COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC	**)**	**Case No.**
CORPORATION FOR A GENERAL	**)**	**2012-00535**
ADJUSTMENT IN RATES	**)**	

DIRECT TESTIMONY OF

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ON BEHALF OF

SIERRA CLUB

Date
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1. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Frank Ackerman. I am a senior economist at Synapse Energy Economics, Inc., 485 Massachusetts Avenue, Cambridge MA 02139.

Q. Please describe your professional experience before beginning your current position at Synapse Energy Economics.

A. Before coming to Synapse in late 2012, I worked for many years at two research institutes at Tufts University in Medford, Massachusetts, focusing on issues of energy, climate change, and policy analysis. I received a PhD in economics from Harvard University, and have taught economics at Tufts University and at the University of Massachusetts. A copy of my resume is attached as Exhibit Ackerman-1.

Q. Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government, and utilities.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Sierra Club.

Q. Have you filed testimony in other recent regulatory proceedings?

A. Yes. I filed testimony on behalf of the Sierra Club in Indiana, in the recent CPCN case filed by Duke Energy Indiana (Cause No. 44217).

Q. Have you testified previously in Kentucky?

A. No, I have not.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the request by Big Rivers Electric Corporation ("BREC," or "the Company") for a rate increase, and to discuss alternative approaches to the underlying problem that has led to this request.

Q. Are you sponsoring any exhibits?

A. Yes. I have prepared the following exhibits to my prepared testimony:

1. Exhibit Ackerman-1	Professional CV for Frank Ackerman
2. Exhibit Ackerman-2	Evansville Courier & Press Article "Century Aluminum to buy Alcan's Sebree Smelter"
3. Exhibit Ackerman-3	Sargent & Lundy Study
4. Exhibit Ackerman-4	Wilson Direct Testimony
5. Exhibit Ackerman-5	Steinhurst Direct Testimony
6. Exhibit Ackerman-6	Metal Miner Article "Power Costs in the Production of Primary Aluminum"
7. Exhibit Ackerman-7	Evansville Courier & Press Article "UPDATE: Big Rivers seeking $74 Million annual increase in wholesale electric rates"

Q. How is your testimony organized?

A. My testimony is organized as follows:

1. Introduction and Qualifications.
2. Summary of Conclusions and Recommendation.
3. The Long-term Problem: Excess Capacity.
4. Costs to Maintain and Upgrade BREC's Power Plants.
5. Subsidies for Smelters: A Question for State Policy.
6. BREC's Options: Finding the Least Bad Choice.
7. Potential Revenue from Power Plant Sales.
8. Implications of Bankruptcy for Ratepayers.

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATION

Q. Please summarize your conclusions.

A. My conclusions can be summarized by section, as follows. In Section 3, I demonstrate that BREC had more than enough capacity to serve its load, even before the departure of either of the smelters. Since the smelters represent two-thirds of BREC's load, their announced departure would leave BREC with vastly more capacity than is needed for its remaining customers. Off-system sales, and the search for new customers, do not appear able to produce enough revenue to justify keeping this excess capacity.

In Section 4, I evaluate the costs required to bring BREC's power plants into compliance with current and anticipated environmental regulations. The roughly $60 million for MATS compliance discussed by BREC witnesses in this case is only a small part of what will be needed. According to Sargent & Lundy, the Company's consultants in the Big Rivers 2012 CPCN case, the costs for environmental compliance at BREC's plants could exceed $500 million. This does not include the impact of any potential future greenhouse gas regulations, which could further decrease the profitability of coal plants.

In Section 5, I review the issue of subsidies designed to keep the smelters in business. If such subsidies are deemed appropriate, they should be provided by Kentucky state economic development funds, not by the utility that serves the smelters – or by its other ratepayers.

In Section 6, I describe BREC's choices in responding to the loss of the smelters. If off-system sales are not sufficient to support the existing capacity, then BREC will have to idle, sell, or decommission some of its plants. BREC has barely begun to face these choices, and is still relying on the unsupported hope that off-system sales will recover enough to avoid the hardest decisions.

In Section 7, I discuss the potential revenue from selling coal plants. The limited recent data suggests sale prices around $100 - $160/kw of capacity, a small fraction of the book value net of depreciation, or of the current value in rate base, of BREC's plants.

Finally, in Section 8, I explore the potential implications of bankruptcy for BREC's customers. This painful topic unfortunately cannot be avoided, due to the large debt borne by BREC and the relatively limited revenues available from either off-system electricity sales or from sales of assets. Reorganization following a bankruptcy could lead to BREC's remaining (non-smelter) customers paying rates based on the MISO market price of electricity, plus transmission, distribution, and administrative costs. If keeping BREC out of bankruptcy imposes rates much higher than this, it would not be in the customers' best interests.

Q. Please summarize your recommendation.

A. I recommend that the Commission reject the requested rate increase. It would impose substantial burdens on BREC's remaining customers, yet it would be far from enough to solve the underlying problem of excess capacity. Indeed, BREC has already announced its intention to promptly file another request for a rate increase in response to the second smelter's departure. Yet another rate increase would be required to cover the costs of bringing BREC's power plants into compliance with environmental regulations; only a small fraction of these costs are included in the current request. Instead of seeking an endless series of rate increases, BREC should be directed to explore other approaches that can resolve its long-term problems, reduce its total capacity, and offer stable, affordable rates to BREC's customers.

3. THE LONG-TERM PROBLEM: EXCESS CAPACITY

Q. Please describe the fundamental issue addressed in this case.

A. BREC is a generation and transmission cooperative, owned by and operated on behalf of three distribution cooperatives in western Kentucky. BREC's service territory includes about 112,000 rural and industrial customers – and two large aluminum smelters, Century and Alcan, which together represent more than two-thirds of BREC's load. (Although Century Aluminum has recently agreed to acquire the Alcan smelter, I will continue to use the traditional names to distinguish the two smelters.)

In August 2012, the Century smelter gave the required 12 months' notice that it intended to stop buying electricity from BREC in August 2013. BREC then filed its current request for a substantial rate increase on the remaining smelter and the non-smelter customers, in order to make up for its revenue losses. The Alcan smelter gave notice in January 2013 of its intention to stop buying electricity from BREC as of January 2014; BREC has stated that it will soon have to request an additional rate increase to compensate for the loss of the second smelter. In an April 29, 2013 *Evansville Courier & Press* article (attached as Exhibit Ackerman-2), BREC President and CEO Mark Bailey was cited as saying the two rate increases together could increase residential electric rates as much as 40 percent.[1]

Q. Has BREC proposed any reductions in capacity in response to this substantial loss of load?

A. They have not proposed any permanent reductions in capacity. They have proposed idling the Wilson plant – their newest and most efficient (lowest heat rate) plant – until 2019.

Q. Is BREC's proposal an appropriate response to the loss of one or both smelters?

A. No, it is not. With the loss of one or both smelters, BREC will have far more capacity than it needs to serve its remaining customers, as reflected in extraordinarily high reserve ratios. BREC's proposal in this case, responding to the loss of the first smelter, does not discuss sale or permanent retirement of any of its excess capacity, but asks its remaining customers to pay much higher rates in order to maintain and add selected new environmental controls to its plants.

BREC owns and operates 1444 MW of capacity and has contractual rights to another 375 MW (from Henderson and SEPA combined), for a total of 1819 MW (Berry testimony, p.5). With both smelters, the highest forecast monthly billing demand in 2013 is 1529 MW (Exhibit Barron-3, p.1), so BREC has an ample 19%

[1] Chuck Stinett, "Century Aluminum to Buy Alcan's Sebree Smelter," *Evansville Courier & Press*, April 29, 2013, http://www.courierpress.com/news/2013/apr/29/century-aluminum-buy-alcans-sebree-smelter/.

reserve margin. Even with both smelters on its system, BREC is well above MISO's planning reserve margin of 14.2% in 2013, declining to 13.4% in 2022.[2]

As the smelters leave, BREC's reserve margin will shoot up from ample to absurd. Without the Century smelter, BREC's 2013 highest monthly demand drops to 1047 MW, implying a 74% reserve margin; after the departure of Alcan a few months later, the corresponding peak demand would be 679 MW, and the reserve margin would be 168%.

The Wilson plant has a capacity of 417 MW, somewhat less than the 482 MW of demand from the Century smelter. If Wilson goes off-line when Century leaves, BREC will still have 1402 MW of remaining capacity to serve 1047 MW of demand, a 34% reserve margin. When Alcan leaves, BREC, with all current capacity except Wilson on-line, would have a 106% reserve margin.

Q. Is detailed modeling required to confirm that BREC will have excess capacity after the smelters depart?

A. No. BREC with both smelters has a (forecasted 2013) peak monthly demand of 1529 MW; without the Century smelter it would have 1047 MW; without both smelters, it would have 679 MW. It is simply not possible for a generation fleet that is appropriate to serve 1529 MW of load to be equally appropriate for 679 MW of load. When both smelters have departed, only 808 MW of capacity would be needed to achieve the same 19% reserve margin that BREC currently maintains.

Roughly this amount of capacity, or more, could be achieved by keeping any two of the following four generation resources: the Coleman Station, the Green Station, the Wilson Station, and the contractual rights to power from elsewhere. That is, any two of those four resources, as well as the Reid Station, could be retired or sold, and BREC would still have adequate capacity to serve its non-smelter load.

[2] The planning reserve margin is an estimate of the reserve capacity needed to meet the one day in 10 years standard for loss of load expectation. MISO, "Planning Year 2013 LOLE Study Report," p.14, https://www.misoenergy.org/Library/Repository/Study/LOLE/2013%20LOLE%20Study%20Report.pdf, accessed May 21, 2013.

Q. Can BREC justify keeping some of its excess capacity in order to generate electricity for sale outside its service territory?

A. No. This strategy has failed, on multiple grounds. Even with both smelters present, BREC sold 18% of its MWh of generation in 2010 and 23% in 2011 to customers other than its members and smelter contracts (BREC 2011 financial statement, application tab 35, p.61). To replace the smelters, BREC would need very large increases in these off-system sales. In effect, BREC is gambling on the ability to either profitably sell into the market or sign up new customers for a massive amount of energy generation. This gamble is unjustified in light of market conditions and BREC's marketing experience (discussed in this section), BREC's apparent failure to account for the full set of costs facing its coal units (discussed in Section 4), and BREC's failure to produce any production cost modeling supporting its strategy (discussed in Section 6).

Q. Please describe the market conditions that are unfavorable for BREC's plans to increase off-system sales.

A. Ample capacity is available in neighboring states and service territories, and the market price of electricity in MISO is quite low. This is documented in the 2011 "State of the Market" report (published in June 2012, the latest available) by MISO's independent market monitor, Potomac Economics: MISO met its July 2011 all-time record peak demand, during a period of record high temperatures, without any emergency procedures or involuntary load reductions; "this is partly because MISO currently has a sizable capacity surplus, as is reflected in [near-zero] capacity prices."[3] In MISO's 2013-2014 planning resource auction, the clearing price for capacity was a mere \$1.05/MW-day.[4] The MISO capacity surplus seems likely to last for some time; a recent NERC assessment of long-

[3] Potomac Economics, "2011 State of the Market Report for the MISO Electricity Markets," June 2012, p.ii, http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf, accessed May 20, 2013.
[4] "2013/2014 MISO Planning Resource Auction Results," https://www.midwestiso.org/Library/Repository/Report/Resource%20Adequacy/2013-2014%20MISO%20Planning%20Resource%20Auction%20Results.pdf, accessed May 22, 2013.

term reliability found that MISO's reserve margins will be at or above NERC's "reference margin level" through 2021.[5]

Other fundamental factors that depress the potential for BREC's off-system sales include the low price of natural gas, which leads to lower electricity prices, and the increasing recognition of the potential for energy efficiency and demand-side management (DSM) programs, which directly reduce the demand for electricity. (I will discuss energy efficiency and DSM options in Section 4, below.)

Q. How much of an increase in off-system sales would be required to replace the smelters?

A. In 2011, BREC sold 6,855 GWh of energy to the smelters, compared to 3,056 GWh in off-system sales (BREC 2011 annual report, p.61, application tab 35). Thus BREC would need to more than triple its off-system sales to replace the amount of energy sold to smelters. Since prices for off-system sales are currently lower than rates paid by the smelters in the recent past, an even greater increase would be needed to replace the dollars of revenue received from the smelters.

Q. Is BREC projecting a major increase in off-system sales and revenues in the near future?

A. No. In the response to AG 1-18, BREC stated, "Big Rivers' off-system sales margins are not forecasted to increase significantly for the next few years because depressed wholesale market prices will drive low sales volumes and margins per MWh." BREC's data and projections confirm this pessimistic outlook. In the forecasts developed for this case, BREC projects off-system sales volume of only [redacted] GWh in 2013 and [redacted] GWh in 2014, [redacted] (confidential response to PSC 1-57). Revenue per MWh of off-system sales declined to $33.30 in 2011, down from $37.90 in 2010 and $48.03 in 2007 (BREC 2011 financial statement, p.32). [redacted]

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[5] NERC, "2012 Long-Term Reliability Assessment," November 2012, pp.57-58, http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012_LTRA_FINAL.pdf, accessed May 21, 2013.

[redacted]

Q. How successful has BREC been in recent attempts to increase off-system sales?

A. In response to a request for information about recent off-system electricity marketing efforts (PSC 2-18), BREC listed [redacted] potential customers it had contacted. At least [redacted] of them appeared to have definitely turned down BREC's proposals, while [redacted] had definitely accepted, as of February 28, 2013 (the date of BREC's data response).

Q. Has BREC faced the problem of excess capacity before?

A. Yes, this is a longstanding problem for BREC. In its 2010 bond prospectus BREC says that its 1996 bankruptcy "was precipitated largely by our inability to sell our capacity in excess of that required to serve our Members at prices sufficient to cover all of our costs" (BREC application, tab 33, p.8).

Under the 1998 reorganization plan that resolved the bankruptcy, BREC leased its generation assets to Western Kentucky Energy Corporation (WKEC, then a subsidiary of LG&E Energy, later a subsidiary of E.ON), and purchased power to serve its customers from another LG&E subsidiary (bond prospectus, tab 33, pp.8-9). This agreement transferred the costs of maintaining and operating BREC's excess capacity to WKEC: BREC could buy the amount of power it needed, while WKEC bore the unprofitable burden of marketing the excess power from BREC's plants. This may explain the willingness of E.ON to compensate BREC with more than $860 million in the Unwind Transaction of 2009 (BREC bond prospectus, p.10). The Unwind eliminated the last 14 years of the 25-year reorganization plan; thus E.ON found it worthwhile to pay more than $60 million per year of early release from this agreement.

Since the Unwind, off-system electricity sales have been important to BREC, even with both smelters present. In view of the market conditions I described above, there is little prospect for revival in BREC's off-system sales revenues.

Q. Has the risk of adverse market conditions and declining load been brought to BREC's attention in the past?

A. Yes. The December 2011 report[6] by the Commission staff on the BREC 2010 IRP notes that

> "Big Rivers has experienced large declines in the demand for electricity in the past and is well aware of the price sensitivity of its direct-serve customers and other large customers. One purpose of a long-range load forecast's sensitivity analysis is to investigate how a utility will be affected by adverse conditions and then to plan accordingly. The EPA has been openly working on implementing new air and water quality regulations for some time. It seems short-sighted to update the load forecast biennially only and to not attempt to incorporate the effects of these new regulations, the effects of which could have serious impacts on Big Rivers' regional economy and on Big Rivers' service territory specifically. Waiting until events are known tends to defeat the purpose of prudent risk analysis and planning." (p.21)

The report then recommends that

> "Big Rivers should run forecast simulations in its sensitivity analysis in order to gain a better understanding of the probability of occurrence for the various scenarios, including the potential closure of one or both of the aluminum smelters on its system." (p.22)

Q. Are some BREC plants needed by MISO for reliability purposes?

A. MISO reliability studies that would answer this question are just beginning, and are not available to the public (see responses to SC 2-15 and 2-16). BREC has confirmed, however, that if the Company planned to idle or retire a unit that was found to be needed for reliability purposes, it would expect to receive

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[6] Kentucky Public Service Commission, "Staff Report On the 2010 Integrated Resource Plan of Big Rivers Electric Corporation, Case No. 2010-00443," December 2011, http://psc.ky.gov/agencies/psc/industry/electric/irp/201000443_122011.pdf, accessed May 23, 2013.

reimbursement from MISO to keep the plant operational until any necessary reliability fixes were made (see response to SC 2-17c).

MISO does not appear to be concerned about transmission issues involving BREC. In MISO's detailed 2012 Transmission Expansion Plan, there is only one comment on Big Rivers, in the section on "NERC Reliability Assessment Results Overview." That comment reads in full:

"Big Rivers Electric Corporation (BREC)

There are no thermal or voltage issues requiring network expansions."[7]

In response to PSC 2-21(f)(1), BREC provided a memo describing the results of power flow studies performed by the Company to evaluate the idling of either the Coleman station or the Wilson station. The memo indicates that if both smelters continue operating at current levels, there could be unacceptable line overload conditions if certain other major lines were out of service and the Coleman plant were idled. However, BREC acknowledges that it has not explored alternatives that could mitigate these potential reliability concerns (see response to SC 2-16(d)). BREC should work with MISO to develop cost estimates for transmission reinforcement and/or upgrade projects that could alleviate these reliability concerns. These transmission upgrades may be significantly more cost effective than continuing to run the Coleman plant—especially in light of the substantial control costs that will be needed to keep Coleman in compliance with current and future environmental regulations, as discussed in the next section.

4. COSTS TO MAINTAIN AND UPGRADE BREC'S POWER PLANTS

Q. How much will it cost to bring BREC's plants into compliance with current and anticipated environmental regulations?

A. BREC's proposed expenditure of about $60 million on MATS compliance is only the beginning of an extensive and expensive process of upgrades that will be

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[7] "MISO Transmission Expansion Plan 2012," p.43, https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP12/MTEP12%20Report.pdf, accessed May 21, 2013.

required to continue running these plants. The total cost, according to BREC's own consultant in a previous case, will likely be more than $500 million.

In its recent application for a Certificate of Public Convenience and Necessity (Case 2012-00063), BREC submitted an Environmental Compliance Study performed by the consulting firm Sargent & Lundy ("S&L Study", attached as Exhibit Ackerman-3).[8] The S&L Study assessed the potential impacts of various recently issued, proposed, and pending environmental regulations on BREC's fleet and recommended compliance strategies for meeting those future regulations. The S&L Study evaluated the impacts of several regulations, including the Cross-State Air Pollution Rule ("CSAPR"), the Ozone and Particulate Matter National Ambient Air Quality Standards ("NAAQS"), the Utility Maximum Achievable Control Technology rule (now called the Mercury and Air Toxics Standard - "MATS"), the Clean Water Act Section 316(b) cooling water intake structure regulation ("316(b)"), and the proposed rule regarding Coal Combustion Residuals ("CCR").

Q. Are compliance costs for CSAPR still relevant, since that regulation was overturned in the courts last year?

A. While CSAPR was vacated by the U.S. Court of Appeals for the D.C. Circuit in August 2012, the EPA is required to adopt a replacement rule to address the impact of transported pollutants on downwind states. Since EPA recently adopted a more stringent particulate matter NAAQS[9] and is expected to propose a more stringent Ozone NAAQS this year, the replacement for CSAPR is likely to be more stringent than the vacated rule. In the S&L Study, the impact of more stringent Ozone and PM NAAQS was accounted for by decreasing emission allocations available under CSAPR by 20 percent. At this time, this serves as a reasonable proxy for estimating the possible costs to BREC from the anticipated CSAPR replacement rule.

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[8] Sargent & Lundy, "Big Rivers Electrical Corporation Environmental Compliance Study," February 13, 2012, http://psc.ky.gov/pscscf/2012%20cases/2012-00535/20130306_Big%20Rivers_Response%20to%20AG%201-179.pdf.
[9] 78 Fed. Reg. 3806 (January 15, 2013).

Q. Please summarize the compliance costs estimated in the S&L study.

A. The table below summarizes the S&L Study's estimated capital costs (in millions of dollars) for the recommended strategy to bring the BREC units into compliance with the identified regulations:

Regulation	Coleman	Wilson	Green	HMP&L	Reid	TOTAL
CSAPR + NAAQS	29.6	139.0	162.0	6.3	1.2	**338.1**
MATS	28.3	11.2	18.5	0.5	N/A	**59.5**
316(b)	8.0	N/A	2.0	2.0	2.0	**14.1**
CCR	38.0	N/A	28.0	28.0	N/A	**94**
TOTAL	**103.9**	**150.2**	**210.5**	**36.8**	**3.2**	**505.8**

Q. Are there additional environmental regulations that may impose costs beyond those identified in the S&L Study?

A. The S&L Study estimates do not include costs necessary for compliance with the recently-proposed Effluent Limitation Guidelines and Standards (ELG) for steam electric power plants. However, the Study did find that limits on discharge of mercury, sulfates, chlorides, and other constituents could require the installation of advanced wastewater treatment/removal systems at all of BREC's plants. These systems represent costs BREC will have to incur to continue operating all of its plants, in addition to the $506 million identified in the S&L Study. In its response to SC 2-9, BREC acknowledged that it has no estimate of the cost of ELG compliance.

In addition, the S&L Study did not estimate the costs of complying with future regulations of CO_2 through federal legislation or EPA rulemaking. CO_2 regulation will have a significant impact on the economics of coal-fired units. While there is not currently a federal law or proposed rulemaking governing CO_2 emissions at existing power plants, discussions at the EPA and at the Congressional level are ongoing, and there is a real possibility of such regulations being adopted within the remaining lifetime of BREC's plants.

The most recent legislative proposal to reduce emissions of CO_2 has taken the form of a Clean Energy Standard (CES), as introduced by Senator Bingaman on March 1, 2012. A CES encourages the use of low-carbon power through the allocation of clean energy credits to those generation technologies that emit less CO_2, which generation owners would consider in their dispatch decisions. In Senator Bingaman's bill, credits are determined based on individual power plant emissions and generating sources are given a certain number of credits based on their carbon profile, with lower emitting sources rewarded with a larger number of clean energy credits. In any given year, electric utilities would be required to hold a certain number of clean energy credits for a specific percentage of their sales.

Furthermore, the EPA recently proposed the first ever greenhouse gas new source performance standards ("NSPS") under Clean Air Act Section 111(b). The NSPS sets unit-specific performance standards for significant new sources of greenhouse gases. EPA is also required to establish a NSPS program for *existing* sources of greenhouse gases under Clean Air Act Section 111(d). While EPA has yet to propose such a program, it is widely anticipated that performance standards for existing plants are on the horizon. The Edison Electric Institute recently produced a white paper describing possible scenarios for GHG regulation under 111(d) and anticipating a proposal "sometime in 2013."[10]

Q. Does BREC face additional costs of maintaining its plants, beyond the level required for compliance with environmental regulations?

A. Yes. In order to meet the minimum financial margins required by its loan agreements, BREC has drastically cut back on maintenance at its plants. Since the Unwind Transaction in July 2009, BREC has delayed, reduced in scope, or cancelled 22 of its 24 scheduled maintenance outages – solely for financial reasons (Berry testimony, pp.7-8). Catching up on the resulting agenda of deferred maintenance will require an expenditure of about [redacted] by 2016, in addition to $212 million of scheduled "asset replacement and capital improvements" and [redacted] of routine, non-outage maintenance costs over the next four years (Berry testimony, pp.14-16).

[10] Edison Electric Institute, *Existing Source GHG NSPS White Paper*, November 19, 2012, available at: http://online.wsj.com/public/resources/documents/carbon04232013.pdf, accessed May 22, 2013.

Q. What conclusions do you draw from the costs of environmental compliance and deferred maintenance at BREC's power plants?

A. It is critical to factor in the full range of costs facing BREC's coal units in evaluating whether it is reasonable to project that they are going to be profitable again. The greater those costs are, the higher the hurdle facing the plants.

BREC has not submitted production cost modeling in this case that would allow a comprehensive evaluation of the economics of its power plants. In testimony in last year's CPCN case, however, my colleagues Rachel Wilson and William Steinhurst, both of Synapse Energy Economics, described numerous flaws and questionable assumptions in BREC's modeling of the costs of these plants (see Wilson and Steinhurst testimony in 2012 CPCN case, attached as Exhibits Ackerman-4 and Ackerman-5).

In one noteworthy error identified by Ms. Wilson, BREC used the PACE Global price forecast, which incorporated an assumed CO_2 price in into its projection of future electricity prices – but BREC's production cost modeling of its own plants, in the same case, assumed that there was no CO_2 price (Wilson testimony, p.23). I believe it is reasonable to assume that future electricity prices will include a CO_2 price; it is also reasonable to assume that this price will apply to BREC as well as everyone else. This, of course, increases the estimated costs of operating BREC's plants.

Ms. Wilson recalculated BREC's plant costs, correcting modeling flaws and using better input assumptions, such as the use of the Energy Information Administration's *Annual Energy Outlook 2012* natural gas price forecast in place of BREC's PACE Global forecast. In her recalculation, every one of BREC's coal units was uneconomic compared to replacement with a natural gas combined cycle plant. This suggests that BREC's plants will not be able to compete with natural gas plants in bidding for off-system electricity customers: natural gas plants, with lower costs than BREC, will be able to sell electricity at a lower price than BREC.

Q. What role should BREC include for energy efficiency, as it develops its future resource plans?

A. In the 2012 CPCN case, Dr. Steinhurst explained that BREC was inappropriately dismissive of the potential of demand-side management (DSM) and energy efficiency, arguing that BREC should be able to achieve much greater efficiency savings. He referred to BREC's projected savings of 0.01% of non-smelter sales as "barely a token amount," since industry leaders have been able to save energy equal to 1% of retail sales, and numerous states have programs saving more than 0.5% of sales (Steinhurst testimony, 2012 CPCN, pp.11-12). If future electricity prices rise as dramatically as BREC is hoping, more ambitious energy efficiency programs will become cost-effective – for BREC, as well as its prospective off-system customers.

In this case, in response to a question (SC 1-13) about its DSM budget of $1 million, BREC responded that the budgeted amount "was selected to represent approximately 1% of revenue from the rural load" (response to SC 1-13a), and "is not adequate to achieve all cost-effective energy savings from DSM" (response to SC 1-13b). In short, BREC acknowledges that its DSM spending is arbitrary in amount, and insufficient to maximize cost-effective energy savings. Increases in DSM effort and expenditure will be a bargain for BREC's customers, in contrast to continued investment in maintaining and retrofitting BREC's uneconomic coal plants.

Q. Has BREC responded appropriately to the costs it will incur to maintain its plants?

A. No; it appears to be gambling on future increases in electricity prices, offering only to idle one plant for a few years. In effect, BREC is now planning to double down on a bet it has been losing since the 1990s. Under BREC's proposal, its customers will have to pay the costs of maintaining an idled plant for some years to come, in order to continue making this bet. Market conditions, however, give no grounds for believing that BREC's luck is about to change. This is not a prudent gamble for a financially constrained utility to make.

Q. Is it reasonable to guess that capacity will soon become scarcer and electricity prices will rise, after the current wave of coal plant retirements resulting from tighter environmental regulations and cheap natural gas?

A. If there is such an opportunity, how many other utilities will anticipate the same trends, and will also see it as a reason to keep their coal plants on-line? If enough utilities keep their coal plants on-line in the hopes of being able to profit from a future capacity shortfall, then there will be no shortfall, and no future profits from this strategy.

Even if other utilities do not pursue this strategy, hopes of future price increases appear to be exaggerated. As I noted above, MISO has substantial excess capacity at present, so that some retirements can occur without creating shortfalls; this is all the more true because new renewable and gas capacity is being added by some MISO utilities. Also, if electricity prices rise, energy efficiency and demand reduction measures will become increasingly cost-effective; many utilities, including BREC, have only begun to explore the potential of this resource. As efficiency measures are more widely adopted, the demand for electricity will be curtailed.

In short, it is imprudent for a utility with resources as limited as BREC's to gamble the ratepayers' money on a (chronically inaccurate) hunch about future electricity markets and prices.

5. SUBSIDIES FOR SMELTERS: A QUESTION FOR STATE POLICY

Q. There have been suggestions in the media that the smelters may want to negotiate a return to BREC under new or improved terms. Should BREC preserve the capacity needed to serve the smelters, to allow their return?

A. Not unless the smelters are willing to commit to return, on terms that do not unreasonably shift costs and risk to other ratepayers. As I explained in Section 3, the generation resources needed to serve BREC's remaining (non-smelter) customers as of 2014 are vastly different in scope from the resources needed to serve BREC's current customers, including the smelters. It is an unreasonable burden on BREC's non-smelter customers to charge them for carrying the excess capacity that might be needed if the smelters change their mind at some future date.

Q. Under what terms should BREC be willing to take the smelters back into its system?

A. BREC, like any regulated utility, has one primary responsibility: to provide least-cost, reliable service to its customers. To avoid cross-subsidization and unfair burdens on any categories of customers, each customer class should pay the incremental costs of the service it receives, plus a fair share of the common, fixed costs of utility operation.

If the smelters want to return to BREC, then BREC should calculate the revenue requirements for serving them as well as the rural and industrial customers. The smelters should be charged rates that recover the difference between BREC's with-smelters and without-smelters revenue requirements, plus the smelters' share of BREC's fixed costs that serve all customers. Charging them anything less forces the other customers to subsidize the smelters. To make the remaining customers whole, the smelters – like any other group of customers – must pay the full cost that they add to revenue requirements, plus their proportionate share of common costs.

If, as seems likely, the optimal without-smelters BREC system involves shedding excess capacity, then the cost to accept the smelters back into BREC could rise over time. As BREC progresses toward resizing itself for its non-smelter load, it may become more expensive to reverse course and serve the additional smelter load. This provides a financial incentive for the smelters to return promptly (if they intend to return), before BREC reduces its capacity.

Q. Is BREC adopting this approach in negotiations about the potential return of one or both smelters?

A. It is impossible to answer this question at present, due to BREC's initial refusal to discuss the negotiations. In response to questions about a tentative agreement between BREC and Century Aluminum – an agreement that was announced in a recent press release from Century Aluminum – BREC made the implausible assertion that such questions "are not reasonably calculated to lead to the discovery of admissible evidence" (see the responses to SC 2-24, 2-25, and 2-26). A motion to allow supplemental discovery on this issue was granted by the Commission on May 22, so I anticipate receiving more information about this topic soon. Once BREC's responses have been received, it may be appropriate to supplement my testimony.

Q. Is it important to subsidize the smelters, in order to preserve jobs and incomes in Kentucky?

A. The commonwealth of Kentucky could make such a decision; many states have made similar decisions about major industries. In that case, the subsidy should be provided by the state government, not by the small fraction of the state's households and businesses that happen to fall in the same service territory as the smelters. That is, a subsidy intended to preserve jobs should be made from state economic development funds, not from increases in neighboring ratepayers' electric bills.

Indeed, the current agreements are already very favorable to the smelters, to the potential detriment of BREC's financial health. As explained by BREC witness Billie Richert, the existing smelter agreements effectively limit BREC's margins to 1.24 times their interest obligations (Richert testimony, pp.6-9). This is a lower margin than is achieved by numerous other generation and transmission cooperatives (see exhibit Richert-2). There is a very narrow window between the minimum margin of 1.10 times interest payments that is required to comply with BREC's financial obligations and be eligible for further financing, and the maximum margin of 1.24 times interest that is imposed by the smelter agreements (Richert testimony, pp.23-25). There appears to be little or no slack remaining to offer an even better deal to the smelters – except by imposing additional costs on the non-smelter customers.

Q. Are you endorsing state subsidies to keep the smelters in business?

A. I am not expressing a position for or against such subsidies; that is a complex question of state policy, involving considerations that extend well beyond the scope of this hearing. I would, however, note two concerns in relation to subsidies for smelters.

First, the argument that the smelters need lower electric rates to remain internationally competitive should be carefully examined. Information about electric rates paid by smelters elsewhere is difficult to obtain. An article in the trade press in 2009 (attached as Exhibit Ackerman-6) concluded that at that time, aluminum smelters in China and Australia were paying \$0.050 - \$0.055 per kwh for electricity, i.e. \$50 - \$55 per MWh.[11] [redacted]

Second, the Kentucky state government has recently produced a thoughtful economic development plan, which does not place a priority on, or even mention, the aluminum industry. Adopted in 2012 after incorporating extensive stakeholder input, *Kentucky's Unbridled Future* identifies 10 strategic sectors for Kentucky's economic development, in the areas of advanced manufacturing (much of it automobile-related), sustainable manufacturing (much of it related to energy efficiency and renewable energy), technology (focusing on life sciences), transportation, and healthcare services.[12] The low cost of electricity is mentioned at the end of the list of Kentucky's advantages in most of these sectors; other advantages such as research strengths, clusters of complementary industries, the state's central location, and excellent transportation logistics are featured more prominently.

In view of this detailed statement of priorities, it is possible but by no means certain that the state would decide to subsidize aluminum smelters. One of the strongest arguments for such subsidies, from this perspective, might be that the state's aluminum industry is an important supplier to the high-priority automobile and renewable energy industries. In any case, this is a decision that belongs in the

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[11] Stuart Burns, "Power Costs in the Production of Primary Aluminum," *MetalMiner*, February 26, 2009, http://agmetalminer.com/2009/02/26/power-costs-the-production-primary-aluminum/.

[12] For the official announcement of *Kentucky's Unbridled Future*, see http://www.thinkkentucky.com/newsroom/NewsLetters/Jan2012/NLJan2012.htm. For the document itself, see http://boyettestrategicadvisors.com/wp-content/uploads/2012/07/Kentuckys-Unbridled-Future-REVISED2.pdf. (Both accessed May 9, 2013). The word "aluminum" literally does not appear in *Kentucky's Unbridled Future*.

realm of Kentucky's statewide economic development planning and funding, not in electric rate design for one limited part of the state.

6. BREC'S OPTIONS: FINDING THE LEAST BAD CHOICE

Q. If BREC's off-system sales are not sufficient to support its current capacity after the departure of one or both smelters, what should it do?

A. There are three choices, none of them good. The question is: which choice is least bad? BREC could idle, or mothball, some of its plants, planning to bring them back into service in the future. Or it could sell some of its coal plants at whatever price it can get for them, even if this is far below book value. Finally, it could retire and decommission some of its plants. While none of these paths is attractive, BREC has an obligation to its remaining customers to evaluate any options that would result in lower rates.

Q. Has BREC considered any of the choices you have proposed?

A. BREC has continued to engage in what I consider wishful thinking about the potential for increased off-system sales (see response to PSC 2-18 on the failure, to date, of expanded off-system sales marketing). As discussed earlier, there is no evidence that this will be fruitful for them.

BREC has proposed mothballing the Wilson plant, a proposal that seems puzzling. Wilson is their newest, most efficient plant; it might therefore seem like the last, not the first, plant to idle. A news story on this rate case (attached as Exhibit Ackerman-7) suggests that the choice may have been somewhat arbitrary. The story quotes Marty Littrell, BREC Manager of Communications and Community Relations, as saying about the proposal to mothball a plant, "We still don't know if it would be Wilson or not. We had to put something down for the rate case, and that's what we put down. But that could change."[13] If accurately quoted, that statement suggests a remarkable lack of rigorous analysis in preparation of the application for a major rate increase.

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[13] Chuck Stinnett, "Big Rivers seeking $74 million annual increase in wholesale electric rates," *Evansville Courier & Press*, January 16, 2013, http://www.courierpress.com/news/2013/jan/16/big-rivers-seeking-74-million-increase-in-rates/.

BREC has also rejected the option of retirement of any coal units. Explaining this position, in response to SC 1-23(b), BREC stated:

> "Big Rivers has not evaluated the retirement, rather than idling, of any of its generating units as an option for mitigating the impact of the termination of the Century contract and/or the decline in off-system sales. Despite the fact that current wholesale electricity market prices are low, Big Rivers' generating units have significant remaining useful life and Big Rivers' members would be unduly harmed if Big Rivers were to retire assets instead of temporarily idling them. Although Big Rivers' members will continue to incur some costs over the next three years associated with idled units, Big Rivers' members will be able to reap significant benefits from the units in the future, either by selling wholesale power and using the proceeds to reduce member rates or by supporting the Western Kentucky economy by supplying power to industries."

In other words, BREC is proposing to throw good money after bad on the projection that it will be able to profitably sell energy into the market or to new customers in a few years, yet they have provided no evidence to support that assumption and there is little reason to expect that to be true. BREC has engaged in relatively little long-range planning; it acknowledges performing 15-year production cost model runs to determine when idled plants would return to service, but refuses to provide such model runs on the grounds that they are not relevant to this proceeding (response to SC 2-2).

Q. Is long-run analysis, such as 15-year modeling, normally required for utility planning?

A. Yes. Power plants and transmission lines are large, long-lived investments; it is not possible to make good decisions about them in the absence of long-term planning. The Kentucky statute governing integrated resource planning by electric utilities, 807 KAR 5:058, repeatedly makes this clear. Sections 7 and 8 of 807 KAR 5:058, specifying the data requirements for integrated resource planning, identify 7 separate categories of information that must be forecast for 15 years, including base load, summer and winter peak demand, energy sales and generation, detailed description of available generating facilities, energy inputs by fuel type, and actions to be taken to comply with the Clean Air Act.

In this context, it should be noted that BREC requested to delay its IRP filing until 2014 (a request granted by the Commission) so that it can first figure out how to respond to the smelter terminations. If this delay to allow better analysis and planning makes sense for the IRP filing, it is equally sensible for any rate increase that responds to the smelter terminations.

Q. Has BREC performed any long-run analyses in this case?

A. Although BREC has argued that this rate case is only concerned with revenue requirements for the next few years, it has also supplied a longer-term analysis in response to AG 1-89. That analysis, the "Load Concentration Analysis and Mitigation Plan" (LCAMP) of June 2012, [redacted]

[redacted]

[redacted]

[redacted]

Q. What support does BREC offer for its projection that the Wilson plant, if idled, could profitably return to service in 2019?

A. In response to SC 1-21d, BREC says, "Based on the present ACES market price forecasts, Wilson is currently scheduled to re-start in 2019…" However, BREC also seems to deny the use of any price projections beyond 2014 in the current rate case. In response to SC 1-21e, asking about "any forecasted market prices in MISO for 2015, 2016, and any future years beyond 2016" and the use of such forecasts in this application, BREC responded, "The process for 2015, 2016, and any future year beyond 2016 are not incorporated into this application because the forecasted test period includes September 1, 2013 through August 31, 2014 exclusively."

[redacted]

[redacted]

[redacted]

Q. Do you have any comments on the PACE Global energy price projections?

A. I have not had an opportunity to examine these price projections. However, in the 2012 CPCN case, my colleague Rachel Wilson examined the PACE Global forecast of natural gas prices, used by BREC in that case. She recommended against use of that forecast, since it is higher than other forecasts developed in 2011 and 2012. For example, the PACE Global natural gas price forecast is higher than the Energy Information Administration's *Annual Energy Outlook* 2011 and 2012 gas price forecasts (Wilson testimony in 2012 CPCN case, pp.21-22.) Since the price of electricity is based, to a significant extent, on the price of natural gas, an excessively high forecast for natural gas translates directly into an excessively high forecast for electricity prices.

7. POTENTIAL REVENUE FROM POWER PLANT SALES

Q. How much could BREC expect to receive from the sale of some of its coal plants?

A. There are only a handful of recent transactions involving sale of existing coal plants between separate companies.[15] The individual transactions are often large and complex, allowing some difference of opinion in estimating the actual price paid for the plants. In the recent cases, it appears that the price per kw of capacity has been around $100 - $160, even for relatively large coal plants with scrubbers.

Q. Please describe those recent sales of coal plants, and the prices paid for them.

A. In August 2012, Exelon sold three Maryland power plants with a total capacity of 2,648 MW, of which more than 2,000 MW is coal (the remainder consists of oil

[15] Much higher prices have been proposed at times for internal sales, for instance between regulated and non-regulated subsidiaries of the same parent corporation. Such sales, however, may not reflect true market prices, since the parent corporation is effectively paying itself, and may benefit financially from moving assets from one subsidiary to another.

and gas-fired units at those plants), for $400 million.[16] The average price was thus $151/kw.

In March 2013, Dominion Resources sold three power plants, the Brayton Point and Kincaid coal-fired plants (totaling 2,628 MW) and a 50% interest in the Elwood gas-fired plant (the plant's total capacity is 1,424 MW) to Energy Capital Partners. According to Dominion, its after-tax proceeds will amount to about $650 million.[17] A *Platts* financial newsletter story estimated the true purchase price at about $450 million, or $132/kw of capacity.[18] A *Wall Street Journal* article commented on this transaction that "after stripping out tax benefits, the implied underlying price paid per kilowatt of capacity was just over $100."[19]

Also in March 2013, Ameren agreed to divest an Illinois-based subsidiary to Dynegy; that subsidiary owns five coal-fired plants totaling 4,100 MW, 80% of another 1,186 MW coal- and gas-fired plant, an energy marketing business, and a retail energy business. Dynegy did not making any cash payment to Ameren, but has assumed $825 million in debt associated with the coal plants. If $825 million is interpreted as the purchase price for the 5,050 MW of capacity that Dynegy acquired, then the price was $163/kw.[20]

Q. How does BREC's current valuation of its plants compare to their potential sale prices?

A. In the cost of service study submitted in this rate case, BREC calculates its total utility plant rate base, excluding transmission, and net of accumulated depreciation, at $978,881,050 (Exhibit Wolfram-3, p.2). For 1444 MW of

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[16] See Exelon's press release, August 9, 2012, at http://www.exeloncorp.com/newsroom/PR_20120809_EXC_Mdcoalplantsale.aspx (accessed May 15, 2013).

[17] See Dominion's press release, March 11, 2013, at http://dom.mediaroom.com/2013-03-11-Dominion-To-Sell-Three-Merchant-Power-Stations-To-Energy-Capital-Partners (accessed May 15, 2013).

[18] "Recent plant sales establish new floor for coal assets," *Platts*, March 14, 2013, http://www.platts.com/RSSFeedDetailedNews/RSSFeed/ElectricPower/6260790 (accessed May 15, 2013).

[19] Liam Denning, "There is Life After Death for Coal Power," *Wall Street Journal*, March 31, 2013, http://online.wsj.com/article/SB10001424127887323361804578390561956760382.html (accessed May 15, 2013).

[20] See Dynegy's press release, March 14, 2013, http://phx.corporate-ir.net/phoenix.zhtml?c=147906&p=irol-newsArticle_Print&ID=1796097&highlight= (accessed May 15, 2013).

capacity, this amounts to $678/kw, or more than 4 times the price per kw of recent coal plant sales. The net book value of the Reid, Coleman, Green, and Wilson coal-fired units, at the start of 2013, was $791,986,950 (SC 2-6). This amounts to $548/kw, or more than 3 times the price per kw of recent sales.

8. IMPLICATIONS OF BANKRUPTCY FOR RATEPAYERS

Q. If BREC sells or closes some of its plants, would it be forced back into bankruptcy?

A. This is a difficult question which depends on many unknowns, including the choice of which units to dispose of, and the prices at which they can be sold. It depends, as well, on BREC's ability to renegotiate any of its current debts. The risk of bankruptcy, however, is real and cannot be ignored. At the end of 2012 BREC had long-term debt of $925 million, owed to CFC, RUS, CoBank, and Ohio County (Kentucky) bonds sold on BREC's behalf; against these debts BREC had $189 million of cash, investments, and reserves, excluding the reserves from the Unwind that are pledged to ratepayers (KIUC 2-45, attachment pp.29, 31). Thus BREC appears to have net debts of $736 million. Selling all of its generation capacity at $160/kw would bring in an amount equal to only about one-third of BREC's net debt.

Q. BREC voluntarily assumed these debts, in some cases quite recently. Isn't the company obligated to do whatever is necessary to repay its debts – even if that means much higher rates for its remaining ratepayers?

A. Under ordinary circumstances, this would certainly be true. A small loss of load or temporary reduction in sales would not provide legitimate grounds for contemplating bankruptcy.

On the other hand, consider an extraordinary worst-case scenario, in which an unpredictable event such as an earthquake suddenly removes 99% of a utility's customers and sales. (Something close to this happened to Entergy New Orleans in the aftermath of Hurricane Katrina, leading to a bankruptcy that lasted almost two years.) Assume that the utility has substantial debts, incurred to provide and maintain service to the former customer base. In such a case, it seems clear that the remaining 1% of post-earthquake customers should not be expected to pay hugely inflated rates to repay the utility's debts. Those debts were undertaken to serve the vastly greater pre-earthquake load, and cannot be repaid by the survivors. Instead, the utility should eliminate the debts by selling most of its assets and/or declaring bankruptcy. This would allow the survivors to receive electric service at rates that are based on their current cost of service, not on debts that were only needed to serve the ghosts of the past.

Q. What is the relevance of this worst-case scenario to BREC's situation today?

A. The twin earthquakes of the two smelters' departures are taking BREC more than two-thirds of the way from the earlier status quo to my worst-case scenario (when measured by loss of load). In 2014, after both smelters depart, BREC's remaining customers are in danger of being forced to pay for debts incurred to serve BREC's two giant ex-customers. If, as seems unfortunately likely, off-system energy sales and asset sales cannot pay off these debts, then the option of bankruptcy must be considered in the discussion of strategies for serving BREC's remaining customers.

Q. Did BREC's previous bankruptcy impose economic hardships on its customers?

A. Not compared to more recent years. In fact, BREC's electric rates were lower in the years soon after the bankruptcy than they have been since the Unwind Transaction. From 2000 to 2008, under the agreement that resolved the bankruptcy, wholesale rates to members were low and stable, roughly $35-$36/MWh for rural customers and $30-$31/MWh for industrial customers (BREC 2008 Annual Report, p. 18, application tab 35). Since the Unwind, rates have shot upward; average wholesale rates reached $46.78/MWh for rural customers and $41.68 for industrial customers by 2011, prior to application of the reserves set up in the Unwind[21] (BREC 2011 Annual Report, p.32, application tab 35).

[21] The Unwind Transaction set aside funds reserved for rate reduction for BREC's customers, so the rates actually paid in 2011 were lower than the figures reported here; these reserves provide only temporary rate relief, and will be exhausted within a few years.

Other factors are also involved in the recent increase in rates: BREC's revenue from off-system sales has dropped due to the economic downturn and the decline in market prices for electricity; and the 2009 smelter agreements, as discussed above, have placed great pressure on BREC's finances. Yet the fact remains that BREC's previous bankruptcy did not impose high rates or unreliable service on BREC's customers.

Q. Have you calculated the cost of post-bankruptcy service for BREC's customers?

A. No, I have not. Such calculations were not possible within the tight time frame of this case. I recommend, however, that post-bankruptcy rates be estimated, in order to provide a standard against which to judge the proposals for rescuing BREC.

Q. How should the hypothetical post-bankruptcy rates be estimated?

A. Suppose, in the worst case, that bankruptcy resulted in the retirement or sale of all of BREC's generation assets. A reorganized BREC could still buy power from MISO and deliver it to the distribution cooperatives. The new BREC would need to charge its customers the MISO market price, plus the cost of transmission, plus reasonable administrative and general expenses and margin. The distribution cooperatives would add distribution costs, as at present. Calculation of such "no-generation" rates would be much simpler than BREC's current rate design process. If the rates required to keep BREC in business today are significantly higher than the no-generation rates based on MISO prices, then the ratepayers could experience lower rates after another bankruptcy.

Calculation of the no-generation costs and rates would also provide a useful benchmark against which BREC's power plants could be evaluated. Should a reorganized, post-bankruptcy BREC retain and operate a reduced generation fleet, sized appropriately for its reduced customer base? This should be allowed only if it would lead to rates comparable to or lower than the no-generation rates.

Q. Would retirement or sale of BREC's generation assets expose its customers to greater risks?

A. The only increased risk for customers from loss of BREC's plants would occur if MISO electricity prices rise well above BREC's costs of generation (including the substantial costs to bring BREC's plants into compliance with environmental regulations, described above). In that case, BREC customers would have to pay MISO prices, rather than having access to BREC's own generation. This is the future scenario – a dramatic rise in electricity prices, making old coal plants newly profitable – which BREC has been gambling on, without success, for years. As I have explained, current market conditions and projections do not provide any reason to think that BREC will do better on this gamble in the future.

Q. Does this conclude your testimony?

A. Yes, it does.

BEN TAYLOR AND SIERRA CLUB

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

VERIFICATION

I, Frank Ackerman, verify, state, and affirm that I prepared or supervised the preparation of the testimony filed with this Verification, and that my testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Frank Ackerman

COMMONWEALTH OF MASSACHUSETTS)
COUNTY OF MIDDLESEX)

SUBSCRIBED AND SWORN TO before me by Frank Ackerman on this 24th day of May, 2013.

JANICE CONYERS
Notary Public
Commonwealth of Massachusetts
My Commission Expires
July 27, 2018

Notary Public, Ma. State at Large
My Commission Expires 7/27/18