EAST KENTUCKY POWER COOPERATIVE

A Touchstone Energy® Cooperative

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PUBLIC SERVICE
COMMISSION

March 31, 2020

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

Re: Annual Resource Assessment for East Kentucky Power Cooperative, Inc. (Administrative Case No. 387).

Dear Mr. Chandler:

Pursuant to the Commission's Order dated October 7, 2005 in Administrative Case No. 387, please find enclosed for filing with the Commission an original and ten copies of the 2017 Annual Resource Assessment for East Kentucky Power Cooperative, Inc. ("EKPC").

Also enclosed, please find as a supplement a discussion of the price elasticity study commissioned by EKPC pertaining to forecasted demand, energy and reserve margin information provided in the Annual Resource Assessment, as requested by the Executive Director in a May 31, 2013 letter to me. Please note that this discussion, resulting from a study by GDS Associates (GDS) conducted for EKPC in 2015, is identical to the one provided by EKPC to the Commission in filing its 2017, 2018 and 2019 Annual Resource Assessments, and is consistent with the current assumptions in EIA's long-term energy forecast (https://www.eia.gov/outlooks/aeo/assumptions/pdf/commercial.pdf, page 10). As such, GDS believes that the conclusions and recommendations made in the 2015 study regarding residential and commercial price elasticity are still reasonable today. The results of this price elasticity summary were employed by EKPC in conducting the sensitivity analysis found in its 2019 Integrated Resource Plan (Case No. 2019-00096).

If you have any questions, please call me.

Very truly yours,

Patrick C. Woods
Director, Regulatory and Compliance Services

Enclosures

4775 Lexington Road, POB 707
Winchester, KY 40392
859-744-4812

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

A REVIEW OF THE ADEQUACY OF KENTUCKY'S GENERATION CAPACITY AND TRANSMISSION SYSTEM	))))	**PSC ADMINISTRATIVE CASE NO. 387**

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 in the above-referenced case dated December 20, 2001, 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.

Darrin Adams

Subscribed and sworn before me on this 31st day of March, 2020.

Notary Public 590567

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

A REVIEW OF THE ADEQUACY OF KENTUCKY'S GENERATION CAPACITY AND TRANSMISSION SYSTEM	))))	**PSC ADMINISTRATIVE CASE NO. 387**

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 in the above-referenced case dated December 20, 2001, 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 31st day of March, 2020.

Gary W. Willey #590567
Notary Public

EAST KENTUCKY POWER COOPERATIVE, INC.

UPDATED INFORMATION TO BE FILED ANNUALLY AS SUPPLEMENT TO THE ANNUAL REPORT

AS ORDERED on October 7, 2005 in the CLOSED PSC ADMINISTRATIVE CASE 387

PUBLIC SERVICE COMMISSION'S REQUEST DATED 12/20/01

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

A REVIEW OF THE ADEQUACY OF	**)**	
KENTUCKY'S GENERATION	**)**	**ADMINISTRATIVE**
CAPACITY AND TRANSMISSION	**)**	**CASE NO. 387**
SYSTEM	**)**	

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC ADMINISTRATIVE CASE 387

PUBLIC SERVICE COMMISSION'S REQUEST DATED 12/20/01

East Kentucky Power Cooperative, Inc. (EKPC) hereby submits responses to the information requests contained in Appendix G to the Order of the Public Service Commission ("PSC") in this case dated December 20, 2001, as subsequently revised by Orders dated March 29, 2004 and October 7, 2005. Each response with its associated supportive reference materials is individually tabbed.

The requests listed below, which were originally contained in Appendix G of the Commission's Order dated December 20, 2001, are no longer required pursuant to the Commission's Order of March 29, 2004, amending the previous Order.

Request No. 1
Request No. 2
Request No. 5
Request No. 9
Request No. 10

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC ADMINISTRATIVE CASE NO. 387

ANNUAL RESOURCE ASSESSMENT FILING

PUBLIC SERVICE COMMISSION REQUEST DATED 12/20/01

REQUEST 3

RESPONSIBLE PERSON: **Julia J. Tucker**

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

Request 3. Actual and weather-normalized coincident peak demands for the just completed calendar year. Demands should be disaggregated into (a) native load demand (firm and non-firm) and (b) off-system demand (firm and non-firm).

Response 3a. Refer to table below.

Monthly Native Load Peak Demands 2019

	Actual (Firm and Non-Firm) (MW)	Weather Adjusted (Firm and Non-Firm) (MW)
January	3,073	3,380
February	2,448	3,159
March	2,834	2,705
April	2,077	2,077
May	2,060	2,014
June	2,177	2,287
July	2,338	2,448
August	2,366	2,440
September	2,276	2,039
October	2,224	1,798
November	2,723	2,873
December	2,714	2,801

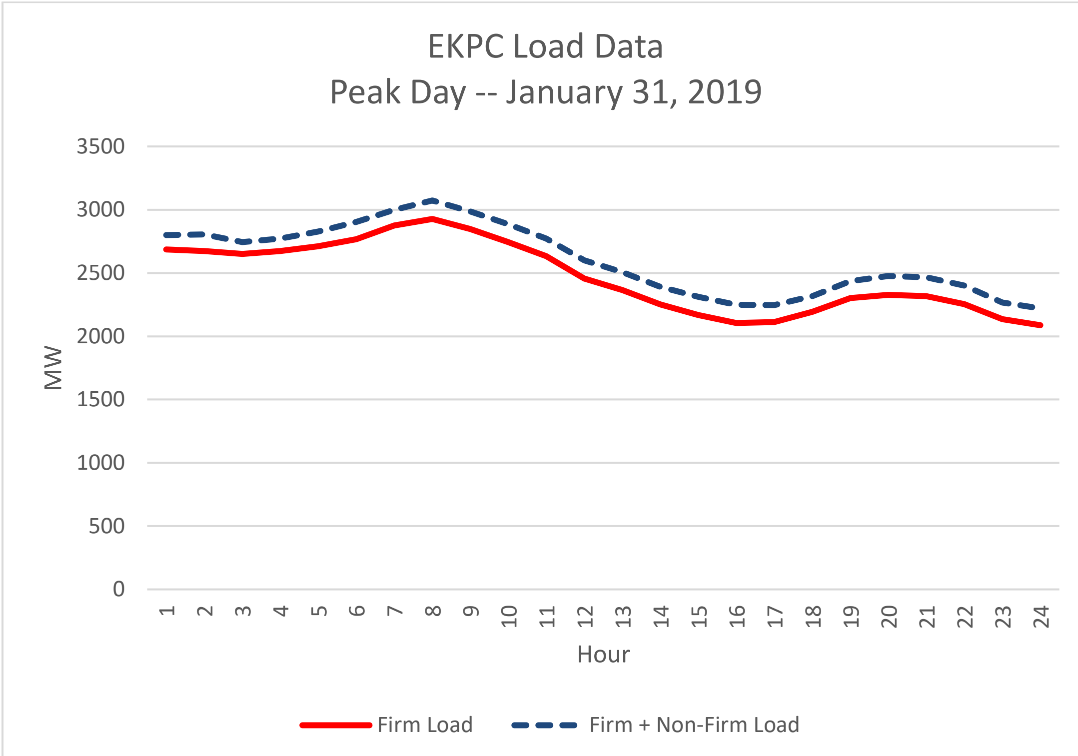
Response 3b. EKPC had no off-system demand obligations during the calendar year 2019.

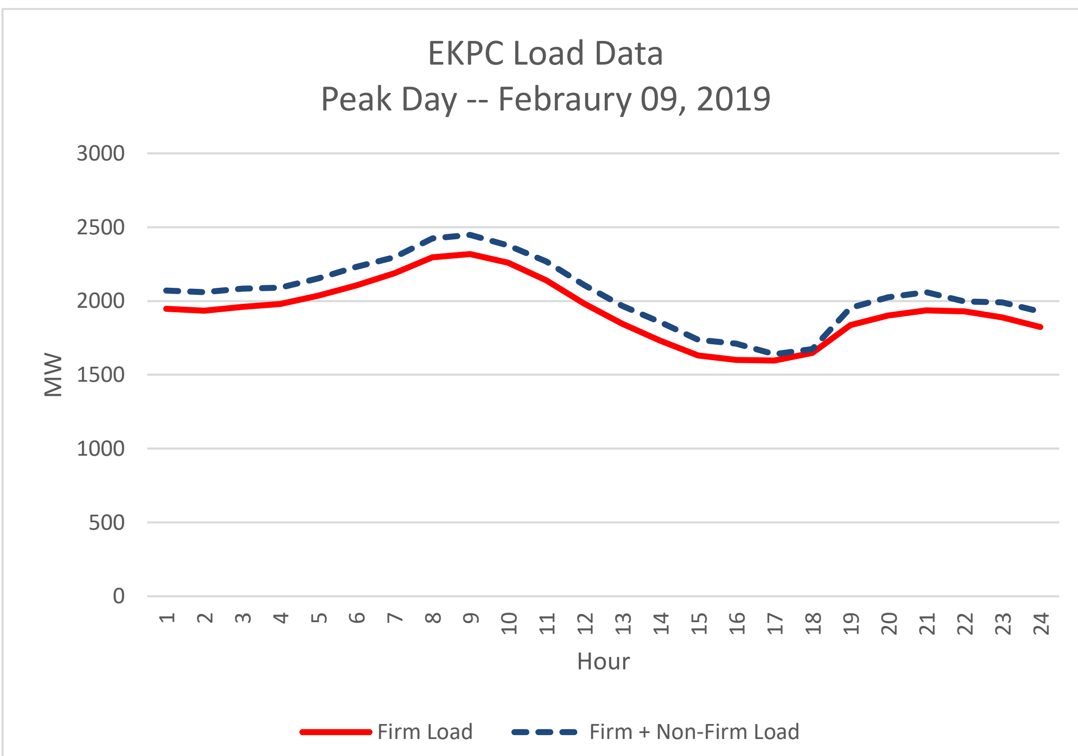
EAST KENTUCKY POWER COOPERATIVE, INC.
PSC ADMINISTRATIVE CASE NO. 387
ANNUAL RESOURCE ASSESSMENT FILING

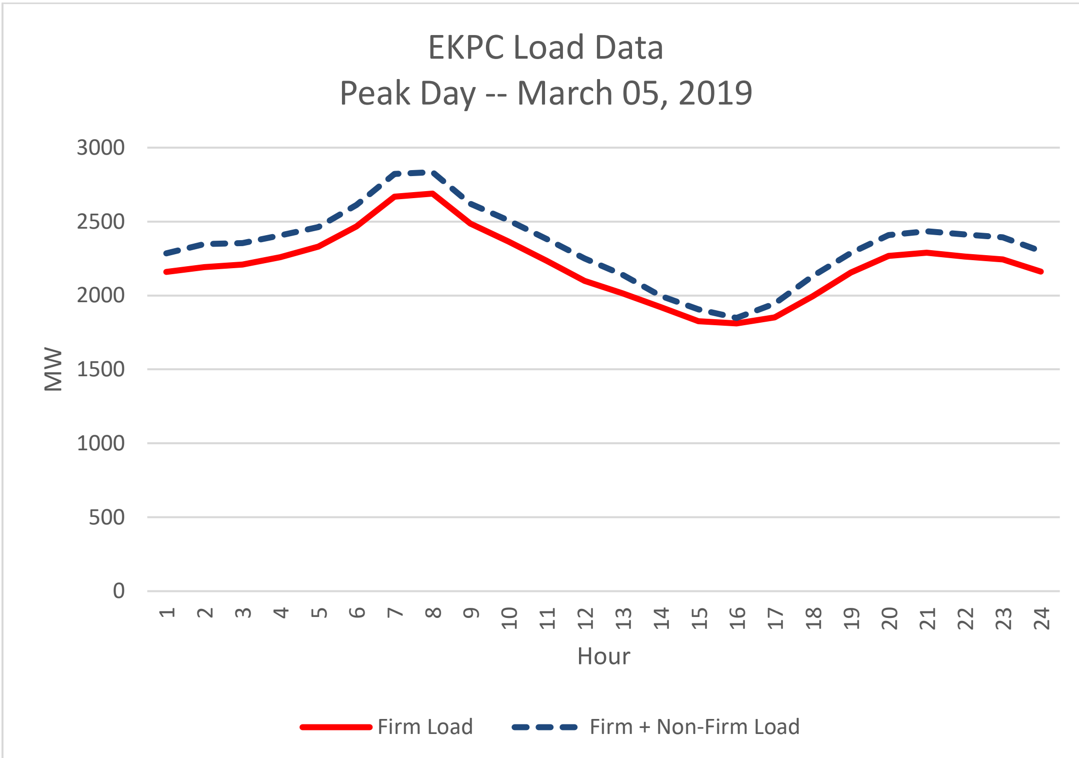
PUBLIC SERVICE COMMISSION REQUEST DATED 12/20/01
REQUEST 4
RESPONSIBLE PERSON: **Julia J. Tucker**
COMPANY: **East Kentucky Power Cooperative, Inc.**

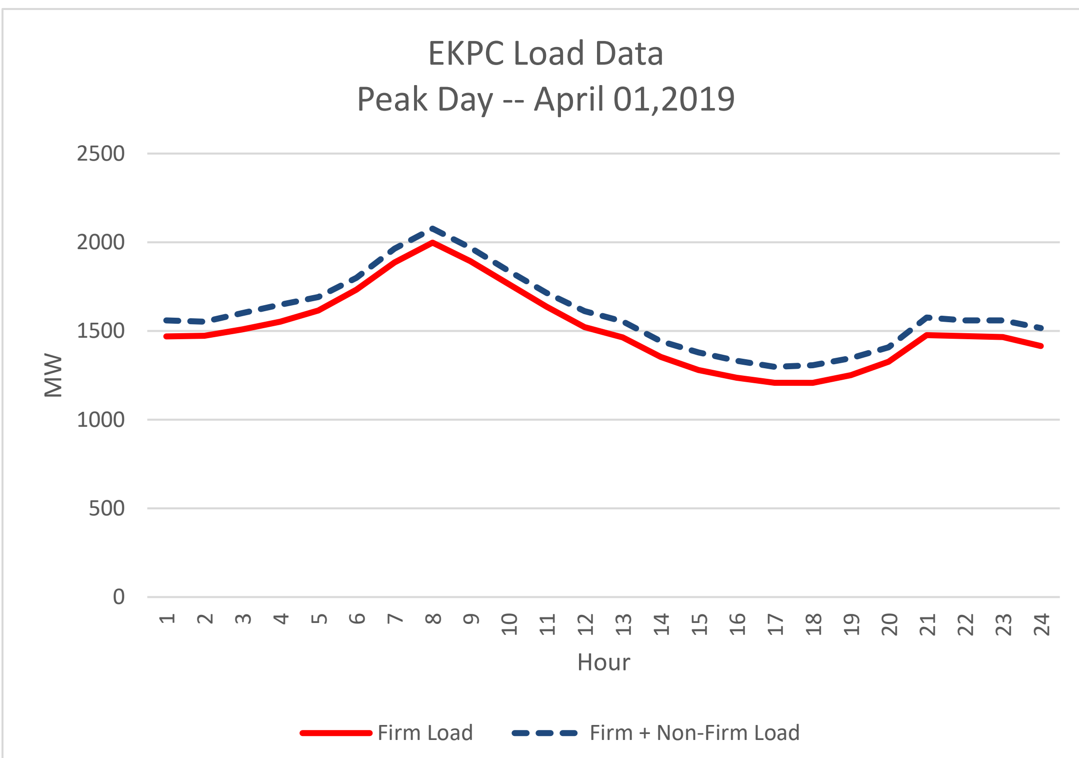
Request 4. Load shape curves that show actual peak demands and weather-normalized peak demands (native load demand and total demand) on a monthly basis for the just completed calendar year.

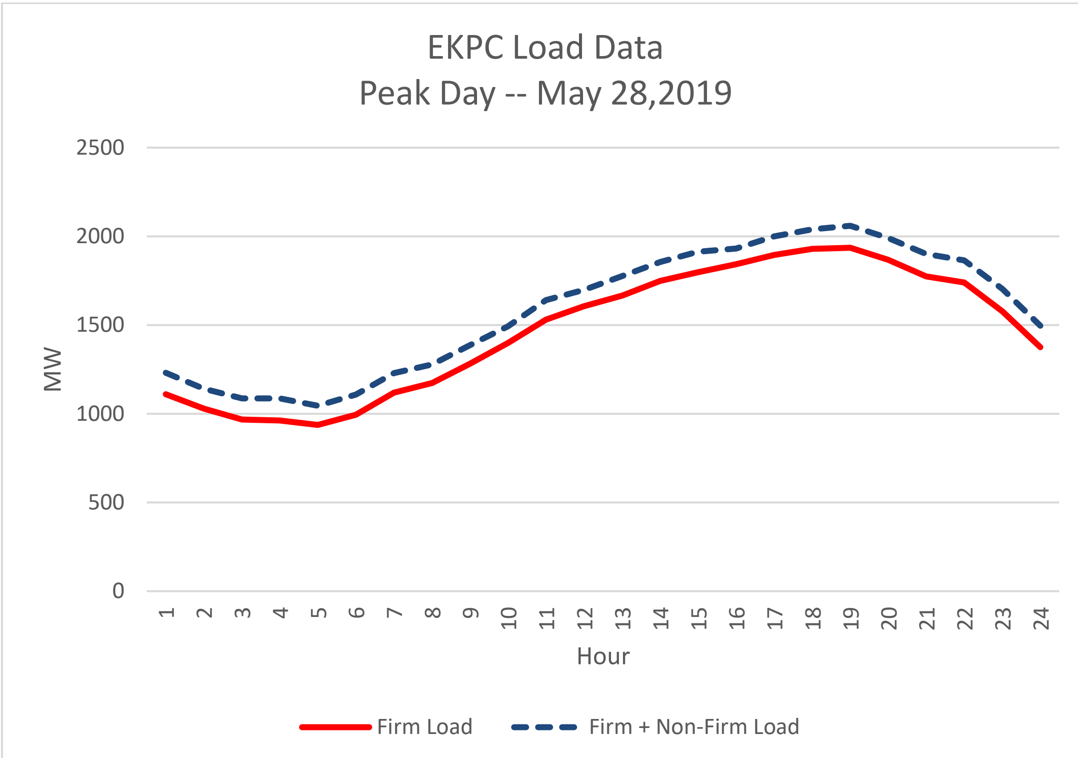
Response 4. Actual monthly peak-day load shapes are presented on pages 2 through 7 of this response. EKPC performs an analysis to weather-normalize the peak hour but EKPC does not weather-normalize the peak-day load shapes.

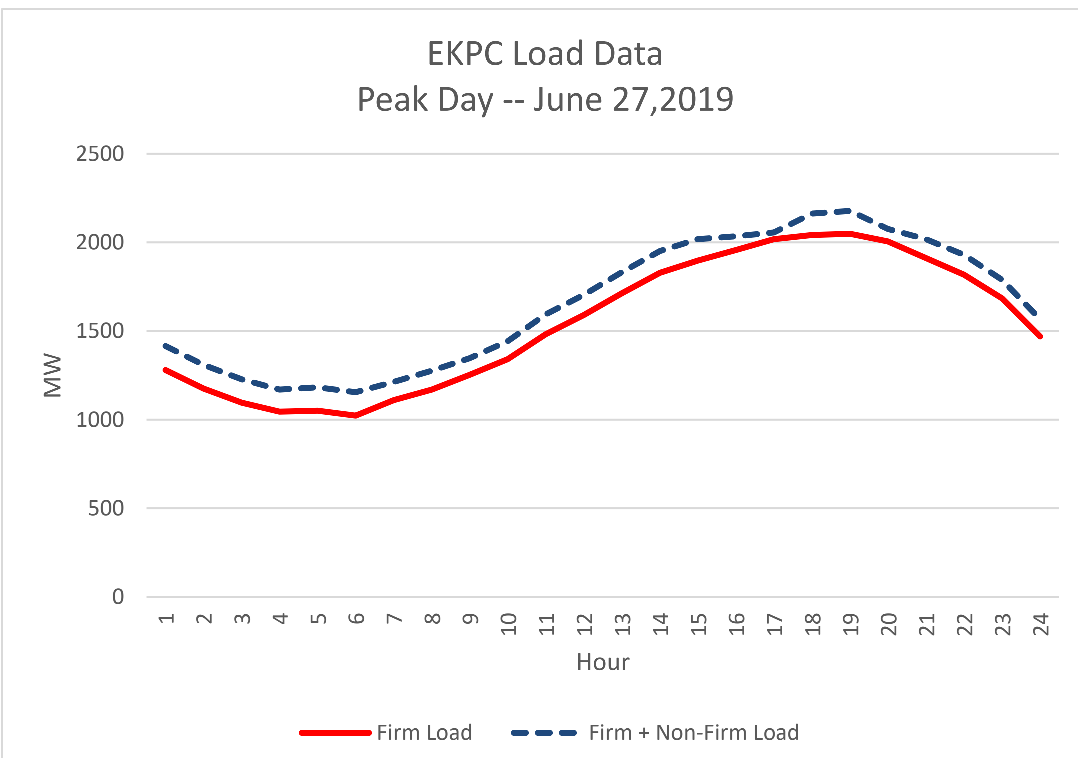

EKPC Load Data
Peak Day -- January 31, 2019
3500
3000
2500
2000
1500
1000
500
0
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour
Firm Load
Firm + Non-Firm Load

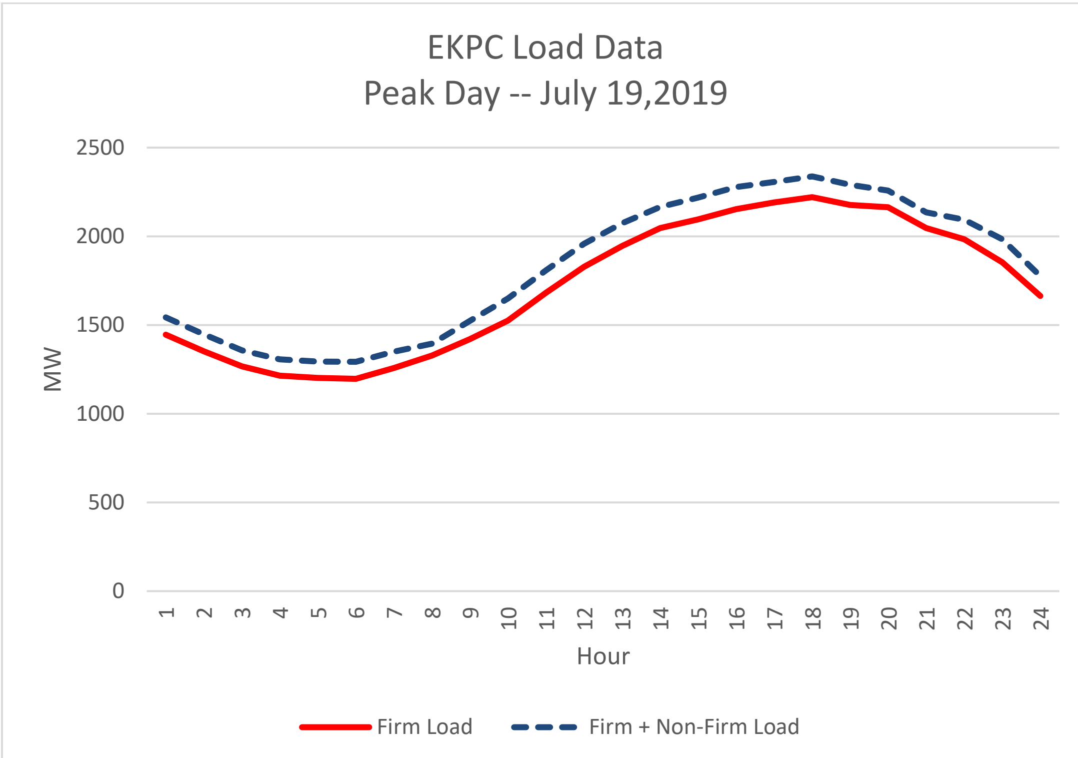

EKPC Load Data
Peak Day -- Febraury 09, 2019
3000
2500
2000
1500
1000
500
0
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour
Firm Load
Firm + Non-Firm Load

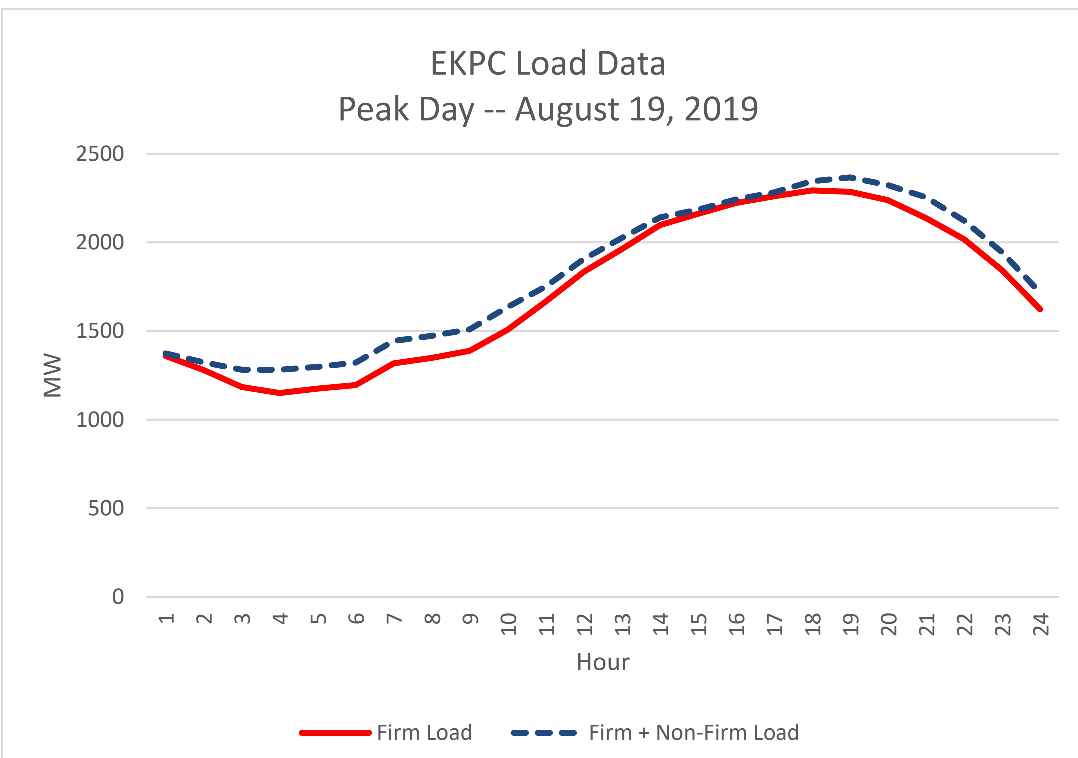

EKPC Load Data
Peak Day -- March 05, 2019
MW
3000
2500
2000
1500
1000
500
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Firm Load
Firm + Non-Firm Load

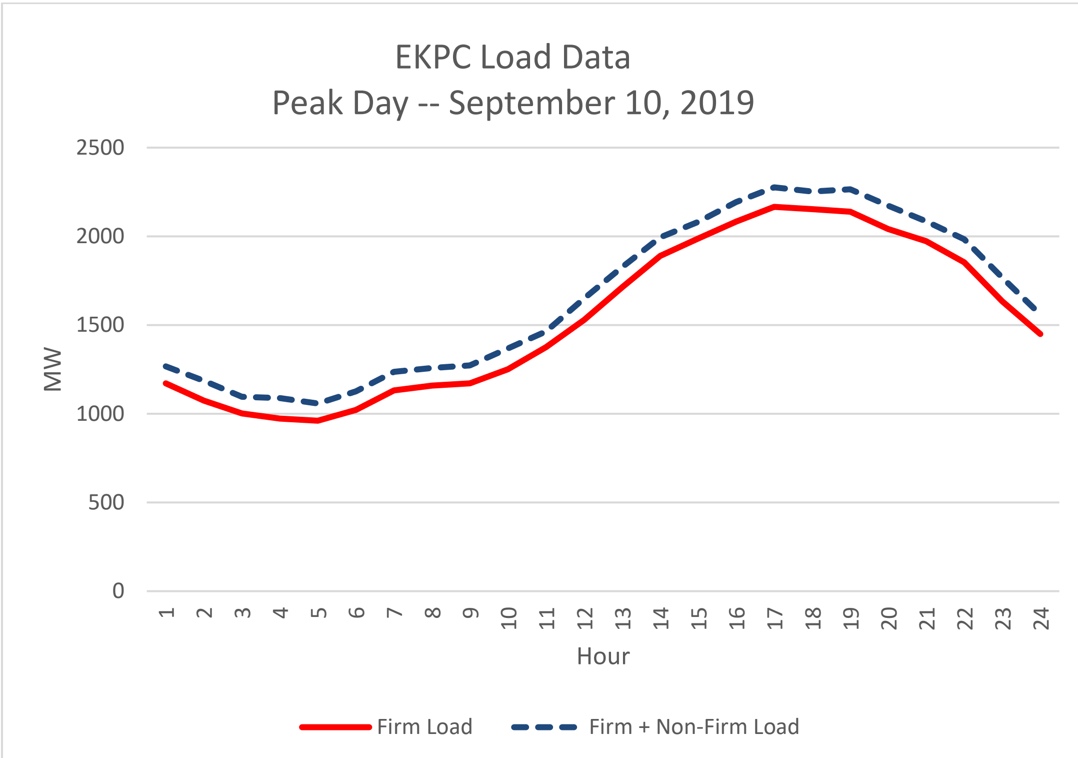

EKPC Load Data
Peak Day -- April 01,2019
MW
2500
2000
1500
1000
500
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Firm Load
Firm + Non-Firm Load

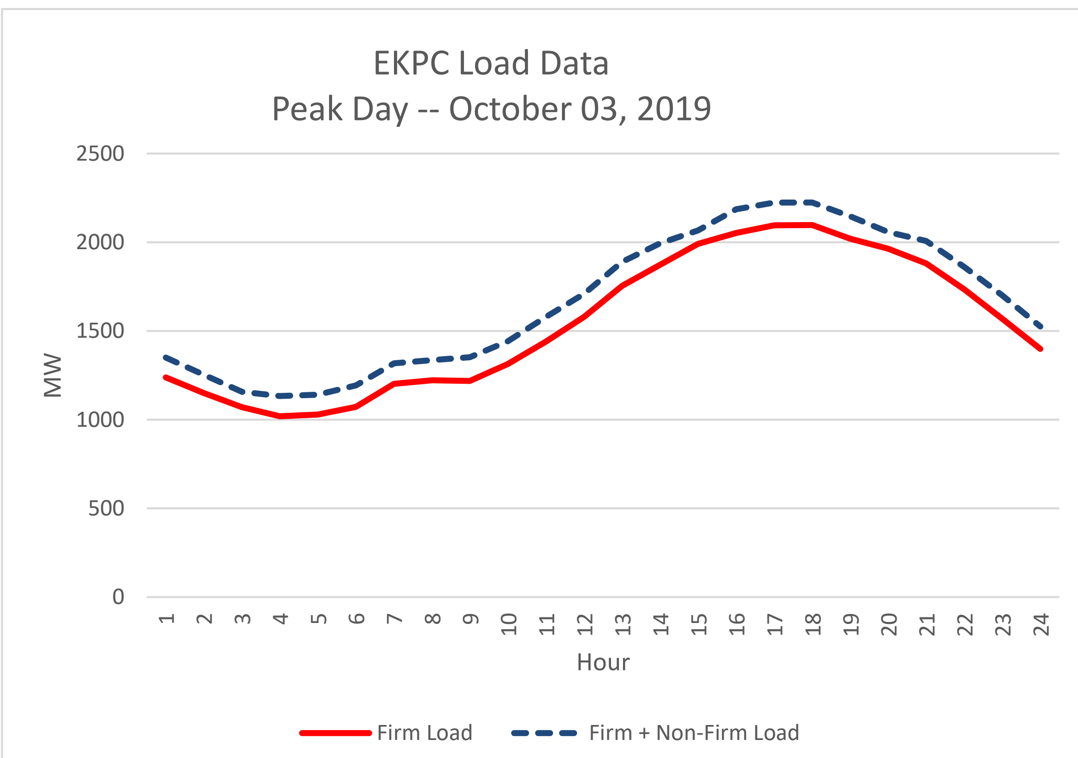

EKPC Load Data
Peak Day -- May 28,2019
2500
2000
1500
1000
500
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Firm Load
Firm + Non-Firm Load

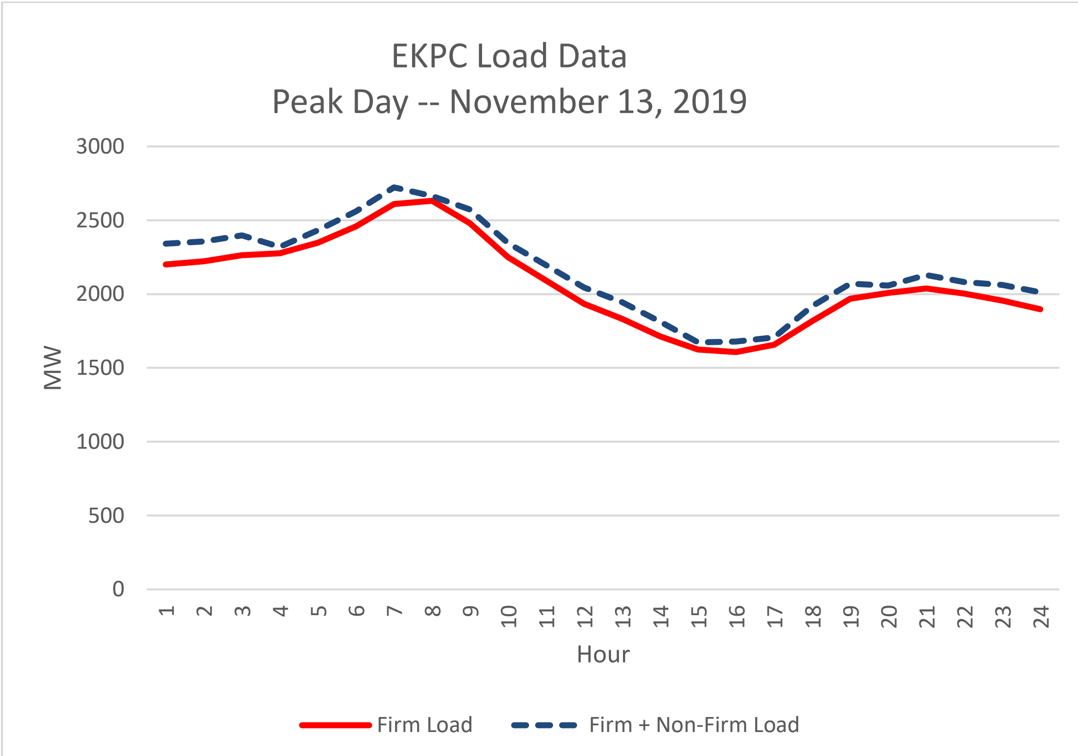

EKPC Load Data
Peak Day -- June 27,2019
2500
2000
1500
1000
500
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Firm Load
Firm + Non-Firm Load

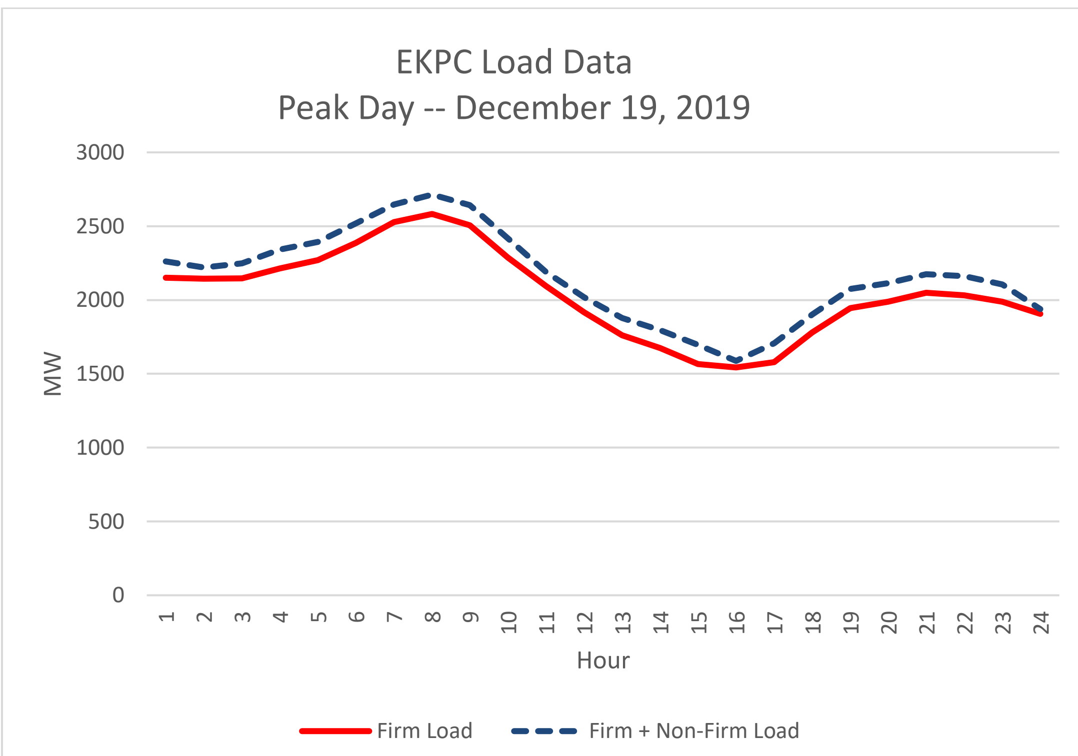

EKPC Load Data
Peak Day -- July 19,2019
MW
2500
2000
1500
1000
500
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Firm Load
Firm + Non-Firm Load


EKPC Load Data
Peak Day -- August 19, 2019
MW
2500
2000
1500
1000
500
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Firm Load
Firm + Non-Firm Load


EKPC Load Data
Peak Day -- September 10, 2019
2500
2000
1500
1000
500
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Firm Load
Firm + Non-Firm Load


EKPC Load Data
Peak Day -- October 03, 2019
2500
2000
1500
1000
500
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Firm Load
Firm + Non-Firm Load


EKPC Load Data
Peak Day -- November 13, 2019
3000
2500
2000
1500
1000
500
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Firm Load
Firm + Non-Firm Load


EKPC Load Data
Peak Day -- December 19, 2019
3000
2500
2000
1500
1000
500
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Firm Load
Firm + Non-Firm Load

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC ADMINISTRATIVE CASE NO. 387
ANNUAL RESOURCE ASSESSMENT FILING

PUBLIC SERVICE COMMISSION REQUEST DATED 12/20/01
REQUEST 6
RESPONSIBLE PERSON: Julia J. Tucker
COMPANY: East Kentucky Power Cooperative, Inc.

Request 6. Based on the most recent demand forecast, the base case demand and energy forecasts and high case demand and energy forecasts for the current year and the following four years. The information should be disaggregated into (a) native load (firm and non-firm demand) and (b) off-system load (both firm and non-firm demand).

Response 6a. EKPC prepares higher and lower growth scenarios to bracket its baseline forecast. The ranges are shown in the table below. The peaks are firm native load only. EKPC does not prepare range forecasts for non-firm native load.

Net Winter Peak Demand (MW)				Net Summer Peak Demand (MW)				Total Requirements (GWh)			
Season	*Low Case*	*Base Case*	*High Case*	*Year*	*Low Case*	*Base Case*	*High Case*	*Year*	*Low Case*	*Base Case*	*High Case*
2019-20	3,240	3,281	3,323	2020	2,347	2,377	2,407	2020	13,353	14,354	15,426
2020-21	3,266	3,323	3,383	2021	2,383	2,425	2,469	2021	14,018	15,110	16,294
2021-22	3,275	3,349	3,426	2022	2,394	2,448	2,504	2022	14,101	15,242	16,494
2022-23	3,282	3,373	3,469	2023	2,391	2,457	2,527	2023	14,188	15,373	16,695
2023-24	3,294	3,401	3,516	2024	2,404	2,483	2,566	2024	14,326	15,556	16,950

Response 6b. EKPC is projecting no off-system demand.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC ADMINISTRATIVE CASE NO. 387

ANNUAL RESOURCE ASSESSMENT FILING

PUBLIC SERVICE COMMISSION REQUEST DATED 12/20/01

REQUEST 7

RESPONSIBLE PERSON: **Julia J. Tucker**

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

Request 7. The target reserve margin currently used for planning purposes, stated as a percentage of demand. If changed from what was in use in 2001, include a detailed explanation of the change.

Response 7. EKPC integrated into PJM on June 1, 2013. EKPC is required to provide its pro-rated share of the PJM reserve requirements. PJM is a summer peaking system, so EKPC's reserve requirement shifted from previously being based on winter peak to summer peak. Additionally, EKPC's load diversity with PJM's peak period acts to reduce EKPC's net reserve requirements. EKPC participates in the Reliability Pricing Model ("RPM"), which results in EKPC carrying reserves of roughly 3% of its summer load. In addition to the summer reserve requirements, EKPC plans for 5% reserves on its winter peak load expectations to hedge its winter market price exposure.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC ADMINISTRATIVE CASE NO. 387

ANNUAL RESOURCE ASSESSMENT FILING

PUBLIC SERVICE COMMISSION REQUEST DATED 12/20/01

REQUEST 8

RESPONSIBLE PERSON: **Julia J. Tucker**

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

Request 8. Projected reserve margins stated in megawatts and as a percentage of demand for the current year and the following 4 years. Identify projected deficits and current plans for addressing these. For each year identify the level of firm capacity purchases projected to meet native load demand.

Response 8. The table below shows the projected summer peak and reserve levels.

Year	Summer Load (MW)	Capacity (MW)	Reserves (%)	Winter Load (MW)	Capacity (MW)	Reserves (%)
2020	2,376	3,132	32%	3,248	3,434	6%
2021	2,530	3,132	24%	3,296	3,434	4%
2022	2,543	3,132	23%	3,363	3,434	2%
2023	2,581	3,132	21%	3,356	3,434	2%
2024	2,599	3,132	21%	3,383	3,434	2%

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC ADMINISTRATIVE CASE NO. 387
ANNUAL RESOURCE ASSESSMENT FILING

PUBLIC SERVICE COMMISSION REQUEST DATED 12/20/2001
REQUEST 11
RESPONSIBLE PERSON: **Julia J. Tucker**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 11. A list that identifies scheduled outages or retirements of generating capacity during the current year and the following four years.

Response 11. Please see scheduled outage information on pages 2 through 3 of this response.

<u>Weeks of Maintenance</u>

Cooper Unit 1

2020	4	week(s) or less
2021	4	week(s) or less
2022	4	week(s) or less
2023	4	week(s) or less
2024	4	week(s) or less

Cooper Unit 2

2020	4	week(s) or less
2021	4	week(s) or less
2022	9	week(s) or less
2023	4	week(s) or less
2024	4	week(s) or less

Spurlock Unit 1

2020	13	week(s) or less
2021	7	week(s) or less
2022	8	week(s) or less
2023	7	week(s) or less
2024	7	week(s) or less

Spurlock Unit 2

2020	13	weeks or less
2021	6	weeks or less
2022	6	weeks or less
2023	7	weeks or less
2024	7	weeks or less

Spurlock Unit 3

2020	5	week(s) or less
2021	5	week(s) or less
2022	5	week(s) or less
2023	5	week(s) or less
2024	5	week(s) or less

JK Smith CT1

2020	4	week(s) or less
2021	4	week(s) or less
2022	4	week(s) or less
2023	4	week(s) or less
2024	4	week(s) or less

JK Smith CT2

2020	11	week(s) or less
2021	4	week(s) or less
2022	4	week(s) or less
2023	4	week(s) or less
2024	4	week(s) or less

JK Smith CT3

2020	4	week(s) or less
2021	4	week(s) or less
2022	4	week(s) or less
2023	4	week(s) or less
2024	4	week(s) or less

JK Smith CT4

2020	4	weeks or less
2021	4	weeks or less
2022	4	weeks or less
2023	4	weeks or less
2024	4	weeks or less

JK Smith CT5

2020	4	week(s) or less
2021	4	week(s) or less
2022	4	week(s) or less
2023	4	week(s) or less
2024	4	week(s) or less

Spurlock Unit 4

2020	8	week(s) or less
2021	5	week(s) or less
2022	5	week(s) or less
2023	5	week(s) or less
2024	5	week(s) or less

Bluegrass CT1

2020	14	week(s) or less
2021	7	week(s) or less
2022	7	week(s) or less
2023	8	week(s) or less
2024	7	week(s) or less

Bluegrass CT2

2020	14	week(s) or less
2021	7	week(s) or less
2022	7	week(s) or less
2023	10	week(s) or less
2024	7	week(s) or less

Bluegrass CT3

2020	11	week(s) or less
2021	7	week(s) or less
2022	7	week(s) or less
2023	8	week(s) or less
2024	7	week(s) or less

JK Smith CT6

2020	4	week(s) or less
2021	4	week(s) or less
2022	4	week(s) or less
2023	4	week(s) or less
2024	4	week(s) or less

JK Smith CT7

2020	4	week(s) or less
2021	4	week(s) or less
2022	4	week(s) or less
2023	4	week(s) or less
2024	2	week(s) or less

JK Smith CT9

2020	6	week(s) or less
2021	6	week(s) or less
2022	6	week(s) or less
2023	6	week(s) or less
2024	6	week(s) or less

JK Smith CT10

2020	6	week(s) or less
2021	6	week(s) or less
2022	6	week(s) or less
2023	6	week(s) or less
2024	6	week(s) or less

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC ADMINISTRATIVE CASE NO. 387
ANNUAL RESOURCE ASSESSMENT FILING

PUBLIC SERVICE COMMISSION REQUEST DATED 12/20/01
REQUEST 12
RESPONSIBLE PERSON: **Julia J. Tucker**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 12. Identify all planned base load or peaking capacity additions to meet native load requirements over the next 10 years. Show the expected in-service date, size and site for all planned additions. Include additions planned by the utility, as well as those by affiliates, if constructed in Kentucky or intended to meet load in Kentucky.

Response 12. EKPC does not currently have any plans for new base load or peaking capacity additions to meet native load requirements over the next 10 years.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC ADMINISTRATIVE CASE NO. 387

ANNUAL RESOURCE ASSESSMENT FILING

PUBLIC SERVICE COMMISSION REQUEST DATED 12/20/01

REQUEST 13

RESPONSIBLE PERSON: **Darrin Adams**

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

Request 13. The following transmission energy data for the just completed calendar year and the forecast for the current year and the following four years:

Request 13a. Total energy received from all interconnections and generation sources connected to the transmission system.

Request 13b. Total energy delivered to all interconnections on the transmission system.

Response 13a &13b. The total energy received from all interconnections and from generation sources connected to the EKPC transmission system for calendar year 2019 was 21,783,881 MWh. The total energy delivered to all interconnections on the EKPC system in 2019 was 8,643,167 MWh.

The forecasted total energy requirements for the EKPC system for 2020 through 2024 are as follows:

2020	14,354,291 MWh
2021	15,109,727 MWh
2022	15,241,723 MWh
2023	15,373,488 MWh
2024	15,555,697 MWh

Request 13c. Peak load capacity of the transmission system.

Response 13c. The transmission capacity of a grid system changes constantly based on factors like generation dispatch, ambient temperature, load characteristics, facility outages, power transfers, etc. EKPC's transmission system is planned and constructed to deliver all of its generation resources to its native load delivery points and to other contracted users of the EKPC transmission system during forecasted normal summer and winter peak load conditions. EKPC's transmission system is also designed to accommodate an outage of a single transmission facility and/or generating unit. Also, EKPC designs its transmission system to deliver its generation resources to its native load delivery points during "extreme" weather conditions (1-in-10 year temperatures) for summer and winter with all facilities in service.

Other than simulation of imports into EKPC to replace an outage of a single generating unit, the transfers used in the EKPC transmission planning process are those modeled in the NERC MMWG models, which are typically the long-term firm transactions known at the time of the development of the models.

Transfer studies performed in regional assessments by both SERC and PJM have not identified any significant limitations within the EKPC system. Therefore, EKPC's system is expected to be capable of handling a reasonable level of overlaid transfers while also delivering energy to EKPC's native-load customers and other transmission customers using EKPC's transmission system to deliver energy for their native-load customers (for instance, LG&E/KU).

Request 13d. Peak demand for summer and winter season on the transmission system.

Response 13d. For peak demand for summer and winter season on the transmission system, refer to table below.

Summer	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Date	8/19/2019					
Hr.	1900					
Peak Demand (MW)	2366	2377	2425	2448	2457	2483
Winter	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Date	1/31/2019	1/22/2020*				
Hr.	0800	0800				
Peak Demand (MW)	3073	2653	3323	3349	3373	3401

*Reflects January 2020 actual winter peak.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC ADMINISTRATIVE CASE NO. 387

ANNUAL RESOURCE ASSESSMENT FILING

PUBLIC SERVICE COMMISSION REQUEST DATED 12/20/01

REQUEST 14

RESPONSIBLE PERSON: **Darrin Adams**

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

<u>Request 14.</u> Identify all planned transmission capacity additions for the next 10 years. Include the expected in-service date, size and site for all planned additions and identify the transmission need each addition is intended to address.

<u>Response 14.</u> Pages 2 through 7 of this response include EKPC's 10-year transmission expansion plan for the 2020-2029 period. During this period, EKPC expects to make the following transmission improvements for replacement of aging transmission line and substation infrastructure, normal system development, and load growth to serve native load customers and other long-term contracted uses of the EKPC transmission system.

1.15 miles of new 161 kV transmission line
0.7 mile of new 138 kV transmission line
21.4 miles of new transmission line (69 kV)
216.71 miles of transmission line reconductor/rebuild (69 kV)
0.71 miles of transmission line conductor operating temperature upgrade
1 new transmission station (150 MVA added)
3 new 69 kV transmission switching stations
13 transmission capacitor banks retired/reduced (74.02 MVAR reduction)
4 projects to upgrade terminal facilities
4 new distribution substations (144 MVA added)
10 upgrades of existing distribution substations (65 MVA added)

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2020 – 2029)	
A. New Transmission Lines and Status Changes **Project Description**	**Needed In-Service Date**
Construct a new West Shelby-Bekaert 69 kV line section using 556 MCM ACSR/TW (2.0 miles)	3/2021
Construct a new Fox Hollow-Fox Hollow Jct 161 kV line section using 795 MCM ACSR (0.9 miles)	12/2021
Construct a new Carson-EK Carrollton 69 KV line using 556 MCM ACSR (10.1 miles)	12/2025
Construct a new EK Carrollton-KU Carrollton 69 KV interconnection using 556 MCM ACSR (0.1 miles)	12/2025

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2020 – 2029)	
B. Transmission Line Re-conductor/Rebuilds **Project Description**	**Needed In-Service Date**
Rebuild Tharp Tap-KU Elizabethtown and Kargle-KU Elizabethtown double circuit 69kv line section to 954 MCM ACSR (1.4 miles)	7/2020
Rebuild the existing 2/0 ACSR Lyman B. Williams Tap-Tunnel Hill Tap 69 kV line section (1.5 miles) using 556.5 MCM ACSR/TW conductor (part of Nelson County-Elizabethtown 69 kV circuit)	8/2020
Rebuild the existing 4/0 ACSR Preston-KU Owingsville 69 kV line section (4.4 miles) using 556.5 MCM ACSR/TW conductor (part of Goddard-Hillsboro 69 kV circuit)	9/2020
Rebuild the existing 3/0 ACSR Leon-Airport Road 69 kV line section (5.7 miles) using 556.5 MCM ACSR/TW conductor (part of Leon-Skaggs 69 kV circuit)	10/2020
Rebuild the existing 4/0 ACSR KU Owingsville-Peasticks 69 kV line section (1.93 miles) using 556.5 MCM ACSR/TW conductor. (part of Goddard-Hillsboro 69 kV circuit)	12/2020
Rebuild the existing 2/0 ACSR Elizabethtown-Tunnel Hill Tap 69 kV line section (3.4 miles) using 556.5 MCM ACSR/TW conductor (part of Nelson County-Elizabethtown 69 kV circuit)	12/2020
Rebuild Monticello-Homestead 69 kV line section using 556 MCM ACSR/TW conductor (1.96 miles)	12/2020
Rebuild the existing 2/0 ACSR (5.8 miles) and the 266 ACSR (0.48 miles) sections of the Grants Lick-Griffin Junction 69 kV line using 556.5 MCM ACSR/TW conductor	5/2021
Rebuild the existing 2/0 ACSR Lyman B. Williams Tap-Roanoke Tap 69 kV line section (4.48 miles) using 556.5 MCM ACSR/TW conductor (part of Nelson County-Elizabethtown 69 kV circuit)	8/2021

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2020 – 2029)	
B. Transmission Line Re-conductor/Rebuilds Project Description	**Needed In-Service Date**
Rebuild the existing 4/0 ACSR Three Links Junction-Conway line section (1.81 miles) using 556 MCM ACSR conductor (part of Three Links Junction-Tyner 69 kV circuit)	9/2021
Rebuild the existing 3/0 ACSR Pine Knot-Jellico Creek 69 kV line section (7.8 miles) using 556.5 MCM ACSR/TW conductor. (part of McCreary County-KU Wofford 69 kV line section)	5/2022
Rebuild the existing 4/0 ACSR Hodgenville-Magnolia 69 kV line section (8.2 miles) using 556.5 MCM ACSR/TW conductor (part of Hodgenville-Green County 69 kV circuit)	5/2022
Rebuild the Brodhead-Three Links Junction 69 kV line section (8.2 miles) using 556.5 MCM ACSR/TW wire (part of Walnut Grove-Three Links Junction 69 kV circuit)	12/2022
Rebuild the existing 4/0 & 266 MCM ACSR KU Carrollton-Milton 69 kV line section (13.9 miles) using 556.5 MCM ACSR/TW conductor.	12/2022
Rebuild the existing 3/0 ACSR Goddard-Oak Ridge 69 kV line section (8.04 miles) using 556.5 MCM ACSR/TW conductor (part of Goddard-Plumville 69 kV circuit)	6/2023
Rebuild the existing 3/0 ACSR Jellico Creek-Goldbug 69 kV line section (10.54 miles) using 556.5 MCM ACSR/TW conductor (part of McCreary County-KU Wofford 69 kV circuit)	9/2023
Rebuild the existing 4/0 ACSR Three Links-Conway 69 kV line section (7.8 miles) using 556.5 MCM ACSR/TW conductor (part of Three Links Junction-Tyner 69 kV circuit)	9/2023
Rebuild Norwood Junction - Shopville 69 kV line section (6.3 miles) using 556.5 MCM ACSR/TW conductor (part of Somerset-Pulaski County-Walnut Grove 69 kV circuit)	12/2023
Rebuild the existing 3/0 ACSR Goldbug-KU Wofford 69 kV line section (2.33 miles) using 556.5 MCM ACSR/TW conductor (part of McCreary County-KU Wofford 69 kV circuit)	12/2023
Rebuild the existing 4/0 ACSR Milton-EK Bedford 69 kV line section (8.7 miles) using 556.5 MCM ACSR/TW conductor.	12/2023
Rebuild the existing 4/0 ACSR Magnolia-Summersville 69 kV line section (15.0 miles) using 556.5 MCM ACSR/TW conductor (part of Hodgenville-Green County 69 kV circuit)	12/2023
Rebuild the existing 3/0 ACSR Beattyville-Beattyville Distribution 69 kV line section (1.91 miles) using 556.5 MCM ACSR/TW conductor (part of Beattyville-Tyner 69 kV circuit)	5/2024
Rebuild the existing 3/0 ACSR Oak Ridge-Charters 69 kV line section (8.95 miles) using 556.5 MCM ACSR/TW conductor (part of Goddard-Plumville 69 kV circuit)	9/2024

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2020 – 2029)	
B. Transmission Line Re-conductor/Rebuilds Project Description	**Needed In-Service Date**
Rebuild the existing 3/0 ACSR of the Beattyville Distribution-Booneville 69 kV line section (7.0 miles) using 556.5 MCM ACSR/TW conductor (part of Beattyville-Tyner 69 kV circuit)	5/2025
Rebuild the existing 4/0 ACSR Boone-Big Bone 69 kV line section (6.3 miles) using 556.5 MCM ACSR/TW conductor (part of Boone-Owen County 69 kV circuit)	6/2025
Rebuild the existing 4/0 ACSR Big Bone-Munk 69 kV line section (7.0 miles) using 556.5 MCM ACSR/TW conductor (part of Boone-Owen County 69 kV circuit)	6/2025
Rebuild the existing 4/0 ACSR Munk-Oakley Noel 69 kV line section (4.54 miles) using 556.5 MCM ACSR/TW conductor (part of Boone-Owen County 69 kV circuit)	6/2025
Rebuild the existing 4/0 ACSR Oakley Noel-Munk Junction 69 kV line section (5.76 miles) using 556.5 MCM ACSR/TW conductor (part of Boone-Owen County 69 kV circuit)	6/2025
Rebuild the existing 4/0 ACSR Munk Junction-Williamstown 69 kV line section (4.9 miles) using 556.5 MCM ACSR/TW conductor (part of Boone-Owen County 69 kV circuit)	6/2025
Rebuild the existing 4/0 ACSR Clay Village-Clay Village KU 69 kV line section (1.6 miles) using 556.5 MCM ACSR/TW conductor	6/2025
Rebuild the existing 4/0 ACSR Boone-Burlington 69 kV line section (2.9 miles) using 556.5 MCM ACSR/TW conductor (part of Boone-Hebron 69 kV circuit)	6/2025
Rebuild the existing 4/0 ACSR Burlington-Bullittsville 69 kV line section (3.5 miles) using 556.5 MCM ACSR/TW conductor (part of Boone-Hebron 69 kV circuit)	6/2025
Rebuild the existing 3/0 ACSR Booneville-White Oak 69 kV line section (5.48 miles) using 556.5 MCM ACSR/TW conductor (part of Beattyville-Tyner 69 kV circuit)	5/2026
Rebuild the existing 4/0 ACSR Morgan County-Maytown Junction 69 kV line section (10.2 miles) using 556.5 MCM ACSR/TW conductor (part of Hope-Morgan County 69 kV circuit)	5/2027
Rebuild the existing 4/0 ACSR Morgan Co-Hot Mix Road 69 kV line (2.1 miles) using 556.5 MCM ACSR/TW conductor (part of Morgan County-Skaggs 69 kV circuit)	9/2027
Rebuild the existing 3/0 ACSR of the White Oak-Tyner 69 kV line (14.9 miles) using 556 MCM ACSR conductor. (Beattyville-Tyner)	5/2028

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2020 – 2029)	
C. Transmission Line High Temperature Upgrades Project Description	**Needed In-Service Date**
Increase the maximum conductor operating temperature of the 556.5 MCM ACSR conductor in the KU Elizabethtown-Tharp Tap 69 kV line section (0.71 miles) from 212F to 302F.	7/2020

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2020 – 2029)	
D. New Transmission Substations Project Description	**Needed In-Service Date**
Add a new 161 kV station, including a new 161-69 kV 150 MVA autotransformer, at Fox Hollow 69 KV substation.	12/2021

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2020 – 2029)	
E. New Transmission Switching Stations Project Description	**Needed In-Service Date**
Construct a new Patriot Parkway 69 kV switching station along the Elizabethtown-KU Rogersville 69 kV line, near the Rineyville Junction tap point.	12/2021
Construct a new Penn 69 kV switching station at the existing Penn distribution substation location.	12/2021
Construct a new EK Carrollton 69 KV switching station near the KU Carrollton substation.	12/2025

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2020 – 2029)	
G. Capacitor Bank Reductions Project Description	**Needed In-Service Date**
Reduce the size of the Pulaski County capacitor bank from 23.4 MVAR to 16.837 MVAR	12/2020
Retire the Lancaster 13.2 MVAR capacitor bank	12/2020
Reduce the size of the Bloomfield capacitor bank from 15.31 MVAR to 13.776 MVAR	12/2020
Reduce the size of the Thelma capacitor bank from 16.8 MVAR to 15.307 MVAR	12/2020

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2020 – 2029)	
G. Capacitor Bank Reductions Project Description	**Needed In-Service Date**
Reduce the size of the Slat capacitor bank from 20.41 MVAR to 16.327 MVAR	12/2021
Reduce the size of the Maytown capacitor bank from 10.2 MVAR to 8.164 MVAR	12/2021
Reduce the size of the Loretto capacitor bank from 13.78 MVAR to 10.715 MVAR	12/2021
Reduce the size of the Coburg capacitor bank from 8.4 MVAR to 7.143 MVAR	12/2021
Retire the Newfoundland 14.4 MVAR capacitor bank	12/2021
Reduce the size of the Munfordville capacitor bank from 23.4 MVAR to 14.286 MVAR	12/2022
Reduce the size of the Sublett capacitor bank from 14.4 MVAR to 10.798 MVAR	12/2022
Reduce the size of the Woodlawn capacitor bank from 19.8 MVAR to 16.837 MVAR	12/2022
Retire the Lees Lick 10.71 MVAR capacitor bank	12/2022

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2020 – 2029)	
H. Terminal Facility Upgrades Project Description	**Needed In-Service Date**
Upgrade disconnect switch W45-643 associated with the Green County 161/69kV auto transformer to 1200A	5/2020
Upgrade the jumper associated with Green County - KU Greensburg 69 kV line section from 4/0 ACSR to 556 MCM ACSR	5/2020
Replace the 5% reactor in the Spurlock-KU Kenton 138 kV line with a 7.5% reactor	6/2020
Upgrade the current transformer associated with Clay Village - KU Clay Village Tap 69 kV line section to at least 76 MVA Winter Long-Term Emergency rating	12/2021

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2020 – 2029)	
I. New Distribution Substations and associated Tap Lines Project Description	**Needed In-Service Date**
Construct a new North Sharkey 138-25 KV 18/24/30 MVA substation and associated 138 kV tap line (0.7 miles).	9/2020
Construct a new South Marion Industrial Park 161-13.8 KV 30/40/50 MVA substation and associated 161 kV tap line (0.25 miles).	11/2020
Construct a new White Oak Distribution substation and associated 69 kV tap line (0.1 mile). Retire the existing South Fork substation.	12/2021
Construct a new Broughtontown 69-25 KV 12/16/20 MVA substation and associated 69 kV tap line (7.4 miles).	12/2021

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2020 – 2029)	
J. Distribution Substation Additions and Upgrades Project Description	**Needed In-Service Date**
Upgrade the existing Alcan #1 distribution transformer from 11.2/14 to 12/16/20 MVA	6/2020
Rebuild the Lancaster station in a new location, including a new ~1.5 mile 69 kV transmission tap line, and upgrade to 12/16/20 MVA.	12/2020
Rebuild the Beattyville distribution substation in a new location, including a new 69 kV tap line (0.1 mile), and upgrade to 12/16/20 MVA.	12/2020
Rebuild and upgrade the Lees Lick distribution substation to 12/16/20 MVA	12/2020
Rebuild and upgrade the Monticello substation to 12/16/20 MVA	12/2020
Upgrade the 3M #1 distribution transformer from 11.2/14 MVA to 15/20/25 MVA	12/2021
Rebuild and upgrade the Penn distribution substation from 11.2/14 MVA to 12/16/20 MVA.	11/2022
Rebuild and upgrade the Highland distribution substation from 11.2/14 MVA to 12/16/20 MVA, including a new 69 kV transmission tap line (0.1 mile)	12/2022
Rebuild and upgrade the Rice distribution substation from 11.2/14 MVA to 12/16/20 MVA	12/2022
Rebuild and upgrade the existing Albany distribution substation from 11.2/14 MVA to 12/16/20 MVA	12/2023

Price Elasticity of Demand

1 Introduction

East Kentucky Power Cooperative, Inc. ("EKPC") filed an Integrated Resource Plan ("IRP") with the Kentucky Public Service Commission ("KPSC") on April 23. 2012[1]. The KPSC Staff filed a report titled "Staff Report on the 2012 Integrated Resource Plan of East Kentucky Power Cooperative, Inc. ", on September 2013. In its report, Staff recommended that "EKPC should discuss and report separately the impact on demand and energy forecasts of any projected increases in the price of electricity to its ultimate customers in its next IRP. The price elasticity of the demand for electricity should be fully examined and discussed, and a sensitivity analysis should be performed."

2 Study Objective

EKPC engaged GDS Associates, Inc. ("GDS") to conduct an independent study to estimate price elasticity of demand from primary source data to allow EKPC forecasters to verify and refine the elasticity assumptions that have been assumed for previous planning analyses, and to provide a basis for elasticity assumptions used in future load forecasts. Additionally, in efforts to provide support for EKPC's analysis, the study entailed conducting secondary research to identify price elasticity study results conducted by other electric utilities and research firms. In response to the recommendation made by Staff, this report presents the estimated impact of potential increases in the price of electricity to EKPC's ultimate customers. Additionally, results of the study provide the input necessary to conduct sensitivity analysis in EKPC's next load forecast and IRP.

3 Methodology

Econometric modeling was used to perform the price elasticity analysis. Multiple model specifications were investigated to help provide a reasonable range of elasticity estimates. Models were developed at the aggregate EKPC level by customer class and at the member distribution cooperative level by class. All models were analyzed using data on an annual and monthly basis. GDS developed the methodology, conducted the analysis, and reviewed the methodology and results with EKPC staff prior to publishing this report.

3.1 Data

A database of the components necessary to build econometric models was developed by EKPC and provided to GDS. This section describes the data and sources used for the analysis.

3.1.1 Utility Billing History

Monthly number of customers, kWh sales, and revenues by revenue class (residential, commercial, industrial, street lighting, and public authorities) were compiled for each member cooperative for January 2000 through September 2014.

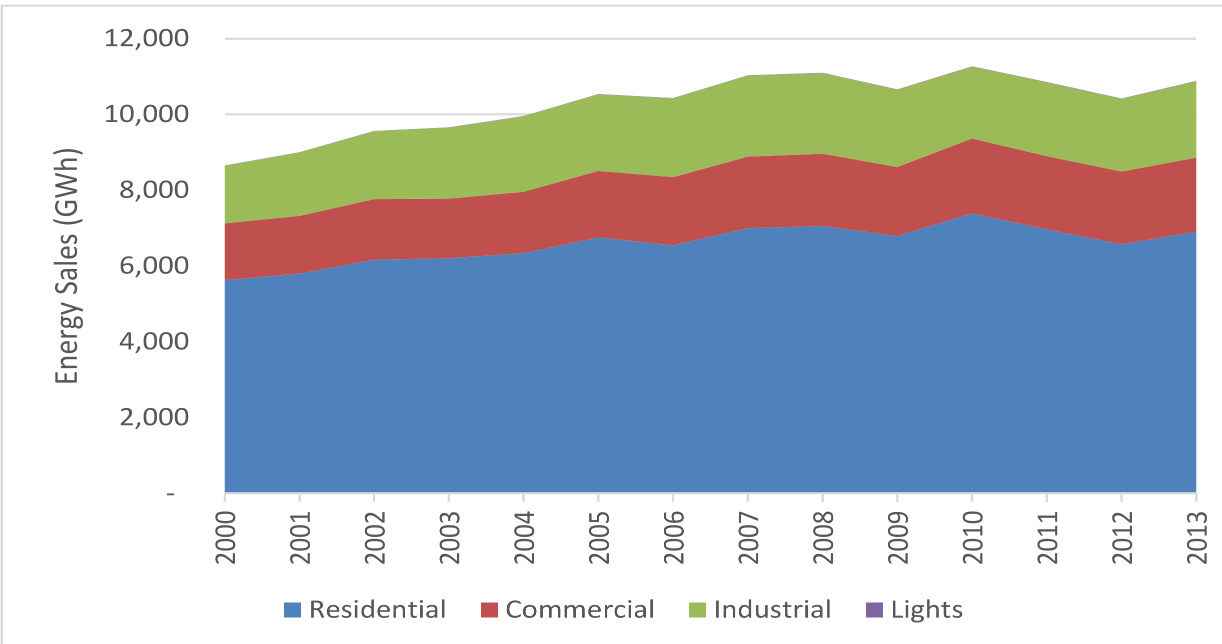
The residential class represents 93% of the total number of customers served by EKPC's member distribution cooperatives. In 2013, the class represented 58% of total energy sales, totaling 6,900 GWh. Residential energy sales have grown by an average compound rate of 1.6% per year from 2000 through 2013.

[1] KPSC Case No. 2012-00149

The commercial class, including public authority accounts, represented 7% of EKPC's customers and 18% of energy sales in 2013. In terms of both number of customers and energy sales, the class grew faster than the residential class from 2000 through 2013. Energy sales averaged 2.1% per year in compound growth.

The industrial class consists of less than 150 total accounts, but represented 25% of total energy sales in 2013. Growth in the industrial class has been healthy, averaging 2.2% per year in energy sales growth.

Figure 2.1 – Energy Sales by Class (2000-2013)



3.1.2 Price of Electricity

Nominal price of electricity was computed using the utility billing history. Annual average revenue per kWh was used to represent nominal price each year. The Purchase Consumption Expenditure ("PCE") deflator, provided by Woods & Poole Economics, Inc., was used to compute real price of electricity. The annual real price of electricity was used to represent price in every month for econometric models developed using monthly data.

Table 2.1 – Purchase Consumption Expenditure Deflator (2009=100)

Year	PCE	Year	PCE
2000	83.1	2008	100.1
2001	84.7	2009	100.0
2002	85.9	2010	101.7
2003	87.6	2011	104.1
2004	89.7	2012	106.0
2005	92.3	2013	107.3
2006	94.7	2014	109.4
2007	97.1		

Real residential price has risen by an average of 7% per year from 2000 through 2013. Commercial and industrial prices have risen a little more modestly at 5% per year.

Figure 2.2 – Residential Price (EKPC Total)

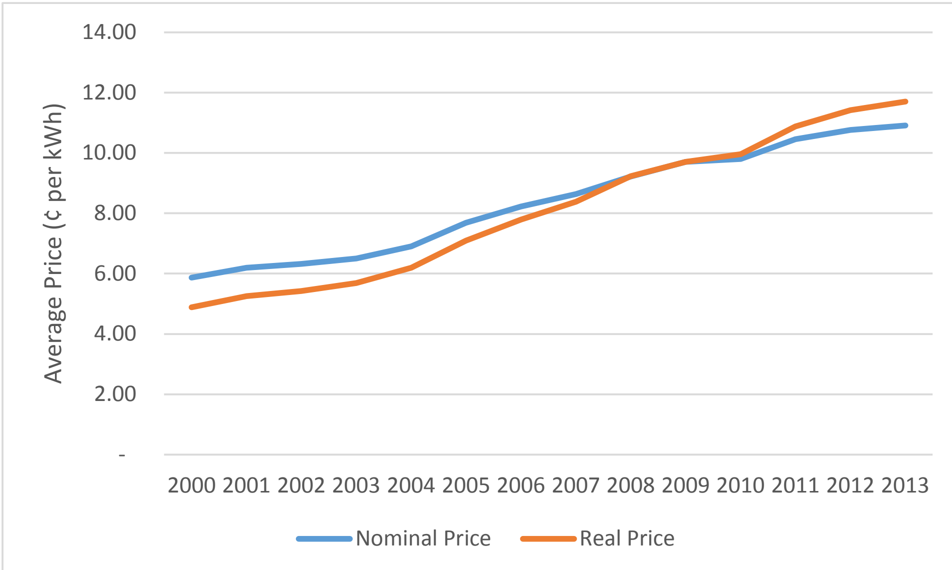
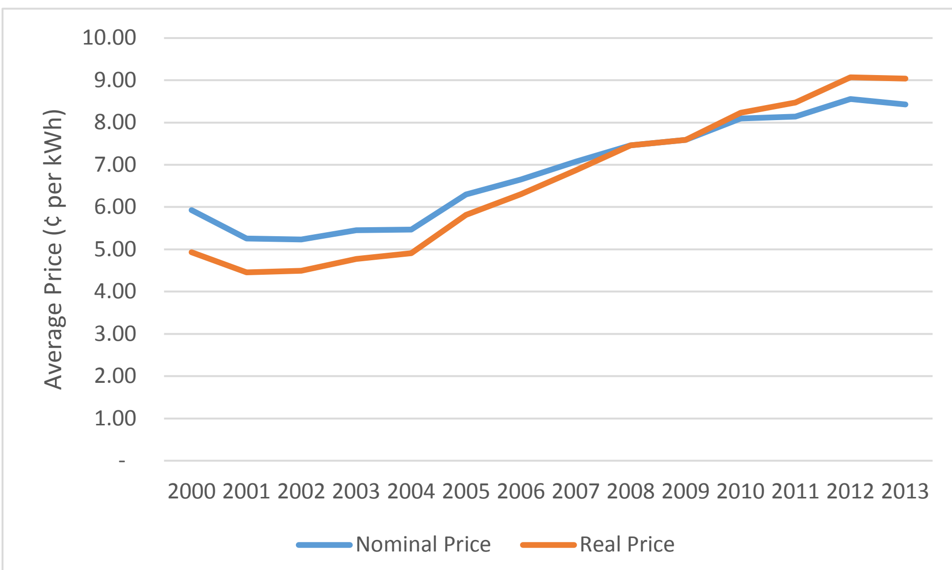


Figure 2.3 – Commercial and Industrial Price (EKPC Total)



3.1.3 Weather Data

Monthly heating degree days ("HDD") and cooling degree days ("CDD") were obtained from the National Oceanic and Atmospheric Association ("NOAA"). Seven weather stations are used to represent local climatological conditions for EKPC's members (see Table 2.2). Due to the fact that reported kWh sales are often based on billing cycle readings and weather data are perfect calendar months, models were tested using actual month weather data, one month lag of weather data, and an average of the current and prior month.

Table 2.2 – Weather Station Assignment

Weather Station	EKPC Member Cooperatives Assigned to Station
Lexington, KY	Blue Grass Energy Cooperative, Clark Energy Cooperative, Inter-County Energy Cooperative
Bowling Green, KY	Farmers RECC, Taylor County RECC
Covington, KY	Fleming-Mason Energy Cooperative, Owen Electric Cooperative
Huntington, WV	Grayson RECC
Jackson, KY	Big Sandy RECC, Cumberland Valley Electric, Jackson Energy Cooperative, Licking Valley RECC
Louisville, KY	Nolin RECC, Salt River Electric Cooperative, Shelby Energy Cooperative
Somerset, KY	South Kentucky RECC

For the EKCP aggregate analyses, weighted average HDD and CDD were computed using class sales assigned to each weather station in each month as the weighting factors.

3.1.4 Economic Data

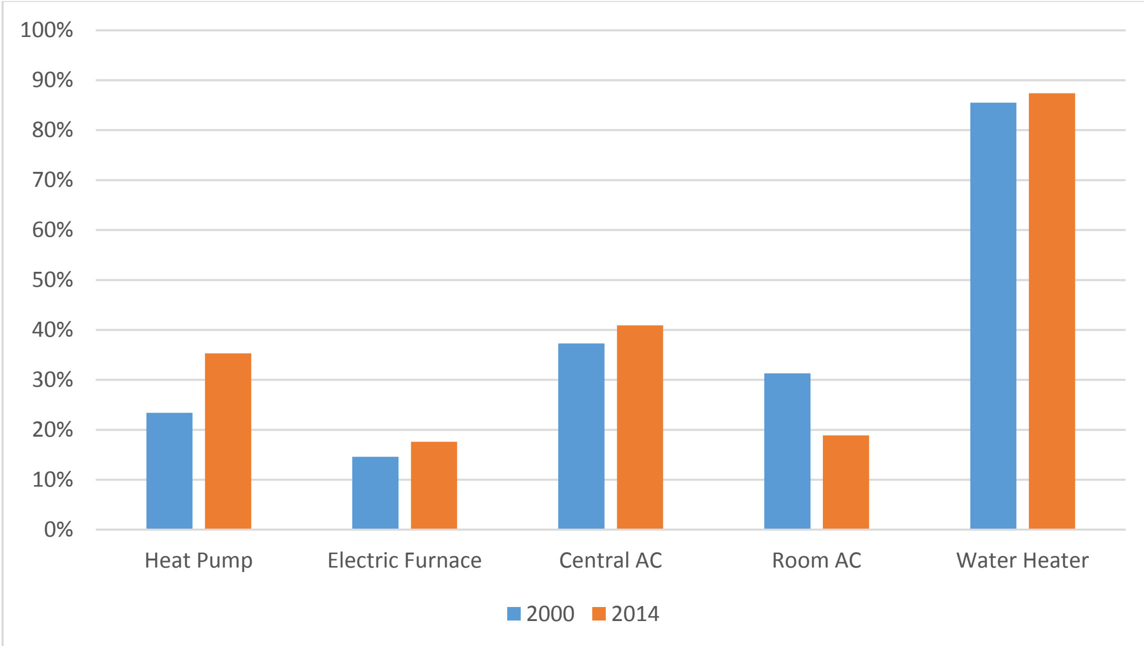
Economic time series data for each member cooperative's service territory was collected from IHS Global Insight[2]. Global Insight draws data from the US Census Bureau, the Bureau of Labor Statistics, and the Bureau of Economic Analysis to develop historical economic time series. For this study, population, real total personal income, and employment were included in the analysis database.

3.1.5 Residential End-Use Appliance Data

Residential electric appliance saturation data was provided to GDS by EKPC staff. The most recent survey was completed in 2013, and surveys have been conducted every two to three years since 1981. EKPC staff interpolated market share information for the intervening years. Appliance efficiency trends over time for major end-use appliances (HVAC equipment and water heaters) were obtained from the Energy Information Administration's ("EIA") Annual Energy Outlook. Appliance saturations are specific to the member service territories. Appliance efficiencies are assumed to be consistent for the entire EKPC territory.

[2] Economic Outlook, March 2014

Figure 2.4 – Residential Electric End-Use Saturations (EKPC Total)



3.2 Econometric Modeling

Several econometric model specifications were designed and tested to evaluate price elasticity of demand. Furthermore, models were developed for the entire EKPC territory in aggregate and for each individual member distribution cooperative. The following sections describe the model designs for the residential and commercial classes. Resultant elasticity estimates produced by these models are provided in Section 3.

3.2.1 Residential Models

Three separate model specifications were tested for the residential price elasticity estimate, one using monthly data and two using annual data. Equations 2.1 through 2.3 show the models tested for aggregate EKPC residential usage. Equations 2.1 and 2.2 were tested for individual member cooperatives.

Equation 2.1

$$AvgUse_{y,m} = \beta_0 + \beta_1 RealPrice_y + \beta_2 PCAPInc_{y,m} + \beta_3 wHDD_{y,m} + \beta_4 wCDD_{y,m} + \varepsilon_{y,m}$$

Equation 2.2

$$AvgUse_y = \beta_0 + \beta_1 RealPrice_y + \beta_2 PCAPInc_y + \beta_3 wHDD_y + \beta_4 wCDD_y + \varepsilon_y$$

Equation 2.3

$$Ln(AvgUse_{y)} = \beta_0 + \beta_1 Ln(RealPrice_y) + \beta_2 Ln(PCAPInc_y) + \beta_3 Ln(wHDD_y) + \beta_4 Ln(wCDD_y) + \varepsilon_y$$

Where:

β_0, β_1, β_2, β_3, and β_4	Regression coefficients
y	Index for the year
m	Index for the month
AvgUse	Residential average usage (kWh per customer)
RealPrice	Real price of electricity
PCAPInc	Per capita income
wHDD	Weighted heating degree days (see further explanation below)
wCDD	Weighted cooling degree days (see further explanation below)
Ln	Natural logarithm
ε	Error term

For some of the individual member models, per capita income had a negative coefficient or had a coefficient with a p-value well in excess of 0.20. A negative coefficient for per capita income is theoretically incorrect, indicating average household energy consumption declines as income increases. In such instances, per capita income was removed from the models.

GDS also tested for first order autocorrelation in the residuals using the Durbin-Watson statistic. In models in which autocorrelation was evident, a first order autoregressive parameter was included in the model to correct for the correlation. This correction helps produce unbiased and more efficient estimators of the coefficients relative to a model with correlated residuals and no autoregressive parameter.

3.2.1.1 Weighted HDD and CDD

For the residential models, HDD and CDD were weighted to take electric appliance market share and efficiency into account. In theory, average usage will be more sensitive to weather as weather-sensitive electric appliances are added to the home (HVAC and water heaters). Likewise, as those appliances become more efficient, average usage will become less sensitive to weather. Therefore, a weighting scheme is developed for the HDD and CDD that effectively multiplies the weather variables by market share (direct relationship) and divides by an index for the change in efficiency over time (indirect relationship). For example, the weights for HDD in January 2000 and January 2014 are shown in table 2.3.

Table 2.3 – Example Development of HDD weights

Line No.	Item	Formula	January 2000	January 2014
[1]	Heat Pump Saturation		0.234	0.351
[2]	Heat Pump Efficiency (HSPF)		6.830	7.550
[3]	Efficiency Index (Sep 2014=1.00)		0.896	0.991
[4]	Heat Pump Weight	[1]÷[3]	0.261	0.354
[5]	Electric Furnace Saturation		0.146	0.175
[6]	Furnace Efficiency		3.410	3.410
[7]	Efficiency Index (Sep 2014=1.00)		1.000	1.000
[8]	Heat Pump Weight	[5]÷[7]	0.146	0.175
[9]	Weight for HDD	[4]+[8]	0.407	0.529

3.2.2 Small Commercial Models – EKPC Aggregate

Three separate model specifications were tested for the aggregate EKPC small commercial price elasticity estimate, one using monthly data and two using annual data. Equations 2.4 through 2.6 show the models tested.

Equation 2.4

$$AvgUse_{y,m} = \beta_0 + \beta_1 RealPrice_y + \beta_2 Emp_{y,m} + \beta_3 HDD_{y,m} + \beta_4 CDD_{y,m} + \varepsilon_{y,m}$$

Equation 2.5

$$AvgUse_y = \beta_0 + \beta_1 RealPrice_y + \beta_2 Emp_y + \beta_3 HDD_y + \beta_4 CDD_y + \varepsilon_y$$

Equation 2.6

$$Ln(AvgUse_{y)} = \beta_0 + \beta_1 Ln(RealPrice_y) + \beta_2 Ln(Emp_y) + \beta_3 Ln(HDD_y) + \beta_4 Ln(CDD_y) + \varepsilon_y$$

Where:

β_0, β_1, β_2, β_3, and β_4	Regression coefficients
y	Index for the year
m	Index for the month
AvgUse	Residential average usage (kWh per customer)
RealPrice	Real price of electricity
Emp	Employment
HDD	Billing cycle heating degree days
CDD	Billing cycle cooling degree days
Ln	Natural logarithm
ε	Error term

3.2.3 Industrial Models – EKPC Aggregate

Three separate model specifications were tested for the industrial price elasticity estimate for aggregate EKPC industrial sales, one using monthly data and two using annual data. Equations 2.7 through 2.9 show the models tested.

Equation 2.7

$$AvgUse_{y,m} = \beta_0 + \beta_1 RealPrice_y + \beta_2 Emp_{y,m} + \sum_m \beta_{3,m} I_m + \varepsilon_{y,m}$$

Equation 2.8

$$AvgUse_y = \beta_0 + \beta_1 RealPrice_y + \beta_2 Emp_y + \varepsilon_y$$

Equation 2.9

$$Ln(AvgUse_{y)} = \beta_0 + \beta_1 Ln(RealPrice_y) + \beta_2 Ln(Emp_y) + \varepsilon_y$$

Where:

β_0, β_1, β_2, and $\beta_{3,m}$	Regression coefficients
y	Index for the year
m	Index for the month
AvgUse	Residential average usage (kWh per customer)
RealPrice	Real price of electricity
Emp	Employment
I_m	Indicator variable for month m
Ln	Natural logarithm
ε	Error term

3.2.4 Commercial and Industrial Models by Member Cooperative

Econometric models consistent with Equation 2.4 were run for the combined commercial and industrial classes by member cooperative. As will be discussed further in Section 3, however, it was difficult to produce models for some members that provided theoretically sound results for price elasticity.

4 Results and Conclusions

At the EKPC aggregate level, the multiple econometric specifications produced elasticity estimates that were statistically equivalent at 90% confidence. The residential models by member cooperative produced a wider array of results as might be expected, but all provided a theoretically correct negative price elasticity estimate. The same cannot be said for all C&I models at the member cooperative level.

4.1 Residential Elasticity

The measured overall price elasticity of demand is approximately -0.25, indicating that a 1% increase in real prices will result in a 0.25% decrease in residential average usage per household across the entire EKPC system. Individual member results vary from a low of -0.02 to a high of -0.73. The higher variability in elasticity estimates at the member level is more likely a function of the data than a true significant difference in price response across different territories. Data adjustments, alignment of billing cycles with weather, and other anomalies are more likely to impact results at the member-level, whereas aggregate data will help average out some of that noise in the data and provide a truer estimate of overall price sensitivity.

Table 3.1 – Aggregate EKCP Residential Price Elasticity Estimates

Model Specification	Estimated Price Elasticity
Monthly Model (Equation 2.1)	-0.271
Annual Model (Equation 2.2)	-0.247
Annual Log-Log Model (Equation 2.3)	-0.181

None of the elasticity estimates shown in Table 3.1 can be verified as statistically different from the others at 90% confidence. Three separate modeling approaches providing consistent results supports the conclusion that the estimated elasticity is reasonable.

Table 3.2 – Member Cooperative Residential Price Elasticity Estimates

Member	Monthly Model (Equation 2.1) Price Elasticity Estimate	Annual Model (Equation 2.2) Price Elasticity Estimate
Jackson Energy Cooperative	-0.730	-0.298
Salt River Electric Cooperative	-0.023	-0.131
Taylor County RECC	-0.069	-0.488
Inter-County Energy Coop.	-0.172	-0.124
Shelby Energy Cooperative	-0.049	-0.035
Farmers RECC	-0.260	-0.223
Owen Electric Cooperative	-0.239	-0.062
Clark Energy Cooperative	-0.190	-0.187
Nolin RECC	-0.156	-0.116
Fleming-Mason Energy Coop.	-0.201	-0.287
South Kentucky RECC	-0.232	-0.177
Licking Valley RECC	-0.105	-0.076
Cumberland Valley Electric	-0.333	-0.060
Big Sandy RECC	-0.163	-0.194
Grayson RECC	-0.517	-0.240
Blue Grass Energy Cooperative	-0.128	-0.121
Weighted Average*	***-0.233***	***-0.168***

* Weights based on 2013 residential energy sales.

Given that: a) noise in billing data has more impact at the member level, and b) for some member models, per capita income did not have significance in the model, GDS recommends that EKPC use a consistent price elasticity estimate based on the aggregated model results provided in Table 3.1**. It is concluded that an elasticity in the range of -0.20 and -0.30 would be a reasonable assumption based on the results of this analysis**.

4.2 Commercial and Industrial Elasticity

Commercial and industrial price elasticity estimates are lower than residential. The small commercial class has an elasticity of approximately -0.10 and the industrial class is about -0.05. Smaller commercial accounts might be quite price inelastic due to several factors, including having little control over electricity consumption (for instance a convenience store with many freezers and refrigerator cases), being a tenant that does not pay the electric bill, or having electricity generally be a small proportion of the budget. Furthermore, large commercial and industrial accounts are unlikely to alter operations in response to small changes in price, but there is certainly a point where, if price goes too high or margins are too low for a company, they might stop operation altogether or shut down a shift, causing a large response to price at some certain threshold. It is reasonable to assume that, as a class, commercial customers are less sensitive to long-term price changes than are residential customers.

Table 3.3 – Aggregate EKPC Commercial and Industrial Price Elasticity Estimates

Model Specification	Small Commercial Price Elasticity	Industrial Price Elasticity
Monthly Model (Equations 2.4 and 2.7)	-0.149	-0.102
Annual Model (Equation 2.5 and 2.8)	-0.117	-0.034
Annual Log-Log Model (Equation 2.6 and 2.9)	-0.097	-0.030

At the member distribution cooperative level, several of the models were unable to measure a statistically significant (indicating a likelihood of a zero elasticity) or theoretically correct (negative coefficient) price elasticity. Due to some members having very few industrial accounts, the member-level analysis was conducted for the commercial and industrial customers in aggregate. As with the residential elasticity, GDS would recommend use of a system-wide elasticity estimate for EKPC's load forecasting. An elasticity assumption in the range of -0.05 to -0.15 is for all commercial and industrial customers based on this analysis.

Table 3.4 – Member Cooperative C&I Price Elasticity Estimates

Member	Monthly Model (Equation 2.4) Price Elasticity Estimate
Jackson Energy Cooperative	-0.177
Salt River Electric Cooperative	-0.045
Taylor County RECC	-0.090
Inter-County Energy Coop.	-0.396
Shelby Energy Cooperative	n/a[1]
Farmers RECC	-0.221
Owen Electric Cooperative	-0.285
Clark Energy Cooperative	-0.131
Nolin RECC	-0.473
Fleming-Mason Energy Coop.	-0.067
South Kentucky RECC	n/a[1]
Licking Valley RECC	-0.023
Cumberland Valley Electric	n/a[1]
Big Sandy RECC	-0.175
Grayson RECC	-0.384
Blue Grass Energy Cooperative	-0.094

4.3 Secondary Research

Secondary research included a review of publically available information related to current price elasticity estimates being made by others in the industry. **Results of the review are provided below and confirm that the elasticity estimates derived for EKPC are consistent with industry estimates**.

Many utilities filing Integrated Resource Plans ("IRP") with regulatory commissions throughout the country make reference to using price of electricity in their forecasting models. However, many either do not indicate the assumed or resultant price elasticities, or they protect the information under confidentiality arrangements. GDS identified three utilities that included elasticity information publicly in their IRP reports. Delmarva Power and Light reported a residential elasticity of -0.13 in its 2014 IRP. They assumed a price elasticity of demand of -0.04 for commercial and -0.14 for industrial. Ameren Missouri's 2014 IRP states that the residential price elasticity they use is -0.14. They also reference a study conducted a few years prior to the 2014 IRP in which they estimated a residential elasticity of -0.16. Big Rivers Electric Corporation[3] reported a price elasticity of -0.18 for all rural customers combined in their 2014 IRP. KU/LGE reports in its March 2014 IRP that they used elasticity estimates of -0.1 for residential and -0.05 for commercial. These estimates are all reasonably consistent with the results obtained for EKPC.

The National Renewal Energy Laboratory ("NREL") completed an analysis of price elasticity in February 2006.[4] They found national residential elasticity of -0.24 and an elasticity of -0.27 for the East South Central region (of which Kentucky is a part). The estimated nationwide commercial price elasticity was -0.21 and the East South Central estimate was -0.27. Although the commercial elasticity estimates for NREL are higher than the EKPC estimates, they are close enough for practical purposes[5]. NREL also conducted analysis at the state level and determined that the price elasticity coefficient for the Kentucky model was not significantly different than zero for both the residential and commercial classifications.

Finally, GDS examined an analysis conducted by the EIA[6]. The study examined, in part, the impacts on energy consumption of potential policies that would limit energy-related carbon dioxide emissions. More specifically, the impacts of a future fee on CO_2 emissions were analyzed for three carbon-fee cases, \$10, \$20, and \$30 per metric ton of CO_2 in 2020 and rising by 5 percent per year annually thereafter. The EIA study was conducted at the national level and for each Census region. EIA reports that the electricity sector alters investment and operating decisions to reduce CO_2 emissions in response to CO_2 fees, and customers react to resulting higher retail electricity prices by cutting demand. An analysis of the changes in electricity prices and energy consumption for the three carbon-fee cases relative to the EIA reference case was performed, and the elasticity of demand (energy consumption) with respect to price for the residential and commercial sectors combined was -0.21 for the East South Central region.

4.4 Conclusions

Based on the analysis conducted, various model specifications produce stable elasticity estimates for the residential and commercial customer classes. Results at the aggregate EKPC level produce reliable estimates of long-term price elasticity of demand for electricity consumption. The range of values estimated from models at the member cooperative level are somewhat volatile but within a reasonable range of the aggregate estimates. GDS recommends use of the aggregate model results for purposes of analyzing load response to price anywhere in the EKPC territory. Furthermore, the estimates derived in

[3] GDS prepared Big Rivers' 2014 IRP, including performing the price elasticity analysis. The elasticity assumption was reported in the public version of the IRP.

[4] Bernstein, M.A. and J. Griffin. "Regional Differences in the Price-Elasticity of Demand for Energy." NREL, Subcontractor Report NREL/SR-620-39512. February 2006.

[5] Although the elasticity estimate of -0.1 for EKPC is half as much as the elasticity estimate of -0.2 for NREL's regional model, the estimated load reduction per 1% increase in price is only 0.1% different between the two assumptions.

[6] Energy Information Administration, *Further Sensitivity Analysis of Hypothetical Policies to Limit Energy-Related Carbon Dioxide Emission*, Supplement to the Annual Energy Outlook 2013, July 2013. http://www.eia.gov/forecasts/aeo/supplement/co2/pdf/aeo2013_supplement.pdf

this analysis are consistent with the price elasticity assumptions used by the US Energy Information Administration for its Annual Energy Outlook forecasting, providing greater confidence in the results obtained herein.

- GDS recommends using a **RESIDENTIAL** price elasticity in the range of **-0.20 TO -0.30** as a reasonable assumption for load forecasting residential price sensitivities.
- GDS recommends using a **COMMERCIAL** price elasticity in the range of **-0.05 TO -0.15** as a reasonable assumption for load forecasting commercial price sensitivities.