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10 CFR 50.90

U. S. Nuclear Regulatory Commission
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Monticello Nuclear Generating Plant
Docket 50-263
Renewed Facility Operating License
License No. DPR-22

Monticello Extended Power Uprate: Response to NRC Containment and Ventilation Review Branch (SCVB) Request for Additional Information (RAI) dated March 19, 2009, and March 26, 2009 (TAC No. MD9990)

References:
1. NSPM letter to NRC, License Amendment Request: Extended Power Uprate (L-MT-08-052) dated November 5, 2008, Accession No. ML083230111
2. Email P. Tam (NRC) to G. Salamon, K. Pointer (NSPM) dated March 19, 2009, Monticello - Draft RAI from Containment and Ventilation Branch re: proposed EPU amendment (TAC MD9990), Accession No. ML090880003
3. Email K. Feintuch (NRC) to K. Pointer (NSPM) dated March 26, 2009, re: Monticello EPU - Additional RAI items pertaining to Containment (TAC No. MD9990)

Pursuant to 10 CFR 50.90, the Northern States Power Company, a Minnesota corporation (NSPM), requested in Reference 1 an amendment to the Monticello Nuclear Generating Plant (MNGP) Renewed Operating License (OL) and Technical Specifications to increase the maximum authorized power level from 1775 megawatts thermal (MWt) to 2004 MWt.

On March 19, 2009, the U.S. Nuclear Regulatory Commission (NRC) Containment and Ventilation Review Branch provided the requests for additional information (RAI) contained in Reference 2. On March 26, 2009, the SCVB provided additional RAIs shown in Reference 3. Enclosure 1 provides the NSPM response to SCVB RAIs in References 2 and 3.

In accordance with 10 CFR 50.91, a copy of this letter is being provided to the designated Minnesota Official.

Summary of Commitments

NSPM commits to evaluating the changes in condensate and feed pump area heat load to confirm temperatures remain within design limits prior to RFO25. If necessary, modifications to the HVAC system for this area will be implemented to maintain these areas within the design limits.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on July 13, 2009.

Timothy J. O'Connor
Site Vice President, Monticello Nuclear Generating Plant
Northern States Power Company - Minnesota

Enclosure

cc: Administrator, Region III, USNRC
Project Manager, Monticello, USNRC
Resident Inspector, Monticello, USNRC
Minnesota Department of Commerce

ENCLOSURE 1

NSPM RESPONSE TO SCVB RAIs DATED MARCH 19, 2009 and MARCH 26, 2009

NRC RAI No. 1

Refer to Enclosure 5, "Safety Analysis Report for Monticello Constant Pressure Power Uprate" of letter dated November 5, 2008, (PUSAR). Information regarding decay heat model, 2σ uncertainty, guidance of GE SIL 636 Rev 1, and crediting of passive heat sinks in drywell (DW), wetwell (WW) airspace and suppression pool (SP) is not stated for various analysis except for long-term suppression pool temperature response as indicated below. Please provide the information as per the following table for the current and extended power uprate (EPU) conditions. Provide justification if uncertainty and guidance of SIL 636 Revision 1 was not included.

NSPM Response

Analysis		Decay Heat Model[1]	2σ Uncertainty Included?	SIL 636 Rev 1 Included?	Passive Containment Heat Sinks Included?
Short-Term Drywell Pressure	Current[2]	ANS 5-1971	N/A[3]	N/A[3]	No
	EPU	ANS 5-1971	N/A[3]	N/A[3]	No
Long-Term RSLB SP Temperature	Current[4]	ANS 5.1-1979	Yes	Yes	Yes
	EPU	ANS 5.1-1979	Yes	Yes	Yes
Long-Term 0.5 sq-ft MSLB Drywell Temperature	Current[5]	ANS 5.1-1979	No[6]	No	Yes
	EPU	ANS 5.1-1979	Yes	Yes	Yes
DBA LOCA for NPSH	Current[4]	ANS 5.1-1979	Yes	Yes	Yes
	EPU	ANS 5.1-1979	Yes	Yes	Yes
Appendix R Fire	Current[7]	ANS 5.1-1979	No	No	No
	EPU	ANS 5.1-1979	No	Yes	Yes
Station Blackout	Current[7]	ANS 5.1-1979	No	No	No
	EPU	ANS 5.1-1979	No	Yes	Yes
ATWS	Current[8]	May-Witt	N/A[9]	N/A[9]	No
	EPU	May-Witt	N/A[9]	N/A[9]	No
Small Steam Line Break	Current[10]	ANS 5.1-1979	Yes	Yes	Yes
	EPU	ANS 5.1-1979	Yes	Yes	Yes

Footnotes:

1. Decay heat models include May-Witt, ANSI/ANS 5-1971, and ANSI/ANS 5.1-1979.
2. MNGP USAR Table 5.2-4, from Table 3 of GE-NE-T2300731-00-01-01, Revision 1
3. ANSI/ANS 5-1971 + 20 percent is used for the short-term drywell pressure analysis. SIL-636 is not applicable to analyses that assume ANSI/ANS 5-1971.
4. MNGP USAR Table 5.2-4, from 4.4.2 of GE-NE-0000-0002-8817-01-R2
5. MNGP USAR Table 5.2-8, from Table D-1 of T2300731-00-01-01, Revision 1
6. The current DBA LOCA analysis was performed at 102 percent of 1880 MW_{th} with nominal ANS 5.1-1979 decay heat. This bounds 2σ at 1775 MW_t.
7. NEDC-32546P, Revision 1
8. The CLTP value stated in the EPU PUSAR (187°F) is not based on any pre-EPU analysis, but is an EPU analysis at CLTP.
9. The May-Witt decay heat model does not require an uncertainty adder and SIL-363 does not apply.
10. Reported on page 2-2 of GE-NE-0000-0002-8817-01.

NRC RAI No. 2

Refer to PUSAR, for the short term LOCA analysis which resulted in drywell peak pressure and temperature listed in Table 2.6-1, please confirm that the assumption for FW coastdown was the same as in current analysis or more conservative. If FW coastdown used in analysis was less conservative, please justify.

NSPM Response

Both the current and EPU short-term LOCA analyses include consideration for feedwater coastdown. The current analysis assumed a 4-second coastdown, which is typical for LAMB break flow analyses, and is consistent with the ECCS-LOCA evaluation for ECCS performance. The EPU short-term LOCA analysis assumes a 5-second coastdown, which is more conservative for the short-term LOCA peak drywell pressure analysis with LAMB blowdown.

NRC RAI No. 3

Refer to PUSAR, for the short term LOCA analysis which resulted in drywell peak pressure and temperature listed in Table 2.6-1, please confirm that the assumption for MSIV closure time was the same as in current analysis or more conservative. If MSIV closure time used in analysis was less conservative, please justify.

NSPM Response

The MSIV closure time used in the EPU short-term LOCA analysis is more conservative than the MSIV closure time used in the current short-term LOCA analysis.

The current short-term LOCA analysis for peak drywell pressure uses the LAMB vessel model for calculating break flow, and assumes a MSIV closure time of 5 seconds.

The EPU short-term LOCA analysis for peak drywell pressure also uses the LAMB vessel model for calculating break flow, but assumes a MSIV closure time of 3 seconds. The faster closure time results in maintaining reactor vessel pressure higher longer, with a resulting higher break flow calculation, which results in a more conservative estimate for peak drywell pressure. Therefore, the use of a different MSIV closure time than that of the current analysis is considered justified.

NRC RAI No. 4

PUSAR, Section 2.6.3.1.1 does not describe the type of LOCA break (for example steam line break) that resulted in the peak drywell gas temperature of 338°F. As per the USAR Revision 24, Table 5.2-8, the peak drywell gas temperature 335°F is based on a small steam line break LOCA. Please provide the break area in the EPU and the current analysis of record. Please describe the analysis method, inputs, assumptions, and differences with the current analysis in the USAR. In the EPU analysis, for how much transient time does the drywell gas temperature exceed the EPU drywell wall temperature of 278°F given in Table 2.6-1?

NSPM Response

As with the current analysis for peak drywell gas temperature (335°F), the EPU analysis for peak drywell gas temperature (338°F) is also based on a small steam line break LOCA. In this specific instance, the term "small steam line break" is used to characterize a range of small and intermediate sized steam line breaks used in analyses to evaluate the drywell gas temperature response.

The current analysis and the EPU analysis for environmental qualification of equipment in the drywell includes evaluation of the drywell gas temperature response for three steam break sizes, one at 0.50 sq-ft, again at 0.10 sq-ft, and finally at 0.01 sq-ft. The peak drywell gas temperature is the bounding temperature from these three break sizes. For the current analysis the bounding temperature was obtained from the 0.5 sq-ft analysis. For the MNGP EPU, the bounding temperature (338°F) was also obtained from the 0.5 sq-ft break size case.

The EPU drywell gas temperature analysis for environmental qualification uses the same methodology as was used in the current analysis for environmental qualification. The GEH SHEX computer code is used to evaluate containment response to the various assumed steam line breaks. Analysis assumptions are used which maximize the drywell gas temperature response. The reactor is assumed to be initially operating at 102 percent rated reactor power and at rated steam dome pressure and rated core flow. Initial containment conditions include 3.0 psig in the drywell and wetwell, 135°F and 20 percent relative humidity in the drywell airspace, and 90°F and 100 percent relative humidity in the wetwell airspace. Initial suppression pool level is assumed to be at the Technical Specification low water level (LWL). A loss of offsite power (LOOP) is assumed to occur coincident with the small steam line break. An additional worst-case single failure of one onsite emergency diesel generator (EDG) is also assumed. Since the failure of the onsite EDG may be due to the failure of a single DC power supply, which also could render the high-pressure coolant injection (HPCI) system inoperable, the HPCI system is also assumed to fail. No credit is assumed for operation of either the reactor core isolation cooling (RCIC) system or the control rod drive (CRD) system flow to the reactor vessel. Break flow rates are calculated based on the Homogeneous

Equilibrium Model (HEM). The drywell wall is treated as a passive heat sink. Heat transfer to the wall assumes condensing heat transfer (1x Uchida) until the wall temperature exceeds the saturation temperature for the drywell, and natural convective heat transfer thereafter. A single core spray (CS) pump and two low-pressure coolant injection (LPCI) pumps respond as designed to the decrease in reactor vessel water level. In accordance with plant emergency procedures, operators isolate the two LPCI pumps and initiate containment cooling in wetwell spray cooling mode. When drywell gas temperature reaches 281°F, operators initiate drywell spray cooling mode as well. When suppression pool temperature reaches 120°F, operators initiate a controlled vessel cooldown at 100°F/hr until reactor pressure reaches 65 psia, where it is maintained for the remainder of the event. Operator action is conservatively not credited for the first 10 minutes following initiation of the event.

For the MNGP EPU analysis for drywell environmental qualification, the 0.5.sq-ft steam line break evaluation results in the longest time for which the drywell gas temperature exceeds the peak reported drywell wall temperature of 278°F. The SHEX analysis indicates drywell gas temperature first exceeds 278°F at 5.4 seconds. In accordance with the conservative assumption that operator action is not credited for the first 10 minutes of the event, drywell sprays are initiated at 10 minutes as directed by plant emergency procedures. Thus the drywell gas temperature exceeds the peak reported drywell wall temperature of 278°F for approximately 10 minutes. However, during this time period, the drywell pressure is no higher than 48 psia, which has a corresponding saturation temperature of approximately 278°F. Therefore, the drywell wall temperature cannot exceed the saturation temperature of 278°F due to the condensing heat transfer.

NRC RAI No. 5

PUSAR, Section 2.6.3.1.1, third sentence, please explain the basis of the 35-psig drywell pressure?

NSPM Response

The 35-psig drywell pressure was generically developed for use in Mark I containments and corresponds to a calculated maximum post blowdown drywell pressure assuming all non-condensable gases in the containment are stored in the wetwell airspace and the wetwell airspace is saturated (100 percent relative humidity) and in thermal equilibrium with the suppression pool with a post blowdown temperature of 140°F. This pressure is also the basis for the 281°F drywell design temperature used for early Mark I plants (saturation temperature at 35 psig).

NRC RAI No. 6

PUSAR, Section 2.6.1.1.1 a) "Bulk Pool Temperature" describes a different approach for calculating long term suppression pool temperature response using the RHR heat exchanger K value. In this approach the minimum K-value is 147 Btu/sec °F and is assumed to increase with increase in suppression pool temperature. This approach is less conservative than the method used in USAR which assumes a constant value of K. Please explain why a different approach is used for EPU analysis and how is assurance provided that the heat exchangers will not have a K value less than 147 Btu/sec °F or less than values in the table in Section 2.6.1.1.1 of the PUSAR?

NSPM Response

PUSAR Section 2.6.1.1.1(a) states:

> . . . the design basis analysis, which assumes containment cooling using the suppression pool cooling mode of RHR, uses a slightly modified RHR containment cooling capability from that used in the USAR. For this analysis, a heat exchanger K-value was used that improves with the temperature of the hot inlet liquid as shown in the table below. Below 110°F and above 195°F the K-value is assumed constant, and varies linearly with inlet temperature between the values shown in the table.

Hot Inlet Temperature (°F)	Heat Exchanger K-Value (BTU/sec°F) (based on 90°F service water)	
	1 RHR / 1 RHRSW	2 RHR / 2 RHRSW
≤ 110	146.5	190.8
125	147.6	
160	149.7	
165		194.5
≥195	151.6	196.1

> . . .
> Additionally, there is no difference between the methodology used to calculate the varying K values and the constant K values. In either case the values for K have been conservatively derived using vendor design assumptions including fouling factors. Confirmation of the ability of the RHR heat exchangers to support the K values used is verified by performance of a heat exchanger efficiency test.

The design point for the RHR heat exchanger has a 125°F shell side (RHR water) inlet temperature and 85°F tube side (river water) inlet temperature. The overall heat transfer coefficient expressed as K for this point is 147 BTU/sec-°F. Temperature dependent K values can be used to more accurately model the heat exchanger performance as water temperature changes during the event. The K values provided in PUSAR Section 2.6.1.1.1.a) show the expected variation in K values as temperature changes over the range of concern for accidents. This more accurately predicts heat exchanger capacity.

Verification of acceptable margin to the K value used in the analysis is provided by the annual performance of the "RHR (Residual Heat Removal) Heat Exchanger Efficiency Test", surveillance test 1136. The test acceptance criteria are normalized based on the fluid process temperatures to define a K value equivalent to a 147 BTU/sec-°F for the design point of the RHR heat exchanger, i.e. 125°F shell side (RHR water) inlet temperature and 85°F tube side (river water) inlet temperature. The results of this test are trended and provide an indication whether any deterioration in heat removal capabilities has occurred with time. Based on these trends the RHR heat exchangers are cleaned to maintain the K value at or above the design value.

The most recent RHR heat exchanger performance tests show the margin above the acceptance criteria for K value at the design point as reflected below:

	K Value Margin Above Acceptance Criteria for #11 RHR Heat Exchanger (BTU/sec-°F)	K Value Margin Above Acceptance Criteria for #12 RHR Heat Exchanger (BTU/sec-°F)
December 12, 2007	18.7	15.9
February 10, 2009	14.9	12.5

NRC RAI No. 7

PUSAR Sections 2.6.1.1.1 and 2.6.5, why is K-value for the RHR heat exchanger assumed to be constant at 147 Btu/sec°F in the DBA LOCA NPSH analysis (Section 2.6.5) as compared to K as varying with hot side inlet temperature in the long term suppression pool temperature response analysis (Section 2.6.1.1.1)? Please verify if constant K-value of 147 Btu/sec°F was used in the Appendix R Fire, SBO, ATWS and SBA analysis for NPSH and is consistent with the current analysis in USAR.

NSPM Response

It should be noted that EPU analyses were specifically developed to evaluate NPSH for the special events (SBO, and ATWS) and the SBA, and represent a new set of analyses, which are not currently documented in the MNGP USAR. Comparisons made between the EPU analyses and current analyses, with respect to the RHR heat exchanger K application, are made based on comparisons to the current suppression pool temperature analyses of record for these events.

The version of SHEX used for the MNGP EPU long-term containment response includes the capability to vary the RHR heat exchanger K-value with heat exchanger hot inlet temperature. Use of this capability provides a more accurate prediction of the suppression pool temperature response and a better indication of available margins. This additional capability in SHEX, however, is not available for the containment spray mode. The DBA LOCA NPSH analysis conservatively assumes containment cooling via the containment spray mode, and therefore could not use the variable K-value. MNGP EPU PUSAR Table 2.6-1 shows two values for peak bulk suppression pool temperature. The first value, 203°F, reflects the peak temperature assuming use of the direct suppression pool cooling mode of RHR. The second value, 207°F, reflects the peak temperature assuming use of the containment spray cooling mode of RHR. Since the hotter peak pool temperature results in a more limiting margin for NPSH evaluation, use of the constant K-value is conservative. Use of the variable K-value is a change from the current analysis in the MNGP USAR.

For the NPSH analysis for special events (Appendix R Fire, SBO, and ATWS), drywell spray is not assumed unless drywell temperature exceeds 281°F when plant emergency procedures direct initiation of drywell spray.

For the Appendix R Fire analysis for NPSH, since drywell temperature never exceeds 281°F, the scenario assumes containment cooling is achieved using the direct suppression pool cooling mode of RHR and the one-pump variable K-value was used to evaluate the containment response. Use of the variable K-value is a change from the current Appendix R suppression pool temperature analysis of record.

For the SBO analysis for NPSH, containment cooling is not available for the entire coping period of the event, and therefore the SBO containment response assumes there is no containment cooling for the coping period. This is not a change from the current SBO suppression pool temperature analysis of record.

For the PRFO/ATWS analysis for NPSH, since drywell temperature never exceeds 281°F, the scenario assumes containment cooling is achieved using the direct suppression pool cooling mode of RHR and the variable K-value was used to evaluate the containment response. The PRFO/ATWS scenario assumes all RHR pumps and heat exchangers are available and therefore the two-pump variable K-values are doubled for two loops of suppression pool cooling. There is no current plant-specific analysis for ATWS.

For the LOOP/ATWS analysis for NPSH, the drywell temperature exceeds 281°F just after 15 minutes, so containment cooling begins with suppression pool cooling at 10 minutes, and switching to drywell spray cooling when the drywell temperature exceeds 281°F. While in suppression pool cooling mode, a fixed K-value of 149.46 BTU/sec°F is used, which is evaluated from the one-pump variable K-value for a pool temperature of 156°F, the suppression pool temperature at 10 minutes. When the pool cooling mode is switched to drywell spray mode just after 15 minutes, a fixed K-value of 150.0 BTU/sec°F is used, which is evaluated from the one-pump variable K-value for a pool temperature of 165.5°F, the suppression pool temperature when drywell spray is initiated. Although a fixed K-value is used, the values used are based upon the variable K-value method. There is no current plant-specific analysis for ATWS.

For the SBA analysis for NPSH, containment spray cooling is initiated at 10 minutes. Although the version of SHEX used cannot directly use a variable K-value while in containment spray mode, an alternate method was used to simulate the one-pump variable K-value for evaluation of the containment response. Use of the variable K-value is a change from the current SBA suppression pool temperature analysis of record.

NRC RAI No. 8

PUSAR, Section 2.6.1.1.1, fourth paragraph, states the EPU analysis assumes thermal equilibrium for the first 30 second and subsequently heat and mass transfer between the wetwell airspace and the suppression is mechanistically modeled. Please justify why is it conservative for suppression pool long term temperature response analysis as opposed to assuming thermal equilibrium between the wetwell airspace and the suppression pool as assumed in the current licensing basis per USAR Revision 24, Table 5.2-7 item number 6.

NSPM Response

During the early blowdown period of a DBA LOCA event, agitation of the suppression pool surface due to pool swell and later due to steam condensation enhances mixing between the wetwell airspace and the suppression pool, which results in significant heat and mass transfer between the pool and the airspace such that thermal equilibrium adequately models the wetwell airspace and suppression pool response during this period of the event.

To model the higher expected mixing that occurs during this early blowdown period, it is assumed that, for the first 30 seconds, thermodynamic equilibrium conditions exist in the wetwell. After 30 seconds, it is assumed that pool surface agitation is reduced, resulting in reduced heat and mass transfer, and a mechanistic model for heat and mass transfer is used instead. The assumption of mechanistic heat and mass transfer results in less heat transfer and less mass transfer (by evaporation) from the suppression pool to the wetwell airspace. This results in a slight increase in the energy retained in the suppression pool, and consequently a (slightly) higher pool temperature. However, the effect of this modeling assumption on the suppression pool temperature is small due to the relatively small energy transferred to the wetwell airspace gas with either modeling assumption.

NRC RAI No. 9

PUSAR, Section 2.6.1.1.1, third paragraph states "Confirmation of the ability of the RHR heat exchanger to support the K value used is verified by performance of a heat exchanger efficiency test." Please verify if the testing is performed as per NRC Generic Letter (GL) 89-13.

NSPM Response

Testing of the Residual Heat Removal (RHR) heat exchangers is performed by the "RHR Heat Exchanger Efficiency Test", surveillance test 1136. This testing is performed as per NRC Generic Letter (GL) 89-13.

NRC RAI No. 10

PUSAR Section 2.6.5, under the heading "DBA LOCA", third paragraph states "The pump flow rates for the long-term case are 4000 gpm total RHR flow and 3035 gpm for CS pump "A" and 3029 gpm for CS pump "B"." Please verify if one or two CS loops (one pump per loop) are used for the DBA LOCA NPSH analysis and which pump is used?

NSPM Response

The evaluation of ECCS pump NPSH for the DBA LOCA was performed under calculation CA-07-038, Revision 0, "Determination of Containment Overpressure Required for Adequate NPSH for Low Pressure ECCS Pumps with Suction Strainer Debris Loading at EPU Conditions. This calculation was provided to the NRC in Reference 1.

This analysis included a number of different long-term cases to assure the limiting NPSH case was evaluated. Cases 2 and 5 used the 'B' CS pump with the 'B' RHR pump. Cases 3 and 6 used the 'A' CS pump with the 'C' RHR pump. Cases 8 and 10 used all CS pumps and RHR pumps.

Reference:

10-1: NSPM Letter L-MT-09-004 from Timothy O'Connor to USNRC, "Response to NRC Containment & Ventilation Branch Request for Additional Information (RAIs) dated December 18, 2008 (TAC No. MD9990)"

NRC RAI No. 11

Refer to PUSAR Section 2.6.5, under the heading "Small Steam Line Break Accident (SBA)". Please verify that the input parameters used were biased to maximize the suppression pool temperature and minimize the wetwell pressure or that their nominal values were used. Provide justification if nominal values of the input parameters were used in the analysis and the analysis is conservative.

NSPM Response

PUSAR Section 2.6.5, under the heading "Small Steam Line Break Accident (SBA)," discusses the net positive suction head (NPSH) evaluation for the RHR and ECCS pumps and includes discussion of the containment analysis of the SBA in support of the NPSH evaluation. Input parameters used for this SBA containment analysis to support NPSH evaluation were biased to maximize the suppression pool temperature and minimize the wetwell pressure.

NRC RAI No. 12

PUSAR Section 2.6.5, please define the various pump flows for RHR and CS pumps used in the DBA LOCA, Appendix R, SBO, ATWS, SBA analysis, i.e., whether these are pump runnout flow, rated flow or design flow. Please verify if these flows are consistent with the current analysis in the USAR and with operating procedures. If these are not the same, provide a tabulation of the EPU values, the current analysis values used for analyzing these events, and the operating procedure values and provide justification for the differences. How do these pump flows compare with flows used in the DBA LOCA analysis for long term suppression pool temperature response in PUSAR Section 2.6.1.1.1.

NSPM Response

PUSAR Section 2.6.5 includes a discussion of long-term suppression pool temperature response that applies to both design basis accident profiles done to maximize containment response and to those profiles done to minimize containment response for the evaluation of ECCS pump NPSH. DBA LOCA evaluations assume pump runout capabilities for the first 10 minutes of the event sequences. Other events such as SBO, ATWS and Appendix R have these pumps started by operator action at the design flow rates specified below. For DBA LOCA sequences it is assumed that at 10 minutes operator actions will establish containment heat removal and throttle pumps in service to maintain these pumps within NPSH limits as required by the Emergency Operating Procedures (EOPs).

In the first 600 seconds of the event flow rate assumptions vary between the DBA LOCA containment response and NPSH analysis. For this period of time operating procedures maximize injection to the reactor. The flow rates assumed by analysis are shown below:

Pump Flow <600 Seconds for Containment Analysis

	CLTP[1]	EPU[3]	NPSH[2]
RHR	1 pump – NA 2 pumps – 8000 gpm 4 pumps – 17,400 gpm	1 pump – 4320 gpm 2 pumps – 8641 gpm	'A' Pump – 4278 gpm 'B' Pump – 4327 gpm 'C' Pump - 4330 gpm 'D' Pump – 4347 gpm
CS	4370 gpm per pump	4245 gpm per pump	'A' Pump – 4285 gpm 'B' Pump – 4204 gpm

1. The containment analysis assumptions for CLTP are shown in USAR Table 5.2-7. Table 5.2-7 shows that for the first 10 minutes 1 CS and 2 RHR pumps were running at nominal flow rates. The 4 pump case was used to evaluate containment response for NPSH only.
2. The flow rates for the NPSH analysis are based on a hydraulic model that provides an evaluation of actual capability based on individual pump characteristic curves and system hydraulic resistance. These values are the same for CLTP and EPU and were used to evaluate NPSH.
3. The EPU containment analysis is an average of all pumps from the NPSH analysis.

Event	RHR Flow (gpm)			CS Flow (gpm)		
	CLTP	EPU	Procedure	CLTP	EPU	Procedure
DBA <600 seconds (RHR pumps A, B, C, D CS pumps A and B)	4278 4327 4330 4347	4278 4327 4330 4347	As Needed[1]	4285 4204	4285 4204	As Needed[1]
DBA >600 seconds	4000	4000	4000 / pump	3035 3029	3035 3029	>2800[2]
SBA[3] <600 seconds	NA[4]	4320	As Needed[1]	NA[4]	3020	As Needed[1]
SBA >600 seconds	NA[4]	4000	4000 / pump	NA[4]	3020	>2800[2]
ATWS[5]	NA[4]	4000 / pump	4000 / pump	NA[4]	3035	See Note Number 5.
SBO	NA[4]	4000 / pump[6]	4000 / pump	NA[4]	0[7]	Not used
Appendix R	4000	4000	4000	3029	3029	2700 - 4100[8]

[1] RHR and CS will initiate with the injection valves fully open, i.e. in pump runout flow. Procedures allow the operators to inject as needed to achieve desired reactor water levels to establish adequate core cooling. NPSH limits are provided in EOPs which allow pump flow at analytical values shown or higher. Cautions against exceeding NPSH limits are provided in EOPs to insure pump reliability. CS rated pump flow rate is 3020 gpm at 145 psig reactor pressure. RHR pump design rated flow rate is 4000 gpm/pump in containment cooling mode.

[2] CS flow is required by EOPs to be >2800 gpm if at 2/3 core height to insure adequate core cooling.

[3] For the SBA prior to 600 seconds the event is bounded by the DBA LOCA since makeup requirements are substantially lower. The use of one RHR and one CS pump was assumed.

[4] SBA, ATWS and SBO were not evaluated as part of the CLTP license basis and therefore are shown as not applicable, NA, in table above.

[5] The EOPs for an ATWS event control water level in a band that insures acceptable power reduction. CS is not a preferred injection source and other systems would be expected to be used to maintain vessel inventory, therefore the use of CS flow of 3035 gpm for NPSH evaluation is conservative. RHR is identified as a preferred injection source; however the maximum flow requirement (16,000 gpm) would be associated with suppression pool cooling which is assumed above.

[6] RHR flow for suppression pool cooling does not start until restoration of power after 4 hours. All pumps are started in torus cooling mode after 4 hours.

[7] Core cooling is provided by HPCI for this event and therefore CS is not used.

[8] The analysis assumed a maximum CS flow of 3029 gpm, the discrepancy between the procedure and analysis is being addressed by CAP 01176349.

NRC RAI No. 13

PUSAR Section 2.6.1.2.2, besides SRV opening set point, the SRV load in the suppression pool would depend on the SRV discharge line air and water volumes, and configuration of the submerged structures in the suppression pool. Please verify these parameters will not change under EPU conditions.

NSPM Response

Loads due to initial SRV actuation are determined by parameters including the SRV setpoints, SRV Discharge Line (SRVDL) volume, line lengths and friction losses, and number of turns. Because all these parameters including the SRV setpoints do not change, loads due to initial SRV actuations are not impacted by EPU.

Loads due to subsequent SRV actuations depend primarily on the SRVDL reflood height at the time of SRV opening and SRV setpoints. The number of SRV cycles will increase with EPU due to a higher steaming rate at increased decay power levels. EPU will reduce the time between actuations to about 12 seconds. The time at which equilibrium height is re-established remains less than 6 seconds after the SRV closes, which is independent of reactor power level. The current SRV low-low set logic includes a minimum 8-second delay after valve closure. The current SRV low-low set logic therefore prevents subsequent SRV actuations until after the SRVDL reflood level stabilizes to the equilibrium height.

Therefore, the current specified loads due to initial and subsequent SRV actuations are not affected by EPU.

NRC RAI No. 14

PUSAR Section 2.6.1.5, EPU has resulted in changes in temperature response both in the drywell and wetwell. Refer to GL 96-06, please explain why pipe penetration integrity of water filled isolated piping that is susceptible to thermally induced over-pressurization is unaffected by the EPU. Please explain why the higher temperatures of EPU conditions will not affect the calculated leakage pressure through the valve bonnet gaskets and discs for each of the penetrations.

NSPM Response

The scope of the equipment subject to GL 96-06 was described in Page 3 of a letter from the Northern States Power (NSP), a predecessor licensee to NSPM, dated January 28, 1997 (Reference 1), and was accepted by the NRC staff by the associated SER. Thirteen lines containing air or water were identified as potentially susceptible. No new air or water lines have since been routed through primary containment, thus the potentially affected lines within the GL 96-06 scope do not change at EPU conditions.

The water filled lines are discussed below:

a. RHR SDC - RHR SDC was later modified to allow piping pressure relief via a bypass line and check valve. Therefore, there is no EPU impact.

b. RHR Head Spray - The RHR head spray line and valves have been removed from the plant, therefore, there is no EPU impact.

c. Drywell Floor Drain lines - Drywell floor drains – a rupture disk was installed for pressure relief, therefore, there is no EPU impact.

d. DW equipment drain sump line - A rupture disk was installed to relieve pressure, therefore, there is no EPU impact.

e. RWCU Supply – In accordance with plant procedures and a previous commitment, the temperature of the water volume between these valves is verified greater than LOCA temperature or drained if both valves are closed during operation. Therefore, there is no EPU impact.

f. RBCCW Supply and Return - A calculation was performed to verify no boiling in RBCCW piping and identified procedural changes to prevent boiling. This calculation covers situations where drywell fans do not trip or are restarted by the operator. The assumed maximum temperature is based on an EOP requirement to spray the drywell which does not change due to EPU.

g. Demineralized Water - This line is maintained drained during operation per plant procedures, therefore, there is no EPU impact.

h. Recirculation Sample - The trapped fluid is at a significantly higher temperature than containment. Plant procedural controls for the Recirculation Sample Penetration require draining the penetration if the valves are closed for more than 4 hours. Therefore, there is no EPU impact.

i. Steam Drain - These valves are closed during startup under hot conditions at approximately 500 psig. During operation, process steam remains on both ends of the isolation boundary keeping the line hot. Therefore, there is no EPU impact.

Reference:

14-1: NSPM Letter William J. Hill to U.S. NRC, "120 Day Response to NRC Generic Letter 96-06 Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions," dated January 28, 1997.

NRC RAI No. 15

PUSAR Section 2.6.2: Please explain why a feedwater line break and main steam line break under EPU conditions are not considered for subcompartment analysis?

NSPM Response

Refer to the response for RAI No.16 for an explanation of why only the annulus region is discussed. Within the annulus region, the controlling break relative to pressurization within the current licensing basis is the recirculation suction nozzle/safe end break. A break at this location results in higher mass and energy releases than any other break, including breaks of the feedwater or main steam lines. The main steam lines are located above the elevation of the annulus region discussed and therefore do not impact pressurization of this region. The generic guidelines in NEDC-32424P (Reference 1) specify that the break flow will be compared with the analytical or experimental basis for the LOCA subcompartment pressurization dynamic loads. If the calculated break flow conditions with power uprate are within the range of break flow conditions used to define the loads, subcompartment pressurization dynamic loads are not affected by the power uprate.

Reference:

15-1: General Electric Company (GE), Licensing Topical Report NEDC-32424P, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate" (ELTR1), dated February 1995.

NRC RAI No. 16

PUSAR Section 2.6.2: Please explain why drywell head subcompartment pressurization is not done at EPU conditions.

NSPM Response

The technical discussion in Section 2.6.2 applies to the annulus area between the biological shield wall and the reactor vessel. As addressed in the Monticello Current Licensing Basis discussion in PUSAR Section 2.6.2, MNGP is not a SRP 6.2.1.2 plant and the 10 CFR 50 Appendix A criteria do not apply to MNGP with respect to subcompartment pressurization. There is no known correspondence between MNGP and the AEC/NRC on subcompartment pressurization except for that done during power rerate. The power rerate evaluation only addressed the annulus area between the biological shield wall and the reactor vessel for a recirculation suction line break. This evaluation was approved by the NRC Staff power rerate SER. For EPU the same evaluation as done previously for power rerate was performed to confirm the annulus loads remain within design and are acceptable at EPU conditions.

The drywell head area is subject to steam breaks only. Since the reactor will operate at the same pressure at EPU, pressurization from steam line breaks, including the head vent, does not change as a result of EPU and is therefore not evaluated further. Dynamic effects from these breaks are also not changed at EPU conditions.

NRC RAI No. 17

PUSAR Section 2.6.2, last sentence under "Technical Evaluation" states "To increase margins, these shield bricks will be removed by modification". Please describe the proposed modification and explain how margins between the energy required for containment liner penetration and brick missile energy will be increased.

NSPM Response

The bioshield structure has multiple piping penetrations, three of which have shielding bricks installed in the gap between the pipe and the structure. The three penetrations are the two jet pump instrument penetrations and the Standby Liquid Control/core differential pressure penetration. The modification field work was completed during the refueling outage that ended in May 2009 and permanently removed the shield bricks from these penetrations and verified that all other shield bricks have been removed.

Margin, as used in the last sentence of the technical evaluation of PUSAR Section 2.6.2, refers to the potential for containment liner damage due to missile generation from a LOCA. Removal of these bricks eliminated potential shield brick missiles caused by subcompartment pressurization resulting from a break.

NRC RAI No. 18

PUSAR Section 2.6.6: The drawdown time is the time period following the start of the accident during which loss of offsite power causes loss of secondary containment vacuum (relative to atmospheric pressure) which is assumed to result in releases from the primary containment directly to the environment without filtering. What is the affect of EPU on the reactor building drawdown time and dose evaluation?

NSPM Response

A drawdown time was estimated for MNGP as part of the Alternate Source Term (AST) project to determine the reasonableness and conservatism of the AST five minute time assumption for the positive pressure period. During the positive pressure period, radionuclide removal from Standby Gas Treatment System (SBGT) operation is not credited. The drawdown calculation determined that the positive pressure period was less than 2 minutes using a single lumped node GOTHIC calculation. EPU affects the reactor building heat load assumption in this calculation. Other relevant assumptions such as leak rates are unchanged.

Over the 5 minute period of concern, the decrease in air density from the slight EPU increase in reactor building temperature is not significant. Assuming the process air temperature range of concern is 70°F to 150°F in this period, the EPU heatup may conservatively increase the process temperature an additional 10°F over that estimated for CLTP. For example, assuming the initial process temperature is 85°F at CLTP (or for instance 110°F), EPU could conservatively result in a process temperature increase to 95°F (120°F) in the first five minutes post-LOCA. The commensurate change in air density factor (ρ_{op} / ρ_{std}) for a ten degree delta temperature over the range of concern above is not significant (0.98 using values from Crane Technical Paper 410). The MNGP fan is rated at 10.5 inches-w.g. (water gauge) at 70°F. When the density correction is applied, the fan static pressure would be reduced by approximately 0.2 inches-w.g. The resulting change in the developed static pressure is insignificant, fan performance is not affected significantly, and given the excess SGTS flow capacity and existing margin, the calculated drawdown time would not approach the 5 minute assumption.

Given that the actual draw down time does not change significantly for EPU and does not approach the 5 minute positive pressure assumption for the AST evaluation, there is no change to the current design basis analysis for Monticello due to EPU

NRC RAI No. 19

PUSAR Table 2.6-1 provides the drywell wall temperature of 273°F for the current analysis and 278°F for the EPU analysis for a 0.5 sq ft steam line break. Please verify that the 278°F wall temperature analysis is based on the EPU maximum drywell gas temperature of 338°F. For this analysis, please provide a comparison table listing the analysis method used, assumptions, and inputs for the current analysis and EPU analysis and provide justification for differences. Please verify that the EPU analysis for a 0.5 sq-ft steam line break is limiting.

NSPM Response

The containment analysis performed for maximum drywell temperature response for environmental qualification was discussed in detail in response to RAI No. 4. This same analysis for the 0.5 sq-ft steam line break was used to determine the drywell wall temperature response. This confirms that the EPU analysis that results in the maximum wall temperature of 278°F is based on the same EPU analysis that also results in the maximum drywell gas temperature of 338°F.

The drywell temperature response was evaluated for three distinct steam line break sizes: 0.5 sq-ft, 0.1 sq-ft, and 0.01 sq-ft. The 0.5 sq-ft break size was the largest size investigated since a steam break larger than this will result in rapid reactor vessel depressurization. This rapid depressurization will cause flashing of saturated water in the vessel, two-phase level swell, and two-phase flow from the break. The drywell temperature response resulting from two-phase flow will be at the saturation temperature for the drywell pressure, which is considerably less than the superheated temperature reached with a steam-only break. The results for the maximum 0.5 sq-ft break bound the smaller break sizes with regard to peak drywell temperature and peak drywell wall temperature. As the drywell pressure for this event prior to initiation of drywell sprays is about 47.4 psia, the drywell wall temperature approaches but never exceeds the saturation temperature for 47.4 psia, 278°F, due to condensation on the drywell wall.

The principal difference between the results of the current analysis and the results of the EPU analysis is due to the use of more conservative initial containment conditions. For the current analysis, the containment pressure (drywell and wetwell) was assumed to be at 0.75 psig, with the drywell also at 100 percent relative humidity. For the EPU analysis, the containment pressure (drywell and wetwell) was assumed to be at 3.0 psig, with the drywell at 20 percent relative humidity. This results in more initial air in the containment, and a result of higher wetwell pressure following air purge from the drywell to the wetwell. The higher wetwell pressure forces higher drywell pressure due to the downcomer submergence. The higher drywell pressure induces a higher drywell steam temperature. The higher drywell pressure has a higher saturation temperature, which induces a higher drywell wall temperature prior to initiation of the drywell spray.

See Table 19-1 for a comparison of the drywell temperature analyses for CLTP and EPU conditions.

Table 19-1
Comparison Table for DW Temperature Analyses

	Current	EPU
Model (Method)	SHEX(1)	SHEX
Break Size (sq-ft)	0.01, 0.10, 0.50	0.01, 0.10, 0.50
Break Type	99.7% Steam	100% Steam
Break Model	HEM	HEM
Initial Conditions		
Drywell		
Pressure (psig)	0.75	3.0
Temperature (°F)	135.0	135.0
Relative Humidity (%)	100.0	20.0
Wetwell		
Pressure (psig)	0.75	3.0
Temperature (°F)	90.0	90.0
Relative Humidity (%)	100.0	100.0
Suppression Pool		
Temperature (°F)	90.0	90.0
Level	LWL	LWL
DW Shell Heat Transfer	1x Uchida	1x Uchida
DW Spray Initiation Time(2) (min.)	10.0	10.0

(1) For the current analysis, SHEX was used to evaluate the containment response for only the first 24 hours of the event due to computational restrictions using SHEX at the time the analysis was performed. After the first 24 hours, since the containment response changes slowly and is easily modeled with simpler methods, a simplified FORTRAN program was used to model the long-term cooldown of the containment atmosphere. For the EPU analysis, SHEX was used for the entire event analysis to 400 days.

(2) DW spray is assumed to be initiated when drywell temperature increases to the drywell spray initiation temperature of 281°F per plant EOPs, but this action is not credited in the analysis until this DW Spray Initiation Time.

NRC RAI No. 20

PUSAR Section 2.6.1.2.1, second paragraph, last sentence, please explain why the vent thrust loads at EPU conditions are less than the Monticello plant specific values calculated for the Mark I containment long term program.

NSPM Response

The original MNGP Plant Unique Load Definition (PULD) analysis and the MNGP EPU analysis for vent thrust loads both use the same methodology for evaluating containment response and vent thrust loads. This methodology uses the GEH M3CPT containment code to evaluate the containment response used to evaluate the vent thrust loads in accordance with the Mark I Load Definition Report.

The original PULD analysis calculated break flow rates using the homogeneous equilibrium model (HEM) for evaluating critical break flow rate, and the vessel model internal to M3CPT. The vessel model internal to M3CPT is very simplistic, and requires very conservative assumptions to account for subcooled liquid break flows that maximize the containment pressure response required for evaluating bounding vent thrust loads.

The EPU analysis of the DBA LOCA containment response for calculating vent thrust loads uses the GEH LAMB code for calculating break flow rates as input to the M3CPT code. Break flow rates calculated with LAMB use the same break flow model (HEM) as used with the M3CPT internal vessel model. But the LAMB vessel model is more detailed than the M3CPT internal vessel model, and can therefore, provide break flow rates more consistent with the GEH BWR vessel, especially with regard to subcooled liquid break flows.

The vent thrust loads at EPU conditions are therefore less than the MNGP PULD values because the containment response for the EPU conditions uses LAMB break flow rates rather than the break flow rates calculated with the vessel model in M3CPT.

NRC RAI No. 21

PUSAR Table 2.6-1, identifies the new limit for peak bulk suppression pool temperature as 208 °F. Please verify that all equipment that requires qualification is still acceptable at the increased EQ temperature.

NSPM Response

For primary containment equipment at MNGP, there is no distinction made between equipment located in the drywell or the suppression pool with respect to qualification temperature. The EQ volume for the entire primary containment volume is labeled "drywell." The bounding temperature for the primary containment is used as the qualification temperature.

For EPU conditions the calculated peak drywell temperature is 338°F, which bounds the peak bulk suppression pool temperature limit of 208 °F. Section 3.4.2 Drywell Temperature and Pressure Evaluation and Table 3.4.2-1 (Reference 1) demonstrate that EQ equipment is qualified for the peak drywell temperature above.

Reference:

21-1: Enclosure 17, Revised Response to NRC EEEB Review Question documented in L-MT-08-052 (Accession No. ML083230111).

NRC RAI No. 22

PUSAR Table 2.6-1, Note 3 states maximum internal pressure for drywell and wetwell is 62 psig. What is meant by maximum internal pressure?

NSPM Response

Maximum internal pressure is a term consistent with the containment code of record. The source of the maximum internal pressure is the MNGP USAR. See USAR Section 5.2.1.1. This section lists the design code of record as ASME Section III Subsection B, 1965 Edition with Winter 1965 Addenda.

According to Paragraph N-1312 of the addenda, the design internal pressures may differ from the maximum containment pressure provided that the design pressure is greater than or equal to 90 percent of the maximum containment pressure. The maximum internal pressure for the MNGP containment was specified as 62 psig, and the design pressure is accordingly
56 psig.

NRC RAI No. 23

PUSAR Table 2.6-1, Note 5, why is 0.5 sq ft steam break into the drywell assumed for this analysis? Please explain why a multiplier greater than 1 (e.g., the value of 1.2 is recommended in NUREG 0800 BTP 6-2 Revision 3) was not used with the Uchida condensing heat transfer coefficient for determining the containment liner temperature of 278°F? Is the assumption of initiation of sprays at 10 minutes from LOCA consistent with emergency operating procedures?

NSPM Response

Large steam break areas result in rapid depressurization of the reactor vessel. The rapid depressurization causes a rapid level swell in the reactor vessel that ultimately results in a liquid-steam mixture being expelled from the break. The liquid in the break flow absorbs energy from the drywell steam environment and evaporates into steam. This evaporation of the liquid break flow forces the drywell atmosphere to drop from superheated conditions to saturated conditions. Thus, for maximum drywell temperature, larger steam break areas are bounded by intermediate and small steam break areas. As identified in the response to RAI No. 19, the 0.5 sq-ft steam break is the largest steam break size for which rapid level swell is not assumed to reach the break elevation and therefore does not saturate the drywell environment, and is therefore the bounding steam break area for maximum drywell temperature.

A single calculation was performed for the drywell gas and drywell wall temperature response with the main focus on maximizing the drywell gas temperature. BTP 6-2, "Minimum Containment Pressure Model for PWR ECCS Performance Evaluation," which uses assumptions to minimize the containment airspace pressure and temperature response, was not recognized as applicable for this evaluation. Instead, the containment wall temperature evaluation is performed consistent with the containment temperature evaluation for environmental qualification, which assumes a condensing heat transfer coefficient of 1x the Uchida correlation. If a greater multiplier on the Uchida correlation were to be used, such as the 1.2x recommended in BTP 6-2, the wall temperature would reach the saturation temperature of 278°F slightly earlier in the event, but the wall temperature would still be limited by the saturation temperature due to the condensation on the walls, and therefore the peak wall temperature would not be affected.

Plant emergency operating procedures direct operators to initiate drywell sprays when drywell temperature exceeds 281°F. For the 0.5 and 0.1 sq-ft breaks, the SHEX analysis results indicate drywell temperature exceeds 281°F before 10 minutes. The long-term containment analysis for maximum drywell temperature for environmental qualification conservatively does not credit operator action to initiate drywell sprays until after 10 minutes. Thus the assumption of initiation of sprays at 10 minutes from LOCA is consistent with emergency operating procedures. The assumption of initiation of sprays at 10 minutes is also consistent with the current licensing basis as discussed in MNGP USAR Section 5.2.3.9.

NRC RAI No. 24

PUSAR Section 2.6.3.1.1, please provide justification for increasing the drywell airspace temperature limit from 335°F to 340°F.

NSPM Response

The peak drywell gas temperature is a limit in a sense that it is a rounded value of an analytical result that can be used as a design input for equipment qualification temperature. The equipment qualification at EPU is addressed in PUSAR Section 2.3.1 and in Enclosure 17 to L-MT-08-052 (Accession No. ML083230111). The drywell design temperature limit of 281°F is not affected by this limit.

The limit represents a bounding peak value for a stair step envelope for steam line breaks. See USAR Table 5.2-8, Drywell Temperature Envelopes for Small Steam Breaks, which is shown below. This table was constructed to support the power rerate to 1775 MWt. The actual calculated peak value that corresponds to the 335°F temperature portion of this envelope is 331°F. If an envelope is similarly constructed for EPU, the corresponding value for the limiting 0-300 second portion would be 340°F which bounds the analytical result of 338°F.

Table 5.2-8 Drywell Temperature Envelopes for Small Steam Breaks

DRYWELL TEMPERATURE ENVELOPE*

TIME AFTER ACCIDENT	DRYWELL TEMP. (°F)
0 - 300 seconds	335
300 - 600 seconds	330
600 - 1500 seconds (=0.017 days)	285
0.017 - 1.0 days	285 - 190
1.0 - 5.0 days	190 - 150
5.0 - 50 days	150 - 120
50 - 400 days	120 - 110

* Analysis performed at 102% of 1880 MWt and 90°F RHR Service Water

NRC RAI No. 25

PUSAR Section 2.6.5, under heading "Technical Evaluation," second paragraph, first sentence, please define what is meant by "realistic decay heat model."

NSPM Response

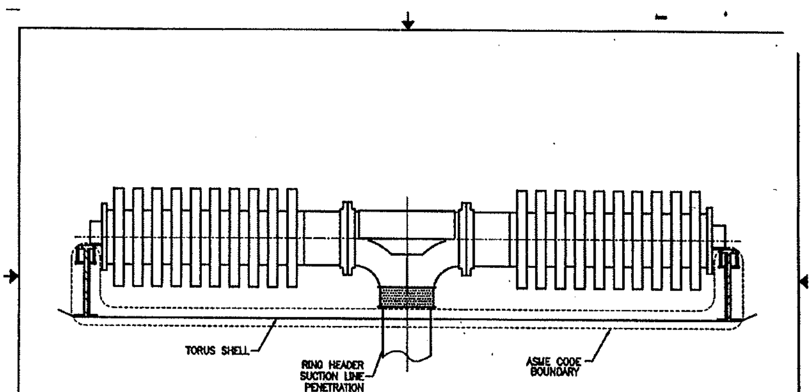
The ANS/ANSI 5.1-1979 decay heat model is considered a more realistic decay heat model as compared to the older models of May-Witt and ANS/ANSI 5-1971 +20 percent used in earlier DBA LOCA containment analyses and in current short-term containment analyses. However, the ANS/ANSI 5.1-1979 decay heat is generated with conservatively biased inputs that consider fuel enrichment, plant fuel cycle, End-of-Cycle average exposure, and fuel residence time. In addition, consistent with the recommendations of GE SIL 636 Revision 1, contributions from U-239 and Np-239, plus other actinides as well as contributions from activation products produced with the structural materials, have been included in the decay heat calculation. Also, for the DBA-LOCA and for the SBA analyses, an uncertainty adder of 2σ is used.

NRC RAI No. 26

PUSAR Section 2.6.5, under heading "Suction Strainer Debris Loading", please specify the type of strainer installed in Monticello and included in the EPU analysis?

NSPM Response

The pumps in the Emergency Core Cooling Systems take their suction water from a common ring header around the suppression pool. The ring header has four suction lines to the suppression pool, each of these four suction lines have one strainer assembly consisting of two PCI Sure Flow strainer modules. Each module is a 40-inch nominal diameter, convoluted cylindrical strainer approximately seven feet long. Each strainer assembly is connected to a torus suction penetration by a rams head tee. The total surface area of the new strainer assemblies is approximately 1200 Ft^2 with 1/8 inch nominal diameter holes and approximately 40 percent open area. A sketch and some pictures are shown below.



ECCS SUCTION STRAINER ASSEMBLY

FIGURE 2

NRC RAI No. 27

PUSAR Section 2.6.5, under heading "Appendix R Fire", please describe the Appendix R fire scenario on which the analysis is based (e.g., fire zone, equipment affected, assumed operator actions etc), and indicate if it is the limiting case for NPSH margin.

NSPM Response

The applicable fire zones for the Appendix R fires are either the Cable Spreading Room (Zone 8) or the Control Room (Zone 9). USAR Sections J.4.4 and J.4.5 describe the safe shutdown equipment and the event assumptions. See USAR Appendix J.5 for the fire hazards analyses for these zones and the equipment affected.

For both of these fire scenarios, only the minimum complement of safe shutdown equipment is assumed undamaged and available, and safe shutdown is accomplished remotely at the Alternate Shutdown (ASDS) panel. The minimum complement of safe shutdown equipment assumed available in the mitigation sequence in the analysis is as follows.

- One train of Core Spray (CS) System
- One Residual Heat Removal (RHR) Pump for suppression pool cooling
- One RHR Heat Exchanger
- One RHR Service Water (RHRSW) Pump
- Two Safety Relief Valves (SRVs)

For other fire zones: both divisions with full suppression pool cooling are available, or one full division with two RHR pumps is available, and suppression pool cooling is more effective in reducing torus water temperature than a single RHR pump. Thus the Control Room or Cable Spreading Room scenarios result in the limiting torus water temperature which is the key parameter for determining NPSH margin.

For analysis purposes, the assumed operator actions are RPV depressurization and torus cooling which are described in Section 2.5.1.4 of the MNGP PUSAR. Procedural controls govern operator actions for shutdown outside the control room.

NRC RAI No. 28

PUSAR Section 2.6.5, under heading "Small Steam Line Break Analysis", third paragraph, last sentence states "The CS pump is expected to maintain water level during this event, and actual flow rate is expected to be significantly less (approximately 200 gpm)." Please verify if the CS pump is designed to operate at such low flow conditions without any problems.

NSPM Response

PUSAR Section 2.6.5 has a typographical error. It should read "approximately 2000 gpm", rather than" approximately 200 gpm." A corrected PUSAR page is attached to clarify the typographical error.

satisfy the NPSHR, and available wetwell pressure, for PRFO Case 1, PRFO Case 2, and the LOOP Case respectively. NSPM is requesting that the staff review be based on the use of 3% NPSH required curves. Both 1% and 3% NPSHR curves are provided for information. Adequate margin to the peak containment overpressure value of 20.36 psia previously approved for DBA and Appendix R events is available.

Based on the above, Monticello is requesting approval of overpressure credit to meet NPSH requirements during an ATWS event.

Small Steam Line Break Accident (SBA)

Following a 0.01 ft^2 Small Steam Line Break Accident (SBA), the RHR and CS pumps operate to provide the required core and containment cooling as well as maintain RPV water level. Adequate NPSH margin (NPSH available minus NPSH required) is required during this period to assure the essential pump operation. The NPSH margins for the ECCS pumps were evaluated for the limiting conditions following an SBA.

EPU RTP operation increases the reactor decay heat, which increases the heat addition to the suppression pool following this event. As a result, the peak suppression pool water temperature and peak containment pressure increase. Containment analyses were performed for the SBA event at EPU conditions. The analysis indicates that overpressure is available during the event. Thus, adequate NPSH margin exists during the SBA event if the available containment overpressure is credited.

The SBA analysis assumed one RHR pump in LPCI injection mode from 0-600 seconds at a flow of 4320 gpm. At 600 seconds LPCI injection is secured and one RHR pump is operating in Containment Spray mode for the remainder of the event at a flow of 4000 gpm. One CS pump is assumed to be operating at 3020 gpm. The CS pump is expected to maintain water level during this event, and actual flow rate is expected to be significantly less (approximately ~~200~~ 2000 gpm).

Table 2.6-9 and Figures 2.6-7 and 2.6-8 provide the results of the containment response including suppression pool temperature, required containment pressure to satisfy the NPSHR, and available wetwell pressure, for the SBA event. All NPSHR values are based on the 3% NPSHR curves. The amount of overpressure credit requested for this event is below the 20.36 psia peak value for DBA LOCA. NSPM is requesting approval of overpressure credit to meet NPSH requirements during an SBA event.

Suction Strainer Debris Loading

The methodology used by Monticello to determine the amount of debris generated and transported to the strainers is generally based on NEDO-32686, the BWROG Utility Resolution Guidance for ECCS Suction Strainer Blockage (Reference 24). The assumption used for protective coatings, specifically inorganic zinc with epoxy topcoat, was 85 lbm. This is the bounding value recommended by NEDO-32686, Section 3.2.2 and is not affected by EPU.

NRC RAI No. 29

PUSAR Section 2.6.5, for the NPSH cases analyzed, DBA LOCA, Appendix R Fire, ATWS and SBA, it is stated that containment overpressure (COP) is required to meet the required pump NPSH. Please clarify whether the COP required is necessitated due to conservatism in the analysis, and whether it can be (or has been) shown that with a realistic analysis, COP is not needed.

NSPM Response

At MNGP only the DBA and Appendix R fire events were previously evaluated for the need for containment overpressure to satisfy NPSH requirements for the ECCS pumps. The most recent NRC approval of the use of containment overpressure at Monticello was with approval of Amendment 139 (Reference 1) on June 2, 2004. The EPU project is the first review of the other events for containment overpressure needs.

The maximum wetwell pressure required in the table below is the pressure above atmospheric pressure needed to support ECCS pump NPSH requirements, i.e., containment overpressure. In all cases atmospheric pressure was defined as 14.26 psia. The containment overpressure required is based on the use of a deterministic approach not a realistic analysis.

Event	EPU Maximum Wetwell Pressure Required (psig)
Fire (Appendix R – Case No. 1)	2.48
Fire (Appendix R – Case No. 2)	2.33
Small Break Accident	5.29
Design Basis Accident	6.01
ATWS PRFO Case No. 1	1.94
ATWS PRFO Case No. 2	2.94
ATWS LOOP	4.07
Station Blackout	0

The evaluation of ECCS pump NPSH for the DBA LOCA was performed under calculation CA-07-038, Rev. 0, "Determination of Containment Overpressure Required for Adequate NPSH for Low Pressure ECCS Pumps with Suction Strainer Debris Loading at EPU Conditions." This calculation was provided to the NRC as part of letter L-MT-09-004 (Reference 2) on December 18, 2008.

Cases 5 and 6 of this calculation provided a statistical evaluation of the limiting design basis accident to determine if a more realistic approach would support that COP is not needed. The statistical design basis accident evaluation provided by these cases assumed the availability of only 1 division of power consistent with the deterministic design basis accident analysis approach. These evaluations showed the need for 1.8 psig of containment overpressure with these assumptions.

Case 10 of the calculation did an evaluation assuming containment failure, i.e., no overpressure but realistically assumed the availability of both divisions of ECCS equipment. In this case no containment overpressure is required.

The remaining events were not evaluated statistically.

Reference:

29-1: Amendment 139 to Facility Operating License No. DPR-22 on June 2, 2004.

29-2: NSPM letter L-MT-09-004 from Timothy O'Connor to U.S. NRC, "Response to NRC Containment & Ventilation Branch Request for Additional Information (RAIs) dated December 18, 2008 (TAC No. MD9990)."

NRC RAI No. 30

PUSAR Section 2.7.6, under heading “Technical Evaluation”, last sentence of first paragraph states “EPU may affect the HVAC serving these areas as a result of slightly higher process temperature.” Please explain what heat load causes the process temperature slightly higher.

NSPM Response

The higher process temperature referred to is an increase in the torus water temperature that affects piping heat loads.

NRC RAI No. 31

PUSAR Section 2.7.6, under heading "Technical Evaluation", last sentence of second paragraph last sentence, please explain why HPCI room temperature is expected to remain within its design limit without taking credit for HVAC operation.

NSPM Response

The current design basis heat-up calculation for the HPCI Room does not assume operation of the air conditioning units to maintain the HPCI room below 125°F during the time the HPCI system must operate (up to 2.76 hrs) after the start of an accident from operation at 1880 MWt. The calculation uses the torus water temperature profile for a small break. The torus water temperature profile is affected by EPU therefore this calculation is affected. This calculation includes conservatisms that, based on engineering judgment, provide sufficient margin to maintain a room temperature of 125°F without taking credit for the room air conditioning units at the revised pool temperature profile. Some of the conservatisms included in the calculation are: (1) a heat load of 820.26 Btu/hr for uninsulated steam pipe (insulated steam pipe conservatively modeled as uninsulated); (2) the inclusion of non-essential electrical heat loads even though a loss of off-site power is assumed; (3) allowing the maximum amount of uninsulated piping. Therefore, the conservatisms in the existing design calculation are considered to provide sufficient margin to maintain a room temperature of 125°F at EPU conditions without taking credit for HVAC operation.

NRC RAI No. 32

PUSAR Section 2.7.6, under heading "Technical Evaluation", fourth paragraph, what is the EPU impact on reactor building HVAC system, which is described in USAR Revision 24, Section 5.3.4, that performs cooling under normal conditions. What are the results of evaluation of the EPU impact due to additional heat load in the fuel pool on the reactor building HVAC system.

NSPM Response

Areas in the reactor building which may be affected by EPU process changes or electrical load increases during normal or accident conditions are the Drywell, Steam Chase, ECCS Pump Rooms, HPCI Room and RCIC Room. Each of these areas has dedicated cooling and was individually evaluated for heat load increases resulting from EPU and the ability of the area HVAC to maintain the area temperature within design limits. The evaluations concluded that the area temperatures would be maintained within design conditions.

Other areas of the reactor building with dedicated cooling are the Control Rod Drive Pump Rooms (V-AC-7A & V-AC-7B), 985 foot elevation (SGTS Area, Cooling Water Heat Exchanger Area, Fuel Pool Heat Exchanger Area, Access Areas, Main Exhaust Plenum and Reactor Recirc MG Set Fan Room) (V-AC-9), Elevator Machine Room (V-AC-25), and the Refueling Floor (V-AH-4A & V-AH-4B) with the rest of the building being supplied by the Reactor Building Main Supply Units (V-AC-10A & V-AC-10B). Based on review, CPPU is not considered to affect the heat loads in these areas.

Although normal spent fuel pool EPU decay heat loads are higher than the CLTP heat loads, the existing Spent Fuel Pool Cooling and Cleanup System has the capacity to maintain the spent fuel pool below the design limit. Since the design limit of 140°F is maintained, there is no change to the design heat load associated with the spent fuel pool area as a result of EPU and the Reactor Building HVAC system.

NRC RAI No. 33

PUSAR Section 2.7.5, under heading "Conclusion" states the proposed EPU with respect to HVAC operation in drywell is acceptable. However there is no evaluation of drywell HVAC under the heading "Technical Evaluation".

NSPM Response

The effect of EPU on the drywell atmosphere heat loads and the ability of the Primary Containment Cooling and Ventilation System to maintain the drywell atmosphere below the design limit (135°F, bulk average) were evaluated and documented. Drywell heat loads affected by EPU are feedwater piping loads and biological shield gamma heating. The evaluation concluded that the drywell heat load increase as a result of EPU was insignificant (0.26 percent) and the Primary Containment Cooling and Ventilation System will be able to maintain the bulk average temperature within design limits. The Technical Evaluation section only addressed those areas of the reactor building with significantly higher heat loads due to EPU.

NRC RAI No. 34

PUSAR Section 2.7.5, under heading “Technical Evaluation”, please describe how the increase in the area temperature of 1.8 °F or less is calculated. Is this based on the EPU revised design heat load in that area while the currently designed HVAC system serving that area is operating?

NSPM Response

Areas in the Reactor Building that will experience higher loads due to EPU are the Steam Tunnel, HPCI Room, and the RHR and Core Spray Pump Rooms. The Steam Tunnel (less than 1°F) and the RHR and Core Spray Pump Rooms (1.8°F) are expected to see a small increase in the calculated room temperature. The HPCI Room is not expected to see an increase in the calculated room temperature. The method used to calculate these increases is given below.

Steam Tunnel – The less than 1°F increase is calculated as follows:

Heat loads to the room considered in design calculations are from system piping (Main Steam and Feedwater). EPU does not impose changes to the Main Steam temperature, therefore there are no changes to heat loads from the Main Steam System. For Feedwater, EPU results in a 12.6°F increase (383.7°F to 396.3°F) at 2004 MWt (LPU). Based on a reference temperature of 90°F this 12.6°F increase in pipe temperature represents a 4.3 percent increase [12.6/(383.7-90)] in the difference between the reference temperature and piping temperature.

From existing design calculations at a room temperature of 104°F and a pipe insulation temperature of 160°F, which are the worst case heat load conditions evaluated, the feedwater piping accounts for approximately 15 percent of the piping heat load. Given that room temperature is linearly proportional to heat load and the feedwater temperature increases 4.3 percent and that the feedwater piping accounts for 15 percent of the total heat load, the feedwater increase results in a 0.7 percent increase (4.3 percent of 15 percent) in room temperature above the reference temperature. Conservatively, taking a 1 percent increase and applying it to the difference between the maximum measured room temperature (121.8°F) and the reference temperature of 90°F, results in a EPU room temperature increase of 0.3°F [0.01*(121.8-90)]. In addition to the heat load increase, it was assumed that the cooling coil returns an increased air temperature to the room. Assuming a 10°F approach for the coiling coil and applying the same percentage increase results in an additional 0.1°F increase to the room. Therefore, the estimated total room temperature increase was determined to be 0.4°F.

RHR & Core Spray Pump Rooms - The 1.8°F increase is calculated as follows:

Electrical heat loads in the room remain unchanged. Piping heat loads are from RHR and Core Spray piping, with the majority of the piping containing torus water, with the torus water temperature following a LOCA increasing as a result of EPU. The torus temperature used in existing design calculations is based on a maximum torus temperature of 191°F. The maximum EPU torus water temperature following a LOCA is 208°F. This 17°F increase was evaluated for its affect on the piping heat load and the resulting room temperature. The RHR piping and heat exchanger surfaces are insulated. Existing design calculations calculate the temperature of the insulation surface and conclude that this temperature will quickly be exceeded by the room temperature and therefore the RHR piping does not play a significant role in the room heat load. The EPU torus water temperature was used to repeat the calculations and the same conclusion was reached for EPU operation.

The Core Spray piping is not insulated and thus pipe surface temperature was assumed to be the torus water temperature. The contribution of this piping to the overall heat load varies as the room and torus water temperature change. Existing design calculation tabulate Core Spray piping heat loads as a function of room temperature and torus water temperature. The maximum Core Spray piping load of 63,293 Btu/hr occurs at a room temperature of 115°F and the maximum torus water temperature of 191°F. Using the fixed electrical load (341,500 Btu/hr) results in a maximum total heat load of 404,793 Btu/hr of which the piping accounts for 15.6 percent (63,293 / 404,793) of the overall load.

Based on a reference temperature of 90°F the 17°F increase in pipe temperature represents a 16.8 percent increase [17/(191-90)] in the difference between the reference temperature and piping temperature. A 16.8 percent increase in the maximum Core Spray piping heat load results in an EPU piping load of 73,927 Btu/hr (1.168 x 63,293). Adding this to the Electrical Heat Load (341,500 Btu/hr) results in a maximum EPU heat load of 415,447 Btu/hr.

From above, the worst case piping heat load accounts for 15.6 percent of the total heat load. Given that room temperature is linearly proportional to heat load, the torus temperature increases 16.8 percent, and that the core spray piping accounts for 15.6 percent of the total heat load, the torus water temperature increase results in a 2.7 percent increase (16.8 percent of 15.6 percent) in room temperature.

Existing design calculations calculate the maximum room temperature to be 143.8°F. Taking a 2.7 percent increase and applying it to the difference between the maximum measured room temperature (143.8°F) and the reference temperature of 90°F results in a EPU room temperature increase of 1.5°F [0.027*(143.8-90)]. In addition to the heat load increase it was assumed that the cooling coil returns an increased air temperature to the room. Assuming a 10°F approach for the cooling coil and applying the same percentage increases results in an additional 0.27°F increase to the room. Therefore, the total room temperature increase was determined to be 1.8°F.

NRC RAI No. 35

PUSAR Section 2.7.5, under heading "Technical Evaluation" and "Conclusion", please provide the result and conclusion of the detail evaluation of the feedwater and condensate pump area heat load.

NSPM Response

The condensate pump motors and feedwater pump motors are being replaced by EPU related modifications. The final motor selection, which may affect the heat load, has not presently been completed. Changes in heat load will be evaluated upon completion of the final designs, including motor selection, to confirm area temperatures remain within design limits (less than 130°F for the Condensate Pump Area and less than 104°F for the Reactor Feed Pump Area). If necessary, modifications to the HVAC system will be implemented to maintain these areas within the design limits.

NRC RAI No. 36

PUSAR Section 2.7.1.1, fourth paragraph discusses the EPU effects on the CREF due to increase in the radiological source term during LOCA, and use of RG 1.3 for evaluation of loading of CREF charcoal filters. USAR Revision 24 Table 14.7-13 provides assumptions used in the current LOCA dose analysis. USAR Section 14.7.2.4.3, "Control Room Dose Evaluations" lists the parameters applied in the control room dose evaluations for the current analysis. Please list and justify the differences (if any) in assumptions or parameters used in EPU control room dose evaluation, and LOCA dose analysis as per RG 1.3, from the current analysis assumptions and parameters listed in USAR Table 14.7-13 and Section 14.7.2.4.3.

NSPM Response

The control room dose evaluation for personnel dose is in accordance with Regulatory Guide (RG) 1.183 as previously approved for MNGP by the staff. See SERs dated December 7, 2006 (Reference 1) and April 17, 2007 (Reference 2) . The source term has been adjusted for 102 percent of the EPU power of 2004 MWt per Section 2.9 of the PUSAR. The primary containment leak rate percentage of L_a has been increased from 61 percent to 66 percent for the 24-72 hour time frame and from 50 percent to 66 percent for the 72-90 hour time frame to account for increased Drywell (DW) pressure. In addition, the EPU increase in Main Steam (MS) pipe temperature results in a decrease in radionuclide deposition within the MS piping and main condenser.

The use of RG 1.3 for EQ purposes is in accordance with NUREG-0737 Item II.B.2 and this method has been previously approved for MNGP by the NRC staff (Reference 3). The TIDs and dose rates were scaled for EPU.

References:

36-1: NRC (P. S. Tam) letter to NMC (J. T. Conway), "Monticello Nuclear Generating Plant - Issuance of Amendment Re: Full-Scope Implementation Of The Alternative Source Term Methodology (TAC No. MC8971)," dated December 7, 2006

36-2: NRC (P. S. Tam) letter to NMC (J. T. Conway), "Monticello Nuclear Generating Plant (MNGP) - Correction Of Safety Evaluation Associated With Alternative Source Term Amendment (TAC No. MC8971)," dated April 17, 2007

36-3: Letter from D. B. Vassallo, NRC, to D. M. Musolf, Safety Evaluation, "NUREG 0737 Item II.B.2 Plant Shielding Modifications," dated May 25, 1983

NRC RAI No. 37

Regulatory Guide 1.82 Revision 3 states that the use of containment accident pressure is acceptable for operating reactors when there is no practicable alternative. Please explain why there is no practicable way that Monticello can be modified (design change, procedures, etc.) so that the need for containment accident pressure in determining available NPSH is not necessary.

NSPM Response

The response below discusses the current license basis for use of containment accident overpressure at the MNGP. A short discussion of the modifications that would be needed to avoid the need for overpressure is provided. There are no procedure changes that would enable elimination of the need for overpressure.

Amendment 139 (Reference 1) provided documentation of the most recent NRC review of the use of containment overpressure at the MNGP. This included the consideration of the use of containment overpressure for the limiting design bases accident.

The evaluation of ECCS pump NPSH for the DBA LOCA for Extended Power Uprate was performed under calculation CA-07-038, Revision 0, "Determination of Containment Overpressure Required for Adequate NPSH for Low Pressure ECCS Pumps with Suction Strainer Debris Loading at EPU Conditions." This calculation was provided to the NRC as part of letter L-MT-09-004 (Reference 2) on December 18, 2008.

Case 10 of CA-07-038 did an evaluation assuming containment failure, i.e. no overpressure available but realistically assumed the availability of both divisions of ECCS equipment with all RHR pumps available for torus cooling. The calculation was based on use of statistical inputs, not the limiting inputs used for a deterministic analysis of NPSH for the license bases. Case 10 showed no containment overpressure is required. The containment pressure to support NPSH requirements in Case 10 was within 0.3 psi of atmospheric pressure which shows little margin. Use of limiting inputs for this calculation as shown in Case 8 of CA-07-038 resulted in the need for 1 psig of containment overpressure which shows that the existing equipment can not eliminate the need for containment overpressure.

The modifications required to support the capability to eliminate the need for containment accident overpressure under a deterministic approach would require the ability to justify operation of all RHR and RHRSW pumps under single failure rules that now apply. This would require installation of additional diesel generators, battery systems, RHR heat exchanger replacement, larger pumps and potentially piping replacement to be able to support the larger containment cooling capacity. A significant reanalysis and licensing approval effort would be required to upgrade the availability of the RHR Pumps, RHRSW pumps, and associated equipment needed to operate (i.e.

valves, room coolers, etc.) to make more containment cooling capability available. Based on these analyses, new or different plant procedures for operator actions would be required. Accordingly, the design scoping, the detailed design completion, physical modifications, plant procedures revision, and licensing actions necessary would require major effort with little additional safety benefit.

References:

37-1: Issuance of Amendment Responding to Monticello Nuclear Generating Plant, License Amendment Request dated June 2, 2004, Revised Analysis of Long-Term Containment Response and Over pressure Required for Adequate NPSH for Low Pressure ECCS Pumps, (TAC No. MB7185) (Amendment 139 to DPR-22)

37-2: NSPM Letter L-MT-09-004 from Timothy O'Connor to the U.S. NRC, "Response to NRC Containment & Ventilation Branch Request for Additional Information (RAIs) dated December 18, 2008 (TAC No. MD9990)."

NRC RAI No. 38

Please address why associated circuit issues cannot result in either a loss of containment integrity or actuation of containment overcooling during those Appendix R fire events which require use of containment accident pressure in determining available NPSH.

NSPM Response

In Section 2.0, "Proposed Change" of Enclosure 1 to the MNGP LAR (Reference 1), NSPM provided information regarding the use of containment overpressure at MNGP. This section identified a staff SER that had approved containment overpressure for an Appendix R event as of June 2, 2004. The use of containment overpressure for an Appendix R event had not been an explicit part of the plant's licensing basis prior to that date.

During the research for this question, NSPM has found that the associated circuits analyses conducted previous to 2004 did not include a loss of containment overpressure as a potential detrimental impact on safe shutdown. This was expected as containment overpressure had not been previously credited for this event. However, the associated circuits' analysis was not revised to include this impact commensurate with the change to the design basis above in 2004. This finding has been entered into the MNGP corrective action program for evaluation at CLTP and EPU conditions.

Reference:

38-1: Enclosure 1 to L-MT-08-052, "License Amendment Request: Extended Power Uprate (TAC No. MD9990)"