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May 6, 2021

BY HAND DELIVERY

The Honorable Connie Graley, Executive Secretary
West Virginia Public Service Commission
201 Brooks Street
Charleston, West Virginia 25323

RE: ***Appalachian Power Company & Wheeling Power Company***

Application for the issuance of a Certificate of Public Convenience and Necessity for internal modifications at coal fired generating plants necessary to comply with federal environmental regulations

Case No. 20-1040-E-CN

Dear Ms. Graley,

Please find enclosed for filing in the above-captioned case an original and twelve copies of the Public Version of the Direct Testimony of Rachel Wilson on Behalf of the Sierra Club. A confidential version of this testimony will also be filed under seal in accordance with Rule 4.1.6 of the Commission's Rules of Practice and Procedure.

Thank you,

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Enclosure

Copied: Service List

PUBLIC SERVICE COMMISSION

OF WEST VIRGINIA

CHARLESTON

APPALACHIAN POWER COMPANY & WHEELING POWER COMPANY	**Case No. 20-1040-E-CN**

Application for the issuance of a Certificate of Public Convenience and Necessity for internal modifications at coal fired generating plants necessary to comply with federal environmental regulations

DIRECT TESTIMONY OF RACHEL WILSON

ON BEHALF OF THE SIERRA CLUB

PUBLIC VERSION

May 6, 2021

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1. INTRODUCTION AND QUALIFICATIONS

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

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

Q. Please describe Synapse Energy Economics.

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

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

Q. Please summarize your work experience and educational background.

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

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

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

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

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

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

A. I am testifying on behalf of Sierra Club.

Q. Have you testified previously before the West Virginia Public Service Commission?

A. Yes, in Case No. 20-0065-E-ENEC.

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

A. Yes. I have submitted expert testimony in electric utility dockets in Minnesota, Kentucky, Indiana, Oklahoma, Missouri, Texas, Virginia, Washington, Georgia, Mississippi, Alabama, North Carolina, and South Carolina.

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

A. My testimony evaluates the application of Appalachian Power Company (APCo) and Wheeling Power Company (WPCo) (collectively, the Companies) for approval of a rate adjustment clause for capital investments and operations and maintenance (O&M) expenses to comply with the federal Coal Combustion Residuals (CCR) and Effluent Limitation Guidelines (ELG) regulations in lieu of retirement of the Amos, Mountaineer, and Mitchell coal plants. The Amos plant consists of three units for a total of 2,930 MW. Mountaineer is a single-unit plant with a capacity of 1,320 MW. The Mitchell plant, of which WPCo is a co-owner, consists of two units and totals 1,560 MW plant.

I first present the results of an alternative modeling analysis that compares three cases for the Amos and Mountaineer units:

1) **Synapse APCo BAU**, which includes the CCR and ELG investments at APCo's four existing coal-fired units and a retirement date of December 31, 2040 for each, as proposed in the Companies' application;

2) **Synapse APCo Retirement 1**, which includes the CCR investments at the Amos plant but not ELG investments and retires those units on December 31, 2028. It includes both CCR and ELG investments at Mountaineer and retires that plant on December 31, 2040; and

3) **Synapse APCo Retirement 2**, which includes the CCR investments, but not ELG investments, at both Amos and Mountaineer, and retires all four units on December 31, 2028.

Second, I present the results of a similar alternative modeling analysis that compares two cases for the Mitchell plant:

1) **Synapse WPCo BAU**, which includes the CCR and ELG investments at WPCo's share of Mitchell and retires the plant on December 31, 2040, as proposed in the Companies' application; and

2) **Synapse WPCo Retirement**, which includes the CCR investments, but not the ELG investments, at the Mitchell plant, and retires the units on December 31, 2028.

Q. Please identify the documents and filings on which you base your opinions.

A. My findings rely primarily upon the testimony, exhibits, and discovery responses of the Companies and its witnesses. I also rely on certain industry publications and data sources.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit Number	**Description of Exhibit**	**Protected Status**
Exhibit RW-1	Resume of Rachel S. Wilson	Non-Confidential
Exhibit RW-2	Response to Sierra Club 2-18, Confidential Attachment 1	Confidential
Exhibit RW-3	Response to Sierra Club 4-12, Attachment 1	Non-Confidential
Exhibit RW-4	Response to Sierra Club 4-13, Attachment 1	Non-Confidential
Exhibit RW-5	Response to Sierra Club 4-14, Attachment 1	Non-Confidential
Exhibit RW-6	*KPMG report: Outlook for what's ahead for energy tax incentives (updated)*	Non-Confidential
Exhibit RW-7	*West Virginia's Energy Future: Ramping Up Renewable Energy to Decrease Costs, Reduce Risks, and Strengthen Economic Opportunities for West Virginia* (2020), Executive Summary, West Virginia University Law Center for Energy and Sustainable Development.	Non-Confidential

2. OVERVIEW OF TESTIMONY AND CONCLUSIONS

Q. Please summarize your primary conclusions.

A. My independent modeling demonstrates that it is uneconomic, and therefore not in the best interest of ratepayers, for APCo to invest in both CCR and ELG costs at the Amos plant to be allowed to continue running the plants until their retirement on December 31, 2040. Investing only in CCR costs at the Amos plant, and retiring its three units in 2028, is the least-cost option, resulting in ratepayer savings of $1.4 billion under a Base with No Carbon commodity price forecast.

When a price on carbon dioxide (CO_2) emissions is included as part of the analysis, ratepayer savings rise to more than $2.4 billion when Amos forgoes ELG investments, retires at the end of 2028, and is replaced with a combination of renewable and battery storage resources. A scenario in which both Amos and Mountaineer are retired at the end of 2028 results in a savings to ratepayers of approximately $1.5 billion, relative to the Synapse BAU scenario.

A summary of the resource additions, retirements, and net present value of revenue requirements in the Synapse modeling is shown in Table 1 under a 'No Carbon' commodity forecast, and in Table 2 under a 'With Carbon' commodity forecast.

Table 1. Summary of Synapse modeling results (2050), Amos and Mountaineer, No Carbon Forecast

	Synapse BAU	Synapse Retirement 1	Synapse Retirement 2
NPVRR (2021-2050)	$14.7	$13.3	$14.4
Solar (MW)	10,940	17,660	17,660
Wind (MW)	695	495	495
Storage (MW)	4,232	1,536	1,536
Gas (MW)	450	450	450
Coal (MW)	0	0	0

Table 2. Summary of Synapse modeling results (2050), Amos and Mountaineer, With Carbon Forecast

	Synapse BAU	Synapse Retirement 1	Synapse Retirement 2
NPVRR (2021-2040)	$16.4	$14.0	$14.9
Solar (MW)	13,220	19,740	19,740
Wind (MW)	14,195	14,195	14,195
Storage (MW)	5,528	2,784	2,784
Gas (MW)	450	450	450
Coal (MW)	0	0	0

For WPCo, my analysis similarly shows that retiring the Mitchell plant at the end of 2028 is more economic for ratepayers than ELG investments and continued operation of the plant through 2040. WPCo would save $118 million over the analysis period under a No Carbon forecast, or $350 million when a carbon price is included.

Table 3. Summary of Synapse modeling results (2050), Mitchell Plant

	Base No Carbon		Base With Carbon	
	Synapse WPCo BAU	Synapse WPCo Retirement	Synapse WPCo BAU	Synapse WPCo Retirement
NPVRR (2021-2050)	$2.5	$2.4	$2.8	$2.5
Solar (MW)	1,660	1,660	1,620	1,580
Wind (MW)	400	400	1,500	1,500
Storage (MW)	168	72	72	0
Gas (MW)	0	0	0	0
Coal (MW)	0	0	0	0

Q. Please summarize your primary recommendations.

A. Based on my findings, I first recommend that the Commission approve the CCR compliance costs at the Amos plant, but deny the ELG costs. The use of industry standard pricing for replacement capacity and energy shows that the retirement of the Amos plant in 2028 is economic and results in substantial savings to customers, even under a base commodity forecast that does not include a price or constraint on future CO_2 emissions. Customer savings from forgoing ELG investment would only increase—substantially—if an effective carbon price did materialize in the coming years.

Second, I recommend that the Commission approve the CCR costs at the Mountaineer plant, but deny the costs associated with ELG compliance, at least at this time. The Synapse analysis shows that a scenario that retires both Amos and Mountaineer in 2028 yields savings to ratepayers when compared to a scenario in which both plants do not retire until 2040. While the Synapse modeling in this docket shows that the retirement of both Amos and Mountaineer is more expensive than the retirement of Amos alone, we only model a single type of constraint on CO_2. It is widely expected that the Biden administration will soon be implementing some type of carbon policy, but it remains to be seen what form that policy might take, or how stringent it might be. It is thus premature, at the current time, to approve the ELG costs at Mountaineer. Rather, the Commission should deny the ELG costs until APCo can present an analysis of the effect of upcoming carbon regulations on the operation of the plant.

Finally, I recommend that the Commission approve the CCR compliance costs at the Mitchell plant, but deny the ELG costs. The Companies' own modeling shows that the 2028 retirement of the Mitchell plant is economic in two of the three commodity price forecasts it considered, and the Synapse analysis shows that retirement is clearly the least-cost option for ratepayers under the two commodity price forecasts that were modeled.

3. SUMMARY OF APCO'S APPLICATION

Q. What are APCo and WPCo requesting in their Application in this docket?

A. APCo and WPCo are requesting the Commission's approval of an Environmental Compliance Surcharge (ECS) to provide interim cost recovery for the ELG and CCR compliance work.[1] Broken down by plant, the total cost of compliance with CCR and ELG for Amos is $177.1 million, while the cost for Mountaineer is $72.9 million, and $133.5 million for Mitchell.[2]

Q. Did the Companies present any analysis supporting their Application?

A. Yes. According to the Direct Testimony of James F. Martin, he prepared an economic analysis that compared three compliance scenarios for APCo:

- Case 1 assumes CCR and ELG investments at both Amos and Mountaineer, with a retirement date of December 31, 2040 for both plants;
- Case 2 assumes only CCR investments at Amos and retirement with a retirement date of December 31, 2028, with CCR and ELG investments at Mountaineer with retirement in 2040; and

1 Direct Testimony of Christian T. Beam at 9:9–9:12.

2 Direct Testimony of Brian D. Sherrick at 11:6–11:20.

- Case 3 assumes only CCR investments at both Amos and Mountaineer, with a retirement date of 2028.[3]

For WPCo, Mr. Martin compared two compliance cases:

- Case 1 assumes CCR and ELG investments at Mitchell, with a retirement date of December 31, 2040; and
- Case 2 assumes only CCR investments at Mitchell, with a retirement date of December 31, 2028.[4]

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

Q. What were the results of the Companies' analyses?

A. According to APCo, its Case 1— which installs CCR and ELG technologies at both Amos and Mountaineer and retires the plants in 2040—is the least-cost option when comparing the net present value of revenue requirements (NPVRR). The revenue requirements for each case, under each commodity forecast, are shown below in Table 4 along with the change in costs (or the "delta") relative to Case 1.

3 Direct Testimony of James F. Martin at 4:6–4:16.

4 *Id.* at 4:19-4:23.

Table 4. Comparison of net present value of revenue requirements, APCo modeled scenarios

		NPVRR ($ Millions)	Delta from Case 1 ($ Millions)	Delta from Case 1 (Percent)
Case 1	Base With Carbon	$20,578		
	Base No Carbon	$18,435		
	Low Band	$17,088		
Case 2	Base With Carbon	$20,754	$176	0.86%
	Base No Carbon	$18,730	$295	1.60%
	Low Band	$17,333	$245	1.43%
Case 3	Base With Carbon	$20,951	$374	1.81%
	Base No Carbon	$19,057	$622	3.37%
	Low Band	$17,569	$480	2.81%

Source: Exhibit JFM D-1.

The percentage differences reflected above between APCo's Cases were calculated by Synapse. Notably, Case 2—in which the Amos units retire in 2028—is less than 1 percent more expensive in the Company's modeling than Case 1 under the Base With Carbon forecast, and only 1.6 percent more expensive when carbon is excluded. These differentials are extremely small, and thus even a small adjustment to APCo's input assumptions that increases the costs to continue to operate existing coal or, alternatively, lowers the cost of replacement resources could shift the results such that the 2028 retirement of one or both coal plants becomes the more economic option under the Companies' cases.

The respective costs of WPCo's two Mitchell cases are shown in Table 5.

Table 5. Comparison of net present value of revenue requirements, WPCo modeled scenarios

		NPVRR ($ Millions)	Delta from Case 1 ($ Millions)	Delta from Case 1 (Percent)
Case 1	Base With Carbon	$3,814		
	Base No Carbon	$3,449		
	Low Band	$3,020		
Case 2	Base With Carbon	$3,805	($9)	-0.24%
	Base No Carbon	$3,450	$2	0.06%
	Low Band	$3,006	($14)	-0.46%

Source: Exhibit JFM D-2.

The results of WPCo's own analysis show that under two of the three commodity price forecasts, there is a net benefit to retirement of the Mitchell plant. Under WPCo's third price forecast, Base No Carbon, the net benefit of continued operation is negligible, at only $2 million, or 0.06 percent. The Companies' own analysis shows that continued operation of Mitchell is not in the best interest of ratepayers.

Q. How does APCo's analysis assume the Amos and Mountaineer units will operate into the future?

A. Under a No Carbon commodity price forecast, APCo's results show generation at APCo's thermal units, including both Amos and Mountaineer, increasing between 2021 and 2028, after which generation falls until 2032 and then grows more slowly until the units retire at the end of 2040. Those patterns are shown below in CONFIDENTIAL Figure 1.

CONFIDENTIAL Figure 1. Generation in APCo's Case 1, No Carbon (Amos and Mountaineer operate until 2040)

[redacted]

Source: Companies' Response to Staff Request No. 1-2, Confidential Attachment APCo Base without Carbon – AM+MNTR CCR&ELG Optimal Plan.xlsx[5]

Q. What does generation look like in APCo's other cases?

A. In Case 2, which retires Amos at the end of 2028, generation looks very similar. The retirement of the Amos plant causes coal generation to drop steeply from 2028 to 2029, and it rises more slowly in the 2030s. One might expect to see a greater volume of renewables added as replacement for the retiring Amos plant,

5 This document contains spreadsheet data contained in numerous tabs and can be produced upon request.

but CONFIDENTIAL Figure 2 shows only a slight increase near the end of the analysis period, with much of the generation gap being filled by imported energy from PJM.

CONFIDENTIAL Figure 2. Generation in APCo's Case 2,
No Carbon (Amos retires in 2028, Mountaineer operates until 2040)

[redacted]

Source: Companies' Response to Staff Request No. 1-2, Confidential Attachment APCo Base without Carbon – AM CCR Only+MNTR CCR&ELG Optimal Plan.xlsx[6]

6 This document contains voluminous spreadsheet data in numerous tabs and can be produced upon request.

Q. How does WPCo's analysis assume the Mitchell plant will operate?

A. WPCo's analysis assumes that generation at the Mitchell plant will follow a similar pattern to the thermal generation in the APCo scenarios: starting low in 2021, rising steeply, and then falling at the end of the decade. This pattern is shown in CONFIDENTIAL Figure 3

CONFIDENTIAL Figure 3. Generation in WPCo's Case 1, No Carbon (Mitchell operates until 2040)

[redacted]

Source: Companies' Response to Staff Request No. 1-2, Confidential Attachment WPCo Base without Carbon –CCR&ELG Optimal Plan.xlsx [7]

7 This document contains voluminous spreadsheet data in numerous tabs and can be produced upon request.

Q. In the scenarios in which Amos, Mountaineer, and Mitchell retire, what sort of replacement capacity is selected in the Companies' analysis?

A. In the APCo scenarios, the PLEXOS model selects between 2,618 MW and 3,094 MW of gas-fired combustion turbines, the capacity-only power purchase agreement (PPA), and varying amounts of solar, depending on whether a carbon price was included. Mr. Martin states in his direct testimony that the PLEXOS model chose the cheapest capacity options available to replace Amos and Mountaineer, due to the low level of market energy prices in the AEP Fundamentals Forecast. Because energy from the PJM market is inexpensive, the model did not choose thermal units with low heat rates, which might be expected to run more, or renewable resources, which Mr. Martin says are less valuable when market prices are low.[8] Instead, APCo's plans "result in very heavy reliance on the PJM energy market for the energy needed to serve customers."[9] Even when Amos, Mountaineer, and Mitchell continue to operate until 2040, the PLEXOS model begins to select large volumes of imports beginning in 2030, as shown in CONFIDENTIAL Figure 1 and CONFIDENTIAL Figure 3, above.

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8 Direct Testimony of James F. Martin at 21:13–21:18.

9 *Id.* at 20:6–20:7.

Q. Can you draw any conclusions about APCo's input assumptions from this heavy reliance on imports from PJM?

A. Yes. When making the decision about which resources to build, PLEXOS considers both the cost of capacity (MW) and the cost of energy ($/MWh) of different types of replacement resource. The calculation is complicated by APCo's ability to purchase from or sell to the PJM market. The PLEXOS model chose primarily capacity resources (combustion turbines) in APCo's analysis, rather than energy resources (solar and wind), instead choosing to purchase energy from PJM. This suggests that APCo's market energy price forecast is low, its renewable prices are high, or both.

Q. What does APCo forecast about the performance of the units at the Amos and Mountaineer plants in its Case 1?

A. The capacity factors look different at each of the plants. For Amos, APCo projects that the capacity factors of these units are going to increase in the near term and peak in 2027 or 2028. By 2032, the capacity factors are at approximately **[BEGIN CONFIDENTIAL INFORMATION]** [redacted] **[END CONFIDENTIAL INFORMATION]** or less for each of the units. The Amos units, which were intended to operate as "baseload" generators with high levels of output, would be only slightly better than peaking units. Mountaineer is the better performing plant but also starts to see some declines in capacity factor in the 2030s under a Base No Carbon price forecast. Annual capacity factor projections are shown in CONFIDENTAL Table 6.

CONFIDENTAL Table 6. Comparison of capacity factors at Amos and Mountaineer under APCo's Case 1, Base No Carbon

[redacted]

Source: Companies' Response to Sierra Club Request No. 2-18, Confidential Attachment 1.[10]

Q. What does WPCo forecast about the performance of the units at the Mitchell plant in its Case 1?

A. The Mitchell units are the worst performers of the group under the Companies' projections, with capacity factors never getting higher than **[BEGIN CONFIDENTIAL INFORMATION]** [redacted] **[END CONFIDENTIAL INFORMATION]** under the Base No Carbon price forecast. By 2032, capacity factors at each of the units have dropped below **[BEGIN CONFIDENTIAL INFORMATION]** [redacted] **[END CONFIDENTIAL**

10 Enclosed as Exhibit RW-2.

INFORMATION] Annual capacity factor projections for the Mitchell units are shown below in CONFIDENTAL Table 7.

CONFIDENTAL Table 7. Comparison of capacity factors at Mitchell under WPCo's Case 1, Base No Carbon

[redacted]

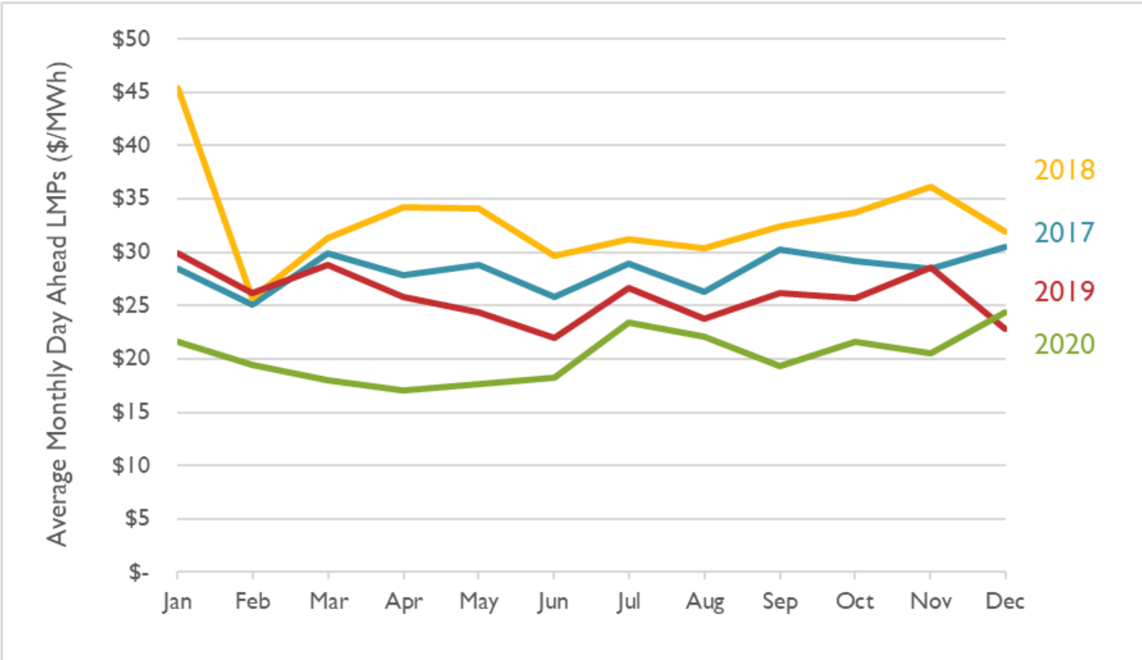
Source: Companies' Response to Sierra Club 2-18, Confidential Attachment 1.[11]

Q. Are these projections consistent with recent experience at the Amos and Mountaineer plants?

A. No. APCo's coal units have operated less in recent years as a result of declines in locational marginal prices (LMPs). Except for 2018, LMPs at the Amos node in PJM have come down each year since 2017. Monthly average day-ahead prices are shown below in Figure 4.

11 Enclosed as Exhibit RW-2.

Figure 4. Historical average monthly day-ahead LMPs at the Amos node



Source: PJM Data Miner, Available at: https://www.pjm.com/markets-and-operations/etools/data-miner-2.

In contrast to recent historical declines in LMPs, APCo's market energy price forecast shows a steady increase over time. The Company's existing coal units respond by increasing generation steeply before falling off after 2027. Those patterns are shown, using the forecasted capacity factors for the Amos 1 unit, in CONFIDENTIAL Figure 5.

CONFIDENTIAL Figure 5. Comparison of historical and projected PJM AEP power prices and Amos 1 capacity factors

[redacted]

Sources: Historical LMPs come from the PJM Data Miner. Historical capacity factors come from EPA's Clean Air Markets Database. Projected market prices come from the AEP Fundamentals Forecast. Projected capacity factors come from the Companies' Response to Sierra Club Response No. 2-18, Confidential Attachment 1.

When we compare the operating costs of the Amos and Mountaineer plants, calculated from APCo's PLEXOS outputs as the sum of fuel, variable O&M, emissions costs, and start/shutdown costs, to the AEP Fundamentals Forecast for market energy, we see that **[BEGIN CONFIDENTIAL INFORMATION]** [redacted] **[END CONFIDENTIAL INFORMATION]** Mountaineer is a better performer, as shown in CONFIDENTIAL Figure 6, but operates at **[BEGIN CONFIDENTIAL**

INFORMATION] [redacted], **[END CONFIDENTIAL INFORMATION]** meaning that it is uneconomic during a large portion of hours.

CONFIDENTIAL Figure 6. Comparison of APCo's market energy forecast versus operating cost of its coal plants

[redacted]

Sources: Energy market prices come from the Companies' Response to Staff Request No. 1-2, Fundamentals Forecast. Operating costs were calculated using the Companies' Response to Staff Request No. 1-2, Confidential Attachment APCo Base without Carbon – AM+MNTR CCR&ELG Optimal Plan.xlsx.

In APCo's analysis, the Amos and Mountaineer plants offer capacity and energy value to its customers in the near-term but offer very little energy value (as evidenced by declining capacity factors) in the later part of the decade and beyond.

4. SYNAPSE MODELING METHODOLOGY

Q. **Do you present an alternative to the APCo and WPCo modeling analyses?**

A. Yes, I did.

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

A. The Synapse analysis uses the EnCompass capacity optimization and dispatch model, developed by Anchor Power Solutions, to simulate resource choice impacts in the APCo and WPCo service territories.

Q. Is EnCompass a widely accepted industry model?

A. Yes. EnCompass was released in 2016 and several major utilities have transitioned to the model since that time. For example, the three investor-owned utilities in Minnesota (Minnesota Power, Otter Tail Power, and Xcel Energy) adopted the EnCompass model in 2019, along with Great River Energy, the largest of the state's electric cooperatives.[12] Duke Energy announced in 2020 that it had chosen EnCompass to expand its capabilities in resource planning.[13] Public Service New Mexico and Public Service Company of Colorado are two other IOUs that have adopted EnCompass in recent years.

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12 Anchor Power Solutions, *Minnesota Plans for its Energy Future with EnCompass* (December 2019), available at https://anchor-power.com/news/minnesota-plans-for-its-energy-future-with-encompass/.

13 Anchor Power Solutions, *Duke Energy Implemented EnCompass Software* (May 2020), available at https://anchor-power.com/news/duke-energy-implemented-encompass-software/.

Q. What did Synapse model in its analysis?

A. Synapse modeled three different scenarios in our analysis for the APCo plants:

1) **Synapse APCo BAU** includes the CCR and ELG investments at APCo's four existing coal-fired units and retires those units on December 31, 2040;

2) **Synapse APCo Retirement 1** includes only the CCR investments at the Amos plant, and retires those units on December 31, 2028, and includes both CCR and ELG investments at the Mountaineer plant and retires that plant in 2040; and

3) **Synapse APCo Retirement 2** includes only the CCR investments at both Amos and Mountaineer and retires all four units on December 31, 2028.[14]

A matrix of these scenarios is shown in Table 8.

Table 8. Matrix of Synapse APCo modeling scenarios

	Plant	Synapse APCo BAU	Synapse APCo Retirement 1	Synapse APCo Retirement 2
Retrofit Technology	Amos	CCR/ELG	CCR	CCR
	Mountaineer	CCR/ELG	CCR/ELG	CCR
Retirement Date	Amos	2040	2028	2028
	Mountaineer	2040	2040	2028

14 As noted by APCo 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 APCo 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.

Synapse modeled two different scenarios in its analysis of WPCo and the Mitchell plant:

1) **Synapse WPCo BAU** includes the CCR and ELG investments at Mitchell and retires the two units on December 31, 2040; and
2) **Synapse WPCo Retirement** includes the CCR investments only at the Mitchell plant, and retires those units on December 31, 2028.

A matrix of these scenarios is shown in Table 9.

Table 9. Matrix of Synapse WPCo modeling scenarios

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

Q. Do the input assumptions used in the Synapse analysis conform to the Companies' assumptions?

A. Largely, yes. To ensure a valid, apples-to-apples comparison, the Synapse analysis uses the Companies' assumptions for peak and annual energy, load shape, reserve margin, unit retirements, distributed solar additions, commodity prices (fuel, CO_2, and energy market prices), and compliance costs for CCR/ELG at Amos, Mountaineer, and Mitchell under the 2028 and 2040 retirement dates. The sources for key input assumptions in the Synapse modeling are shown in Table 10.

Table 10. Sources of input assumptions in Synapse modeling

Assumption	Source
Load Forecast	APCo/WPCo response to AG 1-2, Martin Workpapers
Load Shape	APCo/WPCo response to SC 2-34, Attachments 1 and 2
Reserve Margin	Martin Direct Testimony
Coal Prices	APCo/WPCo response to Staff 1-2, AEP Fundamentals Forecast
Gas Prices	APCo/WPCo response to Staff 1-2, AEP Fundamentals Forecast
CO2 Prices	APCo/WPCo response to Staff 1-2, AEP Fundamentals Forecast
Market prices	APCo/WPCo response to Staff 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	APCo/WPCo response to AG 1-2, Martin Workpapers
Amos/Mountaineer Op Costs	APCo/WPCo response to AG 1-2, Martin Workpapers
CCR/ELG Costs	APCo/WPCo response to AG 1-2, Martin Workpapers
Transmission Costs	APCo/WPCo response to AG 1-2, Martin Workpapers

Q. Did you have to adjust any of the Companies' input assumptions?

A. Yes, I had to adjust the Companies' assumptions on pricing for solar, wind, and battery storage resources. APCo provided the annual cost values as they were input into the PLEXOS model in its Response to Sierra Club's Fourth Set of Discovery and indicated that the source of its pricing for these resources was the Energy Information Administration's (EIA) 2020 Annual Energy Outlook (AEO). However, EIA did not publish annual overnight capital cost projections for forward-looking years in this version of the AEO, so I was unable to confirm APCo's values. EIA did publish those values in AEO 2021, however, so I was able to compare APCo's data to a more recent version of AEO. For solar, APCo's assumed PPA price is \$60.31/MWh in 2026.[15] This is nearly twice the assumed levelized cost of energy from EIA in AEO 2021 for solar resources in 2026, which is \$33.68/MWh.[16] APCo has stated that its cost assumptions come from EIA, but there is a substantial discrepancy between APCo's assumed costs for new resources and those reported by EIA in AEO 2021. This discrepancy makes solar appear much more expensive than it is, and therefore overstates the cost of alternatives to the continued operation of Amos and Mountaineer.

Q. Are you able to determine the source of that discrepancy?

A. No. In the responses to Sierra Club's Fourth Set of Discovery Requests, APCo's values are not adequately sourced and many of the Company's calculations lack underlying formulas, so it was impossible to determine how APCo's values deviated from EIA and if those deviations were reasonable.[17]

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15 Companies' Response to Sierra Club Request No. 5-3, Attachment 1 (enclosed as Exhibit RW-3).

16 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.

This document shows a cost of \$29.04 in 2020\$. That value was converted to nominal dollars using APCo's assumed inflation rate of 2.5% from its Response to Sierra Club Request No. 5-3, Attachment 1.

17 Exhibit RW-3.

Q. Are there any other data points that lead you to believe that APCo's new resource costs are unreasonably high?

A. Yes. The current prices of wind and solar in PJM also lead me to believe that APCo's assumptions are unreasonably high. Solar PPA pricing in PJM in Q4 2020 was $37.50/MWh, while wind PPAs were priced at $35.50/MWh.[18] Analysts note that both prices are an increase over prior years because of both disruptions due to COVID-19 and supply constraints that have arisen due to high demand.[19] Over the longer term, basic economics suggests that the market will respond to these supply constraints and that prices will stabilize.

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

A. The Synapse modeling uses industry standard cost assumptions from the National Renewable Laboratory's (NREL) 2020 Advanced Technology Baseline (ATB) for utility-scale photovoltaic (PV) solar, onshore wind, and battery storage resources. NREL's ATB 2020 data is quite similar to the estimates of overnight capital costs from EIA 2021. A comparison of the capital costs for solar PV from both sources is shown in Figure 7.

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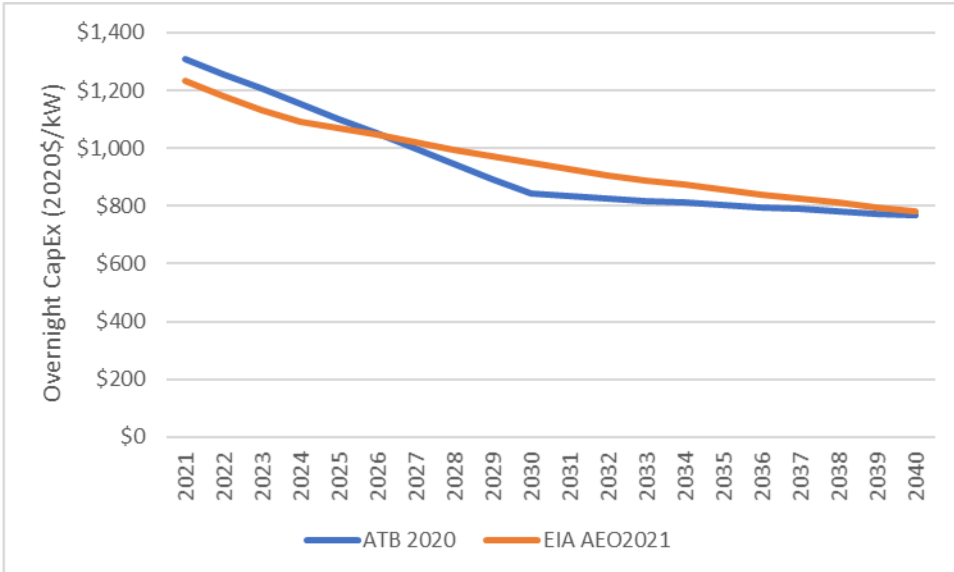
18 Level 10 Energy, *North America, Q4 2020 LevelTen Energy PPA Price Index* (January 12, 2021), available at https://leveltenenergy.com/blog/ppa-price-index/q4-2020/.

19 *Id.*

Figure 7. Comparison of overnight capital cost forecasts for solar PV, ATB 2020 and AEO 2021

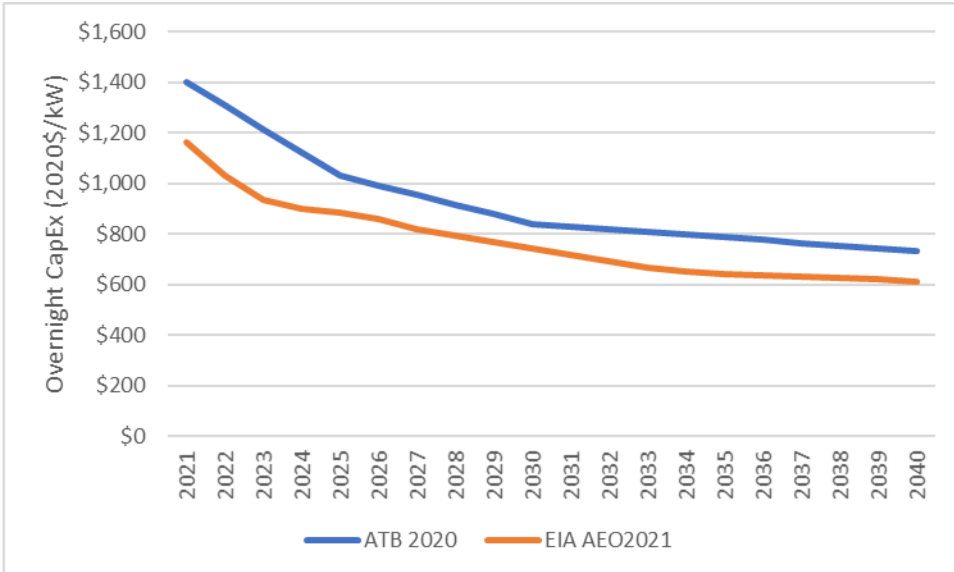


Sources: National Renewable Energy Laboratory, Annual Technology Baseline (2020), available at: https://atb.nrel.gov/electricity/2020/data.php; Energy Information Administration, Annual Energy Outlook (2021) at Table 55, available at: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=123-AEO2021&cases=ref2021&sourcekey=0.

Battery storage costs are more conservative in NREL's ATB Moderate Case than in AEO 2021. Those overnight capital costs are shown in Figure 8.[20]

20 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 APCo for the purposes of this analysis.

Figure 8. Comparison of overnight capital cost forecasts for battery storage, 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.

Q. The capital costs you have shown from EIA are generally similar to or lower than ATB. Why are you suggesting that APCo's costs are too high?

A. Costs for wind, solar, and battery storage have two major components: capital and fixed O&M. A comparison of these components between APCo and EIA for a solar PV resource coming online in 2026 shows that APCo's fixed O&M costs are much higher than those being used in AEO 2021.

Table 11. Comparison of APCo solar PPA cost with EIA levelized solar costs, $/MWh[21]

	Capital	Fixed O&M	Transmission	Tax Credit	Total
APCo	$42.60	$19.04	-	$0.31	$60.31
AEO 2021	$26.21	$6.87	$3.22	-$2.62	$33.68

Q. Are there any other reasons that APCo's cost calculations might be too high?

A. Yes. APCo seems to use an inflation rate of 2.5 percent to convert EIA's price forecast from real dollars to nominal.[22] Given that inflation between 2010 and 2020 averaged only 1.68 percent[23] this value seems high.

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

A. As shown in the section above, the EIA and NREL overnight capital costs are actually quite similar. However, EIA's input costs are based on a single source – a report from Sargent & Lundy, published in December 2019[24] and provided by

21 The assumed tax credit for APCo was calculated by simply subtracting the capital and O&M components from the Total PPA price.

22 Exhibit RW-3.

23 Saint Louis Federal Reserve, *Implicit Price Deflators and Conversion Factors*, available at: https://fred.stlouisfed.org/series/GDPDEF#0.

24 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.

APCo in responses to discovery.[25] The NREL ATB, on the other hand, incorporates several different sources, including analyses from both NREL and Oak Ridge National Laboratory, data from EIA, and information from a variety of published reports to arrive at its forecasts of generation technology cost and performance.[26]

NREL's ATB is a widely used source of renewable and storage pricing data. Detroit Edison used the 2018 ATB Mid costs in its 2019 Integrated Resource Plan, with some intervenors arguing that the costs were too conservative.[27] In its recent Integrated Resource Plan filing in Minnesota, Xcel Energy used ATB 2019 as the basis for its renewable and storage costs.[28]

Lastly, in order to accurately model these replacement resources, we need more than just the forecasted capital costs. We also need annual estimates of fixed

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25 Companies' Response to Sierra Club Request No. 2-28, Attachment 1, also available online at https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf.

26 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.

27 *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/068t0000009jWc2AAE.

28 *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/xe-responsive/Company/Rates%20&%20Regulations/The-Resource-Plan-No-Appendices.pdf

O&M cost, which the AEO 2021 does not provide. NREL's ATB does provide these data, however, which, when combined with performance data, allows for a levelized cost calculation that utilizes data from a single source.

5. SYNAPSE MODELING RESULTS - APCO

Q. What were the results of the Synapse modeling analysis for APCo?

A. In contrast to APCo's modeling analysis, the Synapse modeling found that West Virginia ratepayers save money under each of the Retirement scenarios relative to the continued operation of Amos and Mountaineer. The retirement of Amos in 2028 is the least-cost scenario, however, under the Base No Carbon commodity price forecast, with a cost savings to customers of $1.4 billion. When compared to the Synapse BAU, the early retirement of both Amos and Mountaineer in 2028 would save ratepayers approximately $266 million.

The benefits to ratepayers from retirement grow significantly under the Base With Carbon price forecast relative to the BAU. The retirement of Amos in 2028 results in ratepayer savings of $2.4 billion, while the retirement of both Amos and Mountaineer results in savings of $1.5 billion. The revenue requirements for each of the four Synapse scenarios, under APCo's Base No Carbon and Base With Carbon pricing forecasts are shown in Table 12.

Table 12. Net present value of revenue requirements, APCo, Synapse modeling scenarios

Scenario	Base No Carbon NPVRR ($Millions)	Base No Carbon Delta from BAU ($Millions)	Base With Carbon NPVRR ($Millions)	Base With Carbon Delta from BAU ($Millions)
Synapse APCo BAU	$14,694		$16,421	
Synapse APCo Retirement 1	$13,303	($1,391)	$13,981	($2,440)
Synapse APCo Retirement 2	$14,428	($266)	$14,879	($1,542)

Q. Can the NPVRR values for the Synapse scenarios be compared directly to the NPVRR values from APCO's analysis?

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

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

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

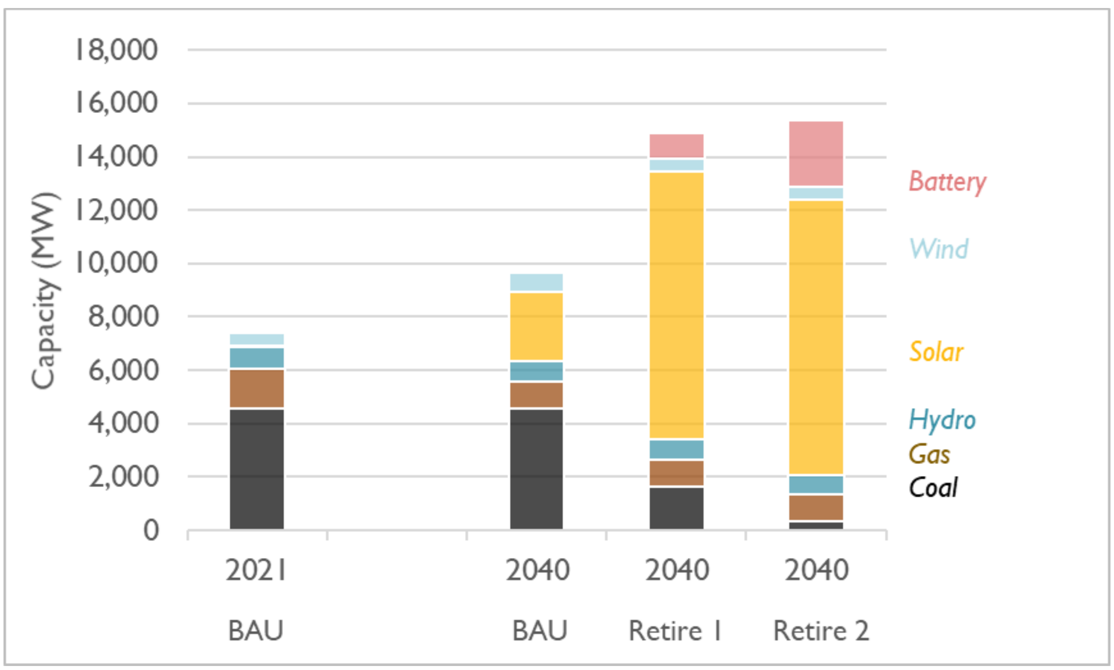
It is not the delta between the APCo scenarios and the Synapse scenarios that matters in this case, but the deltas between each entity's own set of modeled scenarios. For all of these reasons, the Synapse NPVRR values should be compared to each other and not compared directly to the APCo values.

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

A. In the Synapse BAU, we include new units similar to APCo's own capacity expansion, adding 160 MW of new solar in 2024, which grows to a cumulative total of 1,420 MW by 2040,[29] and 200 MW of new wind in 2025. In all other scenarios, EnCompass was allowed to optimize the buildout of replacement resources for the retiring coal units beginning with wind in 2023 and with replacement solar PV and battery storage resources in 2024. Solar PV and battery storage were offered as both standalone and paired resources.

Capacity in 2040 looks different in each of the Synapse scenarios, as shown in Figure 9.

Figure 9. Comparison of nameplate capacity in Synapse modeled scenarios, Base No Carbon



29 Solar units were offered in 20-MW increments in the Synapse EnCompass modeling, so the unit additions are slightly larger than in APCo's modeling, which starts with 150 MW of new solar in 2025 and increases to 1,350 MW in 2040.

The BAU adds the solar and wind increments described above but looks largely unchanged relative to 2021. In contrast, the Retirement 1 scenario has retired a large volume of coal capacity and added additional solar and battery storage. The Retirement 2 scenario has even greater coal retirements and further additions of replacement renewables and storage.

Solar resources in the Retirement 1 scenario begin building slightly ahead of the Amos retirement in 2028. The renewables provide inexpensive energy, and the battery storage provides capacity and stores energy for later use. Note that batteries can also provide ancillary services, which were not valued in this analysis.

Because of their lower capacity credits relative to fossil resources, EnCompass has to build more solar and storage to replace the capacity at the retiring Amos plant. Cumulative capacity, by year and resource, is shown in Table 13 for Synapse Retirement 1. In addition to what is shown in Table 13, EnCompass also selects 400 MW of the Capacity Only PPA in 2029.[30]

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30 The Capacity Only PPA was included in the Companies' 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.

Table 13. Cumulative capacity additions, by year, in Synapse Retirement 1 under Base No Carbon

		Synapse Retirement 1		
Year	Solar	Paired Solar	Battery	Paired Battery
2021	-	-	-	-
2022	-	-	-	-
2023	-	-	-	-
2024	-	-	-	-
2025	-	-	-	-
2026	600	-	-	-
2027	1,200	-	-	-
2028	1,800	-	-	-
2029	2,400	500	480	300
2030	3,000	760	480	456
2031	3,600	760	480	456
2032	4,200	760	480	456
2033	4,800	760	480	456
2034	5,400	760	480	456
2035	6,000	760	480	456
2036	6,600	760	480	456
2037	7,200	760	480	456
2038	7,800	760	480	456
2039	8,400	760	480	456
2040	9,000	760	480	456

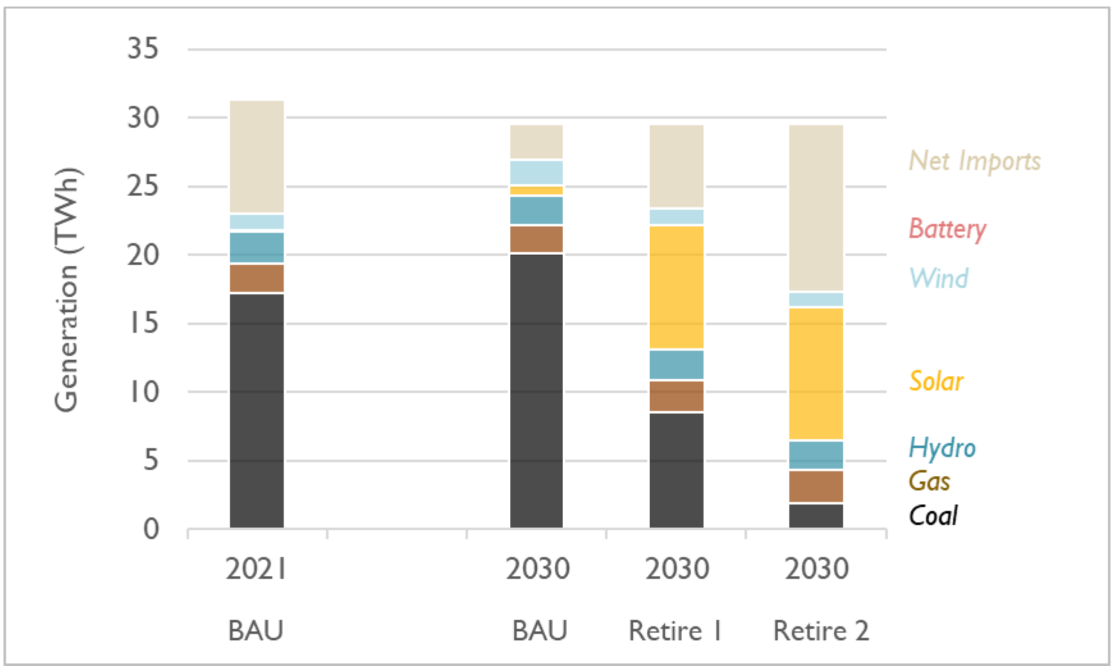
Q. How do the cumulative annual capacity builds in Retirement 2 compare to Retirement 1?

A. The resource builds in Retirement 2 look very similar to those in Retirement 1, except that EnCompass adds 1,396 MW of standalone battery storage in 2029 as a replacement for the retiring Mountaineer plant.

Q. How does modeled generation compare between the Synapse modeling scenarios?

A. The addition of solar and storage resources causes the generation profiles of Retirement 1 and Retirement 2 to look much different than the Synapse BAU. Generation in 2030 (after the modeled coal retirements) for each of the scenarios is shown in Figure 10, below.

Figure 10. Generation in the Synapse modeling scenarios, 2030, Base No Carbon



When compared to 2021, coal generation in the BAU has increased. There is more wind and solar, but less generation from gas and fewer imports. Retirement 1 and Retirement 2, comparatively, have much less fossil fuel generation than in 2021 and large amounts of new solar generation. The primary differences between Retirement 1 and Retirement 2 is that there is less coal generation and a greater number of net imports in 2030 when Mountaineer also retires. These net imports decline over time as the model adds additional generating resources post-2030.

Q. How do CO_2 emissions compare between the various Synapse scenarios?

A. Emissions of CO_2 in the Retirement 1 and Retirement 2 scenarios fall dramatically relative to the BAU after the retirement of three to four existing coal units at the end of 2028. Emissions in 2021, 2030, and 2040 for these three scenarios are shown in Table 14. By 2040, CO_2 emissions in the Retirement 1 scenario are less than half of the emissions in the BAU, while emissions in Retirement 2 are 87 percent lower than the BAU.

Table 14. Comparison of CO_2 emissions in the Synapse modeled scenarios, APCo

	2021	2030	2040
Synapse APCo BAU	18.1	20.8	20.9
APCo Retirement 1	18.1	9.6	9.2
APCo Retirement 2	18.1	3.2	2.8

Like many of its utility peers, AEP has committed itself to net-zero CO_2 emissions by 2050 and has an interim goal to cut emissions 80 percent from 2000 levels by 2030, while adding more than 10,000 MW of regulated wind and solar.[31] The Synapse Retirement 1 and 2 scenarios allow APCo to contribute to AEP's

31 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).

corporate goals, while the BAU keeps CO_2 emissions constant from 2021 through 2040 and adds minimal amounts of renewable resources. While emissions drop in the Synapse BAU after the retirements of Amos and Mountaineer in 2040, APCo contributes little to AEP's interim goal of 80 percent reductions by 2030 in our analysis.

Q. What is the effect of including a CO_2 price in the Synapse modeling analysis?

A. The difference in NPVRR for the BAU, which relies more heavily on coal, in a forecast that includes a carbon price versus one that does not is much greater than the difference between either Retirement 1 or Retirement 2 when a CO_2 price is added. As shown in **Table 15**, the CO_2 price adds more than $1.7 billion to the cost of the BAU scenario, but only $678 million to Retirement 1 and $451 million to Retirement 2. In other words, the risk of following the BAU path given the future uncertainties of carbon pricing is much greater than in a scenario that retires one or more of APCo's coal plants.

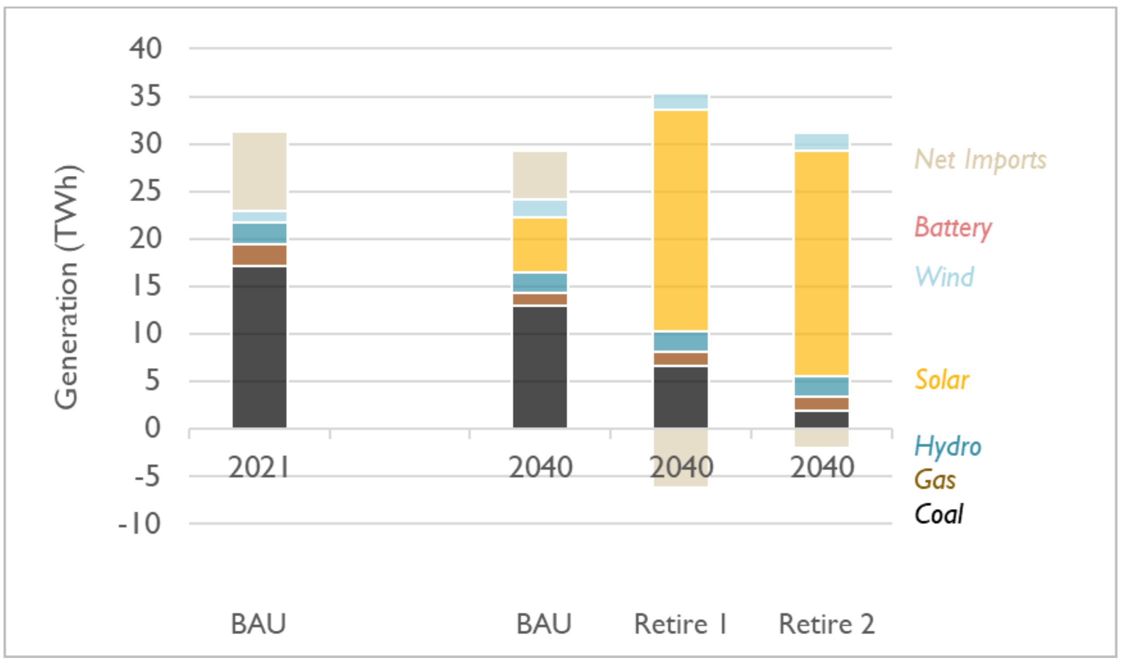
Table 15. Comparison of scenarios with and without a carbon price

Scenario	NPVRR ($Millions) No Carbon	NPVRR ($Millions) With Carbon	Delta
Synapse BAU	$14,694	$16,421	$1,727
Synapse Retirement 1	$13,303	$13,981	$678
Synapse Retirement 2	$14,428	$14,879	$451

Q. What happens to generation in the Retirement 2 scenario when a CO_2 price is included?

A. With a CO_2 price, the generation mix in the Retirement 2 scenario is almost entirely renewable by 2040, as shown in Figure 11. The remaining coal on the system comes from the Ohio Valley Electric Corporation's Kyger Creek and Clifty Creek units, which have modeled retirement dates of December 31, 2040.

Figure 11. Generation in the Synapse modeling scenarios, 2040, Base With Carbon



By 2040, APCo has become a net energy exporter in both the Retirement 1 and Retirement 2 scenarios.

Q. You also filed testimony in Virginia on the proposed compliance investments at Amos and Mountaineer. What did those results show?

A. The Virginia results showed a net benefit to the 2028 retirement of the Amos plant under a Base No Carbon forecast of $200 million, while savings under a Base With Carbon scenario reached $1.1 billion relative to the Synapse BAU.

Q. Why do your results in that docket differ from those presented here?

A. In the Virginia analysis, we only ran the model through 2040. The revenue requirement presented in that docket did not capture the replacement of Amos and Mountaineer after their BAU retirement on December 31, 2040 and ten years of operation of these replacement resources. The Virginia analysis also did not include the Capacity Only PPA as an available replacement resource option.

6. SYNAPSE MODELING RESULTS - WPCO

Q. What were the results of the Synapse modeling analysis for WPCo and the Mitchell plant?

A. The Synapse modeling found that retirement of Mitchell in 2028 results in a cost savings to customers of $118 million relative to retirement in 2040 under the Base No Carbon price forecast. With a carbon price, the savings grow to $350 million when Mitchell is retired. Those revenue requirements are shown in Table 16.

Table 16. Net present value of revenue requirements, WPCo, Synapse modeling scenarios

Scenario	Base No Carbon		Base With Carbon	
	NPVRR ($Millions)	Delta from BAU ($Millions)	NPVRR ($Millions)	Delta from BAU ($Millions)
Synapse WPCo BAU	$2,530		$2,825	
Synapse WPCo Retirement	$2,412	($118)	$2,475	($350)

Q. What types and quantities of replacement resources were selected to replace the Mitchell plant?

A. Like the APCo results, the model selects a combination of solar, wind, and battery resources. It also selects 150 MW of the Capacity Only PPA in 2029 and every year thereafter. Cumulative capacity, by year and resource, is shown in Table 17 for Synapse WPCo Retirement. Resource additions are only shown through 2040.

Table 17. Cumulative capacity additions, by year, in Synapse WPCo Retirement under Base No Carbon

	Synapse WPCo Retirement			
Year	Solar	Wind	Battery	Capacity PPA
2021	-	-	-	-
2022	-	-	-	-
2023	-	-	-	-
2024	-	-	-	-
2025	-	-	-	-
2026	400	-	-	-
2027	900	-	-	-
2028	1,020	-	-	-
2029	1,440	100	-	150
2030	1,440	100	-	150
2031	1,460	100	-	150
2032	1,460	100	-	150
2033	1,500	100	-	150
2034	1,500	100	-	150
2035	1,520	100	12	150
2036	1,520	100	12	150
2037	1,540	100	12	150
2038	1,540	100	12	150
2039	1,540	200	12	150
2040	1,540	200	12	150

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

A. There are several important takeaways from the Synapse modeling analysis. First, the retirement of Amos in 2028 is the least-cost scenario and is in the best interest of West Virginia ratepayers under conditions in the electric sector as they exist today. The Retirement 1 scenario it saves more than $1.4 billion between 2021 and 2050. For WPCo, the retirement of Mitchell in 2028 is also the least-cost option for ratepayers with a benefit of $118 million.

Second, the Synapse analysis shows that the 2028 retirement of Mountaineer is also economic when compared to the Synapse BAU, saving $266 million, under conditions as they exist today. Retirement 2 is not the least-cost scenario in this analysis; however, policies that change the relative economics of replacement resources when compared to existing coal units could change the costs of these resource portfolios.

Third, the Commission should note that it is in the economic interests of APCo's ratepayers to integrate additional renewable and storage capacity slightly ahead of the actual retirement year for Amos and/or Mountaineer. This low-variable-cost energy both displaces more expensive fossil generation and/or imported energy and reduces APCo's reliance on the PJM market.

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

7. COMPARING THE SYNAPSE AND APCO MODELING ANALYSES

Q. How do the resource additions in APCo's Case 2, which retires Amos in 2028, compare to Synapse Retirement 1?

A. APCo's Case 2 adds more than 2,000 MW of new combustion turbines and short-term-capacity-only PPAs, as well as small amounts of new solar to replace the retiring Amos plant in 2028. The Synapse Retirement 1 scenario, by contrast, adds 2,900 MW of new solar and 780 MW of battery storage resources, as shown in Table 18.[32] It also adds 400 MW of short-term capacity PPAs, but only in 2029.

32 In the Synapse modeling, Amos retires on December 31, 2028, and 2,900 MW of new solar and 780 MW of new battery are online on or before January 1, 2029.

Table 18. Comparison of new resource capacity (MW), Amos retires

	APCo Case 2				Synapse Retirement 1		
Year	New CT	ST PPA	New Solar	New Wind	New Solar	ST PPA	New Battery
2021	0		0	0	0	0	0
2022	0		0	0	0	0	0
2023	0		0	0	0	0	0
2024	0		150	0	0	0	0
2025	0		150	0	0	0	0
2026	0		150	0	600	0	0
2027	0		150	0	1,200	0	0
2028	1,666	400	150	0	1,800	0	0
2029	1,666	350	150	0	2,900	400	780
2030	1,666	400	150	0	3,760	0	936
2031	1,666	400	150	0	4,360	0	936
2032	1,666	400	150	0	4,960	0	936
2033	1,666	400	150	0	5,560	0	936
2034	1,666	400	150	0	6,160	0	936
2035	1,666	400	150	0	6,760	0	936
2036	1,666	400	300	0	7,360	0	936
2037	1,666	400	300	0	7,960	0	936
2038	1,666	350	450	0	8,560	0	936
2039	1,904	100	600	0	9,160	0	936
2040	3,094	350	750	0	9,760	0	936

Q. How do the resource additions in APCo's Case 3, which retires both Amos and Mountaineer in 2028, compare to Synapse Retirement 2?

A. APCo's Case 3 adds more than 3,200 MW of new combustion turbines and short-term-capacity-only PPAs, as well as small amounts of new solar, to replace the retiring Amos and Mountaineer plants. The Synapse Retirement 2 scenario, by contrast, adds 2,900 MW of new solar and 2,176 MW of battery storage resources, as shown in Table 19.[33] It also adds 400 MW of short-term-capacity PPAs for a single year in 2029.

Table 19. Comparison of new resource capacity (MW), Amos and Mountaineer retire

	APCO Case 3				Synapse Retirement 2		
Year	New CT	ST PPA	New Solar	New Wind	New Solar	ST PPA	New Battery
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
2024	0	0	150	0	0	0	0
2025	0	0	150	0	0	0	0
2026	0	0	150	0	600	0	0
2027	0	0	150	0	1,200	0	0
2028	2,856	400	150	0	1,800	0	0
2029	2,856	350	150	0	2,900	400	2,176
2030	2,856	400	150	0	4,000	0	2,476
2031	2,856	400	150	0	4,600	0	2,476
2032	2,856	400	150	0	5,200	0	2,476
2033	2,856	400	150	0	5,800	0	2,476
2034	2,856	400	150	0	6,400	0	2,476
2035	2,856	400	150	0	7,000	0	2,476
2036	2,856	400	300	0	7,600	0	2,476
2037	2,856	400	300	0	8,200	0	2,476
2038	2,856	350	450	0	8,800	0	2,476
2039	3,094	100	600	0	9,400	0	2,476
2040	3,094	350	750	0	10,000	0	2,476

33 In the Synapse modeling, Amos and Mountaineer retire on December 31, 2028, and 2,900 MW of new solar and 2,176 MW of new battery are online on or before January 1, 2029.

Q. Why do APCO's replacement resource selections look so much different than those in the Synapse scenarios?

A. In its modeling, Synapse used widely accepted price forecasts for replacement renewables and storage resources. Prices used by both APCo and Synapse for wind and solar are shown in Table 20.

Table 20. Comparison of prices for new resources in APCO and Synapse modeling

Year	Solar		Wind	
	APCO	Synapse	APCO	Synapse
2021	$49.70	$33.63		
2022	$48.34	$32.80	$40.77	
2023	$47.33	$31.94	$45.77	$45.25
2024	$56.11	$31.05	$41.44	$45.00
2025	$60.46	$30.12	$56.52	$44.71
2026	$60.31	$29.15	$57.21	$44.39
2027	$60.38	$28.15	$57.89	$44.04
2028	$60.51	$27.10	$58.58	$43.65
2029	$60.65	$26.02	$59.23	$43.22
2030	$60.85	$24.90	$59.91	$42.76
2031	$61.17	$25.12	$60.55	$43.28
2032	$61.56	$25.33	$61.21	$43.80
2033	$61.87	$25.55	$61.80	$44.33
2034	$62.15	$25.77	$62.35	$44.85
2035	$62.34	$25.99	$62.84	$45.38
2036	$62.59	$26.21	$63.40	$45.91
2037	$62.76	$26.43	$63.91	$46.45
2038	$62.91	$26.64	$64.41	$46.98
2039	$63.11	$26.86	$64.97	$47.52
2040	$63.39	$27.08	$65.66	$48.05

Sources: Companies' Response to Sierra Club Request Nos. 4-12, 4-13.

In 2028, for example, APCo's solar PPA price is $60.51/MWh.[34] 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 APCo's projections. Similarly, APCo's levelized cost for wind in 2028 is $58.58/MWh,[35] while the Synapse wind cost is $43.65/MWh. The Synapse modeled resources are much more cost-effective and competitive with APCo's forecasted on-peak market price of $34.87/MWh and the off-peak market energy price of $28.21/MWh.[36] Because wind and solar are more economic resources than in APCo's modeling, EnCompass builds renewables in the Retirement 1 scenario in order to displace generation from more expensive fossil-fueled units, to displace imports, and to be able to sell energy to the market. This is in stark contrast to APCo's modeled scenarios, which build fewer renewables and rely instead on existing fossil generation and imports from PJM.

APCo's modeling builds no battery storage resources because of the Company's high assumed build costs for these resources. The build costs used by APCo in the PLEXOS model are shown in comparison to ATB and EIA.

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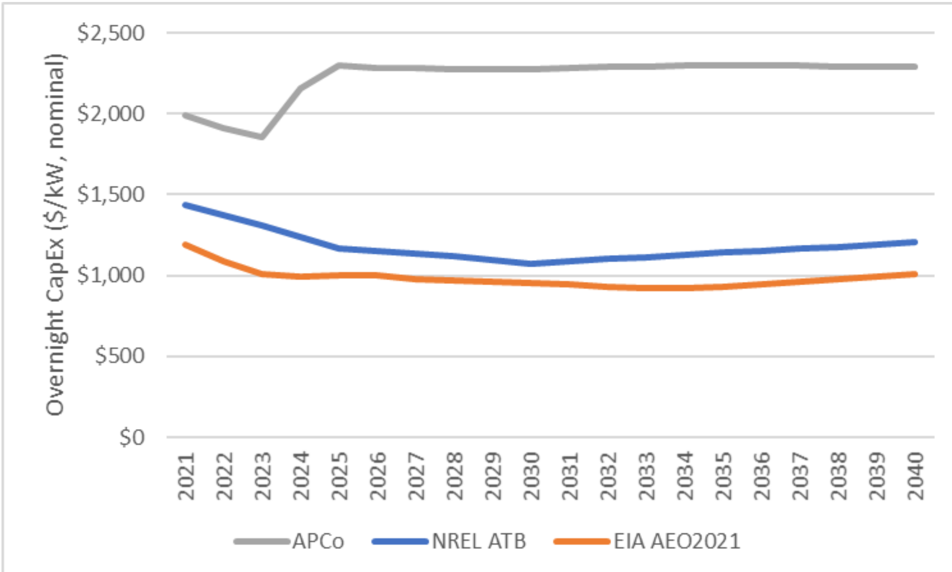
34 Exhibit RW-3.

35 Companies' Response to Sierra Club Request No. 4-13, Attachment 1 (enclosed as Exhibit RW-4).

36 *See* Companies' Response to Sierra Club Request No. 1-2, Attachment Trecazzi-FF-Appendix B-Base.xlsx. This attachment is not included as an exhibit due to its voluminous size, but it can be made available upon request.

Figure 12. Comparison of overnight capital cost forecasts for battery storage, APCo, 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; Companies' Response to Sierra Club Request No. 4-14, Attachment 1, enclosed as Exhibit RW-5.

8. COAL-FIRED POWER PLANTS WILL BECOME INCREASINGLY UNECONOMIC IN THE FUTURE

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

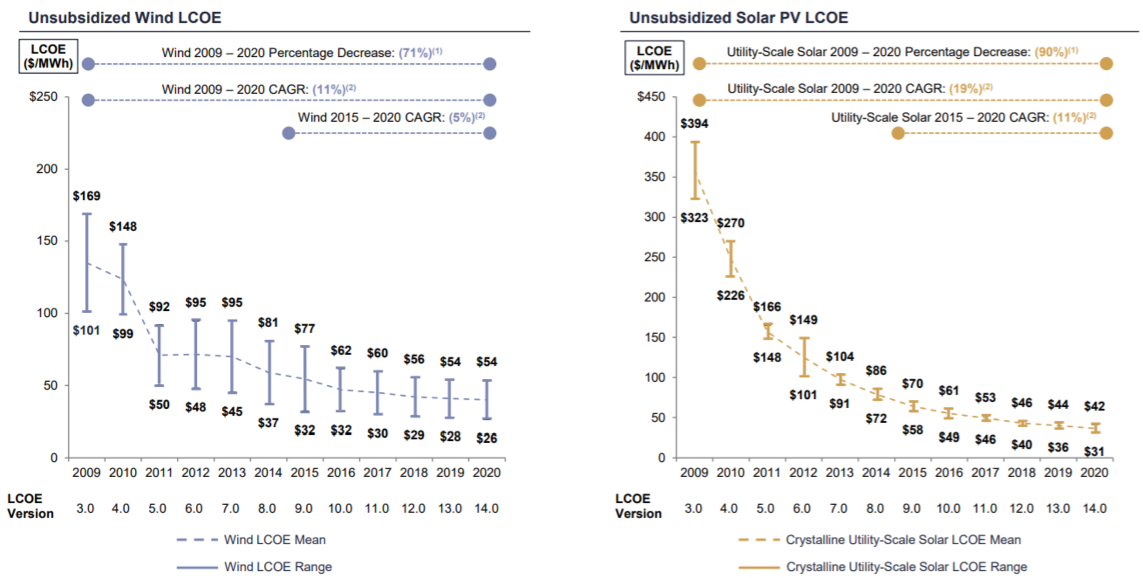
A. Existing coal-fired generating units will be become even less economic than they are today, because of both economic and regulatory forces that will increase the costs of operation at coal units relative to other types of capacity. In the past five years, 48 GW of coal has retired in the United States, with an additional 2.7 GW scheduled to retire in 2021.[37]

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

A. The primary economic factor is the cost of clean generation technologies, which have fallen dramatically over the previous decade. On a levelized cost of energy (LCOE) basis, costs for wind are now 71 percent lower than the costs in 2009, with a compound annual rate of decline of 11 percent per year. Costs for solar are now 90 percent lower than in 2009, with a compound annual rate of decline of 19 percent per year. Those annual trends are shown in Figure 13.

37 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 13. 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.

Battery storage technologies have experienced similar cost declines, but over a shorter period of time. Bloomberg New Energy Finance (BNEF) analyzed historical battery storage costs, finding that costs for lithium-ion batteries have fallen 76 percent between 2012 and the first half of 2019 and noting that these declines were the most striking of all observed energy technology cost trends.[38]

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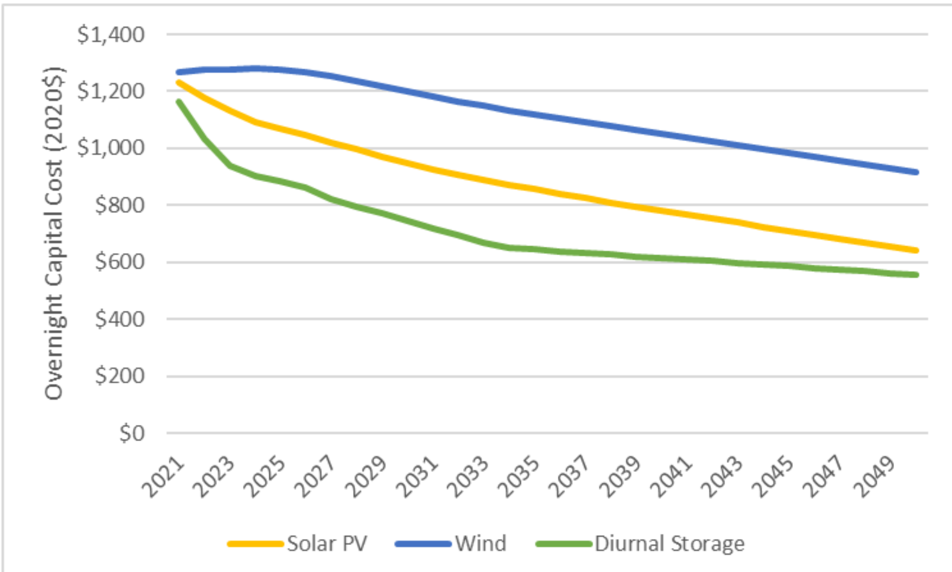
38 HJ Mai, *Electricity costs from battery storage down 76 percent since 2012: BNEF*, UTILITY DIVE (March 26, 2019), available at: https://www.utilitydive.com/news/electricity-costs-from-battery-storage-down-76-since-2012-bnef/551337/.

These three technologies are predicted to experience continued cost declines, though at varying rates. The US EIA's forecasts used in developing AEO 2021 for solar PV, wind, and storage resources are shown below in Figure 14.

Figure 14. 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.*

Given APCo's emphasis on inexpensive capacity in the form of new gas-fired combustion turbines as the primary resource selection in its own modeling,[39] battery storage costs warrant particular attention. The Synapse modeling uses APCo's values for firm capacity credit, with solar PV and wind receiving 40 percent and 12 percent, respectively, and battery storage resources given a higher

39 Direct Testimony of James F. Martin at 21:13–21:18.

amount of firm capacity of 80 percent. These firm capacity values, coupled with declining prices, make storage resources a cost-effective replacement resource for traditional peaking units. In fact, a 2018 report by GTM Research and Wood Mackenzie predicted that energy storage technologies will regularly compete head-to-head with new gas-fired peaking units by 2022, and that new gas peaking units will be rare by 2028.[40]

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

A. One regulatory force is the increase to renewable portfolio standards (RPS) in neighboring states that also operate in the PJM market. The volume of zero-variable-cost resources on the grid in PJM will increase in future years as neighboring states increase their renewable energy targets, implement more stringent targets for carbon dioxide emissions reductions, or both. In 2018, for example, New Jersey increased its RPS to 50 percent by 2030.[41] In 2019, Maryland legislators passed a bill that also increases its RPS to 50 percent by

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40 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.

41 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.

2030.[42] The District of Columbia increased its RPS to 100 percent renewable energy by 2040.[43] The locational marginal price for energy will decline as a greater number of these renewable generators come online, further lowering energy revenues earned by coal units.

Q. Are there other relevant regulatory forces?

A. Almost certainly, though we do not yet know what they will look like. President Biden has announced the goal of net-zero carbon dioxide emissions on the country's power grid by 2035. There are no policies currently in place that are explicitly intended to achieve this goal; however, it might be assumed that they will consist of a combination of incentives for zero-carbon energy and additional costs for fossil-fueled generators. Earlier this year, the U.S. Court of Appeals for the D.C. Circuit struck down President Trump's Affordable Clean Energy Rule, requiring the EPA to draft new regulations governing emissions of CO_2 from power plants. We can almost certainly expect new regulations from the EPA in the next four years.

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42 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/.

43 Robert Walton, *DC eases path for renewable generators as it pursues 100% goal*, UTILITY DIVE (February 13, 2019), available at https://www.utilitydive.com/news/dc-eases-path-for-renewable-generators-as-it-pursues-100-goal/548259/.

There have also been different proposals put forth by members of the United States Congress to extend the production tax credit (PTC) and investment tax credit (ITC) for renewables and storage for a period of ten years. The proposals vary, but different provisions include an increased credit for resources cited in low-income areas, as well as the option for regulated utilities to opt out of tax normalization requirements.[44] Extensions of the PTC and ITC would lower the costs of replacement resources for APCo and WPCo.

9. ECONOMIC IMPACTS OF COAL RETIREMENTS IN WEST VIRGINIA

Q. Do you agree that retiring the Amos and Mitchell plants in 2028 would have detrimental effects on the West Virginia economy and on jobs?

A. There would be job losses associated with the closing of these coal plants, yes. However, these coal resources would be replaced with a mix of in-state resources that would create new jobs and add to the state's gross domestic product (GDP). In a recent report published by West Virginia University prior to the filing of the APCo 2021 Integrated Resource Plan, the authors found that thousands of jobs were created in energy efficiency and renewable energy when these resources

44 KPMG, *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.

were used to replace retiring coal, such that there was a positive employment impact through 2030 and an almost neutral impact through 2035.[45]

Q. Have there been any recent developments that might alter the results of this analysis?

A. Yes. Senator Manchin of West Virginia has recently co-sponsored an $8 billion bill, the *American Jobs in Energy Manufacturing Act of 2021*, expanding the advanced energy manufacturing tax credit to attract clean energy manufacturing and recycling to former fossil fuel sites.[46] In addition, there is a $4 billion carve-out for companies that set up operations in communities where coal mines or coal power plants have closed.

Q. Has the coal industry responded to these developments?

A. Yes. The president of the United Mine Workers of America recently said that it will support the transition away from coal in exchange for job retraining, wage

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45 West Virginia University Law Center for Energy and Sustainable Development. *West Virginia's Energy Future: Ramping Up Renewable Energy to Decrease Costs, Reduce Risks, and Strengthen Economic Opportunities for West Virginia* (2020), available at https://energy.law.wvu.edu/files/d/b1ff1183-e9ae-4ad0-93bf-aa3afa1da785/wv-s-energy-future-wvu-col-cesd-final.pdf. The Executive Summary is enclosed as Exhibit RW-7.

46 American Jobs in Energy Manufacturing Act of 2021, S.B. 622, 117th Congress (2021–2022), available at https://www.congress.gov/117/bills/s622/BILLS-117s622is.pdf.

replacement, and preferential hiring for out-of-work miners, as well as the type of tax incentives proposed by Senator Manchin.[47]

10. CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your conclusions.

A. My independent modeling demonstrates that it is uneconomic, and not in the best interest of ratepayers, for APCo to invest in CCR and ELG costs at both Amos and Mountaineer to operate the plants until December 31, 2040. Investing only in CCR costs at the Amos plant and retiring the three units in 2028 results in ratepayer savings of $1.4 billion under a Base with No Carbon commodity price forecast. While the 2028 retirement of both Amos and Mountaineer results in a cost savings of $266 million relative to the Synapse BAU, which retires the plants in 2040, it is not the least-cost scenario in the Synapse modeling, under conditions in the electric sector as they exist today.

When a price on CO_2 emissions is included as part of the analysis, ratepayer savings rise to more than $2.4 billion when Amos is retired and replaced with a combination of renewable and battery storage resources. A scenario in which both Amos and Mountaineer are retired at the end of 2028 results in savings to

47 Tim de Chant, *Coal miners' union lobbies for jobs in renewable energy*, ARSTECHNICA (April 20, 2021), available at https://arstechnica.com/tech-policy/2021/04/coal-miners-union-lobbies-for-jobs-in-renewable-energy/.

ratepayers of approximately $1.5 billion relative to a scenario that does not retire the plants until the end of 2040.

For WPCo, retiring the Mitchell plant at the end of 2028 is more economic for ratepayers than a 2040 retirement date, saving $118 million over the duration of the analysis period under a Base with No Carbon case, and $350 million when a carbon price is included.

Q. Please summarize your recommendations.

A. I offer three recommendations. First, the Commission should approve the CCR compliance costs at the Amos plant, but deny the ELG costs. The use of industry-standard pricing for replacement capacity and energy shows that the retirement of the Amos plant in 2028 is economic and results in savings to customers, even in a scenario that does not include a price or other constraint on future CO_2 emissions.

Second, I recommend that the Commission approve the CCR costs at the Mountaineer plant, but deny the costs associated with ELG compliance at this time. The Synapse analysis shows that the retirement of both Amos and Mountaineer in 2028 yields savings to ratepayers when compared to a scenario in which both plants continue to operate through 2040. While the Synapse modeling in this docket shows that the retirement of both Amos and Mountaineer is more expensive than the retirement of Amos alone, we only model a single type of constraint on CO_2. It is expected that the Biden administration will soon be implementing some type of carbon policy, but it remains to be seen what form that policy might take, or how stringent it might be. It is thus premature to approve ELG costs at Mountaineer. Rather, the Commission should deny recovery of the ELG costs without prejudice until APCo can present an analysis of the effect of upcoming carbon regulations on the operation of the plant.

Finally, I recommend that the Commission approve the CCR compliance costs at the Mitchell plant, but deny the ELG costs. The Companies' own modeling shows that the 2028 retirement of the Mitchell plant is economic in two of the three commodity price forecasts it considered, and the Synapse analysis shows that retirement is the least-cost option for ratepayers under all three forecasts.

Q. Does this conclude your direct testimony?

A. Yes.

INDEX OF EXHIBITS

Exhibit Number	Description of Exhibit	Protected Status
Exhibit RW-1	Resume of Rachel S. Wilson	Non-Confidential
Exhibit RW-2	Response to Sierra Club 2-18, Confidential Attachment 1	Confidential
Exhibit RW-3	Response to Sierra Club 4-12, Attachment 1	Non-Confidential
Exhibit RW-4	Response to Sierra Club 4-13, Attachment 1	Non-Confidential
Exhibit RW-5	Response to Sierra Club 4-14, Attachment 1	Non-Confidential
Exhibit RW-6	*KPMG report: Outlook for what's ahead for energy tax incentives (updated)*	Non-Confidential
Exhibit RW-7	*West Virginia's Energy Future: Ramping Up Renewable Energy to Decrease Costs, Reduce Risks, and Strengthen Economic Opportunities for West Virginia* (2020), Executive Summary, West Virginia University Law Center for Energy and Sustainable Development.	Non-Confidential

Exhibit RW-1

Resume of Rachel S. Wilson

Rachel Wilson, Principal Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 I 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.

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.

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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.

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TESTIMONY

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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.

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.

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 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 October 2020

Exhibit RW-3

Response to Sierra Club 4-12, Attachment 1

Plexos Addition of 150 MW Utility Tier 1 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	1052	1	150.00	157,853	7.272%	2.500%	30	26.00%	SLD	11,982	11,982	(0)	(0)
2023	1012	1	150.00	151,798	7.272%	2.500%	30	26.00%	SLD	11,522	11,522	(0)	(0)
2024	981	1	150.00	147,083	7.272%	2.500%	30	26.00%	SLD	11,164	11,164	(0)	(0)
2025	1141	1	150.00	171,076	7.272%	2.500%	30	26.00%	SLD	12,985	12,985	(0)	(0)
2026	1217	1	150.00	182,575	7.272%	2.500%	30	26.00%	SLD	13,858	13,858	(0)	(0)
2027	1209	1	150.00	181,321	7.272%	2.500%	30	26.00%	SLD	13,763	13,763	(0)	(0)
2028	1206	1	150.00	180,865	7.272%	2.500%	30	26.00%	SLD	13,728	13,728	(0)	(0)
2029	1204	1	150.00	180,625	7.272%	2.500%	30	26.00%	SLD	13,710	13,710	(0)	(0)
2030	1203	1	150.00	180,419	7.272%	2.500%	30	26.00%	SLD	13,695	13,695	(0)	(0)
2031	1203	1	150.00	180,416	7.272%	2.500%	30	26.00%	SLD	13,694	13,694	(0)	(0)
2032	1206	1	150.00	180,837	7.272%	2.500%	30	26.00%	SLD	13,726	13,726	(0)	(0)
2033	1210	1	150.00	181,512	7.272%	2.500%	30	26.00%	SLD	13,778	13,778	(0)	(0)
2034	1213	1	150.00	181,904	7.272%	2.500%	30	26.00%	SLD	13,807	13,807	(0)	(0)
2035	1215	1	150.00	182,184	7.272%	2.500%	30	26.00%	SLD	13,829	13,829	(0)	(0)
2036	1214	1	150.00	182,088	7.272%	2.500%	30	26.00%	SLD	13,821	13,821	(0)	(0)
2037	1215	1	150.00	182,221	7.272%	2.500%	30	26.00%	SLD	13,831	13,831	(0)	(0)
2038	1214	1	150.00	182,076	7.272%	2.500%	30	26.00%	SLD	13,820	13,820	(0)	(0)
2039	1212	1	150.00	181,812	7.272%	2.500%	30	26.00%	SLD	13,800	13,800	(0)	(0)
2040	1212	1	150.00	181,733	7.272%	2.500%	30	26.00%	SLD	13,794	13,794	(0)	(0)
2041	1213	1	150.00	181,915	7.272%	2.500%	30	26.00%	SLD	13,808	13,808	(0)	(0)
2042	1212	1	150.00	181,734	7.272%	2.500%	30	26.00%	SLD	13,794	13,794	(0)	(0)
2043	1212	1	150.00	181,846	7.272%	2.500%	30	26.00%	SLD	13,803	13,803	(0)	(0)
2044	1213	1	150.00	181,987	7.272%	2.500%	30	26.00%	SLD	13,814	13,814	(0)	(0)
2045	1213	1	150.00	181,958	7.272%	2.500%	30	26.00%	SLD	13,811	13,811	(0)	(0)
2046	1213	1	150.00	181,928	7.272%	2.500%	30	26.00%	SLD	13,809	13,809	(0)	(0)
2047	1213	1	150.00	181,955	7.272%	2.500%	30	26.00%	SLD	13,811	13,811	(0)	(0)
2048	1213	1	150.00	181,976	7.272%	2.500%	30	26.00%	SLD	13,813	13,813	(0)	(0)
2049	1213	1	150.00	181,888	7.272%	2.500%	30	26.00%	SLD	13,806	13,806	(0)	(0)
2050	1212	1	150.00	181,773	7.272%	2.500%	30	26.00%	SLD	13,797	13,797	(0)	(0)

Real Annuity Factor =	12.077
Nominal Annuity Factor =	9.609
SLD Factor =	0.0759041603

2020 APCo IRP
Solar Alternative Pricing

COD EOY	Modeling YR	Annual Levelized Cost ($/MWh) **EIA** T2 (w ITC)	Annual Levelized Cost ($000) EIA T2 (w ITC)	esc	**$/kW** FOM		Input FOM T2 FOM
2021	2022	$37.08	11,982		-	$38.62	$52.19
2022	2023	$35.66	11,522	0.96	-	$38.25	$51.70
2023	2024	$34.55	11,164	0.97	-	$38.06	$51.44
2024	2025	$40.19	12,985	1.16	-	$38.36	$51.83
2025	2026	$42.89	13,858	1.07	-	$38.66	$52.25
2026	2027	$42.60	13,763	0.99	-	$38.94	$52.62
2027	2028	$42.49	13,728	1.00	-	$39.30	$53.11
2028	2029	$42.43	13,710	1.00	-	$39.68	$53.62
2029	2030	$42.38	13,695	1.00	-	$40.07	$54.14
2030	2031	$42.38	13,694	1.00	-	$40.48	$54.70
2031	2032	$42.48	13,726	1.00	-	$40.93	$55.31
2032	2033	$42.64	13,778	1.00	-	$41.40	$55.95
2033	2034	$42.73	13,807	1.00	-	$41.86	$56.57
2034	2035	$42.80	13,829	1.00	-	$42.31	$57.18
2035	2036	$42.78	13,821	1.00	-	$42.73	$57.75
2036	2037	$42.81	13,831	1.00	-	$43.18	$58.35
2037	2038	$42.77	13,820	1.00	-	$43.61	$58.93
2038	2039	$42.71	13,800	1.00	-	$44.04	$59.51
2039	2040	$42.69	13,794	1.00	-	$44.48	$60.11
2040	2041	$42.73	13,808	1.00	-	$44.96	$60.76
2041	2042	$42.69	13,794	1.00	-	$45.41	$61.36
2042	2043	$42.72	13,803	1.00	-	$45.89	$62.01
2043	2044	$42.75	13,814	1.00	-	$46.37	$62.66
2044	2045	$42.74	13,811	1.00	-	$46.84	$63.29
2045	2046	$42.74	13,809	1.00	-	$47.31	$63.93
2046	2047	$42.74	13,811	1.00	-	$47.79	$64.59
2047	2048	$42.75	13,813	1.00	-	$48.28	$65.24
2048	2049	$42.73	13,806	1.00	-	$48.75	$65.87
2049	2050	$42.70	13,797	1.00	-	$49.22	$66.51
2050	2051	$43.00	13,895	1.01	-	$49.83	$67.34

	Generic Solar **EIA**	
Annual Energy (GWh)	323.1126	107.7042
Capacity (MW)	150	50
Capacity Factor (%)	24.6	24.6
Inflation (%)	1%	

Project Name	OpCo	Capacity MW	COD	Tier	30 Year PPA Proxy (Upfront ITC)	Plexos YR
2021COD-ApCo-Tier 1-F1	ApCo	150	2021	Tier 1	$49.70	
2022COD-ApCo-Tier 1-F1	ApCo	150	2022	Tier 1	$48.34	
2023COD-ApCo-Tier 1-F1	ApCo	150	2023	Tier 1	$47.33	*AP_PPA Solar T1 2024*
2024COD-ApCo-Tier 1-F1	ApCo	150	2024	Tier 1	$56.11	*AP_PPA Solar T1 2025*
2025COD-ApCo-Tier 1-F1	ApCo	150	2025	Tier 1	$60.46	*AP_PPA Solar T1 2026*
2026COD-ApCo-Tier 1-F1	ApCo	150	2026	Tier 1	$60.31	*AP_PPA Solar T1 2027*
2027COD-ApCo-Tier 1-F1	ApCo	150	2027	Tier 1	$60.38	*AP_PPA Solar T1 2028*
2028COD-ApCo-Tier 1-F1	ApCo	150	2028	Tier 1	$60.51	*AP_PPA Solar T1 2029*
2029COD-ApCo-Tier 1-F1	ApCo	150	2029	Tier 1	$60.65	*AP_PPA Solar T1 2030*
2030COD-ApCo-Tier 1-F1	ApCo	150	2030	Tier 1	$60.85	*AP_PPA Solar T1 2031*
2031COD-ApCo-Tier 1-F1	ApCo	150	2031	Tier 1	$61.17	*AP_PPA Solar T1 2032*
2032COD-ApCo-Tier 1-F1	ApCo	150	2032	Tier 1	$61.56	*AP_PPA Solar T1 2033*
2033COD-ApCo-Tier 1-F1	ApCo	150	2033	Tier 1	$61.87	*AP_PPA Solar T1 2034*
2034COD-ApCo-Tier 1-F1	ApCo	150	2034	Tier 1	$62.15	*AP_PPA Solar T1 2035*
2035COD-ApCo-Tier 1-F1	ApCo	150	2035	Tier 1	$62.34	*AP_PPA Solar T1 2036*
2036COD-ApCo-Tier 1-F1	ApCo	150	2036	Tier 1	$62.59	*AP_PPA Solar T1 2037*
2037COD-ApCo-Tier 1-F1	ApCo	150	2037	Tier 1	$62.76	*AP_PPA Solar T1 2038*
2038COD-ApCo-Tier 1-F1	ApCo	150	2038	Tier 1	$62.91	*AP_PPA Solar T1 2039*
2039COD-ApCo-Tier 1-F1	ApCo	150	2039	Tier 1	$63.11	*AP_PPA Solar T1 2040*
2040COD-ApCo-Tier 1-F1	ApCo	150	2040	Tier 1	$63.39	*AP_PPA Solar T1 2041*
2041COD-ApCo-Tier 1-F1	ApCo	150	2041	Tier 1	$63.56	*AP_PPA Solar T1 2042*
2042COD-ApCo-Tier 1-F1	ApCo	150	2042	Tier 1	$63.82	*AP_PPA Solar T1 2043*
2043COD-ApCo-Tier 1-F1	ApCo	150	2043	Tier 1	$64.09	*AP_PPA Solar T1 2044*
2044COD-ApCo-Tier 1-F1	ApCo	150	2044	Tier 1	$64.31	*AP_PPA Solar T1 2045*
2045COD-ApCo-Tier 1-F1	ApCo	150	2045	Tier 1	$64.54	*AP_PPA Solar T1 2046*
2046COD-ApCo-Tier 1-F1	ApCo	150	2046	Tier 1	$64.78	*AP_PPA Solar T1 2047*
2047COD-ApCo-Tier 1-F1	ApCo	150	2047	Tier 1	$65.02	*AP_PPA Solar T1 2048*
2048COD-ApCo-Tier 1-F1	ApCo	150	2048	Tier 1	$65.23	*AP_PPA Solar T1 2049*
2049COD-ApCo-Tier 1-F1	ApCo	150	2049	Tier 1	$65.43	*AP_PPA Solar T1 2050*
2050COD-ApCo-Tier 1-F1	ApCo	150	2050	Tier 1	$66.02	

Appalachian Power
Investment Carrying Charges - Updated October 2020
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)	7.27	7.27	7.27	7.27	7.27	7.27	7.27	7.27	7.27	7.27	7.27	7.27
Depreciation (2)	49.02	31.87	23.28	18.14	7.99	4.74	3.20	2.33	1.78	1.55	1.17	0.85
FIT (3) (4)	1.06	0.76	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	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22
Carrying Cost Per Year	58.58	41.13	32.59	27.31	17.12	14.01	12.49	11.51	10.90	10.63	10.20	9.82

(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	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-ApCo-Tier 2-F1	ApCo	150	2021	Tier 2	24.59%	23.45%	30%	$1,195	$38.62	$18.88	$55.97	$37.08	$49.70
2022COD-ApCo-Tier 2-F1	ApCo	150	2022	Tier 2	24.59%	23.45%	30%	$1,149	$38.25	$18.70	$54.36	$35.66	$48.34
2023COD-ApCo-Tier 2-F1	ApCo	150	2023	Tier 2	24.59%	23.45%	30%	$1,113	$38.06	$18.61	$53.16	$34.55	$47.33
2024COD-ApCo-Tier 2-F1	ApCo	150	2024	Tier 2	24.59%	23.45%	10%	$1,108	$38.36	$18.76	$58.94	$40.19	$56.11
2025COD-ApCo-Tier 2-F1	ApCo	150	2025	Tier 2	24.59%	23.45%	0%	$1,102	$38.66	$18.91	$61.80	$42.89	$60.46
2026COD-ApCo-Tier 2-F1	ApCo	150	2026	Tier 2	24.59%	23.45%	0%	$1,095	$38.94	$19.04	$61.64	$42.60	$60.31
2027COD-ApCo-Tier 2-F1	ApCo	150	2027	Tier 2	24.59%	23.45%	0%	$1,092	$39.30	$19.22	$61.70	$42.49	$60.38
2028COD-ApCo-Tier 2-F1	ApCo	150	2028	Tier 2	24.59%	23.45%	0%	$1,091	$39.68	$19.40	$61.83	$42.43	$60.51
2029COD-ApCo-Tier 2-F1	ApCo	150	2029	Tier 2	24.59%	23.45%	0%	$1,089	$40.07	$19.59	$61.98	$42.38	$60.65
2030COD-ApCo-Tier 2-F1	ApCo	150	2030	Tier 2	24.59%	23.45%	0%	$1,089	$40.48	$19.79	$62.17	$42.38	$60.85
2031COD-ApCo-Tier 2-F1	ApCo	150	2031	Tier 2	24.59%	23.45%	0%	$1,092	$40.93	$20.01	$62.49	$42.48	$61.17
2032COD-ApCo-Tier 2-F1	ApCo	150	2032	Tier 2	24.59%	23.45%	0%	$1,096	$41.40	$20.25	$62.89	$42.64	$61.56
2033COD-ApCo-Tier 2-F1	ApCo	150	2033	Tier 2	24.59%	23.45%	0%	$1,098	$41.86	$20.47	$63.20	$42.73	$61.87
2034COD-ApCo-Tier 2-F1	ApCo	150	2034	Tier 2	24.59%	23.45%	0%	$1,100	$42.31	$20.69	$63.49	$42.80	$62.15
2035COD-ApCo-Tier 2-F1	ApCo	150	2035	Tier 2	24.59%	23.45%	0%	$1,100	$42.73	$20.90	$63.67	$42.78	$62.34
2036COD-ApCo-Tier 2-F1	ApCo	150	2036	Tier 2	24.59%	23.45%	0%	$1,100	$43.18	$21.12	$63.92	$42.81	$62.59
2037COD-ApCo-Tier 2-F1	ApCo	150	2037	Tier 2	24.59%	23.45%	0%	$1,099	$43.61	$21.33	$64.10	$42.77	$62.76
2038COD-ApCo-Tier 2-F1	ApCo	150	2038	Tier 2	24.59%	23.45%	0%	$1,098	$44.04	$21.53	$64.24	$42.71	$62.91
2039COD-ApCo-Tier 2-F1	ApCo	150	2039	Tier 2	24.59%	23.45%	0%	$1,097	$44.48	$21.75	$64.44	$42.69	$63.11
2040COD-ApCo-Tier 2-F1	ApCo	150	2040	Tier 2	24.59%	23.45%	0%	$1,098	$44.96	$21.98	$64.72	$42.73	$63.39
2041COD-ApCo-Tier 2-F1	ApCo	150	2041	Tier 2	24.59%	23.45%	0%	$1,097	$45.41	$22.20	$64.89	$42.69	$63.56
2042COD-ApCo-Tier 2-F1	ApCo	150	2042	Tier 2	24.59%	23.45%	0%	$1,098	$45.89	$22.44	$65.15	$42.72	$63.82
2043COD-ApCo-Tier 2-F1	ApCo	150	2043	Tier 2	24.59%	23.45%	0%	$1,099	$46.37	$22.67	$65.42	$42.75	$64.09
2044COD-ApCo-Tier 2-F1	ApCo	150	2044	Tier 2	24.59%	23.45%	0%	$1,099	$46.84	$22.90	$65.65	$42.74	$64.31
2045COD-ApCo-Tier 2-F1	ApCo	150	2045	Tier 2	24.59%	23.45%	0%	$1,098	$47.31	$23.13	$65.87	$42.74	$64.54
2046COD-ApCo-Tier 2-F1	ApCo	150	2046	Tier 2	24.59%	23.45%	0%	$1,099	$47.79	$23.37	$66.11	$42.74	$64.78
2047COD-ApCo-Tier 2-F1	ApCo	150	2047	Tier 2	24.59%	23.45%	0%	$1,099	$48.28	$23.60	$66.35	$42.75	$65.02
2048COD-ApCo-Tier 2-F1	ApCo	150	2048	Tier 2	24.59%	23.45%	0%	$1,098	$48.75	$23.83	$66.56	$42.73	$65.23
2049COD-ApCo-Tier 2-F1	ApCo	150	2049	Tier 2	24.59%	23.45%	0%	$1,097	$49.22	$24.06	$66.76	$42.70	$65.43
2050COD-ApCo-Tier 2-F1	ApCo	150	2050	Tier 2	24.59%	23.45%	0%	$1,105	$49.83	$24.36	$67.36	$43.00	$66.02

Exhibit RW-4

Response to Sierra Club 4-13, Attachment 1

Plexos Addition of 200 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 Method Annuity Calculation ($000)	Levelized Cost Annuity ($000)	SLD vs Levelized Annuity ($000)	SLD vs Levelized Annuity (%)
2022	2023	**905**	1	200.00	180,950	7.272%	2.500%	30	26.00%	SLD	13,735	13,735	0	0
2023	2024	1095	1	200.00	219,026	7.272%	2.500%	30	26.00%	SLD	16,625	16,625	0	0
2024	2025	908	1	200.00	181,568	7.272%	2.500%	30	26.00%	SLD	13,782	13,781.7	0	0
2025	2026	1504	1	200.00	300,817	7.272%	2.500%	30	26.00%	SLD	22,833	22,833	0	0
2026	2027	1519	1	200.00	303,843	7.272%	2.500%	30	26.00%	SLD	23,063	23,063	0	0
2027	2028	1534	1	200.00	306,742	7.272%	2.500%	30	26.00%	SLD	23,283	23,283	0	0
2028	2029	1549	1	200.00	309,722	7.272%	2.500%	30	26.00%	SLD	23,509	23,509	0	0
2029	2030	1562	1	200.00	312,451	7.272%	2.500%	30	26.00%	SLD	23,716	23,716	0	0
2030	2031	1577	1	200.00	315,314	7.272%	2.500%	30	26.00%	SLD	23,934	23,934	0	0
2031	2032	1590	1	200.00	317,934	7.272%	2.500%	30	26.00%	SLD	24,133	24,133	0	0
2032	2033	1603	1	200.00	320,627	7.272%	2.500%	30	26.00%	SLD	24,337	24,337	0	0
2033	2034	1614	1	200.00	322,883	7.272%	2.500%	30	26.00%	SLD	24,508	24,508	0	0
2034	2035	1624	1	200.00	324,775	7.272%	2.500%	30	26.00%	SLD	24,652	24,652	0	0
2035	2036	1631	1	200.00	326,249	7.272%	2.500%	30	26.00%	SLD	24,764	24,764	0	0
2036	2037	1641	1	200.00	328,112	7.272%	2.500%	30	26.00%	SLD	24,905	24,905	0	0
2037	2038	1648	1	200.00	329,653	7.272%	2.500%	30	26.00%	SLD	25,022	25,022	0	0
2038	2039	1656	1	200.00	331,107	7.272%	2.500%	30	26.00%	SLD	25,132	25,132	0	0
2039	2040	1665	1	200.00	332,973	7.272%	2.500%	30	26.00%	SLD	25,274	25,274	0	0
2040	2041	1678	1	200.00	335,614	7.272%	2.500%	30	26.00%	SLD	25,475	25,475	0	0
2041	2042	1689	1	200.00	337,851	7.272%	2.500%	30	26.00%	SLD	25,644	25,644	0	0
2042	2043	1702	1	200.00	340,328	7.272%	2.500%	30	26.00%	SLD	25,832	25,832	0	0
2043	2044	1714	1	200.00	342,865	7.272%	2.500%	30	26.00%	SLD	26,025	26,025	0	0
2044	2045	1727	1	200.00	345,369	7.272%	2.500%	30	26.00%	SLD	26,215	26,215	0	0
2045	2046	1737	1	200.00	347,450	7.272%	2.500%	30	26.00%	SLD	26,373	26,373	0	0
2046	2047	1750	1	200.00	349,935	7.272%	2.500%	30	26.00%	SLD	26,561	26,561	0	0
2047	2048	1761	1	200.00	352,289	7.272%	2.500%	30	26.00%	SLD	26,740	26,740	0	0
2048	2049	1773	1	200.00	354,617	7.272%	2.500%	30	26.00%	SLD	26,917	26,917	0	0
2049	2050	1783	1	200.00	356,686	7.272%	2.500%	30	26.00%	SLD	27,074	27,074	0	0
2050	2051													
2051														

Real Annuity Factor = 12.077
Nominal Annuity Factor = 9.609
SLD Factor = 0.0759041603

2020 APCo IRP
Wind Alternative Pricing
Column K
35%

Updated: 10/15/2020
source: EIA Solar & +Storage, Wind LCOEs Results by OpCo Including AFUDC (Solar with c Output Check

should match column H

COD Dec	Annual Levelized Cost ($/MWh) 35 CF	Annual Levelized Cost ($000) 35 CF		Screening FOM $/kW	FOM $/kW	Plex Year	FO&M Cost ($000)	Max Capacity (MW)	Wind FOM Check
2022	$22.40	13,735		56.38	76.19	2023	0		
2023	$27.11	16,625	1.21	57.26	77.38	2024	0		
2024	$22.48	13,782	0.83	58.19	78.63	2025	11637.24	200	0.00
2025	$37.24	22,833	1.66	59.17	79.96	2026	11834.08	200	0.00
2026	$37.61	23,063	1.01	60.14	81.27	2027	12027.96	200	0.00
2027	$37.97	23,283	1.01	61.12	82.60	2028	12258.29	200	0.17
2028	$38.34	23,509	1.01	62.10	83.92	2029	12420.16	200	0.00
2029	$38.68	23,716	1.01	63.08	85.24	2030	12615.52	200	0.00
2030	$39.03	23,934	1.01	64.07	86.58	2031	12813.84	200	0.00
2031	$39.36	24,133	1.01	65.05	87.90	2032	13044.84	200	0.18
2032	$39.69	24,337	1.01	66.03	89.23	2033	13206.04	200	0.00
2033	$39.97	24,508	1.01	67.00	90.54	2034	13399.92	200	0.00
2034	$40.20	24,652	1.01	67.96	91.84	2035	13592.32	200	0.00
2035	$40.38	24,764	1.00	68.92	93.13	2036	13821	200	0.19
2036	$40.61	24,905	1.01	69.90	94.46	2037	13980.08	200	0.00
2037	$40.81	25,022	1.00	70.88	95.79	2038	14176.92	200	0.00
2038	$40.99	25,132	1.00	71.87	97.13	2039	14375.24	200	0.00
2039	$41.22	25,274	1.01	72.91	98.52	2040	14620.91	200	0.20
2040	$41.54	25,475	1.01	73.98	99.98	2041	14797.04	200	0.00
2041	$41.82	25,644	1.01	75.05	101.42	2042	15010.16	200	0.00
2042	$42.13	25,832	1.01	76.14	102.90	2043	15229.2	200	0.00
2043	$42.44	26,025	1.01	77.24	104.38	2044	15490.56	200	0.21
2044	$42.75	26,215	1.01	78.34	105.86	2045	15667.28	200	0.00
2045	$43.01	26,373	1.01	79.42	107.33	2046	15884.84	200	0.00
2046	$43.32	26,561	1.01	80.54	108.83	2047	16106.84	200	0.00
2047	$43.61	26,740	1.01	81.65	110.33	2048	16373.58	200	0.22
2048	$43.90	26,917	1.01	82.75	111.83	2049	16550.84	200	0.00
2049	$44.15	27,074	1.01	83.85	113.31	2050	16769.88	200	0.00
2050	$44.76	27,448	1.01	85.12	115.02	2051			
2051			0.00	56.54	76.41	2052			

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

Scenario	OpCo	Capacity MW	COD Year	Wind CF	Build Cost ($/kW)	PTC Credit	Levelized O&M $/kW	Levelized O&M $/MWh	Levelized Cost of Energy $/MWh	Levelized Capital Cost $/MWH
2022COD-ApCo-0.35CF	ApCo	200	2022	35%	$1,296	60%	$56.38	$18.37	$40.77	$22.40
2023COD-ApCo-0.35CF	ApCo	200	2023	35%	$1,306	40%	$57.26	$18.66	$45.77	$27.11
2024COD-ApCo-0.35CF	ApCo	200	2024	35%	$1,317	60%	$58.19	$18.96	$41.44	$22.48
2025COD-ApCo-0.35CF	ApCo	200	2025	35%	$1,333	0%	$59.17	$19.28	$56.52	$37.24
2026COD-ApCo-0.35CF	ApCo	200	2026	35%	$1,346	0%	$60.14	$19.60	$57.21	$37.61
2027COD-ApCo-0.35CF	ApCo	200	2027	35%	$1,359	0%	$61.12	$19.92	$57.89	$37.97
2028COD-ApCo-0.35CF	ApCo	200	2028	35%	$1,372	0%	$62.10	$20.24	$58.58	$38.34
2029COD-ApCo-0.35CF	ApCo	200	2029	35%	$1,384	0%	$63.08	$20.56	$59.23	$38.68
2030COD-ApCo-0.35CF	ApCo	200	2030	35%	$1,397	0%	$64.07	$20.88	$59.91	$39.03
2031COD-ApCo-0.35CF	ApCo	200	2031	35%	$1,409	0%	$65.05	$21.20	$60.55	$39.36
2032COD-ApCo-0.35CF	ApCo	200	2032	35%	$1,420	0%	$66.03	$21.52	$61.21	$39.69
2033COD-ApCo-0.35CF	ApCo	200	2033	35%	$1,430	0%	$67.00	$21.84	$61.80	$39.97
2034COD-ApCo-0.35CF	ApCo	200	2034	35%	$1,439	0%	$67.96	$22.15	$62.35	$40.20
2035COD-ApCo-0.35CF	ApCo	200	2035	35%	$1,446	0%	$68.92	$22.46	$62.84	$40.38
2036COD-ApCo-0.35CF	ApCo	200	2036	35%	$1,454	0%	$69.90	$22.78	$63.40	$40.61
2037COD-ApCo-0.35CF	ApCo	200	2037	35%	$1,460	0%	$70.88	$23.10	$63.91	$40.81
2038COD-ApCo-0.35CF	ApCo	200	2038	35%	$1,467	0%	$71.87	$23.42	$64.41	$40.99
2039COD-ApCo-0.35CF	ApCo	200	2039	35%	$1,476	0%	$72.91	$23.76	$64.97	$41.22
2040COD-ApCo-0.35CF	ApCo	200	2040	35%	$1,487	0%	$73.98	$24.11	$65.66	$41.54
2041COD-ApCo-0.35CF	ApCo	200	2041	35%	$1,497	0%	$75.05	$24.46	$66.28	$41.82
2042COD-ApCo-0.35CF	ApCo	200	2042	35%	$1,508	0%	$76.14	$24.81	$66.94	$42.13
2043COD-ApCo-0.35CF	ApCo	200	2043	35%	$1,519	0%	$77.24	$25.17	$67.61	$42.44
2044COD-ApCo-0.35CF	ApCo	200	2044	35%	$1,530	0%	$78.34	$25.53	$68.28	$42.75
2045COD-ApCo-0.35CF	ApCo	200	2045	35%	$1,539	0%	$79.42	$25.88	$68.89	$43.01
2046COD-ApCo-0.35CF	ApCo	200	2046	35%	$1,551	0%	$80.54	$26.25	$69.56	$43.32
2047COD-ApCo-0.35CF	ApCo	200	2047	35%	$1,561	0%	$81.65	$26.60	$70.21	$43.61
2048COD-ApCo-0.35CF	ApCo	200	2048	35%	$1,571	0%	$82.75	$26.97	$70.87	$43.90
2049COD-ApCo-0.35CF	ApCo	200	2049	35%	$1,580	0%	$83.85	$27.33	$71.48	$44.15
2050COD-ApCo-0.35CF	ApCo	200	2050	35%	$1,602	0%	$85.12	$27.74	$72.50	$44.76

Appalachian Power
Investment Carrying Charges - Updated October 2020
For Economic Analyses

	Investment Life (Years)											
	2	3	4	5	10	15	20	25	30	33	40	50
Return (1)	7.27	7.27	7.27	7.27	7.27	7.27	7.27	7.27	7.27	7.27	7.27	7.27
Depreciation (2)	49.02	31.87	23.28	18.14	7.99	4.74	3.20	2.33	1.78	1.55	1.17	0.85
FIT (3) (4)	1.06	0.76	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	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22
Carrying Cost Per Year	58.58	41.13	32.59	27.31	17.12	14.01	12.49	11.51	10.90	10.63	10.20	9.82

(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-5

Response to Sierra Club 4-14, Attachment 1

Plexos Addition of 25 MW Storage 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 (%)
2021	1991	1	25.00	49,772	7.272%	2.500%	10	26.00%	SLD	6,018	6,018	(0)	(0)
2022	1915	1	25.00	47,863	7.272%	2.500%	10	26.00%	SLD	5,787	5,787	(0)	(0)
2023	1855	1	25.00	46,376	7.272%	2.500%	10	26.00%	SLD	5,607	5,608	(0)	(0)
2024	2158	1	25.00	53,941	7.272%	2.500%	10	26.00%	SLD	6,522	6,522	(0)	(0)
2025	2303	1	25.00	57,567	7.272%	2.500%	10	26.00%	SLD	6,961	6,961	(0)	(0)
2026	2287	1	25.00	57,172	7.272%	2.500%	10	26.00%	SLD	6,913	6,913	(0)	(0)
2027	2281	1	25.00	57,028	7.272%	2.500%	10	26.00%	SLD	6,895	6,896	(0)	(0)
2028	2278	1	25.00	56,952	7.272%	2.500%	10	26.00%	SLD	6,886	6,887	(0)	(0)
2029	2275	1	25.00	56,887	7.272%	2.500%	10	26.00%	SLD	6,878	6,879	(0)	(0)
2030	2275	1	25.00	56,886	7.272%	2.500%	10	26.00%	SLD	6,878	6,879	(0)	(0)
2031	2281	1	25.00	57,019	7.272%	2.500%	10	26.00%	SLD	6,894	6,895	(0)	(0)
2032	2289	1	25.00	57,232	7.272%	2.500%	10	26.00%	SLD	6,920	6,920	(0)	(0)
2033	2294	1	25.00	57,355	7.272%	2.500%	10	26.00%	SLD	6,935	6,935	(0)	(0)
2034	2298	1	25.00	57,444	7.272%	2.500%	10	26.00%	SLD	6,946	6,946	(0)	(0)
2035	2297	1	25.00	57,413	7.272%	2.500%	10	26.00%	SLD	6,942	6,942	(0)	(0)
2036	2298	1	25.00	57,455	7.272%	2.500%	10	26.00%	SLD	6,947	6,947	(0)	(0)
2037	2296	1	25.00	57,410	7.272%	2.500%	10	26.00%	SLD	6,942	6,942	(0)	(0)
2038	2293	1	25.00	57,326	7.272%	2.500%	10	26.00%	SLD	6,932	6,932	(0)	(0)
2039	2292	1	25.00	57,301	7.272%	2.500%	10	26.00%	SLD	6,928	6,929	(0)	(0)
2040	2294	1	25.00	57,359	7.272%	2.500%	10	26.00%	SLD	6,935	6,936	(0)	(0)
2041	2292	1	25.00	57,302	7.272%	2.500%	10	26.00%	SLD	6,929	6,929	(0)	(0)
2042	2293	1	25.00	57,337	7.272%	2.500%	10	26.00%	SLD	6,933	6,933	(0)	(0)
2043	2295	1	25.00	57,382	7.272%	2.500%	10	26.00%	SLD	6,938	6,938	(0)	(0)
2044	2295	1	25.00	57,372	7.272%	2.500%	10	26.00%	SLD	6,937	6,937	(0)	(0)
2045	2295	1	25.00	57,363	7.272%	2.500%	10	26.00%	SLD	6,936	6,936	(0)	(0)
2046	2295	1	25.00	57,372	7.272%	2.500%	10	26.00%	SLD	6,937	6,937	(0)	(0)
2047	2295	1	25.00	57,378	7.272%	2.500%	10	26.00%	SLD	6,938	6,938	(0)	(0)
2048	2294	1	25.00	57,350	7.272%	2.500%	10	26.00%	SLD	6,934	6,935	(0)	(0)
2049	2293	1	25.00	57,314	7.272%	2.500%	10	26.00%	SLD	6,930	6,930	(0)	(0)
2050	2309	1	25.00	57,719	7.272%	2.500%	10	26.00%	SLD	6,979	6,979	(0)	(0)
Real Annuity Factor =				6.936									
Nominal Annuity Factor =				6.205									
SLD Factor =				0.1209128767									

2020 APCo IRP
Storage Alternative Pricing

25 MW size

	Modeling YR	Annual Levelized Cost ($/MWh) T1 (No PTC)	**EIA** T2 (w PTC)	Annual Levelized Cost ($000) EIA Storage	esc		**$/kW** FOM	FO&M Charge Plexos $/KW-Yr	Input FOM	Scaled up to 25 MW ELCC has 20 MW
2021	2021	-	*$37.08*	6,018		BAT 2021	$25.28		$34.17	$42.71
2022	2022	-	*$35.66*	5,787	0.96		$25.04	0.99	$33.84	$42.30
2023	2023	-	*$34.55*	5,608	0.97		$24.92	0.99	$33.67	$42.09
2024	2024	-	*$40.19*	6,522	1.1631218		$25.11	1.01	$33.94	$42.42
2025	2025	-	*$42.89*	6,961	1.0672161		$25.31	1.01	$34.21	$42.76
2026	2026	-	*$42.60*	6,913	0.9931359		$25.49	1.01	$34.45	$43.06
2027	2027	-	*$42.49*	6,896	0.9974856		$25.73	1.01	$34.77	$43.46
2028	2028	-	*$42.43*	6,887	0.9986702		$25.98	1.01	$35.11	$43.88
2029	2029	-	*$42.38*	6,879	0.9988593		$26.23	1.01	$35.45	$44.31
2030	2030	-	*$42.38*	6,879	0.9999811		$26.50	1.01	$35.81	$44.76
2031	2031	-	*$42.48*	6,895	1.0023382		$26.79	1.01	$36.21	$45.26
2032	2032	-	*$42.64*	6,920	1.003731		$27.11	1.01	$36.63	$45.79
2033	2033	-	*$42.73*	6,935	1.0021576		$27.41	1.01	$37.04	$46.30
2034	2034	-	*$42.80*	6,946	1.0015398		$27.70	1.01	$37.44	$46.79
2035	2035	-	*$42.78*	6,942	0.9994719		$27.98	1.01	$37.81	$47.26
2036	2036	-	*$42.81*	6,947	1.0007341		$28.27	1.01	$38.21	$47.76
2037	2037	-	*$42.77*	6,942	0.9992034		$28.55	1.01	$38.59	$48.23
2038	2038	-	*$42.71*	6,932	0.9985505		$28.83	1.01	$38.96	$48.70
2039	2039	-	*$42.69*	6,929	0.9995645		$29.12	1.01	$39.35	$49.19
2040	2040	-	*$42.73*	6,936	1.0010002		$29.44	1.01	$39.78	$49.72
2041	2041	-	*$42.69*	6,929	0.9990078		$29.73	1.01	$40.17	$50.22
2042	2042	-	*$42.72*	6,933	1.0006137		$30.04	1.01	$40.59	$50.74
2043	2043	-	*$42.75*	6,938	1.0007772		$30.35	1.01	$41.02	$51.28
2044	2044	-	*$42.74*	6,937	0.9998386		$30.66	1.01	$41.44	$51.80
2045	2045	-	*$42.74*	6,936	0.9998339		$30.97	1.01	$41.85	$52.32
2046	2046	-	*$42.74*	6,937	1.0001521		$31.29	1.01	$42.28	$52.85
2047	2047	-	*$42.75*	6,938	1.0001123		$31.60	1.01	$42.70	$53.38
2048	2048	-	*$42.73*	6,935	0.9995205		$31.91	1.01	$43.12	$53.90
2049	2049	-	*$42.70*	6,930	0.9993634		$32.22	1.01	$43.54	$54.42
2050	2050	-	*$43.00*	6,979	1.0070677		$32.61	1.01	$44.07	$55.09

solar LCOE (reflects learning curve)

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-ApCo-Tier 2-F1	ApCo	150	2021	Tier 2	24.59%	23.45%	30%	$1,195	$38.62	$18.88	$55.97	$37.08	$49.70
2022COD-ApCo-Tier 2-F1	ApCo	150	2022	Tier 2	24.59%	23.45%	30%	$1,149	$38.25	$18.70	$54.36	$35.66	$48.34
2023COD-ApCo-Tier 2-F1	ApCo	150	2023	Tier 2	24.59%	23.45%	30%	$1,113	$38.06	$18.61	$53.16	$34.55	$47.33
2024COD-ApCo-Tier 2-F1	ApCo	150	2024	Tier 2	24.59%	23.45%	10%	$1,108	$38.36	$18.76	$58.94	$40.19	$56.11
2025COD-ApCo-Tier 2-F1	ApCo	150	2025	Tier 2	24.59%	23.45%	0%	$1,102	$38.66	$18.91	$61.80	$42.89	$60.46
2026COD-ApCo-Tier 2-F1	ApCo	150	2026	Tier 2	24.59%	23.45%	0%	$1,095	$38.94	$19.04	$61.64	$42.60	$60.31
2027COD-ApCo-Tier 2-F1	ApCo	150	2027	Tier 2	24.59%	23.45%	0%	$1,092	$39.30	$19.22	$61.70	$42.49	$60.38
2028COD-ApCo-Tier 2-F1	ApCo	150	2028	Tier 2	24.59%	23.45%	0%	$1,091	$39.68	$19.40	$61.83	$42.43	$60.51
2029COD-ApCo-Tier 2-F1	ApCo	150	2029	Tier 2	24.59%	23.45%	0%	$1,089	$40.07	$19.59	$61.98	$42.38	$60.65
2030COD-ApCo-Tier 2-F1	ApCo	150	2030	Tier 2	24.59%	23.45%	0%	$1,089	$40.48	$19.79	$62.17	$42.38	$60.85
2031COD-ApCo-Tier 2-F1	ApCo	150	2031	Tier 2	24.59%	23.45%	0%	$1,092	$40.93	$20.01	$62.49	$42.48	$61.17
2032COD-ApCo-Tier 2-F1	ApCo	150	2032	Tier 2	24.59%	23.45%	0%	$1,096	$41.40	$20.25	$62.89	$42.64	$61.56
2033COD-ApCo-Tier 2-F1	ApCo	150	2033	Tier 2	24.59%	23.45%	0%	$1,098	$41.86	$20.47	$63.20	$42.73	$61.87
2034COD-ApCo-Tier 2-F1	ApCo	150	2034	Tier 2	24.59%	23.45%	0%	$1,100	$42.31	$20.69	$63.49	$42.80	$62.15
2035COD-ApCo-Tier 2-F1	ApCo	150	2035	Tier 2	24.59%	23.45%	0%	$1,100	$42.73	$20.90	$63.67	$42.78	$62.34
2036COD-ApCo-Tier 2-F1	ApCo	150	2036	Tier 2	24.59%	23.45%	0%	$1,100	$43.18	$21.12	$63.92	$42.81	$62.59
2037COD-ApCo-Tier 2-F1	ApCo	150	2037	Tier 2	24.59%	23.45%	0%	$1,099	$43.61	$21.33	$64.10	$42.77	$62.76
2038COD-ApCo-Tier 2-F1	ApCo	150	2038	Tier 2	24.59%	23.45%	0%	$1,098	$44.04	$21.53	$64.24	$42.71	$62.91
2039COD-ApCo-Tier 2-F1	ApCo	150	2039	Tier 2	24.59%	23.45%	0%	$1,097	$44.48	$21.75	$64.44	$42.69	$63.11
2040COD-ApCo-Tier 2-F1	ApCo	150	2040	Tier 2	24.59%	23.45%	0%	$1,098	$44.96	$21.98	$64.72	$42.73	$63.39
2041COD-ApCo-Tier 2-F1	ApCo	150	2041	Tier 2	24.59%	23.45%	0%	$1,097	$45.41	$22.20	$64.89	$42.69	$63.56
2042COD-ApCo-Tier 2-F1	ApCo	150	2042	Tier 2	24.59%	23.45%	0%	$1,098	$45.89	$22.44	$65.15	$42.72	$63.82
2043COD-ApCo-Tier 2-F1	ApCo	150	2043	Tier 2	24.59%	23.45%	0%	$1,099	$46.37	$22.67	$65.42	$42.75	$64.09
2044COD-ApCo-Tier 2-F1	ApCo	150	2044	Tier 2	24.59%	23.45%	0%	$1,099	$46.84	$22.90	$65.65	$42.74	$64.31
2045COD-ApCo-Tier 2-F1	ApCo	150	2045	Tier 2	24.59%	23.45%	0%	$1,098	$47.31	$23.13	$65.87	$42.74	$64.54
2046COD-ApCo-Tier 2-F1	ApCo	150	2046	Tier 2	24.59%	23.45%	0%	$1,099	$47.79	$23.37	$66.11	$42.74	$64.78
2047COD-ApCo-Tier 2-F1	ApCo	150	2047	Tier 2	24.59%	23.45%	0%	$1,099	$48.28	$23.60	$66.35	$42.75	$65.02
2048COD-ApCo-Tier 2-F1	ApCo	150	2048	Tier 2	24.59%	23.45%	0%	$1,098	$48.75	$23.83	$66.56	$42.73	$65.23
2049COD-ApCo-Tier 2-F1	ApCo	150	2049	Tier 2	24.59%	23.45%	0%	$1,097	$49.22	$24.06	$66.76	$42.70	$65.43
2050COD-ApCo-Tier 2-F1	ApCo	150	2050	Tier 2	24.59%	23.45%	0%	$1,105	$49.83	$24.36	$67.36	$43.00	$66.02

Appalachian Power
Investment Carrying Charges - Updated October 2020
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)	7.27	7.27	7.27	7.27	7.27	7.27	7.27	7.27	7.27	7.27	7.27	7.27
Depreciation (2)	49.02	31.87	23.28	18.14	7.99	4.74	3.20	2.33	1.78	1.55	1.17	0.85
FIT (3) (4)	1.06	0.76	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	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22
Carrying Cost Per Year	58.58	41.13	32.59	27.31	17.12	14.01	12.49	11.51	10.90	10.63	10.20	9.82

(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 report: Outlook for what’s ahead for energy tax incentives (updated)

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 CO2 that otherwise would be released into the atmosphere and industrial facilities would be required to capture at least 50% of the CO2 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

	Biden Plan	**GREEN Act**	**Wyden Plan**
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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Exhibit RW-7

West Virginia University Law Center for Energy and Sustainable Development, Executive Summary: *West Virginia's Energy Future: Ramping Up Renewable Energy to Decrease Costs, Reduce Risks, and Strengthen Economic Opportunities for West Virginia* (2020)

WEST VIRGINIA'S ENERGY FUTURE

RAMPING UP RENEWABLE ENERGY TO DECREASE COSTS, REDUCE RISKS, AND STRENGTHEN ECONOMIC OPPORTUNITIES FOR WEST VIRGINIA

WVULAW
Center for Energy and
Sustainable Development

1 EXECUTIVE SUMMARY

At the end of this tumultuous and historic year, West Virginia's electric utilities will publish plans showing the resources they intend to use to generate electricity for West Virginians over at least the next decade.

In anticipation of those plans, this report regarding West Virginia's Energy Future shares the following findings based on almost a year of research, economic modeling, debate, and expert feedback:

- **For at least five reasons, our electric utilities urgently need to consider a major ramping up of renewable energy and energy efficiency that begins today.**

  These five reasons provide the backdrop for why we need to consider a major ramping up of renewable energy and energy efficiency:

  1. Renewable energy is now cheap, and it's continuing to get cheaper.
  2. Customers — both businesses and individuals — overwhelmingly are demanding renewable energy.
  3. Diversifying our power resource mix is critical to competing in the growing regional renewable energy economy and, more broadly, securing a place in the 21st century energy economy.
  4. The financial risk posed by emissions from power plants is growing due to majority public support for bipartisan proposals to address climate change by charging fees for carbon dioxide emissions. These fees would necessarily hit coal-fired power plants hardest because those plants emit the most carbon dioxide.
  5. Major lenders and investors increasingly are withholding capital from utilities that aren't transitioning away from emission-heavy resource mixes.

- **A major ramping up of renewable energy and energy efficiency in West Virginia over the next fifteen years would be cost-competitive versus our current trajectory of continued dependence on coal — while also delivering important additional benefits.**

  Specifically, diversifying our electric resource mix through a major ramping up of renewable energy and energy efficiency:

  1. Is cost-competitive versus our current trajectory of continued dependence on coal — either ≤ 5% cheaper or ≤ 5% more expensive depending on whether a modest carbon dioxide emissions fee is charged (as is currently anticipated in the planning of most electric utilities).
  2. Creates thousands of renewable energy and energy efficiency jobs, presents a net-positive impact on overall employment in the state through 2030, and has an almost neutral (-0.0002%) net-impact on overall employment through 2035.
  3. Would diversify our economy, reduce our exposure to downswings in the coal industry, and enable us to join the growing regional renewable energy economy.
  4. Would leave the door open for innovation in the coal industry to address emissions liabilities and regain competitiveness.
  5. Creates no new liabilities for emissions and reduces our financial exposure to fuel costs.
  6. Avoids billions of dollars' worth of adverse health impacts.

- **West Virginia's ramping up of renewable energy and energy efficiency should be complemented with a federal reinvestment in miners, coal communities, and our new energy economy.**

  As Congress considers bipartisan proposals to charge for carbon dioxide emissions, our congressional leaders should consider withholding their support unless the legislation is paired with a federal reinvestment in West Virginia to honor the contributions of our coal communities and secure West Virginia's role in the new energy economy. Doing so can ensure that ramping up renewable energy and energy efficiency in West Virginia is beneficial for all West Virginians and creates positive employment effects not only through 2030 but also beyond.

- **We can make the ramping up of renewable energy and energy efficiency in West Virginia work for everyone, including customers, current power plant workers and their communities, and our electric utilities.**

  The ramping up of renewable energy and energy efficiency in West Virginia can and should be pursued in a way that works for our utilities, their employees and communities, and customers. West Virginia can benefit from the example of other states like New Mexico that are demonstrating how low-cost debt can be used to replace legacy fossil fuel power plants with new renewable energy facilities – all while listening to communities and delivering jobs and other economic benefits.

The West Virginia Legislature already took an important step in this direction in 2020 when the House of Delegates unanimously passed Coal Transition Plan legislation. This legislation would mandate worker and community input in a planning process coordinated by the W.V. Department of Commerce to anticipate and strategically respond to economic dislocations caused by coal's declining competitiveness. If this unanimous bipartisan legislation is also approved by the Senate and Governor, it will bring increased resources and coordination to efforts to make the energy transition work for all West Virginians.

Especially when presented in this summary form, our findings could be perceived as suggesting that diversifying the electric resource mix in West Virginia by ramping up renewable energy and efficiency will be easy. That certainly is not the case.

The transition described in our report can only be implemented in a favorable way if it is carried out with deliberate planning and care for everyone involved (as contemplated in the Coal Transition Plan legislation passed by the House of Delegates). Notwithstanding the challenge involved, it is a process that we should embark on urgently and with determination. Avoiding this discussion will not temper the broader economic and financial forces that are transforming the energy industry around us. Therefore, we should confront this challenge head on and begin a new of chapter of West Virginian energy leadership with the grit and perseverance that Mountaineers have demonstrated for centuries.

TABLE OF CONTENTS

ACKNOWLEDGEMENTS

The following organizations provided invaluable support and technical assistance in making this report possible:

West Virginia University College of Law, Center for Energy & Sustainable Development

Downstream Strategies

Synapse Energy Economics

GridLab

WVULAW
Center for Energy and Sustainable Development

The Center for Energy and Sustainable Development is an energy and environmental public policy and research organization at the West Virginia University College of Law. The Center focuses on strengthening opportunities for West Virginia and its residents in the context of nationwide trends to reduce carbon emissions and pursue sustainable energy policies.

GridLAB

GridLab is an innovative non-profit that provides technical grid expertise to enhance policy decision-making and to ensure a rapid transition to a reliable, cost effective, and low carbon future.

Synapse
Energy Economics, Inc.

Synapse Energy Economics is a small, independent research and consulting firm specializing in energy, economic, and environmental topics. Since its inception in 1996, Synapse has grown to become a leader in providing rigorous analysis of the electric power sector for public interest and governmental clients. Synapse's expertise includes environmental economics, resource planning, electricity dispatch and economic modeling, energy efficiency, renewable energy, energy storage, transportation and building sector electrification, transmission and distribution, rate design and cost allocation, risk management, benefit-cost analysis, environmental compliance, climate science, and both regulated and competitive electricity and natural gas markets.

Downstream Strategies
Ideas that sustain.

Downstream Strategies is an environmental and economic development consulting firm located in West Virginia. We are considered the go-to source for objective, data-based analyses, plans, and actions that strengthen economies, sustain healthy environments, and build resilient communities.

CERTIFICATE OF SERVICE

I certify that on May 6, 2021, I sent an accurate copy of the foregoing by electronic mail—along with an invitation to request a hardcopy by First-Class United States Mail—to:

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