Kentucky Power Company
KPSC Case No. 2023-00092
Joint Intervenor's Second Set of Data Request
Dated July 24, 2023

DATA REQUEST

JI 2_1 Please refer to Kentucky Power's responses to Joint lntervenors' Initial Requests 1.29(b) and 1.29(c), which state, inter alia, that the Company anticipated that the MPS will be completed by the end of June 2023, and filed with the Commission in Case No. 2022-00392.

a. Was the MPS completed by the end of June 2023?

i. If yes, please produce a copy of the MPS, if it has not yet been filed with the Commission.

ii. If not, please explain in full why the MPS was not completed on the anticipated timeline.

iii. If not, please explain when Kentucky Power anticipates receiving the completed MPS.

b. Has the MPS been filed in Case No. 2022-00392? If not, please explain in detail why not.

c. Assuming that the MPS is complete at the time of your response to this question, please state the date when it was completed.

RESPONSE

a. and c. Yes, the MPS was completed by June 16, 2023. Please refer to the Company's response to KPSC 2-3 for a copy of the MPS.

b. Yes. The MPS was filed on August 11, 2023 in Case No. 2022-00392.

Witness: Brian K. West

Kentucky Power Company
KPSC Case No. 2023-00092
Joint Intervenor's Second Set of Data Request
Dated July 24, 2023

DATA REQUEST

JI 2_2 In reference to the MPS and the potential for DSM programs, please explain whether the Company has assessed the employment and training levels of industries (i.e., electrical, energy audits, and HVAC) in its service territory that would support DSM programs.

a. If so, please share the findings from the assessment.

b. Please indicate whether the Company would provide training to such industries if there were a gap in either employment needs or training.

RESPONSE

The Company has not performed this type of study.

a-b. In the past, when Kentucky Power hired a third-party implementer to administer a DSM program, they were hired based upon their expertise and other factors. When the third-party implementer was located out of state, local staff were hired and trained to conduct the day-to-day operations of the DSM program. Implementers will often develop a network of approved trade allies that have undertaken training and have a demonstrated knowledge of the program offerings.

Witness: Brian K. West

Kentucky Power Company
KPSC Case No. 2023-00092
Joint Intervenor's Second Set of Data Request
Dated July 24, 2023

DATA REQUEST

JI 2_3 Please explain whether the Company has evaluated the economic development that could be derived from the investment into DSM. If yes, please indicate the level of projected economic development, including investment and jobs. If not, please explain in detail why not.

RESPONSE

DSM programs are focused on reducing a utility's energy demand over the long term by encouraging customers to modify their level of energy usage. The Company has not performed this type of analysis. However, please see Appendix C, Non-Energy Benefits, at page 61 of 123, of the Market Potential Study for a discussion of increased jobs or job skills.

Witness: Brian K. West

DATA REQUEST

JI 2_4 Please indicate whether Kentucky Power would implement DSM programs internally or whether it would issue a request for proposal for a third-party implementer, and please explain the reasons why in detail.

RESPONSE

The Company objects to the request to the extent it is not reasonably calculated to lead to the discovery of admissible evidence in this case. Without waiving this objection, the Company states as follows:

The Company has not made a determination about internal or third-party implementation of any future DSM programs.

Witness: Brian K. West

DATA REQUEST

JI 2_5 Please refer to Kentucky Power's response to Staff's Initial Request 1.52(b) and answer the following requests.
a. At any time in the last three years, did Kentucky Power reevaluate the terms of either of its two demand response tariffs, Rider D.R.S. and Tariff C.S.-1.R.P.? For example, did Kentucky Power consider whether adjustment(s) to any term(s) or condition(s) might increase or reduce participation, system costs, or system benefits?
i. If so, please explain each such reevaluation process, including identification of the timing, contributors, and conclusions.
ii. If not, please explain why not.
b. For each of the demand response tariffs identified in response to Staff's Initial Request 1.52(b), please state whether aggregators may participate on behalf of customers.
i. If aggregators may not participate, please state whether and when Kentucky Power anticipates revisions to allow aggregation.
c. For each of the demand response tariffs identified in response to Staff's Initial Request 1.52(b), please explain whether Kentucky Power has considered allowing customers to select definite notification windows (e.g., notification at least 120 minutes before order to reduce demand).

RESPONSE

The Company objects to this request to the extent it calls for legal analysis or a legal conclusion, which are not the appropriate subject of discovery. Without waiving this objection the Company states as follows:

a. Kentucky Power leadership, AEPSC Regulatory, and Commercial Operations meet informally to discuss Rider D.R.S. participation and compliance with curtailment events after they have occurred. At this time, Rider D.R.S. is deemed to be satisfactory for the Company's peak shaving requirements. Tariff C.S.-I.R.P. is a PJM-registered program and is designed to comport with PJM's rules surrounding demand response participation.

b. With respect to Rider D.R.S. and Tariff C.S.-I.R.P, based on Kentucky Power's review of applicable authority, the law does not allow third-party aggregators to provide services to Kentucky Power customers. Kentucky Power does not anticipate contracting with third-party aggregators to provide those services on behalf of the third-party aggregator.

c. Tariff C.S.-I.R.P. participation is predicated upon PJM Demand Response rules which permit 120 minutes notification times. In order to be granted that notification time, justification for the time frame is required to be provided by the participant. Rider D.R.S. currently has a 90-minute notification but the Company is not adverse to allowing up to 120 minute notifications to support potential additional participation.

Witness: Brian K. West

DATA REQUEST

JI 2_6 Please refer to Kentucky Power's response to Staff's Initial Request 1.52(b).
a. Please detail why at a time when the Company is capacity short that it did not evaluate the potential for:
i. Residential demand reductions
ii. Expansion of the commercial and industrial demand response programs.
b. The Company notes that it wanted to reduce the cost of the MPS. Please provide the level of cost estimated to provide the demand response portion of the MPS.

RESPONSE

a. A residential demand response program was offered for a short time in the Company's previous DSM portfolio. The program was hindered by technological issues in communicating with devices to control thermostats and water heaters. In addition, very few customers elected to participate in the program. Based on this experience, the Company decided to not include residential demand response program potential as part of the Market Potential Study. The Company offers commercial and industrial customers the option to participate in Tariff C.S.-I.R.P., Rider D.R.S. or Tariff V.C.S.

b. The requested information is not in the Company's possession, custody or control.

Witness: Brian K. West

Kentucky Power Company
KPSC Case No. 2023-00092
Joint Intervenor's Second Set of Data Request
Dated July 24, 2023

DATA REQUEST

JI 2_7 Please refer to Kentucky Power's response to Staff's Initial Request 1.52(b) and answer the following requests.
a. Please provide Kentucky Power's most-recent study of demand response potential among its industrial customers.
b. Please provide Kentucky Power's most-recent study of demand response potential among its commercial customers.

RESPONSE

a. & b. Please see KPCO_R_JI_2_7_Attachment1 for the most recent demand response analysis.

Witness: Brian K. West

Kentucky Power Company (KPCO)

Market Potential Assessment

Final Report

Demand Response Analysis

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Prepared for:
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July 30, 2015

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INTRODUCTION

In mid-2014, Kentucky Power Company (KPCO) retained Applied Energy Group (AEG) to conduct this Demand Side Management (DSM) Potential Study.

KPCO is investigating the market potential for a wide variety of Demand Side Management (DSM) options by completing a comprehensive DSM Study which consists of three primary components: **market research**, a full **DSM potential analysis (Energy Efficiency and Demand Response),** and **DSM program plan** from 2016 to 2025. The market research component has collected electricity end-use data, end-use saturation data, customer demographics information that will provide insight on how KPCO customers are using electricity and energy efficiency decisions have been made. This data was used as the foundation for the potential analysis and program designs.

To produce a reliable and transparent estimate of DSM resource potential, AEG performed the following key tasks:

- Conducted primary market research to collect data directly from a representative, statistical sample of KPCO customers, including: electric end-use data, equipment saturation data, and customer demographics.
- Characterized KPCO service territory by how customers use energy through market profiles for the residential, commercial and industrial sectors.
- Employed updated technology data, modeling assumptions, and energy baselines that reflect both current and anticipated federal, state, and local energy efficiency legislation that will impact DSM potential.
- Estimated the technical, economic, and achievable potential for energy efficiency and demand response within the KPCO service territory over the 2016-2035 horizon, including energy savings and peak demand savings.
- Provided results broken down by customer segment, DSM measure, and end use/technology; included potential impacts, costs, and cost-effectiveness tests to enable KPCO to prioritize initiatives and integrate with long-term planning process.

In summary, the potential study provided a solid foundation for the development of the DSM program design. AEG used the measure-level savings estimates to guide program potential development that align with KPCO's near-term implementation accomplishments and budgetary constraints as well as long-term strategic goals and planning constraints. The 2016-2025 program designs are detailed in a separate report that will be filed with the Kentucky Public Service Commission.

Objectives

This report documents the estimates of the potential reductions in peak demand for electricity customers in the KPCO service territory from demand response (DR) efforts from 2016 to 2035.

The AEG team performed the following tasks to meet KPCO's key objectives for this volume:

- Used information and data collected from the KPCO service territory by AEG and data provided by KPCO, as well as secondary data sources to describe the segmentation and peak demand of the customers

- Developed a baseline projection of how customers are likely to use electricity in absence of future demand response programs. This defines the metric against which future program savings are measured.
- Established program participation, program peak demand impacts, and program costs based on demand response programs within the region, demand response studies conducted by AEG, and internal AEG staff knowledge and experience with demand response program implementation.
- Estimated the achievable potential (low and high) at the program level for demand response within the KPCO service territory over the 2016-2035 planning horizon.

Report Organization

This report is presented in 5 volumes as outlined below. This document is **Volume 4: Demand Response Potential Analysis**.

- Volume 1, Executive Summary
- Volume 2, Market Research Report
- Volume 3, Energy Efficiency Potential Analysis
- **Volume 4, Demand Response Potential Analysis**
- Volume 5, Market Research and Potential Appendices

Abbreviations and Acronyms

Throughout the report we use several abbreviations and acronyms. Table 1-1 shows the abbreviation or acronym, along with an explanation.

Table 1-1 Explanation of Abbreviations and Acronyms

Acronym	Explanation
ACS	American Community Survey
AEO	Annual Energy Outlook forecast developed by EIA
AHAM	Association of Home Appliance Manufacturers
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
Auto-DR	Automated Demand Response
B/C Ratio	Benefit to Cost Ratio
BEST	AEGs Building Energy Simulation Tool
C&I	Commercial and Industrial
CAC	Central Air Conditioning
CFL	Compact Fluorescent Lamp
CPP	Critical Peak Pricing
C&I	Commercial and Industrial
DHW	Domestic Hot Water
DLC	Direct Load Control
DR	Demand Response
DSM	Demand Side Management
EE	Energy Efficiency
EIA	Energy Information Administration
EUL	Estimated Useful Life
EUI	Energy Usage Intensity
FERC	Federal Energy Regulatory Commission
HH	Household
HID	High Intensity Discharge Lamps
HVAC	Heating Ventilation and Air Conditioning
ICAP	Installed Capacity
IOU	Investor Owned Utility
LED	Light Emitting Diode Lamp
LoadMAP	AEGs Load Management Analysis and Planning™ tool
MW	Megawatt
NPV	Net Present Value
O&M	Operations and Maintenance
PCT	Programmable Communicating Thermostat
RIM	Ratepayer Impact Measure
RTP	Real-Time Pricing
RTU	Roof Top Unit
TOU	Time-Of-Use
TRC	Total Resource Cost test
UCT	Utility Cost Test
UEC	Unit Energy Consumption
WH	Water Heater

ANALYSIS APPROACH

Overview of Analysis Approach

This analysis functions as a survey of options for KPCO. KPCO has conducted DR pilots in the past, but there are no historical DR programs. Therefore, the study serves as an exploration into the demand response programs available to KPCO and presents potential savings from those opportunities.

The major steps used to perform the demand response potential assessment are listed below. We describe these analysis steps in detail throughout the remainder of this section.

1. Market Characterization
    - o Segment the market into customer classes
    - o Establish baseline peak demand and customer count forecasts
2. Define the relevant DR options by customer class
3. Outline participation hierarchy for DR options to prevent double-counting of impacts
4. Develop DR program assumptions which include participation rates, unit savings, and program costs
5. Estimate DR potential and develop program budgets and supply curves
6. Assess cost-effectiveness of DR options
7. Conduct sensitivity analysis

Market Characterization

The analysis begins with segmentation of the KPCO customer base and a description of how customers use energy in the peak hour.

Segmentation of Customers for DR Analysis

For the DR analysis, we divided the KPCO customers into segments that corresponded with the customer classes that KPCO uses to categorize their customers. The first dimension of customer segmentation is by sector into residential, and commercial and industrial (C&I). Street lighting customers are excluded from the analysis because the load typically occurs at night, and therefore has no potential to impact loads at the system peak hour. C&I customers are divided further according to maximum demand values. Residential is considered as single group.

The C&I size segments generally follow the thresholds for the KPCO C&I rate classes:

- The smallest size category, with maximum demand less than 15 kW, is based on the size description of SGS (Small General Service) customers in KPCO’s rate structure.
- Customers with peak demand between 15 kW and 100 kW are defined as small to medium C&I.
- The next category is the medium to large customers, designated between 100 to 1,000 kW, which corresponds with the MGS and LGS (Medium General Service and Large General Service).
- Lastly, the large category contains those customers with over 1,000 kW, based on the size description for the Quantity Power customers in KPCO’s rate structure.

Table 2-1 shows the overall market segmentation approach for the study.

Table 2-1 Overall Market Segmentation Approach

Dimension	Segmentation Variable	Description	
Dimension 1	Sector	Residential Commercial and Industrial (C&I)	
Dimension 2	Customer Size Classes	Residential	
		C&I Customers (segmented by max demand)	
		Small C&I	<15 kW
		Small to Medium C&I	Between 15 and 100 kW
		Medium to Large C&I	100 – 1,000 kW
		Large C&I	>1,000 kW

Baseline Customer and Coincident Peak Projection

The next step was to define the baseline projection for the number of customers and peak demand for each customer segment. We began by using actual billing data from KPCO to characterize the base year of 2013. The same sector customer totals used to characterize the 2013 base year in the energy efficiency (EE) potential study were also used for the demand response analysis. The total customer count projections through 2026 were provided by AEP's Load Research department, and adjusted to correspond to the segmentation scheme defined above and projected out to 2035. Table 2-2 presents customer projections for residential sector and the five C&I customer classes.

Table 2-2 Baseline Projection of Customer Count by Segment

Customer Class	2013 (Base Year)	2016	2017	2018	2025	2035
Residential Customers						
All Residential	140,164	138,522	138,257	138,011	136,259	133,670
C&I Customers						
Small	25,102	25,375	25,477	25,555	25,991	26,786
Small/Medium	5,706	5,768	5,791	5,809	5,908	6,088
Medium/Large	719	727	729	732	744	767
Large	62	63	63	63	64	66
Total C&I	**31,589**	**31,932**	**32,060**	**32,159**	**32,707**	**33,707**
Total Portfolio	**171,753**	**170,453**	**170,317**	**170,170**	**168,966**	**167,377**

AEP provided the peak demand forecast for the C&I classes combined. The demand distribution from 2013 customer billing data was applied to the C&I coincident demand forecasts by rate classes to arrive at the coincident peak projection by the C&I classes. Table 2-3 presents the system peak projection data, and the coincident peak forecast for residential and C&I customers (by size classes).[1]

Table 2-3 Coincident Peak Projection by Customer Class (MW)

Customer Class	2013 (Base Year)	2016	2017	2018	2025	2035
Residential Sector						
All Residential	764	748	743	737	742	755
C&I Customers						
Small	30	29	29	29	30	30
Small/Medium	123	120	122	122	123	125
Medium/Large	135	132	134	133	135	137
Large	336	329	333	333	337	342
Total C&I	**623**	**610**	**617**	**617**	**625**	**634**
Total Portfolio System Peak	**1,387**	**1,358**	**1,361**	**1,355**	**1,367**	**1,390**

Demand Response Options

For this study, six DR options were considered.[2] The options are broadly categorized into non-rate-based DR options and rate-based DR options. The options are listed below.

- **Non-rate based DR Options**
  - Direct Load Control (DLC)
    1. Space Heating (Winter)
    2. Water Heating (Summer & Winter)
    3. Central Air Conditioning (Summer)
  - Firm Curtailment Agreement (Summer)
  - Non-Firm Curtailment Agreement – Non Firm (Summer)
- **Rate-based DR Options**
  - Time-Of-Use Rates (Summer[3])

Table 2-4 shows the eligible customer classes for each DR option, briefly indicates the load control mechanism, the associated reliability, and whether the option is currently offered by KPCO.

[1] It should be noted that because of differing methodologies, models, and segmentation; the system peak demand forecast used in the Demand Response analysis is slightly different than that used in the Energy Efficiency analysis of volume 3. This does not, however, materially affect the results and outcome of the study.

[2] Other than the DR options listed here, we also discussed consideration of the "Fast DR" option with the KPCO team. Under this option, DR resources would provide ancillary services, and therefore this option would consist more of 24/7 load-balancing or frequency-balancing resources, so they do not impact peak load. With ~30% of KPCO generation coming from intermittent wind, such programs may be important. However, even progressive power markets place very little market value on such programs. With traditional avoided cost methodologies, these products would almost certainly not be economic. Therefore, potential impacts for Fast DR do not form a part of the current analysis.

[2] Time-of-Use rates are not event-driven like most demand response programs, but are rather a means to achieve predictable, permanent load shifting on a day-to-day basis from peak hours to off-peak hours. TOU rates can be established to be in effect every day of the year or seasonally. Since the summer peak is the time of most interest in this analysis, we assume that the TOU rate is in effect for the summer season.

Table 2-4 List of DR options

DR Option	Eligible Customer Classes	Mechanism	Reliability[4]	Current KPCO offering?
Non-Rate based DR Options				
Direct Load Control (DLC)	Residential	Switch or Controllable Thermostat for AC, DHW, Space heater	Firm	No
Direct Load Control (DLC)	Small to Medium C&I	Switch or Controllable Thermostat for AC or Space Heater	Firm	No
Firm Curtailment Agreement	C&I, Medium to Large and above	Customer enacts their customized, mandatory curtailment plan. Penalties apply for non-performance.	Firm	No
Non Firm Curtailment Agreements	C&I, Large and above	Customer enacts their customized, voluntary curtailment plan. No penalties for non-performance.	Non-firm	No
Rate-based DR Options				
Time-Of-Use (TOU) Rates	All segments	Higher rate for a particular block of hours that occurs every day	Non-firm	No

The objective of these options is to realize demand reductions from eligible customers during the highest load hours of the summer and winter season as defined by the utility. Each program type provides demand response using different load reduction and incentive strategies designed to target different types of customers. From the utility perspective, each of the different program types can be called with different notification time, (in other words, this is the lead time that a DR program has before the demand reduction event begins). Having a mix of programs provides load reduction that can be called under many different conditions. Table 2-5 shows notification times typically associated with the DR options considered in the analysis.

[4] Reliability in this case is referring to the customer's commitment to the specific program. It is not related to the technology that calls the events.

Table 2-5 Typical Notification Times for DR Options

DR Option	Notification Timing			
	Day-ahead	Two to four hours	30 minutes to one hour	Instantaneous to 10 min
Direct Load Control				X
Firm Curtailment Agreement	X	X	X	
Non Firm Curtailment Agreements		X	X	
Time of Use	X	X	X	

The demand-response options included in this study are described below.

Direct Load Control (DLC)

In the analysis, we assume the programs will entail control of eligible cooling units (central air conditioners and heat pumps). As well as space heating units for the winter peak season. Additionally, we assume that residential participants that have electric water heaters are also eligible to include the water heater as a curtailable load for both the summer and winter peak seasons.

Eligible customers for the DLC option are residential customers with cooling, heating, and water heating equipment (central air conditioners, heat pumps, and electric water heaters) in KPCO's service territory. Also small and small to medium C&I customers with eligible space heating and central AC equipment are assumed eligible for participation.

Curtailment Agreement

Under this option, participating customers agree to reduce demand by a specific amount or curtail their consumption to a pre-specified level. In return, they receive a fixed incentive payment in the form of capacity credits or reservation payments (typically expressed as $/kW-month or $/kW-year). Customers are paid to be on call even though actual load curtailments may not occur. The amount of the capacity payment varies with the load commitment level. In addition to the fixed capacity payment, participants receive a payment for energy reduction. Because it is a firm, contractual arrangement for a specific level of load reduction, enrolled loads represent a firm resource and can be counted toward installed capacity (ICAP) requirements. Penalties are assessed for under-performance or non-performance. Events may be called on a day-of or day-ahead basis as conditions warrant.

This option is typically delivered by third party load aggregators, and is most attractive for customers with maximum demand greater than 100 kW. For the current analysis, we assume that this option will be offered to medium to large and large customers. This option is attractive for large C&I customers with flexibility in their operations. Customers with 24x7 operations/continuous processes or with obligations to continue providing service (such as schools and hospitals) are often not good candidates for this option.

Curtailment Agreement- Non Firm

The Curtailment Agreement- Non Firm option offers participants the opportunity to receive a credit for voluntarily reducing load when an emergency DR event is called. Customers usually do not pay a penalty if they are unable to meet their energy reduction amount and are not under contract for a specific quantity of load. Events may be called on a day-of or day-ahead basis. Participants are paid a credit for each kWh they reduce during the event. There is no capacity payment associated with this option since it does not represent a firm resource.

Rate-Based Option

One rate-based option (or time varying rates) was considered in the study, which was Time-Of-Use (TOU) rates.

Time of Use Tariff (TOU)

A TOU rate occurs when the rate for purchasing or using electricity is more expensive during a particular block of hours each day. Relative to a revenue-equivalent flat rate, the rate during on-peak hours is higher, while the rate during off-peak hours is lower. This provides customers with motivation to move consumption out of the higher-price on-peak hours into the lower cost off-peak hours. Larger price differentials provide an incentive for customers to shift consumption. The study assumes that this rate is offered to all customer classes but selection of this tariff is voluntary, or “opt-in.”

Time-of-Use rates are not event-driven like the other demand response programs considered here, but are rather a means to achieve predictable, permanent load shifting on a day-to-day basis from peak hours to off-peak hours. TOU rates can be established to be in effect every day of the year or seasonally. Since the summer peak is the time of most interest in this analysis, we assume that the TOU rate is in effect for the summer season. Time-of-use rates are typically not included as a demand-response option, per se, because customer response is not event driven. However, we included TOU in this demand-response potential studies because it provides valuable information to KPCO for future tariff design. Also, critical peak pricing tariffs are often layered on top of a TOU rate.

The following demand response options were considered, but qualitatively screened out:

Smart Appliance DLC

This program is a relatively unproven and emerging technology. Existing research on impacts by appliance type show relatively low reductions. Additionally, the technical infrastructure investment costs are likely to be prohibitively high in terms of communication and control for enabling reductions from these devices.

Fast DR

DR resources for providing ancillary services need to be Auto-DR enabled, thereby entailing high infrastructure costs. They need to be available 24x7 with a high degree of reliability. Therefore, participation is challenging and likely to be low. Overall, the option is unlikely to be cost-effective under current system conditions. However, with increasing amount of renewable sources coming online, the value of flexible resources like Fast DR are likely to gain value.

Thermal Energy Storage

These technologies have not experienced significant improvements in technology or price and are still not coming into the mainstream.

Critical Peak Pricing (CPP)

The CPP option involves significantly higher prices during relatively short critical peak periods on event days only to encourage customers to reduce their usage. The customer incentive is a more heavily discounted rate during off-peak hours throughout the year (relative to a standard TOU rate). Event days are dispatched on relatively short notice (day ahead or day-of) typically for a limited number of days during the year. Over time, event-trigger criteria become well-established so that customers can expect events based on hot weather or other factors. Events can also be called during times of system contingencies or emergencies.

For participation in this rate-based option, it is preferable for customers to have advanced meters, primarily for bill settlement purposes. KPCO has no future plans to introduce AMI meters into their service territory, therefore this program was not included in the analysis

Interruptible Tariffs

An interruptible tariff is where large commercial customers enroll directly with the utility in an agreement to have their load curtailed or shut off during system contingencies. This type of program is slowly being replaced with more sophisticated DR programs that involve more updated technology, better management of large C&I portfolios, and more stream lined incorporation of third party suppliers.

Program Participation Hierarchy

To avoid double counting of load reduction impacts, program-eligibility criteria were defined to ensure that customers do not participate in mutually exclusive programs at the same time. For example, residential customers cannot participate in both an air conditioning DLC program and a rate-based program, both of which could target the same load for curtailment on the same days. Table 2-6 shows the participation hierarchy by customer class for applicable DR options.

Table 2-6 Participation Hierarchy in DR Options by Customer Segment

Customer Class	Priority / Loading	DR Options	Eligible Customers
Residential, Small C&I, Small/Medium C&I	First	Direct Load Control	Residential customers with eligible cooling equipment (CAC and heat pump) and Electric Water Heating Small and Medium C&I customers with eligible cooling equipment (CAC and heat pumps).
	Second	TOU	All residential and small and medium C&I customers not enrolled in DLC
Med/Large C&I, Large C&I	First	Curtailment Agreements	Customers not enrolled in existing contracts.
	Second	Non Firm Curtailment Agreements	Customers not enrolled in Interruptible load or Curtailment Agreements.
	Third	TOU	Customers not enrolled in any of the above three options.

Key Program Assumptions

The next step is to develop the key data elements for the potential calculations: customer participation levels, per-customer load reduction, and program costs.

Program Participation Rates

In general, we developed program participation based on the performance of similar programs within states geographically and demographically comparable to Kentucky. The 50th percentile was selected from participation rates across several different programs in relevant states to develop the lower bound of potential savings (achievable potential low) and the 75th percentile was selected to develop the upper bound for potential savings (achievable potential high). The participation rates were vetted with internal AEG staff and compared to other demand response analysis conducted by AEG staff and for other similar utilities.

New DR programs need time to ramp up and reach a steady state. During ramp up, customer education, marketing and recruitment, in addition to the physical implementation and installation of any hardware, software, telemetry, or other equipment required takes place.

For KPCO, we assumed that programs ramp up over three to five years, which is typical of industry experience. For direct load control and rate-based options, participation ramps up following an “S-shaped” diffusion curve over a five-year timeframe. For the Curtailment Agreements option, which is typically third-party-delivered over shorter contract periods, participation ramps up linearly over a three-year timeframe. This same assumption is used for Curtailment Agreements – Non Firm as well. Table 2-7 shows the participation assumptions for the achievable low scenario in DR options by customer class. Table 2-8 shows participation rates for the achievable high scenario.

Table 2-7 Achievable Potential Low Participation Rates by Option and Customer Class (percent of eligible customers)

Option		Start Year	Yr 1	Yr 2	Yr 3	Yr 4	Yrs 5-19
Res	CAC DLC	2016	1.9%	3.4%	4.9%	6.3%	7.8%
Res	Space Heating DLC	2016	1.9%	3.4%	4.9%	6.3%	7.8%
Res	Water Heating DLC	2016	2.9%	5.1%	7.3%	9.5%	11.7%
Res	Time-Of-Use	2020	0.9%	2.7%	5.4%	8.1%	9.0%
Sml/Med. C&I	CAC DLC	2016	1.4%	2.4%	3.4%	4.5%	5.5%
Sml/Med. C&I	Space Heating DLC	2016	1.4%	2.4%	3.4%	4.5%	5.5%
Sml/Med. C&I	Curtailment	2020	4.2%	7.3%	10.4%	13.5%	16.6%
Sml/Med. C&I	Time-Of-Use	2020	2.4%	7.2%	14.4%	21.6%	24.0%
Med/Large C&I	Firm Curtailment	2016	4.2%	7.3%	10.4%	13.5%	16.6%
Med/Large C&I	Non Firm Curtailment	2016	1.3%	2.4%	3.4%	4.4%	5.4%
Med/Large C&I	Time-Of-Use	2020	2.4%	7.2%	14.4%	21.6%	24.0%
Large C&I	Firm Curtailment	2016	4.2%	7.3%	10.4%	13.5%	16.6%
Large C&I	Non Firm Curtailment	2016	1.3%	2.4%	3.4%	4.4%	5.4%
Large C&I	Time-Of-Use	2020	2.4%	7.2%	14.4%	21.6%	24.0%

Table 2-8 Achievable Potential High Participation Rates by Option and Customer Class (percent of eligible customers)

Option		Start Year	Yr 1	Yr 2	Yr 3	Yr 4	Yrs 5-19
Res	CAC DLC	2016	3.3%	5.7%	8.1%	10.6%	13.0%
Res	Space Heating DLC	2016	3.3%	5.7%	8.1%	10.6%	13.0%
Res	Water Heating DLC	2016	4.5%	7.9%	11.3%	14.7%	18.1%
Res	Time-Of-Use	2020	1.2%	3.6%	7.2%	10.8%	12.0%
Sml/Med. C&I	CAC DLC	2016	2.6%	4.5%	6.4%	8.4%	10.3%
Sml/Med. C&I	Space Heating DLC	2016	2.6%	4.5%	6.4%	8.4%	10.3%
Sml/Med. C&I	Curtailment	2020	7.6%	13.2%	18.9%	24.6%	30.3%
Sml/Med. C&I	Time-Of-Use	2020	3.2%	9.6%	19.2%	28.8%	32.0%
Med/Large C&I	Firm Curtailment	2016	7.6%	13.2%	18.9%	24.6%	30.3%
Med/Large C&I	Non Firm Curtailment	2016	3.1%	5.4%	7.7%	10.0%	12.3%
Med/Large C&I	Time-Of-Use	2020	3.2%	9.6%	19.2%	28.8%	32.0%
Large C&I	Firm Curtailment	2016	7.6%	13.2%	18.9%	24.6%	30.3%
Large C&I	Non Firm Curtailment	2016	3.1%	5.4%	7.7%	10.0%	12.3%
Large C&I	Time-Of-Use	2020	3.2%	9.6%	19.2%	28.8%	32.0%

Load Reduction Impacts

The per-customer load reduction, multiplied by the total number of participating customers, provides the potential demand savings estimate. Load reduction impact assumptions are primarily based on secondary research. Details are provided in the Appendix. Table 2-9 presents the per-customer load reductions used for estimating the potential.

Table 2-9 Per-Unit Load Reduction by Option and Customer Class

Customer Class	Option	Data Element	Unit	Reduction
Residential	CAC DLC	Peak Reduction (kW)	kW	1.004
Residential	Space & Water Heat DLC	Peak Reduction (kW)	kW	0.847
Residential	Time-Of-Use	Per Customer Impact w/ Tech (%)	%	7.4%
Residential	Time-Of-Use	Per Customer Impact w/o Tech (%)	%	7.4%
Small C&I	CAC DLC	Peak Reduction (kW)	kW	0.997
Small C&I	Space Heating DLC	Peak Reduction (kW)	kW	0.997
Small C&I	Firm Curtailment	Per Customer Impact w/ Tech (%)	%	10%
Small C&I	Firm Curtailment	Per Customer Impact w/o Tech (%)	%	10%
Small C&I	Time-Of-Use	Per Customer Impact w/ Tech (%)	%	0.3%
Small C&I	Time-Of-Use	Per Customer Impact w/o Tech (%)	%	0.3%
Sml/Medium C&I	CAC DLC	Peak Reduction (kW)	kW	0.997
Sml/Medium C&I	Space Heating DLC	Peak Reduction (kW)	kW	0.997
Sml/Medium C&I	Firm Curtailment	Per Customer Impact w/ Tech (%)	%	10%
Sml/Medium C&I I	Firm Curtailment	Per Customer Impact w/o Tech (%)	%	10%
Sml/Medium C&I	Time-Of-Use	Per Customer Impact w/ Tech (%)	%	4.2%
Sml/Medium C&I	Time-Of-Use	Per Customer Impact w/o Tech (%)	%	4.2%
Med/Large C&I	Firm Curtailment	Per Customer Impact w/ Tech (%)	%	10%
Med/Large C&I	Firm Curtailment	Per Customer Impact w/o Tech (%)	%	10%
Med/Large C&I	Non Firm Curtailment	Per Customer Impact w/ Tech (%)	%	10%
Med/Large C&I	Non Firm Curtailment	Per Customer Impact w/o Tech (%)	%	10%
Med/Large C&I	Time-Of-Use	Per Customer Impact w/ Tech (%)	%	4.9%
Med/Large C&I	Time-Of-Use	Per Customer Impact w/o Tech (%)	%	4.9%
Large C&I	Firm Curtailment	Per Customer Impact w/ Tech (%)	%	10%
Large C&I	Firm Curtailment	Per Customer Impact w/o Tech (%)	%	10%
Large C&I	Non Firm Curtailment	Per Customer Impact w/ Tech (%)	%	10%
Large C&I	Non Firm Curtailment	Per Customer Impact w/o Tech (%)	%	10%
Large C&I	Time-Of-Use	Per Customer Impact w/ Tech (%)	%	4.9%
Large C&I	Time-Of-Use	Per Customer Impact w/o Tech (%)	%	4.9%

Program Costs

Program costs include fixed and variable cost elements: program development costs, annual program administration costs, marketing and recruitment costs, enabling technology costs for purchase and installation, annual O&M costs, and participant incentives. These assumptions are based on actual AEG program implementation experience, and the study team's experience in developing program costs for other similar studies. Details are presented in Appendix A.

Cost-effectiveness Assessment

The cost-effectiveness assessment of DR options is based on the total resource cost (TRC) test, which in the case of DR programs is essentially identical to the utility cost test (UCT) and the ratepayer impact measure (RIM). The benefits used in the TRC test are comprised of the avoided capacity and T&D benefits attributable to the impacts of the proposed programs. Given the small number of hours impacted by DR programs, as well as customer pre-cooling or “snapback” that commonly increases energy usage before or after DR events, this analysis does not consider any energy impacts or benefits. As mentioned above, the costs are made up of program development costs, annual program administration costs, marketing and recruitment costs, enabling technology costs for purchase and installation, annual O&M costs, and participant incentives.

Because there is no cost to the customer to participate, and because no lost revenues are experienced from the utility side, the TRC formulation essentially becomes equivalent to the UCT and RIM. All of these tests use the same stream of benefits by default, and for DR, they reduce to the same stream of costs as well. For consistency, we will continue referring to the cost-effectiveness test as TRC.

We assessed the cost-effectiveness of individual DR options with different program-start years until the first cost-effective year for starting the program was identified. Demand savings for a particular option are therefore realized only in years the option is cost-effective. Once an option is deployed, benefit-to-cost ratios were estimated for each contiguous program cycle independently throughout the study time period. A nominal discount rate of 8.08% was used to calculate the net present value (NPV) of benefits and costs over the useful life of an option. This corresponds to a real discount rate of 6.08% when the effects of 2.0% annual inflation are removed. All impacts in this report are presented at the customer meter, but electric peak demand delivery losses of 6.37% are accounted for order to gross up impacts to the generator for economic analysis purposes.

Cost-effectiveness results by DR option are presented in Sections 3 and 4.

Program Lifetimes

Calculation of cost effectiveness requires an assumption about DR program lifetimes. Table 2-10 presents lifetime assumptions by DR option. For pricing assumptions, program life is tied to the life of the meter, which is assumed to be 20 years. Curtailment Agreements, which are typically third-party-delivered capacity reductions, often have a contract term of three to five years.

Table 2-10 DR Program Life Assumptions

DR Option	Lifetime (Years)
Direct Load Control	10
Curtailment Agreements & Non Firm Curtailment	3
Time Of Use	20

Avoided Costs

Calculation of cost effectiveness also requires an assumption about the value of avoided capacity and T&D infrastructure costs. The value is $7.93 per kW-year in terms of real 2013 dollars for the 2013 base year, and rises to $90.71 in 2035. The avoided capacity cost forecast was provided by AEP Load Research.

De-rating of Avoided Costs

The full value of the avoided costs is based on the performance of a peaking generator, which is not equivalent to a demand response program. For estimating DR benefits, we apply a de-rating factor to the avoided capacity costs to reflect that DR programs supply a lower resource value than equivalent supply-side options. The lowering of value can be attributed primarily to the following factors:

- A DR program is not as dispatchable as a supply-side option like a natural gas peaking generator. A peaking plant will run approximately 200 to 400 hours per year, while a DR program is typically constrained to runs from 40 to 100 hours per year
- Many DR programs are vested with a seasonal limitation - e.g., one cannot exercise direct load control for Central AC in the middle of winter.
- DR programs are also limited by constraints on human behavior and/or presence of automation systems

De-rating factors are often applied by utilities & grid operators to account for the reduced value of the different availability and dispatchability profiles. There are many ways to calculate this, based on program characteristics, value of load at certain hours, etc., but there does not appear to be an industry-standard method. A review of available literature on the topic indicated capacity de-rating values generally range from 0.60 to 1.00. In this study, we assumed the de-rating factor to be at the mid-pint of this range, with a value of 0.80.

Estimate DR Potential

Once all of the above steps are complete, the estimation of DR potential is performed. Achievable potential is calculated by multiplying the eligible customers by the participation rates and per-customer impacts for each program. The analysis develops two levels of achievable potential, low and high, which are explained below. We also track the program costs and cost-effectiveness data as described above such that we can estimate total program budgets.

- **Achievable Technical Potential** is defined as the theoretical upper limit for potential. For this case, the utility offers all programs no matter their cost effectiveness. Potential is effectively based on customer participation rates, because the avoided costs were not used as an economic screen for DR programs. This achievable technical potential analysis scenario and results are described in Section 4
- **Achievable Potential High** estimates customer participation in economic demand response programs under ideal market, implementation, and customer preference conditions and an appropriate regulatory framework. Information channels are assumed to be established and efficient for marketing, educating consumers, and coordinating with trade allies and delivery partners. Achievable Potential High establishes a maximum target for the cost effective DR savings that an administrator can hope to achieve through its DR programs and involves incentives that represent a substantial portion of the incremental cost combined with high administrative and marketing costs.
- **Achievable Potential Low** reflects expected program participation given barriers to customer acceptance, non-ideal implementation conditions, and limited program budgets. This represents a lower bound on achievable potential.

DEMAND RESPONSE POTENTIAL RESULTS

In this section, we present the potential savings from cost-effective DR programs only. The subset of programs that are cost effective at some point during the time horizon of the study for both scenarios consists of the following programs:

- C&I TOU
- C&I Non firm Curtailment (for some segments)

This section presents DR potential results for each potential case and peak season at an aggregate level. Each potential case is broken down by DR option and customer class. This section also summarizes the cost-effectiveness results.

Section 4 presents our estimate of program savings without performing the cost-effectiveness screen.

Summary of Potential Savings from Cost-Effective Programs

Figure 3-1 presents the aggregate demand response potential from all cost-effective DR options for all levels of potential and all scenarios for the summer season. The winter peak season results are not shown because they were not cost effective for KPCO. Demand response summer peak savings range from 0.57 MW in 2020 to 5.8 MW in 2035 within the achievable low case, which translates into 0.04% to 0.4%% of KPCO's system peak reduction, respectively.

Figure 3-1 Summary of Demand Response Savings (Summer)

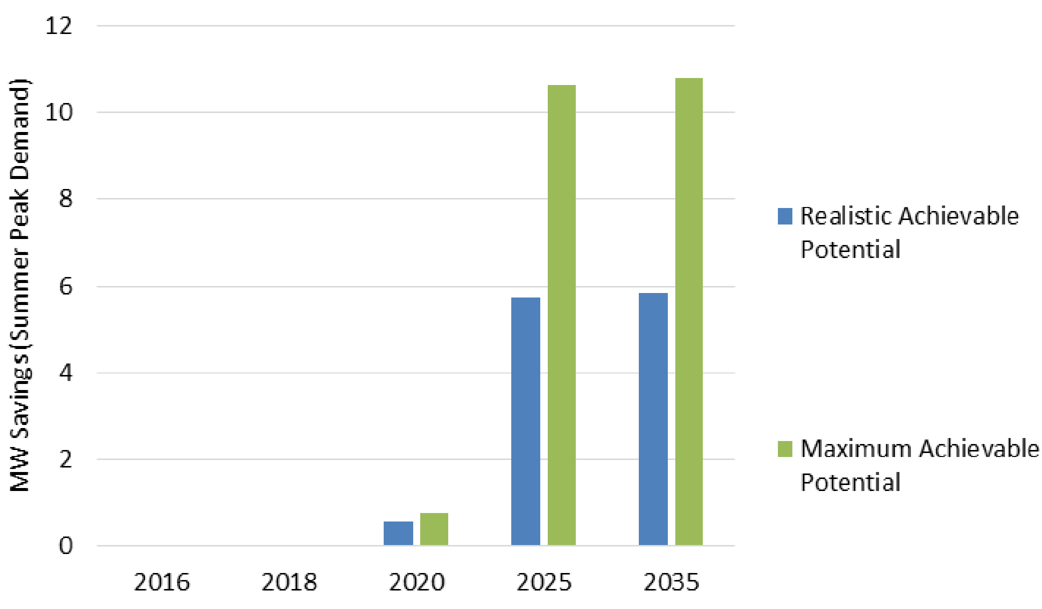
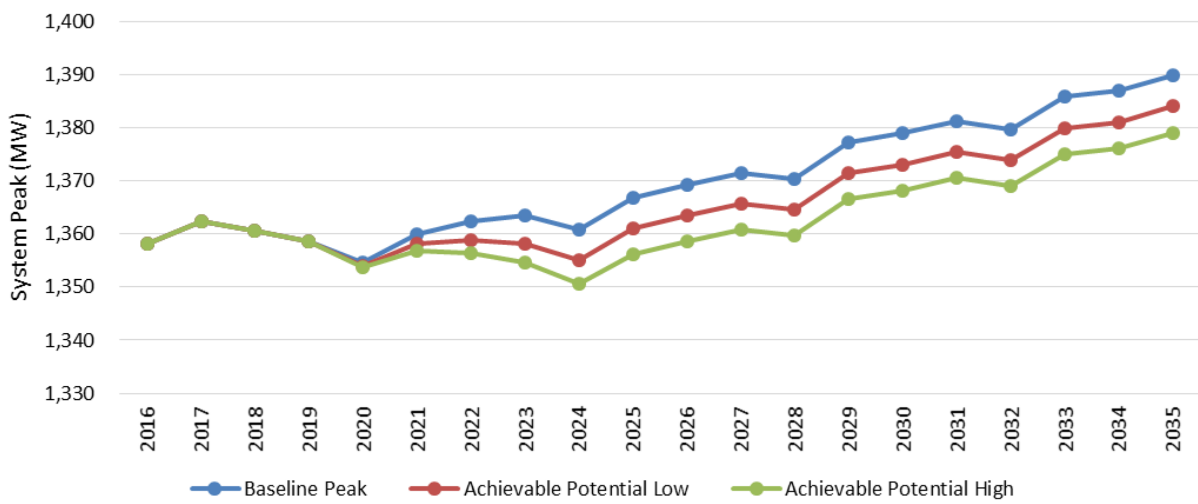


Table 3-1 Summary of Demand Response Savings (Summer)

	2016	2018	2020	2025	2035
System Peak Projection (MW)	1,358	1,361	1,355	1,367	1,390
Achievable Potential Low (MW)	1,358	1,361	1,354	1,361	1,384
Potential (% of System Peak)	0.0%	0.0%	0.0%	0.4%	0.4%
Achievable Potential High (MW)	1,358	1,361	1,354	1,356	1,379
Potential (% of System Peak)	0.0%	0.0%	0.1%	0.8%	0.8%

Figure 3-2 shows savings from new and existing DR options relative to baseline peak projection.[5]

Figure 3-2 Potential Cases vs. Baseline Peak Projection (Summer)



Potential Estimates by DR Option

Cost-effectiveness Results

The potential results presented above for the portfolio of DR options includes only those options that are cost-effective. The TRC test was applied year by year to identify the first year in which a particular DR option was cost-effective. Table 3-2 and Table 3-3 presents the benefit-cost ratios for DR options by customer class for each potential scenario[6]. For the achievable low case:

- TOU is cost effective for small, medium, and large C&I customers beginning in 2020 in both scenarios.
- Non-firm Curtailment Agreements become cost effective beginning in 2021 for Large C&I customers within the achievable high scenario

As similar trend exists for achievable potential high savings.

[5] Please note that KPCO's baseline peak forecast, as represented here, does not account for the impact from existing demand reduction options.
[6] Once a program is cost-effective and enacted, the TRC ratio is computed over the program's lifetime and therefore is identical until the beginning of the next lifetime.

Table 3-2 Achievable Potential Low Benefit Cost Ratios

Option	Customer Class	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
CAC DLC	Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Small C&I	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Small/Medi C&I	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Space Heating DLC	Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Small C&I	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Small/Med C&I	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WH DLC	Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Curtailment Agreement	Med/Large C&I	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Large C&I	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Non Firm Curtailment	Med/Large C&I	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Large C&I	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Time-Of-Use	Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Small C&I	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Small/Med C&I	0.00	0.00	0.00	0.00	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66
	Med/Large C&I	0.00	0.00	0.00	0.00	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25
	Large C&I	0.00	0.00	0.00	0.00	7.70	7.70	7.70	7.70	7.70	7.70	7.70	7.70	7.70	7.70	7.70	7.70	7.70	7.70	7.70	7.70

Table 3-3 Achievable Potential High Benefit Cost Ratios

Option	Customer Class	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
CAC DLC	Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Small C&I	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Small/Medi C&I	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Space Heating DLC	Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Small C&I	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Small/Med C&I	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WH DLC	Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Curtailment Agreement	Med/Large C&I	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Large C&I	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Non-Firm Curtailment	Med/Large C&I	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Large C&I	0.00	0.00	0.00	0.00	0.00	1.01	1.01	1.01	1.28	1.28	1.28	1.34	1.34	1.34	1.30	1.30	1.30	1.25	1.25	1.25
Time-Of-Use	Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Small C&I	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Small/Med C&I	0.00	0.00	0.00	0.00	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69
	Med/Large C&I	0.00	0.00	0.00	0.00	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47
	Large C&I	0.00	0.00	0.00	0.00	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81

Savings from Achievable Low Case

Figure 3-3 and Table 3-4 show savings by DR option for achievable potential low scenario. A key observation from the results is:

- Time of Use if the only program that is cost effective within the study time frame.

Figure 3-3 Achievable Potential Low by DR Option (Summer Peak Demand)

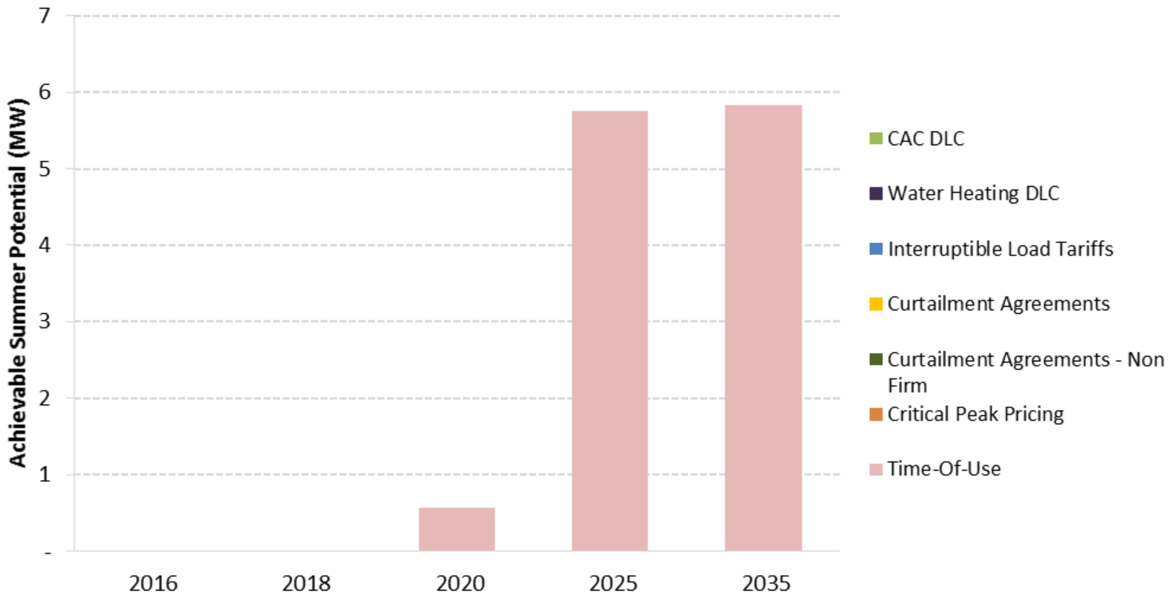


Table 3-4 Achievable Potential Low by DR Option

	2016	2018	2020	2025	2035
System Peak Projection (MW)	1,358	1,361	1,355	1,367	1,390
Achievable Summer Potential (MW)					
CAC DLC	-	-	-	-	-
Water Heating DLC	-	-	-	-	-
Curtailment Agreements	-	-	-	-	-
Non Firm Curtailment	-	-	-	-	-
Time-Of-Use	-	-	0.57	5.75	5.83
Total Potential Summer	**-**	**-**	**0.57**	**5.75**	**5.83**
Achievable Summer Potential (% of Peak)					
CAC DLC	0.00%	0.00%	0.00%	0.00%	0.00%
Water Heating DLC	0.00%	0.00%	0.00%	0.00%	0.00%
Curtailment Agreements	0.00%	0.00%	0.00%	0.00%	0.13%
Non-firm Curtailment	0.00%	0.00%	0.00%	0.00%	0.00%
Time-Of-Use	0.00%	0.00%	0.04%	0.42%	0.42%
Total Potential Summer	**0.00%**	**0.00%**	**0.04%**	**0.42%**	**0.42%**

Savings from Achievable High Case

Figure 3-4 and Table 3-5 show savings by DR option for achievable potential high scenario. Key observations from these results are:

- Time of Use is cost effective beginning in 2020, contributing 0.76 MW of savings potential and rising to 7.22 MW by 2035.
- Non-firm Curtailment agreements with large C&I customers becomes cost effective in 2021.

Figure 3-4 Achievable Potential High by DR Option (Summer)

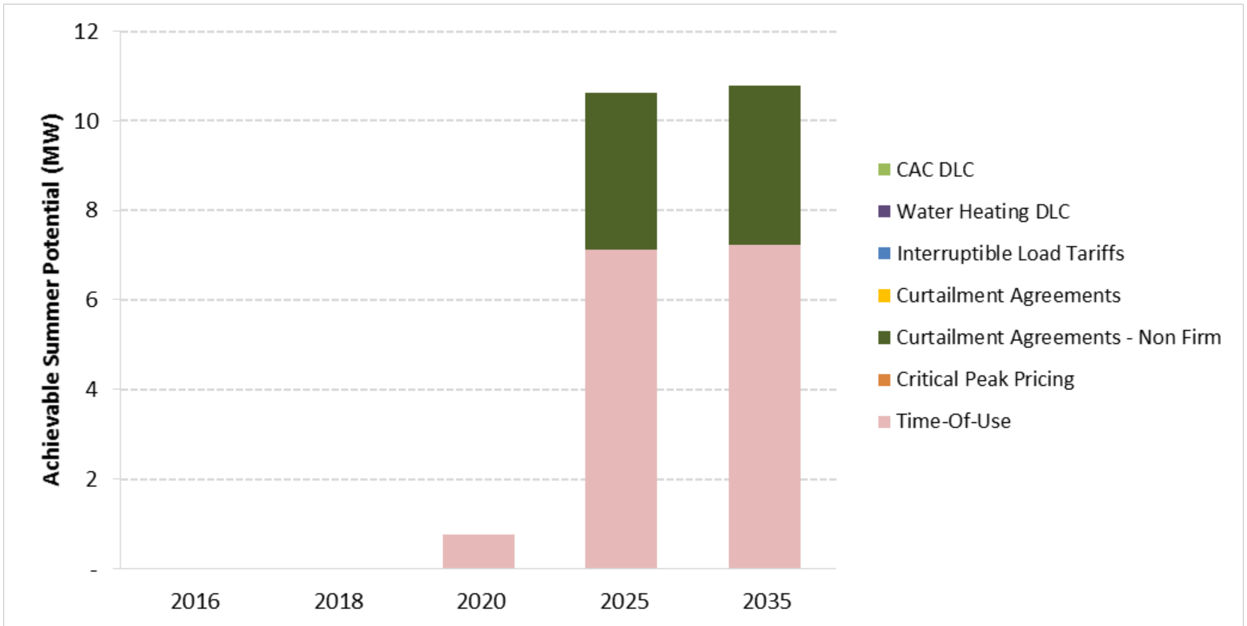


Table 3-5 Achievable Potential High by DR Option

	2016	2018	2020	2025	2035
System Peak Projection (MW)	1,358	1,361	1,355	1,367	1,390
Achievable Summer Potential (MW)					
CAC DLC	-	-	-	-	-
Water Heating DLC	-	-	-	-	-
Curtailment Agreements	-	-	-	-	-
Non Firm Curtailment	-	-	-	3.51	3.57
Time-Of-Use	-	-	0.76	7.12	7.22
Total Potential Summer	**-**	**-**	**0.76**	**10.63**	**10.79**
Achievable Summer Potential (% of Peak)					
CAC DLC	0.00%	0.00%	0.00%	0.00%	0.00%
Water Heating DLC	0.00%	0.00%	0.00%	0.00%	0.00%
Curtailment Agreements	0.00%	0.00%	0.00%	0.00%	0.00%
Non Firm Curtailment	0.00%	0.00%	0.00%	0.26%	0.26%
Time-Of-Use	0.00%	0.00%	0.06%	0.52%	0.52%
Total Potential Summer	**0.00%**	**0.00%**	**0.06%**	**0.78%**	**0.78%**

Potential Estimates by Customer Class

DR potential by customer class is shown in Figure 3-5 and Table 3-6 for achievable potential low and Figure 3-6 and Table 3-7 for achievable potential high. Key observations are:

- The residential sector does not play a role in the potential savings.
- Among the C&I classes, the bulk of the savings opportunities are associated large customers throughout the study horizon.
- Small and small/medium C&I customers play a lesser role in both potential cases.

Figure 3-5 Achievable Potential Low by Customer Class (Summer)

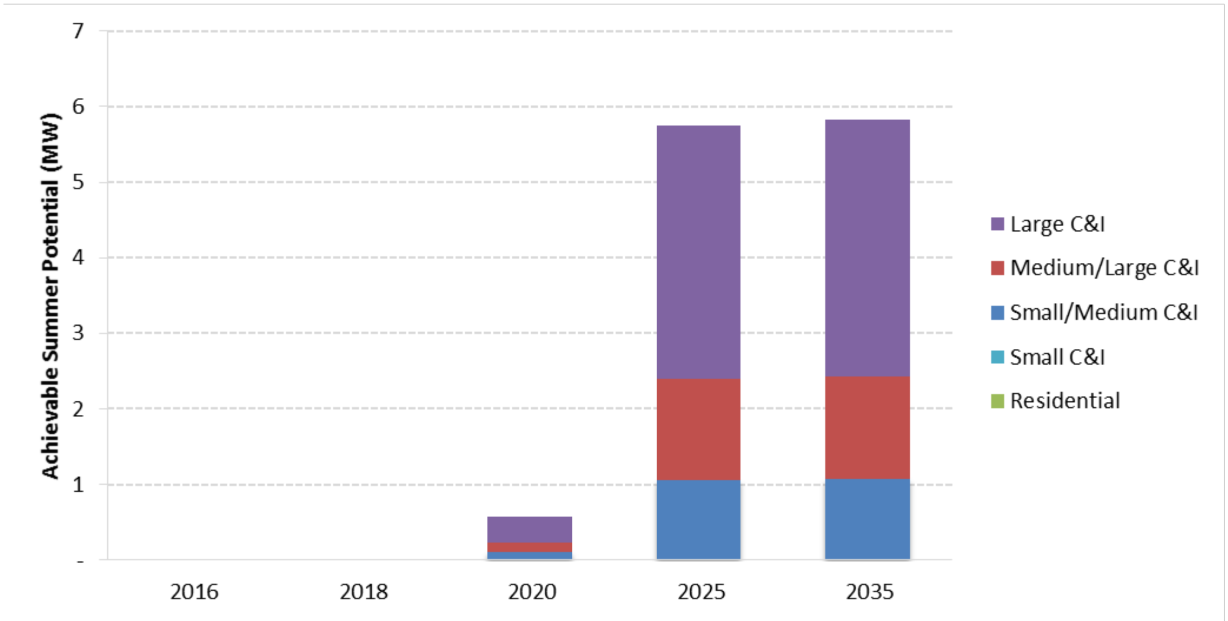


Table 3-6 Achievable Potential Low by Customer Class (Summer)

	2016	2018	2020	2025	2035
System Peak Projection (MW)	1,358	1,361	1,355	1,367	1,390
Potential (MW)					
Residential	-	-	-	-	-
Small C&I	-	-	-	-	-
Small/Medium C&I	-	-	0.10	1.05	1.07
Medium/Large C&I	-	-	0.13	1.34	1.36
Large C&I	-	-	0.33	3.35	3.40
Total Potential	**-**	**-**	**0.57**	**5.75**	**5.83**
Potential (% of System Peak)					
Residential	0.00%	0.00%	0.00%	0.00%	0.00%
Small C&I	0.00%		0.00%	0.00%	0.00%
Small/Medium C&I	0.00%	0.00%	0.01%	0.08%	0.08%
Medium/Large C&I	0.00%	0.00%	0.01%	0.10%	0.10%
Large C&I	0.00%	0.00%	0.02%	0.25%	0.24%
Total Potential	**0.00%**	**0.00%**	**0.04%**	**0.42%**	**0.42%**

Figure 3-6 Achievable Potential High by Customer Class (Summer)

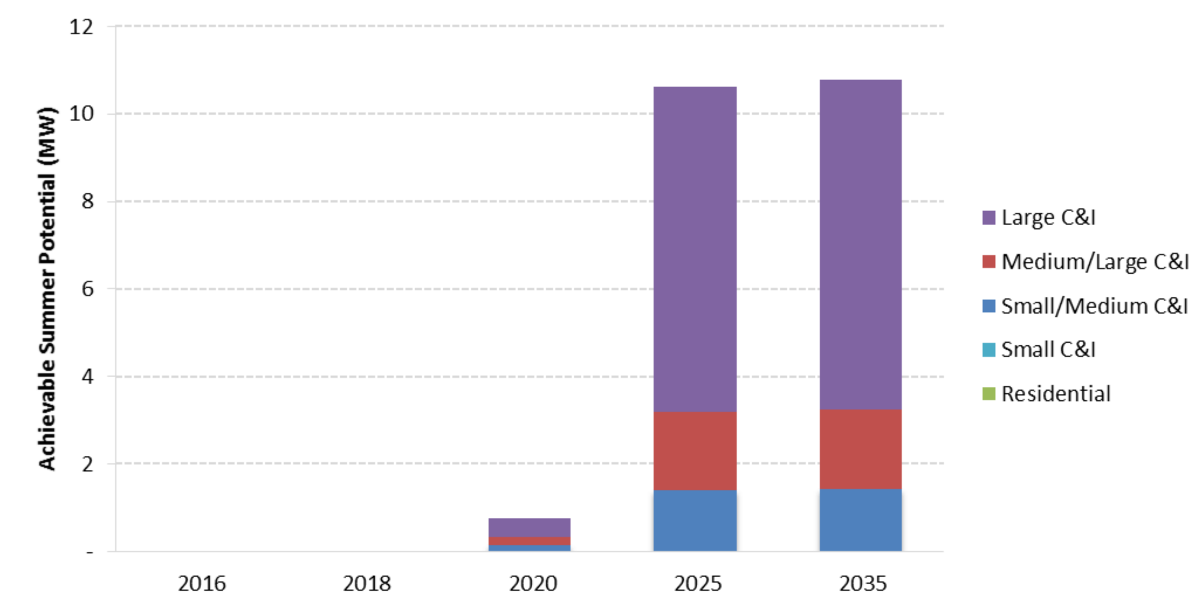


Table 3-7 Achievable Potential High by Customer Class (Summer)

	2016	2018	2020	2025	2035
System Peak Projection (MW)	1,358	1,361	1,355	1,367	1,390
Potential (MW)					
Residential	-	-	-	-	-
Small C&I	-	-	-	-	-
Small/Medium C&I	-	-	0.14	1.40	1.42
Medium/Large C&I	-	-	0.18	1.79	1.82
Large C&I	-	-	0.44	7.44	7.55
Total Potential	**-**	**-**	**0.76**	**10.63**	**10.79**
Potential (% of System Peak)					
Residential	0.00%	0.00%	0.00%	0.00%	0.00%
Small C&I	0.00%	0.00%	0.00%	0.00%	0.00%
Small/Medium C&I	0.00%	0.00%	0.01%	0.10%	0.10%
Medium/Large C&I	0.00%	0.00%	0.01%	0.13%	0.13%
Large C&I	0.00%	0.00%	0.03%	0.54%	0.54%
Total Potential	**0.00%**	**0.00%**	**0.06%**	**0.78%**	**0.78%**

Potential DR Program Costs

Table 3-8 and Table 3-9 presents program cost estimates from several perspectives for both potential scenarios, along with 2035 DR potential for reference:

- Cumulative program costs for the portfolio of DR options is approximately $1 million over 2015-2035 for delivering 5.8 MW of savings in 2035.
- Average program costs for 2015-2035 for KPCO to achieve this level of savings are estimated to be $60 thousand per year.
- Levelized costs over the 2015-2035 timeframe for the entire portfolio are estimated to be $63.980/kW-yr, which is C&I curtailment agreements. Critical peak pricing programs for residential and C&I customers offer an attractive opportunity for realizing load reductions at low cost. The DLC programs for all sectors are not cost effective.
- For the achievable high scenario, utility spending is increased to account for the increase amount of participation and the increased costs associated with achieving the increased participation.

Table 3-8 Achievable Potential Low Program Costs (Summer)

DR Option	2016 – 2035 Cumulative Utility Spend (Million $)	2016 – 2035 Average Spend per Year (Million $)	2016 – 2035 Levelized Cost ($/kW-yr)	2035 MW Potential
Residential DLC	-	$0.00	-	-
Residential TOU	-	$0.00	-	-
C&I DLC	-	$0.00	-	-
C&I Curtailment Agreement	-	$0.00	-	-
C&I Non Firm Curtailment	-	$0.00	-	-
C&I TOU	$1.18	$0.06	$63.98	5.83
Total	**$1.18**	**$0.06**	**$63.98**	**5.8**

Table 3-9 Achievable Potential High Program Costs (Summer)

DR Option	2016 – 2035 Cumulative Utility Spend (Million $)	2016 – 2035 Average Spend per Year (Million $)	2016 – 2035 Levelized Cost ($/kW-yr)	2035 MW Potential
Residential DLC	-	$0.00	-	-
Residential TOU	-	$0.00	-	-
C&I DLC	-	$0.00	-	-
C&I Curtailment Agreement	-	$0.00	-	-
C&I Non Firm Curtailment	$0.61	$0.03	$53.78	3.57
C&I TOU	$1.48	$0.08	$62.65	7.22
Total	**$2.09**	**$0.11**	**$116.42**	**10.8**

Figure 3-7 and Figure 3-8 shows the annual program costs by DR option for both potential scenarios. Within the achievable low scenario, there are high costs in the beginning of the projection are due to the start up costs of launching the programs, these eventually level out and rise slightly as most participants are incorporated into the program. Within the high scenario, non-firm curtailment agreements are the highest cost due to higher incentives, and higher participation.

Figure 3-7 Annual Achievable Potential Low DR Program Costs (Summer)

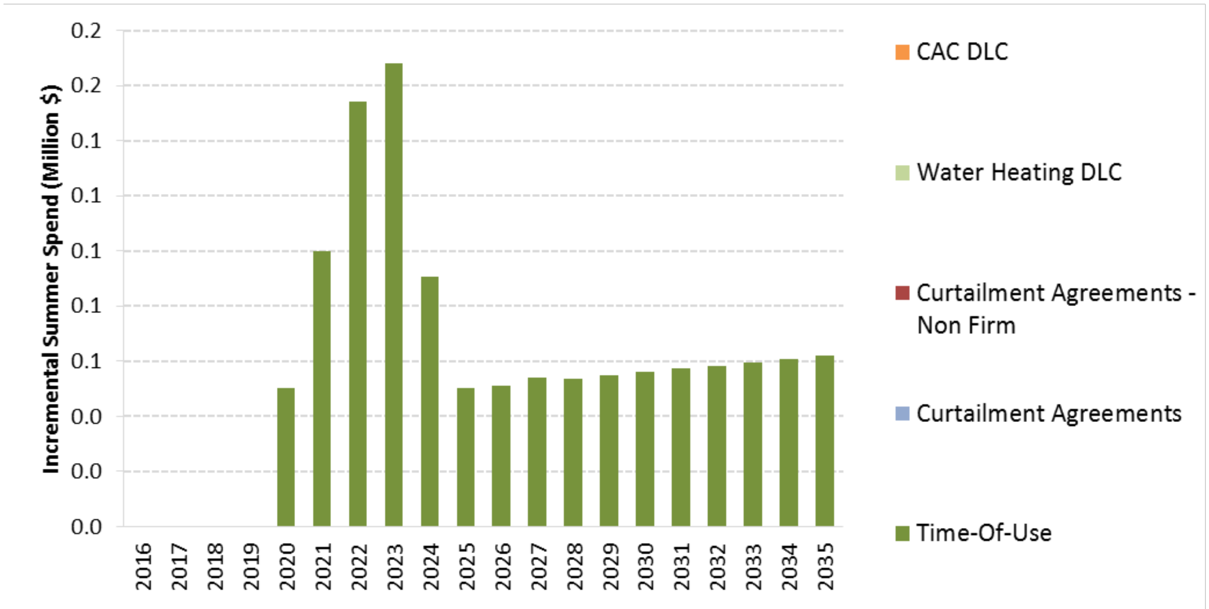
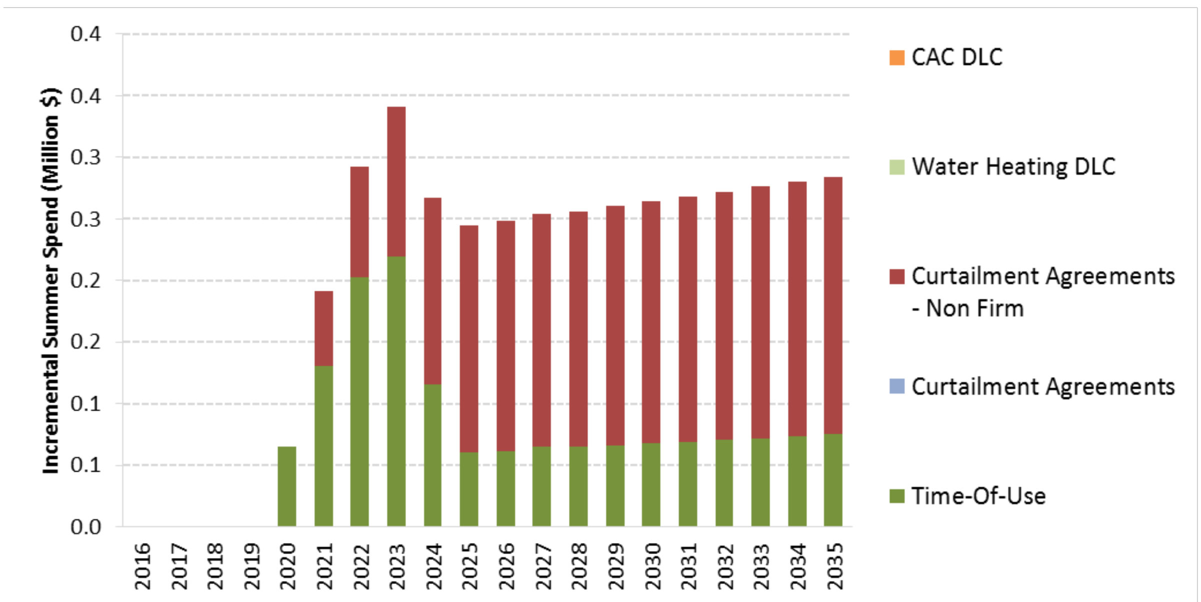


Figure 3-8 Annual Achievable Potential High DR Program Costs (Summer)



DEMAND RESPONSE ACHIEVABLE TECHNICAL POTENTIAL

This section presents the achievable technical potential savings from each DR program. This potential case does not consider cost-effectiveness. The DR programs are not economically screened, and therefore, all programs are included.

Table 4-1 and Figure 4-1 present the achievable potential low for the summer and winter peak seasons, showing savings from DR options relative to the baseline peak projection.

Table 4-1 Summary of Demand Response Achievable Technical Potential Savings

	2016	2018	2020	2025	2035
System Peak Projection (MW)	1,358	1,361	1,355	1,367	1,390
Achievable Technical Potential (Summer)	1,352	1,345	1,328	1,333	1,356
RAP (as % of Baseline)	0.5%	1.2%	1.9%	2.5%	2.4%
Achievable Technical Potential (Winter)	1,345	1,328	1,302	1,305	1,328
RAP (as % of Baseline)	1.0%	2.4%	3.9%	4.5%	4.4%

Figure 4-1 Potential Cases vs. Baseline Peak Projection Achievable Technical Potential

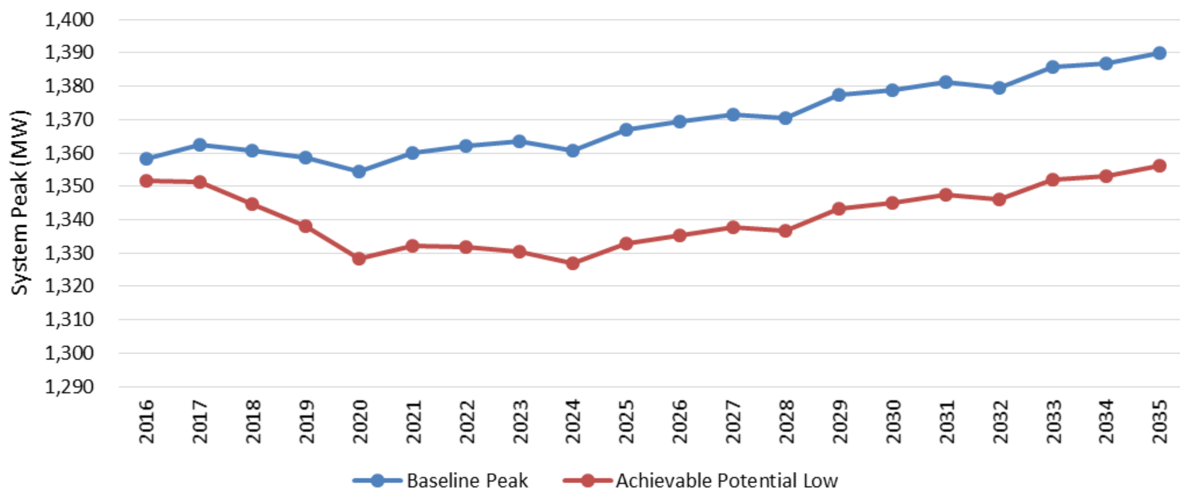


Table 4-2 Achievable Technical Potential Benefit Cost Ratios

Option	Customer Class	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
CAC DLC	Residential	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28
	Small C&I	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69
	Small/Medi C&I	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61
Space Heating DLC	Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Small C&I	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	1.48	1.48	1.48	1.48	1.48	1.48	1.48	1.48	1.48	1.48
	Small/Med C&I	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
WH DLC	Residential	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
Firm Curtailment	Large C&I	0.41	0.41	0.41	0.67	0.67	0.67	0.76	0.76	0.76	0.84	0.84	0.84	0.85	0.85	0.85	0.83	0.83	0.83	0.80	0.80
	Extra Large C&I	0.50	0.50	0.50	0.74	0.74	0.74	0.84	0.84	0.84	0.92	0.92	0.92	0.93	0.93	0.93	0.91	0.91	0.91	0.89	0.89
Non-Firm Curtailment	Large C&I	0.30	0.30	0.30	0.61	0.61	0.61	0.70	0.70	0.70	0.75	0.75	0.75	0.75	0.75	0.75	0.72	0.72	0.72	0.69	0.69
	Extra Large C&I	0.50	0.50	0.50	0.88	0.88	0.88	0.99	0.99	0.99	1.08	1.08	1.08	1.08	1.08	1.08	1.04	1.04	1.04	1.00	1.00
Time-Of-Use	Residential	0.00	0.00	0.00	0.00	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93
	Small C&I	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	Medium C&I	0.00	0.00	0.00	0.00	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66
	Large C&I	0.00	0.00	0.00	0.00	5.04	5.04	5.04	5.04	5.04	5.04	5.04	5.04	5.04	5.04	5.04	5.04	5.04	5.04	5.04	5.04
	Extra Large C&I	0.00	0.00	0.00	0.00	7.52	7.52	7.52	7.52	7.52	7.52	7.52	7.52	7.52	7.52	7.52	7.52	7.52	7.52	7.52	7.52

Figure 4-2, Figure 4-3, and Table 4-3 show savings by DR option for winter and summer achievable technical potential. Key observations from these results are:

- DLC programs for both sectors is a top contributor throughout the analysis timeframe. The highest contributor to savings overall is the water heating DLC program. The large impacts are driven by high electric water heating saturation in the KPCO service territory and a large per-customer reduction.
- Firm curtailment agreements are also a top contributing program throughout the projection.
- In the later years of the projection, the time of use programs come online and contribute a substantial portion of savings.

Figure 4-2 Achievable Technical Potential by DR Option (Summer)

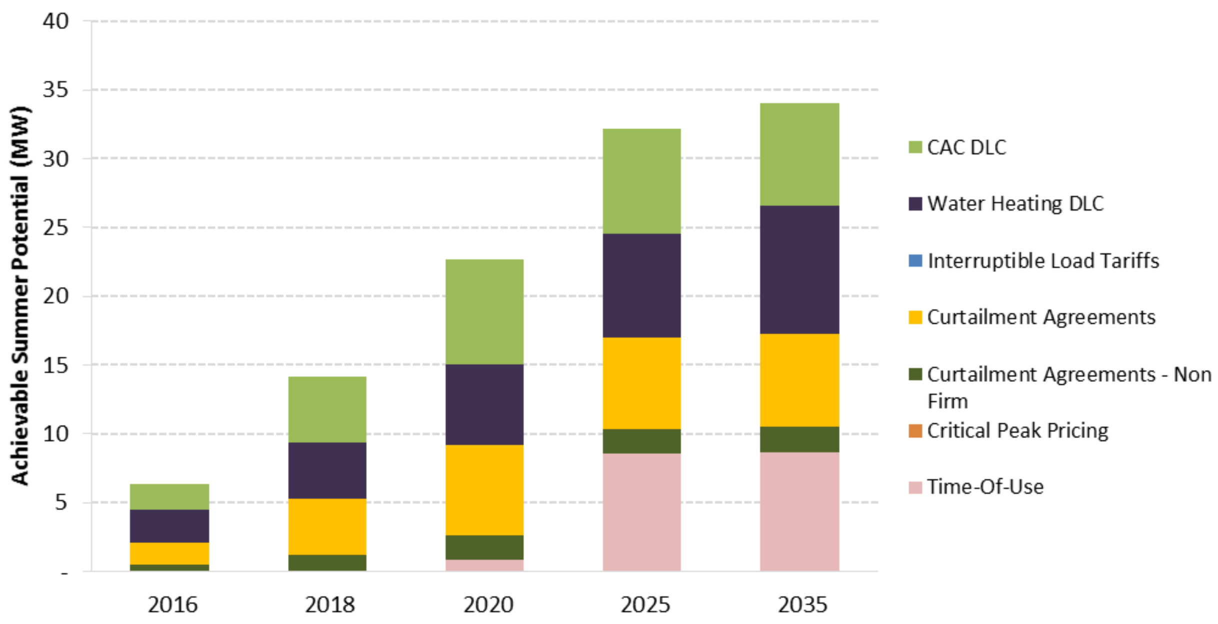


Figure 4-3 Achievable Technical Potential by DR Option (Winter)

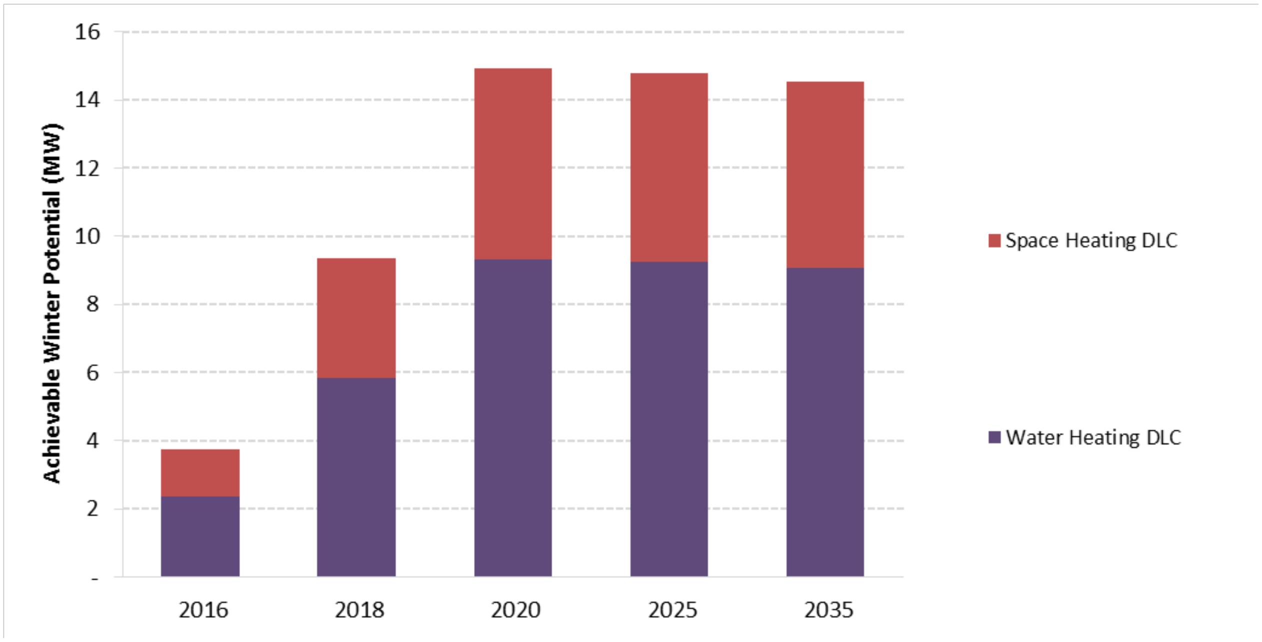


Table 4-3 Achievable Technical Potential by DR Option

	2016	2018	2020	2025	2035
System Peak Projection (MW)	1,358	1,361	1,355	1,367	1,390
Achievable Winter Technical Potential (MW)					
Space Heating DLC	1.41	3.52	5.61	5.57	5.47
Water Heating DLC	2.35	5.84	9.31	9.23	9.05
Achievable Summer Technical Potential (MW)					
CAC DLC	1.92	4.79	7.63	7.58	7.47
Water Heating DLC	2.35	5.84	9.31	9.23	9.05
Curtailment Agreements	1.62	4.10	6.55	6.64	6.74
Curtailment Agreements - Non Firm	0.50	1.19	1.78	1.80	1.83
Time-Of-Use	-	-	0.85	8.54	8.68
Total Winter DR Technical Potential	**3.76**	**9.36**	**14.92**	**14.79**	**14.53**
Total Summer DR Technical Potential	**6.39**	**15.92**	**26.13**	**33.79**	**33.77**
Achievable Winter Technical Potential (% of Peak)					
Space Heating DLC	0.10%	0.26%	0.41%	0.41%	0.39%
Water Heating DLC	0.17%	0.43%	0.69%	0.68%	0.65%
Achievable Summer Technical Potential (% of Peak)					
CAC DLC	0.14%	0.35%	0.56%	0.55%	0.54%
Water Heating DLC	0.17%	0.30%	0.43%	0.55%	0.67%
Curtailment Agreements	0.11%	0.27%	0.40%	0.41%	0.40%
Curtailment Non Firm	0.04%	0.08%	0.11%	0.11%	0.11%
Time-Of-Use	0.00%	0.00%	0.06%	0.58%	0.58%
Total Winter Technical Potential	**0.28%**	**0.69%**	**1.10%**	**1.08%**	**1.05%**
Total Summer Technical Potential	**0.30%**	**0.74%**	**1.24%**	**1.80%**	**1.78%**

Achievable Technical Potential Estimates by Customer Class

Summer and winter DR potential by customer class for achievable low scenario is shown in Figure 4-4, Figure 4-5, and Table 4-4 . Key observations are:

- Residential sector is the largest contributor for summer and winter peak savings throughout the projection, with 3.69 MW in winter technical potential and 4.09 MW in summer achievable technical potential in 2016.
- Large C&I customers are the next largest contributor, mainly due to non-firm curtailable agreements.
- Small C&I customers play a very small role in both summer and winter achievable technical potential.

Figure 4-4 Achievable Technical Potential by Customer Class (Summer)

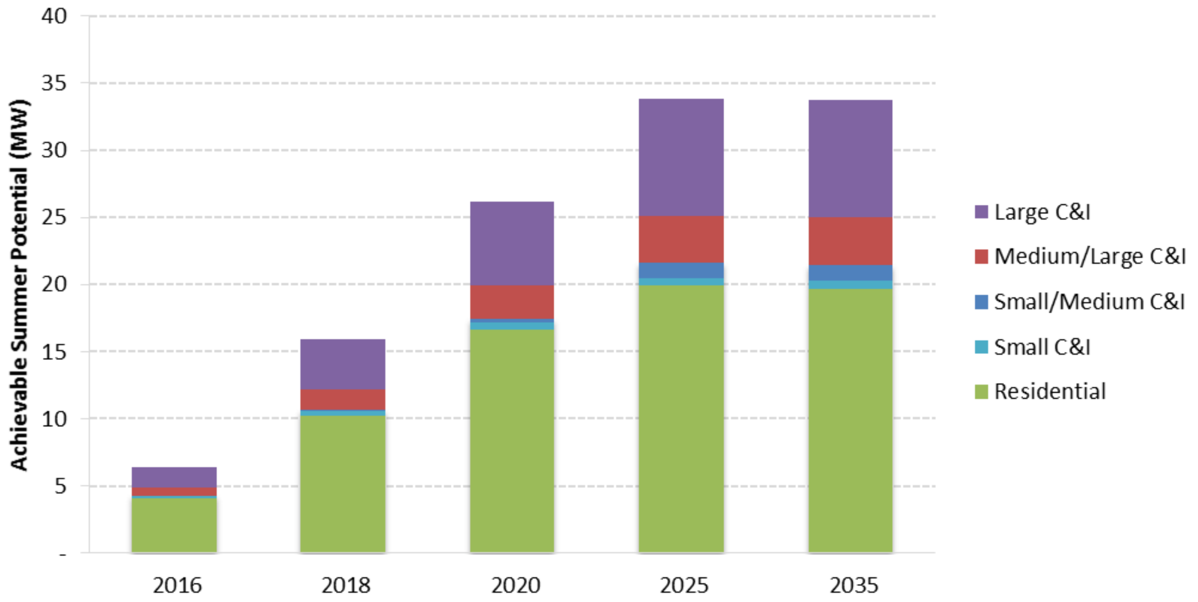


Figure 4-5 Achievable Technical Potential by Customer Class (Winter)

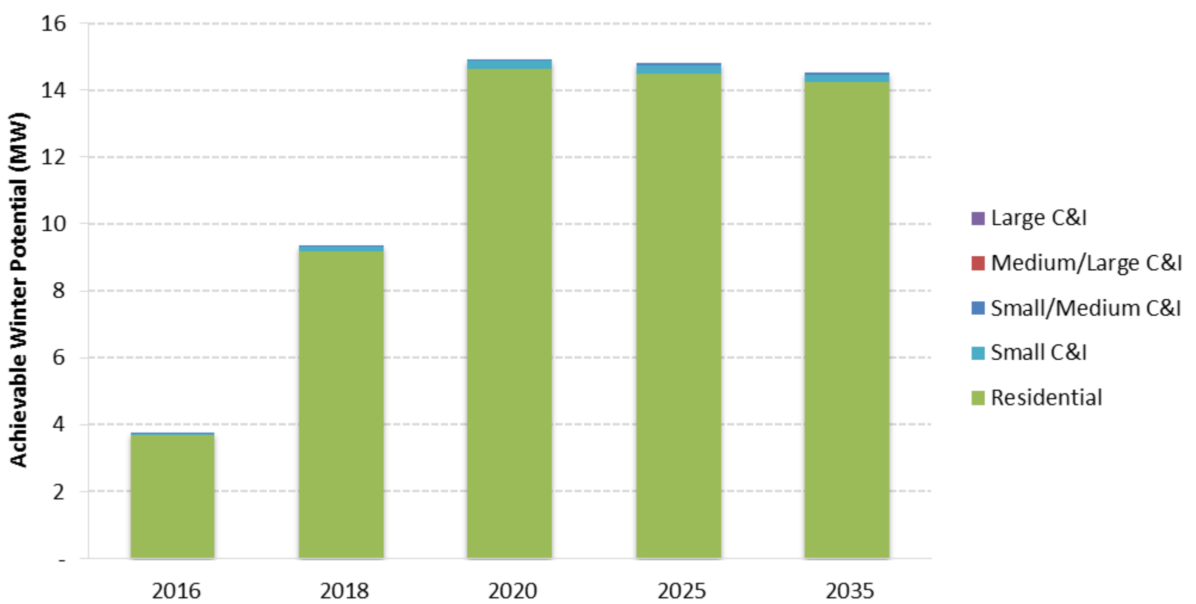


Table 4-4 Achievable Technical Potential by Customer Class

	2016	2018	2020	2025	2035
System Peak Projection (MW)	1,358	1,361	1,355	1,367	1,390
Achievable Winter Potential (MW)					
Residential	3.69	9.18	14.63	14.50	14.22
Small C&I	0.06	0.15	0.24	0.24	0.25
Small/Medium C&I	0.01	0.03	0.05	0.05	0.06
Medium/Large C&I	-	-	-	-	-
Large C&I	-	-	-	-	-
Achievable Winter Potential (% of Peak)					
Residential	0.27%	0.67%	1.08%	1.06%	1.02%
Small C&I	0.00%	0.01%	0.02%	0.02%	0.02%
Small/Medium C&I	0.00%	0.00%	0.00%	0.00%	0.00%
Medium/Large C&I	0.00%	0.00%	0.00%	0.00%	0.00%
Large C&I	0.00%	0.00%	0.00%	0.00%	0.00%
Total Winter Potential	**3.76**	**9.36**	**14.92**	**14.79**	**14.53**
Achievable Summer Potential (MW)					
Residential	4.09	10.20	16.63	19.90	19.66
Small C&I	0.14	0.35	0.57	0.59	0.61
Small/Medium C&I	0.03	0.08	0.23	1.15	1.17
Medium/Large C&I	0.61	1.52	2.49	3.48	3.53
Large C&I	1.52	3.78	6.21	8.67	8.80
Achievable Summer Potential (% of Peak)					
Residential	0.30%	0.75%	1.23%	1.46%	1.41%
Small C&I	0.01%	0.03%	0.04%	0.04%	0.04%
Small/Medium C&I	0.00%	0.01%	0.02%	0.08%	0.08%
Medium/Large C&I	0.04%	0.11%	0.18%	0.25%	0.25%
Large C&I	0.11%	0.28%	0.46%	0.63%	0.63%
Total Summer Potential (MW)	**6.39**	**15.92**	**26.13**	**33.79**	**33.77**

Achievable Technical Potential DR Program Costs

Table 4-5 presents the program cost estimates from several perspectives for achievable technical potential summer and winter potential, along with 2035 DR technical potential for reference.

- Cumulative program costs for the portfolio of summer DR options is approximately $36 million over 2016-2035 for delivering 33.77 MW of savings in 2035.
- Average program costs for 2016-2035 for KPCO to achieve this level of savings are estimated to be $850 thousand per year.
- Levelized costs over the 2015-2035 timeframe for the entire portfolio are estimated to be $9,061/kW-yr.C&I TOU, the largest option, cost approximately $8,161/kW-year. The high total levelized cost forC&I TOU, is due to the programs higher NPV costs and lower potential driven by the Small C&I customers.

Table 4-5 Achievable Technical Potential Program Costs[7] (Summer)

DR Option	2016 – 2035 Cumulative Utility Spend (Million $)	2016 – 2035 Average Spend per Year (Million $)	2016 – 2035 Levelized Cost ($/kW-yr)	2035 MW Potential
Residential DLC (CAC)	$16.93	$0.89	$152.70	15.80
Residential TOU	$3.33	$0.18	$74.70	3.86
C&I DLC	$1.50	$0.08	$295.72	0.72
C&I Curtailment Agreement	$9.56	$0.50	$171.70	6.74
C&I Curtailment Non Firm	$2.50	$0.13	$204.75	1.83
C&I TOU	$2.70	$0.14	$8,161.97	4.83
Total Summer	**$36.51**	**$1.92**	**$9,061.56**	**33.77**
Residential DLC (Space & Water Heating)	$14.48	$0.76	$147.04	14.22
C&I DLC (Space Heating)	$1.68	$0.09	$230.32	0.30
Total Winter	**$16.16**	**$0.85**	**$377.36**	**14.53**

Figure 4-6 and Figure 4-7 shows the annual program costs by DR option for the achievable technical potential case. The Curtailment Agreements options constitute a relatively small portion of the portfolio costs during the summer season. The DLC programs constitute a large portion of the costs for the summer season. These high costs are from marketing and recruiting customers, purchasing and installing enabling technology, and providing customer incentives. The TOU program costs spike within the early years to account for the program development costs, and eventually levels out.

[7] Costs are represented in real 2013 dollars.

Figure 4-6 Annual Achievable Technical Potential DR Program Costs (Summer)

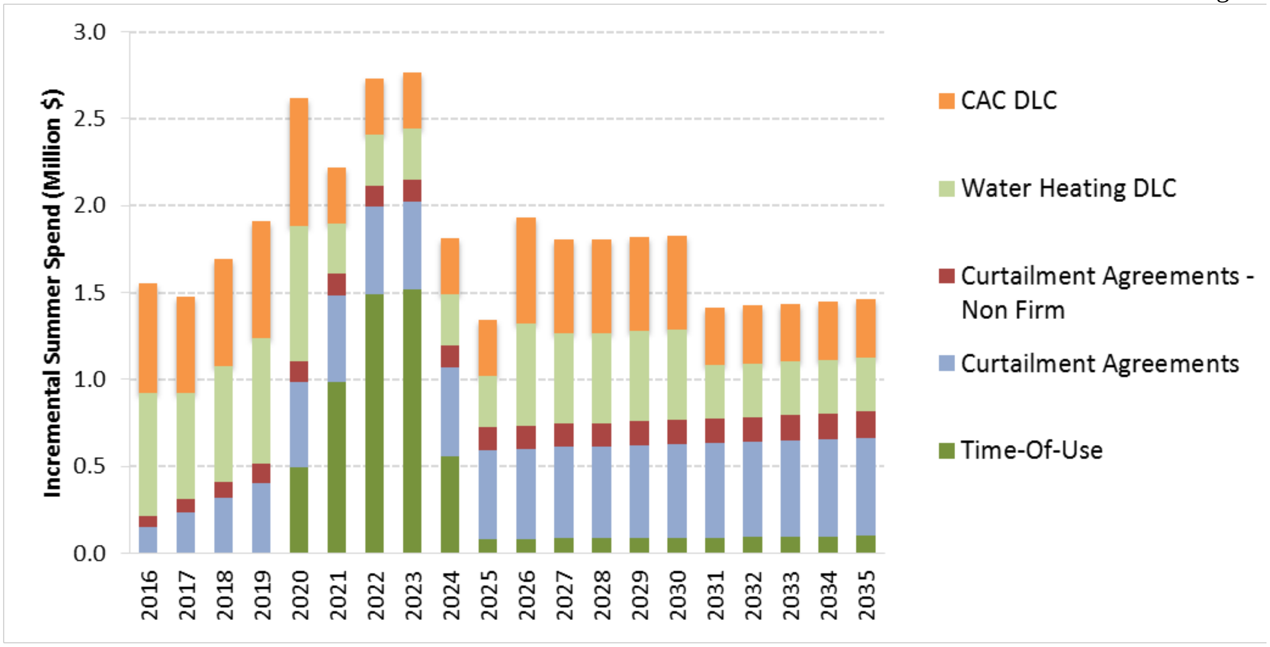
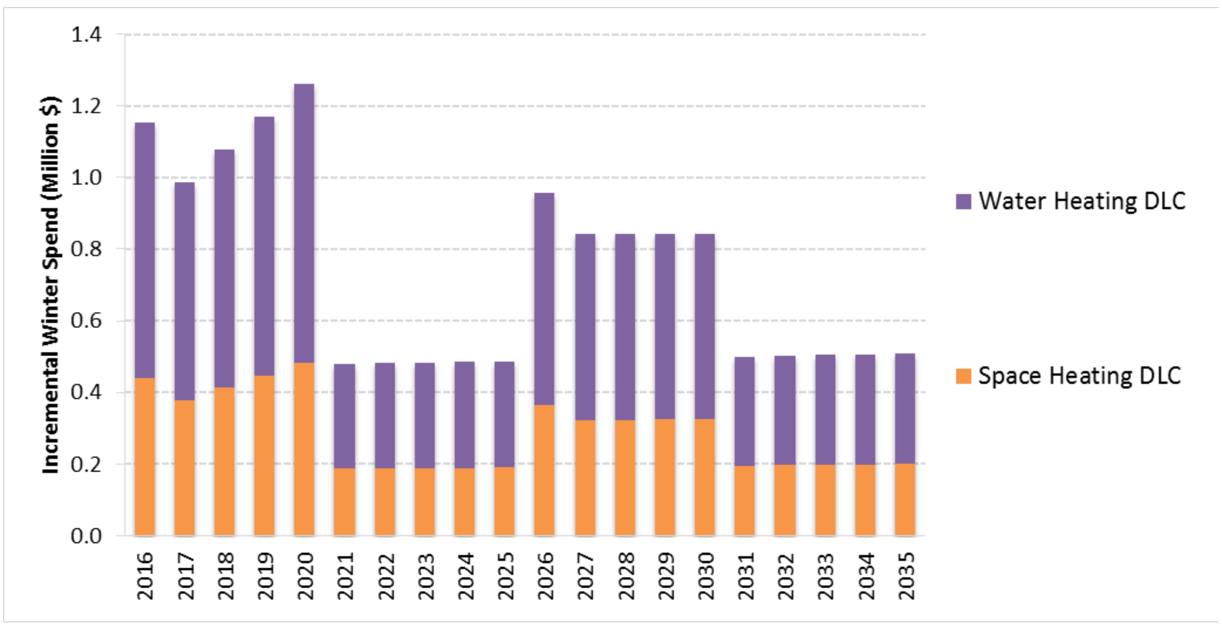


Figure 4-7 Annual Achievable Technical Potential DR Program Costs (Winter)



SECTION 5

CONCLUSIONS

The results of this study reveal that there is some potential for demand response savings in the KPCO service territory. Our analysis has shown that KPCO can realize the following savings from DR options:

- A 5.7 MW peak demand reduction is achievable by 2025, and 5.8 MW is achievable by 2035. This corresponds to 0.4% of projected baseline summer peak demand in 2025 and 2035.
- DLC and Curtailment programs were not cost effective and therefore, there is no potential savings for the summer or winter peak season.
- Savings in 2035 could be achieved at an overall portfolio cost of $1 million, with an average levelized cost of $63.98/kW-yr over 2016-2035 timeframe.

The DR program options with the most potential are:

- Medium to large and large customers that would participate in the Time of Use rate option at 5.75 MW potential in 2025 and 5.83 MW in 2035.

It should also be noted that DSM programs intimately involve the customer, and as such, need continuity, consistency, and careful attention. You cannot merely flip a switch on human behavior like one might plan to do for a supply-side resource. Sudden starts, stops, and changes in program frameworks can confuse and alienate customers, the market, and associated trade- and contractor-groups. Therefore, when ramping programs up and down in the context of long-term planning, the time required to engage, educate, and recruit customers should be carefully considered.

APPENDIX:

Cost Effectiveness Inputs

The following tables present the cost effectiveness inputs for each program offering.

- Residential Direct Load Control
- Residential C&I TOU
- C&I Direct Load Control
- C&I Curtailment Agreement
- C&I Non-Firm Curtailment Agreement

Table 6-1 Residential Direct Load Control Program Cost Assumptions

Item	Unit	Value	Basis for Assumption
Program Development Cost	$/program	66,666.67	We assumed 2 FTEs to develop the program at an annual FTE cost of $100,000. That number is divided among the three DLC programs for the Residential sector.
Program Administration Cost	$/MW	5,000	We assumed an annual program administration cost of $5/kW-yr, based on program implementation experience.
Annual Marketing and Recruitment Costs	$/new participant	90	We assumed a one-time $40 payment to the customer for enrolling in the program, plus $50 per customer marketing costs. (Ref: Review of utility program incentives, TVA Potential Study; Global Energy Partners, 2011)
Cost of Equip + Install for CAC	$/new participant	140	Assumes $60 capital cost for switch, plus $80 installation cost (Ref: PacifiCorp DSM Potential Study, 2013)
Cost of Equip + Install for Space Heating &Water Heating Control	$/new participant	100	Assumes $60 capital cost for switch, plus $40 installation cost (Ref: PacifiCorp DSM Potential Study, 2013)
Annual O&M cost	$/MW	5.00	We assumed the annual O&M cost to be 3.5% of the control equipment cost.
Per participant annual incentive for CAC	$/participant/yr.	20	We assumed a $5/month incentive for AC, for 4 summer months (June-September) (Ref: LG&E/KU program)
Per participant annual incentive for Space Heating & Water Heating control	$/participant/yr.	12	Assumes $3/month incentive for WH, for 4 summer months (June-September) (Ref: LG&E/KU program)

Table 6-2 Residential and C&I TOU Program Cost Assumptions

Item	Unit	Value	Basis for Assumption
Program Development Cost	$/program	20,000	We assumed that 2 FTE (@$100,000 annual cost) is required to develop the program. We assumed that this cost is equally split between all customer classes, and both the TOU and CPP programs.
Program Administration Cost	$/MW-yr	5,000	Standard assumption for is $5,000. (Ref: TVA Potential Study, 2011)
Annual Marketing and Recruitment Costs	$/new participant	50	Standard assumption for is $50. (Ref: TVA Potential Study, 2011)
Cost of Equip + Install for Space Heating Control (GS customers)	$/new participant	200	We assumed load control switch capital cost at $100, plus $100 installation cost.

Table 6-3 C&I Direct Load Control Program Cost Assumptions

Item	Unit	Value	Basis for Assumption
Program Development Cost	$/program	12,500	We assumed an additional total of $50,000 to run the C&I DLC programs, which is split equally across the four customer classes and programs. This cost is in addition to the Residential DLC programs, which assumes most of the development costs.
Program Administration Cost	$/MW	5,000	We assumed an annual program administration cost of $5/kW-yr, based on program implementation experience
Annual Marketing and Recruitment Costs	$/new participant	155	We assumed a one-time $80 payment to the customer for enrolling in the program, plus $75 per customer marketing costs. Per customer marketing costs for small commercial customers is assumed to be 50% higher as compared to residential customers. Also, at sign-up, customers are paid double the amount paid to residential customers.
Cost of Equip + Install for CAC	$/technology	140	We assumed $60 capital cost for switch, plus $80 installation cost (Ref: PacifiCorp DSM Potential Study, 2013)
Cost of Equip + Install for Space Heating & Water Heating Control	$/technology	100	We assumed $60 capital cost for switch, plus $40 installation cost (Ref: PacifiCorp DSM Potential Study, 2013)
Annual O&M cost	$/participant/yr.	15	We assumed the annual O&M cost to be about 10% of the control equipment cost.
Per participant annual incentive for CAC	$/participant/yr.	48	Assumed to be the same as Residential.
Per participant annual incentive for Space & Water Heating control	$/participant/yr.	12	Assumed to be the same as Residential.

Table 6-4 C&I Curtailment Agreements (Firm and Non-Firm) Program Cost Assumptions

Item	Unit	Value	Basis for Assumption
Program Development Cost	$/program	50,000	We assumed that 1 FTE (@$100,000 annual cost) is required to develop interruptible tariffs. We assumed that this cost is equally split between the two customer classes (Med/Large C&I and Large C&I)
Program Administration Cost	$/MW-yr	15,000	We assumed an annual program administration cost of $15/kW-yr. (Ref-TVA Potential Study, 2011; KCPL Potential Study, 2013). The administrative costs for Capacity Reduction are likely to be higher as compared to that for DLC option, due to paperwork associated with customer contracts and participation agreements, settlement, etc.
Annual Marketing and Recruitment Costs	$/new participant	50	We assumed this cost to only include the marketing cost, and does not include any upfront payment to the customer in the form of incentives. (Ref: TVA Potential Study; Global Energy Partners, 2011)
Per kW Annual Incentive (Curtailment Agreement)	$/kW/year	40	We reduced the assumption from $50 to $25, which is referenced from KCP&L Demand Side Resource Potential Study, 2013; TVA Potential Stdy, 2011
Per kWh Annual Incentive (Curtailment Agreement)	$/kWh/year	.03	Based on LMP (locational marginal pricing) data for PJM Independent Service Operator in KY).
Per kWh Annual Incentive (Non Firm Curtailment)	$/kWh/year	.50	Based on NYISO Emergency Demand Response program data.

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DATA REQUEST

JI 2_8 2.8. Please refer to Kentucky Power's response to Joint lntervenors' Initial Request 1.38, explaining that the 6.2 MW of peak DR capability reported in the IRP (page 62 of 1182), comes from participation in Rider D.R.S and Tariff C.S.-1.R.P. a. Please state the number of participating customers and aggregate load participating in Rider D.R.S. b. Please state the number of participating customers and aggregate load participating in Tariff C.S.-1.R.P.

RESPONSE

a. Kentucky Power has three customers on Rider D.R.S. with an aggregated contracted load of 38,100 kW with 36,300 kW interruptible.

b. Kentucky Power has five customers on Tariff C.S.-I.R.P. with an aggregated contracted load of 20,900 kW with 14,400 kW interruptible.

Witness: Brian K. West

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DATA REQUEST

JI 2_9 Please refer to Kentucky Power's response to Joint lntervenors' Initial Request 1.52(b) and answer the following requests.
a. Since performing its IRP modeling, what analysis has Kentucky Power undertaken concerning sites within its service territory that likely would qualify for the energy community adder to the PTC and ITC? Please explain in full.
b. Has Kentucky Power reviewed the interactive mapping tool available through the lnteragency Working Group on Coal & Power Plant Communities & Economic Revitalization? (https://energycommunities.gov/energy-communitytax-credit-bonus/)?
i. If yes, does Kentucky Power agree that substantial portions of its service territory would be eligible for the energy communities tax credit bonus? If you disagree, please explain in full.
ii. If not, please explain in detail why not.

RESPONSE

a. The Company objects to this request to the extent it is not reasonably calculated to the discovery of admissible evidence. The Company further objects to the extent the request calls for legal analysis or a legal conclusion, which are not the appropriate subject of discovery. Without waiving these objections, the Company states as follows:
The IRP does not include location-specific assumptions for generic generation resources. The requested analysis would be location-specific. The Company has not performed the requested analysis nor made determinations about specific resources or their location.

b. No. The IRP does not include location-specific assumptions for generic generation resources.

Witness: Brian K. West

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DATA REQUEST

JI 2_10 Please refer to Kentucky Power's response to AG/KIUC Initial Request 1.5, which asked Kentucky Power to "[p]rovide a copy of all agreements between Liberty, AEP, and/or the Company for Liberty to participate in the development of the IRP and/or to share information", Kentucky Power states it "does not have any such requested documents in its possession or control."
a. Is Kentucky Power aware of any such documents that exist outside of the Company's possession or control? If yes, please identify the documents and explain why they are not in the Company's possession or control.

RESPONSE

The Company objects to this request on the ground that it is not reasonably calculated to lead to the discovery of admissible evidence in this case. The Company further objects to this request to the extent it refers to matters other than the Company's 2022 Integrated Resource Plan or its preparation. Without waiving this objection, the Company states as follows:

No. Please refer to the Company's response to AG-KIUC 1_5. The Company's 2022 Integrated Resource Plan was prepared by the Company with the support of Charles Rivers Associates (CRA). CRA's services to Kentucky Power were provided pursuant to Kentucky Power's engagement of CRA.

Witness: Brian K. West

DATA REQUEST

JI 2_11 Please refer to Kentucky Power's Response to Joint lntervenors' Initial Request 1.18, Public and Confidential Attachments 1 and 2.
a. Please confirm that the level of the Ebon load included in the load forecasts modeled for the IRP is [redacted]
b. Please confirm that Kentucky Power included [redacted] in the IRP load forecast for Ebon (Confidential Attachment 2) [redacted] (Confidential Attachment 1).
c. Please explain [redacted] these two numbers.
d. Please explain in detail why Public Attachment 2 states that the three existing customers and the proposed customer "A" were not included in the IRP load forecast.
e. Please explain in detail why Public Attachment 2 states that the proposed Ebon facility was included in the IRP load forecast even though Ebon's special contract has not yet been approved by the Commission (see pending Case No. 2022-00387).
f. Please confirm that the Company did not perform any Aurora modeling runs for this IRP that did not include the Ebon load. If you are unable to confirm, please explain in detail why not.

RESPONSE

[redacted]

[redacted]

d. Those anticipated loads were not known at the time the load forecast was developed in early 2022.

e. The Ebon anticipated load referenced met the criteria for inclusion in the load forecast used for the IRP.

f. The base load forecast used in the IRP includes the anticipated Ebon load. The Company also analyzed a low-load scenario in the ECR Portfolio, which reflects generically a reduced load across all Kentucky Power costumers, and not costumer-specific reductions.

Witness: Glenn R. Newman (subpart a-e)

Witness: Thomas Haratym, CRA (subpart f)

DATA REQUEST

JI 2_12 Please refer to Kentucky Power's Response to AG/KIUC Initial Request 1.6, in which Kentucky Power responded, "PJM Delivery Years 2024/25 and 2025/26, the Company has bilateral contracts for capacity with a third party."

a. Please identify the third party with whom Kentucky Power has the referenced capacity contract.

b. Please identify the type of resource or combination of resources that are providing said capacity.

c. Please state the amount for which capacity was contracted.

d. Please state the price(s) for which the capacity was contracted.

e. Please produce a copy of each of the contracts.

RESPONSE

Please see the Company's response to AG-KIUC 2_7.

Witness: Brian K. West

DATA REQUEST

JI 2_13 Is Kentucky Power developing plans to construct a NGCC or NGCT at the Big Sandy site?
a. Please explain in detail the status of any such planning, including the potential timeframe when Kentucky Power anticipates proposing construction and the anticipated timeframe that Kentucky Power will propose for the NGCC or NGCT to begin operation.
b. Please produce copies of any documents in the Company's possession concerning any plans to construct a NGCC or NGCT at the Big Sandy site.

RESPONSE

a & b. No specific plans or documents have been developed at this time to construct a new gas resource, including at the Big Sandy site. Please also see the Company's response to KPSC 2_17.

Witness: Brian K. West

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DATA REQUEST

JI 2_14 Please refer to Joint Intervenors' Initial Request 1.4, which refers to IRP Section 5.7. addressing "Short-Term Market Purchase". Joint Intervenors' Initial Request 1.4(a) requested the workpaper(s) underlying Figure 35, titled "PJM Capacity Price Outlook." Joint Intervenors' Initial Request 1.4(b) requested that Kentucky Power identify and describe the source for the Company's forecasted price levels in the PJM Reliability Pricing Mechanism. Kentucky Power's response directed Joint Intervenors to the response to Staff's Initial Request 1.13, which concerns calculation of avoided capacity and energy cost.
a. Please explain the relationship between the requested data and the response to Staff's Initial Request 1.13.
b. Please produce the requested workpaper(s) underlying Figure 35.
c. Please identify and describe the source for the Company's forecasted price levels in the PJM Reliability Pricing Mechanism.

RESPONSE

a. The Company's initial response incorrectly referenced KPSC 1_13. Please see the response to part b below for the requested workpaper.

b. Please see KPCO_R_KPSC_1_8_Attachment2 (tab 'Capacity Price').

c. The outlook for the PJM RPM was developed by CRA. This was performed for each capacity year by modeling the supply structure of PJM as the UCAP of each eligible resource offered at an estimated net avoidable going forward cost. The intersection of this supply merit order and the PJM demand curve (adjusted through time by demand) forms the price for each year.

Witness: Thomas Haratym, CRA

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DATA REQUEST

JI 2_15 Please refer to Footnote 15 on page 87 of the IRP. The footnote indicates the consideration of partial ownership for the NGCC option modeled. Please explain if the Company is also considering partial ownership of the NGCT option modeled in Aurora.

RESPONSE

The general consideration for a partial ownership of the NGCT option was not considered in this IRP since the block size of a CT was only 240 MW. The general consideration of a partial ownership for the NGCC was noted because of the 1,100MW sizing of a 2x1 Combined Cycle unit.

Witness: Brian K. West

DATA REQUEST

JI 2_16 Please refer to Figure 14 on page 88 of the IRP. Please provide the source of the capital costs for the NGCC options modeled in Aurora.

RESPONSE

The source of capital cost was the EIA AEO 2022, escalated by PPI and NREL learning curves. Please see section 5.1 of the IRP Report, beginning on page 86 of 1182, for more detail.

Witness: Thomas Haratym, CRA

DATA REQUEST

JI 2_17 Please refer to Figure 15 on page 89 of the IRP. Please provide the source of the capital costs for the NGCT modeled in Aurora.

RESPONSE

The source of capital cost was the EIA AEO 2022, escalated by PPI and NREL learning curves. Please see section 5.1, beginning on page 86 of 1182, of the IRP Report for more detail.

Witness: Thomas Haratym, CRA

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DATA REQUEST

JI 2_18 For the new NGCC and NGCT resource options modeled in Aurora, please explain if the Company will need to invest in any new gas pipeline capital expenditures for those resources. a. If yes, please explain if the Company incorporated those costs into the Aurora model and provide the supporting workbooks, with all formulas and links intact, used to develop those costs.

RESPONSE

For the purposes of the IRP, new gas resources were assumed to require gas pipeline interconnection. An interconnection cost was assumed as part of the NGCT costs as described in the associated EIA report "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies" (February 2020), Table 6.1. Any costs associated with potential new gas pipeline infrastructure are expected to be resource specific.

Witness: Thomas Haratym, CRA

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DATA REQUEST

JI 2_19 Please explain if firm gas transportation costs were assumed for either the NGCC or NGCT options modeled in Aurora. If firm transportation costs were modeled, please provide the source and dollar amount of those costs.

RESPONSE

Firm gas transportation costs were not included in the IRP modeling.

Witness: Thomas Haratym, CRA

DATA REQUEST

JI 2_20 Please refer to the Companies response to Joint Intervenors' Initial Request 1.51. Please provide the supporting workbook, with all formulas intact, used to develop the $18.9/kW interconnection cost.

RESPONSE

Please see KPCO R_JI 1_51_Attachment1.

Witness: Thomas Haratym, CRA

DATA REQUEST

JI 2_21 Please refer to Section 2.2.5 of the IRP. Please explain how the Company considers naturally-occurring energy efficiency in its load forecast.

RESPONSE

Naturally occurring energy efficiency is captured in the Company's residential and commercial energy models. Appliance, equipment and lighting efficiency trends are reflected in these models.

Witness: Glenn R. Newman

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DATA REQUEST

JI 2_22 Please refer to page 35 of the IRP where it states, "The saturation forecasts are based on EIA forecasts and analysis by Itron. The efficiency trends are based on DOE forecasts and Itron analysis."
a. Please explain what the analysis is that Itron performed.
b. Please explain which EIA and DOE forecasts were used.

RESPONSE

a. The Company does not participate in Itron's preparation of the Statistically Adjusted End-Use (SAE) Model. The Company understands that Itron uses Census region data from EIA and synthesizes it for the SAE Model spreadsheets. The Company refines the inputs in the model using, for example historical residential company specific appliance saturation data along with information from the SAE spreadsheets to create a company specific appliance saturation forecast. The SAE spreadsheets have a variety of items captured in the models, including efficiency trends, Where possible, the Company uses inputs tied to the Company's service area and not just the Census region.

b. The Company used the 2021 SAE model inputs which are tied to The EIA's 2021 Annual Energy Outlook.

Witness: Glenn R. Newman

DATA REQUEST

JI 2_23 Please refer to the workbook "KPCO_R_JI 1_42 attachment1".
a. Please explain the "Supplemental Eff. Adj. Savings (ENERGY)" calculated in rows 33 to 72 of the worksheet named "SEA".
b. Please confirm if the energy efficiency savings labeled as "Supplemental Eff. Adj. Savings (ENERGY)" as shown in worksheet "SEA" are the level of savings modeled in Aurora for each energy efficiency bundle.
c. Please explain how the Company developed the percentages calculated in columns X, Y, Z, and AA, in rows 4 to 24 of the worksheet named "SEA".
d. Please confirm if the Company modeled the cost of new energy efficiency bundles in Aurora based on the costs shown in the worksheet "Summary".
e. Please confirm if the line loss number is a marginal or average value.
f. Please provide the source of the line loss number.

RESPONSE

a. "Supplemental Efficiency Adjustment (SEA)" is included to align the projections of future energy efficiency potential with the embedded efficiency trends already included in the KPCo forecast. The SEA functions to net out incremental efficiency already embedded in the IRP load forecast.

b. The specific Aurora inputs for each bundle were developed from the KPCO_R_JI 1_42_attachment1 workbook by GDS Associates. The resulting level of savings modeled in Aurora for each energy efficiency bundle is shown in KPCO_R_JI_2_23_Attachment 1.

c. The Company's Statistically Adjusted End-Use (SAE) models capture energy efficiency trends that may also be reflected in potential Company sponsored DSM/EE programs. It is perceived that these DSM/EE programs will accelerate the adoption of naturally occurring energy efficiency gains. To avoid double counting these savings, the Company degrades the DSM/EE savings over the forecast horizon to properly account for the energy efficiency gains that are included in the SAE model. The Company developed the percentages to reflect the decaying nature of net to gross DSM program savings over time. These percentages are based on measured historical relationships.

d. The specific Aurora inputs for each bundle were developed from the KPCO R_JI 1_42_attachment1 workbook by GDS and Associates. The costs modeled in Aurora for each energy efficiency bundle is shown in KPCO_R_JI_2_23_Attachment 1.

e. The line loss number is an average value.

f. The line loss value was identified through a Loss Study report prepared for Kentucky Power by Management Applications Consulting, Inc.

Witness: Glenn R. Newman (subpart a,c,e,f)

Witness: Jeffrey R. Huber, GDS (subpart b, d)

Witness: Gregory J. Soller (subpart a)

DATA REQUEST

JI 2_24 Please confirm if the new resource costs modeled in Aurora are on a real or nominal basis.

RESPONSE

Costs were modeled in AURORA on a real basis.

Witness: Thomas Haratym, CRA

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DATA REQUEST

JI 2_25 Please explain how the topology was set up in Aurora for the Company's IRP modeling.

RESPONSE

For the purposes of the IRP, transmission interconnections between PJM AEP Zone and surrounding zones were included in the AURORA model.

Witness: Thomas Haratym, CRA

DATA REQUEST

JI 2_26 Please refer to the Company's response to Joint Intervenors' Initial Request 1.43(b). Please provide supporting documentation for the assumption that lithium-ion batteries have a project life of ten years.

RESPONSE

Please see EIA report "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies" (February 2020), section 18.2.

Witness: Thomas Haratym, CRA

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DATA REQUEST

JI 2_27 Please refer to page 138 of the IRP where it states that "While price paths are developed for the period 2022-2037, data from 2037 is singled out for the portfolio cost analysis as representative of the study period." Please explain why 2037 was singled out for the portfolio cost analysis period.

RESPONSE

The stochastic analysis is intended to capture long-term risks to the portfolio. The supply structure and output levels of the portfolio are broadly stable from 2030 onwards. 2037 is the final year of the analysis and represents a reasonable snapshot of the conditions during the latter part of the outlook horizon.

Witness: Thomas Haratym, CRA

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DATA REQUEST

JI 2_28 Please refer to Figures 62 and 63 on page 140 of the IRP. Please provide the supporting workbooks, with all formulas and links intact, used to develop Figures 62 and 63.

RESPONSE

Please see KPCO_R_JI_2_28_Attachment1.

Witness: Thomas Haratym, CRA

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DATA REQUEST

JI 2_29 Please refer to the workbook "KPCO_R JI_ 1 62 Atachment1", worksheet "Tax Credits" and page 93 of the IRP that references an ITC of 30%.
a. Please confirm that the ITC value reported in the column labeled "Safe Harbor ITC" is what was modeled for new resources in Aurora.
b. Please confirm that the PTC values reported in this worksheet are the values modeled in Aurora for new wind and solar resources.
c. Please explain how the Company treated the ITC for battery storage resources, i.e., if it was treated as a reduction to the capital cost or normalized over the project life.

RESPONSE

a. Confirmed - the ITC value reported in the column labeled "Safe Harbor ITC" is what was modeled for new resources in AURORA.

b. Confirmed - the PTC values reported in this worksheet are the values modeled in AURORA for new wind and solar resources.

c. The ITC for battery storage was treated as a reduction in capex, which itself is amortized over the life of the asset.

Witness: Thomas Haratym, CRA

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DATA REQUEST

JI 2_30 Please refer to the workbook "04-KPCO _R_KPCO _R_KPSC 1 8 Attachment1 ", worksheet "KPCO Obligation".
a. Please confirm if the peak modeled in Aurora is from the forecast labeled "KPCo Coincident Peak" or "KPCo Peak".
b. Please explain how the coincidence factors in rows 41, 42, and 43 were developed.

RESPONSE

a. The peak modeled in AURORA is from the forecast labeled "KPCo Coincident."

b. The coincidence factor row 41 was calculated from the Kentucky Power Peak Load shown beginning on row 29 with the Kentucky Power PJM Summer Coincident Peak Load shown beginning in row 16 in the referenced attachment.

Witness: Thomas Haratym, CRA

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DATA REQUEST

JI 2_31 Please refer to '05-KPCO_R_KPSC 1 8_Atachment2".
a. Please confirm that the Company used a capital recovery factor to translate the capital costs for all new supply side resources into the $/MW-week input field in Aurora.
i. If the Company did use a capital recovery factor, please provide the supporting workbook, with all formulas and links intact, used to develop the capital recovery factor.

RESPONSE

a. Confirmed.

b. Please see KPCO_R_JI_2_31_Attachment1.

Witness: Thomas Haratym, CRA

DATA REQUEST

JI 2_32 Please refer to "KPCO_R_KPSC_ 1 8 ConfidentiaIAttachment7" worksheet "E2 (financials) + Tables 15_ 16".
a. Please provide the version of this worksheet with all formulas and links intact, that show the development of the financial categories for each of the portfolios modeled in the IRP. The financial categories include Existing Depreciation, New Depreciation, Capital Charge, Fixed O&M, Fuel Costs, Emission Costs, Other VOM Costs, Market Purchases Costs, Sales Revenue, and Taxes.

RESPONSE

Please see KPCO_R_JI_2_32_Attachment1.

Witness: Thomas Haratym, CRA

DATA REQUEST

JI 2_33 Please refer to "12-KPCO_R_KPSC 1 8_Attachment9", worksheet "Natural Gas Prices". Please provide the cell references for the natural gas price forecast modeled in Aurora.

RESPONSE

The IRP Portfolios used the TCO natural gas price forecast.

Witness: Thomas Haratym, CRA

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DATA REQUEST

JI 2_34 Please refer to Section 5.7 on pages 110–11 of the IRP. Please provide the historical capacity market purchases that the Company has made over the past ten years.

RESPONSE

Beginning with PJM Delivery Year (DY) 2018/2019 the following purchases have occurred:

DY 22/23 (Post 12/7/22): 152.4 MWs
DY 23/24: 65.2 MWs
DY 24/25: 80.0 MWs
DY 25/26: 85.0 MWs

Witness: Brian K. West

DATA REQUEST

JI 2_35 Please refer to Section 8.2 on page 183 of the IRP where it states that initiating an All-Source Request for Proposal is one of the items in the Three-Year Action Plan. Please confirm if the Company is planning to conduct a stakeholder workshop and solicit stakeholder feedback on the RFP before it is released.

RESPONSE

The Company plans to issue an All-Source RFP in alignment with the 3-year action plan outlined in the IRP. Kentucky Power values the input of its stakeholders but, the Company has no current plans to conduct a stakeholder workshop prior to its issuance. Additionally, the RFP will be posted on the Company's website under "Business to Business" located at: https://www.kentuckypower.com/business/b2b/.

Witness: Brian K. West

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DATA REQUEST

JI 2_36 Please refer to Kentucky Power's response to Joint Intervenors' Initial Request 1.25, which states, "For purposes of the IRP, it is assumed that the Company has access to capacity markets to satisfy its PJM capacity obligations."
a. What do "capacity markets" include "for purposes of the IRP"?
b. As a FRR entity, does the Company have access to PJM's capacity market?

RESPONSE

a. The reference to "capacity markets" for the purposes of this IRP was intended to generally mean access to existing generation, planned generation and bilateral contracts across PJM.

b. As an FRR entity, the Company does not have specific access to PJM's RPM Capacity Market to purchase capacity but is able to secure capacity resources through direct bilateral contracts.

Witness: Gregory J. Soller

Haratym Verification Form.doc

DocVerify ID: CFC19961-C5A1-493F-B584-3CB6CD40EB50
Created: September 07, 2023 05:13:14 -8:00
Pages: 1
Remote Notary: Yes/ State: KY

E-Signature Summary

E-Signature 1: Tomasz Haratym (TH)
September 07, 2023 06:56:02 -8:00 [B6E0969F284C] [38.122.101.202]
THaratym@crai.com (Principal) (Personally Known)

E-Signature Notary: Marilyn Michelle Caldwell (MMC)
September 07, 2023 06:56:02 -8:00 [D37D679763F9] [167.239.221.101]
mmcaldwell@aep.com
I, Marilyn Michelle Caldwell, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Tomasz J. Haratym, being duly sworn, deposes and says he is the Associate Principal, for Charles River Associates, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Tomasz Haratym

Tomasz J. Haratym

Commonwealth of Kentucky)
) Case No. 2023-00092
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Tomasz J. Haratym, on September 7, 2023.

Notary Public

MARILYN MICHELLE CALDWELL
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
Commission # KYNP71841
My Commission Expires May 05, 2027

Notarial act performed by audio-visual communication

My Commission Expires May 5, 2027

Notary ID Number KYNP71841

VERIFICATION

The undersigned, Jeffrey R. Huber, being duly sworn, deposes and says he is the Principal, for GDS Associates, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Jeffrey R. Huber

State of Georgia)
)
County of Cobb)

Case No. 2023-00092

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Jeffrey R. Huber, on September 8, 2023

Notary Public

My Commission Expires January 8, 2027

Notary ID Number ______________

LISA D PARKER
Notary Public, Georgia
Bartow County
My Commission Expires
January 08, 2027

STATE OF GEORGIA NOTARY PUBLIC

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E-Signature Summary

E-Signature 1: Reid Newman (RN)
September 05, 2023 13:13:34 -8:00 [99AD28FB0DE7] [167.239.221.104]
rnewman@aep.com (Principal) (Personally Known)

E-Signature Notary: Marilyn Michelle Caldwell (MMC)
September 05, 2023 13:13:34 -8:00 [11793C1E05F8] [167.239.221.101]
mmcaldwell@aep.com
I, Marilyn Michelle Caldwell, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Glenn R. Newman, being duly sworn, deposes and says he is the Manager of Economic Forecasting for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Reid Newman

Glenn R. Newman

Commonwealth of Kentucky)
) Case No. 2023-00092
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Glenn R. Newman, on September 5, 2023.

Notary Public

MARILYN MICHELLE CALDWELL
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
Commission # KYNP71841
My Commission Expires May 05, 2027

Notarial act performed by audio-visual communication

My Commission Expires ______________

Notary ID Number ______________

Soller Verification Form.doc

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E-Signature Summary

E-Signature 1: Gregory J. Soller (GJS)
August 31, 2023 08:15:45 -8:00 [36816C35689F] [167.239.221.106]
gsoller@aep.com (Principal) (Personally Known)

E-Signature Notary: Marilyn Michelle Caldwell (MMC)
August 31, 2023 08:15:45-8:00 [C5DFC300B166] [167.239.221.101]
mmcaldwell@aep.com
I, Marilyn Michelle Caldwell, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Gregory J. Soller, being duly sworn, deposes and says he is the Resource Planning Manager for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Gregory J. Soller

Gregory J. Soller

Commonwealth of Kentucky)
) Case No. 2023-00092
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Gregory J. Soller, on August 31, 2023.

MARILYN MICHELLE CALDWELL
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
Commission # KYNP71841
My Commission Expires May 05, 2027

Notarial act performed by audio-visual communication

Notary Public

My Commission Expires May 5, 2027

Notary ID Number KYNP71841

VERIFICATION

The undersigned, Brian K. West, being duly sworn, deposes and says he is the Vice President, Regulatory & Finance for Kentucky Power, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Brian K. West

Commonwealth of Kentucky)
) Case No. 2023-00092
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Brian K. West, on August 31, 2023

Marilyn Michelle Caldwell
Notary Public

My Commission Expires May 5, 2027

Notary ID Number KYNP7841