COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

2019 INTEGRATED RESOURCE PLAN OF EAST	**)**	**CASE NO.**
KENTUCKY POWER COOPERATIVE, INC.	**)**	**2019-00096**

RESPONSES TO STAFF'S FIRST REQUEST FOR INFORMATION TO EAST KENTUCKY POWER COOPERATIVE, INC.

DATED FEBRUARY 24, 2020

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2019-00096

COMISSION STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020

East Kentucky Power Cooperative, Inc. ("EKPC") hereby submits responses to the information requests of the Commission Staff ("PSC") in this case dated February 24, 2020. Each response with its associated supportive reference materials is individually tabbed.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

2019 INTEGRATED RESOURCE PLAN OF EAST) CASE NO.
KENTUCKY POWER COOPERATIVE, INC.) 2019-00096

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Darrin Adams, 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 Request for Information in the above-referenced case dated February 24, 2020, 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 16th day of March, 2020.

#590567
Notary Public

GWYN M. WILLOUGHBY
Notary Public
Kentucky – State at Large
My Commission Expires Nov 30, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

2019 INTEGRATED RESOURCE PLAN OF EAST KENTUCKY POWER COOPERATIVE, INC.	**)** **)**	**CASE NO.** **2019-00096**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Scott Drake, 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 Request for Information in the above-referenced case dated February 24, 2020, 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.

Scott Drake

Subscribed and sworn before me on this 16th day of March, 2020.

Gwyn M. Willoughby #580567
Notary Public

GWYN M. WILLOUGHBY
Notary Public
Kentucky – State at Large
My Commission Expires Nov 30, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

2019 INTEGRATED RESOURCE PLAN OF EAST KENTUCKY POWER COOPERATIVE, INC.	**))**	**CASE NO. 2019-00096**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Craig A. Johson, 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 Request for Information in the above-referenced case dated February 24, 2020, 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.

Craig A J

Subscribed and sworn before me on this 16th day of March, 2020.

#590567
Notary Public

GWYN M. WILLOUGHBY
Notary Public
Kentucky – State at Large
My Commission Expires Nov 30, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

2019 INTEGRATED RESOURCE PLAN OF EAST KENTUCKY POWER COOPERATIVE, INC.	))	**CASE NO. 2019-00096**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Jerry Purvis, 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 Request for Information in the above-referenced case dated February 24, 2020, 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 16th day of March, 2020.

#590567
Notary Public

GWYN M. WILLOUGHBY
Notary Public
Kentucky – State at Large
My Commission Expires Nov 30, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

2019 INTEGRATED RESOURCE PLAN OF EAST KENTUCKY POWER COOPERATIVE, INC.	**))**	**CASE NO. 2019-00096**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Tom Stachnik 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 Request for Information in the above-referenced case dated February 24, 2020, 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 16th day of March, 2020.

Gwyn M Willoughby #590567
Notary Public

GWYN M. WILLOUGHBY
Notary Public
Kentucky – State at Large
My Commission Expires Nov 30, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

2019 INTEGRATED RESOURCE PLAN OF EAST KENTUCKY POWER COOPERATIVE, INC.	**))**	**CASE NO. 2019-00096**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Julia J. Tucker, being duly sworn, states that she has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Public Service Commission Staff's First Request for Information in the above-referenced case dated February 24, 2020, and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Julia J. Tucker

Subscribed and sworn before me on this 16th day of March, 2020.

Gwyn M Willoughby
Notary Public #590562

GWYN M. WILLOUGHBY
Notary Public
Kentucky – State at Large
My Commission Expires Nov 30, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

2019 INTEGRATED RESOURCE PLAN OF EAST KENTUCKY POWER COOPERATIVE, INC.	**)** **)**	**CASE NO. 2019-00096**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Mary Jane Warner, being duly sworn, states that she has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Public Service Commission Staff's First Request for Information in the above-referenced case dated February 24, 2020, and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Mary Jane Warner

Subscribed and sworn before me on this 16th day of March, 2020.

Gwyn M. Willoughby
Notary Public #590567

GWYN M. WILLOUGHBY
Notary Public
Kentucky – State at Large
My Commission Expires Nov 30, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

2019 INTEGRATED RESOURCE PLAN OF EAST KENTUCKY POWER COOPERATIVE, INC.	**))**	**CASE NO. 2019-00096**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Patrick C. Woods, 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 Request for Information in the above-referenced case dated February 24, 2020, 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 16th day of March, 2020.

Notary Public #5920567

GWYN M. WILLOUGHBY
Notary Public
Kentucky – State at Large
My Commission Expires Nov 30, 2021

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020

REQUEST 1

RESPONSIBLE PERSON: **Julia J. Tucker**

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

Request 1. Refer to the 2019 IRP, page 2.

Request 1a. Provide EKPC's allocation from the Cumberland System for the five-years ending December 31, 2019.

Response 1a. The following table lists EKPC's maximum MW allocation per month over the requested five-year time period.

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2015	64	64	62	71	71	61	66	64	51	42	54	79
2016	78	77	77	70	66	67	67	72	58	37	20	64
2017	74	76	76	76	74	72	72	70	52	53	64	76
2018	76	71	72	73	67	64	64	64	51	59	65	62
2019	61	56	61	65	56	59	69	66	49	49	67	77

Request 1b. Identify EKPC's all-time summer and winter peaks and the dates on which they occurred.

Response 1b. EKPC’s all-time winter peak of 3,507 MW occurred February 20, 2015 at 8 a.m. EKPC’s all-time summer peak of 2,481 MW occurred August 9, 2007 at 5 p.m.

Request 1c. Provide EKPC's all-time highest annual energy requirement.

Response 1c. EKPC’s all-time highest annual energy occurred in 2018 at 13,576 GWh.

Request 1d. Identify and explain any changes in the load forecast since the filing of the IRP.

Response 1d. There have been no changes to the long-term load forecast since the IRP filing. EKPC updates the long-term load forecasts on a 2-year cycle, in accordance with the RUS-approved Work Plan.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 2
RESPONSIBLE PERSON: Julia J. Tucker
COMPANY: East Kentucky Power Cooperative, Inc.

Request 2. Refer to the IRP, page 3. Identify and provide a summary of the significant savings benefits EKPC received each year from June 1, 2013, through May 31, 2018, from its operations in PJM Interconnection LLC.

Response 2. In accordance with the Final Order from Case No. 2012-00169, EKPC files an Annual Report each year regarding its participation in the PJM Interconnection, LLC. ("PJM") There is a summary table of the costs and benefits that EKPC incurs with its operations within PJM included with this report. The following are the summary tables from each of the reports that have been filed regarding these operations from June 1, 2013 through May 31, 2018. The original Order required a filing date of May 31 each year, which resulted in EKPC having to only include data through March 31 of that year. EKPC requested, and was granted, a change in annual filing dates to July 31 each year so the full PJM operating year could be reflected in the report. Therefore, there was no data reported for April 1, 2014 through May 31, 2014. Those two months would not be expected to cause a material change in the overall results of the cost / benefits report.

June 1, 2013 through March 31, 2014

Category	Costs	Benefits
Administrative Costs	[redacted]	
Transmission Costs	[redacted]	
Trade Benefits		[redacted]
Capacity Benefits		[redacted]
Avoided PTP Transmission Charges		[redacted]
Subtotal	[redacted]	[redacted]
Net Benefits		[redacted]

June 1, 2014 through May 31, 2015

Category	Costs	Benefits
Administrative Costs	[redacted]	
Transmission Costs	[redacted]	
Trade Benefits		[redacted]
Capacity Benefits		[redacted]
Avoided PTP Transmission Charges		[redacted]
Subtotal	[redacted]	[redacted]
Net Benefits		[redacted]

June 1, 2015 through May 31, 2016

Category	Costs	Benefits
Administrative Costs	[redacted]	
Transmission Costs	[redacted]	
Trade Benefits		[redacted]
Capacity Benefits		[redacted]
Avoided PTP Transmission Charges		[redacted]
Subtotal	[redacted]	[redacted]
Net Benefits		[redacted]

June 1, 2016 through May 31, 2017

Category	Costs	Benefits
Administrative Costs	[redacted]	
Transmission Costs	[redacted]	
Trade Benefits		[redacted]
Capacity Benefits		[redacted]
Avoided PTP Transmission Charges		[redacted]
Subtotal	[redacted]	[redacted]
Net Benefits		[redacted]

June 1, 2017 through May 31, 2018

Category	Costs	Benefits
Administrative Costs	[redacted]	
Transmission Costs	[redacted]	
Trade Benefits		[redacted]
Capacity Benefits		[redacted]
Avoided PTP Transmission Charges		[redacted]
Subtotal	[redacted]	[redacted]
Net Benefits		[redacted]

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 3
RESPONSIBLE PERSON: Julia J. Tucker
COMPANY: East Kentucky Power Cooperative, Inc.

Request 3. Refer to the IRP, page 5. Provide a discussion of EKPC's price hedging strategy for its winter load position.

Response 3. EKPC expects to have sufficient existing resources to meet its winter peak load needs for the next four years. In the 2024 time frame, EKPC will need to purchase additional resources to cover its winter peak loads. That hedge could be provided by various resources including PPAs and/or new generating resources. Since EKPC does not need additional summer capacity in the forecasted time frame, then EKPC could seek resources that are specifically provided in the winter season. As the need draws closer, EKPC will review all options and seek to find the most economic solution by issuing a Request for Proposals for supply resources.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 4
RESPONSIBLE PERSON: Scott Drake
COMPANY: East Kentucky Power Cooperative, Inc.

Request 4. Refer to the IRP, pages 12 and 13. Discuss in detail the impacts of the repeal of The Federal Clean Power Plan on the value of EE as a compliance option.

Response 4. EKPC was looking at energy efficiency as a possible compliance option, but the Federal Clean Power Plan was repealed. The value of energy efficiency as a compliance option depends on the regulations imposed on carbon or other emissions that effects the cost of energy and/or capacity. If future regulations constrain carbon or other emissions, EKPC will evaluate energy efficiency as a compliance option based on the financial impact of the restrictions imposed.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 5
RESPONSIBLE PERSON: Julia J. Tucker
COMPANY: East Kentucky Power Cooperative, Inc.

Request 5. Refer to the IRP, Section 3.1, Table 3-4, pages 39-40, and Technical Appendix Volume 1, Table 7-3, page 59.

Request 5a. Describe the nature of the Seasonal Sales category.

Response 5a. Seasonal Sales are sales to customers with seasonal residences such as vacation homes and weekend retreats. Seasonal sales are relatively small and are only reported by one of EKPC's owner-members.

Request 5b. Describe the cause of the decline in customers and the resulting energy sales from 2011 to 2012.

Response 5b. In 2011, only one owner-member reported Seasonal Sales. In 2012, that owner-member reclassified those sales into the Residential class. Also, in 2012, a different owner-member began reporting Seasonal Sales.

Request 5c. Describe both the Office Use category and the Own Use category and describe how they differ.

Response 5c. Office Use represents the electric usage of the owner-members' facilities while Own Use represents EKPC's usage.

Request 5d. Provide an update to Table 3-4 with the % Loss and Losses columns filled in with megawatt hours in addition to the percentage distribution and transmission losses.

Response 5d. See Table 3-4 below.

Table 3-4
Total Sales and Requirements

Year	Total Retail Sales (MWh)	Office Use (MWh)	% Loss	Distribution Loss (MWh)	Purchased Power (MWh)	Own Use (MWh)	Purchased Power (MWh)	% Losses	Transmission Losses (MWh)	Total Requirements (MWh)
2007	12,034,113	10,291	4.3%	537,856	12,582,260	7,491	12,589,751	3.9%	490,616	13,080,367
2008	12,069,760	10,431	4.5%	565,956	12,646,146	7,932	12,654,078	2.3%	294,013	12,948,091
2009	11,465,841	10,173	4.2%	505,895	11,981,909	8,247	11,990,156	3.3%	390,816	12,380,972
2010	12,233,507	10,401	4.4%	567,997	12,811,906	8,654	12,820,560	4.3%	555,732	13,376,292
2011	11,809,733	9,742	3.8%	469,596	12,289,071	10,146	12,299,217	3.0%	367,781	12,666,998
2012	11,407,734	9,120	4.4%	526,552	11,943,406	8,811	11,952,217	2.0%	237,853	12,190,070
2013	11,892,868	9,977	4.0%	498,059	12,400,903	8,270	12,409,174	1.9%	235,416	12,644,590
2014	12,357,874	10,497	4.1%	530,031	12,898,402	8,246	12,906,648	2.0%	256,868	13,163,516
2015	11,768,687	10,008	4.3%	524,746	12,303,441	8,190	12,311,631	2.4%	293,311	12,604,942
2016	12,143,355	10,270	4.1%	520,618	12,674,244	8,203	12,682,447	2.8%	357,506	13,039,953
2017	11,855,444	9,992	3.9%	475,357	12,340,793	8,374	12,349,167	2.7%	330,944	12,680,111
2018	12,460,774	10,551	4.6%	532,969	13,004,293	8,367	13,012,660	2.6%	356,347	13,369,007
2019	12,812,750	10,551	4.6%	542,620	13,365,921	8,367	13,374,287	2.6%	361,693	13,735,980
2020	13,407,879	10,551	4.6%	550,376	13,968,806	8,367	13,977,173	2.6%	377,118	14,354,291
2021	14,136,129	10,551	4.6%	554,226	14,700,906	8,367	14,709,273	2.6%	400,454	15,109,727
2022	14,251,687	10,551	4.6%	559,461	14,821,699	8,367	14,830,065	2.6%	411,658	15,241,723
2023	14,374,902	10,551	4.6%	565,045	14,950,497	8,367	14,958,864	2.6%	414,624	15,373,488
2024	14,546,124	10,551	4.6%	572,668	15,129,343	8,367	15,137,709	2.6%	417,988	15,555,697
2025	14,684,795	10,551	4.6%	579,224	15,274,570	8,367	15,282,937	2.6%	421,346	15,704,283
2026	14,831,995	10,551	4.6%	586,125	15,428,671	8,367	15,437,038	2.6%	425,404	15,862,441
2027	14,971,348	10,551	4.6%	592,418	15,574,317	8,367	15,582,684	2.6%	429,685	16,012,368
2028	15,134,636	10,551	4.6%	599,786	15,744,973	8,367	15,753,340	2.6%	432,305	16,185,645
2029	15,232,792	10,551	4.6%	604,685	15,848,028	8,367	15,856,395	2.6%	436,000	16,292,394
2030	15,361,992	10,551	4.6%	610,537	15,983,080	8,367	15,991,447	2.6%	437,578	16,429,025
2031	15,495,642	10,551	4.6%	616,697	16,122,890	8,367	16,131,257	2.6%	440,528	16,571,785
2032	15,663,646	10,551	4.6%	624,244	16,298,441	8,367	16,306,807	2.6%	445,656	16,752,464
2033	15,781,363	10,551	4.6%	629,966	16,421,879	8,367	16,430,246	2.6%	448,938	16,879,184

Request 5e. Refer to the Technical Appendix, Volume 1, Section 8, table 8-1, page 66. The Base Case Net Requirements value for 2018 does not match the comparable Net Requirements value in Table 3-4. Provide the correct value in the appropriate table.

Response 5e. The tables match for all years except 2018. The data should be:

Season	Low Case	Base Case	High Case
2018	12,436,479	**13,369,007**	14,367,167

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 6
RESPONSIBLE PERSON: Julia J. Tucker
COMPANY: East Kentucky Power Cooperative, Inc.

Request 6. Refer to the IRP, Section 3.2, pages 41-43.

Request 6a. Provide and compare each of the final owner-member forecast results (including historical data) in spreadsheet format that form the basis for EKPCs load forecast.

Response 6a. The anonymized owner-member load forecasts that are the basis for the EKPC system load forecast are provided on the attached CD. Note the highlight indicates the data matches the tables on IRP pages 39 and 40. The Residential, Large Commercial and Industrial Data forecasts do not sum to the value in the tables due to adjustments made to the EKPC system forecast for interruptions of large loads and adjustments made to residential sales for decreases in sales due to energy efficiency and demand response programs. These assumptions are developed at the system level, not the owner-member level.

<u>Request 6b.</u> In light of the decline in the coal industry and population losses and other changes to economic or demographic drivers, discuss any major differences between the set of owner-members including number of customers, consumption patterns, expected economic growth drivers, etc., and how those drivers comport with the overall assumptions enumerated on pages 42-43.

<u>Response 6b.</u> The economic forecasts from IHS are used in the owner-member class models. The economic regions are defined in Section 4 of the technical appendix and the outlook for each is described in the following.

The East region, the one most impacted by the declining coal industry, is projected to have declining population over the 5- and 20-year periods of less than 0.5% per year, approximately 34,000 individuals. The number of households, however, is expected to stay relatively flat. There are few employment opportunities, therefore, the region is expected to remain consistent with the last 5 years. The resulting load forecast for this region is consistent with these assumptions. The residential class sales are flat for the first 5 years of the forecast and has a growth rate of 0.18% for the entire 20-year period. All of the classes result in regional total sales growth rates of close to 0.30% for the 5- and 20-year forecast period.

The North East region is not expected to lose population, however, the average growth rate is small, about 0.2% in the near and long term. The number of households is expected to stay relatively flat at 0.5% average growth. There are limited employment opportunities in this region as well. The resulting load forecast for this region is consistent with these assumptions. The residential class sales are projected to have average growth rate of 0.5% in the near and long term. All of the classes result in the regional total sales growth rates of 1.3% and 1.1% for the 5- and 20-year forecast period, respectively. The total sales growth rates are higher than residential class due to growth in the industrial sector of this region.

The North, North Central and Central regions' outlook is strong. As a whole, population is expected to grow from 0.5% to 1.1%, nearly 200,000 individuals. The number of households is expected to grow at an average growth rate of 1.2% in the near term and 1.0% in the long term. The Central region is slightly stronger at 1.5% and 1.3%. These equate to an increase of over 150,000 households in these regions. There are more employment opportunities in the small commercial and industrial sectors. Even though all of the businesses may not be served by the owner-members, some of the employees live on owner-member lines. The resulting load forecast for this region is consistent with these assumptions. The residential class sales are projected to have an average growth rate of 1.2% in the near and long term. The small commercial class sales are projected to grow at 1.25% in the near and long term and large commercial sales growth rates are 8.6% for the near term and 2.7% in the long term. The 8.6% includes an expansion of an existing industrial customer. All of the classes result in the regional total sales growth rates of 4.1% and 1.8% for the 5- and 20-year forecast period, respectively.

The South and South Central regions' outlook is growing moderately. As a whole, population is expected to grow an average of 0.5% per year, nearly 50,000 individuals. The number of households is expected to grow at an average growth rate of almost 1.0%

in the near term and long term, an increase of over 40,000 households in these regions. There are employment opportunities in the small commercial and industrial sectors. Even though all of the businesses may not be served by the owner-members, some of the employees live on owner-member lines. The resulting load forecast for this region is consistent with these assumptions. The residential class sales are projected to have an average growth rate of 0.5% to 0.8% in the near and long term. The small commercial class sales are projected to grow close to 1.0% in the near and long term and large commercial sales growth rates are 5.0% for the near term and 2.6% in the long term. The 5.0% includes known additions and/or expansions. All of the classes result in the regional total sales growth rates of 1.5% and 1.2% for the 5- and 20-year forecast periods, respectively.

The combined results of these regions yield the 1.4% average 20-year growth rate for the EKPC system forecast.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST INFORMATION REQUEST RESPONSE

COMMISSION STAFF'S FIRST INFORMATION REQUEST DATED 02/24/2020
REQUEST 7
RESPONSIBLE PERSONS: **Julia J. Tucker**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 7. Refer to the IRP, Section 3.3.2, page 52.

Request 7a. Provide a copy of the most recent residential retail member survey questionnaire.

Response 7a. The questionnaire is on pages 2 and 3 of this response and is entitled "2018 Residential Retail Member Survey".

Request 7b. Provide a list of the residential demographic variables derived from the survey and maintained by EKPC for DSM program evaluation and load forecasting purposes.

Response 7b. The demographic variables include the age of the head of household and the number of people living at the residence.

2018 MEMBERSHIP ENERGY USE SURVEY

PLEASE ANSWER THE SURVEY, TO THE BEST OF YOUR KNOWLEDGE, FOR THE RESIDENCE ASSOCIATED WITH ACCOUNT NUMBER 1027002903

Please fill in marks like this: ●
NOT like this: ⊗ ✓

ABOUT YOUR RESIDENCE

1. What type of residence is this? *(SELECT ONLY ONE)*

○ Single family home
○ Manufactured/Modular home
○ Mobile home/Trailer (Single Wide)
○ Mobile home/Trailer (Double Wide)
○ Apartment, Duplex, Townhouse or Condo
○ Other________________________

2. Is this residence occupied year round or seasonally?

○ Year round
○ Seasonally

3. What type of **Internet** connection do you have at this residence? *(SELECT ONLY ONE)*

○ None
○ DSL
○ Broadband Cable
○ Satellite
○ Wireless
○ Other

4. Approximately what year was this residence built? *(SELECT ONLY ONE)*

○ 2014 or later
○ 2010 to 2013
○ 2000 to 2009
○ 1990 to 1999
○ 1980 to 1989
○ 1970 to 1979
○ 1969 or earlier

5. How many square feet of living space does this residence have? Please do **not** count any garage, unfinished basement, or unfinished attic. *(SELECT ONLY ONE)*

○ Less than 800 sq ft
○ 800 - 1199 sq ft
○ 1200 - 1599 sq ft
○ 1600 - 1999 sq ft
○ 2000 - 2399 sq ft
○ 2400 - 2799 sq ft
○ 2800 - 3199 sq ft
○ 3200 - 3599 sq ft
○ 3600 sq ft or more
○ Not Sure

ABOUT YOUR SPACE CONDITIONING

6. What is the **main fuel** used to heat this residence most of the time? *(SELECT ONLY ONE)*

○ No heat ---> *(SKIP TO QUESTION 11)*
○ Electricity
○ Natural gas
○ LP/Bottled Gas/Propane
○ Fuel oil/Kerosene
○ Wood/Coal
○ Other (Please describe____________)

7. Which best describes the heating system(s) used to heat this residence? *(SELECT ALL THAT APPLY)*

1 ○ Electric furnace
2 ○ Electric heat pump
3 ○ Geothermal heat pump
4 ○ ETS (Electric thermal storage)
5 ○ Electric built in units (wall, ceiling, or baseboard)
6 ○ Portable electric heater
How many? ○ One ○ Two ○ Three or more
7 ○ Natural gas furnace
8 ○ LP/Bottled Gas/Propane furnace
9 ○ Fuel oil furnace
10 ○ Woodburning fireplace
11 ○ Wood/Coal Stove
12 ○ Other ____________________

8. Of the heating systems chosen in Question #7 which one do you use **most often**? (*Specify one number*) ______

9. What is the approximate age in years of your **main** heating system? *(SELECT ONLY ONE)*

○ 1 year
○ 2 - 5 years
○ 6 - 10 years
○ 11 - 15 years
○ 16 - 20 years
○ 20+ years

10. What was the **secondary** fuel used to heat this residence in the last twelve months? *(SELECT ALL THAT APPLY)*

○ No secondary heat used
○ Electricity
○ Natural gas
○ LP/Bottled Gas/Propane
○ Fuel oil/Kerosene
○ Wood/Coal
○ Other (Please describe____________)

11. What type of air conditioning systems are used at this residence? *(SELECT ALL THAT APPLY)*

○ Electric central
○ Electric central heat pump
○ Geothermal heat pump
○ Electric room or window units
How many? ○ One ○ Two ○ Three or more
○ None of the above (*SKIP TO QUESTION 13*)

Next Page >

12. What is the approximate age in years of your **main** air conditioning system? *(SELECT ONLY ONE)*

○ 1 year
○ 2 - 5 years
○ 6 - 10 years
○ 11 - 15 years
○ 16 - 20 years
○ 20+ years

13. At this residence, do you have a mini split ductless heat pump(s) for heating and cooling?

○ No
○ Yes (how many_____)

ABOUT YOUR WATER HEATING

14. How many water heaters are installed at this residence? *(SELECT ONLY ONE)*

○ None *(SKIP TO QUESTION 19)*
○ One
○ Two
○ Three or more

15. What type of fuel is used to heat the water in this residence? *(SELECT ONLY ONE)*

○ Electricity
○ Natural gas
○ LP/Bottled gas/Propane
○ Other

16. What is the approximate size of your **main** water heater tank? *(SELECT ONLY ONE)*

○ 20 gallons or less
○ 20-29 gallons
○ 30-39 gallons
○ 40-49 gallons
○ 50-59 gallons
○ 60 gallons or larger
○ Tankless
○ Not sure

17. What is the approximate age in years of your **main** water heater tank? *(SELECT ONLY ONE)*

○ 1 year
○ 2 - 5 years
○ 6 - 10 years
○ 11 - 15 years
○ 16 - 20 years
○ 20+ years

18. Do you have an electric heat pump water heater at this residence?

○ No
○ Yes

ABOUT YOUR APPLIANCES

19. How many of each of the following do you regularly use in this home? *(SELECT ONE PER ROW)*

	0	1	2	3+
Electric range/oven	○	○	○	○
Refrigerator under 20 years old	○	○	○	○
Refrigerator over 20 years old	○	○	○	○
Standup/chest freezer	○	○	○	○
PC/Laptop/Tablet	○	○	○	○
Plug-in electric golf cart	○	○	○	○

SATISFACTION

20. On a scale of one to seven, with seven being very satisfied and one being not satisfied at all, how satisfied are you overall with your electric provider? *(SELECT ONLY ONE)*

1	2	3	4	5	6	7
○	○	○	○	○	○	○

Not at all Satisfied .... Very Satisfied

ABOUT YOUR HOUSEHOLD

21. What is the age of your residence's head of household? *(SELECT ONLY ONE)*

○ Under 25 years
○ 25 - 34 years
○ 35 - 44 years
○ 45 - 54 years
○ 55 - 64 years
○ 65 years or older

22. Including yourself, how many people live in this residence most of the time? (Fill in the box)

Number of people in household ☐☐

23. Do you currently own a plug-in electric vehicle?

○ Yes
○ No, but I am in the market for one
○ No, but I am open to the idea
○ No, and I do not plan on getting one soon

ADDITIONAL COMMENTS

Please return your survey using the prepaid return envelope provided.

Thank You Very Much For Your Time And Participation!

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 8
RESPONSIBLE PERSONS: Julia J. Tucker
COMPANY: East Kentucky Power Cooperative, Inc.

Request 8. Refer to the IRP, Section 3.5.1, Table 3-13, page 56. Explain the rationale for reclassifying Commercial customers to Residential beginning in 2018.

Response 8. The customer counts and energy sales data are from the RUS Form 7 provided by the owner-members. Class shifts are made at the owner-member level. EKPC has no input to or data from the choice to reclassify any customers.

EAST KENTUCKY POWER COOPERATIVE, INC.
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FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 9
RESPONSIBLE PERSONS: Julia J. Tucker
COMPANY: East Kentucky Power Cooperative, Inc.

Request 9. Refer to the IRP, Section 3.3.3, page 53.

Request 9a. Explain how electricity price elasticities of demand for residential, commercial and industrial customers and owner member distribution adders are layered with wholesale power rates to develop year over year electric rate changes.

Response 9a. Electric rates have an impact on electric use per customer and therefore are included in the energy model specifications. The owner-member level forecasts use each owner-member's average cents per kWh plus the distribution adder for that owner-member. Owner-members provide projections of expected increases for the forecast period. The historical relationship between the rates by class are maintained for the forecast period. Projected wholesale rate year over year percent changes, based on EKPC's Board-approved financial forecast, are applied resulting in the rate assumption used in the load forecast models. Within the model, the elasticities are applied as shown in the equations provided in Response 16e.

Request 9b. Though not listed as an explanatory variable in Sections 3.4.1 .1 and 3.4.1 .2, explain whether the electric rates developed in this section are the electric rates used in the residential sales forecast as outlined in the Technical Appendix and presumably in the small commercial sales forecast.

Response 9b. The electric rates developed for each owner-member are used in the residential and small commercial sales forecasts. See Response 16e for equations.

EAST KENTUCKY POWER COOPERATIVE, INC.
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FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 10
RESPONSIBLE PERSON: Julia J. Tucker
COMPANY: East Kentucky Power Cooperative, Inc.

Request 10. Refer to the IRP, Section 3.4.1.3. Presumably, large commercial and industrial customers export their products outside of the county. Product sales drive production activity, which drives energy sales. Explain why it is reasonable to limit modeling large commercial and industrial energy sales as a function of the real gross county product for their specific service area as opposed to a broader economic measure.

Response 10. The Gross County Product (GCP) is a calculated measure of economic value produced within the county. This is all economic value generated within the county. As economic value is produced, GCP increases. If economic value is exported, GCP does not decrease because that value was generated within the county. Imports into a county would decrease GCP, however, that would be offset by increases in GCP as those imports are used to create other goods/services.

In forecasting GCP, IHS uses global and national indicators to forecast state level Gross Domestic Product (GDP). County forecasts are then constrained to their respective metro or non-metro areas, with rural counties being constrained to non-metro portions of the state forecast and metro areas that span multiple states being split into state-specific pieces. Overall, the county forecasts pick up national forecast assumptions in that they are driving the state and metro outlooks. Global assumptions are also utilized in that the US model incorporates the outlook for the global economy.

Since GCP forecasts are based upon state, national, and global economic drivers it is viewed as a good predictive value of commercial and industrial electric consumption.

EAST KENTUCKY POWER COOPERATIVE, INC.
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STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 11
RESPONSIBLE PERSON: Julia J. Tucker
COMPANY: East Kentucky Power Cooperative, Inc.

Request 11. Refer to the IRP, Section 3.5.3, Table 3-15, and Technical Appendix Volume 1 (Technical Appendix), Section 7, Table 7-2, page 58. Beginning in the year 2018, data contained in the Annual Average column of the tables does not match, which appears to cause other columns to disagree.

Request 11a. Explain the table discrepancies and provide an update to both tables.

Response 11a. Table 7-2 within the Technical Appendix Volume 1 does not include an adjustment for interruptible load. Table 7-2 on page two of this response is an updated version that includes a reduction for interruptible load.

Table 7-2
Large Commercial Summary
Historical and Projected

	Customers			*Use Per Customer*			*Class Sales*		
	Annual Average	Annual Change	% Change	Annual Average (MWh)	Change (MWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
2007	122	-13	-9.6	25,607	2,961	13.1	3,124,043	66,859	2.2
2008	132	10	8.2	23,361	-2,246	-8.8	3,083,589	-40,454	-1.3
2009	138	6	4.5	20,521	-2,839	-12.2	2,831,935	-251,654	-8.2
2010	125	-13	-9.4	22,767	2,246	10.9	2,845,857	13,922	0.5
2011	128	3	2.4	22,571	-195	-0.9	2,889,142	43,285	1.5
2012	130	2	1.6	22,321	-251	-1.1	2,901,688	12,546	0.4
2013	135	5	3.8	22,355	34	0.2	3,017,925	116,237	4.0
2014	136	1	0.7	23,870	1,515	6.8	3,246,287	228,362	7.6
2015	129	-7	-5.1	23,099	-771	-3.2	2,979,716	-266,571	-8.2
2016	138	9	7.0	23,888	789	3.4	3,296,495	316,779	10.6
2017	149	11	8.0	22,788	-1,100	-4.6	3,395,430	98,935	3.0
2018	152	3	2.0	22,356	-432	-1.9	3,398,144	2,714	0.1
2019	156	4	2.6	23,133	777	3.5	3,608,750	210,606	6.2
2020	160	4	2.6	25,901	2,768	12.0	4,144,183	535,433	14.8
2021	163	3	1.9	29,904	4,003	15.5	4,874,338	730,155	17.6
2022	165	2	1.2	29,941	37	0.1	4,940,304	65,966	1.4
2023	168	3	1.8	29,806	-135	-0.5	5,007,458	67,154	1.4
2024	169	1	0.6	30,006	200	0.7	5,071,019	63,561	1.3
2025	171	2	1.2	30,061	55	0.2	5,140,502	69,483	1.4
2026	175	4	2.3	29,704	-358	-1.2	5,198,169	57,667	1.1
2027	176	1	0.6	29,778	74	0.3	5,240,948	42,779	0.8
2028	178	2	1.1	29,703	-75	-0.3	5,287,182	46,234	0.9
2029	180	2	1.1	29,603	-100	-0.3	5,328,538	41,356	0.8
2030	183	3	1.7	29,449	-154	-0.5	5,389,079	60,541	1.1
2031	186	3	1.6	29,256	-193	-0.7	5,441,597	52,518	1.0
2032	188	2	1.1	29,240	-16	-0.1	5,497,115	55,518	1.0
2033	190	2	1.1	29,171	-69	-0.2	5,542,559	45,444	0.8
2034	193	3	1.6	29,008	-163	-0.6	5,598,527	55,968	1.0
2035	196	3	1.6	28,873	-135	-0.5	5,659,157	60,630	1.1
2036	199	3	1.5	28,746	-128	-0.4	5,720,395	61,238	1.1
2037	201	2	1.0	28,683	-63	-0.2	5,765,292	44,897	0.8
2038	203	2	1.0	28,646	-37	-0.1	5,815,131	49,839	0.9

Request 11b. If necessary, provide an update to any relevant discussion or chart or graph that relies on data portrayed in the correct(ed) tables.

Response 11b. No other updates were required as this table was the only adjustment.

EAST KENTUCKY POWER COOPERATIVE, INC.
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FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 12
RESPONSIBLE PERSON: Julia J. Tucker
COMPANY: East Kentucky Power Cooperative, Inc.

Request 12. Refer to IRP, Section 3, Tables 3-17 and 3-18, pages 60-61, and Technical Appendix, Section 7, Tables 7-4 and 7-5. Comparing the tables, it appears that Table 3-17 is identical to Table 3-18 and that Table 7-4 may contain the correct information. Confirm which tables contain the correct intended information and provide an update to tables that do not contain the correct intended information.

Response 12. Table 3-17 displays duplicate values from Table 3-18. The correct version of Table 3-17 is on page two of this response.

Table 3-17
Public Buildings Class
Historical and Projected Retail Members and Sales

	Customers			***Use Per Customer***			***Class Sales***		
	Annual Average	Annual Change	% Change	Monthly Average (kWh)	Change (MWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
2007	969	38	4.1	2,273	286	14.4	26,427	4,231	19.1
2008	993	24	2.5	2,860	587	25.8	34,074	7,647	28.9
2009	998	5	0.5	2,965	105	3.7	35,507	1,433	4.2
2010	1,046	48	4.8	3,172	207	7.0	39,809	4,301	12.1
2011	1,084	38	3.6	2,958	-213	-6.7	38,468	-1,341	-3.4
2012	1,096	12	1.1	2,676	-282	-9.5	35,194	-3,274	-8.5
2013	1,109	13	1.2	2,796	121	4.5	37,215	2,021	5.7
2014	1,117	8	0.7	2,966	169	6.1	39,753	2,537	6.8
2015	1,132	15	1.3	2,871	-95	-3.2	38,996	-757	-1.9
2016	1,137	5	0.4	2,758	-113	-3.9	37,627	-1,369	-3.5
2017	1,156	19	1.7	2,637	-121	-4.4	36,578	-1,049	-2.8
2018	1,176	20	1.7	2,773	136	5.2	39,136	2,558	7.0
2019	1,197	21	1.8	2,754	-19	-0.7	39,560	424	1.1
2020	1,214	17	1.4	2,748	-5	-0.2	40,028	467	1.2
2021	1,230	17	1.4	2,736	-12	-0.4	40,400	373	0.9
2022	1,246	16	1.3	2,729	-7	-0.3	40,819	419	1.0
2023	1,263	17	1.3	2,721	-8	-0.3	41,248	429	1.1
2024	1,280	16	1.3	2,716	-5	-0.2	41,702	454	1.1
2025	1,296	16	1.3	2,707	-9	-0.3	42,085	383	0.9
2026	1,313	17	1.3	2,699	-7	-0.3	42,522	437	1.0
2027	1,329	16	1.2	2,694	-5	-0.2	42,958	436	1.0
2028	1,345	16	1.2	2,690	-4	-0.1	43,422	464	1.1
2029	1,362	17	1.3	2,680	-10	-0.4	43,804	382	0.9
2030	1,378	16	1.2	2,674	-6	-0.2	44,218	414	0.9
2031	1,394	16	1.2	2,666	-8	-0.3	44,613	395	0.9
2032	1,411	17	1.2	2,659	-7	-0.3	45,039	426	1.0
2033	1,427	16	1.1	2,651	-9	-0.3	45,401	362	0.8

EAST KENTUCKY POWER COOPERATIVE, INC.
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FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 13
RESPONSIBLE PERSON: Julia J. Tucker
COMPANY: East Kentucky Power Cooperative, Inc.

Request 13. Refer to the IRP, Sections 3.3.3 and 3.6.1, pages 53 and 62. Explain the source of the various electric price data and precisely what electric prices are used and for the base, peak demand and scenario forecast results.

Response 13. The base load forecast referenced on page 53 is developed from a bottom-up approach. A forecast is developed for each owner-member using assumptions specific to that owner-member. These are summed to determine the EKPC system load forecast. Electric rates have an impact on energy use per customer and therefore are included in the model specifications. The owner-member level forecasts use each owner-member's average cents per kWh plus the distribution adder for that owner-member. Owner-members provide projections of expected increases for the forecast period. Projected wholesale rate changes, based on EKPC's Board-approved financial forecast, are added resulting in the rate assumption used in the load forecast models.

Page 62 discusses the scenario case development. RUS requires scenarios be constructed bounding the system load forecast. As stated above, the EKPC system load forecast is developed from the bottom up, 16 owner-member forecasts summed. However, scenarios are not developed at the owner-member level. A separate model is constructed to represent the base forecast. The model is redefined using optimistic assumptions and again using pessimistic assumptions. The percent differences between these results and the base case are then applied to the EKPC system load forecast referenced on page 53 to determine the high and low case demand and energy levels as reported on page 63.

The high and low rates used for the scenario models are developed using a weighted average of the owner-member's rates used in each owner-member's forecast. The historical and projected rates are weighted based on energy sales and rates of each owner-member. The 3.2% and 1.1%, as stated on Page 62, are applied to the weighted average rate to determine the rate assumption for the scenarios. In the models, these rates, with the elasticity coefficient applied, are used to determine the energy use per customer.

EAST KENTUCKY POWER COOPERATIVE, INC.
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FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 14
RESPONSIBLE PERSON: Julia J. Tucker
COMPANY: East Kentucky Power Cooperative, Inc.

Request 14. Refer to the IRP, Technical Appendix, Section 3.14, pages 23-24, and Section 4, pages 29-30, and Section 5, page 41.

Request 14a. Provide a copy of the IHS Global Insights Inc. ("IHS") count level forecasts.

Response 14a. A confidential copy of the IHS count level forecasts is provided on the attached CD as four spreadsheets entitled; 14.a GCP (real GCP), 14.a Employment (Total Nonfarm), 14.a Households, and 14.a Population.

Request 14b. Provide a step by step discussion of the process of converting IHS county level forecasts into regional forecasts and the into owner-member service territory forecasts. A numerical example should be included in the discussion.

Response 14b. County level forecast data is retrieved from IHS Global Insights. Utilizing GIS shape files of each owner-member's service territory, the portion of each county served by each owner-member is determined. The owner-member's share of each county is applied to the county level data. This provides a representation of the owner-member's share of the county level data. Owner-member's portion of their counties served is added up to get their service territory totals. EKPC has divided its owner-members' service areas into seven economic regions based on the owner-member service territorial boundaries.

As an example, the county level economic data retrieved from IHS, shows the population of Estill County to be 14,240 in 2018. The GIS shape file reports that Jackson Energy serves 89.7% of Estill County. Multiplying the county total, by the percentage served yields a representation of the population served. In this example, Jackson serves 89.7% or 12,773 people of Estill County's total population of 14,240.

Request 14c. Confirm that the process outlined in Section 5 page 41 is generally used to transform HIS county level data and forecasts into owner-member service territory level data and forecasts.

Response 14c. GIS shape files are used to carve out the area of each county served by each owner-member. Please see example used in 14.b.

Request 14d. Confirm that the variables listed in Section 4, page 29, are forecast at the owner-member service territory level that will be used in the residential and other forecasting models.

Response 14d. Real GCP, GCP, Total Employment (manufacturing), Total Employment (non-manufacturing), Households, Population and Real Personal Income are all county level forecasts provided by IHS. Using the GIS shape file carve out outlined in 7.b, these county level forecasts are used to build a representation for each of the owner-member's service territories.

Request 14e. The second and third sentences in subpart 3. of Section 5, page 41, seem to indicate that, for each of the owner members, the final equations may not uniformly include the same explanatory variables. Provide a copy of each owner member's final equation for service territory customer forecast.

Response 14e. The Regression Model Specs are provided on pages 4 through 19 of this response.

Project:	**H:\Load Forecasting Department\Load Forecast Long Term\2018\ITRON Files\Fcst2018**
Model:	**ResCusts**
Dependent Variable:	**mSales.ResCusts**
Date:	**December 14, 2018**
Time:	**02:28 PM**
Estimation Begin Date:	**2009:1**
Estimation End Date:	**2018:3**
Forecast Period End Date:	**2038:12**

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
CONST	43758.267	5523.546	7.922	0%
Econ.HH	304.874	98.401	3.098	0%
mBin.Dec08	0.000	0.000	0.000	100%
mBin.Yr2018Plus	627.809	186.518	3.366	0%
mBin.Yr2015	-103.641	93.430	-1.109	27%

Model Statistics	
Iterations	1
Adjusted Observations	111
Deg. of Freedom for Error	106
R-Squared	0.227
Adjusted R-Squared	0.197
AIC	11.473
BIC	11.595
F-Statistic	7.763
Prob (F-Statistic)	0.000
Log-Likelihood	-789.24
Model Sum of Squares	2854488
Sum of Squared Errors	9743768
Mean Squared Error	91922.34
Std. Error of Regression	303.19
Mean Abs. Dev. (MAD)	229.10
Mean Abs. % Err. (MAPE)	0.38%
Durbin-Watson Statistic	1.192
Durbin-H Statistic	2.680
Ljung-Box Statistic	202.19
Prob (Ljung-Box)	0.000
Skewness	0.298
Kurtosis	3.461
Jarque-Bera	2.621
Prob (Jarque-Bera)	0.270

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.00
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	**Coefficient**	**Mean**	**Elast**
Econ.HH	304.874	56.159	0.281
mBin.Dec08	0.000	0.000	0.000
mBin.Yr2018Plus	627.809	0.027	0.000
mBin.Yr2015	-103.641	0.108	-0.000

Project:	**H:\Load Forecasting Department\Load Forecast Long Term\2018\ITRON Files\Fcst2018**
Model:	**ResCusts**
Dependent Variable:	**mSales.ResCusts**
Date:	**December 14, 2018**
Time:	**02:24 PM**
Estimation Begin Date:	**2008:1**
Estimation End Date:	**2018:3**
Forecast Period End Date:	**2038:12**

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
Econ.HH	846.086	1.271	665.812	0%
mBin.Yr2018Plus	104.992	93.036	1.129	26%
AR(1)	0.819	0.050	16.341	0%

Model Statistics	
Iterations	10
Adjusted Observations	122
Deg. of Freedom for Error	119
R-Squared	0.993
Adjusted R-Squared	0.993
AIC	9.136
BIC	9.205
F-Statistic	5895.289
Prob (F-Statistic)	0.000
Log-Likelihood	-727.42
Model Sum of Squares	160290849
Sum of Squared Errors	1078523
Mean Squared Error	9063.22
Std. Error of Regression	95.20
Mean Abs. Dev. (MAD)	63.59
Mean Abs. % Err. (MAPE)	0.20%
Durbin-Watson Statistic	2.424
Durbin-H Statistic	0.037
Ljung-Box Statistic	27.11
Prob (Ljung-Box)	0.299
Skewness	-0.892
Kurtosis	10.158
Jarque-Bera	276.682
Prob (Jarque-Bera)	0.000

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.00
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	**Coefficient**	**Mean**	**Elast**
Econ.HH	846.086	37.425	1.000
mBin.Yr2018Plus	104.992	0.024	0.000

Project:	**H:\Load Forecasting Department\Load Forecast Long Term\2018\ITRON Files\Fcst2018**
Model:	**ResCusts**
Dependent Variable:	**mSales.ResCusts**
Date:	**December 14, 2018**
Time:	**10:57 AM**
Estimation Begin Date:	**2008:1**
Estimation End Date:	**2018:3**
Forecast Period End Date:	**2038:12**

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
Econ.HH	748.412	0.296	2532.605	0%
mBin.Yr2012	-161.479	27.629	-5.844	0%
mBin.Yr2018Plus	-85.592	53.124	-1.611	11%

Model Statistics	
Iterations	1
Adjusted Observations	123
Deg. of Freedom for Error	120
R-Squared	0.318
Adjusted R-Squared	0.307
AIC	9.041
BIC	9.109
F-Statistic	18.657
Prob (F-Statistic)	0.000
Log-Likelihood	-727.52
Model Sum of Squares	461075
Sum of Squared Errors	988507
Mean Squared Error	8237.56
Std. Error of Regression	90.76
Mean Abs. Dev. (MAD)	73.51
Mean Abs. % Err. (MAPE)	0.33%
Durbin-Watson Statistic	0.196
Durbin-H Statistic	0.302
Ljung-Box Statistic	772.19
Prob (Ljung-Box)	0.000
Skewness	0.211
Kurtosis	2.391
Jarque-Bera	2.814
Prob (Jarque-Bera)	0.245

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.00
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	**Coefficient**	**Mean**	**Elast**
Econ.HH	748.412	29.566	1.001
mBin.Yr2012	-161.479	0.098	-0.001
mBin.Yr2018Plus	-85.592	0.024	-0.000

Project:	**H:\Load Forecasting Department\Load Forecast Long Term\2018\ITRON Files\Fcst2018**
Model:	**ResCusts**
Dependent Variable:	**mSales.ResCusts**
Date:	**December 14, 2018**
Time:	**10:54 AM**
Estimation Begin Date:	**2010:1**
Estimation End Date:	**2018:3**
Forecast Period End Date:	**2038:12**

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
CONST	9175.712	1346.185	6.816	0%
Econ.HH	488.366	14.950	32.667	0%
mBin.Yr2017Plus	384.892	76.453	5.034	0%

Model Statistics	
Iterations	1
Adjusted Observations	99
Deg. of Freedom for Error	96
R-Squared	0.959
Adjusted R-Squared	0.958
AIC	10.702
BIC	10.781
F-Statistic	1125.957
Prob (F-Statistic)	0.000
Log-Likelihood	-667.22
Model Sum of Squares	97133872
Sum of Squared Errors	4140855
Mean Squared Error	43133.91
Std. Error of Regression	207.69
Mean Abs. Dev. (MAD)	170.86
Mean Abs. % Err. (MAPE)	0.32%
Durbin-Watson Statistic	0.700
Durbin-H Statistic	-0.310
Ljung-Box Statistic	238.38
Prob (Ljung-Box)	0.000
Skewness	0.275
Kurtosis	2.301
Jarque-Bera	3.258
Prob (Jarque-Bera)	0.196

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.00
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	**Coefficient**	**Mean**	**Elast**
Econ.HH	488.366	90.538	0.827
mBin.Yr2017Plus	384.892	0.152	0.001

Project:	**H:\Load Forecasting Department\Load Forecast Long Term\2018\ITRON Files\Fcst2018**
Model:	**ResCusts**
Dependent Variable:	**mSales.ResCusts**
Date:	**December 14, 2018**
Time:	**02:23 PM**
Estimation Begin Date:	**2009:1**
Estimation End Date:	**2018:3**
Forecast Period End Date:	**2038:12**

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
CONST	14558.323	651.386	22.350	0%
Econ.HH	108.968	42.054	2.591	1%
AR(1)	0.705	0.068	10.319	0%

Model Statistics	
Iterations	9
Adjusted Observations	110
Deg. of Freedom for Error	107
R-Squared	0.625
Adjusted R-Squared	0.618
AIC	6.549
BIC	6.623
F-Statistic	89.206
Prob (F-Statistic)	0.000
Log-Likelihood	-513.28
Model Sum of Squares	121335
Sum of Squared Errors	72769
Mean Squared Error	680.08
Std. Error of Regression	26.08
Mean Abs. Dev. (MAD)	19.49
Mean Abs. % Err. (MAPE)	0.12%
Durbin-Watson Statistic	1.937
Durbin-H Statistic	1.166
Ljung-Box Statistic	50.22
Prob (Ljung-Box)	0.001
Skewness	-0.258
Kurtosis	4.250
Jarque-Bera	8.380
Prob (Jarque-Bera)	0.015

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.00
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	**Coefficient**	**Mean**	**Elast**
Econ.HH	108.968	15.500	0.104

Project:	**H:\Load Forecasting Department\Load Forecast Long Term\2018\ITRON Files\Fcst2018**
Model:	**ResCusts**
Dependent Variable:	**mSales.ResCusts**
Date:	**December 14, 2018**
Time:	**02:27 PM**
Estimation Begin Date:	**2009:1**
Estimation End Date:	**2018:3**
Forecast Period End Date:	**2038:12**

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
CONST	1685.170	2379.443	0.708	48%
Econ.HH	636.975	111.780	5.698	0%
mBin.Aug15	462.056	17.704	26.099	0%
AR(1)	0.944	0.025	37.559	0%

Model Statistics	
Iterations	17
Adjusted Observations	110
Deg. of Freedom for Error	106
R-Squared	0.987
Adjusted R-Squared	0.987
AIC	6.430
BIC	6.528
F-Statistic	2719.767
Prob (F-Statistic)	0.000
Log-Likelihood	-505.73
Model Sum of Squares	4882584
Sum of Squared Errors	63431
Mean Squared Error	598.41
Std. Error of Regression	24.46
Mean Abs. Dev. (MAD)	18.18
Mean Abs. % Err. (MAPE)	0.12%
Durbin-Watson Statistic	2.016
Durbin-H Statistic	1.744
Ljung-Box Statistic	26.09
Prob (Ljung-Box)	0.349
Skewness	-0.525
Kurtosis	3.553
Jarque-Bera	6.446
Prob (Jarque-Bera)	0.040

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.00
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	**Coefficient**	**Mean**	**Elast**
Econ.HH	636.975	20.961	0.885
mBin.Aug15	462.056	0.009	0.000

Project:	**H:\Load Forecasting Department\Load Forecast Long Term\2018\ITRON Files\Fcst2018**
Model:	**ResCusts**
Dependent Variable:	**mSales.ResCusts**
Date:	**December 14, 2018**
Time:	**10:31 AM**
Estimation Begin Date:	**2010:1**
Estimation End Date:	**2018:3**
Forecast Period End Date:	**2038:12**

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
CONST	5044.288	261.235	19.309	0%
Econ.HH	468.789	17.597	26.641	0%
SMA(1)	0.131	0.108	1.206	23%

Model Statistics	
Iterations	11
Adjusted Observations	99
Deg. of Freedom for Error	96
R-Squared	0.898
Adjusted R-Squared	0.896
AIC	7.060
BIC	7.139
F-Statistic	422.235
Prob (F-Statistic)	0.000
Log-Likelihood	-486.96
Model Sum of Squares	954816
Sum of Squared Errors	108544
Mean Squared Error	1130.67
Std. Error of Regression	33.63
Mean Abs. Dev. (MAD)	22.27
Mean Abs. % Err. (MAPE)	0.19%
Durbin-Watson Statistic	1.813
Durbin-H Statistic	0.371
Ljung-Box Statistic	18.32
Prob (Ljung-Box)	0.787
Skewness	2.313
Kurtosis	16.902
Jarque-Bera	885.508
Prob (Jarque-Bera)	0.000

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.00
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	**Coefficient**	**Mean**	**Elast**
Econ.HH	468.789	14.845	0.580

Project:	**H:\Load Forecasting Department\Load Forecast Long Term\2018\ITRON Files\Fcst2018**
Model:	**ResCusts**
Dependent Variable:	**mSales.ResCusts**
Date:	**December 14, 2018**
Time:	**02:29 PM**
Estimation Begin Date:	**2008:1**
Estimation End Date:	**2018:3**
Forecast Period End Date:	**2038:12**

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
Econ.HH	1019.614	1.095	931.341	0%
mBin.Yr2018Plus	60.086	64.377	0.933	35%
SAR(1)	0.574	0.075	7.668	0%

Model Statistics	
Iterations	10
Adjusted Observations	111
Deg. of Freedom for Error	108
R-Squared	0.769
Adjusted R-Squared	0.765
AIC	9.513
BIC	9.587
F-Statistic	119.942
Prob (F-Statistic)	0.000
Log-Likelihood	-682.49
Model Sum of Squares	4743756
Sum of Squared Errors	1423812
Mean Squared Error	13183.44
Std. Error of Regression	114.82
Mean Abs. Dev. (MAD)	86.40
Mean Abs. % Err. (MAPE)	0.38%
Durbin-Watson Statistic	0.691
Durbin-H Statistic	0.233
Ljung-Box Statistic	349.48
Prob (Ljung-Box)	0.000
Skewness	-0.426
Kurtosis	3.095
Jarque-Bera	3.401
Prob (Jarque-Bera)	0.183

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.00
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	**Coefficient**	**Mean**	**Elast**
Econ.HH	1019.614	22.300	0.999
mBin.Yr2018Plus	60.086	0.024	0.000

Project:	**H:\Load Forecasting Department\Load Forecast Long Term\2018\ITRON Files\Fcst2018**
Model:	**ResCusts**
Dependent Variable:	**mSales.ResCusts**
Date:	**December 14, 2018**
Time:	**02:18 PM**
Estimation Begin Date:	**2005:1**
Estimation End Date:	**2017:12**
Forecast Period End Date:	**2038:12**

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
CONST	4680.545	1188.344	3.939	0%
Econ.Pop	163.099	20.296	8.036	0%
mBin.Yr2010	-58.351	30.634	-1.905	6%
mBin.Yr16Plus	43.746	22.860	1.914	6%

Model Statistics	
Iterations	1
Adjusted Observations	156
Deg. of Freedom for Error	152
R-Squared	0.308
Adjusted R-Squared	0.295
AIC	9.120
BIC	9.198
F-Statistic	22.570
Prob (F-Statistic)	0.000
Log-Likelihood	-928.71
Model Sum of Squares	603130
Sum of Squared Errors	1353939
Mean Squared Error	8907.49
Std. Error of Regression	94.38
Mean Abs. Dev. (MAD)	76.63
Mean Abs. % Err. (MAPE)	0.54%
Durbin-Watson Statistic	0.337
Durbin-H Statistic	-1.091
Ljung-Box Statistic	1381.62
Prob (Ljung-Box)	0.000
Skewness	0.396
Kurtosis	2.488
Jarque-Bera	5.791
Prob (Jarque-Bera)	0.055

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.00
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	**Coefficient**	**Mean**	**Elast**
Econ.Pop	163.099	58.525	0.671
mBin.Yr2010	-58.351	0.077	-0.000
mBin.Yr16Plus	43.746	0.154	0.000

Project:	**H:\Load Forecasting Department\Load Forecast Long Term\2018\ITRON Files\Fcst2018**
Model:	**ResCusts**
Dependent Variable:	**mSales.ResCusts**
Date:	**December 14, 2018**
Time:	**02:25 PM**
Estimation Begin Date:	**2013:1**
Estimation End Date:	**2018:3**
Forecast Period End Date:	**2038:12**

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
Econ.Pop	236.452	1.920	123.167	0%
mBin.Yr2015Plus	-76.390	108.938	-0.701	49%
AR(1)	0.960	0.032	29.634	0%

Model Statistics	
Iterations	12
Adjusted Observations	62
Deg. of Freedom for Error	59
R-Squared	0.989
Adjusted R-Squared	0.989
AIC	9.402
BIC	9.505
F-Statistic	1837.629
Prob (F-Statistic)	0.000
Log-Likelihood	-376.45
Model Sum of Squares	63726427
Sum of Squared Errors	682013
Mean Squared Error	11559.54
Std. Error of Regression	107.52
Mean Abs. Dev. (MAD)	84.12
Mean Abs. % Err. (MAPE)	0.15%
Durbin-Watson Statistic	1.758
Durbin-H Statistic	0.135
Ljung-Box Statistic	101.84
Prob (Ljung-Box)	0.000
Skewness	-0.058
Kurtosis	2.544
Jarque-Bera	0.571
Prob (Jarque-Bera)	0.752

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.00
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	**Coefficient**	**Mean**	**Elast**
Econ.Pop	236.452	242.170	1.008
mBin.Yr2015Plus	-76.390	0.619	-0.001

Project:	**H:\Load Forecasting Department\Load Forecast Long Term\2018\ITRON Files\Fcst2018**
Model:	**ResCusts**
Dependent Variable:	**mSales.ResCusts**
Date:	**December 14, 2018**
Time:	**02:21 PM**
Estimation Begin Date:	**2013:1**
Estimation End Date:	**2018:3**
Forecast Period End Date:	**2038:12**

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
Econ.Pop	381.084	0.401	949.772	0%
mBin.Yr2015Plus	67.556	57.893	1.167	25%
mBin.Yr2018Plus	111.358	80.890	1.377	17%
AR(1)	0.648	0.096	6.765	0%

Model Statistics	
Iterations	15
Adjusted Observations	62
Deg. of Freedom for Error	58
R-Squared	0.047
Adjusted R-Squared	-0.002
AIC	9.012
BIC	9.149
F-Statistic	0.720
Prob (F-Statistic)	0.826
Log-Likelihood	-363.34
Model Sum of Squares	22201
Sum of Squared Errors	446817
Mean Squared Error	7703.74
Std. Error of Regression	87.77
Mean Abs. Dev. (MAD)	65.75
Mean Abs. % Err. (MAPE)	0.14%
Durbin-Watson Statistic	2.073
Durbin-H Statistic	0.087
Ljung-Box Statistic	21.11
Prob (Ljung-Box)	0.632
Skewness	0.005
Kurtosis	4.083
Jarque-Bera	3.027
Prob (Jarque-Bera)	0.220

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.00
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	**Coefficient**	**Mean**	**Elast**
Econ.Pop	381.084	125.085	0.999
mBin.Yr2015Plus	67.556	0.619	0.001
mBin.Yr2018Plus	111.358	0.048	0.000

Project: **H:\Load Forecasting Department\Load Forecast Long Term\2018\ITRON Files\Fcst2018**
Model: **ResCusts**
Dependent Variable: **mSales.ResCusts**
Date: **December 14, 2018**
Time: **02:27 PM**
Estimation Begin Date: **2010:1**
Estimation End Date: **2018:3**
Forecast Period End Date: **2038:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	-22560.158	5409.848	-4.170	0%
Econ.Pop	568.886	43.929	12.950	0%
AR(1)	0.953	0.020	46.562	0%

Model Statistics	
Iterations	9
Adjusted Observations	98
Deg. of Freedom for Error	95
R-Squared	0.999
Adjusted R-Squared	0.999
AIC	7.015
BIC	7.094
F-Statistic	69631.978
Prob (F-Statistic)	0.000
Log-Likelihood	-479.79
Model Sum of Squares	150439085
Sum of Squared Errors	102623
Mean Squared Error	1080.24
Std. Error of Regression	32.87
Mean Abs. Dev. (MAD)	25.22
Mean Abs. % Err. (MAPE)	0.06%
Durbin-Watson Statistic	1.612
Durbin-H Statistic	0.294
Ljung-Box Statistic	37.02
Prob (Ljung-Box)	0.044
Skewness	0.105
Kurtosis	3.345
Jarque-Bera	0.665
Prob (Jarque-Bera)	0.717

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.00
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
Econ.Pop	568.886	119.731	1.489

Project:	**H:\Load Forecasting Department\Load Forecast Long Term\2018\ITRON Files\Fcst2018**
Model:	**ResCusts**
Dependent Variable:	**mSales.ResCusts**
Date:	**December 14, 2018**
Time:	**02:10 PM**
Estimation Begin Date:	**2008:1**
Estimation End Date:	**2018:3**
Forecast Period End Date:	**2038:12**

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
CONST	6518.156	1138.977	5.723	0%
Econ.HH	661.268	46.100	14.344	0%
mBin.Yr2018Plus	71.685	83.842	0.855	39%
MA(1)	0.885	0.044	19.992	0%

Model Statistics	
Iterations	15
Adjusted Observations	123
Deg. of Freedom for Error	119
R-Squared	0.881
Adjusted R-Squared	0.878
AIC	9.369
BIC	9.461
F-Statistic	292.386
Prob (F-Statistic)	0.000
Log-Likelihood	-746.74
Model Sum of Squares	9959392
Sum of Squared Errors	1351146
Mean Squared Error	11354.17
Std. Error of Regression	106.56
Mean Abs. Dev. (MAD)	87.63
Mean Abs. % Err. (MAPE)	0.38%
Durbin-Watson Statistic	0.869
Durbin-H Statistic	0.476
Ljung-Box Statistic	445.46
Prob (Ljung-Box)	0.000
Skewness	-0.593
Kurtosis	2.455
Jarque-Bera	8.731
Prob (Jarque-Bera)	0.013

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.00
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	**Coefficient**	**Mean**	**Elast**
Econ.HH	661.268	24.737	0.715
mBin.Yr2018Plus	71.685	0.024	0.000

Project: **H:\Load Forecasting Department\Load Forecast Long Term\2018\ITRON Files\Fcst2018**
Model: **ResCusts**
Dependent Variable: **mSales.ResCusts**
Date: **December 14, 2018**
Time: **02:11 PM**
Estimation Begin Date: **2014:1**
Estimation End Date: **2018:3**
Forecast Period End Date: **2038:12**

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
Econ.HH	984.073	1.192	825.303	0%
mBin.Yr2017Plus	310.541	49.881	6.226	0%

Model Statistics	
Iterations	1
Adjusted Observations	51
Deg. of Freedom for Error	49
R-Squared	0.291
Adjusted R-Squared	0.276
AIC	10.218
BIC	10.294
F-Statistic	10.033
Prob (F-Statistic)	0.001
Log-Likelihood	-330.92
Model Sum of Squares	528870
Sum of Squared Errors	1291459
Mean Squared Error	26356.30
Std. Error of Regression	162.35
Mean Abs. Dev. (MAD)	125.12
Mean Abs. % Err. (MAPE)	0.56%
Durbin-Watson Statistic	0.449
Durbin-H Statistic	0.214
Ljung-Box Statistic	156.74
Prob (Ljung-Box)	0.000
Skewness	0.261
Kurtosis	2.616
Jarque-Bera	0.893
Prob (Jarque-Bera)	0.640

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.00
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	**Coefficient**	**Mean**	**Elast**
Econ.HH	984.073	22.687	0.996
mBin.Yr2017Plus	310.541	0.294	0.004

```
Project:                    H:\Load Forecasting Department\Load Forecast Long Term\2018\ITRON Files\Fcst2018
Model:                      ResCusts
Dependent Variable:         mSales.ResCusts
Date:                       December 14, 2018
Time:                       02:20 PM
Estimation Begin Date:      2007:1
Estimation End Date:        2018:3
Forecast Period End Date:   2038:12

Variable            Coefficient     StdErr    T-Stat     P-Value
CONST                12490.748    2340.797     5.336          0%
Econ.HH                313.095      63.855     4.903          0%
mBin.Feb09            1607.004     249.833     6.432          0%
mBin.Yr2018Plus       1190.147     148.504     8.014          0%

Model Statistics                                  Forecast Statistics
Iterations                            1           Forecast Observations                 0
Adjusted Observations               135           Mean Abs. Dev. (MAD)               0.00
Deg. of Freedom for Error           131           Mean Abs. % Err. (MAPE)           0.00%
R-Squared                         0.527           Avg. Forecast Error                0.00
Adjusted R-Squared                0.517           Mean % Error                      0.00%
AIC                              11.057           Root Mean-Square Error             0.00
BIC                              11.143           Theil's Inequality Coefficient    0.000
F-Statistic                      48.740           -- Bias Proportion                0.00%
Prob (F-Statistic)                0.000           -- Variance Proportion            0.00%
Log-Likelihood                  -933.92           -- Covariance Proportion          0.00%
Model Sum of Squares            9003451
Sum of Squared Errors           8066208
Mean Squared Error             61574.11
Std. Error of Regression         248.14
Mean Abs. Dev. (MAD)             204.83
Mean Abs. % Err. (MAPE)           0.85%
Durbin-Watson Statistic           0.127
Durbin-H Statistic               -1.978
Ljung-Box Statistic             1358.98
Prob (Ljung-Box)                  0.000
Skewness                          0.480
Kurtosis                          2.256
Jarque-Bera                       8.301
Prob (Jarque-Bera)                0.016


Variable            Coefficient       Mean      Elast
Econ.HH                313.095      36.665      0.478
mBin.Feb09            1607.004       0.007      0.000
mBin.Yr2018Plus       1190.147       0.022      0.001
```

Project: H:\Load Forecasting Department\Load Forecast Long Term\2018\ITRON Files\Fcst2018
Model: ResCusts
Dependent Variable: mSales.ResCusts
Date: December 14, 2018
Time: 10:55 AM
Estimation Begin Date: 2013:1
Estimation End Date: 2018:3
Forecast Period End Date: 2038:12

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	6706.723	501.149	13.383	0%
Econ.Pop	168.702	4.783	35.270	0%

Model Statistics	
Iterations	1
Adjusted Observations	63
Deg. of Freedom for Error	61
R-Squared	0.953
Adjusted R-Squared	0.952
AIC	7.177
BIC	7.245
F-Statistic	1243.984
Prob (F-Statistic)	0.000
Log-Likelihood	-313.47
Model Sum of Squares	1578252
Sum of Squared Errors	77391
Mean Squared Error	1268.71
Std. Error of Regression	35.62
Mean Abs. Dev. (MAD)	28.23
Mean Abs. % Err. (MAPE)	0.12%
Durbin-Watson Statistic	0.411
Durbin-H Statistic	0.038
Ljung-Box Statistic	136.74
Prob (Ljung-Box)	0.000
Skewness	0.203
Kurtosis	2.667
Jarque-Bera	0.725
Prob (Jarque-Bera)	0.696

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.00
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
Econ.Pop	168.702	104.770	0.725

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 15
RESPONSIBLE PERSON: Julia J. Tucker
COMPANY: East Kentucky Power Cooperative, Inc.

Request 15. Refer to the IRP, Technical Appendix, Volume 1, Table 7-3, page 41.

Request 15a. For each owner-member cooperative, explain and illustrate how the Share variables are derived. Include in the explanation a copy of RUS Form 7.

Response 15a. EKPC assumes the question is referencing Table 5-1 on page 41 of the Technical Appendix. See Response 14b.

Request 15b. Explain how the specific share variable is combined with the regional population and household variables to obtain the owner-member specific population and household variable.

Response 15b. The share variables and the economic variables are not combined. Both are variables within the model but are never combined. To understand how economic variables are transformed from county level to owner-member representations, see response 14.b.

Request 15c. Provide each owner member's final regression equation used to forecast its residential customers.

Response 15c. See Response 14.e Regression Model Specs.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 16
RESPONSIBLE PERSON: Julia J. Tucker
COMPANY: East Kentucky Power Cooperative, Inc.

Request 16. Refer to the IRP, Section 3.4.1.1, Residential Sales, pages 53-54, and Technical Appendix, Volume 1, Technical Appendix, pages 19, 41-51, and Exhibit LF-1, pages 32-35. Between the referenced discussions of how residential sales are forecast, there appears to be slight variation.

Request 16a. Section 3.4.1 .1 provides a list of various economic variables that, where appropriate, are used to forecast residential sales. However, the list does not appear to match and may contain explanatory variables different from those listed in the referenced parts of the Technical Appendix. Explain whether the list was intended to be representative only of explanatory variables used to forecast both the number of customers and customer usage.

Response 16a. EKPC develops each owner-member's customer and energy forecasts using variables that both capture the impacts of the historical trends, as well as the projected trends of the explanatory variables. EKPC maintains many databases, including economic data, load, customers and others. The forecast process evaluates many models using different variables. The final model specification is the one that best captures the historical trends and variable forecasts.

Request 16b. Of the variables listed in Section 3.4.1 .1, explain how each is used to obtain the residential sales forecast.

Response 16b. Given the nuances of each owner-member, the equations vary. The sales forecasts are a function of customers and use per customer. Customer history is used with an economic driver to forecast customers. The economic driver used is either the number of households or population based upon historic correlation. The variable with the stronger correlation produces a better forecast. Owner-member residential customer equations are provided in Response 14e. Autoregressive terms and binaries are used to smooth historical anomalies. Other economic variables were evaluated but these were the strongest explanatory variables.

For use-per-customer, the models use the SAE formulas provided in Response 16d.

Projecting residential customers and sales, employment, real gross county product, real total personal income, or consumer price index may not be explicitly used in an equation as a stand-alone variable, however, it may influence a variable, such as CPI on household income. Also, studying the individual variable projections helps EKPC understand the outlook for the service territories.

Heating and cooling degree days are used to measure customer response to weather. This calculated historic response to temperature changes is then applied to normal weather. These are used in the SAE equations, see Response 16d.

Request 16c. Reconcile the lists of variables in Section 3.4.1 .1 and those listed in the equations in the Technical Appendix and confirm that the variable listed in the equations in the Technical Appendix are the only variables used to obtain the residential sales forecast.

Response 16c. Both references discuss variables that influence the overall forecast results. Some variables are stand-alone variables used in the model specifications such as population. Some variables are used in the development of other variables, such as HDD. Other variables influence decisions about the final models by providing insight to the overall outlook.

<u>Request 16d.</u> In the Technical Appendix, the Coollndex and CoolUse equations listed page 47 do not agree with the equations in Exhibit LF-1 page 34. Provide the equations EKPC used to obtain the "Heat, Cool and Water Heat and Other" variables for the equation listed page 47.

<u>Response 16d.</u> The Exhibit LF-1 is an Itron report reviewing the results of their 2018 Residential SAE Update. The content describes the results, equations and methods followed in performing their analyses. While EKPC uses the SAE approach, the equations used are not exactly the same that ITRON uses. The equation for 'CoolIndex' shown on page 33 of the same exhibit is what EKPC uses. The 'StructuralIndex' variable in included in EKPC variable development but not explicitly included as a stand-alone variable.

The residential class equations are structured as follows:

HeatUse = (HHSizeIdx^Elas.HHSize) * (HHIncIdx^Elas.HHInc) *
(ResPriceIdx^Elas.ResPrice) * HDDIdx

XHeat = HeatUse * ResEl.Heating

CoolUse = (HHSizeIdx^Elas.HHSize) * (HHIncIdx^Elas.HHInc) *
(ResPriceIdx^Elas.ResPrice) * CDDIdx

XCool = CoolUse * ResEl.Cooling

OtherUse = (HHSizeIdx^Elas.HHSize) * (HHIncIdx^Elas.HHInc) *
(ResPriceIdx^Elas.ResPrice) * DaysIdx

OtherEqpIndex = (ResEI.EWHeat) * (MonthlyMults.EWHeat) + (ResEI.ECook) * (MonthlyMults.ECook) +
(ResEI.Ref1) * (MonthlyMults.Ref1) + (ResEI.Ref2) * (MonthlyMults.Ref2) +
(ResEI.Frz) * (MonthlyMults. Frzh) + (ResEI.Dish) * (MonthlyMults.Dish) +
(ResEI.CWash) * (MonthlyMults.CWash) + (ResEI.EDry) * (MonthlyMults.EDry) +
(ResEI.TV) * (MonthlyMults.TV) + (ResEI.Light) * (MonthlyMults.Light) +
(ResEI.Misc) * (MonthlyMults.Misc)

XOther = OtherUse * OtherEqpIndex

Variable Explanations:

HHSizeIdx = household size index; Elas.HHSize = household size elasticity coefficient

HHIncIdx = household income index; Elas.HHInc = household income elasticity coefficient

ResPriceIdx = residential price index; Elas.ResPrice = residential price elasticity coefficient

HDDIdx = heating degree day index; ResEI.Heating = residential heating efficiency index

CDDIdx = cooling degree day index; ResEI.Cooling = residential cooling efficiency index

DaysIdx, MonthlyMults are used to convert data to monthly and daily

These are multiplied by the Indices developed as described in the Exhibit LF-1 pages 1 through 9. EKPC uses each owner-member’s end-use survey data to develop the indices for the following:

EWHeat = Electric water heating
ECook = Electric stove
Ref1 = Refrigerator 1
Ref2 = Refrigerator 2
Frz = Freezer
Dish = Dishwasher

CWash = Clothes Washer
EDry = Electric Clothes Dryer
TV = Television(s)
Light = Lighting
Misc = Other load

Other variables, such as electric vehicles or electric golf carts, will be added when the saturation indicates they may be impacting energy sales.

The small commercial class equations are constructed similarly.

HeatUse = ComPriceIdx ^ Elas.ComPrice * ComVar * HDDIdx
XHeat = HeatUse * ComEI.Heat
CoolUse = ComPriceIdx ^ Elas.ComPrice * ComVar * CDDIdx
XCool = CoolUse * ComEI.Cool
OtherUse = ComPriceIdx ^ Elas.ComPrice * ComVar * DaysIdx
XOther = OtherUse * ComEI.NonHVAC

Variable Explanations:

ComPriceIdx = commercial price index Elas.ComPrice = commercial price elasticity coefficient
ComVar = GDP index * commercial output +
non-manufacturing employment index * (1 – commercial output)
where commercial output is the GDP weight
HDDIdx = heating degree day index
CDDIdx = cooling degree day index
ComEI.Heat = electric heat efficiency index
ComEI.Cool = cooling efficiency index
ComEI.NonHVAC = other use efficiency index

EKPC does not conduct an energy use survey for the small commercial class. ITRON data is the basis for the indices. Owner-member specific economic projections are used.

Request 16e. Provide the equations EKPC used to forecast owner-member customer numbers.

Response 16e. See Response 15c.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 17
RESPONSIBLE PERSON: Julia J. Tucker
COMPANY: East Kentucky Power Cooperative, Inc.

Request 17. Refer to the IRP, Section 3.4.1 .2, Small Commercial Sales, page 54 and to Technical Appendix, pages 19 and 55. Section 3.4.1.2 provides a list of various economic variables which, where appropriate, may be used to forecast small commercial sales. The Technical Appendix discussions are quite vague as to the exact process including which explanatory variables may or may not be used to forecast small commercial energy sales.

Request 17a. Provide a more robust and detailed discussion including the equations of exactly how small commercial sales are forecast.

Response 17a. The small commercial class consists of more diverse customers than the residential class. There are customers with usage up to 1 MW, yet there are cases where a large number of customer accounts have very little usage such as cable repeater accounts. As with the residential sales class, EKPC develops each owner-member's customer and energy forecasts for the small commercial class using variables that both capture the impacts of the historical trends, as well as the projected trends of the explanatory variables. The same databases, including economic data, load, customers and others are used to glean insights into customer and load growth or decline. The forecast process evaluates many models using different variables. The final model specification captures the historical trends and variable forecasts.

The customer forecast process involves analyzing employment, historical customer trends, and residential customer history and forecasts. Specifications for this class that address the diversity are required. For sales, the models use the SAE formulas provided in Response 16d.

Request 17b. SAE models could also be used to forecast small commercial usage. If not already discussed, explain whether or not SAE models were used to forecast small commercial usage.

Response 17b. For energy, the models use the SAE formulas provided in Response 16d. EKPC does not conduct an energy use survey for the small commercial class and thus uses data developed by ITRON for the indices. Owner-member specific rates and economic projections are used.

Request 17c. If not already discussed, for the variables listed in Section 3.4.1.2, explain how each is used in forecasting small commercial sales and whether this list includes all the variables used in the small commercial forecast.

Response 17c. See Response 16d.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020

REQUEST 18

RESPONSIBLE PERSONS: **Julia J. Tucker**

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

Request 18. Refer to the IRP, Technical Appendix, Section 7, pages 55-56. The probability of actually acquiring large commercial or industrial development can vary greatly between potential industrial parks. Potential occupants will view potential sites very differently depending on the degree to which the site is move-in ready, i.e., finished roads, access and proximity to major transportation corridors, all necessary utilities installed, all local, state, and federal studies and permits completed, shell building completed, etc. The degree of industrial park readiness is not evenly distributed between owner members. Provide a copy of the probabilistic model equation(s) and explain the rationale for distributing forecast new commercial industrial load among the 16 members.

Response 18. The large commercial and industrial class has significantly fewer customers than the other classes but the energy sales are significant. A regression equation based on the system total historical customers, which is over 100 customers, results in a stronger equation for the additions than individual owner-member equations.

Over the past 20 years, system-wide, 58 new customers have been added. Over the next 20 years, 55 customers are projected, about three per year.

These additional customers per year were proportioned to the owner-members based on historical percent-to-total customers. However, after discussions are held with owner-members and additional insights are provided regarding their view of new industrial customers, adjustments are made for each owner-member. This class is treated on a case-by-case basis, however, a starting point is needed for discussion and this approach provides a reasonable forecast from which to start.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 19
RESPONSIBLE PERSON: **Julia J. Tucker**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 19. Refer to the IRP, Technical Appendix, page 20.

Request 19a. Changing economic conditions, great appliance efficiencies, etc. could affect class load factors. For example, the slowly declining number and operational activity of coal mining operations over time may affect realized class load factors. Explain whether the various class load factors change or have changed over time.

Response 19a. Load factors have improved for certain appliances. Heat pumps have become more efficient over the past 10 years. These efficiency gains are reflected in the historical data, and thus in the projections of energy and demand. Water heating and air conditioning efficiencies have improved and are not expected to change over the next 5 to 10 years. Lighting improved significantly with the change to LEDs. While these impacts are gradual impacts due to attrition and adoption rates, they are accounted for implicitly in the historical data and explicitly as a function of the efficiency indices developed by ITRON using the EIA appliance efficiency projections.

Request 19b. Explain whether EKPC assumes that a class' load factor is constant going forward for forecasting purposes.

Response 19b. The load factors are relatively flat for the forecast period. While there are efficiency improvements accounted for in the assumptions, these changes occur gradually. There are no projected improvements resulting in the overall load factor changing significantly.

Request 19c. Explain the basis for each class load factor used in the forecast.

Response 19c. The residential and small commercial load factors are derived using load research data and publicly available data where EKPC data is not available. The large commercial class load factors are based on actual historical data as EKPC has individual meters on all of these customers. These, as well as the energy efficiency indices, and end-use monthly peak contributions to the peaks are the basis for the models. After the preliminary meetings, the models are adjusted as needed to reflect the owner-members' input.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2019-00096

FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020

REQUEST 20

RESPONSIBLE PERSON: **Julia J. Tucker**

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

Request 20. Refer to the IRP, Technical Appendix, Section 3, page 24 and Section 8, page 65.

Request 20a. Explain how historical and forecast data is modified to account for normal weather.

Response 20a. Monthly historical heating and cooling degree data are averaged over the 15 years or 20 years and that is used as the normal assumption. The 90 and 10 percentiles are used to set the extreme and mild series. The base model is rerun using the newly defined normal degree days. The other 2 series are used in the high and low case models.

Request 20b. In Section 3, explain why normal weather based on historic 20-year values is only used for most and not all owner members.

Response 20b. The sentence is incorrect. All 16 did use 20 years for the 2018 load forecast. Discussions were held to consider changing the time frame, however, the difference between the 15 and 20-year normals were minimal.

Request 20c. In Section 8, explain why weather variations are based on 15-year historic values rather than the 20-year values used in the base case forecasts.

Response 20c. Some research indicates that the weather may be acting differently in recent history as compared to longer term history. There was very minimal difference in the normal weather considerations between 15-and 20 years. The shorter time duration was utilized for the weather variations discussed in Section 8 in an attempt to pick up the shorter-term weather patterns, if indeed they are changing as compared to longer term history.

Request 20d. Provide a comparison of the differences in heating and cooling degree days using 15- and 20-year historic values.

Response 20d. Monthly comparisons provided in Response 20e.

History		HDD	CDD	Total
1999 - 2018	20 year	4457	1298	5755
2004 - 2018	15 year	4417	1335	5751

Request 20e. Provide a comparison of the heating and cooling degree days in the base, mild, and severe weather scenarios. Include in the response whether the comparison is based on the 15- or 20-year historic basis.

Response 20e.

Heating Degree Days
Used in the Scenario Models
Based on 15 Years of History

Month	Normal	Extreme	Mild
1	979	1128	795
2	812	1030	620
3	580	737	401
4	271	360	198
5	91	146	40
6	4	13	0
7	0	1	0
8	1	2	0
9	31	75	11
10	255	351	175
11	560	673	451
12	832	976	715
	4417	5492	3407

Cooling Degree Days
Used in the Scenario Models
Based on 15 Years of History

Month	Normal	Extreme	Mild
1	0	0	0
2	1	2	0
3	5	16	0
4	24	39	9
5	124	166	52
6	274	325	216
7	356	440	263
8	337	426	255
9	176	255	118
10	39	91	5
11	2	5	0
12	0	0	0
	1335	1766	918

Heating Degree Days

Based on 20 Years of History

Month	Normal	Extreme	Mild
1	986	1133	835
2	796	1010	639
3	596	760	412
4	272	356	201
5	91	147	52
6	6	18	0
7	0	0	0
8	1	1	0
9	39	83	14
10	260	331	191
11	552	679	441
12	858	1025	717
	4457	5542	3500

Cooling Degree Days

Based on 20 Years of History

Month	Normal	Extreme	Mild
1	0	0	0
2	1	0	0
3	3	7	0
4	25	47	8
5	112	159	45
6	263	315	196
7	356	452	267
8	336	419	255
9	166	238	108
10	35	80	5
11	2	4	0
12	0	0	0
	1298	1721	884

REDACTED

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 21
RESPONSIBLE PERSON: **Darrin Adams**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 21. Refer to the IRP, page 28.

Request 21a. Provide a copy of the Federal Energy Regulatory Commission docket for the transmission case with LG&E/KU.

Response 21a. Please see pages 3 through 294 of this response include all filed documents in the Federal Energy Regulatory Commission docket (EL16-8) related to the referenced transmission case.

Request 21b. Explain what EKPC plans to do to or has done to alleviate the transmission issue with LG&E/KU.

Response 21b. [redacted]

REDACTED

[redacted]

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

East Kentucky Power Cooperative, Inc. v. Louisville Gas & Electric/Kentucky Utilities	)	Docket No. EL16-___-000

NOTICE OF COMPLAINT

(November ___, 2015)

Take notice that on October 30, 2015, the East Kentucky Power Cooperative, Inc. ("East Kentucky") filed a formal complaint against Louisville Gas & Electric/Kentucky Utilities ("LKE") pursuant to Sections 206, 211, and 306 of the Federal Power Act ("FPA") and Rule 206 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission, alleging that LKE's failure to accept East Kentucky's designation of new Network Load under the East Kentucky-LKE Network Service Agreement is contrary to the terms of the LKE Open Access Transmission Tariff and the Commission's policies concerning open access and transmission pricing.

East Kentucky certifies that copies of the complaint were served on the contacts for LKE as listed on the Commission's list of Corporate Officials.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent's answer and all interventions, or protests must be filed on or before the comment date. The Respondent's answer, motions to intervene, and protests must be served on the Complainants.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 5 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, DC. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (insert date).

Kimberly D. Bose,
Secretary.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
	)	
East Kentucky Power Cooperative, Inc.	)	
v.	)	Docket No. EL16-___-000
Louisville Gas & Electric/Kentucky Utilities	)	
	)	
	)	

COMPLAINT

Pursuant to Sections 206, 211, and 306 of the Federal Power Act ("FPA")[1] and Rule 206 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"),[2] East Kentucky Power Cooperative, Inc., ("East Kentucky") submits this Complaint against Louisville Gas & Electric/Kentucky Utilities ("LKE"). LKE's failure to accept East Kentucky's designation of new Network Load under East Kentucky's Network Integrated Transmission Service Agreement ("NITSA") with LKE is contrary to the terms of the LKE Open Access Transmission Tariff ("Tariff") and the Commission's policies concerning open access and transmission pricing.

East Kentucky respectfully requests that the Commission order LKE to accept East Kentucky's identification of a new Delivery Point and designation of new Network Load as set forth in the attached proposed amended NITSA between East Kentucky and LKE.[3] The amended NITSA is needed in connection with East Kentucky's acquisition of the Bluegrass Generating Station ("Bluegrass"), an existing gas-fired peaking facility interconnected with LKE's

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[1] 16 U.S.C. §§ 824e, 824j-1, and 825e (2006).

[2] 18 C.F.R. § 385.206 (2015).

[3] *See* Proposed Amended East Kentucky NITSA with LKE appended hereto as Attachment 1.

transmission system. East Kentucky will integrate Bluegrass with its other resources and Network Load. The proposed agreement complies with the terms of the LKE Tariff, correctly identifies new Network Load, and fairly compensates LKE for the transmission service that LKE will provide. If necessary, East Kentucky requests waiver of the LKE Tariff and acceptance of the attached proposed amended NITSA as a non-conforming agreement in order to allow the Commission to grant the requested relief.

The instant Complaint is necessitated by LKE's refusal to accept the arrangements East Kentucky has proposed in order to integrate Bluegrass as a new Network Resource in a reasonable and economic manner. LKE instead insists that East Kentucky either: (1) reserve and pay for several hundreds of megawatts of excessive and duplicative Point-to-Point service that would increase LKE's annual transmission charges to East Kentucky from approximately $7 million to approximately $17 million; or (2) purchase several hundreds of megawatts of additional Network Service for additional specific delivery points already served by the East Kentucky transmission system so that, during any hour in the year, the amount of East Kentucky's Network Load under its NITSA with LKE is at least equal to the nominal capacity of the Bluegrass units.

I. COMMUNICATIONS

East Kentucky requests that all correspondence and communications regarding this filing be addressed to the following persons, who should be placed on the Commission's official service list in this proceeding:

Mr. David Crews
Senior Vice President, Power Supply
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
Winchester, KY 40391
Tel: 859-745-9706
Email: David.crews@ekpc.coop

Sherman Goodpaster, Esq.
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Debra Roby
Melissa Alfano
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Washington, DC 20005
Tel: 202-371-9030
Email: arobbins@jsslaw.com
droby@jsslaw.com
malfano@jsslaw.com

* denotes lead counsel

East Kentucky respectfully requests waiver of Rule 203(b) of the Commission's Rules of Practice and Procedure[4] to allow each of these individuals to be included on the official service list in this proceeding.

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[4] 18 C.F.R. § 385.203(b).

II. DESCRIPTION OF THE PARTIES

A. East Kentucky Power Cooperative, Inc.

East Kentucky is a not-for-profit electric generation and transmission cooperative organized and existing under Chapter 279 of the Kentucky Revised Statutes.[5] East Kentucky owns and purchases 2,794 MW of net summer generating capability and 3,009 MW of net winter electric generating capability to serve approximately 525,000 homes, businesses, and industries in 87 Kentucky counties through its 16 member distribution cooperatives.[6] East Kentucky experienced an all-time winter peak of 3,507 MW on February 20, 2015. East Kentucky is a transmission owning member of the PJM Interconnection, LLC ("PJM"), owning 2,938 miles of electric transmission lines.[7] East Kentucky has outstanding debt through the Rural Utilities Service and therefore is not a Commission-jurisdictional "public utility" under the Federal Power Act.[8]

Most of East Kentucky's member load (3,000 MW, or approximately 80%) is physically connected to transmission facilities owned by East Kentucky. Through East Kentucky's voluntary integration into PJM, that portion of East Kentucky's load is located within the PJM footprint in the EKPC Zone, as are East Kentucky's current Network Resources.[9] A smaller portion of East Kentucky's load, however, is physically connected to the LKE transmission system.[10] LKE is outside the PJM footprint and has not participated in a Regional Transmission

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[5] Kentucky Revised Statutes, Section 279.010 *et seq*.

[6] *See* Affidavit of David Crews at P 5 ("Crews Affidavit"), appended hereto as Attachment 2.

[7] *Id.* at PP 5, 8.

[8] *See* 16 U.S.C. § 824(e), (f).

[9] Crews Affidavit at P 8.

[10] *Id.* at PP 6, 8.

Organization since it withdrew from MISO in 2006.[11] That portion of East Kentucky's load is pseudo-tied to PJM and is treated as part of East Kentucky's internal zonal load in PJM.[12] As a result of these arrangements, all of East Kentucky's Network Resources and East Kentucky's entire Network Load are internal to PJM, regardless of whether the resources or load are connected to the East Kentucky transmission system or the LKE transmission system. The Commission previously approved these arrangements as part of its broader approval of the PJM-East Kentucky filings to integrate East Kentucky into PJM.[13]

East Kentucky also purchases network transmission service from LKE to deliver the energy dispatched by PJM to serve the pseudo-tied East Kentucky load.[14] The designated Network Load under the LKE NITSA is comprised of the sum of the East Kentucky delivery points on the LKE system.[15]

The Bluegrass facility is physically connected to the LKE system. The amendment to East Kentucky's NITSA with LKE that is the subject of this Complaint is needed to address delivery of Bluegrass output to the portion of East Kentucky's Network Load that is connected to East Kentucky's transmission facilities.

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[11] *See Louisville Gas and Electric Co.*, 114 FERC ¶ 61,282 at P 4 (2006) (approving LKE's withdrawal from MISO).

[12] Crews Affidavit at P 8.

[13] *See* Letter Order issued May 22, 2013 in Docket Nos. ER13-1177-000, *et al*.

[14] Crews Affidavit at P 10. *See* Service Agreement No. 4 for Network Integration Transmission Service between LKE and East Kentucky ("Current LKE-East Kentucky NITSA"), approved via Letter Order in Docket No. ER14-2968, January, 6, 2015. The rate charged by LKE for transmission service across the LKE system is calculated pursuant to the LKE Tariff and is not an item of dispute in this complaint.

[15] *Id*. Likewise, LKE has a non-conforming NITSA with PJM to serve its load on the East Kentucky-PJM transmission system. Under that non-conforming agreement, LKE pays the East Kentucky transmission rate to serve its load but does not buy ancillary services from PJM. *See* PJM Service Agreement No. 3518, Service Agreement For Network Integration Transmission Service between LKE and PJM.

B. Louisville Gas & Electric/Kentucky Utilities ("LKE")

Louisville Gas & Electric ("LG&E") is a public utility that owns and operates electric generation, transmission, and distribution facilities, and also natural gas distribution, transmission, and storage facilities in Kentucky and Indiana.[16] Kentucky Utilities ("KU") is a public utility that owns and operates electric generation, transmission, and distribution facilities in Kentucky, with limited operations in Tennessee and Virginia.[17] LG&E and KU ("LKE") together own or control approximately 8,300 MW of generating capacity and, in addition, hold minority interests in several entities that own generation. LG&E and KU are owned by PPL Corporation. Together LG&E and KU serve approximately 943,000 electric customers.

LKE operates a joint electric balancing authority area for LG&E and KU and owns approximately 5,484 circuit miles of electric transmission lines.[18] In addition, LG&E and KU each has franchised retail service territories. KU also supplies power to several wholesale customers under cost-based formula rates.[19]

LKE provides transmission service over its combined LG&E and KU transmission systems under a single Tariff. Pursuant to the terms set by the Commission in approving LKE's withdrawal from the Midcontinent Independent System Operator, Inc. ("MISO"), TranServ International, Inc. ("TranServ") and the Tennessee Valley Authority serve as the Independent Transmission Organization and the reliability coordinator, respectively, for LKE's electric transmission facilities.[20]

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[16] *Bluegrass Generation Company, L.L.C.*, 139 FERC ¶ 61,094 at P 3 (2012) ("Bluegrass Generation Co.").

[17] *Id*.

[18] *Id*.

[19] *Id*.

[20] *E.ON U.S. LLC*, 133 FERC ¶ 61,012 (2010) (accepting the revised independent transmission organization agreement).

III. BACKGROUND

A. The Parties' Intertwined Transmission Systems and Cross-Use of their Respective Transmission Facilities

The LKE and East Kentucky transmission systems and service territories are extensively intertwined. This highly intertwined configuration originates from a series of Kentucky administrative and court decisions aimed at protecting Kentucky customers from having to pay for wasteful duplication of facilities.[21] Today, LKE and East Kentucky share 66 interconnection points between their transmission systems.[22] Each uses the other's facilities to serve a portion of its native-load customers through numerous load interconnection points. Specifically, East Kentucky serves 566 MW (peak) of its member load that is directly connected to the LKE transmission system, while LKE serves approximately 100 MW (peak) of LKE load that is connected directly to the East Kentucky transmission system.[23]

B. East Kentucky's Acquisition of Bluegrass and Related Transmission Service Request

On June 26, 2015, East Kentucky executed an agreement with Bluegrass Generating Company, LLC to purchase the Bluegrass facility, an existing three-unit, 495 MW (summer capability) gas-fired generating station located in Oldham County, Kentucky.[24] As noted above,

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[21] *See Kentucky Utilities Company v. Public Service Commission*, 252 S.W.2d 885 (Ky. 1952).

[22] Crews Affidavit at P 6.

[23] *Id.* at P 6.

[24] *Id.* at P 12. In 2012, LKE sought to purchase Bluegrass to add to LKE's fleet. The Commission conditionally approved the transaction, but concluded that LKE's purchase of Bluegrass raised market power concerns that required mitigation. The Commission stated that such market power mitigation measures could have included LKE relinquishing operational control of Bluegrass. *See Bluegrass Generation Company, L.L.C.*, 139 FERC ¶ 61,094 (2012). Shortly thereafter, LKE withdrew its application and terminated its acquisition efforts. *See* Letter from LKE to the Commission in Docket No. EC12-29 dated June 19, 2012 (stating that the Bluegrass-LKE transaction would not be consummated).

Bluegrass is interconnected to the LKE transmission facilities.[25] The Bluegrass asset transaction is scheduled to close by December 31, 2015.[26] East Kentucky intends to use Bluegrass as a Network Resource to serve its member load.[27] East Kentucky will use output from Bluegrass chiefly to serve that portion of East Kentucky's Network Load that is connected to the LKE transmission facilities.[28] However, there may be some hours during which the output of Bluegrass exceeds the amount of East Kentucky member load on the LKE system. In these hours, East Kentucky intends to deliver any Bluegrass output that exceeds the amount of East Kentucky's Network Load connected to the LKE transmission facilities to the East Kentucky Network Load connected to the East Kentucky transmission facilities.[29]

East Kentucky intends to use its NITSA with LKE to integrate Bluegrass with East Kentucky's loads in the manner described above.[30] Accordingly, East Kentucky submitted a transmission service request to TranServ to designate Bluegrass as a Network Resource under East Kentucky's NITSA with LKE.[31] TranServ, in its capacity as LKE's Independent Transmission Organization, studied the peak load and generation conditions of Bluegrass and concluded that transmission service is available to deliver the Bluegrass output to East

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[25] Crews Affidavit at P 12. Under the purchase agreement, East Kentucky would buy the entire Bluegrass facility. However, one of the Bluegrass units is under contract with LKE for its full output until May 1, 2019.

[26] *Id.* at P 13.

[27] *Id.* at P 14. Pursuant to East Kentucky's request to LKE to designate Bluegrass as a Network Resource, TranServ, in its capacity as LKE's Independent Transmission Organization, conducted a transmission service study and determined that although some network upgrades are necessary to provide service, the upgrades can be in place to allow the service to commence as requested.

[28] *Id.* at P 14.

[29] *Id.*

[30] *Id.*

[31] On November 26, 2014, East Kentucky requested Network Service for Bluegrass Units 1 and 2, and on April 29, 2015, East Kentucky requested Network Service for Bluegrass Unit 3. Affidavit of Denver York at P 10, appended hereto as Attachment 3 ("York Affidavit").

Kentucky's Network Load on the LKE system.[32] LKE confirmed that East Kentucky may add Bluegrass as a new Network Resource under the East Kentucky-LKE NITSA.[33] To East Kentucky's knowledge, there is no dispute regarding delivery of Bluegrass output to East Kentucky's Network Load on the LKE system. Rather, the dispute arises from the charges LKE seeks to impose in order for East Kentucky to deliver Bluegrass output to East Kentucky's Network Load on the East Kentucky system.

East Kentucky approached TranServ and LKE on several occasions to resolve delivery of the Bluegrass output to East Kentucky Network Loads connected to East Kentucky system in the manner described.[34] East Kentucky proposed to modify its existing NITSA with LKE to add a new delivery point at one or more points of interconnection between the LKE and East Kentucky systems. East Kentucky further proposed that the designated Network Load at that new delivery point would in each hour be the difference between the output of Bluegrass and East Kentucky's Network Load on the LKE system.[35] The sum of the delivery point requirements in each hour would be the basis for determining East Kentucky's monthly coincident peak on the LKE system, which is the demand used for billing for network service under the LKE Tariff.[36] East Kentucky would fully compensate LKE for the use of the LKE transmission system by paying LKE's network charge based on East Kentucky's monthly coincident peak usage of the LKE

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[32] Crews Affidavit at P 17. As Mr. Crews explains, TranServ concluded that although some network upgrades are necessary to provide the requested service, the service could be granted given the upgrades are expected to be completed prior to the timeframe needed. Additionally, operating parameters were specified under certain real-time loading conditions that permit LKE's Reliability Coordinator to curtail Bluegrass on a non-discriminatory basis with possible curtailment of LKE's own generation and/or load.

[33] York Affidavit at P 11. Although LKE has confirmed this to East Kentucky, LKE has not filed with the Commission an amended Network Service Agreement to add Bluegrass as a Designated Network Resource.

[34] *Id.* at P 13.

[35] *Id.* at P 14.

[36] *See* Attachment 1. East Kentucky provided this proposed NITSA to both LKE and TranServ during discussions involving the Bluegrass transmission arrangements.

transmission system because any Bluegrass output delivered to East Kentucky's Network Load on the East Kentucky system would be included in that coincident peak demand.

East Kentucky's efforts to discuss the arrangement with TranServ and LKE were unproductive. TranServ simply referred East Kentucky to LKE.[37] LKE rejected the arrangement and has not offered any reasonable alternative.[38] LKE instead has advised East Kentucky that, if East Kentucky intends to deliver any of the Bluegrass output to serve East Kentucky loads on East Kentucky's system, then East Kentucky may purchase Point-to-Point service for the full amount of the Bluegrass facility less the anticipated minimum load physically connected to the LKE system—over 400 MW of transmission service—*in addition* to the existing East Kentucky-LKE Network Service arrangements for East Kentucky's load on the LKE system.[39] LKE also suggested that East Kentucky could designate delivery points currently served from East Kentucky's own transmission system as delivery points under the LKE NITSA, in sufficient amounts so that East Kentucky's minimum load on the LKE system would always be at least equal to the nominal nameplate rating of Bluegrass.[40] This would force East Kentucky to designate several hundred megawatts of load served by East Kentucky's own transmission facilities as Network Load on the LKE transmission system.[41] East Kentucky advised LKE of its view that requiring East Kentucky to reserve 400 MW or more of Point-to-Point service or adding hundreds of megawatts of additional load as Network Load are both unreasonable

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[37] York Affidavit at P 17.

[38] *Id.* at PP 14-15.

[39] *Id.* at P 15.

[40] *Id.* at P 16.

[41] *Id.*

approaches.[42] LKE's approach would subject East Kentucky to duplicative transmission charges as well as excessive charges for an amount of transmission service that LKE would not be providing.[43]

East Kentucky's current payments to LKE for Network Service total approximately $7 million per year.[44] Under LKE's approach, East Kentucky's aggregate annual payments to LKE would increase by $10 million, totaling approximately $17 million.[45]

Bluegrass is a gas-fired peaking resource that typically will be dispatched when demand is at its highest.[46] Bluegrass is also subject to NOx restrictions and can only run up to 7% of the year's total hours.[47] Under economic dispatch, East Kentucky forecasts Bluegrass will run less than 6% of the year's total hours.[48] For the first few years of East Kentucky's ownership, only two of the three Bluegrass units will be available for East Kentucky's use because the output of the third unit is committed under a power purchase contract with LKE until May 1, 2019.[49] During that time, it is unlikely that the Bluegrass output will exceed the East Kentucky load on the LKE system at the time of LKE's system peak.[50] East Kentucky expects the same will be true during a majority of the off-peak hours as well.[51]

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[42] York Affidavit at P 18.

[43] *Id.*

[44] *Id.* at P 19.

[45] *Id.*

[46] Crews Affidavit at P 12.

[47] *Id.*

[48] *Id.*

[49] *Id.* at P 13.

[50] *Id.* at P 15.

[51] *Id.*

After May 1, 2019, all three Bluegrass units will be available to East Kentucky. However, by then, East Kentucky forecasts that its peak load on the LKE system may exceed 600 MW.[52] Because of this increase in demand on the LKE system, and because of the peaking nature of the plant and NOx restrictions, the Bluegrass output will likely exceed East Kentucky's LKE-connected load during only a limited number of hours each year.[53]

Under the terms of the Bluegrass asset purchase agreement, the sale of the facility is scheduled to close by December 31, 2015.[54] East Kentucky needs the Bluegrass facility to serve its native-load customers. East Kentucky is facing deactivation of several facilities in its fleet by April 16, 2016, growing demand on its system, and winter peaks in excess of its remaining resources.[55] East Kentucky has spent the last several months attempting to resolve the issue with LKE. It is imperative that LKE's refusal to grant transmission service on just and reasonable terms not disrupt this transaction. East Kentucky is thus left with no recourse but to submit this Complaint.

IV. COMPLAINT

East Kentucky is seeking to amend its NITSA with LKE in order to deliver the output of Bluegrass that exceeds East Kentucky's member load connected to LKE's transmission facilities to East Kentucky's member load connected to East Kentucky's transmission facilities, as shown on the attached proposed amended NITSA.[56] The proposed amendments seek to: (1) establish the

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[52] Crews Affidavit at PP 15-16.

[53] *Id.* at P 16.

[54] *Id.* at P 13.

[55] *Id.* at P 11.

[56] *See* Attachment 1.

Point of Delivery as one or more points of interconnection between LKE and East Kentucky transmission facilities; and (2) designate a portion of East Kentucky's member load connected to the East Kentucky transmission facilities as new Network Load under the East Kentucky-LKE NITSA, with the amount of that load stated as the output of Bluegrass in any hour minus the aggregate East Kentucky member load served from the LKE transmission facilities.

For the following reasons, the Commission should find that the proposed arrangements are just and reasonable and consistent with the LKE Tariff. Alternatively, if the Commission finds that the proposed arrangements are not consistent with the LKE Tariff, East Kentucky requests that the Commission find that the LKE Tariff is unjust and unreasonable as applied to East Kentucky. Additionally, if and to the extent necessary, East Kentucky seeks waiver of the LKE Tariff in order to adopt the amended NITSA as a non-conforming agreement.

A. East Kentucky's Proposed Relief is Consistent with Both the *pro forma* Tariff and the LKE Tariff

1. The *pro forma* and LKE Tariffs allow East Kentucky to designate a portion of the East Kentucky member load not directly connected to the LKE system as Network Load under the NITSA with LKE.

East Kentucky's proposal is consistent with the flexibility provided for under Section 31.3 of the *pro forma* and LKE Tariffs. Section 31.3 permits a Network Service customer to designate load that is not directly connected to the Transmission Provider as part of the customer's Network Load. The LKE Tariff adopts this provision essentially *verbatim*. Section 31.3 of the LKE Tariff provides:

> "This section applies to both initial designation pursuant to Section 31.1 and the subsequent addition of new Network Load not physically interconnected with the Transmission Owner. To the extent that the Network Customer desires to obtain transmission service for a load outside the Transmission Owner's Transmission

> System, the Network Customer shall have the option of (1) electing to include the entire load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Point-to-Point Transmission Service under Part II of the Tariff. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application."

Section 31.3 permits East Kentucky to designate, as part of its Network Load under a modified NITSA with LKE, its member load that is not directly connected to the LKE system. The only condition to doing so is that East Kentucky must designate one or more Network Resources for that load, which East Kentucky has satisfied by identifying Bluegrass as that designated Network Resource.[57]

In attempting to justify its proposal that East Kentucky add to the LKE NITSA the load served at numerous delivery points on the East Kentucky System, LKE contended that its Tariff would not permit East Kentucky to add less than all of the load at any given substation or delivery point. LKE also contended that East Kentucky's approach, which would measure the amount of Bluegrass output at the new delivery point as the difference between the output in that hour and East Kentucky's Network Load served from the LKE transmission facilities in the same hour, is tantamount to splitting load in purported violation of the LKE Tariff.

These contentions are invalid for several reasons, including: (a) the heavily integrated nature of the LKE and East Kentucky systems; (b) the fact that the designated Network Resource associated with that load (*i.e.* Bluegrass) has a total capacity of 495 MW, and only a portion of

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[57] York Affidavit at P 11.

Bluegrass output would be delivered from the LKE transmission facilities to East Kentucky's Network Load connected to the East Kentucky transmission facilities; (c) that East Kentucky's *entire* load is served as Network Load under the PJM Tariff or the LKE Tariff; and (d) that network service is intended to afford flexibility in economically integrating resources and loads, not to impose artificial restrictions that produce unjust and unreasonable results.

Examination of the purpose underlying Section 31.3 further confirms that LKE's contentions are unreasonable. Section 31.3 must be read in conjunction with section 1.25 of the Tariff. In defining "Network Load," section 1.25 states, in relevant part, that a "Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery." Network Load was defined in this manner to prevent customers from combining Network and Point-to-Point service at a single, discrete delivery point (*e.g.*, a customer utilizing behind-the-meter generation).[58]

East Kentucky is not a transmission-dependent wholesale customer with behind-the-meter generation. It is an interconnected utility with its own transmission system and fleet of generating resources, and is a voluntary participating transmission owner in PJM.[59] East Kentucky is not seeking the proposed arrangements to avoid paying for Network Service. East

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[58] An example of this combination of Network and Point-to-Point service would include a customer that wished to serve a portion of its load at a single delivery point with behind-the-meter generation firmed up through non-firm Point-to-Point service, and exclude that amount of load from its Load Ratio Share. *See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A at p. 30,260-61, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002) ("For the reasons stated above, a network customer will not be permitted to take a combination of both network and point-to-point transmission services under the *pro forma* tariff to serve the same discrete load… Moreover, the Commission will allow a network customer to either designate all of a discrete load as network load under the network integration transmission service or to exclude the entirety of a discrete load from network service and serve such load with the customer's 'behind-the-meter' generation and/or through any point-to-point transmission service.")

[59] Crews Affidavit at P 8.

Kentucky pays the LKE network rate to serve East Kentucky's total Network Load on the LKE system.[60] Indeed, because East Kentucky's *entire* Network Load (*i.e.*, its member load on both its own system and the LKE system) is treated as internal load in the East Kentucky transmission pricing zone in PJM, East Kentucky pays the zonal network rate to serve East Kentucky's *entire* Network Load (East Kentucky's member load on both systems) pursuant to the East Kentucky-PJM NITSA.[61] All of East Kentucky's load is subject to PJM's Network Service charges, and is not at all akin to load served from behind-the-meter generation that might escape paying for Network Service in the absence of this Tariff provision.

2. East Kentucky's proposed NITSA accurately reflects East Kentucky's use of the LKE system.

LKE should be fairly compensated for the service it provides to East Kentucky for service associated with East Kentucky's delivery of Bluegrass output to the proposed delivery point for the new Network Load. The amended NITSA, as proposed by East Kentucky, defines East Kentucky's new Network Load as the amount of Bluegrass output that exceeds East Kentucky's Network Load on the LKE system.[62] Defining the amount of new Network Load in this manner accurately reflects the transmission service that LKE will provide and ensures that LKE will receive its full Network Service rate for this service.

East Kentucky's proposal also is consistent with Commission policy as expressed in Order No. 888-A. There, the Commission addressed pricing for transmission service to entities with load in multiple control areas. Several commenters complained that, if a Network Service customer with resources and loads in control area A also wished to serve Network Load in

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[60] York Affidavit at P 8.

[61] *Id.* at P 7.

[62] *See* Attachment 1. The new Network Load is defined as the "Bluegrass Load."

control area B, the customer would be required to include the control area B load as Network Load in both control areas, and that the customer would be exposed to the possibility of paying two Network Service charges for the control area B load. In Order No. 888-A, the Commission summarized the solution proposed by these commenters as:

> [T]hese entities propose that a network customer be allowed to use its network service to transmit power and energy from resources in control area A to serve load in control area B without designating the control area B load as network load for billing purposes. These entities suggest that no additional compensation should be required if such transfers to load in adjacent control areas plus other network transactions on behalf of the transmission customer in control area A do not exceed the customer's coincident demand in control area A.[63]

The Commission rejected the argument that a customer receiving Network Service in control area A should be able to serve load in control area B without that load being designated as additional Network Load in control area A. In so ruling, the Commission stated that, "[b]ecause the additional transmission service to non-designated network load outside of the transmission provider's control area is a service for which the transmission provider must separately plan and operate its system beyond what is required to provide service to the customer's designated network load, it is appropriate to have an additional charge associated with the additional service."[64]

East Kentucky's proposed amended NITSA satisfies the Commission's concern about appropriately compensating the transmission provider for transmission planning and operations. The East Kentucky load (the "control area B" load in the Commission's example) is designated

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[63] Order No. 888-A, FERC Stats & Regs. 31,048 at pp. 30,254-55.

[64] *Id*. at p. 30,255.

as additional Network Load in the NITSA with LKE. Whenever East Kentucky uses LKE transmission service to serve the East Kentucky Network Load on the East Kentucky system with Bluegrass output, which only will be during the hours when Bluegrass output exceeds the amount of East Kentucky load connected to LKE's system, the "Network Load" value for the amount of Bluegrass output delivered to the East Kentucky-connected load will be included in the determination of East Kentucky's coincident peak for billing under East Kentucky's NITSA with LKE. East Kentucky's proposed amendments would compensate LKE for this additional service at the LKE Network Service rate, while not requiring East Kentucky to pay for service that it will not use.[65] LKE would be sufficiently and justly compensated for the service it provides.

By contrast, LKE's refusal to provide the flexibility East Kentucky seeks would result in excessive charges to East Kentucky and is inconsistent with the Commission's policy of encouraging transmission providers to design rates that avoid double recovery of transmission costs.[66] When adopting the *pro forma* tariff, the Commission stated:

> [We] did not intend for a transmission provider to receive two payments for providing service to the same portion of a transmission customer's load. Any such double recovery is unacceptable and inconsistent with cost causation principles.[67]

The Commission further stated that it would evaluate claims of double recovery on a case-by-case basis, and that a customer could file a Section 206 complaint where such concerns exist.[68]

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[65] *See* Attachment 1.

[66] Order No. 888-B at p. 62,096 ("Moreover, while we expect transmission providers to design rates that will avoid double recovery of such transmission costs or ancillary costs, we believe that this is a fact-specific issue that is appropriately addressed on a case-by-case basis.")

[67] *Id.*

[68] *Id.*

Here, East Kentucky is already a Network Customer of LKE for that portion of East Kentucky's load connected to the LKE system. LKE has approved East Kentucky's addition of Bluegrass as a Network Resource under the East Kentucky-LKE NITSA to serve East Kentucky's load connected to the LKE system. In most hours, the Bluegrass output will be delivered to the LKE-connected East Kentucky load. It is only when the Bluegrass output exceeds that Network Load that such output will be used to serve East Kentucky's Network Load connected to East Kentucky's system.

LKE's proposal would require East Kentucky to purchase Point-to-Point or Network Service for the full amount of Bluegrass capacity less the anticipated minimum value of the load physically connected to the LKE system, in addition to the existing charges East Kentucky pays to LKE under the current East Kentucky-LKE NITSA. The result would be a double charge in that East Kentucky would pay the NITSA charge for the East Kentucky load on the LKE system (500-570 MW, depending on coincident peak), plus a *separate* Network Service or Point-to-Point charge for delivering Bluegrass output to that same load. And it would result in excessive charges because East Kentucky would never use the combined 900 to 1,000 MW total of LKE transmission service for which LKE seeks to charge East Kentucky. The largest amount of transmission service that East Kentucky would use on the LKE system would be the greater of the East Kentucky Network Load on the LKE system, or the Bluegrass output, but not both at the same time.

The Commission's policy that transmission providers provide flexibility to address unique circumstances should not be lost on LKE. Indeed, LKE itself is the beneficiary of the Commission's willingness to accept a NITSA with specific terms to address unusual circumstances. When East Kentucky integrated into PJM, LKE was concerned that it would be subjected to PJM charges in connection with service across East Kentucky's facilities to serve the LKE load that is physically connected to the East Kentucky system.[69] LKE itself is not a transmission owning member of PJM and is outside the PJM footprint. LKE required a Network Service agreement with PJM to serve this load. Under its agreement, LKE pays East Kentucky's zonal transmission rate but does not buy any ancillary services from PJM. The Commission also approved arrangements that treat LKE's load on the East Kentucky system as outside PJM, notwithstanding East Kentucky's integration into PJM.[70] East Kentucky is not challenging these arrangements. The point is that LKE is the beneficiary of the Commission's policy that transmission customers should be afforded flexibility in structuring arrangements to integrate their resources and loads. Here, East Kentucky is seeking an arrangement that is flexible yet consistent with the LKE tariff and the Commission's policies on transmission pricing and the nature of Network Service.

B. The Commission Has Accepted Agreements Similar to the Agreement East Kentucky Proposes

East Kentucky's proposed arrangements are consistent with other arrangements accepted for filing by the Commission. For example, in 2012, the Commission accepted for filing an amended Network Service Agreement between Southern Company Services, Inc. ("Southern") and Southern Mississippi Electric Power Association ("SMEPA").[71] According to the filing, SMEPA's transmission facilities, load, and generation are widely dispersed throughout the state

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[69] *See* East Kentucky filing letter in Docket No. ER13-1177 at 10-12 (March 28, 2013) (discussing the treatment of the LKE load on the East Kentucky system, the stipulation between East Kentucky, LKE, and PJM which held LKE harmless from the additional charges that it might incur as a result of East Kentucky joining PJM, and the non-conforming NITSA between LKE and PJM that implemented that stipulation.)

[70] *See* Letter Order in Docket Nos. ER13-1177-000, *et al*. (May 22, 2013)

[71] *See* Letter Order in Docket No. ER12-1724-000, at 2 (June 4, 2012).

of Mississippi and heavily intertwined with the facilities of Mississippi Power Company ("Mississippi Power"), a Southern Company subsidiary, and with Entergy Mississippi, Inc., an Entergy operating company.[72] SMEPA has approximately 150 MW of load interconnected with the transmission facilities of Mississippi Power. Under the Southern-SMEPA arrangements, that load is pseudo-tied to SMEPA's Balancing Authority Area.[73] To serve this load, SMEPA takes Network Service from Southern Company pursuant to a NITSA under the Southern Company open access transmission tariff.[74] The SMEPA-Southern NITSA allows SMEPA's pseudo-tied loads to be served from various resources. In order to permit SMEPA "to improve its efficiency in its use of the system," SMEPA and Southern amended their NITSA in two material respects: (1) to establish a new delivery point at the interchange point between the Southern system and the SMEPA system; and (2) to calculate the Network Load at the new delivery point, which would be "a calculated value for flow into the SMEPA balancing authority area."[75] The value of the Network Load at the new delivery point would be calculated on an hourly basis to equal the energy generated by Network Resources located within the Southern Balancing Authority Area that is not used to serve SMEPA's Network Load located within the Southern Balancing Authority Area.[76] The Commission accepted the amended NITSA for filing.[77]

In 2013, the Commission accepted similar arrangements between SMEPA and MISO in connection with SMEPA's integration into MISO.[78] MISO recognized the heavily intertwined

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[72] Filing letter in FERC Docket No. ER12-1724-000, at 2 (May 7, 2012).

[73] *Id*.

[74] *Id*.

[75] *Id*.

[76] *Id*.

[77] *See* Letter Order in Docket No. ER12-1724-000, at 2 (June 4, 2012).

[78] *Midcontinent Indep. System Operator, Inc.*, 145 FERC ¶ 61,242 (2013).

systems of SMEPA, Southern Company, and Entergy Mississippi. At that time, Entergy Mississippi was in the process of integrating into MISO. SMEPA's integration into MISO would soon follow. Southern Company is not a transmission-owning member of MISO, which meant that a portion of SMEPA's load and resources would be physically located outside of the MISO region. However, the SMEPA-Southern load would be pseudo-tied into the SMEPA-MISO Local Balancing Area.[79] SMEPA intended to serve that portion of SMEPA's load that is physically connected to the Southern Company system with resources internal to the SMEPA-MISO system.[80] MISO did not require SMEPA to arrange for separate Point-to-Point service under the MISO Tariff to allow SMEPA to deliver its internal resources to SMEPA load on the Southern Company system.[81] MISO instead patterned the SMEPA-MISO Network Service Agreement after the SMEPA-Southern Network Service Agreement. In its filing letter to the Commission, MISO stated:

> Requiring SMEPA to take MISO's drive-out Point-to-Point Transmission Service for the Southern NITSA load will create operational inefficiencies and deprive SMEPA and its members of certain key benefits of the commercial bargain underpinning the FERC-accepted Southern NITSA arrangements…[T]his load supply arrangement requires a high level of transmission service flexibility that only Network Service can provide.[82]

MISO further acknowledged that Network Service is inherently more flexible than Point-to-Point transmission service, which would be the only alternative on the MISO side, in that Point-to-Point service requires reserving and scheduling specific amounts of service between specific Points of Receipt and Points of Delivery. MISO explained that such an arrangement would be

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[79] *See* Filing Letter in Docket No. ER13-2008 at 3 (July 23, 2013).

[80] *Id*.

[81] *Id*. at 4.

[82] *Id*.

particularly unsuitable in SMEPA's case and would impose undue cost and operational burdens.[83]

MISO also found it appropriate to provide flexibility in its NITSA with SMEPA because of the fact that the loads served under the SMEPA-Southern NITSA represent an integral part of SMEPA's total native load. The loads are indistinguishable from the rest of SMEPA's native load, which is attached to the transmission and distribution facilities of SMEPA and its members. MISO patterned the SMEPA-MISO NITSA after the SMEPA-Southern NITSA because it provides SMEPA with "sufficient" firm transmission to designate the network resources under the Southern NITSA as designated Network Resources under the MISO Tariff. MISO found that there was no basis for treating SMEPA's Southern loads differently than SMEPA's MISO loads. Requiring a subset of SMEPA's native load to take drive-out Point-to-Point service while the rest of the SMEPA native load can enjoy the benefits of Network Service would be unduly discriminatory and would result in cost-shifts among its members.

The approach embodied in the SMEPA-Southern NITSA and the subsequent SMEPA-MISO NITSA reflects an appropriate solution for East Kentucky and LKE. The SMEPA-Southern and SMEPA-MISO Network Service arrangements ensure efficient use of the transmission system and appropriately compensate the affected transmission owners for SMEPA's use of their transmission facilities. Like SMEPA, East Kentucky's Network Loads and generating resources straddle different systems and control areas. East Kentucky appropriately modeled its proposed amended NITSA with LKE after the SMEPA-Southern and SMEPA-MISO NITSAs.[84]

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[83] *Id*. at 5.

[84] *See* Attachment 1; *see also* filed NITSA in Docket No. ER12-1724 (May 7, 2012).

Notably, for the SMEPA-Southern arrangements, no waiver of the Southern Tariff was sought or required, meaning that the arrangements contained in the NITSA were proposed and accepted as being consistent with and conforming to the provisions of the Tariff. Southern and SMEPA were able to adopt the provisions that allowed SMEPA to designate a portion of the SMEPA load on the SMEPA system as additional Network Load under its NITSA with Southern, and to calculate that additional Network Load as the amount of flow onto the SMEPA system from the Southern system. Nor was it considered a departure under the MISO Tariff for MISO to permit SMEPA to identify points of delivery as being certain points of interconnection between SMEPA and Southern Company, and to identify its load at those points of delivery as a calculated value for flow into the balancing authority area.[85] Likewise, East Kentucky's proposed amended NITSA is a conforming arrangement under the LKE Tariff in that Section 31.3 of LKE's Tariff contains the same language as the *pro forma* tariff.[86]

V. REQUESTED RELIEF

East Kentucky seeks relief in the form of the attached Amended Network Integrated Transmission Service Agreement.[87] The proposed modifications include the addition of a new delivery point (the "Bluegrass Delivery Point"). The new Network Load at the Bluegrass Delivery Point would be a calculated value for flow into the East Kentucky system at the Bluegrass Delivery Point.

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[85] MISO did obtain waiver of Section 31.3 of its Tariff in order to allow SMEPA to pseudo-tie its load on the Southern Company system to the MISO footprint. That waiver was necessitated by a requirement in the MISO Tariff that network load be physically connected to the MISO transmission system. MISO's provision is a Commission approved departure from the *pro forma* tariff, and is not included in the LKE Tariff.

[86] *See* section IV.A.1 *supra.*

[87] *See* Attachment 1.

VI. ALTERNATIVE REQUEST

The Commission should find that East Kentucky's requested relief is consistent with the LKE Tariff as well as the Commission's intent that transmission customers have flexibility when structuring arrangements to integrate their load and resources, its open access and transmission pricing policies, and its acceptance of similar arrangements.[88] That said, if the Commission concludes otherwise, East Kentucky respectfully requests that the Commission find that the LKE Tariff is unjust and unreasonable as applied to East Kentucky. Additionally, if and to the extent necessary, East Kentucky seeks waiver of Section 31.3 of the LKE Tariff in order to adopt the amended NITSA as a non-conforming agreement.

Generally, a request for waiver of a Tariff provision must meet four requirements: (1) a concrete problem exists that needs to be remedied; (2) the waiver will not produce undesirable consequences; (3) the waiver is of limited scope; and (4) the entity seeking the waiver acted in good faith.[89] The Commission has stated, "[w]here good cause for a waiver of limited scope exists, there are no undesirable consequences, and the resultant benefits to customers are evident, the Commission has found that a one-time waiver [of tariff provisions] is appropriate."[90]

The Commission has previously granted waiver of Section 31.3 of the Tariff. For example, in the SMEPA-MISO proceeding,[91] MISO sought and obtained waiver of Section 31.3

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[88] *See* section IV *supra.*

[89] *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,069 at PP 8-9 (2011); *ISO New England Inc.*, 134 FERC ¶ 61,182 at P 8 (2011); *California Indep. Sys. Operator, Inc.,*132 FERC ¶ 61,004 at P 10 (2010); *Hudson Transmission Partners, LLC*, 131 FERC ¶ 61,157 at P 10 (2010); *Pittsfield Generating Co., L.P.*, 130 FERC ¶ 61,182 at P 9-10 (2010); *accord ISO New England Inc. EnerNOC*, 122 FERC ¶ 61,297 at P 13 (2008); *Central Vermont Public Service Corp.*, 121 FERC ¶ 61,225 at P 28 (2007); *Waterbury Generation LLC*, 120 FERC ¶ 61,007 at P 31 (2007); *Acushnet Co.*, 122 FERC ¶ 61,045 at P 14(2008).

[90] *California Independent System Operator Corp.*, 124 FERC ¶ 61,031 at P 19 (2008), *reh'g denied*, 124 FERC ¶ 61,293 (2008) (granting waiver request).

[91] *See, e.g., Midcontinent Indep. System Operator, Inc.*, 145 FERC ¶ 61,242 at P 11 (2013).

of its Tariff to allow SMEPA to pseudo-tie its external loads on the Southern Company system into MISO. Waiver was necessary in that case because the MISO Tariff requires network load to be physically interconnected to the MISO transmission system, which is a departure from the *pro forma* tariff. MISO justified its request based on the fact that SMEPA's loads on the different systems are indistinguishable and it would be unfair to charge them Point-to-Point service instead of providing Network Service.[92] The Commission accepted the proposed NITSA, concluding that the arrangement was just and reasonable "because it is consistent with the flexibility provided under section 31.3 of the *pro forma* OATT."[93]

MISO also sought waiver of Section 31.3 when the Arkansas Electric Cooperative Corporation ("AECC") sought to integrate into MISO. Like SMEPA, AECC has load and resources that are heavily intertwined with companies within and outside of MISO.[94] MISO proposed to accept AECC's pseudo-tied load as sufficient to meet its Tariff requirement that load be physically interconnected with the MISO transmission system.[95] MISO also stated that, without the non-conforming NITSA, a large portion of the AECC Native Load would have been subject to MISO Regional Through and Out Rates for Point-to-Point service and AECC would not have sufficient flexibility to be able to use its resources to serve its load.[96] The Commission accepted the proposed NITSA, again finding that the arrangement was just and reasonable

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[92] *See* Section IV.B *supra*.

[93] *Midcontinent Indep. Sys. Operator, Inc.*, 146 FERC ¶ 61,094 at P 44 (2014) ("AECC") (*citing Midcontinent Indep. Sys. Operator, Inc.*, 145 FERC ¶ 61,242 at P 11 (2012)).

[94] *See* AECC Filing Letter in Docket No. ER14-684 at 3 ("AECC Filing Letter").

[95] AECC at P 8.

[96] AECC Filing Letter at 4.

"because it is consistent with the flexibility provided under section 31.3 of the pro forma OATT."[97]

In this case, East Kentucky has identified a concrete problem for which a remedy is necessary. East Kentucky and LKE have heavily intertwined systems, where each has native load connected to the other's system. Each relies on the other's transmission system to serve that native load. Until now, neither had generating resources physically connected to the other's system. This unique arrangement makes this a case of first impression as between LKE and East Kentucky under the LKE Tariff. Unless a remedy is adopted: (1) East Kentucky will be unable to efficiently and cost-effectively integrate its resources and loads, as Network Service is intended to achieve; and (2) LKE will succeed in forcing East Kentucky to pay excessive and unreasonable charges for transmission service, including charges for service that East Kentucky does not need.

Waiver of section 31.3 of the LKE Tariff will not produce undesirable results. East Kentucky's proposed calculation for its new Network Load ensures that LKE is properly and justly compensated for East Kentucky's use of the LKE system.[98]

The requested waiver would be limited in scope. The waiver is limited to the identification of East Kentucky's new Network Load under the LKE NITSA and the calculation of that new Network Load for purposes of arriving at the proper billing determinants.[99]

East Kentucky acted in good faith in attempting to resolve the issue with TranServ and LKE, but was unable to obtain agreement concerning the proposed arrangements.[100] Waiver is

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[97] AECC at P 44 (*citing Midcontinent Indep. Sys. Operator, Inc.*, 145 FERC ¶ 61,242 at P 11 (2012)).

[98] *See* Section IV.A.2, *supra*.

[99] *See* Attachment 1.

[100] York Affidavit at PP 14, 17.

appropriate here because of the unique facts and circumstances surrounding the integrated nature of the loads and service territories of East Kentucky and LKE. Thus, should the Commission conclude that East Kentucky's requested remedy requires waiver of the LKE Tariff, East Kentucky respectfully submits that waiver is appropriate and that the attached amended NITSA with LKE should be adopted.

VII. RULE 206 COMPLAINT REQUIREMENTS

A. Action or Inaction Alleged to Violate Statutory Standards or Regulatory Requirements (Rule 206(b)(1))

LKE refuses to accept East Kentucky's designation of new Network Load and identification of a new delivery point. These modifications are necessary to allow East Kentucky to efficiently and cost-effectively integrate East Kentucky's resources and loads as Network Service is intended to achieve. LKE's refusal violates Section 31.3 of the LKE Tariff and is contrary to the Commission's policy on open access and transmission pricing. The specifics of East Kentucky's allegations and proposed remedy are set forth in Section IV.

B. Legal Bases for Complaint (Rule 206(b)(2))

The legal bases for this complaint are set forth in Section IV.

C. Issues Presented as They Relate to the Complainant (Rule 206(b)(3))

The issue presented is whether East Kentucky should be permitted to amend its existing NITSA with LKE in order to: (1) establish a new delivery point at the interchange point between the LKE system and the East Kentucky system; and (2) calculate the Network Load at the new delivery point, which would be a calculated value for flow into the East Kentucky system equal to the amount of Bluegrass output that exceeds the amount of East Kentucky's Network Load on the LKE system so that such output is used to serve East Kentucky's Network Load on the East Kentucky system.

D. Quantification of Financial Impact on Complainant (Rule 206(b)(4))

LKE's unreasonable request that East Kentucky purchase Point-to-Point transmission service or designate an additional several hundred MW of Network Load to the NITSA in order to deliver a portion of the Bluegrass facility would increase East Kentucky's current NITSA payments to LKE by approximately 243% (from approximately $7 million to approximately $17 million).

E. Nonfinancial Impacts on Complainant (Rule 206(b)(5))

LKE's actions harm East Kentucky and its member cooperatives by preventing East Kentucky from using an additional resource that will efficiently serve East Kentucky's load. Not granting East Kentucky's requested relief would establish precedent that would allow a Transmission Owner to demand unreasonable terms and conditions for Network Service for reasonable transmission service requests.

F. Related Proceedings (Rule 206(b)(6))

The specific matters raised in this Complaint are not pending before the Commission in any other docket to which East Kentucky is a party.

G. Specific Relief Requested (Rule 206(b)(7))

The specific relief requested is set forth in Sections V and VI.

H. Documents that Support the Complaint (Rule 206(b)(8))

East Kentucky submits the following Attachments and Exhibits in support of the facts set forth in this Complaint:

Attachment 1: Proposed Amended East Kentucky NITSA with LKE
Attachment 2: Affidavit of David Crews
Attachment 3: Affidavit of Denver York

I. Dispute Resolution (Rule 206(b)(9))

Prior to filing this complaint, East Kentucky engaged in good-faith negotiations with TranServ and LKE in an attempt to resolve the issues concerning East Kentucky's right to designate new Network Load under its NITSA with LKE pursuant to section 31.3 of the LKE Tariff. The parties have not been able to resolve the issues presented in this Complaint in a mutually-agreeable manner. East Kentucky therefore does not believe that the Commission's alternative dispute resolution procedures would help dispose of this matter.

J. Form of Notice (Rule 206(b)(10))

A Form of Notice suitable for publication in the Federal Register is attached.

K. Service on Respondent (Rule 206(c))

In accordance with Rule 206(c), East Kentucky is serving a copy of this Complaint on LKE, through the individuals listed on the Commission's list of Corporate Officials, concurrent with East Kentucky's filing of the complaint at the Commission.

VIII. CONCLUSIONS

East Kentucky respectfully requests that the Commission accept East Kentucky's proposed amended NITSA. This relief is consistent with and conforms to the LKE Tariff and Commission policy. If the Commission views East Kentucky's requested relief as a non-conforming arrangement, East Kentucky respectfully requests that the Commission find that the circumstances between East Kentucky and LKE warrant a non-conforming arrangement. Thus, if necessary, East Kentucky alternatively requests that the Commission find that the LKE Tariff is unjust and unreasonable as applied to East Kentucky, or grant waiver of the LKE Tariff in order to allow the Commission to grant the requested relief.

Respectfully submitted,

Alan Robbins

Alan Robbins
Debra Roby
Melissa Alfano
Jennings Strouss & Salmon, PLC
1350 I Street, NW, Suite 810
Washington, DC
Tel. 202.371.9030

October 30, 2015

Attachment 1

Proposed East Kentucky – LKE NITSA

AMENDED SERVICE AGREEMENT No. 4 FOR NETWORK INTEGRATION TRANSMISSION SERVICE

This Amended Service Agreement, made and entered into this ~~25th~~ day of ~~September, 2014~~, is by and between Louisville Gas & Electric Company / Kentucky Utilities Company ("LG&E/KU" or "Transmission Owner") and East Kentucky Power Cooperative ("Network Customer") (LG&E/KU and the Network Customer are hereinafter referred to jointly as "Parties") to provide Network Integration Transmission Service ("NITS"), as approved by the Independent Transmission Organization ("ITO") under the Transmission Owner's Open Access Transmission Tariff (hereinafter referred to as the "Tariff").

The Network Customer agrees to all terms and conditions set forth in the Tariff as may be in effect from time to time. The applicable terms and conditions from FERC-approved Rate Schedule No. 400 executed between LG&E/KU and EKPC on January 5, 2006 are incorporated herein by reference. The Network Customer must fulfill requirements outlined in Section 29.1 of the Tariff, Conditions Precedent for Receiving Service.

Any notice or request made to or by the Transmission Owner or Network Customer regarding this Service Agreement shall be made in writing and shall be telecommunicated or delivered either in person or by prepaid mail to the representative of the other party as indicated below. Such representative and address for notices or requests may be changed from time to time by notice by one party to the other.

Service under this Service Agreement shall commence on the later of (1) September 1, 2006, (2) the date on which construction of all of the Direct Assignment Facilities and/or Network Upgrades are completed that are required to provide reliable service, or (3) such other date as it is permitted to become effective by the Commission. Service under this Service Agreement shall terminate on August 31, 2026.

The terms and conditions of the Network Operating Agreement between the Transmission Owner and the Network Customer are incorporated by reference herein.

TRANSMISSION OWNER:
LG&E/KU VP, Transmission 220 West Main St PO Box 32010 Louisville, KY 40232

NETWORK CUSTOMER: EKPC
Executive VP & COO, P.O. Box 707 Winchester, KY 40392-0707

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

<u>Transmission Customer</u>:

By:	~~*/s/ Don Mosier*~~	~~EVP & COO~~	~~9/17/14~~
	Name	Title	Date

<u>Transmission Owner</u>:

By:	~~*/s/ Tom Jesse*~~	~~VP of Transmission~~	~~9/25/14~~
	Name	Title	Date

SPECIFICATIONS FOR NETWORK INTEGRATION TRANSMISSION SERVICE

1.0 Term of Network Service: Twenty Years

Start Date: September 1, 2006

Termination Date: August 31, 2026

2.0 Description of capacity and/or energy to be transmitted across the Transmission Owner's Transmission System (including electric Balancing Area in which the transaction originates).

See Section 3.0

3.0 Network Resources

(1) Transmission Customer Generation Owned:

Resource Capacity Designated as Network Resource
EKPC system resources up to amount of network load, EKPC system resources are listed in Exhibit A, attached hereto.

(2) Transmission Customer Generation Purchased:

Source Capacity
Market purchases up to amount of network load if/as approved through the appropriate Tariff process.

Total Network Resources: (1) + (2) = Amount of Network Load

4.0 Network Load

Transmission Customer Loads:

Transmission Voltage Location	Level	Total MWs	Interruptible MWs
ALEX CREEK	69		0
ARKLAND	69		0
BEDFORD	69		0
BEULAH BEAM	69		0
BLEDSOE	69		0
BLUE LICK	69		0
BRIDGEPORT	69		0
BRIDGEPORT #2	69		0
BROOKS	69		0
BUSH	69		0
CAMP GROUND	69		0
CAMPBELLSBURG	69		0
CAMPBELLSVILLE (Taylor County REA)	69		0
CARPENTER	69		0
CAVE RUN	69		0
CEMETERY ROAD	69		0
CHAD	69		0
CUMBERLAND FALLS	69		0
EAST CAMPBELLSVILLE	69		0
EKPC OFFICE	69		0
EMANUEL	69		0
GALLATIN STEEL	345		0
GIRDLER	69		0
GOSPEL HILL	34		0
GREEN RIVER PLAZA	69		0

HINKLE	69	0
HINKSTON	69	0
JERICHO	69	0
JONESVILLE	69	0
KNOB CREEK	34	0
LEBANON	69	0
LONG LICK	69	0
LONG RUN	69	0
MILE LANE	69	0
MILLERS CREEK	69	0
MILTON	69	0
MT VICTORY	69	0
MT WASHINGTON	69	0
NINEVAH	69	0
NORTH CORBIN	69	0
NORTH MADISON	69	0
OVEN FORK	69	0
OXFORD	69	0
PINE MOUNTAIN	69	0
RICE	69	0
ROCKHOLD	69	0
SHARKEY	138	0
SHELBY CITY	69	0
SOUTH ELKHORN	69	0
SOUTHVILLE	69	0
SOUTHPOINT	69	0
TAYLORSVILLE	69	0
TREEHAVEN	69	0
VAN METER	69	0
WEST MT WASHINGTON	69	0
*		0

Total MWs:

Total Interruptible MWs: 0

* This Delivery Point ("Bluegrass Delivery Point") shall be the point at which output from Bluegrass in excess of Transmission Customer's Network Load on the Transmission Owner's system shall be delivered to Transmission Customer's Network Load on Transmission Customer's system. The Network Load at the Bluegrass Delivery Point will be a calculated value (on an integrated hourly basis) for flows into the Transmission Customer's system at the Bluegrass Delivery Point. The Network Load for the Bluegrass Substation Delivery Point shall be calculated as follows:

Bluegrass Load = Bluegrass Resource Energy
less
LG&E/KU BAA Network Load

For the purposes of this provision, the terms in the above calculation shall be defined as:

Bluegrass Load shall mean the amount of hourly Network Load at the Bluegrass Delivery Point. The minimum value for the Network Load for the Bluegrass Delivery Point shall be zero. The maximum value of the Bluegrass Load during a calendar month shall not exceed the higher of: (1) the amount of Transmission Customer Network Load located in the LG&E/KU Balancing Authority Area, excluding the load associated with the Bluegrass Delivery Point; or (2) the total output of the Bluegrass Facility.

Bluegrass Resource Energy shall mean the hourly sum of all energy delivered from the Bluegrass Generating Station to serve Transmission Customer's Network Load.

LG&E/KU BAA Network Load shall mean Transmission Customer's hourly Network Load located in the LG&E/KU Balancing Authority Area, excluding the load associated with the Bluegrass Delivery Point.

5.0 Designation of party subject to reciprocal service obligation:

6.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

6.1 Load Ratio Share of Annual Transmission Revenue Requirement:

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6.2 Facilities Study Charge:

Intentionally Left Blank

6.3 Direct Assignment Facilities Charge:

EKPC Long Lick - All costs incurred to add the tap structure for the EKPC Long Lick substation on the existing KU 69kV line between Adams and Scott County. These costs are estimated to be approximately $900,000 per ITO System Impact Study LGE-2013-015. The cost includes a tap structure with three-way switch and raising the parallel 138kV circuit to maintain clearance for the tap line. The cost estimate includes motor operated switches at the request of the customer. Upon the authorization to proceed, this project will take approximately twelve months to complete. Service to the EKPC Long Lick new delivery point shall not commence until all necessary construction of facilities has been completed, or June 1, 2016, whichever is later.

EKPC Bridgeport #2 - All costs incurred to add a 69kV breaker and all associated equipment at the KU West Frankfort substation to facilitate EKPC construction of a 69kV line to their existing Bridgeport substation. These costs are estimated to be approximately $840,000 per ITO System Impact Study LGE-2014-007. Upon the authorization to proceed, this project will take approximately twelve months to complete. Service to the EKPC Bridgeport #2 new delivery point shall not commence until all necessary construction of facilities has been completed, or June 1, 2016, whichever is later.

6.4 Ancillary Services Charge:

Schedule 1 (Schedule, System Control and Dispatch Services), Schedule 2 (Reactive Supply and Voltage Control from Generation Sources Service) and Schedule 11 (Loss Compensation Service)

6.5 Rates for NITS Service:

The Transmission Owner will share Form 1 data with EKPC at least 30 days prior to populating the Transmission Owners Attachment O with such Form 1 data and will provide a copy of the populated Attachment O not later than May 15 of each year. The Transmission Owner shall provide such supporting material as may reasonably be requested by EKPC in order to understand and verify the basis for LG&E’s population of its Attachment O each year.

For transmission service charged under this Service Agreement, EKPC shall pay the Network Integration Transmission Service rate under Schedule 10 of the OATT as modified herein.

6.6 Redispatch Charges:

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Attachment A

Date of Update: 19-Sep-08

Customer	Resource	Unit	Source	Sink	Percent Owned	Resource Capacity {MW)	Capacity Designated as a Network Resource	Start Time	Stop Time	Location of DNR	Electrical Location
EKPC	Dale	1	EKPC	EKPC.LGEE		23	23	September 1, 2006	N/A	Clark County, KY	Dale Station 69 kV
EKPC	Dale	2	EKPC	EKPC.LGEE		23	23	September 1, 2006	N/A	Clark County, KY	Dale Station 69 kV
EKPC	Dale	3	EKPC	EKPC.LGEE		75	75	September 1, 2006	N/A	Clark County, KY	Dale Station 69 kV
EKPC	Dale	4	EKPC	EKPC.LGEE		75	75	September 1, 2006	N/A	Clark County, KY	Dale Station 138 kV
EKPC	Cooper	1	EKPC	EKPC.LGEE		116	116	September 1, 2006	N/A	Pulaski County, KY	Cooper Station 69 kV
EKPC	Cooper	2	EKPC	EKPC.LGEE		225	225	September 1, 2006	N/A	Pulaski County, KY	Cooper Station 69 kV
EKPC	Spurlock	1	EKPC	EKPC.LGEE		325	325	September 1, 2006	N/A	Mason County, KY	Spurlock Station 345 kV
EKPC	Spurlock	2	EKPC	EKPC.LGEE		525	525	September 1, 2006	N/A	Mason County, KY	Spurlock Station 345 kV
EKPC	Gilbert	3	EKPC	EKPC.LGEE		268	268	September 1, 2006	N/A	Mason County, KY	Spurlock Station 345 kV
EKPC	J.K. Smith	1	EKPC	EKPC.LGEE		150	150	September 1, 2006	N/A	Clark County, KY	J.K. Smith Station 138 kV
EKPC	J.K. Smith	2	EKPC	EKPC.LGEE		150	150	September 1, 2006	N/A	Clark County, KY	J.K. Smith Stallion 138 kV
EKPC	J.K. Smith	3	EKPC	EKPC.LGEE		150	150	September 1, 2006	N/A	Clark County, KY	J.K. Smith Station 138 kV
EKPC	J.K. Smith	4	EKPC	EKPC.LGEE		98	98	September 1, 2006	N/A	Clark County, KY	J.K. Smith Station 138 kV
EKPC	J.K. Smith	5	EKPC	EKPC.LGEE		98	98	September 1, 2006	N/A	Clark County, KY	J.K. Smith Station 138 kV
EKPC	J.K. Smith	6	EKPC	EKPC.LGEE		98	98	September 1, 2006	N/A	Clark County. KY	J.K. Smith Station 138 kV
EKPC	J.K. Smith	7	EKPC	EKPC.LGEE		98	98	September 1, 2006	N/A	Clark County, KY	J.K. Smith Station 138 kV
EKPC	Bavarian	1-4	EKPC	EKPC.LGEE		3	3	September 1, 2006	N/A	Boone County, KY	Boone-Renaker 138 kV line
EKPC	Green Valley	13	EKPC	EKPC.LGEE		2	2	September 1, 2006	N/A	Boyd County, KY	Argentum-Leon 69 kV line
EKPC	Laurel Ridge	1-4	EKPC	EKPC.LGEE		3	3	September 1, 2006	N/A	Laurel County, KY	North Landon-Laurel Co. 69 kV line
EKPC	Laurel Ridge	5	EKPC	EKPC.LGEE		1	1	September 1, 2006	N/A	Laurel County, KY	North Landon-Laurel Co. 69 kV line
EKPC	Hardin County	1-3	EKPC	EKPC.LGEE		2	2	September 1, 2006	N/A	Hardin County, KY	Elizabethtown-Nelson Co. 69 kV line
EKPC	Pendleton Co.	1-4	EKPC	EKPC.LGEE		3	3	September 1, 2006	N/A	Pendleton County, KY	Stanley Parker-Bracken Co. 138 kV line
EKPC	Bluegrass Generating Purchase	2	LGEE	EKPC.LGEE	0	160	160	December 1, 2008	April 1, 2009	Oldham, KY	Buckner 345 kV

EKPC	Bluegrass Station	1	LGEE	EKPC.LGEE	100	165	165	January 1, 2016	N/A	Oldham County, KY	Buckner 345 kV
EKPC	Bluegrass Station	2	LGEE	EKPC.LGEE	100	165	165	January 1, 2016	N/A	Oldham County, KY	Buckner 345 kV

Note 1: Resource Capacity and Capacity Designated as Network Resource based on the higher of the summer or winter rating
Note 2: Load is pseudo tied into the EKPC Control Area

Attachment 2

Affidavit of David Crews

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
	)	
East Kentucky Power Cooperative, Inc.	)	
v.	)	Docket No. EL16-___-000
Louisville Gas & Electric/Kentucky Utilities	)	
	)	
	)	

Affidavit of David Crews

Introduction

1. My name is David Crews. I am the Senior Vice President of Power Supply at the East Kentucky Power Cooperative, Inc. ("East Kentucky"). My business address is 4775 Lexington Road, Winchester, Kentucky 40391.

2. I received a bachelor's degree in Civil Engineering from North Carolina State University and I am a registered professional engineer in North Carolina. Prior to joining East Kentucky, I served as Manager of Federal Regulatory Affairs at Progress Energy Service Co. I also served as the Director of Coal Marketing and Trading for Progress Fuels, and as Director of Power Trading Operations at Progress. I began working at East Kentucky in January of 2011. In all, I have more than 32 years of experience in the electric utility industry.

3. In my capacity as Senior Vice President of Power Supply, I oversee East Kentucky's Power Supply, which includes the areas of Power Supply Planning, Load Forecasting, PJM Market Operations, Fuel Supply, Renewable Energy Projects, Demand Side Management and Energy Efficiency.

4. The purpose of this affidavit is to provide background information concerning East Kentucky and the history and nature of the East Kentucky and Louisville Gas & Electric, Company/ Kentucky Utilities ("LKE") intertwined systems. I also discuss East Kentucky's purchase arrangement for the Bluegrass Generating Station.

The Intertwined Systems of East Kentucky and LKE

5. East Kentucky is a not-for-profit electric generation and transmission cooperative serving 16 member distribution systems throughout Kentucky. East Kentucky owns and purchases 2,794 MW of net summer generating capability and 3,009 MW of net winter electric generating capability to serve approximately 525,000 homes, businesses and industries in 87 Kentucky counties. East Kentucky experienced an all-time winter peak of

3,507 MW on February 20, 2015. East Kentucky owns 2,938 miles of electric transmission lines.

6. Due to geography and a series of Kentucky administrative and court decisions dating back to the 1950's, the service territories and facilities of electric utility companies in Kentucky are heavily intertwined. East Kentucky's transmission system is heavily intertwined with the transmission system of the LKE. As a result, East Kentucky has load on the LKE system and LKE has load on the East Kentucky system. East Kentucky serves 566 MW (peak) of its member load that is connected directly to the LKE transmission system, while LKE serves approximately 100 MW (peak) of LKE load that is connected directly to the East Kentucky transmission system. Today, LKE and East Kentucky share 66 interconnection points between their transmission systems.

7. In 2014, East Kentucky's load on the LKE system peaked at approximately 566 MW, while LKE's load on the East Kentucky system peaked at 112 MW

8. In June 2013, East Kentucky became a transmission owning member of PJM Interconnection, LLC ("PJM"). At that time, East Kentucky turned over operational control of its transmission system to PJM. Approximately 80% of East Kentucky's load is physically connected to the PJM system. The East Kentucky load that is physically connected to the LKE transmission system is pseudo-tied to PJM and is treated as part of East Kentucky's internal zonal load in PJM. East Kentucky serves its entire member load under the East Kentucky/PJM Network Integration Transmission Service Agreement ("NITSA"). These arrangements were approved by the Commission when East Kentucky integrated with PJM in 2013.

9. LKE is not a transmission owning member of PJM. It is my understanding that LKE was formerly a member of the Mid-continent Independent System Operator, Inc., but withdrew in 2006 and is not currently a member of any regional transmission organization.

10. In addition to the East Kentucky/PJM NITSA, East Kentucky has a NITSA with LKE. The East Kentucky/LKE NITSA allows East Kentucky to serve its network load on the LKE system with East Kentucky's network resources. East Kentucky's transmission arrangements are more fully described in the affidavit of Denver York.

East Kentucky's Purchase of the Bluegrass Facility to Serve Member Load

11. East Kentucky serves its member load with resources owned or under contract by East Kentucky. Due to environmental regulations and restrictions, East Kentucky is facing deactivation of certain of its coal-fired plants by April 16, 2016. East Kentucky is also experiencing growing demand on its system and has a winter peak in excess of its remaining resources. East Kentucky is in the process of securing replacement resources.

12. On June 26, 2015, East Kentucky executed an agreement with Bluegrass Generating Company, LLC to purchase the Bluegrass Facility ("Bluegrass"). Bluegrass is an existing

three-unit, 495 MW (summer capability) gas-fired generating station located in Oldham County, Kentucky and is physically connected to the LKE system. Bluegrass is a peaking resource that typically will be dispatched when demand is at its peak. Bluegrass is also subject to NOx restrictions, which permit the facility to run only up to 7% of the year's total hours. Under economic dispatch, East Kentucky forecasts Bluegrass will run less than 6% of the year's total hours.

13. The Bluegrass transaction is scheduled to close by December 31, 2015. For the first few years of East Kentucky's ownership, two of the three Bluegrass units will be available for East Kentucky's use. The output of the third unit is under a power purchase contract with LKE until May 1, 2019, after which East Kentucky will be entitled to the output.

14. East Kentucky intends to use the Bluegrass resource to serve its member-load. Because of its location, output from Bluegrass will first be used to serve East Kentucky network load on the LKE system. However, there may be some hours during which the Bluegrass output exceeds the amount of East Kentucky load on the LKE system. In these hours, East Kentucky intends to deliver any Bluegrass output that exceeds the amount of East Kentucky's Network Load on the LKE system to East Kentucky's Network Load on the East Kentucky system using its NITSA with LKE.

15. From January 2016 through April 2019, it is unlikely that the Bluegrass output will exceed the East Kentucky load on the LKE system at the time of LKE's system peak. East Kentucky expects the same will be true for a majority of the off-peak hours as well. After May 1, 2019, all three Bluegrass units will be available to East Kentucky.

16. East Kentucky expects its load on the LKE system to grow. By 2019, East Kentucky's peak demand on the LKE system is projected to exceed 600 MW. Because of this increase in demand on the LKE system, and because of peaking nature of the plant and NOx restrictions, the Bluegrass output will likely only exceed East Kentucky's LKE-based load during a limited number of hours each year. Even so, East Kentucky must be able to utilize Bluegrass as a Network Resource for its total network load, whether that load is on the LKE system or the East Kentucky system.

17. In order to facilitate its use of Bluegrass, East Kentucky filed a request with LKE to designate Bluegrass as a Network Resource under East Kentucky's NITSA with LKE. TranServ, acting as LKE's Independent Transmission Organization, studied the peak load and generation conditions of Bluegrass and concluded that transmission service is available to deliver the Bluegrass output to East Kentucky's load. TranServ determined that some network upgrades are necessary to provide service, but the upgrades can be in place to allow the service to commence as requested. Furthermore, operating parameters were specified under certain real-time loading conditions that permit LKE's Reliability Coordinator to curtail Bluegrass on a non-discriminatory basis with possible curtailment of LKE's own generation and/or load. East Kentucky has no objection to these operating parameters. LKE also confirmed that East Kentucky may add the Bluegrass resource as a Network Resource under the East Kentucky/LKE NITSA. Thus, to my knowledge, there

is no apparent dispute associated with delivering the Bluegrass output to East Kentucky's network load on the LKE system, or the appropriate charges for that network service.

18. The dispute arises in connection with how to bill East Kentucky when East Kentucky delivers that amount of Bluegrass output that is in excess of the East Kentucky load on the LKE system to the East Kentucky load on the East Kentucky system. At East Kentucky's request, several meetings and calls were convened for East Kentucky and LKE to discuss East Kentucky's transmission needs and how these can be met to the satisfaction of both East Kentucky and LKE. The early indication from LKE staff in these discussions was that some agreement could be reached that would accomplish East Kentucky's objective at a reasonable cost. However, LKE expressed reluctance in subsequent discussions to offer any arrangements that were fair, equitable, and financially appropriate.

19. As discussed more fully in the affidavit of my colleague Denver York, East Kentucky has proposed an arrangement that would compensate LKE for its actual usage of the LKE transmission system coincident with the system's monthly peak, which is how network service is billed under the LKE Tariff. The proposed arrangement is based on an agreement accepted by the Commission for another cooperative with a similarly intertwined system. LKE has indicated no interest in pursuing that proposal. Instead, LKE has taken the position that East Kentucky must reserve point-to-point transmission or designate additional delivery points on the East Kentucky system as network loads under its NITS reservation to provide adequate coverage for the potential excess output from Bluegrass Station. Under LKE's approach, East Kentucky would be paying duplicative and unnecessary transmission charges for transmission service that East Kentucky does not actually use in real-time operations. We have estimated that the point to point approach would increase East Kentucky's annual transmission payment to LKE for network service from approximately $7 million to approximately $17 million.

20. In order to ensure delivery of Bluegrass, East Kentucky expects to submit transmission service requests to LKE in the manner that LKE has dictated, but East Kentucky did so under protest. East Kentucky worked with LKE to understand its position and to try to develop an arrangement that fairly compensates LKE for East Kentucky's use of the LKE transmission system without unjustly placing a financial burden on the East Kentucky Owner-Member ratepayers.

21. This concludes my affidavit.

Affidavit of David Crews

I, **David Crews**, being duly sworn according to law, state under oath that the forgoing statements are true and correct to the best of my knowledge, information, and belief.

David Crews

Date: 10/30/2015

Verification
State of Kentucky)
County of Clark)

Subscribed and sworn before me, a Notary Public, on this 30th day of October, 2015.

Gwyn M. Willoughby
Notary Public

My commission expires: 11/30/17

GWYN M. WILLOUGHBY
Notary Public
State at Large
Kentucky
My Commission Expires Nov 30, 2017

Attachment 3

Affidavit of Denver York

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

East Kentucky Power Cooperative, Inc.)
v.) Docket No. EL16-___-000
Louisville Gas & Electric/Kentucky Utilities)

Affidavit of Denver York

1. My name is Denver York. I am the Senior Vice President of Power Delivery and system Operations at East Kentucky Power Cooperative, Inc. ("East Kentucky"). My business address is 4775 Lexington Road, Winchester, Kentucky 40391.

2. I received a bachelor's degree in electrical engineering from the Florida Institute of Technology and a masters degree in electrical engineering and math from the Georgia Institute of Technology.

3. In my capacity as Vice President of Power Delivery and system Operations, I oversee the physical planning, design, and operations of the East Kentucky transmission system in the long-term and in real-time.

4. A description of East Kentucky, the history and intertwined nature of the East Kentucky and LKE systems, as well as East Kentucky's purchase of the Bluegrass facility, is provided in the affidavit of my colleague, David Crews.

5. The purpose of my affidavit is to describe East Kentucky's overall transmission arrangements, including the transmission arrangements between East Kentucky and PJM and separately, East Kentucky and Louisville Gas & Electric/ Kentucky Utilities ("LKE"). I will also describe the meetings between East Kentucky and LKE where we attempted to resolve our differences concerning Network Service arrangements for the delivery of the Bluegrass Generating Station ("Bluegrass").

6. In June 2013, East Kentucky voluntarily became a transmission owning member of PJM Interconnection, Inc. ("PJM"). At that time, East Kentucky turned over operational control of its transmission system to PJM. Approximately 80% of East Kentucky's load is physically connected to the PJM system. The East Kentucky load that is physically connected to the LKE transmission system is pseudo-tied to the PJM Balancing Authority and is treated as part of East Kentucky's internal zonal load in PJM. These arrangements were approved by the Commission when East Kentucky integrated with PJM in 2013.

7. East Kentucky serves its entire member load, including its pseudo-tied load from the LKE system, pursuant to the East Kentucky/PJM Network Integration Transmission

Service Agreement ("NITSA"), and it pays the PJM zonal network service rate for East Kentucky's entire load.

8. In addition to the East Kentucky/PJM NITSA, East Kentucky is party to a NITSA with LKE. The East Kentucky/LKE NITSA allows East Kentucky to serve its network load on the LKE system with East Kentucky's network resources. East Kentucky pays the LKE network rate for the amount of East Kentucky network load on the LKE system.

9. As discussed in the affidavit of David Crews, East Kentucky has entered into a purchase agreement for the Bluegrass facility and intends to use the Bluegrass resource to serve its member-load. That transaction is scheduled to close by December 31, 2015. As Mr. Crews explains, because of its location, output from Bluegrass will first be used to serve East Kentucky load on the LKE system.

10. East Kentucky submitted requests to LKE to designate Bluegrass as a Network Resource under East Kentucky's NITSA with LKE. On November 26, 2014, East Kentucky requested Network Service for Bluegrass Units 1 and 2, and on April 29, 2015, East Kentucky requested Network Service for Bluegrass Unit 3.

11. On June 11, 2015 (for Units 1 and 2) and October 5, 2015 (for Unit 3), TranServ, acting as the LKE Independent Transmission Organization, notified EKPC that network transmission service is available, and that East Kentucky may add Bluegrass output as a new Network Resource under the East Kentucky/LKE NITSA.

12. As Mr. Crews also explains in his affidavit, there may be times when the Bluegrass output will exceed East Kentucky's LKE-based load. In those hours, East Kentucky intends to use that excess output to serve its member-load on East Kentucky's system.

13. During the summer of 2015, I, along with other representatives East Kentucky, met with LKE to discuss amending the East Kentucky/LKE NITSA to also allow East Kentucky to deliver Bluegrass output to East Kentucky load on the East Kentucky system. During those discussions, we reminded LKE that Bluegrass output would only need to be delivered to East Kentucky member-load on the East Kentucky system when the output of Bluegrass exceeded the demand of the East Kentucky load on the LKE system.

14. East Kentucky proposed to amend the East Kentucky/LKE NITSA in two respects. First, we would add a new delivery point at one or more points of interconnection between the LKE and East Kentucky systems. Second, we would calculate the load at that new delivery point as the difference between the output of Bluegrass and East Kentucky's network load on the LKE system. This would determine East Kentucky's total Network Load on the LKE system. Specifically, if the Bluegrass output exceeded the East Kentucky load on the LKE system, then the positive difference at the time of the system monthly peak would be added to the sum of the load at the other East Kentucky delivery points at the time of LKE's peak. If the Bluegrass output did not exceed the East

Kentucky load on the LKE system, then there would be nothing to add. LKE rejected this arrangement.

15. LKE instead advised East Kentucky that if it intends to deliver any of the Bluegrass output to serve its network load on East Kentucky's system, then it would need to submit a request to purchase Point-to-Point service for an amount equal to the difference between the nominal nameplate rating of Bluegrass and the minimum amount of East Kentucky network load on the LKE system at any time during the year, *in addition* to the existing East Kentucky/LKE Network Service arrangements for East Kentucky's load on the LKE system.

16. LKE also suggested that East Kentucky could designate delivery points served from East Kentucky's own transmission system as delivery points under the LKE NITSA in sufficient amounts so that East Kentucky's minimum load on the LKE system would always be at least equal to the nominal nameplate rating of Bluegrass. This would mean that East Kentucky would have to designate (and pay for) several hundred megawatts of additional load that is currently served by East Kentucky's own system as new network load on the LKE system.

17. During the course of our discussions with LKE, East Kentucky approached TranServ to assist in resolving the issue. TranServ is the independent entity charged with administering LKE's transmission tariff in a non-discriminatory manner. TranServ simply referred East Kentucky back to LKE.

18. During the course of our discussions with LKE over several months, I and others at East Kentucky advised LKE that requiring East Kentucky to reserve Point-to-Point service, which would be several hundred additional megawatts, or to require us to designate delivery points from our own system in order to add several hundred additional megawatts of network load under the LKE NITSA was an unreasonable approach given the nature of the two systems and the amount of service actually needed. We also advised them that this would double charge East Kentucky for service that it is already paying for, as well as subject East Kentucky to charges for transmission that East Kentucky would not use. The largest amount of transmission service that East Kentucky would use on the LKE system would be the greater of East Kentucky's member load on the LKE system *or* the Bluegrass output, but not both in the aggregate.

19. East Kentucky's current payments to LKE for Network service (approximately 566 MW peak) total approximately $7 million per year. Under LKE's approach, East Kentucky's aggregate annual payments under East Kentucky's current Network Service and the purchase of additional service that LKE proposed would total approximately $17 million.

20. This concludes my affidavit.

Affidavit of Denver York

I, **Denver York**, being duly sworn according to law, state under oath that the forgoing statements are true and correct to the best of my knowledge, information, and belief.

Denver York

Date: 10/30/2015

Verification

State of ~~Kentucky~~ Florida)
County of ~~Clark~~ Bay)

Subscribed and sworn before me, a Notary Public, on this 30 day of October, 2015.

Shania Banks-Sutton
Notary Public

SHANIA BANKS-SUTTON
Commission # FF 144320
Expires July 23, 2018
Bonded Thru Troy Fain Insurance 800-385-7019

My commission expires: July 23, 2018

Certificate of Service

I hereby certify that I have this day served the foregoing document upon the following contacts for LKE as listed on the Commission's list of Corporate Officials:

Gerald A. Reynolds
General Counsel, Chief Compliance Officer and Corporate Secretary
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40202
Telephone: 502-627-3297
Fax: 502-627-4622
Email: gerald.renolds@lge-ku.com

Michael S. Beer
Vice President, Federal Regulatory and Policy
LG&E and KU Energy LLC
220 West Main Street
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Telephone: 502-627-3547
Fax: 502-627-4622
Email: mike.beer@lge-ku.com

Dated at Washington, D.C. this 30th day of October, 2015.

/s/ Jennifer Spangler
Jennifer Spangler
Legal Assistant
Jennings, Strouss & Salmon, P.L.C.
1350 I Street, NW, Suite 810
Washington, DC 20005-3305
(202) 464-0572
jspangler@jsslaw.com

Document Content(s)

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

East Kentucky Power Cooperative, Inc.

v. Docket No. EL16-8-000

Louisville Gas and Electric Company/
Kentucky Utilities Company

NOTICE OF COMPLAINT

(November 3, 2015)

Take notice that on November 2, 2015, pursuant to sections 206, 211 and 306 of the Federal Power Act, 16 U.S.C. 824e, 824j-1 and 825e (2006) and Rule 206 of the Federal Energy Regulatory Commission's (Commission) Rules of Practice and Procedure, 18 CFR 385.206 (2015), East Kentucky Power Cooperative, Inc. (East Kentucky or Complainant) filed a complaint against Louisville Gas and Electric Company/Kentucky Utilities Company (LKE or Respondents) alleging that LKE's failure to accept East Kentucky's designation of new Network Load under the East Kentucky-LKE Network Service Agreement is contrary to the terms of the LKE Open Access Transmission Tariff and the Commission's policies concerning open access and transmission pricing, all as more fully explained in the complaint.

The Complainant certifies that copies of the complaint were served on the contacts for the Respondent as listed on the Commission's list of corporate officials.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211, 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent's answer and all interventions, or protests must be filed on or before the comment date. The Respondent's answer, motions to intervene, and protests must be served on the Complainants.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 5 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for electronic review in the Commission's Public Reference Room in Washington, DC. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on November 23, 2015.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Document Content(s)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
East Kentucky Power Cooperative, Inc.	)	
	)	Docket No. EL16-8-000
v.	)	
	)	
Louisville Gas & Electric/Kentucky Utilities	)	
	)	

ANSWER OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY

Pursuant to Rules 206(f) and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or the "Commission")[1] and the Notice of Complaint issued November 3, 2015, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "LG&E/KU") hereby submit this Answer to the October 30, 2015 complaint filed in the above-referenced docket by East Kentucky Power Cooperative, Inc. ("EKPC") (the "Complaint").

For the reasons stated below, the Complaint is without merit and should be summarily rejected. EKPC fails to support its request for a Network Integration Transmission Service Agreement ("NITSA") that deviates significantly from the provisions of the LG&E/KU Open Access Transmission Tariff ("OATT")[2] and long-standing Commission policy in a manner that would unduly restrict efficient operation of the LG&E/KU Transmission System. LG&E/KU

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[1] 18 C.F.R. §§ 385.206(f), 385.213 (2015).

[2] The LG&E/KU OATT is currently located under LG&E's "Transmission" title in eTariff, and may be found here: http://etariff.ferc.gov/TariffBrowser.aspx?tid=794. Capitalized terms not otherwise defined shall have the meaning in Section 1 of the LG&E/KU OATT.

have acted in accordance with the provisions of their OATT and the requirements of Order Nos. 888[3] and 890.[4]

I. EXECUTIVE SUMMARY

Two days after submitting a transmission service request related to Bluegrass,[5] EKPC filed a Complaint that attaches a proposed NITSA amendment, predicated on the formation of a fictitious "load" point named after a generating station (the "Bluegrass Delivery Point") that would serve to support any occasional energy imbalance between Bluegrass generation and EKPC's Network Loads on LG&E/KU's Transmission System. LG&E/KU submit that:

- EKPC's requested service would be a clear violation of the terms of the OATT and longstanding Commission precedent;

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[3] *See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g,* Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g,* Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g,* Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Pol'y Study Group v. FERC,* 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC,* 535 U.S. 1 (2002).

[4] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g,* Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g,* Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g,* Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification,* Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[5] *See* Attachment 1 Affidavit of Christopher Balmer at PP 3-4. EKPC submitted an original Request for NITS service for units 1 & 2 on November 26, 2014. This request was granted on June 11, 2015 (limited to serve load on the LG&E/KU Transmission System). On April 29, 2015, EKPC filed a request for NITS service for unit 3. This request, with the same limitation, was approved on October 5, 2015. On October 28, 2015, EKPC submitted two additional TSRs with the following comments:

(1) 81823340 for 283MW from 1-1-2016 to 5-1-2019 with this comment - To make BLGR 1 and 2 DNRs for EK load on the EK system. EKPC is designating an interface delivery point that represents the hourly difference between the output of these units and EK load on the [LG&E/KU] system. 283 MW is the max difference projected; and

(2) 81823354 for 476MW from 5-1-2019 to 5-1-2024 with this comment - To make BLGR 1,2,& 3 DNRs for EK load on the EK system. EKPC is designating an interface delivery point that represents the hourly difference between the output of these units and EK load on the [LG&E/KU] system. 476 MW is the max difference projected.

- EKPC has failed to support its burden to modify the OATT, as its request would result in preferential service and impair efficient operation of the LG&E/KU Transmission System;
- EKPC has not fully represented lower cost service options; and
- EKPC has failed to meet the requirements for a waiver.

A. The OATT Requires Designation of Discrete Load, Not Generator Imbalance

Section 1.25 of the LG&E/KU OATT states that "[a] Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery." Under Section 31.3 of the LG&E/KU OATT, a Network Customer may nominate load outside the LG&E/KU Transmission System as Network Load if ***and only if*** the customer elects "to include the entire load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load." The choice is binary – either all of a discrete load can be included and served by NITS, or all of a discrete load can be excluded from NITS and the load ratio share-based charges that would otherwise apply and be served under a separate arrangement. EKPC's request clearly violates this directive – intermittent, positive energy imbalances do not equate to a nomination of discrete load for purposes of the OATT.

In an order issued in June of this year, the Commission reemphasized that a customer's "request to designate less than its entire load as network load violates both [the] OATT and longstanding Commission policy, which require network customers to designate their entire load as network load to receive network service."[6] As correctly explained to EKPC by LG&E/KU,[7]

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[6] *Ariz. Pub. Serv. Co.*, 151 FERC ¶ 61,191 at P 26 (2015).

[7] Balmer Affidavit at P 19.

EKPC has two options to deliver output of the Bluegrass unit over and above the current amount of designated Network Load:

(1) purchase Point-to-Point service; or

(2) designate additional discrete load points within EKPC's system as LG&E/KU Network Load to increase EKPC's minimum designated load to equal the output of Bluegrass, and be billed for that load under the EKPC NITSA with LG&E/KU on a coincident peak demand basis.

These approaches were specifically endorsed by the Commission in Order No. 888-B.[8]

EKPC, on the other hand, states that it intends the positive imbalance of Bluegrass to serve EKPC's load connected to the EKPC transmission facilities in PJM.[9] But its proposed "use [of] its NITSA with [LG&E/KU] to integrate Bluegrass with East Kentucky's load"[10] is inconsistent with the OATT. First, EKPC has not identified discrete portions of its load in PJM that would be identified as Network Load under the LG&E/KU OATT. Second, there are no proposed limitations that would prevent PJM from dispatching Bluegrass to serve demand elsewhere in PJM. Section 28.6 of the LG&E/KU OATT prohibits the use of NITS to support energy transfers outside of "discrete" physical load identified as Network Load under the LG&E/KU OATT.[11] Permitting NITS to serve non-discrete loads outside the Transmission Provider's system would set a new precedent applicable to other Transmission Providers and Transmission Customers beyond the specific case of EKPC.

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[8] *Supra* n. 3.

[9] Complaint at 8.

[10] *Id.*

[11] Section 28.6 provides, "[t]he Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties."

What EKPC plainly seeks is the firmness of NITS with the flexibility and hourly pricing of non-firm Point-to-Point Transmission Service, a combination of pricing options not sanctioned by the OATT. To the contrary, the Commission has clearly stated, "[t]he concept of allowing a "split system" or splitting a discrete load is antithetical to the concept of network service" and would create "the potential for a customer to "game the system" thereby evading some or all of its load-ratio cost responsibility for network services."[12] EKPC's primary support for its Complaint is a non-precedential letter order issued by delegated authority that cannot be used to overturn the plain language of the OATT.[13]

Furthermore, the example of Arkansas Electrical Cooperative Corporation ("AECC") cited by EKPC supports LG&E/KU's understanding of the OATT requirements. AECC and the Midcontinent Independent System Operator ("MISO") agreed that AECC's NITS service in the Southwest Power Pool ("SPP") could not be used to both serve AECC's load in the SPP system and simultaneously support transfers to MISO.[14]

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[12] Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,259 (1997) (citations omitted). The Commission also found,

> NRECA and TDU Systems, however, argue that network customers located in multiple control areas should not have to pay for any additional point-to-point transmission service to make sales to non-designated load located in a separate control area. We disagree. Because the additional transmission service to non-designated network load outside of the transmission provider's control area is a service for which the transmission provider must separately plan and operate its system beyond what is required to provide service to the customer's designated network load, it is appropriate to have an additional charge associated with the additional service.

Id. at 30,255.

[13] *E.g.*, *Westar Energy, Inc.*, 124 FERC ¶ 61,057 at P 26 (2008); *Norwalk Power, LLC*, 122 FERC ¶ 61,273 at P 25 (2008). The Commission has explained that "actions taken by its staff pursuant to delegated authority do not constitute Commission precedent binding the Commission in future cases and the exercise of . . . delegated authority cannot serve to supplant the policies [the Commission has] established in [its] decisions and regulations." *Mid-Continent Area Power Pool*, 97 FERC ¶ 61,038 at 61,184 n.10 (2001) (citing *Phoenix Hydro Corp.*, 26 FERC ¶ 61,389, at 61,870 (1984), *aff'd*, 775 F.2d 1187, 1191 (D.C. Cir. 1985)) (internal quotations omitted).

[14] As stated by SPP,

> All of the AECC resources within SPP have been designated by AECC to serve AECC *loads within SPP* . . . but not AECC loads within EAI . . . Therefore, SPP would clarify that the SPP NITSA is not currently structured to serve AECC load within EAI, nor does the SPP NITSA recognize that AECC designated resources may be utilized for AECC load located outside of SPP.

EKPC's requested service is a clear violation of LG&E/KU's OATT and Commission precedent. EKPC's complaint, therefore, should be summarily rejected.

B EKPC Has Failed To Satisfy Its Burden To Modify the OATT

To grant EKPC's requested service would require a determination that the Commission's *pro forma* OATT provisions are unjust and unreasonable;[15] yet it remains clear that the Commission's OATT provisions are entirely just and wholly reasonable. In fact, if LG&E/KU were to grant EKPC's request, EKPC would be receiving discriminatory, preferential treatment to the detriment of other LG&E/KU Transmission Customers in several ways.

First, to ensure the firmness of EKPC's NITS service to the non-discrete, non-load based Bluegrass Delivery Point, LG&E/KU would be required to reserve firm transmission capacity over the relevant flowgates every hour of every day up to the potential total amount of Bluegrass Generating Station ("Bluegrass") output – even if by EKPC's own admission, the facility is environmentally restricted to run only 7% of the hours in a year with most of the output during those hours being devoted to serve Network Load on the LG&E/KU Transmission System.[16]

LG&E/KU have opposed EKPC's proposal because it would impair efficient utilization of the LG&E/KU Transmission System, decreasing Available Transfer Capability ("ATC") that would and should be available to other Transmission Customers, improperly restricting access of

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Midcontinent Indep. Sys. Operator Inc., Docket No. ER14-684-000, Motion of Southwest Power Pool, Inc. to Accept Comments Out of Time and Comments at 5 (Jan. 23, 2014). Further, "AECC and MISO aver[red] that the proposed NITSA is not intended to affect the terms and conditions of existing SPP service." *Midcontinent Indep. Sys. Operator Inc.*, Docket No. ER14-684-000, Arkansas Electric Cooperative Corporation's Answer to Motion to File Comments Out of Time and Comments of Southwest Power Pool, Inc. at 3 (Feb. 7, 2014). Accordingly, the Commission's acceptance was "without prejudice to any necessary arrangements AECC must make with SPP regarding the pseudo-tie or any transmission service on SPP's transmission system." *Midcontinent Indep. Sys. Operator Inc.*, 146 FERC ¶ 61,094 at P 45 (2014).

[15] *Coalition of Eastside Neighborhoods for Sensible Energy, et. al., v. Puget Sound Energy, et. al.*, 153 FERC ¶ 61,076 at P 61 (2015) ("Complainants have not met their burden of proof under section 206 of the FPA to demonstrate that the Respondents' actions . . . have violated any applicable requirement or are otherwise unjust, unreasonable, or unduly discriminatory, or preferential.").

[16] *See* Complaint at Attachment 2, Affidavit of David Crews at P 12.

other Transmission Customers to the PJM Interconnection LLC ("PJM") market (to the benefit of EKPC's generation physically located in PJM). As explained in the affidavit of Christopher Balmer, LG&E/KU already have an annual firm Point-to-Point Transmission Service request from a third party Transmission Customer for export capacity into PJM over these affected facilities.[17]

Second, EKPC's proposal that its "Bluegrass Delivery Point" deliveries be calculated on an after-the-fact basis complicates the ability to release the unused firm transmission for non-firm use, due to a lack of customer-supplied load forecasts for the delivery point, necessary for the release of transmission for non-firm use. Third, EKPC's request compromises effective planning of the LG&E/KU system due to the unprecedented level of variability in load, for which LG&E/KU would need to plan. In accordance with Section 28.2 of the OATT, LG&E/KU are responsible for planning their transmission system to meet the needs of their Network Customers.[18] EKPC's request would require LG&E/KU to somehow plan for a 476 MW potential imbalance service that can appear, in whole or in part, in any hour over the course of a given year. Unlike physical load that is predicated on historical usage patterns and meteorological conditions, EKPC could vary the imbalance amounts exported off the LG&E/KU

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[17] Balmer Affidavit at P 16.

[18] Section 28.2 provides,

> The Transmission Owner will plan (subject to regional plans and coordination), construct, operate and maintain the Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to make available to the Network Customer Network Integration Transmission Service over the Transmission Owner's Transmission System. The Transmission Owner, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer under Part III of this Tariff. This information must be consistent with the information used by the ITO to calculate available transfer capability. The Transmission Owner shall include the Network Customer's Network Load in the Transmission System planning and shall, consistent with Good Utility Practice, endeavor to construct and place into service sufficient transfer capability to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Owner's delivery of its own generating and purchased resources to its Native Load Customers.

Transmission System based on its use of its portfolio of Network Resources. Such unprecedented "loads" would wreak havoc on sound transmission planning.

C. EKPC Has Not Fully Represented Lower Cost Service Options

EKPC offers an unsupported and exaggerated price for compliance with the Commission's requirements. Based on LG&E/KU's review of EKPC's actual load (connected to the LG&E/KU Transmission System) for the period July 1, 2014 to June 30, 2015, LG&E/KU identified the highest 600 hours of load in the winter months (December, January, and February), which are the periods most likely to require the services of a peaking resource such as Bluegrass. The 600 hours were spread across 64 unique days. When these hourly loads are compared to the maximum Bluegrass generation, the difference is a maximum of 39 MW for both the initial two units and then 231 MW when the third unit is added.

Therefore, for illustrative purposes, if EKPC were to request and utilize Point-to-Point Transmission Service for an assumed total of 39 MW of excess output above their discrete load on the LG&E/KU transmission system, it would cost $179,244 for three months of monthly firm Point-to-Point Transmission Service. For a 231 MW reservation, the price would be $1,061,676 for three months of monthly firm Point-to-Point Transmission Service.[19] Obviously, the rates for daily firm and non-firm service would be even less. While these examples are only illustrative, if EKPC chose to use the OATT services to meet the limited needs EKPC asserts that it has, its transmission costs could be well below the $10,000,000 cited by EKPC.[20]

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[19] Balmer Affidavit at P 21-22.

[20] *Id*. LG&E/KU's authorized rates are $1,532/MW for monthly firm Point-to-Point Transmission Service; $71.00/MW for daily firm Point-to-Point Transmission Service, and $4.44/MWh for non-firm service.

D. EKPC Has Failed To Meet the Requirements for a Waiver

EKPC seeks to impose this preferential treatment over the almost twenty-year term of the NITSA. Given that EKPC's request will impose significant harm to third parties, particularly with respect to the determination of ATC, and is not of limited scope, EKPC has not met the Commission's long-standing criteria for a waiver.[21]

Accordingly, EKPC has failed to support its Complaint that LG&E/KU violated the OATT, that these provisions of the OATT are not just and reasonable, or that EKPC qualifies for a waiver. The Complaint should be denied.

II. COMMUNICATIONS

All correspondence and communications in this proceeding should be addressed to the following persons.[22]

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III. BACKGROUND

LG&E and KU are both public utilities and are wholly-owned subsidiaries of LG&E and KU Energy LLC, a public utility holding company and a wholly-owned subsidiary of PPL Corporation ("PPL"). PPL is headquartered in Allentown, Pennsylvania. LG&E is an electric and natural gas utility based in Louisville, Kentucky. LG&E currently serves customers in Louisville and 16 surrounding counties. KU is an electric utility based in Lexington, Kentucky,

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[21] *See, e.g.*, *Sw. Pub. Serv. Co.*, 150 FERC ¶ 61,128 at P 33 (2015).

[22] 18 C.F.R. § 385.2010 (2015).

serving 77 Kentucky counties and five counties in Virginia. LG&E/KU operate a combined Commission-approved OATT based on the requirements of Order Nos. 888 and 890.

EKPC is an electric generation and transmission cooperative that owns and purchases 2,794 MW of net summer generating capability and 3,009 MW of net winter electric generating capability to serve approximately 525,000 homes, businesses, and industries in 87 Kentucky counties through its 16 member distribution cooperatives. EKPC is a transmission-owning member of PJM, owning 2,938 miles of electric transmission lines. A portion of EKPC's load, however, is served off of LG&E/KU's transmission system using a NITSA executed under the LG&E/KU OATT.

The Bluegrass unit is a presently-operational 495 MW (summer capability) gas-fired generating station located in Oldham County, Kentucky, and consists of three units: Bluegrass Unit 1, Bluegrass Unit 2, and Bluegrass Unit 3. On June 26, 2015, EKPC executed an agreement to purchase Bluegrass from Bluegrass Generating Company, LLC, the facility's current owner. EKPC has expressed to LG&E/KU its intention to use the Bluegrass Units as Network Resources to serve portions of EKPC's load that are interconnected to the LG&E/KU transmission system.

LG&E/KU are in the process of preparing for filing an amendment to the EKPC NITSA in connection with EKPC's pending acquisition of Bluegrass after which EKPC will be able to use Bluegrass as a designated Network Resource ("DNR") to serve EKPC load interconnected to the LG&E/KU transmission system. The amendment will also specify cost responsibility for necessary upgrades at the Bridgeport #2 service point; clarify responsibility for the provision of ancillary services; and delineate EKPC's responsibility for any redispatch charges under the terms of the LG&E/KU OATT.[23]

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[23] The last substantive modification to the EKPC NITSA was made in Docket No. ER14-2968-001, which was accepted on January 6, 2015. LG&E/KU filed a re-collation filing on January 23, 2015 in Docket No. ER15-

IV. ANSWER

A. LG&E/KU Have Properly Interpreted Their OATT Consistent with Order No. 888

On June 26, 2015, East Kentucky executed an agreement with Bluegrass Generating Company, LLC to purchase the Bluegrass facility, an existing three-unit, 495 MW (summer capability) gas-fired generating station located in Oldham County, Kentucky and interconnected to the LG&E/KU Transmission System.[24] EKPC states that it will use output from Bluegrass "chiefly" to serve Network Load that is connected to the LG&E/KU Transmission System.[25] There is no dispute between EKPC and LG&E/KU with respect to the designation of Bluegrass as a Network Resource to serve these discrete Network Loads.[26]

EKPC notes, however, that there may be some hours, primarily after May 2019, during which the combined output of the Bluegrass units exceeds the amount of Network Load EKPC has on the LG&E/KU system.[27] In these hours, EKPC seeks to deliver the additional supply off the LG&E/KU Transmission System to the PJM system using its NITS service rather than a separate Point-To-Point Transmission Service reservation.[28] In other words, EKPC is proposing to take any hourly positive energy imbalance on the LG&E/KU Transmission System and deem it "load" at the border between the LG&E/KU and EKPC systems. As stated by EKPC,

> This Delivery Point ("Bluegrass Delivery Point") shall be the point at which output from Bluegrass in excess of Transmission Customer's Network Load on the Transmission Owner's system shall be delivered to Transmission Customer's Network Load on Transmission Customer's system. The Network Load at the

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898-000. There were no substantive changes to the NITSA. The Commission accepted the entire re-collation filing on March 24, 2015.

[24] Complaint at 7-8.

[25] *Id*. at 8.

[26] *Id*. at 9.

[27] *Id.* at 9 and 11. *See also* Crews Affidavit at P 15.

[28] Complaint at 9.

> Bluegrass Delivery Point will be a calculated value (on an integrated hourly basis) for flows into the Transmission Customer's system at the Bluegrass Delivery Point.[29]

The "Bluegrass load" is not based on any physical customer demand for electricity but simply represents a positive imbalance between EKPC's Bluegrass Network Resources and its physical Network Loads.[30] According to EKPC,

> The minimum value for the Network Load for the Bluegrass Delivery Point shall be zero. The maximum value of the Bluegrass Load during a calendar month shall not exceed the higher of: (1) the amount of Transmission Customer Network Load located in the LG&E/KU Balancing Authority Area, excluding the load associated with the Bluegrass Delivery Point; or (2) the total output of the Bluegrass Facility.[31]

In accordance with Section 28.3 of their OATT, LG&E/KU make available firm transmission service over the LG&E/KU Transmission System to the Network Customer for the delivery of capacity and energy from the Network Customer's designated Network Resources to service the Network Customer's Network Loads "on a basis that is comparable to the Transmission Owner's use of the Transmission System to reliably serve its Native Load Customers." No customer is to obtain preferential use of the Transmission System.

In its Complaint, EKPC seeks customer-specific transmission service that violates the requirements of the OATT and adversely impacts the provision of non-discriminatory transmission service to other LG&E/KU Transmission Customers. Accordingly, LG&E/KU have acted reasonably in opposing EKPC's proposed form of hybrid service. The Commission has recognized that the provision of services beyond those required by Order No. 888 and 890 is voluntary, not required, on the part of transmitting utilities.[32]

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[29] *Id*. at Attachment 1, Proposed EKPC NITSA at Section 4.0.

[30] *Id*. ("Bluegrass Load = Bluegrass Resource Energy less LG&E/KU BAA Network Load").

[31] *Id.*

[32] *Carolina Power & Light Co.*, 123 FERC ¶ 61,291 at P 20 (2008).

1. EKPC's Requested Service Is Barred by the OATT – Network Customers Must Identify Discrete Network Loads Not Residual Imbalances

In order to utilize NITS, the Transmission Customer must identify discrete Network Load at a Point of Delivery. The Customer does not have to identify all of its load but must include the entire load associated with the Point of Delivery. The Commission explained in Order No. 888-A:

> The concept of allowing a "split system" or splitting a discrete load is antithetical to the concept of network service. A request for network service is a request for the integration of a customer's resources and loads. Quite simply, a load at a discrete point of delivery cannot be partially integrated – it is either fully integrated or not integrated. Furthermore, such a split system creates the potential for a customer to 'game the system' thereby evading some or all of its load-ratio cost responsibility for network services.[33]

Thus, under Section 28.1 of the LG&E/KU OATT, "Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Balancing Authority Area and any additional load that may be designated pursuant to Section 31.3 of the Tariff." Network Load, under Section 1.25 of the LG&E/KU OATT, must include the entire load at "discrete" Points of Delivery.

> A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.[34]

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[33] Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,259 (1997) (citations omitted); *see also Transmission Access Pol'y Study Group v. FERC*, 225 F.3d 667, 726 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002) (affirming the Commission's findings on behind-the-meter generation).

[34] LG&E/KU OATT, Section 1.25.

Section 31.3 of the LG&E/KU OATT addresses Network Load not physically interconnected with the LG&E/KU Transmission System and states:

> This section applies to both initial designation pursuant to Section 31.1 and the subsequent addition of new Network Load not physically interconnected with the Transmission Owner. To the extent that the Network Customer desires to obtain transmission service for a load outside the Transmission Owner's Transmission System, the Network Customer shall have the option of (1) electing to include the ***entire*** load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load, or (2) excluding that ***entire*** load from its Network Load and purchasing Point-To-Point Transmission Service under Part II of the Tariff. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.[35]

According to EKPC, "Section 31.3 permits East Kentucky to designate, as part of its Network Load under a modified NITSA with [LG&E/KU], its member load that is not directly connected to the [LG&E/KU] system."[36] LG&E/KU agree with this statement. EKPC, however, goes on to state, "[t]he only condition to doing so is that East Kentucky must designate one or more Network Resources for that load, which East Kentucky has satisfied by identifying Bluegrass as that designated Network Resource."[37] This statement is not correct. EKPC ignores the requirement to designate the ***entire*** Network Load at that new service point.

To be clear Section 31.3 requires:

(1) the identification of a discrete, metered and measurable load; and

(2) that the ***entirety*** of the load be served under the Transmission Provider's NITS.

EKPC's proposal fails both of these requirements. EKPC seeks to serve an undefined portion of its load on the PJM system based on occasional hourly positive energy imbalances resulting from the difference in the output of a designated Network Resource located on the

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[35] *Id.* at Section 31.3 (emphasis added).

[36] Complaint at 14.

[37] *Id.*

LG&E/KU Transmission System and physical Network Loads served from the LG&E/KU Transmission System. Energy imbalance located on an adjacent transmission system is not a discrete load in another transmission system. To utilize NITS for the additional potential output of Bluegrass, beyond the currently existing levels of Network Load, EKPC will have to identify an additional Point of Delivery or Points of Delivery that can be separately metered.

EKPC states that Section 31.3 "was defined in this manner to prevent customers from combining Network and Point-to-Point service at a single, discrete delivery point (*e.g.*, a customer utilizing behind-the-meter generation)."[38] EKPC's reading of the provision is too narrow and directly contrary to the Commission's express holding in Order No. 888. The requirement to designate all or none of a customer's actual physical load at a discrete Point of Delivery is clearly applicable to customers with loads in multiple systems. The Commission addressed this issue in Order No. 888 as follows:

> As to the concerns raised by AEC & SMEPA and NRECA about pancaked rates for network service provided to load served by more than one network service provider, we have stated that if a customer wishes to exclude a particular load at discrete points of delivery from its load ratio share of the allocated cost of the transmission provider's integrated system, it may do so. Customers that elect to do so, however, must seek alternative transmission service for any such load that has not been designated as network load for network service. This option is also available to customers with load served by "behind the meter" generation that seek to eliminate the load from their network load ratio calculation.[39]

EKPC reads "also available" as "only available." There is no difference in the requirement to identify all or none of the load at a discrete point whether the load is served from another transmission system or from behind-the-meter.

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[38] *Id.* at 15.

[39] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,736 (1996).

In accordance with the OATT, EKPC cannot operate its designated Network Resources above their designated Network Load on the LG&E/KU Transmission System using NITS.[40] Accordingly, LG&E/KU have explained to EKPC that it has two options to deliver output of the Bluegrass unit over and above the current amount of designated Network Load:

(1) request and purchase Point-to-Point service in any desired amount sufficient to deliver the desired level of output of the Bluegrass Units; or

(2) designate any number of additional load points within EKPC's system as LG&E/KU Network Load to increase EKPC's minimum designated load to equal the desired level of output of Bluegrass, and be billed for that load under NITS.[41]

EKPC cites the heavily-integrated nature of the EKPC and LG&E/KU systems and that only a portion of Bluegrass output would be delivered from the LG&E/KU Transmission System to EKPC's loads in PJM.[42] These statements may be correct but do not undermine the requirements of the OATT. The clear requirements of the Commission's *pro forma* OATT do not impose "artificial restrictions that produce unjust and unreasonable results," as alleged by EKPC.[43] As explained by the Commission, "allowing services and rates unique to every customer would undercut the primary goal of Order No. 888 of providing for non-discriminatory open access transmission."[44]

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[40] *See* LG&E/KU OATT, Section 30.4.

[41] Balmer Affidavit at P 19. In Order No. 890-B, the Commission clarified:

> to the extent necessary, that there is no *per se* prohibition on a transmission customer using both point-to-point and network transmission service, but that any use of point-to-point service by a network customer does not decrease the size of the network customer's load for purposes of calculating its load ratio share payment obligations except to the extent the discrete load being served has been excluded in its entirety from network service.[41]

Order No. 890-B, 123 FERC ¶ 61,299 at P 219 (2008).

[42] Complaint at 14–15.

[43] *Id.* at 15.

[44] *Fla. Power & Light Co.*, 116 FERC ¶ 61,012 at P 14 (2006).

2. EKPC Misapplies Order No. 888 and 888-A

EKPC argues that its proposal is consistent with the Commission's directives in Order Nos. 888, 888-A, and 888-B. EKPC's arguments do not withstand scrutiny. In Order No. 888-A, the Commission held that "splitting a discrete load is antithetical to the concept of network service."[45]

In discussing Order No. 888-A, EKPC notes that,

> [t]he Commission rejected the argument that a customer receiving Network Service in control area A should be able to serve load in control area B without that load being designated as additional Network Load in control area A. In so ruling, the Commission stated that, "[b]ecause the additional transmission service to non-designated network load outside of the transmission provider's control area is a service for which the transmission provider must separately plan and operate its system beyond what is required to provide service to the customer's designated network load, it is appropriate to have an additional charge associated with the additional service."[46]

EKPC states it meets this test because

> Whenever East Kentucky uses [LG&E/KU] transmission service to serve the East Kentucky Network Load on the [PJM] system with Bluegrass output, which only will be during the hours when Bluegrass output exceeds the amount of East Kentucky load connected to [LG&E/KU's] system, the "Network Load" value for the amount of Bluegrass output delivered to the East Kentucky-connected load will be included in the determination of East Kentucky's coincident peak for billing under East Kentucky's NITSA with [LG&E/KU].[47]

The Commission, however, never intended load ratio share to be a measure of positive generation imbalance. Rather it is based on the requirements of the physical demand at discrete metered points. EKPC's determination to only be charged based on generator imbalances within

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[45] Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,259.

[46] Complaint at 17.

[47] *Id.* at 18.

its control is the type of gaming the Commission sought to prevent by requiring all load at discrete points be designated.[48]

EKPC notes that when adopting the *pro forma* tariff, the Commission stated, "[we] did not intend for a transmission provider to receive two payments for providing service to the same portion of a transmission customer's load. Any such double recovery is unacceptable and inconsistent with cost causation principles."[49] EKPC omits the next sentence of Order No. 888-A which states, "[n]either did the Commission intend to allow a transmission customer to designate less than its total load as network load at a discrete point of delivery even though a portion of that load is served under a pre-existing contract."[50]

What EKPC fails to address is that the service it is requesting was specifically rejected by the Commission in Order No. 888-B.[51] In response to a comment that a network customer can integrate loads and resources in multiple control areas only by purchasing network service in each control area and point-to-point service for transmission between the control areas, the Commission discussed the options available to a customer desiring to serve load in two control areas:

- In this regard, we also disagree with TDU Systems' assertion that we have required a network customer to assign a designated network resource to a single control area and limit the scheduling of such resources to serve load in a single control area. Tariff sections 30.6 and 31.3 allow for the designation of both network resources and network loads that are not physically interconnected with the transmission provider. Under the pro forma tariff, a network customer that seeks network service for all of its loads in multiple control areas may designate all such loads as network loads. By designating all of its loads as network loads, such network customer will receive comparable service in each control area and

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[48] Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,259 (a split system (with only part of the load designated) "creates the potential for a customer to "game the system," thereby evading some or all of its load-ratio cost responsibility for network services").

[49] Complaint at 18 (*referring to* Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,261-262 (1997)).

[50] Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,262 (1997).

[51] *See* Order No. 888-B, 81 FERC ¶ 61,248 at 62,095-96 (1997).

will have the ability to schedule the output of network resources between and among control areas, just as a transmission provider or other network customer would need to do to serve load in an adjacent control area.[52]

- Alternatively, a network customer with resources and load in multiple control areas may elect to designate only such load that is located in a single control area as its designated network load and separately arrange for transmission service (e.g., point-to-point service) to serve load in adjacent control areas from generation resources located in the control area in which it designated its network load. Here too the network customer would be receiving comparable transmission service because a transmission provider or any other network customer seeking to serve load in an adjacent control area would also have to arrange for point-to-point transmission service to make the service possible.[53]

These are in fact the exact two options LG&E/KU have offered to EKPC, but which EKPC continues to find objectionable. Instead, EKPC insists on a third option, that of designating a fictitious "load" other than an entire discrete load. In an order this year, the Commission found the customer's "request to designate less than its entire load as network load violates both [the] OATT and longstanding Commission policy, which require network customers to designate their entire load as network load to receive network service."[54] EKPC's Complaint should be rejected for the same reason.

3. EKPC's Request also Violates the OATT Restrictions on Use of NITS for Off-System Transactions

Section 28.6 of the LG&E/KU OATT prohibits the use of NITS to support energy transfers outside of "discrete" physical load identified as Network Load under the LG&E/KU

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[52] *Id.*

[53] *Id.* at n. 157.

[54] *Ariz. Pub. Serv. Co.*, 151 FERC ¶ 61,191 at P 26 (2015); *see also Fla. Municipal Power Agency v. Fla. Power & Light Co.*, 65 FERC ¶ 61,125, *reh'g dismissed,* 65 FERC ¶ 61,372 (1993), *final order*, 67 FERC ¶ 61,167 (1994), *clarified*, 74 FERC ¶ 61,006 (1996), *reh'g denied,* 96 FERC ¶ 61,130 (2001), *aff'd, Fla. Municipal Power Agency v. FERC,* 315 F.3d 362 (D.C. Cir. 2003), *cert. denied,* 540 U.S. 946 (2003); *Fla. Power & Light Co.,* 105 FERC ¶ 61,287 (2003), *order on reh'g*, 106 FERC ¶ 61,204 (2003), *remanded*, *Fla. Municipal Power Agency v. FERC*, 411 F.3d 287 (D.C. Cir. 2005), *order on remand*, 113 FERC ¶ 61,290 (2005), *order on reh'g,* 116 FERC ¶ 61,012 (2006); *Ameren Servs. Co. v. Prairieland Energy, Inc.*, 131 FERC ¶ 61,125 (2010); *Consumers Energy Co.,* 86 FERC ¶ 63,004 at 65,032 (1999), *aff'd*, Opinion No. 456, 98 FERC ¶ 61,333 (2002).

OATT.[55] EKPC states that it intends the positive imbalance of Bluegrass to serve EKPC's load in PJM connected to the EKPC transmission facilities.[56] There are two problems with this statement. First, EKPC has not identified discrete portions of its load in PJM that would be identified as Network Load under the LG&E/KU OATT. Stated another way, EKPC's load served off of the PJM system is Network Load under the PJM Tariff. It is not Network Load under the LG&E/KU OATT.

Second, there are no proposed limitations that would prevent PJM from dispatching Bluegrass to serve demand elsewhere in PJM. There is no assurance that the winter peaking need identified by EKPC[57] is consistent with PJM as a whole.[58] Permitting NITS to serve non-discrete loads outside the Transmission Provider's system in this manner is a violation of the *pro forma* Section 28.6 and would sanction an unprecedented practice applicable to other Transmission Providers and Transmission Customers beyond the specific case of EKPC.

B. EKPC's Request to Modify the OATT Should Be Rejected

EKPC states that to the extent the Commission finds that LG&E/KU have acted in accordance with the OATT, the Commission should find the OATT "unjust and unreasonable as applied to [EKPC]."[59] This request is without merit. The Commission should deny any attempt

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[55] Section 28.6 provides:

> The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission System.

[56] Complaint at 8.

[57] *Id.* at 12.

[58] Assuming that EKPC bids Bluegrass into the PJM capacity and energy markets, the unit can be dispatched by PJM in any of up to 613 hours to meet needs outside of EKPC's own zone. (According to the Complaint at Attachment 2, Affidavit of David Crews at P 12, Bluegrass is environmentally restricted to run 7% or 613 of the 8,760 hours in a year).

[59] Complaint at 25.

to modify the OATT to permit the proposed extremely inefficient use of the LG&E/KU Transmission System.

1. Good Cause Supports the Requirement to Designate Actual Load

As a Transmission Provider under the OATT, LG&E/KU must, *inter alia*, calculate and post ATC, release unscheduled firm transmission service for non-firm use, and plan their system to support the needs of Network Customers as well as Native Load. EKPC's request will create inefficiencies and complications for each of these important responsibilities.

As explained in the affidavit of Christopher Balmer, EKPC's proposed service request would require LG&E/KU to set aside ATC on the applicable flowgates.[60] The NERC MOD-030 standards covering the AFC calculation methodology do not contemplate this type of "hybrid" transmission service. MOD-030, R6.1, the standard pertaining to the calculation of Existing Transmission Commitments, states that the impact of firm Network Integration Transmission Service, including the impacts of generation to load, should be based on load forecast for the time period being calculated and the unit commitment and dispatch order.[61] Since EKPC is not designating load as required under the OATT for NITS, a reliable load forecast will not be available for the proposed Bluegrass Delivery point.

EKPC's request would, for example, restrict transfer capacity from LG&E/KU to PJM, first by up to 283 MW and, after May 2019, by up to 476 MW to support any potential positive energy imbalance EKPC would have between its Network Resources and Network Load in that hour.[62] NITS is a firm service. To ensure potential deliverability, prevent oversubscription of firm transmission service, and limit reliance on transmission loading relief procedures, this

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[60] Balmer Affidavit at P 14-15.

[61] *Id*. at P 14.

[62] *Id*. at P 15.

transmission capacity would be withheld from use by other potential customers even though, by EKPC's own admission, Bluegrass is environmentally restricted to run only 7% of the hours in a year.[63] Furthermore, during many of those hours, Bluegrass will be used, in whole or in large part, to support EKPC's Network Load on the LG&E/KU Transmission System.[64] Nevertheless, EKPC confirmed that what it is requesting is for ATC to be held to serve to PJM from the Bluegrass "maxed out" for all hours.[65]

By withholding valuable transfer capacity into PJM and elsewhere on the LG&E/KU Transmission System, EKPC's proposal limits access to the PJM energy market to the benefit of EKPC's other generation located physically within PJM. As Mr. Balmer explains, LG&E/KU already have third party requests for transmission over the interface with PJM.[66]

Moreover, EKPC proposes that its "Bluegrass Delivery Point" deliveries be calculated on an after-the-fact basis, which complicates the ability to release this predominately unused transmission capacity for non-firm use. In accordance with NERC reliability criteria MOD-030, R6.2, NITS reservations are effectively "released" in the Available Flowgate Capacity process

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[63] *See* Complaint at Attachment 2, Affidavit of David Crews at P 12.

[64] EKPC states,

> For the first few years of East Kentucky's ownership, only two of the three Bluegrass units will be available for East Kentucky's use because the output of the third unit is committed under a power purchase contract with [LG&E/KU] until May 1, 2019. During that time, it is unlikely that the Bluegrass output will exceed the East Kentucky load on the [LG&E/KU] system at the time of [LG&E/KU]'s system peak. East Kentucky expects the same will be true during a majority of the off-peak hours as well.

Complaint at 11. EKPC also writes,

> After May 1, 2019, all three Bluegrass units will be available to East Kentucky. However, by then, East Kentucky forecasts that its peak load on the [LG&E/KU] system may exceed 600 MW. Because of this increase in demand on the [LG&E/KU] system, and because of the peaking nature of the plant and NOx restrictions, the Bluegrass output will likely exceed East Kentucky's [LG&E/KU]-connected load during only a limited number of hours each year.

Complaint at 12.

[65] Balmer Affidavit at P 6.

[66] *Id.* at P 16.

by the use of the customer forecasted loads and block dispatch of designated Network resources for the time period being calculated.[67] Since EKPC is not designating load as required under the OATT for NITS, a reliable load forecast will not be available for the proposed Bluegrass Delivery point. Moreover, the dispatch signal to Bluegrass may be associated with needs on the PJM system within or outside of the EKPC Zone. Thus, it is harder to determine the non-firm AFC.

Furthermore, in accordance with Section 28.2 of the OATT, LG&E/KU are responsible for planning their transmission system to meet the needs of their Network Customers. Mr. Balmer demonstrates the problems EKPC's proposal presents for LG&E/KU's transmission planning process. [68] EKPC would have LG&E/KU account for a 476 MW of potential imbalance service that can appear, in whole or in part, in any of a limited number of hours over the course of a given year. Unlike physical load that is predicated on historical usage patterns and meteorological conditions, EKPC could vary the imbalance amounts exported off the LG&E/KU Transmission System based on its use of its portfolio of Network Resources.[69] This variability compromises effective planning of the LG&E/KU system.

As a complainant, EKPC bears the burden of proof to show that a rate, or in this case LG&E/KU's approved version of the Commission's *pro forma* OATT, is unjust and unreasonable.[70] EKPC has not met its burden. In particular, EKPC's Complaint fails to identify the harms its preferential treatment would impose on other Transmission Customers and LG&E/KU as the non-discriminatory Transmission Provider. EKPC's request would set a new

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[67] *Id.* at P 17.

[68] *Id.* at P 18.

[69] *Id.*

[70] 16 U.S.C. § 824e(b) (2013).

precedent for Transmission Providers and other Transmission Customers whereby NITS service could be used to support transactions outside of service to discrete Network Loads. The Commission should reject the Complaint.

2. EKPC Statements as to Potential Costs Do Not Withstand Scrutiny

EKPC makes the statement that it will be forced to spend an additional $10 million in Point-to-Point Transmission Service charges or purchase "several hundreds of megawatts of additional network service."[71] But EKPC's $10 million estimate for Point-to-Point Transmission Service charges does not fairly represent EKPC's options, and EKPC provides no support for the purported amount of necessary additional network service. Moreover, EKPC has misstated the scope and substance of its discussions with LG&E/ KU.

In particular, EKPC claims that LG&E/KU "insists that EKPC either: (1) reserve and pay for several hundreds of megawatts of excessive and duplicative Point-to-Point service that would increase [LG&E/KU]'s annual transmission charges to East Kentucky from approximately $7 million to approximately $17 million; or (2) purchase several hundreds of megawatts of additional Network Service."[72] Neither statement is correct. To be clear, as described in the affidavit of Christopher Balmer, LG&E/KU have presented options and have not suggested any particular course.[73] EKPC can submit a request to the Independent Transmission Operator ("ITO") for the desired amount of Point-To-Point transmission capacity from LG&E/KU to PJM and go through the OATT process to procure and pay for the requested service. EKPC may reserve any amount of Point-To-Point Transmission Service on a long-term, yearly, monthly or daily basis or even non-firm hourly Point-To-Point Transmission Service.

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[71] Complaint at 2.

[72] *Id.*

[73] Balmer Affidavit at P 7.

With respect to the potential cost of utilizing additional Point-to-Point Transmission Service, LG&E/KU reviewed EKPC's actual load (connected to the LG&E/KU Transmission System) for the period July 1, 2014 to June 30, 2015 and identified the highest 600 hours of load in the winter months (December, January, and February), the periods most likely to require the services of a peaking resource such as Bluegrass.[74] These 600 hours were spread across 64 unique days.[75] LG&E/KU then compared these hourly loads to the maximum Bluegrass generation for both the initial two units (which resulted in a maximum difference of 39 MW) and then the addition of the third unit (which resulted in a maximum difference of 231 MWs).

For illustrative purposes, if EKPC utilizes Point-to-Point Transmission Service for an assumed total of 39 MW of excess output above their discrete load on the LG&E/KU Transmission System, it would cost $179,244 for three months of monthly firm Point-to-Point Transmission Service; $177,216 for 64 days of daily firm Point-to-Point Transmission Service; and $37,429 for 8,430 MWhs of hourly non-firm service.[76] For 231 MW of transmission service, the prices increase to $1,061,676 for three months of monthly firm Point-to-Point Transmission Service; $1,049,664 for 64 days of daily firm Point-to-Point Transmission Service; and $510,254 for 114,922 MWhs of hourly non-firm service.[77] Regardless of the exact calculations, the above example serves to illustrate clearly that the cost to EKPC for transmission service could, at EKPC's choosing, be significantly less than the additional $10 million EKPC claims in its Complaint.

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[74] Balmer Affidavit at P 21-22.

[75] *Id.*

[76] *Id.*

[77] *Id.*

Use of additional network service is also straightforward. EKPC can apply for service with the ITO and define the additional discrete EKPC points of delivery in PJM to be designated as additional Network Load and go through the OATT process to procure the service. All designated Network Loads, including the added discrete EKPC load in PJM, would be metered at the load points and billed at the LG&E and KU coincident monthly peak OATT rate.

With regard to the option of designating additional Network Load points, EKPC has stated:

> EKPC understands that it must designate "load" associated with the service it seeks, which is to deliver incremental output from Bluegrass Station to EKPC load within the EKPC transmission system. However, EKPC interprets load differently than LG&E/KU, such that EKPC could designate an interface point to receive the incremental output from Bluegrass Station on an hourly basis and this would be considered designated Network Load. Regardless, EKPC has no problem with designating specific loads within the EKPC transmission system as Network Loads, but is not in agreement that EKPC should be billed for NITS on the LG&E/KU system when EKPC is not actually using the LG&E/KU transmission system to deliver energy to these loads.[78]

LG&E/KU do not understand this response. In accordance with Section 34.2 of the OATT, NITS customers are charged based on their monthly Network Load "including its designated Network Load not physically interconnected with the Transmission Owner under Section 31.3" coincident with the Transmission Owner's Monthly Transmission System Peak. Thus, there is a usage-based component of the NITS rate based on the actual measurement of the real load being integrated. What EKPC cannot do is fail to identify and measure and pay based upon the entire, discrete EKPC load in PJM associated with the delivery point. There is no ability under the Tariff to use NITS to deliver excess energy not associated with identified, real Network Loads.

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[78] Kentucky PSC Case No. 2015-00267, Response to Supplemental Response 1a to LG&E/KU Supplemental Request for Information filed October 28, 2015.

EKPC also argues that paying for Point-To-Point Transmission Service to deliver power from Bluegrass to EKPC loads external to the LG&E/KU Transmission System while also having NITS service for EKPC loads internal to LG&E/KU is paying for service twice. EKPC is in error. These are two distinctly separate services under the OATT and recognized by the Commission as different services. As the Commission stated in Order 888-A,

> NRECA and TDU Systems, however, argue that network customers located in multiple control areas should not have to pay for any additional point-to-point transmission service to make sales to non-designated load located in a separate control area. We disagree. Because the additional transmission service to non-designated network load outside of the transmission provider's control area is a service for which the transmission provider must separately plan and operate its system beyond what is required to provide service to the customer's designated network load, it is appropriate to have an additional charge associated with the additional service.[79]

Directly contrary to EKPC's arguments, the Commission has determined in Order 888-A that in this exact situation, in which service across multiple control areas is implicated, it is appropriate to have an "additional charge associated with the additional service."

As the Commission concluded in Order No. 890-A, Transmission Customers "ultimately must evaluate the financial advantages and risks and choose to use either network integration or firm point-to-point transmission service to serve load."[80] The Transmission Provider, LG&E/KU, has presented options to EKPC based on the OATT requirements. EKPC's Complaint does not accurately portray these options, many of which can be implemented at costs substantially below the amount cited by EKPC.

3. EKPC Cannot Use a Voluntary Arrangement Accepted by Delegated Authority as Precedent to Support Its Preferential Service

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[79] Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,255 (1997) (citations omitted).

[80] Order No. 890-A, 121 FERC ¶ 61,297 at P 970 (2008).

EKPC notes that in 2012, the Commission accepted for filing an amended Network Service Agreement between Southern Company Services, Inc. ("Southern") and Southern Mississippi Electric Power Association ("SMEPA").[81] In Docket No. ER12-1724-000, the Commission accepted by delegated authority an uncontested arrangement in which Southern voluntarily agreed that SMEPA could use NITS for deliveries at the Purvis Substation calculated as the positive imbalances from its other Network Resources and Network Loads up to a monthly cap.[82] EKPC states, "[n]otably, for the SMEPA-Southern arrangements, no waiver of the Southern Tariff was sought or required, meaning that the arrangements contained in the NITSA were proposed and accepted as being consistent with and conforming to the provisions of the Tariff."[83] EKPC presumes too much. Delegated letter orders are not precedential.[84] There is no Commission precedent that would warrant overturning the plain language of the OATT.

Later in its pleading, EKPC cites the MISO NITSA with AECC in support of its waiver request. While, as discussed below, that proceeding did not even involve a waiver,[85] closer examination reveals that the example of AECC supports LG&E/KU's position and directly contradicts EKPC's proposed use of NITS to export from the LG&E/KU Transmission System. When MISO filed the AECC agreement, the SPP intervened and stated:

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[81] Complaint at 20.

[82] *See Ala. Power Co.*, Docket No. ER12-1724-000, Letter Order Accepting Tariff Filing of Alabama Power Company (Jun. 4, 2013); *Ala. Power Co.*, Docket No. ER12-1724-000, Tariff Filing of Alabama Power Company (May 2, 2013).

[83] Complaint at 24. EKPC states that in 2013, the Commission accepted similar arrangements between SMEPA and MISO in connection with SMEPA's integration into MISO Docket No. ER13-2008. Complaint at 21. The MISO NITSA did not contain the imbalance arrangement reflected in SMEPA's NITSA with Southern.

[84] *See, e.g.*, *Wolverine Power Supply Coop., Inc.*, 135 FERC ¶ 61,165 at P 15 & n.22 (2011) ("The Commission has explained that actions taken by its staff pursuant to delegated authority 'do not constitute Commission precedent binding on the Commission in future cases' and the 'exercise of . . . delegated authority cannot serve to supplant the policies [the Commission] has established in [its] decisions and regulations.") (internal quotations omitted); *PacifiCorp*, 143 FERC ¶ 61,167 at n.10 (2013) ("A delegated letter order does not constitute legal precedent that is binding on the Commission."); *Westar Energy, Inc.*, 124 FERC ¶ 61,057 at P 26 (2008).

[85] *Midcontinent Indep. Sys. Operator Corp.*, 146 FERC ¶ 61,094 (2014).

> All of the AECC resources within SPP have been designated by AECC to serve AECC loads *within SPP* . . . but not AECC loads within EAI. . . . Therefore, SPP would clarify that the SPP NITSA is not currently structured to serve AECC load within EAI, nor does the SPP NITSA recognize that AECC designated resources may be utilized for AECC load located outside of SPP. MISO's claim that AECC's loads are indistinguishable from all its Native Load is not consistent with AECC's current arrangement with SPP. In its transmission service arrangements with SPP, AECC has clearly delineated designated resources for its SPP load and these arrangements do not provide service for AECC's native load requirements within EAI. Likewise, AECC's load existing within EAI's footprint is served by AECC resources located within EAI, and SPP has no direct involvement with the arrangements between AECC and EAI.[86]

SPP's comments emphasize that AECC's SPP NITSA is used only to serve load in SPP. This is the same position LG&E/KU have explained to EKPC. In its Order, the Commission noted,

> AECC states that it does not intend to convert designated network resources in SPP to designated network services in MISO, and AECC acknowledges that its existing transmission service arrangements within SPP were not designed to address transmission services needs in the Entergy Arkansas Local Balancing Authority area.[87]

Indeed, "AECC and MISO aver[red] that the proposed NITSA is not intended to affect the terms and conditions of existing SPP service."[88] Accordingly, the Commission's acceptance was "without prejudice to any necessary arrangements AECC must make with SPP regarding the pseudo-tie or any transmission service on SPP's transmission system."[89] EKPC's example of AECC fails to support its Complaint.

An uncontested letter order issued under delegated authority cannot be used to reverse longstanding precedent regarding the permissible uses of NITS. The Commission has

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[86] *Midcontinent Indep. Sys. Operator Inc.*, Docket No. ER14-684-000, Motion of Southwest Power Pool, Inc. to Accept Comments Out of Time and Comments at 5 (Jan. 23, 2014) (emphasis in original).

[87] *Midcontinent Indep. Sys.Operator, Inc*., 146 FERC ¶ 61,094 at P 36 (2014).

[88] *Midcontinent Indep. Sys. Operator Inc.*, Docket No. ER14-684-000, Arkansas Electric Cooperative Corporation's Answer to Motion to File Comments Out of Time and Comments of Southwest Power Pool, Inc. at 3 (Feb. 7, 2014).

[89] *Midcontinent Indep.t Sys. Operator, Inc*., 146 FERC ¶ 61,094 at P 45 (2014).

recognized that transmission providers are not required to offer service beyond the OATT requirements.[90] LG&E/KU have acted reasonably and in accordance with Good Utility practice in not agreeing to a request that, while it would benefit that particular customer, would create inefficiencies on the LG&E/KU Transmission System.

C. EKPC Has Not Met the Requirements for a Waiver

As an alternative form of relief, EKPC requests "waiver of Section 31.3 of the [LG&E/KU] Tariff" and acceptance of their proposed non-conforming agreement.[91] In evaluating waiver requests, the Commission considers whether: (1) the applicant was unable to comply with the tariff provision at issue in good faith; (2) the waiver is of limited scope; (3) a concrete problem will be remedied by granting the waiver; and (4) the waiver would not have undesirable consequences, such as harming third parties.[92] A waiver must meet all four criteria. EKPC's request fails these requirements.

As explained previously, EKPC's request for a preferential, non-conforming NITSA would have a profound negative effect on other Transmission Customers and impair efficient utilization of the LG&E/KU Transmission System. The Commission must not countenance granting a waiver that will result in this harm.

With respect to the limited scope requirement, the Commission considers whether the request is for a limited duration. For example, in *Southwest Power Pool, Inc.*,[93] the Commission determined that Southwest Power Pool, Inc.'s request for a limited waiver to delay

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[90] *Carolina Power & Light Co.*, 123 FERC ¶ 61,291 at P 20 (2008) ("We accept Progress Energy's proposal to eliminate Network Contract Demand Service effective June 14, 2008, which is after 60 days notice. Progress Energy voluntarily offered Network Contract Demand Service. That service is not required by the Commission under Order Nos. 888 or 890. Therefore, Progress Energy is entitled to no longer make Network Contract Demand Service available (beyond its customers currently receiving that service).").

[91] Complaint at 25.

[92] *Sw. Pub. Serv. Co.*, 150 FERC ¶ 61,128 at P 33 (2015).

[93] *Southwest Power Pool, Inc.*, 144 FERC ¶ 61,223 (2013).

implementation of systematic and automated curtailment rules in its tariff for the period from March 19, 2013 to June 1, 2013 was "of limited scope and duration."[94] Similarly, in *New York Independent System Operator, Inc.*,[95] the Commission found that the New York Independent System Operator, Inc.'s request for limited waiver of sections of its tariff that apply a formula for calculation of congestion payments was "limited in scope and duration in that it is limited solely to the month of January 2014."[96] In contrast, the Commission found that Allegheny Generating Station LLC's request for temporary waiver of a tariff provision setting forth how to calculate unforced capacity was not limited in scope when it covered three consecutive Capability Periods spanning eighteen months, stating "[w]e question whether a waiver in this context – covering three capability periods – is truly limited in scope."[97]

In this case, EKPC is seeking a waiver of Section 31.3 of the LG&E/KU OATT to adopt the amended NITSA as a non-conforming agreement.[98] Under the unexecuted amended NITSA attached to the Complaint, the termination date of the agreement is 2026.[99] Unlike the limited waivers in *Southwest Power Pool, Inc.* and *New York Independent System Operator, Inc.*, which lasted several months, EKPC's waiver would be in effect for eleven years, far exceeding the eighteen month waiver rejected by the Commission in *Allegheny Generating Station LLC*. Because the requested waiver is not limited in scope, the Commission should deny EKPC's request for waiver of Section 31.3 of the LG&E/KU OATT.

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[94] *Id.* at P 51.

[95] *N.Y. Indep. System Operator, Inc.*, 147 FERC ¶ 61,138 (2014).

[96] *Id.* at P 13.

[97] *Allegheny Generating Station LLC*, 147 FERC ¶ 61,147 at P 19 (2014).

[98] Complaint at 25.

[99] *See* Complaint, Attachment 1.

In support of its waiver request, EKPC cites *Midcontinent Independent System Operator Inc.*[100] This case, however, was not decided on waiver grounds. The Commission accepted the non-conforming NITSA because:

> While section 31.3 of MISO's Tariff is an approved deviation from the Commission's *pro forma* open access transmission tariff (OATT), section 31.3 of the *pro forma* OATT provides the option of designating Network Load that is not physically interconnected with the transmission provider's system. Thus, we find that the inclusion of SMEPA's pseudo-tied load in the NITSA is just and reasonable because it is consistent with the flexibility provided under section 31.3 of the *pro forma* OATT.[101]

The Commission accepted the non-conforming NITSA and reaffirmed the *pro forma* version of OATT Section 31.3 – the same provision currently reflected in the LG&E/KU OATT. Stated another way, the Commission did not "waive" LG&E/KU's version of Section 31.3 but rather accepted a NITSA based on it. Indeed, the only use of "waiver" in the letter order is in reference to the requested effective date.

As noted above, EKPC also cites to the MISO NITSA with AECC in support of its waiver request. Again, the proceeding involved acceptance of a non-conforming NITSA and not the granting of a waiver[102] and LG&E/KU have already explained how SPP protested any exports of AECC Network Resources under SPP's tariff to MISO and how MISO and AECC acceded to SPP's position.[103]

EKPC has failed to support its request for a waiver of Section 31.3 of the LG&E/KU OATT. EKPC seeks preferential and improper use of a NITSA that would negatively affect other customers through a reduction of ATC. The arrangement is not limited in duration but

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[100] *Midcontinent Indep. Sys. Operator Inc.*, 145 FERC ¶ 61,242 (2013).

[101] *Id.* at P 11.

[102] *Midcontinent Indep. Sys. Operator Corp.*, 146 FERC ¶ 61,094 (2014).

[103] *See Midcontinent Indep. Sys. Operator Inc.*, Docket No. ER14-684-000, Arkansas Electric Cooperative Corporation's Answer to Motion to File Comments Out of Time and Comments of Southwest Power Pool, Inc. at 3 (Feb. 7, 2014).

proposed to be in place for decades. The precedent cited by EKPC does not involve requests for waivers and, upon closer examination, supports LG&E/KU's reasonable interpretation of the OATT. Accordingly, EKPC's request should be denied.

D. EKPC Should Have Requested LG&E/KU to File an Unexecuted Amended NITSA

As explained in the Affidavit of Christopher Balmer, EKPC submitted an original Request for NITS service for Bluegrass Units 1 and 2 on November 26, 2014.[104] This request was granted on June 11, 2015 (limited to serve load on the LG&E/KU Transmission System).[105] On April 29, 2015, EKPC filed a request for NITS service for Unit 3. [106] This request, with the same limitation, was approved on October 5, 2015.[107] On October 28, 2015, *two days prior to filing the Complaint*, EKPC submitted two additional TSRs:

(1) 81823340 for 283MW from 1-1-2016 to 5-1-2019 with this comment - To make BLGR 1 and 2 DNRs for EK load on the EK system. EKPC is designating an interface delivery point that represents the hourly difference between the output of these units and EK load on the [LG&E/KU] system. 283 MW is the max difference projected; and

(2) 81823354 for 476MW from 5-1-2019 to 5-1-2024 with this comment - To make BLGR 1,2,& 3 DNRs for EK load on the EK system. EKPC is designating an interface delivery point that represents the hourly difference between the output of these units and EK load on the [LG&E/KU] system. 476 MW is the max difference projected.[108]

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[104] Balmer Affidavit at P 3.

[105] *Id*.

[106] *Id*.

[107] *Id*.

[108] *Id*. at P 4.

Under Section 29.1 of the OATT, the Transmission Customer is to make a request. If the request is denied, the appropriate remedy is to request the service agreement to be filed unexecuted.[109] EKPC has ignored this process.[110]

The Commission has stated,

> When we stated in Order Nos. 888 and 888-A that we would consider alternative proposals for allocating the cost of network integration and would evaluate those alternatives on the merits on a case-by-case basis, we intended those alternative proposals to come from the utilities who we were directing, in those rulemakings, to file open access transmission tariffs; if a transmission provider believed that an alternative arrangement made more sense for its system… However, we did not intend for each and every customer of a transmission provider to have the opportunity to demand that the transmission provider create alternative services which benefit that particular customer, *i.e.*, we did not intend to create the option of separate and individual customer-by-customer transmission services and rates.[111]

EKPC's Complaint is a transparent demand that LG&E/KU as the Transmission Provider "create alternative services which benefit that particular customer." EKPC has failed to sustain its burden that LG&E/KU have violated their OATT, that the OATT is unjust or unreasonable,[112] or that it meets the requirements for a waiver.[113] Whether by means of denying this Complaint filed under Section 206 or by means of denying an EKPC protest to the filing of an unexecuted

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[109] LG&E/KU OATT, Section 29.1 ("Subject to the terms and conditions of Part III of the Tariff, the Transmission Owner will make available Network Integration Transmission Service to any Eligible Customer, provided that . . . the Eligible Customer executes a Service Agreement pursuant to Attachment F for service under Part III of the Tariff or requests in writing that the Transmission Owner file a proposed unexecuted Service Agreement with the Commission.") (emphasis added).

[110] In accordance with Rule 206(b)(6), EKPC states that the specific matters raised in this Complaint are not pending before the Commission in any docket. While correct as of this moment, EKPC knows that LG&E/KU is planning on filing the amended NITSA to add Bluegrass this month.

[111] *Fla. Power & Light Co.*, 113 FERC ¶ 61,290 at P 6 (2005); *see also Id*. at P 7 ("That customer, however, is not permitted to craft a transmission service unique to its circumstances, but which is not offered by the transmission provider.").

[112] 16 U.S.C. § 824e(b) (2013).

[113] *Sw. Pub. Serv. Co.*, 150 FERC ¶ 61,128 at P 33 (2015).

NITSA by LG&E/KU under Section 205, the Commission should reject the preference requested by EKPC.

V. CONCLUSION

WHEREFORE, for the foregoing reasons, LG&E/KU respectfully request that the Commission deny EKPC's Complaint.

Respectfully submitted,

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Counsel for LG&E/KU

Dated: November 23, 2015
Washington, DC

CERTIFICATE OF SERVICE

I hereby certify that on this 23rd day of November, 2015, I have served a copy of the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

/s/ Thomas S. DeVita
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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

LOUISVILLE GAS AND ELECTRIC/	**)**	**Docket Nos. EL16-8-000**
KENTUCKY UTILITIES COMPANY	**)**	
	)	
	)	

AFFIDAVIT OF

CHRISTOPHER D. BALMER

LOUISVILLE GAS AND ELECTRIC
KENTUCKY UTILITIES COMPANY

Filed: November 23, 2015

AFFIDAVIT OF CHRISTOPHER D. BALMER

1. My name is Christopher Balmer. I am the Director of Transmission Strategy and Planning for LG&E/KU. As part of my duties, I am responsible for administration of LG&E/KU's responsibilities as the Transmission Owner under the LG&E/KU Joint *Pro Forma* Open Access Transmission Tariff ("OATT"). My business address is 220 West Main Street, Louisville, Kentucky, 40202. A complete statement of my education and work experience is attached to this affidavit as Exhibit No. 1.

2. LG&E and KU each own transmission facilities in Kentucky. Since LG&E and KU merged in 1998, their facilities have been operated as a single integrated transmission system. The rates, terms, and conditions of service over the combined LG&E/KU Transmission System are governed by the LG&E/KU OATT on file with the Federal Energy Regulatory Commission ("FERC" or the "Commission"). The LG&E/KU OATT generally follows the *pro forma* OATT promulgated by the Commission in Order Nos. 888 and 890. LG&E/KU are the Transmission Owner under their OATT, and they have delegated certain transmission-related functions to TranServ International, Inc. as the Independent Transmission Organization ("ITO"), and the Tennessee Valley Authority ("TVA") as the Reliability Coordinator. Broadly speaking, TVA is responsible for compliance with the North American Electric Reliability Corporation ("NERC") reliability standards applicable to Reliability Coordinators. The ITO is responsible for evaluating transmission service requests, processing applications, and conducting system impact studies. LG&E/KU as the Transmission Owner are responsible for operating the Transmission System and providing transmission service.

EKPC Transmission Service Requests for Bluegrass

3. On November 26, 2014, EKPC requested to add Bluegrass Units 1 and 2 as designated Network Resources under its existing Network Integration Transmission Service Agreement ("NITSA"). EKPC submitted a similar request for Bluegrass Unit 3 on April 29, 2015. TranServ, acting as LG&E/KU's ITO, received, studied, and granted Network Service from the Bluegrass units solely to serve EKPC load on the LG&E/KU Transmission System. Approval for Bluegrass Units 1 and 2 was granted on June 11, 2015, and approval for Bluegrass Unit 3 was granted on October 5, 2015.

4. On October 28, 2015, EKPC submitted new transmission service requests related to Bluegrass:

   - 81823340 for 283MW from 1-1-2016 to 5-1-2019 with this comment - To make BLGR 1 and 2 DNRs for EK load on the EK system. EKPC is designating an interface delivery point that represents the hourly difference between the output of these units and EK load on the [LG&E/KU] system. 283 MW is the max difference projected.

   - 81823354 for 476MW from 5-1-2019 to 5-1-2024 with this comment - To make BLGR 1,2,& 3 DNRs for EK load on the EK system. EKPC is designating an interface delivery point that represents the hourly difference between the output of these units and EK load on the [LG&E/KU] system. 476 MW is the max difference projected.

   These requests are currently under review by the ITO.

Other Meetings Between LG&E/KU and EKPC Concerning Bluegrass

5. Representatives from EKPC have had several communications with LG&E/KU related to EKPC's desire to have additional transmission service for those occasions when Bluegrass generation might exceed EKPC's load on the LG&E/KU Transmission System. For example, on August 25, 2015, LG&E/KU participated in a conference call with EKPC and the ITO. On September 8, 2015 a meeting was held between EKPC,

LG&E/KU, and the ITO. On September 29, 2015, LG&E/KU and EKPC had another conference call, and on October 8, 2015, LG&E/KU and EKPC held a meeting, joined by their respective legal counsels, who shared their interpretation of the OATT and FERC Order Nos. 888 & 890.

6. During these discussions, EKPC confirmed it was requesting firm capacity to be available to PJM from Bluegrass (maxed out) for all hours. LG&E/KU concluded that accepting a non-conforming OATT transmission arrangement, as EKPC proposed, would be inconsistent with the OATT, result in unacceptable negative impacts to other customers, and impair efficient operation of the Transmission System. LG&E/KU expressed these sentiments to EKPC. EKPC stated that what it was requesting "conformed" to the OATT. LG&E/KU informed EKPC that they disagreed with this interpretation but if EKPC believed its proposal was conforming, then EKPC should submit its proposal to the ITO as the Administrator of the LG&E/KU OATT.

7. During the meetings with EKPC, LG&E/KU presented options to EKPC. LG&E/KU never insisted on a particular type of service or quantity of service. LG&E/KU provided explanations as to what requests would be consistent with the OATT requirements.

Non-Conforming Nature of EKPC's Request

8. Under the OATT, Transmission Customers may request Firm and Non-Firm Point-To-Point Transmission Service for the receipt of capacity and energy at designated Point(s) of Receipt, and the transfer of capacity and energy to designated Point(s) of Delivery. Transmission Customers may also request Network Integration Transmission Service ("NITS") to deliver capacity and energy from designated Network Resources to serve

discrete Network Loads. Transmission Customers may file transmission service requests with the ITO at any time.

9. "Network Load" under Section 1.25 of the LG&E/KU OATT, must include the entire load at "discrete" Points of Delivery.

> A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

10. Section 31.3 of the LG&E/KU OATT addresses Network Load not physically interconnected with the LG&E/KU Transmission System and states:

> This section applies to both initial designation pursuant to Section 31.1 and the subsequent addition of new Network Load not physically interconnected with the Transmission Owner. To the extent that the Network Customer desires to obtain transmission service for a load outside the Transmission Owner's Transmission System, the Network Customer shall have the option of (1) electing to include the ***entire*** load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Point-To-Point Transmission Service under Part II of the Tariff. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

11. EKPC's request for the creation of a new point of service, the "Bluegrass Delivery Point," is not based on a physical customer demand for electricity (i.e., there is no real, discrete load associated with the "Bluegrass Delivery Point"), but simply represents a positive imbalance between EKPC's Bluegrass Network Resources and its physical Network Loads on the LG&E/KU Transmission System. According to EKPC,

> The minimum value for the Network Load for the Bluegrass Delivery Point shall be zero. The maximum value of the Bluegrass Load during a calendar month shall not exceed the higher of: (1) the amount of Transmission Customer Network Load located in the LG&E/KU Balancing Authority Area, excluding the load associated with the Bluegrass Delivery Point; or (2) the total output of the Bluegrass Facility.

12. EKPC seeks to serve an undefined portion of its load on the PJM system or to make sales into the PJM market based on occasional hourly positive energy imbalances resulting from the differences in the output of designated Network Resources and physical Network Loads served from the LG&E/KU Transmission System. EKPC states on page 8 of its Complaint that it intends the positive imbalance of Bluegrass to serve EKPC's load in PJM. First, EKPC has not identified discrete portions of its load in PJM that would be identified as Network Load under the LG&E/KU OATT. Second, there are no proposed limitations that would prevent PJM from dispatching Bluegrass to serve demand elsewhere in PJM. Section 28.6 of the LG&E/KU OATT prohibits the use of NITS to support energy transfers outside of "discrete" physical load identified as Network Load under the LG&E/KU OATT. It provides:

> The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non- designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission System.

13. Energy imbalance is not a discrete load. To utilize NITS for the additional potential output of Bluegrass, beyond the currently-existing levels of Network Load, EKPC will have to identify an additional discrete Point of Delivery or Points of Delivery that can be separately metered.

Negative Impacts of EKPC's Non-Conforming Requests

1. Impairment of Available Transfer Capability

14. The NERC MOD-030 standards that cover the Available Flowgate Capability ("AFC") calculation methodology do not contemplate the type of "hybrid" transmission service requested by EKPC. MOD-030, R6.1 of the standard pertaining to the calculation of Existing Transmission Commitments ("ETC") states that the impact of firm NITS, including the impacts of generation to load, should be based on load forecast for the time period being calculated and the unit commitment and dispatch order. Again, since EKPC is not designating load as required under the OATT for NITS, a reliable load forecast will not be available for the proposed Bluegrass delivery point.

15. EKPC's request would, for example, restrict transfer capacity from LG&E/KU to PJM, first by up to 283 MW and, after May 2019, by up to 476 MW to support any potential positive energy imbalance EKPC would have between Bluegrass generation and its Network Load on the LG&E/KU Transmission System in that hour. NITS is a firm service. LG&E/KU would need to ensure potential deliverability, prevent oversubscription of firm transmission service, and limit reliance on transmission loading relief procedures. Thus, this capacity would be withheld from use by other potential customers even though, by EKPC's own admission, Bluegrass is environmentally restricted to run only 7% of the hours in a year. By withholding valuable transfer capacity into PJM and elsewhere on the LG&E/KU Transmission System, EKPC's proposal limits access to the PJM energy market, impairs efficient utilization of the Transmission System, and doesn't provide compensation for the reservation to PJM which reduces transmission cost for other Transmission Customers.

16. Other LG&E/KU OATT customers currently purchase (or are requesting) long-term firm Point-to-Point Transmission Service in addition to NITS for off the LG&E/KU Transmission System deliveries, including deliveries to PJM. For example, Kentucky Municipal Power Agency requested 120 MWs of firm Point-to-Point Transmission Service to PJM on October 6, 2015. The existing transmission planning processes and ATC calculations are in place to incorporate modeling inputs from these types of conforming OATT services and not non-conforming arrangements.

2. Impairment of Non-Firm Transmission Service

17. EKPC's proposal, that its "Bluegrass Delivery Point" deliveries be calculated on an after-the-fact basis, complicates the ability to release the unused transmission capacity for non-firm use. Under NERC MOD-030, R6.2, NITS reservations are effectively "released" in the AFC process by the use of the customer-forecasted loads and block dispatch of designated Network Resources for the time period being calculated. Since EKPC is not designating load as required under the OATT for NITS, a reliable load forecast will not be available for the proposed Bluegrass delivery point.

3. Impairment of Transmission Planning

18. In accordance with Section 28.2 of the OATT, LG&E/KU are responsible for planning their transmission system to meet the needs of their Network Customers. EKPC's proposal would have LG&E/KU account for 476 MW of potential imbalance service that can appear, in whole or in part, in any of a limited number of hours over the course of a given year. Unlike physical load that is predicated on historical usage patterns and meteorological conditions, EKPC could vary the imbalance amounts exported off the LG&E/KU Transmission System based on its use of its portfolio of Network Resources.

This variability compromises effective planning of the LG&E/KU system. Without designating Network Load or requesting long-term firm Point-to-Point service under existing OATT offerings, it is unclear what LG&E/KU should plan for in their transmission planning process and how to appropriately calculate ATC.

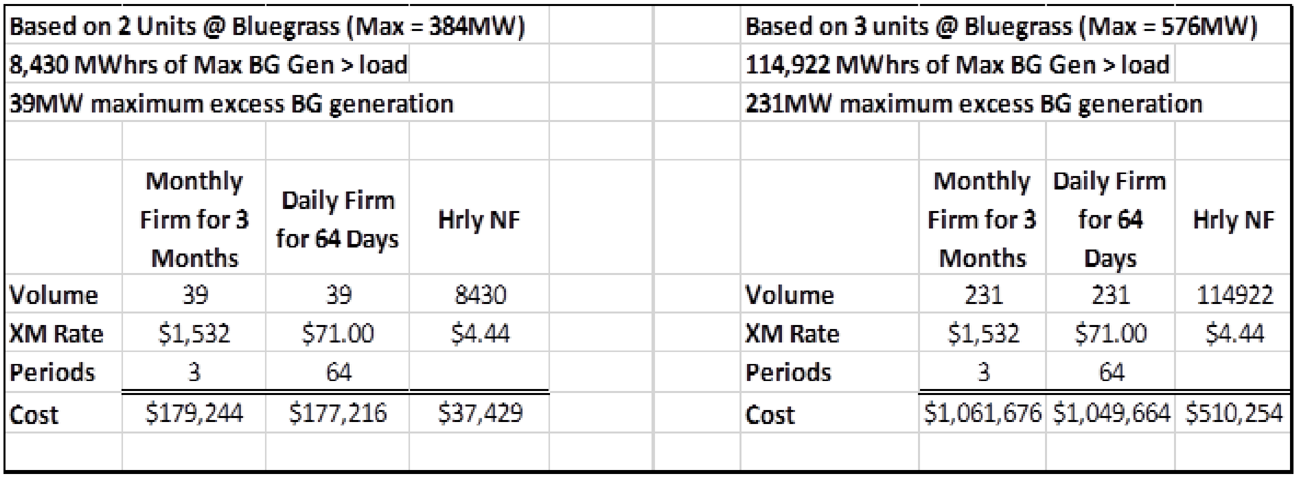
Options Consistent with the OATT

19. LG&E/KU have explained to EKPC that EKPC has two options to deliver the output of Bluegrass over and above the current amount of designated Network Load: (1) purchase Point-to-Point service in any desired amount sufficient to deliver the desired level of output of the Bluegrass units; or (2) designate any number of additional discrete load points within EKPC's system as LG&E/KU Network Load to increase EKPC's minimum designated load to equal the desired level of output of Bluegrass and be billed for that load under the EKPC NITSA with LG&E/KU on a coincident peak demand basis.

20. It is completely within EKPC's own discretion what amount, if any, of Point-to-Point service to request, which additional discrete loads points within EKPC's system, if any, to designate as network load under its LG&E/KU OATT NITS service, and what level of output of Bluegrass to accommodate through transmission service under LG&E/KU's OATT.

21. But for purposes of assessing the potential cost of utilizing additional Point-to-Point Transmission Service, LG&E/KU reviewed EKPC's actual load (connected to the LG&E/KU Transmission System) for the period July 1, 2014 to June 30, 2015 and identified the highest 600 hours of load in the winter months (December, January, and February), the periods most likely to require the services of a peaking resource such as Bluegrass. These 600 hours were spread across 64 unique days. LG&E/KU then

compared these hourly loads to the maximum Bluegrass generation for both the initial two units and then the addition of the third unit, assuming maximum output of Bluegrass units was desired. The results are summarized below for monthly firm, daily firm, and hourly non-firm service.



Based on 2 Units @ Bluegrass (Max = 384MW)						Based on 3 units @ Bluegrass (Max = 576MW)			
8,430 MWhrs of Max BG Gen > load						114,922 MWhrs of Max BG Gen > load			
39MW maximum excess BG generation						231MW maximum excess BG generation			
	Monthly Firm for 3 Months	Daily Firm for 64 Days	Hrly NF				Monthly Firm for 3 Months	Daily Firm for 64 Days	Hrly NF
Volume	39	39	8430			Volume	231	231	114922
XM Rate	$1,532	$71.00	$4.44			XM Rate	$1,532	$71.00	$4.44
Periods	3	64				Periods	3	64	
Cost	$179,244	$177,216	$37,429			Cost	$1,061,676	$1,049,664	$510,254

22. If, for example, EKPC were to utilize Point-to-Point Transmission Service for an assumed total of 39 MW of excess output above EKPC's discrete load on the LG&E/KU Transmission System it would cost $179,244 for three months of monthly firm Point-to-Point Transmission Service; $177,216 for 64 days of daily firm Point-to-Point Transmission Service; and $37,429 for 8,430 MWhs of hourly non-firm service. For a 231 MW reservation, the prices increase to $1,061,676 for three months of monthly firm Point-to-Point Transmission Service; $1,049,664 for 64 days of daily firm Point-to-Point Transmission Service; and $510,254 for 114,922 MWhs of hourly non-firm service. These costs are well below the $10,000,000 cited by EKPC. If less than maximum output of the Bluegrass units were desired, the amounts would, of course, be even less.

23. This concludes my affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

LOUISVILLE GAS AND ELECTRIC/)
KENTUCKY UTILITIES COMPANY)
)
)

Docket Nos. EL16-8-000

County of Jefferson
State of Kentucky

I, Christopher Balmer, being first duly sworn, hereby certify that the foregoing affidavit has been prepared by me, with the assistance of others working under my direction and supervision, and is true and accurate to the best of my knowledge, information, and belief.

Christopher Balmer

SUBSCRIBED AND SWORN to me, this 23rd th day of November, 2015.

Notary Public

My Commission expires on: Jan. 22, 2017

KATHY L. WILSON

Exhibit No. 1

Christopher D. Balmer

Director, Transmission Strategy & Planning
LG&E and KU Energy, LLC
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Louisville, Kentucky 40202
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Education
Indiana University Southeast, B.S. in Business - 1988

Professional Experience
LG&E and KU Energy, LLC
2011-present – Director, Transmission Strategy & Planning
2011-2011 – Manager, Fuels Risk Management
2001-2010 – Trading Manager

LG&E Energy Marketing, Louisville, Kentucky
1998-2000 – Trading Manager
1997-1998 – Product Manager

PennUnion Energy Services, Houston, TX
1996-1997 – Manager, Structuring & Optimization

Tenneco Energy Marketing Co., Houston, TX
1993-1996 – Manager, Midwest Trading, Senior Account Executive, Supervisor, Operations

EnTrade Corporation, Louisville, KY
1990-1993 – Market Strategist, Transportation Specialist

Citizens Fidelity Bank, Louisville, KY
1989-1990 – Assistant Supply Manager

Document Content(s)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

East Kentucky Power Cooperative, Inc.	)	
	)	
v.	)	**Docket No. EL16-8-000**
	)	
Louisville Gas & Electric/	)	
Kentucky Utilities	)	

ANSWER OF TRANSERV INTERNATIONAL TO COMPLAINT

TranServ International, Inc. ("TranServ") submits this answer to the October 30, 2015 complaint filed by East Kentucky Power Cooperative, Inc. ("EKPC") against Louisville Gas & Electric and Kentucky Utilities ("LKE").[1] The complaint asks the Commission to direct LKE to accept EKPC's identification of a new Network Load[2] associated with the existing network integration transmission service that it currently obtains from LKE in order to serve its load connected to LKE's system. EKPC intends to use this new Network Load to transmit energy from the Bluegrass facility, an existing gas-fired generating station connected to LKE's transmission system, to EKPC's native load customers directly connected to EKPC's transmission system during those hours when the output of the Bluegrass facility exceeds EKPC's network load on LKE's transmission system.

TranServ answers this complaint in order to make two points. First, TranServ wishes to correct the record as to its communications with EKPC regarding EKPC's

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[1] TranServ submits this answer pursuant to Rules 206(f) and 213 of the Commission's Rules of Practice and Procedure (18 C.F.R. §§ 385.206(f), 385.213).

[2] Unless otherwise specified, capitalized terms are used herein as defined in LKE's Open Access Transmission Tariff.

request to add a new Network Load at a delivery point representing the difference between the Bluegrass output and EKPC's LKE-connected load. Contrary to EKPC's implication, TranServ, in its role as the Independent Transmission Organization ("ITO") for LKE, has not simply ceded to LKE responsibility for processing EKPC's request. Rather, TranServ has handled EKPC's request in a manner consistent with the procedures set forth in the LKE's Open Access Transmission Tariff ("LKE OATT") for processing and evaluating transmission service requests. Second, TranServ disagrees with EKPC's assertion that its proposal is consistent with the provisions of LKE's OATT. It is clear from the plain language of LKE's OATT that the service requested by EKPC would be non-conforming in nature.

I. Background

As described in EKPC's complaint, EKPC is currently in the process of purchasing the Bluegrass generating facility, a 495 MW gas-fired generating station interconnected to LKE's transmission system. EKPC states that it intends to primarily utilize Bluegrass to serve its load connected to LKE transmission facilities. However, to the extent that the output of Bluegrass exceeds the amount of EKPC load on LKE's system during a particular hour, EKPC wishes to use this additional output to serve EKPC load connected to its own transmission system. In order to facilitate this outcome, EKPC has proposed to designate a new Network Load at a delivery point that would in each hour be the difference between the output of Bluegrass and EKPC's LKE-connected load. The sum of the delivery point requirements in each hour would be the basis for determining EKPC's monthly coincident peak on the LKE system, which is the demand used for billing for network service under the LKE OATT. EKPC just recently submitted an application for transmission service to TranServ reflecting this proposal to designate a new Network Load based on a "virtual" delivery point.

II. Motion to Intervene

TranServ moves to intervene in the above-captioned proceeding and to be granted full party status. TranServ is the ITO for Louisville Gas & Electric and Kentucky Utilities pursuant to the terms of the ITO agreement between LKE and TranServ dated August 29, 2011 ("ITO Agreement") and Attachment P of the LKE OATT. As part of its ITO functions, TranServ is responsible for evaluating transmission service requests under LKE's OATT, including processing applications and conducting system impact studies. Accordingly, TranServ has a direct and substantial interest in the outcome of this proceeding that cannot be adequately represented by any other party.

All service of pleadings and documents and all communications regarding this proceeding should be addressed to the following:

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III. Answer

A. TranServ has Appropriately Responded to EKPC's Request in Accordance with its Responsibilities as the Independent Transmission Organization for LKE's Transmission System.

In its complaint, EKPC states that when it approached TranServ regarding its proposal to designate a new Network Load representing the difference between the output of the Bluegrass facility and EKPC's LKE-connected load, TranServ "simply referred [EKPC] to LKE."[3] This statement mischaracterizes the interactions between EKPC and TranServ. EKPC first informed TranServ of its proposal in the context of discussions that took place this summer regarding EKPC's request to designate Bluegrass as a new Network Resource to serve EKPC's load connected to the LKE transmission system. After completion of the study relating to this request, EKPC presented LKE and TranServ with a proposed amended Network Integration Transmission Service Agreement ("NITSA") that would not only include Bluegrass as a new Network Resource, but would also add a new Network Load representing the delivery to EKPC's transmission system of any output from Bluegrass that exceeded the demand from EKPC's LKE-connected load. TranServ and LKE had two discussions with EKPC in order to better understand the nature of EKPC's request. Subsequently, TranServ also had a meeting with EPKC without LKE participating at which TranServ indicated that the appropriate course of action would be for EKPC to submit an application for a new Network Load in accordance with Sections 29.2 and 31.2 of the LKE OATT.[4]

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[3] EKPC Complaint at 10.

[4] Section 29.2 of the LKE OATT sets forth the application procedures for Network Integration Transmission Service. Section 31.2 states that a transmission customer wishing to add a new Network Load must submit a new application in accordance with Section 29.2.

In late October, EKPC submitted applications for a new Network Load.[5] Consistent with the procedures set for in Section 29.2, TranServ acknowledged the receipt of EKPC's applications and after reviewing the application, contacted EKPC and informed them that it was deficient in two respects.[6] First, EKPC's application did not include a description of the Network Loads at discrete points of delivery on LKE's transmission system, including substation and voltage information, as required under Section 29.2(iii) of the LKE OATT. Second, EKPC's ten year load forecast, as required by that same Section, did not comply with LKE's transmission study application, which requires that customers provide off-peak load data based on a temperature of 70-80 degrees. TranServ informed EKPC that they should resubmit their applications with the appropriate information.[7] On November 20, EKPC submitted revised applications to TranServ with updated off-peak load data, but without descriptions of Network Load at discrete points of delivery.

As explained below, TranServ does not agree with EKPC that its request to include a new Network Load representing the difference between the output of the Bluegrass facility and its LKE-connected load is consistent with the provisions of the LKE OATT. TranServ has appropriately declined to opine on whether a non-conforming amendment should be made to the existing NITSA between EKPC and LKE in order to

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[5] On October 30, 2015, EKPC submitted two applications to modify its existing Network Integration service with LKE, one for service during the period 2016-2018 and the other for service commencing in 2019.

[6] Section 29.2 requires the ITO to acknowledge a request for transmission service within ten days of receipt and notify the customer within 15 days of receipt if the application fails to meet any of the requirements of Section 29.2, specifying the reasons for such failure.

[7] *See* LKE's current network service application, available at http://www.oasis.oati.com/LGEE/LGEEdocs/LGEE_Network_Service_Application_07172015.xls

provide EKPC with such service. Pursuant to the ITO Agreement and the LKE OATT, TranServ's responsibilities include processing and evaluating all requests for transmission service made under the LKE OATT, consistent with the provisions thereof. TranServ has fully, and independently, met those responsibilities in the context of EKPC's request. LKE retains the responsibility for tendering, entering into and filing transmission service agreements, as well as sole authority for filing with the Commission any changes to its tariff.[8] Therefore, although TranServ does not agree with EKPC's assertion that the service it is requesting is contemplated under the existing provisions of LKE's OATT, it is LKE's obligation to determine whether an agreement for non-conforming service and/or request for waiver of its OATT should be filed with the Commission.[9]

B. The Service Requested by EKPC is Not Within the Scope of Transmission Service Available Under LKE's Existing OATT.

EKPC argues that its proposal for designating under its existing LKE NITSA a new Network Load based on the hourly difference between the output of the Bluegrass facility and EKPC's LKE-connected load is consistent with LKE's OATT.[10] However, the relevant language in LKE's existing OATT does not support EKPC's position. The key provision in the LKE OATT (per the Commission's pro forma OATT) is Section 31.3, which provides that a network customer that wishes to designate Network Load that is not physically interconnected to the transmission owner's transmission system may do

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[8] *See* LKE OATT, Attachment P at Sections 3.2.5, 5.3, Appendix 1.

[9] Consistent with its obligation to administer the LKE OATT independently, TranServ would not hesitate to express any concerns it had with such a proposal, particularly in terms of the potential for discriminatory impact to other customers.

[10] EKPC Complaint at 13.

so pursuant to two options: (1) including the entire load as Network Load and designating Network Resources in connection with such load; or (2) excluding the entire Network Load and purchasing Point-to-Point Transmission Service to serve that load. EKPC, however, seeks to utilize what would, in effect, be a third option by defining a new "Network Load" so as to include only that load on EKPC's system that is being served by Bluegrass during a particular hour. As EKPC acknowledges, Section 31.3 must be read in conjunction with the definition of Network Load in the LKE OATT:

> The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangement under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

EKPC's proposal is plainly inconsistent with this language. Significantly, in its applications for Network Service, EKPC fails to identify Network Load at discrete "Point(s) of Delivery," which is defined as a point or points on the transmission system where capacity and energy transmitted will be made available to the Receiving Party.[11] Instead, EKPC proposes what amounts to a "virtual" point of delivery between the LKE and EKPC systems that represents the hourly difference (when positive) between the output of the Bluegrass facility and the amount of EKPC load directly connected to the LKE system.

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[11] *See* LKE OATT, Definition of "Point(s) of Delivery."

Despite the discrepancies between its proposal and the actual language of the LKE OATT, EKPC contends that Commission precedent supports a broader reading of Section 31.3 and the definition of Network Load. However, none of the precedent cited by EKPC supports reading the LKE OATT in the manner EKPC suggests. First, EKPC argues that its proposal is consistent with the Commission's underlying purpose in defining Network Load so as to prohibit partial designation. EKPC claims that the Commission intended to prevent customers from combining Network and Point-to-Point service at a single, discrete delivery point, such as a customer utilizing behind-the-meter generation. EKPC states that this limitation should not apply to it because it "is not a transmission-dependent wholesale customer with behind-the-meter generation" but rather an "interconnected utility with its own transmission system and fleet of generating resources."[12] However, the Commission has never stated that the limit on partial designation only applies to "transmission-dependent wholesale customers" as opposed to "interconnected utilities."[13] The rule against partial designation of Network Load applies to EKPC in the same manner as it does to all other transmission customers.

EKPC also argues that its proposal is consistent with Section 31.3 because the Commission, in Order No. 888-A, stated that a customer receiving Network Service in a control area A should be able to serve load in control area B for an "additional charge," and EKPC proposes to pay an "additional charge" for any difference between the

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[12] EKPC Complaint at 15.

[13] In Order No. 888-A, the Commission used the example of a "municipal power agency" that wished to exclude a portion of the load of a member city with generation behind the meter. A municipal power agency could obviously be a transmission-owning utility in its own right. *See* Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,261, n.249 (1997).

Bluegrass output and its LKE-connected load.[14] However, it is clear from Order No. 888-A that the Commission used the term "additional charge" to specifically refer to the charge associated with a transmission customer obtaining point-to-point transmission service to serve its external load, and not some alternative pricing option.[15] This approach is directly reflected in Section 31.3 of the OATT which, as described above, provides transmission customers with only two options for obtaining transmission service for an external load: either designating the external load as a Network Load, or excluding the entire load from its Network Load and obtaining point-to-point transmission service for such load. There is no third option of the sort proposed by EKPC for service based on the hour-to-hour difference between its internal load and the output of a specific Network Resource such as Bluegrass. As such, there is no merit to EKPC's suggestion that LKE should be compelled, pursuant to the terms of the existing tariff, to provide EKPC transmission service on such terms.

Finally, in support of its proposal, EKPC points to two network service agreements accepted by the Commission that EKPC claims reflect the same solution that EKPC wishes to include in its NITSA with LKE: 1) an amended NITSA between Southern Company and the Southern Mississippi Electric Power Association ("SMEPA"); and 2) a NITSA between SMEPA and the Midcontinent Independent System Operator ("MISO").[16] The SMEPA/Southern agreement was accepted for filing by the Commission through a delegated letter order, which does not represent a

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[14] EKPC Complaint at 17-18.

[15] Order No. 888-A at 30,255 (finding that a transmission customer could exclude a discrete Network Load located in another control area "and to serve such load using point-to-point transmission service").

[16] EKPC Complaint at 20-24.

Commission finding of justness and reasonableness. The proceeding involving the SMEPA/MISO NITSA did not even address the type of arrangement proposed by EKPC, but rather simply involved the Commission granting MISO's proposal to allow a customer to designate Network Load that is not physically connected with its transmission system, per Section 31.3 of the *pro forma* OATT.[17] These examples do not support EKPC's argument that LKE must provide EKPC the requested service under the terms of LKE's OATT.

For these reasons, EKPC's claim that its proposal to designate a new Network Load representing the difference between the output of the Bluegrass facility and EKPC's LKE-connected load represents a service already contemplated under LKE's OATT is without merit, and the Commission should reject it.

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[17] *Midcontinent Independent System Operator, Inc*., 145 FERC ¶ 61,242 at P 11 (2013). At the time of this proceeding, Section 31.3 of MISO's tariff stated that all Network Load must be physically interconnected with a MISO transmission owner or ITC within the geographic region in which facilities subject to the MISO tariff are located.

IV. Conclusion

TranServ respectfully requests that the Commission grant it party status in this proceeding and act on EKPC's complaint consistent with the comments provided herein.

Respectfully submitted,

/s/ Michael Kunselman____

Stephen Palmer
Michael Kunselman
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The Atlantic Building
950 F Street, NW
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Counsel for TranServ International

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon all of the parties listed on the official service list for the above-referenced proceeding, pursuant to the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Washington, D.C. this 23rd day of November, 2015.

/s/ Michael Kunselman
Michael Kunselman

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December 6, 2016

VIA ELECTRONIC FILING

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Request for Change in Service List

Dear Secretary Bose,

Please update the Commission's official service list for docket No.EL16-8-000, including all sub-dockets, to make the following changes in representatives and contact information for East Kentucky Power Cooperative, Inc.

Remove:	**Replace with:**
Alan I. Robbins Debra D. Roby Gary J. Newell Melissa A. Alfano Jennings, Strouss & Salmon, P.L.C. 1350 I Street NW, Suite 810 Washington, D.C. 20005-3305 (202) 371-9030 arobbins@jsslaw.com droby@jsslaw.com gnewell@jsslaw.com malfano@jsslaw.com	Sherman Goodpaster, III Senior Corporate Counsel East Kentucky Power Cooperative, Inc. 4775 Lexington Road P.O. Box 707 Winchester, KY 40392 (859) 745-9375 sherman.goodpaster@ekpc.coop

Thank you for your assistance in this matter.

Very truly yours,

JENNINGS, STROUSS & SALMON, P.L.C.

By Alan Robbins
Alan I. Robbins

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 6th day of December, 2016.

/s/ Emily Ray
Emily Ray
Legal Assistant
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Document Content(s)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

East Kentucky Power Cooperative, Inc.)
)
v.) Docket No. EL16-8-000
)
Louisville Gas & Electric/Kentucky Utilities)

MOTION FOR LEAVE TO ANSWER AND ANSWER OF EAST KENTUCKY POWER COOPERATIVE, INC.

Pursuant to Rules 212 and 213 of the Federal Energy Regulatory Commission's ("Commission") Rules of Practice and Procedure,[1] East Kentucky Power Cooperative, Inc. ("East Kentucky") respectfully moves for leave to answer[2] and answers the pleadings filed by Louisville Gas & Electric/Kentucky Utilities ("LKE") and TranServ International, Inc. ("TranServ") on November 23, 2015 in this proceeding. East Kentucky corrects the several mischaracterizations and misrepresentations set forth in Respondents' Answers and provides factual information to rebut claims of Respondents.

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[1] 18 C.F.R. §§ 385.212 and 385.213 (2015).

[2] The Commission's Rules of Practice and Procedure do not provide for answers to answers unless otherwise ordered by the decisional authority. 18 C.F.R. § 385.213(a)(2). The Commission has accepted such answers when they clarify the issue or assist in creating a complete record. *See, e.g. New York Public Service Commission v. New York Independent System Operator, Inc.*, 153 FERC ¶ 61,022 (2015) (answers to answer permitted because they provided information that assisted in the decision-making process); *Shetek Wind Inc., Jeffers South, LLC v. Midwest Independent Transmission System Operator, Inc.*, 138 FERC ¶ 61,250 (2012) (answers to answer permitted because they provided information that assisted in the decision-making process); *PJM Interconnection, L.L.C.*, 127 FERC ¶ 61,1,97 (2009) (answer to answer permitted to assist Commission in decision-making process); *New Power Company v. PJM Interconnection, L.L.C.*, 98 FERC ¶ 61,208 (2002) (answer accepted to provide new factual and legal material to assist Commission in decision-making process). In this answer, East Kentucky corrects several fundamental misstatements and mischaracterizations made by LKE and TranServ, which will provide clarification and correction to assist the Commission in its decision-making.

I. SUMMARY

East Kentucky is seeking to use Network Integration Transmission Service ("NITS") for the very purpose that NITS provides—to integrate its Network Load and Network Resources. East Kentucky's requested service is consistent with the *pro forma* and LKE Tariffs. East Kentucky is not "splitting" its load. All of East Kentucky's Network Loads and Network Resources are internal to PJM's Balancing Authority Area ("BAA"), with most load and resources being directly connected to East Kentucky's transmission system, but with a portion of its Network Load and one new Network Resource (the Bluegrass units) connected to LKE's transmission system.

In their attempt to cast East Kentucky's request as a "significant deviation" from Tariff service, LKE miscast the requested service as "generator imbalance," incorrectly refer to "fictitious" or "virtual" load and delivery points, and mischaracterize other fundamental facts of East Kentucky's requested service.

East Kentucky's Answer briefly addresses the following:

- East Kentucky's proposal seeks to *integrate* its resources and load, consistent with the LKE Tariff, not to split its load. East Kentucky's reasonable and legitimate request is entirely consistent with LKE Tariff service and proffers a reasonable solution to the unique system configuration that involves the heavily interconnected and intertwined systems of two integrated utilities. *See* Section II.A, *infra.*

- LKE's transmission planning arguments are without merit. East Kentucky's requested service will not introduce any planning complications. The data and information LKE claim to need is already being provided to them. *See* Section II.B, *infra.*

- East Kentucky is neither "gaming" Network Service nor "splitting" its load.[3] LKE's Answer is premised on the misapplication of policy designed to prevent customers from avoiding full payment obligations for Network Service. The fact is that *all* East Kentucky load (regardless of which system to which the load is connected) is covered under and pays for Network Service. *See* Section II.C, *infra.*

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[3] Answer of Louisville Gas and Electric Company and Kentucky Utilities Company, at 17-18 ("LKE Answer").

- East Kentucky's request is not "imbalance" service. The service requested by East Kentucky is neither premised upon nor involves "imbalances." This is another effort by LKE to mischaracterize East Kentucky's request for Network Service. *See* Section II.D, *infra.*

- East Kentucky's request does not involve "fictitious" or "virtual" load or delivery points.[4] East Kentucky seeks to use NITS to integrate real Network Load and Resources at real Delivery Points. All of the East Kentucky Network Load and Resources are physically located in or pseudo-tied to a single balancing area (the PJM BAA). *See* Section II.E, *infra.*

- East Kentucky should pay LKE for the Network Service it provides, but should not pay for service that LKE will not be providing. The Commission's policies on transmission planning and pricing protect East Kentucky from overpaying LKE in this case. LKE would have East Kentucky pay for hundreds of megawatts of duplicative charges for firm network or point to point transmission services that LKE would not be providing (and which East Kentucky does not need), or to avoid such charges by relying on short-term or non-firm service instead of long-term firm service. *See* Section II.F, *infra.*

II. ANSWER

A. East Kentucky is seeking to *integrate* its Resources and Load in a *single balancing area,* which is entirely consistent with the LKE Tariff.

East Kentucky's objective is to *integrate* its Network Load and Network Resources. LKE argue as though East Kentucky is simply a load serving entity on the LKE system with behind the meter generation, as though LKE perform balancing functions for East Kentucky, and as though East Kentucky is attempting to construct arrangements that would enable it to avoid paying for Network Service. All of these suggestions are false. East Kentucky is not a load serving entity within the LKE BAA or dependent on LKE for such services. East Kentucky is an integrated electric system. As explained in the Complaint,[5] East Kentucky's and LKE's

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[4] *Id*. at 2-7, 13-16.

[5] Complaint of East Kentucky Power Cooperative, Inc. at 7, 16-20 ("Complaint").

transmission systems are highly intertwined because of state law aimed at preventing duplication of facilities.

Although located on two transmission systems, *all* of East Kentucky's Network Load and Network Resources are within one, single Balancing Authority Area—the PJM BAA. The East Kentucky Network Load connected to the LKE transmission system is pseudo-tied into the PJM BAA, and is treated as internal PJM load. Likewise, all of East Kentucky's Network Resources are pseudo-tied to the PJM BAA, with the exception of the Bluegrass Units, which will be pseudo-tied after the Bluegrass transaction closes.[6] At that point, all East Kentucky Network Resources will be treated as *internal* PJM resources.

LKE argue that East Kentucky's proposed arrangements "significantly depart" from the LKE Tariff.[7] But, East Kentucky is seeking to implement *exactly* what LKE admit that section 28.1 of the LKE Tariff offers: "a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated resources) to serve *their Network Load in the Balancing Authority Area* and any additional load that may be designated pursuant to Section 31.3 of the Tariff."[8]

To accomplish this, East Kentucky proposes to add to its Network Integration Transmission Service Agreement ("NITSA") with LKE an actual delivery point, which would be called the "Bluegrass Delivery Point."[9] At this delivery point, East Kentucky would deliver

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[6] *See* Complaint at 5. Bluegrass units 1 and 2 will be Dynamically Scheduled to PJM by May 1, 2016 and pseudo-tied to PJM by January 2, 2017. Unit 3 will be pseudo-tied to PJM in 2019 after LKE's existing purchase agreement terminates.

[7] LKE also raises the specter that East Kentucky's request violates the restriction on the use of NITS for off-system transactions. LKE Answer at 19. East Kentucky has repeatedly explained that Bluegrass is needed to serve East Kentucky's load. East Kentucky's Network Load will always exceed the output of Bluegrass.

[8] *See* LKE Answer at 13 (*citing* LKE OATT Section 28.1) (emphasis added).

[9] East Kentucky began discussions with both LKE and TranServ at least as early as November 2014 (much more than the two days in advance of the filing of the Complaint as LKE implies on page 33 of their Answer). *See*

output from the Bluegrass Units to the extent that such output exceeds that amount of East Kentucky's Network Load connected to the LKE transmission system. That additional Bluegrass Unit output would be used to serve East Kentucky Network Load that is connected to the East Kentucky transmission system. This is clearly set forth in East Kentucky's Complaint[10] and in the proposed amended NITSA submitted with the Complaint.[11]

B. East Kentucky's proposed NITSA amendments will not create transmission planning complications for LKE.

It is true that LKE must calculate and post ATC, release unscheduled firm transmission service for non-firm use, and plan their system to support the needs of Network Customers as well as Native Load.[12] East Kentucky's request does not prevent LKE from performing any of these activities, nor does it unreasonably burden them when doing so. LKE will still be able to both calculate and post ATC values just as they do today, with only minor modifications to recognize the service East Kentucky has requested.[13]

The Tennessee Valley Authority ("TVA") is currently responsible for calculating the initial Available Flowgate Capability ("AFC") for LKE.[14] TranServ, acting as the LKE Independent Transmission Organization, uses the initial values calculated by TVA to determine the final AFC values for the LKE system.[15] TVA receives daily load forecast information for the

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Affidavit of Denver York, attached to the East Kentucky Complaint, at P 10 ("York Affidavit"). Neither LKE nor TranServ ever expressed any concern about "fictional" or "virtual" load or delivery points until they filed their respective answers.

[10] Complaint at 9, 16.

[11] *See* Proposed Amended East Kentucky NITSA with LKE, appended to the Complaint as Attachment 1.

[12] *See* LKE Answer at 21; *see also* Affidavit of Darrin Adams at P 5, attached hereto as Attachment 4 ("Adams Affidavit").

[13] Adams Affidavit at P 4.

[14] *Id.* at P 5.

[15] *Id.*

East Kentucky system from PJM. The amount of East Kentucky's load connected to the LKE system in the LKE ATC calculation process is adjusted daily to provide the best estimate of load based on historical usage patterns and meteorological conditions.[16]

Therefore, TVA, on behalf of LKE, now receives each day, and will continue to receive, an expected load forecast for East Kentucky for each hour of the next 7 days, for the peak hour of each day for days 8 through 31, and for the peak hour of each month for months 2 through 18.[17] The maximum output values of the Bluegrass units are also known and are essentially fixed values, with only minor variance seasonally. With these two data values—the maximum output of the Bluegrass units and the forecasted total East Kentucky load connected to the LKE transmission system, the potential usage of transmission by East Kentucky to deliver Bluegrass output to East Kentucky load connected to the East Kentucky transmission system is easily derived.[18]

LKE will also be capable of releasing unscheduled firm transmission service for non-firm use.[19] PJM provides a merit order dispatch for units within the PJM market to TVA for its ATC calculation purposes. The Bluegrass units will be included in this merit order dispatch once East Kentucky becomes the owner and operator of the plant. This will provide an indication of whether PJM anticipates that it will dispatch the units within the applicable periods for ATC calculation purposes.[20] If PJM expects to dispatch the units at a level below maximum output or PJM does not expect to dispatch the units based on this merit order, LKE can offer this

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[16] Adams Affidavit at P 5.

[17] *Id.*

[18] *Id.*

[19] *Id.* at P 6.

[20] *Id*. at P 6.

unscheduled capacity for non-firm uses, just as they do with other firm reservations that are not being used within a specified timeframe. East Kentucky is willing to provide all non-price information it has available regarding expected dispatch of the units for ATC calculation purposes to aid in LKE continuing to utilize the system efficiently.[21]

Finally, East Kentucky's requested service does not hinder LKE's ability to plan their system to support the needs of their Network Customers as well as Native Load. As explained, PJM and East Kentucky currently provide, and will continue to provide, the information that LKE needs to plan its system for the needs of all Network Customers.[22] The information LKE receive regarding East Kentucky's load forecast and the maximum output of the Bluegrass units is adequate to plan the system. In fact, in response to a formal request made by LKE in September 2015, East Kentucky and LS Power (as the current owner and operator of the Bluegrass Units) provided this exact information to LKE and TranServ to comply with their planning requirements for the NERC MOD-032-1 Reliability Standard.[23] Therefore, LKE have indicated, through the formal request made to Load-Serving Entities and Resource Planners, that this is the information needed to adequately plan the system for the LKE transmission customers to serve their load with their generation resources.[24]

LKE argue that East Kentucky's proposed service request would require LKE to set aside ATC on the applicable flowgates.[25] East Kentucky agrees that LKE will need to do so.[26] East

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[21] Adams Affidavit at P 6.

[22] *Id.* at P 7.

[23] *See* Memorandum from LG&E/ KU Planning Coordinator to Load Serving Entity, re Aggregate Load Data Request, dated September 1, 2015, hereto as Attachment 5; *See* Memorandum from LG&E/ KU Planning Coordinator to Resource Planner, re Resource Planner Data Request, dated September 1, 2015, hereto as Attachment 6; *see also* Adams Affidavit at P 8.

[24] Adams Affidavit at P 8.

[25] LKE Answer at 21.

Kentucky is requesting Network Transmission Service to deliver the output of the Bluegrass units to East Kentucky load connected to the East Kentucky transmission system. Therefore, this request should be treated like any other granted transmission service by being recognized as a reservation in the ATC calculation process.[27]

LKE also argue that East Kentucky could use other options to acquire the desired service, either by reserving Point-to-Point service or by designating additional Network Loads for service under the LKE Tariff.[28] However, LKE fail to point out that, even if East Kentucky elected to request either type of service, as LKE have described, the data used and the ATC calculation still would be much the same.[29] PJM would still provide to TVA on behalf of LKE the same load forecast and the same generation dispatch information regardless of whether East Kentucky acquires the service it is seeking or it requested the service that LKE specify. Therefore, the end result of the ATC calculation would not change.[30]

LKE claim that the NERC MOD-030 Reliability Standard "states that the impact of firm Network Integration Transmission Service, including the impacts of generation to load, should be based on [the] load forecast for the time period being calculated and the unit commitment and dispatch order. Since East Kentucky is not designating load as required under the OATT for NITS, a reliable load forecast will not be available for the proposed Bluegrass Delivery Point." [31]

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[26] Adams Affidavit at P 9.

[27] *Id.*

[28] LKE Answer at 24-26. East Kentucky responds to this argument. However, East Kentucky also notes that these suggestions go beyond LKE's role as transmission owner or provider. It is not for LKE to determine how a competitor can or should utilize resources to serve load. These LKE suggestions would have East Kentucky utilize service that is inferior to Network Service. East Kentucky's request for Network Service is not only appropriate, but it is the most efficient way to utilize the system and resources to serve Network Load.

[29] Adams Affidavit at P 10.

[30] *Id.*

[31] LKE Answer at 21.

This is incorrect. PJM already supplies on a daily basis to TVA, and will continue to supply, the information that is needed to calculate the expected amount of power to be delivered to the Bluegrass Delivery Point.[32] LKE's attempt to portray the ability to incorporate East Kentucky's proposed service into its ATC calculation process as difficult or complicated, when in reality it will require no substantial deviations from the *status quo*.

LKE argue that if the transmission service proposed by East Kentucky is granted, transfer capacity to PJM would be restricted.[33] However, a review of firm requests for transmission service on paths into PJM for the period from March 1, 2014 to November 30, 2015 submitted on the LKE Open Access Same-Time Information System ("OASIS") indicates that there is limited interest or need for this path, and the requests for service into PJM that have been submitted are primarily for peak periods.[34] Over this period, only *six* unique requests for transmission service with a Point of Delivery of PJM have been submitted to LKE (excluding requests associated with transmission service for the Bluegrass units). Of these six requests, three were for daily firm transmission service during February 2015, when high-demand conditions were being experienced. The remaining three requests are for yearly firm service, with two of these being granted and the remaining one currently under study.[35] This shows that there is not significant interest in transmission service to PJM through the LKE system. In contrast, over the same period there were 89 requests submitted for transmission service with a Point of Receipt of

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[32] Adams Affidavit at P 11.

[33] LKE Answer at 21-22.

[34] Adams Affidavit at P 12.

[35] *Id*.

PJM (*i.e.*, for transactions leaving PJM and being delivered either into or across the LKE system) that were either granted (85) or refused (4).[36]

In fact, it appears that the LKE system often has ample transfer capability on paths into PJM that is not being utilized in lower load periods.[37] For example, a review of the archived offerings on the LKE OASIS for Daily Firm service from LKE to PJM indicates that for the September – October 2015 period, ATC in excess of 500 MW was available in 51 of the 61 days in the period, and for 35 of those days the ATC posted exceeded 1,000 MW.[38] East Kentucky's requested service will provide some utilization of the LKE system during these lower load periods and create the opportunity for LKE to be compensated for East Kentucky's excess usage in off-peak months, when there is limited demand for use of transmission capacity by other transmission customers.[39]

LKE state that "East Kentucky proposes that its 'Bluegrass Delivery Point' deliveries be calculated on an after-the-fact basis, which complicates the ability to release this predominantly unused transmission capacity for non-firm use."[40] However, LKE confuse East Kentucky's proposal for how to determine the billing for the service with integration of the service into the ATC calculation process.[41] All information needed to determine the expected usage at the Bluegrass Delivery Point will be provided before the real-time delivery of energy, not after-the-

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[36] Adams Affidavit at P 12.

[37] *Id.* at P 13.

[38] *Id.*

[39] *Id.*

[40] LKE Answer at 22.

[41] Adams Affidavit at P 14.

fact. LKE will have sufficient opportunity to release any capacity not expected to be used by East Kentucky as non-firm AFC.[42]

LKE argue that it will be "harder" to determine the non-firm AFC because the "dispatch signal to Bluegrass may be associated with needs on the PJM system within or outside of the East Kentucky Zone."[43] This too is a false argument, given that PJM provides all necessary information regarding load forecast and generation dispatch to TVA for the ATC calculation process in order to make the non-firm AFC calculation process straightforward. It should be noted that PJM provides the same type of information as that provided by LKE's other Network Customers, including the LKE affiliated load serving entity.[44]

Just as confirmed transmission reservations are identified as Existing Transmission Commitments to be accounted for when calculating ATC, another factor used to reduce ATC is Transmission Reliability Margin ("TRM"). LKE and TVA have formed a Contingency Reserve Sharing Group ("CRSG") to provide mutual assistance for unanticipated generation outages on either system.[45] Varying amounts of flowgate capacity—and in some cases, large amounts—are set aside on each system in anticipation of the need to deliver generation output from one system to another.[46] Although the anticipated usage of this reserved capacity is much less than 7% of the hours in the year (which is the amount of hours the Bluegrass units are currently restricted to operate each year),[47] LKE seem to have no qualms about implementing significant reductions in ATC within its system to accommodate this very infrequently used service. Furthermore, LKE

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[42] Adams Affidavit at P 14.

[43] LKE Answer at 23.

[44] Adams Affidavit at P 15.

[45] *Id.* at P 16.

[46] *See* Transmission Reliability Margin Implementation Document, at 7, attached hereto as Attachment 7.

[47] *See* Complaint at 11.

receive no compensation for use of this service. On the surface, the only explanation for this different perspective regarding service that is very similar to East Kentucky's proposed service is that the ATC set aside for the CRSG benefits the reliability to customers of the affiliated LKE load serving entity, whereas East Kentucky's service is for an entity not affiliated with LKE.[48]

In addition to this component of TRM, LKE recognize the need to set aside TRM on its flowgates for a generation dispatch uncertainty component. As stated in the LKE TRM Implementation Document, "generation dispatch uncertainty or the location and output of generation that is assumed in the Planning/Study Horizon might be vastly different from actual conditions in the Operating Horizon. The dispatch profile of generation can vary which can cause flows on the flowgate to vary. Variations occur because of unit availability and changes in dispatch order due to operating cost changes."[49] LKE have recognized the need for load serving entities to have flexibility in the dispatch of generation resources and has established a methodology to calculate this uncertainty and reduce the Available Flowgate Capability by this component. The affiliated LKE load serving entity is one of the primary beneficiaries of the TRM set aside to allow this flexibility.[50] Therefore, LKE already have a process in place to address the concerns they stated regarding the uncertainty of whether the Bluegrass units will be dispatched.[51]

LKE also argue that East Kentucky's request could introduce variability in dispatched generation, making it difficult for LKE to plan.[52] East Kentucky disagrees.[53] LKE already face

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[48] Adams Affidavit at P 16.

[49] *See* Attachment 7 at 7.

[50] Adams Affidavit at P 17.

[51] *Id.*

[52] LKE Answer at 23.

variability with much greater uncertainty than would exist with the Bluegrass resource. Yet, LKE are currently able to calculate and post ATC.[54] For example, Nucor Steel Gallatin ("Nucor") is a steel manufacturer and the largest single retail customer served by any of East Kentucky's owner-member distribution cooperatives.[55] The nature of the steel manufacturing process makes Nucor's load a "non-conforming" load because it is capable of large swings in demand within very short time periods. Nucor's demand level ranges from 0 MW up to as much as approximately 174 MW. Nucor is served from one of East Kentucky's Network Load delivery points directly connected to the LKE transmission system.[56] However, LKE do not make any special modifications to its ATC calculation process to account for the swings in Nucor load. PJM's load forecast provided to TVA does not provide individual delivery point forecasts for East Kentucky's Network Loads, so the Nucor forecast is simply folded into the total load forecast number provided by PJM. TVA uses the load forecast for East Kentucky provided by PJM to scale the loads in its models to match the load forecast value provided. Therefore, the Nucor load value is adjusted up or down by the same scale factor as all other, vastly less dynamic, East Kentucky loads. As a result, the amount of load for Nucor in the models used for ATC calculation purposes could be, for instance, 174 MW, whereas the actual load could be zero MW based on the Nucor production schedule for a given day.[57] This difference between the information used by LKE for planning and ATC calculation purposes and the actual real-time conditions has not resulted in LKE's inability to plan their system. Nor does this difference seem

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[53] Adams Affidavit at P 18.

[54] *Id.*

[55] *Id.* at P 19.

[56] *Id.*

[57] *Id.*

to have created an unreliable, constrained transmission system. LKE have accepted that this difference will occur from time to time and decided that no special processes are needed to improve accuracy.[58]

C. LKE's claims that East Kentucky's requested service is contrary to Commission policy are incorrect.

East Kentucky set forth in its Complaint the authority and reasoning supporting its requested service. Section IV.A.1 of the Complaint discusses the *pro forma* and LKE Tariff provisions and Commission policy. Section IV.A.2 of the Complaint explains that East Kentucky's proposed amended NITSA accurately reflects its proposed use of and payment for LKE's transmission system.

LKE argue that "East Kentucky's determination to only be charged based on generator imbalances within its control is the type of gaming the Commission sought to prevent by requiring all load at discrete points be designated."[59] This, too, is addressed in the Complaint. No such gaming is involved here (nor are any imbalances, as further discussed, *infra,* Section II.D).[60] The Commission's "gaming" concern is that a customer would serve some, but not all, of its load through Network Service, with the result that all of the customer's load would benefit from Network Service without fully paying for it.[61] Here, however, the deliveries to the

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[58] Adams Affidavit at P 19.

[59] LKE Answer at 17-18.

[60] Complaint at 14-16.

[61] *See* Complaint at 15-16; *see also Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A at p. 30,259, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

Bluegrass Delivery Point will be accounted for as part of East Kentucky's Network Load on the LKE system and will be billed and paid for accordingly.

LKE cite to *Arizona Public Service* and others for their claim that East Kentucky's request violates long-standing Commission policy.[62] But every case relied on by LKE and cited in footnote 54 of their Answer involved a customer's effort to avoid Network Service charges for load served from behind-the-meter generation. East Kentucky does no present a behind-the-meter generation case. LKE present no cases that address the actual facts of the instant situation,[63] whereas East Kentucky's Complaint provides similar requests for similarly situated entities.[64]

As explained in its Complaint, East Kentucky is not a transmission-dependent wholesale customer with behind-the-meter generation. It is an interconnected utility with its own transmission system and fleet of generating resources that is a voluntary participating

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[62] *See* LKE Answer at 19, n. 54.

[63] LKE misrepresent the AECC case and the purpose for which East Kentucky cited to it. East Kentucky cited *AECC* in the section seeking alternative relief in the form of waiver, explaining that the Commission has allowed flexibility in structuring transmission arrangements and has allowed departures from the tariff for good cause. *See* Complaint at 26-27. As East Kentucky discussed in its Complaint, MISO and AECC sought and obtained approval to waive the requirement under the MISO Tariff that load be physically connected to the MISO system. This non-conforming arrangement was necessary in order to pseudo-tie into MISO a portion of AECC's load that is connected to the SPP system. MISO explained that, absent the non-conforming arrangement, AECC would have faced substantial point-to-point charges and regional through and out rates to integrate its Network Load, which would have produced unjust and unreasonable results under the circumstances. East Kentucky cited to *AECC* for the proposition that the Commission intends for Transmission Providers to provide flexibility in order to avoid an unjust and unreasonable result. In *AECC*, the Commission accepted the non-conforming NITSA, finding that the arrangement was just and reasonable "because it is *consistent with the flexibility provided under section 31.3 of the pro forma OATT*." *Midcontinent Indep. System Operator, Inc*. 146 FERC ¶ 61,094 at P 44 (2014) (*quoting Midcontinent Indep. Sys. Operator, Inc.*, 145 FERC ¶61,242 at P 11 (2013)).

LKE incorrectly claim that *AECC* supports their position. LKE Answer at 5. The *AECC* case did not involve the use of AECC network resources in SPP to serve AECC network load in MISO. Because the Commission did not address this question, LKE's reliance on *AECC* misplaced. *Midcontinent Indep. System Operator, Inc*. 146 FERC ¶ 61,094 at P 45 (2014).

[64] Complaint at 20-24.

Transmission Owner in PJM.[65] East Kentucky is not seeking the proposed arrangements to avoid paying for Network Service. East Kentucky pays the LKE network rate to serve East Kentucky's total Network Load on the LKE system.[66] And, *all* of East Kentucky's load (including that which is connected to LKE's system) is subject to PJM's Network Service charges. Thus, East Kentucky's load is not at all akin to load served from behind-the-meter generation that might escape paying for Network Service in the absence of this Tariff provision.

LKE also argue that "allowing services and rates unique to every customer would undercut the primary goal of Order No. 888 of providing for non-discriminatory open access transmission."[67] Under LKE's view, the Commission could never grant waiver or accept a non-conforming agreement. Yet, as explained in the Complaint, even LKE have and continue to benefit from non-conforming arrangements associated with East Kentucky's integration into PJM.[68] Here, for the reasons set forth in the Complaint, East Kentucky seeks an arrangement with LKE that is consistent with both the terms and underlying spirit of the *pro forma* and LKE Tariffs. Alternatively, if the Commission deems it a non-conforming arrangement, then waiver is appropriate for the reasons stated in the Complaint.

D. East Kentucky's Complaint has nothing to do with "imbalances."

Much of LKE's Answer is framed in terms of what it labels as East Kentucky's request to deliver a "residual imbalance," or "positive energy imbalance" to "non-discrete loads."[69] East Kentucky's Complaint and its requested service have nothing to do with "imbalances." East

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[65] *See* Affidavit of David Crews at P 8, appended to the Complaint as Attachment 2.

[66] *See* York Affidavit at P 8.

[67] *See* LKE Answer at 16 (*quoting Fla. Power & Light Co.*, 116 FERC ¶ 61,012 at P 14 (2006)).

[68] Complaint at 19-20.

[69] *See* LKE Answer at 4, 6, 11, 13, and 14.

Kentucky's use of a resource's output to serve its Network Load is not an imbalance. Dispatching a unit to produce energy to serve network load does not create an imbalance. Notably, LKE do not perform any Balancing Area duties for the East Kentucky load or resources; it neither dispatches East Kentucky's resources nor follows East Kentucky's load. East Kentucky's Network Load on the LKE transmission system is pseudo-tied to the PJM BAA. It is factually incorrect and purposely misleading for LKE to describe the requested service as an imbalance.

E. East Kentucky's load and delivery point are neither "fictitious" nor "virtual."

LKE's repeated statements that East Kentucky is seeking to utilize "fictitious" load and delivery points are factually incorrect and misleading.[70] East Kentucky's load on both the LKE and East Kentucky/PJM systems is real. The delivery point that will be designated as the "Bluegrass Delivery Point" already exists.[71] East Kentucky will be using output of Bluegrass in excess of East Kentucky's Network Load on the LKE transmission system to serve East Kentucky's Network Load on the East Kentucky transmission system. These loads are referred to separately only because of the transmission systems to which they are attached, but they are all East Kentucky Network Load, are all within the PJM BAA, and are all served by East Kentucky as a single load.

There likewise is nothing fictional, virtual, or non-discrete about the Bluegrass Delivery Point. The delivery points are actual, physical delivery points at which the LKE and East

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[70] *Id*. at 2 ("East Kentucky filed a Complaint that attaches a proposed NITSA amendment, predicated on the formation of a fictitious "load" point named after a generating station (the "Bluegrass Delivery Point") that would serve to support any occasional energy imbalance between Bluegrass generation and East Kentucky's Network Loads on LG&E/KU's Transmission System."); *id*. at 19 ("Instead, East Kentucky insists on a third option, that of designating a fictitious "load" other than an entire discrete load.").

[71] TranServ similarly mischaracterizes the proposed Delivery Point as a "virtual" delivery point. TranServ Answer at 3, 7. TranServ is wrong for the same reasons that LKE are wrong.

Kentucky transmission systems are physically and electrically connected, and at which East Kentucky has Network Load connected to and served from the East Kentucky transmission system. With its acquisition of Bluegrass, East Kentucky needs the ability to use the Bluegrass resource, as it uses all other Network Resources, to serve all of its Network Load.

The fact that East Kentucky would for billing purposes calculate the amount of Network Load that is using NITS provided by LKE does not render the load, the resource, nor the delivery point fictional. The calculation is necessary and appropriate to ensure that: (1) East Kentucky fully compensates LKE for the NITS service it provides by reflecting all deliveries made from Bluegrass to the Bluegrass Delivery Point so that such deliveries are factored into LKE's billing to East Kentucky for the NITS it provides; and (2) East Kentucky does not pay duplicative charges for services that LKE are not providing and that East Kentucky does not need.

F. LKE would over charge East Kentucky for service.

LKE's claim that East Kentucky exaggerates the financial impact of their position is unfounded and misleading.[72] East Kentucky explained that buying hundreds of megawatts of firm Point-to-Point or Network Service as proposed by LKE, would cost East Kentucky approximately $10 million more annually.[73] The billing resulting from LKE's approach ignores the fact the maximum amount of service they could provide can never exceed the greater of either East Kentucky's load on the LKE system, or the output of Bluegrass. LKE do not allege that East Kentucky' estimate is incorrect, nor do they address the limits on the amount of service it would be providing.

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[72] LKE Answer at 24-25.

[73] Complaint at 29.

LKE instead suggest that East Kentucky could lessen the financial effect by instead relying on short-term firm or even non-firm service.[74] Suffice it to say that East Kentucky does not intend to, nor should it have to, rely on short-term or non-firm transmission service to support its acquisition of a new generating resource in order to serve East Kentucky's native load. LKE's "money-saving" suggestions are neither prudent nor useful.

III. CONCLUSIONS

For the foregoing reasons, East Kentucky respectfully requests that the Commission accept this Motion for Leave to Answer and Answer, and that the Commission grant its Complaint.

Respectfully submitted,

Alan Robbins

Alan Robbins
Debra Roby
Melissa Alfano
Jennings Strouss & Salmon, PLC
1350 I Street, NW, Suite 810
Washington, DC
Tel. 202.371.9030

December 9, 2015

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[74] LKE Answer at 24.

CERTIFICATE OF SERVICE

I hereby certify that I have, on this 9th day of December 2015, caused a copy of the foregoing document to be served upon all those listed in the official service list in this Proceeding.

// Jennifer Spangler//
Jennifer Spangler
Legal Assistant
Jennings Strouss & Salmon, P.L.C.
1350 I Street, NW, Suite 810
Washington, DC 20005-3305
(202) 464-0572
jspangler@jsslaw.com

Attachment 4

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

East Kentucky Power Cooperative, Inc.
v.
Louisville Gas & Electric/Kentucky Utilities

Docket No. EL16-8-000

Affidavit of Darrin Adams

Introduction

1. My name is Darrin Adams. I am the Director of Power Delivery Planning, Design and Construction at the East Kentucky Power Cooperative, Inc. ("East Kentucky"). My business address is 4775 Lexington Road, Winchester, Kentucky 40391. I have been employed by East Kentucky since June 2004.

2. I received a bachelor's degree in Electrical Engineering from the University of Kentucky and I am a registered professional engineer in the Commonwealth of Kentucky. I also hold a bachelor's in Liberal Arts from Transylvania University. Prior to joining East Kentucky, I was employed as a transmission planning and operations engineer with Louisville Gas & Electric/Kentucky Utilities ("LKE") for more than 10 years. In all, I have more than 24 years of experience in the electric utility industry.

3. The purpose of this affidavit is to provide factual information to rebut claims asserted by LKE in their Answer to East Kentucky's Complaint.

Transmission Planning

4. It is true that LKE must calculate and post ATC, release unscheduled firm transmission service for non-firm use, and plan their system to support the needs of Network Customers as well as Native Load. East Kentucky's request does not prevent LKE from performing any of these activities, nor does it unreasonably burden them when doing so. LKE will still be able to both calculate and post ATC values just as they do today, with only minor modifications to recognize the service East Kentucky has requested.

5. The Tennessee Valley Authority ("TVA") is currently responsible for calculating the initial Available Flowgate Capability ("AFC") for LKE. TranServ, acting as the LKE Independent Transmission Organization, uses the initial values calculated by TVA to determine the final AFC values for the LKE system. TVA receives daily load forecast information for the East Kentucky system from PJM. The amount of East Kentucky's

load connected to the LKE system in the LKE ATC calculation process is adjusted daily to provide the best estimate of load based on historical usage patterns and meteorological conditions. Therefore, TVA, on behalf of LKE, now receives each day, and will continue to receive, an expected load forecast for East Kentucky for each hour of the next 7 days, for the peak hour of each day for days 8 through 31, and for the peak hour of each month for months 2 through 18. The maximum output values of the Bluegrass units are also known and are essentially fixed values, with only minor variance seasonally. With these two data values—the maximum output of the Bluegrass units and the forecasted total East Kentucky load connected to the LKE transmission system, the potential usage of transmission by East Kentucky to deliver Bluegrass output to East Kentucky load connected to the East Kentucky transmission system is easily derived.

6. LKE will also be capable of releasing unscheduled firm transmission service for non-firm use. PJM provides a merit order dispatch for units within the PJM market to TVA for its ATC calculation purposes. The Bluegrass units will be included in this merit order dispatch once East Kentucky becomes the owner and operator of the plant. This will provide an indication of whether PJM anticipates that it will dispatch the units within the applicable periods for ATC calculation purposes. If PJM expects to dispatch the units at a level below maximum output or PJM does not expect to dispatch the units based on this merit order, LKE can offer this unscheduled capacity for non-firm uses, just as they do with other firm reservations that are not being used within a specified timeframe. East Kentucky is willing to provide all non-price information it has available regarding expected dispatch of the units for ATC calculation purposes to aid in LKE continuing to utilize the system efficiently.

7. PJM and East Kentucky currently provide, and will continue to provide, the information that LKE needs to plan its system for the needs of all Network Customers.

8. In fact, in response to a formal request made by LKE in September 2015, East Kentucky and LS Power (as the current owner and operator of the Bluegrass Units) provided East Kentucky’s load forecast and the maximum output of the Bluegrass units to LKE and TranServ to comply with their planning requirements for the NERC MOD-032-1 Reliability Standard. LKE have indicated, through the formal request made to Load-Serving Entities and Resource Planners, that this is the information needed to adequately plan the system for the LKE transmission customers to serve their load with their generation resources.

9. LKE claim that East Kentucky’s proposed service request would require LKE to set aside ATC on the applicable flowgates. East Kentucky agrees that LKE will need to do so. East Kentucky is requesting Network Transmission Service to deliver the output of the Bluegrass units to East Kentucky load connected to the East Kentucky transmission system. Therefore, this request should be treated like any other granted transmission service by being recognized as a reservation in the ATC calculation process.

Rebuttal to LKE's Suggestion that East Kentucky Should Use Inferior Service

10. LKE suggest that East Kentucky could use other options to acquire the desired service, either by reserving Point-to-Point service or by designating additional Network Loads for service under the LKE Tariff. However even if East Kentucky elected to request either type of service, as LKE have described, the data used and the ATC calculation still would be much the same. PJM would still provide to TVA on behalf of LKE the same load forecast and the same generation dispatch information regardless of whether East Kentucky acquires the service it is seeking or it requested the service that LKE specify. Therefore, the end result of the ATC calculation would not change.

Correction to LKE's Claim concerning NERC MOD-030

11. LKE claim that the NERC MOD-030 Reliability Standard "states that the impact of firm Network Integration Transmission Service, including the impacts of generation to load, should be based on [the] load forecast for the time period being calculated and the unit commitment and dispatch order. Since East Kentucky is not designating load as required under the OATT for NITS, a reliable load forecast will not be available for the proposed Bluegrass Delivery Point." This is incorrect. PJM already supplies on a daily basis to TVA, and will continue to supply, the information that is needed to calculate the expected amount of power to be delivered to the Bluegrass Delivery Point.

Rebuttal to Alleged Restriction on Transfer Capacity

12. LKE claim that if the transmission service proposed by East Kentucky is granted, transfer capacity to PJM would be restricted. However, a review of firm requests for transmission service on paths into PJM for the period from March 1, 2014 to November 30, 2015 submitted on the LKE Open Access Same-Time Information System ("OASIS") indicates that there is limited interest or need for this path, and the requests for service into PJM that have been submitted are primarily for peak periods. Over this period, only six unique requests for transmission service with a Point of Delivery of PJM have been submitted to LKE (excluding requests associated with transmission service for the Bluegrass units). Of these six requests, three were for daily firm transmission service during February 2015, when high-demand conditions were being experienced. The remaining three requests are for yearly firm service, with two of these being granted and the remaining one currently under study. This shows that there is not significant interest in transmission service to PJM through the LKE system. In contrast, over the same period there were 89 requests submitted for transmission service with a Point of Receipt of PJM (*i.e.*, for transactions leaving PJM and being delivered either into or across the LKE system) that were either granted (85) or refused (4).

13. It appears that the LKE system often has ample transfer capability on paths into PJM that is not being utilized in lower load periods. For example, a review of the archived offerings on the LKE OASIS for Daily Firm service from LKE to PJM indicates that for the September – October 2015 period, ATC in excess of 500 MW was available in 51 of

the 61 days in the period, and for 35 of those days the ATC posted exceeded 1,000 MW. East Kentucky's requested service will provide some utilization of the LKE system during these lower load periods and create the opportunity for LKE to be compensated for East Kentucky's excess usage in off-peak months, when there is limited demand for use of transmission capacity by other transmission customers.

14. LKE claim that East Kentucky proposes that its 'Bluegrass Delivery Point' deliveries be calculated on an after-the-fact basis, which complicates the ability to release this predominantly unused transmission capacity for non-firm use. However, LKE confuse East Kentucky's proposal for how to determine the billing for the service with integration of the service into the ATC calculation process. All information needed to determine the expected usage at the Bluegrass Delivery Point will be provided before the real-time delivery of energy, not after-the-fact. LKE will have sufficient opportunity to release any capacity not expected to be used by East Kentucky as non-firm AFC.

15. LKE argue that it will be harder to determine the non-firm AFC because the dispatch signal to Bluegrass may be associated with needs on the PJM system within or outside of the East Kentucky Zone. However, PJM provides all necessary information regarding load forecast and generation dispatch to TVA for the ATC calculation process in order to make the non-firm AFC calculation process straightforward. It should be noted that PJM provides the same type of information as that provided by LKE's other Network Customers, including the LKE affiliated load serving entity.

16. Just as confirmed transmission reservations are identified as Existing Transmission Commitments to be accounted for when calculating ATC, another factor used to reduce ATC is Transmission Reliability Margin ("TRM"). LKE and TVA have formed a Contingency Reserve Sharing Group ("CRSG") to provide mutual assistance for unanticipated generation outages on either system. Varying amounts of flowgate capacity—and in some cases, large amounts—are set aside on each system in anticipation of the need to deliver generation output from one system to another. Although the anticipated usage of this reserved capacity is much less than 7% of the hours in the year (which is the amount of hours the Bluegrass units are currently restricted to operate each year), LKE currently plans for significant reductions in ATC within its system to accommodate this very infrequently used service. As far as I know, LKE receive no compensation for use of this service.

<u>Rebuttal to "Variability in Dispatch" Claim</u>

17. In addition to this component of TRM, LKE recognize the need to set aside TRM on its flowgates for a generation dispatch uncertainty component. As stated in the attached LKE TRM Implementation Document, "generation dispatch uncertainty or the location and output of generation that is assumed in the Planning/Study Horizon might be vastly different from actual conditions in the Operating Horizon. The dispatch profile of generation can vary which can cause flows on the flowgate to vary. Variations occur because of unit availability and changes in dispatch order due to operating cost changes."

LKE have recognized the need for load serving entities to have flexibility in the dispatch of generation resources and have established a methodology to calculate this uncertainty and reduce the Available Flowgate Capability by this component. The affiliated LKE Load Serving Entity is one of the primary beneficiaries of the TRM set aside to allow this flexibility. Therefore, it would appear that LKE already have a process in place to address the concerns they stated in their Answer regarding the uncertainty of whether the Bluegrass units will be dispatched.

18. LKE claim that East Kentucky's request could introduce variability in dispatched generation, making it difficult for LKE to plan. But, LKE already face variability with much greater uncertainty than they would experience with the Bluegrass resource. Yet, LKE are currently able to calculate and post ATC.

19. One example is Nucor Steel Gallatin ("Nucor"). Nucor is a steel manufacturer and the largest single retail customer served by any of East Kentucky's owner-member distribution cooperatives. The nature of the steel manufacturing process makes Nucor's load a "non-conforming" load because it is capable of large swings in demand within very short time periods. Nucor's demand level ranges from 0 MW up to as much as approximately 174 MW. Nucor is served from one of East Kentucky's Network Load delivery points directly connected to the LKE transmission system. However, LKE do not make any special modifications to its ATC calculation process to account for the swings in Nucor load. PJM's load forecast provided to TVA does not provide individual delivery point forecasts for East Kentucky's Network Loads, so the Nucor forecast is simply folded into the total load forecast number provided by PJM. TVA uses the load forecast for East Kentucky provided by PJM to scale the loads in its models to match the load forecast value provided. Therefore, the Nucor load value is adjusted up or down by the same scale factor as all other, vastly less dynamic, East Kentucky loads. As a result, the amount of load for Nucor in the models used for ATC calculation purposes could be, for instance, 174 MW, whereas the actual load could be zero MW based on the Nucor production schedule for a given day. This difference between the information used by LKE for planning and ATC calculation purposes and the actual real-time conditions has not resulted in LKE's inability to plan their system. Nor does this difference seem to have created an unreliable, constrained transmission system. LKE have accepted that this difference will occur from time to time and decided that no special processes are needed to improve accuracy.

20. This concludes my affidavit.

I, **Darrin Adams**, being duly sworn according to law, state under oath that the foregoing statements are true and correct to the best of my knowledge, information and belief.

Darrin Adams

Darrin Adams

Date: Dec. 9, 2015

Verification

State of Kentucky)
Count of Clark)

Subscribed and sworn before me, a Notary Public, on this 9th day of December, 2015.

Gwyn M. Willoughby

Notary Public

My commission expires: 11/30/17

GWYN M. WILLOUGHBY
Notary Public
State at Large
Kentucky
My Commission Expires Nov 30, 2017

Attachment 5

LG&E KU
PPL companies

To: Load Serving Entity (LSE) September 1, 2015

From: LG&E/ KU Planning Coordinator

Subject: Aggregate Load Data Request

Dear LSE:

To comply with the NERC MOD-032-1 reliability standard, LG&E/KU is requesting a forecast of your loads connected to the LG&E/KU transmission system by delivery point. Attached is a workbook with the NERC model bus numbers for each delivery point. The forecast needs to be supplied starting in 2016 spring through 2026 summer and 2026/27 winter. When more than one distribution step-down transformer exists at a delivery point, please include a forecast for each transformer.

There is a separate sheet in the workbook for each of the seasons and/or load scenarios. The load scenarios are:

- Winter Peak: represents 50% probability that loads are below this level and 50% probability loads are above this level.
- Summer Peak: represents 50% probability that loads are below this level and 50% probability loads are above this level.
- Summer shoulder: defined as 70% to 80% of the 50/50 summer peak load
- Winter Peak extreme cold winter temperatures: represents 90% probability that load are below this level and 10% probability loads are above this level.
- Summer Peak extreme heat summer temperatures: represents 90% probability that load are below this level and 10% probability loads are above this level.
- Light load: lowest loads or middle of the night on a spring day
- Spring peak: maximum loads expected for March, April or May
- Fall Peak: maximum loads expected for September, October, or November

The MW or real power load and power factor must be included. It is assumed that the power factor will not change in the same season year to year, so only one power factor is included for each sheet in the workbook. If this assumption is incorrect, please add columns and include a power factor for each year.

The data is required no later than October 31, 2015. Please submit the data via email to:

NERC.mod-32-steadystate@lge-ku.com

If the LG&E/KU Planning Coordinator finds that there is a technical concern with the data supplied, you will be notified. If you are not notified, the data requirement for the aggregate load in 2015 can be considered complete.

If you have any questions on this data request or the spreadsheet included, please call or email one of the following:

Matthew Burns: 859-367-5645 Matthew.Burns@lge-ku.com

Delyn Kilpack: 502-722-6735 Delyn.Kilpack@lge-ku.com

Thank you for your cooperation as we all strive to maintain the reliability of the Bulk Electric System.

Delyn Kilpack

Manager, Transmission Strategy and Planning

Attachment 6

LG&E KU
PPL companies

To: Resource Planner (RP) September 1, 2015

From: LG&E/ KU Planning Coordinator

Subject: Resource Planner Data Request

Dear RP:

To comply with the NERC MOD-032-1 reliability standard, the LG&E/KU Planning Coordinator is requesting the following data:

- a list of the scheduled firm transactions expected to occur for the ten year planning horizon

The resource planning data is due no later than October 31, 2015. Email the following with the required data.

NERC.mod-32-steadystate@lge-ku.com

Attached is a workbook for the scheduled transactions. Some transaction data for transmission service is known and included in the workbook (taken from OASIS reservations). Please make any edits to the scheduled transactions, and/or add any that may have been omitted.

If the LG&E/KU Planning Coordinator finds that there is a technical concern with the data supplied, you will be notified. If you are not notified, the data requirement for scheduled firm transaction data in 2015 can be considered complete.

If you have any questions on this data request or the spreadsheet included, please call or email one of the following:

Matthew Burns: 859-367-5645 Matthew.Burns@lge-ku.com

Delyn Kilpack: 502-722-6735 Delyn.Kilpack@lge-ku.com

Thank you for your cooperation as we all strive to maintain the reliability of the Bulk Electric System.

Delyn Kilpack

Manager, Transmission Strategy and Planning

Attachment 7

LG&E KU

Transmission Reliability Margin Implementation Document

(TRMID)

Effective Date: November 10, 2015

Approved by:

Delyn Kilpack, Manager - Transmission Strategy & Planning Date: 11/4/15

Chris Balmer, Director – Transmission Strategy & Planning Date: 11/4/15

Tom Jessee, VP – Transmission Date: 11/4/2015

Revision History

Date	Description
October 31, 2007	Initial LGEE draft of TRM methodology submitted for Customer review.
February 18, 2009	Removed "DRAFT", no customer comments; Added signatures to cover page; Added Revision History
April 1, 2009	Corrected references to MISO CRS and expanded "Use of TRM in ATC Calculations" section
January 18, 2011	Major revision to comply with NERC Standard MOD-008-1, which is to be effective 4/1/2011.
September 9, 2011	Refinement of section 8.0 regarding R3 of standard; Miss type of revision History year; Update signature line
June 1, 2013	Periodic review; Update signature line; Remove references to EKPC due to transition to PJM
April 24, 2015	Revised the Rate A table in Section 6.0 to include CRSG and Generation Dispatch component.
November 10, 2015	Revisions to implement new calculation methodology

Table of Contents

1.0 Purpose (R1)

This implementation document, TRMID, describes the methodology used in the calculation of Transmission Reliability Margin (TRM) and the application of TRM in the calculation of Available Flowgate Capability (AFC) used in the process of approving Transmission Service Requests (TSR).

2.0 Overview

Louisville Gas and Electric Company/Kentucky Utilities Company (collectively "LG&E/KU") uses an AFC methodology for calculation of Available Transfer Capability (ATC), which is documented in the Available Transfer Capability Implementation Document (ATCID). AFC values include decrements for TRM to provide operating flexibility and ensure secure operation of the interconnected network and accommodate reasonable uncertainties in system conditions. TRM is reserved to preserve transmission capacity on each identified Flowgate in the operating and planning horizons to model uncertainty in system conditions and for delivery of energy as required under generator Contingency Reserve Sharing (CRS) Agreements. The TRM process defined within this methodology is referenced in Attachment C of the Open Access Transmission Tariff (OATT).

3.0 Definitions

Definitions can be found in the NERC Glossary for italicized terms.

Available Flowgate Capability (AFC)

Available Transfer Capability (ATC)

Balancing Authority (BA)

Bulk Electric System (BES)

Capacity Benefit Margin (CBM)

Contingency Reserve

Contingency Reserve Sharing: (CRS) – Sharing between two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies by the provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.

Contract Path

Emergency Rating

Flowgate

Normal Rating

Operating Horizon – The period of the Hourly Operating Horizon differs for hours starting before noon and hours starting after noon. For hours starting before noon, the period includes the current hour through midnight, Eastern Standard Time ("EST") of the current day. For hours starting after 12 noon EDT, the period includes the then current hour through midnight EST of the following day. For example, the Hourly Operating Horizon for the hour of 10:00 a.m. EST January 1 includes the current hour and extends until the following midnight EST (*i.e.*, from 10:00 a.m. EST to midnight EST for a total of 14 hours). However, the Hourly Operating Horizon for 1:00 p.m. of January 1 extends until midnight EST of the next day (*i.e.*, from 1:00 p.m. EST January 1 to midnight the following day for a total of 36 hours).

Outage Transfer Distribution Factor (OTDF)

Planning Horizon – The period beginning at the end of the Hourly Operating Horizon and ending at the end of the 31st calendar day following the current day.

Power Transfer Distribution Factor (PTDF)

Study Horizon – The period beginning at the end of the Planning Horizon and ending at the end of the 18th calendar month following the current month.

Reliability Coordinator (RC)

Total Transfer Capability (TTC)

Transfer Distribution Factor (TDF)

Transmission Operator (TO)

Transmission Reliability Margin (TRM)

4.0 TRM Components (R1.1, R1.2)

LG&E/KU, as the Transmission Operator (TOP), considers the TRM components of LG&E/KU transmission system uncertainty described in this section in the TRM calculations. TRM component values will be set to zero, if they are not applicable.

Because the AFC methodology is used for the LG&E/KU Flowgates, the impact of power transfers on a transmission network is not path specific. Instead, TRM is applied against the Total Flowgate Capability ratings and is implemented as a MW reduction of those ratings. This allows the application of TRM on every Flowgate in LG&E/KU as necessary.

TRM will account for the following components of LG&E/KU transmission system uncertainty:

- Network Uncertainty
  - Allowances for simultaneous path interactions
  - Forecast uncertainty in transmission system topology
  - Allowances for parallel path (loop flow) impacts
  - Aggregate load forecast uncertainty
  - Load distribution uncertainty
  - Inertial response and frequency bias
  - Short-term System Operator response
- Contingency Reserve Sharing (CRS) Uncertainty
- Generation Dispatch Uncertainty

4.1 Network Uncertainty

Modeling assumptions utilized to calculate AFC values can contribute to uncertainties. While LG&E/KU does not explicitly utilize all FERC allowed uncertainty components to establish TRM values for Flowgates, the flow uncertainties due to the following potential modeling inaccuracies are addressed by a TRM component for each Flowgate equal to 2% of the Flowgate rating.

- Allowances for simultaneous path interaction
- Forecast uncertainty in transmission system topology
- Allowance for parallel path (loop flow) impacts
- Aggregate load forecast uncertainty
- Load distribution uncertainty
- Inertial response and frequency bias
- Short-term system operator response

4.2 CRS Uncertainty

LG&E/KU and TVA have established a Contingency Reserve Sharing Group (TEE CRSG). As such, entities with reserve sharing obligations under the TEE CRSG, must set aside transmission capability to export these reserves. Similarly, transmission capability must also be set aside for importing CRS assistance from other TEE CRSG member systems. The CRS uncertainty component of TRM is a minimum value that each TO must reserve on the Flowgate and should not be sold at any time.

When applicable, this component must be considered for both CRS needs of the Transmission Provider's own transmission system, as well as, the CRS needs of neighboring systems. Care is taken not to over-state the CRS component of TRM when adjoining systems' TRM values sufficiently encompass the through-flow requirements. LG&E/KU simulates the outage of certain generators of neighboring TEE CRSG participants.

The calculation process to quantify this component of TRM is to modify the base generation dispatch normally provided in the power flow models to simulate the generator outage and the TEE CRSG redispatch. The Flowgates are simulated on the base case and the CRS dispatch case. The difference between the flows for each Flowgate in the two cases (normal and CRS dispatch) constitutes the TRM MW value for the CRS impact on each Flowgate. Only the maximum MW value difference (normal and CRS) when looking at all the CRS contingencies in included for evaluation in the TRM MW value for the CRS impact component.

4.3 Generation Dispatch Uncertainty

Generation dispatch uncertainty or the location and output of generation that is assumed in the Planning/Study Horizon might be vastly different from actual conditions in the Operating Horizon. The dispatch profile of generation can vary which can cause flows on the Flowgate to vary. Variations occur because of unit availability and changes in dispatch order due to operating cost changes. Variations in generating patterns can significantly affect transfer capability, especially when specific generators or combination of generators significantly impacts a particular Flowgate. These generation dispatch changes can be internal or external to the LG&E/KU Balancing Area.

The calculation process to quantify this value of the TRM component consists of modifying the generation dispatch normally provided in the power flow base case to simulate an outage of one generator with internal redispatch. The Flowgates are simulated on the base case and the redispatch case. The difference between the flows for each Flowgate in the two cases (normal and redispatch) constitutes the value for the generation dispatch impact on each Flowgate. Only the maximum MW value difference (normal and redispatch) when looking at all the generation outage models is included for evaluation in the TRM for the generation dispatch uncertainty component.

5.0 No Double Counting between TRM and CBM (R2)

Double counting between TRM and CBM is removed during CBM calculations, as required by FERC Order 890, NERC standard MOD-004-1, and MOD-008-1. The CBM Implementation Document has details.

6.0 TRM on Temporary Flowgates

Temporary Flowgates created by TVA as the RC will be assigned a TRM equal to 3% of the Flowgate rating.

7.0 Use of TRM in ATC Calculations (R1.3)

LG&E/KU uses an AFC methodology (NERC MOD-030-02) for calculation of ATC for each posted path. Firm and Non-Firm AFC values include a decrement for TRM of Network Uncertainty (2% of Flowgate rating), plus the maximum of the applicable CRS and Generation Dispatch Uncertainties in all horizons.

7.1 Excessive Congestion

Flowgates that experience an excessive level of congestion may be subjected to additional TRM to reduce future congestion. LG&E/KU will review these situations and will make a determination whether to increase the uncertainty component of TRM under these circumstances.

8.0 Frequency of Calculations (R4, R5)

TRM updates are typically performed quarterly but will be performed every 13 months at a minimum. LG&E/KU shall provide the TRM values to its Transmission Service

Provider(s) and Transmission Planners(s) no more than seven calendar days after a TRM value is initially established or subsequently changed.

9.0 Document Control (R3,R5)

LG&E/KU and/or the ITO posts and will maintain on OASIS its TRMID, for Transmission Service Providers, Reliability Coordinators, Planning Coordinators, Transmission Planner, and Transmission Operators, to review at any time.

- TRM value updates will be sent to the LG&E/KU Transmission Service Provider(s) and Transmission Planners(s) within seven calendar days from the time the values are updated and reviewed by the ITO.
- This TRMID, and if requested, underlying documentation (if any) used in determining TRM, in the format of the Transmission Operator, shall be made available within 30 calendar days following a written request being received. Requests for such information should be made to Ashley Moore the Manager, Policy & Tariffs at Ashley.Moore@lge-ku.com with a subject line of "TRM Documentation Request".

Document Content(s)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

East Kentucky Power Cooperative, Inc.	)	
	)	**Docket No. EL16-8-000**
v.	)	
	)	
Louisville Gas and Electric Company/	)	
Kentucky Utilities Company	)	

MOTION FOR LEAVE TO ANSWER AND LIMITED ANSWER OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY

Pursuant to Rules 212 and 213 of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") Rules of Practice and Procedure,[1] Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "LG&E/KU") submit this Motion for Leave to Answer and Limited Answer ("Answer") to East Kentucky Power Cooperative, Inc.'s ("EKPC") December 9, 2015 Motion for Leave to Answer and Answer (the "December 9th Answer").[2]

For the reasons stated in LG&E/KU's November 23, 2015 Answer (the "November 23rd Answer") to EKPC's October 30, 2015 Complaint (the "Complaint") and the additional reasons stated below, the Complaint is without merit and should be summarily rejected. LG&E/KU have properly administered their Open Access Transmission Tariff (the "OATT").[3]

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[1] 18 C.F.R. §§ 385.212, 385.213 (2015).

[2] *Louisville Gas & Elec. Co. et al. v. E. Ky. Power Coop., Inc.*, Docket No. EL16-8-000, Motion for Leave to Answer and Answer of East Kentucky Power Cooperative, Inc. (Dec. 9, 2015).

[3] The LG&E/KU OATT is currently located under LG&E's "Transmission" title in eTariff, and may be found here: http://etariff.ferc.gov/TariffBrowser.aspx?tid=794. Capitalized terms not otherwise defined shall have the meaning set forth in Section 1 of the LG&E/KU OATT.

I. MOTION FOR LEAVE TO ANSWER

Although the Commission's procedural rules generally do not provide for answers to answers, protests, or similar filings unless otherwise ordered,[4] the Commission may, for good cause shown, permit such answers.[5] The Commission has previously accepted answers to answers when doing so will assist in the decision-making process.[6]

LG&E/KU respectfully submit the following Answer in order to correct several misstatements of fact and law contained in EKPC's December 9th Answer, thereby ensuring that the record before the Commission is complete and accurate. This will assist the Commission's decision-making process. Accordingly, LG&E/KU respectfully request that the Commission accept this Answer for good cause shown.

II. LIMITED ANSWER

A. The Plain Language of the LG&E/KU OATT Warrants Denial of the Complaint

The subject of EKPC's Complaint is transmission service under the LG&E/KU OATT. That LG&E/KU voluntarily agreed to facilitate a dynamic transfer for EKPC[7] does not excuse

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[4] 18 C.F.R. § 385.213(a)(2).

[5] 18 C.F.R. § 385.101(e) (2015).

[6] *See, e.g.*, *Emera Me.*, 153 FERC ¶ 61,283 at P 29 (2015) ("We will accept the answers filed here because they have provided information that assisted us in our decision-making process."); *PPL Corp.*, 153 FERC ¶ 61,257 at P 27 (2015) ("We accept the Talen Energy Answer and the Macquarie Reply because they have provided information that assisted us in our decision-making process."); *Cal. Indep. Sys. Operator Corp.*, 153 FERC ¶ 61,186 at P 28 (2015) ("We will accept the answers and replies filed by [Imperial Irrigation District], [California Independent System Operator Corporation], and Powerex because they have provided information that assisted us in our decision-making process.").

[7] In Order No. 888, the Commission addressed the issue of requiring transmission providers to offer dynamic scheduling and decided not to make that service mandatory:

> [W]e will not require that the transmission provider offer Dynamic Scheduling Service to a transmission customer, although it may do so voluntarily. If the customer wants to purchase this service from a third party, the transmission provider should make a good faith effort to accommodate the necessary arrangements between the customer and the third party for metering and communication facilities.

See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg.

either EKPC or LG&E/KU from the need to adhere to the rates, terms and conditions of the LG&E/KU OATT. Stated another way, it does not matter what EKPC pays as a Transmission Customer or is paid as a Transmission Owner under the PJM Interconnection, L.L.C. ("PJM") Open Access Transmission Tariff ("PJM Tariff"). EKPC is a Network Integration Transmission Service ("NITS") customer under the LG&E/KU OATT and must balance its designated Network Resources with discrete Network Loads served using the LG&E/KU Transmission System. The non-conforming service that EKPC requests in its Complaint fails this core requirement.[8]

In the December 9th Answer, EKPC alleges that its transmission service request "is entirely consistent with [LG&E/KU] Tariff service."[9] However, TranServ International, Inc. ("TranServ"), the Independent Transmission Organization responsible for evaluating transmission service requests under LG&E/KU's OATT, does not agree with EKPC that its request to include a new Network Load representing the difference between the output of the Bluegrass facility and its LG&E/KU-connected load is consistent with the provisions of the LG&E/KU OATT.[10] As TranServ notes, the "key provision" is Section 31.3, "which provides that a network customer that wishes to designate Network Load that is not physically

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21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 at p. 31,710-711 (1996), *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom.*, Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom.*, New York v. FERC, 535 U.S. 1 (2002). The Commission has clearly stated that dynamic scheduling is an optional transmission service. Order No. 888 at 31,705 ("We will not require other interconnected operations services as part of an open access transmission tariff. If a transmission provider supplies such services voluntarily, they may be added to a customer's service agreement with the transmission provider.").

[8] Thus, EKPC's statement in the December 9th Answer stating that it is not seeking to avoid paying for Network Service on the LG&E/KU system is incorrect. *See* December 9th Answer at 3. EKPC's whole proposal is designed to avoid paying for NITS or Point-To-Point Transmission Service in accordance with the plain language of the LG&E/KU OATT.

[9] *Id.* at 2.

[10] *See Louisville Gas & Elec. Co. et al. v. E. Ky. Power Coop., Inc.,* Docket No. EL16-8-000, Answer to Complaint of TranServ International, Inc. at 5 (Nov. 23, 2015).

interconnected to the transmission owner's transmission system may do so pursuant to two options: (1) including the entire load as Network Load and designating Network Resources in connection with such load, or (2) excluding the entire Network Load and purchasing Point-to-Point Transmission Service to serve that load."[11] For TranServ, EKPC's request is "plainly inconsistent" with the OATT, and there is "no merit to EKPC's suggestion that [LG&E/KU] should be compelled, pursuant to the terms of the existing tariff, to provide EKPC transmission service on such terms."[12]

While EKPC states that the December 9th Answer is an answer to both LG&E/KU and TranServ,[13] EKPC never even expressly mentions TranServ's straightforward interpretation of the OATT. Instead, EKPC has simply chosen to read the words "discrete" and "entire" out of the LG&E/KU OATT.[14] It is a longstanding principle of FERC jurisprudence that when a tariff is unambiguous, it is controlling.[15] Moreover, a tariff should not be interpreted in a manner that

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[11] *Id.* at 6-7.

[12] *Id.* at 7, 9.

[13] December 9th Answer at 1.

[14] Section 1.25 of the LG&E/KU OATT states that "[a] Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a ***discrete*** Point of Delivery." (emphasis added). In the December 9th Answer, EKPC cites Section 28.1 of the OATT, which states that NITS "allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated resources) to serve their Network Load in the Balancing Authority Area and any additional load that may be designated pursuant to Section 31.3 of the Tariff." December 9th Answer at 4. However, Section 31.3 provides:

> This section applies to both initial designation pursuant to Section 31.1 and the subsequent addition of new Network Load not physically interconnected with the Transmission Owner. To the extent that the Network Customer desires to obtain transmission service for a load outside the Transmission Owner's Transmission System, the Network Customer shall have the option of (1) electing to include the ***entire*** load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load, or (2) excluding that ***entire*** load from its Network Load and purchasing Point-To-Point Transmission Service under Part II of the Tariff. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

(emphasis added).

[15] *See* Koch Gateway Pipeline Co. v. FERC, 136 F.3d 810, 814 (D.C. Cir. 1998) (when interpreting tariffs, a court first looks to see whether the language of the tariff is unambiguous because if so, it is controlling); Ameren Servs. Co. v. FERC, 330 F.3d 494, 498 (D.C. Cir. 2003) (unambiguous language in settlement agreement is

renders one of its terms meaningless.[16] EKPC's Complaint, which is premised on the violation of these fundamental principles, should be summarily rejected.

B. EKPC's Reference to Other Authorized Uses of Transmission Capacity Does Not Support Its Request for Unauthorized Service

EKPC seeks to justify its Complaint by citing other examples where LG&E/KU are required to set aside transmission capacity. EKPC's December 9th Answer does not withstand scrutiny as EKPC is failing to distinguish specifically authorized uses under the OATT from its unauthorized request.

As noted in the December 9th Answer, LG&E/KU reserve a Transmission Reliability Margin (the "TRM").[17] Completely different from the unauthorized request EKPC has made, Attachment C of the LG&E/KU OATT specifically and expressly authorizes this practice, which benefits the entire Balancing Authority Area. The TRM facilitates participation in a Contingency Reserve Sharing Group, a practice sanctioned by NERC Standard BAL-002-1. A Reserve Sharing Group lowers the overall reserve margin that needs to be maintained not only by the LG&E/KU Balancing Authority Area, but also in all of the participating Balancing Authority Areas.[18] EKPC's request, on the other hand, does not conform to the provisions of the LG&E/KU OATT, and is designed to confer an unprecedented benefit solely to one customer, EKPC.

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controlling); *Pac. Gas & Elec. Co.*, 107 FERC ¶ 61,154 at P 19 (2004) (stating "when the language of a contract is explicit and clear . . . then the court may ascertain the intent from its written terms and not go further.").

[16] *Great Lakes Gas Transmission Ltd. P'ship*, 93 FERC ¶ 61,008 at 61,019, n.8 (2000).

[17] December 9th Answer at 10-11.

[18] Accordingly, the affiliated LG&E/KU load-serving entity is one of the primary beneficiaries of the TRM set aside to allow this flexibility. Therefore, LG&E/KU already have a process in place to address the concerns they stated regarding the uncertainty of whether the Bluegrass units will be dispatched. *See id.* at 12.

Next, EKPC analogizes itself to an industrial load whose output can vary between 0 and 174 MW depending on the production schedule.[19] LG&E/KU do not disagree that certain loads can place more variability on the system than others. Nevertheless, the essential distinction is that the industrial load is a discrete Network Load that has been properly identified in accordance with the OATT, while EKPC's proposed Bluegrass Delivery Point is not.

EKPC's statement in the December 9th Answer that the service requested by the Complaint requires no deviations from the status quo[20] is without merit. EKPC wants to restrict transfer capacity from LG&E/KU to PJM first by up to 283 MW and, after May 2019, by up to 476 MW until the end of the service agreement in 2026.[21] Any statement in the December 9th Answer that focuses on a historical two-month sample of transfer capability is not apropos to EKPC's request, which is a request for all hours of all days through an initial contract term expiring in 2026.

C. Rejection of EKPC's Request Will Avoid Setting an Unwarranted Precedent Regarding the Use of NITS

EKPC's request, if approved, would set an unwarranted precedent. Rather than respecting longstanding principles regarding the scope and manner of services offered under the OATT, any Transmission Customer could seek preferential treatment to address their specific circumstances. This is antithetical to the concept of non-discriminatory open access. In accordance with Section 28.3 of the OATT, LG&E/KU make available firm transmission service over the LG&E/KU Transmission System to the Network Customer "on a basis that is comparable to the Transmission Owner's use of the Transmission System to reliably serve its

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[19] *Id.* at 13.

[20] *Id.* at 9.

[21] *See* Complaint at Attachment 1.

Native Load Customers." EKPC's request is for a service far beyond that approved by the Commission for any Transmission Customer.

For example, NITS is a demand-based service based on load-ratio shares. EKPC seeks to convert this to a hybrid demand and generation-based service,[22] and EKPC proposes to be charged for deliveries at the Bluegrass Delivery Point only on the basis of actual energy delivered – not on 100% of the discrete load at the point of delivery.[23] Stated another way, LG&E/KU's customers and other Transmission Customers will be subsidizing the transmission capacity reserved and not paid for by EKPC. In Order No. 888-A, the Commission recognized that permitting a NITS customer to designate less than its full load at a discrete point would allow the customer to "game the system," thereby evading some or all of its load-ratio cost responsibility.[24]

In addition, NITS is not permitted, and should not be permitted to be used to support off-system sales to non-Network Loads,[25] which is what would result during those hours in which the combined output of the Bluegrass units exceeds the amount of Network Load EKPC has on the LG&E/KU system. In the November 23rd Answer, LG&E/KU noted that another

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[22] December 9th Answer at 4-5 ("At this delivery point, EKPC would deliver output from the Bluegrass Units to the extent that such output exceeds that amount of East Kentucky's Network Load connected to the [LG&E/KU] transmission system.").

[23] *See* Complaint at 18.

[24] The Commission explained in Order No. 888-A:

> The concept of allowing a "split system" or splitting a discrete load is antithetical to the concept of network service. A request for network service is a request for the integration of a customer's resources and loads. Quite simply, a load at a discrete point of delivery cannot be partially integrated – it is either fully integrated or not integrated. Furthermore, such a split system creates the potential for a customer to "game the system" thereby evading some or all of its load-ratio cost responsibility for network services.

Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,259 (1997) (citations omitted); *see also* Transmission Access Policy Study Group v. FERC, 225 F.3d 667, 726 (D.C. Cir. 2000), *aff'd sub nom.*, New York v. FERC, 535 U.S. 1 (2002) (affirming the Commission's findings on behind-the-meter generation).

[25] *See* LG&E/KU OATT, Section 30.4.

transmission provider, the Southwest Power Pool, Inc. ("SPP"), similarly objected to the use of designated network resources for off-system transfers.[26] EKPC's precedent-setting request for such clearly impermissible use of NITS, therefore, should be rejected.

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[26] November 23rd Answer at 5. As stated by SPP,

> All of the [Arkansas Electrical Cooperative Corporation ("AECC")] resources within SPP have been designated by AECC to serve AECC *loads within SPP* . . . but not AECC loads within [Entergy Arkansas, Inc. ("EAI")] . . . Therefore, SPP would clarify that the SPP [Network Integration Transmission Service Agreement ("NITSA")] is not currently structured to serve AECC load within EAI, nor does the SPP NITSA recognize that AECC designated resources may be utilized for AECC load located outside of SPP.

Midcontinent Indep. Sys. Operator Inc., Docket No. ER14-684-000, Motion of Southwest Power Pool, Inc. to Accept Comments Out of Time and Comments at 5 (Jan. 23, 2014) (emphasis retained).

III. CONCLUSION

For the reasons set forth herein, LG&E/KU respectfully request that the Commission accept this Answer in order to ensure that the record before the Commission is complete and accurate.

Respectfully submitted,

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Counsel for Louisville Gas and Electric Company and Kentucky Utilities Company

December 22, 2015
Washington, D.C.

CERTIFICATE OF SERVICE

I hereby certify that on this the 22nd day of December, 2015, I have caused a copy of the foregoing document to be served upon each person listed in the Secretary's official service list for the above-referenced proceeding.

/s/ Thomas S. DeVita
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Document Content(s)

154 FERC ¶ 61,144

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

East Kentucky Power Cooperative, Inc. Docket No. EL16-8-000

v.

Louisville Gas & Electric Company/Kentucky Utilities Company

ORDER DENYING COMPLAINT

(Issued February 26, 2016)

1. On November 2, 2015, East Kentucky Power Cooperative, Inc., (EKPC) filed a complaint against Louisville Gas & Electric Company (LG&E) and Kentucky Utilities Company (KU) (collectively, LG&E/KU), pursuant to sections 206, 211 and 306 of the Federal Power Act (FPA)[1] and Rule 206 of the Commission's regulations. The complaint alleges that LG&E/KU's failure to accept EKPC's designation of new Network Load[2] under EKPC's Network Integration Transmission Service Agreement (NITSA)[3] with LG&E/KU is contrary to the terms of the LG&E/KU Open Access Transmission Tariff

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[1] 16 U.S.C. §§ 824e, 824j-l, and 825e (2012).

[2] EKPC submitted an amended NITSA as an attachment to the complaint that defines EKPC's new Network Load as the amount of Bluegrass Generating Station (Bluegrass station) output that exceeds EKPC's Network Load on the LG&E/KU system. *See* Attachment 1, Section 4.

[3] On December 21, 2015, LG&E/KU filed with the Commission an updated NITSA, adding the Bluegrass Generating Station as a Network Resource, currently pending in Docket No. ER16-598-000.

(Tariff)[4] and the Commission’s policies concerning open access and transmission pricing. EKPC, which is in the process of acquiring the Bluegrass station, requested network service to allow EKPC to use the Bluegrass station output to serve native EKPC load on the EKPC system, in addition to EKPC load on the LG&E/KU system. EKPC requests that the Commission find that LG&E/KU’s denial of network service is unjust and unreasonable as applied to EKPC. EKPC further seeks waiver of the LG&E/KU Tariff to adopt an amended NITSA as a non-conforming agreement to LG&E/KU’s Tariff.

2. As discussed more fully below, we deny EKPC’s complaint because EKPC has failed to support its request for a NITSA which differs significantly from the LG&E/KU Tariff and the Commission’s policies on open access transmission. Moreover, we also find that EKPC has not shown, pursuant to section 206 of the FPA, that LG&E/KU’s Tariff is unjust and unreasonable as it relates to EKPC. We also deny the requested waiver because, in the circumstances presented, EKPC has not shown that its waiver would be limited in scope or would not cause harm to third parties.

I. Background

3. EKPC, an exempt generation and transmission cooperative,[5] transferred functional control of its transmission facilities rated 100 kV and above to PJM Interconnection, L.L.C. (PJM) and is, therefore, a transmission owning member of PJM. EKPC owns and purchases 2,794 megawatts (MW) of net summer generating capability and 3,009 MW of net winter generating capability to service approximately 525,000 customers in 87 Kentucky counties through its 16 member distribution cooperatives. Most of EKPC’s member load (3,000 MW, or approximately 80 percent) is physically connected to transmission facilities owned by EKPC. Because of EKPC’s integration into PJM, this load is located within the PJM footprint in the EKPC Zone.

4. LG&E and KU are both public utilities. LG&E serves customers in Louisville, Kentucky and 16 surrounding counties and KU serves 77 Kentucky counties and five counties in the Commonwealth of Virginia. LG&E/KU operate under a combined

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[4] In this order, we use the term “Tariff” or “LG&E/KU Tariff” to represent LG&E/KU’s Open Access Transmission Tariff (OATT) and “*pro forma* OATT” to represent the tariff promulgated by the Commission under Order Nos. 888 and 890. We also capitalize the terms “Network Load,” “Point-to-Point,” and “Network Resource” as those terms are capitalized and identified in LG&E/KU’s Tariff.

[5] *See* 16 U.S.C. § 824(f) (2012).

Commission-approved Tariff based on the requirements of Order Nos. 888[6] and 890.[7] LG&E/KU are outside the PJM footprint and do not participate in a Regional Transmission Organization since their withdrawal from the Midcontinent Independent System Operator, Inc. (MISO) in 2006.[8]

5. The LG&E/KU and EKPC transmission systems and service territories are intertwined. LG&E/KU and EKPC share 66 interconnection points between their transmission systems. Each uses the other's facilities to serve a portion of their native-load customers through numerous load interconnection points. The small portion of EKPC's load that is physically connected to the LG&E/KU transmission system is pseudo-tied[9] to PJM and is treated as part of EKPC's internal zone load in PJM. The Commission approved these arrangements as part of its broader approval of the PJM and EKPC joint filing to integrate EKPC into PJM.[10]

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[6] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[7] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[8] *See Louisville Gas and Electric Co*., 114 FERC ¶ 61,282 (2006).

[9] A pseudo-tied resource is a resource (i.e., generation unit or load) that is functionally transferred from the Balancing Authority (BA) in which the resource is physically located to another BA that has operational responsibility for the resource.

[10] PJM and EKPC's joint filing in connection with EKPC's integration into PJM accepted by delegated letter order issued May 22, 2013. *See East Kentucky Power Coop., Inc.*, Docket No. ER13-1177-000, *et al.* (May 22, 2013) (delegated letter order).

6. On June 26, 2015, EKPC executed an agreement with Bluegrass Generating Company, LLC to purchase the Bluegrass station, and the transaction was scheduled to close by December 31, 2015. The Bluegrass station is a 495-MW (summer capacity) natural gas-fired peaking facility, which is located within LG&E/KU's footprint. The Bluegrass station has three units: Bluegrass Unit 1, Bluegrass Unit 2, and Bluegrass Unit 3. Bluegrass Unit 3 is subject to a power purchase contract with LG&E/KU until May 1, 2019, so it will not be available to serve EKPC's load until after that date. The Bluegrass station is also subject to NO_x restrictions and can only run up to seven percent of the year's total hours. However, EKPC forecasts that the Bluegrass station will run less than six percent of the year's total hours.

II. Complaint

A. EKPC's Proposal to Integrate the Bluegrass station into EKPC's Network Load

7. In its complaint, EKPC states that it anticipates using the output from the Bluegrass station as a Network Resource to serve its member load. EKPC asserts that it will use output from the Bluegrass station chiefly to serve that portion of its load which is connected to LG&E/KU's transmission facilities.[11] However, EKPC states that there may be some hours during which the output of the Bluegrass station exceeds the amount of EKPC member load on the LG&E/KU system.[12] During these hours, EKPC asserts that it intends to deliver any Bluegrass station output that exceeds the amount of EKPC's Network Load connected to the LG&E/KU transmission facilities to EKPC's Network Load connected to the EKPC transmission facilities.

8. EKPC states that it intends to use its NITSA with LG&E/KU to integrate the Bluegrass station with EKPC's loads in the manner described above. Accordingly, EKPC asserts that it submitted a transmission service request to TranServ International, Inc. (TranServ) to designate the Bluegrass station as a Network Resource under EKPC's NITSA with LG&E/KU.[13] EKPC states that TranServ (in its capacity as LG&E/KU's Independent Transmission Organization) concluded that transmission service is available to deliver the Bluegrass station output to EKPC's Network Load on LG&E/KU's transmission system and LG&E/KU confirmed that EKPC may add the Bluegrass station as a new Network Resource under EKPC-LG&E/KU NITSA. EKPC states there is no

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[11] EKPC Complaint at 12.

[12] *Id*. at 7-8.

[13] *Id*. at 8.

dispute between the parties regarding the delivery of the Bluegrass station output to EKPC's Network Load on the LG&E/KU system. Rather, EKPC asserts the dispute is with regard to the charges LG&E/KU seek to impose for the delivery of the Bluegrass station output to EKPC's Network Load from LG&E/KU's transmission system to EKPC's system.[14]

9. EKPC asserts that it approached TranServ and LG&E/KU on several occasions to resolve the issues regarding delivery of the Bluegrass station output to EKPC's Network Loads and the compensation issue, but reached no resolution.[15] EKPC states that it had proposed, and proposes in its complaint, to modify its existing NITSA with LG&E/KU to deliver the output of the Bluegrass station that exceeds EKPC's member load connected to LG&E/KU's transmission facilities. EKPC states that the proposed amendments to the LG&E/KU-EKPC NITSA seek to: (1) establish the Point of Delivery as one or more points of interconnection between EKPC's system and LG&E/KU's system; and (2) designate a portion of EKPC's member load connected to EKPC's transmission facilities as new Network Load under the EKPC-LG&E/KU NITSA, with the amount of that load stated as the output of the Bluegrass station in any hour minus the aggregate EKPC member load served from the LG&E/KU transmission facilities.[16] EKPC asserts that, pursuant to its proposed amended NITSA, the sum of the delivery point requirements in each hour would be the basis for determining EKPC's monthly coincident peak on the LG&E/KU system, which is the demand used for billing for network service under the LG&E/KU Tariff.

10. EKPC states that LG&E/KU rejected the above proposed amendments. EKPC states LG&E/KU have instead advised EKPC that, if EKPC intends to deliver any of the Bluegrass station output to service EKPC's load on the EKPC transmission system, EKPC may purchase Point-to-Point service for the full amount of the Bluegrass station output, less the anticipated minimum load physically connected to the LG&E/KU system. EKPC asserts that LG&E/KU also suggested that EKPC could designate delivery points currently served from EKPC's own transmission system as delivery points under the LG&E/KU NITSA, in sufficient amounts so that EKPC's minimum load on LG&E's system would always be at least equal to the nominal nameplate rating of the Bluegrass station. EKPC argues that LG&E/KU's suggested arrangements would force EKPC to designate several hundred megawatts of load served by EKPC's own transmission facilities as Network Load on the LG&E/KU transmission system.

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[14] *Id*. at 9.

[15] *Id*.

[16] *Id*.

11. EKPC asserts that it advised LG&E/KU that requiring EKPC to reserve 400 MW or more of Point-to-Point service or adding hundreds of megawatts of additional load as Network Load is unreasonable and expensive.[17] EKPC argues that LG&E/KU's suggestion would subject EKPC to duplicative charges as well as excessive charges for an amount of transmission service that LG&E/KU would not be providing. EKPC contends that its current payments to LG&E/KU for network service total approximately $7 million per year, but LG&E/KU's approach would increase these payments by $10 million, totaling approximately $17 million per year.[18]

B. <u>Consistency With LG&E/KU's Tariff and Commission Policy</u>

12. EKPC argues that its proposal is consistent with the flexibility provided for under section 31.3 of the *pro forma* OATT and the LG&E/KU Tariff.[19] EKPC asserts that section 31.3 of the *pro forma* OATT permits a network service customer to designate load that is not directly connected to the transmission provider as part of the customer's Network Load and the LG&E/KU Tariff adopts this provision essentially verbatim.[20] EKPC asserts section 31.3 of the LG&E/KU Tariff permits EKPC to designate, as part of its Network Load under a modified NITSA with LG&E/KU, its member load that is not directly connected to the LG&E/KU system. EKPC contends that the only condition for doing so is that EKPC must designate one or more Network Resources for that load, which EKPC has satisfied by identifying the Bluegrass station as that designated resource.

13. EKPC argues that the purpose underlying section 31.3 further confirms that LG&E/KU's refusal to accept EKPC's proposed amendments to the NITSA is unreasonable.[21] EKPC states that sections 31.3 and 1.25 defining "Network Load" must be read together. EKPC states that section 1.25 states, in relevant part, that a network customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete point of delivery.[22] EKPC states that

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[17] *Id*. at 10.

[18] *Id*. at 11.

[19] *Id*. at 13.

[20] *Id*.

[21] *Id*. at 15.

[22] *Id*. at 15.

Network Load was defined in this manner in Order No. 888 to prevent customers from combining Network and Point-to-Point service at a single, discrete delivery point (e.g., a customer utilizing behind-the-meter generation).[23] EKPC contends that it is not a transmission-dependent wholesale customer with behind-the-meter generation because it is an interconnected utility. EKPC further contends that it is not seeking the proposed arrangements to avoid paying for network service because all of its load is subject to PJM's network service charges, and is not at all akin to load served from behind-the-meter generation that might escape paying for network service in the absence of this Tariff provision.

14. EKPC argues that its proposal is also consistent with Commission policy as expressed in Order No. 888-A.[24] EKPC asserts that, in Order No. 888-A, the Commission addressed pricing for transmission service to entities with load in multiple control areas. EKPC states that several commenters in that proceeding complained that, if a network service customer with resources and load in control area A also wished to serve Network Load in control area B, the customer would be required to include the control area B load as Network Load in both control areas, and that the customer would be exposed to the possibility of paying two network service charges for the control area B load. EKPC asserts that the Commission summarized the solution proposed by these commenters as:

> [T]hese entities propose that a network customer be allowed to use its network service to transmit power and energy from resources in control area A to serve load in control area B without designating the control area B load as network load for billing purposes. These entities suggest that no additional compensation should be required if such transfers to load in adjacent control areas plus other network transactions on behalf of the transmission customer in control area A do not exceed the customer's coincident demand in control area A.[25]

EKPC argues that the Commission rejected the argument that a customer receiving network service in control area A should be able to serve load in control area B without that load being designated as additional Network Load in control area A. EKPC asserts that the Commission stated that:

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[23] *Id.* (citing Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,260-61).

[24] *Id*. at 16.

[25] *Id.* at 17 (citing Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,254-55).

> [b]ecause the additional transmission service to non-designated network load outside of the transmission provider's control area is a service for which the transmission provider must separately plan and operate its system beyond what is required to provide service to the customer's designated network load, it is appropriate to have an additional charge associated with the additional service.[26]

15. EKPC argues that its proposed amended NITSA satisfies the Commission's concern about compensating the transmission provider for transmission planning and operations. EKPC asserts that the EKPC-connected load (the control area B load in the Commission's example) is designated as additional Network Load in the NITSA with LG&E/KU. EKPC contends that, whenever EKPC uses LG&E/KU's transmission service, the Network Load value for the amount of the Bluegrass station output delivered to the EKPC-connected load will be included in the determination of EKPC's coincident peak for billing under the parties' NITSA. By contrast, EKPC argues that LG&E/KU's refusal to provide flexibility would result in excessive overcharges inconsistent with the Commission's policy of encouraging transmission providers to design rates that avoid double recovery of transmission costs.[27]

16. EKPC asserts that the Commission's policy that transmission providers provide flexibility to address unique circumstances should not be lost on LG&E/KU.[28] EKPC contends that LG&E/KU are the beneficiary of the Commission's willingness to accept a NITSA with specific terms to address unusual circumstances. EKPC states that, when EKPC integrated into PJM, LG&E/KU were concerned that they would be subject to PJM charges in connection with service across EKPC's facilities to serve the LG&E/KU load that is physically connected to the EKPC system. EKPC states that the Commission accepted arrangements to treat LG&E/KU's load on the EKPC system as outside of PJM, notwithstanding EKPC's integration into PJM. Here, EPKC states that it is seeking an arrangement based on its use of LG&E/KU's system and the Commission's policies on transmission pricing.

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[26] *Id.* (citing Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,255).

[27] *Id.* at 18 (citing Order No. 888-B, 81 FERC ¶ 61,248 at 62,096. "Moreover, while we expect transmission providers to design rates that will avoid double recovery of such transmission costs or ancillary costs, we believe that this is a fact-specific issue that is appropriately addressed on a case-by-case basis").

[28] *Id.* at 20-21.

C. Consistency With Commission Precedent

17. EKPC contends that its proposed arrangements are consistent with other arrangements accepted for filing by the Commission. EKPC states that the Commission accepted for filing an amended NITSA between Southern Company Services (Southern) and Southern Mississippi Electric Power Association (SMEPA) which was similar to the circumstances here.[29] EKPC asserts that the SMEPA-Southern NITSA allows SMEPA's pseudo-tied loads to be served from various resources. EKPC states that SMEPA and Southern amended their NITSA to: (1) establish a new delivery point at the interchange point between the Southern system and the SMEPA system; and (2) calculate the Network Load at the new delivery point, which would be "a calculated value for flow into the SMEPA balancing authority area."[30] EKPC asserts that the value of the Network Load at the new delivery point would be calculated on an hourly basis similar to the energy generated by Network Resources located within the Southern balancing authority area that is not used to serve SMEPA's Network Load located within the Southern balancing authority area.

18. Next, EKPC argues the Commission accepted a similar filing between SMEPA and MISO in connection with SMEPA's integration into MISO.[31] EKPC asserts that MISO recognized the heavily intertwined systems of SMEPA, Southern and Entergy Mississippi. EKPC states that Southern is not a transmission-owning member of MISO, which meant that a portion of SMEPA's load and resources would be physically located outside the MISO region. EKPC asserts that SMEPA intended to serve that portion of SMEPA's load that is physically connected to the Southern system with resources internal to the SMEPA-MISO system and MISO did not require SMEPA to arrange for separate Point-to-Point service under the MISO Tariff to allow SMEPA to deliver its internal resources to SMEPA load on the Southern system. Instead, EKPC argues MISO patterned the SMEPA-MISO NITSA after the SMEPA-Southern NITSA and provided flexibility to SMEPA in its NITSA.

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[29] *Id*. at 20 (citing *Alabama Power Co*., Docket No. ER12-1724-000, (June 4, 2012) (delegated letter order) (SMEPA-Southern)).

[30] *Id*. (citing SMEPA filing letter at 2).

[31] *Id*. at 21 (citing *Midcontinent Indep. System Operator, Inc.*, 145 FERC ¶ 61,242 (2013) (MISO-SMEPA)).

19. EKPC contends that the approach embodied in the SMEPA-Southern NITSA and the subsequent SMEPA-MISO NITSA reflects an appropriate solution here. EKPC avers that it appropriately modeled its proposed amended NITSA with LG&E/KU after the SMEPA-Southern and SMEPA-MISO NITSAs.

D. Alternative Requests for Relief

20. EKPC argues that the Commission should find that its proposed amended NITSA is consistent with the LG&E/KU Tariff as well as the Commission's intent that transmission customers have flexibility when structuring arrangements to integrate their load and resources. However, if the Commission concludes otherwise, EKPC requests that the Commission find that the LG&E/KU Tariff is unjust and unreasonable as applied to EKPC.[32]

21. Additionally, to the extent necessary, EKPC seeks waiver of section 31.3 of the LG&E/KU Tariff to adopt the proposed amended NITSA as a non-conforming agreement. EKPC states that it meets the Commission's requirements for granting waiver requests: (1) the entity seeking the waiver acted in good faith; (2) the waiver is of limited scope; (3) a concrete problem exists that needs to be remedied; and (4) the waiver will not produce undesirable consequences.[33]

22. In this case, EKPC states it has identified a concrete problem for which a remedy is necessary. EKPC asserts that, until now, neither EKPC nor LG&E/KU had generating resources physically connected to the other's system and unless a remedy is adopted, EKPC will not be able to cost-effectively integrate its resources and loads (as network service is intended to achieve) and LG&E/KU will succeed in forcing EKPC to pay excessive and unreasonable charges for service that EKPC does not need.

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[32] *Id*. at 25.

[33] *Id*. (citing *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,069, at PP 8-9 (2011); *ISO New England Inc.*, 134 FERC ¶ 61,182, at P 8 (2011); *California Indep. Sys. Operator Corp.*,132 FERC ¶ 61,004, at P 10 (2010); *Hudson Transmission Partners, LLC*, 131 FERC ¶ 61,157, at P 10 (2010); *Pittsfield Generating Co., L.P.*, 130 FERC ¶ 61,182, at PP 9-10 (2010); *accord ISO New England Inc. EnerNOC*, 122 FERC ¶ 61,297, at P 13 (2008); *Central Vermont Public Service Corp.*, 121 FERC ¶ 61,225, at P 28 (2007); *Waterbury Generation LLC*, 120 FERC ¶ 61,007, at P 31 (2007); *Acushnet Co.*, 122 FERC ¶ 61,045, at P 14 (2008)).

23. EKPC argues that waiver of the section 31.3 of the LG&E/KU Tariff will not produce undesirable results because EKPC's proposed calculation for its new Network Load ensures that LG&E/KU will be properly compensated for EKPC's use of LG&E/KU's transmission system. Moreover, EKPC argues that the waiver is limited to the identification of EKPC's new Network Load under the LG&E/KU NITSA and the calculation of that load for purposes of arriving at the proper billing determinants.

24. Finally, EKPC states it acted in good faith by attempting to resolve this issue with TranServ and LG&E/KU but it was unable to obtain agreement concerning the proposed arrangements.

III. **Notice of Filing and Responsive Pleadings**

25. Notice of EKPC's complaint was published in the *Federal Register*, 80 Fed. Reg. 69,217 (2015), with answers, interventions, and protests due on or before November 23, 2015. A timely motion to intervene and answer was filed by TranServ.

26. LG&E/KU filed an answer to the complaint on November 23, 2015. On December 9, 2015, EKPC filed a motion for leave to answer and answer to LG&E/KU's answer and TranServ's answer. On December 22, 2015, LG&E/KU filed a motion for leave to answer and limited answer (December 22 answer).

A. **LG&E/KU Answer**

27. In their answer, LG&E/KU assert they have properly interpreted their Tariff consistent with Order No. 888. LG&E/KU state that there is no dispute between them and EKPC with respect to the designation of the Bluegrass station as a Network Resource to serve EKPC's discrete Network Load on LG&E/KU's transmission system.[34] However, LG&E/KU explain that EKPC is proposing to take any hourly positive energy imbalance on the LG&E/KU transmission system and deem it as load at the border between the LG&E/KU and EKPC systems.[35] LG&E/KU further explain that the Bluegrass station load output is not based on any physical customer demand for

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[34] In Docket No. ER16-598-000, in which LG&E/KU seek to amend their NITSA with EKPC to add the Bluegrass station as a Network Resource, LG&E/KU include the following statement authorized by EKPC:

> "…EKPC does not oppose this set of amendments to its NITSA in order to add the Bluegrass Units as Network Resources."

[35] LG&E/KU Answer at 11.

electricity but simply represents a positive imbalance between EKPC's Bluegrass station Network Resources and its physical Network Loads.[36]

28. LG&E/KU state that no customer should get preferential use of the transmission system. LG&E/KU explain that EKPC is seeking customer-specific transmission service that violates the requirements of the Tariff and would adversely impact the provision of non-discriminatory transmission service to other LG&E/KU transmission customers.[37] Therefore, LG&E/KU believe that they acted rationally in denying EKPC's proposed form of hybrid service.[38]

29. LG&E/KU contend that to be able to utilize network integration transmission service, the transmission customer must identify discrete Network Load at a point of delivery. Further, LG&E/KU contend that the customer does not have to identify its entire load, but must include the entire load associated with the point of delivery.[39] LG&E/KU argue that EKPC fails to meet both of these requirements.[40] LG&E/KU explain that energy imbalance located on an adjacent transmission system is not a discrete load in another transmission system.[41]

30. LG&E/KU maintain that they explained to EKPC its two options to deliver output of the Bluegrass station over and above the current amount of designated Network Load: (1) request and purchase Point-to-Point service in any desired amount sufficient to deliver the desired level of output of the Bluegrass station; or (2) designate any number of additional load points within EKPC's system as LG&E/KU Network Load to increase EKPC's minimum designated load to equal the desired level of output of the Bluegrass station, and be billed for that load under network integration transmission service. LG&E/KU explain that, even though EKPC and LG&E/KU may have heavily-integrated systems, it does not undermine the requirements of the Tariff.[42]

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[36] *Id.* at 12.

[37] *Id.*

[38] *Id.*

[39] *Id.* at 13.

[40] *Id.* at 14.

[41] *Id.* at 15.

[42] *Id.* at 16.

31. LG&E/KU state that EKPC's proposal is not consistent with the Commission's directives in Order Nos. 888, 888-A and 888-B. LG&E/KU state that, in a recently issued order, the Commission found the customer's "request to designate less than its entire load as network load violates" the *pro forma* OATT and Commission policy.[43] Moreover, LG&E/KU state that the Commission never intended load ratio share to be a measure of positive generation imbalance, but instead based on the requirements of the physical demand at discrete metered points.[44] LG&E/KU contend that EKPC's determination to be charged only based on generator imbalances within its control is the type of gaming that the Commission sought to prevent by requiring that all load at discrete points be designated.[45]

32. LG&E/KU contend that, aside from EKPC not identifying discrete portions of EKPC's load in PJM that would be identified as Network Load under the Tariff, there are also no proposed limitations that would prevent PJM from dispatching the Bluegrass station to serve demand elsewhere in PJM. In addition, LG&E/KU argue that there is no assurance that the winter peaking need identified by EKPC is consistent with PJM as a whole.[46]

33. LG&E/KU state that the Commission should deny any attempt to modify the Tariff to permit the proposed extremely inefficient use of the LG&E/KU transmission system.[47] LG&E/KU explain that EKPC's proposed service request would require

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[43] *Id*. at 19 (citing *Ariz. Pub. Serv. Co.*, 151 FERC ¶ 61,191, at P 26 (2015) (*Arizona Public Service*); *see also Fla. Municipal Power Agency v. Fla. Power & Light Co.*, 65 FERC ¶ 61,125, *reh'g dismissed*, 65 FERC ¶ 61,372 (1993), *final order*, 67 FERC ¶ 61,167 (1994), *clarified*, 74 FERC ¶ 61,006 (1996), *reh'g denied*, 96 FERC ¶ 61,130 (2001), *aff'd, sub nom. Fla. Municipal Power Agency v. FERC*, 315 F.3d 362 (D.C. Cir. 2003), *cert. denied*, 540 U.S. 946 (2003); *Fla. Power & Light Co.*, 105 FERC ¶ 61,287 (2003), *order on reh'g*, 106 FERC ¶ 61,204 (2004), *remanded*, *Fla. Municipal Power Agency v. FERC*, 411 F.3d 287 (D.C. Cir. 2005), *order on remand*, 113 FERC ¶ 61,290 (2005), *order on reh'g*, 116 FERC ¶ 61,012 (2006); *Ameren Servs. Co. v. Prairieland Energy, Inc.*, 131 FERC ¶ 61,125 (2010); *Consumers Energy Co.*, 86 FERC ¶ 63,004, at 65,032 (1999), *aff'd*, Opinion No. 456, 98 FERC ¶ 61,333 (2002)).

[44] *Id*. at 17.

[45] *Id*. at 17-18.

[46] *Id*. at 20.

[47] *Id*. at 20-21.

LG&E/KU to set aside transmission capacity on the applicable flowgates and because EKPC is not designating load as required under the Tariff for network integration transmission service, a reliable load forecast will not be available for the proposed Bluegrass station delivery point.[48] Therefore, LG&E/KU contend that to ensure deliverability, prevent oversubscription of firm transmission service, and limit reliance on transmission loading relief procedures, this transmission capacity would be withheld from use by other potential customers even though, by EKPC's own admission, the Bluegrass station is environmentally restricted to run only seven percent of the hours in a year.[49] In addition, LG&E/KU state that, unlike physical load that is predicted on historical usage patterns and meteorological conditions, EKPC could vary the imbalance amounts exported off the LG&E/KU transmission system based on its use of its portfolio of Network Resources. Moreover, LG&E/KU argue that this variability compromises effective planning of the LG&E/KU system.[50]

34. LG&E/KU explain that EKPC proposes that its Bluegrass station delivery point deliveries would be calculated on an after-the-fact basis, which complicates the ability to release this predominately unused transmission capacity for non-firm use.[51] Further, LG&E/KU argue that there is no ability under the Tariff to use network integration transmission service to deliver excess energy not associated with identified, real Network Loads.[52] LG&E/KU also state that, while EKPC claims that it would be paying for service twice, the Commission determined in Order No. 888-A that when service across multiple control areas is implicated, it is appropriate to have an additional charge associated with the additional service.[53]

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[48] *Id*. at 21.

[49] *Id*. at 21-22. For example, LG&E/KU state that EKPC's request would restrict transfer capacity from LG&E/KU to PJM by up to 283 MW and after May 2019, by up to 476 MW to support any potential positive energy imbalance EKPC would have between its Network Resources and Network Load in that hour.

[50] *Id*. at 23.

[51] *Id.* at 22.

[52] *Id*. at 26.

[53] *Id*. at 27.

35. LG&E/KU argue that EKPC's statements about its potential costs are unsupported and do not withstand scrutiny.[54] LG&E/KU state that it reviewed EKPC's actual load for the period July 1, 2014 to June 30, 2015 and identified the highest 600 hours of load across 64 unique days in the winter months – the periods most likely to require the services of a peaking resource such as the Bluegrass station. LG&E/KU then explain their calculations for different types of Point-to-Point service and that regardless of the exact calculations, the cost to EKPC for transmission service could be significantly less than the additional $10 million EKPC claims in its complaint.[55]

36. LG&E/KU contend that EKPC has not met its burden to show that LG&E/KU's Tariff is unjust and unreasonable. Moreover, LG&E/KU state that there is no Commission precedent that would warrant overturning the plain language of the Tariff.[56] Further, LG&E/KU argue that EKPC fails to identify the harms its preferential treatment would impose on other transmission customers and LG&E/KU as the non-discriminatory transmission provider.[57] In addition, LG&E/KU explain that EKPC's request would set a new precedent for transmission providers and other transmission customers whereby network integration transmission service could be used to support transactions outside of service to discrete Network Loads.[58]

37. LG&E/KU state that EKPC notes that, in 2012, the Commission accepted for filing the SMEPA-Southern NITSA by delegated authority. However, LG&E/KU note that delegated letter orders are not precedential.

38. Finally, LG&E/KU argue that EKPC has failed to meet the four requirements necessary to obtain a waiver. LG&E/KU explain that EKPC's request for a preferential, non-conforming NITSA would have a profound negative effect on other transmission customers and impair efficient utilization of the LG&E/KU transmission system.[59] Further, LG&E/KU contend that EKPC's preferential and improper use of a NITSA

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[54] *Id.* at 24.

[55] *Id.* at 25.

[56] *Id.* at 28.

[57] *Id.* at 23.

[58] *Id.* at 24.

[59] *Id.* at 30.

would negatively affect other customers through a reduction of transmission capacity.[60] LG&E/KU state that EKPC's request is also not limited in scope because the termination date of the agreement is 2026, and therefore, the waiver would be in effect for eleven years.[61] LG&E/KU state that the Commission should reject EKPC's complaint and request for waiver.

B. TranServ Answer

39. In its answer, TranServ states that it does not agree with EKPC that its request to include a new Network Load representing the difference between the output of the Bluegrass station and its LG&E/KU-connected load is consistent with the provisions of LG&E/KU's Tariff. TranServ asserts the relevant language in section 31.3 of LG&E/KU's Tariff (per the Commission's *pro forma* OATT) provides that a network customer wishing to designate Network Load that is not physically interconnected to the transmission owner's system may do so pursuant to two options: (1) including the entire load as Network Load and designating Network Resources in connection with such load; or (2) excluding the entire Network Load and purchasing Point-to-Point service to serve that load. TranServ argues that EKPC, however, seeks a third option which would define "Network Load" so as to include only that load on EKPC's system that is being served by the Bluegrass station during a particular hour.

40. TranServ states that, as acknowledged by EKPC, section 31.3 of the Tariff must be read in conjunction with the definition of Network Load in the Tariff. TranServ argues that, upon review, EKPC's proposal is plainly inconsistent with the language in the Tariff. Significantly, TranServ asserts that EKPC fails to identify Network Load at discrete "Point(s) of Delivery," which is defined as a point or points on the transmission system where capacity and energy transmitted will be made available to the receiving party.[62] TranServ states that, instead, EKPC proposes what amounts to a "virtual" point of delivery between the LG&E/KU and EKPC systems that represents the hourly difference (when positive) between the output of the Bluegrass station and the amount of EKPC load directly connected to the LG&E/KU system.[63]

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[60] *Id*. at 32.

[61] *Id*. at 31.

[62] TranServ Answer at 7 (citing LG&E/KU Tariff, Section 1.37, "Point(s) of Delivery").

[63] *Id*. at 7-8.

41. TranServ argues that, despite the inconsistencies between EKPC's proposal and the actual language of the LG&E/KU Tariff, EKPC contends that Commission policy and precedent supports a broader reading of section 31.3 and the definition of Network Load. TranServ claims, however, that none of the precedent cited by EKPC supports such a reading. First, TranServ asserts that EKPC argues that its proposal is consistent with the Commission's underlying purpose in defining Network Load so as to prohibit partial designation. TranServ states that EKPC claims that: (1) the Commission intended to prevent customers from combining Network and Point-to-Point service at a single, discrete delivery point, such as a customer using behind-the-meter generation, and (2) this limitation should not apply to EKPC because it is not a transmission-dependent wholesale customer with behind-the-meter generation. TranServ states that the Commission has never stated that the limit on partial designation only applies to "transmission-dependent wholesale customers" as opposed to "interconnected utilities." TranServ avers that the rule against partial designation of Network Load applies to EKPC in the same manner as it does to all other transmission customers.

42. Next, TranServ states EKPC argues that its proposal is consistent with section 31.3 because the Commission, in Order No. 888-A, stated that a customer receiving network service in control area A should be able to serve load in control area B for an "additional charge," and EKPC proposed to pay an "additional charge" for any difference between the Bluegrass station output and its LG&E/KU-connected load.[64] TranServ argues, however, it is clear from Order No. 888-A that the Commission used the term "additional charge" to specifically refer to the charge associated with a transmission customer obtaining Point-to-Point service to serve its external load, and not some alternative pricing option.[65] TranServ contends this approach is reflected in section 31.3 of the Tariff which provides transmission customers with only two options for obtaining service for an external load. As such, TranServ argues there is no merit to EKPC's suggestion that LG&E/KU should be compelled to, pursuant to its Tariff, provide EKPC transmission service on such terms.

43. Finally, TranServ states that EKPC points to two NITSAs accepted by the Commission which EKPC claims reflect the same solution that it is proposing to the Commission. TranServ argues that the SMEPA-Southern NITSA was accepted by the Commission in a delegated letter order so it cannot be used as binding precedent. TranServ states that the SMEPA-MISO NITSA did not address the type of arrangement

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[64] *Id*. at 9 (citing EKPC Complaint at 17-18).

[65] *Id*. (citing Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, at 30,255, finding that a transmission customer could exclude a discrete Network Load located in another control area "and to serve such load using point-to-point transmission service").

proposed by EKPC, but rather simply involved the Commission granting MISO's proposal to allow a customer to designate Network Load that is not physically connected with its transmission system, per section 31.3 of the *pro forma* OATT.

C. EKPC Answer

44. In its answer, EKPC states that its proposal seeks to integrate its resources and load, consistent with the LG&E/KU Tariff, not split its load. EKPC asserts that LG&E/KU argue as though: (1) EKPC is simply a load serving entity on the LG&E/KU system with behind-the-meter generation; (2) LG&E/KU perform balancing functions for EKPC; and (3) EKPC is attempting to construct arrangements that would enable it to avoid paying for service. EKPC maintains that all of these arguments are false. EKPC states that its reasonable legitimate request is consistent with LG&E/KU's Tariff and that it proffers a reasonable solution to the unique system configuration of EKPC and LG&E/KU.

45. EKPC argues that its proposed NITSA amendments will not create transmission planning complications for LG&E/KU. EKPC states that, while it is true that LG&E/KU must calculate and post available transmission capacity, release unscheduled firm transmission service for non-firm use, and plan their system to support the needs of Network Customers as well as Native Load, its request does not inhibit LG&E/KU's performance of any of these activities. EKPC also asserts that the data and information LG&E/KU claim to need is already available to them.[66]

46. EKPC claims that, contrary to LG&E/KU's arguments otherwise, it is not seeking to "game" network service or "split" its load. EKPC states LG&E/KU's answer is premised on the misapplication of policy designed to prevent customers from avoiding full payment obligations for network service. EKPC states that LG&E/KU cite to *Arizona Public Service* and other cases for their claim that EKPC's request violates long-standing Commission policy.[67] But, EKPC argues that every case relied on by

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[66] EKPC states that the Tennessee Valley Authority (TVA) is currently responsible for calculating the initial available flowgate capability (flow capabilities) for LG&E/KU and that TranServ uses the initial values calculated by TVA to determine final flow capabilities for the LG&E/KU system. EKPC asserts that TVA receives daily load forecast information from PJM for the EKPC system. Therefore, EKPC argues that TVA, on behalf of LG&E/KU, now receives each day an expected load forecast for EKPC for each hour of the next seven days, for the peak hour of each day for days eight through 31, and for the peak hour of each month for months two through 18.

[67] EKPC Answer at 15.

LG&E/KU in their answer involved a customer's effort to avoid network service charges. EKPC argues that all of EKPC's load (regardless of which system to which the load is connected) is covered under and pays for network service.

47. EKPC argues that its request is not, as suggested by LG&E/KU, an "imbalance service." EKPC states that the service requested by EKPC is neither premised upon nor involves "imbalance." Moreover, EKPC asserts that its request does not involve "fictitious" or "virtual" load or delivery points. EKPC states that it seeks to use the NITSA to integrate real Network Load and resources at real delivery points and that all of its resources are physically located in or pseudo-tied to a single balancing area (i.e., the PJM Balancing Area).

48. Finally, EKPC argues that it should only pay LG&E/KU for the network service they provide. EKPC states that the Commission's policies on transmission planning and pricing protect EKPC from overpaying LG&E/KU in this case. EKPC claims that LG&E/KU would have EKPC pay for hundreds of megawatts of duplicative charges for firm Network or Point-to-Point services that LG&E/KU would not be providing.

D. LG&E/KU December 22 Answer

49. In their December 22 answer, LG&E/KU state that the plain language of the Tariff warrants denial of EKPC's complaint because it is a longstanding principle of Commission jurisprudence that when a tariff is unambiguous, it is controlling.[68] LG&E/KU argue that, while EKPC alleges that its transmission service request is consistent with LG&E/KU's Tariff, TranServ (in its capacity as LG&E/KU's Independent Transmission Organization) does not agree with EKPC that its proposal is consistent with section 31.3 and section 1.25 of the Tariff. LG&E/KU argue that, for TranServ, the proposal to provide service in such a manner is plainly inconsistent with the terms of LG&E/KU's Tariff. Moreover, LG&E/KU argue that the Tariff should not be interpreted in such a manner that renders one of its terms meaningless. LG&E/KU assert that EKPC's complaint, which is premised on a violation of these fundamental principles, should be summarily rejected.

50. LG&E/KU argue that EKPC's proposal, if approved, would set an unwarranted precedent regarding the use of network integration transmission service and would allow EKPC to receive preferential treatment to address its specific circumstances. LG&E/KU argue that this would be contrary to the concept of non-discriminatory open access service. Moreover, LG&E/KU assert that network integration transmission service is a

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[68] LG&E/KU December 22 Answer at 4-5 (citing *Koch Gateway Pipeline Co. v. FERC*, 136 F.3d 810, 814 (D.C. Cir. 1998) (*Koch Gateway*)).

demand-based service based on load-ratio shares; however, EKPC seeks to convert this to a hybrid demand and generation-based service. Therefore, LG&E/KU argue the Commission should reject EKPC's attempt to change the nature of its network integration transmission service.

IV. Discussion

A. Procedural Matters

51. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2015), the timely, unopposed motion to intervene serves to make the entity that filed it a party to the proceeding.

52. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2015), prohibits an answer to a protest and/or answer unless otherwise ordered by the decisional authority. We accept EKPC's and LG&E/KU's answers because they have assisted us in our decision-making process.

B. Substantive Matters

53. As discussed below, we deny EKPC's complaint because EKPC has failed to support its request for an amended NITSA that differs significantly from LG&E/KU's Tariff. Moreover, we also find that EKPC has not shown, pursuant to section 206 of the FPA, that LG&E/KU's Tariff is unjust and unreasonable as it relates to EKPC. We also deny the requested waiver because, in the circumstances presented, EKPC has not shown that its waiver would be limited in scope or that it would not cause harm to third parties.

1. Consistency With LG&E/KU's Tariff and Commission Policy

54. EKPC asserts that its proposed amendment to the EKPC-LG&E/KU NITSA to designate new Network Load and identification of a new delivery point is consistent with section 31.3 of LG&E/KU's Tariff. EKPC further argues that LG&E/KU's refusal to accept the amended NITSA both violates section 31.3 of the Tariff and is contrary to Commission policy on open access transmission. We disagree. Based on our review of the language of the provisions at issue, we find that LG&E/KU's refusal to accept EKPC's proposed amended NITSA is consistent with the LG&E/KU Tariff and is consistent with Commission policy.

55. Section 31.3 of LG&E/KU's Tariff provides:

> This section applies to both initial designation pursuant to Section 31.1 and the subsequent addition of new Network Load not physically interconnected with the Transmission Owner. To the extent that the Network Customer desires to obtain transmission service for a load outside the Transmission Owner's Transmission System, the Network Customer

> shall have the option of (1) electing to include the entire load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Point-to-Point Transmission Service under Part II of the Tariff. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.[69]

56. In interpreting section 31.3, EKPC is correct that it must be read together with section 1.25 defining "Network Load." Specifically, section 1.25 of the LG&E/KU Tariff defines Network Load as:

> The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but *may not designate only part of the load at a discrete Point of Delivery*. Where an Eligible Customer has elected *not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-to-Point Transmission Service* that may be necessary for such non-designated load.[70]

Reading the two sections together, as suggested by EKPC, confirms that a customer may designate its entire load as Network Load and designate Network Resources to serve that load or the customer may exclude the entire load and purchase Point-to-Point service to serve that load. In its proposal, EKPC suggests creating a Point or Points of Delivery between the LG&E/KU and EKPC transmission systems that represent the hourly difference between the output of the Bluegrass station and the amount of EKPC's load directly connected to the LG&E/KU system when that load is less than the output of the Bluegrass station. This proposal is not contemplated under the language of the Tariff which requires EKPC to either designate its entire load (LG&E/KU load plus individual delivery points inside its own network) as Network Load in all hours, or arrange for

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[69] Louisville Gas & Electric Tariff Part III_31, Part III_31 Designation of Network Load, 1.0.0.

[70] Louisville Gas & Electric Tariff Part 1_01, Part 1_01 Definitions, 1.0.0 (emphasis added).

alternative transmission service. Instead, EKPC argues that it has a right to designate Network Load that is not based on the entire load served at discrete points of delivery but instead reflects its use of the LG&E/KU system on a sporadic basis to deliver excess generation from the Bluegrass facility to the point of delivery between the LG&E/KU and EKPC transmission systems. This type of load designation is not contemplated by the Tariff or Commission policy, and as such, EKPC is not allowed to split its load in the manner proposed.

57. By seeking to split its load on a sporadic basis, EKPC would limit its payment for network service while requiring LG&E/KU to hold transmission service in reserve for EKPC to accommodate its maximum potential delivery of excess generation from the Bluegrass facility to the EKPC transmission system. EKPC proposes to designate a portion of the load on its own transmission system as LG&E/KU Network Load based upon the output of the Bluegrass station in any hour minus the EKPC load on the LG&E/KU transmission system. EKPC would, therefore, limit its transmission payments based on its hourly use for such deliveries. At the same time, since LG&E/KU would have difficulty predicting in advance the amount of transmission that EKPC would use for such deliveries in any hour, it would have to hold transmission service for EKPC for which it may not receive compensation. We do not read section 31.3 of the Tariff as requiring LG&E/KU to permit a customer to purchase network service solely on such a basis. Under section 31.3, EKPC would have the option of designating Network Load based upon the entire load served at discrete points of delivery or purchasing firm or non-firm Point- to-Point service. Either option would ensure that EKPC pays for the transmission service that LG&E/KU must hold for EKPC's potential use of the LG&E/KU system.

58. EKPC further contends that its interpretation of section 31.3 and section 1.25 (i.e., Network Load) is consistent with Commission policy, as expressed in the *pro forma* OATT and Order Nos. 888 and 888-A. Specifically, EKPC avers that, since it is not a transmission-dependent wholesale customer utilizing behind-the-meter generation, the restrictions on the amount of load that may be designated as Network Load at discrete points of delivery do not apply to EKPC. We do not find EKPC's argument to be persuasive. There is nothing in sections 31.3 or 1.25 of the Tariff (which adopts the *pro forma* OATT almost verbatim) or Order Nos. 888 and 888-A that requires LG&E/KU to permit partial designation of Network Load. Moreover, nothing in Order Nos. 888,

888-A and the *pro forma* OATT suggests that transmission customers such as EKPC would be specifically exempt from the limitation against partial designation.[71]

59. In Order No. 888, the Commission addressed the issue of designating only a portion of a transmission customer's Network Load:

> [W]e have stated that if a customer wishes to exclude a particular load at discrete points of delivery from its load ratio share of the allocated cost of the transmission provider's integrated system, it may do so. Customers that elect to do so, however, must seek alternative transmission service for any such load that has not been designated as network load for network service. This option is also available to customers with load served by "behind the meter" generation that seek to eliminate the load from their network load ratio calculation.[72]

60. In Order No. 888-A, in clarifying its definition of Network Load, the Commission stated that, "[t]he bottom line is that all potential transmission customers, including those with generation behind the meter, must choose between network integration transmission service and point-to-point transmission service."[73] Moreover, the Commission stated:

> The concept of allowing a "split system" or splitting a discrete load is antithetical to the concept of network service. A request for network service is a request for the integration of a customer's resources and loads. Quite simply, a load at a discrete point of delivery cannot be partially integrated—it is either fully integrated or not integrated. Furthermore, such a split system creates the potential for a customer to "game the system" thereby evading some or all of its load-ratio cost responsibility for network services.[74]

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[71] *See also Duke Power Co.*, 81 FERC ¶ 61,010 (1997) (where the Commission acknowledges that "order Nos. 888 and 888-A do not permit a network customer to take a combination of both network and point-to-point transmission service to serve the same discrete load.").

[72] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,736.

[73] Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,260.

[74] *Id.* at 30,259.

This language shows that the Commission used the "behind-meter-generation" language as an example of transmission customers subject to the provision but it did not explicitly exclude, as suggested by EKPC, other transmission customers from this provision. Finally, the Commission asserted that it would allow network customers to either designate all of a discrete load as Network Load under network integration transmission service or exclude the entirety of a discrete load from network service and serve such load with the customer's "behind-the-meter" generation and/or through any Point-to-Point service.[75]

61. Next, EKPC argues that Commission precedent favors its interpretation of the definition of Network Load and section 31.3 because the Commission has accepted similar arrangements from other entities. However, the cases cited by EKPC do not support its arguments that LG&E/KU is required to accept EKPC's proposal to add the Bluegrass station. *SMEPA-Southern*, cited by EKPC, involved an amendment to the parties' NITSA that was accepted by delegated letter order and therefore does not reflect binding Commission precedent.[76]

62. MISO-SMEPA, also cited by EKPC, involves the Commission's acceptance of a non-conforming NITSA between MISO and SMEPA that allowed SMEPA to designate load not physically connected with its MISO's transmission system as Network Load. At the time of the filing, section 31.3 of MISO's Tariff required all Network Load to be physically interconnected to the MISO transmission system.[77] The MISO provision was an approved deviation from the *pro forma* OATT which provides option of designating Network Load not physically interconnected with the transmission provider's system. Section 31.3 of LG&E/KU's Tariff already has a provision allowing this. However, as it concerns EKPC's proposal in this proceeding, the facts in MISO-SMEPA are not similar to facts at issue here because SMEPA did not request to designate less than its entire load at discrete points of delivery.

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[75] *Id.* at 30,260-30,261.

[76] *See Gas Transmission Northwest Corporation v. FERC*, 504 F.3d 1318, 1320 (D.C. Cir. 2007) ("FERC's acceptance of a pipeline's tariff sheets does not turn every provision of the tariff into 'policy' or 'precedent'"); *Wolverine Power Supply Coop., Inc.*, 135 FERC ¶ 61,165, at P 15 & n.22 (2011) (actions taken by Commission pursuant to delegated authority do not constitute Commission precedent).

[77] *See* MISO-SMEPA, 145 FERC ¶ 61,242 at 4 (MISO's Tariff section 31.3 provides "all Network Load must be physically interconnected with a Transmission Owner or ITC within the geographic area in which facilities subject to the Tariff are located").

63. Therefore, based on the foregoing, we find it reasonable for LG&E/KU to interpret the LG&E/KU Tariff as preventing the designation of part of the load at discrete points of delivery on the EKPC transmission system as Network Load. The alternatives for providing customers transmission service for such external load are spelled out in section 31.3 of LG&E/KU's Tariff.

64. EKPC also argues that, if the Commission determines that its proposal to add the Bluegrass facility is not consistent with the provisions of the LG&E/KU Tariff, then the Commission should find that LG&E/KU's Tariff is unjust and unreasonable as applied to EKPC. As the complainant, EKPC bears the burden of showing under FPA section 206 that LG&E/KU's Tariff is unjust and unreasonable.[78] We find that EKPC has not met its burden. As stated previously, section 31.3 and the definition of Network Load in LG&E/KU's Tariff mirrors the language in the Commission's *pro forma* OATT. The Commission created the *pro forma* OATT as a model for utilities to provide open access transmission service to customers. The Commission has also stated that "we did not intend for each and every customer of a transmission provider to have the opportunity to demand that the transmission provider create alternative services which benefit that particular customer."[79] EKPC apparently seeks a determination that LG&E/KU's Tariff should not apply to EKPC based on what it suggests are the unusual circumstances associated with its use of the LG&E/KU system and the accommodations we provided LG&E/KU in the past.[80] However, we find no basis for making such a finding here because EKPC has not justified why such a departure from the *pro forma* OATT and the LG&E/KU Tariff is necessary due to its situation.

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[78] *See* 16 U.S.C. § 824e(b) (2012).

[79] *Fla. Power & Light Co.*, 113 FERC ¶ 61,290, at P 6 (2005).

[80] *See Fla. Power & Light Co.*, 116 FERC ¶ 61,012, at P 14 (2006) ("Order No. 888 and its *pro forma* transmission tariff provide for network integration and point-to-point transmission service. It is one thing for a transmission provider to propose to offer an additional service to its customers. It is another, very different matter for each individual transmission customer to seek transmission services uniquely tailored to its particular needs. Allowing services and rates unique to every customer would undercut the primary goal of Order No. 888 of providing for non-discriminatory open access transmission.").

2. Alternative Request for Relief

65. Next, EKPC states that, if the Commission concludes that EKPC's suggested relief is not consistent with the LG&E/KU Tariff, it requests a waiver of section 31.3 in order to adopt the amended NITSA as a non-conforming agreement. The Commission has previously granted waivers of tariff provisions when: (1) the entity seeking the waiver acted in good faith; (2) the waiver is of limited scope; (3) a concrete problem needed to be remedied; and (4) the waiver does not have undesirable consequences, such as harming third parties.[81] EKPC argues that its request for waiver meets these criteria. We disagree.

66. Specifically, we find that EKPC has failed to demonstrate that its requested waiver would not have undesirable consequences, such as harming third parties. We are persuaded by LG&E/KU's argument that EKPC's request for a non-conforming NITSA could have a negative effect on other transmission customers through a reduction of transmission capacity and could impair efficient utilization of the LG&E/KU transmission system. Accordingly, we deny EKPC's requested waiver.

The Commission orders:

EKPC's complaint is hereby denied, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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[81] *See Clean Energy Future – Lordstown, LLC,* 152 FERC ¶ 61,076 (2015), *see also Air Energy TCI Inc.*, 143 FERC ¶ 61,172 (2013)*; Aragonne Wind, LLC*, 145 FERC ¶ 61,106 (2013); *WM Renewable Energy, L.L.C.*, 134 FERC ¶ 61,022 (2011). *Central Vermont Pub. Serv. Corp.*, 121 FERC ¶ 61,225 (2007); *Waterbury Generation LLC*, 120 FERC ¶ 61,007 (2007); *Acushnet Co.*, 122 FERC ¶ 61,045 (2008).

Document Content(s)

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

East Kentucky Power Cooperative, Inc.	Docket No. EL16-8-001
v.	
Louisville Gas & Electric Company/Kentucky Utilities Company	

ORDER GRANTING REHEARING FOR FURTHER CONSIDERATION

(April 27, 2016)

Rehearing has been timely requested of the Commission's order issued on February 26, 2016, in this proceeding. *East Kentucky Power Cooperative, Inc., v. Louisville Gas & Electric Company/Kentucky Utilities Company,* 154 FERC ¶ 61,144 (2016). In the absence of Commission action within 30 days from the date the rehearing request was filed, the request for rehearing (and any timely requests for rehearing filed subsequently)[1] would be deemed denied. 18 C.F.R. § 385.713 (2015).

In order to afford additional time for consideration of the matters raised or to be raised, rehearing of the Commission's order is hereby granted for the limited purpose of further consideration, and timely-filed rehearing requests will not be deemed denied by operation of law. Rehearing requests of the above-cited order filed in this proceeding will be addressed in a future order. As provided in 18 C.F.R. § 385.713(d), no answers to the rehearing requests will be entertained.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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[1] *See San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange*, 95 FERC ¶ 61,173 (2001) (clarifying that a single tolling order applies to all rehearing requests that were timely filed).

Document Content(s)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

East Kentucky Power Cooperative, Inc.	)	
v.	)	
	)	Docket No. EL16-8-000
Louisville Gas & Electric	)	
Company/Kentucky Utilities Company	)	

REQUEST FOR REHEARING BY EAST KENTUCKY POWER COOPERATIVE, INC.

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March 28, 2016

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

East Kentucky Power Cooperative, Inc. v. Louisville Gas & Electric Company/Kentucky Utilities Company	)))))	Docket No. EL16-8-000

REQUEST FOR REHEARING BY EAST KENTUCKY POWER COOPERATIVE, INC.

Pursuant to Section 313(a) of the Federal Power Act ("FPA")[1] and Commission Rule 713,[2] East Kentucky Power Cooperative, Inc. ("EKPC") respectfully requests rehearing of the February 26, 2016 Order Denying Complaint ("Order") in this proceeding.[3] The Order denies the November 2, 2015 complaint filed by EKPC against Louisville Gas & Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "LG&E/KU"), pursuant to FPA Sections 206, 211, and 306. EKPC alleged in the Complaint that, by refusing to accept EKPC's designation of a new Network Load under the Network Integration Transmission Service Agreement ("NITSA") between LG&E/KU and EKPC, LG&E/KU had acted contrary to the terms of the LG&E/KU Open Access Transmission Tariff ("LG&E/KU Tariff") and that such refusal was unjust, unreasonable, unduly discriminatory and otherwise unlawful under the FPA. For the reasons set forth below, EKPC respectfully submits that the Order is

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[1] 16 U.S.C. § 825l(a) (2012).

[2] 18 C.F.R. § 385.713 (2015).

[3] *East Kentucky Power Coop. v. Louisville Gas & Electric Company/ Kentucky Utilities*, 154 FERC ¶ 61,144 (2016) ("Order").

not the product of reasoned decision-making, and that the arrangements it would put in place for EKPC's use of its Bluegrass generating resource would be unjust, unreasonable and unduly discriminatory, in violation of the FPA. Accordingly, EKPC seeks rehearing of the Order.

I. INTRODUCTION AND SUMMARY OF ARGUMENT

EKPC's Complaint was necessitated by LG&E/KU's refusal to amend the existing NITSA between the parties in a manner that would allow EKPC to economically integrate a new generating resource recently acquired by EKPC, the Bluegrass Generating Station ("Bluegrass"). In its pre-Complaint discussions with LG&E/KU and in the Complaint itself, EKPC proposed amendments to its NITSA with LG&E/KU that would: (1) establish a new Point of Delivery under the NITSA as one or more points of interconnection between the transmission facilities of LG&E/KU and EKPC; and (2) designate a portion of EKPC's member load connected to the EKPC transmission facilities as new Network Load under the NITSA, with the amount of that load equal to the positive difference between the output of Bluegrass in any hour minus the aggregate EKPC member load served from the LG&E/KU transmission facilities in the same hour.[4] The Complaint asked the Commission to find that the amended NITSA proposed by EKPC is consistent with the LG&E/KU Tariff. Alternatively, EKPC asked that, if the

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[4] More specifically, the amended Service Specifications proposed in the Complaint stated that the new Point of Delivery (denominated the "Bluegrass Delivery Point") would be the point(s) at which output from Bluegrass in excess of EKPC's Network Load under the NITSA is delivered to EKPC's Network Load on EKPC's transmission system. The Specifications also stated that the "Network Load" at the Bluegrass Delivery Point would be a calculated value for flows into EKPC's system at the Bluegrass Delivery Point equal in any hour to the positive difference between the amount of energy delivered from Bluegrass to serve EKPC Network Load minus the total amount of EKPC's Network Load in the LG&E/KU Balancing Authority Area ("BAA"), excluding the load associated with the Bluegrass Delivery Point.

Commission were to find that the proposed NITSA is not consistent with the LG&E/KU Tariff, the Commission then find the Tariff's terms to be unjust and unreasonable as applied to EKPC. Finally, EKPC asked that, if the Commission declined to grant relief on either of the foregoing bases, that it waive the application of the Tariff terms found to be inconsistent with EKPC's proposal.

In the Order, the Commission denied EKPC's Complaint, essentially on three grounds. First, the Commission found that the terms of the LG&E/KU Tariff do not permit EKPC's proposed definition of the "Network Load" of the Bluegrass Delivery Point, because (according to the Order) the Tariff only allows Network Load to be a customer's "entire load" at a discrete point of delivery.[5] Second, the Commission found that EKPC had failed to show that the terms of the LG&E/KU Tariff are unjust and unreasonable as applied to EKPC.[6] Finally, the Commission found that EKPC had not met the criteria that must be satisfied for a waiver of the Tariff's terms.[7]

EKPC seeks rehearing on a number of grounds, each of which is specified below. In general, EKPC seeks rehearing because the Order relies on findings and conclusions that are not the product of reasoned decision-making and are not supported by substantial evidence in the record. In numerous instances, the Order: (1) omits any specification of the evidence upon which the Order is based; (2) relies on conclusory analysis that fails to meaningfully discuss the evidence and arguments; (3) makes findings that are contrary to the evidence; (4) disregards or

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[5] Order at P 56.

[6] *Id*. at P 64.

[7] *Id*. at P 66.

misapplies relevant precedent; (5) applies pertinent tariff language in a mechanistic and inflexible fashion contrary to long-standing practice; and (6) fails to give effect to important Commission policies. Further, the Commission erred in failing to set for hearing the many disputed factual matters identified in the EKPC and LG&E/KU submittals. Those disputed factual matters are material to the issues raised in the Complaint, and an on-the-record determination of those disputed factual matters is a necessary predicate to a supportable Commission decision resolving the issues in the Complaint. For these reasons, the Order falls short of satisfying the Commission's obligations under the FPA and the Administrative Procedure Act[8] to engage in reasoned decision-making supported by substantial record evidence that results in the establishment of just, reasonable, and not unduly discriminatory rates, terms and conditions for transmission service.[9]

The Order largely hinges on the view that EKPC's proposal would constitute impermissible "load splitting." For the reasons discussed in detail herein, that conclusion is

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[8] 5 U.S.C. §§ 551 *et. seq.*

[9] The obligation to engage in reasoned decision-making imposes on the Commission a number of specific requirements and duties. For example, the Commission must "examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made." *Motor Vehicle Mfr. Ass 'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (internal quotation marks and citations omitted); *Fla. Gas Transmission Co. v. FERC*, 604 F.3d 636, 639 (D.C. Cir. 2010). The Commission has a duty to engage arguments raised before it. *See NorAm Gas Transmission Co. v. FERC*, 148 F.3d 1158, 1165 (D.C. Cir. 1998) *citing KN Energy, Inc. v. FERC,* 968 F.2d 1295, 1303 (D.C. Cir. 1992). A decision that fails to address arguments presented to the Commission "can hardly be classified as reasoned." *PPL Wallingford Energy LLC v. FERC*, 419 F.3d 1194, 1198 (D.C. Cir. 2005); *see also Canadian Ass'n of Petroleum Producers v. FERC,* 254 F.3d 289, 299 (D.C. Cir. 2001) (failing to respond meaningfully to facially legitimate arguments demonstrates that a decision is not a product of reasoned decision-making); *Moraine Pipeline Co. v. FERC*, 906 F.2d 5, 9 (D.C. Cir. 1990) (Commission failed to engage in reasoned decision-making where it "fail[ed] to respond to [petitioner's] arguments"). The Commission must specify the evidence on which it relied and explain how that evidence supports the conclusion it reached. *City of Charlottesville v. FERC,* 661 F.2d 945, 950 (D.C. Cir. 1981). If the Commission "offer[s] an explanation for its decision that runs counter to the evidence," it has not engaged in reasoned decision-making. *See National Fuel Gas Supply Corp. v. FERC,* 468 F.3d 831 at 839 (D.C. Cir. 2006).

factually and legally incorrect, and is inexplicably dismissive of the fact that EKPC modeled its proposal on virtually identical arrangements that are on file with the Commission. This is but one of the findings in the Order that is legally in error, not reflective of reasoned decision-making, and that is not supported by the record.

EKPC also showed that LG&E/KU provide themselves more favorable use of the transmission system than they are making available to EKPC. In connection with LG&E/KU's reserve-sharing arrangements with the Tennessee Valley Authority ("TVA"), LG&E/KU essentially sets aside transmission capacity to enable it to provide reserve-sharing to TVA when called upon to do so, and without paying for that set-aside transmission capacity. Although the Order concludes, incorrectly, that EKPC's proposed arrangements would not adequately compensate LG&E/KU and would diminish LG&E/KU's ability to make service available to others, the Order failed to address the discrimination inherent in LG&E/KU's favoring of its own native load under the reserve sharing arrangements while rejecting EKPC's arrangements, even while EKPC would compensate LG&E/KU and even while EKPC's arrangements are less disruptive to system planning and operations than are LG&E/KU's own arrangements.

The Order leaves EKPC with two options for integrating Bluegrass, neither of which is efficient or cost-effective. To the contrary, those narrow options would increase EKPC's costs to integrate Bluegrass by increased transmission charges payable to LG&E/KU of up to $10 million per year starting in 2019, while at the same time potentially depriving EKPC of the operational flexibility that is the essence of Network Service. (Because of the potential impact of the Order, EKPC has begun exploring construction of a new transmission line to directly connect Bluegrass to EKPC's transmission system.) In effect, the Order is rewarding LG&E/KU for creating a transactional seam with PJM that would not have existed but for the decision of LG&E/KU to withdraw from MISO in 2006.[10] No Commission precedent or policy justifies such a result.

II. STATEMENT OF ISSUES AND SPECIFICATION OF ERRORS

A. Statement of Issues

In compliance with Commission Rule 713(c)(2), 18 C.F.R. § 385.713(c)(2), EKPC provides the following brief statement of issues raised on rehearing, EKPC's position with respect to each, and representative authority on which EKPC relies.

1. Issue: Was it error for the Commission to treat EKPC's proposed arrangement as "load-splitting" prohibited by the LG&E/KU Tariff where the evidence showed that EKPC's proposal did not involve combining network and point-to-point transmission service at a single point of delivery. EKPC's Position: Yes. The evidence showed that EKPC's proposal is not in conflict with provisions of the LG&E/KU Tariff that prohibit load-splitting. In making findings and reaching conclusions at odds with the record evidence, the Commission failed to discharge its obligation to engage in reasoned decision-making. *National Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831 (D.C. Cir. 2006).

2. Issue: Did the Commission engage in reasoned decision-making by relying on the decision in *Duke Power* Company, 81 FERC ¶ 61,010 (1997) as a basis for rejecting EKPC's proposed arrangement without considering that the *Duke* decision actually supports EKPC's position regarding the definition of "Network Load" under the Commission's *pro forma* Open Access Transmission Tariff? EKPC's Position: No. The Commission failed to articulate a rational basis for relying on a portion of the Duke decision but disregarding the portion that supports EKPC's position. That failure renders its action the product of unreasoned decision-making. *Duke Power* Company, 81 FERC ¶ 61,010 (1997); *Motor Vehicle Mfr. Ass 'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29 (1983).

3. Issue: Did the Commission engage in reasoned decision-making in rejecting EKPC's reliance on MISO integration arrangements implemented by and for the South Mississippi Electric Power Association as providing a fair and workable model for integrating EKPC's Bluegrass resource into PJM? EKPC's Position: No. The grounds cited by the Order for refusing to follow or adopt the SMEPA model here were erroneous and unreasoned. As a result, the Commission failed in its duty to meaningfully engage

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[10] *See Louisville Gas & Electric Company/ Kentucky Utilities*, 114 FERC ¶ 61,282 (2006) (order approving LG&E/KU's withdrawal from MISO.)

the arguments presented to it. NorAm Gas Transmission Co. v. FERC, 148 F.3d 1158 (D.C. Cir. 1998); KN Energy, Inc. v. FERC, 968 F.2d 1295 (D.C. Cir. 1992); PPL Wallingford Energy LLC v. FERC, 419 F.3d 1194 (D.C. Cir. 2005). Further, the Commission's effort to disclaim the significance of its acceptance of the SMEPA integration filings disregards the fact that the Commission has a duty to evaluate all submittals for justness and reasonableness and to reject filings that do not meet the statutory requirements. 18 C.F.R. § 375.307; Tejas Power Corp. v. FERC, 908 F.2d 998 (D.C. Cir. 1990); High Island Offshore System, L.L.C., 110 FERC ¶ 61,043 (2005), aff'd, Petal Gas Storage, L.L.C. v. FERC, 496 F.3d 695 (D.C. Cir. 2007); PJM Interconnection, L.L.C., Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc., 144 FERC ¶ 61,217 (2013).

4. Issue: Did the Commission rely on erroneous or unreasoned grounds for its conclusion that LG&E/KU's interpretation of the tariff is just and reasonable? EKPC's Position: Yes. That conclusion is premised on the belief that EKPC's position would result in prohibited load-splitting. That factual premise, however, is incorrect and contrary to the record. Because the premise for the Commission's conclusion was erroneous, the resulting conclusion is not the product of reasoned decision-making. National Fuel Gas Supply Corp. v. FERC, 468 F.3d 831 (D.C. Cir. 2006).

5. Issue: Was the Order's rejection of EKPC's proposal consistent with Commission policy? EKPC's Position: No. The record demonstrates that EKPC's proposal would be consistent with, and would promote, several important Commission policies, including policies favoring the integration of resources and loads across RTO/non-RTO boundaries on reasonable terms. The Commission's failure to engage EKPC's arguments in this regard renders its decision the product of unreasoned decision-making. PPL Wallingford Energy LLC v. FERC, 419 F.3d 1194 (D.C. Cir. 2005); Canadian Ass'n of Petroleum Producers v. FERC, 254 F.3d 289 (D.C. Cir. 2001); Moraine Pipeline Co. v. FERC, 906 F.2d 5 (D.C. Cir. 1990).

6. Issue: Did the Commission engage in reasoned decision-making in reaching the conclusion that EKPC's proposal would cause LG&E/KU to suffer inadequate compensation for the use of its transmission system? EKPC's Position: No. The Commission's conclusion is based on incorrect findings as to how EKPC would be charged for Network Service at the Bluegrass Delivery Point, and on the effect of EKPC's proposed arrangement on LG&E/KU's ability to sell uncommitted transmission capability. Because the Commission's conclusion was based on factual findings that were incorrect, that conclusion was not the product of reasoned decision-making. National Fuel Gas Supply Corp. v. FERC, 468 F.3d 831 (D.C. Cir. 2006).

7. Issue: Is the Commission's conclusion that EKPC failed to demonstrate that the LG&E/KU Tariff is unjust and unreasonable as applied to EKPC supported by the record and the product of reasoned decision-making? EKPC's Position: No. In reaching this conclusion, the Commission either disregarded or failed to give proper weight to evidence demonstrating that relevant provisions of the LG&E/KU Tariff would impose undue burdens on EKPC and are otherwise unjust and unreasonable as applied to EKPC. In so doing, the Commission failed in its duty to engage in reasoned decision-making.

Motor Vehicle Mfr. Ass ‘n v. State Farm Mut. Auto. Ins. Co., 463 U.S. 29 (1983); National Fuel Gas Supply Corp. v. FERC, 468 F.3d 831 (D.C. Cir. 2006).

8. Issue: In failing to consider the undue discrimination in favor of LG&E/KU's affiliate load-serving entity that results from the adoption of LG&E/KU's position, did the Commission violate its obligation to engage in reasoned decision-making? EKPC's Position: Yes. The Commission has a legal duty to prevent undue discrimination. Federal Power Act §§ 205, 206. That duty extends to the terms and conditions on which wholesale transmission services are provided. New York v. FERC, 535 U.S. 1 (2002). The Commission's failure to engage EKPC's arguments concerning the unduly discriminatory impacts resulting from adoption of LG&E/KU's position renders its action the product of unreasoned decision-making. PPL Wallingford Energy LLC v. FERC, 419 F.3d 1194 (D.C. Cir. 2005); NorAm Gas Transmission Co. v. FERC, 148 F.3d 1158 (D.C. Cir. 1998).

9. Issue: Did the Commission engage in reasoned decision-making in its rejection of EKPC's alternative request for waiver of provisions of the LG&E/KU Tariff that the Commission interprets as inconsistent with EKPC's proposed NITSA amendment? EKPC's Position: No. In rejecting EKPC's alternative waiver request, the Commission disregarded or failed to give proper weight to evidence supporting the waiver, and otherwise failed to engage the evidence. This failure renders its denial of EKPC's waiver request the product of unreasoned decision-making. NorAm Gas Transmission Co. v. FERC, 148 F.3d 1158 (D.C. Cir. 1998); KN Energy, Inc. v. FERC, 968 F.2d 1295 (D.C. Cir. 1992); PPL Wallingford Energy LLC v. FERC, 419 F.3d 1194 (D.C. Cir. 2005).

10. Issue: Did the Commission commit error by failing to set for hearing the numerous material factual matters in dispute between EKPC and LG&E/KU? EKPC's Position: Yes. Where there are factual matters in dispute that are material to the resolution of the issues in a proceeding, the Commission may not dispose of those matters without holding a hearing. Public Service Co. of NH v. FERC, 600 F.2d 944 (D.C. Cir. 1979); Citizens for Allegan County, Inc. v. Federal Power Commission, 414 F.2d 1125 (1969).

B. Specification of Errors

In compliance with Commission Rule 713(c)(1), 18 C.F.R. § 385.713(c)(1), EKPC specifies the following errors in the Commission's Order.

1. In the Order, the Commission committed error in treating EKPC's proposed NITSA arrangement for Bluegrass as "load-splitting" prohibited by the LG&E/KU Tariff, given the evidence showing that EKPC's proposal did not involve combining network and point-to-point transmission service at a single point of delivery.

2. In the Order, the Commission committed error by relying on the decision in Duke Power Company, 81 FERC ¶ 61,010 (1997) as a basis for rejecting EKPC's proposed arrangement without considering that the Duke decision actually supports EKPC's position regarding the definition of "Network Load" under the Commission's pro forma

Open Access Transmission Tariff.

3. In the Order, the Commission committed error by rejecting EKPC's reliance on MISO integration arrangements implemented by and for the South Mississippi Electric Power Association as providing a fair and workable model for integrating EKPC's Bluegrass resource into PJM. Further, the Commission committed error by failing to consider the SMEPA-Southern Company amended NITSA as a workable solution for EKPC simply because the SMEPA-Southern Company NITSA was accepted via delegated authority, and disregarding the fact that the Commission later considered and accepted the SMEPA-Southern Company NITSA as part of the amended MISO-SMEPA NITSA.

4. In the Order, the Commission committed error by relying on erroneous or unreasoned grounds for its conclusion that LG&E/KU's interpretation of the tariff is just and reasonable.

5. In the Order, the Commission committed error by rejecting EKPC's proposed NITSA amendments even though the arrangement proposed by EKPC promotes several important Commission policies.

6. In the Order, the Commission committed error by relying on unreasoned decision-making to reach the conclusion that EKPC's proposal would cause LG&E/KU to suffer inadequate compensation for the use of its transmission system.

7. In the Order, the Commission committed error in finding that EKPC failed to demonstrate that the LG&E/KU Tariff is unjust and unreasonable as applied to EKPC, because that finding is not supported by the record and is not the product of reasoned decision-making.

8. In the Order, the Commission committed error in failing to consider that the adoption of LG&E/KU's position results in undue discrimination in favor of LG&E/KU's affiliated load-serving entity.

9. In the Order, the Commission committed error in rejecting EKPC's alternative request for waiver of the LG&E/KU Tariff provisions that the Commission interprets as inconsistent with EKPC's proposed NITSA amendment, becasuse that rejection is not supported by the record and is not the product of reasoned decision-making.

10. In the Order, the Commission committed error in by failing to set for hearing the numerous material factual matters that the record shows to be in dispute between EKPC and LG&E/KU.

III. ARGUMENT

A. The Commission Did Not Engage in Reasoned Decision-making in Reaching the Conclusion that the Service Arrangement Sought by EKPC is Inconsistent with the LG&E/KU Tariff.

1. FERC Erred in Treating EKPC's Proposed Arrangement as "Load-Splitting" Prohibited by the LG&E/KU Tariff.

The Order found that (1) the NITSA amendment EKPC proposed in its Complaint conflicts with the terms of the LG&E/KU Tariff, and with Commission policy and precedent, (2) EKPC failed to show that the Tariff's terms are unjust and unreasonable as applied to EKPC, and (3) EKPC's request for waiver of the Tariff fell short of satisfying the applicable requirements. EKPC demonstrates below that these findings are factually unsupported and legally flawed.

The Commission's finding that EKPC's proposed arrangement conflicts with the LG&E/KU Tariff is explained only by the Order's superficial and perfunctory analysis of the Tariff's language. Indeed, the Commission's textual analysis of the Tariff occupies only *a portion of a single paragraph* of the Order.[11] There, the Order quotes section 1.25 of the LG&E/KU Tariff (which defines the term "Network Load"), emphasizing the portion of that section's third sentence which states that a transmission customer "may not designate only part of the load at a discrete Point of Delivery." The Order then states that when sections 1.25 and 31.3 of the Tariff are read in conjunction, it "confirms that a customer may designate its entire

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[11] Order at P 56. Other paragraphs under the pertinent section heading of the Order either recite EKPC's position (P 54) or quote from the Tariff (P 55 and the first portion of P 56) before the discussion moves on to the purported effect of EKPC's position (P 57) and the consistency of EKPC's position with Commission policy and precedent (PP 58 – 64). The textual analysis, such as it is, occupies only the latter portion of P 56 of the Order.

load as Network Load and designate Network Resources to serve that load or the customer may exclude the entire load and purchase Point-to-Point service to serve that load." The Order then explains the conclusion that the NITSA amendment sought by EKPC is inconsistent with these tariff provisions, as follows:

> In its proposal, EKPC suggests creating a Point or Points of Delivery between the LG&E/KU and EKPC transmission systems that represent the hourly difference between the output of the Bluegrass station and the amount of EKPC's load directly connected to the LG&E/KU system when that load is less than the output of the Bluegrass station. This proposal is not contemplated under the language of the Tariff which requires EKPC to either designate its entire load (LG&E/KU load plus individual delivery points inside its own network) as Network Load in all hours, or arrange for alternative transmission service. Instead, EKPC argues that it has a right to designate Network Load that is not based on the entire load served at discrete points of delivery but instead reflects its use of the LG&E/KU system on a sporadic basis to deliver excess generation from the Bluegrass facility to the point of delivery between the LG&E/KU and EKPC transmission systems. This type of load designation is not contemplated by the Tariff or Commission policy, and as such, *EKPC is not allowed to split its load in the manner proposed*.[12]

In short, the linchpin of the Commission's textual analysis is the finding that EKPC's proposal is precisely the type of "load splitting" prohibited by section 1.25 of the Tariff.[13]

In characterizing EKPC's proposal as an effort to engage in prohibited "load-splitting," however, the Order disregards the underlying purpose of the Tariff language on which it relies. A review of pertinent precedent shows that the language in question was directed toward an entirely different problem—namely, a tactic in which a transmission customer uses a

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[12] Order at P 56 (emphasis added).

[13] *See also*, Order at P 57 (describing EKPC's proposal as "seeking to split its load on a sporadic basis").

combination of Network and Point-to-Point ("PTP") service at a single delivery point to reduce its Network Service charges. Order No. 888-A, in particular, makes it clear that the Commission was focused on preventing that specific tactic in crafting the *pro forma* tariff's definition of "Network Load." There, in rejecting a commenter's request for "partial network service," the Commission observed:

> Utilities, both commenting on the NOPR and on rehearing …, express concern that customers allowed to divide a discrete load between point-to-point and network services would create a "split system." The concept of allowing a "split system" or splitting a discrete load is antithetical to the concept of network service. … Furthermore, such a split system creates the potential for a customer to "game the system" thereby evading some or all of its load-ratio cost responsibility for network services.[14]

To illustrate the problem it was trying to address through the definition of Network Load, the Commission cited a customer that designates as Network Load a specific amount of load at a particular delivery point, and then uses either behind-the-meter generation or short-term firm PTP service to lower its monthly coincident peak load for Network Service billing purposes, "thereby reducing if not eliminating its load-ratio cost responsibility for network service."[15] The Commission concurred in the view expressed by certain utility commenters that allowing customers to combine Network and PTP service at a single delivery point "would lead to the possibility of gaming the system," and that "any cost responsibility evaded by a network customer in this manner would be borne by the remaining network customers and native load."[16]

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[14] Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at p. 30,259.

[15] *Id.*

[16] *Id.* at pp. 30,259-60.

The precedent confirms that the *pro forma* tariff's definition of "Network Load," including the specific language of the LG&E/KU Tariff on which the Order relies, was designed to prevent the gaming of Network Service charges through the use of both Network and PTP service at a single delivery point. But the Order fails to recognize that *EKPC's proposed arrangement bears no resemblance to the tactic the Commission sought to prevent in Order 888* through the definition of "Network Load."

The NITSA amendment EKPC included in its Complaint would not combine Network and PTP service at the new Bluegrass delivery point, nor would the amendment facilitate or promote the "gaming" of Network Service charges. On the contrary, EKPC's proposal would *increase* its load ratio share of LG&E/KU transmission costs whenever Bluegrass output exceeds EKPC's LG&E/KU-connected load. Under EKPC's proposal it would never pay less than its coincident peak load-based share of the costs of the LG&E/KU transmission system,[17] and, in fact, EKPC's coincident peak share would increase whenever Bluegrass output exceeds that load at the time of the coincident peak. Thus, NITS billing would capture EKPC's full use of the LG&E/KU transmission system and EKPC would pay LG&E/KU accordingly. That is a very different outcome than that which the Tariff is designed to avoid—gaming or splitting to reduce or avoid network charges.

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[17] As EKPC stated in its Complaint:

> The amended NITSA, as proposed by [EKPC], defines [EKPC's] new Network Load as the amount of Bluegrass output that exceeds [EKPC's] Network Load on the [LG&E/KU] system. Defining the amount of new Network Load in this manner accurately reflects the transmission service that [LG&E/KU] will provide and ensures that [LG&E/KU] will receive its full Network Service rate for this service.

Complaint at 16.

There is another important reason, also ignored by the Order, why the arrangement EKPC seeks would not violate the ban on combining Network and PTP service at a single delivery point: through the Commission-approved arrangements in place today, *all EKPC load, including the load at EKPC delivery points connected to the LG&E/KU transmission system, is Network Load under the PJM Open Access Transmission Tariff*. The instantaneous loads of EKPC's delivery points on the LG&E/KU transmission system are telemetered to PJM and added to the instantaneous loads of the EKPC delivery points connected to the PJM (EKPC) transmission system. As a result, all EKPC delivery points today receive and are charged for PJM Network Service. But, *in addition to* PJM Network Service, those EKPC delivery points connected to the LG&E/KU transmission system *also* receive and pay for LG&E/KU Network Service. The question of "gaming the system" by combining Network and PTP service simply is not relevant in this context. There can be no credible concern that EKPC is engaged in an effort to escape network service charges when *all* of its load already is covered under PJM Network Service, and the portion of that total load that is connected to the LG&E/KU system is, *in addition,* already also covered by LG&E/KU Network Service.

What *is* relevant here—in fact, not just relevant but *central*—is the question of how a transmission customer whose loads or resources span more than one Regional Transmission Organization ("RTO") (or, as here, an RTO and non-RTO area) can bring together those loads and resources in a comprehensive and cost-effective integration. EKPC's proposed NITSA amendment would establish a framework for integrating Bluegrass output (along with the output of EKPC's other power supply resources) with the totality of EKPC's load in an efficient and cost-effective manner, and to do so within a Commission-approved RTO.

The Commission should look with favor on such arrangements and do what it can to promote them, chiefly because consumers would benefit from an efficient and cost-effective integration of Bluegrass within PJM. Yet, the Order goes in the opposite direction, forcing EKPC to choose between two inefficient and needlessly costly options—paying new PTP charges to LG&E/KU pancaked on top of the Network Service charges EKPC already pays LG&E/KU and PJM, or, instead, re-segmenting its load by designating certain of its PJM (EKPC) delivery points as new LG&E/KU Network delivery points. This means that load served from *EKPC's* transmission system would be charged as though it also is being served from *LG&E/KU's* system, when in fact it is not, simply so that EKPC can retain the use for its members of any Bluegrass output that exceeds the amount of EKPC load being served from the LG&E/KU transmission system at the time.

Contrary to the assertions made by LG&E/KU, the terms of their Tariff do not preclude the arrangement EKPC requested. It therefore is arbitrary and unreasoned for the Commission to require that EKPC instead choose between two highly inefficient and extremely costly alternatives.[18] It is one thing to avoid gaming that would allow a customer to escape network charges for a portion of its load. It is quite another to force a customer to pay *additional* transmission service charges when the entirety of its load is already under the umbrella of PJM Network Service and, indeed, a portion of that load is already paying *duplicative* charges for

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[18] *See* Order at P 56 (EKPC must choose between either designating its entire load (LG&E/KU load plus individual delivery points inside its own network) as Network Load under the LG&E/KU Tariff in all hours, or reserving and paying for point-to-point service to use Bluegrass energy to serve member load located on EKPC's own transmission system).

Network Service.[19] The former is what the tariff is intended to avoid. The latter is what the Order would require of EKPC.

2. The *Duke* Decision Cited by the Order Supports EKPC's Reading of the LG&E/KU Tariff.

The Order asserts that "[t]here is nothing in sections 31.3 or 1.25 of the [LG&E/KU] Tariff … or Order Nos. 888 and 888-A that requires LG&E/KU to permit partial designation of Network Load."[20] As support, the Order cites the Commission's decision in *Duke Power Co.*, 81 FERC ¶ 61,010 (1997), "where the Commission acknowledges that order Nos. 888 and 888-A do not permit a network customer to take a combination of both network and point-to-point transmission service to serve the same discrete load."[21] That particular aspect of Duke is irrelevant here because nothing about EKPC's proposal involves combining Network and Point-to-Point transmission service at any single delivery point. Moreover, a more complete reading of *Duke* reveals that the Commission's action in that proceeding actually supports approval of EKPC's position.

The issue in Duke was whether the transmission arrangements through which the Southeastern Power Administration ("SEPA") delivered preference power to customers could be accommodated under Duke's tariff or instead required a bilateral non-tariff agreement. SEPA and Duke were concerned that the definition of Network Load in the *pro forma* tariff would

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[19] The portion of EKPC's member load connected to the LG&E/KU system is subject to *two* sets of Network Service charges: in addition to paying PJM Network Service charges for that load, EKPC also is assessed LG&E/KU Network Service charges for the same load.

[20] Order at P 58. That the Order is more focused on what is "required" as distinct from that which is permissible is troubling. The OATT is supposed to be the minimum service available, not a cap on service. This rigid view permeates the Order.

[21] Order at P 58, n. 71.

preclude the arrangements being proposed because SEPA wanted to designate only part of the preference customer's load at a delivery point as "Network Load," while the remainder of the customer's load at that location would be served under a different arrangement.[22] In response to that concern, the Commission stated:

> This concern is unfounded. The parties are correct that the Commission's order Nos. 888 and 888-A do not permit a network customer to take a combination of both network and point-to-point transmission service to serve the same discrete load. However, the fact that the portion of the preference customers' loads met by their SEPA allocation would be served under Duke's open access transmission tariff, while the remainder of the load continues to be met by bundled service, would not alter the network nature of the service. *The entire load would be served on a network basis*, but payment would be made to Duke by SEPA for the SEPA preference customers' allocation, and by the preference customers for the remainder of their loads.[23]

Finding "no sufficient reason why the proposed transmission and ancillary services at issue here cannot be … accommodated under Duke's open access transmission tariff," the Commission directed Duke to file a tariff-based service agreement consistent with the Commission's unbundling requirements.[24]

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[22] SEPA's contracts with its preference power customers specified a fixed power allocation for each customer and made SEPA responsible for delivering that amount to the customer's delivery point. SEPA had concluded that point-to-point service was not a viable option, *see* 81 FERC ¶ 61,010 at n. 10, but the concern arose because SEPA would be designating as Network Load at each delivery point only a small portion of the preference customer's total load at that location.

[23] 81 FERC ¶ 61,010 at p. 61,047 (footnote omitted).

[24] Indeed, the pre-existing arrangements between Duke and SEPA involved various complicated arrangements relative to pumping power and bartered or reciprocal provisions of various ancillary services such that the apparent mismatch with the OATT was very stark. The Commission there determined that those other arrangements should be unbundled from the transmission arrangements which, as noted above, the Commission concluded did not violate the OATT provision aimed at preventing load splitting. *Id*. at pp. 61,047-48.

Here, the arguments for a finding that the requested service cannot be accommodated under the Tariff are even less compelling than they were in *Duke*. The Order finds that EKPC's proposed arrangement is "not contemplated by the Tariff" because, at the new Bluegrass delivery point, the designated Network Load would be a value other than "the entire load served at [a] discrete point[] of delivery."[25] What *Duke* holds, however, is that the Tariff does *not* require that the entire load at a discrete point of delivery be served under the same service agreement, as long as, when the service arrangements for the delivery point are considered in total, "[t]he entire load would be served on a network basis."[26] In *Duke*, that requirement was satisfied even though the portion of the customer's load in excess of the network service procured by SEPA would be served under a legacy bundled service arrangement between the customer and Duke. Here, the requirement is satisfied even more for the new Bluegrass delivery point by the fact that, after taking account of the network service EKPC would take from LG&E/KU for that delivery point, any remaining EKPC load would also continue to be designated Network Load under the PJM Open Access Tariff. As a result, *the entire load at the Bluegrass delivery point at all times would be served through the provision of Commission-approved Tariff Network Service*. These facts provide an even more compelling case than *Duke* for finding that the requirements of the "Network Load" definition are satisfied.

The Order's misreading and misapplication of *Duke* is clear error. Rehearing should be granted.

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[25] Order at P 56.

[26] 81 FERC ¶61,010 at p. 61,047.

B. The Commission Erred in Ruling that FERC Precedent Does Not Support EKPC's Proposal.

As discussed in EKPC's Complaint, EKPC's proposed NITSA amendment was modeled on the recently implemented arrangement through which South Mississippi Electric Power Association ("SMEPA") integrated its resources and loads in MISO. Initially, SMEPA's integration into MISO was complicated by the fact that, like EKPC, SMEPA's resources and loads spanned an RTO (MISO) and an adjacent non-RTO area (the Southern Company System). In that, and a number of other respects, the SMEPA situation bears a striking similarity to that faced by EKPC. EKPC modeled its proposal on the approach that worked for SMEPA precisely because that arrangement was accepted by the Commission.

The reason the SMEPA arrangement was successful is two-fold. First, the involved parties approached the integration problem creatively and in good faith, with (by all indications) the shared goal of finding a solution that would allow SMEPA to integrate its resources and loads in a reasonable and efficient manner. Second, the Commission accepted the solution developed by the parties, and did not interpose objections based on a rote and inelastic application of the *pro forma* Tariff.

In the following discussion, EKPC provides a brief description of the SMEPA arrangement and a discussion of why that arrangement should have been viewed by the Commission as an appropriate model for resolving EKPC's complaint. EKPC also addresses the Commission's stated rationale for refusing to apply the SMEPA model, and explains why that rationale does not reflect reasoned decision-making.

1. Overview of the SMEPA Arrangement, and its Similarity to the Case at Hand.

Because EKPC's prior filings describe the SMEPA situation in some detail, we offer here only a brief overview of the SMEPA arrangement and its clear similarities to EKPC's situation.

An essential ingredient in SMEPA's successful integration into MISO was the execution of an amendment to SMEPA's NITSA with Southern Company that designated a new delivery point for the Network Service SMEPA purchases from Southern (the "Purvis Substation Delivery Point") at a location where SMEPA's transmission facilities interconnect with those of Southern.[27] Of critical importance is how SMEPA's Network Load at the Purvis delivery point was defined. Rather than being expressed as the aggregate demand of SMEPA customer load served from Purvis during the coincident peak hour, SMEPA's Network Load at the new delivery point was defined to be a calculated value representing energy flow from the Southern system into SMEPA's system. Arithmetically, SMEPA's Network Load at Purvis is simply the amount by which, during Southern's coincident peak hour, the total energy produced by SMEPA's power supply resources on the Southern System exceeds SMEPA's load on the Southern System. As Southern described the arrangement in its filing of the amendment:

> The Purvis Substation Delivery Point is located within the SoCo BAA at the interchange point between Southern Companies' transmission system and SMEPA's transmission system. The Network Load for the Purvis Substation Delivery Point would be a calculated value for flow into the SMEPA balancing authority area. The value of the Network Load at the Purvis Substation Delivery Point would be calculated on an hourly basis to equal the energy generated by Network Resources located within the SoCo BAA that is not used to serve SMEPA's Network Load located within the SoCo BAA.[28]

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[27] A portion of SMEPA's member load, about 150 MW, is interconnected with the transmission facilities of Mississippi Power Company, a Southern Company subsidiary. This load is pseudo-tied to SMEPA, enabling it to be integrated with the remainder of SMEPA's load (which is interconnected with Entergy) and resources into MISO.

[28] Transmittal letter dated May 7, 2012 in *Alabama Power Co.*, Docket No. ER12-1724-000, at 2. SMEPA's calculated Network Load at Purvis is bounded on the low side by zero and on the high side by a value equal to the sum of the capacity from SMEPA's designated Network Resources minus the sum of the applicable, seasonal

[Footnote continued on following page]

Also notable is Southern's statement of the purpose of this arrangement: "The addition of the Purvis Substation Delivery Point will permit SMEPA to improve its efficiency in its use of the system."[29] The Commission accepted the Purvis amendment to the SMEPA-Southern NITSA by letter order dated June 4, 2012.

Through the amended NITSA with Southern Company and the creation of the Purvis Substation Delivery Point, SMEPA was able to utilize any "excess" energy generated by its resources on the Southern system to serve SMEPA member load external to Southern. This was crucial for SMEPA because: (1) SMEPA had far more resource capacity in the Southern Company region than it had load in Southern; and (2) the SMEPA load external to Southern (which was the bulk of SMEPA's load), was served from the transmission system of Entergy, which—along with SMEPA itself—was in the process of being integrated into MISO. Without the Southern NITSA amendment and the creation of the Purvis Network Load, a very substantial portion of SMEPA's resource portfolio could not have been integrated into MISO (that is, unless SMEPA purchased drive-out PTP service from Southern at a cost that almost certainly would have been prohibitive).[30]

On the MISO side of the arrangement, a NITSA amendment also was necessary, but for a different reason: MISO's Tariff, in effect, prohibited the use of MISO Network Service to serve loads not physically connected to the facilities of a MISO Transmission Owner. MISO agreed to

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minimum load forecasts for SMEPA's delivery points (other than Purvis itself) on the Southern system. Southern's filing of the NITSA amendment discussed in text is available on eLibrary at Accession No. 20120507-5084.

[29] *Id.*

[30] And, setting aside the cost, the fixed reservation and scheduling requirements of PTP service would have functioned very poorly for the dynamic load value at Purvis.

file a non-conforming NITSA amendment, which it did in Docket No. ER13-2008-000, so that SMEPA's member load on the Southern transmission system could be integrated into MISO with the rest of SMEPA's loads. As MISO explained in requesting Commission approval of a NITSA with SMEPA that varied from the express terms of MISO's Tariff, "requiring SMEPA to take MISO's drive-out Point-to-Point Transmission Service for the Southern NITSA load will create operational inefficiencies and deprive SMEPA and its members of certain key benefits of the commercial bargain underpinning the FERC-accepted Southern NITSA arrangements."[31] MISO urged that SMEPA's load-supply arrangement "requires a high level of transmission service flexibility that only Network Service can provide."[32] MISO noted that, unless the non-conforming NITSA was accepted, SMEPA would be forced to use PTP service to serve its load on the Southern system. MISO reminded the Commission that "Network Service is inherently more flexible than Point-to-Point Transmission Service."[33] Finally, MISO noted that, given the location of SMEPA's system:

> SMEPA has limited alternatives to MISO's membership once Entergy's transmission, load and generation are integrated into the MISO Energy and Operating Reserve Markets. The Commission has sought to encourage RTO membership, *including a recognition that non-jurisdictional utilities may require limited accommodations to make their RTO membership financially feasible.* The proposed MISO NITSA will achieve this purpose while imposing no undue

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[31] Transmittal Letter dated July 23, 2013 in FERC Docket No. ER13-2008-000, at 4.

[32] *Id.*

[33] *Id.* at 5. Driving the point home, MISO highlighted the Commission's own statements in Order Nos. 888 and 888-A in which, after comparing Network and Point-to-Point service, the Commission found that PTP service imposes on customers "a relatively higher risk associated with the availability of firm transmission capacity," as well as less of the operational flexibility a customer requires to integrate and economically utilize its generating resources. *Id.* at n. 11, citing Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,260 (1997).

burdens on any third party.[34]

The MISO-SMEPA NITSA and the SMEPA-Southern NITSA are the two inter-dependent hand-in-glove parts of a unified arrangement that allowed SMEPA to integrate its resources and loads into MISO in an efficient and cost-effective manner. Any doubt that the MISO-SMEPA NITSA and the SMEPA-Southern NITSA are the closely-fitted pieces of a single arrangement should be dispelled by the fact that the MISO-SMEPA NITSA *expressly incorporates the SMEPA-Southern NITSA by reference*.[35]

2. The Order's Erroneous Refusal to Consider the SMEPA Integration Model.

Notwithstanding the close parallels between the arrangement proposed by EKPC and the arrangements that facilitated SMEPA's entry into MISO, the Order rejects EKPC's reliance on the SMEPA arrangements. It does so, not based on a careful analysis of the SMEPA transaction and a finding of any critical differences, but instead based on narrow ground that the order accepting those arrangements is a delegated order. The Order's rejection of EKPC's reliance on the SMEPA example is not the product of reasoned decision-making and is contrary to law.

(a) The Arrangement EKPC Seeks is Directly Analogous to the Commission-Accepted SMEPA-Southern Arrangement.

In rejecting any reliance on its acceptance of the amended SMEPA-Southern NITSA, the Commission gives no consideration to the substantive relevance of that agreement. Instead, the Order relies only on the fact that the amended NITSA was accepted by delegated letter order,

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[34] *Id.*, at 6 (emphasis added) (*citing Southwest Power Pool, Inc.*, 125 FERC ¶ 61,239 (2008)).

[35] *Id.*, at 4.

stating that its action "therefore does not reflect binding Commission precedent."[36] Beyond that, the Order gives no further consideration to the SMEPA-Southern NITSA.

That the Commission elects not to bind itself to the decisions of its delegates does not insulate or detach the Commission from those decisions. It is inconsistent with the Commission's obligations under the Federal Power Act and Commission practice in other proceedings for the Commission to casually dismiss the SMEPA-Southern NITSA as irrelevant simply because it was accepted for filing in a delegated letter order that contained the boilerplate "no precedent" disclaimer. The Commission has an affirmative duty to evaluate all filings (including those agreed upon by the parties involved) for their consistency with statutory standards and Commission policy,[37] and it has not been reluctant to reject unopposed or widely supported filings that were found to offend Commission policy in some respect.[38] The regulation governing the Commission's delegations of authority to the Office of Energy Market Regulation provides in relevant part that the Director or his designee, may, under Sections 205 and 206 of the Federal Power Act, accept for filing an uncontested rate schedule or rate schedule changes.[39] Even so, the Director must ensure that the agreement complies "with all statutory requirements and with all applicable Commission rules, regulations and orders." Id. One must assume, then, that the SMEPA-Southern NITSA was subjected to such an evaluation and found to be consistent

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[36] Order at P 61.

[37] *See, e.g., Tejas Power Corp. v. FERC*, 908 F.2d 998, 1003 (D.C. Cir. 1990).

[38] *See, e.g., High Island Offshore System, L.L.C.*, 110 FERC ¶ 61,043, at P 30 (2005), *aff'd, Petal Gas Storage, L.L.C. v. FERC*, 496 F.3d 695, 697 (D.C. Cir. 2007) (rejecting uncontested settlement found to confer benefits on a discriminatory basis). *See also PJM Interconnection, L.L.C., Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc*., 144 FERC ¶ 61,217 (2013) (rejecting uncontested settlement found to be inconsistent with Commission policy requiring demonstration of net benefits prior to pass-through of RTO realignment costs).

[39] *See* 18 C.F.R. § 375.307.

with the Southern tariff, FPA standards and FERC policy. The Director could not have accepted the SMEPA-Southern amended NITSA without determining that it was consistent with the Commission-approved Southern transmission tariff, and that it met the "just and reasonable" standard under Section 205 to which all FERC-accepted agreements are held.

Under 18 C.F.R. § 375.307(a)(1), the Director of the Office of Energy Market Regulation is delegated the authority to accept for filing, *inter alia*, "uncontested tariff or rate schedule changes submitted by public utilities … if they comply with all applicable statutory requirements, and with all applicable Commission rules, regulations and orders for which waivers have not been granted." That delegation of authority does not include the authority to accept for filing a non-conforming NITSA, since, by definition, it would not comply with applicable regulations. (Non-conforming NITSAs may be accepted through letter orders, but only those that are issued by direction of the Commission itself, as with the MISO-SMEPA NITSA.)[40] For the Director to have accepted for filing the Southern-SMEPA NITSA amendment through exercise of delegated authority, a determination first must have been made that the amended NITSA—including the Network Load definition for the Purvis Substation Delivery Point—conformed to Southern's tariff terms. Absent such a determination, the exercise of delegated authority to accept the amended NITSA for filing would have been invalid.[41]

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[40] *See Midcontinent Independent System Operator, Inc.*, 145 FERC ¶61,242 (2013).

[41] *See Pacific Gas and Electric Co*. 144 FERC ¶ 61,107 at P 19 (2013) (reversing a decision to delegate decision-making authority because the matter was contested); *Shell Oil Co.*, 43 FERC ¶ 61,477 at p. 62,179 (1988) (finding that Commission staff exceeded its delegated authority by dismissing an application in proceeding that was "contested" because a protest had been filed).

The Commission's acceptance of the NITSA therefore is deserving of credence, even if the acceptance by delegated letter order falls short of creating "binding precedent." EKPC modeled its proposal on the SMEPA arrangements largely because they had been accepted by the Commission. That a delegated order is not "binding precedent" does not explain why the Order rejected EKPC's proposed arrangements when the SMEPA arrangements on which EKPC's proposal was modeled were deemed acceptable.

(b) The Order's Rejection of EKPC's Reliance on the MISO-SMEPA NITSA Was Based on a Misunderstanding of the Relevance of That Agreement.

Equally deficient is the Order's stated rationale for refusing to give weight to its acceptance of the MISO-SMEPA NITSA.[42] The Order first focuses on what is, in the instant context, an irrelevant distinction: namely, that the MISO Tariff precluded the designation of Network Load not physically connected to a MISO Transmission Owner, while "Section 31.3 of LG&E/KU's Tariff already has a provision allowing this."[43] Apparently recognizing that this distinction has no relevance to the matters actually at issue here, the Order then points to another distinction: "[A]s it concerns EKPC's proposal in this proceeding, the facts in MISO-SMEPA are not similar to facts at issue here because SMEPA did not request to designate less than its entire load at discrete points of delivery."[44] This reflects a fundamental misunderstanding of the relevance of the MISO-SMEPA arrangement to the case at hand.

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[42] *See* Order at P 62.

[43] *Id.*

[44] *Id.*

Contrary to the Order's mistaken presumption, EKPC did not point to the MISO-SMEPA NITSA as an additional example of a "less than entire load" designation. Rather, it was *the NITSA between SMEPA and Southern Company* that involved a Network Load designation which was other than the "entire load" at a delivery point. As noted above, in SMEPA-Southern the designated Network Load at the Purvis Substation Delivery Point was "calculated on an hourly basis to equal the energy generated by Network Resources located within the SoCo BAA that is not used to serve SMEPA's Network Load located within the SoCo BAA."[45] It was the Purvis network load designation *in SMEPA-Southern* that is analogous to the Bluegrass delivery point arrangement EKPC has proposed. The MISO-SMEPA arrangement is relevant for a different purpose: as part of SMEPA's overall transitioning of its loads and resources into MISO, it integrates the energy from SMEPA's Southern-area resources which was made available, through the Southern-SMEPA NITSA, to serve SMEPA's post-transition load in the MISO BAA. In that way, MISO-SMEPA demonstrates, not just the technical feasibility of the overall arrangement, but also that the Southern-SMEPA NITSA was an efficient and cost-effective mechanism for integrating SMEPA's Southern-area resources and loads into MISO.[46] There is no reason why the analogous arrangement EKPC has proposed for the Bluegrass delivery point would not also provide an efficient and cost-effective mechanism for integrating that resource within PJM.

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[45] Transmittal letter dated May 7, 2012 in *Alabama Power Co*., Docket No. ER12-1724-000, at 2.

[46] *See* Transmittal Letter dated July 23, 2013 in FERC Docket No. ER13-2008-000, at 4-5 (noting that SMEPA's Southern-area load supply arrangement "requires a high level of transmission service flexibility that only Network Service can provide," and that "[t]he Southern NITSA provides SMEPA with sufficient firm transmission to designate the network resources under the Southern NITSA as Designated Network Resources under the MISO Tariff.").

(c) By Choosing to Reject the SMEPA Example, the Commission Foregoes a Practical and Proven Solution to the Problem at Hand.

By focusing on the purported differences between SMEPA's and EKPC's circumstances rather than the actual similarities, the Order fails to apprehend the relevance and importance of the SMEPA example. The SMEPA-Southern NITSA and the MISO-SMEPA NITSA together formed a coherent and practical solution to a complex problem that, when given more careful analysis than appears in the Order, is found to be strikingly similar to the Bluegrass integration problem. In both instances, the key that unlocks a solution is a Network Load definition that ties to the dynamic relationship between Network Resource output and Network Load, rather than focusing on delivery point load alone. The SMEPA integration problem was favorably resolved because the parties put their experience in utility operations and planning to good use, searching for and ultimately finding a solution that is both practical and fair. And, when it was presented with that solution through the amended NITSA filings, the Commission also focused on helping the parties achieve an efficient and cost-effective result. Thus, in considering the MISO-SMEPA part of the package, the Commission treated the tariff as a framework for solutions, not an un-scalable mountain of obstacles. Consistent with that approach, the Commission chose not to mechanistically apply the strict letter of the MISO Tariff in order to find reasons to reject the proposal, but instead gave effect to "the flexibility provided under section 31.3 of the pro forma OATT."[47] Accordingly, the Commission decided that a deviation from the Tariff was just and

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[47] *Midcontinent Independent System Operator, Inc.*, Docket No. ER13-2008-000, 145 FERC ¶ 61,242, at P 11 (2013) (emphasis added).

reasonable because allowing that deviation made it possible for SMEPA to bring all its loads and resources into MISO in a more cost-effective way.

The Order does not reveal why it tacks in the opposite direction here. Rather than viewing the SMEPA example as a source of useful guidance on how Bluegrass could be integrated into PJM in an efficient and cost effective manner for EKPC, the Order instead hunts for differences that, while ultimately unimportant, are cited in the Order for the purpose of declaring the SMEPA example inapt. Setting SMEPA to the side on that basis, the Order then applies a narrow and unyielding reading of the LG&E/KU Tariff that, in turn, forms the basis for the Order's conclusion that EKPC's proposal "is not contemplated under the language of the Tariff."[48]

The Order's narrow and mechanistic application of the Tariff is at odds not only with the more flexible approach applied in MISO-SMEPA, but also with the Commission's long-held view that the *pro forma* tariff prescribes the *minimum* terms and conditions of non-discriminatory service, not the maximum.[49] Neither is the Order's mechanistic approach a good or thoughtful application of the Commission's accumulated expertise in how resources and loads

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[48] Order at P 56.

[49] *See, e.g.*, Order No. 888, FERC Statutes and Regulations, Regulations Preambles January 1991-June 1996 ¶31,036, at p. 31,655; Order No. 890, FERC Statutes and Regulations, Regulations Preambles 2006-2007 ¶ 31,241 at P 14; Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, *FERC Statutes and Regulations*¶31,323 at P 16 (2011)); *Atlantic City Elec. Co.*, *et al.*, 77 FERC ¶ 61,148 (1996) ("In the Open Access Rule, the Commission required all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to file open-access non-discriminatory transmission tariffs with minimum terms and conditions of non-discriminatory service"); *Idaho Power Co*., 137 FERC ¶ 61,235 at P 34 (2011) ("The Commission prescribed in Order No. 888 the rules for transmission providers to file open access transmission tariffs that contained minimum terms and conditions for non-discriminatory service."); and *FirstEnergy Corp*., 114 FERC ¶61,132 at P 10 (2006) ("All public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce are now required to have open access transmission tariffs that contain minimum terms and conditions of non-discriminatory service.")

can best be integrated within and across RTO borders. On the contrary, the Order's approach is akin to what the court in *Scenic Hudson* almost certainly had in mind when it observed that the Commission's role as protector of the public interest "does not permit it to act as an umpire blandly calling balls and strikes for adversaries appearing before it."[50]

In the Order, the Commission's "balls and strikes" approach to the issues, coupled with its application of an inexplicably narrow and inflexible reading of the Tariff, produces a result that deprives EKPC of the benefits of an efficient Bluegrass integration and provides LG&E/KU with a windfall of millions of dollars of increased transmission charges that are disproportionate to the service involved. Interpreting the LG&E/KU tariff in a way that only gives EKPC a choice between "bad" and "worse" is far less of a contribution to the problem-solving process than the Commission is capable of making. EKPC respectfully prays that the Commission will use this request for rehearing as a vehicle for helping in forging a practical solution to EKPC's need to integrate Bluegrass.

C. The Commission Erred in Concluding that LG&E/KU's Interpretation of the Tariff is Just and Reasonable.

Based on its flawed evaluation of the facts and its summary dismissal of contrary authorities, the Order sets forth the following conclusion:

> Therefore, based on the foregoing, we find it reasonable for LG&E/KU to interpret the LG&E/KU Tariff as preventing the designation of part of the load at discrete points of delivery on the EKPC transmission system as Network Load. The alternatives for providing customers transmission service for such external load are spelled out in section 31.3

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[50] *Scenic Hudson Preservation Conf. v. FPC*, 354 F.2d 608, 620 (2d Cir. 1965), *cert. denied*, 384 U.S. 941 (1966).

of LG&E/KU's Tariff.[51]

In stating that it was "reasonable" for LG&E/KU to interpret Tariff section 31.3 as it did, the Commission implicitly acknowledges that LG&E/KU's interpretation is not the only possible or even plausible reading of that section. In other words, the Commission (in effect) concedes that *other* readings of section 31.3 also are possible, and presumably that one of those other readings might be found "reasonable" in other circumstances. Were it otherwise—that is, if the Commission's view is that the LG&E/KU interpretation is the *only possible reading* of the pertinent language—the Commission could easily have said so, which would have obviated the need to declare the LG&E/KU interpretation "reasonable."

The possibility of other reasonable interpretations of Tariff section 31.3 begs the question: Was it correct for the Order to find the specific interpretation tendered by LG&E/KU to be "reasonable" in the circumstances presented by the Complaint? EKPC submits that the answer is "no." As is readily apparent on the face of the Order, the conclusion that LG&E/KU's Tariff interpretation is reasonable flows directly from the Commission's finding that EKPC's proposal would result in prohibited "load splitting." Because (as explained above) that finding itself was erroneous, the conclusion the Commission drew from it also must be judged erroneous.

Furthermore, as EKPC recounts elsewhere in this Request, the LG&E/KU interpretation would subject EKPC to substantial operational burdens and considerable additional cost (on the order of $5-10 million per year, possibly more) simply to be able to use Bluegrass output to serve its members' loads at delivery points connected to the PJM transmission system. Those

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[51] Order at P 63.

additional charges would be layered on top of the fully compensatory charges EKPC already pays LG&E/KU and PJM for Network Service. Under these circumstances, the evidence does not support the Commission pronouncement that the LG&E/KU interpretation is "reasonable." The process by which the Commission reached that conclusion was not one of reasoned decision-making.

D. The Order's Rejection of EKPC's Proposal is Not Supported by Commission Policy.

The Order rejects EKPC's assertion that the arrangement it proposed for integrating Bluegrass output is consistent with Commission policies on open access transmission. In fact, the Order includes an affirmative finding that LG&E/KU's rejection of EKPC's proposal comports with Commission policy. The basis for that finding, however, is not specified, and, indeed, the Order never even identifies the specific Commission policy that is the subject of the purported filing. Closer inspection of the Order reveals that the Commission's "policy" finding is bound up with, and is essentially indistinguishable from, its determination that the *language* of the LG&E/KU Tariff mandates rejection of EKPC's position.[52]

The closest the Order comes to identifying a "policy" that supports rejection of EKPC's position is the Commission's asserted aversion to "load splitting." And while one could argue that this is less a policy than an interpretation of the Tariff, the more important fact is that, as shown above, EKPC's position here does not call for service with both Network and Point-to-

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[52] *See, e.g.*, Order at P 54 ("Based on our review of the language of the provisions at issue, we find that LG&E/KU's refusal to accept EKPC's proposed amended NITSA is consistent with the LG&E/KU Tariff and is consistent with Commission policy."). *See also id*. at P 56 (stating with respect to EKPC's proposed Network Load definition for the Bluegrass Delivery point that "[t]his type of load designation is not contemplated by the Tariff or Commission policy").

Point service at the same delivery point, which is what the Commission generally means when it refers to the "splitting" of load. Ironically, it is *the rulings in the Order*, rather than EKPC's position, that would require load-splitting as that term is generally understood. To be specific, according to the Commission one of the alternatives the Tariff makes available to EKPC is to purchase Point-to-Point service from Bluegrass to one or more points on the EKPC transmission system. Load connected to the EKPC system, however, will continue to be served as EKPC Network Load under the PJM Tariff. Thus, under that alternative, load at delivery points on the EKPC system would be served with *both* PJM Network Service and LG&E/KU Point-to-Point service. In short, it is the Order itself that runs afoul of the only policy even arguably identified in the Order as supporting the LG&E/KU position.

Just as problematic is that the Order disregards the several Commission policies that are *directly undercut* by the Commission's endorsement of LG&E/KU's position. One such Commission policy is comparability—the requirement that a transmission owner make its system available to the same extent, and subject to the same or comparable terms and conditions, as govern the transmission owner's own use of its system. That policy is undermined by the adoption of LG&E/KU's position given the evidence submitted by EKPC showing that LG&E/KU seek to impose more burdensome terms on EKPC's use of Bluegrass than they impose on themselves or TVA in implementing those entities' Contingency Reserve Sharing Agreement.[53]

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[53] *See* the discussion at Part III. G, *infra*, and Attachment 4 to the "Motion for Leave to Answer and Answer" filed by EKPC on December 9, 2015 (Affidavit of Darrin Adams) at ¶ 16.

Another important Commission policy that is undermined by the adoption of LG&E/KU's position is that of minimizing the effect of seams between RTO areas, or between RTOs and non-RTO areas. Here, one of the unique components of the factual backdrop is the decision by LG&E/KU to withdraw from MISO in 2006.[54] Had LG&E/KU not withdrawn from MISO, EKPC's purchase of Network Service from PJM for its entire member load, including that which is connected to the LG&E/KU transmission system, would have allowed EKPC to utilize Bluegrass in the manner it seeks without paying additional transmission charges to LG&E/KU. LG&E/KU's position regarding the imposition of additional charges on EKPC is made possible only because LG&E/KU withdrew from MISO and created a new pricing seam that did not exist while LG&E/KU were MISO members. By adopting LG&E/KU's position, the Commission undermines its own policy of reducing seams-related impacts. Indeed, to the extent the Commission's adoption of LG&E/KU's position may be perceived as rewarding those entities for creating the new seam, the Order even goes against the grain of the Commission's general policy of promoting RTO participation by transmission-owning utilities.

Other Commission policies contravened by the Order's adoption of LG&E/KU's position are discussed in Part III.H.3, *infra*, and we incorporate that discussion here by reference. For instant purposes, the point is that LG&E/KU's interpretation of the Tariff cannot be deemed "reasonable" if it offends the important and well-established Commission policies discussed here and below (which it does). Moreover, from the face of the Order it is clear that the Commission failed to consider the conflict between LG&E/KU's interpretation of the Tariff and other

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[54] *See Louisville Gas & Electric Company/ Kentucky Utilities*, 114 FERC ¶ 61,282 (2006) (order approving LG&E/KU's withdrawal from MISO.)

Commission policies. That failure is another reason why the Commission's determination that LG&E/KU's interpretation of the Tariff was "reasonable" cannot be deemed a product of reasoned decision-making.

E. The Commission's Finding that EKPC's Proposal Would Cause LG&E/KU to Suffer Inadequate Compensation for the Use of its Transmission System is Not the Product of Reasoned Decision-making.

The Order's second principal finding is that EKPC failed to show that the terms of the LG&E/KU Tariff are unjust and unreasonable as applied to EKPC. In order to make that finding, it would have been necessary for the Commission to evaluate the Tariff's impacts on EKPC, as through an analysis of the additional costs EKPC would incur if it is forced to integrate Bluegrass in the manner proposed by LG&E/KU.[55] An analysis that focuses on the impacts on EKPC cannot be found in the Order, however. Instead, the Order turns the tables and focuses on whether LG&E/KU would be adversely affected by the arrangement EKPC proposed. Looking through that end of the telescope, the Commission found that EKPC's proposed arrangement would cause LG&E/KU to suffer inadequate compensation for the use of their transmission system.

In detail, after characterizing EKPC's proposal as "load splitting" prohibited by the Tariff and Commission policy,[56] the Commission stated:

> EKPC proposes to designate a portion of the load on its own transmission system as LG&E/KU Network Load based upon the output of the Bluegrass station in any hour minus the EKPC load on the LG&E/KU transmission system.

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[55] EKPC estimates the additional costs to be at least $5-10 million per year starting in 2019.

[56] Order at P 56. EKPC believes that the characterization of its proposal as a form of load-splitting is incorrect and at odds with the facts as presented in the pleadings. *See* Part III.A.1, *supra*.

> EKPC would, therefore, limit its transmission payments based on its hourly use for such deliveries. At the same time, since LG&E/KU would have difficulty predicting in advance the amount of transmission that EKPC would use for such deliveries in any hour, it would have to hold transmission service for EKPC for which it may not receive compensation. We do not read section 31.3 of the Tariff as requiring LG&E/KU to permit a customer to purchase network service solely on such a basis.[57]

The conclusion that EKPC's proposal would deprive LG&E/KU of appropriate compensation is rooted in two subsidiary findings: First, that EKPC's payments for service would not fully reflect its use of the system; and, second, that the arrangement EKPC proposes would prevent LG&E/KU from securing revenues from sales of transmission service to others. Each of these subsidiary findings is erroneous and unsupported, as we demonstrate below.

1. There is No Basis for the Commission's Finding That EKPC's Proposal Would Under-Compensate LG&E/KU.

As noted, the Commission concluded that, in designating a new Network Load equal to the difference in any hour between Bluegrass output and EKPC's load on the LG&E/KU system, "EKPC would … limit its transmission payments based on its hourly use for such deliveries."[58] Although it is less than entirely clear what the Commission meant by this statement, the implication is that EKPC's proposal would somehow provide LG&E/KU less compensation than is proper given the use EKPC would make of their system. The facts belie such a conclusion.

Under EKPC's proposal, the designated Network Load at the new Bluegrass delivery point in each hour would be the difference between the output of Bluegrass and EKPC's

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[57] Order at P 57.

[58] *Id.*

Network Load on the LG&E/KU system. The sum of EKPC's delivery point requirements in each hour, including its requirements at the Bluegrass delivery point, would be the basis for determining its aggregate coincident peak demand on the LG&E/KU system each month. This aggregate coincident peak demand is the value used in determining a Network Customer's charge for Network Service each month under the LG&E/KU Tariff. By paying its monthly charge for Network Service, EKPC would compensate LG&E/KU to the full extent of EKPC's actual use of the transmission system during each month, including such use as is attributable to deliveries of energy to the Bluegrass delivery point during that month.[59]

Given the manner in which LG&E/KU develop charges to Network Service customers, it is puzzling that the Order states that "EKPC would … limit its transmission payments based on its hourly use for such deliveries."[60] This is precisely how *all* Network Service customers pay for service on the LG&E/KU system; their charges are based on each customer's "hourly use" of the system during the hour in which the LG&E/KU peak load for the month occurs. EKPC's proposal—pursuant to which it would pay for Network Service at the Bluegrass delivery point each month based on actual deliveries during the coincident peak hour for the month—is entirely consistent with the method LG&E/KU use to calculate charges for all Network Customers.

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[59] LG&E/KU charge network customers a monthly charge that is the product of the customer's total coincident peak demand in the month times the monthly rate in effect for the pertinent billing year. The monthly rate is determined by dividing LG&E/KU's net annual transmission revenue requirement by a divisor that includes twelve months of coincident peak network load, and then dividing that annual rate by 12. The derivation of the monthly rate is shown most recently in Attachment 1.0 to LG&E/KU's March 15, 2016 informational filing in Docket No. ER16-1187-000. Each month, the load at the Bluegrass delivery point during the LG&E/KU coincident peak hour would be included in the EKPC Network Load to which the monthly Network Rate is applied.

[60] Order at P 57.

Further, because the aggregate EKPC Network Load used for billing purposes each month would include (and be increased by) the load of the Bluegrass delivery point during the coincident peak hour of that month, LG&E/KU would be fully and properly compensated for the use of their system to serve that load. EKPC will never pay less than its share of the costs of the LG&E/KU system as dictated by the EKPC load connected to the LG&E/KU system,[61] and, in fact, EKPC would pay *more* than a share of system costs commensurate with its LG&E/KU-connected load whenever Bluegrass output exceeds that load at the time of the coincident peak. The Order's suggestion that EKPC somehow would avoid paying proper compensation by "limit[ing] its transmission payments based on its hourly use for such deliveries" is contrary to EKPC's showing that its proposal ensures LG&E/KU would be fully compensated for serving Network Load at the Bluegrass delivery point.

The Commission based its decision on an explanation that runs counter to the evidence, however, it failed to engage in reasoned decision-making.[62] The Commission had an affirmative duty to engage EKPC's arguments and to square its decision with those arguments.[63] With

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[61] As EKPC stated in its Complaint:

> The amended NITSA, as proposed by [EKPC], defines [EKPC's] new Network Load as the amount of Bluegrass output that exceeds [EKPC's] Network Load on the [LG&E/KU] system. Defining the amount of new Network Load in this manner accurately reflects the transmission service that [LG&E/KU] will provide and ensures that [LG&E/KU] will receive its full Network Service rate for this service.

Complaint at 16.

[62] *See National Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831, 839 (D.C. Cir. 2006).

[63] *See NorAm Gas Transmission Co. v. FERC*, 148 F.3d 1158, 1165 (D.C. Cir. 1998) ("[i]t most emphatically remains the duty of this court to ensure that an agency engage the arguments raised before it--that it conduct a process of reasoned decision making") (*citing KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1303 (D.C. Cir. 1992)).

regard to the question of whether EKPC's proposal would properly compensate LG&E/KU, the Order's reasoning is incorrect and the Order's conclusion is not supported by the record.

2. EKPC's Proposal Would Not Prevent LG&E/KU from Selling Transmission Service to Others.

The second finding underlying the Commission's conclusion that EKPC's proposal would cause LG&E/KU to suffer inadequate compensation is that "since LG&E/KU would have difficulty predicting in advance the amount of transmission that EKPC would use for such deliveries [to the Bluegrass delivery point] in any hour, it would have to hold transmission service for EKPC for which it may not receive compensation."[64] This finding is contrary to the evidence, and therefore is in error, on at least the following grounds.

First, EKPC demonstrated through detailed affidavit evidence that its proposal would not prevent LG&E/KU from calculating and posting Available Transmission Capability ("ATC") or from selling unscheduled firm transmission service for non-firm use. That is because LG&E/KU receives on an ongoing basis detailed forecasts of EKPC load and generation that allow it to predict—for both operational and planning purposes—the amounts of transmission service likely to be needed each day to serve EKPC's load at the Bluegrass Delivery Point. In detail, through the sworn affidavit testimony of Mr. Darrin Adams, EKPC's Director of Power Delivery Planning, Design and Construction,[65] EKPC demonstrated the following:

- Currently, the Tennessee Valley Authority ("TVA") is responsible for calculating initial Available Flowgate Capability ("AFC") values for the LG&E/KU transmission system. TranServ, acting as the Independent

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[64] Order at P 57.

[65] Mr. Adams' affidavit ("Adams Affidavit") was submitted as Attachment 4 to the "Motion for Leave to Answer and Answer" filed by EKPC in this docket on December 9, 2015.

Transmission Organization, uses the initial values calculated by TVA to determine final AFC values for the LG&E/KU system.[66]

- Each day, PJM provides daily load forecast information for the EKPC system to TVA. TVA (on behalf of LG&E/KU) is provided each day with a forecast of EKPC load for each hour for each of the next 7 days, for the peak hour of each day for days 8 through 31, and for the peak hour of each month for months 2 through 18.[67] The amount of EKPC load connected to the LG&E/KU system in the ATC calculation process is adjusted each day to provide the best estimate of load taking into account historical usage patterns and meteorological conditions.[68]
- The maximum output values of the Bluegrass units also are known to LG&E/KU. These are essentially fixed values, with only minor seasonal variation[69] akin to that commonly seen in other thermal generating units with which LG&E/KU are familiar.
- From these sets of data—the maximum output of the Bluegrass units and the forecasted total EKPC load connected to the LG&E/KU transmission system—it is a simple and straightforward matter for LG&E/KU to derive a projection of EKPC's hourly Network Load at the Bluegrass Delivery Point.[70]

EKPC's Network Load at the Bluegrass Delivery Point is no more difficult for LG&E/KU to project than any other Network Load for which a Network Customer provides forecasts to its Transmission Provider. And, importantly, the information that would enable LG&E/KU to calculate EKPC's hourly Network Load at the Bluegrass Delivery Point will be provided *before* the real-time delivery of energy takes place, not "after-the-fact" as LG&E/KU inaccurately claimed in its filings.[71] As a result, LG&E/KU would be able to release any

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[66] Adams Affidavit at ¶ 5.

[67] *Id*.

[68] *Id*.

[69] *Id*..

[70] *Id*.

[71] *Id*. at P 14.

transmission capacity that the forecasts indicate will not be required by EKPC to serve its Network Load on the LG&E/KU system (including Network Load at the Bluegrass Delivery Point) just as it is able to do now. By releasing any such unused capacity and selling it as non-firm ATC, LG&E/KU would be able to secure additional revenue to meet its annual transmission revenue requirement.

Second, the Commission's statement that LG&E/KU would be disadvantaged by the need to "reserve" transmission capacity for serving EKPC's Bluegrass Delivery Point belies a fundamental misconception of Network Service.[72] In operating and planning its transmission system, every provider of Network Service depends on its Network Customers' forecasts of Network Load and Network Resource output. The Transmission Provider takes these forecasts into account, along with its other firm service commitments, in determining the amounts of firm and non-firm ATC it can offer for sale to others. While not a "reservation" in the conventional sense, the obligation to serve Network Load represents a commitment of system capability that necessarily reduces a Transmission Provider's opportunity to realize revenue through sales of service to others. The Network Load at EKPC's Bluegrass Delivery Point imposes no greater impediment to revenue maximization than any other Network Load served from the LG&E/KU system.

Third, nothing about the arrangement proposed in EKPC's Complaint would prevent LG&E/KU from selling non-firm service using transmission capacity that is not forecast to be needed to serve Network Load at the Bluegrass Delivery Point; neither would LG&E/KU's

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[72] *See* Order at P 57.

marketing of such capacity on a non-firm basis be burdened by the EKPC arrangement. In fact, from LG&E/KU's perspective, transmission capacity not needed to serve the Bluegrass Delivery Point in any hour would be indistinguishable from other transmission capacity needed to serve Network Load during high-demand periods but available for sale on a non-firm basis during other periods. Therefore, to reject EKPC's NITSA amendment on the theory that LG&E/KU "would have to hold transmission service for EKPC for which it may not receive compensation"[73] improperly discriminates against the EKPC proposal, given that the same could be said of any other Network Load served from the LG&E/KU system.

In sum, there is no support for the Order's conclusion that the arrangement proposed by EKPC would cause LG&E/KU to suffer inadequate compensation for the use of its transmission system.[74] The Commission came to that conclusion without specifying any respect in which EKPC's extensive evidence to the contrary was flawed or unavailing. In failing to engage the evidence and arguments presented by EKPC on this point, the Commission fell short of satisfying its duty to engage in reasoned decision-making, and the Order is not supported by the record evidence. Rehearing therefore should be granted.

F. In Finding that EKPC Failed to Demonstrate that the LG&E/KU Tariff is Unjust and Unreasonable as Applied to EKPC, the Commission Committed Error.

Having found that EKPC's proposed amended NITSA was not consistent with the LG&E/KU Tariff, the Commission denied EKPC's alternative request that the Commission find the LG&E/KU Tariff's terms to be unjust and unreasonable as applied to EKPC's integration of

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[73] *Id.*

[74] *Id.*

its Bluegrass resource. But, the Commission's perfunctory discussion of this element of the Complaint failed to articulate a rational basis for its finding that is grounded in logic or record support.

1. The Commission Did Not Articulate a Rational Basis for Concluding that EKPC Failed to Demonstrate that the LG&E/KU Tariff is Unjust and Unreasonable as Applied in This Instance.

Finding that EKPC had failed to demonstrate that the LG&E/KU Tariff is unjust and unreasonable as applied to EKPC in this case, the Order simply reiterates the Commission's earlier findings regarding the consistency between the LG&E/KU Tariff and the pro forma Tariff, and repeats the Commission's disinclination to give "each and every customer" the opportunity to "create alternative services which benefit that particular customer."[75] Merely reciting its earlier findings, the Order proves nothing about whether the Tariff is unjust and unreasonable as applied in this particular instance.

The Order also states that "EKPC apparently seeks a determination that LG&E/KU's Tariff should not apply to EKPC based on what it suggests are the unusual circumstances associated with its use of the LG&E/KU System and the accommodations we provided LG&E/KU in the past."[76] The Commission misconstrues EKPC's discussion of the unique nature of the LG&E/KU and EKPC systems, and the prior waivers and accommodations that LG&E/KU received for its own load on the EKPC system. To be sure, EKPC cited these and other factors for the Commission's consideration, but by no means were the only grounds

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[75] *Id.* at P 64.

[76] *Id.*

advanced by EKPC to support its Complaint. Indeed, these factors were cited as examples of how flexible arrangements were necessary to accommodate LG&E/KU's withdrawal from MISO and EKPC's subsequent integration into PJM, given the heavily intertwined nature of the LG&E/KU and EKPC systems. Applying the LG&E/KU Tariff in a rigid and mechanistic fashion, as the Order does in this case, is contrary to the previously approved flexibility.

One cannot discern from the Order the facts and circumstances upon which the Order relied to conclude that EKPC failed to demonstrate that the LG&E/KU tariff is unjust and unreasonable in this instance. Apart from citing to the SMEPA NITSAs, and explaining how EKPC's proposed amended NITSA would promote integration of network resources and efficient use of the transmission system, EKPC also proffered substantial factual evidence including affidavits from senior EKPC personnel.[77] This evidence identified operational burdens and excessive charges that would result absent relief. None of this information is analyzed, discussed or even mentioned in the Order's findings.

2. Contrary to the Commission's Finding, EKPC Provided Substantial Evidence that the Pertinent Provisions of the LG&E/KU Tariff are Unjust and Unreasonable, or Produce Unjust and Unreasonable Results, as Applied to the Instant Case.

EKPC proffered substantial evidence in support of its Complaint. EKPC witness David Crews explained how EKPC and LG&E/KU each serve native load that is connected to the others' system, and described the existing arrangements.[78] Messrs. Crews and Denver York

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[77] *See* Affidavit of David Crews, Attachment 2 to the Complaint;("Crews Affidavit"); *and* Affidavit of Denver York, Attachment 3 to the Complaint ("York Affidavit"); *and* Adams Affidavit.

[78] Crews Affidavit at ¶¶ 5-10.

provided relevant factual background oftheir attempts to arrive at a reasonable arrangement that ensured that EKPC could integrate its network resource to serve its native load, while promoting efficient use of the transmission systems and ensuring appropriate compensation to LG&E/KU for EKPC's use of the LG&E/KU system.[79] EKPC's witnesses explained that all EKPC load, including that served from the LG&E/KU system is internal to PJM, and that EKPC needed to integrate this new resource to serve its native load.[80] EKPC explained how often EKPC expects to run Bluegrass and the manner in which it would be used to serve its native load connected to both systems (*i.e.*, dispatched first to serve the load connected to the LG&E/KU system).[81]

EKPC explained that the largest amount of transmission service that EKPC would use on the LG&E/KU system would be the greater of the EKPC load connected to the LG&E/KU system or the Bluegrass output, but not both in the aggregate.[82] EKPC proffered evidence explaining the unreasonable operational and economic burdens that would result if EKPC were forced to arrange for separate Point-to-Point service, which would be several hundred megawatts, in addition to the network service for which it already pays LG&E/KU; and they explained why it was also unreasonable to force EKPC to designate delivery points from EKPC's own system in order to add several hundred additional megawatts of network load under the

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[79] Crews Affidavit at ¶ 17; York Affidavit at ¶¶ 13-14.

[80] Crews Affidavit at ¶ 17; York Affidavit at ¶ 9.

[81] Crews Affidavit at ¶ 12.

[82] York Affidavit at ¶ 18.

LG&E&/KU NITSA, forcing EKPC to pay LG&E/KU for service to load that is not connected to the LG&E/KU system.[83]

EKPC explained that LG&E/KU's rigid interpretation of its own tariff would force EKPC to utilize inferior service to use its network resources to serve EKPC's native load. EKPC estimated that under LG&E/KU's unreasonable approach, EKPC would face duplicative and unnecessary additional transmission charges, increasing EKPC's annual transmission payments to LG&E/KU from approximately $7 million to $17 million per year, which would not reflect the service that EKPC would actually need or use in real time operations.[84] (Because of the potential impact of the Order, EKPC has begun exploring construction of a new transmission line to directly connect Bluegrass to EKPC's transmission system.) EKPC also proffered evidence that its proposal would not restrict LG&E/KU's transfer capacity, affect timely exchange of information with LG&E/KU, or produce any material difference in variability of dispatched generation.[85]

None of this information was addressed by the Order in concluding that EKPC failed to meet its burden in demonstrating the unjust and unreasonable result that is produced in applying the provisions of the LG&E/KU Tariff to EKPC's requested amended NITSA. Recognizing that EKPC's objective is to integrate its new resource with its native loads and not to "game the system," the evidence overwhelmingly demonstrates that application of the LG&E/KU Tariff

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[83] *Id*. at ¶¶ 18-19.

[84] *Id*.

[85] Adams Affidavit at ¶¶ 12-16.

will produce unjust and unreasonable results in this case, and that the Commission is justified in adopting EKPC's proposed amended NITSA with LG&E/KU.

G. The Order Fails to Consider the Undue Discrimination in Favor of LG&E/KU's Affiliate Load-Serving Entity that Results from the Adoption of LG&E/KU's Position.

As noted above, for the Commission to conclude that EKPC failed to show that the Tariff is unjust and unreasonable as applied to EKPC, it would have been necessary for the Commission to evaluate the impacts on EKPC of applying the Tariff's terms. Judging from the Order, the Commission never engaged in that evaluation—a failure that renders the Order arbitrary and unreasoned. Had the Commission performed the required evaluation, though, it would have found that application of the Tariff terms, in addition to imposing substantial and unwarranted additional costs on EKPC (up to $5-10 million per year, possibly more), also would have unduly discriminatory impacts on EKPC. To be specific, rejection of EKPC's proposed NITSA amendment disfavors EKPC's Network Load as compared to load served by LG&E/KU's affiliated load-serving entity. EKPC pointed out this element of discrimination in its filings; yet, the Order does not address the issue at all. In failing to address the matter, the Commission (in effect) puts its imprimatur on precisely the sort of undue discrimination that the Commission's open access transmission policies were meant to eliminate.

In detail (and as noted above), EKPC included in its submittals the sworn affidavit testimony of Mr. Darrin Adams, Director of Power Delivery Planning, Design and Construction for EKPC.[86] In his affidavit, Mr. Adams describes an arrangement between TVA and

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[86] The Commission accepted EKPC's December 9, 2015 Answer. *See* Order at P 52.

LG&E/KU that expressly sets aside a share of each party's transmission system capability to allow for the sharing of generation reserves when necessary. Mr. Adams states in his affidavit:

> Just as confirmed transmission reservations are identified as Existing Transmission Commitments to be accounted for when calculating ATC, another factor used to reduce ATC is Transmission Reliability Margin ("TRM"). [LG&E/KU] and TVA have formed a Contingency Reserve Sharing Group ("CRSG") to provide mutual assistance for unanticipated generation outages on either system. Varying amounts of flowgate capacity—and in some cases, large amounts—are set aside on each system in anticipation of the need to deliver generation output from one system to another. Although the anticipated usage of this reserved capacity is much less than 7% of the hours in the year (which is the amount of hours the Bluegrass units are currently restricted to operate each year), [LG&E/KU] currently plans for significant reductions in ATC within its system to accommodate this very infrequently used service. As far as I know, [LG&E/KU] receive no compensation for use of this service.[87]

The beneficiaries of the reserve sharing arrangement between LG&E/KU and TVA are the native load customers of the affiliated LG&E/KU load-serving entity—a fact that LG&E/KU openly acknowledge[88]—since the arrangement is expressly aimed at lowering the generation reserve margin needed to ensure continuity of service to native load customers during unplanned outages of either party's generating facilities. And what the arrangement also shows is that, when their native load customers stand to benefit, LG&E/KU are more than willing to set aside transmission capacity they otherwise might be able to sell to third parties – indeed, to do so *without compensation* – to accommodate a service that is expected to be infrequently required (if at all).

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[87] Adams Affidavit at ¶ 16.

[88] *See* "Motion for Leave to Answer and Limited Answer of Louisville Gas and Electric Company and Kentucky Utilities Company," filed December 22, 2015, at n.18 (stating that "the affiliated LG&E/KU load-serving entity is one of the primary beneficiaries of the TRM set aside to allow this flexibility.").

LG&/KU would have more information about EKPC's anticipated use than it has with respect its own reserve sharing arrangements, and EKPC would be compensating LG&E/KU. Yet, without undertaking any analysis of LG&E/KU's own use of the system, the Order concludes that it is the arrangements proposed *by EKPC* that would result in inefficient use of the LG&E/KU system. That conclusion is at odds with the record evidence, including the testimony offered by Mr. Adams in his Affidavit. By failing to reconcile this conclusion with the evidence, the Order failed to engage in reasoned decision-making.

In these circumstances, any claim that the NITSA amendment proposed by EKPC would adversely affect LG&E/KU's operations or planning is unsupported by the record evidence. EKPC's proposed arrangement would have no greater impact on operations or planning—indeed, it would necessarily have *less* of an impact—than the CRSG set-aside now causes for LG&E/KU.[89] The reason why LG&E/KU, as a transmission provider, would withhold a service from EKPC that they are willing to provide for their own use should not go unnoticed: the ATC set aside for the CRSG benefits the customers of the affiliated LG&E/KU load serving entity, while the service requested by EKPC would benefit an unaffiliated competitor. LG&E/KU's refusal to accommodate the arrangement sought by EKPC violates the Commission's long-

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[89] EKPC's arrangement would have less of an impact than the CRSG set-aside because, as demonstrated in EKPC's submittals and above, a forecast of Network Load at the Bluegrass Delivery Point is easily developed from the information provided to LG&E/KU by EKPC or on its behalf by PJM. Breakdowns of generation, on the other hand, are impossible to predict, which means that use of the CRSG transmission set-aside cannot be forecasted for either near-term operational or longer-term planning purposes.

standing comparability principle;[90] LG&E/KU's refusal is, by the same token, unduly discriminatory and therefore in conflict with essential FPA requirements.

The Order fails to address the discriminatory nature of LG&E/KU's refusal to accommodate EKPC's service request, even though this objection was detailed in Mr. Adams' affidavit and in EKPC's December 9, 2015 reply to the LG&E/KU and TranServ answers to the Complaint. The Commission's failure to engage EKPC's comparability and discrimination arguments renders its Order the product of unreasoned decision-making. On rehearing, the Commission should address the evidence presented by EKPC on this matter and should find on these grounds that LG&E/KU's rejection of EKPC's proposed NITSA amendment was contrary to both the comparability principle and the FPA's prohibition against undue discrimination.

H. The Commission Should Further Consider EKPC's Alternative Request for Waiver.

EKPC requested in its Complaint that, if the Commission were to determine that the LG&E/KU Tariff does not provide for the service sought by EKPC, the Commission should grant a waiver and adopt the proposed arrangements as a non-conforming service agreement.[91] The Commission disagreed that EKPC met the criteria for a waiver,[92] based solely on the following explanation:

> Specifically, we find that EKPC has failed to demonstrate that its requested waiver would not have undesirable consequences, such as harming third parties. We are persuaded by LG&E/KU's argument that EKPC's request for

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[90] *See Am. Elec. Pwr. Serv. Corp.*, 64 FERC ¶ 61,279 (1993), *reh'g granted*, 67 FERC ¶ 61,168, *clarified*, 67 FERC ¶ 61,317 (1994).

[91] Complaint at 25; Order at PP 20-24, 65.

[92] Order at P 65.

> a non-conforming NITSA could have a negative effect on other transmission customers through a reduction of transmission capacity and could impair efficient utilization of the LG&E/KU transmission system. Accordingly, we deny EKPC's requested waiver.[93]

This conclusory dismissal of EKPC's request is not explained by reasoned decision-making and is not supported by substantial record evidence. Under the unique circumstances involved, the denial of the waiver request frustrates broader Commission policy objectives that would be furthered by the waiver. These points are discussed separately below.

1. The Order's Denial of EKPC's Waiver Request Is Not Supported by Substantial Record Evidence and Does Not Reflect Reasoned Decision-making

The Order states that the Commission is persuaded by LG&E/KU's argument about the alleged impact of the proposed non-conforming agreement on other customers without specifically identifying the argument upon which this portion of the Order is premised.[94] Without analyzing or even referencing the arguments upon which the Order states that it is premised, the Order does not articulate the basis for or explain the reasoning underlying the conclusion reached.

The Order leaves it to the reader to divine the basis for the Order's conclusion. Review of the Order reveals that Paragraph 38 recounts in summary fashion LG&E/KU's arguments in response to EKPC's waiver request, but no findings are made there. Similarly, Paragraph 33 summarizes various LG&E/KU arguments regarding alleged impacts on efficiencies and other

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[93] *Id.*, at P 66.

[94] *Id.*

customers, but makes no findings. But EKPC also responded to these arguments (and included a supporting affidavit in so doing), as summarized in Paragraph 45 of the Order.[95]

While the Order summarized the Parties' arguments in the foregoing paragraphs, none of the arguments are addressed in the "Substantive Matters" section of the "Discussion" section of the Order. The Order sets forth no discussion or analysis of the competing arguments, and never addresses EKPC's rebuttal to LG&E/KU's claims at all. Finally, the Order sets forth no discussion of the first three criteria for a waiver, basing the rejection solely on the unexplained conclusion that the Commission was "persuaded" by the unidentified arguments by LG&E/KU regarding effects on system efficiency and availability of service to other customers.

One cannot reasonably conclude that the Commission's determination in this respect is supported by substantial evidence when no findings were made, no citations to any evidence are included in the Order, but there existed disputed issues of fact by virtue of the parties' respective affidavits. For that reason, the Commission at a minimum should have set the matter for hearing.[96] A hearing would have allowed full development of the factual issues bearing on whether EKPC's request would adversely impact LG&E/KU's system or service to others, would have afforded EKPC the opportunity to prove that LG&E/KU is in fact providing itself with preferential service,[97] and would have allowed EKPC due process to test and challenge the

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[95] The Commission accepted EKPC's Answer, as well as LG&E's subsequent answer to that answer. *See* Order at P 52.

[96] *See Public Service Co. of NH v. FERC,* 600 F. 2d 944, 955 (D.C. Cir. 1979)("The Commission may reach decisions without holding evidentiary hearings only when there are no material facts in dispute.").

[97] *See* EKPC's Answer, Affidavit of Darrin Adams at ¶ 16. *See also* Section III.G *supra*.

broad but ultimately incorrect assertions of LG&E/KU upon which the Order, with no explanation, relied.

Due to the lack of discussion, reasoned decision-making and supporting record evidence, the Order's denial of EKPC's alternative request for relief is unlikely to survive judicial review.

2. EKPC's Proposal Meets the Criteria for a Waiver

EKPC demonstrated that it meets the other criteria governing waivers.[98] The Order sets forth no discussion of those other criteria, premising the denial of the waiver solely on the conclusion that EKPC did not satisfy the fourth criteria.[99] Because the Order is silent as to the other criteria, there is nothing new or specific that EKPC can address at this time. To the extent that the Order could be interpreted as implicitly finding that EKPC did not meet any of those criteria, EKPC respectfully seeks rehearing of those issues as well. EKPC is acting in good faith, the waiver is specific and limited in scope, and the waiver would remedy an existing concrete problem that imposes adverse impacts on EKPC (impacts that arise chiefly due to EKPC being sandwiched, both literally and figuratively, between the RTO paradigm of PJM and the stand-alone paradigm of LG&E/KU).

3. EKPC's Waiver Request Is Consistent With Broader Commission Policy Objectives and Should Be Granted

EKPC attempted to explain in its Complaint that it seeks to do nothing more than utilize the newly-acquired Bluegrass Generating Station to serve its member load, and to do so in a

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[98] EKPC Complaint at 25 – 28.

[99] *See* Order P 66.

manner that sensibly and fairly reconciles the difficulties of EKPC being caught between the RTO paradigm of PJM and the stand-alone paradigm of LG&E/KU.

Even if one concludes that the arrangements proposed by EKPC are not authorized by the letter of the LG&E/KU Tariff, the arrangements are consistent with the purposes and intent of the tariff, which is essentially the same as the *pro forma* tariff approved by the Commission. An objective of Order No. 888 and the tariff is to foster open access and to allow transmission customers to use an owner's transmission system on a basis comparable to the use that the owner itself makes of that system.[100] For the reasons explained in the prior pleadings and previously herein, EKPC is proposing fair and reasonable use of the system and to compensate LG&E/KU for that use on the same basis upon which all billing for network integration service is premised.

The Commission long ago made clear that the services to be made available under the tariff are the ***minimum*** expected access—not the only, and not the maximum.[101] The Order nevertheless greeted EKPC's proposed arrangements, which adapt the LG&E/KU paradigm to the unique facts confronting EKPC, with a curt and summary dismissal. That dismissal seemingly did not consider much of what EKPC is seeking to accomplish or the effects of the Commission's denial.

EKPC is attempting to add capacity to the PJM market and to better enable EKPC to serve its member cooperatives reliably and at the lowest cost reasonably possible. At the same time, LG&E/KU—a competitor of EKPC's—has no incentive to cooperate with EKPC; LG&E/KU stand to gain millions of dollars of increased revenue from EKPC for virtually no

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[100] *See* note 49, *supra.*

[101] *Id.*

practical change in the level of network service it has to make available to EKPC. By denying the Complaint and the alternative request for waiver, the Commission has effectively endorsed LG&E/KU's competition-based incentives to thwart EKPC and extract usage charges that bear no reasonable nexus to the amount of service that will be taken.

Among the elements that run counter to Commission policy objectives is that LG&E/KU is effectively being rewarded for being a stand-alone entity. If LG&E/KU participated in either MISO or PJM, EKPC would not have to pay *any* network charges to LG&E/KU because all of EKPC's load (including EKPC's load on the LG&E/KU transmission system) is treated by PJM as being within the EKPC transmission pricing zone. But because LG&E/KU is outside of MISO and PJM, EKPC is required to take NITS under the LG&E/KU Tariff ***in addition to*** taking NITS for its entire load under the PJM Tariff.[102] EKPC did not contest that fact in its Complaint, but EKPC is seeking to be charged by LG&E/KU for NITS service on a basis that reasonably reflects the service actually being made available, rather than being forced to pay the disproportionate amount that literal application of the LG&E/KU Tariff to this situation causes EKPC to have to pay.

Granting of the waiver provides a means by which the Commission could have ameliorated much of the odd and economically inefficient impacts that result under these unique circumstances from rigid application of the LG&E/KU Tariff, without requiring the Commission to set precedent under the pertinent provisions of the LG&E/KU Tariff, or the *pro forma* tariff

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[102] Further underscoring the perverse effects of the situation is the fact that it is EKPC, a non-FERC jurisdictional entity, that elected to integrate into PJM and which operates in the context of the PJM markets, whereas LG&E/KU, a FERC-jurisdictional public utility, has not participated in an RTO since it withdrew from the Midcontinent Independent System Operator, Inc. some ten years ago.

upon which LG&E/KU's Tariff is based. Instead, LG&E/KU have been handed a windfall at the expense of EKPC and, ultimately, the end-use customers served by EKPC's member cooperatives. This result is not consistent with the underlying objectives of open and non-discriminatory access.

EKPC respectfully asks the Commission to take a fresh look at EKPC's waiver request. Doing so should induce the Commission to realize that EKPC's alternative request for relief is supported, warranted and will further the Commission's overall policy objectives.

IV. CONCLUSION

WHEREFORE, for the reasons stated herein, the Commission should grant rehearing of the February 26, 2016 "Order Denying Complaint" in this proceeding. On rehearing, the Commission should reverse its denial of the EKPC Complaint and grant the relief requested by EKPC therein. If the Commission declines to grant the relief requested by EKPC in its Complaint, the Commission should, at a minimum, set for hearing the numerous disputed factual matters identified in the EKPC and LG&E/KU submittals.

Respectfully submitted,

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March 28, 2016

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CERTIFICATE OF SERVICE

I hereby certify that I have on this date caused a copy of the foregoing document to be served on each person included on the official service list maintained for this proceeding by the Commission's Secretary, by electronic mail or such other means as a party may have requested, in accordance with Rule 2010 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.2010.

Dated this the 28th day of March, 2016 at Washington, D.C.

/S/ CHRISTINE O. AMOONARQUAH
Christine O. Amoonarquah

Document Content(s)

157 FERC ¶ 61,039
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, and Colette D. Honorable.

East Kentucky Power Cooperative, Inc. Docket No. EL16-8-001

v.

Louisville Gas & Electric Company/Kentucky Utilities Company

ORDER DENYING REHEARING

(Issued October 20, 2016)

1. In an order dated February 26, 2016, the Commission denied a complaint filed by East Kentucky Power Cooperative, Inc. (EKPC) against Louisville Gas & Electric Company (LG&E) and Kentucky Utilities Company (KU) (collectively, LG&E/KU) alleging that their failure to accept EKPC's designation of new Network Load under the parties' Network Integration Transmission Service Agreement (NITSA) was contrary to the terms of the LG&E/KU Open Access Transmission Tariff (Tariff)[1] and the Commission's policies concerning open access transmission. In its complaint, EKPC also sought waiver of LG&E/KU's Tariff to adopt an amended NITSA as a non-conforming agreement to LG&E/KU's Tariff.[2]

2. In denying EKPC's complaint, the Commission found that EKPC had neither supported its request for a NITSA which differs significantly from the LG&E/KU Tariff and the Commission's policies on open access transmission, nor shown, pursuant to

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[1] In this order, we use the term "Tariff" or "LG&E/KU Tariff" to represent LG&E/KU's Open Access Transmission Tariff (OATT) and "*pro forma* OATT" to represent the tariff promulgated by the Commission under Order Nos. 888 and 890. We also capitalize the terms "Network Load," "Point-to-Point," and "Network Resource" as those terms are capitalized and identified in LG&E/KU's Tariff.

[2] *E. Ky. Power Coop., Inc. v. Louisville Gas & Elec. Co./Ky. Utils. Co.*, 154 FERC ¶ 61,144, at PP 1-2 (2016) (February 26 Order).

section 206 of the Federal Power Act (FPA), that LG&E/KU's Tariff was unjust and unreasonable as it related to EKPC. The Commission also denied EKPC's waiver request because, in the circumstances presented, EKPC had not shown that its waiver request would be limited in scope or would not cause harm to third parties.[3]

3. On March 28, 2016, EKPC timely filed a request for rehearing of the February 26 Order. For the reasons discussed below, we deny EKPC's request for rehearing.

I. Background

4. EKPC, an exempt generation and transmission cooperative,[4] is a transmission owning member of PJM Interconnection L.L.C (PJM). Approximately 80 percent of EKPC's member load is physically connected to transmission facilities owned by EKPC and located within the PJM footprint in the EKPC Zone.

5. LG&E and KU are both public utilities, and serve customers in Kentucky and Virginia. LG&E/KU are outside the PJM footprint and do not participate in a Regional Transmission Organization. LG&E/KU operate under a combined Commission-approved Tariff.[5]

6. The LG&E/KU and EKPC transmission systems and service territories are intertwined and share 66 interconnection points. Each uses the other's facilities to serve a portion of their native-load customers through these interconnection points. The small portion of EKPC's load that is physically connected to the LG&E/KU transmission system is pseudo-tied[6] to PJM and is treated as part of EKPC's internal zone load in PJM.

7. EKPC acquired the Bluegrass station in December 2015. In its complaint, EKPC asserted that it expected to use output from the Bluegrass station as a Network Resource chiefly to serve that portion of its member load which is connected to LG&E/KU's transmission facilities.[7] The Bluegrass station is a three-unit, 495-MW (summer

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[3] *Id.* P 2.

[4] *See* 16 U.S.C. § 824(f) (2012).

[5] *See Louisville Gas & Elec. Co.*, 114 FERC ¶ 61,282, *order on reh'g sub nom. E.ON U.S., LLC*, 116 FERC ¶ 61,020 (2006).

[6] A pseudo-tied resource is a resource (i.e., generation unit or load) that is functionally transferred from the Balancing Authority (BA) in which the resource is physically located to another BA that has operational responsibility for the resource.

[7] Complaint at 12.

capacity) natural gas-fired peaking facility, which is located within LG&E/KU's footprint. One unit of the Bluegrass station, Unit 3, is subject to a power purchase contract with LG&E/KU until May 1, 2019, so it will not be available to serve EKPC's load until after that date. EKPC has expected to deliver any excess output produced by the station to EKPC's load connected to LG&E/KU's transmission facilities.

8. In order effectuate this arrangement, EKPC alleged that it submitted a transmission service request to TranServ International, Inc. (TranServ), LG&E/KU's Independent Transmission Organization, to designate the Bluegrass station as a Network Resource under EKPC's NITSA with LG&E/KU.[8] TranServ permitted EKPC to add the Bluegrass station as a new Network Resource, and the parties reached agreement regarding the delivery of the Bluegrass station output to EKPC's Network Load on the LG&E/KU system. But a dispute arose with regard to the charges for delivering the Bluegrass station's output over LG&E/KU's transmission system to EKPC's load on the EKPC system.[9]

9. EKPC sought to modify the existing NITSA to: (1) establish the Point of Delivery as one or more points of interconnection between EKPC's system and LG&E/KU's system; and (2) designate a portion of EKPC's member load connected to EKPC's transmission facilities as new Network Load under the EKPC-LG&E/KU NITSA, with the amount of that load stated as the output of the Bluegrass station in any hour minus the aggregate EKPC member load served from the LG&E/KU transmission facilities.[10] EKPC's proposed amended NITSA would determine EKPC's monthly coincident peak load on the LG&E/KU system, which is the demand used for billing for network service under the LG&E/KU Tariff, based on the sum of the delivery point requirements in each hour.

10. According to the complaint, LG&E/KU rejected this proposal and stated that, if EKPC intends to deliver any of the Bluegrass station output to service EKPC's load on the EKPC transmission system, EKPC may purchase Point-to-Point service for the full amount of the Bluegrass station output, less the anticipated minimum load physically connected to the LG&E/KU system. EKPC asserted that LG&E/KU also suggested that EKPC could designate delivery points currently served from EKPC's own transmission system as delivery points under the LG&E/KU NITSA, in sufficient amounts so that EKPC's minimum load on LG&E's system would always be at least equal to the nominal nameplate rating of the Bluegrass station.

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[8] *Id.* at 8.

[9] *Id.* at 9.

[10] *Id.*

11. In EKPC's view, this arrangement would force it to designate several hundred megawatts of load served by EKPC's own transmission facilities as Network Load on the LG&E/KU transmission system. EKPC contends that LG&E/KU's approach – which would increase EKPC's network service payments to approximately $17 million per year --is unreasonable, expensive, and excessive in part because the resulting charges are for an amount of transmission service that LG&E/KU would not provide.[11]

12. In the February 26 Order, the Commission denied EKPC's complaint. The Commission found that LG&E/KU's Tariff requires EKPC either to designate its entire load as Network Load in all hours or to arrange for alternative transmission service. Thus, EKPC's request to designate Network Load based on EKPC's use of the LG&E/KU system on a sporadic basis for the delivery of excess generation from the Bluegrass station was not contemplated by LG&E/KU's Tariff (which adopts the Commission's *pro forma* Open Access Transmission Tariff (OATT) nearly verbatim) or Commission policy. The Commission therefore denied EKPC's request to split its load in lieu of designating EKPC's entire load served at discrete points of delivery.[12] The Commission found EKPC failed to meet its burden to show that LG&E/KU's Tariff was unjust and unreasonable as applied to EKPC.[13] The Commission also denied EKPC's request for waiver of LG&E/KU's Tariff because EKPC's proposed amended NITSA could negatively affect other transmission customers by reducing transmission capacity and impairing efficient use of LG&E/KU's system.[14]

II. Discussion

13. On rehearing, EKPC alleges several errors in the February 26 Order. For the reasons discussed below, we deny rehearing of the February 26 Order.

14. Under the Commission's *pro forma* OATT attached to Order Nos. 888 and 890, customers of transmission owners may sign up for Network Integration Transmission Service (Network service), under which they receive firm transmission service to serve their designated Network Load.[15] Alternatively, such customers may take Point-to-Point

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[11] *Id.* at 10-11.

[12] February 26 Order, 154 FERC ¶ 61,144 at P 56.

[13] *Id.* P 64.

[14] *Id.* P 66.

[15] Section 28.3 of the *Pro Forma* OATT defines Network Integration Transmission Service as a firm service under which a transmission customer delivers "capacity and energy from its designated Network Resources to service its Network

(continued ...)

Transmission Service, which the *pro forma* OATT defines as "reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery."[16] Because EKPC has customers on LG&E/KU's system, EKPC has subscribed to Network service for all of its load within LG&E/KU's system. EKPC's payment for such service is based on the proportionate share of its customers' use of the LG&E/KU system.[17] EKPC has acquired the Bluegrass station located inside LG&E/KU's transmission footprint. As long as EKPC uses that facility to serve its customer load inside of LG&E/KU's transmission system, EKPC can do so under its current NITSA.

15. EKPC, however, also wants to use the Bluegrass station to serve load on its own transmission facilities during those periods in which the output of the Bluegrass station exceeds EKPC's load on the LG&E/KU system. LG&E/KU is willing to accommodate this use of the Bluegrass station if EKPC either expands its NITSA to accommodate the extra load or if EKPC wants to enter into a Point-to-Point service agreement to export the extra power from the Bluegrass station. EKPC contends that these two options are unjust and unreasonable and maintains LG&E/KU is required to accommodate the export use under a firm NITSA as long as EKPC pays a rate only for the hours in which it uses the facility to export.

16. We affirm the Commission's conclusion that LG&E/KU has not acted in an unjust and unreasonable manner in refusing to enter into such an agreement. Under the *pro forma* OATT, Network service must be purchased to serve a customer's full load throughout the year.[18] When servicing load outside of a transmission owner's footprint,

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Loads on a basis that is comparable to the Transmission Provider's use of the Transmission System to reliably serve its Native Load Customers." *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299, app. B, *Pro Forma* OATT, §28.3 (2008) (*Pro Forma* OATT), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[16] *Pro Forma* OATT, § 1.37.

[17] *See id.* § 1.17 (defining a transmission customer's Load Ratio as the "Ratio of a Transmission Customer's Network Load to the Transmission Provider's total load computed in accordance with Sections 34.2 and 34.3 of the Network Integration Transmission Service under Part III of the Tariff and calculated on a rolling twelve month basis.").

[18] *Id.* § 29.2(vii) (The minimum term for Network Integration Transmission Service is one year.").

the *pro forma* OATT requires that the customer either elect to include the entire load as Network Load for all purposes or to exclude that entire load from its Network Load and purchase firm or non-firm Point-to-Point Transmission Service.[19] If LG&E/KU were required to revise the NITSA as proposed by EKPC, LG&E/KU would have to reserve transmission service to deliver the maximum excess output from the Bluegrass station. Such a commitment would tie-up firm transmission service that could be sold to others and compensate LG&E/KU only for service limited to the hours when EKPC exports power outside of the LG&E/KU system. These are not options that the *pro forma* OATT requires LG&E/KU to afford to customers.

17. EKPC contends that requiring it to purchase additional Network service or Point-to-Point service would result in increasing its costs for the use of the Bluegrass station.[20] While paying for Network or firm Point-to-Point service could be more expensive than EKPC's proposal, that cost reflects the firm quality of the service and LG&E/KU's obligation to provide that service any hour of the entire year. Requiring LG&E/KU to adopt EKPC's proposal would result in LG&E/KU having to provide such firm service based on payments only for service limited to EKPC's use of the Bluegrass station to export power at the time of the LG&E/KU coincident peak.

18. We address below EKPC's specific rehearing arguments.

A. Whether EKPC's Proposed Amended NITSA Constitutes Load-Splitting Prohibited by LG&E/KU's Tariff and the Commission's *pro forma* OATT

19. EKPC argues that the Commission erred in treating EKPC's proposed NITSA arrangement for the Bluegrass station as "load-splitting," which is prohibited by the LG&E/KU Tariff and the Commission's *pro forma* OATT attached to Order No. 888-A. EKPC states that its proposal did not qualify as "load-splitting" because its proposed amended NITSA did not entail combining network and point-to-point transmission service at a single point of delivery to reduce Network Service Charges.[21] EKPC argues that its proposed amended NITSA instead increases its load ratio share of LG&E/KU transmission costs whenever the Bluegrass station output exceeds EKPC's load connected to LG&E/KU. EKPC further asserts that it would never pay less than its coincident peak load-based share of the LG&E/KU transmission system costs – EKPC

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[19] *See id.* § 31.3.

[20] EKPC could reduce its costs further by purchasing non-firm service under which it would pay for service only during the hours it requires the service.

[21] Rehearing Request at 6, 8, 10-13.

asserts that, in fact, EKPC's coincident peak share would increase whenever the Bluegrass station output exceeds that load at the time of the coincident peak. EKPC states that as a result of this, all load is paid through network integration transmission service billing, which should not be seen as any kind of "load-splitting."[22]

20. EKPC argues that its proposed amended NITSA does not improperly combine Network and Point-to-Point service at a single Delivery Point because all of EKPC's load, including load at Delivery Points connected to the LG&E/KU transmission system, is currently designated Network Load under PJM's OATT.[23] EKPC asserts that the Commission has forced EKPC to choose between two inefficient and costly options, even when EKPC is not using the LG&E/KU transmission system: (1) paying for new Point-to-Point LG&E/KU service pancaked on Network service already paid to LG&E/KU and PJM or (2) re-segmenting EKPC's load by designating some of EKPC's PJM Delivery Points as LG&E/KU Delivery Points.[24] EKPC argues that the Commission erred in relying on select portions of *Duke* to reject EKPC's designation of Network Load.[25] EKPC argues that because EKPC's proposed amended NITSA would not amount to load-splitting and EKPC's proposed amended NITSA would save EKPC between $5 and $10 million per year in additional costs and operational burdens, the Commission was wrong to declare reasonable LG&E/KU's interpretation of its Tariff.[26] We disagree.

21. As explained in the February 26 Order,[27] where a Network Customer, such as EKPC, wishes to obtain transmission service for load outside the Transmission Owner's Transmission System, Section 31.3 of LG&E/KU's Tariff (which adopts the *pro forma* OATT discussed in Order Nos. 888 and 890 almost verbatim) provides the Network Customer the choice of either:

> (1) electing to include the entire load as Network Load for all purposes under Part III of the Tariff and designating Network

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[22] *Id.* at 13.

[23] *Id.* at 14.

[24] *Id.* at 15.

[25] *Id.* at 6, 8-9, 16-18 (citing *Duke Power Co.*, 81 FERC ¶ 61,010 (*Duke*), *reh'g denied*, 81 FERC ¶ 61,312 (1997), *order rejecting compliance filing*, 84 FERC ¶ 61,136 (1998), *order dismissing compliance filing and accepting settlement sub nom. Duke Energy Corp.*, 86 FERC ¶ 61,220 (1999)).

[26] *Id.* at 7, 9, 30-32.

[27] February 26 Order, 154 FERC ¶ 61,144 at PP 55-56.

> Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Point-to-Point Transmission Service under Part II of the Tariff.[28]

Section 1.25 of LG&E/KU's Tariff (which also adopts the *pro forma* OATT discussed in Order Nos. 888 and 890 almost verbatim) permits a Network Customer to choose to designate less than its total load as Network Load. Section 1.25, however, prohibits a Network Customer from designating "only part of the load at a discrete Point of Delivery."[29] This tariff language unambiguously sets up a choice for transmission customers to choose between two types of transmission service: Network or Point-to-Point service.[30]

22. EKPC proposes to designate Network Load at a new Delivery Point that reflects less than EKPC's entire load at the Delivery Point and thus violates the prohibition on designating part of its load at a discrete Delivery Point. At this new Delivery Point, the output from the Bluegrass station in excess of EKPC's Network Load would be delivered to EKPC's Network Load on EKPC's transmission system.[31] The Commission, in the

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[28] Louisville Gas and Electric Company, Transmission, Part III_31, Part III_31 Designation of Network Load, 10.0.0.

[29] Louisville Gas and Electric Company, Transmission, Part 1_01, Part 1_01 Definitions, 10.0.0.

[30] *See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, at 30,260, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC,* 535 U.S. 1 (2002) ("The bottom line is that all potential transmission customers, including those with generation behind the meter, must choose between network integration transmission service or point-to-point transmission service. . . . For the reasons stated above, a network customer will not be permitted to take a combination of both network and point-to-point transmission services under the *pro forma* tariff to serve the same discrete load."); *cf. Koch Gateway Pipeline Co.*, 136 F.3d 810, 814-15 (D.C. Cir. 1998) ("We first look to see if the language of the tariff is unambiguous—that is, if it reflects the clear intent of the parties to the agreement. If the tariff language is ambiguous, we defer to the Commission's construction of the provision at issue so long as that construction is reasonable.").

[31] *See* Rehearing Request at 2 n.4.

February 26 Order, was therefore correct in finding that EKPC's proposed amended NITSA would split EKPC's load at discrete Delivery Points to designate less than its full load at such Delivery Points, a practice not contemplated by LG&E/KU's Tariff.[32] Where a Network Customer declines "to designate a particular load at discrete points of delivery as Network Load," Section 1.25 of LG&E/KU's Tariff holds the Eligible Customer "responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load."[33] Instead of allowing EKPC to split its Network Load between Network and Point-to-Point service, LG&E/KU's Tariff requires EKPC to choose one or the other and to make separate arrangements for Point-to-Point service rather than combining these types of transmission service.

23. EKPC asserts both that its proposed amended NITSA would ensure EKPC is paying the proper Load Ratio when output from the Bluegrass station exceeds EKPC's Network Load under the NITSA and that EKPC's proposed amended NITSA would exempt it from paying "inefficient" and "needlessly costly" pancaked transmission charges. LG&E/KU's Tariff (and the *pro forma* OATT) establishes a bright line between Network and Point-to-Point transmission service. EKPC's proposal would not ensure that EKPC is contributing the correct Load Ratio of LG&E/KU's transmission system's costs because EKPC would reserve and pay for Network transmission service at an amount less than EKPC's entire load at a discrete Delivery Point. Similarly, requiring EKPC to pay for Network service provided by both PJM and LG&E/KU ensures EKPC pays for the distinct transmission services it receives from both LG&E/KU and PJM.[34] The charges that EKPC describes as "inefficient" and "needlessly costly" are in fact charges that the Commission has long recognized as appropriate for the type of use EKPC seeks to make of LG&E/KU's transmission system: Network service. EKPC's proposal would evade these charges based on EKPC's Load Ratio on LG&E/KU's

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[32] February 26 Order, 154 FERC ¶ 61, 144 at P 57.

[33] Louisville Gas and Electric Company, Transmission, Part 1_01, Part 1_01 Definitions, 10.0.0.

[34] *See* Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,255 ("NRECA and TDU Systems, however, argue that network customers located in multiple control areas should not have to pay for any additional point-to-point transmission service to make sales to non-designated load located in a separate control area. We disagree. Because the additional transmission service to non-designated network load outside of the transmission provider's control area is a service for which the transmission provider must separately plan and operate its system beyond what is required to provide service to the customer's designated network load, *it is appropriate to have an additional charge associated with the additional service*.") (emphasis added).

system, in derogation of the LG&E/KU's Tariff and the Commission's *pro forma* OATT.[35] Therefore, in contrast to EKPC's assertions,[36] the Commission did not err in treating LG&E/KU's interpretation of its Tariff as reasonable and finding that EKPC had not met its burden of proof.

24. We reject the contention that the Commission erred in relying on *Duke* in the February 26 Order to find that EKPC was seeking improperly to split its Network Load.[37] In *Duke*, the Commission rejected a bilateral contract for network transmission service and required ancillary services to deliver power to Southeastern Power Administration's (SEPA's) preference customers, finding that these services could be unbundled and provided under Duke Power Company's OATT. As explained in the February 26 Order,[38] the Commission in *Duke* acknowledged that "[O]rder Nos. 888 and 888-A do not permit a network customer to take a combination of both network and point-to-point transmission service to serve the same discrete load."[39] The Commission found, however, that SEPA's preference customers could be served through Duke's OATT because:

> the fact that the portion of the preference customers' loads met by their SEPA allocation would be served under Duke's open access transmission tariff, while the remainder of the load continues to be met by bundled service, *would not alter the network nature of the service. The entire load would be served on a network basis*, but payment would be made to Duke by SEPA for the SEPA preference customers'

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[35] *See* February 26 Order, 154 FERC ¶ 61,144 at P 57 (finding that EKPC's proposal to "split its load on a sporadic basis" would "*limit its transmission payments based on its hourly use for such deliveries*.") (emphasis added); *see also* Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,259 ("The concept of allowing a 'split system' or splitting a discrete load is antithetical to the concept of network service. A request for network service is a request for the integration of a customer's resources and loads. Quite simply, a load at a discrete point of delivery cannot be partially integrated. Furthermore, such a split system creates the potential for a customer to 'game the system' thereby evading some or all of its load-ratio cost responsibility for network services").

[36] Rehearing Request at 7, 9, 30-32.

[37] *Id.* at 6, 8-9, 16-18 (citing *Duke*, 81 FERC ¶ 61,010).

[38] February 26 Order, 154 FERC ¶ 61,144 at P 58 n.71.

[39] *Duke*, 81 FERC ¶ 61,010 at 61,047.

> allocation, and by the preference customers for the remainder of their loads.[40]

In *Duke*, the Commission found Network and Point-to-Point service would have been permissibly combined because all of SEPA's preference customers' load was served on a network basis. Here, by contrast, EKPC's proposed amended NITSA expressly contemplates designating Network Load at a new Delivery Point in an amount equal to the output from the Bluegrass station that *exceeds* EKPC's Network Load on LG&E/KU's system and is delivered to EKPC's system, rather than the entire load located at the Delivery Point.[41] Consistent with *Duke*, the Commission in the February 26 Order was therefore correct to find that EKPC's proposed amended NITSA would split EKPC's load at the Delivery Point and would therefore violate LG&E/KU's Tariff and the *pro forma* OATT.

B. Comparison to Other NITSAs

25. EKPC argues that the Commission erred by rejecting EKPC's reliance on NITSAs accepted by the Commission between South Mississippi Electric Power Association (SMEPA) and Midcontinent Independent System Operator, Inc. (MISO) (SMEPA-MISO), and SMEPA and Southern Company Services (Southern) (SMEPA-Southern), which EKPC claims are similar to EKPC's proposed amended NITSA.[42] EKPC argues that giving no weight to the SMEPA-Southern NITSA, which was uncontested and approved by delegated authority, contravenes the Commission's obligations under the FPA to ensure just and reasonable rates and suggests that the Commission and its staff did not adequately scrutinize the SMEPA-Southern NITSA.[43] EKPC argues that the Commission also erred in distinguishing EKPC's proposed amended NITSA in this case from the SMEPA-MISO NITSA, which was approved by the Commission and modeled on the SMEPA-Southern NITSA. EKPC argues that, contrary to the Commission's assertions, the SMEPA-Southern NITSA, not the SMEPA-MISO NITSA, represents a

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[40] *Id.* (emphasis added).

[41] *See* Complaint at 9 ("propos[ing] to modify [EKPC's] existing NITSA with [LG&E/KU] to add a new delivery point at one or more points of interconnection between the [LG&E/KU] and [EKPC] systems" and "further propos[ing] that the designated Network Load at that new delivery point would in each hour be the difference between the output of Bluegrass and [EKPC's] Network Load on the [LG&E/KU] system.").

[42] Rehearing Request at 6, 9, 19-30.

[43] *Id.* at 23-26.

"'less than entire load' designation," and the SMEPA-MISO NITSA represents an analogous "efficient and cost-effective" mechanism for integrating EKPC's Bluegrass station into PJM.[44] EKPC contends that the Commission should have focused on the "dynamic relationship between Network Resource output and Network Load, rather than focusing on delivery point alone" to compare the SMEPA NITSAs with EKPC's proposed amended NITSA in this proceeding.[45] We disagree.

26. We reaffirm that the SMEPA-Southern NITSA is not precedent binding on the Commission because the SMEPA-Southern NITSA was a bilateral agreement acceptable to both parties, which was accepted via delegated letter order.[46]

27. We reject EKPC's attempt to equate its proposed amended NITSA with the SMEPA-MISO NITSA. In that proceeding, Section 31.3 of MISO's Tariff deviated from Section 31.3 of the *pro forma* OATT by requiring all Network Load to be connected physically to MISO's transmission system.[47] The Commission, in approving the SMEPA-MISO NITSA, approved a request to designate load not physically connected with MISO's transmission system as Network Load.[48] MISO's Tariff itself did not conform to the *pro forma* OATT and both SMEPA and MISO apparently consented to this arrangement. Here, by contrast, Section 31.3 of LG&E/KU's Tariff conforms to the *pro forma* OATT, which prohibits a Network service customer from designating only part of its load at a discrete Delivery Point, and LG&E/KU objects to EKPC's proposed deviation from the *pro forma* OATT.

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[44] *Id.* at 23, 26-28.

[45] *Id.* at 28.

[46] *See* February 26 Order, 154 FERC ¶ 61,144 at P 61 n.76; *see also Gas Transmission Nw. Corp. v. FERC*, 504 F.3d 1318, 1320 (D.C. Cir. 2007) (acceptance of uncontested filings does not establish policy or precedent); 18 C.F.R. § 35.4 (2016) ("The fact that the Commission permits a rate schedule or tariff, tariff or service agreement or any part thereof . . . to become effective shall not constitute approval by the Commission of such rate schedule or tariff, tariff or service agreement or part thereof . . . .").

[47] *Midcontinent Indep. Sys. Operator, Inc.*, 145 FERC ¶ 61,242 at PP 4, 11 (2013).

[48] *Id.* P 11.

C. Whether EKPC's Proposed Amended NITSA Promotes Commission Policies

28. EKPC argues that the Commission in the February 26 Order failed to identify which specific Commission policy matched its interpretation of LG&E/KU's Tariff and that the February 26 Order itself would require load-splitting. EKPC argues that the February 26 Order disregards the Commission's "requirement that a transmission owner make its system available to the same extent, and subject to the same or comparable terms and conditions, as govern the transmission owner's own use of its system" given how LG&E/KU and Tennessee Valley Authority (TVA) implement their Contingency Reserve Sharing Agreement.[49] EKPC argues that the February 26 Order will exacerbate seams between regional transmission organization (RTO) areas and between RTO-areas and non-RTO areas, especially given LG&E/KU's withdrawal from MISO and the additional transmission charges EKPC faces due to the February 26 Order.[50] We disagree.

29. As discussed above, the February 26 Order followed Commission policy articulated in the *pro forma* OATT and the preamble to Order Nos. 888 and 888-A, which generally mirror the LG&E/KU Tariff. On a practical level, the Commission explained why following this policy was important: EKPC's proposed amended NITSA would "limit its transmission payments based on its hourly use for" deliveries from the Bluegrass station to the EKPC system.[51] The Commission further explained that because of LG&E/KU's "difficulty predicting in advance the amount of transmission that EKPC would use for such deliveries in any hour, [LG&E/KU] would have to hold transmission service for EKPC for which it may not receive compensation."[52] The Commission also found that other customers on LG&E/KU's system would be harmed through reduced transmission capacity and inefficient use of LG&E/KU's transmission system.[53] In Order No. 888-A, the Commission described the burden that load-splitting imposes on other network customers: "[b]ecause network and native load customers bear any residual system costs on a load-ratio basis, any cost responsibility evaded by a network customer in this manner would be borne by the remaining network customers and native load."[54]

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[49] Rehearing Request at 7, 9, 32-33.

[50] *Id.* at 34-35.

[51] February 26 Order, 154 FERC ¶ 61,144 at P 57.

[52] *Id.*

[53] *Id.* P 66.

[54] Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,259-30,260.

Requiring that EKPC take either Network or Point-to-Point transmission service on LG&E/KU's transmission system while EKPC also pays for Network transmission service from PJM does not split EKPC's load—rather, it compensates LG&E/KU for the service LG&E/KU provides in a manner that accurately reflects EKPC's load ratio on LG&E/KU's system, minimizes harm to other customers, and uses LG&E/KU's system more efficiently.

30. The February 26 Order rejected EKPC's preferred interpretation LG&E/KU's Tariff and the *pro forma* OATT and denied EKPC's request for waiver of LG&E/KU's Tariff. LG&E/KU's nonparticipation in MISO and EKPC's participation in PJM are voluntary. To the extent that EKPC wishes to address broader seams issues between LG&E/KU and PJM, or the consequences of LG&E/KU's withdrawal from MISO on EKPC's participation in PJM, these concerns are outside the scope of EKPC's complaint and request for waiver in this proceeding. Regardless of LG&E/KU's withdrawal from MISO exacerbating seams confronting EKPC, we have not required elimination of rate-pancaking between LG&E/KU and PJM,[55] except with respect to certain hold-harmless commitments associated with their withdrawal from MISO,[56] and LG&E/KU's OATT reflects this policy. EKPC has also not explained how the Commission's endorsement of LG&E/KU's position violates the requirement that LG&E/KU provide service comparable to the service LG&E/KU and TVA impose on themselves through their Contingency Reserve Sharing Agreement.[57]

D. Whether EKPC's Proposal would Cause LG&E/KU to Suffer Inadequate Compensation for Use of its Transmission System

31. EKPC argues that the Commission erred in finding that EKPC's proposed amended NITSA would deprive LG&E/KU of adequate compensation for use of its transmission system in light of EKPC's use of that system and LG&E/KU's inability to obtain revenues from transmission service provided to other customers.[58] EKPC explains that its proposed amended NITSA would define the Network Load at the Bluegrass station in each hour as equal to the difference between the Bluegrass station's output and EKPC's Network Load on the LG&E/KU system, and that the sum of EKPC's Delivery Point requirements in each hour (including the Bluegrass station Delivery Point) would

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[55] *See Louisville Gas & Elec. Co.*, 114 FERC ¶ 61,282 at P 111 n.67.

[56] *Id.* P 45.

[57] *See City of Vernon v. FERC*, 845 F.2d 1042, 1047 (D.C. Cir. 1988) ("the Commission cannot be asked to make silk purse responses to sow's ear arguments").

[58] Rehearing Request at 6, 9, 35-36.

be used to determine EKPC's monthly aggregate coincident peak demand on the LG&E/KU system. According to EKPC, that monthly aggregate coincident peak demand is used to determine a Network Customer's monthly charge for Network Service and would fairly compensate LG&E/KU for EKPC's use of LG&E/KU's transmission system consistent with how LG&E/KU charges all other Network Customers. EKPC represents that, under its proposed amended NITSA, EKPC would never pay less than its share of the costs for EKPC's load connected to LG&E/KU's system and would pay more than its share of system costs whenever the Bluegrass station's output exceeds its other load connected to LG&E/KU's system during coincident peaks.[59]

32. EKPC also argues that its proposed amended NITSA would not preclude LG&E/KU from obtaining revenues from transmission service provided to other customers. Specifically, EKPC states that "LG&E/KU receives on an ongoing basis detailed forecasts of EKPC load and generation that allow it to predict—for both operational and planning purposes—the amounts of transmission service likely to be needed each day to serve EKPC's load at the Bluegrass Delivery Point."[60] EKPC therefore reasons that its proposed amended NITSA "would not prevent LG&E/KU from calculating and posting Available Transmission Capability ('ATC') or from selling unscheduled firm transmission service for non-firm use."[61] EKPC argues that these forecasts will enable LG&E/KU to release transmission capacity EKPC is not expected to use to serve its load on LG&E/KU's system and to sell such capacity as non-firm ATC to enable LG&E/KU to meet its annual transmission revenue requirement. Using such forecasts to serve Network Load at the Bluegrass station Delivery Point, according to EKPC, would be no different than how LG&E/KU uses other customers' forecasted Network Load because all forecasts necessarily reduce a Transmission Provider's firm and non-firm ATC.[62] EKPC argues that rejecting its proposed amended NITSA would discriminate against EKPC because LG&E/KU should be allowed to sell non-firm ATC no longer needed by EKPC in the same way as LG&E/KU sells non-firm ATC from other Network Customers.[63] We disagree.

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[59] *Id.* at 36-39.

[60] *Id.* at 39.

[61] *Id.* In Order No. 890, the Commission amended the *pro forma* OATT to change the common abbreviation "ATC" from Available Transmission Capability to Available Transfer Capability. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 2 n.3.

[62] Rehearing Request at 40-41.

[63] *Id.* at 41-42.

33. Defining EKPC's Network Load on LG&E/KU's system as the difference between the Bluegrass station's output in any hour minus the aggregate EKPC member load on the LG&E/KU system in that hour is based on two different variables: the Bluegrass station's output in any hour and EKPC's Network Load on the LG&E/KU system during that hour. This is less than EKPC's full load at a discrete Delivery Point and would effectively narrow the amount of Network Load contributing to EKPC's total Load Ratio Share. In contrast, other Network Customers' Network Load is calculated under LG&E/KU's Tariff using those Network Customers' respective total Load Ratio Shares reflecting their entire loads at discrete Delivery Points on a rolling twelve month basis.[64] Although EKPC and all other Network Customers have forecasting abilities, EKPC's proposal would give an undue preference to EKPC to the detriment of other Network Customers whose Network Load is measured by their proportional use of LG&E/KU's system based on their entire loads at discrete designated Delivery Points in relation to LG&E/KU's total load. EKPC would enjoy this undue preference under its proposed amended NITSA because EKPC would only have to pay for the portion of its load at designated Delivery Points that is served with the Bluegrass station's excess output during the coincident peak hour. As discussed in the February 26 Order, this would require LG&E/KU to reserve ATC for EKPC when that ATC could be available to other Network Customers and would distort every Network Customer's Load Ratio Share. We therefore reaffirm the finding that EKPC's proposed amended NITSA would inadequately compensate LG&E/KU for use of its transmission system.

E. Whether EKPC Demonstrated that the LG&E/KU Tariff is Unjust and Unreasonable as Applied to EKPC

34. EKPC argues that the Commission did not explain sufficiently how LG&E/KU's Tariff is just and reasonable as applied to EKPC and did not apply LG&E/KU's Tariff with flexibility similar to other NITSAs. EKPC argues that the Commission has not addressed the operational burdens and excessive charges identified by senior EKPC personnel in affidavits filed in this proceeding. For example, EKPC states that rejecting EKPC's proposed amended NITSA would force EKPC to arrange for separate Point-to-Point service on top of Network service EKPC already pays LG&E/KU. Alternatively, EKPC states that it would have to designate Delivery Points on EKPC's own system to add several hundred additional megawatts of Network Load under the LG&E/KU NITSA, which would force EKPC to pay for service to load that is not connected to the LG&E/KU system. EKPC asserts that this additional Network service charge is duplicative of what EKPC already pays LG&E/KU annually, increasing that amount from $7 million to $17 million. EKPC represents that the February 26 Order has caused EKPC to explore constructing a new transmission line to connect the Bluegrass station directly

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[64] *See Pro Forma* OATT, § 1.17.

to EKPC's system.[65] EKPC asserts that its proposed amended NITSA "would not restrict LG&E/KU's transfer capacity, affect timely exchange of information with LG&E/KU, or produce any material difference in variability of dispatched generation."[66] We disagree.

35. Again, the terms of LG&E/KU's Tariff, the Commission's *pro forma* OATT, and Commission precedent provide EKPC a distinct choice of taking Network or Point-to-Point service to serve EKPC's Network Load on LG&E/KU's system and do not allow EKPC to split that Network Load.[67] While selecting either of these choices might cost EKPC more than its proposed amended NITSA would, that does not mean such costs are duplicative or unjustified as applied to EKPC. Arranging Point-to-Point service for the Bluegrass station or designating EKPC's entire load to be served by the Bluegrass station at a discrete Delivery Point ensures that EKPC pays for the services it receives and its Network Load is correctly incorporated into EKPC's Load Ratio on LG&E/KU's system. Moreover, LG&E/KU need not create separate services to accommodate EKPC's unusual circumstances.[68]

F. Whether LG&E/KU's Position Results in Undue Discrimination in Favor of LG&E/KU's Affiliated Load-Serving Entity

36. EKPC contends that rejecting its proposed amended NITSA would allow LG&E/KU to discriminate unduly against EKPC's Network Load in favor of LG&E/KU's affiliated load-serving entity. According to EKPC, LG&E/KU and TVA have entered into an agreement that "is expressly aimed at lowering the generation reserve margin needed to ensure continuity of service to native load customers during unplanned outages of either party's generating facilities."[69] EKPC states that both parties are setting aside such ATC without compensation despite needing that capacity less frequently than the Bluegrass station would need capacity on LG&E/KU's system and that EKPC's proposed amended NITSA would not disrupt operation of LG&E/KU's

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[65] *Id.* at 44-46.

[66] *Id.* at 46.

[67] *See supra* PP 14-17, 21-23, 27, 29; *see also* February 26 Order, 154 FERC ¶ 61,114 at PP 55-64.

[68] February 26 Order, 154 FERC ¶ 61,144 at P 64 (citing *Fla. Power & Light Co.*, 116 FERC ¶ 61,012, at P 14 (2006); *Fla. Power & Light Co.*, 113 FERC ¶ 61,290, at P 6 (2005)).

[69] Rehearing Request at 48.

system any more than that arrangement.[70]

37. The proposed NITSA amendment requiring LG&E/KU to keep ATC available for Network transmission service for EKPC's Bluegrass station's intermittent output is not comparable to an agreement relating to contingency reserves needed to meet North American Electric Reliability Corporation (NERC) reliability standards.[71] Because we find that these uses of transmission are not comparable, their different treatment by LG&E/KU is not unduly discriminatory.[72]

G. Whether the Commission Should Have Granted EKPC's Waiver Request and/or Set this Matter for Hearing

38. EKPC argues that, in denying EKPC's request for waiver of LG&E/KU's Tariff, the Commission lacked substantial record evidence to conclude that EKPC's proposed amended NITSA would harm third-party customers and erred in relying only on that

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[70] *Id.*

[71] *See* EKPC December 9, 2015 Answer, attach. 7, LG&E/KU Transmission Reliability Margin Implementation Document (TRMID) (effective Nov. 10, 2015) (noting that Transmission Reliability Margins are "reserved to preserve transmission capacity on each identified Flowgate in the operating and planning horizons to model uncertainty in system conditions and for delivery of energy as required under generator Contingency Reserve Sharing Agreements"). LG&E/KU's agreement with TVA defines a Contingency Reserve Sharing Agreement as:

> Sharing between two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies by the provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.

Id. See also Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 273 (defining uses of Transmission Reliability Margins).

[72] *Am. Elec. Power Serv. Corp.*, 67 FERC ¶ 61,168 at 61,490, *clarified*, 67 FERC ¶ 61,317 (1994) ("an open-access tariff that is not unduly discriminatory or anticompetitive should offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's uses of its system.").

waiver criterion. EKPC states that the Commission neither responded to EKPC's arguments nor cited evidence upon which the Commission relied. EKPC argues that given the affidavits presented by the parties, the Commission should have at least set this matter for hearing to determine whether waiver of the LG&E/KU Tariff would harm others and whether LG&E/KU was providing to itself preferential service.[73] EKPC argues that its waiver request is consistent with Commission policy to promote open access through Order No. 888 and the *pro forma* OATT by adding the Bluegrass station's capacity to the PJM market through reliable and lowest cost service to EKPC's member cooperatives. In contrast, EKPC describes the Commission in the February 26 Order as rewarding LG&E/KU for providing no additional service and for operating outside an RTO.[74] We disagree.

39. As described above,[75] EKPC's requested waiver, complaint, and proposed amended NITSA are inconsistent with the plain meaning of LG&E/KU's Tariff and Commission policy and precedent. There are thus no material disputes of fact that would require setting this matter for hearing. Accordingly, the Commission was well within its discretion to decide this matter on the submissions already filed.[76]

40. In doing so, the Commission gave "meaningful consideration"[77] to EKPC's waiver request: by explaining how EKPC's proposed amended NITSA would require LG&E/KU to reserve ATC for EKPC in an inefficient way and in finding that EKPC's proposed amended NITSA would be inconsistent with LG&E/KU's Tariff, Order Nos. 888 and 888-A, and the *pro forma* OATT. The Commission adequately described the harm to other transmission customers in denying EKPC's requested waiver.[78] The

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[73] Rehearing Request at 50-53.

[74] *Id.* at 53-56.

[75] *See supra* PP 14-17, 21-23, 27, 29, 35.

[76] *See, e.g.*, *Woolen Mill Assocs. v. FERC*, 917 F.2d 589, 592 (D.C. Cir. 1990) (citing *Pa. Pub. Util. Comm'n v. FERC*, 881 F.2d 1123, 1124, 1126 (D.C. Cir. 1989); *Cerro Wire & Cable Co. v. FERC*, 677 F.2d 124, 128-29 (D.C. Cir. 1982)); *State of Cal. ex rel. Lockyer v. FERC*, 329 F.3d 700, 713 (9th Cir. 2003) (citing *Friends of the Cowlitz v. FERC*, 253 F.3d 1161, 1173 (9th Cir. 2001); *Pac. Gas & Elec. Co.*, 746 F.2d 1383, 1387 (9th Cir. 1984); *Sierra Ass'n for the Environment v. FERC*, 744 F.2d 661, 663 (9th Cir. 1984)).

[77] *United Gas Pipe Line Co. v. FERC*, 707 F.2d 1507, 1511 (D.C. Cir. 1983).

[78] February 26 Order, 154 FERC ¶ 61,144 at P 57.

Commission did not need to repeat in detail those findings in denying waiver. Because the Commission found that one element dispositive, the Commission did not need to address the other aspects of EKPC's waiver request.

<u>The Commission orders</u>:

EKPC's request for rehearing of the February 26 Order is hereby denied, as described in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Document Content(s)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 22
RESPONSIBLE PERSONS: Julia J. Tucker
COMPANY: East Kentucky Power Cooperative, Inc.

Request 22. Refer to the IRP, pages 62-63, and Technical Appendix, Section 8, pages 65-66.

Request 22a. Explain whether the electric price growth rate variations used for the residential class is also used for either the small commercial class or the industrial class.

Response 22a. The growth rate variations are used for small commercial.

Request 22b. Explain how far into the future the ACES Power Marketing forward market energy prices go.

Response 22b. ACES forward market energy prices were available through the entire study period for the 2019 Integrated Resource Plan which goes through 2033.

Request 22c. Paragraph 4 indicates that the industrial class was not changed. Explain whether the statement pertaining to the industrial class refers to the number of industrial customers only. If so, explain the rationale behind a static customer count under optimistic and pessimistic economic scenarios.

Response 22c. Available data indicated the large commercial and industrial class is not likely to change significantly on a system-wide basis for the forecast period. Therefore, neither the load nor the customer counts were adjusted for the scenarios.

Request 22d. Explain whether the industrial class energy use and peak demand changes under any of the economic or weather variation scenarios.

Response 22d. Neither the load nor the customer counts were adjusted for the scenarios.

Request 22e. Since the basis for EKPC's base case scenario is the IHS county level data and other economic data, explain whether EKPC had to rerun all of its models from the ground up to obtain the high and low case scenario results reported in Table 8-1.

Response 22e. See Response 13.

Request 22f. Explain whether EKPC produced, but did not report, scenarios isolating the economic from the weather scenario effects. If so, provide the results of the base case with optimistic and pessimistic economic assumptions and of the base case with mild and severe weather.

Response 22f. EKPC did not develop the alternate scenarios. In accordance with the RUS-approved Work Plan, the scenarios developed represent best and worst case scenarios.

EAST KENTUCKY POWER COOPERATIVE, INC.
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FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 23
RESPONSIBLE PERSONS: Julia J. Tucker
COMPANY: East Kentucky Power Cooperative, Inc.

Request 23. Refer to the IRP, Section 3.7.1, page 64.

Request 23a Provide a copy of the appliance saturation survey and a list of the variables populated by the survey data.

Response 23a. The appliance saturation survey and a list of the variables populated by the survey data is provided on the attached CD and is subject to confidential treatment.

Variables include:
- Electric Furnace
- Geothermal Heat
- Secondary Heat
- Central Air Conditioning
- Heat Pump Air Conditioning
- Room Air Conditioning
- Heat Pump Heat
- Electric Stove
- Refrigerator
- Freezer
- Dishwasher
- Electric Clothes Dryer

Room Air Conditioning
Electric Water Heating
Electric Furnace Fan
Electric Clothes Dryer
Television

<u>Request 23b.</u> Explain whether the survey has evolved over time by adding or subtracting questions.

<u>Response 23b.</u> The survey has evolved. For the past 20 years, input is gathered from owner-members, internal users of the data, as well as EKPC’s leadership. Questions are added or deleted reflecting the changing appliance stock and customer behaviors. For example, the survey being conducted in 2020 includes questions about electric vehicle ownership and charging.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 24
RESPONSIBLE PERSON: **Scott Drake**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 24. Refer to the IRP, Technical Appendix, Volume 2, Exhibit DSM-1, page 18 of 93, and Case No. 2019-00059, application, page 3.

Request 24a. Page 18 of 93 in the Technical Appendix indicates that the avoided cost of energy "is based on an annual system marginal cost." Page 3 of the application in Case No. 2019-00059, indicates that "EKPC's avoided cost of energy is the forward price for energy in the energy market operated by PJM Interconnection, LLC ("PJM")." Page 3 also states "EKPC's avoided cost of capacity is the forward price curve of PJM's Base Residual Auction ("BRA") for capacity." Provide a reconciliation of the two filing statements regarding what energy and capacity costs were used in the DSM program evaluations for the current IRP.

Response 24a. The energy and capacity costs used in the DSM program evaluations for the current IRP are the same as those referenced on page 3 of the application in Case No. 2019-00059.

On page 18 of 93 of the Technical Appendix Volume 2, Exhibit DSM-1, GDS Associates simply used a more general description for avoided energy costs.

Request 24b. Page 18 of 93 goes on to state "Natural gas and water avoided costs (considered in the Total Resource Cost Test) were based on the Henry Hub forward price curve and the 2016 water and sewer rates for Kentucky-American Water Company, respectively." Explain whether the natural gas and water and sewer rates are used in the calculation of capacity costs and in the TRC or any other test.

Response 24b. Natural gas and water and sewer rates are not used in the calculation of electric capacity costs. They are used in the TRC as well as the Participant Test and the Societal Test. They are used for measures which save water and/or natural gas. For example, the CARES Low-Income program saves natural gas as well as electricity.

Request 24c. For years outside the avoided cost timeframe, confirm that future year avoided costs were escalated at an inflation rate of 2.2 percent.

Response 24c. Yes, a 2.2% inflation rate was used to escalate avoided costs for years beyond the avoided cost forecast timeframe.

Request 24d. Explain the basis of and rationale for using a 2.2 percent inflation rate.

Response 24d. The 2.2% long-term inflation rate is based on long-term inflation expectations reported by the Survey of Professional Forecasters and issued by the Federal Reserve Bank of Philadelphia.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 25

RESPONSIBLE PERSON:	**Scott Drake**
COMPANY:	**East Kentucky Power Cooperative, Inc.**

Request 25. Refer to the IRP, Section 5, pages 86-92 and the Technical Appendix, Volume 2, Exhibit DSM-1, Tables 4-5 through 4-8, pages 33-36 of 93.

Request 25a. Explain which of the various programs listed in Tables 4-5 and in 4-7 are represented in the various programs listed in the tables beginning on page 86 and in Table 5-4.

Response 25a. Table 4-5 of Exhibit DSM-1 represents savings potential by measure. The following measures are represented in the programs listed in the tables beginning on page 86 and Table 5-4 in Section 5:

Heat Pump
Touchstone Energy Home
Air Sealing
Standard LEDs
Home Energy Report
Ductless Mini-Split AC/HP
Ceiling Insulation

Table 4-7 presents savings potential by end-use under several budget scenarios.

The following end-uses are represented in the programs listed in the afore-referenced tables in Section 5:

HVAC Shell
HVAC Equipment
Lighting
New Construction

Request 25b. The various program savings potentials listed in DSM-1 Tables 4-5 and 4-7 do not appear to agree with the cumulative Impact on Total Requirements column in the tables listed on pages 86- 90. If not already addressed, explain and reconcile the apparent differences.

Response 25b. There are several reasons why the savings potentials in Tables 4-5 and 4-7 of Exhibit DSM-1 do not agree with the cumulative impact on Total Requirements column in the tables listed on pages 86-90 of Section 5.

First, while there are several columns in Tables 4-5 and 4-7, the relevant column is the column labeled "$3.0M" in Table 4-7. The program participation levels for the programs covered in the tables listed on pages 86-90 of Section 5 were derived using a $3.0 million total annual budget for energy efficiency.

Second, there is not a one-to-one correspondence between the end-uses in Table 4-7 and the programs on pages 86-90. For example, the “HVAC Shell” end-use is targeted in both the Button-Up Weatherization program and the CARES Low-Income program.

Third, the budget allocations which were used to prepare Table 4-7 differed from the budget allocations used for the energy efficiency programs on pages 86-89 (page 90 has the demand response programs which have a separate budget that is not included in the $3.0 million for energy efficiency).

The end-uses in Table 4-7 were scaled down to $3.0 million according to their contribution to the overall achievable potential.

The program budgets in the tables on pages 86-89 were driven by participation. Program cost-effectiveness was a major factor in preparing these participation estimates. As a result, programs like the Residential Lighting program and the new construction programs (Touchstone Energy and ENERGY STAR Manufactured Home) had higher impacts on total requirements than the corresponding end-uses in Table 4-7 column “$ 3.0 M”.

The bottom line is that the combined impact on total requirements for the programs on pages 86-89 (135,076 MWh) is approximately 30% higher than the total cumulative annual MWh for the $3.0 M scenario in Table 4-7 (103,688 MWh).

Request 25c. Provide the location in DSM-1 where the savings to capacity are calculated and that correspond to the seasonal capacity savings listed in the tables on pages 86-90.

Response 25c. While GDS Associates (the preparer of Exhibit DSM-1) used measure specific kWh and kW to calculate individual measure cost-effectiveness, the savings potential for energy efficiency was only reported in MWh. The savings potential for demand response was reported in MW.

EAST KENTUCKY POWER COOPERATIVE, INC.
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FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020

REQUEST 26

RESPONSIBLE PERSON: **Scott Drake**

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

Request 26. Refer to the IRP, Section 1.3, page 3. Explain whether the DSM forecast includes the recent changes from the OMS Filing, Case No. 2019-00059, in which the Commission approved several modifications to EKPC's OMS tariffs.

Response 26. Yes. The DSM impacts in the 2019 IRP account for the DSM program changes in Case No. 2019-00059.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 27
RESPONSIBLE PERSON: **Scott Drake**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 27. Refer to the IRP, Section 1.5, page 4. Explain how the results from Case 2019-00059 support the action of continuing to develop and promote cost-effective DSM programs.

Response 27. The DSM program modifications approved in Case 2019-00059 serve to improve the cost-effectiveness of programs in a period of sharp decline in avoided costs (benefits) as well as budget restrictions.

For example, the Button-Up Weatherization program was redesigned to offer incentives only on measures which remain cost-effective despite the drop in avoided costs. Several measures in the previous Button-up program are no longer cost-effective and those measures were eliminated from the program.

DSM resource acquisition levels can be adjusted upward or downward in response to changes in the operating environment (ie: changes in avoided energy or capacity costs, regulation changes, etc.).

DSM programs reduce the energy and load (demand) required of EKPC's purchase from the PJM market while allowing EKPC to monetize its generation resources in the PJM market. The netting effect is beneficial to EKPC. EKPC will continue to develop cost-effective programs and will adjust the programs offered in the future based on the changing avoided energy and capacity costs, cost associated with regulation changes, etc.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 28
RESPONSIBLE PERSON: Scott Drake
COMPANY: East Kentucky Power Cooperative, Inc.

Request 28. Refer to the IRP, Section 1.9, page 14. Reconcile the $3 million residential EE budget scenario mentioned here, with the projected DSM program expenditures of $5.9 million explained in Case 2019-00059, with EKPC's Response to Commission Staff's Second Request for Information (May 7, 2019).

Response 28. The $5.9 million referenced in EKPC's Response to Commission Staff's Second Request of Information in Case 2019-00059 is the difference between the total DSM program expenditures for 2017 and the projected DSM program expenditures in future years. The projected DSM program expenditures in future years was $4.6 million. This figure included both the EKPC transfer payments of $3 million for its energy efficiency programs, an additional $1.6 million for other expenditures, including EKPC administrative and promotional costs as well as the costs for the Residential DLC program.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020

REQUEST 29

RESPONSIBLE PERSON: Scott Drake

COMPANY: East Kentucky Power Cooperative, Inc.

Request 29. Refer to the IRP, Section 5.0, page 83. Explain in detail how all the programs were shown to be cost-effective using the TRC test.

Response 29. EKPC conducted a detailed cost-effectiveness analysis for the nine programs in the DSM portfolio.

A detailed description of this quantitative evaluation process can be found in the Technical Appendix Volume 2, pages DSM-11 to DSM-13.

Table DSM-2 on page DSM-14 gives the TRC cost-effectiveness test results for each program.

Two programs have a TRC under 1.0: the CARES Low-Income program, and the Energy Audit program. Low-income programs historically have not had TRCs above 1, and utility commissions, including the Kentucky PSC, have allowed utilities to offer them to serve this disadvantaged community. The Energy Audit program is a member service tool to assist and educate end-use members with high bill complaints. It is included in the portfolio because educating the end-use member about energy consumption and energy saving opportunities at home produces electricity savings on the average.

Detailed information on program assumptions and cost-effectiveness results can be found in the Technical Appendix Volume 2, Exhibits DSM-3 and DSM-4.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2019-00096

FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 30
RESPONSIBLE PERSON: Scott Drake
COMPANY: East Kentucky Power Cooperative, Inc.

Request 30. Refer to Table 5-2, Existing Programs-Duration, page 85. Explain in detail how the expected duration of each program is determined.

Response 30. There are two aspects to program duration: years of new participation, and the savings lifetime for that new participation.

Each program adds new participants for the 15-year planning horizon of the IRP.

The savings lifetimes vary by program according to the nature of the measures in each program. EKPC reviews Technical Resource Manuals ("TRMs") publicly available from other states and other reliable information sources to determine the lifetime of savings for each program.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 31
RESPONSIBLE PERSON: Scott Drake
COMPANY: East Kentucky Power Cooperative, Inc.

Request 31. Refer to the IRP, page 91. Explain in detail how the 7 percent discount rate was determined.

Response 31. The 7 percent discount rate was based on a forecast of EKPC's Weighted Average Cost of Capital back in 2018 when the cost-effectiveness evaluations were being developed.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 32
RESPONSIBLE PERSON: **Scott Drake**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 32. Refer to the Technical Appendix Volume 2, Exhibit DSM-2. Provide the 2018 DSM Annual Report or most recent report available that is not already part of the IRP.

Response 32. The 2018 DSM Annual Report is provided on pages 2 through 21 of this response.

DSM

Demand Side Management
2018 Annual Report

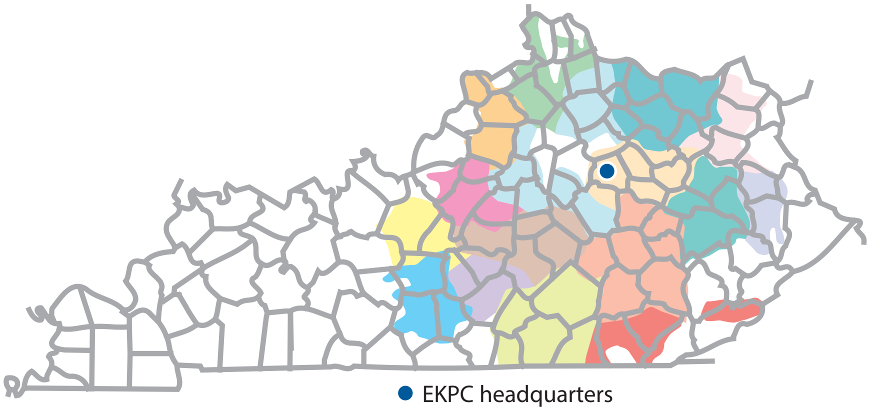
EAST KENTUCKY POWER COOPERATIVE
A Touchstone Energy® Cooperative

Table of Contents

Who We Are

Located in the heart of the Bluegrass state, East Kentucky Power Cooperative is a not-for-profit generation and transmission (G&T) electric utility with headquarters in Winchester, Ky. Our cooperative has a vital mission: to safely generate and deliver affordable, reliable electric power to 16 owner-member cooperatives serving more than one million Kentuckians.

Together, with our 16 owner-members, we're known as Kentucky's Touchstone Energy Cooperatives. The member co-ops distribute energy to over 530,000 Kentucky homes, farms, businesses and industries across 87 counties. We're leaders in energy efficiency and environmental stewardship. And we're committed to providing power to improve the lives of people in Kentucky.



Sixteen distribution cooperatives, which are called the member systems, own EKPC. The 16 co-ops include:

- ● Big Sandy RECC
- ● Blue Grass Energy Cooperative
- ● Clark Energy Cooperative
- ● Cumberland Valley Electric
- ● Farmers RECC
- ● Fleming-Mason Energy Cooperative
- ● Grayson RECC
- ● Inter-County Energy
- ● Jackson Energy Cooperative
- ● Licking Valley RECC
- ● Nolin RECC
- ● Owen Electric Cooperative
- ● Salt River Electric Cooperative
- ● Shelby Energy Cooperative
- ● South Kentucky RECC
- ● Taylor County RECC

East Kentucky Power Generation

Coal	Generation
Spurlock	1,346 new MW
Cooper	341 net
MW	
Total	**1,687 net MW**

Hydro	Generation
Southeastern Power Adm. (SEPA)	170 MW

Natural Gas	Generation
Smith Combustion Turbine Units	Summer 753 net MW Winter 989 net MW
Bluegrass** Combustion Turbine Units	Summer 501 net MW Winter 567 net MW
Total Natural Gas Summer	**1,254 net MW**
Total Natural Gas Winter	**1,556 net MW**

Landfill	Generation
Bavarian	4.6 net MW
Laurel Ridge	3.0 net MW
Green Valley	2.3 net MW
Pearl Hollow	2.3 net MW
Pendleton	3.0 net MW
Glasgow***	0.9 net MW
Total Landfill	**16.1 net MW**

SolarGeneration	
Cooperative Solar	8.5 net MW

** Under an existing agreement, which continues until April 2019, a third party receives the output of one Bluegrass Generating Station unit.

*** Under an existing agreement, a third party receives the output of Glasgow in a 10-year power purchase agreement.

Residential Lighting:

Since 2003, EKPC and its owner-member cooperatives have provided more than one million compact fluorescent lights (CFL) and light-emitting diodes (LED) bulbs to members.

In 2018, cooperatives provided more than 54,676 LEDs to its members. Each member who participated in a free, online energy audit called BillingInsights™ received an LED, along with Annual Meeting attendees. These LEDs are expected to result in a lifetime savings of 10,498 MWh and 20,995,584 pounds of carbon dioxide emissions.

HVAC Duct Sealing:

Since the 1990s, EKPC and its owner-member cooperatives have offered this program to reduce the energy loss through a home's HVAC duct system. This program provides incentives to members who seal ductwork through traditional mastic sealers. Duct loss measurement requires the use of a blower door test (before and after the duct sealing work is performed). Duct leakage per system must be reduced to below 10 percent of the fan's rated capacity. All joints in the duct system must be sealed with foil tape and mastic. This program was targeted to single-family homes using electric furnaces or electric heat pumps. All participating homes must have duct systems that are at least two years old to qualify for the incentive. The program was offered only to homes that had centrally-ducted heating systems in unconditioned areas.

In 2018, 37 HVAC Duct Sealing rebates were provided to members, resulting in a lifetime savings of 498 MWh and 996,480 pounds of carbon dioxide emissions.

Button-Up Weatherization:

Since the early 1990s, EKPC and its owner-member cooperatives have offered this program to improve a home's energy efficiency, comfort, and reduce energy use. This program offers incentives to members who add insulation materials or use other weatherization techniques to reduce heat loss in the home. Any member who resides in a site-built or manufactured home that is at least two years old and uses electricity as their primary source of heat is eligible.

This program offers a whole-house approach with multiple levels.

Button-Up Weatherization with Air Sealing:
This version of the Button-Up encourages members to air seal the envelope of their home in addition to the regular Button-Up improvements. A blower door test is required to demonstrate the impact in kW demand reduction, and an added incentive is paid based on that reduction.

Advanced Weatherization Level 2:
Level 2 encourages homeowners to address all of their home's inefficiencies at one time. The resulting BTUh savings can be as much as 150 percent of Button- Up Level I. Achieving this level of savings results in a greater incentive.

Advanced Weatherization Level 3:
*This version represents the highest level. Level 3 also encourages homeowners to address all of their home's inefficiencies at one time. The resulting BTUh savings can be as much as 200 percent of Button-Up Level I.
Achieving this level of savings results in an even greater incentive.*

Levels 2 and 3 of this program are targeted to members who currently heat their home with electricity, particularly homes with unfinished basements, homes that have partition walls separating a crawl space or garage, and Cape Cod style homes (1.5 stories).

In 2018, 557 Button-Up rebates were provided to members, resulting in a lifetime savings of 12,300 MWh and 24,599,167 pounds of carbon dioxide emissions.

Touchstone Energy Home:

Since 2003, EKPC and its owner-member cooperatives have offered this program to increase energy efficiency in new-home construction. This program is designed to encourage new homes to be built to higher standards for thermal integrity and equipment efficiency, as well as to choose a geothermal or an air-source heat pump, rather than less efficient forms of heating and cooling. Homes built to Touchstone Energy Home standards typically use 30 percent less energy than the same home built to typical construction standards. Plans are submitted before the home is built, a pre-drywall inspection is made, and a blower door test is administered after the home is built to verify that the home meets the standard.

This program is targeted towards the residential new construction market and members who are constructing new site-built homes.

In 2018, 472 Touchstone Energy Home rebates were provided to members, resulting in a lifetime savings of 24,193 MWh and 48,386,640 pounds of carbon dioxide emissions.

EKPC's owner-members have also used this program to partner with Kentucky's affordable housing builders. Relationships with these organizations have led to improved efficiency in affordable housing and lower monthly energy costs for recipients of these homes.

CARES:

The Community Assistance Resources for Energy Savings (CARES) program began in early 2015, and provides an incentive to enhance the weatherization and energy efficiency services provided to the end-use members by the Kentucky Community Action Agencies (CAA) network. EKPC and its owner-members provide an incentive to the CAA implementing the project on behalf of the end-use member.

This program is available to end-use members who qualify for weatherization and energy-efficiency services through their local CAA in all service territories of participating cooperatives. The maximum incentive possible per household is $2,000.

In 2018, 66 CARES incentives were provided, resulting in a lifetime savings of 4,684 MWh and 9,367,380 pounds of carbon dioxide emissions.

Heat Pump Retrofit:

For decades, EKPC and its owner-member cooperatives have offered this program to lower the cost of heating homes and increase comfort. This program provides incentives for members to replace their existing resistance heat source with a high-efficiency heat pump through three levels of rebates.

Level 1 offers a rebate for a 13 SEER/7.5 HSPF heat pump. Level 2 offers a rebate for a 14 SEER/8.0 HSPF heat pump. Level 3 offers a rebate for a 15 SEER/8.5 HSPF or higher heat pump. The existing heating system must be two years or older to qualify for incentives unless the heat pump is being installed in a new manufactured home. New manufactured homeowners who install a heat pump qualify based on the levels above.

The program is targeted to members who currently use a resistance heat source. Incentives are offered when the homeowner's primary source of heat is an electric resistance furnace, ceiling cable heat, or baseboard heat in both site-built and manufactured homes.

In 2018, 524 Heat Pump Retrofit rebates were provided to members, resulting in a lifetime savings of 81,658 MWh and 163,316,440 pounds of carbon dioxide emissions.

Direct Load Control:

Since 2008, EKPC and its owner-member cooperatives have offered this program to manage peak usage. This program offers incentives to members who enroll central air-conditioners and electric water heaters. Switches are installed and, during periods of high demand, the utility briefly cycles the appliance off in order to reduce system peaks and save on costs for peak power. Although EKPC's system typically peaks in winter, member's heating appliances are not interrupted to lower peak. Member comfort and safety are top priority.

This program is targeted to any member with central air-conditioning, heat pump or electric tank water heaters, 40 gallons or greater.

In 2018, 205 switches were installed, resulting in a reduction of 0.164 MW during the summer months and 0.034 MW in the winter.

Appliance Recycling:

The Appliance Recycling program began in 2014 in an effort to encourage members to recycle old, inefficient refrigerators and freezers. Members receive a $50 incentive for recycling refrigerators and/or freezers that meet qualifying conditions. The appliances must be in working condition, plugged in and running at scheduled pick-up, between 7.75 and 30 cubic feet, and empty and defrosted with water lines disconnected.

EKPC and its owner-member cooperatives partner with Appliance Recycling Centers of America, Inc. (ARCA) for proper recycling procedures that meet all federal and state requirements.

This program was available to all end-use members who qualify.

In 2018, 1,057 incentives were provided to members, resulting in a lifetime savings of 5,432 MWh and 10,864,560 pounds of carbon dioxide emissions.

ENERGY STAR Appliance Rebate:

The ENERGY STAR Appliance Rebate program began in 2014 in an effort to encourage members to purchase new, energy-efficient appliances. EKPC and its owner-member cooperatives provide the incentives to members who purchase and install the ENERGY STAR certified appliances listed in the table.

This program was available to all end-use members who qualify.

In 2018, 10,717 rebates were provided to members, resulting in a lifetime savings of 37,396 MWh and 74,791,976 pounds of carbon dioxide emissions.

ENERGY STAR Appliances	Rebate
Refrigerator	$100
Freezer	$50
Dishwasher	$50
Clothes Washer	$75
Heat Pump Water Heater	$300
Heat Pump	$300
Central Air Conditioning	$300

ENERGY STAR Manufactured Home:

The ENERGY STAR Manufactured Home program began in 2014. An upstream program, EKPC works directly with the manufacturer to automatically upgrade the home to ENERGY STAR certified standards. EKPC utilizes a third-party administrator, Systems Building Research Alliance (SBRA), to verify information and ensure quality control.

Once the installation address is verified to be on a participating cooperative's service lines, the member will automatically receive the upgrade. An ENERGY STAR certified manufactured home is a home that has been designed, produced and installed by the home manufacturer to meet ENERGY STAR requirements for energy efficiency. These manufactured homes feature efficient heating and cooling equipment, water heaters, properly installed insulation, high-performance windows, tight construction and sealed ducts.

This program is available to all end-use members who qualify.

In 2018, 30 rebates were provided to members, resulting in a lifetime savings of 5,376 MWh and 10,752,300 pounds of carbon dioxide emissions.

Commercial Programs:

Commercial & Industrial Advanced Lighting

For several years, EKPC and its owner-member cooperatives have offered this program to improve lighting in commercial or industrial facilities. This program offers incentives to install high-efficiency lamps and ballasts, including, but not limited to, LED exit signs, T-5 fluorescent fixtures and advanced controls.

This program was targeted to any existing commercial or industrial facility in the service territory of a distribution cooperative. The facility and its lighting must have been in service for at least two years.

In 2018, 183 C&I Advanced Lighting rebates were provided to members, resulting in a lifetime savings of 175,269 MWh and 350,538,554 pounds of carbon dioxide emissions.

Industrial Compressed-Air

For several years, EKPC and its owner-member cooperatives have offered this program to refund the cost of a leak-detection audit. This program is designed to reduce electricity consumption through detecting and repairing compressed-air leaks. Compressed-air production and distribution represents one of the primary electricity costs in many industrial plants. Both the supply side (compressors and conditioning equipment) and the demand side (distribution and end use) can be targeted to significantly improve energy efficiency.

This program was targeted to any existing commercial or industrial facility that uses electricity compressed air applications.

Impact Measures:

System summary of 2018 DSM program savings

DSM program totals for installed measures in 2018

All programs	Participation	Annual Energy Savings (MWh)	Summer Demand Savings (MW)	Winter Demand Savings (MW)	2018 program costs	Lifetime energy savings (MWh)	Cost of demand saved ($/kW)	Cost of energy saved ($/kWh)	Lifetime CO2 savings (lbs)
All DSM Programs	68,853	29,391	4.419	4.261	$7,267,557	358,162	$1,391	0.020	716,324,401

Appliance Recycling

Residential program	Participation	Annual Energy Savings (MWh)	Summer Demand Savings (MW)	Winter Demand Savings (MW)	2018 program costs	Measure life (years)	Lifetime energy savings (MWh)	Cost of energy saved ($/kWh)	Lifetime CO2 savings (lbs)
Appliance Recycling	1,057	776	0.112	0.078	$258,320	7	5,432	$0.05	10,864,560

Button-Up Weatherization

Residential program	Participation	Annual Energy Savings (MWh)	Summer Demand Savings (MW)	Winter Demand Savings (MW)	2018 program costs	Measure life (years)	Lifetime energy savings (MWh)	Cost of energy saved ($/kWh)	Lifetime CO2 savings (lbs)
Button-Up level 1	556	812	0.191	0.628	$355,863	15	12,185	$0.03	24,369,204
Button-Up level 2	0	0	0	0	0	0	0	0	0
Button-Up level 3	1	8	0.002	0.006	$2,625	15	115	$0.02	229,963

CARES

Residential program	Participation	Annual Energy Savings (MWh)	Summer Demand Savings (MW)	Winter Demand Savings (MW)	2018 program costs	Measure life (years)	Lifetime energy savings (MWh)	Cost of energy saved ($/kWh)	Lifetime CO2 savings (lbs)
CARES	66	312	0.048	0.095	$157,095	15	4,684	$0.03	9,367,380

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* Includes $941,590 program administration and promotional expenses.

Commercial and Industrial

C&I programs	Participation	Annual Energy Savings (MWh)	Summer Demand Savings (MW)	Winter Demand Savings (MW)	2018 program costs	Measure life (years)	Lifetime energy savings (MWh)	Cost of energy saved ($/kWh)	Lifetime CO2 savings (lbs)
Commercial Lighting	183	17,527	2.493	1.668	$1,293,209	10	175,269	$0.007	350,538,554
Compressed Air	0	0	0	0	-	-	0	0	0

Direct Load Control

Residential program	Participation	Annual Energy Savings (MWh)	Summer Demand Savings (MW)	Winter Demand Savings (MW)	2018 program costs	Cost of Demand saved ($/KW)
DLC Air Conditioner	140	0.7	0.14	0	$155,795.41	$1,112.82
DLC Water Heater	65	0.65	0.024	0.034	$72,333.59	$3,007.63
DLC total	205	1.35	0.164	0.034	$228,129.00	$1,390.61

Energy Audits

Residential program	Participation	Annual Energy Savings (MWh)	Summer Demand Savings (MW)	Winter Demand Savings (MW)	2018 program costs	Measure life (years)	Lifetime energy savings (MWh)	Cost of energy saved ($/kWh)	Lifetime CO2 savings (lbs)
In-home	2	1	0.000	0.000	$809	8	10	$0.08	20,800
Online	327	169	0.000	0.000	$132,191	5	847	$0.16	1,694,520

ENERGY STAR® Appliance Rebate

Residential program	Participation	Annual Energy Savings (MWh)	Summer Demand Savings (MW)	Winter Demand Savings (MW)	2018 program costs	Measure life (years)	Lifetime energy savings (MWh)	Cost of energy saved ($/kWh)	Lifetime CO2 savings (lbs)
ES Heat Pump	1,665	1,233	0.460	0.000	$955,780	15	18,488	$0.05	36,975,960
ES Central Air Conditioner	388	167	0.164	0.000	$125,660	15	2,507	$0.05	5,014,920
ES Clother Washer	2,428	664	0.057	0.133	$226,645	12	7,967	$0.03	15,934,800
ES Dishwasher	2,598	195	0.025	0.025	$154,195	10	1,948	$0.08	3,896,280
ES Freezer	396	20	0.003	0.002	$19,570	12	243	$0.08	485,616
ES Heat Pump Water Heater	245	240	0.022	0.056	$58,610	13	3,117	$0.02	6,234,800
ES Refrigerator	2,997	260	0.013	0.026	$407,490	12	3,125	$0.13	6,249,600
ES Total	10,717	2,779	0.744	0.241	$1,947,950	—	37,396	$0.052	74,791,976

ENERGY STAR® Manufactured Home

Residential program	Participation	Annual Energy Savings (MWh)	Summer Demand Savings (MW)	Winter Demand Savings (MW)	2018 program costs	Measure life (years)	Lifetime energy savings (MWh)	Cost of energy saved ($/kWh)	Lifetime CO2 savings (lbs)
ES Manufactured Home	30	358	0.015	0.086	$129,000	15	5,376	$0.02	10,752,300

Heat Pump Retrofit

Residential program	Participation	Annual Energy Savings (MWh)	Summer Demand Savings (MW)	Winter Demand Savings (MW)	2018 program costs	Measure life (years)	Lifetime energy savings (MWh)	Cost of energy saved ($/kWh)	Lifetime CO2 savings (lbs)
Heat Pump	524	4,083	0.196	0.000	$1,090,954	20	81,658	$0.01	163,316,440

HVAC Duct Seal

Residential program	Participation	Annual Energy Savings (MWh)	Summer Demand Savings (MW)	Winter Demand Savings (MW)	2018 program costs	Measure life (years)	Lifetime energy savings (MWh)	Cost of energy saved ($/kWh)	Lifetime CO2 savings (lbs)
HVAC Duct Sealing	37	42	0.012	0.039	$20,000	12	498	$0.040	996,480

Residential Lighting

Residential program	Participation	Annual Energy Savings (MWh)	Summer Demand Savings (MW)	Winter Demand Savings (MW)	2018 program costs	Measure life (years)	Lifetime energy savings (MWh)	Cost of energy saved ($/kWh)	Lifetime CO2 savings (lbs)
LEDs	54,676	1,312	0.131	0.219	$50,943	8	10,498	$0.000	20,995,584

Touchstone Energy Home

Residential program	Participation	Annual Energy Savings (MWh)	Summer Demand Savings (MW)	Winter Demand Savings (MW)	2018 program costs	Measure life (years)	Lifetime energy savings (MWh)	Cost of energy saved ($/kWh)	Lifetime CO2 savings (lbs)
TSE Home Prescriptive	153	393	0.101	0.379	$214,200	20	7,858	$0.030	15,716,160
TSE Home Performance	319	817	0.210	0.789	$444,680	20	16,335	$0.030	32,670,480

2018 Basic Program Assumptions [1]

Measure: Button-Up Level 1

Annual kWh Saved:	2,205
Winter Demand Savings:	1.71
Summer Demand Savings:	0.52
Lifetime of Savings:	15 years
Installation Rate:	100%
TRC: [2]	1.45

Measure: Button-Up Level 2

Annual kWh Saved:	4,567
Winter Demand Savings:	3.53
Summer Demand Savings:	1.07
Lifetime of Savings:	15 years
(Weighted mix of measures)	
Installation Rate:	100%
TRC:	1.52

Measure: Button-Up Level 3

Annual kWh Saved:	6,090
Winter Demand Savings:	4.71
Summer Demand Savings:	1.43
Lifetime of Savings:	15 years
(Weighted mix of measures)	
Installation Rate:	100%
TRC:	1.56

Measure: Button-Up w/Air Seal

Annual kWh Saved:	3,045
Winter Demand Savings:	2.35
Summer Demand Savings:	0.720
Lifetime of Savings:	15 years
Installation Rate:	100%
TRC:	1.44

Measure: HVAC Maintenance Program

For a typical heat pump in typical residence to same home reduced by 12% savings

Annual kWh Saved:	1,354
Winter Demand Savings:	1.07
Summer Demand Savings:	0.40
Lifetime of Savings:	12 years
Installation Rate:	100%
TRC:	1.15

Measure: Heat Pump SEER 13

From Electric Furnace and Central Air to ENERGY STAR SEER 13, HSPF 7.5

Annual kWh Saved:	7,174
Winter Demand Savings:	0
Summer Demand Savings:	0 .15
Lifetime of Savings:	20 years
Installation Rate:	100%
TRC:	1.52

Measure: Heat Pump SEER 14

From Electric Furnace and Central Air to ENERGY STAR SEER 14, HSPF 8.0

Annual kWh Saved:	7,533
Winter Demand Savings:	0
Summer Demand Savings:	0.32
Lifetime of Savings:	20 years
Installation Rate:	100%
TRC:	1.32

Measure: Heat Pump SEER 15

From Electric Furnace and Central Air to ENERGY STAR SEER 15, HSPF 8.5

Annual kWh Saved:	7,978
Winter Demand Savings:	0
Summer Demand Savings:	0.45
Lifetime of Savings:	20 years
Installation Rate:	100%
TRC:	1.08

Measure: Touchstone Energy Home

Prescriptive and Performance Level #2 – Encourages new homes to be built to a standard of at least SEER 14.5, HSPF 8.2; HERS Rating of 79 and below

Annual kWh Saved:	2,568
Winter Demand Savings:	2.48
Summer Demand Savings:	0.66
Lifetime of Savings:	20 years
Installation Rate:	100%
TRC:	1.98

Measure: Touchstone Energy Home

Performance Level #1 – Encourages new homes to be built to a standard of at least SEER 14.5, HSPF 8.2; HERS rating of 80-85

Annual kWh Saved:	1,758
Winter Demand Savings:	1.7
Summer Demand Savings:	0.45
Lifetime of Savings:	20 years
Installation Rate:	100%
TRC:	2.06

Measure: LEDs

Annual kWh Saved:	24
Winter Demand Savings:	0.0040
Summer Demand Savings:	0.0024
Lifetime of Savings:	8 years
Installation Rate:	80%
TRC:	2.13

Measure: Commercial Advanced Lighting

Unit is 1 kW connected load savings

Annual kWh Saved:	4,252
Winter Demand Savings:	0.45
Summer Demand Savings:	0.85
Lifetime of Savings:	10 years
Installation Rate:	100%
TRC:	2.22

Measure: Industrial Compressed Air

Annual kWh Saved:	3,800
Winter Demand Savings:	0.30
Summer Demand Savings:	0.75
Lifetime of Savings:	7 years
Installation Rate:	0
TRC:	1.62

Measure: Water Heater >40 gals

Annual kWh Saved:	10
Winter Demand Savings:	0.52
Summer Demand Savings:	0.37
Lifetime of Savings:	20 years
Installation Rate:	100%

Measure: Central Air Conditioning

Annual kWh Saved:	5
Winter Demand Savings:	0.0
Summer Demand Savings:	1.0
Lifetime of Savings:	20 years
Installation Rate:	100%

TRC for Load Control Program	2.68

Measure: ENERGY STAR® Appliances

TRC:	1.49 in aggregate

Measure: ENERGY STAR® Heat Pump

Annual kWh Saved:	804
Winter Demand Savings:	0.00
Summer Demand Savings:	0.30
Lifetime of Savings:	20 years
Installation Rate:	100%

Measure: ENERGY STAR® Central Air

Annual kWh Saved:	529
Winter Demand Savings:	0.00
Summer Demand Savings:	0.52
Lifetime of Savings:	15 years
Installation Rate:	100%

Measure: ENERGY STAR® Clothes Washer

Annual kWh Saved:	350
Winter Demand Savings:	0.07
Summer Demand Savings:	0.03
Lifetime of Savings:	12 years
Installation Rate:	100%

Measure: ENERGY STAR® Dish Washer

Annual kWh Saved:	79
Winter Demand Savings:	0.01
Summer Demand Savings:	0.01
Lifetime of Savings:	10 years
Installation Rate:	100%

Measure: ENERGY STAR® Freezer

Annual kWh Saved:	67
Winter Demand Savings:	0.01
Summer Demand Savings:	0.01
Lifetime of Savings:	12 years
Installation Rate:	100%

Measure: ENERGY STAR® Refrigerator

Annual kWh Saved:	100
Winter Demand Savings:	0.01
Summer Demand Savings:	0.01
Lifetime of Savings:	12 years
Installation Rate:	100%

Measure: ENERGY STAR® Heat Pump Water Heater

Annual kWh Saved:	2,200
Winter Demand Savings:	0.51
Summer Demand Savings:	0.20
Lifetime of Savings:	13 years
Installation Rate:	100%

Measure: Appliance Recycling

Annual kWh Saved:	696
Winter Demand Savings:	0.07
Summer Demand Savings:	0.10
Lifetime of Savings:	7 years
Installation Rate:	100%
TRC:	2.01

Measure: CARES

Annual kWh Saved:	4,731
Winter Demand Savings:	1.44
Summer Demand Savings:	0.72
Lifetime of Savings:	15 years
Installation Rate:	100%
TRC:	1.34

Measure: ENERGY STAR® Manufactured Home

Annual kWh Saved:	11,947
Winter Demand Savings:	2.88
Summer Demand Savings:	0.51
Lifetime of Savings:	15 years
Installation Rate:	100%
TRC:	4.09

1 Savings numbers are "ex ante" or as planned gross savings except where noted.
2 Total Resource Cost (TRC) is an overall program benefits/costs analysts ratio.

EAST KENTUCKY POWER COOPERATIVE

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EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 33
RESPONSIBLE PERSON: Jerry B. Purvis
COMPANY: East Kentucky Power Cooperative, Inc.

Request 33. Refer to the IRP, Section 2.0, page 29. Provide an update on the status of the Affordable Clean Energy Rule (ACE) proposed by the U.S. Environmental Protection Agency (EPA).

Response 33. EPA issued the Proposed Rule to replacement for the Clean Power Plan (CPP) on August 21, 2018, entitled the Affordable Clean Energy (ACE) rule. EPA's general approach to the rule is to clarify the Federal and state roles in rulemaking, with particular emphasis on granting states more authority to make decisions about how to implement the ACE. EPA clarifies that the CPP exceeded the EPA's statutory authority and that the ACE rule would follow EPA's historic application of section 111, by focusing on seven (7) candidate technologies that could be cost-effectively implemented at a facility, unit-by-unit. EPA proposed revisions to the New Source Review program to clearly allow projects that improve unit efficiency, which may be required under ACE rule.

EPA published the Final ACE Rule on July 8, 2019. The ACE Final Rule repealed and replaced the CPP. EPA sets Best System of Emission Reduction (BSER) and provides guidance to the states on how to apply BSER. States apply BSER on a unit basis to set standards of performance (short term CO2 emissions rate limits CO2 lbs. /MWh). States are charged with examining the seven (7) potential candidate technologies and operation and maintenance practices that could potentially improve the heat rate efficiency of individual coal units which may result in a reduction of CO2 emissions. In theory, the units will combust less coal but generate the same amount of electricity. All resulting limits must be set based on the CO2 emissions rate from a unit (pounds of CO2 emitted per megawatt hour generated). The Proposed Rule included a revised NSR emissions test, but the Final Rule removed this test.

States have three years to prepare a plan implementing the Rule. Kentucky has already begun collecting information from EGUs for this process. In accordance with the federal ACE rule, the States' Plan is due July 8, 2022. Within 60 days but no later than six months after EPA's receipt of the state plan, EPA shall make a completeness determination. If EPA does not act within the six month period, the plan is deemed to meet the minimum criteria for completeness. The latest date for completeness determination would be January 8, 2023. Within 12 months of finding the state plan complete, EPA must approve or disapprove the plan. The latest date for the EPA approval or disapproval would be January 8, 2024. If EPA disapproves the state plan, EPA must issue a federal plan within two years. The latest date of the federal plan issuance would be January 8, 2026.

The Final ACE Rule has been challenged by numerous environmental non-governmental organizations and public health organizations, with states and industry participation in amicus curiae briefing. The cases have been consolidated in the D.C. Circuit with oral argument likely to take place in the fall of 2020. EKPC is participating in the state implementation process with the KY Energy and Environmental Cabinet for ACE and tracking judicial developments.

EAST KENTUCKY POWER COOPERATIVE, INC.
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STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020

REQUEST 34

RESPONSIBLE PERSON: **Julia J. Tucker**

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

Request 34. Refer to the IRP, Section 2.0, page 30. Provide an update on the Center Hill project, which EKPC estimates will be completed in late 2019.

Response 34. Center Hill has three (3) 45MW units. A contract for complete rehabilitation of the units was awarded in 2014. The Unit 2 project was completed on August 23, 2017. Due to manufacturing defects, the Unit 1 and Unit 3 projects were delayed. Unit 3 is scheduled for completion in May 2020. Unit 1 is scheduled for completion in September 2020. The dam safety projects, including remediation of the earthen dam and an additional saddle dam, were completed in 2019.

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STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 35
RESPONSIBLE PERSON: Julia J. Tucker
COMPANY: East Kentucky Power Cooperative, Inc.

Request 35. Refer to the IRP, Section 2.0, page 32. Confirm that two additional run-of-river projects came online in 2019. If this cannot be confirmed, provide the expected date the projects are expected to come online.

Response 35. There are two projects licensed by FERC (Nos. 13214 and 13213) previously scheduled for 2019. At this time one project is anticipated by Fall 2020, with the second project expected to follow in Fall 2021.

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STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 36
RESPONSIBLE PERSON: Craig A. Johnson
COMPANY: East Kentucky Power Cooperative, Inc.

Request 36. Refer to the IRP, Section 4.0, page 67. Provide the cost for the power block demolition at Dale Station.

Response 36. The cost to demolish Dale Station was $2.4 MM. This cost includes the equipment sold by supply chain, equipment redeployed to other plants, and the recycling rebate from the demo contractor. It does not include the cost to close the ash ponds.

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REQUEST 37
RESPONSIBLE PERSON: Julia J. Tucker
COMPANY: East Kentucky Power Cooperative, Inc.

Request 37. Refer to the IRP, Section 4.0, beginning at page 73. Explain how the Operations and Maintenance escalation factors were determined.

Response 37. The Handy-Whitman index was used as a reference for the escalation index factor, which was 2.3% in 2018.

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STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 38
RESPONSIBLE PERSON: Mary Jane Warner
COMPANY: East Kentucky Power Cooperative, Inc.

Request 38. Refer to the IRP, Section 6.0, page 94. In the third paragraph, EKPC indicates that two planned substation interconnections with TVA and LG&E/KU have minimal transfer benefits.

Request 38a. Explain how reliability will be improved in the respective areas and what "minimal transfer benefits" means.

Response 38a. The new interconnection with TVA in the Glasgow area will establish another connection between EKPC and TVA at 161 kV in the area. EKPC intends to install a 161-69 kV transformer at the Fox Hollow substation to connect to the 69 kV transmission system in the area. EKPC has identified several potential thermal overloads of facilities and potential violations of EKPC minimum voltage criteria in the area for contingency conditions. Additionally, PJM identified a violation of its voltage deviation criterion in this area during contingency conditions. Also, EKPC is required to sectionalize the 69 kV transmission system in the area when outages are required for maintenance, which exposes a significant number of customers to substantial risk of loss of service for a subsequent outage of another transmission facility in the area. EKPC and PJM determined that the proposed new 161 kV interconnection with TVA in the Glasgow area is the preferred solution to address the criteria violations identified, as well as to provide redundancy in the area to support ability to take outages in the area.

The new interconnection with LG&E/KU in the Shelbyville area will establish another connection between EKPC and LG&E/KU at 69 kV in the area. EKPC will construct approximately two miles of new 69 kV line from its existing Bekaert distribution substations to LG&E/KU's existing Simpsonville-Shelbyville 69 kV line, and LG&E/KU will construct a new 69 kV switching station to allow connection of the new EKPC transmission line to the LG&E/KU line. EKPC identified this new interconnection project as the recommended solution to address loss-of-load impacts of either a 69 kV bus outage at the Shelby County substation (which presently results in seven distribution substations experiencing interruption) or an outage of the Shelby County-Logan Tap 69 kV line section (which presently results in six distribution substations experiencing interruption). The new interconnection will provide a second connection to the existing radial 69 kV line from the Shelby County substation that serves the Logan, Budd, and Bekaert distribution substations, thereby providing redundancy in case of an outage of the existing source.

Therefore, in both cases, the interconnections have been proposed to provide reliability improvements in the area by, in particular, providing an additional source into EKPC's 69 kV system in each area. The proposed interconnections will establish additional ties between the respective companies in areas where the systems are already interconnected. EKPC and TVA are interconnected at another location in the Glasgow area, and EKPC and LG&E/KU are interconnected at a third location near Shelbyville. These interconnections are to the EKPC 69 kV system, so power flows are typically much lower than at higher voltage levels (138 kV and above). Since there are already existing interconnections with these companies in the area and since the connections will be to the EKPC 69 kV system rather than at higher voltage levels, the establishment of an additional interconnection in each area will not provide a significant increase in either the expected level of power flows between the companies, or the total power transfer capability between the companies. Consequently, the interconnection will result in minimal transfer benefits.

Request 38b. Provide an update of the status of the two planned interconnections.

Response 38b. Both interconnections are currently in the engineering and procurement phase. In each case, both EKPC and the interconnected company (TVA, LG&E/KU) must build facilities to establish the interconnection. Both TVA and

LG&E/KU will build new transmission substations to facilitate the interconnections. EKPC will build new transmission lines in each case, and in the case of the TVA interconnection will also expand its existing Fox Hollow substation. EKPC has agreements that were developed with each company regarding implementation of the interconnections so that necessary project activities could commence. Each company continues to proceed with activities needed to implement the projects. Currently, the new Bekaert-West Shelby interconnection with LG&E/KU is planned to be in service by December 2020. The East Glasgow Tap-Fox Hollow interconnection with TVA is planned to be in service by December 2021.

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FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 39
RESPONSIBLE PERSON: Darrin Adams
COMPANY: East Kentucky Power Cooperative, Inc.

Request 39. Refer to the IRP, Section 6.0, page 95, regarding EKPC and PJM transmission planning activities.

Request 39a. Describe how EKPC's transmission planning process differs from PJM's planning process in regard to projects developed to address violations of PJM's performance criteria.

Response 39a. The regional planning process within PJM specifies division of responsibility for certain transmission facilities, but includes some overlap of these responsibilities and significant coordination between PJM and its member transmission owners. PJM leads the planning analysis and development of baseline upgrades related to PJM planning criteria, transmission owner planning criteria, operational performance, and economic planning/market efficiency for all facilities 100 kV and above under PJM's operational control. EKPC leads the planning analysis and development of baseline upgrades related to EKPC planning criteria. In both cases, EKPC and PJM coordinate throughout the planning process regarding planning studies, identified violations of criteria, and potential solutions.

EKPC and PJM planning criteria are similar in many respects, but certain differences exist. In some cases, PJM criteria is more conservative (restrictive) than EKPC criteria. In other cases, EKPC criteria are more restrictive than PJM criteria. As an example of where EKPC criteria are more restrictive, EKPC planning criteria specifies an "N-1" contingency event as an outage of a single transmission facility in conjunction with an outage of a single generating unit. PJM planning criteria considers this to be an "N-1-1" contingency event. As an example of where PJM criteria are more restrictive, PJM does not allow shedding of customer load as a solution to violations caused by an "N-1-1" contingency event, whereas EKPC does allow such load shedding in its local planning criteria. PJM defaults to the more restrictive planning criteria within each transmission owner's zone when performing its analysis to ensure adherence to both sets of planning criteria in all cases. Once a violation of either set of planning criteria is identified, PJM and EKPC work together to develop alternatives and the recommended solution to address the violation, unless the violation has been determined to be subject to the PJM competitive planning process. In that case, EKPC can elect to submit a proposal for consideration by PJM as a potential solution, but PJM holds responsibility for selecting the preferred solution from all proposals submitted by potential developers. Regardless of whether the solution is developed through the competitive process or through the PJM/EKPC coordination process, EKPC includes the recommended solution in its planning analysis once approved by PJM.

Request 39b. Explain EKPC's process for incorporating and prioritizing for completion the additional PJM projects into its own list of projects.

Response 39b. Once PJM identifies the need for a baseline project - whether needed to address PJM planning criteria, EKPC planning criteria, or both - in EKPC’s zone and if PJM designates EKPC as the entity responsible for building the project, PJM will send EKPC a notification letter of this designation and asking for confirmation that EKPC accepts the construction responsibility for the project. PJM also provides the date that the project needs to be placed in service. EKPC’s response letter accepting construction responsibility will either provide confirmation that the project can be completed by the specified in-service date or indicate the earliest date that EKPC will be able to complete the project. EKPC incorporates these baseline projects into its capital project portfolio. Projects within EKPC’s capital project portfolio are prioritized based on a number of factors, including whether the project is needed to address violations of PJM and/or EKPC planning criteria.

Request 39c. Explain how the costs associated with the projects identified by EKPC then incorporated into PJM's Regional Transmission Expansion Plan are allocated.

Response 39c. The cost allocation methodology for all PJM projects, including those identified as needed to address PJM transmission owner-filed FERC Form 715 criteria, is described in Schedule 12 of the PJM Open Access Transmission Tariff. Summarizing the description contained in this Schedule 12:

- For each supplemental project (defined in the PJM Operating Agreement as "a transmission expansion or enhancement that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection and is not a state public policy project…") initiated by EKPC and incorporated into PJM's Regional Transmission Expansion Plan ("RTEP") the costs are allocated entirely to the EKPC zone.
- For baseline projects operating at 500 kV and above, and double-circuit 345 kV facilities identified based on EKPC FERC Form 715 filed planning criteria, the cost of each project is allocated based 50% on load-ratio share (zonal load portion of EKPC total peak load) and 50% on a solution-based distribution factors ("DFAX") analysis that determines the relative use of the project by the load in each PJM zone and withdrawals by merchant transmission facilities, and through this power flow analysis, identifies projected benefits for each zone in relation to power flows.

- For baseline projects operating at 345 kV or below identified based on EKPC FERC Form 715 filed planning criteria, each project estimated to cost less than $5,000,000 is allocated entirely to the EKPC zone.
- For each baseline project estimated to cost $5,000,000 or more, the cost is allocated based 100% on the solution-based DFAX analysis.

Request 39d. Explain what steps EKPC takes if PJM does not verify a need for a transmission plan identified by EKPC's local planning process.

Response 39d. The coordination between PJM and EKPC regarding these baseline projects identified by EKPC through application of its FERC Form 715 filed planning criteria includes sharing of models, criteria, assumptions, critical contingencies, and generation dispatch scenarios. Therefore, PJM has available and utilizes the exact information used by EKPC to determine the need. This has resulted in PJM verifying all baseline needs identified by EKPC since EKPC joined PJM in 2013.

EAST KENTUCKY POWER COOPERATIVE, INC.
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STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 40
RESPONSIBLE PERSON: Patrick C. Woods
COMPANY: East Kentucky Power Cooperative, Inc.

Request 40. Refer to the IRP, Section 6.0, page 96, which states that PJM and EKPC bare jointly responsible for 18 Reliability Standards.

Request 40a. Explain how EKPC and PJM, respectively, ensure compliance with these reliability standards.

Response 40a. Upon EKPC's integration with PJM in 2013, PJM assumed responsibility for all or parts of some of the NERC Reliability standards which had previously been the sole responsibility of EKPC. For those standards for which EKPC remained wholly responsible, EKPC's Compliance department staff oversee the Cooperative's efforts to ensure compliance. Similarly, PJM has a dedicated compliance staff which oversees its efforts to ensure compliance with the standards for which it is wholly responsible.

For those standards which are overseen jointly by both EKPC and PJM, the two entities work closely together to ensure compliance using a PJM-developed document that details the tasks to be performed by EKPC, the tasks to be performed by PJM, and the evidence of compliance that is to be provided by EKPC to PJM for use during audits of PJM by Regional Reliability Organizations such as SERC and ReliabilityFirst. In addition, to ensure EKPC compliance efforts are being undertaken to PJM requirements, PJM periodically audits EKPC. The last such audit took place in 2019.

Request 40b. Explain how the costs for the joint compliance are allocated between EKPC and PJM, and explain whether PJM's costs are socialized across PJM's footprint.

Response 40b. The cost of compliance is the manpower to manage the policies, procedures, and processes needed to ensure compliance and the cost of equipment necessary to comply. The equipment costs are born by the transmission owner (EKPC) and not socialized across the PJM footprint. The manpower costs are born by the party who is responsible for the activity. EKPCs manpower costs are not socialized across the PJM footprint. PJMs manpower costs are socialized across the footprint through the administrative fees collected from the members.

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STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 41
RESPONSIBLE PERSON: Darrin Adams
COMPANY: East Kentucky Power Cooperative, Inc.

Request 41. Refer to the IRP, Section 6.0, page 96. Provide any potential operating problems identified by SERC for EKPC since the filing of this IRP report.

Response 41. Since EKPC filed this IRP report, the SERC Near Term Working Group ("NTWG") has performed reliability studies for the 2019 Summer and 2019/20 Winter periods. The purpose of these studies is to evaluate the future performance of the interconnected electric systems within SERC for those peak periods. No potential operational concerns were identified by the SERC NTWG for either of these periods.

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FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 42
RESPONSIBLE PERSON: Darrin Adams
COMPANY: East Kentucky Power Cooperative, Inc.

Request 42. Refer to the IRP, Section 6.0, page 97. Provide EKPC's transmission losses for the five calendar years ending December 31, 2019.

Response 42. EKPC's total energy losses on its transmission system for the 2015-2018 period are provided below. EKPC has not yet finalized calculation of its transmission-system losses for calendar year 2019.

Year	EKPC Transmission-System Energy Losses (MWh)	Percentage of Total Energy Requirements
2015	293,311	2.4%
2016	357,506	2.8%
2017	330,944	2.7%
2018	336,660	2.5%

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FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 43
RESPONSIBLE PERSON: Mary Jane Warner
COMPANY: East Kentucky Power Cooperative, Inc.

Request 43. Refer to the IRP, Section 6.0, page 98. Provide the cost benefit analysis used to determine the transmission expansion projects that are added to EKPC's Transmission Expansion Plan.

Response 43. EKPC does not typically perform a cost-benefit analysis, since there are generally minimal quantifiable economic benefits associated with a transmission expansion project. The primary drivers of these projects are typically maintaining and/or enhancing reliability and ensuring adequate capacity and system performance. EKPC uses a variety of inputs to determine where a need exists and to provide direction in developing potential solutions. These inputs include items such as outage history, ability to back-feed interrupted load, service restoration capability, equipment condition, and ongoing maintenance requirements. These drivers do not usually correspond with a value of cost savings. In many cases, the transmission project identified was determined to be the most cost-efficient solution through engineering judgment based on operational experience and past project costs (for example, installing a transmission capacitor bank in an area to address inadequate voltage level in that area is known to typically be the least-cost solution given the relative cost of a capacitor bank installation versus other alternatives, whether re-conductoring a line, building a new line, or building a new transmission substation). Likewise, EKPC uses engineering judgment to select the projects that are in the later portion of the planning horizon. EKPC will re-assess each of those projects when the need is in the near-term horizon (typically less than five-years) to ensure that the original project identified remains the preferred solution.

For some projects in the transmission expansion plan, alternatives were identified and evaluated, and the final project was selected holistically, considering cost, improvement or risk of degradation in system performance, operational and maintenance flexibility, future expansion needs, etc.

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STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 44
RESPONSIBLE PERSON: Darrin Adams/Tom Stachnik
COMPANY: East Kentucky Power Cooperative, Inc.

Request 44. Refer to the IRP, Section 6.0, page 99, regarding the planned improvements to the EKPC transmission system for the period from 2019 to 2022 summary.

Request 44a. Identify the projects that EKPC plans to file future CPCN for and when EKPC plans to file the CPCNs, if any.

Response 44a. Regarding planned improvements to the EKPC transmission system for the period from 2019 to 2022, EKPC has not yet identified any projects that will require a CPCN. As EKPC continues to develop these projects to refine the scope and the project costs, a decision may be made that applying for a CPCN is required for one or more of the projects.

Request 44 b. If EKPC has already filed CPCNs related to the planned projects, then provide the Case Number.

Response 44 b. EKPC has not filed an application for a CPCN for any of the projects identified in the 2019-2022 period in the IRP.

Request 44c. If EKPC does not plan to file CPCNs for the projects, then explain how EKPC plans to fund those projects.

Response 44c. EKPC will be able to use its working capital and Credit Facility to finance the referenced projects. Over the long-term, EKPC intends to convert that short-term debt to a long-term debt – either with RUS or a private placement through EKPC's existing Trust Indenture.

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STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 45
RESPONSIBLE PERSON: Mary Jane Warner
COMPANY: East Kentucky Power Cooperative, Inc.

Request 45. Refer to the IRP, Section 6.0, page 101, regarding the third paragraph under Generation Related Transmission. Explain if this paragraph has changed since the filing of this IRP report.

Response 45. The statement contained in the referenced paragraph remains valid at this time.

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STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 46
RESPONSIBLE PERSON: **Mary Jane Warner**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 46. Refer to the IRP, Section 7.0, page 116. Regarding the statement, "Prior to requesting this approval, an analysis is conducted taking into account costs, timing, and benefits of the project". Provide the analysis.

Response 46. Most of EKPC's projects are justified based on a critical safety need, necessary compliance to an environmental regulation, or as a requirement to meet operational reliability of units. For an example of EKPC projects requiring a more detailed analysis, such as the construction of dual fuel capability at Bluegrass Station, please refer to pages 2 through 20 of this response for a copy the Bluegrass Capacity Penalty Risk Analysis.

NAVIGANT

Bluegrass Capacity Penalty Risk Analysis

Prepared for:

East Kentucky Power Cooperative

EAST KENTUCKY POWER COOPERATIVE
A Touchstone Energy Cooperative

Submitted by:
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July 31, 2018

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1. INTRODUCTION AND SUMMARY

Navigant was retained by East Kentucky Power Cooperative (EKPC) to perform an evaluation of PJM[1] capacity penalties during Performance Assessment Hours (PAHs) at the Bluegrass Generating Station (Bluegrass) under various potential alternative fuel arrangements. Bluegrass consists of three simple-cycle natural gas-fired combustion turbines of 198 MW (winter) and 165 MW (summer) each located in Oldham County, Kentucky. Each Bluegrass unit has an unforced capacity (UCAP) value in the PJM capacity market of approximately 159 MW, yielding a station total of 477 MW.[2]

Based on widespread generating unit unavailability during the January 2014 Polar Vortex event, PJM instituted capacity performance requirements for PJM generating resources, which phase in over the 2016 to 2020 period. PJM calls PAHs in emergency conditions, and capacity performance resources must be available to provide energy during PAHs throughout the delivery year or be assessed non-performance charges. Beginning in the 2020/21 PJM delivery year, Bluegrass is required to be bid as a capacity performance resource in the PJM capacity market and is subject to PJM non-performance charges if the units at the station fail to supply their UCAP during PAHs.

Bluegrass could be unavailable during PAHs for two primary reasons, a forced outage or natural gas unavailability. For Bluegrass, non-performance charges would be about $1.4 million for a single PAH and could reach as high as $79 million in a single year. This compares to the annual value of Bluegrass in the PJM capacity market of $24 million using 2021/2022 capacity performance prices. As a result, EKPC is considering alternatives to limit fuel unavailability at Bluegrass, including firm gas service during all or parts of the winter season and installation of back-up fuel oil or LNG capability.

Table 1. Bluegrass Fuel Alternatives Overview

Fuel Alternative	Levelized Fixed Cost (M$/year)	Max 1-Year Penalty Across Scenarios Examined (M$)	PV Benefits (Cost) across Scenarios Relative to Status Quo (M$)	Additional Available PAHs Needed to Breakeven with Status Quo over 20 years
Status Quo	$0.0	$17 / $65	--	--
24-hr STF Dec-Feb.	$7.0	$1 / $4	($91) to $10	60
16-hr EFT Dec.-Feb.	$5.5	$1 / $4	($71) to $30	47
24-hr STF Winter	$11.7	$1 / $4	($154) to ($52)	100
16-hr EFT Winter	$9.1	$1 / $4	($120) to ($19)	79
LNG	$6.0	$1 / $4	($78) to $23	51
Fuel Oil	$4.8	$1 / $4	($62) to $38	42

Each of the fuel alternatives identified for Bluegrass (firm gas, LNG, fuel oil) provides similar and substantial risk mitigation against a major single year capacity penalty. The fuel oil alternative is the lowest cost alternative at Bluegrass and represents the most economic means to mitigate capacity penalty risk. Over a 20-year period, Bluegrass would need to be available in only about 42 more PAHs to cover the cost of the fuel oil alternative. However, to reach this level of additional PAHs, there would

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[1] PJM Interconnection, LLC (PJM) is a regional transmission organization (RTO) that manages grid operations and administers the energy, capacity, and ancillary service markets in all or parts of 13 mid-Atlantic and Midwestern states, and the District of Columbia.

[2] Bluegrass summer rating of 165 MW multiplied by (1 minus the Bluegrass EFOR of 3.60%)

need to be enough future PAHs in PJM in which there was a gas interruption on the pipeline serving Bluegrass during the PAHs. Based on the scenarios analyzed in this study, the fuel oil alternative may not pay for itself over 20 years in present value terms. If so, the fuel oil alternative still will provide valuable “insurance” against high single year capacity penalties of as much as $79 million.

Firm Gas Alternatives. At Bluegrass, firm transportation (FT) for gas can be procured from Texas Gas Pipeline for a full-year, or on a monthly basis under short-term firm (STF) at a higher monthly cost. With FT or STF, the contracted amount of firm gas must be spread evenly or “ratably” over the hours in a day (i.e., the maximum hourly amount is 1/24th of the total), which makes it relatively costly for peaking capacity like Bluegrass. Enhanced firm service (EFT) is available at an extra cost which allows the maximum gas quantity in each hour to be 1/16th of the contracted amount. With natural gas unavailability being unlikely in the summer, Navigant examined the alternatives of procuring STF or EFT over the full winter (November to March) and for a more cost-effective 3-month winter period (December to February).

Fuel Oil/LNG Alternatives. Fuel oil capability at Bluegrass will require an estimated $63 million in capital along with additional annual fixed O&M cost and variable O&M charges. LNG capability is estimated to require $81 million in capital along with additional annual fixed O&M and fuel carrying costs.

Levelized Cost of Fuel Alternatives. Table 1 shows the 20-year levelized fixed cost of the fuel alternatives, which range from $4.8 to $11.7 million per year (2018$). These costs could be categorized as the cost of “insurance” against incurring major penalties. Fuel oil is the lowest cost alternative. Procuring EFT from December to February is the next lowest cost alternative, but, unlike fuel oil, does not cover fuel interruptions in any PAHs that could take place in the November or March winter months.

Scenarios Examined. The economics of the Bluegrass fuel alternatives are highly dependent on two uncertain variables, the number of PAHs in the future in the EKPC PJM zone, and the likelihood of gas pipeline interruptions at Bluegrass during these PAHs. As shown in Table 2, Navigant developed *Low*, *Mid* and *High* cases to assess the impact of these two variables yielding 9 total scenarios *(3 x 3)*.

Table 2. PAH and Gas Interruption Cases Analyzed

	Low Case	Mid Case	High Case
Performance Assessment Hours	Polar Vortex every 20 Years with 20 Winter PAHs	Polar Vortex every 10 Years, each with 20 Winter PAHs	Polar Vortex every 5 years, w/four times severity every 10 (80 PAHs)
Gas Interruption during PAHs	5% (1 in 20 Winter PAHs)	20% (1 in 5 Winter PAHs)	33% (1 in 3 Winter PAHs)

The PAH cases are based on the frequency of a Polar Vortex event. Since 2012, there have been no PAHs relevant to EKPC other than during the 2014 Polar Vortex, which had 20 PAHs impacting the EKPC zone. To reflect more severe weather, a 80-PAH polar vortex event every 10 years was included in the *High PAH Case*, based on the most impacted region of PJM during the 2014 Polar Vortex.

Natural gas in the EKPC region during the 2014 Polar Vortex was not interrupted at the EKPC Smith unit, or at Indiana PJM units served from the same pipeline as Bluegrass. However, there have been a number new gas plants on the Texas Gas Pipeline in the PJM area since 2014. The gas interruption cases above were selected to capture a potential range of gas interruptions.

Risk Mitigation. To assess EKPC capacity penalty risk exposure, Table 3 shows the maximum single delivery year penalty incurred across the 9 scenarios examined. This maximum penalty would take place during a polar vortex event year. As reference points, results for 0% and 100% gas interruption during PAHs are also shown (shaded). Each of the fuel alternatives similarly mitigates the maximum single year penalty across the nine scenarios examined, and thus are not listed separately.

Table 3. Maximum Single-Year Penalty in Scenarios Examined (M$2018)

Annual PAHs -->	Polar Vortex (20 PAHs)					Quadruple Polar Vortex (80 PAHs)				
Gas Interuption in PAHs-->	0%	5%	20%	33%	100%	0%	5%	20%	33%	100%
Status Quo	1.0	2.4	7.8	16.7	28.1	3.9	9.2	30.4	65.2	78.9
All Fuel Alternatives	1.0	1.0	1.0	1.0	1.0	3.9	3.9	3.9	3.9	3.9

As shown, the fuel alternatives substantially reduce the potential maximum single year penalty, but the avoided penalty is dependent on the severity of the polar vortex event (e.g., 20 PAHs or 80 PAHs) and the level of gas interruption (e.g., 5%, 20%, or 33%). For example, if there is a 20-PAH polar vortex event and Bluegrass gas was interrupted during 20% of those PAHs (4 hours), the capacity penalty would be $7.8 million. The penalty is never zero in Table 3 given the non-fuel forced outage rate of Bluegrass (3.6%).

PV Benefit/(Cost). Making Bluegrass available in a single PAH would avoid $1.4 million in non-performance charges, but also yield $0.6 million in bonus payments and $0.4 million in energy margins, yielding an incremental net benefit of $2.4 million. Comparing incremental net benefits to the levelized cost of each fuel alternative across the 9 scenarios examined yields the present value benefit (cost) range shown in Table 1. As shown, the range extends from a negative to positive benefit, with fuel oil having the highest benefits.

The last column in Table 1 shows the increased number of available PAHs for Bluegrass to cover the fixed costs of each fuel alternative (i.e., a $0 present value). The fuel oil alternative requires only an additional 42 available PAHs over the 20-year period. Given that penalty risk mitigation is similar (and substantial) across the fuel alternatives[3], the alternative with the lowest levelized cost (fuel oil) is the most economical alternative to select. However, to decide whether the fuel oil alternative is desirable relative to the *Status Quo*, risk mitigation must be assessed against cost.

Risk/Cost Trade-off. Based on our assessment, the fuel alternatives may not pay for themselves under a “most likely” future of likely limited gas interruptions and should be viewed as a type of insurance against bad outcomes. This is illustrated for the fuel oil alternative in Figure 1, which shows the present value of benefits/(costs) over a 20-year period under a *Low*, *Mid* and *High PAH Cases*, as a function of gas interruption percentage at Bluegrass during PAHs.

As shown, under the *Mid PAH Case*, gas interruption during PAHs would need to reach nearly 100% for the fuel oil alternative to achieve a positive overall present value benefit. Under the *Low PAH Case*, the fuel oil alternative never achieves a positive overall present value benefits. However, if PAH hours are more severe as in the *High PAH Case*, Bluegrass gas interruption during PAHs would need to be only about 20% or higher for the alternative to yield an overall present value benefit.

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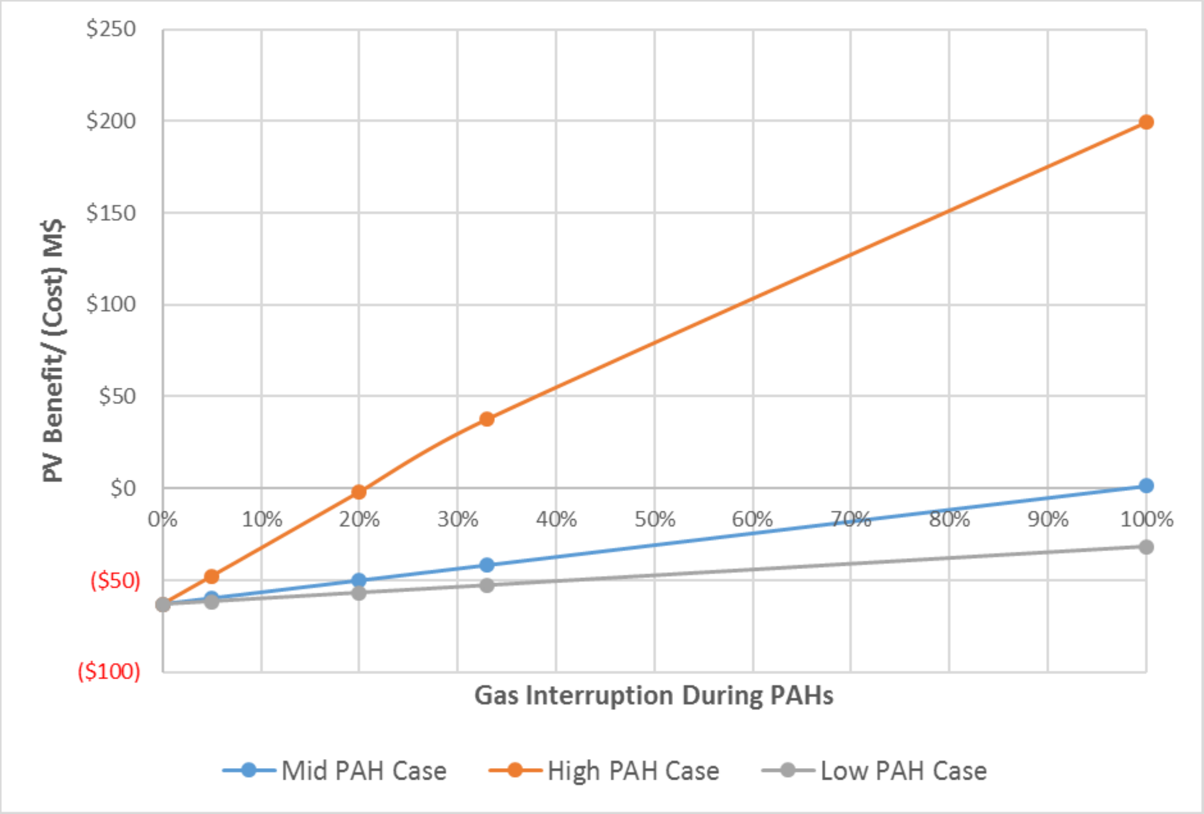
[3] However, within the firm gas alternatives, the 3-month (December to February) procurement of firm gas does not cover any PAHs caused by gas interruption that might take place in November or March.

The single year risk reduction results in Table 3 must be compared to net 20-year benefits in Figure 1 to weigh cost in comparison to risk. The fuel oil alternative may not pay for itself on a present value basis absent severe weather events and Bluegrass gas interruption. Just like any type of insurance, this must be weighed against the risk mitigation the fuel alternative provides by limiting single year penalties.

Figure 1: PV Benefit/(Cost) of Fuel Oil Alternative as a Function of PAHs and Gas Interruption



Other Considerations

- Fuel oil also would help hedge against short-term natural gas price spikes, and the new burners required could yield additional Bluegrass operating hours without exceeding annual NOx limits.
- Forced outage rates can be higher for dual-fuel units switching fuels, particularly during severe weather, if the dual-fuel capability is not regularly tested.
- If fuel oil or LNG is heavily used during a short period, there is the potential for the alternative fuel to run out, particularly if transportation to Bluegrass is limited by a weather event.
- Firm gas service can be turned “on” or “off” as future events unfold. However, firm transportation may not be available if not contracted for a longer time-frame.
- Limiting firm gas to selected months does not mitigate the lower, but still finite, risk of fuel unavailability during a PAH in the other months, while fuel oil and LNG largely mitigate this risk.
- Firm gas contract prices are negotiable and could be less than the maximum tariff rates used here. With STF, overage charges could be used to allow for additional delivery in an hour; however, the long-term reliance on the use of overage during a PAH is likely problematic.

- With capacity performance in place, the likelihood of PAHs should be reduced as owners seek to ensure their plants will be available. This may also increase hourly balancing ratios from recent history, making penalties higher and bonuses lower in a given PAH.
- Use of on-site LNG as a back-up fuel for CTs in the Midwestern U.S. is relatively uncommon, making the potential costs for this alternative more uncertain.
- Other uncertainties such as changes in the PJM capacity performance rules, and early retirement of Bluegrass for unrelated reasons, were not considered in this analysis.

2. BACKGROUND AND ASSUMPTIONS

2.1 Historical Performance Assessment Hours

PJM's non-performance charge was formulated by PJM assuming an average of 30 PAHs during any delivery year, although actual PAHs in recent years have been much lower, including in 2014 during the Polar Vortex event. EKPC has not had a PAH called specifically for the EKPC PJM zone since joining PJM, so the best estimate of PAHs for Bluegrass is those called for the full PJM region. As shown in Table 5, there were about 20 PAH for the full PJM RTO in the 2013/14 delivery year during the Polar Vortex, but no PAHs in the last four years. PJM has stated that a Polar Vortex event like that in 2014 could be expected to take place about once every 10 years.[4]

Table 4. PJM Annual Performance Assessment Hours (PAHs) for Full PJM RTO

Delivery Year	Winter Months	Other Months	Total
2012/13	0	0	0
2013/14	20.27	0	20.27
2014/15	0	0	0
2015/16	0	0	0
2016/17	0	0	0
2017/18	0	0	0

2.2 Potential Bluegrass Capacity Penalties

The non-performance charge would be about $1.4 million if the entire Bluegrass station was unavailable during a single PAH.[5] While non-performance penalties for a particular unit have an annual cap, Bluegrass could potentially face an annual penalty of as high as $79 million if the station were unavailable during enough PAHs. This compares to the annual value of Bluegrass in the PJM capacity market of $24 million per year using the most recent 2021/22 delivery year price of $140/MW-day for capacity performance resources in the Rest of RTO region.[6]

Table 5. Potential Annual Penalties for Bluegrass if Unavailable During PAHs ($M 2018)

Annual PAHs	Potential Annual Non-Performance Penalty (M$)	Bluegrass Capacity Value @2019/20 price (M$)	Potential Annual Penalty as % of Annual Capacity Value
10	$14	$24	57%
30	$41		170%
58 or more	$79		325%

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[4] PJM Response to FERC Data Request for January 2014 Weather Events (http://www.pjm.com/~/media/library/reports-notices/weather-related/20140113-pjm-response-to-data-request-for-january%202014-weather-events.ashx)

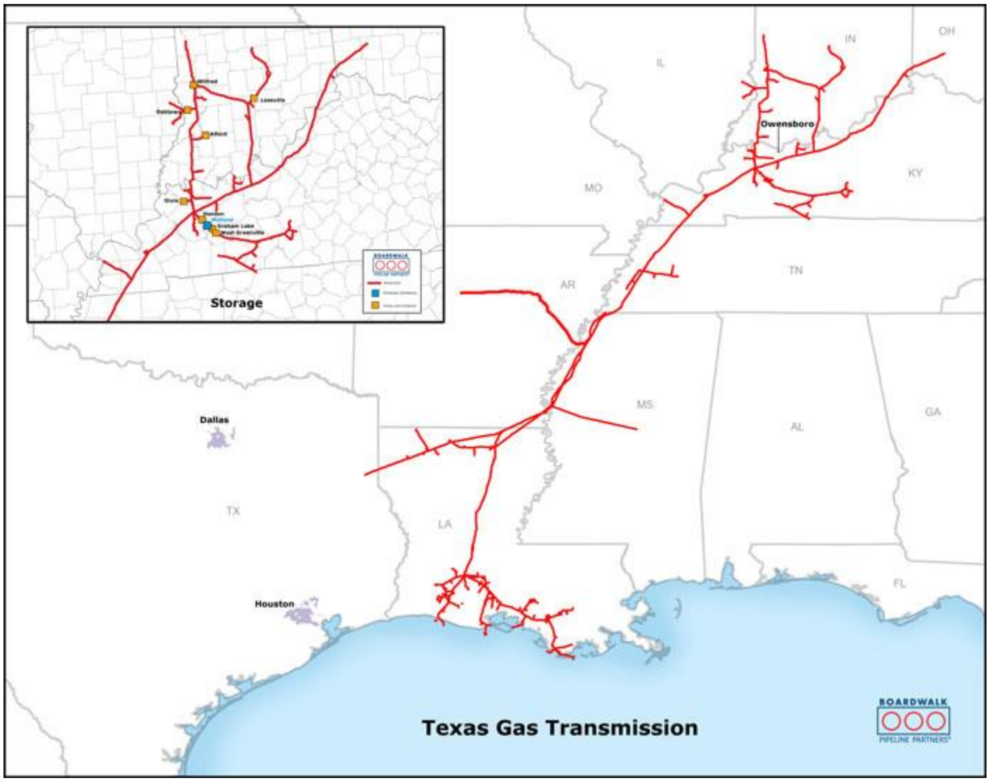
[5] Penalty of $3,687/MWh multiplied by Bluegrass station UCAP of 477 MW and applying a 78.5% Balancing Ratio. The penalties for each unit are subject to an annual cap of 150% of Net CONE. Actual hourly penalties could be higher or lower depending on the balancing ratio during the hour.

[6] $140/MW-day * 477 MW UCAP * 365 days

2.3 Bluegrass Existing Fuel Supply

Natural gas is delivered to Bluegrass by the Texas Gas Transmission pipeline under interruptible service.[7] The Texas Gas system (see Figure 1) is composed of 6,025 miles of pipeline having an average daily throughput of approximately 2.4 billion cubic feet (Bcf) per day in 2016; and has nine natural gas storage fields located in Indiana and Kentucky, which have approximately 84.3 Bcf of working gas capacity.[8]

Figure 2: Texas Gas Transmission Pipeline



2.4 Bluegrass Fuel Alternatives

Given the size of the potential capacity penalties, EKPC is considering alternatives to avoid or limit natural gas unavailability, including firm gas service, and installation of fuel oil or LNG storage.

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[7] IT service is subject to interruption both at the receipt and delivery points, with a scheduling priority based on an economic queue. Firm natural gas supplies which require fixed monthly charges are usually not economic to procure for simple cycle combustion turbines given the relatively low number of hours that the units are called upon to operate over the year.

[8] The principal sources of supply for Texas Gas are regional supply hubs and market centers: offshore Louisiana; Perryville, Louisiana; Henry Hub; Agua Dulce; and Carthage, Texas; Wellhead supplies: Fayetteville Shale in Arkansas, East Texas, northern and southern Louisiana and Mississippi; and Canadian natural gas through a pipeline interconnect with Midwestern Gas Transmission Company at Whitesville, Kentucky. http://www.txgt.com/AboutUsTXGT.aspx

At Bluegrass, natural gas firm transportation can be procured from Texas Gas Pipeline for a full-year (FT)[9], or for a short-term firm (STF)[10] monthly basis at a higher monthly reservation price. With FT or STF, the contracted amount of firm gas must be spread over the hours in a day evenly (i.e., the maximum hourly amount is 1/24th of the total), which makes it relatively prohibitive in cost for a peaking unit like Bluegrass. Enhanced firm gas service (EFT)[11] is available at an extra cost which allows the maximum gas quantity in each hour to be 1/16th of the contracted amount. With natural gas unavailability being unlikely in the summer, we examined the alternatives of procuring STF or EFT over the full winter (November to March) and for a more cost-effective 3-month period (December to February).

Fuel oil or LNG capability and storage would require a significant one-time capital cost to implement at Bluegrass, as provided by EKPC, along with annual fixed O&M and fuel carrying costs. The estimated cost of each fuel alternative is summarized in Table 6.

Table 6. Annualized Cost of Bluegrass Fuel Alternatives

Fuel Alternative	One-Time Capital Cost (2020 Nom$)	Annual Costs $M 2018)	Total Levelized Annual Cost Over 20 Years ($M 2018)
STF Gas Dec-Feb.	--	$7.0	**$7.0**
EFT Gas Dec.-Feb.	--	$5.5	**$5.5**
STF Gas Winter	--	$11.7	**$11.7**
EFT Gas Winter	--	$9.1	**$9.1**
LNG	$81.0	$0.5	**$6.0**
Fuel Oil	$62.8	$0.5	**$4.8**

2.5 Penalties and Benefits

Non-performance penalties collected by PJM in any PAH are distributed back as bonus revenues to any generating units that performed above their expected performance value during the PAH. As PAHs are generally driven by extreme weather, high energy prices also usually take place during PAHs resulting in high energy margins for any units available to operate. Based on historical EKPC prices during winter PAHs over the 2013/14 delivery year (which accounts for all of the recent winter RTO-wide PAHs), we assumed Bluegrass energy margins would be approximately $600/MWh (2018$) during winter PAHs.

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[9] Firm Transportation Service (FT): Provides customers with nominated firm transportation service from designated receipt points to designated delivery points. The firm transportation contract demand must be a daily transportation quantity which is the same for each day of the contract term, which term must be for at least 12 consecutive months of service. FT Service provides customers with firm hourly deliveries up to 1/24th of their firm transportation contract demand.

[10] Short Term Firm Transportation Service (STF). Similar to Texas Gas' FT Rate Schedule except that STF shall be for a term of less than 12 consecutive months, or the daily contract demand may vary by month or season over the term of an agreement one year or longer in length. The seasonal nature of this service is reflected in its peak (winter) and off-peak (summer) rates.

[11] Enhanced Firm Transportation Service (EFT): Available to Texas Gas customers who have transportation service agreement under the FT or STF Rate Schedule. EFT service permits customers to receive deliveries of gas at a variable hourly flow rate up to one-sixteenth (1/16th) of their contract demand except when given notice to customers that EFT service is unavailable.

As shown in Table 7, if Bluegrass is unavailable during a winter PAH, non-performance charges of \$3,687/MWh would apply to the Bluegrass station UCAP of 477 MW multiplied by a 78.5% Balancing Ratio (BR), yielding a charge of \$1.4 million (2018\$).[12] If Bluegrass is available,1) bonus payments of \$2,949/MWh[13] would apply to the 594 MW winter rating net of the UCAP times BR obligation, and 2) energy margins of \$600/MWh would apply to the 594 MW output, yielding a benefit of \$1.0 million. Thus, the net incremental benefit of being available during a single winter PAH is about \$2.4 million (2018\$).

Table 7. Net Benefit of Bluegrass Being Available During a Winter PAH (\$2018)

		--------- Benefit / (Cost) --------			
		\$/MWh	**Applicable MW**		**Total M\$**
If Unavailable:	**Non-Performance**	(\$3,687)	374	*UCAP*BR*	(\$1.38)
If Available:	**Bonus Payment**	\$2,949	220	*ICAP-(UCAP*BR)*	\$0.65
	Energy Margin	\$600	594	*ICAP*	\$0.36
					\$1.00
Net Incremental Benefit of Being Available					\$2.38
ICAP = 594 MW, UCAP = 477 MW, Balancing Ratio (BR) = 0.785					

2.6 Breakeven PAH for Each Alternative

Using the above net benefit for the Bluegrass station being available during a PAH, the breakeven number of PAHs for each fuel alternative to cover its levelized costs over 20 years can be calculated. As shown in Table 8, Bluegrass would only need to become available in an additional 42 winter PAHs over a 20-year period for the fuel oil to become economic. While this is a relatively low number of hours over 20 years, a key question is: 1) how often PAHs will take place in PJM in the future, and 2) how often would gas be interrupted at Bluegrass during these PAHs thereby making the fuel alternative relevant.

Table 8. Additional Available PAHs Needed to Breakeven for Fuel Alternatives (\$M 2018)

Fuel Alternative	Levelized Annual Cost (M\$) A	Net M\$ Benefit of Being Available per PAH B	Additional Available PAHs over 20 Years to Breakeven A/B * 20
STF Gas Dec-Feb.	\$7.0	\$2.33	60
EFT Gas Dec.-Feb.	\$5.5	\$2.33	47
STF Gas Winter	\$11.7	\$2.33	100
EFT Gas Winter	\$9.1	\$2.33	79
LNG	\$6.0	\$2.33	51
Fuel Oil	\$4.8	\$2.29	42

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[12] BR is the ratio of actual PJM generation to total committed PJM generation in the PAH. 78.5% was the average BR in 2014-16.

[13] This \$/MWh figure would be identical to the non-performance charge, except a 20% dilution in bonuses is assumed for demand response coming on-line during a PAH and for selected excusals by PJM. Actual PJM data over time will help refine this figure.

[14] These net benefit per PAH figures incorporate the energy margins for each alternative (\$650/MWh for firm gas, \$662/MWh for LNG (pre-purchased at a non-peak price), and \$578/MWh for fuel oil). The net benefit is reduced by the Bluegrass EFOR of 3.6%, because if the plant is on forced outage, the fuel alternative will not provide a benefit. Start-up costs are not included.

3. SCENARIO ANALYSIS

3.1 Number of Future PAHs

PJM has noted that the chance of a 2014 Polar Vortex event is approximately one in 10 years. As shown in Table 9, Navigant developed three PAH Cases, *Low*, *Mid* and *High*, to analyze based on the PAHs in 2014 during the 2014 Polar Event. In the *Low PAH Case*, a Polar Vortex event was assumed to take place in the EKPC zone once during the 20-year evaluation period. In the *Mid PAH Case*, a Polar Vortex event was assumed to take place once every 10 years, or twice during the 20-year evaluation period.

Table 9. PAH Cases Analyzed[15]

	Low PAH Case	Mid PAH Case	High PAH Case
Performance Assessment Hours	Polar Vortex every 20 Years with 20 Winter PAHs	Polar Vortex every 10 Years, each with 20 Winter PAHs	Polar Vortex every 5 years, with quadruple severity every 10 years (80 PAHs)

In the *High PAH Case*, a Polar Vortex event is assumed to take place every 5 years, or 4 times during the 20-year evaluation period. In addition, in the *High PAH Case*, two of the Polar Vortex events are assumed to have 4 times as many PAHs during that winter, based on the PAHs that took place in the most impacted region of PJM during the 2014 Polar Vortex. While these cases are intended to capture the possible range of PAH outcomes, in practice, the actual number of PAHs in the EKPC zone could be outside of the ranges modeled here.

3.2 Likelihood of Bluegrass Gas Interruption

The overall economics of the fuel alternatives at Bluegrass depend predominately on whether gas will be interrupted at the station during a PAH. Absent gas interruption, only a forced outage would result in significant capacity penalties, and this forced outage risk is similar with or without firm gas or back-up fuel.[16] There are a number of considerations in evaluating the likelihood of gas interruption at Bluegrass:

- Natural gas was not interrupted at the EKPC Smith station during the 2014 Polar Vortex PAHs.[17]
- Gas was not interrupted for other PJM units in Indiana located on the Texas Gas pipeline during the 2014 Polar Vortex.[18]
- There were no winter PAHs affecting EKPC in 2015 through 2018, thus there is no data as to whether natural gas would have been interrupted at Bluegrass since the 2014 Polar Vortex.

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[15] In all cases, 7 non-winter month PAHs were assumed to take place, with no gas interruption at Bluegrass during those PAHs. For simplicity, no PAHs were modeled in years without a Polar Vortex event. PJM analysis of historical data suggests that no winter PAHs occurred over a ten-year sample period outside of the year with the Polar Vortex event.

[16] A separate analysis of the impact of forced outages rates on capacity penalties is presented later in this report.

[17] Bluegrass was not a generating resource in PJM until EKPC's acquisition of the station in 2015. Smith has access to three pipelines, while Bluegrass is only served by the Texas Gas pipeline

[18] Specifically, the Texas Gas pipeline was not included in the list of interrupted pipelines in PJM's *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events* (http://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx). Bluegrass was not a part of PJM at the time, but other PJM units were served by the pipeline.

- With much more natural storage in western PJM than in eastern PJM, the likelihood of gas interruption is likely lower in the west (e.g., EKPC).
- There have been recent coal retirements and natural gas-fired additions in the Ohio, Indiana, Kentucky, and Tennessee region of the Texas Gas pipeline since winter 2014, possibly placing additional strain on gas supplies. Several more are planned in the next few years.
- Longer term, there may be additional development of shale gas in Western Kentucky near the Texas Gas pipeline that potentially could increase local gas supplies.

Given this uncertainty in the level of gas interruptions, to help frame the evaluation of risk, three gas interruption scenarios were developed and evaluated as shown in Table 10. In the *Low Gas Interruption Case*, a 5% chance of gas interruption (1 in 20 hours) at Bluegrass during a winter PAH was assumed. In the *Mid Gas Interruption Case*, a 20% chance (1 in 5 PAHs) *was assumed.* In the *High Gas Interruption Case*, a 33% chance of gas interruption (1 in 3 PAHs) was assumed.

Table 10. Gas Interruption Cases Analyzed

	Low Case	Mid Case	High Case
Gas Interruption During PAHs	5% (1 in 20 Winter PAHs)	20% (1 in 5 Winter PAHs)	33% (1 in 3 Winter PAHs)

Again, gas interruption during PAHs could be outside of these ranges. Given the 2014 Polar Vortex experience, there may be no gas interruption at Bluegrass during PAHs in any particular year. If so, the levelized cost of the fuel alternative could be viewed as the cost of "insurance" purchased in which the were no offsetting "claims".

3.3 Scenario Analysis

The PAH and gas interruption cases were combined to create 9 scenarios, and non-performance charges, bonus payments and energy margins were calculated and netted for each scenario. The analysis was performed over a 20-year period from the 2020/21 delivery year to 2039/2040.[19]

3.3.1 Risk Mitigation: Maximum Annual Penalty Under Each Fuel Alternative

To assess EKPC capacity penalty risk exposure, Table 11 shows the maximum single delivery year penalty incurred across the 9 scenarios examined. This maximum penalty takes place during a polar vortex event year. As reference points, results for 0% and 100% gas interruption during PAHs are also shown (shaded). Each of the fuel alternatives similarly mitigates the maximum single year penalty across the nine scenarios, and thus are not listed separately.

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[19] A 2.0% inflation rate was assumed, and a 5.93% EKPC discount rate was applied to determine present values. See Appendix A for a detailed list of input assumptions applied.

Table 11. Bluegrass Maximum Annual Capacity Penalty (M$ 2018)

Annual PAHs -->	Polar Vortex (20 PAHs)					Quadruple Polar Vortex (80 PAHs)				
Gas Interuption in PAHs-->	0%	5%	20%	33%	100%	0%	5%	20%	33%	100%
Status Quo	1.0	2.4	7.8	16.7	28.1	3.9	9.2	30.4	65.2	78.9
All Fuel Alternatives	1.0	1.0	1.0	1.0	1.0	3.9	3.9	3.9	3.9	3.9

As shown, the fuel alternatives substantially reduce the potential maximum single year penalty, but the avoided penalty is dependent on the severity of the polar vortex event (e.g., 20 PAHs or 80 PAHs) and the level of gas interruption (e.g., 5%, 20%, or 33%). For example, if there is a 20-PAH polar vortex event and Bluegrass gas was interrupted during 20% of those PAHs (4 hours), the capacity penalty would be $7.8 million. The penalty is never zero in Table 11 given the forced outage rate of Bluegrass (3.6%).

3.3.2 Present Value Benefit (Cost) under each Alternative

While Table 11 above focuses on non-performance charges, the economic impact of the fuel alternatives must take into account the significant impact of bonus payments and energy margins that would be obtained place during a PAH if Bluegrass is available to operate. Captured in Table 12 is the present value of each fuel alternative relative to the *Status Quo*, under a *Low*, *Mid* and *High* number of future PAHs, and a *Low*, *Mid* and *High* probability of gas interruptions during these winter PAHs. For results framing, 0% and 100% gas interruption during winter PAHs are also included *(shaded rows)*.

As shown in Table 12A and 12B, in the *Low and Mid PAH Cases*, none of the alternatives yield a positive present value if gas interruption is 33% or lower. In the *High PAH Case* (Table 12C), the fuel oil alternative has a positive present value if gas interruption is just above 20% or higher, and the two December to January firm gas options yield a positive present value if gas interruption levels are 33% or higher.

As shown in Table 12B, if there is a polar vortex every 10 years *(Mid PAH Case)*, and the Bluegrass gas interruption percentage during the polar vortex is 20% *(Mid Gas Interruption Case)*, then the present value benefit of the fuel oil alternative would be negative $50 million, a net cost. In effect, the fuel oil alternative saves $13 million *(2018 present value)* of the alternative's $63 million full cost *(2018 present value)* by allowing Bluegrass to be available during some of the PAHs when it otherwise would not.

Table 12. Present Value Benefits/(Cost) of Each Fuel Alternative (M$, 2018 Present Value)

A. Low PAH Case *(1 Polar Vortex in 20 years)*

Gas Interrupt %	STF (Dec-Feb)	EFT (Dec-Feb)	STF-Winter	EFT-Winter	LNG	Fuel Oil
0%	($93)	($73)	($155)	($121)	($80)	($63)
5%	($91)	($71)	($154)	($120)	($78)	($62)
20%	($87)	($66)	($149)	($115)	($73)	($57)
33%	($82)	($62)	($145)	($111)	($69)	($53)
100%	($61)	($41)	($123)	($189)	($47)	($32)

B. Mid PAH Case *(1 Polar Vortex every 10 years)*

Gas Interrupt %	STF (Dec-Feb)	EFT (Dec-Feb)	STF-Winter	EFT-Winter	LNG	Fuel Oil
0%	($93)	($73)	($155)	($121)	($80)	($63)
5%	($90)	($70)	($152)	($118)	($76)	($60)
20%	($80)	($60)	($142)	($108)	($67)	($50)
33%	($71)	($51)	($133)	($100)	($58)	($42)
100%	($27)	($7)	($89)	($56)	($14)	$1

C. High PAH Case *(1 Polar Vortex every 5 years, w/Quadruple Severity every 10 years)*

Gas Interrupt %	STF (Dec-Feb)	EFT (Dec-Feb)	STF-Winter	EFT-Winter	LNG	Fuel Oil
0%	($93)	($73)	($155)	($121)	($80)	($63)
5%	($78)	($57)	($140)	($106)	($64)	($48)
20%	($31)	($11)	($193)	($59)	($17)	($2)
33%	$10	$30	($52)	($19)	$23	$38
100%	$176	$196	$114	$147	$190	$200

3.3.3 Forced Outage Impacts

Forced outage rates at Bluegrass will impact the non-performance charges and bonus revenues during PAHs. The higher the Bluegrass forced outage rate, the less value the fuel alternative has (if the plant is forced out during a PAH, having fuel available will not matter). During the 2014 Polar Vortex, forced outages driven by the extreme cold were a significant issue in plant unavailability in PJM. Based on data for natural gas plants during the Polar Vortex throughout PJM, we estimated an 18.3% EFOR could apply. As shown in Table 13, a high EFOR will mostly impact the present value benefit (cost) in the *High PAH Case*, when the value of the fuel alternative is most significant.

Table 13. PV Benefit (Cost) of Fuel Oil Alternative as Bluegrass EFOR Varies

Annual PAHs -->	Low PAH Case			Mid PAH Case			High PAH Case		
Gas Interuption in PAHs-->	5%	20%	33%	5%	20%	33%	5%	20%	33%
0% EFOR	(62)	(57)	(52)	(60)	(50)	(41)	(47)	0	41
3.6% EFOR (Base Case)	(62)	(57)	(53)	(60)	(50)	(42)	(48)	(2)	38
18.3% EFOR	(62)	(58)	(54)	(61)	(52)	(45)	(50)	(11)	22

3.4 Summary of Results

Each of the fuel alternatives identified for Bluegrass (firm gas, LNG, fuel oil) provides similar and substantial risk mitigation against a major single year capacity penalty. The fuel oil alternative is the lowest cost alternative at Bluegrass and represents the most economic means to mitigate capacity penalty risk. EFT firm gas for the three-month period from December to February is the next lowest cost alternative but will not cover any PAHs in which there would be fuel interruption in November or March. Over a 20-year period, Bluegrass would need to be available in only about 42 more PAHs to cover the cost of the fuel oil alternative. However, to reach this level of additional PAHs, there would need to be enough future PAHs in PJM in which there was gas interruption on the pipeline serving Bluegrass during those PAHs. Based on the scenarios analyzed in this study, the fuel oil alternative may not pay for itself over 20 years in present value terms. If so, the fuel oil alternative still will provide valuable “insurance” against high single year capacity penalties of as much as $79 million.

4. APPENDIX A – KEY ASSUMPTIONS

1. PAH Cases (winter only), based on 2014 Polar Vortex RTO-wide PAH
    a. Base: Polar Vortex every 10 winters
        i. 2023/24: 20 PAH, 11 in one day
        ii. 2033/34: 20 PAH, 11 in one day
    b. Low: Polar Vortex every 20 winters
        i. 2028/29: 20 PAH, 11 in one day
    c. High: Polar Vortex every 5 winters, with quadruple severity every 10 winters
        i. Quadruple is roughly similar to the BG&E PAH during the 2014 Polar Vortex for January with an EKPC-level polar vortex in December and February
        ii. 2023/24: 79 PAH, 11 in one day (3 times)
        iii. 2028/29: 20 PAH, 11 in one day
        iv. 2033/34: 79 PAH, 11 in one day (3 times)
        v. 2038/39: 20 PAH, 11 in one day

2. Key Assumptions
    a. Bluegrass parameters
        i. Winter capacity of 198 MW per unit, 3 units
        ii. EFOR: 3.6% (base), units either fully on or out during PAH (no partial outages)
        iii. UCAP: 159 MW per unit (summer 165 MW * (1 - 3.6% EFOR))
        iv. Heat Rate: 10.80 mmBtu/MWh, Variable O&M: $3.15/MWh (2018$)
        v. Non-fuel Start Cost: $9.517 per start (2018$), Start Fuel: 350 mmBTu per start

    b. EKPC discount rate (nominal): 5.91% (EKPC average interest rate on long-term debt year-end 2017 of 3.94% multiplied by a 1.50 TIER); Inflation: 2.0% per year

    c. Bluegrass Capacity Penalties/Bonus
        i. PAH Hourly Penalty/(Bonus) = Expected Performance – Actual Performance
            1. If negative, penalty at penalty payment rate, up to annual maximum
            2. If positive, bonus at bonus payment rate
        ii. Expected Performance: UCAP (159.06 MW) * Balancing Ratio
        iii. Actual Performance: Winter ICAP (198 MW) or full out (0 MW)
        iv. Balancing ratio winter: 78.5%
            1. Based on average balancing ratio during 2014-2016 PAHs per PJM *"CP Market Seller Offer Caps for 2020/2021 and 2021/2022 Delivery Year"*
            2. Balancing Ratio is Actual PJM Generation/Total Committed Generation
        v. Bonus Payment Dilution Factor 80%
            1. Reduces PAH bonus payments based on estimate of entry of non-CP capacity (e.g., DR) and PJM excusals for non-performance during PAH.
        vi. Net CONE in EKPC region of 321.57 $/MW-day for 2021/22 ($303.0 in 2018$)
            1. Per 2021/2022 RPM Base Residual Auction Planning Period Parameters
        vii. Performance penalty of $3,687 per MWh (2018$)
            1. [LDA Net CONE ($/MW-day) * Days in Delivery Year]/30
        viii. Bonus payments of $2,949 per MWh (2018$)
            1. Performance penalty multiplied by Dilution Factor
        ix. Annual penalty cap of $165,905 per UCAP MW-year (2018$)
            1. Annual Stop Loss = 1.5 * LDA Net CONE * Days in Delivery Year

- x. Summer season has 7.0 PAH impacting Bluegrass in all scenarios in all years
    1. Bluegrass would incur penalties in summer PAH hours at its 3.6% EFOR
    2. Impacts amount of annual penalty cap that can take place in winter

- d. Alternative Costs
    - i. Firm Gas
        1. 2138.4 Dth/hour per hour per unit (10.8 heat rate * 198 MW winter)
            - a. Amount of gas needed for maximum output chosen to allow for full plant output during PAHs to accrue bonus revenues
        2. STF: $15.17/Dth winter month reservation charge (2018$), 24-hour ratable take, procured for December to February, or all 5 winter months.
        3. EFT: $17.80/Dth per month reservation charge (2018$), 16-hour ratable take, procured for December to February, or all 5 winter months.
            - a. Current Texas Gas Pipeline STF and EFT rates set in 2015 inflated to 2018$ to reflect long-term 20-year rate expectation.
    - ii. Diesel option
        1. $62.8 million capital (nominal dollars 2020 ISD) + $467 thousand annual fixed O&M (2018$)
        2. No heat rate change, enough fuel oil is stored to cover PAHs
        3. Variable O&M increase of $0.98/MWh under fuel oil operation
        4. Unit start cost increased by 1.3 factor under fuel oil operation
        5. Fuel price hedge value of fuel oil in non-PAH hours not considered
        6. Additional Bluegrass operation from new burners (NOx) not considered
    - iii. LNG option
        1. $81 million capital (nominal dollars 2020 ISD) + $467 thousand annual fixed O&M (2018$)

- e. Energy Margins during Winter PAH
    - i. EKPC LMP during Winter PAH of $718/MWh (2018$), all years
        1. Average LMP at EKPC during 2014 Polar Vortex PAH Hours
    - ii. Natural Gas 6.07 $/mmBtu (2018$), all years
        1. 2014 natural gas prices during 2014 Polar Vortex (weighted by PAH hours) plus $0.1692/Dth transmission charge, escalated to 2018$
    - iii. LNG: 4.91 $/mmBtu (2018$), all years
        1. LNG Price at Lake Charles, LA + transmission adder
    - iv. Fuel Oil: 12.58 $/mmBtu (2018$), based on diesel cost at Spurlock

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 47
RESPONSIBLE PERSON: Mary Jane Warner
COMPANY: East Kentucky Power Cooperative, Inc.

Request 47. Refer to the IRP, Section 7.0, page 116. Explain in further detail the economic analysis, risk, and other benefits used to justify the proposed projects.

Response 47. Please refer to Response 46.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 48
RESPONSIBLE PERSON: Julia J. Tucker
COMPANY: East Kentucky Power Cooperative, Inc.

Request 48. Refer to the I RP, page 137. Provide a more detailed description of the hydro-generation facilities on the Kentucky River lock and dam system.

Response 48. There are three known (3) hydroelectric projects on the Kentucky River that are connected to the EKPC system; however, EKPC does not own, operate or dispatch any of these facilities. These are low-impact systems that are run-of-river projects. The capacities and status of the projects are below:

Lock 7, 2.040MW, currently online

Lock 12, 2.64MW, anticipated to be online summer of 2020

Lock 14, 2.64MW, anticipated to be online summer of 2020

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 49
RESPONSIBLE PERSON: Julia J. Tucker
COMPANY: East Kentucky Power Cooperative, Inc.

Request 49. Refer to the IRP, page 139 and 140. Provide the cost for the five lowest cost plans out of the 2,500 plans simulated.

Response 49. The following table lists the average, maximum, and minimum system costs for each of the top five plans. The computer simulation model performs multiple iterations per study case, and these three costs cover the range of costs captured within these iterations. The system cost includes fuel plus variable operations and maintenance costs.

PLAN	Average System Cost	Maximum System Cost	Minimum System Cost
1	$ 91,716,680	$ 91,841,208	$ 91,614,152
2	$ 91,842,440	$ 91,966,952	$ 91,739,920
3	$ 91,860,952	$ 91,985,480	$ 91,758,416
4	$ 91,894,480	$ 92,019,376	$ 91,790,144
5	$ 91,917,520	$ 92,042,424	$ 91,813,176

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2019-00096

FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020

REQUEST 50

RESPONSIBLE PERSON: **Julia J. Tucker**

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

<u>Request 50.</u> Refer to the IRP, page 140. Provide the cost of each option in the five cases identified with and without the DSM Affected Base Resource options.

<u>Response 50.</u> The cases used the values from Table 8.(2)(c):

Table 8.(2)(c)

Resource	Capacity Type	Capacity (MW)	Primary Fuel	Projected Capital Cost (2016$) *	
				$/kW	$M
LMS100 CT	Peaking	100	Natural Gas	[redacted]	[redacted]
Combined Cycle	Peaking/Intermediate	300	Natural Gas	[redacted]	[redacted]
Solar	Renewable	100	Solar	[redacted]	[redacted]
Wind	Renewable	100	Wind	[redacted]	[redacted]
PPA - Winter Seasonal Market	Power Purchase	100	n/a	[redacted]	
PPA - Winter Seasonal Market	Power Purchase	100	n/a	[redacted]	
PPA - Winter Seasonal Market	Power Purchase	100	n/a	[redacted]	

* Capital Costs Source: National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) 2018

Fixed Cost Source: ACES Power Marketing Forecast, November 2018

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2019-00096
FIRST INFORMATION REQUEST RESPONSE

STAFF'S FIRST REQUEST FOR INFORMATION DATED 02/24/2020
REQUEST 51
RESPONSIBLE PERSON: Jerry B. Purvis
COMPANY: East Kentucky Power Cooperative, Inc.

Request 51. Refer to the IRP, Section 9. Provide an update to EKPC's environmental compliance planning since the filing of the IRP.

Response 51. See response to AG-DR-01-040.