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April 6, 2009

RECEIVED
APR 07 2009
PUBLIC SERVICE
COMMISSION

Via Federal Express

Jeff Derouen
Executive Director
Public Service Commission
211 Sower Boulevard, P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: The Applications of Big Rivers Electric Corporation for: (I) Approval of Wholesale Tariff Additions for Big Rivers Electric Corporation, (II) Approval of Transactions, (III) Approval to Issue Evidences of Indebtedness, and (IV) Approval of Amendments to Contracts; and of E.ON U.S., LLC, Western Kentucky Energy Corp., and LG&E Energy Marketing, Inc., for Approval of Transactions, PSC Case No. 2007-00455

Dear Mr. Derouen:

Enclosed are an original and eight copies of the response of Big Rivers Electric Corporation ("Big Rivers") to the Commission Staff's data request dated April 2, 2009. The verification pages will be filed this Wednesday.

Big Rivers looks forward to discussing at the informal conference on April 8, 2009, the progress the unwind transaction parties have made toward setting a final closing date. I certify that a copy of this letter, data request responses, and confidentiality petition have been served each upon each of the persons identified on the attached service list.

Sincerely yours,

James M. Miller

James M. Miller

JMM/ej
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BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE COMMISSION STAFF'S
APRIL 2, 2009 FIRST DATA REQUEST
TO BIG RIVERS ELECTRIC CORPORATION
PSC CASE NO. 2007-00455
April 7, 2009

Item 1) Provide copies of each correspondence since January 1, 2009 between Big Rivers or anyone acting on its behalf and any credit rating agency or anyone acting on the agency's behalf.

Response) Big Rivers interprets the inquiry in this set of data requests as seeking current information about where Big Rivers is in the ratings process, rather than how it got there. With respect to this specific item, Big Rivers attaches information on the rating that has been issued, and information representing the latest communications in the ratings processes that are not concluded.

The in-depth analysis process with Moody's and Standard & Poor's occurred in January and February. There are volumes of e-mails with extensive attachments during that period exchanging analyses and responses to queries in connection with the detailed research that is part of the ratings process. That information is not provided. If Big Rivers has incorrectly assumed that this information is beyond the scope of what the Commission staff is actually seeking, Big Rivers will supplement its response.

Much of the information regarding the status of the ratings process was exchanged verbally. Big Rivers will be prepared to discuss that information at the informal conference on April 8, 2009.

Witness) C. William Blackburn

Credit Opinion

Moody's Global
Corporate Finance

Table of Contents:

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Vice President – Senior Analyst

William L. Hess
Team Managing Director

March 2009

Big Rivers Electric Corporation

Henderson, Kentucky, United States

Key Indicators[1]

Big Rivers Electric Corporation	2007	2006	2005
TIER [2]	1.7	1.5	1.4
DSCR [2]	1.8	1.6	1.8
FFO / Interest	2.1	1.9	1.8
FFO / Debt	6%	5%	4%
Equity / Capitalization	-16%	-21%	-26%
Net Operating Margin	30%	34%	32%

[1] All ratios calculated in accordance with Moody's Electric G&T Cooperative Rating Methodology using Moody's standard adjustments

[2] Moody's definitions may differ from indenture covenants

Rating Drivers

- Expected deleveraging as the unwinding of 1998 vintage transactions nears completion
- Ownership of competitively advantaged coal-fired generation plants
- High industrial concentration to two aluminum smelters
- Rates subject to regulation by the Kentucky Public Service Commission (KPSC)
- Substantial portion of revenues from electricity sold under long-term wholesale power contracts with member owners

Corporate Profile

Big Rivers Electric Corporation is an electric generation and transmission cooperative (G&T) headquartered in Henderson, Kentucky and owned by its three member system distribution cooperatives— Jackson Purchase Energy Corporation; Kenergy Corp; and Meade County Rural Electric Cooperative Corporation. These member system cooperatives provide retail electric power and energy to more than 111,000 residential, commercial, and industrial customers in 22 Western Kentucky counties.

Summary Rating Rationale

The (P)Baa1 senior secured rating considers the anticipated financial benefits to Big Rivers of a series of steps being taken to unwind a lease and other transactions, including an expectation that the cooperative's current deficit net worth will turn substantially positive, cash receipts will be utilized to reduce existing debt, and two new committed bank credit facilities aggregating $100 million will be established to improve liquidity. Revenues generated from competitively priced power sold under long-term wholesale contracts with the three member owners should also continue to generate FFO to interest and debt metrics in support of the rating level, while capital expenditures are largely met with internally generated funds. Big Rivers' rating is a notch below the median A3 senior most rating for the sector. A significant constraint to Big Rivers' rating is the fact that one of its member owners, Kenergy Corp., makes a high concentration of its sales to two aluminum smelters, both of whom face credit challenges due to the significant fall off in both metal prices and demand. In addition, these smelters have the option to terminate their respective power purchase arrangements beginning December 31, 2010, subject to one-year notice. The rating is further constrained because the cooperative's rates are subject to regulation by the KPSC, which is atypical for the sector.

Detailed Rating Considerations

Impending Improvement In Financial Flexibility As Historical Transactions Unwind

Big Rivers took steps in 2008 to buyout two leveraged lease transactions and is nearing completion of a series of other steps to terminate another lease and other long-term transactions previously entered into with E.ON U.S. LLC (formerly known as: LG&E Energy Marketing Inc.) and Western Kentucky Energy Corp. These entities have been leasing and operating the generating units owned by Big Rivers. In turn, Big Rivers has been purchasing the power from these units at generally fixed below market rates to use in servicing the requirements of its three members, exclusive of the load requirements of Kenergy's two large aluminum smelters. At the same time, Big Rivers plans to enter into various new arrangements whereby it would sell to Kenergy 850 MW in aggregate for resale to the two aluminum smelters, contingent upon terminating other agreements, thereby reintroducing a concentration of load risk.

Key credit positives ultimately expected to result from consummation of all the so-called unwind transactions would be as follows: elimination of Big Rivers' deficit net worth, with equity to total capital expected to be close to 30% (among the highest percentages in the G&T rated universe); and partial utilization of the $508.5 million in cash payments to be received from E.ON to repay about $140.2 million of debt owed to the Rural Utilities Service (RUS), and the establishment of $252.9 million of reserves (i.e., $157 million economic reserve for future environmental cost increases, a $35 million Transition Reserve to mitigate potential costs if the smelters decide to terminate their agreements or otherwise curtail their load due to reduced aluminum production, and a $60.9 million Rural Economic Reserve, which would be used over two years to provide credits to rural customers upon exhaustion of the ~~Transition~~ Reserve).
ECONOMIC

As part of this whole process, Big Rivers already completed the buyout of leveraged leases with Bank of America and Phillip Morris Capital Corporation (PMCC) during 2008. Among the positive credit effects of the buyouts were removal of $922 million of defeased obligations (about $735 million of which was off-balance sheet), and removal of exposure to Ambac, albeit at a net cost of $120 million, including a $12 million PMCC note. We note, however, that part of the aforementioned cash payment from E.ON upon consummation of unwinding all the various transactions includes full reimbursement of Big Rivers' lease buyout costs, and the $16 million remaining deferred loss on reacquired debt would be written off.

Under a contract times interest earned ratio (TIER) arrangement with the two smelters, Big Rivers is assured of maintaining a minimum TIER of 1.24x, leaving ample cushion under its financial covenants and positioning itself favorably among its similarly rated peers. We expect this recently solid debt service coverage metric to remain relatively stable (i.e., in a range of 1.3x to 1.65x over the next several years.

Coal-Fired Plants Represent Valuable Assets Even As Environmental Costs Loom

Big Rivers owns generating capacity of about 1,440 megawatts (MW) in four substantially coal-fired plants. Total power capacity is about 1,833 MW, including rights to about 215 MW of coal-fired capacity from Henderson Municipal Power and Light (HMP&L) Station Two and about 178 MW of contracted hydro capacity from Southeastern Power Administration. The economics of power produced from these sources enables Big Rivers to maintain a solid competitive advantage in the Southeast and even more so when compared to other regions around the country. The consistently high capacity factors and efficient operations of the assets results in wholesale rates to members around $35 per MWh, which translates to member retail rates to non-smelter customers around 7 cents per kWh.

Because Big Rivers is substantially dependent on coal-fired generation, it faces a high degree of uncertainty associated with the form and substance of future environmental legislation, the timing for implementation, and the amount of related costs to comply. We view this as more of a medium-term issue at this time and note that the Economic Reserve should help mitigate some of the need for initial rate increases to cover future compliance costs.

Regulatory Risk Exists; However, Offsets Are Present

Big Rivers is subject to regulation for rate setting purposes by the KPSC, which is atypical for the sector and can pose challenges in getting timely rate relief if and when needed. We view the existence of certain fuel and purchased power cost adjustment mechanisms available to Big Rivers as favorable to its credit profile since they can temper risk of cost recovery shortfalls if there is a mismatch relative to existing rate levels. We also note little need for general rate increases by Big Rives in the medium term, although we would not rule out additional revenues generated under the fuel adjustment clause and through use of a portion of the various reserve funds.

Wholesale Power Contracts Are A Linchpin To Sound Credit Profile

The substantial revenues derived under Big Rivers' long-term wholesale contracts with its members currently run through 2023 and will be extended to December 31, 2043 when the unwind of transactions is completed in the near term. The low cost power provided under the contracts makes it unlikely that there will be member disenchantment, even in the face of potential rate increases in the medium to longer term due to environmental compliance costs. The currently overall sound member profile provides assurance of this revenue stream, which is integral to servicing Big Rivers' debt. The potential for further degradation in the creditworthiness of the smelters is a particular credit concern, only tempered in part by assurances of two month's worth of payment obligations covered by letters of credit from an A1 rated financial institution (or some other form acceptable to Big Rivers) under certain circumstances.

Concerns About Potential Loss Of Smelter Load Cannot Be Ignored

Under historical operating conditions, the two smelters served by Kenergy can be expected to consume over 7 million MWh of energy annually, representing a substantial load concentration risk. As noted above in the Summary Rating Rationale, this risk is a significant constraint to Big Rivers' rating, making Big Rivers' operating and risk profile rather unique compared to its peers. At this stage, the earliest possible date that the smelters could serve notice of termination of their contract would be December 31, 2010 (i.e. the smelters cannot provide notice until ongoing transmission capacity upgrade projects are completed). Given the cost effective power being provided by Big Rivers to allow Kenergy to service this load, we do not currently expect the smelters to exercise this option. Moreover, transmission line expansion and legislation to permit sales to non-members, when coupled with the low cost of the power, should enhance Big Rivers' ability to move excess power off system in the event that the smelters cancel their contracts or otherwise reduce load due to curtailment of aluminum production due to market and economic conditions. Indeed, one of the smelters, Century Aluminum of Kentucky, recently announced the orderly curtailment of one of its five potlines, pending improvement in economic conditions. As a result, Big Rivers will move to sell the approximately 87 megawatts of capacity it would otherwise be providing to Kenergy for service to the one Century Aluminum pot line, into the open market.

Liquidity

Big Rivers currently supplements its internally generated funds with a committed $15 million secured line of credit from National Rural Utilities Cooperative Finance Corporation (CFC). As of December 2008, the CFC line had no direct draws against it, but there were $2.7 million of outstanding letters of credit. Prospectively, Big Rivers expects to put in place $100 million of unsecured committed three year revolver capacity, with CFC and CoBank providing $50 million each. Upon effectiveness of the new facilities, the $15 million facility would be terminated and any outstanding letters of credit would be rolled into the new CFC facility which would provide for issuance of up to $10 million of letters of credit. This step would be credit positive, representing a considerable increase in the amount of alternate liquidity available from the banks. Big Rivers expects to report about $38.9 million of unrestricted cash when it completes the audit for December 31, 2008 statements and cash flow from operations is projected to be around $121 million for 2008. Assuming completion of the unwind transactions during April 2009, cash flow from operations in 2009 near $100 million, no change in management's current policy with respect to not returning any patronage capital to members, and the planned additional bank revolvers are finalized, we expect Big Rivers to have sufficient means to meet its anticipated short-term working capital needs, capital expenditures (approximately $90 million) and scheduled principal repayments (approximately $13 million) over the next four quarters.

The quality of the alternate liquidity provided by the anticipated bank revolvers benefits from the multi-year tenor and the absence of any onerous financial covenants, which largely mirror the financial covenants in existing debt documents. Big Rivers is comfortably in compliance with those covenants and we expect that to remain so in the foreseeable future. Additionally, the CFC facility benefits from no ongoing material adverse change (MAC) clause; however, the CoBank facility is considered of lesser quality because of the ongoing nature of its MAC clause related to each drawdown. There are no applicable rating triggers in any of the facilities that could cause acceleration or puts of obligations; however, a ratings based pricing grid applies.

Structural Considerations

Substantially all of Big Rivers' assets are currently subject to the lien of an RUS mortgage; however, certain tax exempt debt of Big Rivers and any outstanding amounts under the existing $15 million secured CFC line of credit enjoy a super priority of payment claim and lien on assets under the current RUS mortgage over RUS. As part of the unwinding of various transactions, Big Rivers will replace the existing RUS mortgage with a new senior secured indenture. The new indenture would re-establish RUS and all senior secured debt holders on equal footing in terms of priority of claim and lien on assets. The new indenture will also provide Big Rivers with the flexibility to access public debt markets while retaining the right to borrow from RUS, if they choose to do so. Given persistent questions about the availability of funds under the federally subsidized RUS loan program, we consider the added flexibility of the new secured indenture to be credit positive.

Rating Outlook

The stable rating outlook is based on expectations that Big Rivers successfully completes the unwind transactions in the near term, thereby improving its financial profile and repositioning itself to continue efficiently meeting the needs of its members in the future.

What Could Change the Rating - Up

Given the rating constraints linked to customer load concentration at Kenergy, rate regulation, and looming pressures tied to environmental issues, a rating upgrade is unlikely in the foreseeable future. Changes to eliminate rate regulation of cooperatives in Kentucky could contribute to a positive action, especially if it coincides with improvement in market conditions for the aluminum smelters and sustained improvement of FFO to interest and debt metrics to near 2.3x and 8%, respectively, on average.

What Could Change the Rating - Down

Loss of significant load (i.e. the smelters) that is not otherwise compensated for through off system power sales could contribute to a negative action, as would lack of regulatory support for substantial and timely recovery of costs. In terms of credit metrics, if FFO to interest and debt falls below 2x and 6%, respectively, for a sustained period of time, then rating pressure could result.

Other Considerations

Mapping To Moody's U.S. Electric Generation & Transmission Cooperaives Rating Methodology

Big Rivers' mapping under Moody's U.S. Electric Generation &Transmission Cooperative rating Methodology appears below. The Indicated Rating for Big Rivers' senior most obligations under the Methodology is Baa1 and relies on historical quantitative data and qualitative assessments. In particular we note that the Baa1 rating is significantly influenced by the weak standing for the factors relating to dependence on purchased power, the percentage of residential sales, and equity as a percentage of capitalization. A more favorable prospective view of some of those factors, especially given the high likelihood we currently ascribe to successful completion of the aforementioned unwind transactions, would likely generate a higher Indicated Rating for Big Rivers under the Methodology. Nevertheless, the unique risks relating to Big Rivers load concentration to the smelters will likely persist and continue to constrain its rating level in the future.

Big Rivers Electric Corporation

Rating Factors

Big Rivers Electric Corporation

U.S. Electric Generation & Transmission Cooperatives	Aaa	Aa	A	Baa	Ba	B	Caa
Factor 1: Wholesale Power Contracts (15%)							
a) % Member Load Served		100%					
Factor 2: Rate Flexibility (20%)							
a) Regulatory Review / Relationship with Regulators				Baa			
b) Board Involvement / Rate Adjustment Mechanism				Baa			
c) Purchased Power / Sales %							100%
d) New Build Capex (% Net PP&E)			27%				
e) Rate Competitiveness			A				
f) Rate Shock Exposure			A				
Factor 3: Member / Owner Profile (20%)							
a) Demand Growth				2.00%			
b) Residential Sales / Total Sales						14.50%	
c) Members' Consolidated Assets ($billions)					$0.38		
d) Members' Consolidated Equity / Capitalization				33.70%			
e) Regulatory Status				Baa			
Factor 4: 3-Year Average Financial Metrics (40%)							
a) TIER		1.5x					
b) DSC		1.7x					
c) FFO / Debt				5.10%			
d) FFO / Interest				1.9x			
e) Equity / Capitalization							-21.10%
f) Net Operating Margin		32.20%					
Factor 5: Size (10%)							
a) MWh Sales				6.2			
b) Revenues ($millions)				$0.30			
c) Net PP&E ($millions)				$0.90			
d) MW Owned and Purchased					1,833		
Rating:							
a) Indicated Rating from Methodology			Baa1				
b) Actual Rating Assigned (Sr. Secured Rating)			(P) Baa1				

Big Rivers Electric Corporation

Report Number: 115312_SC

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Moody's Investors Service

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Publication Date
March 5, 2009

Electric Cooperative Utilities' Credit Quality Remains Sound, But Some Show Signs Of Weakness

Electric cooperative utilities, which are member-owned and generally serve rural areas, have a long history of stable credit quality. Standard & Poor's Ratings Services believes they owe this to the combination of their autonomous ratemaking authority; the revenue stream security that strong, long-term wholesale power contracts provide; and conservative business models that typically focus on the core business objectives of selling low-cost, reliable energy.

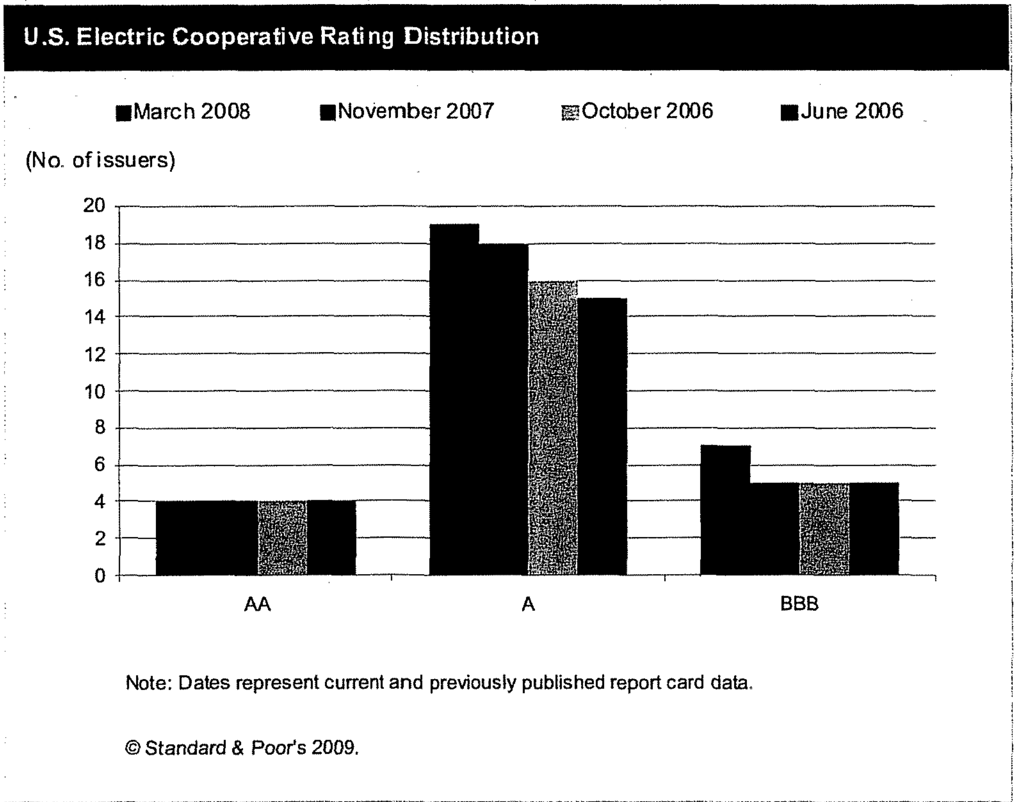
Overall, in our annual review, Standard & Poor's expects this trend to continue in 2009. However, we are also seeing evidence that the financial pressures of large capital programs and fallout from the recession are eroding the financial profiles of some electric cooperative utilities. We believe that economic pressures on customers are sapping some of the strength of autonomous ratemaking tools, making it more difficult for utilities to address rising costs and debt as fully and in as timely a manner as they have before.

Generally Solid Credit Quality

Our ratings and outlooks on cooperative utilities reflect a generally strong sector. We rate more than 75% of these utilities 'A-' or higher, compared with 88% for public power and only 25% for investor-owned utilities. While public power and cooperative utilities share the key credit factors of autonomous ratemaking authority and a narrow strategic focus, we believe that public power's overall credit quality is somewhat stronger than it is for cooperatives. Public power utilities tend to serve areas with more robust and predictable revenue streams than cooperatives' sparsely populated, rural, service areas.

By comparison, investor-owned utilities' overall credit profile is weaker than that of either cooperative or public power utilities. Investor-owned utilities are subject to rate regulation that can delay or even preclude cost recovery, which tempers the benefits of favorable service area demographics. In addition, they frequently place capital at risk in pursuing profits, which, we believe, can erode a utility's credit profile. In our view, these characteristics translate into a risk profile for investor-owned utilities that suppresses their ratings compared with cooperative and public power utilities.

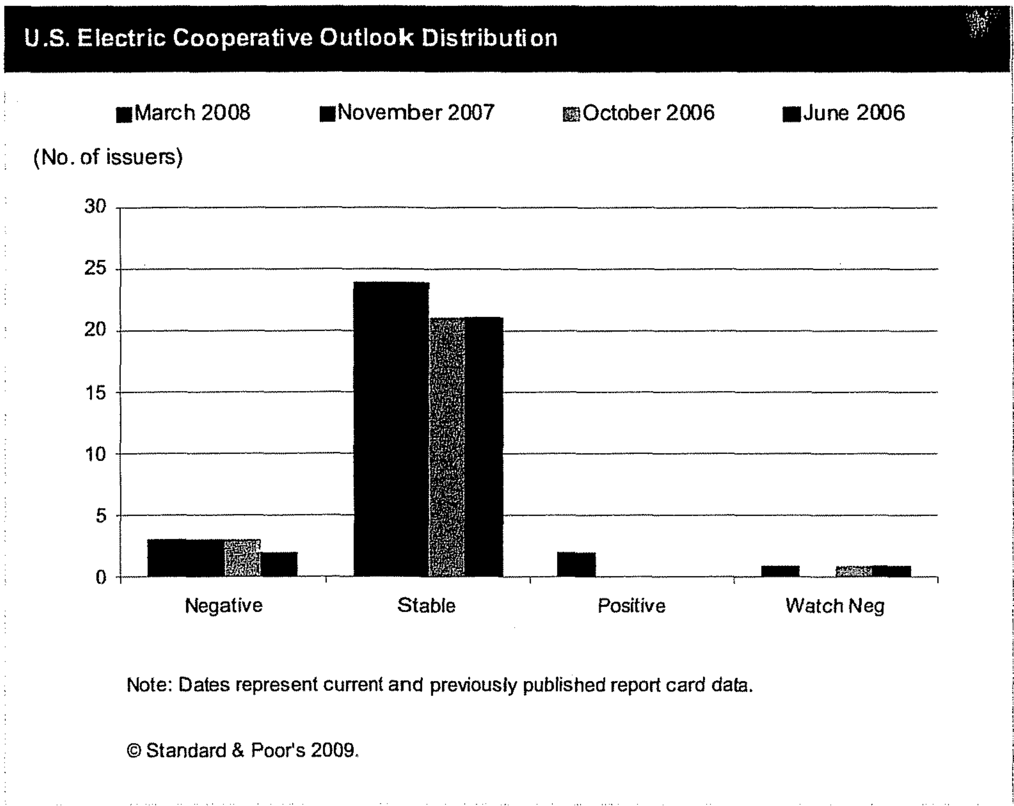
Chart 1



Of our cooperative utility ratings, 80% have stable outlooks. Another 7% have positive outlooks. In 2008, we assigned positive outlooks to two generation and transmission (G&T) cooperatives, Great River Energy and PowerSouth Energy Cooperative. We rate both these utilities 'BBB+'. We believe these utilities are moving toward strengthening financial performance because they raised wholesale rates to address the financial burdens of their large capital programs.

In our view, the positive developments at Great River Energy and PowerSouth do not indicate a broader trend in this sector. We also believe that this sector's prospects for upgrades are increasingly remote. Large capital needs, the specter of tighter and costlier emissions regulation, and the economic downturn's erosion of ratemaking flexibility present barriers to strengthening financial profiles.

Chart 2



Slightly more than 13% of our cooperative utilities ratings are on either negative outlooks or CreditWatch with negative implications. This is a modest increase from historical trends.

Some face shakier prospects

While we have assigned stable outlooks on all the distribution cooperatives we follow, three G&T cooperatives have negative outlooks and one is on CreditWatch with negative implications. Arkansas Electric Cooperative Corp. (AA-/Negative), Seminole Electric Cooperative (A-/Negative) and Western Farmers Electric Cooperative (BBB+/Negative) are all facing financial pressures from sizable capital programs that are adding debt and weakening debt service coverage. Their rate adjustments are not keeping pace with rising debt service obligations and operating costs. We could lower the ratings if credit metrics such as debt service coverage become weaker relative to the current ratings.

On the other hand, Hoosier Energy Rural Electric Cooperative Inc.'s (BBB-/Watch Neg) operations and financial performance are sound, in our view. However, it faces a potentially significant contingent liability that relates to a sale/leaseback transaction covering a generating plant. Hoosier leased the power plant to and then from companies representing equity investors. An investor required the utility to purchase a credit default swap to insulate it from changes in credit quality that might frustrate the investor's receipt of contractual lease payments. Ambac Assurance Corp. (A/Negative/—) provided the credit default swap.

Ambac's problems add to the credit crunch's damaging effects

Following the downgrade on Ambac in 2008, the equity investor directed Hoosier to replace Ambac with appropriately rated party, post collateral, or accelerate lease payments as part of an early lease termination. Hoosier responded by petitioning for an injunction in federal court. The successful petition asserted that termination payments and the prospects of triggering cross-defaults on other financing arrangements would lead to Hoosier's bankruptcy. Because the court granted the injunction, which was premised on its finding, among other factors, that if Hoosier had to pay the contingent liabilities it would cause Hoosier irreparable harm, we lowered the rating on Hoosier to 'BBB-' from 'A-' and placed it on CreditWatch with negative implications. We believe that the outcome of this litigation will play an important role in determining the utility's credit quality.

We see Hoosier's financial challenges and exposure to rating triggers as one of the far-reaching repercussions of the economic crisis. We are also monitoring other cooperative utilities linked with Ambac. Old Dominion Electric Cooperative (A/Stable) had two leases with exposure to the company. It negotiated one lease's end with a termination payment and posted collateral that extinguished the other lease equity's Ambac-related claims. Old Dominion had the financial capacity to resolve these issues because of its sound liquidity and balance sheet. Western Farmers Electric Cooperative (BBB+/Negative) also faces ratings triggers relating to Ambac and is negotiating with its lease's equity investors. The negative outlook on Western Farmers reflects, in our view, its exposure to Ambac as well as declining debt service coverage that reflects rising debt and costs. Lastly, Oglethorpe Power Corp. (A/Stable) is negotiating with its lease's equity investor to resolve Ambac-related ratings triggers.

We believe volatility is also compounding the economic meltdown's effects. For example, some utilities that entered hedging arrangements in the spring and summer of 2008 to insulate customers from swings in fuel prices now find that they must post substantial collateral following sharp fuel price declines. Collateral requirements can add to the financial strains on utilities that are already struggling with higher costs, limited access to liquidity, and constrained ratemaking flexibility.

Capital Needs And Emissions Regulation Could Become Key Credit Factors

Whether cooperative utilities are facing substantial capital needs, regulatory mandates to reduce emissions, demands on liquidity, or customers who are less able to afford their electric bills, we assess these utilities' credit quality by continuing to examine the timeliness and sufficiency of management responses and their implications for lender protection. In our view, influencing the credit quality of cooperative utilities are: regulators and legislators who set emission standards and will soon determine the costs of operating in a carbon-constrained world; fuel markets; the willingness of rate-setters to maintain a strong alignment between revenues and expenses as costs increase; and the influence of customers, who will work to sway the opinion of management, regulators, and legislators. Ultimately, the customer must have both the ability and desire to pay higher rates so that utilities can remain economically viable and comply with environmental regulations.

We believe most cooperative utilities are meeting the challenges of unsettled financial markets, the economy and evolving emissions regulations. Yet, it is also our view that these challenges could erode the credit quality of some cooperative utilities. The magnitude and duration of the recession and the burdens of environmental regulations will influence credit quality trends in this sector.

Issuer Review

Table 1

Issuer Credit Review (cont.'d)

Company	Issuer credit rating*/Senior secured debt rating*	Analyst	Comments
Arkansas Electric Cooperative Corp. (AECC)	AA-/Negative	Judith Waite	We believe the negative outlook on this G&T cooperative reflects AECC's weak debt service coverage in recent years as well as uncertainty as to the size of the rate increases the regulator could provide to strengthen debt service coverage as the utility adds debt. AECC lacks the autonomous ratemaking authority most other cooperative utilities possess because it's wholesale electric rates, as well as its member distribution cooperatives' retail rates, are subject to state regulation. AECC plans to issue debt for generating plant construction. The cooperative's capital spending program in the next four years consists primarily of a $185 million investment for a 70 MW interest in the 600 MW coal-fired Turk plants, scheduled to come online in 2012; and an estimated $300 million to comply with environmental regulations. It will use proceeds from commercial paper sales for initial funding, and additional interim funding is available from the lines of credit from National Rural Utilities Cooperative Finance Corp (CFC), Cobank AFC, and Regions Bank. In addition, a $185.5 million, CFC-led 30-year term loan facility will be available to take out commercial paper in the event that the backup facility is not renewed at the end of the facility's initial three-year life. The CFC credit facility option is available until the earlier of the completion of the Turk Power Plant or Dec. 31, 2012. As of October 2008 (fiscal year-end), AECC had $450 million of debt outstanding.
Associated Electric Cooperative Inc. (AECI), MO	AA/Stable	David Bodek	We believe AECI's board demonstrated its commitment to strong financial margins with a 25.3% rate increase in the second quarter of 2008. This G&T cooperative utility reduced its $2.3 billion, five-year capital program by about $1.0 billion when it shelved a coal project in early 2008 due to high costs and emissions considerations. We understand that AECI plans to substitute a combined-cycle gas-fired power plant for much of the cancelled coal plant's capacity and will need additional generation capacity that will likely add to debt. Other significant components of the capital program relate to emissions controls for the heavily coal-dependent generation fleet. As a coal-dependent utility, AECI is exposed to potentially higher costs as the regulation of carbon and other emissions progresses.
Baldwin County Electric Membership Cooperative, Inc.	A/Stable	Theodore Chapman	This distribution cooperative is an all-requirements member of PowerSouth Energy Cooperative and serves about 66,000 customers in Baldwin County, along the Gulf Coast and Mobile Bay in Alabama. The utility's service area and the surrounding Mobile MSA remain economically vibrant, in our view. We expect a new ThyssenKrupp AG (BBB/Stable/A-2) seven-million-square-foot steel facility in nearby Mount Vernon, Ala. that will eventually employ 2,900 will likely drive growth. In addition, although the bid was recently reopened, Northrop Grumman Corp. and EADS North America remain finalists for a U.S. Department of Defense contract exceeding $40 billion to locally build the next generation of U.S. Air Force aerial refueling tankers. While the preceding large potential employers are not directly in the utility's service area, Baldwin County remains an attractive and likely location to draw many new residents as these companies build their employment ranks. Annual DSC has historically been at least 2.00x or better, and times interest earned coverage has exceeded 1.50x compared with a minimum-required ratio of 1.25x for both. Management expects to maintain an equity-to-assets ratio of 35% or better, despite identified capital expenditures of about $153.8 million through fiscal 2016, which the expected growth will mainly drive.

Table 1

Issuer Credit Review (cont.'d)			
Basin Electric Power Cooperative, ND	A+/Stable	David Bodek	In our opinion, the ratings on Basin Electric reflect a solid financial performance that compensates for the utility's reliance on revenues from affiliate competitive businesses. These businesses' profits are the backbone of Basin's excess coverage margins and low member wholesale rates. Member rates also benefit from low-cost, coal-fired generation. Basin is distinguishable from most G&T cooperatives because of the large role of its competitive operations. Captive members provide only about a third of consolidated operating revenues. Members' wholesale electric rates rose by about 20% in the past five years and according to Basin, could increase by another 75% during the next five, which we believe could limit financial flexibility. While the economic downturn could reduce capital spending, the impact on the rate increases Basin projects remains uncertain because its Dakota Gasification subsidiary's profitability depends on natural gas prices continuing to exceed its production costs. In the past few years, production costs were in our view meaningfully below prevailing natural gas prices, which enhanced consolidated financial performance. However, the recent collapse in natural gas prices could diminish this subsidiary's profitability. A low natural gas price environment could also erode margins from electric sales to Dakota Gasification and wholesale electric markets.
Brazos Electric Power Cooperative Inc., TX	A-/Stable	Theodore Chapman	Texas' largest G&T cooperative is in the early phases of adding what we consider significant generation capacity, in the form of a 225 MW undivided ownership interest and 150 MW purchase power agreement in LS Power Group's Sandy Creek coal plant near Brazos' Waco headquarters, as well as planning for additional intermediate and peaking capacity, all by 2012. Debt-financing the bulk of a $1.9 billion five-year capital program will nearly triple debt outstanding of about $1.0 billion. Brazos projects rate increases that will preserve financial margins as it substantially increases its debt. Even with Sandy Creek's coal-fired capacity, the utility depends highly on owned and contracted gas-fired energy which accounts for a majority of today's energy sales. In our view, Brazos' solid financial profile, strong risk management strategies that include fuel hedging to mitigate natural gas price volatility, and monthly pass-through mechanism have assisted it in managing this exposure.
Brunswick Electric Membership Corp. (BEMC), NC	A/Stable	Judith Waite	BEMC is a distribution cooperative whose rating we raised in November 2008, reflecting what we consider a stronger financial profile following its board's rate increases. Debt service coverage strengthened to more than 2 xs, and we believe debt requirements are moderate compared with the level of debt-funded investment in the past several years. Fixed charge coverage, which treats capacity payments to other power suppliers as debt service, improved to 1.26 xs in 2007 from less than 1.20 xs in previous years; we expect it could be about 1.30 xs in the near term. In the past several years, BEMC took on debt to fund both the investment to place distribution wires underground and install meters that permit automated readings. The installation of automated meter reading systems is complete. Transferring wires to an underground system continues, but the bulk of the work is done. In our view, BEMC's primary challenge continues to be to manage strong growth in its service territory. It serves the southeastern most counties of North Carolina, and has experienced 3%-4% annual customer growth during the past 10 years. As of Sept. 30, 2008, the Shallotte, N.C.-based cooperative had $178.1 million in debt outstanding.
Buckeye Power Inc., OH	A+/Stable	Jeffrey Panger	Dominating Buckeye's power supply is coal fired generation from its Cardinal Station units 2 and3. Mitigating unit-concentration concerns is an agreement whereby American Electric Power supplies backup power to these units, and by the purchase of entitlement from the multi-unit facilities at two stations owned by the Ohio Valley Electric Cooperative (OVEC). Additional scrubbers on the Cardinal station (in 2007 and 2010) and OVEC units will culminate a decade-long program of significant capital spending on environmental upgrades. Buckeye has financed these capital improvements with cash and debt. We expect debt levels, which have more than doubled since 2001, to continue rising through 2013. However, we believe the benefits to operations from a resulting ability to transition to high sulfur coal, at lower cost and with diminished need for costly allowances, alleviate credit concerns. Buckeye has an indenture and can access capital markets on its own, although the bulk of its debt financings to date have been through the RUS. Financial operations are stable, in our view, the product of conservative budgeting for off-system sales. Buckeye manages what we view as a strong 1.3x debt service coverage target that compensates for its sizable capital program and operational challenges related to its resource mix.

Table 1

Issuer Credit Review (cont.'d)			
Central Electric Power Cooperative Inc.	AA/Stable	David Bodek	We rate this G&T cooperative highly to reflect what we view as the low business risk of coordinating the power supply and transmission needs of its member distribution cooperatives. This business risk profile offsets narrow financial margins, in our view. Central does not generate electricity. Rather, it procures power from South Carolina Public Service Authority doing business as Santee Cooper. Central works with Santee Cooper in planning long-term generation resource development.
Central Iowa Power Cooperative (CIPCO)	A/Stable	Peter Murphy	CIPCO is a G&T cooperative that benefits from a diverse generation portfolio that includes coal and nuclear base load resources, natural gas peaking capacity and renewable energy resources. The utility's power supply portfolio is in our view adequate for the intermediate term, which reduces exposure to market volatility. CIPCO is assessing its resource needs, and will need to factor costs and potential renewable energy or emissions regulations into the decision-making process. For fiscal 2008, unaudited figures indicate a slight improvement in margin versus fiscal 2007. CIPCO's new financial policies target debt service coverage of 1.2 xs, which we believe should result in stable and adequate operating margin.
Chugach Electric Association, AK	A-/Stable	Peter Murphy	Chugach serves about 65,360 retail members, and with other contract wholesale sales, are the dominant electricity provider and generator in Alaska. We believe its financial performance remains solid. Chugach expects to end the 2008 fiscal year with a margins-for-interest ratio of about 1.3, and a debt leverage ratio of about 71%. In our view, Chugach faces several unique challenges, including the authority of the Regulatory Commission of Alaska (RCA), over both retail and wholesale contract rates. However, the RCA permits Chugach to pass fuel cost increases to customers through a rate surcharge, insulating it from some commodity price risk. The utility expects to refinance $270 million of non-amortizing principal payments maturing in 2011 and 2012 with long-term debt, but has established a $300 million commercial paper program as an interim refinancing step. We understand that it will also use the program to provide start up financing for large capital projects. In addition, Chugach's capital plan includes pay-as-you-go funding of transmission and distribution projects, and a debt-financing of sizable natural gas-fired generation capacity, needed by 2012. The proposed resource addition will allow the utility to reduce operating costs with the more efficient new unit. We understand that Chugach is considering various scenarios of joint operating or financing of the proposed power plant with Anchorage Municipal Light & Power, for economies of scale. While 40% of Chugach's annual sales are to wholesale customers, the contracts for the two largest wholesale customers expire in 2013 and 2014, which the utility has incorporated into its power supply plan. We believe this will not pose a threat to its financial condition.
Dairyland Power Cooperative (DPC), WI	A/Stable	Jeffrey Panger	DPC has executed all requirements contract extensions with its 25 class A members through 2055. It still depends on coal-fired generation, which accounts for 96% of energy needs. DPC has a 30% interest in Weston 4, a 531 MW supercritical coal unit that began commercial operation in June 2008. The project was developed by Wisconsin Public Service, and constructed under multiprime contracts that were entered before the recent increases in construction costs. Weston 4 was built at a favorable cost of $1,733 per kW (including interest during construction). DPC's surplus energy and power supply additions during the next several years are aimed at boosting renewable energy from 6% to 10% by 2015, in keeping with the state's renewable portfolio standard. Retrofits to DPC's facilities and the rising cost of delivered fuel have exerted upward pressure on wholesale rates, which over the last three years have increased at a 6.5% average annual rate, to $58.88 per MWh. We expect the utility to meet additional environmental upgrades with further, similar wholesale rate increases through 2013. DPC member retail rates are about 7% above the composite of investor owned utilities operating in the utility's four-state service area. DPC is working with other cooperatives to develop a common indenture that will enable it to access capital markets.

Table 1

Issuer Credit Review (cont.'d)			
Diverse Power Inc., GA	A/Stable	Judith Waite	Diverse, a distribution cooperative, is relying increasingly on a portfolio of contracts and power-trading activities to supplement its interest in Oglethorpe Power Corp.'s generating capacity. Oglethorpe accounts for about 55% of Diverse's total energy supply. Contracts and market activity for the balance expose the utility to speculative-grade power suppliers, including the risk of counterparty defaults. Market activities are conducted through the Cobb scheduling group within Oglethorpe's membership. To counter these risks, the Cobb group has established what we consider fairly stringent risk-management policies. Oglethorpe's members, including Diverse, have agreed to purchase 30% of two proposed nuclear units at Plant Vogtle, which are tentatively scheduled to begin operating in 2016 and 2017. Participants in the nuclear plant are assuming construction risk and related financial obligations. Diverse may also participate in other generating units that Oglethorpe's members choose to build. It serves a region along the Alabama border that is growing rapidly. In addition to residential and commercial growth, Kia Motors Manufacturing Group is building in Diverse's service territory a $1.2 billion automotive assembly and manufacturing plant that Kia expects will employ an estimated 2,893 workers when production begins in 2009. Five supplier facilities expect to hire an additional 2,600. The expected increase in residential customers, which account for about 80% of total energy use, drives up the need for additional capacity due to high peak demand.
Georgia Transmission Corp. (GTC)	AA-/Stable/A-1+	Judith Waite	GTC, which operates a transmission grid that is part of the larger Georgia Transmission System, has made what we consider substantial system investments over the past few years and expects to continue to increase transmission capacity to meet the fairly rapid growth of its member distribution cooperatives' retail customers. Contracts with these cooperatives extend through 2040. So far, GTC has been able to fund most of the investment with loans from the FFB under RUS' guaranty, which helps lower the system's overall cost. In 2008, GTC received a $188 million FFB loan to fund several long lead-time bulk system projects. The cooperative expects about $200 million more in early 2009, which will provide initial funding for the $500 million GTC plans to invest in the next several years. While we continue to view GTC as a strong company with a low risk profile because of the exclusively "wires" business, we believe overall debt service coverage remains weak for the 'AA' rating. Debt service coverage (Standard & Poor's-calculated) has been less than 1.1 xs during the past three years. However, in 2009, GTC will extend the FFB debt's maturities. This will lower annual debt service and improve debt service coverage to about 1.2 xs, which supports the stable outlook.
Golden Spread Electric Cooperative (GSEC), TX	A/Stable	Judith Waite	The rating on this G&T cooperative primarily reflects what we consider strong debt service coverage of both direct debt and fixed-charge coverage of capacity payments under purchased power contracts. In our opinion, the financial profile's continued strength depends on the wholesale power contracts with GSEC's 16-member cooperatives, which allow for monthly recovery of all power supply costs, contract services costs, and most other costs. The contracts also provide for 100% step-up for any amount a defaulting member doesn't pay. In our view, the economy of the members' service territories is the principal potential credit weakness. The region is largely agricultural and depends significantly on oil and gas extraction, so the economy is vulnerable to commodity price swings. As a result, we believe electricity prices can be a significant factor in the area's economic health. GSEC's wholesale rates are very competitive, in our opinion. GSEC owns and operates gas-fired generating units that supplement low-cost purchased power contracts, allowing member utilities to offer in our view fairly competitive rates despite low population density, and we understand that management is committed to developing regional transmission for more low-cost supply options
Great River Energy (GRE), MN	BBB+/Positive	David Bodek	The positive outlook on this fast growing, coal-dependent G&T cooperative reflects our view of its declining leverage and the board-adopted, non-binding commitments to target 1.20x DSC and budget to meet net margins targets exclusive of margins derived from competitive, non-electric businesses. The principal non-electric investment is a 49% interest in the Blue Flint Ethanol plant that commenced operations in February 2007. The rating also reflects our view of GRE's November 2006 exit from its energy trading and marketing business. The extent of upward rating action is limited, in our view, because of both sizable generation investment needs necessitated by load growth and an affinity for investments in competitive, non-electric businesses.

Table 1

Issuer Credit Review (cont.'d)			
Guadalupe Valley Electric Power Cooperative Inc., TX	A+/Stable	Theodore Chapman	This distribution cooperative provides retail electricity services to about 61,000 customers in a 12-county area in south-central Texas. An absence of on balance sheet generation translates into sound equity and debt service coverage. The Lower Colorado River Authority (A/Stable/A-1) contract is a take-and-pay requirements contract without minimum requirements or demand payments. The contract will expire in 2016. From 90%-100% of power is sourced from LCRA and the balance is procured under short-term contracts. Distribution needs as the system grows are driving the capital program, of which the utility expects to finance one-third with debt. The utility's above-average load factor, in our opinion, reflects industrial concentrations among customers, including steel mills. Residential customer growth contributes to capital needs, but we believe it should help balance the customer profile.
Hoosier Energy Rural Electric Cooperative Inc.	BBB-/Watch Neg	Jeffrey Panger	On Jan 15, 2009, Standard and Poor's lowered Hoosier's ICR to 'BBB-' from 'A- ' and placed the rating on CreditWatch with negative rating implications. Hoosier is currently in litigation with John Hancock Life Insurance Co., an equity investor in Hoosier's sale-in-lease-out transaction involving its Merom Generating Station. John Hancock is seeking about $120 million in termination payments from Hoosier in the wake of the downgrade on Ambac Assurance Corp., a surety provider on the transaction. Hoosier has represented that it possesses insufficient liquidity to make the termination payment while providing for operating needs, particularly if cross-default provisions are triggered. In affidavits filed in support of its motion for a temporary restraining order, Hoosier maintained that such events would force it to file for protection under Chapter 11 of the U.S. Bankruptcy Code. As of Jan. 13, 2009, the utility had $74 million in unrestricted cash available. Hoosier has only $24 million in remaining capacity under existing credit lines. We believe that the recent downgrade balances the increased risk of bankruptcy from litigation against the "reasonable likelihood of Hoosier succeeding on the merits" as cited by lower courts; the solid credit characteristics that the utility exhibits absent the challenge of litigation; and the sound margins that it continues to produce as an electric cooperative utility. Furthermore, we believe that placing the ratings on CreditWatch with negative implications recognizes the potential for further significant downgrades should Hoosier suffer an adverse ruling that results in lease termination, or should cross defaults and/or bankruptcy filing occur.
Oglethorpe Power Corp., GA	A/Stable/A-1	Judith Waite	We continue to monitor the cost implications of increasing wholesale rates for this G&T cooperative's members, as well as any changes in the risk profile of the membership that result from their power supply arrangements for load above Oglethorpe entitlements, which can be about half of their requirements. Members continue to be responsible for fixed payments of all existing power generation facilities that Oglethorpe owns, and all members have extended their wholesale supply contracts with cooperative through 2050, allowing the utility to issue debt for new assets that matches the assets' expected lives. In addition, the members have agreed to take a 30% share of the cost to build two additional units at the Vogtle nuclear plant site. We currently expect the units to begin operating in 2016 and 2017. Despite the additional debt to fund the construction, Oglethorpe is targeting debt service coverage in the 1.2x-1.3x range, although we believe coverage may be weaker for an acceptably short period in the first few years that the plants begin operating.
Old Dominion Electric Cooperative (ODEC), VA	A/Stable	David Bodek	This G&T is subject to FERC rate regulation, and its members face state rate regulation. Pass-through mechanisms that permit cost recovery without rate proceedings mitigate regulatory uncertainties and related credit concerns. A high proportion of residential customers benefit the utility. The cooperative's largest member, Northern Virginia Electric Cooperative, recently separated from ODEC. In our view, tempering credit concerns were the easing of needs for additional generation resources and the ability to respond through the sizing of substantial power purchases that supplement owned resources.

Table 1

Issuer Credit Review (cont.'d)

PowerSouth Energy Cooperative (formerly known as Alabama Electric Cooperative Inc.)	BBB+/Positive	Judith Waite	The potential for a higher rating for this G&T cooperative stems primarily from our view of the expected strengthening of Power South's financial metrics as a result of gradually increasing wholesale rates and the establishment of a cash reserve to fund a portion of future capacity additions. In our view, an additional positive factor is the improved cash flow at the propane business, which is now self-supporting. Moreover, the stronger southern Alabama and the Northwest Florida economies lend support to the utility's credit profile. However, the financial metrics we expect limit the rating's upward potential. We believe the fixed charge coverage ratio, which includes purchased power capacity payments as fixed obligations, is likely to be less than 1.2 xs in most years. Power South's 16 member cooperatives and four municipally-owned utilities, have all-requirements wholesale contracts through 2050. It will supply retail demand growth with a combination of purchased power, construction of peaking and combustion turbine units, and possibly additional coal-fired generating capacity offset by renewable fuel capacity. Debt outstanding as of Dec. 31, 2008, was $1.15 billion.
San Miguel Electric Cooperative Inc., TX	A-/Stable	Theodore Chapman	This single-asset cooperative owns and operates the 411 MW lignite-fired San Miguel plant for the benefit of its two G&T off-takers, South Texas Electric Cooperative (STEC) and Brazos Electric Cooperative. This plant is an important resource for these utilities, but is only one of several in their portfolios. STEC and Brazos share output and costs equally under long-term contracts expiring in June 2020. Even with an average heat rate of nearly 12,000 BTU per kWh, all-in costs remain stable and competitive, at about $40 per MWh in 2008. The plant exhibits what we consider sound operations. We expect about $104.4 million of additional capital expenditures through 2012, including additional pollution control measures and routine capital maintenance. A recent study of the plant projects a useful life of at least another 25 years, well beyond the existing Brazos and STEC contracts.
Seminole Electric Cooperative, FL	A-/Negative	Jeffrey Panger	Nine of 10 of Seminole's members have extended their contracts with the utility through 2045, although Lee County, Seminole's second-largest member, has received RUS approval to curtail service to 70% of requirements by 2010 and completely by 2014. Seminole's remaining members, whom we believe exhibit strong credit quality, had been experiencing substantial load growth, but the economic downturn has abated this. The flatter demand and Lee County's exit alleviates near-term power supply needs and capital cost pressures. Seminole is currently assessing power-supply plans, and is considering four options that are not necessarily mutually exclusive. These options include participating in a new nuclear plant, the construction of a 750 MW coal facility (the facility recently received site certification after protracted litigation), a combined cycle unit on a recently purchased site in northern Florida, and power purchase contracts. These power-supply options could result in significant debt. Mounting debt levels, and its impact on cash flow, could exert downward pressure on the rating. Financing for these projects is complicated by the first mortgage lien that the RUS holds. We understand that Seminole is working with other cooperatives to develop a common indenture that will enable it to access capital markets. In the event that it is unable to gain RUS approval for the indenture, Seminole could seek to refinance its RUS obligations. The utility's Midulla generating station suffered a large outage in April 2007, but came back online in June 2008. Increased purchased power costs contributed to weaker financial metrics in 2007, but unaudited 2008 results indicate some improvement. Seminole's 2009 budget reflects its plan to build equity to 10% by 2015 (it was 7.2% as of Dec. 31, 2007). As such, management expects coverage and net margins to improve.
Snapping Shoals Electric Membership Corp., GA	A+/Stable/—	Judith Waite	Snapping Shoals is a distribution cooperative that strengthened its financial profile by raising base rates to recover higher purchased power costs. Therefore, we revised its outlook to stable from negative in March 2008. Net revenues cover fixed charges (debt service plus the fixed component of purchased power costs) by about 1.3 xs. We expect the margin to remain fairly stable at least through 2014-2105 when contracts with independent electricity sellers, which supply about 30% of Snapping Shoals' electricity requirements, expire. The utility purchases this power in affiliation with seven other members of Oglethorpe. Oglethorpe supplies the other 70% from generating plants owned jointly with Georgia Power Corp. (A/Stable/—) and others. Snapping Shoals' contract with Oglethorpe extends through 2050. Along with Oglethorpe's 38 other members, Snapping Shoals will also own 30% of the two nuclear units being built at the Vogtle nuclear plant site, currently scheduled to begin operating in 2016 and 2017.

Table 1

Issuer Credit Review (cont.'d)

South Mississippi Electric Power Association (SMEPA), MS	BBB+/Stable	David Bodek	SMEPA is a G&T cooperative whose adequate debt service coverage and high leverage, in our opinion, are key to the rating. Debt service coverage has been about 1.1 xs, after excluding capitalized interest. Fixed charge coverage that treats capacity payments to other suppliers as debt service was weaker, at about 1.05 xs. Debt represents 85% of capitalization. Moreover, SMEPA projects it will add about $350 million of debt for capital projects through 2012, thereby increasing its debt by nearly 50%. In our view, factors tempering the financial profile's weaknesses include long-term wholesale power contracts that place nearly 100% of the revenue stream under the utility's rate setting authority, the board's repeated use of rate increases to respond to rising costs, the utility's freedom from external regulatory oversight of rates, and its competitive rates.
South Texas Electric Cooperative, TX	A-/Stable	Theodore Chapman	This small-but-growing G&T cooperative is in the early stages of significant investment in both base load and peaking generation additions, which will continue to pressure rates. As of Dec. 31, 2008, the cooperative had about $300 million in long-term debt outstanding. In fiscal 2007, STEC refinanced existing obligations such that it is no longer an RUS borrower. We expect this to make it easier to find long-term financing for its share of Coleto Creek Unit No. 2, International Power PLC's 650 MW supercritical pulverized coal units at the site of the similarly sized unit No. 1 in Goliad County. STEC is also phasing in 200 MW of gas-fired peakers, which will allow it to retire older, less efficient units by 2010.
Square Butte Electric Cooperative	A-/Stable	Peter Murphy	Square Butte owns a single lignite-fired mine-mouth generating station. About one-third of output is sold under a long-term contract to a generation and transmission cooperative, Minnkota Power, for resale to its 11 members in Minnesota and North Dakota. Minnesota Power and Light purchases the balance under a long-term contract. The contracts provide revenue predictability. We believe costs of meeting emissions controls should be moderate and only require modest rate adjustments in support of sound, but thin debt service coverage.
Tri-State Generation & Transmission Association, CO	A/Stable	David Bodek	Although this G&T cooperative's financial metrics eroded in recent years because of increased market power purchases needed to meet growing energy demand and replace reduced hydroelectric availability, the outlook remains stable to reflect what we see as a commitment to credit quality implicit in the series of recent rate adjustments and the plan to strengthen debt service coverage incrementally in coming years. Credit quality will hinge on Tri-State's adhering to the debt service coverage milestones its board has established. Deviations will negatively influence the ratings. Whether electricity comes from self-built generation or market purchases, in our view exposure to natural gas price volatility heightens credit risk because Tri-State lacks an automatic rate adjustment mechanism for capturing changes in fuel and purchased power costs.
Vermont Electric Cooperative (VEC) Inc.	BBB-/Stable/—	Judith Waite	Unlike most cooperatives, VEC lacks rate-setting autonomy. Moreover, this distribution cooperative does not have an automatic fuel and purchased power cost-adjustment mechanism. On an annual basis, the utility's exposure to volatile fuel costs is in our view moderate: about 95%-97% of its purchased power is contracted, system-generated power purchased in one-to-five-year strips at fixed prices. The utility purchases about 3%-5% from the spot market. However, there are times when it must purchase replacement power, and without a fuel and purchased power cost-adjustment mechanism, VEC will not recover these costs until the next rate case, if at all. However, in November 2008, VEC filed for a 9.4% rate increase, which went into effect Jan. 1, 2009, and also filed an alternative rate plan that would allow VEC to adjust rates quarterly to recover transmission costs, which are the more volatile component of electricity costs in Maine. If the Vermont Public Service Board (VPSB) approves, VEC can adjust interim rates beginning in July 2009. In addition to reducing the frequency of rate filings at the VPSB, which is costly and time-consuming, the ability to pass through fluctuating transmission costs, if approved, will also strengthen the financial profile. As of September 2008, VEC had $41.2 million of debt outstanding.

Table 1

Issuer Credit Review (cont.'d)			
Wabash Valley Power Association, IN	BBB+/Stable	Peter Murphy	Wabash Valley has deferred recognizing expenses in the past three years; however, the level of deferrals is declining and they have consistently been amortized in the ensuing fiscal year. In 2005 and 2006, deferrals totaled $58 million and $29 million, respectively. The current year's deferral is in our view a modest $5 million. Performance issues at Wabash's integrated coal gasification plant near Terre Haute, Ind., caused negative budget variances and power cost deferrals. We believe satisfactory performance of the 280 MW plant is critical to Wabash's financial standing. We expect a recently adopted 5.5% rate increase should help the utility avoid deferrals. Typically, deferred balances are fully amortized in the following fiscal year. Wabash is adding one member, Citizens Electric, to its existing 28 members; but three members have given the required 10-year notice to terminate their contracts. The potential net loss is about 10% of Wabash's current load, after accounting for the newest member's addition to load. Members who have provided notice of termination may rescind it if they cannot secure favorable alternative power supply arrangements. The loss of three members does not threaten credit quality at this time, due to Citizens' partial offset, and the long 10-year timeframe before sales reductions occur.
Western Farmers Electric Cooperative, OK	BBB+/Negative	David Bodek	We revised our outlook on this G&T cooperative to negative from stable to reflect our view of the trend of weakening debt service coverage and the utility's exposure to contingent financial liabilities tied to ratings triggers in a lease-leaseback transaction. Addressing debt service coverage issues could be a challenge because we understand the utility plans substantial capital additions that might double debt within five years. Moreover, we believe end-use customers' retail rates are already high relative to state averages, which may diminish financial flexibility. Long-term member contracts place virtually the entire revenue stream under WFEC's ratemaking authority and provide revenue stream stability that also benefits from the members' residential customers' substantial contributions to the stream. The utility can use a discretionary pass-through mechanism to recover changes in operating costs from members.

*Ratings are as of March 2, 2008. DSC—Debt service coverage. FERC—Federal Energy Regulatory Commission. FFB— Federal Financing Bank. G&T—Generation and transmission. MSA—Metropolitan statistical area. KW—Kilowatt. kWh—Kilowatt-hour. MW—Megawatt. MWh—Megawatt-hour. RUS—Rural Utilities Service

Recent Rating Activity

Table 2

Recent Rating/Outlook/CreditWatch Actions*

Issuer	To	From	Date	Reason
Hoosier Energy Rural Electric Cooperative Inc., IN	BBB-/Watch Neg	A-/Stable	Jan. 14, 2009	Hoosier is in litigation with John Hancock Life Insurance Co., an equity investor in a sale in, lease out transaction. In court filings, Hoosier maintains that making termination payments would force it to file for protection under Chapter 11 of the U.S. Bankruptcy Code.
Western Farmers Electric Cooperative, OK	BBB+/Negative	BBB+/Stable	Dec. 17, 2008	The negative outlook reflects what we consider weak debt service coverage, as well as our view of the utility's exposure to contingent financial liabilities tied to ratings triggers in a lease-leaseback transaction.
Brunswick Electric Membership Corp., NC	A/Stable/—	A-/Stable/—	Nov. 17, 2008	The upgrade reflects what we consider improved financial performance as a result of board-adopted rate enhancements
Great River Energy, MN	BBB+/Positive/—	BBB+/Stable/—	April 18, 2008	The outlook revision reflects what we consider a track record of strong coverage for a G&T cooperative, coupled with our expectations that management will adjust rates to address costs of the large capital program.
Snapping Shoals Electric Membership Corp., GA	A+/Stable	A+/Negative	March 25, 2008	The outlook revision reflects in our view a strengthened financial profile, as higher power costs have been recouped following rate adjustments.
PowerSouth Energy Cooperative	BBB+/Positive/—	BBB+/Stable/—	Feb. 15, 2008	The utility is building equity and, in our view, improving credit metrics as it prepares for capital additions. Also, in our opinion, its unregulated propane business is no longer a financial drain.

*For the period from Nov. 26, 2007, to March 5, 2009. G&T—Generation and transmission

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Table 3

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Discussion with Standard and Poor's

Big Rivers Electric Corporation

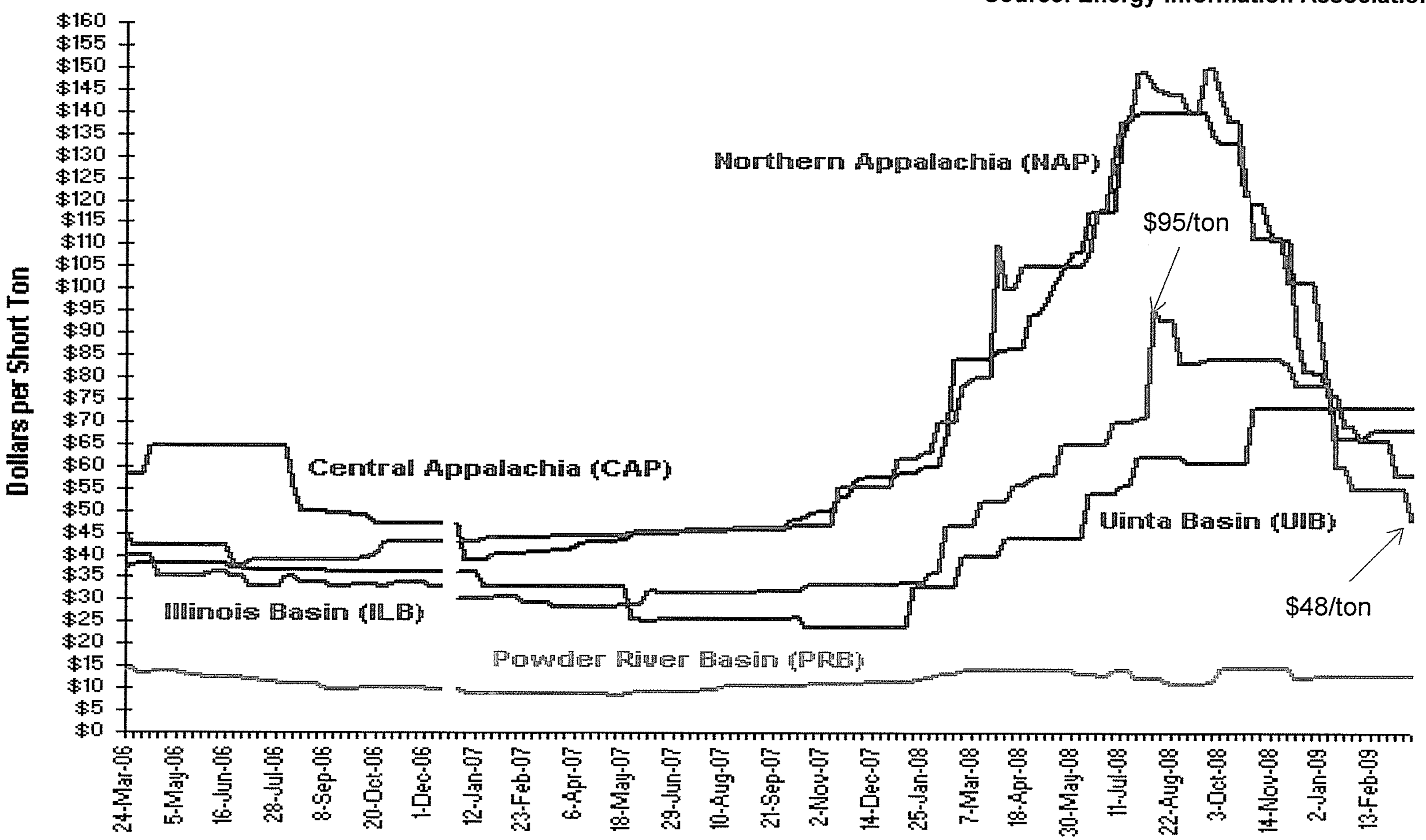
Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

March 30, 2009

Spot Coal Market Prices

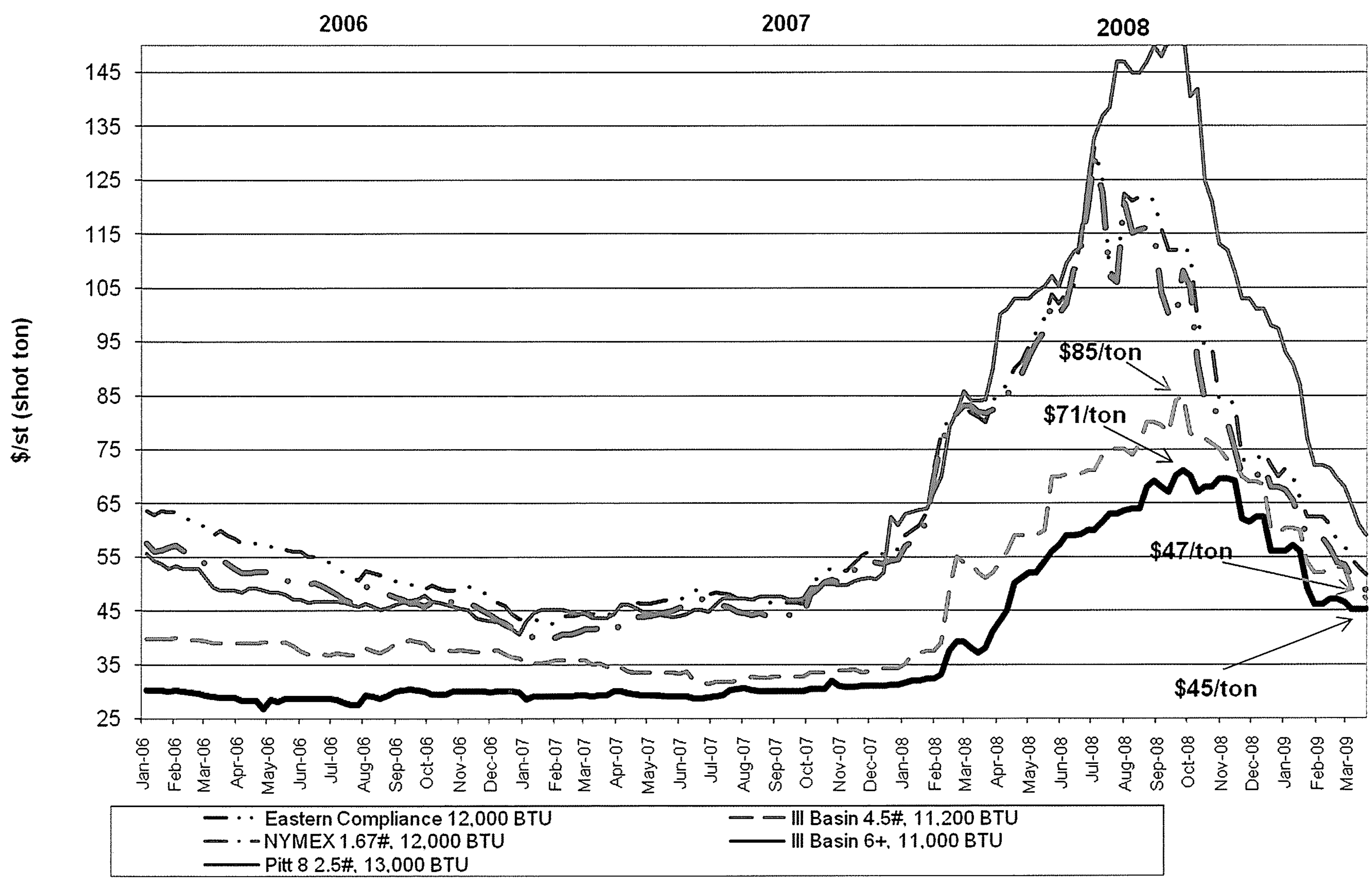
Source: Energy Information Association



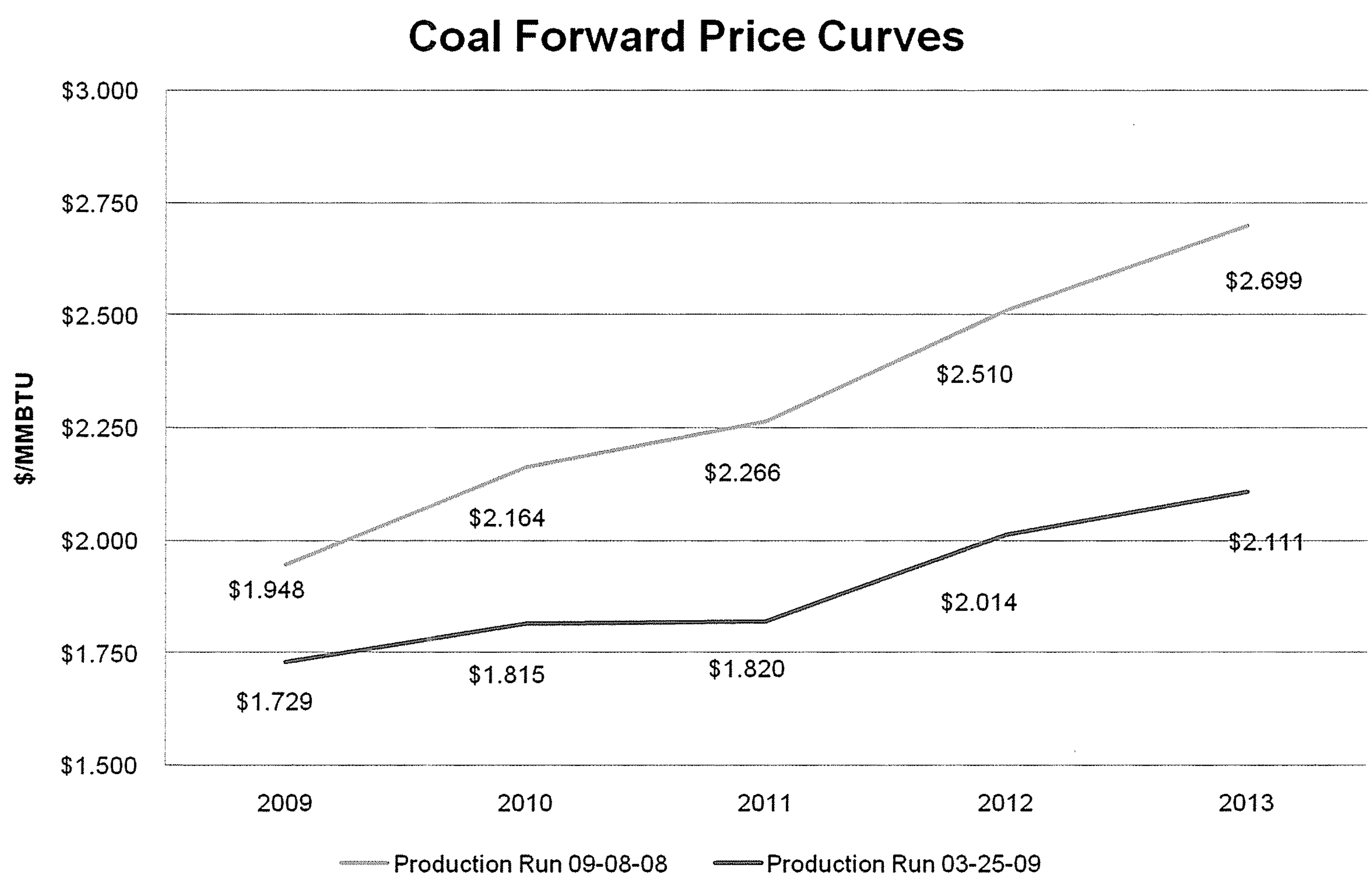
Key to Coal Commodities by Region[1]

Central Appalachia:	Big Sandy/Kanawha 12,500 Btu, 1.2 lbSO2/mmBtu	Powder River Basin:	8,800 Btu, 0.8 lb SO2/mmBtu
Northern Appalachia:	Pittsburgh Seam 13,000 Btu, <3.0 lbSO2/mmBtu	Uinta Basin in Colo.:	11,700 Btu, 0.8 lb SO2/mmBtu
Illinois Basin:	11,800 Btu, 5.0 lb SO2/mmBtu		

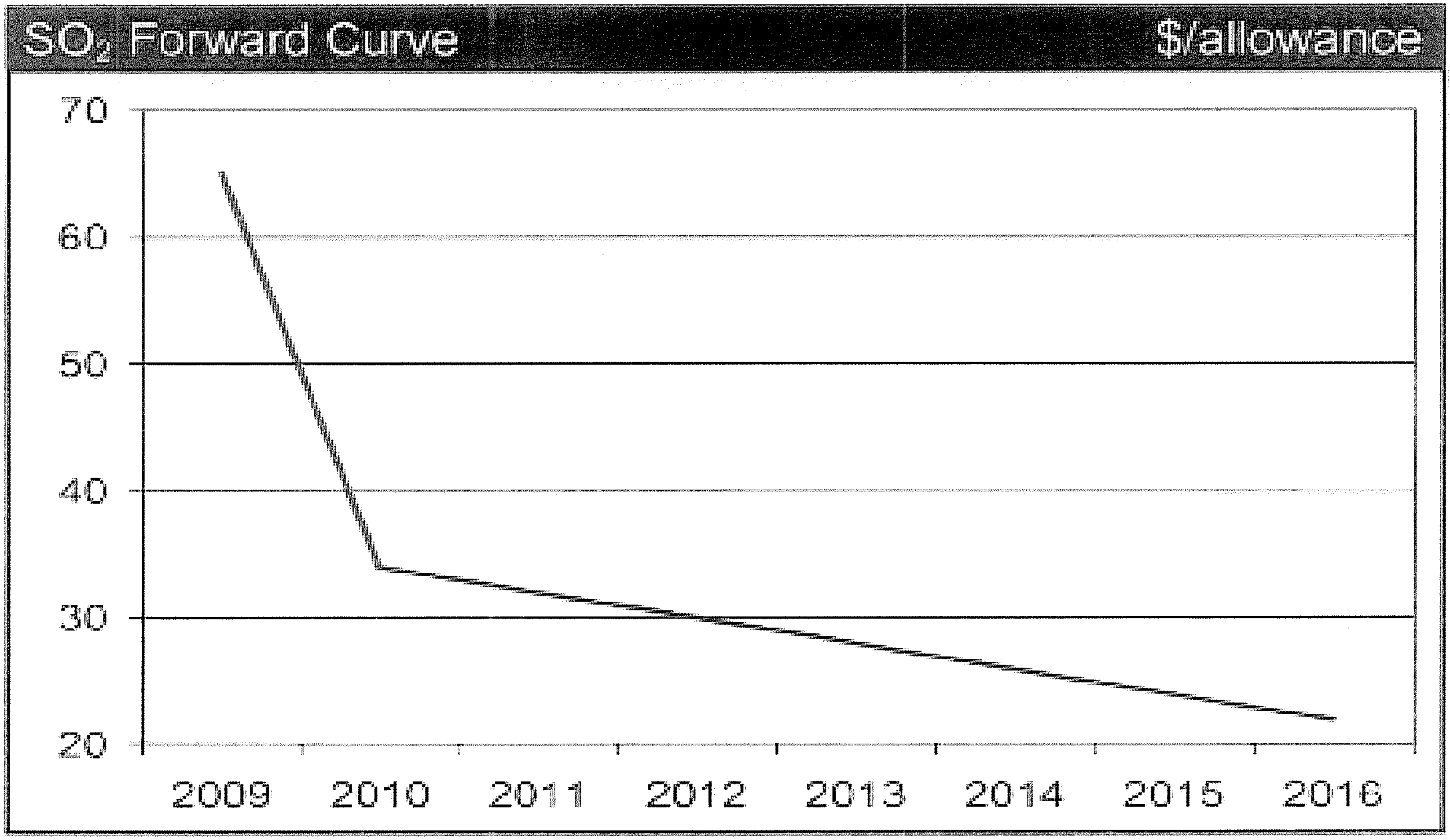
Argus Coal Daily Prompt Spot Coal



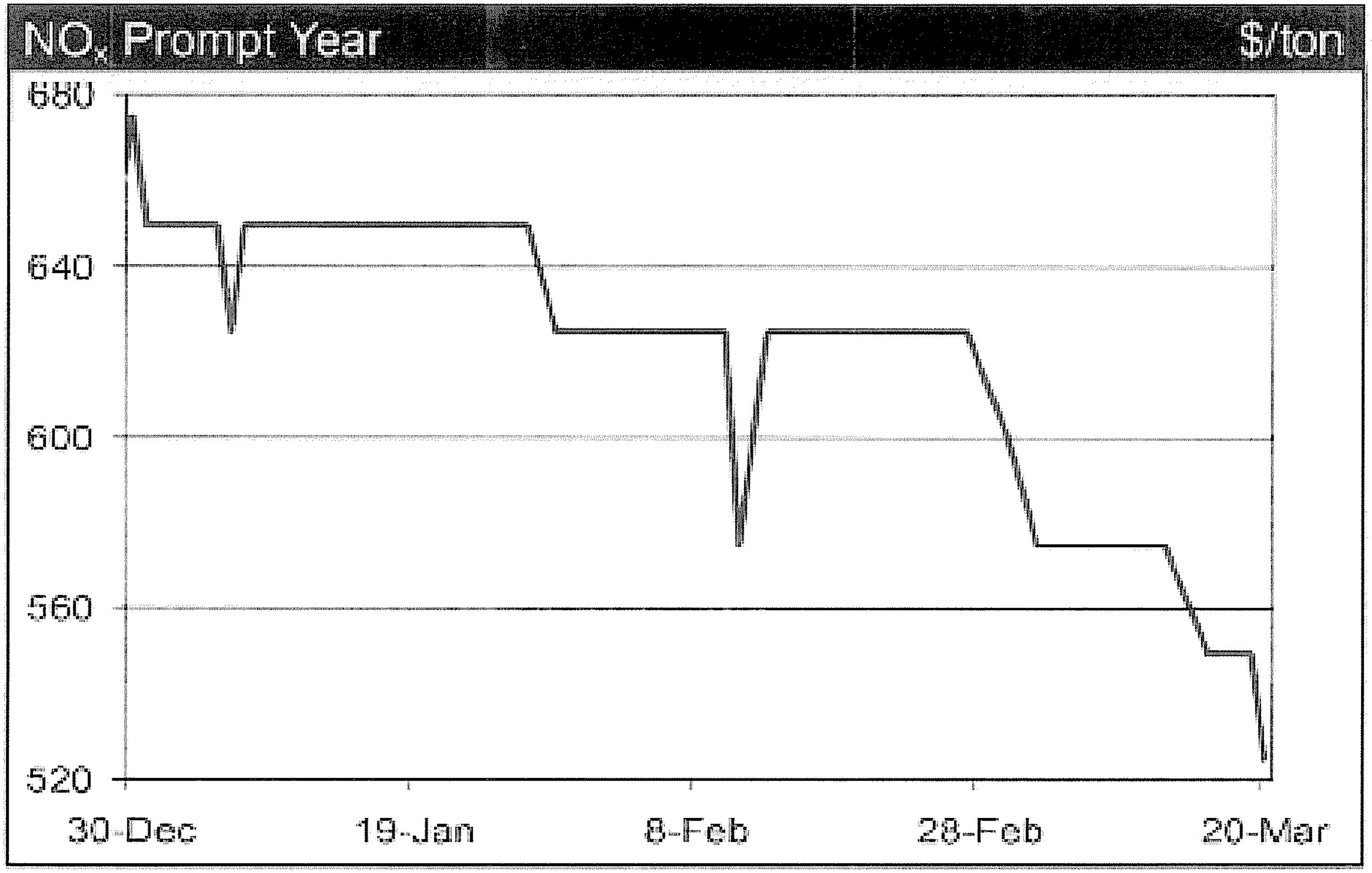
Big Rivers Coal Forward Price Curves



Market Forward Pricing SO_2



Market Forward Pricing NOx



Discussion with Fitch Ratings

Big Rivers Electric Corporation

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

March 31, 2009

Participants

Big Rivers Electric Corporation

William C. Denton, *Chair of the Board*

Mark A. Bailey, *President & CEO*

C. William Blackburn, *Senior VP Financial & Energy Services & CFO*

Western Kentucky Energy Corporation

Robert W. Berry, *General Manager Reid/Green/HMP&L Station Two Generating Stations*

Orrick Herrington & Sutcliffe

Carl F. Lyon, *Counsel*

Goldman, Sachs & Co.

Mark W. Glotfelty, *Vice President, Investment Banking*

Sullivan Mountjoy Stainback & Miller, P.S.C.

James M. Miller, *General Counsel*

Post-unwind Management Changes

Robert W. Berry, *VP & Chief Production Officer*

Big Rivers
ELECTRIC CORPORATION

Meeting Objectives

- Introduce Big Rivers Electric Corporation
- Explain the contemplated unwind transaction
- Discuss post-unwind Big Rivers
- Answer questions
- Discuss timeline for assigning ratings

Table of Contents

I. Overview of Big Rivers Electric Corporation

Big Rivers

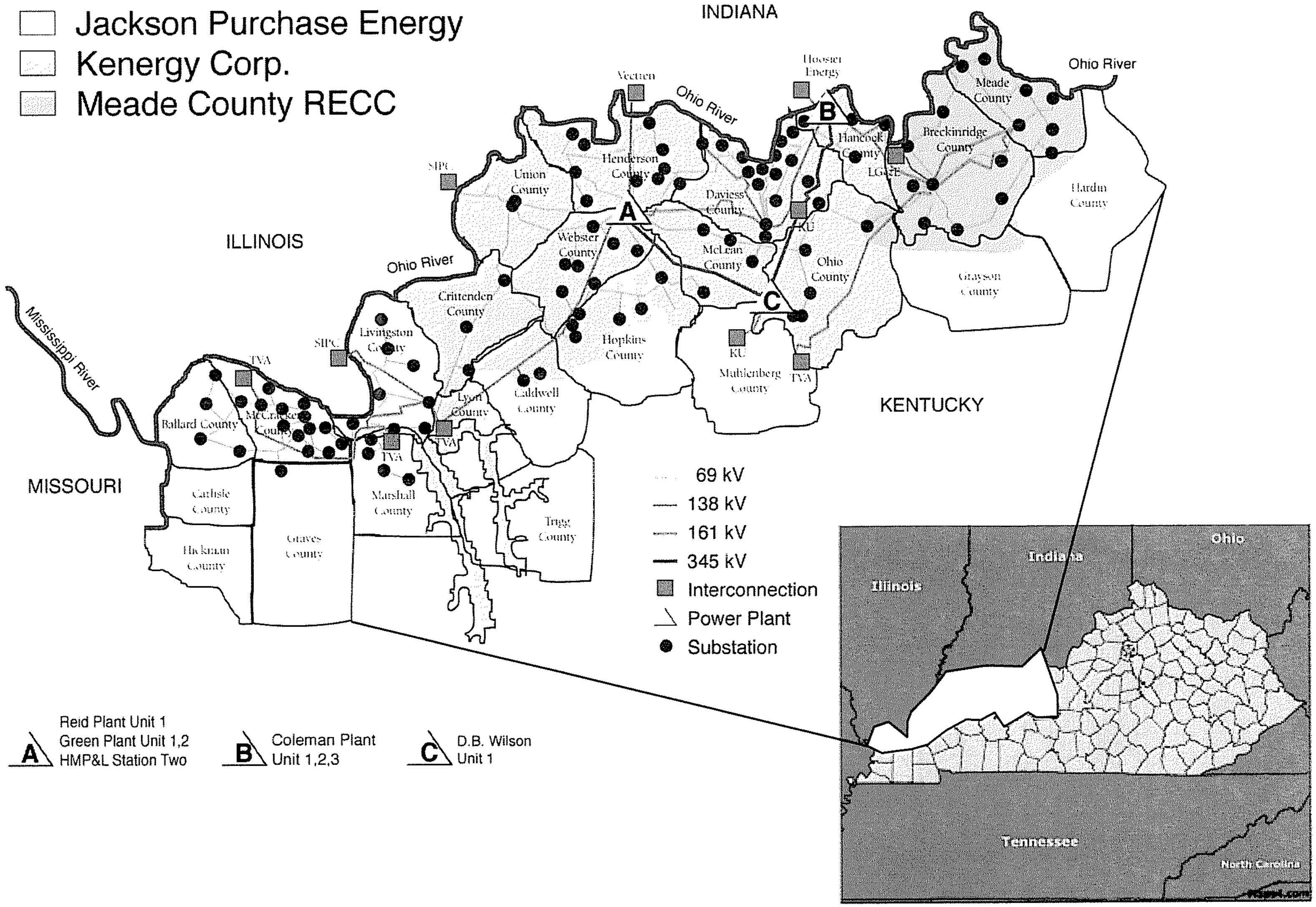
Overview of Big Rivers Electric Corporation

- Big Rivers Electric Corporation ("Big Rivers") was formed in 1961 and is based in Henderson Kentucky
- Big Rivers supplies wholesale electric and transmission service to three electric distribution cooperatives ("Members")
  - Kenergy Corp. ("Kenergy")
  - Meade County Rural Electric Cooperative Corporation
  - Jackson Purchase Energy Corporation
- Members are local customer-owned cooperatives providing service to approximately 110,000 retail customers on a not-for-profit basis
  - Members serve residential, commercial and industrial customers located in portions of 22 western Kentucky counties
- Big Rivers provides capacity and energy to its members through a combination of 5 owned generation stations, one leased generation station and purchased power
  - Net capacity of owned generation – 1,440 MW
  - Net capacity of leased generation – 215 MW
  - Power purchased from SEPA – 178 MW
  - 1,243 miles of transmission lines and 22 substations

Key 2008 Statistics

Energy Sales	5,157 GWh
Operating Revenues	\$244 mm
Total Assets	\$1,074 mm
Non-Smelter Member Wholesale Rate	\$34.57/MWh

Big Rivers Members' Service Territory



Big Rivers

Big Rivers' Available Generation Resources

	Fuel Type	Net Capacity (MW)	Commercial Operation
Owned Generation			
Kenneth C. Coleman Plant			
Unit 1	Coal	148.0	1969
Unit 2	Coal	137.0	1970
Unit 3	Coal	154.0	1972
Robert D. Green Plant			
Unit 1	Coal	231.0	1979
Unit 2	Coal	223.0	1981
Robert A. Reid Plant			
Unit 1	Coal/Gas	65.0	1966
Combustion Turbine	Oil/Gas	65.0	1979
D.B. Wilson Unit 1	Coal	416.8	1986
Owned Subtotal		***1,439.8***	
Leased Generation			
HMP&L Station Two			
Unit 1	Coal	152.2	1973
Unit 2	Coal	158.2	1974
City's Current Capacity Allocation[a]		(95.0)	
Leased Subtotal		***215.4***	
Total Owned/Leased Generation		***1,655.2***	
Purchased Power			
Member's SEPA Allocation	Hydro	178.0	
Total Capacity		**1,833.2**	

(a) Big Rivers operates Station Two, which is owned by the City of Henderson, and is entitled to all capacity and energy not taken by the City

Big Rivers Coal Fired Power Plants System Performance

- Eight of the nine coal generating units are equipped with Flue Gas Desulphurization systems (FGDs) to control SO2 emissions
- Wilson 1, HMP&L 1 and HMP&L 2 are equipped with Selective Catalytic Reduction systems (SCRs) to control NOx emissions
- Big Rivers' system performance actively benchmarked against the industry
- System performance is routinely compared to a panel of similar generating units
  - Fossil-steam units
  - US Midwest (Former ECAR, MAPP & MAIN)
- System performance is above average when compared to similar size/type units, with Big Rivers' larger units performing in the top quartile

Key Performance Indicators per IEEE Standards
(6 Year Averages 2003 thru 2008)

Unit	Net Generation (MWhrs)	Net Heat Rate (BTU/kwh)	Gross Capacity Factor (GCF) (%)	Gross Output Factor (GOF) (%)	Equivalent Availability Factor (EAF) (%)	Equivalent Forced Outage Rate (EFOR) (%)
Coleman 1	944,930	10,706	72.4	82.7	86.8	5.0
Coleman 2	953,082	11,210	75.0	81.9	90.9	3.0
Coleman 3	945,747	10,444	70.6	79.1	87.5	6.7
Green 1	1,791,249	11,103	89.7	98.2	92.2	2.2
Green 2	1,734,904	11,253	89.8	95.1	93.9	1.7
HMP&L 1	1,043,229	10,819	78.7	92.6	84.1	7.6
HMP&L 2	1,047,585	11,126	75.9	86.5	83.9	5.3
Reid 1	214,472	13,594	40.2	70.4	86.9	9.3
Wilson 1	3,149,396	11,393	87.4	98.2	87.9	7.7
SYSTEM	**11,824,594**	**11,121**	**80.5**	**90.7**	**87.5**	**5.3**

Big Rivers' members provide some of the lowest cost residential electricity in the nation.

Average Residential Rate – Kentucky
As of July 1, 2008

Kentucky Utility	Cents/ kWh
East Kentucky Power Cooperatives	9.1
Kentucky Power	8.5
Duke Energy	8.4
LG&E	7.1
Jackson Purchase	7.1
Kenergy	7.0
Meade County	7.0
Kentucky Utilities	6.6

Source: Kentucky Public Service Commission

Average Residential Rate – National
December 2008

National Region	Cents/ kWh
Pacific Noncontiguous	23.2
New England	18.0
Middle Atlantic	14.0
Pacific Contiguous	11.5
West South Central	11.3
South Atlantic	10.6
East North Central	10.2
Mountain	9.2
East South Central	9.6
Kentucky	**8.5**
West North Central	8.1

Source: Energy Information Administration

Big Rivers' members provide some of the lowest cost commercial and industrial electricity in the nation.

Average Commercial & Industrial Rate – National
2008

National Region	Cents/ kWh
Pacific Noncontiguous	19.9
New England	14.3
Middle Atlantic	10.5
Pacific Contiguous	9.0
West South Central	8.7
South Atlantic	8.2
East North Central	7.7
East South Central	7.7
Meade County	7.0
Mountain	6.7
West North Central	6.0
Kentucky	**5.9**
Jackson Purchase	5.4
Kenergy – excluding Smelters	4.1
Kenergy – Smelters	3.5

Sources: RUS Form 7 and Energy Information Administration

II. Current Arrangements

Current Arrangements

- In 1998, Big Rivers entered into a 25 year operating lease of its owned and leased generation facilities to Western Kentucky Energy Corp. ("WKEC") and concurrently entered in to a Power Purchase Agreement ("PPA") with LG&E Energy Marketing ("LEM"), both of which are now subsidiaries of E.ON
  - Provides for fixed annual rent payments to Big Rivers ranging from $31 mm – $35 mm over the life of the transaction
  - LG&E owns output and is obligated to operate and maintain the facilities pursuant to prudent utility practice and to provide Big Rivers a fixed amount of power under a PPA
  - Big Rivers and WKEC pay an agreed share of capital expenditures and certain environmental operating costs
- Members wholesale power contracts expire 1/1/2023
- Big Rivers fulfills its power supply obligations to its members, which currently do not include the smelters, through a PPA with LEM at generally fixed prices through 2023
  - PPA between LEM and Big Rivers is currently at prices that are significantly below market rates
- Substantially all of Big River's assets are subject to the lien of an RUS Mortgage
  - Parties to the mortgage are the RUS, Ambac, Dexia, US Bank (PCB Trustee) and CFC
- Debt outstanding totals $1.2 bn
  - 5.75% New RUS Note: $760 mm
  - Non-interest bearing ARVP Note: $246 mm
  - Variable rate tax-exempt Pollution Control Bonds ("PCBs"): $142 mm
  - 8% LEM Settlement Note: $16 mm (to be forgiven upon the Unwind closing)
  - 8.5% PMCC Promissory Note: $12 mm (to be paid upon the Unwind closing)

III. The Unwind Transaction

Big Rivers

The Unwind Transaction

- In 2003, E.ON approached Big Rivers about unwinding the lease transaction
- Since 2003, Big Rivers has utilized various professionals and consultants in the analysis, negotiations and documentation required for the unwind and the new power supply arrangements with the smelters
  - The Brattle Group – Assisting with financial modeling
  - ACES Power Marketing – Assisting with production cost modeling
  - Black & Veatch – Assisted with development of transition plan from status quo to unwind to post-unwind
  - JDG Consulting – Assisting the Members in protecting their interests
  - Legal – Utilizing several law firms for advice to management and the board, negotiation and development of documents, FERC issues, financing documents, regulatory approvals, labor issues, etc.
- Big Rivers' Board of Directors instructed that the unwind must not violate the following principles:
  - Receive significant economic benefits
  - Must be economically viable and retain the ability to raise sufficient capital to reliably serve its Members in the future
  - Non-Smelter members must not subsidize the Smelters
  - Must be rated BBB/Baa2 or better by Fitch and Moody's

Big Rivers

Big Rivers' Board of Directors

Name	Since	Occupation	Member Board Since
William C. Denton, Chair	4/1995	President, Mortgage Network North America	1994
James G. Sills, Vice Chair	3/1995	Physician – retired	1984
Lee Bearden, Secretary/Treasurer	9/1998	Vice President, Bank of Benton	1998
Larry F. Elder	6/2000	President, Dynalectric Co. – retired	1996
Paul Edward Butler	7/2002	Postmaster – retired	1991
Louis Wayne Elliott	9/2007	Farmer	1998

Principle reasons the Board supports the "Unwind":

- Substantially improves Big Rivers' financial health
- Enables greater flexibility for Big Rivers
- Allows Big Rivers to operate and maintain its owned and leased generating facilities
- Benefits the economy of western Kentucky

Most Recent Member Residential Retail Rate Increase:

Kenergy	2/2009	4.2%
Jackson Purchase	7/2008	9.5%
Meade	1/2008	9.0%

Big Rivers and its Members are in harmony

Big Rivers

KPSC March 6, 2009 Order

- Termination of all existing arrangements with E.ON approved
- Tariff amendments approved
- Rates approved
- Fuel Adjustment Clause approved
- Environmental Surcharge approved
- Smelter contracts approved
- Financing Agreements approved
- Big Rivers has accepted conditions in order
- E.ON has accepted condition in order that it add $60.9 million to cash consideration to Big Rivers

Big Rivers

The unwind contemplates $817.1 mm of compensation from E.ON.

Form of Compensation	Value ($mm)
Cash	508.5
Residual Value Payment	141.4
Fuel Inventory & Other	51.0
Settlement Promissory Note	15.7
Coleman Scrubber	98.5
SO2 Allowances	2.0
Total	817.1

- Big Rivers will apply $140 mm of the unwind proceeds to the New RUS Note
- Big Rivers also will fund three reserves with $252.9 mm:
  - Economic Reserve ($157 mm): Mitigate effect of potential fuel and environmental cost increases to Members for service to their non-Smelter members
  - Rural Economic Reserve ($60.9 mm): Mitigate cost increases to Rural Customers over 24 months after depletion of Economic Reserve
  - Transition Reserve ($35 mm): Mitigate potential costs associated with the termination of the Smelter Agreements

The unwind will dramatically improve Big Rivers' balance sheet.

	12/31/2008	
	Audited Statements	**Post-Transaction**
Balance Sheet ($M)		
Net Utility Plant	913	1,011
Cash & Investments		
Transition Reserve	–	35
Economic Reserve	–	157
Rural Economic Reserve	–	61
Unrestricted	39	125
Receivables, Invt. & Other	122	92
Assets	**1,074**	**1,481**
Equities	(155)	372
Debt		
RUS	869	730
PCBs & Other	170	142
Total	1,039	872
Deferred Revenue - Economic Reserves	-	218
Payables & Other	190	19
Equities & Liabilities	**1,074**	**1,481**
Equities as a % of Total Capitalization	***-18%***	***30%***

Big Rivers

The unwind will allow Big Rivers to improve its financial condition and provide reliable, low cost power to its members.

- TIER is projected at 1.27 or higher and Cash Debt Service Coverage ratio is projected to range from 1.44 to 2.24 thru 2023
- The unwind will allow Big Rivers to regain operation of the facilities, ensuring prudent use, proper maintenance and reliable output
- Member wholesale contracts extended through 12/31/2043 (an additional 21 years)
- As a condition of closing, Big Rivers must be rated BBB/Baa2 or better
- $253 mm of funded reserves will help cushion members from rate increases
- Big Rivers' exposure to the Smelters is mitigated by credit support in the form of a letter of credit from a 'A+' rated bank in the amount of two months due under the Smelter Contracts
- Big Rivers' low cost power, which is below the MISO and other regional market rates, provides ample opportunity to market excess power
  - Big Rivers is substantially enhancing its transmission export capability, by 868 MW, in two phases, the first completed April 2008 and the second under construction with completion expected by the end of 2010

IV. The Smelters

Overview of Smelters

- Sebree Kentucky Smelter (Alcan Corporation)
  - Alcan is owned by Rio Tinto, an international mining group, and is Rio Tinto's only US aluminum smelter
  - Commenced operation in 1973
  - Produces 186,000 metric tons of primary aluminum annually from its 3 potlines
  - Base contract demand: 368 MW
  - Projected annual energy consumption: 3.1 TWh
- Hawesville Kentucky Smelter (Century Aluminum Company)
  - Century is a public company and through its various subsidiaries owns and operates aluminum smelters in Kentucky, South Carolina, West Virginia and Iceland
  - Commenced operation in 1970
  - Produces 244,000 metric tons of primary aluminum annually from its 5 potlines
  - Base contract demand: 482 MW
  - Projected annual energy consumption: 4.2 TWh
  - Based on March 2009 announcement will be electing contract section 10.3, Potline Reduction Sales (assists Century financially while maintaining Big Rivers' margins)

Big Rivers negotiated new long-term Smelter contracts as a condition of the unwind.

- Big Rivers and Kenergy (the Member serving the Smelters) will terminate the existing power purchase arrangements with LEM at the closing date of the unwind
  - Big Rivers and Kenergy will enter into the Smelter Wholesale Power Contracts in which Big Rivers will supply energy to Kenergy for resale to the Smelters through the end of 2023 on a take-or-pay basis, subject to a 1 year termination notice from the Smelter(s)
- The two aluminum smelters, owned by Alcan and Century, have a base demand of 850 MW and typically use 98% of the energy
- Energy made available to the Smelters will consist of three types:
  - ***Base Monthly Energy:*** 368 MW hourly for Alcan and 482 MW hourly for Century
  - ***Supplemental Energy:*** 10 MW hourly of interruptible energy to each Smelter
  - ***Back-up Energy:*** Imbalance energy for Kenergy made available to the Smelters
- Charges to the Smelters will also include the following adjustments:
  - Base Rate always 25 cents per MWh over Large Industrial
  - Fuel Adjustment Clause ("FAC") - Provides for changes in fuel costs
  - Environmental Surcharge ("ES") - Provides for recovery of non-fuel variable production expenses (emission allowances, reagents and waste disposal)
  - Purchased Power Adjustment ("PPA") - Provides for recovery of purchased power costs (non-FAC PPA regulatory account for non-smelter members)
  - TIER Adjustment (described on following page)
  - Surcharges - Mitigate impact of FAC and ES on Non-Smelter Members

Big Rivers

The new Smelter agreements enable Big Rivers to maintain a 1.24 Contract TIER.

- 2010 Rebate
  - Contract TIER before adjustment (line 4) exceeds 1.24
  - $18.8mm is available for Rebate, split ratably between Non-Smelter Members and Smelters
- 2011 TIER Adjustment
  - TIER before adjustment (line 4) is below 1.24
  - $13.1mm is contributed by Smelters via TIER Adjustment

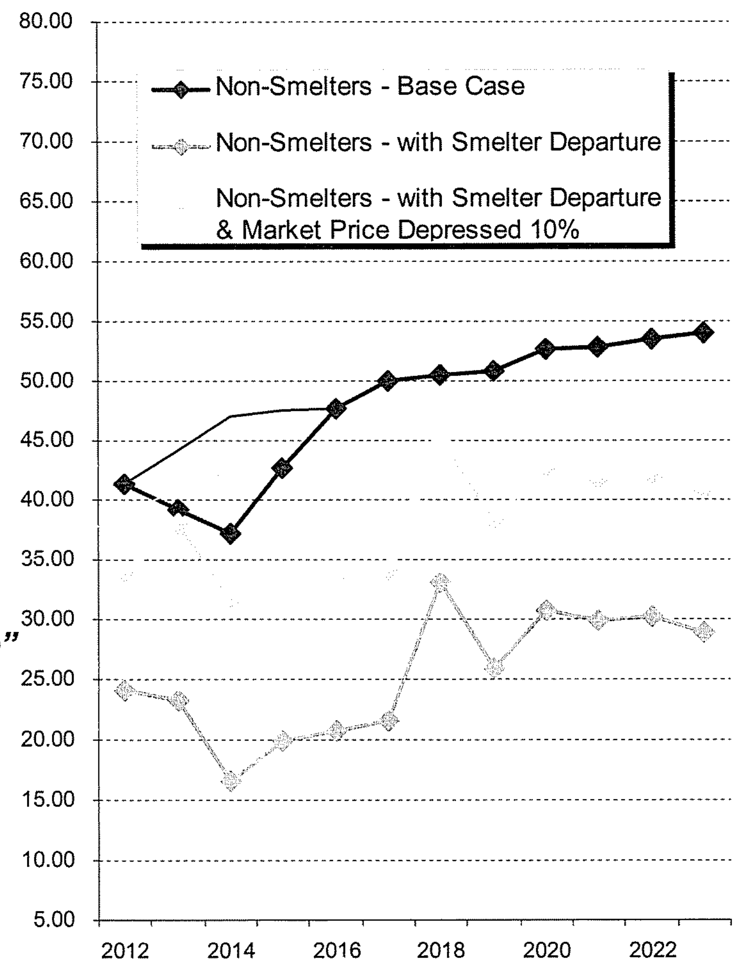
Sample Rebate and TIER Adjustment

		2010	2011
		$mm	
1	**Before Rebate/TIER Adjustment**		
2	Net Margin + Interest Charges	79.9	47.5
3	Interest Charges	49.3	48.8
4	Contract TIER	1.62	.97
5	**Rebate**		
6	Members	(6.2)	-
7	Smelters	(12.6)	-
8	Total	(18.8)	-
9	**TIER Adjustment**		
10	Smelters	-	13.1
11	Total	-	13.1
12	**After Rebate/TIER Adjustment**		
13	Net Margin + Interest Charges	61.1	60.6
14	Interest Charges	49.3	48.8
15	Contract TIER	1.24	1.24

Non-Smelter Member rates are also projected to be attractive in the event of a departure of the Smelters.

In Base Case, Rural Economic Reserve offsets rates over 24 month period starting in mid 2013 (but no offset in "upside" Smelters-leave scenarios)

Effects of Smelter Departure on Wholesale Rates ($/MWh)



Assumptions

Two scenarios assuming Smelters leave in 2011, for illustration:

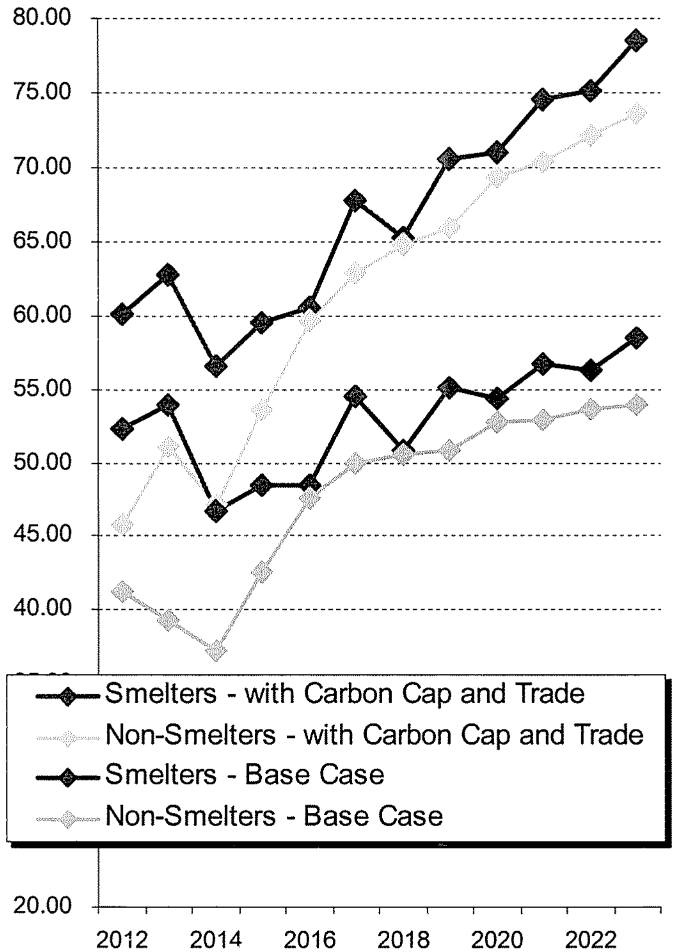
1. BREC sells smelter capacity into market @ 84% load factor
   - Additional market revenues more than offset lost smelter revenues
   - Member rates reduced by 44%, on average, from 2012 - 2023
2. BREC sells smelter capacity into market @ 84% load factor and a 10% price discount
   - Additional market revenues offset lost smelter revenues in some years, but exceed in others
   - Member rates reduced by 17%, on average, from 2012 – 2023

Note: Graph represents financial projections filed with the KPSC, modified per order of 3/6/09

Non-Smelter Member rates are projected to remain attractive in the event of carbon regulation.

Non-Smelter rates reflect impact of Rural Economic Reserve

Effects of Carbon Regulation on Wholesale Rates ($/MWh)



Assumptions

- 2.25 tons of CO2 emissions for each ton of coal consumed
- Carbon regime starting in 2012
- Cost applicable to either a tax or allowances in a cap and trade regime assumed at $7.0/ ton of CO2, or approximately $7.9/ MWh:

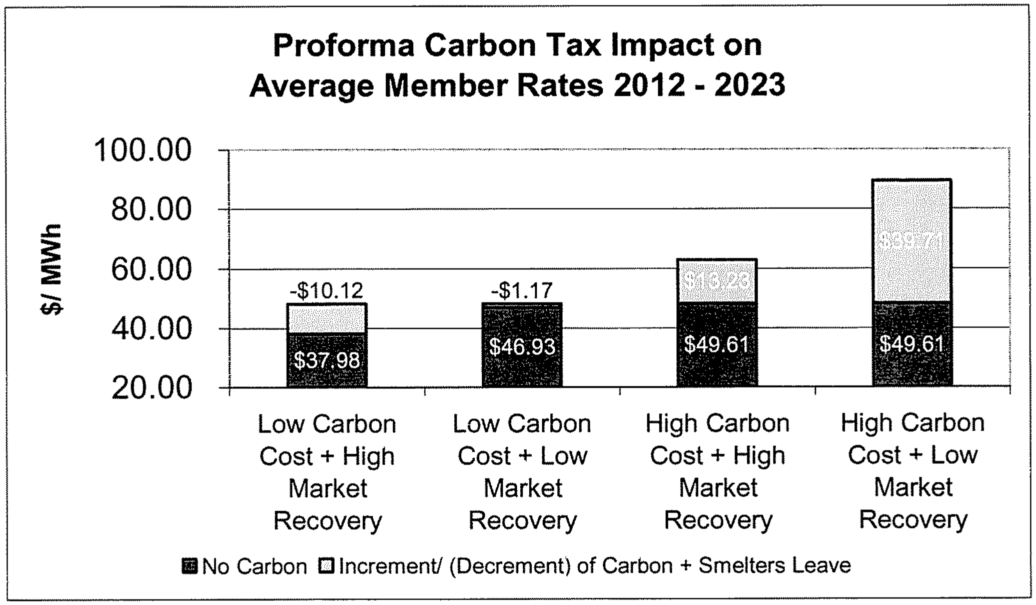
Carbon Costs per MWh Modeled for 2012

Cost per Ton of CO2	$7.00
Emissions Rate/ Ton Coal	2.25
Assumed Coal btu/ lb	10,999
Assumed Heat Rate (btu/kwh)	11,046
Cost Per MWh	$7.91

- Costs escalate by $1 annually through 2023
- Carbon costs per MWh assumed fully recovered in market electricity sales (as well as reflected in purchases)
- Thus at left, each customer class assumed to approximately bear its share of costs

Carbon Impacts for Low/High Carbon Costs and Low/High Market Recovery, Assuming Smelters Leave

- For simplicity, carbon tax assumed
- Assumptions varied as follows
  - Carbon cost per Ton: Low/High
  - Assumed recovery of Carbon Costs in market Electricity Prices: Low/High



Base Year Carbon Rate ($/CO2 ton) *	7.00	7.00	30.00	30.00
Market Price Reflection of Carbon	100%	60%	100%	60%
Average Member Rates:				
No Carbon/ Smelters Stay				
Before Impact of Rural Economic Reserve	49.61	49.61	49.61	49.61
Rural Economic Reserve	(1.50)	(1.50)	(1.50)	(1.50)
Net	48.10	48.10	48.10	48.10
Increment/ (Decrement) of Carbon + Smelters Leave	(10.12)	(1.17)	13.23	39.71
Total Average Member Rates	37.98	46.93	61.33	87.81

* Plus escalation at $1/ year through 2023

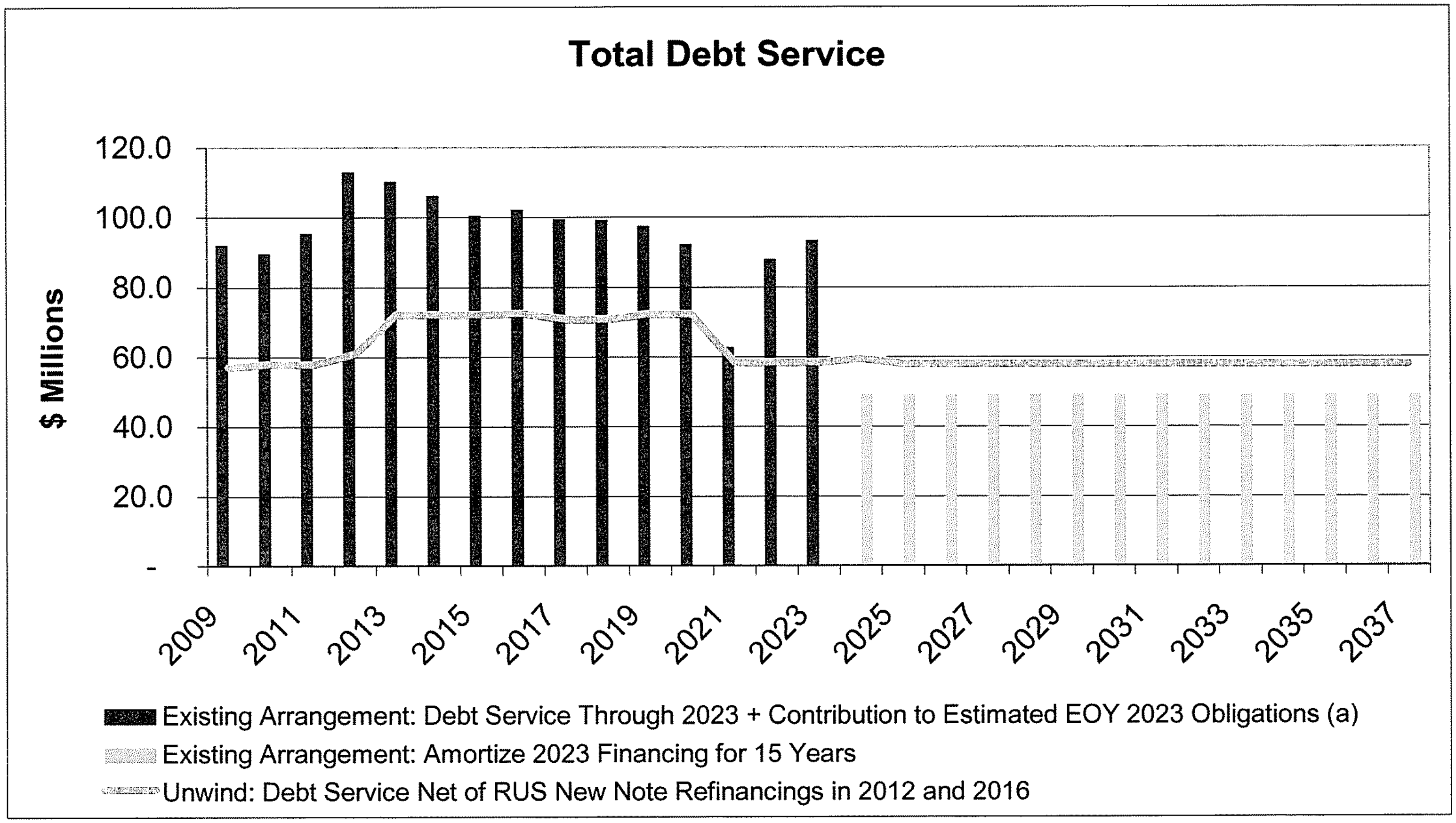
V. Post-Unwind Big Rivers – Projected Financials

Big Rivers

Big Rivers will restructure its debt service profile.

Big Rivers intends to pay $140 mm on the New RUS Note at the Unwind closing

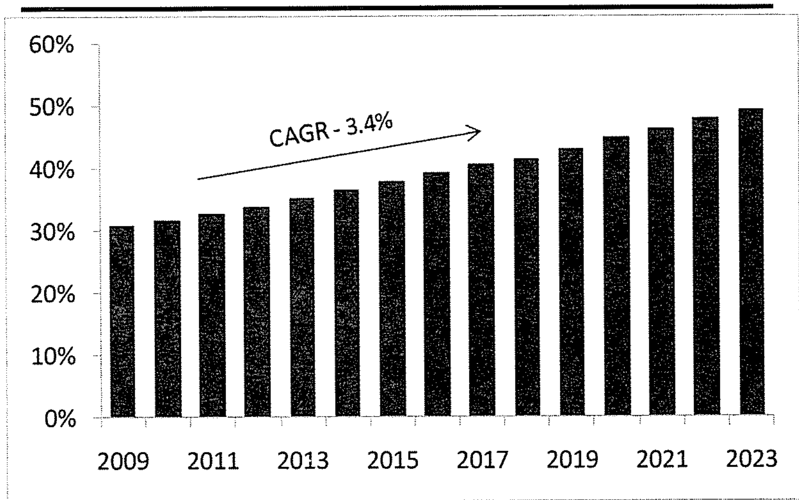
Big Rivers will:
- *Refinance one or both issues of PCBs ($142.1 mm) shortly following the Unwind closing*
- *Refinance $60 mm of New RUS Note by 2012*
- *Refinance an additional $200 mm of New RUS Note by 2016*



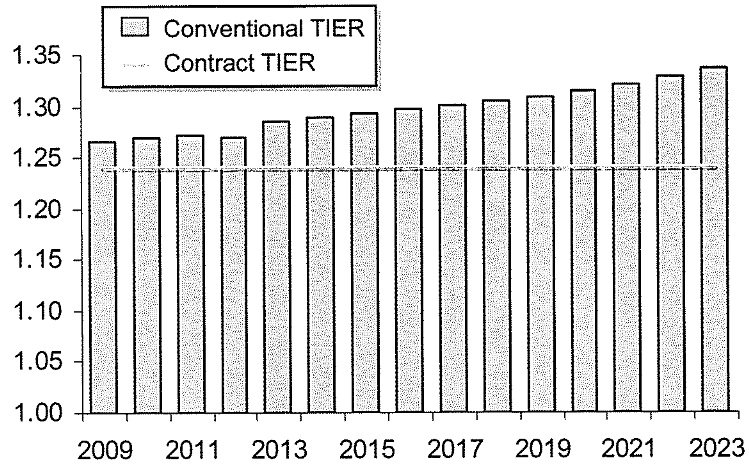
(a) Estimated EOY 2023 Obligations include RUS Asset Residual Value Payment (ARVP) Note, LG&E Parties' Residual Value Payment (RVP), acquisition of inventory, and costs of refinancing.

Big Rivers' will have strong financial metrics post-unwind.

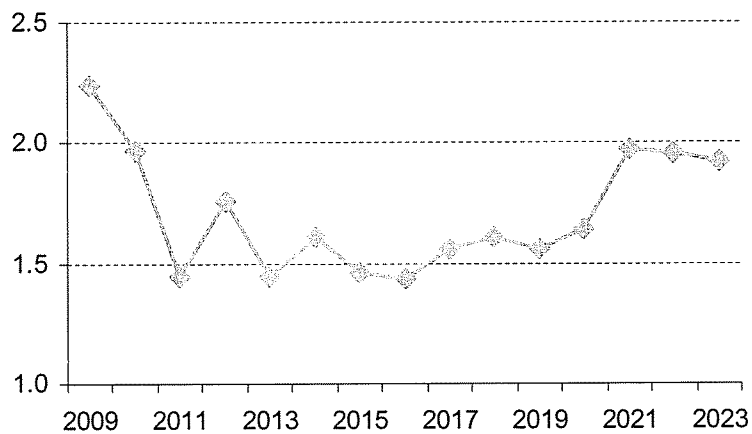
Equity to Capitalization



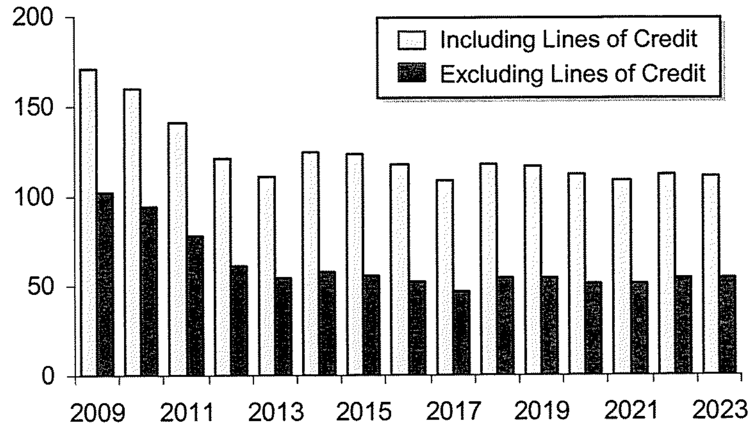
TIER



Debt Service Coverage



Days Cash on Hand ($mm)



Note: Graphs represent financial projections filed with the KPSC; values adjusted for RUS New Note refinancings in 2012 and 2016

Big Rivers' projected financial metrics compare favorably to other rated G&Ts.

Selected Financial Statistics[a]

	Ratings M/S/F	Total Operating Revenues ($mm)	Net Operating Margin (%)	Member Rates[b] (Mills)	Equity to Total Capitalization (%)	(FFO + Interest)/ Interest Coverage(x)	DSC(x)	FFO/ Debt (%)
Big Rivers – 2009[c]	***Baa1/NR/NR[d]***	***572***	***9.9***	***35.5***	***30.9***	***2.0***	***1.6***	***5.6***
Brazos Electric, TX[e]	NR/A-/A	970	9.3	78.8	18.0	2.5	1.3	6.8
Buckeye Power	A1/A+/A+	418	11.0	45.1	34.7	2.5	1.2	9.5
Chugach Electric	A2/A-/A-	288	9.6	81.0	30.0	2.1	3.1	6.1
Dairyland Power	A2/A/NR	374	10.5	58.9	15.2	1.1	1.1	0.4
Great River Energy	A3/BBB+/A-	830	11.9	48.6[e]	13.0	1.7	1.2	2.8
Oglethorpe Power	A3/A/A	1,239	15.9	50.4[e]	13.6	1.5	1.1	3.6
South Texas Electric	NR/A-/A-	204	8.8	75.0	15.2	1.9	1.7	5.2
Tri-State	Baa1/A/A-	1,161	15.0	62.0	24.6	3.1	1.3	12.0
Median[f]		624	10.8	68.5	16.6	2.0	1.3	5.7
Mean[f]		686	11.5	66.8	20.5	2.1	1.5	5.8

(a) Source: Goldman Sachs compiled data from 2008 reported financial information
(b) Big Rivers data represents Non-Smelter members rates
(c) Projected
(d) Moody's rating is prospective
(e) 2007 Data
(f) Calculations do not include Big Rivers' statistics

VI. Risk Assessment and Mitigation

Risk Mitigation – Serving Smelters

Risks	Mitigation
Generation Availability	■ Non-Fuel Purchase Power Adjustment (PPA) in contract to pass on costs of purchased power needed as a result of generator outages ■ Transmission upgrades for imports as well as exports of smelter power
Fuel Costs	■ Fuel Adjustment Clause (FAC)
Environmental	■ Environmental Surcharge (ES)
Financial	■ 1.24 guaranteed Contract TIER within bandwidth ■ 2 Surcharges to offset members' FAC and ES ■ Always 25 cents over Large Industrial rate ■ Widening bandwidth through contract term ■ Credit issues addressed in contract

Risk Mitigation – Smelters Leaving

Risks	Mitigation
Wheeling Power Off System	■ $20 million investment in transmission expansion to get excess power off system ■ Legislation enacted to permit sales to non-members
Market Rates Lower Than Smelter Contract Revenues	■ Aces Power Marketing study shows less than 5% probability
Financial	■ $35 million cash Transition Reserve to absorb potential initial impact

Big Rivers Electric Corporation

Risk Mitigation – Generation

Risks	Mitigation
Availability	■ Purchased Power Adjustment with smelters and Non-FAC Purchased Power Adjustment regulatory account for non-smelter member to pass on purchased power cost ■ Liquidity, balance sheet and credit ratings assure ability to purchase power ■ No change in operations on Day 1-Chief Production Officer long time Big Rivers/WKE employee
Load Growth	■ 150 MW of capacity available for future load growth ■ Expansion tariff in place to manage load growth ■ Annual non-Smelter load growth projected at about 2%

Big Rivers Electric Corporation

Risk Mitigation – Financial

Risks	Mitigation
Financial Flexibility	■ Internal ERM Policies • Trading Credit Policy • Financial • Cash and Investment ■ Equity to Capitalization 30% ■ Approximately $100 mm operating cash ■ $100 mm in lines of credit ■ Non-FAC Purchased Power Adjustment, FAC and ES pass through costs ■ Smelter 1.24 Contract TIER within bandwidth
Financing	■ Pay down $140 mm RUS debt at closing ■ Will refinance one or both PCB issues shortly following Unwind closing ($142.1 mm) ■ Indenture allows access to capital markets ■ Flexibility in subsequent refinancing of $260 mm of RUS debt (to levelize and extend debt service by 2016) ■ Strong financial health of members backs up all requirements contract

Risk Mitigation – Environmental

Risks	Mitigation
Past Practices of WKE	■ Termination Agreement indemnifications ■ Pre-closing environmental audit to identify potential problems
SO_2 and NO_x	■ All units scrubbed except smaller Reid units - Permits to transfer ■ In compliance- Permits to transfer
Carbon	■ Sensitivities modeled ■ Big Rivers still competitive relative to regional markets due to low cost generation
Staffing	■ Existing WKE environmental department employees returning to Big Rivers

Big Rivers Electric Corporation

Risk Mitigation – Fuels

Risks	Mitigation
Costs	■ Monthly FAC - Pass through of realized fuel costs ■ Hedge policy - part of Enterprise Risk Management ("ERM") ■ New Coleman scrubber permits use of lower cost high sulfur coal ■ Rate stabilization through the Economic Reserve, Rural Economic Reserve and Smelter surcharges
Transportation	■ Big Rivers generating units in heart of western Kentucky portion of Illinois basin coal fields resulting in 50 percent truck delivery ■ Remaining 50 percent is barged ■ No real exposure to railroad delivery
Purchasing	■ Trading Authority Policy ■ Fuel Procurement Policy ■ Hired WKE fuels director - already on board ■ Big Rivers is assuming all WKEC fuel contracts

Risk Mitigation – Business Day One

Risks	Mitigation
Day One	■ Information Technology ("IT") • E. ON short-term support agreement (up to 18 months) • Long-term Oracle software and EDS support ■ Generation Dispatch • E.ON short-term up to 18-month agreement • Long-term outsourced to ACES
Staffing At Plants	■ Offer jobs to all WKE employees - 70% former Big Rivers employees ■ 12-month retention bonus ■ Competitive wage and benefit package (including incentive bonus plan)
Additional Hiring	■ Hiring has begun, adding support staff to replace Louisville E.ON employees

Appendix A: Financial Model Output and Sensitivities

Big Rivers

Selected Base Case Assumptions

- **Unwind Transaction:**
  - Assumed Unwind closing date of December 31, 2008 in Financial Model filed with KPSC
- **Reduction of RUS New Note and Ongoing Financing:**
  - $140 mm from transaction proceeds applied to reduce RUS New Note principal upon closing
  - Refinancing of $60 mm of RUS New Note by 2012 and an additional refinancing of $200 mm of RUS New Note by 2016
  - Assumes 5% interest on the Tax-exempt PCBs; refinanced shortly following the Unwind closing
- **Production and Variable Cost Inputs:**
  - Production and variable cost inputs primarily driven by a Production Cost Model prepared by ACES Power Marketing:
    - energy sales revenues
    - costs of variable energy costs production and purchase
  - Offsystem sales comprise 9.4% of total load at an average price of $64.96/ MWh
  - Plant capacity factors average 81.9%; heat rates are projected by Big Rivers at approximately 11,000 btu/ kWh on average
- **Fixed Operating Cost Assumptions:**
  - Fixed O&M cost inputs have been developed by Big Rivers and encompass production, transmission and administrative & general ("A&G") costs
- **Depreciation and Amortization:**
  - Current average book depreciation rates amortize gross assets over a period in excess of 50 years, based on a 1998 depreciation study. Additionally, new assets added between 2011 and 2016 will be depreciated on a 37 year basis.
- **Capital Expenditures:**
  - Annual average of $51.2 mm - $43.6mm for production, $4.3mm for transmission and $3.3mm for A&G

Big Rivers' will have an increasingly strong balance sheet (i.e. equity ratio)

Balance Sheet ($mm)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Assets															
Net Utility Plant	1,071	1,087	1,107	1,104	1,109	1,104	1,098	1,091	1,072	1,054	1,039	1,022	1,003	984	966
Cash & Investments	101	104	63	63	43	45	35	29	23	44	31	27	32	35	33
Transition Reserve	36	38	39	41	43	44	46	48	50	52	54	56	58	61	63
Economic Reserve	128	97	70	34	-	-	-	-	-	-	-	-	-	-	-
Rural Economic Reserve	63	66	69	71	55	19	-	-	-	-	-	-	-	-	-
Receivables, Inventories & Other	121	126	134	143	149	123	132	135	147	147	156	155	160	162	168
Total	1,520	1,518	1,482	1,456	1,399	1,336	1,312	1,303	1,292	1,296	1,280	1,259	1,253	1,242	1,231
Equities & Liabilities															
Equities	386	400	413	427	440	453	466	478	490	502	514	525	536	547	558
Debt	865	857	846	834	811	786	766	742	714	708	676	643	622	599	574
Deferred Revenue – Economic Reserves	191	163	138	106	55	19	-	-	-	-	-	-	-	-	-
Payables & Other	77	100	84	89	94	81	82	83	88	86	90	91	95	96	99
Total	1,520	1,518	1,482	1,456	1,401	1,339	1,314	1,303	1,292	1,296	1,280	1,259	1,253	1,242	1,231
Equities/ Total Capitalization	31%	32%	33%	34%	35%	37%	38%	39%	41%	41%	43%	45%	46%	48%	49%

* Reflects simultaneous RUS New Note refinancings (borrowing and paydown) in 2012 and 2016.

Big Rivers

The Smelter contracts are structured to achieve a contract TIER of 1.24, which results in a conventional TIER of at least 1.27.

TIER ($mm)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Margins	14.3	13.3	13.2	13.9	13.2	12.9	12.6	12.4	12.1	11.8	11.8	11.5	11.2	10.9	10.6
Interest & Related	53.6*	49.3	48.8	51.4	48.3	46.8	45.3	43.9	42.4	40.8	40.6	38.8	37.3	35.6	34.1
Adjustment per Smelter Agreement	(1.4)	(1.5)	(1.5)	(1.6)	(1.6)	(1.7)	(1.8)	(1.8)	(1.9)	(2.0)	(2.1)	(2.2)	(2.2)	(2.3)	(2.4)
Numerator for Contract TIER	**66.4**	**61.2**	**60.6**	**63.7**	**59.9**	**58.1**	**56.1**	**54.4**	**52.6**	**50.6**	**50.3**	**48.1**	**46.3**	**44.1**	**42.3**
Denominator – Interest Expense	53.6*	49.3	48.8	51.4	48.3	46.8	45.3	43.9	42.4	40.8	40.6	38.8	37.3	35.6	34.1
Contract TIER	**1.24**	**1.24**	**1.24**	**1.24**	**1.24**	**1.24**	**1.24**	**1.24**	**1.24**	**1.24**	**1.24**	**1.24**	**1.24**	**1.24**	**1.24**
Adjustment per Smelter Agreement	1.4	1.5	1.5	1.6	1.6	1.7	1.8	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4
Income Tax	-	-	-	-	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8
Numerator for Conventional TIER	67.8	62.6	62.1	65.3	62.1	60.4	58.5	56.9	55.2	53.3	53.1	51.0	49.3	47.3	45.5
Conventional TIER	**1.27**	**1.27**	**1.27**	**1.27**	**1.29**	**1.29**	**1.29**	**1.30**	**1.30**	**1.31**	**1.31**	**1.32**	**1.32**	**1.33**	**1.34**

* 2009 interest expense includes $3.8 mm remaining unamortized PCB refinancing costs.

Debt service coverage (DSC) is projected to remain in a healthy range of 1.44 to 2.24.

Debt Service Coverage ($mm)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Cash Available for Debt Service															
Receipts	543.9	576.7	583.4	635.0	649.5	572.4	594.5	617.8	664.3	649.2	675.0	681.6	704.1	708.2	727.4
Disbursements excl. CapX	(451.6)	(498.3)	(530.3)	(565.8)	(599.3)	(494.2)	(508.1)	(512.7)	(552.8)	(534.5)	(561.6)	(561.7)	(587.9)	(592.7)	(614.0)
Economic Reserve	35.5	36.1	30.8	38.3	35.7	-	-	-	-	-	-	-	-	-	-
Rural Economic Reserve	-	-	-	-	18.9	38.5	19.7	-	-	-	-	-	-	-	-
Income Tax	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.3)	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.5)	(0.5)
Cash Available for Debt Service	127.8	114.5	83.9	107.5	104.8	116.5	105.8	104.7	111.1	114.3	113.0	119.5	115.7	115.0	113.0
Interest Expenditures	43.7	43.0	42.1	44.2	40.7	38.8	36.7	34.7	32.8	30.6	29.7	27.2	24.6	22.7	20.4
Scheduled Principal *	13.3	15.1	15.8	16.7	31.6	33.5	35.6	37.9	38.2	40.4	42.8	45.3	34.0	35.9	38.2
Debt Service	57.0	58.0	57.9	60.9	72.3	72.3	72.3	72.6	71.0	71.0	72.5	72.5	58.6	58.6	58.6
Cash DSC	2.24	1.97	1.45	1.76	1.45	1.61	1.46	1.44	1.57	1.61	1.56	1.65	1.98	1.96	1.93

* Scheduled Principal shown net of RUS New Note refinancings in 2012 and 2016.

Projected cash balances and lines of credit will maintain strong liquidity.

Days Cash on Hand ($mm)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Average Cash Balance	148.7	139.9	122.3	102.9*	94.9	87.7	85.5	79.4*	75.1	84.4	90.3	83.9	86.4	92.8	96.1
Lines of Credit	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total	**248.7**	**239.9**	**222.3**	**202.9**	**194.9**	**187.7**	**185.5**	**179.4**	**175.1**	**184.4**	**190.3**	**183.9**	**186.4**	**192.8**	**196.1**
Operating Expense	**529.7**	**545.7**	**574.8**	**612.2**	**642.3**	**549.2**	**552.5**	**554.9**	**587.5**	**571.3**	**595.8**	**601.2**	**622.5**	**625.5**	**643.5**
Days Liquidity, including Lines of Credit	171	160	141	121	111	125	123	118	109	118	117	112	109	112	111
Days Liquidity, excluding Lines of Credit	102	94	78	61	54	58	56	52	47	54	55	51	51	54	54

* Cash Balance shown net of New RUS Note refinancings in 2012 and 2016.

Big Rivers

Non-Smelter Member rates will remain competitive.

Rate Derivation * ($/ MWh)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Non-Smelter Members															
Base Rate	35.45	35.42	35.39	35.36	35.33	35.31	35.28	35.26	38.67	38.64	38.62	38.61	38.58	38.56	38.67
Non-FAC Purchased Power Adj.	-	-	(0.10)	(0.10)	(0.10)	0.42	0.41	0.40	0.41	0.40	0.39	1.52	1.48	1.45	1.59
FAC	11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
Environmental Surcharge	2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
Surcredits	(3.28)	(3.20)	(3.12)	(3.64)	(3.55)	(3.47)	(3.39)	(3.32)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
Rebate (Accrual)	(0.09)	(1.73)	-	-	-	-	-	-	-	-	-	-	-	-	-
Rate Stabilization (Economic Reserve)															
Economic Reserve	(10.13)	(10.08)	(8.38)	(10.19)	(9.28)	-	-	-	-	-	-	-	-	-	-
Rural Economic Reserve	-	-	-	-	(4.90)	(9.78)	(4.88)	-	-	-	-	-	-	-	-
Blended Rate	35.36	35.78	40.98	41.26	39.24	37.23	42.62	47.64	49.94	50.54	50.84	52.67	52.88	53.57	53.98

* Reflects accrual basis (vs. cash basis)

Big Rivers

Smelter rates are reasonable throughout their contract, thru 2023.

Rate Derivation ($/MWh) *	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Smelters															
Large Industrial Rate @ 98%	27.90	27.90	27.90	27.86	27.90	27.90	27.90	27.86	30.62	30.62	30.62	30.58	30.62	30.62	30.71
Additional Smelter Charge	.25	.25	.25	.25	.25	.25	.25	.25	.25	.25	.25	.25	.25	.25	.25
Base Rate	28.15	28.15	28.15	28.11	28.15	28.15	28.15	28.11	30.87	30.87	30.87	30.83	30.87	30.87	30.96
TIER Adjustment	–	–	1.79	2.25	1.59	1.64	2.78	2.59	3.55	.54	3.67	2.97	4.30	3.53	4.75
Purchased Power Adjustment	.08	(.39)	.48	.27	.57	.26	.44	.58	2.09	.88	1.78	1.15	2.07	1.74	2.54
FAC	11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
Environmental Surcharge	2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
Surcharges	1.57	1.58	1.58	1.88	1.88	1.87	1.87	1.86	2.60	2.58	2.61	2.59	2.60	2.59	2.60
Rebate (accrued)	(0.10)	(1.73)	–	–	–	–	–	–	–	–	–	–	–	–	–
Effective Rate	**43.11**	**42.98**	**49.19**	**52.33**	**53.92**	**46.67**	**48.42**	**48.44**	**54.47**	**50.77**	**55.05**	**54.30**	**56.77**	**56.32**	**58.53**

* Reflects accrual basis
(vs. cash basis)

Big Rivers

Big Rivers has considered the cost of generation in the event of carbon regulation.

- Assumptions:
  - 2.25 tons of CO_2 emissions for each ton of coal consumed
  - Carbon regime starting in 2012
  - Cost applicable to either a tax or allowances in a cap and trade regime assumed \$7/ ton of CO_2
  - Costs escalate by \$1 annually through 2023
  - *No offsets from Rural Economic Reserve in Smelters-Leave scenarios*

	Wholesale Rates - $/MWh	Period Weighted Average	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Base Case													
1	Non-Smelter Member	48.10	41.26	39.24	37.23	42.62	47.64	49.94	50.54	50.84	52.67	52.88	53.57	53.98
2	Smelter	53.00	52.33	53.92	46.67	48.42	48.44	54.47	50.77	55.05	54.30	56.77	56.32	58.53
	Carbon Regime. Smelters Stay													
	Tax													
3	Non-Smelter Member	63.67	49.83	48.50	47.88	54.94	61.02	65.01	65.59	68.00	71.07	72.83	74.14	76.54
4	Smelter	66.17	59.90	62.76	56.50	59.08	60.17	66.77	65.04	69.51	70.14	73.29	74.11	76.80
	Cap and Trade													
5	Non-Smelter Member	62.09	45.78	48.36	47.23	56.33	59.66	62.86	64.76	65.92	69.35	70.49	72.21	73.68
6	Smelter	66.87	60.11	62.76	56.62	59.50	60.61	67.81	65.22	70.58	70.99	74.57	75.15	78.55
	Cap and Trade with Base Year													
7	Non-Smelter Members	50.35	41.26	40.90	38.84	45.42	49.66	51.78	52.92	53.04	55.41	55.74	56.65	57.20
8	Smelters	55.24	53.58	55.36	48.30	50.28	50.49	56.36	53.20	57.31	57.06	59.66	59.44	61.80
	Carbon Regime. Smelters Leave													
	*Tax **													
9	Non-Smelter Members	37.98	24.16	30.57	25.22	29.67	31.64	33.46	46.09	40.01	46.02	46.26	47.79	47.43
	*Cap and Trade **													
10	Non-Smelter Members	39.40	31.96	31.83	26.19	30.69	32.58	34.41	46.96	40.90	46.89	47.14	48.53	48.24
	*Cap and Trade with Base Year **													
11	Non-Smelter Members	27.34	24.90	24.15	17.59	21.20	22.20	22.80	34.78	27.54	32.86	32.16	32.75	31.44

* Smelters modeled to leave in BOY 2011

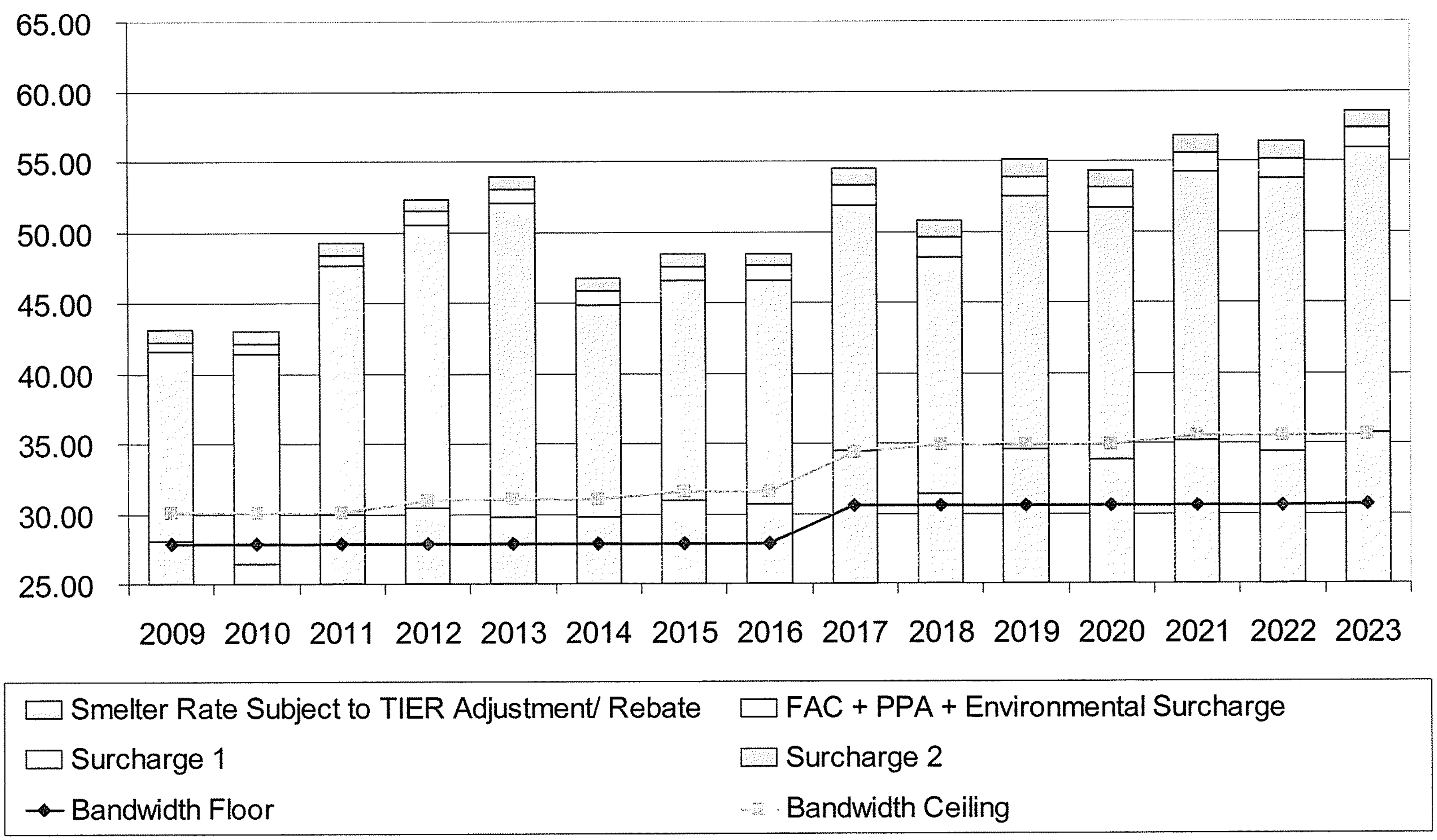
Non-Smelter Member rates will remain attractive in the event of a departure of the Smelters.

Wholesale Rates - $/MWh	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Base Case												
Non-Smelter Member (a)	41.26	39.24	37.23	42.62	47.64	49.94	50.54	50.84	52.67	52.88	53.57	53.98
Smelter	52.33	53.92	46.67	48.42	48.44	54.47	50.77	55.05	54.30	56.77	56.32	58.53
Base Case - Smelters Leave												
Non-Smelter Member (b)	24.16	23.32	16.66	20.06	20.89	21.63	33.14	25.99	30.88	30.01	30.38	28.96
Base Case - Smelters Leave and Market Price Depressed 10%												
Non-Smelter Member (b)	37.32	37.68	31.26	32.64	33.39	33.88	44.76	37.98	42.47	41.55	41.91	40.46

a) Impact of Rural Economic Reserve is reflected

b) Impact of Rural Economic Reserve is not reflected in Smelters-leave scenarios

Smelter Rates ($/MWh) and Bandwidth



BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE COMMISSION STAFF'S
APRIL 2, 2009 FIRST DATA REQUEST
TO BIG RIVERS ELECTRIC CORPORATION
PSC CASE NO. 2007-00455
April 7, 2009

Item 2) Provide copies of any credit ratings or drafts of credit ratings issued since January 1, 2009 of Big Rivers' debt.

Response) Please see response of Big Rivers to Item 1 of this data request.

Witness) C. William Blackburn

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE COMMISSION STAFF'S
APRIL 2, 2009 FIRST DATA REQUEST
TO BIG RIVERS ELECTRIC CORPORATION
PSC CASE NO. 2007-00455
April 7, 2009

Item 3) Will Big Rivers proceed to close the Unwind Transaction if it receives one credit rating of its debt that is below investment grade?

Response) Big Rivers does not presently plan to close the Unwind Transaction without two investment-grade ratings, which, among other things, is a requirement for the Rural Utilities Service agreement to an indenture to secure Big Rivers' obligations to its senior creditors. If Big Rivers changes its view on this position, it will bring the matter back to the Commission for further discussion and review.

Witness) Mark A. Bailey

Item 4) Explain in detail all ramifications to Big Rivers' future financing plans if the Unwind Transaction closes and Big Rivers has a credit rating below investment grade from one credit rating agency. Include with the response a discussion of the estimated impact on the interest rate payable by Big Rivers on future debt issuances.

Response) As stated in Big Rivers' response to Item 3, Big Rivers' position is that it does not anticipate closing the Unwind Transaction without two investment-grade ratings. If Big Rivers changes its position, it will return to the Commission with an analysis of all the implications of closing the Unwind Transaction without two investment grade ratings.

Witness) C. William Blackburn

Item 5) Refer to the Transaction Termination Agreement, Section 10.3(ee).

a. Has Big Rivers conducted the necessary tests within 90 days of the date of closing to demonstrate the net output of each generating plant?

b. If no, provide the dates that the tests will be conducted.

c. If yes, provide the date that each plant was tested and the results of each test. For each plant with a tested net output that was less than the MWs specified in Section 10.3(ee), explain in detail the remedial action that will be taken prior to closing the Unwind Transaction to increase the net output to the specified levels and provide the date that each plant will be retested.

Response) a. See response to subparagraph c, below.

b. See response to subparagraph c, below.

c. The capabilities of all Big Rivers' generating plants have been tested. A summary of the results of those tests is attached as Attachment A to this response. Big Rivers has concluded that the results of these tests satisfy the material requirements of the closing condition found in Section 10.3(ee) of the Transaction Termination Agreement, a copy of which is attached for convenience as Attachment B to this response.

Section 10.3(ee) requires that "[w]ithin 90 days of the Scheduled Unwind Closing Date, WKEC shall have demonstrated to Big Rivers' reasonable satisfaction through actual performance data or physical testing, that the Generating plants are physically capable of generating the net output specified below." The "Scheduled Unwind Closing Date," a defined term in the Transaction Termination Agreement, is July 15, 2008. While Section 10.3(ee) does not require that testing of the units occur within 90 days of the Scheduled Unwind Closing Date, in fact the tests of all units except the Reid CT did occur in that time frame. The object of the closing condition in Section 10.3(ee) is for Big Rivers to obtain demonstration of the continuing capabilities of the Big Rivers generating units that have been operated by an E.ON subsidiary since 1998. Big Rivers now has that evidence and, absent some adverse intervening event, at the closing of the Unwind Transaction will consider this condition to be satisfied.

Witness) David Spainhoward

Transaction Termination Agreement Section 10.3(ee)
Big Rivers Electric Corporation's Response to Commission
Staff's Data Request Dated April 2, 2009, Item 5

Attachment "A"

Capacity Test Results

	Contractual Capacity Oct. 1 - April 30	Contractual Capacity May 1 - Sept. 30	Capacity Test Date	Capacity test results
Coleman	443	440	07/25/08	450
Wilson	419	417	05/23/08	422
Green	454	454	05/16/08	458
Reid	130	130	**	130
Station II	311	310	06/11/08	319

** (Reid #1 tested 7/18/08 & Reid CT tested 4/1/09) (bb) Member Contract Extension. Each Member Cooperative shall have consented to the Transaction, and each Member Cooperative shall have extended its Member Contract as required to permit the condition set forth in paragraph (u) of this Section 10.3 to be satisfied.

(cc) Gypsum Facilities of Plant Green. The facilities on the Plant Green site which were installed to produce gypsum shall have been removed, and the site on which Plant Green is situated shall be restored to the condition which existed prior to the construction of such gypsum facilities (subject to other changes in the condition of that Site unrelated to the installation or removal of those gypsum facilities).

(dd) Condition of Generating Plants. Solely in the reasonable judgment of Big Rivers, each Generating Plant shall be in all material respects in good condition and state of repair, ordinary wear and tear excepted, consistent with Prudent Utility Practice.

(ee) Capabilities of Generating Plants. Within 90 days of the Scheduled Unwind Closing Date, WKEC shall have demonstrated to Big Rivers' reasonable satisfaction through actual performance data or physical testing, that the Generating Plants are physically capable of generating the net output specified below. The demonstration contemplated above shall be at WKEC's sole cost; provided, that in the event Big Rivers insists on physical testing of any Generating Plant(s) as the means for satisfying this condition, Big Rivers agrees to reimburse WKEC for 50% of its out of pocket costs and expenses incurred to conduct that testing. The scope and method of any such test shall be acceptable to Big Rivers in its reasonable discretion, and, prior to conducting any such test, WKEC and Big Rivers shall agree upon the "out-of-pocket" costs appropriate to such test, including the cost of fuel to be utilized in connection with such test. Measurement and testing of net output shall be conducted in accordance with East Central Area Reliability (ECAR) "Procedures for the Uniform Rating and Testing Generation Equipment," dated May, 1998. Testing will utilize coal (or, in the case of the Reid combustion turbine unit, fuel oil or natural gas) having characteristics that meet or exceed the fuel box design for each Generating Plant to maximize the capacity output of the Generating Plant. Big Rivers shall be provided the opportunity to have a representative present to observe the testing. The operation of the Generating Plants during the testing shall conform to all Permits and other Applicable Law. The net output for the Generating Plants which must be demonstrated (depending on the time of year of such testing) are:

Net Output of Generating Plants

	May 1 – September 30	Oct. 1 – April 30
3 Unit Plant Coleman	440MW	443 MW
Plant Wilson	417MW	419 MW
2 Unit Plant Green	454MW	454 MW
2 Unit Plant Reid	130MW	130 MW
2 Unit Station Two	310MW	311 MW

Net outputs for Plant Green, Plant Reid and Station Two may be revised in accordance with the procedure set forth in Section 12.7. If, notwithstanding such reasonable and practicable efforts provided in Section 12.7, the Parties shall be unable to confirm the net outputs set forth above for Plant Green, Plant Reid and Station Two prior to the Closing, the net outputs of Plant Green, Plant Reid and Station Two set forth above shall be aggregated for purposes of the demonstrated capability referred to in the first sentence of this paragraph (ee).

(ff) No Forced Outage at Generating Plants. No forced outage of any Generating Plant shall have occurred for a period greater than five (5) consecutive days during the 30-day period immediately preceding the Unwind Closing Date, and no forced outage of any Generating Plant shall be pending. Any Generating Plant which is not operating by reason of a scheduled outage of the same shall be readily capable of operating to Big Rivers' reasonable satisfaction at its then-rated capacity (determined in accordance with the parameters set forth in paragraph (ee) of this Section 10.3) following the work, repairs or upgrades contemplated in connection with that scheduled outage, and no permanent derating of any Generating Plant (below the operating capabilities described in paragraph (ee) of this Section 10.3) shall have occurred. Big Rivers may request that any Generating Plant which is not operating on the Unwind Closing Date, but which is in "stand-by mode", be restarted at the sole cost of Big Rivers prior to the Closing for a period not longer than 24 hours, provided that Big Rivers shall be entitled to the power produced during such test period.

(gg) [Reserved].

(hh) Gypsum Offtake. Either the Synthetic Purchase Agreement shall be in full force and effect, or a gypsum offtake contract with an entity reasonably acceptable to Big