ADV-401

BEFORE THE

PUBLIC SERVICE COMMISSION OF THE STATE OF NORTH DAKOTA

JOINT APPLICATION OF OTTER TAIL POWER COMPANY AND MONTANA-DAKOTA UTILITY FOR AN ADVANCE DETERMINATION OF PRUDENCE FOR ITS BIG STONE AIR QUALITY CONTROL SYSTEM PROJECT	)))))	**DOCKET NO. PU-11-165** **DOCKET NO. PU-11-163**

PUBLIC REDACTED VERSION

INITIAL TESTIMONY

OF

RICHARD S. HAHN

ON BEHALF OF

THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

ADVOCACY STAFF

OCTOBER 21, 2011

DOCKET NO. PU-11-165 AND PU-11-163

INITIAL TESTIMONY OF RICHARD S. HAHN

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INITIAL TESTIMONY

OF

RICHARD S. HAHN

I. QUALIFICATIONS

Q. Please state your name, position, and business address.

A. My name is Richard S. Hahn. I am employed by La Capra Associates, Inc. ("La Capra") as a Principal Consultant. My business address is One Washington Mall, 9th Floor, Boston, Massachusetts 02108.

Q. Please summarize your professional experience and qualifications.

A. I received my Bachelor's in Science, Electrical Engineering, in 1973, and my Masters in Science, Electrical Engineering, in 1974, both from Northeastern University. I received my Masters in Business Administration from Boston College in 1982. Since joining La Capra, I have worked on many projects related to energy markets, forecasts of wholesale market prices, utility resource planning projects, and asset valuations. Prior to joining La Capra, I worked at NSTAR Electric & Gas (formerly Boston Edison Company) from 1973 to 2003. Throughout my career, I have gained and demonstrated considerable experience and expertise in utility planning activities. I am a registered professional

electrical engineer in the Commonwealth of Massachusetts. My resume is provided in Exhibit ___ (RSH-1).

Q. Please summarize La Capra Associates and its business.

A. La Capra Associates provides consulting services in energy planning, market analysis, and regulatory policy in the electricity and natural gas industries. We serve a national and international clientele from our offices in Boston, Massachusetts, Portland, Maine, and Williston, Vermont providing consulting services to a broad range of organizations involved with energy markets, including renewable energy producers, private and public utilities, energy producers and traders, energy consumers and consumer advocates, regulatory agencies, and public policy and energy research organizations. Our technical skills include power market forecasting models and methods, economics, management, planning, rates and pricing, and energy procurement, and contracting. Our experience includes detailed analyses of energy and environmental performance of the electric systems, economic planning for transmission, and market analytics.

II. PURPOSE OF TESTIMONY

Q. On whose behalf are you appearing in these proceedings?

A. I am testifying on behalf of the North Dakota Public Service Commission Advocacy Staff ("Advocacy Staff").

Q. Please describe the purpose of your testimony.

A. La Capra has been retained by the Advocacy Staff to assist in reviewing the joint application of the Otter Tail Power Company ("OTP") and the Montana-Dakota Utility ("MDU", collectively "the Companies") for an advance determination of prudence related to their proposed Big Stone Air Quality Control System ("AQCS") project. Specifically, we were asked to perform an independent review and critique of the Companies' analysis of the AQCS project at Big Stone. Our assessment methodology was to utilize the discovery process to obtain a detailed understanding of each Company's filing and the underlying assumptions, inputs and analyses.

Q. Please summarize your conclusions and recommendations.

A. Based upon my review of the Companies' application, I conclude that the AQCS is the preferred option for compliance with South Dakota's proposed implementation of the Regional Haze Rule. The AQCS is the least cost option studied. While I disagree with some of the assumptions and methodologies used by the Companies, adjusting for those differences does not alter the conclusion that the AQCS is the lowest cost option studied. The Company has proposed an AQCS based on reasonable emission control technologies and, at the Company's estimated cost, it is cost effective relative to other alternatives. However, the difference between the AQCS option and the next best alternative is considerably narrower than portrayed in the Applicants' analysis. Thus, the estimated capital cost for the AQCS becomes critical in determining the prudence of this investment. The proposed investment in mercury control equipment does not

qualify for an advance determination and should not be approved. I recommend that the Commission approve the Companies' application and grant an advance determination of prudence for the cost estimate contained in the application. However, I recommend that the Commission condition its determination upon:

1) Finalization of the environmental regulations requiring AQCS in the same form as currently proposed; and
2) Final actual costs being within 10% of the costs estimated by the Companies in its application including escalation, AFUDC, and financing costs. Without the mercury control costs, the estimate of the capital costs of the AQCS including escalation, AFUDC, and financing costs is $534 million. Therefore, I recommend approval of an advance determination of prudence for up to $585 million for 100% of the project. Amounts above this level would be subject to further justification by the Companies and further prudence review by the Commission.

I recommend that the Commission require the Companies to periodically report on the status of the project costs and the finalization of the SIP.

III. BASIS FOR REVIEW OF THE APPLICATION

Q. What approvals are the Companies seeking in this Application?

A. OTP and MDU are seeking an advance determination of prudence for AQCS at the Big Stone coal fired power facility.[1]

Q. What is the basis for the Companies' request for an advance determination of prudence?

A. Provisions for an advance determination of prudence are set forth in North Dakota law.[2] That provision was amended in 2011 and became law on August 1 of this year. OTP has indicated that it agrees to have this application (which pre-dated the change in law) to be considered under the new version of the law. I have conducted my review of this Application under the provision of the now-current advance determination of prudence law.

Q. What are the key provisions of the advance determination of prudence law as it pertains to the Companies' Application?

A. The statute allows a utility to apply for an advance determination of prudence for modification of an energy conversion facility, among other resource additions. It is my understanding that the AQCS project qualifies for consideration.

For qualifying resource additions, the Commission may issue an order approving the request for an advance determination if the Commission finds the project to be prudent. There are added considerations for resource additions that are in-state;

[1] See OTP May 20, 2011 Cover letter to its Application in this proceeding.

[2] N.D. Century Code § 49-05-16.

however, the Big Stone facility is located in South Dakota. I have conducted my review using the provisions that apply to out of state resources. Specifically, the presumption of prudence afforded in-state resource additions and the requirement to consider the benefits of having the resource located in-state would not apply to this Application. If the Commission grants a determination of prudence, the project would be subject to specific reporting requirements until its date of commercial operation.

Q. How have you conducted your review in light of this understanding?

A. In this circumstance, it is the Companies' burden to prove that the proposal is economically superior to alternatives in the market and that it is needed to provide energy benefits to customers. I have reviewed the Companies' supporting evidence with that standard of review in mind. The prudence standard that would apply must address whether the decision to proceed with the AQCS project is reasonable and consistent with lowest reasonable cost to consumers based on information that is known or knowable at the time the decision is made.

Q. What is your understanding of the statutory requirements for consideration of environmental requirements in planning?

A. My understanding of North Dakota law is that the Commission may not use the projected costs of complying with yet-to-be-enacted environmental laws or regulations in determining resource additions that are consistent with lowest cost to consumers.[3] In other words, a resource addition that is reasonable only in the event of enactment of prospective environmental laws or regulations cannot be

[3] ND Cent. Code §49-02-23

determined to be prudent. The Regional Haze rule of the Federal Clean Air Act ("CAA") is an enacted rule. However, the South Dakota Regional Haze State Implementation Plan ("SD Haze SIP") that determines how the Regional Haze rule applies to Big Stone Plant has not yet received final approval from the United States Environmental Protection Agency ("EPA"). Until it is approved by the EPA, the SD Haze SIP should not be used to justify an advance determination of prudence. Similarly, the EPA proposed National Emission Standards for Hazardous Air Pollutants ("NESHAP") on March 16, 2011 that would limit hazardous air pollutants such as mercury at Big Stone and other electric utility steam generating units ("EGUs"). Until the rule is finalized by the EPA, NESHAP should not be used to justify an advance determination of prudence. I have conducted my review of this Application with this understanding of the treatment of environmental compliance costs.

IV. BIG STONE AQCS AND MERCURY CONTROLS PROJECTS

Q. Please summarize the components of the Big Stone AQCS Project.

A. The Big Stone AQCS Project, as proposed by the Applicants, has four main components:

1. Semi-Dry Flue Gas Desulfurization ("semi-dry FGD") to reduce sulfur dioxide ("SO2") emissions;
2. Selective Catalytic Reduction ("SCR") with Separated OverFire Air ("SOFA") to control nitrogen oxide ("NOx") emissions;

3. Activated Carbon Injection ("ACI") to control mercury emissions; and
4. Balance of plant modifications necessary to install and operate the control technologies, including boiler modifications, replacing the existing baghouse, replacing the ID fans, reinforcing the boiler and duct work, and modifying the plant electrical infrastructure.

Q. What are the expected costs of the AQCS project according to the application?

A. The Companies' estimate of capital costs for installation of the AQCS without including the ACI component for mercury control is $489.4 million in 2016 dollars, +/- 20%. This figure is based on a conceptual cost estimate provided by Sargent and Lundy, and includes [TRADE SECRET DATA BEGINS _____ _____ TRADE SECRET DATA ENDS] for the SCR project and [TRADE SECRET DATA BEGINS _____ TRADE SECRET DATA ENDS] for the semi-dry FGD and new baghouse. The ACI component is estimated to cost an additional $5.0 million. OTP's share of the total project cost (including ACI) would be $266 million, and MDU's share would be $112 million. The cost estimates are based on the assumption that the applicants will contract with a single erection contractor to coordinate site work, but issue separate requests for proposals for each major project component. The applicants claim that this approach, rather than a typical EPC or "turnkey" approach, is most likely to achieve lowest cost.

Q. What is the expected cost to North Dakota ratepayers?

A. According to the application, MDU's North Dakota customers will see an approximate 16 percent increase in rates as a result of its share of this total project cost of $78 million. OTP's North Dakota customers will also see an approximate 16 percent increase in rates as a result of its share of this total project cost of $108 million.[4]

Q. What is the purpose of the AQCS project?

A. The purpose of the AQCS project is to bring Big Stone Generating Station into compliance with the SD Haze SIP.

Q. Please describe the SD Haze SIP and its current status.

A. The Regional Haze Rule under the CAA was promulgated in 1999 and finalized in 2005 to improve air quality and clarity in 156 national parks and wilderness areas. States must develop rules determining, among other requirements, unit-specific Best Available Retrofit Technology ("BART") to reduce visibility-impairing particulate matter pollution from EGUs. The South Dakota Department of Environment and Natural Resources ("SD DENR") found that Big Stone is both BART-eligible and subject to BART. SD DENR further determined that BART for Big Stone should be SCR with SOFA for NOx control, semi-dry FGD for SO2 control, and the existing baghouse for particulate matter control. SD DENR submitted the SD Haze SIP with these BART determinations to the EPA on January 21, 2011. At this time the EPA has not yet acted to approve the SD Haze SIP.

[4] Joint Exhibit 3 to the Application, at pages 15-16

Q. Would AQCS bring Big Stone into compliance with the proposed SD Haze SIP?

A. Yes, it would. The SCR/SOFA and semi-dry FGD components of the AQCS project are sufficient to comply with the SD Haze SIP.[5] Although a new baghouse is not required for BART, the Companies claim that it is necessary to accommodate the additional flue gas draft requirements caused by the SCR/SOFA and semi-dry FGD systems. The ACI component is not part of BART, and is therefore unnecessary for compliance with the SD Haze SIP. I discuss the Companies' proposed mercury control plan in more detail in Section VII of my testimony below.

Q. Will the AQCS project be adversely affected if an advance determination of prudence is not issued prior to EPA approval of the SD Haze SIP?

A. No, it will not. The compliance deadline with the SD Haze SIP is not an absolute deadline, but rather a relative deadline based on the date of final approval of the SD Haze SIP. The Companies' application assumes that the SD Haze SIP will be approved in 2011, which would require the Big Stone AQCS to be installed and operational by 2016. The Companies state that the project's design would need to be finalized and procurement of major elements be initiated by early 2012. In this scenario, however, it should be noted that this assumes that by early 2012 the SD Haze SIP has already been approved. If the EPA delays approval into 2012, the compliance deadline would shift to 2017 and the Companies would no longer need to finalize project design and initiate procurement in early 2012. Since the

[5] South Dakota's Regional Haze State Implementation Plan at 99-103. http://denr.sd.gov/des/aq/aqnews/RHSIPReview.pdf

project can be completed in less than five years, there is no need for the Commission to issue a final advance determination of prudence prior to final approval of the SD Haze SIP. A final decision on the advanced determination of prudence should be conditional upon the final approval of the SIP.

V. EVALUATION OF OTP'S REASONABLENESS ANALYSIS

Q. Please summarize the areas of concern you have identified while reviewing the reasonableness of the Burns & McDonnell analysis?

A. I conclude that there are a number of issues with the evaluation, including the input assumptions, the modeling of certain alternative scenario costs, and the choice of options to be considered. Additionally, I believe there is considerable uncertainty as to the likely final cost of the AQCS project. I believe that Burns & McDonnell have overstated the busbar fixed costs in the Proforma model. However, I also note that there are several key assumptions that we believe are reasonable.

Q. What are the assumptions that you believe are reasonable?

A. We have analyzed the coal prices for Big Stone that were used in the Applicants' economic analysis, and conclude that they are close to what an independent forecast would yield and are therefore reasonable. Also, the capital cost per KW for a new natural gas fired combined cycle plant is what we have typically seen for other projects.

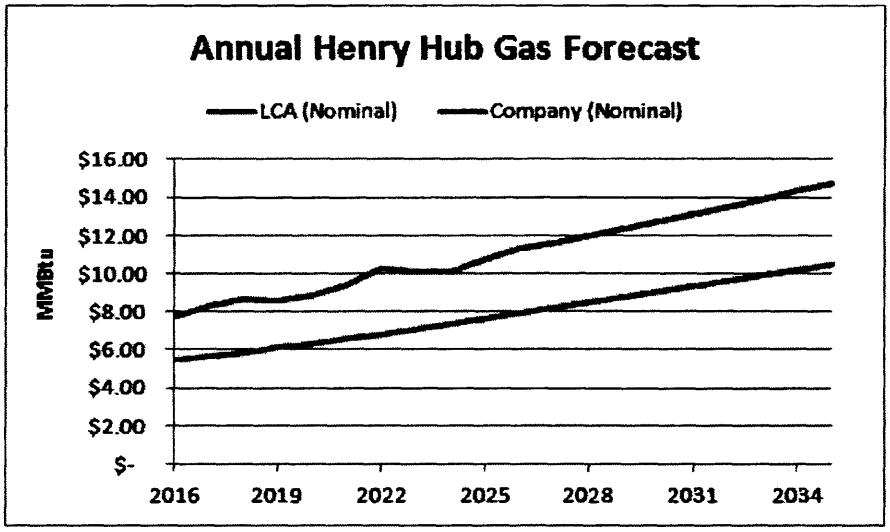
Q. With respect to other input assumptions, what concerns have you identified?

A. There are multiple concerns related to the input assumptions, which I will discuss below. The fuel forecast vintage is from December 2009 and should have been updated before filing, which was made on or about May 20, 2011. The cost of wind is not reflective of current market conditions, and the escalation of wind costs per MWH after the in-service year at 4% annually is questionable.

Q. Please describe your concerns related to the fuel forecasts.

A. The fuel forecasts in the Burns & McDonnell study were taken from the 2010 IRP. This means that the natural gas commodity forecast was 1½ years old at the time of the filing of this application. Since that time, injections of new supplies and new pipeline capacity have led to lower gas prices and the market outlook for the future is similarly suppressed, as natural gas futures are significantly below the company's 2009 forecast (see Figure 1 for a comparison of natural gas price forecasts).

Figure 1



Q. What is the market value of wind power assumed by Burns & McDonnell in its analysis?

A. Burns & McDonnell assumes a wind PPA is priced at $67.11 per MWH in 2016 dollars in the economic modeling. This is calculated by starting with the 2009 market price of wind energy of $71 per MWH provided by Otter Tail Power, subtracting $20 per MWH to account for the PTC and escalating the resulting $51 per MWH by 4% per year between 2009 and 2016 to reach $67.11 per MWH in 2016 dollars.[6]

Q. What is the basis of Otter Tail Power's 2009 market price of wind energy?

A. This information was requested in a discovery question. In Otter Tail Power's response to ND-LCA-3-4, it states the $71 per MWH figure was based upon installed costs, O&M costs and expected generation, but does not give any specific numbers.

Q. What is the capacity factor of wind assumed in the Burns & McDonnell analysis?

A. Burns & McDonnell assumes a capacity factor of 40% for wind farms in its analysis.

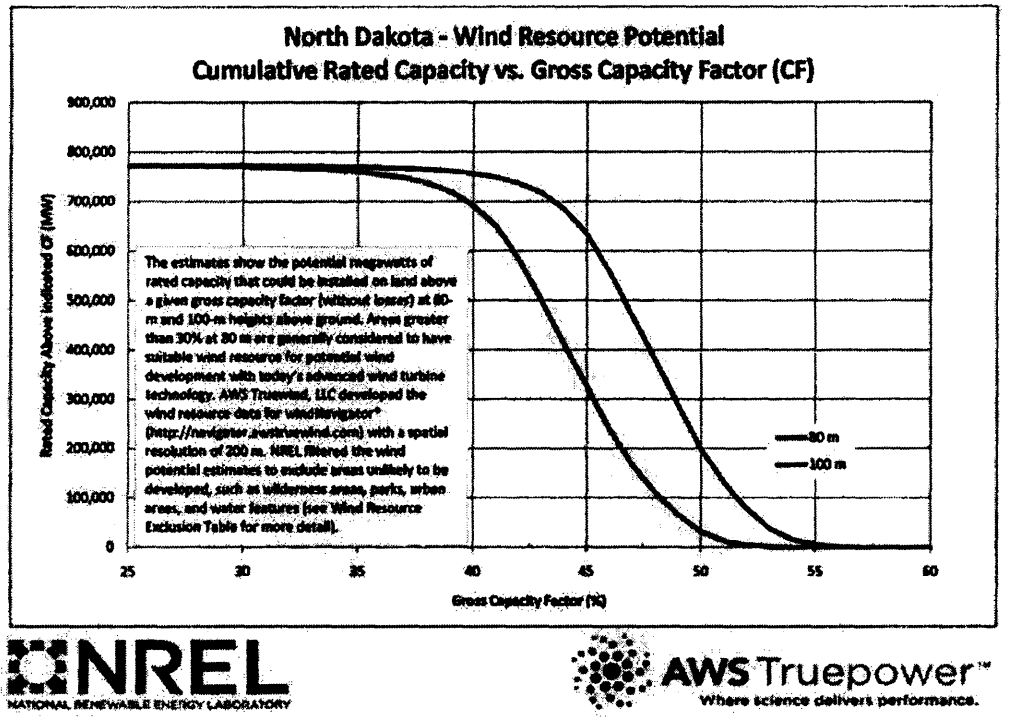
Q. Do you think that the capacity factor assumed by Burns & McDonnell is appropriate?

A. This capacity factor is slightly low given the strong wind resource available in North Dakota. The National Renewable Energy Laboratory recently conducted a

[6] OTP Attachment 9 to the Application, at 6

study of wind potential in the United States. This study produced charts showing the amount of wind potential by state at different capacity factors. The North Dakota chart reproduced in Figure 2 below shows that there is about 25,000 MW of wind potential at a gross capacity factor of 50% and above. Given that a 50% gross capacity factor is equivalent to a 42.5% net capacity factor[7], there is the potential for 25,000 MW of wind facilities of 42.5% capacity factor and above in the state.

Figure 2



[7] The assumed net to gross ratio of 0.85 was provided by the National Renewable Energy Laboratory ("NREL")

Q. Do you think that the cost of wind power modeled by Burns & McDonnell is appropriate?

A. No. The value assumed by Burns & McDonnell is too high. The Lawrence Berkeley National Laboratory's ("LBNL") recent "2010 Wind Technologies Market Report", states that in 2010 the average price for wind power built in the Heartland region was $46 per MWH during the 2007 through 2010 time period. LBNL states that the turbine prices have fallen 20 to 33 percent since 2008, but that this price decline was not reflected in installed costs or PPA prices for 2010 projects as these developers were operating under old turbine contracts in 2010. LBNL expects this price to come down in 2011 and 2012 as installed costs start to reflect the lower turbine prices. LBNL has seen this in some projects in the Heartland region already with a number PPAs in the low $40 per MWH or lower.[8]

Q. Can you point to recent examples of North Dakota wind farms with lower costs than the value used in Burns & McDonnell's economic analysis?

A. Yes. In Minnesota Public Service Commission Docket Numbers: E015/M-11-234 and E015/M-11-626, Minnesota Power Company filed for Approval of Investments and Expenditures for the Bison 2 and Bison 3 wind farms respectively. These wind farms are located in Morton and Oliver Counties in North Dakota and have projected revenue requirements of $22 per MWH and $29 per MWH respectively.

[8] Wiser R. and M. Bolinger. 2010 Wind Technologies Market Report. LBNL-4820E. June 2011. Accessed at http://eetd.lbl.gov/ea/emp/re-pubs.html.

Q. What do you think is an appropriate market value of wind power to use in the economic analysis?

A. I believe $42 per MWH in 2016 dollars is an appropriate value of wind power to use in the economic analysis. This number assumes that the production tax credit is renewed. It is based on a 2011 capital cost of $1,750 and operations and maintenance costs of $28.77 per MWH. Both operations and maintenance and capital costs are assumed to increase at 2.5 percent per year between 2011 and 2016. This escalation rate is lower than the 4 percent per year assumed by the Applicants because wind power installed costs are expected to decline in 2012 according to the LBNL report referenced above. The 2.5 percent rate includes a decline in 2012 and then assumes that prices increase thereafter.

Q. Is the PTC adjustment handled correctly in the Burns & McDonnell analysis?

A. No. It appears that the levelized value of $20 per MWH calculated by Burns & McDonnell does not take into account the fact that the PTC is a tax credit and not an ordinary source of revenue. When calculating the PTC's effect on the PPA price, the PTC should be grossed up for taxes before being levelized. The wind farm owner will be taxed on the revenue it receives from selling the energy generated, so it is incorrect to subtract the tax credit directly from the pre-tax PPA price as it appears Burns & McDonnell has done. Assuming a federal tax rate of 35% and a state tax rate of 5.15%, the composite tax rate in North Dakota would be 38.35%. The 2011 value of the PTC is $22 per MWH. Grossing this up yields an equivalent pre-tax value of $36 per MWH in 2011. A wind project would be

eligible to receive this credit, which is adjusted each year for inflation using the consumer price index, for 10 years. Levelizing the pre-tax PTC assuming inflation of 2.5% and a 9.125% discount rate yields a levelized value of $26 per MWH for a project installed in 2011. The levelized value of the PTC for a project installed in 2016 would be $29 per /MWH in 2016 dollars. Correcting this calculation means that the PTC adjustment for a project installed in 2011 would be $26 per MWH and the adjustment for a project installed in 2016 would be $29 per MWH.

Q. In your summary you mentioned the modeling of certain costs in the Alternative Regulatory Response scenarios as a concern. Could you elaborate?

A. In the modeling done by Burns & McDonnell for the alternatives to the Big Stone AQCS, certain costs were included that I believe are unreasonable. In particular, $82 million of "stranded costs" were included. This cost, according to Page 5 of the Burns & McDonnell report, represents the "current book value" of Big Stone.

Q. Why do you believe this is unreasonable?

A. The current book value of Big Stone is a sunk cost. It could be recovered in rates regardless of which option OTP uses for meeting its energy requirements. In a comparison of the economic value of alternative resource configurations for identification of a least cost plan, costs which have already been incurred and which will exist no matter what option is selected should not be considered.

Q. The Companies review four potential options – the AQCS and three alternatives. Do you believe that was sufficient?

A. No, I believe that, while the options considered do present some reasonable alternatives to the AQCS, additional resource options should have been likewise considered.

Q. What other resources do you believe should have been considered?

A. The Burns & McDonnell analysis did not consider the MISO market in any of its scenarios. Additionally, the analysis did not consider other, potentially cheaper alternatives to procuring capacity such as a natural gas fired combustion turbine. In particular, these two resource options in combination would appear to represent an attractive alternative by separating energy from capacity. Historically low MISO prices indicate that market purchases could be a source of low cost energy while CTs potentially offer a low fixed cost capacity alternative.

Q. Are there any other considerations related to the potential use of MISO market energy?

A. Yes, there is also the question of risk. As OTP identified in its IRP filing, unlimited reliance on the spot market could realize a significant reduction in the net present value of revenue requirements.[9] However, as OTP also notes in its IRP, to do so would expose OTP (and its ratepayers) to large exposure to market fluctuations. However, this in and of itself does not make reliance on the spot market, especially in moderation, an unacceptable alternative. Understanding the potential savings and risks of different levels of reliance on the spot market should be a part of any analysis such as the one Burns & McDonnell performed for the companies.

[9] OTP IRP as modified 9/17/2011, page 5-16.

Q. The Companies have not considered energy efficiency as an alternative to the AQCS. Do you believe that this is reasonable?

A. Yes. The Big Stone plant is the largest baseload resource in the energy portfolio of both OTP and MDU. At a 75% capacity factor, which is supported by actual recent operating data, the Big Stone plant produces in excess of 3 million MWH per year. OTP's share of the output is about 1.6 million MWH, which represents roughly one-third of total energy requirements. It is extremely unlikely that sufficient additional energy efficiency ("EE") could be achieved by 2016 to replace Big Stone's output for either company. While incremental EE was not considered in either the Company's analysis or our own, we would expect that EE could contribute to an alternative solution with Wind, CCs and CT to reduce the overall cost of the alternative. By omitting EE from our analysis of alternatives, our alternatives cost may be somewhat higher. This conservatism in our analysis of the alternatives is part of our conclusion that the capital cost estimate of the AQCS is a critical factor.

Q. Are the technologies chosen by the Companies for the AQCS project appropriate?

A. Yes. The technologies selected are reasonable. Installing an SCR is a very common measure to reduce NOx emissions. An FGD is the typical measure to reduce SO2 emission, although there are several different types of scrubbers. The Applicants performed a screening evaluation of a Dry FGD versus a Wet FGD, and found that the Dry FGD was the lower cost option. Based upon the analysis provided by the Applicants, I find the selection of technologies to be reasonable.

Q. Did you review the AQCS capital costs modeled in the Burns &McDonnell analysis?

A. According to the application, the FGD costs [TRADE SECRET DATA BEGINS _____ TRADE SECRET DATA ENDS] The cost estimate of the SCR was [TRADE SECRET DATA BEGINS _____. TRADE SECRET DATA ENDS] The total for the project is $490 million or $1,030 per KW in 2016 dollars. These costs exclude AFUDC and the cost of the mercury control. As I explain later in this testimony, I do not believe that the proposed mercury control system is eligible for inclusion in a request for an advanced determination of prudence, so I have removed those costs from my analysis. The Application states that the Big Stone AQCS costs for both the FGD and the SCR are $617 per KW in 2010 dollars, excluding AFUDC and the cost of certain boiler modifications required at Big Stone that were not required at other projects.[10] Costs for comparable projects range from $525 per KW to $850 per KW, according to information from Sargent & Lundy. It is my understanding that this range of costs is also in 2010 dollars and excludes AFUDC. So the application states that the $617 per KW cost in 2010 dollars for the Big Stone AQCS is comparable to other similar projects. Applying escalation to the $617 per KW cost for the FGD and the SCR in 2010 dollars brings the cost for these components to $780 per KW in 2016 dollars. This would mean that the boiler modifications would cost $1,030 per KW less $780 per KW, or about $250 per KW in 2016 dollars. This equates to approximately $120 million in 2016 dollars.

[10] Application, page 10, footnote 22.

Adjusting for escalation and boiler modifications explains much of the difference between the $617 per KW and the $1,030 per KW.

Q. Were you able to review the underlying data for the information provided by Sargent & Lundy?

A. No. In response to a discovery question that requested such information, Sargent & Lundy declined to provide any supporting information, citing confidentiality concerns. So I am not able to examine these numbers in greater detail. However, I did attempt to compare the AQCS cost estimate to other projects I have reviewed.[11] In a Wisconsin proceeding, FGD costs were cited as $470 to $585 per KW, and SCR costs ranged from $235 to $290 per KW, excluding AFUDC. The range for a combined FGD / SCR was $705 per KW to $875 per KW. A FGD and SCR at Oak Creek cost $820 per KW. A FGD and ACI at Columbia Energy Center cost $685 per KW. An SCR at Edgewater 5 cost $430 per KW. A FGD and SCR at Pleasant Prairie cost $435 per KW. While there is a wide range of costs, this data confirms that the AQCS estimate in this proceeding for the FGD and the SCR are nearer to the middle of the range, and that boiler modifications bring it to the higher end of the expected range.

Q. What do you conclude from this data?

A. The AQCS costs estimate was based upon a unit-specific engineering analysis by Sargent & Lundy for the Big Stone unit. Each generating unit has its own unique characteristics, so comparisons to other projects are difficult at best. However, the Big Stone AQCS cost without the Big Stone boiler modifications is near the

[11] These costs were escalated to 2016$ to the extent possible.

middle of the range provided by Sargent & Lundy. This implies that the AQCS cost estimate is unlikely to be unreasonably low to help justify the project. Based upon this assessment, I accept the Applicants cost estimate for the AQCS as reasonable. I also agree with the Companies that actual costs could vary from the estimate. In my economic evaluation, I will test higher capital costs using the range provided in the filing.

Q. Have you reviewed the busbar cost calculations in the Applicants' economic analysis?

A. Yes, I have reviewed the spreadsheet model provided by Burns & McDonnell.

Q. Do you have any concerns with this model?

A. I believe that the spreadsheet model does not accurately simulate the cost of service model that is used in utility rate setting processes. The spreadsheet model does not include any accelerated depreciation for income tax purposes. It includes a different treatment for debt and equity. Specifically, the spreadsheet model uses a rate base calculation for equity, while using a principal and interest loan calculation for the debt portion of capitalization. These assumptions would affect the fixed costs that recover the invested capital. To assess the impact of these assumptions on these fixed costs, I used La Capra Associates' revenue requirements model with the Companies' cost assumptions to estimate the annual fixed costs for the AQCS. Figure 3 below shows the annual dollars per MWH fixed costs using the spreadsheet and the La Capra models. The graph shows that the La Capra model yields lower fixed costs than does the spreadsheet model.

Figure 3

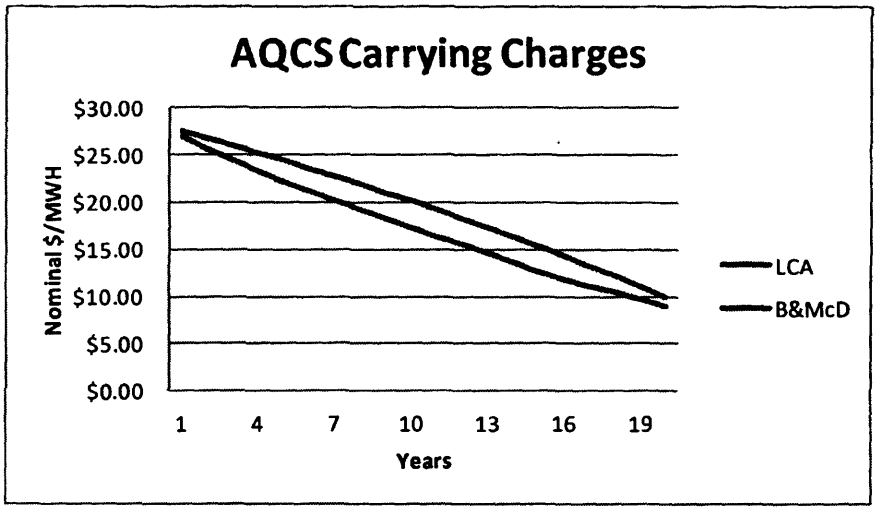


Figure 4 below presents a similar graph but for the NG CCGT option. The fixed costs from the La Capra model are also lower.

Figure 4

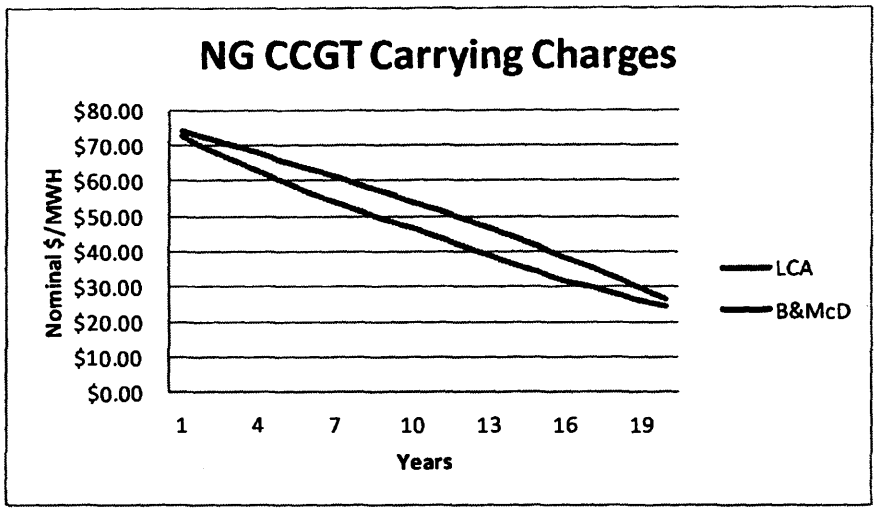


Figure 5 below shows a comparison of the fixed costs for the AQCS and the NG CCGT. It should be noted that the NG CCGT is assumed to have a capacity factor of 35%, while the Big Stone with the AQCS is assumed to have a 75% capacity factor. This difference in capacity factor causes the large discrepancy in dollars per MWH costs.

Figure 5
Levelized Carrying Charges

	AQCS $495 Million	NG CCGT $621 million	difference
B&McD	$21.83	$58.70	$36.88
LCA	$19.77	$53.17	$33.40
difference	$2.06	$5.53	$3.47

In our review of the economic comparison of the AQCS versus other alternatives, adjustments will be made to reflect the above differences in fixed costs

Q. Based on the analysis presented above, have you reached any conclusions as to the reasonableness of the analysis presented in support of the Companies' joint application for an advance determination of prudency?

A. I have. Based on the reasons outlined above, I believe the Burns & McDonnell analysis requires certain adjustments. I believe, however, that the framework of the analysis is reasonable, and that it is possible to reach a reasonable conclusion if the issues itemized above were to be corrected. I have attempted to do that in Section VI.

VI. REVISED REASONABLENESS ANALYSIS

Q. Please describe the scenarios that you tested under your revised reasonableness analysis.

A. I tested three scenarios using the modifications described in Section V: the Big Stone AQCS project, the NGCC plus wind scenario and one new scenario – a wind, market purchases and NGCTs scenario.

Q. Did you also test sensitivities against those scenarios?

A. Yes, I tested the same range of sensitivities that Burns & McDonnell listed on page 7 of their analysis plus a few additional sensitivities.

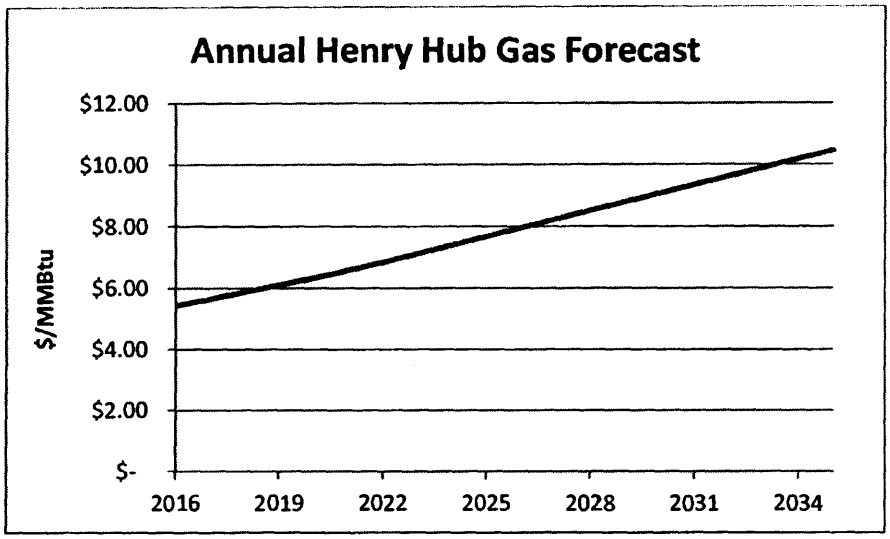
Q. Please describe the modifications you made to the Big Stone AQCS project scenario.

A. For the Big Stone AQCS project scenario I began with the case that excluded the ACI costs (capital and fixed O&M) and then modified the fixed cost calculations to reflect the adjustments to the cost of service model that I described above. All other inputs were left alone.

Q. Please describe the modifications you made to the NGCC plus wind scenario.

A. For the NGCC plus wind scenario I made several adjustments. First, I adjusted for the cost of service changes as in the Big Stone AQCS scenario. Next, I excluded the stranded cost allocation. Then, I adjusted the cost of new wind to be $42 per MWH in 2016 levelized dollars. Finally, I adjusted the natural gas forecast to reflect average Henry Hub futures during the month of April 2011 (see Figure 6).

Figure 6



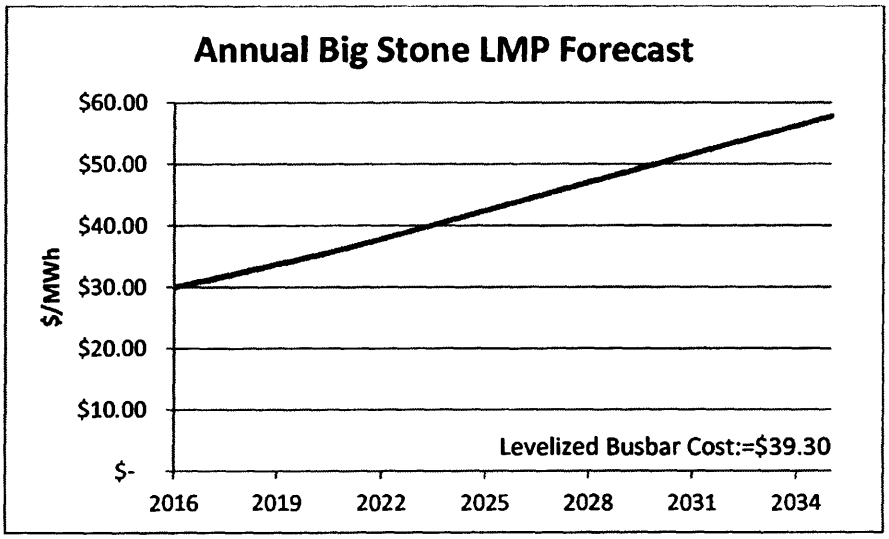
Q. Please describe the NGCT plus market purchases and wind scenario you designed.

A. I started with the NGCC plus wind scenario as modeled above. I added market purchases to the available assumptions and set them to 34% of the replacement energy needed. Then I replaced the CC cost and performance information with comparable data for a CT instead. I assumed a 10% capacity credit for wind resources and added 427.5[12] MWs of CTs to ensure that the capacity position was roughly identical to the AQCS scenario. The CTs were presumed to run only enough to generate energy (after considering the wind and market purchases) that Big Stone would have produced so that the scenario was on equal footing with the AQCS scenario. For pricing of the market purchases I took the natural gas forecast listed above and applied an average market heat rate of 5,460 Btu per

[12] Because this scenario is intended to represent building wind (instead of a wind PPA) I assigned the wind a small capacity credit, which reduced the amount of CTs needed to reach 475 MWs of total capacity.

KWH[13] (see Figure 7 for the LMP forecast). Applying a market heat rate to a forecast of natural gas prices is a common way to develop LMPs.

Figure 7



Finally, I converted the LMP forecast into a levelized busbar cost using the same formulae used in the Companies' pro formas.

Q. What were the results of this modified analysis?

A. Figure 8 below summarizes the results of my analysis and compares them to the Companies' results. The costs for the alternative scenarios that I examined generally show a lower difference from the cost of the AQCS than does the Companies' analysis. The scenario with CTs, wind and market purchases is the lowest cost option, approximately 4% less expensive than the AQCS. However, this scenario would also increase the Companies' reliance on market purchases. For example, in the OTP IRP, market purchases represented 10% of the total

[13] The calculation of average market heat rate was based on historical LMP data at Big Stone divided by historical Henry Hub natural gas prices.

2011-2025 OTP energy portfolio. If the CT / Wind / market purchase alternative to the AQCS were implemented, we estimate that the portion of the energy portfolio supplied by market purchases would more than double to a total of 21%. Such an open position is high and would expose customers in North Dakota to unacceptable risks. Therefore, we agree with the Applicants that the AQCS is the preferred option. However, the cost advantage of the AQCS over the next best non-market alternative has been reduced to 6% in my analysis from 42% in the Companies' analysis. This reduction in the economic advantage of the AQCS means that the AQCS cost estimate becomes critical in deciding whether and under what conditions an advance determination or prudence should be granted.

Figure 8

Levelized Costs

Scenario	B&M Results	LCA Results
Big Stone + AQCS	$ 70.89	$ 68.86
NGCC Alone	$ 103.38	$ 81.88
Variance from AQCS	$ 32.49	$ 13.02
NGCC + Wind	$ 100.43	$ 73.30
Variance from AQCS	$ 29.53	$ 4.44
Big Stone on NG	$ 117.25	N/A
Variance from AQCS	$ 46.35	N/A
NGCT + Wind + Market Purchases	N/A	$ 66.14
Variance from AQCS	N/A	$ (2.72)

Q. Please discuss the sensitivities you ran against these three scenarios.

A. I used similar sensitivity variables and ranges as Burns & McDonnell did in their analysis. I also included a few additional sensitivities (see Figure 9 for details). It is also important to note that all sensitivities continued to exclude capital and O&M costs for the ACI technology.

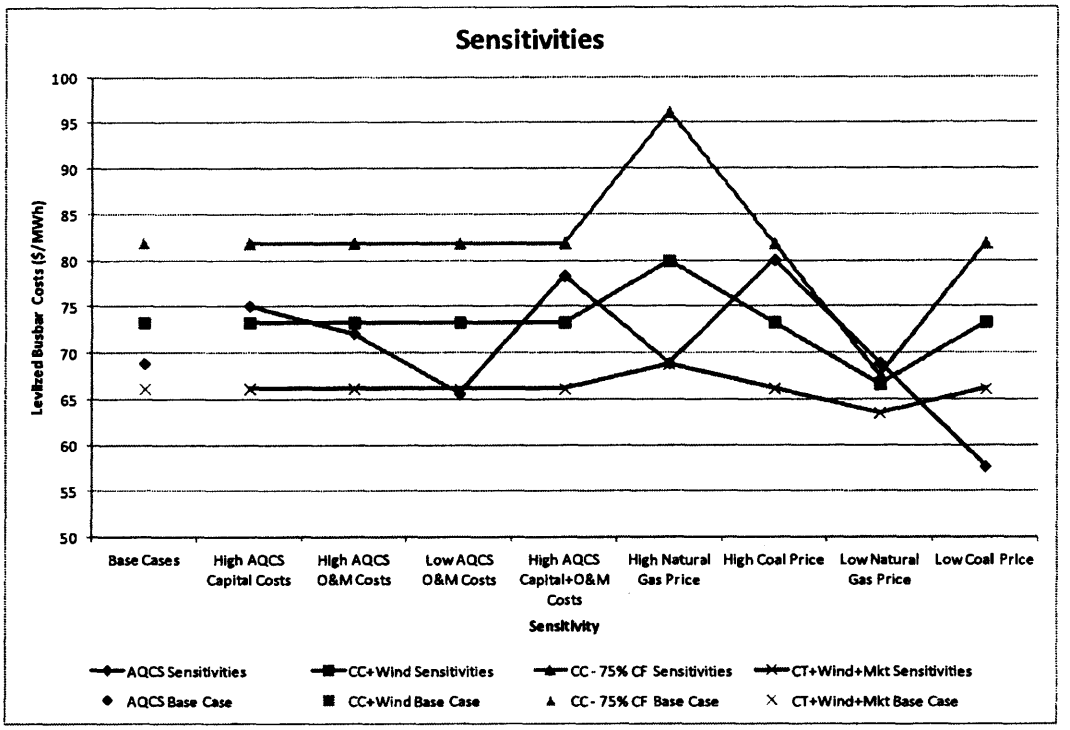
Figure 9

Variable	Low Case Modifier	Reference Case Modifier	High Case Modifier
AQCS Capital Costs	N/A	0%	30%
Coal Costs	-30%	0%	30%
AQCS O&M Costs	-30%	0%	30%
Natural Gas Costs	-30%	0%	30%

Q. What were the results of the sensitivity runs?

A. There were several sensitivities where the alternatives were competitive with the AQCS, in particular the case with market purchases. These scenarios were the AQCS coming in 30% over budget, AQCS O&M costs increasing by 30% or coal costs being up 30% or natural gas costs being down 30%. There were also multiple sensitivities in which the economic advantage of the AQCS increased, including low coal, low AQCS O&M and high natural gas. Even the high AQCS O&M sensitivity did not completely remove the advantage in economics enjoyed by the AQCS except with respect to the market case. Figure 10 shows the results of the sensitivities.

Figure 10



Q. Did you perform any other checks against the base scenarios?

A. Yes, I also investigated what reducing the overall capacity factor of Big Stone would do to these calculations.[14] While I did not attempt to capture the complex changes in plant operations inherent in such a reduction in capacity factor, I did recalculate the busbar costs to account for the fact that this would mean less energy available to cover fixed costs.

Q. What were the results of this review?

[14] Per Sargent & Lundy in their "SO_2, NO_x and Mercury Reduction Study", "Big Stone, designed for base load service, is located in a region with significant wind-generated power potential. With the development of wind farms, OTP anticipates a shift in the Big Stone load profile toward more frequent cycling duty, meaning daily operations at loads of 50% maximum continuous rating (MCR) and lower." (Attachment 4, page 2-5.

A. While the gap between scenarios was reduced, the AQCS continued to be the least cost non-market alternative for both an assumed 70% capacity factor and an assumed 65% capacity factor (see Figure 11).

Figure 11

Scenario	Base Case	70% CF Case	65% CF Case
AQCS	$ 68.86	$ 71.12	$ 73.72
CC+Wind	$ 73.30	$ 74.70	$ 76.31
CC - 75% CF	$ 81.88	$ 83.89	$ 86.21
CT+Wind+Mkt	$ 66.14	$ 67.54	$ 69.46

Q. Based on this modified analysis, what is your conclusion as to the reasonableness of selecting the Big Stone AQCS scenario as the most prudent course of action?

A. Despite the fact that some scenarios under certain conditions appear to be lower cost than the Big Stone AQCS, adding the AQCS onto the existing Big Stone unit appears to be the best combination of low cost, reasonable risk options to meet the requirements of the SD Haze SIP as it exists at this time. This analysis does indicate that the range between options is narrower than the B&M analysis showed and that therefore the estimate of AQCS costs is a critical component of the reasonableness of selecting the AQCS as an option. I believe that a narrow band of costs should be established should the AQCS be found to be prudent.

Q. Should the fact that the EPA has not yet issued a final decision on the SD SIP be a factor in this process?

A. It should not be a factor in the analysis to determine best alternatives, and I have not considered it during my review of the Burns & McDonnell analysis or during the calculation of my own alternative analysis. However, I believe it should be considered within the context of deciding if the advance determination of prudence should be issued. While the best available information today suggests that the AQCS will meet the requirements of the SD Haze SIP more economically and at less risk than the alternatives, there still exists some potential that those requirements could change due to the EPA's upcoming decision. Further analysis would be needed should the EPA fail to approve the SD Haze SIP as currently configured, as any potential changes in the requirements could alter the estimated cost of the AQCS and therefore could impact the selection of a least cost option. Furthermore, based on the language of the Regional Haze regulations[15], the clock doesn't start on required action by the Companies until the EPA issues that final determination. Based on those facts, I believe that it would be in the North Dakota ratepayers' interest to either delay the determination of prudence or to issue a decision conditional on the EPA approving the SIP as currently configured.

VII. MERCURY CONTROL ISSUES

Q. Why are the Companies proposing the ACI system as part of AQCS?

[15] "In accordance with 40 CFR (e)(1)(iv), DENR will require BART to be installed and operating as expeditiously as practicable, but no later than 5 years from EPA's approval of South Dakota's Regional Haze Program. The deadline for installing BART will be established in ARSD 74:36:21:06." – SD Haze SIP, at 103. http://denr.sd.gov/des/aq/aqnews/RHSIPReview.pdf

A. The Companies are proposing the ACI system for mercury control in anticipation of the EPA finalizing proposed national emission standards for hazardous air pollutants ("NESHAP") for EGUs under CAA section 112(d). The companies expect the NESHAP compliance deadlines to coincide with the AQCS project timeline.

Q. Please describe the proposed NESHAP for EGUs and its current status.

A. In 2008, the U.S. Court of Appeals vacated the EPA's 2005 Clean Air Mercury Rule and obligated the agency to develop utility hazardous air pollutant ("HAP") emission standards based on maximum achievable control technology ("MACT"). The EPA published a proposed utility MACT rule May 3, 2011. Under the proposed rule, Big Stone would be required to reduce mercury emissions to below 1.0 lb/TBtu. The EPA expects and is under court order to issue a final rule by November 16, 2011. The consent decree also mandates that compliance with the rule be completed by January 1, 2015, with up to a one year extension.

Q. Does the proposed ACI component of AQCS qualify for an advance determination of prudence at this time?

A. No, it does not. In the absence of a final utility MACT rule, installing ACI is not consistent with lowest reasonable cost to consumers based on information that is known or knowable at the time the decision is made. As I explained in my discussion of the standard of review in Section III above, the analysis of lowest reasonable cost cannot assume compliance costs from future environmental regulations.

Q. If the utility MACT rule is finalized in essentially the same form as currently proposed, would installation of ACI be prudent?

A. Yes. Assuming the Commission finds that continued operation of Big Stone with AQCS is reasonable, installing ACI appears to me to be a reasonable approach to compliance with the utility MACT rule as it is currently proposed.

Q. Are there significant costs to delaying a ruling on advance determination of prudence for installation of ACI until the utility MACT rule is finalized?

A. No. First, the EPA is under court order to promulgate the final rule by November 16 of this year, so in all likelihood the rule will be finalized before the Commission hears this case. In the event that the final rule is delayed, however, there is still no significant cost to delaying installation of ACI, even if the rest of the AQCS project moves forward. The Companies have indicated that the cost of installing ACI separately from the AQCS project is no greater than the cost of installing it as a component of AQCS.[16] Finally, the Companies' timetable for the AQCS project indicates that work related to the ACI system is not planned until March 2013. Even if the final utility MACT rule is delayed significantly, there appears to be plenty of opportunity for the ACI to be installed according to schedule.

Q. What action do you recommend the Commission take with respect to the proposed ACI component of AQCS?

[16] See OTP Response to Information Request No. ND-LCA-3-1

A. I recommend that the Commission base any decision about an advance determination of prudence for ACI on the final utility MACT rule.

VIII. CONCLUSIONS AND RECOMMENDATIONS

Q. Would you summarize your findings with respect to the issues before the Commission in this proceeding?

A. Based upon my review of the Companies' application, I conclude that the AQCS is the preferred option for compliance with South Dakota's proposed implementation of the Regional Haze Rule. The AQCS is the least cost non-market option studied. While I disagree with some of the assumptions and methodologies used by the Companies, adjusting for those differences does not alter the conclusion that the AQCS is the lowest cost non-market option studied. The AQCS is based upon reasonable choices of technologies at an acceptable cost estimate. However, the difference between the AQCS option is considerably narrower in our independent analysis than in the Applicants' analysis. Thus, the estimated capital cost for the AQCS becomes critical in determining the prudence of this investment. I recommend that the Commission approve the Companies' application and grant an advance determination of prudence for the cost estimate contained in the application. However, I recommend that the Commission condition its determination upon finalization of the environmental regulations requiring AQCS in the same form as currently proposed. I recommend that the Commission require the Companies to periodically report on the status of the project costs and the finalization of the SIP

Q. Does this conclude your testimony?

A. Yes.

La Capra Associates

Richard S. Hahn

Principal Consultant

Mr. Hahn is a senior executive in the energy industry, with diverse experience in both regulated and unregulated companies. He joined La Capra Associates in 2004. Mr. Hahn has a proven track record of analyzing energy, capacity, and ancillary services markets, valuation of energy assets, developing and reviewing integrated resource plans, creating operational excellence, managing full P&Ls, and developing start-ups. He has demonstrated expertise in electricity markets, utility planning and operations, sales and marketing, engineering, business development, and R&D. Mr. Hahn also has extensive knowledge and experience in both the energy and telecommunications industries. He has testified on numerous occasions before the Massachusetts Department of Public Utilities, and also before FERC.

SELECTED EXPERIENCE – LA CAPRA ASSOCIATES

- Reviewed and analyzed a proposed retail rate increase by Fitchburg Gas and Electric Company before the Massachusetts Department of Public Utilities. Provided expert testimony before the Massachusetts Department of Public Utilities regarding the Company's proposed Capital Spending Plan, and an accompanying recovery mechanism.
- Conducted a study of non-transmission alternatives to a proposed substation and related transmission upgrades in Georgia, Vermont.
- Reviewed and analyzed damages claimed in litigation between a developer of renewable energy facilities and the owner of the host site.
- Evaluated the decision of PacifiCorp to acquire new generating resources in Utah. Filed testimony before the Public Service Commission of Utah.
- Served as a principal advisor and key team member in La Capra Associates' assessment of strategic options for Entergy Arkansas, Inc. subsequent to its withdrawal from the Entergy System Agreement.
- Conducted a study of non-transmission alternatives to a proposed substation and related transmission upgrades in Jay, Vermont.
- Reviewed and evaluated the construction of and cost recovery for a large cogeneration plant for a mid-west utility; utilized heat balance analysis to develop new cost allocators between steam and electric sales.
- Analyzed fuel costs, market sales and revenues, capacity position, and performance parameters for a large- mid-west utility.
- Performed a review and analysis of the proposed merger between FirstEnergy and Allegheny Energy. Provided expert testimony before the FERC and the Pennsylvania Public Utilities Commission regarding merger policy, benefits and market power issues.
- Performed a study of non-transmission alternatives to a proposed transmission project in the Lewiston-Auburn area of Central Maine Power Company's service territory. Testified before the Maine Public Utilities Commission.
- Analyzed a proposed plan by National Grid to procure 2011 default service power supplies and comply with Renewable Energy Standards. Provided expert testimony before the Rhode Island Public Utilities Commission.
- Served as an advisor to the Pennsylvania Office of Consumer Advocate in reviewing 2011 default service plans for Pennsylvania Electric Distribution Companies.

- Analyzed a purchase power agreement between National Grid and on offshore wind project in Rhode Island. Provided expert testimony before the Rhode Island Public Utilities Commission.
- Reviewed and analyzed a proposed retail rate increase by Western Massachusetts Electric Company before the Massachusetts Department of Public Utilities. Provided expert testimony before the Massachusetts Department of Public Utilities regarding the Company's proposed Capital Plan, and an accompanying recovery mechanism.
- Served as an advisor to the developer of a utility-scale Solar PV facility in Massachusetts.
- Evaluated a proposed Solar PV installation for a large retail customer in Massachusetts. Performed an analysis of the appropriate rate of return and its impact on facility electric costs and financial feasibility.
- Assessed the economic impact of an additional interconnection between ISO-NE and NYISO; analyzed impact on market prices and congestion.
- Reviewed and analyzed the capacity position of a large mid-west utility and the impact of that position on electric rates.
- Performed an economic evaluation of a proposed transmission line in New England. Assessed the project's ability to deliver renewable energy to load centers and the impact of the project on Locational Marginal Prices.
- Analyzed a proposed interconnection of a large new industrial load in Massachusetts. Evaluated proposed substation configuration and developed alternatives that achieved comparable reliability at lower costs. Assessed cost recovery options.
- Reviewed the Energy Efficiency and Conservation Programs proposed by Pennsylvania Power & Light and Philadelphia Electric Company in response to Act 129, Pennsylvania legislation that requires Electric Distribution Companies to achieve certain annual consumptions and demand reduction by 2013. Provided expert testimony before the Pennsylvania Public Utilities Commission regarding program design, benefit cost analyses, and cost recovery.
- Assisted in the review and analysis of a proposed retail rate increase by National Grid before the Rhode Island Public Utilities Commission. Provided expert testimony before the Rhode Island Public Utilities Commission regarding the Company's proposed Inspection & Maintenance Program, its Capital Plan, its Storm Funding Plan, and its Facilities Plan
- Reviewed and analyzed Time-of-Use rates proposed by Pennsylvania Power & Light. Provided expert testimony before the Pennsylvania Public Utilities Commission regarding compliance with Commission requirements, rate design, cost recovery, and consumer education issues.
- Assisted in the review and analysis of a proposed retail rate increase by National Grid before the Massachusetts Department of Public Utilities. Provided expert testimony before the Massachusetts Department of Public Utilities regarding the Company's proposed Inspection & Maintenance Program, its Capital Plan, its Storm Funding Plan, and its Facilities Plan.
- Performed a review and analysis of the proposed merger between Exelon and NRG. Provided expert testimony before the Pennsylvania Public Utilities Commission regarding merger policy, benefits and market power issues.
- Reviewed the needs analysis and load forecast supporting a proposed Transmission Project in Rhode Island. Provided expert testimony before the Rhode Island Public Utilities Commission.
- Performed an assessment of plans to procure Default Service Power Supplies for a Rhode Island utility. Provided expert testimony before the Rhode Island Public Utilities Commission.
- Served as an advisor to Vermont electric utilities regarding the evaluation of new power supply alternatives. Developed and applied a probabilistic planning tool to model uncertainty in costs and operating parameters.

- Conducted a review of Massachusetts electric utilities' proposal to construct, own, and operate large scale PV solar generating units. Served as an advisor to the Massachusetts Attorney General in settlement negotiations. Performed an analysis of the appropriate rate of return and its impact on ratepayer costs and financial feasibility. Provided expert testimony before the Massachusetts Department of Public Utilities.
- Served as a key member of a La Capra Associates Team evaluating wind generation RFPs in Oklahoma.
- Performed an assessment of plans to procure Default Service Power Supplies for Pennsylvania utilities. Provided expert testimony before the Pennsylvania Public Utilities Commission.
- Performed an assessment of a merchant generator proposal to construct, own, and operate 800 MW of large scale PV solar generating units in Maine.
- Analyzed proposed environmental upgrades to several existing coal-fired power plants in Wisconsin, including an economic evaluation of this investment compared to alternative supply resources. Provided expert testimony in three separate proceedings before the Public Service Commission of Wisconsin.
- Reviewed Pennsylvania Act 129 and Commission rules for Energy Efficiency Plans
- Performed a study of non-transmission alternatives (NTAs) to a proposed set of transmission upgrades to the bulk power supply system in Maine.
- Served as a key member of the La Capra Associates Team advising the Connecticut Energy Advisory Board (CEAB) on a wide range of energy issues, including integrated resources plan and the need for and alternatives to new transmission projects.
- Performed a study of non-transmission alternatives (NTAs) to a proposed set of transmission upgrades to the bulk power supply system in Vermont.
- Served as an advisor to the Delaware Public Service Commission and three other state agencies in the review of Delmarva Power & Light's integrated resource plan and the procurement of power supplies to meet SOS obligations.
- Served as an expert witness in litigation involving a contract dispute between the owner of a merchant powerplant and the purchasers of the output of the plant.
- Served as an advisor to the Maryland Attorney General's Office in the proposed merger between Constellation Energy and the FPL Group.
- Reviewed and analyzed outages for Connecticut utilities during the August 2006 heat wave. Prepared an assessment of utility filed reports and corrective actions.
- Conducted a study of required planning data and prepared forecasts of the key drivers of future power supply costs for public power systems in New England.
- Reviewed and analyzed Hawaiian Electric Company integrated resource plan and its DSM programs for the State of Hawaii. Prepared written statement of position and testified in panel discussions before the Hawaii Public Utility Commission.
- Assisted the Town of Hingham, MA in reviewing alternatives to improve wireless coverage within the Town and to leverage existing telecommunication assets of the Hingham Municipal Light Plant.
- Conducted an extensive study of distributed generation technologies, options, costs, and performance parameters for VELCO and CVPS.
- Analyzed and evaluated proposals for three substations in Connecticut. Prepared and issued RFPs to seek alternatives in accordance with state law.

- Performed an assessment of merger savings from the First Energy – GPU merger. Developed a rate mechanism to deliver the ratepayers share of those savings. Filed testimony before the PA PUC.
- Prepared long term price forecasts for energy and capacity in the ISO-NE control area for evaluating the acquisition of existing powerplants.
- Conducted an assessment of market power in PJM electricity markets as a result of the proposed merger between Exelon and PSEG. Developed a mitigation plan to alleviate potential exercise of market power. Filed testimony before the PA PUC.
- Performed a long-term locational installed capacity (LICAP) price forecast for the NYC zone of the NYISO control area for generating asset acquisition.
- Served as an Independent Evaluator of a purchase power agreement between a large mid-west utility and a very large cogeneration plant. Evaluated the implementation of amendments to the purchase power agreement, and audited compliance with very complex contract terms and operating procedures and practices.
- Performed asset valuation for energy investors targeting acquisition of major electric generating facility in New England. Prepared forecast of market prices for capacity and energy products. Presented overview of the market rules and operation of ISO-NE to investors.
- Assisted in the performance of an asset valuation of major fleet of coal-fired electric generating plants in New York. Prepared forecast of market prices for capacity and energy products. Analyzed cost and operations impacts of major environmental legislation and the effects on market prices and asset valuations.
- Conducted an analysis of the cost impact of two undersea electric cable outages within the NYISO control area for litigation support. Reviewed claims of cost impacts from loss of sales of transmission congestion contracts and replacement power costs.
- Reviewed technical studies of the operational and system impacts of major electric transmission upgrades in the state of Connecticut. Analysis including an assessment of harmonic resonance and type of cable construction to be deployed.
- Conducted a review of amendments to a purchased power agreement between an independent merchant generator and the host utility. Assessed the economic and reliability impacts and all contract terms for reasonableness.
- Assisted in the development of an energy strategy for a large Midwest manufacturing facility with on-site generation. Reviewed electric restructuring rules, electric rate availability, purchase & sale options, and operational capability to determine the least cost approach to maximizing the value of the on-site generation.
- Assisted in the review of the impact of a major transmission upgrade in Northern New England.
- Negotiated a new interconnection agreement for a large hotel in Northeastern Massachusetts.

SELECTED EXPERIENCE – NSTAR ELECTRIC & GAS

President & COO of NSTAR Unregulated Subsidiaries

Concurrently served as President and COO of three unregulated NSTAR subsidiaries: Advanced Energy Systems, Inc., NSTAR Steam Corporation, and NSTAR Communications, Inc.

Advanced Energy Systems, Inc.

- Responsible for all aspects of this unregulated business, a large merchant cogeneration facility in Eastern Massachusetts that sold electricity, steam, and chilled water. Duties included management, operations, finance and accounting, sales, and P&L responsibility.

NSTAR Steam Corporation

- Responsible for all aspects of this unregulated business, a district energy system in Eastern Massachusetts that sold steam for heating, cooling, and process loads. Duties included management, operations, finance and accounting, sales, and P&L responsibility.

NSTAR Communications, Inc.

- Responsible for all aspects of this unregulated business, a start-up provider of telecommunications services in Eastern Massachusetts. Duties included management, operations, finance and accounting, sales, and P&L responsibility.
- Established a joint venture with RCN to deliver a bundled package of voice, video, and data services to residential and business customers. Negotiated complex indefeasible-right-to-use and stock conversion agreements.
- Installed 2,800 miles of network in three years. Built capacity for 230,000 residential and 500 major enterprise customers.
- Testified before the Congress of the United States on increasing competition under the Telecommunications Act of 1996.

VP, Technology, Research, & Development, Boston Edison Company

- Responsible for identifying, evaluating, and deploying technological innovation at every level of the business.
- Reviewed Electric Power Research Institute (EPRI), national laboratories, vendor, and manufacturer R&D sources. Assessed state-of-the-art electro-technologies, from nuclear power plant operations to energy conservation.

VP of Marketing, Boston Edison Company

- Promoted and sold residential and commercial energy-efficiency products and customer service programs.
- Conducted market research to develop an energy-usage profile. Designed a variable time-of-use pricing structure, significantly reducing on-peak utilization for residential and commercial customers.
- Designed and marketed energy-efficiency programs.
- Established new distribution channels. Negotiated agreements with major contractors, retailers, and state and federal agencies to promote new energy-efficient electro-technologies.

Vice President, Energy Planning, Boston Edison Company

- Responsible for energy-usage forecasting, pricing, contract negotiations, and small power and cogeneration activities. Directed fuel and power purchases
- Implemented an integrated, least-cost resource planning process. Created Boston Edison's first state-approved long-range plan.
- Assessed non-traditional supply sources, developed conservation and load-management programs, and purchased from cogeneration and small power-production plants.
- Negotiated and administered over 200 transmission and purchased power contracts.

- Represented the company with external agencies. Served on the Power Planning Committee of the New England Power Pool.
- Testified before federal and state regulatory agencies.

EMPLOYMENT HISTORY

La Capra Associates, Inc. **Boston, MA**
Principal Consultant 2004 – present

Advanced Energy Systems, Inc. **Boston, MA**
President and COO 2001-2003

NSTAR Steam Corporation **Cambridge, MA**
President and COO 2001-2003

NSTAR Communications, Inc.
President and COO 1995-2003

Boston Edison Company **Boston, MA**

VP, Technology, Research, & Development	1993-1995
VP, Marketing, Boston Edison Company	1991-1993
Vice President, Energy Planning, Boston Edison Company	1987-1991
Manager, Supply & Demand Planning	1984-1987
Manager, Fuel Regulation & Performance	1982-1984
Assistant to Senior Vice President, Fossil Power Plants	1981-1982
Division Head, Information Resources	1978-1981
Senior Engineer, Information Resource Division	1977-1978
Assistant to VP, Steam Operations	1976-1977
Electrical Engineer, Research & Planning Department	1973-1976

EDUCATION

Boston College Boston, MA
Masters in Business Administration 1982

Northeastern University Boston, MA
Masters in Science, Electrical Engineering 1974

Northeastern University Boston, MA
Bachelors in Science, Electrical Engineering 1973

PROFESSIONAL AFFILLIATIONS

Director, NSTAR Communications, Inc.	1997-2003
Director, Advanced Energy Systems, Inc.	2001-2003
Director, Neuco, Inc.	2001-2003
Director, United Telecom Council	1999-2003
Head, Business Development Division, United Telecom Council	2000-2003
Elected Commissioner – Reading Municipal Light Board	2005-present
Registered Professional Electrical Engineer in Massachusetts	