

Comments on Draft Portland General Electric Company 2009 Integrated Resource Plan

David Schlissel, Geoff Keith, Rachel Wilson, Lucy Johnston, David White, Jeremy Fisher and Erin Brandt

October 5, 2009



22 Pearl Street Cambridge, MA 02139

www.synapse-energy.com 617.661.3248

Synapse has reviewed Portland General Electric Company's ("PGE) Draft 2009 Integrated Resource Plan ("IRP") and has the following comments.

1. PGE predetermined the 15 portfolios that would be examined in the IRP. However, the Draft IRP does not describe or provide the analyses or methodology that PGE used to develop these portfolios. The Draft IRP also provides no data or analyses which show that the 15 portfolios it has developed for the IRP are the least cost portfolios and that there are not any alternative portfolios with lower cost and less risk.

An alternative used by other utilities is to allow the capacity expansion model to select the lowest cost plans based on the input assumptions and then the utility evaluates the relative reasonableness and risks of these lowest cost plans.

 Synapse agrees with PGE's observation that "a strategy that is overly reliant on market purchases is risky both from a cost and supply perspective." (page 49) However, the key question is what level of purchases constitutes being "overly reliant" on the market.

The Draft IRP limits market purchases to "about 100 MWa" of short and medium purchases and spot market purchases are limited to up to 300 MW of capacity. (pages 210 and 214) However, PGE does not provide any evidence to support these limits or to show that buying additional capacity or energy from the market would be more expensive or would present more significant risks for ratepayers.

PGE should justify the reasonableness of the limits it has placed on offsystem capacity and energy purchases or run scenarios in which larger offsystem purchases are allowed.

3. The Draft IRP provides no analysis showing that any of the portfolios, except for the Oregon CO₂ Compliance portfolio, actually would result in meaningful reductions in PGE's greenhouse gas emissions by 2020. At the same time, the Draft IRP provides no evidence whatsoever on what the CO₂ emissions would be in any of the portfolios under any of the Futures examined, in any years before or after 2020.

The IRP should evaluate plans for actually reducing the Company's CO₂ emissions rather than just paying for the purchase of allowances. For example, given the reductions that are being discussed by the federal government and that are included in the proposed Waxman-Market bill and other legislation that has been introduced in the U.S. Congress in recent years, the IRP should evaluate how PGE would reduce its CO₂ emissions by 17 percent (from 2005 levels) by 2020, by 42 percent by 2030 and by 83 percent by 2050. By actually reducing its CO₂ emissions, PGE would reduce its risk exposure to the uncertain costs of complying with future state, regional or federal regulation of greenhouse gas emissions regulations.

4. PGE says that it tested the portfolios using 21 different futures representing various potential risks and uncertainties. (page 201) However, the Draft IRP only provides a qualitative description of the various futures examined. (pages 222-223) There is no explanation of how the assumptions in each future differ from those in the reference case.

For example, the Draft IRP states that there are high and low wholesale electricity price cases examined in one or more of the futures, but PGE does not indicate what the revised wholesale prices are or how they were calculated. (page 223)

- 5. PGE provides only levelized natural gas prices (in 2009\$) and not the annual costs it used in its modeling analyses. (see page 75, for example) Without this information, it is not possible to evaluate the reasonableness of the reference, high and low gas price assumptions used by PGE.
- 6. PGE assumes a "high" natural gas price trajectory in several of futures that is significantly higher than the reference natural gas price forecast (\$12.84versus \$7.70 per MMbtu in levelized 2009\$, or approximately 67 percent higher). (page 75) However, PGE does not provide any evidence supporting the natural gas prices in this "high" price trajectory other than to say it is based on a combination of disappointing supply and the substitution of gas for coal to limit CO₂ emissions. The use of this extremely "high" natural gas price forecast biases the results of any analysis against the natural gas alternatives and in favor of the coal alternatives, including the continued operation of the Boardman plant.

Although it is reasonable to assume a range of future natural gas prices in resource planning, there is no evidence presented in the Draft IRP to support any assumption that "disappointing" supplies of natural gas, on their own or in combination with federal regulation of greenhouse gas emissions, would result in natural gas prices that are 67 percent higher than the reference case. In fact, such a conclusion is contrary to the more favorable outlook for domestic natural gas supplies discussed in the Draft IRP at pages 2, 77 and 78.

At the same time, as shown in the attached Public Testimony of David A. Schlissel in Wisconsin Public Service Commission Docket No. 5-CE-138, there is no modeling evidence that shows that federal regulation to limit CO_2 emissions will lead to significant increases in natural gas prices of anything near 67 percent in any single year, let alone throughout the period 2010 through 2040.

PGE should re-examine its IRP portfolio analyses using a "high" natural gas price forecast that is, perhaps, 20 percent (not 67 percent) higher than the base price forecast.

7. The Draft IRP shows that PGE has a range of price forecasts for PRB coal. (Figure 5-2 on page 86) PGE also has identified a long list of uncertainties for a number of key factors concerning coal supply and prices. (page 89) However, PGE has not examined any future with coal prices above its base case forecast even though it did examine a future with "low coal prices" below its reference case assumptions. (see pages 222-223) This is not reasonable. At a minimum, PGE should examine futures that reflect the full range of its own coal price forecasts.

The attached Direct Testimony of Thomas Sanzillo in Public Service Commission of Wisconsin Docket No. 5-CE-138 supports the conclusion that there are significant uncertainties that could affect future coal prices and supply availability. This evidence supports the examination of futures that reflect higher coal prices.

- 8. At the direction of the Commission's IRP Guidelines, one of the carbon price futures scenarios examined in the IRP analyses assumed a \$0/ton CO₂ regulatory cost. (page 264) Unfortunately, assuming that there will not be any price for CO₂ regulatory costs at any point in the period 2010 through 2040 is simply not reasonable given the concerns about greenhouse gas emissions that are being expressed at the state, regional and national levels and the regulatory and the legislative proposals that are being currently discussed by the federal government. Coal is the most carbon-intensive fuel. The results of any future that assumes a \$0/ton CO₂ regulatory cost consequently are distorted in favor of the coal alternatives, including the continued operation of the coal-fired Boardman plant.
- 9. PGE makes a number of pessimistic assumptions in its IRP analyses concerning future wind capital and operating costs and performance:
 - high wind integration costs. (page 125)
 - a very low (i.e., 5 percent) wind capacity value. (page 211)
 - declining Pacific Northwest wind capacity factors. (page 149)

Given the uncertainties in future wind integration costs, wind capacity values and future wind capacity factors, PGE should model at least one future which reflects more favorable assumptions for these factors. Moreover, given that there is a significant expectation that long-term wind capital costs may decline over time due to increased manufacturing capability, it would be reasonable to examine a future with lower wind capital costs.

10. The Company does not provide the annual revenue requirements or the NPVRR for any of its portfolio modeling analyses except for the reference case NPV for each portfolio. This data is essential for evaluating and verifying the conclusions of the modeling results presented in Chapter 11 of the Draft IRP and, without this data those conclusions and results cannot be evaluated.

Instead of providing the results of the individual portfolios under the 21 futures that PGE says it examined, the Draft IRP only presents, for example, the average costs of for the four worst futures for each portfolio (in 2009\$)." (see, for example, Figures 11-3 and 11-4) Moreover, the Draft IRP does not even identify which are the four worst futures for each portfolio. All of this information is essential for evaluating the reasonableness of the risk assessments presented in the Draft IRP.

The Company does not provide any supporting data or calculations for the portfolio probabilities of low and high expected costs presented in Figures 11-5 through 11-7. Again this information is essential for evaluating the reasonableness of the risk assessments in the Draft IRP.

- 11. The Company does not provide any of the supporting data or calculations for its stochastic risk analyses (Figures 11-8 through 11-10) or for its reliability and diversity analyses. (Figures 11-12 through 11-14) Without these supporting data and calculations, it is impossible to evaluate, let alone verify, the results of this stochastic risk analysis.
- 12. The stochastic modeling analysis presented in the Draft IRP includes a number of factors that are significant risks for gas fired plants, such as variations in natural gas prices. These variations in natural gas prices were included even though those variations also were examined in the deterministic modeling analyses.

However, the stochastic modeling analysis excludes a number of factors that are significant risks for coal plants such as variations in CO_2 regulatory costs and variations in coal prices. Excluding these factors biases the stochastic analysis in favor of continued operation of the Boardman plant. These also are important risks that need to be considered in resource planning analyses.

- 13. The Company also has presented no evidence or analysis that shows that the variations among the reliability of the various portfolios shown in Figures 11-11 and 11-12 represent any meaningful, let alone significant, differences in the risks for system reliability or for ratepayers.
- 14. The Company also has not provided any evidence or analyses showing that the variations in the HHI diversity analyses presented in Figures 11-13 and 11-14 represent significant differences in the actual risks of the various portfolios.
- 15. The IRP does not demonstrate that continued operation of Boardman is the most prudent course of action.
 - Figure 11-2 and Table 11-2 show that the portfolio "Boardman through 2014" actually has a slightly lower NPVRR than PGE's preferred "Diverse Thermal with Green" portfolio under the reference case assumptions.

- Figure 11-2 and Table 11-2 also show that the portfolios "Boardman through 2011" and "Boardman through 2017" have only very slightly higher (less than ½ of a percentage point) NPVRR than the Company's preferred "Diverse Thermal with Green" portfolio under reference case assumptions.
- Figures 11-15 and 11-16 show that the "Boardman through 2011," "Boardman through 2014" and "Boardman through 2017" (collectively the "Boardman retirement portfolios") all would have lower CO₂ emissions and lower CO₂ intensity in 2020 than would PGE's preferred "Diverse Thermal with Green" portfolio.
- Figures 11-11 and 11-12 show that the retirement of Boardman and its replacement by a natural gas-fired plant would not significantly affect the reliability of PGE's system. This is not a surprising result given the amounts of additional natural gas-fired capacity that PGE adds in these portfolios to replace the Boardman plant. The Company has not studied any portfolio in which Boardman would be replaced by a combination of additional energy efficiency, renewable resources and gas-fired capacity.
- Figure 12-1 compares PGE's preferred "Diverse Thermal with Green" portfolio with the Boardman retirement portfolios by looking at the "Average of Four Worst futures (2010-2040) NVPRR versus the Base Case NVPRR, 2010-2040." However, PGE does not identify which are the four worst futures for each portfolio or what the NPVRR were for each such future. Thus, it is not possible to determine how each retirement portfolio compared to the Company's preferred "Diverse Thermal with Green" portfolio in each individual future examined.

As explained earlier, it is quite possible that PGE's assumption that the natural gas prices in its "high" price trajectory would be 67 percent above the reference case has significantly distorted and biased the results presented in the Draft IRP, including those presented in Chapter 12. Indeed, Figure 12-10 shows that the "Boardman through 2014" portfolio is more significantly affected by higher gas prices than the "Diversified Thermal with Green" portfolio. This is not surprising given greater natural gas-fired generation in that portfolio and the extremely high prices assumed by PGE in its "high" natural gas price forecast.

• Figure 12-2 shows that the "Boardman through 2014" portfolio has a better combined probability of good and bad outcomes than PGE's preferred "Diverse Thermal with Green" portfolio. (page 283) According to PGE, "Better portfolios have a high probability of combined good vs. bad outcomes."

- Figures 12-6 and 12-7 compare the Boardman retirement scenarios with PGE's preferred "Diverse Thermal with Green" portfolio. Figure 12-6 shows only a relatively minor difference between the HHIs of the "Diversified Thermal with Green" portfolio and the HHIs for each of the Boardman retirement portfolios. PGE has not shown that these minor differences in HHIs among these portfolios represent any meaningful, let alone any significantly higher, risks for system reliability or for ratepayers.
- PGE has similarly not shown that the somewhat larger differences in HHIs shown in Figure 12-7 represent significantly higher risks, in any way, for system reliability or for ratepayers. All that PGE has shown is that the HHIs are higher for some portfolios than for others. Moreover, the HHI figures presented in the Draft IRP are not weighted to reflect the relative risks of the different technologies or fuel options.
- Figure 12-8 presents the "Average NVPRR of Four Worst Futures" ٠ for the Boardman retirement portfolios and PGE's preferred "Diversified Thermal with Green" portfolio. (page 289) It is again difficult to assess the significance of the NVPRR presented in this Figure because the specific four worst futures are not identified nor how each portfolio performed in each such "worst future." However, it is clear from Figure 12-8 that the differences among the "Average NVPRR of Four Worst Futures" for each of the portfolios presented in this Figure are not very large when considering that the modeled period is 30 years. For example, the "NVPRR of Four Worst Futures" for the "Boardman through 2017" portfolio appears to be only about one percent higher than the comparable NVPRR for PGE's preferred "Diversified Thermal with Green" portfolio. This is a very small difference given the uncertainties in the possible values for key input assumptions.

BEFORE THE PUBLIC SERVICE COMMISSION OF WISCONSIN

) Joint Application of Wisconsin Power & Light Company, Wisconsin Public Service Corporation, and Madison Gas and Electric Company for a Certificate of Authority to Install Emissions Reductions Systems at the Columbia Energy Center Units 1 and 2

DOCKET NO. 05-CE-138

DIRECT TESTIMONY OF DAVID A. SCHLISSEL ON BEHALF OF JOHN MUIR CHAPTER OF THE SIERRA CLUB

PUBLIC VERSION – PROTECTED MATERIALS REDACTED

SEPTEMBER 25, 2009

List of Exhibits

- Exhibit 400 (DAS-1) Current Resume for David A. Schlissel
- Exhibit 401 (DAS-2) Strategic Energy Assessment: Energy 2014 Ensuring the Availability, Reliability, and Sustainability of Wisconsin's Electric Energy Supply, Final Report, April 2009, Docket 5-ES-104, at pages XI to XII.
- Exhibit 402 (DAS-3) Synapse 2008 CO₂ Price Forecasts, July 2008.
- Exhibit 403 (DAS-4) Response to Data Request No. 1(WPL)-SC/INT-10.
- Exhibit 404 (DAS-5) Response to RFP 3(WPSC)-SC/RFP-22 [WPSC Confidential: Not Shared with Co-Applicants]
- Exhibit 405 (DAS-6) Report and Recommendation Concerning the Little Gypsy Unit 3 Repowering Project, submitted by Entergy Louisiana to the Louisiana Public Service Commission, April 1, 2009, at pages 6-8.
- Exhibit 406 (DAS-7) Response to Data Request No. 2(WPL)-SC/INT-24.
- Exhibit 407 (DAS-8) Attachment to WPL Response to Data Request No. 2(WPL)-CUB-CW/Inter-18. [WPL Confidential: Not Shared with Co-Applicants]
- Exhibit 408 (DAS-9) Response to Data Request No. 2(MGE)-SC/INT 24, parts a-d.
- Exhibit 409 (DAS-10)Response to Data Request No. 2(MGE)-SC/INT-31, part b.
- Exhibit410 (DAS-11) Response to Data Request No. 3(WPSC)-SC/INT-26, parts a, b, and d. [WPSC Confidential: Not Shared with Co-Applicants]
- Exhibit 411 (DAS-12)Response to Data Request No. 3(WPSC)-SC/INT-33, part a. [WPSC Confidential: Not Shared with Co-Applicants]
- Exhibit 412 (DAS-13)Attachment to Response to Data Request No. 3(WPSC)-SC/INT-26, part k. [WPSC Confidential: Not Shared with Co-Applicants]
- Exhibit 413 (DAS-13)Response to Data Request No. 2(MGE)-SC/INT-26, part c.
- Exhibit 414 (DAS-14)Response to Data Request No. 3(WPSC)-SC/INT-28, part c.

Exhibit 415 (DAS-15)Response to Data Request No. 2 (WPL)-SC/INT-26, part c.

1	1.	Introduction
2	Q.	What is your name, position and business address?
3	A.	My name is David A. Schlissel. I am a Senior Consultant at Synapse Energy
4		Economics, Inc, 22 Pearl Street, Cambridge, MA 02139.
5	Q.	Please describe Synapse Energy Economics.
6	A.	Synapse Energy Economics ("Synapse") is a research and consulting firm
7		specializing in energy and environmental issues, including electric generation,
8		transmission and distribution system reliability, market power, electricity market
9		prices, stranded costs, efficiency, renewable energy, environmental quality, and
10		nuclear power.
11		Synapse's clients include state consumer advocates, public utilities commission
12		staff, attorneys general, environmental organizations, federal government, state
13		governments and utilities. A complete description of Synapse is available at our
14		website, <u>www.synapse-energy.com</u> .
15	Q.	Please summarize your educational background and recent work experience.
16	A.	I graduated from the Massachusetts Institute of Technology in 1968 with a
17		Bachelor of Science Degree in Engineering. In 1969, I received a Master of
18		Science Degree in Engineering from Stanford University. In 1973, I received a
19		Law Degree from Stanford University. In addition, I studied nuclear engineering
20		at the Massachusetts Institute of Technology during the years 1983-1986.
21		Since 1983 I have been retained by governmental bodies, publicly-owned utilities,
22		and private organizations in 28 states to prepare expert testimony and analyses on
23		engineering and economic issues related to electric utilities. My recent clients
24		have included the General Staff of the Arkansas Public Service Commission, the
25		U.S. Department of Justice, the Attorney General of the State of New York, cities
26		and towns in Connecticut, New York and Virginia, state consumer advocates, and
27		national and local environmental organizations

1		I have testified before state regulatory commissions in Arizona, New Jersey,
2		California, Connecticut, Kansas, Texas, New Mexico, New York, Vermont, North
3		Carolina, South Carolina, Maine, Illinois, Indiana, Ohio, Massachusetts, Missouri,
4		Rhode Island, Wisconsin, Iowa, South Dakota, Georgia, Minnesota, Michigan,
5		Florida and North Dakota and before an Atomic Safety & Licensing Board of the
6		U.S. Nuclear Regulatory Commission.
7		A copy of my current resume is attached as Exhibit 400 (DAS-1).
8	Q.	On whose behalf are you testifying in this case?
9	A.	I am testifying on behalf of the John Muir Chapter of the Sierra Club. ("Sierra
10		Club")
11	Q.	Have you testified previously before the Public Service Commission of
12		Wisconsin ("PSCW")?
13	А.	Yes. I have testified in PSCW Dockets Nos. 6630-CE-209, 6630-CE-197, 6690-
14		UR-115, 05-EI-136, 6690-CE-187, 6630-EI-113 and 6680-CE-170.
15	Q.	What is the purpose of your testimony?
16	A.	Synapse was retained by the Sierra Club to assist in reviewing whether the
17		proposed emissions reduction systems at Columbia Units 1 and 2 are economic
18		for the companies' ratepayers and should be approved. In particular, Synapse was
19		asked to examine (1) the reasonableness of the Applicants' EGEAS modeling of
20		the installation of the scrubber and ACI system at Columbia Units 1 and 2 and
21		their proposed alternatives to the project, (2) the reasonableness and feasibility of
22		continuing to operate the Columbia Units 1 and 2 and/or other coal-fired units
23		owned by the Applicants in light of anticipated CO ₂ emissions regulations and/or
24		legislation and other regulatory emission reduction requirements and (3) the
25		reasonableness of the Applicants' assumptions concerning future CO ₂ prices and
26		coal prices.

1		
2		This testimony presents the results of our analyses.
3	Q.	Please summarize your conclusions.
4	A.	Our conclusions are as follows:
5 6 7 8 9		1. The Applicants' EGEAS modeling analyses are biased in favor of the completion of the emissions reduction project and the continued operation of Columbia Units 1 and 2 by a number of unreasonable assumptions concerning future CO ₂ prices, the impact that greenhouse gas regulation will have on natural gas prices and future coal prices
10 11 12 13		 The Applicants have modeled a number of Futures scenarios that include no monetization of CO₂. The Commission should give no weight to any EGEAS modeling scenario that does not include a future CO₂ cost in any year of the period 2010 through 2039.
14 15 16 17 18 19 20 21		3. In the Applicants' Futures scenarios that include monetization of CO_2 , the Applicants have modeled only a single, relatively low, set of CO_2 prices. Relying on a single set of CO_2 prices is unreasonable given the uncertainty about the specific emissions caps and design features of future federal regulation of greenhouse gas emissions. It would be more reasonable to consider a range of future CO_2 prices such as the Synapse Mid, High and Low forecasts that reflects the potential for higher emissions costs than the Applicants have modeled.
22 23 24 25 26 27		4. The Applicants have arbitrarily increased natural gas prices by 30 percent in most of the Futures scenarios they modeled with CO ₂ monetization to reflect what they claim would be the impact of federal regulation of greenhouse gases. Although it is possible that natural gas demand, and, consequently, natural gas prices could be higher due to greenhouse gas emissions regulations in some circumstances, the effect is very

Public - Protected Materials Redacted

1		complicated and will depend on a number of factors. Therefore, it is very
2		difficult to determine, at this time, the amount by which natural gas prices
3		might be raised, if at all, due to CO ₂ emissions regulations or legislation.
4	5.	The results of independent modeling analyses of the Waxman-Markey bill
5		and other climate change legislation do not provide any evidence for the
6		Applicants' assumption that regulation of greenhouse gas emissions will
7		increase natural gas prices by 30 percent beginning two years before that
8		regulation goes into effect and continuing throughout the entire planning
9		period. In fact, the modeling by the U.S. EPA, Energy Information
10		Administration (EIA of the DOE) and others shows that there are many
11		scenarios in which natural gas prices would remain approximately the
12		same or would decrease as a result of federal regulation of greenhouse gas
13		emissions. Even in those scenarios in which natural gas prices rise in
14		some years as a result of greenhouse gas emissions, they do not increase
15		by 30 percent in any single year, let alone in every year between 2013 and
16		2039, as the Applicants have assumed.
17	6.	The combination of low CO ₂ prices and much higher natural gas prices
18		biases the Applicants' EGEAS modeling analyses in favor of coal (that is,
19		the completion of the emissions reduction project and the continued
20		operation of Columbia Units 1 and 2) and against the natural gas-fired
21		alternatives.
22	7.	
23		
24		
25		
26		

Public - Protected Materials Redacted

1 2 3 8. In a study for the Commission, the Energy Center of Wisconsin has 4 projected that by 2018, the cumulative energy efficiency savings for the 5 State of Wisconsin could reach 13.0 percent of total electricity sales and 6 12.9 percent of electricity peak demand. At a minimum, the Applicants 7 should have run sensitivity studies that modeled this level of energy 8 efficiency as part of the portfolio of alternatives to the emissions reduction 9 project at Columbia Units 1 and 2. However, they have failed to do so by 10 apparently limiting their energy efficiency assumptions to the levels 11 required under Act 141. 12 9. Instead of including increased spending on energy efficiency and DSM, 13 above Act 141 levels, as one of the portfolio of alternatives to the 14 emissions reduction project at Columbia Units 1 and 2, the Applicants 15 have instead focused on a number of expensive, and in some cases very 16 expensive, alternatives. It is unreasonable to focus on these expensive 17 supply-side options without considering that additional energy efficiency 18 and DSM can offer less expensive alternatives, at least in large part, to the 19 expenditure of what the Applicants now predict will be \$627 million for 20 emissions control equipment at Columbia Units 1 and 2. 21 Q. Are there other members of the Synapse project team who are presenting 22 testimony in this proceeding? 23 A. Yes. Christopher James and Thomas Sanzillo also are presenting testimony in this 24 proceeding.

1 Q. Were there other members of the Synapse project team who also assisted in 2 the analyses undertaken by Synapse as part of its evaluation of the proposed 3 emissions reduction project at Columbia Units 1 and 2? 4 A. Yes. Dr. David White, Alice Napoleon, Rachel Wilson and Nick Doolittle from 5 Synapse also were members of our project team. Copies of their resumes are 6 available at www.synapse-energy.com. 7 **FUTURE CO2 EMISSIONS COSTS** 8 Q. Have the Applicants adequately considered the potential financial risks of 9 future CO₂ emissions in their modeling analyses? 10 A. No. In fact, the Applicants did not include any monetized value for CO₂ emissions 11 in three of the alternate "Futures" that they examine – that is, Futures 1, 3 and 4. 12 Moreover, in the remaining seven "Futures" examined by the Applicants, i.e., 13 Futures 2 and 5 through 10, the Applicants only considered a single price 14 trajectory that begins with a \$12/ton price in 2015 and that increases to \$38/ton in 2025 and \$53/ton in 2039 (all in nominal dollars).¹ 15 16 Relying on a single CO_2 price trajectory, as the Applicants have done, is 17 unreasonable. Given the uncertainty about the specific emission caps and design 18 features of the future federal regulation of greenhouse gas emissions, it would 19 have been more reasonable to consider a range of future CO₂ prices rather than 20 the single price trajectory assumed by the Applicants. 21 Q. Should the Commission give any weight to the results of the modeling 22 scenarios in which the Applicants did not assume any monetized value for CO₂ emissions? 23 24 A. No. As the Commission indicated in its Strategic Energy Assessment for 2014, 25 regulation of greenhouse gas emissions is inevitable and the Applicants' plans

¹ Application, Appendix C, at page 19 of 44 and Table 8 in Non-Confidential Attachment A.

Public - Protected Materials Redacted

1		should include CO_2 monetization. ² Given the trends in the legislation that has
2		been introduced and considered in the U.S. Congress in recent years, it is
3		unreasonable to assume that there will not be any regulation of CO_2 emissions
4		(and, hence, no monetized values for CO_2 emission) at any time before the year
5		2039. There may be uncertainty over the specific monetized values for CO_2
6		emissions, but federal regulation of greenhouse gas emissions is a matter of when
7		and how, not if.
8	Q.	How does the monetized value that the Applicants have assumed for CO ₂
9		emissions compare with other CO ₂ price forecasts?
10	A.	Figure 1 below compares the annual CO ₂ emissions prices that the Applicants
11		have assumed in their Futures 2 and 5 through 10 with the current Synapse Mid,
11 12		have assumed in their Futures 2 and 5 through 10 with the current Synapse Mid, High and Low CO_2 price forecasts. ³ These annual emissions prices are in

² Exhibit 401 (DAS-2) Strategic Energy Assessment: Energy 2014 – Ensuring the Availability, Reliability, and Sustainability of Wisconsin's Electric Energy Supply, Final Report, April 2009, Docket 5-ES-104, at pages XI to XII.

³ Additional information about the Synapse CO₂ price forecasts is presented in Exhibit 402 (DAS-3).



As can be seen, the single set of annual CO₂ prices used by the Applicants in their
 EGEAS modeling fairly closely tracks the Synapse Low CO₂ price forecast but is
 significantly lower than the Synapse Mid CO₂ price forecast, let alone the
 Synapse High CO₂ price forecast.

Q. Have the Applicants acknowledged that the Synapse CO₂ price forecasts are reasonable for use in resource planning?

9 A. Yes. The Applicants have acknowledged that the Synapse CO₂ price forecasts are
10 reasonable for resource planning.⁴ However, the Applicants also have said that
11 while all three of Synapse's CO₂ price forecasts (Mid, High and Low) "may be
12 reasonable for purposes of utility resource planning, the low and mid forecasts
13 should be given a significantly higher probability of occurrence than that
14 accorded to the high forecast."

1	Q.	But isn't it correct that the Applicants did not include the Synapse Mid CO_2
2		price forecast in any modeling scenario?
3	A.	That is correct. As shown in Figure 1, the single set of CO_2 prices assumed by the
4		Applicants in their Futures 2 and 5 through 10 was only marginally higher than
5		the Synapse Low Forecast. The Applicants have not examined the viability of
6		continued operation of Columbia Units 1 and 2 with the emissions reductions
7		equipment under any higher set of CO ₂ prices, including the Synapse Mid CO ₂
8		price forecast.
9	Q.	Are the Synapse CO_2 price forecasts consistent with the results of the CO_2
10		prices being projected for the Waxman-Markey bill that has recently being
11		approved by the U.S. House of Representatives and is currently being
12		deliberated in the U.S. Senate?
13	A.	Yes. Figure 2 below compares the CO ₂ emissions prices that the Applicants have
14		assumed in their Figures 2 and 5 through 10 and the Synapse CO_2 price forecasts
15		with the results of the independent modeling of the legislation that has been
16		introduced in the U.S. Congress in recent years. The CO_2 emissions prices in
17		Figure 2 are levelized prices in 2009 year dollars.
18		In this Figure:
19 20		• S.280 refers to the McCain Lieberman bill introduced in 2007 in the 110 th U.S. Congress
21 22		• S.1766 refers to the Bingaman-Specter bill introduced in 2007 in the 110 th U.S. Congress
23 24		• S. 2191 refers to the Lieberman-Warner bill introduced in 2007 in the 110 th U.S. Congress
25 26		• HR. 2454 refers to the Waxman-Markey bill introduced in 2009 in the current 111 th U.S. Congress

⁴ For example, see the Application, EGEAS Summary Report, Appendix C, at page 21 of 44.

1 The modeling analyses in Figure 2 includes studies prepared by the U.S. EPA, the 2 Energy Information Administration ("EIA") of the US Department of Energy, the 3 Clean Air Task Force, the American Council for Capital Formation and the 4 National Association of Manufacturers, CRA, International, Duke University, the 5 Massachusetts Institute of Technology ("MIT") and the Natural Resources 6 Defense Council ("NRDC").

7 8

Figure 2: Applicant and Synapse CO₂ Prices Compared to Results of Modeling of Proposed Federal Legislation



9

10 This comparison clearly demonstrates that the range of the Synapse CO_2 price 11 forecasts remains reasonable when the results of the EPA and EIA modeling of 12 H.R. 2454, the Waxman-Markey legislation, are included. Figure 2 also clearly 13 demonstrates that the single set of CO_2 prices assumed by the Applicants in their 14 modeling of Futures 2 and 5 through 10 are too low when compared to the ranges

	Colu Dock Dire	umbia Units 1 and 2 xet No. 05-CE-138 ct Testimony of David A. Schlissel Public - Protected Materials Redacted	
1		of possible CO ₂ costs that have been projected in the EPA and EIA's modeling	of
2		HR. 2454, the Waxman-Markey legislation. ⁵	
3	Q.	Have you seen any more recent CO ₂ price forecasts that have been prepare	d
4		by or for the Applicants?	
5	A.	[REDACTED]	
6			6
7			
8			
9			
10			
10			
11			
12			
13			
14			
15			
16			
17			
10			
18			
19			

The results of the US EPA and EIA's modeling of the Waxman-Markey bill are included as the 3^{rd} , 4^{th} and 5^{th} bars from the right in Figure 2. Exhibit 404 (DAS-5) WPSC Confidential – Not Shared with Co-Owners. WPSC's response to Data Request No. 3(WPSC)-SC/RFP-22. 5

⁶

1		
2		[REDACTED]
3		
4		
5	Q.	What is your conclusion concerning the CO ₂ prices assumed by the
6		Applicants in their EGEAS modeling?
7	A.	As I noted earlier, the Commission should not give any weight to any scenario
8		that does not include any CO_2 prices – it is unreasonable to expect that there will
9		not be any regulation of greenhouse gases at any time before 2039.
10		In addition, the single set of CO ₂ prices assumed by the Applicants, while just
11		within the zone of reasonableness, was too low to use as the only CO_2 price
12		considered. The Applicants should have modeled a range of future CO_2 prices
13		such as the Synapse Low, Mid and High forecasts.
14	O :	What impact does the limited modeling of CO2 prices have?
	· ·	
15	A:	By ignoring the potential for higher CO ₂ prices, the Applicants have biased their
15 16	A:	By ignoring the potential for higher CO_2 prices, the Applicants have biased their EGEAS modeling analyses in favor of the continued operation of Columbia Units
15 16 17	A:	By ignoring the potential for higher CO_2 prices, the Applicants have biased their EGEAS modeling analyses in favor of the continued operation of Columbia Units 1 and 2 because coal is the most carbon intensive fuel. ⁷
15 16 17 18 19	A:	By ignoring the potential for higher CO ₂ prices, the Applicants have biased their EGEAS modeling analyses in favor of the continued operation of Columbia Units 1 and 2 because coal is the most carbon intensive fuel. ⁷ IMPACT OF GREENHOUSE GAS REGULATION ON NATURAL GAS PRICES
15 16 17 18 19 20	A: Q.	 By ignoring the potential for higher CO₂ prices, the Applicants have biased their EGEAS modeling analyses in favor of the continued operation of Columbia Units 1 and 2 because coal is the most carbon intensive fuel.⁷ IMPACT OF GREENHOUSE GAS REGULATION ON NATURAL GAS PRICES Do the Applicants adjust natural gas and/or coal prices to reflect federal
15 16 17 18 19 20 21	A: Q.	 By ignoring the potential for higher CO₂ prices, the Applicants have biased their EGEAS modeling analyses in favor of the continued operation of Columbia Units 1 and 2 because coal is the most carbon intensive fuel.⁷ IMPACT OF GREENHOUSE GAS REGULATION ON NATURAL GAS PRICES Do the Applicants adjust natural gas and/or coal prices to reflect federal regulation of greenhouse gas emissions?
15 16 17 18 19 20 21 22	А: Q. А.	 By ignoring the potential for higher CO₂ prices, the Applicants have biased their EGEAS modeling analyses in favor of the continued operation of Columbia Units 1 and 2 because coal is the most carbon intensive fuel.⁷ IMPACT OF GREENHOUSE GAS REGULATION ON NATURAL GAS PRICES Do the Applicants adjust natural gas and/or coal prices to reflect federal regulation of greenhouse gas emissions? Yes. The Applicants have increased natural gas prices by 30 percent beginning in
 15 16 17 18 19 20 21 22 23 	А: Q. А.	 By ignoring the potential for higher CO₂ prices, the Applicants have biased their EGEAS modeling analyses in favor of the continued operation of Columbia Units 1 and 2 because coal is the most carbon intensive fuel.⁷ IMPACT OF GREENHOUSE GAS REGULATION ON NATURAL GAS PRICES Do the Applicants adjust natural gas and/or coal prices to reflect federal regulation of greenhouse gas emissions? Yes. The Applicants have increased natural gas prices by 30 percent beginning in 2013 and have decreased coal prices by 10 percent in their Futures 5 through 10

⁷ For example, a typical new combined cycle plant is expected to emit on the order of 1000 to 1200 lbs of CO₂ per MWh. The average CO₂ emissions from Columbia Units 1 and 2 was approximately 2200 lbs per MWh during 2007 and 2008.

Public - Protected Materials Redacted

Q. In what years do the Applicants apply these increased natural gas and decreased coal prices?

A. Remarkably, in Futures 5 through 10, the Applicants raise natural gas prices by 30
percent and decrease coal prices by 10 percent starting in 2013 even though the
monetized values for CO₂ emissions do not start until 2015. Raising natural gas
prices two years before carbon regulation even begins (that is in 2013) is
unreasonable and biases the analyses against natural gas options and in favor of
the continued operation of Columbia Units 1 and 2.

9 Q. Do you agree with the Applicants' assumption that natural gas prices would 10 increase by 30 percent if the federal government adopts legislation or 11 regulations to regulate and reduce greenhouse gas emissions?

- 12 A. No. It is possible that natural gas demand could be somewhat higher due to CO_2 13 emission regulations and, as a result, natural gas prices could be expected to be 14 somewhat higher than otherwise would be the case. However, the effect is very 15 complicated and will depend on a number of factors, such as how much new 16 natural gas capacity is built as a result of the higher coal-plant operating costs due 17 to the CO₂ emission allowance prices, how much additional DSM and renewable 18 alternatives are added to the U.S. system, the levels and prices of any incremental 19 natural gas imported into or developed in the U.S., and changes in the dispatching 20 of the electric system. Indeed, depending on future circumstances there may be 21 some periods in which the prices of natural gas may be lower as a result of CO_2 22 regulations. Thus it is very difficult to determine, at this time, the amount by 23 which natural gas prices might be increased, if at all, due to the regulation of CO_2 24 emission.
- In fact, as I will discuss below, the detailed modeling of proposed greenhouse gas
 legislation does not support any assumption that the price of natural gas would

8

For example, see WPL's Response to Data Request No. 1(WPL)-SC/INT-1.

1 2		increase by anything close to 30 percent as a result of a federal program for regulating greenhouse gas emissions.
3	Q.	Has Synapse examined the impact that the enactment of CO_2 emissions
4		regulations might have on natural gas prices?
5	А.	Yes. As part of our work on climate change issues, Synapse has reviewed the
6		publicly available modeling results concerning the impact that adoption and
7		implementation of CO ₂ regulatory legislation could have on natural gas prices.
8		The results of our review are presented in Figure 4, below.
9		More particularly, Figure 4 shows the levelized percentage changes in natural gas
10		prices (i.e., increases or decreases from the base case that has no regulation of
11		greenhouse gas emissions) in a large number of scenarios from the major climate
12		change proposals that have been introduced in the U.S. Congress in recent years.
13		Each data points shown in Figure 4 reflects the levelized change in the natural gas
14		prices in a modeled scenario and the levelized CO_2 price for that scenario.
15		The levelized CO ₂ prices and natural gas price changes presented in Figure 4 have
16		been developed from the results of modeling by the Joint Program at MIT on the
17		Science and Policy of Global Change, the U.S. EPA, and the EIA of the
18		Department of Energy, and cover multiple climate change proposals in the 110th
19		U.S. Congress: Senate Bill S.280 (the McCain-Lieberman bill), Senate Bill
20		S.1766 (the Bingaman-Specter bill), Senate Bill S.2191 (the Lieberman-Warner
21		bill) and House Bill 2454 in the 111 th Congress (the American Clean Energy and
22		Security Act of 2009, "Waxman-Markey").



Figure 4: The relationship between CO₂ emissions allowance prices and natural gas prices.

1

2

3

4 The red square at the top of Figure 4 reflects the Applicants' assumption that there 5 would be a 30 percent increase in natural gas prices. The location of this red square also reflects the Applicants' assumption that there would only be a 6 7 relatively low set of CO₂ prices. As shown clearly in Figure 4, none of the results 8 of any of the independent modeling analyses support the Applicants assumption 9 that regulation of CO₂ emissions will increase natural gas prices by 30 percent. 10 Instead, the modeling evidence suggests that federal regulation of greenhouse gas 11 emissions can be expected to have a much smaller impact on natural gas prices 12 than the 30 percent increase that the Applicants have assumed in their EGEAS 13 modeling. This is true even with CO_2 prices that are significantly higher than the CO₂ prices that the Applicants have assumed in their EGEAS modeling. 14 15 In fact, the results of the modeling of a substantial number of the CO₂ regulation

16 scenarios represented in Figure 4 suggest that the adoption of greenhouse gas

1		regulation would lead to lower natural gas prices as the demand for and the use of
2		natural gas decline due to its greenhouse gas emissions. Thus, there is no credible
3		modeling evidence to support the Applicants' assumption that federal regulation
4		of greenhouse gas emissions would inevitably lead to a 30 percent increase in the
5		price of natural gas, particularly at relatively low CO ₂ prices. In fact, there is no
6		clear evidence that CO_2 prices in the range that the Applicants have used in their
7		EGEAS will push natural gas prices higher at all.
8	Q.	Does Figure 4, above, include the recent modeling of the HR 2454, the
9		Waxman-Markey legislation that has been approved by the U.S. House of
10		Representatives?
11	A.	Yes. The results of the recent EIA modeling of the Waxman-Markey bill are
12		included in Figure 4.
13	Q.	Have you seen any other evidence that suggests that federal regulation of
14		greenhouse gas emissions will not cause natural gas prices to increase by 30
15		percent as the Applicants have assumed in their EGEAS modeling?
16	A.	Yes. Figure 5, below, presents the annual percentage changes in natural gas
17		prices in each of the scenarios examined by the EIA in its recent modeling of the
18		Waxman-Markey bill from the gas prices in the EIA's reference case without any
19		regulation of CO ₂ emissions. This information provides insight in the ranges of
20		natural gas prices that could be expected from adoption of the Waxman-Markey
21		bill.

22



Figure 5:

1

2

3

4

5

6 7

8

9

10

11

12

Annual Changes in Natural Gas Prices from Reference Case in EIA Modeling of Proposed Waxman-Markey Legislation

As can be seen from Figure 5, under the Waxman-Markey bill that has been passed by the House of Representatives, natural gas prices would not increase by 30 percent in any of the years in any of the scenarios studied by the EIA. At most, natural gas prices would spike above 20% for four or five years in the most restrictive scenario studied by the EIA, i.e., a scenario in which the numbers of international offsets are severely limited and the deployment of alternative technologies also is not increased above reference case levels. However, even in this restricted scenario, natural gas prices do not increase by 30 percent in any year through 2030.

In fact, Figure 5 shows that in many of the cases studied by the EIA, natural gas prices would decrease over time as a result of the federal regulation of greenhouse gas emissions.

1 Figure 5 provides additional publicly available modeling evidence that contradicts 2 the Applicants' assumption in their Futures 5 through 10 that natural gas prices 3 will increase by 30 percent two years before CO₂ regulation begins and will 4 remain 30 percent higher in every year through 2039. 5 Q. But doesn't common sense suggest that regulating greenhouse gas emissions 6 will lead to less coal-fired generation and more of a dependence on natural 7 gas - thereby increasing the demand for and price of natural gas? 8 A. Not necessarily, especially over the mid-to-longer term. In fact, there are several 9 reasons why federal regulation of greenhouse gas emissions may not lead to any 10 meaningful increases in the price of natural gas. First, natural gas plants also emit 11 CO_2 . Thus, there will be incentives as a result of federal regulation of greenhouse 12 gases to shift away from use of natural gas to more carbon neutral options such as 13 energy efficiency and renewable resources. This will act to reduce the demand for 14 natural gas as well as coal-fired generation. 15 It also is generally accepted that strategies for reducing our national greenhouse 16 gas emissions will require implementing complementary policies adding large 17 amounts of new wind and energy efficiency. Thus, legislative proposals for 18 regulation of greenhouse gases, such as the Waxman-Markey bill also included 19 increased investments in these areas. Consequently, carbon legislation, when 20 coupled with increasing amounts of new wind and energy efficiency, actually may 21 lead to decreases in the demand for and, consequently, reduced costs for natural 22 gas over the long term, counter to what the Applicants have assumed.

For example, a recent study by the U.S. Department of Energy's National Renewable Energy Laboratory examined the costs and benefits of achieving 20 percent wind energy penetration by 2030.⁹ One of the benefits that this DOE study found was that wind generation could displace up to 50 percent of the

⁹ 20 Percent Wind Energy by 2030, available at http://www.20percentwind.org/20p.aspx?page=Report.

electricity that would be generated from natural gas – this, in turn, could translate
 into a reduction in national demand for natural gas of 11 percent.¹⁰

3 The identification of substantially increased natural gas supplies within the past 4 year also will affect the impact that regulation of CO₂ emissions can be expected 5 to have on natural gas prices. Indeed, the identification of these new supplies of 6 natural gas has been described as a structural change in the natural gas market. 7 This structural change has two important impacts on the resource planning for 8 emissions reduction systems at Columbia Units 1 and 2. First, as a result of the 9 existing and expected supply glut, current and projected prices of natural gas have 10 been reduced. At the same time, the dramatically increased supplies of natural 11 gas that are being identified should be able to accommodate any increased 12 demands from fuel switching as a result of federal regulation of greenhouse gas 13 emissions without causing significant increases in natural gas prices.

14 The structural change in the natural gas markets already has had a significant 15 impact on utilities' resource planning. For example, in early April of this year, 16 Entergy Louisiana informed the Louisiana Public Service Commission of its 17 intent to defer (and perhaps cancel) a proposal to retire an existing gas-fired 18 power plant and, in its place, to build a new coal-fired unit. Entergy explained 19 that it no longer believes that a new coal plant would provide economic benefits 20 for its customers due to its current expectation that future gas prices would be 21 much lower than previously anticipated:

22 Perhaps the largest change that has affected the Project economics 23 is the sharp decline in natural gas prices, both current prices and 24 those forecasted for the longer-term. The prices have declined in 25 large part as a result of a structural change in the natural gas 26 market driven largely by the increased production of domestic gas 27 through unconventional technologies. The decline in the long-term 28 price of natural gas has caused a shift in the economics of the 29 Repowering Project, with the Project currently – and for the first

¹⁰ <u>Id</u>, at pages 16 and 154.

Public - Protected Materials Redacted

1 2	time – projected to have a negative value over a wide range of outcomes as compared to a gas-fired (CCGT) resource. ¹¹
3	4. Recent Natural Gas Developments
4 5 6 7 8 9 10 11 12 13	Until very recently, natural gas prices were expected to increase substantially in future years. For the decade prior to 2000, natural gas prices averaged below \$3.00/mmBtu (2006\$). From 2000 through May 2007, prices increased to an average of about \$6.00/mmBtu (2006\$). This rise in prices reflected increasing natural gas demand, primarily in the power sector, and increasingly tighter supplies. The upward trend in natural gas prices continued into the summer of 2008 when Henry Hub prices reached a high of \$131.32/mmBtu (nominal). The decline in natural gas prices since the summer of 2008 reflects, in part, a reduction in demand
14	resulting from the downturn in the U.S. economy.
15	* * * *
16 17 18 19 20 21 22 23 24 25 26 27 28 29	However, the decline also reflects other factors, which have implications for long-term gas prices. During 2008, there occurred a seismic shift in the North American gas market. "Non- conventional gas" – so called because it involves the extraction of gas sources that previously were non-economic or technically difficult to extract – emerged as an economic source of long-term supply. While the existence of non-conventional natural gas deposits within North America was well established prior to this time, the ability to extract supplies economically in large volumes was not. The recent success of non-conventional gas exploration techniques (e.g., fracturing, horizontal drilling) has altered the supply-side fundamentals such that there now exists an expectation of much greater supplies of economically priced natural gas in the long-run
30	* * * *
31 32 33 34 35	Of course, it should be noted that it is not possible to predict natural gas prices with any degree of certainty, and [Entergy Louisiana] cannot know whether gas prices may rise again. Rather, based upon the best available information today, it appears that gas prices will not reach previous levels for a sustained period of time

Exhibit 405 (DAS-6). <u>Report and Recommendation Concerning the Little Gypsy Unit 3</u> <u>Repowering Project</u>, submitted by Entergy Louisiana to the Louisiana Public Service <u>Commission, April 1, 2009</u>, at pages 6-8.

Public - Protected Materials Redacted

1 2	because of the newly discovered ability to produce gas through non-traditional recovery methods ¹² [Emphasis added]
3	Entergy's conclusion that there has been a seismic shift in the domestic natural
4	gas industry was confirmed in early June 2009 by the release of a report by the
5	American Gas Association and an independent organization of natural gas experts
6	known as the Potential Gas Committee, the authority on gas supplies. This report
7	concluded that the natural gas reserves in the United States are 35 percent higher
8	than previously believed. The new estimates show "an exceptionally strong and
9	optimistic gas supply picture for the nation," according to a summary of the
10	report. ¹³
11	A Wall Street Journal Market Watch article titled "U.S. Gas Fields From Bust to
12	Boom" similarly reported that huge new gas fields have been found in Louisiana,
13	Texas, Arkansas and Pennsylvania and cited one industry-backed study as
14	estimating that the U.S. now has enough natural gas to satisfy nearly 100 years of
15	current natural gas-demand. ¹⁴ It further noted that
16 17 18 19 20 21 22	Just three years ago, the conventional wisdom was that U.S. natural-gas production was facing permanent decline. U.S. policymakers were resigned to the idea that the country would have to rely more on foreign imports to supply the fuel that heats half of American homes, generates one-fifth of the nation's electricity, and is a key component in plastics, chemicals and fertilizer.
23 24 25 26	But new technologies and a drilling boom have helped production rise 11% in the past two years. Now there's a glut, which has driven prices down to a six-year low and prompted producers to temporarily cut back drilling and search for new demand. ¹⁵
27	The existence of higher natural gas reserves and the new recovery techniques
28	discussed above should significantly reduce any impact on natural gas prices from
29	the adoption of a federal program regulating greenhouse gas emissions.

¹² <u>Id</u>, at pages 17, 18 and 22.

¹³ *Estimate Places Natural Gas Reserves 35 percent Higher*, New York Times, June 9, 2009.

¹⁴ Available at http://online.wsj.com/article/SB12410459891270585.html.

Public - Protected Materials Redacted

1	Q.	Have the Applicants provided any credible evidence to support their
2		assumption that natural gas prices would immediately increase by 30 percent
3		starting in 2013 and would be 30 percent higher in every year of the study
4		period?
5	A.	No. When asked to identify the basis of their assumption that natural gas prices
6		would increased by 30% under CO_2 regulation, the Applicants cited a number of
7		sources as purportedly supporting "changes in coal and gas forecasts if
8		greenhouse gases are regulated." ¹⁶ However, these sources suffer from one or
9		more of the following serious flaws:
10		• They make exaggerated claims about the impact that CO ₂ regulation will
11		have on natural gas prices without offering any supporting analyses or
12		evidence.
13		• They assume that coal would be displaced only by natural gas and,
14		consequently, don't allow for the displacement of coal by additional
15		energy efficiency and renewable resources. This inflates the amount of
16		natural gas that would be required and the impact on natural gas prices.
17		• They assume that very major CO ₂ prices would be implemented in a single
18		step, nearly overnight, rather than phased in over time. This is contrary to
19		the greenhouse gas legislation that has been introduced in Congress in
20		recent years in which CO ₂ prices would start low and increase over time.
21		In addition, some of the sources cited by the Applicants assume much higher CO_2
22		prices than the Applicants have used in their EGEAS modeling for Columbia
23		Units 1 and 2. For example, in support of their assumption that natural gas prices
24		will increase 30%, the Applicants cite a study from the Cambridge Energy
25		Research Associates ("CERA"), presented by WPL in Docket No. 6680-CE-170,

15

Id. For example, see WPSC's Response to Sierra Club's Data Request No. 1(WPSC)-SC/INT-1. 16

Public - Protected Materials Redacted

1	which assumed assumed CO_2 prices of \$40/metric tonne and \$80/metric tonne. ¹⁷
2	The prices assumed by CERA, while within a range of reasonableness, were
3	substantially higher than the CO ₂ prices used by the Applicants in their EGEAS
4	modeling in this proceeding. Thus to bolster their argument that CO ₂ prices lead
5	to gas price increases, the Applicants' attempt to use a high gas price that is
6	connected to much higher CO_2 price without also using the much higher CO_2
7	price.
8	Clearly, the Applicants want the Commission to accept such scenarios that
9	include low CO_2 prices and high natural gas prices that have been artificially
10	increased by the assumption that the low CO ₂ prices will have a substantial (i.e.,
11	30 percent) impact on gas prices. However, as I have shown above, such a
12	combination of low CO ₂ prices and much higher gas prices is not supported by
13	any analysis and improperly biases the EGEAS modeling analyses in favor of coal
14	and against the natural gas alternatives.
15	At the same time that they have relied on flawed studies, in some instances the
16	Applicants have been selective in the evidence from the various studies that they
17	have chosen to rely on. For example, the very table from the EIA's April 2008
18	report on the Lieberman-Warner Climate Security Act of 2007 on which the
19	Applicants want to rely for the assumption that CO ₂ regulation will lead to higher
20	delivered natural gas prices also shows that CO ₂ regulation would lead to higher
21	delivered coal prices. ¹⁸ However, the Applicants have chosen to selectively cite
22	the finding that delivered natural gas prices would be higher due to federal
23	greenhouse gas regulations while ignoring the finding that delivered coal prices
24	also would be higher.

¹⁷ Exhibit___(KLY-1) in Docket No. 6680-CE-170, at page 18.

¹⁸ Both of these results are due to the fact that the delivered prices in this Table in the EIA report include the cost of the CO_2 emissions allowances.

Public - Protected Materials Redacted

Q. What assumption did WPL make in its 2008 EGEAS modeling in Docket No. 6680-CE-170 as to the impact that regulation of greenhouse gas emissions would have on natural gas prices?

- A. In the EGEAS modeling runs in Docket No. 6680-CE-170 that compared the
 conversion of the Neenah facility to a combined cycle unit to the building of the
 proposed Nelson Dewey 3 plant, WPL assumed that natural gas prices would be
 raised by 10 percent in scenarios with monetized CO₂ emissions values.¹⁹ Now,
 less than a year later, the same Company has assumed that the same set of CO₂
 prices will lead to much higher 30 percent increases in natural gas prices.
- Q. What are reasonable assumptions regarding the impact that CO₂ regulation
 will have on natural gas prices that should be used in the EGEAS modeling
 of the proposed emissions reduction systems at Columbia Units 1 and 2?
- 13 A. The base case analysis should assume that CO₂ regulation will not have a 14 measurable impact on natural gas prices. At the same time, I would suggest that 15 sensitivity cases be run which assume that gas prices might increase somewhat 16 over time as a result of CO₂ regulation. As I testified in Docket No. 6680-CE-17 170, with the Synapse mid CO_2 prices, such sensitivity cases could assume that 18 natural gas prices would be perhaps 5 percent higher than base case levels by 19 2015 or 2020 and 10 percent higher by 2025 or 2030. Although the results of the 20 modeling that I have discussed suggests that natural gas prices actually could be 21 lower over time as a result of CO₂ regulation, to be conservative I would 22 recommend that such scenarios not be run at this time.
- Intervenors have requested that the Applicants run several more reasonable
 EGEAS scenarios in which (1) natural gas prices are not increased as a result of
 CO₂ emissions regulations and (2) natural gas prices increase by 10 percent
 beginning in the year in which the regulation of CO₂ emissions also begins.

¹⁹

Rebuttal Testimony of Randy Bauer in Docket No. 6680-CE-170, at page 17, lines 3-6.

Public - Protected Materials Redacted

1		THE APPLIANTS MODELING OF ENERGY EFFICIENCY
2	Q.	Applicant witnesses Niccolls, Daavettila and Block have testified that existing
3		levels of energy efficiency are included in the Applicants' EGEAS modeling
4		analyses through the load forecasts and that existing levels of DSM impacts,
5		such as interruptible load and direct load control are included through
6		forecast adjustment, modeling of units or both. ²⁰ Is it possible to determine,
7		even approximately, what levels of energy efficiency and demand side
8		management are reflected in each of the Applicants' EGEAS modeling
9		analyses?
10	A.	The answer is yes for WPL but, unfortunately, is no for WPSC and MGE.
11	Q.	What information has WPL provided concerning the levels of energy
12		efficiency and DSM in its EGEAS modeling?
13	A.	[REDACTED]
14		
15		
16		
17		21
18	Q.	What levels of peak demand and energy requirements reductions did WPL
19		then assume in its EGEAS modeling?
20	A.	[REDACTED]

Direct Testimony of J. Niccolls, S. Daavettila and J. Block, July 10, 2009, at page 46, lines 2-4.
 Exhibit 406 (DAS-7) WPL Response to Data Requests No. 2(WPL)-S/INT-24, parts a-d and Exhibit 407 (DAS-8) the Attachment to WPL's Response to Data Request No. 2(WPL)-CUB-CW/Inter-18.

Columbia Units 1 and 2 Docket No. 05-CE-138 **Direct Testimony of David A. Schlissel** Public - Protected Materials Redacted 1 2 3 Q. Did WPL assume that additional reductions in peak demands and energy 4 requirements could be achieved through each year of the 2010-2039 planning 5 period in its EGEAS modeling? 6 A. [REDACTED] 7 8 9 10 11 12 13 14 Q. What information did MGE provide concerning the energy efficiency and DSM savings it assumed in its EGEAS modeling in this proceeding? 15 A. Through discovery the Sierra Club asked MGE to identify the annual reductions it

16 17 had assumed in its EGEAS modeling in its demand and energy requirements for 18 each of the years 2010-2039 due to existing and new energy efficiency and DSM programs.²² Instead of providing the requested quantification of the energy 19 20 efficiency and DSM program savings assumed by MGE in its EGEAS modeling 21 for either its existing or new efforts, MGE provided the following general 22 response: 23 Reductions in demand and energy due to energy conservation and 24 load management efforts by MGE's customers, rather than being 25 explicitly quantified, are reflected in the base historical data used in the peak electric demand and energy forecasts. The methods 26

27

used by MGE to develop its peak electric demand and energy

²² Exhibit 408 (DAS-9). MGE's Response to Data Request No. 2 (MGE)-SC/INT-24, parts a-d.

Public - Protected Materials Redacted

1 2		forecasts capture, by definition, any realized conservation and load management savings reflected in the marketplace. ²³
3		The only quantification that MGE did provide was that it had modeled three types
4		of DSM impacts in its EGEAS modeling for its existing Power Control Program,
5		Voltage Control Program and Interruptible Customer Program and that the
6		estimated potential demand impact from these three DSM programs during
7		summer peak periods are approximately 28 MW, 12 MW and 29 MW . ²⁴ The
8		peak demand savings from these three programs represent only 7.7 percent of
9		MGE's load forecast in 2018. MGE otherwise has failed to provide any
10		quantification of any savings in its energy requirements due to existing or new
11		energy efficiency or DSM efforts that it included in its EGEAS modeling.
12	Q.	What information has WPSC provided concerning the savings from energy
13		efficiency and DSM that it assumed in its EGEAS modeling in this
14		proceeding?
15	A.	
16		
17		
18		
19		
20		25
21		26
22		

²³ Exhibit 408 (DAS-9) MGE Response to Data Request No. 2 (MGE)-SC/INT-24, parts a-d.

Exhibit 409 (DAS-10) MGE Response to Data Request No. 2 (MGE)-SC/INT-31, part b.

²⁵ Exhibit 410 (DAS-11) WPSC response to Data Request No. 3 (WPSC)-SC/INT-26, part a.

²⁶ Exhibit 410 (DAS-11) WPSC Response to Data Request No. 3(WPSC)-SC/INT-26, part b.



²⁷ Exhibit 411 (DAS-12) WPSC response to Data Request No. 3 (WPSC)-SC/INT-33. part a.

 $[\]frac{28}{1d}$.

²⁹ Exhibit 410 (DAS-11) WPSC response to Data Request No. 3(WPSC)-SC/INT-26, part d.

³⁰ Calculation based on information provided in Exhibit 412 (DAS-13) 'EPC Handout FCST200810 redacted.pdf, provided in response to Data Request No. 3(WPSC)-SC/INT-26, part k.

Public - Protected Materials Redacted

Q. Have the Applicants reasonably represented in their EGEAS modeling analyses the potential reductions in their peak demands and energy requirements from energy efficiency and DSM efforts?

4 A. As best as we can determine, no. According to the Energy Efficiency Potential 5 Study prepared by the Energy Center of Wisconsin for the Commission, the 6 cumulative energy efficiency savings for the State of Wisconsin could reach 13.0 percent of total electricity sales by 2018 and 12.9 percent of electricity peak 7 demand.³¹ As discussed above, there is no evidence that the Applicants have 8 9 modeled these reductions in their EGEAS analyses nor have they shown that spending on additional energy efficiency and DSM efforts, above Act 141 levels, 10 11 would not be a cost-effective alternative (or part of a portfolio of cost-effective 12 alternatives) to the proposed emissions reductions project and continued operation 13 of Columbia Units 1 and 2.

Q. Did any of the Applicants model any increased spending on energy efficiency or DSM, above the Act 141 levels, as an alternative to the Columbia Units 1 and 2 emissions reduction project?

- A. No. Each of the Applicants has indicated that it did not model increased spending
 on energy efficiency or DSM as an alternative to the proposed emissions
 reduction project beyond what is required by Act 141.³²
- Q. Is the failure to include additional spending on energy efficiency and/or DSM
 as one of the set of alternatives to the proposed emission reduction project
 prudent?
- A. No. Prudent planning would look at all cost-effective alternatives to the proposed
 emissions reduction project. From what I have seen, with only the minor

³¹ Energy Efficiency and Customer-Sited Renewable Resource Potential in Wisconsin for the Years 2012 and 2018. Energy Center of Wisconsin, August 2009, at pages EE-20 and EE-21.

³² See Exhibits 413 (DAS-4) MGE's Response to Data Request No. 2(MGE)-SC/INT-26.c, Exhibit 414 (DAS-15) WPSC's Response to Data Request No. 3(WPSC)-SC/INT-28 .c. and Exhibit 415 (DAS-16) WPL's Response to Data Request No. 2(WPL)-SC/INT-26.c.

exceptions noted above, the Applicants have focused on expensive, and in some
cases, very expensive, supply-side alternatives to the emissions reduction project.
It is unreasonable to focus on these expensive supply-side options without
considering that additional energy efficiency and DSM can offer less expensive
alternatives, at least in large part, to the expenditure of what the Applicants now
predict will be \$627 million for emissions control equipment at Columbia Units 1
and 2.

8 Q. To which options are you referring when you say that the Applicants have 9 considered some very expensive supply-side alternatives in their EGEAS 10 modeling?

11 A. The new nuclear plants that the Applicants made available to the EGEAS model 12 (and appear to have forced the EGEAS model to add in Futures 6 and 7) would be 13 very expensive alternatives even at the costs assumed by the Applicants. 14 Moreover, given the uncertainties associated with the construction cost and 15 schedules for any new nuclear power plants, the new nuclear units assumed by the Applicants in their EGEAS modeling can reasonably be expected to cost far more 16 17 and be available far later than the Applicants have assumed. This is especially true given (1) the nuclear industry's very poor record of projecting the 18 19 construction costs of the existing generation of nuclear power plants (i.e., nuclear plants actually cost 200 to 300 percent more than had been projected at the start of 20 21 construction), (2) the fact that no new nuclear units have been built in the United 22 States in decades, (3) the significant cost increases and regulatory delays that are 23 being announced to new nuclear plants that are already in the 24 licensing/construction pipeline and (4) the significant problems that have been 25 experienced by new nuclear plant construction projects overseas. It is very likely 26 that a new nuclear plant will cost significantly more than the Applicants have 27 assumed in their EGEAS modeling and that any new nuclear units in Wisconsin (or even outside the state but partly owned by Wisconsin utilities) will not be 28

1		available until after 2025, the first year that the Applicants have assumed such
2		units will be available.
3	Q.	Does this complete your testimony?
4	A.	Yes.
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		

BEFORE THE PUBLIC SERVICE COMMISSION OF WISCONSIN

) Joint Application of Wisconsin Power & Light Company, Wisconsin Public Service Corporation, and Madison Gas and Electric Company for a Certificate of Authority to Install Emissions Reductions Systems at the Columbia Energy Center Units 1 and 2

DOCKET NO. 05-CE-138

DIRECT TESTIMONY OF THOMAS SANZILLO ON BEHALF OF WISCONSIN CHAPTER OF THE SIERRA CLUB

PUBLIC VERSION CONTAINS REDACTED MATERIALS

September 25, 2009 **PUBLIC VERSION**

Table of Contents

INTRODUCTION
THE SHORT TERM COAL PRICE CLIMATE: PRB AND OTHER TYPES5
THE MID AND LONG-TERM COAL PRICE CLIMATE: PRB AND OTHER TYPES
THE APPLICANTS' PRB COAL PRICE FORECAST AND ASSUMPTIONS 16
A PRB BUSINESS PLAN

List of Exhibits

Exhibit 423 (TS-1)	Current Resume

- Exhibit 424 (TS-2) Smith Article (Wall Street Journal)
- Exhibit 425 (TS-3) Glustrom Study Excerpt
- Exhibit 426 (TS-4) Response of Wisconsin Power and Light Company to Sierra Club Discovery Request No. 1(WPL)-SC/INT-15, Attachment 1 [CONFIDENTIAL-SHARED WITH CO-OWNERS]
- Exhibit 427 (TS-5) Response of Wisconsin Power and Light Company to Sierra Club Discovery Request No. 1(WPL)-SC/INT-15, Attachment 2 [CONFIDENTIAL-NOT SHARED WITH CO-OWNERS]
- Exhibit 428 (TS-6) Excerpt from Response of Wisconsin Public Service Corporation to Sierra Club's Data Request No. 3(WPSC)-SC/RFP-16, Attachment Workpapers RFP 16 [CONFIDENTIAL-NOT SHARED WITH CO-OWNERS]

PUBLIC - Contains Redacted Materials

1 Introduction

2	Q.	What are your name, position and business address?
3	A.	My name is Thomas Sanzillo. I am Senior Associate at TR Rose Associates, Inc,
4		150 East 49 th Street, New York, New York, 10019.
5	Q.	Please describe TR Rose Associates, Inc.
6	А.	TR Rose Associates, Inc. is a public policy and finance consulting organization.
7		The organization has developed several areas of specialization including energy
8		policy, public finance and budgeting. TR Rose Associates clients include
9		foundations, non profits, business and labor organizations.
10	Q.	Please summarize your work experience and educational background.
11	A.	For the past twenty five years, I have served in a number of government finance
12		positions in the City and State of New York.
13		From 2002-2007, I served as the First Deputy Comptroller for the State of New
14		York. The State Comptroller is the equivalent of the chief financial officer, and
15		the first deputy is a constitutional officer charged with all operational
16		responsibilities of the Comptroller's office. The staff of the Comptroller's Office
17		is 2,400 employees, mostly accountants, auditors, investment and budget analysts,
18		attorneys, claims administrators, procurement experts and support personnel.
19		In this capacity I supervised the New York State Common Retirement Fund. The
20		Fund is a \$150 billion global fund with investments across a broad set of asset
21		classes. The Fund has considerable holdings in the energy industry.
22		The Comptroller also serves as the Chief Procurement Officer reviewing and
23		approving 44,000 contracts worth \$85 billion annually. These contracts cover all
24		aspects of government operations including: master service agreements between
25		public utilities and private energy companies, power plants, debt instruments for
26		public utilities and other contracts for the operation of energy functions of the
27		state and its public authorities.

1

PUBLIC - Contains Redacted Materials

1	The Comptroller supervises the design, fieldwork, report preparation and
2	recommendations for some 400 audits annually of state and local government and
3	public authorities. Audits and reviews during my tenure have been conducted on
4	power plant construction cost controls, management and operation of the New
5	York Power Authority in a changing deregulated market, the rate setting
6	mechanism used by the Long Island Power Authority, the budget and
7	procurement practices of public utilities, demand side efficiency programs and
8	internal controls and contracting processes of state research and development
9	agencies.

In addition to these reviews, other policy work resulted in a published report on
New York's deregulation effort: restructuring of the industry, new challenges for
the Public Service Commission, creation of a statewide power pool and the
impact on local property tax assessments and collections.

14The job also requires review and approval of a debt portfolio for local and state15governments of over \$200 billion – including approximately \$20 billion in energy16related authority debt. This includes the review, approval and monitoring of the17largest public borrowing in the nation's history for the decommissioning of the18LILCO nuclear power plant and the purchase of it by the publicly owned Long19Island Power Authority.

As the chief accountant for the State of New York the Comptroller is also responsible for the annual audit. The State Comptroller also oversees the accounting and fiscal affairs 1700 units of local government.

- 23 Since September 2007 TR Rose Associates has been retained by several
- 24 environmental organizations to review the financial assumptions of coal-fired
- 25 power plants. Our organization has reviewed proposals and prepared expert
- 26 testimony before the Iowa Utility Board (In Re: Interstate Power and Light
- 27 Company: GCU-07-1 and RPU-08-01); and public reports and statements in
- 28 South Carolina, Kentucky, New Jersey, Ohio and Texas related to coal plants and

		PUBLIC - Contains Redacted Materials
1		what impact the price of coal had on the financial feasibility of the proposed
2		plant.
3		I hold a Bachelor of Arts degree in Politics from the University of California at
4		Santa Cruz.
5		A copy of my current resume is attached as Exhibit 423 (TS-1).
6	Q.	On whose behalf are you testifying in this case?
7	A.	I am testifying on behalf of the Wisconsin Chapter of the Sierra Club. ("Sierra
8		Club")
9	Q.	Have you testified previously before the Public Service Commission of
10		Wisconsin ("PSCW")?
11	А.	No.
12	Q.	What is the purpose of your testimony?
10		
13	A.	TR Rose was asked by the Sierra Club to assist in reviewing whether the proposed
13 14	А.	TR Rose was asked by the Sierra Club to assist in reviewing whether the proposed additions are economically sound and should be approved. In particular, TR Rose
13 14 15	A.	TR Rose was asked by the Sierra Club to assist in reviewing whether the proposed additions are economically sound and should be approved. In particular, TR Rose was asked to examine: (1) the reasonableness of the assumptions used by the
13 14 15 16	A.	TR Rose was asked by the Sierra Club to assist in reviewing whether the proposed additions are economically sound and should be approved. In particular, TR Rose was asked to examine: (1) the reasonableness of the assumptions used by the Applicants to establish the coal price forecast in the application, and, (2) evaluate
13 14 15 16 17	А.	TR Rose was asked by the Sierra Club to assist in reviewing whether the proposed additions are economically sound and should be approved. In particular, TR Rose was asked to examine: (1) the reasonableness of the assumptions used by the Applicants to establish the coal price forecast in the application, and, (2) evaluate the reasonableness of any data, or datasets used by the Applicants as they
13 14 15 16 17 18	A.	 TR Rose was asked by the Sierra Club to assist in reviewing whether the proposed additions are economically sound and should be approved. In particular, TR Rose was asked to examine: (1) the reasonableness of the assumptions used by the Applicants to establish the coal price forecast in the application, and, (2) evaluate the reasonableness of any data, or datasets used by the Applicants as they prepared the coal forecast.
13 14 15 16 17 18 19	А. Q.	 TR Rose was asked by the Sierra Club to assist in reviewing whether the proposed additions are economically sound and should be approved. In particular, TR Rose was asked to examine: (1) the reasonableness of the assumptions used by the Applicants to establish the coal price forecast in the application, and, (2) evaluate the reasonableness of any data, or datasets used by the Applicants as they prepared the coal forecast. What is the basic point of the testimony?
13 14 15 16 17 18 19 20	А. Q. А.	 TR Rose was asked by the Sierra Club to assist in reviewing whether the proposed additions are economically sound and should be approved. In particular, TR Rose was asked to examine: (1) the reasonableness of the assumptions used by the Applicants to establish the coal price forecast in the application, and, (2) evaluate the reasonableness of any data, or datasets used by the Applicants as they prepared the coal forecast. What is the basic point of the testimony? The next forty years of the coal industry – its mining, marketing, trading, use,
 13 14 15 16 17 18 19 20 21 	А. Q. А.	 TR Rose was asked by the Sierra Club to assist in reviewing whether the proposed additions are economically sound and should be approved. In particular, TR Rose was asked to examine: (1) the reasonableness of the assumptions used by the Applicants to establish the coal price forecast in the application, and, (2) evaluate the reasonableness of any data, or datasets used by the Applicants as they prepared the coal forecast. What is the basic point of the testimony? The next forty years of the coal industry – its mining, marketing, trading, use, disposal, and most of all its price dynamics – will not be like the last forty.
 13 14 15 16 17 18 19 20 21 22 	А. Q. А.	 TR Rose was asked by the Sierra Club to assist in reviewing whether the proposed additions are economically sound and should be approved. In particular, TR Rose was asked to examine: (1) the reasonableness of the assumptions used by the Applicants to establish the coal price forecast in the application, and, (2) evaluate the reasonableness of any data, or datasets used by the Applicants as they prepared the coal forecast. What is the basic point of the testimony? The next forty years of the coal industry – its mining, marketing, trading, use, disposal, and most of all its price dynamics – will not be like the last forty. Although recent coal prices have declined, industry analysts and market data tell

¹ The Powder River Basin (PRB) is in northeastern Wyoming and southern Montana between the Wind River and the Black Hills. The region has significant reserves of sub-bituminous coal. Low mining costs, combined with low sulfur content have led to a rapid increase in production from the region, especially in the last several decades. It is the country's predominant coal producer supplying upwards of 46% of the

	PUBLIC - Contains Redacted Materials
1	percent, and perhaps more, between 2009 and 2012. Coal from the PRB is
2	expected to be the primary source of coal for Columbia Units 1 and 2, the power
3	plants under consideration in this proceeding.
4	Thereafter, the price environment for Powder River Basin coal will continue to
5	rise significantly due to new industry cost pressures as mining becomes more
6	complex and expensive and as large coal producers cultivate a worldwide base of
7	users.
8	Domestically, coal producers will use PRB's low price to capture a larger portion
9	of the energy market. Further success with this strategy will place additional
10	upward pressure on prices and hasten the depletion of PRB mines as an energy
11	resource. As a result, future PRB coal supplies come with heightened risks
12	regarding supply availability. In fact, recent indications from the United States
13	Geological Survey (USGS) and industry leaders have raised red flag warnings
14	about long term supply sufficiency in the Powder River Basin.
15	These price pressures are structural in nature and will redefine the nation's coal
16	markets going forward making prices less responsive to the normal patterns of
17	domestic business cycles. This will further erode coal's competitive edge with
18	other power generation fuels.
19	The Applicants in this proceeding have adopted a coal price estimate that employs
20	a straightforward application of a government forecast model for Powder River
21	Basin coal. In the current environment, and for the foreseeable future, this
22	approach is fatally flawed. The forecast model relied upon to produce the
23	Applicants' assumption that PRB coal will increase in price
24	is plagued by an exceptionally high error rate. This model
25	alone is insufficient. In addition, as I will show below, credible evidence indicates

nation's coal. The sub-bituminous nature of the coal means that the coal has a 25-35% lower heat content than coal from bituminous mines. Most of the coal produced in the region is moved out by two railroads owned by either Union Pacific or Burlington Northern Santa Fe.

	DIG	ter restiniony of rhomas Sanzino
		PUBLIC - Contains Redacted Materials
1		that the price of PRB coal will rise at a rate considerably higher than
2		annual rate assumed by the Applicants.
3	The	Short Term Coal Price Climate: PRB and Other Types
4	Q.	What are the most significant short term factors currently having an
5		influence on the coal industry?
6	А.	In the short term the coal industry is being influenced by a multitude of factors.
7		First, the recession in the United States and global economic slowdown has
8		diminished the world wide demand for both metallurgical and thermal coal. There
9		is currently weakened demand for coal as a component in the process of steel
10		production (metallurgical steel), and a slowing of coal demand for electricity. ² In
11		the face of diminished demand coal producers in the United States have curtailed
12		production.
13		Although estimates for total 2009 United States production levels are loose at this
14		point, some industry analysts suggest that domestic production could be down
15		between 100 and 150 million tons in 2009. ³ According to the Energy Information
16		Administration, United States mines produced 1.17 billion tons of coal in 2008. ⁴
17		Second, the price of natural gas has declined precipitously. ⁵ For those areas of the
18		country, like Wisconsin, ⁶ where the electric grid is served by both coal and
19		natural gas (and other fuels), grid managers make choices regarding which power
20		generation source to use, in part, based on the current price of fuel. As the cost of
21		natural gas decreases, it becomes less expensive relative to a coal plant, and vice
22		versa. The calculation to determine at what point natural gas becomes less

² Smith, Rebecca, *Electricity Prices Plummet*, Wall Street Journal, August 12, 2009

³ Coal and Energy Price Report, U.S. production likely to shed 100 million tons-plus, but will even that be enough?, Volume 11, No. 33. July 10, 2009.

⁴ <u>www.eia.doe.gov/cneaf/coal/weekly/weekly.html/archmonth.html</u>, 2008 (Archival Monthly Coal Files)

⁵ Krauss, Clifford, *Natural Gas Prices Plummet to a Seven-Year Low*, New York Times, August 20, 2009.

⁶ While coal and nuclear power dominate Wisconsin's power grid, natural gas does provide approximately 6.5% of its generation. Energy Information Agency, *Wisconsin, State Energy Profile,* http://tonto.eia.doe.gov/state/state_energyprofiles.cfm?side=WI.

	PUBLIC - Contains Redacted Materials
1	expensive than coal is complicated. ⁷ However, the current magnitude of the
2	decrease in the price of natural gas prices has made it clear that natural gas is
3	highly competitive in most places around the country. One industry analyst put
4	the issue this way:
5 6 7	If natural gas prices remain at low levels, coal's market share will continue to be sliced by what most in the industry believe is a fairly significant margin. ⁸
8	The third factor influencing the market currently is a series of coal industry
9	acquisitions – one coal company buying another, and one company buying
10	another's mining assets. These actions are being taken by companies that are
11	currently financially strong and can look to buy assets when the market is low and
12	coal prices are weak. Most notably, Arch Coal has purchased the Jacobs Ranch
13	mine (a Wyoming – PRB property) from Rio Tinto ⁹ and Alpha Natural Resources
14	purchased Foundation Coal, a major supplier of PRB coal, to create one of the
15	largest coal producers in the country. ¹⁰
16	A fourth factor influencing the dominant producers of coal in the United States is
17	the role of their international sales and holdings on their balance sheets. A review
18	of the second quarterly statement of Peabody Energy, for example, highlights how
19	the company looks to Asia and India to grow its asset base (an asset base
20	originally created in the United States) in order to stabilize its balance sheet. ¹¹
21 22	"Emerging Asia holds the world's fastest-growing economies, and those economies are fueled by coal. As the Pacific markets far outpace

⁷ For a detailed discussion of the methodological issues involved see: Doyle Trading Associates and Hill and Associates, Inc., *The Coal Trading Handbook, 2007 Edition, An Insider's Guide to Coal Trading and the Coal Industry,* March 2007., pps. 3-26 through 3-29.

⁸ Coal and Energy Price Report, *Market Commentary*, Volume 11, No. 141, July 22, 2009.

⁹ Arch Coal, Inc., *Bank of America Merrill Lynch 2009 Global Metals and Mining Conference*, Barcelona, Spain, May 13, 2009, pps 7-8. This particular purchase created some fears in the buyer community concerning Arch's dominance and market control in the PRB region, see: Coal and Energy Price Report, *PRB Consumers eye future more than present in questioning Arch/Rio deal*, Volume 11, no. 49, March 11, 2009.

¹⁰ Alpha Natural Resources, *Alpha Resources and Foundation Coal Holdings Complete Merger, Creating One of Americas Largest Coal Producers*, July 31, 2009.

¹¹ Peabody Energy, Second Quarter News Release, July 21, 2009.

	PUBLIC - Contains Redacted Materials
1	other major economies, Peabody has the best leverage, and the
2	majority of our focus and investments will be in these key regions.
3	Based on current trends in the Pacific markets, we expect to increase
4	our Australia metallurgical and thermal coal sales in 2010, using
5	existing capacity."
6	Massey Energy similarly describes how its product – Central Appalachian coal –
7	is well-positioned for international markets. ¹²
8	In spite of the current weak market conditions, Massey continues to
9	believe the following factors will contribute to a supply/demand
10	balance that is favorable to Central Appalachian coal producers in the
11	long-term.
12	• The quality of Central Appalachia coal allows it to enjoy
13	significant market diversity and its proximity to sea ports
14	makes it a viable source of coal to fill the growing demand for
15	energy throughout most of the world.
16	• Economic expansion continues in the world's largest
17	developing countries. In the longer-term, this economic
18	development will drive higher demand for steel and sustain the
19	global demand for metallurgical coal
20	
21	The reduced demand for coal in the US due to cutbacks in steel production and
22	reduced use of electricity (coupled with very low natural gas prices) has forced
23	down the price of coal for the short run. It is unclear what, if any, impact
24	consolidations in the industry have had on short term pricing. Acquisitions tend to
25	position businesses to take advantage of future growth. And, finally, the global
26	reach of the larger US coal producers has maintained their solvency in the short
27	term.

¹² Massey Energy, *First Quarter Highlights*, (News Release), April 28, 2009.

PUBLIC - Contains Redacted Materials

1 Q. What impacts are these short term factors having on the price of coal in

2 general in the United States, and PRB coal in particular?

- A. Table 1 shows that the price of coal has risen sharply, and dropped just as
- 4 precipitously, over the past two years. The dynamic is true for all forms of coal
 5 across the country.
- 6

Table 1

Average Weekly Spot Price of Coal¹³

7 8

Type of Coal	07/13/07	07/11/08	07/10/09
Central Appalachian	\$45.60	\$134.55	\$52.30
Northern Appalachian	45.25	138.00	46.50
Illinois Basin	31.50	70.00	41.00
Powder River Basin	9.15	14.00	8.75

9

10

11 The Mid and Long-Term Coal Price Climate: PRB and Other Types

12

Q. What are middle and longer term factors influencing the coal industry in the United States?

- A. There are multiple long term factors that are having an impact on the coal industry
 and the long term price of coal. Some of those factors will grow from the short
 term issues already discussed, and some have broader implications. These longer
 term factors generally point to higher prices.
- 19 First, there are generalized indications of economic recovery taking place both
- 20 domestically and internationally. According to Federal Reserve Chairman Ben
- 21 Bernanke, "prospects for a return to growth in the near term appear good".¹⁴ My
- 22 analysis has followed a number of coal industry reports with similar notes of

¹³ Energy Information Agency, *Coal: Average Weekly Coal Spot Prices, Business Week Ended,* www.eia.doe.gov

	PUBLIC - Contains Redacted Materials
1	optimism suggesting strength in both international and domestic steel markets and
2	some interest among domestic coal users in the electric utility industry. ¹⁵
3	Second, coal industry officials believe that 16 GW of electricity will come on line
4	in the next four years from new coal plants. These additions to the nation's energy
5	grid are expected to add 55 million tons of new demand for coal, half of which is
6	expected to be contracted from mines in the Powder River Basin. ¹⁶
7	Third, coal industry officials see support for coal in the economic stimulus
8	legislation including Future Gen, various Clean Coal initiatives, carbon capture
9	and storage legislation and new transmission upgrade benefits as evidence of
10	continued federal support for coal's future. ¹⁷
11	Fourth, the largest coal producers in the United States are increasingly looking
12	beyond the borders of the United States to market and trade coal. Arch Coal and
13	Peabody, two of the largest players in the Powder River Basin, are increasingly
14	building their shareholder value strategies on global coal. Within the United
15	States, this hinges on a robust market that: a) exports considerable tonnage of
16	Central Appalachian (CAPP) and Northern Appalachian (NAPP) coal to Europe
17	at premium prices; b) furthers the trend of PRB coal's penetration into eastern
18	markets in the United States ¹⁸ ; and c) generates profits that allow for investment
19	in PRB exports to China. ¹⁹
20	Fifth, there is some indication that the price of natural gas may remain relatively
21	low. Recent reports suggest that the nation's long-term supply of natural gas is

¹⁴ Bernanke, Ben, *Speech at Annual Economic Symposium*, Federal Reserve Board of Kansas City, Jackson Hole, Wyoming, August 21, 2009.

¹⁵ Coal and Energy Price Report, *Signs emerge to suggest coal markets have a chance to improve – eventually*, Volume 11, no. 151, August 5, 2009.

¹⁶ Arch Coal, Inc., *Bank of America Merrill Lynch 2009 Global Metals and Mining Conference*, Barcelona, Spain, May 13, 2009.

¹⁷ Peabody Energy, *RBC 2009 Global Energy and Power Conference*, June 1-2, 2009, p. 15.

¹⁸ Doyle Trading Consultants, LLC and Hill and Associates, Inc., *The Coal Trading Handbook: 2007 Edition*, March 2007, I-32.

¹⁹ Tomich, Jefferey, *From Afar, Arch Eyes Opportunity China*, St. Louis Post-Dispatch, November 25, 2008.

1		PUBLIC - Contains Redacted Materials 35% higher then expected. ²⁰ The long-term impact of this disclosure is unclear,
2		however an increase in supply of natural gas, coupled with the its relative
3		environmental benefits compared to coal, may provide natural gas with a
4		competitive advantage going forward, depressing coal prices.
5	Q.	How are the markets looking at coal generally and PRB specifically in the
6		medium term?
7	А,	The New York Mercantile Exchange (NYMEX) provides a trading platform for
8		three types of coal futures contracts. This trading platform provides those who are
9		buying and selling PRB coal with a risk management tool. It also provides energy
10		planners with a rough guide to understanding coal price futures. Current NYMEX
11		coal futures are shown in Table 2.
12		Table 2

- 13
- **Futures Price Increases**²¹

14

NYMEX Clear Port (dollars per ton)

Type of Coal	October 2009	October 2011	October 2012
CAPP Coal Futures	\$44.13	\$66.45	\$69.37
Eastern Rail CSX	48.34	63.91	n/a
West Rail PRB	6.74	10.98	n/a

15

16 According to the NYMEX:

- In general the price of coal is likely to rise over the next two years, and
 it is likely to increase by double digits in both years.
- CAPP coal is likely to increase by 51% over the next two years, or
 20 23% per year.

²⁰ Mouawad, Jad, *Estimate Places Natural Gas Reserves 35% Higher*, New York Times, June 18, 2009.

²¹ New York Mercantile Exchange, OTC Settlement Data, September 8, 2009. www.nymex.com/settle_fut_otc.aspx,

	Dire	
		PUBLIC - Contains Redacted Materials
1		• Eastern Rail coal is likely to increase by 32%, or 15% annually.
2		• Powder River Basin is likely to increase by 63%, or 31.5% annually.
3	Q.	Are there any other price indicators currently available?
4	A.	Yes. Peabody Energy has published slightly longer-term projections of Powder
5		River Basin coal prices. ²² The company projects June 2009 PRB prices at \$8.23
6		per ton rising to \$14.10 in 2012. This is a 71% increase over a three period or a
7		20% annual increase in the price of PRB coal.
8	Q.	Are there any emerging factors that will create additional risk for coal-fired
9		power plants?
10	A.	Yes. For many decades coal has been seen as a cheap, reliable and abundant
11		supply of fuel for the nation's electricity and other needs. America's coal reserves
12		have often been compared to Saudi Arabia's oil fields because of its purported
13		abundance. It has often been quoted that the coal reserves in the United States will
14		serve the country for the next 250 years. As the country works toward a consensus
15		on energy policy, many long-held assumptions are being tested, including the
16		depth and reliability of the nation's coal reserves.
17		Government officials have recently determined that the methods they use to
18		determine the size, quality and economic utility of existing coal reserves are not
19		reliable. One study, conducted by the United States Geological Society (USGS),
20		released in 2008 called into question the fundamental premise that coal reserves
21		would be available at economically feasible prices. ²³ In that study, the USGS
22		recognized that the methods used to determine the size, quality and economic
23		utility of existing coal reserves are not reliable.

 ²² Peabody Energy, *Op Cit*, p.7
 ²³ United States Geological Society, *Assessment of Coal Geology, Resources and Reserves in the Gillette Coalfield, Powder River Basin, Wyoming,* Open-File Report: 2008-102. http://pubs.usgs,gov/of/2008/1202/

PUBLIC - Contains Redacted Materials

1	The USGS study has raised many questions, but perhaps most important for this
2	proceeding, is that it focused on the Powder River Basin's Gillette mines. The
3	USGS concluded that the useful life of these mines, from an economic standpoint,
4	is about 22 years. This represents 6% of the useful life of the mine that had been
5	projected prior to the 2008 USGS study.
6	The abstract to the study states:
7	The Gillette coalfield, within the Powder River Basin in east-central
8	Wyoming, is the most prolific coalfield in the United States. In 2006,
9	production from the coalfield totaled over 431 million short tons of
10	coal, which represented over 37 percent of the Nation's total yearly
11	production. The Anderson and Canyon coal beds in the Gillette
12	coalfield contain some of the largest deposits of low-sulfur
13	subbituminous coal in the world. By utilizing the abundance of new
14	data from recent coal bed methane development in the Powder River
15	Basin, this study represents the most comprehensive evaluation of coal
16	resources and reserves in the Gillette coalfield to date. Eleven coal
17	beds were evaluated to determine the in-place coal resources. Six of
18	the eleven coal beds were evaluated for reserve potential given current
19	technology, economic factors, and restrictions to mining. These
20	restrictions included the presence of railroads, a Federal interstate
21	highway, cities, a gas plant, and alluvial valley floors. Other
22	restrictions, such as thickness of overburden, thickness of coal beds,
23	and areas of burned coal were also considered.
24	The total original coal resource in the Gillette coalfield for all eleven
25	coal beds assessed, and no restrictions applied, was calculated to be
26	201 billion short tons. Available coal resources, which are part of the
27	original coal resource that is accessible for potential mine development
28	after subtracting all restrictions, are about 164 billion short tons (81
29	percent of the original coal resource).
30	Recoverable coal, which is the portion of available coal remaining
31	after subtracting mining and processing losses, was determined for a
32	stripping ratio of 10:1 or less. After mining and processing losses were
33	subtracted, a total of 77 billion short tons of coal were calculated (48
34	percent of the original coal resources).
35	Coal reserves are the portion of the recoverable coal that can be mined,
36	processed and marketed at a profit at the time of the economic
37	evaluation. With a discounted cash flow at 8 percent rate of return, the
38	coal reserves estimate for the Gillette coalfield is 10.1 billion short

	PUBLIC - Contains Redacted Materials
1	tons of coal (6 percent of the original resource total) for the 6 coal
2	beds.
3	In response to the United States Geological Survey and industry discussion on this
4	matter the Wall Street Journal ran a lengthy piece covering industry opinion on
5	the issue. ²⁴
6	Every year, federal employee George Warholic calculates America's
7	vast coal reserves the same way his predecessors have for decades: He
8 9	looks up the prior year's coal-reserve estimate, subtracts the year's nationwide production and arrives at a new official tally
,	hadon whee production and antives at a new official any.
10	Coal provides nearly one-quarter of the total energy consumed in the
11	U.S., and by Mr. Warholic's estimate, the country has enough in the
12	ground to last about 240 years. A belief in this nearly boundless supply
13	has led officials to dub the U.S. the "Saudi Arabia of Coal."
14	But the estimate, recent findings show, may be wildly overconfident.
15	While there is almost certainly as much coal in the ground as Mr.
16	Warholic's Energy Information Administration believes, relatively
17	little of it can be profitably extracted. Last year, the U.S. Geological
18	Survey completed an extensive analysis of Wyoming's Gillette coal
19	field, the nation's largest and most productive, and determined that
20	less than 6% of the coal in its biggest beds could be mined profitably,
21	even at prices higher than today's
22	In the field, challenges are becoming more apparent. Mining
23	companies report they have to dig deeper and move more earth to
24	extract coal from aging mines, driving up costs. Utilities have grown
25	skittish about whether suppliers can ship promised coal on time.
26	American Electric Power Co., the nation's biggest coal buyer, says it
27	has stepped up its due diligence to make sure its suppliers can make
28	deliveries after some firms missed shipments last fall. It even bought a
29	mine to lock down supplies.
30	"We are very much concerned, and it's getting worse," said Tim Light,
31	senior vice president for AEP
32	The agency [USGS] began with the Powder River's rich Gillette coal
33	field, an 80-mile-long strip in northeastern Wyoming that contains the

²⁴ Ex. 424 (TS-2) Smith, Rebecca, U.S. Forsees a Thinner Cushion of Coal, Wall Street Journal, June 8, 2009

	PUBLIC - Contains Redacted Materials
1	nation's 10 top-producing mines. About one-third of all coal in the
2	country is produced there. Some 1.2 million short tons leave the field
3	daily, a river of coal filling more than 75 trains of 125 to 150 cars
4	each.
5	For the Gillette study, USGS engineers, geologists and economists
6	spent three years analyzing data from 10,200 drill holes, the most
7	comprehensive study ever attempted of the region. The team
8	concluded there are 201 billion short tons of coal in the Gillette field.
9	Environmental rules and physical challenges put much of that out of
10	reach, leaving what they figured were 77 billion short tons of
11	recoverable coal.
12	Little is presently worth mining. Analyzing coal beds that contained
13	82% of the Gillette deposits, the team determined that with coal selling
14	for \$10.50 a ton, the prevailing price two years ago, less than 6% of
15	the coal could be extracted profitably enough to leave mining
16	companies an 8% rate of return.
17	If Powder River prices were to hit \$60 a ton in current dollars, as much
18	as 47% could be extracted. But at that price, coal would have a tough
19	time competing with other fuels and technologies
20	The findings are percolating through the coal and power industries.
21	"USGS made a leap forward with this study," says Vic Svec,
22	spokesman for Peabody Energy Resources, the U.S.'s biggest coal
23	company. He adds that when his company plugs in prices as the USGS
24	study did, it reaches similar conclusions
25	Even at the Gillette field, where surface mining started around 1924
26	and production still is buoyant, obstacles are emerging.
27	Coal at its [sic] Gillette's eastern edge lies mostly close to the surface
28	but the seams generally slope downward in a westerly direction,
29	forcing miners to dig progressively deeper to extract it. At Arch Coal's
30	Black Thunder mine, five pits are moving westward and will intersect
31	the main Burlington Northern-Santa Fe railroad line at some point.
32	Arch then will have to move heavy equipment to the other side of the
33	tracks and dig a new pit down several hundred feet, which it says
34	could cost \$100 million or more.
35	Coal's big buyer, the power industry, has grown increasingly nervous
36	about securing reliable suppliers for power plants that often have a
37	useful life of 50 or 60 years. Plants fine-tune their equipment to burn
38	the coal they expect to receive and to remove its particular pollutants
39	from the waste stream. That makes it problematic to switch suppliers.

PUBLIC - Contains Redacted Materials 1 A professional review of the literature on coal reserves makes a similar point: 2 The 10.1 billion tons of economically accessible coal noted in USGS 2008-1202 would last about 22 years at the present rates of production 3 4 of approximately 454 million tons of coal per year. This estimate of 5 economic coal reserves assumes that all of the 10.1 billion tons is 6 accessed and the production of coal from the Powder River Basin 7 doesn't change. Both of these assumptions are rather questionable as 8 there are significant legal and economic issues related to coal mine 9 operation and expansion. Also, as mines play out in other parts of the 10 country, an increasing percentage of the country's coal is likely to 11 come from the Powder River Basin.²⁵ 12 The United States Geological Survey report, the industry commentary in the Wall 13 Street Journal, and the Glustrom study, all conclude there is now uncertainty 14 regarding the size of the nation's economically recoverable coal reserves. 15 The Gillette study is significant because the estimated reserve that is now 16 considered economically recoverable is dramatically lower than originally 17 projected. In addition, the mines involved currently provide a significant portion 18 of the nation's annual coal production. 19 20 21 22 Recognizing the impact of decreased supply, AEP, a large utility, has exercised an 23 option to own a mine in order to control its own supply of coal. This is not an 24 option that small and mid sized utilities have at their disposal. The Applicants in 25 this proceeding are not in a position to hedge the increasing price of coal by 26 purchasing a mine. 27 The issue, as it has been developed thus far, leaves energy professionals with no 28 reliable understanding of the nation's coal reserves. The formal method for

²⁵ Ex. 425 (TS-3) Glustrom, Leslie, *Coal: Cheap and Abundant...Or Is It?*, Version 1.1, February 2009. The Glustrom study contains an exhaustive recounting of the history of the methodologies and seminal studies used to guide United States policy on the topic of coal reserves.

PUBLIC - Contains Redacted Materials

- 1 estimating recoverable reserves, previously used by government and industry, is
- 2 no longer useable. This issue creates a new area of risk when performing due
- 3 diligence on coal plant investments.²⁶

4 The Applicants' PRB Coal Price Forecast and Assumptions

5 Q. How does this general background on coal price dynamics relate to the

6 **Columbia emissions control project?**

7	А.	
8		27
9		
10		
11		
12		
13		
14		
15		29
16		
17		
18		
19		

²⁶ The Glustrom study offers some practical guidance to energy professionals engaged in the due diligence process of selecting among energy options. Glustrom suggests the following questions be explored: 1) What mines are supporting the power plants in my state or region?; 2) What is the expected life span of these mines?; 3) What expansion plans do these mines have? 4) What geologic, economic or legal constraints might exist to future mine expansion?, and, 5) What plans, if any, does my utility, industry or state need to make in the face of possible long-term constraints on coal supply? See: Glustrom, *Op Cit*, p. 62.

²⁷ Ex. 426 (TS-4). File: 1(WPL)-SC-INT-15 Att 1 – CONFIDENTIAL.pdf. [CONFIDENTIAL: SHARED WITH CO-APPLICANTS])

²⁸ Ex. 427 (TS-5). File: 1(WPL)-SC-INT-15 Att 2 - CONFIDENTIAL.pdf [CONFIDENITAL: (WPL) NOT SHARED WITH CO APPLICANTS]

²⁹ Ex. 428 (TS-6). Wisconsin Public Service Corporation's Response to No. 3(WPSC)-SC/RFP-16, from disc "3-SC WPSC Response – CONFIDENTIAL-NOT SHARED WITH CO-OWNERS." EIA rates tab,

Columbia Units 1 and 2 Docket No. 05-CE-138 **Direct Testimony of Thomas Sanzillo** PUBLIC - Contains Redacted Materials 1 2 3 4 5 6 7 8 9 10 11 12 13 14 Is there adequate support for using the 15 **Q**. assumption in the 16 **EGEAS modeling?** No. On an annual basis the Energy Information Agency publishes an evaluation 17 A. 18 that compares EIA's projected versus actual coal prices to electric generating 19 plants. The most recent report states that between 1982 and 2008 the Annual 20 Energy Outlook has an average absolute percent "point difference" of 44.5%.³⁰ 21 While there may be many factors that go into a discussion of an error rate of 22 44.5%, taken alone, the EIA forecast cannot be taken as an authoritative source. 23 Here is how one leading coal expert characterizes EIA data and how it needs to be

24 handled by those who are active decision makers in the industry:

EIA Annual Energy Outlook escalation data (release date full report: June 2008. [CONFIDENTIAL: (WPSC) NOT SHARED WITH CO APPLICANTS], pp. 1-4).

³⁰ DOE/EIA, Annual Energy Outlook Retrospective Review: Evaluation Projections in Past Editions (1982-2008), Table 2., (DOE/EIA-0640(2008), September 2008.

1 2 3 4 5 6 7 8		PUBLIC - Contains Redacted Materials The poor coal sector has the weekly Energy Information Agency coal production estimate, which comes with the guarantee of a significant quarterly revision – eight weeks after the quarter has ended. (Note: EIA revisions are based on the Mine Safety and Health Administration quarterly mine data.) Other data from the EIA is too stale to use. Coal burn by utility comes with a 3-month delay. Coal stocks – also 3 months late – are published for regions, but not for specific plants.
9 10 11		The EIA is of interest to market historians; Genscape (an industry based information source) data is a critical tool for market traders and analysts. ³¹
12		The preference is for industry-based, real-time, decision-oriented information for
13		the purpose of investment and energy planning.
14	Q.	Has any such information been submitted in this application, and what does
15		it tell us?
16	A.	Some data have been provided, but they have limited value. The broader
17		background discussion thus far indicates annual
18		
19		
20		
21		
22		
23		
24		
24		
24		
24 25 26		
24 25 26 27		
24 25 26 27 28		
24 25 26 27 28 29		

Columbia Units 1 and 2 Docket No. 05-CE-138 Direct Testimony of Thomas Sanzillo PUBLIC - Contains Redacted Materials

However, in order to adequately understand how a particular contract fits into the
overall business strategy of each of the applicants, a comprehensive review of all
the relevant coal contracts of each Applicant, including the producers, contract
terms, quantities, heat content, prices, timing and additional provisions of these
contracts as well as an understanding of the business strategies involved by utility
managers, would be required. This information has not been produced as of the
date of this filing.

16 Q: What can you conclude from your review of documentation produced by17 the Applicants?

A: While the applicants have not provided sufficient information to account
for the many variables that influence the overall rate of growth in coal prices over
time,

and based on the new information from USGS we
expect these increases to escalate further.

23

7

8

25

24

³¹ Doyle Trading Consultants, *Op Cit*, 1-53.



- ³² Response of Wisconsin Power and Light Company to Sierra Club Discovery Request No. 1(WPL) SC/RFP-2. File attachment: "RIO102_Confidential (Not Shared with Co-Applicants).pdf"
- ³³ Response of Wisconsin Power and Light Company to Sierra Club Discovery Request No. 1(WPL)-SC/RFP-2. File attachment: "RIO097_Confidential (Not Shared with Co-Applicants) pdf"
- ³⁴ Response of Wisconsin Power and Light Company to Sierra Club Discovery Request No. 1(WPL)-SC/RFP-2. File attachment: "ARCH091 Confirm_Confidential (Not Shared with Co-Applicants).pdf"

³⁵ Response of Wisconsin Power and Light Company to Sierra Club Discovery Request No. 1(WPL)-SC/RFP-2. File attachment: "FND091_Confidential (Not Shared with Co-Applicants).pdf"

PUBLIC - Contains Redacted Materials



³⁶ Response of Wisconsin Power and Light Company to Sierra Club Discovery Request No. 1(WPL)-SC/RFP-2. File attachment: "RIO094 Confidential (Not Shared with Co-Applicants).pdf" ³⁷ Response of Wisconsin Power and Light Company to Sierra Club Discovery Request No. 1(WPL)-SC/RFP-2. File attachment: "RIO093_Confidential (Not Shared with Co-Applicants).pdf" ³⁸ Response of Wisconsin Power and Light Company to Sierra Club Discovery Request No. 1(WPL)-SC/RFP-2. File attachment: "RIO096_Confidential (Not Shared with Co-Applicants).pdf" ³⁹ Response of Wisconsin Power and Light Company to Sierra Club Discovery Request No. 1(WPL)-SC/RFP-2. File attachment: "PBDY101_Confidential (Not Shared with Co-Applicants).pdf"

.

	PUBLIC - Contains Redacted Materials							
1								
2	Q.	Is there any other factor that should be considered?						
3	A.	Yes.						
4		The current life expectancies of those mines are as follows:						
5		Table 4						
6		Life Expectancy of Mines Currently Providing Coal 40						
7]	Mine	Life Expectancy (yrs.)			
					10.4			
					10.0			
					10.6			
					9.0			
8					14.4			
0								
9		According to the Glustrom study, the data on mine life expectancy needs to be						
10		interpreted very carefully.						
11		Many of th	ne maior i	mines in the l	Powder River Bas	sin have	• 10-15 years	
12		of life span remaining (at current rates of production) and are presently						
13		applying to lease more of the federally owned coal in hopes of mine						
14		expansion. The application to lease more federal coal is accompanied						
15		by the preparation of an Environmental Impact Statement ("EIS")						
16		prepared by the Bureau of Land Management ("BLM") in the United						
I7		States Department of the Interior. These Bureau of Land Management						
18		EIG S provide estimates of existing life span for the Powder Kiver Basin mines as well as the expected life span extensions if the lasse of						
20		federal coal is approved and the mine expansion is approved by the						
21		State of Wyoming. ⁴¹						

 $^{^{40}}$ Glustrom, *Op Cit*, p. 57. Public information was not readily available for all mines. 41 Ibid

PUBLIC - Contains Redacted Materials

- 1 The data developed through this analysis by the agencies show that there will be 2 fundamental change in mine source in fifteen or twenty years, if not sooner. This 3 comes with a financial risk that is not acknowledged in the application.
- 4 **A PRB Business Plan**

5 Q. How could the new coal landscape be better addressed in this application?

6 A. The Applicants' assumptions undergirding their fuel price forecasts ignore the last 7 five years of experience. The Applicants ignore the fact that coal supply is now 8 subject to a global market and the price signals from recent market volatility and 9 new findings related to coal reserves. The Applicants' supply and price forecasts 10 are, therefore, unrealistic. The Applicants should be required to submit to the 11 Commission a coal source risk management analysis addressing both short and 12 long term issues related to current dynamics in the mining industry, mining costs, 13 mine capacity, reserve measures, coal contracts, coal purchase strategy, coal 14 prices, transportation and some analytical conclusions regarding how MGE, WPL, 15 and WPS will fare in the coming years.

- 16 There is no substitute currently available that provides better information than the 17 Applicants' own market experience with the coal producers. A systematic 18 analysis of that data is needed. The EIA data can only assist in such an 19 undertaking; it is not a substitute for one. Such analysis would benefit from 20 comprehensive data regarding prior contract performance from the specific coal 21 producers for which WPL submitted contract data in this case. This would 22 include, at minimum, price and performance analysis. The facts, analysis and 23 conclusions should then be used to update the EGEAS model and the analysis that 24 flows from it.
- Absent such a study, the Commission is left with only formulaic projections that are, at best, rough approximations of future performance based on some rough approximation of past performance. Recent information and USGS analysis, however, further undermines the assumptions made by the applicants.

PUBLIC - Contains Redacted Materials

- 1 Q: Can you conclude that the coal forecast relied on by the Applicants was 2 reasonable?
- 3 A: For the reasons stated above, I cannot conclude that the coal forecast relied on by
- 4 the Applicants was reasonable.
- 5 Q: Does this end your testimony?
- 6 A: Yes.