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

February 7, 2014

Mr. Michael J. Pacilio
Senior Vice President
Exelon Generation Company, LLC
President and Chief Nuclear Officer (CNO)
Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: BRAIDWOOD STATION, UNITS 1 AND 2, AND BYRON STATION, UNIT NOS. 1 AND 2 - ISSUANCE OF AMENDMENTS REGARDING MEASUREMENT UNCERTAINTY RECAPTURE POWER UPRATE (TAC NOS. MF2418, MF2419, MF2420, AND MF2421)

Dear Mr. Pacilio:

The U.S. Nuclear Regulatory Commission (the Commission) has issued the enclosed Amendment No. 174 to Facility Operating License, No. NPF-72, and Amendment No. 174 to Facility Operating License, No. NPF-77, for the Braidwood Station, Units 1 and 2, respectively, and Amendment No. 181 to Facility Operating License, No. NPF-37, and Amendment No. 181 to Facility Operating License, No. NPF-66, for the Byron Station, Unit Nos. 1 and 2, respectively. The amendments are in response to your application dated June 23, 2011, as supplemented by letters dated August 25, November 1, and December 9, 2011; February 20, March 5, March 30 (two letters), April 27, May 16, June 26, August 8, September 13, and October 9, 2012; and July 5, September 5, October 8, October 24, November 13, and November 18, 2013.

A copy of the Safety Evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

Chris L. Peabody for

Joel S. Wiebe, Senior Project Manager
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. STN 50-456, STN 50-457,
STN 50-454 and STN 50-455

Enclosures:
1. Amendment No. 174 to NPF-72
2. Amendment No. 174 to NPF-77
3. Amendment No. 181 to NPF-37
4. Amendment No. 181 to NPF-66
5. Safety Evaluation

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

EXELON GENERATION COMPANY, LLC

DOCKET NO. STN 50-456

BRAIDWOOD STATION, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 174
License No. NPF-72

1. The U.S. Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Exelon Generation Company, LLC (the licensee) dated June 23, 2011, as supplemented by letters dated August 25, November 1, and December 9, 2011; February 20, March 5, March 30 (two letters), April 27, May 16, June 26, August 8, September 13, and October 9, 2012; and July 5, September 5, October 8, October 24, November 13, and November 18, 2013, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, by changes to the Technical Specifications as indicated in the attachment to this license amendment and the following paragraphs the Facility Operating License No. NPF-72 is hereby amended to read as follows:

A. Paragraph 2.C.(1):

Maximum Power Level

The licensee is authorized to operate the facility at reactor core power levels not in excess of 3645 megawatts thermal (100 percent rated power) in accordance with the conditions specified herein and other items identified in Attachment 1 to this license. The items identified in Attachment 1 to this license shall be completed as specified. Attachment 1 is hereby incorporated into this license.

B. Paragraph 2.C.(2)

Technical Specifications

The Technical Specifications contained in Appendix A as revised through Amendment No. 174 and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, are hereby incorporated into the license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 180 days of the date of issuance. The licensee shall fulfill the Regulatory Commitments as identified in Attachment 4 of its June 23, 2011, license amendment request.

FOR THE NUCLEAR REGULATORY COMMISSION

Michele G. Evans

Michele G. Evans, Director
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical
Specifications and Facility Operating License

Date of Issuance: February 7, 2014

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

EXELON GENERATION COMPANY, LLC

DOCKET NO. STN 50-457

BRAIDWOOD STATION, UNIT 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 174
License No. NPF-77

1. The U.S. Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Exelon Generation Company, LLC (the licensee) dated June 23, 2011, as supplemented by letters dated August 25, November 1, and December 9, 2011; February 20, March 5, March 30 (two letters), April 27, May 16, June 26, August 8, September 13, and October 9, 2012; and July 5, September 5, October 8, October 24, November 13, and November 18, 2013, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, by changes to the Technical Specifications as indicated in the attachment to this license amendment and the following paragraphs the Facility Operating License No. NPF-77 is hereby amended to read as follows:

A. Paragraph 2.C.(1):

Maximum Power Level

The licensee is authorized to operate the facility at reactor core power levels not in excess of 3645 megawatts thermal (100 percent rated power) in accordance with the conditions specified herein and other items identified in Attachment 1 to this license. The items identified in Attachment 1 to this license shall be completed as specified. Attachment 1 is hereby incorporated into this license.

B. Paragraph 2.C.(2)

Technical Specifications

The Technical Specifications contained in Appendix A as revised through Amendment No. 174 and the Environmental Protection Plan contained in Appendix B, both of which are attached to License No. NPF-72, dated July 2, 1987, are hereby incorporated into this license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 180 days of the date of issuance. The licensee shall fulfill the Regulatory Commitments as identified in Attachment 4 of its June 23, 2011, license amendment request.

FOR THE NUCLEAR REGULATORY COMMISSION

Michele G. Evans

Michele G. Evans, Director
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical
Specifications and Facility Operating License

Date of Issuance: Febraury 7,2014

ATTACHMENT TO LICENSE AMENDMENT NOS. 174 AND 174

FACILITY OPERATING LICENSE NOS. NPF-72 AND NPF-77

DOCKET NOS. STN 50-456 AND STN 50-457

Replace the following pages of the Facility Operating Licenses and Appendix "A" Technical Specifications with the attached pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove	Insert
License NPF-72	License NPF-72
Page 3	Page 3
License NPF-77	License NPF-77
Page 3	Page 3
TSs	TSs
Page 1.1-6	Page 1.1-6
Page 2.0-1	Page 2.0-1
Page 3.4.1-1	Page 3.4.1-1
Page 3.4.1-2	Page 3.4.1-2
Page 5.6-4	Page 5.6-4

(3) Exelon Generation Company, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use at any time any byproduct, source and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) Exelon Generation Company, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(5) Exelon Generation Company, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to possess but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. The license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

The licensee is authorized to operate the facility at reactor core power levels not in excess of 3645 megawatts thermal (100 percent rated power) in accordance with the conditions specified herein and other items identified in Attachment 1 to this license. The items identified in Attachment 1 to this license shall be completed as specified. Attachment 1 is hereby incorporated into this license.

(2) Technical Specifications

The Technical Specifications contained in Appendix A as revised through Amendment No. 174 and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, are hereby incorporated into the license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Emergency Planning

In the event that the NRC finds that the lack of progress in completion of the procedures in the Federal Emergency Management Agency's final rule, 44 CFR Part 350, is an indication that a major substantive problem exists in achieving or maintaining an adequate state of emergency preparedness, the provision of 10 CFR Section 50.54(s)(2) will apply.

material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) Exelon Generation Company, LLC pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(5) Exelon Generation Company, LLC pursuant to the Act and 10 CFR Parts 30, 40 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. The license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

The licensee is authorized to operate the facility at reactor core power levels not in excess of 3645 megawatts thermal (100 percent rated power) in accordance with the conditions specified herein and other items identified in Attachment 1 to this license. The items identified in Attachment 1 to this license shall be completed as specified. Attachment 1 is hereby incorporated into this license.

(2) Technical Specifications

The Technical Specifications contained in Appendix A as revised through Amendment No. 174 and the Environmental Protection Plan contained in Appendix B, both of which are attached to License No. NPF-72, dated July 2, 1987, are hereby incorporated into this license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Emergency Planning

In the event that the NRC finds that the lack of progress in completion of the procedures in the Federal Emergency Management Agency's final rule, 44 CFR Part 350, is an indication that a major substantive problem exists in achieving or maintaining an adequate state of emergency preparedness, the provision of 10 CFR Section 50.54(s)(2) will apply.

1.1 Definitions

PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)	The PTLR is the unit specific document that provides the reactor vessel pressure and temperature limits including heatup and cooldown rates, and the pressurizer Power Operated Relief Valve (PORV) lift settings for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.6.6.
QUADRANT POWER TILT RATIO (QPTR)	QPTR shall be the ratio of the maximum upper excore detector calibrated output to the average of the upper excore detector calibrated outputs, or the ratio of the maximum lower excore detector calibrated output to the average of the lower excore detector calibrated outputs, whichever is greater.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3645 MWt.
REACTOR TRIP SYSTEM (RTS) RESPONSE TIME	The RTS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its RTS trip setpoint at the channel sensor until loss of stationary gripper coil voltage. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.
RECENTLY IRRADIATED FUEL	Fuel that has occupied part of a critical reactor core within the previous 48 hours. Note that all fuel that has been in a critical reactor core is referred to as irradiated fuel.

2.0 SAFETY LIMITS (SLs)

2.1 SLs

2.1.1 Reactor Core SLs

In MODES 1 and 2, the combination of THERMAL POWER, Reactor Coolant System (RCS) highest loop average temperature, and pressurizer pressure shall not exceed the limits specified in the COLR; and the following SLs shall not be exceeded.

2.1.1.1 In MODE 1, the Departure from Nucleate Boiling Ratio (DNBR) shall be maintained ≥ 1.24 for the WRB-2 DNB correlation for a thimble cell, ≥ 1.25 for the WRB-2 DNB correlation for a typical cell and ≥ 1.19 for the ABB-NV DNB correlation for a thimble cell and a typical cell.

2.1.1.2 In MODE 2, the DNBR shall be maintained ≥ 1.17 for the WRB-2 DNB correlation, and ≥ 1.13 for the ABB-NV DNB correlation and ≥ 1.18 for the WLOP DNB correlation.

2.1.1.3 In MODES 1 and 2, the peak fuel centerline temperature shall be maintained as follows:

a. < 5080°F decreasing by 58°F per 10,000 MWD/MTU burnup for Westinghouse fuel,

b. < 5173°F decreasing by 65°F per 10,000 MWD/MTU burnup for AREVA NP fuel (Unit 1 only), and

c. < 5189°F decreasing by 65°F per 10,000 MWD/MTU burnup for AREVA NP fuel containing Gadolinia (Unit 1 only).

2.1.2 RCS Pressure SL

In MODES 1, 2, 3, 4, and 5, the RCS pressure shall be maintained ≤ 2735 psig.

2.2 SL Violations

2.2.1 If SL 2.1.1 is violated, restore compliance and be in MODE 3 within 1 hour.

2.2.2 If SL 2.1.2 is violated:

2.2.2.1 In MODE 1 or 2, restore compliance and be in MODE 3 within 1 hour.

2.2.2.2 In MODE 3, 4, or 5, restore compliance within 5 minutes.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

LCO 3.4.1 RCS DNB parameters for pressurizer pressure, RCS average temperature (T_{avg}), and RCS total flow rate shall be within the limits specified below:

a. Pressurizer pressure within the limit specified in the COLR;

b. RCS average temperature (T_{avg}) within the limit specified in the COLR; and

c. RCS total flow rate ≥ 386,000 gpm and within the limit specified in the COLR.

----------NOTE----------
Pressurizer pressure limit does not apply during:

a. THERMAL POWER ramp > 5% RTP per minute; or

b. THERMAL POWER step > 10% RTP.

APPLICABILITY: MODE 1.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more RCS DNB parameters not within limits.	A.1	Restore RCS DNB parameter(s) to within limit.	2 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	Verify pressurizer pressure is within the limit specified in the COLR.	In accordance with the Surveillance Frequency Control Program
SR 3.4.1.2	Verify RCS average temperature (T_{avg}) is within the limit specified in the COLR.	In accordance with the Surveillance Frequency Control Program
SR 3.4.1.3	Verify RCS total flow rate is ≥ 386,000 gpm and within the limit specified in the COLR.	In accordance with the Surveillance Frequency Control Program
SR 3.4.1.4	----------NOTE---------- Not required to be performed until 7 days after ≥ 90% RTP. ---------- Verify by precision heat balance that RCS total flow rate is ≥ 386,000 gpm and within the limit specified in the COLR.	In accordance with the Surveillance Frequency Control Program

5.6 Reporting Requirements

5.6.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

5. ComEd letter from D. Saccomando to the Office of Nuclear Reactor Regulation dated December 21, 1994, transmitting an attachment that documents applicable sections of WCAP-11992/11993 and ComEd application of the UET methodology addressed in "Additional Information Regarding Application for Amendment to Facility Operating Licenses-Reactivity Control Systems."

6. WCAP-16009-P-A, Revision 0, "Realistic Large-Break LOCA Evaluation Methodology Using the Automated Statistical Treatment of Uncertainty Method (ASTRUM)," January 2005.

7. WCAP-10079-P-A, "NOTRUMP, A Nodal Transient Small Break and General Network Code," August 1985.

8. WCAP-10054-P-A, "Westinghouse Small Break ECCS Evaluation Model using NOTRUMP Code," August 1985.

9. WCAP-10216-P-A, Revision 1, "Relaxation of Constant Axial Offset Control - F_Q Surveillance Technical Specification," February 1994.

10. WCAP-8745-P-A, "Design Bases for the Thermal Overpower ΔT and Thermal Overtemperature ΔT Trip Functions," September 1986.

11. WCAP-14565-P-A, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," October 1999;

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met; and

d. The COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

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

EXELON GENERATION COMPANY, LLC

DOCKET NO. STN 50-454

BYRON STATION, UNIT NO. 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 181
License No. NPF-37

1. The U.S. Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Exelon Generation Company, LLC (the licensee) dated June 23, 2011, as supplemented by letters dated August 25, November 1, and December 9, 2011; February 20, March 5, March 30 (two letters), April 27, May 16, June 26, August 8, September 13, and October 9, 2012; and July 5, September 5, October 8, October 24, November 13, and November 18, 2013, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, by changes to the Technical Specifications as indicated in the attachment to this license amendment and the following paragraphs the Facility Operating License No. NPF-37 is hereby amended to read as follows:

A. Paragraph 2.C.(1):

Maximum Power Level

The licensee is authorized to operate the facility at reactor core power levels not in excess of 3645 megawatts thermal (100 percent rated power) in accordance with the conditions specified herein.

B. Paragraph 2.C.(2)

Technical Specifications

The Technical Specifications contained in Appendix A as revised through Amendment No. 181 and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, are hereby incorporated into this license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 180 days of the date of issuance. The licensee shall fulfill the Regulatory Commitments as identified in Attachment 4 of its June 23, 2011, license amendment request.

FOR THE NUCLEAR REGULATORY COMMISSION

Michele G. Evans

Michele G. Evans, Director
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical
Specifications and Facility Operating License

Date of Issuance: Febraury 7, 2014

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

EXELON GENERATION COMPANY, LLC

DOCKET NO. STN 50-455

BYRON STATION, UNIT NO. 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 181
License No. NPF-66

1. The U.S. Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Exelon Generation Company, LLC (the licensee) dated June 23, 2011, as supplemented by letters dated August 25, November 1, and December 9, 2011; February 20, March 5, March 30 (two letters), April 27, May 16, June 26, August 8, September 13, and October 9, 2012; and July 5, September 5, October 8, October 24, November 13, and November 18, 2013, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, by changes to the Technical Specifications as indicated in the attachment to this license amendment and the following paragraphs the Facility Operating License No. NPF-66 is hereby amended to read as follows:

A. Paragraph 2.C.(1):

Maximum Power Level

The licensee is authorized to operate the facility at reactor core power levels not in excess of 3645 megawatts thermal (100 percent rated power) in accordance with the conditions specified herein.

B. Paragraph 2.C.(2)

Technical Specifications

The Technical Specifications contained in Appendix A (NUREG-1113), as revised through Amendment No. 181 and the Environmental Protection Plan contained in Appendix B, both of which were attached to License No. NPF-37, dated February 14, 1985, are hereby incorporated into this license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 180 days of the date of issuance. The licensee shall fulfill the Regulatory Commitments as identified in Attachment 4 of its June 23, 2011, license amendment request.

FOR THE NUCLEAR REGULATORY COMMISSION

Michele G. Evans

Michele G. Evans, Director
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical
Specifications and Facility Operating License

Date of Issuance: Febraury 7, 2014

ATTACHMENT TO LICENSE AMENDMENT NOS. 181 AND 181

FACILITY OPERATING LICENSE NOS. NPF-37 AND NPF-66

DOCKET NOS. STN 50-454 AND STN 50-455

Replace the following pages of the Facility Operating License and Appendix A Technical Specifications with the attached pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove	Insert
License NPF-37	License NPF-37
Page 3	Page 3
License NPF-66	License NPF-66
Page 3	Page 3
TSs	TSs
Page 1.1-6	Page 1.1-6
Page 2.0-1	Page 2.0-1
Page 3.4.1-1	Page 3.4.1-1
Page 3.4.1-2	Page 3.4.1-2
Page 5.6-4	Page 5.6-4

(4) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use in amounts as required any byproduct, source and special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(5) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

The licensee is authorized to operate the facility at reactor core power levels not in excess of 3645 megawatts thermal (100 percent power) in accordance with the conditions specified herein.

(2) Technical Specifications

The Technical Specifications contained in Appendix A as revised through Amendment No. 181 and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, are hereby incorporated into this license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Deleted.

(4) Deleted.

(5) Deleted.

(6) The license shall implement and maintain in effect all provisions of the approved fire protection program as described in the licensee's Fire Protection Report, and as approved in the SER dated February 1987 through Supplement No. 8, subject to the following provision:

> The licensee may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

(3) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use at any time any byproduct, source and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(5) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. The license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

The licensee is authorized to operate the facility at reactor core power levels not in excess of 3645 megawatts thermal (100 percent rated power) in accordance with the conditions specified herein.

(2) Technical Specifications

The Technical Specifications contained in Appendix A (NUREG-1113), as revised through Amendment No. 181 and the Environmental Protection Plan contained in Appendix B, both of which were attached to License No. NPF-37, dated February 14, 1985, are hereby incorporated into this license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Deleted.

(4) Deleted.

(5) Deleted.

1.1 Definitions

PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)	The PTLR is the unit specific document that provides the reactor vessel pressure and temperature limits including heatup and cooldown rates, and the pressurizer Power Operated Relief Valve (PORV) lift settings for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.6.6.
QUADRANT POWER TILT RATIO (QPTR)	QPTR shall be the ratio of the maximum upper excore detector calibrated output to the average of the upper excore detector calibrated outputs, or the ratio of the maximum lower excore detector calibrated output to the average of the lower excore detector calibrated outputs, whichever is greater.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3645 MWt.
REACTOR TRIP SYSTEM (RTS) RESPONSE TIME	The RTS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its RTS trip setpoint at the channel sensor until loss of stationary gripper coil voltage. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.
RECENTLY IRRADIATED FUEL	Fuel that has occupied part of a critical reactor core within the previous 48 hours. Note that all fuel that has been in a critical reactor core is referred to as irradiated fuel.

2.0 SAFETY LIMITS (SLs)

2.1 SLs

2.1.1 Reactor Core SLs

In MODES 1 and 2, the combination of THERMAL POWER, Reactor Coolant System (RCS) highest loop average temperature, and pressurizer pressure shall not exceed the limits specified in the COLR; and the following SLs shall not be exceeded.

2.1.1.1 In MODE 1, the Departure from Nucleate Boiling Ratio (DNBR) shall be maintained ≥ 1.24 for the WRB-2 DNB correlation for a thimble cell, ≥ 1.25 for the WRB-2 DNB correlation for a typical cell and ≥ 1.19 for the ABB-NV DNB correlation for a thimble cell and a typical cell.

2.1.1.2 In MODE 2, the DNBR shall be maintained ≥ 1.17 for the WRB-2 DNB correlation, and ≥ 1.13 for the ABB-NV DNB correlation and ≥ 1.18 for the WLOP DNB correlation.

2.1.1.3 In MODES 1 and 2, the peak fuel centerline temperature shall be maintained < 5080°F, decreasing by 58°F per 10,000 MWD/MTU burnup.

2.1.2 RCS Pressure SL

In MODES 1, 2, 3, 4, and 5, the RCS pressure shall be maintained ≤ 2735 psig.

2.2 SL Violations

2.2.1 If SL 2.1.1 is violated, restore compliance and be in MODE 3 within 1 hour.

2.2.2 If SL 2.1.2 is violated:

2.2.2.1 In MODE 1 or 2, restore compliance and be in MODE 3 within 1 hour.

2.2.2.2 In MODE 3, 4, or 5, restore compliance within 5 minutes.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

LCO 3.4.1 RCS DNB parameters for pressurizer pressure, RCS average temperature (T_{avg}), and RCS total flow rate shall be within the limits specified below:

a. Pressurizer pressure within the limit specified in the COLR;

b. RCS average temperature (T_{avg}) within the limit specified in the COLR; and

c. RCS total flow rate ≥ 386,000 gpm and within the limit specified in the COLR.

----------NOTE----------
Pressurizer pressure limit does not apply during:

a. THERMAL POWER ramp > 5% RTP per minute; or

b. THERMAL POWER step > 10% RTP.

APPLICABILITY: MODE 1.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more RCS DNB parameters not within limits.	A.1 Restore RCS DNB parameter(s) to within limit.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	Verify pressurizer pressure is within the limit specified in the COLR.	In accordance with the Surveillance Frequency Control Program
SR 3.4.1.2	Verify RCS average temperature (T_{avg}) is within the limit specified in the COLR.	In accordance with the Surveillance Frequency Control Program
SR 3.4.1.3	Verify RCS total flow rate is ≥ 386,000 gpm and within the limit specified in the COLR.	In accordance with the Surveillance Frequency Control Program
SR 3.4.1.4	----------NOTE---------- Not required to be performed until 7 days after ≥ 90% RTP. ---------- Verify by precision heat balance that RCS total flow rate is ≥ 386,000 gpm and within the limit specified in the COLR.	 In accordance with the Surveillance Frequency Control Program

5.6 Reporting Requirements

5.6.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

5. ComEd letter from D. Saccomando to the Office of Nuclear Reactor Regulation dated December 21, 1994, transmitting an attachment that documents applicable sections of WCAP-11992/11993 and ComEd application of the UET methodology addressed in "Additional Information Regarding Application for Amendment to Facility Operating Licenses-Reactivity Control Systems."

6. WCAP-16009-P-A, Revision 0, "Realistic Large-Break LOCA Evaluation Methodology Using the Automated Statistical Treatment of Uncertainty Method (ASTRUM)," January 2005.

7. WCAP-10079-P-A, "NOTRUMP, A Nodal Transient Small Break and General Network Code," August 1985.

8. WCAP-10054-P-A, "Westinghouse Small Break ECCS Evaluation Model using NOTRUMP Code," August 1985.

9. WCAP-10216-P-A, Revision 1, "Relaxation of Constant Axial Offset Control - F_Q Surveillance Technical Specification," February 1994.

10. WCAP-8745-P-A, "Design Bases for the Thermal Overpower ΔT and Thermal Overtemperature ΔT Trip Functions," September 1986.

11. WCAP-14565-P-A, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," October 1999;

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met; and

d. The COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 174 TO FACILITY OPERATING LICENSE NO. NPF-72,

AMENDMENT NO. 174 TO FACILITY OPERATING LICENSE NO. NPF-77,

AMENDMENT NO. 181 TO FACILITY OPERATING LICENSE NO. NPF-37,

AND AMENDMENT NO. 181 TO FACILITY OPERATING LICENSE NO. NPF-66

EXELON GENERATION COMPANY, LLC

BRAIDWOOD STATION, UNITS 1 AND 2

BYRON STATION, UNIT NOS. 1 AND 2

DOCKET NOS. STN 50-456, STN 50-457,

STN 50-454, AND STN 50-455,

1.0 INTRODUCTION

By Application to the U.S. Nuclear Regulatory Commission (NRC, the Commission) dated June 23, 2011 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML111790026), as supplemented by letters dated August 25, November 1, and December 9, 2011; February 20, March 5, March 30 (two letters), April 27, May 16, June 26, August 8, September 13, and October 9, 2012; and July 5, September 5, October 8, October 24, November 13, and November 18, 2013 (ADAMS Accession Nos. ML11255A332, ML113050427, ML113430811, ML12052A113, ML12066A052, ML12093A242, ML12096A051, ML12121A496, ML12138A091, ML12178A294, ML12222A037, ML12258A330, ML12285A087, ML13186A178, ML13248A519, ML13281A819, ML13298A477, ML13318A232, and ML13324A94, respectively), Exelon Generation Company, LLC (Exelon, the licensee) requested changes to the technical specifications (TSs) and facility operating licenses for Braidwood Station (Braidwood), Units 1 and 2, and Byron Station (Byron), Unit Nos. 1 and 2. Portions of the June 23, 2011, application and December 9, 2012, letter contain sensitive unclassified non-safeguards information and, accordingly, have been withheld from public disclosure in accordance with 10 CFR Part 2, 2.350. The supplemental letters dated August 25, November 1, and December 9, 2011; February 20, March 5, March 30 (two letters), April 27, May 16, June 26, August 8, September 13, and October 9, 2012; and July 5, September 5, October 8, October 24, November 13, and November 18, 2013, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the staff's original proposed no significant hazards consideration determination as published in the Federal Register on December 6, 2011 (77 FR 28630).

Enclosure

The proposed changes would increase the maximum steady-state reactor core power level from 3586.6 megawatts thermal (MWt) to 3645 MWt, which is an increase of approximately 1.63 percent. In addition to the above changes, the June 23, 2011, application as supplemented by the licensee's letter dated August 8, 2012, included a revised steam generator tube rupture (SGTR) and margin to overfill (MTO) analysis that was submitted for NRC approval and is evaluated in this safety evaluation. This revised analysis was performed as the MTO values in the current analysis of record (AOR) are unacceptably small and revisions to the analysis assumptions are necessary. Specifically, the licensee proposes to revise the TSs:

- Definition Section 1.1 to change the definition of RATED THERMAL POWER;
- Safety Limits (SLs) 2.1.1.1 and 2.1.1.2 to modify the departure from nucleate boiling (DNB) ratio and use of DNB correlations;
- Limiting Condition for Operation (LCO) 3.4.1.C to modify the reactor coolant system (RCS) total flow rate for measurement uncertainty recapture (MUR) uprated power conditions;
- Surveillance Requirements (SRs) 3.4.1.3 and 3.4.1.4 to modify the RCS total flow rate for MUR uprated power conditions, and
- TS 5.6.5 to add analytical methods used to determine the core operating limit.

2.0 REGULATORY EVALUATION

2.1 Measurement Uncertainty Recapture (MUR) Power Uprate (PU)

Nuclear power plants are licensed to operate at a specified maximum core thermal power, often called RTP [reactor thermal power]. In Section 50.46 of Title 10 to the *Code of Federal Regulations* (10 CFR), "Acceptance criteria for emergency core cooling systems for light-water nuclear power reactors," the NRC requires that emergency core cooling system (ECCS) performance under loss of coolant accident (LOCA) conditions be evaluated and that the estimated performance satisfy certain criteria. Licensees may conduct an analysis that "realistically describes the behavior of the reactor system during a LOCA" (often termed a "best-estimate analysis"), or they may develop a model that conforms with the requirements of Appendix K, "ECCS Evaluation Models," 10 CFR Part 50. Most ECCS evaluations are based on Appendix K requirements.

Appendix K, "[Emergency Core Cooling System] ECCS Evaluation Models," of 10 CFR Part 50, formerly required licensees to assume that the reactor has been operating continuously at a power level at least 1.02 times the licensed power level when performing LOCA and ECCS analyses. This requirement was included to ensure that instrumentation uncertainties were adequately accounted for in the safety analyses. In practice, many of the design bases analyses assumed a 2 percent power uncertainty, consistent with 10 CFR Part 50, Appendix K. The NRC staff considers the assumed power level to be an input parameter of the ECCS evaluation.

In existing nuclear power plants, the neutron flux instrumentation continuously indicates the reactor core thermal power. This instrumentation must be periodically calibrated to accommodate the effects of fuel burnup, flux pattern changes, and instrumentation setpoint drift. The reactor core thermal power generated by a nuclear power plant is determined by steam plant calorimetry, which is the process of performing a heat balance around the nuclear steam supply system (called a calorimetric). The accuracy of this calculation depends primarily upon the accuracy of feedwater (FW) flow rate and net enthalpy

measurements. As such, an accurate measurement of FW flow rate and temperature is necessary for an accurate calibration of the nuclear instrumentation. Of the two parameters, flow rate and temperature, the most important in terms of calibration sensitivity is the FW flow rate.

The originally installed instruments for measuring FW flow rate in existing nuclear power plants were usually a venturi or a flow nozzle, each of which generates a differential pressure proportional to the FW velocity in the pipe. Of the two, the venturi was the most widely used because of relatively low head loss. However, error in determination of flow rate is introduced due to venturi fouling and, to a lesser extent, flow nozzle fouling, the transmitter, and the analog-to-digital converter.[1]

Because of the desire to reduce flow instrumentation uncertainty to enable operation of the plant at a higher power while remaining within the licensed rating, the industry assessed alternate flow rate measurement techniques and found that ultrasonic flow meter (UFMs) are a viable alternative. UFMs are based on computer-controlled electronic transducers that do not have differential pressure elements that are susceptible to fouling. Caldon, Inc. (now part of Cameron Measurement Systems) developed a UFM called a "leading edge flow meter" and named it the LEFM Check system. It followed this system with the LEFM CheckPlus system, which consists essentially of two Check systems in the same spool piece and provides a more accurate FW flow measurement than the Check system. Both of these UFMs have demonstrated better measurement accuracies than the differential pressure type instruments and provide on-line verification to ensure that the UFM is operating within its uncertainty bounds.

A change to the Commission's regulations at 10 CFR Part 50, Appendix K, was published in the Federal Register on June 1, 2000 (65 FR 34913), which became effective July 31, 2000. This change allows licensees to use a power level less than 1.02 times the RTP for the LOCA and ECCS analyses, but not a power level less than the licensed power level, based on the use of state-of-the art FW flow measurement devices that provide a more accurate calculation of power. Licensees can use a lower uncertainty in the LOCA and ECCS analyses provided that the licensee has demonstrated that the proposed value adequately accounts for instrumentation uncertainties. As there continues to be substantial conservatism in other Appendix K requirements, sufficient margin to ECCS performance in the event of a LOCA is preserved.

However, this change to 10 CFR Part 50, Appendix K, did not authorize increases in licensed power levels for individual nuclear power plants. As the licensed power level for a plant is contained in its operating license, licensees seeking to raise the licensed power level must submit a license amendment request (LAR) which must be reviewed and approved by the NRC staff. Braidwood, Units 1 and 2, and Byron, Unit Nos. 1 and 2, are currently licensed to operate at a maximum power level of 3586.6 MWt, which includes a 2 percent margin in the ECCS evaluation model to allow for uncertainties in RTP measurement. The LAR proposes to reduce this uncertainty to 0.37 percent.

2.2 Applicable Guidance

Regulatory Guide (RG) 1.105, Revision 3, "Setpoints for Safety-Related Instrumentation," describes a method acceptable to the NRC staff for complying with the NRC regulations for

[1] "Venturi" will generally be used in the remainder of this document to reference both venturis and flow nozzles.

assuring that setpoints for safety-related instrumentation are initially within and remain within the TS limits. The method described in RG 1.105 for combining instrument uncertainties can be used for combining the uncertainties associated with the secondary calorimetric calculation. This allows licensees to justify a power uprate with reduced margin between the licensed power level and the power level assumed in the ECCS analysis by using more accurate instrumentation to calculate the reactor thermal power.

RG 1.105, Revision 3, endorses the Instrument Society of America (ISA) 67.04, Section 4.4.1, "Square-root-sum-of-squares method (SRSS)" which states:

> It is acceptable to combine uncertainties that are random, normally distributed, and independent by the SRSS method. When two independent uncertainties, (± a) and (± b), are combined by this method, the resulting uncertainty is (± c), where $c = (a^2 + b^2)^{1/2}$.

This standard in Section 4.4.2, "Algebraic method" states:

> It is acceptable to combine uncertainties that are not random, not normally distributed, or are dependent by the algebraic method. In this method, the combination of two dependent uncertainties, (+a, -0) and (+0, -b), results in a third uncertainty distribution with limits (+a, -b).

In the review of uncertainties in determining a trip setpoint and its allowable values, the NRC staff typically uses 95/95 tolerance limits as an acceptable criterion, i.e., a 95 percent probability that the constructed limits contain 95 percent of the population of interest for the surveillance interval selected.

Caldon, Inc., now Cameron, submitted an engineering topical report (TR) ER-80-P, "Improving Thermal Power Accuracy and Plant Safety While Increasing Operating Power Level Using the LEFM [leading edge flow measurement] Check™ System," in March 1997, (ADAMS Accession No. ML003670328) that describes the LEFM, includes calculations of power measurement uncertainty using a Check system in a typical two-loop pressurized-water reactor (PWR) or a two-feedwater-line boiling-water reactor (BWR) and provides guidance for determining plant-specific power calorimetric uncertainties. The NRC staff approved this report on March 8, 1999 (ADAMS Accession No. ML11353A016), for a Comanche Peak Steam Electric Station exemption to the 2 percent uncertainty requirement in Appendix K to 10 CFR Part 50 and approved a 1 percent uprate for using the LEFM at Comanche Peak Steam Electric Station. Following approval of the amendment to Appendix K (paragraph I.A) on May 3, 2000 (ADAMS Accession No. ML003711059) (published on (65 FR 34921) on June 1, 2000) that allowed for an uncertainty less than 2 percent, Cameron submitted several supplements. The latest supplement was provided in May 2008, Cameron ER-157-P, Revision 8, "Supplement to Engineering Report ER-80-P: Bases for a PU with the LEFM Check™ or LEFM CheckPlus™" (ADAMS Accession No. ML102950252). The NRC staff approved use to the Cameron supplement in the NRC staff's safety evaluation (SE) dated August 16, 2010 (ADAMS Accession No. ML102950252).

Revision 8 of ER-157- P, states that:

> [t]he redundancy inherent in the two measurement planes of an LEFM CheckPlus also makes this system more resistant to component failures, when compared to the [LEFM] Check.
>
> For any single component failure, continued operation at a power greater than that prior to the uprate can be justified with a CheckPlus system ... since the system with the failure is no less than an LEFM Check.

As stated in the NRC staff's SE dated August 16, 2010 (ADAMS Accession No. ML1029502520, Licensees referencing ER-157-P, Revision 8, must ensure compliance with the following limitations and conditions:

1. Continued operation at the pre-failure power level for a pre-determined time and the decrease in power that must occur following that time are plant-specific and must be acceptably justified.

2. The only mechanical difference that potentially affects the quoted statement is that the CheckPlus has 16 transducer housing interfaces with the flowing water, whereas, the LEFM Check has 8. Consequently, a CheckPlus operating with a single-failure that is assumed to disable one plane of transducers is not identical to an LEFM Check. Although the effect on hydraulic behavior is expected to be negligible, this must be acceptably quantified if a licensee wishes to operate as stated. An acceptable quantification method is to establish the effect in an acceptable test configuration such as can be accomplished at the Alden Research Laboratories (ARL).

As stated in the NRC staff's SE dated August 16, 2010 (ADAMS Accession No. ML1029502520, Licensees can reference ER-157-P, Revision 8, in their applications for MUR PUs for LEFM Check or LEFM CheckPlus LEFM system subject to the following additional qualifications:

1. A CheckPlus operating with a single-failure is not identical to an LEFM Check. Although the effect on hydraulic behavior is expected to be negligible, this must be acceptably quantified if a licensee wishes to operate using the degraded CheckPlus at an increased uncertainty.

2. An applicant with a comparable geometry can reference the Section 3.2.1 in ER-157-P, Revision 8, finding to support a conclusion that downstream geometry does not have a significant influence on CheckPlus calibration. However, CheckPlus test results do not apply to a Check and downstream effects with use of a CheckPlus with disabled components that make the CheckPlus comparable to a Check must be addressed. An acceptable method is to conduct applicable Alden Laboratory tests.

3. An applicant that requests a MUR with the upstream flow straightener configuration discussed in Section 3.2.2 should provide justification for claimed CheckPlus uncertainty that extends the justification provided in a letter from Caldon dated March 19, 2010, "Documentation to support review of Caldon ER-157-P, Revision 8," (ADAMS Accession No. ML100840025). Since this evaluation does not apply to the

Check, a comparable evaluation must be accomplished if a Check is to be installed downstream of a tubular flow straightener.

4. An applicant assuming large uncertainties in steam moisture content should have an engineering basis for the distribution of the uncertainties or, alternatively, should ensure that their calculations provide margin sufficient to cover the differences shown in Figure 1 of a letter dated March 18, 2010 (ADAMS Accession No. ML100820167).

2.3 Method of NRC Staff Review

The NRC staff reviewed the licensee's application to ensure that: (1) there is assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) activities proposed will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public. The purpose of the NRC staff's review is to ensure that instrumentation uncertainties were adequately accounted for in the safety analyses and to determine whether the licensee has demonstrated that the proposed value adequately accounts for instrumentation uncertainties. The NRC issued Regulatory Information Summary (RIS) 2002-03, "Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications" (ADAMS Accession No. ML013530183), to provide guidance to licensees on the scope and detail of the information that should be provided to the NRC staff for MUR PU requests. While RIS 2002-03 does not set forth NRC requirements, its use aids licensees in the preparation of their MUR PU submittals, while also providing guidance to the NRC staff for the conduct of its review.

The NRC staff's review of the LAR focused on the following information suggested in Attachment 1 to the RIS 2002-03 to determine whether the proposed MUR PU meets applicable NRC requirements:

- A detailed description of the plant-specific implementation of the FW flow measurement technique and the power increase gained as a result of implementing this technique (Section I – Attachment 1, RIS 2002-03);
- A detailed discussion for each accident and/or transient for which the existing analyses of record bound plant operation at the proposed uprated power level and those analyses that are not covered by the reload methodology for the plant (Sections II and III);
- A discussion of the effect of the power uprate on the structural integrity of major plant components (Section IV);
- A discussion of the effect of the power uprate on electrical equipment (Section V);
- A discussion of the effect of the power uprate on major plant systems (Section VI);
- Other (Section VII), and;
- Changes to technical specifications, protection system settings, and emergency system settings (Section VIII).

The licensee stated in its application that its LAR was submitted consistent with the guidance of RIS 2002-03.

2.4 Proposed MUR PU at Braidwood, Units 1 and 2 and Byron, Unit Nos. 1 and 2

The proposed amendment is based on the use of the Cameron LEFM CheckPlus ultrasonic, multi-path, transit time flowmeter system that would decrease the uncertainty in the measurement of FW flow, thereby decreasing the power level measurement uncertainty from 2.0 percent to 0.37 percent. The proposed PU is based on a redistribution of analytical margin originally required of ECCS evaluation models performed in accordance with the requirements set forth in 10 CFR Part 50, Appendix K, and "ECCS Evaluation Models."

Byron and Braidwood were originally designed with FW flow and temperature instrumentation consisting of venturis, differential pressure transmitters, and thermocouples. Modifications required for the MUR PU include installation of the CheckPlus LEFM system. Existing FW flow and temperature instrumentation will be retained and used for comparison monitoring of the LEFM system and as a backup FW flow measurement when needed.

The FW flow measurement system permanently installed is the Cameron LEFM CheckPlus ultrasonic eight-path transit time flowmeter. As discussed above, the CheckPlus LEFM design is addressed in ER-80-P, ER-160-P, and ER-157-P, which have been approved by the NRC. It will be used for continuous calorimetric power calculation determination by providing FW mass flow and temperature input data to the plant computer system that is used for automated performance of the calorimetric power calculations.

The CheckPlus LEFM system consists of one flow element (spool piece) installed in each of the steam generator (SG) FW flow headers. The FW piping configurations are stated to have been explicitly modeled as part of the CheckPlus LEFM meter factor and accuracy assessment testing performed at ARL. The planned installation location of each CheckPlus LEFM is stated to conform to the applicable requirements in Cameron's Installation and Commissioning Manual and Cameron ER-80-P and ER-157-P, and the bounding uncertainty analysis is stated to be addressed by ER-800, ER-801, ER-802, and ER-803.

The LEFM instrumentation installation has been completed in each of the four units as follows:

- Braidwood Unit 1 Spring 2012 (during refueling outage (RFO) A1R16);
- Braidwood Unit 2 Spring 2011 (during RFO A2R15);
- Byron Unit 1 Spring 2011 (during RFO B1R17); and,
- Byron Unit 2 Fall 2011 (during RFO B2R16)

3.0 TECHNICAL EVALUATION

3.1 Safety Systems

3.1.1 FW Flow Measurement Technique and Power Measurement Uncertainty (RIS 2002-03, Attachment 1, Section I)

3.1.1.1 Instrumentation and Control

Regulatory Evaluation

Section 50.36(c)(1)(ii)(A) of 10 CFR Part 50, "Technical specifications" requires, in part, that, where a limiting safety system setting is specified for a variable on which a safety limit has been placed, the setting be so chosen that automatic protective action will correct the abnormal situation before a safety limit is exceeded.

General Design Criterion (GDC) 13 of Appendix A, 10 CFR Part 50, "Instrumentation and Control," requires among other things, that instrumentation be provided to monitor variables and systems and that controls be provided to maintain these variables and systems within prescribed operating ranges.

GDC 20, of Appendix A, "Protection System Functions," requires, among other things, that the protection system be designed to initiate operation of appropriate systems to ensure that specified acceptable fuel design limits are not exceeded.

In RG 1.105, Revision 3, "Setpoints for Safety-Related Instrumentation," a method acceptable to the NRC staff is described for complying with the NRC regulations for assuring that setpoints for safety-related instrumentation are initially within and remain within the TS limits. The method described in RG 1.105 for combining instrument uncertainties can be used for combining the uncertainties associated with the secondary calorimetric calculation. This allows licensees to justify a power uprate with reduced margin between the licensed power level and the power level assumed in the ECCS analysis by using more accurate instrumentation to calculate the reactor thermal power.

As discussed in Section 2.2, the NRC approved two topical reports ER-80-P-A and Cameron ER-157-P-A as an acceptable way of conforming to the regulations. When it originally approved ER-80-P-A, the NRC established four criteria for licensees to address. The criteria are as follows:

- Discuss maintenance and calibration procedures that will be implemented with the incorporation of the LEFM, including processes and contingencies for inoperable LEFM instrumentation and the effect on thermal power measurements and plant operation.

- For plants that currently have LEFMs installed, provide an evaluation of the operational and maintenance history of the installed instrumentation and confirmation that the installed instrumentation is representative of the LEFM system and bounds the analyses and assumptions set forth in ER-80-P.

- Confirm that the methodology used to calculate the uncertainty of the LEFM in comparison to the current FW instrumentation is based on accepted plant setpoint methodology (with regard to the development of instrument uncertainty). If an alternative approach is used, the application should be justified and applied to both venturi and UFM instrumentation installations for comparison.

- Licensees for plant installations where the ultrasonic meter (including LEFM) was not installed with flow elements calibrated to a site-specific piping configuration (flow profiles and meter factors not representative of the plant-specific installation), should

provide additional justification for use. This justification should show that the meter installation is either independent of the plant-specific flow profile for the stated accuracy, or that the installation can be shown to be equivalent to known calibrations and plant configurations for the specific installation including the propagation of flow profile effects at higher Reynolds numbers. Additionally, for previously installed calibrated elements, the licensee should confirm that the piping configuration remains bounding for the original LEFM installation and calibration assumptions.

Technical Evaluation

Neutron flux instrumentation is calibrated to the core thermal power, which is determined by an automatic or manual calculation of the energy balance around the plant nuclear steam supply system. This calculation is called "secondary calorimetric" for a PWR. The accuracy of this calculation depends primarily on the accuracy of FW flow and FW net enthalpy measurements. FW flow is the most significant contributor to the core thermal power uncertainty. A more accurate measurement of this parameter will result in a more accurate determination of core thermal power.

FW flow rate is typically measured using a venturi. This device generates a differential pressure proportional to the FW velocity in the pipe. Because of the high cost of calibrating the venturi and the need to improve flow instrumentation measurement uncertainty, the industry evaluated other flow measurement techniques and found the Cameron LEFM CheckPlus LEFM to be viable alternatives.

LEFM Technology and Measurement

The Cameron LEFM CheckPlus system uses a transit time methodology to measure fluid velocity. The basis of the transit time methodology for measuring fluid velocity and temperature is that ultrasonic pulses transmitted through a fluid stream travel faster in the direction of the fluid flow than opposite the flow. The difference in the upstream and downstream traversing times of the ultrasonic pulse is proportional to the fluid velocity in the pipe, and the temperature is determined using a pre-established correlation between the mean propagation velocity of the ultrasound pulses in the fluid and the fluid pressure.

The system uses multiple diagonal acoustic paths instead of a single diagonal path, allowing velocities measured along each path to be numerically integrated over the pipe cross-section to determine the average fluid velocity in the pipe. This fluid velocity is multiplied by a velocity profile correction factor, the pipe cross-section area, and the fluid density to determine the FW mass flow rate in the piping. The mean fluid density may be obtained using the measured pressure and the derived mean fluid temperature as an input to a table of thermodynamic properties of water. The velocity profile correction factor is derived from calibration testing of the LEFM CheckPlus system in a plant-specific piping model at a calibration laboratory.

The Cameron LEFM CheckPlus system uses 16 transducers, eight each in two orthogonal planes of the spool piece. In the Cameron LEFM CheckPlus system, when the fluid velocity measured by an acoustic path in one plane is averaged with the fluid velocity measured by its companion path in the second plane, the transverse components of the two velocities are canceled and the result reflects only the axial velocity of the fluid. This makes the numerical integration of four pairs of averaged axial velocities and computation of volumetric flow inherently more accurate than a result obtained using four acoustic paths in a single plane.

Also, because there are twice as many acoustic paths in the CheckPlus LEFM System, than in the Check System, and there are two independent clocks to measure the transit times, errors associated with uncertainties in path length and transit time measurements are reduced.

The NRC staff's review in the area of instrumentation and control covers the proposed plant-specific implementation of the FW flow measurement technique and the power increase gained as a result of implementing this technique. The staff conducted its review to confirm that the licensee's implementation of the proposed FW flow measurement device is consistent with staff-approved ER-157-P and that the licensee adequately addressed the four additional requirements listed in the staff's August 16, 2010, SE. The NRC staff also reviewed the power measurement uncertainty calculations to ensure: (1) the conservatively proposed uncertainty value of 0.37 percent correctly accounts for all uncertainties associated with power level instrumentation errors, and (2) the uncertainty calculations meet the relevant requirements of Appendix K to 10 CFR Part 50, as described in section 2.1, above.

The licensee provided in Attachment 7 to its June 23, 2011, application, the following information about the Cameron LEFM CheckPlus System FW flow measurement technique and its implementation at Byron and Braidwood, Units 1 and 2. The Cameron LEFM CheckPlus System consists of an electronic cabinet (with its own cooling system) installed in the main steam line tunnel and measurement spool pieces installed in each of the four main FW flow lines upstream of the existing FW venturi flow meters. Each measurement section consists of 16 ultrasonic, multipath, transit time transducers, and FW pressure input.

The electronic cabinet controls magnitude, sequences transducer operations, makes time measurements, and calculates volumetric flow, temperature, and mass flow. The system software determines velocities at precise locations. The FW mass flow rate and temperature are transmitted to the plant process computer for use in calorimetric measurement of reactor thermal output. In the event of system failure the control room operators are alerted.

The UFM values for FW mass flow and temperature will be directly substituted for the existing venturi-based flow and resistance temperature detector (RTD) temperature inputs used in the plant calorimetric measurement calculations. The existing venturi-based FW flow and RTD temperature will continue to be used for other plant functions and may be used for plant calorimetric calculations in the event of a UFM failure.

Evaluation of Information provided in response to RIS 2002-03, Attachment 1, Section I, guidance, Items A through H, is provided below.

Items A through C

Items A, B, and C, in Section I of Attachment 1 to RIS 2002-03 guide licensees to identify the approved TRs, provide references to the NRC's approval of the measurement technique, discuss the plant-specific implementation of the guidelines in the TR, and identify the NRC staff's approval of the FW flow measurement technique.

In its June 23, 2011, letter (the submittal), the licensee identified Cameron TR ER-80-P, Revision 0, issued March 1997 , and its supplement, TR ER-157-P, Revision 8, and Revision 8, Errata, issued May 2008, as applicable to the Cameron LEFM CheckPlus

System. The licensee also referenced the NRC approval of the TRs ER-80-P and ER-157-P in SEs dated March 8, 1999, and August 16, 2010.

The licensee stated in its submittal that the Cameron LEFM CheckPlus system will be permanently installed in Byron and Braidwood, Units 1 and 2, according to the conditions, limitations and qualifications of the August 16, 2010 SE approving ER-157P. The Cameron LEFM CheckPlus system was installed in Braidwood, Unit 1, during the spring of 2012. The Cameron LEFM CheckPlus system for Braidwood, Unit 2, was installed during the spring of 2011. The Cameron LEFM CheckPlus system for Byron, Unit No. 1, was installed during the spring of 2011. The Cameron LEFM CheckPlus system for Byron, Unit No. 2 was installed during the fall of 2011.

On the basis of its review of the licensee's submittals, as reflected in the above discussion, the NRC staff finds that the licensee has sufficiently addressed the plant-specific implementation of the Cameron LEFM CheckPlus system using proper TR guidelines. Therefore, the staff concludes that the licensee's description of the FW flow measurement technique and implementation of the power uprate using this technique contains the information requested by Items A through C of Section I of Attachment 1 to RIS 2002-03.
Item D

Item D in Section I of Attachment 1 to RIS 2002-03 guides licensees to address four criteria when implementing the FW flow measurement uncertainty technique. The NRC staff SEs for ER-80-P, dated March 8, 1999, and ER-157-P, dated August 16, 2010, both include these four plant-specific criteria, to be addressed by a licensee referencing these TRs for a PU. The licensee's submittal addresses each of the four criteria as described below.

1. Discuss maintenance and calibration procedures that will be implemented with the incorporation of the LEFM, including processes and contingencies for inoperable LEFM instrumentation and the effect on thermal power measurements and plant operation.

   Licensee Response:

   > Implementation of the MUR power uprate license amendment will include developing the necessary procedures and documents required for continued calibration and maintenance of the LEFM system. Plant maintenance and calibration procedures will be revised to incorporate Cameron's maintenance and calibration requirements prior to raising power above the current licensed thermal power of 3586.6 MWt. The Braidwood and Byron Technical Requirement Manuals (TRMs) will be revised to address contingencies for inoperable LEFM instrumentation.
   >
   > A modification package has been developed for each installation outlining the steps to install and test the LEFM CheckPlus system. When each unit is shutdown for their respective refueling outages the LEFM CheckPlus systems will be installed. Following installation, testing will include an in-service leak test, comparisons of FW flow and thermal power calculated by various methods, and final commissioning testing. The LEFM CheckPlus system installation and commissioning will be performed according to Cameron procedures. Commissioning and start-up of the LEFM CheckPlus System will be performed by qualified Cameron personnel with site personnel assistance. The

commissioning process provides final positive confirmation that actual field performance meets the uncertainty bounds established for the instrumentation. Final site-specific uncertainty analyses acceptance will occur after completion of the commissioning process.

The Braidwood and Byron, Units 1 and 2, LEFM CheckPlus system was calibrated in a site-specific model test at ARL. The testing at ARL provides traceability to National Standards. The spool piece calibration factor uncertainty is based on Cameron engineering reports. The calibration tests included a site-specific model of each of the Units hydraulic geometry.

Preventive maintenance will be performed based on vendor recommendations. The preventive maintenance program and LEFM CheckPlus system continuous self-monitoring feature ensure that the LEFM remains bounded by the ER-80P, as supplemented by ER-157P, analysis and assumptions. Establishing and continued adherence to these requirements assures that the LEFM CheckPlus system is properly maintained and calibrated. The preventive maintenance activities will be identified via the associated plant modification package. Typical activities performed include power supply checks, pressure transmitter checks, and clock verifications. Maintenance of the LEFM system will be performed by personnel who are qualified.

Instrumentation, other than the LEFM system, that contributes to the power calorimetric computation will be periodically calibrated and maintained using existing site procedures. Maintenance and test equipment, tolerance settings, calibration frequencies, and instrumentation accuracy were evaluated and accounted for in the thermal power uncertainty calculation.

NRC Staff Evaluation and Conclusion

The NRC staff finds that the description of the calibration and maintenance procedures (and associated documentation) states that Exelon will incorporate the appropriate Cameron requirements. Therefore the NRC staff concludes that this is consistent with the staff's SE for the LEFM system and that the licensee has adequately addressed Criterion 1 (of plant-specific criteria identified in the SE on the TR) and the information submitted meets the regulatory guidance in RIS 2002-03.

2. For plants that currently have LEFMs installed, provide an evaluation of the operational and maintenance history of the installed instrumentation and confirmation that the installed instrumentation is representative of the LEFM system and bounds the analysis and assumptions set forth in ER-80-P.

Licensee Response:

At the time of the submittal, only Byron, Unit No. 1, and Braidwood, Unit 2, had installed the LEFM CheckPlus systems. Based on the results of the modification and commissioning testing the LEFM CheckPlus systems as installed are in conformance with the analysis

and assumptions given in Cameron's TR ER-80P, ER-157P, and the Byron and Braidwood unit specific "Bounding Uncertainty Analysis for Thermal Power Determination Reports", as well as the performance parameters identified in the Alden Laboratory Meter Factor Calculation and Accuracy Assessments. As of June 17, 2011, there has been no performance, operational, or maintenance issues that would indicate any non-conformance with the above.

NRC Staff Evaluation and Conclusion

The NRC staff became aware of a trending issue after June 17, 2011, through NRC oversight programs. Based on the NRC staff's evaluation of the trending issue in section 3.1.1.3 in this SE and because the licensee provided an evaluation of the operational and maintenance history as well as the issue evaluated in section 3.1.1.3, the NRC staff concludes that the licensee's response is adequate to address Criterion 2 and meets the regulatory guidance in RIS 2002-03.

3. Confirm that the methodology used to calculate the uncertainty of the LEFM in comparison to the current FW instrumentation is based on accepted plant setpoint methodology (with regard to the development of instrument uncertainty). If an alternative approach is used, the application should be justified and applied to both venturi and UFM instrumentation installations for comparison.

Licensee Response:

Cameron has performed Unit specific bounding uncertainty analysis for Byron and Braidwood Stations, Unit 1 and 2. Copies of these analyses are provided in the licensee's June 23, 2011, submittal. The calculations in these analyses are consistent with Cameron's TR ER-80P, as supplemented by ER-157P, ISA-P67.04.02-2000, "Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation" and Exelon standard NES-EIC-20.04. This approach has been approved by the NRC. The core thermal power uncertainty calculation which takes into account the uncertainty associated with the FW flow venturis is performed in accordance with Exelon standard NES-EIC-20.04 and is consistent with ISA-RP67.04.02-2000.

The fundamental approach used is to statistically combine inputs to determine the overall uncertainty. Channel statistical allowances are calculated for the instrument channels. Dependent parameters are arithmetically combined to form statistically independent groups, which are then combined using the square root of the sum of the squares approach to determine the overall uncertainty.

NRC Staff Evaluation and Conclusion

Based on the licensee's response the NRC staff found that the methodology used to calculate uncertainty as described above is based on accepted plant setpoint methodology, which meets the regulatory guidance for an approved method of meeting the relevant requirements of 10 CFR Part 50, Appendix K, as described in Section 2 of this SE.

Therefore, the NRC staff concludes that the licensee has adequately addressed Criterion 3 and meets the regulatory guidance.

4. Licensees for plant installations where the ultrasonic meter (including LEFM) was not installed with flow elements calibrated to a site specific piping configuration (flow profiles and meter factors not representative of the plant specific installation), should provide additional justification for use. This justification should show that the meter installation is either independent of the plant specific flow profile for the stated accuracy, or that the installation can be shown to be equivalent to known calibrations and plant configurations for the specific installation including the propagation of flow profile effects at higher Reynolds numbers. Additionally, for previously installed calibrated elements, the licensee should confirm that the piping configuration remains bounding for the original LEFM installation and calibration assumptions.

   Licensee Response:

   Criterion 4 does not apply to Byron or Braidwood Stations, Units 1 or 2. Byron and Braidwood Stations LEFM CheckPlus systems were calibrated at Alden Research Laboratory. Cameron engineering reports for each of the Units evaluating the calibration test data from Alden Research Laboratory have been completed and have been provided. The calibration factors used for each Units LEFMs are based on the analysis contained in reports docketed as part of the LAR.

   NRC Staff Evaluation and Conclusion

The NRC staff determined that the LEFM installations at Braidwood and Byron, Units 1 and 2, were calibrated to unit specific piping configurations. Therefore, the NRC staff concludes that Criterion 4 does not apply to Braidwood or Byron, Unit Nos. 1 or 2.

Item E

Item E in Section I of Attachment 1 to RIS 2002-03 guides licensees in the submittal of a plant-specific power measurement uncertainty calculation to explicitly identify all parameters and their individual contributions to the power uncertainty.

To address Item E of RIS 2002-03, in Attachments 8a-8d of the submittal, the licensee provided Cameron engineering reports ER-800, ER-801, ER-802, and ER-803. These reports provide calculations that demonstrate that the total thermal power uncertainty for the bounding unit is 0.345 percent. The licensee added additional margin to support support a power increase of 1.63 percent. The NRC staff concludes that this power increase is acceptable because there is .025 percent margin to the 102 percent analyzed power level.

100% (current authorized power) + 0.345% (uncertainty) + 1.63% (power uprate) + .025% (margin) = 102% (analyzed power level)

The licensee proposes that all units be uprated to the same power level.

In October 2011, the NRC staff reviewed and audited the calculations and determined that the licensee identified the parameters associated with the thermal power measurement uncertainty, provided individual measurement uncertainties, and calculated the overall

thermal power uncertainty. The NRC staff determined that the licensee's calculations arithmetically summed uncertainties for parameters that are not statistically independent and statistically combined with other parameters. The NRC staff also determined that the licensee combined random uncertainties using the square root sum of squares approach and added systematic biases to the result to determine the overall uncertainty. The NRC staff finds that this methodology is consistent with the vendor determination of the Cameron LEFM CheckPlus system uncertainty, as described in the referenced TRs, and is consistent with the guidelines in RG 1.105.

The NRC staff finds that the licensee has provided calculations of the total power measurement uncertainty at the plants, explicitly identifying parameters and their individual contribution to the power uncertainty. Therefore, the NRC staff concludes that the licensee provided the information requested in Item E of Section I of Attachment 1 to RIS 2002-03, and that this information is consistent with RG 1.105, above.

Item F

Item F in Section I of Attachment 1 to RIS 2002-03 guides licensees to provide information to address the specified aspects of the calibration and maintenance procedures related to all instruments that affect the power calorimetric.

In Attachment 7 to its June 23, 2011, submittal, the licensee addressed each of the following five aspects of the calibration and maintenance procedures listed in Item F of RIS 2002-03:

1. Maintaining Calibration

   The licensee states that calibration will be based on the appropriate LEFM CheckPlus technical manuals. Other calorimetric process instrumentation and computer points are maintained and calibrated using approved procedures.

2. Controlling Hardware and Software Configuration

   The licensee states that the Cameron LEFM CheckPlus system is designed and manufactured in accordance with the vendor's quality assurance program. The licensee stated that they will maintain, after installation, the software and hardware configuration by using existing procedures and processes, which include verification and validation of software configuration changes.

3. Performing Corrective Actions

   The licensee states that Station personnel will monitor plant instrumentation that affects the power calorimetric input, including UFM inputs and that any problems detected will be handled according to the Station's corrective action process.

4. Reporting Deficiencies to the Manufacturer

   The licensee states that deficiencies associated with the vendor's processes or equipment will be reported to the vendor as needed to support corrective action.

5. Receiving and Addressing Manufacturer Deficiency Reports

   The licensee states that Cameron has procedures to notify users of important LEFM deficiencies. The licensee stated that it has existing processes to address the receipt of Cameron's deficiency reports.

On the basis of its review of the above statements, the NRC staff finds that the licensee has addressed the calibration and maintenance aspects of the Cameron LEFM CheckPlus System and all other instruments affecting the power calorimetric. Therefore, the staff concludes that the licensee has provided the information identified in Item F of Section I of Attachment 1 to RIS 2002-03, and that the information meets the regulatory guidance.

Items G and H

Items G and H in Section I of Attachment 1 to RIS 2002-03, guide licensees to provide a proposed allowed outage time (AOT) for the instrument and to propose actions to reduce power if the AOT is exceeded.

In its June 23, 2011, submittal, the licensee proposed a 72-hour AOT for operating above 3586.6 MWt (i.e., the current licensed thermal power limit) if the UFM becomes non-operational. The licensee specifically noted that any failure of the UFM, including failures of a single path or plane, will be treated as a complete failure of the UFM system and thus start the plant's allowable 72 hours to remain above 3586.6 MWt. In addition, the licensee stated in the submittal that the ability of the plant to stay above 3586.6 MWt is contingent upon its ability to maintain steady-state conditions. If the plant should reduce power below 3586.6 MWt during the AOT, the plant will not be permitted to return above that value until the UFM function is fully restored.

The licensee states in the submittal that during the 72-hour AOT, the plant would use the existing FW venturis for the calorimetric calculation. The licensee stated that because the FW venturis are regularly normalized to the UFM measurements, their measurements should be equivalent to the UFM over the 72-hour AOT. The NRC staff finds that use of calibrated FW venturis to remain at the uprated power level during the 72 hours that follow a UFM being declared non-operational is consistent with previous MUR submittals that the staff has approved. Venturi nozzle fouling and transmitter drift were considered as potential sources of error within the AOT window.

The licensee states in the submittal that the basis for the 72-hour AOT includes the fact that there has been no evidence of FW venturi fouling at Braidwood and Byron, Unit Nos. 1 and 2. This conclusion was reached by Exelon based on a review of historical records and analysis of FW flow. The licensee concluded that since there has been no observed FW venturi fouling, it is unlikely that fouling or sudden de-fouling will occur in the 72-hour AOT. In addition, Exelon analyzed the expected drift of the FW venturi and determined that this drift would be insignificant during a 72-AOT.

By letter dated November 1, 2011, Exelon provided information

1. which allowed the NRC staff to understand the conformance of the implementation with respect to the TR,

2. confirmed that the assumptions listed in the TR were valid for Braidwood and Byron MUR application or described how plant-specific information was used in the application,
3. confirmed that either a sufficiently large number of samples were used such that the two sigma values were 95/95 values or Students-t was used as a multiplier for establishing the 95/95 confidence interval, and
4. explained that a number of discrepancies resulted from misquoting the TR and explained that these errors did not affect the application since the numbers were provided for comparison purposes.

The NRC staff determined that the responses appropriately resolved the staff's questions.

On the basis of its review of the licensee's submittals, the NRC staff finds that the licensee has provided sufficient justification for the proposed AOT and the proposed actions to reduce power level if the AOT is exceeded. Therefore, the staff concludes that the licensee has provided the information requested by Items G and H of Section I of Attachment 1 to RIS 2002-03, and the information provided meets the regulatory guidance.

Conclusion

The NRC staff reviewed the licensee's proposed plant-specific implementation of the FW flow measurement device and the power uncertainty calculations and determined that the licensee's proposed license amendment is consistent with the staff-approved TR ER-157P. The NRC staff has also determined that the licensee adequately accounted for instrumentation uncertainties in the reactor thermal power measurement uncertainty calculations and demonstrated that the calculations meet the relevant requirements of 10 CFR Part 50, Appendix K, as described in Section 2 of this SE. The NRC staff finds the instrumentation and control aspects supporting the proposed thermal power to be acceptable.

3.1.1.2 Plant Specific Implementation of the Applicable Topical Reports
(RIS 2002-03, Attachment 1, Section I.1)

Regulatory Evaluation

Paragraph I.A of Appendix K to 10 CFR Part 50 allows licensees to justify a smaller margin for power measurement uncertainty. Licensees may apply the reduced margin to operate the plant at a power level higher than the previously licensed power. In the LAR, the licensee proposed to use a Cameron LEFM CheckPlus system to decrease the uncertainty in the measurement of FW flow, thereby decreasing the power level measurement uncertainty from 2.0 percent to 0.37 percent.

As discussed previously, the NRC determined that ER-80-P and ER-157-P, which describe the Cameron LEFM CheckPlus System for the measurement of FW flow, are an acceptable way of conforming to the regulations

The NRC staff's SE dated August 16, 2010, discussed criteria for testing in a certified facility, transfer from the test facility, initial operation, and long-term in-plant operation. These criteria are:

- Traceability to a recognized national standard. This requires no breaks in the chain of comparisons, all chain links must be addressed, and there can be no unverified assumptions,

- Calibration, and

- Acceptable addressing of uncertainty beginning with an initial estimate of the bounding uncertainty and continuing through all aspects of initial calibration in a certified test facility, transfer to the plant, initial operation, and long-term operation.

For CheckPlus LEFM, meeting these criteria includes documenting:

- Design and characteristics information,

- Calibration testing at a certified test facility,

- Any potential changes associated with differences between testing and plant operation including certification that initial operation in the plant is consistent with pre-plant characteristics predictions, and

- In-plant operation.

Technical Evaluation

Initial Design and Characteristics

To determine volumetric flow rate, the Caldon UFM transmits an acoustic pulse along a selected path and records the arrival of the pulse at the receiver. Another pulse is transmitted in the opposite direction and the time for that pulse is recorded. Since the speed of an acoustic pulse will increase in the direction of flow and will decrease when transmitted against the flow, the difference in the upstream and downstream transit times for the acoustic pulse provides information on flow velocity. Once the difference in travel times is determined, the average velocity of the fluid along the acoustic path can be determined. Therefore, the difference in transit time is proportional to the average velocity of the fluid along the acoustic path.

The CheckPlus LEFM provides an array of 16 ultrasonic transducers installed in a spool piece to determine average velocity in eight paths. The transducers are arranged in fixtures such that they form parallel and precisely defined acoustic paths. The chordal placement is intended to provide an accurate numerical integration of the axial flow velocity along the chordal paths. Using Gaussian quadrature integration, the velocities measured along the acoustic paths are combined to determine the average volumetric flow rate through the flow meter cross section. Note that this process assumes a continuous velocity profile in the flow area perpendicular to the spool piece axis. Although the velocity profile can be distorted, the distortion cannot be such that the Gaussian quadrature process no longer provides an acceptable mathematical fit to the profile, such as may occur if the profile is distorted in a way that is not recognized by the CheckPlus LEFM due to an upstream flow straightener.

To obtain the actual average flow velocity a calibration factor is applied to the integrated average flow velocity indicated by the UFM. The calibration factor for the Caldon UFMs is determined through meter testing at ARL and is equal to the true area averaged flow

velocity divided by the flow velocity determined from the average meter paths to correlate the meter readings to the average velocity and, hence, to the average meter volumetric flow. The mass flow rate is found by multiplying the spool flow area by the average flow velocity and density. The mean fluid density is obtained using the measured pressure and the derived mean fluid temperature as an input to a table of thermodynamic properties of water. Typically, the difference between an uncalibrated CheckPlus LEFM and ARL test results is less than 0.5 percent. This close agreement means that obtaining a correction factor for a CheckPlus LEFM is relatively insensitive to error for operation under test conditions.

Use of a spool piece and chordal paths improves the dimensional uncertainties including the time measurement of the ultrasonic signal and enables the placement of the chordal paths at precise locations generally not possible with an externally mounted UFM. This allows a chordal UFM to integrate along off-diameter paths to more efficiently sample the flow cross section. In addition, a spool piece has the benefit that it can be directly calibrated in a flow facility, improving measurement uncertainty compared to externally mounted UFMs that were historically installed in nuclear power plant FW lines.

The NRC staff concludes that the licensee acceptably meets the guidance as approved in the NRC staff's SE dated August 16, 2010, for the above aspects of its proposed use of CheckPlus LEFMs. Flow straighteners are not used immediately upstream of the installations and other potential distortions of the flow profile are either absent or acceptably addressed in ARL testing. Coverage of other aspects of the proposed use is addressed in other sections of this SE.

Test Facility Considerations

Test Facility Qualification

Calibration testing at a qualified test facility and at the plant involves traceability to a national standard, facility uncertainty, and facility operation. At www.aldenlab.com, ARL states that "Alden is the largest independent supplier of National Institute of Standards and Technology (NIST) traceable Flow Meter Calibration Services in the country." The NRC staff audited testing at ARL in February 2006 and verified ARL's statement with respect to traceability to NIST (ADAMS Accession No. ML11311A174). The NRC's audit found that ARL's processes and operation were consistent with the claimed facility uncertainties. The NRC staff also observed testing during a visit to ARL in August 2009, and observed some improvements in test facility hardware. The NRC staff concludes that these changes would not change its previous conclusions during the February 2006 audit regarding test operations and results. In Attachments 8a-8d of the licensee's June 23, 2011, submittal, Cameron restated that "all elements of the lab measurements...are traceable to NIST standards."

All CheckPlus LEFM installations to date have been calibrated at ARL. The audit also confirmed that ARL was providing acceptable test data for the configurations under test. Consequently, the NRC staff determined that the qualification of ARL does not need to be investigated further or confirmed with respect to CheckPlus LEFM testing provided test conditions remain consistent with the referenced conditions.

Based on the above, the NRC staff concludes that ARL meets the stated testing criteria.

Test Fidelity and Test Range

Test fidelity, such as test versus planned plant configuration, test variations to address configuration differences, and potential effects of operation on flow profile and calibration, should be addressed on a plant-specific basis. As stated in the NRC staff's August 16, 2010, SE, applicant requests must provide a comparison of the test and plant piping configurations with an evaluation of the effect of any differences that could affect the UFM calibration. Further, sufficient variations in test configurations must be tested to establish that test-to-plant differences have been bracketed in the determination of UFM calibration and uncertainty. Historically, calibration testing has acceptably covered upstream effects by applying a variation of configurations to distort the flow profile. Further, if the spool piece may be rotated during plant installation from the nominal test rotation, the effect of rotation should be addressed during testing.

Plant piping configuration drawings must, at a minimum, include isometrics with dimensional information that describe piping, valves, FW flow meters, and any other components from the FW pumps to at least 10 pipe diameters downstream of the FW flow meter that is most distant from the FW pump. Preferable are scale three dimensional (3D) drawings in place of isometrics that show this information. Test information must include 3D drawings of the test configuration including dimensions.

In its June 23, 2011, application the licensee provided an attachment of the typical installation locations drawings for the LEFMs at each of the four units. The LEFMs are installed upstream of the venturis in the plants and downstream of the common FW header. There are no flow straighteners being installed. Distances between the exit of the CheckPlus LEFM spool pieces and the downstream venturis in the tests and plant are sufficient such that there will be no effect on the LEFM. As discussed in the section of Evaluations of the Effect of Downstream Piping Configurations on Calibration, below, the NRC staff concludes that this separation distance is large enough such that there will be no effect on UFM calibration and the facility uncertainty is acceptable and meets the guidance in the NRC staff's August 16, 2010, SE.

Weigh tank tests were run at different flow rates for each simulated FW loop. Tests included 100 percent and lower flow rates through the CheckPlus LEFM and some tests included an eccentric orifice upstream in the FW pipes containing the CheckPlus LEFM. Most test results were included in the reported main FW calculation. The NRC staff concludes that based on the tests that were run at different flow rates, the tests meet the August 16, 2010, guidance for variance in test configurations.

Transfer from Test to Plant and In-Plant Installation

As stated in the NRC staff's August 16, 2010, SE, each applicant for a PU must conduct an in-depth evaluation of the UFM following installation at its plant that includes consideration of any differences between the test and in-plant results and must prepare a report that describes the results of the evaluation. This report should address such items as calibration traceability, potential loss of calibration, cross-checks with other plant parameters during operation to ensure consistency between thermal power calculation based upon the LEFM and other plant parameters, and final commissioning testing. The process should be described in written documentation and a final commissioning test report should be available for NRC inspection.

The NRC notes that, to date, the only UFM calibration traceability associated with transfer from the test facility to United States nuclear power plants that has been acceptably demonstrated is that provided by the Check and CheckPlus LEFMs due to the ability to provide the flow distribution/velocity profile as a function of radius and angular position in the spool piece, the small calibration correction necessary to fit test data to UFM indication, and the demonstrated insensitivity to changes in operation associated with transfer changes and plant changes. Although other means have been used to obtain flow rate, such as use of tracers in the FW, they have not been demonstrated to provide the small uncertainty obtainable with a CheckPlus LEFM. Transfer uncertainty is associated with any changes due to installation in the plant such as mechanical and operating conditions. Mechanical perturbations include such items as transducer installation, mechanical misalignment, and fidelity between the test and plant. Changes in operating conditions involve consideration of such potential effects as noise due to pumps and valves, changes in flow profile, including swirl, flow rate, and temperature.

As previously identified, the test facility configuration and test parameters are expected to provide a basis for providing fidelity between the test and plant. However, an exact correspondence is probably not possible. Potential differences are expected to have been addressed and the UFM is expected to provide a capability to both identify differences and to address them during operation.

The licensee addressed uncertainty in Appendices 8a-8d of the submittal. As stated in the section on Test Fidelity and Test Range, above, the NRC staff determined that the facility uncertainty is acceptable. Appendices 8a-8d of the submittal are referenced for transducer installation uncertainty. The content is essentially identical to Appendix D of Cameron's Engineering Report ER-157(NP-A), Revision 8 that the NRC staff found acceptable in its October 15, 2010, SE (ADAMS Accession No. ML102950252 for both documents). Based on the above, the NRC staff concludes that the licensee's treatment of transducer installation uncertainty is acceptable. The licensee showed that LEFM commissioning will include verification of ultrasonic signal quality and evaluation of actual plant hydraulic flow profiles as compared to those documented during the ARL testing. These parameters will be incorporated as required into the LEFM during commissioning. This meets the regulatory guidance as approved in the NRC staff's October 15, 2010, SE. The NRC staff therefore concludes that it is acceptable.

In-Plant Operation

Many of the calibration aspects associated with transfer from a test facility to the plant apply during operation as valve positions change, different pumps are operated, and physical changes occur in the plant. The latter include such items as temperature changes, preheater alignment and characteristics changes, pipe erosion, pump wear, crud buildup and loss, and valve wear. Further, potential UFM changes, such as transducer degradation or failure, may also occur and the UFM should be capable of responding to such behavior. Either the UFM must remain within calibration and traceability must continue to exist during such changes or the UFM must clearly identify that calibration and traceability are no longer within acceptable parameters. The NRC staff's SE, dated August 16, 2010, concluded that the Check and CheckPlus UFMs have an ability to provide the flow distribution/velocity profile as a function of radius and angular position in the spool piece and the demonstrated insensitivity to changes in operation associated with transfer changes and plant changes. Further, as stated above, UFM operation should be cross-checked with other plant parameters that are related to FW flow rate. Should such checking identify abnormal

behavior, the validity of the final commissioning test report should be confirmed, and the final commissioning test report should be updated as necessary to reflect the new information. Further, the UFM must be considered inoperable if its calibration is no longer established to be within acceptable limits.

Section I.1 of Reference V provides coverage of training, calibration, maintenance, procedures, entry into the corrective action program, and procedures to ensure compliance with the requirements of 10 CFR Part 50, Appendix B. Based on the above, the NRC staff concludes that in-plant operation meets regulatory guidance and is acceptable.

Operation with a Failed Component

The NRC Staff's August 16, 2010, SE states that licensees referencing ER-157P, Revision 8, must ensure compliance with the following limitations and conditions:

(1) Continued operation at the pre-failure power level for a pre-determined time and the decrease in power that must occur following that time are plant specific and must be acceptably justified.

(2) The only mechanical difference that potentially affects the quoted statement is that the CheckPlus has 16 transducer housings interfacing with the flowing water whereas the LEFM Check has 8. Consequently, a CheckPlus operating with a single-failure is not identical to an LEFM Check. Although the effect on hydraulic behavior is expected to be negligible, this must be acceptably quantified if an applicant wishes to operate as stated. An acceptable quantification method is to establish the effect in an acceptable test configuration such as can be accomplished at ARL.

Sections I.1.G-I.1.H of the submittal address AOT, monitoring of CheckPlus LEFM status, and operational processes associated with a degraded or non-operational CheckPlus LEFM. Based on the information in the submittal the NRC staff determined that the difference between a degraded CheckPlus LEFM and a Check is covered by the ARL test results.

To operate above the current license thermal power (CLTP) of 3586.6 MWt, the licensee proposes to use the Cameron LEFM CheckPlus System in the normal mode. In the normal mode of operation, both planes of transducers are in service and system operations are processed by both central processing units (CPUs). The LEFM reading will be used as input for the FW flow in the calorimetric. The licensee plans to respond to single-path or single-plane failures in the same way that they will respond to a whole system failure. In the event of a failure of a single-path or single-plane or other system failure, the licensee will declare the system inoperable. The required action will be to restore the system to operable within 72 hours AOT or actions will be required to reduce power to the CLTP or 3586.6MWt any time the plant is above the CLTP. If the plant is below the CLTP of 3586.6MWt when the LEFM is declared inoperable, the plant will not be allowed to increase power above the CLTP of 3586.6MWt.

The licensee provided justification for the proposed 72-hour Technical Requirements Manual (TRM) technical limiting condition operation (TLCO) action time. This justification included the statements as follows:

> There has been no evidence of FW flow venturi fouling at Byron or Braidwood Stations. This is based on a review of historical work orders that document this observation as part of a procedural requirement performed every refueling outage. In addition, historical data was gathered over the last several years where FW venturi flow was analyzed. This data indicated that there was no divergence in FW flow indication that would suggest venturi fouling...a typical power measurement uncertainty calculation for a two-loop PWR is shown to be approximately 1.4%. The systematic error associated with feed flow nozzle differential pressure in this calculation is shown to be approximately 1.0%. Assuming this was calculated based on an 18-month cycle; this would represent a maximum potential drift in the differential pressure measurement of less than 0.002% per day. Over a 72-hour period, this would have an insignificant effect on the FW flow measurement. FW flow differential pressure instrument drift history at Byron and Braidwood is consistent with the assumptions of this typical calculation.

The reference above as well as the consistency with outage times previously approved for other plants with similar operating experience provides assurance that the plant will operate safely for the 72-hour outage time and maintain the licensed power level. Therefore, the NRC staff concludes that under normal operating conditions the drift of a venturi over a 72-hour period would be minimal.

The actions required to be taken within the AOT as described above are to be covered in the LEFM operability requirements contained in the Byron and Braidwood TRM TLCO. Based on the above, the NRC staff concludes that operation with an inoperable (non-functional) CheckPlus LEFM has been acceptably addressed and planned operation with a failed CheckPlus LEFM component has been acceptably addressed and meets the regulatory guidance.

Spool Piece Dimensional Effects on UFM Response

Appendix A of ER-157-P addresses the effect of variation in such spool piece dimensions as as-built internal diameter and sonic path lengths, path angles, and path spacing. The NRC staff determined that the licensee's description for addressing these effects is acceptable.

Transducer Installation Sensitivity

Transducers may be removed after ARL testing to avoid damage during shipping the spool piece to the plant. Further, transducers may be replaced following failure or deterioration during operation. Replacement potentially introduces a change in position within the transducer housing that could affect the chordal acoustic path. The licensee's submittal dated June 23, 2011, Attachment 7, refers to ER-157-P, to address transducer replacement uncertainties. Appendix D of ER-157-P addresses replacement sensitivity by describing tests performed at the Caldon Ultrasonics flow loop and provides a comparison of test results to analyses of potential placement variations that shows that the test results are bounded by predicted behavior. The NRC staff concludes that there could be an uncertainty associated with the test loop even if nothing were changed. This is not addressed in ER-157-P. Rather, ER-157-P conservatively assumes that all of the test uncertainty is due to transducer replacement. Further, as stated in ER-157-P, the analyses predict a larger uncertainty than obtained during testing, and the analysis uncertainty is used for transducer replacement uncertainty.

Based on the conservative aspects described above, the NRC staff concludes that this approach is sufficient to cover the inability of the test loop to achieve flow rates comparable to those obtained in plant installations and to cover any analysis uncertainty associated with applications that has pipe diameters that differ from the tests. Consequently, the NRC staff concludes that the transducer replacement has been acceptably addressed by the licensee in Attachment 7 of its submittal and the ER-157-P, Revision 8, process for determining transducer replacement uncertainty is acceptable.

The Effects of Random and Coherent Noise of LEFM CheckPlus Systems

Appendix C of ER-157-P provides a proprietary methodology for test- and plant-specific calculation of the contribution of noise to CheckPlus LEFM uncertainty. The NRC staff's SE dated August 16, 2010, concluded that applicants may use this methodology in their MUR requests.

The licensee's June 23, 2011, submittal demonstrates that critical performance parameters, including signal to noise ratio, are continually monitored for every individual meter path and alarm setpoints are established to ensure corresponding assumptions in the uncertainty analysis remain bounding. The NRC staff determined that signal noise will be minimized via strict adherence with Cameron design requirements. LEFM commissioning included verification of ultrasonic signal quality.

In Appendices A.3 to Appendices 8a-8d of the submittal, the licensee reported test signal to noise ratios for random and coherent noise that were within the assumptions in the Cameron Topical Report ER-80-P, and that uncertainty attributable to the electronics and signal to noise ratio are included in the overall meter factor uncertainty.

The NRC staff concludes that the test results and the above Appendices 8a-8d of the submittal coverage of noise are sufficient to ensure that this topic is acceptably addressed.

Evaluation of the Effect of Downstream Piping Configurations on Calibration

The turbulent flow regimes that exist when the plant is near full-power results in limited upstream flow profile perturbation from downstream piping. Consequently, the effects of downstream equipment need not be considered for normal CheckPlus LEFM operation provided changes in downstream piping, such as the entrance to an elbow, are located greater than two pipe diameters downstream of the chordal paths. However, if the CheckPlus LEFM is operated with one or more transducers out of service, the acceptable separation distance is likely a function of transducer to elbow orientation. In such cases, if separation distance is less than five pipe diameters, it should be addressed.[2] [3]

As discussed in the section on Test Fidelity and Test Range, above, separation from downstream components is needed so that CheckPlus LEFM operation will not be affected. The NRC staff concludes that the in plant separation from downstream piping components such as elbows and venturis is acceptable and will not affect CheckPlus LEFM operation.

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[2] This was the case, for example, with a Calvert Cliffs application that the NRC found acceptable. In that installation, the distance between the spool piece exit is 15 inches from the downstream elbow and the chordal paths are 2.7 diameters upstream of the entrance to the piping bend.

[3] Although this is not addressed in ER-157P Rev. 8, it is addressed in the August 16, 2010 NRC SE (ADAMS Accession No. ML102160663).

Evaluation of Upstream Flow Straighteners on CheckPlus LEFM Calibration[4]

Operation with an upstream flow straightener is known to affect CheckPlus LEFM calibration to a greater extent than most other upstream hardware. If a licensee proposes this configuration, it must provide justification.

A previously undocumented effect of upstream tubular flow straighteners on CheckPlus LEFM calibration was discovered during ARL testing while NRC staff members were at the site on August 24, 2009, that did not appear to apply to any previous CheckPlus LEFM installations. Additional tests were conducted with several flow straighteners and two different pipe/spool piece diameters to enhance the statistical data basis, and also to develop an understanding of the interaction between flow straighteners and the CheckPlus LEFM. The results are provided in ER-790-P, Revision 1 (ADAMS Accession No. ML100840026). It should be noted that the results do not apply to the Check UFM. Consequently, the findings do not apply to a Check UFM that is installed downstream of a tubular flow straightener.

Cameron concluded that two additional meter factor uncertainty elements are necessary if a CheckPlus LEFM is installed downstream of a tubular flow straightener and provided uncertainty values derived from the test results. The data also provide insights into the unique flow profile characteristics downstream of tubular flow straighteners and a qualitative understanding of why the flow profile perturbations may affect the CheckPlus LEFM calibration.

Cameron determined that the two uncertainty elements are uncorrelated and therefore combined them as the root sum squared to provide a quantitative uncertainty. The NRC staff concluded that the Cameron approach is valid, but is concerned that the characteristics of existing tubular flow straighteners in power plants may not be adequately represented by samples tested in the laboratory. The NRC staff determined that any applicant that requests an MUR with this configuration should provide justification for claimed CheckPlus LEFM uncertainty in addition to the justification provided in ER-790-P.

The NRC staff concludes that, because there are no flow straighteners installed in the licensee's FW lines flow straightener effects are not a concern.

Other Thermal Power Calculation Considerations

Steam Moisture Content

Qualification 5 in the NRC Staff's August 16, 2010, SE states:

> An applicant assuming large uncertainties in steam moisture content should have an engineering basis for the distribution, of the uncertainties or, alternatively, should ensure that their calculations provide margin sufficient to cover the differences shown in Figure 1 of Cameron ER-764, "The Effect of the Distribution of the Uncertainty in Steam Moisture Content on the Total Uncertainty in Thermal Power (ADAMS Accession No. ML100820167).

[4] This is not addressed in ER-157P Rev. 8 but is addressed in the August 16, 2010 NRC SE.

In its June 23, 2011, submittal, the licensee states:

> The uncertainty associated with steam enthalpy due to moisture content for Byron Units 1 and 2 and Braidwood Units 1 and 2 respectively are ±0.0034%, ±0.0061%, ±0.0021%, and ±0.0044%. These values are based on actual in-plant moisture carryover tests. . . . these uncertainty values are relatively small in comparison to the other uncertainties associated with the power uncertainty calculation . . .

Based on the licensee's statement regarding relatively small uncertainty values, the NRC staff concludes that this qualification is not applicable to this application and that the steam moisture content meets the regulatory guidance in the NRC staff's SE dated August 16, 2010.

Deficiencies and Corrective Actions

In its submittal dated June 23, 2011, the licensee identified its process for addressing Cameron deficiency reports as well as reporting deficiencies to the manufacturer. In each case Byron and Braidwood Stations will use their corrective action program. In the case of receiving deficiency reports, Byron and Braidwood Stations will document and address applicable deficiencies in its corrective action program as well.

The NRC staff concludes that the information in the submittal meets the regulatory guidance in RIS 2002-03 and since the licensee's corrective action program meets the requirement of Appendix B, concludes that the information is acceptable.

Reactor Power Monitoring

Licensees should identify guidance to ensure that reactor thermal power licensing requirements are not exceeded. Proposed guidance was addressed by the NRC in a letter dated October 8, 2008 (ADAMS Accession No. ML082690105).

The NRC staff assessment provided in its October 8, 2008, letter and the licensee response to Criterion 1, as summarized in Section 3.1.1.1, Item D, above, provides an acceptable description to ensure operation consistent with the NRC staff guidance to prevent overpower operation. The NRC staff therefore concludes that the licensee's reactor power monitoring meets the regulatory guidance.

<u>Uncertainty</u>

The NRC staff provided an assessment that addressed uncertainty in Section 3.1.1.1, Item D.3, above. The following discussion provides supplemental information.

Cameron considers flow rate uncertainty associated with the test facility, measurement (including transducer installation), extrapolation from test conditions to plant operating conditions, modeling, and data scatter. The NRC staff's evaluation of these factors is discussed below.

Test Facility Uncertainty

The budgeted test facility uncertainty is consistent with past NRC staff evaluations. The NRC staff finds this uncertainty is acceptable.

Measurement Uncertainty

In its submittal dated June 23, 2011, The licensee addresses uncertainty due to such contributors as thermal expansion; dimensions; temperature, pressure, and density determination; and transducer installation. The contribution of some of these contributors was evaluated in Section 3.1.1.1, Item D and Section 3.1.1.2 (this section), above. Based on its evaluations, the NRC staff concludes that measurement uncertainty is acceptably addressed as stated in the above sections.

Extrapolation Uncertainty

Although calibration tests were performed, they were conducted at room temperature. This resulted in Reynolds numbers about a factor of 10 less than would occur in the plant and an extrapolation is necessary to obtain an in-plant calibration factor. A positive aspect of the CheckPlus LEFM is that the calibration factor is close to one and small errors in the extrapolation do not significantly affect extrapolation accuracy. Another aspect is that the Check and CheckPlus LEFM characteristics permit an alternate extrapolation approach that is typically less sensitive to error than a Reynolds number extrapolation. This involves the flatness ratio (FR), which for the CheckPlus is defined as the ratio of the average axial velocity at the outside chords (chords 1, 4, 5, and 8) to the average axial velocity at the inside chords (chords 2, 3, 6, and 7) [5]:

$$FR = (V_1 + V_4 + V_5 + V_8) / (V_2 + V_3 + V_6 + V_7)$$

Where FR is a function of Reynolds number, pipe wall roughness, and the piping system configuration.

The effect of the configuration is evaluated in laboratory tests. The effect of Reynolds number is deduced from the fully developed flow inverse power law profile which may be written in several forms including the following:

$$\frac{V}{V_{max}} = \{X|R\}^{\frac{1}{n}}$$

where X = radial location, R = pipe radius, and the exponent *n* varies with Reynolds number and is determined from experimental data. The advantage of this approach is that a plot of FR versus calibration factor is linear and the calibration factor is insensitive to variation in FR. These results are consistent with analytic predictions and have been confirmed via ARL tests of many plant configurations. Further, minor changes in calibration factor observed in different hydraulics configurations are predictable and can be confirmed analytically. Therefore, if plant conditions result in a change in FR, the calibration factor may be adjusted to reflect the change in the FR.

Cameron also uses swirl rate, defined as:

$$\text{Swirl Rate} = \text{Average}\left[\frac{V_1 - V_5}{2 - y_S}, \frac{V_8 - V_4}{2 - y_S}, \frac{V_2 - V_6}{2 - y_L}, \frac{V_7 - V_3}{2 - y_L}\right]$$

[5] Details of this method are proprietary. This discussion is taken from the non-proprietary References T and U.

Where y_S and y_L are normalized chord locations for outside/short and inside/long paths.

Cameron also uses swirl rate to characterize behavior obtained during ARL tests.

The licensee provided experimental data of calibration factor as a function of FR and swirl rate for each of the CheckPlus LEFM instruments in Appendices A.3 to Appendices 8a-8d of the submittal.

Cameron includes an uncertainty term for extrapolation from laboratory conditions to plant conditions that is computed from empirical equations to account for change in Reynolds number and other effects such as a difference in pipe wall roughness. The calibration factor is shown to change in the fifth significant figure over a factor of ten change in Reynolds number between the test and plant conditions. With respect to extrapolation uncertainty, some of the uncertainty was likely already addressed by parametric testing over Reynolds numbers and FRs.

Based on the very small change in calibration factor between the test and plant conditions, as well as the parametric testing over Reynolds numbers and FRs, the NRC staff concludes that extrapolation uncertainty has been acceptably addressed.

Modeling Uncertainty

Cameron uses FR and swirl rate to characterize the velocity distribution and to validate the experimentally determined calibration factor when installed in a plant. Don Augenstein in a paper presented in September 2008 discussed application of calibration data obtained at ARL for 330 hydraulic configurations with 75 CheckPlus LEFMs with an average calibration factor of 1.002 with a standard deviation of ± 0.0039.

Cameron discussed its experience in calibrating over 100 UFMs with 500 different test configurations since typically 4 or 5 configurations were tested for each UFM. An approach is discussed where different numbers of subsets of configurations were considered applicable to the licensee's installation and modeling sensitivity was computed using that information. Because different configurations chosen are consistent with the licensee's installation and Cameron's calibration experience, the NRC staff concludes that the licensee's approach is acceptable.

Data Scatter Uncertainty

The precision with which the calibration factor is determined includes all calibration data for each CheckPlus LEFM and 95 percent confidence limits are calculated. The NRC staff concludes that using the 95 percent confidence for all calibration data for each CheckPlus LEFM is acceptable.

Conclusion

Based on the above evaluation, the NRC staff concludes that the licensee has adequately implemented topical reports ER-80P and ER-157P and meets the conditions and limitations identified in the NRC staff's SE dated August 16, 2010.

3.1.1.3 Evaluation of Trends for Byron, Unit No. 1

Introduction to and summary of NRC Audit and Licensee Response to Byron, Unit No. 1, LEFM vs. Plant Parameter Discrepancies

The LEFMs were installed at Byron, Unit No. 1 during refueling outage (RFO) B1R17. Following the outage, in late April 2011, poly acrylic acid (PAA) was injected to control SG crud buildup.[6] Multiple indications showed a rise in thermal power when thermal power was held constant by controlling via the LEFMs from May to September 19, 2011 (Byron, September 19, 2011), and an extensive troubleshooting effort was initiated to investigate the discrepancy between the LEFMs and other multiple indications. The troubleshooting investigation was conducted by Exelon, Cameron, and Dominion Engineering and subjected to an in-depth review by MPR Associates, ILD Inc., and Dominion Engineering. Troubleshooting was completed in April 2012 (Borton, October 9, 2012, Attachment 2), and did not clearly identify the cause of the observed behavior. Byron, Unit No. 2, and the Braidwood units did not exhibit as large a discrepancy and no other plants had a similar discrepancy. The licensee reported that no other plants used PAA injection.

The NRC staff has audited the troubleshooting investigation and has conducted independent calculations based on the proprietary and non-proprietary data provided by Exelon and Cameron. One aspect of the trouble shooting was a determination that there was no significant deposit on the LEFM aperatures. The NRC staff did not accept the assumptions and analysis approach but confirmed the conclusion via independent analysis as discussed below.

On the basis of observed FR[7] data and the assumption that the power law or the modified Reichardt equation represented the flow profile, and study of operating data, the NRC staff determined that the effective change in CheckPlus LEFM calibration was less than 6×10^{-4} percent and therefore was negligible.

Estrada (March 2012), concluded that analyses from all elements of the LEFM algorithm were in the range of + 0.05 percent to + 0.079 percent, in the opposite direction of the postulated LEFM drift that would be consistent with the best estimate based on other plant variable trends that indicated a LEFM change of about - 0.4 percent. He also concluded that the difference between LEFM indication and the best estimate was within the root sum square of the ± 0.3 percent LEFM uncertainty and the best estimate uncertainty of ± 0.55 percent.

The average difference between the LEFM and other parameters that can be used to determine FW flow rate or thermal power was about 0.25 percent at the end of the increased difference that occured from May, 2011 to September, 2011. Operating parameters from October, 2011 to May, 2013 established that differences had stabilized and were no longer increasing. The requested increase in thermal power corresponds to a power uncertainty of 0.37 percent, the calculated bounding value for system mass flow rate uncertainty was < 0.3 percent and the thermal power uncertainty was < 0.4 percent. The staff concludes that the observed differences are smaller than the uncertainties that Caldon

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[6] Industry experience had shown that PAA could reduce iron oxide accumulation on secondary side SG surfaces and that it could remove previously deposited iron-based corrosion products from secondary plant surfaces.

[7] The CheckPlus determines average flow velocities along straight line paths of two lengths. FR is the ratio of the measured velocity via the shorter path to the measured velocity via the longer path. Flow rate is determined by multiplying each velocity by the flow area it is assumed to represent and correcting for the angle between the measurement and the direction of flow.

calculated that were part of the basis for the LAR. On this basis alone, the observed differences between LEFM and other plant indications are not sufficient to invalidate the FW flow rate indicated by the LEFMs. Further, the NRC staff concludes that the LEFMs are not affected by PAA injection and the observed deviation in thermal power and FW flow rates are not due to the LEFMs.

Examination of the data by the licensee, as well as the staff, strongly indicates that the venturis are affected by PAA injection although the reasons are not clear nor are the differences between Byron, Unit Nos. 1 and 2, fully understood.

The licensee's troubleshooting team also postulated reasons for deviation in other plant parameters. All members of the licensee's troubleshooting team did not accept the conclusions and the NRC staff concluded the reasons for the deviation were not sufficiently supported to lead to firm conclusions.

Discussion

Information provided during an audit conducted at Cameron's headquarters on May 14, 2013, was that Byron and Braidwood are the only stations that use PAA injection in FW. Thus, Byron considered that there was a lack of data concerning possible impact of PAA on LEFM operation. With respect to FW venturis and steam flow rate indications, PAA was known to have an impact.

Byron initiated an extensive troubleshooting plan when an upward trend in secondary parameters occurred that indicated Byron, Unit No. 1, thermal power was increasing in contrast to LEFM indications that thermal power was constant. This included securing PAA injection for two months and injecting PAA at an increased concentration after that. Securing PAA was accomplished to see if the upward trend would be reversed. Increasing PAA concentration was to discern if accumulation of PAA or PAA byproducts occurred that would cause secondary parameters to reach a higher magnitude.

Observed power behavior

During the time between May 2011, and September 2011, Byron, Unit No. 1, was operated so that flow rate indicated by the LEFMs was essentially constant and other plant parameters indicated an increasing flow rate. The Byron observations of the effect on thermal power, and NRC staff estimates of the changes, were as follows:

Item	Percent Change	
	Byron	NRC estimate from Data
Impulse Pressure	0.21	0.20
First Stage Pressure	-	0.29
SG Steam Flow	0.20	0.25
LEFM Temperature	-	0.02
Pump Flow	0.23	0.20
RCS Differential Temperature	0.26	0.49[8]
Core Thermal Power	0.25	-

[8] Hot leg streaming changes will influence this parameter and could cause significant error.

Venturi Thermal Power	0.27	-
LEFM Thermal Power	0.01	-
LEFM Flow Rate	~0.05[9]	0.04

The largest change in the difference between flow rates occurred between the LEFMs and venturis. The correspondence of multiple indications of an increasing flow rate and thermal power with a close-to-constant LEFM indication raised questions regarding LEFM calibration drift and accuracy.

Byron troubleshooting program

Summary

The LEFMs were installed at Byron, Unit No. 1, during RFO B1R17 that ended in late April 2011. Following start-up, PAA was injected to control SG crud buildup. Multiple indications showed a gradual rise in thermal power when thermal power was held constant by controlling via the LEFMs from May to September 19, 2011 (Byron, September 19, 2011.), and Byron initiated an extensive troubleshooting effort to investigate the discrepancy. The troubleshooting investigation was conducted by Exelon, Cameron, and Dominion Engineering and subjected to an in-depth review by MPR Associates, ILD Inc., and Dominion Engineering. Troubleshooting was completed in April, 2012 (Borton, October 9, 2012 Attachment 2), and did not identify the cause of the observed behavior. Byron, Unit No. 2, and the Braidwood units did not exhibit as large a discrepancy and no other plants had a similar discrepancy.

Key results of Exelon's troubleshooting program and the NRC staff findings included the following:

- Cameron used many diagnostic indicators to conclude that there were no LEFM anomalies. It concluded that LEFM performance was within its design basis. The NRC staff also concluded that the LEFM performance was within its design basis..

- PAA build-up or PAA byproducts on LEFM surfaces were determined not to be a cause. The NRC staff did not identify any phenomenon that would contradict this conclusion.

- No anomalies were identified where hydraulic impacts, secondary parameter instrumentation drift, erosion/corrosion, or calorimetric program errors were identified that would result in the observed secondary parameter drifts. As discussed below, the NRC staff identified some anomalies that were not explained and Cameron identified interactions that it posited could explain the behavior.

The licensee provided the following observations based on further study:

- A best estimate methodology based on five power system conversion measurements (secondary parameters) was used to calculate thermal power. Byron concluded that current thermal power was consistent with the previous two cycles that operated on the venturis at 100 percent power. NRC staff review of a comparison of indicated

[9] Cameron estimate of maximum bias (Ultrasonics, May 14, 2013).

thermal power (ITP) versus Best Estimate Thermal Power (BETP) established the following:

- BETP > ITP from April 2008 to Refueling Outage B1R17 in 2011.
- BETP < ITP in May, 2011 and gradually increased to equal ITP in September, 2011. Operation was with LEFM controlling IPT.
- BETP > ITP for several following months when operating under venturi control.
- BETP = ITP subsequently until February, 2012 when operating under LEFM control.

- Comparison with Byron, Unit No. 2, and Braidwood, Unit 2, startups in 2011, failed to show similar upward trends in secondary parameters. The NRC staff confirmed this conclusion by examining the data.
- Review of industry operating experience did not identify differences between LEFM and venturi indication that occurred at Byron 1.
- Byron found no significant issues or errors in inputs to the plant calorimetric that would result in the observed drifts.
- Byron did not identify any power plant failure mechanisms that would explain the drifts.

With regard to the last two items, the NRC staff notes that Cameron believes it identified reasons for drifts in steam flow rate and venturi behavior. The Cameron conclusions and additional unexplained anomolies identified by the NRC staff are discussed below.
NRC staff review of operating parameters from October 2011 to May 2013, established that differences had stabilized and were no longer increasing. This is important because it eliminates a potential concern that continued drift could raise questions regarding LEFM operating outside its uncertainty limits.

<u>Discussion of selected aspects of troubleshooting program</u>

The licensee's troubleshooting investigation was described in its submittal dated October 9, 2012, and updated during an audit conducted at the Cameron offices on May 14, 2013. Potential failures and licensee conclusions were as follows:

(1) "Installation configuration results in hydraulic impacts causing the LEFM to read lower than actual."

- There were no significant differences in piping configurations between trains and UFM installation was consistent with specifications.
- There were no upstream obstructions that could affect the LEFMs

Review complete and determined not to be a cause.

(2) "Plant process computer (PPC) interface to LEFM is causing errors in the data."

- LEFM flow indication was determined to be accurately communicated to and displayed on the PPC.
- Modeling of programs and flow calculations to handle net flow and tempering line flows were determined to be correct.

Review complete and determined not to be a cause.

(3) "LEFM problem causing erroneous readings."

- Commissioning changes such as software changes; cable lengths; and alarm, hydraulic, and setup configurations were determined to not significantly affect LEFM readings.
- No significant differences were found between trains or with respect to Alden Labs test results.
- Environmental conditions were within specifications.
- Operating experience (OE) review found no new applicable information.
- Power supplies were within specifications.
- Pressure and temperature inputs have not drifted which eliminates bad sensor input as a cause.
- No significant integration errors were found with internal integration.
- Evaluation of transfer to Venturi control and observance of trends to identify potential LEFM problems did not identify errors.

Byron concluded that no anomalies were identified and this failure mode was not a cause.

(4) "Venturi calibration or drift issue is causing the descrepancy."

- Byron initially stated there were no unexplained drifts or deviations.
- No secondary calibrations of the flow elements or correction factors have been applied to the venturies that would cause large bias or uncertainty.
- No significant diverging trends were found in the LEFMs compared with other balance of plant (BOP) parameters.
- Venturi bypass flow has been stable and there are no gaps to allow bypass flow.

- Newly developed discharge coefficients were correctly implemented and the discharge coefficient extrapolation method was determined not to be in error.

Byron concluded that no anomalies were identified and this failure mode was not a cause.

(5) "External interaction with venturi / LEFM spools by either PAA or erosion / corrosion."

- PAA injection was expected to cause an indicated 0.2% increase in flow rate indicated by the venturies. An uncertainty of 0.3% was added to the calorimetric to compensate for the increase. Byron concluded that the impact on the venturies did not change. Further, it stated that PAA injection was not expected to affect the LEFMs.

Byron concluded that no anomalies were identified and this failure mode was not a cause.

(6) "Calorimetric input or program fault."

- FW flows, SD flow, FW temperature, steam temperature, and steam pressure calorimetric inputs were verified as correct. However, two issues were identified:

- Tempering lines normally are expected to pass about 40,000 lbs/hr per loop of feedwater flow that bypasses the LEFMs and venturis (160,000 lbs/hr total). These lines were individually isolated with the expectation that measured feedwater flow would increase by about 40,000 lbs/hr for each isolation. This occurred with Loops A, B, and C with a nearly identical decrease within something less than 2000 lbs/hr per loop but Loop D isolation caused an indicated increase in feedwater flow of 46,000 lbs/hr in contrast to a pre-isolation flow rate of 41,000 lbs/hr, a difference of 5000 lbs/hr. Byron stated that this anomaly would represent a 0.03 percent change in thermal power based on a total feedwater flow rate of 16 X 10^6 lbs/hr and would not be the cause of the observed drifts in secondary parameters.

- SG blowdown flow was isolated with the expectation that feedwater flow rate indicated by the venturis and the LEFM would decrease by the same amount from individual blowdown flows of 18,000 lbs/hr. Most loops showed a nearly identical decrease within 2000 lbs/hr but Loop B decreased by ~ 28,000 lbs/hr, a change from expectations of 10,000 lbs/hr or a change of 0.063 percent based on total feedwater flow. Byron concluded that this change would have a conservative impact of core thermal power in contrast to the change in the opposite direction that was observed when LEFM flow was held constant and other plant parameters indicated an increase in power.

- Program was reviewed against plant parameters and verified to correctly calculate thermal power.

Byron concluded that this failure mode was not a cause.

The NRC staff evaluated the licensee's troubleshooting efforts and finds the licensee's conclusions regarding the various failure modes acceptable. The staff identified and

discussed several issues with the licensee. For example, the NRC staff noted that Train B FR decreased from May to September, 2011 whereas Trains A, C, and D increased. The staff concluded that the changes were within expectations and do not significantly affect MF. The NRC staff also observed that there were unexplained differences between venturi and other indications. It also observed that venturi differential pressures for A, B, and D decrease by about one inch from May to September, 2011 while C increased by the same amount. The licensee provided information during the audit that venturis were known to be affected by PAA injection. Cameron and the NRC staff reached the same conclusion. Based on the staff's obsersvation of the licensee's troubleshooting efforts, the staff concludes the various failure modes were appropriately eliminated.

Effect of changing PAA injection concentration

The PAA was injected following startup from RFO B1R17 in late April 2011, until November 2011. The venturis and other secondary side parameters that can be related to thermal power showed a linear increase relative to the LEFMs from May 2011, until September 2011, while the LEFMs were used to control FW flow rate and thermal power to a steady state. A power reduction then occurred after which the venturi to LEFM ratio appeared to stablize at a value slightly larger than before the reduction. PAA injection was stopped for two months starting in November 2011. Within a day of stopping PAA, the venturi indication decreased relative to the LEFMs. There was no further change in the difference between the venturis and LEFMs while PAA was stopped. Upon re-initialization of PAA, the venturi indication increased by about 0.15 percent in less than a day relative to the LEFM; a reversal of the behavior when PAA was stopped.

The PAA injection rate was increased in Byron, Unit No. 1 in February 2012. With one exception, there was no change in the venturi to LEFM comparison through mid-March 2012. The exception was a short time when PAA injection stopped. During this time, the ratio changed as described in the above paragraph.

PAA injection was increased in Byron, Unit No. 2, in February 2012. LEFM and venturi tracked closely into March 2012, with a slightly closer correspondence in March. This convergence was more pronounced when compared to other plant parameters with an initial relative correspondence of about 0.998 and a March correspondence of 0.999.

Additionally, several of the licensee's investigators concluded that PAA had no impact on the LEFMs.

The NRC staff concludes that the venturi behavior described above varies with PAA injection and demonstrates that PAA affected the Byron 1 venturis.

Best estimate (BE) comparisons

A BE methodology can be developed that combines independent variables on the basis of including their individual uncertainties as weighting factors to obtain an estimate with an uncertainty that is less than any of the individual variables. Three BE methodologies were developed by different investigators and applied to compare indicated thermal power to BE thermal power from April 2008, to February, 2012. From 2008 until RFO B1R17 indicated power was less than BE power, a comparison that continued following RFO B1R17 until LEFMs were used to control thermal power. At this time, LEFM thermal power reversed and was greater than BE thermal power. The two then converged until September 2011, when

power control was changed to the venturis and the pre-RFO B1R17 behavior was observed. A change back to LEFM control resulted in close correspondence that continued into February 2012, when the Byron report comparison terminated.

Assessment of LEFM

The NRC staff independently examined aspects of the observed behavior. This examination is summarized below.

Dimensional information

(Spadaro, July, 2010) provided drawings of the ARL configurations that specified spool piece dimensions and Cameron provided tolerances and as-built dimensions during the May 14, 2013, audit that established that the as-built LEFMs were within tolerances. As-built wall thicknesses were measured in May 2010, and again in March 2012, following 11 months of operation (Estrada, March, 2012). Neglecting measurement uncertainty, Cameron calculated that the change would introduce a net change in internal diameter of – 0.024 percent and a flow error of + 0.012 percent (Ultrasonics, May 14, 2013). Dimensional changes are not a likely cause of the observed behavior.

Effect of deposit in transducer apertures

Estrada reported that the drift from May 2011, to November 2011, due to a postulated corrosion layer in the apertures was ruled out on the basis of measurements that established that there was little wall thickness change and a rationale that a small deposit on aperture walls "is not sufficiently thick to transmit acoustic energy and, therefore, not capable of altering the effective sound velocity in the aperture."

The NRC staff does not agree with Cameron's rationale. First, Cameron concluded that evidence of little change in spool piece diameter established that there was no deposit on the spool piece walls and, therefore, there was no deposit in the apertures. While the NRC staff agrees that there was no significant change in diameter based on the measurements, this is not justification regarding deposits in the apertures. It is possible for a deposit to form in the apertures while the spool piece walls remain deposit-free. While Cameron's conclusion that a small deposit on the aperture walls is not thick enough to transmit acoustic energy may be correct, this does not address the effect of a deposit on the aperture window that reduces the measured time from one transducer to another due to decrease in transmission distance and the change in velocity of sound between water and a deposit in the volume where the deposit displaced water.

Assuming a deposit affects all apertures equally, the Cameron LEFM can indicate the effect of a deposit on the transducer housings in the apertures because there will be a larger effect on the measured short path sound velocity in comparison to the long path sound velocity. This can be expressed in terms of the "flatness ratio," FR, defined by the following equation:

$$FR = \frac{V_1 + V_4 + V_5 + V_8}{V_2 + V_3 + V_6 + V_7}$$

where V_1, V_4, V_5, and V_8 are velocities measured along the outside chords (the short paths) and V_2, V_3, V_6, and V_7 are velocities measured along the inside chords (the long paths)

A change in FR can be approximated by the following equation:

$$\frac{y_s'}{y_l'} = \frac{y_s}{y_l} + \Delta FR$$

where: y_s = short path length
y_l = long path length

and the prime indicates the new path length.

If an effective deposit thickness, x, increases on the transducer window surfaces that is identical on all windows and has the properties of water, then:

$$y_s - y'_s = 2x \qquad y_l - y' = 2x$$

and:

$$y_s - y'_s = y_l - y'$$

so that:

$$y_l' = \frac{y_s - y_l}{\frac{y_s}{y_l} + \Delta FR - 1}$$

Estrada provided FR changes during a seven month period starting in May, 2011. Using these data, the NRC staff estimated the predicted thickness changes would change flow rate by less than 0.01 percent, in agreement with Cameron's conclusion. This is not a likely cause of the observed behavior.

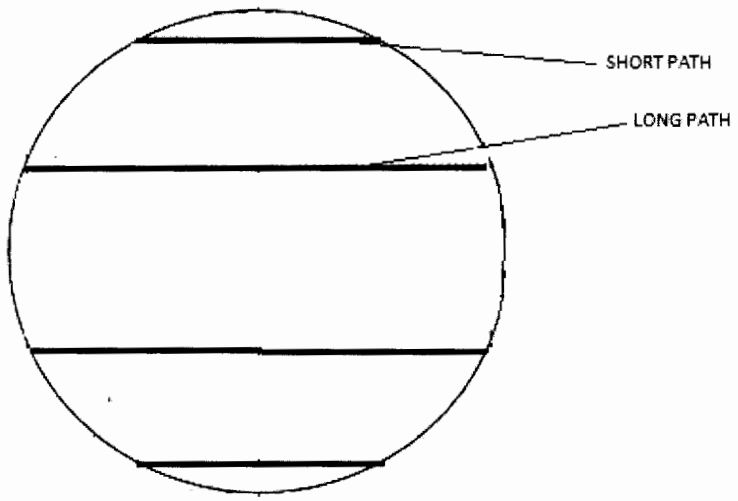
Effect of flatness ratio (FR) change on meter factor (MF)

FR, as discussed above, is defined as:

$$FR = \frac{V_1+V_4+V_5+V_8}{V_2+V_3+V_6+V_7} = \frac{V_S}{V_L}$$

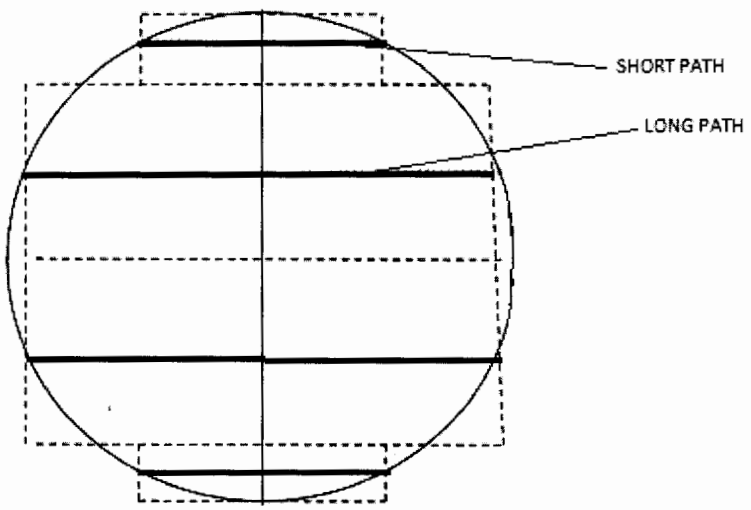
where V_1, V_4, V_5, and V_8 are velocities measured along the outside chords (the short paths), V_2, V_3, V_6, and V_7 are velocities measured along the inside chords (the long paths), V_S is the mean short part velocity, and V_L is the mean long path velocity. The paths are illustrated by the horizontal lines in the following figure that correspond to the paths between the CheckPlus LEFM transducers[10]:

[10] Measurements are at an angle with respect to pipe length. Velocities are translated into this configuration for calculation purposes.



FR can be determined experimentally, such as by testing at ARL where the CheckPlus LEFM will provide the velocity data.

Once the V's are determined, the flow rate determined by the CheckPlus LEFM can be calculated by multiplying the rectangular vertical widths (weighting factors) indicated in the following figure by the dash lines by the corresponding velocities times two:

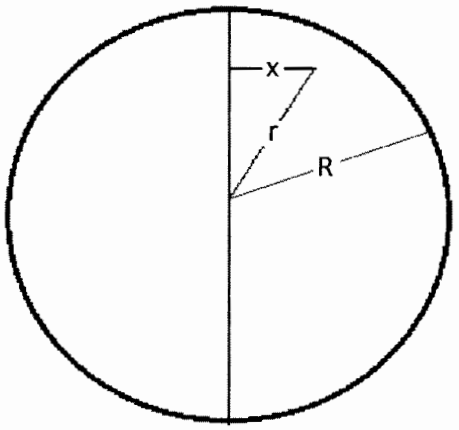


Cameron uses the same weighting factors for all of its nuclear applications. As is demonstrated below, this does not appear to be consistent with theoretical analyses when FR is compared to MF in an analysis of the ARL data obtained with the Byron, Unit No. 1, LEFMs.

Once the CheckPlus LEFM flow rate has been calculated, MF can be determined by comparing the CheckPlus LEFM flow rate to the experimentally determined data.

FR and MF can also be calculated using an assumed symmetric velocity distribution that is a function of pipe radius, expressed as V(r), where r is the reduced radial position with the origin at the pipe centerline and $0 \leq r \leq 1$. Since the CheckPlus LEFM determines a mean

velocity along the path, the calculation must be based on the same path, as illustrated by the "x" dimension in the following figure:



where the mean velocity is calculated by 1/X $\int_0^X V(x)dx$ where x= X at r = R and V(x) is determined from the assumed V(r) where the relationship between x and r is obtained from the geometry illustrated in the figure.

The calculations define MF as the flow rate calculated by 2π $\int_0^1 V(r)\, r\, dr$ divided by the calculated LEFM flow rate obtained by two times $\int V(x)\, dx$ over the short and long path lengths multiplied by the corresponding weighting factors.

Spadaro described the velocity profile by the power law:

$$V = (1 - r)^{1/n}$$

where V is the velocity normalized to the maximum value, and n is a function of Reynolds number and pipe roughness that changes the shape of the profile. FR and MF were calculated using an Excel spreadsheet with the calculation based on dividing the dimension spans into 1000 increments to provide an accurate calculation that addresses profile changes near the LEFM wall. The NRC staff used the same approach except it assumed the increment size was ten times smaller in the last 20 steps near the wall, a total of 1018 increments. The NRC staff assessed the calculation accuracy by changing the number of increments with the results summarized in the following table for a typical FR where the comparisons were obtained using the NRC staff methodology:

Nominal number of increments	Calculated relative short path velocity	Calculated relative long path velocity	Calculated relative FR	Calculated relative MF
1000	1.0000	1.0000	1.0000	1.0000
500	1.0000	1.0000	1.0000	1.0000
250	1.0001	1.0001	1.0000	1.0001

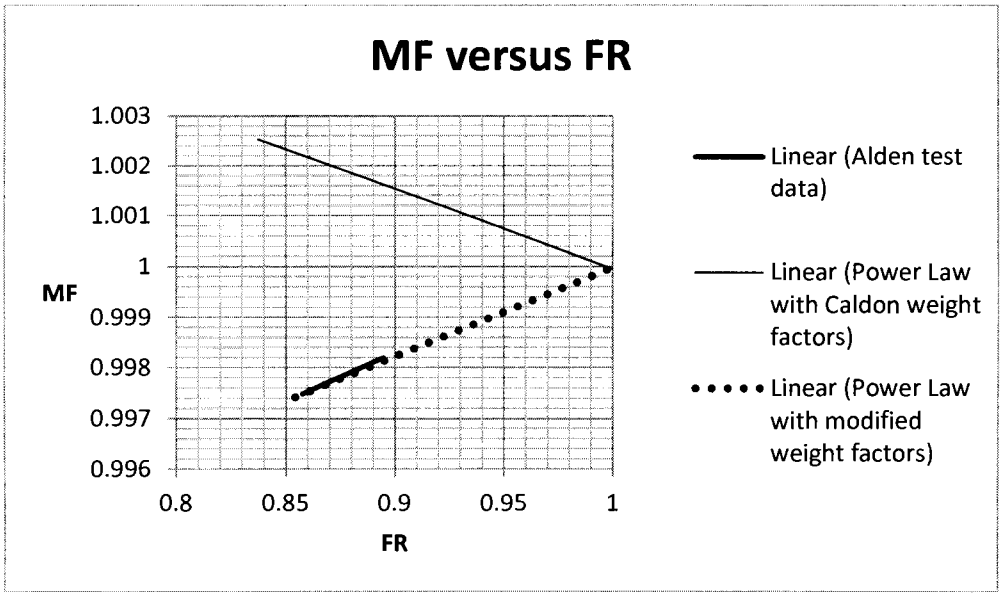
The calculations using 1000 increments do not introduce a significant numerical error.

Estrada (Estrada, January 2002), used the power law and weighting factors determined by Caldon to calculate MF as a function of FR and found that the calculations could be fitted by a straight line. All MF's were greater than one for FR < 1 and the results converged to MF = 1 at FR = 1. In support of the NRC staff's conclusion, the comparisons are illustrated below as well as the NRC's conclusions as to the significance of the different approaches.

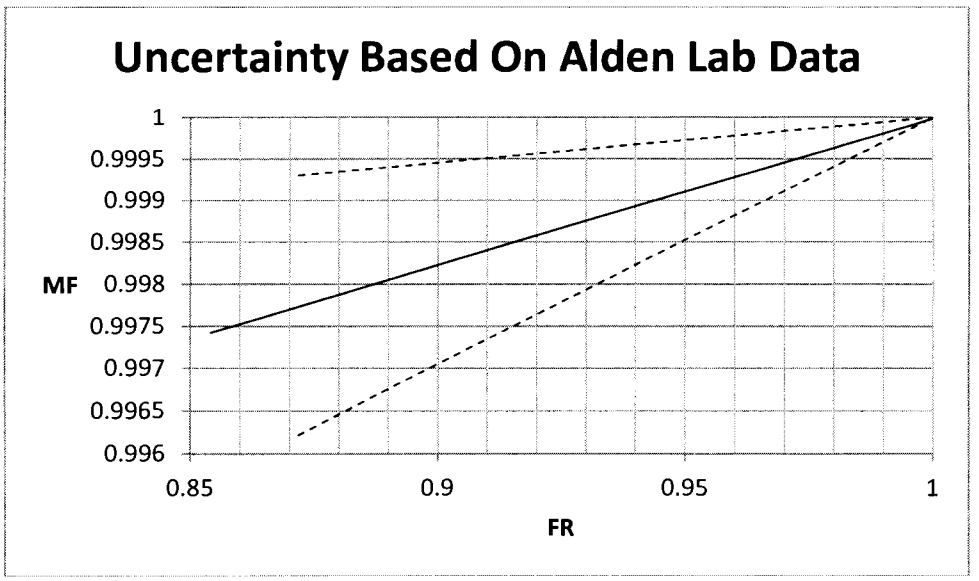
Each of the four CheckPlus LEFMs installed at Byron, Unit No. 1, was tested at ARL. There were three test piping configurations in addition to a configuration to model the plant installation for each CheckPlus LEFM. More than one flow rate was included in each configuration test. The configuration variations were, for example, to introduce swirl to bracket any variations that would be encountered in the plant. The test report (Spadaro, July 2010), provided FR versus MF for each of the 16 test configurations. All MF's were less than one yet, as stated above, the results were plotted on Estrada's straight line where the line is limited to MF > 1. This was achieved by offsetting the MF for each meter such that the average MF was on the predicted curve. The off-set "data" correspondence to the straight line was an excellent fit. Caldon explained that the purpose of this work was to illustrate the dependence of MF on FR and, in this case, the change was small, as is discussed below.

In contrast, the NRC staff calculated MF behavior using the power law and the Caldon weighting factors and compared it to a straight line fit of the Alden Labs test results for the four LEFMs installed at Byron 1. The comparison is shown in the following figure where the upper solid line is the calculation and the lower solid line is a straight line fit to the data. There is effectively no correspondence. The NRC staff also modified the weighting factors so that the power law reproduced the mean MF and FR of the 16 ARL test results and, using the modified weighting factors, repeated the calculation to obtain the dash line. The fit of the power law to the data line is excellent.

The importance of this information is that MF is related to FR by a straight line that converges to MF =1 as FR approaches 1 and, regardless of which line is used, MF as a function of FR can be predicted as long as the approach is consistent. Further, MF does not change significantly over the tested range as shown by the ARL solid line in the figure. Consequently, the NRC staff did not pursue the discrepancy since resolution was not necessary for the regulatory purpose addressed herein.



The above calculations were based on nominal test values without considering the ARL flow rate uncertainty. There is significant scatter in the 16 data points, in part due to testing different configurations to bracket possible variations introduced in the plant installation. Simply obtaining the standard deviation, σ, without considering variation in FR, approximating uncertainty as two times σ, and applying the uncertainty at the mean FR of the data provided the following approximation of the data scatter. Note that the upper extreme never reaches MF = 1 except at FR = 1 in contrast to the Caldon extrapolation of the data to the Caldon calculation that Caldon used to evaluate MF sensitivity. Further note that Caldon's approach results in a reduction in MF with increasing FR whereas the Alden data establishes that MF increases with increasing FR. In contrast, the absolute magnitude of the MF changes is identical due to the mirror image of the two calculations with respect to MF = 1.



The NRC staff used it's Excel spreadsheet to calculate the velocity distributions and effect on MF that corresponded to the observed FR's provided by Estrada for the May 2011, to November 2011, FR's. The conclusion from the NRC staff study was that, regardless of which approach is used (which changes the curve that applies), the change in FR that occurred between May and September 2011, is predicted to introduce a maximum change in MF of about 6×10^{-6} which is negligible. Stated differently, the NRC staff concludes that the CheckPlus LEFM calibration is not calculated to have changed by more than about 6×10^{-4} percent. Further, an important consideration for determining the significance of Byron Unit 1 trend is that the test data included the expected plant configuration and modifications that caused swirls that were greater than observed during plant operation. Therefore, the NRC staff concludes that the Byron Unit 1 trend was not significant.

Effect of thermal expansion

The coefficient of thermal expansion is a multiplier on both the numerator and denominator in calculation of MF. Therefore the NRC staff concludes that thermal expansion has no effect on MF assuming there are no other effects that perturb the calculation.

Effect of a change in speed of sound of FR

The change in the speed of sound affects the numerator and denominator equally. Therefore, the NRC staff conlcudes that there is no effect on FR assuming there are no other effects perturbing FR.

Coherent noise

Cameron investigated the interaction of coherent noise that can interact with the acoustic signals and can affect transit time measurements. Cameron concluded that coherent noise did not account for the LEFM trend in comparison with other plant parameters. The NRC staff finds this conclusion acceptable based on the Cameron investigation.

LEFM conclusions

The licensee did not identify any cause of a change in LEFM characteristics that would indicate a significant measurement error was caused by the LEFMs. Based on the NRC Staff's independent review discussed above, the NRC staff concludes the licensee's evaluation is acceptable. Based on the information in this section, the NRC staff further concludes that the LEFMs are not affected by the PAA and LEFM characteristics remain within the initially established uncertainty bounds.

Cameron's examination of other indicators of flow rate[11]

Thermal power increased by about 0.5 percent from May 2011, to September 2011, by using the LEFM indications for control. Thus, for discussion purposes, thermal power based on LEFM indications may be treated as constant when assessing other parameters that may be used to determine thermal power. During this time, venturi flow, turbine pressure indicators, and total steam flow all indicated that thermal power was increasing at a greater rate. The venturis indicated a rate increase larger than the other indicators. Consequently, the NRC staff concludes that either the LEFM or the other indicators were providing

[11] Discussion based on information provided in the May 14, 2013 audit (Ultrasonics, May 14, 2013) unless otherwise stated.

erroneous information. As discussed above, no cause was identified that would change LEFM characteristics such that a significant measurement error would result. The NRC staff therefore accepts the licensee's determination that other parameters changed is correct.

Venturis

The venturis are located downstream of the PAA injection location. Cameron stated that PAA is a dispersant that leads to a feed stream that contains collioidal corrosion products. These can be electrochemically attracted to the stainless steel surface in the venturi throat since the high throat velocity sweeps away the neutralizing free electrons. Cameron stated that this causes venturi fouling that, in turn, makes the venturis indicate a flow rate that is higher than actual.

Cameron also identified that PAA interaction that affected venturi calibration was observed before LEFM installation and pointed out that a brief cessation of PAA injection led to an immediate shift of 2 percent in indicated venturi flow indication relative to all other indicators of FW flow rate.

Cameron concluded that PAA changed FW calibration by approximately 3 percent or more and could explain the observed discrepency between the LEFM and venturi flow rate indications.

The NRC staff observed that there were differences between venturi indications. However, when each venturi flow rate was compared to the corresponding LEFM flow rate, all venturis exhibited a similar upward trend with approximately the same slope from May to September 2011. Based on the above the NRC staff concludes that the Cameron conclusions are acceptable.

Turbine pressure indicators and main steam flow

There are two water paths to the SGs, FW flow that is measured by the LEFMs and venturis, and tempering flow that is also measured but bypasses the LEFMs and venturis. Tempering flow rate was approximately one percent of FW flow rate during the comparison period and was stated to be constant. As identified in (6), above, an anomaly related to the tempering flow was identified by the NRC staff. However, the anomaly is not significant, is not a cause of the secondary parameter shift and therefore, is not a regulatory concern.

There are two flow paths that exit the SGs, main steam flow, and blowdown flow. SG steam flow is therefore equal to tempering flow plus main feed flow minus blowdown flow. Blowdown flow rate is measured and was about 0.5 percent of total flow into the SGs during the comparison period. As identified in (6), above, an anomaly related to the blowdown flow was identified by the NRC staff. However, the anomaly is not significant, is not a cause of the secondary parameter shift and therefore, is not a regulatory concern.

Most of the steam flow enters the turbine with about 5 percent entering the second stage reheater. Cameron stated that there was no evidence that steam flow to the second stage reheater changed significantly as a fraction of total steam flow. Changes in SG steam flow in the comparison period were stated to be less than 0.1 percent.

First stage pressure is a measure of vapor flow rate and Cameron stated that, for practical purposes, is not affected by change in moisture content. Therefore Cameron concluded that

if FW, blowdown, and tempering flow rates are constant, a decrease in steam moisture will increase vapor flow rate and first stage pressure. Cameron also stated that, "Because the steam flow and first stage pressure instruments respond differently to changes in moisture content, their indications can be used to estimate trends in moisture content." It also stated that changes in differential pressure across steam flow nozzles and first stage pressure "can be used to calculate the change in moisture carryover." A Cameron moisture trend calculation showed a moisture decrease "approximately equal to the discrepancy between turbine flows and LEFM flow."

Cameron concluded that:

- "The process change in moisture carry-over is the most plausible explanation consistent with all of the data."
- "The change in moisture carry-over should be expected given the effects intended with the PAA addition."

The NRC evaluated the Cameron efforts and determined that the Cameron conclusions are reasonable because PAA caused a steam pressure increase "apparently due to removal of corrosion products from the SG tube surface" and "reduction of deposits on separator cans by a similar mechanism could lead to a reduction in moisture."

Recent plant characteristics

The PAA was restored in January 2012, during steady state operation after an extended period when PAA was not injected. Exelon provided data normalized to one after an initial transient that followed re-initiation of PAA. Upon re-initiation, steam flow indication immediately decreased by 0.5 percent and venturi indication increased by 0.16 percent before reaching a relative value of one while LEFM, best estimate core thermal power, impulse pressure, and MWt were unchanged. Although there were numerous power transients following re-initiation, indications that apply to flow rate remained consistent after the initial transient until the plant was shut down for RFO B1R18 in August 2012. The licensee identified that a divergence in steam mass flow rate occurred previously when PAA was isolated and an upward trend occurred that was attributed to likely occurrence of new deposits on secondary steam separator surfaces or the SG outlet nozzle venturi surfaces. These deposits were postulated to have cleared when PAA was restored in January 2012. The NRC staff considers this experience as supporting a conclusion that PAA affects both SG flow rate and venturi indication. Further it observes that PAA caused indicated SG flow rate to decrease and venturi flow rate to increase. The former is opposite to the 2011 behavior and twice as large whereas the venturi indicated flow rate change is essentially identical to the change that occurred in 2011. In both of these cases, the change was immediate in contrast to the change that occurred over several months from May to September in 2011.

After startup following RFO B1R18 in October 2012, until May, 2013, the parameters were essentially unchanged during full power operation. This indicated that whatever was causing the parameter divergence was no longer occurring. The licensee stated that it plans to continue to perform detailed trending assessments through start-up and power ascension following RFO B1R19.

Conclusion for Other Indicators of Flow Rate

As summarized, above, the average difference between the LEFM and other parameters that can be used to determine FW flow rate or thermal power was about 0.25 percent at the end of the increased difference that occured from May 2011, to September 2011. Operating parameters from October 2011, to May 2013, established that differences had stabilized and were no longer increasing. The requested increase in thermal power corresponds to a power uncertainty of 0.37 percent, the calculated bounding value for system mass flow rate uncertainty was < 0.3 percent and the thermal power uncertainty was < 0.4 percent. The observed differences are smaller than the uncertainties that Caldon calculated that were part of the basis for the LAR. On this basis alone, the NRC staff concludes that the observed differences between LEFM and other plant indications are not sufficient to invalidate the FW flow rate indicated by the LEFMs. Further, based on its review, the NRC staff concludes that the LEFMs are not affected by PAA injection and the observed deviations in thermal power and FW flow rates are not due to the LEFMs. The NRC staff further concludes that the anomalies noted do not affect the NRC staff's conclusions stated above.

Based on the examination of the data, the NRC staff concludes that the venturis are affected by PAA injection although the reasons are not clear and the differences between Byron, Unit Nos 1 and 2, are not fully understood. Postulated reasons for deviation in other plant parameters have not been accepted by all licensing personnel and are not sufficiently supported to lead to firm conclusions. As discussed above, the NRC staff determined that although the venturis as well as other plant parameters are affected by PAA, the NRC staff concluded that LEFM characters remain within the initially established uncertainty bounds and, therefore, LEFM performance is not affected.

3.1.1.4 Regulatory Commitments

The licensee provided the following regulatory commitments, applicable to the above discussion, in Attachment 4 of the submittal:

Limitations regarding operation with an inoperable LEFM system will be included in the TRM prior to increasing power above 3586.6 MWt.

The LEFM system for each unit at Byron and Braidwood Stations will be installed prior prior to increasing power above 3586.6 MWt.

For Byron Station Units 1 and 2; and Braidwood Station Units 1 and 2; final acceptance of the unit-specific uncertainty analyses will occur after the completion of the commissioning process and prior to increasing power above 3586.6 MWt.

The NRC staff concludes that the licensee's implementation of the above commitments prior to raising power above 3586.6 MWt (CLP) is acceptable. The NRC staff further concludes that revising the TRM and installing the LEFM system in accordance with 10 CFR Part 50.59 is acceptable because 10 CFR Part 50.59 establishes criteria to determine whether or not NRC approval is required. The NRC staff also concludes that final acceptance of the unit-specific uncertainty analysis is adequately controlled by the licensee's design control program required by 10 CFR Part 50, Appendix B.

3.1.1.5 Conclusion

The above review covers the aspects of the requested 1.63 percent MUR thermal power uprate that are specific to the CheckPlus LEFM installations. Based on the above, the NRC staff concludes that the requested MUR thermal PU of 1.63 percent is acceptable with respect to the CheckPlus LEFM installations.

3.1.2 Containment Systems Design (RIS 2002-03, Attachment 1, Section VI)

3.1.2.1 Regulatory Evaluation

GDC 4, in Appendix A to 10 CFR Part 50, "Environmental and dynamic effects design basis," addresses the environmental qualification of SSCs important to safety. The NRC staff reviewed the licensee's prediction of conditions in containment during postulated accidents. No regulation specifically addresses the determination of the mass and energy release into the containment following a postulated design basis accident. However, GDCs 16 and 50, address the requirements for the containment pressure resulting from a postulated design basis LOCA.

Part 50, Appendix A, GDC 16, "Containment design," specifies that the reactor containment and associated systems shall be provided to establish an essentially leak tight barrier against the uncontrolled release of radioactivity to the environment and to assure that the containment design conditions important to safety are not exceeded for as long as postulated accident conditions require.

Part 50, Appendix A, GDC 38, "Containment heat removal," specifies that a system to remove heat from the reactor containment be provided and that this system shall reduce rapidly, consistent with the functioning of other associated systems, the containment temperature and pressure following any LOCA.

Part 50, Appendix A, GDC 50, "Containment design basis," specifies that the reactor containment, including access openings, penetrations, and the containment heat removal system shall be designed to accommodate, without exceeding (with sufficient margin) the design leakage rate resulting from a design basis LOCA.

The regulations at 10 CFR Part 50, Appendix J, Option B, define P_a as the calculated peak containment internal pressure related to the design basis LOCA as specified in the TSs. As discussed in Section 3.1 of this SE input, the P_a values in TS Section 5.5.16, Containment Leakage Rate Testing Program, remain greater than the P_a values calculated for the uprate.

Chapters 6.2.1 "Containment Functional Design," 6.2.1.2, "Subcompartment Analysis," 6.2.1.3, "Mass and Energy Release Analysis for Postulated Loss-of-Coolant Accidents," and 6.2.1.4, "Mass and Energy Release Analysis for Postulated Secondary System Pipe Ruptures," of the SRP provide review guidance in the area of containment safety analysis.

3.1.2.2 Technical Evaluation

Short-Term (Subcompartment) LOCA Mass and Energy Release and Containment Analysis (RIS 2002-03, Attachment 1, Section VI.1.B)

Chapter 6.2.1.2, "Subcompartment Analysis," of the SRP, defines a subcompartment as any fully or partially enclosed volume within the primary containment that houses high energy piping and would limit the flow of fluid to the main containment volume in the event of a postulated pipe rupture within that volume. Sub-compartment analyses verify that the walls of a sub-compartment maintain their structural integrity following the rupture of any high energy line within the sub-compartment.

In Section II.2.14 of Attachment 5 to the licensee's submittal, letter, the licensee states that the current M&E sub-compartment releases are bounding for the MUR PU. The NRC staff concludes that this is expected and is acceptable without further review because RIS 2002-03 states that in areas (e.g., accident/transient analyses, components, systems) for which the existing analyses of record do bound plant operation at the proposed uprated power level, the staff will not conduct a detailed review. Therefore the SRP Chapter 6.2.1.2 continues to be met.

Since the current mass and energy release for the MUR PU remains bounding, the NRC staff concludes that the current predicted responses of the sub-compartments remain bounding and therefore GDCs 16 and 50 are met.

LOCA Long-Term Mass and Energy Release and Containment Response
(RIS 2002-03, Attachment 1, Section VI.1.B)

The license describes the LOCA mass and energy release and containment calculations in Section III.15 of Attachment 5 to the licensee's submittal.

The M&E evaluation model consists of the following Westinghouse computer codes: SATAN78, WREFLOOD10325, FROTH, and EPITOME. The Westinghouse COCO code was used for the containment analyses. These codes were used and found acceptable by the NRC staff in a previous power uprate for the Byron and Braidwood units.[12]

The licensee re-analyzed the LOCA long-term M&E release analyses to take into account "an identified inconsistency" in the M&E analyses and to include several input changes from the current analysis that are listed in Section III.15 of Attachment 5 to the licensee's June 23, 2011, letter. The inconsistency was identified in the EPITOME computer code. The licensee describes this inconsistency in its November 1, 2011 supplement.

Several other revisions were made to the M&E and containment analyses. These are listed in Section III.15 of Attachment 5 to the licensee's submittal. These changes either correct input or make the analyses more realistic. For example, the operating time of the containment spray system is revised to reflect the time specified in the emergency procedures.

As a result of these changes, the recalculated peak containment pressure and P_a, remain below the TS values currently in Section 5.5.16, Containment Leakage Rate Testing Program. Therefore, no change is required to the TS values of P_a.

[12] Letter from George F. Dick, USNRC, to Oliver D. Kingsley, President, Exelon Nuclear, Exelon Generation Company, LLC, Issuance of Amendments; Increase in Reactor Power, Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, May 4, 2001

The licensee states in Section III.15.5 of Attachment 5 to the submittal, that the long-term containment pressures for the Byron and Braidwood units are well below 50 percent of the peak value within 24 hours. This satisfies the requirement of GDC 38, Containment Heat Removal, and the guidance of SRP, Sections 6.2.1.1A and 6.2.1.3.

Since the analyses were done with acceptable methods and assumptions, the NRC staff finds the licensee's long-term containment LOCA analyses to be acceptable and GDC 38 is met.

Main Steam Line Break (MSLB) and FW, Mass and Energy (M&E) Releases Inside Containment and Containment Response (RIS 2002-03, Attachment 1, Section VI.1.B)

The containment response to the main FW is not analyzed, consistent with the UFSAR since the specific enthalpy of the fluid discharged into the containment is less than that for the limiting MSLBs.

The licensee predicted M&E releases for the MSLB accident using the LOFTRAN computer code. The licensee calculated the containment response with the COCO computer code. These codes were used and found acceptable by the NRC staff in a previous power uprate for the Byron and Braidwood units in a letter dated May 4, 2001 (ADAMS Accession No. ML011420274).

In its letter dated November 1, 2011, the licensee in response to a staff RAI concerning the modeling of the SGs, the licensee states:

> The Byron and Braidwood analysis used conservative steam generator modeling that is consistent with the NRC approved methodology found in WCAP-8822, "Mass and Energy Releases Following a Steam Line Rupture," September 1976. The Main Steam Line Break (MSLB) analyses use the LOFTRAN code (methodology found in WCAP-8822). The steam generator model is described in Section 4 of WCAP-7907-P-A, "LOFTRAN Code Description," April 1984. The user input consists of geometric parameters and the initial thermal/hydraulic conditions, including initial steam generator (SG) water mass. The important SG input parameters that impact the MSLB results are:
>
> - Initial SG water mass – this value has been set conservatively high.
> - The secondary SG water volume at which the SG tubes are assumed to start to uncover. This value has been set conservatively low to maximize the primary-to-secondary side heat transfer.
> - The quality transient of the break effluent is input by the user. It is set conservatively high to maximize the vapor release which maximizes the containment pressure.

The licensee states that small changes were made to some operating parameters which were evaluated using representative cases. The peak containment pressure and temperature cases were re-evaluated, as well as two additional hot-zero power limiting

cases for each unit. The parameters chosen for the re-analyzed cases are given in Table III.16-1 of Section III.16 of Attachment 5 to the licensee's June 23, 2011, letter. The NRC staff has reviewed the analysis inputs and assumptions and finds them acceptable.

The licensee states that for the re-analyzed cases of the MSLB inside the containment the resultant maximum containment pressures are 34.6 psig and 31.4 psig, respectively, for Byron and Braidwood, Units 1 and 2. These values are less than the peak containment pressures of 39.3 psig for Unit 1, and 38.3 psig for Unit 2, for the current analyses of record. The pressure values are also less than the containment design pressure of 50 psig. The licensee states that the maximum containment air temperature for the peak case increased by 0.6 °F for Braidwood and Byron Unit 1, and the current maximum air temperature for Braidwood and Byron Unit 2 remains bounding.

Since the licensee used approved methods and conservative input assumptions for the MSLB inside containment analyses, the staff finds these analyses and results acceptable and SRP Chapter 6.2.1.4 is met.

The NRC staff had questions regarding a calculation of containment conditions used to derive the electrical equipment environmental qualification temperature and pressure profiles. In the November 1, 2011, submittal the licensee states:

> The electrical equipment environmental qualification (EQ) temperature profile is a composite curve that bounds the results from both the Main Steam Line Break Mass and Energy Release Inside Containment and the LOCA Mass and Energy Release Analyses. The electrical equipment EQ pressure profile is a curve that conservatively assumes the pressure equals the containment design pressure for the first twenty minutes of the event then corresponds to saturated ambient conditions for the remaining duration of the event.

This is conservative because the actual pressure is less than the design pressure. and therefore the NRC staff finds this acceptable and GDC 4 is met.

3.1.2.3 Conclusion

The licensee has re-performed the containment safety analyses to incorporate the correction to the EPITOME computer code used for long term containment analyses and several other revisions to the containment analysis. These re-analyses were done with acceptable methods and assumptions. Based on the above, the NRC staff determined that the containment analyses are acceptable and comply with GDCs 4, 16, 38, and 50, and the applicable SRP guidance.

3.1.3 Engineered Safety Features (ESF) Heating Ventilation and Air Conditioning (HVAC) (RIS 2002-03, Attachment 1, Section VI.1.F)

3.1.3.1 Regulatory Evaluation

The NRC's regulations and guidance specify criteria for control room habitability and post-accident fission product control and removal.

Environmental and dynamic effects design basis, GDC 4, requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the

environmental conditions associated with postulated accidents, including the effects of the release of post-accident fission products and toxic gases.

Part 50 Appendix A, GDC 19, "Control room," requires adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent, to any part of the body, for the duration of the accident.

Part 50 Appendix A, GDC 41, "Containment atmosphere cleanup," requires that systems to control fission products released into the reactor containment be provided to reduce the concentration and quality of fission products released to the environment following postulated accidents. Control of releases of radioactive materials to the environment, GDC 41, requires that the plant design include means to control the release of radioactive gaseous and liquid effluents for normal operation and anticipated operational occurrences (defined in 10 CFR Part 50, Appendix A).

Part 50 Appendix A, GDC 61, "Fuel storage and handling and radioactivity control" requires that systems that may contain radioactivity be designed to assure adequate safety under normal and postulated accident conditions.

Part 50 Appendix A, GDC 64, "Monitoring radioactivity releases," requires that means shall be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences, and postulated accidents.

Guidance in SRP, Sections 6.4, Control Room Habitability System; 6.5.2, Containment Spray as a Fission Product Cleanup System; 9.4.1, Control Room Area Ventilation System; 9.4.2, Spent Fuel Pool Area Ventilation System; 9.4.3, Auxiliary and Radwaste Area Ventilation System; 9.4.4, Turbine Area Ventilation System; and 9.4.5, Engineered Safety Feature Ventilation System, contain specific review criteria.

3.1.3.2 Technical Evaluation

The following are ESFs ventilation systems which serve various equipment areas:

- Diesel-generator (DG) room ventilation system,
- Miscellaneous electrical equipment room ventilation system,
- Switchgear heat removal system, and
- Auxiliary building (AB) heating, ventilation, and air condition (HVAC) system,

The licensee states in Attachment 5, Section VI.1.F.ii of the June 23, 2011, letter, that:

> the diesel-generator room, miscellaneous electric equipment room, and switchgear room do not contain piping that is expected to see an increase in fluid temperature as a result of MUR power uprate implementation. In addition, the electrical equipment load demand and transmission loads are also not expected to increase as a result of MUR power uprate implementation. As such, the area heat loads in these rooms will not be impacted by MUR power uprate.

With regard to the AB HVAC system, the licensee states:

> The auxiliary building heat load under normal operation will not increase in most areas under MUR power uprate conditions. For those areas with no increase in heat load, there are no adverse operational or equipment effects. Heat loads in a limited number of areas did increase under MUR power uprate conditions. The heat load increase in these areas was minimal and was evaluated to be acceptable. It is noted that the ESF cubicle coolers only operate during operation of the corresponding pump. These unit coolers are actively cooled by Essential Service Water (ESW) during accident conditions. It is noted that the sump temperature under MUR power uprate conditions will not exceed the value used in the existing analyses. Therefore, the auxiliary building HVAC system is acceptable for the MUR power uprate.

The fuel handling area is also served by the AB ventilation system.

In response to an NRC staff concern, the licensee, in a letter dated November 1, 2011 further explained the AB heat loads as follows:

> The evaluation to support the MUR- PU (power uprate) evaluated the potential sources of heat input into the Auxiliary Building; however it was not a comprehensive room-by-room evaluation. The evaluation concluded that the Auxiliary Steam System is the only potential source of increased heat input to areas of the Auxiliary Building. The evaluation determined that there was no impact to ESF cubicles.
>
> The Auxiliary Steam System is fed by the Auxiliary Boiler and by Extraction Steam from the High Pressure Turbine. The Auxiliary Boiler is not impacted by the MUR-PU. The temperature of extraction steam system is expected to increase slightly (2.5 °F, 0.6 %) with MUR-PU conditions; therefore the Auxiliary Steam system temperature is also expected to increase slightly. The consequent increase in heat load is not considered significant. The Auxiliary Steam system provides heating for various auxiliary services (e.g., batching Boric Acid in the Auxiliary Building). Therefore any potential increases in temperature to the Auxiliary Building areas could only be impacted by the small increase in the temperature of the Auxiliary Steam. It should also be noted that the decrease in Steam Generator Blowdown temperature is expected to offset the increase in Auxiliary Steam. Therefore, minimal impact on the areas of the Auxiliary Building is expected.

With respect to the control room and auxiliary electrical equipment rooms, the licensee states in Section VI.1.F.i of Attachment 5 to the licensee's submittal, that:

> The control room and auxiliary electric equipment rooms do not contain piping that is expected to see an increase in fluid temperature as a result of MUR power uprate implementation. In addition, the electrical equipment load demand and transmission loads are also not expected to be increased as a result of MUR power uprate implementation. As such, the area heat loads will not be impacted by MUR power uprate.

Based on the above, the NRC staff concludes that, as expected, the impact of the uprate on the Byron and Braidwood safety-related heating ventilation and air conditioning systems is not significant. The NRC staff therefore finds operation of these systems at MUR conditions to be acceptable.

3.1.3.3 Conclusion

Based on the above, the NRC determined that the increase in heat loads due to the uprate in the CR and on the ESF ventilation systems is not significant. The NRC staff therefore concludes that, Byron, Unit Nos.1 and 2, and Braidwood, Units 1 and 2, remain in compliance with GDCs 4, 19 41, 60, 61, and 64, and the applicable SRP.

3.2 Accident Analysis

3.2.1 Bounded Accident Analyses (RIS 2002-03, Attachment 1, Section II)

In large part, the basis for acceptability of this proposed amendment is that the MUR power level conditions are bounded by the current AOR.

3.2.1.1 Regulatory Evaluation

The licensee proposed to use a Cameron LEFM CheckPlus system to decrease the uncertainty in the measurement of FW flow, thereby, decreasing the power level measurement uncertainty from 2.0 percent to 0.37 percent.

The NRC staff used the guidelines in RIS 2002-03 to determine the acceptability of the proposed amendment. The accident source term (AST) consequences evaluation is located in section 3.5.1 of this SE.

3.2.1.2 Technical Evaluation

Although the licensee concluded that certain existing analyses were bounding of uprated plant operation with reduced uncertainty, the analyses were shown to be bounding in one of three different ways:

- For analyses that assume steady-state plant operation with a core power of 3672 MWt, there is a 2 percent margin for power measurement uncertainty at the CLTP, 3586.6 MWt. These analyses are bounding also of plant operation at the uprated RTP of 3645 MWt, with operating margin;

- For analyses that assume steady-state plant operation with a core power of 100 percent, the licensee evaluated accident or transient, and reanalyzed as necessary; or,

- Zero-power transients were not re-analyzed.

Table 3.2.1 – Bounded Accident and Transient Analyses

Transient/Accident	Analytic Power Level (% CLTP)	NRC Review Findings
Main Steam Line Break Mass and Energy Releases Outside Containment	102	Acceptable
Natural Circulation Cooldown	102	Acceptable

Transient/Accident	Analytic Power Level (% CLTP)	NRC Review Findings
Inadvertent Opening of a Steam Generator Relief or Safety Valve	NA	Bounded by other Analysis Acceptable
Steam Pressure Regulator Malfunction or Failure that Results in Decreasing Steam Flow	NA	No such regulator at the plants
Loss of Nonemergency AC Power to the Plant Auxiliaries (Loss of Offsite Power)	102	Acceptable
Loss of Normal FW Flow	102	Acceptable
FW System Pipe Break	102	Acceptable
Reactor Coolant Pump Shaft Seizure (Locked Rotor)/Reactor Coolant Pump Shaft Break/Locked Rotor with Loss of Offsite Power	PCT/ RCS Overpressure 102 100	Bounded Reanalyzed see Section. 3.2.2
Uncontrolled Rod Cluster Control Assembly Bank Withdrawal from a Subcritical or Low Power Startup Condition	0	Acceptable
Rod Cluster Control Assembly Misoperation	100	Acceptable[13]
Startup of an Inactive Reactor Coolant Pump at an Incorrect Temperature	NA	TS Precludes Acceptable
Chemical and Volume and Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant	NA	Not Power Dependent Acceptable
Spectrum of Rod Cluster Control Assembly Ejection Accidents	102 0	Acceptable Acceptable
Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory	NA	Bounded by other analysis including Inadvertent ECCS Acceptable
Failure of Small Lines Carrying Primary Coolant Outside Containment	NA	Bounded by other analysis Acceptable
Loss of Coolant Accident Resulting from a Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary (Best Estimate LOCA)	102	Acceptable

[13] The NRC staff verified that the licensee used the NRC approved methodology in WCAP-11394 and concluded that analysis is not sensitive to power and therefore the existing analysis is acceptable.

Transient/Accident	Analytic Power Level (% CLTP)	NRC Review Findings
Small Break LOCA Analysis	102	Acceptable
Post-LOCA Long-Term Core Cooling/Subcriticality	102	Acceptable

3.2.1.3 Conclusion

RIS 2002-03, indicates that in areas (e.g., accident/transient analyses, components, systems) for which the existing analyses of record do bound plant operation at the proposed uprated power level, the staff will not conduct a detailed review. The NRC staff therefore finds the licensee's analyses that were performed at 102 percent of the CLTP level acceptable without detailed review. The NRC staff concludes that the licensee's analysis performed at 0 percent of the CLTP will not change at the proposed uprated power level and therefore are acceptable. The NRC staff concludes that items in Table 3.2.1 identified as 100 percent or N/A are acceptable based on the information in the comment column.

3.2.2 Accident Analysis Not Bounded by Current Analysis of Record (AOR) (RIS 2002-03, Attachment 1, Section III)

The licensee reviewed their current analysis of record and reanalyzed the accidents that were not bounded by the proposed MUR power level.

Table 3.2.2 – Accident and Transient Analyses

Transient/Accident	Analytic Power Level (% CLTP)
FW System Malfunctions Causing a Reduction in FW Temperature	100
FW System Malfunctions Causing an Increase in FW Flow	100
Excessive Increase in Secondary Steam Flow	100
Steam System Piping Failure at Zero Power	0
Steam System Piping Failure at Full Power	100
Loss of External Load/Turbine Trip/Inadvertent Closure of Main Steam Isolation Valves/Loss of Condenser Vacuum and Other Events Causing a Turbine Trip	RCS Overpressure 102 Transient 100 MSS Overpressure NA
Partial Loss of Forced Reactor Coolant Flow	100
Complete Loss of Forced Reactor Coolant Flow	100

Transient/Accident	Analytic Power Level (% CLTP)
Reactor Coolant Pump Shaft Seizure (Locked Rotor)/Reactor Coolant Pump Shaft Break/Locked Rotor with Loss of Offsite Power	PCT/ RCS Overpressure 102 100
Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power	8 (limiting case) 100 60 10
Inadvertent Operation of Emergency Core Cooling During Power Operation	102 (Peak Pressurizer Volume) 100
Inadvertent Opening of a Pressurizer Safety or Relief Valve	100
Steam Generator Tube Rupture	102
Anticipated Transients without Scram (ATWS)	100

The licensee also re-analyzed some accidents for other issues that they found and adjusted for the proposed MUR power level. The licensee also proposed to adopt VIPRE sub-channel analysis code. The re-analysis using the VIPRE code used a core power level of 3648 MWt for the MUR departure from nucleate boiling (DNB) analyses. This is a 1.7 percent increase to the CLTP and is consistent with revised thermal design procedure (RTDP). The VIPRE usage, as well as, the RTDP methodology was reviewed by NRC staff. The NRC staff verified that the MUR power uprate DNBR calculations are based on a minimum measured flow of 386,000 gpm and supports the TS changes to require RCS flow to be greater than or equal to 386,000 gpm. The NRC staff concludes that the requested TS LCO 3.4.1.C and the associated SRs 3.4.1.3 and 3.4.1.4 changes to require and verify RCS flow to be ≥ 386,000 are adequate based on the DNBR calculations.

Methodology for Determining Departure from Nucleate Boiling Ratio

The NRC staff determined that the proposed MUR PU request does not fundamentally alter the basic thermal-hydraulic approach. However, in order to demonstrate the existence of adequate margin in the departure from nucleate boiling ratio (DNBR) under thermal-hydraulic conditions expected following the MUR power uprate, the licensee has proposed two specific changes to the current methodology:

- The ABB-NV and WLOP departure from nucleate (DNB) correlations will replace the W-3 correlation, which is currently used to determine the DNBR under conditions where the primary DNB correlation is not applicable.

- Westinghouse's proprietary version of the VIPRE-01 code (i.e., VIPRE-W) will replace the THINC-IV and FACTRAN codes, which are currently used for thermal-hydraulic calculations within fuel assembly subchannels and determination of the transient temperature distribution and heat flux for a fuel rod.

Implementation of these changes to the current DNBR methodology, as discussed below, requires revisions to the technical specifications.

As noted above, the fundamental approach governing the licensee's DNBR calculations for non-loss-of-coolant-accident (non-LOCA) transients would not be changed by the MUR PU. The licensee's application indicates that, dependent upon conditions associated with the specific event being analyzed, one of two NRC-accepted methods will continue to be used to determine the DNBR:

- Where applicable, the licensee uses the revised thermal design procedure (RTDP) to determine the DNBR. As described in topical report WCAP-11397-P-A [2], the RTDP uses nominal input values along with a statistical methodology to calculate a DNBR design limit value that accounts for uncertainties associated with plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer codes, and DNB correlation predictions. In addition to uncertainties that are accounted for statistically, the RTDP incorporates margin to accommodate penalties (e.g., for rod bow) and to allow flexibility in the design and operation of the plant.

- In cases where the RTDP is not applicable, the licensee uses the standard thermal design procedure (STDP). The STDP is a conservative approach that accounts for uncertainties deterministically by applying the uncertainties directly to nominal input values. Consequently, in contrast to the DNBR design limit for the RTDP that incorporates uncertainties statistically, the appropriate DNBR limit for the STDP is the DNB correlation limit, with consideration for any applicable DNBR penalties.

Consistent with Section 4.4 of the Standard Review Plan (NUREG-0800), the licensee indicated that the thermal-hydraulic design basis for DNB is established to avoid DNB on the limiting fuel rod, during both normal operation and anticipated transients, with at least a 95% probability at a 95% confidence level. The licensee stated that the WRB-2 DNB correlation will continue to be the primary DNB correlation used in the analysis of the VANTAGE+ fuel following the MUR PU. As discussed in topical report WCAP-10444-P-A, "Westinghouse Reference Core Report, Vantage 5 Fuel Assembly," September 1985, (ADAMS Accession No. ML080650329) the WRB-2 correlation was developed to provide improved prediction of DNB performance for Westinghouse fuel designs employing support grids with a proprietary mixing vane design. WCAP-10444-P-A further establishes the parameter ranges (e.g., pressure, mass flow rate, fuel design parameters) for which the WRB-2 correlation is applicable. Although WCAP-10444-P-A nominally pertains to an antecedent of the VANTAGE+ fuel currently loaded at Byron and Braidwood (i.e., VANTAGE 5 fuel), a subsequent NRC staff safety evaluation for topical report WCAP-12610-P-A, "VANTAGE+ Fuel Assembly Reference Core Report," April 1995" (ADAMS Accession No. ML090720988) concluded that this fuel design is essentially equivalent in hydraulic design to VANTAGE+ fuel.

However, as noted above, the licensee has proposed to replace the W-3 correlation, which currently serves as the secondary DNB correlation, with the ABB-NV and WLOP correlations. Secondary DNB correlations supplement primary correlations under conditions where the primary DNB correlation is not applicable. The licensee proposes to use the ABB-NV and WLOP DNB correlations, consistent with their respective ranges of applicability, for prediction of DNB in two specific ranges where the primary WRB-2 correlation is not applicable:

- Over a length of approximately 30 inches from the bottom of the fuel rods up to the first mixing vane grid.
- In a pressure range below the minimum value for which the WRB-2 correlation has been demonstrated to be applicable (i.e., 1440 psia).

The applicability of the ABB-NV and WLOP correlations for DNB predictions in these supplemental regions and their association with the VIPRE-W code is established in WCAP-14565-P-A, Addendum 2-P-A (ADAMS Accession No. ML081280711), "Addendum 2 to WCAP-14565-P-A, Extended Application of ABB-NV Correlation and Modified ABB-NV Correlation WLOP for PWR Low Pressure Applications," April 2008. This topical report states that the ABB-NV correlation was developed exclusively from data for pressurized-water reactor (PWR) fuel without mixing vane grids. While the ABB-NV correlation is not applicable under low pressure conditions, as discussed in WCAP-14565-P-A, Addendum 2-P-A, a modified version of this correlation was developed and designated as the WLOP correlation, which is compatible with reduced pressures and a broader range of flows extending into the low-flow range. In accordance with documented limitations and conditions, the staff's safety evaluation (ADAMS Accession No. ML081280713) accompanying WCAP- 14565-P-A, Addendum 2-P-A, found (1) application of the ABB-NV correlation to the region of a Westinghouse fuel assembly upstream of the first mixing vane grid to be acceptable, and (2) application of the WLOP correlation to be acceptable for reduced pressures down to a lower limit of 185 psia.

One of the limitations and conditions imposed by the staff in its approval of the ABB-NV and WLOP correlations in WCAP-14565-P-A, Addendum 2-P-A, is that these DNB correlations may only be implemented in conjunction with the VIPRE-W code. This stipulation was necessary because these correlations' development and technical justification were based on the VIPRE-W code and associated modeling specifications. Therefore, in order to implement the ABB-NV and WLOP correlations, the licensee has proposed to use the VIPRE-W code as the licensing basis code for sub-channel thermal-hydraulic analysis and DNBR calculations, as a replacement for the THINC-IV and FACTRAN codes. As noted in the licensee's application, the VIPRE-W code has been used to perform sub-channel analysis to verify that the DNB design criterion continues to be met for the VANTAGE+ fuel at MUR PU conditions for DNB-limiting safety analysis events (i.e., including events that do not make use of the ABB-NV or WLOP correlation). In accordance with documented limitations and conditions, the staff's safety evaluation (ADAMS Accession No. ML993160153) for WCAP-14565-P-A, ""VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," October 1999, concluded that such use of the VIPRE-W code is acceptable for licensing calculations as a replacement for THINC-IV and FACTRAN.

Because the DNB correlations and VIPRE-W code proposed by the licensee have been previously approved via the NRC's topical report review process, the present review focused on the licensee's compliance with the limitations and conditions documented in the staff's safety evaluations for pertinent approved topical reports. In its application dated June 23, 2011, the licensee specifically addressed compliance of the proposed application of the ABB-NV and WLOP DNB correlations and VIPRE-W code with the limitations and conditions in the NRC staff's safety evaluations of topical reports WCAP-11397-P-A, WCAP-14565-P-A, and WCAP-14565-P-A, Addendum 2-P-A. The NRC staff evaluated the licensee's compliance with the limitations and conditions associated with these topical reports, as well

as other information in the licensee's application to determine whether the proposed application is in compliance with the approved methodology in these topical reports. The staff concludes that the licensee had adequately addressed the limitations and conditions for the topical reports enumerated above and further did not identify inconsistencies between the licensee's application and other aspects of these topical reports.

As noted above, revisions to the Byron and Braidwood technical specifications are necessary to support the licensee's implementation of the ABB-NV and WLOP DNB correlations and the VIPRE-W code.

First, to incorporate appropriate limits for the ABB-NV and WLOP DNB correlations, the licensee has proposed changes to the safety limits in Section 2.1.1 of the technical specifications (TS):

- The licensee has proposed to revise Safety Limit 2.1.1.1 to include the DNBR design limit of 1.19 for the ABB-NV correlation. This limit is applicable in Mode 1 and is compatible with the RTDP methodology.

- The licensee has proposed to revise Safety Limit 2.1.1.2 to replace the DNB correlation limit for the W-3 correlation with the DNB correlation limits for the ABB-NV (1.13) and WLOP (1.18) correlations. These limits are applicable in Mode 2 and are compatible with the STDP methodology.

Second, the licensee has proposed to add WCAP-14565-P-A, a topical report previously reviewed and accepted by the staff, to the list of references in TS 5.6.5 that identifies the analytical methods used to determine core operating limits.

The DNB correlations and correlation limits proposed as safety limits in Section 2.1.1 of the Byron and Braidwood technical specifications are applicable to the VANTAGE+ fuel currently in use at these facilities. The licensee's application stated that the DNBR design limit of 1.19 for the ABB-NV correlation in Safety Limit 2.1.1.1 was derived using the approved RTDP methodology in WCAP-11397-P-A, with current computer code and plant operating parameter uncertainties (with the exception of a reduced feedwater flow uncertainty associated with the installation of ultrasonic flow meters) and proprietary DNBR sensitivity factors that have been calculated using the VIPRE-W code. Based on the information provided in the licensee's application, the staff concludes that the DNBR design limit value of 1.19 for the ABB-NV correlation was derived using a methodology consistent with previously approved topical reports (i.e., WCAP-11397-P-A, WCAP-14565-P-A, and WCAP-14565-P-A, Addendum 2-P-A). On the basis of additional information provided by the licensee in its letter dated December 9, 2011, the staff further determined that the specific uncertainty and bias inputs used in the determination of the DNBR design limit for the ABB-NV correlation comply with the conditions and limitations in the staff's safety evaluation for WCAP-11397-P-A. Finally, the correlation limit values the licensee has proposed to include in Safety Limit 2.1.1.2 for the ABB-NV and WLOP correlations were previously accepted by the staff in its review of WCAP-14565-P-A, Addendum 2-P-A.

Based on its review documented in the foregoing evaluation, the staff concludes that the licensee has implemented the ABB-NV and WLOP DNB correlations and the VIPRE-W code in a manner consistent with approved methods contained in previously reviewed topical reports, including limitations and conditions n the NRC staff's corresponding safety evaluations. Therefore, the staff concludes that the revisions to the technical specifications

for Byron and Braidwood discussed above are associated with the implementation of these methods for the prediction of DNB are acceptable.

Review of Re-analyzed Events

The NRC staff's review of the following accidents covered:

1. Description of the causes of the event and the description of the event itself,
2. Initial conditions,
3. Values of reactor parameters used in the analysis,
4. Analytical methods and computer codes used, and the
5. Results of the associated analysis.

The NRC staff used specific review criteria contained in Chapter 15, "Transient and Accident Analysis," of the SRP, and other guidance.

FW System Malfunctions Causing a Reduction in FW Temperature or an Increase in FW Flow

An increase in FW flow or reduction in temperature will result in increased subcooling in the affected SGs. The increased subcooling will then create a greater load demand on the reactor coolant system (RCS) which decreases the RCS temperature which can produce a reactivity insertion. The neutron overpower, overtemperature and overpower ΔT trips are designed to prevent power increases that could lead to DNBR becoming less than its limit value.

The NRC staff reviewed the initial conditions that the licensee used for the event. The analysis uses a 1.5 °F RCS average temperature bias and a minimum SG tube plugging level and maximum FW temperature.

The licensee used NRC-approved codes LOFTRAN, VIPRE-W, and ANC, as well as the RTDP to calculate DNBR. The current analysis was performed at 3600.6 MWt and the MUR-PU analysis was performed at 3672 MWt.

The licensee chose a limiting case for the four units which showed a reduction in FW temperature event with D5 SGs. The results showed that the resulting DNBR was greater than the safety analysis limit. The NRC staff reviewed the analysis and results, and found them to be acceptable.

Excessive Increase in Secondary Steam Flow

An increase in secondary steam flow creates a mismatch between the reactor core and the SG load demand. The RPS signals that protect against this event include the low pressurizer pressure, over-temperature ΔT, and power range high neutron flux.

The licensee used NRC-approved code LOFTRAN as well as the RTDP to calculate DNBR. The current analysis was performed at 3600.6MWt and the MUR-PU analysis was performed at 3672 MWt.

The NRC staff reviewed the initial conditions for the event. The most limiting case assumed minimum reactivity feedback, automatic rod control and the Babcock & Wilcox International (BWI) SGs with zero tube plugging.

The analysis showed the worst-case minimum DNBR and it gave more than 20 percent safety analysis margin. The NRC staff reviewed the analysis and the results and found them to be acceptable.

Steam Supply Piping Failure at Zero Power

The steam break would result in an increase in steam flow initially which removes more energy from the RCS and causes a reduction in temperature and pressure. The cooldown can result in an insertion of positive reactivity. The most reactive rod cluster control assembly (RCCA) is assumed to be stuck in its fully withdrawn position and the possibility of returning to power exists.

The licensee used NRC-approved LOFTRAN, VIPRE, and ANC case along with the standard thermal design procedure (STDP) to calculate the minimum DNBR and peak linear heat rate (PLHR). The licensee reanalyzed the event to address revised reactivity feedback coefficients associated with MUR power level.

The NRC staff reviewed the initial conditions and assumptions for the event. The initial conditions included various conservative assumptions, as well as the assumption that the maximum break size corresponds to the size of the flow restricting nozzle in the two SG types. Protective functions available to provide protection for a steamline break included the safety injection (SI) system, overpower trips, redundant isolation of the main FW lines, and trip of the fast acting steamline stop valves.

The limiting case was found to be with Braidwood and Byron Unit 2s with a break size of 1.4 ft^2, alternating current (ac) power available and low T_{ave}. The minimum DNBR value is above the limit value of 1.18 and the maximum PLHR is below its limit value. The NRC staff noted that there was a reduction in margin to the limits which the licensee stated occurred due to power uprate reactivity coefficients creating a more severe return to power as well as the analysis being performed in a more conservative manner to bound cycle to cycle variations in future reloads. The NRC staff reviewed the analysis and the results, and found them to be acceptable.

Steam System Piping Failure at Full-Power

The steam break would result in an increase in steam flow initially which removes more energy from the RCS and causes a reduction in temperature and pressure. The cooldown can result in an insertion of positive reactivity which can cause a power excursion.

The licensee used NRC-approved LOFTRAN, VIPRE, and ANC, as well as the RTDP to calculate the minimum DNBR and PLHR. The current analysis was performed at 3600.6 MWt and the MUR-PU analysis was performed at 3672 MWt.

The NRC staff reviewed the initial conditions and assumptions for the event. The initial conditions included maximum moderator reactivity feedback and least negative Doppler power feedback. The limiting break size that was found to bound all break sizes was 0.95ft^2. Protective functions that may be used to mitigate this event include the reactor trip, and SI.

Westinghouse applies the Condition II acceptance criteria such that damage to the fuel rods is precluded.

The limiting case shows that the power increases during the transient until the reactor trips on overpower ΔT. The minimum DNBR and PLHR were both found to be within the safety limits identified in the UFSAR Section 4.4. The NRC staff reviewed the analysis and the results, and found them to be acceptable.

Loss of External Load/Turbine Trip/Inadvertent Closure of Main Steam Isolation Valves/Loss of Condenser Vacuum and Other Events Causing a Turbine Trip

The turbine trip event is the event found to be bounding for this analysis. For the event the turbine stop valves close very rapidly which cuts off steam flow to the turbine. The steam dumps (SDs) are initiated. The secondary temperature increases as well. The SDs and condenser normally accept the excess steam.

The licensee used the STDP for the maximum RCS and main steam system (MSS) pressure overpressure concerns. The RCS overpressure event was not reanalyzed as it is bounded by the AOR. The MSS overpressure event was analyzed based on the RCS overpressure case with automatic pressure control assumed and minimum SG tube plugging modeled. NRC-approved LOFTRAN is also used for the overpressure event.

For the DNB case, the licensee used NRC-approved LOFTRAN and the RTDP to calculate DNBR. The current analysis was performed at 3600.6 MWt and the MUR-PU analysis was performed at 3672 MWt. The DNB case assumed minimum SG tube plugging as well as the RCS flow rate corresponding to minimum measured flow of 386,000 gpm.

The NRC staff reviewed the initial conditions and assumptions for the event. One assumption is that the conditions in the reactor must cause the reactor trip (i.e., there is no reactor trip on the turbine trip). No credit is taken for SD and main FW flow is terminated at the time of the turbine trip and no auxiliary FW is credited. Manual rod control is modeled for conservatisms. No credit is taken for the SG PORVs. The MSSVs are at or greater than the TS limit of 3 percent.

The results for the MSS overpressure event showed that the overpressure case came in under the pressure limit of 1318.5 psia at about 1313.5 psia for Braidwood and Byron Unit 1s and 1310.6 psia for Braidwood and Byron Unit 2s. The minimum DNBR event showed that the minimum DNBR was above the safety limit. The NRC staff reviewed the analysis and results, and found them to be acceptable.

Partial Loss of Forced Reactor Coolant Flow

The partial loss of forced reactor coolant flow would occur from the failure of an RCP. When the reactor is at power the loss of an reactor coolant pump (RCP) would result in a loss of coolant flow and a rapid increase in the coolant temperature which could lead to DNB.

The licensee used NRC-approved LOFTRAN and VIPRE codes along with the RTDP to calculate the minimum DNBR. The current analysis was performed at 3600.6 MWt and the MUR-PU analysis was performed at 3672 MWt. The analysis is performed assuming the loss of two RCPs with four loops in operation.

The NRC staff reviewed the initial conditions and assumptions for the event. The most negative Doppler-only power coefficient was modeled. The low RCS flow reactor trip is credit as being available to mitigate the event.

The results showed that the minimum DNBR was above the safety analysis limit. The NRC staff reviewed the analysis and the results, and found them to be acceptable.

Complete Loss of Forced Reactor Coolant Pump (RCP) Flow

The complete loss of forced reactor coolant flow would occur with the loss of all four RCPs and loss of the RCPs would cause immediate loss of coolant flow and a rapid increase in coolant temperature.

The licensee used NRC-approved LOFTRAN and VIPRE computer codes as well as the RTDP methodology to calculate a minimum DNBR. The current analysis was performed at 3600.6 MWt and the MUR-PU analysis was performed at 3672 MWt. Two cases were analyzed. One was the complete loss of all four RCPS and the other was the frequency decay event resulting in the complete loss of forced coolant flow.

The NRC staff reviewed the initial conditions and assumptions for the event. The most negative Doppler-only power coefficient was modeled. The RCP power Supply Undervoltage or Underfrequency and the low RCS flow reactor trip functions are credited to mitigate this event.

The frequency decay event was shown to be the limiting case. The reactor trips on the underfrequency trip signal after the frequency decay of 5 Hz/sec occurs for 1.2 seconds. The minimum DNBR was shown to be above the DNBR safety analysis limit. The NRC staff reviewed the analysis and the results, and found them to be acceptable.

Reactor Coolant Pump Shaft Seizure (Locked Rotor)/Reactor Coolant Pump Shaft Break/Locked Rotor with Loss of Offsite Power

When an instantaneous RCP shaft seizure occurs, the flow through the loop reduces rapidly with no RCP coastdown. The coolant in the primary side heats up and expands causing an insurge into the pressurizer. Pressure suppression including sprays and the PORVs would actuate to lower pressure.

The licensee used NRC-approved LOFTRAN and VIPRE codes along with the RTDP methodology. The case that is performed as bounding is the locked rotor rods-in-DNB case. The codes and methodology are used to determine the percentage of fuel rods experiencing a DNBR. The current analysis was performed at 3600.6 MWt and the MUR-PU analysis was performed at 3672 MWt. The locked rotor is analyzed as one locked rotor with four loops operating and a concurrent loss of offsite power at the time of the reactor trip. The staff reviewed the initial conditions and assumptions for this event. The most negative Doppler-only power coefficient was modeled. The low RCS flow reactor trip is credited as available to mitigate the event.

The results showed that the percentage of fuel rods exceeding the DNBR limit is less than the 2 percent fuel rod failures for the radiological dose calculations. The NRC staff reviewed the analysis and the results, and found them to be acceptable.

Uncontrolled Rod Cluster Control Assembly (RCCA) Bank Withdrawal at Power

This event occurs when an uncontrolled RCCA is withdrawn from the core at power. This can occur due to operator action or malfunction in the rod control system. The result is an increase in the core heat flux and an increase in the RCS temperature. The RPS is designed to terminate this event before the limits are exceeded.

The licensee used NRC-approved LOFTRAN code and the RTDP methodology to analyze this event. The MUR-PU analysis was performed at 3672 MWt. There are a variety of automatic RPS features which are designed to prevent core damage during this event and they include: power range neutron flux, positive neutron flux rate, overtemperature ΔT, overpower ΔT, high pressurizer pressure, and high pressurizer water level reactor trips. In addition to the RPS features there are rod withdrawal blocks, that would limit this event, which include high neutron flux, overpower ΔT, and overtemperature ΔT.

The NRC staff reviewed the initial conditions and assumptions for this event. Minimum and maximum reactivity feedback cases are analyzed. Reactor tips are assumed to be at their maximum values. The reactor trip assumes the highest worth RCCA is stuck fully withdrawn. Power levels of 10, 60, and 100 percent are considered.

This event is considered a Condition II event. The results were shown for the range of considered conditions. The minimum DNBR was greater than the safety analysis limit for each of the analyzed events. The NRC staff reviewed the analysis and the results, and found them to be acceptable.

Inadvertent Operation of the Emergency Core Cooling System (ECCS) During Power Operation

The inadvertent operation of the ECCS at power could be caused by operator error, test sequence error, or a false electrical actuation signal. If the actuation signal occurs the suction of the charging pumps changes to the refueling water storage tank (RWST). The charging pumps then are aligned to start pumping the borated RWST water into the RCS. The accumulators and low head injection systems are not able to inject into the RCS at normal pressure. This event is analyzed to show: (1) show that there is no fuel clad damage, as indicated by the calculated minimum of DNBR, and (2) to show that the event will not escalate into a more serious event. In the first case, the reactor is not assumed to trip from the SI signal.

For the DNBR analysis, the SI signal is considered to not cause a reactor trip in the analyzed event. The reactor power will decrease due to the injection of borated water and the pressurizer pressure and water level decrease. The reactor will eventually trip by low pressurizer pressure trip or a manual trip.

The licensee used NRC-approved LOFTRAN code and the RTDP methodology to calculate the minimum DNBR. The current analysis was performed at 3600.6 MWt and the MUR-PU analysis was performed at 3672 MWt.

The NRC staff reviewed the initial conditions and assumptions for this event. The reanalysis was done for the DNB case. Some assumptions included: zero moderator temperature coefficient, low absolute value Doppler power coefficient, manual rod control, pressurizer

heaters inoperable, reactor trip on low pressurizer pressure, no operator action, and no credit for the steam dump. This event is considered a Condition II event.

The results showed the power decreasing due to boron injection. The DNBR is shown to increase throughout the event. There was an expected decrease in the minimum DNBR due to the power increase from the initial conditions (MUR).

The NRC staff reviewed the analysis and results and found them to be acceptable for the DNB case of the Inadvertent Operation of the ECCS during Power Operation event.

For the analysis to demonstrate the inadvertent ECCS operation does not escalate into a more serious event, the analysis was done at 102 percent of CLTP. The current licensing basis (CLB) analysis is documented in the final safety analysis report (FSAR) and dated 2002. The licensee states that this analysis continues to bound operation at the MUR power level. Since 2002, the NRC staff has issued a RIS 2005-29 regarding this event and the problems that can occur when the pressurizer is filled. The licensee's CLB analysis indicates the pressurizer is predicted to fill. The RIS states that no action or written response is required and the licensee has not updated its CLB analysis to address the concerns outlined in the RIS. The RIS states that the NRC staff will apply the guidance from the applicable standard review plans during reviews in which the accident analysis is revised (e.g., power uprates) and may have questions about how this issue has been addressed. Given that this accident analysis is performed at 102% power and therefore was not (and need not be) revised for an MUR power uprate, and the licensee has not updated the analysis in response to the RIS, the issue was determined to be outside the scope of the MUR PU. The staff intends to pursue this issue generically by clarifying the expectations in the RIS and is also considering plant-specific actions to address the issue. Based on the above, the NRC staff concludes it is acceptable to address this issue generically and apart from evaluation of a plant specific MUR PU.

Inadvertent Opening of a Pressurizer Safety or Relief Valve

The inadvertent opening of power-operated relief valve (PORV) would cause depressurization of the RCS. The analysis uses the more conservative assumption of the conditions of a pressurizer safety valve (PSV) opening because the PSVs have close to twice the steam flow rate relief capacity of the PORVs. The event initially starts with rapidly decreasing RCS pressure then the filling of the pressurizer.

The licensee used NRC-approved LOFTRAN code and the RTDP methodology to calculate the minimum DNBR. The current analysis was performed at 3600.6MWt and the MUR-PU analysis was performed at 3672 MWt. The NRC staff reviewed the initial conditions and assumptions for this event. The cases were run to find the most limiting result between the Braidwood and Byron Units 1 and 2 SGs. Maximum SG tube plugging and least negative Doppler-only power coefficient are assumed. The low pressurizer pressure and overtemperature ΔT reactor trips are credited to be available to mitigate the event. This event is considered a Condition II event.

The results showed the most limiting case being the Braidwood and Byron Unit 2 SGs with maximum tube plugging and minimum FW temperatures. The results showed the depressurization and the nuclear power, as well as the minimum DNBR. The reactor trip occurs on low pressurizer pressure. The minimum DNBR was greater than the DNBR safety analysis limit.

The NRC staff reviewed the analysis and the results and found them to be acceptable for all of the Braidwood and Byron Units for the DNB event of the inadvertent opening of a pressurizer safety or relief valve.

Steam Generator Tube Rupture (SGTR) Margin to Overfill (MTO) Steam Generator (SG)

The licensee performed the thermal and hydraulic analysis using LOFTTR2 program and methodology. The licensee looked at the failure of an intact SG PORV, failure of ruptured SG MSIV, and failure of ruptured SG FW control valve to determine the limiting single failure. The limiting single-failure was determined to be the failure of an intact SG PORV was found to be limiting due to the increased cooldown time.

The NRC staff reviewed the initial conditions and the assumptions for this event. For both units the SG MTO considered the minimum operating temperature with the minimum main FW temperature. They both also assumed the maximum SG tube plugging. The failure of a PORV on an intact SG was used for the limiting case. The secondary side volume available for the Braidwood and Byron Unit 1 SGs is 5122 ft^3 and the secondary side volume available for Braidwood and Byron Unit 2 SGs is 5955 ft^3. The licensee performed the analysis to show that the secondary side of the ruptured SG did not completely fill with water.

The event initiates with a tube rupture with water flowing from the primary to the secondary side of the SG. The RCS starts losing coolant and the pressurizer level and pressure are decreased. The reactor trip occurs on overtemperature ΔT trip signal. The reactor power decreases to decay heat and the turbine stop valves close. The SDs are unavailable due to assumed loss of offsite power. This also causes main FW flow to stop and the SG flow is provided by the auxillary feedwater (AFW). The energy in the secondary side is released through the SG PORVS and safety valves. The pressurizer pressure signal starts the SI and flow is delivered to recover pressurizer level. The licensee assumes that the AFW flow to the ruptured SG will be isolated within nine minutes and the MSIV for the same SG is closed at 18 minutes. Three minutes of operator action time are assumed before cooldown is started. The cooldown is performed with two of the intact SGs since one of the intact SG PORVs is the assumed failure. After the cooldown termination temperature is reached the cooldown is terminated and a four-minute operator action time is assumed before RCS depressurization. The RCS depressurization is terminated when the RCS pressure is less than that of the ruptured SG and the pressurizer level was adequate. A three-minute operator action time is assumed before the SI is terminated.

The maximum ruptured SG water volume for the Braidwood and Byron Unit 1 case was shown to be 5068 ft^3. The result was 54 ft^3 of MTO. The maximum ruptured SG water volume for the Braidwood and Byron Unit 2 case was shown to be 5685 ft^3. The result was 270 ft^3 of MTO. Based on the positive value of the MTO, the NRC staff determined that the MTO is acceptable.

The NRC staff reviewed the analysis and results and found them to be acceptable based on the demonstrated MTO.

As stated in its June 23, 2011, submittal, the licensee will implement the plant modifications identified in Attachment 4 to its submittal, in accordance with 10 CFR 50.59, "Changes, tests and experiments" to support the SG MTO assumptions prior to raising power above 3586.6 MWt (current licensed power (CLP)):

- Installing safety-related air accumulator tanks to support AFW flow control
- Increase the capacity of the Braidwood and Byron Unit 1 SG PORVs
- Modify Byron and Braidwood Unit 2 SG PORVs to achieve analysis flow rates
- Install uninterruptible power supplies (UPS) on two of the four SG PORVs
- Install a manual isolation valve upstream of each high head SI valve

The NRC staff concludes that the licensee's implementation of the above plant modifications prior to raising power above 3586.6 MWt (CLP) is acceptable. The NRC staff further concludes that installing the modifications in accordance with 10 CFR Part 50.59 is acceptable because 10 CFR Part 50.59 establishes criteria to determine whether or not NRC approval is required.

Regulatory Commitments

The licensee provided the following regulatory commitment, applicable to the SGTR MTO, in Attachment 4 of the submittal:

Modifications to support SGTR MTO analysis single failure considerations will be implemented prior to increasing power above 3586.6 MWt.

The NRC staff reviewed this licensee regulatory commitment. The NRC staff concludes that the licensee's implementation of the above plant modifications prior to raising power above 3586.6 MWt (CLP) is acceptable. The NRC staff further concludes that installing the modifications in accordance with 10 CFR Part 50.59 is acceptable because 10 CFR Part 50.59 establishes criteria to determine whether or not NRC approval is required.

Conclusion

The NRC staff has reviewed the licensee's analyses of the above events and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the specified acceptance fuel design limits (SAFDLs) and the reactor coolant pressure boundary (RCPB) pressure limits will not be exceeded as a result of these events. Therefore, the NRC staff finds the proposed uprate acceptable with respect to the events and modifications described above.

3.3 Plant Systems

This section focuses on the structural integrity of major plant components as discussed in RIS 2002-03.

3.3.1 Regulatory Evaluation

The NRC staff's review focused on verifying that the licensee has provided assurance that plant systems will continue to operate safely at the uprated power level. The impact of the proposed licensed power on the structural integrity of major plant components using the criteria noted in RIS 2002-03, Attachment 1, Sections II and III.

3.3.2 Technical Evaluation

Main Steam

Main Steam Safety Valves (MSSVs)

The licensee evaluated the performance of the MSSVs at a 1.7 percent increase in RTP. One primary function of the MSSVs is to protect the SGs and main steam piping and components from overpressure. The design pressure rating of the SGs did not change at the new power level and the licensee concluded that the existing MSSV lift setpoints remain in accordance with the guidance provided in the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code). The licensee also evaluated the steam relieving capacity of each MSSV for mitigating accidents and transients. The licensee found the capacity to be "acceptable relative to the sizing criteria." Since the new operating power level and maximum power remain within the current analyzed limits, the NRC staff finds that the current design bounds operation at the increased power level.

Main Steam Isolation Valves (MSIVs)

The licensee evaluated the performance of the MSIVs at a 1.7 percent increase in RTP. The critical safety function for the MSIVs is to rapidly isolate a SG in the event of a downstream steam line rupture. The licensee evaluation at the higher steam flow rate found that there was no impact upon the critical variables used in calculating the design loads and associated stresses resulting from rapid closure of the MSIVs. Based on the licensee's evaluation, the NRC staff concludes that operating at the increased power had no significant impact on the nuclear steam supply system (NSSS) and balance of plant (BOP) interface requirements for the MSIVs.

Steam Generator (SG) Power Operated Relief Valves (PORVs)

The licensee evaluated the capacity of the SG PORVs, atmospheric relief valves. The licensee stated that the PORVs are sized to have a capacity equal to approximately 10 percent of rated steam flow at no-load pressure. The SG PORVs in Byron and Braidwood, Units 1, meet this capacity, but the PORVs in Byron and Braidwood, Units 2, have a capacity of 9.3 percent at uprated conditions. An evaluation of the installed capacity concluded that the original design bases, in terms of plant cooldown capability, can still be achieved for the range of power uprate NSSS design parameters. Therefore, the SG PORVs are acceptable for operation at uprate conditions. Note that the Units 1 and 2, PORV trim will be modified to address SG margin to overfill concerns as noted in Attachment 5a of Exelon's letter to the NRC dated June 23, 2011 (ADAMS Accession No. ML111790026), as supplemented by Exelon's letter to the NRC dated August 8, 2012 (ADAMS Accession No. ML12222A037). This modification will increase the PORV steam relief capacity.

The licensee concluded that the SG PORV relief capacity needed to be increased in order to provide adequate margin in the design basis cooldown rate for mitigating a SGTR. In order to increase the capacity of the SG PORVs, the licensee proposed to install a larger size valve trim on Unit 1 (Braidwood and Byron) SG PORVs. In its letter dated August 12, 2012, the licensee stated that the flow rate will increase from approximately 420,000 lbs/hr to approximately 540,000 lbs/hr. The increase flow rate permits operators to release steam at higher rate, allowing the operators to quickly cool down and depressurize the RCS. The

time to terminate the primary to secondary leakage is critical to maintaining an adequate margin to overfill. The increased steam release rate adversely affects the off-site dose calculations, resulting from a SGTR. Therefore, the modification to increase the trim size on the Unit 1 SG PORV requires prior NRC approval. The impact on the off-site dose assessment from the increase in steam rate released is addressed in Section 3.5.1 of this SE report. Based on the information provided by the licensee, the NRC staff concludes that the modification to the Unit 2 PORVs was needed to restore the flow rates used in the analysis and, therefore, there was no impact on the analyzed off-site dose calculations and prior NRC approval is not required.

In addition to the PORV trim modification, the licensee identified the need to install uninterruptable power supplies (UPS) to the SG PORVs controllers. In the event of a loss of either Division 1 or Division 2 electrical power, two of the four SG PORVs would lose their control power and could no longer be operated remotely. Certain accidents can cause the loss of the function of a remaining SG; the associated SG PORV would also be lost. In such an event, the remaining single SG PORV would not be sufficient to meet the design basis cool down rate. The licensee opted to install UPS on only two of the four SG PORVs (1/2-MS018J-C and D) on each of the four units. Since the licensee opted to only install UPS on two of the four SG PORVs, the NRC staff requested additional information on each of the SG PORV component's power sources to verify independence. In a letter dated, February 20, 2012 (ADAMS Accession No. ML12052A113), the licensee provided a list of the electrical power supplies to each of the SG PORVs and controllers. The staff reviewed the information provided and confirmed each pair of SG PORVs was powered from separate electrical divisions. With the installation of the UPS, in the event of a loss of an electrical division, one of the two SG PORVs powered from that division would remain functional with power. Therefore, only one SG PORV would lose its functionality. Based on the licensee's evaluation, the staff concludes that installation of a UPS to two of the four SG PORVs will improve the plant's capabilities to mitigate accidents by removing a vulnerability that could cause the loss of two SG PORVs with a single-failure of an electrical division.

The implementation of the modification is evaluated in the SGTR MTO SG section above.

Steam Dumps (SDs)

The licensee performed an analysis of the SD performance at a 1.7-percent increase in RTP. The licensee confirmed the ability of the SDs to work in conjunction with the reactor control system to withstand an external load reduction of up to 50 percent of plant-rated electrical load without a reactor trip. Based on the licensee's evaluation, the NRC staff concludes the SDs would continue to function at the increased power level similar to the manner they perform at current power level.

Moisture Separator Reheaters (MSRs)

The licensee performed an analysis of the MSRs shell and tube bundle at a 1.7-percent increase in RTP, and determined that the LAR did not require any physical or operational changes to the MSRs at the increased power level. Based on the licensee's evaluation, the NRC staff concludes that the new operating conditions are within the accepted limits of the original design of the MSR constructed under the provision of ASME Section-VIII Division 1.

Moisture Separator Reheater Safety Relief Valves (SRVs)

The licensee performed an analysis of the total relief valve capacity of MSR SRVs at a 1.7 percent increase in RTP. The licensee determined the current relief capacity of 12,267,000 lb/hr at 275 psia will encompass the maximum flow at the increased power level of 11,244,391 lb/hr. Based on the licensee's evaluation, the NRC staff concludes that the MSR safety relief valve capacities remain within the requirements of ASME Section-VIII Division 1.

Extraction Steam

The licensee performed an analysis of the extraction steam system at a 1.7 percent increase in RTP. The licensee's evaluation of the operating parameters (pressure, temperature, flow, velocity) in the extraction steam system would not be significantly impacted at the new conditions and would operate within the current design limits of the components in the extraction steam system. Based on the licensee's evaluation, the NRC staff concludes that the extraction steam system will continue to operate within the confines of its current design capabilities at the increased power level.

Condensate and Main FW

The licensee calculates that condensate flow will increase approximately 1.9 percent at the new operating power. The licensee evaluated the relevant parameters in the condensate and FW systems and determined that operating at the new power level would not exceed the piping design specifications. The additional FW and extraction steam flow through the FW heaters will result in a small temperature increase in the FW supplied to the SGs. The licensee found that the small temperature increase is within the current design operating range for the FW system and SGs. In its June 23, 2011, application, the licensee stated that adjustment of the feedwater pump speed control program to accommodate the minor increase in flow (1.9 percent) due to the MUR PU, will help maintain the feedwater control valves (FCVs) near their current full power stroke positions without significantly affecting system performance." Based on the licensee's evaluation, the NRC staff concludes that the increased flow rates will remain within the capabilities of the current condensate and FW pumps. With respect to these minor changes in the main FW system, the NRC staff concludes that the condensate and main FW system's primary safety function to isolate main FW will not be adversely impacted while operating at the increased power level.

FW Heaters

The NRC staff reviewed the relevant parameters associated with the FW heater trains and concludes that operating at the new power level will not exceed any of the FW heaters design specifications. The licensee stated in its submittal dated June 23, 2011, that it will monitor wall thickness through its flow accelerated corrosion (FAC) program. The NRC staff finds that the licensee's plan to monitor wall thickness through its flow accelerated corrosion (FAC) program for the FW heaters to be adequate for the increased power level.

FW Heaters and Moisture Separator Reheater Vents and Drains

The licensee evaluated the vents and drains for the FW heaters and MSRs at a 1.7 percent increase in RTP. The licensee determined that several flow control valves (FCVs) did not have adequate operating margins. To resolve the issue, the licensee proposed changes to

the flow control valve trim for heater No. 2 normal (all four units), heater No. 2 emergency (Byron, Unit Nos. 1 and 2), and heater No. 3 emergency (Byron, Unit Nos. 1 and 2). Based upon the licensee's resolution of the issue, the NRC staff finds the vent and drain system for the FW heaters and moisture separator reheaters acceptable for the 1.7 percent increase in RTP.

Auxiliary Feedwater (AFW)

The licensee evaluated the interface of the AFW system with NSSS system. One of the safety functions for the AFW system is to provide a minimum flow during accidents and transients. The licensee does not propose any changes to the AFW pumps' design or performance; therefore, the minimum required flow capacities will remain the same. The licensee's analysis for the PU conditions confirmed that the current AFW system flow capacities are acceptable to meet the minimum flow requirements. Therefore, the licensee concluded that the current AFW system flow and pressure requirements and capabilities remain bounding for operating at the increased power level. Since the proposed power increase remains within the current design maximum core power of 102 percent (3658.3 MWt), the licensee found that the current inventory requirement in the condensate storage tank (CST) of 212,000 gallons remains bounding for the new higher power operating condition.

However, the licensee does intend to make changes to the current AFW system. The licensee found it necessary to add air accumulators to the AFW FCVs to adequately support the SGTR analysis. The licensee discovered vulnerability in controlling flow during a SGTR. The AFW FCVs are normally controlled by station instrument air (IA); however, IA is not available in the event of a loss of off-site power. Upon loss of the IA, the FCVs would go full-open. In the event of failure of the AFW motor-operated isolation valve to close, the FCV would need to close in order to isolate AFW flow to a ruptured SG. The air accumulators are designed to supply 30 minutes of air to keep the valve closed, giving the operators time to implement local manual actions. In the analysis of a SGTR, the licensee states that AFW flow control is maintain throughout the event.[14] The staff asked the licensee to provide justification of having only 30 minutes of air supply. In a letter dated February 20, 2012 (ADAMS Accession No ML12052A113), the licensee credited 30 minutes of air as a sufficient time for an operator to be dispatched to locally close the FCV by using its manual hand wheel. The licensee calculated 27.3 cubic feet of air is required to supply the FCVs for 30 minutes. The licensee is installing an air accumulator with 33.4 cubic feet, allowing a sufficient margin to maintain the FCVs function for at least 30 minutes. The NRC staff reviewed the licensee's response and finds the modification will assist the licensee with mitigating a SGTR by reducing a vulnerability in the event one of the electrical isolation valves fails to function. The implementation of the modification is evaluated in the SGTR MTO SG section above.

[14] The licensee stated in its February 20, 2012,letter that the Unit 1 AFW flow was limited to the throttled flow value based on the installation of the safety related air accumulators. Since the Unit 2 SGs have sufficient MTO, the Unit 2 AFW flow values were conservatively assumed to fail open even though the throttled flow could have been assumed in the analysis based on the installation of the safety related air accumulators.

Safety-Related Cooling Water

The licensee performed evaluations of capabilities of the safety-related cooling water systems at the 1.63 percent PU conditions or 3645 MWt. These included a review of the component cooling (CC) water system, essential service water (ESX) system, ultimate heat sink (UHS), and residual heat removal (RHR).

Component Cooling (CC) Water System

The licensee evaluation of the CC water system confirmed that the heat removal capabilities are sufficient to accomplish a required plant cooldown to support operation at the increased power conditions for normal plant operation, plant shutdown, and following an accident. Based upon the information and evaluations performed by the licensee to show the design of the CC system at the increased power level is bounded by existing plant analyses, the staff finds the CC system acceptable for the 1.63 percent increase in power.

Essential Service Water (ESX) System

The licensee's evaluation of the ESX system confirmed that the normal and accident heat loads for operation at the proposed increased power level are bounded by the current design basis analyses with additional margin for calorimetric uncertainty. The licensee review of the existing ESX flows will continue to support the heat removal requirements at PU conditions; therefore, the ESX system and component design parameters remain bounding for operations at the increased power level. Based upon the information and evaluations performed by the licensee to show the design of the ESX system at increase power level is bounded by existing plant analyses, the staff finds the ESX system acceptable for the 1.63 percent increase in power.

Ultimate Heat Sink (UHS)

The UHS must be capable of providing cooling water to the ESX system in order to prevent the inlet temperature from exceeding its limits during operating conditions. The licensee's evaluation determined the current ESX system inlet temperature is bounding for the increased power condition. Based upon the information and evaluations performed by the licensee to show the design of the UHS system at increase power level is bounded by existing plant analyses, the staff finds the UHS system acceptable for the 1.63 percent increase in power.

Residual Heat Removal (RHR) System/Shutdown Cooling

The licensee performed an analysis of the RHR system to assess the impact of the increased heat load on the cooldown time. The licensee's evaluation of the RHR system confirmed that the cooldown times will increase at the higher power level due to the associated increase in the decay heat load. Using two trains, the time to cool down from 350 degree Fahrenheit (°F) to 140 °F increased from 39.9 hours to 42.3 hours, considering no spent fuel pool (SFP) heat load. Considering a minimum SFP heat load, the time increased from 43.6 hours to 46.7 hours. For the single-train case, the licensee calculated the time to cooldown from 350 °F to 200 °F increased from 47.6 hours to 50.3 hours, considering no SFP heat load. Hence, the licensee concluded that the current time for single-train cooldown of 72 hours continues to meet design requirements at the increased power conditions.

The licensee concluded that the cooldown time assuming various design conditions for the RHR system is adequately sized for normal cooldown heat loads associated with the power uprate. Based upon the information and evaluations performed by the licensee to show the design of the RHR system at increased power level is bounded by existing plant analyses, the NRC staff finds the system acceptable for the 1.63 percent increase in power.

Conclusion for Safety-Related Cooling Water Systems

Based upon the information and evaluations performed by the licensee showing the design of the CC, ESX, UHS, and RHR systems at the proposed power level is bounded by existing plant analyses, the staff finds these systems acceptable.

Spent Fuel Pool (SFP) Storage and Cooling

In its June 23, 2011, application the licensee evaluated three scenarios for the SFP fuel cooling system for operation at the proposed power conditions. Operating at the proposed power will slightly increase the decay heat load in the SFP. The licensee's calculation show an increase of approximately 3.5 °F in the expected peak SFP water temperature for each of the three scenarios. For each scenario, the peak SFP water temperature remains well below the FC system design maximum temperature of 200 °F. Therefore, the licensee determined that the current FC system capacity for the SFP bounds the requirements under MUR conditions for all three scenarios, with significant margin; and all existing components, including associated pressures and flow rates, have been evaluated as acceptable for operation at the increased power level.

The SFP provides for storage of various fuel assembly types of different initial fuel enrichments and exposure histories. Of the six assumptions identified in the SFP criticality calculation, the licensee identified that only two parameters will be affected by operating at a higher power level. First, a higher SFP temperature will impact the moderator reactivity coefficient. Secondly, the amount of uranium depleted in the fuel during power operation will be impacted at increased power conditions. The licensee's criticality analysis conservatively uses a SFP temperature of 39.2 °F, which is the maximum possible density of the water in the SFP. Therefore, the actual SFP reactivity resulting from a higher temperature will be lower than the design maximum calculated value regardless of SFP water temperature. The licensee maintains spent fuel in zones in the SFP based on fuel burn-up. Operating at a higher power level should not impact the SPF criticality analysis as long as the licensee stores fuel in designated regions allowed by current license basis. Based on this evaluation, the licensee concluded that the current criticality calculation remains valid and will not be impacted by operating at the proposed power.

For SFP storage and cooling, based upon the information and evaluations performed by the licensee to show the design of the spent fuel cycle (FC) system at increased power level is bounded by existing plant analyses, the staff finds the FC system acceptable for the proposed power.

Radioactive Waste

The licensee evaluated the liquid and gaseous radioactive waste systems for operating at the proposed power. The licensee determined that there was an insignificant impact on the gaseous and liquid waste volumes at the increased power level. The licensee found the

liquid and gaseous waste systems are bounded by the existing system design parameters and are acceptable at the proposed power conditions.

For the radioactive waste systems, based upon the information and evaluations performed by the licensee to show the design of the liquid and gaseous radioactive waste systems at increase power level is bounded by existing plant analyses, the staff finds the liquid and gaseous radioactive waste systems acceptable for the proposed power.

Steam Generator Tube Rupture (SGTR) Methodology

In its June 23, 2011, submittal, the licensee changed the methodology used to mitigate a SGTR accident summarized in FSAR, Section 15.6.3. The new methodology follows the NRC-approved methodology described in Westinghouse Commercial Atomic Power (WCAP)-10698-P-A, "SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill." Within this new methodology are critical operator actions that must be performed within a specified time period. These operator actions are: (1) isolate AFW flow to the ruptured SG, (2) close the MSIV on the ruptured SG, (3) initiate a RCS cooldown and depressurization, and (4) terminate SI flow.

The NRC staff noted that two SG PORVs were opened late in the event to stop overfill from occurring. The staff asked the licensee to justify whether this activity should be a time critical operator action. In a letter dated February 20, 2012 (ADAMS Accession No. ML12052A113), the licensee explained that the WCAP analysis does not identify specific operator actions after SI termination. The licensee states that any required operator actions after SI termination are implemented at the required time within the LOFTRAN computer model. Based on the licensee's evaluation the NRC staff determined that the licensee's analysis meets the guidance of WCAP-10698-P-A.

Flooding analysis

Operating at the proposed power requires approximately a 1.9 percent increase in flow rates in the condensate, main FW and main steam systems (MSSs). The licensee evaluated the impact of the increased flow rates on the current flooding analysis and determined that the current flood levels were not affected by operating at an increase power level. Based upon the information and evaluations performed by the licensee to show the effects on internal flooding at the proposed power are bounded by existing plant analyses, the NRC staff finds the internal flooding analysis acceptable for operation at the proposed power.

3.3.3 Conclusion

Based on the above, the NRC staff finds the licensee's request to be acceptable with respect to the balance of plant systems affected by the power uprate. This acceptance is based on the licensee's indication that the design capability of the BOP systems will continue to bound the impacts of the uprate.

3.4 Engineering and Materials

3.4.1 Reactor Vessel Integrity and Internals

The NRC staff's review in the area of reactor vessel (RV) integrity focuses on the impact of the proposed power on pressurized thermal shock (PTS) calculations, neutron fluence

calculations, RV pressure-temperature (P-T) limits, upper shelf energy (USE) evaluations, and the RV surveillance capsule withdrawal schedules. This review was conducted, consistent with the guidance contained in RIS 2002-03, to verify that the results of licensee analyses related to these areas continue to meet the requirements of 10 CFR Part 50, Sections 50.60 and 50.61, and 10 CFR Part 50, Appendices G and H, following implementation of the proposed power.

Pressurized Thermal Shock (PTS)

Regulatory Evaluation

The PTS evaluation provides a means for assessing the susceptibility of the PWR RV beltline materials to failure during a PTS event to assure that adequate fracture toughness exists during reactor operation. The NRC staff's requirements, methods of evaluation, and safety criteria for PTS assessments are in 10 CFR 50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events." The NRC staff's review covered the PTS methodology and the calculations for the reference temperature for PTS (RTPTS) at the expiration of the license, considering neutron embrittlement effects.

Technical Evaluation

Section IV.1.C.i of Attachment 5 to the June 23, 2011, submittal, stated that PTS calculations were performed for Braidwood and Byron units using the current 40-year end of license (EOL) neutron fluence values and all the Braidwood and Byron units RV materials will continue to meet the 10 CFR 50.61 PTS screening criteria.

The PTS screening criteria are 270 °F for RV plates, forgings, and axial welds and 300 °F for RV circumferential welds. For the Braidwood units, the limiting RTPTS values reported in Section IV.1.C.i of Attachment 5 are 98 °F for both units' intermediate to lower shell forging circumferential weld. The staff found that the limiting RTPTS values in the Braidwood 1 PTLR, Revision 4, and Braidwood, Unit 2, PTLR, Revision 4, for the corresponding RV materials are 99 °F for Unit 1 and 98 °F for Unit 2. The discrepancies between these two sources are insignificant, and the staff determined that they have no impact on the Braidwood units PTS evaluations. For the Byron units, the limiting RTPTS values reported in Section IV.1.C.i of Attachment 5 are 109 °F for the intermediate shell forging for Byron Unit 1 and 114 °F for the intermediate to lower shell forging circumferential weld for Byron Unit 2.

However, the NRC staff found that the limiting RTPTS values in the Byron, Unit Nos. 1 and 2, PTLRs (2006) for the corresponding RV materials are 110 °F for Unit 1 and 116 °F for Unit 2. The discrepancies between these two sources are within 2 °F, and the staff determined that they have no impact on the Byron units PTS evaluations because the highest number is below the lowest PTS screening criteria of 270 °F.

Conclusion

Since the RTPTS values for the limiting RV beltline materials of Braidwood, Units 1 and 2, and Byron, Units 1 and 2, are lower than the PTS screening criterion of 270 °F for forging and 300 °F for circumferential welds, the NRC staff concludes that after implementation of the MUR PU, the Braidwood and Byron units RV beltline materials would continue to meet the PTS screening criteria requirements of 10 CFR 50.61 and maintain structural integrity

during a PTS event. The NRC staff has determined that the changes identified in the proposed LAR will not significantly impact the remaining safety margin.

Pressure and Temperature (P-T) Limits and Upper Shelf Energy (USE)

Regulatory Evaluation

Appendix G of 10 CFR Part 50, provides fracture toughness requirements for ferritic (low alloy steel or carbon steel) materials in the reactor coolant pressure boundary (RCPB), including requirements on the USE values used for assessing the safety margins of the RV materials against ductile tearing and for calculating P-T limits for the plant. These P-T limits are established to ensure the structural integrity of the ferritic components of the RCPB during any condition of normal operation, including anticipated operational occurrences and hydrostatic tests. The NRC staff's review of the USE assessments covered the impact of the MUR PU on the neutron fluence values for the RV beltline materials and the USE values for the RV materials through the end of the current licensed operating period. The NRC staff's P-T limits review covered the P-T limits methodology and the calculations for the number of effective full-power years (EFPYs) specified for the P-T limits, considering neutron embrittlement effects on the RV beltline materials under the proposed uprate.

Technical Evaluation

The NRC staff found that the current P-T Limits and low temperature overpressurization protection system (LTOPS) setpoints in the 2006 Byron Unit 1 PTLR are based on one quarter or three quarters of the RV wall thickness (¼T or ¾T) adjusted reference temperature (ART) values of 106 °F and 97 °F for the limiting material – the intermediate shell forging. Byron Unit 2 has two limiting materials: the ¼T and ¾T ART values for the circumferential weld are 107 °F and 89 °F; the corresponding values for nozzle shell forging are 52 °F and 37 °F.

In its submittal the licensee stated that,

> [f]or Unit1, the limiting ART values used in the development of the current P-T limit curves at 32 EFPY [effective full-power year] bound the ...[uprate limit ART values (at 32 EFPY).

The NRC staff accepts this conclusion because the maximum fluence value on record (i.e., the 2006 Byron 1 PTLR) bounds the MUR maximum value reported in Table IV.1.C.ii-1 of Attachment 5. For Byron Unit No. 2, the licensee stated in the application,

> [f]or Unit 2, the limiting ART values used in the development of the current P-T limit curves at 32 EFPY are slightly lower than the ...[uprate] limiting ART values (at 32 EFPY).

The NRC staff was unable to verify this statement because the maximum fluence value on record (i.e., the 2006 Byron Unit 2 PTLR) also bounds the MUR maximum value reported in Table IV.1.C.ii-1. In the November 1, 2011, supplement, the licensee stated that the uprate neutron fluence value calculated specifically for the Byron Unit 2 nozzle shell forging at 32 EFPY is greater than the neutron fluence value used in the development of the current P-T limit curves in the 2006 Byron 2 PTLR for the nozzle shell forging at 32 EFPY, and this neutron fluence increase for the Byron 2 nozzle shell forging material resulted in higher ART

values at 32 EFPY for the uprate as compared to those used in the development of the current P-T limit curves. The response further stated that the PTLR will be updated to reflect the uprate ART values and the 30.5 EFPY specified for the Byron 2 P-T limit curves. Since the PTLR will be updated to reflect the uprate ART values and the revised 30.5 EFPY for the Byron 2 P-T limit curves, the NRC staff determined that this issue is resolved and the licensee's evaluation is acceptable. The NRC further concludes that updating the PTLR is adequately controlled by TS 5.6.6.

For the Braidwood, Units 1 and 2, the licensee stated that the current P-T limits in Braidwood, Unit 1, PTLR, Revision 4, and Braidwood, Unit 2, PTLR, Revision 4, are licensed through 32 EFPY. It further stated that, "[t]he limiting ART values used in the development of the current P-T limit curves at 32 EFPY bound the MUR [PU] limiting ART values (at 32 EFPY) for both Units. Therefore, the current heatup and cooldown curves are valid through EOL (32 EFPY) with the MUR [PU] and do not require update."

The NRC staff accepts this conclusion because the maximum fluence value on record (i.e., the Braidwood 1 PTLR, Revision 4, and the Braidwood 2 PTLR, Revision 4), bounds the MUR PU maximum value reported in Table IV.1.C.ii-1 of Attachment 5. This means that the limiting ART remains unchanged considering MUR PU. Therefore, the current Braidwood, Units 1 and 2, P-T limits and LTOPS setpoints based on the same limiting ARTs remain valid through 32 EFPY.

For the USE evaluation, Section IV.1.C.v of Attachment 5 to the June 23, 2011, submittal, stated that the projected EOL Charpy USE decreases due to MUR PU fluence at the ¼T location were calculated per RG 1.99, Revision 2. It further stated that the limiting projected ¼T USE values are 75 ft-lbs for the intermediate to lower shell forging circumferential weld for Braidwood 1, 66 ft-lbs for the intermediate to lower shell forging circumferential weld for Braidwood, Unit 2, 65 ft-lbs for the nozzle to intermediate shell forging circumferential weld for Byron, Unit No. 1, and 68 ft-lbs for the nozzle to intermediate shell forging circumferential weld for Byron, Unit No. 2. However, the calculation details of these limiting USE values or their reference is not given in Attachment 5. The 2006 Byron PTLRs and the Braidwood PTLRs, Revision 4, contain no USE estimates either. By letter dated October 12, 2011, the NRC staff requested additional information.

In its November 1, 2011, response, the licensee provided the information requested, including detailed calculation of EOL USEs for the beltline materials of Braidwood and Byron units, supporting the MUR PU request. The staff performed independent calculations and found that minor discrepancies exist between the provided EOL USEs and the staff's values, primarily due to use of different initial USEs. The initial USEs used by the staff are based on the NRC's reactor vessel integrity database (RVID) which was updated in 2001 to reflect the NRC staff's review of the power increase request for the Braidwood and Byron units as documented in the approved Amendment No. 113 for Braidwood, Units 1 and 2, and approved Amendment No. 119 for Byron, Unit Nos. 1 and 2 (dated May 4, 2001). Using the staff's initial USE values for the limiting materials mentioned above (75 ft-lbs for all four limiting materials) instead of the licensee's values (80 ft-lbs for Braidwood, Units 1 and 2, and Byron, Unit No. 2, and 77 ft-lbs for Byron, Unit No. 1), the NRC staff's arrived at EOL USEs of 70.3 ft-lbs for the limiting material of Braidwood, Unit 1, 61.9 ft-lbs for Braidwood, Unit 2, 63.3 ft-lbs for Byron, Unit No. 1, and 63.8 ft-lbs for Byron, Unit No. 2. In summary, both the licensee's and the NRC staff's calculated EOL USEs for the Braidwood and Byron units are above 50 ft-lbs as required by 10 CFR Part 50, Appendix G.

Conclusion

The licensee addressed the impact of the MUR PU on the Braidwood, Units 1 and 2, and Byron, Unit Nos. 1 and 2, USE evaluations. These analyses are documented in Attachment 5 to the licensee's letter of June 23, 2011, as supplemented by the November 1, 2011, response, to the NRC staff RAI. Since both the licensee's and the staff's calculated EOL USEs for the beltline materials of the Braidwood and Byron units are above 50 ft-lbs, the staff concludes that the RV beltline materials for the Braidwood and Byron units will continue to satisfy the EOL USE criteria specified in 10 CFR Part 50, Appendix G, at the proposed power.

The NRC staff has determined that the changes identified in the proposed LAR will not impact the remaining safety margin. Therefore, the NRC staff finds the proposed power to be acceptable with respect to the P-T limits and USE.

Reactor Vessel (RV) Material Surveillance Program

Regulatory Evaluation

The RV material surveillance program provides a means for determining and monitoring the fracture toughness of the RV beltline materials to support analyses for ensuring the structural integrity of the ferritic components of the RV. Appendix H of 10 CFR Part 50 provides the staff's requirements for the design and implementation of the RV material surveillance program.

Technical Evaluation

In its June 23, 2011, application, the licensee stated that the NRC-approved RV surveillance capsule withdrawal schedules for the Braidwood and Byron units are contained in the PTLR for each unit. It further stated that the current capsule withdrawal schedule in the PTLRs will be updated to reflect the latest capsule fluence, lead factor, and withdrawal EFPY associated with each capsule. The updated capsule withdrawal schedules for Byron, Unit Nos. 1 and 2, can be found in Tables IV.1.C.vi-1 and IV.1.C.vi-2, and for Braidwood, Units 1 and 2, in Tables IV.1.C.vi-3 and IV.1.C.vi-4 of Attachment 5 to the submittal. However, the source or reference for the latest capsule fluence, lead factor, and withdrawal EFPY associated with each capsule is not given. In its October 12, 2011, letter, the NRC staff requested additional information.

In its November 1, 2011, response, the licensee stated that the vessel and surveillance capsule fluence values contained in the submittal were calculated as part of the MUR PU project and are not contained in any prior surveillance capsule reports. Since the revised fluence calculations were based on the methodologies in WCAP-14040-A, Revision 4, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves," and WCAP-16083-NP-A, Revision 0, "Benchmark Testing of the FERRET Code for Least Squares Evaluation of Light Water Reactor Dosimetry," which meet the requirements of RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," the revised capsule fluence, lead factor, and withdrawal EFPY associated with each capsule and the RV fluence values are acceptable. This issue is resolved.

The surveillance program requirements in Appendix H of 10 CFR Part 50 were established to monitor the radiation-induced changes in the mechanical and impact properties of the RV materials. Appendix H of 10 CFR Part 50 requires licensees to monitor changes in the fracture toughness properties of ferritic materials in the RV beltline region of light-water nuclear power reactors. Appendix H of 10 CFR Part 50 states that the design of the surveillance program and the withdrawal schedule must meet the requirements of the edition of American Standard Testing of Materials (ASTM) E 185, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels," that is current on the issue date of the ASME Code, to which the RV was purchased. Later editions of ASTM E 185 may be used including those editions through 1982 (i.e., ASTM E 185-82). This evaluation is limited to the current 40-year period of operation for these units.

Section IV.1.C.vi of Attachment 5 indicated that the surveillance capsule withdrawal schedules are consistent with ASTM E 185-82. Table 1 of ASTM E 185-82 requires that either a minimum of three, four, or five surveillance capsules be removed from each of the vessels, as based on the projected nil-ductility reference temperature shift (ΔRTNDT) of the limiting material at the clad-vessel interface location of the RV at the EOL. Since Braidwood, Units 1 and 2, and Byron, Unit Nos. 1 and 2, PTLRs indicated that the EOL ΔRTNDT values of each unit's limiting materials are less than 100 °F, the staff determined that each Braidwood or Byron unit only needs three surveillance capsules to meet the ASTM E 185-82 requirement. The RV materials surveillance program for each Braidwood or Byron unit contains six capsules, three are designated as required and three are standby. The three required capsules for each unit were withdrawn and tested to support current license operation. The staff compared the capsule withdrawal EFPYs in Table IV.1.C.vi-1 and Table IV.1.C.vi-2 for Byron, Unit Nos. 1 and 2, and TableIV.1.C.vi-3 and Table IV.1.C.vi-4 for Braidwood, Units 1 and 2, with those in the ASTM E 185-82 for plants with three capsules and concludes that the licensee's surveillance capsule withdrawal schedules in the LAR for the Braidwood and Byron units are in accordance with ASTM E 185-82 and are, therefore, acceptable. All standby capsules have also been withdrawn to avoid excessive irradiation and for future use, but have not been tested. Reinsertion of the withdrawn standby capsules is beyond the ASTM E 185-82 requirements for supporting current license operation.

Conclusion

The NRC staff concludes that the licensee's surveillance capsule withdrawal schedules in the LAR for Braidwood, Units 1 and 2, and Byron, Unit Nos. 1 and 2, are acceptable because all required capsules have already been withdrawn in accordance with the requirements of ASTM E 185-82 to support the current 40-year license operation. The revised capsule fluence, lead factor, and withdrawal EFPY associated with each capsule and the RV fluence values in the LAR are based on additional information provided in the licensee's supplement dated November 1, 2011, and are acceptable as discussed above.

3.4.2 RV Internals and Core Support Structures

Regulatory Evaluation

The RV internals and core support structures include SSCs that perform safety functions or whose failure could affect safety functions performed by other SSCs. These safety functions include reactivity monitoring and control, core cooling, and fission product confinement (within both the fuel cladding and the reactor coolant pressure boundary). The NRC's acceptance criteria for RV internals and core support structures are based on GDC 1

and 10 CFR 50.55a for material specifications, controls on welding, and inspection of RV internals and core supports. Matrix 1 of NRC Review Standard (RS)-001, Revision 0, "Review Standard for Extended Power Uprates" (ADAMS Accession No. ML033640024), provides references to the NRC's approval of the recommended guidelines for RV internals in TRs WCAP-14577, Revision 1-A, "License Renewal Evaluation: Aging Management for Reactor Internals" (ADAMS Accession No. ML010430375) and BAW-2248-A, "Demonstration of the Management of Aging Effects for the Reactor Vessel Internals" (ADAMS Accession No. ML003708443).

The SE dated December 16, 2011 (ADAMS Accession No. ML11308A770), on materials reliability program (MRP) report 1016596 (MRP-227), Revision 1, "Pressurized Water Reactor (PWR) Internals Inspection and Evaluation Guidelines [I&E]," provides the NRC's evaluation of the industry's recommended I&E guidelines for RV internals which summarized the industry effort on this issue for the past few years. The NRC staff considers the MRP-227 report, as modified by the NRC staff, a replacement of the WCAP-14577, Revision 1-A, report and the BAW-2248-A report and will make necessary changes in the next revision of NRC RS-001.

Technical Evaluation

The licensee discussed the impact of the Braidwood, Units 1 and 2, and Byron, Unit Nos. 1 and 2, MUR PU on the structural integrity of the RV internals in Attachment 5 of the LAR, Section IV.1.A.ii and the licensee's November 1, 2011, supplement. The licensee concluded that the RV internals continue to meet their design criteria at proposed power conditions.

The staff reviewed the licensee's evaluation of the structural integrity of the Braidwood and Byron RV internals using NRC RS-001, Revision 0. Table Matrix-1 of NRC RS-001, Revision 0, provides the staff's guidance for evaluating the potential for extended power uprates to induce aging effects on RV internals. Depending on the magnitude of the projected RV internals fluence, Table Matrix-1, may be applicable to the MUR application. However, the WCAP-14577, Revision 1-A, report and the BAW-2248-A report cited in Matrix 1 are no longer applicable since issuance of the SE on the MRP-227 report, which summarized most recent industry recommended I&E guidelines for PWR RV internals. Section IV.1.A.ii of Attachment 5 to the EGC's June 23, 2011, submittal, provides information for only a few RV internals and, therefore, appears incomplete. In its letter dated October 12, 2011, the staff requested additional information.

In its November 1, 2011, response, the licensee stated that the Exelon PWR Reactor Internals Management Program provides the necessary oversight and management to ensure that the integrity and operability of RV internals are consistent with the MRP-227 report requirements. The response further stated that (1) Exelon is an active participant in the MRP efforts relative to the development of the MRP-227 report for PWR RV internals inspections, (2) Exelon will prepare the necessary RV internals aging management plan in accordance with NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," Revision 2, as part of the overall license renewal process, of which Aging Management Program (AMP) XI.M16A provides recommended content for an acceptable PWR RV Internals AMP that references the MRP-227 report, and (3) an inspection plan will be submitted with the License Renewal Application, consistent with Category D plants as discussed in NRC RIS 2011-07, "License Renewal Submittal Information for Pressurized Water Reactor Internals Aging Management," dated July 21, 2011.

Since the licensee confirmed that Exelon has participated in the industry's initiatives on age-related degradation of all PWR RV internals, including core support structures and plans to submit its plant-specific program consistent with the MRP-227 report guidelines, the NRC staff concludes that the licensee's November 1, 2011, response is adequate to resolve the questions in the NRC staff's October 12, 2011 (ADAMS Accession No. ML11262A161), letter. Exelon's participation in the industry's initiatives as described in its November 1, 2011, response also provides assurance that the Braidwood and Byron units' RV internals AMPs will be developed or modified from the current AMPs in accordance with the MRP-227-A report. In addition, the Braidwood and Byron units MUR PU results in very small changes to aging parameters such as temperature and neutron flux. Based on the above, the staff determined that the licensee's RV internals evaluation considering uprated conditions is acceptable.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the impact that uprate conditions will have on the structural integrity assessments for the RV internals. The staff has determined that the licensee's RV internals evaluation considering the uprate is acceptable because: (1) the Braidwood and Byron units' RV internals AMPs will be developed or modified from the current AMPs in accordance with the MRP-227-A report and (2) the Braidwood and Byron units uprate results in very small changes to aging parameters such as temperature and neutron flux. The staff has determined that the changes identified in the proposed request will not significantly impact the remaining safety margin.

3.4.3. Mechanical and Civil Engineering

3.4.3.1 Regulatory Evaluation

Nuclear power plants are licensed to operate at a specified core thermal power, referred to as the CLTP. 10 CFR Part 50, Appendix K, requires licensees to assume that the reactor has been operating continuously at a power level at least 1.02 times the licensed power level when performing ECCS analyses for LOCAs. This requirement is included to ensure that instrumentation uncertainties are adequately accounted for in these analyses. Appendix K to 10 CFR Part 50 allows licensees to assume a power level less than 1.02 times the licensed power level (but not less than the licensed power level), provided the licensee has demonstrated that the proposed value adequately accounts for instrumentation uncertainties.

Section 3.1, "Conformance with NRC General Design Criteria," of the Byron and Braidwood UFSAR states that the design of both Braidwood and Byron fully satisfy and are in compliance with the intent of Appendix A to 10 CFR 50 "General Design Criteria for Nuclear Power Plants." The NRC staff's assessment of the proposed MUR PU in the areas of mechanical and civil engineering and the acceptance criteria are based on continued conformance with the requirements of the design and licensing basis of Braidwood and Byron.

The primary guidance used by Exelon and other licensees for LARs involving MUR PU is outlined in RIS 2002-03, "Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications," which provides licensees with a guideline for organizing LAR submittals for the MUR PU. Section IV of RIS 2002-03, Mechanical/Structural/Material Component Integrity and Design," provides information to licensees on the scope and detail

of the information which should be submitted to the NRC staff regarding the impact an MUR power uprate has on the structural and pressure boundary integrity of the SSC.

The NRC has recently issued similar MUR PU license amendments for the Surry Power Station, Units 1 and 2, on September 24, 2010, (ADAMS Accession No. ML101750002), for the Prairie Island Nuclear Generating Plant, Units 1 and 2, on August 18, 2010, (ADAMS Accession No. ML102030573), and for the North Anna Power Station, Units 1 and 2, on October 22, 2009 (ADAMS Accession No. ML092250616).

3.4.3.2 Technical Evaluation

The NRC staff's review focused on the licensee's assessment of the impact of the proposed power on the design-basis analysis of record and covers the structural and pressure boundary integrity of the piping, components and supports which make up the NSSS and the BOP systems. The NRC staff's review also focused on the impact of the proposed power on postulated high-energy break line (HELB) locations and corresponding dynamic effects resulting from the postulated HELB, including pipe whip and jet impingement.

Tables 3-1 and 3-2 of Attachment 1 to the licensee's June 23, 2011, submittal, show the pertinent temperatures, pressures, and flow rates for the eight cases (four cases for Braidwood and Byron Unit 1; four cases for Braidwood and Byron Unit 2) associated with Braidwood and Byron's MUR PU conditions. The licensee evaluated the effects of the proposed MUR PU at a bounding reactor core power level of 3658 MWt which corresponds to the proposed licensed power following the uprate (3645 MWt) plus an uncertainty measurement value of 0.345 percent (approximately 13 MWt). The licensee evaluated four cases of NSSS parameters. Cases 1 and 2 represent an average vessel temperature of 575 °F, with Case 2 representing an average 5 percent (for Unit 1) and 10 percent (for Unit 2) of SG tubes being plugged. Cases 3 and 4 represent an average vessel temperature of 588 °F, with Case 4 representing an average 5 percent (for Unit 1) and 10 percent (for Unit 2) of SG tubes being plugged. The evaluations performed by the licensee to demonstrate continued structural and pressure boundary integrity of the aforementioned SSC, at the proposed licensed power conditions, considered the most limiting values of the parameters stipulated in the eight cases, depending on which parameters were used in the AOR for the SSC.

The guidance in Section IV.1.A of RIS 2002-03, identifies certain structure, system and components (SSCs) to be evaluated to determine whether they are able to support the implementation of the proposed licensed power. The evaluations discussed in Section IV of RIS 2002-03 focus on determining what impact the proposed power would have on the AOR for a particular SSC and determine whether the AOR needs to be revised as a result of the proposed licensed power. If the AOR for a particular SSC was performed at conditions which bound those which will be present at the proposed licensed power, no further evaluation is required. Furthermore, Section IV.1.B of RIS 2002-03 indicates that for those SSCs whose AOR is affected by implementation of an MUR PU, the licensee should address the following, as they relate to the impact of the proposed licensed power on the AOR: stresses, cumulative usage factors (i.e., fatigue), flow induced vibration (FIV), and changes in temperature, pressure and flow rates resulting from the PU.

The pressure-retaining components which must be evaluated in support of an MUR PU include the following: the RPV, including the RPV nozzles and supports; the reactor vessel internals (RVIs); the pressure-retaining portions of the control rod drive mechanisms

(CRDMs); NSSS piping, pipe supports and branch nozzles associated with the RCS; BOP piping and supports; SGs, including their supports, the SG shells, secondary side internal support structures and nozzles; the pressure retaining portions of the RCPs; the pressurizer, including the pressurizer shell, nozzles and the surge line. The licensee has summarized the design codes of record for the above components in Table IV.1.D-1 of its submittal.

Reactor Vessel Structure

The licensee evaluated the effects of the proposed MUR PU on the structural integrity of the RPV in Section IV.1.A.i of Attachment 7 to the submittal. The licensee stated that the Byron and Braidwood reactor vessels were previously analyzed with a minimum normal operating inlet temperature of 538.2°F and a maximum normal operating outlet temperature of 620.3°F. The MUR temperature values (538.2°F - 618.4°F) are bounded by the values in the AOR (538.2°F - 620.3°F). The licensee further stated that the NSSS design transients associated with the reactor vessel components remain unchanged for the proposed licensed power.

In the supplement dated February 20, 2012, the licensee indicated that: (1) the uprated RCS design conditions given in Tables 3-1 and 3-2 of Attachment 1 of the submittal provide a T_{avg} range in which the minimum T_{cold} is 541.4°F and the maximum T_{hot} is 620.9°F; (2) the reactor vessel AOR evaluated a minimum T_{cold} of 538.2°F and a maximum T_{hot} of 620.3 °F; (3) the uprate maximum T_{hot} of 620.9 °F exceeds the maximum T_{hot} evaluated in the reactor vessel AOR; and (4) the MUR PU minimum T_{cold} is bounded by the minimum T_{cold} evaluated in the reactor vessel AOR.

The licensee further stated that normally a reconciliation analysis would be necessary because the uprated maximum T_{hot} is not bounded by the maximum T_{hot} evaluated in the reactor vessel AOR. However, all Braidwood and Byron units have plant operational limits which restrict the minimum T_{cold} to 538.2 °F and the maximum T_{hot} to 618.4 °F. The plant operational limits will remain in place for the MUR PU. Therefore, the minimum T_{cold} and maximum T_{hot} evaluated in the reactor vessel AOR bound those of the proposed licensed power when the plant operational limits are taken into consideration.

Based on the licensee's response, the plant operational limits for all Braidwood and Byron units restricting the minimum T_{cold} to 538.2 °F and the maximum T_{hot} to 618.4 °F, and the fact that the design parameters used in the AOR for the RPV remain bounding, the NRC staff concludes that there is assurance that the structural integrity of the RPV will be adequately maintained following the implementation of the proposed uprate.

The licensee also discussed the update of the lifting lug interface loads in Section IV.1.A.i of Attachment 7 to the submittal. In response to the staff's question regarding the relevancy of the lifting lugs and the proposed license amendment, in supplement dated February 20, 2012, the licensee stated that: (1) there are three lifting lugs oriented 120 degrees apart around the external side of the reactor vessel closure head which the integrated head package lift rod assemblies attach through a lift rod clevis and clevis pin; and (2) the lifting lug mechanical loads identified for current operating conditions did not change due to the proposed licensed power.

Based on the licensee's response regarding the function of the reactor vessel closure head lifting lugs and the guidance in RIS 2001-03, the NRC staff finds these lifting lugs outside

the scope of the NRC's uprate review. Thus, the NRC staff's evaluations and conclusions discussed in this SE are not applicable to the reactor vessel closure head lifting lugs.

Reactor Vessel Internals (RVI) Mechanical Evaluation

The licensee summarized its evaluation of the effects of the proposed licensed power on the structural integrity of the RVIs in Section IV.1.A.ii of Attachment 7 to the submittal.

The licensee's mechanical evaluation of the RVIs focused on the impact of the proposed licensed power on the design basis loads from a seismic event, LOCAs and FIV. The licensee stated that the proposed licensed power has no impact on the design basis seismic, LOCA, and FIV, loads used in the mechanical evaluation of the RVIs. In a letter dated February 20, 2012, the licensee provided further information and confirmed, that the change in T_{cold} and T_{hot} fluid densities, due to the proposed licensed power, is less than 0.1 percent and the current analysis of record remains unchanged. Furthermore, the licensee, in its letter dated February 20, 2012, stated the following:

1. The AOR for the Braidwood and Byron RVIs was performed with conservative gamma heating rates. The proposed licensed power gamma heating rates were verified to remain bounded by the conservative heating rates used in the AOR.

2. The design inputs, i.e. LOCA hydraulic and seismic forces and geometry, are not changing from the current analysis of record for the MUR power uprate; therefore, there is no impact on the allowable deflections provided in Byron and Braidwood UFSAR Table 3.9-4, "Maximum Deflections Allowed for Reactor Internal Support Structure." The values provided in UFSAR Table 3.9-4 remain valid for the MUR PU.

3. All the design loading conditions noted in Section 3.9.5.2 of the Braidwood and Byron Updated Final Safety Analysis Report (UFSAR) were considered in the structural assessment of the reactor vessel internal components to assess the impact of the proposed MUR PU. The design loads associated with the design of the reactor vessel internals remain bounded by the AOR. The maximum calculated stresses and cumulative fatigue usage factor for the most limiting component of the reactor vessel internals are unaffected by the MUR PU and remain bounded by the AOR.

4. The impact of the proposed MUR PU on the incore instrumentation support structures, including both the upper support columns and the lower support columns, was assessed. The proposed MUR PU conditions are bounded by the design input used in the AOR; thus, the stresses and the cumulative fatigue usage factors in these components remain unchanged from the AOR.

Considering that the design parameters used in the AOR for the RVIs remain bounding and the RVIs continue to meet their design basis acceptance criteria under the conditions of the proposed licensed power, the NRC staff concludes that the licensee has adequately addressed the effects of the proposed MUR on these components and that there is assurance that the structural integrity of the RVIs will be adequately maintained following implementation of the proposed licensed power.

Control Rod Drive Mechanisms (CRDMs)

The licensee evaluated the effects of the proposed licensed power on the structural integrity of the CRDMs in Section IV.1.A.iii of Attachment 7 in the submittal.

In the February 20, 2012, supplement, the licensee indicated that the proposed licensed power conditions have no impact on the seismic or LOCA loads used in the AOR of the CRDMs. In addition, the licensee stated that the CRDMs assessment for the proposed licensed power considered all pressure and thermal design transients and load combinations noted in Section 3.9.4 of the Byron and Braidwood UFSAR and concluded that the proposed licensed power has no impact on the AOR of the CRDMs and remain in compliance with the design basis code of record.

Furthermore, the licensee stated, in the submittal, that the proposed licensed power has no effect on the structural qualification of the integrated head package CRDMs seismic support assembly since the revised loads are bounded by the existing design basis loads. Because the licensee shows that the design input parameters used in the AOR for the qualification of the CRDMs are not affected by the proposed licensed power uprate and the CRDMs continue to meet their design basis acceptance criteria under the conditions of the proposed licensed power, the NRC staff concludes that the licensee has adequately addressed the effects of the proposed licensed power on the CRDMs and that there is assurance that the structural integrity of the CRDMs will be adequately maintained following implementation of the proposed licensed power.

Reactor Coolant System (RCS) Piping and Supports

The licensee evaluated the effects of the proposed licensed power on the structural integrity of the RCS piping and associated supports in Section IV.1.A.iv of Attachment 7 in the submittal.

In the supplement dated February 20, 2012, the licensee indicated that the conditions associated with the proposed licensed power were evaluated to determine the impact on the existing design basis reactor coolant loop (RCL) analysis for the following:

- RCL piping stresses and displacements,
- Primary equipment nozzle loads (RPV inlet and outlet nozzles, SG inlet and outlet nozzles, and RCP suction and discharge nozzles),
- Primary equipment support loads (RPV nozzle supports, SG columns and lateral bumpers, RCP columns and lateral supports, and pressurizer supports), and pressurizer surge line piping stresses and displacements including the effects of thermal stratification

The licensee further stated that:

- The current RCL thermal analysis in the design basis AOR remains bounding;
- The RCL deadweight and seismic analyses remain unaffected by the proposed licensed power because there is no change to the configuration of the RCL piping and supports;
- Primary side NSSS design transients and pressurizer surge line transients are not affected due to the proposed licensed power;

- There is no adverse effect on the fatigue evaluation of the RCL and pressurizer surge line, including the effects of thermal stratification;
- The LOCA hydraulic forcing functions used in the design basis RCL piping AOR analyses remains bounding for the proposed licensed power;
- Thrust and jet impingement forces used in the current AOR remain bounding;
- There are no changes due to the proposed licensed power to the piping or component qualification from the design basis, including: primary equipment nozzles, Class 1 auxiliary piping analysis, and surge line stratification;
- The NSSS component supports, which include the reactor vessel, steam generator, reactor coolant pump, and pressurizer supports, were assessed at the proposed licensed power and were shown to remain bounded by the current design basis AOR; and
- The maximum primary and secondary stresses and the maximum fatigue usage factors associated with the current design basis AOR are applicable to the proposed licensed power.

Because the licensee shows that the RCS piping and associated supports, and NSSS equipment nozzles and supports continue to meet their design basis acceptance criteria under the conditions of the proposed licensed power, the NRC staff concludes that there is assurance that the structural integrity of the RCS piping and associated supports, and NSSS equipment nozzles and supports will be adequately maintained following implementation of the proposed licensed power.

Balance of Plant (BOP) Piping and Supports

The licensee evaluated the effects of the proposed licensed power on the structural integrity of the BOP piping and associated supports in Section IV.1.A.v of Attachment 7 in the June 23, 2011, submittal. The licensee in its supplement dated February 20, 2012, provided a list of those BOP piping systems that were evaluated for the proposed licensed power conditions, and provided information regarding the methodology used in the evaluation of BOP piping systems.

The licensee stated in its letters dated February 20, and May 16, 2012, that the AOR design input parameters for the main steam system, SG blowdown system, AFW system, chemical and volume control system, SI system, containment spray system, and circulating water piping remain bounding. In its February 20, 2012, letter the licensee further stated that for seismic piping there was no pressure increases and for the non-seismic piping none of the piping exceeded the design pressure as a result of the proposed licensed power for the BOP piping systems.

The licensee performed a detailed review of those piping systems that the proposed licensed power operating temperature exceeded the CLTP operating temperature by more than one percent. The licensee stated that for piping systems that are currently in compliance with the design code of record, increasing the system temperature by one percent will not affect the acceptability of the piping and its associated support system. The NRC staff considers a one percent screening criterion reasonable to assess the effects of temperature increase in BOP piping systems.

With the exception of heater drain and condensate booster piping systems, all other BOP piping systems passed the 1 percent screening criterion. For the heater drain and condensate booster piping systems, the licensee determined that the proposed licensed

power operating temperature was bounded by the temperature condition used in the design basis AOR. In addition, the licensee stated that no pipe or pipe support modifications are required for the MUR PU.

The NRC staff concludes that the licensee's evaluation of the BOP piping and supports under the proposed licensed power conditions is acceptable. This acceptance is based on the licensee's demonstration that the design basis requirements associated with the BOP piping systems will continue to be satisfied following the implementation of the proposed licensed power. Because compliance with the criteria stipulated in the design codes of record for the piping system is maintained, the NRC staff concludes that there is assurance that the structural integrity of the affected BOP piping and supports will be adequately maintained following the implementation of the proposed PU.

Steam Generators (SGs) Structural Evaluation

The licensee evaluated the effects of the proposed licensed power on the structural integrity of the SGs in Section IV.1.A.vi of Attachment 7 in the submittal. The Unit 1 SGs at Braidwood and Byron are BWI, and the Unit 2 SGs are Westinghouse model D-5.

As stated in Section IV.1.A.vi.1.b of Attachment 7 to the submittal, the licensee performed a structural analysis of Unit 1 SGs to review the impact of the proposed licensed power conditions. In response to the staff's letter dated February 14, 2012, the licensee in the supplements dated February 20, March 30, and May 16, 2012, stated that the primary and secondary side design temperatures and design pressures for the proposed licensed power remain unchanged from the original analysis; however, the proposed licensed power did result in changes to the transient load conditions requiring a reconciliation analysis of Unit 1 SGs. The licensee also provided the maximum stress intensity and the cumulative fatigue usage factors for the critical components of the primary and secondary sides, including nozzles, of the Unit 1 SGs. The licensee verified that these components meet the acceptance criteria of the ASME Code of record for the respective service conditions.

Because the licensee has demonstrated that the design basis acceptance criteria associated with the most limiting Unit 1 SG components will remain satisfied following the implementation of the proposed licensed power, the NRC staff concludes that there is assurance that the structural integrity of the Braidwood and Byron, Unit 1, SGs will be adequately maintained following implementation of the proposed licensed power.

As stated in Section IV.1.A.vi.2.b of Attachment 7 to the submittal, the licensee also evaluated the Unit 2 SGs and concluded that the current design basis analysis remains applicable to the proposed licensed power since the design input parameters used in the AOR are equal to or envelop those parameters associated with the uprate.

Because the licensee has demonstrated that the parameters associated with the uprate are equal to or enveloped by the design input parameters used in the current AOR for the Unit 2 SGs, the NRC staff concludes that there is assurance that the structural integrity of the Braidwood and Byron, Unit 2 SGs will be adequately maintained following implementation of the proposed uprate.

Reactor Coolant Pump (RCP)

The licensee evaluated the effects of the proposed licensed power on the structural integrity of the RCP in Section IV.1.A.vii of Attachment 7 in the submittal.

The licensee evaluated the impact of the proposed licensed power on the structural integrity of the RCPs and concluded that the existing structural analysis of the RCPs remain unaffected because: (1) there were no changes in the RCS design or operating pressure; (2) the MUR proposed licensed power conditions remain bounded by the design parameters used in the original analysis of record; and (3) there are no changes to nozzle or support foot loads for the proposed licensed power.

Because the licensee has demonstrated that the AOR for structural analysis of the RCPs will remain unaffected following the implementation of the proposed licensed power, the NRC staff concludes that there is assurance that the structural integrity of the RCPs will be adequately maintained following the implementation of the proposed licensed power.

Pressurizer

In its structural evaluation of the pressurizer, summarized in Section IV.1.A.viii of its June 23, 2011 submittal, the licensee stated that: (1) the limiting pressurizer conditions occur when the RCS pressure is high and the RCS T_{hot} and T_{cold} are low; and (2) no changes were made in the RCS design or operating pressure.

In the supplement dated February 20, 2012, the licensee stated that there is no impact on the pressurizer AOR as a result of the proposed licensed power transient changes; and provided a comparison of pressurizer design parameters for the current operating conditions, the proposed licensed power operating conditions, and the AOR design conditions and concluded that the temperature differential parameters used in the AOR remain bounding for the proposed licensed power conditions.

The licensee also performed an assessment of the structural weld overlay for the pressurizer surge, spray, and safety and relief nozzles. The licensee concluded that the AOR for these components bounds the proposed licensed power conditions and the design basis acceptance criteria remain satisfied at the proposed licensed power.

Because the licensee's evaluations demonstrated that the design parameters used in the AOR for the pressurizer, including all components and nozzles, envelop the proposed licensed power conditions, and the design basis acceptance criteria remain satisfied at the proposed licensed power conditions, the NRC staff concludes that there is assurance that the structural integrity of the pressurizer will continue to be maintained following implementation of the proposed licensed power.

High-Energy Line Breaks (HELB) and Associated Dynamic Effects

The licensee evaluated the effects of the proposed licensed power on systems classified as high energy to determine whether any changes to the HELB AOR will result from the implementation of the proposed licensed power. This assessment is summarized in Section IV.1.B.vii of Attachment 7 to the June 23, 2011, submittal.

As indicated in the summary of the licensee's assessment, the current AOR for HELB was reviewed to compare the temperatures, pressures and flow rates in high energy piping at the uprated conditions with those in the current AOR. Based on this comparison, the licensee determined that the input parameters used in the current AOR bound those at the uprated conditions. As such, the licensee stated that the proposed licensed power does not result in any new or revised pipe break locations. The licensee also concluded that the dynamic effects evaluations associated with the HELB postulated in the current AOR, including those due to jet impingement and pipe whipping, remain valid at the proposed licensed power conditions.

In the April 27, 2012, supplement, the licensee stated that the uprate evaluations appropriately considered the UFSAR criteria related to high and moderate energy fluid system classification, HELB and moderate energy line crack postulation. The HELB evaluations were performed consistent with the Byron and Braidwood UFSAR by evaluating the high energy systems for potential increases in stress; and no new high or moderate energy systems were added as a result of evaluation at uprated conditions, and no new HELB or moderate energy line crack locations were identified.

During the review, NRC staff became aware of a non-conformance related to the turbine building (TB) HELB analysis. The NRC staff requested the licensee to address the impact of resolution of this nonconformance on the accuracy of the information provided in the submittal. In the August 25, 2011 supplement, the licensee confirmed that: (1) the TB HELB analyses, that supported the proposed licensed power, used thermodynamic assumptions that enveloped both current licensed thermal power and proposed licensed power conditions; (2) no new HELB locations were identified as a result of proposed licensed power in the piping portions in the AB including the steam tunnel; (3) the design basis for the turbine building HELB analysis will be maintained; (4) the restoration activities to resolve the nonconformance are being tracked in the Byron and Braidwood corrective action program; and (5) the conclusions stated in the submittal, relative to the HELB analyses remain valid.

The NRC staff concludes that there is assurance that the proposed licensed power does not result in any new or revised pipe break locations and that the dynamic effects associated with the postulated rupture of piping in the current AOR remain valid. This conclusion is based on the licensee's (1) demonstration that the design input for HELB AOR relative to temperatures, pressures and flow rates will remain bounding under the proposed licensed power; (2) demonstration that the piping configuration and seismic stresses are unaffected by the proposed licensed power; and (3) evaluations of the proposed licensed power that demonstrated that piping stresses were not affected and no new or revised break locations were identified.

<u>High-Energy Line Break (HELB) Non-conformance</u>

The licensee evaluated the consequences of HELBs inside containment, AB, and TB with respect to impact on safety-related equipment. Inside the containment, the licensee identified one instance where the qualified lifetime of a specific level transmitter was reduced from 36.2 years to 35.64 years. The licensee's evaluation of high-energy piping in the AB showed either: (1) no change in the safe SD capability, based upon the existing evaluation using compartmentalization, which limits the effects of a HELB to only one train of safety-related equipment, or (2) in those circumstances where a high-energy line may affect more than one train, the license stated that the operating parameters of high-energy

lines in the auxiliary building did not adversely affect the maximum temperature, pressure, or relative humidity.

In the submittal, the licensee stated that it analyzed high-energy pipe breaks for piping with a maximum operating pressure that exceeds 275 psig and the maximum operating temperature that equals or exceeds 200 °F. Additionally, the licensee evaluated for cracks in high-energy piping in which either the operating pressure exceeds 275 psig or the operating temperature equals or exceeds 200 °F. However, this methodology does not agree with the licensing basis stated in the Byron and Braidwood UFSAR. In the Byron and Braidwood UFSAR, Section 3.6.1.1.1, "Definitions," the licensee defines a high-energy fluid system at these facilities as one where either or both of the following requirements are met:

1. maximum operating temperature exceeds 200 °F
2. maximum operating pressure exceeds 275 psig.

The NRC staff requested that the licensee re-evaluate the effects on plant systems at the proposed power using the current licensing basis definition for HELBs. In a letter dated April 27, 2012, the licensee corrected its definition for high-energy lines used in the MUR PU June 23, 2011, submittal to agree with UFSAR, Section 3.6.1.1.1, and confirmed that evaluations for high and moderate energy lines were performed using the classification as stated in the UFSAR. The licensee did not identify any additional high energy break or moderate energy line crack locations at the proposed power condition. The licensee's response resolves the staff's concern.

By letter dated August 22, 2011 (ADAMS Accession No. ML112150563), NRC staff stated, in part, that:

> The NRC staff has become aware through the inspection program of a current nonconformance from the current licensing and design basis for the high-energy line break analysis provided in part for review of the MUR power uprate license amendment request. In general, a licensee's corrective action program addresses deviations and nonconformances with most elements of the licensing bases. NRC staff involvement in most of these situations is through the inspection, assessment, and enforcement programs. Provided the licensee is able to correct the problem and restore compliance, nonconformance from the licensing bases is not addressed by a licensing-related process. However, in order to have confidence that the related licensing and design basis information provided in your amendment request will not change and lengthen the review process, the NRC staff requires additional information.

The additional information requested was to discuss the licensee plans for resolving the non-conformance. In particular, the licensee was requested to address the impact of resolution on the accuracy of the information provided to the NRC staff in its June 23, 2011, submittal.

By late 2012, the NRC staff became concerned with the progress the licensee was making in resolving the non-conformance. In addition, it was not clear to the NRC staff that the licensee would be able to restore conformance to the licensing and design basis. In a letter dated December 6, 2012 (ADAMS Accession No. ML12271A308), the NRC staff stated, in part,

> The NRC staff has determined that the current analyses of record for the HELB does not bound the requested uprated power level. As a result of this determination, the NRC staff needs additional information to support resolution of the HELB nonconformance and complete a detailed review of the power uprate application. The specific information needed is requested in the enclosure to this letter. However, based on discussions with your staff, it is NRC staff's understanding that the modifications and analysis needed to support the NRC's review is not yet available.
>
> As such, because the needed information is not available to proceed, the NRC staff has suspended the review of the MUR pending the completion of the required modifications and analyses associated with the HELB nonconformance. The NRC staff has also determined that a confirmatory audit may be needed to validate that the resolution scope, including extent of condition, modifications, and analyses bound plant operations at the uprated power level.

By letter dated July 5, 2013 (ADAMS Accession No. ML13186A178), the licensee responded to the requested information and stated that they were ready to support a confirmatory audit on or after July 15, 2013. The NRC conducted the audit July 17 and 18, 2013, and determined, in part, that the resolution of the non-conformance was sufficiently complete to restart the review of the MUR application. The licensee's July 5, 2013, letter, and the audit confirmed that the licensee was using the GOTHIC Code instead of the KITTY6 code originally used to analyze the temperature and pressure effects of the TB HELB. By e-mail dated August 28, 2013, the NRC staff requested additional information regarding the TB HELBs and how this was used to develop the input to the GOTHIC Code. The licensee responded with the additional information on September 5, 2013. The information and the NRC staff's evaluation is discussed below.

Plant Configuration

In the TB piping layout, the main steam (MS), FW and heater drain (HD) systems high energy lines are routed in proximity to the ventilation connections between the turbine and AB. Therefore a HELB in the MS, FW, or HD systems can affect the AB safety-related equipment in the Miscellaneous Electrical Equipment Rooms (MEERs), engineered safety feature (ESF) switchgear rooms, cable spreading (CS) rooms, and emergency diesel generator (EDG) rooms that have ventilation connections to the TB. The ventilation connections would allow the HELB steam to enter the safety-related equipment rooms exposing the equipment to high temperature and humidity as well as pressurize the rooms thus creating a differential pressure loading on the walls separating the AB rooms. The ventilation connections are provided with fire dampers, the closing of which is important as it stops the flow of steam into the safety-related equipment rooms. The closure of the dampers also results in a loss of ventilation which causes further room heat-up due to equipment internal heat loads. Some of the non-conformances identified in the previous analysis are as follows:

a) The analysis took credit for the fire dampers to close on high temperature and isolate the AB from the HELB. It erroneously assumed the fusible links melted, closing the damper at the time the local environment reached 165 °F. The Underwriters Laboratories standard for the fusible links identifies a range of allowable times for the damper actuation depending on its surrounding temperature.

b) The analysis did not account for the ventilation airflow paths from the AB rooms of interest. It assumed the rooms were dead-ended with no outflow and therefore limited the amount of HELB M&E released into the room. In reality, there are ducted vent paths exiting the room resulting in greater HELB M&E release into the room.

c) The analysis did not comply with the requirements of single-failure criterion.

The UFSAR, Section 3.6, states:

> "The effects of HELBs in the TB have been evaluated with respect to potential impact on safety-related equipment located in adjoining auxiliary building rooms."

and that:

> "The possible effects associated with the postulated break of piping considered are structural loads due to pressurization, increases in pressure and temperature which could affect environmental qualification of equipment, and damage due to pipe whip and jet impingement."

Modifications

The licensee presented the following plant modifications based on which the revised HELB mitigation strategy is developed:

a) Replaced normally open fire dampers with normally open reverse-flow-style HELB dampers which are single failure proof (dual sets of blades) in the ventilation connections to protect the MEERs, ESF switchgear rooms, cable tunnel, DG rooms, CS rooms, and non-ESF switchgear rooms. The new dampers close on high differential pressure in the reverse flow direction, i.e., high differential pressure in the direction of flow of the HELB steam. The dampers are designed to close within 0.5 sec of damper-specific actuation pressure differences in the reverse direction from normal flow. The new HELB dampers have an integral fire damper. The modifications also included addition of deflectors for protection of the dampers from missiles and jet impingement where needed.

b) Installed new HELB barrier doors at elevation 451-ft, modified existing doors at elevation 401-ft and 426-ft, and reinforced roll-up doors at 401-ft and (426-ft for Braidwood only) to isolate the safety related equipment rooms from HELB effects.

c) Modified logic by providing auto-transfer of TB control room make-up intake to outside air on detecting a TB high pressure

d) Increased temperature set-point of the fire damper fusible link to allow auto-restoration of ventilation flow and close on fire.

e) Modified ventilation fans operational logic by providing an auto-trip on high differential pressure and auto-restart after a time delay.

f) Modified logic by providing an auto-start of EDG supply fans (on outside air) on EDG start. Modified logic by providing an auto-start of EDG supply fans on high room

temperature to ensure EDG availability following a TB HELB even when EDG do not auto-start by a Loss-Of-Offsite Power (LOOP) or Safety Injection (SI) signal.

g) Modified logic by providing a high temperature auto-trip of diesel oil storage tank (DOST) rooms exhaust fans.

h) Reinforced divisional block walls separating safety related equipment rooms for applicable load combinations, i.e., HELB pressure load and seismic.

The scope of audit included a review of the revised licensing basis analysis that addresses: (1) the increase in pressure, temperature and humidity due to TB HELB that would affect the environmental qualification of the safety related equipment in the AB rooms, and (2) differential pressure loads applied on the AB walls due to TB HELB. Specifically, the audit included a review of the following: (a) the licensee's methodology for the analysis, (b) the licensee's inputs and assumptions for the analysis, (c) the licensee's analyses based on the most limiting postulated break considering maximum mass and energy release (M&E) releases in combination with the most limiting break locations, (d) the results for the pressure, temperature, and humidity in the rooms of the AB their use for the evaluation of environmental qualification of the safety related equipment installed in the AB rooms, and (e) the results for the differential pressures across the separating walls of the AB rooms and their use in the load combinations for stress analysis of the walls.

The review of postulating break locations and the methodology used for it, and pipe whip and jet impingement analysis due to HELB mentioned in the UFSAR, Section 3.6, were not in scope of this audit.

During the July 17, 2013, audit, the licensee provided a slide presentation of the HELB non-conformance resolution. The licensee subsequently presented the GOTHIC HELB model input data tables for boundary conditions, flow paths, initial conditions, components, forcing functions, control variables, heat sinks, and the output graphs. During the presentation, the licensee verbally provided satisfactory responses to the NRC staff questions with the exception of a global question on reasons for using lumped-parameter GOTHIC models instead of subdivided models and a question on not postulating certain other break locations and considering the M&E releases from these locations. This issue is discussed below in the section identified as "Mass and Energy Release."

Methodology Review

The licensee used the GOTHIC, Version 7.2a, computer code for the TB HELB analysis. GOTHIC is a state-of-the-art general purpose thermal-hydraulics computer code maintained by Numerical Applications, Inc. (NAI), for the Electric Power Research Institute (EPRI) for performing containment analyses. GOTHIC is qualified under the NAI Quality Assurance (QA) program which conforms to the requirements of 10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," with error reporting in accordance with 10 CFR Part 21, "Reporting of Defects and Noncompliance."

GOTHIC is widely used by the nuclear industry and applications of this code have been previously approved by the NRC staff on a case-by-case basis. The NRC has accepted containment analysis using GOTHIC methodology replacing the previously existing analysis for North Anna 1 and 2, Surry 1 and 2, Kewaunee, and Millstone 2 and 3. The NRC has also accepted containment sub-compartment HELB analysis using GOTHIC methodology

for Riverbend Station Unit 1. The NRC has accepted outside containment sub-compartment HELB analysis using GOTHIC methodology for the Advanced Boiling Water Reactor, Units 3 and 4, newly planned reactors by the South Texas Project utility.

GOTHIC HELB Model Review

The licensee developed a lumped-parameter GOTHIC model of the TB and AB together with the ventilation air flow paths connections. The model included the modifications described above at the MUR PU level. The lumped-parameter GOTHIC modeling approach assumes each walled room in the TB and AB as a separate volume within which the transient values of the thermal-hydraulic parameters do not vary spatially. The licensee analyzed MS line breaks of 0.3 ft^2, 0.5 ft^2 , and 1.4 ft^2 areas, 20-inch and 26-inch heater drain line breaks, and 30-inch FW line breaks. The key assumptions used in the analysis are: (a) M&E release considered maximized transient enthalpies of superheated steam for the MSLBs and constant high enthalpy M&E release from liquid line breaks, (b) maximum differential pressure to close and re-open the new dampers, (c) minimum and maximum closure time considered for the new dampers, (d) high differential pressure trips and time-delay auto-restart modeled for AB fans, (e) high room temperature trips modeled for DOST room fans, and (f) modeled AB room concrete walls, floors and ceilings as heat sinks. The NRC staff finds the licensee's assumptions to be reasonable and acceptable.

Mass and Energy (M&E) Release

For MSLBs, the licensee used the M&E release data given in Westinghouse report WCAP-10961, "Steamline Break Mass/Energy Releases for Equipment Environment Qualification Outside Containment," Revision 1, October 1985. The transient M&E release data provides progressively increasing enthalpies with decreasing mass flow rates with respect to time, conservatively maximizing superheat to maximize the effect of M&E releases on environmental qualification of equipment. Additional conservatism is present in the M&E release data because the actual M&E release will be less than the assumed due to piping losses up to the TB. The Westinghouse transient M&E release is based on: (a) maximizing superheat, (b) full-power plus measurement uncertainty, (c) offsite power available, (d) failure of a steam line isolation valve to close, and (e) split breaks. For Byron and Braidwood, the Westinghouse approach has been accepted by the NRC for maximizing the effect of M&E releases on environmental qualification of equipment located outside containment (see NUREG-0876, Supplement No. 7, "Safety Evaluation Report related to the operation of Byron, Units 1 and 2, Docket Nos. STN 50-454 and STN 50-455," November 1986, page 3-4, and NUREG- 1002, Supplement No. 2, "Safety Evaluation Report related to the operation of Braidwood, Units 1 and 2, Docket Nos. 50-456 and 50-457," October 1986, page 3-18). The licensee analyzed three high pressure MS line break (MSLB) sizes, 1.4 ft^2, 0.5 ft^2, and 0.3 ft^2 areas. The maximum effective MS break flow area considered is 1.4 ft^2 because of the integral flow restrictors in the SGs. The licensee justified the M&E release from a 1.4 ft^2 area MS line break can conservatively be used for the M&E releases for the 36-inch MSLB. In addition the licensee considered low pressure MS breaks of 42-inch at TB EL. 451-ft (9.1684 ft^2 area), 44-inch at TB EL. 451-ft (10.0847 ft^2 area), and 24-inch at TB EL. 426 ft (2.7922 ft^2 area). The licensee justified that the M&E releases for the liquid line breaks which has more mass flow and no superheat bounds the M&E releases from the low pressure MS breaks.

For HD line (liquid) breaks, the licensee calculated the choked mass release using the equations for the Henry-Fauske critical flow model.

For FW line (liquid) breaks the licensee used the pump runout mass flow that flashes steam to atmospheric pressure and credits break isolation times to limit water volumes discharged.

NRC Staff Review and Execution of Selected GOTHIC Models

The NRC staff reviewed the input data in selected electronic GOTHIC files provided by the licensee during the audit. Three MSLB model files, one for each TB elevation, and one FW line break model file were selected for review and execution on the NRC computer using the GOTHIC, Version 7.2a, same as used by the licensee.

On executing these models, the staff obtained the same results for the TB pressures, temperatures, relative humidity, switchgear room temperatures, and relative humidity as shown in licensee documents reviewed during the audit. The maximum differential pressures between the switchgear division 1 and 2 rooms were also consistent with licensee results.

As stated in the UFSAR, the HELB analysis should determine the effects of the M&E release from the postulated break on the structural loads due to pressurization in the AB rooms, and effects of increases in pressure and temperature on the environmental qualification of equipment in the AB. In a request for additional information (RAI) dated August 29, 2013, the licensee was requested to provide the following:

> "Describe in detail the postulated piping failures and their locations utilized for the analyses of M&E release from piping located in the TB that could affect safety related equipment located in adjoining auxiliary building rooms and how this information was used to provide input to the GOTHIC analysis. If bounding conditions have been utilized for these analyses identify the piping failures utilized, their bounding M&E and the bounding locations that would envelop the resulting effects on the safety-related equipment located in adjoining auxiliary building rooms. In addition, justify how this/these M&Es and location(s) bound others.
>
> This justification should include, but is not limited to, consideration of a HE [high energy] release near a HELB damper that would allow pressurization of room while the damper is closing while another room is not yet pressurizing because its damper is farther away from the HE release, thereby creating differential pressure across the wall that separates the two rooms."

In its response dated September 5, 2013, (ADAMS Accession No. ML13248A519), the licensee stated that the analysis used closure characteristics of newly installed HELB dampers based on the maximum and the minimum time to close obtained from the test data. The licensee further stated that it used engineering judgment to justify that the differential pressure across the walls in the AB would not exceed the calculated values. The NRC staff concludes that the licensee's reliance on engineering judgment was not sufficient to demonstrate that the pressure wave from the postulated break would not enter one room through its damper and then enter another adjacent room as it traveled to the next damper thereby creating a differential pressure across the rooms' common wall.

During a September 25, 2013, telephone discussion with the licensee to clarify its response, the licensee agreed to supplement its response. In its supplemental response dated

October 8, 2013, the licensee referred to the TB HELB jet impingement on AB openings analysis results and has drawn the following conclusion:

> ...none of the DG Room, ESF Switchgear Room, or MEER HELB dampers are impacted by, or are within the zone of influence of, a line break jet. Any jet created by a HELB would dissipate prior to reaching a HELB damper. Once the jet dissipates (zone of influence) the high energy fluid in the jet would immediately separate into flashed steam and liquid. The flashed steam would immediately mix with air in the TB area, causing relative humidity and pressure in the TB area to rise. Since air with a relative humidity of less than 100% behaves as an ideal gas, the TB area in front of the separate division dampers would pressurize uniformly. Therefore, the separate divisions' HELB dampers in the TB area would be subjected to the same pressure simultaneously. Additionally, the TB HELB dampers will close before the TB area reaches 100% relative humidity, therefore assuming uniform pressurization is valid for the timeframe being discussed. Due to the uniform pressurization of the TB area in front of the separate division dampers, and that there are no DG Room, ESF Switchgear Room, or MEER HELB dampers affected by a HELB jet, the lumped volume approach used in the GOTHIC analysis is justified.
>
> Since the uniform pressurization of the TB area results in both rooms beginning to pressurize at the same time there is no differential pressure created across the walls separating the rooms due to one room beginning to pressurize before the other.

The licensee's qualitative explanation regarding uniform pressurization of division 1 and 2 switchgear rooms is not quantitatively validated. Based on the licensee's explanation, the NRC determined it could not conclude that high pressure heated steam would simultaneously pressurize both switchgear rooms equally and not produce a differential pressure effect. In addition the NRC determined that, not considering blockages such as presence of large equipment; condenser, turbine, reheater's, etc., introduce further uncertainty in the analysis.

Subsequently, in response to the NRC staff's determination, the licensee in its November 18, 2013, supplement provided quantitative evaluation showing that the newly installed HELB dampers are not directly impinged by the TB HELBs. In addition, the licensee quantitatively justified that maximum wall differential pressures, used for the structural qualification of the AB divisional walls, derived from the closure characteristics of the newly installed HELB dampers, based on the maximum and the minimum time to close obtained from test data, envelope the differential pressures created due to break locations in the TB with regard to damper location. Regarding the consideration of equipment blockages, the licensee stated there is no large equipment or walls located between adjacent HELB dampers. The licensee therefore determined no impact on the HELB initiated sonic pressure wave propagation through the TB environment due to blockages or obstructions. Based on the licensee's evaluation, the NRC staff concludes that the differential pressure on the AB divisional walls would not exceed the design capability of the walls.

The NRC staff also determined that the licensee demonstrated significant margins and conservatisms included in the GOTHIC analysis differential pressure calculations due to damper performance and ventilation system operation.

In the December 6, 2012, letter, the NRC staff requested the licensee to summarize the extent of condition review related to the HELB non-conformance. In its July 5, 2013, response, the licensee stated it performed a detailed review of the HELB analyses of other plant structures containing high-energy lines that could impact safety-related equipment. The structures reviewed were:

- AB (other than those areas impacted by the TB HELBs),
- MSIV Room/main steam tunnel, and
- Containment building

The extent-of-condition review determined that the HELB analyses supporting these structures have been performed consistent with the current Braidwood and Byron licensing basis. Based on this extent-of-condition review, the licensee concluded that the supporting HELB analyses for the above identified structures were not impacted by the non-conformances identified in the TB HELB analyses.

As stated in previous supplemental letters to NRC staff, dated August 25, 2011 (ADAMS Accession No. ML11255A332) and April 27, 2012 (ADAMS Accession No. ML12121A496), the licensee has indicated that the design basis for the TB HELB (i.e., the qualification of Class 1 E electrical equipment in the identified AB rooms) are not adversely impacted by a TB HELB and confirmed that the conclusions stated in the original LAR for the MUR LAR as related to the HELB analyses remain valid. The licensee also stated that no new high or moderate energy systems were added as a result of evaluation at MUR PU conditions, and no new HELB or moderate energy line crack locations were identified.

The licensee's evaluation concluded that operation at the proposed power level does not result in any new or revised high or moderate energy-line break locations. As a result, the current high and moderate energy line break analyses bound operation at the higher power level. The licensee concludes that the postulated area high temperatures and pressures resulting from HELBs remain valid at the increased power conditions. Based upon the information and evaluations performed by the licensee to show the effects from a HELB at the increased power level are bounded by existing plant analyses, the NRC staff finds the HELB analysis acceptable at the proposed power.

Conclusion

Based on the above review, the NRC staff concludes that: (a) the licensee used an approved methodology for the TB HELB analysis, (b) the GOTHIC inputs and assumptions are conservative, (c) the output results for the pressure, temperature, and humidity in the AB rooms to be used for environmental qualification (EQ) are limiting, and (d) the results of differential pressure analysis across the AB walls are limiting.

Based on the licensee's response in the November 18, 2013, supplement, the NRC staff concludes that the licensee satisfactorily justified that the TB HELB analysis meets the current licensing basis requirements.

Spent Fuel Pool (SFP) Structure (RIS 2002-03, Attachment 1, Section VI.1.D)

The NRC staff requested the licensee to provide information and confirm that, for the expected proposed licensed power conditions, the SFP structure including the SFP liner and the spent fuel racks remain capable of performing their intended design functions and continue to be in compliance with the design basis acceptance criteria. The licensee in its letters dated March 30, May 16, June 26, and September 13, 2012, provided the following information:

1. For the case of a full core offload with loss of one heat exchanger train, the peak SFP bulk water temperature will increase to 166.6°F from the current peak SFP temperature of 162.7°F. The licensee also stated that for the scenario of a full core offload with loss of one heat exchanger train the:

    - Peak temperature was calculated using conservative assumptions (e.g., no evaporation heat loss);
    - Calculated temperature of 166.6 °F is a short term condition;
    - Temperature during a normal refueling with two heat exchangers operable will not peak above 140 °F;
    - SFP temperature alarm is set at 149 °F to alert the operators for an abnormal condition, such as loss of SFP cooling; and
    - Average temperature of the SFP walls and the bottom slab, assuming a 70 °F on the exterior face of the SFP structure, will approximately be 118 °F.

2. A detailed structural evaluation of the SFP structure has been performed, using a bounding temperature of 167 °F, to investigate the MUR power uprate condition. The results of this structural evaluation confirm that the SFP structure is in compliance with the design basis acceptance criteria. Specifically, this evaluation resulted in a maximum rebar stress of 30.3 ksi to be within the allowable limit of 54 ksi and concrete shear stress nearly equal to the ACI [American Cement Institute] code allowable limit (i.e., safety factor of 1.01).

    In its June 26, 2012, letter, the licensee stated that: (1) at the proposed licensed power, evaluation of the effects of the SFP peak temperature on the SFP rebar stresses used the design methodology and load combinations, consistent with the plant licensing basis requirements, described in the UFSAR, Section 3.8.4, but eliminated conservative evaluation of the thermal moment due to the axial temperature increase; (2) in previous design calculations, including the SFP structural evaluation for the stretch power uprate, the thermal moment induced by the axial temperature increase was conservatively treated as a mechanical moment; and (3) removing this conservatism resulted in the reduction in the rebar stress from 53.7 ksi, as indicated in the NRC SE for the stretch power uprate, dated May 4, 2001, to 30.3 ksi.

3. The SFP spent fuel racks were evaluated in the existing analyses of record for a design temperature of 200 °F, which bounds the peak MUR SFP temperature of 166.6 °F.

4. The SFP liner and anchorage system were re-evaluated for a temperature of 167 °F which bounds the proposed licensed power peak SFP temperature of 166.6 °F and the analysis results demonstrated that the stresses were within design basis

acceptance criteria. The UFSAR will be updated to reflect the results of the SFP liner re-evaluation for the proposed licensed power condition.

The NRC staff concludes that there is assurance that the structural integrity of the SFP structure, the SFP liner and racks will be adequately maintained following the implementation of the proposed licensed power. This conclusion is based on the following:

1. The AOR for the SFP racks will remain unaffected following the implementation of the MUR PU as the design of these components were based on a temperature of 200 °F which bounds the peak MUR SFP temperature of 166.6 °F.

2. Section 9.1.2.3.10 of the Braidwood and Byron UFSAR states the following:

   > The liner plate and anchorage system have been designed for the forces resulting from long-term shrinkage of concrete, and a temperature rise to 158°F from the 70°F ambient temperature with nominal cooling. The maximum compression force in the liner is calculated using the total strain of the long-term shrinkage of the concrete and the temperature rise. This compressive stress in the liner is limited to 0.90 Fy.

   The licensee in its letter dated September 13, 2012, stated that the AOR for the SFP liner and its anchorage system has been revised to assess the effects of the proposed licensed power temperature condition. The results of this evaluation, which considered a temperature of 167 °F bounding the peak MUR SFP temperature of 166.6 °F, demonstrated that the liner and its anchorage system are in compliance with the design basis acceptance criteria stated in the Braidwood and Byron Braidwood UFSAR. In addition, the licensee stated that the UFSAR will be updated to reflect the results of this analysis.

3. The licensee performed a structural evaluation of the SFP structure, using a bounding temperature of 167 °F, consistent with the plant licensing basis requirements and demonstrated that the SFP structure will remain in compliance with the design basis acceptance criteria.

4. The ACI 349 limits concrete surface temperature to 150 °F for normal operation or any other long-term periods. For the case of a full-core offload with loss of one heat exchanger train, the peak SFP bulk water temperature will increase to 166.6 °F from the current peak SFP temperature of 162.7 °F. This minimal temperature increase of approximately 4 °F is a short-term condition. The acceptance of the current SFP bulk temperature of 162.7 °F has been documented in the NRC SE for stretch power uprate. The temperature of 166.6 °F, as a short-term temperature condition, will have negligible effects on the SFP concrete properties considering that the SFP temperature alarm is set to 149 °F which provides an additional measure to alert the operators for an abnormal condition.

<u>Containment Structure Design Basis Pressure and Temperature</u>

The NRC staff requested the licensee to confirm that the design basis pressure and temperatures (normal operating and accident temperature) used in the design of the containment structure and its internal structures remain bounding following implementation

of the proposed licensed power. In response to the staff's letter dated February 14, 2012, the licensee confirmed, in its letter dated February 20, 2012, that: (1) the design basis containment pressure and temperature for normal operation are not affected by the proposed licensed power; (2) for primary system pipe breaks (i.e., LOCAs), the containment peak pressure and temperature for the proposed licensed power remain bounded by the containment structure design pressure and temperature; and (3) for secondary MSLB, the peak pressure remains bounded by the containment design pressure and there is a very small calculated increase (0.6 °F) in the peak containment air temperature for Unit 1 while Unit 2 remains bounded by the AOR. Furthermore, the licensee stated that the design inputs used in the AOR of the containment internal structures remain bounding following implementation of the proposed licensed power.

The Section 3.1.2 of this SE concludes that a small increase of 0.6 °F in the Unit 1 containment vapor temperature for an MSLB does not affect the current containment structure peak temperature determined by the LOCA condition.

Based on the licensee's response to the staff's February 14, 2012, letter, as outlined above, and the staff's evaluation of a small increase of 0.6 °F in the Unit 1 containment vapor temperature for an MSLB, the NRC staff concludes that there is assurance that the structural integrity of the containment and its internal structures will continue to be maintained following implementation of the proposed licensed power because the proposed licensed power containment pressure and temperature conditions are enveloped by the design basis pressure and temperature used in the design of the containment and its internal structures.

3.4.3.3 Conclusion

The NRC staff has reviewed the licensee's assessment of the impact of the proposed licensed power on the structural and pressure boundary integrity of pressure-retaining components and supports and RVIs. Based on its review delineated above, the NRC staff finds the proposed licensed power acceptable with respect to the structural integrity of the SSCs affected by the PU. This acceptance is based on the licensee's demonstration that the regulatory requirements will continue to be satisfied following implementation of the proposed licensed power.

Specifically, the licensee demonstrated that: (1) the structural integrity of most SSCs at Byron and Braidwood stations are not affected by the proposed licensed power, as evidenced by the fact that their AOR are unaffected; (2) those SSCs for which the AOR is affected by the proposed power uprate will continue to satisfy the applicable structural design basis acceptance criteria at the proposed licensed power conditions; and (3) the HELB AOR, including postulated break locations and associated dynamic effects, is unaffected by the proposed licensed power.

Based on these considerations, the NRC staff concludes that there is assurance that the structural integrity of these SSCs at Braidwood and Byron will be adequately maintained and the implementation of the proposed licensed power will not preclude the ability of these SSC to perform their intended functions.

3.4.4 Electrical Engineering (RIS 2002-03, Attachment 1, Section V.1)

3.4.4.1 Regulatory Evaluation

The regulatory requirements which the staff applied in its review of the application include GDC 17, "Electric power systems." 10 CFR Part 50, Appendix A, requires, in part, that an onsite power system and an offsite electrical power system be provided with sufficient capacity and capability to permit functioning of structures, systems, and components important to safety. Conformance to GDC 17 is discussed in the Braidwood and Byron UFSAR, Section 3.1.

Section 50.63 of 10 CFR, "Loss of all alternating current [AC] power," requires, in part, that all nuclear plants have the capability to withstand a loss of all ac power (station blackout (SBO)) for an established period of time, and to recover there from.

Section 50.49 of 10 CFR, "Environmental Qualification (EQ) of Electric Equipment Important to Safety for Nuclear Power Plants," requires, in part, the licensees to establish programs to qualify electric equipment important to safety, located in harsh environment.

3.4.4.2 Technical Evaluation

The licensee indicated that it developed the request consistent with the guidelines in NRC RIS 2002-03, "Guidance on the Content of Measurement Uncertainty Recapture Uprate Applications." The electrical equipment design information is provided in Attachment 7, Section V, of the licensee's submittal.

The NRC staff reviewed the licensee's evaluation of the impact of the proposed licensed power on the following electrical systems/components:

- Grid Stability
- Power Block Equipment (Main Generator, Transformers, Isolated-phase Bus Duct)
- Switchyard
- Alternating Current (ac) Distribution System
- Emergency Diesel Generators (EDGs)
- Direct Current (DC) system
- Station Blackout (SBO)
- Environmental Qualification (EQ) Program

Grid Stability

In Section 3.4.7, Attachment 1, of the June 23, 2011, submittal and as supplemented by letter dated March 30, 2012, the licensee provided a summary of the grid stability study to support the proposed licensed power for both Braidwood and Byron.

The grid operator, Pennsylvania, New Jersey and Maryland (PJM) Interconnection, completed a system stability analysis to assess the impact of the proposed licensed power for both Braidwood and Byron on the stability of generating plants in the Commonwealth Edison (ComEd) control area. This study considered a single-unit trip, loss of the largest unit on the grid, loss of the most critical transmission circuit, and the loss of load. All of the scenarios considered in this study were found to be stable with respect to primary-clearing of the fault and maintenance (prior outage) outage. The breaker failure scenarios were also

found stable for Braidwood and Byron, except for three breaker failure scenarios for Braidwood. The revised Generator Transient Stability Study and Interim Generator Deliverability Study report for the Braidwood Station Units 1 and 2 is provided in the March 30, 2012, letter indicated that following the implementation of new ComEd criteria, all of the breaker failure scenarios, considered in this study, were found to be stable.

ComEd Transmission Planning also completed an assessment of the capability of the grid to ensure adequate post-trip and LOCA voltage levels for both Braidwood and Byron. Power flow simulations were performed using 2012 transmission grid models for a total of four system load conditions.

For Braidwood, the study concluded that the lowest post-contingency switchyard voltage is 349.5 kilovolt (kV) which remains above the minimum required switchyard voltage of 349.2 kV. However, for Byron, in one of the load conditions (a postulated scenario that analyzes a unit trip with the other unit in shutdown condition and with a system load level equal to 75 percent of the 50/50 load forecast), the post-contingency switchyard voltage is lower than the minimum required voltage of 339.8 kV.

The NRC staff questioned the measures the licensee used to resolve the above deficiency regarding Byron's offsite power source voltage requirement assuming a single contingency (N-1 condition), to meet the intent of GDC 17. The licensee, in its letter dated August 25, 2011, stated that this potential low voltage condition is an existing condition and is not related to the MUR PU. The licensee further stated that the contingency scenario is considered acceptable because sufficient transmission system assets such as capacitor banks and other generating assets in the area remain available, which can be used to improve contingency voltage above the minimum required for Byron, when necessary. The staff requested the licensee to explain the actions that are required to be taken to address the single contingency voltage requirement to ensure Byron station has the minimum required post-trip voltage for meeting the design basis requirements. In its response, letter dated April 27, 2012, the licensee stated:

> The Byron Grid voltage analysis (documented in Attachment 10b, "ComEd: 2012 Power Grid Voltage Analysis for Byron Generating Station with MUR Power Uprate," of the LAR) postulated [multiple] scenarios including a conservative scenario that identified a potential issue with low voltage in the Byron switchyard for the 75% of the 50/50 load case (i.e., one Byron unit offline and the trip of the operating unit). This postulated scenario is considered conservative because it does not take credit for other readily available transmission or generating assets.
>
> Subsequent to the completion of the grid voltage analysis discussed above, ComEd performed an additional analysis, "Follow-up Analysis for Byron 2012 Grid Adequacy Study." This action confirmed that there are sufficient transmission assets (i.e., existing capacitors that can be switched on remotely) that will maintain the lowest post contingency voltage above the Byron limit. The Transmission Operator (i.e., PJM) is responsible for implementing non-cost actions (i.e., switching on the existing capacitors or taking other actions) as needed to resolve the voltage concern. In addition, there are other generating assets available in the area and the Byron Sensitivity Study Summary shows that post contingency voltage in the Byron switchyard will remain above the Byron limit if some of these generating assets are placed in service.

PJM and ComEd continuously monitor post-contingency voltages regarding Byron Station. The normal PJM operating protocol is for the Transmission Operator (i.e., PJM) to notify the nuclear power plant operator (i.e., Exelon), through the Transmission Owner (i.e., ComEd), when the post contingency switchyard voltage is predicted to fall below the Byron Station minimum required voltage. PJM Operating Manuals and Byron Station procedures have been developed to control this operating protocol as follows:

- PJM Manual 39, "Nuclear Plant Interface Coordination," Revision 3, Section 2.4, "Notification and Mitigation Protocols for NPIR [Nuclear Plant Interface Requirements] Voltage Limits," controls the notification and mitigation protocols for nuclear plant voltage limits.

- PJM Manual 3, Transmission Operations," Revision 38, Section 5, "Index and Operating Procedures for PJM RTO [Regional Transmission Operator] Operation," controls the Day-Ahead actions and Real-Time Operator actions for nuclear facilities.

    - If the Day-Ahead studies predict potential low voltage conditions at Byron Station, ComEd would add capacitors as needed to maintain the lowest post contingency voltage above the Byron Station limit and, if necessary, Exelon Generation Company, LLC (EGC) would be informed.

    - If necessary, EGC would authorize PJM to place other generating assets in the area online (i.e., redispatch/off-cost generation) to resolve the potential low voltage conditions.

- Byron Station Abnormal Operating Procedure 0BOA ELEC-1, "Degraded Switchyard Voltage," would be entered if predicted or actual degraded grid voltage conditions exist.

    - 0BOA ELEC-1 directs the Byron Station Operator to perform evaluations based on actual Non-ESF 4 kV bus loading to determine if the predicted post Byron Station unit trip voltage or actual voltage is adequate.

- TSs 3.8.1, "AC Sources Operating," and 3.8.2, "AC Sources-Shutdown," would be entered and the appropriate limiting condition for operation (LCO) applied if the Byron Station Operator determines that the predicted or actual voltage is less than the procedurally specified limit.

The NRC staff reviewed the above response and determined that the licensee has established adequate measures to address the potential low voltage issue (N-1 case) identified in the ComEd Transmission Planning study.

Based on its review, the staff finds that the proposed licensed power will not adversely impact the grid stability for both Braidwood and Byron, and the licensee will continue to meet the requirements of GDC 17.

Power Block Equipment

As a result of the MUR PU, the rated thermal power will increase to 3645 MWt from the previously analyzed thermal power level of 3586.6 MWt. The staff has reviewed the capability of the main equipment, such as the main generator, isolated phase bus duct, main step-up transformers, and auxiliary transformers under the proposed licensed power conditions, as discussed below.

In its letter dated June 23, 2011, Attachment 7, Section V.1.F, the licensee stated that the main generator has a nameplate rating of 1361 Megavolt-amperes (MVA) (based on 75 psig hydrogen pressure), 0.9 power factor, and 25 kV rated voltage. The licensee provided Generator Capability Curves for both Braidwood and Byron in its letter dated December 9, 2011. In its June 23, 2011, letter the licensee provided calculated Megawatts electric (MWe) for each unit of Braidwood and Byron for the Summer and Winter seasons, with a bounding value of 1294.4 MWe for Byron corresponding to the Winter weather.

The NRC staff reviewed the interim generator deliverability study for Braidwood and Byron Unit 1 and Unit 2 at the proposed licensed power, provided in the licensee's June 23, 2011, letter, Attachment 10a and 10b, respectively. Based on projected maximum real power (MWe) and reactive power (MVARs) dispatch, and review of the generator capability curves, the staff finds that each of the main generator ratings is adequate to support the MUR PU operation.

The licensee stated that each of the Braidwood and Byron Unit 1 and Unit 2 main step-up transformers consist of 2-700 MVA transformers in parallel, totaling 1400 MVA capacity. The 1400 MVA rated capacity is above the main generator 1361 MVA output capability. The NRC staff finds that the main step-up transformers have adequate capacity to carry the main generator full output at the proposed licensed power conditions.

The licensee stated that the isolated phase bus (IPB) duct is rated for 33,000 amperes. The generator rated output at 1361 MVA and nominal voltage of 25 kV is 31,431 amperes. The staff finds that the IPB has adequate rating to operate at the proposed licensed power conditions.

According to the UFSAR, each of the four units has a set of two unit auxiliary transformers (UATs), which supply the unit's normal auxiliary power, are connected to the unit main generator by IPB ducts. The licensee stated that the evaluation of the loading summaries determined that the existing UATs have sufficient capacity with a minimum margin of approximately 32 percent at Braidwood and 25 percent at Byron to support the proposed licensed power without modification. The BOP load increase results in a small increase (<0.5 percent) in the loading of UATs. The staff finds that UATs have adequate capacity for the proposed licensed power conditions.

According to the UFSAR, a set of two system auxiliary transformer (SATs), connected to the 345-kV switchyard, supply required auxiliary power under startup, shutdown, and DBA load conditions. The licensee stated that an evaluation of the connected loading determined that the existing SATs have sufficient capacity with a minimum margin of approximately 32 percent at Braidwood and 25 percent at Byron to support operation at the proposed licensed power conditions and no modification is necessary. The staff finds that the SATs have adequate capacity for the proposed licensed power conditions.

Based on the above, the NRC staff finds that power block equipment have adequate capacity for operation at the proposed licensed power conditions without modification.

Switchyard

According to the UFSAR of Braidwood and Byron, the 345-kV switchyard of each station is configured in a double ring bus configuration, with circuit breakers, disconnect switches, buses, and other associated equipment. Overhead 345-kV transmission lines distribute power to the various points of the transmission system.

In Attachment 7, Section V.1.G of the submittal, the licensee stated that the transmission lead from the main power transformers to the 345-kV switchyard is capable of carrying the generator full output of each unit and the current to the switchyard is bounded by the generator capability. The licensee's evaluation of the switchyard system demonstrated that a small increase in power output does not significantly impact the switchyard equipment. Based on the licensee's evaluation the NRC staff concludes that the switchyard system analyses bound the uprated conditions.

The NRC staff finds that since the main generator and the main step-up transformer ratings remain unchanged due to the MUR PU, the switchyard equipment ratings are not impacted.

Alternating Current (ac) Distribution System

The ac distribution system is the source of power for the nonsafety-related buses and for the safety-related emergency buses. The system consists of the 6.9 kV, 4.16 kV, 480 volt (V), and 120 V systems. In its June 23, 2011, submittal, Attachment 7, Section V.1.E, the licensee stated that the electrical load changes resulting from the proposed uprate occur primarily at the 6.9 kV buses while the 4.16 kV, 480 V, and 120 V, systems will not see a load increase. The 6.9 kV loads that will be affected by the MUR PU are the condensate pump/condensate booster pump motor, heater drain pump motor, and RCP.

In response to a staff question regarding the extent of changes at the 6.9 kV bus, the licensee, in its letter dated December 9, 2011, stated that the revised brake horsepower values of above motors at MUR PU conditions do not exceed the motor nameplate rating and the existing motors remain unaltered. The licensee concluded that the loading margin after the MUR PU at the 6.9 kV buses is a minimum of 36 percent, which is adequate. Additionally, since the motors have not changed and the overall load change is <0.5 percent of the individual bus load, the load changes do not change the short-circuit ratings of 6.9 kV switchgear, and the motor protective relay settings. The licensee also concluded that the worst-case bus voltages on the 4.16 kV safety-related buses are also not impacted due to MUR PU conditions.

In response to another staff question regarding the effect of LEFM Check-plus system on loading at the low voltage buses and other impact on the power distribution system, the licensee, in its letter dated December 9, 2011, stated that the LEFM CheckPlus system will use 120 V AC nonsafety power sources. Therefore, the licensee concluded that the safety-related power supplies and EDG loading will remain unaffected due to LEFM CheckPlus LEFM system addition.

Based on the above, the NRC staff finds that the minor load changes at the 6.9 kV system will not adversely impact the safety-related buses which will continue to support the plant safety related loads for the proposed licensed power conditions.

Emergency Diesel Generators (EDGs)

In Attachment 7, Section V.1.A to the submittal, the licensee stated that the onsite ac power system for each unit consists of two diesel generators (DGs), one for each ESF division. The DGs provide an independent emergency source of power in the event of a complete loss of offsite power. The DG supplies all of the electrical loads required for reactor safe shutdown with or without a LOCA. The licensee stated that the station electric loads that change as a result of the uprate are not fed from the EDG system and there are no increases to the emergency bus loads supported by the EDGs.

The NRC staff finds that the EDG system is not impacted by the proposed licensed power, and therefore the existing system remains adequate for operation at the proposed licensed power conditions.

Direct Current (dc) System

The dc power system provides control and motive power for vital equipment during all normal as well as emergency conditions of the plant. In Attachment 7, Section V.1.E, to the submittal, the licensee stated that the 125 V dc system loads are not related to the power generation process and are independent of the uprate.

Since, the proposed licensed power does not impact the loading of the dc power system, the staff finds that the 125 V dc electrical distribution systems remains acceptable for operation at the proposed licensed power conditions.

Station Blackout (SBO)

Section 50.63 of 10 CFR requires, in part, that each light-water cooled nuclear power plant be able to withstand and recover from a loss of all ac power, referred to as an SBO. Braidwood and Byron SBO coping duration is four hours.

In Attachment 7, Section V.1.B, to the submittal, the licensee evaluated the proposed licensed power impact on the alternate ac power source, and the other SBO coping issues: RCS inventory, condensate storage tank inventory, Class 1E battery capacity, ventilation, compressed air, and containment isolation.

Impact on ac Power Source

The ac power source consists of the excess capacity of the running EDG on the non-blacked out unit. The running EDG can be cross-tied to the bus of the same electrical division on the blacked out Unit from the main control room within 10 minutes. The licensee stated that there are no increases to the emergency loads supported by the EDGs as a result of the proposed licensed power. The total loading on the EDG for SBO will remain within the 2000-hour rating of the EDG. Based on the licensee's evaluation the NRC staff concludes that the proposed licensed power will have no adverse impact for coping with a SBO event for the required coping period.

Impact on Reactor Coolant Inventory

The licensee stated that the non-blacked-out unit's available EDG provides power to one charging pump per unit, which will provide the water required for maintaining reactor inventory at an adequate level to ensure the core remains covered and natural circulation is not affected.

Impact on Condensate Storage Tank (CST)

The CST provides adequate inventory for decay heat removal (DHR) following a SBO event at the proposed licensed power conditions. In response to a staff question regarding the inventories during pre- and post- uprate conditions, the licensee in its letter dated December 9, 2011, stated that as per TS Section B 3.7.6, the CST-required capacity is 212,000 gallons for each unit whereas the required condensate inventory per unit for an SBO event is 81,231 gallons under the proposed licensed power conditions. Therefore, the NRC staff finds that the each station's minimum CST inventory is well above the SBO required inventory.

Impact on Class 1E battery capacity

The licensee stated that both Braidwood and Byron, Class 1E, batteries have sufficient capacity to provide adequate power for safe SD loads. The proposed licensed power does not affect any dc powered loads. In response to a staff question, the licensee, in its supplement dated December 9, 2011, confirmed that battery capacity margins remain available, which are in addition to the design factors that are included in the battery sizing calculation (i.e., 1.05 percent for design margin, 1.25 percent for aging, and 1.11 percent for temperature correction). Based on the licensee's evaluation, the NRC staff concludes that there is not a significant impact on the Class 1E battery capacity.

Impact on Ventilation

The licensee performed an evaluation for the heat, ventilation, and air conditioning (HVAC) in the areas containing SBO equipment, such as CR and auxiliary electric equipment rooms, CC water pump and motor-driven AFW pump area, diesel-driven AFW pump area, ESX pump room, RHR pump room and charging pump room, DG rooms, battery rooms, and miscellaneous electric equipment and switchgear rooms. The licensee stated that the temperatures in these areas are unaffected by the uprate, as the heat load in those areas during SBO is not power level dependent. Based on the licensee's evaluation, the NRC staff concludes that there is not a significant impact on ventilation.

Impact on Compressed Air

The licensee stated that no equipment that needs compressed air for operability has been identified for SBO. Therefore, the licensee concluded that compressed air is not needed. Based on the licensee's evaluation the NRC staff concludes that compressed air is not impacted.

Containment Isolation

The licensee stated that the uprate does not add or remove any containment isolation valves. The ability to close or operate containment isolation valves and position indication capability is not related to the power level. Based on the licensee's evaluation the NRC staff

concludes that containment isolation at current plant conditions remains applicable at the proposed licensed power conditions.

Conclusion

Based on above information, the staff finds that the proposed licensed power will have no adverse impact on Braidwood and Byron's SBO coping duration. Therefore, the NRC staff finds that the licensee will continue to meet the requirements of 10 CFR 50.63 for the proposed licensed power conditions.

Equipment Qualification (EQ) Program

In Attachment 7, Section V.1.C to the submittal, the licensee stated that Class 1E electrical equipment will function, as required, under normal, abnormal, and/or accident environmental conditions. No equipment will be added, removed, or modified as a result of the proposed licensed power. In addition, there is no change in the function of the equipment within the scope of the program. The proposed licensed power does not require any zones to be modified and has no impact on the qualification process.

The evaluation of the effects of the proposed licensed power on the environmental parameters used in qualifying the Class 1E equipment, such as temperature, pressure, and radiation, under normal, abnormal, and/or accident conditions is discussed as follows. For the normal operating conditions, all the existing values of the environmental parameters remain bounding for proposed licensed power. Because of the conservatism in the current analyses, these analyses remain bounding for the slight increase in normal radiation doses expected for the proposed licensed power conditions.

For the abnormal conditions, the most relevant for EQ is a two-hour loss of ventilation to various AB areas following a HELB and accompanying loss of offsite power. In its letter dated August 25, 2011, the licensee stated that no new HELB locations were identified as a result of proposed licensed power in the piping portions in the AB including the steam tunnel.

The licensee stated that the current qualification of Class 1E electrical equipment in the various AB areas is not adversely impacted by a TB HELB analysis corresponding to proposed licensed power conditions. The NRC staff evaluation of the resolution of the non-conformance is contained in this SE.

The licensee stated that the temperature and pressure values for the containment under accident environmental conditions were revised for the proposed licensed power conditions. The licensee performed an evaluation and determined that all equipment in containment within the scope of the EQ program remains qualified. Only in one case, a slight reduction in qualified life (from 36.2 to 35.64 years) was required for the Byron, Unit No. 2, GEMS containment level transmitters.

The NRC staff asked the licensee to provide a temperature, pressure and radiation profile to demonstrate that adequate margins remain with respect to EQ of electrical equipment in accordance with the Institute of Electrical and Electronics Engineers Standard (IEEE) 323-1974, "Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations," under the worst-case accident conditions at the proposed licensed power conditions. The

licensee, in its supplement dated December 9, 2011, provided the following clarifications regarding the margins relating to EQ parameters:

Radiation

The current total integrated dose (TID) includes a 10 percent margin per IEEE-323-1974 requirements. Also, the TID had been analyzed to a power level of ≥102 percent, which bounds the proposed licensed power. Based on the licensee's evaluation the NRC staff concludes that the TID analysis remains valid.

Pressure

The long-term LOCA M&E release were both re-analyzed for Braidwood and Byron. For the reanalyzed LOCA M&E release cases, the resultant maximum containment pressure of 42.6 psig and 38.26 psig for Units 1 and 2 are less than the peak containment pressures for the current licensing bases of 42.77 psig and 38.36 psig for Units 1 and 2, respectively. The NRC staff finds that the current peak pressure input for EQ is 50 psig, which bounds the reanalyzed peak containment pressure and the current licensing bases pressure for both LOCA M&E release and release cases.

Temperature

The temperature profile considered for EQ of electrical equipment is a composite curve that bounds the results from the MSLB M&E release inside the containment and the LOCA M&E release analyses. Both the long-term LOCA M&E release and the MSLB M&E release were re-analyzed for the proposed licensed power. The EQ evaluation included consideration of margins in peak temperature and post-accident operating time (PAOT) in accordance with the IEEE-323-1974, i.e., 15 °F peak temperature and 10 percent in PAOT. The licensee evaluation showed that all EQ electrical equipment is qualified with sufficient temperature margin. The NRC staff finds that the containment temperature profile considered for EQ is bounded by equipment design temperature.

The NRC staff finds that the licensee adequately addressed the effects of the proposed licensed power on the environmental conditions for the qualification of electrical equipment. Therefore, the staff finds that the proposed licensed power will have no significant impact on the licensee's EQ program and that the licensee will continue to meet the requirements of 10 CFR 50.49.

3.4.4.3 Regulatory Commitments

The licensee provided the following regulatory commitment, applicable to the electrical equipment, in Attachment 4 of the submittal:

> Non-safety related modifications for the power uprate, including switchyard modifications will be implemented prior to increasing power above 3586.6 MWt.

The NRC staff reviewed this licensee regulatory commitment. The NRC staff concludes that the licensee's implementation of the above plant modifications prior to raising power above 3586.6 MWt (CLP) is acceptable. The NRC staff further concludes that installing the modifications in accordance with 10 CFR Part 50.59 is acceptable because 10 CFR Part 50.59 establishes criteria to determine whether or not NRC approval is required.

3.4.4.4 Conclusion

Based on the technical evaluation provided above, the staff finds that Braidwood and Byron will continue to meet GDC 17, 10 CFR 50.63, and 10 CFR 50.49. Therefore, the NRC staff finds the proposed licensed power acceptable.

3.4.5 Chemical Engineering and Steam Generator Integrity

3.4.5.1 Introduction

The NRC staff has reviewed the submittal, as supplemented by a letter dated December 9, 2011, in accordance with RIS 2002-03, "Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications," concerning: Coatings in containment (VI.1.B), Flow-Accelerated Corrosion (IV.1.E), Steam Generators (IV.1.A.vi), and the Chemical Volume Control System (IV.1.A.v).

3.4.5.2 Coatings in Containment (RIS 2002-03, Attachment 1, Section VI.1.B)

Regulatory Evaluation

Protective coating systems (Paints) provide a means for protecting the surfaces of facilities and equipment from corrosion and contamination from radionuclides and also provide wear protection during plant operation and maintenance activities. The NRC staff's review covered protective coating systems used inside the containment for their suitability for and stability under design basis loss-of-coolant accident (DBLOCA) conditions, considering radiation and chemical effects. The NRC's acceptance criteria for protective coating systems are based on: (1) 10 CFR Part 50, Appendix B, which states quality assurance requirements for the design, fabrication, and construction of safety-related SSCs, and (2) RG 1.54, Revision 2, Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants. Specific review criteria are contained in SRP, Section 6.1.2, Protective Coating Systems (Paints) – Organic Materials Review Responsibilities.

Technical Evaluation

The licensee stated that the current licensing basis for containment conditions during a DBLOCA bounds the maximum accident primary containment conditions under MUR PU conditions. Additionally, the licensee stated that coating acceptability was based on the acceptance criteria of ANSI N101.2-1972, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities," and NRC RG 1.54, Revision 0. The staff reviewed the licensee's UFSAR and finds that current licensing basis will continue to bound containment conditions under MUR PU conditions. The staff concludes that the licensee has demonstrated with assurance that the coatings will continue to be acceptable following implementation of the proposed licensed power.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed licensed power on protective coating systems and concludes that the licensee has appropriately addressed the impact of changes in conditions following a DBLOCA and their effects on the protective coatings. The staff further concludes that the licensee has provided assurance that the current protective coatings will continue to be acceptable following implementation

of the proposed licensed power and will meet the requirements of 10 CFR Part 50, Appendix B. Therefore, the staff finds the proposed licensed power acceptable with respect to protective coatings systems.

3.4.5.3 Flow-Accelerated Corrosion (FAC) (RIS 2002-03, Attachment 1, Section IV.1.E)

Regulatory Evaluation

The FAC is a corrosion mechanism occurring in carbon steel components exposed to single-phase or two-phase water flow. Components made from stainless steel are immune to FAC and significantly reduced in components containing even small amounts of chromium or molybdenum. The rates of material loss due to FAC depend on the system flow velocity, component geometry, fluid temperature, steam quality, oxygen content, and pH. During plant operation, it is not normally possible to maintain all of these parameters in a regime that minimizes FAC; therefore, loss of material by FAC can occur. The licensee stated that the FAC program is based on GL 89-08, Erosion/Corrosion-Induced Pipe Wall Thinning, May 2, 1989 (ADAMS Accession No. ML031200731), the guidelines in the EPRI Report NSAC-202L, Recommendation for an Effective Flow-accelerated Corrosion Program, and the Institute of Nuclear Power Operations (INPO) report INPO EPG-06, Engineering Program Guide - Flow Accelerated Corrosion (FAC). The NRC's acceptance criteria are based on the structural evaluation of the minimum acceptable wall thickness for the components undergoing degradation by FAC. The staff reviewed the effects of the proposed licensed power on FAC and the adequacy of the licensee's FAC program to predict the rate of material loss so that repair or replacement of damaged components could be made before reaching a critical thickness.

Technical Evaluation

The licensee stated that the FAC program provides a standardized method of identifying, inspecting, and tracking components susceptible to FAC wear in both single- and two-phase flow conditions. Program elements include: FAC susceptibility analysis and modeling; FAC inspection and evaluation; operational experience reviews; and crossover/crossunder main steam piping and moisture separators/reheaters inspections and evaluations. In general, the licensee stated that plant systems are considered susceptible to FAC unless excluded by defined criteria. The criteria includes: material; moisture content; temperature; dissolved oxygen; frequency of system usage; plant-specific operating experience; and industry operating experience.

The licensee utilizes the CHECWORKS Steam/FW Application (SFA) FAC monitoring computer code. The CHECWORKS SFA computer code has been used to create unit-specific databases, and once the database has been built, the application is used to perform analysis and data interpretation. The licensee stated that these analytical models result in wear-rate analyses that rank components in order of predicted FAC wear and predicted time to reach minimum allowable wall thickness. The NRC staff reviewed the licensee's submittal and requested additional information concerning the licensee's FAC program to include a sample of components expected to experience the greatest increases in wear at the proposed licensed power conditions, and a comparison of the nominal, current and measured wall thickness, to the thickness predicted by the CHECWORKS SFA FAC model of those sample components.

In its response dated December 9, 2011, the licensee provided a sample list of components that are expected to experience the greatest wear rates prior to and following implementation of the proposed licensed power. The licensee stated that the components selected were representative of the highest predicted wear rates from the CHECWORKS updates that were performed for the stretch PU for Byron, Unit No. 1, which historically has operated at the highest power level of the four Braidwood and Byron units. Of the 20 lines provided, 19 lines showed that the predicted wall thickness was more conservative than the measured wall thickness. The licensee stated that the CHECWORKS SFA models will be updated for both Braidwood and Byron's units in order to incorporate the system changes associated with the proposed licensed power. The NRC staff concludes that the licensee design control program is sufficient to control the update to the models. The NRC staff further concludes that it is acceptable to update the models in accordance with 10 CFR 50.59, because 10 CFR Part 50.59 establishes criteria to determine whether or not NRC approval is required.

The NRC staff finds that the current FAC program incorporates adequate conservatism to ensure that components susceptible to FAC are managed appropriately prior to exceeding minimum wall thickness. The staff finds that the updated FAC program, with the incorporated system changes resulting from the proposed licensed power, will provide assurance that components susceptible to FAC will be managed appropriately at the proposed licensed power.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the proposed licensed power on the FAC analysis and concludes that the licensee has adequately addressed the impact of changes in plant operating conditions on the FAC analysis. Additionally, the staff concludes that the licensee has demonstrated the updated analyses will reasonably predict the loss of material by FAC and will ensure timely repair or replacement of degraded components following implementation of the proposed licensed power. Therefore, the staff finds the proposed licensed power acceptable with respect to FAC.

3.4.5.4 Steam Generator (SG) Tube Integrity (RIS 2002-03, Attachment 1, Section IV.1.A.vi)

Regulatory Evaluation

The SG tubes constitute a large part of the RCPB. As a result, their integrity is important to the safe operation of the facility. The staff's review in this area covered the effects of changes in operating conditions resulting from the proposed licensed power on the SG materials and program. Specific review criteria for meeting the applicable regulations are contained in SRP Section 5.4.2.1, Steam Generator Materials, for the SG materials and SRP 5.4.2.2, Steam Generator Program, for the SG program.

In general, SRP, Section 5.4.2.1, provides recommendations to ensure that: (1) the materials used to fabricate the SG are selected, processed, tested, and inspected to appropriate specifications, (2) the fracture toughness of the ferritic materials is adequate, (3) the design of the steam generator limits the susceptibility of the materials to degradation and corrosion, (4) the materials used in the SG are compatible with the environment to which they will be exposed, (5) the design of the secondary side of the SG permits the chemical or mechanical removal of chemical impurities, and (6) any degradation to which the materials are susceptible (including fracture) is avoided, can be managed through the

inservice inspection program, or can be controlled through limits placed on operating parameters. Performing periodic SG inspections will ensure that the integrity of the SG is maintained at a level comparable to that in the original design requirements.

In general, SRP, Section 5.4.2.2, provides recommendations to: (1) ensure that the design of the SG is adequate for implementing a steam generator program, and (2) verify that the steam generator program will result in maintaining tube integrity during operation and postulated accident conditions. The SG program is intended to ensure that the structural and leakage integrity of the tubes is maintained at a level comparable to that of the original design requirements.

Technical Evaluation

The Units1 and 2 SGs at Braidwood and Byron are different models as each Unit 1 has model BWI Replacement Steam Generators (RSGs) and each Unit 2, has Westinghouse Model D5 SGs. The licensee evaluated the change in operating conditions at the proposed licensed power conditions. In general, the licensee determined that the change in operating conditions at proposed licensed power conditions is small from a steam generator perspective. As a result, the licensee's evaluations showed that either prior analyses were bounding or that the increase in the various calculated values were within acceptance limits.

The NRC staff evaluated the information provided by the licensee. The staff finds that the changes in operating conditions at the proposed licensed power conditions to be small. The new operating temperatures and pressures are typical of those used by other plants with recirculating SGs, which the NRC staff has approved for use. Similar SGs have operated successfully under these conditions. As a result, from a SG materials perspective, the staff concludes that the materials used in the SG remain acceptable, the fracture toughness of the ferritic materials is adequate, the design still limits the susceptibility of the materials to degradation and corrosion, the materials used in the steam generator remain compatible with the environment, the design permits the removal of impurities, and that any degradation that could occur is either avoided or can be managed.

With respect to the SG program, the changes in operating conditions have no effect on the ability to implement the program. As a result, the staff concludes that the design of the SG remains adequate for implementing the SG program. The changes in operating conditions may result in increased susceptibility to degradation and may result in increased degradation growth rates. Although this may occur, the SG program is still adequate (and acceptable) since it requires the licensee to continue to ensure tube integrity for the operating interval between inspections. With respect to the tube repair criteria included in the TSs for the SG program, the NRC staff expects that small changes in operating conditions will have a small effect, if any, on the structural limits for the tubes. Since the tube repair criterion is determined from the structural limit, it may also be slightly affected by the proposed licensed power conditions. The staff concludes that the tube repair criteria remain valid under the proposed licensed power conditions based on staff approval of identical repair criteria at other similarly designed and operated units and the performance-based TS requirement to ensure tube integrity for the operating interval between inspections. As a result of the above, the staff concludes that the SG program remains acceptable for the proposed licensed power conditions.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed licensed power on the Braidwood and Byron, Units 1 and 2 SGs and concludes that the licensee has adequately assessed the continued acceptability of the SG materials and program under the proposed licensed power conditions. The staff has confirmed that the materials in the SG will continue to be adequate to support operation at the proposed licensed power. The staff has also confirmed that the licensee has a program that ensures SG tube integrity, and that the applicability of this program has not changed as a result of the proposed licensed power. Therefore, the NRC staff finds the proposed licensed power acceptable with respect to SG tube integrity.

3.4.5.5 Steam Generator Blowdown System (SGBS) (RIS 2002-03, Attachment 1, Section VI.1.B)

Regulatory Evaluation

Control of secondary-side water chemistry is important for preventing degradation of SG tubes. The SGBS provides a means for removing SG secondary-side impurities and, thus, assists in maintaining acceptable secondary-side water chemistry in the SGs. The design basis of the SGBS includes consideration of expected and design flows for all modes of operation. The staff's review covered the ability of the SGBS to remove particulate and dissolved impurities from the SG secondary side during normal operation, including condenser in-leakage and primary-to-secondary leakage. The NRC's acceptance criteria for the SGBS are based on GDC 14), "Reactor Coolant Pressure Boundary (RCPB)," as it requires that the RCPB be designed so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture. Specific review criteria are contained in SRP, Section 10.4.8, Steam Generator Blowdown System (PWR).

Technical Evaluation

The licensee stated that the blowdown flow rates required during plant operation are based on chemistry control and tube-sheet sweep requirements to control the buildup of solids. The blowdown flow rate required for controlling chemistry and the buildup of solids in the steam generators is related to allowable condenser in-leakage, total dissolved solids in the plant circulating water system, and allowable primary to secondary leakage. Since these variables are not impacted by the proposed licensed power, the licensee stated that the blowdown required to control secondary chemistry and SG solids will not be impacted by operation at the proposed licensed power. Therefore, the MUR PU will not challenge the design flow rate of 360 gpm for the SGBS system. The licensee stated that SGBS operating temperatures and pressures will decrease and remain bounded by the existing parameters under uprate conditions. Additionally, the licensee stated that operation at the proposed licensed power will not significantly increase the potential for FAC on the SGBS piping and components.

The staff reviewed the licensee's UFSAR and confirmed that the current licensing basis for the SGBS will continue to bound the system post MUR PU implementation.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of operation at the proposed licensed power on the SGBS and concludes that the licensee has adequately addressed changes in system flow and impurity levels and their effects on the SGBS. The staff further concludes that the licensee has demonstrated that the SGBS will continue to be acceptable and will continue to meet the requirements of 10 CFR Part 50, GDC-14, following implementation of the proposed licensed power. Therefore, the staff finds the proposed licensed power acceptable with respect to the SGBS.

3.4.5.6 Chemical and Volume Control System (CVCS)

Regulatory Evaluation

The CVCS provides a means for: (1) maintenance of programmed water level in the pressurizer (i.e., maintain required water inventory in the RCS, (2) supplying seal-water flow to the RCPs, (3) control of reactor coolant water chemistry conditions, activity level, soluble chemical neutron absorber concentration, and makeup, (4) emergency core cooling (part of the system is shared with the ECCS), and (5) provide means for filling, draining, and pressure testing of the RCS.

The NRC staff has reviewed the safety-related functional performance characteristics of the CVCS components. The NRC's acceptance criteria are based on (1) GDC 14, "Reactor Coolant Pressure Boundary (RCPB)," as it requires that the RCPB be designed to have an extremely low probability of abnormal leakage, or rapidly propagating fracture, and of gross rupture, and (2) GDC 29, "Protection Against Anticipated Operational Occurrences," requires that the reactivity control systems be designed to assure an extremely high probability of accomplishing their functions in the event of condenser in-leakage or primary-to-secondary leakage. Specific review criteria are contained in SRP Section 9.3.4, Chemical and Volume Control System (PWR).

Technical Evaluation

The licensee stated that the only auxiliary equipment design transients potentially impacted by operation at the proposed licensed power were those transients associated with full-load NSSS design temperatures (Thot and Tcold). The licensee additionally stated that these temperature transients are defined by the differences between RCS loop coolant temperature and the temperature of coolant in the auxiliary systems connected to the RCS loops. Since the operating coolant temperatures in the auxiliary systems are not impacted by the proposed licensed power, the licensee stated that the temperature difference between auxiliary systems and the RCS loops is only affected by changes in the RCS operating temperatures.

The design transients assume a full-load NSSS Thot and Tcold of 630 °F and 560 °F, respectively. The licensee stated that these full-load temperatures were selected for equipment design to ensure that the temperature transients would be conservative for a wide range of NSSS design parameters. The licensee compared the approved range of Thot (608.6 – 620.9 °F) and Tcold (541.4- 555.1 °F) for the proposed licensed power at full-load with the temperatures used to develop the current design transients, and the comparison showed that the proposed licensed power temperatures are lower, which results in less severe design temperature transients. Therefore, the licensee stated that the

existing auxiliary equipment design transients are conservative and bounding for the proposed licensed power.

The NRC staff reviewed the UFSAR and confirmed that the design basis for the CVCS remains bounding for MUR PU conditions. The staff also reviewed the licensee's evaluation of Auxiliary Equipment Design Transients concerning CVCS and required additional information concerning the affect of the proposed licensed power on the nitrogen-16 activity in the letdown system. The licensee's response, dated December 9, 2011, stated that the existing design basis reactor water fission product and activation product inventory remained bounding at MUR PU conditions. Since the existing design basis remains bounding, the staff's finds the proposed licensed power acceptable with regard to nitrogen-16 activity.

Conclusion

The NRC staff has reviewed the licensee's evaluations and UFSAR, Section 9.3.4, and has determined that the CVCS will continue to perform its design basis function based on current design transients bounding the operating conditions post MUR PU implementation. The staff concludes that the licensee has demonstrated that the CVCS will continue to be acceptable and will continue to meet the requirements of GDCs 14 and 29 following implementation of the proposed licensed power. Therefore, the staff finds the proposed licensed power acceptable with respect to the CVCS.

3.4.6 Effect of MUR on Major Components

3.4.6.1 Safety-Related Valves

Regulatory Evaluation

The NRC staff reviewed the licensee's safety-related valves analyses for Braidwood and Byron, Unit Nos. 1 and 2. The staff examined the overall design change and included plant-specific evaluations of Generic Letter(s) (GL) 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves," GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves," and GL 96-06, "Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions." The NRC's acceptance criteria for reviewing the safety related valve analysis are based on 10 CFR 50.55a, "Codes and Standards."

Technical Evaluation

In its submittal dated June 23, 2011, the licensee reviewed the impact of the proposed MUR PU on the existing safety-related valves design basis. No changes in RCS flow, design, or operating pressure were made as part of the proposed licensed power. The licensee's evaluation contained in its June 23, 2011, application concluded that the temperature changes due to the power uprate have, at most, an insignificant effect on the differential pressures used in the existing analyses. As a result, none of the safety-related valves required a change to their design or operation as a result of the proposed licensed power. The analyses also confirmed that the existing MSSVs capacity is adequate for overpressure protection at the proposed licensed power conditions and that the existing lift setpoints are unchanged. The NRC staff reviewed the licensee's analysis and determined that none of

the safety-related valves required a change to their design or operation as a result of the proposed licensed power.

The licensee also evaluated the impact of the proposed MUR PU on the current air operated valve (AOV) program, GL 89-10 and GL 96-05 motor-operated valve (MOV) program, and GL 95-07 PLTB program. The overall system evaluations concluded that valve function, valve design, operational conditions, thrust, and torque requirements are unaffected by the MUR PU and all valves remain capable of performing their design basis functions. Therefore, no changes are required to the existing AOV, MOV, and PLTB, programs.

Conclusion

Based on the NRC staff's review of the licensee's evaluations, the NRC staff concludes that the performance of existing safety-related valves is acceptable with respect to the proposed licensed power and 10 CFR 50.55a, "Codes and Standards," continues to be met.

3.4.6.2 Safety-Related Pumps

Regulatory Evaluation

The NRC staff reviewed the licensee's safety-related pump analysis. The NRC's acceptance criteria for reviewing the safety-related pumps analysis is based on the requirements in 10 CFR 50.55a.

Technical Evaluation

The NRC staff reviewed the impact of the proposed licensed power conditions on the existing design basis analyses for safety-related pumps. The evaluation showed that there are no significant changes to the maximum operating conditions and no changes to the design basis requirements that would affect pump performance. The current plant design is considered bounding under the proposed licensed power conditions and requires no modifications to pump systems.

Conclusion

Based on its review of the licensee's analysis, the NRC staff concludes that the performance of existing safety-related pumps is acceptable with respect to the proposed licensed power and 10 CFR 50.55a, "Codes and Standards," continues to be met.

3.4.6.3 Inservice Testing (IST) Program

Regulatory Evaluation

The NRC's acceptance criteria for reviewing the safety-related pumps analysis is based on the requirements in 10 CFR 50.55a. The Code of Record for Braidwood and Byron, Units 1 and 2, is the ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code) 2001 Edition through the 2003 Addenda.

Technical Evaluation

In its June 23, 2011, submittal, the licensee described the review of the IST program for safety-related pumps and valves at Braidwood and Byron, Units 1 and 2, for the proposed licensed power. The IST program assesses the operational readiness of pumps and valves within the scope of the ASME OM Code. There were no significant changes to operating conditions or the design basis requirements that would affect component performance, test acceptance criteria, or reference values. Therefore, the existing IST program will not be impacted by operation at the proposed licensed power.

Conclusion

Based on its review of the licensee's evaluation, the NRC staff concludes that the IST program will be acceptable, as is, at the proposed licensed power conditions and 10 CFR 50.55a, "Codes and Standards," continues to be met.

3.5 Safety Programs (RIS 2002-03, Attachment 1, Section VII)

Attachment 1, Section VII is intended to ensure that all necessary changes to procedures and modifications to the facilities to support the uprate are completed prior to implementation of the uprate and will adversely affect defense in depth or safety margins.

3.5.1 Radiological Dose Assessment

3.5.1.1 Regulatory Evaluation

This evaluation addresses the impact of the proposed changes on previously analyzed design basis accident (DBA) radiological consequences and the acceptability of the revised analysis results. The regulatory requirements for which the NRC staff based its acceptance are the accident dose criteria in 10 CFR 50.67 "Accident source term," as supplemented by accident specific criteria in Section 15 of NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants." and 10 CFR Part 50, Appendix A, GDC 19, "Control Room," as supplemented by Section 6.4 of the SRP. The staff used the regulatory guidance provided in the following documents in performing its review:

- RG 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors";
- RG 1.195, "Methods and Assumptions for Evaluating Radiological Consequences of Design Basis Accidents (DBA) at Light-Water Nuclear Power Reactors";
- SRP 15.0.1, "Radiological Consequence Analyses Using Alternative Source Terms," Revision 0, July 2000;
- NUREG-0800, SRP, Section 6.4, "Control Room Habitability Systems;"
- RG 1.23, "Meteorological Monitoring Programs for Nuclear Power Plants," Revision 1, March 2007;
- RG 1.145: "Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants";
- NUREG/CR-2858, "PAVAN: An Atmospheric-Dispersion Program for Evaluating Design- Basis Accidental Releases of Radioactive Materials from Nuclear Power Stations"; and

- NUREG/CR-6331, "Atmospheric Relative Concentrations in Building Wakes," Revision 1, May1997.

The NRC staff also considered relevant information in the Braidwood and Byron's UFSAR, TSs, and applicable previous licensing actions.

The licensee has accounted for the potential increase in measurement uncertainty should the LEFM system experience operational limitations. The licensee proposes to modify the Technical Requirements Manual (TRM) to add a TRM Limiting Condition for Operation (TLCO). TLCO 3.3.k, "Feedwater Flow Instrumentation," that allows operation at the proposed licensed power for up to 72 hours with an inoperable LEFM system; otherwise, power must be reduced to less than or equal to the current licensed power level of 3586.6 MWt, which corresponds to 98.3% RTP as noted in the TLCO.

In RIS 2002-03, "Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications," recommends that, to improve efficiency of the NRC staff's review, licensees requesting an MUR PU should identify existing DBA analyses of record which bound plant operation at the proposed uprated power level. For any DBA for which the existing analyses of record do not bound the proposed uprated power level, the licensee should provide a detailed discussion of the re-analysis. The NRC staff's review covers the impact of the proposed licensed power on the results of dose consequence analyses as noted in RIS 2002-03, Attachment 1, Sections II and III.

3.5.1.2 Technical Evaluation

Radiological Consequences of Design Basis Accidents

The NRC approved a full-scope alternative source term (AST) for Braidwood and Byron by letter dated September 8, 2006 (ADAMS Accession No. ML062340420), as Amendment No. 140 to the Braidwood, Units 1 and 2, and Amendment No. 147 to Byron, Unit Nos. 1 and 2. The licensee performed radiological consequence analyses for the following six DBAs to determine CR and offsite exposure.

- LOCA
- Fuel Handling Accidents (FHA)
- Control Rod Ejection Accident (CREA)
- Locked Rotor Accident (LRA)
- Main Steam Line Break (MSLB)
- Steam Generator Tube Rupture (SGTR)

The NRC approved a revised AST for Braidwood and Byron by letter dated February 5, 2009 (ADAMS Accession No. ML090230613), as Amendment No. 155 to Braidwood, and as Amendment No. 160 to Byron. These amendments approved removing credit for the CR ventilation system recirculation prefilters and reducing the assumed CR unfiltered inleakage.

LOCA Radiological Consequences Analysis

The NRC staff reviewed the impact of the proposed 1.63 percent PU on the LOCA radiological analysis, as documented in Section 15.6.5 of the Braidwood and Byron UFSAR. In its submittal, the licensee stated that the current LOCA dose AOR for Braidwood and

Byron is unaffected by the requested PU because it was performed assuming a power level of 3658 MWt which bounds the proposed licensed power of 3645 MWt. The LOCA analysis assumptions do not include steam mass releases. Therefore, the revised steam mass releases do not affect the LOCA analysis. The NRC staff verified that the existing Braidwood and Byron UFSAR, Chapter 15, radiological analysis source term and release assumptions bound the conditions for the proposed 1.63 percent PU, considering the higher accuracy of the FW measurement instrumentation. The NRC staff finds that, for the proposed licensed power, the radiological consequences of a postulated LOCA continue to meet the dose limits given in 10 CFR 50.67 and GDC 19.

Fuel Handling Accident (FHA) Radiological Consequences Analysis

The NRC staff reviewed the impact of the proposed 1.63 percent PU on the FHA radiological analysis, as documented in Section 15.7.4 of the Braidwood and Byron UFSAR. In its submittal, the licensee stated that the current FHA dose AOR for Braidwood and Byron is unaffected by the proposed licensed power because it was performed assuming a power level of 3658 MWt which bounds the proposed power level of 3645 MWt. The NRC staff verified that the existing Braidwood and Byron UFSAR, Chapter 15, radiological analysis source term and release assumptions bound the conditions for the proposed 1.63 percent power uprate, considering the higher accuracy of the FW measurement instrumentation. The NRC staff finds that, for the proposed PU, the radiological consequences of a postulated FHA continue to meet the dose limits given in 10 CFR 50.67 and GDC 19, as well as applicable dose acceptance criteria given in SRP, Section 15.0.1.

Control Rod Ejection Accident (CREA) Radiological Consequences Analysis

The NRC staff reviewed the impact of the proposed 1.63 percent power uprate on the CREA radiological analysis, as documented in Section 15.4.8 of the Braidwood and Byron UFSAR. In its submittal, the licensee stated that the current CREA dose AOR for Braidwood and Byron is unaffected by the proposed licensed power because it was performed assuming a power level of 3658 MWt, which bounds the proposed power level of 3645 MWt. The NRC staff verified that the existing Braidwood and Byron UFSAR, Chapter 15, radiological analysis source term and release assumptions bound the conditions for the proposed 1.63 percent power uprate, considering the higher accuracy of the FW measurement instrumentation. The NRC staff finds that, for the proposed PU, the radiological consequences of a postulated CREA continue to meet the dose limits given in 10 CFR 50.67 and GDC 19, as well as applicable dose acceptance criteria given in SRP, Section 15.0.1.

Locked Rotor Accident (LRA) Radiological Consequences Analysis

The NRC staff reviewed the impact of the proposed 1.63 percent PU on the LRA radiological analysis, as documented in UFSAR, Section 15.3.3, of the Braidwood and Byron UFSAR. The current LRA radiological analysis assumes a power level of 3658 MWt, which bounds the proposed power level of 3645 MWt. The licensee stated that the release pathways, and dose conversion factors are unchanged from the current licensing basis. However, in support of its proposed licensed power submittal, the licensee reanalyzed the steam mass release calculations during a LRA. The licensee's calculated steam mass release results are shown in Table 3.5.1-1.

Table 3.5.1-1

Braidwood and Byron Steam Release for LRA

Current		MUR Uprate	
Interval (hours)	**Total Steam Mass Release (lbm)**	**Interval (hours)**	**Total Steam Mass Release (lbm)**
0 to 2	719,000	0 to 2	457,000
2 to 8	1,109,000	2 to 40	3,323,000
8 to 40	2,664,000		
Total	4,492,000	Total	3,780,000

The licensee calculated the vented steam releases from the intact-loop SGs for the 0 to 2 hour time period and the 2 to 40-hour time period for the LRA. After the first two hours, it is assumed the plant will have cooled down and stabilized at no-load conditions. The additional 38 hours are required to cool down and depressurize the plant from no-load conditions to the Residual Heat Removal)RHR) operating conditions. The licensee revised its methodology such that a separate time step from 2 to 8 hour is no longer calculated. The NRC staff finds that this change in methodology has no impact on the LRA radiological dose assessment. The NRC staff also finds that the current LRA radiological consequence analysis assumes steam mass release rates that bound the re-analyzed values. Therefore, the assumptions and parameters for the current LRA radiological consequences analysis are unchanged.

The NRC staff verified that the existing Braidwood and Byron, UFSAR, Chapter 15, radiological analysis source term and release assumptions bound the conditions for the proposed 1.63 percent PU to 3645 MWt, considering the higher accuracy of the FW measurement instrumentation. Therefore, the NRC staff finds that, for the proposed licensed power, the radiological consequences of postulated LRA continue to meet the dose limits given in 10 CFR 50.67 and GDC 19, as well as applicable dose acceptance criteria given in SRP, Section 15.0.1.

Main Steam Line Break (MSLB) Radiological Consequences Analysis

The NRC staff reviewed the impact of the proposed 1.63 percent PU on the MSLB radiological analysis, as documented in UFSAR, Section 15.1.5, of Braidwood and Byron. The current MSLB radiological analysis is based upon the AST methodology. The analysis involves primary coolant radiological source release to the secondary side from the SG and then to the environment. The source terms for equilibrium conditions with 1 % failed fuel are normalized to the TS Dose Equivalent Iodine-131 (DEI-131) limits in the primary coolant, which removes the power dependence from the analysis. The licensee states that the release pathways and dose conversion factors are unchanged from the current licensing basis. However, in support of its proposed licensed power submittal, the licensee revised the Braidwood and Byron steam mass release calculation. Therefore, the licensee recalculated the MSLB accident dose consequence analysis because steam mass release is an assumption in the MSLB accident analysis.

The licensee states that the revised calculation showed that the steam release values used in the current MSLB accident radiological consequence analysis do not bound MUR conditions. Therefore, the licensee revised Braidwood and Byron MSLB accident radiological consequence analysis using the updated steam release values. The updated steam mass release values are shown in Table 3.5.1-2.

Table 3.5.1-2

Braidwood and Byron Steam Release for MSLB

Current		MUR Uprate	
Interval (hours)	**Total Steam Mass Release (lbm)**	**Interval (hours)**	**Total Steam Mass Release (lbm)**
0 to 2	442,000	0 to 2	447,000
2 to 8	977,000	2 to 40	3,279,000
8 to 40	2,216,000		
Total	3,635,000	Total	3,726,000

The licensee calculated the vented steam releases from the intact-loop SGs for the 0 to 2-hour time period and the 2 to 40-hour time period for the LRA. After the first two hours, it is assumed the plant will have cooled down and stabilized at no-load conditions. The additional 38 hours are required to cool down and depressurize the plant from no-load conditions to the RHR operating conditions. The licensee revised its methodology such that a separate time step from 2 to 8-hour is no longer calculated. The NRC staff finds that this change in methodology has no impact on the MSLB radiological dose assessment. The CR modeling remains the same as described in the Braidwood and Byron current licensing basis. The licensee's limiting calculated MSLB dose results are given in Table 3.5.1-3.

Table 3.5.1-3

Calculated Radiological Consequences for MSLB

Event Condition	Location	Calculated Dose (rem TEDE[1])	Acceptance Criteria (rem TEDE)
Pre-Accident Iodine Spike	EAB	0.145	25[2]
	LPZ	0.083	25[2]
	Control Room	0.580	5.0[2]
Post-Accident Iodine Spike	EAB	0.201	2.5[3]
	LPZ	0.459	2.5[3]
	Control Room	2.845	5.0[2]

[1] Total effective dose equivalent; [2] From 10 CFR 50.67; [3] From SRP 15.0.1

The NRC verified that the revised MSLB accident radiological dose analysis was calculated using the same methodology that was approved for the Braidwood and Byron AST license amendment. The NRC also verified that, besides the revised steam mass release values, no other assumption and parameters were changed for the MSLB accident dose analysis that were approved for the Braidwood and Byron AST license amendment. Therefore, the NRC staff finds that, for the proposed licensed power of 3645 MWt, the radiological consequences of postulated MSLB continue to meet the dose limits given in 10 CFR 50.67 and GDC 19, as well as applicable dose acceptance criteria given in SRP, Section 15.0.1.

Steam Generator Tube Rupture (SGTR) Radiological Consequences Analyses

In support of its June 23, 2011, submittal, the licensee revised the Braidwood and Byron SGTR accident analysis. The SGTR accident is postulated as a complete severance of a single SG tube. The licensee SGTR radiological consequences analysis evaluated two separate radiological source term cases; an accident initiated iodine spike case and a pre-accident iodine spike case. The accident initiated iodine spike case assumed the primary coolant activity was initially at the long-term TS limit of 1.0 μCi/gm DE I-131 when the event occurs. The accident is assumed to cause the iodine concentration to spike by addition of iodine activity by a factor of 335 times the equilibrium iodine appearance rate for eight hours. The pre-accident iodine spike case assumed the primary coolant iodine concentration was at the current licensing basis value of 60 μCi/gm DE I-131. These assumptions are consistent with Braidwood's and Byron's current licensing basis.

For both cases, all modeling other than the activity source term is the same. The primary-to-secondary coolant leakage of 0.218 gpm per SG goes to the three intact SGs. The activity in the coolant is available for release to the environment through secondary coolant steaming through the SG PORVs. The licensee assumed an iodine partitioning factor of 0.01 in the intact SGs in accordance with RG 1.183 guidance. One hundred percent of the noble gases are assumed to be released. Primary coolant was assumed to pass through the ruptured SG tubes and be available for release to the outside environment by steaming through the ruptured SG PORV. A portion of the rupture flow flashes directly to steam while the remainder of the flow mixes with the secondary coolant and, subsequently, steams through the PORV. In these releases, the licensee also postulates the additional presence of iodine activity at the proposed secondary coolant concentration limit of 0.1 μCi/gm DE I-131. The flashing fraction and partitioning fractions for the ruptured SG are in accordance with RG 1.183 guidance.

In support of its proposed licensed power submittal, the licensee revised the Braidwood and Byron steam mass release calculation. Therefore, the licensee recalculated the SGTR accident dose consequence analysis because steam mass release is an assumption in the SGTR accident analysis. Break flow, flashed break flow, and steam releases from the intact and ruptured SGs were modeled using data from the thermal and hydraulic analyses discussed in Attachment 5a of its June 23, 2011, submittal. The licensee states that the SGTR dose analyses added 10 percent to the mass transfer that was calculated. The 10 percent increase in mass transfers results in approximately a 10 percent increase in the calculated doses. In addition, approximately 5 percent margin was added to the total calculated doses. The RCS and intact SG masses were modeled at the initial values listed in Table 3.5.1-4 of this SE. The CR modeling remains the same as described in the Braidwood and Byron current licensing basis.

Table 3.5.1-4

Braidwood and Byron RCS and SG Mass Data for Steam Release for SGTR

	Unit 1	Unit 2
Event	**Liquid Mass (lbm)**	**Liquid Mass (lbm)**
Initial RCS	548,000	488,000
Initial Ruptured SG	103,000	68,900
Minimum Ruptured SG	41,500	>68,900
Initial Intact SGs (total)	310,000	206,000

The licensee's limiting calculated MSLB dose results are given in Table 3.5.1-5.

Table 3.5.1-5

Calculated Radiological Consequences for SGTR

Event Condition	Location	Unit 1 TEDE Dose (rem TEDE[1])	Unit 2 TEDE Dose (rem TEDE[2])	Acceptance Criteria (rem TEDE)
Pre-Accident Iodine Spike	EAB	3.5	3.7	25[2]
	LPZ	0.63	0.69	25[2]
	CR	1.7	2.0	5.0[2]
Accident Initiated Iodine Spike	EAB	1.8	2.1	2.5[3]
	LPZ	0.33	0.41	2.5[3]
	CR	0.46	0.56	5.0[2]

[1]Total effective dose equivalent. [2]From 10 CFR 50.67. [3]From SRP 15.0.1

The NRC verified that the revised SGTR accident radiological dose analysis was calculated using the same methodology that was approved for the Braidwood and Byron AST license amendment. The NRC also verified that, besides the revised steam mass release values, no other assumption and parameters were changed for the SGTR accident dose analysis that were approved for the Braidwood and Byron AST license amendment. Therefore, the NRC staff finds that, for the proposed licensed power of 3645 MWt, the radiological consequences of postulated SGTR continue to meet the dose limits given in 10 CFR 50.67 and GDC19, as well as applicable dose acceptance criteria given in SRP, Section 15.0.1.

Atmospheric Dispersion Estimates

In the February 13, 2006, (ADAMS Accession No. ML060450176), response to an NRC RAI with respect to the February 15, 2005, Braidwood and Byron AST LAR (ADAMS Accession No. ML050560102), the licensee made the commitment to reevaluate the atmospheric dispersion factors (X/Q values) based on the finer wind speed categories provided in the latest appropriate regulatory guidance the next time calculations associated with the dose consequences for the LOCA, MSLB, CREA, LRA, SGTR and FHA were revised. In support of the proposed licensed power submittal, the MSLB and SGTR accident radiological dose

analysis were revised. In accordance with the commitment, the licensee performed a reevaluation of the offsite X/Q values for the MSLB and SGTR. The regulatory guidance on finer wind speed categories is provided in NRC RG 1.23. The use of finer wind speed categories was the only change made in the reevaluation of the offsite X/Q values.

Meteorological Data

As part of its August 25, 2011, supplement, the licensee provided the meteorological data set for years 1994 - 1998 in the form of hourly data formatted for input into the ARCON96 atmospheric dispersion computer code (NUREG/CR-6331, Revision 1), and in the form of a joint wind speed, wind direction, and atmospheric stability frequency distribution for input to the PAVAN atmospheric dispersion computer code (NUREG/CR-2858). The meteorological data originated from the Braidwood and Byron meteorological tower databases and are the same data previously used as a basis for making atmospheric dispersion estimates for use in the DBA dose assessments performed in support of the February 15, 2005, Braidwood and Byron AST LAR. The NRC staff reviewed the meteorological data and found that it provided an acceptable basis for making estimates of atmospheric dispersion in support of the proposed licensed power.

Control Room (CR) Atmospheric Dispersion Factors

The licensee states in its August 25, 2011, supplement, that the CR X/Q values are unchanged and remain consistent with the values noted in the NRC's September 8, 2006, SE for the Byron and Braidwood AST LAR, Table 1, "Byron Units 1 & 2 and Braidwood Units 1 & 2 Control Room Atmospheric Dispersion Factors." The NRC staff determined that the CR X/Q values listed in the September 8, 2006, AST LAR SE are acceptable for use in making DBA dose assessments in support of the proposed licensed power.

Offsite Atmospheric Dispersion Factors

The licensee calculated the new offsite X/Q values for the MSLB and SGTR using the same methods applied in the February 15, 2005, Braidwood and Byron AST LAR. The offsite X/Q values found acceptable for the other analyzed accidents in the September 8, 2006, AST LAR SE remain unchanged. The licensee used guidance provided in RG 1.145 and the PAVAN atmospheric dispersion computer code. Meteorological data from the 5-year period, 1994-1998, was used in the analysis. The format of the PAVAN meteorological input for the X/Q calculations consisted of a joint wind direction, wind speed, and atmospheric stability class frequency distribution. At each station, the outer containment wall and the midpoint between the two reactors were the assumed release points for the exclusion area boundary (EAB) and low-population zone (LPZ), respectively.

The X/Q calculations utilized 11 wind speed categories as defined in RG 1.23, Revision 1, with the first category identified as "calm." For both stations, the minimum non-calm wind speed was fixed at 0.8 mph. A midpoint was assumed between each of the Regulatory Guide 1.23, Revision 1 wind speed categories (Nos. 2-11) to be inclusive of all monitored wind speeds. Table 2 of the August 25, 2011, supplement, contains the revised wind speed categories used in the analysis.

The licensee notes in the August 25, 2011, supplement that the offsite X/Q values used in the SGTR analysis are the same as those used in the MSLB analysis. The descriptions of the updated assumptions for the offsite X/Q values for the SGTR are the same as those for

the MSLB offsite X/Q values. The bounding set of offsite X/Q values are also the same for both the SGTR and MSLB.

The NRC staff performed a qualitative review of the inputs and assumptions used in the licensee's PAVAN computer calculations and of the resulting X/Q values. The staff calculated comparative X/Q values, and found the results to be similar to the EAB and LPZ X/Q values calculated by the licensee. Therefore, on the basis of this review, the NRC staff determined that the resulting offsite EAB and LPZ X/Q values for the MSLB and SGTR generated by the licensee and presented in Table 3.3.1-6 of this SE are acceptable for use in making DBA dose assessments in support of the proposed licensed power.

Table 3.3.1-6

Byron and Braidwood Bounding Offsite Atmospheric Dispersion Factors (X/Q Values) for the MSLB and SGTR

	X/Q Values (sec/m^3)				
	0 to 2 Hours	**2 to 8 Hours**	**8 to 24 Hours**	**1 to 4 Days**	**4 to 30 Days**
EAB	6.18E-04				
LPZ	1.10E-04	5.13E-05	3.51E-05	1.53E-05	4.68E-06

3.5.1.3 Conclusion

As described above, the staff reviewed the assumptions, inputs, and methods used by the licensee to assess the radiological consequences of DBAs for the proposed 1.63 percent rated thermal power increase at Braidwood and Byron. The NRC staff finds that the licensee used analysis methods and assumptions consistent with the regulatory requirements and guidance identified in Section 3.3.1.1, above. The staff compared the doses estimated by the licensee to the applicable criteria identified. The NRC staff finds that the licensee's estimates of the EAB, LPZ, and CR doses comply with these criteria. The staff further finds there is assurance that Braidwood and Byron as modified by the proposed license amendment, will continue to provide sufficient safety margins with adequate defense-in-depth to address unanticipated events and to compensate for uncertainties in accident progression and analysis assumptions and parameters. Therefore, the proposed licensed power is acceptable with respect to the radiological consequences of DBAs.

3.5.2 Fire Protection (FP)

The purpose of the fire protection program is to provide assurance, through a defense-in-depth design, that a fire will not prevent the performance of necessary plant safe-shutdown functions, nor will it significantly increase the risk of radioactive releases to the environment. The NRC staff's review focused on the effects of the increased decay heat due to the MUR PU on the plant's safe-shutdown analysis to ensure that SSCs required for the safe-shutdown of the plant are protected from the effects of the fire and will continue to be able to achieve and maintain safe-shutdown following a fire.

3.5.2.1 Regulatory Evaluation

The acceptance criteria for this review are based on: (1) 10 CFR 50.48, "Fire protection," insofar as it requires the development of a fire protection program to ensure, among other things, the capability to safely shutdown the plant; (2) GDC 3 of Appendix A to 10 CFR Part 50, insofar as it requires that [a] SSCs important to safety be designed and located to minimize the probability and effect of fires, [b] non-combustible and heat resistant materials be used, and [c] fire detection and suppression systems be provided and designed to minimize the adverse effects of fires on SSCs important to safety; and (3) GDC 5 of Appendix A to 10 CFR Part 50, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions.

A revision to 10 CFR Part 50, Appendix K, effective July 31, 2000, allowed licensees to use a power uncertainty of less than 2 percent in design basis LOCA analyses, based on the use of state-of-the-art FW flow measurement devices that provide for a more accurate calculation of reactor power. Appendix K to 10 CFR Part 50 did not originally require that the reactor power measurement uncertainty be determined, but instead required a 2 percent margin. The revision allows licensees to justify a smaller margin for power measurement uncertainty based on power level instrumentation error. This type of change is also commonly referred to as an MUR PU.

Attachment 1, Sections II and III of Attachment 1 of RIS 2002-03, recommends that to improve the efficiency of the staff's review, licensees requesting an MUR PU should identify current accident and transient analyses of record which bound plant operation at the proposed uprated power level. For any design basis accident for which the existing analyses of record do not bound the proposed uprated power level, the licensee should provide a detailed discussion of the re-analysis.

3.5.2.2 Technical Evaluation

The licensee re-evaluated the applicable SSCs and safety analyses at the proposed MUR core power level of 3645 MWt against the previously analyzed core power level of 3586.6 MWt. The NRC staff reviewed Attachment 5, MUR Technical Evaluation, Section VII.6.A, "Fire Protection Program," of the submittal. The staff also reviewed the licensee's approved FP program. The review covered the impact of the proposed MUR PU on the results of the safe-shutdown fire analysis and on the effects of the uprate on the post-fire safe-shutdown capability and increase in decay heat generation following plant trips.

The NRC staff's review of the Attachment 5, Technical Evaluation, Section VII.6.A, "Fire Protection Program," to the submittal identified areas in which additional information was necessary to complete the review of the proposed uprate , the licensee responded to the NRC staff RAI as discussed below.

On page VII-5 of Attachment 5 to the submittal the NRC staff noted that Technical Evaluation, Section VII.6.A, "Fire Protection Program," states that,

> ...an analysis of the change in combustible loading determined that the overall increase in fire loading is small and does not change the fire load classification of each affected fire zone...

In its submittal dated June 23, 2011, the licensee stated that the uprate conditions result in changes to combustible loading (addition of instrumentation, control and power cable). The NRC staff reviewed the licensee's assessment of the proposed plant modifications at uprate conditions and the licensee's statement that the modifications will be evaluated in accordance with the FP license condition and 10 CFR 50.59 processes to determine whether those modifications will require prior NRC approval before implementation.

The NRC staff noted that the licensee was not clear regarding whether there are FP program plant modifications planned (e.g., adding new cable trays, or re-routing of existing cables) as a result of the uprate. By letter dated November 1, 2011, the licensee indicated that the uprate will not involve plant modifications to the fire protection system, or changes to the fire protection program. However, the licensee did state that the LEFM modification will add small amounts of combustible material in the form of instrumentation, control and power cable insulation to 12 Braidwood, Unit 2, fire zones; seven Byron, Unit No. 1, fire zones; and seven Byron, Unit No. 2, fire zones. The Braidwood, Unit 1, LEFM modification was still under development at the time of the submittal. The change in fire loading resulting from the LEFM modification for Braidwood, Unit 1, is intended to be similar to the changes identified for the other three units. In addition, the licensee stated that Section 2.3 of the Fire Protection Report (FPR), currently lists cable insulation as a fire hazard in the affected fire zones and, therefore, the LEFM installation does not introduce a new fire hazard in these fire zones. The licensee stated that the change in combustible loading is well within the available combustible loading margins.

The licensee indicated that the modification to increase the capacity of the SG PORVs for Braidwood and Byron, Unit 1, only should not add any additional combustible material and has no impact on the FP system or program. The other modifications associated with the PU were still under development at the time of the submittal and will be evaluated in accordance with the licensee's design change process required by 10 CFR Part 50, Appendix B, Criterion III.

The NRC staff questioned whether proposed modifications associated with the SGTR and MTO would impact the FP program and the plant's compliance with its FP licensing basis. Further, the staff questioned how the licensee intends to ensure that once developed and implemented, the modifications will not change this impact. In a supplement dated March 30, 2012, the licensee stated that the SGTR and MTO modifications were still being developed. The impact of these modifications on the fire protection program will be evaluated in accordance with Exelon's configuration change process. The licensee stated that per the process, these modifications will be evaluated to assure the changes do not adversely impact the approved FPR and will not adversely impact the ability to achieve and maintain safe shutdown in accordance with the existing license conditions for the units.

In Attachment 5, Section VII.6.A.i, on page VII-6, the licensee states that the fire protection water is utilized to supply the SFP and as cooling to the centrifugal charging pumps. The NRC staff questioned whether there are any other uses of fire water pumps and water for non-fire protection uses. The NRC staff also questioned whether the non-fire suppression use of fire protection water will impact the need to meet the fire protection system design demands.

In its response dated November 1, 2011, the licensee stated that there is no design basis accident or transient (other than fire) that credits the use of the FP system at Braidwood or Byron. However, the licensee stated that there are situations beyond the design basis in

which Braidwood or Byron would use the FP system as an alternate water source in EOPs, and other procedures for situations in which the design basis sources of water are unavailable. The licensee identified the following four provisions for non-fire suppression use of the FP system: (1) FP water as a backup source of make-up water for the SFP, (2) FP water as an alternate cooling source to the centrifugal charging pumps (using temporary hoses) if the design basis sources are not available, (3a Braidwood only) FP water as a backup source to supply emergency cooling water to station air compressors in the event of loss of non-essential service water, (3b Byron only) FP water as a backup to supply alternate cooling water to the emergency diesel generators (EDG) in the unlikely event that essential service water is not available, and (4) FP water is credited in certain security event scenarios. Further, the licensee stated that the power uprate has no impact on the use of the FP system in these situations.

The licensee's response satisfactorily addresses the NRC staff concerns and based on the licensee's analysis concluded that all the above non-fire suppression uses of fire protection water are beyond design basis and not affected by the proposed uprate.

3.5.2.3 Conclusion

Based upon its review described above, the NRC staff determined that the proposed MUR PU will not have a significant impact on the FP program or post-fire safe-shutdown capability and, therefore, finds the proposed amendment acceptable.

3.5.3 Human Factors

The scope of this review included licensee-identified changes to operator actions, human-system interfaces, procedures, and training needed for the proposed MUR PU and for consistency with the assumptions and results of the revised SGTR and MTO analyses.

3.5.3.1 Regulatory Evaluation

The NRC staff has developed a standard set of questions for human factors reviews of MURs (RIS 2002-03, Attachment 1, Section VII, Items 1 through 4), which were used for this review.

Appendix A to 10 CFR 50, GDC 19, "Control room," states that a control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in a safe condition under accident conditions, including loss-of-coolant accidents. Equipment at appropriate locations outside the control room shall be provided: (1) with a design capability for prompt hot shutdown of the reactor, including necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown, and (2) with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

Section 50.120, "Training and qualification of nuclear power plant personnel" to 10 CFR requires that the licensee establish, implement, and maintain a training program.

Chapter 13.2.1, "Reactor Operator Requalification Program; Reactor Operator Training" to NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition" (SRP), is used to determine that the training provided, or to be provided, for reactor operators and senior reactor operators will be adequate to provide

assurance that all reactor operator qualification requirement items will be met at the time needed.

Chapter 13.5.2.1, "Operating and Emergency Operating Procedures" to NUREG-0800 is intended to provide the criteria used to describe the operating procedures that will be used by the operating organization (plant staff) to ensure that routine operating, off-normal, and emergency activities are conducted in a safe manner.

Chapter 13 of the SRP guidance is supplemented by information in the following NUREGs:

- NUREG-0700, "Human-System Interface Design Review Guidelines" Revision 2;
- NUREG-0711, "Human Factors Engineering Program Review Model," Revision 2; and,
- NUREG-1764, "Guidance for the Review of Changes to Human Actions."

Chapter 18 of the SRP provides criteria for reviewing the process by which training programs are developed.

Generic Letter (GL) 82-33, "Supplement 1 to NUREG-0737 - Requirements for Emergency Response Capability" provides additional clarification regarding Safety Parameter Display Systems, Detailed Control Room Design Reviews, and RG1.97 (Revision 2) - Application to Emergency Response Facilities, Upgrade of emergency Operating Procedures, Emergency Response Facilities, and Meteorological Data.

Regulatory Guide 1.97 describes a method that the NRC staff considers acceptable for use in complying with the agency's regulations with respect to satisfying criteria for accident monitoring instrumentation in nuclear power plants.

Information Notice 97-78, "Crediting Operator Actions in Place of Automatic Actions and Modifications of Operator Actions, Including Response Times."

Regulatory Issue Summary (RIS) 2007-21, Revision 1, "Adherence to Licensed Power Limits," addresses a method for ensuring adherence to their maximum thermal power limit

3.5.3.2 Technical Evaluation

The following subsections include the NRC's technical evaluation of the licensee's response to the questions in RIS 2002-03, Attachment 1, Section VII, Items 1 through 4, as well as the licensee's compliance with the other regulatory documents listed in Section 3.3.3.1, above. The NRC staff's human factors review addresses whether the licensee has adequately considered the effects of the proposed licensed power, and the revised SGTR and MTO analyses on programs, procedures, training, and plant design features related to operator performance during normal and accident conditions. The NRC human factors evaluation is conducted to confirm that the licensee has analyzed the effects of the proposed changes and properly concluded that operator performance will not be adversely affected as a result of system and procedure changes made to implement the proposed licensed power.

Operator Actions (RIS 2002-03, Attachment 1, Section VII.1)

In the submittal, the licensee stated that existing operator actions, with the exception of operator response times to mitigate the SGTR, are not affected by the MUR PU and no new

manual actions were created. The licensee reviewed the following safety analyses for potential impact: (1) Appendix R, 10 CFR 50; (2) boron dilution; (3) small-break LOCA; (4) Radioactive steam release from a subsystem or component; (5) large-break LOCA; (6) MSLB; (7) main FW break; (8) SGTR; and (9) FHA. The licensee also evaluated operator response times associated with SGTR and MTO scenarios.

Attachment 1, "Evaluation of Proposed Changes," to the June 23, 2011, submittal, describes one modification being installed to support the SGTR and MTO single- failure assumptions which is a manual operator action to locally isolate a manual isolation valve. This manual action is not replacing an automatic function but is simply an equivalent manual action for locally isolating high head safety injection flow into the RCS. The licensee states that this manual action is not time sensitive and that procedure changes will be made to dispatch an operator to the valve location upon identification of a SGTR accident, well in advance of potential need for manual valve isolation. Attachment 5a of the submittal discusses the SGTR and MTO in more detail and includes a table with operator action times demonstrated during SGTR demonstration runs on the Braidwood simulator. Because the manual action is not time sensitive, the NRC staff finds that the licensee's statement is reasonable in Section I.1. A of their submittal that the operator action times assumed in the analysis are conservative relative to actual operator performance.

Based on the licensee's statements in their submittal relating to any impacts of the proposed licensed power on operator actions, the NRC staff concludes that the proposed licensed power will not adversely impact operator actions or their response times. The NRC staff further finds that the statements provided by the licensee do not adversely affect defense in depth or safety margins and meet the relevant regulatory criteria listed in Section 3.5.3.1, above.

Emergency Operating Procedures (EOP) and Abnormal Operating Procedures (AOP)
(RIS 2002-03, Attachment 1, Section VII.2.A.)

In its June 23, 2011, submittal, the licensee stated that the EOP and AOP were reviewed to determine any proposed licensed power impact. The licensee stated that no changes are required to operator mitigation actions as a result of the MUR PU with the exception of the operator response times noted for mitigation of the SGTR which were discussed above and found to be acceptable because they were not time sensitive. The NRC staff concludes that the neither the proposed licensed power nor the SGTR analysis revision present any adverse impacts to the EOPs and AOPs. This conclusion is based upon the following licensee statement: (1) EOP setpoints and associated operator procedures will be revised to reflect a total core power that bounds the MUR PU, (2) procedure changes and any associated operator training will be completed during the PU implementation and prior to operation above 3586.6 MWt, and (3) SGTR operator action timing assumptions have been validated by demonstration runs on the Braidwood simulator as part of the licensed operator qualification and requalification program at Braidwood and Byron. Implementation of the PU license amendment will include developing the necessary procedures and documents required for maintenance and calibration of the LEFM system. Plant maintenance and calibration procedures will be revised to incorporate maintenance and calibration requirements. The procedure changes will be addressed using standard Exelon procedure updating processes prior to increasing power above 3586.6 MWt. The NRC staff concludes that the licensee's revision of the maintenance and calibration procedures prior to raising power above 3586.6 MWt (CLP) is acceptable.

The NRC staff finds that the statements provided by the licensee meet the relevant regulatory criteria listed in Section 3.5.3.1, above.

Changes to Control Room Controls, Displays, and Alarms
(RIS 2002-03, Attachment 1, Section VII.2.B)

In its submittal dated June 23, 2011, the licensee described the evaluations performed to identify CR changes in support of the proposed MUR, SGTR, and MTO analysis changes. The licensee identified that changes are required to certain nonsafety-related systems, including minor equipment changes, replacements, and setpoint or alarm point changes. These changes will be made in accordance with the requirements of 10 CFR 50.59, validated and verified in accordance with the Exelon "Configuration Change Control for Permanent Physical Plant Changes," process, and will be implemented prior to rising above the current licensed thermal power of 3586.6 MWt. This control process change will initiate any necessary changes to the simulator hardware, procedures, and operator training. The proposed licensed power modification will implement the changes that are required to certain non-safety related systems, including CR displays and alarms.

The NRC staff has reviewed the licensee's evaluation of the proposed changes to the CR and concludes that the proposed changes are not significant and do not present any adverse effects to the operators' functions in the CR. The licensee stated that all modifications to the CR and simulators and providing training on these changes will be completed prior to rising above the current licensed thermal power of 3586.6 MWt. The NRC staff finds that the statements provided by the licensee do not adversely affect defense in depth or safety margins and meet the relevant regulatory guidance listed in Section 3.5.3.1, above.

Control Room (CR) Plant Reference Simulator RIS 2002-03, Attachment 1, Section VII.2.C)

In its submittal, the licensee stated that the proposed licensed power is being implemented under the plant modification process administrative controls. As part of this process, simulator modifications will be implemented. The submittal also included statements that these modifications will be evaluated, implemented and tested per Braidwood and Byron plant procedures. Simulator fidelity will be revalidated per Byron and Braidwood-approved procedures. The licensee stated that necessary simulator modifications will be completed in time to support operator training associated with this uprate.

The NRC staff has reviewed the licensee's evaluation of proposed changes to the plant simulator related to the proposed licensed power. The licensee stated that all modifications to the plant simulator and incorporation of these changes into the operator training program will be completed prior to increasing power above 3586.6. The NRC staff finds that the statements provided by the licensee do not adversely affect defense in depth or safety margins and meet the relevant regulatory guidance listed in Section 3.5.3.1, above. The NRC staff further concludes that completing the modifications to the plant simulator and incorporation of the changes into the operator training program prior to increasing power above 3586.6 is acceptable.

Operator Training (RIS 2002-03, Attachment 1, Section VII.2.D)

The licensee stated in its June 23, 2011, submittal, that the operator training program requires revision as a result of the proposed licensed power and SGTR MTO analysis. The

licensee further stated in its submittal that operator training will be developed and the operations staff will be trained on the plant modifications, TSs, and procedure changes will be implemented per controlled plant procedures prior to operating above the current licensed thermal power of 3586.6 MWt.

The NRC staff has reviewed the licensee's evaluation of the proposed changes to the operator training program. The staff concludes that the proposed changes are appropriate and do not present any adverse effects to the operators' functions in the CR. The licensee stated that training will be provided on these changes prior to the proposed licensed power implementation. The NRC staff finds that the statements provided by the licensee do not adversely affect defense in depth or safety margins and meet the relevant regulatory guidance listed in Section 3.5.3.1, above. The NRC staff further concludes that completing the training prior to increasing power above 3586.6 is acceptable.

Modifications (RIS 2002-03, Attachment 1, Section VII.3)

The licensee stated in its submittal that the LEFM system for Braidwood and Byron, Units 1 and 2, will be installed prior to uprate implementation and that other nonsafety-related modifications for the proposed licensed power, including minor equipment changes, replacements, and setpoint or alarm point changes will be implemented prior to uprate implementation. In addition, modifications to support SGTR MTO analysis single failure considerations will be implemented prior to the uprate. Further, the licensee has stated that plant maintenance and calibration procedures will be revised, the plant simulator will be modified for the proposed licensed power conditions, and the changes will be validated in accordance with plant configuration control processes. Maintenance personnel will be qualified on LEFM and operator training will be completed. The licensee stated that all of the above actions will be completed prior to rising above the current licensed thermal power of 3586.6 MWt. The NRC staff finds that the statements provided by the licensee do not adversely affect defense in depth or safety margins and meet the relevant regulatory guidance listed in Section 3.5.3.1, above. The NRC staff further concludes that completing the modifications prior to increasing power above 3586.6 is acceptable.

Temporary Operation above Licensed Full Power Level (RIS 2002-03, Attachment 1, Section VII.4)

Braidwood and Byron General Operating Procedures (BGP 100-3), "Power Ascension," and BwGP 100-3, "Power Ascension 5% to 100%," proactively direct operator actions to maintain licensed power levels at or below 100 percent. The licensee's November 1, 2011, supplement, references the Nuclear Energy Institute (NEI) guidance endorsed in RIS 2007-21, Revision 1, by the NRC for adhering to the licensed thermal power limit. While operating at rated power, the goal of the operator is to achieve a one-hour average less than or equal to maximum allowed (i.e., the maximum thermal power as stated in the plant operating license). The following guidance is in the procedures:

- During full steady state power operation, operators are directed to monitor reactor power using the 10-minute Calorimetric:
    - In the event the 10-minute calorimetric exceeds 100 percent, during steady state operation, operators are directed to initiate actions within 15 minutes to restore the 10-minute calorimetric to less than 100 percent.

  - While temporary power excursions greater than 100 percent power may occur due to reactor coolant system temperature changes, secondary plant efficiency changes, etc., and are allowable, operators are directed that the 1-hour calorimetric should not be allowed to exceed 100 percent.

- For unplanned activities that are expected to cause an increase in reactor power such that the 10-minute calorimetric will be greater than 100 percent, operators are directed to initiate actions such that the 10-minute calorimetric does not exceed 100 percent.

- For unplanned activities that cause the 10-minute calorimetric to exceed 100 percent operators are directed not to wait for the transient to subside, but to take prompt corrective action to limit the time that the 10-minute calorimetric exceeds 100 percent.

The NRC staff finds that the licensee's procedures direct the operator to take action if there is any deviation above the licensed power levels. The NRC staff concludes that this meets the RIS 2002-03 guidance to limit the allowed deviation to a value corresponding to the uncertainty in power level credited by the uprate application.

3.5.3.3 Regulatory Commitments

The licensee provided the following regulatory commitments, applicable to the above discussion, in Attachment 4 of the submittal:

Plant maintenance and calibration procedures will be revised to address Cameron's maintenance and calibration requirements prior to increasing power above 3586.6 MWt.

Each station's simulator will be modified for the uprated conditions and the changes will be validated in accordance with plant configuration control processes prior to increasing power above 3586.6 MWt.

Maintenance personnel will be qualified on LEFM system prior to work on the system.

Operator training will be completed on the LEFM modification and uprated power operations prior to increasing power above 3586.6 MWt.

The NRC staff concludes that the licensee's implementation of the above commitments as stated is acceptable. The NRC staff further concludes that revising the plant maintenance and calibration procedures in accordance with 10 CFR Part 50.59 is acceptable because 10 CFR Part 50.59 establishes criteria to determine whether or not NRC approval is required. The NRC staff also concludes that simulator modifications and operator training is adequately controlled by the licensee's design control program required by 10 CFR Part 50, Appendix B. The NRC staff concludes that the licensee's implementation of maintenance personnel qualification is adequately controlled by TS 5.3.1.

3.5.3.4 Conclusion

Based on its review as described above, the NRC staff finds that the licensee has adequately considered the impact of the proposed LAR on operator actions, EOPs and AOPs, CR components, plant simulator, and operator training programs. As a result, the

NRC concludes that the licensee's activities meet the regulatory requirements and guidance identified in Section 3.3.3.1, above.

3.6 Changes to Technical Specifications, Protection and Emergency Systems Settings (RIS 2002-03, Attachment 1, Section VIII)

Approval of the measurement uncertainty recapture uprate allows the licensee to implement the following changes to the license and TSs:

- Item 2.C(1) "Maximum Power Level," of the operating licenses will be increased to 3645 megawatts thermal (entire SE);
- TS Section 1.1, will be revised to change the definition of RATED THERMAL POWER (RTP) to increase the value of RTP from 3586.6 to 3645 MWt (entire SE);
- TS Section 2.1.1.1 will be revised to add the ≥ 1.19 limit for the ABB-NV DNB correlation for a thimble cell and a typical cell (Section 3.2.2);
- TS 2.1.1.2 will be revised to delete the ≥ 1.30 for the W-3 DNB correlation and add the ≥ 1.13 for the ABB-NV correlation and the ≥ 1.18 for the WLOP DNB correlation (Section 3.2.2);
- TS LCO 3.4.1.c will be revised to change the RCS flow rate from ≥ 380,900 gpm to ≥ 386,000 gpm (Section 3.2.2);
- SR 3.4.1.3 will be revised to verify that the RCS flow rate is ≥ 386,000 gpm (Section 3.2.2);
- SR 3.4.1.4 will be revised to verify that the RCS flow rate is ≥ 386,000 gpm (Section 3.2.2);
- TS 5.6.5, "Core Operating Limits Report (COLR)" will be revised to add reference WCAP-14565-P-A (Section 3.2.2).

The acceptability of each of these changes is discussed in the assessment above and is based on the NRC staff determination that the changes are consistent with the safety analysis performed in accordance with NRC approved methodologies. The NRC staff therefore finds the proposed changes to the license and TSs acceptable.

3.7 Technical Conclusion

The NRC staff confirmed that the licensee provided all information requested by RIS-2002-03. As the methodology used to quantify the uncertainty in the reactor thermal power uncertainty calculation is consistent with the limitations and conditions in the NRC approved topical reports, the NRC finds that the licensee may apply a reduced margin for ECCS evaluation consistent with Appendix K of 10 CFR 50. Therefore, the request to uprate the current licensed power from 3586.6 to 3645 MWt and the associated changes to the TSs for Braidwood, Units 1 and 2, and Byron Unit Nos. 1 and 2 are acceptable.

4.0 REGULATORY COMMITMENTS

In Attachment 4 to its June 23, 2011, submittal, the licensee provided a list of regulatory commitments. A requirement is included in Section 3 of the NRC license amendment associated with this SE, to ensure these Regulatory Commitments are implemented.

Commitment	Implementation	Commitment Type	
		One-Time Action (Yes/No)	On-Going Commitment (Yes/No)
Limitations regarding operation with an inoperable LEFM system will be included in the TRM.	Prior to increasing power above 3586.6 MWt	No	Yes
The LEFM system for each unit at Byron and Braidwood Stations will be installed prior to uprate implementation	Prior to increasing power above 3586.6 MWt	Yes	No
Plant maintenance and calibration procedures will be revised to address Cameron's maintenance and calibration requirements.	Prior to increasing power above 3586.6 MWt	No	Yes
For Byron Station Units 1 and 2; and Braidwood Station Units 1 and 2; final acceptance of the unit-specific uncertainty analyses will occur after the completion of the commissioning process.	Prior to increasing power above 3586.6 MWt	Yes	No
Non-safety related modifications for the power uprate, including switchyard modifications, will be implemented.	Prior to increasing power above 3586.6 MWt	Yes	No
Modifications to support SGTR MTO analysis single failure considerations will be implemented.	Prior to increasing power above 3586.6 MWt	Yes	No
Each station's simulator will be modified for the uprated conditions and the changes will be validated in accordance with plant configuration control processes.	Prior to increasing power above 3586.6 MWt	Yes	No
Maintenance personnel will be qualified on LEFM system.	Prior to work on the system	No	Yes
Operator training will be completed on the LEFM modification and uprated power operations.	Prior to increasing power above 3586.6 MWt	No	Yes

5.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Illinois State official was notified of the proposed issuance of the amendment. The State official had no comments.

6.0 ENVIRONMENTAL CONSIDERATION

The amendments change a requirement with respect to the installation or use of facility components located within the restricted area as defined in 10 CFR Part 20. The NRC staff has determined that the amendments involve no significant increase in the amounts and no significant change in the types of any effluents that may be released offsite and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendments involve no significant hazards consideration, and there has been no public comment on such finding (77 FR 28630). Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

7.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) there is reasonable assurance that such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

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