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Fred Dacimo
Vice President
License Renewal

May 22, 2008

Re: Indian Point Units 2 & 3
Docket Nos. 50-247 & 50-286

NL-08-086

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

SUBJECT: **Supplemental Reply to Request for Additional Information Regarding License Renewal Application – Severe Accident Mitigation Alternatives Analysis**

Reference: NRC letter dated April 9, 2008; "Request for Additional Information Regarding the Review of the License Renewal Application for Indian Point Nuclear Generating Unit Nos. 2 and 3 (TAC Nos. MD5411 and MD5412)"

Dear Sir or Madam:

Entergy Nuclear Operations, Inc. is providing, in Attachment I, the additional information requested in the referenced letter pertaining to NRC review of the License Renewal Application for Indian Point 2 and Indian Point 3. The additional information provided in this transmittal addresses staff questions regarding Severe Accident Mitigation Alternatives analysis.

There are no new commitments identified in this submittal. If you have any questions or require additional information, please contact Mr. R. Walpole, Manager, Licensing at (914) 734-6710.

I declare under penalty of perjury that the foregoing is true and correct. Executed on 5-22-08.

Sincerely,

Peter W. Conroy for

Fred R. Dacimo
Vice President
License Renewal

A128
NRR

Attachment:

1. Supplemental Reply to NRC Request for Additional Information Regarding License Renewal Application – Severe Accident Mitigation Alternatives Analysis

cc: Mr. Bo M. Pham, NRC Environmental Project Manager
Ms. Kimberly Green, NRC Safety Project Manager
Mr. John P. Boska, NRC NRR Senior Project Manager
Mr. Samuel J. Collins, Regional Administrator, NRC Region I
Mr. Sherwin E. Turk, NRC Office of General Counsel, Special Counsel
IPEC NRC Senior Resident Inspectors Office
Mr. Paul D. Tonko, President, NYSERDA
Mr. Paul Eddy, New York State Dept. of Public Service

ATTACHMENT I TO NL-08-086

SUPPLEMENTAL REPLY TO NRC REQUEST FOR ADDITIONAL INFORMATION

REGARDING

LICENSE RENEWAL APPLICATION

Severe Accident Mitigation Alternatives Analysis

ENTERGY NUCLEAR OPERATIONS, INC
INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 and 3
DOCKETS 50-247 and 50-286

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION (RAI)
REGARDING THE ANALYSIS OF SEVERE ACCIDENT MITIGATION ALTERNATIVES (SAMAS)
FOR INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3

The U.S. Nuclear Regulatory Commission (NRC or staff) has reviewed the information related to the analysis of SAMAs provided by the applicant in the Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3) LRA. The staff has identified that additional information is needed to complete the review as addressed below.

SAMA Round 2 RAI 1

The response to RAI 1d addresses why the total loss of service water (SW) is low for both units but does not discuss the reason for Unit 2 having a loss of SW contribution that is nearly an order of magnitude lower than Unit 3. Explain the plant or model features that cause this difference.

Response to SAMA Round 2 RAI 1

As discussed in response to RAI 1d, the total loss of service water initiating event is low for both units and the service water systems on the units are comparable. The IP2 contribution to total loss of service water is lower than that of IP3 due to differences in the data used to estimate the initiating event frequency for total loss of service water for the two units.

For both units, the initiating event frequency for total loss of service water was calculated using a system fault tree. Since the service water systems are similar for the units, the system fault trees are similar, with the major contribution to initiating event frequency coming from common cause failure (CCF) for strainer plugging and independent failures of the six service water pumps to run.

The IP2 CCF for strainer plugging is lower than the IP3 value due to differing data calculation methods. Since the IP3 model update occurred later than the IP2 model update, it took advantage of lessons learned in the interim related to data calculation methods. Specifically, the IP2 failure rate for strainer plugging is a generic value Bayesian-updated using plant-specific data reflecting zero failures for the update time period. The IP3 failure rate for strainer plugging is the generic value without Bayesian updating. The more conservative IP3 approach resulted in a higher independent failure rate for IP3 strainer plugging and a correspondingly higher CCF term.

Also, the IP2 CCF term for strainer plugging was calculated using ALPHA factors taken from NUREG-5497. The IP3 CCF term for strainer plugging was calculated using ALPHA factors published by the NRC on their website. The NRC factors are higher than the ones from NUREG-5497, which resulted in a higher CCF term for IP3.

The IP2 service water pump independent failure-to-run probability is lower than the IP3 value and reflects the differences in plant-specific data that was used for the updates of both units.

If the more conservative IP3 data calculation methods were used for IP2, it would result in an increase in the IP2 total loss of service water initiating event frequency and a slight increase (less than 2%) in the baseline internal events CDF. A sensitivity study indicates that the IP2 SAMAs that could potentially be impacted by this change would remain not cost-effective. See the following table.

Phase II SAMA	Baseline Benefit with Revised SW Initiator	Baseline Benefit (Revised SW Initiator) With Uncertainty	Estimated Cost
002 - Create an independent RCP seal injection system without a dedicated diesel.	$202,981	$427,329	$1,000,000
005 - Improve ability to cool the RHR heat exchangers by allowing manual alignment of the fire protection system.	$64,904	$136,640	$565,000
064 - Provide backup cooling water source for the CCW heat exchangers.	$36,542	$76,931	$710,000
067 - Provide hardware connections to allow the primary water system to cool the charging pumps.	$8,091	$17,034	$576,000

SAMA Round 2 RAI 2

Explain why the IP3 analysis cases for "DC Power/AFW System Changes," "AC Power Cross-Tie with IP2," and "Backup DC Power Supply," result in no reduction in population dose or offsite economic cost risk (OECR) for the SAMAs considered therein, where some portion of the affected sequences may result in an offsite release.

Response to SAMA Round 2 RAI 2

Although as shown in ER Table E.4-2, the IP3 analysis cases for "DC Power/AFW System Changes," "AC Power Cross-Tie with IP2," and "Backup DC Power Supply" result in no reduction in population dose or offsite economic cost risk (OECR), the values for each individual release mode do show various degrees of reduction. The population dose and OECR are the total values calculated by summing over all release modes.

For example, the population dose and offsite economic cost risk for the IP3 base case and analysis case "DC Power/AFW System Changes" (SAMA 024, 025, 026, 042, and 056) are given as follows:

	Base Case			**DC Power/AFW System Changes**		
Release Mode	Frequency (/yr)	Population Dose Risk (person-rem/yr)	Offsite Economic Cost Risk ($/yr)	Frequency (/yr)	Population Dose Risk (person-rem/yr)	Offsite Economic Cost Risk ($/yr)
NCF	6.30E-06	2.42E-02	9.69E-01	6.00E-06	2.31E-02	9.23E-01
EARLY HIGH	9.43E-07	1.24E+01	2.81E+04	9.43E-07	1.24E+01	2.81E+04
EARLY MEDIUM	1.24E-06	6.35E+00	1.41E+04	1.24E-06	6.35E+00	1.41E+04
EARLY LOW	1.46E-07	1.99E-01	3.13E+02	1.45E-07	1.98E-01	3.11E+02
LATE HIGH	4.23E-07	1.79E+00	4.40E+03	4.22E-07	1.79E+00	4.39E+03
LATE MEDIUM	2.01E-06	3.57E+00	5.68E+03	2.00E-06	3.56E+00	5.67E+03
LATE LOW	3.75E-07	2.01E-01	1.96E+02	3.71E-07	1.99E-01	1.95E+02
LATE LOWLOW	5.66E-08	2.62E-02	2.60E+01	5.61E-08	2.60E-02	2.58E+01
Total	1.15E-05	**2.45E+01**	**5.28E+04**	1.12E-05	**2.45E+01**	**5.28E+04**

These results show that the population dose risk and offsite economic cost risk for the analysis case are lower than that of the base case for some of the individual release modes. However, the dominating release modes are unchanged. Thus, the reductions in the non-dominant modes are not significant enough to show a change in the rounded total of all the release modes.

This is also true for analysis cases "AC Power Cross-Tie with IP2" (SAMA 027) and "Backup DC Power Supply" (SAMA 058), since the dominant release modes are unchanged for them as well. These three analysis cases have their greatest impact on SBO and transient sequences because they mitigate power failures. They have little to no impact on SGTR, ISLOCA and internal flooding sequences. Since the contribution to the dominant release modes from SBO and transient sequences is small relative to SGTR, ISLOCA and internal flooding (see Figure E.3-2 for example), the fact that these analysis cases do not have an impact on the dominant release modes is reasonably expected.

SAMA Round 2 RAI 3

In environmental report Tables E.2-3 and E.4-3, the benefit value for Sensitivity Case 3 (Loss of Tourism and Business) is same as for the Baseline Case for a large number of analysis cases. Confirm whether Sensitivity Case 3 values were actually calculated (i.e., the Baseline Case values were used) when the reduction in population dose and OECR were below some threshold value. If so, the revised benefit values provided in response to RAI 4e (i.e., columns 2 and 3 of the tables) may understate the benefits for the affected SAMAs. The affected SAMAs include: IP2 SAMAs 4-6, 18, 25-27, 29-32, 34-39, 41-43, 48-50, 56, 59, 63, 64, 67, 68, and IP3 SAMAs 2, 24-26, 28, 29, 32, 33, 35-37, 40, 42, 47, 48, 51, 56, 58, and revised SAMA 30. Update the tables provided in response to RAI 4e, if necessary, to assure that the benefit estimates for the aforementioned SAMAs fully account for the impacts of loss of tourism and business.

Response to SAMA Round 2 RAI 3

All Sensitivity Case 3 benefit values shown in ER Tables E.2-3 and E.4-3 were actually calculated. No assumptions were made in the calculation regarding any threshold values of the reduction in population dose and OECR. The method used to calculate the benefit values is described in ER Section 4.21. Core damage frequency (CDF), population dose risk (PDR), and offsite economic cost risk (OECR) are key parameters for the benefit calculation.

Although the benefit values for Sensitivity Case 3 are the same as those for the Baseline Case for many analysis cases, the cost values are different. Benefit is defined as the difference in severe accident cost between the base case and a SAMA case. In Sensitivity Case 3, both the base case (cost of a severe accident with existing plant) and the SAMA case (cost of a severe accident if proposed modification is implemented) are impacted by the change to include loss of tourism and business.

To demonstrate, IP2 analysis case (Service Water Pumps, SAMA 004) is used as an example. Results in the following table show that base case and SAMA 004 costs are higher for Sensitivity Case 3 than those for the Baseline Case. However, the benefit values turn out to be the same. This characteristic of the SAMA 004 results applies to the other SAMAs listed in the RAI. Therefore, the tables provided in response to RAI 4e fully account for the impacts of loss of tourism and business and an update is not necessary.

Comparison of Benefit Values Between Baseline Case and Sensitivity Case 3
for
IP2 SAMA 004

Baseline Case	**CDF** (1/yr)	**PDR** (person-rem/yr)	**OECR** ($/yr)	**Cost** ($/yr)	**Benefit** ($/yr)
Base Case	1.79E-05	22.0	4.49E+04	1,337,939	
SAMA 004	1.75E-05	21.9	4.48E+04	1,326,194	11,745*
Sensitivity Case 3					
Base Case	1.79E-05	22.0	5.13E+04	1,406,822	
SAMA 004	1.75E-05	21.9	5.12E+04	1,395,077	11,745*

*Apply a multiplication factor of 3.8 (external events factor) to obtain the values shown in Table E.2-3.

SAMA Round 2 RAI 4

The response to RAI 2b indicates that steam generator tube ruptures (SGTRs) induced by high primary side pressures following core damage are addressed in the IP2 probabilistic risk assessment model using the information from the NUREG-1150 In-Vessel Expert Panel. The modeling approach does not appear to be explicitly provided. The response associated with IP3 does not appear to address this issue. Describe the current IP2 and IP3 modeling approach for thermally-induced SGTR events including the conditional probabilities and the associated conditions used to assess the likelihood of a thermally-induced SGTR (TI-SGTR), and the conditional probabilities for a stuck open main steam safety valve during a TI-SGTR event. Provide the bases for these values.

Response to SAMA Round 2 RAI 4

Thermally induced steam generator tube ruptures (TI-SGTR) were considered in both the IP2 and IP3 Level 2 analyses. The possibility of a TI-SGTR was considered for two conditions:

1) high RCS pressure and steam generators dry (no secondary-side cooling), and
2) high RCS pressure and steam generators initially dry, with recovery of secondary-side cooling prior to challenging the steam generator tubes.

The first condition was assumed to apply to transient event sequences in which RCS pressure is at the pressurizer PORV setpoint (2335 psig) at the time of core damage. No credit was taken for recovery of secondary side cooling in these sequences. The probability for this case was based on information contained in NUREG-1150, which was applied using the established quantification guidelines for the IP2 and IP3 Level 2 analyses. Specifically, the NUREG-1150 expert panel results for the probability of a TI-SGTR have a distribution that ranges from 10^{-5} to 0.1208 with a mean value of 0.018 (and a median value of 10^{-4}, as shown in Table 2-1 of NUREG/CR-4551, Volume 2, Rev 1, Part 1). This mean value was used in the Surry PRA [NUREG-CR/4551, Volume 3, Revision 1, Part 2, October 1990] for the probability of temperature induced steam generator tube rupture. Based on the previously established IP2 and IP3 Level 2 analysis guidelines, the temperature induced steam generator tube rupture probability was categorized as extremely unlikely, and a value of 0.01 was used.

The second condition was assumed to apply to station blackout sequences in which RCS pressure is at the pressurizer PORV setpoint at the time of core damage. Since additional time is available prior to challenging the steam generator tubes in this scenario (steam generators do not dry out until after battery depletion), it was judged that there was a high likelihood that power (and therefore secondary side cooling and other mitigating system functions) could be recovered prior to that time. The human error probability for failure to align auxiliary feedwater following AC power recovery (0.052) and the probability of a TI-SGTR, as derived above (i.e. 0.01), were combined resulting in a TI-SGTR probability of 0.0005 for these sequences.

The NUREG-1150 conditional TI-SGTR probability implicitly assumed a large differential pressure based on high RCS pressure and depressurization of the secondary side. A stuck-open main steam safety valve, or other secondary side depressurization path, is required to

create this large differential pressure. The probability of a TI-SGTR would be less with a lower differential pressure.

The current IP2 and IP3 Level 2 analyses conservatively applied the TI-SGTR conditional probabilities as described above without accounting for the probability associated with additional failures (e.g. a stuck-open main steam safety valve) that would be required to create a large differential pressure.

SAMA Round 2 RAI 5

Provide an assessment of the impact on the identification and screening of SGTR-related SAMAs if the conditional probabilities of TI-SGTR (discussed in item 4 above) are increased to values comparable to those reported in NUREG-1570. Provide a further evaluation and discussion of any additional SGTR-related SAMAs that could become potentially cost-beneficial under these assumptions (including the SAMAs addressed by the analysis cases identified in item 2 above) and Entergy's planned follow-up actions regarding these SAMAs.

Response to SAMA Round 2 RAI 5

Although final industry consensus on the TI-SGTR issue has not been reached, a sensitivity study was performed to determine the impact of applying values derived from the NUREG-1570 report. The full lists of IP2 and IP3 Phase II SAMAs were reviewed for impact including those SAMAs identified in item 2 above. Of those, the following twenty seven IP2 SAMAs and twenty two IP3 SAMAs were identified as potentially impacted by the TI-SGTR assumption.

IP2 SAMAs: 1, 6 18, 19, 20, 25, 26, 27, 28, 29 ,30, 31, 32, 35, 39, 40, 42, 44, 46, 52, 54, 59, 60, 61, 62, 65, 66
IP3 SAMAs: 1, 16, 17, 18, 23, 24, 25, 26, 27, 28, 29, 30, 33, 38, 40, 42, 43, 55, 56, 58, 61, 62

Since IP2 SAMAs 28, 44, 54, 60, 61 and 65 and IP3 SAMAs 55, 61 and 62 were previously determined to be potentially cost-beneficial, they were not re-evaluated. Of the remaining SAMAs, those for which the implementation cost outweighed the benefit by less than a factor of five were re-evaluated. This screening criterion was applied to facilitate the re-evaluation by limiting it to those potentially impacted SAMA candidates with a realistic possibility of becoming cost-beneficial. The SAMAs re-evaluated were:

IP2 SAMAs: 1, 6, 19, 29, 62, 66
IP3 SAMAs: 17, 26, 30*

* As revised in response to Item 5.g in the previous NRC RAI

The baseline case (Table 5.8 of NUREG-1570) associated with moderate tube degradation was used for this sensitivity study. The full conditional induced SGTR value (0.25) shown for that case was used. The NUREG-1570 conditional probability was applied to all high/dry sequences in the Level 2 model for each unit; in both station blackout and transient sequences. The benefit values for this SAMA re-evaluation included the additional impact of the loss of tourism and business, consistent with our response to Item 4.e in the previous set of SAMA RAIs. Tables 1 and 2 show the values for the IP2 and IP3 SAMAs re-evaluated in this sensitivity analysis. While the severe accident costs of both the baseline case and the individual SAMAs increased, the extent to which the revised TI-SGTR assumption impacted the delta cost varied, based on the nature of the specific SAMA. IP2 SAMA 019 and IP3 SAMA 017, "Increase secondary side

pressure capacity such that a SGTR would not cause the relief valves to lift," were uniquely impacted since those changes were assumed to fully preclude TI-SGTR.

No additional SAMAs were found potentially cost beneficial as a result of this sensitivity analysis.

Although the NUREG-1570 baseline case values were used for this sensitivity analysis, the baseline case applies to a steam generator with a moderate flaw distribution. The IP2 and IP3 steam generators have been replaced and are being maintained in accordance with the stringent standards recommended by NEI 97-06. The IP2 and IP3 steam generators have only 0.19% and 0.12% of the tubes plugged, and would be classified as "pristine" in accordance with generic criteria established by Westinghouse for categorizing steam generator tube integrity. Corrosion has not been observed in either the IP2 or IP3 steam generators. Therefore, use of the baseline case for this sensitivity study is conservative relative to application of the NUREG-1570 results for pristine generators (Table 5.8, Case 8).

Table 1

IP2 Phase II SAMA	Original Sensitivity Case 3 Benefit with Uncertainty	Revised Sensitivity Case 3 Benefit with Uncertainty	% Increase	Estimated Implementation Cost
001 - Create an independent RCP seal injection system with a dedicated diesel.	$427,328	$444,550	4.03%	$1,137,000
006 - Add a diesel building high temperature alarm.	$59,897	$59,897	0.00%*	$274,000
019 - Increase secondary side pressure capacity such that a SGTR would not cause the relief valves to lift.	$2,599,379	$4,631,411	78.17%	$13,000,000
029 - Increase/ improve DC bus load shedding.	$93,964	$93,964	0.00%*	>$160,000
062 - Provide a hard-wired connection to an SI pump from ASSS power supply.	$601,598	$618,818	2.86%	$722,000
066 - Harden the EDG building and fuel oil transfer pumps against tornados and high winds.	$4,008,913	$4,284,657	(See Note 1)	>$10,000,000

* The impact of the revised TI-SGTR assumption on this SAMA results in no discernible change in the benefit value.

Note 1: IP2 SAMA 066 impacts only high wind events. The additional benefit factor associated with external event impacts would represent a double counting of the benefit of this SAMA and has, therefore, not been applied in this case. Since the original sensitivity case conservatively included this double counting, the values are not comparable.

Table 2

IP3 Phase II SAMA	Original Sensitivity Case 3 Benefit with Uncertainty	Revised Sensitivity Case 3 Benefit with Uncertainty	% Increase	Estimated Implementation Cost
017 - Increase secondary side pressure capacity such that an SGTR would not cause the relief valves to lift.	$4,552,986	$8,083,218	77.54%	$13,000,000
026 - Increase/ improve DC bus load shedding.	$51,100	$51,100	0.00%*	>$160,000
030 - Provide a portable diesel-driven battery charger.	$145,626	$188,677	29.56%	$494,000

* The impact of the revised TI-SGTR assumption on this SAMA results in no discernible change in the benefit value.

SAMA Round 2 RAI 6

The SAMA analysis for Beaver Valley Power Station identified as potentially cost-beneficial the purchase or manufacture of a "gagging device" that could be used to close a stuck-open steam generator safety value *[sic]* on the ruptured steam generator prior to core damage in SGTR events. Provide an evaluation of the viability of this SAMA for IP2 and IP3, including the estimated costs and benefits under the assumptions of items 5 and 8.

Response to SAMA Round 2 RAI 6

The SAMA determined to be potentially cost beneficial in the Beaver Valley LRA included implementing procedural guidance to close the RCS loop stop valve to isolate the generator from the core and providing a mechanical device (and procedural guidance) to close a stuck open steam generator safety valve. This SAMA is only partially viable at Indian Point since the IP2 and IP3 designs do not include the capability to isolate a specific RCS loop. Although the ultimate determination of the viability of gagging a stuck open safety valve will require a detailed evaluation of the impact on other required EOP actions, the potential for such a SAMA to be cost-beneficial has been evaluated using the assumptions described in the responses to RAI 5 and 8.

The impact of successfully gagging a stuck open main steam safety valve following a steam generator tube rupture initiating event was conservatively bounded by eliminating failure of early steam generator isolation. This was evaluated in the IP2 Level 1 model by setting the following basic events to zero: MSS-XHE-FO-SGISO, MSS-SRV-CO-45A-D, MSS-SRV-CO-46A-D, MSS-SRV-CO-47A-D, MSS-SRV-CO-48A-D and MSS-SRV-CO-49A-D. This was evaluated in the IP3 Level 1 model by setting the following basic events to zero: SGISO, MSS-SRV-CO-45-1 thru 4, MSS-SRV-CO-46-1 thru 4, MSS-SRV-CO-47-1 thru 4, MSS-SRV-CO-48-1 thru 4 and MSS-SRV-CO-49-1 thru 4.

To address the issue raised in RAI-5, this SAMA was also evaluated by conservatively assuming that gagging was fully successful in preventing all TI-SGTRs. The probability of the TI-SGTR event in the modified Level 2 model was, therefore, set to zero for IP2 and IP3. To determine the benefit of this SAMA, the cost of a severe accident following implementation of the SAMA was subtracted from the baseline cost including the impact of the NUREG-1570 results on TI-SGTR.

The following table provides the results of this SAMA evaluation. The table includes both the benefit associated with reducing the impact of the Level 1 Steam Generator Tube Rupture Initiating Event and the benefit associated with assuming that the SAMA is fully effective in eliminating all TI-SGTR events. The benefit values shown in that table account for the additional impact of the loss of tourism and business, including uncertainty, consistent with our response to Item 4.e in the previous set of SAMA RAIs. The cost of implementing this SAMA at each unit, including purchasing and storing a dedicated gagging device, revising procedures and providing associated training, was estimated consistent with the approach taken for previous SAMAs, as described in response to RAI 8.

While the approach taken above is very conservative, the results indicate that this additional SAMA is potentially cost beneficial and it has been submitted for engineering project cost-benefit analysis for more detailed examination of viability and implementation cost.

SAMA Evaluation of a Gagging Device for a Stuck Open Main Steam Safety Valve				
Unit	**Level 1 (IE-SGTR) Benefit**	**Level 2 Benefit of Eliminating TI-SGTR**	**Total Benefit**	**Estimated Cost**
IP2	$826,216	$2,032,032	$2,858,248	$50,000
IP3	$834,639	$3,530,232	$4,364,871	$50,000

SAMA Round 2 RAI 7

The response to RAI 4e states that Sensitivity Case 3 with uncertainty results in two additional SAMAs (009 and 053) for IP2 and one additional SAMA (053) for IP3. Discuss Entergy's planned follow-up actions regarding these additional SAMAs.

Response to SAMA Round 2 RAI 7

Although these SAMAs were only identified as potentially cost beneficial in the sensitivity case 3 evaluation with uncertainty, and not in the baseline evaluation, IP2 SAMAs 009 and 053 and IP3 SAMA 053 have been submitted for engineering project cost-benefit analysis for more detailed examination of viability and implementation cost.

SAMA Round 2 RAI 8

The response to RAI 5l shows a $236,000 contingency cost as part of the cost breakdown. However, Section 4.21.5.4, "Final Screening and Cost/Benefit Evaluation (Phase II)" of the environmental report states that "the cost estimates for implementing the SAMAs did not include the cost of replacement power during extended outages required to implement the modifications, nor did they include contingency cost associated with unforeseen implementation obstacles." Explain this apparent discrepancy. Identify any other cost estimates in the SAMA analyses that include contingency costs. Provide the impact on the SAMA evaluation if all contingent costs are included.

Response to SAMA Round 2 RAI 8

The site-specific implementation cost estimates include some contingency costs. The contingencies included in these cost estimates account for the fact that these preliminary cost estimates have a high degree of uncertainty and neglect significant project requirements and cost add-ons. They do not account for unanticipated problems that might impact implementation following a more detailed cost estimate. Given the bounding nature of the benefit analysis, it is reasonable to include this type of contingency in the preliminary cost estimates.

The wording in 4.21 was intended to refer to contingencies associated with unforeseen project obstacles that might arise even with a more detailed estimate. However, since the wording can be misinterpreted, the sentence in Section 4.21 is revised as follows.

The cost estimates for implementing the SAMAs did not include the cost of replacement power during extended outages required to implement the modifications~~, nor did they include contingency cost associated with unforeseen implementation obstacles~~.

Accounting for all contingent costs is not within the scope of the SAMA analysis. Addition of contingent costs would not change the conclusion regarding the economic viability of the SAMAs listed as not cost effective. The potentially cost-beneficial SAMAs have been submitted for engineering project cost-benefit analysis, which appropriately accounts for contingency costs, to determine if implementation is desirable.