COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF SOUTH KENTUCKY	)	
RURAL ELECTRIC COOPERATIVE	)	
CORPORATION FOR APPROVAL OF	)	**CASE NO.**
MASTER POWER PURCHASE AND SALE	)	**2018-00050**
AGREEMENT AND TRANSACTIONS	)	
THEREUNDER	)	

DIRECT TESTIMONY OF MICHAEL MCNALLEY
ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: April 12, 2018

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

A. My name is Mike McNalley and my business address is East Kentucky Power Cooperative, Inc. ("EKPC"), 4775 Lexington Road, Winchester, Kentucky 40391. I am Executive Vice President and Chief Financial Officer for EKPC.

Q. Please briefly describe your education and professional experience.

A. I obtained my undergraduate degree in economics from Reed College in Portland, Oregon, and my Masters of Business Administration from Dartmouth College. Prior to joining EKPC, I held various positions with DTE Energy ("DTE"), including Chief Financial Officer and Chief Operating Officer of one of DTE's subsidiaries, DTE Energy Technologies. Prior to joining DTE, I served as the corporate leader of finance or as a senior executive at various companies including Corrillian Corp., System2, Inc., and Oliver & Thompson, Inc., all located in Portland, Oregon, and Ford Motor Company, then located in Detroit, MI. I have been employed by EKPC since July 2010.

Q. Please briefly describe your duties at EKPC.

A. I am responsible for accounting, finance, performance measures, pricing and regulatory services, risk management, marketing, information technology, and supply chain at EKPC.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss how EKPC undertakes measures to mitigate rate increase pressures, to address how those measures are implicated by the proposed South Kentucky-Morgan Stanley transaction, and to provide empirical data reflecting the potential economic impact of this transaction or others like it, on the various owner-members of EKPC.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes, I am sponsoring Exhibit MM-1 through Exhibit MM-3.

Q. Explain the concept of mitigation of rate increase pressures, and how this concept differs from mitigating the lost opportunity.

A. Mitigation of rate increase pressures are the efforts we undertake to achieve acceptable financial performance, operate reliably and safely, and forestall the need for base rate increases. These efforts are achieved through two broad categories: growth of our sales through economic development and other efforts, and keeping our costs down to essential levels given the strategic direction set by EKPC's Board.

Lost opportunity cannot be mitigated. This represents the opportunities for revenue growth and cost savings that would have been available to all owner-members. However, the South Kentucky transaction diverts these opportunities to mitigate rate increase pressure, rendering them unavailable for the benefit of the other owner-members.

Q. Describe the measures EKPC employs on an ongoing basis to mitigate against rate increase pressures.

A. EKPC has an active economic development effort, intended to welcome new commercial and industrial customers to its owner-members' territories and to help existing customers grow and expand their businesses. This group is very active with the Kentucky Economic Development Cabinet and county economic development professionals across our served counties. We also encourage wise expansion of electricity use by our owner-members' retail members, such as switching from gasoline to electric vehicles.

EKPC also has ongoing efforts to manage operating costs. For example, since 2010 EKPC has held its headcount essentially flat in spite of bringing substantial new assets on line. Where EKPC has had cost increases, it has sought reductions that would offset them so that the rate pressure is minimized. Examples include EKPC's entry into PJM, which has resulted in substantial savings (much is passed directly to owner-members via the Fuel Adjustment Clause ("FAC")), several financings which have saved substantially in EKPC's annual interest expense, switching to lower cost coal which EKPC's scrubbers enable, and numerous smaller reductions EKPC identifies and implements each year. These mitigation efforts benefit all EKPC owner-members across the board.

Q. Describe whether it would be prudent and reasonable for EKPC to attempt to immediately mitigate a twenty-year loss of 58MW of demand in a single action or course of actions, and why or why not.

A. Mr. Mosier addresses this best in his testimony. I will simply add that it is rarely advantageous, in my experience, to attempt to resolve an issue like this in a single transaction. EKPC is more likely to find success in a series of smaller transactions which we enter over time – this allows it to avoid speculating on market prices by locking in all at once. That said, if EKPC identifies an attractive opportunity to fully mitigate the entire 58 MW, 508,000 MWh and 20-year term, I am sure EKPC would pursue that.

Q. Describe how mitigation efforts serve to benefit the distribution cooperatives of EKPC as a collective group?

A. Mitigation efforts benefit EKPC's owner-members and their retail members by deferring the need, in whole or in part, for a base rate increase. However, these efforts do not, and cannot, fully mitigate the impact on the other owner-members from South Kentucky's election because that election results in a permanent shift of costs, which our mitigation efforts cannot change. In effect, this becomes a lost opportunity to our owner-members; mitigation merely avoids the potential base rate impact of the cost shift. In other words, the mitigation efforts are devoted to simply offsetting the South Kentucky election, resulting in a "wash," whereas in the absence of that transaction the benefits of EKPC's mitigation efforts would inure to all of its owner-members as a net gain.

Q. Describe the rate increase pressures on the EKPC system that can be reasonably anticipated if the proposed Morgan Stanley transaction is approved.

A. The Morgan Stanley transaction with South Kentucky reduces EKPCs load by approximately 508,000 MWh every year for twenty years. EKPC's current rates include fixed and variable cost recovery. Some variable cost will be avoided by no longer needing to supply that load. The remaining variable costs, all fixed costs, and EKPC's margin will have to be recovered. EKPC's only method of recovering these costs is a base rate increase. It is worth noting that such a rate increase would be revenue-neutral to EKPC; that is, it would not increase its total revenue above what it is the day before South Kentucky's load leaves. Rather, the rate increase would simply reallocate EKPC's revenue requirement, with the vast majority under its current rate design being borne by its owner-members other than South Kentucky.

To the extent EKPC can grow load, find "replacement" customers, or reduce expenses, that potential rate increase can be mitigated. However, the impact of the South Kentucky contract cannot be mitigated, only the rate increase pressure can be mitigated. This is because, as explained above, EKPC pursues these mitigation actions in the ordinary course of business and they would normally benefit all of EKPC's owner-members. Rather than receive those benefits in the form of a deferred ordinary base rate increase or an increase in their ownership equity in EKPC, these mitigation benefits will instead be applied to offset this action by South Kentucky.

Q. Explain the purpose of your memorandum dated December 27, 2017, and what the memorandum was intended to convey.

A. The memorandum was drafted by me and circulated by our CEO, Tony Campbell, in an e-mail dated December 29, 2017. Its purpose was to provide some basic insights into the impacts of the South Kentucky transaction on EKPC and its owner-members, including South Kentucky. These impacts are immediate cost shifts for the FAC and Environmental Surcharge ("ES") because of their formulaic nature, but much less immediate for base rates. These are the major impacts on EKPC and its owner-members resulting from South Kentucky's action and thus were the focus of the memorandum.

Having described the potential impacts, EKPC and I sought to reassure our owner-members that EKPC had identified potential actions to mitigate the base rate impact and would pursue those. My effort was to be factual and provide reasonable estimates of the potential impacts without being inflammatory, so that owner-members and EKPC could have informed conversations about the subject matter. Further, since EKPC did not have a board meeting scheduled for January, the memorandum provided similar information to its Directors. The tone was intentional, identifying both the impact and the possible courses of action EKPC would consider in order to mitigate the potential rate increases South Kentucky's actions could cause.

Q. Describe what mitigation steps or factors EKPC would reasonably anticipate to attempt to offset the rate increase pressures resulting from the proposed transaction.

A. The memorandum identifies efforts EKPC can take to mitigate the base rate increase which would otherwise be needed as a result of South Kentucky's action. They are presented in temporal order from actions EKPC could take quickly to those that require more time to develop and execute. In describing these I noted the 18-month notice period as required and provided in South Kentucky's Amendment 3 election because that notice allows EKPC to pursue mitigation in an orderly manner.

Immediate actions identified include selling the energy into PJM day ahead and real-time markets. These could not be executed until the South Kentucky load leaves EKPC's system, at which time EKPC could immediately begin. This is in effect an automatic option since each day EKPC bids its generation into the market and purchases its load, with the net being to the benefit of EKPC's owner-members. The South Kentucky reduction in load from EKPC would reduce the amount EKPC purchases from the market, so that the net amount (energy generated and sold versus energy purchased) would be larger. Unfortunately, daily prices on most days of the year will be substantially below EKPC's tariff rates, and this option, therefore, will only mitigate a small part of the cost shift and rate increase pressure. The memorandum goes on to describe other options such as load growth on EKPC's system, and bi-lateral agreements for the power. Load growth is pursued for its own merits. EKPC does not expect to make any greater or lesser effort in this regard. It should be noted, however, that new significant loads generally require a discounted rate for some time (under EKPC's Economic Development Rider) and are typically on a lower rate tariff because they are commercial or industrial customers. For those reasons, it will take more than 508,000 MWh of economic development success to fully offset the base rate pressures from South Kentucky's actions.

Bi-lateral agreements would be more difficult to execute because they require identification of a counter-party or counter-parties who together can utilize the entire 58 MW and 508,000 MWh ideally at prices similar to EKPC's tariff rates (which would fully mitigate the loss). There could be a municipality or other load that would be interested in some or all of EKPC's available capacity and energy so it would not rule out this possibility.

From the discussion above and in the memorandum, it should be clear that full mitigation is unlikely, but partial mitigation is realistic. The unmitigated costs that are shifted to EKPC and, therefore, to its other owner-members might be large enough to cause EKPC to accelerate its next base rate case. One consideration EKPC must study is whether its current rate structure fairly allocates costs to each owner-member. For example, legacy costs of the system EKPC has built over time based on the encouragement and board-room votes of each owner-member should logically be paid by those owner-members and should not be able to be avoided or shifted to others. If the proposed transactions are approved, EKPC will need to undertake cost of service and rate design studies to better understand these issues and may propose new rate design and rate structures to ensure fair, non-bypassable rates.

Q. Describe how these mitigation steps or factors would impact the collective group of EKPC distribution cooperatives if the proposed Morgan Stanley transaction is not in place.

A. If the Morgan Stanley transaction had never been executed, EKPC would have continued its pursuit of new loads (economic development) and cost reductions. Any benefits realized therefrom would have inured to all of EKPC's owner-members (including South Kentucky) in the form of growth on their systems, increased EKPC margins which are allocated back to EKPC's owner-members, and deferred base rate increases. As a result of the South Kentucky transaction, however, these benefits will instead be devoted to partially mitigating the base rate increase necessitated to manage the cost shift. Because of this effect, it is correct to say that EKPC can partially mitigate the base rate increase impact but cannot mitigate the cost shift impact.

Q. Describe the additional alternate source elections that have been made by EKPC owner-members since the notice by South Kentucky and explain how those elections and/or others like them would impact the mitigation factors addressed above.

A. During the month of February 2018, five of EKPC's owner-members submitted notices of alternate source elections totaling 45.1 MW. These additional notices bring the total alternate source elections to 114.4 MW. At this level, the 2.5 percent threshold established in Section 3(A)(iv) of the 2015 Memorandum of Understanding and Agreement is exceeded and no owner-member can request an alternate source election of more than 5 percent of the rolling average of the owner-members' coincident peak demand.

As I stated in the December 27, 2017 memorandum, if there were additional alternate source elections by the owner-members, EKPC would follow similar mitigation plans as discussed in response to the South Kentucky election. However, EKPC's natural load growth would not be sufficient to absorb all of the load loss by the time the notices were effective. The need to mitigate an additional 45.1 MW of load will further limit the success of the partial mitigation I previously stated was realistic. The owner-members who have not made alternate source elections will likely be affected the most by the resulting cost shifts. The owner-members who have made alternate source elections will also be affected by the resulting cost shifts, but the impact will theoretically be lessened because the anticipated benefits of those elections would offset the cost shifts. Quantifying in dollars the estimated impact of multiple alternate source elections becoming effective over the next two years would be virtually impossible.

Q. Have you prepared a spreadsheet that attempts to set forth the hypothetical economic impact on owner-members of EKPC, including South Kentucky, based on various scenarios of additional alternate sources by EKPC members?

A. Yes. This spreadsheet is identified as **Exhibit MM-1**.

Q. Describe what assumptions you made and what variables you utilized to construct this analysis.

A. The purpose of the spreadsheet I created (MM-1) was simply to attempt to show the cost shift impact of three scenarios which were under consideration by several owner-members and EKPC as potential resolutions to the South Kentucky actions. The scenarios were: (a) the SKRECC election alone (15%); (b) that election reduced to 10% with the balance of the 58MW shared proportionately by the remaining 15 owner-members; and, (c) that election reduced to 5% with the balance shared. The result was that while the cost shift does decline for the 15 owner-members under scenarios (b) and (c), the apparent benefit to South Kentucky also significantly declines -- and for the entire system, total cost increases. This last result is not a surprise because the assumed cost of the Morgan Stanley transaction in this spreadsheet (which was constructed when those figures were not available to EKPC) is greater than EKPC's current internal dispatch (variable) cost of producing energy and its overall variable cost of energy delivered to owner-members including PJM purchases over the past 12 months.

Several key assumptions underpin this spreadsheet including:

- No mitigation (necessary to see the cost shift and rate impacts);
- The prices paid by South Kentucky to Morgan Stanley equate to $40/MWh;
- Rate E (residential) is the rate avoided by South Kentucky (for ease of computation);
- Future billings after South Kentucky's contract effective date will be similar to the 12 months prior to this analysis; and
- That no other owner-member makes a new Amendment 3 election or acts on any election made since the South Kentucky notice was received.

These simplifying assumptions enable the analysis to show the impacts consistent with the purpose of the spreadsheet.

Q. What are your takeaways from Exhibit MM-1?

A. There are several key takeaways. First, all owner-members will have an increase in their bills from EKPC as a result of South Kentucky's action, in each scenario. Some of this increase is immediate in the FAC and ES, the balance is in a future base rate adjustment. Second, as the South Kentucky contract is "shared" under scenarios (b) and (c) the cost shift to each owner-member is reduced, but never eliminated. Third, as the South Kentucky contract is "shared" under scenarios (b) and (c), the apparent benefit to South Kentucky diminishes (by more than the reduction in cost shift to the other 15 owner-members). Lastly, when the contract is shared equally (5% to each owner-member) under scenario (c), there is a net cost increase borne by all owner-members. To me, this suggests that the Morgan Stanley transaction is likely fundamentally uneconomic across EKPC's system and only appears to be attractive to South Kentucky because of its presumed ability to avoid and shift EKPC's fixed costs to EKPC's other fifteen owner-members.

Q. Have you reviewed the Net Present Value ("NPV") analysis that EnerVision prepared for South Kentucky concerning the proposed Morgan Stanley transaction?

A. South Kentucky provided the NPV analysis in response to EKPC's first data request, Item 26, and I have reviewed the spreadsheets provided.

Q. The NPV analysis includes numerous cost and rate components. Did any of the assumptions made by EnerVision concerning the cost and rate components raise concerns or questions in your mind?

A. Any NPV analysis will be based on a variety of assumptions and the opinions of reasonable people will differ on the appropriate assumptions to utilize, especially when the analysis is looking at a 20-year period. However, EnerVision's assumptions related to the growth in energy sales during the period, the EKPC agency fee, the pricing of the South Kentucky demand and energy that would remain with EKPC, and the treatment of transmission and transmission-related costs did concern me.

Q. Could you describe EnerVision's assumption concerning the growth in energy sales and your concern?

A. EnerVision assumed that there would be no growth in the energy sales for the load that would remain with EKPC. However, EnerVision also assumed that the cost of those sales would increase over the 20-year period. Absent a base rate case, the increase in the cost of sales would be reflected in sales growth. I realize this assumption does not directly affect the NPV analysis, but the absence of any growth in sales results in cost per MWh values that are inflated.

Q. Could you describe EnerVision's assumption concerning the EKPC agency fee and your concern?

A. EnerVision assumed that the EKPC agency fee would remain unchanged during the entire 20-year period. I would note that there have been no negotiations yet as to what the appropriate agency fee would be for the services South Kentucky is expecting EKPC to perform for it under the proposed Morgan Stanley transaction. EnerVision has assumed an agency fee based on the administration fee incorporated into EKPC's cogeneration tariffs. Regardless of what the final agency fee is, it would not be reasonable to assume this fee would remain fixed for the 20-year period.

Q. Could you describe EnerVision's assumptions concerning the demand and energy that would remain with EKPC and your concerns?

A. EnerVision assumed that the demand and energy remaining with EKPC would be priced under EKPC's Rate E1 option. However, South Kentucky's demand and energy are priced under EKPC's Rate E2 option. As shown in the NPV analysis, on the E-Tariff tab, under both the "Base Case EKPC Cost" and "Remaining EKPC Cost" the total cost under Rate E2 is lower than Rate E1. In addition, all of EKPC's base rates, including the Rate E options, were adjusted by the Commission's August 7, 2017 Order in a FAC review case, with the changes *effective September 1, 2017*. The NPV analysis reflects the rates in effect *prior to September 1, 2017*. Lastly, there was no recognition of the FAC. While it is a variable cost, the FAC is needed to adjust base energy rates to reflect actual fuel costs.

Q. Could you describe EnerVision's assumptions concerning the treatment of transmission and transmission-related costs and your concerns?

A. While EnerVision did utilize EKPC's Network Integration Transmission Service ("NITS") rates, it failed to include in the analysis the current NITS rate for the 2017-2018 PJM year. Instead, EnerVision used the NITS rate for the 2016-2017 year and escalated it by a fixed factor. EnerVision also assumed that the NITS rate for the 2012-2013 year was the same as the 2013-2014 year. EKPC did not become a member of PJM until June of 2013. Prior to joining PJM, EKPC had its own OATT NITS rate, which was $1.62/kW-month.

In addition, EnerVision utilized an escalation factor that does not appear to be reasonable. As discussed by Mr. Mosier, the historic changes in EKPC's NITS rate and information gleaned from several State of the Market reports issued by the Independent Market Monitor for PJM would support escalation factors of between 10 and 13 percent annually. EnerVision utilized an escalation factor of 3 percent. For transmission-related ancillary costs, for the Schedule 1A rate EnerVision used a 2016 rate it obtained from the State of the Market report and escalated it by a fixed factor. Since joining PJM, EKPC has calculated its Schedule 1A rate and it is part of the PJM tariffs. The Schedule 1A rate for the 2017-2018 year is $0.2695/MWh. Lastly, EnerVision used the 2016 rate of $0.52/MWh for "Transmission Enhancement Cost Recovery" and escalated it by a fixed escalation factor. However, the 2017 State of the Market report shows the rate increased to

$0.64/MWh. In addition, a review of the State of the Market reports would support an escalation factor of approximately 14 percent annually.

Q. Of the concerns you have listed, do any have a significant impact on the NPV analysis?

A. As I mentioned previously, the lack of recognizing growth in the energy sales does not affect the NPV analysis. The use of the current Rate E2 rates coupled with an average FAC factor would impact the NPV analysis as would including an escalation factor on the EKPC agency fee. The most significant impact on the NPV analysis comes from the transmission and transmission-related costs which must include a reasonable escalation factor for the NITS transmission service.

Q. Have you attempted to model these changes in the NPV analysis to see what the impacts would be?

A. Using the spreadsheet provided in South Kentucky's response to EKPC's first data request, Item 26, EKPC has run two versions of the NPV analysis. The modifications to each spreadsheet are listed at the bottom of the "20 Yr Compare" tab. One version is based on a 10 percent escalation factor for the NITS transmission and is provided as **Exhibit MM-2** to my testimony. The other version is based on a 13 percent escalation factor and is provided as **Exhibit MM-3** to my testimony. Since South Kentucky has a request for confidential treatment pending for the original spreadsheet, these exhibits should also be treated as confidential.

Q. What were the results of the two versions of the NPV analysis?

A. Using the 10 percent escalation factor for the NITS transmission produced an 83 percent reduction in the NPV compared to the results EnerVision originally calculated. Using the 13 percent escalation factor produced a 108 percent reduction in the NPV compared to the results EnerVision originally calculated.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF SOUTH KENTUCKY RURAL ELECTRIC COOPERATIVE CORPORATION FOR APPROVAL OF MASTER POWER PURCHASE AND SALE AGREEMENT AND TRANSACTIONS THEREUNDER	)	**CASE NO. 2018-00050**

VERIFICATION OF MICHAEL MCNALLEY

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF CLARK)

Michael McNalley, Executive Vice President and Chief Financial Officer at East Kentucky Power Cooperative, Inc., being duly sworn, states that he has read the foregoing prepared direct testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

Michael McNalley

The foregoing Verification was signed, acknowledged and sworn to before me this 12th day of April, 2018 by Michael McNalley.

NOTARY PUBLIC

Commission No. 590567

My Commission Expires: 11/30/2021

East Kentucky Power Cooperative, Inc. **Exhibit MM-1**

Ammendment 3 Summary of Preliminary Analyses

Summary of Cases: Total Unmitigated Impact on Owner-Member Billing

Member	Base Case	Case 1: SK 10%, Spread	Case 2: SK 5% Spread
Big Sandy	$547,480	$442,884	$323,011
Blue Grass	$2,717,694	$2,197,866	$1,604,390
Clark	$1,080,330	$863,183	$613,597
Cumberland Valley	$1,096,898	$875,208	$620,432
Farmers	$1,121,296	$865,024	$569,072
Fleming-Mason	$1,668,807	$1,429,072	$1,158,848
Grayson	$562,259	$450,105	$321,501
Inter-County	$1,033,482	$845,724	$631,834
Jackson	$2,047,297	$1,614,655	$1,116,337
Licking Valley	$620,564	$493,512	$347,371
Nolin	$1,573,025	$1,270,243	$924,412
Owen	$2,840,200	$2,251,092	$1,584,623
Salt River	$2,660,762	$2,058,925	$1,363,552
Shelby	$873,845	$698,931	$499,234
Taylor County	$1,370,679	$1,152,917	$903,205
Totals	$21,814,618	$17,509,342	$12,581,418
South Kentucky:			
Initial Bill Reduction	$30,422,032	$21,610,131	$10,805,069
Share of Base Rates, FAC, and Surcharge	$1,495,520	$1,268,457	$764,887
Net Effect on SK	$29,242,756	$20,609,904	$10,227,260
Net EKPC Billing Difference	$7,428,138	$3,100,562	($2,354,158)

Exhibit MM-2

Consistent with South Kentucky Rural Electric Cooperative Corporation's pending request for confidential treatment of its response to EKPC's First Information Request, Item 26, Sheets 1 through 3 of 5 of this Exhibit are treated as confidential

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

PJM

Dollars per MWh (from 2013 SOM Report, Volume 1; Table 8 (used to be table 9)) >>>>

	Description	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Operating Reserves (Uplift)	DA and RT operating reserves	$1.07	$0.69	$0.86	$0.93	$0.97	$0.45	$0.63	$0.61	$0.48	$0.79	$0.79	$0.79	$0.59
Reactive	Reactive Supply and Voltage Control	$0.22	$0.20	$0.24	$0.25	$0.26	$0.29	$0.31	$0.32	$0.36	$0.44	$0.42	$0.43	$0.80
PJM Administrative Fees	Advance control center, Sch 9 FERC/OPSI/MMU	$0.36	$0.43	$0.54	$0.50	$0.38	$0.40	$0.38	$0.24	$0.31	$0.36	$0.37	$0.42	$0.43
Transmission Enhancement Cost Recovery	T upgrades (e.g., TrAIL, PATH)									$0.09	$0.21	$0.29	$0.34	$0.39
Regulation	Regulation procured through Reg market	$0.50	$0.42	$0.50	$0.50	$0.79	$0.53	$0.63	$0.70	$0.34	$0.35	$0.32	$0.26	$0.24
Transmission Owner (Schedule 1A)	Sch 1A charged to T customers	$0.08	$0.07	$0.07	$0.11	$0.09	$0.09	$0.09	$0.09	$0.08	$0.09	$0.09	$0.08	$0.08
Day Ahead Scheduling Reserve (DASR)	Procured through DASR market								$0.00	$0.00	$0.01	$0.05	$0.05	$0.06
Synchronized Reserves	Procured through Synch Res market		$0.11	$0.19	$0.16	$0.15	$0.10	$0.11	$0.09	$0.05	$0.06	$0.09	$0.04	$0.04
Black Start	Avg cost of Black Start service		$0.00	$0.02	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.03	$0.14
NERC/RFC	Avg cost of NERC and RFC charges							$0.01	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02
RTO Startup and Expansion	AEP, ComEd, DAY integration expenses		$0.04	$0.05	$0.10	$0.37	$0.15	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Load Response -	DA and RT load response charges to LSEs	$0.00	$0.00	$0.02	$0.00	$0.00	$0.03	$0.07	$0.03	$0.00	$0.00	$0.01	$0.01	$0.07
Transmission Facility Charges	Ramapo project charged to PJM Mid-Atlantic	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Non-Synchronized Reserves	Procured through Non-Synch market												$0.00	$0.00
Estimated Applicable AS and PJM Fees	Aggregate estimate based on historical, fuel, etc.	$2.23	$1.96	$2.49	$2.56	$3.03	$2.06	$2.26	$2.12	$1.75	$2.36	$2.48	$2.48	$2.87

	basis for estimate		2014	2015	2016	2017	2018	2019	2020	2021
Operating Reserves (Uplift)	2015 + 2%	2.0%	$1.18	$0.38	$0.17	$0.38	$0.39	$0.40	$0.40	$0.41
Reactive	2016 + 2%	2.0%	$0.40	$0.37	$0.39	$0.40	$0.41	$0.41	$0.42	$0.43
PJM Administrative Fees	2016 + 2%	2.0%	$0.44	$0.44	$0.45	$0.46	$0.47	$0.48	$0.49	$0.50
Transmission Enhancement Cost Recovery	2016 + 2%	14.0%	$0.42	$0.51	$0.52	$0.64	$0.73	$0.83	$0.95	$1.08
Regulation	2015 + 2%	2.0%	$0.33	$0.23	$0.11	$0.23	$0.23	$0.24	$0.25	$0.26
Transmission Owner (Schedule 1A)	2016 + 2%	2.0%	$0.09	$0.09	$0.09	$0.27	$0.27	$0.28	$0.29	$0.29
Day Ahead Scheduling Reserve (DASR)	2016 + 2%	2.0%	$0.05	$0.10	$0.07	$0.07	$0.07	$0.07	$0.08	$0.08
Synchronized Reserves	2016 + 2%	2.0%	$0.21	$0.12	$0.05	$0.05	$0.05	$0.05	$0.05	$0.06
Black Start	2016 + 2%	2.0%	$0.08	$0.06	$0.08	$0.08	$0.08	$0.08	$0.09	$0.09
NERC/RFC	2016 + 2%	2.0%	$0.02	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03
RTO Startup and Expansion	2016		$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Load Response -	2016		$0.08	$0.02	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Transmission Facility Charges	2016		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Non-Synchronized Reserves	2016		$0.02	$0.02	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Estimated Applicable AS and PJM Fees			$3.33	$2.38	$1.98	$2.63	$2.76	$2.90	$3.06	$3.24
Ancillary Services excluding Transmission Enhancement Cost Recovery (TECR)			$2.91	$1.87	$1.46	$1.99	$2.03	$2.07	$2.11	$2.16
			$4.39	$2.78	$2.89	$3.06	$3.12	$3.18	$3.28	$3.43
			12/18/13	12/18/14	2/26/15	9/22/2015 >>>				
Gas Prices in Model >>			$4.39	$2.78	$2.89	$3.06	$3.12	$3.18	$3.28	$3.43

Using EKPC Ancillary Schedule 1-A; escalate as originally modeled
Using SOM Transmission Enhancement Cost Recovery for 2017 and escalating at the historic rate of 14%

SOM = State of the Market report

Period	SOM TECR Charges	%age Change
2012-13	$0.34	
2013-14	$0.39	15.5%
2014-15	$0.42	8.9%
2015-16	$0.51	19.2%
2016-17	$0.52	2.1%
2017-18	$0.64	24.2%
Sum of Percentage Change		69.9%
Average for 5 years		14.0%

Assumptions for Adders to Proposals

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
NITS			escalation >>	n/a	n/a	n/a	n/a	n/a	10.0%	10.0%	10.0%
$/MW-year (per PJM T Rev Req'ts & Rate)			$19,440	$20,020	$25,753	$19,660	$21,334	$26,424	$29,066	$31,973	$35,170
equivalent $/kW-month			$1.620	$1.668	$2.146	$1.638	$1.778	$2.202	$2.422	$2.664	$2.931
	EKPC transmission rate, for year ending May 31st.										
Ancillary Services ($/MWh)											
Total Ancillary Service Charges	$2.48	$2.48	$2.87	$3.33	$2.38	$1.98	$2.63	$2.76	$2.90	$3.06	$3.24
Ancillary without Transmission Enhance-ment Cost Recovery				$2.91	$1.87	$1.46	$1.99	$2.03	$2.07	$2.11	$2.16
Transmission Enhancement Cost Recovery (TECR)				$0.42	$0.51	$0.52	$0.64	$0.73	$0.83	$0.95	$1.08
	actual >>						estimated >>				

SOM = PJM State of Market Report

Period	EKPC Rate ($kW/mo)	%age Change	SOM Trans. Serv. Charges	%age Change
2012-13	$1.620		$4.78	
2013-14	$1.668	2.963%	$5.20	8.7%
2014-15	$2.146	28.657%	$5.95	14.5%
2015-16	$1.638	-23.672%	$7.08	19.0%
2016-17	$1.778	8.547%	$7.81	10.1%
2017-18	$2.202	23.847%	$8.84	13.1%
Sum of Percentage Change		40.342%		65.4%
Average for 5 years		8.068%		13.1%

Exhibit MM-3

Consistent with South Kentucky Rural Electric Cooperative Corporation's pending request for confidential treatment of its response to EKPC's First Information Request, Item 26, Sheets 1 through 3 of 5 of this Exhibit are treated as confidential

[redacted]

REDACTED

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PJM

Dollars per MWh (from 2013 SOM Report, Volume 1; Table 8 (used to be table 9)) >>>>

	Description	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Operating Reserves (Uplift)	DA and RT operating reserves	$1.07	$0.69	$0.86	$0.93	$0.97	$0.45	$0.63	$0.61	$0.48	$0.79	$0.79	$0.79	$0.59
Reactive	Reactive Supply and Voltage Control	$0.22	$0.20	$0.24	$0.25	$0.26	$0.29	$0.31	$0.32	$0.36	$0.44	$0.42	$0.43	$0.80
PJM Administrative Fees	Advance control center, Sch 9 FERC/OPSI/MMU	$0.36	$0.43	$0.54	$0.50	$0.38	$0.40	$0.38	$0.24	$0.31	$0.36	$0.37	$0.42	$0.43
Transmission Enhancement Cost Recovery	T upgrades (e.g., TrAIL, PATH)									$0.09	$0.21	$0.29	$0.34	$0.39
Regulation	Regulation procured through Reg market	$0.50	$0.42	$0.50	$0.50	$0.79	$0.53	$0.63	$0.70	$0.34	$0.35	$0.32	$0.26	$0.24
Transmission Owner (Schedule 1A)	Sch 1A charged to T customers	$0.08	$0.07	$0.07	$0.11	$0.09	$0.09	$0.09	$0.09	$0.08	$0.09	$0.09	$0.08	$0.08
Day Ahead Scheduling Reserve (DASR)	Procured through DASR market								$0.00	$0.00	$0.01	$0.05	$0.05	$0.06
Synchronized Reserves	Procured through Synch Res market		$0.11	$0.19	$0.16	$0.15	$0.10	$0.11	$0.09	$0.05	$0.06	$0.09	$0.04	$0.04
Black Start	Avg cost of Black Start service		$0.00	$0.02	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.03	$0.14
NERC/RFC	Avg cost of NERC and RFC charges							$0.01	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02
RTO Startup and Expansion	AEP, ComEd, DAY integration expenses		$0.04	$0.05	$0.10	$0.37	$0.15	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Load Response -	DA and RT load response charges to LSEs	$0.00	$0.00	$0.02	$0.00	$0.00	$0.03	$0.07	$0.03	$0.00	$0.00	$0.01	$0.01	$0.07
Transmission Facility Charges	Ramapo project charged to PJM Mid-Atlantic	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Non-Synchronized Reserves	Procured through Non-Synch market												$0.00	$0.00
Estimated Applicable AS and PJM Fees	Aggregate estimate based on historical, fuel, etc.	$2.23	$1.96	$2.49	$2.56	$3.03	$2.06	$2.26	$2.12	$1.75	$2.36	$2.48	$2.48	$2.87

	basis for estimate		2014	2015	2016	2017	2018	2019	2020	2021
Operating Reserves (Uplift)	2015 + 2%	2.0%	$1.18	$0.38	$0.17	$0.38	$0.39	$0.40	$0.40	$0.41
Reactive	2016 + 2%	2.0%	$0.40	$0.37	$0.39	$0.40	$0.41	$0.41	$0.42	$0.43
PJM Administrative Fees	2016 + 2%	2.0%	$0.44	$0.44	$0.45	$0.46	$0.47	$0.48	$0.49	$0.50
Transmission Enhancement Cost Recovery	2016 + 2%	14.0%	$0.42	$0.51	$0.52	$0.64	$0.73	$0.83	$0.95	$1.08
Regulation	2015 + 2%	2.0%	$0.33	$0.23	$0.11	$0.23	$0.23	$0.24	$0.25	$0.26
Transmission Owner (Schedule 1A)	2016 + 2%	2.0%	$0.09	$0.09	$0.09	$0.27	$0.27	$0.28	$0.29	$0.29
Day Ahead Scheduling Reserve (DASR)	2016 + 2%	2.0%	$0.05	$0.10	$0.07	$0.07	$0.07	$0.07	$0.08	$0.08
Synchronized Reserves	2016 + 2%	2.0%	$0.21	$0.12	$0.05	$0.05	$0.05	$0.05	$0.05	$0.06
Black Start	2016 + 2%	2.0%	$0.08	$0.06	$0.08	$0.08	$0.08	$0.08	$0.09	$0.09
NERC/RFC	2016 + 2%	2.0%	$0.02	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03
RTO Startup and Expansion	2016		$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Load Response -	2016		$0.08	$0.02	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Transmission Facility Charges	2016		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Non-Synchronized Reserves	2016		$0.02	$0.02	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Estimated Applicable AS and PJM Fees			$3.33	$2.38	$1.98	$2.63	$2.76	$2.90	$3.06	$3.24
Ancillary Services excluding Transmission Enhancement Cost Recovery (TECR)			$2.91	$1.87	$1.46	$1.99	$2.03	$2.07	$2.11	$2.16
			$4.39	$2.78	$2.89	$3.06	$3.12	$3.18	$3.28	$3.43
			12/18/13	12/18/14	2/26/15	9/22/2015 >>>				
Gas Prices in Model >>			$4.39	$2.78	$2.89	$3.06	$3.12	$3.18	$3.28	$3.43

SOM = State of the Market report

Using EKPC Ancillary Schedule 1-A, escalate as originally modeled
Using SOM Transmission Enhancement Cost Recovery for 2017 and escalating at the historic rate of 14%

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Sum of Percentage Change		69.9%
Average for 5 years		14.0%

Assumptions for Adders to Proposals

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
NITS			escalation >>	n/a	n/a	n/a	n/a	n/a	13.0%	13.0%	13.0%
$/MW-year (per PJM T Rev Req'ts & Rate)			$19,440	$20,020	$25,753	$19,660	$21,334	$26,424	$29,859	$33,741	$38,127
equivalent $/kW-month			$1.620	$1.668	$2.146	$1.638	$1.778	$2.202	$2.488	$2.812	$3.177
	EKPC transmission rate, for year ending May 31st.										
Ancillary Services ($/MWh)											
Total Ancillary Service Charges	$2.48	$2.48	$2.87	$3.33	$2.38	$1.98	$2.63	$2.76	$2.90	$3.06	$3.24
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Transmission Enhancement Cost Recovery (TECR)				$0.42	$0.51	$0.52	$0.64	$0.73	$0.83	$0.95	$1.08
	actual >>						estimated >>				

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Period	EKPC Rate ($kW/mo)	%age Change	SOM Trans. Serv. Charges	%age Change
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2016-17	$1.778	8.547%	$7.81	10.1%
2017-18	$2.202	23.847%	$8.84	13.1%
Sum of Percentage Change		40.342%		65.4%
Average for 5 years		8.068%		13.1%