long
Assistant Attorney General
North Carolina Department of Justice
P. O. Box 629
Raleigh, North Carolina 27602

Mr. G. A. Copp
Licensing - EC050
Duke Power Company
526 South Church Street
Charlotte, North Carolina 28242-0001

Regional Administrator, Region II
U.S. Nuclear Regulatory Commission
101 Marietta Street, NW. Suite 2900
Atlanta, Georgia 30323

Elaine Wathen
Lead REP Planner
Division of Emergency Management
116 West Jones Street
Raleigh, North Carolina 27603-1335

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.

Duke Power Company
P.O. Box 1006
Charlotte, NC 28201-1006

M. S. Tuckman
Senior Vice President
Nuclear Generation
(704)382-2200 Office
(704)382-4360 Fax

DUKE POWER

August 18, 1995

RECEIVED
AUG 21 1995
DUKE POWER CO.
NUCLEAR ENGINEERING

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

M. S. Tuckman

cc: Mr. R. E. Martin, Project Manager
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 14H25, OWFN
Washington, D. C. 20555

Mr. V. Nerses, Project Manager
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 14H25, OWFN
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

bxc: G. A. Copp
K. S. Canady
G. B. Swindlehurst
M. H. Hazeltine
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.

<u>Question 8</u>

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.

<u>Response</u>

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).

<u>Question 13</u>

DPC should revise §9.0 (References) in Revision 1.

<u>Response</u>

When Revision 3 to DPC-NE-3000 is approved, the references will be updated accordingly.

Duke Power Company
P.O. Box 1006
Charlotte, NC 28201-1006

M. S. Tuckman
Senior Vice President
Nuclear Generation
(704)382-2200 Office
(704)382-4360 Fax

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

M. S. Tuckman

cc: Mr. V. Nerses, Project Manager
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 14H25, OWFN
Washington, D. C. 20555

Mr. R. E. Martin, Project Manager
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 14H25, OWFN
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. G. F. Maxwell
Senior Resident Inspector
McGuire Nuclear Station

Attachment 1

Key Word: Secondary Equipment

RECEIVED
AUG 31 1995
DUKE POWER CO.
NUCLEAR ENGINEERING

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.

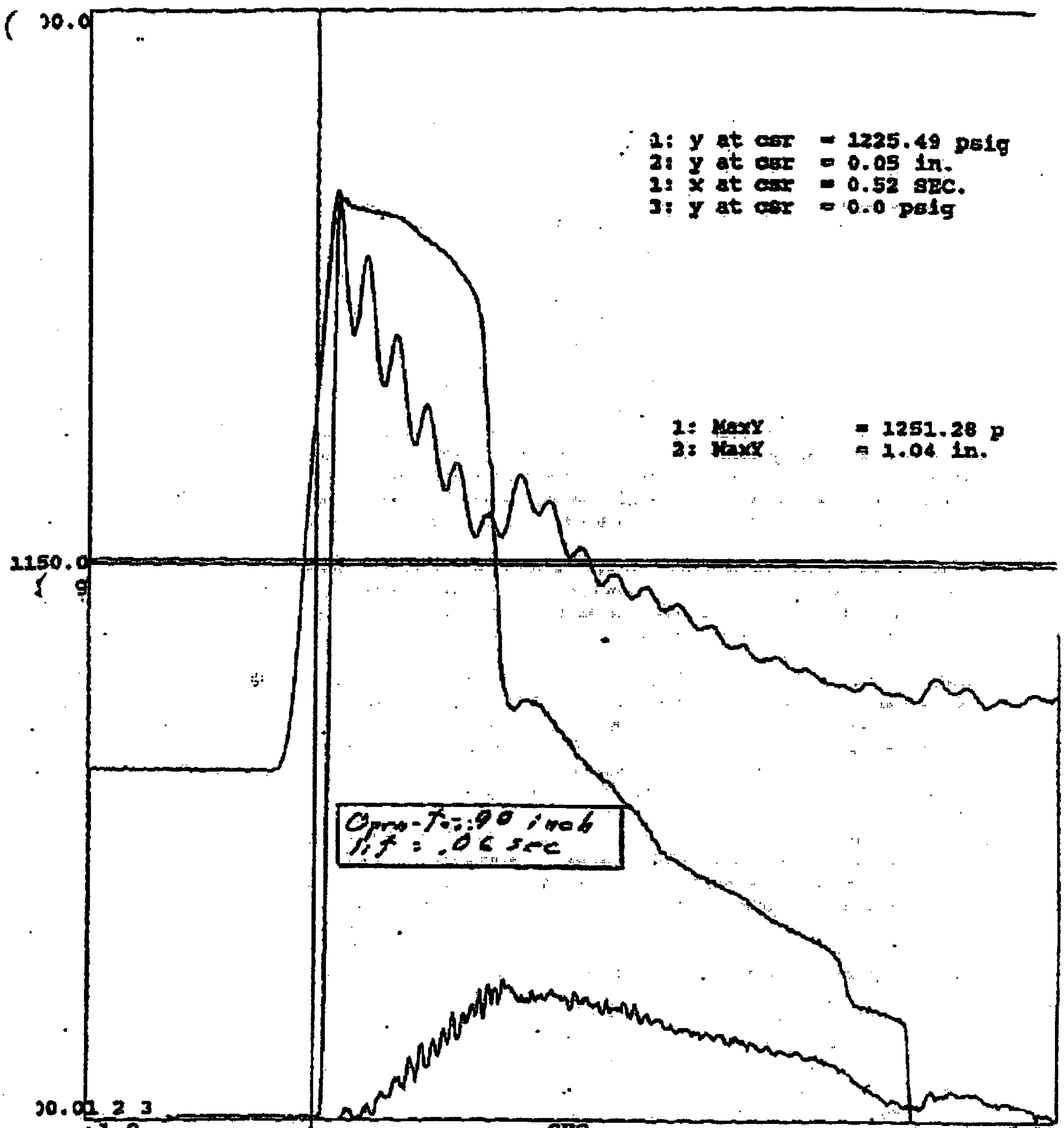
If you wish to discuss this subject further, please contact the undersigned at 875-5627.

Grant Cutri

Grant Cutri
McGuire Valve Engineering

Attachments (2)

Christy Ray
8/29/95
Attachment 1 sh 2 of 5



Valve S/N N60951-07-0025 Open to close = 3.91 sec
6 R 10 Set Pressure = 1220 psig
Sheet 1 of 2

cc: Mr. V. Nerses, Project Manager
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 14H25, OWFN
Washington, D. C. 20555

Mr. R. E. Martin, Project Manager
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 14H25, OWFN
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. G. F. Maxwell
Senior Resident Inspector
McGuire Nuclear Station

Mr. R. J. Freudenberger
Senior Resident Inspector
Catawba Nuclear Station

bxc: G. A. Copp
J. E. Snyder (MNS)
M. S. Kitlan (CNS)
G. B. Swindlehurst
T. R. Niggel
ELL

Duke Power Company
P.O. Box 1006
Charlotte, NC 28201-1006

M. S. Tuckman
Senior Vice President
Nuclear Generation
(704)382-2200 Office
(704)382-4360 Fax

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

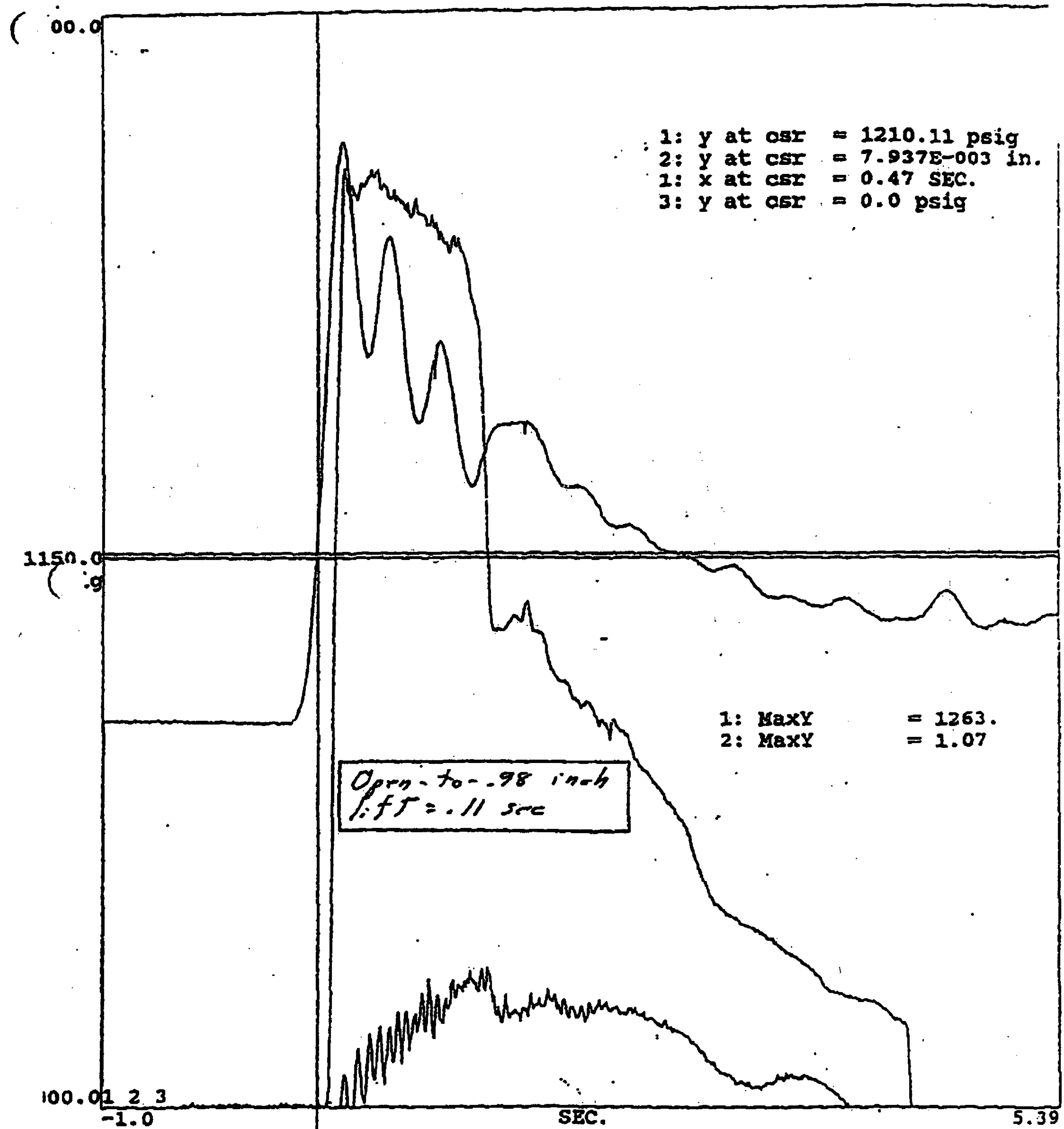
M. S. Tuckman

1995.08-29 09:10 #655 P.06/06

S083843152

FROM :CROSBY POWER GROUP

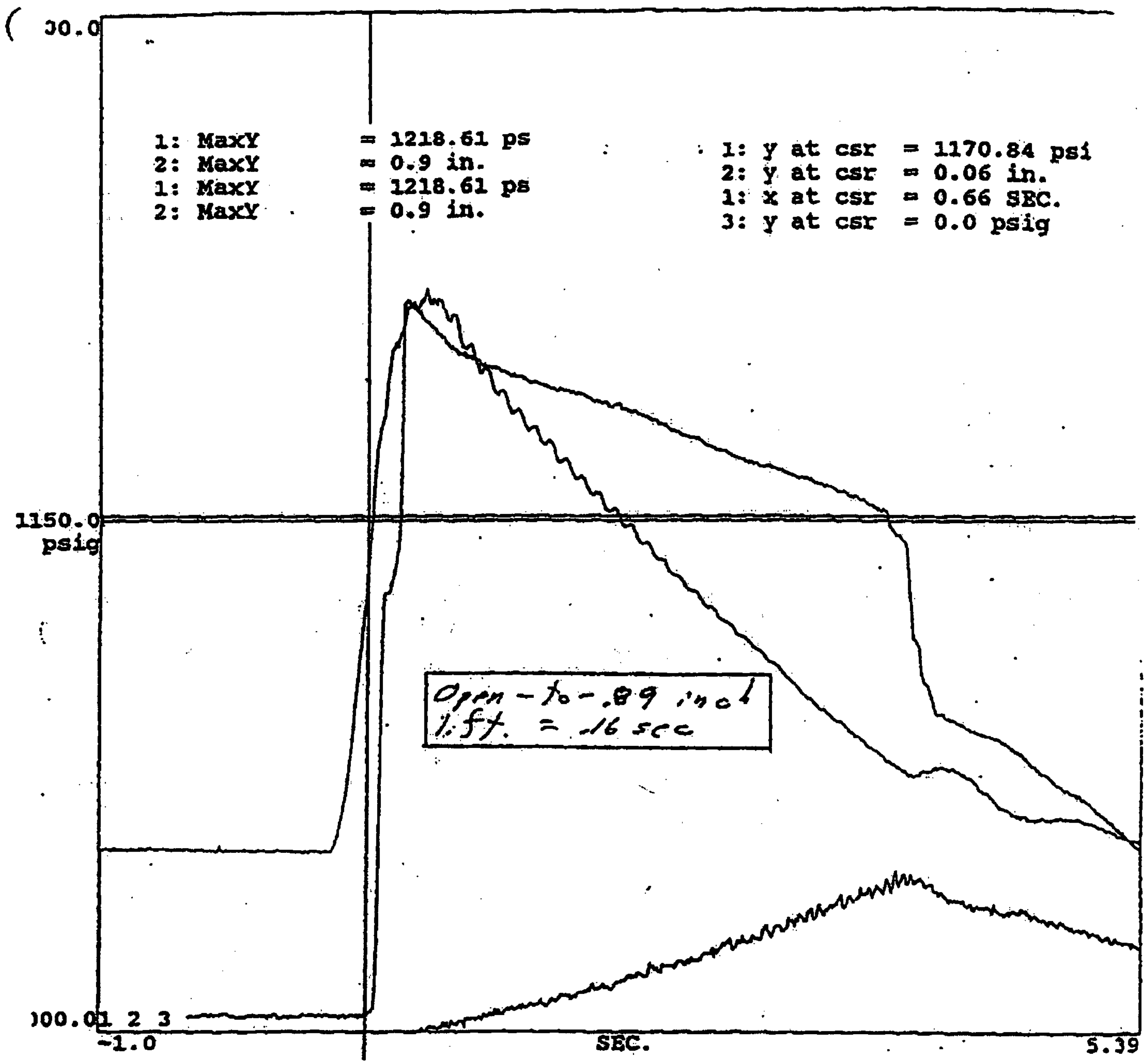
Christy Ray
8/29/95
Attachment 1 sh 3 of 5



Valve S/N N60951-01-0034
6R10 Set Pressure = 1205
Sheet 1 of 1

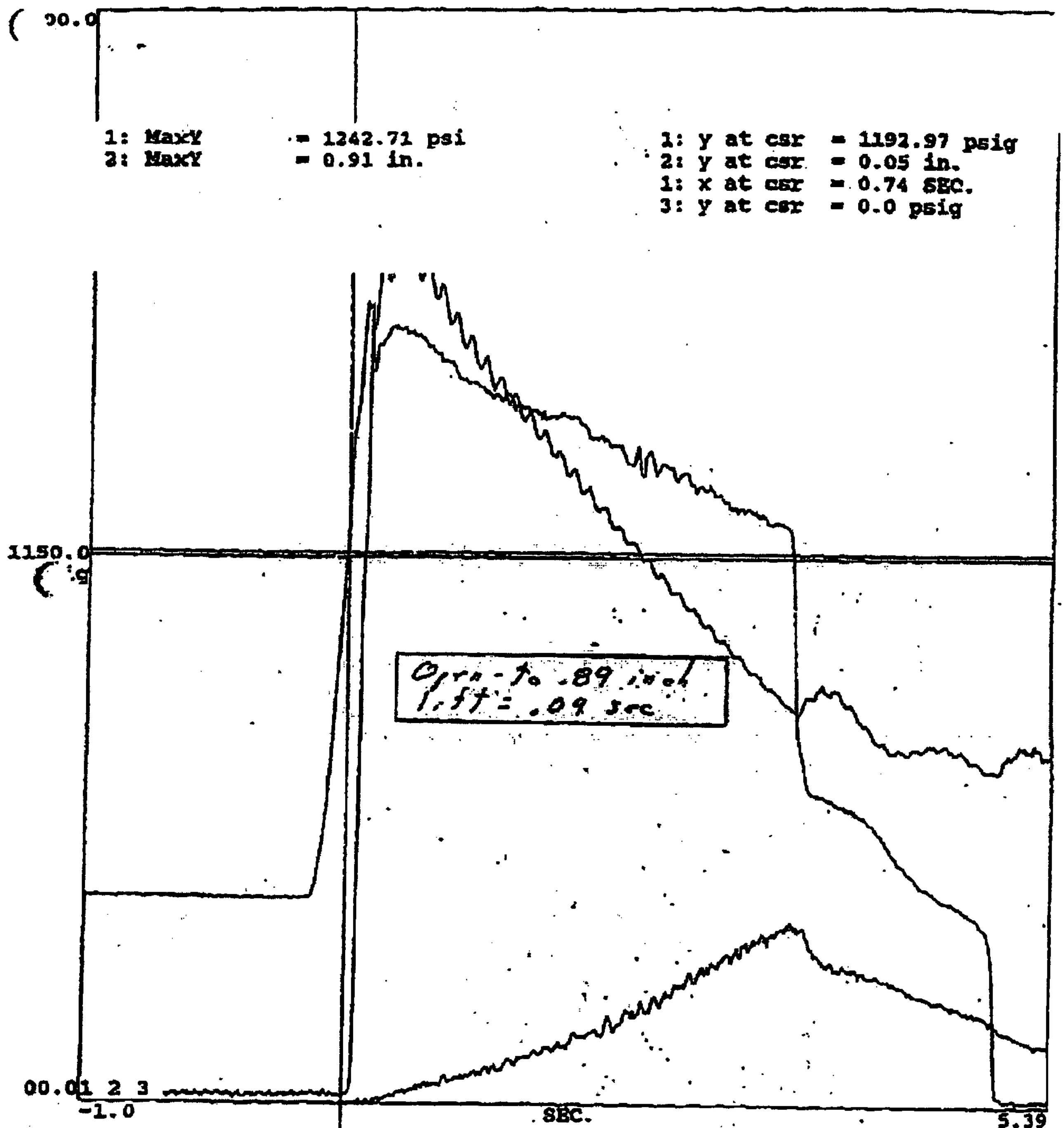
Open-to-close = 3.89 sec

Christy Ray
8/29/95
Attachment 1 sh 4 of 5



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



Valve S/N N5C937-01-0005 Open-to-close = 4.28 sec
6 Q 8 Set Pressure = 1190 psig
Sheet 1 of 1

Attachment 2
~~CNC-1552.08-00-02~~
DPC-1552.08-00-0165

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 of .586 ")	Time to Maximum Steam Flow (rated steam flow of 608k lb/hr)	Pressurization Rate (psi/sec)
603	.016 sec	.080 sec	2.9
608	.020 sec	.078 sec	286
611	.024 sec	.072 sec	322
1305	.031 sec	.062 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

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

Duke Power Company
P.O. Box 1006
Charlotte, NC 28201-1006

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.

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

Duke Energy Corporation
Catawba Nuclear Station
4800 Concord Road
York, SC 29745
(803) 831-4251 OFFICE
(803) 831-3426 FAX

September 25, 1998

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."

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

G.R. Peterson

xc:

L.A. Reyes
U.S. Nuclear Regulatory Commission
Regional Administrator, Region II
Atlanta Federal Center
61 Forsyth St., SW, Suite 23T85
Atlanta, GA 30303

D.J. Roberts
Senior Resident Inspector (CNS)
U.S. Nuclear Regulatory Commission
Catawba Nuclear Station

P.S. Tam
NRC Senior Project Manager (CNS)
U.S. Nuclear Regulatory Commission
Mail Stop O-14H25
Washington, D.C. 20555-0001

Duke Power.
A Duke Energy Company

M. S. Tuckman
Executive Vice President
Nuclear Generation

Duke Power Company
A Duke Energy Company
EC07H
526 South Church Street
P.O. Box 1006
Charlotte, NC 28201-1006

(704) 382-2200 OFFICE
(704) 382-4360 FAX

April 19, 2000

U. S. Nuclear Regulatory Commission
ATTENTION: Document Control Desk
Washington D.C. 20555

Subject: Duke Energy Corporation
McGuire Nuclear Station, Units 1 and 2
Docket Nos. 50-369 and 370
Catawba Nuclear Station, Units 1 and 2
Docket Nos. 50-413 and 414
Topical Report DPC-NE-3002-A, Revision 4

Reference: Letter, Duke Energy Corporation to U.S. NRC, March 1, 2000, License Amendment Request for FOL and Technical Specification 1.1 Definitions - Dose Equivalent Iodine

Attached for review is Revision 4 to the Duke Energy Corporation Topical Report DPC-NE-3002-A, "UFSAR Chapter 15 Transient Analysis Methodology." This topical report revision consists of two minor changes, which are attached in the form of markups to three affected pages of the previously approved Revision 3 (NRC SER dated February 5, 1999). The approved version of Revision 3 was submitted to the NRC Document Control Desk on May 13, 1999.

The first change (see attached page 5-18) corrects the description of the primary coolant volume that is used in the UFSAR Section 15.4.6 Boron Dilution Accident Analysis for Mode 4 for Catawba Nuclear Station. The current topical report description of the primary coolant volume used in the analysis includes the Reactor Coolant System excluding the pressurizer, the pressurizer surge line, and the reactor vessel upper head. It was later determined that the correct minimum primary coolant volume for the

Mode 4 boron dilution analysis would include only those regions of the Reactor Coolant System which circulate during the residual heat removal mode. The proposed change reflects the correct minimum mixing volume. The need for this topical report change was identified during the Catawba UFSAR verification project, and will update DPC-NE-3002-A to be consistent with the UFSAR that was previously revised by Revision 6. The need for the topical report revision was not identified at the time that the UFSAR revision was implemented. The change in the methodology is a conservative change, in that the mixing volume for the Mode 4 boron dilution accident is being revised to a smaller volume. The results of the analysis continue to meet the acceptance criterion.

The second change (see attached pages 7-8 and 7-9) is required to support the above referenced Catawba FOL and Technical Specifications license amendment request (LAR). The referenced submittal describes reanalysis of the UFSAR Section 15.6.3 Steam Generator Tube Failure Accident for Catawba. The details of the reanalysis are not repeated in this submittal. The revisions in the attachment are necessary to support the reanalyses. The first part of this change involves an increase from two to three in the number of main steam line PORVs credited in the Catawba analysis. This change is consistent with the current Technical Specifications which requires all four main steam line PORVs to be operable, with one PORV being the limiting single failure. The second part of this change specifies three minute operator response times for depressurizing the primary system and for initiating safety injection termination. The topical report revisions are being submitted to maintain consistency with the referenced LAR submittal. These changes are not applicable to McGuire, and the revisions include separating the McGuire and Catawba methodology assumptions as necessary.

Approval of this topical report revision is requested concurrent with, or prior to, the approval of the referenced LAR submittal. This submittal has a requested review/approval date of September 1, 2000.

Please address any questions to J. S. Warren (704) 382-4986 or G. B. Swindlehurst (704) 382-5176.

Very truly yours,

M. S. Tuckman

M. S. Tuckman

Attachments

xc w/Attachments:

L. A. Reyes, Regional Administrator
U. S. Nuclear Regulatory Commission
Region II
Atlanta Federal Center
61 Forsyth St., SW, Suite 23T85
Atlanta, GA 30303

Mr. C. P. Patel, Project Manager (CNS)
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop O-8 H12
Washington, D. C. 20555-0001

Mr. F. Rinaldi, Project Manager (MNS)
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop O-8 H12
Washington, D. C. 20555-0001

Mr. D. J. Roberts
NRC Senior Resident Inspector
Catawba Nuclear Station

Mr. S. M. Shaeffer
NRC Senior Resident Inspector
McGuire Nuclear Station

bxc:

w/o Attachment
G. B. Swindlehurst
C. J. Thomas
M. T. Cash
K. L. Crane
G. D. Gilbert
K. E. Nicholson
T. K. Pasour (2)
J. S. Warren
ELL

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.

"Since the Technical Specifications allow for only a single train of the Residual Heat Removal System (RHRS) to be in operation, the Mode 4 dilution volume is assumed to be comprised of the reactor vessel (excluding the upper head), the RHR System, and portions of the hot and cold legs between the RHR inlet and outlet connections."

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

For McGuire,

For Catawba, three steam line PORVs on the intact steam generators are assumed to be operable

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).

For McGuire, initiate
- ~~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). For Catawba, this action is initiated 3 minutes after the primary system is 20°F subcooled (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.

- Initiate SI termination 3 minutes after completing the depressurization of the primary system (credit).

Duke Power.
A Duke Energy Company

M. S. Tuckman
Executive Vice President
Nuclear Generation

Duke Power Company
A Duke Energy Company
EC07H
526 South Church Street
P.O. Box 1006
Charlotte, NC 28201-1006

(704) 382-2200 OFFICE
(704) 382-4360 FAX

August 24, 2000

U. S. Nuclear Regulatory Commission
Washington D.C. 20555
ATTENTION: Document Control Desk

Subject: Duke Energy Corporation
Catawba Nuclear Station, Units 1 and 2
Docket Nos. 50-413 and 414
Topical Report DPC-NE-3002-A, Revision 4

Reference: Letter, Duke Energy Corporation to U.S. Nuclear Regulatory Commission, ATTENTION: Document Control Desk, Dated April 19, 2000, SUBJECT: Topical Report DPC-NE-3002-A, Revision 4

In the letter referenced above, Duke Energy Corporation submitted proposed Revision 4 to Topical Report DPC-NE-3002-A, *UFSAR Chapter 15 Transient Analysis Methodology*. Revision 4 specifies a three minute operator response time for depressurizing the primary system and for initiating safety injection termination following a steam generator tube rupture related to offsite dose. The proposed change in operator response time is consistent with that approved by an NRC Safety Evaluation dated April 29, 1997 for a steam generator tube rupture related to overfill. Following the April 19, 2000 submittal, the NRC asked several questions on the proposed change to the operator response times. These questions were discussed in a Duke/NRC telephone conference call held on August 22, 2000. The NRC questions, along with Duke's answers, are contained in the attachment to this letter.

Approval of this topical report revision is requested concurrent with, or prior to, the approval of a forthcoming related Catawba license amendment request that will revise the steam generator tube rupture licensing basis.

Please address any questions to J. S. Warren (704) 382-4986 or G. B. Swindlehurst (704) 382-5176.

Very truly yours,

M. S. Tuckman

M. S. Tuckman

Attachment

xc w/Attachment:

L. A. Reyes, Regional Administrator
U. S. Nuclear Regulatory Commission
Region II
Atlanta Federal Center
61 Forsyth St., SW, Suite 23T85
Atlanta, GA 30303

Mr. C. P. Patel, Project Manager (CNS)
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop O-8 H12
Washington, D. C. 20555-0001

Mr. F. Rinaldi, Project Manager (MNS)
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop O-8 H12
Washington, D. C. 20555-0001

Mr. D. J. Roberts
NRC Senior Resident Inspector
Catawba Nuclear Station

Mr. S. M. Shaeffer
NRC Senior Resident Inspector
McGuire Nuclear Station

bxc:

w/Attachment
G. B. Swindlehurst
C. J. Thomas
G. D. Gilbert
T. Baumgardner
K. E. Nicholson
T. K. Pasour (2)
J. S. Warren
ELL

Attachment 1

Duke Energy Corporation
Topical Report DPC-NE-3002-A, Revision 4
Response to NRC Questions Regarding Manual Actions Related to Steam Generator Tube Failure

Statement of NRC Questions:

In order to take credit for initiating depressurization of the primary system within 3 minutes after the primary system is 20% subcooled, and initiating SI termination 3 minutes after completing depressurization based on the April 29, 1997 Safety Evaluation, it is necessary to show that all conditions, information required, indications available and sequence of actions, etc., are identical or equivalent. Please describe the following items, or indicate that they are identical to the April 29, 1997 SE conditions, and describe any differences in them between the current event and that related to the April 29, 1997 SE:

- Control room conditions (e.g, alarms, peripheral activities being conducted)
- Information required by the operator to initiate each action
- Information required to know that the action has been successfully completed.
- Qualified displays providing the above information
- Sequence of actions leading up to, and to accomplish the intended result
- Procedures used to accomplish the actions
- Consequence of not accomplishing each action within the 3-minute time frame
- Risk significance of not accomplishing the actions
- Ability to recover from plausible errors in performance of manual actions, and the expected time required to make such a recovery

Attachment 1

Duke Responses:

- Control room conditions (e.g. alarms, peripheral activities being conducted):

  There are no changes to the available alarms and indications associated with either evolution. The conduct of control room activities is essentially the same. It is CNS practice to clear the control room of any unrelated activity at the onset of any significant event.

- Information required by the operator to initiate each action:

  The sequence leading into these evolutions has not changed. The operators are responding to the same indications and information.

- Information required to know that the action has been successfully completed:

  The actions are accomplished with control board devices, each of which has direct position indication associated with the device. In addition, the associated parameter, such as pressurizer pressure, pump current indication, and flow indications, are all available on the control boards, and have not changed since the original submittal.

- Qualified displays providing the above information:

  There are no changes to the displays used in either sequence. All are QA1 qualified instruments.

- Sequence of actions leading up to, and to accomplish the intended result:

  There is no change in the sequence leading up to the first sequence (initiating depressurization). There is no technical change to the method of actually initiating the depressurization (see discussion below for the procedural enhancements). There is no change to the second sequence (terminating safety injection).

Attachment 1

- Procedures used to accomplish the actions:

  The procedural guidance to initiate the depressurization has been enhanced to decrease the time needed to initiate the depressurization. All "notes" and "cautions" were removed from the sequence, since they were generic, operator knowledge items, and added no value to the sequence. The original procedure format required the operators to familiarize themselves with the depressurization termination criteria prior to initiating the depressurization (opening the PORV). The new sequence simply makes a quick verification of the parameters, and opens the PORV. A procedural "loop" is provided to continuously monitor the parameters as the primary pressure drops, and termination occurs when the correct values are achieved. Training on the changes were conducted in a recent operator requal segment, and the changes have been issued.

- Consequences of not accomplishing each action within the 3-minute time frame:

  Analysis indicates that the expected dose increase is approximately 1 rem (from 15 rem to 16 rem) for an increase from 3 to 5 minutes. This increase is considered insignificant and remains well below 10% of the 10CFR100 limit.

- Risk significance of not accomplishing the actions:

  The operator actions to depressurize the primary system and terminate safety injection are not independent. A delay in accomplishing the depressurization reduces the time available for terminating safety injection if steam generator overfill is to be prevented. The risk associated with steam generator overfill is judged to be small and the risk increase as a result of small delays in accomplishing these actions is judged to be insignificant.

Attachment 1

- Ability to recover from plausible errors in performance of manual actions, and the expected time required to make such a recovery:

  As noted above, each action is accomplished with control board devices that have both direct indication of the component status, and control board indication of the affected parameters. During these evolutions, these parameters are the direct focus of the control room team. Recognition of any error would be almost immediate. The devices employed to accomplish the results are simple switches and pushbuttons, meaning that recovery would neither be difficult nor time consuming.

Duke Power.
A Duke Energy Company

M. S. Tuckman
Executive Vice President
Nuclear Generation

Duke Power Company
A Duke Energy Company
EC07H
526 South Church Street
P.O. Box 1006
Charlotte, NC 28201-1006

(704) 382-2200 OFFICE
(704) 382-4360 FAX

September 22, 2000

U. S. Nuclear Regulatory Commission
Washington D.C. 20555
ATTENTION: Document Control Desk

Subject: Duke Energy Corporation
Catawba Nuclear Station, Units 1 and 2
Docket Nos. 50-413 and 414
Topical Report DPC-NE-3002-A, Revision 4

Reference: 1) Letter, Duke Energy Corporation to U.S. Nuclear Regulatory Commission, ATTENTION: Document Control Desk, Dated April 19, 2000, SUBJECT: Topical Report DPC-NE-3002-A, Revision 4

2) Letter, Duke Energy Corporation to U.S. Nuclear Regulatory Commission, ATTENTION: Document Control Desk, Dated August 24, 2000, SUBJECT: Topical Report DPC-NE-3002-A, Revision 4

In Reference 1 and supplemented in Reference 2, Duke Energy Corporation submitted proposed Revision 4 to Topical Report DPC-NE-3002-A, *UFSAR Chapter 15 Transient Analysis Methodology*. Revision 4 specifies a three minute operator response time for depressurizing the primary system and for initiating safety injection termination following a steam generator tube rupture related to offsite dose. Following the submittals referenced above, the NRC asked additional questions on the proposed change to the operator response times. These questions were discussed in a Duke/NRC telephone conference call held on September 19, 2000. This conference call identified the need for additional changes to be included in the proposed Revision 4. These additional changes clarify the differences between McGuire and Catawba in regard to responding to the steam generator tube rupture event. The necessary clarifications have

been made and are included on the attached revised mark-up of Page 7-9 of Topical Report DPC-NE-3002-A. Following NRC approval of the proposed Revision 4, Duke will reissue this document in final form and submit it to the NRC in accordance with the guidance of NEREG-0390.

Duke is maintaining the originally requested approval date for this topical report revision. Approval is requested concurrent with, or prior to, the approval of a forthcoming related Catawba license amendment request that will revise the steam generator tube rupture licensing basis.

Please address any questions to J. S. Warren (704) 382-4986 or G. B. Swindlehurst (704) 382-5176.

Very truly yours,

M. S. Tuckman

M. S. Tuckman

Attachment

xc w/Attachment:

L. A. Reyes, Regional Administrator
U. S. Nuclear Regulatory Commission
Region II
Atlanta Federal Center
61 Forsyth St., SW, Suite 23T85
Atlanta, GA 30303

Mr. C. P. Patel, Project Manager (CNS)
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop O-8 H12
Washington, D. C. 20555-0001

Mr. D. J. Roberts
NRC Senior Resident Inspector
Catawba Nuclear Station

bxc:

<u>w/Attachment</u>
G. B. Swindlehurst
C. J. Thomas
G. D. Gilbert
T. Baumgardner
M. H. Chernoff
K. E. Nicholson
T. K. Pasour (2)
J. S. Warren
ELL

- Identify and isolate ruptured steam generator consistent with assumptions in WCAP-10698 (Reference 5). 15 minute minimum delay (credit).

For Catawba, isolate the

- ~~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).
(Catawba) (McGuire)

- Manually control auxiliary feedwater to maintain zero power steam generator levels (nominal).

(Catawba) 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)~~. (McGuire)

For McGuire, initiate

- ~~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). For Catawba, this action is initiated 3 minutes after the primary system is 20°F subcooled (credit).

- Initiate SI termination 3 minutes after completing the depressurization of the primary system (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.

Duke Power.
A Duke Energy Company

M. S. Tuckman
Executive Vice President
Nuclear Generation

Duke Power
526 South Church St. EC07H
Charlotte, NC 28202
P. O. Box 1006 EC07H
Charlotte, NC 28201-1006
(704) 382-2200 OFFICE
(704) 382-4360 FAX

March 21, 2001

U. S. Nuclear Regulatory Commission
Washington D.C. 20555-0001
ATTENTION: Document Control Desk

Subject: Duke Energy Corporation
Catawba Nuclear Station, Units 1 and 2
Docket Nos. 50-413 and 414
Topical Report DPC-NE-3002, Revision 4

Reference: 1) Letter, Duke Energy Corporation to U.S. Nuclear Regulatory Commission, ATTENTION: Document Control Desk, Dated April 19, 2000, SUBJECT: Topical Report DPC-NE-3002, Revision 4

2) Letter, Duke Energy Corporation to U.S. Nuclear Regulatory Commission, ATTENTION: Document Control Desk, Dated August 24, 2000, SUBJECT: Topical Report DPC-NE-3002, Revision 4

3) Letter, Duke Energy Corporation to U.S. Nuclear Regulatory Commission, ATTENTION: Document Control Desk, Dated September 22, 2000, SUBJECT: Topical Report DPC-NE-3002, Revision 4

In the letters referenced above, Duke Energy Corporation submitted proposed Revision 4 to Topical Report DPC-NE-3002, *UFSAR Chapter 15 Transient Analysis Methodology*. In order to support the NRC's review and approval of this topical report, Duke is submitting the attached Catawba Procedure EP/1/A/5000/E-3, *Steam Generator Tube Rupture*.

Please address any questions to J. S. Warren at (704) 382-4986.

Very truly yours,

M. S. Tuckman

M. S. Tuckman

Attachment

xc w/Attachment:

L. A. Reyes, Regional Administrator
U. S. Nuclear Regulatory Commission
Region II
Atlanta Federal Center
61 Forsyth St., SW, Suite 23T85
Atlanta, GA 30303

Mr. C. P. Patel, Project Manager (CNS)
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop O-8 H12
Washington, D. C. 20555-0001

Mr. D. J. Roberts
NRC Senior Resident Inspector
Catawba Nuclear Station

bxc:

w/o Attachment
G. B. Swindlehurst
C. J. Thomas
G. D. Gilbert
T. Baumgardner
M. H. Chernoff
K. E. Nicholson
T. K. Pasour (2)
J. S. Warren
ELL