EAST KENTUCKY POWER COOPERATIVE

RECEIVED
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PUBLIC SERVICE
COMMISSION

March 31, 2015

Mr. Jeff Derouen
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. Derouen:

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 2014 Annual Resource Assessment for East Kentucky Power Cooperative, Inc. ("EKPC").

Also enclosed, please find a discussion of the consideration given to price elasticity in the forecasted demand, energy and reserve margin information provided in the Assessment, as requested in your May 31, 2013 letter to me.

If you have any questions, please call me.

Very truly yours,

Patrick C. Woods
Director, Regulatory and Compliance Services

Enclosures

4775 Lexington Rd. 40391
P.O. Box 707, Winchester,
Kentucky 40392-0707

Tel. (859) 744-4812
Fax: (859) 744-6008
www.ekpc.coop

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

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)

Amanda Stacy, 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.

Amanda Stacy

Subscribed and sworn before me on this 31st day of March, 2015.

Gwyn M. Willoughby
Notary Public

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

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, 2015.

Gwyn M. Willoughby
Notary Public

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

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.

Monthly Native Load Peak Demands for 2014

	Actual (Firm and Non-Firm) (MW)	Weather Adjusted (Firm and Non-Firm) (MW)
January	3,425	2,995
February	2,815	2,780
March	2,636	2,514
April	2,034	2,052
May	1,809	1,944
June	2,173	2,254
July	2,192	2,300
August	2,149	2,337
September	2,097	2,070
October	1,679	1,733
November	2,519	2,362
December	2,333	2,578

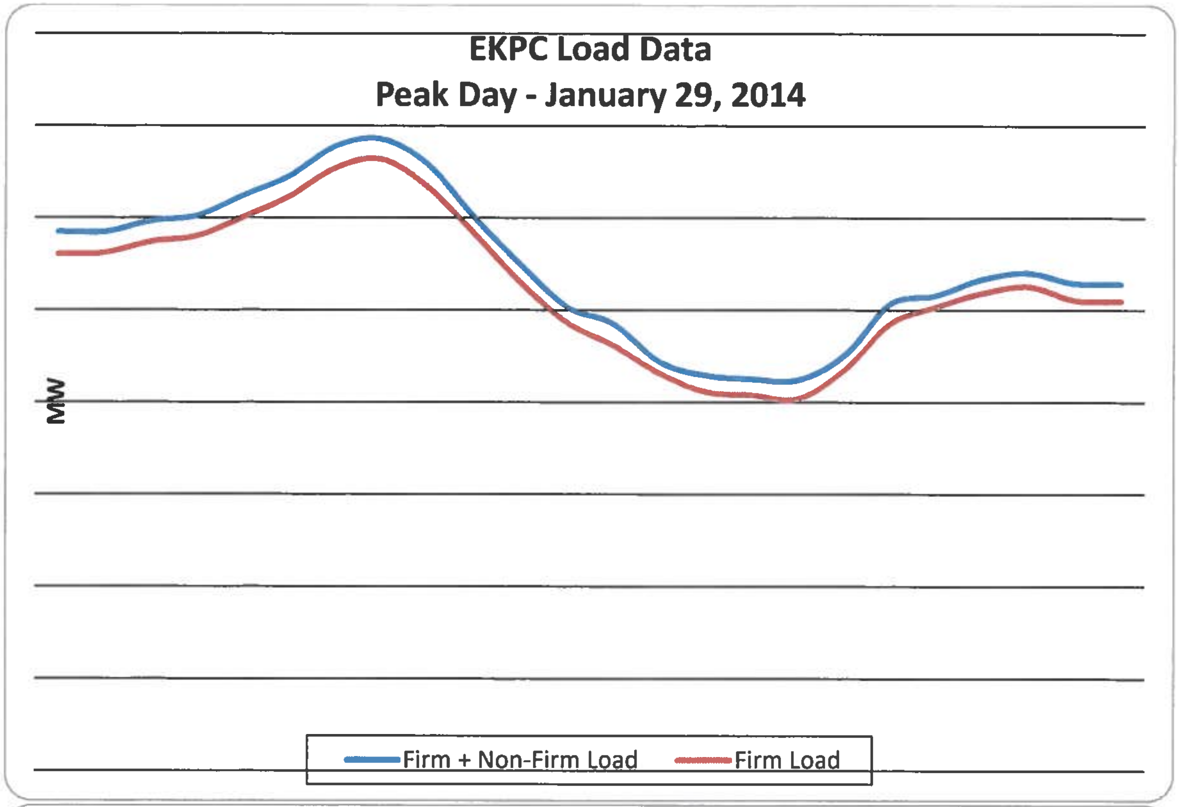
Response 3b. EKPC had no off-system demand obligations during the calendar year 2014.

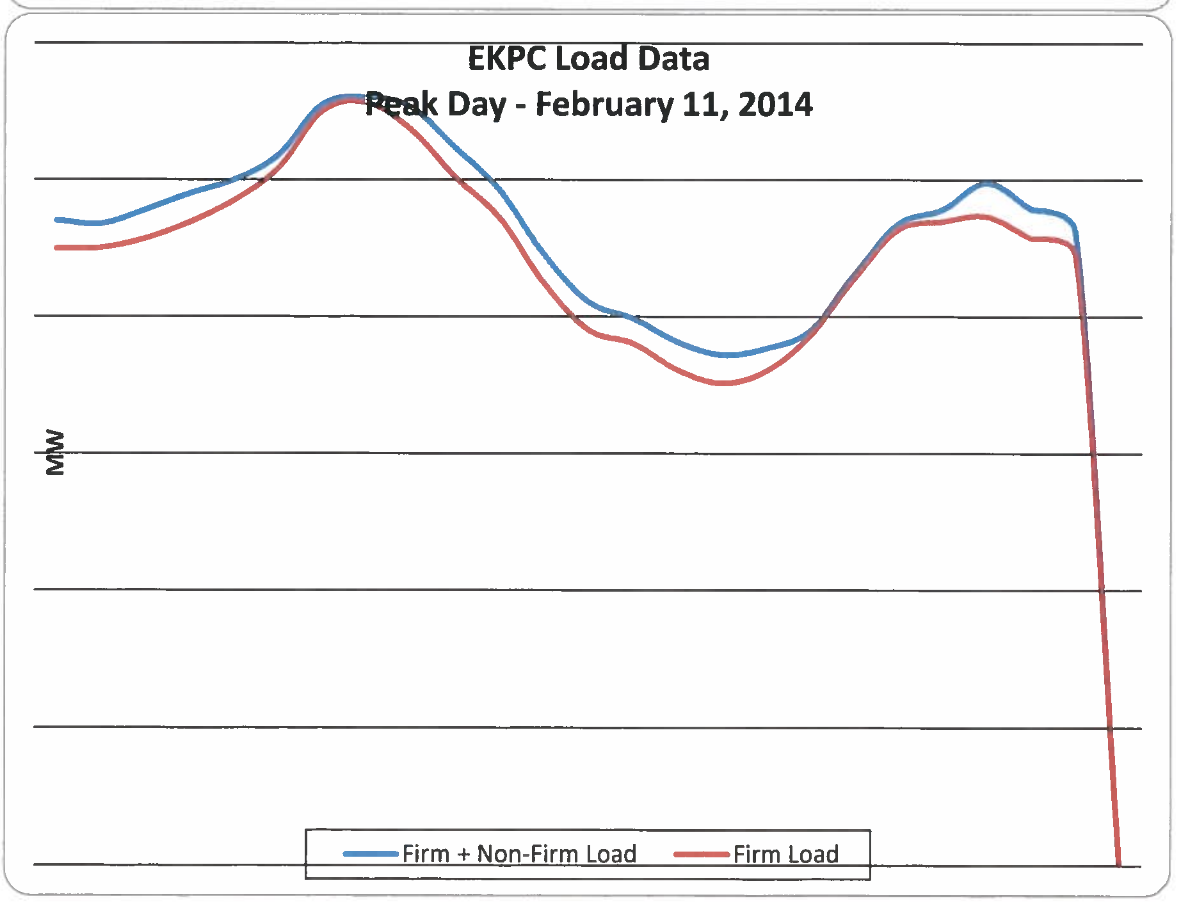
EAST KENTUCKY POWER COOPERATIVE, INC.
PSC ADMINISTRATIVE CASE NO. 387
ANNUAL RESOURCE ASSESSMENT FILING

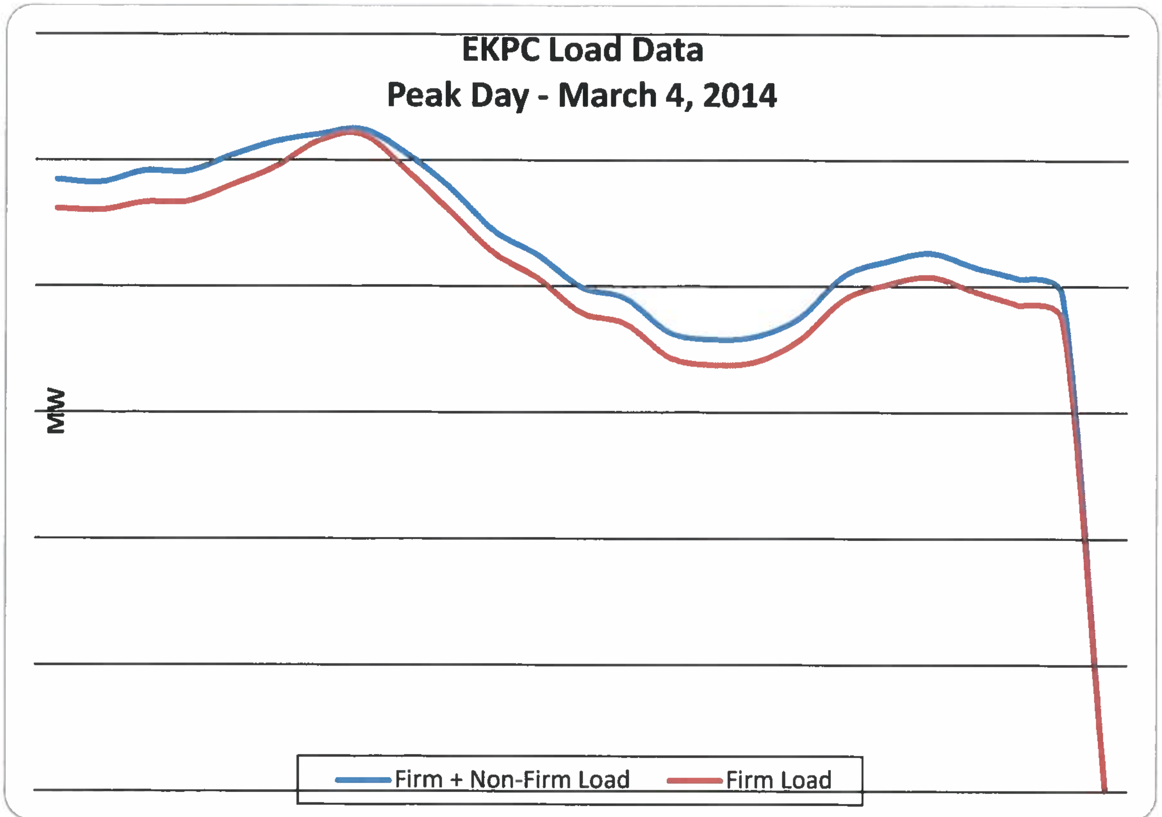
PUBLIC SERVICE COMMISSION REQUEST DATED 12/20/01
REQUEST 4
RESPONSIBLE PERSON: **Julia J. Tucker**
COMPANY: **East Kentucky Power Cooperative, Inc.**

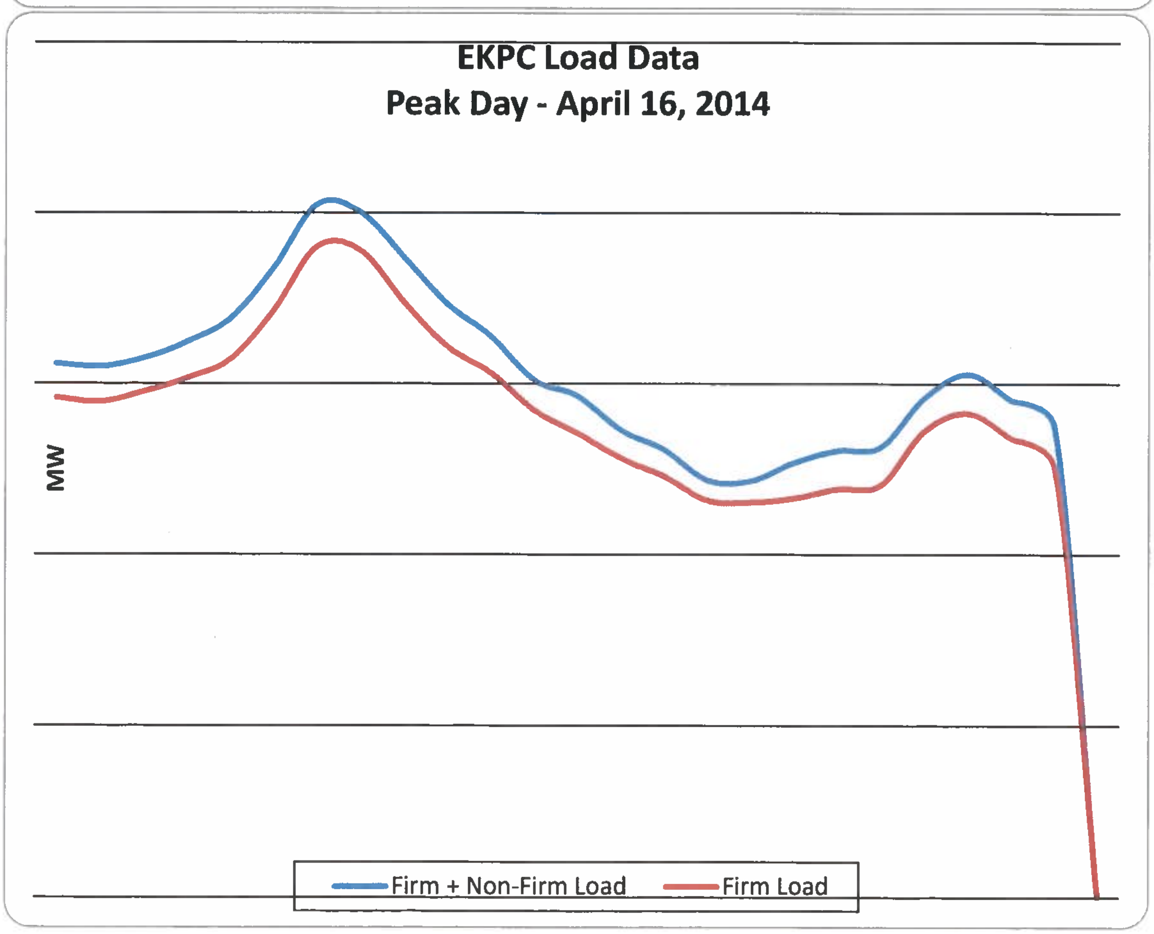
Request 4. Load shape curves that show actual peak demands and weather-normalized peak demands (native load demand and total demand) on a monthly basis for the just completed calendar year.

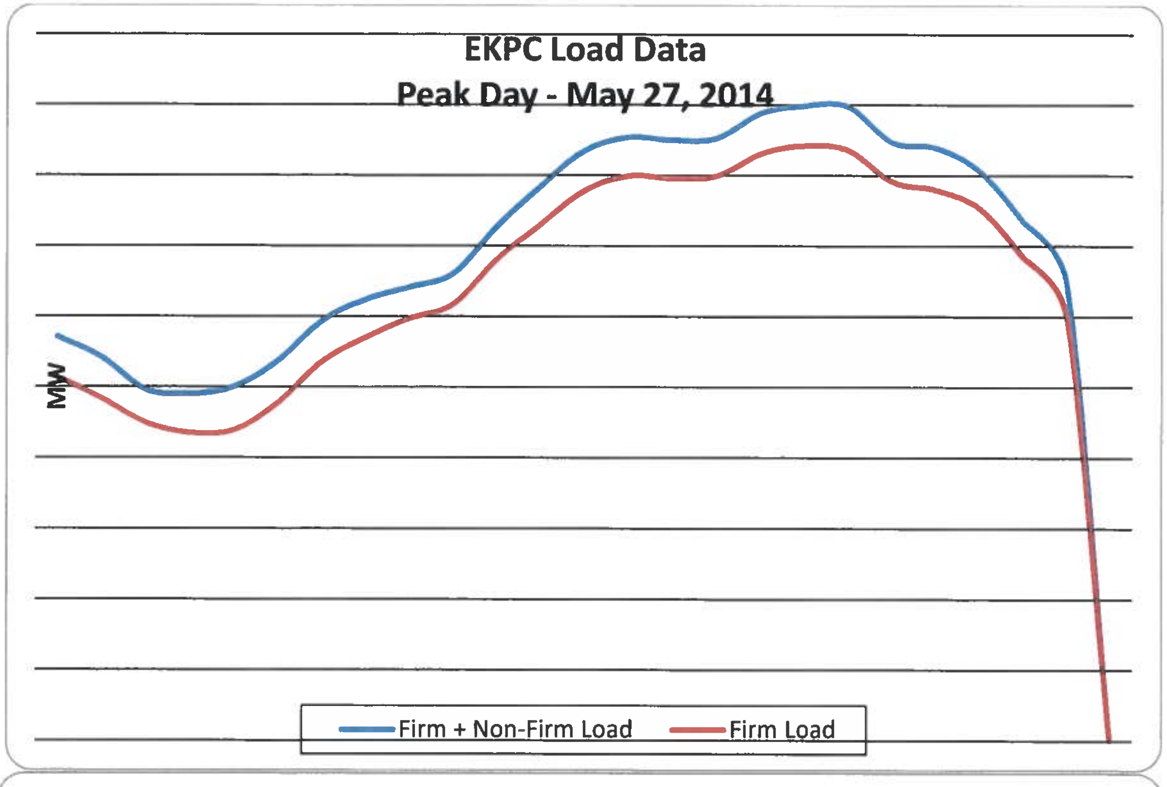
Response 4. Actual monthly peak-day load shapes are presented on pages 2 through 7 of this response. EKPC performs an analysis to weather-normalize the peak hour but EKPC does not weather-normalize the peak-day load shapes.

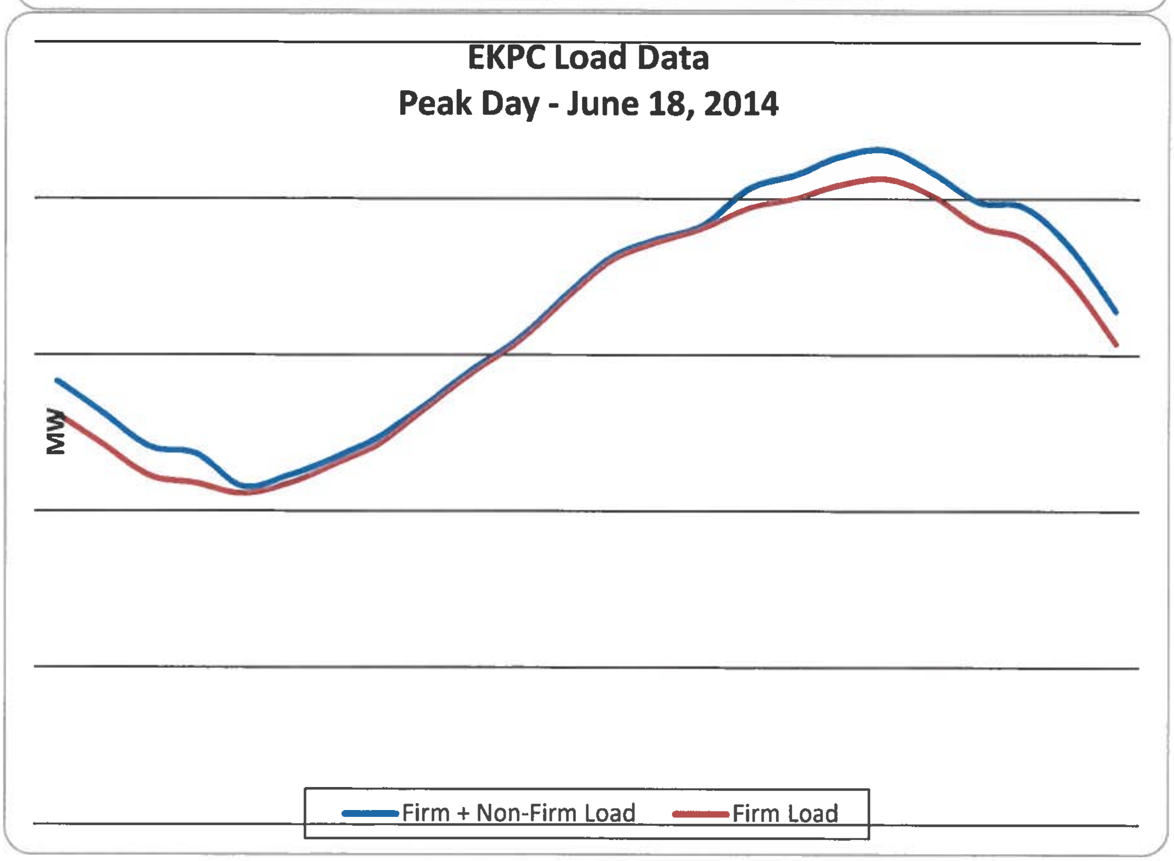

EKPC Load Data
Peak Day - January 29, 2014
MW
Firm + Non-Firm Load
Firm Load

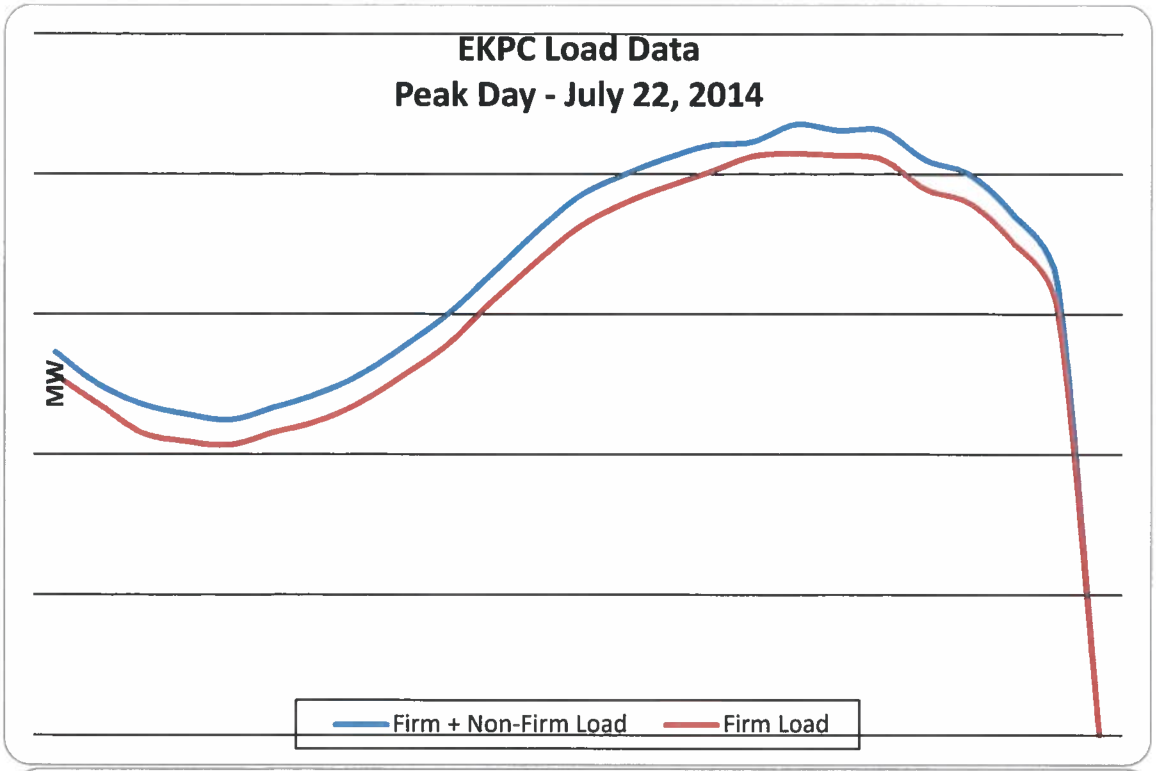

EKPC Load Data
Peak Day - February 11, 2014
MW
Firm + Non-Firm Load
Firm Load

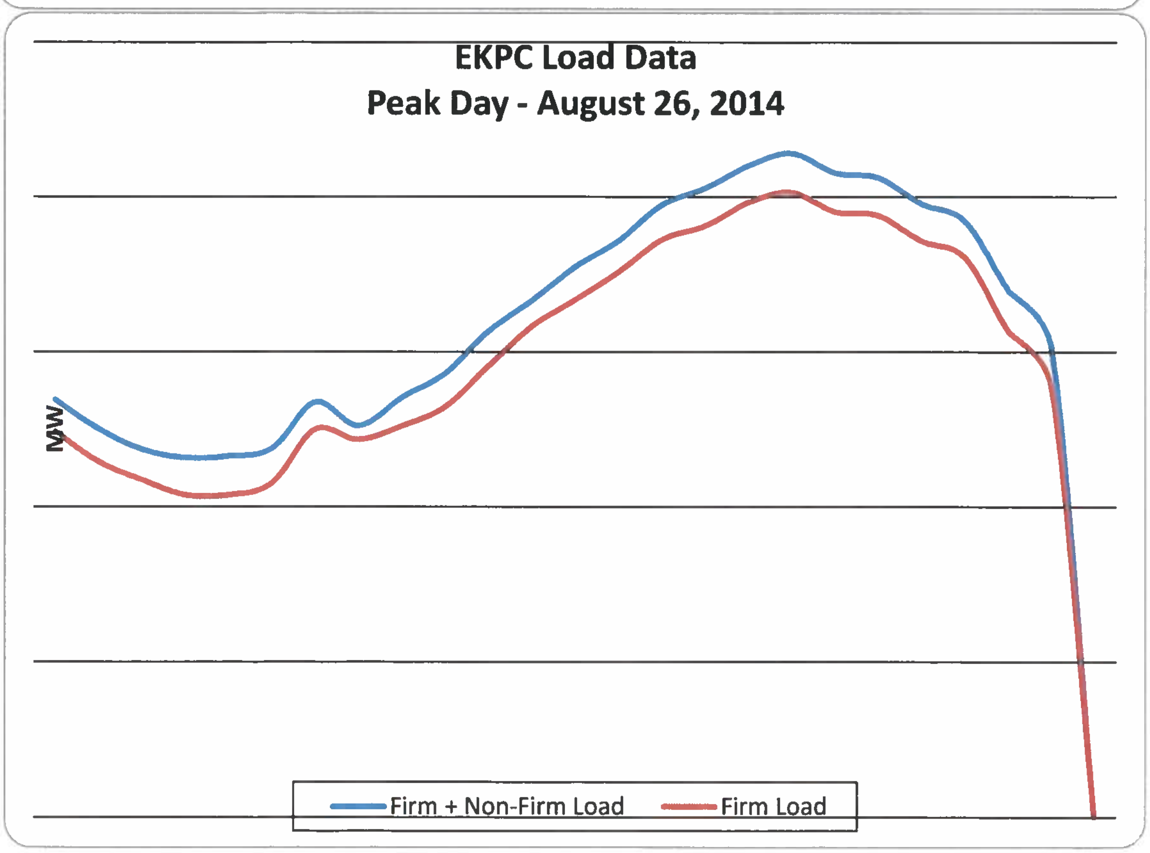

EKPC Load Data
Peak Day - March 4, 2014
MW
Firm + Non-Firm Load
Firm Load

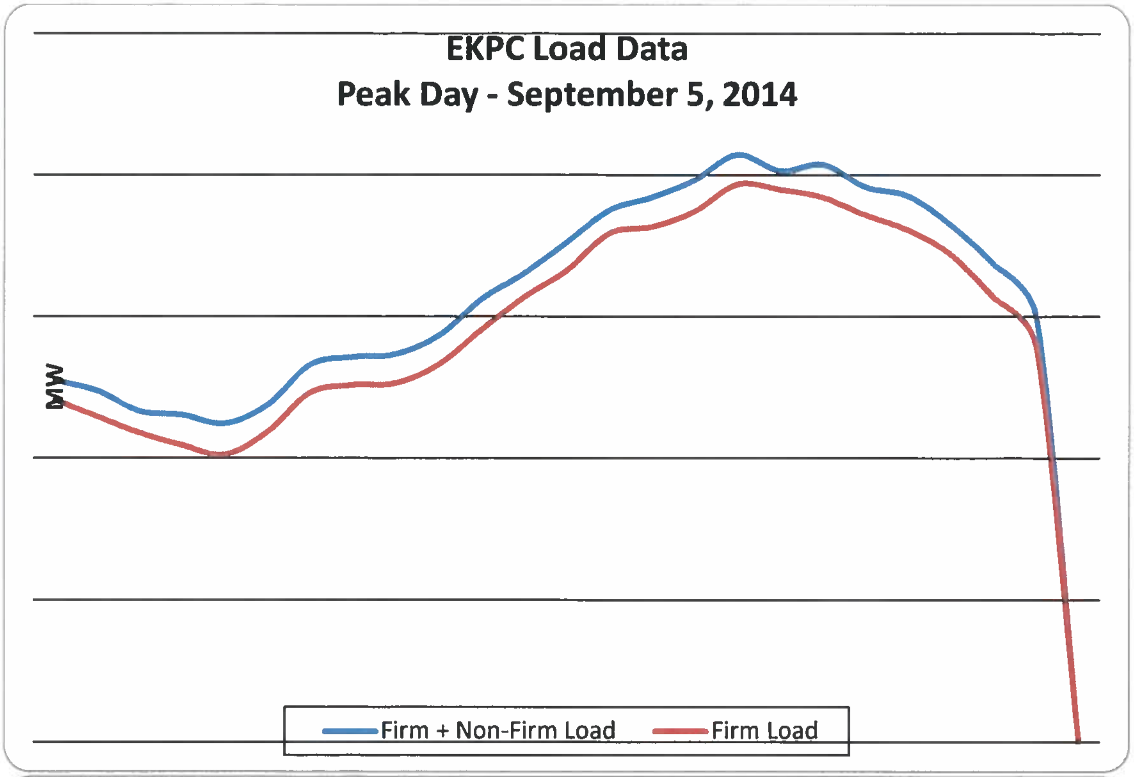

EKPC Load Data
Peak Day - April 16, 2014
MW
Firm + Non-Firm Load
Firm Load

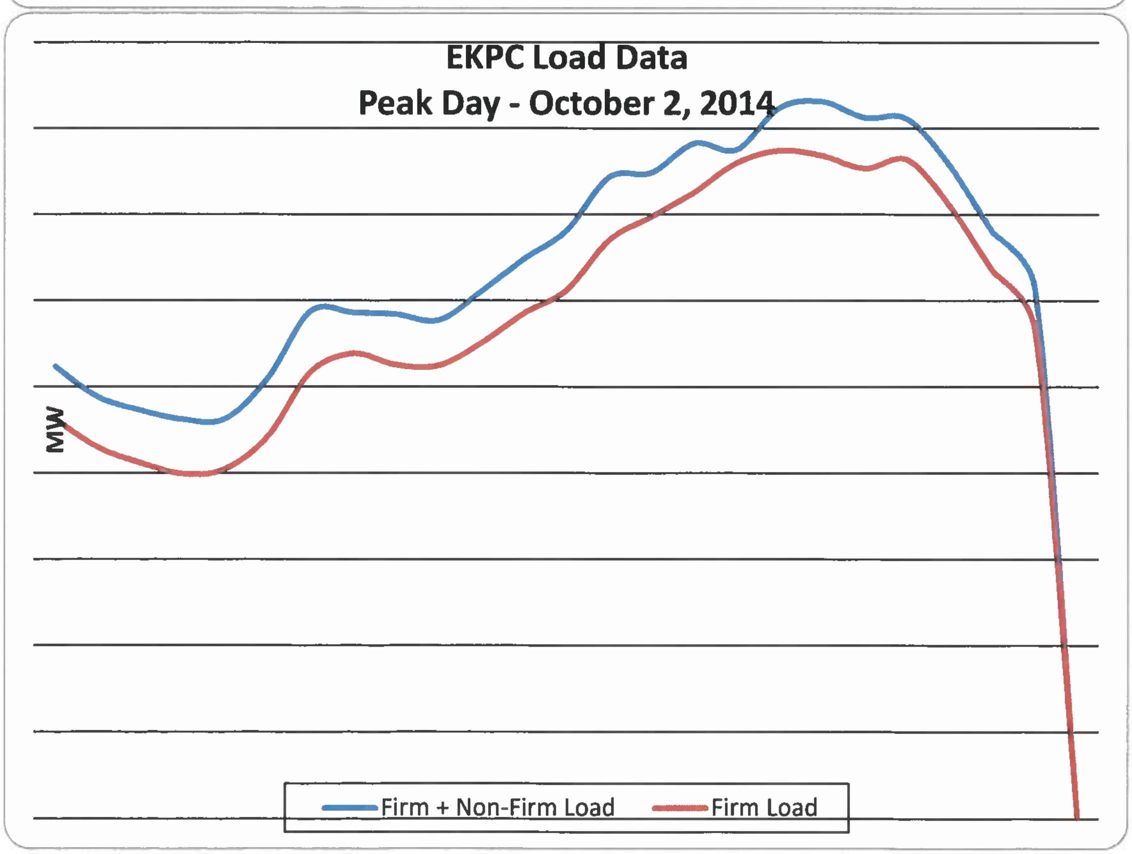

EKPC Load Data
Peak Day - May 27, 2014
MW
Firm + Non-Firm Load
Firm Load

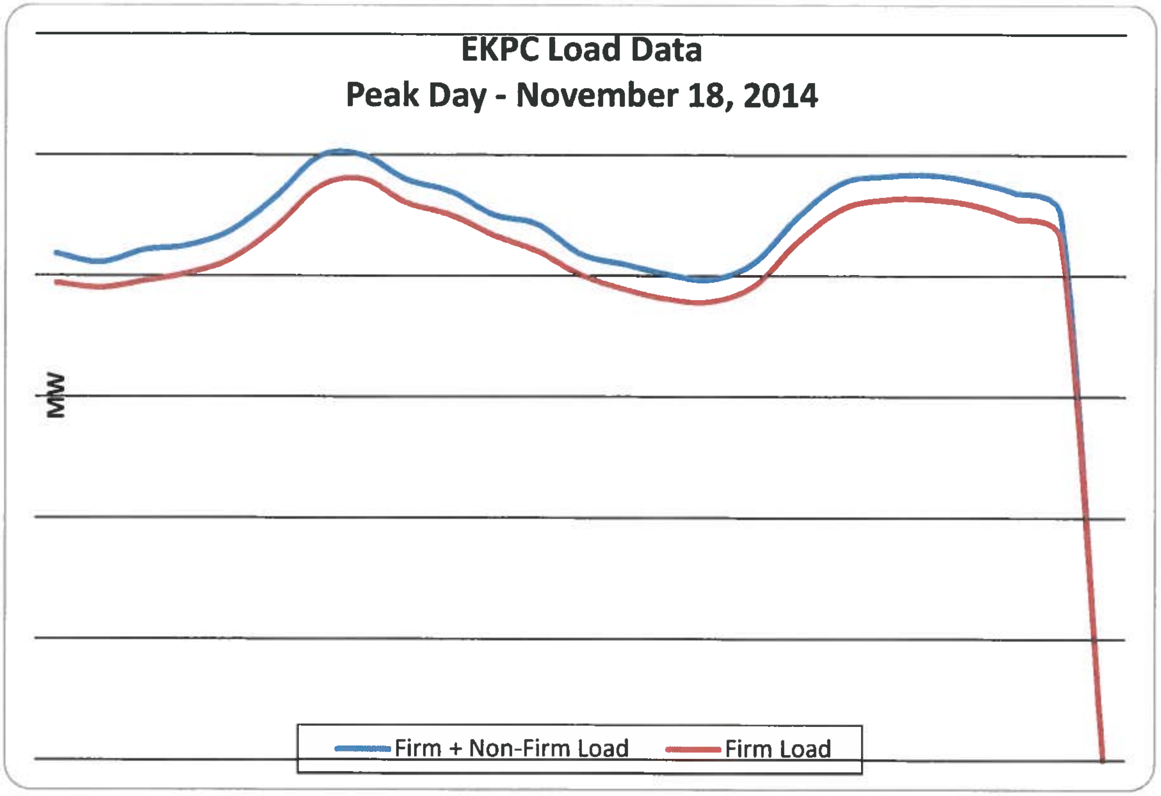

EKPC Load Data
Peak Day - June 18, 2014
MW
Firm + Non-Firm Load
Firm Load

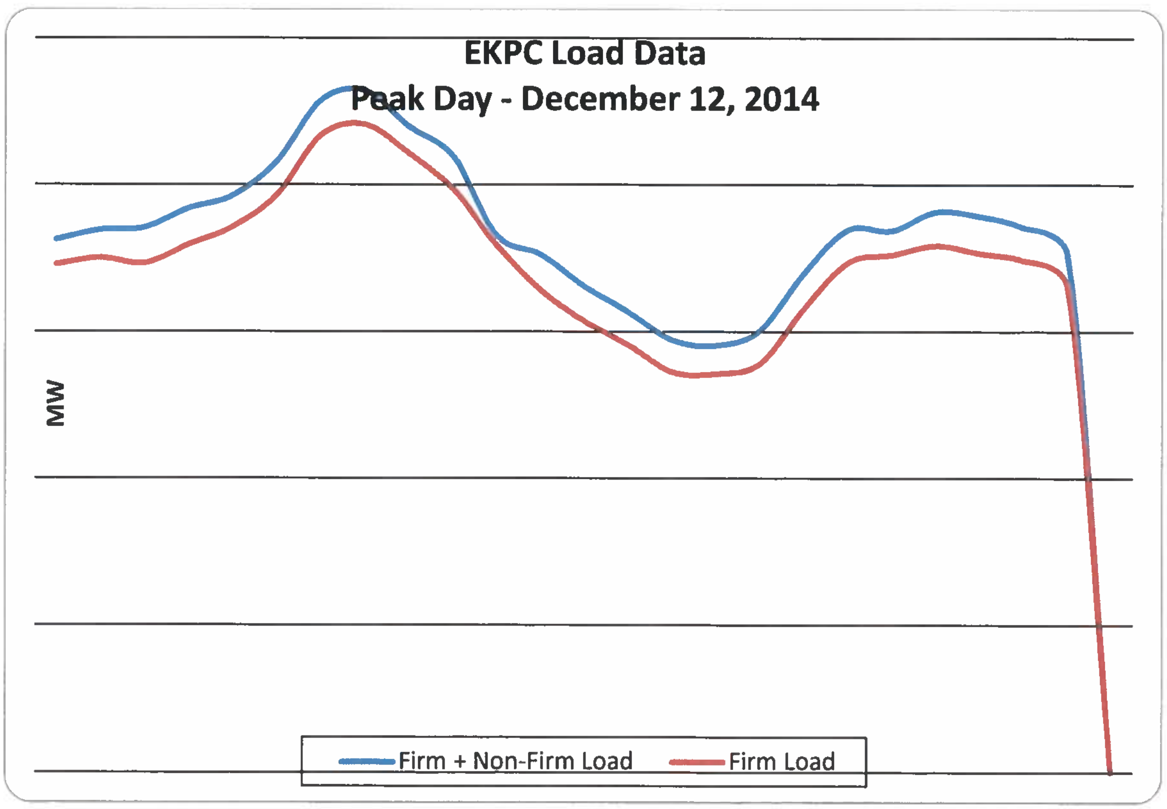

EKPC Load Data
Peak Day - July 22, 2014
MW
Firm + Non-Firm Load
Firm Load


EKPC Load Data
Peak Day - August 26, 2014
MW
Firm + Non-Firm Load
Firm Load


EKPC Load Data
Peak Day - September 5, 2014
MW
Firm + Non-Firm Load
Firm Load


EKPC Load Data
Peak Day - October 2, 2014
MW
Firm + Non-Firm Load
Firm Load


EKPC Load Data
Peak Day - November 18, 2014
MW
Firm + Non-Firm Load
Firm Load


EKPC Load Data
Peak Day - December 12, 2014
MW
Firm + Non-Firm Load
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 scenario 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.

Total Winter Peak Demand (MW)				Total 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
2014-2015	3,127	3,254	3,318	2015	2,350	2,400	2,444	2015	13,152	13,368	13,659
2015-2016	3,146	3,294	3,387	2016	2,364	2,440	2,507	2016	13,201	13,564	13,972
2016-2017	3,170	3,323	3,443	2017	2,369	2,484	2,575	2017	13,196	13,782	14,304
2017-2018	3,157	3,354	3,506	2018	2,376	2,527	2,641	2018	13,205	13,975	14,629
2018-2019	3,150	3,382	3,565	2019	2,387	2,566	2,703	2019	13,235	14,148	14,929

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

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 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. Based on current conditions, EKPC carries approximately 6% reserves on its summer peak load during the first three years under the Fixed Resource Requirements ("FRR") plan. Starting on June 1, 2016, EKPC will participate in the Reliability Pricing Model ("RPM"), which will lower EKPC's resource requirements, to roughly 3% of its summer peak load. In addition to the summer reserve requirements, EKPC economically hedges near 100% of its winter peak load expectations.

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)*	Total Capacity (MW)	Reserves (%)	Winter Load (MW)*	Total Capacity (MW)	Reserves (%)	Firm Capacity Purchases (MW)
2015	2324	2927	126%	3507	3276	93%	200**
2016	2342	2672	114%	3225	3176	98%	149***
2017	2366	2672	113%	3239	2926	90%	313
2018	2389	2672	112%	3250	2926	90%	324
2019	2403	2672	111%	3254	2926	90%	328

* Net of DSM
** Actual
*** 1000 MW already purchased and included in available capacity

As indicated in the table above, there are no projected reserve deficits during the summer, but there are significant deficits in winter.

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 below and through page 6 of this response. Please note that Dale 1 and Dale 2 will be placed in inactive status April 2015 and Dale 3 and Dale 4 will be placed in inactive status in April 2016.

Dale Unit 1

2015	0	weeks or less
2016	0	weeks or less
2017	0	weeks or less
2018	0	weeks or less
2019	0	weeks or less

Dale Unit 2

2015	0	weeks or less
2016	0	weeks or less
2017	0	weeks or less
2018	0	weeks or less
2019	0	weeks or less

Dale Unit 3

2015	0	weeks or less
2016	0	weeks or less
2017	0	weeks or less
2018	0	weeks or less
2019	0	weeks or less

Dale Unit 4

2015	0	weeks or less
2016	0	weeks or less
2017	0	weeks or less
2018	0	weeks or less
2019	0	weeks or less

JK Smith CT1

2015	9	weeks or less
2016	1	weeks or less
2017	1	weeks or less
2018	1	weeks or less
2019	1	weeks or less

JK Smith CT2

2015	2	weeks or less
2016	9	weeks or less
2017	1	weeks or less
2018	1	weeks or less
2019	1	weeks or less

JK Smith CT3

2015	1	weeks or less
2016	1	weeks or less
2017	9	weeks or less
2018	1	weeks or less
2019	1	weeks or less

JK Smith CT4

2015	2	weeks or less
2016	2	weeks or less
2017	1	weeks or less
2018	1	weeks or less
2019	1	weeks or less

JK Smith CT5

2015	4	weeks or less
2016	2	weeks or less
2017	1	weeks or less
2018	1	weeks or less
2019	1	weeks or less

JK Smith CT6

2015	4	weeks or less
2016	2	weeks or less
2017	1	weeks or less
2018	1	weeks or less
2019	1	weeks or less

JK Smith CT7

2015	1	weeks or less
2016	4	weeks or less
2017	1	weeks or less
2018	1	weeks or less
2019	1	weeks or less

JK Smith CT9

2015	4	weeks or less
2016	4	weeks or less
2017	4	weeks or less
2018	4	weeks or less
2019	4	weeks or less

JK Smith CT10

2015	4	weeks or less
2016	4	weeks or less
2017	4	weeks or less
2018	4	weeks or less
2019	4	weeks or less

Cooper 1

2015	6	weeks or less
2016	4	weeks or less
2017	4	weeks or less
2018	4	weeks or less
2019	4	weeks or less

Cooper 2

2015	7	weeks or less
2016	4	weeks or less
2017	4	weeks or less
2018	4	weeks or less
2019	4	weeks or less

Spurlock 1

2015	9	weeks or less
2016	9	weeks or less
2017	8	weeks or less
2018	8	weeks or less
2019	8	weeks or less

Spurlock 2

2015	4	weeks or less
2016	5	weeks or less
2017	4	weeks or less
2018	4	weeks or less
2019	4	weeks or less

Spurlock 3

2015	8	weeks or less
2016	4	weeks or less
2017	4	weeks or less
2018	4	weeks or less
2019	4	weeks or less

Spurlock 4

2015	4	weeks or less
2016	6	weeks or less
2017	4	weeks or less
2018	4	weeks or less
2019	4	weeks 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 has no definitive planned capacity additions at this time. However, EKPC is short on capacity to supply its winter peak period load. PJM provides enough capacity to cover EKPC's winter peak load, but prices for that energy are not secured. EKPC's experiences in January of 2014 solidified the need to secure price hedges for its winter load position. Power Purchase Agreements, along with owned generation, have supplied the price certainty for EKPC during the past winter peak period. That need will be expanded when the Dale 3 and 4 units are placed on inactive status in April 2016, due to not being compliant with the EPA Mercury and Air Toxic Standard rules. EKPC will either need to continue to enter into Power Purchase Agreements going forward or pursue other economic power supply alternatives identified in its RFP process. EKPC will seek to find the most economical alternative to meet its power supply requirements and meet future EPA rules. EKPC refreshed its RFP offers in summer 2014 and is currently negotiating with a third party for a potential long-term solution to its winter capacity needs.

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: **Amanda Stacy**
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 2014 was 22,790,243 MWh. The total energy delivered to all interconnections on the EKPC system in 2014 was 9,704,627 MWh.

The forecasted total energy requirements for the EKPC system for 2015 through 2019 are as follows:

2015 13,368,393 MWh

2016 13,563,866 MWh

2017 13,781,894 MWh

2018 13,974,738 MWh

2019 14,147,514 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, contingencies, 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).

EKPC has constructed facilities to address some of the limitations that had previously been identified on its transmission system. These facilities include the J.K. Smith-West Garrard 345 kV line, the J.K. Smith-North Clark 345 kV line, the Cranston-Rowan County 138 kV line, and the Marion County 161-138 kV transformer upgrade. EKPC has implemented dynamic ratings on some highly-loaded facilities to increase available capacity based on actual ambient system conditions.

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

Response 13d.

Summer	2014	2015	2016	2017	2018	2019
Date	7/22/2014					
Hr.	1800					
Peak Demand (MW)	2190	2334	2363	2396	2428	2456

Winter	2014	2015	2016	2017	2018	2019
Date	1/29/2014	2/20/2015*				
Hr.	800	800				
Peak Demand (MW)	3428	3507	3239	3259	3282	3302

* Represents February 2015 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: **Amanda Stacy**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 14. 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.

Response 14. Pages 2 through 7 of this response include EKPC's 10-year transmission expansion plan for the 2015-2024 period. During this period, EKPC expects to make the following transmission improvements for normal system development and load growth to serve native load customers and not to provide for large wholesale power transfers.

18 miles of new transmission line (69 kV)
54 miles of transmission line reconductor/rebuild (69 kV)
188 miles of transmission line operating temperature upgrades
1 transmission substation upgrade (50 MVA added)
10 transmission capacitor banks (277 MVAR)
8 projects – upgrade terminal facilities
11 upgrades of existing distribution substations (213 MVA added)
9 new distribution substations (175 MVA added)

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2015 – 2024)	
A. New Transmission Lines and Status Changes **Project Description**	**Needed In-Service Date**
Operate the Cynthiana-Headquarters and Sideview-Cane Ridge 69 kV lines normally-closed.	12/2015
Establish a 69 kV interconnection with Duke Energy at Hebron by installing two 69 kV circuit breakers at EKPC's Hebron.	6/2015
Construct a new 69 KV line between KU's West Frankfort substation and the Bridgeport substation (1.2 miles). Install a 69 KV switch between the Bridgeport #1 and Bridgeport #2 substations and operate this switch normally-open, with Bridgeport #1 served from the new line and Bridgeport #2 served from the existing tap line.	6/2016
Construct a new 69 KV line from Beattyville Distribution-Oakdale using 556 ACSR (11.66 miles). Operate this new line normally closed and operate the existing Oakdale Jct.-Oakdale line normally open.	12/2017
Construct a 2nd 69 KV line, using 556.5 MCM ACSR conductor between the Russell County and Sewellton substations (0.88 miles). Install terminal equipment at the Russell County substation. Serve the Sewellton distribution station radially from the Russell County substation.	12/2021
Construct a 2nd 69 KV line, using 266.8 MCM ACSR conductor between the Powell County and Stanton substations (0.10 miles). Install terminal equipment at the Powell County substation. Serve the Stanton distribution station radially from the Powell County substation.	12/2022
Construct a new 69 KV line using 556.5 MCM ACSR conductor between the Tommy Gooch and KU Standford substations (3.9 miles). Operate this line normally-open.	12/2023

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2015 – 2024)	
B. New Transmission Substations **Project Description**	**Needed In-Service Date**
NONE	

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2015 – 2024)	
C. New Transmission Switching Stations **Project Description**	**Needed In-Service Date**
NONE	

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2015 – 2024)	
D. Transmission Transformer Upgrades **Project Description**	**Needed In-Service Date**
Bullitt County 161-69 KV transformer replacement upgrade to 150 MVA	6/1/2019

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2015 – 2024)	
E. Terminal Facility Upgrades Project Description	**Needed In-Service Date**
Increase the Zone 3 distance relay setting at Barren County associated with the Barren County-Bonnieville 69 kV line to at least 85 MVA.	6/2019
Upgrade the 4/0 bus and jumpers at Nelson County substation associated with the Nelson County-West Bardstown Jct. 69 kV line using 500 MCM copper or equivalent equipment.	6/2020
Upgrade the 4/0 bus and jumpers at Denny substation associated with the Denny-Wayne County 69 kV line using 500 MCM copper or equivalent equipment.	6/2020
Upgrade the 600A CT at Denny associated with the Denny-Wayne County 69 kV line with a 1200A CT.	6/2020
Upgrade the 4/0 bus and jumpers at Green County substation associated with the Green County-KU Taylor County 69 kV line using 500 MCM copper or equivalent equipment.	6/2023
Upgrade the 400 A metering CT at Laurel County associated with the Laurel County-KU Hopewell 69 KV line section with an 800 A CT.	6/2024
Upgrade the 600 A disconnect switch switches W59-613 and W59-615 at the Barren County substation associated with the Barren County-Bonnieville 69 KV line using 1200 A switches.	6/2024
Upgrade the 600 A disconnect switches W59-633 and W59-635 at the Barren County substation associated with the Barren County-Cave City Jct. 69 KV line using 1200 A switches. Upgrade the 600 A switch W49-615 at Cave City Jct. with a 1200 A switch.	6/2024

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2015 – 2024)	
F. Transmission Line Re-conductor/Rebuilds Project Description	**Needed In-Service Date**
Re-conductor the Cynthiana Jct-Hdqtrs 69 kV line section (10.23 miles) using 556.5 MCM ACTW wire.	12/2015
Re-conductor the Owen County-New Castle 69 KV line section (19.9 miles) using 556.5 MCM ACTW conductor	6/2016
Re-conductor the Brodhead-Three Links Jct 69 kV line section (8.2 miles) using 556.5 MCM ACTW wire.	12/2017
Re-conductor the Cave City Jct.-Seymour Tap 69 KV line section (0.51 miles) using 556.5 MCM ACTW conductor.	6/2019
Re-conductor the Leon-Airport Road 69 kV line section (5.72 miles) using 556.5 MCM ACTW conductor.	12/2019
Re-conductor the Seymour Tap-KU Horse Cave Tap 69 KV line section (1.98 miles) using 556.5 MCM ACTW conductor.	6/2021
Re-conductor the Albany-Snow Jct 69 kV line section (4.40 miles) using 556.5 MCM ACTW wire.	12/2021
Re-conductor the South Bardstown-W. Bardstown Jct 69 kV line section (2.5 miles) using 556.5 MCM ACTW wire.	12/2022
Re-conductor the Fort Knox Tap-Rineyville Tap 69 KV line section (0.40 miles) using 556.5 MCM ACTW conductor.	6/2024

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2015 – 2024)	
G. Transmission Line High Temperature Upgrades **Project Description**	**Needed In-Service Date**
Increase the MOT of the Helechawa-Sublett Junction 69 kV line section to 167°F.	6/2015
Increase the MOT of the Glendale-Hodgenville 69 kV line section to 212°F.	6/2015
Increase the MOT of the J.K. Smith-Union City 138 kV line section to 330°F (LTE at 312°F).	6/2015
Increase the MOT of the Headquarters-Millersburg Jct. 69 kV line section to 167°F.	6/2015
Increase the MOT of the Colesburg Jct.-Colesburg 69 kV line section to 167°F.	6/2015
Increase the MOT of the Etown EK #1-Tunnel Hill Junction 69 kV line section to 284°F. (LTE at 266°F)	6/2015
Increase the MOT of the Union City-Lake Reba Tap 138 kV line section to 330°F. (LTE at 312°F)	6/2015
Increase the MOT of the Kargle-KU Elizabethtown 69 KV line section to 266°F. (LTE at 248°F)	6/2015
Increase the MOT of the Cave City-Seymour Tap 69 KV line section to 302°F. (LTE at 284°F)	6/2015
Increase the MOT of the Seymour Tap-KU Horse Cave Tap 69 KV line section to 302°F. (LTE at 284°F)	6/2015
Increase the MOT of the Owens Illinios_Bluegrass Parkway Tap 69 KV line section to 212°F.	6/2015
Increase the MOT of the North Springfield-South Springfield Jct. 69 kV line section to 167°F.	6/2015
Increase the MOT of the Loretto-Sulphur Creek 69 kV line section to 167°F.	6/2015
Increase the MOT of the Loretto-South Springfield Junction 69 kV line section to 212°F.	6/2015
Increase the MOT of the West Bardstown Jct.- South Bardstown 69 kV line section to 284°F. (LTE at 266°F)	6/2016
Increase the MOT of the Oakdale Jct.-Oakdale 69 kV line section to 167°F.	6/2016

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2015 – 2024)	
G. Transmission Line High Temperature Upgrades (continued) Project Description	**Needed In-Service Date**
Increase the MOT of the Pelfrey Jct.-Pelfrey 69 kV line section to 167°F.	6/2016
Increase the MOT of the Zula Tap-Zula 69 kV line section to 167°F.	6/2016
Increase the MOT of the Ninevah-Ninevah KU Junction 69 kV line section to 167°F.	6/2016
Increase the MOT of the Arkland Tap-Oven Fork 69 kV line section to 167°F.	6/2016
Increase the MOT of the Mount Olive Jct.-Mount Olive 69 kV line section to 167°F.	6/2016
Increase the MOT of the Davis Junction-Fayette 69 kV line section to 266°F. (LTE at 248°F)	6/2017
Increase the MOT of the Booneville Tap-Booneville 69 kV line section to 167°F. COMPLETE	6/2017
Increase the MOT of the South Bardstown-West Bardstown 69 KV lin section to 284°F. (LTE at 266°F)	6/2017
Increase the MOT of the Eberle Tap-Eberle 69 kV line section to 167°F.	6/2017
Increase the MOT of the Rowan County-Elliottville 69 kV line section to 167°F.	6/2017
Increase the MOT of the Mount Sterling-Fogg Pike-Reid Village 69 kV line section to 167°F.	6/2017
Increase the MOT of the Jellico Creek Tap-Jellico Creek 69 kV line section to 167°F.	6/2017
Increase the MOT of the Penn-Keith 69 kV line section to 167°F.	6/2017
Increase the MOT of the Tharp Tap-Tharp 69 kV line section to 167°F.	6/2017
Increase the MOT of the Big Bone Tap-Big Bone 69 kV line section to 167°F.	6/2017
Increase the MOT of the Cave Run Tap-Cave Run 69 kV line section to 167°F.	6/2017
Increase the MOT of the Carson-New Liberty 69 kV line section to 167°F.	6/2017
Increase the MOT of the Griffin-Griffin Junction 69 kV line section to 167°F.	6/2017
Increase the MOT of the Bacon Creek Tap-South Corbin 69 kV line section to 212°F.	6/2018
Increase the MOT of the J.K. Smith-Dale 138 kV line section to 275°F. (LTE at 257°F)	6/2018
Increase the MOT of the Baker Lane-Holloway Jct. 69 KV line section to 266°F. (LTE at 248°F)	12/2023
Increase the MOT of the Rineyville-Smithersville Tap 69 KV line section to 302°F. (LTE at 284°F)	6/2024
Increase the MOT of the Stephensburg_Upton Tap 69 KV line section to 302°F. (LTE at 284°F)	6/2024

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2015 – 2024)	
H. Capacitor Bank Additions **Project Description**	**Needed In-Service Date**
Retire the Mckee 10.7 MVAR capacitor bank.	12/2015
Install a 14.286 MVAR, 69 kV capacitor bank at Magoffin County Substation.	12/2015
Retire the Hilda 18.37 MVAR capacitor bank and move to Big Woods.	12/2016
Install a 22.96 MVAR, 69 kV capacitor bank at Owen County Substation.	6/2017
Install a 161 kV, 81.636 MVAR capacitor bank (2 stages of 40.818 MVARs each) at Cooper Station	12/2017
Resize the Cedar Grove 69 kV capacitor bank from 10.8 to 20.409 MVAR.	6/2018
Install a 18.368 MVAR, 69 KV capacitor bank at Maggard substation	12/2019
Install a 12.245 MVAR, 69 kV capacitor bank at the East Campbellsville Substation	6/2020
Install a 17.858 MVAR, 69 kV capacitor bank at Fox Hollow Substation.	12/2020
Resize the Williamstown 69 KV capacitor bank from 8.4 MVAR to 11.225 MVAR.	12/2021
Install a 33.165 MVAR, 69 KV capacitor bank at Elizabethtown substation.	12/2021
Install a 16.837 MVAR, 69 KV capacitor bank at Wayne County substation.	12/2021
Install a 25.511 MVAR, 69 KV capacitor bank at Sewellton Junction substation.	12/2021
Install a 69 kV, 51.022 MVAR capacitor bank at Somerset Substation.	12/2024

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2015 – 2024)	
I. New Distribution Substations and associated Tap Lines **Project Description**	**Needed In-Service Date**
Construct a new Pleasant Grove #2 69-12.5 kV, 12/16/20 MVA Substation and associated 69 kV tap line (0.1 mile)	6/2015
Construct a new Bridgeport #2 69-25 kV, 12/16/20 MVA substation and associated 69 kV tap line (0.1 miles). Replace the existing Bridgeport #1 15/20/25 MVA transformer with a 12/16/20 MVA transformer.	6/2015
Construct a new South Bardstown 69-12.5 KV, 12/16/20 MVA substation and associated 69 KV tap line (0.2 mile) to the West Bardstown Jct.- West Bardstown 69 KV line section.	6/2016
Construct a new Long Lick 69-25 kV, 12/16/20 MVA Substation and associated 69 kV tap line (0.7 miles)	6/2016
Construct a new Defoe 69-12.5 KV, 12/16/20 MVA substation and associated 69 KV tap line (5.0 mile) to the Clay Village-New Castle 69 KV line section.	12/2016
Construct a new Roanoke 69-12.5 kV, 12/16/20 MVA Substation and associated 69 kV tap line (5.0 miles)	12/2016
Construct a new Big Woods 69-12.5 kV, 12/16/20 MVA Substation and associated 69 kV tap line (0.2 mile)	12/2016
Construct a new Roseville 69-25 kV, 12/16/20 MVA Substation and associated 69 kV tap line (3.5 miles)	12/2016
Construct a new Tommy Gooch #2 69-25 kV, 12/16/20 MVA Substation and associated 69 kV tap line (0.1 mile)	12/2017

EKPC 10-YEAR TRANSMISSION EXPANSION SCHEDULE (2015 – 2024)	
J. Distribution Substation Additions and Upgrades **Project Description**	**Needed In-Service Date**
Upgrade the existing Bank Lick 69-12.5 kV, 11.2/14 MVA Substation to 12/16/20 MVA.	6/2015
Upgrade the existing Peytons Store 69-25 kV, 11.2/14 MVA Substation to 12/16/20 MVA.	12/2015
Upgrade the existing Jellico Creek 69-13.2 kV, 5.6/7 MVA Substation to 11.2/14 MVA, and convert to 25 kV low-side.	12/2015
Upgrade the existing Williamstown 69-12.5 kV, 11.2/14 MVA Substation to 15/20/25 MVA.	3/2016
Upgrade the existing Holloway 69-12.5 kV, 11.2/14 MVA Substation to 15/20/25 MVA.	6/2016
Upgrade the existing Rectorville 69-12.5 kV, 11.2/14 MVA Substation to 12/16/20 MVA, and convert to 25 kV low-side.	6/2017
Upgrade the McKinney's Corner 69-12.5 kV, 6 MVA substation to 12/16/20 MVA.	12/2017
Upgrade the existing W.M. Smith #2 69-12.5 kV, 11.2/14 MVA Substation to 15/20/25 MVA.	6/2019
Upgrade the existing Shepherdsville #2 69-12.5 kV, 11.2/14 MVA substation to 12/16/20 MVA.	6/2019
Upgrade the existing Mt. Washington #1 69-12.5 kV, 11.2/14 MVA substation to 12/16/20 MVA.	6/2019
Upgrade the existing Phil 69-12.5 kV, 11.2/14 MVA substation to 12/16/20 MVA	12/2019

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.

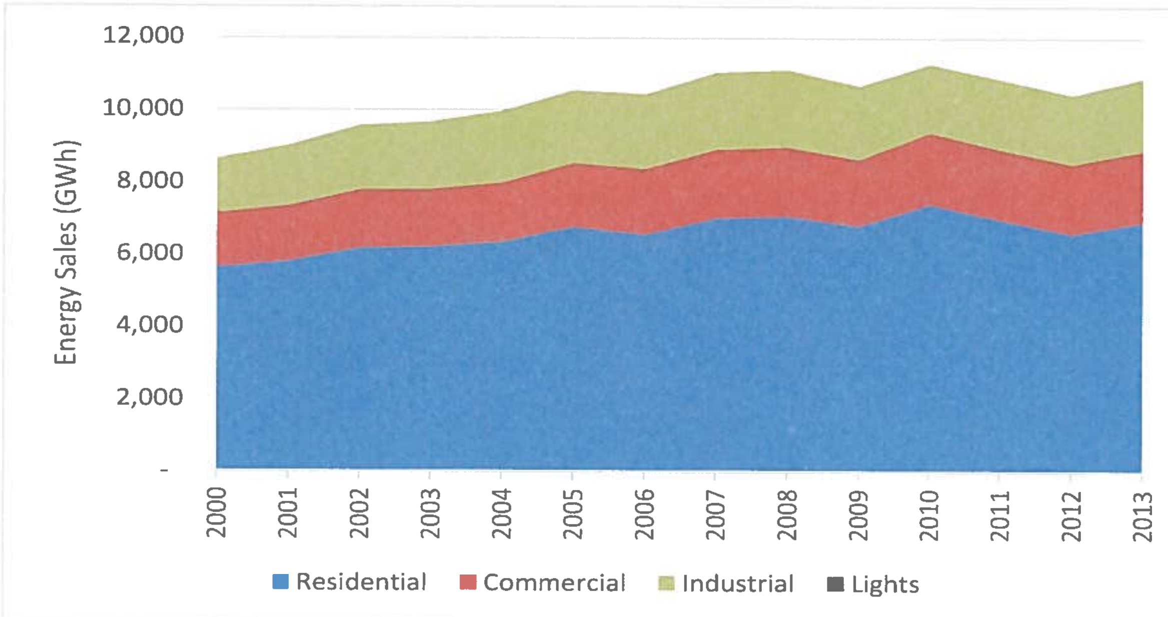
The residential class represents 93% of the total number of customers served by EKPC's member distribution cooperatives. In 2013, the class represented 58% of total energy sales, totaling 6,900 GWh. Residential energy sales have grown by an average compound rate of 1.6% per year from 2000 through 2013.

[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)

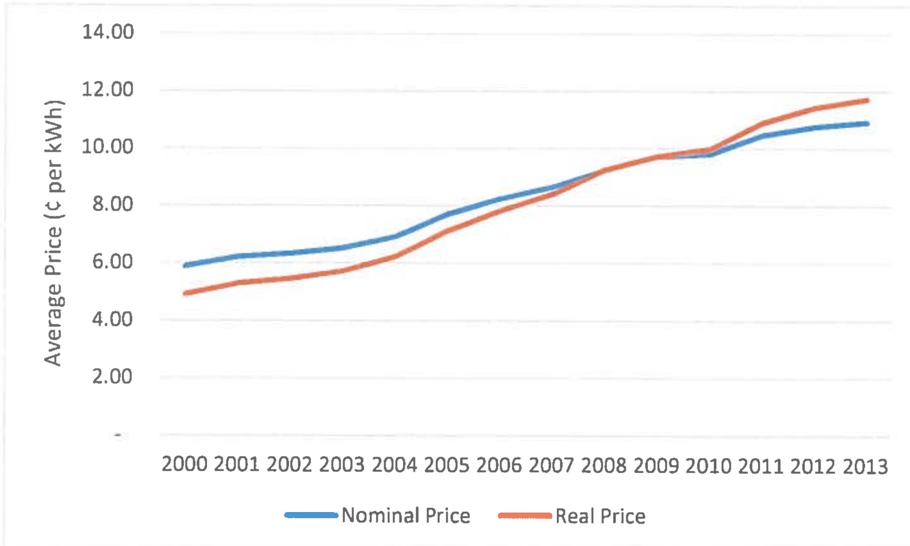
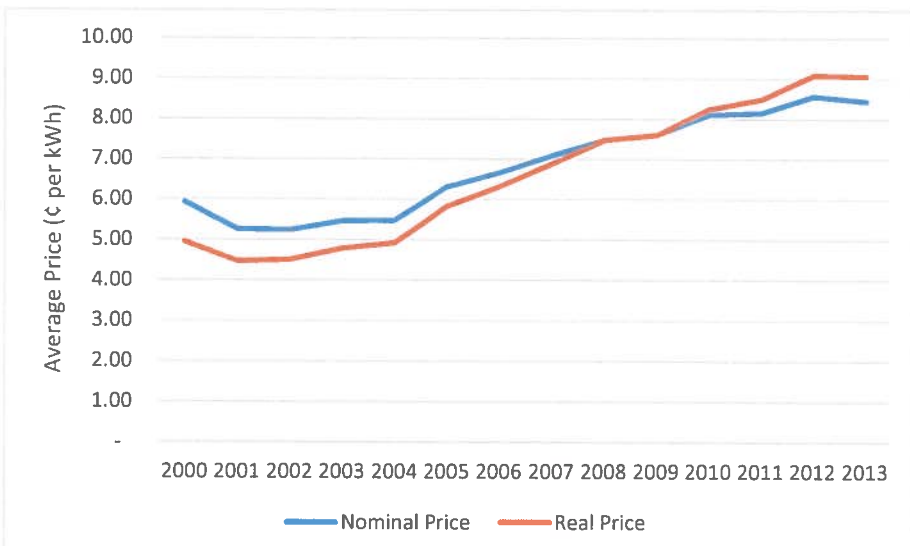


Figure 2.3 – Commercial and Industrial Price (EKPC Total)



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

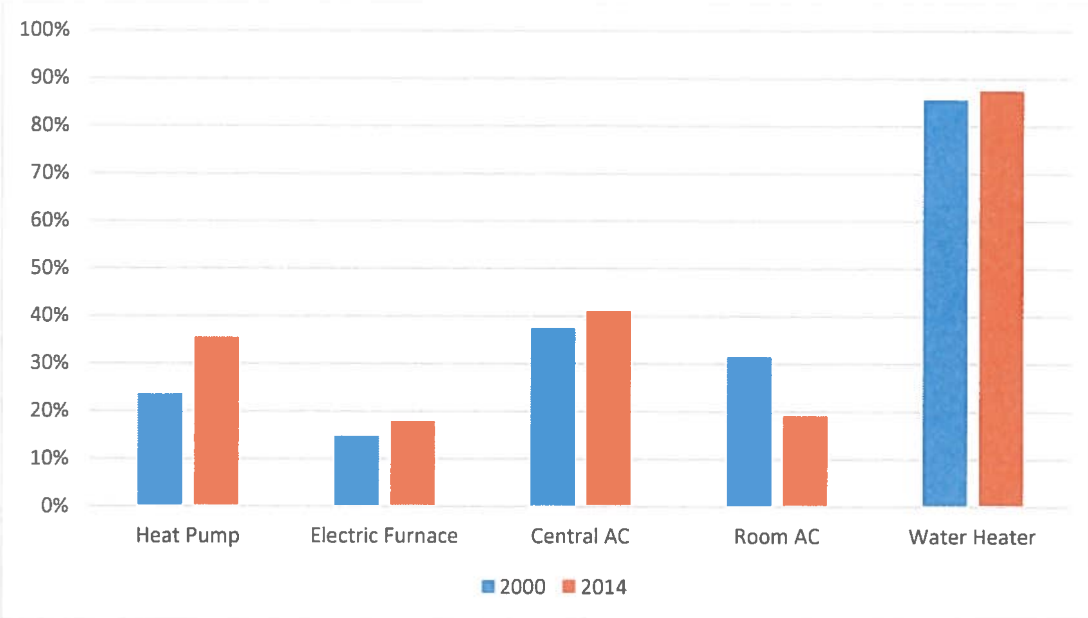
Economic time series data for each member cooperative's service territory was collected from IHS Global Insight[2]. Global Insight draws data from the US Census Bureau, the Bureau of Labor Statistics, and the Bureau of Economic Analysis to develop historical economic time series. For this study, population,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

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[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.