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Via Overnight Mail

July 26, 2013

Mr. Jeff Derouen, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Re: Case No. 2012-00535

Dear Mr. Derouen:

Please find enclosed the original and ten (10) copies of the PUBLIC VERSION of the BRIEF OF KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. I also enclose a copy of the CONFIDENTIAL pages to be filed under seal.

By copy of this letter, all parties listed on the Certificate of Service have been served. Please place these documents of file.

Very Truly Yours,

Michael L. Kurtz, Esq.
Kurt J. Boehm, Esq.
Jody Kyler Cohn, Esq.
BOEHM, KURTZ & LOWRY

MLKkew
Attachment
cc: Certificate of Service
Quang Nyugen, Esq.

G:\WORK\KIUC\Kenergy - Big Rivers\2012-00535 (2012 Rate Case)\Derouen Ltr - confidential.docx

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by electronic mail (when available) and by regular U.S. mail, unless other noted, this 26th day of July, 2013 to the following:

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JUL 29 2013

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter of: The Application of Big Rivers Electric Corporation for an Adjustment of Rates.	: : :	Case No. 2012-00535

<u>PUBLIC VERSION</u>

MAIN BRIEF OF

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

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July 26, 2013

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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter of: The Application of Big Rivers Electric Corporation for an Adjustment of Rates.	: : :	Case No. 2012-00535

MAIN BRIEF OF KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

Comes now, the Kentucky Industrial Utility Customers, Inc. ("KIUC") representing the interests of Domtar Paper Co., LLC, Kimberly Clark Corporation and Aleris International, Inc. and submits its Main Brief to the Kentucky Public Service Commission ("Commission") as follows:

I. INTRODUCTION AND SUMMARY

A. A History of Crisis, Which Needs a Comprehensive Resolution.

No utility under this Commission's jurisdiction has careened from crisis to crisis to crisis over the last thirty years like Big Rivers Electric Corporation ("Big Rivers" or "Company"). When the Wilson plant came online in the early 1980s, its capacity was excess and rate recovery was repeatedly denied. Big Rivers defaulted on its debt, the RUS brought foreclosure actions in federal court, and an RUS loan embargo was placed on all Kentucky electric cooperatives.[1] After a financial workout plan with the creditors was reached,[2] the Century and Alcan smelters were placed on variable electric rates that were tied to the world-wide price of aluminum.[3]

In the early 1990s, the Commission disallowed tens of millions of dollars in fuel costs as unreasonable after a Commission ordered focused management audit found that several coal contracts were imprudent. The

[1] Big Rivers Response to KIUC Initial Request for Information (Feb. 28, 2013), Item 34, 1985 Annual Report.
[2] Id., 1989 Annual Report.
[3] *An Investigation of Big Rivers Electric Corporation's Rates for Wholesale Electric Service*, Case No. 9885, Order (Aug. 10, 1987).

FBI later proved that those coal contracts were the unlawful product of a long-running kickback conspiracy centered around Big Rivers' General Manager, William Thorpe.[4] To discharge those contracts and to restructure debt, Big Rivers filed a pre-packaged bankruptcy in 1996.[5] The bankruptcy process led to the 1998 Transaction, whereby Big Rivers entered into a 25-year lease of its generating units to E.ON and its subsidiaries.[6]

For the first eleven years of having an E.ON subsidiary operate its power plants, Big Rivers' rates were stable. That period of relative tranquility ended in another emergency immediately before the Unwind closed. In 2000 Big Rivers entered into two sets of leveraged leases of its Wilson and Green Units. As part of that sale/leaseback transaction, Big Rivers purchased credit support from Ambac. But in mid-2008 Ambac had its credit rating downgraded, which caused the sale/leaseback to unravel. To avoid another bankruptcy, Big Rivers bought out of its leveraged lease with Phillip Morris Credit Corp. for $121.7 million on September 30, 2008. The use of essentially all of its cash reserves coupled with an inability to borrow caused Big Rivers to seek a 21.6% emergency rate increase on March 2, 2009.[7] In that case, Mr. Bailey warned the Commission (just as he does here) that Big Rivers needed "every dollar" of its emergency rate increase and the failure to do so could result in "insolvency."[8] By Order issued May 27, 2009, the request for emergency rate relief was denied.

In what seems to have become a recurring theme, in the recently completed 2011 rate case Big Rivers used the same litigation tactic that is uses now: argue that there is "no leeway" and that every dollar requested is essential and that the alternative is "potential bankruptcy."[9] However, in the 2011 rate case, Big Rivers received two-thirds of what it requested, and no bankruptcy resulted.

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[4] Big Rivers Response to KIUC Initial Request for Information (Feb. 28, 2013), Item 34, 1993 Annual Report.
[5] Id., 1998 Annual Report.
[6] Id., 1999 Annual Report.
[7] Case No. 2009-00040.
[8] Case No. 2009-00040, Direct Testimony of Mark A. Bailey (March 2, 2009) at 4.
[9] Case No. 2011-00036, Rebuttal Testimony of Mark A. Bailey at 7-8.

After Alcan gave its notice of contract termination on January 31, 2013, it took Moody's, Standard & Poor's, and Fitch less than three days to downgrade Big Rivers' credit ratings to well below investment grade. The electric utility industry is one of the most capital intensive in the world, yet Big Rivers cannot borrow in the private credit markets for needed investments. Adequate service to customers could be threatened.

Big Rivers has once again put this Commission in a very difficult position. Big Rivers claims that the Commission faces one of two choices: grant it every dollar of its pancaked rate cases or force Big Rivers into bankruptcy.[10] This so-called "stark choice" is a scare tactic and a false construct. As discussed *infra*, KIUC has an alternative plan that involves a reasonable rate increase on August 20, 2013 coupled with the use of the $135 million in Reserve Funds to allow Big Rivers to meet its credit obligations until a comprehensive plan is developed to right size the system to serve the non-smelter load. Such a comprehensive solution should involve all stakeholders: Big Rivers, Kenergy, Meade County, Jackson Purchase, the Attorney General, KIUC, Sierra Club, Century Aluminum, the three creditors (RUS, Co-Bank, and CFC), and the Commission.

If a comprehensive solution is not reached, then the Commission will not just have to deal with two pancaked rate cases, two smelter market access contract cases, and multiple financing applications. Instead, in all likelihood, the litigation will get worse. Multiple appeals by numerous parties in numerous cases on numerous issues are possible. More rate cases by Big Rivers and/or Kenergy, Meade County, and Jackson Purchase would be likely as the economy shrinks and usage declines in the wake of the two pending rate cases. The current management of Big Rivers is honest, hard-working, and talented in engineering matters. But an additional skill set centered on corporate restructuring is now needed to right-size the utility for a post-smelter world.

Not too long ago East Kentucky Power Cooperative was teetering with a dangerously low equity ratio, a power plant under construction it did not need, and a Board of Directors that was slow to adapt. This Commission had the foresight to order a Management Audit that recommended many bitter pills for the good of the organization. Those Management Audit recommendations were followed. Under the leadership of the new CEO, East Kentucky has stable rates and a growing equity ratio, Smith Unit 1 was cancelled midway through

[10] Rebuttal Testimony of Mark A. Bailey at 4:18-20.

construction,[11] and East Kentucky's future looks relatively secure as a winter-peaking member of PJM. The same turnaround may be possible for Big Rivers. But only if there is a comprehensive solution. Rate increase on top of rate increase on top of rate increase is not a viable plan.

The decisions of the two smelters to leave Big Rivers' system will result in the Company losing approximately 68% of its total load by the end of January 2014.[12] Big Rivers seeks Commission approval to recover 100% of the costs of that excess capacity from its remaining non-smelter customers. According to Big Rivers' own calculations, the cumulative impacts of the Century and Alcan rate cases would raise rates, including all billing components, to Large Industrials by 110% on an "all-in" basis as of July 2014 (when the Economic Reserve is projected to be exhausted). Those cases would also raise Rural rates, including all billing components, to the average residential household by 72.3% on an "all in" basis as of April 2015 (when the Rural Reserve is projected to be exhausted), which amounts to an increase to the average residential customer of $881 per year. Big Rivers' proposal to impose the entire cost burden associated with the smelters' departure on its remaining customers, while continuing to pump additional money into its unneeded and uneconomic coal-fired power plants in the hopes that those plants will someday have future value, is not reasonable.

B. KIUC's Adjustments to Big Rivers' Proposed Revenue Requirement.

Big Rivers' proposed $68.6 million revenue requirement is flawed and should be adjusted in several ways to: 1) prevent the Company from over-collecting from its customers; and 2) establish a balanced approach that equitably shares the burden of Big Rivers' excess capacity among Big Rivers, its creditors, and its customers.

As an initial matter, three adjustments to the proposed $68.6 million revenue requirement are necessary in order to correct Big Rivers' fully forecasted test year in light of its recent decision to idle Wilson beginning February 1, 2014 as well as its decision not to issue certain pollution control bonds. These adjustments are as follows:

1. <u>A reduction of $11.685 million</u> to remove depreciation expense for the 7 months of the 12 month fully forecasted test period that Wilson will be idled;

[11] *See An Investigation of East Kentucky Power Cooperative Inc.'s Need for the Smith Generating Facility*, Case No. 2010-00238, Order (Feb. 28, 2011).
[12] See Direct Testimony of Lane Kollen (May 24, 2013) ("Kollen Testimony") at 28:1-3 (calculated based on average monthly demand).

2. A reduction of $16.333 million to reflect the 7 months of the savings that will result from idling Wilson that are not taken into account in the 12 month fully forecasted test period;

3. A reduction of $4.353 million for interest expense and related TIER on pollution control bonds that will not be issued;[13]

These are traditional revenue requirement adjustments that should be made to correct inaccuracies in the Company's fully forecasted test year. These three adjustments reduce the proposed revenue requirement to $36.23 million.

The final adjustment that should be made is to eliminate excess capacity costs by reducing Big Rivers' revenue requirement by an additional 40% ($14.50 million). 40% represents Century's current share of the internal load on the Big Rivers' system.[14] The Company's remaining customers do not benefit from the excess capacity resulting from Century's departure, which is not physically or economically "used and useful." Reducing the proposed revenue requirement in this manner is consistent with the balanced approach the Commission has previously used to address excess capacity issues.[15]

We are not advocating that Century be forced to pay this excess capacity adjustment. Nor do we advocate that Big Rivers should somehow absorb this cost. Instead, under the formula rate plan contained in our recommended solution, this cost will be paid out of the $135 million Reserve Funds until a comprehensive resolution is reached. Indeed, under our recommended solution, any revenue shortfall needed for Big Rivers to achieve a 1.24 TIER would be supplied from the Reserve Funds to "buy time" to work out a viable settlement. If a consensus plan cannot be reached, then the Commission would be required to set rates at that time.

If the Commission makes all of KIUC's recommended adjustments, the result would be a $21.7 million base rate increase in this proceeding.

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[13] Kollen Testimony at 60:1-10.
[14] Bailey Direct Testimony at 8:9-10.
[15] *In the Matter of Big Rivers Electric Corporation's Notice of Changes in Rates and Tariffs for Wholesale Electric Service and of a Financial Workout Plan*, Case No. 9613, Order (March 17, 1987) ("1987 Order") at 37.

C. KIUC's Recommended Solution.

Big Rivers' has proposed a fundamentally inequitable approach to resolving issues resulting from the pending Century and Alcan departures. Under that approach, Big Rivers' remaining customers would pay 100% of the costs of its 1000 MW of excess capacity (resulting in a 110% increase for the average Large Industrial customer and an increase of $881 per year for the average residential customer), while its three creditors (who were fully aware of the risks of a smelter departure when they lent money to Big Rivers) would receive full payment on their loans and Century (which now owns both the Hawesville and Sebree smelters) would enjoy a 30% rate reduction.[16] Though Big Rivers' proposes to temporarily mask the impacts of its requested rate increases to customers by accelerating the use of its MRSM and RER credits beginning February 2014, this approach would create a ticking time bomb. When those credits run out, Big Rivers' remaining customers will feel the full brunt of those 110% Large Industrial and $881 per year residential rate increases, which would automatically take place at that point in time.

The Commission does not have to simply adopt Big Rivers' inequitable "time bomb" approach and instead, can view the case as presenting more than a "stark choice" between two extreme options. As it has in the past, the Commission can develop a balanced approach to resolving Big Rivers' financial issues that spreads the cost burden associated with the pending Century and Alcan departures among all stakeholders. KIUC recommends such an approach, under which the Commission would:

- Approve a reasonable base rate increase of $21.7 million for Big Rivers' remaining customers for the five months prior to the Commission's order in the pending Alcan rate case (September 1, 2013 through January 31, 2014);
- Direct Big Rivers to use the $135 million in the ratepayer Reserve Funds to provide the additional compensation the Company needs to meet its 1.24 TIER target on a monthly basis;
- Explicitly direct Big Rivers to work with all stakeholders to achieve a reasonable negotiated solution to the Company's financial issues prior to the exhaustion of the Reserve Funds.

[16] Case No. 2013-00221, Direct Testimony of Sean Byrne (July 19, 2013) at 5:11-13.

There are many benefits to KIUC's approach, including: 1) avoiding rate shock to customers; 2) achieving an equitable sharing of the excess capacity costs resulting from Century's departure rather than forcing Big Rivers' remaining customers to take on 100% of the cost burden ; 3) preventing Big Rivers from having to make a Chapter 11 filing since the Company will continue to meet its monthly debt obligations using the $135 million in ratepayer Reserve Funds; 4) providing an incentive for the creditors to work with Big Rivers in a reasonable manner prior to the exhaustion of the ratepayer Reserve Funds; 5) providing additional time for the significant uncertainties surrounding Century's departure (i.e. the impacts of MISO's "must run" decision on Coleman) to be resolved; 6) providing additional time in which the economics of investing additional capital in the Wilson and Coleman units can be comprehensively studied; and 7) establishing a framework that can also be used in the pending Alcan rate case (approving a reasonable rate increase and allowing Big Rivers to draw on the ratepayer Reserve Funds to meet a 1.24 TIER monthly target).

In contrast to Big Rivers' "time bomb" approach, KIUC's recommends an "hourglass" approach which provides Big Rivers with additional time and a strong incentive to find a balanced resolution to its financial issues resulting from the smelters' departure. The use of the $135 million in Reserve Funds is the key to this approach. Since the Reserve Funds were created by the Commission expressly for the benefit of customers, it makes sense to use them as a tool in this case to protect those customers from substantial rate increases while still ensuring that Big Rivers can achieve the earnings targets it needs in order to not default on its loan covenants.

If a reasonable workout plan has not been reached and/or Big Rivers' rate mitigation plan is unsuccessful by the time the $135 million Reserve Funds are exhausted, then Big Rivers could file another rate case. At that time, the Commission would have important additional information upon which to make its ruling.

II. ARGUMENT

A. Big Rivers' Proposal To Recover 100% Of The Excess Capacity Caused By The Departure of Century From Its Remaining Customers Is Inequitable And Contrary To Commission Precedent.

1. If Granted, The Pancaked Effect Of The Century And Alcan Rate Cases Would Be A 110% Increase To Large Industrial Customers And A 72% Increase To Rural Customers At Retail, Forcing Those Customers To Pay For Excess Capacity That Is Not "Used And Useful" Once The Smelters Leave The System.

The decisions of the two smelters to leave Big Rivers' system will result in the Company losing approximately 68% of its total load by the end of January 2014.[17] Yet Big Rivers does not intend to reduce the total amount of its generating capacity to reflect its soon-to-be substantially diminished load, despite the fact that it will have a 190% reserve margin once both smelters have departed.[18] Instead, Big Rivers seeks Commission approval to recover 100% of the costs of that excess capacity from its remaining non-smelter customers, even though the Company has not comprehensively studied whether that capacity will provide any benefit to those remaining customers either now or in the future.

According to Big Rivers' own calculations, the cumulative impacts of the Century and Alcan rate cases would raise rates, including all billing components, to Large Industrials by 110% on an "all-in" basis as of July 2014 (when the Economic Reserve is projected to be exhausted), as shown below.

Proposed Increases for Large Industrial Customers Due to "Century" and "Alcan" Rate Cases

Current Rates	3.7556¢/kWh	N/A
Century Rate Case Request[19]	4.7203¢/kWh	25.6%
Alcan Rate Case Request[20]	7.91¢/kWh	67.6%
Combined Impact of Century and Alcan Rate Cases	**7.91¢/kWh**	**110%**

[17] Direct Testimony of Lane Kollen (May 24, 2013) ("Kollen Testimony") at 28:1-3 (calculated based on average monthly demand).
[18] Kollen Testimony at 29:2-9.
[19] Attachment A, KIUC Ex. 8 (for Large Industrial customers taking service at transmission voltage, wholesale and retail rates are substantially the same).
[20] Case No. 2013-00199, Ex. Wolfram-8 at 2; Attachment B (Sierra Club Ex. 6).

Those cases would also raise Rural rates, including all billing components, to the average residential household by 72.3% on an "all in" basis as of April 2015 (when the Rural Reserve is projected to be exhausted), which amounts to an increase to the average residential customer of $881 per year.

Proposed Increases for Rural Customers Due to "Century" and "Alcan" Rate Cases

Current Rates	7.8103¢/kWh	N/A	N/A
Century Rate Case Request[21]	9.5346¢/kWh	23.8%	$269
Alcan Rate Case Request[22]	13.46/kWh	41.2%	$612
Combined Impact of Century and Alcan Rate Cases on Average Residential Customer	**13.46/kWh**	**72.3%**	**$881**

KIUC believes that it is important to look at the cumulative impact of all components from these increases, not just base rates. Big Rivers' agreed that this is the appropriate way to view a proposed rate increase. According to Mr. Bailey, Big Rivers takes the same approach when evaluating a rate increase. During cross-examination Mr. Bailey stated "*...when we evaluate percentages and dollars, we look at the bottom line because we know that's the way the customers look at it. They aren't breaking it into environmental and fuel and base* [rates]."[23] Big Rivers' witness, John Wolfram, also confirmed that KIUC's method of calculating the customer rate impact is correct.[24]

The cumulative impact of these two cases would represent the largest rate increase over such a short period in the history of the Kentucky. KIUC is not aware of any case or cases in which any Commission in the nation has allowed a utility to double its rates within a year as Big Rivers proposes to do through its "pancaked" rate cases. According to SNL financial data, which begins in 1980, the largest rate increase ever approved for a regulated utility in the United States was 57% (in 1986), the next largest was 45% (in 1989).[25] It is not hyperbole to state that Big Rivers is requesting that the Commission approve *historic* rate increases.

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[21] Attachment A, KIUC Ex. 8.
[22] Case No. 2013-00199 Ex. Wolfram-8 at 1; Attachment B (Sierra Club Ex. 6).
[23] Tr. July 1, 2013 at 11:57:23.
[24] Tr. July 3, 2013 at 12:09:00.
[25] Attachment C (SNL list of all state commission decision since 1980 approving a rate increase of 10% or higher).

Rate increases approaching the magnitude of Big Rivers' current requests have only been experienced in recent years in states that were in the process of deregulating. And they have been met with extreme responses. In June of 2007, as that state moved from frozen legacy rates to market-based rates, the Maryland Commission approved residential increases of 72% for Baltimore Gas and Electric Co. That decision was so unpopular that the General Assembly fired the Maryland Commissioners, only to have the Maryland Court of Appeals overturn its action.[26] The same year, the Illinois Commission decided to allow deregulated electricity to be procured via a "reverse auction" process that resulted in rate increases ranging from 26% to 55%. In response, the Illinois General Assembly enacted the Illinois Power Agency Act which, *inter alia*, banned reverse auctions and required ComEd and Ameren to provide $1 billion in refunds to Illinois electric customers.[27]

These proposed rate increases could be devastating to Big Rivers' customers, given that the Company serves a residential base that earns 20% below the Kentucky average household income[28] and has traditionally attracted energy-intensive industries with the promise of low-electric rates. And if Big Rivers' non-smelter customers are ultimately unable to absorb these staggering increases and it loses additional load as a result, the Company would likely have to file another rate increase, which would only amplify the cost burden imposed on any remaining customers.

Worse, these rate increases may be even larger in the long run since Big Rivers' requested increases do not account for additional costs that the Company will incur related to its excess capacity, including costs required for compliance with future environmental regulations. For example, Big Rivers estimates that its Coleman and Wilson units will require an additional [redacted] million in capital spending over the next four years.[29] Big Rivers' proposal to impose the entire cost burden associated with the smelters' departure on its remaining customers, while continuing to pump additional money into its unneeded and uneconomic coal-fired power plants in the hopes that those plants will someday have future value, is not reasonable.

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26 http://articles.baltimoresun.com/2007-01-18/news/0701180028_1_monopoly-commission-electricity.
27 http://www.citizensutilityboard.org/ciLiveWire_IEP_ERRR.html.
28 http://quickfacts.census.gov/qfd/states/21000.html.
29 KIUC Ex. 5 CONFIDENTIAL and Attachment G (excerpts from KIUC Ex. 5).

2. Big Rivers' Proposed $68.6 Million Rate Increase, If Granted, Would Force Its Remaining Customers To Pay For The Costs Of Excess Capacity Approximately 2.5 Times The Company's Native Load Requirements.

Like customers served by an investor-owned utility, customers located in the exclusive service territory of a cooperative utility must only pay rates that are just and reasonable.[30] Such rates do not include the costs of any utility facilities that are not "used and useful" in providing service to those customers. The Commission has repeatedly upheld this fundamental principle in the past, specifically disallowing costs that were not just and reasonable and/or that did not result from "used and useful" facilities. For example, in two successive 1980s rate cases, the Commission denied recovery of the costs of Big Rivers' Wilson plant because the resulting increase in rates would not have been just and reasonable.[31] The Commission also denied recovery of 25% of the costs associated with LG&E's Trimble County 1 because its generating capacity was excessive compared to the capacity necessary to serve the load of its customers.[32]

In this case, Big Rivers asks the Commission to force its non-smelter customers to pay unjust and unreasonable costs associated with facilities that are not "used and useful" in providing service to those customers – its Wilson and Coleman units. Once the smelters leave Big Rivers' system, these units will represent excess capacity that non-smelter customers should not be required to pay for.

As the following chart reflects, Big Rivers' currently owns 1,819 MW of generation, which is used to meet its 1,428 MW monthly average demand.

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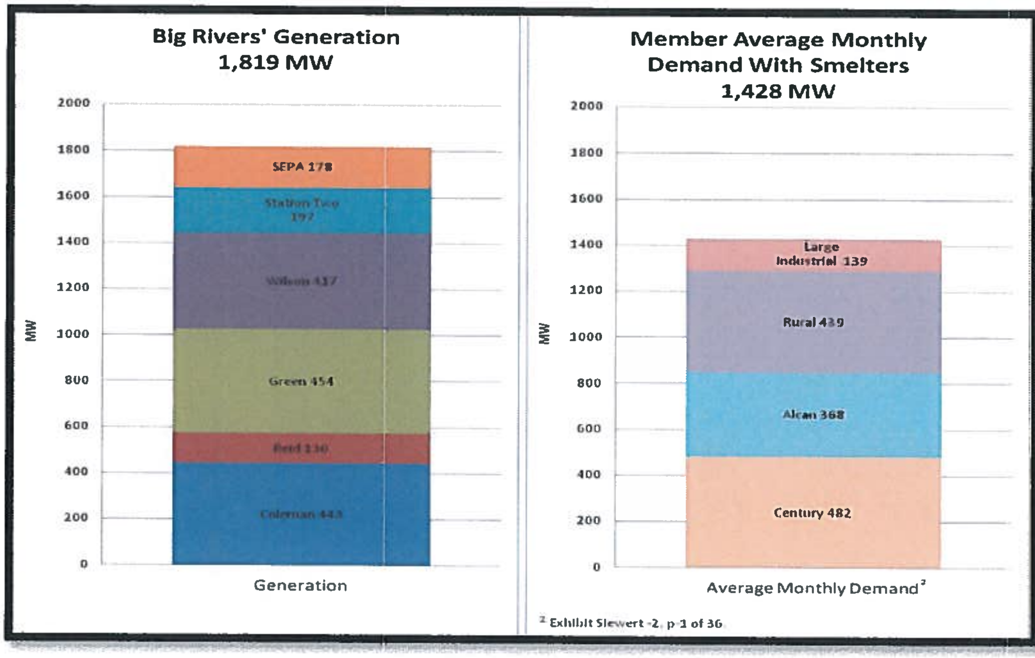
[30] KRS 279.010(12); 1987 Order at 39. In that Order, the Commission held that cooperatives organized under KRS 279 are subject to all of the provisions of KRS 278 and that rate base and debt service coverage for a cooperative utility must be determined by applying the same standards applicable to investor-owned utilities. Id at 39. The Commission also stated that "[a] *cooperative's system is defined as consisting of "any plant, works, facilities and properties ...used or useful in the generation, production, transmission or distribution of electric energy" and that "[i]n balancing the equities to determine just and reasonable rates, the used and useful standard must be applied to cooperatives in the same manner as it is applied to investor-owned utilities.*" Id.

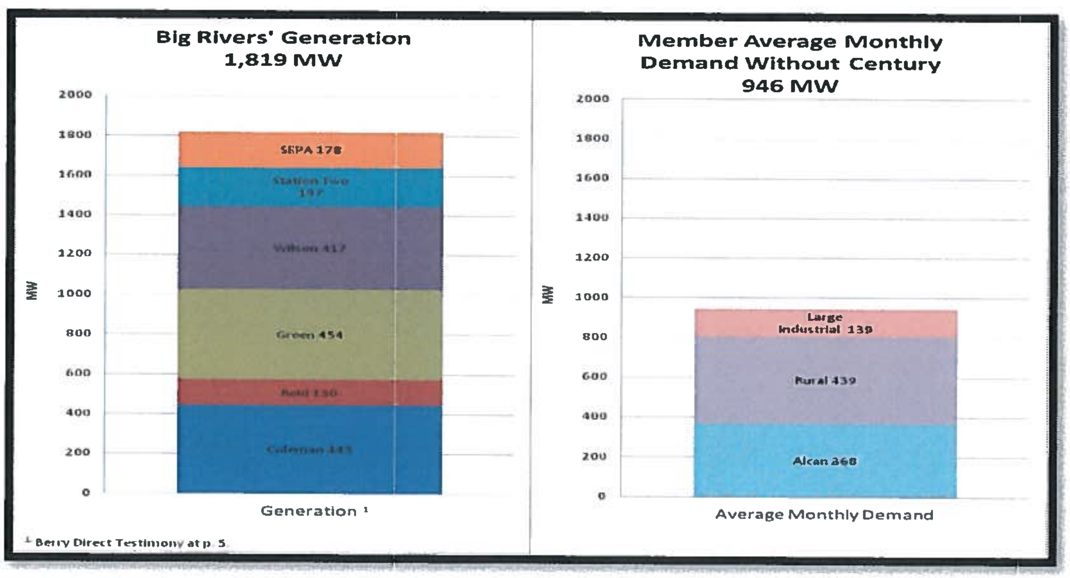
[31] *In the Matter of Big Rivers Electric Corporation's Notice of Changes in Rates and Tariffs for Wholesale Electric Service and of a Financial Workout Plan*, Case No. 9613, Order (May 6, 1985) at 23 ("*Big Rivers' current lack of a line of credit is due solely to the financial problems related to the Wilson plant. As stated many times in this record, the costs and problems attendant to the Wilson plant will not be reflected in Big Rivers' current rates*"); Case No. 9885, Order (Aug. 10, 1987).

[32] *A Formal Review of the Current Status of Trimble County Unit No. 1*, Case No. 9934, Order (July 1, 1988) at 33.



[33]

After Century leaves the Big Rivers' system on August 20, 2013, the Company's average monthly demand will fall to 946 MW, as shown below.



[34]

The chasm between Big Rivers' generating capacity and its monthly average demand widens once Alcan leaves the system on January 31, 2014.

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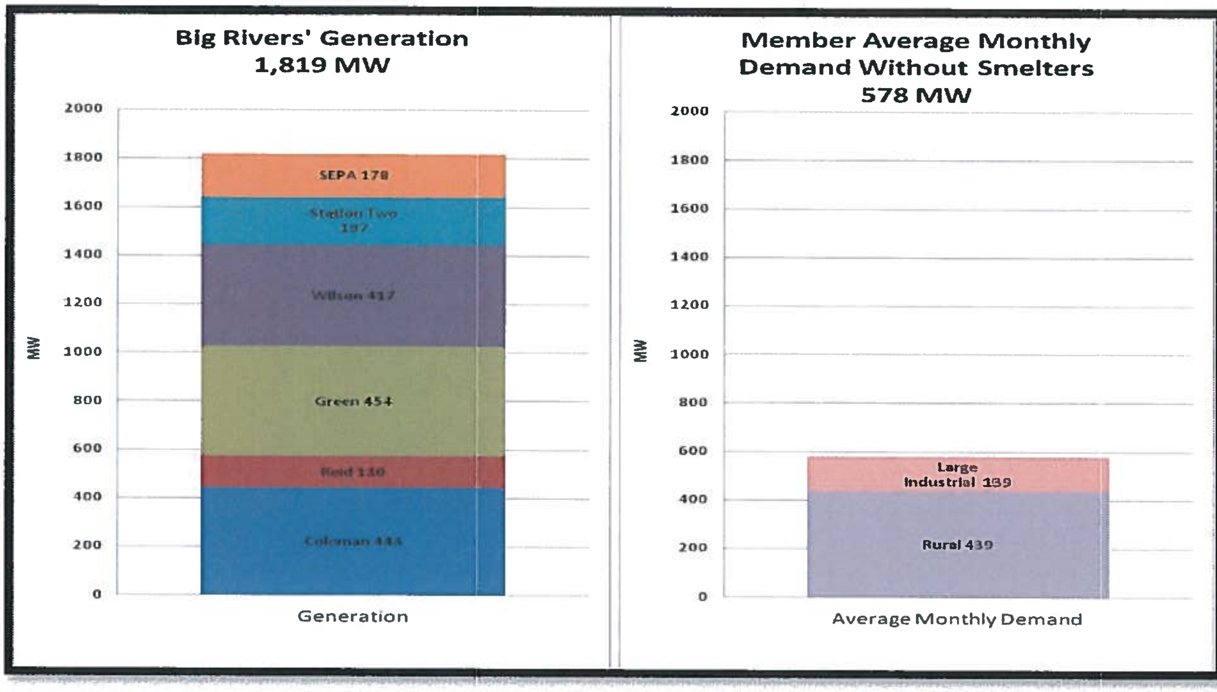
[33] Direct Testimony of Robert W. Berry (Jan. 15, 2013) ("Berry Direct Testimony") at 5; Direct Testimony of Travis A. Siewert, Ex. Siewert-2 at 1. The average load in MW was computed by summing the monthly loads and dividing by 12.
[34] Berry Direct Testimony at 5.



[35]

Consequently, the pending loss of the Century and Alcan loads will result in Big Rivers having capacity far in excess of its average monthly demand. The Company's present reserve margin of 23%, which is perhaps a little high relative to other utilities in Kentucky and to the MISO planning reserve margin of 16.7%, will skyrocket as each smelter's load leaves the system. The Century load loss causes Big Rivers' reserve margin to jump up to 83% and the Alcan load loss further inflates the Company's reserve margin to 190%.[36]

Big Rivers' projected reserve margins will far exceed the reserve margins of other Kentucky utilities, as shown below:

[35] Berry Direct Testimony at 5.
[36] Kollen Testimony at 29:4-9.

Comparison of Reserve Margins For Utilities in Kentucky	Generating Capacity MW	Peak Load MW	Reserve Margin MW	Reserve Margin Percentage
Kentucky Power Company (1)	1,526	1,240	286	23%
Kentucky Utilities Company	5,104	4,292	812	19%
Louisville Gas and Electric Company	3,431	2,704	727	27%
Duke Energy Kentucky	1,141	894	247	28%
East Kentucky Power Cooperative	3,099	2,481	618	25%
Big Rivers With Smelters	1,819	1,478	341	23%
Big Rivers Without Century	1,819	996	823	83%
Big Rivers Without Century and Alcan	1,819	628	1,191	190%

Source data: FERC Form 1s, and RUS Form 12s, 10-K for KPCo, and BREC filing in this proceeding.

(1) The Kentucky Power Company generating capacity reflects its MLR share of the AEP system and its peak load is shown at the AEP system summer peak so the capacity and peak load are matched.

Without the smelters, Big Rivers will have *two and a half times* the generating capacity and reserve margin that it needs to meet the load of its remaining customers.

Big Rivers could meet its native load energy obligations once the smelters leave without running its Coleman and Wilson units. In fact, Big Rivers' could meet its projected native load energy needs with just its Green Units and SEPA.[37] In 2014, Big Rivers projects that native load will be 3,391,114 MWh.[38] In 2014, Green Units 1 and 2 are estimated to produce 3,281,036 MWh. The two Green units alone, therefore, are projected to satisfy nearly all of Big Rivers' native load energy obligation in 2014. When the 301,929 MWh from SEPA is added to the Green figures, Big Rivers has 3,582,965 MWh of energy, or more than enough to satisfy its native load obligation. When Big Rivers' share of HMP&L is added, the Company can serve the energy needs of its native load and sell large volumes of energy off-system. The Company's Wilson and Coleman units therefore represent 6,218,178 MWh of excess energy and 870 MW of excess capacity that is not "used and useful" in providing service to the non-smelter customers.[39] Yet Big Rivers plans to idle and continue to incur expenses, including significant capital expenditures, on those units until it is profitable to run those units as a merchant generator, if that ever occurs.

[37] Attachment D, KIUC Ex. 4 (Energy Available for Market Sales with Coleman and Wilson Running).
[38] Attachment D, KIUC Ex. 4.
[39] Attachment D, KIUC Ex. 4.

Unfortunately, Big Rivers is not likely to succeed as a merchant generator in the near future. According to the Company's own projections, the excess capacity from its Wilson and Coleman units cannot be sold economically into the market for at least the next six years.[40] In fact, Big Rivers would need to earn an around-the-clock margin of [redacted]/MWh on all energy produced in order for taking Wilson out of mothball status to be economic.[41]

Despite the fact that Big Rivers' excess capacity is not physically or economically "used and useful" to its non-smelter customers, the Company nevertheless has included 100% of the unavoidable fixed costs (interest expense, margin, depreciation and non-fuel fixed O&M) related to that excess capacity in its proposed revenue requirement in this proceeding. This is not reasonable. A utility subject to the ratemaking authority of the Commission does not have an unrestricted right to recover any and all costs that it may incur, including the costs of its excess capacity. The minimum standards for recovery require that the costs be prudent, reasonable, and necessary to provide regulated utility service.[42] Otherwise, any and all costs actually incurred by a regulated utility would be recoverable from customers, subject only to reviews for accuracy. The Commission's role in setting fair, just, and reasonable rates, however, transcends that of a mere auditor and requires the application of informed judgment to balance the conflicting demands of the utility's customers and its creditors/investors.

Because Big Rivers' capacity has been rendered no longer "used and useful" due to the smelters leaving the system for lower cost market power, it is reasonable to equitably share the resulting cost burden between the Company's customers and its creditors. Forcing customers to pay 100% of the costs associated with that excess capacity is against the weight of this Commission's precedent. The Commission has a statutory mandate to set

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[40] KIUC Ex. 15 at 1.

[41] The savings from idling both units are around [redacted] million. Attachment E, KIUC Ex.2. Wilson produces approximately 3 million MWh a year. Attachment D, KIUC Ex. 4. Therefore, it would take [redacted]/MWh increase in market prices to exceed the savings from idling the unit (3 million MWh x [redacted]/MWh = [redacted] million).

[42] In applying these standards, the Kentucky Commission generally does not allow utilities to recover the following costs:

1) Certain advertising expenses and political donations. 807 KAR 5:016;
2) Acquisition costs or expenses incurred through affiliate transactions that are in excess of market. KRS §278.2207;
3) Unreasonable rate case expenses. *In the Matter of the Application of Big Rivers Electric Corporation for a General Adjustment in Rates*, Case No. 2011-00036, Order (Jan. 29, 2013) at 5-6;
4) Unreasonable fuel costs (FAC). *See* 807 KAR 5:056. *An Examination by the Public Service Commission of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation From November 1, 1991 to April 30, 1992*, Case No. 90-360-C, Order (July 21, 1994). In fact, the Commission's denial of unreasonable fuel costs, plus excess generating capacity that could not be sold in the wholesale market for adequate margins, was a factor in Big Rivers' 1996 bankruptcy;
5) Environmental costs related to off-system sales (ECR). *An Examination by the Public Service Commission of the Environmental Surcharge Mechanism of Kentucky Power Company D/B/A American Electric Power for the Six-Month Billing Periods Ending December 31, 1998 and December 31, 1991 and for the Two-Year Billing Period Ending June 30, 1999*, Case No. 2000-00107 (Feb. 8, 2001).

rates at just and reasonable levels for Big Rivers and its customers, but there is no statutory requirement that the Commission set rates at levels sufficient to pay off all creditors, without regard for the rate impact on customers.

3. Big Rivers' Proposal To Continue To Incur Capital Costs Associated With The Wilson And Coleman Units Is Based Upon Limited And Subjective Instinct And/Or Questionable Projections, Rather Than Comprehensive And Objective Analysis.

At the hearing, Big Rivers witnesses Bailey opined that, even if the Wilson and Coleman are not currently "used and useful," they may have some value in the future. With respect to those units, Mr. Bailey stated:

> *"…my instincts are that this market's growing stronger and since we have competitive generation assets, they're valuable assets that can produce value for our member owners in the future and that's why we believe that to take a short-term view would be imprudent."*[43]
>
> ***
>
> *Q: "And so you believe that it's appropriate to ask your remaining customers to bear the costs of maintaining 1000 MW of excess capacity on the expectation that the market will improve sometime around 2019?"*
>
> *A: "The assets have produced value to our members for many, many years. We expect they will in the future…we believe patience is a virtue in this particular case."*[44]

Unfortunately, Mr. Bailey's assessment of the future value of the Wilson and Coleman units is not supported by objective analysis. Aside from instincts of Big Rivers' management, the little evidence Big Rivers presents to support its contention that the Wilson and Coleman units may once again be economic to run in 2019 is highly questionable.[45] The Chart below shows Big Rivers' projected market prices and Big Rivers' projected variable costs for the Wilson and Coleman power plants.[46]

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[43] Tr. July 1, 2013 at 15:06:34.
[44] Tr. July 1, 2013 at 15:06:51.
[45] KIUC Ex. 15. *See* Confidential Response to Ben Taylor and Sierra Club Supplemental Requests for Information, Item 2, Attachment (Big Rivers 2013-2027 Budget Exhibits- Base Case).
[46] KIUC Ex. 15 at 1 – CONFIDENTIAL.

[redacted]

While the modeling assumptions used to produce these projections are still unclear, the fact that the projections show a sudden spike in market prices in 2019 strongly suggests that the model assumed that federal environmental regulations will lead to a dramatic market price increase. The Big Rivers modeling relies on market price projections obtained from ACES and, perhaps, other vendors. ACES typically provides multiple forecasts (including a base case, low case, and high case forecast) to a client for modeling purposes. Though Big Rivers never clarified which type of ACES forecast it used in modeling its market price projections for this case, its projected sudden spike in market prices for 2019 may be the result of using a high case ACES forecast that contained more aggressive assumptions regarding carbon emission regulations.

Sierra Club witness Dr. Ackerman testified that the spike in Big Rivers' market projection in 2019 is not only unexplained, but is also contrary to two other electricity price forecasts (from IPL/Ventyx and the Energy Information Administration's Annual Energy Outlook), which do not reflect similar spikes in market prices in 2019:

> *... [Big Rivers] is assuming a dramatic increase in the price of electricity around 2019, with no corresponding increase in generation costs. The Company has not explained this price jump in its modeling, which is not present in electricity price forecasts from IPL/Ventyx or the Energy Information Administration's Annual Energy Outlook. However, if Big Rivers' error in carbon price modeling identified in the 2012 CPCN case by Sierra Club witness Rachel Wilson — wherein Big Rivers effectively assumed that every utility in the country would have to pay a price*

for its CO_2 emissions except for Big Rivers — has not yet been corrected, then the result would be an erroneous jump in electricity prices after 2018, much like the forecasts found in the Company's production cost model runs.[47]

With respect to Big Rivers' modeling of its own costs, Mr. Bailey confirmed that Big Rivers did not include "*the costs of any regulations that are proposed, but not finalized…*"[48] The disparity between the market price projections and the production costs strongly suggests that Big Rivers is comparing a market price forecast that reflects additional federal regulations and costs for coal-fired power plants to a production cost model that does not reflect these same regulations and costs.

Unfortunately, Big Rivers never provided a satisfactory explanation for its seemingly incongruous market price and cost modeling comparison, as Dr. Ackerman explained during cross-examination:

> "[T]*he mystery of those is that there is a corner in the curve – that Big Rivers' forecasts that its plants will be profitable by essentially predicting that prices turn upward in 2019 and so does the volume of sales. This, in my experience, this is not common in economic forecasts to see a sudden corner at a date certain in the future. And the only argument which I have found surrounding this all is that the arguments about the error in asymmetric treatment of carbon prices in the previous case produces a corner in the curve at exactly the same point. So I hypothesize that if that error continued, it would in fact explain the puzzling pattern that we see here. If that error did not continue, we need another explanation of the same puzzling pattern, of the same sudden corner in the curve in 2019. All of the notions of the future profitability of Wilson or Coleman, and so on, depend on that curve having a corner at 2019. As I show, two other price forecasts have no such corner and I'm not aware of any other forecast that had that.'*[49]

Given Big Rivers' failure to explain this major anomaly in its market pricing forecast, it would be unreasonable for the Commission to approve the substantial rate increases Big Rivers' requests in this case based upon the Company's questionable projections and/or its lukewarm assurance that "*we believe right now, based on our current projections, that Wilson will be in the money, so to speak, by 2019. That's a projection. It could be sooner, it could be later. We do not know.*"[50]

Additionally, even if Big Rivers' market and cost projections are 100% correct, and market prices dramatically increase in 2019 without a corresponding increase in Big Rivers' costs, Big Rivers is still asking customers to carry two unused power plants for a full six years. That is an awfully long time to incur costs on

[47] Supplemental Testimony of Dr. Frank Ackerman at 10:3-11.
[48] Tr. July 1, 2013 at 15:08:29.
[49] Tr. July 3, 2013 at 16:38:27.
[50] Tr. July 1, 2013 at 15:05:20.

In spite of the fact that Big Rivers did not comprehensively study the reasonableness of keeping its Wilson and Coleman units running and forcing non-smelter customers to keep paying for costs associated with those units, the Company will continue to make capital expenditures on the units even though the expected life of the Coleman units could be as short as 11 years.[55] Mr. Berry estimated that between 2013 and 2016, Coleman would require [redacted] million in additional capital spending, including spending for environmental compliance.[56] [redacted] million is a lot of money to spend on a power plant that is not currently needed. Big Rivers plans to spend this money on the hope that Coleman may become marginally economic in 2019 if market prices dramatically increase and Coleman's production costs stay flat.

Mr. Berry also estimated that the Wilson unit would require [redacted] million in additional capital spending between 2013 and 2016.[57] The ultimate level of these costs could be even larger, however, depending upon future environmental regulations. Big Rivers' ability to undertake any additional spending necessary for environmental compliance is questionable, given that the Obama's administration has a stated policy of phasing out coal-fired generation and the RUS' total budget for loans to finance such spending may be a mere $1 billion for all generation cooperatives in the United States.[58]

One option that Big Rivers should have comprehensively studied and provided to the Commission in this case is whether the Wilson and Coleman units should be retired. If studies on this question ultimately indicate that the units should be retired, the Commission would have flexibility in considering how to handle those retirements. The Commission has already approved flexible solutions to resolve plant retirement/cancellation issues for other utilities in the past, including East Kentucky Power, and it could do so in the case of Big Rivers as well.[59]

Retiring the Wilson and/or Coleman units does not have to be substantially adverse to Big Rivers' finances. Big Rivers has $400 million in patronage capital (equity) that can be used to help reduce any amount of

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[55] KIUC Ex. 5 at 16.
[56] KIUC Ex. 5, Attachment G (excerpts from KIUC Ex. 5).
[57] KIUC Ex. 5, Attachment G (excerpts from KIUC Ex. 5).
[58] KIUC Ex. 13 (The President's Climate Action Plan); Tr. July 2, 2013 at 9:41:26.
[59] *An Investigation of East Kentucky Power Cooperative Inc.'s Need for the Smith Generating Facility*, Case No. 2010-00238, Order (Feb. 28, 2011).

the units that the Company would be required to write-off.[60] For example, if it is determined that Coleman should be retired, the Commission could require Big Rivers to write off half of the value of Coleman (approx. $90 million) and allow the Company to recover the other half (approx. $90 million) from customers over an extended period of time. In that case, Big Rivers could use $90 million of its $400 million of patronage capital to cover the write-off for financial purposes. This approach could make sense because the Commission would be using patronage capital that belongs to consumers to protect those very same customers from paying for plants that are no longer "used and useful."[61] These decisions should be part of any workout process.

It is one thing for an investment grade utility to invest capital on environmental equipment for coal generation to serve native load as part of a well documented least cost and diversified generation portfolio. That is KU, LG&E, East Kentucky and Kentucky Power. It is quite another thing for a cooperative with very little borrowing capability to continue to pour money into coal generation not needed for native load and which essentially has a merchant function in the MISO market. That is Big Rivers.

In light of Big Rivers' failure to provide a comprehensive, objective analysis of the value of its excess capacity to non-smelter customers, it is not reasonable for the Commission to make a permanent decision forcing customers to pay for all the costs associated with that excess capacity in this proceeding. Instead, the Commission should adopt KIUC's approach outlined below, which provides valuable time for both Big Rivers and the Commission to comprehensively analyze these issues prior to making such a permanent decision.

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[60] Tr. July 2, 2013 at 10:19:26.
[61] Tr. July 2, 2013 at 10:19:31.

4. **Big Rivers' Rate Mitigation Plan Is Unduly Optimistic, And Even If Its Most Optimistic Forecast Comes To Pass, Requires Customers To Pay For Excess Capacity For Six Years Before That Capacity Is Economic To Run.**

It would be unreasonable for the Commission to set rates in this case based on hopeful, but unfounded, speculation that market conditions will significantly improve for Big Rivers in the short or medium term. This is true for both regulatory and economic reasons.

Rates set by the Commission must always be fair, just and reasonable under Kentucky law. Rates cannot be set at unreasonable levels, even temporarily. Raising rates temporarily to an unreasonable level in this case in the hope that market conditions may improve and ultimately allow rates to decline back down to a reasonable level is not an option. Rates should be set at reasonable levels based upon what is known when they are set, not based upon speculation about future market conditions. Even if the Commission accepted Big Rivers' projections of a sudden upswing in the power market in 2019 (that would not be offset by an increase in Big Rivers' costs) as reliable, it is not reasonable to set rates based upon market conditions that may exist 6 years after those rates were set.

Additionally, the likelihood is very low in the near to intermediate term that the financial fortunes of Big Rivers will be turned around through an increase in the wholesale market price of energy, an increase in the value of coal-fired generation, moving out of MISO to PJM, entering into a long-term purchase power agreement, finding a new wholesale distribution cooperative member willing to pay above-market rates, or attracting a new end-use customer to locate on the system that is large enough to make a difference.

First, there is a low probability that market conditions will improve sufficiently and quickly enough to make a difference in this case, the Alcan increase case, or the other related future rate increases. In its financial model, Big Rivers projects very depressed wholesale energy prices through at least 2019. This depressed market forecast is confirmed by forward prices reported for the MISO region.[62] In many of the off-peak hours energy prices do not even cover Big Rivers' variable cost of production.

On April 5, 2013, MISO released the results of its first capacity auction under its recently enhanced resource adequacy construct. The system-wide clearing price for the 2013/2014 planning year was $1.05/MW-

[62] Kollen Testimony at 67:12-14.

day.[63] In other words, the Company's excess capacity has a market value of nearly $0, at least in the near-term. For comparative reference purposes, $1.05/MW-day is equal to $0.032/kW month, which is a mere 0.19% of the $16.95/kW month proposed for the Rural class demand charge in this case.

The market value of any excess generating capacity in MISO, especially coal-fired capacity and its attendant environmental risk, is low and can be expected to stay low at least in the near to intermediate term. In January 2013, SNL Energy released its Regional Reserve Margin Outlook for ISO New England, New York ISO, PJM, Electric Reliability Council of Texas, California ISO, Southwest Reserve Sharing Group, Northwest Power Pool, and MISO. MISO has a substantial capacity oversupply situation which is expected to last until late in the next decade.

> *"SNL Energy's expected case for MISO sees surplus conditions of nearly 10,000 MW or more for the next few years, with at least 4,000 MW of excess from 2016-2020 (see Figure 8). After 2020, we expect the surplus to slowly decline due to demand growth."*[64]

MISO's own 2013 Summer Resource Assessment outlines its excess capacity:

> *"During the 2013 summer peak hour, MISO expects adequate resources to serve load, with a 28.1 percent forecasted Reserve Margin, which far exceeds the requirement of 14.2 percent."*[65]
>
> ***
>
> *"MISO forecasts the coincident Net Internal Demand to peak at 91,532 MW, with 117,267 MW of capacity to serve MISO load."*[66]

Big Rivers has made a vigorous attempt to market its excess capacity to energy buyers over the past several months, without success. If other market participants believed that the price of electricity would dramatically increase in 2019, as Big Rivers' projects, it is reasonable to assume that Big Rivers would be able to enter into a long-term contract as a seller at a favorable price. But this has not occurred. [redacted]

[63] KIUC Ex. 14 and Attachment J (excerpts from KIUC Ex. 14).
[64] Kollen Testimony at 67:6-16.
[65] KIUC Ex. 12.
[66] KIUC Ex. 12.

[redacted][67]

[redacted]

[67] Sierra Club Ex. 1 at 6-7 - CONFIDENTIAL. [redacted]

[redacted]

Exacerbating this issue, the value of coal-fired units, especially those located in MISO that need significant capital upgrades based on current environmental regulations, continues to decrease as environmental regulations on those units increase. President Obama just outlined a climate action plan that is aimed at reducing carbon emissions on existing generation.[68] In addition, the U.S. Supreme Court recently granted certiorari on CSAPR, which could reintroduce stringent standards for coal-fired plants.[69] When CSAPR was originally vacated in August of 2012, Big Rivers cancelled plans to build a $139 million Scrubber on Wilson and an $81 million SCR on Green.[70] If CSPAR is reinstated, there may again be a need for Big Rivers to incur these costs.

Entering into a long-term power purchase agreement, in lieu of selling the power plants, is not likely to provide any relief. Such an agreement necessarily would be priced to reflect the depressed current market conditions and therefore would not likely provide full cost recovery. Further, because Big Rivers no longer is investment grade, the counterparty risk of doing business with Big Rivers likely would put off potential purchasers.

An attempt by Big Rivers to exit MISO after the minimum five year contract term and join PJM in the hopes of receiving greater capacity compensation also is probably not a realistic or effective solution. There is an open issue as to whether adequate transmission capacity exists to do this.[71] In addition, doing so would require Big Rivers to successfully maneuver through the extensive regulatory approval process that must be completed before such a move would be permissible. Finally, Big Rivers could be responsible for its share of MTEP projects approved during its membership in MISO.

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[68] KIUC Ex. 13.
[69] *EPA v. EME Homer City Generation*, Case No. 12-1182 (petition for writ of certiorari granted June 24, 2013).
[70] Case No. 2012-00063, Ex. Berry-2 at 1.
[71] In response to Sierra Club Data Request 1-4, in which the Sierra Club sought the Company's projections for capacity and energy prices in the PJM, the Company stated: "Big Rivers is a MISO participant and does not currently have transmission access to the PJM market."

Hoping that a new distribution cooperative can be served at a wholesale rate above market assumes that the new customer will act irrationally. There is no basis to assume that a new wholesale customer will willingly pay more than market value for energy or capacity. The very fact that Big Rivers' costs are above-market is the primary reason that the smelters plan to leave the Company's system. Moreover, in the case of TVA cooperatives, there is typically a five-year notice provision in their contracts. And TVA just lost a large uranium plant that it was serving in Paducah, KY,[72] so it is unlikely to welcome Big Rivers as a merchant generator, and may even seek to undercut Big Rivers' efforts to sell power in its territory.

Holding out hope that a large energy-intensive retail load may be incentivized to locate in the service territories of Kenergy, Meade County, or Jackson Purchase is likewise unfounded. Big Rivers would need to replace its entire Large Industrial Load of 950,000 MWh *7.6 times* in order to fill the hole left by the loss of its 7,300,000 MWh smelter load. Big Rivers analogizes the loss of load over 7.6 times the size of its current Large Industrial load to "*owning an apartment building; and losing a couple of tenants*."[73] It is more akin to owning an apartment building with 100 tenants, losing 68 of them, and then asking the remaining 32 tenants to pay not only their rents but also to pay the lost rents of the former 68 tenants. And finding a new apartment tenant is a lot easier than convincing a new industrial customer to locate in your service territory when you will soon have the highest electric rates in Kentucky.[74]

Large loads desire rate certainty, which would certainly not occur as a customer of Big Rivers. Moreover, Big Rivers' proposal to impose the cost burden of 100% of its excess capacity on Rural and Large Industrial customers runs directly counter to any economic development goals. The best way to attract a new energy-intensive load is to equitably balance the costs of excess capacity between the Company's customers and creditors. Minimizing rate increases through such balancing will promote economic development. Big Rivers' proposal to dramatically increase rates in this proceeding with the risk of additional huge rate increases looming will dampen and may even kill economic development in its territory.[75]

For all of these reasons, Big Rivers' mitigation plan is unduly optimistic. Thus, it would be unlawful and

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[72] KIUC Ex. 11.
[73] Tr. July 2, 2013 at 10:58:05.
[74] Sierra Club Ex. 6.
[75] Kollen Testimony at 70:10-20.

unreasonable for the Commission to drastically raise customers' rates for the next 6 years based upon the hope that the Company's mitigation plan will ultimately succeed.

5. Big Rivers Ignored Its Obligation To Treat Its Own Customers Reasonably In Favor Of Protecting Its Creditors, While Exacerbating The Level Of The Proposed Rate Increases Based Upon Misguided Principles Of Ratemaking.

The level of Big Rivers' proposed rate increases in this case and the Alcan rate case was exacerbated by Big Rivers' insistence on upholding its obligations to everyone except its own customers. For instance, [redacted]

[redacted]

[redacted]

[redacted]

In addition, Big Rivers refuses to begin discussing a reasonable solution to its debt issues with its creditors based upon a fear of the potential repercussions. But Big Rivers' fear is based merely upon speculation about how the creditors may react, rather than actual knowledge, as Mr. Bailey conceded:

> Mr. Bailey: *"we have no way of knowing how our lendors would react to a request to reduce our loan obligations to them."*[76]
>
> ***
>
> *"Q: ... if the Commission did not approve the full amount of rate increase you've requested in this case, would that give the lenders an incentive to negotiate with you?*
>
> *A: Hard to say. I can't predict what they might be willing to do."*[77]

Creditor concessions are especially appropriate in this instance because Big Rivers' interest rates reflect the higher risk associated with serving the smelters. Big Rivers' creditors were fully informed of the risks associated with the smelters potential departure when they loaned money to the Company. When CoBank and CFC negotiated the terms of their loans to Big Rivers, and before they actually loaned $537 million to Big Rivers in mid-2012, the Company provided a July 12, 2012 Disclosure Statement to those creditors, which warned them of the risks of potential smelter contract terminations:

> *The Smelters have made public statements that the unanticipated magnitude of the current and future rate increases projected by Big Rivers as well as Big Rivers' recent evaluation of the impact of environmental legislation is what drives the current need for a statewide solution to the Smelters' increasing utility costs. Local representatives of Alcan informed economic development officials in state government in February of this year that* ***projected power rates in 2013-2015 make it difficult for Alcan to envision a long-term future for the Sebree plant.***[78]
>
> * * *
>
> *Local representatives of Century have told Big Rivers and others in state government that rates at the status quo level are* ***not sustainable for Century's Hawesville smelter even in the short term, and that $50/MWh power puts their smelter's viability at great risk****. Century wrote Big Rivers on April 18, 2012, stating that at the current LME prices the Hawesville aluminum smelter* ***cannot sustain operations*** *at Big Rivers' current and projected power rates, and requesting to renegotiate the power rate provisions of its contract. Big Rivers has commenced discussions with Century relating to the sustainability of the Hawesville smelter. Century reported on April 24, 2012, that with the current power price forecast and assuming that the LME remains at its*

[76] Tr. July 1, 2013 at 15:40:52.
[77] Tr. July 1, 2013 at 15:43:25.
[78] AG Ex. 6 at 39 (emphasis added).

*current level, **the Hawesville plant is not viable from an economic standpoint.***[79]

* * *

*Since the meeting on June 14th, the Smelters have advanced other proposals to Big Rivers requesting significant rate reductions for the Smelters. Big Rivers offered a counterproposal and it has been rejected by the Smelters. On June 25, 2012, Big Rivers advised the Smelters that the gap between their demand and the Big Rivers' proposal is far larger than Big Rivers has the ability to close. **There can be no assurances as to the outcome of this situation and as to whether one or both of the Smelters will give one year's notice, terminate its Smelter Agreement and close its smelting operations.***[80]

That the smelters might terminate their contracts was a risk that creditors received value for taking on through higher interest rates. Given that creditors were fully informed of the risks they were undertaking when they invested in Big Rivers, it should come as no surprise to those creditors if the Company initiates discussions with them to achieve a reasonable resolution of its debt issues.

The following table shows the principal amounts owed to each creditor that it used to compute the interest expense for the test year and the annual interest expense on these principal amounts included in the test year revenue requirement.[81]

Big Rivers Electric Corporation
Principal and Interest Expense by Creditor
During the Test Year
$ Millions

Lender	Average Debt Outstanding	Interest Expense
CFC	284.705	12.693
CoBank	223.690	9.752
RUS Series A and B Notes	218.471	12.699
Polution Control Bonds	141.321	8.470
ECP Borrowing	40.410	1.155
CFC CTC Loan	40.394	2.214
Less: Capitalized Interest		(2.480)
Add: Amortization-Debt Expense		0.505
Total	948.990	45.008

79 AG Ex. 6 at 40 (emphasis added).
80 AG Ex. 6 at 40 (emphasis added).
81 Kollen Testimony at 75:18-76:1.

The Commission should also note that Big Rivers has a contractual obligation to propose rates at levels sufficient to recover all of the Company's costs, including the debt service necessary to repay its creditors. In other words, these agreements require the Board and the management of Big Rivers to do exactly what they have done in this case, i.e., seek rate increases to recover 100% of the costs associated with the Century termination from customers. Thus, the Company's Board and management are contractually obligated to seek these increases regardless of whether the increases will result in just and reasonable rates and regardless of whether the Board or management actually believe that the rates sought will be just and reasonable.[82]

Big Rivers cites not only this contractual obligation to its creditors, but also its moral obligation to pay its debts to them,[83] while ignoring any moral obligation to treat its customers reasonably. The Commission should not so easily disregard the impact of Big Rivers' requests on its non-smelter customers. The Commission has an independent statutory obligation to set rates at "fair, just, and reasonable" levels for customers. Fulfilling that obligation does not entail granting Big Rivers' 100% of its requested increase in this case.

Big Rivers' Rural and Large Industrial customers did not cause the Company's financial problems resulting from the Century termination. But those customers will experience substantial real world impacts as a result of the Company's proposed rate increase. For instance, as KIUC witness Steve Henry testified, Domtar operates in a paper market that has been declining at a rate of 4% per year.[84] Dramatically increasing its electricity costs through this rate case, and subsequently the Alcan rate case, does nothing to help Domtar weather this downturn. If Domtar was ultimately forced to shut down its operations as a result of the death spiral of rate increases that could be initiated by this case, it would impact not only Domtar's employees, but also the surrounding community. Kyle Estes, Superintendent for the Hancock County Schools System, explained such impacts:

> *"...if Domtar closed their Hawesville plant, the direct impact would be a net loss of income for the school district of $258,913 of utility tax income. Also, it would be $79,000 of property tax income for the school system and intangible assessed income exceeding $100,000 a year. Total, this comes to $438,720 of lost income to the local school system. To put this in context, this is approximately 4% of our entire estimated expenditures. Or to put it another way, it's*

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[82] Kollen Testimony at 23:7-17.
[83] Tr. July 1, 2013 at 12:02:53.
[84] Direct Testimony of Steve Henry at 3:1-3.

approximately 8 teachers that we would lay off. As I stated earlier, this is merely the direct financial impact of losing Domtar. The indirect effects of losing this employer would be much worse.'[85]

In addition, KIUC witness Kelly Thomas explained how the proposed rate increases could impact Aleris' decision to invest in its Lewisport facility:

Unfortunately, the proposed rate increase, together with the potential for additional and substantial increases in the future, is a major impediment to a future investment. A significant change in the cost structure of the Lewisport facility of the magnitude contemplated in this rate case will force us to consider alternative investment opportunities elsewhere.[86]

KIUC witness Bill Cummings also emphasized the importance of maintaining competitive electric prices to Kentucky's economy, stating *"[a] reliable, low cost power supply is critical to the long term success of the Kimberly-Clark Owensboro site."*[87]

For this reason, customers push for the Commission to adopt a more reasonable solution to Big Rivers' financial difficulties in this case. As Mike Baker, Director of Economic Development for the Hancock Industrial Foundation stated:

"...the Hancock County Industrial Foundation respectfully requests the Commission use all the authorities, experience, and wisdom in its power to find creative and sustainable solutions to these complex issues - solutions that will, to the extent possible, in our changing economic climate, ensure our local industries' ability to compete, grow, and thrive in a global and challenging marketplace and ensure a reliable, competitive, and sustainable supply of industrial power. The economic health of our county, our region, thousands of residents and employees, and businesses are in the balance.'[88]

6. Big Rivers' Witness William Snyder Correctly Understands That Creditor Concessions May Be Available As Part Of A Comprehensive Resolution.

Big Rivers' response to the loss of roughly 68% of its load with the termination of the two smelter contracts has been to simply calculate the amount needed to replace the smelter revenues and to ask the Commission to raise rates on its remaining customers in order to replace all of those revenues. As discussed

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[85] Tr. July 1, 2013 at 10:37:44.
[86] Direct Testimony of Kelly Thomas at 4:17-24.
[87] Direct Testimony of Bill Cummings at 7:4-5.
[88] Tr. July 1, 2013 at 10:35:11-54.

above, Big Rivers has indicated that it has not, and does not plan to approach its creditors to discuss the possibility of creditor concessions. But Big Rivers' own witness, Mr. Snyder, a corporate restructuring specialist with Deloitte Financial Advisory Services, testified that it can often be productive to negotiate with creditors under appropriate circumstances.

Mr. Snyder stated in his Direct Testimony that lenders would not have any incentive to negotiate with Big Rivers for rate relief if Big Rivers were to receive approval to raise rates sufficient to service its debts.

> "[A] *company facing economic challenges should develop a plan to maximize revenues, minimize expenses and adjust its operations and asset utilization to fit the short and long term goals of the plan. Only after these things are done and if there is still a need, does a company have sufficient credibility to rationally negotiate with its lenders. Since value is dependent upon revenue, cash flow and profitability, an integral component of that plan is a determination of anticipated revenue. This rate case is an essential part of that process since obtaining fair and reasonable rates is a critical element of the Big Rivers mitigation plan along with management actions to reduce expenses. Attempting to obtain concessions from creditors before addressing Big Rivers' revenue requirements would be counterproductive. Rational lenders will not participate in meaningful discussions before this step is completed.*"[89]

If the Commission does not approve Big Rivers' request to recover 100% of the cost of its excess capacity from remaining customers, Mr. Snyder states that creditor concessions, outside of Chapter 11, are a possibility. During cross-examination Mr. Snyder stated:

> Q: "*...assuming the Commission accepts the Attorney General's recommendation for no increase in the revenues or another intervenor's recommendation for perhaps some increase, but not to the level that Big Rivers has requested, wouldn't such a determination by the Commission give Big Rivers an opportunity to rationally negotiate or obtain concessions from its creditors*?"
>
> A: "*Yes...*"[90]

Mr. Snyder gave specific examples of lenders working with utilities to reduce the utility's debt-service obligations prior to any Chapter 11 filing:

> Q: "*What can the [lendors] do to help create a workout*?"
>
> A: "*...The lenders agreed to reduce their interest rates and their amortization substantially to give CoServe enough time to basically sell assets and gets its utilization up and it worked out*

[89] Rebuttal Testimony of William Snyder (June 24, 2013) at 6.
[90] Tr. July 2, 2013, at 11:50:58.

successfully so banks can do that…"[91]

Mr. Snyder continued:

"*…the banks can give you rate relief, they can give you relief on amortization, they can give you relief on giving you new money…All of those are on the table.*"[92]

Mr. Snyder also agreed with Vice-Chairman Gardner that it is common for creditors to loan new money to companies in order to avoid an ultimate write-down of debt:

Vice-Chairman Gardner: "*It is not unusual, is it, in either a pre-bankruptcy negotiation or a bankruptcy itself for existing lenders to loan more money?*"

A: "*As a matter of fact, it's very common in a filing for the existing lendors to put up what's called the 'debtor-in-possession' financing, absolutely, it's very common.*"[93]

Mr. Snyder spoke specifically about the process that Big Rivers would undertake if the Commission ordered a rate increase that did not allow them to service its debt, stating that such a scenario would give Big Rivers' creditors an enormous incentive to work cooperatively to avoid a write-down. Mr. Snyder testified:

Mr. Snyder: "*…It's not like a money-center bank in New York where you just write it off, too bad, right? It's a co-op and so all those losses go back to the existing members. So it's a little more complicated in this case because you've got the federal government, you've got two co-ops. And so there's a huge propensity to avoid taking a write-down, you know, and so CoServe bent over as much as they could, they did everything they could to avoid taking a write-down in that case…that was a good outcome…*"[94]

Q: "*What is going through [the lendor's] minds in the process? What are their risks?*"

A: "*Well, they take…remember I told you a co-op's a little bit different, right? And since this loan's fairly new, I don't know if they even have any reserves on them, right, and so…big co-ops are going to be very, very, very hesitant to take a hit, 'a write-down,' because if they have no reserves, then that is passed straight through to the members , you know, immediately. That's a painful thing. And so…I can just tell you from experience from the co-ops, they're going to be very reticent to take a hit with no reserves so…I'm sure they're very concerned.*"

Q: "*So does that mean* [lendors] *have an incentive to work with Big Rivers and negotiate and work with the Commission and try to find a solution?*"

A: "*Oh absolutely, 'cause remember I think, I'm sure CFC finances other co-ops that this Commission is involved with so I mean, it's like one big happy family, right?*"

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[91] Tr. July 2, 2013 at 11:59:35.
[92] Tr. July 2, 2013 at 12:05:19.
[93] Tr. July 2, 2013 at 13:00:29.
[94] Tr. July 2, 2013 at 12:01:38.

Vice-Chairman Gardner and Mr. Snyder also discussed the benefits of negotiating with creditors outside the context of a Chapter 11 filing.

> Vice-Chairman Gardner: "*...on the backend, you've got a Chapter 11 process that forces collaboration, you only have three lenders, so...and you don't have much value with rejecting leases or contracts in a Chapter 11, so it makes sense that, before a bankruptcy would be filed, you would sit down with your lendors and try to work something out?*
>
> A: "*I totally agree, unless you ran out of money. I totally agree.*"[95]

In contrast to the multiple benefits that can be negotiated if Big Rivers' rate request is not approved in its entirety, Mr. Snyder stated that any creditor concessions would be off the table if Big Rivers received Commission approval of its rate request.

> Q: "*Now on the other hand, if the Commission gives Big Rivers 100% of the revenue it asks for, then there's really no incentive for the bank, CFC or CoBank, to negotiate because the problem's solved?*"
>
> A: "*Absolutely, and it's solved with just people sitting in this* [hearing] *room so they don't even have to call them.*"[96]

It is important that Big Rivers' creditors have an incentive to negotiate. If the Commission adopts KIUC's formula rate plan to approve a base rate increase that balances the burden of paying for Big Rivers' excess capacity between Big Rivers, its creditors and its remaining customers, and then uses the Reserve Funds to bring Big River's earnings to its target 1.24 TIER, the Commission should explicitly require Big Rivers to work with its creditors during this additional time to find a reasonable solution to the issues associated with Big Rivers' excess capacity. The retention of a "turnaround specialist" like Mr. Snyder should greatly assist Big Rivers in achieving a reasonable solution to its current financial issues. Mr. Snyder testified that such a specialist could get up to speed in 6-8 weeks.[97]

As Mr. Snyder explained, Big Rivers' creditors have an incentive to negotiate with the Company on these issues since they cannot easily write off any losses resulting from their investment in Big Rivers. And since creditors were fully aware of Big Rivers' financial difficulties at the time they decided to invest in the Company,

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[95] Tr. July 2, 2013 at 12:50:13.
[96] Tr. July 2, 2013 at 12:05:00.
[97] Tr. July 2, 2013 at 12:46:00.

Big Rivers' creditors should not be surprised if the Company were forced to begin discussions with them. This requires the Commission to craft its Order in a way that Big Rivers will be sufficiently motivated to pursue this option.

Although the possibility that Big Rivers may ultimately need to file a Chapter 11 petition if the ratepayer Reserve Funds are exhausted prior to securing a reasonable resolution to Big Rivers' financial issues, the Commission should not be unduly troubled by that potential outcome. Mr. Snyder agreed with Big Rivers' counsel that "*bankruptcy can be positive for some companies*."[98] Additionally, other utility bankruptcy experts have described how it can lead to positive outcomes for electric utilities:

> "*Chapter 11 bankruptcy can be a tremendously effective means of resolving a troubled company's financial problems. The Bankruptcy Code provides a debtor company with many useful means of restructuring pre-existing debt and disposing of other financial liabilities. Indeed, Chapter 11 has proven successful at some level in every recent utility bankruptcy.*"[99]
>
> "*Chapter 11 has proven itself a very effective process for restoring electric utilities to viability and will likely continue to be useful in future utility bankruptcies.*"[100]

Indeed, Big Rivers has already experienced bankruptcy itself, with positive results, as the Company itself explained in its 1998 Annual Report:

> "*Three years ago, Big Rivers faced the possibility of no future. High debt service, high coal costs, excess capacity and high rates had all combined to paint a bleak picture for its future. Thanks to the efforts of the board, member systems, staff, creditors, and others, Big Rivers overcame those challenges. Today at Big Rivers, the switch is on; there is a new attitude, a new vision, and a new look that does indeed see a future.*"[101]

The specter of bankruptcy should not make the Commission feel obligated to make a decision in this case that would result in unreasonably high rates and that puts all of the financial burden on Big Rivers' shrinking customer base. As Vice Chairman Gardner discussed with Mr. Snyder, the Chapter 11 is a collaborative process that strives to achieve the best possible outcome for all interested parties:

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[98] Tr. July 2, 2013 at 12:55:15.
[99] KIUC Ex. 10 or Attachment K (excerpts from KIUC Ex. 10).
[100] Id.
[101] Big Rivers Response to KIUC Initial Request for Information (Feb. 28, 2013), Item 34, BREC 1998 Annual Report.

Vice Chairman Gardner: "*Isn't the bankruptcy code for Chapter 11s in general, encourage collaborative, consensual plans as opposed to cram-downs or hostile plans*?"

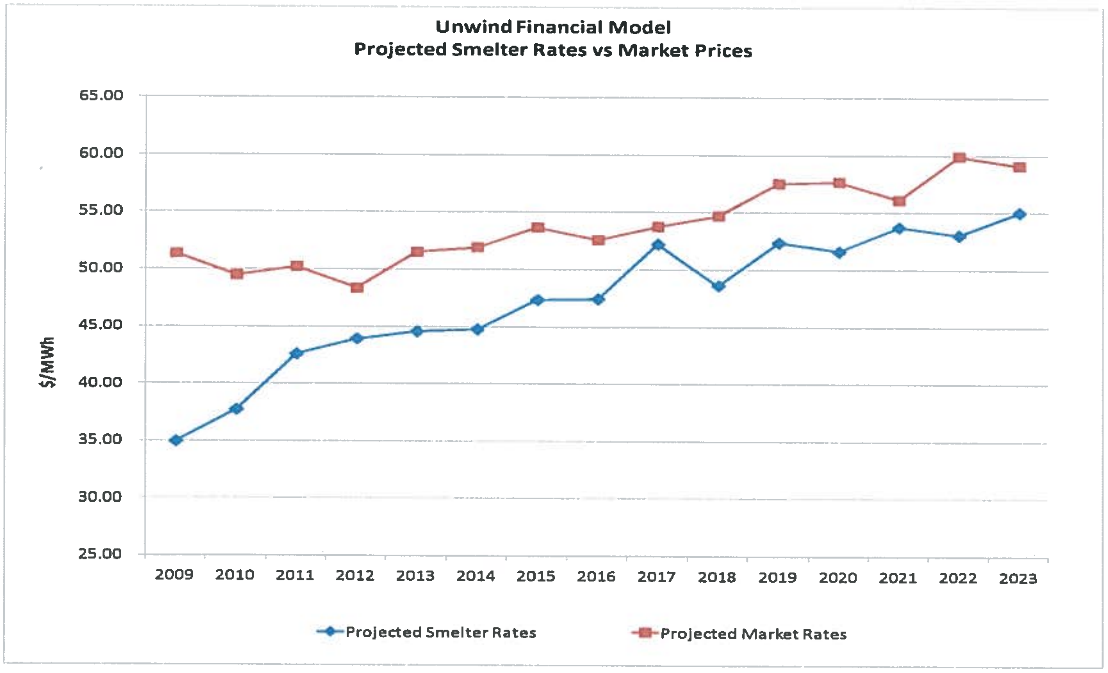
A: "*...The Chapter 11 process actually, I agree with you, forces collaboration...*"[102]

7. Big Rivers' Proposal To Raise Rates To Rural And Large Industrial Customers While The Smelters Receive A 30% Rate Decrease Is Directly Contrary To Big Rivers' Position In The 2009 Unwind Transaction, In Which It Repeatedly Assured The Commission That The Non-Smelter Customers Would Not Be Harmed If The Smelters Terminated Their Electric Service Contracts.

One of the fundamental concepts underlying the Commission's approval of the 2009 Unwind Transaction was that Big Rivers would provide electric service to the smelters if, and only if, the provision of service to them, or the subsequent termination of electric service to the smelters, would *not* result in a rate burden to the non-smelter customers.[103] In fact, the entire structure of the Unwind Transaction was premised on the assumption that the Company could earn wholesale market margins greater than those set forth in the smelter contracts in the event that either smelter terminated its contract. Big Rivers has turned the representations made in the Unwind Transaction on their head. Instead of protecting its non-smelter customers from unreasonable rate increases, it is now primarily concerned with protecting its creditors and Century.

In that case, Big Rivers provided the Commission financial model projections showing that wholesale market prices would be greater than the smelter rates in each future year. The following chart reflects those projections.[104]

[102] Tr. July 2, 2013 at 12:48:56.
[103] Case No. 2007-00455.
[104] Case No. 2007-00455, Ex. 8 to the Company's Application (Company Financial Model).



The smelter contract pricing was considered an economic concession by Big Rivers for the purpose of allowing continued operation of the smelters and enhancing employment opportunities for the region. The parties agreed that Big Rivers' net margins likely would be greater if Big Rivers were to sell its excess energy into the wholesale market rather than to sell its excess energy for resale to the smelters.[105]

Big Rivers repeatedly assured the Commission in the Unwind proceeding that providing service to the smelters would not negatively affect the rates of the non-smelter customers. In the *unlikely* event that the smelters terminated their contracts and sales to the wholesale power market did not produce revenues greater than the smelter rates, the $35 million Transition Reserve Account was established so that the Transition Reserve, and *not* Big Rivers' remaining non-smelter customers, would make up the difference.[106] That account is no longer available to absorb any of the excess capacity costs resulting from the smelter terminations, however, since it is earmarked for capital expenditures in the ordinary course of business.[107] But this does not mean that Big Rivers can now seek to impose 100% of the costs resulting from the smelter departure on its non-smelter customers in the present case.

[105] Kollen Testimony at 39:1-3.
[106] Unwind Transaction Case, Direct Testimony of William Blackburn (December 28, 2007) at 86-87.
[107] See Case No. 2012-00492, Order (March 26, 2013) at 4.

In its Order approving the Unwind Transaction, the Commission was clear that Big Rivers and its creditors, not Rural and Large Industrial customers, were assuming the risk that the wholesale market and the Transition Reserve would provide adequate revenue for Big Rivers to service its debt obligations if one or both of the smelters terminated their contracts:

> *Big Rivers viewed this [E.ON] proposal as an opportunity to improve its financial position for the benefit of itself and its members, as a means to obtain financing on more favorable terms, and as a way to better manage its long term power supply.* ***After analyzing the risks associated with supplying power to the Smelters, including operating and maintaining generation, load concentration, fuel supply, and financial risks, Big Rivers decided to enter into discussions to terminate, or "unwind", the 1998 lease transactions and agreements, with the intent of obtaining significant compensation for assuming those risks.***[108]

The Commission continued:

> *Although it would not be possible to guarantee the future financial health of the Smelters, providing them with a long-term supply of power priced at below market prices should enable them to maintain their current competitive positions and continue in operation over the long term. It was for this reason that Big Rivers entered into negotiations with the Smelters on new service agreements that will provide them power at competitive prices* ***while providing protections to Big Rivers and its non-Smelter customers against the risks inherent in resuming the role of power supplier to the Smelters.***[109]

In exchange for assuming the risk of serving the smelters, including the possibility that the smelters might terminate their contracts, Big Rivers and its creditors received substantial compensation at the closing of the Unwind Transaction. Big Rivers received approximately $756 million in cash and non-cash benefits,[110] and its creditors received the following:[111]

- Philip Morris Credit Corporation received $121.7 million, as payment in full for the failed sale/leaseback transaction.
- Bank of America received approximately $6 million.
- RUS received approximately $140 million and commitments to pay another $260 million in the future.

In that case, Big Rivers never informed the Commission that it would seek to recover 100% of the lost smelter margins from the remaining customers if one or both of the smelters exercised the right to terminate its

[108] Case No. Case No. 2007-00455, Order (March 6, 2009) at 7 (emphasis added).
[109] Id. at 15 (emphasis added).
[110] Id. at 11.
[111] Id. at 10-21.

contract. Rather, Big Rivers maintained that a smelter termination would not adversely impact its non-smelter customers, stating:

> *"...even if it is assumed that both Smelters cancel their contracts at the earliest possible date allowed, alternative sales into the market are more than adequate to replace the lost revenues associated with the loss of the Smelter load....This is true even if a ten percent reduction in market prices is assumed."*[112]

Four years after the completion of the Unwind Transaction, Big Rivers' position with regard to protecting its non-smelter customers is starkly different. Now, Big Rivers' plan is for the creditors that made risky loans to Big Rivers to continue to receive their full debt service without any contribution, and for Century to receive a 30% rate decrease while Rural and Large Industrial customers absorb 72% and 110% rate increases respectively. Everyone wins except for Big Rivers' Rural and Large Industrial customers. Big Rivers should not be allowed to disregard its previous representations and force non-smelter customers to pay 100% of the costs resulting from the Smelters' decision to termination their contracts with the Company.

B. KIUC's Recommends Reducing Big Rivers' Proposed Rate Increase From $68.6 Million To $21.7 Million.

Big Rivers' proposed $68.6 million revenue requirement is overstated and should be adjusted in several ways to: 1) prevent the Company from over-collecting from its customers; and 2) establish a balanced approach that equitably shares the burden of Big Rivers' financial issues among Big Rivers, its creditors, and its customers.

Three adjustments to the proposed $68.6 million revenue requirement, explained in greater detail below, are necessary in order to correct Big Rivers' fully forecasted test year in light of its recent decision to idle Wilson beginning February 1, 2014 as well as its decision not to issue certain pollution control bonds. These adjustments are as follows:

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[112] KIUC's Responses to Big Rivers First Request for Information, Item No. 13, Attachment (citing Big Rivers' Supplemental Response to the Commission Staff's Initial Requests, PSC Case No 2007-00455 (May 30, 2008), Item 33).

1. A reduction of $11.685 million to remove depreciation expense for the 7 months of the 12 month fully forecasted test period that Wilson will be idled;
2. A reduction of $16.333 million to reflect the 7 months of the savings that will result from idling Wilson that are not taken into account in the 12 month fully forecasted test period;
3. A reduction of $4.353 million for interest expense and related TIER on pollution control bonds that Big Rivers no longer plans to issue.

If made, these adjustments reduce the proposed revenue requirement to $36.23 million.

The final adjustment that should be made is to eliminate excess capacity costs by reducing Big Rivers' revenue requirement by an additional 40% ($14.5 million). 40% represents Century's current share of the internal load on the Big Rivers' system.[113] The Company's remaining customers do not benefit from the excess capacity resulting from Century's departure, which is not physically or economically "used and useful." Reducing the proposed revenue requirement in this manner is consistent with the balanced approach the Commission has previously used to address excess capacity issues.[114]

These adjustments are explained in detail below.

1. The Revenue Requirement Should Be Adjusted to Reflect Ceasing Depreciation on the Coleman and Wilson Units When Those Units Are Idled.

Big Rivers' Application was filed based upon the assumption that the Wilson plant would be idled and the Coleman plant would run during the future test year used to establish its proposed $68.6 million revenue requirement.[115] In Data Responses, Big Rivers explained that it *"...currently believes it is more cost effective for Big Rivers' Members to lay up Wilson Station than to run the plant until 2019."*[116] But in a drastic change of course, Big Rivers recently decided that it will now effectively idle the Coleman plant beginning September 1, 2013 and will run the Wilson plant until February 2014 when that unit will also be idled.[117]

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[113] Bailey Direct Testimony at 8:9-10.
[114] 1987 Order at 37.
[115] Berry Direct Testimony at 22.
[116] KIUC Ex. 1 (Response to Attorney General Initial Request for Information, Item 113).
[117] Tr. July 1, 2012 at 12:16:50-12:17:04; Direct Testimony of Billie Richert at 15.

Once Wilson is idled on February 1, 2014, Big Rivers should cease depreciation on that unit. In response to Staff's cross-examination questions on this issue, Big Rivers' CFO Billie Richert stated that "*there are no definitive pronouncements or standards*" on whether depreciation should be ceased on an idled plant.[118]

KIUC disagrees. The RUS Uniform System of Accounts ("USOA") clearly establishes that depreciation on idled generating assets should cease while the asset is idled. The USOA requires that the original cost of electric plant included in Account 101 Electric Plant in Service and the subsidiary plant accounts must be "*used by the utility in its electric utility operations.*" Specifically, for Account 101, the USOA provides:

> ***101 Electric Plant in Service***
> *This account shall include the original cost of electric plant, included in Accounts 301 to 399, prescribed herein, owned and used by the utility in its electric utility operations, and having an expectation of life in service of more than one year from date of installation, including such property owned by the utility but held by nominees.*

Once the Wilson plant is idled, it will no longer be "used by the utility," consistent with the language of Account 101. Consequently, it will no longer qualify as "Electric Plant in Service" and will be removed from Account 101. Once this occurs, there will no longer be any Electric Plant in Service to depreciate, and consequently, there no longer will be any related depreciation expense recorded in Account 403 Depreciation Expense. The USOA states for Account 403:

> ***403 Depreciation Expense***
> *A. This account shall include the amount of depreciation expense for all classes of depreciable electric plant in service except such depreciation expense as is chargeable to clearing accounts or to Account 416, Costs and Expenses of Merchandising, Jobbing and Contract Work.*

Once the original cost of the Wilson plant that no longer is used by the utility is removed from Account 101, the USOA directs that the original cost of the plant, net of accumulated depreciation, be recorded in Account 105 Electric Plant Held for Future Use, as long as the utility has a definite plan to use the plant in the future. Big Rivers claims to have a definite plan to use the Wilson plant in the future if it becomes economic to run again. For Account 105, the USOA provides:

[118] Tr. July 2, 2013 at 10:48:30.

105 Electric Plant Held for Future Use

> *A. This account shall include the original cost of electric plant (except land and land rights) owned and held for future use in electric service under a definite plan for such use, to include: (1) Property acquired (except land and land rights) but never used by the utility in electric service, but held for such service in the future under a definite plan, and (2) property (except land and land rights) previously used by the utility in service but retired from such service and held pending its reuse in the future, under a definite plan, in electric service.*

Once the original cost of the Wilson plant is transferred from Account 101 to Account 105, depreciation ceases for accounting purposes. Depreciation expense again will commence if the Wilson plant is returned to service and the original cost of the plant is then transferred from Account 105 back to Account 101. The USOA defines depreciation as follows:

> *Depreciation, as applied to depreciable electric plant, is the loss in service value, not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.*

Temporarily ceasing depreciation once the Wilson plant is idled is consistent with the fact that the plant will no longer be experiencing a "loss in service value" or "wear or tear" because it will not be operated. When Wilson is idled, there will be no operating hours and, to the extent that a plant's operating hours are a relevant indicator of expected service life, then the Wilson plant will have roughly the same remaining operating hours of depreciable life left after it is returned to service than if it had remained in service.

This view is supported by the testimony of Big Rivers' depreciation witness, Ted Kelly of Burns & McDonald. Mr. Kelly's depreciation Report shows that the Estimated Remaining Lives of each of Big Rivers' generating units (including Wilson and Coleman) are based on the expected typical operating hours and maintenance experience of the unit.[119] At the hearing, Mr. Kelly confirmed that "*the expected useful life of the plant*" was "*based on typical* [future probable] *operating hours*."[120] Using this methodology, once a plant such as Wilson is idled, it is no longer accruing operating hours. Therefore, that plant's expected remaining useful life is not decreasing. Mr. Kelly supported this concept stating: "*when these units are layed-up and they're not*

[119] Depreciation Report at II-4 to II-7.
[120] Tr. July 2, 2013 at 20:49:10.

operating they will have less operating hours, less wear and tear, [and] *less mileage.*"[121]

Commission Staff explored this concept with Ms. Richert during the hearing, demonstrating that suspending depreciation during a period of time in which a plant is idled does not deprive a utility from ultimately recovering its investment in the asset. Rather, if depreciation is suspended while a plant is idled, but depreciation expense was allowed once the plant was placed back into service at an annual amount sufficient to make up for the lost period of depreciation, the utility would not lose the ability to recover its investment.[122]

In response to the KIUC proposal to temporarily suspend depreciation on the Company's idled Wilson and Coleman power plants in accordance with the requirements of the RUS Uniform System of Accounts ("USOA"), the Company failed to cite any contrary authoritative accounting requirements or guidance or to address the specific requirements of the RUS USOA cited and relied on by Mr. Kollen in his Direct Testimony. In her testimony at hearing, Ms. Richert could cite to no authoritative accounting guidance that either required or prohibited the cessation of depreciation.

Big Rivers was given a one last chance to provide a compelling reason to continue depreciation on idled plants when Commission Staff asked a Post-Hearing Data Request to "[p]*rovide documentation in support of Big Rivers' position that depreciation expense should continue on idled plant.*"[123] In response, the Company declared that "[d]*epreciation expense should continue on idled plant based on accounting standards and guidance by the various authoritative accounting sources and agencies including the Financial Accounting Standards Board ("FASB"), the United States Code of Federal Regulations ("CFR"), the International Accounting Standards Board ("IASB"), the Internal Revenue Service ("IRS"), and the Rural Utilities Service ("RUS").*"

In this response, the Company failed to provide any analyses of these alleged requirements in support of its declaration, citing only a single excerpt from the Basis for Conclusions issued by the IASB, an international accounting standards organization whose requirements are not applicable in the U.S. To be clear, the Company is NOT subject to the requirements of the IASB. It is subject only to the accounting requirements of the FASB, which sets U.S. Generally Accepted Accounting Principles ("GAAP"), the RUS and its USOA for recording

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121 Tr. July 2, 2013 at 20:50:00.
122 Tr. July 2, 2013 at 10:56:10.
123 Commission Staff Post-Hearing Data Request, Item 4.

revenues, expenses, assets, and liabilities, and the Commission, which sets rates and determines the ratemaking and accounting treatment for many of the Company's revenues, expenses, assets, and liabilities. The FASB sets U.S. accounting standards and it has not adopted the IASB International Accounting Standards. There are significant differences between U.S. GAAP and the standards adopted by other countries and those adopted by the IASB. Thus, while the Basis for Conclusions issued by the IASB may be interesting as an academic exercise, it is completely irrelevant to this issue in this proceeding. Similarly, the Internal Revenue Service implements and enforces federal tax laws. Generally, neither the federal tax code nor the IRS proscribes ratemaking or accounting requirements.

One authoritative and well-recognized source for depreciation concepts and applications that was not cited by the Company in its response to the hearing data request is the NARUC Depreciation Manual entitled "Public Utility Depreciation Practices." The NARUC Depreciation Manual is relied on as a source document by all legitimate experts on utility depreciation methods and analyses. The NARUC Depreciation Manual states: "*Generally accepted accounting principles require expenses, such as depreciation, to be allocated by systematic and rational procedures to the periods during which the related assets expected to provide benefits. The simplest and most logical way to accomplish this is to use a method that distributes the cost of property in a reasonable and consistent manner to all the accounting periods in which the property is providing utility service.*"[124]

The fact is that U.S. GAAP, the RUS USOA, and the Commission's ratemaking determination of the appropriate depreciation rates are the only relevant factors on this issue in this proceeding. Of these three, it is the Commission's determination that is primary for ratemaking purposes. It isn't U.S. GAAP, which has no ratemaking authority. U.S. GAAP only specifies how transactions are to be recorded, including the effects of ratemaking decisions. It isn't the RUS, which has no ratemaking authority, and only specifies how transactions are to be recorded, including the effects of ratemaking decisions. The Commission should not be misled by the Company's attempts to use the claim that the RUS has to approve the depreciation rates to impose the RUS-approved rates for ratemaking purposes. The RUS does not have the jurisdiction to set depreciation rates for ratemaking purposes. The only regulatory body with that statutory authority is this Commission.

[124] NARUC Depreciation Manual at 17 (footnote omitted).

Regardless of the requirements set forth in the RUS USOA, the RUS may not approve a 0% depreciation rate if the Commission sets the depreciation rates to suspend the depreciation on the Wilson and Coleman plants while they are idled. The unfortunate truth is that the RUS has a dual role as both a creditor and as the overseer of the USOA. Unfortunately, the RUS' role as a creditor may conflict in important respects with and even supersede its role in objectively overseeing the Company's depreciation rates and compliance with the USOA.

Even if the RUS does not agree with the Commission's determination of a depreciation rate of 0% for the Wilson plant while they are idled and declines to adopt it, U.S. GAAP and the RUS USOA generally require that accounting follows the ratemaking determination. If, contrary to the requirements of the RUS USOA, the RUS ultimately does not allow the Company to use a 0% depreciation rate for its RUS accounting and reporting, then the RUS USOA provides an alternative that still recognizes the Commission's decision to set the depreciation rate at 0%. The USOA allows the Company to reconcile the difference in timing (if the RUS recognizes depreciation earlier and the Commission later) through deferred accounts that are included in the USOA specifically for the purpose of reconciling the expenses allowed for ratemaking purposes and otherwise reported for accounting purposes. More specifically, the Company could defer the depreciation expense through a credit to account 403 *Depreciation Expense* and a debit to account 182.3 *Other Regulatory Assets* based on the Commission's ratemaking determination that the depreciation rate is 0% for ratemaking purposes. The RUS USOA describes account 182.3 as follows:

> *A. This account shall include the amounts of regulatory-created assets, not includable in other accounts, resulting from the ratemaking actions of regulatory agencies. (See the definition of regulatory assets and liabilities.)*
>
> *B. The amounts included in this account are to be established by those charges which would have been included in net income, or accumulated other comprehensive income, determinations in the current period under the general requirements of the Uniform System of Accounts but for it being probable that such items will be included in a different period(s) for purposes of developing the rates that the utility is authorized to charge for its utility services. When specific identification of the particular source of a regulatory asset cannot be made, such as in plant phase-ins, rate moderation plans, or rate levelization plans, Account 407.4, Regulatory Credits, shall be credited. The amounts recorded in this account are generally to be charged, concurrently with the recovery of the amounts in rates, to the same account that would have been charged if included in income when incurred, except all regulatory assets established through the use of Account 407.4 shall be charged to Account 407.3, Regulatory Debits, concurrent with the recovery of the amounts in rates.*

Another utility, Northern States Power Company ("NSP," a subsidiary of Xcel Energy), recently proposed a similar deferral of the depreciation expense on Sherco 3, one of its coal-fired units, that was idled for an extended period due to a catastrophic equipment failure.[125] In that proceeding, NSP offered to defer the depreciation expense associated with Sherco 3, amortize that deferral over the remaining life of the unit, and essentially suspend and restart the remaining life starting when the unit was placed back in service. The Administrative Law Judge accepted the Company's offer to defer the depreciation expense for the test year. Although NSP is subject to the FERC USOA, the accounting requirements for plant that is not used and useful are the same. Instead of setting the depreciation rate to 0%, the NSP approach was to continue the depreciation, but to defer it and include $0 in the revenue requirement. The effect is the same.

The fact is that Mr. Kollen's testimony on this issue remains unrebutted. Pursuant to the procedural schedule, the Company had every opportunity to rebut Mr. Kollen's testimony on a factual basis, but did not do so. At the hearing, the Staff provided the Company yet another opportunity to rebut Mr. Kollen's testimony on a factual basis through the hearing data request, but again the Company did not do so, except to make an unsubstantiated declaration and to cite to an international accounting standard that does not apply to Big Rivers. In fact, in response to Staff hearing request Item 4, the Company itself cited the same provisions of the RUS USOA that Mr. Kollen relied on, although it provided no analyses of those provisions or rebuttal to Mr. Kollen's analysis.

In summary, only the Commission has the ratemaking authority to set the depreciation rates on the Wilson and Coleman plants. It should set the depreciation rates to 0% for the Wilson and Coleman plants while they are idled. This ratemaking is consistent with the RUS USOA accounting requirements, which do not allow depreciation expense on plant that is not in service for accounting purposes. There is no relevant authoritative guidance that precludes the temporary cessation of depreciation expense when the assets are idled. In the alternative, the Commission should authorize a deferral.

Big Rivers indicated that Wilson will be idled for 7 out of the 12 months of the future test period in this case. Since Wilson will only be running for 5 months of the forecasted test period, Big Rivers should only

[125] Minnesota Public Utilities Commission, Docket No. OAH 68-2500-30266 PUC E-002/GR-12-961.

recover 5 months of depreciation on Wilson. Accordingly, it would be appropriate to reduce Big Rivers' depreciation on Wilson in the forecasted test year in this case by 7/12ths. Since a full year of depreciation on Wilson equals $20.031 million,[126] KIUC recommends that the Commission reduce Big Rivers' proposed revenue requirement by $11.685 million to reflect this adjustment removing 7 months of Wilson depreciation expense.

2. The Revenue Requirement Should Be Adjusted To Reflect The Savings Resulting From The Recent Decision To Idle Wilson Beginning February 2014.

The fully forecasted test year used by Big Rivers to establish its proposed revenue requirement in this case assumed that only one of its plants (Wilson) would be idled during that year. Subsequent to the filing of that fully forecasted test year, however, Big Rivers decided to run Wilson until February 2014 and then idle Wilson for the final 7 months of the forecasted test year (February through August 2014).[127] The Company also decided to idle or "effectively idle" the Coleman units beginning September 1, 2013 (Century will be responsible for the costs associated with any units that are required by MISO to continue operating).[128]

According to Mr. Berry, idling the Wilson or Coleman plants results in roughly [redacted] million in savings per plant.[129] However, although Big Rivers included [redacted] million in savings from idling *one* plant in its fully forecasted test year (Coleman), it did not account for its recent decision to idle *two* plants (Wilson and Coleman) for 7 months in calculating its proposed revenue requirement in this case. Failing to account for that 7 months of additional savings from Wilson would result in Big Rivers over-recovering from its customers.

Accordingly, in order to properly account for the 7 months of additional savings to Big Rivers, the Company's proposed revenue requirement should be reduced to reflect 7/12th of the savings that Big Rivers would get from idling the Wilson plant for a full year. Since a full year of idling Wilson would result in [redacted] in savings to Big Rivers,[130] the Commission should reduce Big Rivers' proposed revenue requirement by 7/12ths of that amount, or $16.333 million.

3. The Revenue Requirement Should Be Adjusted to Reflect Interest Expense and Related TIER on a $58.8 Million Pollution Control Bond That The Company No Longer Plans to Issue.

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[126] Kollen Testimony at 69:14-17.
[127] Tr. July 1, 2013 at 12:16:50-12:17:04.
[128] Rebuttal Testimony of Robert W. Berry(June 24, 2013) at 18:1-16.
[129] Attachment E, KIUC Ex. 2.
[130] Attachment E, KIUC Ex. 2.

In its proposed revenue requirement, Big Rivers included $4.375 million for the interest expense and related TIER on a new $58.8 million pollution control bond that it no longer plans to issue. When the Company filed this case, it planned to issue this new debt in March 2013 and use the proceeds to refund and retire the existing pollution control debt held by Dexia, which was scheduled to mature on June 1, 2013. Although the Company sought authorization to issue this debt in Case No. 2012-00492, it later amended its request and effectively withdrew it. In other words, Big Rivers no longer plans to issue this debt. Therefore, an adjustment should be made to remove this expense, which would further reduce its proposed revenue requirement by $4.353 million.[131]

4. The Revenue Requirement Should Be Reduced To Reflect An Excess Capacity Adjustment.

The final modification that should be made is to reduce the revenue requirement to reflect an excess capacity adjustment. There really can be little doubt that under any type of traditional analysis excess generating capacity exists on the Big Rivers system. The 190% reserve margin and the idling of Coleman and Wilson prove this point. But what should be done about the excess capacity is not easy to answer. The Attorney General and the Sierra Club both say that none of the excess capacity costs associated with Century getting market access should be borne by consumers. Big Rivers says that position would result in certain bankruptcy. The alternative rate plan that KIUC recommends is a middle-ground that raises rates to a reasonable level and uses the ratepayer Reserve Funds to assure financial solvency. Yet even under KIUC's alternative rate plan, some excess capacity adjustment is appropriate.

There are numerous reasonable ways to make an excess capacity adjustment. For example, all or part of the $63 million attributable to Century terminating its contract could be removed from the revenue requirement. Another methodology would be to remove all or part of the fixed costs of the generation (Wilson and Coleman) that is no longer "used and useful." In order to fashion a workable resolution, we are recommending that KIUC's proposed revenue requirement of $36.23 million be reduced by 40% ($14.5 million), since Century currently makes up 40% of Big Rivers' internal load.[132] KIUC's current recommendation to reduce the revenue

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[131] Response to Staff Data Request 2-13.
[132] Bailey Direct Testimony at 8:9-10.

requirement by Century's share of the Company's total internal load (40%) differs from the recommendation contained in the Direct Testimony of Lane Kollen. In that testimony, Mr. Kollen recommended that 31.3% of the $63 million attributable to Century's departure should be recovered from remaining customers and that creditors should share 68.7% of the excess capacity costs.[133] Mr. Kollen's original recommendation resulted in a reduction to revenue requirements of $43.3 million.[134] In light of KIUC's current recommendation to use the $135 million in Reserve Funds to protect customers and to assist Big Rivers in meeting its debt obligations, KIUC has reduced its excess capacity adjustment from $43.3 million to $14.5 million. This modified recommendation preserves the Reserve Funds for a longer period of time while a workout plan is developed.

This excess capacity adjustment is necessary to achieve a balanced approach that equitably shares the cost burden associated with Century's departure. The Company's remaining customers did not cause the financial issues Big Rivers raises in this case nor do those customers benefit from the excess capacity resulting from Century's departure, which is not physically or economically "used and useful" to those customers. Though Big Rivers' remaining customers arguably should not have to pay for any of the costs of that excess capacity, reducing the proposed revenue requirement in this manner is consistent with the balanced approach the Commission has previously used to address such issues.[135]

If the Commission makes all of KIUC's recommended adjustments, the result would be a $21.7 million base rate increase in this proceeding. As discussed below, any additional revenue needed for Big Rivers to achieve a 1.24 TIER each month would come from the $135 million Reserve Funds.

[133] Kollen Testimony at 58:13-18.
[134] Kollen Testimony at 59:15-17.
[135] 1987 Order at 37.

C. The Commission Should Adopt KIUC's Formula Rate Plan Which Provides For A Reasonable Rate Increase Coupled With The Use Of The Reserve Funds Until A Resolution Of The Excess Capacity Situation Can Be Reached.

1. The Commission Can Address Big Rivers' Financial Difficulties In This Case By Adopting An Approach That Balances the Interests of All Stakeholders, As It Has Done in the Past.

The Commission has for decades been grappling with the fundamental fact that the Big Rivers system is inherently unstable due to the size of the smelters compared to the rest of the customer load. The solution now proposed by the Company is the same solution that Big Rivers proposed in 1987 when it first sought recovery of the unneeded Wilson plant costs, i.e., to assign 100% of the burden of the excess capacity to customers, rather than allocate the burden between customers and creditors. That solution was not then, and is not now, in the public interest and will seriously damage the regional economy of Western Kentucky, ultimately harming all households and businesses that take service from the Distribution members served by Big Rivers.

In addressing Big Rivers' issues in the past, the Commission found that both customers *and* creditors have a role in addressing, resolving, and sharing the effects of generating capacity that is both physically and economically excess compared to the needs of the utility's customers. In Big Rivers' financial workout plan case, Case No. 9613, the Commission determined that customers should not be held responsible for 100% of Big Rivers' debts. Specifically, the Commission "*emphatically*" declared:

> *We emphatically reject the claims of REA, the banks, and Big Rivers that the members of the cooperative ultimately bear the total risk and responsibility for the utility's debts. The distribution cooperatives and their members do not stand in the same position as shareholders of an investor-owned company. The REA, with its oversight and monitoring responsibility, bears a substantial amount of the risk associated with Big Rivers' actions. The creditor banks are compensated for the risks they take. Cooperative members must shoulder a portion of the risk, too, since they have a say in the affairs of the utility. Nor are the aluminum companies exempt from responsibility. Until the downturn of recent years, these companies or their predecessors were in frequent contact with Big Rivers' management. Rather than allocate the risk among all parties now, we have chosen to give the participants an opportunity to discuss the allocation among themselves as a revised workout plan is negotiated.*[136]

The Commission added that "*Big Rivers' ratepayers should not have unlimited responsibility for the payment of Big Rivers' debt. Furthermore, they should not be required to provide all the revenues required to*

[136] 1987 Order at 19.

offset shortfalls arising from insufficient off-system sales."[137]

The Commission also concluded that the application of the "used and useful" standard involves a balancing of interests, stating:

> *The establishment of fair, just and reasonable rates involves a balancing of utility and ratepayer interests. After balancing these interests, the Commission may conclude in a given case that rates should be based upon prudent investments even where facilities are cancelled prior to completion of construction. On the other hand, in considering the need for facilities on an economic basis, the Commission may decide that it is not in the customers' interest to pay rates that include the cost of unneeded facilities.*[138]

The Commission concluded that in applying the "used and useful" standard, it "*must carry out a complex balancing of equities and allocation of risk.*"[139] The Commission ordered the parties to develop a workout plan that "*must offer an equitable balance among all interests,*" i.e. the utility, customers, and creditors.[140]

The Commission should apply the same reasoning and establish such an equitable balancing of all interests in this case. By the end of the 1980s, Big Rivers had emerged from its workout experience with a positive outcome, as explained in the Company's 1989 Annual Report:

> *"The decade of the '80s was extremely turbulent and frustrating for Big Rivers Electric Corporation. It began with great promise for growth, and construction of the D.B. Wilson Plant was started in 1980. By 1982, the economy had turned downward, aluminum prices dropped significantly, and by 1984 Big Rivers faced financial difficulties. During the ensuing years, the corporation was embroiled in Kentucky Public Service Commission (KPSC) hearings, lawsuits, threatened foreclosure by the Rural Electrification Administration (REA), and negotiations to resolve its financial problems.* ***However, these trying times resulted in a complete restructuring of debt and a workout plan which promises a stable, progressive future.*****"*[141]

A positive outcome is possible in the present circumstances as well. Accordingly, in this case, the Commission should similarly balance the cost burden associated with Big Rivers' excess capacity, which no longer is used and useful, by equitably sharing that burden between the Company's customers and its creditors. If Big Rivers' can simply collect 100% of its proposed increase from customers, the Company has no incentive to work with creditors to achieve such a balance. Instead, particularly given that Big Rivers only has a small number

[137] 1987 Order at 37.
[138] 1987 Order at 37.
[139] 1987 Order at 39.
[140] 1987 Order at 43.
[141] Big Rivers Response to KIUC Initial Request for Information (Feb. 28, 2013), Item 34, 1989 Annual Report (emphasis added).

of creditors with which to work on a reasonable resolution, the Commission should require the Company to develop a plan that reasonably balances the cost burden associated with its debt.

The Commission's goal, as mandated by statute, is to establish fair, just, and reasonable rates. Kentucky courts have held that "[t]*here is no litmus test for this and there is no single prescribed method to accomplish the goal*."[142] Establishing rates that are fair, just, and reasonable requires a balancing of interests among the utility and its customers and creditors and is dependent upon on the particular facts and circumstances of each case. For example, Kentucky courts have held that rates for smelters that vary with the world-wide price of aluminum can be fair, just, and reasonable.[143] Moreover, the Commission's authority to establish fair, just, and reasonable rates is broad, as the Supreme Court of Kentucky explained when it found that the Commission has authority to approve the establishment of a rider not specifically authorized by statute outside of a general rate case:

> *"We hold that so long as the rates established by the utility were fair, just, and reasonable, the PSC has broad ratemaking power to allow recovery of such costs outside the parameters of a general rate case and even in the absence of a statute specifically authorizing recovery of such costs."*[144]

2. The Commission Should Amend The Terms Of The Rural Reserve Fund So That It Does Not Discriminate Against Large Industrial Customers.

During the Unwind Transaction, the E.ON Entities agreed to reimburse Big Rivers for one-half of the cost of buying out leverage leases with Philip Morris Credit Corporation, amounting to approximately $60.9 million. As a condition of approving the Unwind Transaction the Commission ordered that E.ON double this $60.9 payment and that the additional $60.9 million be used to establish a new Rural Reserve fund that would be credited against Rural rates "*upon the exhaustion of the Non-Smelter Economic Reserve*."[145] The Rural Reserve was created by the Commission. Big Rivers did not negotiate for this benefit.

At the time that the Rural Reserve Fund was established it may have been reasonable to limit the use of it to Rural customers and to exclude non-smelter, Large Industrial customers from receiving this benefit. Although the Commission's reason for excluding Large Industrial customers from this fund is not explained in the

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[142] *National-Southwire Aluminum Co. v. Big Rivers Elec. Corp.*, 113 P.U.R.4th 89 (1990) at 513.
[143] *National-Southwire Aluminum Co. v. Big Rivers Elec. Corp.*, 113 P.U.R.4th 89 (1990).
[144] *Kentucky Public Service Commission v. Com. Ex. rel. Conway*, 324 S.W.3d 373, 374 (2010).
[145] Case No. 2007-00455, Order (March 6, 2009) at 25-26.

Commission's orders in the Unwind case it perhaps was done because the smelter rate was tied to the Large Industrial rate. That will no longer be the case when the Hawesville and Sebree smelters exit the Big Rivers' system. This exclusion no longer makes sense. Large Industrial customers such as Aleris, Domtar and Kimberly Clark, who submitted testimony in this proceeding, should not be discriminated against in favor of other business customers that happen to be categorized as "Rural" rather than Large Industrial. As the Commission is aware, "Rural" includes residential customers, but it also includes commercial customers, big and small, as well as smaller industrial customers. Many of these Rural customers are national or multi-national businesses like Wal-Mart, Burger King, Sam's Club, etc. There is no justification for the Commission to favor other commercial and industrial customers over the Large Industrial customers that provide thousands of high-paying jobs and provide the foundation for the Western Kentucky economy.

The discriminatory language in the Rural Reserve Fund is particularly unfair to the Large Industrial customer group in these "pancaked" rate cases because Large Industrial customers will see their bills increase by a 110% while Rural customers absorb a somewhat lesser 72.3% increase if both of Big Rivers' rate increases are approved. Big Rivers has asked all of its customers to shoulder a tremendous burden in paying for 100% of the excess capacity that was built to support the smelter load. Neither the Rural nor Large Industrial customers bear any responsibility for the dire situation that faces Big Rivers. The Commission should treat each of these customer groups equally with respect to the very limited mitigation tools that the Commission has at its disposal.

Further, Large Industrial customers are already subsidizing Rural customers by paying above cost of service rates.[146] Large Industrial customers not only are deprived of the benefit of the Commission Established Rural Reserve Fund and will be subject to a significantly higher rate increase from the "pancaked" rate cases, but a subsidy is also built into their current rates that is used to offset the rates paid by Rural customers. The Commission should redefine and redistribute the Rural Reserve it created. Doing so avoids undue discrimination against Big Rivers' Large Industrial Customers. Such discrimination is prohibited by KRS 278.170(1), which provides:

> *No utility shall, as to rates or service, give any unreasonable preference or advantage to any person or subject any person to any unreasonable prejudice or disadvantage, or establish or*

[146] Kollen Testimony at 62.

maintain any unreasonable difference between localities or between classes of service for doing a like and contemporaneous service under the same or substantially the same conditions.

The Commission created the Rural Reserve Fund. It has the authority to change its terms. The Commission changed the terms of another fund created during the Unwind transaction as recently as March of 2013. The Transition Reserve Account was specifically set up during the Unwind Transaction so that in the event that the smelters terminated their contracts and sales to the wholesale power market did not produce revenues greater than the smelter rates, the Transition Reserve could be used to make up the difference. However, when Big Rivers was unable to secure financing to pay off its 1983 PCB Bonds, which were set to mature in June of 2013, the Commission allowed Big Rivers to repurpose the Transition Reserve to help pay off this debt.[147] By changing the terms of the Transition Reserve Account, the Commission used the resources it had to solve a problem for Big Rivers and its customers as circumstances changed from what was originally anticipated in the Unwind Transaction. The Commission should likewise change the terms of the Rural Reserve Fund in order to fit the circumstances of today.

It is critical to eliminate the discriminatory language in the Rural Reserve Fund for the equitable reasons described above. Eliminating the Rural/Large Industrial distinction is also important to the mechanics of KIUC's proposed Formula Rate Plan. Blending the Rural Reserve and the Economic Reserve allows Big Rivers to draw from the accounts monthly in order to meet their target TIER, without concern that one account will run out before the other.

3. KIUC's Proposed Formula Rate Plan.

Big Rivers has characterized the Commission's choice in this case as between two extreme options; approve 100% of Big Rivers' rate request or force it into bankruptcy. There is a third viable approach that prevents rate shock to customers and maintains compliance with the Company's debt covenants. That alternative approach is largely outlined in KIUC Ex. 7, and would require the Commission to take the following actions in this case:

[147] Case No. 2012-00492, Order (March 26, 2013): "*Big Rivers is authorized to use the Transition Reserve funds to replace up to $35 million of the aforementioned CoBank funds and use them for capital expenditures in the ordinary course of business, as requested in its amended application.*"

a) Approve a reasonable base rate increase of $21.7 million for Big Rivers' remaining customers for the five months prior to the Commission's order in the pending Alcan rate case (September 1, 2013 through January 31, 2014).

b) Direct Big Rivers to use the $135 million in the ratepayer Reserve Funds to provide the additional compensation the Company needs to meet a 1.24 MFIR target on a monthly basis. This provision would require the Commission to eliminate both the MSRM and RER riders, and establish a new tariff to fund this mechanism. It would also be necessary for the Commission to blend the Rural Economic Reserve and Economic Reserve funds so that all customers are treated equally;

c) Explicitly direct Big Rivers to work with all stakeholders to equitably address excess capacity costs and require Big Rivers to retain a workout specialist to assist in this process. The Commission should set forth the parameters of the discussions with the creditors and a timeframe for resolution.

There are multiple benefits to this approach. It prevents rate shock to customers that would otherwise result from Big Rivers' proposed increase (though those customers would still be paying for a proportion of Big Rivers' excess capacity under this compromise approach). It also utilizes the existing $135 million in Reserve Funds to maintain Big Rivers' compliance with all of its debt covenants.

This approach also provides valuable time in which Big Rivers, its creditors, and its customers can work collaboratively to resolve the Company's debt obligations in a way that does not put 100% of Big Rivers' financial burden on the shoulders of its customers. This additional time also gives Big Rivers and the Commission the opportunity to comprehensively analyze what should be done with the Company's excess capacity and to attempt to right-size Big Rivers. During this time, the significant uncertainties surrounding the Century contract, MISO SSR payments, Century transmission revenue, capital or O&M expenses of Coleman 1, 2 and 3, or off-system sales margins can perhaps be resolved.

If Big Rivers has not developed a reasonable solution to address its financial issues by the time that its Reserve Funds are depleted, Big Rivers can file for additional rate relief. In that future case, the Commission would have the benefit of additional time and information. The Commission could observe whether Big Rivers worked effectively with its creditors and customers. And the Commission could examine more deeply whether additional expenditures on the Wilson and Coleman units are economically justified. Hence, this would allow the Commission to take a more cautious approach than merely approving Big Rivers' proposed 110% increases on Large Industrial customers and $881 per year increase to an average residential household on a permanent basis.

Another benefit of KIUC's Formula Rate Plan is that it automatically adjusts for the significant uncertainties related to the revenue impact of the Century contract case and the revenue impact of physically idling Coleman versus "effectively" idling Coleman.[148] For example, if Century completes the installation of capacitors early in the test year Big Rivers will idle Coleman and begin receiving transmission revenue from Century.[149] This transmission revenue is not included in the revenue requirement. There are other uncertainties as well. If Coleman is physically idled depreciation on Coleman should cease. The amount of any SSR payments received by Big Rivers is unknown.

Although the impact of these revenue items is currently unknown, their ultimate resolution will impact the amount of revenue Big Rivers' needs to collect from its remaining customers during the fully forecasted test year. The KIUC Formula Rate approach prevents guesswork related to these uncertainties. Any additional revenue that Big Rivers receives (or expense which is incurred) that is not accounted for in the approved revenue requirement will be reflected in the Company's monthly TIER calculation, which is based on actual financial results.

Consistent with the Commission's balanced approach to addressing Big Rivers' financial difficulties in the past, KIUC's alternative approach ensures the financial integrity of Big Rivers during the term of the rate plan, results in fair rates for customers, gives Big Rivers an opportunity to implement its rate mitigation plan, provides Big Rivers time to quantify the economics of continued capital spending on Coleman and Wilson, requires no guess work about the Century/MISO SSR situation, and gives the Big Rivers' creditors an incentive to negotiate a reasonable solution to the Company's financial issues. This approach can also easily be extended to the pending Alcan rate increase case.

The Commission's goal in this proceeding should be to buy time for Big Rivers to determine the best course of action to right-size the Company without burdening the Rural and Large Industrial ratepayers with clearly unreasonable and unsustainable rate increases.

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[148] Case No. 2013-00221.

[149] While Coleman is a MISO "must-run" unit, it is contemplated that Century can use its transmission payments to offset its SSR payments to Big Rivers.

III. CONCLUSION

WHEREFORE, KIUC respectfully requests that the Commission take the following actions:

1) Reduce Big Rivers proposed $68.6 million revenue requirement to $21.7 million in order to reflect the following adjustments:

   - A reduction of $11.685 million to remove depreciation expense for the 7 months of the 12 month fully forecasted test period that Wilson will be idled;
   - A reduction of $16.333 million to reflect the 7 months of the savings that will result from idling Wilson that are not taken into account in the 12 month fully forecasted test period;
   - A reduction of $4.353 million for interest expense and related TIER on pollution control bonds that Big Rivers no longer plans to issue;
   - A reduction of $14.5 million to remove Century's share of Big Rivers' excess capacity costs. This adjustment is necessary to achieve a balanced approach that equitably shares the cost burden associated with Century's departure.

2) Adopt KIUC's Formula Rate Approach in Order to allow Big Rivers to meet a 1.24 TIER and not default on its loan covenants. In order to implement the Formula Rate Approach the Commission would:

   - Approve a reasonable base rate increase of $21.7 million for Big Rivers' remaining customers for the five months prior to the Commission's order in the pending Alcan rate case (September 1, 2013 through January 31, 2014).
   - Direct Big Rivers to use the $135 million in the ratepayer Reserve Funds to provide the additional compensation the Company needs to meet its 1.24 TIER target on a monthly basis;
   - Explicitly direct Big Rivers to work with all stakeholders to achieve a reasonable negotiated solution to the Company's financial issues prior to the exhaustion of the Reserve Funds.

Respectfully submitted,

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July 26, 2013

Attachment A

ESTIMATED RATE INCREASES TO RURAL CLASS DUE TO CENTURY TERMINATION [1]

RURAL	Base Period [1]			Test Year [1]			Century Increase on Aug 21, 2013 [2]		
	Rural Bill Units	Rural Rate	Rural Billing	Rural Bill Units	Rural Rate	Rural Billing	Rural Rate	Rural Billing	Rural Percent
Demand	5,388,931	9.50	51,194,845	5,322,297	16.45399947	87,573,072	6.95	36,378,228	71.06%
Energy	2,420,925,805	0.029736	71,988,650	2,436,557,000	0.030000	73,096,710	0.000264	1,108,060	1.54%
Base Rate	2,420,925,805	0.050883	123,183,494	2,436,557,000	0.065941	160,669,782	0.01538494	37,486,288	30.43%
Non-Smelter Non-FAC PPA	2,420,925,805	(0.001242)	(3,006,790)	2,436,557,000	(0.000781)	(1,902,951)	0.000461	1,103,839	-36.71%
FAC	2,420,925,805	0.003480	8,424,822	2,436,557,000	0.005141	12,526,340	0.001661	4,101,518	48.68%
Environmental Surcharge	2,420,925,805	0.002534	6,134,626	2,436,557,000	0.003897	9,495,263	0.001363	3,360,637	54.78%
Surcredit	2,420,925,805	(0.004110)	(9,950,005)	2,436,557,000	(0.001738)	(4,234,736)	0.002372	5,715,269	-57.44%
Economic Reserve	2,420,925,805	(0.006442)	(15,595,604)	2,436,557,000	(0.010114)	(24,643,337)	(0.003672)	(9,047,733)	58.01%
Rate Increases ($/kWh), Billings, %		0.045103	109,190,543		0.062346	151,910,360	0.01753286	42,719,817	39.12%
Cumul Rate Increases ($/kWH), Billings, %							0.062346	42,719,817	39.12%
Distribution Rates ($/kWh)[3]		0.033000					0.033000		
Retail Rates ($/kWH) Bef and Aft Increase		0.078103					0.095346		23.8%
Avg Monthly Residential Bill @ 1300 kWh		$101.53					$123.95		
Average Annual Residential Increase							$269.00		

[1] Base Period and Test Year Amounts from Tab 59 of Company's filing in Case No. 2012-00535. Test Year Base Revenue Further Adjusted to Match Rebuttal Exhibit Wolfram 5.3.

[2] Century Increase computed as difference between Test Year and Base Period revenues/billings.

(1)

ESTIMATED RATE INCREASES TO LARGE INDUSTRIAL CLASS DUE TO CENTURY TERMINATION [1]

LARGE INDUSTRIAL	Base Period [1]			Test Year [1]			Century Increase on Aug 21, 2013 [2]		
	Large Industrial Bill Units	Large Industrial Rate	Large Industrial Billing	Large Industrial Bill Units	Large Industrial Rate	Large Industrial Billing	Large Industrial Rate	Large Industrial Billing	Large Industrial Percent
Demand	1,700,070	10.50	17,850,735	1,674,594	11.96	20,028,144	1.46	2,177,409	12.20%
Energy	953,161,521	0.024505	23,357,223	943,698,679	0.030000	28,310,960	0.005495	4,953,737	21.21%
Base Rate	953,161,521	0.043233	41,207,958	943,698,679	0.051223	48,339,105	0.00755659	7,131,147	17.31%
Non-Smelter Non-FAC PPA	953,161,521	(0.001249)	(1,190,863)	943,698,679	(0.000781)	(737,029)	0.000468	453,835	-38.11%
FAC	953,161,521	0.003490	3,326,542	943,698,679	0.005125	4,836,456	0.001635	1,509,913	45.39%
Environmental Surcharge	953,161,521	0.002364	2,252,893	943,698,679	0.003092	2,917,916	0.000728	665,023	29.52%
Surcredit	953,161,521	(0.004156)	(3,961,493)	943,698,679	(0.001777)	(1,676,953)	0.002379	2,284,541	-57.67%
Power Factor Penalty/Adjustments			111,014				0.000000	(111,014)	-100.00%
Economic Reserve	953,161,521	(0.006241)	(5,948,917)	943,698,679	(0.009302)	(8,778,285)	(0.003061)	(2,829,368)	47.56%
Rate Increases ($/kWh), Billings, %		0.037556	35,797,133		0.047580	44,901,210	0.00964723	9,104,077	25.43%
Cumul Rate Increases ($/kWH), Billings, %							0.047203	9,104,077	25.43%

[1] Test Year Amounts from Tab 59 of Company's filing in Case No. 2012-00535. Base Period Amounts revised in reponse to KIUC 1-30 c.
Test Year Base Revenue Further Adjusted to Match Exhibit Wolfram 5.3 .

[2] Century increase computed as difference between Test Year and Base Period revenues/billings.

ESTIMATED RATE INCREASES TO ALCAN DUE TO CENTURY TERMINATION[1]

ALCAN	Base Period [1]			Test Year [1]			Century Increase [2]		
	Bill Units	Rate	Billing	Bill Units	Rate	Billing	Rate	Billing	Percent
Energy	3,159,206,400	0.039405	124,489,441	3,159,206,400	0.046968	148,381,606		23,892,165	19.19%
Base Variable Energy	14,918,211	0.021806	325,307					(325,307)	-100.00%
Back-Up Energy	5,422,732	0.039529	214,355					(214,355)	-100.00%
Surplus Energy	(1,075,243)	0.034709	(37,321)					37,321	-100.00%
Supplemental Energy	93,586	0.030114	2,818					(2,818)	-100.00%
TIER Adjustment	3,159,206,400	0.002942	9,294,224	3,159,206,400	0.002945	9,303,467		9,243	0.10%
Non-FAC PPA	3,159,206,400	-0.000505	(1,595,399)	3,159,206,400	(0.000369)	(1,165,347)		430,052	-26.96%
FAC	3,159,206,400	0.003492	11,032,520	3,159,206,400	0.005121	16,176,808		5,144,288	46.63%
Environmental Surcharge	3,159,206,400	0.002263	7,148,088	3,159,206,400	0.002819	8,905,812		1,757,724	24.59%
Surcharge	3,159,206,400	0.001860	5,876,534	3,159,206,400	0.001872	5,912,468		35,934	0.61%
Adjustment			1,844			0		(1,844)	-100.00%
Rate Increases ($/kWh), Billings, %		0.049618	156,752,411		0.059355	187,514,814	0.009737	30,762,403	19.62%
Cumul Rate Increases ($/kWH), Billings, %									

[1] Base Period and Test Year Amounts from Tab 59 of Company's filing in Case No. 2012-00535. Test Year Base Revenue Further Adjusted to Match Rebuttal Exhibit Wolfram 5.3.

[2] Century Increase computed as difference between Test Year and Base Period revenues/billings.

3

Attachment B

U.S. Energy Information Administration - Average Retail Price of Electricity in 2011

RESIDENTIAL

#	Entity	State	Class of Ownership	Avg. ¢/kWh
1	Henderson City Utility Comm	KY	Public	6.13
2	Jackson Purchase Energy Corporation	KY	Cooperative	7.07
3	City of Benham	KY	Public	7.28
4	City of Falmouth	KY	Public	7.35
5	Kenergy Corp	KY	Cooperative	7.46
6	City of Nicholasville	KY	Public	7.50
7	Meade County Rural E C C	KY	Cooperative	7.53
8	City of Frankfort - (KY)	KY	Public	7.62
9	City of Berea Municipal Utility	KY	Public	7.73
10	City of Bardstown	KY	Public	7.75
11	City of Bardwell	KY	Public	7.89
12	Kentucky Utilities Co	KY	Investor Owned	8.02
13	Duke Energy Kentucky	KY	Investor Owned	8.39
14	Barbourville Utility Comm	KY	Public	8.58
15	Louisville Gas & Electric Co	KY	Investor Owned	8.60
16	Corbin City Utilities Comm	KY	Public	8.75
17	Madisonville Municipal Utils	KY	Public	8.83
18	City of Paris - (KY)	KY	Public	8.89
19	City of Olive Hill - (KY)	KY	Public	9.32
20	Salt River Electric Coop Corp	KY	Cooperative	9.39
21	Taylor County Rural E C C	KY	Cooperative	9.50
22	City of Providence - (KY)	KY	Public	9.51
23	City of Franklin - (KY)	KY	Public	9.53
	Big Rivers Total: Rural ~ NET of MRSM	KY	Cooperative	9.56
24	City of Paducah - (KY)	KY	Public	9.66
25	Kentucky Power Co	KY	Investor Owned	9.66
26	City of Russellville - (KY)	KY	Public	9.81
27	City of Owensboro - (KY)	KY	Public	9.84
28	City of Hopkinsville	KY	Public	9.85
29	Cumberland Valley Electric, Inc.	KY	Cooperative	9.92
30	Williamstown Utility Comm	KY	Public	10.01
31	City of Jellico	KY	Public	10.03
32	Nolin Rural Electric Coop Corp	KY	Cooperative	10.16
33	City of Glasgow	KY	Public	10.17
34	South Kentucky Rural E C C	KY	Cooperative	10.24
35	City of Murray - (KY)	KY	Public	10.31
36	Warren Rural Elec Coop Corp	KY	Cooperative	10.32
37	Tri-County Elec Member Corp	KY	Cooperative	10.33
38	Farmers Rural Electric Coop Corp	KY	Cooperative	10.35
39	Shelby Energy Co-op, Inc	KY	Cooperative	10.42
40	Owen Electric Coop Inc	KY	Cooperative	10.52
41	Blue Grass Energy Coop Corp	KY	Cooperative	10.62
42	Pennyrile Rural Electric Coop	KY	Cooperative	10.69
43	City of Fulton - (KY)	KY	Public	10.71
44	Big Sandy Rural Elec Coop Corp	KY	Cooperative	10.72
45	Fleming-Mason Energy Coop Inc	KY	Cooperative	10.75
46	City of Bowling Green - (KY)	KY	Public	10.84
47	City of Benton - (KY)	KY	Public	10.95
48	Clark Energy Coop Inc - (KY)	KY	Cooperative	11.00
49	Inter County Energy Coop Corp	KY	Cooperative	11.00
50	Licking Valley Rural E C C	KY	Cooperative	11.21
51	City of Mayfield Plant Board	KY	Public	11.29
52	City of Vanceburg	KY	Public	11.58
53	West Kentucky Rural E C C	KY	Cooperative	11.62
54	City of Princeton - (KY)	KY	Public	11.66
55	Jackson Energy Coop Corp - (KY)	KY	Cooperative	11.66
56	City of Hickman	KY	Public	11.67
57	Grayson Rural Electric Coop Corp	KY	Cooperative	12.37
58	Hickman-Fulton Counties RECC	KY	Cooperative	13.01
	Big Rivers Total: Rural ~ GROSS of MRSM	KY	Cooperative	13.46

Source: http://www.eia.gov/electricity/data.cfm#sales

Case No. 2013-00199
Exhibit Wolfram-8

U.S. Energy Information Administration: Average Retail Price of Electricity in 2011

INDUSTRIAL

#	Entity	State	Class of Ownership	Avg. ¢/kWh
1	Kenergy Corp	KY	Cooperative	4.14
2	Electric Energy Inc	KY	Investor Owned	4.27
3	Corbin City Utilities Comm	KY	Public	4.62
4	Tennessee Valley Authority	KY	Federal	4.76
	Big Rivers Total: Large Industrial ~NET of MRSM	**KY**	**Cooperative**	**4.96**
5	City of Bardstown	KY	Public	5.07
6	Henderson City Utility Comm	KY	Public	5.08
7	Owen Electric Coop Inc	KY	Cooperative	5.28
8	Williamstown Utility Comm	KY	Public	5.52
9	Kentucky Utilities Co	KY	Investor Owned	5.66
10	**Jackson Purchase Energy Corporation**	**KY**	**Cooperative**	**5.89**
11	Louisville Gas & Electric Co	KY	Investor Owned	5.98
12	City of Hopkinsville	KY	Public	5.99
13	Kentucky Power Co	KY	Investor Owned	6.03
14	Fleming-Mason Energy Coop Inc	KY	Cooperative	6.16
15	Nolin Rural Electric Coop Corp	KY	Cooperative	6.18
16	City of Nicholasville	KY	Public	6.41
17	Grayson Rural Electric Coop Corp	KY	Cooperative	6.47
18	City of Frankfort - (KY)	KY	Public	6.64
19	Blue Grass Energy Coop Corp	KY	Cooperative	6.68
20	Duke Energy Kentucky	KY	Investor Owned	6.70
21	Shelby Energy Co-op, Inc	KY	Cooperative	6.71
22	Salt River Electric Coop Corp	KY	Cooperative	6.77
23	City of Berea Municipal Utility	KY	Public	6.78
24	Big Sandy Rural Elec Coop Corp	KY	Cooperative	6.84
25	Barbourville Utility Comm	KY	Public	6.91
26	City of Franklin - (KY)	KY	Public	7.13
27	Inter County Energy Coop Corp	KY	Cooperative	7.13
28	City of Owensboro - (KY)	KY	Public	7.19
29	Jackson Energy Coop Corp - (KY)	KY	Cooperative	7.30
30	Farmers Rural Electric Coop Corp	KY	Cooperative	7.43
31	City of Murray - (KY)	KY	Public	7.61
32	West Kentucky Rural E C C	KY	Cooperative	7.81
33	Licking Valley Rural E C C	KY	Cooperative	7.90
	Big Rivers Total: Large Industrial ~GROSS of MRSM	**KY**	**Cooperative**	**7.91**
34	Tri-County Elec Member Corp	KY	Cooperative	7.98
35	City of Glasgow	KY	Public	8.01
36	Cumberland Valley Electric, Inc.	KY	Cooperative	8.02
37	Pennyrile Rural Electric Coop	KY	Cooperative	8.15
38	Warren Rural Elec Coop Corp	KY	Cooperative	8.19
39	City of Bowling Green - (KY)	KY	Public	8.23
40	South Kentucky Rural E C C	KY	Cooperative	8.35
41	Clark Energy Coop Inc - (KY)	KY	Cooperative	8.57
42	City of Paris - (KY)	KY	Public	8.61
43	City of Russellville - (KY)	KY	Public	9.01
44	City of Fulton - (KY)	KY	Public	9.16
45	City of Vanceburg	KY	Public	9.27
46	Taylor County Rural E C C	KY	Cooperative	9.42
47	City of Benton - (KY)	KY	Public	9.45
48	City of Mayfield Plant Board	KY	Public	9.57
49	City of Paducah - (KY)	KY	Public	9.63
50	City of Princeton - (KY)	KY	Public	10.75
51	Hickman-Fulton Counties RECC	KY	Cooperative	12.67

eia.gov/electricity/data.cfm#sales

U.S. Energy Information Administration - Average Retail Price of Electricity in 2011

RESIDENTIAL

#	State	Avg. ¢/kWh
1	Idaho	7.87
2	Washington	8.28
3	North Dakota	8.58
4	Louisiana	8.96
5	Utah	8.96
6	Arkansas	9.02
7	Wyoming	9.11
8	**Kentucky**	**9.20**
9	Nebraska	9.32
	Kentucky with Big Rivers NET Increase	**9.33**
10	South Dakota	9.35
11	West Virginia	9.39
12	Oklahoma	9.47
13	Oregon	9.54
	Kentucky with Big Rivers GROSS Increase	**9.55**
14	Missouri	9.75
15	Montana	9.75
16	Tennessee	9.98
17	Indiana	10.06
18	Mississippi	10.17
19	North Carolina	10.26
20	Iowa	10.46
21	Virginia	10.64
22	Kansas	10.65
23	Minnesota	10.96
24	New Mexico	11.00
25	Georgia	11.05
26	South Carolina	11.05
27	Texas	11.08
28	Arizona	11.08
29	Alabama	11.09
30	Colorado	11.27
31	Ohio	11.42
32	Florida	11.51
33	Nevada	11.61
34	Illinois	11.78
35	Wisconsin	13.02
36	Pennsylvania	13.26
37	Michigan	13.27
38	Maryland	13.31
39	District of Columbia	13.40
40	Delaware	13.70
41	Rhode Island	14.33
42	Massachusetts	14.67
43	California	14.78
44	Maine	15.38
45	New Jersey	16.23
46	Vermont	16.26
47	New Hampshire	16.52
48	Alaska	17.62
49	Connecticut	18.11
50	New York	18.26
51	Hawaii	34.68

Source: http://www.eia.gov/electricity/data.cfm#sales

U.S. Energy Information Administration - Average Retail Price of Electricity in 2011

INDUSTRIAL

#	State	Avg. ¢/kWh
1	Washington	4.09
2	Idaho	5.10
3	Utah	5.10
4	Iowa	5.21
5	Montana	5.27
6	**Kentucky**	**5.33**
7	Wyoming	5.41
8	Oklahoma	5.46
9	Oregon	5.47
	Kentucky with Big Rivers NET Increase	**5.49**
10	Arkansas	5.63
11	Louisiana	5.69
12	Missouri	5.85
13	South Carolina	5.94
14	North Carolina	6.01
	Kentucky with Big Rivers GROSS Increase	**6.05**
15	New Mexico	6.06
16	Ohio	6.12
17	Indiana	6.17
18	West Virginia	6.18
19	South Dakota	6.20
20	North Dakota	6.24
21	Texas	6.24
22	Alabama	6.25
23	Illinois	6.42
24	Nebraska	6.43
25	Minnesota	6.47
26	Virginia	6.49
27	Mississippi	6.53
28	Arizona	6.55
29	Georgia	6.60
30	Nevada	6.65
31	Kansas	6.71
32	District of Columbia	6.89
33	Colorado	7.06
34	Tennessee	7.23
35	Michigan	7.32
36	Wisconsin	7.33
37	Pennsylvania	7.73
38	New York	7.83
39	Florida	8.55
40	Maryland	8.76
41	Maine	8.88
42	Delaware	8.91
43	Vermont	9.83
44	California	10.11
45	Rhode Island	11.27
46	New Jersey	11.43
47	New Hampshire	12.27
48	Connecticut	13.24
49	Massachusetts	13.38
50	Alaska	15.71
51	Hawaii	28.40

Source: http://www.eia.gov/electricity/data.cfm#sales

Attachment C

SNLTable

Docket Number	Company Name	State	Rate Case Completion Date (mm/dd/yyyy)	Authorized Rate Change/Revenue (%)
D-RPU-85-9	Interstate Power and Light Company	IA	2/10/1986	57.30
C-D-86-11, 89-1	Entergy Louisiana, LLC	LA	7/6/1989	45.10
D-142,098-U	Kansas Gas and Electric Company	KS	9/27/1985	45.00
D-U-32220	Southwestern Electric Power Company	LA	2/27/2013	43.70
D-84-0109/85-0006 (CIPS)	Ameren Illinois Company	IL	5/8/1985	42.00
D-84.11.71	NorthWestern Corporation	MT	8/28/1985	40.00
C-R-870732	Pennsylvania Power Company	PA	5/3/1988	36.50
D-06-0072 (IP)	Ameren Illinois Company	IL	11/21/2006	32.90
D-E-017-GR-81-315	Otter Tail Power Company	MN	6/15/1982	31.20
C-R-870657	Duquesne Light Company	PA	3/23/1988	29.50
D-07-0587 (IP)	Ameren Illinois Company	IL	9/24/2008	29.20
C-U-1008-185	Avista Corporation	ID	2/6/1984	28.00
C-8352	Conowingo Power Company	MD	1/27/1992	27.30
C-10, 124	Otter Tail Power Company	ND	7/20/1981	26.50
D-82-0892 (elec.)	MidAmerican Energy Company	IL	10/13/1983	25.90
C-88-170-EL-AIR	Cleveland Electric Illuminating Company	OH	1/31/1989	25.00
Ca-U-83-26	Avista Corporation	WA	1/19/1984	25.00
C-07-0551-EL-AIR (TE)	Toledo Edison Company	OH	1/21/2009	24.55
D-83.9.68	MDU Resources Group, Inc.	MT	7/2/1984	24.40
C-88-171-EL-AIR	Toledo Edison Company	OH	1/31/1989	24.40
Ca-37803	Southern Indiana Gas and Electric Company, Inc.	IN	2/5/1986	24.30
D-09AL-299E	Public Service Company of Colorado	CO	12/3/2009	23.90
D-6998	Hawaiian Electric Company, Inc.	HI	6/30/1992	23.70
D-83-307-E O-84-142	South Carolina Electric & Gas Co.	SC	3/2/1984	23.30
D-3254	El Paso Electric Company	TX	8/14/1980	23.10
Ca-U-81-15	Avista Corporation	WA	11/25/1981	23.00
C-27882,83	New York State Electric & Gas Corporation	NY	10/20/1981	22.00
C-ER-85-128, EO-85-185	Kansas City Power & Light Company	MO	4/23/1986	21.70
Ca-U-81-41	Puget Sound Energy, Inc.	WA	3/12/1982	21.60
D-U-14495	Entergy Gulf States Louisiana, L.L.C.	LA	11/17/1980	21.60
D-83-302-E O-84-108	Duke Energy Carolinas, LLC	SC	2/22/1984	21.40
C-U-7091	Wisconsin Electric Power Company	MI	7/13/1982	21.30
D-7640	El Paso Electric Company	TX	3/30/1988	21.30
C-ER-2010-0356 (L&P)	KCP&L Greater Missouri Operations Company	MO	5/4/2011	21.30
D-U-14690	Entergy Louisiana, LLC	LA	5/26/1981	21.10
D-RPU-83-22	MidAmerican Energy Company	IA	4/25/1984	21.00
C-2006-00172	Duke Energy Kentucky, Inc.	KY	12/21/2006	20.50
D-E-01933A-07-0402	Tucson Electric Power Company	AZ	12/1/2008	19.90
C-05-59-EL-AIR	Duke Energy Ohio, Inc.	OH	12/21/2005	19.80
D-EL09-018	Black Hills Power, Inc.	SD	7/7/2010	19.40

C-PUE-2008-00046	Appalachian Power Company	VA	11/17/2008	19.30
D-142,099-U	Kansas City Power & Light Company	KS	9/27/1985	19.00
D-U-15180	Southwestern Electric Power Company	LA	4/23/1982	18.70
D-3716	Southwestern Electric Power Company	TX	6/18/1981	18.60
D-9441, SUB 20	PacifiCorp	WY	3/1/1985	18.30
D-E-22, SUB 273	Virginia Electric and Power Company	NC	12/5/1983	18.20
C-PUE-2009-00029	Kentucky Utilities Company	VA	3/4/2010	18.20
D-U-15271	Entergy Gulf States Louisiana, L.L.C.	LA	9/15/1982	18.10
C-08-E-0887	Central Hudson Gas & Electric Corporation	NY	6/22/2009	18.10
D-RPU-83-24	MidAmerican Energy Company	IA	4/6/1984	18.00
Ca-U-81-17	PacifiCorp	WA	12/16/1981	18.00
Ca-U-82-38	Puget Sound Energy, Inc.	WA	7/25/1983	18.00
C-08-0709-EL-AIR	Duke Energy Ohio, Inc.	OH	7/8/2009	17.80
C-U-7791	Indiana Michigan Power Company	MI	9/26/1984	17.70
D-81.8.70	PacifiCorp	MT	5/27/1982	17.60
D-E-001-GR-81-345	Interstate Power and Light Company	MN	6/24/1982	17.50
Ca-U-82-12, 35	PacifiCorp	WA	2/1/1983	17.50
D-11AL-947E	Public Service Company of Colorado	CO	4/26/2012	17.30
C-91-414-EL-AIR	Dayton Power and Light Company	OH	1/22/1992	17.10
D-82-0026	Commonwealth Edison Company	IL	12/1/1982	17.10
C-U-16180	Indiana Michigan Power Company	MI	10/14/2010	17.00
AP-83-0552 De-830717	PacifiCorp	CA	7/18/1984	17.00
C-AVU-E-04-1	Avista Corporation	ID	9/9/2004	16.90
D-RPU-85-11	Interstate Power and Light Company	IA	3/31/1986	16.80
D-82.8.54	NorthWestern Corporation	MT	5/12/1983	16.80
C-U-7660- Fermi 2	DTE Electric Company	MI	4/1/1986	16.60
C-ER-2009-0089	Kansas City Power & Light Company	MO	6/10/2009	16.40
Ca-43111	Southern Indiana Gas and Electric Company, Inc.	IN	8/15/2007	16.30
C-28553	Long Island Lighting Company	NY	8/27/1984	16.20
D-3871	Entergy Texas, Inc.	TX	9/17/1981	16.20
D-U-30689	Cleco Power LLC	LA	10/14/2009	16.10
D-80.4.2.4714A (elec)	NorthWestern Corporation	MT	12/22/1980	16.00
D-4620	El Paso Electric Company	TX	12/30/1982	15.70
D-3270-UR-10-E	Madison Gas and Electric Company	WI	7/22/1982	15.70
D-E-015/GR-09-1151	ALLETE (Minnesota Power)	MN	11/2/2010	15.70
C-91-418-EL-AIR	Columbus Southern Power Company	OH	5/12/1992	15.70
C-PAC-E-11-12	PacifiCorp	ID	1/10/2012	15.60
D-02S-594E	Black Hills Colorado Electric Utility Company, LP	CO	6/25/2003	15.60
C-27744	Consolidated Edison Company of New York, Inc.	NY	3/12/1981	15.50
D-UE-213	Idaho Power Co.	OR	2/24/2010	15.40
D-ER-11080469	Atlantic City Electric Company	NJ	10/23/2012	15.37
D-9454, SUB 18	PacifiCorp	WY	4/11/1983	15.30
A-12-02-014	California Pacific Electric Company, LLC	CA	11/29/2012	15.30
C-U-1006-185	Idaho Power Co.	ID	8/20/1982	15.30
D-07-0566	Commonwealth Edison Company	IL	9/10/2008	15.10
C-91-370	Duke Energy Kentucky, Inc.	KY	5/5/1992	15.10

Source: SNL Financial LC

C-94-1918-EL-AIR	Columbus Southern Power Company	OH	11/9/1995	15.10
D-E-01345A-05-0816	Arizona Public Service Company	AZ	6/28/2007	15.10
D-84-175-U	Southwestern Electric Power Company	AR	5/29/1985	15.00
C-9061	Kentucky Power Company	KY	12/4/1984	15.00
D-D90.6.39 (elec)	NorthWestern Corporation	MT	7/19/1991	14.80
D-82-328-E O-83-583	Duke Energy Progress, Inc.	SC	9/28/1983	14.70
C-R-850152	PECO Energy Company	PA	6/26/1986	14.50
D-3673-U	Georgia Power Company	GA	9/30/1987	14.50
D-09-KCPE-246-RTS	Kansas City Power & Light Company	KS	6/24/2009	14.40
AP-61138 De-8212055	Southern California Edison Co.	CA	12/13/1982	14.40
C-U-15981	Wisconsin Electric Power Company	MI	7/1/2010	14.20
C-1727	Southwestern Public Service Company	NM	7/19/1982	14.00
D-11-528	Delmarva Power & Light Company	DE	11/29/2012	14.00
AP-820843 De-8304066	Sierra Pacific Power Company	CA	4/20/1983	14.00
D-90-0169	Commonwealth Edison Company	IL	3/8/1991	13.90
C-PUE-850029	Potomac Edison Company	VA	4/2/1986	13.80
D-9441, SUB 25	PacifiCorp	WY	6/2/1986	13.80
DPU 10-70	Western Massachusetts Electric Company	MA	1/31/2011	13.80
C-27774	Long Island Lighting Company	NY	5/20/1981	13.60
C-86-2026-EL-AIR	Toledo Edison Company	OH	12/16/1987	13.60
C-07-0551-EL-AIR (OE)	Ohio Edison Company	OH	1/21/2009	13.56
C-12-1682-EL-AIR	Duke Energy Ohio, Inc.	OH	5/1/2013	13.40
C-ER-2010-0130	Empire District Electric Company	MO	8/18/2010	13.40
D-2840	AEP Texas Central Company	TX	1/23/1980	13.30
D-7764	Hawaii Electric Light Company, Inc.	HI	2/10/1995	13.30
D-10-EPDE-314-RTS	Empire District Electric Company	KS	6/23/2010	13.20
D-E-001-GR-91-605	Interstate Power and Light Company	MN	6/12/1992	13.20
C-10, 334	Otter Tail Power Company	ND	4/19/1983	13.10
D-E-01345A-08-0172	Arizona Public Service Company	AZ	12/16/2009	13.10
D-20004-81-ER-09	MDU Resources Group, Inc.	WY	4/27/2010	13.10
C-9093	Delmarva Power & Light Company	MD	7/19/2007	13.10
D-9561	AEP Texas Central Company	TX	12/19/1990	13.00
D-7195	AEP Texas North Company	TX	11/30/1987	12.90
C-U-1009-137	PacifiCorp	ID	9/10/1984	12.70
D-08S-520E	Public Service Company of Colorado	CO	5/27/2009	12.70
D-6630-UR-110 (elec.)	Wisconsin Electric Power Company	WI	4/30/1998	12.70
D-06S-234EG	Public Service Company of Colorado	CO	12/1/2006	12.70
C-ER-2012-0175 (L&P)	KCP&L Greater Missouri Operations Company	MO	1/9/2013	12.60
D-10AL-008E	Black Hills Colorado Electric Utility Company, LP	CO	8/4/2010	12.60
C-2009-00459	Kentucky Power Company	KY	6/28/2010	12.50
D-05-EPDE-980-RTS	Empire District Electric Company	KS	12/9/2005	12.50
D-6107	Green Mountain Power Corporation	VT	1/23/2001	12.50
D-40824	Southwestern Public Service Company	TX	6/6/2013	12.44
D-4634	Central Vermont Public Service Corporation	VT	9/16/1982	12.40
C-10-E-0362	Orange and Rockland Utilities, Inc.	NY	6/16/2011	12.40
D-U-15297	Cleco Power LLC	LA	9/15/1982	12.30

Source: SNL Financial LC

Ca-U-82-10	Avista Corporation	WA	12/29/1982	12.30
D-E-001/GR-10-276	Interstate Power and Light Company	MN	8/12/2011	12.30
C-ER-2007-0004 (L&P)	KCP&L Greater Missouri Operations Company	MO	5/17/2007	12.30
C-U-9656	Indiana Michigan Power Company	MI	2/12/1991	12.20
C-2005-00341	Kentucky Power Company	KY	3/14/2006	12.20
Ca-36818	Duke Energy Indiana, Inc.	IN	1/20/1983	12.00
C-28053,54	Rochester Gas and Electric Corporation	NY	7/13/1982	12.00
C-R-821945	Duquesne Light Company	PA	1/27/1983	12.00
D-81-163-E O-82-284	Duke Energy Progress, Inc.	SC	6/1/1982	12.00
D-E-22, SUB 265	Virginia Electric and Power Company	NC	8/26/1982	12.00
D-9454, SUB 13	PacifiCorp	WY	5/19/1982	12.00
D-ER-90091090J	Atlantic City Electric Company	NJ	7/3/1991	12.00
C-AVU-E-08-01	Avista Corporation	ID	9/30/2008	12.00
C-91-410-EL-AIR	Duke Energy Ohio, Inc.	OH	5/12/1992	12.00
C-ER-2009-0090 (L&P)	KCP&L Greater Missouri Operations Company	MO	6/10/2009	12.00
D-UE-100749	PacifiCorp	WA	3/25/2011	12.00
C-U-1008-234, 204	Avista Corporation	ID	2/14/1986	11.96
D-133,002-U	Kansas City Power & Light Company	KS	3/29/1983	11.90
C-U-3850	Entergy Mississippi, Inc.	MS	11/24/1980	11.80
C-27826	Central Hudson Gas & Electric Corporation	NY	7/14/1981	11.80
D-3270-UR-114 (elec)	Madison Gas and Electric Company	WI	12/12/2005	11.80
D-6680-UR-112 (elec)	Wisconsin Power and Light Company	WI	4/3/2003	11.80
D-4865	Green Mountain Power Corporation	VT	9/6/1984	11.70
D-R-2010-2179522	Duquesne Light Company	PA	2/24/2011	11.70
D-E-002-GR-81-342	Northern States Power Company - MN	MN	6/25/1982	11.60
D-E-01933A-12-0291	Tucson Electric Power Company	AZ	6/11/2013	11.60
D-D2007.7.79	MDU Resources Group, Inc.	MT	4/22/2008	11.50
D-4510	Entergy Texas, Inc.	TX	10/22/1982	11.50
D-37364	Southwestern Electric Power Company	TX	4/16/2010	11.50
D-RPU-04-1	Interstate Power and Light Company	IA	12/14/2004	11.50
D-U-1933 De-56659	Tucson Electric Power Company	AZ	10/24/1989	11.50
D-82.4.28	PacifiCorp	MT	1/24/1983	11.40
D-9491	Texas-New Mexico Power Company	TX	2/7/1991	11.40
C-08-0278-E-P	Appalachian Power Company	WV	6/27/2008	11.40
C-8616 (elec.)	Louisville Gas and Electric Company	KY	3/2/1983	11.30
D-83-707	Nevada Power Company	NV	1/3/1984	11.30
D-85121163-E	Public Service Electric and Gas Company	NJ	4/6/1987	11.30
C-81-782-EL-AIR	Ohio Power Company	OH	7/14/1982	11.30
D-3460	Oncor Electric Delivery Company LLC	TX	6/26/1981	11.30
C-08-00273-UT	Public Service Company of New Mexico	NM	5/28/2009	11.30
D-U-14648	Cleco Power LLC	LA	3/23/1981	11.20
C-U-7660	DTE Electric Company	MI	7/16/1985	11.10
C-U-4224	Entergy Mississippi, Inc.	MS	1/21/1983	11.00
D-08-WSEE-1041-RTS (WR)	Westar Energy, Inc.	KS	1/21/2009	11.00
D-08-WSEE-1041-RTS (KG&	Kansas Gas and Electric Company	KS	1/21/2009	11.00
D-4065	Narragansett Electric Company	RI	2/9/2010	11.00

D-83-0537 (Phase 2)	Commonwealth Edison Company	IL	10/24/1985	11.00
D-05-UR-102 (WEP-EL)	Wisconsin Electric Power Company	WI	1/25/2006	11.00
C-8429	Kentucky Power Company	KY	6/18/1982	11.00
D-4400	AEP Texas Central Company	TX	7/29/1982	10.90
D-7195, 6755	Entergy Texas, Inc.	TX	5/16/1988	10.90
D-E-22, Sub 479	Virginia Electric and Power Company	NC	12/21/2012	10.90
D-6690-UR-113 (elec.)	Wisconsin Public Service Corporation	WI	6/20/2002	10.90
D-818-726	Jersey Central Power & Light Company	NJ	7/22/1982	10.80
D-85-78-E O-85-841	Duke Energy Carolinas, LLC	SC	10/2/1985	10.80
D-09-0307 (CIPS)	Ameren Illinois Company	IL	4/29/2010	10.80
D-20000-384-ER-10	PacifiCorp	WY	9/22/2011	10.80
D-81-0600 (CILCO-E)	Ameren Illinois Company	IL	7/1/1982	10.80
C-ER-83-42	Empire District Electric Company	MO	6/17/1983	10.75
C-28550,51	New York State Electric & Gas Corporation	NY	4/18/1984	10.70
C-ER-83-49	Kansas City Power & Light Company	MO	7/8/1983	10.60
C-87-689-EL-AIR	Ohio Edison Company	OH	1/26/1988	10.60
D-6690-UR-18-E	Wisconsin Public Service Corporation	WI	4/27/1982	10.60
D-4220-UR-114 (elec.)	Northern States Power Company - WI	WI	1/5/2006	10.60
D-2006-024	Maine Public Service Company	ME	7/6/2006	10.60
D-20150	Entergy Texas, Inc.	TX	6/29/1999	10.50
C-ER-2009-0090 (MPS)	KCP&L Greater Missouri Operations Company	MO	6/10/2009	10.50
D-R-2010-2161694	PPL Electric Utilities Corporation	PA	12/16/2010	10.50
AP-821248 De-8312068-E	Pacific Gas and Electric Company	CA	12/22/1983	10.50
C-05-E-0934	Central Hudson Gas & Electric Corporation	NY	7/24/2006	10.50
C-ER-2007-0004 (MPS)	KCP&L Greater Missouri Operations Company	MO	5/17/2007	10.50
C-7604 0-65827	Potomac Edison Company	MD	6/14/1982	10.40
D-3270-UR-113 (elec)	Madison Gas and Electric Company	WI	12/22/2004	10.40
C-R-80021082	West Penn Power Company	PA	2/3/1981	10.30
D-07-0586 (CIPS)	Ameren Illinois Company	IL	9/24/2008	10.30
C-ER-2010-0036	Union Electric Company	MO	5/28/2010	10.30
D-6680-UR-111 (elec.)	Wisconsin Power and Light Company	WI	9/12/2002	10.30
C-ER-2006-0314	Kansas City Power & Light Company	MO	12/21/2006	10.30
C-80-141-EL-AIR	Ohio Edison Company	OH	2/11/1981	10.20
D-9300	Oncor Electric Delivery Company LLC	TX	8/16/1991	10.20
C-ER-2012-0166	Union Electric Company	MO	12/12/2012	10.20
D-E-22,SUB314	Virginia Electric and Power Company	NC	2/14/1991	10.20
D-820100-EU	Duke Energy Florida, Inc.	FL	1/25/1983	10.20
Ca-29450	Oklahoma Gas and Electric Company	OK	12/20/1985	10.10
C-09-E-0715	New York State Electric & Gas Corporation	NY	9/16/2010	10.10
D-6690-UR-117 (elec.)	Wisconsin Public Service Corporation	WI	12/22/2005	10.10
C-U-1008-219	Avista Corporation	ID	1/30/1985	10.00
DPU-956	Commonwealth Electric Company	MA	5/28/1982	10.00
C-U-4620	Entergy Mississippi, Inc.	MS	6/14/1985	10.00
D-837-620-E	Public Service Electric and Gas Company	NJ	3/23/1984	10.00
C-27909	Orange and Rockland Utilities, Inc.	NY	12/1/1981	10.00
D-07-12001	Sierra Pacific Power Company	NV	6/27/2008	10.00

D-08-12002	Nevada Power Company	NV	6/24/2009	10.00
D-6531	Hawaiian Electric Company, Inc.	HI	10/17/1991	10.00
C-07-0248-E-GI	Appalachian Power Company	WV	6/22/2007	10.00
D-DE-03-200	Public Service Company of New Hampshire	NH	9/2/2004	10.00
D-06-035-21	PacifiCorp	UT	12/1/2006	10.00

Attachment D

(CONFIDENTIAL)

Attachment E

(CONFIDENTIAL)

Attachment F

BIG RIVERS ELECTRIC CORPORATION

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

Response to Ben Taylor and Sierra Club's Initial Request for Information dated February 14, 2013

April 25, 2013

Item 23) ***State whether Big Rivers has 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 of the decline in off-system sales revenues.***

a. If so:

a. (i) Identify which unit or units were evaluated

a. (ii) Explain the results of that evaluation

a. (iii) Produce any report or other document regarding that evaluation

b. If not, explain why not.

c. State whether the recent notice of termination of Alcan's retail electric service agreement with Kenergy has led to the evaluation of the retirement, rather than idling, of any of Big Rivers' generating units.

c. (i) If so:

1. Identify which unit or units were evaluated

2. Explain the results of that evaluation

3. Produce any report or other document regarding that evaluation.

c. (ii) If not, explain why not.

Response) No.

a. N/A

b. 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.

c. The Alcan notice of termination has not led to the evaluation of retirement of any of Big Rivers generating units.
   i. N/A
   ii. See Item 23b.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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

Response to Ben Taylor and Sierra Club's Initial Request for Information dated February 14, 2013

April 25, 2013

Item 32) *For each of the Wilson, Green, Coleman, Reid, or HMP&L generating units:*

a. *Identify the estimated retirement date*
b. *Produce any analysis or assessment of the economics of continued operation of such unit*
c. *Produce any analysis or assessment of the impact that retirement of each unit would have on capacity adequacy, transmission grid stability, transmission grid support, voltage support, or transmission system reliability*
d. *Identify any transmission grid upgrades or changes that would be needed to permit the retirement of any of the units*
e. *Produce any analysis or assessment of the need for the continued operation of each unit.*

Response)

a. Per Big Rivers 2012 Depreciation Study conducted by Burns & McDonnell Engineering the expected retirement dates for Big Rivers generating assets in "Scenario 1" on page II-4 are as follows:

Green Units 1 & 2	2041
HMP&L Units 1 & 2	2035
Reid Unit 1	2025
Wilson Unit 1	2045
Coleman Units 1, 2 & 3	2035

b. No analysis or assessments have been done.

c. See Big Rivers' response to PSC 2-21(f)(1).

d. Big Rivers has not performed the studies necessary to identify the transmission grid upgrades needed to permit the retirement of any of the generating units currently operating on its system.

e. See Big Rivers' response to PSC 2-21(f)(1).

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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

Response to Ben Taylor and Sierra Club's
Supplemental Requests for Information
Dated May 6, 2013

May 15, 2013

Item 22) *Refer to your response to SC DR 1-23(b). With regards to Big Rivers' coal-fired generating units:*

a. *Identify and produce any analyses, studies, or documents that support your contention that "Big Rivers' members will be able to reap significant benefits from the units in the future."*
b. *Identify any estimate or projection of the level of "significant benefits" that Big Rivers' members will be able to reap in the future.*

Response)

a. Big Rivers' Members will continue to reap significant benefits from the units in the future because these units will be available to provide safe, reliable, low-cost power for decades in the future.
b. Big Rivers has not attempted to quantify the inherent benefits that its Members will experience in the future as result of power plant ownership. The power plants have a significant remaining useful life and are valuable assets that will continue to provide a needed service to Big Rivers' Members for decades to come.

Witness) Robert W. Berry

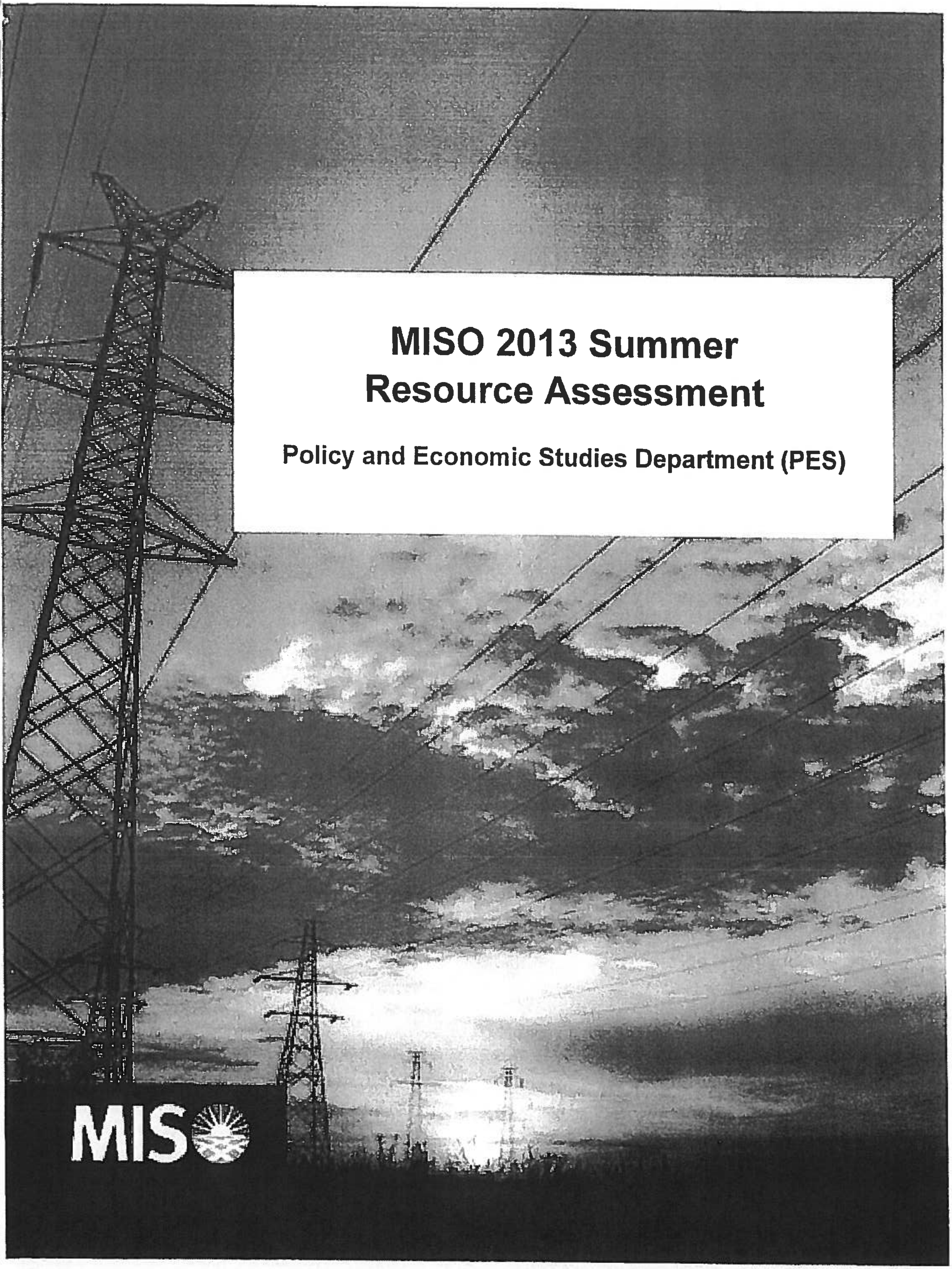
Attachment G

(CONFIDENTIAL)

Attachment H

(CONFIDENTIAL)

Attachment I



MISO 2013 Summer Resource Assessment

Policy and Economic Studies Department (PES)

MISO

1 Executive Summary

During the 2013 summer peak hour, MISO expects adequate resources to serve load, with a 28.1 percent forecasted Reserve Margin, which far exceeds the requirement of 14.2 percent. It is always possible for a combination of higher loads, higher forced outage rates, fuel limitations, low water levels and other factors to lead to curtailment of firm load; however, this is a low probability event for the 2013 summer.

MISO forecasts the coincident Net Internal Demand to peak at 91,532 MW, with 117,267 MW of capacity to serve MISO load, during the 2013 summer season. Included in the capacity are 6,119 MW of Net Interchange, and 3,394 MW of behind-the-meter generation, and 40 MW of Demand Response Resources. MISO expects 1,600 MW of wind capacity to be available to serve load this summer, which is approximately 13 percent of wind Nameplate Capacity.

MISO does not anticipate Environmental Regulations to have an impact during the 2013 summer season; however, MISO is currently evaluating these regulations' impacts post 2013 summer.

For planning year 2013 MISO's Planning Reserve Margin Requirement is 14.2 percent which is 2.5 percentage points lower than last year's requirement. The major driver of this decrease is an adjusted model which allows MISO to access more external resources from neighboring entities.

MISO forecasts a 28.1 percent Reserve Margin for 2013 summer peak, which is 13.9 percentage points higher than the Planning Reserve Margin Requirement of 14.2 percent.

MISO does not anticipate any significant impacts from Bulk Electric System (BES) transmission lines and/or BES transformers being out-of-service through the summer season. MISO does not foresee any transmission constraints that could significantly impact reliability.

Furthermore, MISO does not foresee any operational risks internal to MISO or external which would adversely impact summer reliability. MISO coordinates extensively with neighboring reliability coordinators as part of the seasonal assessment and outage coordination processes, and via scheduled daily conference calls and ad-hoc communications as need arises in real-time operations. MISO is not aware of any significant issues in neighboring areas expected to threaten overall system reliability. There is always the potential for low water levels and/or high water temperatures to result from unusually hot and dry weather, and these situations would be resolved through existing procedures depending on the circumstances.

Table 1-1 on the next page provides capacity forecasts, demand forecasts, and a range of reserve margin levels for the upcoming 2013 summer peak. Section 2 provides corresponding risk of MISO initiating Emergency Operating Procedures this summer. The likelihood of such an event has a low probability of occurrence.

Attachment J

(CONFIDENTIAL)

Attachment K

f utility plant-in-
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value of the plant
to obtain the best

CHAPTER 11 REORGANIZATION OF UTILITY COMPANIES

*Ralph R. Mabey**

*Patrick S. Malone***

I. INTRODUCTION

On April 6, 2001, Pacific Gas and Electric (PG&E), the utility unit of PG&E Corporation, filed for reorganization under Chapter 11 of the United States Bankruptcy Code after months of intense media coverage of the "California Energy Crisis." PG&E filed for Chapter 11 after spending $9 billion in excess of revenues to purchase electricity to supply its customers, exhausting its ability to borrow, while consumer rates remained frozen by the California Public Utilities Commission (CPUC) at a level far below prices at which PG&E could buy power on the wholesale market.[1] According to PG&E Chairman Robert D. Glynn, Jr., PG&E

> chose to file for Chapter 11 reorganization affirmatively because we expect the court will provide the venue needed to reach a solution, which thus far the State and the State's regulators have been unable to achieve .... The regulatory and political processes have failed us, and now we are turning to the court.[2]

Similar problems face Southern California Edison (SCE) that might drive it toward bankruptcy as well.

Although PG&E is the latest, and perhaps largest, utility to file for bankruptcy, it is only the most recent in a series of utility bankruptcies, mostly involving electric power utilities, which began in the late 1980s. As deregulation and other forces have come to bear on the natural gas and electric power industries over the last decade, several utilities have turned to Chapter 11 in an effort to save their troubled companies.

Because of the historical role of regulation in the utility sector, such

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* Mr. Mabey is a partner at LeBoeuf, Lamb, Greene & MacRae, L.LP. where he heads the international insolvency and reorganization practice. He has, inter alia, served as Chapter 11 Trustee of Cajun Electric Power Cooperative and as a United States Bankruptcy Judge from 1979 to 1983.

** Mr. Malone is an associate in the Salt Lake City, Utah office of LeBoeuf, Lamb, Greene & MacRae.

1. PACIFIC GAS AND ELEC. CO., News Release, *Pacific Gas and Electric Company Files for Chapter 11 Reorganization*, (April 6, 2001), *available at* http://www.pge.com /006a_news_rel/ 01405.shtml.

2. *Id.*

bankruptcy in early March. PG&E disputed these claims, arising out of PG&E's power purchases and grid fees, purportedly on the basis that the California market failure and unexpected power shortages constitute a force majeure for which PG&E should not be held responsible.

Another remaining issue in the pending PG&E bankruptcy, and in subsequent cases, will be the disposition of forward contracts (contracts which provide the ability to buy or sell commodities in the market on a forward basis) entered into by PG&E. Prior precedent suggests that settlement payments on such forward contracts made prior to filing may not be avoidable as preferences under section 546(e) of the Bankruptcy Code, unless such payments qualify as fraudulent transfers under section 548(a)(1)(A) of the Bankruptcy Code.[71] Moreover, the Bankruptcy Code expressly allows the closing out of forward contracts.[72]

It is also noteworthy that the California Attorney General has asked the Securities and Exchange Commission (SEC) to investigate billions of dollars that were transferred from PG&E to its parent company, PG&E Corporation, between 1997 and 1999. The SEC has a right to make such an investigation in certain circumstances under the Public Utility Holding Company Act (PUHCA). It has been reported that PG&E Corporation claims it is an intrastate entity that is exempt from PUHCA.[73] If improper, these cash transfers might be voidable as fraudulent transfers.

Finally, it is important to note that Chapter 11 is a very public fishbowl. No doubt, as this article is being written, there are a number of felines hungrily eyeing PG&E as it swims in circles.

V. CONCLUSION

Chapter 11 bankruptcy can be a tremendously effective means of resolving a troubled company's financial problems. The Bankruptcy Code provides a debtor company with many useful means of restructuring preexisting debt and disposing of other financial liabilities. Indeed, Chapter 11 has proven successful at some level in every recent utility bankruptcy. Chapter 11, however, is not a panacea for all economic ills. There are some problems that simply may not be resolvable under Chapter 11 alone. The current California energy crisis is one such situation not easily resolved under the Bankruptcy Code. The ultimate resolution of the crisis will likely require a difficult political resolution.

Fortunately, not every utility bankruptcy involves the same intractable problems facing the California utilities. Chapter 11 has proven itself a very effective process for restoring electric utilities to viability and will likely continue to be useful in future utility bankruptcies. In fact, the PG&E bankruptcy may increase the likelihood of success in future utility bank-

71. *In re* Olympic Natural Gas Co., 258 B.R. 161 (Bankr. S.D. Tex. 2001) (interpreting 11 U.S.C. § 546(e) (2000)).

72. 11 U.S.C. § 556 (2000).

73. Jessica Berthold, *California Attorney General Asks SEC to Probe PG&E Cash Transfer*, THE DAILY BANKR. REV., July 9, 2001.