Virginia State Corporation Commission
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Case Number (if already assigned)	PUR-2020-00258
Case Name (if known)	Appalachian Power Company - For approval of an Environmental Rate Adjustment Clause, Rider E-RAC
Document Type	EXTE
Document Description Summary	Please find attached for filing in the above-captioned case the Public Version of the Direct Testimony of Rachel Wilson on behalf of the Sierra Club. Thanks!
Total Number of Pages	80
Submission ID	21467
eFiling Date Stamp	4/9/2021 1:59:05PM

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

PETITION OF

APPALACHIAN POWER COMPANY | Case No. PUR-2020-00258

For approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 e of the Code of Virginia

DIRECT TESTIMONY OF RACHEL WILSON

ON BEHALF OF THE SIERRA CLUB

PUBLIC VERSION

April 9, 2021

Summary of the Direct Testimony of Rachel Wilson

Appalachian Power Company (APCo) submitted a petition for approval of an environmental 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 and Mountaineer coal plants. In support of this petition, APCo provided a modeling analysis demonstrating that these costs, and the continued operation of the Amos and Mountaineer coal plants, are part of a least-cost resource plan when compared to alternative scenarios that retire one or both plants on December 31, 2028.

My independent modeling examines three scenarios: 1) Synapse BAU, which includes the CCR and ELG investments at APCo's four existing coal-fired units and operates those units through 2040; 2) Synapse Retirement 1, which includes the CCR investments at the Amos plant, retires those units on December 31, 2028, and includes both CCR and ELG investments at the Mountaineer plant with a retirement date of 2040; and 3) Synapse Retirement 2, which includes the CCR investments at both Amos and Mountaineer and retires all four units on December 31, 2028.

I find that it is uneconomic to invest in both CCR and ELG retrofits and continue to run Amos through 2040 under a Base with No Carbon scenario. Investing in only CCR costs at the Amos plant and retiring it in 2028 results in ratepayer savings of $200 million. When a price on carbon dioxide emissions is included as part of the analysis, ratepayer savings rises to $1.1 billion when Amos is retired and replaced with a combination of renewable and battery storage resources. Retirement of Amos and Mountaineer in 2028 also results in net savings of approximately $670 million relative to the Synapse BAU.

I recommend that the Commission approve the CCR costs at both the Amos and Mountaineer plants but deny APCo's petition for recovery of ELG costs, resulting in a retirement date of December 31, 2028 for both the Amos and Mountaineer plants.

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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 State Corporation Commission of Virginia?

A. Yes, in Case No. PUE-2015-00075, Case No. PUR-2018-00065, Case No PUR-2020-00015, and Case No PUR-2020-00035.

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

A. My testimony evaluates Appalachian Power Company's (APCo or the Company) application 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 and Mountaineer coal plants. I present the results of an alternative modeling analysis that compares three cases:

1) Synapse BAU, which includes the CCR and ELG investments at APCo's four existing coal-fired units and operates those units through 2040;

2) Synapse Retirement 1, which includes 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 with a retirement date of 2040; and

3) Synapse Retirement 2, which includes the CCR investments at both Amos and Mountaineer and retires all four 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 APCo 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 2-15, Confidential Attachment 1	Confidential
Exhibit RW-3	Response to Sierra Club 5-3, Attachment 1	Non-Confidential
Exhibit RW-4	Response to Sierra Club 5-4, Attachment 1	Non-Confidential
Exhibit RW-5	Response to Sierra Club 5-5, Attachment 1	Non-Confidential

2. OVERVIEW OF TESTIMONY AND CONCLUSIONS

Q. Please summarize your primary 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 in order to continue running the plants through 2040. Investing only in CCR costs at the Amos plant and retiring the three units in 2028 results in ratepayer savings of more than $200 million 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 rises to more than $1 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 a savings to ratepayers of approximately $670 million relative to a scenario that operates the plants through 2040.

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

Table 1. Summary of Synapse modeling results (2040), No Carbon

	Synapse BAU	Synapse Retirement 1	Synapse Retirement 2
NPV (2021-2040)	$11.8	$11.6	$12.3
CO_2 Emissions (million tons)	21.7	8.6	2.2
Solar (MW)	1,520	10,080	10,220
Wind (MW)	695	495	495
Storage (MW)	0	888	2,272
Gas (MW)	1,020	1,020	1,020
Coal (MW)	4,568	1,638	333

Table 2. Summary of Synapse modeling results (2040), With Carbon

	Synapse BAU	Synapse Retirement 1	Synapse Retirement 2
NPV (2021-2040)	$13.7	$12.5	$13.0
CO_2 Emissions (million tons)	15.5	6.6	2.2
Solar (MW)	1,520	10,160	10,260
Wind (MW)	695	695	895
Storage (MW)	0	908	2,272
Gas (MW)	1,020	1,020	1,020
Coal (MW)	4,568	1,638	333

Q. Please summarize your primary recommendations.

A. Based on my findings, I 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 savings to customers, even in a scenario that does not include a price or 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 in a scenario with a constraint on carbon (in the form of a CO_2 price), 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, 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.

3. SUMMARY OF APCO'S PETITION

Q. What is APCo requesting in its Petition in this docket?

A. APCo is requesting the Commission's approval of its environmental rate adjustment clause (E-RAC), which includes cost recovery relating to environmental projects at the Amos and Mountaineer plants. Specifically, APCo is seeking the recovery of $125 million in capital projects to comply with the federal CCR Rule, which regulates the disposal of the fly ash, bottom ash, and gypsum generated at coal-fired generating units. It is also seeking the recovery of $125 million in capital projects to comply with the federal ELG, which establishes limits on the discharge of wastewater from flue gas desulfurization, fly ash and bottom ash transport water, and flue gas mercury control.[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.[2]

Q. Did APCo present any analysis supporting its Petition?

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

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1 Direct Testimony of Christian T. Beam at 4:11–4:14.

2 Direct Testimony of Brian D. Sherrick at 9:14–9:21.

- Case 1 assumes CCR and ELG investments at both Amos and Mountaineer, and continued operation of both plants until 2040;
- Case 2 assumes CCR investments at Amos and retirement in 2028, with CCR and ELG investments at Mountaineer with retirement in 2040; and
- Case 3 assumes CCR investments at both Amos and Mountaineer, with a retirement date of 2028.[3]

This analysis was 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 APCo's analysis?**

A. APCo found that its Case 1, which installs CCR and ELG technologies at both Amos and Mountaineer and operates the plants through 2040, was 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 in Table 3, along with the change in costs (delta) relative to Case 1.

3 Direct Testimony of James F. Martin at 4:3–4:14.

Table 3. 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: APCo response to Sierra Club 1-02, Martin Sch 46 Section 2 and Testimony Tables Workpaper.xlsx[4]

The percentage differences reflected above between Cases were calculated by Synapse. Notably, Case 2 (which retires the Amos units 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 would shift the results such that the 2028 retirement of one or both coal plants becomes the more economic option.

Q. How do the Amos and Mountaineer units operate in APCo's analysis?

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

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

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 in CONFIDENTIAL Figure 1.

[redacted]

Source: Response to Sierra Club 1-02. Confidential APCo Base without Carbon – AM+MNTR CCR&ELG Optimal Plan.xlsx[5]

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

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 make a steep drop 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, 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.

[redacted]

Source: Response to Sierra Club 1-02. Confidential APCo Base without Carbon – AM CCR Only+MNTR CCR&ELG Optimal Plan.xlsx[6]

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

A. The PLEXOS model selects between 2,618 MW and 3,094 MW of gas-fired combustion turbines, the capacity-only PPA, and varying amounts of solar, depending on whether a carbon price was included. Mr. Martin states in his direct

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

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.[7] Instead, APCo's plans "result in very heavy reliance on the PJM energy market for the energy needed to serve customers."[8] Even when Amos and Mountaineer continue to operate until 2040, the PLEXOS model begins to select large volumes of imports beginning in 2030, as shown in CONFIDENTIAL Figure 1, above.

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

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7 Direct Testimony of James F. Martin at 21:13 to 21:18.

8 Direct Testimony of James F. Martin at 20:6 to 20:7.

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. APCo projects that the capacity factors of these units are going to increase in the near term and peak in 2026 or 2027. By 2031, capacity factors are around **[BEGIN CONFIDENTIAL INFORMATION]** [redacted] **[END CONFIDENTIAL INFORMATION]** for Amos Units 1 and 2, and just under **[BEGIN CONFIDENTIAL INFORMATION]** [redacted] **[END CONFIDENTIAL INFORMATION]** for Amos 3. APCo would essentially be running these "baseload" units, designed for high levels of output, as peaking units. We see a similar but slower decline at Mountaineer, and by 2035 the plant is operating at a capacity factor of only **[BEGIN CONFIDENTIAL INFORMATION]** [redacted] **[END CONFIDENTIAL INFORMATION]**. Annual capacity factor projections are shown in CONFIDENTAL Table 4.

[redacted]

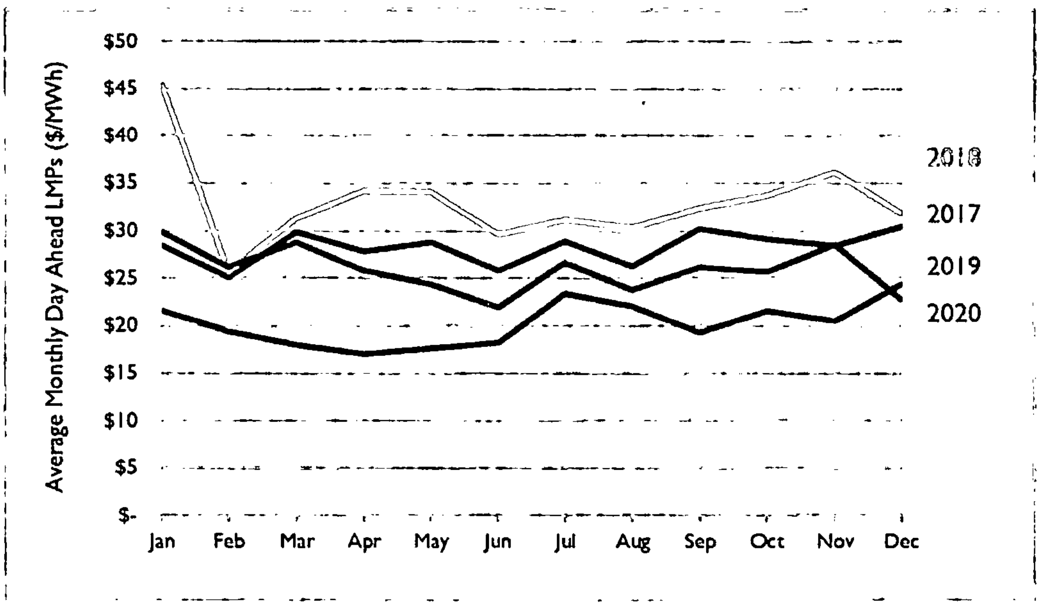
Source: Response to Sierra Club 2-15, Confidential Attachment 1[9]

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

A. No. Except for 2018, locational marginal prices at the Amos node in PJM have come down each year since 2017. Monthly average day-ahead prices are shown in Figure 3.

9 Attached as Exhibit RW-2.

Figure 3. 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.

APCo's coal units have generally responded to these LMPs by generating less as prices decline.

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 4.

[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 Response to SC 2-15, 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 5, but operates at **[BEGIN CONFIDENTIAL INFORMATION]** [redacted]

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

[redacted]

Sources: Energy market prices come from Response to SC 1-02, Trecazzi-FF-Appendix B-Base.xlsx. Operating costs were calculated using Response to Sierra Club 1-02. Confidential APCo Base without Carbon – AM+MNTR CCR&ELG Optimal Plan.xlsx.

APCo's analysis, then, shows that 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 ANALYSIS

Q. Do you present an alternative to APCo's modeling analysis?

A. Yes, and I describe that alternative modeling analysis in this section.

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 APCo's service territory.

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.[10] Duke Energy announced in 2020 that it had chosen EnCompass to expand its capabilities in resource planning.[11] 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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10 Anchor Power Solutions. December 2019. Available at: https://anchor-power.com/news/minnesota-plans-for-its-energy-future-with-encompass/

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

Q. What did Synapse model in its analysis?

A. Synapse modeled three different scenarios in our analysis:

1) Synapse BAU includes the CCR and ELG investments at APCo's four existing coal-fired units and operates those units through 2040;

2) Synapse Retirement 1 includes 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

3) Synapse Retirement 2 includes the CCR investments at both Amos and Mountaineer and retires all four units on December 31, 2028.[12]

A matrix of these scenarios is shown in Table 5.

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

Table 5. Matrix of Synapse modeling scenarios

	Plant	Synapse BAU	Synapse Retirement 1	Synapse 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

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

A. Largely, yes. To ensure a valid comparison, the Synapse analysis uses APCo's 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 both Amos and Mountaineer under the 2028 and 2040 retirement dates.[13] The sources for key input assumptions in the Synapse modeling are shown in Table 6.

Table 6. Sources of input assumptions in Synapse modeling

Assumption	Source
Load Forecast	SC 1-02, Martin Workpapers
Load Shape	SC 3-2, Attachment 1
Reserve Margin	Martin Direct Testimony
Coal Prices	AEP Fundamentals Forecast
Gas Prices	AEP Fundamentals Forecast
CO2 Prices	AEP Fundamentals Forecast
Market prices	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	SC 1-02, Martin Workpapers
Amos/Mountaineer Op Costs	SC 1-02, Martin Workpapers
CCR/ELG Costs	SC 1-02, Martin Workpapers
Transmission Costs	SC 1-02, Martin Workpapers

Q. Did you have to adjust any of APCo's input assumptions?

A. Yes, I had to adjust APCO's 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 Set 5, and indicated that the source of its pricing for these resources was the EIA's Annual Energy Outlook (AEO) 2020. However, EIA did not publish annual overnight capital cost projections in this version of 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 later version of AEO. For solar, APCo's assumed PPA price is \$60.31/MWh in 2026.[14] This is nearly twice the assumed levelized cost of energy

14 Response to Sierra Club 5-3, Attachment 1, attached as Exhibit RW-3.

from EIA in AEO 2021 for solar resources in 2026, which is $33.68/MWh.[15] APCo has stated that its cost assumptions come from EIA, and yet 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 actually 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 provided as part of Sierra Club Set 5, 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.[16]

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

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15 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 Response to SC 5-003, Attachment 1.

16 Exhibit RW-3.

was $37.50/MWh while wind PPAs were priced at $35.50/MWh.[17] 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.[18] Over the longer term, basic economics suggests that we can expect the market to respond to these supply constraints and for prices to 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 solar PV, onshore wind, and battery storage resources. NREL's data is 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 6.

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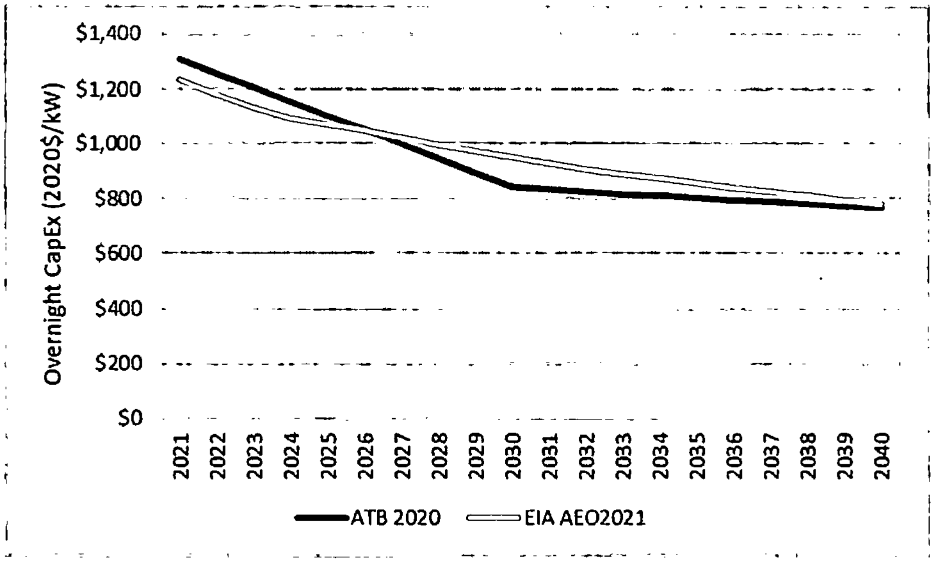
17 Level 10 Energy. *North America, Q4 2020 LevelTen Energy PPA Price Index*, available at: https://leveltenenergy.com/blog/ppa-price-index/q4-2020/

18 *Id.*

Figure 6. Comparison of overnight capital cost forecasts for solar PV, ATB 2020 and AEO 2021



Sources: *NREL, ATB 2020,* https://atb.nrel.gov/electricity/2020/data.php

Energy Information Administration, Annual Energy Outlook 2021. Table 55, 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 7.[19]

19 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.

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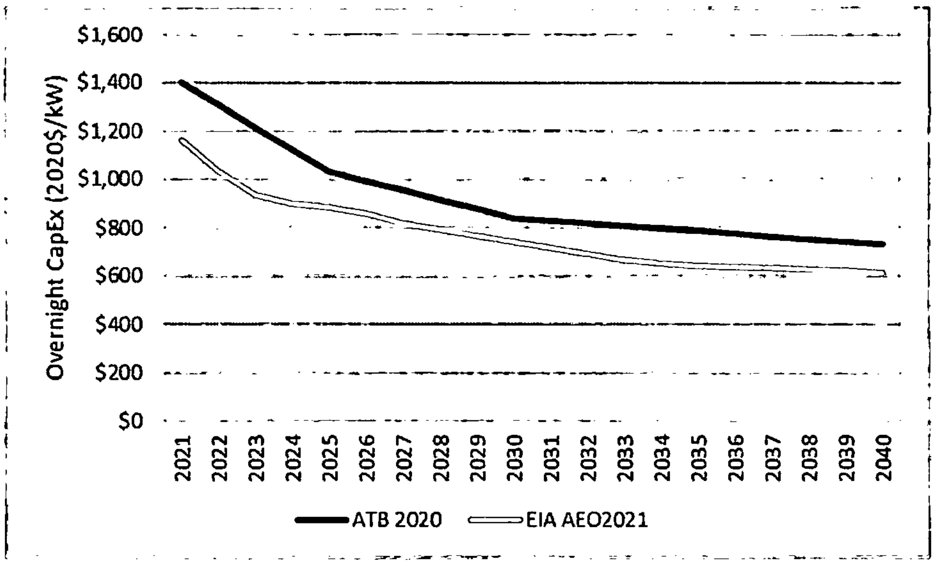
Figure 7. Comparison of overnight capital cost forecasts for battery storage, ATB 2020 and AEO 2021



Sources: *NREL, ATB 2020,* https://atb.nrel.gov/electricity/2020/data.php

Energy Information Administration, Annual Energy Outlook 2021. Table 55, 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.

21041029

Table 7. Comparison of APCo solar PPA cost with EIA levelized solar costs, $/MWh[20]

	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.[21] Given that inflation between 2010 and 2020 averaged only 1.68 percent,[22] 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[23] and provided by

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

21 Exhibit RW-3.

22 Implicit Price Deflators & Conversion Factors, available at https://fred.stlouisfed.org/series/GDPDEF#0

23 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.

APCo in responses to discovery.[24] 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.[25]

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.[26] In its recent Integrated Resource Plan filing in Minnesota, Xcel Energy used ATB 2019 as the basis for its renewable and storage costs.[27]

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 O&M costs. The EIA AEO 2021 does not provide such annual estimates. NREL's ATB

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24 Response to Sierra Club 2-28, Attachment 1, available online at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf.

25 NREL. July 9, 2020. *2020 Annual Technology Baseline Electricity Data Now Available*. Available at: https://www.nrel.gov/news/program/2020/2020-annual-technology-baseline-electricity-data-now-available.html.

26 Michigan Public Service Commission. February 20, 2020. In the matter of the application of DTE Electric Company for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief. Case No. U-20471. Available at: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000009jWc2AAE.

27 Xcel Energy's 2020-2034 Upper Midwest Resource Plan before the Minnesota Public Utilities Commission. PUC Docket No. E002/RP-19-368.

does provide these data, however, which, when combined with performance data, allows for a levelized cost calculation that utilizes data from a single source.

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

A. In contrast to APCo's modeling analysis, the Synapse modeling found that the retirement of Amos in 2028 is the least-cost scenario under the Base No Carbon commodity price forecast, with a cost savings to customers of just over $200 million.

Under the Base With Carbon, however, both Retirement 1 and Retirement 2 result in savings to ratepayers relative to the BAU. The retirement of Amos in 2028 results in ratepayer savings of $1.1 billion, while the retirement of both Amos and Mountaineer results in savings of almost $670 million. 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 8.

Table 8. Net present value of revenue requirements, Synapse modeling scenarios

	Base No Carbon		Base With Carbon	
Scenario	NPVRR ($Millions)	Delta from BAU ($Millions)	NPVRR ($Millions)	Delta from BAU ($Millions)
Synapse BAU	$11,803		$13,654	
Synapse Retirement 1	$11,597	($206)	$12,514	($1,140)
Synapse Retirement 2	$12,281	$478	$12,985	($669)

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 number of reasons why results would differ, and I will highlight the key reasons here. First, 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, in order 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 of the modeled Synapse scenarios and are not driving the differences in these scenarios. The only way that one can perfectly replicate a utility's analysis is to use the same model and version number and use that utility's 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 2040. The Synapse NPVRR values in all scenarios will thus be lower than APCo's values because they include fewer years.

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?

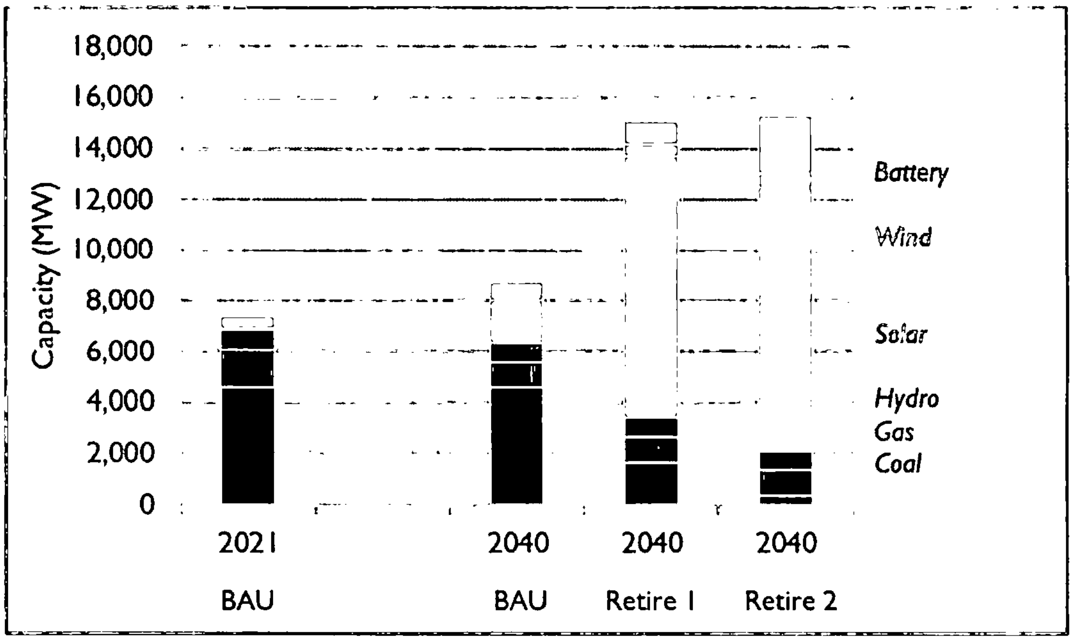
A. In the Synapse BAU, we include new units similar to APCo's own capacity expansion, adding 160 MW of new solar in 2024, which grows to a cumulative MW total of 1,420 by 2040,[28] and 200 MW of new wind in 2025. In all other scenarios, EnCompass was allowed to optimize the buildout of replacement resources for the retiring coal units beginning in 2023 with wind and 2024 with replacement solar

28 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.

PV and battery storage resources. 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 8.

Figure 8. Comparison of nameplate capacity in Synapse modeled scenarios, Base No Carbon



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.

Renewables and storage in the Retirement 1 scenario begin building slightly ahead of the Amos retirement in 2028. They provide inexpensive energy, in the case of renewables, and to provide capacity and to store energy for later use in the case of battery storage. 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 9 for Synapse Retirement 1.

Table 9. Cumulative capacity additions, by year, in Synapse Retirement 1 under Base No Carbon

SEE 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	300	300
2030	3,000	980	300	588
2031	3,600	980	300	588
2032	4,200	980	300	588
2033	4,800	980	300	588
2034	5,400	980	300	588
2035	6,000	980	300	588
2036	6,600	980	300	588
2037	7,200	980	300	588
2038	7,800	980	300	588
2039	8,400	980	300	588
2040	9,000	980	300	588

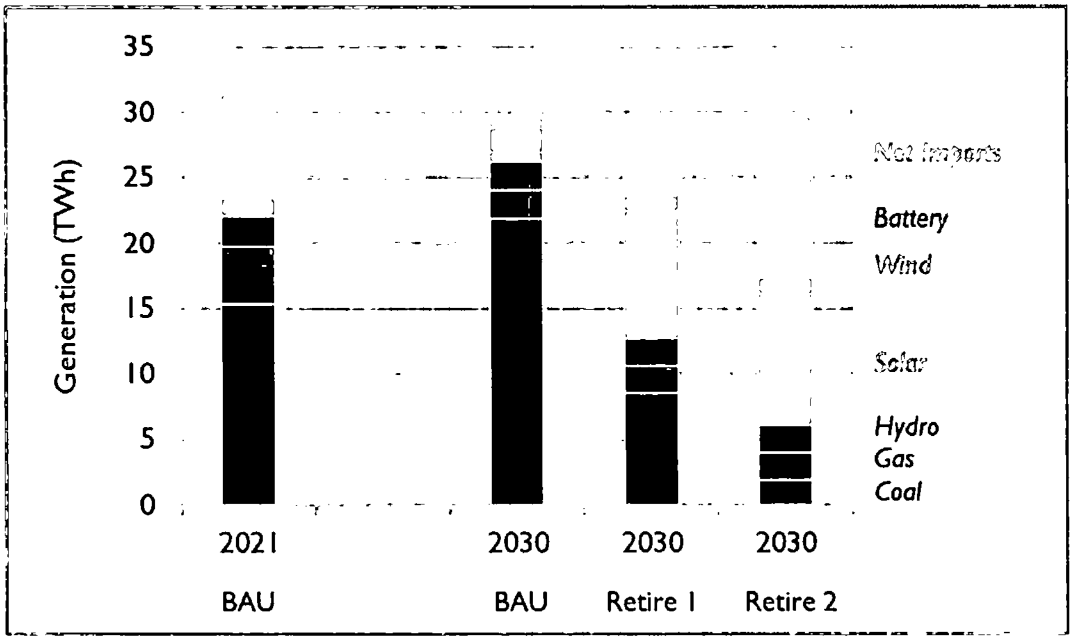
Q. How do the cumulative annual capacity builds in Retirement 2 compare to Retirement 1?

A. The resource builds in Retirement 2 look very similar to those in Retirement 1 through the first few years of the optimization period. EnCompass adds 1,300 MW of standalone battery storage by 2029 as a replacement for the retiring Mountaineer plant, as well as 120 MW of additional paired solar and 72 MW of additional paired batteries.

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 9, below.

Figure 9. 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.

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 2030 and 2040 for these three scenarios are shown in Table 10. By 2040, CO_2 emissions in the Retirement 1 scenario are only 40 percent of the emissions in the BAU, while emissions in Retirement 2 are 90 percent lower than the BAU.

Table 10. Comparison of CO_2 emissions in the Synapse modeled scenarios

	2030	2040
Synapse BAU	22.6	21.7
Retirement 1	9.5	8.6
Retirement 2	3.0	2.2

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.[29] The Retirement 1 and 2 scenarios allow APCo to contribute to these AEP corporate

29 AEP. Clean Energy Future. Available at: https://www.aep.com/about/ourstory/cleanenergy#:~:text=Achieving%20net%20zero%20carbon%20dioxide,billion%20in%20renewables%20through%202025

goals, while the BAU keeps CO_2 emissions fairly constant from 2021 onward and adds minimal amounts of renewable resources.

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

A. There are several effects. First, 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 11**, the CO_2 price adds more than $1.8 billion to the cost of the BAU scenario, but less than half of that to Retirement 1, and $704 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 APCo coal plants.

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

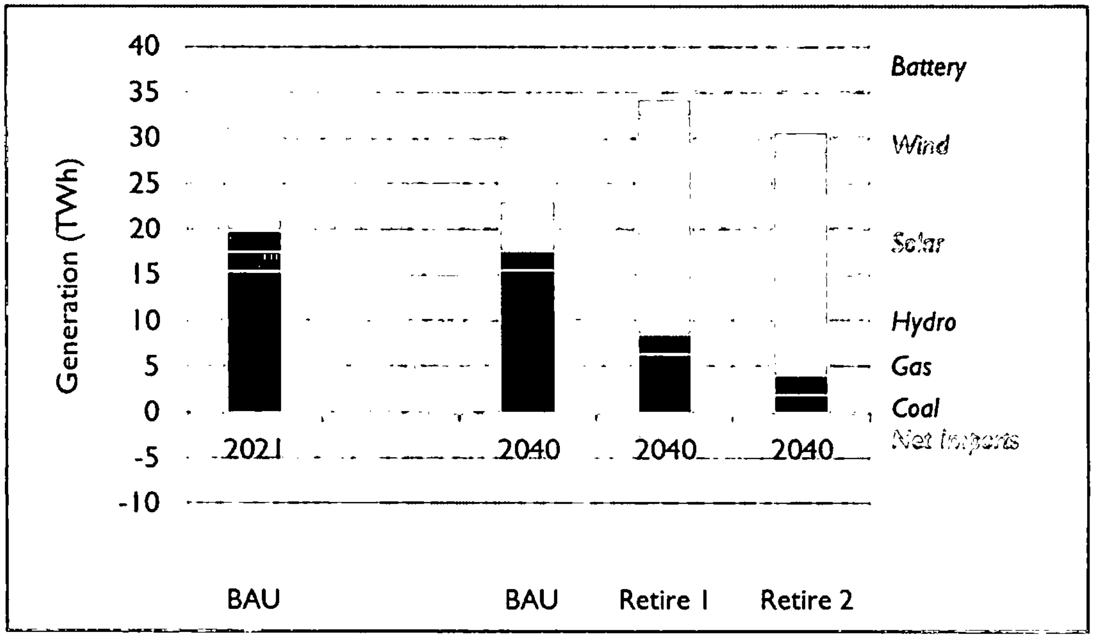
Scenario	NPVRR ($Millions) No Carbon	NPVRR ($Millions) With Carbon	Delta
Synapse BAU	$11,803	$13,654	$1,851
Synapse Retirement 1	$11,597	$12,514	$917
Synapse Retirement 2	$12,281	$12,985	$704

Second, under a commodity forecast that includes a CO_2 price beginning in 2028, as APCo's does, the difference between the Retirement 2 and Retirement 1 scenario is much smaller. With no CO_2 price, it is $684 more expensive to also retire Mountaineer in 2028, but when a CO_2 price is added, that different falls to $471 million.

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 10. The remaining coal on the system comes from the OVEC units (Kyger Creek and Clifty Creek), which have modeled retirement dates of December 31, 2040.

Figure 10. 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. What should the Commission conclude from the Synapse modeling analysis?

A. There are several important takeaways from the Synapse modeling analysis. First, that the retirement of Amos in 2028 has been shown to be the least-cost scenario and is in the best interests of Virginia ratepayers because it saves more than $200 million between 2021 and 2040.

Second, the Commission should note that it is in the economic interest of APCo's ratepayers to integrate additional renewable and storage capacity slightly ahead of the actual retirement year for Amos and 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 of the modeled scenarios. Synapse used the Mid set of forecasts from ATB 2020, but as noted above, these have often been judged as too conservative. NREL ATB also publishes 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.

5. 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 and 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 600 MW of battery storage resources, as shown in Table 12.[30]

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30 In the Synapse modeling, Amos retires on December 31, 2028 and 2,900 MW of new solar and 600 MW of new battery are online on or before January 1, 2029.

Table 12. 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	New Wind	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	0	600
2030	1,666	400	150	0	3,980	0	888
2031	1,666	400	150	0	4,580	0	888
2032	1,666	400	150	0	5,180	0	888
2033	1,666	400	150	0	5,780	0	888
2034	1,666	400	150	0	6,380	0	888
2035	1,666	400	150	0	6,980	0	888
2036	1,666	400	300	0	7,580	0	888
2037	1,666	400	300	0	8,180	0	888
2038	1,666	350	450	0	8,780	0	888
2039	1,904	100	600	0	9,380	0	888
2040	3,094	350	750	0	9,980	0	888

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 and small amounts of new solar to replace the retiring Amos and Mountaineer plants. The Synapse Retirement 1 scenario, by contrast, adds 2,900 MW of new solar and 1,100 MW of battery storage resources, as shown in Table 13.[31]

Table 13. Comparison of new resource capacity (MW), Amos and Mountaineer retire

	APCO Case 3				Synapse Retirement 2		
	New CT	ST PPA	New Solar	New Wind	New Solar	New Wind	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	0	1,100
2030	2,856	400	150	0	4,100	0	2,260
2031	2,856	400	150	0	4,720	0	2,272
2032	2,856	400	150	0	5,320	0	2,272
2033	2,856	400	150	0	5,920	0	2,272
2034	2,856	400	150	0	6,520	0	2,272
2035	2,856	400	150	0	7,120	0	2,272
2036	2,856	400	300	0	7,720	0	2,272
2037	2,856	400	300	0	8,320	0	2,272
2038	2,856	350	450	0	8,920	0	2,272
2039	3,094	100	600	0	9,520	0	2,272
2040	3,094	350	750	0	10,120	0	2,272

31 In the Synapse modeling, Amos retires on December 31, 2028 and 2,900 MW of new solar and 600 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 14.

Table 14. Comparison of prices for new resources in APCO and Synapse modeling

	Solar ($/MWh)		Wind ($/MWh)	
Year	APCo	Synapse	APCo	Synapse
2021	$49.70	$33.25		
2022	$48.34	$32.43	$40.77	
2023	$47.33	$31.58	$45.77	$44.82
2024	$56.11	$30.70	$41.44	$44.57
2025	$60.46	$29.78	$56.52	$44.28
2026	$60.31	$28.82	$57.21	$43.97
2027	$60.38	$27.83	$57.89	$43.62
2028	$60.51	$26.80	$58.58	$43.24
2029	$60.65	$25.73	$59.23	$42.82
2030	$60.85	$24.62	$59.91	$42.36
2031	$61.17	$24.83	$60.55	$42.88
2032	$61.56	$25.05	$61.21	$43.40
2033	$61.87	$25.26	$61.80	$43.92
2034	$62.15	$25.48	$62.35	$44.44
2035	$62.34	$25.70	$62.84	$44.96
2036	$62.59	$25.91	$63.40	$45.49
2037	$62.76	$26.13	$63.91	$46.02
2038	$62.91	$26.34	$64.41	$46.55
2039	$63.11	$26.56	$64.97	$47.08
2040	$63.39	$26.77	$65.66	$47.61

In 2028, for example, APCo's solar PPA price is $60.51/MWh.[32] In contrast, the solar PPA price in the Synapse modeling is $26.80/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,[33] while the Synapse wind cost is $43.24/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.[34] 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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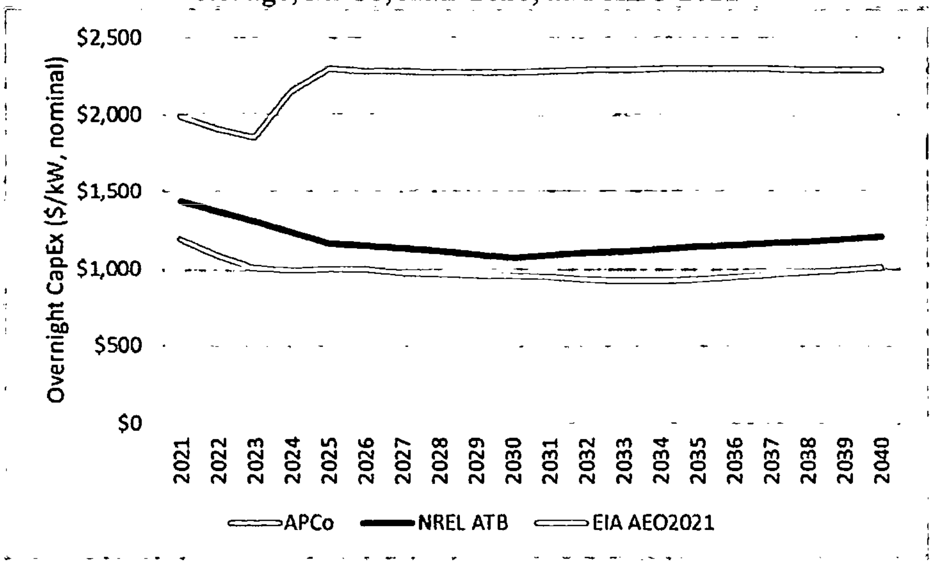
32 Exhibit RW-3.

33 Response to SC 5-4, Attachment 1, attached as Exhibit RW-4.

34 Response to SC 1-02, Trecazzi-FF-Appendix B-Base.xlsx, is not attached as an exhibit due to its voluminous size. It can be made available upon request.

Figure 11. Comparison of overnight capital cost forecasts for battery storage, APCo, ATB 2020, and AEO 2021



Sources: *NREL, ATB 2020,* https://atb.nrel.gov/electricity/2020/data.php

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

Response to Sierra Club 5-5, Attachment 1.[35]

6. 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

35 Attached as Exhibit RW-5.

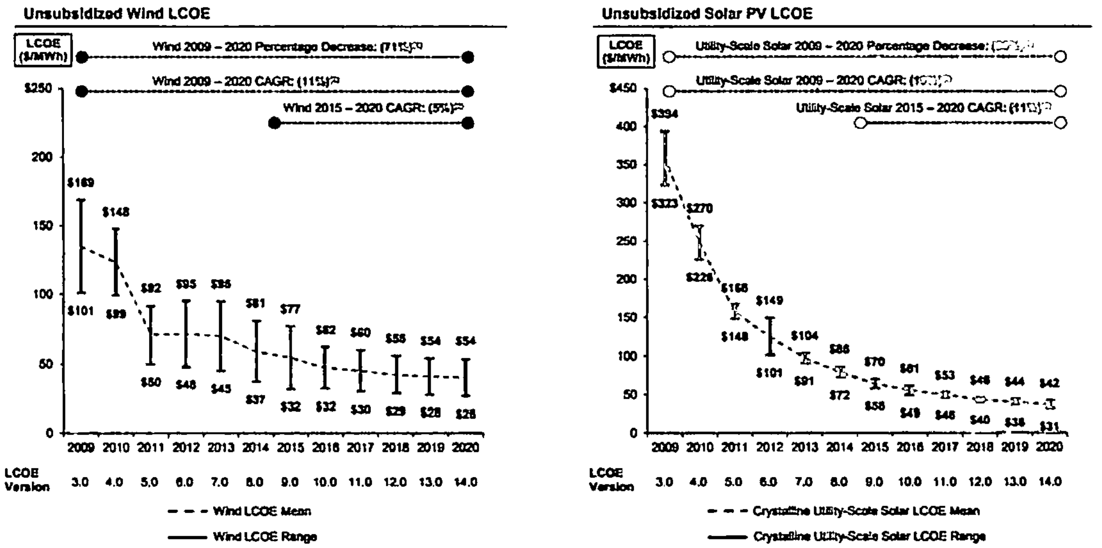
costs of operation at coal units relative to other types of capacity. In the past five years, 48 GW of coal has retired in the United States, with an additional 2.7 GW scheduled to retire in 2021.[36]

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 12.

36 US EIA. January 12, 2021. *Nuclear and coal will account for majority of U.S. generating capacity retirements in 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 12. Historic levelized cost of energy for wind and solar technologies



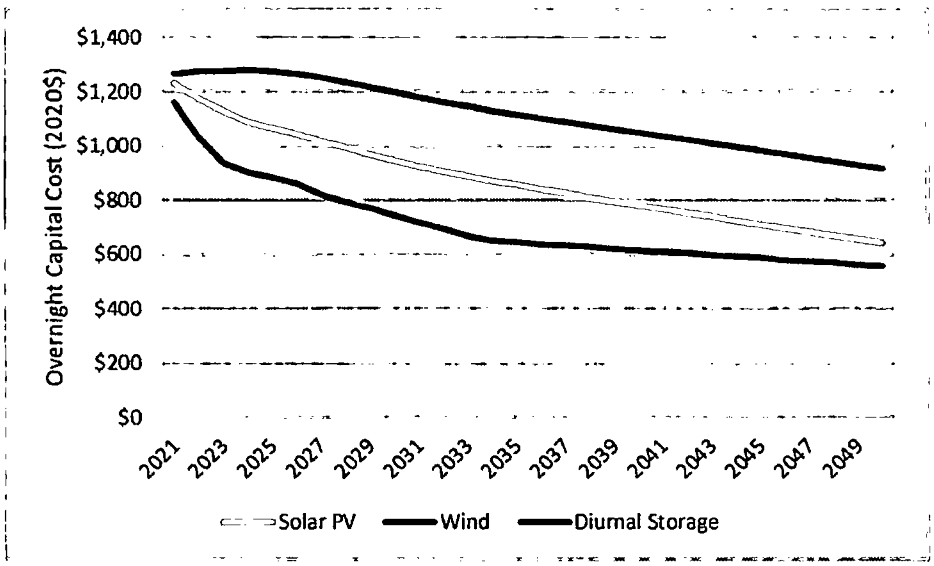
Source: Lazard. 2020. Levelized Cost of Energy Analysis—Version 14.0, available at: https://www.lazard.com/media/451419/lazards-levelized-cost-of-energy-version-140.pdf.

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.[37]

37 Utility Dive. 2019. Electricity costs from battery storage down 76 percent since 2012: BNEF. 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 13.

Figure 13. Forecast of overnight capital costs for new solar, wind, and storage



Source: *Energy Information Administration, Annual Energy Outlook 2021, Table 55, available at https://www.eia.gov/outlooks/aeo/data/browser/#/?id=123-AEO2021&region=5-11&cases=ref2021&start=2019&end=2050&f=A&linechart=ref2021-d113020a.3-123-AEO2021.5-11&map=&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,[38] we should pay particular attention to battery storage costs. The Synapse modeling uses APCo's values for firm capacity credit, with solar PV and wind receiving 40

38 Direct Testimony of James F. Martin at 21:13 to 21:18.

percent and 12 percent, respectively, and battery storage resources given a higher amount of firm capacity at 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.[39]

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

A. One such regulatory force is the increase to RPS standards 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 renewable portfolio standard (RPS) to 50 percent by 2030.[40] In 2019, Maryland

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39 Greentech Media, Will Energy Storage Replace Peaker Plants? (March 1, 2018), available at: https://www.greentechmedia.com/webinars/webinar/will-energy-storage-replace-peaker-plants#gs.6JwDozs.

40 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.

legislators passed a bill that also increases its RPS to 50 percent by 2030.[41] The District of Columbia increased its RPS to 100 percent renewable energy by 2040.[42] 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. Yes, 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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41 Utility Dive. *Maryland 50% RPS bill doubles offshore wind target, expands solar-carve out* (2019), available at: https://www.utilitydive.com/news/maryland-50-rps-bill-doubles-offshore-wind-target-expands-solar-carve-out/552421/.

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

7. 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 in order to continue running the plants through 2040. Investing only in CCR costs at the Amos plant and retiring the three units in 2028 results in ratepayer savings of more than $200 million 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 rises to more than $1 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 a savings to ratepayers of approximately $670 million relative to a scenario that operates the plants through 2040.

Q. Please summarize your recommendations.

A. I offer two recommendations. First, that the Commission approve the CCR compliance costs at the Amos plant, but deny the ELG costs. The use of current 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 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 in a scenario with a constraint on carbon (in the form of a CO_2 price), 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, 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.

Q. Does this conclude your direct testimony?

A. Yes.

EXHIBIT RW-1

Resume of Rachel S. Wilson

Synapse Energy Economics, Inc.

Rachel Wilson, Principal Associate

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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.

PUBLICATIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Wilson, R., B. Biewald. 2013. *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans.* Synapse Energy Economics for Regulatory Assistance Project.

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

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

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

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

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

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

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

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

Hausman, E., T. Comings, R. Wilson, and D. White. 2011. *Electricity Scenario Analysis for the Vermont Comprehensive Energy Plan 2011.* Synapse Energy Economics for Vermont Department of Public Service.

Hornby, R., P. Chernick, C. Swanson, D. White, J. Gifford, M. Chang, N. Hughes, M. Wittenstein, R. Wilson, B. Biewald. 2011. *Avoided Energy Supply Costs in New England: 2011 Report.* Synapse Energy Economics for Avoided-Energy-Supply-Component (AESC) Study Group.

Wilson, R., P. Peterson. 2011. *A Brief Survey of State Integrated Resource Planning Rules and Requirements.* Synapse Energy Economics for American Clean Skies Foundation.

Johnston, L., E. Hausman., B. Biewald, R. Wilson, D. White. 2011. *2011 Carbon Dioxide Price Forecast.* Synapse Energy Economics.

Fisher, J., R. Wilson, N. Hughes, M. Wittenstein, B. Biewald. 2011. *Benefits of Beyond BAU: Human, Social, and Environmental Damages Avoided Through the Retirement of the US Coal Fleet.* Synapse Energy Economics for Civil Society Institute.

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

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

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

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

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

TESTIMONY

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

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

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

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

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.

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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 5-3
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%	

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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 5-4
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

210470219

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 cOutput Check

COD Dec	Annual Levelized Cost ($/MWh) 35 CF	Annual Levelized Cost ($000) 35 CF		Screening FOM $/kW (should match column H)	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 5-5
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 ($/MWh) EIA T1 (No PTC)	Annual Levelized Cost ($/MWh) EIA T2 (w PTC)	Annual Levelized Cost ($000) EIA Storage	esc		$/kW FOM	FO&M Charge Plexos $/KW-Yr	FO&M Charge Input FOM	Scaled up to 25 MW ELCC has 20 MW
2021	2021	-	$37.08	6,01[illegible]		BAT 2021	$25.20		$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