COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company	)	
For Approval of A Certificate of Public Convenience	)	
And Necessity For Environmental Project	)	Case No. 2021-00004
Construction At The Mitchell Generating Station, An	)	
Amended Environmental Compliance Plan, And	)	
Revised Environmental Surcharge Tariff Sheets	)	

DIRECT TESTIMONY OF

MARK A. BECKER

ON BEHALF OF KENTUCKY POWER COMPANY

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I. INTRODUCTION AND BACKGROUND

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Mark A. Becker, and my business address is 212 East Sixth Street, Tulsa, Oklahoma.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the American Electric Power Service Corporation ("AEPSC") as a Managing Director of Resource Planning.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science degree in Electrical Engineering from the University of Arkansas in 1983. I have over 35 years of experience working for investor-owned and municipal electric utilities and energy trading companies. The majority of my experience, approximately 30 years, has been related to performing a utility's resource planning and operational analysis functions using the proprietary long-term resource optimization software models known as Strategist® and PLEXOS®.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY?

A. I am responsible for the coordination and performance of long-term generation resource planning studies using the PLEXOS® modeling software tool for Kentucky Power Company ("Kentucky Power" or the "Company") and the other regulated operating companies within American Electric Power Company, Inc. ("AEP"). The PLEXOS®

studies include the development of Integrated Resource Plans ("IRP") and the economic evaluation of generating unit disposition alternatives for AEP's regulated operating companies, including Kentucky Power. This includes ongoing evaluations of generating unit disposition alternatives as external factors change that could alter the companies' plans for those generating units going forward.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have filed written testimony or testified in regulatory proceedings on behalf of AEP regulated operating companies in Louisiana, Arkansas, Texas, and Oklahoma. In addition, I testified before this Commission in Kentucky Power Company's December 2011 Environmental Compliance Plan filing (Case No. 2011-00401) and filed Direct Testimony in support of Kentucky Power's application (Case No. 2012-00578) for a Certificate Of Public Convenience And Necessity for the partial transfer of AEP Ohio Power's interest in the Mitchell Generating Station ("Mitchell" or "Mitchell Plant") to Kentucky Power Company.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe an analysis I prepared and presented to the Company for consideration in its evaluation of the costs and benefits of making certain Coal Combustion Residual ("CCR") and Effluent Limitation Guideline ("ELG") compliance expenditures at the Mitchell Plant. The potential investment would enable Mitchell to continue to provide capacity and energy value to customers, and delay hundreds of millions of dollars of investments in replacement capacity, through 2040, Mitchell's currently planned retirement year. In addition, I evaluated a CCR Only compliance option, under which the Mitchell Plant must be retired at the end of 2028. Each of these two compliance options was evaluated under three difference fundamental pricing forecasts, for a total of six scenarios, as follows:

1) Case 1 (CCR and ELG) - Assumes that both of the CCR and ELG compliance expenditures, totaling $67 million, are made at Mitchell and it continues to operate until December 31, 2040, when replacement capacity is obtained. This compliance option was evaluated under three fundamental pricing scenarios: Base with Carbon, Base No Carbon, and Low No Carbon.

2) Case 2 (CCR Only) - Assumes that only the CCR compliance expenditures, totaling $18 million, are made at Mitchell and it continues to operate until December 31, 2028, when replacement capacity is obtained. This compliance option was also evaluated under the three fundamental pricing scenarios described above in Case 1.

Q. ARE YOU SPONSORING ANY SCHEDULES OR EXHIBITS IN THIS PROCEEDING?

A. I am sponsoring the following exhibits, which are attached to my testimony:

- Company Exhibit MAB-1 – Economic Analysis
- Company Exhibit MAB-2 – Capacity Plans

III. <u>ECONOMIC ANALYSIS SUMMARY</u>

Q. PLEASE DESCRIBE THE BASIC GOAL OF YOUR ANALYSIS.

A. The economic analysis is designed to help the Company answer the question of whether making the CCR and ELG compliance investments makes economic sense for customers. Planning decisions such as this will have long-term cost of service impacts, and thus should be evaluated based on the net present value ("NPV") of the cost and revenue impacts. The NPV effects of the compliance decision here largely rest on the incremental cost of CCR and ELG compliance, plus the future cost profile of Mitchell versus the next best option to replace it if it retires in 2028 without making certain compliance investments. The next best option in this context represents the lowest cost replacement resource, or combination of resources, which could be used to replace Mitchell. A 2028 retirement of either of the two units at Mitchell will create a need for replacement capacity to cover the Company's peak load obligations. Thus, this analysis necessarily requires an evaluation of other capacity options compared to continued operation of Mitchell.

Q. WHAT WERE THE RESULTS OF YOUR ANALYSES?

A. The NPV of the forecasted cost of service differences between Case 1 and Case 2 is summarized in Table 1, along with the cost of compliance provided to me by Company Witness Brian D. Sherrick. Amounts in Table 1 and throughout my testimony and exhibits represent the Company's 50 percent ownership share of both Mitchell units. Positive values in this table mean that Case 2 (CCR Only) is expected to result in slightly higher NPV of customer costs (i.e. more costly for customers), under both the Base No Carbon and Low No Carbon fundamental forecasts, than Case 1's CCR and ELG analysis. Negative values suggest a CCR Only strategy will be less costly for customers under the Base With Carbon fundamental forecast.

Table 1 - Incremental Cost of 2028 Retirement

Kentucky Power Company's Half of Mitchell				NPV of Customer Revenue Requirement Increase / (Savings) Versus Case 1 ($ Millions)		
Case Number	Case Description	Retirement Year	Compliance Capital Cost ($ million)	Base With Carbon	Base No Carbon	Low No Carbon
Case 1	Mitchell CCR and ELG	2040	67			
Case 2	Mitchell CCR Only	2028	18	(6)	27	20

The NPV amounts in Table 1 represent a difference between cases of less than 1% of the total NPV of Kentucky Power's expected total energy production cost of service, which is expected to be between $3.5 and $4.3 billion (depending on the case) over the entire study period. Total study period NPV's are shown in my Exhibit MAB-1. Under the base case scenario, which includes a carbon tax, the Case 1 (CCR Only) alternative is slightly less expensive ($6 million) for customers. Under the other two scenarios which exclude a carbon tax, a CCR-only strategy and 2028 retirement are estimated to be slightly more expensive for customers ($20 to $27 million) on an NPV basis than running the Mitchell Plant through 2040.

Q. WHAT ARE THE MAIN DRIVERS OF THE ANALYSIS?

A. There are three main drivers. The first key driver in this economic analysis is the future Mitchell capital and operating cost, inclusive of the CCR and ELG compliance cost, net of the energy value of continuing to operate the units. Amounts already invested in the plant as of the time of this filing are considered sunk costs and are not included in my analysis. The second key driver is the initial capital cost, future operating costs or purchased power cost, net of energy value of resources which would be needed to replace Mitchell if it were to retire in either 2040 (Case 1) or 2028 (Case 2). The third key driver is the forecast of power and fuel prices, including how those are influenced by possible future carbon regulations.

Q. COULD YOU PLEASE PROVIDE A HIGH LEVEL DESCRIPTION OF YOUR ANALYSIS?

A. The methodology used in the analysis was the same process the Company typically employs in planning analyses. A few changes in assumptions were required in order to provide an answer to the question at hand in this proceeding, which is focused on the economic impacts of a 2028 retirement of Mitchell if ELG compliance investments are not made.

To summarize the major pieces of the analysis, the first step was to prepare a forecast of the Company's load requirements and available generation resources, known as a Capability, Load, and Reserve ("CLR") analysis. This was prepared with and without Mitchell to determine the need for generating resources to meet customers' peak demand requirements, including satisfying the PJM Interconnection LLC ("PJM") minimum capacity reserve margin requirement.

The second step was to forecast the incremental future capital requirements and fixed and variable operating costs for Mitchell (with and without compliance costs), the balance of the Company's generation resources, along with a wide range of resource options which could be considered to replace them when they retire.

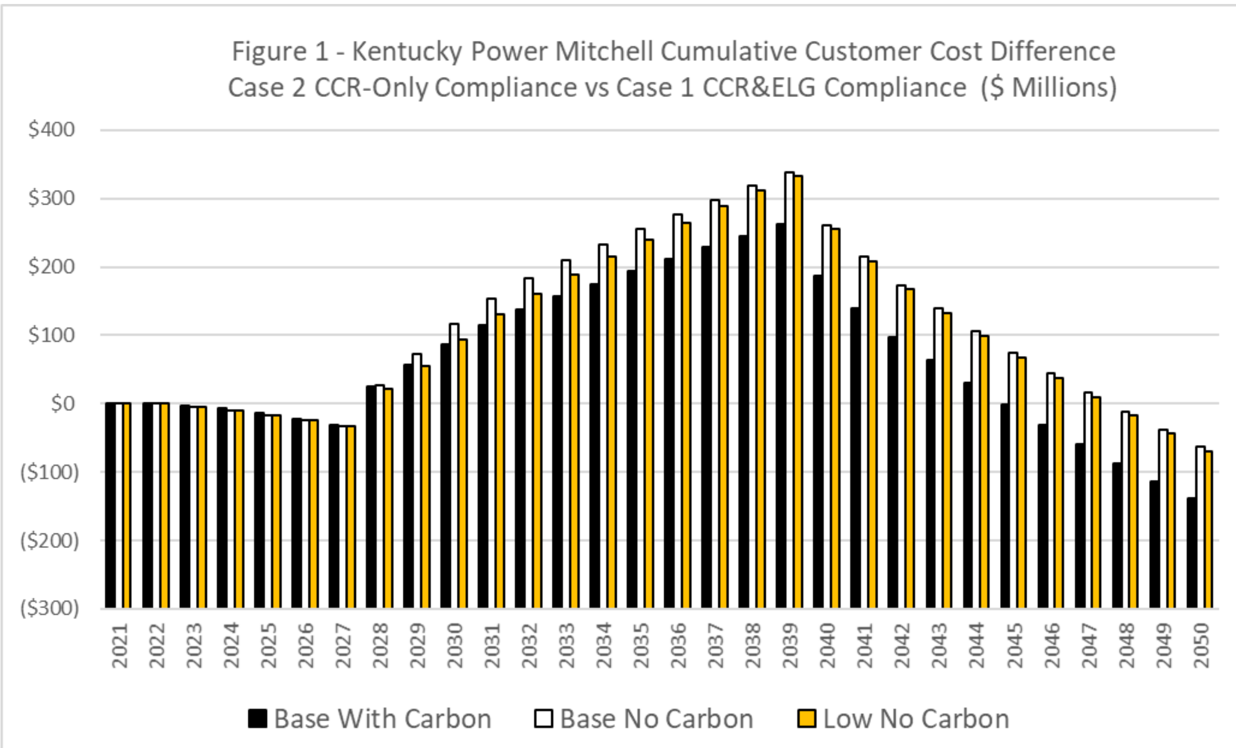
The third step was to use the PLEXOS® model to select optimal resources needed to serve load with and without Mitchell at the lowest cost. The model forecasts the generation output and energy value based on an economic dispatch, and nets that value against the fixed costs of each resource option under multiple commodity price scenarios.

Q. WHAT DO YOU EXPECT THE ANNUAL FINANCIAL IMPACTS OF A 2028 RETIREMENT WILL BE OVER THE FORECAST PERIOD?

A. This is illustrated below in Figure 1. That graph depicts the cumulative nominal difference in net customer costs in millions of dollars through 2050, whereby the annual cost difference in each year is added to the prior year's cumulative total impact moving from left to right across the graph. This view is shown for all three fundamental forecast cases.

The three bars are relatively close to each other, which indicates that the analysis is not very sensitive to the differences in fundamental forecast assumptions.

The size of each bar on Figure 1 represents the cumulative difference between Case 2, which is a CCR Only 2028 retirement case, and Case 1, which represents a CCR and ELG compliance case with a 2040 retirement. Bars below zero represent a cumulative net savings to customers. Bars above zero represent a cumulative net cost to customers.



If the Company were to incur only the CCR compliance cost and retire Mitchell in 2028, customers would initially see a savings through 2027 versus the Case 2 CCR and ELG compliance option. This is largely because the capital investment for ELG compliance would not be incurred. In addition, the Company has assumed in this analysis that other maintenance capital and landfill capital expense could be reduced in the 2023-2028 period immediately prior to retirement, creating customer savings.

Q. WOULD THE INITIAL SAVINGS UNDER CASE 2 (CCR ONLY) CHANGE WITH THE REQUIRED RETIREMENT OF MITCHELL BEGINNING IN 2028?

A. Yes. The period between 2028 and 2039 is the critical period when the customer costs would increase because of the need to replace the Mitchell capacity due to its retirement. Without Mitchell, customers will incur approximately $500 million of replacement capacity costs in 2028 that would be delayed by making investments to comply with the ELG Rule. Notably, the cumulative impact switches from a net savings to a net cost in the year Mitchell would be retired (2028) due to the cost of replacement resources.

Each of the years 2028 through 2039 would result in large net costs to customers under Case 2 where only the CCR compliance investments made. In Figure 1, the cumulative net cost of Case 2 (CCR Only) grows to between $263 million and $338 million by 2039. It is these years that drive the NPV of a compliance decision. Then, beginning in 2040, the cumulative net cost of Case 2 (CCR Only) begins to decline. This is because additional investments for new resources would be needed if Mitchell retires in 2040. Beginning in 2040, the cost of those new resources begins to appear in the cost of service in Case 1, reducing the difference between Case 1 (CCR and ELG) and Case 2 (CCR Only). The cumulative impact of Case 2 (CCR Only) versus Case 1 (CCR and ELG) flips from a net cost to a net savings to customers between 2046 and 2048, depending on the fundamentals case. The cumulative net savings under Case 2 (CCR Only) reaches between $62 million and $139 million by 2050.

IV. CAPACITY, LOAD, AND RESOURCE ("CLR") ANALYSIS

Q. PLEASE DESCRIBE THE CLR ANALYSIS.

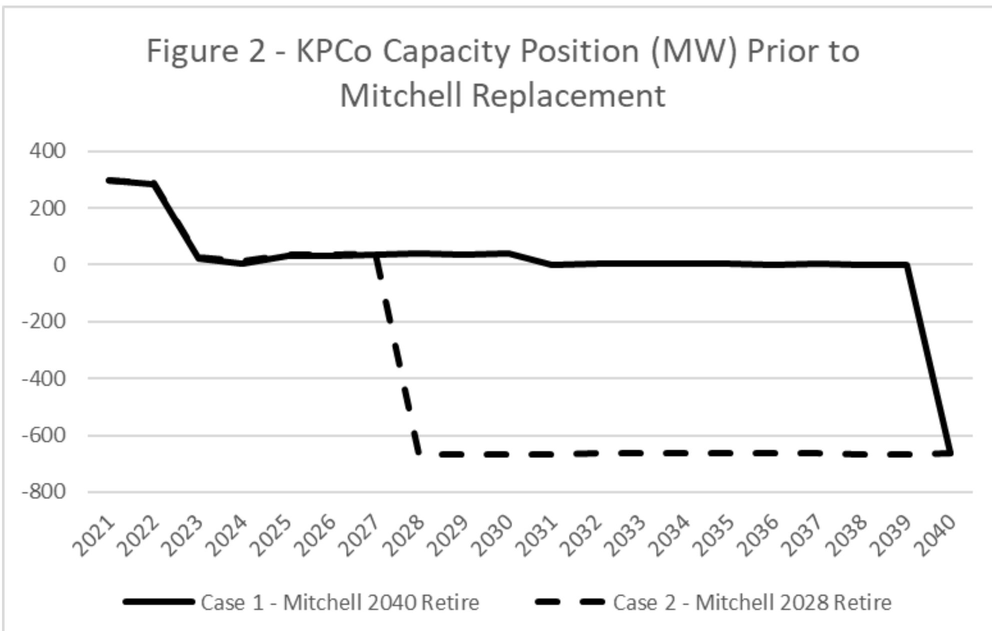
A. The first step in the CLR analysis is to determine how many megawatts of replacement capacity would be needed, and when, if Mitchell retires. This involves forecasting load and resources in order to determine the amount of capacity that will be needed to meet PJM's minimum reserve margin requirement.

Q. WHAT IS PJM'S MINIMUM RESERVE MARGIN REQUIREMENT?

A. This requirement can be described in two ways. The requirement is forecasted to be 14.9% on an installed capacity ("ICAP") or nameplate basis, or 8.6% on an unforced capacity ("UCAP") basis. The difference between ICAP and UCAP is the downward adjustment that PJM makes for an assumed forced outage rate to get to UCAP. For modeling purposes, all capacity must be converted from nameplate megawatts into UCAP megawatts, applying an assumed forced outage rate and other reductions in credited capacity as determined by PJM, which I will discuss later in my testimony. A utility must maintain reserve capacity (Capacity – Peak Load) of at least 8.6% of UCAP above its peak load, based on the most recent PJM capacity auction. For example, if a utility has a capacity of 1,086 UCAP megawatts (MW) and a peak load of 1,000 MW, then its reserve margin would be 8.6% ((1,086 -1,000)/1,000). The CLR analysis solves for the optimal lowest-cost plans to maintain that level of reserve margin.

Q. PLEASE DISCUSS THE INITIAL CLR CAPACITY POSITIONS FOR THE SCENARIOS YOU PREPARED.

A. The initial CLRs are reflective of the Company's UCAP capacity position prior to the addition of new capacity resources to satisfy the PJM minimum reserve requirement. The capacity position refers to the number of megawatts above or below the PJM minimum reserve requirement (calculated on an UCAP basis) described above. Figure 2 provides Kentucky Power's projected capacity positions under assumed 2028 and 2040 retirements. Once the Company's Rockport unit power agreement ends in 2022, Kentucky Power's capacity is roughly equal to the load requirement plus its required reserve margin. This drops to a roughly 700 MW short position when Mitchell retires in either case. This analysis demonstrates that Mitchell could not be retired without being replaced.



V. <u>MODELING PROCESS AND MAJOR ASSUMPTIONS</u>

Q. PLEASE DESCRIBE YOUR MODELING PROCESS.

A. The PLEXOS® model uses linear programming to produce optimal resource plans for a given set of inputs, such as market energy prices and operating and capital costs of each available resource. The optimal plan is defined as the group of resources which produces the lowest NPV of customer costs net of revenues over the forecast window. The

PLEXOS® model was used to produce simulations of the hourly economic dispatch of the Company's existing generating resources through their assumed retirement dates, and a suite of available new resource options through 2050 in the PJM energy market, to determine each of the scenarios' annual variable energy production revenues and costs. This planning tool is intended to produce a view of what plausible least-cost resource plans could look like under a given set of assumptions. Actual future resource additions could differ based on market conditions and resource availability at the time.

Q. WHAT ARE THE VARIABLE AND FIXED CHARGES CONSIDERED IN CONNECTION WITH THE MODELING?

A. Variable energy production costs include fuel costs, variable operations and maintenance ("O&M") costs, emission costs, if any, and emission retrofit reagent costs. In addition to variable energy production revenues and costs, the fixed costs for each existing and new resource option were calculated. Fixed costs for all resources included annual fixed O&M costs and recovery of levelized carrying charges on future on-going capital expenditures, including the CCR and ELG capital expenditures. The current capital investment in Mitchell is a sunk cost which is assumed to be recovered from customers equally in all scenarios. The current capital investment in Mitchell thus was excluded from the analysis.

Levelized fixed charge rates, which include a return on capital investment, income and property taxes, and depreciation, were applied to the CCR and ELG capital and all future capital expenses by PLEXOS® for computational efficiency. These levelized rates produce the same NPV of carrying costs over the lifetime of an investment as would carrying charges based on a forecast of rate base declining with depreciation over time.

Q. WHAT DO THE ANNUAL NET COST FOR EACH OF THE TWO CASES REPRESENT?

A. The annual net cost for each of the scenarios was created by netting the annual variable and fixed costs for Mitchell, the Company's other generating resources, and the new resource additions against the annual revenues that those resources would receive from making energy sales into the PJM energy market. The NPV of the annual net costs was calculated for each CCR and ELG compliance scenario and used as a basis to compare the economics of those scenarios.

Q. PLEASE DESCRIBE THE CCR AND ELG COMPLIANCE COST USED IN THE TWO CASES.

A. Table 2 provides a summary of the Case 1 (CCR and ELG) and Case 2 (CCR Only) compliance costs provided to me by Company Witness Sherrick for use in the analysis.

TABLE 2 - Kentucky Power's half of Mitchell CCR and ELG Compliance Investment Costs

		Compliance Cost ($ Millions)
Case 1 (CCR and ELG) (2040 Retirement)	Capital	$66
	ARO	$1
	Total	**$67**
Case 2 (CCR Only) (2028 Retirement)	Capital	$13
	ARO	$5
	Total	**$18**

Q. WHAT ASSUMPTIONS DID YOU MAKE ABOUT FUTURE INCREMENTAL CAPITAL COSTS AT MITCHELL?

A. In Case 1 (CCR and ELG), where the Mitchell Plant is assumed to operate through 2040, the CCR and ELG compliance capital plus 100% of the ongoing capital expense forecasts were included through 2035. From 2036 until 2040 a "glide path" capital expense forecast was used where maintenance capital is reduced during those years as the 2040 retirement date approaches. For the Case 2 (CCR Only) compliance scenarios (2028 retirement), only the CCR compliance costs were included, plus a glide path reduced capital expense forecast for the ongoing maintenance capital between 2023 and 2028. In addition, the ongoing landfill expansion capital, which would be required to operate beyond 2028, was eliminated entirely.

Q. WHAT ASSUMPTIONS DID YOU MAKE REGARDING THE FUTURE OPERATIONS AND MAINTENANCE COSTS AT MITCHELL?

A. The Company assumed that the currently forecasted level of O&M through 2029 was used in all cases. In years after that, in the 2040 retirement case (Case 1), O&M was maintained at that level. This assumption will likely produce higher than actual costs in light of the reduced capacity factors that the economic dispatch model predicts could happen if power prices and fuel costs turn out as they have been forecasted. Also, it is very likely that less maintenance, waste disposal, and other costs would be required if the units run at those reduced capacity factors. That potential upside for customers during the 2029-2040 period has not been included in this analysis. Lower O&M consistent with operations primarily as a capacity resource out in the 2030's would make the economics of Case 1 (CCR and ELG) less expensive for customers than shown in Figure 1.

VI. REPLACEMENT RESOURCES

Q. WHAT RESOURCES WERE AVAILABLE FOR THE MODEL TO SELECT TO REPLACE MITCHELL UPON ITS RETIREMENT IN EITHER CASE 1 OR CASE 2?

A. For this analysis the Company elected to adopt the U.S. Energy Information Administration's ("EIA") major utility scale options as the primary options available in PLEXOS® to pick from in forming optimal resource plans. These primary options are summarized in Table 3.[1] Supply-side resource options including natural gas base/intermediate and peaking generating technologies and intermittent renewable resources including large-scale solar, wind and battery storage were considered in this plan. In addition, a range of demand-side load reduction options not shown in Table 3 were also considered.

TABLE 3

Type	Capability (MW) (e) Std. ISO	Summer	Winter	Installed Cost (d,f) ($/kW)	Capacity Factor (%)	LCOE (g) ($/MWh)
Base Load						
SMALL MODULAR REACTOR NUCLEAR POWER PLANT, 600 MW	600	580	630	7,700	90	135.9
ULTRA-SUPERCRITICAL COAL WITH 90% CO2 CAPTURE, 650 MW	650	630	690	6,700	75	174.5
COMB TURBINE H CLASS, COMB-CYCLE SINGLE SHAFT W/90% CO2 CAPTURE, 430 MW	370	370	390	1,400	75	94.1
COMB TURBINE H CLASS, 1100-MW COMBINED CYCLE	1,080	1,060	1,110	1,100	75	52.6
COMB TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT, 430 MW	420	410	430	1,300	75	59.5
Peaking						
COMB TURBINE F CLASS, 240-MW SIMPLE CYCLE	230	240	250	700	25	92.4
COMB TURBINES AERODERIVATIVE, 100-MW SIMPLE CYCLE	100	110	110	1,200	25	118.9
INTERNAL COMBUSTION ENGINES, 20 MW	20	20	20	2,000	25	167.3
Intermittent						
BATTERY ENERGY STORAGE SYSTEM, 50 MW / 200 MWH	50	50	50	1,471	25	119.1
ONSHORE WIND, LARGE PLANT FOOTPRINT, 200 MW(2024 Inst. Cost)	200	200	200	1,317	35	41.4
SOLAR PHOTOVOLTAIC, 150 MW AC (2021 Inst. Cost)	150	150	150	1,195	25	56.0

[1] The Company referred to the EIA ANNUAL ENERGY OUTLOOK 2020 report (https://www.eia.gov/outlooks/aeo/pdf/aeo2020.pdf) and the associated EIA Capital Cost and Performance Characteristic Estimate for Utility Scale Electric Power Generating Technologies (https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf) to inform the analysis process.

To reduce the computational problem size within PLEXOS®, the number of alternatives explicitly modeled was reduced through an economic screening process which analyzed various supply options and developed a quantitative comparison on a 40 year levelized basis. For example, new coal and nuclear units were not considered as resource options for the purposes of the Company's modeling due to their relatively high capital costs. However, it is important to note that alternative technologies with comparable cost and performance characteristics may ultimately be substituted should technological or market-based profile changes warrant.

Also, when available, the Company may take advantage of economic market capacity and energy opportunities. Prospectively, these opportunities could take the place of currently planned resources and will be evaluated on a case-by-case basis pursuant to through requests for proposals (RFPs). Other technologies included in the EIA report were not included in the modeling due to their respective costs and to improve modeling process time.

Q. DID THE COMPANY MODEL THE USE OF POWER PURCHASE AGREEMENTS ("PPA") TO REPLACE SOME OR ALL OF THE MITCHELL CAPACITY?

A. Yes. While the Company sees considerable risk in relying on a significant level of a series of one-year PPAs in long-term resource planning, the model was also given a one year capacity-only PPA option to pick from. This option was made available to test if energy market prices in the three fundamental forecast scenarios were at a low enough level which would suggest a capacity-only PPA could economically replace resources which provide both energy and capacity. The assumed capacity price for the PPA was based on a forecast of the PJM capacity market price in each of the three cases. Those prices are described in the testimony of Company Witness Trecazzi. This price was used based on the reasonable assumption that the owner of any available capacity resource would not rationally accept less than that price in exchange for committing that capacity in a bilateral contract, rather than bidding it into the annual capacity auction that is available to PJM market participants.

The single-year capacity-only PPA option was capped at 400 MW. The cap was appropriate given the significant uncertainty regarding the availability of capacity. Such a resource would have to be a resource that had not already been committed elsewhere. In addition, the owner of the resource must be willing to execute short-term deals with a price and other terms and conditions acceptable to both parties. This short-term option would not entitle the Company to any energy, and thus would increase exposure to the PJM energy market price risk, versus the market hedge that comes with owning an actual physical resource or contracting for both capacity and energy. Prudent long-term planning should not include reliance on this type of short-term resource for anything but a contract to cover a small portion of total capacity requirements, because of the uncertainty and risk that comes with it.

Q. WHAT TECHNOLOGIES WERE SELECTED BY THE MODEL TO REPLACE MITCHELL IF IT WERE TO RETIRE?

A. The nameplate capacity of the major additions selected by the model as replacements for Mitchell if it were to retire in 2040 (Case 1) are summarized below in the top half of Table 4. These amounts also include replacements for Big Sandy 1, which is assumed to retire and be replaced in 2030. The resources selected in the 2028 retirement case (Case 2) in the bottom half of Table 4, are smaller because they only include Mitchell replacements.

Exhibit MAB-2 shows the modeled optimal capacity resource plans on a UCAP basis for Case 1 and Case 2 by year for the three fundamental pricing scenarios, including the resources shown in Table 4.

TABLE 4 - KPCo Optimal Major Replacement Capacity Additions Through the Retirement Year - Nameplate Megawatts

	Gas Combustion Turbines	Cumulative Solar	Cumulative Wind	Capacity Only PPA	**Total**
Case 1 - Mitchell CCR&ELG 2040 Retirement (Resource Additions from 2021-2040) *					
Base with Carbon	480	450	400	300	**1,630**
Base No Carbon	480	300	-	400	**1,180**
Low No Carbon	480	300		400	**1,180**
Case 2 - Mitchell CCR Only 2028 Retirement (Resource additions from 2021-2028) *					
Base with Carbon	480		400	150	**1,030**
Base No Carbon	480			200	**680**
Low No Carbon	480			200	**680**

* Case 1 additions through 2040 include replacements for both Mitchell and Big Sandy 1. Big Sandy 1 is assumed to retire in 2030. Case 2 additions through 2028 only include replacements for Mitchell.

Resource selection is heavily driven by the amount of credit each type of resource is given towards a capacity obligation vis-a-vis other options. I will discuss this further later in my testimony. Table 4 represents which replacement resources would be expected to produce the lowest overall costs, if the assumptions embedded in the scenarios (such as power and gas prices) turn out as they have been forecasted.

Q. CAN YOU PROVIDE FURTHER DETAIL REGARDING THE RESOURCE SELECTIONS?

A. The attributes of the gas combustion turbines ("CT"), PPA, solar, and wind resources that were modeled are:

1. CTs were picked to provide the majority of the 2028 replacement resource. The 480 MW CT which the model selected is expected to cost $445 million.
2. Either 150 or 200 MW of short-term capacity-only PPAs were selected in the three 2028 retirement scenarios. The fact that less than the full 400 MW of PPA available to the model was selected indicates that resources which also provide energy are preferable in those scenarios, given the energy and capacity price forecasts. PPAs totaling 300 MW or 400 MW were selected in the 2040 retirement cases. The additional PPA capacity was selected in part to replace Big Sandy 1.
3. 450 MW of solar assets were selected in all cases, although additions would not be expected to be added economically until after 2028. The model first selected solar in 2030 when Big Sandy 1 is forecasted to retire. Per Table 3 above, EIA expects each 150 MW block of solar would cost $1,195/KW (or $213 million) if built today. EIA expects the cost of solar to decline significantly between now and 2028, and this decline was incorporated into the modeling. Other resource types also are expected to be less costly capacity during that timeframe.
4. Wind was added in these optimal plans only when a carbon burden was included. Power prices are higher in those cases, making wind an economically attractive option when combined with production tax credits expected to be available through 2025.

Q. WHY DID THE MODEL SELECT GAS COMBUSTION TURBINES AS THE PRIMARY REPLACEMENT CAPACITY OPTION?

A. At the low level of market energy prices contained in these forecasts, energy available from the PJM market is inexpensive, and thus the model did not pick resources with higher capital costs such as combined cycle gas units, which are more efficient and would be anticipated to generate significant amounts of energy as well as capacity. In addition, renewable resources are less valuable when market prices are low. As a result, the model solved for the lowest overall cost by picking the least expensive capacity options available. These plans would result in very heavy reliance on the PJM energy market for the energy needed to serve customers.

Capacity affordability is driven by both the up-front installation cost (as shown above in Table 3) and the credit as a percentage of nameplate capacity each type of resource will receive in PJM's capacity market construct. I have illustrated the combination of these two factors below in Table 5. Solar and wind resources receive a much smaller fraction of their nameplate capacity value as a credit than Mitchell or a gas CT receives. The percentage of nameplate capacity accorded wind and solar resources will decline over time if the amounts of those technologies installed grows substantially as has been predicted, and if PJM's proposed Effective Load Carrying Capability ("ELCC") methodology is approved by FERC. PJM's latest projection available when this analysis was performed would result in a 12% credit for wind and 40% credit for Solar in 2028 when capacity would be needed. The Company would get much more value for an investment in natural gas units when viewed on a firm capacity basis because of the high capacity credit gas receives versus the other options.

Table 5 - Firm Capacity Cost Comparison

Capacity Investment Alternatives - Projected to 2028 in-service date	Nameplate Capacity MW	2028 PJM Firm Capacity Credit %	2028 PJM Firm Capacity MW	Projected 2028 Capital Investment ($ Millions)
Natural Gas CT Capacity - $900/KW	703	95%	668	$633
Unsubsidized Solar Capacity - No ITC $1,000/KW	1,670	40%	668	$1,670
Subsidized Solar Capacity - 30% ITC $700/KW	1,670	40%	668	$1,169
Wind Capacity - $1,200/KW	5,567	12%	668	$6,680

VII. TRANSMISSION IMPACTS

Q. WOULD RETIRING MITCHELL CREATE VOLTAGE OR THERMAL ISSUES WITH THE TRANSMISSION SYSTEM?

A. Yes. AEP's Transmission Planning group evaluated this issue and determined that Mitchell could not be retired without substantial investments in the high voltage transmission system, although the amount is somewhat dependent on if and when other

AEP plants retire. The Amos and Mountaineer plants owned by AEP affiliate Appalachian Power Company ("APCo") are also subject to CCR and ELG compliance requirements, and similar CCR/ELG proceedings to this one are currently underway in West Virginia and Virginia for those two plants. Amos serves an especially critical role in maintaining stability near the center of AEP's 765 kV transmission grid, as well as interconnections with portions of the grid owned by neighboring utilities. The West Virginia proceeding also includes Mitchell, which is co-owned between Kentucky Power and AEP Affiliate Wheeling Power Company ("WPCo").

If either Amos or Mitchell retire in 2028, with the other plant still operating, the Company estimates that $100 million of transmission upgrades would be required. If Amos and Mitchell both retire in 2028, AEP estimates that an additional $100 million of transmission upgrades would be required, for a total of $200 million. No additional transmission upgrades would be anticipated beyond those needed for the Mitchell and Amos retirements if Mountaineer also retires in 2028.

AEP estimates that roughly half of these investments would be required in the AEP zone within PJM and half in the Allegheny zone, which leaves AEP's share of the transmission upgrades at $50 million if the ELG compliance investments are not made at Mitchell and it retires in 2028. Some of this would be spent in Ohio by Ohio Power Company and some in West Virginia by a combination of APCo and WPCo. Transmission costs such as these are allocated across all of the AEP East system companies under a cost sharing agreement.

For the purposes of this analysis, I assumed that Kentucky Power would be allocated 4.9% of the $50 million AEP zonal share of the transmission investment required if Mitchell retires in 2028, based on its load ratio share of the AEP Zonal peak load in 2019. This amounts to $2.5 million for Kentucky Power. A 50-year levelized carrying charge was applied to that amount and the resulting annual cost of $242,000 was included in the Kentucky Power CCR only (Case 2) scenarios for each company beginning in 2028.

Predicting transmission impacts assuming these plants retire in 2040 is difficult. Power flows on the grid could change significantly between 2028 and 2040 due to plant retirements, load changes, new generation resources, and new transmission to serve them. Despite these uncertainties, in this analysis the Company assumed the same level of investment required in 2028 would also be required in 2040. Effectively, this means that similar to delaying the replacement generation requirement by 12 years, the CCR and ELG compliance investments will also delay the transmission investment.

Q. COULD THESE TRANSMISSION CONSTRAINTS BE ELIMINATED WITH REPLACEMENT RESOURCES?

A. Yes. Replacement gas-fired resources that are sited either on the sites of these plants, or located close by would eliminate the need for transmission investments that would be caused by retirements. Due to their intermittent nature, wind and solar resources would not eliminate the transmission impacts of plant retirements. Because of the transmission issues, location will necessarily be a consideration when evaluating economics of replacement assets. Assuming everything else is equal, replacement gas assets sited at these plant locations would have a cost advantage and be easier to bring online, versus resources located elsewhere.

Q. WHAT TRANSMISSION COSTS WERE INCLUDED IN THE COSTS OF REPLACEMENT RESOURCES IN THE CCR ONLY (CASE 2) SCENARIOS?

A. For the purposes of this analysis, the cost of replacement resources assumed only the minimal interconnection costs that EIA has incorporated in its new resource cost estimates. In addition, no congestion costs were assumed to be incurred by the wind resources, although additional congestion costs are a significant risk as wind continues to be added in the PJM region.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Kentucky Power Company
Mitchell CCR & ELG Analysis

		2020 Base with Carbon Commodity Price Forecast									
		NPV Revenue Requirements ($ Millions)					NPV of 2028 Retirement Net Cost/(Savings) versus Continued Operation Through 2040				
		2021-2027 Period	2028-2039 Period	2040-2050 Period	End-Effects Period	Total Study Period	2021-2027 Period	2028-2039 Period	2040-2050 Period	End-Effects Period	Total Study Period
Case 1	Mitchell CCR & ELG 2040 Retire	1,125	1,536	875	795	4,331	-		-	-	-
Case 2	Mitchell CCR Only 2028 Retire	1,104	1,667	795	759	4,325	(21)	130	(80)	(36)	(6)

		2020 Base without Carbon Commodity Price Forecast									
		NPV Revenue Requirements ($ Millions)					NPV of 2028 Retirement Net Cost/(Savings) versus Continued Operation Through 2040				
		2021-2027 Period	2028-2039 Period	2040-2050 Period	End-Effects Period	Total Study Period	2021-2027 Period	2028-2039 Period	2040-2050 Period	End-Effects Period	Total Study Period
Case 1	Mitchell CCR & ELG 2040 Retire	1,082	1,300	813	748	3,944	-		-	-	-
Case 2	Mitchell CCR Only 2028 Retire	1,059	1,466	734	712	3,971	(23)	165	(80)	(36)	27

		2020 Low Band without Carbon Commodity Price Forecast									
		NPV Revenue Requirements ($ Millions)					NPV of 2028 Retirement Net Cost/(Savings) versus Continued Operation Through 2040				
		2021-2027 Period	2028-2039 Period	2040-2050 Period	End-Effects Period	Total Study Period	2021-2027 Period	2028-2039 Period	2040-2050 Period	End-Effects Period	Total Study Period
Case 1	Mitchell CCR & ELG 2040 Retire	963	1,141	728	658	3,489	-		-	-	-
Case 2	Mitchell CCR Only 2028 Retire	940	1,299	648	622	3,509	(23)	158	(80)	(36)	20

KENTUCKY POWER COMPANY - CASE 1 CCR & ELG
2020 KP CCR /ELG ANALYSIS PLAN ASSUMING 12/31/2040 MITCHELL RETIREMENT OPTIMAL PLAN
Base With Carbon Commodity Pricing

	Utility Costs (Nominal$000)									
	(1) Load Cost - 100% of Load Purchased at PJM Market Energy Price	(2) Fuel Costs - New and Existing Resources	(3) Emission Costs - New and Existing Resources	(4) Mitchell Fixed O&M and Ongoing Capital Recovery	(5) Variable O&M (new and existing) + Fixed O&M and PPA Costs - New Resources	(6) Levelized Return, Taxes, and Depreciation - New Owned Resources	(7) Marginal Losses / Contracts	(8) Less: Market Energy Revenue - 100% of Generation sold at PJM Market Energy Price	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs	NPV (7.07%)
	$000	$000	$000	$000	$000	$000	$000	$000	$000	
2021	133,534	32,588	2,055	37,416	20,890	0	(2,487)	39,708	184,289	$172,120
2022	142,393	48,454	3,746	53,988	22,166	2,187	(2,655)	62,130	208,147	$353,686
2023	151,317	57,979	4,278	50,097	22,482	15,908	(2,827)	94,437	204,797	$520,534
2024	160,558	67,251	5,568	51,711	18,160	15,641	(3,004)	112,883	203,001	$674,998
2025	166,579	63,879	5,609	56,012	29,645	26,990	(3,110)	125,871	219,732	$831,152
2026	171,574	75,782	7,170	56,335	31,164	26,980	(3,200)	141,217	224,589	$980,219
2027	177,571	71,272	6,742	57,927	31,310	26,968	(3,309)	135,319	233,160	$1,124,757
2028	237,952	45,195	25,683	59,692	29,201	26,954	(4,450)	134,721	285,507	$1,290,057
2029	235,205	42,721	24,095	61,573	29,580	26,938	(4,394)	125,016	290,702	$1,447,252
2030	235,269	30,267	15,510	63,777	29,194	26,800	(4,399)	102,359	294,058	$1,595,762
2031	232,041	12,622	7,856	57,502	49,881	26,800	(4,336)	71,712	310,654	$1,742,293
2032	230,872	7,656	4,650	58,684	50,467	26,800	(4,307)	62,727	312,093	$1,879,783
2033	236,568	2,784	1,615	59,867	51,128	26,800	(4,412)	55,464	318,884	$2,010,988
2034	237,366	2,346	1,406	61,049	52,290	26,800	(4,419)	54,972	321,864	$2,134,675
2035	239,287	0	0	61,640	52,990	26,800	(4,454)	51,685	324,577	$2,251,168
2036	243,424	0	0	62,113	53,975	39,891	(4,533)	66,585	328,285	$2,361,212
2037	252,309	0	0	62,468	54,951	40,664	(4,699)	69,522	336,171	$2,466,459
2038	260,854	1,955	1,194	62,704	56,148	55,762	(4,858)	90,429	343,331	$2,566,849
2039	265,285	0	0	62,822	56,880	54,519	(4,940)	89,064	345,503	$2,661,204
2040	271,365	1,082	268	62,478	82,895	139,638	(5,053)	108,614	444,060	$2,774,466
2041	275,796	1,138	287	31,821	84,319	140,750	(5,140)	110,779	418,193	$2,874,088
2042	280,898	543	137	25,238	91,109	140,750	(5,233)	112,015	421,426	$2,967,850
2043	287,393	382	97	18,675	92,913	140,750	(5,355)	114,646	420,208	$3,055,168
2044	294,861	418	107	16,574	89,272	140,750	(5,489)	118,319	418,173	$3,136,326
2045	302,911	217	56	14,422	90,809	140,750	(5,639)	121,377	422,149	$3,212,845
2046	312,705	447	114	12,831	92,668	140,750	(5,832)	125,951	427,732	$3,285,257
2047	321,451	202	51	11,120	94,471	140,750	(5,990)	129,576	432,479	$3,353,638
2048	331,864	209	53	9,432	96,599	140,750	(6,189)	134,474	438,245	$3,418,355
2049	340,624	216	55	7,978	97,622	140,750	(6,348)	137,726	443,170	$3,479,478
2050	350,768	229	58	6,744	91,335	140,750	(6,535)	141,505	441,845	$3,536,394
Net Present Value $000 (2021$)										
Utility NPV 2021-2027	836,709	310,986	25,833	275,306	132,142	80,574	(15,614)	521,179	1,124,757	
Utility NPV 2028-2039	1,178,676	76,498	43,040	299,125	220,804	156,395	(21,989)	416,101	1,536,447	
Utility NPV 2040-2050	614,198	1,066	269	46,135	184,713	286,947	(11,444)	246,694	875,190	
NPV of End Effects beyond 2050									794,915	
TOTAL Utility Cost, Net NPV (2021$)									4,331,309	

KENTUCKY POWER COMPANY - CASE 2 CCR ONLY

2020 KP CCR/ELG ANALYSIS PLAN ASSUMING 12/31/28 MITCHELL RETIREMENT OPTIMAL PLAN

Base With Carbon Commodity Pricing

	Utility Costs (Nominal$000)									
	(1) Load Cost - 100% of Load Purchased at PJM Market Energy Price	(2) Fuel Costs - New and Existing Resources	(3) Emission Costs - New and Existing Resources	(4) Mitchell Fixed O&M and Ongoing Capital Recovery	(5) Variable O&M (new and existing) + Fixed O&M and PPA Costs - New Resources	(6) Levelized Return, Taxes, and Depreciation - New Owned Resources	(7) Marginal Losses / Contracts	(8) Less: Market Energy Revenue - 100% of Generation sold at PJM Market Energy Price	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs	NPV (7.07%)
	$000	$000	$000	$000	$000	$000	$000	$000	$000	
2021	133,534	32,588	2,055	37,526	20,890	0	(2,487)	39,708	184,399	$172,223
2022	142,393	48,454	3,746	53,781	22,166	3,905	(2,655)	62,400	209,388	$354,871
2023	151,317	57,979	4,278	45,426	22,482	17,571	(2,827)	94,965	201,261	$518,838
2024	160,558	67,251	5,568	46,170	18,160	17,646	(3,004)	113,727	198,621	$669,969
2025	166,579	63,879	5,609	49,494	29,645	26,990	(3,110)	126,656	212,428	$820,933
2026	171,574	75,782	7,170	48,948	31,164	26,980	(3,200)	141,924	216,495	$964,628
2027	177,571	71,272	6,742	49,412	31,310	27,454	(3,309)	135,999	224,452	$1,103,767
2028	237,952	57,803	28,442	50,139	47,529	81,194	(4,450)	157,886	340,724	$1,301,037
2029	235,205	21,843	4,907	25,026	45,287	81,398	(4,394)	86,630	322,641	$1,475,502
2030	235,269	20,734	4,854	26,037	46,239	80,381	(4,399)	85,177	323,938	$1,639,103
2031	232,041	8,272	2,034	14,167	71,385	93,317	(4,336)	78,274	338,605	$1,798,818
2032	230,872	5,490	1,350	8,191	72,234	93,317	(4,307)	72,515	334,631	$1,946,237
2033	236,568	4,237	1,025	6,347	73,313	93,317	(4,412)	72,185	338,211	$2,085,395
2034	237,366	3,115	748	5,344	74,655	93,317	(4,419)	69,521	340,605	$2,216,283
2035	239,287	2,239	547	4,662	75,755	93,317	(4,454)	68,509	342,844	$2,339,333
2036	243,424	1,271	311	4,334	77,237	107,159	(4,533)	82,875	346,329	$2,455,425
2037	252,309	1,190	290	4,155	78,540	108,099	(4,699)	85,978	353,906	$2,566,224
2038	260,854	1,487	363	4,155	80,088	122,023	(4,858)	104,645	359,467	$2,671,333
2039	265,285	594	146	4,155	81,207	122,023	(4,940)	105,223	363,247	$2,770,533
2040	271,365	1,082	268	3,570	83,163	122,023	(5,053)	109,087	367,331	$2,864,225
2041	275,796	1,138	287	3,365	84,319	122,023	(5,140)	110,743	371,045	$2,952,615
2042	280,898	543	137	2,825	91,109	122,023	(5,233)	111,996	380,305	$3,037,229
2043	287,393	382	97	2,571	92,913	122,023	(5,355)	114,638	385,386	$3,117,311
2044	294,861	418	107	2,362	89,272	122,023	(5,489)	118,317	385,236	$3,192,076
2045	302,911	217	56	1,869	90,809	122,023	(5,639)	121,377	390,869	$3,262,926
2046	312,705	447	114	1,474	92,668	122,023	(5,832)	125,951	397,648	$3,330,245
2047	321,451	202	51	1,071	94,471	122,023	(5,990)	129,576	403,703	$3,394,075
2048	331,864	209	53	662	96,599	122,023	(6,189)	134,474	410,748	$3,454,732
2049	340,624	216	55	242	97,622	122,023	(6,348)	137,726	416,707	$3,512,205
2050	350,768	229	58	242	91,335	122,023	(6,535)	141,505	416,615	$3,565,871
Net Present Value $000 (2021$)										
Utility NPV 2021-2027	836,709	310,986	25,833	252,393	132,142	85,255	(15,614)	523,936	1,103,767	
Utility NPV 2028-2039	1,178,676	67,209	24,372	77,445	322,969	463,261	(21,989)	445,176	1,666,766	
Utility NPV 2040-2050	614,198	1,066	269	4,253	184,781	249,014	(11,444)	246,800	795,338	
NPV of End Effects beyond 2050									759,000	
TOTAL Utility Cost, Net NPV (2021$)									4,324,871	

KENTUCKY POWER COMPANY - CASE 2 MINUS CASE 1
2020 KPCO CCR/ELG PLAN DIFFERENCE BETWEEN 12/31/28 MITCHELL RETIREMENT AND 12/31/40 MITCHELL RETIREMENT
Base with Carbon Commodity Pricing

Utility Costs (Nominal$000)

	(1) Load Cost - 100% of Load Purchased at PJM Market Energy Price	(2) Fuel Costs - New and Existing Resources	(3) Emission Costs - New and Existing Resources	(4) Mitchell Fixed O&M and Ongoing Capital Recovery	(5) Variable O&M (new and existing) + Fixed O&M and PPA Costs - New Resources	(6) Levelized Return, Taxes, and Depreciation - New Owned Resources	(7) Marginal Losses / Contracts	(8) Less: Market Energy Revenue - 100% of Generation sold at PJM Market Energy Price	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs	(10) - Sum of Column 9 Figure 1 Support - Cumulative Difference	NPV (7.07%)
	$000	$000	$000	$000	$000	$000	$000	$000	$000		
2021	0	0	0	110	0	0	0	0	110	110	103
2022	0	0	0	(207)	0	1,719	0	271	1,241	1,351	1,185
2023	0	0	0	(4,671)	0	1,663	0	528	(3,536)	(2,185)	(1,696)
2024	0	0	0	(5,541)	0	2,005	0	844	(4,380)	(6,566)	(5,029)
2025	0	0	0	(6,518)	0	0	0	785	(7,303)	(13,869)	(10,219)
2026	0	0	0	(7,387)	0	0	0	708	(8,094)	(21,964)	(15,592)
2027	0	0	0	(8,515)	0	487	0	680	(8,708)	(30,671)	(20,990)
2028	0	12,607	2,760	(9,553)	18,328	54,240	0	23,165	55,217	24,546	10,980
2029	0	(20,878)	(19,188)	(36,547)	15,707	54,460	0	(38,386)	31,939	56,485	28,251
2030	0	(9,532)	(10,657)	(37,740)	17,045	53,582	0	(17,182)	29,880	86,365	43,341
2031	0	(4,351)	(5,822)	(43,335)	21,504	66,517	0	6,562	27,952	114,317	56,525
2032	0	(2,165)	(3,300)	(50,493)	21,767	66,517	0	9,788	22,538	136,855	66,454
2033	0	1,453	(590)	(53,519)	22,186	66,517	0	16,721	19,327	156,182	74,406
2034	0	769	(658)	(55,705)	22,366	66,517	0	14,548	18,741	174,923	81,608
2035	0	2,239	547	(56,978)	22,765	66,517	0	16,823	18,267	193,190	88,165
2036	0	1,271	311	(57,779)	23,262	67,267	0	16,290	18,043	211,234	94,213
2037	0	1,190	290	(58,313)	23,589	67,435	0	16,455	17,735	228,969	99,765
2038	0	(468)	(831)	(58,549)	23,939	66,261	0	14,216	16,137	245,106	104,484
2039	0	594	146	(58,667)	24,327	67,504	0	16,159	17,744	262,850	109,330
2040	0	0	0	(58,909)	269	(17,615)	0	474	(76,729)	186,121	89,759
2041	0	0	0	(28,456)	0	(18,727)	0	(35)	(47,148)	138,974	78,528
2042	0	0	0	(22,413)	0	(18,727)	0	(20)	(41,121)	97,853	69,379
2043	0	0	0	(16,104)	0	(18,727)	0	(8)	(34,823)	63,030	62,143
2044	0	0	0	(14,213)	0	(18,727)	0	(2)	(32,938)	30,093	55,750
2045	0	0	0	(12,553)	0	(18,727)	0	0	(31,280)	(1,187)	50,080
2046	0	0	0	(11,357)	0	(18,727)	0	0	(30,084)	(31,271)	44,988
2047	0	0	0	(10,050)	0	(18,727)	0	0	(28,777)	(60,048)	40,438
2048	0	0	0	(8,770)	0	(18,727)	0	0	(27,497)	(87,545)	36,377
2049	0	0	0	(7,736)	0	(18,727)	0	0	(26,463)	(114,008)	32,727
2050	0	0	0	(6,503)	0	(18,727)	0	0	(25,230)	(139,237)	29,477
Net Present Value $000 (2021$)											
Utility NPV 2021-2027	0	0	0	(22,913)	0	4,681	0	2,757	(20,990)		
Utility NPV 2028-2039	0	(9,290)	(18,667)	(221,681)	102,165	306,866	0	29,075	130,319		
Utility NPV 2040-2050	0	0	(0)	(41,882)	69	(37,933)	0	106	(79,852)		
NPV of End Effects beyond 2050									(35,915)		
TOTAL Utility Cost, Net NPV (2021$)									(6,438)		

KENTUCKY POWER COMPANY - CASE 1 CCR & ELG
2020 KP CCR /ELG ANALYSIS PLAN ASSUMING 12/31/2040 MITCHELL RETIREMENT OPTIMAL PLAN
Base No Carbon Commodity Pricing

	Utility Costs (Nominal$000)									
	(1) Load Cost - 100% of Load Purchased at PJM Market Energy Price	(2) Fuel Costs - New and Existing Resources	(3) Emission Costs - New and Existing Resources	(4) Mitchell Fixed O&M and Ongoing Capital Recovery	(5) Variable O&M (new and existing) + Fixed O&M and PPA Costs - New Resources	(6) Levelized Return, Taxes, and Depreciation - New Owned Resources	(7) Marginal Losses / Contracts	(8) Less: Market Energy Revenue - 100% of Generation sold at PJM Market Energy Price	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs	NPV (7.07%)
	$000	$000	$000	$000	$000	$000	$000	$000	$000	
2021	133,999	33,606	2,118	37,416	20,967	0	(2,496)	41,259	184,350	$172,178
2022	142,032	49,926	3,843	53,988	22,298	4,860	(2,648)	63,099	211,199	$356,406
2023	150,413	54,300	3,891	50,097	8,342	6,877	(2,809)	75,865	195,246	$515,472
2024	159,225	65,400	5,436	51,711	6,641	8,327	(2,979)	96,121	197,640	$665,857
2025	164,055	60,861	5,361	56,012	6,221	1,812	(3,062)	89,068	202,192	$809,546
2026	170,432	74,469	7,148	56,335	7,565	1,737	(3,178)	106,328	208,180	$947,722
2027	178,464	72,480	6,881	57,927	7,511	850	(3,328)	103,742	217,042	$1,082,267
2028	185,133	81,326	7,790	59,692	8,223	836	(3,454)	115,206	224,340	$1,212,154
2029	186,160	75,011	6,938	61,573	7,748	821	(3,471)	103,119	231,661	$1,337,423
2030	186,913	61,223	5,383	63,777	6,761	682	(3,489)	83,930	237,319	$1,457,278
2031	182,448	25,800	2,408	57,502	29,609	682	(3,399)	34,780	260,269	$1,580,043
2032	183,320	18,536	1,669	58,684	29,610	682	(3,410)	24,668	264,422	$1,696,532
2033	188,489	10,911	931	59,867	29,789	682	(3,504)	14,462	272,702	$1,808,735
2034	193,301	14,423	1,245	61,049	30,940	682	(3,592)	18,499	279,550	$1,916,162
2035	197,417	11,197	947	61,640	31,266	682	(3,670)	14,337	285,142	$2,018,502
2036	200,338	9,305	784	62,113	32,111	682	(3,725)	12,064	289,543	$2,115,559
2037	207,770	16,121	1,359	62,468	33,125	682	(3,864)	20,148	297,512	$2,208,702
2038	215,600	21,959	1,858	62,704	34,479	682	(4,010)	27,512	305,759	$2,298,107
2039	218,083	19,252	1,615	62,822	34,452	13,879	(4,056)	36,160	309,888	$2,382,735
2040	223,779	28,912	2,245	62,478	60,906	98,997	(4,162)	61,015	412,140	$2,487,856
2041	228,324	3,922	0	31,821	60,144	98,997	(4,250)	31,996	386,962	$2,580,037
2042	233,241	2,418	0	25,238	61,269	98,997	(4,341)	30,699	386,125	$2,665,946
2043	238,247	2,250	0	18,675	62,643	98,997	(4,435)	31,277	385,101	$2,745,969
2044	242,630	1,230	0	16,574	63,660	98,997	(4,511)	30,717	387,863	$2,821,244
2045	250,659	1,684	0	14,422	65,031	98,997	(4,662)	32,451	393,681	$2,892,603
2046	259,069	2,184	0	12,831	66,583	98,997	(4,828)	34,182	400,654	$2,960,431
2047	266,627	1,030	0	11,120	67,318	111,911	(4,965)	48,983	404,058	$3,024,318
2048	276,034	1,779	0	9,432	69,106	111,911	(5,145)	51,740	411,377	$3,085,067
2049	283,733	1,373	0	7,978	69,804	111,911	(5,285)	52,871	416,642	$3,142,531
2050	291,144	1,392	0	6,744	63,161	111,911	(5,421)	52,943	415,988	$3,196,117
Net Present Value $000 (2021$)										
Utility NPV 2021-2027	833,079	306,547	25,457	275,306	64,980	19,145	(15,545)	426,702	1,082,267	
Utility NPV 2028-2039	946,559	172,797	15,725	299,125	115,369	7,114	(17,622)	238,598	1,300,468	
Utility NPV 2040-2050	508,808	11,022	573	46,135	130,538	209,419	(9,471)	83,642	813,381	
NPV of End Effects beyond 2050									747,805	
TOTAL Utility Cost, Net NPV (2021$)									3,943,921	

KENTUCKY POWER COMPANY - CASE 2 CCR ONLY
2020 KP CCR/ELG ANALYSIS PLAN ASSUMING 12/31/28 MITCHELL RETIREMENT OPTIMAL PLAN
Base No Carbon Commodity Pricing

	Utility Costs (Nominal$000)									
	(1) Load Cost - 100% of Load Purchased at PJM Market Energy Price	(2) Fuel Costs - New and Existing Resources	(3) Emission Costs - New and Existing Resources	(4) Mitchell Fixed O&M and Ongoing Capital Recovery	(5) Variable O&M (new and existing) + Fixed O&M and PPA Costs - New Resources	(6) Levelized Return, Taxes, and Depreciation - New Owned Resources	(7) Marginal Losses / Contracts	(8) Less: Market Energy Revenue - 100% of Generation sold at PJM Market Energy Price	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs	NPV (7.07%)
	$000	$000	$000	$000	$000	$000	$000	$000	$000	
2021	133,999	33,606	2,118	37,526	20,967	0	(2,496)	41,259	184,461	$172,280
2022	142,032	49,926	3,843	53,781	22,298	5,037	(2,648)	63,125	211,144	$356,460
2023	150,413	54,300	3,891	45,426	8,342	6,704	(2,809)	75,865	190,402	$511,580
2024	159,225	65,400	5,436	46,170	6,641	8,327	(2,979)	96,121	192,098	$657,748
2025	164,055	60,861	5,361	49,494	6,221	1,812	(3,062)	89,069	195,673	$796,805
2026	170,432	74,469	7,148	48,948	7,565	1,737	(3,178)	106,328	200,793	$930,078
2027	178,464	72,480	6,881	49,412	7,511	850	(3,328)	103,742	208,527	$1,059,345
2028	185,133	89,932	7,790	50,139	29,417	54,505	(3,454)	128,751	284,709	$1,224,184
2029	186,160	14,891	0	25,026	23,702	54,471	(3,471)	24,302	276,477	$1,373,686
2030	186,913	14,392	0	26,037	24,192	67,407	(3,489)	34,063	281,390	$1,515,798
2031	182,448	5,357	0	14,167	49,226	80,323	(3,399)	30,597	297,525	$1,656,137
2032	183,320	3,848	0	8,191	49,943	80,135	(3,410)	27,844	294,182	$1,785,736
2033	188,489	3,473	0	6,347	50,946	80,135	(3,504)	27,456	298,430	$1,908,526
2034	193,301	2,664	0	5,344	52,038	80,135	(3,592)	26,417	303,475	$2,025,146
2035	197,417	2,364	0	4,662	52,937	80,135	(3,670)	26,362	307,483	$2,135,504
2036	200,338	2,001	0	4,334	54,284	80,135	(3,725)	26,114	311,253	$2,239,839
2037	207,770	1,694	0	4,155	55,066	80,135	(3,864)	26,687	318,267	$2,339,480
2038	215,600	3,114	0	4,155	56,654	80,135	(4,010)	29,599	326,049	$2,434,817
2039	218,083	1,378	0	4,155	57,316	80,441	(4,056)	27,630	329,687	$2,524,853
2040	223,779	2,603	0	3,570	59,026	80,441	(4,162)	29,888	335,369	$2,610,392
2041	228,324	3,922	0	3,365	60,144	80,441	(4,250)	31,996	339,949	$2,691,374
2042	233,241	2,418	0	2,825	61,269	80,441	(4,341)	30,699	345,155	$2,768,167
2043	238,247	2,250	0	2,571	62,643	80,441	(4,435)	31,277	350,440	$2,840,988
2044	242,630	1,230	0	2,362	63,660	80,441	(4,511)	30,717	355,094	$2,909,903
2045	250,659	1,684	0	1,869	65,031	80,441	(4,662)	32,451	362,572	$2,975,624
2046	259,069	2,184	0	1,474	66,583	80,441	(4,828)	34,182	370,740	$3,038,387
2047	266,627	1,030	0	1,071	67,318	93,354	(4,965)	48,983	375,452	$3,097,751
2048	276,034	1,779	0	662	69,106	93,354	(5,145)	51,740	384,050	$3,154,465
2049	283,733	1,373	0	242	69,804	93,354	(5,285)	52,871	390,350	$3,208,303
2050	291,144	1,392	0	242	63,161	93,354	(5,421)	52,943	390,929	$3,258,660
Net Present Value $000 (2021$)										
Utility NPV 2021-2027	833,079	306,547	25,457	252,393	64,980	19,159	(15,545)	426,725	1,059,345	
Utility NPV 2028-2039	946,559	77,400	4,510	77,445	214,901	358,121	(17,622)	195,805	1,465,508	
Utility NPV 2040-2050	508,808	4,312	0	4,253	130,058	171,550	(9,471)	75,702	733,808	
NPV of End Effects beyond 2050									712,200	
TOTAL Utility Cost, Net NPV (2021$)									3,970,860	

KENTUCKY POWER COMPANY - CASE 2 MINUS CASE 1
2020 KPCO CCR/ELG PLAN DIFFERENCE BETWEEN 12/31/28 MITCHELL RETIREMENT AND 12/31/40 MITCHELL RETIREMENT
Base without Carbon Commodity Pricing

	Utility Costs (Nominal$000)										
	(1) Load Cost - 100% of Load Purchased at PJM Market Energy Price	(2) Fuel Costs - New and Existing Resources	(3) Emission Costs - New and Existing Resources	(4) Mitchell Fixed O&M and Ongoing Capital Recovery	(5) Variable O&M (new and existing) + Fixed O&M and PPA Costs - New Resources	(6) Levelized Return, Taxes, and Depreciation - New Owned Resources	(7) Marginal Losses / Contracts	(8) Less: Market Energy Revenue - 100% of Generation sold at PJM Market Energy Price	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs	(10) - Sum of Column 9 Figure 1 Support - Cumulative Difference	NPV (7.07%)
	$000	$000	$000	$000	$000	$000	$000	$000	$000		
2021	0	0	0	110	0	0	0	0	110	110	103
2022	0	0	0	(207)	0	177	0	25	(55)	55	55
2023	0	0	0	(4,671)	0	(173)	0	0	(4,844)	(4,789)	(3,892)
2024	0	0	0	(5,541)	0	0	0	0	(5,542)	(10,331)	(8,108)
2025	0	0	0	(6,518)	0	0	0	0	(6,519)	(16,850)	(12,741)
2026	0	0	0	(7,387)	0	0	0	0	(7,387)	(24,236)	(17,644)
2027	0	0	0	(8,515)	0	0	0	0	(8,515)	(32,751)	(22,922)
2028	0	8,606	0	(9,553)	21,193	53,669	0	13,546	60,369	27,617	12,029
2029	0	(60,120)	(6,938)	(36,547)	15,954	53,651	0	(78,817)	44,816	72,433	36,263
2030	0	(46,830)	(5,383)	(37,740)	17,431	66,725	0	(49,867)	44,070	116,503	58,520
2031	0	(20,442)	(2,408)	(43,335)	19,617	79,641	0	(4,182)	37,256	153,760	76,094
2032	0	(14,687)	(1,669)	(50,493)	20,333	79,453	0	3,176	29,761	183,520	89,204
2033	0	(7,438)	(931)	(53,519)	21,157	79,453	0	12,994	25,728	209,249	99,790
2034	0	(11,759)	(1,245)	(55,705)	21,098	79,453	0	7,918	23,924	233,173	108,984
2035	0	(8,833)	(947)	(56,978)	21,671	79,453	0	12,025	22,341	255,514	117,002
2036	0	(7,304)	(784)	(57,779)	22,173	79,453	0	14,049	21,710	277,224	124,280
2037	0	(14,427)	(1,359)	(58,313)	21,941	79,453	0	6,540	20,755	297,979	130,778
2038	0	(18,845)	(1,858)	(58,549)	22,175	79,453	0	2,087	20,290	318,269	136,710
2039	0	(17,874)	(1,615)	(58,667)	22,864	66,562	0	(8,530)	19,799	338,068	142,117
2040	0	(26,309)	(2,245)	(58,909)	(1,880)	(18,556)	0	(31,128)	(76,771)	261,297	122,536
2041	0	0	0	(28,456)	0	(18,556)	0	0	(47,012)	214,285	111,337
2042	0	0	0	(22,413)	0	(18,556)	0	0	(40,970)	173,315	102,222
2043	0	0	0	(16,104)	0	(18,556)	0	0	(34,661)	138,654	95,019
2044	0	0	0	(14,213)	0	(18,556)	0	0	(32,769)	105,885	88,659
2045	0	0	0	(12,553)	0	(18,556)	0	0	(31,110)	74,776	83,021
2046	0	0	0	(11,357)	0	(18,556)	0	0	(29,913)	44,862	77,956
2047	0	0	0	(10,050)	0	(18,556)	0	0	(28,606)	16,256	73,433
2048	0	0	0	(8,770)	0	(18,556)	0	0	(27,326)	(11,070)	69,398
2049	0	0	0	(7,736)	0	(18,556)	0	0	(26,292)	(37,363)	65,772
2050	0	0	0	(6,503)	0	(18,556)	0	0	(25,059)	(62,422)	62,544
Net Present Value $000 (2021$)											
Utility NPV 2021-2027	0	0	0	(22,913)	0	14	0	23	(22,922)		
Utility NPV 2028-2039	0	(95,397)	(11,215)	(221,681)	99,532	351,008	0	(42,792)	165,040		
Utility NPV 2040-2050	0	(6,710)	(573)	(41,882)	(479)	(37,869)	0	(7,939)	(79,574)		
NPV of End Effects beyond 2050									(35,605)		
TOTAL Utility Cost, Net NPV (2021$)									26,939		

KENTUCKY POWER COMPANY - CASE 1 CCR & ELG
2020 KP CCR /ELG ANALYSIS PLAN ASSUMING 12/31/2040 MITCHELL RETIREMENT OPTIMAL PLAN
Low Band No Carbon Commodity Pricing

	Utility Costs (Nominal$000)									
	(1) Load Cost - 100% of Load Purchased at PJM Market Energy Price	(2) Fuel Costs - New and Existing Resources	(3) Emission Costs - New and Existing Resources	(4) Mitchell Fixed O&M and Ongoing Capital Recovery	(5) Variable O&M (new and existing) + Fixed O&M and PPA Costs - New Resources	(6) Levelized Return, Taxes, and Depreciation - New Owned Resources	(7) Marginal Losses / Contracts	(8) Less: Market Energy Revenue - 100% of Generation sold at PJM Market Energy Price	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs	NPV (7.07%)
	$000	$000	$000	$000	$000	$000	$000	$000	$000	
2021	118,377	22,500	1,115	37,416	20,465	0	(2,203)	28,463	169,207	$158,034
2022	120,583	28,475	1,992	53,988	20,929	5,037	(2,247)	38,227	190,531	$324,233
2023	123,860	31,308	2,180	50,097	5,139	6,716	(2,311)	46,048	170,940	$463,498
2024	130,692	35,992	2,812	51,711	3,950	8,327	(2,444)	57,059	173,982	$595,881
2025	136,809	37,123	3,023	56,012	3,982	1,812	(2,557)	58,028	178,176	$722,504
2026	141,210	41,873	3,713	56,335	4,361	1,737	(2,636)	62,641	183,953	$844,599
2027	147,723	40,178	3,540	57,927	4,400	850	(2,757)	60,771	191,090	$963,057
2028	152,075	41,260	3,661	59,692	4,481	836	(2,838)	60,953	198,215	$1,077,818
2029	152,181	33,274	2,776	61,573	4,259	821	(2,842)	48,636	203,406	$1,187,808
2030	153,417	33,473	2,668	63,777	4,531	682	(2,862)	46,584	209,102	$1,293,412
2031	154,670	10,580	974	57,502	25,899	682	(2,889)	17,916	229,503	$1,401,666
2032	151,566	7,105	635	58,684	27,984	682	(2,822)	12,301	231,534	$1,503,666
2033	156,543	3,829	323	59,867	29,281	682	(2,913)	6,452	241,160	$1,602,892
2034	157,167	1,504	131	61,049	30,014	682	(2,920)	3,049	244,578	$1,696,879
2035	159,653	895	77	61,640	30,543	682	(2,966)	2,147	248,377	$1,786,023
2036	162,470	0	0	62,113	31,460	682	(3,020)	1,142	252,562	$1,870,684
2037	168,344	2,699	224	62,468	32,174	682	(3,131)	4,182	259,278	$1,951,857
2038	173,880	2,201	184	62,704	33,078	682	(3,231)	3,878	265,621	$2,029,525
2039	176,493	1,627	134	62,822	33,218	13,879	(3,282)	13,701	271,190	$2,103,586
2040	182,985	6,855	205	62,478	59,700	98,997	(3,402)	32,126	375,693	$2,199,410
2041	184,406	4,843	0	31,821	60,497	98,997	(3,428)	29,777	347,360	$2,282,158
2042	188,654	4,028	0	25,238	61,711	98,997	(3,510)	29,322	345,798	$2,359,094
2043	193,195	5,018	0	18,675	63,310	98,997	(3,593)	31,278	344,323	$2,430,644
2044	198,430	4,461	0	16,574	64,388	98,997	(3,692)	31,729	347,430	$2,498,072
2045	207,368	6,273	0	14,422	66,040	98,997	(3,862)	36,547	352,692	$2,562,001
2046	211,850	6,261	0	12,831	67,497	98,997	(3,945)	36,829	356,662	$2,622,381
2047	218,618	5,457	0	11,120	68,222	111,911	(4,071)	50,301	360,956	$2,679,453
2048	225,299	4,843	0	9,432	69,778	111,911	(4,204)	51,295	365,762	$2,733,467
2049	231,075	5,992	0	7,978	70,716	111,911	(4,307)	53,602	369,762	$2,784,465
2050	236,183	4,480	0	6,744	63,782	111,911	(4,406)	52,172	366,523	$2,831,679
Net Present Value $000 (2021$)										
Utility NPV 2021-2027	698,621	177,827	13,502	275,306	53,015	19,168	(13,036)	261,347	963,057	
Utility NPV 2028-2039	775,861	71,315	6,079	299,125	105,637	7,114	(14,450)	110,150	1,140,529	
Utility NPV 2040-2050	414,814	10,886	52	46,135	131,478	209,419	(7,722)	76,970	728,093	
NPV of End Effects beyond 2050									657,680	
TOTAL Utility Cost, Net NPV (2021$)									3,489,358	

KENTUCKY POWER COMPANY - CASE 2 CCR ONLY
2020 KP CCR/ELG ANALYSIS PLAN ASSUMING 12/31/28 MITCHELL RETIREMENT OPTIMAL PLAN
Low Band No Carbon Commodity Pricing

	Utility Costs (Nominal$000)									
	(1) Load Cost - 100% of Load Purchased at PJM Market Energy Price	(2) Fuel Costs - New and Existing Resources	(3) Emission Costs - New and Existing Resources	(4) Mitchell Fixed O&M and Ongoing Capital Recovery	(5) Variable O&M (new and existing) + Fixed O&M and PPA Costs - New Resources	(6) Levelized Return, Taxes, and Depreciation - New Owned Resources	(7) Marginal Losses / Contracts	(8) Less: Market Energy Revenue - 100% of Generation sold at PJM Market Energy Price	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs	NPV (7.07%)
	$000	$000	$000	$000	$000	$000	$000	$000	$000	
2021	118,377	22,500	1,115	37,526	20,465	0	(2,203)	28,463	169,317	$158,136
2022	120,583	28,475	1,992	53,781	20,929	4,777	(2,247)	38,205	190,086	$323,948
2023	123,860	31,308	2,180	45,426	5,139	6,877	(2,311)	46,048	166,431	$459,539
2024	130,692	35,992	2,812	46,170	3,950	8,327	(2,444)	57,057	168,442	$587,707
2025	136,809	37,123	3,023	49,494	3,982	1,537	(2,557)	58,000	171,411	$709,522
2026	141,210	41,873	3,713	48,948	4,361	1,993	(2,636)	62,636	176,827	$826,888
2027	147,723	40,178	3,540	49,412	4,400	850	(2,757)	60,763	182,583	$940,072
2028	152,075	49,294	3,661	50,139	21,129	54,418	(2,838)	75,396	252,482	$1,086,252
2029	152,181	13,048	0	25,026	19,880	54,403	(2,842)	24,061	237,634	$1,214,750
2030	153,417	13,270	0	26,037	22,256	67,711	(2,862)	32,700	247,129	$1,339,559
2031	154,670	5,580	0	14,167	46,157	80,323	(2,889)	32,048	265,962	$1,465,010
2032	151,566	3,708	0	8,191	49,059	80,135	(2,822)	27,119	262,719	$1,580,748
2033	156,543	3,960	0	6,347	51,214	80,135	(2,913)	27,303	267,985	$1,691,011
2034	157,167	3,346	0	5,344	52,311	80,135	(2,920)	24,407	270,977	$1,795,143
2035	159,653	2,798	0	4,662	53,140	80,135	(2,966)	23,826	273,596	$1,893,338
2036	162,470	2,600	0	4,334	54,508	80,135	(3,020)	23,860	277,167	$1,986,247
2037	168,344	2,691	0	4,155	55,362	80,135	(3,131)	24,689	282,867	$2,074,806
2038	173,880	3,350	0	4,155	56,829	80,135	(3,231)	26,559	288,559	$2,159,181
2039	176,493	2,152	0	4,155	57,543	80,441	(3,282)	25,250	292,252	$2,238,993
2040	182,985	4,406	0	3,570	59,529	80,441	(3,402)	29,172	298,356	$2,315,092
2041	184,406	4,843	0	3,365	60,497	80,441	(3,428)	29,781	300,344	$2,386,640
2042	188,654	4,028	0	2,825	61,711	80,441	(3,510)	29,324	304,826	$2,454,460
2043	193,195	5,018	0	2,571	63,310	80,441	(3,593)	31,279	309,662	$2,518,807
2044	198,430	4,461	0	2,362	64,388	80,441	(3,692)	31,729	314,661	$2,579,875
2045	207,368	6,273	0	1,869	66,040	80,441	(3,862)	36,547	321,582	$2,638,166
2046	211,850	6,261	0	1,474	67,497	80,441	(3,945)	36,829	326,748	$2,693,482
2047	218,618	5,457	0	1,071	68,222	93,354	(4,071)	50,301	332,349	$2,746,031
2048	225,299	4,843	0	662	69,778	93,354	(4,204)	51,295	338,436	$2,796,008
2049	231,075	5,992	0	242	70,716	93,354	(4,307)	53,602	343,470	$2,843,381
2050	236,183	4,480	0	242	63,782	93,354	(4,406)	52,172	341,464	$2,887,366
Net Present Value $000 (2021$)										
Utility NPV 2021-2027	698,621	177,827	13,502	252,393	53,015	19,048	(13,036)	261,299	940,072	
Utility NPV 2028-2039	775,861	53,764	2,119	77,445	205,790	358,187	(14,450)	159,795	1,298,921	
Utility NPV 2040-2050	414,814	10,261	0	4,253	131,435	171,550	(7,722)	76,218	648,373	
NPV of End Effects beyond 2050									622,075	
TOTAL Utility Cost, Net NPV (2021$)									3,509,441	

KENTUCKY POWER COMPANY - CASE 2 MINUS CASE 1
2020 KPCO CCR/ELG PLAN DIFFERENCE BETWEEN 12/31/28 MITCHELL RETIREMENT AND 12/31/40 MITCHELL RETIREMENT
Low Band No Carbon Commodity Pricing

	Utility Costs (Nominal$000)										
	(1) Load Cost - 100% of Load Purchased at PJM Market Energy Price	(2) Fuel Costs - New and Existing Resources	(3) Emission Costs - New and Existing Resources	(4) Mitchell Fixed O&M and Ongoing Capital Recovery	(5) Variable O&M (new and existing) + Fixed O&M and PPA Costs - New Resources	(6) Levelized Return, Taxes, and Depreciation - New Owned Resources	(7) Marginal Losses / Contracts	(8) Less: Market Energy Revenue - 100% of Generation sold at PJM Market Energy Price	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs	(10) - Sum of Column 9 Figure 1 Support - Cumulative Difference	NPV (7.07%)
	$000	$000	$000	$000	$000	$000	$000	$000	$000		
2021	0	0	0	110	0	0	0	0	110	110	103
2022	0	0	0	(207)	0	(259)	0	(22)	(445)	(334)	(285)
2023	0	0	0	(4,671)	0	161	0	(0)	(4,510)	(4,844)	(3,959)
2024	0	0	0	(5,541)	0	0	0	(2)	(5,540)	(10,384)	(8,174)
2025	0	0	0	(6,518)	0	(275)	0	(28)	(6,766)	(17,149)	(12,982)
2026	0	0	0	(7,387)	0	256	0	(5)	(7,126)	(24,275)	(17,712)
2027	0	0	0	(8,515)	0	0	0	(8)	(8,507)	(32,782)	(22,985)
2028	0	8,034	0	(9,553)	16,648	53,582	0	14,443	54,267	21,485	8,434
2029	0	(20,226)	(2,776)	(36,547)	15,621	53,582	0	(24,574)	34,227	55,713	26,942
2030	0	(20,203)	(2,668)	(37,740)	17,725	67,029	0	(13,884)	38,027	93,740	46,147
2031	0	(5,000)	(974)	(43,335)	20,258	79,641	0	14,132	36,459	130,199	63,344
2032	0	(3,396)	(635)	(50,493)	21,075	79,453	0	14,818	31,185	161,383	77,083
2033	0	131	(323)	(53,519)	21,934	79,453	0	20,851	26,824	188,207	88,119
2034	0	1,842	(131)	(55,705)	22,297	79,453	0	21,357	26,400	214,607	98,264
2035	0	1,902	(77)	(56,978)	22,597	79,453	0	21,679	25,219	239,826	107,315
2036	0	2,600	0	(57,779)	23,048	79,453	0	22,717	24,605	264,430	115,563
2037	0	(8)	(224)	(58,313)	23,188	79,453	0	20,508	23,589	288,019	122,948
2038	0	1,149	(184)	(58,549)	23,751	79,453	0	22,681	22,938	310,957	129,655
2039	0	525	(134)	(58,667)	24,325	66,562	0	11,549	21,062	332,020	135,407
2040	0	(2,449)	(205)	(58,909)	(172)	(18,556)	0	(2,954)	(77,338)	254,682	115,682
2041	0	0	0	(28,456)	0	(18,556)	0	4	(47,016)	207,666	104,481
2042	0	0	0	(22,413)	0	(18,556)	0	2	(40,972)	166,694	95,366
2043	0	0	0	(16,104)	0	(18,556)	0	1	(34,661)	132,033	88,163
2044	0	0	0	(14,213)	0	(18,556)	0	0	(32,769)	99,263	81,803
2045	0	0	0	(12,553)	0	(18,556)	0	0	(31,110)	68,154	76,164
2046	0	0	0	(11,357)	0	(18,556)	0	0	(29,913)	38,240	71,100
2047	0	0	0	(10,050)	0	(18,556)	0	0	(28,606)	9,634	66,577
2048	0	0	0	(8,770)	0	(18,556)	0	0	(27,326)	(17,692)	62,542
2049	0	0	0	(7,736)	0	(18,556)	0	0	(26,292)	(43,985)	58,916
2050	0	0	0	(6,503)	0	(18,556)	0	0	(25,059)	(69,044)	55,688
Net Present Value $000 (2021$)											
Utility NPV 2021-2027	0	0	0	(22,913)	0	(121)	0	(48)	(22,985)		
Utility NPV 2028-2039	0	(17,550)	(3,959)	(221,681)	100,153	351,074	0	49,644	158,393		
Utility NPV 2040-2050	0	(625)	(52)	(41,882)	(44)	(37,869)	0	(752)	(79,720)		
NPV of End Effects beyond 2050									(35,605)		
TOTAL Utility Cost, Net NPV (2021$)									20,083		

2020 KP Mitchell CCR/ELG Analysis - Case 1 CCR and ELG
EIA_Base with Carbon Commodity Pricing
KP Optimization Expansion Plan (Supply-side, Renewables, VVO, DR, EE) for Mitchell 1&2 CCR Expenditures Only (12/31/40 Retirement)

	Planning Peak Load (MW)	Required Generation Capacity (MW)	Firm Generation Capacity without New Additions (MW)	237 MW CT-Frame	Commercial DSM Firm Capacity (MW)	Residential DSM Firm Capacity (MW)	Distributed Solar Firm Capacity (MW)	Utility Solar Firm Capacity (MW)	CVR Firm Capacity (MW)	Wind Firm Capacity (MW)	Short Term PPA Capacity (MW)	Firm Generation Capacity with New Additions (MW)	Capacity Reserves Above Required Generation without New Additions (MW)	Reserve Margin without New Capacity Additions (%)	Capacity Reserves Above Required Generation with New Capacity Additions (MW)	Reserve Margin with New Capacity Additions (%)	Nameplate Solar	Nameplate Wind	Testimony Figure 2 Capacity Reserves Above Required Generation with New Capacity Additions (MW) except for Mitchell
2021	955	1,038	1,333	0	0	0	0.00	0	0	0	0	1,333	295	39.51	295	39.5	0	0	295
2022	978	1,062	1,344	0	3	1	0.00	0	0	0	0	1,347	281	37.36	285	37.7	0	0	285
2023	993	1,078	969	0	6	1	1.02	0	0	24	100	1,102	(109)	(2.39)	24	11.0	0	200	24
2024	919	998	969	0	8	2	1.53	0	0	24	0	1,004	(29)	5.39	6	9.3	0	200	6
2025	917	996	969	0	7	2	1.53	0	0	48	0	1,028	(27)	5.63	31	12.0	0	400	31
2026	916	995	969	0	7	2	1.53	0	0	48	0	1,027	(26)	5.75	32	12.1	0	400	32
2027	914	992	969	0	6	2	2.04	0	0	48	0	1,026	(23)	6.06	34	12.3	0	400	34
2028	909	987	969	0	5	1	2.04	0	0	48	0	1,025	(18)	6.59	38	12.8	0	400	38
2029	909	987	969	0	4	1	2.56	0	0	48	0	1,025	(18)	6.61	38	12.7	0	400	38
2030	906	984	969	0	3	1	3.07	0	0	48	0	1,024	(15)	6.90	40	13.0	0	400	40
2031	904	982	678	0	2	1	3.58	0	0	48	250	983	(304)	(25.04)	0	8.6	0	400	0
2032	900	978	678	0	2	0	3.58	0	0	48	250	982	(300)	(24.71)	4	9.0	0	400	4
2033	901	978	678	0	1	0	4.09	0	0	48	250	981	(300)	(24.75)	3	8.9	0	400	3
2034	899	976	678	0	1	0	4.60	0	0	48	250	981	(298)	(24.59)	5	9.2	0	400	5
2035	898	975	678	0	0	0	4.60	0	0	48	250	981	(297)	(24.49)	6	9.3	0	400	6
2036	895	972	678	0	0	0	5.11	41	0	48	200	972	(294)	(24.24)	0	8.6	150	400	0
2037	895	972	678	0	0	0	5.11	41	4	48	200	976	(294)	(24.28)	4	9.0	150	400	4
2038	894	971	678	0	0	1	5.62	81	8	48	150	971	(293)	(24.19)	0	8.6	300	400	0
2039	893	970	678	0	0	1	5.62	81	8	48	150	971	(292)	(24.11)	1	8.7	300	400	1
2040	890	966	10	476	0	0	6.13	122	8	48	300	970	(956)	(98.85)	3	9.0	450	400	-664
2041	891	967	10	476	0	0	6.13	122	10	48	300	972	(957)	(98.85)	5	9.2	450	400	-663
2042	889	966	0	476	0	0	6.64	122	10	48	350	1,013	(966)	(100.00)	47	13.8	450	400	-621
2043	888	965	0	476	0	0	7.15	122	10	48	350	1,013	(965)	(100.00)	48	14.0	450	400	-620
2044	885	961	0	476	0	0	7.15	122	10	48	300	963	(961)	(100.00)	2	8.8	450	400	-666
2045	886	962	0	476	0	0	7.67	122	10	48	300	963	(962)	(100.00)	1	8.7	450	400	-667
2046	885	961	0	476	0	0	8.18	122	10	48	300	964	(961)	(100.00)	3	8.9	450	400	-665
2047	884	960	0	476	0	0	8.69	122	10	48	300	965	(960)	(100.00)	5	9.1	450	400	-663
2048	881	956	0	476	0	0	9.20	122	10	48	300	965	(956)	(100.00)	9	9.6	450	400	-659
2049	882	958	0	476	0	0	9.20	122	10	48	300	965	(958)	(100.00)	7	9.5	450	400	-660
2050	881	956	0	476	0	0	9.20	122	10	48	300	965	(956)	(100.00)	9	9.6	450	400	-659

2020 KP Mitchell CCR/ELG Analysis - Case 2 CCR Only
EIA_Base with Carbon Commodity Pricing
KP Optimization Expansion Plan (Supply-side, Renewables, VVO, DR, EE) for Mitchell 1&2 CCR Expenditures Only (12/31/28 Retirement)

	Planning Peak Load (MW)	Required Generation Capacity (MW)	Firm Generation Capacity without New Additions (MW)	237 MW CT-Frame	Commercial DSM Firm Capacity (MW)	Residential DSM Firm Capacity (MW)	Distributed Solar Firm Capacity (MW)	Utility Solar Firm Capacity (MW)	CVR Firm Capacity (MW)	Wind Firm Capacity (MW)	Short Term PPA Capacity (MW)	Firm Generation Capacity with New Additions (MW)	Capacity Reserves Above Required Generation without New Additions (MW)	Reserve Margin without New Capacity Additions (%)	Capacity Reserves Above Required Generation with New Capacity Additions (MW)	Reserve Margin with New Capacity Additions (%)	Nameplate Solar	Nameplate Wind	Testimony Figure 2 - Capacity Reserves Above Required Generation with New Capacity Additions (MW) except for Mitchell
2021	955	1,038	1,333	0	0	0	0.00	0	0	0	0	1,333	296	39.54	296	39.5	0	0	296
2022	978	1,062	1,344	0	5	1	0.00	0	0	0	0	1,349	281	37.36	287	38.0	0	0	287
2023	993	1,078	969	0	9	2	1.02	0	0	24	100	1,105	(109)	(2.39)	27	11.4	0	200	27
2024	919	998	969	0	14	3	1.53	0	0	24	0	1,011	(29)	5.39	12	9.9	0	200	12
2025	917	996	969	0	12	2	1.53	0	0	48	0	1,033	(27)	5.63	37	12.6	0	400	37
2026	916	995	969	0	11	2	1.53	0	0	48	0	1,031	(26)	5.75	36	12.6	0	400	36
2027	914	992	969	0	10	2	2.04	0	0	48	0	1,031	(23)	6.06	39	12.8	0	400	39
2028	909	987	301	476	8	3	2.04	0	0	48	150	988	(686)	(66.86)	1	8.7	0	400	-667
2029	909	987	301	476	7	3	2.56	0	0	48	150	987	(686)	(66.86)	0	8.6	0	400	-668
2030	906	984	301	476	5	2	3.07	0	0	48	150	986	(683)	(66.77)	1	8.8	0	400	-666
2031	904	982	10	476	4	2	3.58	41	0	48	400	984	(972)	(98.87)	2	8.8	150	400	-666
2032	900	978	10	476	3	1	3.58	41	0	48	400	982	(968)	(98.86)	4	9.1	150	400	-663
2033	901	978	10	476	2	1	4.09	41	0	48	400	981	(968)	(98.87)	3	8.9	150	400	-665
2034	899	976	10	476	1	0	4.60	41	0	48	400	981	(966)	(98.86)	5	9.1	150	400	-663
2035	898	975	10	476	0	0	4.60	41	0	48	400	980	(965)	(98.86)	5	9.2	150	400	-663
2036	895	972	10	476	0	0	5.11	81	4	48	350	975	(962)	(98.86)	3	9.0	300	400	-664
2037	895	972	10	476	0	0	5.11	81	8	48	350	978	(962)	(98.86)	6	9.2	300	400	-662
2038	894	971	10	476	0	0	5.62	122	10	48	300	972	(961)	(98.86)	1	8.7	450	400	-667
2039	893	970	10	476	0	0	5.62	122	10	48	300	972	(960)	(98.86)	2	8.8	450	400	-666
2040	890	966	10	476	0	0	6.13	122	10	48	300	972	(956)	(98.85)	6	9.3	450	400	-662
2041	891	967	10	476	0	0	6.13	122	10	48	300	972	(957)	(98.85)	5	9.2	450	400	-663
2042	889	966	0	476	0	0	6.64	122	10	48	350	1,012	(966)	(100.00)	47	13.8	450	400	-621
2043	888	965	0	476	0	0	7.15	122	10	48	350	1,013	(965)	(100.00)	48	14.0	450	400	-620
2044	885	961	0	476	0	0	7.15	122	10	48	300	963	(961)	(100.00)	2	8.8	450	400	-666
2045	886	962	0	476	0	0	7.67	122	10	48	300	963	(962)	(100.00)	1	8.7	450	400	-667
2046	885	961	0	476	0	0	8.18	122	10	48	300	964	(961)	(100.00)	3	8.9	450	400	-665
2047	884	960	0	476	0	0	8.69	122	10	48	300	965	(960)	(100.00)	5	9.1	450	400	-663
2048	881	956	0	476	0	0	9.20	122	10	48	300	965	(956)	(100.00)	9	9.6	450	400	-659
2049	882	958	0	476	0	0	9.20	122	10	48	300	965	(958)	(100.00)	7	9.5	450	400	-660
2050	881	956	0	476	0	0	9.20	122	10	48	300	965	(956)	(100.00)	9	9.6	450	400	-659

2020 KP Mitchell CCR/ELG Analysis - Case 1 CCR and ELG
EIA Base without Carbon Commodity Pricing
KP Optimization Expansion Plan (Supply-side, Renewables, VVO, DR, EE) for Mitchell 1&2 CCR Expenditures Only (12/31/40 Retirement)

	Planning Peak Load (MW)	Required Generation Capacity (MW)	Firm Generation Capacity without New Additions (MW)	237 MW CT-Frame	Commercial DSM Firm Capacity (MW)	Residential DSM Firm Capacity (MW)	Distributed Solar Firm Capacity (MW)	Utility Solar Firm Capacity (MW)	CVR Firm Capacity (MW)	Wind Firm Capacity (MW)	Short Term PPA Capacity (MW)	Firm Generation Capacity with New Additions (MW)	Capacity Reserves Above Required Generation without New Additions (MW)	Reserve Margin without New Capacity Additions (%)	Capacity Reserves Above Required Generation with New Capacity Additions (MW)	Reserve Margin with New Capacity Additions (%)	Nameplate Solar	Nameplate Wind
2021	955	1,038	1,333	0	0	0	0.00	0	0	0	0	1,333	295	39.51	295	39.5	0	0
2022	978	1,062	1,344	0	5	2	0.00	0	0	0	0	1,350	281	37.36	288	38.1	0	0
2023	993	1,078	969	0	9	6	1.02	0	0	0	100	1,085	(109)	(2.39)	7	9.3	0	0
2024	919	998	969	0	14	10	1.53	0	4	0	0	998	(29)	5.39	0	8.6	0	0
2025	917	996	969	0	12	10	1.53	0	4	0	0	997	(27)	5.63	1	8.7	0	0
2026	916	995	969	0	11	9	1.53	0	4	0	0	995	(26)	5.75	0	8.6	0	0
2027	914	992	969	0	10	8	2.04	0	4	0	0	993	(23)	6.06	0	8.6	0	0
2028	909	987	969	0	8	6	2.04	0	4	0	0	990	(18)	6.59	3	8.9	0	0
2029	909	987	969	0	7	5	2.56	0	4	0	0	987	(18)	6.61	0	8.6	0	0
2030	906	984	969	0	5	4	3.07	0	4	0	0	985	(15)	6.90	1	8.7	0	0
2031	904	982	678	0	4	3	3.58	0	4	0	300	992	(304)	(25.04)	10	9.7	0	0
2032	900	978	678	0	3	2	3.58	0	4	0	300	990	(300)	(24.71)	12	10.0	0	0
2033	901	978	678	0	2	1	4.09	0	4	0	300	989	(300)	(24.75)	11	9.8	0	0
2034	899	976	678	0	1	1	4.60	0	4	0	300	988	(298)	(24.59)	12	10.0	0	0
2035	898	975	678	0	0	0	4.60	0	4	0	300	988	(297)	(24.49)	13	10.0	0	0
2036	895	972	678	0	0	0	5.11	0	4	0	300	988	(294)	(24.24)	16	10.4	0	0
2037	895	972	678	0	0	0	5.11	0	4	0	300	987	(294)	(24.28)	15	10.3	0	0
2038	894	971	678	0	0	0	5.62	0	4	0	300	988	(293)	(24.19)	17	10.5	0	0
2039	893	970	678	0	0	0	5.62	41	4	0	250	978	(292)	(24.11)	8	9.5	150	0
2040	890	966	10	476	0	0	6.13	81	4	0	400	978	(956)	(98.85)	11	9.9	300	0
2041	891	967	10	476	0	0	6.13	81	4	0	400	978	(957)	(98.85)	10	9.8	300	0
2042	889	966	0	476	0	0	6.64	81	4	0	400	968	(966)	(100.00)	2	8.8	300	0
2043	888	965	0	476	0	0	7.15	81	4	0	400	968	(965)	(100.00)	4	9.0	300	0
2044	885	961	0	476	0	0	7.15	81	4	0	400	968	(961)	(100.00)	7	9.4	300	0
2045	886	962	0	476	0	0	7.67	81	4	0	400	969	(962)	(100.00)	6	9.3	300	0
2046	885	961	0	476	0	0	8.18	81	4	0	400	969	(961)	(100.00)	8	9.5	300	0
2047	884	960	0	476	0	0	8.69	122	4	0	350	960	(960)	(100.00)	0	8.7	450	0
2048	881	956	0	476	0	0	9.20	122	4	0	350	961	(956)	(100.00)	5	9.1	450	0
2049	882	958	0	476	0	0	9.20	122	4	0	350	961	(958)	(100.00)	3	9.0	450	0
2050	881	956	0	476	0	0	9.20	122	4	0	350	961	(956)	(100.00)	5	9.1	450	0

2020 KP Mitchell CCR/ELG Analysis - Case 2 CCR Only
EIA Base without Carbon Commodity Pricing
KP Optimization Expansion Plan (Supply-side, Renewables, VVO, DR, EE) for Mitchell 1&2 CCR Expenditures Only (12/31/28 Retirement)

	Planning Peak Load (MW)	Required Generation Capacity (MW)	Firm Generation Capacity without New Additions (MW)	237 MW CT-Frame	Commercial DSM Firm Capacity (MW)	Residential DSM Firm Capacity (MW)	Distributed Solar Firm Capacity (MW)	Utility Solar Firm Capacity (MW)	CVR Firm Capacity (MW)	Wind Firm Capacity (MW)	Short Term PPA Capacity (MW)	Firm Generation Capacity with New Additions (MW)	Capacity Reserves Above Required Generation without New Additions (MW)	Reserve Margin without New Capacity Additions (%)	Capacity Reserves Above Required Generation with New Capacity Additions (MW)	Reserve Margin with New Capacity Additions (%)	Nameplate Solar	Nameplate Wind
2021	955	1,038	1,333	0	0	0	0.00	0	0	0	0	1,333	296	39.54	296	39.5	0	0
2022	978	1,062	1,344	0	5	2	0.00	0	0	0	0	1,351	281	37.36	288	38.1	0	0
2023	993	1,078	969	0	9	6	1.02	0	0	0	100	1,085	(109)	(2.39)	7	9.3	0	0
2024	919	998	969	0	14	10	1.53	0	4	0	0	998	(29)	5.39	0	8.6	0	0
2025	917	996	969	0	12	10	1.53	0	4	0	0	997	(27)	5.63	1	8.7	0	0
2026	916	995	969	0	11	9	1.53	0	4	0	0	995	(26)	5.75	0	8.6	0	0
2027	914	992	969	0	10	8	2.04	0	4	0	0	993	(23)	6.06	0	8.6	0	0
2028	909	987	301	476	8	6	2.04	0	4	0	200	998	(686)	(66.86)	11	9.8	0	0
2029	909	987	301	476	7	5	2.56	0	4	0	200	996	(686)	(66.86)	9	9.5	0	0
2030	906	984	301	476	5	4	3.07	41	4	0	150	984	(683)	(66.77)	0	8.6	150	0
2031	904	982	10	476	4	3	3.58	81	4	0	400	982	(972)	(98.87)	0	8.6	300	0
2032	900	978	10	476	3	2	3.58	81	4	0	400	980	(968)	(98.86)	2	8.8	300	0
2033	901	978	10	476	2	1	4.09	81	4	0	400	979	(968)	(98.87)	0	8.6	300	0
2034	899	976	10	476	1	1	4.60	81	4	0	400	978	(966)	(98.86)	2	8.8	300	0
2035	898	975	10	476	0	1	4.60	81	4	0	400	977	(965)	(98.86)	2	8.8	300	0
2036	895	972	10	476	0	0	5.11	81	4	0	400	977	(962)	(98.86)	5	9.2	300	0
2037	895	972	10	476	0	0	5.11	81	4	0	400	977	(962)	(98.86)	4	9.1	300	0
2038	894	971	10	476	0	0	5.62	81	4	0	400	977	(961)	(98.86)	6	9.3	300	0
2039	893	970	10	476	0	0	5.62	81	4	0	400	977	(960)	(98.86)	7	9.4	300	0
2040	890	966	10	476	0	0	6.13	81	4	0	400	978	(956)	(98.85)	11	9.9	300	0
2041	891	967	10	476	0	0	6.13	81	4	0	400	978	(957)	(98.85)	10	9.8	300	0
2042	889	966	0	476	0	0	6.64	81	4	0	400	968	(966)	(100.00)	2	8.8	300	0
2043	888	965	0	476	0	0	7.15	81	4	0	400	968	(965)	(100.00)	4	9.0	300	0
2044	885	961	0	476	0	0	7.15	81	4	0	400	968	(961)	(100.00)	7	9.4	300	0
2045	886	962	0	476	0	0	7.67	81	4	0	400	969	(962)	(100.00)	6	9.3	300	0
2046	885	961	0	476	0	0	8.18	81	4	0	400	969	(961)	(100.00)	8	9.5	300	0
2047	884	960	0	476	0	0	8.69	122	4	0	350	960	(960)	(100.00)	0	8.7	450	0
2048	881	956	0	476	0	0	9.20	122	4	0	350	961	(956)	(100.00)	5	9.1	450	0
2049	882	958	0	476	0	0	9.20	122	4	0	350	961	(958)	(100.00)	3	9.0	450	0
2050	881	956	0	476	0	0	9.20	122	4	0	350	961	(956)	(100.00)	5	9.1	450	0

2020 KP Mitchell CCR/ELG Analysis - Case 1 CCR and ELG
2020 Low Band No Carbon Commodity Pricing
KP Optimization Expansion Plan (Supply-side, Renewables, VVO, DR, EE) for Mitchell 1&2 CCR Expenditures Only (12/31/40 Retirement)

	Planning Peak Load (MW)	Required Generation Capacity (MW)	Firm Generation Capacity without New Additions (MW)	237 MW CT-Frame	Commercial DSM Firm Capacity (MW)	Residential DSM Firm Capacity (MW)	Distributed Solar Firm Capacity (MW)	Utility Solar Firm Capacity (MW)	CVR Firm Capacity (MW)	Wind Firm Capacity (MW)	Short Term PPA Capacity (MW)	Firm Generation Capacity with New Additions (MW)	Capacity Reserves Above Required Generation without New Additions (MW)	Reserve Margin without New Capacity Additions (%)	Capacity Reserves Above Required Generation with New Capacity Additions (MW)	Reserve Margin with New Capacity Additions (%)	Nameplate Solar	Nameplate Wind
2021	955	1,038	1,333	0	0	0	0.00	0	0	0	0	1,333	295	39.51	295	39.5	0	0
2022	978	1,062	1,344	0	5	2	0.00	0	0	0	0	1,351	281	37.36	288	38.1	0	0
2023	993	1,078	969	0	9	6	1.02	0	0	0	100	1,085	(109)	(2.39)	7	9.3	0	0
2024	919	998	969	0	14	10	1.53	0	4	0	0	998	(29)	5.39	0	8.6	0	0
2025	917	996	969	0	12	10	1.53	0	4	0	0	997	(27)	5.63	1	8.7	0	0
2026	916	995	969	0	11	9	1.53	0	4	0	0	995	(26)	5.75	0	8.6	0	0
2027	914	992	969	0	10	8	2.04	0	4	0	0	993	(23)	6.06	0	8.6	0	0
2028	909	987	969	0	8	6	2.04	0	4	0	0	990	(18)	6.59	3	8.9	0	0
2029	909	987	969	0	7	5	2.56	0	4	0	0	987	(18)	6.61	0	8.6	0	0
2030	906	984	969	0	5	4	3.07	0	4	0	0	985	(15)	6.90	1	8.7	0	0
2031	904	982	678	0	4	3	3.58	0	4	0	300	992	(304)	(25.04)	10	9.7	0	0
2032	900	978	678	0	3	2	3.58	0	4	0	300	990	(300)	(24.71)	12	10.0	0	0
2033	901	978	678	0	2	1	4.09	0	4	0	300	989	(300)	(24.75)	11	9.8	0	0
2034	899	976	678	0	1	1	4.60	0	4	0	300	988	(298)	(24.59)	12	10.0	0	0
2035	898	975	678	0	0	0	4.60	0	4	0	300	988	(297)	(24.49)	13	10.0	0	0
2036	895	972	678	0	0	0	5.11	0	4	0	300	988	(294)	(24.24)	16	10.4	0	0
2037	895	972	678	0	0	0	5.11	0	4	0	300	987	(294)	(24.28)	15	10.3	0	0
2038	894	971	678	0	0	0	5.62	0	4	0	300	988	(293)	(24.19)	17	10.5	0	0
2039	893	970	678	0	0	0	5.62	41	4	0	250	978	(292)	(24.11)	8	9.5	150	0
2040	890	966	10	476	0	0	6.13	81	4	0	400	978	(956)	(98.85)	11	9.9	300	0
2041	891	967	10	476	0	0	6.13	81	4	0	400	978	(957)	(98.85)	10	9.8	300	0
2042	889	966	0	476	0	0	6.64	81	4	0	400	968	(966)	(100.00)	2	8.8	300	0
2043	888	965	0	476	0	0	7.15	81	4	0	400	968	(965)	(100.00)	4	9.0	300	0
2044	885	961	0	476	0	0	7.15	81	4	0	400	968	(961)	(100.00)	7	9.4	300	0
2045	886	962	0	476	0	0	7.67	81	4	0	400	969	(962)	(100.00)	6	9.3	300	0
2046	885	961	0	476	0	0	8.18	81	4	0	400	969	(961)	(100.00)	8	9.5	300	0
2047	884	960	0	476	0	0	8.69	122	4	0	350	960	(960)	(100.00)	0	8.7	450	0
2048	881	956	0	476	0	0	9.20	122	4	0	350	961	(956)	(100.00)	5	9.1	450	0
2049	882	958	0	476	0	0	9.20	122	4	0	350	961	(958)	(100.00)	3	9.0	450	0
2050	881	956	0	476	0	0	9.20	122	4	0	350	961	(956)	(100.00)	5	9.1	450	0

2020 KP Mitchell CCR/ELG Analysis - Case 2 CCR Only
2020 Low Band No Carbon Commodity Pricing
KP Optimization Expansion Plan (Supply-side, Renewables, VVO, DR, EE) for Mitchell 1&2 CCR Expenditures Only (12/31/28 Retirement)

	Planning Peak Load (MW)	Required Generation Capacity (MW)	Firm Generation Capacity without New Additions (MW)	237 MW CT-Frame	Commercial DSM Firm Capacity (MW)	Residential DSM Firm Capacity (MW)	Distributed Solar Firm Capacity (MW)	Utility Solar Firm Capacity (MW)	CVR Firm Capacity (MW)	Wind Firm Capacity (MW)	Short Term PPA Capacity (MW)	Firm Generation Capacity with New Additions (MW)	Capacity Reserves Above Required Generation without New Additions (MW)	Reserve Margin without New Capacity Additions (%)	Capacity Reserves Above Required Generation with New Capacity Additions (MW)	Reserve Margin with New Capacity Additions (%)	Nameplate Solar	Nameplate Wind
2021	955	1,038	1,333	0	0	0	0.00	0	0	0	0	1,333	296	39.54	296	39.5	0	0
2022	978	1,062	1,344	0	5	2	0.00	0	0	0	0	1,350	281	37.36	288	38.1	0	0
2023	993	1,078	969	0	9	6	1.02	0	0	0	100	1,085	(109)	(2.39)	7	9.3	0	0
2024	919	998	969	0	14	10	1.53	0	4	0	0	998	(29)	5.39	0	8.6	0	0
2025	917	996	969	0	12	10	1.53	0	4	0	0	997	(27)	5.63	1	8.7	0	0
2026	916	995	969	0	11	9	1.53	0	4	0	0	995	(26)	5.75	0	8.6	0	0
2027	914	992	969	0	10	8	2.04	0	4	0	0	993	(23)	6.06	0	8.6	0	0
2028	909	987	301	476	8	6	2.04	0	4	0	200	998	(686)	(66.86)	11	9.8	0	0
2029	909	987	301	476	7	5	2.56	0	4	0	200	995	(686)	(66.86)	8	9.5	0	0
2030	906	984	301	476	5	4	3.07	41	4	0	150	984	(683)	(66.77)	0	8.6	150	0
2031	904	982	10	476	4	3	3.58	81	4	0	400	982	(972)	(98.87)	0	8.6	300	0
2032	900	978	10	476	3	2	3.58	81	4	0	400	980	(968)	(98.86)	2	8.9	300	0
2033	901	978	10	476	2	1	4.09	81	4	0	400	979	(968)	(98.87)	0	8.7	300	0
2034	899	976	10	476	1	1	4.60	81	4	0	400	978	(966)	(98.86)	2	8.8	300	0
2035	898	975	10	476	0	1	4.60	81	4	0	400	977	(965)	(98.86)	2	8.8	300	0
2036	895	972	10	476	0	0	5.11	81	4	0	400	977	(962)	(98.86)	5	9.2	300	0
2037	895	972	10	476	0	0	5.11	81	4	0	400	977	(962)	(98.86)	5	9.1	300	0
2038	894	971	10	476	0	0	5.62	81	4	0	400	977	(961)	(98.86)	6	9.3	300	0
2039	893	970	10	476	0	0	5.62	81	4	0	400	977	(960)	(98.86)	7	9.4	300	0
2040	890	966	10	476	0	0	6.13	81	4	0	400	978	(956)	(98.85)	11	9.9	300	0
2041	891	967	10	476	0	0	6.13	81	4	0	400	978	(957)	(98.85)	10	9.8	300	0
2042	889	966	0	476	0	0	6.64	81	4	0	400	968	(966)	(100.00)	2	8.8	300	0
2043	888	965	0	476	0	0	7.15	81	4	0	400	968	(965)	(100.00)	4	9.0	300	0
2044	885	961	0	476	0	0	7.15	81	4	0	400	968	(961)	(100.00)	7	9.4	300	0
2045	886	962	0	476	0	0	7.67	81	4	0	400	969	(962)	(100.00)	6	9.3	300	0
2046	885	961	0	476	0	0	8.18	81	4	0	400	969	(961)	(100.00)	8	9.5	300	0
2047	884	960	0	476	0	0	8.69	122	4	0	350	960	(960)	(100.00)	0	8.7	450	0
2048	881	956	0	476	0	0	9.20	122	4	0	350	961	(956)	(100.00)	5	9.1	450	0
2049	882	958	0	476	0	0	9.20	122	4	0	350	961	(958)	(100.00)	3	9.0	450	0
2050	881	956	0	476	0	0	9.20	122	4	0	350	961	(956)	(100.00)	5	9.1	450	0

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E-Signature Summary

E-Signature 1: Mark A. Becker (MAB)
February 05, 2021 08:40:49 -8:00 [C14E6992102B] [167.239.2.87]
mabecker@aep.com (Principal) (Personally Known)

E-Signature Notary: S. Smithhisler (SRS)
February 05, 2021 08:40:49 -8:00 [6F3C273F2271] [167.239.221.82]
srsmithhisler@aep.com
I, S. Smithhisler, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Mark A. Becker, being duly sworn, deposes and says he is a Managing Director of Resource Planning for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the forgoing testimony, and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

C14E6992102B

Mark A. Becker

Signed on 2021/02/05 08:40:49 -8:00

Mark A. Becker

STATE OF OHIO)

) Case No. 2021-00004

COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Mark A. Becker, this 5th day of February 2021.

NOTARY PUBLIC

STATE OF OHIO

Sarah Smithhisler

Commission # 2019-RE-775042

Electronic Notary Public

State of Ohio

My Comm Exp. Apr 29, 2024

Notary Stamp 2021/02/05 09:40:49 PST 6F3C273F2271

6F3C273F2271

S. Smithhisler

Signed on 2021/02/05 08:40:49 -8:00

Notary Public

Notary ID Number: 2019-RE-775042