June 28, 2012

RECEIVED

JUN 28 2012

PUBLIC SERVICE COMMISSION

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

Re: PSC Case No. 2012-00169

Dear Mr. Derouen:

Please find enclosed for filing with the Commission in the above-referenced case, an original and ten copies of the responses of East Kentucky Power Cooperative, Inc. ("EKPC") to the Commission Staff's First Information Request , dated June 15, 2012. Also enclosed are an original and ten copies of EKPC's responses to the Attorney General's Initial Data Requests and to the Data Requests of Kentucky Utilities Company and Louisville Gas and Electric Company, both dated June 15, 2012.

Very truly yours,

Mark David Goss
Counsel

Enclosures

CC: Parties of Record

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF EAST KENTUCKY POWER	)	
COOPERATIVE, INC. TO TRANSFER	)	CASE NO.
FUNCTIONAL CONTROL OF CERTAIN	)	2012-00169
TRANSMISSION FACILITIES TO PJM	)	
INTERCONNECTION, L.L.C.	)	

RESPONSES TO COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION TO EAST KENTUCKY POWER COOPERATIVE, INC. DATED JUNE 15, 2012

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2012-00169

PUBLIC SERVICE COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION DATED 06/15/12

East Kentucky Power Cooperative, Inc. ("EKPC") hereby submits responses to the information requests of Public Service Commission Staff's ("PSC") in this case dated June 15, 2012. Each response with its associated supportive reference materials is individually tabbed.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. TO TRANSFER FUNCTIONAL CONTROL OF CERTAIN TRANSMISSION FACILITIES TO PJM INTERCONNECTION, L.L.C.	)))))	**CASE NO. 2012-00169**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Anthony S. Campbell, being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Public Service Commission Staff's First Information Request in the above-referenced case dated June 15, 2012, and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Anthony S Campbell

Subscribed and sworn before me on this 28th day of June, 2012.

Gwyn M. Willoughby
Notary Public

MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. TO TRANSFER FUNCTIONAL CONTROL OF CERTAIN TRANSMISSION FACILITIES TO PJM INTERCONNECTION, LLC	)	**CASE NO. 2012-00169**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Ralph L. Luciani, being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Public Service Commission Staff's First Information Request in the above-referenced case dated June 15, 2012, and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Ralph L. Luciani

Subscribed and sworn before me on this 25 day of June, 2012.

Notary Public

CHRISTINE McCAFFREY
NOTARY PUBLIC
DISTRICT OF COLUMBIA
My Commission Expires
October 14, 2012

CHRISTINE McCAFFREY NOTARY PUBLIC DISTRICT OF COLUMBIA

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. TO TRANSFER FUNCTIONAL CONTROL OF CERTAIN TRANSMISSION FACILITIES TO PJM INTERCONNECTION, L.L.C.	)))))	**CASE NO. 2012-00169**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Mike McNalley, being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Public Service Commission Staff's First Information Request in the above-referenced case dated June 15, 2012, and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Subscribed and sworn before me on this 28th day of June, 2012.

Notary Public

MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. TO TRANSFER FUNCTIONAL CONTROL OF CERTAIN TRANSMISSION FACILITIES TO PJM INTERCONNECTION, L.L.C.	)))))	**CASE NO. 2012-00169**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Don Mosier, being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Public Service Commission Staff's First Information Request in the above-referenced case dated June 15, 2012, and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Don Mosier

Subscribed and sworn before me on this 28th day of June, 2012.

Gwyn McWilliams
Notary Public

MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2012-00169

FIRST REQUEST FOR INFORMATION RESPONSE

COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION DATED 06/15/12

REQUEST 1

RESPONSIBLE PERSON: Don Mosier

COMPANY: East Kentucky Power Cooperative, Inc.

Request 1. Refer to East Kentucky's Application ("Application"), page 6, paragraph 11, which states, "EKPC thereafter tendered written questions to PJM that touched upon organizational, operational and financial aspects of the integration process and subsequent participation in PJM." Provide copies of the written questions submitted by East Kentucky and the responses thereto by PJM Interconnection, LLC ("PJM").

Response 1. Copies of the written questions submitted by East Kentucky and the responses thereto by PJM are included on the attached CD.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2012-00169

FIRST REQUEST FOR INFORMATION RESPONSE

COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION DATED 06/15/12

REQUEST 2

RESPONSIBLE PERSON: **Anthony S. Campbell**

COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 2. Refer to the Application, page 6, paragraph 12, and the Direct Testimony of Anthony S. Campbell page 8.

Request 2a. Provide a copy of the Charles River Associates March 13, 2012 presentation to the East Kentucky Board.

Response 2a. A copy of the Charles River Associations March 13, 2012 presentation to the East Kentucky Board is included on pages 2 through 13 of this response.

Request 2. Provide a copy of the PJM related material considered by the Board Risk Oversight Committee at its November 2011 meeting and any materials provided by the two visiting G&Ts related to the pros and cons of operating inside a RTO.

Response 2a. A copy of the PJM related material considered by the Board Risk Oversight Committee at its November 2011 meeting is included on pages 14 through 27 of this response. Copies of presentations from Old Dominion Electric Cooperative and Big Rivers Electric Cooperative are provided on pages 28 through 52 of this response.

CRA's Presentation
to Bd.
3-13-2012

EKPC RTO Membership Assessment

Final Presentation and Summary of Findings

March 5, 2012

Charles River Associates

PRIVILEGED ATTORNEY /
CLIENT WORK PRODUCT

Introduction/Overview

- **On behalf of East Kentucky Power Cooperative ("EKPC"), Charles River Associates ("CRA") has assessed the costs and benefits of EKPC joining the PJM Interconnection ("PJM").**

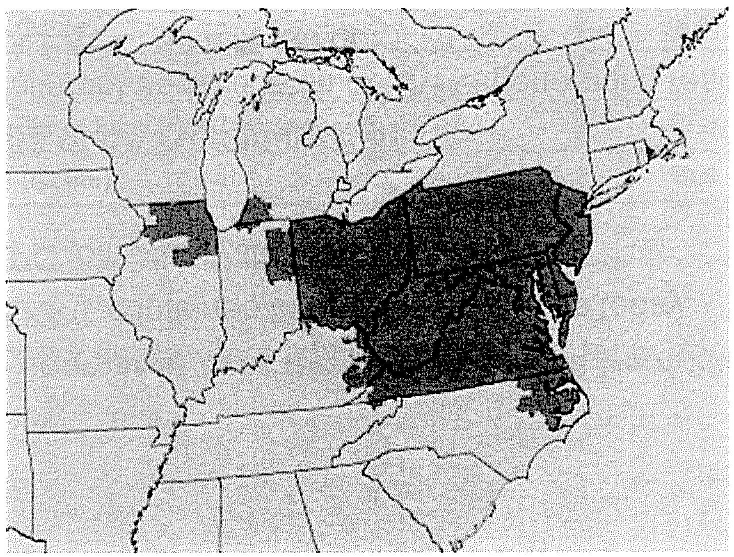
- **Based on the analysis performed, we conclude that EKPC joining PJM will yield significant economic benefits to EKPC.**
  - The benefits are relatively robust.
  - However, the benefits are highly dependent on the allocation of PJM regional high voltage transmission expansion costs as well as PJM capacity market benefits.

- **A number of important qualitative considerations have been identified as well, with both qualitative benefits and offsetting costs likely to be incurred by EKPC in joining PJM.**

Introduction/Overview

- **PJM is a regional transmission organization ("RTO") that coordinates the movement of wholesale electricity in all or parts of 14 states, including Kentucky.**
  - PJM has a "Day 2" market -- a two-settlement (day-ahead and real-time) energy market using hourly locational marginal prices and financial transmission rights ("FTRs").
    - *Other Day 2 markets include the Midwest ISO, ISO NE, and the NY ISO.*
  - EKPC interconnects directly with PJM through AEP-Kentucky and Duke Ohio (as of 2012).

PJM Territory Currently Served



Duke KY and Duke OH moved to PJM in 2012.

CRA Charles River Associates

PRIVILEGED ATTORNEY / CLIENT WORK PRODUCT

Alternatives Examined

- **Two alternatives were compared over the 10-year period from 2013 to 2022:**
  1. *Status Quo Case*: EKPC continues to operate as it does today.
  2. *Join PJM Case*: EKPC joins the PJM RTO in June 2013.

- **Key Sources of <u>Benefits</u> of EKPC joining PJM**
  - More efficient commitment and dispatch of EKPC generating resources leading to lower "adjusted production costs" for EKPC, as a result of:
    - *Elimination of EKPC-PJM wheeling charges (depancaking)*
    - *EKPC participation in a fully integrated regional market (e.g., joint commitment)*
  - EKPC taking advantage of peak load diversity as a member of PJM to require significantly less planning reserves.
  - EKPC avoiding long-term firm point-to-point transmission charges that it reserves today to ensure that EKPC has the ability to import power throughout the year.

- **Key Sources of <u>Costs</u> of EKPC joining PJM**
  - Additional Administrative Charges
  - PJM Transmission Expansion Costs

CRA Charles River Associates

PRIVILEGED ATTORNEY /

Net Benefits for EKPC

- **EKPC joining PJM will yield significant economic benefits to EKPC over the June 2013-December 2014 period and over the entire 2013 to 2022 period.**

2013-2022 Benefits (Costs) to EKPC of Joining PJM
(in millions of 2012 present value ("2012 PV") dollars; positive numbers are benefits)

	2013-14	2013-22 PrValue
Decrease in Adjusted Production Costs *(Trade Benefits)*	7.0	52.7
Administrative Costs	(10.4)	(48.3)
Transmission Costs	(4.0)	(66.4)
PJM Capacity Market Impacts	15.3	147.8
Avoided Long-Term Firm PTP Transmission Charges	12.0	56.1
Net Benefits (Costs)	**19.9**	**142.0**

– Each of the cost-benefit parameters summarized in the table above are discussed in turn in the following pages.

Adjusted Production Costs

- **Adjusted Production Costs:**
  → Own-system generating unit costs *(fuel, variable O&M, emission allowances)*
  plus "Off-system" Purchase Costs
  minus "Off-System" Sales Revenue

  Fuel + **Purchase Costs** – **Sales Revenue**

- **To determine adjusted production costs, CRA used the GE MAPS model.**
  - GE MAPS is a detailed economic dispatch and production costing model that simulates the operation of the electric power system taking into account transmission topology.
    - *All loads and generating units in the Eastern U.S. and Canada are modeled.*
    - *Outputs include hourly dispatch of generating units and locational marginal prices (LMPs).*
  - Hourly energy flows and prices between EKPC and neighboring regions (PJM, TVA, LG&E) from GE MAPS are used to value "off-system" purchases and sales.

- **The reduction in EKPC's adjusted production costs from the *Status Quo Case* to the *Join PJM Case* are the EKPC "trade benefits" of joining PJM**
  - A more efficient dispatch results from eliminating EKPC-PJM wheeling charges (depancaking), and EKPC participating in a fully integrated regional market (e.g., joint commitment)

Administrative Costs

- **Additional EKPC Administrative Costs in the *Join PJM Case:***
  - **RTO Administrative Charges:**
    - *Charges assessed by PJM to all load to run the Day 2 RTO market*
      - Assessed by PJM under various tariff schedules (Control Area Administration, FTR Administration, Market Support, Regulation Market Administration, Capacity Market Administration, etc.).
    - *Roughly $0.33/MWh, or $35.0 million for EKPC over the 2013-2022 period (2012 PV).*
  - **EKPC Internal Costs:**
    - *Costs incurred by EKPC for additional staff and equipment to interface with the RTO*
      - Estimated as a one-time $1 million integration cost in 2013, plus $600 thousand per year in additional labor, equipment and legal costs.
    - *Yields $5.6 million over the 2013-2022 period (2012 PV).*
  - **FERC Charges:**
    - *Additional FERC charges paid by EKPC as a member of an RTO that it does not pay as a separate G&T cooperative.*
    - *Roughly $0.07/MWh, or $7.7 million for EKPC over the 2013-2022 period (2012 PV).*

CRA Charles River Associates

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CLIENT WORK PRODUCT

Transmission Costs

- **Additional Transmission Costs and Revenues for EKPC in the *Join PJM Case:***
  - **Transmission Expansion Costs:**
    - 500 kV and above. In the *Join PJM Case*, EKPC would be allocated the cost of all 500 kV and above projects approved through PJM's annual transmission planning process.
      - *PJM allocates the cost of these projects on a pro rata basis to all load, regardless of whether the project was approved prior to a new member's entry date.*
      - *EKPC's estimated cost allocation would range from $4.8 million in 2014 to $15.4 million by 2022, for a total cost over the 2013-2022 period of $70.2 million.*
        - Estimate includes 50% of two large projects, currently "in abeyance", starting in 2020
    - Below 500 kV. For projects below 500 kV, only those projects approved while EKPC was a member would be potentially allocable to EKPC.,
      - *The allocation would be based on the projected impact any proposed new line would have on EKPC, and as such the benefits/costs are assumed to offset.*
  - **Transmission Revenue:**
    - In the *Join PJM Case*, EKPC as a transmission owner would share in the PJM firm transmission revenue that is collected under the PJM tariff.
      - *This is estimated to yield $3.7 million of revenue to EKPC over the 2013-2022 period.*

CRA Charles River Associates

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PJM Capacity Market Benefits

- **PJM Capacity Market Impacts**
  - ***Status Quo Case:***
    - EKPC is winter peaking and must meet a 12% planning reserve requirement in both the winter and summer in the *Status Quo Case.*
    - EKPC is projected to be short in winter capacity from 2013 to 2022, but long in summer for much of this period relative to this 12% target.
      - *EKPC would need to construct new capacity or swap summer for winter capacity with a neighboring region.*
  - ***Join PJM Case:***
    - In contrast, as a member of PJM, EKPC would need to effectively meet only a 3% planning reserve requirement that would apply only in the summer, as a result of:
      - *The significant summer peaking nature of PJM as a whole making EKPC's winter peak non-binding when integrated into PJM.*
      - *EKPC's regional load diversity with PJM in the summer.*
      - *The relatively high availability factor of EKPC's generating units.*
  - **The difference in meeting capacity reserve requirements over the 2013 to 2022 period is estimated to yield $147.8 million** *(2012PV)* **of benefits to EKPC in the *Join PJM Case*.**

Avoided Long-term Firm Charges

- **Avoided Long-term Firm Transmission costs**
  - In the *Status Quo Case*, EKPC reserves long-term firm transmission to ensure that EKPC has the ability to import power through the year.
    - *Absent this reservation, transmission through neighboring systems may not be available at times when EKPC is short of economic energy or capacity.*
    - *Currently, EKPC has a 400 MW long-term firm reservation with PJM.*
  - In the *Join PJM Case*, under the PJM Day 2 market which allocates transmission within the RTO on a economic basis, these arrangements would not be needed to access economic energy.
  - Mitigating the need for long-term firm transmission yields an additional $56.1 million (2012 PV) of benefits to the *Join PJM Case* over the study period.

Sensitivity Results

- **Sensitivity cases were conducted in 2011 to assess the impact of key uncertain assumptions.**
  - *EKPC benefits were substantially positive across the GE MAPS sensitivity cases examined.*
    - Lower gas prices tend to decrease trade benefits as price disparities between regions decrease.
    - Low load growth tends to decrease capacity prices and thus capacity benefits.
  - *Gas prices in the current study have decreased significantly from those used in Case 1 last year.*

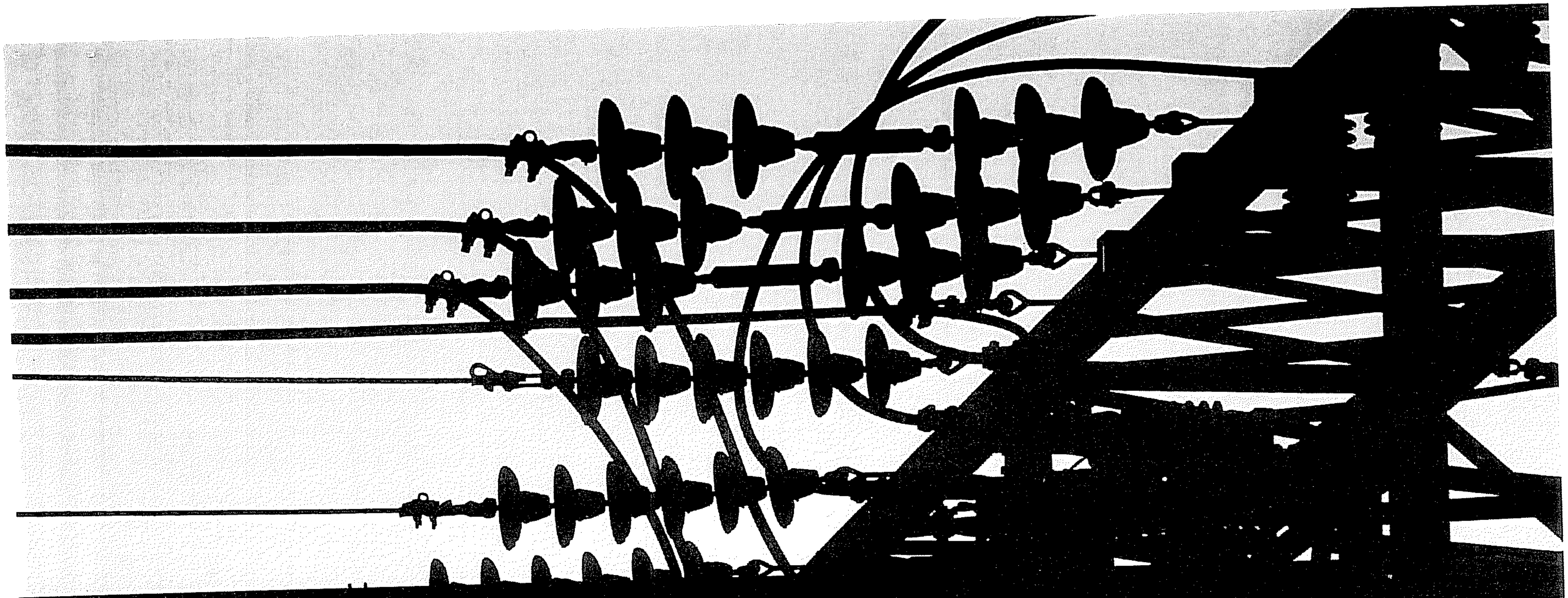
2011 GE MAPS Analysis of 2013-2017 Trade and Capacity Benefits (Costs) to EKPC of Joining PJM
(in millions of 2011 present value dollars, positive numbers are benefits)

2011 Case	Total	Change from Case 1
1: Base 2011 Gas Prices and Load	**90.4**	
2: High Load, High Gas, Small coal retirements (incl. Dale & Cooper 1)	**205.3**	*+114.9*
3: Low Load, Low Gas	**44.8**	*(45.6)*
4: Small coal retirements (incl. Dale & Cooper 1)	**120.0**	*+29.6*
5: CSAPR/MACT by 2017, retire Dale & Cooper 1	**117.5**	*+27.0*

- **An analysis of EKPC joining the Midwest ISO was also performed in 2011.**
  - *New high-voltage transmission would be required to implement a direct interconnection.*
  - *Without a direct interconnection, the benefits to EKPC of joining PJM were significantly higher.*

Qualitative Findings

- **While the quantitative figures show material benefits to EKPC of joining PJM, there are a number of key risks, including most importantly:**
  - Transmission Cost Allocation
    - *The PJM high-voltage transmission expansion cost allocation to EKPC are significant and dependent on PJM load growth, congestion and allocation mechanisms.*
    - *EKPC would have only a limited role in the approval of these PJM expansion plans.*
  - Capacity Market Diversity Benefits
    - *These benefits are dependent on the continued diversity of EKPC's demand profile with that of PJM, and the low outage rates of EKPC's generating units.*
  - RTO Exit Costs
    - *While PJM does not impose exit fees, an exiting member must pay its share of transmission projects approved while a member and any prior commitments made in the PJM congestion and capacity markets.*
    - *As such, the decision to join an RTO should be viewed as a long-term decision and the anticipated benefits should be material.*



PJM RTO Membership Discussion

November 7, 2011

Don Mosier

EAST KENTUCKY POWER COOPERATIVE
A Touchstone Energy Cooperative

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Liberty Audit Required EK Look at Market Options

- Audit issues M-8 and M-11
  - Ways to improve market access, asset ownership alternatives, diversification and whether RTO membership makes sense
  - RTO membership in and of itself supports all of these goals
- ACE'S performed an assessment and recommended EK join PJM (Jan-11)
  - ACES ruled out MISO for various reasons – <u>we had CRA reconfirm this</u>
  - Audit however required independence
- EKPC held RFP and chose independent expert Charles Rivers Assoc. (CRA)
  - Recent work for Big Rivers, Entergy and many others
  - Broad modeling capabilities and RTO market knowledge

Our Interconnections Support PJM Membership

- EKPC interconnected w/Duke OH; Moving to PJM 1/2012
- EKPC interconnected w/PJM member Kentucky Power
- EKPC self-supplies most load needs supplemented by market purchases
  - Short energy & capacity in winter
  - Long energy & capacity in summer

  A strategic advantage in an RTO
  - Today EKPC routinely buys from and sells into RTOs, mostly PJM
- No available long term transmission paths available to TVA and LG&E
  - Would require significant upgrade costs
  - Little strategic advantage due to limited uncommitted resources

We Evaluated Various Options along with ACES

Alternative 1 - Purchase Power Supply and Transmission from TVA

Alternative 2 - Purchase Power Supply and Transmission from LG&E/KU

Alternative 3 - Construct an Interconnection to Big Rivers Electric Cooperative

Alternative 4 - Participate on the Interface of an RTO with Import Transmission (Status Quo)

Alternative 5 - Join the PJM or MISO – MISO not preferred by ACES

We Compared PJM's Proposal* with ACES, CRA

	Benefit ($millions/year)		
	PJM	CRA	APM
Energy/Market Interaction	20.00	9.64	12.37
Capacity	22.10	13.44	2.19
Ancillary Services	3.75	N/A	0.00
Transmission Right Revenue	1.30	0.00	13.28
Transmission Losses Benefit	N/A	N/A	2.89
PTP Transmission Revenue/Avoided Cost	0.75	7.12	0.53
PJM Administrative Fees	(4.00)	(5.29)	(5.27)
Transmission Cost Allocations	(6.85)	(8.07)	(13.03)
Net Benefit	37.05	16.84	12.96

*We also obtained and reviewed MISO's proposal during the ACES evaluation

We Reviewed in Detail CRA's Assessment with the Board

2013-2017 Benefits (Costs) to EKPC of Joining PJM vs. MISO
(in millions of 2011 present value ("2011 PV") dollars; positive numbers are benefits)

	PJM Base Case	MISO Base Case
Trade Benefits (adjusted production costs)	40.6	36.4
Administrative Costs	(22.3)	(26.5)
Transmission Expansion Costs, net	(34.0)	(24.4)
PJM Capacity Market Benefits	56.6	11.3
Avoided Long-Term Firm PTP Charges	30.0	0.0
Total Net Benefits (Costs)	**70.9**	(3.3)

- Under "Base Case" conditions, EKPC joining PJM will yield significant economic benefits to EKPC
- MISO provides no positive benefit in the base case
- CRA notes that LG&E/KU entering MISO had no impact on PJM being best for EK

CRA's Sensitivity Analyses Were All Positive for EKPC

- **The net benefits of joining PJM remain substantially positive across the sensitivity scenarios examined.**

2013-2017 Benefits (Costs) to EKPC of Joining PJM
(in millions of 2011 present value dollars, positive numbers are benefits)

	Base	Sens. 1	Sens. 2	Sens. 3	Sens. 4
Trade Benefits	40.6	107.1	29.9	50.8	48.2
Administrative Costs	(22.3)	(22.3)	(22.3)	(22.3)	(22.3)
Transmission Expansion Costs, net	(34.0)	(34.0)	(34.0)	(34.0)	(34.0)
PJM Capacity Market Benefits	56.6	122.1	20.6	57.8	57.8
Avoided Long-Term Firm PTP Charges	30.0	30.0	30.0	30.0	30.0
Total Net Benefits (Costs)	**70.9**	**202.8**	**24.2**	**82.3**	**79.7**

Sensitivity 1: *High load growth, high natural gas prices, small (<150MW) **unscrubbed** coal retired by 2017*

Sensitivity 2: *Low load growth, low natural gas prices (PROTRACTED RECESSION)*

Sensitivity 3: *Small (<150MW) **unscrubbed** coal plants (including Dale and Cooper 1) retire by 2017*

Sensitivity 4: *CSAPR/MACT rules in effect leading to coal plant retirements (including Dale and Cooper 1) by 2017*

We Discussed with Board the Pros and Cons of PJM*

PROS

- Material economic benefit, redundantly analyzed and stress tested
- Directly supports EKPC Strategic Plan
  - Finance – Equity goal and reduce rate pressure
  - G&T Assets – Portfolio diversification, partnering
  - Operations – Maximize unit performance
  - People – High performance culture
- Eliminates reserve sharing risk w/ PP&L and TVA
- Reduces annual capacity planning reserves from 12% to approx. 2.3% <u>across summer only</u>
- Anticipated coal retirements (11GW) & higher energy prices (20%?)
  - Should provide increased margin opportunity and help levelize playing field with our neighbors

CONS

- 500kV and > transmission cost exposure (should convert to beneficiary pays per PJM/FERC)
- Long term commitment
- Rules WILL change – we have this risk anyway
- Penalties for poor performance
- Disciplined management of tools to limit congestion exposure
- No guarantees that financial estimates will be realized
- Independence – "what is it worth?"
- First capacity sales auction participation not until 2013 for the 2016/2017 planning year – may pressure early capacity benefit projections

(*Refer also to "EKPC RTO Decision Points" sent via email Nov. 1, 2011)

We Began Looking at What Impacts Members May "See"

- EK will be the wholesale market participant (along with ACES)
- Membership in PJM should largely be transparent to the Members
- The existing tariffs on file at KY PSC between EK and its Members likely do not need to be revised
- PJM will file EK's transmission tariff with FERC on EK's behalf
- We will hear in December from ODEC and Big Rivers on their experience

For the Board's Consideration

- Management has reviewed carefully the various analyses and supports the recommendations of its outside experts
- The Board may consider for approval that EK Management:
  - Is authorized to conduct final negotiations with PJM
  - Will report back on final terms & conditions for Board approval
  - Management may begin expending reasonable sums of money to begin an orderly integration process
- Membership would commence June 1, 2013

Questions and Discussion

RTO Membership Discussions with the Board

- January 2011 – Reported ACES' "ISO Analysis" received Dec. 2010
- March 2011 – COO "Strategic Power Supply Options"
- July 2011 – COO/CRA "RTO Analysis and Membership Study Update"
- August 2011 – COO Update Provided PJM RTO Operating Overview
- September 2011 – COO/ACES "Presentation on PJM RTO"
- October 2011 – PJM Executive Staff Provided Overview, COO "Recap of PJM Value Proposition and Membership"

*EKPC pays based on 1.9% load ratio share of Admin Fees and Transmission Cost Allocation

PJM Integration Preliminary Timeline

EKPC RTO Action Timeline	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
Present Recommendation to EKPC Board																			
Decide on RTO Membership																			
Request Kentucky PSC Hearing																			
FERC Filing																			
FERC Approval																			
Kentucky PSC Approval																			
Apply for PJM Membership																			
Receive Approval for PJM Membership																			
PJM Request NERC Certification																			
EKPC Staff Training																			
EKPC Generator Operator and Transmission Operator PJM Certification																			
PJM/MISO Complete Load and Generation Deliverability Study (IRM and CETO/CETL)																			
Submit Generation and Load data for RPM/Module E (FRR Plan through 2014/15)																			
Set up for ARR Registration																			
ARR/FTR Allocation and Auction																			
Set Up Network Model																			
TO Coordination/Communication Set Up (submit outages to PJM)																			
Convert EKPC OASIS to PJM OASIS																			
Generation Coordination/Communication Set Up (sumbmit planned outages to PJM)																			
Generator Testing for Ancillary and Capacity Markets																			
EKPC Verify Generation Modeled in Sandbox Environment																			
Market Trials																			
RPM BRA																			
Go live																			

Touchstone Energy Cooperatives

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PJM Provided EKPC with a Proposal - Summary

- PJM revised their original proposal to reflect actual EKPC data as used by CRA herein and latest PJM operating results
- Annual minimum benefit in line with CRA's analysis

Category	Minimum Benefit ($ millions / year)	Maximum Benefit ($ millions / year)
Energy	20	20
Capacity	9.9	34.3
Ancillary Services	2.4	5.1
Transmission Right Net Revenue	(0.5)	3.1
PTP Transmission Revenue	0.75	0.75
PJM Administrative Fees	(4.2)*	(3.8)*
Net Benefit without Transmission Cost Allocation	**28.4**	**59.4**
Likely Transmission Cost Allocation	(9.0)*	(4.7)*
Net Benefit with Transmission Cost Allocation	**19.4**	**54.8**

*EKPC pays based on 1.9% load ratio share of Admin Fees and Transmission Cost Allocation

ODEC®
Your Touchstone Energy Partner

PJM Membership
ODEC's Perspective

East Kentucky Power Cooperative

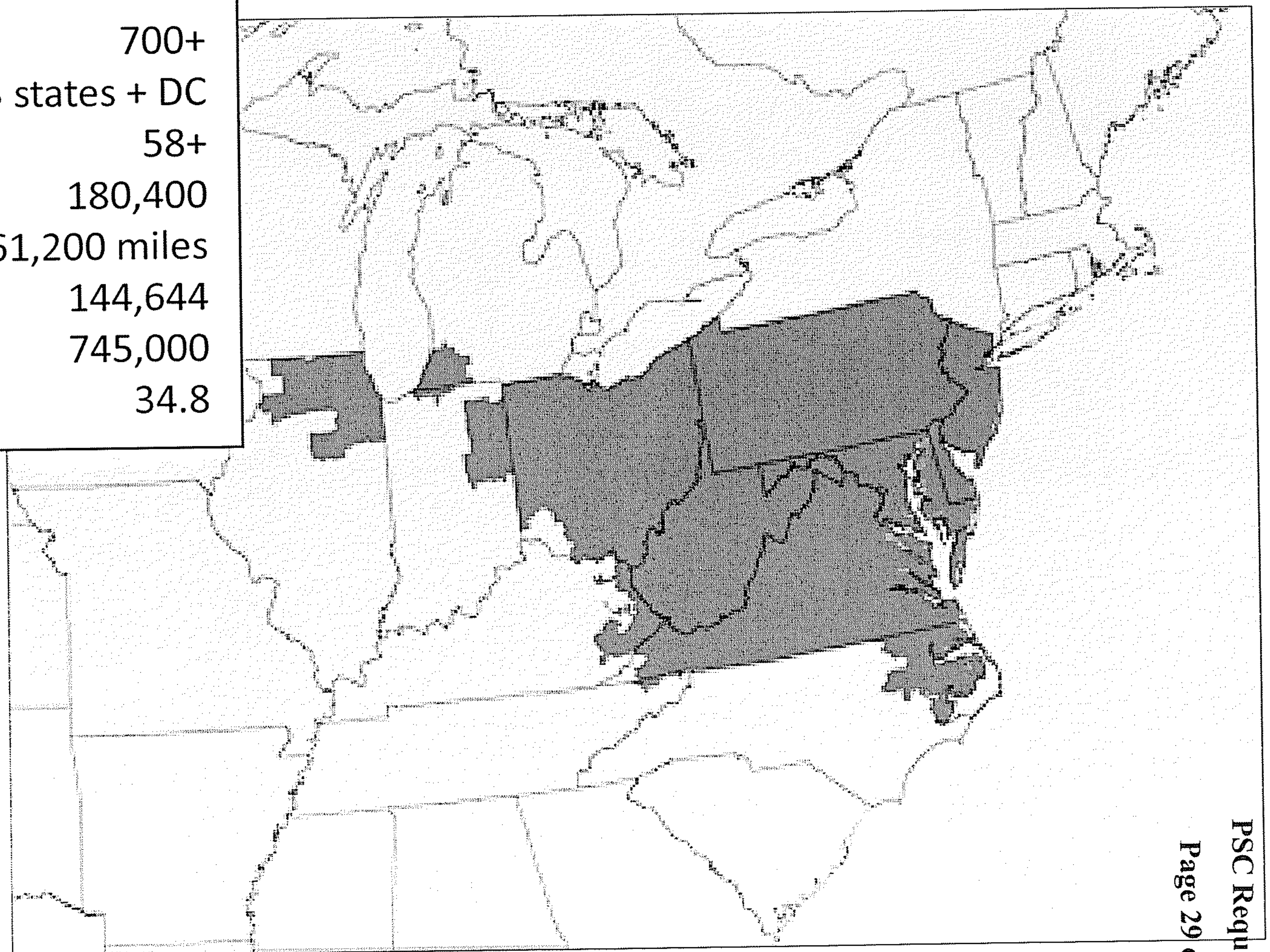
Board Meeting

December 6, 2011

PJM Footprint

KEY STATISTICS (2010)

PJM members	700+
Area served	13 states + DC
Millions of people served	58+
MWs of generating capacity	180,400
Transmission	61,200 miles
Peak demand in megawatts	144,644
GWh of annual energy ('10)	745,000
Annual Billings ($B '10)	34.8



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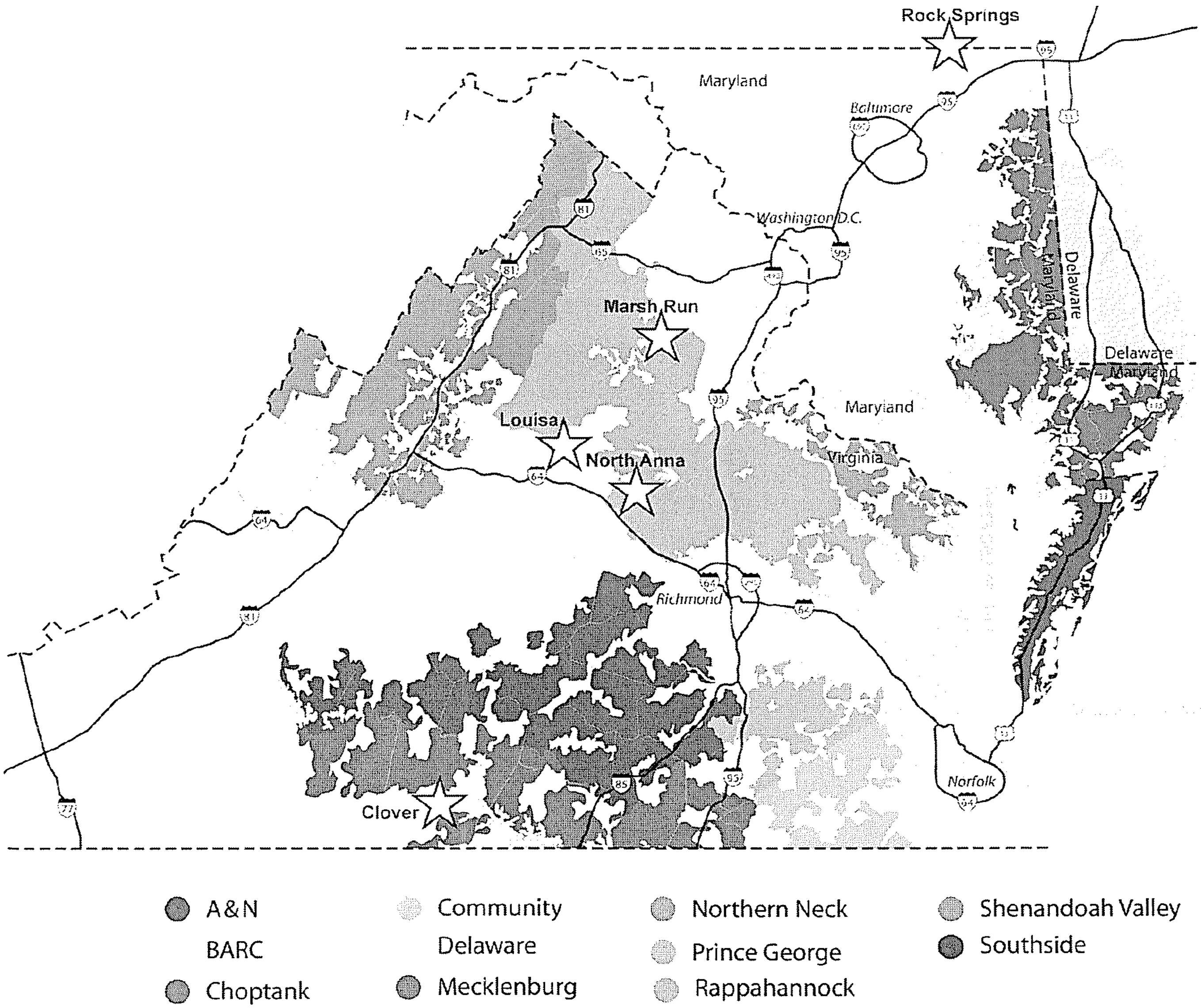
ODEC Members' Service Territory



ODEC®
Your Touchstone Energy Partner

ODEC By the Numbers

Number of Members	11
Member Location	VA, MD and DE
Number of Retail Accounts	~ 550,000
Number of Consumers	~1.2 million
Peak Demand	~2,600 MW
Owned Generation	~2,000 MW
Contracted Renewable Resources	200+ MW
Annual Average Energy Sales	~12,000,000 MWh
Total Assets	~$1.5 billion
Credit Ratings	A, A3, A

As of year end 2010

2010 Resource Mix

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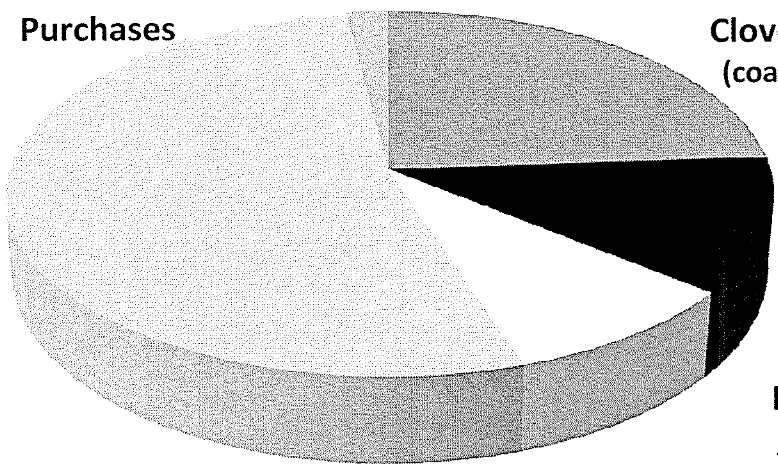
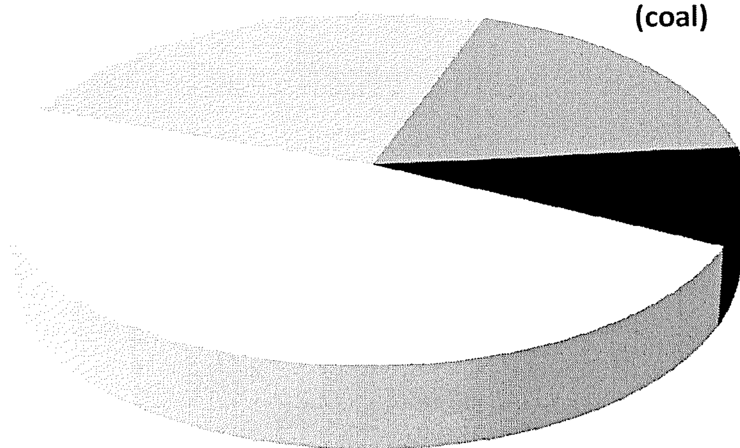
Energy



2010 Energy Sales = 12,610,811 MWh

Capacity



2010 Peak Demand = 2,635 MW (July)

PJM Membership "Pros"

- **Generation**
  - System reserves sharing
  - Liquid market for sale of excess capacity/energy
  - Ancillary service markets
- **Power Market**
  - Liquid trading hubs and market price visibility
  - More counterparties – both physical and financial transactions
  - Transactions – no OATI scheduling or cut schedules, just congestion pricing
  - Provides hedge for potential large load swings
- **Transmission**
  - Firm, non-pancaked transmission access
  - Enhanced transmission revenues
  - PJM assistance with certain NERC requirements
- **Governance/Administration**
  - Independent Board and FERC regulation
  - Independent Market Monitor
  - Mature organization and market structure
  - Members have some control via FERC 205 authority

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PJM Membership "Cons"

- **Generation**
  - Loss of dispatch control – bidding required
  - Maintenance scheduled and approved by PJM
  - Scheduling more complicated for gas
- **Power Market**
  - Liquid trading hubs provide "dirty" hedges for load due to locational differences
  - Complex market, difficult to assess/manage long term risks
- **Transmission**
  - Loss of some operational and planning control
  - Take direction from PJM
  - Planning becomes collaborative*
- **Governance/Administration**
  - PJM staff focused more on supply
  - Large, multi-party stakeholder process
  - More FERC involvement to keep up with PJM Tariff and rule changes
  - Personnel requirements to oversee and participate in the process

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Issues for Consideration regarding PJM Membership

- Non-member income and tax-related issues
- Regulatory jurisdiction
- Generation planning
- Negotiating terms prior to finalizing membership
- 24/7 operations and changes in business approach
- Transmission zone
- Level of EKPC member involvement

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Questions?

Midwest Independent System Operator (MISO) Integration Experience

East Kentucky Power Cooperative Board Meeting
December 6, 2011
Mark Bailey

Big Rivers Electric Corporation Quick - Overview

- Formed in June 1961
- Members are Kenergy, Jackson Purchase Energy and Meade County RECC
  - Serve 22 western Kentucky counties and over 112,000 retail consumers
- Governed by a six-member board – two per member
- 1,266 miles of transmission lines
- 22 substations & 22 interconnects linking our system with seven surrounding utilities
- Over 600 employees

Big Rivers

Big Rivers Generation Assets

- **Owned Generation - 1,444 MW**
  - Kenneth Coleman (Hawesville) – **443 MW (B)**
  - Robert Reid (Robards) – **130 MW (A)**
  - Robert Green (Robards) – **454 MW (A)**
  - D.B. Wilson (Centertown) – **417 MW (C)**

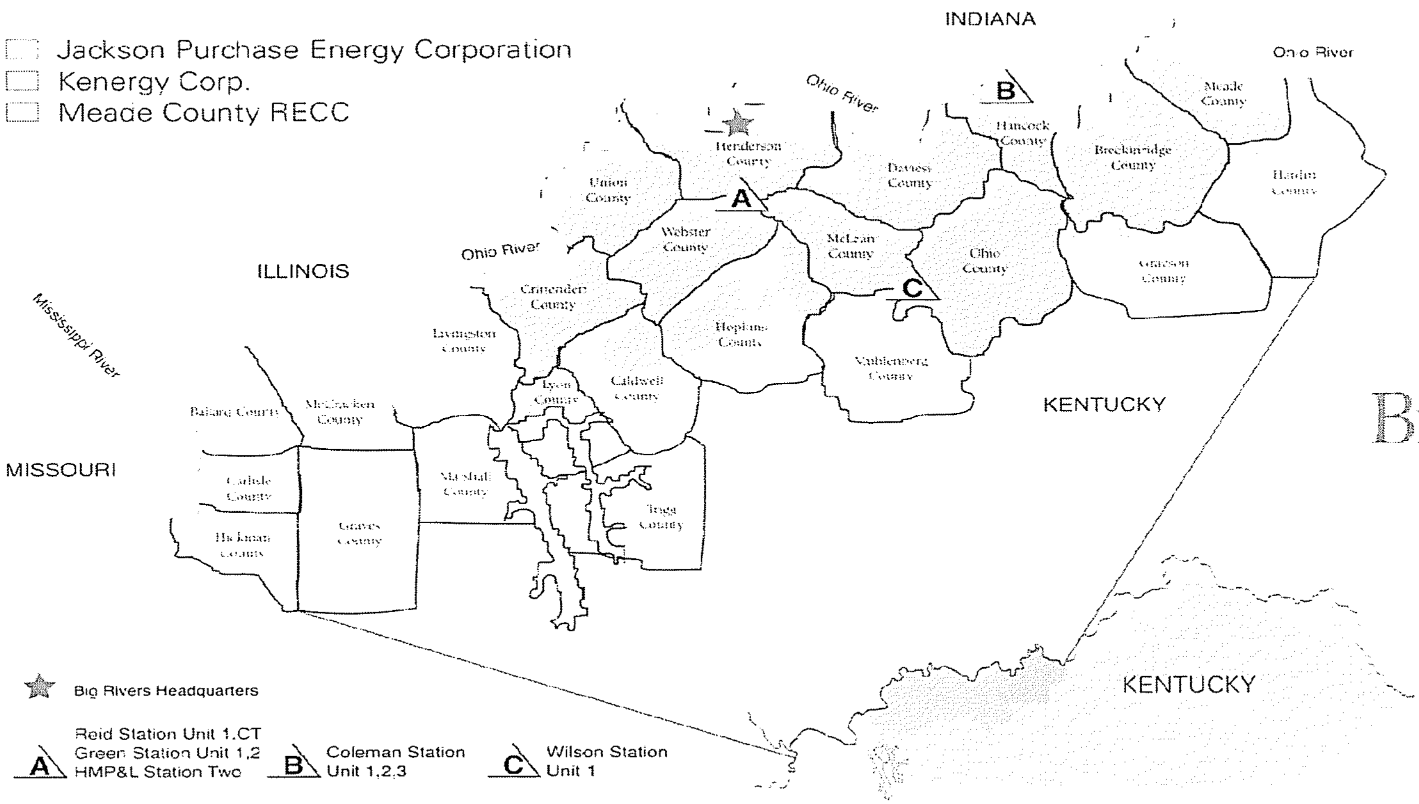
- **Henderson Municipal Power & Light (HMP&L) Station Two - 202 MW**
- **Southeastern Power Administration (SEPA) – 178 MW**

- ***Total Generation – 1,824 MW***

Big Rivers
ELECTRIC CORPORATION

4

Big Rivers Electric Corporation



FERC Background - ISO/RTOs

- 1994 Energy Policy Act Gave FERC Authority to deregulate Wholesale Power Markets
- To Effectively Deregulate Power Markets, FERC Enacted Orders 888/889 in 1996
  - **Developed Rules**:
    - For Deregulation of Wholesale Power Markets
    - To Provide Fair and Open Transmission Access (Transmission Remains Regulated)
    - To Incent Efficient Use of Generation and Transmission Resources
    - Code of Conduct Rules Between Intercompany Generation and Transmission Functions
  - Oversaw and Approved Methods for Rule Compliance
- FERC Initially Tried to Mandate Regional Transmission Organizations (RTOs) in 2000 (Order 2000)
  - Conditioned most utility mergers at the time on joining an ISO/RTO
  - Less Forceful on RTO Requirements Now, but still Favors More Price Transparency, Joint Planning, and RTO Participation
- FERC Enacted Order 890 in 2007
  - Amended Orders 888/889
  - Clarified Transmission Access Rules
  - Required More Inter Regional Transmission Planning

Big Rivers

Big Rivers

Why Midwest Independent Transmission System Operator (Midwest ISO)?

- NERC requirement to maintain reserve generation capacity and spinning reserves,
- Previous Reserve Sharing Group consisting of a subset of MISO Members & other utilities dissolved at the end of 2009,
- Several options were considered (i.e. PJM, SPP, Standalone, another Separate Subgroup)
- Joining MISO was ultimately determined to be the most <u>cost-effective</u> option,
- Financial impact was estimated to be anywhere from a small positive (i.e. less than $1 million per year to a large negative up to $29 million per year.)
- MISO agreed to provide reserve sharing service under special tariff in 2010 while Big Rivers proceeded through the PSC approval and integration processes,

Big Rivers Reserve Self Supply Basics

- Big Rivers requires **417 MW** of contingency reserve (loss of its largest generating unit, D.B. Wilson) to meet its NERC requirements alone.
- Self-supply plan would necessitate an addition of a minimum of **200 MW** of new peaking generating capacity and **200 MW** of interruptible load.
- New generation was estimated to cost ~**$100 million** over the five-year study period.
- Big Rivers estimated Midwest ISO membership to provide a net benefit of **$132 million** over initial five year membership period with Smelters providing 200 MW of interruptible load.

Big Rivers

Midwest ISO Cost Sharing

- Major concern and area of uncertainty – potential for millions of dollars per year of transmission expansion in the longer term,
- We are **<u>not</u>** responsible for projects approved prior to joining,
- We **<u>are</u>** responsible for projects approved while being a member – even if we leave MISO,
- Big Rivers cost for Midwest ISO transmission expansion cost sharing (Major Transmission Expansion Plan (MTEP) or Multi Value Projects (MVP) costs) have been zero,
- One MVP project is under consideration for approval this year (difficult to assess the future cost allocation to Big Rivers),
- It's estimated Big Rivers could have either MTEP or MVP costs of **$300,000** in 2013,
- In 2015, Big Rivers costs are estimated to increase to ~**$11 million**.

Big Rivers

Traditional (Non-RTO/ISO) Market Features

- **Transmission:** Independent Transmission Providers
  - BREC and other non-RTO utilities operated under their FERC Approved Transmission Tariff that govern the Rules of Use of Transmission System for Native Load and Transmission Sales

- Adhere to Traditional Transmission Reservation Processes (e.g. point-to-point, network reservations)

- **Reliability:** Independent Balancing Authorities
  - Locally Manage Voltage and Frequency Regulation, Reserves, and Reliability
  - Usually groups of utilities banded together to meet spinning reserve requirements

- **Energy Hedging and Sales:** Forward and most Spot Market activity via Bilateral Transactions
  - Would Buy/Sell with MISO in Spot Market when viable

- **Capacity:** Required Planning Reserves
  - State Approved Integrated Resource Plan partly based on SERC Required Reserve Margin of 12%

Big Rivers

MISO Market Design Features

- MISO Functionally Controls Entire Transmission Footprint
  - Single Balancing Authority Responsible for Keeping the Lights On
  - Administers One Transmission Tariff For All Users

- Administers Market Tools for Efficient Generation Dispatch and Use of Transmission System
  - Financial Transmission Rights (FTR) Market to Address Congestion
  - Two-Part Locational Marginal Pricing Location Marginal Pricing (LMP) Energy Market
    - Day Ahead market
    - Real Time market
  - Ancillary Service Markets (Voltage & Frequency Regulation, Spinning & Non-Spinning Reserves)
  - Module-E (long term) Capacity Requirements
    - Requires 12% Planning Reserves
    - Lack of Compliance Results in $80,000/MW/Mo. Penalty
    - MISO Currently Pushing for a More Defined Capacity Market Structure
  - Balancing Market/Settlements/Member Costs

Big Rivers

Key Responsibilities

Midwest ISO

- Tariff Administration
- Open-Access Same-Time Information System (OASIS) Administration
- Security Coordination
- The Balancing Authority
- Address all Seams Issues
- Energy Imbalances
- Energy Scheduling
- Maintenance Scheduling
- Congestion Management
- Ancillary Services
- Market Monitoring
- Unit Commitment

Big Rivers

- Physical Control of Systems
- Load Projection
- Unit & Auxiliary Service
- Unit Dispatch Per MISO Instruction
- Maintenance Requests
- Emergency and Planned Switching
- Monitoring of Real-time Flows

Big Rivers

Midwest ISO Benefits

Big Rivers

- Big Rivers successfully integrated into Midwest ISO on **December 2010**,
- Became the **35th** transmission owning member of the Midwest ISO,
- Access to **57,000 miles** of interconnected transmission valued at **<u>$17 billion</u>**,
- Access to **347** market participants that performs **<u>$24.3 billion</u>** in energy transactions per year,
- Met **NERC** reserve requirements,
- In 2011, we've been able to sell **<u>92%</u>** of our available generation versus **<u>88%</u>** the year before *(~480,000 MWH's)* – primarily due to lowering spinning reserve requirements (*32 MW versus 3 MW*)

MISO Credit/Cash Flow/Settlements

- **MISO serves as a "Buyer to Every Seller" and "Seller to Every Buyer" for Spot Market Energy**
- **MISO Manages Credit Margin Requirements For:**
  - Financial Transmission Rights (FTR)
  - Energy and Ancillary Market Activity
- **MISO Maintains Weekly Settlements**
  - Weekly Settlements Mitigate Credit Requirements, but Affects Cash Management
  - Settlement Statements are Extensive and Require Constant Detailed Validation

Big Rivers

Experience To-Date

- Big Rivers had to accept a minimum **<u>five-year</u>** membership (expires at the end of 2014),
- A one-year withdrawal is required to exit (earliest request end of 2013)
- Big Rivers transferred functions described on "slide 11",
- Only minor issues thus far during the integration,
- Expected $5.3 million annual membership fee,
  - Administrative costs have been lower than expected (**$350,000 savings**),
- No congestion related limitations - nearly complete elimination of transmission congestion since joining MISO (had ~ 50 incidents in 2007-2009),
- Positive effect on importing and exporting power into the Midwest ISO,
- No impact on distribution members other than learning about MISO and costs associated with membership.

Big Rivers

Summary of MISO Benefits

- **Efficient Use of Generation and Transmission – Centralized Planning**
  - Large Area Dispatch and Unit Commitment Optimization
  - Eliminates Transmission Rate Pancaking
  - Better Transmission Planning
  - Fair and Equitable Access to Transmission
- **Single Balancing Authority and Consolidated Reliability Coordination**
- **Transparency**
  - Day Ahead and Real Time Energy Market By Location
  - Transparent Transmission Congestion Mechanism
- **Use of Multiple Products to Manage Risk**
  - Transmission Congestion Rights (FTR's - Financial Transmission Rights)
  - Ancillary Services

Big Rivers

Conclusion

- Midwest ISO is still the most cost effective option for meeting Big Rivers' contingency reserve requirement.
- A drastically new way of business.
- Markets are more efficient, but more complicated.
- More alternatives for hedging & optimization.
- Changes are ongoing and challenging.
- Very beauracratic and quasi governmental governance – little say in process.

- The benefit has been greater than estimated – on positive side of estimated range.
- Big Rivers realized a benefit from the ability to sell more power into the market than prior to MISO membership.
- The administrative costs are less than anticipated (likely to return to originally expected levels in 2012).
- Less additional staff than originally estimated.
- Transmission constraints have been virtually eliminated.
- MTEP/MVP has progressed slower and at lower cost than originally expected.
- Requires more coordination
  - Within BREC
  - With ACES Power Marketing
  - With MISO
- May want John Sturm of ACES to come address EKPC as well.

Big Rivers

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2012-00169
FIRST REQUEST FOR INFORMATION RESPONSE

COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION DATED 06/15/12
REQUEST 3
RESPONSIBLE PERSON: **Don Mosier**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 3. Refer to the Application, page 8, paragraph 16, which states, "[f]inally, PJM also manages a sophisticated regional planning process for transmission expansion to ensure the continued reliability of the electric system." Provide the following:

Request 3a. Does East Kentucky currently have employees performing the regional planning process for the transmission expansion of East Kentucky's transmission system to ensure the continued reliability of its electric system?

Response 3a. EKPC's Transmission Planning department is solely responsible for all transmission planning activities at EKPC currently, including any regional planning that is occurring. EKPC's Transmission Planning department is responsible for coordinating with the SERC Regional Reliability Entity, and participating in its regional planning processes. EKPC employees also coordinate with neighboring entities to address regional planning issues.

EKPC presently participates in a regional planning collaborative called the Central Public Power Partners (CPPP). This group consists of EKPC, Associated Electric Cooperative Inc. (AECI), and the Tennessee Valley Authority (TVA). The CPPP provides a forum to discuss regional planning issues within the CPPP footprint, as well as interregional planning issues affecting one or more members of the collaborative. The CPPP does not have formal regional planning processes in place at this time. Presently, each member presents its own plans to the group for information, but no formal regional plans are developed.

Request 3b. If yes, what is the number of employees and the annual cost associated with this function?

Response 3b. EKPC's Transmission Planning department consists of 4 full-time employees, including the department manager. All of these employees participate in regional planning activities to varying degrees. The costs associated with this function are primarily travel expenses to attend SERC and CPPP meetings. The total annual cost to attend these meetings is estimated to be $5,000.

Request 3c. Will East Kentucky continue to incur any cost for the transmission planning process in Kentucky if it joins PJM?

Response 3c. EKPC will maintain primary responsibility for planning activities associated with its transmission system after integration into PJM. EKPC does not anticipate any change in staffing levels within the transmission planning department after integration. EKPC must remain a member of one of the North American Electric Reliability Council (NERC) Regional Reliability Entity's, such as SERC. EKPC will continue its participation in SERC regional planning activities. EKPC will no longer be a member in the CPPP after integration into PJM. Instead, EKPC will participate in the PJM planning process to satisfy its regional and interregional planning obligations per FERC Order 1000.

As a result of these new and continuing needs and obligations, EKPC expects its costs incurred for the transmission planning process to remain roughly equivalent to the existing costs.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2012-00169
FIRST REQUEST FOR INFORMATION RESPONSE

COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION DATED 06/15/12
REQUEST 4
RESPONSIBLE PERSON: **Don Mosier**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 4. Refer to the Application, page 14, paragraph 32, which states, "EKPC will continue as a member of the TEE Contingency Reserve Sharing Group ("TCRSG") which assures that no harm comes to any ratepayers of the other members of the TCRSG." Provide the following:

Request 4a. Explain whether PJM tariffs expressly authorize a transmission owner to be a party to a contract with non-PJM members for purposes of sharing reserves such as is provided for under the TCRSG. If no, will PJM need to file a tariff to authorize East Kentucky's continued participation in the TCRSG?

Response 4a. PJM currently manages Dominion's obligations of a Virginia Carolina (VACAR) reserve sharing agreement that was in effect prior to Dominion joining PJM. EKPC expects that it will also be able to successfully work with PJM to meet the obligations under the TCRSG. Please also see the response to Request 25b.

Request 4b. The amount, in kW or kWh, which East Kentucky relied upon or supplied resources associated with the TCRSG for each of the last five years.

Response 4b. The TCRSG began functioning on January 1, 2010. The Kw relied upon or supplied from that time until present are as follows:

	Relied Upon	Supplied
April 2010	20,000 kWh	
June 2010	99,000 kWh	
November 2010		68,000 kWh
August 2011		47,000 kWh
November 2011		13,000 kWh
May 2012		27,000 kWh
Total	**119,000 kWh**	**155,000 kWh**

Request 4c. The amount of any revenue and expense that East Kentucky incurred as a result of being a member of the TCRSG for each of the last five years.

Response 4c. Revenue from energy supplied to the TCRSG from EKPC:

November 2010	$6,800
August 2011	$4,700
November 2011	$1,300
May 2012	$2,700
Total Revenue	**$15,500**

Expense:

July 2009	Software Development	$12,675
Sept 2009	Software Development	$10,901
Jan 2010	Administrator Fee	$113,109

Feb 2010	Software Development	\$32,077
April 2010	Cost of Energy Purchased from the RSG	\$2,000
June 2010	Cost of Energy Purchased from the RSG	\$9,900
Aug 2010	Software Development	\$22,448
Dec 2010	Administrator Fee	\$117,310
Dec 2011	Administrator Fee	\$123,786
Total Expense		**\$444,206**

Request 4d. Whether East Kentucky expects to receive any revenues associated with the TCRSG once it is a full member of PJM.

Response 4d. EKPC expects to receive revenues associated with the TCRSG once it is a full member of PJM from reserves supplied to the group by EKPC, no differently than if EKPC were not a member of PJM.

Request 4e. Whether East Kentucky expects to incur any expenses associated with the TCRSG once it is a full member of PJM.

Response 4e. EKPC expects to incur expenses such as the Annual Administrator Fee, Software Development Fee, and cost of Reserves used by EKPC.

Request 4f. Provide copies of any written or electronic correspondence that references the Tennessee Valley Authority ("TVA), the TCRSG, and East Kentucky's proposed membership in PJM.

Response 4f. The requested correspondence is included on pages 4 through 17 of this response.

TEE CONTINGENCY RESERVE SHARING GROUP
Operating Committee Meeting
DRAFT – Meeting Minutes
Tuesday June 5, 2012

Attendees:

Representatives:
EKPC – Chuck Dugan
LGEKU – Charlie Freibert (Vice-Chair)
TVA BA – Phillip Wiginton (Chair)
TVA Admin –Nate Schweighart

Alternates:
EKPC – Greg Whittaker
LGEKU – Charlie Martin
TVA BA – Edd Forsythe
TVA Admin – Scott Homberg

Guests:
TVA BA – Kelly Casteel
TVA Admin – Scott Davison (phone)

Quorum

All representatives were in attendance.

1. Approval of Notes of Meeting – February 23, 2012

Draft notes of meeting for February 23, 2012 were approved with no changes.

2. Representative Changes

TVA verified everyone received their notification of administrator representative change. The letter stated that Nate Schweighart would be the new TEE CRSG Administrator representative replacing Martha Dalloul. LGEKU and EKPC had received the notification and had no changes to their representatives.

3. Review of Action Items from February 23, 2012 Meeting

1. Scott Homberg handed out example tag templates for submission by sink CRSG entities for TCRSG events exceeding 60 minutes in duration in order to ensure compliance with INT-010 and its future revisions. Discussion occurred about how to associate the tag with TRM. Scott said that in order to pass automated validation a TSN number needs to be created for TRM such that it can be associated with the tag.

   Action Item: Each entity is responsible for establishing TSN numbers for their TRM and to build their own tag templates. Action item to be completed by next meeting.

LGEKU says TranServ is taking over the ITO function in September. They have an automated process. EKPC's process is not automated so it isn't as important for them to have a TSN number for their TRM.

2. Scott Homberg handed out language changes to the TCRSG protocols for section 2.6.1.2 to address tagging of extensions. Since there will be other changes to the protocol before the next TCRSG meeting, it was decided to approve the changes at that time. The group discussed implementation plan and decided that if the software is in place and all other required actions have been completed, such as create the TRM TSN and tag templates, an email vote can be taken. If the vote is in the affirmative, entity can begin tagging 60 minute extensions before the protocol language change occurs.

3. Scott Davison gave an update to the group regarding the requested software changes. Scott reported that the "easy button" change that had been approved last meeting was 60% completed. Personnel changes had caused work to halt but a new employee was hired and a new version should be ready for testing in a couple of weeks. Scott agreed that the tagging changes outlined by Scott Homberg can be rolled into the annual maintenance cost and can be tested with the "easy button" change that will not exceed $6,000.00.

   Action Item: Scott Davison will provide Admins the new version of the CRSG application in three weeks for testing.

4. Scott Davison reported on TCRSG application uptime/downtime. The program was unavailable for 600 minutes. Of those 600 minutes, 500 were non-application related. The process currently has a 99.54% uptime. Scott states that they plan on making a change to the CRSG program and database to isolate it from the other systems. The project is in process but no firm date has been established. This change would have no affect on the current internet connection.

5. Nate Schweighart reported on discussions that Martha Dalloul had with Transmission Planning specifically Tim Smith and Josh Lewey. The TCRSG group discussed the issues with restudying deliverability every year and how that the more times a certain time period is restudied for deliverability the more risk there is that the time period will be found undeliverable. It was suggested that the deliverability studies be five years studies with reasonable headroom. The headroom could keep the deliverability from having to be restudied every year, even if the reserve amounts change every year. It was also discussed that if additional TRM is required for the reserve sharing group, the deliverability request could just be for the incremental change in transfer and not for the whole amount.

   Action Item: Nate Schweighart will write a paper describing the proposed change in deliverability studies and will send it to the TCRSG representatives. Each representative will discuss the change with their Tariff/Guideline groups in order to verify the change doesn't violate the Tariff/Guidelines.

   The group also discussed moving up the submission date of the peak load and Most Sevier Single Contingency (MSSC) to September 1st instead of October 1st.

   The Operating Committee agreed to move up the submission date to September 1st and make the change to the protocols at the next meeting.

   Action Item: The Operating Committee agreed to true up the distribution list before the next deliverability study information request.

Action Item: The Administrator agreed to CC the Operating Committee on the deliverability emails in order to keep all entities in the loop.

4. Review Contingency Reserve Activation Events

Scott Homberg reviewed the CR events that occurred 1st Quarter 2012.

5. Impact of LGEKU Transition to TranServ

LGEKU reports that the CRSG functions currently handled by the SPP ITO are transitioning to TranServ on 09/01/12. LGEKU notes that SPP will need to be removed from CRSG at that time.

Action Item: LGEKU will contact Clay to make arrangements for SPP's removal from the TCRSG application.

6. TCRSG Agreement - Duration Extension

The Operating Committee discussed the fact that the current reserve sharing group only requires six month notice in order to leave the group. Is any entity could leave in such short duration it makes it hard for entities to count of the reserves in the long term. All entities seemed open to extending the duration of the agreement. It was decided if anyone has a specific proposal the group will review the proposal.

The Operating committee also discussed how PJM would fit into the agreement if EKPC were to join the PJM market. EKPC stated that currently EKPC plans on joining the PJM Balancing Authority Area on June 1, 2013. EKPC states that PJM will need to be able to review the TCRSG documents in order to determine PJM's involvement in the group. The operating committee decided an NDA is needed if the documents were to be shared with PJM.

Action Item: TVA will draft a NDA for giving PJM the protocols, agreement and administration documents.

Action Item: Once PJM has time to review the documents, EKPC will set up an initial meeting with PJM and the Operating Committee. It will be a face to face meeting at EKPC and will occur on or around the next Operating Committee meeting.

7. ACE Diversity Interchange

Phillip Wiginton explained why ACE Diversity Interchange would be advantageous to the reserve sharing group entities. Not a whole lot of downside could be found for ADI. There were some questions on how transmission service would be handled for ADI. Phillip said that other groups did not obtain transmission service because these imbalance flows occur regardless of ADI. The size of ADI would be ~150 MW. The group decided it was open to the concept and would consider ADI if there was a specific proposal presented to the Operating Committee.

Action Item: Phillip Wiginton will look into scheduling a trip to an entity that is currently using ADI such as BPA.

8. Schedule Next Meeting

The Operating Committee decided the next meeting will be hosted by EKPC sometime in August on the tail end of meeting with PJM. The committee decided to wait until EKPC talks to PJM before the exact date was determined.

Denver York

From: Denver York
Sent: Saturday, December 03, 2011 7:10 AM
To: Tony Campbell; Don Mosier; Mike McNalley; David Crews; David K. Mitchell - HQ; Craig Johnson; Stacy Barker; David Smart; Jerry Purvis; Barry Mayfield
Cc: Chuck Dugan
Subject: Meeting with KU/LGEE

All,

David Crews, Chuck Dugan and I met with folks from KU/LGEE trading and marketing yesterday. Charlie Friebert, Director of Marketing, was at that meeting and is also their liaison for the TEE Contingency Reserve Sharing Group. We briefed them of our likely intentions of pursuing negotiations with PJM regarding becoming a member effective June 2013. We also stated that is in our best interest and our intention to continue participation in the CRSG indefinitely and that PJM has indicated that this is acceptable. The message was reasonably well received and they agree to keep this information in-house until we were able to contact TVA with the same message.

As some of you know, KU/LGEE contacted us to discuss our positions WRT CSAPR emissions allowance caps. Of course their current settlement for $2.3 billion in recovery was discussed. My read on the conversation was that the provision in that settlement that prevents them from cleaning up the Brown plant until Utility MACT is final presents a challenge for them. They will not have time to clean that up if they must delay.

David may want to add further comments regarding our discussions if he wishes.

Denver York, PE
VP, System Operations & Power Delivery
East Kentucky Power Cooperative
(859) 745-9235 (office)
(859) 582-2946 (mobile)

Denver York

From: Denver York
Sent: Monday, December 05, 2011 5:54 PM
To: Tony Campbell
Cc: Don Mosier
Subject: Re: TVA reserve sharing group meeting

Will update you two when we return.

/***/

Denver York, PE
VP, System Operations & Power Delivery
East Kentucky Power Cooperative
(859) 745-9235 (office)
(859) 582-2946 (mobile)

/***/

On Dec 5, 2011, at 3:03 PM, "Tony Campbell" <tony.campbell@ekpc.coop> wrote:

> I'm fine with you not attending the board meeting.
>
> TC
>
> Sent from my iPhone
>
> On Dec 5, 2011, at 2:33 PM, "Denver York" <denver.york@ekpc.coop> wrote:
>
>> Chuck Dugan just informed me that the quarterly meeting is tomorrow and that it would be a perfect opportunity for us to inform them of our potential PJM membership.
>>
>> There is nothing on the Board agenda that I would have direct input to. Would you both think it would be more important for Chuck and I to drive to Chattanooga to discuss the PJM issue with them face-to-face?
>>
>> Thanks,
>>
>> Denver
>>
>> Denver York, PE

Denver York

From: Denver York
Sent: Tuesday, April 03, 2012 12:01 PM
To: Ann Wood
Subject: Re: Information for PJM Testimony

Some combination of Darrin and Chuck should answer this.

/***/

Denver York, PE
VP, System Operations & Power Delivery
East Kentucky Power Cooperative
(859) 745-9235 (office)
(859) 582-2946 (mobile)

/***/

On Apr 3, 2012, at 11:49 AM, "Ann Wood" <ann.wood@ekpc.coop> wrote:

Thank you, Denver. Would you happen to know the answer to this one, or if it's relevant today?

How will joining PJM impact EKPC's current interconnection agreements?

From: Denver York
Sent: Tuesday, April 03, 2012 10:56 AM
To: Ann Wood; Chuck Dugan
Cc: Don Mosier
Subject: RE: Information for PJM Testimony

From: Ann Wood
Sent: Friday, March 30, 2012 9:38 AM
To: Denver York; Chuck Dugan
Subject: Information for PJM Testimony

Denver and Chuck:

David Samford at FBT is enhancing Don Mosier's testimony for the PJM filing. Would you provide answers to the following questions?

1) Does EKPC plan to transfer control of its 69 KV facilities to PJM?

At this time, EKPC only anticipates turning over functional control of facilities rated at 100 kV and above. As there is precedent for facilities below 100 kV to be included, EKPC will continue to evaluate whether or not EKPC would benefit economically from placement of these facilities under PJM control. In either case, reliability of EKPC's grid is not affected by the decision.

2) How does becoming its own load zone and balancing authority change in PJM compared to today? (meaning we're our own today)

The most significant difference between operating the transmission system today and after becoming a member of PJM is the need to coordinate transmission level maintenance activities with the RTO.

3) Will remaining a member of the current reserve sharing group limit EKPC's ability to realize the full benefits of PJM?

No. PJM would act on behalf of EKPC to meet its obligation to the group. Because of the greater number of resources available as a member of the PJM RTO, EKPC anticipates that EKPC's costs would likely be less to meet its obligation than if it remained outside the PJM RTO.

And this one is my question and I don't know that it's even relevant now...

How will joining PJM impact EKPC's current interconnection agreements?

Thank you both and please call if these need clarification.

Have a great weekend,
Ann

Ann Wood
Director, Regulatory Services
East Kentucky Power Cooperative, Inc.
P.O. Box 707
Winchester, Kentucky 40392-0707
Direct Line: (859) 745-9670
Fax: (859) 744-6008
Cell: (859) 595-6185

Denver York

From: David Crews
Sent: Tuesday, April 17, 2012 11:36 PM
To: Denver York; Don Mosier
Cc: Chuck Dugan
Subject: Re: Reserve Sharing Commitment to 10 years

I agree with Don. The CRA analysis is 10 years and we are looking for a long term arrangement.

Sent from my HTC Inspire™ 4G on AT&T

----- Reply message -----
From: "Denver York" <denver.york@ekpc.coop>
To: "Don Mosier" <Don.Mosier@ekpc.coop>
Cc: "David Crews" <David.Crews@ekpc.coop>, "Chuck Dugan" <chuck.dugan@ekpc.coop>
Subject: Reserve Sharing Commitment to 10 years
Date: Tue, Apr 17, 2012 8:29 pm

I will tell Nate that, although we will consider something between five and ten, for anything less than ten we will have to perform our analyses as if the RSG did not exist, which would be amsubstantial erosion of any value.

Denver York, PE
VP, System Operations & Power Delivery
East Kentucky Power Cooperative
(859) 745-9235 (office)
(859) 582-2946 (mobile)

On Apr 17, 2012, at 8:23 PM, "Don Mosier" <Don.Mosier@ekpc.coop> wrote:

> This is one concern i have about entering into an alternative to PJM. 5 years is not long term. We need to value then the loss of the RSG inthe comparison at 5 years. The partnership would have to mitigate and exceed any foregone opportunity for some period beyond 5 years. To me its a troubling sign of their commitment, though we are early in the process.
>
> On Apr 17, 2012, at 8:06 PM, "Denver York" <denver.york@ekpc.coop> wrote:
>
>> All,
>>
>> Nate from TVA is asking if something less than a ten-year committment yo the RSG would potentially be acceptable to EKPC. I can understand their hesitation to make a ten year committment and can also see how something between five and ten would help us decide between a PJM option and a stand-alone option if there can be value there. I mean to say that, if we can find enough value in working with TVA to offset the potential value of joining PJM, then I would not let the fact that we only have a five-year committment to the RSG get in the way.
>>
>> Do any of you have grief if I let Nate know that EKPC would consider five years to be the minimum, but that we would have to consider anything less than ten as less valueable as we consider our options?

Thanks,
Denver

Denver York, PE
VP, System Operations & Power Delivery
East Kentucky Power Cooperative
(859) 745-9235 (office)
(859) 582-2946 (mobile)

Begin forwarded message:

From: "Schweighart, Nathan" <naschweighart@tva.gov>
Date: April 16, 2012 1:38:58 PM EDT
To: "York, Denver" <denver.york@ekpc.coop>
Subject: Reserve Sharing Commitment to 10 years

Mr. York,

I've been looking into the Reserve Sharing Commitment Duration Extension item that came from the TVA/EKPC meeting. I was hoping to get some more information from EKPC as to what minimum time durations are required to meet your needs. We have been discussing internally and the question has come up that if we cannot meet 10 years what sort of duration would still meet your needs? If only the 10 years would work for EKPC then we will limit our discussion to that, if shorter durations (but still longer than 6 months) could possible work then we will include those scenarios also in our internal discussions.

Thanks for your help and let me know if you need any more clarification.

Nate Schweighart
Tennessee Valley Authority
Manager, Transmission & Interchange Services
423.697.4189

Write a wise saying and your name will live forever.
-Anonymous

Denver York

From:	Denver York
Sent:	Thursday, April 19, 2012 9:34 PM
To:	Don Mosier; David Crews
Subject:	Fwd: Issues regarding EKPC membership in Reserve Sharing Group as a member of PJM
Attachments:	image001.jpg

Denver York, PE
VP, System Operations & Power Delivery
East Kentucky Power Cooperative
(859) 745-9235 (office)
(859) 582-2946 (mobile)

Begin forwarded message:

From: Chuck Dugan <chuck.dugan@ekpc.coop>
Date: April 17, 2012 2:08:08 PM EDT
To: Denver York <denver.york@ekpc.coop>, Ann Wood <ann.wood@ekpc.coop>, Sherman Goodpaster <sherman.goodpaster@ekpc.coop>
Subject: FW: Issues regarding EKPC membership in Reserve Sharing Group as a member of PJM

FYI... this is the response from PJM. I will discuss with the RSG.
Thanks,
Chuck

From: kozaf@pjm.com [mailto:kozaf@pjm.com]
Sent: Tuesday, April 17, 2012 1:38 PM
To: Chuck Dugan
Subject: Re: Issues regarding EKPC membership in Reserve Sharing Group as a member of PJM

Chuck,
Good to hear from you!
Regarding reserve sharing, we would treat a call for reserves from your RSG partners as a call on PJM. We would be your agent in the RSG. The reserves would come from the PJM operating reserves. EKPC would not have to carry the reserves in your area, unless your RSG agreement required it. Basically, we would fulfill all of the obligations of the RSG on your behalf. We do this for Dominion today. They continue to be in the VACAR RSG and we are their agent.
Hope this helps.
Frank

Sent from my iPhone

On Apr 17, 2012, at 12:54 PM, "Chuck Dugan" <chuck.dugan@ekpc.coop> wrote:

> Hi Frank,
> We have some questions regarding EKPC membership in PJM and how this would affect EKPC participation in our current Reserve Sharing Group. We are trying to get a picture of how things would work.

If TVA or LGE/KU were to call on reserves from EKPC, would reserves be supplied from the overall PJM reserves or would they come from the pool?
Would EKPC be required to carry the reserve amount for the group? Currently this is 94 MW's.

I believe there may be another member of PJM that is a member is an external Reserve Sharing Group. You may not be able to give me any specifics related to that group but I was hoping you could give me an idea as to how our RSG would look with EKPC in PJM.

Thank you,
Chuck

<image001.jpg>

<Chuck Dugan.vcf>

Denver York

From: Denver York
Sent: Wednesday, May 02, 2012 12:06 PM
To: Ann Wood; David Crews
Cc: Don Mosier
Subject: RE: Comments

In Mr. Mosier's testimony, (page 4, line 21), the statement is made "which is not always the most economic choice." I would suggest "when more economic choices might be available without these constraints."

In response to the question starting on page 5, line 19: I believe the concepts of reserve margin and operating reserve are blurred and should remain distinct. I clearly indicate that the 12% is a reserve margin (long term planning reserves) and that the TCRSG does not contribute to that, but is used operationally (short-term) to ensure we can handle contingencies as they arise. Also, the 2% is a type of operational reserves held to manage minute-by-minute load and frequency fluctuations, missed load forecasts, and other operational issues. I might propose the following response to the question:

"EKPC currently has an internal target to maintain a 12% capacity reserve margin – which equals approximately 360 MW – on its winter peak load. In addition to this capacity reserve margin – which is used for planning purposes – EKPC must carry operating reserves during all periods of time. EKPC relies heavily on the TEE Contingency Reserve Sharing Group ("TCRSG") along with TVA, KU, and LG&E to meet the North American Electric Reliability Council ("NERC") imposed contingency reserve standards. Also, EKPC maintains an additional operating reserve of 2% of its peak forecasted load for the day to provide for regulation of load and frequency."

Alternatively, take out all references to operating reserve (contingency through the TCRSG and the 2% regulating) and reference only the capacity reserve margin since that is the source of value we are discussing.

In the question starting on page 6 (line 9), a statement is made in the response that, "Transmission paths sourcing in TVA and KU/LG&E are limited because of an existing inadequacy of high voltage transmission lines connecting us with our neighbors." I have concern that this statement could close the door on us should we decide to withdraw this application in favor of pursuing opportunities with TVA that are being discussed. However, I believe it prudent to send the message to the Commission that we need more high voltage lines with our neighbors. Just food for thought should Don want to consider it.

My same comment applies to the response to the question on page 8 starting on line 9. The last sentence states that, "I would add that a lack of available long-term firm transmission from either TVA or KU/LG&E limits the viability of these alternatives." This one is softer because it says "available long-term firm" instead of physical connections.

From: Ann Wood
Sent: Wednesday, May 02, 2012 11:08 AM
To: David Crews; Denver York
Subject: Comments

David and Denver:

I am going to FBT this afternoon to work with Mark David and David in making final changes to the application. Please let me know by noon today if you have comments from your review of the documents.

Thank you,

Ann

Ann Wood
Director, Regulatory Services
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Direct Line: (859) 745-9670
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EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2012-00169

FIRST REQUEST FOR INFORMATION RESPONSE

COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION DATED 06/15/12

REQUEST 5

RESPONSIBLE PERSON: Don Mosier

COMPANY: East Kentucky Power Cooperative, Inc.

Request 5. Refer to the Application, pages 14-15, paragraph 32. Explain how "Participation in PJM through the rights and benefits afforded to transmission owners and generation owners will allow East Kentucky to position itself to efficiently comply with existing and anticipated federal obligations imposed by the U.S. Environmental Protection Agency (EPA) and the Federal Energy Regulatory Commission (FERC)."

Response 5. Participation in PJM will afford EKPC the flexibility to comply with current and future EPA regulations through EKPC's compliance plans and/or through the PJM market. The PJM market will enable EKPC to gain access to economic generation and transmission during times when its fleet is being retro-fitted or repowered to meet new EPA regulations. Overall, PJM offers EKPC opportunity and flexibility in generation, transmission and environmental compliance.

PJM has already begun incorporating EKPC into its planning processes in anticipation of EKPC becoming a full member on June 1, 2013. Therefore, EKPC is being considered in all regional planning activities of PJM moving forward. EKPC will begin participating in the regional planning meetings occurring at PJM immediately as well. These immediate actions and activities will be used to comply with FERC Order 1000 for the period until EKPC becomes a full member of PJM. Once full membership is achieved, EKPC and PJM will continue forward in much the same manner with regard to regional planning. That is, EKPC will effectively be a PJM member for regional planning purposes prior to the actual integration date. The primary difference between the period prior to June 1, 2013 (or an alternate final integration date) and the period after that date is that once EKPC becomes a full member, EKPC will become responsible for allocation of regional planning costs per PJM's approved methodology.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2012-00169
FIRST REQUEST FOR INFORMATION RESPONSE

COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION DATED 06/15/12
REQUEST 6
RESPONSIBLE PERSON: **Don Mosier**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 6. Refer to the Application, page 15, paragraph 34, and footnote 21. Explain how and why East Kentucky members will always be able to purchase power at East Kentucky's avoided cost and how that avoided cost is calculated.

Response 6. As a market participant, EKPC plans to bid all of its generation into the PJM market and purchase all of the energy required to serve its members systems' load from the same market. The net effect of these purchases and sales is that EKPC's energy costs are capped at the price EKPC could have generated the energy from its plants, because EKPC's capacity exceeds its demand. When the energy market is less than the cost of EKPC's generation, then the member systems' energy costs will reflect the market costs. When the energy market is more expensive than EKPC's generation costs, then the members will pay EKPC's generation costs. Thus, EKPC's generation costs cap the exposure to market cost volatility to the member systems. EKPC attempts to operate its system comparable to this approach today by utilizing available transmission to make economic purchases and sales with the PJM marketplace. EKPC cannot currently fully optimize its system with PJM because EKPC is limited by the available transmission and its market price estimation capability. When integrated into the PJM system, EKPC will be economically dispatched within the PJM system and will not have to estimate how to maximize its operations as an outside participant. During periods where EKPC's load exceeds its available generating capacity such as during winter months, load will pay the Day Ahead hourly price of energy for that amount, much like EKPC does today outside of PJM. Similarly, during periods of unplanned forced outages, EKPC's load will pay the applicable Day Ahead price of energy it consumes or the Real Time price for that energy when unplanned forced outages occur in Real Time. The net effect is very similar in cost impact to EKPC generating and load serving operations today since EKPC currently meets its purchased power needs through Day Ahead or Real Time purchases from PJM.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2012-00169
FIRST REQUEST FOR INFORMATION RESPONSE

COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION DATED 06/15/12
REQUEST 7
RESPONSIBLE PERSON: Don Mosier
COMPANY: East Kentucky Power Cooperative, Inc.

Request 7. Refer to the Application, page 9, paragraph 19, and the Direct Testimony of Don Mosier, pages 5-6 and 15.

Request 7a. Explain whether East Kentucky will need to construct additional transmission capacity to allow it to fully participate in PJM's markets.

Response 7a. PJM will not require EKPC to construct new transmission to "to fully participate in PJM markets." Notwithstanding, PJM is in the process of completing market integration generation deliverability studies to determine the extent of any NERC reliability criteria violations for which transmission expansion solutions must be developed necessary to ascribe Capacity Status to generating units in order to permit the specific participation of each in PJM capacity markets.

Beginning with PJM's 2012 RTEP process cycle and going forward, and consistent with the RTEP Protocol in PJM's Operating Agreement Schedule 6, EKPC BES facilities and lower voltage EKPC facilities that will be monitored by PJM Operations will be studied as part of annual RTEP required baseline contingency, generator deliverability, load deliverability thermal and voltage, n-1-1 thermal and voltage, short circuit and stability analyses. The scope of those studies will determine any additional upgrades arising out of application of PJM planning criteria. To the extent that PJM identifies reliability criteria violations as part of those studies, PJM will work with EKPC to develop transmission upgrades to solve them. Consistent with established RTEP procedures, all identified upgrades will be reviewed with the PJM Transmission Expansion Advisory Committee (TEAC) before recommendation to the PJM Board for approval.

Request 7b. Explain why and how East Kentucky's excess energy will be able to be sold more efficiently due to less frequent transmission constraints.

Response 7b. EKPC must currently rely on available transmission capacity ("ATC") reported through the OASIS to make sales into PJM. EKPC owns the rights to 400 MW of firm transmission from PJM to EKPC, but does not own the rights to any firm transmission from EKPC back to PJM. There are many times when there is no ATC from EKPC back to PJM, prohibiting EKPC from selling its excess energy into the PJM markets due primarily to external hourly import constraints on PJM's full border. Once a fully participating PJM member purchasing network transmission service, EKPC will be able to fully utilize network transmission services within PJM and all of EKPC's generated energy can be sold into the PJM marketplace.

Request 7c. Explain why and how East Kentucky's capacity reserve margin can be reduced by approximately 70 MW.

Response 7c. EKPC currently maintains enough operating reserves to cover its reserve sharing pro-rata share of capacity reserve. EKPC currently operates within a reserve sharing group with Tennessee Valley Authority and the LG&E/KU companies. The three companies together must maintain enough available capacity to cover the largest one generating unit that any of the three companies own. The applicable share of coverage is based upon the participant's native load requirements. If EKPC were operating within the PJM system, EKPC would still be required to carry its pro-rata share of the largest single unit contingency, which would be similar in size to what is being covered today, in a capacity reserve but EKPC's pro-rata share would be much smaller based on many more than three participants within the PJM system.

Request 7d. If not addressed above, explain whether the 94 MW that East Kentucky holds back as part of its current reserve sharing arrangement is counted as part of the 360 MW capacity reserve margin.

Response 7d. Yes, the 94 MW of operating reserves that are retained as part of the current reserve sharing arrangement is included in the 360 MW capacity reserve margin. The capacity reserve margin includes all operating reserves, which includes the 94 MW, reserves for extreme weather and reserves for load forecast error.

Request 7e. If not addressed above, explain how East Kentucky calculated that an additional 70 MW that could be offered into the PJM capacity market.

Response 7e. Please see Response 7c above.

Request 7f. Explain what East Kentucky's capacity reserve margin will be and how East Kentucky will meet its capacity reserve margin requirements after becoming a fully integrated PJM member.

Response 7f. EKPC will be required to carry its prorated share of the PJM capacity reserves based on the five highest PJM coincident summer peak demands. Based on historical information, EKPC would expect to carry slightly less than 3% of its summer peak load in capacity reserves based on EKPC's load diversity as compared to the PJM load characteristics. EKPC will be required to supply these reserves with proven capacity resources provided by generating units or purchases.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2012-00169

FIRST REQUEST FOR INFORMATION RESPONSE

COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION DATED 06/15/12

REQUEST 8

RESPONSIBLE PERSON: **Don Mosier**

COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 8. Refer to Mosier Testimony, page 6. Explain whether the lack of firm transmission capacity paths with TVA, Louisville Gas and Electric Company, and Kentucky Utilities Company are the result of existing line loading, which would limit the ability of those utilities to provide adequate firm transmission capacity to East Kentucky.

Response 8. The lack of firm Available Transmission Capacity (ATC) between the EKPC system and the TVA, LG&E, or KU systems is due to existing loading issues on flowgates (transmission lines or transformers) external to EKPC. EKPC has requested firm service from TVA, and has been notified that no ATC exists due to constraints within the TVA system identified during the System Impact Study (SIS) process. Similarly, LG&E/KU postings of ATC for its interface with EKPC typically indicate that no firm transmission capacity is available due to loading issues on flowgates within the LG&E/KU system and/or other external systems.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2012-00169
FIRST REQUEST FOR INFORMATION RESPONSE

COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION DATED 06/15/12
REQUEST 9
RESPONSIBLE PERSON: **Don Mosier**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 9. Refer to Mosier Testimony, page 14.

Request 9a. Explain how East Kentucky determines the offer price for its generation that is to be bid into both the capacity and the energy markets; i.e., what East Kentucky costs are included in each of the offer bids.

Response 9a. Energy: EKPC would expect to offer its generation into the energy market on a variable cost basis. That cost would include, but not be limited to, start-up costs, fuel, variable operations and maintenance, plus environmental control costs, such as allowances, limestone, lime, ammonia, etc. If EKPC has a unit that must stay on line at a minimum load level for operational reasons, then EKPC will designate that unit as must run and will be subject to whatever the market price bears.

Capacity: EKPC is not making additional investment to sell into the capacity market. Therefore, EKPC would expect to offer its generation into the capacity market as a price taker. EKPC will sell its capacity into the market and will buy enough capacity to serve its firm load plus the required reserves. Since EKPC will sell more capacity into the market than what it will be required to purchase to serve its load plus reserves for the next several years, the net result will create a positive cash flow to the EKPC members.

Request 9b. Explain whether the capacity and energy from each East Kentucky generating unit is bid into the capacity and energy markets separately and, if not, why not.

Response 9b. Capacity and energy for each generating unit will be bid into the markets separately.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2012-00169

FIRST REQUEST FOR INFORMATION RESPONSE

COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION DATED 06/15/12

REQUEST 10

RESPONSIBLE PERSON: **Don Mosier**

COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 10. Refer to Mosier Testimony, pages 14-15 and 19-24.

Request 10a. Explain what pricing zone(s) East Kentucky will be assigned and what other utilities are in the zone(s)

Response 10a. East Kentucky will be assigned to a new zone referred to as the EKPC Zone. There are no other utilities in the EKPC Zone.

Request 10b. If known, explain and discuss the types of generation that set prices in the energy markets and the extent to which it is time sensitive.

Response 10b. In the PJM energy markets all generators with a dispatchable range of MW are eligible to set price. This includes generation types such as Steam, Combined Cycle, Combustion Turbines, and Intermittent resources (i.e. Solar, Hydro and Wind). These generators are powered by Coal, Gas, Landfill Gas, Oil, Nuclear, Hydro, Wind, Batteries, and Solar. In the PJM Day-Ahead Markets, the generation owners submit an offer price representative of the lowest amount the generator is willing to accept for a corresponding MW output. These offers are submitted into the PJM Day-Ahead market at noon the day prior to the actual operating day. If the generator is selected in the

Day-Ahead market, the offer price remains in effect for the operating day. If the generator is not selected in the Day-Ahead Market, the generation owners may offer the generator at a different price level during the hours 1600 and 1800 the day prior to the actual operating day. The offer submitted at that time remains in effect for the operating day. In the PJM Day-Ahead market, prices are calculated and settled at each location on an hourly basis. In the PJM Real-Time Market, prices are calculated at 5 minute intervals and are settled on an hourly basis.

Request 10c. If known, explain and describe the energy and capacity market zones into which East Kentucky will be assigned including principle economic and demographic drivers behind recent market clearing prices.

Response 10c. In the PJM Day-Ahead and Real-Time Markets, East Kentucky will be assigned to a new zone, EKPC. In the PJM Capacity Market, East Kentucky will be assigned to a new Locational Deliverability Area (LDA), EKPC. PJM is currently conducting the Locational Deliverability Analysis. Upon the completion of the Locational Deliverability Analysis it will be decided to which of the parent LDAs EKPC will be mapped (i.e. RTO, Western PJM, etc). Market clearing prices are affected by many factors including weather, fuel price, environmental restrictions, generator availability, transmission outages and congestion on the system. Please see the response to Request 10.d on the economic and demographic drivers behind the recent Capacity market clearing prices.

Request 10d. If known, explain and discuss the reasons for and the issues surrounding the recent price spike in the PJM capacity market.

Response 10d. The PJM Capacity Market Base Residual Auction ("BRA") for the 2015/2016 Delivery Year was impacted by a series of significant developments. Over the next three years an unprecedented amount, over 14,000 MW, of generation retirements have been announced driven largely by environmental regulations, primarily EPA Mercury and Air Toxics Standards (MATS) and the High Electricity Demand Day Rule (HEDD) in New Jersey which have compliance deadlines of April 16, 2015 and May 1, 2015 respectively. These environmental rules and resulting resource retirements significantly impacted the RPM auction results. The announced generation retirements send a strong signal that there would be a need for new resources, and this auction witnessed a record number of new generation offers, 6,854 MW; a record number of demand resource offers, 19,956.3 MW; and a record number of energy efficiency resource offers, 940.3 MW. This significant amount of additional resource offers also impacted the RPM auction results. The auction results also represent the continuing trend, starting in the 2014/2015 BRA, of a significant decline in the amount of coal-fired generation cleared and a significant shift to increased amounts of new natural gas-fired generation cleared. The auction clearing prices are higher than the previous auction driven largely by the impact of environmental regulations.

Request 10e. Explain whether the recent PJM capacity price spike would have affected East Kentucky if it had already been a fully integrated member of PJM and, if so, how.

Response 10e. If East Kentucky was a fully integrated member of PJM for 2015/2016 Delivery Year and was not separated in price from the rest of PJM, the Resource Clearing Price for East Kentucky would have been the same as that of EKPC's parent LDA. EKPC's parent LDA will be determined as a part of the Locational Deliverability Analysis, which is currently being conducted. The current expectation is that EKPC will be a part of Parent LDA (i.e. RTO, Western PJM, etc), of which the clearing prices for the 2015/2016 Base Residual Auction for the Capacity market only increased by approximately $10 per MW-day. This increase would provide a positive benefit to EKPC since it will be long in net capacity and selling into the capacity market.

EAST KENTUCKY POWER COOPERATIVE, INC.
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FIRST REQUEST FOR INFORMATION RESPONSE

COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION DATED 06/15/12
REQUEST 11
RESPONSIBLE PERSON: **Don Mosier**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 11. If known, explain how and the extent to which East Kentucky anticipates that each of its generation units will be dispatched and in what order, generally.

Response 11. EKPC expects its generation units to dispatch in the same order after PJM integration as they are dispatched today as a stand alone utility. EKPC economically orders and dispatches its fleet today and utilizes the PJM market to buy and/or sell on an economic basis. The difference between being a fully integrated PJM member and a stand alone entity is that EKPC will be included with the economic dispatch within PJM as opposed to EKPC estimating the PJM market prices and then dispatching. Additionally, transmission availability from EKPC to PJM will not be a limiting issue after integration. The results of the CRA study, Exhibit RLL-2, indicate that EKPC could realize less than 10% production cost savings by being fully dispatched by PJM. The bulk of these savings are based on running the coal units as much or slightly more within PJM and running gas combustion turbines less. PJM market purchases are expected to increase to displace the gas generation.

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FIRST REQUEST FOR INFORMATION RESPONSE

COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION DATED 06/15/12
REQUEST 12
RESPONSIBLE PERSON: **Don Mosier**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 12. Explain whether East Kentucky expects natural gas prices to remain low and, if yes, the anticipated effects of continuing low gas prices on East Kentucky's unit dispatch order.

Response 12. The expected natural gas prices used in the Charles Rivers Associates study are shown on page 43 of 49 in Exhibit RLL-2.

Natural gas prices are a key driver in the amount of EKPC excess energy sales as the EKPC system is largely coal-fired. With gas prices relatively low, reducing the barriers to trade with the rest of PJM by joining PJM allows EKPC greater access to lower cost gas-fired resources during certain hours of the year and thereby increases EKPC's off-system purchases and decreases its excess energy sales. If gas prices become higher than currently forecast and move toward more historic levels, reducing the barriers to trade with the rest of PJM by joining PJM would increase EKPC's excess energy sales and reduce its off-system purchases.

EAST KENTUCKY POWER COOPERATIVE, INC.
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FIRST REQUEST FOR INFORMATION RESPONSE

COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION DATED 06/15/12
REQUEST 13
RESPONSIBLE PERSON: **Don Mosier**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 13. Explain the extent to which East Kentucky anticipates that, as a PJM member, its natural gas combustion turbines will be run as peaking units only or run during other times as well.

Response 13. EKPC's gas combustion turbines will be dispatched economically. A gas price in the $4.00/mmBtu range or higher will result in the combustion turbines being run as peaking units primarily. Continued lower prices will drive the combustion turbines to be operated more frequently based on economic dispatch order. This dispatch order does not differ based on EKPC's transfer of functional control to PJM but rather is driven by natural gas prices. EKPC optimizes the operation of the combustion turbines today based on market price to operate and hours available for operation under the station air permit limitations. This same optimization will continue in the PJM market.

EAST KENTUCKY POWER COOPERATIVE, INC.
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COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION DATED 06/15/12
REQUEST 14
RESPONSIBLE PERSON: **Don Mosier**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 14. If East Kentucky integrates into PJM and participates in the RPM market, explain the operational and financial ramifications of a forced outage to a unit already scheduled to be dispatched and run.

Response 14. Generator Forced Outage in PJM is defined as an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

In the PJM Day-Ahead and Real-Time Markets, a unit which is scheduled in Day-Ahead to run and which experiences a forced outage will be required to pay their locational Real-Time deviations from day-ahead schedules at the locational Real-Time pricing and will also be charged a portion of the Balancing Operating Reserves in proportion to a participant's locational Real-Time deviations from Day-Ahead schedules and generating resource deviations during that Operating Day.

Forced outages are also used to determine a unit's Equivalent Demand Forced Outage Rate (EFORd). The EFORd is a measure of the probability that a non-intermittent generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate and is based on forced outage data from an October through September period. The Generator Resource Performance Indices Manual (M-22) details the EFORd equation. Under the PJM Capacity Market rules as detailed in the PJM Capacity Market Manual (M-18), the unforced capacity (UCAP) value of a generation resource is installed capacity rated at summer conditions that are not on average experiencing a forced outage or forced de-rating. The unforced capacity is calculated as the installed capacity multiplied by one minus the Equivalent Demand Forced Outage Rate for a unit. A unit's final UCAP value for a Delivery Year is based on an EFORd calculated using forced outage data from the October through September period immediately preceding the Delivery Year. If the unit's UCAP amount committed to RPM for the Delivery Year is greater than unit's final UCAP value for a DY, a Capacity Resource Deficiency Charge will be assessed for the unit commitment shortfall, unless replacement capacity is specified. The Daily Capacity Resource Deficiency Charge is equal to the Daily Deficiency Rate times the daily commitment shortfall in MWs. The Daily Deficiency Rate is equal to the party's weighted average resource clearing price for such unit plus the higher of (0.2 * party's weighted average resource clearing price for such unit, or $20/MW-day). It should be noted that forced outage is a common event for all generating units which are mechanical devices. The index EFORd is used as a measure of performance of generators. Good performance lowers the EFORd of a generator and increases its value in both capacity and energy markets.

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REQUEST 15
RESPONSIBLE PERSON: Don Mosier
COMPANY: East Kentucky Power Cooperative, Inc.

Request 15. If known, explain the degree to which East Kentucky's full integration into PJM assists PJM (or neighboring PJM members in the relevant pricing zone) with reliability issues regarding environmental compliance, maintenance outage scheduling and etc.

Response 15. PJM has not yet studied these issues. PJM's original analysis for reliability regarding environmental compliance, maintenance outage scheduling, and etc. did not find reliability issues other than local issues, which PJM intends to address with reliability must run designation for critical generating units and transmission upgrades; the addition of EKPC is not expected to affect these results.

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REQUEST 16
RESPONSIBLE PERSON: **Don Mosier**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 16. Refer to the Mosier Testimony, pages 24 and 27-29.

Request 16a. Has East Kentucky been in contact with all its existing interruptible load customers about participating in PJM's Demand Response program and, if so, what have been the preliminary responses?

Response 16a. East Kentucky has discussed becoming a full PJM member with Gallatin Steel, East Kentucky's largest interruptible load. East Kentucky has not spoken to all interruptible customers. East Kentucky plans to host a local stakeholder meeting with PJM representatives and interruptible customers to provide the interruptible customers with PJM Demand Response Program information. No date has been set for this meeting.

Request 16b. Provide any analysis that East Kentucky has which demonstrates whether membership in PJM will impact the frequency or duration of interruptions for customers participating in the Direct Load Control Program.

Response 16b. East Kentucky will continue to be the DSM Aggregator and does not anticipate significant changes to the frequency and duration of interruptions for customers participating in the Direct Load Control Program.

<u>Request 16c.</u> Explain in detail how and why the terms of these programs will change if East Kentucky is a member of PJM.

<u>Response 16c.</u> East Kentucky does not anticipate changes to the Direct Load Control Program terms as described in the East Kentucky Tariff section DSM-3a and 3b. As the Members System's Direct Load Control Program tariffs are very similar, East Kentucky does not anticipate changes to those tariffs either.

East Kentucky believes amendments may be required for the interruptible customer's Industrial Power Agreements containing "buy through" provisions as that option may not be available in the PJM Demand Response Program.

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REQUEST 17
RESPONSIBLE PERSON: **Mike McNalley**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 17. Refer to the Direct Testimony of Mike McNalley ("McNalley Testimony"), page 7, lines 9 through 11, where it states, "[f]irst, we think these savings will help offset increased costs in other areas of our business, such as environmental compliance expenses." Provide the following:

Request 17a. Were the Long-Term Firm PTP Transmission Charges included as an expense when East Kentucky's current base rates were established?

Response 17a. No. The Long-Term Firm Point-to-Point Transmission Charges were not included as an expense when EKPC's current base rates were established. EKPC filed its most recent base rate increase (Case No. 2010-00167) on May 27, 2010 using 2011 as the forecasted test year. EKPC did not enter into the 400 MW of transmission rights with MISO (now with PJM) until late 2010. The first month that EKPC purchased this transmission was November 2011.

Request 17b. Will the savings associated with Avoided Long-Term Firm PTP Transmission Charges flow to the ratepayers only after the conclusion of a new base rate case for East Kentucky? If no, explain how the savings will flow to ratepayers without a base rate case.

<u>Response 17b.</u> No. Please see the response to Request 17a. The Long-Term Firm Point-to-Point Transmission Charges are not included in EKPC's current rates. However, this avoided transmission charge will positively impact EKPC's margins, which would benefit EKPC's member ratepayers through EKPC's capital credit allocation.

<u>Request 17c.</u> Does East Kentucky agree that a change in level of revenue or expense is not reflected in its environmental surcharge unless that revenue or expense account was previously authorized to be recovered under the environmental surcharge?

<u>Response 17c.</u> EKPC agrees that it can recover through its environmental surcharge only those expenses/return on rate base which relate to environmental compliance plan projects previously authorized by the Commission.

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REQUEST 18

RESPONSIBLE PERSON: **Mike McNalley**

COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 18. Refer to the McNalley Testimony, Exhibit MM-1, year 2017.

Request 18a. Explain whether the PJM reserve margin of approximately 2.8 percent or approximately 70 MW will be added on top of the approximate 2,500 MW summer peak.

Response 18a. Yes, the PJM reserve margin will be added on top of the peak load requirement.

Request 18b. Explain whether for the year 2017, the summer peak of 2,500 MW and the installed generating capability of approximately 3,100 results in a generating reserve margin of 24 percent [(3,100 MW - 2,500 MW)/2,500 MW].

Response 18b. EKPC's installed capacity would result in a larger reserve margin. As explained in the response to Request 9a, EKPC will offer all of its capacity into the market and purchase all of the required capacity back out of the market. Assuming EKPC's capacity requirements are less than what EKPC is able to sell into the market, EKPC will net a positive cash flow for its members by selling its excess capacity into the market.

Request 18c. Explain whether with its generating capability of approximate 3,100 MW, East Kentucky's summer peak could grow to approximately 3,015 MW, and still maintain its 2.8 percent PJM required reserve margin.

Response 18c. Yes, assuming that the PJM reserve requirements remain constant.

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REQUEST 19

RESPONSIBLE PERSON: **Mike McNalley**

COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 19. Refer to the McNalley Testimony, Exhibit MM-2, year 2015, Total Saving-RPM. Provide the following:

Request 19a. An explanation why the amount declined to $9.3 million when in 2014 it was $14.3 million and in 2016 it is $14.8 million.

Response 19a. Please see Table 8 on page 24 of 49of the CRA, Report Exhibit RLL-2, for the underlying cost categories that comprise these annual figures. The decline from 2014 to 2015 is largely driven by an increase in the projected allocation to EKPC of PJM transmission costs. The increase from 2015 to 2016 is largely driven by an increase in EKPC's capacity benefits. See the CRA Report for further detail.

Request 19b. Exhibit MM-2 in electronic format with formula unprotected and intact.

Response 19b. Please see an electronic version of Exhibit MM-2 on the attached CD.

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REQUEST 20
RESPONSIBLE PERSON: **Ralph L. Luciani**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 20. Refer to the Direct Testimony of Ralph L. Luciani ("Luciani Testimony"), Exhibit RLL-2, page 5 of 49, Table 1. Provide the following:

Request 20a. The amount of benefit associated with adjusted production costs as it relates to fuel costs that will flow to the members by way of the fuel adjustment factor.

Response 20a. CRA's modeling yields total annual fuel use by the EKPC generating fleet, including fuel for excess energy sales. Using an approximation that the average annual fuel cost for EKPC's excess energy sales per MWh are equivalent to the overall average annual EKPC fuel cost per MWh, the estimated fuel cost benefits in Table 1 that flow through the fuel adjustment factor are $27.7 million (2013-22 present value).

Request 20b. The amount of benefit associated with adjusted production costs as it relates to variable operation and maintenance costs that will flow to the members by way of a base rate proceeding.

Response 20b. $37.4 million (2013-22 present value).

Request 20c. The amount of benefit associated with adjusted production costs as it relates to emission costs that will flow to the members by way of the environmental surcharge.

Response 20c. $2.1 million (2013-22 present value).

Request 20d. An explanation of how the benefit associated with adjusted production costs as it relates to East Kentucky's "off-system" purchased power costs net of excess energy sales revenue will flow to the members.

Response 20d. Purchased power costs to serve native load flow through the fuel adjustment clause and will create an immediate impact to members. Changes in off system sales revenues will adhere to the EKPC margins and will flow to the members via additional equity.

Request 20e. An explanation of whether the benefits or the costs reflected on Table 1 associated with Administrative Costs, Transmission Costs, PJM Capacity Market Impacts and Avoided Long-Term Firm PTP Transmission Charges will flow to the members only after East Kentucky has a base rate proceeding.

Response 20e. Non-fuel related costs / savings will be reflected via base rates.

Request 20f. The benefits and costs for the 2013-2022 present value column broken down by fuel adjustment clause, environmental surcharge, and base rates.

Response 20f. In 2013-2022 present value, FAC = $27.7 million; ES=$2.1 million; Base Rates=$112.2 million.

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REQUEST 21
RESPONSIBLE PERSON: **Ralph L. Luciani**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 21. Refer to the Luciani Testimony, Exhibit RLL-2, page 13 of 49, Table 4. Provide an explanation to the reasons for the drop in GWH sales between the Status Quo column and the Join PJM column.

Response 21. Natural gas prices are a key driver in the amount of EKPC excess energy sales as the EKPC system is largely coal-fired. With gas prices relatively low, reducing the barriers to trade with the rest of PJM by joining PJM allows EKPC greater access to lower cost gas-fired resources during certain hours of the year and thereby increases EKPC's off-system purchases and decreases its excess energy sales. If gas prices become higher than currently forecast and move toward more historic levels, reducing the barriers to trade with the rest of PJM by joining PJM would increase EKPC's excess energy sales and reduce its off-system purchases. By comparing Tables 4 and 5, one can see that as gas prices gradually increase from 2013 to 2022 the reduction in EKPC excess energy sales in the Join PJM Case decreases. Regardless of gas price levels, in all cases, reducing trade barriers by joining PJM provides EKPC with reductions in total adjusted production costs.

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REQUEST 22

RESPONSIBLE PERSON: **Ralph L. Luciani**

COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 22. Refer to the Luciani Testimony, Exhibit RLL-2, page 14 of 49, Table 5. Provide an explanation to the reasons for the drop in GWH sales between the Status Quo column and the Join PJM column.

Response 22. Please see the response to Request 21.

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REQUEST 23

RESPONSIBLE PERSON: **Ralph L. Luciani**

COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 23. Refer to the Luciani Testimony, Exhibit RLL-2, page 24 of 49, Table 9. Provide the following explanation:

a.) The reasons for the Production Cost Savings for joining PJM to decline from $30.2 million in 2013 to $15.8 million in 2022.

b.) The reasons for the Purchases Cost Savings for joining PJM to increase from ($14.6) million in 2013 to $4.3 million in 2022.

c.) The reasons for the Sales Revenue Cost Savings for joining PJM to increase from ($11.4) million in 2013 to ($6.6) million in 2022.

Response 23a-c. The key factor for these trends is the gradual increase in natural gas prices from 2013 to 2022. As gas prices increase over time, EKPC will generate more as a member of PJM, which increases production costs (thereby reducing production cost savings), decreases purchase costs (thereby increasing purchase cost savings) and increases sales revenues. As shown in Table 9, the total adjusted production cost impact of joining PJM is positive in all years.

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REQUEST 24
RESPONSIBLE PERSON: **Don Mosier**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 24. Refer to the Application, page 17, paragraph 37, which states, "Moreover, East Kentucky will only be able to maximize its capacity benefits if it is permitted to enroll its interruptible load and Direct Load Control resources in PJM's Limited Demand Response Program."

Request 24a. Explain in detail how interruptible load and Direct Load Control resources will be enrolled in the Limited Demand Response Program.

Response 24a. East Kentucky will act as the DSM aggregator for participation in the PJM Demand Response Program for both the interruptible loads and the Direct Load Control Program and will be responsible for the performance of these programs when PJM instructs EKPC to operate them. EKPC will then be eligible to receive capacity credit for these programs, contributing to EKPC's fulfillment of its capacity obligation and reducing the net amount of capacity that EKPC must purchase or increasing the net amount of capacity that EKPC will be able to sell in the RPM auctions.

Request 24b. Provide a chart that shows for 2012 and each of the past five years the frequency, duration, and number of megawatt hours of load curtailed on East Kentucky's system.

Response 24b.

Interruptible Customers			
Year	# Times	# Hours	MWh
2007	54	392	16,458
2008	40	208	25,322
2009	17	100	4,525
2010	22	106	11,903
2011	9	44	3,376
2012 Through 4/2012	0	0	-

Request 24c. Explain whether East Kentucky will be participating in the PJM Limited Demand Response Program on behalf of its members' interruptible customers, or whether East Kentucky is proposing that the retail customers be authorized to participate directly in the PJM program.

Response 24c. East Kentucky will act as the DSM aggregator for participation in the PJM Demand Response Program for both the interruptible loads and the Direct Load Control Program. East Kentucky does not support customers participating in the PJM market independently from East Kentucky or its Member Systems. PJM does not allow customers to enroll directly in its Demand Response Program, and EKPC will commit, as Duke Energy Kentucky did in Case No. 2010-00203, to following PJM procedures to prevent third-party Curtailment Service Providers from enrolling customers in the PJM Demand Response Program without Commission approval.

Request 24d. Explain whether East Kentucky is proposing that its members' interruptible customers be authorized to resell into PJM the power that those customers purchased from an East Kentucky member.

Response 24d. East Kentucky does not propose to allow interruptible customers to sell energy purchased from East Kentucky into the PJM market. EKPC will act as the DSM aggregator and will appropriately allocate the value derived from participating in the PJM Demand Response Program, consistent with its tariffs and special contracts.

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REQUEST 25

RESPONSIBLE PERSON: Don Mosier

COMPANY: East Kentucky Power Cooperative, Inc.

Request 25. Refer to the Application, page 14, paragraph 32, which references the TEE Contingency Reserve Sharing Group ("TCRSG'I).

Request 25a. What benefits, if any, will accrue to the other members of this TCRSG?

Response 25a. EKPC intends to continue as a member of the TCRSG to both reduce its own risk as well as to ensure the other members continue to receive the benefits of membership they receive today. The specific benefits that will accrue to the other member of the TCRSG would be best described by those members.

Request 25b. How will PJM deal with the members of the TCRSG which are not members of PJM?

Response 25b. Full membership in PJM will not be consequential to the operation of the TCRSG when PJM is acting on behalf of EKPC. PJM will immediately respond to reserve calls from TCRSG members in real time and provide the resources in accordance with the requirements of the TCRSG agreement. EKPC will continue to be the signatory to the agreement and PJM will just act on EKPC's behalf in real time. PJM has been acting in this role on behalf of Dominion for a number of years within the VACAR RSG, none of whose other members are full members of PJM.

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REQUEST 26
RESPONSIBLE PERSON: Don Mosier
COMPANY: East Kentucky Power Cooperative, Inc.

Request 26. Explain in detail the benefits to East Kentucky for participating in PJM's Reliability Pricing Model ("RPM'') as opposed to participating only in the Energy Market and choosing Fixed Resource Requirements ("FRRs"). The explanation should include a discussion of East Kentucky's required reserve margin in MWs for the summer season and the winter season under RPM and under FRR.

Response 26. As a member of PJM, EKPC is projected to have capacity to sell in excess of its reserve requirements. EKPC would make these sales into the RPM or bilaterally to other PJM members in need of capacity whether it is under RPM or under FRR. However, in an FRR, EKPC would be required under PJM rules to hold back (not sell capacity into or use in the RPM) an additional 3% of its reserve requirements. Thus, under FRR, EKPC's sales of capacity would be more limited than under RPM, and EKPC's benefits of being a member of PJM would be significantly reduced. As Mr. Luciani noted in his on page 15 of his Direct Testimony, the 3% holdback under an FRR relative to RPM is estimated to reduce EKPC's benefits by $3 million to $9 million per year. As a member of PJM, EKPC would only have a summer reserve requirement to meet under PJM rules whether EKPC is under RPM or under FRR. The key difference will be that EKPC will need to hold back (i.e., not sell) an additional 3% of its summer reserve requirement under FRR.

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REQUEST 27
RESPONSIBLE PERSON: Don Mosier
COMPANY: East Kentucky Power Cooperative, Inc.

Request 27. Refer to the Application, page 16, paragraph 37. Explain the term "installed planning reserve margin," how it is calculated, and whether it differs from East Kentucky's current methodology to calculate its target reserve margin.

Request 27a. How do the installed planning reserves differ from the current PJM's Board's approved Installed Reserve Margin ("IRM")?

Response 27a. The IRM is an installed capacity reserve margin that is applied to the PJM coincident summer peak load for each PJM zone. The resulting reserve requirement is a constant MW value that must be satisfied every day of the Delivery Year. The requirement can be satisfied with generators (based on their summer net dependable ratings), Demand Resources or Energy Efficiency Programs.

Request 27b. What is the current PJM Board approved IRM?

Response 27b. The PJM Board has approved the following IRM values:

- Delivery Year 2012/13 IRM = 15.6%
- Delivery Year 2013/14 IRM = 15.4%
- Delivery Year 2014/15 IRM = 15.4%
- Delivery Year 2015/16 IRM = 15.4%

Request 27c. Explain how is the IRM calculated?

Response 27c. The IRM is calculated using an in-house software application called PRISM. PRISM is a SAS-based application that uses a probabilistic model of PJM generation and peak demand to calculate the loss of load expectation (LOLE) for the PJM system. The IRM represents the amount of installed reserves required by PJM to satisfy an LOLE standard of "one day in ten years." Key drivers of the IRM study include generator availability data, load forecast uncertainty, load diversity and the benefit of interconnection with adjacent systems. Further information on the IRM is available in the following documents:

2011 PJM Reserve Requirement Study
http://www.pjm.com/planning/resource-adequacy-planning/~/media/planning/res-adeq/2011-rrs-study.ashx

PJM Manual 20: PJM Resource Adequacy Analysis
http://www.pjm.com/~/media/documents/manuals/m20.ashx

PJM Generation Adequacy Analysis: Technical Methods
http://www.pjm.com/planning/resource-adequacy-planning/~/media/planning/res-adeq/20040621-white-paper-sections12.ashx

Request 27d. Explain how does IRM differ from installed planning reserve margin?

Response 27d. Please see the response to Request 27a.

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REQUEST 28
RESPONSIBLE PERSON: **Don Mosier**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 28. Explain in detail all of the transmission planning functions that would be provided to East Kentucky by PJM's transmission engineering planning staff and the impacts of PJM membership on East Kentucky's transmission planning and operations planning engineering staff.

Response 28. From *PJM's* perspective, EKPC planning staff will be expected to coordinate a number of planning functions with PJM, consistent with its FERC-approved tariffs. PJM, as an RTO, is the registered NERC Transmission Planner and Planning Authority for its membership. As such PJM has been delegated planning responsibilities for the transmission system within PJM, as well as the responsibility for the reliable interconnection of generation resources. As part of its ongoing responsibilities as an RTO, PJM prepares the RTEP in order to analyze the electric supply needs of the customers in the PJM region. The RTEP directs the installation of transmission projects to address near-term reliability needs and also assesses transmission options requiring a planning horizon of 15 years. The RTEP provides forward-looking information as to the state of the supply and delivery infrastructure and identifies future system needs, both in terms of reliability and market efficiency. The RTEP then directs PJM's transmission-owning members to address reliability needs through specific transmission solutions. Additionally, the information publicly disseminated through the RTEP process gives other resource providers, including generators, demand response providers, and TOs, the opportunity to address identified system needs in a manner that might delay or even obviate the transmission solution first identified in the RTEP.

PJM plans the transmission system as though it were a single system. Corporate and state boundaries are not considered when taking operational action or making planning decisions. By planning for future reliability needs on a region-wide rather than a utility-by-utility or state-by-state basis, PJM's RTEP process helps focus on transmission upgrades that meet reliability criteria and increase economic efficiency.

The Regional Transmission Expansion Planning Protocol and PJM's role in transmission planning in the PJM Region are set forth in Schedule 6 of the PJM Operating Agreement, accessible from PJM's web site via the following URL link: http://pjm.com/documents/~/media/documents/agreements/oa.ashx

This protocol goes on to describe the requirements for the RTEP to conform with NERC and other applicable reliability criteria, the committee structure to be put in place to provide for stakeholder participation in the development of the RTEP, the contents of the RTEP, the procedures used to develop the RTEP, the process of approval of the RTEP by the PJM Board, the obligation of TOs to build upgrades included in the RTEP, and the treatment of interregional transmission upgrades. The planning process is further described in PJM Manuals M-14A through M-14E, accessible from PJM's web site via the following URL link: http://pjm.com/documents/manuals.aspx

Full membership in PJM is not anticipated to have any impact on the staffing level of EKPC's Transmission Planning department. Although the responsibility for certain planning functions will shift from EKPC to PJM, EKPC will maintain primary responsibility for the planning of its 69 kV system and distribution delivery points. Furthermore, EKPC will continue to actively participate in the planning activities of its Regional Entity (presently SERC). A considerable amount of review and coordination of PJM planning activities will also be required by EKPC planning staff. As a result, EKPC expects to remain at current staffing levels within the Transmission Planning department.

Similarly, EKPC does not anticipate any change in staffing levels of its Operations Engineering group once it becomes a full member of PJM. Again, PJM will assume some functions currently performed internally at EKPC, but this will be offset by additional review and coordination activities necessary after EKPC becomes a full member.