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April 6, 2010

RECEIVED
APR 07 2010
PUBLIC SERVICE COMMISSION

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

Re: *Application of Big Rivers Electric Corporation for Approval to Transfer Functional Control of Its Transmission System to Midwest Independent Transmission System Operator*, P.S.C. Case No. 2010-00043

Dear Mr. Derouen:

Enclosed are an original and nine copies of the responses of Big Rivers Electric Corporation ("Big Rivers") to the first data requests propounded to Big Rivers by Public Service Commission ("Commission") staff and Kentucky Industrial Utility Customers, Inc. ("KIUC"). The verifications of the witnesses who prepared those responses are attached to this cover letter.

Big Rivers also files with these responses a petition for confidential treatment of one of the attachments to its response to KIUC Item 7. We enclose an original and ten copies of the petition, ten copies of a sheet representing the redacted material for which confidential treatment is sought and one copy on yellow paper of the material for which confidential treatment is sought.

I certify that a copy of this letter and attachments have been served on each person shown on the attached service list. Please feel free to contact me with any questions you may have.

Sincerely yours,

James M. Miller

James M. Miller
Counsel for Big Rivers Electric Corporation

cc: David G. Crockett
Albert Yockey
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Service List
Case No. 2010-00043

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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
APR 07 2010
PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC)
CORPORATION FOR APPROVAL TO)
TRANSFER FUNCTIONAL CONTROL OF ITS) CASE NO. 2010-00043
TRANSMISSION SYSTEM TO MIDWEST)
INDEPENDENT TRANSMISSION SYSTEM)
OPERATOR, INC.)

PETITION OF BIG RIVERS ELECTRIC CORPORATION FOR CONFIDENTIAL PROTECTION

1. Big Rivers Electric Corporation ("Big Rivers") hereby petitions the Kentucky Public Service Commission ("Commission"), pursuant to 807 KAR 5:001 Section 7 and KRS 61.878(1)(c), to grant confidential protection to one of the attachments to Item 7 of its responses to the data requests of Kentucky Industrial Utility Customers, Inc. The attachment that Big Rivers seeks to protect (the "Confidential Information") contains price projections from ACES Power Marketing ("APM").

2. Big Rivers seeks to protect as confidential the entirety of the attachment. One (1) sealed copy of the attachment, and ten (10) copies of a sheet noting the entire attachment has been redacted are filed with this Petition. 807 KAR 5:001 Sections 7(2)(a)(2), 7(2)(b).

3. A copy of this petition and the sheet noting that the attachment has been redacted have been served on all parties. 807 KAR 5:001 Section 7(2)(c).

4. If and to the extent that the Confidential Information becomes generally available to the public, whether through filings required by other agencies or otherwise, Big Rivers will notify the Commission and have its confidential status removed. 807 KAR 5:001 Section 7(9)(a).

5. The Confidential Information is not publicly available, is not known outside of Big Rivers and other APM members, and is not disseminated within Big Rivers except to those employees and professionals with a legitimate business need to know and act upon the information.

6. In this petition, Big Rivers is seeking confidential treatment of price projections prepared by APM. APM operates in a competitive environment, and uses this data to evaluate the wholesale competitive pricing of third party energy products for its clients, including Big Rivers, and to make recommendations about the wholesale competitive pricing of such third party products to its clients. The projections fall within a category of commercial information "generally recognized as confidential or proprietary, which if openly disclosed would permit an unfair commercial advantage to competitors" of APM. *See* KRS 61.878(1)(c)(1); 807 KAR 5:001 Section 7(2)(a)(1). Moreover, the projections are not publicly available, are not known outside of Big Rivers and other APM members, and are not disseminated within Big Rivers except to those employees and professionals with a legitimate business need to know and act upon the information.

7. Similar APM price projections were granted confidential protection by letter dated April 29, 2008, in In the Matter of: The Applications of Big Rivers Electric Corporation for: (i) Approval of Wholesale Tariff Additions for Big Rivers Electric Corporation, (ii) Approval of Transaction, (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, Case No. 2007-00455.

8. Based on the foregoing, the Confidential Information should be given confidential protection. If the Commission disagrees that Big Rivers is entitled to confidential protection, due

process requires the Commission to hold an evidentiary hearing. *Utility Regulatory Com'n v. Kentucky Water Service Co., Inc.*, 642 S.W.2d 591 (Ky. App. 1982).

WHEREFORE, Big Rivers respectfully requests that the Commission classify and protect as confidential the Confidential Information filed with this petition.

On this the 6th day of April, 2010.

James M. Miller

James M. Miller
Tyson Kamuf
Sullivan, Mountjoy, Stainback
& Miller, P.S.C.
100 St. Ann Street
P.O. Box 727
Owensboro, Kentucky 42302-0727
(270) 926-4000

COUNSEL FOR BIG RIVERS
ELECTRIC CORPORATION

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing Petition for Confidential Treatment to the following on this 6th day of April, 2010:

Keith L. Beall
Gregory A. Troxell
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James M. Miller

James M. Miller
Counsel for Big Rivers Electric Corporation

RECEIVED
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PUBLIC SERVICE
COMMISSION

Item KIUC 1-1) ***Prior to the filing of this Application, Big Rivers relayed estimates to KIUC and/or the Smelters that the dollar impact to Big Rivers to join the Midwest ISO ("MISO") could be in the range of (a) a cost of $8 million a year, (b) a cost of $30 million a year or (c) a benefit of $600,000 a year. Please provide copies of all Documents and Studies received from MISO, ACES, CRA or other third parties that are the source(s) of these estimates. If the estimates were the result of internal calculations, please provide a copy of all Studies, including work papers, relating to those calculations.***

Response) Big Rivers informs me that the only source of figures cited by Big Rivers prior to the filing of this application was the "Preliminary Economic Assessment of Big Rivers Contingency Reserve Options" prepared by CRA. See attached for a copy of this document.

Witness) Ralph L. Luciani

Preliminary Economic Assessment of Big Rivers Contingency Reserve Options

December 17, 2009

CRA Charles River Associates

Introduction

- CRA has been asked to assist Big Rivers in analyzing the economics of procuring contingency reserves to replace those from the Midwest ISO contingency reserve sharing group
- Problem:
  - Big Rivers, as a balancing authority, must hold contingency reserves in order to meet NERC reliability standards.
  - On a stand-alone basis, Big Rivers would require approximately 417 MW of contingency reserves
    - Based on the largest single contingency, the DB Wilson plant.
  - Big Rivers is a member of the Midwest ISO contingency reserve sharing group, which requires Big Rivers to hold only about 32 MW in contingency reserves.
  - As of January 1, the Midwest ISO will no longer permit balancing authorities that are not participants in the Midwest ISO market to be in its contingency reserve sharing group.

Introduction

- Potential Solutions:
  - The TVA reserve sharing group is not available to Big Rivers.
  - Joining the SPP reserve sharing group is an available option and would require Big Rivers to maintain about 32 MW of reserves.
    - However, firm point-to-point transmission from Entergy across TVA would be required and is likely not available for the full quantity (app. 400 MW) needed.
  - Reserve capacity is not currently available for purchase from any neighboring system.
  - Own-system options for supplying reserves include:
    - Existing peaking capacity (e.g., Reid CT 65 MW),
    - Interruptible demand (e.g., smelters),
    - One or more coal-fired units operating at less than full load,
    - New peaking capacity, which would take 1-2 years to put in place.
  - A combination of own-system options and firm transmission from SPP for the remainder is an option.
  - Joining the Midwest ISO and pending regulatory approval, taking reserve service under Midwest ISO Attachment RR, is an option.
    - Dairyland Power Cooperative in Wisconsin is taking this option.

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Summary of Results

- **As shown, we preliminarily estimate the cost of Big Rivers being a member of the Midwest ISO at ($1.6) to $29.1 million per year.**
- **The SPP Contingency Reserve Group is not feasible at this time given the lack of transmission availability through TVA to SPP.**
- **Own-system options could potentially meet the Big Rivers reserve needs, but the cost may be prohibitive given the smelter pricing incentive required and the additional cost incurred in operating coal units at minimum load.**

Big Rivers
Contingency Reserve Options

Option	Preliminary Evaluation
Join Midwest ISO	($1.6) to $29.1 million annual cost
SPP Contingency Reserve Group	Not feasible until at least mid-2012 as transmission across TVA is not available. Would need to be combined with own-system options.
Own System options	Potentially feasible, but costly. Cost would depend on smelter incentive required and the cost of operating coal units at minimum load in the near-term and obtaining new peaking capacity in the longer-term.

RESULTS ARE PRELIMINARY

CRA Charles River Associates

1. Midwest ISO Option

- CRA has performed a preliminary assessment of the economics of Big Rivers joining the Midwest ISO as a participating Transmission Owner (TO).
  - CRA has performed a number of RTO cost-benefit studies, including for SPP, Ameren and Aquila.
- The costs incurred in Big Rivers joining the Midwest ISO include:
  - Administrative charges assessed by the Midwest ISO,
  - Big Rivers capital and staffing requirements for interfacing with the Midwest ISO,
  - Additional payments to the FERC, and
  - Potentially sharing in the cost of new high-voltage transmission on the Midwest ISO system
- On the benefits side, Big Rivers will be able to integrate the commitment and dispatch of its units with the Midwest ISO and to import and export energy to/from the Midwest ISO without incurring wheeling charges.
  - This should serve to increase sales revenues and/or reduce purchase costs for Big Rivers and thereby reduce the cost to serve native load.
- There are a number of other important qualitative-type issues, the impact of which cannot be directly quantified.
- We analyze each of these items in turn below.

1. Midwest ISO Option

- **Big Rivers would want its member and smelter supply contracts treated as Grandfathered Agreements (GFAs).**
  - GFAs can be exempt from various Midwest ISO markets and the associated charges.
  - Carve out GFAs are in effect for most of the coop member load in the Midwest ISO.
  - New load is not eligible for Option B.
- Dairyland requested carve-out GFAs at FERC, but MISO says new load does not qualify.
  - A carve out would save $0.63/MWh.
- **GFAs are not assessed RECB (transmission expansion) costs in the Midwest ISO.**
  - But FERC special treatment of GFAs may end at some point in the future.
- We assume herein that Big Rivers would choose Option A if it can obtain GFAs.
  - Under a carve-out option, trade benefits might be reduced if not fully participating in market-based scheduling.

Midwest ISO Grandfathered Agreement (GFA) Options

Option	GFA Treatment
A	Participate in all markets, and must nominate and hold Financial Transmission Rights (FTRs)
B	Crediting of all congestion and loss charges if timely and cleared day-ahead bilateral transaction schedule is submitted. *New load not eligible.*
C	No FTRs, but participate in all markets
Carve Out	No congestion or loss charges, and financially binding schedules are not required. *New load not eligible.*

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1. Midwest ISO Option

- **Administrative charges assessed by the Midwest ISO.**
  - The Midwest ISO assesses administrative charges under Schedules 10, 16 and 17.
    - The billing determinants are a mixture of demand and energy use by each TO.
    - Under GFA Option A, Big Rivers would pay for FTRs under Schedule 16.
  - The Midwest ISO has a forecast of these charges on a $/MWh basis, which we have used to estimate the charges to Big Rivers in 2010.
    - Based on the 2010 BREC operating budget, the Big Rivers MWH billing basis was assumed to be 12,179,000 MWh.
  - As shown, we estimate an annual charge of $4.3 million in 2010, assuming for purposes of this analysis a full year of membership.
    - The Midwest ISO estimated $4.7 million in administrative charges for Big Rivers.

Big Rivers Annual Administrative Charges
in the Midwest ISO for 2010
(assuming full year of membership)

Schedule	2010 $/MWh	BREC $million
10	0.150	$1.8
16 (FTRs)	0.025	$0.3
17	0.180	$2.2
Total	**0.355**	**$4.3**

1. Midwest ISO Option

- **Additional payments to the FERC**
  - Big Rivers, as a coop, is currently exempt from paying FERC administrative charges.
  - However, as a member of an RTO, Big Rivers would be obligated to pay these charges based on transmission system use.
  - The Midwest ISO assesses FERC charges under Schedule 10-FERC, and forecasts these to be 0.05 $/MWh in 2010
    - As before, the Big Rivers MWH billing basis was assumed to be 12,179,000 MWh.
  - As shown, we estimate an annual FERC charge of $0.6 million in 2010.

Big Rivers FERC Charges
in the Midwest ISO for 2010
(assuming full year of membership)

Schedule	2010 $/MWh	BREC $million
10-FERC	0.05	$0.6

1. Midwest ISO Option

- **Big Rivers capital and staffing requirements for interfacing with the Midwest ISO**
  - Interfacing with the Midwest ISO market, attending stakeholder meetings, responding to filings, etc. likely will require additional Big Rivers staffing, operating costs and capital investment.
  - In our 2005 SPP Cost Benefit Study, utilities estimated their RTO market incremental costs as:
    - Operating costs of \$0.7 to \$2.2 million per year, with new FTE ranging from 4 to 13.
    - Initial capital costs up to \$9 million.
    - Converted to annual revenue requirements, the average across the utilities was roughly \$1.5 million per year.
    - Some functions performed by Big Rivers will be transferred to the Midwest ISO, so there may be some offsetting savings.
  - These costs were estimated to be \$1.5 million per year, subject to refinement based on actual Big Rivers requirements.

Big Rivers Budget Items
for interfacing with Midwest ISO

New FTE, with Benefits
Professional Services
Travel
Computer Software
Computer Hardware
Estimated Annual Cost **\$1.5 million**

1. Midwest ISO Option

- **Sharing in the cost of new high-voltage transmission on the Midwest ISO system**
  - To import Great Plains wind power, the MISO region may invest billions of dollars in high-voltage transmission.
    - The lines likely would be constructed over the 2012 to 2020 time-frame
  - The investment amount is uncertain, and could range from $1 to $10 billion, or more.
    - Cost sharing MISO-wide is uncertain, but could range from 20% (less would be built) to, more likely, 80 to 100%.
  - If Big Rivers load is granted GFA status, it would be exempt from these costs.
    - Member load may be more likely to get GFA status than smelter load.
  - To frame this issue, we have calculated a low, mid and high case.
    - Big Rivers annual costs range from $0 to $26.7 million, with a mid-point of $6.8 million.

Big Rivers Annual High-Voltage Transmission Cost Allocation in the Midwest ISO

	Low	Mid	High
Transmission Investment	$1 B	$5 B	$10 B
MISO-wide Allocation	20%	80%	100%
Investment Carry Charge	15%	15%	15%
BREC Load Ratio Share	1.78%	1.78%	1.78%
BREC Cost (millions of $):			
@ 0% GFAs	*$0.5*	*$10.7*	***$26.7***
@ 36% GFAs (members)	*$0.3*	***$6.8***	*$17.1*
@ 100% GFAs (members+smelters)	***$0.0***	*$0.0*	*$0.0*

Of BREC 2010 native load, 36% is for members (incl. HMP&L), and 64% is for smelters.

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1. Midwest ISO Option

- **Summary of Costs**
  - The total Big Rivers annual cost is $6.4 million per year.
  - If the high-voltage transmission cost allocation is included, the total annual cost ranges from $6.4 to $33.1 million year, with a mid-point of $13.2 million per year.
    - The high-voltage transmission cost sharing would not take place fully until after 2013.

Big Rivers Annual Costs
If Joining Midwest ISO

	BREC Cost (millions)
MISO Administrative Charges	$4.3
FERC Administrative Charges	$0.6
Internal Staffing/Capital Costs	$1.5
High-Voltage Trans. Cost Allocation	Low $0.0 Mid $6.8 High $26.7
Total Annual Cost	**Low $6.4** **Mid $13.2** **High $33.1**

1. Midwest ISO Option

- On the benefits side, Big Rivers will be able to:
  - Integrate the commitment and dispatch of its units with the Midwest ISO and to
  - Import and export energy to/from the Midwest ISO without incurring wheeling charges.
  - In effect, the decrease in trading impediments with the Midwest ISO should result in "trade benefits", which will materialize in a decrease in Big Rivers adjusted production cost:

Adjusted Production Costs =

  Production costs for owned units (fuel, variable O&M and emission costs)

\+ Purchase costs for off-system energy

\- Sales Revenue for off-system sales.

- In CRA's RTO cost benefit studies, we have run the GE MAPS model to determine this impact. GE MAPS includes the transmission topology for the entire Eastern U.S. and optimizes the generation dispatch taking into account transmission constraints.
- Given time constraints, we have performed a much more rudimentary analysis to create a preliminary estimate of trade benefits.

1. Midwest ISO Option

- In our simplified model, we run two cases for the year 2008:
  - Base Case -- Big Rivers not in the Midwest ISO
  - Change Case – Big Rivers joins the Midwest ISO
- We use the following data:
  - Big Rivers:
    - Balancing authority hourly load in 2008
    - Monthly generating unit generation and SEPA purchases in 2008
    - Monthly interchange with TVA and the Midwest ISO in 2008
    - Generating unit parameters (capacity, heat rate, fuels cost, etc) from the 2010 budget
    - Wheeling charge from BREC into the Midwest ISO ($2.88/MWh)
  - Midwest ISO wheeling charge into Big Rivers ($6.32/MWh on-peak/$3.00 off-peak)
  - Hurdle rates (trade impediment) of $3/MWh between the Midwest ISO and Big Rivers in the Base Case, which is eliminated in the Change Case.
  - Midwest ISO hourly Locational Marginal Prices ("LMPs") in 2008 near the Big Rivers border.
  - A 200 MW estimate for the transfer capability from Big Rivers to/from the Midwest ISO.
- We focus on 2008 in this simplified model because we have actual Midwest ISO LMPs for the year.

1. Midwest ISO Option

- In the Base Case:
  - The Big Rivers generating units are dispatched for 2008 such that we roughly match the available historical generating, interchange and load data.
- In the Change Case:
  - The wheeling and hurdle rate (i.e., trading "friction") between Big Rivers and the Midwest ISO are eliminated, and, all else equal, we redispatch the Big Rivers units.
- We then calculate the Adjusted Production Costs in each case, and take the difference to estimate trade benefits.
- As shown, we calculate an annual trade benefit of $6.4 million in this preliminary analysis.

✓ **Based on sensitivity cases, we preliminarily estimate that annual trade benefits are likely in the $4 to $8 million range.**

Big Rivers Estimated Annual Trade Benefits
If Joining the Midwest ISO
(millions of $)

	Base Case	Change Case	Increase
Production Cost	230.7	231.1	0.4
+ Purchases	10.5	13.2	2.7
- Sales Revenue	24.6	34.1	9.5
Adj. Production Costs	**216.6**	**210.1**	**(6.4)**

RESULTS ARE PRELIMINARY

1. Midwest ISO Option

Ancillary Market Costs/Benefits

- The Midwest ISO implemented an Ancillary Services Market (ASM) in January 2009, which integrates the procurement and use of regulation and contingency reserves with the energy market.
- Under the ASM, Big Rivers' load would incur costs to purchase regulation and contingency reserves.
  - The Midwest ISO has estimated that these charges would be $3.4 million per year.
- However, Big Rivers generating units would receive revenues for providing ancillary services.
- Self-supply of the required reserves is permitted, meaning that the Big Rivers' generation units could be used to supply the required reserves for the Big Rivers load.
  - Based on the 2007 Big Rivers transmission rate filing, the revenue requirement for reserves supplied by the Big Rivers' units was estimated to be about $5.3 million which exceeds the $3.4 million Midwest ISO market revenue estimate.
  - For the most part, however, these reserves are being self-supplied to Big Rivers' own load.

✓ **Based on the above costs and the self-supply option, in this preliminary analysis we view the costs/benefits of the ASM to Big Rivers to be roughly a wash.**

CRA Charles River Associates

1. Midwest ISO Option

- **Net Benefits**
  - The net benefits can be calculated by comparing the trade benefits if joining the Midwest ISO to the associated costs.
  - As shown, the net annual benefits(costs) range from a low of ($29.1) million (i.e., a negative benefit, or cost), to a high of $1.6 million.

Big Rivers Annual Net Benefits (Costs)
If Joining Midwest ISO

	Low Benefits	Mid Benefits	High Benefits
Trade Benefits	$4.0	$6.4	$8.0
Total Annual Cost	($33.1)	($13.2)	(6.4)
Net Benefits	**($29.1)**	**($6.8)**	**$1.6**

RESULTS ARE PRELIMINARY

CRA Charles River Associates

1. Midwest ISO Option

Qualitative Issues/Risks

- Member and Smelter Agreements.
  - CRA has not examined whether recovery of any additional costs incurred by Big Rivers via Midwest ISO membership would require modification of the coop and smelter agreements.
  - It is possible that some existing Big Rivers transmission arrangements would not qualify for any GFA status, and thus would be eligible for a high-voltage transmission cost allocation.
  - Big Rivers qualifying for carve-out GFAs will be opposed by the Midwest ISO.
- Wind Power. Our simplified model cannot take into account the potential benefits of greater access to Great Plains wind power that might take place with expanded high-voltage transmission.
  - Subject to transmission limitations with the Midwest ISO, Big Rivers would receive some benefits from this wind power regardless of joining the Midwest ISO.
  - Potentially, transmission improvements between Midwest ISO and Big Rivers could be made if Big Rivers were in the Midwest ISO that would allow for greater access to the windpower.
- HMP&L. The City of Henderson is included in the Big Rivers balancing authority analysis herein. City of Henderson may not agree to join the Midwest ISO, and presumably would require a grandfathered transmission agreement arrangement with Big Rivers.
- Wheeling. Big Rivers would share in the Midwest ISO through and out wheeling revenue to some extent, and to the extent that these are greater than those that would be collected if not in the Midwest ISO, these would reduce the net transmission charges paid by Big Rivers native load.

1. Midwest ISO Option

Qualitative Issues/Risks

- Planning. Big Rivers would not have direct planning control over its transmission system, as transmission improvements would be implemented through the Midwest ISO planning process.
- Management time. Significant training time and management time would be required to integrate into the Midwest ISO. For example, Big Rivers would have to be comfortable with Financial Transmission Rights, the RECB process, Ancillary Service Market implementation, etc.
- Regulatory costs. Significant one-time regulatory and training costs would be required to join the Midwest ISO. It is likely that on-going regulatory costs would increase as well to keep abreast of Midwest ISO FERC filings.
- GFA "RECB" Exclusion. The current exclusion for GFAs to not have to pay for transmission expansion costs depends on continuing FERC acquiescence, as Midwest ISO parties will seek to end this exclusion if these expenditures become significant.
- Exit risk. Leaving an RTO is difficult, and the exit charges can be significant. A decision to join the Midwest ISO would have to be undertaken on the notion that the long-term benefits are significant.

1. Midwest ISO Option

Next Steps

- Trade Benefit Refinement
  - The analysis of trade benefits is highly preliminary.
  - Additional hourly data for the year 2008 would be helpful in improving the estimate.
  - However, ultimately, a GE MAPS analysis would be required to better access the trade benefits taking into account generation dispatch in both Big Rivers and the Midwest ISO, and applicable transmission constraints.
- Implementation Costs Assessment
  - Additional discussions with Dairyland regarding the process they are following would be helpful for estimating the implementation costs that would be incurred with Midwest ISO entry.
- Grandfathered Agreement Assessment
  - A detailed review of the smelter and member coops contracts and the ability to have these and all other Big Rivers transmission arrangements for its load treated as GFAs.

2. SPP Contingency Reserve Group Option

- Joining the SPP Contingency Reserve Group is an available option if firm transmission can be obtained across TVA to SPP Contingency Reserve Group members AECI or Entergy.
  - Given the limited transmission available and the associated cost between SPP and Big Rivers, this option is best combined with own-system options.
  - To assess transmission availability, BREC requested 2 x 100 MW of TVA transmission from BREC to Entergy/AECI and 5 MW of TVA transmission from Entergy/AECI to BREC.
    - Including ancillary charges, the TVA transmission rate is $23,556/MW-year. For 205 MW, the cost would be $4.8 million per year.
    - TVA considered each 100 MW request separately. TVA determined that obtaining 100 MW of transmission would require $4.9 million in transmission upgrades on the TVA system and would not be available until 2012 at the earliest.
    - The 5 MW of transmission from Entergy/AECI to BREC was potentially available.
    - However, TVA further noted that a System Impact Study with MISO, E.ON, and Entergy/AECI would be required before any transmission service could be obtained.

✓ **Given that TVA transmission, if available at all, would not be available until mid-2012 at the earliest, the SPP Contingency Reserve Group is not a near-term option for Big Rivers.**

CRA Charles River Associates

3. Own-system Options

- Own-system options for supplying reserves include:
  - Existing peaking capacity. The 65 MW Reid CT is available. The plant rarely operates, and therefore the loss in value from holding the plant in reserve would be relatively small.
  - Interruptible demand (e.g., smelters): Preliminary talks with the smelters indicated that 200 MW of reserves (effectively one pot line each) could be available, at a yet-to-be determined price. The temporary loss of a pot-line during a reserve shortfall could be costly to the smelters.
  - One or more coal-fired units operating at less than full load. Operating coal units at less than full load will increase BREC supply costs whenever market prices are high. The units also will operate less efficiently at less than full load, increasing average fuel costs. Also, operating at minimum load in certain off-peak periods when market prices are very low and the plant would otherwise not operated will increase BREC supply costs.
    - As an example, we roughly estimate that obtaining about 30 MW of reserves through Coleman 3 operating at minimum load might result in additional Big Rivers supply costs of about $3 to $5 million per year. To obtain the 150 MW or so of reserves that would be needed in addition to the smelters and Reid CT might require 3 to 5 Big Rivers coal units operating at minimum load.
  - New peaking capacity. A new unit would take 1-2 years to put in place. PJM estimates the cost of new peaking capacity at $115/kW-year, before obtaining any energy benefits. In this case, the unit would be held in reserve and energy benefits would be restricted. So, for example, 150 MW of new peaking capacity would cost about $17 million per year.

✓ **Meeting reserves through own-system options is potentially feasible, but would be quite costly when including the cost of operating units at minimum load and the potential smelter price incentive.**

Charles River Associates
1201 F Street, NW
Washington, DC 20004

Item KIUC 1-2) *Assume the projected 2010 cost profile of Big Rivers as reflected in its operating and capital budgets as they existed on July 17, 2009, the closing date of the Unwind Transaction. Alcan, Century and KIUC wish to understand the incremental financial impact resulting from the unexpected development that Big Rivers can no longer participate in the MCRSG but rather must join MISO. Has Big Rivers, CRA, or any other firm acting on behalf of Big Rivers performed a study or otherwise estimated the incremental cost of MISO membership compared to projected operations where reserve sharing was provided by the MCRSG. If so, please provide copies of all such Studies, including work papers. If not, please state the information and assumptions that would be required to perform such an analysis.*

Response) Since the time of the filing of the Application, CRA was asked by Big Rivers to perform an evaluation of the incremental economic impact on Big Rivers of joining the Midwest ISO in comparison to the hypothetical alternative of remaining a member of the terminated MCRSG. CRA performed an additional GE MAPS analysis for the year 2011 in which the MCRSG was hypothetically assumed to remain in place with Big Rivers as a member. This analysis showed decreased costs to serve Big Rivers' load of $2.4 million in 2011 with Big Rivers in the Midwest ISO relative to being a member of the MCRSG. These savings would be offset in 2011 by $4.6 million in Midwest ISO administrative charges, $0.7 million in additional FERC charges, and $0.8 million in internal BREC staffing/equipment charges in 2011 (see Table 2 on page 28 of my Direct Testimony), for an overall net additional cost of $3.6 million in 2011 relative to being a member of the MCRSG. See the attached tables for data analogous to that provided in Table 2 on page 28 of my Direct Testimony and in Table 3-1 and Table 3-4 of Exhibit RLL-3 for this additional 2011 analysis. As discussed at pages 29-33 of my Direct Testimony, there are other qualitative factors which are not quantifiable at this time.

Witness) Ralph L. Luciani

		2011
MCRSG		
+	Production Costs	372.9
+	Purchase Costs	27.5
-	Sales Revenue	10.9
=	Total	389.6
Midwest ISO Case		
+	Production Costs	371.0
+	Purchase Costs	29.9
-	Sales Revenue	13.7
=	Total	387.2
Reduced Cost of Energy Supply in Midwest ISO		
+	Production Cost Savings	1.9
+	Purchase Cost Savings	(2.3)
-	Sales Revenue	(2.9)
=	Total	2.4

Summary of Costs and Benefits of Midwest ISO Case versus MCRSG Case
positive numbers are benefits

	2011
Decreased Cost to Serve Big Rivers Load	2.4
Midwest ISO Administrative Charges	(4.6)
FERC Charges	(0.7)
Internal Staffing/Equipment Costs	(0.8)
Net Benefits	(3.6)

2011

Generation (GWh)

	MCRSG	in-MISO	Increase
Coleman 1	1,000	964	(36)
Coleman 2	990	948	(42)
Coleman 3	974	963	(11)
Wilson	3,086	3,086	-
Green 1	1,706	1,743	38
Green 2	1,663	1,699	36
Reid Steam	115	83	(32)
Reid CT	-	-	-
HMPL 1	1,028	993	(35)
HMPL 2	936	985	49
	11,498	11,464	(33)

Capacity Factor (nameplate)

	MCRSG	in-MISO	Increase
Coleman 1	79%	76%	-3%
Coleman 2	78%	75%	-3%
Coleman 3	74%	73%	-1%
Wilson	84%	84%	0%
Green 1	84%	86%	2%
Green 2	85%	87%	2%
Reid Steam	20%	15%	-6%
Reid CT	0%	0%	0%
HMPL 1	77%	74%	-3%
HMPL 2	67%	71%	4%

Production Costs (M$)

	MCRSG	in-MISO	Increase
Coleman 1	37.9	36.6	(1.3)
Coleman 2	37.2	35.7	(1.5)
Coleman 3	37.0	36.6	(0.4)
Wilson	78.2	78.2	0.0
Green 1	52.3	53.4	1.2
Green 2	50.8	51.9	1.1
Reid Steam	5.6	4.0	(1.6)
Reid CT	0.0	0.0	0.0
HMPL 1	38.4	37.1	(1.2)
HMPL 2	35.5	37.4	1.9
	372.9	371.0	(1.9)

Item KIUC 1-3) ***If not included in your responses to Item 1 or Item 2, please provide all Documents and Studies to/from Big Rivers, CRA, and MISO, or any other firm acting on behalf of Big Rivers relating to the estimate of the benefits and/or costs to Big Rivers to join MISO.***

Response) See the responses to KIUC 1-1 and KIUC 1-2, my Direct Testimony, and Mr. Moeller's Direct Testimony.

Witness) Ralph L. Luciani

Item KIUC 1-4) ***Please provide copies of all Documents and Studies to/from Big Rivers, Dan Becker, and/or ACES relating to (a) the estimate of cost or benefit to Big Rivers to join MISO or (b) of alternative solutions to the reserve sharing issue.***

Response) (a) Big Rivers did not ask either DB Consulting, LLC (Dan Becher) or ACES to perform an estimate of cost or benefit to Big Rivers to join MISO.

(b) Big Rivers sought input from both DB Consulting, LLC (Dan Becher) and ACES with respect to possible alternative solutions to the reserve sharing issue. Documents regarding these inquiries are attached.

Witness) David G. Crockett

David Crockett

From: David Crockett

Sent: Wednesday, April 29, 2009 3:47 PM

To: Mark Bailey

Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite; Travis Housley

Subject: FW: Contingency Reserves

Mark,
My written update for April 27 and 29:

1) Glen made contact with Sam Holeman of Duke Energy and related our interest in possible participation in the VACAR reserve sharing group. Sam indicated that membership matters had to go before a particular committee comprised of representatives of the member utilities and that he would be glad to take it up with that group and get back with Glen. He indicated that he would hold off discussing the particular requirements of their reserve sharing program until after the committee acted on our request.

2) Glen and I have completed a review of operating reserves requirements in SPP and specifically the details contained in the on-line documentation about contingency reserves and reserve sharing. We have a conference call with three or four SPP staffers on Thursday morning to talk further with them.

3) Bill Blackburn reported on Monday that Aces Power Marketing had gotten back in touch and indicated that MISO felt Big Rivers had two alternatives. One was to join another reserve sharing group and the other was to join MISO. Bill indicated that Mike Mattox was given a MISO contact person for any further discussion of the matters.

4) I have spoken with Bob Dalrymple of TVA on Tuesday and explained our concerns about the termination of the Midwest CRSG (MISO) at the end of the year. I asked Bob to investigate the possibility of Big Rivers participating in some fashion within the framework of the reserve sharing arrangement being discussed by E.ON, East Kentucky, and TVA. He said that he would take the matter to TVA legal to see if there was some way to structure the group agreement to allow our participation. I told him that we were also exploring participation with the VACAR group and the SPP group. I asked him to separately address the matter of how TVA could assist us in providing transmission deliverability of contingency reserves energy from either their VACAR or their Entergy/AECI (SPP) interfaces to the Big Rivers interface. He said that he would take up that matter as well.

All other pursuits remain as indicated in previous reports.

Dave

From: David Crockett
Sent: Thursday, April 23, 2009 4:47 PM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite; Travis Housley
Subject: FW: Contingency Reserves

Mark,
My end of week update is as follows:

1) Glen attempted to make contact with VACAR representative identified in their website information. He left a message and is awaiting return contact. He will try again on Friday.

2) David Spainhoward completed a review of the KII Pool Agreement and the System Reserves Agreement and EPA Agreement between HMP&L and BREC. David can find no documentation indicating that the KII Agreement (including its obligations with respect to supply of emergency power and transmission usage for the mutual benefit of all the parties) has been terminated. In fact, there is documentation after year 2000 involving Southern Illinoir Power making reference to that agreement. David believes that the KII Agreement obligations of SIPC and Hoosier Energy (both MISO members) may be helpful in trying to keep MISO cooperative as we seek a solution. David believes the HMP&L agreements make them (financially) responsible for their share of the operating reserves.

3) I have been unsuccessful in talking directly with my TVA contact so far, but will continue with that.

All of the other pursuits are as stated in Tuesday's report. My first report next week will have to be by phone, but I will follow-up on Wednesday by email for the benefit of others on staff.

Dave

From: David Crockett
Sent: Tuesday, April 21, 2009 5:14 PM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite; Travis Housley
Subject: Contingency Reserves

Mark,
Concerning the investigation into the options available to BREC relative to contingency reserves:

1) Bill Blackburn made contact with Aces Power Marketing. Aces contacted MISO concerning possible options for BREC. As noted in the email on this, MISO gave an indication that a solution may be available for us in working with them. Aces is awaiting follow-up information from MISO.

2) I made contact with David Sinclair of E.ON and asked about any planning done for dealing with the contingency reserves issue in the event that the current lease arrangement is still in effect at the end of 2009. He indicated that no planning had occurred and their assumption was that the Unwind closing would occur first.

3) I made contact with Dan Becher of DB Consulting who performs MISO monitoring work for us and four other companies. Dan expressed the opinion that an extension of the sunset date on the current MCRSG agreement wasn't impossible, but was not likely to occur unless MISO was trying to do something for the far western "outsiders" the remaining MAPP region members. He said that MISO has been courting them to entice them to join MISO for quite some time. He said that unfortunately our lot tends to fall with E.ON who is understandably out of favor at MISO. He said that several of the MISO members are convinced that they can meet the NERC standards without outside support and believe that the reserve sharing program is unequally beneficial for the outsider participants who in their opinion aren't paying their way. Dan felt that participation in the MISO ancillary services market would offer a solution to BREC, but it would not be cheap because of MISO's "through and out" firm transmission tariff cost. Dan said that he felt the best option available to BREC was with some other reserve sharing group like one in the SPP region. Dan confirmed that East Kentucky and E.ON were talking with TVA about working together on a reserve sharing arrangement even though he had heard it characterized that TVA wanted an "arm and leg" for their participation.

4) I made contact with John Twitchell and George Carruba of East Kentucky to ask about their discussions with E.ON and TVA. I learned that East Kentucky was exploring the cost of adding equipment to some or all of their combustion turbines to make them "quick start" capable. I learned that the TVA talks were still progressing and that the respective planners were assessing the transmission capabilities (deliverability) needed to make the power exchanges work. No other details of the talks would be shared with me at this time.

5) I called Terry Boston (CEO) of PJM and left a message for him to return my call. I have not heard back from him as yet.

6) Glen Thweatt made contact with Southwest Power Pool (SPP) and expressed our interest in discussing reserve sharing group participation with them. His SPP contact is working on arranging a conference call involving three or four others at SPP next week. He further indicated that they were working with several MAPP members also investigating RSG participation. I assume he was referring to the remaining five MAPP members in the MCRSG. We are currently beginning review of SPP Operating Reserves Criteria documentation from their website. The SPP Reserve Sharing Group membership already includes some SERC members like Associated Electric Cooperative (Missouri) and Entergy Generation (primarily Louisiana and Arkansas).

7) Glen will also be investigating possible participation in the VACAR reserve sharing group. I believe that all participants in this group are members of the SERC region. They are companies operating in either Virginia or the Carolinas.

8) I will be calling a TVA transmission acquaintance to start a discussion on what TVA may be able to do to assist us as well.

9) David Spainhoward has agreed to investigate the terms of and status of the KII Pool Agreement. This is an old operating agreement with Big Rivers, Southern Illinois Power, Hoosier Energy, and Henderson MP&L as its parties. It has both power interchange and transmission language in it.

These are the actions taken and information gathered so far. I will update you again on Thursday evening or Friday morning.

Dave

David Crockett

From: David Crockett
Sent: Friday, July 17, 2009 1:47 PM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; Bob Berry ; David Spainhoward; James Haner; Jennifer Keach; Mark Hite
Subject: FW: Reserve Sharing

Mark,
My update for July 14 and 17:

1) I have not received a response from MISO to my last email and the questions about other arrangements to make TRM available for the SPP RSG participation.

2) I await the July 23 teleconference to get feedback from the new RSG members (E.ON, EKPC, and TVA).

3) Dan Becker (consultant for BREC and others monitoring MISO activities) asked about our efforts to join the SPP RSG. When I explained the transmission difficulties that we had encountered, he offered a piece of advice that he admitted a year ago he would not have given. He indicated that with the startup of the ancillary market that MISO members were greatly benefiting from the single balancing area (BA) operation with very low regulating reserves for the entire BA (he quoted 400 MWs as the total for the entire MISO area) and very low contingency reserves currently under the MCRSG operating agreement and expected to remain low after the MCRSG terminates. Therefore, his advice was to give consideration to the cost versus benefit of being in the MISO. He went on to say that the biggest contention in MISO is the transmission expansion cost allocation subject matter especially with the transmission needed for the wind power resources being planned.

ave

From: David Crockett
Sent: Friday, July 10, 2009 4:15 PM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite
Subject: FW: Reserve Sharing

Mark,
My update for July 3-10:

1) MISO indicated that there is no provision for them to hold TRM for BREC usage to participate in the SPP RSG. I have followed up with some questions about ways that such a provision could be arranged between us other than through the OATT firm transmission reservation route. I await the response, but hold no great hope for that to be successful.

2) TVA indicated that they were reviewing their policy of TRM usage by third parties and was considering the possibility of usage by Energy Deficient systems under an EEA Level 2 or 3 declaration. I don't see that this helps us at all. I will continue to monitor.

3) TVA sent an email to E.ON and EKPC concerning our interest in joining the new reserve sharing group and the specifics of our needs. TVA indicated that the three have agreed to discuss this during a July 23 teleconference call and then get back to me with any questions, concerns, or issues.

4) Bill, Al and I met to discuss the issues and possibilities for BREC to meet the 138 MW contingency reserve obligation if we were to join the new RSG. The subject was also discussed with the smelters at the KPSC on July 6.

Dave

From: David Crockett
Sent: Tuesday, June 30, 2009 5:00 PM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite
Subject: FW: Reserve Sharing

Mark,
My update for Tuesday, June 30:

1) My attempts to persuade TVA and MISO to approve the use of TRM capacity for SPP-BREC reserve sharing power transfers thus far have not been successful. At this point, it's my opinion that the only realistic alternative that we have to participate in the SPP RSG is with firm point-to-point transmission across TVA or MISO or a combination of the two. MISO's transmission service is about 20% more expensive than TVA's, but neither is inexpensive. Using the MISO rates (worst case scenario), I calculate the annual cost of transmission to be on the order of $12 million. This would afford us yearly firm transmission from the SPP market to BREC for replacement power purchases. I don't know if that represents a benefit in terms of power marketing for Bill Blackburn and APM or not. The firm transmission is not fully available on the OASIS postings of either MISO or TVA. If we pursue either of these options further, we will have to make a transmission service request and let them perform a study to determine how to provide the service. There would be a cost and probably 60 days time associated with these studies.

2) I have asked Stuart Goza of TVA to pursue the possibility of BREC participation in the E.ON, EKPC, and TVA reserve sharing group discussions. TVA will discuss with them our desire to have them respond up to their full quantity of reserves for BREC unit outages because of the lack of response by TVA. I have asked for assistance from Bill, Bob, and Al to explore options of how to provide the additional 90 MWs of contingency serves required to cover the Wilson unit outage scenario.

Dave

From: David Crockett
Sent: Friday, June 26, 2009 4:27 PM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite
Subject: FW: Reserve Sharing

Mark,
My update for Friday, June 19:

No updates from either TVA or MISO yet. As reported to the board, I asked Power Supply to wait on making a transmission service request to TVA and MISO because of the TRM usage requests.

My update for Tuesday, June 23:

1) Stuart Goza of TVA responded to my request indicating that the initial feedback from an attorney in TVA's Office of General Counsel was that TRM could <u>not</u> be used by a third party for reserve sharing participation. I responded with additional comments about promoting grid reliability and asked whether the legal feedback was a TVA policy statement or an OATT/FERC legal statement. Awaiting further response.

) Tom Mallinger of MISO responded to my request indicating that the TRM coordination between MISO and SPP was not intended to create a path for flows to occur, but simply was an acknowledgement that the reserve sharing flows would have impacts on both systems and that SPP and MISO would set aside capacity (TRM) to allow the reserve sharing flows to occur in real-time. He further indicated that this same question had been raised by SPP ר behalf of another entity and he had given this same response.

My update for Friday, June 26:

1) Stuart Goza of TVA offered some information about the TVA-EKPC-E.ON reserve sharing group. He indicated that with BREC as a fourth party in the group and assuming the total reserves in the pool cover the largest unit of the group (1270 MW) and assuming the reserve requirements are allocated on a load ratio share basis, the individual contingency reserves would be:

TVA - 939 MW
EKPC - 89 MW
E.ON - 193 MW
BREC - 48 MW

With these numbers, the Wilson unit outage (assumed to be 420 MW) would not be able to be covered with BREC, E.ON, and EKPC reserves only (short by about 90 MWs by my count). That might get us in the ball park though. The challenge would then be to either arrange a separate purchase of 10 minute reserve power from some supplier or to have either quick start generation (combustion turbine) or 10 minute interruptible load contract (s) with existing industrial customer in order to meet the DCS requirement with this smaller RSG. The benefit would be that there is no third party transmission system to cross to allow us to participate in the RSG. This is the first information that I have been able to get about the RSG plans being considered by the other three.

Dave

From: David Crockett
Sent: Thursday, June 18, 2009 10:56 AM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite
Subject: FW: Reserve Sharing

Mark,
My update for Tuesday, June 16:

1) I have asked TVA (Stuart Goza and Bob Dalrymple) to give me a definitive answer as to whether TVA will allow reserve sharing power flows across TVA using their TRM capacity. They are reviewing the request at this time.

2) I have been advised by Carl Monroe of SPP that use of the TRM capacity for reserve sharing has been the subject of discussions between the two organizations. After this conversation, I have asked MISO (Tom Mallinger) to give me a definitive answer as to whether MISO will allow reserve sharing power flows across MISO using their TRM capacity. I am awaiting a response from MISO as well.

3) I have asked Power Supply to consider the need for firm transmission to provide for a reliable supply of replacement power during generating unit outages (planned or forced). Firm transmission is the key element to our participation in the SPP reserve sharing.

All other pursuits have not changed since the last reporting.

Dave

From: David Crockett

Sent: Monday, June 15, 2009 8:05 AM
To: Mark Bailey
: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite
ubject: FW: Reserve Sharing

Mark,
My update for Friday, June 12:

1) I have asked Power Supply to pursue transmission service across MISO as a second possibility to demonstrate that the reserve sharing energy can flow as needed. Again, I have asked that the request identify the possible usage of MISO's Transmission Reserve Margin (TRM) capacity at those interfaces. In this case, we will make reference to a provision in the MISO and SPP Joint Operating Agreement committing each to allow usage of TRM to provide for reserve sharing flows. Even though BREC is not currently a party to that agreement, we will strongly push for MISO to honor that provision of the agreement in light of the fact that BREC will be joining the SPP Reserve Sharing Group and secondly because MISO is currently allowing us access to their TRM under the MCRSG agreement. MISO's OASIS postings are consistent with that approach in that they currently post no firm or non-firm transmission available in 2010 on any BREC paths through the MISO system. They post only TRM capacity available.

All other pursuits have not changed since the last reporting.

Dave

From: David Crockett
Sent: Tuesday, June 09, 2009 4:24 PM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite
ubject: Reserve Sharing

Mark,
My update as of Tuesday, June 9:

1) I have asked Power Supply to pursue transmission service across TVA to demonstrate that the reserve sharing energy can flow when needed by either BREC or the existing SPP Reserve Sharing Group members. I have asked that the request identify both the possible usage of TVA's Transmission Reserve Margin (TRM) capacity at each interface and the possible usage of the "grandfathered" firm transmission (100 MW) for TVA to consider. I have asked my staff to get a copy of the TVA TRM methodology or policy document.

2) I have asked my staff to get a copy of the MISO and SPP "seams" agreement. I have been told that the agreement includes language which provides for usage of each RTOs TRM capacities to allow reserve sharing energy to flow. This may offer an opportunity for Big Rivers to use MISO TRM capacity to deliver and receive SPP RSG energy. I am also reviewing the MISO TRM Policy document. I am also reviewing the MISO Available Transfer Capability (ATC) values posted for each month in 2010 for paths between existing SPP RSG members and BREC.

All other pursuits have not changed since the last reporting.

Dave

David Crockett

From: Bill Blackburn
Sent: Monday, September 28, 2009 12:39 PM
To: Mark Bailey; Albert Yockey; Bob Berry; David Crockett
Subject: FW: Contingency Reserves

FYI

From: Eric Larson [mailto:ericl@acespower.com]
Sent: Monday, September 28, 2009 12:18 PM
To: Bill Blackburn
Subject: Contingency Reserves

Bill,
Thought I'd circle back with you now that we've heard MISO made it down to see you to propose their options. I'm hearing from the team maybe some progress being made by your folks with the SPP reserve group and your AI load. Briefly, we did not find much relief otherwise:

- Local CT. Bluegrass is a 2002 vintage peaker recently purchased by LS Power just outside Louisville. Unfortunately, as discussed with LS, these Siemens units are not the equipment to meet a 15 minute Disturbance Recovery Period.
- MISO. We teed up the meeting for you, but MISO prefers to make their membership approaches direct to the utility. I think one of your staff asked if we could report on their value proposition. To that end if you have study data from MISO in question, we can review it. In terms of Contingency Reserves, the main thing they seem to have going for them is economy of scale and gen length in a depressed energy market.
- Bilateral imports. We spoke with Ameren-unregulated (as a test case, they are long) and MISO staff. MISO energy market does not seem to match the need - hourly energy market versus a 15 minute DRP. MISO further indicated that transmission for such reserves (or "ancillaries") export was something that is not in ATC (although obviously it was in their control to do so up to Dec 31).
- Build. Obviously you don't have time for this, but we did talk to a developer who indicated quick start / multi cycle CT's (Wartsila's, aeroderivatives) are probably at the upper end of installed costs: $1000-1200/kW. Perhaps a bookend for costs for the future.

Anything else I can have our crew look at?

Eric H. Larson
Vice President
ACES Power Marketing
EricL@acespower.com
(317) 344-7152

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hink before you print

Item KIUC 1-5) *Please provide all Documents and Studies generated internally by Big Rivers relating to an estimate of benefits and cost to Big Rivers to join MISO. Please include in your response all agendas, minutes or other Documents considered or reflecting actions, including derivatives and decisions, by the Big Rivers Board of Directors.*

Response) Documentation of the agenda and minutes from the monthly meetings of the Board of Directors beginning in May 2009 and continuing forward to the present time, which indicate the discussion of the reserve sharing issue, are attached. Non-relevant portions of these documents have been redacted. Big Rivers' decision to join the Midwest ISO under the terms of the Memorandum of Understanding executed on December 11, 2009 was based upon the fact that no other feasible solution existed which would provide a contingency reserve supply to meet the NERC standards beginning on January 1, 2010. While no cost estimates were generated internally by Big Rivers for joining the Midwest ISO, Big Rivers relied upon the fact that the representative annual cost of membership supplied by the Midwest ISO was significantly less than the annual cost of self-supply of 400 plus megawatts of contingency reserve, which was the only other option available at the time the decision was made (e.g., 400 MWs times 8,760 hours times 85% capacity factor times $10/MWh projected margin equals $29.8 million in annual lost opportunity margins).

Witness) David G. Crockett

BIG RIVERS ELECTRIC CORPORATION
REGULAR BOARD OF DIRECTORS MEETING
MAY 15, 2009

The regular meeting of the Board of Directors of Big Rivers Electric Corporation was called to order at 8 a.m., CDT, on Friday, May 15, 2009, at 201 Third Street, Henderson, Kentucky 42420.

Redacted

Redacted

David Crockett updated the board on the options identified and explored regarding a replacement for the MISO reserve sharing agreement that will terminate at the end of the year.

Redacted

NOTICE OF REGULAR MEETING OF THE BOARD OF DIRECTORS
OF
BIG RIVERS ELECTRIC CORPORATION

Take notice that the purpose of this meeting is to discuss and take action upon the matters shown on the following agenda, to-wit:

AGENDA
BIG RIVERS ELECTRIC CORPORATION
REGULAR MEETING OF THE BOARD OF DIRECTORS
MAY 15, 2009
8 A.M., CDT

I. [redacted]

II. [redacted]

III. [redacted]

IV. [redacted]

V. [redacted]

VI. [redacted]

VII. [redacted]

VIII. Management's Report:

[redacted]

4. Reserve Sharing Agreement Replacement - Crockett

[redacted]

IX. Legal Report

NOTICE OF REGULAR MEETING OF THE BOARD OF DIRECTORS
OF
BIG RIVERS ELECTRIC CORPORATION

Take notice that the purpose of this meeting is to discuss and take action upon the matters shown on the following agenda, to-wit:

AGENDA
BIG RIVERS ELECTRIC CORPORATION
REGULAR MEETING OF THE BOARD OF DIRECTORS
JUNE 19, 2009
<u>8 A.M., CDT</u>

I. [redacted]

II. [redacted]

III. [redacted]

IV. [redacted]

V. [redacted]

VI. [redacted]

VII. [redacted]

VIII. Management's Report:
1. [redacted]
3. Reserve sharing agreement update - Crockett
4. [redacted]

NOTICE OF REGULAR MEETING OF THE BOARD OF DIRECTORS
OF
BIG RIVERS ELECTRIC CORPORATION

Take notice that the purpose of this meeting is to discuss and take action upon the matters shown on the following agenda, to-wit:

AGENDA
BIG RIVERS ELECTRIC CORPORATION
REGULAR MEETING OF THE BOARD OF DIRECTORS
JULY 31, 2009
<u>8 A.M., CDT</u>

I. [redacted]

II. [redacted]

III. [redacted]

IV. [redacted]

V. [redacted]

VI. [redacted]

VII. [redacted]

VIII. Management's Report:

[redacted]

7. [redacted]
8. Reserve sharing agreement update - Crockett

[redacted]

IX. [redacted]

NOTICE OF REGULAR MEETING OF THE BOARD OF DIRECTORS
OF
BIG RIVERS ELECTRIC CORPORATION

Take notice that the purpose of this meeting is to discuss and take action upon the matters shown on the following agenda, to-wit:

AGENDA
BIG RIVERS ELECTRIC CORPORATION
REGULAR MEETING OF THE BOARD OF DIRECTORS
AUGUST 21, 2009
8 A.M., CDT

I. [redacted]

II. [redacted]

III. [redacted]

IV. [redacted]

V. [redacted]

VI. [redacted]

VII. [redacted]

VIII. **Management's Report:**
[redacted]
6. Reserve sharing agreement update – Crockett
7. [redacted]

IX. [redacted]

NOTICE OF REGULAR MEETING OF THE BOARD OF DIRECTORS
OF
BIG RIVERS ELECTRIC CORPORATION

Take notice that the purpose of this meeting is to discuss and take action upon the matters shown on the following agenda, to-wit:

AGENDA
BIG RIVERS ELECTRIC CORPORATION
REGULAR MEETING OF THE BOARD OF DIRECTORS
SEPTEMBER 18, 2009
<u>8 A.M., CDT</u>

I. [redacted]

II. [redacted]

III. [redacted]

IV. [redacted]

V. [redacted]

VI. [redacted]

VII. [redacted]

VIII. Management's Report:

1. [redacted]

4. Reserve sharing agreement update – Crockett

5. [redacted]

BIG RIVERS ELECTRIC CORPORATION
ANNUAL BOARD OF DIRECTORS MEETING
SEPTEMBER 18, 2009

The annual meeting of the Board of Directors of Big Rivers Electric Corporation was called to order at 8 a.m., CDT, on Friday, September 18, 2009, at 201 Third Street, Henderson, Kentucky 42420.

Redacted

Redacted

Mr. Crockett discussed the reserve sharing agreement options being considered.

NOTICE OF REGULAR MEETING OF THE BOARD OF DIRECTORS
OF
BIG RIVERS ELECTRIC CORPORATION

Take notice that the purpose of this meeting is to discuss and take action upon the matters shown on the following agenda, to-wit:

AGENDA
BIG RIVERS ELECTRIC CORPORATION
REGULAR MEETING OF THE BOARD OF DIRECTORS
OCTOBER 16, 2009
8 A.M., CDT

I. [redacted]

II. [redacted]

III. [redacted]

IV. [redacted]

V. [redacted]

VI. [redacted]

VII. [redacted]

VIII. Management's Report:
1. [redacted]
2. Reserve sharing agreement update - Crockett
3. [redacted]

IX. [redacted]

X. [redacted]

BIG RIVERS ELECTRIC CORPORATION
REGULAR BOARD OF DIRECTORS MEETING
OCTOBER 16, 2009

The regular meeting of the Board of Directors of Big Rivers Electric Corporation was called to order at 8:30 a.m., CDT, on Friday, October 16, 2009, at the Wilson Station, 5663 State Route 85 West, Centertown, Kentucky, 42327.

Redacted

Mr. Crockett updated the board on the reserve sharing agreement issue.

Redacted

NOTICE OF REGULAR MEETING OF THE BOARD OF DIRECTORS
OF
BIG RIVERS ELECTRIC CORPORATION

Take notice that the purpose of this meeting is to discuss and take action upon the matters shown on the following agenda, to-wit:

AGENDA
BIG RIVERS ELECTRIC CORPORATION
REGULAR MEETING OF THE BOARD OF DIRECTORS
NOVEMBER 20, 2009
<u>8 A.M., CST</u>

I. [redacted]

II. [redacted]

III. [redacted]

IV. [redacted]
1. [redacted]

V. [redacted]

VI. [redacted]

VII. New Business:
1. [redacted]
6. MISO Memorandum of Understanding/reserve sharing update - Crockett
[redacted]

VIII. [redacted]

MEMORANDUM OF UNDERSTANDING

This Memorandum of Understanding ("Memorandum"), entered into on October ____, 2009, by and between the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") and Big Rivers Electric Cooperative ("Big Rivers"), individually and collectively referred to herein as "Party" or "Parties," is intended to establish the parameters governing the integration of the transmission facilities of Big Rivers into the transmission grid operated by the Midwest ISO. Pursuant to this understanding, the Midwest ISO and Big Rivers do represent and acknowledge as follows:

FIRST, the Midwest ISO is a non-stock, non-profit corporation organized under the laws of Delaware, and a regional transmission organization ("RTO"), as established by the Federal Energy Regulatory Commission ("FERC") pursuant to Order No. 2000;

SECOND, Big Rivers is a cooperative association organized and existing under the laws of the State of Kentucky that provides electric service to its member cooperatives and certain municipal utilities located in the state of Kentucky; and owns or operates transmission facilities that are contiguous to the transmission facilities that are presently subject to the functional control of the Midwest ISO;

THIRD, Big Rivers has stated its intention to join the Midwest ISO as a Transmission Owner within the scope of the Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc., a Delaware Non-Stock Corporation ("Midwest ISO TOA");

FOURTH, the Parties agree that a phased integration of its transmission facilities, beginning with the ability for Big Rivers to obtain certain RTO and ancillary market services on January 1, 2010, and concluding with full integration of the Big Rivers transmission facilities on June 1, 2010;

NOW, in consequence thereof, the Parties agree as follows with respect to those activities necessary to effectuate the Big Rivers membership in the Midwest ISO.

1. Cost of Application and Integration

1.1 The Parties acknowledge that approval by the FERC pursuant to Section 205 of the FPA will be necessary to implement certain changes to the Midwest ISO's Open Access Transmission, Energy and Operating Reserves Markets Tariff ("Midwest ISO Tariff"), including, without limitation, Attachment O containing the Big Rivers transmission cost of service, and Attachment P to reflect certain Big Rivers Grandfathered Agreements ("GFAs"). The Parties further acknowledge that the Midwest ISO will be required to expend considerable resources in order to prepare and defend applications and other filings associated with the Big Rivers membership, to integrate the facilities of Big Rivers into the transmission grid that it presently operates, to include Big Rivers load into the commercial model underpinning its Energy and Operating Reserves Markets, to assign Auction Revenue Rights ("ARR") and Financial Transmission Rights, and to permit the phased integration requested by Big Rivers beginning January 1, 2010. In consideration of these efforts, Big Rivers agrees to work in good faith with the Midwest ISO to determine, agree upon, and reimburse the Midwest ISO for its reasonable cost of attorney fees, related legal expenses attributed to the Big Rivers integration, and the reasonable quantifiable cost of Midwest ISO internal employee wages and overheads for such integration efforts in the event that Big Rivers elects not to integrate its facilities with the transmission system operated by the Midwest ISO.

1.2 Notwithstanding the provisions of Section 1.1, each Party will bear its own costs in the event that: (a) the FERC does not accept the Section 205 applications necessary to effectuate integration or attaches conditions that are reasonably deemed by Big Rivers to be unacceptable; (b) applicable regulatory authorities, if any, deny Big Rivers permission to transfer functional control of its transmission assets to the Midwest ISO, or attach conditions reasonably deemed by Big Rivers to be unacceptable; or (c) the FERC and all other applicable regulatory authorities approve the transfer of functional control or other requirements needed to integrate, and the Big Rivers facilities are integrated, into the Transmission System of the Midwest ISO. Big Rivers will advise the Midwest ISO in writing of conditions imposed by the FERC or any applicable regulatory authority deemed to be unacceptable within thirty (30) days of the issuance of the order imposing such conditions.

2. Other Authorizations

2.1 Concurrent with or prior to the submission of the necessary FPA Section 205 filings with the FERC, Big Rivers will initiate such activities as may be necessary to secure any applicable regulatory approval to transfer functional control of its transmission assets to the Midwest ISO. The Midwest ISO will provide any reasonable assistance to Big Rivers necessary to prepare and perfect its application(s) to such regulatory authorities and otherwise support the regulatory approval process as Big Rivers may reasonably request.

2.2 Big Rivers will pursue such approvals with diligence and will not to take any action that would prejudice regulatory approval of its application(s). Should Big Rivers not pursue state applications diligently, or should it take action that would prejudice approval, then Big Rivers shall be liable for the integration costs incurred by the Midwest ISO as set forth in Section 1.1 of this Memorandum, notwithstanding the proviso of Section 1.2 set forth above.

3. Relationship With Non-Jurisdictional Entities

3.1 To the extent any non-jurisdictional entity whose transmission facilities are integrated with, or embedded into, the Big Rivers transmission facilities: (a) declines to transfer functional control of its transmission facilities to the Midwest ISO; (b) objects to the functional control of the Big Rivers transmission facilities by the Midwest ISO; or (c) asserts that it will be due compensation from Big Rivers or the Midwest ISO for service over such integrated or embedded facilities, Big Rivers shall so advise the Midwest ISO in writing as soon as it becomes aware of the non-jurisdictional entity's position. The Parties agree to work cooperatively to resolve any issues that may arise in connection with the non-jurisdictional entity's position, including, without limitation, by jointly supporting and defending before the FERC any needed revisions to jurisdictional agreements between Big Rivers and such a non-jurisdictional entity.

4. GFAs and ARR Allocations

4.1 The Midwest ISO and Big Rivers will work cooperatively with each other, and with third parties to GFAs, to determine the appropriate treatment of each such agreements under the Midwest ISO Tariff. The Midwest ISO and Big Rivers will further work together to determine ARR allocations to and within the Big Rivers

Zone. The Parties understand that any unresolved issues relating to GFAs or ARR allocations are subject to FERC jurisdiction.

5. Membership and Withdrawal Obligations

5.1 The Parties agree that Big Rivers will become a member of the Midwest ISO upon its execution of the Midwest ISO TOA which sets forth the respective rights, duties and obligations of a member. Consistent with the Midwest ISO TOA, until such time as the Big Rivers facilities are physically integrated with the transmission system operated by the Midwest ISO, the Big Rivers only financial obligations associated with withdrawal as a member of the Midwest ISO shall be as set forth in Section 1.1 of this Memorandum. Big Rivers shall not be subject to the financial obligations associated with withdrawal under Articles V and VII of the Midwest ISO TOA or the time limits on withdrawal as set forth in Article V of the Midwest ISO TOA, provided, however that withdrawal shall be effective thirty (30) days after the receipt of such notice by the Midwest ISO. In the event Big Rivers elects to take any Midwest ISO tariff service during the period in which it perfects its withdrawal from the Midwest ISO, it shall pay the applicable charges therefore. After the facilities of Big Rivers are integrated with the Transmission System, the financial and withdrawal obligations of Big Rivers shall be as set forth in the Midwest ISO TOA, and not this Paragraph 5.

6. Miscellaneous

6.1 This Memorandum sets forth the basic understanding between the Parties as they undertake certain actions related to the Big Rivers planned membership in the Midwest ISO but the actual terms and conditions of the Big Rivers membership after physical integration of the Big Rivers transmission system will be governed by the Midwest ISO TOA and not this Memorandum. This Memorandum shall not be amended unless such amendment is agreed in writing by duly authorized representatives of the Parties.

6.2. Definitions. All capitalized terms shall be as defined herein. To the extent any capitalized term is not defined herein, it shall have the meaning as set forth in the Midwest ISO Tariff.

6.3 Termination. This Memorandum shall terminate and its provisions shall cease to apply to the Parties at such time as the Big Rivers facilities are physically integrated with the Transmission System operated by the Midwest ISO and, accordingly, the Parties shall have no further obligations to each other hereunder.

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	BIG RIVERS ELECTRIC COOPERATIVE
Name: ______________________	Name: ______________________
Title: ______________________	Title: ______________________
Date: ______________________	Date: ______________________

BIG RIVERS ELECTRIC CORPORATION
REGULAR BOARD OF DIRECTORS MEETING
NOVEMBER 20, 2009

The regular meeting of the Board of Directors of Big Rivers Electric Corporation was called to order at 8 a.m., CST, on Friday, November 20, 2009, at 201 Third Street, Henderson, Kentucky 42420.

Redacted

Redacted

David Crockett provided a reserve sharing update and a review of a Memorandum of Understanding with Midwest ISO. After considerable discussion and upon management's recommendation, Director Elliott moved, seconded by Director Sills, that the following resolution be adopted:

WHEREAS, the Corporation is legally obligated to satisfy the contingency reserve requirements established by the North American Electric Reliability Corporation ("NERC"); and

WHEREAS, management of the Corporation has studied the alternatives available to meet those requirements beginning January 1, 2010, and recommended that the Corporation enter into a memorandum of understanding ("MOU") with the Midwest Independent Transmission System Operator to commence the process for joining MISO and satisfying the NERC contingency reserve requirements.

RESOLVED, that the officers of the Corporation are authorized to negotiate and enter into the MOU on behalf of the Corporation upon the terms that are determined by the President and CEO of the Corporation, in his judgment, to be consistent with the best interests of the Corporation and its members;

FURTHER RESOLVED, that management of the Corporation is authorized and directed to seek such approvals and authorizations as may be required for the Corporation to enter into and perform the MOU, and to seek such expert assistance and expend such funds as may be reasonably required to accomplish those purposes; and

FURTHER RESOLVED, that any officer of the Corporation is authorized to execute on behalf of the Corporation the MOU negotiated with the approval of the President and CEO. The motion was unanimously adopted.

Redacted

NOTICE OF REGULAR MEETING OF THE BOARD OF DIRECTORS
OF
BIG RIVERS ELECTRIC CORPORATION

Take notice that the purpose of this meeting is to discuss and take action upon the matters shown on the following agenda, to-wit:

AGENDA
BIG RIVERS ELECTRIC CORPORATION
REGULAR MEETING OF THE BOARD OF DIRECTORS
DECEMBER 18, 2009
<u>8 A.M., CST</u>

I. [redacted]

II. [redacted]

III. [redacted]

IV. [redacted]

V. [redacted]

VI. [redacted]

VII. [redacted]

VIII. Management's Report:

1. [redacted]
3. Reserve sharing agreement update – Crockett
   - CRA MISO Analysis
4. [redacted]

BIG RIVERS ELECTRIC CORPORATION
REGULAR BOARD OF DIRECTORS MEETING
DECEMBER 18, 2009

The regular meeting of the Board of Directors of Big Rivers Electric Corporation was called to order at 8 a.m., CST, on Friday, December 18, 2009, at 201 Third Street, Henderson, Kentucky 42420.

Redacted

Redacted

Mr. Crockett provided an update on the contingency reserves issue, Big Rivers' efforts with respect to joining MISO and related matters, and a brief summary of the CRA MISO cost analysis.

Redacted

NOTICE OF REGULAR MEETING OF THE BOARD OF DIRECTORS
OF
BIG RIVERS ELECTRIC CORPORATION

Take notice that the purpose of this meeting is to discuss and take action upon the matters shown on the following agenda, to-wit:

AGENDA
BIG RIVERS ELECTRIC CORPORATION
REGULAR MEETING OF THE BOARD OF DIRECTORS
JANUARY 15, 2010
8 A.M., CST

I. [redacted]

II. [redacted]

III. [redacted]

IV. [redacted]

V. [redacted]

VI. [redacted]

VII. [redacted]

VIII. **Management's Report:**
1. [redacted]
2. MISO/reserve sharing agreement update - Crockett
3. [redacted]

BIG RIVERS ELECTRIC CORPORATION
REGULAR BOARD OF DIRECTORS MEETING
JANUARY 15, 2010

The regular meeting of the Board of Directors of Big Rivers Electric Corporation was called to order at 8 a.m., CST, on Friday, January 15, 2010, at 201 Third Street, Henderson, Kentucky 42420.

Redacted

Redacted

The Chair called for management's report. David Crockett updated the board [redacted] on the status of joining MISO and other alternatives to the contingency reserves issue.

Redacted

NOTICE OF REGULAR MEETING OF THE BOARD OF DIRECTORS
OF
BIG RIVERS ELECTRIC CORPORATION

Take notice that the purpose of this meeting is to discuss and take action upon the matters shown on the following agenda, to-wit:

AGENDA
BIG RIVERS ELECTRIC CORPORATION
REGULAR MEETING OF THE BOARD OF DIRECTORS
FEBRUARY 19, 2010
8 A.M., CST

I. [redacted]

II. [redacted]

III. [redacted]

IV. [redacted]

V. [redacted]

VI. [redacted]

VII. [redacted]

VIII. Management's Report:
1. [redacted]
2. MISO/reserve sharing agreement update – Crockett
   a. HMP&L query
3. [redacted]

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy® Cooperative

Board Meeting
February 19, 2010
Management's Report

Item 2 – Contingency Reserve Update

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy® Cooperative

1. KPSC Application Filing – MISO Membership Case No. 2010-00043
   - KIUC Intervention

2. CRA Report – Economic Assessment of Contingency Reserve Options

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy® Cooperative

3. HMP&L Letter/Big Rivers Response
   - Meet with HMP&L

4. SIPC Combustion Turbines/Transmission
   - Determine if SIPC is interested

5. Smelter Interruptible Load
   - No serious discussion on pricing

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy® Cooperative

6. APM Monthly Conference Calls
   - Assistance in MISO Grandfathered Agreement discussion
   - Generation Dispatch Services

7. MISO
   - Contingency Reserve Service
   - Integration

BIG RIVERS ELECTRIC CORPORATION
REGULAR BOARD OF DIRECTORS MEETING
FEBRUARY 19, 2010

The regular meeting of the Board of Directors of Big Rivers Electric Corporation was called to order at 8:50 a.m., CST, on Friday, February 19, 2010, at the Sebree Station, 9000 Hwy. 2096, Robards, Kentucky 42452.

Redacted

Redacted

The Chair called for management's report. David Crockett updated the board [redacted] on the MISO and reserve sharing issue. [redacted]

Redacted

NOTICE OF REGULAR MEETING OF THE BOARD OF DIRECTORS
OF
BIG RIVERS ELECTRIC CORPORATION

Take notice that the purpose of this meeting is to discuss and take action upon the matters shown on the following agenda, to-wit:

AGENDA
BIG RIVERS ELECTRIC CORPORATION
REGULAR MEETING OF THE BOARD OF DIRECTORS
MARCH 19, 2010
<u>8 A.M., CST</u>

I. [redacted]

II. [redacted]

III. [redacted]

IV. [redacted]
1. [redacted]

V. [redacted]

VI. [redacted]

VII. [redacted]

VIII. Management's Report:
1. [redacted]
2. MISO/reserve sharing agreement update (e-mailed) – Crockett
3. [redacted]

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

1. KPSC Application Filing – MISO Membership Case No. 2010-00043
   - MISO Intervention
   - Procedural Schedule Order

2. CRA Report – Economic Assessment of Contingency Reserve Options
   - Draft Comments Submitted
   - Perform Economic Assessment of incremental MISO membership costs (Net $3.6M in 2011)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy® Cooperative

3. MISO

- March 4 meeting – GFA status
- Review of Kenergy contract and smelter contracts (March 23 MISO Mtg)
- Commercial Model Development – MISO Training Delayed
- HMP&L Issues

4. HMP&L Letter/Big Rivers Response

- Met with HMP&L on March 9 – information sharing
- Three options: (1) join MISO; (2) not join – BA & transmission issues; (3) integrate with Big Rivers

5. SIPC Combustion Turbines/Transmission

- SIPC Proposal – capacity and energy pricing
- Capacity Cost - $7.90/kW-month = $7.1M/year for each CT
- Transmission required through MISO

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy® Cooperative

6. Smelter Interruptible Load

- Load magnitude increased to 300 MWs (March 1 meeting)
- Consultant hired to assess MISO membership issues (Matthew Morey – Christensen Associates)
- Suggested LS Power-Bluegrass CTs as source of power

Mark Bailey

From: Mark Bailey

Sent: Wednesday, December 02, 2009 3:31 PM

To: Bill Denton; James Sills; Larry Elder; Lee Bearden; Paul Edd Butler; Wayne Elliott; Burns Mercer; Kelly Nuckols; Sandy Novick

Subject: FW: Call w/ Allan Eyre on MISO

FYI. Yesterday afternoon, the smelters gave us word that they both wanted to work with us in resolving our Reserve Sharing issue. This was good news, but it did not come in time to help us make sure we would have our reserve obligations covered by the first of the year. It will likely take some time to work out an agreement with the smelters and then the agreement will have to be filed with the PSC. The PSC must have it at least 20 days before it can become effective.

The problem is we need to get our MISO admission request before their board by the end of the year. They have to give 10 days notice before having a board call/meeting to act on our request. They have a board meeting tomorrow, but will not be able to act on our admission request then, but they indicated if we gave them notice of our intent by the end of the day today they could at least schedule a board call while their board is all together tomorrow to act on our request later in the month.

If we elect to join MISO and later withdraw before actually joining, we are obligated only to pay the costs they incur up to that point. They estimated today in a call we had with them that their costs would likely be no more than $1.5 million if we withdraw the day before we actually join. Clearly, early on they will not spend that much money on us so we shouldn't be looking at anything near that amount. If we could handle our reserve problem ourselves by backing down our units 400 MW, it would very likely cost us much more than $1.5 million just in lost generation revenue alone. Once we commit to join MISO we can back away after providing a 30 day notice so if we could reach agreement with the smelters relatively soon and file the agreement with the PSC there might be some chance we could back away from MISO by the end of January.

Regards, Mark

Item KIUC 1-6) *Please provide all Documents between Big Rivers and the following entities relating to the possibility of Big Rivers participating with said entities in reserve sharing after December 31, 2009:*

(a) Southeast Power Pool

(b) Tennessee Valley Authority

(c) LGE/KU

(d) VACAR

Response) It is assumed for purposes of this response that the reference to "Southeast Power Pool" in item (a) of the request is intended to refer to the Southwest Power Pool. Documents relating to the possibility of Big Rivers participating with these four entities in reserve sharing after December 31, 2009 are attached.

Witness) David G. Crockett

David Crockett

From: David Crockett

Sent: Wednesday, May 06, 2009 2:16 PM

To: Freibert, Charlie (Charlie.Friebert@eon-us.com); George Carruba

Subject: Reserve Sharing

Charlie & George,
I need to let you know that I have been in touch with Bob Dalrymple of TVA to explore the possibility of Big Rivers participating with TVA, E.ON, and EKPC in the reserve sharing group agreement discussions. Bob has agreed to take my request to others within TVA. I wanted to let you all know of this request and to ask that you please let us know if you have problems or concerns with our participation as far as your companies are concerned. I would further ask you to please let us know if the culmination of your efforts to put together an agreement among the three is imminent. Thank you for your cooperation and consideration in this regard.
Dave Crockett

David Crockett

From: David Crockett
Sent: Wednesday, May 13, 2009 4:12 PM
To: Dalrymple, James R
Subject: RE: Reserve Sharing

Bob,
One other thought on the transmission subject matter. In all the reserve sharing group arrangements that I am aware of (including SPP), the transmission capacity has been designated as part or all of the Transmission Reserve Margin (TRM) for the entities involved. Reserve sharing transactions having a zero ramp rate must have transmission immediately available, I have no idea whether that is important to your folks or not. I look forward to hearing from you on this.
Dave

From: Dalrymple, James R [mailto:jrdalrymple@tva.gov]
Sent: Wednesday, May 13, 2009 3:45 PM
To: David Crockett
Subject: RE: Reserve Sharing

I have asked our folks to let me know the best mechanism for this request.

I will be in touch soon.

Bob

From: David Crockett [mailto:David.Crockett@bigrivers.com]
Sent: Wednesday, May 13, 2009 3:37 PM
To: Dalrymple, James R
Subject: RE: Reserve Sharing

Bob,
VACAR has told us that they are not interested in opening up their reserve sharing group membership to outside companies. So, I need to know what we need to do to begin the assessment of transmission availability and developing options for reserving transmission capabilities for Big Rivers to participate in the SPP Reserve Sharing Group. Big Rivers' largest generating unit is 420 MW. Depending upon the reserves required to be held on the Big Rivers system, the transmission capacity that we would be interested in TVA providing between your Entergy/AECI interfaces and Big Rivers could be on the order of 400 MW.
Dave

From: Dalrymple, James R [mailto:jrdalrymple@tva.gov]
Sent: Wednesday, May 13, 2009 12:34 PM
To: David Crockett
Subject: RE: Reserve Sharing

Dave,

We have discussed options internally and do not believe it is feasible for TVA to provide energy to Big Rivers, /en as part of a reserve sharing group.

Big Rivers and TVA could participate in the same reserve sharing group, but TVA could not provide energy to respond when Big Rivers called on the reserves.

ıs far as transmission deliverability is concerned, we will work with you to assess available transmission and develop options for reserving transmission capabilities Big Rivers may need to participate in other reserve sharing groups.

When you are ready to discuss transmission availability just let us know.

Bob

From: David Crockett [mailto:David.Crockett@bigrivers.com]
Sent: Friday, May 01, 2009 2:50 PM
To: Dalrymple, James R
Subject: Reserve Sharing

Bob,
Just to let you know, I spoke with Carl Monroe of SPP yesterday concerning possible participation in the SPP Reserve Sharing Group. Since the issue of transmission deliverability was recognized as an issue for any of the Kentucky companies currently participating in the Midwest CRSG, Carl commented that he intended to give you a call to discuss that issue and possible solutions. I told Carl that I had already approached you with that matter at least as it related to BREC. So, this is a heads up that you should expect to be contacted by Carl as well.

Do you have any idea at all about the timing of your response or feedback relative to our participation in the possible new reserve sharing group or your support of our involvement in an existing reserve sharing group?

.gain, let me express my appreciation for your assistance in this important reliability compliance matter affecting Big Rivers.

Dave

David Crockett

From: David Crockett

Sent: Saturday, May 23, 2009 12:33 PM

To: Mark Bailey

Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite; Travis Housley

Subject: FW: Contingency Reserves

Mark,
My update for May 22:
1) Stuart Goza of TVA sent ATC values for TVA transmission paths for Entergy to/from Big Rivers and AECI to/from Big Rivers and commented that the numbers didn't look promising. Chris and I had already seen the numbers. They show nothing firm available during the four summer months. There is firm transmission available to some degree every other month except February. Chris has provided me with a very lengthy spreadsheet of all paths to/from Big Rivers as shown on the MISO Oasis site. I have not had time to sort through all the information to see what might be available for us. I intend to get to that as soon as the KPSC ice storm responses are finalized.

All other pursuits are as previously reported.
Dave

From: David Crockett
Sent: Tuesday, May 19, 2009 10:48 AM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite; Travis Housley
Subject: FW: Contingency Reserves

Mark,

My update for May 18:

1) Stuart Goza of TVA contacted me to request that BREC submit a Transmission Service Request (TSR) via the TVA Oasis for the desired transmission capacity. I asked Power Supply to assist me with this task. I have Chris Bradley searching to identify all other reasonable transmission paths between the SPP RSG members and BREC.

2) Carl Monroe of SPP has provided me with some information concerning the application process and timing questions that I raised. I have not fully reviewed it as yet.

3) Charlie Friebert of E.ON contacted me concerning my inquiry into BREC participation in the new reserve sharing group. I will be exploring some ideas with him on how BREC might participate without being able to use TVA reserves.

All other pursuits are as previously reported.

Dave

From: David Crockett
Sent: Thursday, May 14, 2009 10:42 AM

To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite; Travis Housley
Subject: FW: Contingency Reserves

Mark,

My update for May 13:

1) Bob Dalrymple of TVA informed me that TVA felt that it was not feasible for them to provide contingency reserve energy to BREC under a reserve sharing group arrangement. He indicated that they had no problem with BREC being involved in the group, but TVA would not be able to respond to our contingencies. Bob indicated that TVA was ready to explore options for BREC to use TVA transmission capabilities to allow our participation in other reserve sharing groups. I told Bob that participation with the VACAR group was not an option for us. I asked Bob to find out for me the best option for pursuing the transmission assessment to allow reserve sharing energy to flow across TVA to and from the SPP group members (Entergy & AECI) and BREC. I told Bob that we were likely looking at 385 to 400 MWs of transmission capability into BREC and about 30 to 40 MWs out of BREC preferably designated as part of the TVA Transmission Reserve Margin (TRM).

2) I spoke with several of EKPC staff (Jim Lamb, John Twitchell, etc.) and asked whether they would have a problem with BREC involvement in the group even if there was no sharing of reserves from TVA to BREC. Jim said that their only concern was to not "scare" TVA away from the arrangement. I told them that I would be sensitive to that concern, but did not want the door closed on BREC involvement at this time. I told them that we were also exploring participation with the SPP group.

3) I asked Carl Monroe of SPP to provide me with the specific details of the reserve sharing membership process and an estimate of approximately how long the process generally takes. He indicated that our reserves allocation would likely be on the order of 2% of the group total (based on peak system load). The group total reserves generally ranges from 1500 to 1800 MWs and is calculated daily. Therefore, our reserves should be between 30 and 36 MWs. He also indicated that there was a monthly SPP administrative cost for RSG members that would probably run about $2000 to $3000.

All other pursuits are as previously reported.

Dave

From: David Crockett
Sent: Tuesday, May 12, 2009 9:07 AM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite; Travis Housley
Subject: FW: Contingency Reserves

Mark,

My update for May 11:

1) Glen spoke with Tom Abramson (Santee Cooper) who is (I believe) the chair of the VACAR Executive Committee. Tom indicated that the VACAR member companies have no interest in opening up participation in the RSG to outside companies. He stated that the extreme difficulty, time, and expense that would be involved in changing the agreements between the members, their tariffs, etc. in order to affect a change in the reserve sharing terms only is simply not something that the membership has an appetite to undertake.

All other pursuits are as previously reported.

Dave

From: David Crockett

Sent: Friday, May 08, 2009 3:56 PM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite; Travis Housley
ubject: FW: Contingency Reserves

Mark, My update for May 8:

1) Glen spoke with Sam Holeman (Duke Energy) to follow-up on the inquiry about VACAR reserve sharing group participation by BREC. Sam reported that the matter was discussed among members of the Operating Committee of the RSG and they determined that it should be given to the Executive Committee for an official response. Sam said that the hesitance of the Operating Committee to take the matter up was likely because the reserve sharing group has no outside (contract) participants, the agreements among the VACAR member companies date back into the 1950s, and because BREC is not contiguous with the group, there would of necessity be a transmission or deliverability hurdle to get over. Glen advised Sam that we were talking with Bob Dalrymple of TVA on that subject and hoped to get cooperation from them to make participation possible. Sam asked Glen to keep them informed on the TVA transmission pursuit and that he felt that the VACAR Executive Committee would probably not move too quickly on answering our participation question until that matter was resolved.

All other pursuits are as previously reported.

Dave

From: David Crockett
Sent: Wednesday, May 06, 2009 4:59 PM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite; Travis Housley
Subject: FW: Contingency Reserves

ɅIark,
My update for May 6:

1) I asked Bill Blackburn to prepare a cost estimate for MISO membership to wrap up the investigation into MISO related solutions.

2) I received a message from Bob Dalrymple of TVA indicating that he would get back with me next week with some feedback on my questions either concerning the reserve sharing group participation or the transmission access to either VACAR or SPP or both.

3) I sent a message to my E.ON and EKPC contacts whom I believe are involved in the TVA discussions advising them of our conversations with TVA concerning BREC possibly being a part of that RSG and particpating in the discussions to establish that operating agreement. I asked for their feedback on that idea (pro or con) and asked them to keep me apprised of the status of their discussions with TVA.

All other pursuits are as previously reported.
Dave

From: David Crockett
Sent: Monday, May 04, 2009 4:52 PM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite; Travis Housley
Subject: FW: Contingency Reserves

'ark,
.don't have any updates to report on since Friday. All pursuits are as previously reported.

Dave

:rom: David Crockett
Sent: Friday, May 01, 2009 4:35 PM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; David Spainhoward; James Haner; Mark Hite; 'Berry, Bob'; Travis Housley
Subject: FW: Contingency Reserves

Mark,
My update for May 1:

1) Glen and I talked with Carl Monroe, VP and COO at SPP, concerning our participation in their RSG. Carl provided some general information about how the program is administered, how total reserves are calculated and allocated, and various other details including individual agreements among the participating companies, billing processes, etc. Carl indicated that they had talked reserve sharing participation earlier with the other Kentucky companies and with MAPP regional staff inquiring on behalf of the five non-MISO members, all currently in the MCRSG. Carl agreed that the transmission issue across TVA was the only obstacle to overcome and he indicated his intent to talk with Bob Dalrymple of TVA concerning possible coordination between TVA and SPP to provide a solution. I told Carl that I had already asked Bob for assistance on behalf of Big Rivers. Carl also mentioned the possibility of MISO being willing to assist in the solution based on certain provisions of the SPP-MISO Seams Agreement. He admitted that this was probably a stretch as far as the intent of the provisions in that Seams Agreement, but was willing to explore that possibility anyway.

All other pursuits are as noted in the previous updates.

Dave

From: David Crockett
Sent: Wednesday, April 29, 2009 3:47 PM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite; Travis Housley
Subject: FW: Contingency Reserves

Mark,
My written update for April 27 and 29:

1) Glen made contact with Sam Holeman of Duke Energy and related our interest in possible participation in the VACAR reserve sharing group. Sam indicated that membership matters had to go before a particular committee comprised of representatives of the member utilities and that he would be glad to take it up with that group and get back with Glen. He indicated that he would hold off discussing the particular requirements of their reserve sharing program until after the committee acted on our request.

2) Glen and I have completed a review of operating reserves requirements in SPP and specifically the details contained in the on-line documentation about contingency reserves and reserve sharing. We have a conference call with three or four SPP staffers on Thursday morning to talk further with them.

3) Bill Blackburn reported on Monday that Aces Power Marketing had gotten back in touch and indicated that MISO felt Big Rivers had two alternatives. One was to join another reserve sharing group and the other was to join MISO. Bill indicated that Mike Mattox was given a MISO contact person for any further discussion of the matters.

') I have spoken with Bob Dalrymple of TVA on Tuesday and explained our concerns about the termination of the ,idwest CRSG (MISO) at the end of the year. I asked Bob to investigate the possibility of Big Rivers participating in some fashion within the framework of the reserve sharing arrangement being discussed by E.ON, East Kentucky, and TVA. He said that he would take the matter to TVA legal to see if there was some way to structure the group agreement to allow our participation. I told him that we were also exploring participation with the VACAR group and the SPP group. I asked him to separately address the matter of how TVA could assist us in providing transmission deliverability of contingency reserves energy from either their VACAR or their Entergy/AECI (SPP) interfaces to the Big Rivers interface. He said that he would take up that matter as well.

All other pursuits remain as indicated in previous reports.

Dave

From: David Crockett
Sent: Thursday, April 23, 2009 4:47 PM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite; Travis Housley
Subject: FW: Contingency Reserves

Mark,
My end of week update is as follows:

1) Glen attempted to make contact with VACAR representative identified in their website information. He left a message and is awaiting return contact. He will try again on Friday.

2) David Spainhoward completed a review of the KII Pool Agreement and the System Reserves Agreement and SEPA Agreement between HMP&L and BREC. David can find no documentation indicating that the KII Agreement (including its obligations with respect to supply of emergency power and transmission usage for the mutual benefit of all the parties) has been terminated. In fact, there is documentation after year 2000 involving Southern Illinoir Power making reference to that agreement. David believes that the KII Agreement obligations of SIPC and Hoosier Energy (both MISO members) may be helpful in trying to keep MISO cooperative as we seek a solution. David believes the HMP&L agreements make them (financially) responsible for their share of the operating reserves.

3) I have been unsuccessful in talking directly with my TVA contact so far, but will continue with that.

All of the other pursuits are as stated in Tuesday's report. My first report next week will have to be by phone, but I will follow-up on Wednesday by email for the benefit of others on staff.

Dave

From: David Crockett
Sent: Tuesday, April 21, 2009 5:14 PM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite; Travis Housley
Subject: Contingency Reserves

Mark,
Concerning the investigation into the options available to BREC relative to contingency reserves:

1) Bill Blackburn made contact with Aces Power Marketing. Aces contacted MISO concerning possible options for BREC. As noted in the email on this, MISO gave an indication that a solution may be available for us in working with them. Aces is awaiting follow-up information from MISO.

2) I made contact with David Sinclair of E.ON and asked about any planning done for dealing with the

contingency reserves issue in the event that the current lease arrangement is still in effect at the end of 2009. He indicated that no planning had occurred and their assumption was that the Unwind closing would occur first.

) I made contact with Dan Becher of DB Consulting who performs MISO monitoring work for us and four other companies. Dan expressed the opinion that an extension of the sunset date on the current MCRSG agreement wasn't impossible, but was not likely to occur unless MISO was trying to do something for the far western "outsiders" the remaining MAPP region members. He said that MISO has been courting them to entice them to join MISO for quite some time. He said that unfortunately our lot tends to fall with E.ON who is understandably out of favor at MISO. He said that several of the MISO members are convinced that they can meet the NERC standards without outside support and believe that the reserve sharing program is unequally beneficial for the outsider participants who in their opinion aren't paying their way. Dan felt that participation in the MISO ancillary services market would offer a solution to BREC, but it would not be cheap because of MISO's "through and out" firm transmission tariff cost. Dan said that he felt the best option available to BREC was with some other reserve sharing group like one in the SPP region. Dan confirmed that East Kentucky and E.ON were talking with TVA about working together on a reserve sharing arrangement even though he had heard it characterized that TVA wanted an "arm and leg" for their participation.

4) I made contact with John Twitchell and George Carruba of East Kentucky to ask about their discussions with E.ON and TVA. I learned that East Kentucky was exploring the cost of adding equipment to some or all of their combustion turbines to make them "quick start" capable. I learned that the TVA talks were still progressing and that the respective planners were assessing the transmission capabilities (deliverability) needed to make the power exchanges work. No other details of the talks would be shared with me at this time.

5) I called Terry Boston (CEO) of PJM and left a message for him to return my call. I have not heard back from him as yet.

6) Glen Thweatt made contact with Southwest Power Pool (SPP) and expressed our interest in discussing reserve sharing group participation with them. His SPP contact is working on arranging a conference call involving three or four others at SPP next week. He further indicated that they were working with several MAPP members also investigating RSG participation. I assume he was referring to the remaining five MAPP members ı the MCRSG. We are currently beginning review of SPP Operating Reserves Criteria documentation from their website. The SPP Reserve Sharing Group membership already includes some SERC members like Associated Electric Cooperative (Missouri) and Entergy Generation (primarily Louisiana and Arkansas).

7) Glen will also be investigating possible participation in the VACAR reserve sharing group. I believe that all participants in this group are members of the SERC region. They are companies operating in either Virginia or the Carolinas.

8) I will be calling a TVA transmission acquaintance to start a discussion on what TVA may be able to do to assist us as well.

9) David Spainhoward has agreed to investigate the terms of and status of the KII Pool Agreement. This is an old operating agreement with Big Rivers, Southern Illinois Power, Hoosier Energy, and Henderson MP&L as its parties. It has both power interchange and transmission language in it.

These are the actions taken and information gathered so far. I will update you again on Thursday evening or Friday morning.

Dave

David Crockett

From: David Crockett

Sent: Tuesday, June 09, 2009 3:48 PM

To: Bill Blackburn; Bill Yeary

Cc: Al Yockey

Subject: TVA Transmission-ARS

Bill(s),
As part of our pursuit of an alternate reserve sharing group with whom we can participate, I need for you to make some transmission requests of TVA. We need to enter one Transmission Service Request (TSR) on the TVA OASIS site requesting firm (annual) transmission in the amount of 400 MWs from the combined Entergy and AECI interfaces as the points of receipt to the Big Rivers interface as the point of delivery and a second TSR requesting firm (annual) transmission in the amount of 40 MWs from the Big Rivers interface as the point of receipt to the combined Entergy and AECI interfaces as the points of delivery. Each of these requests would be for the year 2010 beginning with the month of January. I would suggest that the TSR identify the transmission need as allowing Big Rivers to participate in the SPP Reserve Sharing Group (RSG) and the transmission service amounts specified in the TSR being the best estimates available at this time. I think that we should further document in the TSR that Big Rivers' participation in the RSG is based upon demonstrating that firm transmission is available to allow the reserve sharing energy to be delivered to existing SPP RSG members from Big Rivers and to Big Rivers from existing RSG members. We can add that this transmission requirement can be met by the usage of TVA's Transmission Reliability Margin (TRM) on these interfaces if such usage is allowed by the terms of the TRM methodology documentation. I would think that this would give TVA enough background information to either consider the request or, at least, to ask additional questions. Let me know if you have any further questions of me in this regard. Otherwise, let me know when you have completed the TSRs on the TVA OASIS sirw. One additional idea, you may want to explore with TVA is whether you could use the "grandfathered" firm transmission (100 MW) to benefit Big Rivers in this regard. Thanks for your assistance.
Dave

David Crockett

From: David Crockett
Sent: Friday, June 12, 2009 3:34 PM
To: Bill Blackburn; Bill Yeary
Cc: Mark Bailey; Al Yockey
Subject: MISO Transmission

Bill(s),
As part of our pursuit of an alternate reserve sharing group with whom we can participate, I need for you to make some transmission requests of MISO in addition to TVA. We need to enter one Transmission Service Request (TSR) on the MISO OASIS site requesting firm (annual) transmission in the amount of 400 MWs from the combined AECI, CSWS (AEPW), EEI, EES (Entergy Energy Services), KCPL (Kansas City Power & Light), MPS (Missouri Public Service Transmission), NPPD (Nebraska Public Power District), OPPD (Omaha Public Power District), SPA (Southwest Power Administration), SPS (Southwestern Public Service Company), WFEC (Western Farmers Electric Cooperative), and WR (Westar Energy Generation) interfaces as the points of receipt to the Big Rivers interface as the point of delivery and a second TSR requesting firm (annual) transmission in the amount of 40 MWs from the Big Rivers interface as the point of receipt to the above combined group of existing SPP Reserve Sharing Group members' interfaces as the points of delivery. Each of these requests would be for the year 2010 beginning with the month of January. I would suggest that the TSR identify the transmission need as allowing Big Rivers to participate in the SPP Reserve Sharing Group (RSG) and the transmission service amounts specified in the TSR being the best estimates available at this time. I think that we should further document in the TSR that Big Rivers' participation in the RSG is based upon demonstrating that firm transmission is available to allow the reserve sharing energy to be delivered to existing SPP RSG members from Big Rivers and to Big Rivers from existing RSG members. We can add that this transmission requirement can be met by the usage of MISO's Transmission Reliability Margin (TRM) on these interfaces if such usage is allowed by the terms of the TRM methodology documentation and consistent with the terms of the Joint Operating Agreement (JOA) between SPP and MISO. I would think that this would give MISO enough background information to either consider the request or, at least, to ask additional questions. Let me know if you have any further questions of me in this regard. Otherwise, let me know when you have completed the TSRs on the MISO OASIS site. Thanks for your assistance.
Dave

David Crockett

From: Carl Monroe [cmonroe@SPP.ORG]
Sent: Wednesday, June 17, 2009 3:01 PM
To: David Crockett
Subject: RE: Reserve Sharing

Yeah.. no prob.. here is what I have....
Carl
[redacted]

From: David Crockett [mailto:David.Crockett@bigrivers.com]
Sent: Wednesday, June 17, 2009 2:15 PM
To: Carl Monroe
Subject: RE: Reserve Sharing

Do you have a phone number and email address for Tom Mallinger? Thanks.
Dave

From: Carl Monroe [mailto:cmonroe@SPP.ORG]
Sent: Wednesday, June 17, 2009 12:56 PM
To: David Crockett
Subject: RE: Reserve Sharing

hat does... we have had discussions with Tom Mallinger of MISO about this before.. Let me know what you find.. .also, about TVA too..
Carl

From: David Crockett [mailto:David.Crockett@bigrivers.com]
Sent: Wednesday, June 17, 2009 11:45 AM
To: Carl Monroe
Subject: RE: Reserve Sharing

Neither TVA nor MISO has firm transmission posted in 2010 in the amounts needed for our reserve sharing participation. TVA has some firm available on a monthly basis, but for five of the twelve months has zero available. MISO allocates all of their available transmission to TRM in every month of the year. And putting a TSR in either of their OASIS sites for annual service would appear to me to result in a study which I'm afraid that I don't have the time to wait for. MISO is already allowing usage of TRM for the MCRSG reserve energy transactions. TVA is working with two other utilities in Kentucky on development of a new reserve sharing group agreement in which they will be setting aside TRM for that purpose as well. Big Rivers is pursuing reserve sharing participation in order to comply with the reliability standards and TRM is allowed to be withheld for reliability purposes. I feel it reasonable to make such a request. I know that they have to be careful that they are following their OATT terms and conditions. I don't know whether I've addressed your question and confusion or not.
Dave

From: Carl Monroe [mailto:cmonroe@SPP.ORG]
Sent: Wednesday, June 17, 2009 10:10 AM
: David Crockett
Subject: RE: Reserve Sharing

I guess I am a little confused.. if you get the transmission through TVA or MISO, is there any reason to be concerned about the TRM?
CArl

From: David Crockett [mailto:David.Crockett@bigrivers.com]
Sent: Monday, June 15, 2009 3:07 PM
To: Carl Monroe
Subject: RE: Reserve Sharing

Sorry for the misunderstanding. Our import transmission needs would be the net of our largest system generating unit minus the Big Rivers contingency reserves. Using your estimate of 2% of the BREC load as a representative number, the range of contingency reserve obligations for us would be from about 25 MWs to 33 MWs. Our largest single unit is net 420 MWs, so the import transmission needed would be between 387 MWs and 395 MWs across TVA or MISO or a combination of the two. I have already posed the question of TRM usage to TVA's Stuart Goza and Bob Dalrymple. Any suggestions with that? Also, do you have a suggestion on a point of contact with MISO?
Dave

From: Carl Monroe [mailto:cmonroe@SPP.ORG]
Sent: Monday, June 15, 2009 2:34 PM
To: David Crockett
Cc: Mark Bailey; Bill Blackburn; David Spainhoward
Subject: RE: Reserve Sharing

Thanks... I was talking about any contact with TVA about their conditions on reserve sharing. Anyway, how much transmission service are you looking for across MISO or TVA?
Carl

From: David Crockett [mailto:David.Crockett@bigrivers.com]
Sent: Monday, June 15, 2009 9:39 AM
To: Carl Monroe
Cc: Mark Bailey; Bill Blackburn; David Spainhoward
Subject: RE: Reserve Sharing

Carl,
Yes, it is time to touch base with MISO. I have asked Big Rivers Power Supply (power marketer) to pursue transmission service across MISO in order to meet our needs for reserve sharing participation in the SPP group. Thank you for providing the link to the JOA document. My reading of the JOA language indicates that the joint commitment to the usage of Transmission Reserve Margin (TRM) was clearly anticipated as result of the operation of the reserve sharing groups within each RTO. MISO has similar commitments to Big Rivers within the existing MCRSG agreement and even though that agreement will expire at year's end, I would think it unconscionable to not extend that provision to Big Rivers as a participant in the SPP RSG. Let me know what your thoughts are about touching base with MISO on this matter.

I don't know how strong our position might be with TVA to allow usage of TRM to flow reserve sharing energy to and from Big Rivers. However, I have also asked Big Rivers Power Supply to pursue transmission service across TVA as well.

Dave

From: Carl Monroe [mailto:cmonroe@SPP.ORG]
Sent: Friday, June 12, 2009 3:14 PM
To: David Crockett

Subject: RE: Reserve Sharing

Let me know if you think it is time to touch base with them.. Here is the link to the JOA we have with MISO.
.ttp://www.spp.org/section.asp?group=409&pageID=27
Carl

From: David Crockett [mailto:David.Crockett@bigrivers.com]
Sent: Friday, June 12, 2009 3:05 PM
To: Carl Monroe
Subject: RE: Reserve Sharing

Carl,
Not as yet.

Incidently, how can I obtain a copy of the SPP-MISO JOA document? I have the MISO-PJM-TVA JRCA document which describes the operating agreements between TVA and the two RTOs individually. Anything you can do to help provide the other documentation would be greatly appreciated.

Dave Crockett

From: Carl Monroe [mailto:cmonroe@SPP.ORG]
Sent: Tuesday, June 02, 2009 2:58 PM
To: David Crockett
Subject: RE: Reserve Sharing

Heard anything from TVA?
Carl

From: David Crockett [mailto:David.Crockett@bigrivers.com]
Sent: Wednesday, May 13, 2009 4:48 PM
To: Carl Monroe
Subject: Reserve Sharing

Carl,
I appreciated you talking recently with us about Big Rivers' interest in participating in the SPP Reserve Sharing Group. One question that I didn't ask was whether any other participant in the RSG is not directly connected to either an SPP member or to a contract member of the RSG? Are we the first to cross that bridge? We have initiated discussions with TVA regarding transmission capability (TRM) to allow us to participate. I will keep you apprised of movement on that front. Otherwise, what exactly is the process for establishing membership in the RSG and what is the approximate timeframe involved in completing the RSG participation requirements (i.e. interchange agreements with other members, SPP administrative functions, etc.)? Does SPP get involved in the development of the interchange agreements? Did I understand you correctly that there is a standard WSPP Agreement document that is generally used for this? Again thank you and I look forward to hearing from you on this.

Dave Crockett
Vice President of System Operations
Big Rivers Electric Corporation
Phone 270-827-2561 ext, 2123
Cell 270-748-4138

David Crockett

From: David Crockett
Sent: Friday, June 26, 2009 3:59 PM
To: Goza, Stuart L
Subject: RE: TVA Transmission Service

Stuart,
I don't think that using EOP-002 provisions under an EEA 3 buys BREC any proof of deliverability and certainly would likely cause a compliance stir in terms of EEAs.

Would TVA consider entering into a bi-lateral agreement to include modeling the effects of generator outages and associated reserve sharing transfers in the determination of "normal" TRM for both parties?

Dave

From: Goza, Stuart L [mailto:slgoza@tva.gov]
Sent: Friday, June 26, 2009 3:22 PM
To: David Crockett
Cc: Dalrymple, James R
Subject: FW: TVA Transmission Service

One option might be to utilize the provisions in NERC Standard EOP-002. The existing NERC Standard EOP-002 states (for EEA Level 3):

3.3 Use of Transmission short-time limits. The Reliability Coordinators shall request the appropriate Transmission Providers within their Reliability Area to utilize available

short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities into the Energy Deficient Entity.

3.4 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator of the Energy Deficient Entity shall evaluate the risks of revising SOLs and IROLs on the

reliability of the overall transmission system. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the

Balancing Authority or Transmission Operator whose equipment would be affected. **The resulting increases in transfer capabilities shall only be made available to the Energy**

Deficient Entity who has requested an Energy Emergency Alert 3 condition. SOLs and IROLs shall only be revised as long as an Alert 3 condition exists or as allowed by the

Balancing Authority or Transmission Operator whose equipment is at risk.

This process in EOP-002 allows for increased transfer capability to be provided directly and only to the entity in EEA 3, so I think we could utilize existing, available TRM to transfer reserve energy if BREC declared an EEA level 3. I don't think we need any special agreement to do this. However, capacity that is setaside for normal TRM in the AFC/ATC process may or may not be there at the time of need – in real time.

If there is not a commitment to setaside TRM for the purpose of transferring reserve sharing energy, then that could be a real issue for proving compliance for deliverability.

Are you suggesting that one option may be for BREC and TVA enter into a bi-lateral agreement to include modeling the effects of generator outages and associated reserve sharing transfers in determination of "normal" TRM, but not setaside that additional TRM specifically for that purpose?

Stuart L. Goza
Manager, Transmission System Services
(423) 697-4191

From: David Crockett [mailto:David.Crockett@bigrivers.com]
Sent: Friday, June 26, 2009 2:54 PM
To: Goza, Stuart L
Cc: Dalrymple, James R
Subject: RE: TVA Transmission Service

Stuart,
Is there a possibility that BREC and TVA could agree on a BA to BA basis to "make transmission capability available for reserve sharing by holding TRM for generation outages in the other's system"? As I stated previously, it would not be my intent that this would involve one party setting aside additional TRM for the other party, but simply to make TRM available for supporting reserve sharing transactions resulting from the other party's generation outages. If the TRM is insufficient to accommodate the full reserve sharing requirement for the path(s) that is/are involved, then TRM would not fully meet the requirements of TOP-002, R7 and additional transmission resources would be needed. At this point, I am not aware of whether TVA has even set aside TRM n the SPP RSG to/from BREC paths. Can you tell me if it has been and what the magnitude is? Thanks.
Dave

From: Goza, Stuart L [mailto:slgoza@tva.gov]
Sent: Tuesday, June 23, 2009 9:15 AM
To: David Crockett
Cc: Dalrymple, James R
Subject: RE: TVA Transmission Service

Dave,

We do value the partnership that TVA and BREC has. My intention of my quick note was not to disappoint, but to provide some feedback as soon as it was available.

You are correct that TVA does not have experience in reserve sharing and utilization of TRM for the purpose of deliverability of reserve sharing – so we are definitely in a learning mode.

TVA aligns its offerings of transmission service in accordance with FERC policy (so long as there is not a conflict with the TVA Act!) I have not been able to find an example of a transmission service provider allowing TRM to be utilized for use in reserve sharing, except in the case of that company being a participant in the reserve sharing group.

In the recent FERC order regarding the Midwest CRSG, FERC stated that the deliverability study submitted by MISO failed. "The submitted deliverability study was intended to demonstrate the requirements of Article 2.1.4 of the Amended CRSG Agreement **as well as NERC reliability standard TOP-002, R7. That NERC reliability standard states that "Each Balancing Authority shall plan to meet capacity and energy reserve**

requirements, including the deliverability/capability for any single Contingency."

For BREC to participate in the SPP reserve sharing group and to be in compliance with NERC Standard TOP-02, R7 – I would expect that BREC would need to demonstate that transmission service across the TVA system was firm. My understanding is that TRM used for delivery of reserve sharing energy is setaside so that it is to always be available. I recently reviewed E.ON's posted TRM methodology and it states that the component of TRM setaside for reserve sharing should not be sold at any time. I don't understand how BREC could count on TRM for deliverability unless it was setaside for that purpose.

I would like to find a way to assist BREC. However, TVA has to be prepared to offer transmission service to all third parties on a non-discriminatory basis. We have to consider your request to allow BREC to utilize TRM in the context of any third party user. This policy type question has to be discussed with TVA's Office of General Counsel. The attorney's response was his initial response and he will investigate further.

However, at the moment, regarding service accross the TVA transmission system, my recommendation is that BREC consider submitting Transmission Service Requests for Annual Firm Transmission Service (and request redispatch be evaluated if TVA cannot accommodate the requested service due to insufficient capability on the TVA transmission system.) It typically takes at least 2 months for a study to be completed.

Thanks,

Stuart L. Goza
Manager, Transmission System Services
(423) 697-4191

From: David Crockett [mailto:David.Crockett@bigrivers.com]
Sent: Monday, June 22, 2009 3:58 PM
To: Goza, Stuart L
Cc: Dalrymple, James R
Subject: RE: TVA Transmission Service

Stuart & Bob,
I'd be lying if I didn't say that I'm disappointed in TVA's response. I know that TVA has not participated in a reserve sharing group situation up to this point in time. I therefore understand that the calculation of TRM and CBM values and the associated methodologies and policies as pertains to reliability for the TVA transmission system has had nothing to do with reserve sharing issues. But, with those matters likely to be the subject of discussion with E.ON and EKPC, I thought that TVA would have cause for revisiting the subject of TRM policy. Reserve sharing group participation is strictly a NERC compliance matter and not a commercial or marketing matter. Big Rivers participates with TVA for a number of RC services in a similar manner (strictly a NERC compliance matter). So, I guess my basic question is whether this initial feedback is a reflection of the TVA TRM policy with regards to how it can be used or whether it is a legal opinion that TRM cannot be used by a third party on either the TVA system or any other for that matter. I suppose that I will leave it with I don't really understand where you are coming from in this situation.
Dave

From: Goza, Stuart L [mailto:slgoza@tva.gov]
Sent: Monday, June 22, 2009 2:05 PM
To: David Crockett
Cc: Dalrymple, James R
Subject: RE: TVA Transmission Service

Initial feedback from an attorney in TVA's Office of General Counsel is that TRM is not available for a third party to utilize to move reserve sharing energy across the TVA transmission system.

Stuart L. Goza
Manager, Transmission System Services
(423) 697-4191

From: Goza, Stuart L
Sent: Wednesday, June 17, 2009 3:39 PM
To: 'David Crockett'
Cc: Dalrymple, James R
Subject: RE: TVA Transmission Service

TVA does not currently offer this service.

I am discussing internally, and will let you know as soon as possible.

If you are aware of any Transmission Service Provider that does provide this service (where the Transmission Service Provider does not participate in the reserve sharing group) please let me know.

Another transmission path for BREC to consider is across MISO to SPP. I do not know if MISO offers for a third party to utilize TRM.

Stuart L. Goza
Manager, Transmission System Services
(423) 697-4191

From: David Crockett [mailto:David.Crockett@bigrivers.com]
Sent: Wednesday, June 17, 2009 3:02 PM
To: Goza, Stuart L
Cc: Dalrymple, James R
Subject: FW: TVA Transmission Service

Stuart,
Is TVA willing to allow its TRM capability to be used to accommodate reserve sharing energy flows to and from Big Rivers?
Dave

From: David Crockett
Sent: Monday, June 15, 2009 5:10 PM
To: 'Goza, Stuart L'
Cc: Dalrymple, James R (Bob)
Subject: RE: TVA Transmission Service

Stuart,
I would not expect TVA to set aside TRM for the sole benefit of Big Rivers. What I was asking was whether usage of TRM (already set aside by TVA for operating uncertainties and reliability purposes) could be used to support reserve sharing transactions which are very short term needs and certainly I would think fall into the category of supporting overall reliability. This is not a request for transmission service to make a profit (power marketing). This is a transmission need to accommodate compliance with reliability standards and TVA as the owner and provider of the transmission would benefit in the process. The transmission service would be provided under the provisions of your OATT and billed at the published rates. Reserve sharing transmission must be billed to the customer on the basis of such usage in order for it to be non-discriminatory.

Dave

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rom: Goza, Stuart L [mailto:slgoza@tva.gov]
Sent: Monday, June 15, 2009 3:10 PM
To: David Crockett
Cc: Dalrymple, James R; Bill Blackburn; Bill Yeary
Subject: RE: TVA Transmission Service

Dave,

The OASIS posting information was for monthly firm. Long Term Firm Point-to-Point Transmission Service may be more appropriate. With this type service, BREC could request that TVA evaluate redispatch if TVA cannot accommodate the requested service due to insufficient capability on the TVA transmission system. Redispatch is not an option for monthly firm service.

I am not aware of any Transmission Service Providers allowing use of TRM for reserve sharing purposes where the owner(s) of the transmission system are not participating in the reserve sharing group. If you know of some examples of this, please let me know. I would expect that there has to be some benefit provided to the transmission owner to offset the cost of setting aside transmission capability as TRM.

Thanks!

Stuart L. Goza
Manager, Transmission System Services
(423) 697-4191

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rom: David Crockett [mailto:David.Crockett@bigrivers.com]
Sent: Monday, June 15, 2009 3:18 PM
To: Goza, Stuart L
Cc: Dalrymple, James R; Bill Blackburn; Bill Yeary
Subject: RE: TVA Transmission Service

Stuart,
I have reviewed your OASIS postings which you provided to me under a separate email and clearly see that no firm transmission is available during five of the twelve months of the year on the paths which would be required to transmit reserve sharing energy to and from Big Rivers. In light of this fact, I need to know if TVA is willing to allow the reserve sharing energy to flow on the basis of the Transmission Reserve Margin (TRM) capability that is set aside for reliability purposes? I would assume that the usage of TRM is the only way that TVA can work with E.ON and EKPC in that reserve sharing arrangement so I don't think that we're breaking new ground with this idea. That appears to me to be the only way that reserve sharing participation with the SPP group can work for Big Rivers using the TVA transmission system. Any suggestions?
Dave

From: Goza, Stuart L [mailto:slgoza@tva.gov]
Sent: Friday, May 15, 2009 10:06 AM
To: David Crockett
Cc: Dalrymple, James R; Dalloul, Martha L; Gardner, John R
Subject: TVA Transmission Service

Bob and I have discussed the potential need for BREC to obtain transmission service across the TVA ansmission system to AECI and/or Entergy to participate in the SPP Reserve Sharing Group.

It will be necessary for BREC to submit Transmission Service Request(s) on the TVA OASIS for the needed service. The TSRs would be processed in accordance with the TVA Transmission Service Guidelines.

BREC needs any assistance in submitting the TSRs, please let me know.

Thanks!

Stuart L. Goza
Manager, Transmission System Services
(423) 697-4191

David Crockett

From: David Crockett
Sent: Friday, July 10, 2009 3:31 PM
To: Tom Mallinger
Subject: RE: MISO Transmission

Mr.. Mallinger,

You indicated in the email response below that there is no provision to hold TRM for BREC to participate in the SPP reserve sharing group. BREC uses the TVA RC and participates with TVA among others in the MISO-PJM-TVA Joint Reliability Coordination Agreement. Do the flowgate coordination principles set forth in that agreement between the TVA RC parties and the MISO RC parties coupled with the MISO-SPP JOA terms open any doors to the possibility of MISO holding TRM for a BREC SPP RSG participation? What do you think of the idea of MISO and BREC discussing the possibility of a seams agreement which identifies some sort of reciprocal arrangement to honor each other's generating unit outages?

David Crockett

From: Tom Mallinger [mailto:TMallinger@midwestiso.org]
Sent: Friday, July 10, 2009 2:43 PM
To: David Crockett
Subject: RE: MISO Transmission

Mr. Crockett,

he Midwest ISO TRM currently includes transmission capacity being held back for Midwest Reserve Sharing events as well as any TRM that has been coordinated with other parties where seams agreements provide for such coordination. When the Midwest Reserve Sharing Agreement ends, the Midwest ISO TRM will be adjusted to only include Midwest ISO managing loss of internal units and any remaining TRM amounts that have been coordinated with other seams parties. There is no provision to hold TRM for BREC participating in the SPP reserve sharing group. Because TRM is not being held for BREC, we cannot use that TRM in real-time to provide transmission capacity to BREC that is then billed to BREC on an after-the-fact basis.

BREC has the ability to reserve either firm or non-firm transmission service from Midwest ISO to accommodate participation in the SPP reserve sharing group. Although you found zero ATC posted on the Midwest ISO OASIS on several paths between BREC and SPP, Midwest ISO does follow the on-the-path rules when reviewing requests for transmission service. To the extent the zero ATCs are due to transmission limits in either BREC or SPP, these limits will be ignored when Midwest ISO evaluates the transmission service request. The best way to determine whether firm or non-firm transmission service is available on the path between BREC and SPP is to submit a request and have it evaluated by the Midwest ISO.

Thanks.

Tom Mallinger

From: David Crockett [mailto:David.Crockett@bigrivers.com]
Sent: Monday, June 29, 2009 11:43 AM
To: Tom Mallinger
Subject: RE: MISO Transmission

ince TRM is currently used as the transmission service capacity for deliveries of reserve power to and from Big Rivers during MCRSG transactions, will MISO allow the usage of TRM capacity currently set-aside on the various

SPP to BREC paths in a similar arragement and then bill for that transmission service per MISO's OATT on a usage basis? According to your OASIS postings, all ATC on these paths are currently designated as TRM. Since reserve sharing participation is a means to provide for compliance with the NERC DCS requirement, I ould hope that MISO would look favorably on this request.
ave Crockett

From: Tom Mallinger [mailto:TMallinger@midwestiso.org]
Sent: Tuesday, June 23, 2009 2:49 PM
To: David Crockett
Subject: RE: MISO Transmission

Mr Crockett:

I received your e-mail on BREC's planned participation in the SPP Reserve Sharing Group (SPP RSG) and your question whether Midwest ISO TRM could be used as a substitute for arranging transmission service between BREC and SPP RSG members. I received a similar request from SPP involving a different entity and will provide you the same answer that I provided SPP on May 1, 2009. There are two issues associated with the use of TRM for reserve sharing, one having to do with arranging a transmission service path and the other having to do with which entities are eligible for the TRM coordination that appears in the MISO-SPP JOA.

First, the TRM coordination that appears in the MISO-SPP JOA was never envisioned to be a substitute for arranging a transmission service path. What it recognizes is that where these paths exist and parties participate in reserve sharing groups, some of these flows will appear on Midwest ISO flowgates and some will appear on SPP flowgates. The TRM coordination recognizes that these flows will occur in real-time and transmission capacity must be held back for these flows. This TRM coordination was never intended to be a substitute for transmission service. It assumes transmission service already exists and addresses the flow that will occur as a result of the transmission service.

Second, the coordination of TRM as described in the MISO-SPP JOA is applicable to those parties for whom SPP as RTO obligations (where SPP administers transmission service and serves as the RC) and not for an entity nat has contracted to take reserve sharing service from SPP. In the case of BREC, it is my understanding that this would be a contract with SPP to take reserve sharing services and not to participate in the SPP market and to take RC services from SPP.

Based on these two issues, the TRM coordination section of the MISO-SPP JOA would not be applicable as a substitute for arranging a transmission service path between BREC and SPP RSG members for BREC's participation in the SPP RSG. If you have questions on this response, you can contact me by phone (317-249-5421) or via e-mail (tmallinger@midwestiso.org).

Thanks.

Tom Mallinger
Midwest ISO

From: David Crockett [mailto:David.Crockett@bigrivers.com]
Sent: Wednesday, June 17, 2009 4:56 PM
To: Tom Mallinger
Subject: MISO Transmission

Tom,
I am pursuing on behalf of Big Rivers Electric Corporation the transmission service needed to prove the deliverability of reserve sharing energy by and between Big Rivers and existing SPP Reserve Sharing Group SG) members. Midwest ISO (MISO) members have numerous interfaces with those existing SPP RSG ompanies and several interfaces with Big Rivers. Big Rivers currently participates in the Midwest Contingency

Reserve Sharing Group (MCRSG) and MISO provides transmission service for those group transactions through the use of TRM. It is my understanding that MISO and SPP have a joint operating agreement in which there is a provision that both MISO and SPP would use TRM to support reserve sharing power flows (generator outages). I ould like to know if MISO will allow the continued use of TRM to support the SPP reserve sharing power flows to and from Big Rivers. Big Rivers would estimate the BREC to SPP transmission requirement to be around 35 MWs and the SPP to BREC requirement to be approximately 390 MWs. I have been communicating with Carl Monroe at SPP and invite you to discuss the matter with him if needed. I am anxious to move forward with the process at SPP and await your response.

Dave Crockett
Vice President of System Operations

David Crockett

From: David Crockett

Sent: Friday, July 17, 2009 1:47 PM

To: Mark Bailey

Cc: Al Yockey; Bill Blackburn; Bob Berry ; David Spainhoward; James Haner; Jennifer Keach; Mark Hite

Subject: FW: Reserve Sharing

Mark,
My update for July 14 and 17:

1) I have not received a response from MISO to my last email and the questions about other arrangements to make TRM available for the SPP RSG participation.

2) I await the July 23 teleconference to get feedback from the new RSG members (E.ON, EKPC, and TVA).

3) Dan Becker (consultant for BREC and others monitoring MISO activities) asked about our efforts to join the SPP RSG. When I explained the transmission difficulties that we had encountered, he offered a piece of advice that he admitted a year ago he would not have given. He indicated that with the startup of the ancillary market that MISO members were greatly benefiting from the single balancing area (BA) operation with very low regulating reserves for the entire BA (he quoted 400 MWs as the total for the entire MISO area) and very low contingency reserves currently under the MCRSG operating agreement and expected to remain low after the MCRSG terminates. Therefore, his advice was to give consideration to the cost versus benefit of being in the MISO. He went on to say that the biggest contention in MISO is the transmission expansion cost allocation subject matter especially with the transmission needed for the wind power resources being planned.

Dave

From: David Crockett
Sent: Friday, July 10, 2009 4:15 PM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite
Subject: FW: Reserve Sharing

Mark,
My update for July 3-10:

1) MISO indicated that there is no provision for them to hold TRM for BREC usage to participate in the SPP RSG. I have followed up with some questions about ways that such a provision could be arranged between us other than through the OATT firm transmission reservation route. I await the response, but hold no great hope for that to be successful.

2) TVA indicated that they were reviewing their policy of TRM usage by third parties and was considering the possibility of usage by Energy Deficient systems under an EEA Level 2 or 3 declaration. I don't see that this helps us at all. I will continue to monitor.

3) TVA sent an email to E.ON and EKPC concerning our interest in joining the new reserve sharing group and the specifics of our needs. TVA indicated that the three have agreed to discuss this during a July 23 teleconference call and then get back to me with any questions, concerns, or issues.

4) Bill, Al and I met to discuss the issues and possibilities for BREC to meet the 138 MW contingency reserve obligation if we were to join the new RSG. The subject was also discussed with the smelters at the KPSC on July

Dave

From: David Crockett
Sent: Tuesday, June 30, 2009 5:00 PM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite
Subject: FW: Reserve Sharing

Mark,
My update for Tuesday, June 30:

1) My attempts to persuade TVA and MISO to approve the use of TRM capacity for SPP-BREC reserve sharing power transfers thus far have not been successful. At this point, it's my opinion that the only realistic alternative that we have to participate in the SPP RSG is with firm point-to-point transmission across TVA or MISO or a combination of the two. MISO's transmission service is about 20% more expensive than TVA's, but neither is inexpensive. Using the MISO rates (worst case scenario), I calculate the annual cost of transmission to be on the order of $12 million. This would afford us yearly firm transmission from the SPP market to BREC for replacement power purchases. I don't know if that represents a benefit in terms of power marketing for Bill Blackburn and APM or not. The firm transmission is not fully available on the OASIS postings of either MISO or TVA. If we pursue either of these options further, we will have to make a transmission service request and let them perform a study to determine how to provide the service. There would be a cost and probably 60 days time associated with these studies.

2) I have asked Stuart Goza of TVA to pursue the possibility of BREC participation in the E.ON, EKPC, and TVA reserve sharing group discussions. TVA will discuss with them our desire to have them respond up to their full quantity of reserves for BREC unit outages because of the lack of response by TVA. I have asked for assistance from Bill, Bob, and Al to explore options of how to provide the additional 90 MWs of contingency reserves required to cover the Wilson unit outage scenario.

Dave

From: David Crockett
Sent: Friday, June 26, 2009 4:27 PM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite
Subject: FW: Reserve Sharing

Mark,
My update for Friday, June 19:

No updates from either TVA or MISO yet. As reported to the board, I asked Power Supply to wait on making a transmission service request to TVA and MISO because of the TRM usage requests.

My update for Tuesday, June 23:

1) Stuart Goza of TVA responded to my request indicating that the initial feedback from an attorney in TVA's Office of General Counsel was that TRM could <u>not</u> be used by a third party for reserve sharing participation. I responded with additional comments about promoting grid reliability and asked whether the legal feedback was a TVA policy statement or an OATT/FERC legal statement. Awaiting further response.

' Tom Mallinger of MISO responded to my request indicating that the TRM coordination between MISO and SPP as not intended to create a path for flows to occur, but simply was an acknowledgement that the reserve sharing flows would have impacts on both systems and that SPP and MISO would set aside capacity (TRM) to allow the reserve sharing flows to occur in real-time. He further indicated that this same question had been raised by SPP on behalf of another entity and he had given this same response.

.My update for Friday, June 26:

1) Stuart Goza of TVA offered some information about the TVA-EKPC-E.ON reserve sharing group. He indicated that with BREC as a fourth party in the group and assuming the total reserves in the pool cover the largest unit of the group (1270 MW) and assuming the reserve requirements are allocated on a load ratio share basis, the individual contingency reserves would be:

TVA - 939 MW
EKPC - 89 MW
E.ON - 193 MW
BREC - 48 MW

With these numbers, the Wilson unit outage (assumed to be 420 MW) would not be able to be covered with BREC, E.ON, and EKPC reserves only (short by about 90 MWs by my count). That might get us in the ball park though. The challenge would then be to either arrange a separate purchase of 10 minute reserve power from some supplier or to have either quick start generation (combustion turbine) or 10 minute interruptible load contract (s) with existing industrial customer in order to meet the DCS requirement with this smaller RSG. The benefit would be that there is no third party transmission system to cross to allow us to participate in the RSG. This is the first information that I have been able to get about the RSG plans being considered by the other three.

Dave

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rom: David Crockett
Sent: Thursday, June 18, 2009 10:56 AM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite
Subject: FW: Reserve Sharing

Mark,
My update for Tuesday, June 16:

1) I have asked TVA (Stuart Goza and Bob Dalrymple) to give me a definitive answer as to whether TVA will allow reserve sharing power flows across TVA using their TRM capacity. They are reviewing the request at this time.

2) I have been advised by Carl Monroe of SPP that use of the TRM capacity for reserve sharing has been the subject of discussions between the two organizations. After this conversation, I have asked MISO (Tom Mallinger) to give me a definitive answer as to whether MISO will allow reserve sharing power flows across MISO using their TRM capacity. I am awaiting a response from MISO as well.

3) I have asked Power Supply to consider the need for firm transmission to provide for a reliable supply of replacement power during generating unit outages (planned or forced). Firm transmission is the key element to our participation in the SPP reserve sharing.

All other pursuits have not changed since the last reporting.

Dave

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om: David Crockett

Sent: Monday, June 15, 2009 8:05 AM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite
Subject: FW: Reserve Sharing

Mark,
My update for Friday, June 12:

1) I have asked Power Supply to pursue transmission service across MISO as a second possibility to demonstrate that the reserve sharing energy can flow as needed. Again, I have asked that the request identify the possible usage of MISO's Transmission Reserve Margin (TRM) capacity at those interfaces. In this case, we will make reference to a provision in the MISO and SPP Joint Operating Agreement committing each to allow usage of TRM to provide for reserve sharing flows. Even though BREC is not currently a party to that agreement, we will strongly push for MISO to honor that provision of the agreement in light of the fact that BREC will be joining the SPP Reserve Sharing Group and secondly because MISO is currently allowing us access to their TRM under the MCRSG agreement. MISO's OASIS postings are consistent with that approach in that they currently post no firm or non-firm transmission available in 2010 on any BREC paths through the MISO system. They post only TRM capacity available.

All other pursuits have not changed since the last reporting.

Dave

From: David Crockett
Sent: Tuesday, June 09, 2009 4:24 PM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; James Haner; Mark Hite
Subject: Reserve Sharing

Mark,
My update as of Tuesday, June 9:

1) I have asked Power Supply to pursue transmission service across TVA to demonstrate that the reserve sharing energy can flow when needed by either BREC or the existing SPP Reserve Sharing Group members. I have asked that the request identify both the possible usage of TVA's Transmission Reserve Margin (TRM) capacity at each interface and the possible usage of the "grandfathered" firm transmission (100 MW) for TVA to consider. I have asked my staff to get a copy of the TVA TRM methodology or policy document.

2) I have asked my staff to get a copy of the MISO and SPP "seams" agreement. I have been told that the agreement includes language which provides for usage of each RTOs TRM capacities to allow reserve sharing energy to flow. This may offer an opportunity for Big Rivers to use MISO TRM capacity to deliver and receive SPP RSG energy. I am also reviewing the MISO TRM Policy document. I am also reviewing the MISO Available Transfer Capability (ATC) values posted for each month in 2010 for paths between existing SPP RSG members and BREC.

All other pursuits have not changed since the last reporting.

Dave

David Crockett

From: David Crockett
Sent: Friday, July 24, 2009 10:04 AM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; 'Berry, Bob'; David Spainhoward; Jennifer Keach ; Mark Hite
Subject: FW: BREC - Reserve Sharing

Mark,
I received this response to my follow-up inquiry about our participation in the new RSG. I am concerned about the recommendation in the third sentence. That doesn't sound encouraging at all.
Dave

From: Goza, Stuart L [mailto:slgoza@tva.gov]
Sent: Friday, July 24, 2009 9:44 AM
To: David Crockett
Cc: Dalrymple, James R; Morris, Keith W
Subject: RE: BREC - Reserve Sharing

A telecon was held on 7/23. TVA, E.ON, and EKPC did discuss issues regarding an additional party potentially joining the TVA/E.ON/EKPC Reserve Sharing Group.

Another telecon is scheduled for 7/29 for further discussion of the issues.

recommend BREC to continue to investigate other options.

I will provide you an update after the 7/29 telecon.

Stuart L. Goza
Manager, Transmission System Services
(423) 697-4191

From: David Crockett [mailto:David.Crockett@bigrivers.com]
Sent: Friday, July 24, 2009 10:25 AM
To: Goza, Stuart L
Cc: Dalrymple, James R; Morris, Keith W
Subject: RE: BREC - Reserve Sharing

Stuart,
Can you give me an update on this matter?
Dave

From: Goza, Stuart L [mailto:slgoza@tva.gov]
Sent: Friday, July 10, 2009 9:57 AM
To: David Crockett
Cc: Dalrymple, James R; Morris, Keith W
Subject: BREC - Reserve Sharing

ON, EKPC, and TVA are now scheduled to have a telecon on 7/23 to discuss issues concerning another party ining the proposed TVA/E.ON/EKPC Reserve Sharing Group.

E.ON and EKPC have expressed to me that they are willing to consider BREC joining the group, but they have questions.

I expect that after the 7/23 discussion that I will be able to provide you with a list of any issues/concerns that the group has, then we can work together to attempt to resolve.

I will keep you informed.

Thanks!

Stuart L. Goza
Manager, Transmission System Services
(423) 697-4191

From: Goza, Stuart L
Sent: Thursday, July 09, 2009 9:40 AM
To: 'David Crockett'
Subject: FW: BREC - Reserve Sharing

FYI -- I sent the email below on 7/1. I expect to know both companies position by Monday, 7/13. I will let you know as soon as possible.

Stuart L. Goza
Manager, Transmission System Services
(423) 697-4191

From: Goza, Stuart L [mailto:slgoza@tva.gov]
Sent: Wednesday, July 01, 2009 11:15 AM
To: George Carruba; Freibert, Charlie; Yocum, Keith
Cc: Morris, Keith W
Subject: BREC - Reserve Sharing

BREC is interested in potentially participating in the TVA, E.ON, EKPC reserve sharing group.

Based on load-ratio allocation to cover the loss of the largest unit (1270 MW) in the pool, the contingency reserve requirements would be:

TVA - 939 MW
EKPC - 89 MW
E.ON - 193 MW
BREC - 48 MW

For loss of the Wilson unit (using 420 MW cap) the allocations would be:

BREC utilizing its on contingency reserves of 48 MW
TVA 286 MW
EKPC - 27 MW
E.ON - 59 MW

As you know, TVA is prohibited by federal law in providing energy to BREC.

However, if TVA, E.ON and EKPC agreed, BREC could still participate in the reserve sharing group --> with the restriction that TVA cannot provide energy to BREC.

E.ON and EKPC reserves should be available from a generation standpoint, but E.ON and EKPC would have to agree to setaside TRM for the full amount to go to BREC rather than just the load-ratio allocation.

E.ON would have to setaside an additional 196 MW of TRM for delivery to BREC (addtional 62 MW to transfer from EKPC + additional 134 MW from E.ON).

If so, then BREC would have to carry an additional 90 MW for a total of 138 MW of reserves.

Would E.ON and EKPC agree to setaside TRM for their full amount of their reserves and make them available for use by BREC?

Stuart L. Goza
Manager, Transmission System Services
(423) 697-4191

David Crockett

From: David Crockett

Sent: Friday, July 31, 2009 2:37 PM

To: Goza, Stuart L

Subject: RE: BREC - Reserve Sharing

Stuart,
In these discussions, were the reserve allocation numbers based upon the load ratio share formula that you calculated and provided to me earlier shared with E.ON and EKPC? Obviously, Big Rivers would be required to carry additional reserves on top of the load ratio share allocation value to make it work for the loss of our largest unit since TVA's obligation to BREC would be zero. Was that a point of discussion among you? I will be preparing a proposal that addresses the issues stated here as soon as possible and forwarding that on to you. Should I share that with a representative of E.ON and EKPC or let you do that? If I am to do it, let me know the contact person if it is other than Charlie Friebert and George Carruba. Thanks.
Dave

From: Goza, Stuart L [mailto:slgoza@tva.gov]
Sent: Thursday, July 30, 2009 5:03 PM
To: David Crockett
Cc: Dalrymple, James R; Morris, Keith W; Freibert, Charlie; George Carruba
Subject: BREC - Reserve Sharing

Dave,

TVA, E.ON and EKPC did have a telecon on 7/29 in which issues regarding an additional party potentially joining the TVA/E.ON/EKPC Reserve Sharing Group (TEE RSG) were discussed.

TVA's position is that TVA is prohibited by Federal law in making off-system sales to BREC which makes it very difficult to structure an arrangement for BREC (or any other party in which TVA cannot sell to) to participate in the TEE RSG.

While the MW allocation could be structured in different ways, the end result would be a separate sub-group within TEE RSG to provide reserves to BREC or perhaps a completely separate RSG (without TVA.)

One issue raised was that this sub-group may not be able to count TVA's largest unit for DCS threshold determination (since TVA cannot participate with BREC). In this situation, then the loss of BREC's Wilson unit would be a DCS event, which would increase compliance risks with NERC Standards for the sub-group. Due to the size of TVA's largest unit, none of the E.ON or EKPC generators exceed the DCS threshold for the existing TEE RSG.

There are numerous legal, regulatory, and technical issues that would have to be resolved, such as:

What rate would E.ON and BREC use for the reserve energy transactions? Would EKPC and E.ON be able to transact with BREC and TVA at the same time, considering TVA's restrictions? Is there sufficient transmission capacity to make sales from the group through E.ON to BREC, and vice versa? Other questions and issues will undoubtedly arise if this is explored in detail.

Given the imminent sunset of the Midwest CRSG, we will continue to move forward with plans for the proposed TEE RSG arrangement and the currently proposed membership. While we're moving forward with those plans, please feel free to send a proposal that addresses at least the major issues. Due to the number of issues involved, however, we hope that you will continue to look at other possibilities as well.

Thanks,

Stuart L. Goza
Manager, Transmission System Services
(423) 697-4191

David Crockett

From: Carl Monroe [cmonroe@SPP.ORG]

Sent: Thursday, August 20, 2009 3:49 PM

To: David Crockett

Subject: RE: SPP Reserve Sharing Group

They floated the idea and only had a question about how firm the 100mw path was and also whether it would be scheduled... maybe time for a discussion on the phone?
Carl

From: David Crockett [mailto:David.Crockett@bigrivers.com]
Sent: Wednesday, August 12, 2009 3:57 PM
To: Carl Monroe
Subject: RE: SPP Reserve Sharing Group

Carl,
When can you float that idea by your RSG membership to confirm whether it will work or not?
Dave

From: Carl Monroe [mailto:cmonroe@SPP.ORG]
Sent: Wednesday, August 12, 2009 2:35 PM
To: David Crockett
Subject: RE: SPP Reserve Sharing Group

Ve think that we could sell that to the members ....
Carl

From: David Crockett [mailto:David.Crockett@bigrivers.com]
Sent: Tuesday, August 11, 2009 4:47 PM
To: Carl Monroe
Subject: SPP Reserve Sharing Group

Carl,
Would it be possible for Big Rivers to participate in the SPP RSG with the sharing of reserves structured such that the SPP RSG would provide up to 100 MWs of reserves to respond to the loss of Big Rivers' largest unit (420 MW) with Big Rivers responsible for the remaining 320 MW? Big Rivers' reserve requirement would be made up of a Load Ratio Share component which would be used to respond to requests by others within the RSG and an additional supplemental reserve requirement making up the difference between that number and 320 MW. Presumably, Big Rivers' units would not be large enough to be NERC reportable disturbances so the group would not be exposed to any additional risk of non-compliance. Big Rivers has 100 MW of firm transmission across TVA which we believe can be utilized to deliver that level of reserves to the Big Rivers border or to the SPP RSG border. I thought I should ask the question first before spending any time and energy on the idea. Thanks for your time.
Dave Crockett

David Crockett

From: David Crockett
Sent: Friday, August 28, 2009 4:29 PM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; Bob Berry ; James Haner; Jennifer Keach; Mark Hite
Subject: FW: Reserve Sharing

My update for August 28 is as follows:

1) SPP RSG members were receptive to our participation at the 100 MW level. A teleconference was held with SPP staff to answer their questions regarding the TVA transmission service that we have and intend to use to implement RSG participation. We also discussed the reserve obligation that BREC would have to the other RSG members. SPP staff indicated that our contingency reserve obligation would be 5 MWs or so assuming the 100 MW limited obligation of the existing RSG members to supply to us for our load. We will have to acquire TVA firm transmission of about 5 MWs to meet that supply obligation. SPP indicated that we could participate as either an SPP member (which we don't want to do) or as a contract participant. SPP forwarded two existing contracts (AECI and SMEPA) with non-RTO members. Bill, Al, and I have these documents for review and usage in preparation of our participation contract agreement should we choose to go that route.

2) E.ON wrote a response to our RSG participation proposal with that new group. Basically, E.ON emphasized the exact same concerns as had been provided by TVA. Since the major concerns as I read them center on NERC/FERC reaction to the arrangements that I proposed, I have asked Chris to pose the questions of RSG structure and arrangements to SERC Compliance staff to see if there is any substance to E.ON's concerns.

3) As you are aware, E.ON may not have the same impression about providing reserve sharing services to OMU as had been indicated by OMU in our meeting with them.

4) E.ON filed a petition with FERC to challenge the reserve re-allocation formula used by MISO when the Nebraska companies exited the RSG in April and challenged the termination of the RSG on December 31 of this year asking that it not be terminated until all parties have suitable alternate arrangements to maintain reliability. MISO sent a termination concurrence form for us to sign which we will not execute. We will indicate our lack of approval of the termination and agreement with E.ON in this matter.

Dave

From: David Crockett
Sent: Friday, August 14, 2009 9:07 AM
To: Mark Bailey
Cc: Al Yockey; Bill Blackburn; Bob Berry ; James Haner; Jennifer Keach; Mark Hite
Subject: Reserve Sharing

Mark,
My update for August 14 is as follows:

1) SPP will discuss with their RSG members our possible participation with BREC supplying reserves equal to its Load Ratio Share to the group (estimated at 35 MWs) and the existing RSG members supplying 100 MWs to BREC for our contingencies. This would require that we have 320 MWs of total contingency reserves including the 35 MWs above in order to recover from a Wilson unit outage. The SPP RSG will take this matter up on August 19-20 during a regular meeting.

2) TVA-E.ON-EKPC have agreed to consider our proposal of participation in the new RSG with arrangements ructured to honor TVA's legal opinion that it cannot respond to our contingencies. I made the proposal and explained why I thought the arrangement would work and not have a negative effect in terms of FERC, NERC, or

SERC acceptance of the RSG. This arrangement would have BREC supplying reserves to the group (estimated at 48 MWs) and the RSG supplying 282 MWs to us. This would require that we have 90 additional MWs of contingency reserves for a total of 138 MWs in order to recover from a Wilson unit outage. They have agreed to onsider our proposal in an August 19 teleconference.

3) We met with OMU yesterday on their Transmission Operator function and registration issue. During the discussion, I asked if OMU had considered how they were going to meet control performance standards and disturbance control standards after May 2010. OMU indicated that this would be covered by E.ON in the Balancing Authority functional services.

Dave

David Crockett

From: Carl Monroe [cmonroe@SPP.ORG]
Sent: Friday, September 11, 2009 8:14 AM
To: David Crockett
Subject: RE: Reserve Sharing
Attachments: WSPP_current_effective_agreement_050609.doc

Our current estimates for admin costs are:

- $7K for initial setup
- $2-3K per month

I have also attached the most current WSPP agreement.
Carl

From: David Crockett [mailto:David.Crockett@bigrivers.com]
Sent: Wednesday, September 09, 2009 3:43 PM
To: Carl Monroe
Subject: FW: Reserve Sharing

Carl,
I was wondering if you were pursuing responses to questions below? One additional matter that surfaced was the usage of the Western Systems Power Pool Agreement that you referred to in one of our earlier conversations. Could you provide me with a copy of that agreement form so that I can have our legal counsel review it? Again ıanks in advance.
Dave

From: David Crockett
Sent: Monday, August 31, 2009 3:48 PM
To: Carl Monroe
Subject: Reserve Sharing

Carl,
A couple of questions regarding the RSG. Did you estimate for me the upfront costs for the initial setup for BREC in the RSG? If so, what was that figure. And am I correct that the administrative costs ongoing were estimated at $2-3k? Also, how does the NERC Disturbance reporting take place within the RSG? Thanks for your help in these matters.
Dave

David Crockett

From: Dalrymple, James R [jrdalrymple@tva.gov]

Sent: Friday, September 25, 2009 7:48 AM

To: David Crockett

Cc: Goza, Stuart L

Subject: RE: Suggested Response -- >FW: BREC - Reserve Sharing

Dave,

Stuart's explanation does convey TVA's position. To further explain our position, some additional background may be helpful.

To resolve a lawsuit brought by Duke, Entergy, and Southern against TVA in the mid-1990s in federal district court in Alabama, TVA entered into a "Consent Judgment" (similar to a settlement) which established how TVA would operate under Section 15d(a) of the TVA Act, specifically with respect to the sale of electric power to "authorized" purchasers. TVA can only sell electric power -- which is defined in the Consent Judgment as capacity and/or energy -- to those entities with whom TVA had existing exchange arrangements on July 1, 1957. This category does not include BREC.

In the reserve sharing group context, if BREC were to be allowed to use TVA's largest unit as its compliance reporting criteria for DCS, then BREC obtains a benefit that none of BREC's generating units would be reportable. Also, by TVA being a participant in the reserve sharing group, BREC would obtain a benefit of a reduction in the amount of reserves that BREC would otherwise have to carry under applicable reliability standards.

.his benefit to BREC (lower reserve requirements and DCS compliance reporting) would be made possible through BREC's "use" of TVA generating capacity (albeit on paper). It is TVA's Office of General Counsel's opinion that under the TVA Act and the Consent Judgment, the use of TVA generating capacity for this purpose is not permissible, regardless of whether TVA is compensated for such use.

I understand that E.ON and EKPC are in discussions with BREC to explore reserve sharing options.

TVA values its partnership with BREC. However TVA must operate within the requirements imposed by the TVA Act and the Consent Judgment.

Let me know if you have additional questions or would like to discuss further.

Thanks.

Bob

From: David Crockett <David.Crockett@bigrivers.com>
To: Goza, Stuart L
Cc: Morris, Keith W; Dalrymple, James R
Sent: Fri Sep 18 17:47:17 2009
Subject: RE: BREC - Reserve Sharing

..uart,

Do I understand you correctly that TVA's opinion is that BREC will be receiving a benefit from TVA's generating capacity through the NERC DCS reporting threshold used in a reserve sharing group setting? What benefit does TVA feel that BREC receives?
nd TVA further is of the opinion that the supposed "benefit" rises to the level of being prohibited by the TVA Act?
BREC would not be using the TVA generating capacity in meeting its individual NERC contingency reserve obligations (i.e. covering the loss of its largest unit). BREC would of course not be receiving any energy product from the TVA generating resources within the structure of the RSG agreement as we have proposed it. And yet TVA is not of the opinion that those provisions are enough to meet its legal obligations?
If all of this is an accurate representation of what you said in the email message below, to say that I am both surprised and disappointed in TVA's position on this is an understatement. I await your reply.
Dave

From: Goza, Stuart L [mailto:slgoza@tva.gov]
Sent: Tuesday, September 15, 2009 9:16 AM
To: David Crockett
Cc: Freibert, Charlie; Van Liere, Wayne; George Carruba; Chuck Dugan; York, Denver; Morris, Keith W; Dalrymple, James R
Subject: RE: BREC - Reserve Sharing

TVA has reviewed (in more detail) the potential addition of BREC in the proposed reserve sharing arrangement between TVA, E.ON and EKPC and has concluded the following:

Pursuant to the TVA Act as reflected in the Consent Judgment entered in *Alabama Power Co. v.* TVA, CV-97-C-0885-S (N.D. Ala. 1997), TVA cannot provide power (capacity and/or energy) to BREC from TVA's generating resources. Therefore, TVA cannot provide energy from TVA generating resources to BREC via a reserve sharing group nor can BREC receive benefits from TVA's generating capacity (that is BREC cannot count TVA's generating capacity for purposes of determination of the threshold for NERC DCS event reporting.)

ould BREC become part of the reserve sharing group, TVA would not provide nor receive reserve sharing energy with BREC.

Charlie Freibert will be responding to your email response below and will further explore with you the feasibility of reserve sharing with E.ON and EKPC.

Stuart L. Goza
Manager, Transmission System Services
(423) 697-4191

From: David Crockett
Sent: Tuesday, September 01, 2009 5:03 PM
To: 'Freibert, Charlie'
Cc: Goza, Stuart L; Morris, Keith W; George Carruba; Chuck Dugan; Van Liere, Wayne; Jim Lamb
Subject: RE: BREC - Reserve Sharing

Charlie,
I appreciate the points of concern that you express related to NERC acceptability, transmission deliverability, and availability of resources to respond during reserve sharing events. However, I don't believe that our proposal with respect to the RSG reserve allocations and response strategies pose a problem either in terms of NERC/SERC acceptance or in terms of defining the compliance obligations of each RSG member. I asked my staff to pose this question to the SERC Compliance staff. Their response is provided below:

om: Bob Goss [bgoss@serc1.org]

Sent: Wednesday, August 26, 2009 6:43 PM
To: Chris Bradley
Subject: RE: Reserve Sharing Group Question

See answers below.

While the response is given in good faith, it will in no way be considered an official SERC Regional Interpretation and will not be binding on enforcement decisions of the SERC compliance program. Actions based on any such response shall have no standing for the purpose of contesting or mitigating any findings of non-compliance by SERC.

Bob

Robert D. (Bob) Goss

Manager of Compliance Audits

SERC Reliability Corporation

Phone - 704-940-8207

Cell - 706-201-6313

Home Office - 706-245-6038

While investigating NERC and SERC requirements for reserve sharing groups, I have found limited discussion regarding the required make-up or structure of reserve sharing groups. Both BAL-002 and the SERC Contingency Reserve Policy seem to allow significant flexibility in the overall organization or structure of a reserve sharing group.

1. Other than BAL-002 and the SERC Contingency Reserve Policy, can you provide any SERC or NERC documents that specify requirements placed on reserve sharing groups?

   I know of no other information except your reserve sharing agreement.

2. Does NERC or SERC make it necessary for each reserve sharing group member to have bi-lateral agreements in place with each of the other members? In other words, would the absence of a bi-lateral agreement between two members of a multi-member reserve sharing group pose a problem?

   I know of no requirement by SERC or NERC for each reserve sharing group member to have bi-lateral agreements in place with each of the other members.
   Since all members of the Midwest Contingency Reserve Sharing Group (Midwest CRSG) have signed this agreement, it may be good business practice to have a bi-lateral agreement with these companies but it may not be necessary. The question might be what would happen if you do not call on reserves from the reserve sharing group then what other agreements are in place that you

can call on for assistance if needed.

Big Rivers is not proposing to challenge or disrupt the position taken by TVA that it cannot sell power outside the TVA fence. Big Rivers has no desire to put the RSG arrangement between the three parties in jeopardy by pursuing participation in the RSG. Big Rivers does not feel that its proposal in any way puts the arrangement in jeopardy. Certainly, the transmission question or deliverability matter needs to be answered, but I believe it can be successfully proven. The only party at risk for sufficient reserves with respect to the loss of its own largest generating unit would be Big Rivers. Big Rivers recognizes that fact and is willing to structure its RSG participation in such a way as to obligate Big Rivers to carry not only its Load Ratio Share reserves available to the group but also the additional supplemental reserves to meet its own largest unit outage requirement. The numbers that were cited in my earlier email were ones calculated by TVA in this regard. So, I would assume that they have no problem with the concept. In light of the SERC response, I see no reason to be concerned that with Big Rivers' involvement in the RSG that the parties could not use the 80% of TVA's largest unit as the compliance reporting criteria. I don't see the logic in concluding that there would be two groups just because there is not a bi-lateral interchange arrangement between each of the parties. I would assume that the intent as far as SERC and NERC are concerned is compliance with the Disturbance Control Standard, not in the form or structure of the RSG. I ask you to consider these points and your position with respect to Big Rivers involvement in the new RSG.
Dave Crockett

From: Freibert, Charlie [mailto:Charlie.Freibert@eon-us.com]
Sent: Thursday, August 20, 2009 1:54 PM
To: David Crockett
Cc: Goza, Stuart L; Morris, Keith W; George Carruba; Chuck Dugan; Van Liere, Wayne
Subject: RE: BREC - Reserve Sharing

Dave,

Thanks for your e-mail. I'd like to respond on behalf of E.ON.

Generally, the more parties in a reserve sharing group, the better it is for everyone. E.ON would welcome additional members in any reserve sharing group involving E.ON. In the case of the proposed TVA-EKPC-E.ON group, however, TVA's position that it cannot sell power outside the TVA fence presents challenges for potential members that are outside the fence. It may be possible for Big Rivers to join this proposed group in a way that benefits everyone, but after spending some time considering your proposal, we are not sure how your proposal would work. Some of our high-level questions are:

- The "first tier" and "second tier" responders concept does not seem applicable here. In the MCRSC, the tiers represent the order in which the parties supply reserves to one another. However, in all cases, all MCRSG parties can supply reserves to anyone else in the group. Here, because one of the parties (TVA) could not sell energy to one of the other parties (Big Rivers), we seem to end up with two separate groups. We're not familiar with any groups like this and are not sure if they would be acceptable to NERC. Are you aware of any guidance from NERC or FERC?
- You mention that "the reserve allocations of RSG members can be structured in any manner that is agreeable to its members." While there may be some flexibility, there are still criteria such as deliverability and the availability of resources to respond during a

reserve sharing event that would need to be considered. (Also, the current and past MCRSG's total reserve amount and allocations are different from the numbers you stated.)

- Your "tier" proposal assumes that all of the parties could use 80% of TVA's Most Severe Single Contingency (MSSC). However, if Big Rivers couldn't take energy from TVA, the 80% of TVA's MSSC wouldn't apply.
- If Big Rivers cannot be involved in a group involving TVA but other group members shared reserves with TVA, would contingency reserves be calculated based on 2 different groups (Group 1 = E.ON, EK, and TVA and Group 2 = E.ON, EK and BR)? We do not know of a situation where one company is a member of two different groups and has two separate sets of reserve obligations from the same set of resources. Would that arrangement reduce or increase E.ON's total obligation? Of course, if E.ON's total reserve obligation is greater, it would be less attractive to E.ON from a business and regulatory perspective and would probably involve additional administrative costs.
- Regarding the rates, we're not sure whether you're proposing market-based rates or cost-based rates as the basis for the pricing methodology. As you know, E.ON cannot currently sell at market-based rates in the Big Rivers Balancing Area.
- If the proposal involves an arrangement that is not customary or approved from a reliability or regulatory perspective, E.ON would need to have assurances that it would be protected from potential risk issues.

E.ON will be glad to consider another proposal that addresses these and other major issues, and will be happy to discuss your next proposal with you in person after we have had a chance to review it.

We are copying other potential members of one or more of the proposed groups and invite them to comment.

Charlie Freibert
Director Energy Marketing
E.ON US - LG&E/KU
220 West Main Street
Louisville, KY 40202
O502-627-3673
F502-627-3613
M502-553-9007
email: charlie.freibert@eon-us.com

From: David Crockett [mailto:David.Crockett@bigrivers.com]
Sent: Tuesday, August 11, 2009 5:27 PM
To: Goza, Stuart L
Cc: Dalrymple, James R; Morris, Keith W; Freibert, Charlie; George Carruba; Albert Yockey
Subject: RE: BREC - Reserve Sharing

Stuart & All,
See comments and proposals added in red below. Let me know how we can support the process of coming to a resolution on these proposed arrangements for the new RSG. Thanks again for your help and consideration of these important matters.
Dave Crockett

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om: Goza, Stuart L [mailto:slgoza@tva.gov]
ent: Thursday, July 30, 2009 5:03 PM

To: David Crockett
Cc: Dalrymple, James R; Morris, Keith W; Freibert, Charlie; George Carruba
Subject: BREC - Reserve Sharing

Dave,

TVA, E.ON and EKPC did have a telecon on 7/29 in which issues regarding an additional party potentially joining the TVA/E.ON/EKPC Reserve Sharing Group (TEE RSG) were discussed.

TVA's position is that TVA is prohibited by Federal law in making off-system sales to BREC which makes it very difficult to structure an arrangement for BREC (or any other party in which TVA cannot sell to) to participate in the TEE RSG.

The reserve obligations of RSG members can be structured in any manner that is agreeable to the members. Big Rivers was proposing that its reserve requirements be structured to include both a "Load Ratio Share" component and an Extra Contingency Reserve component as needed to recover from the loss of its largest unit (Wilson). The numbers for Big Rivers that we were proposing to Stuart were 48 MW as calculated by Load Ratio Share of the RSG's total reserve requirement (1270 MW) and an additional 90 MW of supplemental reserves needed to meet the Wilson unit outage using its rating of 420 MW. Big Rivers doesn't see the foregoing proposal as being significantly different than the structure employed in the MCRSG today. The MCRSG total reserves are 1500 MW of which 750 MW are being carried by the non-MISO members and 750 MW by MISO. That allocation is obviously not based upon a Load Ratio Share formula either. It is simply the allocation arrangement approved by the MCRSG.

While the MW allocation could be structured in different ways, the end result would be a separate sub-group within TEE RSG to provide reserves to BREC or perhaps a completely separate RSG (without TVA.)

Big Rivers doesn't believe that the structure proposed creates a separate sub-group within the RSG. The utilization of the group's contingency reserves can be structured again in any manner agreeable to the members. The utilization of the group's total reserves can be stuructured such that each member's response to an ARS event is different depending upon the member that is requesting assistance. Big Rivers believes that approach would allow TVA to respond to its own ARS events and those of E.ON and EKPC while not responding to Big Rivers if that is the arrangement approved by the group. Big Rivers would again point to the MCRSG utilization structure which is based on a tier approach. The three Kentucky members are first tier responders to each other, second tier responders are the non-MISO MAPP members, and the third tier responder is MISO. The end result is that MISO (though MISO can respond to Big Rivers' events) seldom if ever is called upon to respond since the 750 MW reserve level of the first and second tier members satisfies the request.

One issue raised was that this sub-group may not be able to count TVA's largest unit for DCS threshold determination (since TVA cannot participate with BREC). In this situation, then the loss of BREC's Wilson unit would be a DCS event, which would increase compliance risks with NERC Standards for the sub-group. Due to the size of TVA's largest unit, none of the E.ON or EKPC generators exceed the DCS threshold for the existing TEE RSG.

Again Big Rivers doesn't believe that a tier structure for the utilization of the group's reserves creates either a sub-group or two RSGs as far as NERC Standards compliance is concerned. Big Rivers believes that the group can choose to establish a reportable threshold as the largest unit of the group (TVA's unit) regardless of the matter of Big Rivers' participation. Again Big Rivers would point to the fact that the MCRSG protocol established a NERC reportable threshold of 751 MW which eliminated all units of the Kentucky members. That compliance reporting decision was made by the RSG, it was within the allowable threshhold that NERC Standards require (80% of the group's largest unit), and it was coupled with the reserves allocation approach and the tier utilization approach described above

There are numerous legal, regulatory, and technical issues that would have to be resolved, such as:

What rate would E.ON and BREC use for the reserve energy transactions? Would EKPC and E.ON be able to transact with BREC and TVA at the same time, considering TVA's restrictions? Is there sufficient transmission capacity to make sales from the group through E.ON to BREC, and vice versa? Other questions and issues will undoubtedly arise if this is explored in detail.

Big Rivers would presume that the rate for reserve energy transactions between E.ON and BREC would be structured the same as today under the MCRSG. Big Rivers believes that the issue of simultaneous transactions is resolved by the proposed allocation and utilization structure described above. The only issue raised by simultaneous ARS events would be the availability of total reserves within the group to satisfy both. That issue exists whether or not Big Rivers is a participant. Big Rivers acknowledges that the transmission question must be answered. But, there are ways of dealing with transmission deliverability that we don't currently have in the MCRSG. TVA would be a parallel path for EKPC reserves to flow to Big Rivers and vice versa. Big Rivers and EKPC would not be dependent upon E.ON transmission to meet the deliverability test for reserves shared between the three of us.

Given the imminent sunset of the Midwest CRSG, we will continue to move forward with plans for the proposed TEE RSG arrangement and the currently proposed membership. While we're moving forward with those plans, please feel free to send a proposal that addresses at least the major issues. Due to the number of issues involved, however, we hope that you will continue to look at other possibilities as well.

In light of the imminent sunset of the MCRSG, Big Rivers would ask that the group focus energy on plans that would include Big Rivers' participation in this new RSG arrangement Big Rivers would see it as a win-win situation for all and certainly vitally important to all three of us affected by the termination.

Thanks,

Stuart L. Goza
Manager, Transmission System Services
(423) 697-4191

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David Crockett

From: Freibert, Charlie [Charlie.Freibert@eon-us.com]

Sent: Tuesday, November 03, 2009 9:48 AM

To: Bill Blackburn; David Crockett

Cc: Jim Lamb; George Carruba; Chuck Dugan; Brunner, Bob

Subject: Discussions on a KY CRSG

Bill,

Thank you for the call last Friday requesting a meeting to discuss a KY RSG. E.ON US, (LG&E/KU), is always looking for beneficial ways of addressing contingency reserve requirements and enhancing reliability and thus agrees with a meeting on a KY RSG with BREC, EKPC and E.ON US. Before proceeding with a meeting it would be beneficial for the discussions that the 3 parties sign a confidentiality agreement (CA). I will send a draft for BREC's and EKPC's review later today. Please provide edits to the CA or let me know that you are ready to execute. Once all parties are ready to execute I will fax copies for execution. We suggest a meeting in Louisville at the E.ON US Center as a convenient location for all 3 parties. Please email us and EKPC a few dates that BREC would have available for such a meeting where BREC can share its ideas on a KY RSG.

I look forward to your reply to our suggestions.

Thank you,

'harlie Freibert

Director Energy Marketing

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RE: MISO Transmission

Tom Mallinger [TMallinger@midwestiso.org]

Sent: Thursday, November 05, 2009 9:24 AM

To: David Crockett

Attachments: BREC-KCPL_KCPL-BREC (3).xls (14 KB)

Dave,

I can describe the process Midwest ISO uses to set-aside TRM capacity. Midwest ISO evaluates available capacity on flowgates (both Midwest ISO flowgates and third party flowgates) when a request for transmission service is made. For Midwest ISO flowgates, we include TRM that takes into account uncertainty (load forecast, generator output, load distribution, etc) and the loss of generation (a reserve sharing component). The definition of the flowgate already takes into account the loss of transmission.

The reserve sharing component is calculated by modeling an outage on each generator one at a time to identify the loading that will be experienced on a flowgate. When determining how the lost generation is replaced, the TRM calculation uses a reserve sharing response. The amount of increased flow is evaluated for each of these generator outages one at a time with the generator outage causing the largest increased flow being selected as the reserve sharing component. If a generator outage is no longer valid because it is no-longer part of reserve sharing, this does not mean the reserve sharing component goes to zero. It means we go to the next most limiting generator outage in the set and use its increased flows as the reserve sharing component.

Your October 23 e-mail asked Midwest ISO to provide the list of flowgates that limit "MISO export paths with BREC and maybe MISO export paths with AECI." You also asked that for Midwest ISO flowgates, we identify the generator outages that are being used to determine the reserve sharing component of TRM. In my October 27 response, I provided a list of flowgates with zero monthly firm AFCs along with the generator outages associated with the reserve sharing component of TRM. Of these six flowgate with zero monthly firm AFCs on the MISO to \ECI path, one of these is a Midwest ISO flowgate with an AMRN generator outage being most limiting in the eserve sharing component Of the seven flowgates with zero monthly firm AFCs on the MISO to BREC path, three of these are Midwest ISO flowgates. One of these three has a SIGE generator outage as the most limiting element and two of these three have a BREC generator outage as the most limiting element. However, removing the BREC generator outage does not mean the reserve sharing component of TRM goes to zero. It means the next generator outage in the list will become the generator outage used for the reserve sharing component of TRM. There is also another MISO flowgate with zero monthly firm AFCs that does not have a BREC generator outage as the most limiting element.

Your follow-up e-mail implies that the actual path of interest to BREC is BREC to SPP and SPP to BREC. Since the Midwest ISO OASIS offers service on paths with BAs inside SPP and not the SPP region, I have selected a BA inside SPP (KCPL) to review available transmission capacity on a BREC to KCPL path and a KCPL to BREC path. The attached spreadsheet provides a list of Midwest ISO flowgates with zero monthly firm AFC that limit both paths. I have excluded flowgates where a BREC generator outage is used as the reserve sharing component. You will see there are three Midwest ISO flowgates that limit the BREC to KCPL path and two Midwest ISO flowgates that limit the KCPL to BREC path These flowgate that limit firm AFC do not include other Midwest ISO flowgates that have a BREC generator outage as the reserve sharing component.

Thanks.

Tom Mallinger
Midwest ISO
Phone: 317/249-5421
Fax: 317/249-5703
E-mail: tmallinger@midwestiso.org

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rom: David Crockett [mailto:David.Crockett@bigrivers.com]

Sent: Tuesday, October 27, 2009 4:01 PM
To: Tom Mallinger
Subject: RE: MISO Transmission

Tom,
I suppose at the outset I should start with an admission that I don't understand your process. If currently, MISO has set aside TRM capacity to meet its obligations to BREC to provide contingency reserves pursuant to the MCRSG Agreement. And if that agreement terminates on December 31, 2009, why would MISO include in its TRM calculation process the loss of the BREC Wilson unit. Am I reading the OASIS site postings correctly that all available firm transmission capacity is allocated to meet TRM. And, if it is appropriate for MISO to include the BREC Wilson unit outage in its TRM determination, then would that transmission capacity not be available to accommodate BREC's participation in the SPP Reserve Sharing Group. BREC is even considering a limited SPP RSG participation at a 100 MW or 200 MW contingency reserve obligation of that RSG to BREC. At this point, I simply don't understand how the termination of MISO's obligation to BREC in the MCRSG arrangement doesn't free up some transmission capacity on MISO export paths into BREC. I apologize for continuing to pose questions, but these are very serious matters to BREC.
Dave

From: Tom Mallinger [mailto:TMallinger@midwestiso.org]
Sent: Tuesday, October 27, 2009 8:22 AM
To: David Crockett
Subject: RE: MISO Transmission

Dave,

I have attached a spreadsheet with those flowgates that are limiting (zero AFCs) for monthly firm service from MISO to AECI and from MISO to BREC. There is one MISO flowgate that limits the MISO to AECI path. The TRM for this flowgate is based on an AMRN unit. There are three MISO flowgates that limit the MISO to BREC path. Of these three flowgates, the TRM for one is based on a SIGE unit and the TRM for the other two are based on a BREC unit. Let me know if you have further questions on this. Both of these paths have other non-MISO flowgates that limit AFCs.

Tom Mallinger
Midwest ISO
Phone: 317/249-5421
Fax: 317/249-5703
E-mail: tmallinger@midwestiso.org

From: David Crockett [mailto:David.Crockett@bigrivers.com]
Sent: Friday, October 23, 2009 5:46 PM
To: Tom Mallinger
Subject: MISO Transmission

Tom,
Big Rivers is still pursuing transmission availability to and from SPP Reserve Sharing Group member systems. In light of the ATC postings on the MISO OASIS for paths of interest to Big Rivers, I need to ask for some information to help me understand what I see there. Could you provide me with the list of generators that MISO is using to determine its TRM values specific to MISO export paths with BREC and maybe MISO export paths with AECI? Thanks for your help in this regard.
Dave Crockett
Vice President of System Operations
270-827-2561

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contact the sender and delete the material from your/any storage medium.