

**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 CONSTRUCTION AT THE )  
MITCHELL GENERATING STATION, AN )  
AMENDED ENVIRONMENTAL COMPLIANCE )  
PLAN, AND REVISED ENVIRONMENTAL )  
SURCHARGE TARIFF SHEETS )**

**CASE NO.  
2021-00004**

**Direct Testimony of  
Rachel Wilson**

**On Behalf of  
Sierra Club**

**\* PUBLIC, REDACTED VERSION\***

May 12, 2021

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[EXHIBITS FOLLOW]

**1. INTRODUCTION AND QUALIFICATIONS**

1 **Q. Please state your name, business address, and position.**

2 A. My name is Rachel Wilson and I am a Principal Associate with Synapse Energy  
3 Economics, Incorporated (Synapse). My business address is 485 Massachusetts  
4 Avenue, Suite 3, Cambridge, Massachusetts 02139.

5 **Q. Please describe Synapse Energy Economics.**

6 A. Synapse is a research and consulting firm specializing in energy and environmental  
7 issues, including electric generation, transmission and distribution system  
8 reliability, ratemaking and rate design, electric industry restructuring and market  
9 power, electricity market prices, stranded costs, efficiency, renewable energy,  
10 environmental quality, and nuclear power.

11 Synapse's clients include state consumer advocates, public utilities commission  
12 staff, attorneys general, environmental organizations, federal government agencies,  
13 and utilities.

14 **Q. Please summarize your work experience and educational background.**

15 A. At Synapse, I conduct analysis and write testimony and publications that focus on  
16 a variety of issues relating to electric utilities, including: integrated resource  
17 planning; power plant economics; federal and state clean air policies; emissions  
18 from electricity generation; environmental compliance technologies, strategies, and  
19 costs; electrical system dispatch; and valuation of environmental externalities from  
20 power plants.

1 I also perform modeling analyses of electric power systems. I am proficient in the  
2 use of spreadsheet analysis tools, as well as optimization and electricity dispatch  
3 models to conduct analyses of utility service territories and regional energy  
4 markets. I have direct experience running the Strategist, PROMOD IV,  
5 PROSYM/Market Analytics, PLEXOS, EnCompass, and PCI Gentrader models,  
6 and have reviewed input and output data for several other industry models.

7 Prior to joining Synapse in 2008, I worked for the Analysis Group, Inc., an  
8 economic and business consulting firm, where I provided litigation support in the  
9 form of research and quantitative analyses on a variety of issues relating to the  
10 electric industry.

11 I hold a Master of Environmental Management from Yale University and a  
12 Bachelor of Arts in Environment, Economics, and Politics from Claremont  
13 McKenna College in Claremont, California.

14 A copy of my current resume is attached as Exhibit RW-1.

15 **Q. On whose behalf are you testifying in this case?**

16 A. I am testifying on behalf of Sierra Club.

17 **Q. Have you testified previously as an expert witness before the Kentucky Public**  
18 **Service Commission?**

19 A. Yes, several times: in Case Nos. 2011-00161 and 2011-00162, dockets in which  
20 Louisville Gas & Electric Company and Kentucky Utilities Company sought  
21 certificates of public convenience and necessity (CPCNs) for environmental

1 compliance capital projects; in Case No. 2011-00401, another CPCN docket, filed  
2 by Kentucky Power Company (KPC, or the Company), related to environmental  
3 compliance capital projects; and in Case No. 2012-00063, another such docket,  
4 filed by Big Rivers Electric Corporation.

5 **Q. Have you testified previously as an expert witness in any formal hearings**  
6 **before other regulatory bodies?**

7 A. Yes, many times. I have submitted expert testimony in electric utility dockets in  
8 Minnesota, Indiana, Oklahoma, Missouri, Texas, Virginia, Washington, Georgia,  
9 Mississippi, Alabama, North Carolina, South Carolina, and West Virginia.

10 **Q. What is the purpose of your testimony in this proceeding?**

11 A. My testimony evaluates the application of KPC for a CPCN to undertake capital  
12 investments at the Mitchell power plant—a two-unit, 1,560 MW, coal-fired power  
13 plant located near Moundsville, West Virginia, of which KPC is a 50 percent  
14 owner. Mitchell’s co-owner is Wheeling Power Company, one of KPC’s fellow  
15 subsidiaries of American Electric Power Company (AEP). The capital projects for  
16 which KPC is seeking a CPCN are intended to make Mitchell compliant with  
17 respective deadlines coming up later this decade under the federal Coal Combustion  
18 Residuals (CCR) regulation as well as the Effluent Limitation Guidelines (ELG)  
19 regulation. With respect to the ELG compliance in particular, KPC is proposing to  
20 spend tens of millions on capital projects that would be needed to keep Mitchell  
21 running as a coal-fired plant past the year 2028—instead of the alternative ELG  
22 compliance option of retiring Mitchell’s coal units by the end of that year.

1 In conjunction with my evaluation of KPC's application, I present the results of an  
2 alternative modeling analysis that compares two cases for the Mitchell plant,  
3 identified below. The Synapse analysis includes KPC's input assumptions but  
4 updates prices for solar, wind, and storage consistent with industry standard  
5 sources.

6 **1) Synapse BAU ("business as usual")** – This case features KPC  
7 investing in both CCR and ELG compliance projects at Mitchell and  
8 has the plant retiring on December 31, 2040, as proposed in the  
9 Company's application.

10 **2) Synapse 2028 Retirement** – This case features KPC investing in  
11 CCR compliance projects needed to keep Mitchell operating past  
12 2023, but not the ELG projects, and has the plant retiring on  
13 December 31, 2028.

14 **Q. Are you involved in any other regulatory proceedings concurrently addressing**  
15 **Mitchell's compliance options under the CCR and ELG rules? Please explain.**

16 A. Yes. I am a testifying expert witness for Sierra Club in Case No. 20-1040-E-CN  
17 pending before the West Virginia Public Service Commission. In that case,  
18 Wheeling Power Company, filing jointly with sibling utility and AEP subsidiary  
19 Appalachian Power Company, is seeking a CPCN for capital projects at Mitchell  
20 meant for CCR and ELG compliance, as KPC is in this case. (There are two other  
21 plants at issue as well in that case, in addition to Mitchell, but they are not part of  
22 KPC's portfolio.) As detailed in my testimony filed in that case on May 6, 2021, I

1 have concluded that Wheeling Power's plainly least-cost option for ELG  
 2 compliance is to retire Mitchell in 2028, forgoing investments in the capital projects  
 3 that KPC is proposing in parallel.

4 **Q. Please identify the sources of information on which you base your opinions in**  
 5 **this case.**

6 A. My analysis and findings rely primarily upon the testimony, exhibits, and discovery  
 7 responses of KPC and its witnesses. I also rely on certain industry publications and  
 8 publicly available data sources.

9 **Q. Are you sponsoring any exhibits?**

10 A. Yes. I am sponsoring the following exhibits:

<b>Exhibit Number</b>	<b>Description of Exhibit</b>	<b>Protected Status</b>
Exhibit RW-1	Resume of Rachel S. Wilson	Non-Confidential
Exhibit RW-2	KPC Response to KIUC-AG RFI 1-14, Confidential Attachment 2	Confidential
Exhibit RW-3	KPC Response to Sierra Club RFI 2-5, Attachment 1	Non-Confidential
Exhibit RW-4	KPC Response to Sierra Club RFI 2-6, Attachment 1	Non-Confidential
Exhibit RW-5	KPC Response to Sierra Club RFI 2-7, Attachment 1	Non-Confidential
Exhibit RW-6	<i>KPMG report: Outlook for what's ahead for energy tax incentives (updated)</i>	Non-Confidential

## 2. OVERVIEW OF TESTIMONY AND CONCLUSIONS

11 **Q. Please summarize your primary conclusions.**

12 A. My independent modeling demonstrates that it is uneconomic, and not in the best  
 13 interest of ratepayers, for KPC to invest in both CCR and ELG capital projects at

1 Mitchell and to continue operating the plant through 2040. The lesser-cost, better  
 2 option is instead to invest in only the CCR projects, forgo the ELG investments,  
 3 and retire the plant’s two coal units by the end of 2028. My analysis shows that  
 4 early retirement would save ratepayers \$194 million under a Base case, even with  
 5 No Carbon commodity price forecast. Further, when an effective price on carbon  
 6 dioxide (CO<sub>2</sub>) emissions is added to the analysis, ratepayer savings rise to more  
 7 than \$341 million when Mitchell forgoes ELG investments, retires at the end of  
 8 2028, and is replaced with an alternative resource portfolio. Notably, neither case  
 9 factors in any new non-carbon regulations that could arise in the next twenty years  
 10 and further challenge coal’s competitiveness. A summary of the resource additions,  
 11 retirements, and net present value of revenue requirements (NPVRR) for the year  
 12 2050, in the Synapse modeling, is shown below in Table 1.<sup>1</sup>

**Table 1. Summary of Synapse modeling results (2050)**

	Base No Carbon		Base With Carbon	
	Synapse BAU	Synapse 2028 Retirement	Synapse BAU	Synapse 2028 Retirement
NPVRR (2021-2050)	\$2.9	\$2.7	\$2.8	\$2.5
Solar (MW)	2,240	2,200	2,160	2,160
Wind (MW)	0	0	2,000	1,300
Storage (MW)	36	0	12	0
Gas (MW)	125	125	125	125
Coal (MW)	0	0	0	0

1 Using the year 2050 for the NPVRR means that the Synapse analysis evaluates the annual revenue requirements over the analysis period from 2021 through 2050, discounting the results using KPC’s weighted average cost of capital (WACC). KPC analyzed this same time period, although the Company’s analysis also included what is known as an “end effects” period.



1 **Q. Please summarize your primary recommendations.**

2 A. Based on my findings, I recommend that the Commission grant the CPCN only for  
3 the proposed CCR compliance capital projects and deny the CPCN for the ELG  
4 projects. Using industry standard pricing for replacement resources, the most  
5 economic option for KPC customers is to forgo ELG project investments and  
6 retiring Mitchell in 2028, even under a base commodity forecast that does not  
7 include an effective price or constraint on future CO<sub>2</sub> emissions. Customer savings  
8 from early retirement would only increase—and substantially so—if an effective  
9 carbon price does materialize in the coming years, which a prudent utility should  
10 consider.

### 3. SUMMARY OF KPC'S APPLICATION

11 **Q. What is KPC requesting in its Application in this docket?**

12 A. KPC is requesting the Commission's approval of a CPCN for the CCR and ELG  
13 projects at Mitchell, approval of the Company's 2021 Environmental Compliance  
14 Plan, and an amended environmental compliance surcharge to provide cost  
15 recovery for the ELG and CCR compliance work.<sup>2</sup> The total cost of compliance  
16 with CCR and ELG for Mitchell is \$133.5 million, with KPC's 50 percent share  
17 being \$66.75 million.<sup>3</sup>

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2 KPC Application, page 1.

3 KPC Application, page 7.

1 **Q. Did KPC present any analysis supporting its Application?**

2 A. Yes. According to his Direct Testimony, KPC witness Mark A. Becker prepared an  
3 economic analysis that compared two compliance cases:

- 4 • Case 1 assumes CCR and ELG investments at Mitchell, with a retirement  
5 date of December 31, 2040; and
- 6 • Case 2 assumes only CCR investments at Mitchell, with a retirement date of  
7 December 31, 2028.<sup>4</sup>

8 These analyses were done under three forecasted commodity price assumptions:  
9 Base No Carbon, Base With Carbon, and Low Band, which has a lower gas price  
10 forecast.

11 **Q. What were the results of KPC's analysis?**

12 A. According to KPC, its Case 1—investing in CCR and ELG technologies at Mitchell  
13 and retiring the plant in 2040—is the least-cost option, when comparing the net  
14 present value of revenue requirements (NPVRR). The revenue requirements for  
15 each case, under each commodity forecast, are shown below in Table 2 along with  
16 the change in costs (or the “delta”) relative to Case 1.

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4 Direct Testimony of Mark A. Becker at 3:5-3:13.

**Table 2. Comparison of net present value of revenue requirements, KPC modeled scenarios**

		NPVRR (\$ Millions)	Delta from Case 1 (\$ Millions)	Delta from Case 1 (Percent)
Case 1	Base With Carbon	\$4,331	n/a	n/a
	Base No Carbon	\$3,944	n/a	n/a
	Low Band	\$3,489	n/a	n/a
Case 2	Base With Carbon	\$4,325	(\$6)	-0.14%
	Base No Carbon	\$3,971	\$27	0.68%
	Low Band	\$3,509	\$20	0.57%

*Source: Exhibit MAB-1.*

1 The percentage differences between KPC’s cases reflected above were calculated  
2 by Synapse. Notably, Case 2—in which the Mitchell units retire at the end of  
3 2028—is already the least-cost option in the Company’s modeling under the Base  
4 With Carbon case, and only less than one percent more expensive when a carbon  
5 price is excluded. Mr. Becker notes in his own testimony that there is a difference  
6 between cases of less than one percent of the total NPV of KPC’s expected total  
7 energy production cost of service over the analysis period.<sup>5</sup> That differential is  
8 extremely small, and thus even a small adjustment to KPC’s input assumptions that  
9 either increased the costs to continue to operate existing coal or lowered the cost of  
10 replacement resources (or both) could shift the results such that the 2028 retirement  
11 of Mitchell becomes the more economic option under all of KPC’s cases, even  
12 under the Company’s own analysis.

13 It is imperative to recognize that either (or both) of those are distinctly probable  
14 over the next twenty years. Indeed, it is reasonable to expect that long-term trends

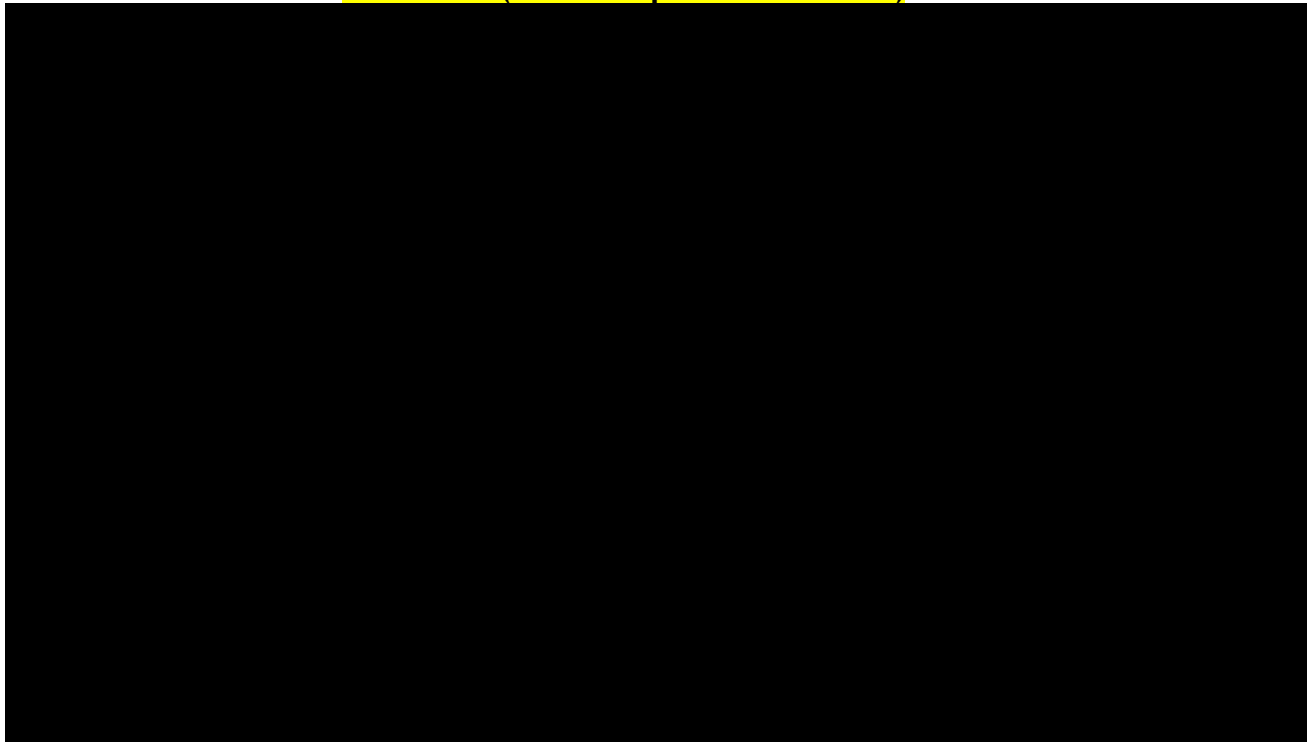
<sup>5</sup> Direct Testimony of Mark A. Becker at 5:1-5:3.

1           such as increasing stringency of environmental regulations and increasing cost-  
2           effectiveness of renewable energy and storage technologies will continue to  
3           increase both the cost and risk of continued investment in coal-fired power plants.

4   **Q.   How does KPC's analysis assume the Mitchell units will operate into the**  
5   **future?**

6   A.   In Case 1, when Mitchell is assumed to operate until the end of 2040, KPC's results  
7           show thermal generation from Mitchell as well as the Company's Big Sandy gas-  
8           fired plant increasing between 2021 and 2028. After that point, however, generation  
9           falls quite steeply and stays low until all the units retire at the end of 2040. In all  
10          years of KPC's analysis, the Company relies heavily on imports from PJM,  
11          particularly after 2030. This pattern is shown below in CONFIDENTIAL Figure 1,  
12          generated from data that KPC provided in discovery.

**CONFIDENTIAL Figure 1. Generation in KPC's Case 1,  
No Carbon (Mitchell operates until 2040)**



*Source: KPC's Response to KIUC AG No. 1-2, Confidential Attachment KPC Base without Carbon – CCR&ELG Optimal Plan.xlsx*

1 **Q. In the scenario in which Mitchell retires in 2028, what sort of replacement**  
2 **capacity is selected in KPC's analysis?**

3 A. When Mitchell retires at the end of 2028, the PLEXOS model selects 480 MW of  
4 gas-fired combustion turbines and 200 MW of a capacity-only power purchase  
5 agreement (PPA).

6 Mr. Becker states in his direct testimony that the PLEXOS model chose the  
7 cheapest capacity options available to replace Mitchell, due to the low level of  
8 market energy prices in the AEP Fundamentals Forecast. Because energy from the  
9 PJM market is relatively inexpensive, the model did not choose thermal units with  
10 low heat rates, which might be expected to run more, or renewable resources, which

1 Mr. Becker says are less valuable when market prices are low.<sup>6</sup> Instead, KPC's  
2 plans "result in very heavy reliance on the PJM energy market for the energy  
3 needed to serve customers."<sup>7</sup> Even when Mitchell continues to operate until 2040,  
4 the PLEXOS model begins to select large volumes of imports beginning in 2030,  
5 as shown in CONFIDENTIAL Figure 1, above.

6 **Q. Can you draw any conclusions about KPC's input assumptions from that**  
7 **heavy reliance on imports from PJM?**

8 A. Yes. When making the decision about which resources to build, PLEXOS considers  
9 both the cost of capacity (in MW) and the cost of energy (in \$/MWh) of different  
10 types of replacement resource. The calculation is complicated by KPC's ability to  
11 purchase from or sell to the PJM market. The PLEXOS model chose primarily  
12 capacity resources (*e.g.*, combustion turbines and the capacity-only PPA) in KPC's  
13 analysis rather than energy resources (*e.g.*, solar and wind), and instead relies on  
14 purchased energy from PJM to meet demand. This suggests that KPC's market  
15 energy price forecast is low, its renewable prices are high, or both.

16 **Q. What does KPC forecast for the performance of the Mitchell units in its**  
17 **Case 1?**

18 A. KPC projects the capacity factors of the Mitchell units to start quite low in the first  
19 year of the analysis period, increase in the near term, and peak in 2026-2028, with  
20 figures in the [REDACTED]. By 2032, the capacity factors are less than [REDACTED] at both

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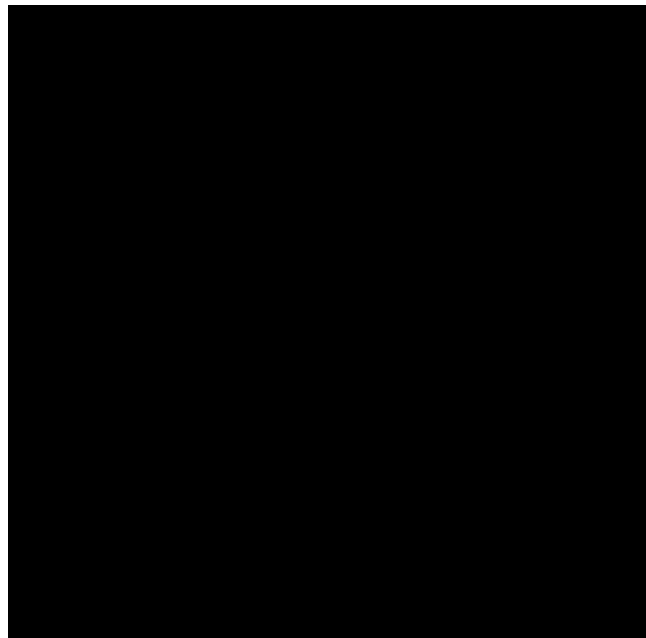
6 Direct Testimony of Mark A. Becker at 18:21–18:28.

7 *Id.* at 18:27–18:28.

1 Unit 1 and Unit 2. The Mitchell units, which were intended to operate as “baseload”  
2 generators with high levels of output, would be operating as if they were peaking  
3 units, under KPC’s projections, if they continued to operate past the 2028  
4 retirement date.

5 Annual capacity factor projections for the Mitchell units are shown below in  
6 CONFIDENTIAL Table 3.

**CONFIDENTIAL Table 3. Comparison of capacity factors  
at Mitchell under Case 1, Base No Carbon**



*Source: KPC Response to KIUC AG RFI 1-14, Confidential Attachment 2*<sup>8</sup>

7 **Q. Are these projections consistent with recent experience at the Mitchell plant?**

8 A. No. Mitchell has operated less in recent years as a result of declines in locational  
9 marginal prices (LMPs) in PJM. From 2019 to 2020, load weighted average real

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8 Attached as Exhibit RW-2.

1 time LMPs fell 20.3 percent, from \$27.32/MWh to \$21.77/MWh.<sup>9</sup> As a result,  
 2 capacity factors at Mitchell were just over 22 percent and 30 percent, for Units 1  
 3 and 2, respectively. Annual capacity factors from the last five years are shown  
 4 below in Table 4.

5 **Table 4. Net capacity factor at the Mitchell units (%)**

	2016	2017	2018	2019	2020
Mitchell 1	52.07	46.50	38.12	35.97	22.43
Mitchell 2	59.99	65.77	42.37	37.78	30.20

6 *Source: KPC Response to KIUC-AG RFI 1-14, Attachment 1*

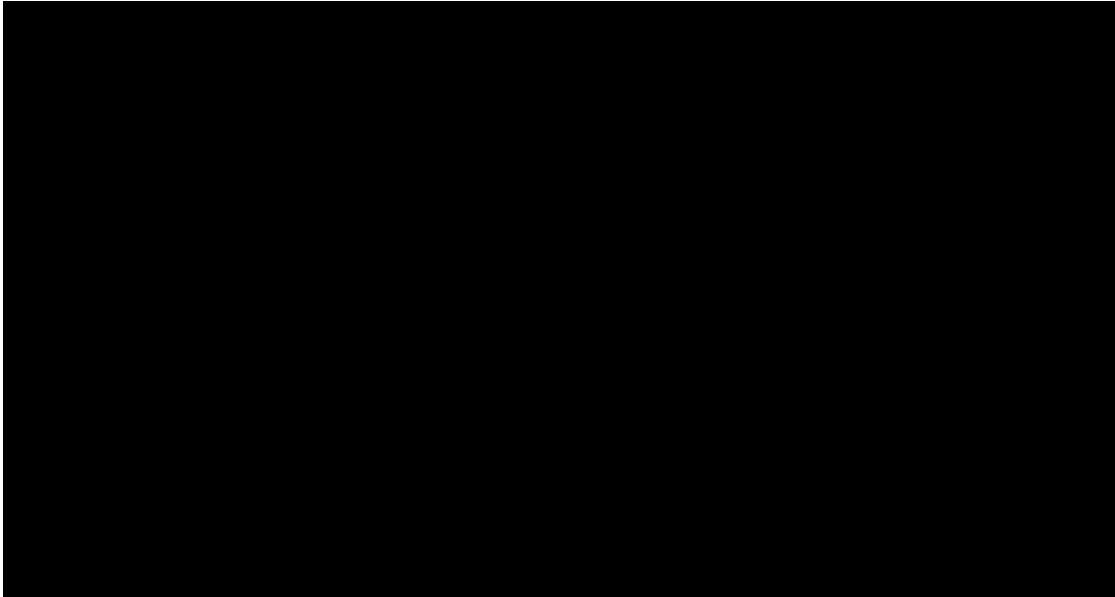
7 Despite declining capacity factors at Mitchell over the last five years, KPC's  
 8 forecast for some reason anticipates increasing generation by the plant over the next  
 9 five years.

10 When we compare the operating costs of the Mitchell units, calculated from KPC's  
 11 PLEXOS outputs as the sum of fuel, variable O&M, emissions costs, and  
 12 start/shutdown costs, to the AEP Fundamentals Forecast for market energy, we see  
 13 that Mitchell is uneconomic relative to both on- and off-peak market prices starting  
 14 in 2031. A comparison of the operating costs of the Mitchell units relative to AEP's  
 15 forecast of both on- and off-peak market energy prices is shown below in  
 16 CONFIDENTIAL Figure 2.

9 <sup>9</sup> Monitoring Analytics. March 29, 2021. *State of the Market Report for PJM*. Members Committee Briefing. Available at: <https://www.pjm.com/-/media/committees-groups/committees/mc/2021/20210329-special/20210329-state-of-the-market-report-for-pjm-2020.ashx>.



**CONFIDENTIAL Figure 2. Comparison of KPC's market energy forecast versus operating cost of its coal plants**



*Sources: Energy market prices come from KPC Response to KIUC-AG RFI 1-2, Attachment 17. Operating costs were calculated using KPC Response to KIUC-AG RFI 1-2, Confidential Attachment 8 – Case 1 CCR and ELG.*

1 In KPC's analysis, the Mitchell units offer capacity and energy value to its  
2 customers in the near-term but offer very little energy value (as evidenced by  
3 declining capacity factors) in the later part of the decade and beyond.

#### 4. SYNAPSE MODELING METHODOLOGY

4 Q. Do you present an alternative to the KPC modeling analysis?

5 A. Yes, I did.

6 Q. Which model did you use to perform your analysis?

7 A. The Synapse analysis uses the EnCompass capacity optimization and dispatch  
8 model, developed by Anchor Power Solutions, to simulate resource choice impacts  
9 in the KPC's service territory.

1 **Q. Is EnCompass a widely accepted industry model?**

2 A. Yes. EnCompass was released in 2016 and several major utilities have transitioned  
3 to the model since that time. For example, the three investor-owned utilities in  
4 Minnesota (Minnesota Power, Otter Tail Power, and Xcel Energy) adopted the  
5 EnCompass model in 2019, along with Great River Energy, the largest of the state's  
6 electric cooperatives.<sup>10</sup> Duke Energy announced in 2020 that it had chosen  
7 EnCompass to expand its capabilities in resource planning.<sup>11</sup> Public Service New  
8 Mexico and Public Service Company of Colorado are two other IOUs that have  
9 adopted EnCompass in recent years.

10 **Q. What did Synapse model in its analysis?**

11 A. Synapse modeled two different scenarios in our analysis for the KPC plants:

- 12 **1) Synapse BAU** includes both CCR and ELG investments at the Mitchell  
13 plant and retires the plant on December 31, 2040;
- 14 **2) Synapse 2028 Retirement** includes only the CCR investments at the  
15 Mitchell plant, not the ELG investments, and retires the plant on December  
16 31, 2028.<sup>12</sup>

17 A matrix of these scenarios is shown below in Table 5.

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10 Anchor Power Solutions. December 2019. Available at: <https://anchor-power.com/news/minnesota-plans-for-its-energy-future-with-encompass/>.

11 Anchor Power Solutions. May 2020. Available at: <https://anchor-power.com/news/duke-energy-implemented-encompass-software/>.

12 As noted by KPC in its Application, CCR compliance will be required by October 17, 2023. ELG costs, however, can be avoided if a plant is shut down by 2028 (and KPC makes a commitment to do so by October 2021). Because of the short time necessary to comply with CCR regulations, and because it is not clear that all costs could be avoided even if a plant ceased operations, I have not considered a scenario where CCR costs were not included.

**Table 5. Matrix of Synapse KPC modeling scenarios**

		Synapse BAU	Synapse 2028 Retirement
Retrofit Technology	Mitchell	CCR/ELG	CCR
Retirement Date	Mitchell	2040	2028

1 **Q. Do the input assumptions used in the Synapse analysis conform to KPC’s**  
 2 **assumptions?**

3 A. Largely, yes. To ensure a valid, apples-to-apples comparison, the Synapse analysis  
 4 uses KPC’s assumptions for peak and annual energy, load shape, reserve margin,  
 5 unit retirements, commodity prices (fuel, CO<sub>2</sub>, and energy market prices), and  
 6 compliance costs for CCR/ELG at Mitchell under the 2028 and 2040 retirement  
 7 dates. The sources for key input assumptions in the Synapse modeling are shown  
 8 below in Table 6.

**Table 6. Sources of input assumptions in Synapse modeling**

Assumption	Source
Load Forecast	KPC response to KIUC-AG RFI 1-2, Becker Workpapers
Load Shape	KPC response to SC RFI 1-7, Attachments 1
Reserve Margin	Becker Direct Testimony
Coal Prices	KPC response to KIUC-AG 1-2, AEP Fundamentals Forecast
Gas Prices	KPC response to KIUC-AG 1-2, AEP Fundamentals Forecast
CO <sub>2</sub> Prices	KPC response to KIUC-AG 1-2, AEP Fundamentals Forecast
Market prices	KPC response to KIUC-AG 1-2, AEP Fundamentals Forecast
Solar Costs	NREL ATB 2020 Mid
Battery Costs	NREL ATB 2020 Mid
Onshore Wind Costs	NREL ATB 2020 Mid, Class 7
Capacity Credit	KPC response to KIUC-AG 1-2, Becker Workpapers
Amos/Mountaineer Op Costs	KPC response to KIUC AG 1-2, Becker Workpapers
CCR/ELG Costs	KPC response to KIUC AG 1-2, Becker Workpapers
Transmission Costs	KPC response to KIUC AG 1-2, Becker Workpapers

1 **Q. Did you have to adjust any of the Company's input assumptions?**

2 A. Yes, I had to adjust KPC's assumptions on pricing for solar, wind, and battery  
3 storage resources. The Company provided the annual cost values as they were input  
4 into the PLEXOS model in its Response to Sierra Club's Second Set of Discovery  
5 and indicated that the source of its pricing for these resources was the Energy  
6 Information Administration's (EIA) 2020 Annual Energy Outlook (AEO).  
7 However, EIA did not publish annual overnight capital cost projections for  
8 forward-looking years in this version of the AEO, so I was unable to confirm KPC's  
9 values. EIA did publish those values in AEO 2021, however, so I was able to  
10 compare KPC's data to a more recent version of AEO. For solar, KPC's assumed  
11 PPA price is \$57.58/MWh in 2026.<sup>13</sup> This is much higher than the assumed  
12 levelized cost of energy from EIA in AEO 2021 for solar resources in 2026, which  
13 is \$33.68/MWh.<sup>14</sup> KPC has stated that its cost assumptions come from EIA, but  
14 there is a substantial difference between EIA's values and those used by KPC in  
15 this analysis.

16 **Q. Are you able to determine the source of that difference?**

17 A. Only generally. KPC's assumptions regarding both the capital and fixed O&M  
18 component costs for solar are higher than those assumed by EIA. My expertise is  
19 not in utility financing or accounting, but KPC's underlying workpapers contain a

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13 KPC Response to Sierra Club RFI 2-5, Attachment 1 (attached as Exhibit RW-3).

14 Energy Information Administration, *Levelized Costs of New Generation Resources in the Annual Energy Outlook 2021* (February 2021), available at [https://www.eia.gov/outlooks/aeo/pdf/electricity\\_generation.pdf](https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf). This document shows a cost of \$29.04 in 2020\$. That value was converted to nominal dollars using KPC's assumed inflation rate of 2.5% from its Response to Sierra Club RFI 2-5, Attachment 1.

1 number of financial assumptions that appear to add to the costs of their replacement  
2 resources.<sup>15</sup> I have not seen the costs of replacement resources calculated in this  
3 way in previous utility dockets in which I have been involved.

4 **Q. Are there any other data points that lead you to believe that KPC's assumed**  
5 **new resource costs are unreasonably high?**

6 A. Yes. KPC's forecasts are higher than currently published PPA prices for both solar  
7 and wind. Solar PPA pricing in PJM in Q4 2020 was \$37.50/MWh, while wind  
8 PPAs were priced at \$35.50/MWh.<sup>16</sup> However, analysts note that both prices are an  
9 increase over prior years, because of disruptions due to COVID-19 as well as  
10 supply constraints that have arisen due to high demand.<sup>17</sup> Over the longer term,  
11 basic economics suggests that the market will respond to these supply constraints  
12 and that prices will stabilize lower.

13 **Q. What source did the Synapse modeling analysis use as the basis for its**  
14 **assumptions around the cost of replacement resources?**

15 A. The Synapse modeling uses industry standard cost assumptions from the National  
16 Renewable Laboratory's (NREL) 2020 Advanced Technology Baseline (ATB) for  
17 utility-scale photovoltaic (PV) solar, onshore wind, and battery storage resources.  
18 NREL's ATB 2020 data is quite similar to the estimates of overnight capital costs

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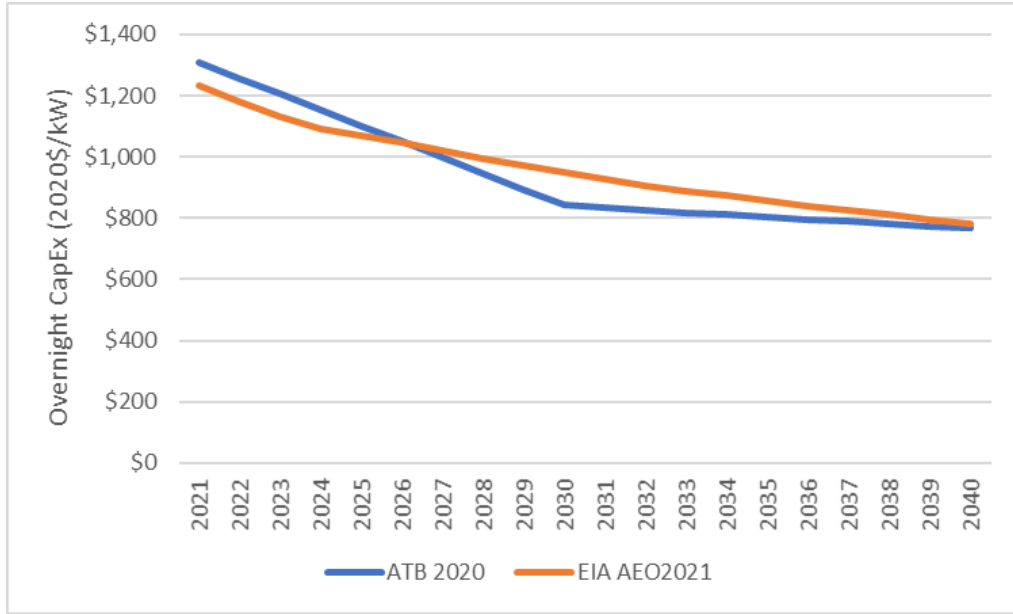
15 Exhibit RW-3.

16 Level 10 Energy. *North America, Q4 2020 LevelTen Energy PPA Price Index*. Available at:  
<https://leveltenenergy.com/blog/ppa-price-index/q4-2020/>

17 *Id.*

1 from EIA 2021. A comparison of the capital costs for solar PV from both sources  
 2 is shown below in Figure 3.

**Figure 3. Comparison of overnight capital cost forecasts for solar PV, ATB 2020 and AEO 2021**

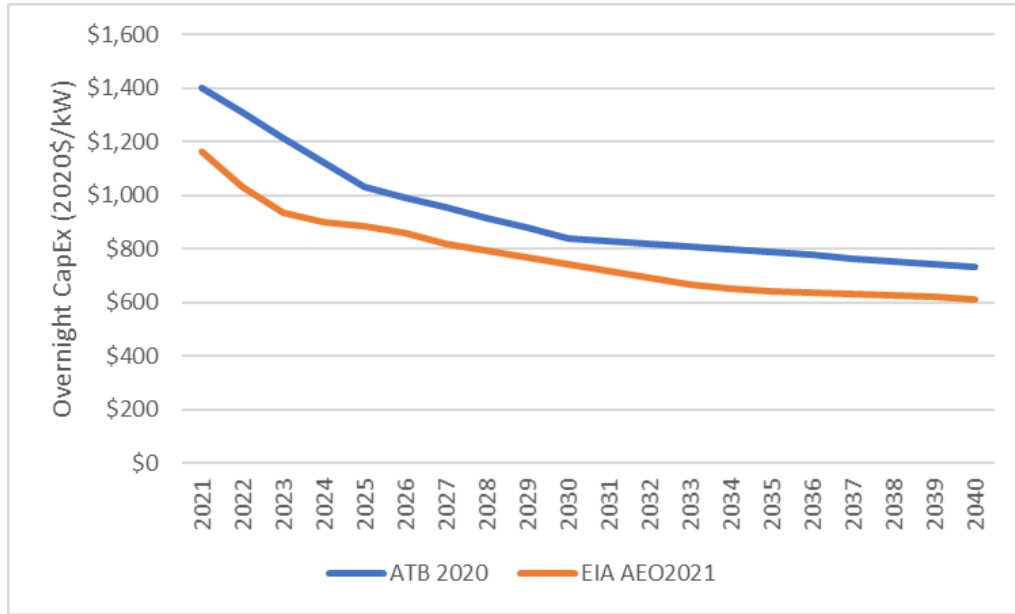


Sources: National Renewable Energy Laboratory, *Annual Technology Baseline (2020)*, available at: <https://atb.nrel.gov/electricity/2020/data.php>; Energy Information Administration, *Annual Energy Outlook (2021)* at Table 55, available at: <https://www.eia.gov/outlooks/aeo/data/browser/#/?id=123-AEO2021&cases=ref2021&sourcekey=0>.

3 Battery storage costs are more conservative in NREL’s ATB Moderate Case than  
 4 in AEO 2021. Those overnight capital costs are shown below in Figure 4.<sup>18</sup>

18 A comparison of wind costs is not presented here because they are not directly comparable between sources, as AEO 2021 presents wind costs by region while NREL ATB presents costs by wind class. Synapse selected Class 7 to represent the wind resource that would be available to KPC for the purposes of this analysis.

**Figure 4. Comparison of overnight capital cost forecasts for battery storage, ATB 2020 and AEO 2021**



1

2 Sources: National Renewable Energy Laboratory, *Annual Technology Baseline (2020)*, available at:  
 3 <https://atb.nrel.gov/electricity/2020/data.php>; Energy Information Administration, *Annual*  
 4 *Energy Outlook (2021)* at Table 55, available at: [https://www.eia.gov/outlooks/aeo/data/browser](https://www.eia.gov/outlooks/aeo/data/browser/#/?id=123-AEO2021&cases=ref2021&sourcekey=0)  
 5 [/#/?id=123-AEO2021&cases=ref2021&sourcekey=0](https://www.eia.gov/outlooks/aeo/data/browser/#/?id=123-AEO2021&cases=ref2021&sourcekey=0).

6 **Q. The capital costs you have shown from EIA are generally similar to, or lower**  
 7 **than, ATB. Why are you suggesting that KPC’s costs are too high?**

8 A. Costs for wind, solar, and battery storage have two major components: capital and  
 9 fixed O&M. A comparison of these components between KPC and EIA for a solar  
 10 PV resource coming online in 2026 shows that KPC’s forecasts of both components  
 11 are higher than those being used in AEO 2021.

**Table 7. Comparison of KPC solar PPA cost with EIA levelized solar costs, \$/MWh**

	Capital	Fixed O&M	Transmission	Tax Credit	Total
KPC	\$44.65	\$12.93	-	-	\$57.58
EIA 2021	\$26.21	\$6.87	\$3.22	-\$2.62	\$33.68

1 **Q. Why did Synapse choose to use NREL ATB 2020 as its source for new resource**  
2 **costs rather than EIA?**

3 A. As shown Figure 3 and Figure 4, above, the EIA and NREL overnight capital costs  
4 for solar and storage are actually quite similar. However, EIA's input costs are  
5 based on a single source: a report from Sargent & Lundy published in December  
6 2019<sup>19</sup> and provided by KPC in responses to discovery.<sup>20</sup> The NREL ATB, on the  
7 other hand, incorporates several different sources, including analyses from both  
8 NREL and Oak Ridge National Laboratory, data from EIA, and information from  
9 a variety of published reports to arrive at its forecasts of generation technology cost  
10 and performance.<sup>21</sup>

11 NREL's ATB is a widely used source of renewable and storage pricing data. Detroit  
12 Edison used the 2018 ATB Mid costs in its 2019 Integrated Resource Plan, with  
13 some intervenors arguing that the costs were too conservative.<sup>22</sup> In its recent

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19 Energy Information Administration. *Annual Energy Outlook 2021: Levelized Costs of New Generation Resources* (February 2021), available at [https://www.eia.gov/outlooks/aeo/pdf/electricity\\_generation.pdf](https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf).

20 KPC Response to KIUC-AG RFI 1-29, Attachment 2, also available online at [https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital\\_cost\\_AEO2020.pdf](https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf).

21 National Renewable Energy Laboratory, *2020 Annual Technology Baseline: Electricity Data Now Available* (July 9, 2020), available at: <https://www.nrel.gov/news/program/2020/2020-annual-technology-baseline-electricity-data-now-available.html>.

22 *In re Application of DTE Electric Company for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief*, Michigan Public Service Commission Case No. U-20471 (February 20, 2020), available at: <https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000009jWc2AAE>.



1 Integrated Resource Plan filing in Minnesota, Xcel Energy used ATB 2019 as the  
2 basis for its renewable and storage costs.<sup>23</sup>

3 Lastly, in order to accurately model these replacement resources, we need more  
4 than just the forecasted capital costs. We also need annual estimates of fixed O&M  
5 cost, which the AEO 2021 does not provide. NREL's ATB does provide these data,  
6 however, which, when combined with performance data, allows for a levelized cost  
7 calculation that utilizes data from a single source.

8 **Q. How do Synapse's modeled costs for wind and solar compare to KPC's?**

9 A. Prices used by both KPC and Synapse for wind and solar are shown below in Table  
10 12.

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23 *Xcel Energy's 2020-2034 Upper Midwest Resource Plan*, Minnesota Public Utilities Commission Docket No. E002/RP-19-368 (July 1, 2019), available at <https://www.xcelenergy.com/staticfiles/xeresponsive/Company/Rates%20&%20Regulations/The-Resource-Plan-No-Appendices.pdf>.

**Table 8. Comparison of prices for new resources  
in KPC and Synapse modeling**

Year	Solar		Wind	
	KPC	Synapse	KPC	Synapse
2021	\$57.60	\$33.63		
2022	\$54.45	\$32.80	\$40.76	
2023	\$52.55	\$31.94	\$45.10	\$45.25
2024	\$56.25	\$31.05	\$40.51	\$45.00
2025	\$57.70	\$30.12	\$55.53	\$44.71
2026	\$57.58	\$29.15	\$56.30	\$44.39
2027	\$57.83	\$28.15	\$57.01	\$44.04
2028	\$57.90	\$27.10	\$57.83	\$43.65
2029	\$58.05	\$26.02	\$58.60	\$43.22
2030	\$58.24	\$24.90	\$59.35	\$42.76
2031	\$58.40	\$25.12	\$60.01	\$43.28
2032	\$58.59	\$25.33	\$60.63	\$43.80
2033	\$58.84	\$25.55	\$61.19	\$44.33
2034	\$59.08	\$25.77	\$61.73	\$44.85
2035	\$59.31	\$25.99	\$62.25	\$45.38
2036	\$59.50	\$26.21	\$62.79	\$45.91
2037	\$59.66	\$26.43	\$63.29	\$46.45
2038	\$59.86	\$26.64	\$63.77	\$46.98
2039	\$60.05	\$26.86	\$64.32	\$47.52
2040	\$60.29	\$27.08	\$64.91	\$48.05

Sources: KPC Responses to Sierra Club RFI 2-5 and 2-6

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In 2028, KPC's solar PPA price is \$57.90/MWh.<sup>24</sup> In contrast, the solar PPA price in the Synapse modeling is \$27.10/MWh, which reflects the projection from NREL ATB 2020 that capital and fixed O&M for solar PV will both be lower than KPC's projections. Similarly, KPC's levelized cost for wind in 2028 is \$57.83/MWh,<sup>25</sup> while Synapse's wind cost is \$43.65/MWh. The Synapse modeled resources are much more cost-effective and competitive with KPC's forecasted on-peak market price of \$34.87/MWh and the off-peak market energy price of \$28.21/MWh.<sup>26</sup>

24 Exhibit RW-3.

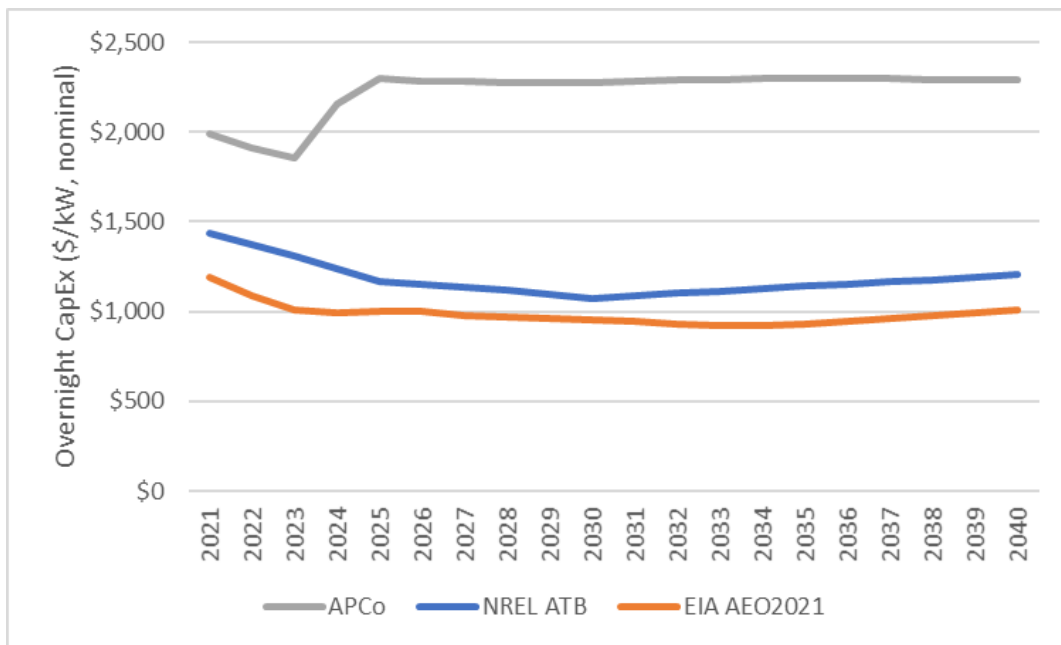
25 KPC Response to Sierra Club RFI 2-6, Attachment 1 (attached as Exhibit RW-4).

26 KPC Response to KIUC-AG RFI 1-2, Attachment 17.

1 **Q. How do KPC’s assumptions about battery storage costs compare to those from**  
 2 **industry sources?**

3 A. KPC’s modeling builds no battery storage resources because of the Company’s high  
 4 assumed build costs for these resources. The build costs used by KPC in the  
 5 PLEXOS model in comparison to ATB and EIA are shown below in Figure 9.

**Figure 5. Comparison of overnight capital cost forecasts for battery storage, KPC, ATB 2020, and AEO 2021**



6 Sources: National Renewable Energy Laboratory, Annual Technology Baseline (2020), available at:  
 7 <https://atb.nrel.gov/electricity/2020/data.php>; Energy Information Administration, Annual Energy  
 8 Outlook (2021) at Table 55, available at: [https://www.eia.gov/outlooks/aeo/data/browser](https://www.eia.gov/outlooks/aeo/data/browser/#/?id=123-AEO2021&cases=ref2021&sourcekey=0)  
 9 [/#/?id=123-AEO2021&cases=ref2021&sourcekey=0](https://www.eia.gov/outlooks/aeo/data/browser/#/?id=123-AEO2021&cases=ref2021&sourcekey=0); and KPC Response to Sierra Club RFI 2-7,  
 10 Attachment 1, attached as Exhibit RW-5.

11 **5. SYNAPSE MODELING RESULTS**

12 **Q. What were the results of the Synapse modeling analysis?**

13 A. In contrast to KPC’s modeling analysis, Synapse’s modeling found that Kentucky  
 14 ratepayers save money under the 2028 Retirement scenario relative to the continued

1 operation of Mitchell until 2040. When compared to the Synapse BAU, the  
 2 retirement of Mitchell in 2028 would save ratepayers approximately \$194 million.

3 The benefits to ratepayers from retirement grow under the Base With Carbon price  
 4 forecast relative to the BAU, with the retirement of Mitchell in 2028 resulting in  
 5 ratepayer savings of \$341 million. The revenue requirements for each of the four  
 6 Synapse scenarios, under KPC's Base No Carbon and Base With Carbon pricing  
 7 forecasts, are shown below in Table 8.

**Table 9. Net present value of revenue requirements, Synapse modeling scenarios**

Scenario	Base No Carbon		Base With Carbon	
	NPVRR (\$Millions)	Delta from BAU (\$Millions)	NPVRR (\$Millions)	Delta from BAU (\$Millions)
Synapse BAU	\$2,850	n/a	\$3,239	n/a
Synapse 2028 Retirement	\$2,656	(\$194)	\$2,898	(\$341)

8 **Q. Can the NPVRR values for the Synapse scenarios be compared directly to the**  
 9 **NPVRR values from KPC's analysis?**

10 **A.** No. There are a few reasons why results would differ. The first key reason is that  
 11 KPC used the PLEXOS model while Synapse used EnCompass. Each model has  
 12 different optimization and dispatch algorithms and would produce different results  
 13 even when using the same inputs. For this reason, Synapse always reproduces a  
 14 utility's base case scenario, or BAU, to produce an NPVRR value to which we can  
 15 compare results from alternative scenarios. In this case we updated the resource  
 16 cost assumptions in the Synapse BAU as well as in our 2028 Retirement scenarios  
 17 so that the BAU costs were not artificially high.

1           Second, Synapse is an independent consulting firm that is not afforded the same  
2           level of access to the details of KPC's electric system as is given to AEP's modelers.  
3           As a result, there may be certain inputs in KPC's analysis that are represented  
4           slightly differently in the Synapse analysis. The key, however, is that these elements  
5           are the same among all the modeled Synapse scenarios and are not therefore driving  
6           the differences in these scenarios. The only way that one can perfectly replicate a  
7           utility's analysis is to use the same model, version number, and exact input files.  
8           The models used by utilities often must be licensed by intervenors on a project basis  
9           and are cost prohibitive. While I am familiar with the PLEXOS model and have  
10          used it in previous work, there are limits to the extent to which one can reconstruct  
11          an analysis without the opportunity to spend time exploring a utility's database  
12          within the model's interface.

13          Finally, KPC's NPVRR values include an analysis period from 2021 to 2050 and  
14          include an end effects period, while the Synapse values only include the period  
15          from 2021 to 2050. The Synapse NPVRR values in all scenarios are not directly  
16          comparable to KPC's because they do not include a similar end effects period.

17          It is not the delta between the KPC scenarios and the Synapse scenarios that matters  
18          in this case, but rather the deltas between each entity's own set of modeled  
19          scenarios. For all of these reasons, the Synapse NPVRR values should be compared  
20          to each other and not compared directly to the KPC values.

1 **Q. What types and quantities of replacement resources are added in the Synapse**  
2 **scenarios?**

3 A. The EnCompass model was allowed to optimize the buildout of replacement  
4 resources for the retiring coal units beginning with wind in 2023 and with  
5 replacement solar PV and battery storage resources in 2024. Solar PV and battery  
6 storage were offered as both standalone and paired resources.<sup>27</sup>

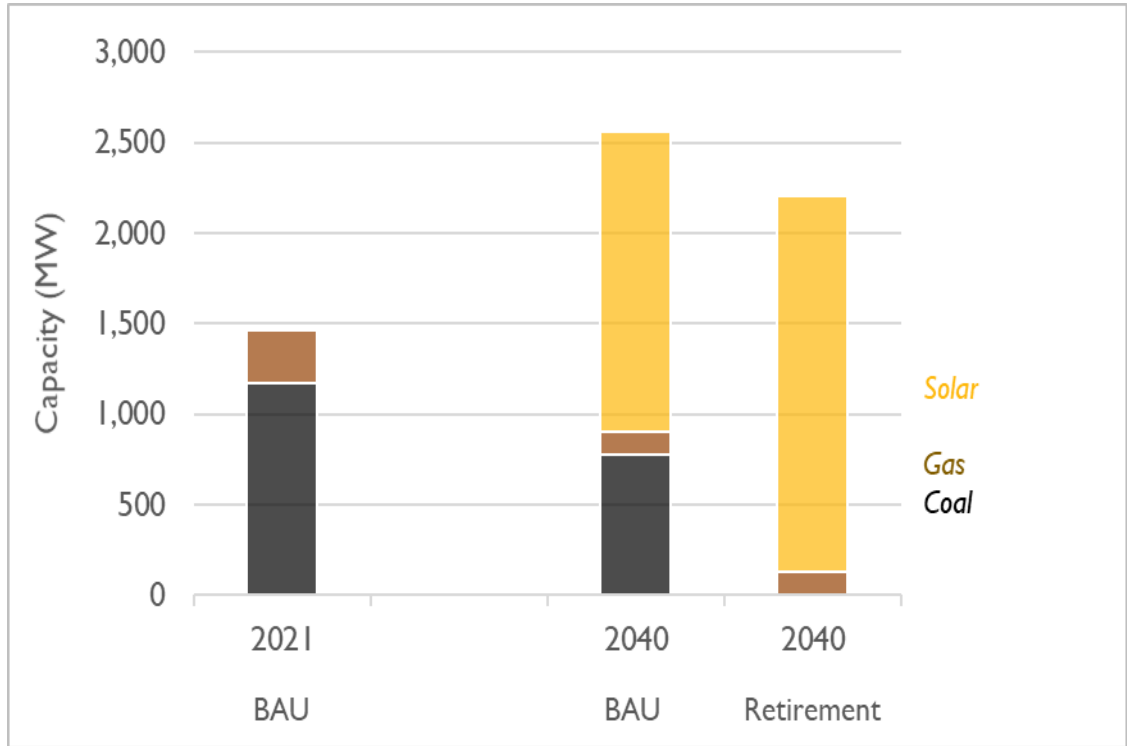
7 Figure 5 below compares the capacity in 2021, which is the same in both scenarios,  
8 to the capacity in 2040 in the BAU and 2028 Retirement scenarios. In addition to  
9 what is shown in Figure 5, EnCompass also selects 50 MW of the Capacity Only  
10 PPA in 2040 in the 2028 Retirement scenario.<sup>28</sup>

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27 Per the Kentucky Power 2019 IRP, a small combustion turbine is added in 2031 as a partial replacement for the Big Sandy unit. This resource is added in both scenarios.

28 The Capacity Only PPA was included in KPC's modeling as a replacement resource option. It is available in 50-MW blocks, with an annual maximum of 400 MW, and is one year in duration. The Capacity Only PPA is priced at the capacity price forecast from the AEP Fundamentals Forecast.

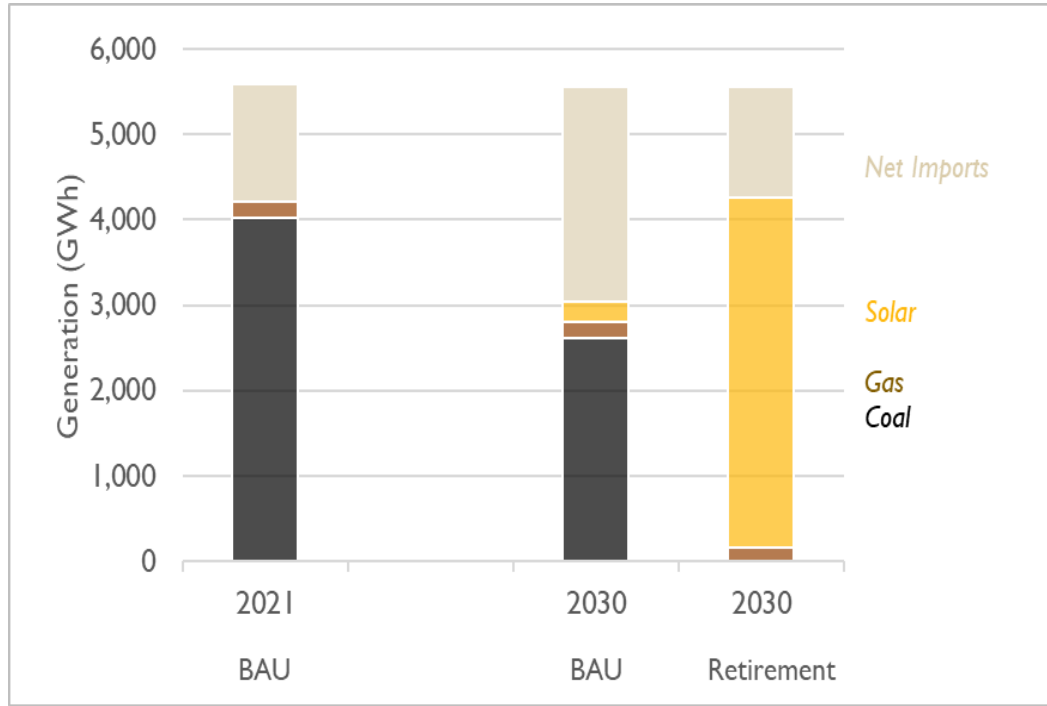
**Figure 6. Comparison of nameplate capacity in Synapse modeled scenarios, Base No Carbon**



1        When we look at generation in 2030 under both scenarios, we see that coal  
 2        generation has declined in the BAU, and imports have increased relative to 2021.  
 3        In the 2028 Retirement scenario, KPC’s generation is largely coming from solar  
 4        resources with smaller amounts of imports. This comparison is shown below in  
 5        Figure 6.

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**Figure 7. Comparison of generation in Synapse modeled scenarios, Base No Carbon**



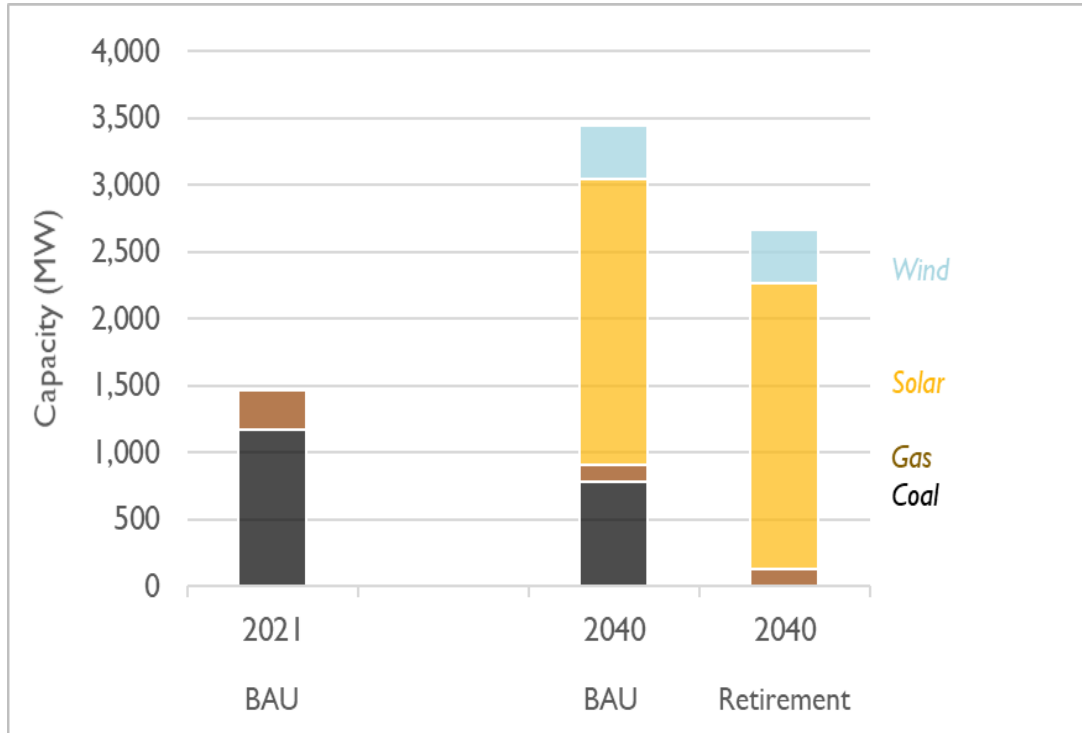
3

4 **Q. Does the resource portfolio look different when a price on CO<sub>2</sub> is included in**  
5 **the modeling?**

6 A. Yes. The addition of a price on CO<sub>2</sub> changes AEP's energy market price forecast  
7 such that the model finds it economic to also add new wind units to the resource  
8 portfolio. The capacity mix under the Base With Carbon commodity price forecast  
9 is shown below in Figure 7.



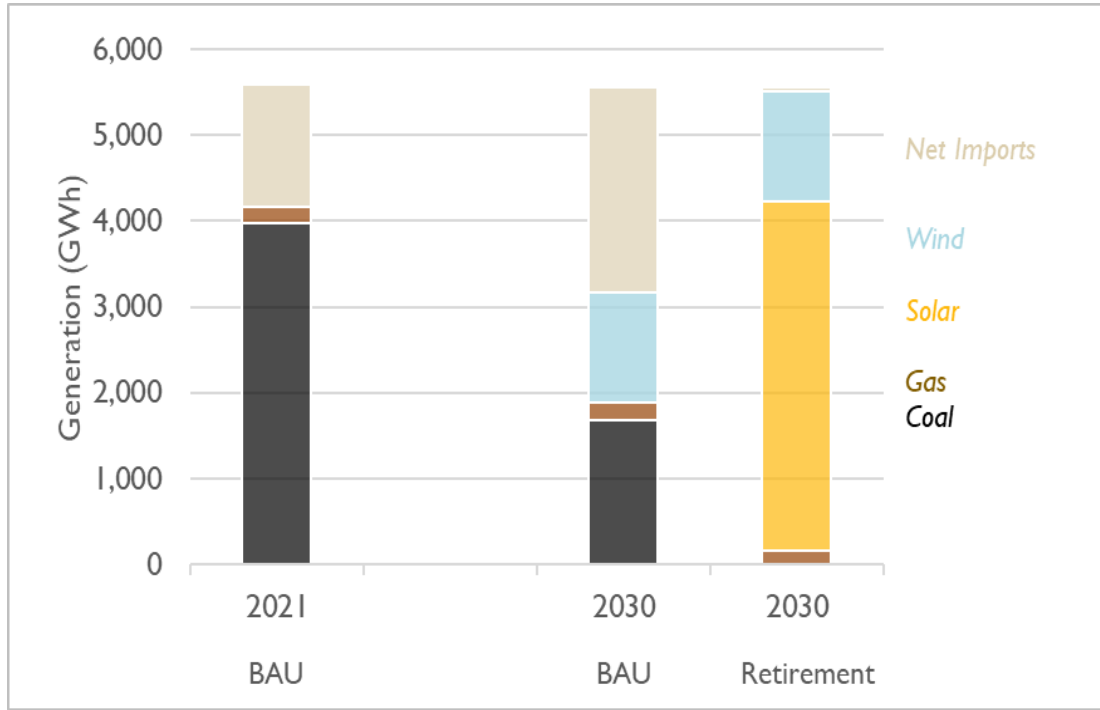
**Figure 8. Comparison of nameplate capacity in Synapse modeled scenarios, Base With Carbon**



1 Wind generation is often complementary to solar generation, producing energy in  
 2 the early mornings, late evenings, and overnight when the sun is not shining. Below,  
 3 Figure 8 shows the generation mix under the two resource portfolios when a CO<sub>2</sub>  
 4 price is included. The addition of wind energy has displaced the majority of the  
 5 imported energy in the 2028 Retirement scenario, such that KPC’s reliance on  
 6 imports in 2030 is shown to be minimal, particularly when compared to the fuel  
 7 mix in the BAU scenario in that same year.

1  
2

**Figure 9. Comparison of generation in Synapse modeled scenarios, Base With Carbon**



3

4 **Q. How do CO<sub>2</sub> emissions compare between the two Synapse scenarios?**

5 A. Emissions of CO<sub>2</sub> in the 2028 Retirement scenario fall dramatically relative to the  
6 BAU after the retirement of Mitchell at the end of 2028 under the Base No Carbon  
7 case. Emissions in 2021, 2030, and 2040 for these two scenarios are shown below  
8 in Table 9, under a No Carbon commodity price forecast.<sup>29</sup> By 2030, CO<sub>2</sub> emissions  
9 in the BAU have fallen by 68 percent relative to 2021, while emissions under the  
10 2028 Retirement scenario have fallen by 97 percent.

**Table 10. Comparison of CO<sub>2</sub> emissions in the Synapse modeled scenarios, Base No Carbon**

	2021	2030	2040
Synapse BAU	4.0	2.7	2.4
Synapse 2028 Retirement	4.0	0.1	0.0

<sup>29</sup> Note that these numbers do not include the emissions associated with PJM imports.

1 AEP, like many of its utility peers, has committed itself to net-zero CO<sub>2</sub> emissions  
 2 by 2050, and has an interim goal to cut emissions 80 percent from 2000 levels by  
 3 2030, while adding more than 10,000 MW of regulated wind and solar.<sup>30</sup> While  
 4 emissions drop in the Synapse BAU after the retirement of Mitchell in 2040, KPC's  
 5 interim emissions reductions are must less than in the 2028 Retirement scenario.

6 **Q. What is the effect of including a CO<sub>2</sub> price in the Synapse modeling analysis?**

7 A. The difference in NPVRR for the BAU, which relies more heavily on coal, in a  
 8 forecast that includes a carbon price versus one that does not is much greater than  
 9 the difference between the Synapse 2028 Retirement scenarios. As shown below in  
 10 Table 10, the CO<sub>2</sub> price adds \$389 million to the cost of the BAU scenario, but only  
 11 \$242 million to the 2028 Retirement scenario. In other words, the risk of following  
 12 the BAU path given the future uncertainties of carbon pricing is much greater than  
 13 in a scenario in which Mitchell retires at the end of 2028.

**Table 11. Comparison of scenarios with and without a carbon price**

Scenario	NPVRR	NPVRR	Delta
	(\$Millions) No Carbon	(\$Millions) With Carbon	
Synapse BAU	\$2,850	\$3,239	\$389
Synapse 2028 Retirement	\$2,656	\$2,898	\$242

14

30 American Electric Power, *Clean Energy Future*, <https://www.aep.com/about/ourstory/cleanenergy#:~:text=Achieving%20net%20zero%20carbon%20dioxide,billion%20in%20renewables%20through%202025> (last accessed April 29, 2021).

1 **Q. Are you suggesting that KPC rely almost exclusively on solar resources to**  
2 **make up a replacement resource portfolio if Mitchell were to retire in 2028?**

3 A. No. Under the pricing assumptions used in the Synapse analysis—which includes  
4 AEP’s market and fuel price forecasts but updates the costs of renewables to be  
5 commensurate with NREL’s ATB—solar is the cheapest resource. The EnCompass  
6 model adds solar resources to meet energy needs in the 2028 Retirement scenario,  
7 displacing as much of KPC’s reliance on imported energy as it can in the hours it  
8 can, but relying on the PJM market to provide the rest. The reserve margin is met  
9 through the building of these resources to provide energy. KPC’s replacement  
10 portfolio, on the other hand, consists entirely of combustion turbines and capacity-  
11 only PPAs, which are intended to provide capacity, but not energy. Neither  
12 portfolio might be expected to serve KPC’s load in an extreme weather event  
13 similar to the one that occurred in Texas in February 2021 (blackouts and high  
14 prices resulted there from a complex set of reasons). However, KPC’s current  
15 portfolio, with its reliance on two units at a single Mitchell plant, also might not be  
16 expected to meet reliability needs.

17 Under the Base With Carbon commodity price forecast, the Synapse 2028  
18 Retirement scenario relies on a combination of wind and solar. This mix of  
19 resources is the one that is more likely actually to materialize, particularly as we  
20 see an extension, or even an increase, in the policies that increase the  
21 competitiveness of these technologies and make the operation of coal less  
22 economic. Given that the retirement of Mitchell would not occur until December

1 21, 2028, KPC would have several years and two more upcoming Integrated  
2 Resource Plans (in 2022 and 2025) to study the ideal replacement resource mix.

3 **Q. You indicated that you also filed testimony in West Virginia on the proposed**  
4 **compliance investments at Mitchell. What did those results show?**

5 A. My West Virginia analysis, set out in my direct testimony filed in WV PSC Case  
6 No. 20-1040-E-CN on May 6, 2021, showed a net benefit to Wheeling Power of  
7 \$118 million with the 2028 retirement of Mitchell under a Base No Carbon forecast,  
8 relative to the Synapse BAU. Savings under a Base With Carbon scenario increased  
9 to \$350 million.

10 **Q. What should this Commission conclude from the Synapse modeling analysis?**

11 A. There are several important takeaways from the Synapse modeling analysis.

12 First, the retirement of Mitchell in 2028 is the least-cost scenario and in the best  
13 interest of Kentucky ratepayers under the regulatory landscape in the electric sector  
14 as it exists today, saving \$194 million. Those savings increase to \$341 million under  
15 a scenario that models an effective price on CO<sub>2</sub>. Moreover, if future additional  
16 environmental regulations not modeled here were to be implemented in the next 20  
17 years that further constrained coal or coal-fired power plants, that could further  
18 increase the savings posed by retiring Mitchell in 2028.

19 Second, the Commission should note that it is in the economic interests of KPC's  
20 ratepayers to integrate additional renewable and storage capacity slightly ahead of  
21 the actual retirement year for Mitchell. This low-variable-cost energy both

1 displaces more expensive fossil generation and/or imported energy and reduces  
2 KPC's reliance on the PJM market.

3 Lastly, the importance of KPC's forecasts for both replacement resources and  
4 market energy prices cannot be understated. These two sets of input assumptions,  
5 both separately and together, are the primary drivers of the revenue requirements  
6 in all modeled scenarios. Synapse used the Mid set of forecasts from ATB 2020,  
7 but as noted above, these have often been criticized as too conservative. The NREL  
8 ATB also includes Low and High cost forecasts for each technology, and KPC  
9 would be advised to model specific nascent resources, like battery storage, using  
10 the Low value to test the sensitivity of its results to changes in technology costs.

## **6. COAL-FIRED POWER PLANTS' INCREASINGLY UNECONOMIC FUTURE PROSPECTS**

11 **Q. What does the future look like for coal-fired generating units in the United**  
12 **States?**

13 **A.** Existing coal-fired generating units will be become even less economic than they  
14 are today, because of economic and regulatory forces that will increase the costs of  
15 operation at coal units relative to other, cheaper types of generation and capacity.  
16 In addition, due to corporate trends and investor preferences beyond economics and  
17 legal constraints, the power sector is moving away from coal in response to  
18 widespread calls to reduce contributions to climate change. In the past five years,

1           48 GW of coal has retired in the United States, with an additional 2.7 GW scheduled  
2           to retire in 2021.<sup>31</sup>

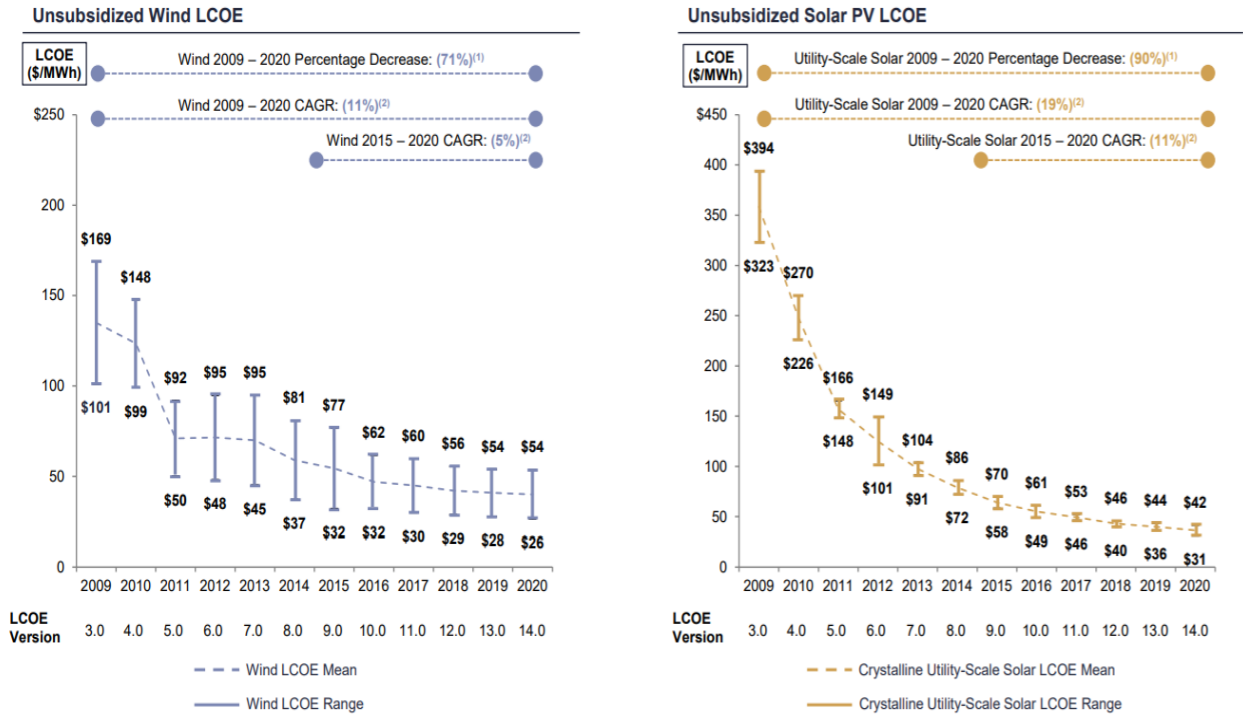
3   **Q.    What are the economic forces that affect the operation of existing coal units?**

4   A.    The primary economic factor is the cost of clean generation technologies, which  
5           have fallen dramatically over the previous decade. On a levelized cost of energy  
6           (LCOE) basis, costs for wind are now 71 percent lower than the costs in 2009, with  
7           a compound annual rate of decline of 11 percent per year. Costs for solar are now  
8           90 percent lower than in 2009, with a compound annual rate of decline of 19 percent  
9           per year. Those annual trends are shown below in Figure 10.

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31 Energy Information Administration, *Nuclear and coal will account for majority of U.S. generating capacity retirements in 2021* (January 12, 2021), available at <https://www.eia.gov/todayinenergy/detail.php?id=46436#:~:text=After%20substantial%20retirements%20of%20coal,of%20the%20U.S.%20coal%20fleet.>

**Figure 10. Historic levelized cost of energy for wind and solar technologies**



Source: Lazard, *Levelized Cost of Energy Analysis 14.0 (2020)*, available at <https://www.lazard.com/media/451419/lazards-levelized-cost-of-energy-version-140.pdf>

1 Battery storage technologies have experienced similar cost declines, but over a  
 2 shorter period of time. Bloomberg New Energy Finance (BNEF) analyzed  
 3 historical battery storage costs, finding that costs for lithium-ion batteries have  
 4 fallen 76 percent between 2012 and the first half of 2019 and noting that these  
 5 declines were the most striking of all observed energy technology cost trends.<sup>32</sup>

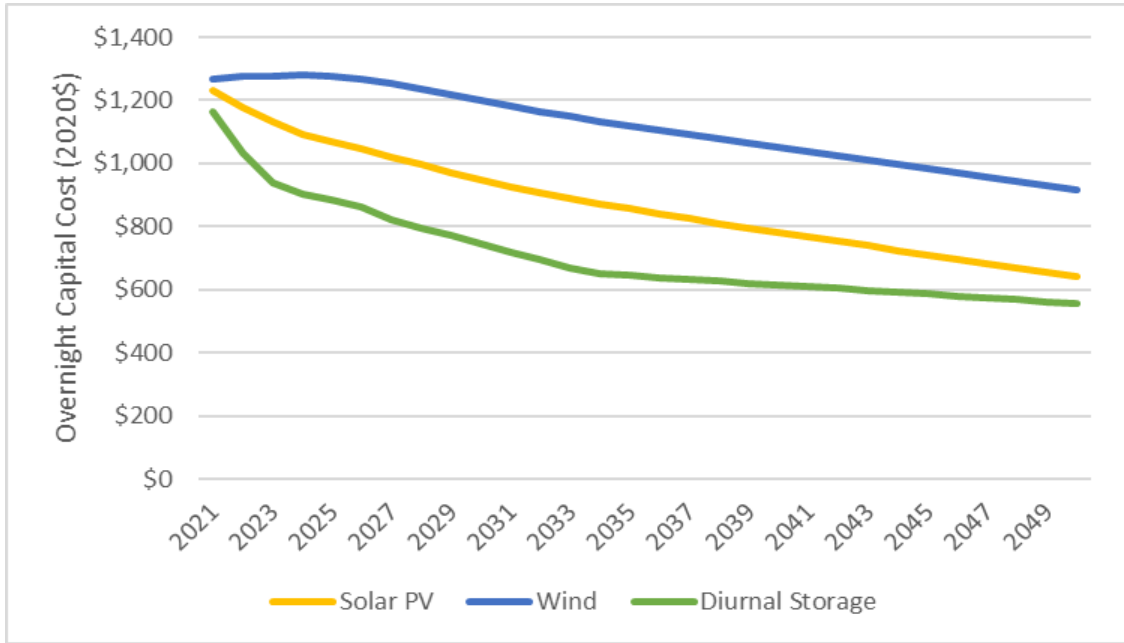
6 These three technologies—solar, wind, and storage—are predicted to continue to  
 7 experience cost declines at varying rates. The US EIA’s forecasts used in

32 HJ Mai, *Electricity costs from battery storage down 76 percent since 2012: BNEF*, UTILITY DIVE (March 26, 2019), available at: <https://www.utilitydive.com/news/electricity-costs-from-battery-storage-down-76-since-2012-bnef/551337/>.



1 developing AEO 2021 for solar PV, wind, and storage resources are shown below  
 2 in Figure 11.

**Figure 11. Forecast of overnight capital costs for new solar, wind, and storage**



Source: Energy Information Administration, *Annual Energy Outlook (2021)* at Table 55, available at: <https://www.eia.gov/outlooks/aeo/data/browser/#/?id=123-AEO2021&cases=ref2021&sourcekey=0>

3 Given KPC’s emphasis on inexpensive capacity in the form of new gas-fired  
 4 combustion turbines as the primary resource selection in its own modeling,<sup>33</sup>  
 5 battery storage costs warrant particular attention. The Synapse modeling uses  
 6 KPC’s values for firm capacity credit, with solar PV and wind receiving 40 percent  
 7 and 12 percent, respectively, and battery storage resources given a higher amount  
 8 of firm capacity of 80 percent. These firm capacity values, coupled with declining  
 9 prices, make storage resources a cost-effective replacement resource for traditional  
 10 peaking units. In fact, a 2018 report by GTM Research and Wood Mackenzie

33 Direct Testimony of Mark A. Becker at 18:21–18:28.

1 predicted that energy storage technologies will regularly compete head-to-head  
2 with new gas-fired peaking units by 2022, and that new gas peaking units will be  
3 rare by 2028.<sup>34</sup>

4 **Q. What are the regulatory forces that challenge the operation of existing coal**  
5 **units?**

6 A. One regulatory force is the increase to renewable portfolio standards (RPS) in  
7 neighboring states that also operate in the PJM market. The volume of zero-  
8 variable-cost resources on the grid in PJM will increase in future years as  
9 neighboring states increase their renewable energy targets, implement more  
10 stringent targets for carbon dioxide emissions reductions, or both. For example, in  
11 2018, New Jersey increased its RPS to 50 percent by 2030.<sup>35</sup> In 2019, Maryland  
12 legislators passed a bill that also increases its RPS to 50 percent by 2030.<sup>36</sup> The  
13 District of Columbia increased its RPS to 100 percent renewable energy by 2040.<sup>37</sup>  
14 There are many other examples, including local/municipal clean energy pledges.  
15 The locational marginal price for energy will decline as a greater number of

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34 Ravi Manghani, *Will Energy Storage Replace Peaker Plants?*, GREENTECH MEDIA (March 1, 2018), available at <https://www.greentechmedia.com/webinars/webinar/will-energy-storage-replace-peaker-plants#gs.6JwDozs>.

35 Energy Information Administration, *Today in energy: Updated renewable portfolio standards will lead to more renewable electricity generation* (2019), available at <https://www.eia.gov/todayinenergy/detail.php?id=38492#:~:text=Under%20the%20previous%20target%2C%20the,35%25%20of%20sales%20by%202030.>

36 Catherine Morehouse, *Maryland 50% RPS bill doubles offshore wind target, expands solar-carve out*, UTILITY DIVE (April 10, 2019), available at <https://www.utilitydive.com/news/maryland-50-rps-bill-doubles-offshore-wind-target-expands-solar-carve-out/552421/>.

37 Utility Dive, *DC eases path for renewable generators as it pursues 100% goal* (2019), available at <https://www.utilitydive.com/news/dc-eases-path-for-renewable-generators-as-it-pursues-100-goal/548259/>.

1 renewable generators come online, further lowering energy revenues earned by coal  
2 units.

3 **Q. Are there other relevant regulatory drivers?**

4 A. Yes, almost certainly, though we do not yet know what they will look like. President  
5 Biden has announced the goal of net-zero carbon dioxide emissions on the  
6 country's power grid by 2035. Policies are not yet in place that are explicitly  
7 intended to achieve this goal; however, it can be assumed that they will consist at  
8 least in part of a combination of incentives for zero-carbon energy and additional  
9 effective costs for fossil-fueled generators. Earlier this year, the U.S. Court of  
10 Appeals for the D.C. Circuit struck down President Trump's Affordable Clean  
11 Energy Rule, requiring the EPA to draft new regulations governing emissions of  
12 CO<sub>2</sub> from power plants. We can expect new regulations affecting the economics of  
13 coal plants from the EPA in the next four years.

14 Meanwhile, there have been different proposals put forth by members of the United  
15 States Congress to extend the production tax credit (PTC) and investment tax credit  
16 (ITC) for renewables and storage for a period of ten years. The proposals vary, but  
17 different provisions include an increased credit for resources cited in low-income  
18 areas, as well as the option for regulated utilities to opt out of tax normalization  
19 requirements.<sup>38</sup> Extensions of the PTC and ITC would lower the costs of  
20 replacement resources for KPC.

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38 KPMG. *KPMG Report: Outlook for What's Ahead for Energy Tax Incentives (Updated)* (2021), available at <https://assets.kpmg/content/dam/kpmg/us/pdf/2021/05/21197.pdf> and enclosed as Exhibit RW-6.

1 **Q. Are there additional forces at play, beyond economic and regulatory levers?**

2 A. Concerns about climate change from consumers and investors, in addition to the  
3 scientific community, are likely only to continue to increase. In response to such  
4 concerns and popular pressure, corporate pledges to reduce carbon emissions are  
5 likely only to strengthen over time. As I noted above, AEP itself has committed to  
6 net-zero CO<sub>2</sub> emissions by 2050 and has an interim goal to cut emissions 80 percent  
7 from 2000 levels by 2030, while adding more than 10,000 MW of regulated wind  
8 and solar.<sup>39</sup> Both the general trend and AEP's current specific goals support the  
9 retirement of Mitchell in 2028. Similarly, they only enhance the risk, if KPC were  
10 to invest in the ELG capital projects, that Mitchell would become a stranded asset  
11 before 2040.

## 12 7. CONCLUSIONS AND RECOMMENDATIONS

13 **Q. Please summarize your conclusions.**

14 A. My independent modeling demonstrates that it is uneconomic, and not in the best  
15 interest of ratepayers, for KPC to invest in both CCR and ELG capital projects at  
16 Mitchell plant in order to continue operating the plant as coal-fired through 2040.  
17 The least-cost option, rather, is to invest in only the CCR projects (to keep Mitchell  
18 operating past 2023), but to forgo the ELG projects and to retire the coal units by  
19 the end of 2028. According to my analysis, retirement in 2028 results in ratepayer

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39 American Electric Power, *Clean Energy Future*, <https://www.aep.com/about/ourstory/cleanenergy#:~:text=Achieving%20net%20zero%20carbon%20dioxide,billion%20in%20renewables%20through%202025> (last accessed April 29, 2021).

1 savings of \$194 million under a Base with No Carbon commodity price forecast,  
2 or \$341 million when an effective carbon price is included. Again, that does not  
3 consider the substantial risk that additional non-carbon regulations could be  
4 promulgated over the next twenty years and further diminish the cost-  
5 competitiveness of coal-fired power plants.

6 **Q. Please summarize your recommendations.**

7 A. Based on my findings, I recommend that the Commission grant a CPCN for the  
8 CCR compliance projects at the Mitchell plant, but not for the ELG projects.

9 **Q. Does this conclude your pre-filed direct testimony?**

10 A. Yes.

## LIST OF EXHIBITS

TO THE DIRECT TESTIMONY OF RACHEL WILSON  
ON BEHALF OF SIERRA CLUB

<b>Exhibit Number</b>	<b>Description of Exhibit</b>	<b>Protected Status</b>
Exhibit RW-1	Resume of Rachel S. Wilson	Non-Confidential
Exhibit RW-2	KPC Response to KIUC-AG RFI 1-14, Confidential Attachment 2 (March 26, 2021)	Confidential
Exhibit RW-3	KPC Response to Sierra Club RFI 2-5, Attachment 1 (May 5, 2021)	Non-Confidential
Exhibit RW-4	KPC Response to Sierra Club RFI 2-6, Attachment 1 (May 5, 2021)	Non-Confidential
Exhibit RW-5	KPC Response to Sierra Club RFI 2-7, Attachment 1 (May 5, 2021)	Non-Confidential
Exhibit RW-6	KPMG. <i>KPMG Report: Outlook for What's Ahead for Energy Tax Incentives (Updated)</i> (2021), available at <a href="https://assets.kpmg/content/dam/kpmg/us/pdf/2021/05/21197.pdf">https://assets.kpmg/content/dam/kpmg/us/pdf/2021/05/21197.pdf</a>	Non-Confidential

## **EXHIBIT RW-1**

Resume of Rachel S. Wilson

## Rachel Wilson, Principal Associate

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Synapse Energy Economics | 485 Massachusetts Avenue, Suite 3 | Cambridge, MA 02139 | 617-453-7044  
rwilson@synapse-energy.com

### PROFESSIONAL EXPERIENCE

**Synapse Energy Economics Inc.**, Cambridge, MA. *Principal Associate*, April 2019 – present, *Senior Associate*, 2013 – 2019, *Associate*, 2010 – 2013, *Research Associate*, 2008 – 2010.

Provides consulting services and expert analysis on a wide range of issues relating to the electricity and natural gas sectors including: integrated resource planning; federal and state clean air policies; emissions from electricity generation; electric system dispatch; and environmental compliance technologies, strategies, and costs. Uses optimization and electricity dispatch models, including Strategist, PLEXOS, EnCompass, PROMOD, and PROSYM/Market Analytics to conduct analyses of utility service territories and regional energy markets.

**Analysis Group, Inc.**, Boston, MA.

*Associate*, 2007 – 2008, *Senior Analyst Intern*, 2006 – 2007.

Provided litigation support and performed data analysis on various topics in the electric sector, including tradeable emissions permitting, coal production and contractual royalties, and utility financing and rate structures. Contributed to policy research, reports, and presentations relating to domestic and international cap-and-trade systems and linkage of international tradeable permit systems. Managed analysts' work processes and evaluated work products.

**Yale Center for Environmental Law and Policy**, New Haven, CT. *Research Assistant*, 2005 – 2007.

Gathered and managed data for the Environmental Performance Index, presented at the 2006 World Economic Forum. Interpreted statistical output, wrote critical analyses of results, and edited report drafts. Member of the team that produced *Green to Gold*, an award-winning book on corporate environmental management and strategy. Managed data, conducted research, and implemented marketing strategy.

**Marsh Risk and Insurance Services, Inc.**, Los Angeles, CA. *Risk Analyst*, Casualty Department, 2003 – 2005.

Evaluated Fortune 500 clients' risk management programs/requirements and formulated strategic plans and recommendations for customized risk solutions. Supported the placement of \$2 million in insurance premiums in the first year and \$3 million in the second year. Utilized quantitative models to create loss forecasts, cash flow analyses and benchmarking reports. Completed a year-long Graduate Training Program in risk management; ranked #1 in the western region of the US and shared #1 national ranking in a class of 200 young professionals.



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## EDUCATION

**Yale School of Forestry & Environmental Studies**, New Haven, CT

Master of Environmental Management, concentration in Law, Economics, and Policy with a focus on energy issues and markets, 2007

**Claremont McKenna College**, Claremont, California

Bachelor of Arts in Environment, Economics, Politics (EEP), 2003. *Cum laude* and EEP departmental honors.

**School for International Training**, Quito, Ecuador

Semester abroad studying Comparative Ecology. Microfinance Intern – Viviendas del Hogar de Cristo in Guayaquil, Ecuador, Spring 2002.

## ADDITIONAL SKILLS AND ACCOMPLISHMENTS

- Microsoft Office Suite, Lexis-Nexis, Platts Energy Database, Strategist, PROMOD, PROSYM/Market Analytics, EnCompass, and PLEXOS, some SAS and STATA.
- Competent in oral and written Spanish.
- Hold the Associate in Risk Management (ARM) professional designation.

## PUBLICATIONS

Bhandari, D., M. Chang, P. Eash-Gates, J. Frost, S. Letendre, J. Litynski, C. Roberto, A. Takasugi, J. Taberner. R. Wilson. 2021. *Exelon Illinois Nuclear Fleet Audit*. Synapse Energy Economics for Illinois Environmental Protection Agency.

Wilson, R., E. Camp, N. Garner, T. Vitolo. 2020. *Obsolete Atlantic Coast Pipeline Has Nothing to Deliver: An examination of the dramatic shifts in the energy, policy, and economic landscape in Virginia and North Carolina since 2017 shows there is little need for new gas generation*. Synapse Energy Economics for Southern Environmental Law Center.

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Eash-Gates, P., D. Glick, S. Kwok. R. Wilson. 2020. *Orlando's Renewable Energy Future: The Path to 100 Percent Renewable Energy by 2020*. Synapse Energy Economics for the First 50 Coalition.

Biewald, B., D. Glick, J. Hall, C. Odom, C. Roberto, R. Wilson. 2020. *Investing In Failure: How Large Power Companies are Undermining their Decarbonization Targets*. Synapse Energy Economics for Climate Majority Project.

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Wilson, R., D. Bhandari. 2019. *The Least-Cost Resource Plan for Santee Cooper: A Path to Meet Santee Cooper's Customer Electricity Needs at the Lowest Cost and Risk*. Synapse Energy Economics for the Sierra Club, Southern Environmental Law Center, and Coastal Conservation League.

Wilson, R., N. Peluso, A. Allison. 2019. *North Carolina's Clean Energy Future: An Alternative to Duke's Integrated Resource Plan*. Synapse Energy Economics for the North Carolina Sustainable Energy Association.

Wilson, R., N. Peluso, A. Allison. 2019. *Modeling Clean Energy for South Carolina: An Alternative to Duke's Integrated Resource Plan*. Synapse Energy Economics for the South Carolina Solar Business Alliance.

Camp, E., B. Fagan, J. Frost, D. Glick, A. Hopkins, A. Napoleon, N. Peluso, K. Takahashi, D. White, R. Wilson, T. Woolf. 2018. *Phase 1 Findings on Muskrat Falls Project Rate Mitigation*. Synapse Energy Economics for Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Allison, A., R. Wilson, D. Glick, J. Frost. 2018. *Comments on South Africa 2018 Integrated Resource Plan*. Synapse Energy Economics for Centre for Environmental Rights.

Hall, J., R. Wilson, J. Kallay. 2018. *Effects of the Draft CAFE Standard Rule on Vehicle Safety*. Synapse Energy Economics on behalf of Consumers Union.

Whited, M., A. Allison, R. Wilson. 2018. *Driving Transportation Electrification Forward in New York: Considerations for Effective Transportation Electrification Rate Design*. Synapse Energy Economics on behalf of the Natural Resources Defense Council.

Wilson, R., S. Fields, P. Knight, E. McGee, W. Ong, N. Santen, T. Vitolo, E. A. Stanton. 2016. *Are the Atlantic Coast Pipeline and the Mountain Valley Pipeline Necessary? An examination of the need for additional pipeline capacity in Virginia and Carolinas*. Synapse Energy Economics for Southern Environmental Law Center and Appalachian Mountain Advocates.

Wilson, R., T. Comings, E. A. Stanton. 2015. *Analysis of the Tongue River Railroad Draft Environmental Impact Statement*. Synapse Energy Economics for Sierra Club and Earthjustice.

Wilson, R., M. Whited, S. Jackson, B. Biewald, E. A. Stanton. 2015. *Best Practices in Planning for Clean Power Plan Compliance*. Synapse Energy Economics for the National Association of State Utility Consumer Advocates.

Luckow, P., E. A. Stanton, S. Fields, B. Biewald, S. Jackson, J. Fisher, R. Wilson. 2015. *2015 Carbon Dioxide Price Forecast*. Synapse Energy Economics.

Stanton, E. A., P. Knight, J. Daniel, B. Fagan, D. Hurley, J. Kallay, E. Karaca, G. Keith, E. Malone, W. Ong, P. Peterson, L. Silvestrini, K. Takahashi, R. Wilson. 2015. *Massachusetts Low Gas Demand Analysis: Final Report*. Synapse Energy Economics for the Massachusetts Department of Energy Resources.

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Fagan, B., R. Wilson, D. White, T. Woolf. 2014. *Filing to the Nova Scotia Utility and Review Board on Nova Scotia Power's October 15, 2014 Integrated Resource Plan: Key Planning Observations and Action Plan Elements*. Synapse Energy Economics for the Nova Scotia Utility and Review Board.

Wilson, R., B. Biewald, D. White. 2014. *Review of BC Hydro's Alternatives Assessment Methodology*. Synapse Energy Economics for BC Hydro.

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Fagan, R., P. Luckow, D. White, R. Wilson. 2013. *The Net Benefits of Increased Wind Power in PJM*. Synapse Energy Economics for Energy Future Coalition.

Hornby, R., R. Wilson. 2013. *Evaluation of Merger Application filed by APCo and WPCo*. Synapse Energy Economics for West Virginia Consumer Advocate Division.

Johnston, L., R. Wilson. 2012. *Strategies for Decarbonizing Electric Power Supply*. Synapse Energy Economics for Regulatory Assistance Project, Global Power Best Practice Series, Paper #6.

Wilson, R., P. Luckow, B. Biewald, F. Ackerman, E. Hausman. 2012. *2012 Carbon Dioxide Price Forecast*. Synapse Energy Economics.

Hornby, R., R. Fagan, D. White, J. Rosenkranz, P. Knight, R. Wilson. 2012. *Potential Impacts of Replacing Retiring Coal Capacity in the Midwest Independent System Operator (MISO) Region with Natural Gas or Wind Capacity*. Synapse Energy Economics for Iowa Utilities Board.

Fagan, R., M. Chang, P. Knight, M. Schultz, T. Comings, E. Hausman, R. Wilson. 2012. *The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region*. Synapse Energy Economics for Energy Future Coalition.

Fisher, J., C. James, N. Hughes, D. White, R. Wilson, and B. Biewald. 2011. *Emissions Reductions from Renewable Energy and Energy Efficiency in California Air Quality Management Districts*. Synapse Energy Economics for California Energy Commission.

Wilson, R. 2011. *Comments Regarding MidAmerican Energy Company Filing on Coal-Fired Generation in Iowa*. Synapse Energy Economics for the Iowa Office of the Consumer Advocate.

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Peterson, P., V. Sabodash, R. Wilson, D. Hurley. 2010. *Public Policy Impacts on Transmission Planning*. Synapse Energy Economics for Earthjustice.

Fisher, J., J. Levy, Y. Nishioka, P. Kirshen, R. Wilson, M. Chang, J. Kallay, C. James. 2010. *Co-Benefits of Energy Efficiency and Renewable Energy in Utah: Air Quality, Health and Water Benefits*. Synapse Energy Economics, Harvard School of Public Health, Tufts University for State of Utah Energy Office.

Fisher, J., C. James, L. Johnston, D. Schlissel, R. Wilson. 2009. *Energy Future: A Green Alternative for Michigan*. Synapse Energy Economics for Natural Resources Defense Council (NRDC) and Energy Foundation.

Schlissel, D., R. Wilson, L. Johnston, D. White. 2009. *An Assessment of Santee Cooper's 2008 Resource Planning*. Synapse Energy Economics for Rockefeller Family Fund.

Schlissel, D., A. Smith, R. Wilson. 2008. *Coal-Fired Power Plant Construction Costs*. Synapse Energy Economics.

## TESTIMONY

**West Virginia Public Service Commission (Case No. 20-1040-E-CN):** Direct testimony of Rachel Wilson evaluating the application of Appalachian Power Company and Wheeling Power Company for approval of a rate adjustment clause for capital investments and operations and maintenance expenses to comply with the federal Coal Combustion Residuals and Effluent Limitation Guidelines regulations in lieu of retirement of the Amos, Mountaineer, and Mitchell coal plants. On behalf of Sierra Club. May 6, 2021.

**Washington Utilities and Transportation Commission (Docket Nos. UE-200900 and UG-200901):** Direct testimony of Rachel Wilson evaluating Avista's treatment of the costs that it plans to incur for both integration with the Western Energy Imbalance Market (EIM) and ongoing operational support. On behalf of the Public Counsel Unit of the Washington Attorney General's Office. April 21, 2021.

**South Carolina Public Service Commission (Docket Nos. 2019-224-E and 2019-225-E):** Surrebuttal testimony of Rachel S. Wilson providing alternative resource modeling in the Duke Energy Carolinas and Duke Energy Progress Integrated Resource Planning dockets. On behalf of Carolinas Clean Energy Business Association, Natural Resources Defense Council, Sierra Club, Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, and Upstate Forever. April 15, 2021.

**Virginia State Corporation Commission (Case No. PUR-2020-00258):** Direct testimony of Rachel Wilson evaluating the application of Appalachian Power Company for approval of a rate adjustment clause for

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capital investments and operations and maintenance expenses to comply with the federal Coal Combustion Residuals and Effluent Limitation Guidelines regulations in lieu of retirement of the Amos and Mountaineer. On behalf of the Sierra Club. April 9, 2021.

**West Virginia Public Service Commission (Case No. 20-0065-E-ENEC):** Direct testimony of Rachel Wilson evaluating coal unit commitment decisions by Monongahela Power Company and the impact on ratepayers. On behalf of Sierra Club. November 16, 2020.

**Virginia State Corporation Commission (Case No. PUR-2020-00035):** Direct testimony of Rachel Wilson evaluating Dominion's 2020 Integrated Resource Plan and providing independent capacity optimization modeling. On behalf of the Sierra Club. September 15, 2020.

**Virginia State Corporation Commission (Case No. PUR-2020-00015):** Direct testimony of Rachel Wilson examining the economics of the coal units owned by Appalachian Power Company as part of the rate case. On behalf of the Sierra Club. July 30, 2020.

**North Carolina Utilities Commission (Docket No. E-2, SUB 1219):** Direct testimony of Rachel Wilson examining the economics of the coal units owned by Duke Energy Progress as part of the rate case. On behalf of the Sierra Club. April 13, 2020.

**North Carolina Utilities Commission (Docket No. E-2, SUB 1219):** Direct testimony of Rachel Wilson examining the economics of the coal units owned by Duke Energy Carolinas as part of the rate case. On behalf of the Sierra Club. February 25, 2020.

**North Carolina Utilities Commission (Docket No. EMP-105, SUB 0):** Rebuttal testimony of Rachel Wilson evaluating the application of Friesian Holdings, LLC for a Certificate of Public Convenience and Necessity. On behalf of Friesian Holdings, LLC. December 12, 2019.

**Alabama Public Service Commission (Docket No. 32953):** Direct testimony of Rachel Wilson regarding Alabama Power Company's petition for a Certificate of Convenience and Necessity. On behalf of the Sierra Club. December 4, 2019.

**North Carolina Utilities Commission (Docket No. EMP-105, SUB 0):** Direct testimony of Rachel Wilson evaluating the application of Friesian Holdings, LLC for a Certificate of Public Convenience and Necessity. On behalf of Friesian Holdings, LLC. November 26, 2019.

**Georgia Public Service Commission (Docket No. 42516):** Direct testimony of Rachel Wilson regarding coal ash spending in Georgia Power's 2019 Rate Case. On behalf of the Sierra Club. October 17, 2019.

**Mississippi Public Service Commission (Docket No. 2019-UA-116):** Direct testimony of Rachel Wilson regarding Mississippi Power Company's petition to the Mississippi Public Service Commission for a Certification of Public Convenience and Necessity for ratepayer-funded investments required to meet Coal Combustion Residuals regulations at the Victor J. Daniel Electric Generating Facility. On behalf of the Sierra Club. October 16, 2019.

---

**Georgia Public Service Commission (Docket No. 42310 & 42311):** Direct testimony of Rachel Wilson regarding various components of Georgia Power's 2019 Integrated Resource Plan. On behalf of the Sierra Club. April 25, 2019.

**Washington Utilities and Transportation Commission (Dockets UE-170485 & UG-170486):** Response testimony regarding Avista Corporation's production cost modeling. On behalf of Public Counsel Unit of the Washington Attorney General's Office. October 27, 2017.

**Texas Public Utilities Commission (SOAH Docket No. 473-17-1764, PUC Docket No. 46449):** Cross-rebuttal testimony evaluating Southwestern Electric Power Company's application for authority to change rates to recover the costs of investments in pollution control equipment. On behalf of Sierra Club and Dr. Lawrence Brough. May 19, 2017.

**Texas Public Utilities Commission (SOAH Docket No. 473-17-1764, PUC Docket No. 46449):** Direct testimony evaluating Southwestern Electric Power Company's application for authority to change rates to recover the costs of investments in pollution control equipment. On behalf of Sierra Club and Dr. Lawrence Brough. April 25, 2017.

**Virginia State Corporation Commission (Case No. PUE-2015-00075):** Direct testimony evaluating the petition for a Certificate of Public Convenience and Necessity filed by Virginia Electric and Power Company to construct and operate the Greensville County Power Station and to increase electric rates to recover the cost of the project. On behalf of Environmental Respondents. November 5, 2015.

**Missouri Public Service Commission (Case No. ER-2014-0370):** Direct and surrebuttal testimony evaluating the prudence of environmental retrofits at Kansas City Power & Light Company's La Cygne Generating Station. On behalf of Sierra Club. April 2, 2015 and June 5, 2015.

**Oklahoma Corporation Commission (Cause No. PUD 201400229):** Direct testimony evaluating the modeling of Oklahoma Gas & Electric supporting its request for approval and cost recovery of a Clean Air Act compliance plan and Mustang modernization, and presenting results of independent Gentrader modeling analysis. On behalf of Sierra Club. December 16, 2014.

**Michigan Public Service Commission (Case No. U-17087):** Direct testimony before the Commission discussing Strategist modeling relating to the application of Consumers Energy Company for the authority to increase its rates for the generation and distribution of electricity. On behalf of the Michigan Environmental Council and Natural Resources Defense Council. February 21, 2013.

**Indiana Utility Regulatory Commission (Cause No. 44217):** Direct testimony before the Commission discussing PROSYM/Market Analytics modeling relating to the application of Duke Energy Indiana for Certificates of Public Convenience and Necessity. On behalf of Citizens Action Coalition, Sierra Club, Save the Valley, and Valley Watch. November 29, 2012.

**Kentucky Public Service Commission (Case No. 2012-00063):** Direct testimony before the Commission discussing upcoming environmental regulations and electric system modeling relating to the application

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of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity and for approval of its 2012 environmental compliance plan. On behalf of Sierra Club. July 23, 2012.

**Kentucky Public Service Commission (Case No. 2011-00401):** Direct testimony before the Commission discussing STRATEGIST modeling relating to the application of Kentucky Power Company for a Certificate of Public Convenience and Necessity, and for approval of its 2011 environmental compliance plan and amended environmental cost recovery surcharge. On behalf of Sierra Club. March 12, 2012.

**Kentucky Public Service Commission (Case No. 2011-00161 and Case No. 2011-00162):** Direct testimony before the Commission discussing STRATEGIST modeling relating to the applications of Kentucky Utilities Company, and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity, and approval of its 2011 compliance plan for recovery by environmental surcharge. On behalf of Sierra Club and Natural Resources Defense Council (NRDC). September 16, 2011.

**Minnesota Public Utilities Commission (OAH Docket No. 8-2500-22094-2 and MPUC Docket No. E-017/M-10-1082):** Rebuttal testimony before the Commission describing STRATEGIST modeling performed in the docket considering Otter Tail Power's application for an Advanced Determination of Prudence for BART retrofits at its Big Stone plant. On behalf of Izaak Walton League of America, Fresh Energy, Sierra Club, and Minnesota Center for Environmental Advocacy. September 7, 2011.

*Resume updated May 2021*

**EXHIBIT RW-2**

KPC Response to KIUC-AG RFI 1-14, Confidential Attachment 2 (March 26, 2021)

**\*CONFIDENTIAL\***



Kentucky Power Company  
KPSC Case No. 2021-00004  
KIUC-AG's First Set of Data Requests  
Dated March 10, 2021

**DATA REQUEST**

**KIUC-AG\_1\_14** Provide the Mitchell Generating Station's Net Capacity Factor over the past five years. Compare that net capacity factor to the modeled or assumed factors of other potential replacement resources.

**RESPONSE**

Please see KPCO\_R\_KIUC\_AG\_1\_14\_Attachment1 for the net capacity factors for the last five years and KPCO\_R\_KIUC\_AG\_1\_14\_ConfidentialAttachment2 for the forecasted capacity factors.

Capacity factors are dependent on market energy and gas prices for dispatchable resource types such as coal or gas fired units. Capacity factor alone is not a good indicator of the overall value of a given resource. The most likely replacement resources for Mitchell would be some combination of solar, wind, or gas-fired resources. Generally speaking, solar resources in PJM experience capacity factors of around 20-25 percent. Wind resource capacity factors vary widely by location, but generally in areas of PJM suitable for wind development wind achieves between 30 percent and 40 percent capacity factors. Simple cycle gas fired peaking resources typically operate at under 10 percent capacity factors. Combined cycle gas-fired units experience capacity factors as high as 70-90 percent when gas prices are low as they have been in recent periods. The capacity factor is lower when gas prices are higher.

Witness: Mark A. Becker

Case 1 Base with Carbon Fundamental Scenario

Description	Year	Mitchell 1	Mitchell 2
Capacity Factor	2021		
Capacity Factor	2022		
Capacity Factor	2023		
Capacity Factor	2024		
Capacity Factor	2025		
Capacity Factor	2026		
Capacity Factor	2027		
Capacity Factor	2028		
Capacity Factor	2029		
Capacity Factor	2030		
Capacity Factor	2031		
Capacity Factor	2032		
Capacity Factor	2033		
Capacity Factor	2034		
Capacity Factor	2035		
Capacity Factor	2036		
Capacity Factor	2037		
Capacity Factor	2038		
Capacity Factor	2039		
Capacity Factor	2040		

Case 1 Base No Carbon Fundamental Scenario

Description	Year	Mitchell 1	Mitchell 2
Capacity Factor	2021		
Capacity Factor	2022		
Capacity Factor	2023		
Capacity Factor	2024		
Capacity Factor	2025		
Capacity Factor	2026		
Capacity Factor	2027		
Capacity Factor	2028		
Capacity Factor	2029		
Capacity Factor	2030		
Capacity Factor	2031		
Capacity Factor	2032		
Capacity Factor	2033		
Capacity Factor	2034		
Capacity Factor	2035		
Capacity Factor	2036		
Capacity Factor	2037		
Capacity Factor	2038		
Capacity Factor	2039		
Capacity Factor	2040		

Case 1 Low No Carbon Fundamental Scenario

Description	Year	Mitchell 1	Mitchell 2
Capacity Factor	2021		
Capacity Factor	2022		
Capacity Factor	2023		
Capacity Factor	2024		
Capacity Factor	2025		
Capacity Factor	2026		
Capacity Factor	2027		
Capacity Factor	2028		
Capacity Factor	2029		
Capacity Factor	2030		
Capacity Factor	2031		
Capacity Factor	2032		
Capacity Factor	2033		
Capacity Factor	2034		
Capacity Factor	2035		
Capacity Factor	2036		
Capacity Factor	2037		
Capacity Factor	2038		
Capacity Factor	2039		
Capacity Factor	2040		

## **EXHIBIT RW-3**

KPC Response to Sierra Club RFI 2-5, Attachment 1 (May 5, 2021)

Kentucky Power Company  
KPSC Case No. 2021-00004  
Sierra Club's Second Set of Data Requests  
Dated April 20, 2021

**DATA REQUEST**

- SC 2\_5** For each solar resource offered to the PLEXOS model as part of the capacity optimization, for each of the years that resource is available as a resource option, provide the following exactly as input into the PLEXOS model:
- a. The capital cost of that resource.
  - b. The fixed O&M associated with that resource, and the source of this assumption.
  - c. If neither (a) nor (b) are applicable, provide the levelized cost of that resource in \$/MWh.
  - d. If none of the above are applicable, describe how capital and operating costs of each solar resource are input into PLEXOS and provide those data.
  - e. All workpapers that derive the cost of the resource, as input into PLEXOS, documenting original source data, with all cells unlocked and formulae intact
  - f. Any and all annual limits for additions of these resources.
  - g. Any and all cumulative limits for additions of these resources.

**RESPONSE**

a-e. Please see KPCO\_R\_SC\_2\_005\_Attachment1 for the PLEXOS inputs for the 150 MW utility-owned and PPA solar options. The capital cost input, which includes return on rate base, depreciation expense, and income taxes net of investment tax credits is provided in Column B of the Tier 2 Build Cost tab. The process used to compute the PLEXOS input value needed to produce levelized fixed carrying costs on invested capital that correspond to the expected levelized costs of electricity is shown on that tab. The Fixed O&M input is shown in Column Q of the Solar Prices tab.

f and g. 150 MW per year and 450 MW cumulative limits were applied to solar capacity additions.

Witness: Mark A. Becker

Plexos Addition of 50 MW Utility Tier 2 Solar Capital Cost Calculation

	Plexos Input Build Cost (\$/kW)	Units Built	Maximum Capacity (MW)	Build Cost (\$000)	WACC (%)	Inflation Rate (%)	Economic Life (Years)	Tax Rate (%)	Depreciation Method	SLD Method Annuity Calculation (\$000)	Levelized Cost Annuity (\$000)	SLD vs Levelized Annuity (\$000)	SLD vs Levelized Annuity (%)
2022	1182	1	150.00	177,283	7.070%	2.500%	30	26.00%	SLD	13,168	13,168	0	0
2023	1098	1	150.00	164,769	7.070%	2.500%	30	26.00%	SLD	12,239	12,239	0	0
2024	1046	1	150.00	156,946	7.070%	2.500%	30	26.00%	SLD	11,658	11,658	0	0
2025	1139	1	150.00	170,912	7.070%	2.500%	30	26.00%	SLD	12,695	12,695	0	0
2026	1173	1	150.00	176,004	7.070%	2.500%	30	26.00%	SLD	13,073	13,073	0	0
2027	1165	1	150.00	174,787	7.070%	2.500%	30	26.00%	SLD	12,983	12,983	0	0
2028	1166	1	150.00	174,924	7.070%	2.500%	30	26.00%	SLD	12,993	12,993	0	0
2029	1163	1	150.00	174,399	7.070%	2.500%	30	26.00%	SLD	12,954	12,954	0	0
2030	1161	1	150.00	174,179	7.070%	2.500%	30	26.00%	SLD	12,938	12,938	0	0
2031	1161	1	150.00	174,102	7.070%	2.500%	30	26.00%	SLD	12,932	12,932	0	0
2032	1159	1	150.00	173,904	7.070%	2.500%	30	26.00%	SLD	12,917	12,917	0	0
2033	1159	1	150.00	173,802	7.070%	2.500%	30	26.00%	SLD	12,910	12,910	0	0
2034	1159	1	150.00	173,907	7.070%	2.500%	30	26.00%	SLD	12,917	12,917	0	0
2035	1160	1	150.00	174,006	7.070%	2.500%	30	26.00%	SLD	12,925	12,925	0	0
2036	1160	1	150.00	174,012	7.070%	2.500%	30	26.00%	SLD	12,925	12,925	0	0
2037	1159	1	150.00	173,881	7.070%	2.500%	30	26.00%	SLD	12,916	12,916	0	0
2038	1157	1	150.00	173,618	7.070%	2.500%	30	26.00%	SLD	12,896	12,896	0	0
2039	1157	1	150.00	173,493	7.070%	2.500%	30	26.00%	SLD	12,887	12,887	0	0
2040	1156	1	150.00	173,327	7.070%	2.500%	30	26.00%	SLD	12,874	12,874	0	0
2041	1156	1	150.00	173,341	7.070%	2.500%	30	26.00%	SLD	12,875	12,875	0	0
2042	1156	1	150.00	173,423	7.070%	2.500%	30	26.00%	SLD	12,882	12,882	0	0
2043	1158	1	150.00	173,636	7.070%	2.500%	30	26.00%	SLD	12,897	12,897	0	0
2044	1158	1	150.00	173,744	7.070%	2.500%	30	26.00%	SLD	12,905	12,905	0	0
2045	1159	1	150.00	173,894	7.070%	2.500%	30	26.00%	SLD	12,916	12,916	0	0
2046	1160	1	150.00	173,941	7.070%	2.500%	30	26.00%	SLD	12,920	12,920	0	0
2047	1159	1	150.00	173,914	7.070%	2.500%	30	26.00%	SLD	12,918	12,918	0	0
2048	1158	1	150.00	173,765	7.070%	2.500%	30	26.00%	SLD	12,907	12,907	0	0
2049	1159	1	150.00	173,805	7.070%	2.500%	30	26.00%	SLD	12,910	12,910	0	0
2050	1158	1	150.00	173,731	7.070%	2.500%	30	26.00%	SLD	12,904	12,904	0	0

Real Annuity Factor = 12.322  
 Nominal Annuity Factor = 9.776  
 SLD Factor = 0.074278159

2020 KPCo CCR/ELG  
 Solar Alternative Pricing

COD EOY	Modeling YR	Column L				Column I		FO&M Charge		FO&M Cos	Max Capacity (MW)	
		Annual Levelized Capital Cost (\$/MWh)	Annual Levelized Cost (\$000)			\$/kW FOM	\$/KW-Yr	Input FOM				
2021	2022	\$45.28	13,168			\$23.74	\$32.08			3563.1	150	\$0.01
2022	2023	\$42.09	12,239	0.93		\$23.81	\$32.18			3574.2	150	\$0.02
2023	2024	\$40.09	11,658	0.95		\$24.01	\$32.44			3606.253	150	\$0.03
2024	2025	\$43.66	12,695	1.09		\$24.25	\$32.78			3640.8	150	\$0.02
2025	2026	\$44.96	13,073	1.03		\$24.55	\$33.18			3685.2	150	\$0.02
2026	2027	\$44.65	12,983	0.99		\$24.93	\$33.68			3740.7	150	\$0.01
2027	2028	\$44.68	12,993	1.00		\$25.33	\$34.23			3806.601	150	\$0.05
2028	2029	\$44.55	12,954	1.00		\$25.73	\$34.76			3862.8	150	\$0.03
2029	2030	\$44.49	12,938	1.00		\$26.13	\$35.31			3918.3	150	-\$0.01
2030	2031	\$44.47	12,932	1.00		\$26.54	\$35.86			3984.9	150	\$0.03
2031	2032	\$44.42	12,917	1.00		\$26.95	\$36.41			4051.47	150	\$0.06
2032	2033	\$44.40	12,910	1.00		\$27.36	\$36.97			4107	150	\$0.02
2033	2034	\$44.42	12,917	1.00		\$27.78	\$37.54			4162.5	150	-\$0.03
2034	2035	\$44.45	12,925	1.00		\$28.21	\$38.12			4229.1	150	-\$0.01
2035	2036	\$44.45	12,925	1.00		\$28.64	\$38.70			4307.469	150	\$0.08
2036	2037	\$44.42	12,916	1.00		\$29.07	\$39.28			4362.3	150	\$0.01
2037	2038	\$44.35	12,896	1.00		\$29.51	\$39.88			4428.9	150	\$0.02
2038	2039	\$44.32	12,887	1.00		\$29.96	\$40.48			4495.5	150	\$0.01
2039	2040	\$44.27	12,874	1.00		\$30.41	\$41.09			4574.599	150	\$0.09
2040	2041	\$44.28	12,875	1.00		\$30.87	\$41.72			4628.7	150	-\$0.01
2041	2042	\$44.30	12,882	1.00		\$31.34	\$42.35			4695.3	150	-\$0.03
2042	2043	\$44.35	12,897	1.00		\$31.81	\$42.99			4773	150	\$0.01
2043	2044	\$44.38	12,905	1.00		\$32.28	\$43.62			4852.859	150	\$0.07
2044	2045	\$44.42	12,916	1.00		\$32.76	\$44.27			4917.3	150	\$0.02
2045	2046	\$44.43	12,920	1.00		\$33.23	\$44.91			4983.9	150	-\$0.01
2046	2047	\$44.42	12,918	1.00		\$33.71	\$45.56			5061.6	150	\$0.03
2047	2048	\$44.39	12,907	1.00		\$34.19	\$46.20			5142.25	150	\$0.09
2048	2049	\$44.40	12,910	1.00		\$34.67	\$46.85			5205.9	150	\$0.03
2049	2050	\$44.38	12,904	1.00		\$35.15	\$47.51			5272.5	150	\$0.00
2050	2051	\$44.32	12,888	1.00		\$35.64	\$48.16					

Generic Solar  
**EIA**  
 Annual Energy (GWh) 290.7882  
 Capacity (MW) 150  
 Capacity Factor (%) 22.1  
 Inflation (%) 1%



Kentucky Power Company  
 Annual Investment Carrying Charges  
 For Economic Analyses  
 As of 12/31/2019

	Investment Life (Years)											
	2	3	4	5	10	15	20	25	30	33	40	50
Return (1)	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07
Depreciation (2)	49.04	31.91	23.32	18.19	8.04	4.78	3.23	2.35	1.81	1.57	1.18	0.85
FIT (3) (4)	1.06	0.77	0.82	0.68	0.64	0.77	0.80	0.69	0.62	0.59	0.54	0.49
Property Taxes, General & Admin Expenses	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45
Carrying Cost Per Year	58.62	41.19	32.66	27.39	17.20	14.07	12.55	11.57	10.95	10.68	10.24	9.86

(1) Based on a 100% (as of 12/31/2019) and 0% incremental weighting of capital costs

(2) Sinking Fund annuity with R1 Dispersion of Retirements

(3) Assuming MACRS Tax Depreciation

(4) @ 21% Federal Income Tax Rate

Project Name	OpCo	COD	Tier	Calc CF	Levelized CF	ITC %	Build Cost \$/kW	Levelized O&M \$/kW	Levelized O&M \$/MWh	Levelized Cost of Energy \$/MWh	Levelized Capital Cost \$/MWh
2021COD-KYP-Tier 2	KYP	2021	Tier 2	23.23%	22.13%	30%	\$1,353	\$23.74	\$12.32	\$57.60	\$45.28
2022COD-KYP-Tier 2	KYP	2022	Tier 2	23.23%	22.13%	30%	\$1,257	\$23.81	\$12.36	\$54.45	\$42.09
2023COD-KYP-Tier 2	KYP	2023	Tier 2	23.22%	22.13%	30%	\$1,198	\$24.01	\$12.46	\$52.55	\$40.09
2024COD-KYP-Tier 2	KYP	2024	Tier 2	23.23%	22.13%	10%	\$1,153	\$24.25	\$12.59	\$56.25	\$43.66
2025COD-KYP-Tier 2	KYP	2025	Tier 2	23.23%	22.13%	0%	\$1,122	\$24.55	\$12.74	\$57.70	\$44.96
2026COD-KYP-Tier 2	KYP	2026	Tier 2	23.23%	22.13%	0%	\$1,114	\$24.93	\$12.93	\$57.58	\$44.65
2027COD-KYP-Tier 2	KYP	2027	Tier 2	23.22%	22.13%	0%	\$1,115	\$25.33	\$13.14	\$57.83	\$44.68
2028COD-KYP-Tier 2	KYP	2028	Tier 2	23.23%	22.13%	0%	\$1,112	\$25.73	\$13.35	\$57.90	\$44.55
2029COD-KYP-Tier 2	KYP	2029	Tier 2	23.23%	22.13%	0%	\$1,110	\$26.13	\$13.56	\$58.05	\$44.49
2030COD-KYP-Tier 2	KYP	2030	Tier 2	23.23%	22.13%	0%	\$1,110	\$26.54	\$13.77	\$58.24	\$44.47
2031COD-KYP-Tier 2	KYP	2031	Tier 2	23.22%	22.13%	0%	\$1,109	\$26.95	\$13.98	\$58.40	\$44.42
2032COD-KYP-Tier 2	KYP	2032	Tier 2	23.23%	22.13%	0%	\$1,108	\$27.36	\$14.20	\$58.59	\$44.40
2033COD-KYP-Tier 2	KYP	2033	Tier 2	23.23%	22.13%	0%	\$1,109	\$27.78	\$14.41	\$58.84	\$44.42
2034COD-KYP-Tier 2	KYP	2034	Tier 2	23.23%	22.13%	0%	\$1,109	\$28.21	\$14.63	\$59.08	\$44.45
2035COD-KYP-Tier 2	KYP	2035	Tier 2	23.22%	22.13%	0%	\$1,109	\$28.64	\$14.86	\$59.31	\$44.45
2036COD-KYP-Tier 2	KYP	2036	Tier 2	23.23%	22.13%	0%	\$1,108	\$29.07	\$15.08	\$59.50	\$44.42
2037COD-KYP-Tier 2	KYP	2037	Tier 2	23.23%	22.13%	0%	\$1,107	\$29.51	\$15.31	\$59.66	\$44.35
2038COD-KYP-Tier 2	KYP	2038	Tier 2	23.23%	22.13%	0%	\$1,106	\$29.96	\$15.54	\$59.86	\$44.32
2039COD-KYP-Tier 2	KYP	2039	Tier 2	23.22%	22.13%	0%	\$1,105	\$30.41	\$15.78	\$60.05	\$44.27
2040COD-KYP-Tier 2	KYP	2040	Tier 2	23.23%	22.13%	0%	\$1,105	\$30.87	\$16.02	\$60.29	\$44.28
2041COD-KYP-Tier 2	KYP	2041	Tier 2	23.23%	22.13%	0%	\$1,105	\$31.34	\$16.26	\$60.55	\$44.30
2042COD-KYP-Tier 2	KYP	2042	Tier 2	23.23%	22.13%	0%	\$1,107	\$31.81	\$16.50	\$60.85	\$44.35
2043COD-KYP-Tier 2	KYP	2043	Tier 2	23.22%	22.13%	0%	\$1,108	\$32.28	\$16.74	\$61.12	\$44.38
2044COD-KYP-Tier 2	KYP	2044	Tier 2	23.23%	22.13%	0%	\$1,108	\$32.76	\$16.99	\$61.41	\$44.42
2045COD-KYP-Tier 2	KYP	2045	Tier 2	23.23%	22.13%	0%	\$1,109	\$33.23	\$17.24	\$61.67	\$44.43
2046COD-KYP-Tier 2	KYP	2046	Tier 2	23.23%	22.13%	0%	\$1,109	\$33.71	\$17.48	\$61.91	\$44.42
2047COD-KYP-Tier 2	KYP	2047	Tier 2	23.22%	22.13%	0%	\$1,108	\$34.19	\$17.73	\$62.12	\$44.39
2048COD-KYP-Tier 2	KYP	2048	Tier 2	23.23%	22.13%	0%	\$1,108	\$34.67	\$17.98	\$62.38	\$44.40
2049COD-KYP-Tier 2	KYP	2049	Tier 2	23.23%	22.13%	0%	\$1,107	\$35.15	\$18.23	\$62.61	\$44.38
2050COD-KYP-Tier 2	KYP	2050	Tier 2	23.23%	22.13%	0%	\$1,106	\$35.64	\$18.48	\$62.80	\$44.32

## **EXHIBIT RW-4**

KPC Response to Sierra Club RFI 2-6, Attachment 1 (May 5, 2021)

Kentucky Power Company  
KPSC Case No. 2021-00004  
Sierra Club's Second Set of Data Requests  
Dated April 20, 2021

**DATA REQUEST**

**SC 2\_6** For each wind resource offered to the PLEXOS model as part of the capacity optimization, for each of the years that resource is available as a resource option, provide the following exactly as input into the PLEXOS model:

- a. The capital cost of that resource.
- b. The fixed O&M associated with that resource, and the source of this assumption.
- c. If neither (a) nor (b) are applicable, provide the levelized cost of that resource in \$/MWh.
- d. If none of the above are applicable, describe how capital and operating costs of each wind resource are input into PLEXOS and provide those data.
- e. All workpapers that derive the cost of the resource, as input into PLEXOS, documenting original source data, with all cells unlocked and formulae intact
- f. Any and all annual limits for additions of these resources.
- g. Any and all cumulative limits for additions of these resources.

**RESPONSE**

a-e. Please see KPCO\_R\_SC\_2\_006\_Attachment1 for the PLEXOS inputs for the 200 MW wind option. The capital cost input, which includes return on rate base, depreciation expense, and income taxes net of production tax credits is provided in Column B of the Build Cost tab. The process used to compute the PLEXOS input value needed to produce levelized fixed carrying costs on invested capital that correspond to the expected levelized costs of electricity is shown on that tab. The Fixed O&M input is shown in Column N of the Wind Prices tab.

f and g. 200 MW per year and 600 MW cumulative limits were applied to wind capacity additions.

Witness: Mark A. Becker

### Plexos Addition of 150 MW Utility Tier 1 Wind Capital Cost Calculation

COD Dec	Plex Yr	Plexos Input Build Cost (\$/kW)	Units Built	Maximum Capacity (MW)	Build Cost (\$000)	WACC (%)	Inflation Rate (%)	Economic Life (Years)	Tax Rate (%)	Depreciation Method	SLD	SLD	SLD	
											Method	Levelized Cost Annuity (\$000)	vs Levelized Annuity (\$000)	vs Levelized Annuity (%)
2022	2023	917	1	200.00	183,406	7.070%	2.500%	30	26.00%	SLD	13,623	13,623	0	0
2023	2024	1088	1	200.00	217,650	7.070%	2.500%	30	26.00%	SLD	16,167	16,167	0	0
2024	2025	887	1	200.00	177,458	7.070%	2.500%	30	26.00%	SLD	13,181	13,181	0	0
2025	2026	1495	1	200.00	299,041	7.070%	2.500%	30	26.00%	SLD	22,212	22,212	0	0
2026	2027	1513	1	200.00	302,650	7.070%	2.500%	30	26.00%	SLD	22,480	22,480	0	0
2027	2028	1530	1	200.00	305,903	7.070%	2.500%	30	26.00%	SLD	22,722	22,722	0	0
2028	2029	1549	1	200.00	309,814	7.070%	2.500%	30	26.00%	SLD	23,012	23,012	0	0
2029	2030	1567	1	200.00	313,435	7.070%	2.500%	30	26.00%	SLD	23,281	23,281	0	0
2030	2031	1584	1	200.00	316,867	7.070%	2.500%	30	26.00%	SLD	23,536	23,536	0	0
2031	2032	1598	1	200.00	319,641	7.070%	2.500%	30	26.00%	SLD	23,742	23,742	0	0
2032	2033	1611	1	200.00	322,115	7.070%	2.500%	30	26.00%	SLD	23,926	23,926	0	0
2033	2034	1621	1	200.00	324,185	7.070%	2.500%	30	26.00%	SLD	24,080	24,080	0	0
2034	2035	1630	1	200.00	326,057	7.070%	2.500%	30	26.00%	SLD	24,219	24,219	0	0
2035	2036	1639	1	200.00	327,718	7.070%	2.500%	30	26.00%	SLD	24,342	24,342	0	0
2036	2037	1648	1	200.00	329,554	7.070%	2.500%	30	26.00%	SLD	24,479	24,479	0	0
2037	2038	1655	1	200.00	331,039	7.070%	2.500%	30	26.00%	SLD	24,589	24,589	0	0
2038	2039	1662	1	200.00	332,359	7.070%	2.500%	30	26.00%	SLD	24,687	24,687	0	0
2039	2040	1670	1	200.00	334,098	7.070%	2.500%	30	26.00%	SLD	24,816	24,816	0	0
2040	2041	1681	1	200.00	336,145	7.070%	2.500%	30	26.00%	SLD	24,968	24,968	0	0
2041	2042	1690	1	200.00	338,058	7.070%	2.500%	30	26.00%	SLD	25,110	25,110	0	0
2042	2043	1701	1	200.00	340,206	7.070%	2.500%	30	26.00%	SLD	25,270	25,270	0	0
2043	2044	1714	1	200.00	342,766	7.070%	2.500%	30	26.00%	SLD	25,460	25,460	0	0
2044	2045	1725	1	200.00	345,030	7.070%	2.500%	30	26.00%	SLD	25,628	25,628	0	0
2045	2046	1737	1	200.00	347,333	7.070%	2.500%	30	26.00%	SLD	25,799	25,799	0	0
2046	2047	1748	1	200.00	349,522	7.070%	2.500%	30	26.00%	SLD	25,962	25,962	0	0
2047	2048	1758	1	200.00	351,684	7.070%	2.500%	30	26.00%	SLD	26,122	26,122	0	0
2048	2049	1768	1	200.00	353,679	7.070%	2.500%	30	26.00%	SLD	26,271	26,271	0	0
2049	2050	1780	1	200.00	355,917	7.070%	2.500%	30	26.00%	SLD	26,437	26,437	0	0
2050	2051													
2051														
Real Annuity Factor =					12.322									
Nominal Annuity Factor =					9.776									
SLD Factor =					0.074278159									

2019 KPCo IRP  
 Wind Alternative Pricing  
 Column J  
 35%  
 Annual

Output Check

COD Dec	Levelized Capital Cost	Levelized Cost (\$000)		Screening FOM	FOM	Plex Year	Generatio	FO&M			
	(\$/MWh)	35 CF						Cost (\$000)	0		
2022	\$22.22	13,623		56.90	76.90	2023	613.2062	11381.2	56.906	0.00	
2023	\$26.36	16,167	1.19	57.50	77.70	2024	616.3852	11531.11	57.65553	0.16	
2024	\$21.50	13,181	0.82	58.34	78.84	2025	613.2062	11668.32	58.3416	0.00	
2025	\$36.22	22,212	1.69	59.25	80.06	2026	613.2062	11848.88	59.2444	0.00	
2026	\$36.66	22,480	1.01	60.26	81.43	2027	613.2062	12051.64	60.2582	0.00	
2027	\$37.05	22,722	1.01	61.25	82.78	2028	616.3852	12285.01	61.42503	0.17	
2028	\$37.53	23,012	1.01	62.29	84.18	2029	613.2062	12458.64	62.2932	0.00	
2029	\$37.97	23,281	1.01	63.32	85.57	2030	613.2062	12664.36	63.3218	0.00	
2030	\$38.38	23,536	1.01	64.35	86.95	2031	613.2062	12868.6	64.343	0.00	
2031	\$38.72	23,742	1.01	65.34	88.29	2032	616.3852	13102.72	65.5136	0.18	
2032	\$39.02	23,926	1.01	66.31	89.61	2033	613.2062	13262.28	66.3114	0.00	
2033	\$39.27	24,080	1.01	67.27	90.91	2034	613.2062	13454.68	67.2734	0.00	
2034	\$39.50	24,219	1.01	68.24	92.21	2035	613.2062	13647.08	68.2354	0.00	
2035	\$39.70	24,342	1.01	69.20	93.52	2036	616.3852	13878.88	69.3944	0.19	
2036	\$39.92	24,479	1.01	70.18	94.84	2037	613.2062	14036.32	70.1816	0.00	
2037	\$40.10	24,589	1.00	71.17	96.17	2038	613.2062	14233.16	71.1658	0.00	
2038	\$40.26	24,687	1.00	72.15	97.50	2039	613.2062	14430	72.15	0.00	
2039	\$40.47	24,816	1.01	73.18	98.89	2040	616.3852	14675.82	73.37909	0.20	
2040	\$40.72	24,968	1.01	74.22	100.30	2041	613.2062	14844.4	74.222	0.00	
2041	\$40.95	25,110	1.01	75.27	101.72	2042	613.2062	15054.56	75.2728	0.00	
2042	\$41.21	25,270	1.01	76.35	103.17	2043	613.2062	15269.16	76.3458	0.00	
2043	\$41.52	25,460	1.01	77.45	104.66	2044	616.3852	15532.12	77.66059	0.21	
2044	\$41.79	25,628	1.01	78.53	106.13	2045	613.2062	15707.24	78.5362	0.00	
2045	\$42.07	25,799	1.01	79.63	107.61	2046	613.2062	15926.28	79.6314	0.00	
2046	\$42.34	25,962	1.01	80.73	109.09	2047	613.2062	16145.32	80.7266	0.00	
2047	\$42.60	26,122	1.01	81.83	110.58	2048	616.3852	16410.68	82.05339	0.22	
2048	\$42.84	26,271	1.01	82.92	112.05	2049	613.2062	16583.4	82.917	0.00	
2049	\$43.11	26,437	1.01	84.02	113.55	2050	613.2062	16805.4	84.027	0.00	
2050	\$43.35	26,583	1.01	85.12	115.03	2051					
2051	\$43.57	26,717	1.01	86.22	116.51	2052					

2023

Generic Wind

Annual Energy (GWh)	613.2
Capacity (MW)	200
Capacity Factor (%)	35
Inflation (%)	1.0%

Kentucky Power Company  
 Annual Investment Carrying Charges  
 For Economic Analyses  
 As of 12/31/2019

	Investment Life (Years)											
	2	3	4	5	10	15	20	25	30	33	40	50
Return (1)	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07
Depreciation (2)	49.04	31.91	23.32	18.19	8.04	4.78	3.23	2.35	1.81	1.57	1.18	0.85
FIT (3) (4)	1.06	0.77	0.82	0.68	0.64	0.77	0.80	0.69	0.62	0.59	0.54	0.49
Property Taxes, General & Admin Expenses	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45
Carrying Cost Per Year	58.62	41.19	32.66	27.39	17.20	14.07	12.55	11.57	10.95	10.68	10.24	9.86

(1) Based on a 100% (as of 12/31/2019) and 0% incremental weighting of capital costs

(2) Sinking Fund annuity with R1 Dispersion of Retirements

(3) Assuming MACRS Tax Depreciation

(4) @ 21% Federal Income Tax Rate

Scenario	OpCo	COD Year	CF	Build Cost (\$/kW)	PTC Credit	Levelized O&M \$/kW	Levelized O&M \$/MWh	Levelized Cost of Energy \$/MWh	Levelized Capital Cost \$/MWh
2022COD-KYP-0.35CF	KYP	2022	35%	\$1,329	60%	\$56.90	\$18.54	\$40.76	\$22.22
2023COD-KYP-0.35CF	KYP	2023	35%	\$1,316	40%	\$57.50	\$18.74	\$45.10	\$26.36
2024COD-KYP-0.35CF	KYP	2024	35%	\$1,322	60%	\$58.34	\$19.01	\$40.51	\$21.50
2025COD-KYP-0.35CF	KYP	2025	35%	\$1,331	0%	\$59.25	\$19.31	\$55.53	\$36.22
2026COD-KYP-0.35CF	KYP	2026	35%	\$1,347	0%	\$60.26	\$19.64	\$56.30	\$36.66
2027COD-KYP-0.35CF	KYP	2027	35%	\$1,361	0%	\$61.25	\$19.96	\$57.01	\$37.05
2028COD-KYP-0.35CF	KYP	2028	35%	\$1,379	0%	\$62.29	\$20.30	\$57.83	\$37.53
2029COD-KYP-0.35CF	KYP	2029	35%	\$1,395	0%	\$63.32	\$20.64	\$58.60	\$37.97
2030COD-KYP-0.35CF	KYP	2030	35%	\$1,410	0%	\$64.35	\$20.97	\$59.35	\$38.38
2031COD-KYP-0.35CF	KYP	2031	35%	\$1,423	0%	\$65.34	\$21.29	\$60.01	\$38.72
2032COD-KYP-0.35CF	KYP	2032	35%	\$1,433	0%	\$66.31	\$21.61	\$60.63	\$39.02
2033COD-KYP-0.35CF	KYP	2033	35%	\$1,443	0%	\$67.27	\$21.92	\$61.19	\$39.27
2034COD-KYP-0.35CF	KYP	2034	35%	\$1,451	0%	\$68.24	\$22.24	\$61.73	\$39.50
2035COD-KYP-0.35CF	KYP	2035	35%	\$1,459	0%	\$69.20	\$22.55	\$62.25	\$39.70
2036COD-KYP-0.35CF	KYP	2036	35%	\$1,467	0%	\$70.18	\$22.87	\$62.79	\$39.92
2037COD-KYP-0.35CF	KYP	2037	35%	\$1,473	0%	\$71.17	\$23.19	\$63.29	\$40.10
2038COD-KYP-0.35CF	KYP	2038	35%	\$1,479	0%	\$72.15	\$23.51	\$63.77	\$40.26
2039COD-KYP-0.35CF	KYP	2039	35%	\$1,487	0%	\$73.18	\$23.85	\$64.32	\$40.47
2040COD-KYP-0.35CF	KYP	2040	35%	\$1,496	0%	\$74.22	\$24.19	\$64.91	\$40.72
2041COD-KYP-0.35CF	KYP	2041	35%	\$1,505	0%	\$75.27	\$24.53	\$65.48	\$40.95
2042COD-KYP-0.35CF	KYP	2042	35%	\$1,514	0%	\$76.35	\$24.88	\$66.09	\$41.21
2043COD-KYP-0.35CF	KYP	2043	35%	\$1,526	0%	\$77.45	\$25.24	\$66.76	\$41.52
2044COD-KYP-0.35CF	KYP	2044	35%	\$1,536	0%	\$78.53	\$25.60	\$67.39	\$41.79
2045COD-KYP-0.35CF	KYP	2045	35%	\$1,546	0%	\$79.63	\$25.95	\$68.03	\$42.07
2046COD-KYP-0.35CF	KYP	2046	35%	\$1,556	0%	\$80.73	\$26.31	\$68.65	\$42.34
2047COD-KYP-0.35CF	KYP	2047	35%	\$1,566	0%	\$81.83	\$26.66	\$69.26	\$42.60
2048COD-KYP-0.35CF	KYP	2048	35%	\$1,574	0%	\$82.92	\$27.02	\$69.87	\$42.84
2049COD-KYP-0.35CF	KYP	2049	35%	\$1,584	0%	\$84.02	\$27.38	\$70.50	\$43.11
2050COD-KYP-0.35CF	KYP	2050	35%	\$1,593	0%	\$85.12	\$27.74	\$71.09	\$43.35
2051COD-KYP-0.35CF	KYP	2051	35%	\$1,601	0%	\$86.22	\$28.09	\$71.66	\$43.57



## **EXHIBIT RW-5**

KPC Response to Sierra Club RFI 2-7, Attachment 1 (May 5, 2021)

Plexos Addition of 50 MW Storage Capital Cost Calculation

	Plexos Input Build Cost	Units Built	Maximum Capacity (MW)	Build Cost (\$000)	WACC (%)	Inflation Rate (%)	Economic Life (Years)	Tax Rate (%)	Depreciation Method	SLD Method Annuity Calculation (\$000)	Levelized Cost Annuity (\$000)	SLD vs Levelized Annuity (\$000)	SLD vs Levelized Annuity (%)
2021	2061	1	50.00	103,059	7.070%	2.500%	10	26.00%	SLD	12,325	12,325	0	0
2022	1982	1	50.00	99,106	7.070%	2.500%	10	26.00%	SLD	11,852	11,852	0	0
2023	1921	1	50.00	96,026	7.070%	2.500%	10	26.00%	SLD	11,484	11,484	0	0
2024	2155	1	50.00	107,775	7.070%	2.500%	10	26.00%	SLD	12,889	12,889	0	0
2025	2267	1	50.00	113,354	7.070%	2.500%	10	26.00%	SLD	13,556	13,556	0	0
2026	2252	1	50.00	112,578	7.070%	2.500%	10	26.00%	SLD	13,463	13,463	0	0
2027	2246	1	50.00	112,295	7.070%	2.500%	10	26.00%	SLD	13,429	13,429	0	0
2028	2243	1	50.00	112,144	7.070%	2.500%	10	26.00%	SLD	13,411	13,411	0	0
2029	2240	1	50.00	112,017	7.070%	2.500%	10	26.00%	SLD	13,396	13,396	0	0
2030	2240	1	50.00	112,016	7.070%	2.500%	10	26.00%	SLD	13,396	13,396	0	0
2031	2246	1	50.00	112,278	7.070%	2.500%	10	26.00%	SLD	13,427	13,427	0	0
2032	2254	1	50.00	112,695	7.070%	2.500%	10	26.00%	SLD	13,477	13,477	0	0
2033	2259	1	50.00	112,938	7.070%	2.500%	10	26.00%	SLD	13,506	13,506	0	0
2034	2262	1	50.00	113,113	7.070%	2.500%	10	26.00%	SLD	13,527	13,527	0	0
2035	2261	1	50.00	113,053	7.070%	2.500%	10	26.00%	SLD	13,520	13,520	0	0
2036	2263	1	50.00	113,134	7.070%	2.500%	10	26.00%	SLD	13,530	13,530	0	0
2037	2261	1	50.00	113,044	7.070%	2.500%	10	26.00%	SLD	13,519	13,519	0	0
2038	2258	1	50.00	112,881	7.070%	2.500%	10	26.00%	SLD	13,500	13,500	0	0
2039	2257	1	50.00	112,832	7.070%	2.500%	10	26.00%	SLD	13,494	13,494	0	0
2040	2259	1	50.00	112,944	7.070%	2.500%	10	26.00%	SLD	13,507	13,507	0	0
2041	2257	1	50.00	112,833	7.070%	2.500%	10	26.00%	SLD	13,494	13,494	0	0
2042	2258	1	50.00	112,903	7.070%	2.500%	10	26.00%	SLD	13,502	13,502	0	0
2043	2260	1	50.00	112,990	7.070%	2.500%	10	26.00%	SLD	13,513	13,513	0	0
2044	2259	1	50.00	112,971	7.070%	2.500%	10	26.00%	SLD	13,510	13,510	0	0
2045	2259	1	50.00	112,953	7.070%	2.500%	10	26.00%	SLD	13,508	13,508	0	0
2046	2259	1	50.00	112,971	7.070%	2.500%	10	26.00%	SLD	13,510	13,510	0	0
2047	2260	1	50.00	112,983	7.070%	2.500%	10	26.00%	SLD	13,512	13,512	0	0
2048	2259	1	50.00	112,928	7.070%	2.500%	10	26.00%	SLD	13,505	13,505	0	0
2049	2257	1	50.00	112,856	7.070%	2.500%	10	26.00%	SLD	13,497	13,497	0	0
2050	2273	1	50.00	113,655	7.070%	2.500%	10	26.00%	SLD	13,592	13,592	0	0
Real Annuity Factor =				7.001									
Nominal Annuity Factor =				6.260									
SLD Factor =				0.119591144									

2020 KPCo IRP  
 Storage Alternative Pricing

50 MW size

Modeling YR		Annual Levelized Cost (\$/MWh)		Annual Levelized Cost (\$000)		\$/kw FOM	FO&M Charge		Scaled up to 50 MW ELCC has 40 MW
		T1 (No PTC)	T2 (w PTC)	Storage	esc		Plexos	Input FOM	
2021	2021	-	\$39.63	12,325		BAT 2021	\$25.28	\$34.17	\$42.71
2022	2022	-	\$38.11	11,852	0.96		\$25.04	0.99 \$33.84	\$42.30
2023	2023	-	\$36.93	11,484	0.97		\$24.92	0.99 \$33.67	\$42.09
2024	2024	-	\$41.45	12,889	1.122341		\$25.11	1.01 \$33.94	\$42.42
2025	2025	-	\$43.59	13,556	1.051771		\$25.31	1.01 \$34.21	\$42.76
2026	2026	-	\$43.29	13,463	0.993152		\$25.49	1.01 \$34.45	\$43.06
2027	2027	-	\$43.18	13,429	0.997485		\$25.73	1.01 \$34.77	\$43.46
2028	2028	-	\$43.13	13,411	0.998659		\$25.98	1.01 \$35.11	\$43.88
2029	2029	-	\$43.08	13,396	0.998866		\$26.23	1.01 \$35.45	\$44.31
2030	2030	-	\$43.08	13,396	0.999993		\$26.50	1.01 \$35.81	\$44.76
2031	2031	-	\$43.18	13,427	1.002335		\$26.79	1.01 \$36.21	\$45.26
2032	2032	-	\$43.34	13,477	1.003715		\$27.11	1.01 \$36.63	\$45.79
2033	2033	-	\$43.43	13,506	1.00216		\$27.41	1.01 \$37.04	\$46.30
2034	2034	-	\$43.50	13,527	1.001545		\$27.70	1.01 \$37.44	\$46.79
2035	2035	-	\$43.48	13,520	0.999469		\$27.98	1.01 \$37.81	\$47.26
2036	2036	-	\$43.51	13,530	1.00072		\$28.27	1.01 \$38.21	\$47.76
2037	2037	-	\$43.47	13,519	0.999207		\$28.55	1.01 \$38.59	\$48.23
2038	2038	-	\$43.41	13,500	0.998558		\$28.83	1.01 \$38.96	\$48.70
2039	2039	-	\$43.39	13,494	0.999562		\$29.12	1.01 \$39.35	\$49.19
2040	2040	-	\$43.43	13,507	1.000991		\$29.44	1.01 \$39.78	\$49.72
2041	2041	-	\$43.39	13,494	0.999017		\$29.73	1.01 \$40.17	\$50.22
2042	2042	-	\$43.42	13,502	1.000622		\$30.04	1.01 \$40.59	\$50.74
2043	2043	-	\$43.45	13,513	1.000774		\$30.35	1.01 \$41.02	\$51.28
2044	2044	-	\$43.44	13,510	0.999827		\$30.66	1.01 \$41.44	\$51.80
2045	2045	-	\$43.44	13,508	0.999839		\$30.97	1.01 \$41.85	\$52.32
2046	2046	-	\$43.44	13,510	1.000163		\$31.29	1.01 \$42.28	\$52.85
2047	2047	-	\$43.45	13,512	1.000106		\$31.60	1.01 \$42.70	\$53.38
2048	2048	-	\$43.43	13,505	0.99951		\$31.91	1.01 \$43.12	\$53.90
2049	2049	-	\$43.40	13,497	0.999369		\$32.22	1.01 \$43.54	\$54.42
2050	2050	-	\$43.71	13,592	1.007076		\$32.61	1.01 \$44.07	\$55.09
			#REF!						

Project Name	OpCo	Capacity MW	COD	Tier	Solar CF	Levelized CF	ITC %	Build Cost \$/kW	Levelized O&M \$/kW	Levelized O&M \$/MWh	Levelized Cost of Energy \$/MWh	Levelized Capital Cost \$/MWh	30 Year PPA Proxy (Upfront ITC)
2021COD-KYP-Tier 2-F2	KYP	150	2021	Tier 2	23.23%	22.13%	30%	\$1,179	\$38.44	\$19.92	\$59.55	\$39.63	\$51.24
2022COD-KYP-Tier 2-F2	KYP	150	2022	Tier 2	23.23%	22.13%	30%	\$1,134	\$38.09	\$19.73	\$57.85	\$38.11	\$49.85
2023COD-KYP-Tier 2-F2	KYP	150	2023	Tier 2	23.22%	22.13%	30%	\$1,099	\$37.90	\$19.64	\$56.57	\$36.93	\$48.82
2024COD-KYP-Tier 2-F2	KYP	150	2024	Tier 2	23.23%	22.13%	10%	\$1,093	\$38.20	\$19.79	\$61.24	\$41.45	\$57.71
2025COD-KYP-Tier 2-F2	KYP	150	2025	Tier 2	23.23%	22.13%	0%	\$1,088	\$38.51	\$19.95	\$63.55	\$43.59	\$62.12
2026COD-KYP-Tier 2-F2	KYP	150	2026	Tier 2	23.23%	22.13%	0%	\$1,080	\$38.79	\$20.10	\$63.39	\$43.29	\$61.97
2027COD-KYP-Tier 2-F2	KYP	150	2027	Tier 2	23.22%	22.13%	0%	\$1,078	\$39.15	\$20.28	\$63.47	\$43.18	\$62.06
2028COD-KYP-Tier 2-F2	KYP	150	2028	Tier 2	23.23%	22.13%	0%	\$1,076	\$39.53	\$20.48	\$63.61	\$43.13	\$62.20
2029COD-KYP-Tier 2-F2	KYP	150	2029	Tier 2	23.23%	22.13%	0%	\$1,075	\$39.92	\$20.68	\$63.76	\$43.08	\$62.35
2030COD-KYP-Tier 2-F2	KYP	150	2030	Tier 2	23.23%	22.13%	0%	\$1,075	\$40.33	\$20.90	\$63.97	\$43.08	\$62.56
2031COD-KYP-Tier 2-F2	KYP	150	2031	Tier 2	23.22%	22.13%	0%	\$1,078	\$40.78	\$21.13	\$64.31	\$43.18	\$62.90
2032COD-KYP-Tier 2-F2	KYP	150	2032	Tier 2	23.23%	22.13%	0%	\$1,081	\$41.26	\$21.38	\$64.72	\$43.34	\$63.30
2033COD-KYP-Tier 2-F2	KYP	150	2033	Tier 2	23.23%	22.13%	0%	\$1,084	\$41.71	\$21.62	\$65.05	\$43.43	\$63.62
2034COD-KYP-Tier 2-F2	KYP	150	2034	Tier 2	23.23%	22.13%	0%	\$1,086	\$42.16	\$21.85	\$65.35	\$43.50	\$63.92
2035COD-KYP-Tier 2-F2	KYP	150	2035	Tier 2	23.22%	22.13%	0%	\$1,085	\$42.59	\$22.07	\$65.54	\$43.48	\$64.12
2036COD-KYP-Tier 2-F2	KYP	150	2036	Tier 2	23.23%	22.13%	0%	\$1,086	\$43.03	\$22.30	\$65.81	\$43.51	\$64.38
2037COD-KYP-Tier 2-F2	KYP	150	2037	Tier 2	23.23%	22.13%	0%	\$1,085	\$43.46	\$22.52	\$66.00	\$43.47	\$64.57
2038COD-KYP-Tier 2-F2	KYP	150	2038	Tier 2	23.23%	22.13%	0%	\$1,083	\$43.89	\$22.74	\$66.15	\$43.41	\$64.73
2039COD-KYP-Tier 2-F2	KYP	150	2039	Tier 2	23.22%	22.13%	0%	\$1,083	\$44.34	\$22.97	\$66.36	\$43.39	\$64.95
2040COD-KYP-Tier 2-F2	KYP	150	2040	Tier 2	23.23%	22.13%	0%	\$1,084	\$44.82	\$23.22	\$66.66	\$43.43	\$65.23
2041COD-KYP-Tier 2-F2	KYP	150	2041	Tier 2	23.23%	22.13%	0%	\$1,083	\$45.26	\$23.45	\$66.84	\$43.39	\$65.42
2042COD-KYP-Tier 2-F2	KYP	150	2042	Tier 2	23.23%	22.13%	0%	\$1,084	\$45.74	\$23.70	\$67.12	\$43.42	\$65.70
2043COD-KYP-Tier 2-F2	KYP	150	2043	Tier 2	23.22%	22.13%	0%	\$1,084	\$46.23	\$23.95	\$67.40	\$43.45	\$65.98
2044COD-KYP-Tier 2-F2	KYP	150	2044	Tier 2	23.23%	22.13%	0%	\$1,084	\$46.70	\$24.20	\$67.64	\$43.44	\$66.22
2045COD-KYP-Tier 2-F2	KYP	150	2045	Tier 2	23.23%	22.13%	0%	\$1,084	\$47.17	\$24.44	\$67.88	\$43.44	\$66.45
2046COD-KYP-Tier 2-F2	KYP	150	2046	Tier 2	23.23%	22.13%	0%	\$1,084	\$47.65	\$24.69	\$68.13	\$43.44	\$66.71
2047COD-KYP-Tier 2-F2	KYP	150	2047	Tier 2	23.22%	22.13%	0%	\$1,084	\$48.14	\$24.94	\$68.39	\$43.45	\$66.97
2048COD-KYP-Tier 2-F2	KYP	150	2048	Tier 2	23.23%	22.13%	0%	\$1,084	\$48.61	\$25.18	\$68.61	\$43.43	\$67.19
2049COD-KYP-Tier 2-F2	KYP	150	2049	Tier 2	23.23%	22.13%	0%	\$1,083	\$49.08	\$25.43	\$68.83	\$43.40	\$67.40
2050COD-KYP-Tier 2-F2	KYP	150	2050	Tier 2	23.23%	22.13%	0%	\$1,091	\$49.69	\$25.74	\$69.45	\$43.71	\$68.01

Kentucky Power Company  
 Annual Investment Carrying Charges  
 For Economic Analyses  
 As of 12/31/2019

	Investment Life (Years)											
	2	3	4	5	10	15	20	25	30	33	40	50
Return (1)	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07
Depreciation (2)	49.04	31.91	23.32	18.19	8.04	4.78	3.23	2.35	1.81	1.57	1.18	0.85
FIT (3) (4)	1.06	0.77	0.82	0.68	0.64	0.77	0.80	0.69	0.62	0.59	0.54	0.49
Property Taxes, General & Admin Expenses	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45
Carrying Cost Per Year	58.62	41.19	32.66	27.39	17.20	14.07	12.55	11.57	10.95	10.68	10.24	9.86

(1) Based on a 100% (as of 12/31/2019) and 0% incremental weighting of capital costs

(2) Sinking Fund annuity with R1 Dispersion of Retirements

(3) Assuming MACRS Tax Depreciation

(4) @ 21% Federal Income Tax Rate

## **EXHIBIT RW-6**

KPMG. *KPMG Report: Outlook for What's Ahead for Energy Tax Incentives (Updated)* (2021)

*available at* <https://assets.kpmg/content/dam/kpmg/us/pdf/2021/05/21197.pdf>



# TaxNewsFlash

United States



No. 2021-197  
May 3, 2021

## KPMG report: Outlook for what's ahead for energy tax incentives (updated)

Coming off year-end extensions, the tax incentives for various renewable and clean energy sources and technologies could see an additional boost from Congress in the coming months.

This report briefly describes the potential for additional extensions and enhancements as proposals from the Biden Administration and Congress take shape.

### **Biden Administration plan**

President Biden has described a two-step plan for “rescue and recovery” in response to the coronavirus (COVID-19) pandemic health and economic crises. With enactment of the “American Rescue Plan Act of 2021” on March 11, 2021, the focus can now shift to recovery.

President Biden on March 31, 2021, announced the “recovery” portion of his two-step plan that focuses on infrastructure, energy, innovation, and other areas. The available information about the plan does not include detailed descriptions, but does include the following energy related tax provisions:

- 10-year extension and phase down of an expanded direct-pay investment tax credit and production tax credit for clean energy generation and storage (paired with strong labor and collective bargaining standards for jobs created by the credits)
- Investment tax credit to mobilize private capital for the buildout of at least 20 gigawatts of high-voltage capacity power lines
- Reform and expansion of section 45Q credit for carbon capture projects
- Tax incentives “to buy American-made” electric vehicles
- Extend and expand home and commercial energy-efficiency tax credits
- Extend section 48C advanced manufacturing tax credit
- Repeal fossil fuel subsidies and reinstate superfund payments

Another notable feature of the Biden plan that could be an interesting companion to the enhanced tax incentives is the plan to establish the “Energy Efficiency and Clean Electricity Standard” (EECES). There are few details about how the EECES would operate, but it could act as a nation-wide standard

requiring utilities to source electricity from specified cleaner resources, similar to renewable portfolio standards currently enacted in several states.

Additional details of the Biden plan are still taking shape but for an indication of how many of these provisions may work it is useful to look to recently introduced legislative proposals. Comprehensive extensions, enhancements, and reforms to the energy tax incentives have recently been proposed in the both the House of Representatives and the Senate.

## **The GREEN Act**

In February 2021, Representative Mike Thompson, (D-CA), a member of the U.S. House of Representatives Committee on Ways and Means reintroduced the “Growing Renewable Energy and Efficiency Now” (GREEN) Act. The Biden plan’s proposals related to energy seem to track the GREEN Act in many ways, which may make the GREEN Act a good early indicator of how the Biden plan will translate into legislative language.

- ***ITC and PTC***

The GREEN Act would reinstate and extend the solar investment tax credit (ITC) at 30% for projects that begin construction before 2026, then phase down to 26% for projects that begin construction in 2026, 22% for projects that begin construction in 2027 and 10% thereafter.

For wind, the GREEN Act would extend the current 60% production tax credit (PTC) for wind facilities that begin construction before 2027.

The GREEN Act would extend the ITC and PTC for other eligible technologies and expand the ITC to include energy storage technology and linear generators.

- ***Direct pay***

A significant feature of the GREEN Act is its inclusion of a “direct pay” provision allowing taxpayers to elect to treat 85% of the ITC and PTC as a payment of tax, entitling them to a refund to the extent the payment exceeds available tax liability. The direct pay provision would apply to projects placed in service after the date of enactment.

- ***Electric vehicles***

The GREEN Act also includes proposals related to electric vehicles, which is another priority area for the Biden Administration. The proposal would extend and expand the existing electric vehicle credit, specifically by increasing the phase-out threshold and permitting used and large vehicles to be eligible for the credit. The GREEN Act would also allow manufacturers that have already passed the existing 200,000 vehicle threshold to continue to benefit from the credit.

- ***Other notable provisions***

- Extension of the section 45Q credit for carbon oxide sequestration facilities that begin construction before the end of 2026 and provide an 85% direct-payment option
- Extension and modification of residential energy and energy efficiency incentives
- Additional allocation of section 48C advanced manufacturing credit, with prevailing wage requirement
- Extension of excise tax credit for alternative fuels
- Extension of availability of publicly traded partnerships for renewable energy projects

## **Senate Finance Chairman Wyden’s proposals**



Senate Finance Committee Chairman Ron Wyden (R-OR) on April 21, 2021 introduced a bill—the “Clean Energy for America Act”—that would aim to create a simpler set of long-term, performance-based energy tax incentives with the goals of being technology-neutral and to promote clean energy in the United States.

- ***ITC and PTC***

The bill would replace the current renewable energy tax incentives with a new clean electricity PTC and ITC. The bill would allow taxpayers to choose between a 30% ITC or a PTC equal to 2.5 cents per kilowatt hour. The credits would apply to facilities with zero or net negative carbon emissions placed in service after December 31, 2022. The Wyden bill would also extend current tax credit provisions through December 31, 2022.

The credits are set to phase out when certain emission targets are achieved, specifically when the Environmental Protection Agency and the Department of Energy certify that the electric power sector emits 75 percent less carbon than 2021 levels.

Qualifying transmission grid improvements also would be eligible for the 30% ITC including standalone energy storage property. Storage technologies eligible for the ITC would not be required to be co-located with power plants and include any technologies that can receive, store and provide electricity or energy for conversion to electricity. Transmission property would include transmission lines of 275 kilovolts (kv) or higher, plus any necessary ancillary equipment. Regulated utilities would have the option to opt-out of tax normalization requirements for purposes of the grid improvement credit. The bill does not, however, include a similar opt-out of the tax normalization provisions for ITC for other types of qualifying facilities.

Under the bill, investments qualifying for the clean emission investment credit, grid credit or energy storage property credit that are located in qualifying low-income areas would qualify for higher credit rates.

- ***Carbon capture***

The section 45Q tax credit would be extended until the power and industrial sectors meet certain emissions goals; however, the bill would make some significant modifications to the credit, in particular, enhanced oil and natural gas recovery projects would no longer qualify for the credit.

In addition, the credit amounts for direct air capture facilities would be significantly enhanced, and the bill would also modify the minimum capture thresholds. Under the proposed modified thresholds, in order to qualify for the section 45Q tax credit, electric generating facilities would be required to capture at least 75% of the CO<sub>2</sub> that otherwise would be released into the atmosphere and industrial facilities would be required to capture at least 50% of the CO<sub>2</sub> which would otherwise be released into the atmosphere. These changes would be effective for projects on which construction begins after December 31, 2021.

- ***Direct pay***

The Wyden bill would provide taxpayers with the option of treating the ITC, PTC, and section 45Q credit as payments of tax; those wishing to avail themselves of this election would have to inform the Treasury Department **before** the facility to which the election relates begins construction. Unlike the GREEN Act, the Wyden bill would not impose a 15% haircut on the amount of the direct pay amount. Also, note that in the Wyden bill, the direct pay election and resulting refund would be allowed at the partnership level. Finally, the new ITC and PTC created by the bill, including the direct pay feature, would be effective for projects that are placed in service after December 31,

2022. For section 45Q, the direct pay provision would apply to projects that begin construction after December 31, 2021.

- **Electric vehicles**

The Wyden bill would modify and enhance the incentives available for electric vehicles. Specifically, the bill would repeal the per-manufacturer vehicle cap and make the credit refundable for individuals. Commercial operators would be able to claim non-refundable credit worth 30% of the purchase of an electric vehicle. The credits would phase out when the electric vehicles represent more than 50% of annual vehicle sales.

- **Other notable provisions**

- Taxpayers receiving credits to pay wages at not less than local prevailing rates and use registered apprenticeship programs
- PTC for production of clean fuels
- Incentives for energy efficient homes and commercial buildings and for clean transportation technologies
- Tax credit bonds for facilities producing clean electricity or clean transportation fuels
- Repeal of certain incentives for fossil fuels, including immediate expensing for intangible drilling costs, percentage depletion, deductions for tertiary injectants and credits for enhanced oil recovery, coal gasification and advanced coal projects; also repeal of the special treatment of fossil fuels under the publicly traded partnership rules

**Table comparing various provisions**

	<b>Biden Plan</b>	<b>GREEN Act</b>	<b>Wyden Plan</b>
ITC	10 yr extension and phase down; no info on credit amount; direct pay but no additional info	Generally provides 30% ITC if construction begins before 2026, then phases down to 10% for construction beginning after 2027; 85% direct pay	Any technology can qualify for ITC the credits as long as emissions at or below zero; 30% credit rate; 100% direct pay; credits will phase out based on emissions targets
PTC	10 yr extension and phase down; no info on credit amount; direct pay but no additional info	Generally extends PTC for projects beginning construction before 2026; credit rate at 60% of statutory rate; 85% direct pay	Any technology can qualify for PTC the credits as long as emissions at or below zero; 30% credit rate; 100% direct pay; credits will phase out based on emissions targets
Storage	Includes "storage" as part of credit proposal but no additional detail	ITC for storage; 85% direct pay	ITC for storage; Regulated utilities can elect out of tax normalization requirements; 100% direct pay
Transmission	ITC for buildout of at least 20 gigawatts of high-voltage capacity	Does not include transmission incentive	ITC for transmission investment; Regulated utilities can elect out tax normalization requirements; 100% direct

	power lines		pay
Carbon capture	“Reform and expand” the 45Q tax credit; add direct pay	Extend 45Q for projects on which construction begins before 2027; 85% direct pay	Section 45Q tax credit would be extended until the power and industrial sectors meet emissions goals; EOR no longer eligible; higher credit for direct air capture; modified minimum capture thresholds; 100% direct pay
Electric vehicles	Provide “tax incentives” to buy American made EVs	Modifies current law credits by increasing phase out limits; creates new credits for used and large electric vehicles	Makes credit refundable for individuals; commercial operators can claim 30% non-refundable credit; credits phase out when EVs represent more than 50% of annual vehicle sales
Manufacturing	Extend 48C	Extend 48C	No incentive for manufacturing
Fossil Fuel Subsidies	“Eliminate tax preferences for fossil fuels”	No provisions related to fossil fuels	Repeal fossil fuel preferences

### KPMG observation

The common thread between the various proposals is the continued incentivization of clean energy development through the tax code. The tax credit regime has proven successful at encouraging new investment and the rules and the industry have evolved together. While the Biden Administration plan and the GREEN Act would mostly extend and enhance the existing tax credits, the Wyden bill—although still tax incentive-based—presents a departure of sorts.

Another common policy is the move toward making the tax credits refundable through a direct pay mechanism. It remains to be seen if and how refundability makes its way into law. Various justifications for direct pay include the limited tax liability of investors and the base erosion anti-abuse (BEAT) limitations on tax credits, but query whether potential higher tax rates and/or BEAT repeal make direct pay seem less necessary?

Finally, it will be interesting to monitor the development of some of the non-tax aspects of these proposals. Specifically will the inclusion of an EECES and strong labor standards become part of the ultimate package and, if so, how could that shape development going forward?

In terms of next steps, the Treasury Department will soon release a “Green Book” that will describe in more detail many of the proposals in the Biden plan. With that additional detail, larger negotiations will determine how the energy and tax portions of the ultimate legislative package take shape. The process is likely to be complicated and, of course, priorities could change during this time. That said, particularly in light of President Biden’s recent commitment to reduce emissions by approximately half by 2030, the emphasis on clean energy is unlikely to subside.

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