Goss ▪ Samford PLLC
Attorneys at Law

March 20, 2013 HAND DELIVERED

Mr. Jeff Derouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Post Office Box 615
Frankfort, Kentucky 40602

RE: PSC Case No. 2012-00428

Dear Mr. Derouen:

Please find enclosed for filing with the Commission in the above-referenced case, an original and fourteen copies of the responses of East Kentucky Power Cooperative, Inc. ("EKPC") to the Commission Staff's First Request for Information, dated February 27, 2013. Also enclosed are an original and fourteen copies of EKPC's responses to the Attorney General's Initial Requests for Information dated February 27, 2013.

Please feel free to call if you have any questions.

Sincerely,

Mark David Goss
Counsel

Enclosures

Cc: Parties of Record

2365 Harrodsburg Road, Suite B-130 | Lexington, Kentucky 40504

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

CONSIDERATION OF THE IMPLEMENTATION	)	
OF SMART GRID AND SMART METER	)	**CASE NO.**
TECHNOLOGIES	)	**2012-00428**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Paul A. Dolloff, being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Public Service Commission Staff's First Request for Information in the above-referenced case dated February 27, 2013, and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Subscribed and sworn before me on this 20th day of March 2013.

Notary Public
MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

CONSIDERATION OF THE IMPLEMENTATION	)	
OF SMART GRID AND SMART METER	)	**CASE NO.**
TECHNOLOGIES	)	**2012-00428**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Scott Drake, being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Public Service Commission Staff's First Request for Information in the above-referenced case dated February 27, 2013, and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Scott Drake

Subscribed and sworn before me on this 20th day of March 2013.

Gwyn M. Willoughby
Notary Public

MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

CONSIDERATION OF THE IMPLEMENTATION	)	
OF SMART GRID AND SMART METER	)	**CASE NO.**
TECHNOLOGIES	)	**2012-00428**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Isaac S. Scott, being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Public Service Commission Staff's First Request for Information in the above-referenced case dated February 27, 2013, 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.

Isaac S. Scott

Subscribed and sworn before me on this 28th day of March 2013.

Notary Public

MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

CONSIDERATION OF THE IMPLEMENTATION	)	
OF SMART GRID AND SMART METER	)	CASE NO.
TECHNOLOGIES	)	2012-00428

RESPONSES TO THE COMMISSION STAFF'S

FIRST REQUEST FOR INFORMATION

DATED FEBRUARY 27, 2013

EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 60
RESPONSIBLE PARTY: Isaac S. Scott

Request 60. Refer to the Direct Testimony of Isaac S. Scott ("Scott Testimony"), page 6. Describe Mr. Scott's understanding of the Commission's experience with technological obsolescence in the telecommunications industry.

Response 60. Mr. Scott understood that due to the pace of technological innovations that occurred in the telecommunications industry, certain utility assets were considered obsolete and retired earlier than anticipated. The depreciation rates that had been applied to these assets had been based on longer service lives, resulting in significant utility plant balances that had not been depreciated. Mr. Scott understood that upon request of the telecommunication utilities, the Commission authorized adjustments to depreciation rates that permitted the telecommunication utilities to recover these plant balances through rates over shorter periods of time than the remaining service lives.

EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 61
RESPONSIBLE PARTY: Isaac S. Scott

Request 61. Refer to the Scott Testimony, page 13, lines 20-24, which refer to customer education. State whether Mr. Scott is familiar with the customer education efforts undertaken by Owen Electric Cooperative in conjunction with its Energy Innovation Vision program and, if so, whether those efforts are consistent with the type of effort to which he refers.

Response 61. Mr. Scott has reviewed information relating to the customer education efforts undertaken by Owen Electric Cooperative ("Owen") in conjunction with its Energy Innovation Vision program. Mr. Scott believes that the Owen program represents the balanced approach he referenced in his testimony on page 13, lines 20-24. For example, by preparing member profiles for the rate offerings, which help define which customers would most likely benefit under the rate, the ultimate effect is to identify customer risks and responsibilities associated with the rate offerings.

EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 62
RESPONSIBLE PARTY: Isaac S. Scott

Request 62. Refer to the Scott Testimony, page 14, lines 17-19, which indicate that EKPC and its members believe the Commission should consider cost recovery through a rate case or "through a rider mechanism." To date, EKPC and its members have expressed a preference for recovery of Demand-Side Management ("DSM") and energy-efficiency program costs through base rates rather than through a DSM surcharge. State whether this statement indicates a different position by EKPC and its members concerning Smart Grid and smart meter cost recovery than their position concerning DSM and energy-efficiency cost recovery.

Response 62. The statement on page 14 of Mr. Scott's testimony does not reflect a different position by EKPC and its Members. First, please note that page 14 contains a discussion of one of the positions expressed in the March 25, 2011 Report of the Joint Parties. Mr. Scott's testimony states the Commission should maintain flexibility and consider either approach as reasonable for cost recovery of Smart Grid and Smart Meter investments. It is true that EKPC and its Members have to date expressed a preference for recovery of DSM and energy-efficiency program costs through base rates rather than utilizing the DSM surcharge. But EKPC has also indicated that it understood that a utility could choose the cost recovery option it believed most appropriate. Please see EKPC's response to the Commission Staff's Initial Data Request dated March 16, 2009, Request 42, page 1 of 2 in Administrative Case No. 2008-00408. EKPC and its Members believe they have been consistent on the cost recovery issue.

EAST KENTUCKY POWER COOPERATIVE, INC.

ADMINISTRATIVE CASE NO. 2012-00428

RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13

REQUEST 63

RESPONSIBLE PARTY: Scott Drake/Isaac S. Scott

Request 63. Refer to the Scott Testimony, page 15, lines 15-17. Provide a general framework concerning how EKPC and its members would engage and educate their customers on customer risks, responsibilities, and benefits associated with the implementation of smart technology. Include in this discussion whether EKPC and its members are conducting similar consumer-education programs in connection with any of their current DSM, or energy-efficiency, programs.

Response 63. Depending on the specifics of the particular smart technology, the education program should focus on identifying for the customer any customer characteristics considered necessary for the deployment to be successful, the expected results from deploying the technology, and the degree to which the customer will need to be actively involved in order to achieve the expected results. The information will have to be organized and presented in clear, understandable terms and avoid being so technical as to overwhelm the customer. The information should contain a listing of any additional equipment that will be required and/or a description of any modifications that will be necessary for existing equipment. The information should also identify any additional costs to the customer associated with the technology deployment.

Dissemination of the education materials would be done through various media. Preliminary advertisements and articles to make customers aware of the technology would be posted in Members' offices, on the Members' websites, and inserts in *Kentucky Living* magazine.

Social media and traditional bill inserts could also be considered. More in depth and detailed presentations would be offered by holding meetings for interested customers and one-on-one meetings with customer service representatives.

EKPC and its Members are following a similar approach to customer education in connection with the DSM and energy efficiency program offerings.

EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 64
RESPONSIBLE PARTY: Isaac S. Scott

Request 64. Refer to the Scott Testimony, page 17, lines 22 through 24, which state, "Especially in deployments of smart meters, the achievability of the benefits is significantly dependent upon customer response and participation, which often is not determinable prior to deployment." Explain how Smart Grid investments differ from DSM investments in that regard. Include in the explanation details regarding whether experiences of other utilities and cost/benefit tests similar to those used in determining the cost-effectiveness of DSM programs could be used in making the Smart Grid investment decision.

Response 64. Please note that the quoted statement was made in the context of registering EKPC's and its Members' objection to the position expressed by the Attorney General and the Community Action Council in their March 25, 2011 Joint Comments that utilities should be viewed as guaranteeing the anticipated benefits identified for a proposed Smart Grid or Smart Meter deployment.

When considering customer response and participation, Mr. Scott believes the difference between Smart Grid investments and DSM investments is related to customer familiarity and understanding the product. Most if not all DSM programs involve technology that has been proven for several years and the results from deployment can generally be identified. Smart Meter technology is still relatively new and the results from deployment are generally described in terms of potential benefits. As Smart Meter technology matures and the results from deployment become more certain, this difference should lessen.

Mr. Scott certainly would agree that as part of a utility's review and evaluation of a proposed Smart Grid or Smart Meter project it would be reasonable to consider the experiences of other utilities with the same or similar projects. However, the consideration of these experiences should not be the sole determining factor of whether the utility should proceed with the proposed project. Mr. Scott also agrees that cost/benefit tests similar to those used in determining the cost effectiveness of DSM programs could be used evaluating proposed Smart Grid or Smart Meter projects; please see page 12, lines 14 through 19 of Mr. Scott's Direct Testimony.

EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 65
RESPONSIBLE PARTY: Isaac S. Scott

Request 65. Refer to the Scott Testimony, page 20, item 4, Basic Consumer Protections; Disconnects. State what changes EKPC and its members would make to how remote disconnects are handled.

Response 65. As a generation and transmission cooperative, EKPC does not have retail customers and consequently does not have the disconnect issue. EKPC and its Members have reviewed 807 KAR 5:006, Sections 14 through 16, and note that Section 14(3) might need to be revised or clarified when there has been a remote disconnection. There likely would not be an inspection of a meter if it is disconnected remotely and then reconnected. The only other possible change may be needed to tariffs to establish different charges for the disconnection for non-payment charge depending on whether a manual or remote disconnection is made.

EAST KENTUCKY POWER COOPERATIVE, INC.

ADMINISTRATIVE CASE NO. 2012-00428

RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13

REQUEST 66

RESPONSIBLE PARTY: Isaac S. Scott

Request 66. Refer to the Scott Testimony, page 33, lines 3-23, and the statement that " . . . . groups of customers have and are resisting these deployments and insisting on 'opt-out' provisions . . . ." Describe in detail the experience of EKPC's members regarding opt out requests.

Response 66. The experience of EKPC's Members regarding requests for opting out of AMR/AMI fall into the following groups:

No requests to opt out

Big Sandy Rural Electric Cooperative Corporation

Blue Grass Energy Cooperative Corporation

Cumberland Valley Electric

Licking Valley Rural Electric Cooperative Corporation

Nolin Rural Electric Cooperative Corporation

Initial customer request to opt out, but dropped after explanation, no opt out

Clark Energy Cooperative, Inc. – 2 or 3 requests/complaints

Farmers Rural Electric Cooperative Corporation – 1 request

Grayson Rural Electric Cooperative Corporation – 1 request

Inter-County Energy Cooperative Corporation – 2 requests

Jackson Energy Cooperative – 1 request

Salt River Electric Cooperative Corporation – 5 requests

Shelby Energy Cooperative, Inc. – 2 requests

South Kentucky Rural Electric Cooperative Corporation – 10 to 15 requests

Taylor County Rural Electric Cooperative Corporation – few requests

<u>Initial customer request to opt out, some dropped after explanation, opt out allowed</u>

Owen Electric Cooperative – 9 requests to opt out; 2 opt outs permitted; some awaiting the Commission's decision in Case No. 2012-00468, Owen's request to revise its meter reading tariff for reimbursement in those situations where Owen is prohibited from using AMI to remotely read meters for monthly billing purposes.

<u>AMI deployment in progress, not applicable</u>

Fleming-Mason Energy Cooperative

Also, please see the Members' responses to Request 114(c) and 114(d).

EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 67
RESPONSIBLE PARTY: Paul A. Dolloff

Request 67. Describe the extent to which EKPC has implemented Smart Grid technology pertaining to its transmission system and substations. Include in the explanation details regarding whether the technology is reliability-related, security- related, or efficiency-related. Also include details regarding whether EKPC believes further investment in such technology could be beneficial, and if so, its plans for future implementation.

Response 67. EKPC has implemented a limited number of Smart Grid technologies pertaining to its transmission system and substations. Each implementation is briefly described below.

System Protection – Reliability

EKPC installs microprocessor based relays when upgrading existing or building new substations. When beneficial to operations and restoration efforts, these relays can be programmed to perform additional functions, apart from their main purpose of issuing trip signals during fault conditions. One such additional function is transfer trip. This scheme allows a relay to provide its trip signal to remote locations to insure that faults are cleared from the system. Another additional function is fault location. Many microprocessor based relays have embedded fault location routines. The ability to pinpoint fault locations enhances restoration efforts by efficiently deploying field crews. Fault location data is also useful when dispatching field crews and aerial patrols to locate problems that did not lead to permanent faults.

Data Recorders – Reliability

EKPC currently uses two types of data recorders: Fault/event recorders and substation monitoring systems. A number of fault recorders are installed on the EKPC system within substations of 100 kV or greater. These fault recorders are connected to a number of microprocessor based relays within a single substation. When any of the relays recognizes a faulted condition, the fault recorder reads and stores the output from all of the relays to which it is connected. Similarly, the event recorders used by EKPC are connected to a number of substation devices, where all of the devices are not necessarily relays. Whenever one of these devices is triggered due to a disturbance, the event recorder reads and stores the output from all of the devices to which it is connected.

I-Grid – Reliability

EKPC has installed the I-Grid system within a large number of distribution substations. I-Grid is an innovative, web-based, distributed, power quality and reliability monitoring and notification system. I-Grid uses low cost I-Sense monitors to capture and transmit power data through the internet to a central server for display on the I-Grid website, as well as send event notification to EKPC. More information about the I-Grid system can be found on the Internet at: https://www.igrid.com/igrid.

Motor Operated Switches – Reliability

EKPC has installed a number of motor operated air break ("MOAB") switches throughout the entire transmission system. Each MOAB has been fully integrated into the Energy Management System, which allows the system operators to open and close these switches remotely. MOABs allow system operators to minimize outages and greatly speed restoration without the need to dispatch service personnel to manually operate switches.

Dynamic Thermal Circuit Ratings – Efficiency

To help EKPC deal with transmission constraints, the use of the dynamic thermal circuit rating ("DTCR") technology has been deployed to increase the rating of various types of equipment based on real-time loading and weather conditions. In addition to the DTCR modeling software, two fully instrumented weather stations have been installed.

Being able to increase the available capacity limits allows EKPC to push existing equipment beyond static ratings, which are based on fixed ambient temperatures, without fear of short or long term damage or increasing maintenance. The additional capacity provided by the EKPC DTCR installation has saved operating costs by delaying or avoiding re-dispatching, dispatching of combustion turbines, and curtailing energy trades.

Currently, EKPC has applied DTCR to three large capacity, high-voltage power transformers and eight high voltage transmission lines. Using a sophisticated, in-house developed, graphical user interface, DTCR results are displayed in real time to system operators.

Fault Locators – Reliability

Started in 2001, the in-house research and development pilot project to install fault locating technology has proven highly successful and has led to system-wide deployment throughout the radial portions of the EKPC 69 kV transmission system. The fault locating technology senses both the loss of voltage and a surge in current, both associated with a fault condition. If a fault is indicated, the fault locators illuminate a beacon for the duration of the outage. A smaller LED light is illuminated for up to 24 hours after power has been restored. Currently, a pilot project is underway to test fault locating technology for use on 69 kV transmission lines with networked (looped) power flow.

Distributed Generation – Reliability

In May 2011, EKPC Member Jackson Energy partnered with Wellhead Energy to install a 350 kW natural gas fired generator. This "GridFox" system was installed on a Jackson Energy distribution feeder. For this distributed generation installation, EKPC implemented a transfer trip scheme between the substation breaker (oil circuit recloser) and the main breaker at the generator location using an existing fiber optic line located between the two sites. The function of the transfer trip scheme is to trip the generator breaker should the substation oil circuit recloser detect a fault on the distribution feeder on which the generator is interconnected.

<u>Reclosers – Reliability</u>

Two of the EKPC Members have installed S&C Electric's IntelliRupters, a Smart Grid type of recloser (breaker and relay combination). One of the ways IntelliRupters differentiate themselves from typical reclosers is by having the ability to communicate with each other. This communication ability allows the devices to operate as a single system, thus containing outages to the minimum of customers as possible.

One of these Members has asked EKPC to consider replacing the substation reclosers with IntelliRupters. Should the cost/benefit analysis prove positive and no loss of functionality or risk of compromised reliability result from installing these units in a substation environment, EKPC will likely install IntelliRupters for this Member's pilot project in 2014.

EKPC will continue to evaluate Smart Grid technologies to determine if such technologies are beneficial to the EKPC system.

EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 98
RESPONSIBLE PARTY: Paul A. Dolloff

Request 98. With regard to calendar years 2007 through 2012, identify and discuss what Smart Grid and/or Smart Meter initiatives the utility implemented. The discussion should include but not be limited to the reasons why each initiative qualifies as a Smart Grid and/or Smart Metering initiative; the date of installation; the total cost of installation; and any benefits resulting from the initiatives, quantifiable or otherwise, received by both the utility and the customers.

Response 98. EKPC would note that the projects listed below were installed over a period of years and the total cost of installation is not readily available.

MV-90

Though installed prior to 2007, EKPC maintains a sophisticated metering system that is used on a select number of large commercial and industrial customers. These particular customers have their energy consumption data (i.e. energy usage, demand, peak demand, etc.) read by and archived in the MV-90 system. Most customer meters are read three times a month; however, some are read as often as daily. EKPC also has the MV-90 Web system in place for customers to access their own usage data.

To clarify, MV-90 is not a type of revenue meter. Instead, MV-90 is a software package that performs a number of meter reading and bill preparation functions. Provided by the Itron company, the MV-90 system performs interval data collection, management, and analysis from commercial and industrial metering devices. It can be used as a data collection engine that interfaces to existing data management and analysis tools, or as an end-to-end interval data management solution. The MV-90 system is a multi-vendor meter data management system for collecting and managing data from the complex metering devices typically used for large commercial and industrial customers. The MV-90 system's data management and analysis tools ensure data integrity and process consistency. The annual maintenance cost for the MV-90 system is approximately $45,000.

More information about the Itron MV-90 system can be found on the Internet at: http://www.itron.com/pages/products_detail.asp?id=itr_000321.xml.

Customer Metering Data Access

There are a few customers that are not on the MV-90 Web system but do have access to their energy consumption data on a near real-time basis. These customers have installed specialized electronic equipment that interfaces with the metering system, telemeters the data within the plant, and displays the data within their control rooms.

Load Research

EKPC also maintains a number of sophisticated load research meters that provide 15-minute kW demand as well as other energy consumption data. These meters have been strategically installed on particular customers who represent an entire class of customer. With this data, EKPC develops usage profiles for each type of customer class. Customer class profile data has any number of uses ranging from marketing to load grow projections. The data from the load research meters are collected and archived within the MV-90 system.

EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 99
RESPONSIBLE PARTY: Paul A. Dolloff

Request 99. With regard to calendar years 2013 through 2018, identify and discuss what additional Smart Grid and/or Smart Meter initiatives the utility has forecasted to be implemented. The discussion should include but not be limited to why each forecasted initiative qualifies as a Smart Grid and/or Smart Metering initiative; the forecasted date of installation; the forecasted total cost of installation; and any forecasted benefits to result from the initiatives, quantifiable or otherwise, received by both the utility and the customers.

Response 99. In 2013, EKPC will integrate into the regional transmission organization PJM Interconnection. LLC. As a requirement of EKPC's integration into PJM, EKPC must provide net generation power production figures for each EKPC generating unit in real time to the PJM operations center. To obtain these net figures, energy consumption from a generating unit's generation step-up ("GSU") transformer and associated general service transformers must be subtracted from the gross output of that particular generating unit. To comply with this requirement, EKPC is installing smart meters on the low voltage side of each GSU transformer. This initiative will be complete prior by June 2013. The cost of this initiative is approximately $300,000. Apart from PJM compliancy, there are no direct benefits associated with this initiative.

EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 100
RESPONSIBLE PARTY: Isaac S. Scott

Request 100. With regard to DA Smart Grid Initiatives provide the following:

a. the number of DA systems installed as of December 31, 2012, along with the associated benefits realized.

b. the number of DA systems to be installed in the next five years.

c. the total number of DA systems to be installed when the DA system is completely deployed.

Response 100a-c. EKPC is a generation and transmission cooperative and does not have distribution automation projects.

EAST KENTUCKY POWER COOPERATIVE, INC.

ADMINISTRATIVE CASE NO. 2012-00428

RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13

REQUEST 101

RESPONSIBLE PARTY: Paul A. Dolloff

Request 101. With regard to Volt/VAR Optimization, provide the following:

a. the number of Volt/VAR Optimization systems installed as of December 31, 2012, along with the associated benefits realized.

b. the number of Volt/VAR Optimization systems to be installed in the next five years, along with the forecasted in-service date.

c. the total number of Volt/VAR Optimization systems to be installed when the Volt/VAR Optimization system is completely deployed.

Response 101 a-c. Volt/VAR Optimization is primarily a distribution function so EKPC does not have Volt/VAR Optimization systems. However, two of EKPC's Members are installing Volt/VAR Optimization systems on a pilot project basis. For each of these installations, EKPC is required to install SCADA accessible control cards within the substation voltage regulators. As a matter of policy, EKPC will install these control cards whenever a Member deploys a SCADA system. The approximate cost of a control card is $500 and one card is required per voltage regulator. Each substation has three voltage regulators.

EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 102
RESPONSIBLE PARTY: Paul A. Dolloff

Request 102. With regard to Supervisory Control and Data Acquisition ("SCADA") Smart Grid Initiatives, provide the following:

Request 102a. The number of SCADA systems installed as of December 31, 2012, along with the associated benefits realized.

Response 102a. EKPC has only one SCADA system, which has been in operation since the 1980s. When EKPC became a self-sufficient balancing authority, it was required to install an energy management system ("EMS") and an associated SCADA system. A SCADA system is a communication platform on which monitoring equipment and intelligent electronic devices reside that bring real time power flow data to a utility control room. SCADA systems allow operators to remotely control intelligent electronic devices installed in the field. The benefits of SCADA systems in conjunction with an EMS are well known and range from providing alarms of abnormal operating conditions to aiding restoration efforts by minimizing and containing power outages.

EKPC installed a new EMS that became operational on April 12, 2012. The new EMS is the Monarch system by Open Systems International. The state estimator function of the new EMS will be functional prior to EKPC joining PJM in June 2013.

The EKPC EMS can be leveraged to provide SCADA functionality to the EKPC Members. As of December 31, 2012, five of the Members are being provided SCADA services using the EKPC EMS/SCADA system.

Request 102b. The number of SCADA systems to be installed in the next five years, along with the forecasted in service date.

Response 102b. As noted in part (a), EKPC has one SCADA system which is fully deployed. EKPC anticipates providing SCADA functionality to at least one or two additional Members, mostly likely in 2014.

Request 102c. The total number of SCADA systems to be installed when the SCADA system is completely deployed.

Response 102c. As noted in part (a), EKPC has one SCADA system which is fully deployed. EKPC anticipates it will likely provide SCADA functionality to six or seven of its Members.

EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 103
RESPONSIBLE PARTY: Isaac S. Scott

Request 103. As it relates to Dynamic Pricing (where rates are established hourly throughout the day) Tariffs or TOU Tariffs, provide the following:

Request 103a. The number of customers the utility has or had on these types of tariffs, identified separately by specific tariff.

Response 103a. EKPC's Section E tariff has been in operation since the early 1990s and a significant portion if not all of the monthly power bill for all 16 Members includes sales under the Section E tariff.

Request 103b. Whether these customers shifted load from high-price times periods to lower-priced time periods.

Response 103b. EKPC is not able to determine whether its Members shifted load from the on-peak to off-peak time period for that portion of the load priced under the Section E tariff.

Request 103c. Whether these customers consumed more, less or the same number of kWh.

Response 103c. EKPC is not able to determine whether its Members consumed more, less, or the same level of kWh as a result of the on-peak and off-peak provision in the Section E tariff.

Request 103d. Whether the utility reached any findings or conclusions based on its experience with customers on Dynamic Pricing and/or TOU Tariffs.

Response 103d. EKPC believes it has been beneficial to its Members to have the on-peak and off-peak provision in the Section E tariff. No other findings or conclusions have been developed.

EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 104
RESPONSIBLE PARTY: Isaac S. Scott

Request 104. Describe precautions taken and/or standards developed by the utility to address concerns regarding cybersecurity and privacy issues.

Response 104. EKPC is subject to the North American Electric Reliability Corporation's ("NERC") reliability standards, which includes cyber security standards. EKPC has invested significant time and resources to implement a Critical Infrastructure Protection ("CIP") compliant cyber security program. EKPC takes its CIP compliance program very seriously and is constantly evaluating it against best practices and CIP clarifications that are issued by NERC. EKPC is committed to a culture of compliance and security of its Critical Assets. EKPC has undergone SERC Reliability Corporation ("SERC") CIP compliance audits with favorable results.

EKPC believes the Commission and its Staff are aware of the sensitivity associated with compliance with the NERC standards. Many documents comprising the EKPC compliance plan and program contain CIP protected information and can only be shared with individuals who have been approved according to the requirements in EKPC's Information Protection Program and NERC Standard CIP-003. After consultation with SERC, it has been agreed that EKPC could release to the Commission its general compliance policy (POL 01-01), a copy of which is provided on pages 3 through 9 of this response. Also provided on pages 10 – 13 of this response is a copy of a February 15, 2013 letter from the CEO of the National Rural Electric Cooperative Association ("NRECA") to Representatives Markey and Waxman that provides a broad overview of the efforts by cooperatives to address cyber security issues. EKPC was a signatory to this letter.

Concerning privacy issues, as a generation and transmission cooperative, EKPC does not have retail customers and consequently does not have the privacy issues that are faced by our Members. However, EKPC treats all the billing information and related information in its billing system with extreme care and maintains the security of the data.

EAST KENTUCKY POWER COOPERATIVE
A Touchstone Energy® Cooperative

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Version #	Final V3
Origination Date	March 16, 2011
Version Date	November 14, 2011

NERC CIP CYBER SECURITY

SECURITY MANAGEMENT CONTROLS

POLICY

Approved by: Date: 11/15/2011
Denver York
Vice President, Power Delivery and System Operations
CIP Senior Manager

Approved by: Anthony S. Campbell Date: 11/16/11
Tony Campbell
President and CEO

Version History

Ver. #	Date/Reason for Revision/Initials
1	February 24, 2011/Rework former policy to conform to new program formatting/RD
2	March 4, 2011/Named the Senior Manager by title in section 4.2 and designated the COO as their backup in section 4.5
3	November 14, 2011 Made section 1.1 more specific. In section 2.1 added vendors and contractors. Eliminated reference to Pol 10-02 in section 4.6.4. because it is under CIP-001.

1.0 PURPOSE

1.1. This Policy describes EKPC's management's commitment to securing and protecting EKPC's Critical Cyber Assets, Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) (ESP), Cyber Assets that authorize and/or log access to the Physical Security Perimeter(s) (PSP) exclusive of hardware at the PSP access point such as electronic lock control mechanisms and badge readers as well as the information associated with these Cyber Assets.

2.0 PERSONS AFFECTED

2.1. This Policy applies to all EKPC, vendor, and contractor personnel having access to or responsibility for the management or support of the Cyber Assets described in Section 1.1.

3.0 DEFINITIONS

3.1. Critical Assets. Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the EKPC Energy Bulk Electric System.

3.2. Cyber Assets. Programmable electronic devices and communication networks including hardware, software, and data.

3.3. Critical Cyber Assets. Cyber Assets essential to the reliable operation of Critical Assets.

3.4. Cyber Security Policies. The set of EKPC policies that are intended to implement the North American Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) standards CIP-002 through CIP-009.

4.0 POLICY

4.1. EKPC is committed to meeting the North American Electric Reliability Council (NERC) Cyber Security Standards (CIP-002 through CIP-009) and has the ability to do so. These standards have been developed to reduce risks to the reliability of the Bulk Electric Systems from any compromise of Critical Cyber Assets or the Critical Assets they control.

4.2. The designated Senior Manager is the Vice President of Power Delivery and System Operations.

4.3. In accordance with Requirement R2 of CIP-003, "Security Management Controls", EKPC has designated a "Senior Manager" who will have overall responsibility for leading and managing the EKPC Implementation of, and adherence to, the NERC Cyber Security Standards.

4.4. Changes to the Senior Manager must be documented with the issuance of a new designation letter by the President & CEO, within thirty (30) calendar days of the effective date.

4.5. If the Senior Manager is unable to serve, the Chief Operating Officer automatically becomes the responsible executive until a new Senior Manager can be appointed.

4.6. The Senior Manager shall be responsible for implementing and maintaining the cyber security policies necessary to comply with NERC Cyber Security Standards CIP-002 through CIP-009, including provisions for emergency situations.

4.6.1. The Senior Manager has the authority to approve and implement cyber security policies and associated procedures across the EKPC organization necessary to ensure compliance with the NERC Cyber Security Standards.

4.6.2. The Senior Manager has the authority to assign ownership of, and responsibility for, cyber security policies and associated procedures necessary to comply with NERC Cyber Security Standards.

4.6.3. The Senior Manager may delegate the approval authority for cyber security policies and procedures.

4.6.4. This cyber security policy, POL 01-01, is the governing policy over the following cyber security policies:

- POL 02-01 – Network Management
- POL 03-01 – Asset Inventory
- POL 04-01 – Access Control Authorization
- POL 04-02 – Protected Cyber Asset and Protected Information Access
- POL 04-03 – Account Management
- POL 05-01 – Change Control and Configuration Management
- POL 06-01 – Testing
- POL 07-01 – Systems Management
- POL 08-01 – Cyber Security Incident Response
- POL 09-01 – Backup and Recovery Operations
- POL 10-01 – Physical Security
- POL 11-01 – Personnel Risk Management
- POL 12-01 – Information Protection
- POL 13-01 – Document Control and Records Management
- POL 14-01 – Security Awareness and Training
- POL 15-01 – Cyber Vulnerability Assessment

4.6.5. The Senior Manager has the authority to assign the development of cyber security policies and procedures.

4.7. The cyber security policies shall be readily available to all EKPC personnel who have access to, or are responsible for, Critical Cyber Assets.

4.8. The Senior Manager shall perform reviews of the cyber security policies annually.

4.8.1. Performance of these reviews shall not be delegated.

4.8.2. Changes resulting from these reviews should be incorporated in policy revisions within thirty (30) calendar days.

4.8.3. Documentation of these cyber security policy reviews shall be maintained for a minimum of three (3) calendar years.

4.9. The Senior Manager shall implement processes to annually review and revise, as necessary, supporting documentation created for the following:

4.9.1. Cyber Security Policies (See Section 4.7)

4.9.2. Authorized Cyber Security Policy Exceptions (See Section 4.11)

4.9.3. Risk Based Methodology for Critical Asset Determination

4.9.4. Critical Asset List

4.9.5. Critical Cyber Asset List

4.9.6. Access Privileges to Protected Information

4.9.7. Authorized Access Approvers List

4.9.8. Cyber Security Training Program

4.9.9. Physical Security Plan and Program

4.9.10. User Account Access Privileges

4.9.11. Cyber Security Incident Response Plan

4.9.12. Critical Cyber Asset Recovery Plan

4.9.13. Critical Cyber Asset Management

4.9.14. ESP Network Management

4.9.15. Test Procedures

4.9.16. Ports and Services

4.9.17. Security Patch Management

4.9.18. Malicious Software Prevention

4.9.19. Account Management

4.9.20. Security Status Monitoring

4.9.21. Disposal and/or Redeployment

4.9.22. Cyber Vulnerability Assessment

4.10. The Senior Manager shall implement a program to assess adherence to the cyber security policies, plans, programs, processes, and procedures; document the assessment results; and implement an action plan to remediate deficiencies identified during the assessments. The assessment program shall include a schedule of assessments that meet the requirements of the NERC Cyber Security Standards. At a minimum, these assessments shall include the following specific programs.

4.10.1. Access Control Program

4.10.2. Information Protection Program

4.11. Emergency situations that will violate a condition of a Cyber Security Policy must be declared as soon as practical by the Senior Manager or delegate, and documented as exceptions.

4.12. Exceptions, including those due to emergency situations, to the cyber security policies shall be documented and authorized by the Senior Manager, or delegates.

4.12.1. Exceptions to the cyber security policies shall be documented within thirty (30) days of being approved by the Senior Manager, or delegates.

4.12.2. Documented exceptions shall include an explanation as to why the exception is necessary and any compensating measures.

4.12.3. Authorized exceptions to the cyber security policies shall be reviewed and approved annually by the Senior Manager or delegates to ensure the exceptions are still required and valid. Such review and approval shall be documented.

4.12.4. Documentation of authorized exceptions and associated approvals from the previous calendar year shall be retained for a minimum of three (3) calendar years.

4.13. For the purposes of all EKPC Cyber Security Policies, Plans, Programs, Processes, and Procedures, the term "annual" or "annually" will be defined as occurring within the same calendar quarter of each year (e.g., a review occurs in April 2009 must occur in April, May, or June of 2010) or sooner.

4.14. Documentation of assignments and delegations shall be retained while in effect. Records of superseded assignments and delegations shall be retained for a minimum of three (3) calendar years.

4.15. Enforcement - Any employee found to have violated the cyber security policies may be subject to disciplinary action, up to and including termination of employment.

5.0 NERC CIP Reference Requirements

5.1. Standard CIP - 003 - 3 Cyber Security -- Systems Management Controls

5.1.1. R1. Cyber Security Policy
5.1.2. R2. Leadership
5.1.3. R3. Exceptions
5.1.4. R4.3
5.1.5. R5.3

6.0 RESPONSIBILITIES

6.1. The assigned Senior Manager is responsible for the approval, implementation, and maintenance of this policy.

National Rural Electric
Cooperative Association
A Touchstone Energy® Cooperative

Glenn English
Chief Executive Officer

February 15, 2013

The Honorable Edward J. Markey
Ranking Member
House Natural Resources Committee
2108 Rayburn House Office Building
Washington, DC 20515

The Honorable Henry A. Waxman
Ranking Member
House Energy & Commerce Committee
2204 Rayburn House Office Building
Washington, DC 20515

Dear Ranking Members Markey and Waxman:

The National Rural Electric Cooperative Association (NRECA) and its members take very seriously the importance of vigilance against cybersecurity risks and the issues highlighted in your broadly-circulated letter of January 17, 2013. While our members, who serve nearly 42 million consumers in 47 states (excluding Massachusetts, Rhode Island and Connecticut), are on the front lines, NRECA supports them by working with policymakers and stakeholders to strengthen the public-private partnerships that are an essential component of grid protection.

It is precisely because of our commitment to responsible grid protection that we and our members are concerned that your letter asks for sensitive information and in some cases, Critical Energy Infrastructure Information (CEII) as defined by the Federal Energy Regulatory Commission (FERC). Sending details asked for in many of the specific questions by electronic means could inadvertently result in the information getting into the wrong hands. Our staff is happy to follow up with yours in a private, confidential setting to discuss these and other questions you may have.

Electric cooperatives have a long, proud tradition of protecting and securing our electric system assets. We are guided by our obligation to serve and the status of our consumers as our owners. The Rural Utilities Service (RUS) has long required each electric cooperative borrower to adhere to rigorous construction standards. Beginning in October 2004, RUS Electric System Emergency Restoration Plan (ERP) regulations in 7 CFR Part 1730 required each borrower to perform a vulnerability and risk assessment and to develop emergency recovery plans regarding physical and cyber incidents. In addition, borrowers are also required to annually exercise their ERP. When disasters strike and electric service is disrupted, cooperatives rely on mutual assistance compacts to deploy teams of line workers across the country to help restore power as quickly and safely as possible. This spirit of cooperation extends to our IOU and municipal counterparts; after Superstorm Sandy, dozens of cooperative crews helped restore power in the Northeast.

Electric cooperatives have participated in each stage of the evolution of the North American Electric Reliability Corporation (NERC), including helping develop Energy Policy Act of 2005 (EPAct '05) amendments to the Federal Power Act which enabled NERC to receive FERC's approval as the Electric Reliability Organization in 2006. Today, numerous electric cooperative technical experts are routinely deployed in NERC teams working on the continual process of writing and improving the already-extensive body of NERC reliability standards, including cyber security standards.

NERC, in a years-long collaborative process with the electric power industry, has produced a body of mandatory, enforceable reliability standards that apply to users, owners and operators of the Bulk Power System. Your letter is particularly concerned with the subset of standards known as the Critical Infrastructure Protection (CIP) standards. To our knowledge, the CIP standards and the Nuclear Regulatory Commission cybersecurity standards are the only mandatory and enforceable cybersecurity standards in place across the vast array of US critical infrastructures. When covered entities are found to have violated the CIP standards, they can be subjected to fines as high as one million dollars per day. NERC has issued sizable fines when entities have been found in violation.

On January 31, 2013, NERC filed its CIP Version 5 standards with FERC for approval. Congressional stakeholders occasionally misunderstand the reasons for having developed multiple versions of the CIP standards in less than six years. NERC and the industry are continuing to address FERC directives, NIST standards and other best practices to make sure the standards evolve with technology and the risks. CIP Version 5 addresses all of FERC's directives and implements key elements of the National Institute of Standards and Technology (NIST) standards.

Electric cooperatives which own or operate Bulk Electric System (BES) assets are required to adhere to one or more of the NERC CIP standards. They have made significant investments in strategic plans, consultants, hardware, software, and full-time employees to ensure compliance and a culture of security at their cooperatives. Electric cooperatives participate in simulations and table-top exercises and NRECA has asked federal government partners to expand these opportunities. However, the electric cooperative network has not simply limited its cybersecurity efforts to a robust, two-way dialogue with NERC and with NERC standards compliance. NRECA and its members (including those cooperatives that are not subject to NERC CIP standards) are engaged in an ongoing conversation with industry and government partners, including FERC, DOE and DHS to increase knowledge of cyber risks and to determine the best means of defense, including implementing appropriate industry best practices.

Throughout 2012, NRECA was a leading participant in the Department of Energy's Electricity Sector Cybersecurity Capability and Maturity Model ("Maturity Model" or "Model") development process and several of our members volunteered to host DOE staff for pilots of the Model. The Model presents senior and front-line utility employees with a series of questions and diagnostics concerning cybersecurity. It is now posted publicly and cooperatives continue to work with DOE and industry representatives to expand its use.

The desire to protect our systems has brought NRECA into a partnership with CEOs of the Edison Electric Institute (EEI), the American Public Power Association (APPA) and the Nuclear Energy Institute (NEI) to focus on implementing recommendations of President Obama's National Infrastructure Advisory Council (NIAC). NIAC recommended that the federal government and electric power sector conduct an ongoing, high-level dialogue. The conversation between our associations, the Secretaries of Homeland Security and Energy and White House national security and cybersecurity leadership staff on grid protection has been very productive and is laying the foundation for a functioning public-private working group that can deploy information and instructions across the electric power sector in the event of a severe cyber-attack on the electric grid.

NRECA's Cooperative Research Network (CRN) has been extremely proactive in developing cybersecurity tools targeting distribution utilities (but applicable to utilities of all sizes) which typically are not subject to NERC standards compliance because their operations do not impact the bulk electric system. Since electric cooperatives are at the forefront of smart grid deployment, our members are very much aware of the need to comprehensively address the security of any new telecommunications-enabled devices. As part of its fulfillment of a $68 million smart grid demonstration program under the American Reinvestment and Recovery Act, CRN developed cybersecurity plans for the 23 participating electric cooperatives. That effort led to the development of a tool that compiles thousands of pages of industry and government guidance on cybersecurity into a digestible, deployable plan. It is publicly available on the web and anecdotal evidence tells us it is in use at many utilities, including some outside the cooperative network. You can download the plan from the web at http://www.nreca.coop/bestbets/cybersecurity. CRN now leads training open to all segments of the industry on the plan and cybersecurity best practices.

It has been several years now since the introduction of the House "Grid Act," which NRECA did not support because it sought to centralize authority to write cybersecurity standards within the federal government. The sheer scope of the efforts made by employees and experts in the electric utility field should highlight the tremendous drawbacks to placing the responsibility for writing highly technical standards impacting the generation and transmission of power - our economy's lifeblood - inside the beltway.

Sincerely,

Glenn English, CEO

Attachment: List of cooperative signatories

Blue Ridge EMC	North Carolina
Brazos Electric Cooperative	Texas
Citizens Electric Corporation	Missouri
East Kentucky Power Cooperative, Inc.	Kentucky
Magic Valley Electric Cooperative, Inc.	Texas
North Star Electric Cooperative	Minnesota
PNGC Power	Oregon, Washington, Idaho, Montana, Wyoming, Utah & Nevada
Seminole Electric Co-op, Inc.	Florida
South Mississippi Electric Power Association	Mississippi
Wabash Valley Power Association	Indiana
Withlacoochee River Electric Cooperative, Inc.	Florida
Wolverine Power Supply Cooperative, Inc.	Michigan

EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 105
RESPONSIBLE PARTY: Paul A. Dolloff/Isaac S. Scott

Request 105. Provide a discussion and details of progress made regarding the concern raised by the utilities as it relates to the interoperability standards for Smart Grid equipment and software.

Response 105. Concerning equipment, though EKPC maintains some legacy equipment that uses the conitel communication protocol and other equipment using the Modbus communication protocol, EKPC has standardized on the use of the DNP 3.0 communication protocol. The recently installed EMS is DNP 3.0 based. No interoperability issues are anticipated as all Smart Grid equipment installed by EKPC will be required to function using the DNP 3.0 protocol.

Concerning software, EKPC is aware that the National Institute of Standards and Technology ("NIST") has working groups in place addressing the various issues related to interoperability standards. The NIST has initiated the Smart Grid Interoperability Panel to assist the NIST with its standards development responsibilities under the Energy Independence and Security Act of 2007. The Panel's website is http://www.nist.gov/smartgrid/sgipbuffer.cfm. In addition, NRECA manages and funds the MultiSpeak Initiative, which the NIST has recognized as one of the foundational smart grid interoperability standards. The MultiSpeak Initiative website is http://www.multispeak.org/Pages/default.aspx. EKPC is also aware of work by EPRI and IEEE.

EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 106
RESPONSIBLE PARTY: Isaac S. Scott

Request 106. Provide a discussion concerning how the costs (investment and operating and maintenance costs) associated with the installation of Smart Grid facilities should be recovered from the ratepayers.

Response 106. As Mr. Scott noted in his testimony on page 14, EKPC believes costs associated with the installation of Smart Grid facilities can be recovered from ratepayers either through rate cases or rider mechanisms. The size of the investment, the financing approach, and whether the utility is investor-owned or a cooperative could influence which approach is utilized. The specific features of the approach used will be dependent on the extent to which the Commission authorizes cost recovery. If recovery is sought through a rate case, EKPC believes the costs associated with the Smart Grid facilities should be included in the cost of service study as a means to reasonably classify and assign the costs to the various rate classes. If recovery is sought through a rider mechanism, EKPC believes a mechanism similar to the approach the Commission authorized for Duke Energy Kentucky's Accelerated Mains Replacement Program ("AMRP") would be appropriate.

EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 107
RESPONSIBLE PARTY: Isaac S. Scott

Request 107. State whether the utility would favor a requirement that it report to the Commission so that the Commission is aware of the jurisdictional Smart Grid and/or Smart Meter activities within the Commonwealth. As a specific example, the requirement could order that a report be provided each September regarding the Smart Grid and/or Smart Meter activities the utility is planning to perform during the upcoming calendar year, followed by an April report of the Smart Grid and/or Smart Meter activities the utility completed the preceding calendar year.

Response 107. EKPC certainly understands the Commission would want to be aware of the jurisdictional Smart Grid and/or Smart Meter activities within Kentucky. However, EKPC would suggest that in order to provide meaningful reporting, the Commission will have to define what constitutes reportable Smart Grid and Smart Meter activities. EKPC also believes the information needs of the Commission may also be influenced by the Commission's determination of whether Certificates of Public Convenience and Necessity are required for Smart Grid and Smart Meter projects. Concerning the specific example provided in the question, while some form of periodic reporting may be beneficial, EKPC believes the suggested September-April reporting sequence is unnecessarily burdensome. The separate reporting of planned activities and actual activities, at different times of the year, could be confusing and could be difficult to reconcile. If periodic reporting is required, EKPC believes it would be more reasonable to have one report filed, possibly on March 31, which would report on the actual

Smart Grid and Smart Meter activities of the previous calendar year and any planned activities for the next 12 months.

EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 108
RESPONSIBLE PARTY: Isaac S. Scott

Request 108. State whether the utility believes KRS 278.285 is an appropriate approach to recovering the costs (investment and operation and maintenance) associated with Smart Grid investments.

Response 108. EKPC believes it may be possible to utilize the provisions of KRS 278.285 as a means to recover the investment and operation and maintenance costs associated for some Smart Grid projects. However, the specific Smart Grid project would have to be a component of a proposed demand-side management plan and that plan would have to satisfy the provisions of KRS 278.285(1)(a) through (j). It would appear that AMI projects would be eligible based on the language in KRS 278.285(1)(j). But not all Smart Grid projects will result in changes in customers' consumption patterns or are necessarily consistent with a utility's most recent long-range integrated resource plan. Identifying which customer class benefits from the projects could be difficult to determine. Lastly, KRS 278.285 does not explicitly state that the costs to be recovered through the demand-side management mechanism include a return on the Smart Grid investment. EKPC is aware that in Case No. 2011-00134 the Commission permitted a return on the investment in load control switches as a cost in the demand-side management mechanism for LG&E and KU. However, the difference in the magnitude of the investment between load control switches and Smart Grid assets is significant and the inclusion of a return on investment as a cost component could be challenged.

While KRS 278.285 could be utilized to recover the investment and operation and maintenance costs associated with certain Smart Grid projects, EKPC would prefer that cost recovery either be accomplished through a base rate case or a separate rider mechanism similar to the Duke Energy Kentucky AMRP rider.

EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 109
RESPONSIBLE PARTY: Isaac S. Scott

Request 109. State whether the utility believes a tracking mechanism as described beginning on page 3 of the Wathen Testimony on behalf of Duke Kentucky is an appropriate approach to recovering the costs associated with Smart Grid investments.

Response 109. As noted in previous responses, EKPC believes the cost recovery for Smart Grid investments can be accomplished through either a base rate case proceeding or through the use of a rider mechanism. EKPC has reviewed the discussion of the tracking mechanism contained in Mr. Wathen's testimony and notes that mechanism is very similar to the AMRP rider the Commission approved for Duke Kentucky in 2002. The Ohio mechanism includes the treatment for "post-in-service carrying costs" which the Commission did not approve for the AMRP rider. As the Commission is already familiar with the AMRP rider, EKPC would suggest that if it is determined by a particular utility that a rider mechanism is the appropriate means of cost recovery for Smart Grid investments, a mechanism similar to the AMRP rider be utilized.

EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 110
RESPONSIBLE PARTY: Scott Drake/Isaac S. Scott

Request 110. State whether the utility has commissioned a thorough DSM and Energy Efficiency ("DSM-EE") potential study for its service territory. If the response is yes, provide the results of the study. If no, explain why not.

Response 110. Although EKPC is not required to commission a DSM-EE potential study, in 2010 EPRI conducted a DSM technical potential study for the residential class of EKPC's member systems. The EPRI report gave high level results: savings by end use. However, it did not provide the underlying data, so EKPC was only able to use it as a sanity check. Overall, EKPC's DSM-EE plan for the residential class matched up very well with the report's total savings potential. A copy of this study is provided on pages 2 through 36 of this response.

ELECTRIC POWER RESEARCH INSTITUTE

Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs for East Kentucky Power Cooperative

(2010-2025)

1021281

Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs for East Kentucky Power Cooperative

(2010-2025)

1021281

Technical Update, May 2010

EPRI Project Manager

C. Holmes

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PRODUCT DESCRIPTION

This report documents the results of a study to assess the achievable potential for electricity energy savings and peak demand reductions for East Kentucky Power Cooperative (EKPC) for 2010–2025. The approach involved applying the methodology and technology data developed for the Electric Power Research Institute (EPRI) National Study on the same subject (report 1016987), adapted to the specific market sector characteristics of the EKPC service territory. The efficient technologies and measures considered are commercially available today. The estimation of economic potential assumes that consumers will adopt the most energy-efficient technology that has a benefit/cost ratio greater than one, measured using the Total Resource Cost Test. Estimates of economic potential are adjusted to account for various market barriers and program implementation factors to quantify the energy efficiency potential that can realistically be achieved.

Results and Findings

The results indicate that the realistic achievable energy efficiency potential for all market sectors is 747 GWh for the year 2025, or 8.9% of the EPRI-calculated baseline forecast of 8,404 GWh for 2025. These savings are in addition to the significant reductions in consumption that are expected to result from the improvements in lighting required by the Energy Independence and Security Act of 2007 (EISA). The savings from EISA are expected to reduce the residential energy forecast by 580 GWh by the year 2025. Therefore, the impact of EISA in the residential sector is projected to be nearly as much as the realistic achievable potential of all other energy efficiency measures combined. The winter demand-related savings associated with energy efficiency programs are 47 MW by the year 2025, which represents roughly 1.2% of the projected system winter peak load for that year. The summer demand-related savings associated with energy efficiency programs are 28 MW by the year 2025, which represents roughly 0.9% of the projected system summer peak load for that year. Demand response (DR) programs could reduce winter peak demand by 243 MW and summer peak demand by 93 MW by 2025, although there is some potential for double counting between the peak reductions that could be achieved from energy efficiency programs and the reductions that could be achieved through DR programs.

Challenges and Objectives

Although the potential savings based on customer economics alone are not insignificant, the results presented in this report do not indicate whether specific programs would be cost-effective from EKPC's point of view. Therefore, these results should be considered as a useful starting point for EKPC's planning as it considers a range of potential options for meeting its future energy requirements as cost-effectively as possible. The results should also be useful to EKPC's energy efficiency program managers in designing programs and setting targets for energy and demand savings and for reductions in environmental externalities.

Applications, Value, and Use

This study indicates that the approach used in the EPRI National Study can be adapted to individual utilities to support utility-specific resource planning and energy efficiency program design. The approach is robust and can readily be updated as more efficient technologies and measures emerge.

EPRI Perspective

The EPRI National Study is unique because it is grounded in commercially available efficiencies and costs and reflects the actual participation results achieved by energy efficiency programs. Because the EPRI National Study considered all regions of the country, the approach can be adapted to virtually any U.S. member utility who requests this assistance.

Approach

The goal of this project was to produce EKPC-specific estimates of energy efficiency savings by applying the approach used in the EPRI National Study. The results are based on commercially available technologies and costs using an equipment stock turnover model. The results are detailed and granular, by end use and by technology. This approach makes the results more transparent than those of other studies that employ a macro "top-down" approach, which is highly sensitive to variations in a few key assumptions.

Keywords

Energy efficiency
Demand response
Demand-side management (DSM)
Potential
Forecasting

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1
INTRODUCTION

Like many other utilities, East Kentucky Power Cooperative (EKPC) is exploring the potential of more efficient electric technologies to help meet the future electricity needs of their member systems, and in helping to reduce carbon emissions. Their baseline forecast is that electricity consumption will grow at an EPRI-calculated compound annual growth rate of 1.9% between 2010 and 2025.

In October of 2009, EKPC engaged EPRI to apply the methodology developed for its national energy efficiency study[1] (the EPRI National Study) to their member systems' service territories. This report documents how the methodology and technology data developed for the National Study were adapted to the EKPC service territory, and the energy efficiency and demand response potential estimates that resulted from that work.

This report will not repeat the detailed descriptions of the technologies, data sources, and methodology that are contained in the National Study. Rather, this report should be viewed as a companion document to the National Study which will highlight EKPC-specific information and results.

EKPC serves 16 distribution cooperatives who, in turn, serve approximately 511,000 retail customers across 87 counties in Kentucky.

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[1] *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.: (2010-2030).* EPRI, Palo Alto, CA: 2009. 1016987.

2
APPROACH FOR ENERGY EFFICIENCY ANALYSIS

Overall Approach

The overall approach is illustrated in Figure 2-1. It is the same approach used in the National Study, with the exception that EKPC-specific data were substituted for the National Study data whenever EKPC data were available.

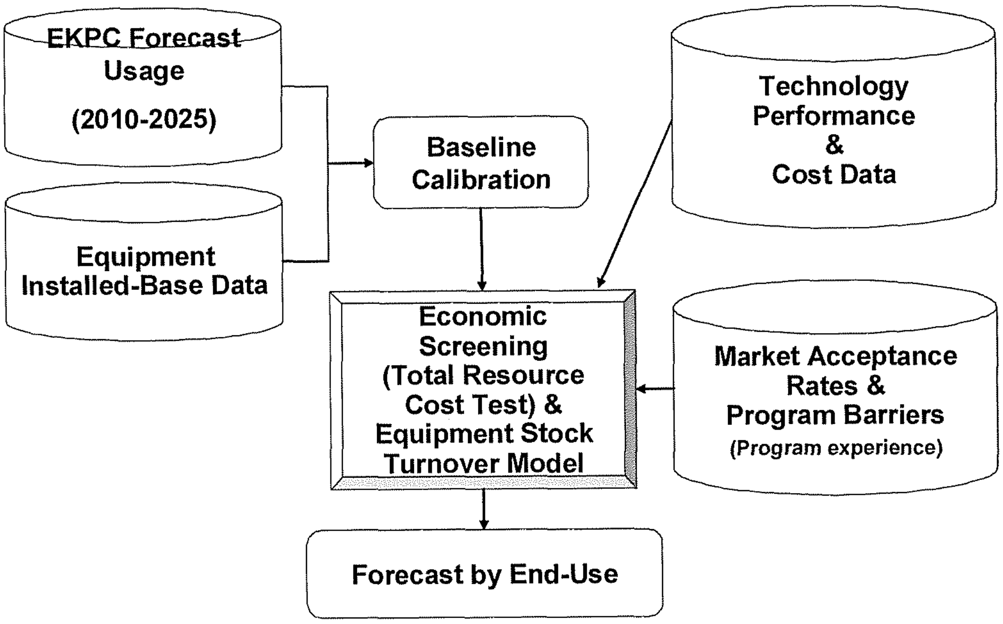

Figure 2-1
Overall Analysis Approach

EKPC provided baseline forecast data (kWh and kW) for 2009 through 2028. They also provided appliance saturation data for the residential sector based on surveys they have conducted over a number years. Where needed, EPRI used secondary data or the equipment share data that were developed for the Southern Region in the national study.

Technology and measure cost and performance data were from EPRI databases supplemented by building simulations and other analysis, and by EKPC data where available. Energy measures considered for the residential sector in this study are shown in Table 2-1.

Table 2-1
Residential Sector Energy Efficiency Measures

Room AC	Storm Doors (Heating)
Central AC	External Shades
Heat Pumps	Ceiling Insulation
Lighting - Linear Fluorescent	Ceiling Insulation (Heating)
Lighting - Compact Fluorescent	Foundation Insulation
Water Heating	Foundation Insulation (Heating)
Dishwashers	Wall Insulation
Dishwashers (DHW)	Wall Insulation (Heating)
Clothes Washers	Reflective Roof
Clothes Washers (DHW)	Windows
Clothes Dryers	Windows (Heating)
Refrigerators	Faucet Aerators
Freezers	Pipe Insulation
Cooking	Low-Flow Showerheads
Color TV	AC Maintenance
Personal Computers	HP Maintenance
Furnace Fans	Duct Repair
Attic Fan	Duct Repair (Heating)
Ceiling Fan	Infiltration Control
Whole-House Fan	Infiltration Control (Heating)
Duct Insulation	Combined Washer/Dryer
Duct Insulation (Heating)	In-home Feedback Monitor
Programmable Thermostat	Dehumidifier
Programmable Thermostat (Heating)	Reduce Standby Wattage

Notes: AC = air conditioning; DHW = domestic hot water; HP = heat pump.

Market acceptance ratios and program implementation factors were taken from the EPRI National Study, but were reviewed by EKPC program managers to ensure that they were consistent with EKPC and Members' experience in implementing such programs in the past.

Definitions of Potential

Consistent with the National Study, four definitions of potential were used in this study[2].

- **Technical Potential** represents the savings due to energy efficiency and demand response programs that would result if all homes and businesses adopted the most efficient, commercially available technologies and measures, *regardless of cost*. Replacement is assumed to occur at the end of their useful lives by the most efficient option available. Technical potential does not take into account the cost-effectiveness of the measures, or any market barriers.
- **Economic Potential** represents the savings due to programs that would result if all homes and businesses adopted the most energy-efficient cost-effective commercially available measures. The economic test applied is a variation on the *Total Resource Cost (TRC) Test*, which compares the incremental cost of the measure relative to the society's baseline option, and to the projected bill savings over the life of the measure. Economic potential does not take into account any market barriers to adoption. Economic potential assumes that most efficient option that passes the economic screen is adopted. For the EKPC study, EKPC projected electricity prices were used in the calculation of economic potential.
- **Maximum Achievable Potential (MAP)** takes into account those barriers that limit customer participation, even under a scenario that assumes customers have perfect information, that utilities offer incentives equal to the incremental cost of energy efficient measures above baseline measures, and that utilities implement programs with high marketing and administrative costs. These barriers can include perceived or real quality differences, aesthetics, customer inertia, or customer preferences for product attributes other than energy efficiency. MAP is estimated by applying market acceptance rates (MARs) to the economic potential savings from each measure. The MARs developed in the EPRI National Study were used in the EKPC study, after a review by EKPC program managers and staff.
- **Realistic Achievable Potential (RAP)**, unlike the other potential estimates, represents a forecast of likely customer behavior. It takes into account existing market, financial, political and regulatory barriers that are likely to limit the amount of savings that might be achieved through energy-efficiency and demand-response programs. For example, utilities do not have unlimited budgets for program implementation. There can be regional differences in attitudes toward energy efficiency and its value as a resource. Market barriers can include imperfect information. RAP is calculated by applying a program implementation factor (PIF) to the MAP for each measure. The program implementation factors were developed by taking into account recent utility experience with such programs and their reported savings. The PIF factors developed for the National Study were reviewed with the EKPC program managers and staff and applied to the EKPC MAP estimates.

Hierarchy of Data Sources

Table 2-2 illustrates the data hierarchy that was applied in this study. If EKPC data were available, they were used. In some cases, EKPC data were available, but had to be adjusted slightly, sometimes constant values were assumed, or the EKPC data might have been

[2] EPRI National Study, p. xiii-xiv.

extrapolated from related information. If EKPC-specific data were unavailable, data for the South Census region from the EPRI National Study were used.

Table 2-2
Hierarchy of Data Sources

Hierarchy Level	Data Source
1	EKPC Provided Data
2	Interpolated/Extrapolated EKPC Data
3	South Census/EPRI National Study

Segmentation Analysis

Figure 2-2 illustrates how the analysis was segmented. Estimates of potential were developed at the EKPC system level for the residential sector, then by end-use, and by measure. (Residential space cooling is used to illustrate the different levels of analysis in Figure 2-2.)

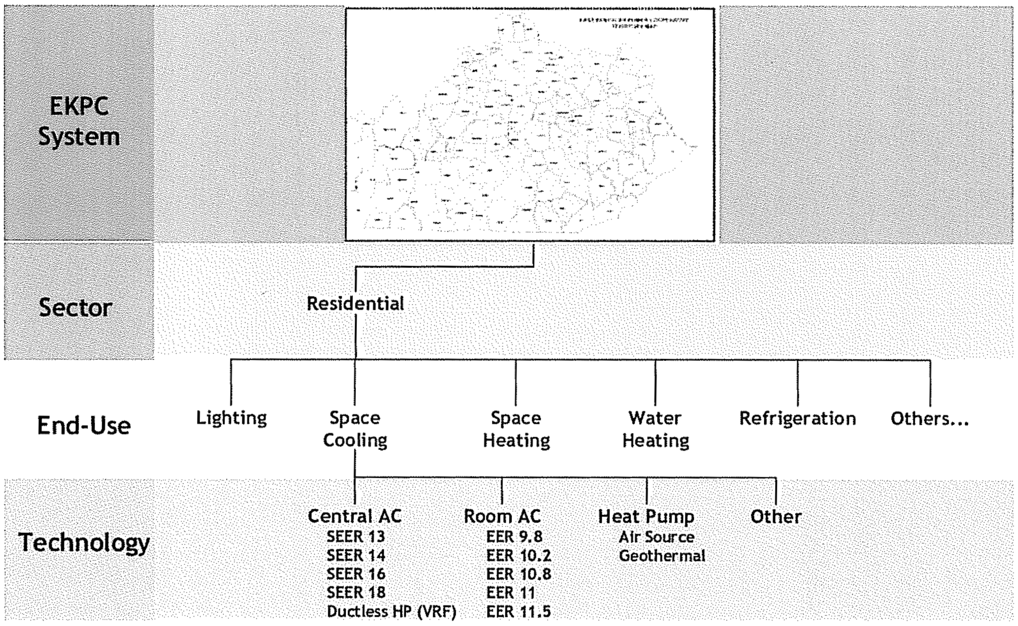

Figure 2-2
Segmentation of Analysis – by End-Use and Measure

EKPC provided historic electricity sales data, as well as forecasts of sales to the year 2028. These forecasts excluded projected impacts from EKPC's own demand-side management programs, and provided the baseline for assessing the energy efficiency and demand response potential within their service territory.

Residential Sector

The model used for the residential sector in the EPRI National Study is a stock turnover model. In all four measures of potential, equipment is assumed to be replaced when it is at the end of its useful life. The model does not assume early retirements based on economics.

Baseline Estimation

Age Distribution of End Uses

A first step in this analysis was to develop historical end-use age distribution data, based on EKPC data on household counts and appliance saturation rates from saturation studies that went back to 1991.[3] The goal was to get to a realistic age distribution of each measure for the year 2010, the starting point for the analysis. The steps were as follows:

1. Begin with total household counts and residential appliances from the saturation survey for 1991.
2. Define initial age distribution "bins" based on EKPC survey data or South census region data, and the turnover rate from each bin to the next. Apply the turnover rate for each year between 1991 and 2010. Any increase in the saturation rate of a given end-use was added to the "new" category, and aged through time as outlined above. (For example, if the saturation rate of room air conditioners increased from 10% to 12%, the 2% increase was assigned to the "new" age bin.)
3. The age distribution of appliances for 1987 that resulted from this analysis was used as the starting age distribution of appliances.

The result of this analytical step was to produce an initial age distribution of appliances for the year 2010, the starting year for the energy potential analysis.

Weather Analysis

The EPRI National Study used weather data for Birmingham, Alabama to represent the unit energy consumption (UECs) for weather-sensitive loads such as heat pumps and central air conditioners. For the EKPC study, EPRI undertook a detailed analysis using Lexington, Kentucky weather data to determine seasonal end-use consumption based on the UECs provided by EKPC. EnergyGauge, a software tool which uses the DOE-2 engineering model, was used to generate 8760 consumption data by end use for a typical EKPC home. Peak summer and winter demands were also calculated for each end use based on the results from EnergyGauge.

Economic Screen – Total Resource Cost Test

Data developed for the EPRI National Study were used to estimate for each efficiency measure:

- kWh impacts
- kW impacts
- incremental costs relative to baseline measures

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[3] EKPC provided the results of residential appliance saturation surveys conducted every two or three years since 1991.

- measure lifetime

With these inputs and EKPC's avoided costs, an economic screen known as the Total Resource Cost Test was estimated over the life of the measure. Basically the screen is a benefit/cost (B/C) ratio, calculated by comparing the present worth of the avoided power supply costs to the incremental measure cost. The formula for calculating this test is as follows:

$$\sum_{i=1}^{t}\left(\frac{\text{Avoided Power Supply Costs}}{(1+r)^{i}}\right) \Big/ \sum_{i=1}^{t}\left(\frac{\text{Incremental Measure Cost}}{(1+r)^{i}}\right)$$

Where:

i = year in which costs or savings are incurred by the participating customer
t = life of measure
r = discount rate (5% real discount rate is assumed)

If the B/C ratio is $\geq$ 1.0, the measure is assumed to be economic. The most energy-efficient measure with a B/C ratio $\geq$ 1.0 is assumed to be adopted.

3
DEMAND RESPONSE POTENTIAL ANALYSIS

The potential for demand response reduction was also estimated in the EPRI National Study[4]. However, potentials were estimated at a much higher level of aggregation than for energy efficiency potential. Programs were broadly characterized by their general approach to reducing load. Then the likelihood of participation by a representative customer was estimated, taking into account market and administrative barriers.

Demand response programs are grouped first by sector and applicable end use:

- Residential sector: direct load control for air conditioning, direct load control for electric heating, direct load control for water heating, and dynamic pricing programs (time-of-use, critical-peak pricing, real-time pricing, and peak time rebates);

These program types fall into three primary categories – direct load control, event-based voluntary shed, and response to price signals.

Data and Assumptions

EKPC-Supplied Data

EKPC provided:

- EKPC system peak demand for 2010
- Each end-use wholesale (residential, general service, manufacturing, etc.) class's percentage of total GWh sales for 2010
- Estimated residential coincident peak loads (consistent with their estimated baseline energy usage)
- Hourly system load data for 2010

EPRI National Study

Estimates from the National Study that were used in this analysis include the estimated technical potential for DR programs in the U.S., end-use share contributions to class peak for the Southern region, and Market Acceptance Ratios for different program types.

Methodology

Developing a Baseline

EPRI used the 2010 EKPC system peak demand as the baseline for the demand response potential analysis. The EKPC system load factor (the ratio of average demand to peak demand) was calculated from the 2010 hourly system load data. EPRI then:

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[4] See EPRI National Study, pp. 2-28 through 2-30.

- Calculated the average out-year peak demand based on the energy forecast times the 2010 average system load factor.
- Apportioned the system peak demand to each end-use wholesale class's percentage of GWh sales. (This assumption implies that all classes have the same load shape. Thus, the residential class's relative contribution to peak demand is understated, and the industrial class's relative contribution to peak demand is overstated.)

Note that there is a potential for double-counting the demand response reduction potential if both energy efficiency programs and demand response programs are implemented. Energy efficiency programs will also reduce system peak to the extent that the end use is coincident with the system peak. To the extent that EE programs reduce peak load, it will lower the remaining peak that is the basis for demand response programs.

Definitions of Potentials[5]

EPRI has developed measures of potential similar to those for energy efficiency measures, with the exception of economic potential. The programs considered in the analysis are assumed to be cost-effective for both the utility and the participating customer, and the predicted acceptance is encompassed in the maximum achievable potential. The measures of potential for demand response are defined as follows in the EPRI National Study:

- Technical Potential – Complete penetration of DR programs among eligible customers, assuming load shed comparable to highest performing customers under existing programs.
- Maximum Achievable Potential – Technical potential adjusted to include market penetration, accounting for perceived market barriers.
- Realistic Achievable Potential – Maximum achievable potential adjusted to reflect regulatory and administrative barriers.

Estimation of DR Potential for EKPC

EPRI estimated the demand response potential for EKPC by applying data and assumptions from the National Study (including estimates of technical potential by program type, engineering analysis and program MAR factors) to EKPC's customer characteristics.

[5] See EPRI National Study, pp. 2-28 through 2-30.

4
BASELINE ENERGY FORECAST

Residential Sector

Calibration of EKPC Forecast to the EPRI Baseline Forecast

As outlined in Section 2, the first step in the analysis is to develop a baseline forecast against which energy efficiency potential can be estimated. EKPC's forecast of total residential electric sales is shown in Figure 4-1. Over the period 2010 to 2025, residential sales are calculated to grow at a compound annual growth rate of 1.9%.

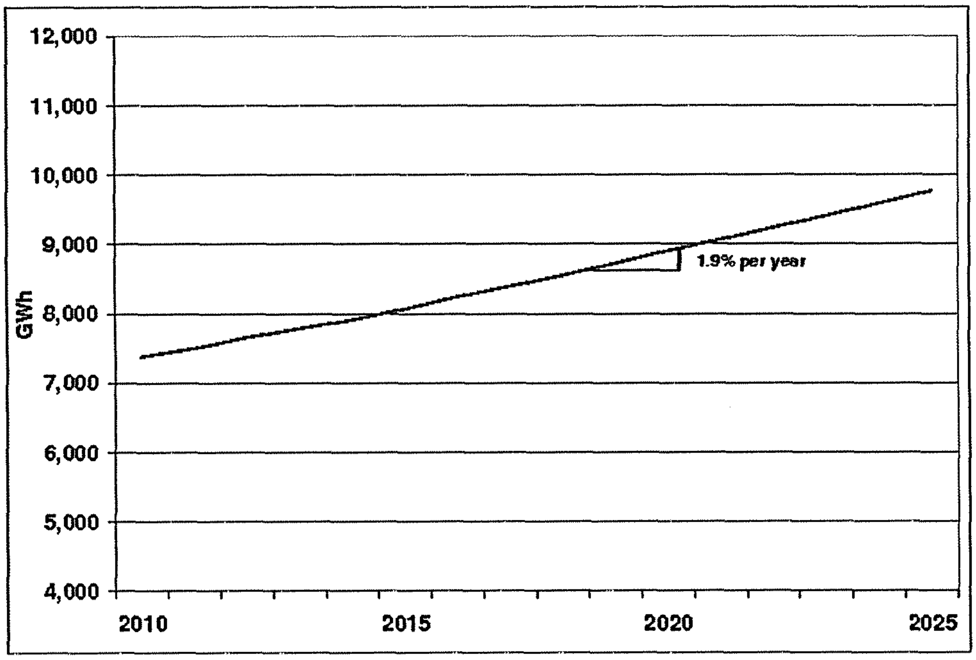

Figure 4-1
EKPC Projected Residential Electricity Consumption, 2010-2025

To estimate energy efficiency potential, it was then necessary to estimate how much each end-use contributed to the growth in aggregate residential consumption. The procedures for developing those estimates were outlined in Section 2. Using EKPC-provided end-use surveys and unit energy consumption (UEC) data, EPRI developed a baseline forecast using its residential stock turnover model. The EPRI baseline forecast was then compared to the EKPC forecast to determine whether the overall model accuracy would be acceptable. The results are shown in Table 4-1.

Table 4-1
EPRI Baseline Forecast of Residential Electricity Sales Compared to the EKPC Forecast of Residential Electricity Sales, 2010-2025

	2010	2015	2020	2025
EPRI Forecast Using Stock Turnover Model				
Residential Total (MWh)	7,341,904	7,821,131	8,292,490	8,984,525
EKPC Forecast				
Residential Total (MWh)	7,374,611	8,059,377	8,899,636	9,760,214
% Difference	**0.4%**	**3.0%**	**6.8%**	**7.9%**

Note: EKPC Forecast is from EKPC February 2010 (No DSM).

The results indicate that the stock turnover model produced annual forecast results that were within 0.4 to 7.9% of the EKPC forecast. Thus the approach can produce results that are reasonable for the energy efficiency potential analysis.

Estimating the Impact of EISA on the EKPC Baseline Forecast

EKPC uses econometric models to forecast electricity demand by sector. This type of modeling is standard practice in the industry because it enables forecasting based on economic variables that are known to affect electricity consumption (overall economic activity, input prices, income growth, etc.). One distinction of the approach, however, is that it is designed to take explicit account of mandated changes in the efficiency of heating, cooling and water heating via projected improvements from EIA. Most notable to this study is the potential impact of the Energy Independence and Security Act (EISA) of 2007 which mandates higher efficiencies for lighting technologies.

Since the EISA impacts are expected to be large, the EPRI team estimated the impact of EISA on EKPC's forecast of residential sales so that it could be taken into account explicitly and separately. There were three steps involved in this process:

1. The EPRI stock turnover model was used to produce an EKPC baseline forecast, ***excluding*** the effects of EISA. (The results of that step and its calibration to the EKPC - provided forecast were shown in Table 4-1.)
2. The EPRI stock turnover model was used again to produce an EKPC baseline forecast, ***including*** the effects of EISA.
3. The forecast including EISA was subtracted from the forecast excluding EISA to isolate the EISA impact. The differences were then subtracted from the forecast provided by EKPC, to produce an EKPC -provided, EISA-adjusted forecast. The results for the residential sector are summarized in Table 4-2 and shown graphically in Figure 4-2.

Table 4-2
Impact of EISA Lighting Requirements on EKPC's Baseline Residential Energy Forecast, 2010-2025

	2010	2015	2020	2025
1. Baseline (Calculated)	7,341,904	7,641,981	7,760,184	8,404,328
2. Baseline (Calculated - w/o EISA)	7,341,904	7,809,256	8,263,190	8,937,222
3. EISA Impacts (1) – (2)	0	179,151	532,306	580,197
4. Baseline (EKPC Provided)	7,374,611	8,059,377	8,899,636	9,760,214
4. Baseline (EKPC Provided) - EISA adjusted	7,374,611	7,880,226	8,367,330	9,180,017
5. EISA Impacts - % of EKPC Baseline	0%	2%	6%	6%

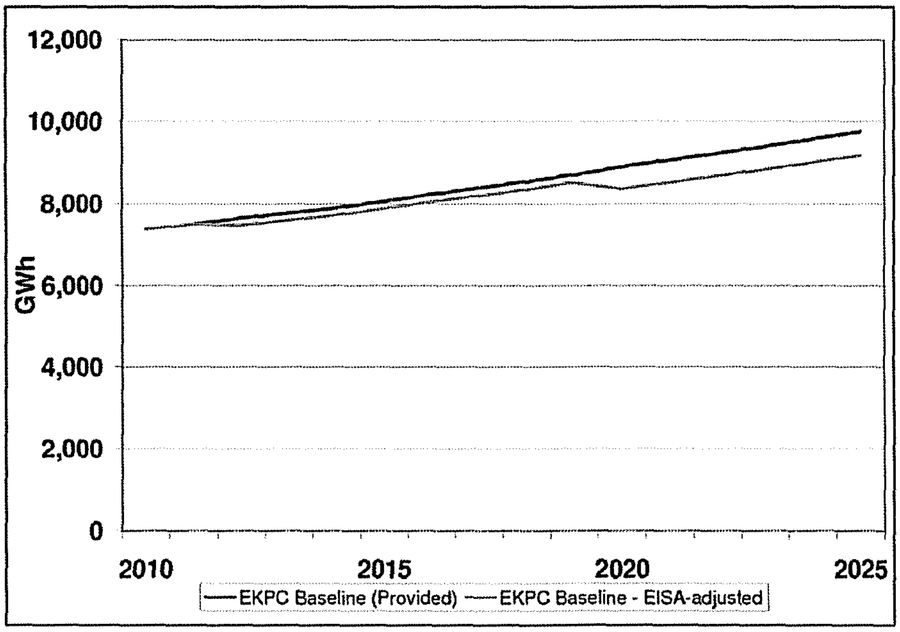

Figure 4-2
EKPC Residential Baseline Forecast, with and without an Adjustment for EISA Lighting Requirements

The results show that EISA is expected to have a substantial impact, reducing the residential baseline by 6% in 2025. These effects need to be taken into account separately to accurately estimate the savings that can be attributed to utility energy efficiency programs.

Forecast Residential Consumption by End Use

Residential electricity consumption by end-use for 2010 and projected for 2025 is shown in Table 4-3. Unlike the baseline in Figure 4-1, this baseline forecast ***does*** reflect the efficiency gains expected from EISA: the end-use share of consumption for lighting is projected to decline from 10% in 2010 to 4% in 2025. Overall shares of energy consumed for other end uses are relatively stable, except that share of consumption used for "other uses" is projected to increase by about 35% (from 17% in 2010 to 23% of total consumption in 2025). This category is dominated by "plug loads" which include a wide variety of miscellaneous devices which can be small in terms of energy draw but are growing in share. It also includes entertainment and communication services, both of which are likely to increase in market saturation and energy intensity (plasma TVs are one notable example). In this study, "other" end uses were modeled as a fixed share of total consumption that is growing over time, based on the forecasts from EIA's 2008 Annual Energy Outlook.

Table 4-3
EKPC Residential Electricity Consumption by End-Use, MWh and % of Total, 2010 and 2025

	2010		**2025**	
	GWh	%	GWh	%
Electric Heating	2,076,720	28%	2,196,547	26%
Other Heat	0	0%	0	0%
Central AC	494,849	7%	530,844	6%
Room AC	208,969	3%	255,976	3%
Water Heating	1,348,632	18%	1,610,683	19%
Refrigerators	261,229	4%	293,393	3%
Cooking	111,502	2%	141,985	2%
Clothes Dryers	406,610	6%	521,324	6%
Freezers	132,555	2%	149,428	2%
Lighting	711,561	10%	368,356	4%
Clothes Washers	33,771	0%	43,205	1%
Dishwashers	23,170	0%	29,340	0%
Color TV (Standard/LCD)	135,143	2%	219,851	3%
Personal Computers	117,236	2%	146,626	2%
Furnace Fans	0	0%	0	0%
Other Uses	1,279,957	17%	1,896,770	23%
Total (Calculated – EISA-adjusted)	**7,341,904**	**100%**	**8,404,328**	**100%**

NOTE: 2010 data are based on saturation levels resulting from the 2007 End-Use Survey. 2025 data are projected as part of this study. Percentages may not add due to rounding.

5
REALISTIC ACHIEVABLE ENERGY EFFICIENCY POTENTIAL

Total

The realistic achievable energy efficiency potential for all sectors, by year is shown in Table 5-1. Based on technologies that are commercially available today, and assuming that equipment is replaced at the end of its useful life with the most energy-efficient measure that has a positive benefit/cost ratio, EPRI estimates that total electricity consumption can be reduced by 8.9% by the year 2025, relative to the calculated EISA-adjusted baseline forecast. Potential winter peak coincident demand savings are estimated to be 1.2% in 2025, with summer peak demand savings of 0.9%. Since EKPC is a winter-peaking system the winter peak demand savings are higher than those achievable in summer.

Table 5-1
Summary of EKPC Realistic Achievable Potential, 2010 – 2025, Total Savings and as a Percent of Each Sector's Calculated Baseline EISA-Adjusted Forecast

	2010	2015	2020	2025
Energy				
Baseline (MWh)	7,341,904	7,641,981	7,760,184	8,404,328
Realistic Achievable (MWh)	0	160,267	359,466	746,951
Potential %	0%	2.1%	4.6%	8.9%
Winter Peak Demand				
Baseline (MW)	3,046	3,368	3,703	4,075
Realistic Achievable (MW)	0	23	30	47
Potential %	0%	0.7%	0.8%	1.2%
Summer Peak Demand				
Baseline (MW)	2,450	2,698	2,961	3,253
Realistic Achievable (MW)	0	11	12	28
Potential %	0%	0.4%	0.4%	0.9%

Energy

The realistic achievable potential for energy savings in the residential sector, by end use and year, is shown in Table 5-2. Note that electricity used for lighting is expected to decline by 580 GWh relative to the baseline forecast for 2025 due to improved lighting efficiencies mandated by EISA. That reduction – which is more than the total remaining residential RAP in 2025 – has already been taken out of the calculated baseline. Other end uses with substantial efficiency opportunities include space heating and water heating, as well as lighting (beyond the effects of EISA).

Table 5-2
Residential Realistic Achievable Energy Efficiency Potential, 2010-2025
By End Use (MWh and Percent of the Total Potential for 2025)

	2010	2015	2020	2025	
	MWh				%
Electric Heating	0	38,784	237,932	530,416	71.0%
Other Heat	0	0	0	0	0.0%
Central AC	0	2,280	12,109	29,994	4.0%
Room AC	0	3,890	11,768	21,020	2.8%
Water Heating	0	10,277	41,561	79,539	10.6%
Refrigerators	0	6,360	15,775	26,658	3.6%
Cooking	0	0	0	0	0.0%
Clothes Dryers	0	0	0	0	0.0%
Freezers	0	2,080	5,177	8,884	1.2%
Lighting (Additional Impacts)	0	95,918	32,878	46,365	6.2%
Clothes Washers	0	0	0	0	0.0%
Dishwashers	0	679	2,265	4,074	0.5%
Color TV (Standard/LCD)	0	0	0	0	0.0%
Personal Computers	0	0	0	0	0.0%
Furnace Fans	0	0	0	0	0.0%
Other Uses	0	0	0	0	0.0%
Total RAP Potential	**0**	**160,267**	**359,466**	**746,951**	**100.0%**

Figure 5-1 illustrates the contribution of various end uses to the total realistic achievable potential for energy savings in the year 2025.

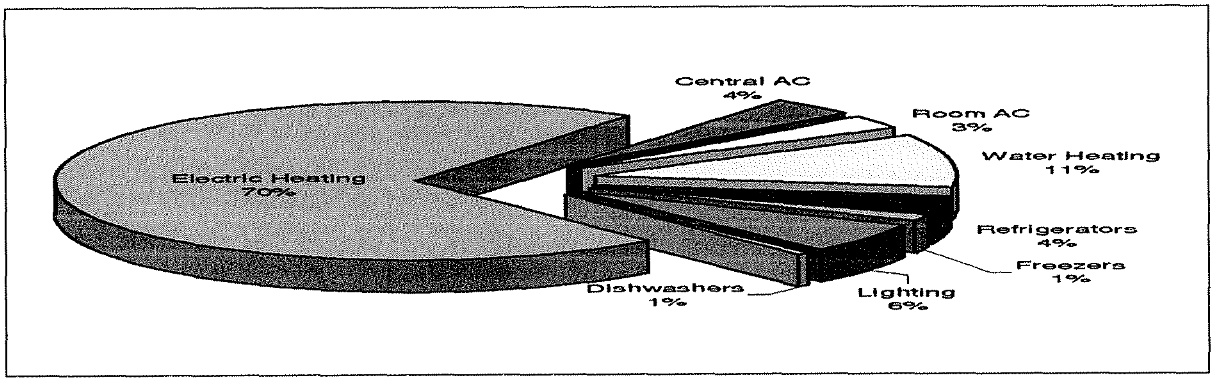

Figure 5-1
Residential Realistic Achievable Energy Efficiency Potential, Energy Savings by End Use, % of Total RAP for 2025

Winter Peak Demand

Table 5-3 shows the winter peak load reduction impacts (kW) associated with each end use. The greatest peak load impacts will come from improvements in space heating (57%), the second largest from lighting (19%) and third is water heating (17%). In total, the residential energy efficiency measures are estimated to have a peak load reduction impact of 47,104 kW by the year 2025, relative to the calculated, EISA-adjusted baseline forecast.

Table 5-3
Residential Realistic Achievable EE Potential – Winter Peak Load Impacts 2010-2025
By End-Use, (kW Reduction and Percent of Total Reduction for 2025)

	2010	2015	2020	2025	
	kW				%
Electric Heating	0	3,490	18,589	27,027	57.4%
Other Heat	0	0	0	0	0.0%
Central AC	0	0	0	0	0.0%
Room AC	0	0	0	0	0.0%
Water Heating	0	549	3,301	7,986	17.0%
Refrigerators	0	366	1,105	2,403	5.1%
Cooking	0	0	0	0	0.0%
Clothes Dryers	0	0	0	0	0.0%
Freezers	0	61	218	561	1.2%
Lighting (Additional Impacts)	0	18,631	6,386	9,006	19.1%
Clothes Washers	0	0	0	0	0.0%
Dishwashers	0	15	52	122	0.3%
Color TV (Standard/LCD)	0	0	0	0	0.0%
Personal Computers	0	0	0	0	0.0%
Furnace Fans	0	0	0	0	0.0%
Other Uses	0	0	0	0	0.0%
Total RAP Potential	**0**	**23,112**	**29,651**	**47,104**	**100.0%**

Figure 5-2 illustrates the contribution of various end uses to the total realistic achievable potential for winter peak load reductions in the year 2025.

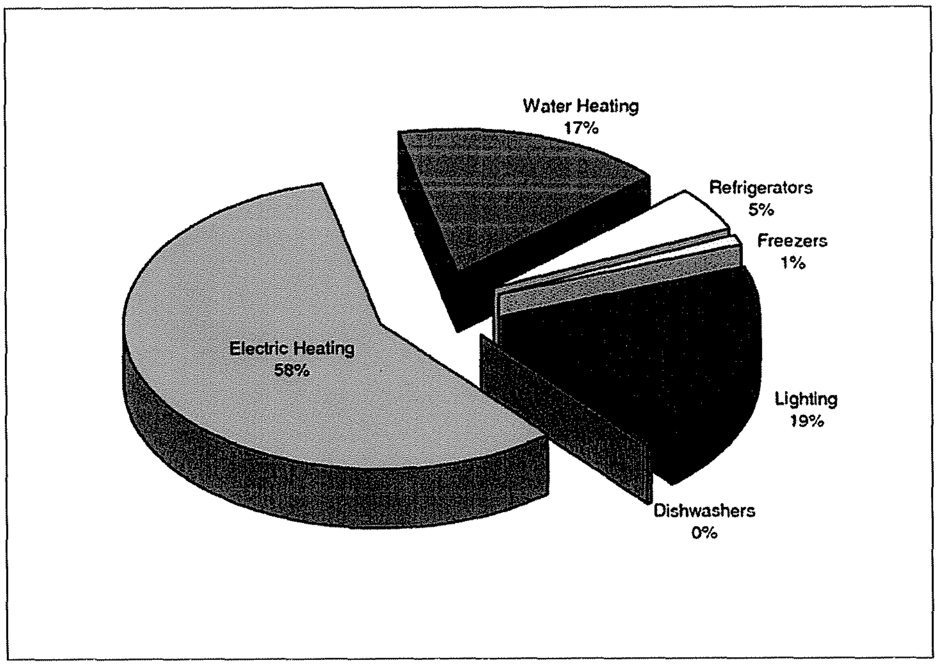

Figure 5-2
Residential Realistic Achievable Energy Efficiency Potential, Winter Peak Demand by End Use, % of Total RAP for 2025

Summer Peak Demand

The realistic achievable potential for summer peak load reduction (kW), by end use and year, is shown in Table 5-4. The greatest peak load impacts will come from improvements in space cooling (46%), the second largest from lighting (16%) and third is water heating (16%). In total, the residential energy efficiency measures are estimated to have a peak load reduction impact of 28,026 kW by the year 2025, relative to the calculated, EISA-adjusted baseline forecast.

Table 5-4
Residential Realistic Achievable EE Potential – Summer Peak Load Impacts 2010-2025
By End-Use, (kW Reduction and Percent of Total Reduction for 2025)

	2010	2015	2020	2025	
	kW				%
Electric Heating	0	0	0	0	0.0%
Other Heat	0	0	0	0	0.0%
Central AC	0	511	3,820	12,859	45.9%
Room AC	0	212	699	1,718	6.1%
Water Heating	0	307	1,849	4,472	16.0%
Refrigerators	0	549	1,658	3,604	12.9%
Cooking	0	0	0	0	0.0%
Clothes Dryers	0	0	0	0	0.0%
Freezers	0	81	291	748	2.7%
Lighting (Additional Impacts)	0	9,315	3,193	4,503	16.1%
Clothes Washers	0	0	0	0	0.0%
Dishwashers	0	15	52	122	0.4%
Color TV (Standard/LCD)	0	0	0	0	0.0%
Personal Computers	0	0	0	0	0.0%
Furnace Fans	0	0	0	0	0.0%
Other Uses	0	0	0	0	0.0%
Total RAP Potential	**0**	**10,992**	**11,562**	**28,026**	**100.0%**

Figure 5-3 illustrates the contribution of various end uses to the total realistic achievable potential for summer peak load reductions in the year 2025.

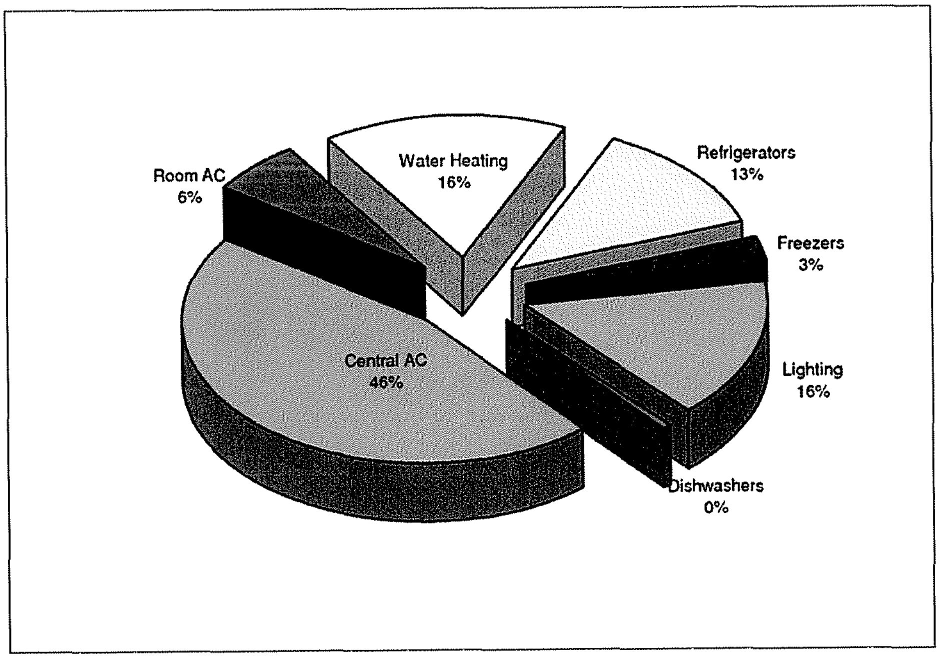

Figure 5-3
Residential Realistic Achievable Energy Efficiency Potential, Summer Peak Demand by End Use, % of Total RAP for 2025

6
DEMAND RESPONSE POTENTIAL

Realistic Achievable Potential

The estimated realistic achievable potential of demand response (DR) programs to reduce system winter peak is shown in Table 6-1. In the residential sector, DR programs have the potential to reduce winter system peak by 6% relative to the baseline for 2025. Price response programs have the highest potential for winter demand reductions accounting for 49% of the realistic achievable potential in 2025.

Table 6-1
Realistic Achievable Potential of Demand Response Programs, Winter Peak Demand Reductions by Program Type

Demand Reductions by Sector and Measure Type	2010	2015	2020	2025
Winter Peak Demand Reductions (MW)				
Residential				
Direct Control Load Management-Electric Heat	36	79	84	91
Direct Control Load Management-Water Heating	18	29	31	33
Price Response Programs (TOU, CPP, RTP)	31	68	109	118
Total Residential	**85**	**175**	**224**	**243**
Percent of Baseline Peak Demand	3%	5%	6%	6%

The estimated realistic achievable potential of DR programs to reduce system summer peak is shown in Table 6-2. In aggregate, DR programs have the potential to reduce system peak by 3% relative to the baseline for 2025. Again price response programs have the highest potential for summer demand reductions accounting for 54% of the realistic achievable summer demand reduction potential in 2025.

Table 6-2
Realistic Achievable Potential of Demand Response Programs, Summer Peak Demand Reductions by Program Type

Demand Reductions by Sector and Measure-Type	2010	2015	2020	2025
Summer Peak Demand Reductions (MW)				
Residential				
Direct Control Load Management-Central AC	9	20	22	24
Direct Control Load Management-Water Heating	10	16	17	19
Price Response Programs (TOU, CPP, RTP)	13	29	46	50
Total Residential	**33**	**65**	**86**	**93**
Percent of Baseline Peak Demand	1%	2%	3%	3%

Table 6-3 summarizes the winter peak load MW reduction potential associated with energy efficiency programs as well as those associated with DR programs. Note that there is the potential for double counting of peak reduction impacts if both energy efficiency and demand response programs are implemented.

Table 6-3
Summary of Peak Load Reduction Impacts from Energy Efficiency and Demand Response Programs, Winter Impacts by Year

	2010	2015	2020	2025
Realistic Achievable Potential from Energy Efficiency (MW)	0	23	30	47
Realistic Achievable Potential from Demand Response Programs (MW)	85	175	224	243
Total EKPC Winter Peak Load Reduction, from EE and DR Programs (MW)	**85**	**198**	**254**	**290**

Table 6-4 summarizes the summer peak load MW reduction potential associated with energy efficiency programs as well as those associated with DR programs. Note that there is the potential for double counting of peak reduction impacts if both energy efficiency and demand response programs are implemented. In both cases the peak load reductions for the summer are less than potential reductions in winter peak demand due to the fact that EKPC is a winter-peaking utility.

Table 6-4
Summary of Peak Load Reduction Impacts from Energy Efficiency and Demand Response Programs, Summer Impacts by Year

	2010	2015	2020	2025
Realistic Achievable Potential from Energy Efficiency (MW)	0	11	12	28
Realistic Achievable Potential from Demand Response Programs (MW)	33	65	86	93
Total EKPC Summer Peak Load Reduction, from EE and DR Programs (MW)	**33**	**76**	**98**	**121**

7 CONCLUSION

This report documents the results of a study to assess the achievable potential for electric energy savings and peak demand reductions for East Kentucky Power Cooperative (EKPC) for the years 2010 through 2025. The approach involved applying the methodology and technology data developed for the EPRI National Study on the same subject, adapted to the specific characteristics of EKPC's service territory.

The efficient technologies and measures considered are commercially available today. The estimation of economic potential assumes that consumers will adopt the most energy-efficient technology that has a benefit/cost ratio greater than one, using the Total Resource Cost Test. Estimates of economic potential are adjusted to account for various market barriers and program implementation factors to the energy efficiency potential that can realistically be achieved.

The results indicate that the realistic achievable energy efficiency potential for all market sectors is 747 GWh for the year 2025, or 8.9% of the EPRI-calculated baseline forecast of 8,404 GWh for 2025. These savings are in addition to the significant reductions in consumption that are expected to result from the improvements in lighting that are required by the Energy Independence and Security Act of 2007 (EISA). The savings from EISA are expected to reduce the residential energy forecast by 580 GWh by the year 2025. Thus, the impact of EISA alone is projected to be nearly as large as the realistic achievable potential of all the other energy efficiency measures combined. The winter demand-related savings associated with energy efficiency programs are 47 MW by the year 2025, which represents roughly 1.2% of the projected system winter peak load for that year. The summer demand-related savings associated with energy efficiency programs are 28 MW by the year 2025, which represents roughly 0.9% of the projected system summer peak load for that year. Demand response programs could reduce winter peak demand by roughly 243 MW and summer peak demand by 93 MW by 2025, although there is some potential for double counting between the peak reductions that could be achieved from energy efficiency programs and the reductions that could be achieved through DR programs.

The results are based on commercially available technologies and costs using an equipment stock turnover model. The results are detailed and granular, by residential end-use and technology. This overall approach makes the results more transparent than other studies which employ a macro "top-down" approach which are highly sensitive to variations in a few key assumptions.

Although the potential savings based on customer economics alone are not insignificant, the results here do not indicate whether specific programs would be cost-effective from EKPC's point of view. Thus, these results should be considered as a useful starting point for EKPC's planning as they assess a range of potential options for meeting future energy requirements as cost-effectively as possible. The results should also be useful to EKPC's energy efficiency program managers in designing EE programs and setting targets for energy and demand savings, as well as reductions in environmental externalities.

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EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 111
RESPONSIBLE PARTY: Scott Drake/Isaac S. Scott

Request 111. Refer to the Munsey Testimony on behalf of Kentucky Power, page 10, lines 11-19 regarding the Green Button initiative. Describe the extent of your utility's participation in this industry-led effort.

Response 111. EKPC has not joined, committed to, or implemented the Green Button initiative. According to the Green Button initiative, the only utility in Kentucky to commit to the initiative is American Electric Power; see http://www.greenbuttondata.org/greenadopt.html .

EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 112
RESPONSIBLE PARTY: Isaac S. Scott

Request 112. Refer to the Roush Testimony on behalf of Kentucky Power, DMR Exhibit 1. Provide a similar exhibit containing a list of time-differentiated rates available to your customers.

Response 112. As a generation and transmission cooperative, EKPC's tariffs are applicable only to its 16 Members. Consequently, EKPC cannot provide an exhibit similar to DMR Exhibit 1.

However, as noted on page 35 of Mr. Scott's Direct Testimony, EKPC has a simple time-of-use structure in its Section E tariff where energy is priced as on-peak and off-peak. EKPC's Section A, B, C, D, E, and G tariffs also recognize the on-peak and off-peak time periods when determining the system peak demand used for billing demand purposes. Finally, EKPC does have a Real-Time Pricing pilot program tariff, but that pilot program ended as of December 31, 2012.

EAST KENTUCKY POWER COOPERATIVE, INC.

ADMINISTRATIVE CASE NO. 2012-00428

RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13

REQUEST 113

RESPONSIBLE PARTY: **Isaac S. Scott**

Request 113. Provide a description of the type of meters (mechanical, electro-mechanical, AMR [one-way communication], AMI [two-way communication]) currently used by the utility. Include in the description the reasons the current meters were chosen and any plans to move to a different type of metering configuration.

Response 113. EKPC uses digital multifunction electricity meters with multi-channel interval recording capability and provides high accuracy revenue class metering. EKPC chose this type of meter for the high accuracy and the ability to record per phase quantities. These meters are also compatible with EKPC's meter data translation system. EKPC has no plans to move to a different type of metering configuration at this time.

EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 114
RESPONSIBLE PARTY: Isaac S. Scott

Request 114. If either AMR or AMI metering is in use, state whether the utility has received any customer complaints concerning those meters. If the response is yes, provide the following:

a. the number of complaints, separated by gas and electric if a combination utility, along with the total number of customers served.

b. how the complaints were addressed by the utility.

c. a detailed explanation as to whether customers should have the ability to opt out of using either AMR or AMI metering.

d. If customers were to be given the opportunity to opt out of using either AMR or AMI metering, provide:

i. an explanation as to whether the utility should establish a monthly manual metering reading tariff or charge applied to the opt-out customers to recover the costs associated with manually reading the non-AMR or -AMI accounts.

ii. an explanation as to whether these opt-out customers could still receive benefit from the utility using either AMR or AMI metering.

iii. an explanation addressing the point at which opt-out customers, either in terms of number of customers or a percent of customers, affect the benefits of the utility using either the AMR or AMI metering.

Response 114. EKPC does not have AMR or AMI metering, so these questions are not applicable.

EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 115
RESPONSIBLE PARTY: Isaac S. Scott

Request 115. In testimony, each utility cited cybersecurity as an area of concern related to the implementation of Smart Grid technologies. Provide and describe your company's policy regarding cybersecurity or the standard your company has adopted governing cybersecurity. If your company has not adopted any policy or standard, identify and describe any industry or nationally recognized standards or guidelines that you may be aware of that the Commission should consider relating to cybersecurity issues and concerns.

Response 115. Please see the response to Request 104.

EAST KENTUCKY POWER COOPERATIVE, INC.
ADMINISTRATIVE CASE NO. 2012-00428
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INFORMATION REQUEST DATED 02/27/13
REQUEST 116
RESPONSIBLE PARTY: Isaac S. Scott

Request 116. If not previously addressed, provide a detailed discussion of whether deployment of smart meters should allow for an opt-out provision.

Response 116. As a generation and transmission cooperative, EKPC has not been and will likely not be deploying smart meters, so the question of an opt-out provision is not applicable. EKPC is aware of the dilemma faced by its Members concerning opt-out. Our Members want to be responsive to their owner-members and offer them choices where reasonable. However, permitting customers to opt-out of a smart meter deployment will result in additional costs that will have to be recovered from the customer opting out.