UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	Docket Nos. 52-012-COL
	)	52-013-COL
NUCLEAR INNOVATION NORTH AMERICA LLC	)	
	)	
(South Texas Project Units 3 and 4)	)	May 9, 2011

DIRECT TESTIMONY OF APPLICANT WITNESSES JEFFREY L. ZIMMERLY AND ADRIAN PIENIAZEK REGARDING CONTENTION CL-2

I. WITNESS BACKGROUND

A. Jeffrey L. Zimmerly (JLZ)

Q1. Please state your full name.

A1. (JLZ) My name is Jeffrey L. Zimmerly ("JLZ").

Q2. By whom are you employed and what is your position?

A2. (JLZ) I am an Environmental Engineer and Corporate Quality Assurance Manager for Tetra Tech NUS, Inc. ("Tetra Tech"), which is a contractor to Nuclear Innovation North America LLC ("NINA") for South Texas Project ("STP") Units 3 and 4. I have been retained by NINA as an independent expert in connection with the adjudication of Contention CL-2 that was submitted by Sustainable Energy and Economic Development Coalition, Susan Dancer, the South Texas Association for Responsible Energy, Daniel A. Hickl, Public Citizen, and Bill Wagner ("Intervenors").

The original lead applicant for STP Units 3 and 4 was the STP Nuclear Operating Company ("STPNOC"). NINA became the lead applicant in early 2011. This testimony refers to both NINA and STPNOC as the "Applicant."

Q3. Please describe your educational and professional qualifications, including relevant professional activities.

A3. (JLZ) My professional and educational qualifications are summarized in the attached *curriculum vitae* (Exh. STP000012). Briefly summarized, I earned a B.S. degree in health physics from Francis Marion University. I have over 10 years experience supporting various government, utility, and industrial clients in the areas of environmental impact assessment, radiological transportation risk assessment, accident analysis, human health and ecological risk assessment, air quality modeling and compliance, occupational and environmental health physics, and radioactive waste management. Since 2000, I have been employed with Tetra Tech. Prior to this employment, I was employed with Westinghouse and Carolina Power and Light Company.

I participated in the preparation of the Environmental Report ("ER") for STP Units 3 and 4, including authoring and reviewing parts of the evaluation of severe accident mitigation design alternatives ("SAMDAs"). I similarly authored and reviewed portions of ER Section 7.5S that the Applicant submitted to the Nuclear Regulatory Commission ("NRC") on November 10, 2009. I also have performed analyses and calculations to support ERs for other new reactor and license renewal applications.

Q4. Please describe the materials that you reviewed in preparation of this testimony.

A4. (JLZ) I have reviewed various materials in preparing this testimony, including the parties' pleadings and supporting materials related to Contention CL-2; the Atomic Safety and Licensing Board's ("Board's") Orders related to this contention; the Applicant's SAMDA evaluation in ER Sections 7.3 and 7.5S; and relevant NRC guidance documents.

B. <u>Adrian Pieniazek (AP)</u>

Q5. Please state your full name.

A5. (AP) My name is Adrian Pieniazek ("AP").

Q6. By whom are you employed and what is your position?

A6. (AP) I am currently the Director of Market Policy for NRG Energy, Inc. ("NRG Energy"). I have more than 27 years of experience in the energy industry and I have been in my current position since 2003. My current responsibilities include representing NRG Energy's interests at the Electric Reliability Council of Texas ("ERCOT") and the Public Utility Commission of Texas ("PUCT") and providing analysis and policy recommendations to numerous NRG Energy business units, with a specific emphasis on wholesale electricity market design issues. NRG Energy is an owner of NINA, the lead applicant for STP Units 3 and 4.

Q7. Please describe your educational and professional qualifications, including relevant professional activities.

A7. (AP) My professional and educational qualifications are summarized in the attached *curriculum vitae* (Exh. STP000002). Briefly summarized, I earned a B.S. degree in Mechanical Engineering from Texas A&M University and an M.B.A. from Our Lady of the Lake University in San Antonio, Texas. I am a registered professional engineer in Texas. Upon graduation from college, I began my career serving in various engineering positions for TXU Energy (now Luminant Energy). Prior to my current position, I was the Director of Asset

Management for Reliant Energy, Inc. in Texas. Prior to that, I served as the Director of Generation Planning for CPS Energy, the municipal power utility serving San Antonio, Texas.

Q8. Please describe the materials that you reviewed in preparation of this testimony.

A8. (AP) I have reviewed various materials in preparing this testimony, including the parties' pleadings and supporting materials related to Contention CL-2; the Board's Orders related to this contention; the Applicant's SAMDA evaluation in ER Sections 7.3 and 7.5S; relevant NRC guidance documents; and relevant ERCOT documents.

II. PURPOSE OF TESTIMONY

Q9. What is the purpose of your testimony?

A9. (JLZ, AP) The purpose of our testimony is to address Contention CL-2.

Q10. Are you familiar with Contention CL-2, as originally proposed by the Intervenors?

A10. (JLZ, AP) Yes, we have reviewed Contention CL-2, which was originally proposed as Contentions CL-2, CL-3, and CL-4 in the December 22, 2009 "Intervenors' Contentions Regarding Applicant's Proposed Revision to Environmental Report Section 7.5S and Request for Hearing." We also have reviewed the December 21, 2009 report prepared by Clarence L. Johnson, titled "Review of Replacement Power Costs for Unaffected Units at the STP Site" ("Johnson Report 1"). The proposed contentions challenged the estimated replacement power costs in the Applicant's SAMDA evaluation in ER Section 7.5S.

Q11. Are you familiar with Contention CL-2, as admitted by the Board on July 2, 2010?

A11. (JLZ, AP) Yes, we have reviewed the Board Order (LBP-10-14), issued on July 2, 2010, that admitted Contention CL-2. As admitted by the Board, Contention CL-2 states: "The Applicant's calculation in ER Section 7.5S of replacement power costs in the event of a forced shutdown of multiple STP Units is erroneous because it underestimates replacement power costs and fails to consider disruptive impacts, including ERCOT market price spikes."

Q12. Are you familiar with the September 14, 2010 "STP Nuclear Operating Company's Motion for Summary Disposition of Contention CL-2"?

A12. (JLZ, AP) Yes, we are familiar with the motion. To support the motion, we prepared the "Joint Affidavit of Jeffrey L. Zimmerly and Adrian Pieniazek" ("Joint Affidavit"). The Joint Affidavit demonstrated that even if the SAMDA evaluation had used the assumptions proposed by the Intervenors in Contention CL-2, there is no change to the conclusion that there are no cost-effective SAMDAs.

We also have reviewed the October 8, 2010, "Intervenors' Response to Applicant's Motion for Summary Disposition of Contention CL-2," including the accompanying October 6, 2010 "Affidavit in Response to Motion for Summary Disposition" ("Johnson Report 2") that was prepared by Mr. Johnson.

Q13. Are you familiar with the Board's rejection of the September 14, 2010 "STP Nuclear Operating Company's Motion for Summary Disposition of Contention CL-2"?

A13. (JLZ, AP) Yes, we have reviewed the Board Order (LBP-11-07), issued on February 28, 2011, that rejected the motion.

Q14. Please summarize your testimony.

A14. (JLZ, AP) Our testimony demonstrates that there are no cost-effective SAMDAs for STP Units 3 and 4. We first provide an overview of the ER SAMDA evaluation. We then discuss SAMDA costs, including inflation and accounting for risk reduction from implementing the SAMDAs. We next conclude that the ER's replacement power cost estimates are reasonable and demonstrate that there are no cost-effective SAMDAs. Finally, we demonstrate that consideration of all issues raised by the Intervenors and the NRC Staff regarding replacement power costs does not change the conclusion that there are no cost-effective SAMDAs. As part of this evaluation, we consider a higher capacity factor and net electrical output, ERCOT pricing data, the Intervenors' own estimates, ERCOT market effects, ERCOT price spikes, and loss of the ERCOT grid. Our evaluation of these issues is conservative, and provides further assurance that there are no cost-effective SAMDAs.

III. OVERVIEW OF THE ER SAMDA EVALUATION

A. Overview of STP Units 3 and 4

Q15. Please describe the STP Units 3 and 4 project.

A15. (JLZ) The STP site is located on the coastal plain of southeastern Texas in Matagorda County. NINA has applied for combined licenses ("COLs") to construct and operate STP Units 3 and 4, utilizing the Advanced Boiling Water Reactor ("ABWR") light water reactor design, each with an expected output of approximately 1,350 MW (gross) and a net electrical output of approximately 1,300 MW. Initial commercial operation for STP Units 3 and 4 could occur as early as 2018, but may occur later. Both STP Units 3 and 4 will be operated by STPNOC. The purpose of STP Units 3 and 4 is to provide baseload power generation for use by the owners and/or sale on the wholesale market.

B. <u>ER Evaluation of Severe Accident Mitigation Alternatives</u>

Q16. Please summarize the accident evaluation in the STP Units 3 and 4 ER as it pertains to SAMDAs.

A16. (JLZ) ER Chapter 7 (Exh. STP000013) discusses the environmental impacts of postulated accidents. Specifically, ER Section 7.1 addresses design basis accidents; ER Section 7.2 discusses the radiological impacts of severe accidents; ER Section 7.3 addresses severe accident mitigation alternatives ("SAMAs"); ER Section 7.4 addresses transportation accidents; and ER Section 7.5S evaluates the impacts of design basis and severe accidents on the co-located units at the STP site. I attest to the truthfulness and accuracy of ER Chapter 7.

Q17. What types of SAMAs are discussed in ER Section 7.3 (Exh. STP000013)?

A17. (JLZ) ER Section 7.3 presents a site-specific analysis of SAMAs. These SAMAs consist of two types of alternatives: (1) SAMDAs; and (2) alternatives involving administrative controls, such as procedures and training.

Q18. To what extent do SAMAs for administrative controls need to be evaluated at the COL stage?

A18. (JLZ) Under the licensing process established in 10 C.F.R. Part 52, procedures and training do not need to be finalized in order to obtain a COL and instead can be developed during construction. ER Section 7.3.3 (Exh. STP000013) states that evaluation of specific administrative controls will occur when the design for STP Units 3 and 4 is finalized and plant administrative processes and procedures are being developed. Prior to fuel load, appropriate administrative controls on plant operations will be developed and incorporated into the management systems for STP Units 3 and 4. Therefore, because procedures and training materials have not and do not need to be developed at this time, and because appropriate procedures and training to mitigate accidents will be developed before fuel load, there is no further evaluation of alternative administrative controls that can fruitfully be conducted at this time.

C. Methodology for SAMDA Evaluations

Q19. How are SAMDAs evaluated?

A19. (JLZ) To perform a SAMDA evaluation, the cost of each SAMDA is compared against the benefit of implementing the SAMDA. As discussed in ER Section 7.3.1 (Exh. STP000013), the analysis determines the maximum benefit from averting all severe accidents through the risk reduction of implementing each of the SAMDAs. If the maximum benefit from averting all severe accidents is lower than the lowest cost of the SAMDAs, then the SAMDAs are screened out and the analysis is complete. However, if the maximum benefit from averting all severe accidents is greater than the cost of any of the SAMDAs, each of those SAMDAs is evaluated further. The cost of each of those individual SAMDAs is evaluated against the benefit of implementing each of those individual SAMDAs. For example, if a SAMDA would eliminate 10% of the total risk of severe accidents, then the benefit of the SAMDA would be approximately 10% of the maximum averted costs of severe accidents.

Q20. How are the identities and costs of SAMDAs determined?

A20. (JLZ) The identities and costs of SAMDAs for designs certified under 10 C.F.R. Part 52 are determined as part of the design certification process. For the ABWR, the design selected for STP Units 3 and 4, the SAMDAs and their costs were identified in the Technical Support Document ("TSD") submitted as part of the ABWR design certification application on December 21, 1994 (Exhs. NRC00009A and NRC00009B).

Q21. What SAMDAs were evaluated in the TSD for the ABWR?

A21. (JLZ) As explained in TSD Appendix A (Exh. NRC00009B), the TSD evaluated a wide variety of ABWR modifications as potential SAMDAs. These are listed in TSD Table A-3. These potential SAMDAs were narrowed to exclude modifications already incorporated into the ABWR design or modifications that are not applicable to the ABWR design. The remaining 21 potential SAMDAs are identified in TSD Table A-4, and are reproduced in Table 1 of this testimony below.

Q22. What are the costs for these SAMDAs identified in the TSD?

A22. (JLZ) The TSD provides estimated costs for the 21 potential SAMDAs. As explained in TSD Appendix A, these costs were conservatively biased on the low side, and actual plant costs are expected to be higher than indicated. (Exh. NRC00009B, page 33). The costs are referenced to 1991 dollars (Exh. NRC00009B, page 47). The costs are identified in TSD Table A-6 (Exh. NRC00009B), and are reproduced in Table 1 of this testimony below.

Table 1 – SAMDAs and Corresponding Costs

SAMDA	Cost (1991 Dollars)
1a. Severe Accident EPGs/AMGs	$600,000
1b. Computer Aided Instrumentation	$599,600
1c. Improved Maintenance Procedures/Manuals	$299,000
2a. Passive High Pressure System	$1,744,000
2b. Improved Depressurization	$598,600
2c. Suppression Pool Jockey Pump	$120,000
2d. Safety Related Condensate Storage Tank	$1,000,000
3a. Larger Volume Containment	$8,000,000
3b. Increased Containment Pressure Capability	$12,000,000
3c. Improved Vacuum Breakers	$100,000
3d. Improved Bottom Head Penetration Design	$750,000
4a. Large Volume Suppression Pool	$8,000,000
5a. Low Flow Filtered Vent	$3,000,000
7a. Drywell Head Flooding	$100,000
8a. Additional Service Water Pump	$5,999,000
9a. Steam Driven Turbine Generator	$5,994,300
9b. Alternate Pump Power Source	$1,194,000
10a. Dedicated DC Power Supply	$3,000,000
11a. ATWS Sized Vent	$300,000
13a. Reactor Building Sprays	$100,000
14a. Flooded Rubble Bed	$18,750,000

As shown in Table 1, the lowest-cost SAMDA for the ABWR was estimated to be $100,000 (1991 dollars). This lowest-cost corresponds to SAMDAs for improved vacuum breakers, drywell head flooding, and Reactor Building sprays.

Q23. How are the costs of severe accidents determined?

A23. (JLZ) The costs of severe accidents are determined using a probabilistic-based approach. This approach accounts for exposure costs, cleanup costs, and replacement power costs associated with the postulated severe accident and corresponding outages, and factors in the likelihood of the severe accident as reflected in the reactor's Core Damage Frequency ("CDF") and the operating lifetime of the plant. Exposure costs include the public and occupational radiation exposure during accidents. Cleanup costs include the costs for offsite and onsite property. Offsite property costs include the short term evacuation and sheltering, interdiction and banning of agricultural products, and cleanup and decontamination. Onsite property costs include cleanup and decontamination, and repair and refurbishment. The cumulative costs correspond to the maximum averted cost-risk of severe accidents.

Q24. How was the benefit of SAMDAs determined in the ER (Exh. STP000013)?

A24. (JLZ) In calculating the benefits of SAMDAs in ER Sections 7.3 and 7.5S, it was assumed that each SAMDA would completely prevent all severe accidents, and thus the benefit was equated to the maximum averted cost-risk. The maximum averted cost-risk of an accident was converted into a net present value using the discount rate. The cost should be discounted because the postulated accident could occur at any time over the life of the plant, and costs incurred in later years have a lower net present value than the same costs incurred nearer in time. Therefore, the maximum averted cost-risk in future years needs to be discounted to the net present value. In general, a long-term 7% real discount rate is reasonable according to the NRC in NUREG/BR-0184, “Regulatory Analysis Technical Evaluation Handbook” (Jan. 1997) (Exh. NRC00008B, page 5.21); however, as part of a sensitivity analysis, the Applicant also conservatively assumed a 3% real discount rate, which results in a significantly higher net present value.

Q25. What is the basis for use of a 7% discount rate?

A25. (JLZ) Section 5.7 of NUREG/BR-0184 provides guidance on quantifying the impacts of regulatory analyses. That section states (Exh. NRC00008B, page 5.21): “Based on OMB’s guidance in Circular A-94, Section 4.3.3 of the Guidelines requires that a 7% real (i.e., inflation-adjusted) discount rate be used for a best estimate. For sensitivity analysis, the Guidelines recommend a 3% discount rate.” Section 8.b of the referenced OMB Circular A-94, “Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs” (Exh. STP000016), states that a 7% real discount rate should be used for a base-case analysis as part of regulatory analyses. This section also states that a sensitivity analysis should be performed. OMB has not modified this guidance specific to regulatory analyses in Circular A-94 since it was referenced in NUREG/BR-0184. The ER’s use of a 7% real discount rate, and a sensitivity analysis using a 3% real discount rate, is consistent with this guidance from the Federal government.

Additional NRC Guidance, NUREG/BR-0058, “Regulatory Analysis Guidelines of the U.S. Nuclear Regulatory Commission” (Rev. 4, Sept. 2004) (Exh. NRC000010), confirms use of the OMB guidance (page 32):

> Based on OMB guidance, present-worth calculations should be presented using both 3 percent and 7 percent real discount rates (Ref. 11). The 3 percent rate approximates the real rate of return on long-term government debt which serves as a proxy for the real rate of return on savings. This rate is appropriate when the primary effect of the regulation is on private consumption.

> Alternatively, the 7 percent rate approximates the marginal pretax real rate of return on an average investment in the private sector, and is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector. As the distribution of regulatory impacts on capital and consumption are not always well known, two sets of base case estimates should be developed and presented—one at 3 percent and one at 7 percent. The use of alternative discount rates as a further sensitivity analysis is appropriate as long as sufficient justification is provided for use of that rate.

The Applicant's analysis of replacement power costs in ER Section 7.5S is consistent with this guidance because it uses a 7% real discount rate, and a sensitivity analysis using a 3% real discount rate.

Q26. Mr. Johnson states (Johnson Report 2 ¶ 7) that a 3% discount rate should be used for the replacement power cost evaluation. How would use of a 3% discount rate change the evaluation?

A26. (JLZ) Use of a 3% discount rate would not change the conclusions of the SAMDA evaluation. As discussed above, ER Section 7.5S estimates replacement power costs using both 7% and 3% discount rates. Our testimony continues this methodology and evaluates changes to the replacement power costs assuming both a 7% and a 3% discount rate. As shown in ER Section 7.5S and in this testimony, whether the 7% or the 3% discount rate is used, there are no cost-effective SAMDAs.

Q27. How would you characterize the methodology in ER Section 7.5S (Exh. STP000013) for comparing costs and benefits for a SAMDA?

A27. (JLZ) The methodology in ER Section 7.5S of comparing the costs and benefits for a SAMDA is conservative, because in actuality there are no SAMDAs that would prevent all severe accidents, and therefore there will always be some cost-risk that cannot be averted. In other words, implementing a SAMDA will not realize all of the benefits of avoiding the severe accidents, but will only achieve a portion of those benefits.

Q28. Please discuss whether the ER's SAMDA evaluation for STP Units 3 and 4 considers accidents originating at STP Units 1 and 2.

A28. (JLZ) ER Section 7.5S (Exh. STP000013) does not consider accidents originating at STP Units 1 and 2. For purposes of a SAMDA evaluation for STP Units 3 and 4, accidents originating at STP Units 1 and 2 should not be considered because there are no SAMDAs for STP Units 3 and 4 that could prevent or mitigate an accident at STP Units 1 and 2.

D. <u>NRC Guidance</u>

Q29. Is there any NRC guidance for SAMDA evaluations?

A29. (JLZ) Yes. NUREG-1555, "Standard Review Plans for Environmental Reviews for Nuclear Power Plants" (Exh. STP000018), recommends use of NUREG/BR-0184 for SAMDA evaluations. Specifically, NUREG-1555, Section 7.3, states that "[r]egulatory positions and specific criteria necessary to meet the regulations" are provided in "NUREG/BR-0184 (NRC 1997b) with respect to the value impact methodology." Thus, NUREG/BR-0184 provides an accepted NRC methodology for use in SAMDA analyses.

NUREG/BR-0184 provides NRC guidance for calculating replacement power costs. NUREG/BR-0184 (Exh. NRC00008A, page 1.2) states that its purpose "is to provide guidance to the regulatory analyst to promote preparation of high-quality regulatory decision-making documents" and to provide "standardized methods of preparation and presentation of regulatory analyses." Additionally, NUREG/BR-0184 (Exh. NRC00008A, page 1.1) states that it provides guidance that "is consistent with NRC policy and, if followed, will result in an acceptable document."

Chapter 5 of NUREG/BR-0184 provides generic methodologies for estimating the value impact of certain activities. Section 5.7.6 includes estimation methodologies for the costs of damage to onsite property, including long-term replacement power costs as discussed in Section 5.7.6.2. Additionally, Section 5.7.7 discusses industry implementation of these cost estimates, including a discussion of short-term replacement power costs in Section 5.7.7.1.

Q30. Please discuss whether the ER SAMDA evaluation followed NRC guidance.

A30. (JLZ) The estimation of replacement power costs for the SAMDA evaluation in ER Sections 7.3 and 7.5S.5 (Exh. STP000013) follows the guidance in NUREG/BR-0184.

E. ER Section 7.3 SAMDA Evaluation for Unit Experiencing Severe Accident

Q31. Please summarize the evaluation of SAMDAs in ER Section 7.3 (Exh. STP000013) for the unit experiencing a severe accident.

A31. (JLZ) The SAMDA analysis in ER Section 7.3 for the unit experiencing a severe accident is based upon the generic SAMDA evaluation for the ABWR design certification. The TSD evaluated various SAMDAs, and determined that the least expensive SAMDA would cost $100,000. The TSD also evaluated the net present value of the cost of accidents, including replacement power costs and non-replacement power costs (such as land contamination and the monetary value of population doses), and it concluded that there are no cost-effective SAMDAs. As shown in ER Section 7.3, the TSD conclusion holds for the STP site.

ER Section 7.3.3 provides a monetary valuation of the cost-risk of accidents at STP Units 3 and 4, including replacement power costs and non-replacement power costs. As shown in ER Table 7.3-1, the net present value (2007 dollars) of the total maximum averted cost-risk for one ABWR is approximately $6,900 (assuming a 7% discount rate) and $12,500 in the sensitivity analysis (assuming a 3% discount rate). These values included replacement power costs of

$4,400 (7% discount rate) and $7,400 in the sensitivity analysis (3% discount rate). The remaining costs included exposure and cleanup costs. The ER used guidance in NUREG/BR-0184 to perform these evaluations.

Q32. What is the conclusion of the ER SAMDA evaluation for the unit experiencing a severe accident?

A32. (JLZ) ER Section 7.3.3 (Exh. STP000013) concludes that, using the maximum averted cost-risk for an ABWR at the STP site, the results of the SAMDA analysis for the ABWR would not be affected; *i.e.*, there would be no cost-effective design alternatives.

F. ER Section 7.5S SAMDA Evaluation for Co-Located Units

Q33. Please summarize the SAMDA evaluation in ER Section 7.5S (Exh. STP000013) that accounts for co-located units.

A33. (JLZ) ER Section 7.5S.5 evaluates the economic impacts of a severe accident at one of the ABWRs at STP Units 3 and 4 and a temporary shutdown of the three co-located STP units that do not experience the postulated severe accident.

Similar to ER Section 7.3, the evaluation in ER Section 7.5S.5 is based upon the maximum averted cost-risk. The monetized impacts are shown in ER Tables 7.5S-1 and 7.5S-2 and include onsite exposure costs, onsite cleanup costs, and replacement power costs. The replacement power costs were calculated using information in NUREG/BR-0184 (Exhs. NRC00008A and NRC00008B).

Q34. How did the ER (Exh. STP000013) calculate these replacement power costs?

A34. (JLZ) The ER started with Section 5.7.7.1 of NUREG/BR-0184 (Exh. NRC00008B), which states that typical short-term replacement power costs for a 910 MWe power plant are $310,000 per day (1993 dollars). To determine replacement power costs for the co-located units following a severe accident at the STP site, this value was first multiplied by the estimated outage duration of the co-located units. For a hypothetical severe accident at an ABWR unit, ER Section 7.5S.5 states that the estimated outage duration at the co-located ABWR is six years. Similarly, for this same postulated accident, ER Section 7.5S.5 states that the estimated outage duration at the co-located STP Units 1 and 2 is two years. These assumptions regarding outage duration are reasonable given the actual experience at Three Mile Island Unit 1 following the accident at Unit 2 in 1979.

These generic replacement power costs were then used in an equation specified in Section 5.7.6.2 of NUREG/BR-0184 to calculate the net present value of replacement power costs over the life of the facility. Finally, the specific net present value of replacement power over the life of the facility was scaled up from a 910 MWe plant to the 1,350 MWe ABWR and multiplied by the CDF for the ABWR. This 1,350 MWe value approximates the gross electrical output of each ABWR unit. After reducing for the plant and site equipment loads, the net electrical output is approximately 1,300 MWe. Use of 1,350 MWe for this calculation is conservative, because it results in higher replacement power cost estimates.

For an ABWR, the CDF for internal events at full power is 1.56×10^{-7} per year. As discussed in ER Section 7.5S.3, external events at the STP site have a small contribution to risk. Additionally, the probability of low power and shutdown events is low. Accordingly, accounting for the probability of those categories of events would not have a material impact on the results of the SAMDA evaluation.

For an accident originating at one of the ABWR units, using a CDF of 1.56×10^{-7} per year and a 7% discount rate, ER Table 7.5S-2 calculated a probability-weighted replacement power cost of $1,980 in 1993 dollars. Using a discount rate of 3% in the sensitivity analysis, the ER calculated a probability-weighted replacement power cost of $2,557 in 1993 dollars. Using a similar process, the ER calculated a probability-weighted replacement power cost at STP Units 1 or 2 (which assumed a net electrical output of 1,280 MWe each) of $688 for a 7% discount rate and $1,153 for the sensitivity analysis using a 3% discount rate.

Q35. How did the ER calculate the total monetized impacts for the units?

A35. (JLZ) The replacement power costs calculated above were added to the other monetized impacts (*e.g.*, onsite exposure cost and onsite cleanup cost) to provide the total monetized impacts for each unit. A similar process was used for the unit experiencing the accident, as discussed in ER Section 7.3 (Exh. STP000013). These monetized impacts can be separated into replacement power costs and non-replacement power costs.

Q36. What are the total monetized impacts using the ER methodology?

A36. (JLZ) As stated in ER Tables 7.3-1 and 7.5S-2 (Exh. STP000013), these total monetized impacts were estimated to be:

Table 2 – Monetized Impacts Using NUREG/BR-0184 Replacement Power Costs in 1993 Dollars

7% Discount Rate				
	ABWR with Severe Accident	**Other ABWR**	**STP Unit 1**	**STP Unit 2**
Non-Replacement Power Costs	$2,454	$1,025	$1,071	$1,071
Replacement Power Costs	$4,400	$1,980	$688	$688
Unit Total	$6,854	$3,005	$1,759	$1,759
Site Total	$13,377			
Sensitivity Analysis -- 3% Discount Rate				
	ABWR with Severe Accident	**Other ABWR**	**STP Unit 1**	**STP Unit 2**
Non-Replacement Power Costs	$5,046	$1,916	$1,895	$1,895
Replacement Power Costs	$7,400	$2,557	$1,153	$1,153
Unit Total	$12,446	$4,473	$3,048	$3,048
Site Total	$23,015			

Q37. How do these monetized impacts compare to the SAMDA costs?

A37. (JLZ) As concluded in ER Section 7.5S.5 (Exh. STP000013): "The Section 7.3 conclusion that there is no cost-effective ABWR operation design change holds for the mitigation of impacts at other site units."

In other words, the total monetized impacts for the severe accident at an ABWR unit are calculated by summing the monetized impacts for the ABWR experiencing the outage, the other ABWR, and STP Units 1 and 2. Using the 7% discount rate, the total monetized impacts are \$6,854 + \$3,005 + \$1,759 + \$1,759 = \$13,377 (in 1993 dollars). Using the more conservative values for the 3% discount rate in the sensitivity analysis, the total monetized impacts are \$12,446 + \$4,473 + \$3,048 + \$3,048 = \$23,015 (in 1993 dollars). As noted above, the lowest-cost SAMDA for the ABWR is \$100,000 (in 1991 dollars). This value is much higher than the total monetized impacts of the accident.

Q38. What is the conclusion of the ER SAMDA evaluation for the co-located units?

A38. (JLZ) The ER concluded that because the total monetized impacts are much lower than the lowest-cost SAMDA, there are no cost-effective SAMDAs. Specifically, ER Section 7.5S.5 (Exh. STP000013) concludes that "[n]one of the severe accident mitigation design alternatives considered for the ABWR would be cost-effective and mitigate the potential impacts (contamination and down time) from a large release severe accident at the existing units."

IV. SAMDA COSTS

A. Escalation of SAMDA Costs

Q39. How are the SAMDA costs for STP Units 3 and 4 estimated?

A39. (JLZ) STP Units 3 and 4 are ABWRs. SAMDA costs for the ABWR were determined during the design certification process and are listed in the TSD. The lowest-cost SAMDA for the ABWR was estimated to be $100,000 (1991 dollars). The SAMDAs and their costs in 1991 dollars are provided in TSD Table 4 (Exh. NRC00009A) and are reproduced in Table 1 of this testimony.

Q40. Did the ER escalate the SAMDA costs to current dollars?

A40. (JLZ) No. The ER did not escalate the TSD SAMDA costs.

Q41. What would be the effect if costs were escalated?

A41. (JLZ, AP) The conversion factor from 1991 dollars to both 2008 or 2009 dollars using the consumer price index of the Bureau of Labor Statistics ("CPI") is 1.58. Thus, in 2008 or 2009 dollars, the lowest-cost SAMDA is $158,000. This increased SAMDA cost provides even more margin between the costs and benefits of the SAMDA evaluation. The conversion factor from 1991 dollars to 2010 dollars using the CPI is 1.60. Thus, in 2010 dollars, the lowest-cost SAMDA is $160,000.

Q42. Why did you use the CPI for the SAMDA cost escalation?

A42. (JLZ, AP) The CPI is a widely accepted methodology for escalating costs. It is a reasonable method for NEPA purposes. In fact, Appendix A of OMB Circular A-94 (Exh. STP000016, pages 18-19) states: "Inflation is usually measured by a broad-based price index, such as the implicit deflator for Gross Domestic Product or the Consumer Price Index." Additionally, the CPI was used to escalate costs in the TSD (Exh. NRC00009B, page 47). To be consistent with the TSD, it is reasonable to use the CPI to escalate the SAMDA costs.

Q43. Did Mr. Johnson agree with using the CPI for this cost escalation?

A43. (JLZ, AP) No. Mr. Johnson stated in Johnson Report 2 (page 2) that "[t]he CPI is not the only available measure of inflation, nor is it necessarily the best measure." However, he did not disagree that the CPI is a reasonable method for calculating inflation.

Q44. How did Mr. Johnson suggest escalating SAMDA costs?

A44. (JLZ, AP) Mr. Johnson provided a few cost escalation scenarios, including use of the Core Personal Consumption Expenditures ("PCE") price index. Using the PCE, Mr. Johnson estimated SAMDA costs of $141,300 and $143,700 in 2008 and 2009 dollars, respectively (Johnson Report 2, page 2). Mr. Johnson also stated that the cost escalation should account for the regional cost of living index. Using a cost index of 91 for the part of Texas that encompasses the STP site, Mr. Johnson concluded that the SAMDA cost in 2009 dollars would be $131,000 (Johnson Report 2, page 3). In other words, Mr. Johnson would use a factor of 1.31 to escalate the TSD SAMDA costs from 1991 dollars to 2009 dollars.

Q45. What are your views on use of the PCE?

A45. (JLZ, AP) The United States uses two primary indices for tracking the prices paid by consumers for goods and services, the CPI and the PCE. The CPI is prepared by the Bureau of Labor Statistics (U.S. Department of Labor) and the PCE is prepared by the Bureau of Economic Analysis (U.S. Department of Commerce). In an article prepared by individuals from these two bureaus, "Comparing the Consumer Price Index and the Personal Consumption Expenditures Price Index" (Nov. 2007) (Exh. STP000019), the two indices are described as follows (footnote 1):

> The CPI measures the change in prices paid by urban consumers for a market basket of consumer goods and services; it is primarily used as an economic indicator and as a means of adjusting current-period data for inflation. The PCE price index measures the change in prices paid for goods and services by the personal sector

> in the U.S. national income and product accounts; it is primarily used for macroeconomic analysis and forecasting.

While there are some differences in their purpose and their calculations, the CPI and PCE both generally track prices paid by consumers for goods and services. We conclude that they are equally applicable and reasonable for escalating SAMDA costs.

Q46. Mr. Johnson stated (Johnson Report 2, page 2) that: "A weakness of the CPI is that it is based on fixed proportions of expenditure components and does not account for households' ability to change those proportions over time in response to price or other factors. Some economists also criticize the CPI because of it[s] sensitivity to volatile price components." What is your view on this statement?

A46. (JLZ, AP) Mr. Johnson's criticism is not applicable to escalation of SAMDA costs. The issue of whether households can change proportions over time does not directly apply to how the cost for implementing a SAMDA would increase over time. As discussed above, we conclude that the CPI and PCE are equally applicable for escalating SAMDA costs. They both provide a general means of tracking inflation over time. We also note that the escalated SAMDA costs using the CPI and PCE are similar. For example, using the CPI, the lowest cost SAMDA is $158,000 in 2009 dollars, and using the PCE, the lowest cost SAMDA is $143,700 in 2009 dollars. For the types of estimates performed in a SAMDA evaluation, we believe either is appropriate and reasonable.

Q47. What are your views on the use of a regional cost of living index?

A47. (JLZ, AP) The regional price differences are not relevant. The TSD already conservatively used lower bounding costs (Exh. NRC00009B, pages 47-52). Additionally, the SAMDAs generally involve components that can be manufactured anywhere in the United

States, not just in the region of Texas in which the plant is located. Thus, use of a regional cost of living index is not appropriate.

Q48. If Mr. Johnson's methodology were used for escalating SAMDA costs, how would it affect the conclusion regarding whether there is a cost-effective SAMDA?

A48. (JLZ, AP) To be conservative, we use Mr. Johnson's 1.31 factor to escalate SAMDA costs from 1991 dollars to 2009 dollars in the evaluation below. The conclusion that there are no cost-effective SAMDAs holds even if Mr. Johnson's cost escalation methodology is used.

Q49. Did the NRC Staff agree with using the CPI for the SAMDA cost escalation?

A49. (JLZ, AP) No. On page 3 of the October 7, 2010 "Affidavit of James V. Ramsdell and Davis M. Anderson Concerning the Staff's Review of STPNOC's Updated SAMDA Evaluation" ("Staff Affidavit"), the NRC Staff stated: "[T]he Bureau of Economic Analysis' Gross Domestic Product Implicit Price Deflator for Nonresidential Structures is the appropriate index to use to adjust the cost of SAMDAs for inflation because SAMDAs relate to structural alternatives in plant design and the GDP deflators are more specific to private capital investment than the CPI." The Staff also stated that "[t]he CPI measures changes in price faced by retail consumers across a typical 'market basket' and would not be appropriate for escalating the costs of SAMDAs." The Staff concluded that using its index the lowest-cost SAMDA would be approximately $225,000.

Q50. What are your views on the Staff's methodology for escalating SAMDA costs?

A50. (JLZ, AP) We conclude that the Staff's methodology for escalating SAMDA costs is reasonable. The Staff correctly notes that the Gross Domestic Product Implicit Price

Deflator for Nonresidential Structures is more specific to private capital investment than the CPI. The Staff's conclusion is correct for not just the CPI, but also the PCE identified by the Intervenors. Implementation of most of the SAMDAs likely would involve more manufacturing and construction activities, rather than consumer activities. The ER relied on the CPI to be more conservative, to use a more general inflation index, and to use the methodology consistent with the TSD. However, to be even more conservative, we use Mr. Johnson's cost escalation methodology in our evaluation below.

Q51. If the Staff's methodology for escalating SAMDA costs were used, how would it affect the conclusion regarding whether there is a cost-effective SAMDA?

A51. (JLZ, AP) The Staff's methodology would result in a higher cost SAMDA in 2009 dollars by a factor of approximately 1.4 (*i.e.*, \$225,000/\$158,000) than if the CPI were used, or a factor of approximately 1.7 (*i.e.*, \$225,000/\$131,000) than if Mr. Johnson's methodology were used. Therefore, use of the CPI or Mr. Johnson's methodology is more conservative than the Staff's methodology. The Staff acknowledged this by stating that using its methodology versus the CPI is not material and does not change the outcome of the SAMDA evaluation (Staff Affidavit, page 3).

B. <u>Accounting for Risk Reduction in SAMDA Costs</u>

Q52. Please discuss whether the SAMDA evaluation in ER Section 7.5S (Exh. STP000013) accounts for the actual risk reduction achieved by implementing the SAMDAs.

A52. (JLZ) It does not. As discussed above, the ER evaluation compares the cost benefit of implementing all of the SAMDAs to the cost of each individual SAMDA. For this comparison, the ER evaluation assumes that the cost benefit of implementing all of the SAMDAs reduces the severe accident risk to zero (Exh. STP000013, page 7.3-3). The ER evaluation is extremely conservative, because no SAMDA would reduce the risk of severe accidents to zero.

Q53. How can the actual risk reduction be accounted for in the SAMDA evaluation?

A53. (JLZ) The actual risk reduction can be factored into the SAMDA evaluation by accounting for the specific reduction in CDF that could be achieved by implementing a specific SAMDA. For example, if implementing a SAMDA would only reduce the CDF by 2%, then the maximum averted cost-risk must be reduced by a factor of 50 to perform the cost-benefit analysis with this particular SAMDA. The TSD discusses this reduction in CDF for many of the ABWR SAMDAs.

Q54. How does accounting for the actual risk reduction change the lowest-cost ABWR SAMDA?

A54. (JLZ) Because the TSD did not identify any cost-effective SAMDAs even after conservatively assuming that each SAMDA would reduce the severe accident risk to zero, the TSD did not need to account for the actual risk reduction. Therefore, the TSD does not identify the reduction in CDF for all SAMDAs. However, the TSD provides the reduction in CDF for many of the ABWR SAMDAs.

Table 3 below identifies specific SAMDAs and the CDF reduction from the TSD (Exhs. NRC00009A and NRC00009B). For example, implementation of SAMDA 2c (Suppression Pool Jockey Pump) would result in a 2% reduction in CDF. The lowest-cost SAMDA for which CDF reduction information is not provided in the TSD is SAMDA 3d (Improved Bottom Head Penetration Design), which costs $750,000 in 1991 dollars. Table 3 provides CDF reduction values for all SAMDAs that cost lower than $750,000.

As shown in Table 3, the risk reduction from each of the listed SAMDAs is much lower than the total CDF. This in turn affects the benefit (averted costs) of the SAMDA. For example, implementation of SAMDA 2c would only reduce the CDF by 2%. Therefore, any averted cost would be reduced by a factor of approximately 50 to account for the actual risk reduction. This would have the same effect as raising the SAMDA cost by a factor of approximately 50. In this example, the risk-adjusted cost of SAMDA 2c would be approximately $6,000,000 (*i.e.*, $120,000 x 50). Using this methodology, all of the SAMDAs identified in Table 3 have a risk-adjusted cost higher than $750,000.

Table 3 – SAMDA Risk Reduction

SAMDA	Cost (1991 Dollars)	CDF Reduction	Reduction of Total CDF	% CDF Reduction	Approximate Risk-Adjusted SAMDA Implementation Cost (1991 Dollars)
1a. Severe Accident EPGs/AMGs	$600,000	No effect on CDF, because mitigative, not preventative (TSD at 36-37)	0	0%	No Benefit
1b. Computer Aided Instrumentation	$599,600	Eliminates 3% of total CDF of 1.56E-7 (TSD at 37)	4.68E-09	3%	$20 Million
1c. Improved Maintenance Procedures/Manuals	$299,000	Eliminates 9% of total CDF of 1.56E-7 (TSD at 37)	1.40E-08	9%	$3 Million
2b. Improved Depressurization	$598,600	Eliminates 14% of total CDF of 1.56E-7 (half of 28%) (TSD at 38)	2.18E-08	14%	$4 Million
2c. Suppression Pool Jockey Pump	$120,000	Eliminates 2% of total CDF of 1.56E-7 (TSD at 38-39)	3.12E-09	2%	$6 Million
3c. Improved Vacuum Breakers	$100,000	Eliminates TSD Case 2 (7.8E-11) (TSD at 18, 40)	7.80E-11	<0.1%	>$100 Million
3d. Improved Bottom Head Penetration Design	$750,000	Not Provided	Conservatively Assume 1.56E-07 (Total CDF)	Conservatively Assume 100% CDF Reduction	$750,000
7a. Drywell Head Flooding	$100,000	Eliminates or reduces the following cases: TSD Case 6 (3.1E-12); TSD Case 7 (3.9E-10); and TSD Case 8 (4.1E-10) (TSD at 18, 42)	8.0E-10 (Maximum)	0.5%	$20 Million
11a. ATWS Sized Vent	$300,000	Conservatively assume that this eliminates TSD Case 9 (1.7E-10) (TSD at 18, 45)	1.70E-10	0.1%	$300 Million
13a. Reactor Building Sprays	$100,000	No effect on CDF (TSD at 45-46)	0	0%	No Benefit

Q55. After accounting for risk reduction of the SAMDAs in Table 3, what is the lowest-cost SAMDA?

A55. (JLZ) As explained above, the approximate risk-adjusted SAMDA implementation costs are equal to or greater than $750,000. Therefore, the risk-adjusted lowest-cost SAMDA is SAMDA 3d (Improved Bottom Head Penetration Design), which costs $750,000 in 1991 dollars. This cost conservatively does not account for any risk reduction for SAMDA 3d. If risk reduction were taken into account for all of the SAMDAs, the lowest cost would be even higher.

Q56. What is the lowest-cost SAMDA in 2009 dollars?

A56. (JLZ) Using Mr. Johnson's methodology, the SAMDA cost would be multiplied by a factor of 1.31 to escalate from 1991 dollars to 2009 dollars. Therefore, the resulting lowest risk-adjusted cost of the SAMDAs in 2009 dollars (SAMDA 3d) is $982,500.

V. REASONABLENESS OF THE ER'S REPLACEMENT POWER COST ESTIMATES

Q57. Please discuss whether the ER's replacement power cost estimates are consistent with NRC guidance.

A57. (JLZ, AP) The Applicant followed the guidance in NUREG/BR-0184 (Exhs. NRC00008A and NRC00008B) to calculate the replacement power costs in ER Section 7.5S (Exh. STP000013). NUREG/BR-0184 is NRC's standard methodology for cost-benefit analyses. In particular, NUREG/BR-0184 is specifically allowed by NUREG-1555 for the performance of SAMDA evaluations. In this regard, forecasting replacement power 40 years into the future is speculative under any circumstances. By using the generic replacement power costs in NUREG/BR-0184, an applicant can avoid the need to speculate about local or regional replacement power costs and use a standard nation-wide value.

Q58. Why were the replacement power costs not escalated to 2009 dollars in ER Section 7.5S?

A58. (JLZ, AP) NUREG/BR-0184 specifies replacement power costs from a similar time period as the SAMDA analysis for the ABWR. The ABWR SAMDA costs from the TSD are provided in 1991 dollars (Exh. NRC00009B, page 47). The replacement power costs in NUREG/BR-0184 are provided in 1993 dollars (Exh. NRC00008B, page 5.51). Therefore, these costs are from similar years and can be compared.

Q59. How do these costs from the ER compare to those provided by Mr. Johnson?

A59. (JLZ, AP) The replacement power costs in Johnson Report 1 (page 4) are in 2008 dollars, which should not be directly compared to the ABWR SAMDA costs from 17 years earlier. When the NUREG/BR-0184 replacement power costs are escalated to account for inflation, the corresponding cost is $449,500 per day for a 910 MWe plant in 2008 dollars (using a 1.45 producer price index-commodities Bureau of Labor Statistics multiplier), or $20.58 per MWh in 2008 dollars. The replacement power cost estimates in NUREG/BR-0184 are substantially higher when reported in 2008 dollars and are closer to those in Johnson Report 1.

Q60. What is your conclusion regarding the reasonableness of the SAMDA evaluation in ER Section 7.5S (Exh. STP000013)?

A60. (JLZ, AP) We conclude that the evaluation is reasonable. The evaluation uses standard NRC methods. Although the replacement power costs using the NRC's methods are somewhat less than those recommended by Mr. Johnson and the current ERCOT market rates, the replacement power costs in NUREG/BR-0184 provide a reasonable input for a SAMDA analysis, especially considering that market rates will likely fluctuate over time.

Q61. Please explain how escalating the replacement power costs in NUREG/BR-0184 to 2009 dollars affects the results of the evaluation in the ER.

A61. (JLZ, AP) Even if the replacement power costs are escalated to 2009 dollars to account for inflation, there is still no change to the conclusions in the ER. When the NUREG/BR-0184 replacement power costs used in the ER are escalated to account for inflation, the corresponding cost is $452,600 per day for a 910 MWe plant in 2009 dollars (using a 1.46 producer price index-commodities Bureau of Labor Statistics multiplier), or $20.72 per MWh in 2009 dollars. Escalating the replacement power costs in Table 2 to 2009 dollars results in the following values:

Table 4 – Monetized Impacts Using NUREG/BR-0184 Replacement Power Costs Escalated to 2009 Dollars

7% Discount Rate				
	ABWR with Severe Accident	**Other ABWR**	**STP Unit 1**	**STP Unit 2**
Non-Replacement Power Costs	$2,454	$1,025	$1,071	$1,071
Replacement Power Costs	$6,424	$2,891	$1,004	$1,004
Unit Total	$8,878	$3,916	$2,075	$2,075
Site Total	$16,945			
Sensitivity Analysis -- 3% Discount Rate				
	ABWR with Severe Accident	**Other ABWR**	**STP Unit 1**	**STP Unit 2**
Non-Replacement Power Costs	$5,046	$1,916	$1,895	$1,895
Replacement Power Costs	$10,804	$3,733	$1,683	$1,683
Unit Total	$15,850	$5,649	$3,578	$3,578
Site Total	$28,656			

Q62. Do the conclusions of the SAMDA evaluation change if replacement power costs from NUREG/BR-0184 are escalated?

A62. (JLZ, AP) No. The lowest-cost SAMDA in the TSD is $100,000 in 1991 dollars. Using Mr. Johnson's lowest-cost SAMDA of $131,000 after escalating to 2009 dollars provides even more margin between the costs and benefits of the SAMDA evaluation. Similarly, if the risk reduction from implementation of the lower cost SAMDAs is considered, then the lowest risk-adjusted cost of the SAMDAs is $982,500. This provides a great margin between the costs and benefits of the SAMDA evaluation.

Q63. What is your conclusion regarding cost-effective SAMDAs for STP Units 3 and 4 using the NUREG/BR-0184 replacement power costs, escalated to account for inflation?

A63. (JLZ, AP) Based on the above information, we conclude that there are no cost-effective SAMDAs for STP Units 3 and 4.

VI. ACCOUNTING FOR INTERVENORS' AND STAFF'S POSITIONS

A. Capacity Factor and Net Electrical Output of STP Units 1 and 2

Q64. The Staff claimed that the replacement power cost estimates from NUREG/BR-0184 should have been scaled up from a 60 to 65% capacity factor to a 95% capacity factor (Staff Affidavit, page 3). How does consideration of a 95% capacity factor affect the estimated monetized impacts?

A64. (JLZ, AP) The ER used the replacement power cost estimate directly from NUREG/BR-0184. The Staff correctly notes that the $310,000/day value in NUREG/BR-0184 assumes an average capacity factor of 60 to 65%. To account for a higher capacity factor, the replacement power cost values in Table 4 can be multiplied by the ratio of the higher capacity factor (95%) and the lower capacity factor (conservatively 60%). This ratio is 1.58. The resulting market price is $32.81 per MWh in 2009 dollars.

Additionally, ERCOT's most current generating capacity data indicate that the net electrical output of STP Units 1 and 2 is 1,362 MW each (Exh. STP000006, page 15). This is higher than the 1,280 MW net electrical output assumed in determining replacement power costs in the ER SAMDA evaluation. To account for a higher net electrical output for STP Units 1 and 2, the replacement power cost values in Table 4 for STP Units 1 and 2 can be multiplied by the ratio of the higher net electrical output (1,362 MW) and the lower net electrical output (1,280 MW). This ratio is 1.06.

Escalating the replacement power costs in Table 4 to account for the higher capacity factor and higher net electrical output for STP Units 1 and 2 results in the following values:

Table 5 – Monetized Impacts Using NUREG/BR-0184 Replacement Power Costs Escalated to 2009 Dollars and Adjusting for a 95% Capacity Factor and Higher STP Units 1 and 2 Net Output (In 2009 Dollars)

7% Discount Rate				
	ABWR with Severe Accident	**Other ABWR**	**STP Unit 1**	**STP Unit 2**
Non-Replacement Power Costs	$2,454	$1,025	$1,071	$1,071
Replacement Power Costs	$10,171	$4,577	$1,692	$1,692
Unit Total	$12,625	$5,602	$2,763	$2,763
Site Total	$23,754			
Sensitivity Analysis -- 3% Discount Rate				
	ABWR with Severe Accident	**Other ABWR**	**STP Unit 1**	**STP Unit 2**
Non-Replacement Power Costs	$5,046	$1,916	$1,895	$1,895
Replacement Power Costs	$17,106	$5,911	$2,836	$2,836
Unit Total	$22,152	$7,827	$4,731	$4,731
Site Total	$39,441			

These values are still well below the lowest risk-adjusted cost of the SAMDAs ($982,500). Therefore, accounting for a higher capacity factor and a higher net electrical output of STP Units 1 and 2 does not change the conclusion that there are no cost-effective SAMDAs.

B. ERCOT Pricing Data

1. 2009 ERCOT Pricing Data

Q65. Do the Intervenors agree with the Applicant's use of replacement power costs from NUREG/BR-0184?

A65. (AP) No. Johnson Report 1 (page 3) states that the Applicant should have used ERCOT pricing data for calculating replacement power costs, rather than using the generic replacement power costs specified in NUREG/BR-0184.

Q66. Please describe how ERCOT provides annual pricing data.

A66. (AP) The ERCOT website posts historical market pricing data for each 15 minute settlement interval. This 15 minute pricing data is available in spreadsheet format and can be summed and averaged over any number of timeframes, such as hourly, daily, monthly and annually. Therefore, pricing data is available for all of 2010 and for previous years.

Another source of ERCOT pricing data is from Potomac Economics, the Independent Market Monitor ("IMM") for the ERCOT Wholesale Market. The IMM publishes an annual state of the market report pursuant to the requirements in Section 39.1515(h) of the Public Utility Regulatory Act. This report reviews and evaluates the outcomes of the ERCOT markets and is submitted to the PUCT and ERCOT. The report also provides an average annual balancing market price for electricity. The most recent version of the IMM's annual report is the "2009 State of the Market Report for the ERCOT Wholesale Electricity Markets" ("2009 SOM Report"), published in July 2010 (Exh. STP000020). The 2010 SOM Report is not yet available. As stated in the 2009 SOM Report (page iv), the balancing energy market allows participants to make real-time purchases and sales of energy to supplement existing contracts.

Q67. What was the 2009 average balancing market price?

A67. (AP) According to the 2009 SOM Report (Exh. STP000020, page v), the 2009 average balancing energy market price in ERCOT was $34.03 per MWh across ERCOT and was $34.76 per MWh in the ERCOT Houston zone where the STP site is located.

Q68. How do the 2010 ERCOT prices (based upon the 15 minute pricing data) compare to the 2009 ERCOT prices?

A68. (AP) The 2010 prices are very similar to the 2009 prices. There was, however, one significant change made to the ERCOT market in 2010. On December 1, 2010, the ERCOT market changed from a zonal market based design to a nodal market based design. Therefore, to compare the 2010 prices to the 2009 prices, I grouped the ERCOT data into (1) the first 11 months of 2010, and (2) December 2010.

Based on the 15 minute settlement interval data for the first 11 months of 2010, the average balancing energy market price across ERCOT was $35.42 per MWh and $36.91 per MWh in the Houston zone where the STP site is located. These values compare very closely to the average prices in 2009 of $34.03 per MWh across ERCOT and $34.76 per MWh in the Houston zone.

For the month of December 2010, the first month of the nodal market implementation, the average market price for energy across all of ERCOT's eight nodal market load zones was $27.55 per MWh. The price in December 2010 for the Houston load zone, which is where the STP site is located, was $28.24 per MWh. Although the December prices are not an exact "apples to apples" comparison with the 2009 prices due to the December 1 market design change, they are nonetheless provided here for reference. The prices in December indicate a reduction in price relative to the other months in 2010.

This testimony uses the 2009 ERCOT prices below instead of the 2010 prices for a number of reasons. First, as discussed above, the 2009 and 2010 ERCOT prices are very similar. Second, the wholesale market design was changed in 2010, and so the 2010 ERCOT prices would not all be from the same market design. Third, earlier pleadings used 2009 dollars. To be consistent, 2009 dollars are continued in this testimony. Finally, a sensitivity analysis using the much higher 2008 ERCOT prices is provided below, which bounds the costs from 2009 and 2010.

Q69. How do the 2009 and 2010 ERCOT prices compare to historical energy pricing in ERCOT?

A69. (AP) Table 6 below provides the average annual balancing energy prices in ERCOT for every year and every zone since the market opened to competition in 2002. The 2009 and 2010 prices tend to be lower than the prices in previous years, with the exception of 2002. This is not surprising because ERCOT's energy prices have always been closely correlated to the price of natural gas, and 2009 and 2010 both had lower average natural gas prices than the two highest energy price years, 2005 and 2008. Because of recent developments in shale gas formations, the outlook for natural gas prices tends to be stable and lower than in 2008. Indeed, the U.S. Energy Information Administration forecasts natural gas prices for energy production to remain below $6.00 per mmBTU until 2026 (Exh. STP000021). Therefore, the ERCOT energy prices for 2009 and 2010 in Table 6 are indicative of an overall stable and relatively low outlook of energy prices in the next 10 to 15 years.

Table 6 – ERCOT Average Annual Balancing Energy Market Prices by Zone ($ per MWh)

	2002	2003	2004	2005	2006	2007	2008	2009	2010*
ERCOT	25.64	44.26	44.64	72.79	55.22	56.35	77.19	34.03	35.42
North	26.62	45.27	45.07	74.70	56.13	56.21	71.19	32.28	36.65
Houston	25.90	43.69	44.83	73.75	55.26	57.05	82.95	34.76	36.91
South	23.86	43.33	44.13	69.46	54.19	56.38	85.31	37.13	36.70
West	25.36	43.94	43.69	71.45	54.30	54.27	57.76	27.18	31.43
Northeast **			43.92	72.51	54.51				

*** 2010 prices are for the first 11 months only.**
**** The Northeast zone only existed in the years 2004 through 2006.**

Q70. How does the 2009 pricing data affect the estimated monetized impacts?

A70. (AP) As discussed previously, when the NUREG/BR-0184 replacement power costs used by the ER are escalated to account for inflation, a higher capacity factor, and a higher net electrical output for STP Units 1 and 2, the corresponding price is $32.81 per MWh in 2009 dollars. Therefore, the $34.76 per MWh from the 2009 SOM Report (Exh. STP000020, page v) is 1.06 times larger. Multiplying the replacement power costs in Table 5 by 1.06 to account for the 2009 ERCOT pricing data results in the following values:

Table 7 – Monetized Impacts Using Replacement Power Costs Based on 2009 ERCOT Pricing Data (In 2009 Dollars)

7% Discount Rate				
	ABWR with Severe Accident	**Other ABWR**	**STP Unit 1**	**STP Unit 2**
Non-Replacement Power Costs	$2,454	$1,025	$1,071	$1,071
Replacement Power Costs	$10,775	$4,849	$1,793	$1,793
Unit Total	$13,229	$5,874	$2,864	$2,864
Site Total	$24,831			
Sensitivity Analysis -- 3% Discount Rate				
	ABWR with Severe Accident	**Other ABWR**	**STP Unit 1**	**STP Unit 2**
Non-Replacement Power Costs	$5,046	$1,916	$1,895	$1,895
Replacement Power Costs	$18,122	$6,262	$3,004	$3,004
Unit Total	$23,168	$8,178	$4,899	$4,899
Site Total	$41,145			

Q71. How do these values affect the SAMDA evaluation?

A71. (AP) These values are still well below the lowest risk-adjusted cost of the SAMDAs ($982,500). Therefore, even using the 2009 ERCOT price of electricity for the replacement power costs, the conclusion that there are no cost-effective SAMDAs remains unchanged.

Q72. Please discuss whether your evaluation forecasts future energy prices.

A72. (AP) Due to the uncertainty, I do not attempt to forecast future energy prices. It is reasonable to use the replacement power costs in 2009 dollars, rather than attempt to forecast future energy prices throughout the life of the STP units, as long as the replacement power costs and SAMDA costs are from the same year. Using current or historical data, instead of forecasted data, removes much of the speculation from the SAMDA evaluation.

2. Sensitivity Analysis Using 2008 ERCOT Pricing Data

Q73. Have you performed a sensitivity analysis for ERCOT pricing data?

A73. (AP) Yes. In order to determine the sensitivity of the above conclusion to changes in ERCOT prices, I also performed a sensitivity analysis using ERCOT pricing data from the year with the highest prices since the ERCOT market was deregulated in 2002.

Q74. Which year had the highest ERCOT pricing data?

A74. (AP) As indicated in Table 6, the highest prices since the ERCOT market was deregulated occurred in 2008.

Q75. What was the 2008 average balancing market price?

A75. (AP) In August 2009, Potomac Economics, the IMM for the ERCOT Wholesale Market, published the “2008 State of the Market Report for the ERCOT Wholesale Electricity Markets” (“2008 SOM Report”) (Exh. STP000022). According to the 2008 SOM Report (page iii), the 2008 average balancing market price in ERCOT was $77.19 per MWh across ERCOT and was $82.95 per MWh in the ERCOT Houston zone where the STP site is located.

Q76. Please discuss whether the 2008 pricing data is appropriate for a sensitivity analysis.

A76. (AP) The prices in the 2008 ERCOT market were higher when compared to the other years since deregulation. Significant transmission congestion in April, May, and June, and the inefficient way by which congestion was relieved in ERCOT's zonal market structure, coupled with relatively strong natural gas prices, resulted in the elevated 2008 balancing energy prices. The year with the second highest prices, 2005, was another year in which there was a strong rise in natural gas prices. As a comparison, the 2009 average balancing market price across ERCOT was $34.03 per MWh and the 2007 average balancing market price across ERCOT was $56.35 per MWh (Exh. STP000020, page v). These prices are much lower than the 2008 data. Furthermore, the significant transmission congestion that occurred in 2008 is unlikely to be repeated, because ERCOT changed its method for dispatching electricity beginning December 1, 2010, to implement a nodal wholesale market design. A nodal market design provides improved dispatch efficiencies and unit specific management of transmission congestion, a significant improvement over the zonal market design. Because the 2008 ERCOT prices are higher than the ERCOT prices in other years, I conclude that use of the 2008 ERCOT prices for a sensitivity analysis is appropriate.

Q77. Johnson Report 2, pages 3-4, states that 2008 ERCOT prices are not conservative and "[s]ince ERCOT power prices are strongly influenced by natural gas prices, a reasonable inference is that ERCOT wholesale power prices are likely to increase at a rate higher than inflation." What is your view on this matter?

A77. (AP) I agree that ERCOT power prices are strongly influenced by natural gas prices. However, I do not believe that ERCOT wholesale power prices are likely to increase at a rate higher than inflation. Experience shows that natural gas prices have often been volatile, extremely difficult to predict, and have not typically followed any type of generally accepted economic indicator. If ERCOT wholesale power prices were "likely to increase at a rate higher than inflation," then the prices in 2009 and 2010 would not be lower than every other previous year since 2003 (see Table 6). I believe a more accurate statement is that 2008 ERCOT prices are conservative for this SAMDA evaluation, ERCOT electricity prices will continue to be strongly influenced by natural gas prices for many years, and that due to shale gas formations the price of natural gas is forecast to remain relatively stable and below 2008 levels for at least the next decade (Exh. STP000021). For periods beyond that, it is not realistic to provide precise forecasts of energy prices, due to the large uncertainties involved in such long-term forecasts.

Q78. How does this 2008 pricing data affect the estimated monetized impacts?

A78. (AP) As discussed above, when the NUREG/BR-0184 replacement power costs used by the ER are escalated to account for inflation, a higher capacity factor, and a higher net electrical output for STP Units 1 and 2, the corresponding price is $32.81 per MWh in 2009 dollars. Therefore, the $82.95 per MWh from the 2008 SOM Report is 2.53 times larger. Multiplying the replacement power costs in Table 5 by 2.53 to account for the 2008 ERCOT pricing data results in the following values:

Table 8 – Monetized Impacts Using Replacement Power Costs Based on the Highest Historical Annual ERCOT Pricing Data from 2008 (In 2009 dollars)

7% Discount Rate				
	ABWR with Severe Accident	**Other ABWR**	**STP Unit 1**	**STP Unit 2**
Non-Replacement Power Costs	$2,454	$1,025	$1,071	$1,071
Replacement Power Costs	$25,713	$11,571	$4,278	$4,278
Unit Total	$28,167	$12,596	$5,349	$5,349
Site Total	$51,462			
Sensitivity Analysis -- 3% Discount Rate				
	ABWR with Severe Accident	**Other ABWR**	**STP Unit 1**	**STP Unit 2**
Non-Replacement Power Costs	$5,046	$1,916	$1,895	$1,895
Replacement Power Costs	$43,245	$14,943	$7,170	$7,170
Unit Total	$48,291	$16,859	$9,065	$9,065
Site Total	$83,280			

Q79. How do these values affect the SAMDA evaluation?

A79. (AP) These values are still well below the lowest risk-adjusted cost of the SAMDAs ($982,500). Therefore, the conclusion that there are no cost-effective SAMDAs is unaffected even if the highest ERCOT prices (*i.e.*, from 2008) are used to perform a sensitivity analysis to calculate the replacement power costs.

C. Intervenors' Replacement Power Cost Estimates

Q80. Have the Intervenors provided their own replacement power cost estimates?

A80. (AP) Yes. The Intervenors have stated that the replacement power costs in the SAMDA evaluation should be based on a forecast of baseline ERCOT market prices rather than on the replacement power costs specified in NUREG/BR-0184. The Intervenors rely upon Johnson Report 1, which states (page 4) that the replacement power costs in ER Section 7.5S.5 "are roughly 3 to 3.8 times the $430 thousand/day cost used by the Applicant," and that a price of $60.01 to $63.19 per MWh in 2020-2025 based on forecasted natural gas prices would be more appropriate.

Q81. Why are the Intervenors' replacement power cost estimates different than the ER's?

A81. (AP) The ER used the NUREG/BR-0184 replacement power cost estimates as a starting point, while Mr. Johnson stated that he used a natural gas price forecast. Additionally, as discussed above, part of the difference between the replacement power costs in ER Section 7.5S.5 and the replacement power costs estimated in Johnson Report 1 are attributable to changes in energy prices over time. In particular, the replacement power costs in NUREG/BR-0184 are in 1993 dollars and the SAMDA costs in the TSD are in 1991 dollars. Johnson Report 1, on the other hand, uses 2008 dollars. Since 1991 and 1993, there have been changes to energy prices that account for some of the discrepancies between the replacement power cost estimates in ER Section 7.5S.5 and those in Johnson Report 1.

Q82. How would use of the Intervenors' estimated replacement power costs affect the SAMDA evaluation?

A82. (AP) Even if the replacement power cost values proposed in Johnson Report 1 were used, they would not impact the conclusions in the SAMDA analysis. Multiplying the replacement power cost estimates in ER Section 7.5S.5 (which are reproduced in Table 2 above) by 3.8 to account for Johnson Report 1 results in the following values:

Table 9 –Monetized Impacts Using Replacement Power Costs Based on Johnson Report 1 (in 2008 dollars)

7% Discount Rate				
	ABWR with Severe Accident	**Other ABWR**	**STP Unit 1**	**STP Unit 2**
Non-Replacement Power Costs	$2,454	$1,025	$1,071	$1,071
Replacement Power Costs	$16,720	$7,524	$2,614	$2,614
Unit Total	$19,174	$8,549	$3,685	$3,685
Site Total	$35,094			
Sensitivity Analysis -- 3% Discount Rate				
	ABWR with Severe Accident	**Other ABWR**	**STP Unit 1**	**STP Unit 2**
Non-Replacement Power Costs	$5,046	$1,916	$1,895	$1,895
Replacement Power Costs	$28,120	$9,717	$4,381	$4,381
Unit Total	$33,166	$11,633	$6,276	$6,276
Site Total	$57,351			

Furthermore, these values are less than the values provided in Table 8 based upon the 2008 ERCOT prices.

Q83. How do these values in Table 9 affect the SAMDA evaluation?

A83. (AP) These values are still well below the lowest risk-adjusted cost of the SAMDAs ($982,500). Therefore, acceptance of the Intervenors' position that the ER's estimated replacement power costs were up to 3.8 times too low does not affect the conclusion that there are no cost-effective SAMDAs.

Q84. How do the Johnson Report 1 replacement power cost estimates relate to those evaluated in Table 8?

A84. (AP) As mentioned previously, Johnson Report 1 (page 4) assumes that the average electricity price per MWh for 2020 to 2025 is $60.01 to $63.19 based on forecasted natural gas prices. These values are well under the $82.95 per MWh considered above based on the 2008 ERCOT pricing data. Therefore, the SAMDA evaluation in our testimony completely bounds the pricing values provided by the Intervenors. A comparison of the replacement power costs in Table 9 using the Intervenors' data with the replacement power costs in Table 8 using

2008 ERCOT pricing data further demonstrates that our testimony bounds the Intervenors' information.

D. ERCOT Market Effects

Q85. Do the Intervenors raise issues related to ERCOT market effects?

A85. (AP) Yes. The Intervenors have stated that the estimated replacement power costs in ER Section 7.5S are low because they do not account for the market effects in the ERCOT region due to the shutdown of the STP units following a severe accident scenario. They also have stated that the SAMDA analysis should account for the impact on consumers from the higher price of electricity due to the outage of the four STP units. Johnson Report 1 (page 5) does not quantify the change in replacement power costs due to these market effects, and states that the impact should be evaluated by the Applicant.

1. Long-Term Impact on Market Effects

Q86. How would the loss of the STP units affect the long-term market cost of electricity in ERCOT?

A86. (AP) For a number of reasons, the loss of the STP units would not have significant long-term market effects in the ERCOT region, and would not dramatically increase annualized replacement power costs. These reasons include the ERCOT reserve margin, demand that is below the peak demand during most of the year, and stimulation of new generation sources.

Q87. How would the reserve margin reduce long-term impacts of loss of the STP units?

A87. (AP) ERCOT has a target reserve margin above its peak hour demand to maintain adequate reserves to reliably meet ERCOT contingencies. The ERCOT board voted in November 2010 to increase the target reserve margin from 12.5% to 13.75% after 2010. The primary reason for this increase in reserve margin is the increase in wind power in ERCOT. Wind power is an intermittent or variable power source. As the wind generating capacity relative to total capacity in ERCOT has increased, ERCOT has increased its target reserve margin to ensure that sufficient generating resources will be available in light of wind power's intermittent operating characteristics. The ERCOT target reserve margin at the peak hour is calculated as (Resources – Firm Load Forecast)/(Firm Load Forecast). The first STP ABWR unit might commence commercial operation as early as 2018, but may be later. ERCOT predicted in its December 2010 "Report on the Capacity, Demand, and Reserves in the ERCOT Region" (Exh. STP000007, page 7) that the peak Firm Load Forecast in 2016 will be 69,477 MW. A 13.75% reserve margin would require approximately 9,553 MW more Resources than Firm Load Forecast. The four STP units will have a net combined capacity of approximately 5,324 MWe (approximately 1,300 MWe each for STP Units 3 and 4 and 1,362 MWe each for STP Units 1 and 2), which is less than the generation represented by the reserve margin. Thus, if ERCOT maintains its target reserve margin it should have enough installed capacity to supply demand, even if all four STP units were to be off-line.

Q88. How does demand below the peak hour demand reduce long-term impacts of loss of the STP units?

A88. (AP) During most of the year, ERCOT operates well below the peak hour demand described above. Thus, for most of the operating hours in a year there should be sufficient operating capacity in ERCOT to replace the STP units. Additionally, in the years after

2016, ERCOT predicts that its Firm Load Forecast will increase. Since ERCOT has historically met its reserve margin targets, an increase in expected load should stimulate further development of capacity after 2016 and the loss of all four STP units should have an even less impact on the ERCOT system.

Q89. How does stimulation of new generation sources reduce long-term impacts of loss of the STP units?

A89. (AP) While loss of the four STP units would have some impact on ERCOT market prices in the short term, the potential multi-year outages for the units would stimulate new generation sources to enter the market. In particular, new combined cycle generation units likely would enter the market if a multi-year outage is expected, and simple cycle generation units could enter even faster. Based on my experience, a simple cycle generation unit could be brought on-line in about a year. Additionally, ERCOT indicated in its December 2010 "Report on the Capacity, Demand, and Reserves in the ERCOT Region" (Exh. STP000007, page 7) that it will have 5,505 MW of mothballed capacity in 2016. This mothballed capacity could be brought back into service and be used to offset some of the lost generation from STP Units 3 and 4. My experience is that these mothballed units can typically be placed back in service within a month or two, depending on how long they have been in mothball status and the procedures used when placing them in mothball status. These units may be higher cost than the lost STP nuclear units, but the addition of this generation would minimize the market effects.

2. Dispatch Model

Q90. Have you performed your own evaluation of the impact of the loss of the STP units on ERCOT market effects?

A90. (AP) Yes. To quantify the effect on ERCOT replacement power costs due to a severe accident scenario, I developed a simplified dispatch model that compares the annual load-weighted average wholesale market price under two scenarios: (1) the price with all four STP units available, and (2) the price with all four STP units removed from service. Since the price of electricity in ERCOT varies significantly depending upon the loads and available generating units (which in turn vary over the course of a year), my model accounted for that variation over the course of a full year.

Q91. How did you develop your dispatch model?

A91. (AP) The dispatch model was developed using publicly available data. The first set of data included in the model was the list of generating units in ERCOT and their corresponding summer capacities from ERCOT's May 2010 "Report on the Capacity, Demand and Reserves in the ERCOT Region" (Exh. STP000006). Each unit was then categorized into one of fifteen different technology types (renewable, nuclear, coal and lignite, combined cycle, etc.) as described in ERCOT's zonal protocols. Once categorized, the units were assigned a generic fuel cost, also described in ERCOT's protocols (August 1, 2010 ERCOT Protocols, Section 6, Ancillary Services (Exh. STP000023)), and then ranked in "dispatch order" based on these costs. Renewable units were the first units in the dispatch order, with a generic fuel cost of $0 per MWh, hydro units were next at $10 per MWh, nuclear units next at $15 per MWh, coal and lignite at $18 per MWh, followed by the natural gas-fired units, which were assigned a heat rate times a fuel index price based on their technology type. Completing the dispatch order were technology types that are used infrequently because of their relatively expensive underlying costs (diesels, load shedding resources, etc.).

Once the unit dispatch ranking was completed, each unit's capacity was corrected by availability and/or capacity factors obtained from ERCOT and the North American Electric Reliability Corporation ("NERC"). For example, ERCOT's website provides information on the actual output of the wind units for each hour in 2009. A comparison of the actual energy output from the wind units to their installed capacity resulted in an average annual capacity factor of 24.5%. Thus, the net capacity of all wind units in the model was designated to be 24.5% of actual installed capacity. For all other unit types, equivalent availability factors were obtained from NERC's Generation Availability Reports for 2005 to 2009 and each unit's capacity was reduced accordingly.

The final data input to the model is ERCOT's actual load demand by hour for 2009, which varies significantly by time of day and time of year. ERCOT also carries ancillary services every hour of every day, which include responsive reserves, non-spinning reserves, and regulation reserves. Therefore, I added an average value for ancillary services to the actual load.

Q92. Mr. Johnson (Johnson Report 2 ¶ 10) claims: "The model's treatment of ancillary services appears simplistic, since ancillary service pricing would be directly affected by significant outage events, such as the loss of STP generating units." Please discuss whether your model accounts for ancillary services.

A92. (AP) The model does account for ancillary services. As mentioned above, I added an average value for each of the operating reserve ancillary services to the actual hourly load values in the model. Operating reserves (except for regulation service that is deployed up and down, as needed, every 4 seconds to maintain frequency) are not typically deployed for energy, *i.e.*, they are carried as capacity available for energy if and when needed for reliability. My model is conservative in that it adds generating units to account for operating reserves as well as the demand at each hour. As a result, the marginal price for each hour reflects the amount of the reserves, and therefore is higher than if the reserves were not considered.

Q93. How does your dispatch model work?

A93. (AP) With the data inputs complete, the model's algorithms then "dispatch" the ranked units to meet the load and operating reserve requirements for each hour in 2009. The model results in a determination of the marginal unit, and the corresponding marginal price, for each hour of 2009, based on the generic costs described previously. Use of the marginal price is appropriate, because the wholesale power price in ERCOT is normally based on the cost of the last unit dispatched. Once the hourly marginal price is determined, the model then calculates the load-weighted average price in ERCOT for the year.

Q94. Mr. Johnson (Johnson Report 2 ¶ 10) claims: "Finally, the model sets all hourly prices equal to marginal costs, which assumes perfect competition. In reality, competitive power markets are susceptible to market power, because one or more suppliers will be pivotal in certain hours. The assumption that no market power will affect power prices is unrealistic." Please discuss whether your model accounts for market power.

A94. (AP) Mr. Johnson is correct in that the model assumes perfect competition. Mr. Johnson is also correct that one or more suppliers will be pivotal in certain hours. In fact, during scarcity conditions when load is high and generating reserves are running short, all suppliers could be deemed pivotal.

For several reasons, it is not necessary or appropriate to account for market power in order to calculate a reasonable cost of the effects of an outage of the STP units. First, as discussed above, my model was run twice, once with all four STP units available and the second with no STP units available. The two cases were then compared to determine the effect of the

STP units only. Any assumption of market power would be made in both cases and they would therefore effectively offset each other. If assumptions were made for market power in the first case, the similar assumptions would also be made in the second case and the net effect would be minimal.

Second, since the market opened to competition in 2002, there has never been a finding of market power abuse by any regulatory or enforcement agency in ERCOT. There have been accusations of market power abuse, and there have been investigations, but no findings of market power abuse have ever occurred. In addition, PUCT Substantive Rule 25.365, Independent Market Monitor, defines the authority and responsibility of the IMM, and the primary objective of the IMM is to "detect and prevent market manipulation strategies and market power abuses" in ERCOT. Therefore, market abuse is unlikely to occur.

Third, there is no practical method for calculating the impact of an abuse of market power. Such a calculation would need to postulate a deliberate act by a supplier. It is not practical, a priori, to identify which supplier would abuse its power, the nature of the abuse, or impact of the abuse. Furthermore, PUCT Rule 25.503(g) prohibits a market participant from engaging in abuse of market power. It is not reasonable to postulate that a market participant will violate applicable regulations.

For all these reasons, perfect competition is a reasonable assumption in the model.

Q95. What are the results of your dispatch model?

A95. (AP) Based on the 2009 average natural gas price of $3.74 per MMBtu (Exh. STP000020, page iv) and the preceding assumptions and methodology, the dispatch model indicates the loss of all four STP units would increase the load-weighted average annual market price in ERCOT by $1.80 per MWh. With all four STP units available, the load-weighted average annual market price was $36.06 per MWh. With all four STP units removed from service, the load-weighted average annual market price increased to $37.86 per MWh. These results are not surprising because the units on the margin for the vast majority of hours during the year are natural-gas fired, with or without the STP units.

Q96. Mr. Johnson (Johnson Report 2 ¶ 10) states: "The model assumes that wind generation, which is substantial in Texas, will have a capacity factor of 24.5%. However, wind generation capability is not spread equally across hours of the day or hours of the year. Wind power output tends to be highest at night and during non-summer periods. For annual reserve margin calculations, ERCOT assumes that 9% - 11% of wind capability is available." What is the impact to the model if wind were assumed to have a capacity factor of less than 24.5%?

A96. (AP) Mr. Johnson is correct in that wind is not spread equally across all hours of the day or hours of the year. Accounting for the hourly variability of wind would have increased the complexity of the simplified dispatch model. Even if the variability of wind across the year were taken into account, the results would not have changed significantly for the same reasons outlined previously; *i.e.*, the purpose of the model is to calculate the "difference" between two separate model runs: (1) with all four STP units available, versus (2) no STP units available. Accounting for hourly variability of wind would have little impact as the same variability would have been modeled in both cases and thus would have offset.

Nonetheless, I have re-run the two cases with the same assumptions as before (*i.e.*, 2009 average gas price and 2009 load), but with the wind capacity factor at zero. This completely removes the zero cost wind resources from the model. With all four STP units available and no wind, the load-weighted average annual market price is $36.75 per MWh. With all four STP units removed from service, the load-weighted average annual market price increased to $39.14 per MWh. Again, these results are not surprising because even with zero wind resources the units on the margin for the vast majority of hours during the year are natural-gas fired, with or without the STP units. To be conservative, this $2.39 per MWh price difference is used below rather than the $1.80 per MWh price difference calculated above.

Q97. What is the accuracy of your dispatch model?

A97. (AP) As a check on the accuracy of my model, I compared the average prices with all four STP units available ($36.06 per MWh or $36.75 per MWh (assuming no wind resources)) with the actual average balancing market price in ERCOT for 2009 ($34.03 per MWh). My calculated price was close to (and slightly higher than) the actual average price. This provides confidence that my model produces reasonable results. Furthermore, since the purpose of my model was to calculate the difference in market prices with and without the four STP units, the magnitude of the average price is not critical.

3. Impact on Replacement Power Costs

Q98. How do the market effects estimated by your dispatch model affect the ERCOT market prices?

A98. (AP) To determine the impact of these market effects on the SAMDA evaluation, I added the increase in price due to shutting down the four STP units and removing the wind resources to the 2008 average balancing price. As discussed above, the 2008 SOM Report provides an average balancing price of $82.95 per MWh. If this amount is increased by $2.39 per MWh to account for the market effects of shutting down the four STP units, the resulting price is $85.34 per MWh. This price is 2.60 times larger than the $32.81 per MWh price when the NUREG/BR-0184 replacement power costs used by the ER are escalated to 2009 dollars to account for inflation, increased capacity factors, and a higher net electrical output for STP Units 1 and 2.

Q99. How do these ERCOT market prices affect the estimated monetized impacts?

A99. (AP) Multiplying the replacement power costs in Table 5 by 2.60 to account for the 2008 ERCOT pricing data and to account for market effects results in the following values:

Table 10 – Monetized Impacts Using Replacement Power Costs Based on 2008 ERCOT Pricing Data and Accounting for Market Effects

7% Discount Rate				
	ABWR with Severe Accident	**Other ABWR**	**STP Unit 1**	**STP Unit 2**
Non-Replacement Power Costs	$2,454	$1,025	$1,071	$1,071
Replacement Power Costs	$26,454	$11,904	$4,401	$4,401
Unit Total	$28,908	$12,929	$5,472	$5,472
Site Total	$52,783			
Sensitivity Analysis -- 3% Discount Rate				
	ABWR with Severe Accident	**Other ABWR**	**STP Unit 1**	**STP Unit 2**
Non-Replacement Power Costs	$5,046	$1,916	$1,895	$1,895
Replacement Power Costs	$44,491	$15,374	$7,376	$7,376
Unit Total	$49,537	$17,290	$9,271	$9,271
Site Total	$85,370			

Q100. How do these values affect the SAMDA evaluation?

A100. (AP) These values are still well below the lowest risk-adjusted cost of the SAMDAs ($982,500). Therefore, acceptance of the Intervenors' position that the ER's estimated replacement power costs should account for market effects does not affect the conclusion that there are no cost-effective SAMDAs.

Q101. Is this evaluation conservative?

A101. (AP) Yes. Use of the 2008 rather than the 2009 average balancing price in this analysis is very conservative. This evaluation also is conservative because it assumes that the higher market price lasts throughout the shutdown period, when in reality the effects would be mitigated based on the factors discussed above.

4. Impact on Consumers

Q102. Do the Intervenors raise issues related to the impact on consumers within ERCOT?

A102. (AP) Yes. Johnson Report 1 (page 5) discusses a sensitivity analysis to illustrate the impacts on consumers within ERCOT of any increase in market price due to shutdown of the four STP units. Johnson Report 1, however, does not provide an actual evaluation of the impacts. Instead, it arbitrarily picks a $10 increase in ERCOT market prices, and states that such an increase would produce a $3.8 billion annual cost to consumers.

Q103. How can the impact to consumers be approximated?

A103. (AP) The impact to consumers can be approximated using the total ERCOT generation in 2009 and the $2.39 per MWh increase in market prices calculated above. As derived from the 2009 ERCOT Hourly Load Data publication (Exh. STP000024), the total generation in ERCOT in 2009 was 307,491,044 MWh. Therefore, the economic impact of the increased market price is $734,903,595 per year. Once the probability of the severe accident is accounted for with the CDF (1.56×10^{-7} per year), the resulting impact is $114.64 per year-squared. Accounting for a 40 year life of the plant and conservatively assuming that the increased market price lasts for six years, the overall economic impact is $27,515. This calculation conservatively does not account for the discount rate.

Q104. How does accounting for the impact to consumers affect the SAMDA evaluation?

A104. (AP) When this $27,515 consumer impact due to market effects is added to the total monetized impacts in Table 8 using the 7% discount rate ($51,462), the resulting monetized impacts are $78,977. Using the 3% discount rate sensitivity analysis, the resulting monetized impacts are $110,795. These values are still well below the lowest risk-adjusted cost of the SAMDAs ($982,500). Therefore, acceptance of the Intervenors' position that the ER's estimated replacement power costs should account for impacts to consumers does not affect the conclusion that there are no cost-effective SAMDAs.

E. ERCOT Price Spikes

Q105. Do the Intervenors raise issues related to ERCOT price spikes?

A105. (AP) Yes. The Intervenors have stated that the replacement power costs should consider additional price spikes that could occur due to the shutdown of the four STP units. Although Johnson Report 1 does not quantify the change in replacement power costs due to these price spikes, it states that price spikes increased ERCOT average prices in 2008 by 20% (Johnson Report 1, page 6).

Q106. What are price spikes?

A106. (AP) As discussed in the 2009 SOM Report (Exh. STP000020, pages 6-7), price spikes are defined as intervals where the load-weighted average Market Clearing Price of Energy in ERCOT is greater than 18 MMbtu per MWh times the prevailing natural gas price (a level that should exceed the marginal costs of virtually all of the on-line generators in ERCOT).

Q107. Have price spikes ever occurred in ERCOT?

A107. (AP) Yes. Based on the above definition, price spikes have occurred in ERCOT every year following deregulation of the market. There were 99, 52, 62, and 64 price spikes per month in 2006, 2007, 2008, and 2009, respectively. As shown by the zonal price duration curves in the 2009 SOM Report (Exh. STP000020, page 6), the price spikes are of short duration and only increased prices above $50 per MWh for a few hundred hours a year total. The short duration is due to ERCOT carrying responsive, regulation, and non-spin reserves, all of which are carried 24 hours a day to handle contingencies.

Q108. What impact do these price spikes have on average prices in ERCOT?

A108. (AP) The impact of these price spikes on average prices was estimated to be 10%, 11%, 20%, and 18% in 2006, 2007, 2008, and 2009, respectively (Exh. STP000020, page 6). This price impact is already accounted for by the average balancing prices in Tables 7 and 8 above.

Q109. Have there been any recent price spike events?

A109. (AP) Yes. On February 2, 2011, the ERCOT market experienced a record breaking arctic cold front that resulted in more than 50 units, representing more than 7,000 MW of generation, being disabled between midnight and 5:30 a.m. This resulted in emergency procedures being invoked by the ERCOT Independent System Operator, with ERCOT ultimately ordering 4,000 MW of firm load to be shed from the grid. The generation scarcity conditions on February 2 resulted in several hours of elevated prices. For example, in an 8 hour period from 3:30 a.m. until 11:30 a.m., the Houston load zone price averaged $2,214 per MWh. And even though the temperatures remained below freezing in most of the ERCOT region on Thursday, February 3, the Houston load zone price from 11:45 a.m. on February 2 until 11:59 p.m. on February 3 averaged $69.75 per MWh. For February 4 and 5 the average Houston load zone price was $37.37 per MWh, even though similar weather conditions continued. This event shows that even with this record breaking cold weather event and with the loss of thousands of megawatts of generation, the price spikes were short lived.

It should also be pointed out that during this severe weather event ERCOT experienced additional instability in the South region of Texas. Due to plant outages in the South region on February 2 and 3 and transmission import constraints, ERCOT operators curtailed approximately 300 MW of firm load, resulting in rolling outages in communities in the South region. The average South load zone price on February 2 and 3 was $749.77. The situation in the South load zone was stabilized by February 4, and the average price on February 4 and 5 was $54.69. Thus, the price spikes in the South, which were not as high as the price spikes on February 2, were nonetheless rectified within 2 days.

Q110. What factors would limit impacts due to price spikes in ERCOT?

A110. (AP) The potential for increases in ERCOT average market prices due to additional price spikes attributable to outages of the STP units would be limited by many of the same factors that would minimize other market effects of shutting down the four STP units. For example, the ERCOT market would adjust to the loss of the STP units and would diminish the impact of price spikes. This would occur as new units enter the market to replace the generation from the STP units. ERCOT also will have approximately 5,505 MW of mothballed capacity that could potentially replace the lost generation. The generation from all four STP units also is less than the 13.75% reserve margin in ERCOT, which was calculated on the peak hour of the year. Therefore, in most, if not all hours of the year, ERCOT should have enough operating reserves to ensure adequate protection against the loss of load. These operating reserves naturally suppress price spikes.

Additionally, the price spikes in the highest priced year of 2008 were primarily due to inefficient zonal management techniques rather than outages of generating stations. The zonal market design no longer existed beginning December 1, 2010, when ERCOT implemented a nodal market design, which provides greater efficiencies than a zonal design when resolving transmission congestion. Therefore, this contributor to ERCOT price spikes is significantly reduced during operation of all four STP units, and will further reduce the net price spikes within ERCOT, even if the STP units were shut down.

The above factors should minimize the impact of any additional price spikes due to the shutdown of the four STP units. Any price spikes from outages of the STP units should be of short duration—a matter of days. Nevertheless, I performed a sensitivity analysis of the impact of price spikes, conservatively assuming that such additional price spikes were to increase ERCOT prices by an additional 20% (doubling the percentage impact of the high price spikes in 2008) for the first year of the outage.

Q111. How can the impact to consumers due to price spikes be approximated?

A111. (AP) As shown above, the 2008 average balancing price is $82.95 per MWh. The impact to consumers due to price spikes can be approximated using the total generation in 2009 and 20% of the $82.95 per MWh market price ($16.59). As derived from the 2009 ERCOT Hourly Load Data publication (Exh. STP000024), the total generation in ERCOT in 2009 was 307,491,044 MWh. Therefore, the economic impact of the price spikes is $5,101,276,420 per year based upon an increase in market price of $16.59. Once the probability of the severe accident is accounted for with the CDF (1.56×10^{-7} per year), the resulting impact is $795.80 per year-squared. Accounting for a 40 year life of the plant and one year of additional price spikes due to the STP outages, the overall economic impact is $31,832. This calculation conservatively does not account for the discount rate.

Q112. How does accounting for the impact to consumers due to price spikes affect the SAMDA evaluation?

A112. (AP) When this $31,832 consumer impact due to price spikes is added to the total monetized impacts in Table 8 using the 7% discount rate ($51,462) and the consumer impacts due to market effects ($27,515), the resulting monetized impacts are $110,809. Using the 3% discount rate sensitivity analysis, the resulting monetized impacts are $142,627. These values are still well below the lowest risk-adjusted cost of the SAMDAs ($982,500). Therefore, acceptance of the Intervenors' position that the ER's estimated replacement power costs should account for price spikes does not affect the conclusion that there are no cost-effective SAMDAs.

F. Loss of the Grid

Q113. Do the Intervenors raise issues related to loss of the grid?

A113. (AP) Yes. Johnson Report 1 (page 7) states that the simultaneous loss of four STP units "could increase the likelihood of outages on the ERCOT grid which result in load shedding, or even uncontrolled blackouts." Although Johnson Report 1 does not quantify the change in costs due to these grid outages, it states that the grid outages will increase the economic costs.

Q114. Please characterize the probability of loss of the ERCOT grid following shutdown of all four STP units.

A114. (AP) Johnson Report 1 (page 7) states that the probability of an ERCOT grid outage following a shutdown of all four STP units "may not be high." Given all of the protective measures established by ERCOT, the Texas Reliability Entity, and NERC, it is extremely unlikely that a shutdown of all four STP units would result in a loss of the ERCOT grid. In fact, the protective measures have been successful in the past, and there has never been a loss of the entire ERCOT grid due to any event.

Q115. What is ERCOT's role in ensuring reliability of the grid?

A115. (AP) ERCOT is responsible for running the grid reliably and avoiding the loss of load as per the ERCOT Protocols, the document approved by the PUCT which contains, among other things, the operating and reliability policies, rules, and standards of ERCOT. In addition, since the Northeast United States Blackout of 2003 (mentioned in Johnson Report 1, page 7), ERCOT, as well as all other electricity regions in the United States, are under strict federally enforced reliability standards. These rigorous standards are monitored and enforced by the Texas Reliability Entity, which has the responsibility of ensuring the reliability of the bulk power system as per the requirements of NERC.

Q116. How could ERCOT ensure grid reliability during a shutdown of STP units?

A116. (AP) The ERCOT grid is designed to simultaneously lose the two largest generators without a loss of the grid (Exh. STP000027, page 8.2-17). In the event of a severe accident at one STP unit, the other units would be shut down in an orderly fashion, *i.e.*, all four units would not be taken off the grid simultaneously. Given the orderly shutdown, ERCOT would have time to adjust to the loss of the four units and to bring other generation sources online, invoke certain demand response programs, and to shed load in a controlled manner, if required. For example, Section 4.5 of the December 1, 2010 ERCOT Nodal Operating Guides (Exh. STP000025), a subset of the ERCOT Protocols, states that it may be necessary to reduce electrical demand due to a shortfall of supply, such as emergency outages of generators. These guides dictate actions to ensure that the ERCOT system frequency remains above 59.5 Hz, including actions such as using DC tie capability, deploying responsive reserves, and shedding loads. These load shed events are very infrequent, and have only occurred five times in the past eight years, most recently on February 2, 2011. For all of these reasons, it is extremely unlikely that the shutdown of the four STP units would result in a loss of the grid.

The low probability for loss of the grid also is attributable to many of the same factors that would minimize other market effects and price spikes due to shutting down the four STP units. For example, any potential for losses of the grid due to the lower generation in ERCOT would be minimized by adjustment of the ERCOT market to the loss of the STP units. This would occur as new units enter the market to replace the generation from the STP units. Additionally, ERCOT will have approximately 5,505 MW of mothballed capacity that could replace the lost generation. The generation from all four STP units also is less than the 13.75% reserve margin in ERCOT, which was calculated on the peak hour of the year. Therefore, in most, if not all hours of the year, ERCOT should have enough operating reserves to ensure adequate protection against the loss of load. These operating reserves naturally suppress grid outages.

Q117. How does the recent emergency event in February of this year reflect ERCOT's responsibilities for ensuring the reliability of the grid when large quantities of generation become unavailable?

A117. (AP) The severe weather event the first week of February 2011, which I previously described, provides an excellent case study on the procedures ERCOT takes to avoid a collapse of the grid during emergency situations. The quantity of generation that became unavailable the morning of February 2 due to the severe weather conditions was unprecedented. The quantity of generation disabled was greater than 7,000 MW, which exceeds the capacity of all four STP units combined. While the February event did result in a controlled process of firm load shedding, at no time during the extended emergency was the entire grid in peril of collapsing. ERCOT prevented a collapse of the grid by invoking what is described in the Protocols as the Energy Emergency Alert levels ("EEA") (Exh. STP000025). The EEA procedures are invoked when "it may be necessary to reduce ERCOT System demand because of a temporary decrease in available electricity supply" (pages 4-5). The stated goal of the EEA procedures is to "provide for maximum possible continuity of service while maintaining the integrity of the ERCOT System to reduce the chance of cascading Outages" (pages 4-5). The EEA procedures worked exactly as planned during the February event and provide a real-life example of how a complete loss of the entire grid is a remote possibility.

Q118. What is the probability of loss of the grid due to a shutdown of the STP units following an accident?

A118. (AP) Although it is difficult to quantify a probability for loss of the ERCOT grid due to shutdown of the four STP units, it is reasonable to assume that the probability is far less than 0.1. The CDF for the ABWR is 1.56×10^{-7} per year. Thus, the probability of a severe accident at one of the ABWR units at the STP site, followed by a shutdown of the other three STP units, followed by a loss of the ERCOT grid, is far less than 10^{-8} per year. Such an occurrence is remote and speculative.

Q119. What would be the economic impact of loss of the grid?

A119. (AP) The cost of a grid outage can be approximated by assuming the outage lasted for 24 hours and calculating the "value of lost load" for the 24 hour black out period. The value of lost load can be approximated using the $3000 per MWh current price cap in ERCOT, which is the price determined by the PUCT as the point at which load is willing to curtail consumption. Using a very high summer load day in 2009 (August 4, 2009) where the load was 1,140,563 MWh, the total estimated value of lost load using the $3000 per MWh approximation is $3.42 Billion. As a point of comparison, Johnson Report 1 (page 7) states that the 2003

Northeast blackout is estimated to have caused $10 Billion in damage, but Johnson Report 1 states that it is an "extreme example."

Q120. Johnson Report 1 states that the combination of high prices and rolling blackouts in the 2000/2001 California energy crisis produced economic damage of $45 billion. Please discuss the relevance of that figure.

A120. (AP) I do not believe the cited cost is applicable to the SAMDA analysis. Mr. Johnson bases the estimated cost of $45 billion on a study entitled *The California Energy Crisis: Causes and Policy Option*, by Christopher Weare (2003), published by the Public Policy Institute of California (Exh. STP000026). Pages 3 to 4 of that study state:

> To gain some perspective on the damage inflicted on the California economy [by the crisis caused by electricity deregulation], one can compare it with other significant economic failures. This crisis has cost $40 billion in added energy costs over the last two years. Increased costs will continue as long as the prices in the long-term contracts signed by the state exceed wholesale rates. On top of these costs, one must add the costs of blackouts and reductions in economic growth caused by the crisis. Thus, conservatively, the total costs can be placed around $40 billion to $45 billion or around 3.5 percent of the yearly total economic output of California.

Thus, of the $45 billion cited by Mr. Johnson, only $0 to $5 billon came from blackouts. The remaining $40 billion came from poor market design, uneconomic long-term contracts, and opportunistic behavior. The $40 billion from deregulation is not relevant to the SAMDA analysis, because it does not pertain to blackouts. The specified cost of the California blackouts is less than the $10 billion cost cited by Mr. Johnson for the Northeast blackout.

Q121. How can the impact to consumers due to loss of the grid be approximated?

A121. (AP) The impact to consumers due to a grid outage can be approximated using the economic impact of the grid outage and the likelihood of the outage. Assuming the extreme example of $10 Billion in damages, once the probability of the severe accident is accounted for with the CDF (1.56×10^{-7} per year) and the 0.1 likelihood that a grid outage would occur following a severe accident, the resulting impact is $156 per year. Because the market would respond to the loss of the STP units, there would be essentially zero likelihood that the shutdown of the STP units would cause any loss of the grid after the first year of their outages. Accounting for a 40 year life of the plant, the overall economic impact is $6,240. This calculation conservatively does not account for the discount rate.

Q122. How does accounting for the impact to consumers due to loss of the grid affect the SAMDA evaluation?

A122. (AP) When this $6,240 impact due to a grid outage is added to the total monetized impacts in Table 8 using the 7% discount rate ($51,462), the consumer impacts due to market effects ($27,515), and the consumer impacts due to price spikes ($31,832), the resulting monetized impacts are $117,049. Using the 3% discount rate sensitivity analysis, the resulting monetized impacts are $148,867. These values are still well below the lowest risk-adjusted cost of the SAMDAs ($982,500). Therefore, acceptance of the Intervenors' position that the ER's estimated replacement power costs should account for grid outages does not affect the conclusion that there are no cost-effective SAMDAs.

Q123. How would the conclusion change if Mr. Johnson's $45 billion of economic impact in California were assumed instead?

A123. (AP) Mr. Johnson stated that the Applicant should assume an economic impact of $45 billion due to the estimated economic damage from the 2000/2001 California energy crisis. As discussed above, this is not appropriate, because $40 billion of that cost is attributable to higher energy prices from deregulation and not blackouts. However, even if this $45 billion economic harm were assumed, this would not affect the conclusions of the SAMDA evaluation.

Using the same methodology as above, but assuming an initial $45 billion economic impact, I calculated that the resulting overall economic impact over the life of the plant is $28,080. When this $28,080 impact due to a grid outage is added to the total monetized impacts in Table 8 using the 7% discount rate ($51,462), the consumer impacts due to market effects ($27,515), and the consumer impacts due to price spikes ($31,832), the resulting monetized impacts are $138,889. Using the 3% discount rate sensitivity analysis, the resulting monetized impacts are $170,707. These values are still well below the lowest risk-adjusted cost of the SAMDAs ($982,500). Therefore, acceptance of the Intervenors' position that the Applicant's estimated replacement power costs should account for grid outages that have an economic harm equivalent to the California energy crisis does not affect the conclusion that there are no cost-effective SAMDAs.

VII. CONCLUSIONS

Q124. What are your conclusions regarding the ER's SAMDA evaluation?

A124. (JLZ, AP) Based on the information provided in the ER and this direct testimony, we conclude that the ER's SAMDA evaluation was reasonable and demonstrates that there are no cost-effective SAMDAs. Consideration of all other issues raised by the Intervenors does not alter the conclusion of the SAMDA evaluation—there are no cost-effective SAMDAs. This conclusion is clearly displayed in the table below, which illustrates that all of the averted costs from implementing a SAMDA are much lower than the lowest risk-adjusted cost of the SAMDAs ($982,500).

Table 11 –Summary of Monetized Impacts and SAMDA Costs

Total Monetized Impacts		
Characteristics	**7% Discount Rate**	**3% Discount Rate Sensitivity Analysis**
Total Costs Using NUREG/BR-0184 Replacement Power Costs in 1993 Dollars (Table 2)	$13,377	$23,015
Total Costs Using NUREG/BR-0184 Replacement Power Costs Escalated to 2009 Dollars (Table 4)	$16,945	$28,656
Total Costs Using NUREG/BR-0184 Replacement Power Costs Escalated to 2009 Dollars and Adjusting for a 95% Capacity Factor and Higher STP Units 1 and 2 Output (Table 5)	$23,754	$39,441
Total Costs Using Replacement Power Costs Based on 2009 ERCOT Pricing Data (Table 7)	$24,831	$41,145
Total Costs Using Replacement Power Costs Based on the Highest Historical Annual ERCOT Pricing Data from 2008 (In 2009 dollars) (Table 8)	$51,462	$83,280
Total Costs Using Replacement Power Costs Based on Johnson Report 1 (in 2008 dollars) (Table 9)	$35,094	$57,351
Total Costs Using Replacement Power Costs Based on 2008 ERCOT Pricing Data and Accounting for Market Effects (Table 10)	$52,783	$85,370
Total Costs Using Replacement Power Costs Based on 2008 ERCOT Pricing Data and Accounting for Market Effects and Consumer Impacts	$78,977	$110,795
Total Costs Using Replacement Power Costs Based on 2008 ERCOT Pricing Data and Accounting for Market Effects, Consumer Impacts, and Price Spikes	$110,809	$142,627
Total Costs Using Replacement Power Costs Based on 2008 ERCOT Pricing Data and Accounting for Market Effects, Consumer Impacts, Price Spikes, and Grid Outages	$117,049	$148,867
Total Costs Using Replacement Power Costs Based on 2008 ERCOT Pricing Data and Accounting for Market Effects, Consumer Impacts, Price Spikes, and Grid Outages (Equivalent to California Energy Crisis)	$138,889	$170,707

Q125. Why are some of the cost values that you provide in this testimony different than those that you provided in your Joint Affidavit to support the Applicant's Motion for Summary Disposition of Contention CL-2?

A125. (JLZ, AP) Following the Applicant's submission of the Motion for Summary Disposition, both the Intervenors and the NRC Staff submitted answers to the motion and the Board issued LBP-11-07 rejecting the motion. We have revised our earlier analysis to address issues raised in these answers and LBP-11-07. We also have removed some of the conservatism included in the Joint Affidavit. However, the evaluation in this testimony is still very conservative.

Q126. What are some examples of this conservatism?

A126. (JLZ, AP) Some examples of this conservatism include:

- Only accounting for actual risk reduction for some of the SAMDAs.
- The SAMDA costs provided in the TSD are biased on the low side, and actual plant costs are expected to be higher.
- Performance of a sensitivity analysis for the replacement power cost estimates based on a 3% discount rate.
- Use of the 2008 ERCOT pricing data (highest prices since the ERCOT market was deregulated in 2002) as a sensitivity analysis for the replacement power cost estimates.
- Assumption that the outages at the STP site would cause additional price spikes, which in turn would increase the market price by 20% during the first year of outages. The 20% is in addition to the 20% increase in market prices from price spikes caused by other factors.
- Assumption that a grid outage due to shutting down the STP units that is equivalent to the 2003 Northeast blackout or the cost of deregulation of the California electricity markets.
- Assumption of no discount rate when estimating the consumer impacts from market effects, price spikes, and grid outages.

This conservatism provides additional assurance that the conclusion that there are no cost-effective SAMDAs is correct.

Q127. Are true, accurate and correct copies of each of the exhibits referenced in your testimony attached?

A127. (JLZ, AP) Yes.

Q128. Does this conclude your testimony?

A128. (JLZ, AP) Yes.

(JLZ, AP) I declare under penalty of perjury that the foregoing is true and correct.

Executed on May 9, 2011.

Executed in Accord with 10 C.F.R. § 2.304(d)

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