BOUNDLESS ENERGY

Legal Department

American Electric Power
1051 E Cary Street, Suite 1100
Richmond, Virginia 23219
AEP.com

April 29, 2022

By Hand

The Honorable Bernard J. Logan, Clerk
State Corporation Commission
Document Control Center
1300 East Main Street, First Floor
Richmond, Virginia 23219

Noelle J. Coates
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Re: In re: Appalachian Power Company's Integrated Resource Plan filing
Case No. PUR-2022-00051

Dear Mr. Logan:

Pursuant to §§ 56-597 through 56-599 of the Code of Virginia, the Commission's Rules of Practice and Procedure, the December 23, 2008 Order Establishing Guidelines for Developing Integrated Resource Plans, Case No. PUE-2008-00099, (IRP Guidelines), and the June 16, 2021 Order in Case No. PUR-2019-00058, enclosed for filing, **UNDER SEAL**, are an original and fifteen copies of the 2022 Integrated Resource Plan (IRP) of Appalachian Power Company (APCo or Company).

This filing contains confidential information and is made **UNDER SEAL** pursuant to Rule 5 VAC 5-20-170 of the Commission's Rules of Practice and Procedure and section (E) (third paragraph) of the IRP Guidelines. As required by the Commission's Rules, the Company is filing separately today a motion for protective treatment of the confidential information and is providing, by copy of this letter, an original and one copy of a public version of the filing (with confidential information redacted) for the use of the public. Also enclosed as part of the filing, pursuant to IRP Guidelines section (E), are a proposed public notice (attached to this letter), and electronic media of the required schedules have been made available via the Company's iManage share site.

Copies of the public version of the filing have been sent to the Office of the Attorney General's Division of Consumer Counsel and to the legislative officials specified in the amendments to § 56-599 of the Code.

Sincerely,

Noelle J. Coates

Enclosures

cc: William H. Chambliss, Esq. (Confidential version)
C. Meade Browder, Jr., Esq. (Public version)
James R. Bacha, Esq.
Mr. William K. Castle

NOTICE TO THE PUBLIC OF A FILING BY APPALACHIAN POWER COMPANY OF ITS INTEGRATED RESOURCE PLAN

CASE NO. PUR-2022-00051

On April 29, 2022, Appalachian Power Company ("APCo" or "Company") filed with the State Corporation Commission ("Commission") the Company's Integrated Resource Plan ("IRP") pursuant to § 56-599 of the Code of Virginia ("Code").

An IRP, as defined by § 56-597 of the Code, is "a document developed by an electric utility that provides a forecast of its load obligations and a plan to meet those obligations by supply side and demand side resources over the ensuing 15 years to promote reasonable prices, reliable service, energy independence, and environmental responsibility." Pursuant to § 56-599 D of the Code, the Commission determines whether an IRP is reasonable and in the public interest.

APCo states that it serves approximately 965,000 customers in Virginia, West Virginia, and Tennessee and that the peak load requirements of APCo's total retail and wholesale customers is seasonal in nature, with distinctive peaks occurring in the summer and winter seasons.

APCo states that its IRP, based upon various assumptions, provides for adequate capacity resources, at reasonable cost, through a combination of supply-side resources, including renewable supply-side resources and demand-side programs through the forecast period. According to the Company, the IRP encompasses the 15-year planning period from 2022 to 2036 and is based on the Company's current assumptions regarding customer load requirements, commodity price projections, supply-side alternative costs, demand side management program costs and analysis, and the effect of environmental rules.

As amended in 2015, § 56-599 of the Code requires, among other things, that an IRP evaluate: (i) the effect of current and pending environmental regulations upon the continued operation of existing electric generation facilities or options for construction of new electric generation facilities; and (ii) the most cost-effective means of complying with current and pending environmental regulations. This IRP considers the effect of environmental rules and the potential cost associated with some form of future regulation of carbon emissions, during the planning period, even though there is considerable uncertainty as to the form future carbon regulation may take."

APCo also notes that it has complied with directives in several recent Commission Orders.

The Commission entered an Order for Notice and Hearing in this proceeding that, among other things, scheduled public hearings on APCo's IRP. On ____________________, the Commission will hold a telephonic hearing, with no witness present in the Commission's courtroom, for the purpose of receiving the testimony of public witnesses. On or before ______ __, 2022, any person desiring to offer testimony as a public witness shall provide to the Commission (a) your name, and (b) the telephone number that you wish the Commission to call during the hearing to receive your testimony. This information may be provided to the Commission in three ways: (i) by filling out a form on the Commission's website at scc.virginia.gov/pages/Webcasting; (ii) by completing and emailing the PDF version of this form to SCCInfo@scc.virginia.gov; or (iii) by calling (804) 371-9141. This public witness hearing will be webcast at scc.virginia.gov/pages/Webcasting.

On ______ __, 2022, at 10 a.m., in the Commission's second floor courtroom located in the Tyler Building, 1300 East Main Street, Richmond, Virginia 23219, the Commission will convene a hearing to receive testimony and evidence offered by the Company, any respondents, and the Commission's Staff.

The Commission takes judicial notice of the ongoing public health issues related to the spread of the coronavirus, or COVID-19. In accordance therewith, all pleadings, briefs, or other documents required to be served in this matter should be submitted electronically to the extent authorized by 5 VAC 5-20-150, *Copies and format*, of the Commission's Rules of Practice and Procedure ("Rules of Practice"). Confidential and Extraordinarily Sensitive information shall not be submitted electronically and should comply with 5 VAC 5-20-170, *Confidential information*, of the Rules of Practice. Any person seeking to hand deliver and physically file or submit any pleading or other document shall contact the Clerk's Office Document Control Center at (804) 371-9838 to arrange the delivery.

Pursuant to 5 VAC 5-20-140, *Filing and service*, of the Commission's Rules of Practice, the Commission has directed that service on parties and the Commission's Staff in this matter shall be accomplished by electronic means. Please refer to the Commission's Order for Notice and Hearing for further instructions concerning Confidential or Extraordinarily Sensitive Information.

An electronic copy of the public version of the Company's IRP may be obtained by submitting a written request to counsel for the Company, Noelle J. Coates, Esquire, 3 James Center, American Electric Power Service Corporation, 1051 East Cary Street, Suite 1100, Richmond, Virginia 23219, or njcoates@aep.com.

On or before ________, 2022, any interested person may file comments on the Company's IRP by following the instructions found on the Commission's website: scc.virginia.gov/casecomments/Submit-Public-Comments. All comments shall refer to Case No. PUR 2022-00051.

On or before _________, 2022 any person or entity may participate as a respondent in this proceeding by filing a notice of participation with the Clerk of the State Corporation Commission, c/o Document Control Center, P.O. Box 2118, Richmond, Virginia 23218-2118, or by filing electronically at scc.virginia.gov/clk/efiling/. Such notice of participation shall include the email addresses of such parties or their counsel. The respondent simultaneously shall serve a copy of the notice of participation on counsel to the Company. Pursuant to Rule 5 VAC 5-20-80 B, *Participation as a respondent,* of the Commission's Rules of Practice, any notice of participation shall set forth: (i) a precise statement of the interest of the respondent; (ii) a statement of the specific action sought to the extent then known; and (iii) the factual and legal basis for the action. Any organization, corporation, or government body participating as a respondent must be represented by counsel as required by Rule 5 VAC 5-20-30, *Counsel*, of the Rules of Practice. All filings shall refer to Case No. PUR-2022-00051.

Any documents filed in paper form with the Office of the Clerk of the Commission in this docket may use both sides of the paper. In all other respects, except as modified by the Commission's Order for Notice and Hearing, all filings shall comply fully with the requirements of 5 VAC 5-20-150, *Copies and format*, of the Commission's Rules of Practice.

The public version of the Company's IRP, the Commission's Rules of Practice and the Commission's Order for Notice and Hearing may be viewed on the Commission's website at: scc.virginia.gov/pages/Case-Information.

APPALACHIAN POWER COMPANY

APPALACHIAN POWER

An AEP Company

BOUNDLESS ENERGY

INTEGRATED RESOURCE PLANNING REPORT

TO THE

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

CASE NO. PUR-2022-00051

PUBLIC VERSION

May 1, 2022

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Executive Summary

This Integrated Resource Plan (IRP, Plan or Report) is submitted by Appalachian Power Company (APCo or Company) based upon the best information available at the time of preparation. This Plan is not a firm commitment to specific resource additions or other courses of action over the period of the plan, as the future is uncertain. The Plan provides the basis for a short-term course of action and strives to maintain optionality in meeting APCo's resource obligations in order for the Company to take advantage of market opportunities and technological advancements. Accordingly, this IRP and the action items described herein are subject to change as new information becomes available or as circumstances warrant.

This IRP is consistent with the requirements of the Virginia Clean Economy Act (VCEA), as well as other legal requirements and regulations. The specific locations within this IRP filing, which respond to each requirement of the IRP, appear in the Appendix as part of APCo's larger index (Exhibit D).

An IRP explains how an electric utility company plans to meet the projected capacity (*i.e.,* peak demand) and energy requirements of its customers. APCo is required to provide an IRP that encompasses a 15-year forecast planning period (in this filing, 2022-2036). This IRP has been developed using the Company's current long-term assumptions for:

- Customer load requirements – peak demand and hourly energy;
- commodity prices – coal, natural gas, on-peak and off-peak power prices, capacity and emission prices;
- supply-side alternative costs – including fossil fuel, renewable generation, and storage resources;
- transmission and distribution planning, including projects that meet the definition of grid transformation projects; and
- demand-side management program costs and impacts.

In addition, APCo considered the effect of environmental rules. This IRP considers the potential cost associated with some form of future regulation of carbon emissions, during the planning period, even though there is uncertainty as to the timing and form future carbon regulation may take.

To meet its customers' future capacity and energy requirements, APCo will continue the operation of, and ongoing investment in, its existing fleet of generation resources including the base-load coal units at Amos and Mountaineer, the natural gas combined-cycle (Dresden) facility, combustion turbine (Ceredo) units. Additionally, the Company will continue to evaluate the benefits and viability of the continued operation of its two gas-steam units at Clinch River. The Clinch River extension will be considered periodically to determine its final date of operation.

The Company will also continue to operate its hydroelectric generators, including Smith Mountain Lake. The Company has a portfolio of 630MW of purchase power agreements consisting of five wind farms, one hydro-electric facility and three solar facilities planned to come online in 2022. During the reporting period, wind contracts of 375MW will expire.

APCo analyzed various scenarios that would provide adequate supply and demand resources to meet its projected peak load obligations and minimize costs to its customers, including energy costs, for the next fifteen years. The key components of APCo's Hybrid Plan based upon these various analyses are as follows:

- Renewable and energy storage resources compliant with the VCEA requirements
- Renewable Energy Credits (RECs) as a resource option that could be selected if they are a less costly VCEA compliance option than other renewable resources, based on a forecasted REC price curve;
- Demand-side resources, including additional EE and Demand Response (DR) programs consistent with the Company's 2021 Energy Efficiency plan and current demand response resources and;
- Distributed resources, primarily in the form of residential and commercial rooftop solar (i.e. Distributed Energy Resources (DERs)).

Key Changes from 2019 IRP

This IRP includes the following changes from the Company's 2019 IRP:

- Addresses the Commission's orders to APCO's 2019 IRP.
- Incorporates requirements of the VCEA related to resource acquisition.
- Incorporates the most recent load forecast consistent with the VCEA filing, which shows a reduced need for capacity additions over the forecast period and energy needs.
- Incorporates the most recent fundamental forecast developed in the second quarter of 2021 and consistent with the recent VCEA filing.
- Incorporates updated renewable costs informed by the Company's 2021 Renewable Request for Proposals (RFP) and Bloomberg New Energy Finance's (BNEF) 2H 2020 U.S. Renewable Energy Market Outlook.
- Updated modeling scenarios evaluating the Clinch River Unit 1 and 2 retirement date alternatives.
- Inclusion of a five-year estimated annual rate impact on a typical residential customer.
- Includes a retirement analysis of the Company's Amos and Mountaineer units, consistent with the Stipulation adopted in Case PUR-2020-00015.

Summary of APCo Resource Plan

APCo's retail sales are projected to remain relatively constant with stronger growth expected from the industrial class (+0.3% per year) while the residential class is projected to decline over the forecast horizon at a compounded annual growth rate (CAGR) of -0.3% per year. APCo's internal energy needs are expected to remain relatively flat and peak demand is expected to change at an average rate of -0.1% per year through 2033. Figure ES- 1 below shows APCo's "going-in" (i.e. before resource additions) capacity position over the planning period, which uses the PJM summer peak to determine resource requirements.

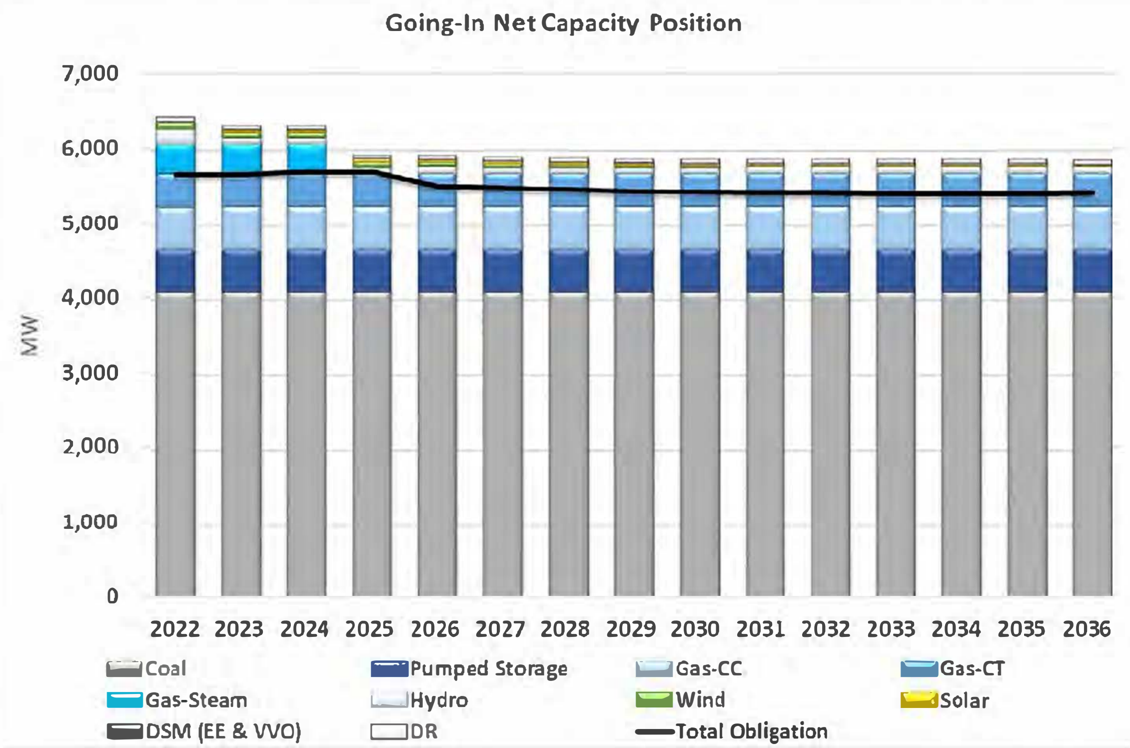

Figure ES- 1. APCo Going-In Net Capacity Position

Over the planning period, the Company does not expect a capacity shortfall. Resource additions stipulated by the VCEA including renewable and storage resources further extend the Company's capacity position and serve to diversify its portfolio while also incorporating PJM's guidance on intermittent resources Effective Load Carrying Capability (ELCC) to ensure effective resource adequacy.

With resource additions driven by VCEA requirements during the reporting period, the Company structured its analysis to understand the near and long-term impacts of various VCEA compliant Portfolios. A key consideration in the analysis was the assessment of the inclusion of natural gas resources in its portfolio. Furthermore, the Company considered the impact of current and potential carbon costs. For this IRP, APCo considered a series of Base and Alternate Portfolios and developed a Hybrid Plan based on the following considerations:

- Minimizing the net present value of revenue requirements (i.e. cost to customers) over the evaluation period, while meeting capacity obligations.
- Compliance with the VCEA requirements.
- Integrating PJM guidance on ELCC for intermittent resources to support resource adequacy.

The cumulative technology capacity additions during the planning period associated with the Hybrid Plan are shown below in Table ES- 1 and in Figure ES- 2.

Table ES- 1. Cumulative Capacity Additions (MW) for Hybrid Plan

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Base RGGI $15 CO2 Hybrid Plan	New Solar (NmPlt)*	15	15	65	285	285	285	285	285	435	735	885	1,035	1,335	1,485	1,785
	New Solar (Firm)*	8	8	35	145	134	125	114	105	139	198	195	228	294	327	393
	New Wind (Nameplate)*	0	0	0	204	1,004	1,004	1,004	1,054	1,154	1,154	1,154	1,154	1,154	1,154	1,154
	New Wind (Firm)*	0	0	0	31	141	131	120	116	127	115	127	127	127	127	127
	Storage Capacity (NmPlt)	0	0	0	0	25	25	25	50	100	150	200	250	300	350	400
	Storage Capacity (Firm)	0	0	0	0	19	18	19	40	89	147	200	250	300	350	400
	New EE	18	34	47	59	71	62	53	36	29	22	16	10	6	3	1
	New DR	8	8	8	8	12	12	12	4	4	4	4	0	0	0	0
	New VVO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
	New DG	0	0	0	35	40	46	52	59	67	72	74	76	77	79	83
Total Additions (Firm & Degraded)		34	50	90	278	417	395	371	361	455	559	616	691	804	886	1,010
Capacity Reserves (MW) without new additions		485	537	521	468	432	443	448	458	462	472	479	481	484	484	465
Capacity Reserves (MW) with new additions		519	587	611	746	849	838	819	819	917	1,030	1,095	1,172	1,288	1,370	1,475

* Includes Owned and PPA resources

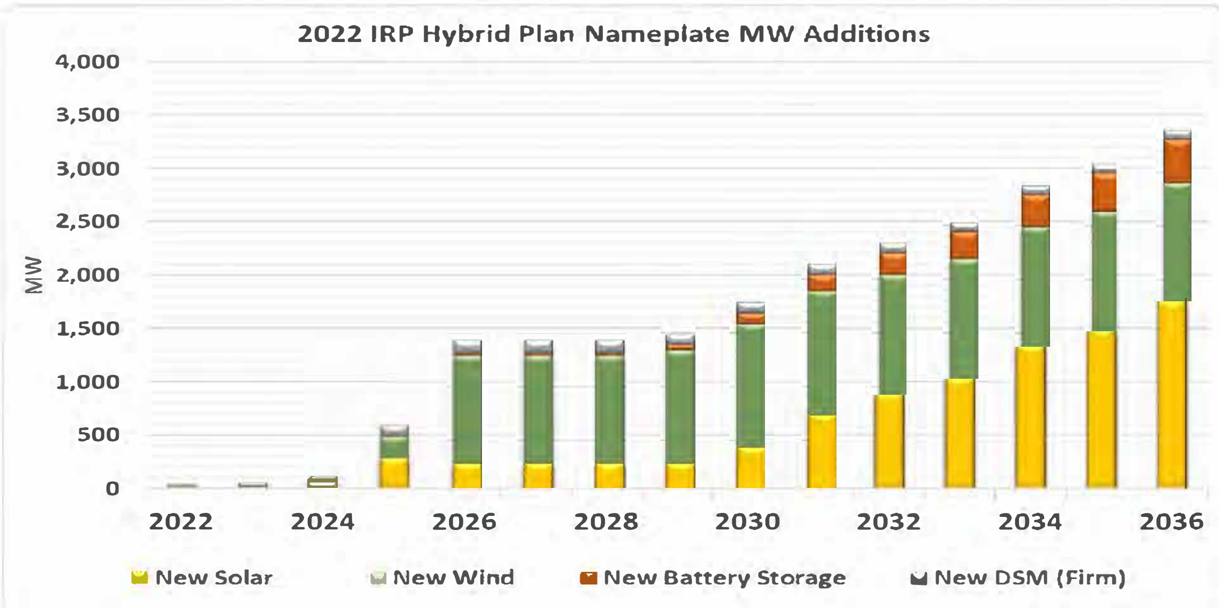

Figure ES- 2. Hybrid Plan Nameplate Cumulative Capacity Additions

The Hybrid Plan is derived from the Base Portfolio which is consistent with the Company's 2021 VCEA Plan. It includes a similar mix of supply-side resources to the Base Portfolio but allows for an earlier addition of wind resources to take advantage of Production Tax Credits (PTC's) available through December 2025 under current law. Furthermore, the Hybrid Plan adds storage resources more uniformly across the reporting period compared to the Base Plan. Finally, the Hybrid plan assumed the extension of the Clinch River plant through the reporting period.

In the Hybrid Plan, incremental DR and EE resources consistent with the Company's 2021 Energy Efficiency plan and current demand response resources and DER resources are included through the reporting period. Incremental Behind the Meter (BTM) DER rooftop solar resources were included with a Nameplate capacity of 340MW by 2036 and reducing its capacity obligation by 83MW.

Figure ES- 3 illustrates APCo's Hybrid Plan Capacity Position that supports the Company's PJM capacity obligations and meets the requirements in the VCEA.

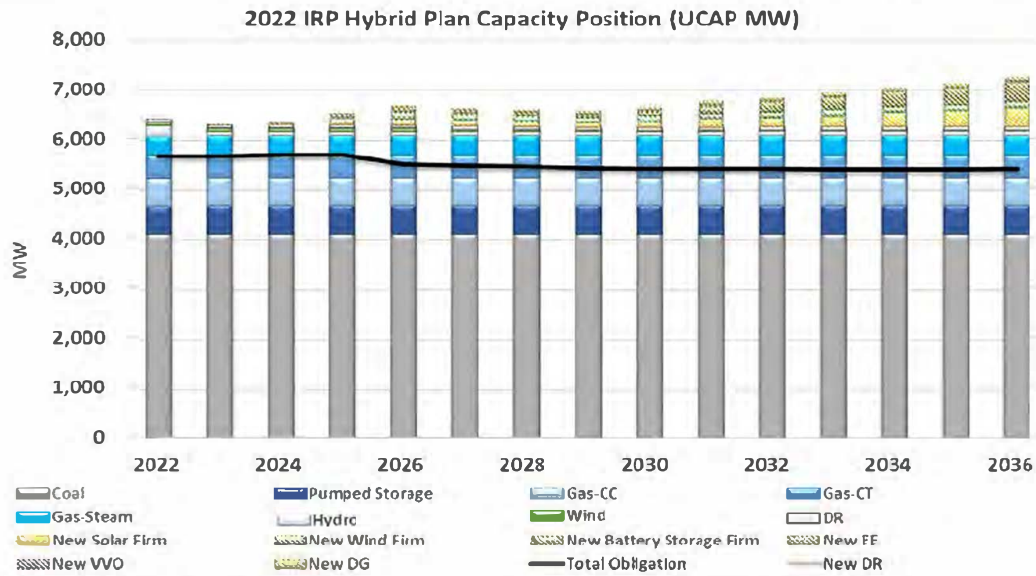

Figure ES- 3. 2022 IRP Hybrid Plan Capacity Position (UCAP MW)

To acquire new resources and specifically, to meet the requirements in the VCEA, the Company conducts multiple RFPs annually including the RPS component (56-585.5.C), the Virginia sited sub-requirement (56-585.5.D) and the energy storage requirements (56-585.5.E.)

While the Company will meet its capacity obligation, the national transition to more intermittent and renewable resources is anticipated to impact the energy output from the Company's fleet of fossil-fueled generators. The Company will maintain appropriate capacity reserves and the Hybrid Plan includes resources to support the renewable energy targets set forth in the VCEA for the Company to Virginia customers. However, energy delivered to APCo's non-Virginia retail customers is expected to be purchased from the market and from fossil resources as shown in Figure ES- 4.

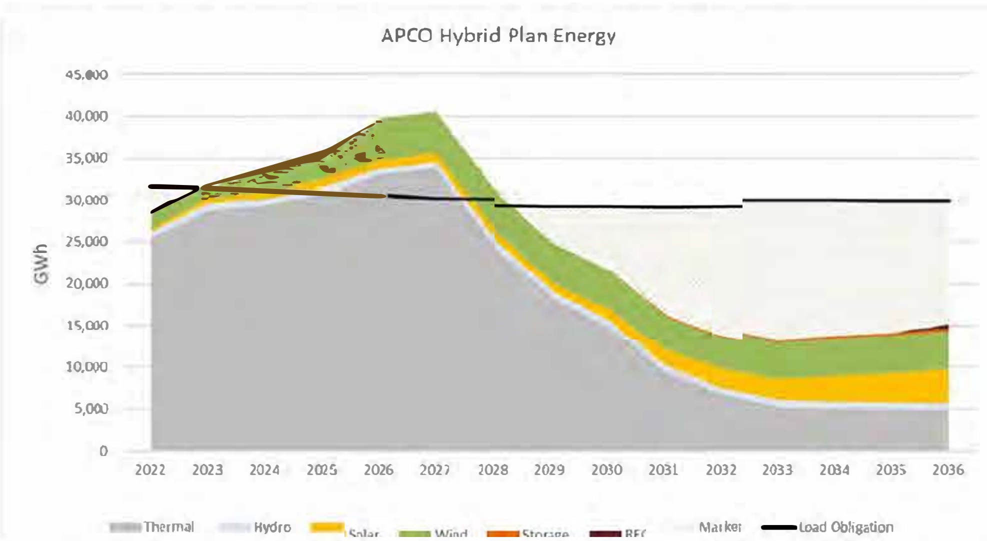

Figure ES- 4. APCo Hybrid Plan Energy

The Hybrid Plan is presented as an option that balances cost, including energy costs while meeting the VCEA mandates.

In summary, the Hybrid Plan:

- Includes 220MW (nameplate) of additional solar resources planned for in service by 2025 (COD Dec 2024)
- Includes 204MW (nameplate) of additional wind resources planned for in service by 2025 (COD Dec 2024)
- Includes 64MW (nameplate) of planned additional 3rd party solar resources by 2025 installed at the distribution level of service
- Incorporates the use of Renewable Energy Credits (RECs) to support the Company's RPS requirements under the VCEA
- Includes EE program savings consistent with the Company's most recent EE plan
- Assumes the continued operation of the Clinch River plant through the reporting period which will be further considered in future IRPs.

Conclusion

The Hybrid Plan provides an optimized selection of resources that balances the Company's obligations for capacity and renewable energy requirements under the VCEA law while also meeting ongoing PJM reliability and capacity obligations.

The IRP process is a continuous activity; assumptions and plans are reviewed as new information becomes available and modified as appropriate. This IRP is not a commitment to specific resource additions or extensions or other courses of action, as the future is highly uncertain. The resource planning process continues to be complex, especially with regard to such things as pending regulatory restrictions, technology advancement, changing energy supply pricing fundamentals, uncertainty of demand and end-use efficiency improvements. These complexities highlight the need for flexibility and adaptability in any ongoing planning activity and resource planning process.

To that end, APCo intends to pursue the following five-year action plan:

1. Issue annual RFPs in compliance with VCEA requirements.
2. Seek competitive offers for energy storage in support of non-wires alternatives and energy storage requirements.
3. Utilize 100% of the Company's hydro resources for VCEA compliance beginning in 2025 through intra-Company transactions at market value.
4. Monitor federal and state regulatory developments related to continued operation of the Amos and Mountaineer plants.
5. Monitor developments in REC markets to evaluate RECs as a compliance option.
6. Continue to evaluate the benefits and viability for the continued operation of the natural gas fired Clinch River plant.
7. Be able to adjust this action plan and future IRPs to reflect changing circumstances.

1.0 Introduction

1.1 Overview

This Report presents the 2022 IRP for APCo including descriptions of assumptions, study parameters, and methodologies. The results integrate supply- and demand-side resources.

The goal of the IRP process is to identify the **amount, timing** and **type** of resources required to supply capacity and energy to customers consistent with current law, maintaining and enhancing rate stability, energy independence, economic development, and service reliability at reasonable prices over the long –term.

In addition to developing a long-term strategy for achieving reliability/reserve margin requirements as set forth by PJM, resource planning is critical to APCo due to its impact on such things as determining capital expenditure requirements, regulatory planning, environmental compliance, and other planning processes.

1.2 Integrated Resource Plan (IRP) Process

This Report covers the processes, assumptions, results and recommendations required to develop the Company's 2022 IRP. As required by Virginia Code § 56-599, APCo's IRP considers options for maintaining and enhancing rate stability, energy independence, economic development, including retention and expansion of energy-intensive industries, and service reliability. The Company files this IRP on May 1, 2022 in compliance with Section 56-599.

This IRP is based upon the best available information at the time of preparation, but changes that may impact its results can, and do, occur without notice. Therefore, this IRP is not a commitment to a specific course of action, and all the resource actions are subject to change.

APCo's IRP process includes the following components/steps:

- Describes the Company, the resource planning process in general, and the implications of current issues as they relate to resource planning;
- provides projected growth in demand and energy which serves as the underpinning of the Plan;
- identifies and evaluates demand-side options such as Energy Efficiency (EE) measures, Demand Response (DR) and Distributed Energy Resources (DERs);
- describes how the IRP ties to underlying PJM reserve margin requirements;
- identifies and evaluates supply-side resource options; and
- performs resource modeling, including modeling various portfolios using a carbon emissions cost consistent with Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI) and beginning in 2028 as a cost for potential future national or regional carbon emission regulation.

As indicated throughout this Report, APCo's IRP process seeks to strike a reasonable balance among the various factors in its development of the Preferred Plan, which provides a road map to inform future resource decisions, including specific resource actions required by the Virginia Clean Economy Act (VCEA).

1.3 Compliance with 2020 and 2021 IRP Orders

APCo's 2022 IRP addresses the requirements of the Commission's final order issued on January 28, 2020 in the Company's 2019 IRP (the 2019 IRP Order) and the Commission's June 16, 2021 Order granting Staff's motion related to the Virginia Clean Economy Act ("VCEA") and other matters, which include the following:

- Included PPA resource options for wind and solar resources
- Included Renewable Energy Credits (RECs) as a resource
- Included Hybrid Solar resources as a capacity resource option
- Integrated PJM guidance on ELCC for intermittent resources to support resource adequacy needs
- Updated modeling scenarios evaluating the current Clinch River Unit 1 and 2 final date of operation
- Inclusion of a five-year estimated annual rate impact on a typical residential customer
- Modeled all portfolios as compliant with the Virginia Clean Economy Act (VCEA).

Furthermore, grid transformation mandates for APCo included 200MW of Virginia solar by 2028. The Company expects its requirements under the VCEA, which have been reflected in this plan, will exceed the requirements related to mandatory projects included in the Grid Transformation Plan. For an index of all requirements and their location in the report, please see Exhibit D in the Appendix.

1.4 Introduction to APCo

APCo's customers consist of both retail and sales-for-resale (wholesale) customers located in the states of Virginia, West Virginia and Tennessee (see Figure 1). Currently, APCo serves approximately 542,000 and 423,000 retail customers in the states of Virginia and West Virginia, respectively. The peak load requirement of APCo's total retail and wholesale customers is seasonal in nature, with distinctive peaks occurring in the summer and winter seasons. APCo's all-time highest recorded peak demand was 8,708MW, which occurred in February 2015; and the highest recorded summer peak was 6,755MW, which occurred in August 2007. The most recent (summer 2021 and winter 2021/22) actual APCo summer and winter peak demands were 5,363MW and 6,631MW, occurring on August 25, 2021 and January 27, 2022, respectively.

Figure 1. APCo's Service Territory

1.5 VCEA Summary

In 2020, the General Assembly passed the Virginia Clean Economy Act, which was signed into law by Governor Northam. The VCEA is a transformative law that seeks to end carbon dioxide emissions from the electric utility industry in Virginia.[1]

1.5.1 VCEA Requirements

There are four primary requirements of the VCEA related to resource acquisition:

1. Annual RPS requirement. For APCo, this requirement is reproduced in Table 1 and begins at 6% in 2021 and escalates to 100% by 2050.

Table 1: APCo VCEA RPS Requirements by Year

Year	APCo RPS Requirement (%)	Year	APCo RPS Requirement (%)
2021	6	2036	53
2022	7	2037	53
2023	8	2038	57
2024	10	2039	61
2025	14	2040	65
2026	17	2041	68
2027	20	2042	71
2028	24	2043	74
2029	27	2044	77
2030	30	2045	80
2031	33	2046	84
2032	36	2047	88
2033	39	2048	92
2034	42	2049	96
2035	45	2050 and thereafter	100%

2. Development of Virginia domiciled solar and wind resources. APCo is required to petition the Commission for 600 MW solar or wind resources by December 31, 2030, with interim targets beginning December 31, 2023; 35% of those resources are required to be contracted via Purchase Power Agreements (PPA's). The Company is using nameplate capacity to determine compliance with these requirements.

[1] Appalachian is a "Phase I" utility as defined in Section 56.585.1. A.1. of the Code of Virginia. As such, this report will refer to the requirements in the VCEA that only apply to Appalachian.

3. Development of Energy Storage resources. By December 31, 2035, the VCEA requires APCo to have petitioned the Commission for necessary approvals to construct or acquire 400 MW of energy storage capacity, or more with Commission approval. These resources must meet the same 35% PPA requirement that applies to the Virginia domiciled solar and wind resources. Further, 10% of the battery installations are required to be behind-the-meter (BTM) installations.

4. The Commission opened Case No. PUR-2020-00120 to establish rules and regulations for the required addition of storage and subsequently issued regulations to determine the appropriate timing of storage additions on December 18, 2020. The Company is working to identify the preferred location and size of storage resources, and will issue an RFP in 2022 for storage resources. See Table 2 for those interim storage addition minimums.[2]

Table 2: VCEA REQUIRED STORAGE ADDITIONS

Date	New Storage Additions (MW)	Cumulative Storage Additions (MW)
12/31/2025	25	25
12/31/2030	125	150
12/31/2035	250	400

5. Energy Efficiency requirement. APCo must implement energy efficiency measures that achieve energy savings equivalent to at least 2% of the Company's 2019 retail sales by 2025. The VCEA also specifies that the Commission shall establish new EE requirements for the period of 2026 to 2028, and for every three year period thereafter. Due to the uncertain nature of any future proceeding regarding the efficacy or cost-effectiveness of additional EE, the amount of EE requirements set by the Commission was assumed to remain constant beyond 2025, with any additional EE in future years only being selected for economic purposes.

1.6 Environmental Justice

Appalachian is committed to the tenets of the Commonwealth's Policy on Environmental Justice and considers it in all prospective transactions for renewable resources. Identification and remediation of potential concerns are made during the RFP process, as discussed in the petition. Because Environmental Justice is specific to the communities immediately surrounding resources, meaningful screening can only be accomplished once potential sites have been identified. The Plexos® selected resource additions identified in this Plan are generic in nature and are not site specific and thus cannot be evaluated for potential Environmental Justice issues.

[2] Order for Notice and Comment, Commonwealth of Virginia, ex rel., State Corporation Commission Ex Parte: In the matter of establishing rules and regulations pursuant to §56-585.5 E 5 of the Code of Virginia related to the deployment of energy storage, Case No. PUR-2020-00120, Doc. Con. Cen. No. 200910238 (Sept. 11, 2020).

2.0 Load Forecast and Forecasting Methodology

2.1 Summary of APCo Load Forecast

The APCo load forecast was developed by the American Electric Power Service Corporation (AEPSC) Economic Forecasting organization and completed in June 2021.[3] The load forecast is the culmination of a series of underlying forecasts that build upon each other. In other words, the economic forecast provided by Moody's Analytics is used to develop the customer forecast which is then used to develop the sales forecast which is ultimately used to develop the peak load and internal energy requirements forecast.

Over the next 15 year period (2022-2036)[4], APCo's service territory is expected to see population decline 0.3% per year and non-farm employment growth of 0.34% per year. APCo is projected to see customer count growth remain relatively flat over this period. Over the same forecast period, APCo's retail sales are projected to decline at 0.2% per year with the industrial class remaining relatively constant while the residential class is projected to decline over the forecast horizon at a compounded annual growth rate (CAGR) of -0.4% per year. Finally, APCo's internal energy is expected to decline at an average rate of 0.4% per year and peak demand is expected to change at an average rate of -0.6% per year through 2036. A factor in the decline is that the Company's wholesale contracts are not assumed to be automatically renewed when they expire.

2.2 Forecast Assumptions

2.2.1 Economic Assumptions

The load forecasts for APCo and the other operating companies in the AEP System incorporate a forecast of U.S. and regional economic growth provided by Moody's Analytics. The load forecasts utilized Moody's Analytics economic forecast issued in January 2021. Moody's Analytics projects moderate growth in the U.S. economy during the 2022-2036 forecast period, characterized by a 2.1% annual rise in real Gross Domestic Product (GDP), and moderate inflation, with the implicit GDP price deflator expected to rise by 2.1% per year. Industrial output, as measured by the Federal Reserve Board's (FRB) index of industrial production, is expected to grow at 1.5% per year during the same period. Moody's projects

[3] The load forecasts (as well as the historical loads) integral to this Resource Plan reflect the traditional concept of internal load, i.e., the load that is directly connected to the utility's transmission and distribution system and that is provided with bundled generation and transmission service by the utility. Such load serves as the starting point for the load forecasts used for generation planning. Internal load is a subset of *connected load*, which also includes directly connected load for which the utility serves only as a transmission provider. Connected load serves as the starting point for the load forecasts used for transmission planning.

[4] 15 year forecast periods begin with the first full forecast year, 2022.

regional employment growth of 0.34% per year during the forecast period and real regional income per-capita annual growth of 1.6% for the APCo service area.

2.2.2 Price Assumptions

The Company utilizes an internally developed service area electricity price forecast. This forecast incorporates information from the Company's financial plan for the near term and the U.S. Department of Energy (DOE) Energy Information Administration (EIA) outlook for the East North Central Census Region for the longer term. These price forecasts are incorporated into the Company's energy sales models, where appropriate.

2.2.3 Specific Large Customer Assumptions

APCo's customer service engineers are in frequent touch with industrial and commercial customers about their needs and activities. From these discussions, expected load additions or deletions are relayed to the Company.

Some customers have opted to purchase generation resources from an alternative supplier. The load for these customers is included in the peak and energy forecasts within this IRP, as they remain part of the Company's capacity obligation in PJM.

2.2.4 Weather Assumptions

Where appropriate, the Company includes weather as an explanatory variable in its energy sales models. These models reflect historical weather for the model estimation period and normal weather for the forecast period.

2.2.5 Demand Side Management (DSM) Assumptions

The Company's long term load forecast models account for trends in EE both in the historical data as well as the forecasted trends in appliance saturations as the result of various legislated appliance efficiency standards (Energy Policy Act of 2005 [EPAct], Energy Independence and Security Act [EISA] of 2007, etc.) modeled by the EIA. In addition to general trends in appliance efficiencies, the Company also administers multiple Demand-Side Management (DSM) programs that the Commissions approve as part of its DSM portfolio. The load forecast utilizes the most current DSM programs, which either have been previously approved by or are pending currently before the Commission, at the time the load forecast is created to adjust the forecast for the impact of these programs. For this IRP, DSM programs through 2021 have been embedded into the load forecast.

2.3 Overview of Forecast Methodology

APCo's load forecasts are based mostly on econometric, statistically adjusted end-use and analyses of time-series data. This is helpful when analyzing future scenarios and developing confidence bands in addition to objective model verification by using standard statistical criteria.

APCo utilizes two sets of econometric models: 1) a set of monthly short-term models which extends for approximately 24 months and 2) a set of monthly long-term models which extends for approximately 30 years. The forecast methodology leverages the relative analytical strengths of both the short- and long-term methods to produce a reasonable and reliable forecast that is used for various planning purposes.

For the first full year of the forecast, the forecast values are generally governed by the short-term models. The short-term models are regression models with time series errors which analyze the latest sales and weather data to better capture the monthly variation in energy sales for short-term applications like capital budgeting and resource allocation. While these models produce extremely accurate forecasts in the short run, without logical ties to economic factors, they are less capable of capturing structural trends in electricity consumption that are more important for longer-term resource planning applications.

The long-term models are econometric, and statistically adjusted end-use models which are specifically equipped to account for structural changes in the economy as well as changes in customer consumption due to increased energy efficiency. The long-term forecast models incorporate regional economic forecast data for income, employment, households, output, and population.

The short-term and long-term forecasts are then blended to ensure a smooth transition from the short-term to the long-term forecast horizon for each major revenue class. There are some instances when the short-term and long-term forecasts diverge, especially when the long-term models are incorporating a structural shift in the underlying economy that is expected to occur within the first 24 months of the forecast horizon. In these instances, professional judgment is used to ensure that the final forecast that will be used in the peak models is reasonable. The class level sales are then summed and adjusted for losses to produce monthly net internal energy sales for the system. The demand forecast model utilizes a series of algorithms to allocate the monthly net internal energy to hourly demand. The inputs into forecasting hourly demand are internal energy, weather, 24-hour load profiles and calendar information.

A flow chart depicting the sequence of models used in projecting APCo's electric load requirements as well as the major inputs and assumptions that are used in the development of the load forecast is shown in Figure 2.

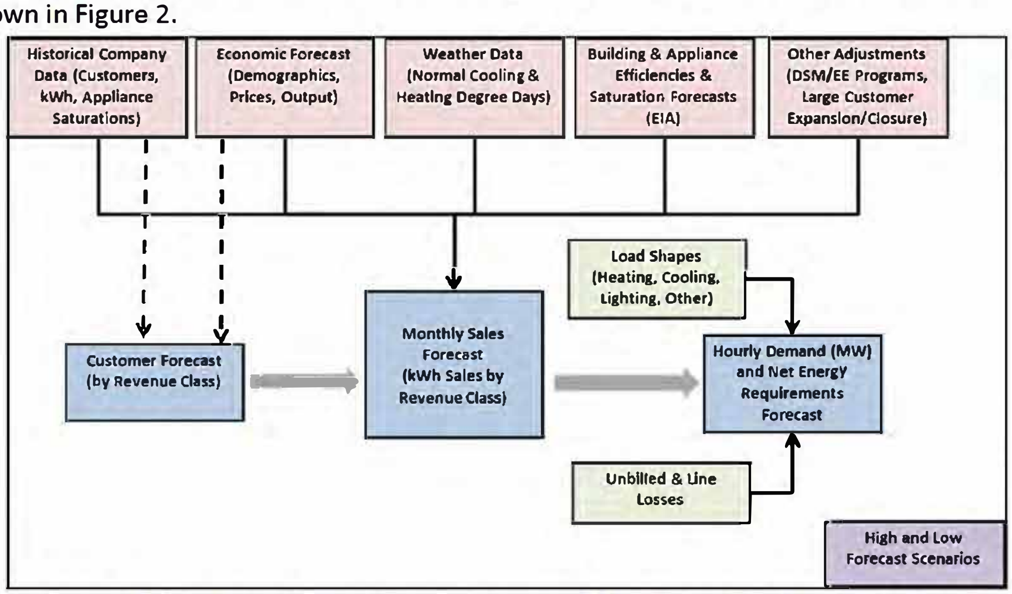

Figure 2. APCo Internal Energy Requirements and Peak Demand Forecasting Method

2.4 Detailed Explanation of Load Forecast

2.4.1 General

This section provides a more detailed description of the short-term and long-term models employed in producing the forecasts of APCo's energy consumption, by customer class. Conceptually, the difference between short- and long-term energy consumption relates to changes in the stock of electricity-using equipment and economic influences, rather than the passage of time. In the short term, electric energy consumption is considered to be a function of an essentially fixed stock of equipment. For residential and commercial customers, the most significant factor influencing the short term is weather. For industrial customers, economic forces that determine inventory levels and factory orders also influence short-term utilization rates. The short-term models recognize these relationships and use weather and recent load growth trends as the primary variables in forecasting monthly energy sales.

Over time, demographic and economic factors such as population, employment, income, and technology influence the nature of the stock of electricity-using equipment, both in size and composition. Long-term forecasting models recognize the importance of these variables and include all or most of them in the formulation of long-term energy forecasts.

Relative energy prices also have an impact on electricity consumption. One important difference between the short-term and long-term forecasting models is their treatment of energy prices, which are only included in long-term forecasts. This approach makes sense because although consumers may suffer sticker shock from energy price fluctuations, there is little they can do to impact them in the short-term. They already own a refrigerator, furnace or industrial equipment that may not be the most energy-efficient model available. In the long term, however, these constraints are lessened as durable equipment is replaced and as price expectations come to fully reflect price changes.

2.4.2 Customer Forecast Models

The Company also utilizes both short-term and long-term models to develop the final customer count forecast. The short-term customer forecast models are time series models with intervention (when needed) using Autoregressive Integrated Moving Average (ARIMA) methods of estimation. These models typically extend for 24 months into the forecast horizon.

The long-term residential customer forecasting models are also monthly but extend for 30 years. The explanatory jurisdictional economic and demographic variables may include gross regional product, employment, population, real personal income and households used in various combinations. In addition to the economic explanatory variables, the long-term customer models employ a lagged dependent variable to capture the adjustment of customer growth to changes in the economy. There are also binary variables to capture monthly variations in customers, unusual data points and special occurrences.

The short-term and long-term customer forecasts are blended as was described earlier to arrive at the final customer forecast that will be used as a primary input into both short-term and long-term usage forecast models.

2.4.3 Short-term Forecasting Models

The goal of APCo's short-term forecasting models is to produce an accurate load forecast for the first full year into the future. To that end, the short-term forecasting models generally employ a combination of monthly and seasonal binaries, time trends, and monthly heating cooling degree-days in their formulation. The heating and cooling degree-days are measured at weather stations in the Company's service area. The forecasts relied on ARIMA models.

The estimation period for the short-term models was January 2008 through January 2018. There are models for residential, commercial, industrial, other retail, and wholesale sectors. The industrial models are comprised of 20 large industrial models and models for the remainder of the industrial sector. The wholesale forecast is developed using models for the cities of Radford and Salem, Craig-Botetourt Electric Cooperative, Old Dominion Electric Cooperative, Virginia Tech and a private system customer in West Virginia. Kingsport Power Company, an affiliated company in Tennessee, is also a wholesale requirements customer of APCo, whose forecast is developed similar to those for the Company's Virginia and West Virginia jurisdictions.

Off-system sales and/or sales of opportunity are not relevant to the net energy requirements forecast as they are not requirements load or relevant to determining capacity and energy requirements in the IRP process.

2.4.4 Long-term Forecasting Models

The goal of the long-term forecasting models is to produce a reasonable load outlook for up to 30 years in the future. Given that goal, the long-term forecasting models employ a full range of structural economic and demographic variables, electricity and natural gas prices, weather as measured by annual heating and cooling degree-days, and binary variables to produce load forecasts conditioned on the outlook for the U.S. economy, for the APCo service-area economy, and for relative energy prices.

Most of the explanatory variables enter the long-term forecasting models in a straightforward, untransformed manner. In the case of energy prices, however, it is assumed, consistent with economic theory, that the consumption of electricity responds to changes in the price of electricity or substitute fuels with a lag, rather than instantaneously. This lag occurs for reasons having to do with the technical feasibility of quickly changing the level of electricity use even after its relative price has changed, or with the widely accepted belief that consumers make their consumption decisions on the basis of expected prices, which may be perceived as functions of both past and current prices.

There are several techniques, including the use of lagged price or a moving average of price that can be used to introduce the concept of lagged response to price change into an econometric model. Each of these techniques incorporates price information from previous periods to estimate demand in the current period.

The general estimation period for the long-term load forecasting models was 1995-2018 The long-term energy sales forecast is developed by blending of the short-term forecast with the long-term forecast. The energy sales forecast is developed by making a billed/unbilled adjustment to derive billed and accrued values, which are consistent with monthly generation.

2.4.4.1 Supporting Model

In order to produce forecasts of certain independent variables used in the internal energy requirements forecasting models, several supporting models are used, including natural gas price and coal production models for APCo's Virginia and West Virginia service areas. These models are discussed below.

2.4.4.1.1 Consumed Natural Gas Pricing Model

The forecast price of natural gas used in the Company's energy models comes from a model of natural gas prices for each state's three primary consuming sectors: residential, commercial, and industrial. In the state natural gas price models sectoral prices are related to East North Census region's sectoral prices, with the forecast being obtained from EIA's "2021 Annual Energy Outlook." The natural gas price model is based upon 1980-2020 historical data.

2.4.4.1.2 Regional Coal Production Model

A regional coal production forecast is used as an input in the mine power energy sales model. In the coal model, regional production depends on mainly Appalachian coal production, as well as on binary variables that reflect the impacts of special occurrences, such as strikes. In the development of the regional coal production forecast, projections of Appalachian and U.S. coal production were obtained from EIA's "2021 Annual Energy Outlook." The estimation period for the model was 1998-2020.

2.4.4.2 Residential Energy Sales

Residential energy sales for APCo are forecasted using two models, the first of which projects the number of residential customers, and the second of which projects kWh usage per customer. The residential energy sales forecast is calculated as the product of the corresponding customer and usage forecasts.

The residential usage model is estimated using a Statistically Adjusted End-Use model (SAE), which was developed by Itron, a consulting firm with expertise in energy modeling. This model assumes that use will fall into one of three categories: heat, cool, and other. The SAE model constructs variables to be used in an econometric equation where residential usage is a function of Xheat, Xcool, and Xother variables.

The Xheat variable is derived by multiplying a heating index variable by a heating use variable. The heating index incorporates information about heating equipment saturation; heating equipment efficiency standards and trends; and thermal integrity and size of homes. The heating use variable is derived from information related to billing days, heating degree-days, household size, personal income, gas prices, and electricity prices.

The Xcool variable is derived by multiplying a cooling index variable by a cooling use variable. The cooling index incorporates information about cooling equipment saturation; cooling equipment efficiency standards and trends; and thermal integrity and size of homes. The cooling use variable is derived from information related to billing days, heating degree-days, household size, personal income, gas prices and electricity prices.

The Xother variable estimates the non-weather sensitive sales and is similar to the Xheat and Xcool variables. This variable incorporates information on appliance and equipment saturation levels; average number of days in the billing cycle each month; average household size; real personal income; gas prices and electricity prices.

The appliance saturations are based on historical trends from APCo's residential customer survey. The saturation forecasts are based on EIA forecasts and analysis by Itron. The efficiency trends are based on DOE forecasts and Itron analysis. The thermal integrity and size of homes are for the West South Central Census Region and are based on DOE and Itron data.

The number of billing days is from internal data. Economic and demographic forecasts are from Moody's Analytics and the electricity price forecast is developed internally.

The SAE residential model is estimated using linear regression models. These monthly models are typically for the period January 1995 through January 2021. It is important to note, as will be discussed later, that this modeling *has* incorporated the reductive effects of the EPAct, EISA, American Recovery and Reinvestment Act of 2009 (ARRA) and Energy Improvement and Extension Act of 2008 (EIEA2008) on the residential (and commercial) energy usage based on analysis by the EIA regarding appliance efficiency trends.

The long-term residential energy sales forecast is derived by multiplying the "blended" customer forecast by the usage forecast from the SAE model.

2.4.4.3 Commercial Energy Sales

Long-term commercial energy sales are forecast using SAE models. These models are similar to the residential SAE models. These models utilize efficiencies, square footage and equipment saturations for the East North Central Region, along with electric prices, economic drivers from Moody's Analytics, heating and cooling degree-days, and billing cycle days. As with the residential models, there are Xheat, Xcool and Xother variables derived within the model framework. The commercial SAE models are estimated similarly to the residential SAE models.

2.4.4.4 Industrial Energy Sales

Based on the size and importance of the Mine Power sector to the overall APCo Industrial base as well as the unique outlook for the mining sector in the long run, the Company models the Mine Power sales separately from the rest of the Industrial manufacturing sales in the long-term forecast models.

2.4.4.4.1 Manufacturing Energy Sales

The Company uses some combination of the following economic and pricing explanatory variables: service area gross regional product manufacturing, FRB industrial production indexes, service area industrial electricity prices and state industrial natural gas price. In addition, binary variables for months are special occurrences and are incorporated into the models. Based on information from customer service engineers there may be load added or subtracted from the model results to reflect plant openings, closures or load adjustments. Separate models are estimated for the Company's Virginia and

West Virginia jurisdictions. The last actual data point for the industrial energy sales models is January 2021.

2.4.4.4.2 Mine Power Energy Sales

For its mine power energy sales models, the Company uses some combination of the following economic and pricing explanatory variables: service area gross regional product mining, regional coal production, and service area mine power electricity prices. In addition, binary variables for months are special occurrences and are incorporated into the models. Based on information from customer service engineers there may be load added or subtracted from the model results to reflect plant openings, closures or load adjustments. Separate models are estimated for the Company's Virginia and West Virginia jurisdictions. The last actual data point for the industrial energy sales models is January 2021.

2.4.4.5 All Other Energy Sales

The forecast of other retail sales, which is comprised of public-street and highway lighting and other sales to public authorities, relates energy sales to service area population and binary variables.

Wholesale energy sales are modeled relating energy sales to economic variables such as service area employment, heating and cooling degree-days and binary variables. Binary variables are necessary to account for discrete changes in energy sales that result from events such as the addition of new customers. Kingsport Power's load is modeled similarly to APCo's retail sales, with the exception that Kingsport Power does not have mine power energy sales.

2.4.4.6 Blending Short and Long-Term Sales

Forecast values for 2021 and 2022 are taken from the short-term process. Forecast values for 2023 are obtained by blending the results from the short-term and long-term models. The blending process combines the results of the short-term and long-term models by assigning weights to each result and systematically changing the weights so that by July 2023 the entire forecast is from the long-term models. The goal of the blending process is to leverage the relative strengths of the short-term and long-term models to produce the most reliable forecast possible. However, at times the short-term models may not capture structural changes in the economy as well as the long-term models, which may result in the long-term forecast being used for the entire forecast horizon.

2.4.4.7 Losses and Unaccounted-For Energy

Energy is lost in the transmission and distribution of the product. This loss of energy from the source of production to consumption at the premise is measured as the average ratio of all Federal Energy Regulatory Commission (FERC) revenue class energy sales measured at the premise meter to the net internal energy requirements metered at the source. In modeling, Company loss study results are applied to the final blended sales forecast by revenue class and summed to arrive at the final internal energy requirements forecast.

2.4.5 Forecast Methodology for Seasonal Peak Internal Demand

The demand forecast model is a series of algorithms for allocating the monthly internal energy sales forecast to hourly demands. The inputs into forecasting hourly demand are blended revenue class sales, energy loss multipliers, weather, 24-hour load profiles and calendar information.

The weather profiles are developed from representative weather stations in the service area. Twelve monthly profiles of average daily temperature that best represent the cooling and heating degree-days of the specific geography are taken from the last 30 years of historical values. The consistency of these profiles ensures the appropriate diversity of the company loads.

The 24-hour load profiles are developed from historical hourly Company or jurisdictional load and end-use or revenue class hourly load profiles. The load profiles were developed from segregating, indexing and averaging hourly profiles by season, day types (weekend, midweek and Monday/Friday) and average daily temperature ranges.

In the end, the profiles are benchmarked to the aggregate energy and seasonal peaks through the adjustments to the hourly load duration curves of the annual 8,760 hourly values. These 8,760 hourly values per year are the forecast load of APCo and the individual companies of AEP that can be aggregated by hour to represent load across the spectrum from end-use or revenue classes to total AEP-East, AEP-West, or total AEP System. Net internal energy requirements are the sum of these hourly values to a total company energy need basis. Company peak demand is the maximum of the hourly values from a stated period (month, season or year).

2.5 Load Forecast Results and Issues

All tables referenced in this section can be found in the Appendix of this Report in Exhibit A.

2.5.1 Load Forecast

Exhibit A-1 presents APCo's annual internal energy requirements, disaggregated by major category (residential, commercial, industrial, other internal sales and losses) on an actual basis for the years 2018-2021 and on a forecast basis for the years 2022-2036. The exhibit also shows annual growth rates for both the historical and forecast periods. Corresponding information for the Company's Virginia and West Virginia service areas are given in Exhibits A-2A and A-2B. Figure 3 provides a graphical depiction of weather normal and forecast Company residential, commercial and industrial sales for 2002 through 2036.

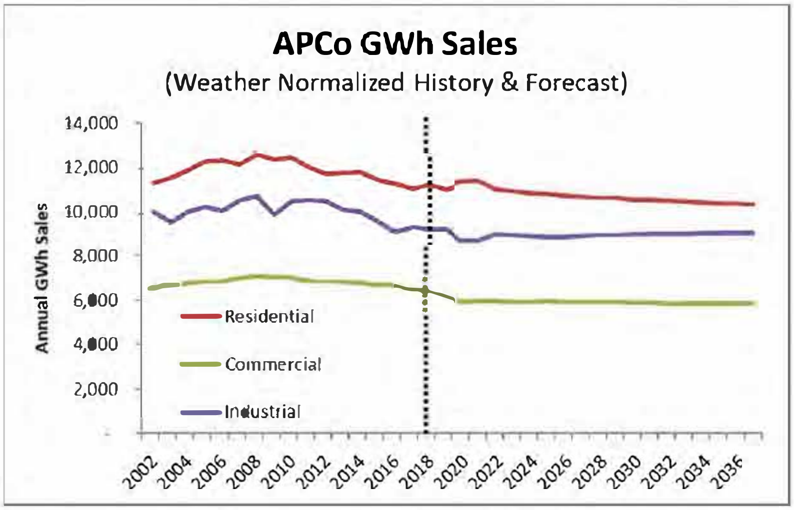

Figure 3: APCo GWh Retail Sales

2.5.2 Peak Demand and Load Factor

Exhibit A-3 provides APCo's seasonal peak demands, annual peak demand, internal energy requirements and annual load factor on an actual basis for the years 2018-2021 and on a forecast basis for the years 2022-2036. The table also shows annual growth rates for both the historical and forecast periods.

Figure 4 presents actual, weather normal and forecast APCo peak demand for the period 2000 through 2036. Figure 4 depicts the Company's annual peak demand, which occurs in the winter season. The Company's capacity planning in PJM is concerned with the Company's peak coincident with the PJM summer peak. This peak demand forecast is discussed in section 2.8.

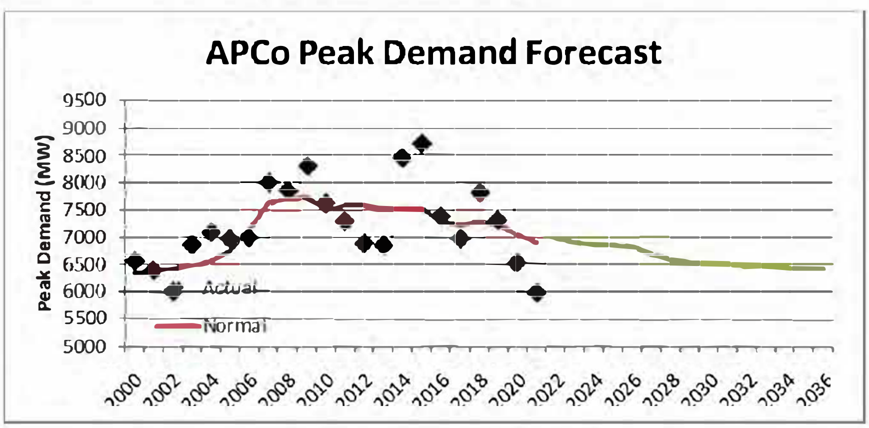

Figure 4: APCo Peak Demand Forecast

2.5.3 Weather Normalization

The load forecast presented in this Report assumes normal weather. To the extent that weather is included as an explanatory variable in various short- and long-term models, the weather drivers are assumed to be normal for the forecast period.

2.6 Load Forecast Trends & Issues

2.6.1 Changing Usage Patterns

Over the past decade, there has been a significant change in the trend for electricity usage from prior decades. Figure 5 presents APCo's historical and forecasted residential and commercial usage per customer between 1991 and 2030. During the first decade shown (1991-2000), residential usage per customer grew at an average rate of 1.2% per year, while the commercial usage grew by 0.6% per year. Over the next decade (2001-2010), growth in residential usage growth was at 0.8% per year while the commercial class usage decreased by 0.4% per year. In the third decade shown (2011-2020) residential usage declines at a rate of 0.6% per year while the commercial usage decreases by an average of 2.0% per year. It is worth noting that the COVID-19 Pandemic had significant impacts on residential and commercial usage. With more people working from home, displaced by economic shutdowns the residential sector saw a 1.7% increase in usage in 2020 and continued impacts were seen by a 0.9% increase in 2021. Meanwhile, the commercial had been in decline for several years experienced a 6.3% decline as businesses were either closed; reduced hours of operations or employees were working remotely. With businesses discovering ways to be more energy efficient, the commercial usage did not experience a significant bounce back in 2021. For the forecast period 2022 through 2030, residential and commercial usage per customer are project to decline at average annual rates of 0.5%.

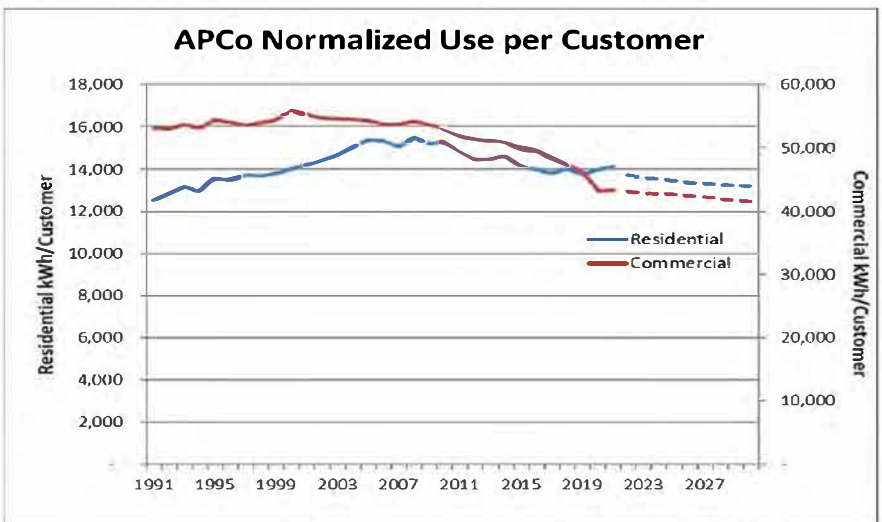

Figure 5. APCo Normalized Use per Customer (kWh)

The SAE models are designed to account for changes in the saturations and efficiencies of the various end-use appliances. Every 3-4 years, the Company conducts a Residential Appliance Saturation Survey to monitor the saturation and age of the various appliances in the residential home. This information is then matched up with the saturation and efficiency projections from the EIA which includes the projected impacts from various enacted federal policies mentioned earlier.

The result of this is a base load forecast that already includes some significant reductions in usage as a result of projected EE. For example, Figure 6 shows the assumed cooling efficiencies embedded in the statistically adjusted end-use models for cooling loads. It shows that the average Seasonal Energy Efficiency Ratio (SEER) for central air conditioning is projected to increase from 11.9 in 2010 to nearly 14.4 by 2030. The chart shows a similar trend in projected cooling efficiencies for heat pump cooling as well as room air conditioning units. Figure 7 shows similar improvements in the efficiencies of lighting and refrigerators over the same period. It is worth noting that lighting has experienced significant changes with the transition from incandescent lighting to more energy efficient alternatives. Going forward, larges gains in energy efficiency are not projected. Meanwhile, energy efficiency gains for refrigerators are expected to continue.

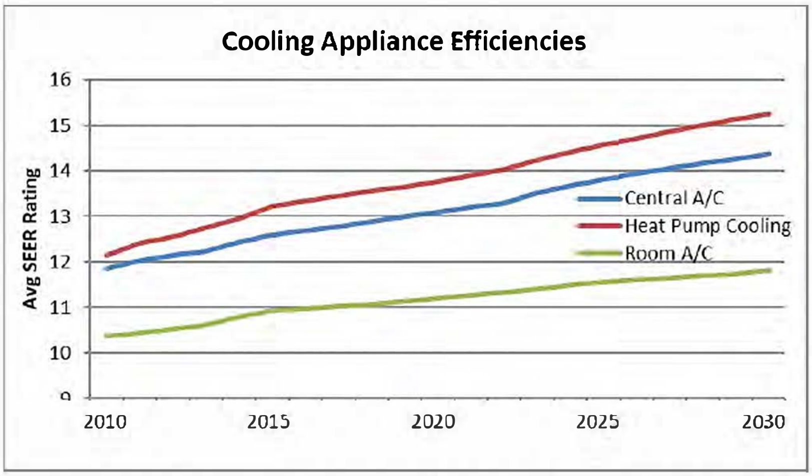

Figure 6. Projected Changes in Cooling Efficiencies, 2010-2030

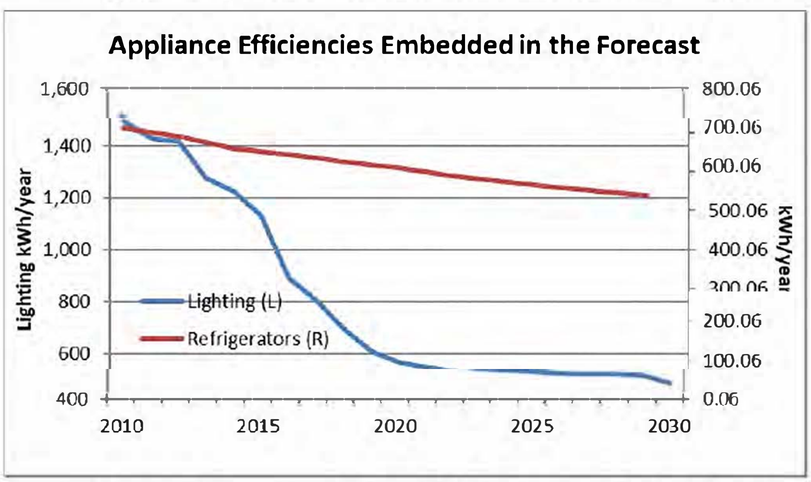

Figure 7. Projected Changes in Lighting & Refrigerator Efficiencies, 2010-2030

Figure 8 shows the impact of appliance, equipment and lighting efficiencies on the Company's weather normal residential usage per customer. This graph provides weather normalized residential energy per customer and an estimate of the effects of efficiencies on usage. In addition, historical and forecast APCo residential customers are provided.

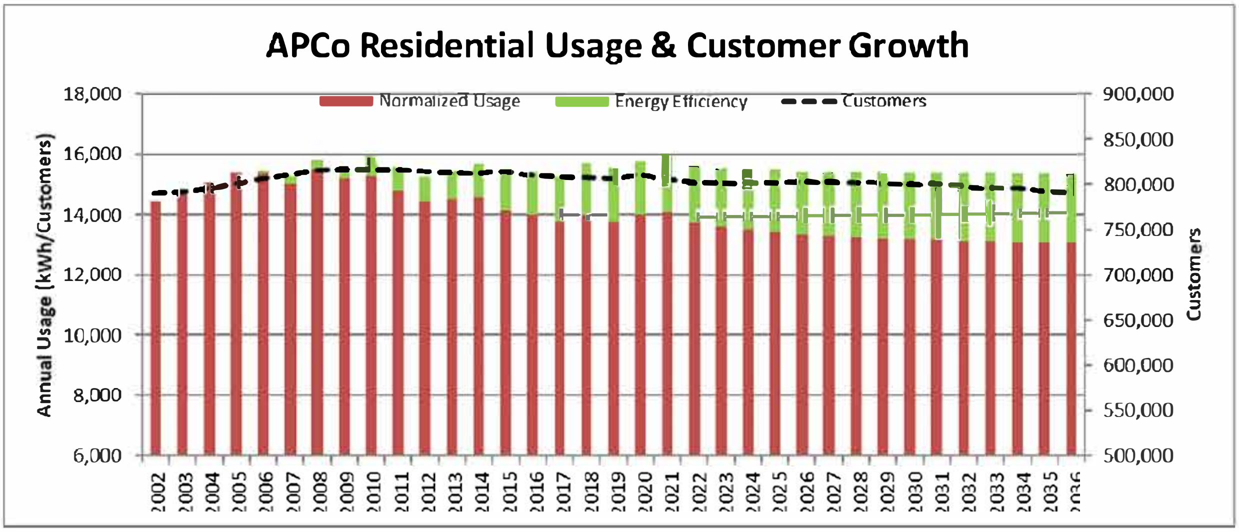

Figure 8. Residential Usage & Customer Growth, 2000-2036

2.6.2 Demand-Side Management (DSM) Impacts on the Load Forecast

The end-use load forecasting models account for changing trends and saturations of energy efficient technologies throughout the forecast horizon. However, the Company is also actively engaged in administering various commission approved DSM and EE programs which would further accelerate the adoption of energy efficient technology within its service territory. As a result, the base load forecast is adjusted to account for the impact of these programs that is not already embedded in the forecast.

For the near term horizon (through 2021), the load forecast includes approved programs from the Company's approved 2020 DSM plan. For the years beyond 2021, the IRP model included programs consistent with the Company's 2021 Energy Efficiency plan and current demand response resources through 2026 and programs after 2026 available for economic selection of optimal levels of economic EE. The initial base load forecast accounts for the evolution of market and industry efficiency standards. As a result, energy savings for a specific EE program are degraded over the expected life of the program. Exhibit A-10 details the impacts of the approved EE programs included in the load forecast, which represent the cumulative degraded value of EE program impacts throughout the forecast period. The IRP process then adds the selected optimal economic EE, resulting in the total IRP EE program savings.

Exhibit A-4 provides the DSM/EE impacts incorporated in APCo's load forecast provided in this Report. Annual energy and seasonal peak demand impacts are provided for the Company and its Virginia and West Virginia jurisdictions.

2.6.3 Interruptible Load

The Company has seven customers with interruptible provisions in their contracts. These customers have interruptible contract capacity of 243MW. However, these customers are expected to have 111MW and 114MW available for interruption at the time of the winter and summer peaks, respectively. An additional customer has 15MW available for interruption in emergency situations in DR agreements. The load forecast does not reflect any load reductions for these customers. Rather, the interruptible load is seen as a resource when the Company's load is peaking. As such, estimates for DR impacts are reflected by APCo in determination of PJM-required resource adequacy (i.e., APCo's projected capacity position). Further discussion of the determination of DR is included in Section 3.4.2.1.

2.6.4 Blended Load Forecast

As noted above, at times the short-term models may not capture structural changes in the economy as well as the long-term models, which may result in the long-term forecast being used for the entire forecast horizon. Exhibit A-5 provides an indication of which retail models are blended and which strictly use the long-term model results. In addition, all of the wholesale forecasts utilize the long-term model results.

In general, forecast values for the year 2022 were typically taken from the short-term process. Forecast values for 2023 are obtained by blending the results from the short-term and long-term models. The blending process combines the results of the short-term and long-term models by assigning weights to each result and systematically changing the weights so that by the end of 2023 the entire forecast is from the long-term models. This blending allows for a smooth transition between the two separate processes, minimizing the impact of any differences in the results. Figure 9 illustrates a hypothetical example of the blending process (details of this illustration are shown in Exhibit A-6). However, in the final review of the blended forecast, there may be instances where the short-term and long-term forecasts diverge especially when the long-term forecast incorporates a structural shift in the economy that is not included in the short-term models. In these instances, professional judgment is used to develop the most reasonable forecast.

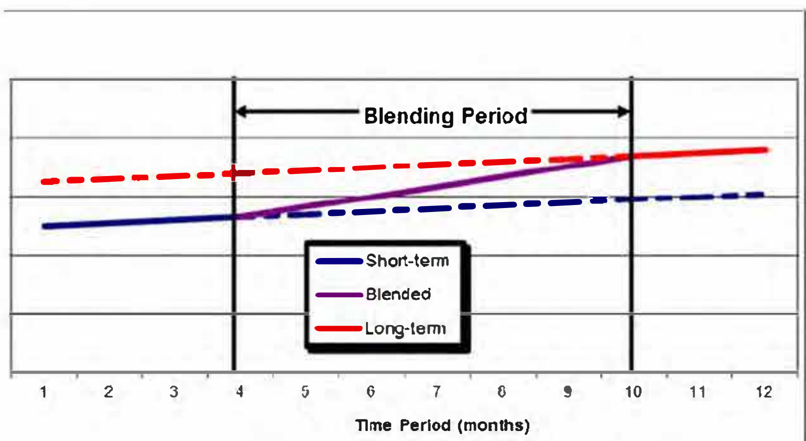

Figure 9. Load Forecast Blending Illustration

2.6.5 Large Customer Changes

The Company's customer service engineers are in continual contact with the Company's large commercial and industrial customers about their needs for electric service. These customers will relay information about load additions and reductions. This information will be compared with the load forecast to determine if the industrial or commercial models are adequately reflecting these changes. If the changes are different from the model results, then additional factors may be used to reflect those large changes that differ from the forecast models' output.

2.6.6 Wholesale Customer Contracts

Company representatives are in continual contact with wholesale customer representatives about their contractual needs. Going forward, the Company does not assume that wholesale contracts will be automatically renewed. Therefore, when each contract expires the forecast assumption is the load that particular customer will go to zero.

2.7 Load Forecast Scenarios

The base case load forecast is the expected path for load growth that the Company uses for planning. There are a number of known and unknown potentials that could drive load growth different from the base case. While potential scenarios could be quantified at varying levels of assumptions and preciseness, the Company has chosen to frame the possible outcomes around the base case. The Company recognizes the potential desire for a more exact quantification of outcomes, but the reality is if all possible outcomes were known with a degree of certainty, then they would become part of the base case.

Forecast sensitivity scenarios have been established which are tied to respective high and low economic growth cases. The high and low economic growth scenarios are consistent with scenarios laid out in the EIA's 2021 Annual Outlook. While other factors may affect load growth, this analysis only considered high and low economic growth. The economy is seen as a crucial factor affecting future load growth.

The low-case, base-case and high-case forecasts of summer and winter peak demands and total internal energy requirements for APCo are tabulated in Exhibit A-7.

For APCo, the low-case and high-case energy and peak demand forecasts for the last forecast year, 2036, represent deviations of about 12.4% below and 13.6% above, respectively, the base-case forecast.

During the load forecasting process, the Company developed various other scenarios.

Figure 10 provides a graphical depiction of the scenarios developed in conjunction with the load provided in this report.

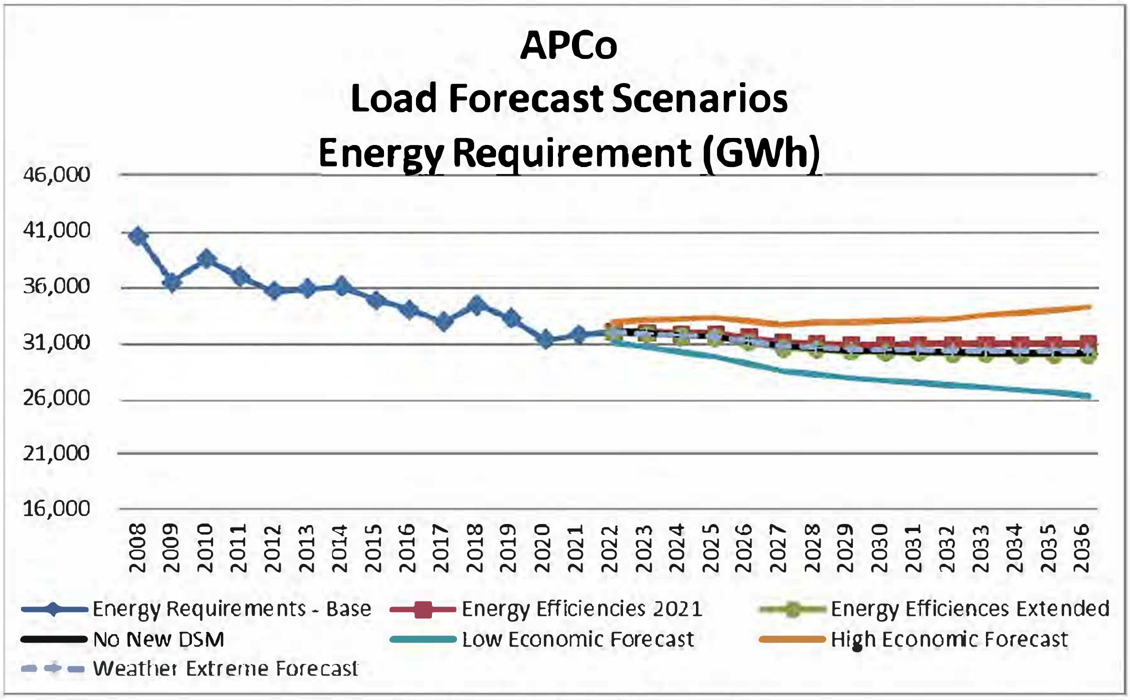

Figure 10. Load Forecast Scenarios

The no new DSM scenario extracts the DSM included in the load forecast and provides what load would be without the increased DSM activity. The energy efficiencies 2021 scenario keeps energy efficiencies at 2021 levels for the residential and commercial equipment. Both of these scenarios result in a load forecast greater than the base forecast.

The energy efficiencies extended scenario has energy efficiencies developing at a faster pace than is represented in the base forecast. This scenario is based on analysis developed by the Energy Information Administration. This forecast is lower than the base forecast due to enhanced energy efficiency for residential and commercial equipment.

The weather extreme forecast assumes increased degree-days for both the winter and summer seasons. This analysis is based on a potential impact of climate change developed by Purdue University. This scenario results in increased load in the summer and diminished load in the winter, with the net result being a higher energy requirements forecast. Exhibit A-8 provides graphical displays of the range of forecasts of summer and winter peak demand for APCo along with the impacts of the weather scenario for each season.

All of these alternative scenarios fall within the boundary of the Company's high and low economic scenario forecasts. The Company's expectations are that any reasonable scenario developed will fall within this range of forecasts.

Although the Company does not explicitly account for enhanced adoption of electric vehicles and/or distributed generation in the load forecast, it does continually monitor the adoption rates and will address the issue as it becomes more significant.

2.8 Long-Term PJM Load Forecast

In its order related to APCo's 2018 IRP, the Commission stated "We further direct APCo to include in all future IRPs modelling that includes, but need not be limited to, the AEP Zone PJM coincident peak load forecast produced by PJM Interconnection, LLC, scaled down to the APCo load serving entity level."

The Company utilized the PJM 2021 Load Forecast to develop a forecast for the APCo load serving entity (LSE) coincident with the PJM RTO. The APCo LSE is comprised of retail load and FERC wholesale load, which includes Kingsport Power, an affiliated company that purchases all of its power needs from the Company. In PJM, the Company is required to include those customers that have chosen alternative energy suppliers in its capacity obligation for Fixed Resource Requirement (FRR) planning. The forecasts provided in this report include choice customers in all analyses.

Exhibit A-9 provides the forecast of the APCo LSE load based on the PJM forecast for the AEP Zone. These forecasts are for the summer season and are coincident with PJM RTO. The summer season is used as it is the critical season for the RTO and it is used for capacity planning. The APCo forecast diversified to be coincident with PJM RTO is also provided, as well as the Company's high forecast diversified to be coincident with the PJM RTO. The Company's forecast tends to be lower than APCo's share of the PJM forecast for the AEP Zone. However, the Company's high forecast is above the PJM forecast. As discussed in the forecast scenario section, any reasonable scenario is expected fall within the boundaries of the high and low economic scenario forecasts.

2.9 Energy Efficiency and Economic Development

Exhibit A-4 reflects those EE programs expected to be in place through 2021 and subtracted from the load forecast as described in Sections 2.2.5 and 2.6.2. The Company will add incremental programs to, at minimum, be in compliance with the VCEA requirements. Section 4.4 discusses in detail the Company's process for selecting the additional energy conservation programs.

On December 1, 2018, the Company submitted a report on economic development in the Appalachian Power service area to the Commission. This report discusses the Company's economic development process, its programs, support, and its Virginia economic development rider. The report also discusses the development activities, research and rural initiatives for the APCo region of the American Electric Power (AEP) Economic Development team. The AEP activities supplement and strengthen the Company's economic development efforts and make available additional resources for the Company. The Company intends to continue to support economic development activities that will benefit the local economy.

2.10 Economic Development

Section 56-599 of the Code of Virginia requires that each IRP consider options for "economic development including retention and expansion of energy-intensive industries."

This IRP sets forth portfolios to meet these and other goals in a reasonable cost manner. The improvement in fuel diversity, including the addition of zero variable cost renewable resources, helps to mitigate the volatility inherent in fuel and purchase power costs. Predictability in retail rates is an important determinant in an energy-intensive company's decision whether to expand within a utility's service territory. Predictability around one of the larger input costs reduces the risk associated with any expansion or relocation investment, in turn reducing capital costs, which engenders more investment.

It is worth noting that pricing is only one of many considerations for a firm's decision in locating or retaining plants. Other variables, such as power reliability, taxes, site availability and socio-economic considerations have varying degrees of importance. The Company endeavors to maintain its transmission and distribution systems to assure acceptable power quality and reliability. The Company does not promote economic development alone, rather it works in concert with local and state economic development teams.

Additionally, some large customers have corporate requirements to supply their energy solely from renewable sources. To accommodate these customers, the Company may have to procure and dedicate specific renewable resources to serve that load. APCo offers both residential and large retail customers the ability to source their entire energy consumption from renewable energy offerings through Rider WWS. Rider REC enables customers to purchase RECs to offset their consumption.. Finally, Rider VWS allows certain commercial customers to purchase some or all of their energy requirements from two of the company's wind farms at a contracted rate.

2.10.1 Economic Development Programs

The Company has economic development programs designed to attract new businesses and expand and retain existing businesses in its service territory. These programs benefit not only APCo through increased electricity sales, but have direct and indirect impacts on jobs for the region. The spillover effects associated with these jobs include the increased income associated with job creation, which in turn results in increased activity for local businesses and the creation of additional jobs, and increased tax revenues for local governments. The increased activity will not be confined to the APCo service area but rather further increases economic activity in other parts of the Commonwealth, as well. An equally important economic development activity is in the retention of existing jobs. Just as there is a positive ripple effect of adding new jobs to a region, there are negative economic ripple effects associated with losing jobs for the region and the Commonwealth as a whole.

The COVID 19 pandemic period continues to rapidly reshape the international economic development landscape. Supply chain fractures and shifting market demands precipitated a surge of new business investment inquiries beginning in late 2020 and continuing through present. Several APCo Virginia served communities and business sites announced historic 'wins' over the last 18 months; the availability of greenfield sites exhibiting high levels of utility infrastructure readiness were noted as key to these location decisions. With several key business sites having announced recently projects, or anticipated to within the next 12 months, the Company continues to recognize the importance of industrial site readiness and has implemented a number of new initiatives which support future site due diligence and development activities. The Company has invested in transmission and distribution facilities in order to make certain business parks that meet criteria prescribed in Section 56-585.1:10 in the Code of Virginia move-in ready for customers. Appalachian Power's investment in the Commonwealth Crossing Business Centre and Southern Virginia Megasite at Berry Hill give Virginia a competitive edge when recruiting new business by demonstrating the sites are construction-ready with valuable utility infrastructure already in place. The company's work at the Commonwealth Crossing site in Henry County is complete and included construction of a new substation and the addition of nearly six miles of transmission line. Work to construct a new substation and five miles of transmission line at the Berry Hill site near Danville should be complete in the fall.

The Company can further encourage potential business expansions or new customer additions by employing its Virginia Economic Development Rider (EDR). The EDR assists both the Company's existing customers and potential new customers. The EDR provides an incentive for customers with 500 kW or larger demand who may be associated with new investment and job growth. The EDR assists existing plants that may be in competition with a firm's other plants, in different parts of the country or world, for expansion or a potential new plant for the firm. In Virginia, APCo can provide incentives from 25-35% of the demand charge and can extend it for a term of up to five years. The EDR allows APCo the flexibility to compete with other utilities when vying for development opportunities.1.5.1

3.0 Resource Evaluation

3.1 Current Resources

An initial step in the IRP process is the demonstration of the capacity resource requirements. This aspect of the traditional "needs" assessment must consider projections of:

- existing capacity resources—current levels and anticipated changes;
- anticipated changes in capability due to efficiency and/or environmental considerations;
- changes resulting from decisions surrounding unit disposition evaluations;
- regional and sub-regional capacity and transmission constraints/limitations;
- load and peak demand;
- current DR/EE; and
- PJM capacity reserve margin and reliability criteria.

3.2 Existing APCo Generating Resources

The underlying minimum reserve margin criterion to be utilized in the determination of APCo's capacity needs is based on the PJM Installed Reserve Margin (IRM) of 14.9 percent.[5] The ultimate reserve margin is determined from the PJM Forecast Pool Requirement (FPR) which considers the IRM and PJM's Pool-Wide Average Equivalent Demand Forced Outage Rate ($EFOR_D$).[6] The PJM FPR is 9.06% for the 2022/2023 PJM planning year, and for IRP modeling, 8.94% was used the remainder of the planning period which ends with the 2036/2037 PJM planning year. Table 1 displays key parameters for APCo's current supply-side resources.

Table 3 identifies the current generating resources included in the Company's plan. Future plans surrounding these assets must take into account each unit's useful service life. Unit retirements are incorporated in APCo's plans based upon each unit's in-service date along with the anticipated service life. Retirement dates are periodically reviewed and adjusted with respect to a unit's ability to maintain safe, reliable, and economic operation, as well as external factors such as environmental regulations.

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[5] Per Section 2.1.1 of PJM Manual 18: PJM Capacity Market (Effective: October 20, 2021). PJM Planning Parameters are updated each year prior to the upcoming Base Residual Auction. These values can be obtained from http://pjm.com/markets-and-operations/rpm.aspx. This IRP uses the PJM Planning Parameters published on October 12, 2021, which reflect PJM's Capacity Performance proposal, as currently interpreted by APCo.

[6] Per Section 2.1.4 of PJM Manual 18: PJM Capacity Market (Effective: October 20, 2021).

$FPR = (1 + IRM) * (1 - EFOR_D)$. Reserve Margin = FPR – 1.

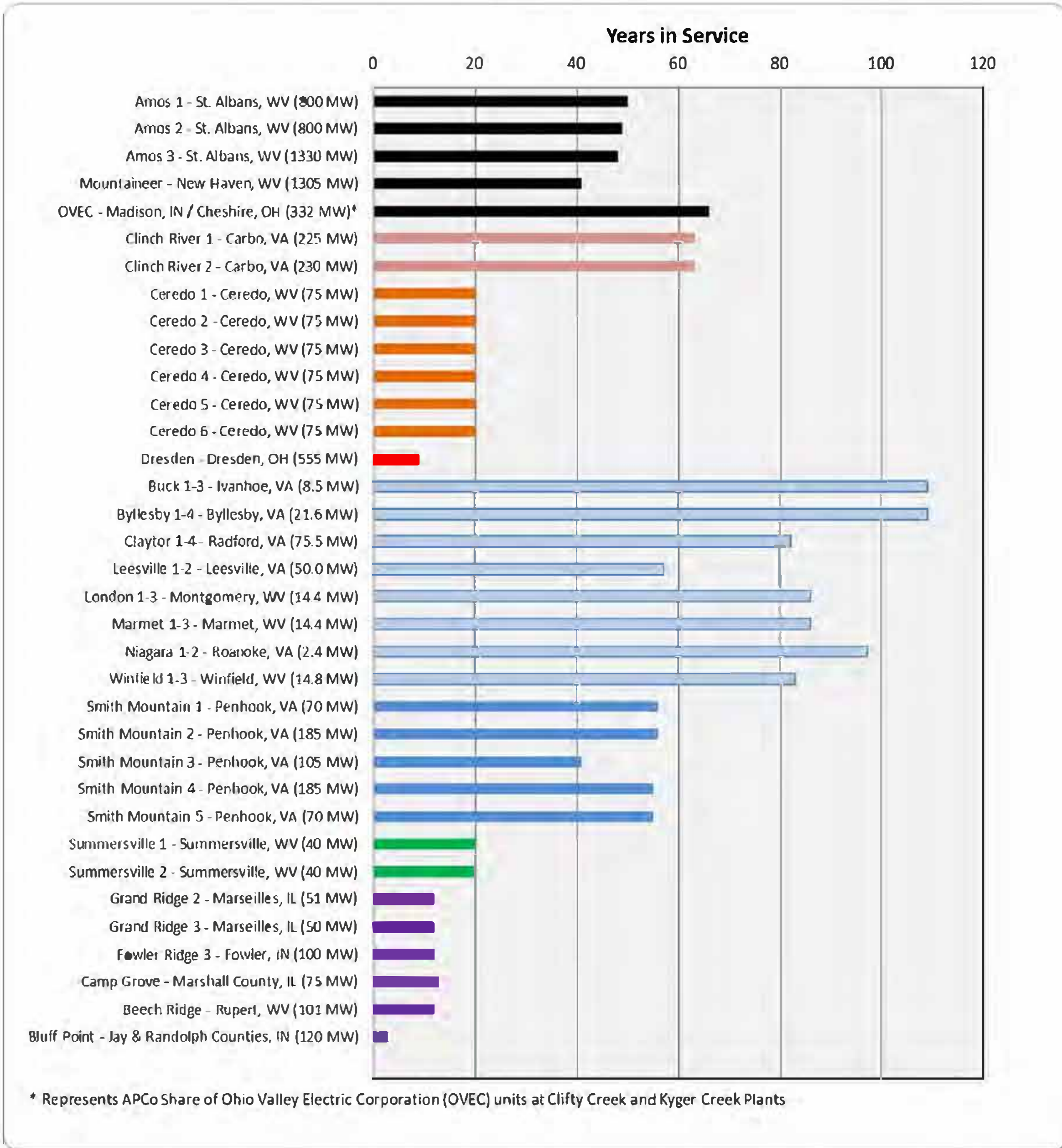
Table 3. APCo Generation Assets as of December, 2021

Unit Name	Location	UnitType	Primary Fuel Type	C.O.D. [1]	PJM Installed Capacity (MW) [2]	
Amos 1	St. Albans, WV	Steam	Coal	1971	800	
Amos 2	St. Albans, WV	Steam	Coal	1972	800	
Amos 3	St. Albans, WV	Steam	Coal	1973	1,330	
Ceredo 1	Ceredo, WV	Combustion Turbine	Gas	2001	76	
Ceredo 2	Ceredo, WV	Combustion Turbine	Gas	2001	76	
Ceredo 3	Ceredo, WV	Combustion Turbine	Gas	2001	76	
Ceredo 4	Ceredo, WV	Combustion Turbine	Gas	2001	76	
Ceredo 5	Ceredo, WV	Combustion Turbine	Gas	2001	75	
Ceredo 6	Ceredo, WV	Combustion Turbine	Gas	2001	76	
Clinch River 1	Carbo, VA	Steam	Gas	1958	225	
Clinch River 2	Carbo, VA	Steam	Gas	1958	232	
Dresden	Dresden, OH	Combined Cycle	Gas	2012	570	
Mountaineer 1	New Haven, WV	Steam	Coal	1980	1,305	
Buck 1 - 3	Ivanhoe, VA	Hydro	--	1912	11	
Byllesby 1 - 4	Byllesby, VA	Hydro	--	1912	19	
Claytor 1 - 4	Radford, VA	Hydro	--	1939	75	
Leesville 1 - 2	Leesville, VA	Hydro	--	1964	50	
London 1 - 3	Montgomery, WV	Hydro	--	1935	14	
Marmet 1 - 3	Marmet, WV	Hydro	--	1935	14	
Niagara 1 - 2	Roanoke, VA	Hydro	--	1924	2	
Winfield 1 - 3	Winfield, WV	Hydro	--	1938	15	
Smith Mountain 1	Penhook, VA	Pump. Stor.	--	1965	65	(A)
Smith Mountain 2	Penhook, VA	Pump. Stor.	--	1965	175	(A)
Smith Mountain 3	Penhook, VA	Pump. Stor.	--	1980	105	(A)
Smith Mountain 4	Penhook, VA	Pump. Stor.	--	1966	175	(A)
Smith Mountain 5	Penhook, VA	Pump. Stor.	--	1966	65	(A)
Clifty Creek 1-6	Madison, IN	Steam	Coal	1956	182	(B)
Kyger Creek	Cheshire, OH	Steam	Coal	1955	150	(B)
Beech Ridge 1	Greenbriar County, WV	Wind	--	2009	14	(C)
Camp Grove	Marshall County, IL	Wind	--	2008	12	(C)
Fowler Ridge	Benton County, IN	Wind	--	2009	13	(C)
Grand Ridge 2-3	Marseilles, IL	Wind	--	2009	16	(C)
Summersville 1-2	Summersville, WV	Hydro	--	2001	80	(C)
Bluff Point	Jay & Randolph Counties, IN	Wind	--	2018	24	(C)
					6,994	

(1) Commercial operation date.
(2) Peak net capability (Summer) as of filing.
(A) Units 1, 3 & 5 have pump-back capability, units 2 & 4 are generation only.
(B) Represents APCO's share of OVEC capacity under the ICPA.
(C) Represents capacity from Power Purchase Agreements (PPAs).

Figure 11 depicts APCo's current generation resources, their nameplate ratings and current age.

Figure 11 Current Resource Fleet (Owned & Contracted) with years in Service, as of December 31, 2021



APCo currently utilizes several capacity entitlements to meet the minimum PJM reserve margin requirement, including generation from Company owned assets, joint ventures, and hydro and wind Power Purchase Agreements (PPAs).

Additionally, the Company is proceeding with integrating a total of 64MW (nameplate) of 3rd party owned solar resources installed at the distribution level of service which are assumed as part of the Going-In resources in the IRP analysis not shown in Table 3. These resources are shown in Table 4.

Table 4. APCo 3rd Party Distribution Level Planned Resource

Facility	Nameplate Capacity MW	Owned / PPA	State	Resource Type	Operation
Leatherwood*	20	PPA	Virginia	Solar	Sept 2021-2036
Whytheville*	20	PPA	Virginia	Solar	June 2022-2036
Amherst*	4.9	Owned	Virginia	Solar	Jan 2023 - Dec 2057
Dogwood*	18.9	PPA	Virginia	Solar	Jan 2025 - Dec 2054

*Behind the Meter Resources

3.2.1 PJM Capacity Performance Rule

On June 9, 2015 FERC issued an order largely accepting PJM's proposal to establish a new "Capacity Performance" product. Beginning with Delivery Year 2020/2021 there are no longer any other options for resources to participate in PJM's Capacity Market. Capacity Performance resources will be held to stricter requirements than current Base resources and will be assessed heavy penalties for failing to deliver energy when called upon. For this IRP, the Company assumes it will continue as a Fixed Resource Requirement (FRR) entity within the PJM Capacity planning process and, consistent with the Capacity Performance rule, assumes that unit capabilities (UCAP) will be based on the current UCAP definition, which is Installed Capacity (ICAP) times 1 minus EFORd or ICAP X (1 – EFORd).

3.3 Environmental Issues and Implications

It should be noted that the following discussion of environmental regulations is the basis for assumptions made by the Company which are incorporated into its analysis within this IRP. Activity including but not limited to Presidential Executive Orders, litigation, petitions for review, and Federal Environmental Protection Agency (EPA) proposals may delay the implementation of these rules, or eventually affect the requirements set forth by these regulations. While such activities have the potential to materially change the regulatory requirements the Company will face in the future, all potential outcomes cannot be reasonably foreseen or estimated and the assumptions made within the IRP represent the Company's best estimation of outcomes as of the filing date. The Company is committed to closely following developments related to environmental regulations, and will update its analysis of compliance options and timelines when sufficient information becomes available to make such judgments.

3.3.1 Clean Air Act (CAA) Requirements

The Clean Air Act ("CAA") establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements. The primary regulatory programs that currently drive investments in AEP operating companies' existing generating units include: (a) periodic revisions to National Ambient Air Quality Standards ("NAAQS") and the development of state implementation plans to achieve any more stringent standards; (b) implementation of the regional haze program by the states and the Federal EPA; (c) regulation of hazardous air pollutant emissions under the Mercury and Air Toxics Standard ("MATS") rule; and (d) implementation and review of the Cross-State Air Pollution Rule ("CSAPR"), a federal implementation plan designed to eliminate significant contributions from sources in upwind states to non-attainment or maintenance areas in downwind states.

Notable developments in significant CAA regulatory requirements affecting the Company's operations are discussed in the following sections.

3.3.2 National Ambient Air Quality Standards (NAAQS)

The Federal EPA periodically reviews and revises the NAAQS for criteria pollutants under the CAA. Revisions tend to increase the stringency of the standards, which in turn may require APCo to make investments in pollution control equipment at existing generating units, or, since most units are already well controlled, to make changes in how units are dispatched and operated. In October of 2021, EPA announced that it was reconsidering its 2020 decision to leave the NAAQS standards unchanged. APCo cannot currently predict if any changes to the NAAQS standards are likely or what such changes may be, but will continue to monitor this issue and any future rulemakings.

3.3.3 Cross-State Air Pollution Rule (CSAPR)

CSAPR is a regional trading program designed to address interstate transport of emissions that contributed significantly to downwind non-attainment with the 1997 ozone and PM NAAQS. CSAPR relies on SO2 and NOX allowances and individual state budgets to compel further emission reductions from electric utility generating units. Interstate trading of allowances is allowed on a restricted sub-regional basis.

In January 2021, EPA finalized a revised CSAPR rule, which substantially reduces the ozone season NOX budgets in 2021-2024. Several utilities and other major emitters have challenged that final rule in the U.S. Court of Appeals for the District of Columbia Circuit and briefing is underway. APCo cannot predict the outcome of that litigation, but believes it can meet the requirements of the rule in the near term. In addition, in February 2022 the EPA Administrator signed a proposed Federal Implementation Plan (FIP) for 2015 Ozone NAAQS that would further revise the ozone season NOX budgets under the existing CSAPR program. The Company is still evaluating the proposed changes.

3.3.4 Mercury and Air Toxics Standard (MATS) Rule

The final MATS Rule became effective on April 16, 2012, and required compliance by April 16, 2015. AEP Management obtained administrative extensions for up to one year at several units to facilitate the installation of controls and/or to avoid serious reliability problems. The rule established unit-specific emission rates for units burning coal on a 30-day rolling average basis for mercury, PM (as a surrogate for particles of non-mercury metals) and hydrogen chloride (as a surrogate for acid gases). In addition, the rule proposed work practice standards, such as boiler tune-ups, for controlling emissions of organic Hazardous Air Pollutants ("HAPs") and dioxin/furans. Compliance was required within three years.

In April 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied all of the petitions for review of the April 2012 final rule. Industry trade groups and several states filed petitions for further review in the U.S. Supreme Court.

In 2015, the U.S. Supreme Court reversed the decision of the U.S. Court of Appeals for the District of Columbia Circuit. The court remanded the MATS rule to the EPA to consider costs in determining whether to regulate emissions of HAPs from power plants. In 2016, the EPA issued a supplemental finding concluding that, after considering the costs of compliance, it was appropriate and necessary to regulate HAP emissions from coal and oil-fired units. Petitions for review of the EPA's determination were filed in the U.S. Court of Appeals for the District of Columbia Circuit. In 2018, the EPA released a revised finding that the costs of reducing HAP emissions to the level in the current rule exceed the benefits of those HAP emission reductions. The EPA also determined that there are no significant changes in control technologies and the remaining risks associated with HAP emissions do not justify any more stringent standards. Therefore, the EPA proposed to retain the current MATS standards without change. A final rule adopting the findings in the proposal was issued in April 2020. The rule has been challenged in the U.S. Court of Appeals for the District of Columbia Circuit.

In early 2022, EPA proposed to revoke its 2020 finding that it is not appropriate and necessary to regulate coal- and oil-fired EGUs under Section 112 of the CAA, and to reaffirm EPA's 2016 supplemental finding that it remains appropriate and necessary to regulate HAPs from such sources. In its proposed rule, EPA states that revocation of the 2020 finding is necessary because it was based on an improper analytical framework that compared the rule's total costs to a "very small subset" of only HAP benefits that could be monetized. EPA now proposes to find that the appropriate and necessary finding is supported under both a "totality-of-the-circumstances" framework or an alternative formal benefit cost analysis (BCA) framework. Although the Agency is not proposing any amendments to MATS in the proposed rule, EPA notes that it is separately reviewing the residual risk and technology review (RTR) for MATS. Therefore, in addition to soliciting comments on all aspects of EPA's proposal to reinstate its appropriate and necessary finding, the Agency requests information on the performance and cost of new or improved technologies that control HAP emissions; improved methods of operation; and risk-related information to further inform the Agency's review of the MATS RTR.

APCo's supercritical units (Amos Units 1-3, Mountaineer Unit 1) are able to meet the MATS Rule requirements as a result of previously installed control equipment including Selective Catalytic Reduction (SCR) for mitigation of nitrogen oxide (NOx) emissions and FGD systems for mitigation of SO2 emissions, which together achieve a co-benefit removal of mercury as well.

3.3.5 Climate Change, CO_2 Regulation and Energy Policy

EPA has promulgated two separate rules in an attempt to regulate CO2 emissions for existing fossil fuel-fired steam electric generating units – the Clean Power Plan ("CPP"), and the Affordable Clean Energy ("ACE") Rule – neither of which is in effect at the present time. The CPP was stayed by the U.S. Supreme Court and ultimately, was repealed and replaced by the ACE Rule. In January 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE rule and remanded it to the EPA. APCo is unable to predict how the EPA will respond to the court's remand. On October 29, 2021, the U.S. Supreme Court granted certiorari and combined four separate petitions seeking review of the D.C. Circuit Court decision. Oral arguments have been held, but APCo is unable to predict the outcome of that litigation.

For purposes of this Integrated Resource Plan, APCo has not directly attempted to model either the Clean Power Plan or Affordable Clean Energy rule. However, as described later, APCo does conduct analysis around carbon regulation through use of a carbon price proxy within the planning process.

3.3.6 Virginia Greenhouse Gas Regulation

In 2021, Virginia officially joined the Regional Greenhouse Gas Initiative (RGGI), a market-based program designed at reducing GHG emissions from electric power plants. Virginia joined the program with an initial statewide emission budget of 28 million tons. That cap is ratcheted down by three percent each year thereafter for a total emissions budget of 19.6 million tons by 2030. RGGI is designed as a cap and trade program where effected entities within Virginia (i.e. Clinch River 1 & 3) will have to procure RGGI emission allowances to cover annual emissions. Annual emissions from Clinch River represent less than 2% of the overall Virginia emission budget established by the GHG Regulations. APCo is currently complying with requirements of the rule through the purchase of emission allowances.

3.3.7 New Source Review Consent Decree

In December 2007, AEP companies entered into a settlement of outstanding litigation (Consent Decree) around New Source Review compliance. Pursuant to the terms of the settlement, those companies have completed environmental retrofit projects on their Eastern units, are operating the units under a declining cap on total SO_2 and NO_x emissions, and will install additional control technologies at certain units. For APCo, the most significant control projects under the Consent Decree involved continuing the installation of previously planned SCR and FGD systems at Amos Units 1-3 and Mountaineer Unit 1. Additionally, the Consent Decree called for APCo's Clinch River units (1-3) to install Selective Non-Catalytic Reduction (SNCR) for NO_x reduction. The retrofits to the APCo plants have been completed.

Two minor modifications to the Consent Decree were made in 2009 and 2010 to adjust the FGD retrofit dates for APCo's Amos Units 1 and 2. In May 2013, a third modification to the Consent Decree was approved that contains specific retrofit requirements for APCo's affiliates, as well as reductions to the caps for SO_2 emissions for the AEP eastern fleet. In January 2017, a fourth modification to the Consent Decree was approved to facilitate the sale of the Gavin units. It is projected that the system caps, as modified, will have little or no effect on the operation of APCo's electric generating facilities.

The annual NO_x and SO_2 caps contained within the Modified New Source Review Consent Decree for the coal units owned by AEP-East operating companies, including APCo, are displayed in Table 5 and Table 6. Additional modifications to the specific retrofit requirements at an APCo affiliate's facility in Indiana, which would include reductions in the AEP-East system caps for NO_x and SO_2 are being sought. These changes are not anticipated to affect APCo's operations at Amos or Mountaineer.

Table 5. Consent Decree Annual NOx cap for AEP East

Calendar Year	Annual Tonnage Limitations for NO_x
2009	96,000
2010	92,500
2011	92,500
2012	85,000
2013	85,000
2014	85,000
2015	75,000
2016, and each year thereafter	72,000

Table 6. Modified Consent Decree Annual SO_2 cap for AEP East

Calendar Year	Annual Tonnage Limitations for SO_2
2016	145,000
2017	145,000
2018	145,000
2019-2021	113,000
2022-2025	110,000
2026-2028	102,000
2029, and each year thereafter	94,000

3.3.8 Coal Combustion Residual (CCR) Rule

The EPA's CCR rule regulates the disposal and beneficial use of CCR, including fly ash and bottom ash created from coal-fired generating units and FGD gypsum generated at some coal-fired plants. The rule applies to active and inactive CCR landfills and surface impoundments at facilities of active electric utilities or independent power producers. In August 2020, the EPA revised the CCR rule to include a requirement that unlined CCR storage ponds cease operations and initiate closure by April 11, 2021. The revised rule provides two options that allow facilities to extend the date by which they must cease receipt of coal ash and close the ponds. The first option provides an extension to cease receipt of CCR no later than October 15, 2023 for most units, and October 15, 2024 for a narrow subset of units; however, the EPA's grant of such an extension will be based upon a satisfactory demonstration of the need for additional time to develop alternative ash disposal capacity and will be limited to the soonest timeframe technically feasible to cease receipt of CCR. Additionally, each request must undergo formal review, including public comments, and be approved by the EPA. APCo's Amos and Mountaineer facilities have requested such extensions; those requests remain pending before EPA. While APCo remains confident that its application complies with the CCR Rule's requirements to receive an extension, APCo is nevertheless evaluating steps that it may be required to take should EPA deny any of its pending applications. The CCR Rule also provided a second option for facilities that committed to cease coal combustion by a date certain. That option is not relevant to APCo's facilities.

Other utilities and industrial sources have been engaged in litigation with environmental advocacy groups who claim that releases of contaminants from wells, CCR units, pipelines and other facilities to ground waters that have a hydrologic connection to a surface water body represent an "unpermitted discharge" under the Clean Water Act ("CWA"). Two cases have been accepted by the U.S. Supreme Court for further review of the scope of CWA jurisdiction. In April 2020, the Supreme Court issued an opinion remanding one of these cases to the Ninth Circuit Court of Appeals based on its determination that discharges from an injection well that make their way to the Pacific Ocean through groundwater may require a permit, if the distance traveled, the length of time to reach the ocean, and other factors make it "functionally equivalent" to a direct discharge from a point source. The second case was also remanded to the lower court.

Prior to the U.S. Supreme Court's decision, EPA opened a rulemaking docket to solicit information to determine whether it should provide additional clarification of the scope of CWA permitting requirements for discharges to ground water, and issued an interpretative statement considering comments received in the rulemaking docket and determined that "releases to groundwater are excluded from the scope of the National Pollutant Discharge Elimination System ("NPDES") program, even where pollutants are conveyed to jurisdictional surface waters via groundwater." In December 2020, the EPA issued draft guidance for public comment on applying the outcome of the U.S. Supreme Court's decision and consideration of functionally equivalent factors. In September 2021, EPA rescinded that guidance. The impact of these developments on CCR units will be determined by further EPA guidance, additional permitting decisions, and future action from the courts.

While the necessary site-specific analyses to determine the requirements under the final CCR Rule are ongoing, initial estimates of anticipated plant modifications and capital expenditures are factored into this IRP. It should be noted that APCo's Amos and Mountaineer Plants are already equipped with dry fly ash handling systems and dry ash landfills to meet current permit requirements, and that these projects also position the plants well for future compliance with the CCR rulemaking.

3.3.9 Clean Water Act Regulations

In 2014, the EPA issued a final rule setting forth standards for existing power plants pursuant to section 316(b) of the Clean Water Act that is intended to reduce mortality of aquatic organisms impinged or entrained in the cooling water. The rule was upheld on review by the U.S. Court of Appeals for the Second Circuit. Compliance timeframes are established by the permit agency through each facility's NPDES permit as those permits are renewed and have been incorporated into permits at several AEP facilities. AEP facilities that have had their wastewater discharge permits renewed have been asked to monitor intake flows, to enhance monitoring practices to assure the current technology is being properly managed, or seek additional information in order to ensure compliance with this rule.

In August 2021, the Federal EPA and the Army Corps of Engineers announced their plan to reconsider and revise the Navigable Waters Protection Rule, which defines "waters of the United States" under the Clean Water Act. Shortly thereafter, the United States District Court for the District of Arizona vacated and remanded the Navigable Waters Protection Rule, which had the effect of reinstating the prior, much broader, version of the rule. Because the scope of waters subject to Federal EPA and Army Corps of Engineers jurisdictions is broader under the prior rule, permitting decisions made in recent years are subject to reevaluation; permits may now be necessary where none were previously required, and issued permits may need to be reopened to impose additional obligations. On December 7, 2021, Federal EPA proposed a rule that would roll back the definition of "waters of the United States" to the pre-2015 definition. Federal EPA also announced that it would be considering further changes through a future rulemaking, which would build upon the foundation of the proposed rule. Management will continue to monitor rulemaking on this issue.

The Federal EPA's ELG rule for generating facilities establishes limits on FGD wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater, which are to be implemented through each facility's wastewater discharge permit. A recent revision to the ELG rule, published in October 2020, establishes additional options for reusing and discharging small volumes of bottom ash transport water, provides an exception for retiring units and extends the compliance deadline to a date as soon as possible beginning one year after the rule was published but no later than December 2025. Management has assessed technology additions and retrofits to comply with the rule and the impacts of the Federal EPA's recent actions on facilities' wastewater discharge permitting for FGD wastewater and bottom ash transport water. For affected facilities that must install additional technologies to meet the ELG rule limits, permit modifications were filed in January 2021 that reflect the outcome of that assessment. We continue to work with state agencies to finalize permit terms and conditions. Other facilities opted to file Notices of Planned Participation (NOPP), pursuant to which the facilities are not required to install additional controls to meet ELG limits provided they make commitments to cease coal combustion by a date certain. The Federal EPA has announced its intention to reconsider the 2020 rule and to further revise limits applicable to discharges of landfill and impoundment leachate. A proposed rule is expected in late 2022. Management cannot predict whether the Federal EPA will actually finalize further revisions or what such revisions might be, but we will continue to monitor this issue and will participate in further rulemaking activities as they arise.

3.4 APCo Current Demand-Side Programs

3.4.1 Background

Demand-Side programs, also known as Demand-side Management (DSM) collectively includes utility programs aimed at influencing both the level of, and timing of, customer use of grid supplied electricity. These types of programs are structured to counter the ongoing need for increased supply resources through customer energy conservation or direct intervention in how customers use electricity. Typically, customer influence is achieved through some form of monetary or product enticement either through utility rebates or electric bill credit payments. Several demand-side programs are available including Energy Efficiency (EE), Demand Reduction (DR), Conservation Voltage Reduction (CVR) and Distributed Generation (DG).

Generally, EE programs pay rebates directly to customers that are designed to encourage either end-use conservation or energy use reduction through the installation of or upgrade to more efficient end-use technologies. Some EE programs do not pay a cash rebate but instead encourage customers to reduce their annual energy consumption, or better manage their cost of electricity. Other types of EE programs seek to influence the manufacture and supply of more efficient end-use technologies through upstream rebate payments to end-use technology providers that reduce the technology cost to end-use customers. EE programs provide both energy and demand savings. Energy savings are accounted for as an around-the-clock energy reduction impact while demand savings are accounted for in terms of their point-in-time, peak coincident use reduction on an hourly basis.

Generally, DR programs offer electric bill credits through tariff pricing mechanisms to elicit point-in-time energy use reductions (also known as demand, or coincident peak demand reductions). DR programs require specific action to monitor and control electricity use during periods of peak usage. Direct load control (DLC) programs allow utility control over customers' end use loads to achieve the specific peak period use reduction. Other types of DR programs allow customers to reduce use during peak periods on their own accord and pay bill credits based on the actual level of usage during peak period events. Demand response programs primarily provide peak coincident demand impacts but can provide energy impacts as well depending upon the extent of use reduction that occurs.

DER typically refers to small-scale customer-sited generation behind the customer meter. Common examples are Combined Heat and Power (CHP), residential and small commercial solar applications, and even wind. Currently, these sources represent a small component of demand-side resources, even with available federal tax credits and tariffs favorable to such applications. APCo's retail jurisdictions have "net metering" tariffs in place which currently allow excess generation to be credited to customers at the retail rate up to the amount of the customer's monthly bill. Although the economics of investments for this resource are not typically favorable, in particular for solar resources, an incremental level of DG resources was applied based on forecasted customer adoption rates.

Volt-VAR Optimization (VVO) is a process by which the utility systematically reduces voltages in its distribution network through the installation and use of sensors and controllers on the grid, resulting in a proportional reduction of load on the network. This voltage reduction still maintains minimum levels needed by customers but elicits lower energy use from end-use customer appliances without any changes in behavior or changes to appliance efficiencies.

Included in the load forecast discussed in Section 1.5 of this Report are the demand and energy impacts associated with APCo's DSM programs that have been approved in Virginia and West Virginia prior to 2022. As will be discussed later, within the IRP process, the potential for additional or "incremental" demand-side resources, including EE activity—over and above the levels embedded in the load forecast—as well as other grid related projects such as Volt VAR Optimization (VVO), are modeled on the same economic basis as supply-side resources. However, because customer-based EE programs are limited by factors such as customer acceptance and saturation, an estimate as to their costs, timing and maximum impacts must be formulated.

3.4.2 DSM Impact on Peak Demand

Peak demand, measured in MW, can be thought of as the amount of power used at the time of maximum customer usage. APCo's maximum (system peak) demand is likely to occur on the coldest winter weekday of the year, in the morning. This happens as a result of the near-simultaneous use of heating by the majority of customers, as well as the normal use of other appliances, commercial equipment, and (industrial) machinery. At other times during the day, and throughout the year, the use of power is less. However, as a member of PJM, the Company's summer peak demand coincident with the RTO is a criterion for determining the Company's capacity obligation.

3.4.2.1 Existing Demand-Side Programs

Included in the load forecast discussed in Section 2 of this Report are the demand and energy impacts associated with APCO's DSM programs approved prior to 2022. A summary of these include:

- Energy Efficiency (EE): APCO currently has approved EE programs in place in its service territories. Programs approved in the Company's 2020 DSM plan are included in the load forecast discussed in section 2. These programs are forecasted to reduce peak demand in 2022 by approximately 6.1 MW and reduce energy consumption by approximately 35 GWh.
- Demand Reduction (DR): DR programs are accounted for as a load shape reduction from the load forecast used in the IRP. For the year 2022, APCO anticipates 50 MW of DR reduction. The majority of this DR is achieved through interruptible load agreements. A smaller portion is achieved through direct load control.
- Distributed Energy Resources (DERs): At the end of 2021 APCo and its affiliate Kingsport Power have a total of 27MW of customer-installed Solar resources consisting of 19.5MW in Virginia, 5.7MW in West Virginia and 1.8MW in Tennessee.
- CVR: While there is no "embedded" incremental VVO load reduction impacts implicit in the base load forecast case, VVO has been modeled as a unique EE resource. APCO is currently implementing a VVO Pilot Program in Virginia on a limited scope by upgrading two circuits per year (six total) over a limited three to four-year period.

3.4.2.2 Energy Efficiency (EE)

EE measures may reduce bills and save money for customers. The trade-off is the up-front investment in a building/appliance/equipment modification, upgrade, or new technology. If consumers conclude that the new technology is a viable substitute and will pay them back in the form of reduced bills over an acceptable period, they will adopt it.

EE measures most commonly include efficient lighting, weatherization, efficient pumps and motors, efficient Heating, Ventilation and Air Conditioning (HVAC) infrastructure, and efficient appliances. Often, multiple measures are bundled into a single program that might be offered to either residential or commercial/industrial customers.

EE measures will reduce the amount of energy consumed but may have limited effectiveness at the time of peak demand. EE is viewed as a readily deployable, relatively low cost, and clean energy resource that provides many benefits. However, market barriers to EE may exist for the potential participant. To overcome participant barriers, a portfolio of EE programs may often include several of the following elements:

- Consumer education
- Technical training
- Energy audits
- Rebates and discounts for efficient appliances, equipment and buildings
- Industrial process improvements

The level of incentives (rebates or discounts) offered to participants is a major determinant in the pace of EE measure adoption.

Additionally, the speed with which programs can be rolled out also varies with the jurisdictional differences in stakeholder and regulatory review processes. The lead time can easily exceed a year for getting programs implemented or modified. This IRP begins adding new demand-side resources in 2022 that are incremental to approved programs included in the Company's 2020 DSM plan. APCo currently has EE programs in place in its Virginia and West Virginia service territories.

3.4.3 Distributed Energy Resources (DERs)

DER typically refers to small-scale customer-sited generation behind the customer meter. Common examples are Combined Heat and Power (CHP), residential and small commercial solar applications, and even wind. Currently, these sources represent a small component of demand-side resources, even with available federal tax credits and tariffs favorable to such applications. APCo's retail jurisdictions have "net metering" tariffs in place which currently allow excess generation to be credited to customers at the retail rate up to the amount of the customer's monthly bill.

Prior to 2026, federal investment tax credits (IT) for residential systems are available and costs for residential customers are expected to decline rapidly. While the cost to install residential solar continues to decline, the economics of such an investment are still high for the customer for a number of years, given APCo's current rates. As Figure 12 illustrates, by APCo state jurisdictional residential sector, the equivalent installed cost a customer would need to realize, on a dollars per watt-AC ($/W$_{AC}$) basis, in order to breakeven on their investment, assuming a 25-year life of the solar panels based on the customer's avoided retail rate and the monetary credit that the customer receives for excess generation can exceed the amount of their overall monthly bill. Thus, the analysis shows that the current cost of residential solar exceeds the cost which would allow a customer to breakeven on an investment over a 25-year period.

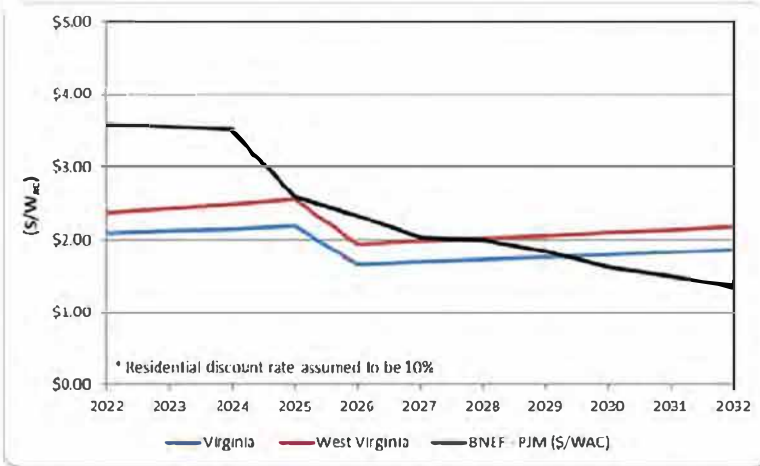


Figure 12. Distributed Solar Breakeven Costs for Residential Customers ($/W$_{AC}$)

3.4.3.1 Load Characteristics of Net-Metered Customers

APCo's net-metered customers are able to realize energy "credits" during the times when generation from their rooftop solar system is greater than their own demand. In the past, solar generators during summer months realized these energy "credits" but not during the winter months, however, this has seemingly changed. Figure 13 and Figure 14 illustrate the average summer and winter load profile for a representative customer with rooftop solar (blue line) and without rooftop solar (red line).

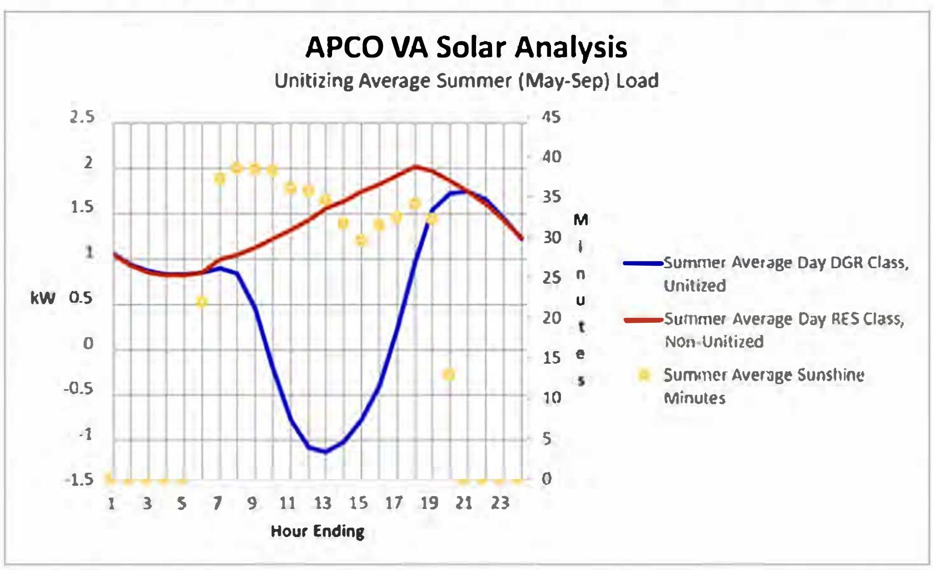


Figure 13. Summer Load Profile for Representative DER Customer with Rooftop Solar Installation

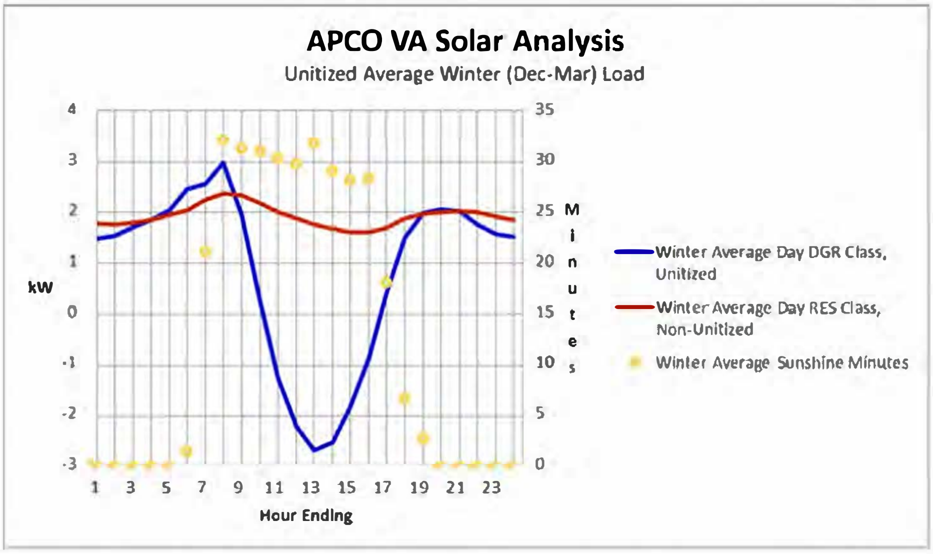


Figure 14. Winter Load Profile for Representative DG Customer with Rooftop Solar Installation

On average, from approximately 9:30am until 5pm in the summer months and 10:30am until 4:30pm in the winter months, a customer with rooftop solar would be supplying electricity to the grid, as evident by the negative load requirement. During these periods when rooftop solar systems are generating they are offsetting the Company's total generation requirement on average. As evident in the figures, however, the total offset is both difficult to quantify and plan for due to the variability of the rooftop solar system's output.

3.4.3.2 Impacts of Increased Levels of Distributed Energy Resources

As mentioned previously, rooftop solar installations allow customers to reduce their energy consumption from the utility and potentially reduce their peak demand. While the latter benefit could lead to a lower overall PJM peak demand for APCo it does not reduce APCo's seasonal peak demand. As discussed in Section 2.0, APCo's overall peak demand generally occurs in the early morning on a winter day. As shown above in Figure 14, during these times of peak demand rooftop solar installations are providing little to no demand savings.

Increasing levels of DERS present challenges for the Company from a distribution planning perspective. Higher penetration of DERS can potentially mask the true load on distribution circuits and stations if the instantaneous output of connected DERS is not known, which can lead to under-planning for the load that must be served should DERS become unavailable. Increased levels of DERS could lead to a requirement that DERS installations include smart inverters so that voltage and other circuit parameters can be controlled within required levels. Additional performance monitoring capabilities for DERS systems will facilitate accurate tracking and integration of DERS generators into the existing resource mix.

3.5 AEP-PJM Transmission

3.5.1 General Description

The AEP eastern transmission system (eastern zone) consists of the transmission facilities of the eleven eastern AEP operating or Transmission companies (Appalachian Power Company [APCo], Ohio Power Company [OPCo], Indiana Michigan Power Company [I&M], Kentucky Power Company [KPCo], Wheeling Power Company [WPCo], Kingsport Power Company [KgPCo], AEP Appalachian Transmission Company [APTC], AEP Indiana Michigan Transmission Company [IMTC], AEP Kentucky Transmission Company [KYTC], AEP Ohio Transmission Company [OHTC], and AEP West Virginia Transmission Company [WVTC]). The Eastern Zone portion of the transmission system is composed of approximately 14,950 miles of circuitry operating at or above 100kV and includes over 2,120 miles of 765kV transmission lines overlaying 3,550 miles of 345kV lines and over 9,000 miles of 138kV circuitry. This expansive system allows the economical and reliable delivery of electric power to approximately 21,610 MW of customer demand connected to the AEP eastern transmission system that takes transmission service under the PJM open access transmission tariff.

The AEP eastern transmission system is part of the Eastern Interconnection, the most integrated transmission system in North America. The entire AEP eastern transmission system is located within the Reliability*First* Corporation (RFC) geographic area. On October 1, 2004, AEP's eastern zone joined the PJM Regional Transmission Organization (RTO) and now participates in the PJM regional planning, operations, and markets.

As a result of the AEP eastern transmission system's geographical location and expanse as well as its numerous interconnections, the eastern transmission system can be influenced by both internal and external factors from its geographical location, expanse, and numerous interconnections. Facility outages, load changes, or generation re-dispatch on neighboring companies' systems, in combination with power transactions across the interconnected network, can affect power flows on AEP's transmission facilities. As a result, the AEP eastern transmission system is designed and operated to perform adequately even with the outage of its most critical transmission elements or the unavailability of generation. The eastern transmission system conforms to the NERC Reliability Standards and applicable RFC standards and performance criteria.

Despite the robust nature of the eastern transmission system, certain outages coupled with extreme weather conditions and/or power-transfer conditions can potentially stress the system beyond acceptable limits. The most significant 765kV transmission line enhancement to the AEP eastern transmission system over the last several years was completed in 2006. This was the construction of a 90-mile 765kV transmission line from Wyoming Station in West Virginia to Jacksons Ferry Station in Virginia. AEP's eastern transmission system assets are aging. Figure 15 below demonstrates the development of that Transmission Bulk Electric System. In order to maintain reliability, significant investments will be necessary over the next decade to address the aging infrastructure and assets.

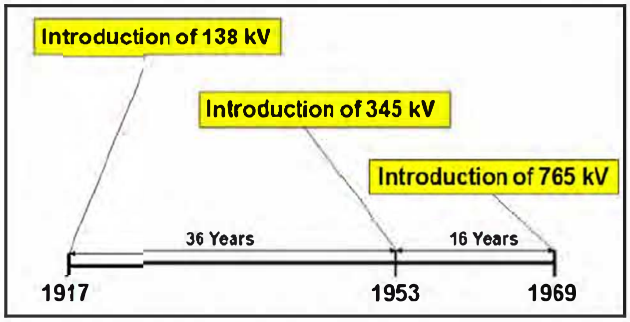


Figure 15. AEP Eastern Transmission System Development Milestones

Over the years, AEP, and more recently PJM, entered into numerous study agreements to assess the impact of the connection of potential merchant generation to the eastern transmission system. AEP companies, in conjunction with PJM, have interconnection agreements in their service territories with several merchant plant developers. Several generation additions are planned to be connected to the eastern transmission system over the next several years (including upgrades to existing facilities, once studied and approved through the PJM Generation Interconnection queue process[7]). There are also significant amounts of merchant generation under study for potential interconnection.

The integration of the merchant generation now connected to the eastern transmission system required incremental transmission system upgrades, such as installation of larger capacity transformers and circuit breaker replacements. None of these merchant facilities required major transmission upgrades that significantly increased the capacity of the transmission network. Other transmission system enhancements will be required to match general load growth and allow the connection of large load customers and any other generation facilities. In addition, transmission modifications may be required to address changes in power flow patterns and changes in local voltage profiles resulting from operation of the PJM and adjacent markets, such as MISO and NYISO.

The transmission line circuit miles in APCo's Virginia service territory include approximately 349 miles of 765kV, 96 miles of 500kV, 69 miles of 345kV, 15 miles of 230kV, 1,652 miles of 138kV, 613 miles of 69kV, 48 miles of 46kV and 83 miles of 34.5kV lines. APCo's West Virginia service territory includes approximately 383 miles of 765kV, 16 miles of 500kV, 329 miles of 345kV, 1,516 miles of 138kV, 4 miles of 88kV, 412 miles of 69kV, 660 miles of 46kV, and 54 miles of 34.5kV lines.

3.5.2 Transmission Planning Process

AEP and PJM coordinate the planning of the transmission facilities in the AEP Eastern Zone through a "bottom up/top down" approach. AEP will continue to develop transmission expansion plans to meet the applicable reliability criteria in support of PJM's transmission planning process. PJM will

[7] PJM Generation Interconnection queue is located at: https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

incorporate AEP's expansion plans with those of other PJM member utilities and then collectively evaluate the expansion plans as part of its Regional Transmission Expansion Plan (RTEP) process. The PJM assessment will ensure consistent and coordinated expansion of the overall bulk transmission system within its footprint. In accordance with this process, AEP will continue to take the lead for the planning of its local transmission system under the provisions of Schedule 6 of the PJM Operating Agreement and Attachment M-3 of the PJM Tariff. By way of the RTEP, PJM will ensure that transmission expansion is developed for the entire RTO footprint via a single regional planning process that considers both regional and local needs and solutions, thus ensuring a consistent view of needs and expansion timing while minimizing expenditures. When regional system upgrade requirements are identified under the RTEP, PJM determines the individual member's responsibility as related to construction and costs to implement the expansion. This process identifies the most appropriate, reliable and economical integrated transmission reinforcement plan for the entire region, while blending the local planning expertise of the transmission owners such as APCo with a regional view and formalized open stakeholder input.

AEP's transmission planning criteria are consistent with North American Electric Reliability Corporation (NERC) and RFC reliability standards. The AEP planning criteria are filed with FERC annually as part of AEP's FERC Form 715 and these planning criteria are posted on the AEP website[8]. Using these criteria, limitations, constraints and future potential deficiencies on the AEP transmission system are identified. Remedies are identified and budgeted as appropriate to ensure that system enhancements will be timed to address anticipated deficiencies.

Similarly, AEP also identifies local needs and solutions through the Attachment M-3 planning process that drives Supplemental and asset management projects in the RTEP. All projects affecting the topology of the grid, whether PJM identified, or Transmission Owner identified, are subject to the stakeholder process within PJM. While PJM does not formally "approve" Owner Projects, these projects are submitted to PJM and reviewed with the Transmission Expansion Advisory Committee (TEAC) and Subregional RTEP Committee – Western on a periodic basis in accordance with the provisions in Attachment M-3 of the PJM Tariff. All TEAC and Subregional RTEP Committee-Western meetings are open, and any transmission stakeholder can attend. Owner Projects are subject to multiple rounds of review and detailed project information, including needs and alternative solutions. The Attachment M-3 process ensures stakeholders have an opportunity to review Owner Projects and include the following meetings and posting requirements:

- Separate stakeholder meetings to discuss:
  - Criteria, assumptions and models used to plan Owner Projects (Assumptions Meeting);
  - Needs underlying Owner Projects (Needs Meeting); and,
  - Potential solutions to meet those needs (Solutions Meeting).

[8] https://www.aep.com/about/codeofconduct/OASIS/TransmissionStudies/

- Posting of criteria, assumptions, and models at least 20 calendar days prior to the Assumptions Meeting and accepting post-meeting comments for ten days after this meeting;
- Posting of criteria violations and drivers at least ten days in advance of the Needs Meeting and accepting post-meeting comments for ten days after this meeting;
- Posting of potential solutions and alternatives identified by PJM Transmission Owners or stakeholders at least ten days in advance of the Solutions Meeting and accepting post-meeting comments for ten days after this meeting; and,
- Opportunity to submit final comments for PJM Transmission Owner review and consideration at least ten days before the Local Plan is integrated into the RTEP.

PJM also coordinates its regional expansion plan on behalf of the member utilities with the neighboring utilities and/or RTOs, including the MISO, to ensure inter-regional reliability. The Joint Operating Agreement between PJM and the MISO provides for joint transmission planning.

3.5.3 System-Wide Reliability Measures

Transmission reliability studies are conducted routinely for seasonal, near-term, and long-term horizons to assess the anticipated performance of the transmission system. The reliability impact of resource adequacy (either supply or demand side) would be evaluated as an inherent part of these overall reliability assessments. If reliability studies indicate the potential for inadequate transmission reliability, transmission expansion alternatives and/or operational remedial measures would be identified and implemented.

3.5.4 Evaluation of Adequacy for Load Growth

As part of the on-going near-term/long-term planning process, AEP and PJM use the latest load forecasts along with information on system configuration, generation dispatch, and system transactions to develop models of the AEP transmission system. These models are the foundation for conducting performance appraisal studies based on established criteria to determine the potential for overloads, voltage problems, or other unacceptable operating problems under adverse system conditions. Whenever a potential problem is identified, PJM and AEP seek solutions to avoid the occurrence of the problem. Solutions may include operating procedures or capital transmission project reinforcements. Through this on-going process, AEP works diligently to maintain an adequate transmission system able to meet forecasted loads with a high degree of reliability.

In addition, PJM performs a Load Deliverability assessment on an annual basis using a 90/10[9] load forecast for areas that may need to rely on external resources to meet their demands during an emergency condition.

[9] 90% probability that the actual peak load will be lower than the forecasted peak load and 10% probability that the actual peak load will be higher than the forecasted peak load.

3.5.5 Evaluation of Other Factors

As a member of PJM, and in compliance with FERC Orders 888 and 889, AEP is obligated to provide sufficient transmission capacity to support the wholesale electric energy market. In this regard, any committed generator interconnections and firm transmission services are taken into consideration under AEP's and PJM's planning processes. In addition to providing reliable electric service to AEP's retail and wholesale customers, PJM will continue to use any available transmission capacity in AEP's eastern transmission system to support the power supply and transmission reliability needs of the entire PJM – MISO joint market.

A number of generation requests have been initiated in the PJM generator interconnection queue. AEP, through its membership in PJM, is obligated to evaluate the impact of these projects and construct the transmission interconnection facilities and system upgrades required to connect any projects that sign an interconnection agreement. The amount of this planned generation that will actually be connected to the transmission system is unknown at this time.

3.5.6 Transmission Expansion Plans

The transmission system expansion plans for the AEP eastern system are developed and reviewed through the PJM stakeholder process to meet projected future requirements. AEP and PJM use power flow analyses to simulate normal conditions, and credible single and double contingencies to determine the potential thermal and voltage impact on the transmission system in meeting the future requirements.

As discussed earlier, AEP, in coordination with PJM, will continue to develop transmission reinforcements to serve its own load areas, in coordination with PJM, to ensure compatibility, reliability and cost efficiency.

3.5.7 FERC Form 715 Information

A discussion of the eastern AEP System reliability criteria for transmission planning, as well as the assessment practice used, is provided in AEP's 2021 FERC Form 715 Annual Transmission Planning and Evaluation Report. That filing also provides pertinent information on power flow studies, transmission maps, and an evaluation and continued adequacy assessment of AEP's eastern transmission system.

As the transmission planner for AEP and its eastern subsidiaries, PJM performs all required studies to assess the robustness of the Bulk Electric System. All the models used for these studies are created by and maintained by PJM with input from all transmission owners, including AEP and its subsidiaries. Information about current cases, models, or results can be requested from PJM directly. PJM is responsible for ensuring that AEP meets all NERC transmission planning requirements, including stability of the system.

Performance standards establish the basis for determining whether system response to credible events is acceptable. Depending on the nature of the study, one or more of the following performance standards will be assessed: thermal, voltage, relay, stability, and short circuit. In general, system response to events evolves over a period of several seconds or more. Steady state conditions can be simulated using a power flow computer program. A short circuit program can provide an estimate of the large magnitude currents, due to a disturbance, that must be detected by protective relays and interrupted by devices such as circuit breakers. A stability program simulates the power and voltage swings that occur as a result of a disturbance, which could lead to undesirable generator/relay tripping or cascading outages. Finally, a post contingency power flow study can be used to determine the voltages and line loading conditions following the removal of faulted facilities and any other facilities that trip as a result of the initial disturbance.

The planning process for AEP's transmission network embraces two major sets of contingency tests to ensure reliability. The first set, which applies to both bulk and local area transmission assessment and planning, includes all significant single contingencies. The second set, which is applicable only to the Bulk Electric System, includes multiple and more extreme contingencies. For the eastern AEP transmission system, thermal and voltage performance standards are usually the most constraining measures of reliable system performance.

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Sufficient modeling of neighboring systems is essential in any study of the Bulk Electric System. Neighboring company information is obtained from the latest regional or interregional study group models, the RFC base cases, the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) power flow library, the PJM base cases, and neighboring companies themselves. In general, sufficient detail is obtained to adequately assess all events, outages, and changes in generation dispatch, which are contemplated in any given study.

3.5.8 Transmission Project Details

A detailed list and discussion of certain transmission projects undertaken by APCo, or its affiliates AEP Appalachian Transmission Company, Inc., AEP West Virginia Transmission Company, Inc. and Transource West Virginia, that have recently been completed or are presently underway in Virginia and West Virginia can be found in the Appendix as Exhibit G. In addition, several other projects outside of Virginia and West Virginia area have also been completed or are underway across the AEP System-East Zone. While they do not directly impact APCo, these projects contribute to the robust health and capacity of the overall transmission grid, which benefits all customers.

AEP's eastern transmission system is anticipated to continue to perform reliably for the upcoming peak load seasons. AEP will continue to assess the need to expand its system to ensure adequate reliability for APCo's customers. AEP anticipates that incremental transmission expansion will continue to provide for expected load growth.

3.6 Evaluation of Electric Distribution Grid Transformation Projects

Section 56-599.B.10 of the Virginia Code requires utilities, as part of their IRPs, to evaluate and consider proposing "[l]ong-term electric distribution grid planning and proposed electric distribution grid transformation projects." In evaluating these projects, the Company considered their ability to: improve system reliability and security, reduce service outages or service restoration times, accommodate or facilitate the integration of renewable electric generators, and support electric vehicle (EV) charging.

The Company is currently undertaking multiple projects that meet the statutory definition of EDGT projects including the installation of advanced metering infrastructure and distribution automation schemes.[10] As it works to repair and/or replace aging distribution infrastructure, and transition to a smart grid. APCo will continue to evaluate other such projects in the coming years. Grid Transformation projects do not typically have a demand or energy impacts associated with them. As a result, the evaluation of these types of projects is, for the large part and due to their nature, different than the evaluation of supply- and demand-side generation resources that is traditionally part of the IRP process.

3.6.1 Projects that "Enhance Electric Distribution Grid Reliability"

3.6.1.1 Vegetation Management

Vegetation management a key component in the management of a modern grid. APCo has seen improvement in the reliability indices associated with circuits subjected to enhanced vegetation management. [11]

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[10] EDGT projects are projects "associated with electric distribution infrastructure, including related data analytics equipment, that is designed to accommodate or facilitate the integration of utility-owned or customer-owned renewable electric generation resources with the utility's electric distribution grid or to otherwise enhance electric distribution grid reliability, electric distribution grid security, customer service, or energy efficiency and conservation, including advanced metering infrastructure; intelligent grid devices for real time system and asset information; automated control systems for electric distribution circuits and substations; communications networks for service meters; intelligent grid devices and other distribution equipment; distribution system hardening projects for circuits, other than the conversion of overhead tap lines to underground service, and substations designed to reduce service outages or service restoration times; physical security measures at key distribution substations; cyber security measures; energy storage systems and microgrids that support circuit-level grid stability, power quality, reliability, or resiliency or provide temporary backup energy supply; electrical facilities and infrastructure necessary to support electric vehicle charging systems; LED street light conversions; and new customer information platforms designed to provide improved customer access, greater service options, and expanded access to energy usage information." Section 56-576 of the Virginia Code.

[11] APCo performed an evaluation of cycle-based vegetation management in the pilot program approved in Case No. PUE-2011-00037. The Pilot demonstrated significant reliability benefits, such as a reduction in the number of customer minutes of interruption (CMI), an improvement in the System Average Interruption Duration Index (SAIDI), and an improvement in the System Average Interruption Frequency Index (SAIFI).

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Managing vegetation on APCo's distribution rights-of-way (ROW) underpins its strategy for maintaining distribution system reliability, as vegetation-related momentary or sustained outages are among the greatest challenges to service reliability. Distribution ROW are typically forty feet wide or less so widening the ROW to increase clearances or to remove danger trees just outside the ROW can reduce the likelihood of outages and improve grid reliability. Danger trees are those trees located just outside the ROW that have a higher risk of falling due to damage, decay, disease, or other factors. Native trees along the Company's ROW can easily exceed sixty feet tall. Trees at risk may have died or have dead branches, have poor soil conditions for the roots, or have damage from disease, insects, or animals. A number of factors including a strong wind or heavily saturated soils can cause the tree to fall across the power line resulting in an extended outage. Therefore, ROW improvement is an extremely important component of the overall capital work plan to enhance grid reliability and improve customer service.

In addition, distribution ROW improvements, including the removal of danger trees, help to reduce the impact of storm damage, which reduces service restoration times. With the deployment of communicating devices including AMI meters on the grid, the Company is better able to pinpoint the location of outage causes and the number of customers affected. By combining ROW improvement and the addition of grid devices, the Company is improving grid performance and reliability.

3.6.1.2 Distribution Automation

APCo is installing Distribution Automation Circuit Reconfiguration (DACR) on selected circuits to improve reliability. These installations reduce the number of customers affected by circuit or partial circuit outages by reconfiguring the un-faulted zones of the circuit using intelligent grid devices. The early installations of DACR utilized non-communicating "loop schemes" where the intelligent grid devices sense loss of source voltage and reconfigure to restore customers. These early schemes did not utilize communications between the devices or provide visibility to the SCADA system. These installations are now being upgraded with communicating devices, a control system to provide more intelligence in operational decisions, and inclusion in the SCADA system to provide visibility to the Distribution Dispatch Center. These upgraded circuits will be considered full DACR. There are currently fifteen circuits with non-communicating "loop schemes". Projects are planned for 2023 and 2026 to upgrade these circuits to full DACR. There are currently sixty-six circuits with full DACR. Projects are planned to install DACR on one hundred additional circuits in 2022 – 2026. Circuits are selected for DACR installation based on consideration of historical reliability, potential for improved reliability and cost. Evaluations by engineering, operations, and customer service personnel are utilized to complete the selections.

APCo is also considering the installation of new transmission lines and substations to provide new circuits that shorten the length and exposure of long radial circuits that currently have limited circuit ties. DACR can then be utilized to improve the reliability in these areas that have historically had lower than desired reliability. Historical outage results and operational experiences are used to select these areas.

3.6.2 "Advanced Metering Infrastructure" & "Expanded Access to Energy Usage" Projects

In 2017, APCo began to deploy the first phase of two-way communicating AMI meters along with the supporting infrastructure. The initial rollout was targeted at urban and suburban areas, including locations with high customer turnover such as apartment complexes and college and university communities within its Virginia service territory. At the end of first quarter 2022, 476,697 AMI meters of 560,352 total meters (85%) have been installed in Virginia. APCo plans to complete installation of AMI meters in Virginia by the end of 2022.

Among other benefits, AMI can provide customers with more information and choice about their energy use, and will provide data to help APCo more efficiently operate the system as levels of DERS and EV continue to increase. It allows for quick and safe connects, disconnects, and reconnects, benefitting both Company employees and customers. Importantly, AMI can provide increased customer education and control by allowing customers access to their data through web portals and mobile applications. Customers with an AMI meter can now view usage history and download interval data from APCo's website.

To connect DACR and AMI is selected areas of service territory, APCo has begun to install fiber optic. An additional benefit of fiber optic is that it can also be used as "middle mile" fiber to provide broadband internet. As part of a multi-year broadband expansion pilot project, Appalachian Power received approval to install up to 238 miles of fiber optic cable on our utility poles in rural Grayson County, Virginia. Our crews installed the first fiber optic cable in December 2020, and as construction progresses, internet service provider, GigaBeam Networks, is completing work needed to offer "last-mile" connectivity to Grayson County's unserved customers. In December 2021, Grayson County's Elk Creek Volunteer Fire Department became the first customer connected, recognizing the critical need for our emergency response teams to be connected. More than 6,000 customers identified in the project area are expected to have access to broadband over the next year.

3.6.3 "Energy Storage" Projects

APCo is testing new ways of combining its existing hydroelectric power with energy storage to support the grid. In 2017, APCo partnered with Greensmith Energy to integrate a 4 MW energy storage system with the Buck and Byllesby hydroelectric power plants in southwest Virginia. The hybrid system combines advanced energy storage and software with hydroelectric generation to provide ancillary services to the grid. The system is commissioned and is currently available for PJM market operations.

APCo is evaluating additional installations of energy storage systems and microgrids that support circuit-level grid stability and reliability. Circuits or parts of circuits with reliability challenges that have proven to be difficult to remedy with traditional solutions are being considered for these installations. Long radial circuits with no or limited ties to other circuits are likely candidates for selection. DACR is not an option for these circuits because there is no tie circuit for reconfiguration. APCo recently selected the Glade/Whitetop circuit as a target to install a BESS (Bulk Electric Storage System) that will demonstrate the use of a DER (Distributed Energy Resource) to provide service to customers in a defined "Island" when the normal source, Glade substation is offline, or when any distribution line overcurrent protective device upstream from the BESS interrupts power flow to customers in the defined island. This project will be proposed to the SCC in a VCEA filing in late 2022, requesting approval to move forward.

APCo is also evaluating the installation of energy storage systems that can reduce or defer the need for additional substation and/or circuit capacity. Evaluations so far have not led to any economically viable projects based on net present value of the energy storage project and the deferred traditional project.

3.6.4 "Distribution System Hardening" Projects

In 2018, a multi-year initiative to modernize and reinforce APCo's underground electrical network including the one located in Roanoke was completed. The project gives APCo the capability to monitor the networks in real time using fiber optics and cutting-edge sensor technology to capture data in five-second intervals. This gives APCo a real-time view of the downtown Roanoke distribution grid, a capability that will be needed as the distribution system becomes a more diverse, flexible system, allowing all resources to connect and manage demand at the same time.

APCo is evaluating the relocation of line sections that are at high risk due to heavy forestation and/or difficult terrain because the outages in these locations can be extended for downstream customers. Historical outage results and operational experiences are used to select these potential relocation areas. APCo has taken steps seeking to strengthen its distribution system to withstand normal weather conditions and minimize customer outage time. APCo already adheres to and carries out a number of hardening activities. The Company currently designs, builds and maintains its distribution facilities to meet and/or exceed the current National Electric Safety Code (NESC) and American National Standard Institute (ANSI) standards established for its particular geographic areas. These standards establish guidelines for the practical safeguarding of persons during the installation, operation and maintenance of electric lines and associated equipment. The NESC and ANSI standards contain the basic provisions that are considered necessary for the safety of employees and the public under normal conditions.

3.7 Journey to a Fully Integrated Planning Process

APCo believes that continuing to deliver safe, reliable, and affordable energy in the future power system will require an integrated approach between transmission, distribution, and generation resource planning. For example, local capacity needs that were previously met through transmission-connection generation might be addressed at a lower cost by distributed energy resources. Non-wire alternatives ("NWA") such as microgrid and distributed scale solar and storage might be a lower cost solution to transmission and distribution constraints than new wire assets. Resilience and safety are enhanced with better visibility over future EV deployment and distributed generation at distribution circuit level to allow the planners to plan for multiple load conditions and increase hosting capacity to integrate more green energy generation. Better visibility also allows APCO to better understand locational value of distribution generation across its network which could lead to more efficient pricing and reduce inequities among DER customers.

In meeting its mission for the power system of tomorrow, AEP created a new Regulated Investment Planning team in 2021, which brings together under one organization Integrated Resource Planning & Analysis, Transmission Planning & Analysis, Distribution Planning & Analysis, and Interconnection Services. Regulated Investment Planning works with APCo and the other AEP operating companies to develop regulated infrastructure programs across generation, transmission, and distribution to derive solutions that best meet the needs of customers.

4.0Modeling Parameters

4.1 Modeling and Planning Process – An Overview

The objective of a resource planning effort is to recommend a system resource plan that balances least-cost objectives with planning flexibility, asset mix considerations, adaptability to risk, conformance with applicable North American Electric Reliability Corporation (NERC) and RTO criteria. In addition, given the unique impact of fossil-fired generation on the environment, the planning effort must ultimately be in concert with anticipated long-term requirements as established by the EPA-driven environmental compliance planning process.

The information presented with this IRP includes descriptions of assumptions, study parameters, methodologies, and results, including the integration of traditional supply-side resources, renewable energy resources, distributed generation and DSM programs.

In general, assumptions and plans are periodically reviewed and modified and new information is incorporated as it becomes available. On-going analysis is required by multiple disciplines across APCo and AEP to ensure that market structures and governances, technical parameters, regulatory constructs, capacity supply, energy adequacy and operational reliability, and environmental mandate requirements are current to ensure optimal capacity resource planning.

Currently, fulfilling a regulatory obligation to serve native load customers represents one of the cornerstones of the APCo IRP process. Therefore, as a result, the objective function of the modeling applications utilized in this process is the development of a least-cost plan, with *cost* being more accurately described as *revenue requirement* under a traditional ratemaking construct.

That does not mean, however, that the most appropriate plan is the one with the absolute least cost over the planning horizon evaluated. Other factors were considered in the determination of the Plan. To challenge the robustness of the IRP, sensitivity analyses were performed to address these factors.

This overall process reflects consideration of options for maintaining and enhancing rate stability; economic development; and service reliability.

4.2 Methodology

The IRP process' goal is to address the gap between resource needs and current resources. Given the various assets and resources that can satisfy this expected gap, a tool is needed to evaluate the myriad of potential combinations and return an optimum solution. *Plexos®* is the primary modeling application used by APCo for identifying and ranking portfolios that address the gap between resource needs and current available resources.[12] *Plexos®* will return the optimal suite of proxy resources (portfolio) that meet

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[12] *Plexos®* is a production cost-based resource optimization model, which was developed and supported by Energy Exemplar, LLC. The *Plexos®* model is currently licensed for use in 37 countries throughout the world.

the resource needs given the cost and performance parameters around sets of potentially available proxy resources–both supply and demand side–and a scenario of economic conditions that include long-term fuel prices, capacity costs, energy costs, emission-based pricing proxies including CO_2, as well as projections of energy usage and peak demand . Portfolios created under similar pricing scenarios may be ranked on the basis of cost, or the cumulative present worth (CPW), of the resulting stream of revenue requirements. The least cost option is considered the optimum portfolio for that unique input parameter scenario.

4.3 The Fundamentals Forecast

The Fundamentals Forecast is a long-term, commodity market forecast principally based upon the assumptions contained in the Energy Information Administration's Annual Energy Outlook (AEO). It is provided to AEPSC and all AEP operating companies for purposes such as resource planning, capital improvement analyses, fixed asset impairment accounting, and others. These projections cover the electricity market within the Eastern Interconnect, the Electric Reliability Council of Texas, and the Western Electricity Coordinating Council. The Fundamentals Forecast includes, among other factors: 1) hourly, monthly and annual regional power prices (in both nominal and real dollars); 2) prices for various qualities of coals; 3) monthly and annual locational natural gas prices, including the benchmark Henry Hub; 4) nuclear fuel prices; 5) SO_2, NOx, and CO_2 burden values; 6) locational implied heat rates; 7) electric generation capacity values; 8) renewable energy subsidies; and 9) inflation factors; 10) VCEA compliance for Virginia utilities among others.

Figure 16 describes the Fundamentals Forecast components, which are sourced directly from the EIA AEO, from third party energy consultancies, or were sourced internally.

Figure 16: FUNDAMENTALS FORECAST COMPONENTS

Forecast Components	EIA	Other	Source
Economy; Inflation/GDP deflators	✓		EIA Reference case
Generating Reserve Margins		✓	RTO Requirements
Electric Load		✓	AEP Load Forecasting
Electric Load shapes		✓	AEP Fundamentals
Solar/Wind production shapes by area		✓	NREL
Coal; Delivered price to EIA regions	✓	✓	EIA Reference case FOB prices + AEP Fundamentals
Natural gas price; Henry Hub	✓		EIA Reference case
Natural gas price; Locational values	✓	✓	EIA Reference case - Henry Hub + AEP Fundamentals
Natural gas supply; Lower 48 production	✓		EIA Reference case
Natural gas demand (Incl. losses)	✓		EIA Reference case
Natural gas; net pipeline/LNG exports	✓		EIA Reference case
Oil price, WTI	✓		EIA Reference case
Fuel Oil price; locational values	✓	✓	EIA Reference case - WTI + AEP Fundamentals
Uranium prices		✓	AEP Fundamentals
Other Fuel(Biofuel, etc...)	✓		EIA Reference case
New gen unit options and capital costs	✓		EIA Reference case
Existing gen units	✓		EIA Reference case
Announced new gen units	✓		EIA Reference case
Aged-out retirements of existing gen units	✓		EIA Reference case
Gen unit maintenance schedule		✓	AEP Fundamentals
Gen unit outages		✓	AEP Fundamentals
Unit-level emission rates; CO_2, SO_2, NO_x		✓	US EPA CEMS data
Application of a CO_2 burden		✓	AEP Environmental
REC		✓	AEP Regulatory Forecast
PTC	✓		EIA Reference case
ITC	✓		EIA Reference case
State-mandated Renewable Portfolio Standards		✓	AEP Environmental
Reporting parameters; Peak/Off-Peak/NERC Holidays		✓	PJM/SPP/other RTO and/or internal guidelines
Transmission/links between Zones		✓	AEP Fundamentals

The Fundamentals Forecasts incorporates requirements of the Virginia Clean Energy Act and the Regional Greenhouse Gas Initiative (RGGI) for both APCo and Dominion:

- Including Virginia in the RGGI, applying RGGI CO_2 prices through 2027 before switching to an assumption of a higher $15/metric ton national standard in 2028
- Applying the Virginia RPS program to Phase I and Phase II utilities within the state
- Retiring all fossil units named in the VCEA by stated retirement dates
- Retiring all remaining Phase I fossil units by 2050 and Phase II fossil units by 2045
- Including the resource additions required for Dominion under the VCEA based upon the Company's understanding of those requirements

The Aurora Energy Market Simulation Model was utilized to create a reasonable proxy for the EIA AEO while providing the level of detail necessary for downstream consumption.

The Aurora model iteratively generates zonal, but not company-specific, long-term capacity expansion plans, annual energy dispatch, fuel burns and emission totals from inputs including fuel, load, emissions, and capital costs, among others. Ultimately, Aurora creates a long-term forecast of the market in which a utility would be operating. AEPSC also has ample energy market research information available for its reference, which includes third-party consultants, industry groups, governmental agencies, trade press, investment community, AEP-internal expertise, various stakeholders, and others. The Aurora model is widely used by utilities for integrated resource and transmission planning, power cost analysis and detailed generator evaluation. The database includes approximately 25,000 electric generating facilities in the contiguous United States, Canada, and Baja Mexico. These generating facilities include wind, solar, biomass, nuclear, coal, natural gas, and oil. A licensed online data provider, ABB Velocity Suite, provides up-to-date information on markets, entities and transactions along with the operating characteristics of each generating facility, which are subsequently exported to the Aurora model.

4.3.1 Commodity Pricing Scenarios

Four commodity pricing scenarios were developed to support the resource plans for APCo including a Base High and Low Scenario and an alternate scenario included only projected RGGI carbon prices through the end of the forecasting period, with no national carbon burden assumed. The Base, High and Low Scenarios included carbon prices associated with the Regional Green House Gas Initiative (RGGI) through 2027, switching to a national $15/metric ton carbon burden beginning in 2028, which escalated at 3.5% annually through the end of the forecasting period.

The annual results from each scenario are shown in Exhibit E and include on-peak and off-peak energy prices, natural gas prices, coal prices, CO_2 prices and capacity prices.

4.4 Demand-Side Management (DSM) Program Screening & Evaluation Process

4.4.1 Overview

The process for evaluating DSM impacts for APCo is divided into two components: "existing DSM programs" and "incremental DSM programs." Existing DSM programs are those that are known or are reasonably well-defined, and follow a pre-existing process for screening and determining ultimate regulatory approval. The impacts of APCo's existing DSM programs are propagated throughout the long-term load forecast. Incremental DSM program impacts which are, naturally, less-defined, are developed with a dynamic modeling process using more generic cost and performance parameter data.

The potential incremental DSM programs were developed and ultimately modeled based on input from APCo's internal subject matter experts and the Electric Power Research Institute's (EPRI) "2014 U.S. Energy Efficiency Potential Through 2035" report with updates from the 2019 Technical Update of this same report. This report served as the basic underpinning for the establishment of potential EE "bundles", developed for residential and commercial customers that were then introduced as a resource option in the *Plexos*® optimization model. In order to reflect potential energy savings available in the industrial sector, the end-usage associated with lighting was combined for both the commercial and industrial sectors. The indoor and outdoor lighting bundles shown below in Table 8 reflect the potential energy savings for both sectors.

4.4.2 Achievable Potential (AP)

The amount of available EE is typically described in three sets: technical potential, economic potential, and achievable potential. The previously-cited EPRI report breaks down the achievable potential into a High Achievable Potential (HAP) and an Achievable Potential (AP), with the HAP having a higher utility cost than the AP. Briefly, the technical potential encompasses all known efficiency improvements that are possible, regardless of cost, and thus, whether or not it is cost-effective (i.e., all EE measures would be adopted if technically feasible). The logical subset of this pool is the economic potential. Most commonly, the total resource cost test is used to define economic potential. This compares the avoided cost savings achieved over the life of a measure/program with the cost to implement it, regardless of who paid for it and regardless of the age and remaining economic life of any system/equipment that would be replaced (i.e., all EE measures would be adopted if economic). The third set of efficiency assets is that which is achievable. As highlighted above, the HAP is the economic potential discounted for market barriers such as customer preferences and supply chain maturity; the AP is additionally discounted for programmatic barriers such as program budgets and execution proficiency.

Of the total technical potential, typically only a fraction is ultimately achievable and only then over time due to the existence of market barriers. The question of how much effort and money is to be deployed towards removing or lowering the barriers is a decision made by state governing bodies (legislatures, regulators or both).

The AP range is typically a fraction of the economic potential range. This achievable amount must be further split between what can or should be accomplished with utility-sponsored programs and what should fall under codes and standards. Both amounts are represented in this IRP as reductions to what would otherwise be in the load forecast.

4.4.3 Evaluating Incremental Demand-Side Resources

The *Plexos*® model allows the user to input incremental EE, DER, DR and VVO as resources, thereby considering such alternatives in the model on equal-footing with more traditional "supply-side" generation resource options. The Company also considered DSM as a reduction to load and is further discussed in Section 5.3.1.

4.4.3.1 Incremental Energy Efficiency (EE) Modeled

Economic demand-side EE modeled over and above existing EE program offerings in the load forecast include potential savings consistent with the APCO 2021 Energy Efficiency plan and current demand response resources as a Going-In assumption from 2022-2026 with similar EE resources available for economic selection by the model beginning in 2027.

To develop these EE resources modeled, the EPRI report and the APCo DSM team provided information on a multitude of current and anticipated end-use measures including measure costs, energy savings, market acceptance ratios and program implementation factors. APCo utilized this data to develop "bundles" of future EE activity for the demographics and weather-related impacts of its service territory. Table 7 lists the individual measure categories considered for both the residential and commercial sectors.

Table 7. Energy Efficiency Measure Categories by Sector

Residential Measures	Ceiling Insulation	Wall Insulation	Windows
	Dish Washer	Refrigerator	Freezer
	Television	Heat Pump	Lighting
	Central AC	Clothes Washer	Clothes Dryer
	Water Heating	Behavioral	
Commercial Measures	Heating Measures	Cooling Measures	Chiller Space Cooling
	Water Heating	Commercial Ventilation	Refrigeration
	Personal Computers	Servers	Indoor Lighting*
	Outdoor Lighting*		

* Indoor and outdoor lighting categories apply to both commercial and industrial sectors to account for potential EE savings in the industrial sector.

From this information and recent APCo DSM activity, APCo developed proxy EE bundles for residential, commercial and industrial customer classes to be modeled within *Plexos*®. These bundles are based on measure characteristics identified within the EPRI report, recent APCo DSM planning, and APCo customer usage.

Table 8 and Table 9 list the energy and cost profiles of EE resource "bundles" for the residential and commercial sectors, respectively. In order to reflect the potential EE savings available in the industrial sector, each of the lighting bundles shown in Table 9 includes potential savings for both commercial and industrial customers.

Table 8. Incremental Residential Energy Efficiency (EE) Bundle Summary

Bundle	Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2022-2026	Yearly Potential Savings (MWh) 2027-2031	Yearly Potential Savings (MWh) 2032-2036	Yearly Potential Savings (MWh) 2037-2041
Thermal Shell - AP	$0.21	6,621	2,794	3,120	2,824
Thermal Shell - HAP	$0.31	20,514	54	0	0
Heating/Cooling - AP	$0.68	49,323	7,365	0	0
Heating/Cooling - HAP	$0.96	7,576	0	0	0
Water Heating - AP	$0.24	34,877	11,711	13,000	6,265
Water Heating - HAP	$0.35	82,827	10,498	10,391	0
Appliances - AP	$0.22	33,242	3,018	3,133	2,460
Appliances - HAP	$0.31	7,449	0	0	0
Lighting - AP	$0.08	1,669	0	0	0
Lighting - HAP	$0.13	1,103	0	0	0
Behavioral Programs	$0.04	23,137	0	0	0

Table 9. Incremental Commercial & Industrial (Lighting) Energy Efficiency (EE) Bundle Summary

Bundle	Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2022-2026	Yearly Potential Savings (MWh) 2027-2031	Yearly Potential Savings (MWh) 2032-2036	Yearly Potential Savings (MWh) 2037-2041
Heat Pump - AP	$9.00	2,985	0	0	0
Heat Pump - HAP	$13.49	199	0	0	0
HVAC Equipment - AP	$0.16	2,932	0	0	0
HVAC Equipment - HAP	$0.24	1,752	0	0	0
Indoor Screw-In Lighting - AP	$0.01	2,872	0	0	0
Indoor Screw-In Lighting - HAP	$0.02	1,219	0	0	0
Indoor HID/Fluor. Lighting - AP	$0.11	17,883	1,897	0	0
Indoor HID/Fluor. Lighting - HAP	$0.17	1,987	0	0	0
Outdoor Lighting - AP	$0.23	6,722	1,144	0	0
Outdoor Lighting - HAP	$0.34	7,469	0	0	0

Each EE bundle is a stand-alone resource within the model with its own unique cost and potential energy and demand savings.

4.4.3.2 Volt VAR Optimization (VVO) Modeled

Potential future VVO circuits incremental to those part of the approved pilot program considered for modeling varied in relative cost and energy-reduction effectiveness. The circuits were grouped into 14 "tranches" based on the relative potential peak demand and energy reduction of each tranche of circuits. The *Plexos*® model was able to pick the most cost-effective tranches first and add subsequent tranches as merited. Table 10 details all of the tranches offered into the model and the respective cost and performance of each.

Table 10. Volt VAR Optimization (VVO) Tranche Profiles

Tranche	No. of Circuits	Capital Investment	Annual O&M	Demand Reduction (kW)	Energy Reduction (MWh)
1	36	$12,600,000	$378,000	11,172	45,996
2	36	$12,600,000	$378,000	9,639	39,684
3	36	$12,600,000	$378,000	8,799	36,227
4	36	$12,600,000	$378,000	8,298	34,163
5	36	$12,600,000	$378,000	7,826	32,222
6	36	$12,600,000	$378,000	7,458	30,705
7	36	$12,600,000	$378,000	7,126	29,340
8	36	$12,600,000	$378,000	6,884	28,343
9	36	$12,600,000	$378,000	6,629	27,292
10	36	$12,600,000	$378,000	6,435	26,493
11	36	$12,600,000	$378,000	6,186	25,470
12	36	$12,600,000	$378,000	5,909	24,329
13	36	$12,600,000	$378,000	5,849	24,081
14	36	$12,600,000	$378,000	5,473	22,532

4.4.3.3 Demand Response (DR) Modeled

Incremental levels of DR was included in the IRP model for the entire operating company. The DR resource is modeled based on the Residential Bring Your Own Thermostat (BYOT) program where customers would own and self-install Wi-Fi enabled thermostats, which will communicate with APCo. Table 11 shows the DR resource offered into the model. A single block of DR resources were available beginning in 2022 with a service life of seven years.

Table 11. Demand Response Resource

Sector	Participants	Demand Savings (kW)	Energy Savings (kWh)	Installation Cost	Annual Cost	Total First Year Cost	Service Life (Years)
Residential / Commercial	1,000	2,000	13,000	55,000	478,000	533,000	7

4.4.3.4 Distributed Energy Resource Evaluation

DER resources were evaluated assuming a residential rooftop solar resource as the primary distributed resource. To determine the level of customer penetration APCo referenced a forecast conducted by IHS Inc. on behalf of PJM[13]. This forecast considered the level of solar photovoltaic (PV) installations over the period of 2022-2037. Figure 17 below depicts the forecast of DERs in APCo over the planning period. To determine the level of DER penetration APCo created a forecast using existing levels of rooftop solar, as well as the incremental additions from PJM's forecast.

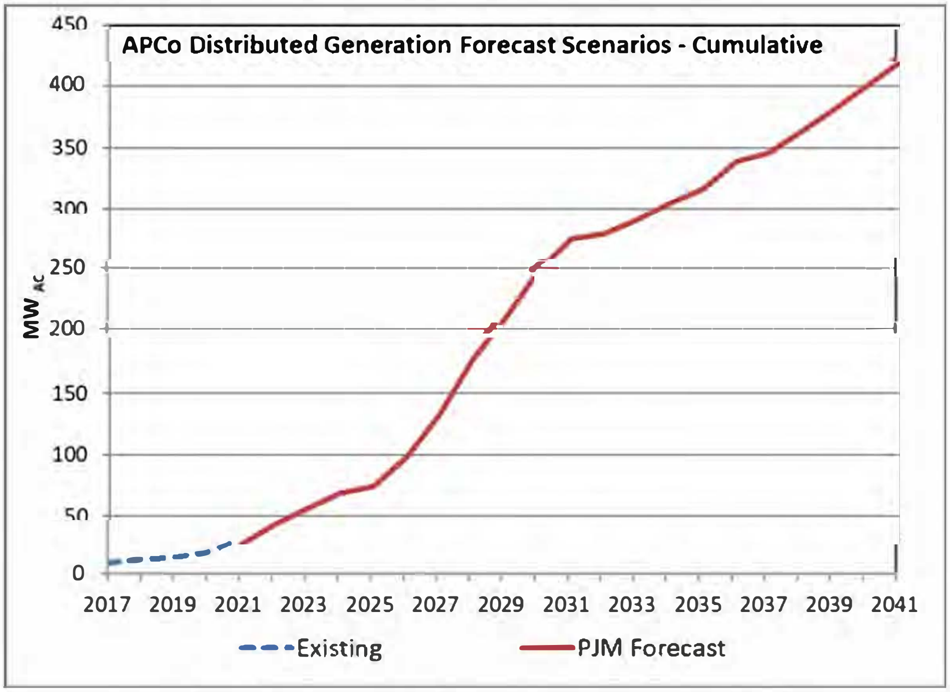


Figure 17. Cumulative DER Additions/Projections for APCo

4.4.3.5 Optimizing Incremental Demand-side Resources

The *Plexos®* software views demand-side resources as non-dispatchable "generators" that produce energy similar to non-dispatchable supply-side generators such as wind or solar. Thus, the value of each resource is impacted by the hours of the day and time of the year that it "generates" energy.

4.5 Supply-side Resource Options

4.5.1 Capacity Resource Options

New construction supply-side alternatives were modeled to represent peaking and base-load/intermediate capacity resource options. To reduce the number of modeling permutations in Plexos®, the available technology options were limited to certain representative unit types. However, it is important to note that alternative technologies with comparable cost and performance characteristics may ultimately be substituted should technological or market-based profile changes warrant.

[13] 2022 State Zonal Breakdown – IHS Capacity at Peak Solar and Battery - Post Meeting available at http://www.pjm.com/-/media/committees-groups/subcommittees/las/2021/20211206/20211206-2022-state-zonal-breakdown-ihs-capacity-at-peak-solar-and-battery-post-meeting.ashx

When applicable, APCo may take advantage of economic market capacity and energy opportunities. Prospectively, these opportunities could take the place of currently planned resources and will be evaluated on a case-by-case basis.

4.5.2 New Supply-side Capacity Alternatives

Small modular nuclear reactor technologies, natural gas base/intermediate and peaking generating technologies were considered in this IRP as well as large-scale solar, wind and energy storage resources. Further details on these technologies are available in Exhibit B of the Appendix. To reduce the computational problem size within *Plexos*®, the number of alternatives explicitly modeled was reduced through an economic screening process which analyzed various supply options and developed a quantitative comparison for each duty-cycle type of capacity (i.e., base-load, intermediate, and peaking) on a thirty year levelized basis. The options were screened by comparing levelized annual busbar costs over a range of capacity factors.

The best of class technology, for each duty cycle, determined by this screening process was explicitly modeled in *Plexos*®. These generation technologies were intended to represent reasonable proxies for each capacity type (base-load, intermediate, peaking). Subsequent substitution of specific technologies could occur in any later plan, based on emerging economic or non-economic factors not yet identified.

AEP continually tracks and monitors changes in the estimated cost and performance parameters for a wide array of generation technologies. Access to industry collaborative organizations such as EPRI and the Edison Electric Institute, AEP's association with architect and engineering firms and original equipment manufacturers, as well as its own experience and market intelligence, provides AEP with current estimates for the planning process. Table 12 offers a summary of the most recent technology performance parameter data developed. Additional parameters such as the quantities and rates of solid waste production, hazardous material consumption, and water consumption are significant; however, the options which passed the screening phase and were included in *Plexos*® were natural gas facilities which generally have limited impacts on these areas of concern.

Table 12. New Generation Technology Options with Key Assumptions

Type	Capability (MW) (e)			Installed Cost (d,f)	Capacity Factor	LCOE (g)
	Std. ISO	Summer	Winter	($/kW)	(%)	($/MWh) [1]
Base Load						
SMALL MODULAR REACTOR NUCLEAR POWER PLANT, 600 MW	600	600	600	7,300	90	129.0
ULTRA-SUPERCRITICAL COAL WITH 90% CO2 CAPTURE, 650 MW	650	630	690	7,200	75	170.8
COMB TURBINE H CLASS, COMB-CYCLE SINGLE SHAFT W/90% CO2 CAPTURE, 430 MW	380	370	390	2,600	75	84.2
COMB TURBINE H CLASS, 1100-MW COMBINED CYCLE(c)	1,030	1,010	1,070	1,100	75	55.6
COMB TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT, 430 MW(c)	420	410	440	1,200	75	58.9
Peaking						
COMB TURBINE F CLASS, 240-MW SIMPLE CYCLE(c)	230	230	250	800	25	95.0
COMB TURBINES AERODERIVATIVE, 100-MW SIMPLE CYCLE(c)	110	100	110	1,300	25	128.4
INTERNAL COMBUSTION ENGINES, 20 MW(c)	20	20	20	2,100	25	173.9
Intermittent						
BATTERY ENERGY STORAGE SYSTEM, 50 MW / 200 MWH(c)	50	50	50	1,470	25	157.0
SOLAR PHOTOVOLTAIC WITH BATTERY ENERGY STORAGE SYSTEM, 150 MWx200 MWh (h)	150	150	150	1,890	20	97.6
ONSHORE WIND, LARGE PLANT FOOTPRINT, 200 MW (i)	200	200	200	1,540	35	41.2
SOLAR PHOTOVOLTAIC, 150 MWAC(h)	150	150	150	1,380	22	55.8

[1] Levelized cost of energy based on capacity factors shown in table

4.5.3 Base/Intermediate Alternatives

Baseload electricity is the minimum level of electricity demand in the system. Traditionally, baseload electricity demand is met by baseload power plants optimized for continuous running. Baseload plants include coal and nuclear plants which generally cannot vary their outputs quickly. However, the electricity supply mix is changing with increased intermittent renewable generation. Furthermore, regulations and changing customers' needs have made new coal and nuclear plants economically infeasible. Coal base-load options were evaluated by APCo but were not included in the *Plexos*® resource optimization modeling analyses.

Intermediate power plants adjust outputs as electricity demand fluctuates. This role has been traditionally met by older and relatively less efficient power plants. But as these power plants retire, new capacity will be needed. For this IRP, natural gas combined cycle is considered as a resource option for intermediate power plants..

4.5.3.1 Small Modular Reactor (SMR)

Small Modular Reactor (SMR) is a new generation of nuclear fission technology utilizing smaller reactor designs, module factory fabrication and passive safety features. The U.S. Department of Energy supports the design, certification, and commercialization of these resources. Key features of an SMR include:

- Small physical footprints and compact designs;
- Limited on-site preparation, leading to faster construction time and scalability;
- Siting flexibility including sites previously occupied by coal-fired plants; and
- Passive safety features, allowing the reactor to safely shutdown in an emergency without requiring human interventions.

SMR can be a zero-carbon alternative for providing base-load electricity without CO_2 emissions. Its siting flexibility and improved safety features allow it to be sited closer to demand centers, reducing transmission investments. However, it is subject to the same economic challenges facing base-load power plants today, namely the erosion in value of base-load electricity as a result of increased intermittent generation.

4.5.3.2 Natural Gas Combined Cycle (NGCC)

An NGCC plant combines a steam cycle and a combustion gas turbine cycle to produce power. Waste heat (~1,100°F) from one or more combustion turbines passes through a HRSG producing steam. The steam drives a steam turbine generator which produces about one-third of the NGCC plant power, depending upon the gas-to-steam turbine design "platform," while the combustion turbines produce the other two-thirds.

The main features of the NGCC plant are high reliability, reasonable capital costs, operating efficiency (at 45-63% Lower Heating Value), low emission levels, small footprint and shorter construction periods than coal-based plants. In the past 8 to 10 years, NGCC plants were often selected to meet new intermediate and certain base-load needs. Although cycling duty is typically not a concern, an issue faced by NGCC when load-following is the erosion of efficiency due to an inability to maintain optimum air-to-fuel pressure and turbine exhaust and steam temperatures. Methods to address these include:

- Installation of advanced automated controls.
- Supplemental firing while at full load with a reduction in firing when load decreases. When supplemental firing reaches zero, fuel to the gas turbine is cutback. This approach would reduce efficiency at full load, but would likewise greatly reduce efficiency degradation in lower-load ranges.
- Use of multiple gas turbines coupled with a waste heat boiler that will give the widest load range with minimum efficiency penalty.

At this time, the Company considers both “1x1” and “2x1” combined cycle configurations to be the best fit as they most align with historical operating experience and expected output relative to the overall Company’s needs.

4.5.4 Peaking Alternatives

Peaking generating sources provide needed capacity during high-use peaking periods and/or periods in which significant shifts in the load (or supply) curve dictate the need for “quick-response” capability. The peaks occur for only a few hours each year and the installed reserve requirement is predicated on a one day in ten-year loss of load expectation, so the capacity dedicated to serving this reliability function can be expected to provide relatively little energy over an annual load cycle. As a result, fuel efficiency and other variable costs applicable to these resources are of lesser concern. Rather, this capacity should be obtained at the lowest practical installed/fixed cost, despite the fact that such capacity often has very high energy costs. Ultimately, such “peaking” resource requirements are manifested in the system load duration curve.

In addition, in certain situations, peaking capacity such as combustion turbines can provide backup and some have the ability to provide emergency, Black Start, capability to the grid.

4.5.4.1 Simple Cycle Combustion Turbines (NGCT)

In “industrial” or “frame-type” Combustion Turbine (CT) systems, air compressed by an axial compressor is mixed with fuel and burned in a combustion chamber. The resulting hot gas then expands and cools while passing through a turbine. The rotating rear turbine not only runs the axial compressor in the front section but also provides rotating shaft power to drive an electric generator. The exhaust from a combustion turbine can range in temperature between 800 and 1,150 degrees Fahrenheit and contains substantial thermal energy. A CT system is one in which the exhaust from the gas turbine is vented to the atmosphere and its energy lost, *i.e.,* not recovered as in a combined-cycle design. While not as efficient (at 30-35% Lower Heating Value), they are inexpensive to purchase, compact, and simple to operate.

4.5.4.2 Aeroderivatives (AD)

Aeroderivatives (AD) are aircraft jet engines used in ground installations for power generation. They are smaller in size, lighter weight, and can start and stop quicker than their larger industrial or "frame" counterparts. For example, the GE 7E frame machine requires 20 to 30 minutes to ramp up to full load while the smaller LM6000 aeroderivative only needs 10 minutes from start to full load. However, the cost per kW of an aeroderivative is considerably higher than a frame machine.

The AD performance operating characteristics of rapid startup and shutdown make the aeroderivatives well suited to peaking generation needs. ADs can operate at full load for a small percentage of the time allowing for multiple daily startups to meet peak demands, compared to frame machines which are more commonly expected to start up once per day and operate at continuous full load for 10 to 16 hours per day. The cycling capabilities provide ADs the ability to backup variable renewables such as solar and wind. This operating characteristic is expected to become more valuable over time as: A) the penetration of variable renewables increases; B) base-load generation processes become more complex limiting their ability to load-follow and; C) more intermediate coal-fueled generating units are retired from commercial service.

AD units weigh less than their industrial counterparts allowing for skid or modular installations. Efficiency is also a consideration in choosing an AD over an industrial turbine. AD units in the less than 100MW range are more efficient and have lower heat rates in simple cycle operation than industrial units of equivalent size. Exhaust gas temperatures are lower in AD units.

4.5.4.3 Reciprocating Engines (RE)

The use of Reciprocating Engines (RE) or internal combustion engines has increased over the last twenty years. According to EPRI, in 1993 about 5% of the total RE units sold were natural gas-fired spark ignition engines and post 2000 sales of natural gas-fired generators have remained above 10% of total units sold worldwide.

Improvements in emission control systems and thermal efficiency have led to the increased utilization of natural gas-fired RE generators incorporated into multi-unit power generation stations for main grid applications. RE generators' high efficiency, flat heat rate curves and rapid response make this technology very well suited for peaking and intermediate load service and as back up to intermittent generating resources. Compared to AD units, RE generators generally have shorter start-time durations. Additionally, the fuel supply pressure required is in the range of 40 to 85 psig; this lower gas pressure gives this technology more flexibility when identifying locations. A further advantage of RE generators is that power output is less affected by increasing elevation and ambient temperature as compared to gas turbine technology. Also, a RE plant generally would consist of multiple units, which will be more efficient at part load operation than a single gas turbine unit of equivalent size because of the ability to shut down units and to operate the remaining units at higher load. Common RE unit sizes have generally ranged from 8MW to 18MW per machine with heat rates in the range of 8,100 –to- 8,600 Btu/kWh (Higher Heating Value).

Regarding operating cost, RE generators have a somewhat greater variable O&M than a comparable gas turbine; however, over the long term, maintenance costs of RE are generally lower because the operating hours between major maintenance can be twice as long as gas turbines of similar size.

4.5.4.4 Energy Storage

The modeling of Energy Storage as a Peaking resource option is becoming a more common occurrence in IRPs. In recent years Lithium-ion battery technology has emerged as the fastest growing platform for stationary storage applications. The stand-alone Energy Storage resource modeled in this plan is a Lithium-ion storage technology and has a nameplate rating of 50 MW/200 MWh, with a round trip efficiency of 82.3%. The modeling of Energy Storage utilized the values shown in Table 12, with the nameplate rating adjusted from 50 MW to 25 MW to align with the storage levels in the Commission's order regarding the interim requirements.

4.5.5 Renewable Alternatives

Renewable generation alternatives use energy sources that are naturally occurring (wind, solar, hydro or geothermal). Until recently, development of renewable resources was largely driven primarily by resource availability, renewable portfolio standards, and supporting tax policies. These drivers remain in place today, and when coupled with reduced costs and increased technology capacity factors, makes renewable technologies highly competitive with traditional fossil resources on a cost of energy basis. In this IRP, two primary technology types, Solar and On-Shore Wind, are considered.

4.5.5.1 Effective Load Carrying Capability

Renewable energy resources, because of their intermittent nature, typically provide more energy value than capacity value, and PJM continues to refine its guidance on the Effective Load Carrying Capability (ELCC) for intermittent resources. In general, under the current PJM draft guidance, as intermittent resources continue to increase in relation to the total of all PJM resources, the planning capacity credit of new renewable resources added to the system will decline. The Company referred to PJM's December 2021 ELCC Report[14] to inform the plan for intermittent resource contributions to the Company's capacity obligations. A summary chart of the ELCC levels assumed in this plan is shown in Figure 18. PJM's December 2021 ELCC Report did not produce projections beyond 2032. For the Company's analysis, the 2032 ELCC values were held constant until the end of the planning horizon.

[14] https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-report-december-2021.ashx

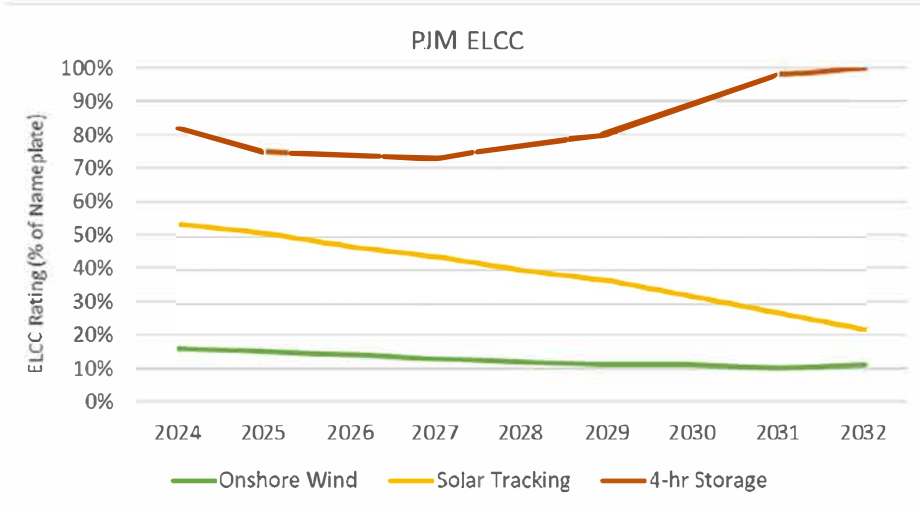


Figure 18. PJM Effective Load Carrying Capability

4.5.5.2 Solar

4.5.5.2.1 Large-Scale Solar

Solar power comes in two forms to produce electricity: concentrating and photovoltaics. Concentrating solar — which heats a working fluid to temperatures sufficient to generate steam to power a turbine — produces electricity on a large scale and is similar to traditional centralized supply assets in that respect. Photovoltaics can more easily be distributed throughout the grid and are a scalable resource that, for example, can be as small as a few kilowatts or as large as 500MW. This IRP assumes its solar resources will be photovoltaic and geographically located in Virginia.

Multiple solar resource types were made available in the *Plexos* model with some limits on the rate with which they could be selected. In the IRP modeling, owned solar, PPA solar and hybrid solar options were included as alternatives. Owned and PPA solar resources were available in yearly quantities amounting to 600 MW. Hybrid Solar systems include a Solar PV plant with a 4 hour closed loop battery storage system associated with it. For this analysis, a 150 MW_{ac} solar plant was modeled, coupled with a 50 MW (200 MWh) Li-Ion Battery Energy Storage system in quantities up to 450 MW per year.

Large-scale solar resources were available starting in 2026 (commercial operation date 12/31/25). The Company relied on information from its 2021 Renewable RFP to model prospective owned solar costs for assets to be placed in service in 2026. The Company included 2 owned options in the modeling, Tier 1 and Tier 2 with Tier 1 informed from lower costs bids and Tier 2 informed by the other bids received. Panel degradation was incorporated by modeling a levelized capacity factor of 23.97% for Tier 1 and 21.78% for Tier 2. The non-levelized capacity factor was 25.3% for Tier 1 and 23% for Tier 2. PPA resources were priced at a levelized cost of energy (LCOE) 8% lower than Tier 1 owned resources, informed by the 2021 Renewable RFP. Figure 19 illustrates the forecasted Utility Tier 1, Tier 2, and PPA Solar LCOE through time. The costs included in these estimates include all costs that would be expected, including a return on rate base, depreciation, land leases, operations and maintenance expense, property taxes, insurance, asset retirement costs, and normalization of the solar investment tax credit (ITC). The property tax and land lease assumptions are tailored to this analysis based on the Company's experience with tax rates in its service territory, and from evaluating specific resources located in both Virginia and in other PJM states.

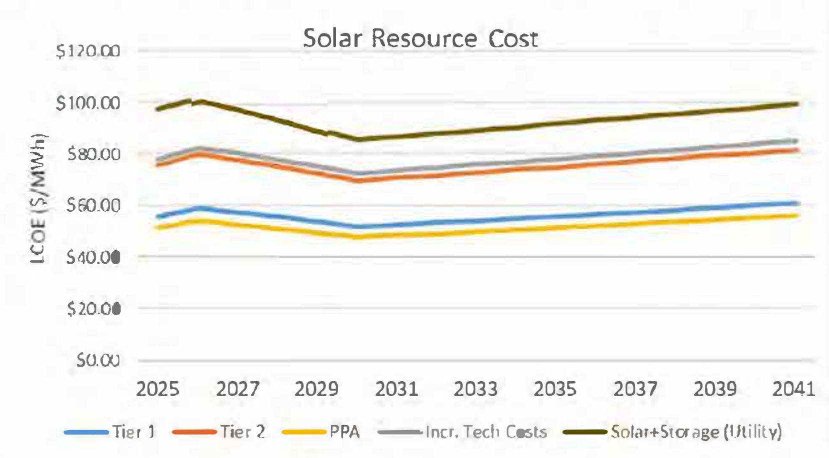


Figure 19. Large-Scale Solar Pricing Tiers

4.5.5.3 On-shore Wind

Large-scale wind energy is generated by turbines ranging from 2 to 5 MW. Typically, multiple wind turbines are grouped in rows or grids to develop a wind turbine power project which requires only a single connection to the transmission system. Location of wind turbines at the proper site is particularly critical as not only does the wind resource vary by geography, but also its proximity to a transmission system with available capacity, which will factor into the cost.

For modeling purposes, owned and PPA Virginia domiciled wind resources are first made available to the model in 2026 (commercial operation date 12/31/25), due to the amount of time necessary to secure resources and obtain any necessary regulatory approvals. Wind resources were modeled with a 35% capacity factor informed from NREL and build costs were informed by Bloomberg New Energy Finance's (BNEF) 2H 2020 U.S. Renewable Energy Market Outlook. Figure 20 shows the forecasted LCOE prices of wind resources assumed for the IRP. The wind pricing reflects the value of Federal Production Tax Credits (PTCs) through 2025 after which they are currently scheduled to retire. PPA resources were priced at an LCOE 8% lower than owned resources.

Figure 20. Levelized Cost of Electricity of Wind Resources (Nominal $/MWh)

4.5.5.4 Hydro

The available sources of, particularly, larger hydroelectric potential have largely been exploited and those that remain must compete with the other uses, including recreation and navigation. The potentially lengthy time associated with environmental studies, Federal Army Corp of Engineer permitting, high up-front construction costs, and environmental issues (fish and wildlife) make new hydro prohibitive at this time. As such, no incremental hydroelectric resources were considered in this IRP.

4.5.5.5 Renewable Energy Credits (RECs)

The Company included RECs as a RPS energy compliance option in the Plexos® modeling, allowing the model to choose whether to build REC qualifying physical resources or purchase market RECs based on economics. REC's were available as an option beginning in 2022. A third party forecast provided by S&P Global , as shown in Figure 21, was used for the base REC price forecast in all portfolios. The Company also evaluated sensitivities with REC prices 50% higher and 50% lower than the base costs referenced in Figure 21 and is further discussed in section 5.2.2.3.

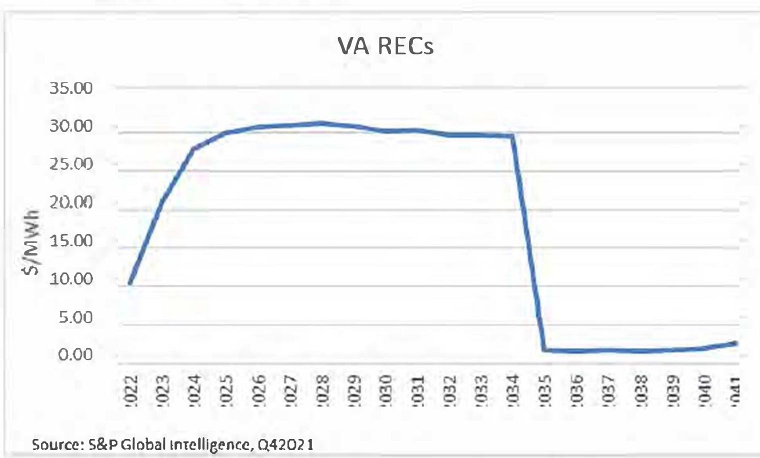


Figure 21. REC Pricing

4.6 Integration of Supply-Side and Demand-Side Options within *Plexos*® Modeling

Each supply-side and demand-side resource is offered into the *Plexos*® model on an equivalent basis. Each resource has specific values for capacity, energy production (or savings), and cost. The *Plexos*® model selects resources in order to reduce the overall portfolio cost, regardless of whether the resource is on the supply- or demand-side, and regardless of whether or not there is an absolute capacity need. In other words, the model selects resources that lower costs to customers even if the reliability requirement is already satisfied.

4.6.1 Optimization of Expanded DSM Programs

As described in Section 4.4.3, EE and VVO options that would be incremental to the current programs were modeled as resources within *Plexos*®. In this regard, they are "demand-side power plants" that produce energy according to their end use load shape. They have an initial (program) cost with *no* subsequent annual operating costs. Likewise, they are "retired" at the end of their useful (EE measure) lives.

4.7 Market Alternatives

As discussed above, the IRP considers proxy supply- and demand-side resource options to develop an optimum solution based on the inputs provided. This includes the Company's fundamental forecast discussed in section The Fundamentals Forecast 4.3 which includes costs for capacity and energy used as proxies for market based resources and shown in Appendix, Exhibit E.

In developing the input resources' costs and performance characteristics, APCo works with various subject matter experts both within and external to the company to develop reasonable proxy resources to be modeled in the IRP. Typically, the experts will use various approaches to develop the proxy estimates. These approaches for example, could include market comparable, recent internal projects and industry collaboration. The results of this analysis are included in Table 12 shown in section 4.5.2

Furthermore, the Company, by itself and through its support from AEPSC, has extensive RFP experience for the procurement of the new resources. AEPSC has previously performed RFPs in Virginia on behalf of APCo, and has also performed RFPs for AEP's other vertically-integrated utilities including KPCo, I&M, SWEPCO, PSO that have resulted in the procurement, or currently planned procurement, of thousands of megawatts of renewable resources. The Company has extensive experience analyzing purchase and sale agreements for both utility-owned and contracted renewables. The Company continues to monitor the market for both owned and power purchase agreement (PPA) resources to be informed of competitive pricing alternatives.

5.0 Resource Portfolio Modeling

5.1 The *Plexos*® Model - An Overview

Plexos® LP long-term optimization model, also known as "LT Plan®," served as the basis from which the APCo-specific capacity requirement evaluations were examined and recommendations were made. The LT Plan® model finds the optimal portfolio of future capacity and energy resources, including DSM additions, which minimizes the CPW of a planning entity's generation-related variable and fixed costs over a long-term planning horizon.

Plexos® accomplishes this by using an objective function which seeks to minimize the aggregate of the following capital and production-related (energy) costs of the portfolio of resources:

- Fixed costs of capacity additions, *i.e.,* carrying charges on incremental capacity additions (based on an APCo-specific, weighted average cost of capital), and fixed O&M;
- fixed costs of any capacity purchases;
- program costs of (incremental) DSM alternatives;
- variable costs associated with APCo generating units. This includes fuel, start-up, consumables, market replacement cost of emission allowances and/or carbon 'tax,' and variable O&M costs;
- distributed, or customer-domiciled, resources which were effectively valued at the equivalent of a full-retail "net metering" credit to those customers; and
- a 'netting' of the production revenue earned in the PJM power market from APCo's generation resource sales *and* the cost of energy – based on unique load shapes from PJM purchases necessary to meet APCo's load obligation.

Plexos® executes the objective function described above while abiding by the following constraints:

- Minimum and maximum reserve margins;
- resource additions (i.e., maximum units built);
- age and lifetime of power generation facilities;
- operation constraints such as ramp rates, minimum up/down times, capacity, heat rates, etc.;
- fuel burn minimum and maximums;
- emission limits on effluents such as SO_2 and NO_X; and
- energy contract parameters such as energy and capacity.

The model inputs that comprise the objective function and constraints are considered in the development of an integrated plan that best fits the utility system being analyzed. *Plexos*® does not develop a full regulatory Cost-of-Service (COS) profile. Rather, it typically considers only the relative load and generation COS that changes from plan-to-plan, and not fixed "embedded" costs associated with existing generating capacity and demand-side programs that would remain constant under any scenario. Likewise, transmission costs are included only to the extent that they are associated with new generating capacity, or are linked to specific supply alternatives. In other words, generic (nondescript or non-site-specific) capacity resource modeling would typically not incorporate significant capital expenditures for transmission interconnection costs.

5.2 *Plexos®* Optimization

5.2.1 Modeling Options and Constraints

The major system parameters that were modeled are described below. The *Plexos* LT Plan® models these parameters in tandem with the objective function in order to yield the least-cost resource plan for each scenario modeled.

There are many variants of available supply-side and demand-side resource options and types. As a practical limitation, not all known resource types are made available as modeling options. A screening of available supply-side technologies was performed with the optimum assets made subsequently available as options. Such screens for supply alternatives were performed for baseload, intermediate, and peaking duty cycles.

The selected technology alternatives from this screening process do not necessarily represent the optimum technology choice for that duty-cycle family. Rather, they reflect proxies for modeling purposes. Other factors which will determine the ultimate technology type (e.g., choices for peaking technologies) are taken into consideration. The full list of screened supply options is included in Exhibit B of the Appendix.

Based on the established comparative economic screenings, the following specific supply alternatives were modeled in *Plexos®* for each designated duty cycle:

- Peaking capacity was modeled, effective in 2026 due to the anticipated period required to approve, site, engineer and construct, from:
    - CT units consisting of "F" class turbines with evaporative coolers, rated at 240 MW total at summer conditions.
    - AD units consisting of 2 aeroderivative turbines at 110 MW total at summer conditions.
    - RICE units consisting of 4 reciprocating engines rated at 20 MW total at summer conditions.
    - Battery Storage units available in 25 MW/100 MWh blocks per year with a round trip efficiency of 83%.

- Intermediate-Baseload capacity was modeled, effective in 2026 due to anticipated period required to approve, site, engineer and construct, from:
    - NGCC "H" class turbine 1x1x1 single shaft rated at 410 MW total at summer conditions
    - NGCC "H" class turbine 2x2x1 1100 MW total at summer conditions
    - NGCC "H" class turbine 1x1x1 single shaft rated with 90% CO_2 Capture at 370 MW total at summer conditions

- Small Modular Reactors (SMRs) rated at 600 MW were made available in 2035 due to an estimated time to construct and achieve regulatory approvals.

- Renewable Resources were modeled with a planned in service by December 2025 (commercial operation) and available for energy in 2026
  - Wind resources were made available up to 300MW annually beginning in 2026. Wind resources were available as both a PPA option up to 100 MW/year and Owned up to 200 MW/year. In total, wind resources were limited to 950MW of nameplate capacity over the planning period in addition to the 204 MW included in the near term.
  - Large-scale solar resources were made available up to 600 MW annually beginning in 2026 and included two pricing tiers of owned resources and a PPA resource. Tier 1 Owned resources were available up to 300 MW each year. Tier 2 Owned resources and Solar PPA resources were available up to 150 MW each year for each resource.
  - Hybrid Solar+Storage resources were made available up to 450MW annually beginning in 2026 up to 1,050MW cumulative.

- Demand-Side Resources included in the modeling were:
  - DER, in the form of distributed solar resources, was embedded in amounts equal to a CAGR of 11.8% over the planning period.

  - EE resources—incremental to those already incorporated into the Company's long-term load and peak demand forecast in up to 21 unique "bundles" of Residential and Commercial measures considering cost and performance parameters for both HAP and AP categories are available in 2022.

  - VVO was available in 14 tranches of varying installed costs and number of circuits/sizes ranging from a low of 5.4 MW up to 11.1 MW of demand savings potential.

- Renewable Energy Credits (RECs) were included as a RPS energy compliance option in the Plexos® modeling, allowing the model to choose whether to build physical resources or purchase RECs based on economics. RECs were available in blocks of 350 GWh which is an estimated annual energy production from a proxy 150 MW block of utility solar. The first year when RECs could be added was assumed to be 2022.

5.2.2 Base Optimized Portfolios

The key decision to be made by APCo over the planning horizon is how to fill the resource needs identified at the lowest cost. Portfolios with various options addressing APCo's capacity and energy resource needs over time were optimized under various commodity prices and load conditions. All Portfolios were modeled to comply with VCEA requirements described in Section 1.5.1. In order to bound APCo's resource selection across varying commodity price and load conditions, six scenarios were initially analyzed for this IRP (see Table 13). The resource portfolios discussed below for these scenarios represent incremental resources which are in addition to those currently in-service. All portfolios also include several renewable resources currently planned and under development including 204 MW of owned wind planned for PJM Planning year 2025, and several solar resources, owned and PPA, amounting to 275 MW nameplate planned for PJM Planning years 2022 and PJM Planning year 2025 consistent with resources in the 2021 VCEA filing.

Table 13. Base Optimized Portfolios

Case	Portfolio Name	Commodity Pricing Conditions	Load Forecast Assumptions
A	Base	RGGI + $15CO2	Base
B	Base, High Commodity	RGGI + $15CO2 HIGH	Base
C	Base, Low Commodity	RGGI + $15CO2 LOW	Base
D	Base, RGGI	RGGI	Base
E	Base-High Load	RGGI + $15CO2	High
F	Base-Low Load	RGGI + $15CO2	Low

5.2.2.1 Commodity Pricing Portfolios

Table 14 shows the capacity additions associated with the cases A-D, Base Portfolios modeled under the Base RGGI + $15 CO_2 commodity forecast, the High and Low price bands of this same commodity forecast and a Base RGGI commodity forecast without a national $15 CO_2 dispatch burden. Recall from Section 4.3.1 that the modeling associated with the Base and Upper Band scenarios assumed a CO_2 dispatch burden, or allowance value, equal to $15.00/metric ton commencing in 2028 and escalating at 3.5% per annum thereafter on a nominal dollar basis. Case D was modeled under a RGGI Only commodity pricing scenario where a national CO_2 dispatch burden was not included. This portfolio was the least cost portfolio of the Base Optimized Portfolios due to no national CO_2 dispatch burden being applied to unit generation.

Table 14. Cumulative Resource Additions – Base Portfolios

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Base RGGI $15 CO2 AM MT 2040	Resources under Development	15	15	65	489	489	489	489	489	489	489	489	489	489	489	489
	New Utility Solar (NmPlt)	0	0	0	0	0	0	0	0	0	150	150	150	300	300	600
	New PPA Solar (NmPlt)	0	0	0	0	0	0	0	0	150	300	450	600	750	900	900
	New Paired Solar (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New Wind (Nameplate)	0	0	0	0	200	400	400	600	600	600	600	600	600	600	600
	New Wind PPA (NmPlt)	0	0	0	0	100	150	250	250	350	350	350	350	350	350	350
	Storage Capacity (NmPlt)	0	0	0	0	25	25	25	25	25	150	150	150	150	150	400
	Storage Paired (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New EE	14	29	44	57	75	71	68	16	13	10	7	5	3	1	1
	New DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New VVO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
	New DG	0	0	0	35	40	46	52	59	67	72	74	76	77	79	83
Total Additions (Firm & Degraded)		22	37	79	268	352	378	385	344	407	578	592	624	689	723	1,048
Capacity Reserves (MW) without new additio		486	536	521	238	203	214	218	229	233	242	250	252	254	255	235
Capacity Reserves (MW) with new additions		508	573	599	506	541	573	573	545	601	785	803	837	905	939	1,245
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
High RGGI $15 CO2 AM MT 2040	Resources under Development	15	15	65	489	489	489	489	489	489	489	489	489	489	489	489
	New Utility Solar (NmPlt)	0	0	0	0	0	0	0	0	0	150	300	300	300	600	900
	New PPA Solar (NmPlt)	0	0	0	0	0	0	0	0	150	300	450	600	750	750	900
	New Paired Solar (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New Wind (Nameplate)	0	0	0	0	200	400	400	600	600	600	600	600	600	600	600
	New Wind PPA (NmPlt)	0	0	0	0	100	150	250	250	350	350	350	350	350	350	350
	Storage Capacity (NmPlt)	0	0	0	0	25	25	25	25	25	150	150	150	150	150	400
	Storage Paired (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New EE	14	29	44	57	75	71	68	16	13	10	7	5	3	1	1
	New DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New VVO	0	0	0	0	0	0	0	0	0	0	0	0	0	6	6
	New DG	0	0	0	35	40	46	52	59	67	72	74	76	77	79	83
Total Additions (Firm & Degraded)		22	37	79	268	352	379	386	344	407	578	625	657	689	762	1,114
Capacity Reserves (MW) without new additio		486	536	521	238	203	214	218	229	233	242	250	252	254	255	235
Capacity Reserves (MW) with new additions		508	573	599	506	541	573	574	545	601	785	836	870	905	978	1,311
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Low RGGI $15 CO2 AM MT 2040	Resources under Development	15	15	65	489	489	489	489	489	489	489	489	489	489	489	489
	New Utility Solar (NmPlt)	0	0	0	0	0	0	0	0	0	150	150	150	300	300	600
	New PPA Solar (NmPlt)	0	0	0	0	0	0	0	0	150	300	450	600	750	900	900
	New Paired Solar (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New Wind (Nameplate)	0	0	0	0	200	400	400	600	600	600	600	600	600	600	600
	New Wind PPA (NmPlt)	0	0	0	0	100	150	250	250	350	350	350	350	350	350	350
	Storage Capacity (NmPlt)	0	0	0	0	25	25	25	25	25	150	150	150	150	150	400
	Storage Paired (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New EE	14	29	44	57	71	68	65	13	11	9	6	4	2	1	1
	New DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New VVO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
	New DG	0	0	0	35	40	46	52	59	67	72	74	76	77	79	83
Total Additions (Firm & Degraded)		22	37	79	268	348	375	383	342	405	576	591	623	689	723	1,048
Capacity Reserves (MW) without new additio		486	536	521	238	203	214	218	229	233	242	250	252	254	255	235
Capacity Reserves (MW) with new additions		508	573	599	506	537	569	571	543	599	783	802	837	905	939	1,245
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Base RGGI Only AM MT 2040	Resources under Development	15	15	65	489	489	489	489	489	489	489	489	489	489	489	489
	New Utility Solar (NmPlt)	0	0	0	0	0	0	0	0	0	150	150	150	300	300	600
	New PPA Solar (NmPlt)	0	0	0	0	0	0	0	0	150	300	450	600	750	900	900
	New Paired Solar (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New Wind (Nameplate)	0	0	0	0	200	400	400	600	600	600	600	600	600	600	600
	New Wind PPA (NmPlt)	0	0	0	0	100	150	250	250	350	350	350	350	350	350	350
	Storage Capacity (NmPlt)	0	0	0	0	25	25	25	25	25	150	150	150	150	150	400
	Storage Paired (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New EE	14	29	44	57	71	68	65	13	11	8	6	4	2	1	0
	New DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New VVO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
	New DG	0	0	0	35	40	46	52	59	67	72	74	76	77	79	83
Total Additions (Firm & Degraded)		22	37	79	268	348	375	383	342	405	576	590	623	689	723	1,048
Capacity Reserves (MW) without new additio		486	536	521	238	203	214	218	229	233	242	250	252	254	255	235
Capacity Reserves (MW) with new additions		508	573	599	506	537	569	571	543	599	783	802	837	905	939	1,245

All four portfolios, A-D, include similar resource additions, primarily defined by the VCEA requirements including:

- Planned resources under development include renewable resources of 204 MW non-VA domiciled wind by 2025 and 285 MW of VA domiciled solar by PJM Planning year 2025

- 300 MW of incremental wind resources in 2026, growing to 950MW by 2030 including both Utility Owned and PPA resources
- 150MW of incremental solar PPA resources beginning in 2030, growing to 1,500MW by 2036 including both Utility Owned and PPA resources
- No change in capacity additions between RGGI+15, Low RGGI+15 and RGGI only cases through 2036
- In the RGGI+$15 High Commodity Price Scenario, 150MW of Utility Solar included in 2034 in the Base Portfolio is brought forward to 2032. An additional 300MW of solar resources is also added by 2036 over the Base Portfolio. This increase in solar capacity recognizes the value of these resources due to higher market energy prices.

With the minimal variation in resource additions between portfolios, the revenue requirements for each of the portfolios did not vary by relatively large amounts. A summary of the revenue requirements over several reporting periods is shown in Table 15. This analysis provides APCo information regarding optimum resource selection under various views of the future.

Table 15. Commodity Portfolios Revenue Requirements

	No Natural Gas Resource Options			
	Base RGGI Only	Low RGGI$15	Base RGGI$15	High RGGI$15
Net Present Value $M				
Utility NPV 2022-2027	$4,824	$4,693	$4,837	$4,876
Utility NPV 2028-2036	$5,667	$6,113	$6,566	$6,965
Utility NPV 2037-2051	$7,122	$7,239	$7,646	$8,044
NPV of End Effects beyond 2051	$5,013	$4,961	$5,290	$5,542
TOTAL Utility Cost, Net Present Value	**$22,627**	**$23,007**	**$24,340**	**$25,427**
Savings / (cost) over Base RGGI$15	*$1,713*	*$1,333*	*$0*	*($1,087)*

Additional analysis completed as part of the Company's VCEA filing in December 2021 also evaluated the impact of using a lower wind capacity factor. In Portfolio 6 of this filing, the capacity factor in that scenario was assumed to be 30.4% instead of the 35% capacity factor assumed in the Base Portfolios. The results were an impact of approximately 2% higher costs when viewed over 30 years.

5.2.2.2 Load Sensitivity Portfolios

Table 16 shows the capacity additions for cases E and F associated with the High Load and Low Load sensitivities, using the RGGI +$15 CO_2 commodity prices. The capacity analysis of the High and Low Load Portfolios illustrates the potential and risk for the Company to meet its capacity obligation under varying load scenarios discussed in Section 2. With the Company's base load forecast and Going-In position indicating sufficient capacity during the reporting period as shown in Figure ES-1, the Low Load Portfolio indicates additional capacity length for the Company when run under the Low Load Scenario. Under a High Load Scenario, however, the capacity length is reduced although no additional resources beyond those identified in the Base Portfolio (Case A) were identified.

Table 16. Cumulative Capacity Additions (MW) for Low and High Load Sensitivity Portfolios

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Base RGGI $15 CO2 High Load AM MT 2040	Resources under Development (	15	15	65	489	489	489	489	489	489	489	489	489	489	489	489
	New Utility Solar (NmPlt)	0	0	0	0	0	0	0	0	0	150	150	150	300	300	600
	New PPA Solar (NmPlt)	0	0	0	0	0	0	0	0	150	300	450	600	750	900	900
	New Paired Solar (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New Wind (Nameplate)	0	0	0	0	200	400	400	600	600	600	600	600	600	600	600
	New Wind PPA (NmPlt)	0	0	0	0	100	150	250	250	350	350	350	350	350	350	350
	Storage Capacity (NmPlt)	0	0	0	0	25	25	25	25	25	150	150	150	150	150	400
	Storage Paired (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New EE	14	29	44	57	75	71	68	16	13	10	7	5	3	1	1
	New DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New VVO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
	New DG	0	0	0	35	40	46	52	59	67	72	74	76	77	79	83
Total Additions (Firm & Degraded)		22	37	79	268	352	378	385	344	407	578	592	624	689	723	1,048
Capacity Reserves (MW) without new addition		336	321	254	(66)	(124)	(148)	(190)	(220)	(247)	(261)	(277)	(327)	(370)	(420)	(496)
Capacity Reserves (MW) with new additions		358	358	333	202	214	211	165	97	121	282	276	258	281	265	514
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Base RGGI $15 CO2 Low Load AM MT 2040	Resources under Development (	15	15	65	489	489	489	489	489	489	489	489	489	489	489	489
	New Utility Solar (NmPlt)	0	0	0	0	0	0	0	0	0	150	150	150	300	300	600
	New PPA Solar (NmPlt)	0	0	0	0	0	0	0	0	150	300	450	600	750	900	900
	New Paired Solar (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New Wind (Nameplate)	0	0	0	0	200	400	400	600	600	600	600	600	600	600	600
	New Wind PPA (NmPlt)	0	0	0	0	100	150	250	250	350	350	350	350	350	350	350
	Storage Capacity (NmPlt)	0	0	0	0	25	25	25	25	25	150	150	150	150	150	400
	Storage Paired (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New EE	14	29	44	57	75	71	68	16	13	10	8	6	4	2	1
	New DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New VVO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
	New DG	0	0	0	35	40	46	52	59	67	72	74	76	77	79	83
Total Additions (Firm & Degraded)		22	37	79	268	352	378	385	344	407	578	592	625	690	724	1,049
Capacity Reserves (MW) without new additio		637	735	772	544	545	590	617	656	694	737	770	802	844	881	901
Capacity Reserves (MW) with new additions		659	771	851	811	883	949	973	973	1,062	1,280	1,324	1,388	1,495	1,566	1,911

5.2.2.3 REC Sensitivity Portfolios

As part of the analysis, the Case A, Base portfolio was modeled to evaluate the impact of higher and lower Renewable Energy Credit (RECs) costs. As discussed in section 4.5.5.5, REC prices were modified by 50% higher and lower than the base REC costs. As shown in Table 17, the low REC sensitivity resources leveraged the economics of lower REC prices to delay the build of 200MW of new wind in 2027 until 2028. The portfolio results indicated that through 2025, RECs were purchased to meet VCEA energy requirements until new renewable resources could be included. Beginning in 2026, the model did not select RECs as a resource to meet its VCEA energy requirements through 2035. However, given the potential volatility of the REC market, strategies that include large reliance on REC purchases must be approached cautiously and are not preferential given that the actual time to acquire renewable resources to replace RECs usually will take years. A summary of the revenue requirements is shown in Table 18. Appendix F provides a summary of the portfolio selections (purchases) of RECS over the reporting period.

Table 17. REC Sensitivity Portfolios

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	Resources under Development (	15	15	65	489	489	489	489	489	489	489	489	489	489	489	489
	New Utility Solar (NmPlt)	0	0	0	0	0	0	0	0	0	150	150	150	300	300	600
	New PPA Solar (NmPlt)	0	0	0	0	0	0	0	0	150	300	450	600	750	900	900
Base	New Paired Solar (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RGGI $15	New Wind (Nameplate)	0	0	0	0	200	200	400	600	600	600	600	600	600	600	600
CO2	New Wind PPA (NmPlt)	0	0	0	0	100	150	250	250	350	350	350	350	350	350	350
Low REC	Storage Capacity (NmPlt)	0	0	0	0	25	25	25	25	25	150	150	150	150	150	400
Price	Storage Paired (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AM MT 2040	New EE	14	29	44	57	75	71	68	16	13	10	7	5	3	1	1
	New DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New VVO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
	New DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
Total Additions (Firm & Degraded)		22	37	79	268	352	352	385	344	407	578	592	624	689	723	1,048
Capacity Reserves (MW) without new additior		486	536	521	238	203	214	218	229	233	242	250	252	254	255	235
Capacity Reserves (MW) with new additions		508	573	599	506	541	547	573	545	601	785	803	837	905	939	1,245
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	Resources under Development (	15	15	65	489	489	489	489	489	489	489	489	489	489	489	489
	New Utility Solar (NmPlt)	0	0	0	0	0	0	0	0	0	150	150	150	300	450	750
	New PPA Solar (NmPlt)	0	0	0	0	0	0	0	0	150	300	450	600	750	900	900
Base	New Paired Solar (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RGGI $15	New Wind (Nameplate)	0	0	0	0	200	400	400	600	600	600	600	600	600	600	600
CO2	New Wind PPA (NmPlt)	0	0	0	0	100	150	250	250	350	350	350	350	350	350	350
High REC	Storage Capacity (NmPlt)	0	0	0	0	25	25	25	25	25	150	150	150	150	150	400
Price	Storage Paired (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AM MT 2040	New EE	14	29	44	57	75	71	68	16	13	10	7	5	3	1	1
	New DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New VVO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
	New DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
Total Additions (Firm & Degraded)		22	37	79	268	352	378	385	344	407	578	592	624	689	756	1,081
Capacity Reserves (MW) without new additior		486	536	521	238	203	214	218	229	233	242	250	252	254	255	235

Table 18. REC Sensitivity Portfolio Revenue Requirements

	No Natural Gas Resource Options		
	Base RGGI$15 Low REC	Base RGGI$15	Base RGGI$15 High REC
Net Present Value $M			
Utility NPV 2022-2027	$4,822	$4,837	$4,845
Utility NPV 2028-2036	$6,578	$6,566	$6,562
Utility NPV 2037-2051	$7,641	$7,646	$7,651
NPV of End Effects beyond 2051	$5,273	$5,290	$5,303
TOTAL Utility Cost, Net Present Value	**$24,314**	**$24,340**	**$24,361**
Savings / (cost) over Base RGGI$15	*$26*	*$0*	*($21)*

5.2.3 Alternative Portfolios

Four additional Portfolios, Cases G-J shown in Table 19, were modeled to test alternative plans. A common parameter in all the alternative portfolios was that natural gas resources were available for selection in the model. This is in contrast to the Commodity Pricing Portfolios (Cases A-D) where natural gas resources were not available.

Table 19. Alternative Portfolios

Case	Scenarios	Commodity Pricing Conditions	Load Forecast Assumptions
G	Base with Nat. Gas resource	RGGI + $15CO2	Base
H	Base with Nat. Gas resource, CR ext	RGGI + $15CO2	Base
I	Increased Technology Costs (Nat. Gas, Renewables)	RGGI + $15CO2	Base
J	Base with Nat. Gas resource	RGGI	Base

The Base with Natural Gas resources, Case G, and the Base, RGGI with Natural Gas resources, Case J, tested the portfolio results under the same parameters and conditions as the Base portfolios, Cases A & D, with the only change being to include Natural Gas resources as an option.

As part of this IRP, the Company evaluated end of service dates for the Clinch River facility. In the Base Portfolio with NG resources, (Case G), the Company assumes Clinch River Unit 1 ceases operation on December 31, 2025 and Clinch River Unit 2 ceases operation on May 31, 2026. For capacity planning purposes, the Company conservatively assumed that, while Clinch River Unit 2 may produce energy through May 2026, the plant would only provide capacity value through the end of 2025, therefore Clinch River's capacity would not be available in Plexos during the 2025/2026 PJM planning year (which covers the period June 1, 2025 through May 31, 2026). Case H evaluated an end of operation date through the end of PJM Planning year 2036/2037 for CR 1 and 2 to help assess potential future alternative retirement dates and provides further annual insights to consider various extension periods. At this time, however, the Company has not formally announced or notified any parties of any final retirement dates for the Clinch River plant.

The Increased Technology Costs Portfolio, Case I, was run to evaluate the impacts of higher resource costs. The Company has conducted several RFP's across multiple jurisdictions and is realizing a high level of volatility in current renewable resource pricing. To test the robustness of the model results, natural gas resources were increased by 15%, solar LCOE resource costs were increased by 40% and wind resource LCOE costs were increased by 50% above those use in the Base Portfolio (Cases A). For this portfolio, the annual and cumulative limits for wind resources was also expanded to allow up to 200 MW PPA and 1200 MW Owned annually to determine if additional renewable resources would be added, even at these higher costs.

The results of the capacity expansion for these portfolios are shown in Table 20. In summary, the Base with Natural Gas resources, Base with Natural Gas resources and Clinch River extended and the Base RGGI with Natural Gas resources (Cases G, H & J) all included the same resources, effectively those resources required for VCEA compliancy.

The Increased Technology Costs Portfolio, Case I, with the increased wind limits, resulted in more owned wind being built in 2026, taking advantage of PTC's but resulting in nearly equal amounts of wind resources by 2036 including 1000MW of wind resources in the Increased Technology Cost portfolio vs. 950MW of wind resources in the Base RGGI+15CO_2 Portfolio. This supports the addition of economic wind resources, even at increased cost, if they are available.

Table 20. Alternative Portfolio Capacity Additions (Nameplate MW)

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Base RGGI $15 CO2 with Natural Gas	Resources under Development (	15	15	65	489	489	489	489	489	489	489	489	489	489	489	489
	New Nat. Gas-CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New Utility Solar (NmPlt)	0	0	0	0	0	0	0	0	0	150	150	150	300	450	750
	New PPA Solar (NmPlt)	0	0	0	0	0	0	0	0	150	300	450	600	750	900	900
	New Paired Solar (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New Wind (Nameplate)	0	0	0	0	200	400	400	600	600	600	600	600	600	600	600
	New Wind PPA (NmPlt)	0	0	0	0	100	150	250	250	350	350	350	350	350	350	350
	Storage Capacity (NmPlt)	0	0	0	0	25	25	25	25	25	150	150	150	150	150	400
	Storage Paired (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New EE	14	29	44	57	75	71	68	16	13	10	7	5	3	1	1
	New DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New VVO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New DG	0	0	0	35	40	46	52	59	67	72	74	76	77	79	83
Total Additions (Firm & Degraded)		22	37	79	268	338	359	355	317	369	543	553	585	651	717	1,036
Capacity Reserves (MW) without new addition		486	536	521	238	203	214	218	229	233	242	250	252	254	255	235
Capacity Reserves (MW) with new additions		508	573	599	506	541	573	573	545	601	785	803	837	905	972	1,272
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Base RGGI $15 CO2 with Natural Gas CR 2036	Resources under Development (	15	15	65	489	489	489	489	489	489	489	489	489	489	489	489
	New Nat. Gas-CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New Utility Solar (NmPlt)	0	0	0	0	0	0	0	0	0	150	150	150	300	450	750
	New PPA Solar (NmPlt)	0	0	0	0	0	0	0	0	150	300	450	600	750	900	900
	New Paired Solar (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New Wind (Nameplate)	0	0	0	0	200	400	400	600	600	600	600	600	600	600	600
	New Wind PPA (NmPlt)	0	0	0	0	100	150	250	250	350	350	350	350	350	350	350
	Storage Capacity (NmPlt)	0	0	0	0	25	25	25	25	25	150	150	150	150	150	400
	Storage Paired (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New EE	14	29	44	57	75	71	68	16	13	10	7	5	3	1	1
	New DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New VVO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New DG	0	0	0	35	40	46	52	59	67	72	74	76	77	79	83
Total Additions (Firm & Degraded)		22	37	79	268	338	359	355	317	369	543	553	585	651	717	1,036
Capacity Reserves (MW) without new addition		485	537	521	468	432	443	448	458	462	472	479	481	484	484	465
Capacity Reserves (MW) with new additions		507	574	600	735	771	802	803	774	831	1,014	1,033	1,066	1,135	1,202	1,501
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Base RGGI $15 CO2 with Natural Gas Increased Tech Cost	Resources under Development (	15	15	65	489	489	489	489	489	489	489	489	489	489	489	489
	New Nat. Gas-CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New Utility Solar (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	150	150	150	300
	New PPA Solar (NmPlt)	0	0	0	0	0	0	0	0	150	300	450	600	750	900	900
	New Paired Solar (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New Wind (Nameplate)	0	0	0	0	800	800	800	800	800	800	800	800	800	800	800
	New Wind PPA (NmPlt)	0	0	0	0	200	200	200	200	200	200	200	200	200	200	200
	Storage Capacity (NmPlt)	0	0	0	0	25	25	25	25	25	150	150	150	150	150	400
	Storage Paired (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New EE	14	29	44	57	75	71	68	16	13	10	7	5	3	1	1
	New DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New VVO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
	New DG	0	0	0	35	40	46	52	59	67	72	74	76	77	79	83
Total Additions (Firm & Degraded)		22	37	79	268	436	417	397	333	374	507	526	591	623	657	949
Capacity Reserves (MW) without new addition		486	536	521	238	203	214	218	229	233	242	250	252	254	255	235
Capacity Reserves (MW) with new additions		508	573	599	506	639	631	615	562	607	749	776	843	878	912	1,184
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Base RGGI Only with ~~Natural~~ Gas	Resources under Development (	15	15	65	489	489	489	489	489	489	489	489	489	489	489	489
	New Nat. Gas-CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New Utility Solar (NmPlt)	0	0	0	0	0	0	0	0	0	150	150	150	300	450	750
	New PPA Solar (NmPlt)	0	0	0	0	0	0	0	0	150	300	450	600	750	900	900
	New Paired Solar (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New Wind (Nameplate)	0	0	0	0	200	400	400	600	600	600	600	600	600	600	600
	New Wind PPA (NmPlt)	0	0	0	0	100	150	250	250	350	350	350	350	350	350	350
	Storage Capacity (NmPlt)	0	0	0	0	25	25	25	25	25	150	150	150	150	150	400
	Storage Paired (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New EE	14	29	44	57	75	71	68	16	13	10	7	5	3	1	1
	New DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New VVO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New DG	0	0	0	35	40	46	52	59	67	72	74	76	77	79	83
Total Additions (Firm & Degraded)		22	37	79	268	338	359	355	317	369	543	553	585	651	717	1,036
Capacity Reserves (MW) without new addition		486	536	521	238	203	214	218	229	233	242	250	252	254	255	235
Capacity Reserves (MW) with new additions		508	573	599	506	541	573	573	545	601	785	803	837	905	972	1,272

A summary of the revenue requirements over several reporting periods is shown in Table 21. As shown, the costs of these portfolios do not vary significantly from the Base Portfolio (Case A) without natural gas resources over the first 15 years. Including natural gas resources in the portfolios reduced the overall net revenue requirement over the full planning horizon, with the model preferring to choose a combustion turbine as a replacement resource over the selection of storage resources when the Amos and Mountaineer plants are scheduled to retire in 2040. Additionally, with the extension of the Clinch River plan through the reporting period as modeled in Case H, the results of this IRP retirement analysis are nearly identical to the natural gas case without the extension. The Increased Technology Cost Portfolio resulted in a higher cost over the Base Portfolio as anticipated given the high capital costs.

Table 21. Alternative Portfolio Revenue Requirements

	No Natural Gas Options	With Natural Gas Resource Options			
	Base RGGI$15	Base RGGI Only	Base RGGI$15	Base RGGI$15 Clinch Extension	Base RGGI$15 Increased Tech Costs
Net Present Value $M					
Utility NPV 2022-2027	$4,837	$4,836	$4,837	$4,841	$4,894
Utility NPV 2028-2036	$6,566	$5,665	$6,567	$6,539	$6,760
Utility NPV 2037-2051	$7,646	$6,646	$7,190	$7,186	$7,905
NPV of End Effects beyond 2051	$5,290	$4,368	$4,766	$4,766	$5,284
TOTAL Utility Cost, Net Present Value	**$24,340**	**$21,515**	**$23,360**	**$23,332**	**$24,842**
Savings / (cost) over Base RGGI$15	-	*$2,825*	*$980*	*$1,008*	*($502)*

5.3 Hybrid Plan

Each of the portfolios provide insight into a potential alternative mix of resources for the future. The Base Portfolios demonstrated the same or little variance in resource additions. The Alternative Portfolios evaluated the results of including Natural Gas resources within the portfolio as well as testing alternative limits for wind resources along with associated resource costs impacts to the plans. The Alternative Portfolios also demonstrated little variances in resource additions among them. For the purposes of evaluating a single plan, the Company developed a Hybrid Plan with the insights obtained from the Base and Alternative Portfolios modeled.

This plan was developed based on the following considerations:

- Minimizing revenue requirements (i.e. cost to customers) over the planning period, while meeting capacity obligations.
- Compliance with the VCEA requirements.
- Integrating PJM guidance on ELCC for intermittent resources to support resource adequacy needs.

The cumulative capacity additions associated with the Hybrid Plan are shown below in Table 22 and in Figure 22.

Table 22. Cumulative Capacity Additions (MW) for Hybrid Plan

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Base RGGI $15 CO2 Hybrid Plan	New Utility Solar (NmPlt)	0	0	50	250	250	250	250	250	250	400	400	400	550	550	850
	New Utility Solar (Firm)	0	0	27	128	118	110	100	93	80	108	88	88	121	121	187
	New PPA Solar (NmPlt)	15	15	15	35	35	35	35	35	185	335	485	635	785	935	935
	New PPA Solar (Firm)	8	8	8	18	16	15	14	13	59	90	107	140	173	206	206
	New Paired Solar (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New Paired Solar (Firm)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New Wind (Nameplate)	0	0	0	204	804	804	804	804	804	804	804	804	804	804	804
	New Wind (Firm)	0	0	0	31	113	105	96	88	88	80	88	88	88	88	88
	New Wind PPA (NmPlt)	0	0	0	0	200	200	200	250	350	350	350	350	350	350	350
	New Wind PPA (Firm)	0	0	0	0	28	26	24	28	39	35	39	39	39	39	39
	Storage Capacity (NmPlt)	0	0	0	0	25	25	25	50	100	150	200	250	300	350	400
	Storage Capacity (Firm)	0	0	0	0	19	18	19	40	89	147	200	250	300	350	400
	Storage Paired (NmPlt)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Storage Paired (Firm)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New EE	18	34	47	59	71	62	53	36	29	22	16	10	6	3	1
	New DR	8	8	8	8	12	12	12	4	4	4	4	0	0	0	0
	New VVO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
	New DG	0	0	0	35	40	46	52	59	67	72	74	76	77	79	83
Capacity Reserves (MW) without new additions		485	537	521	468	432	443	448	458	462	472	479	481	484	484	465
Capacity Reserves (MW) with new additions		519	587	611	746	849	838	819	819	917	1,030	1,095	1,172	1,288	1,370	1,475

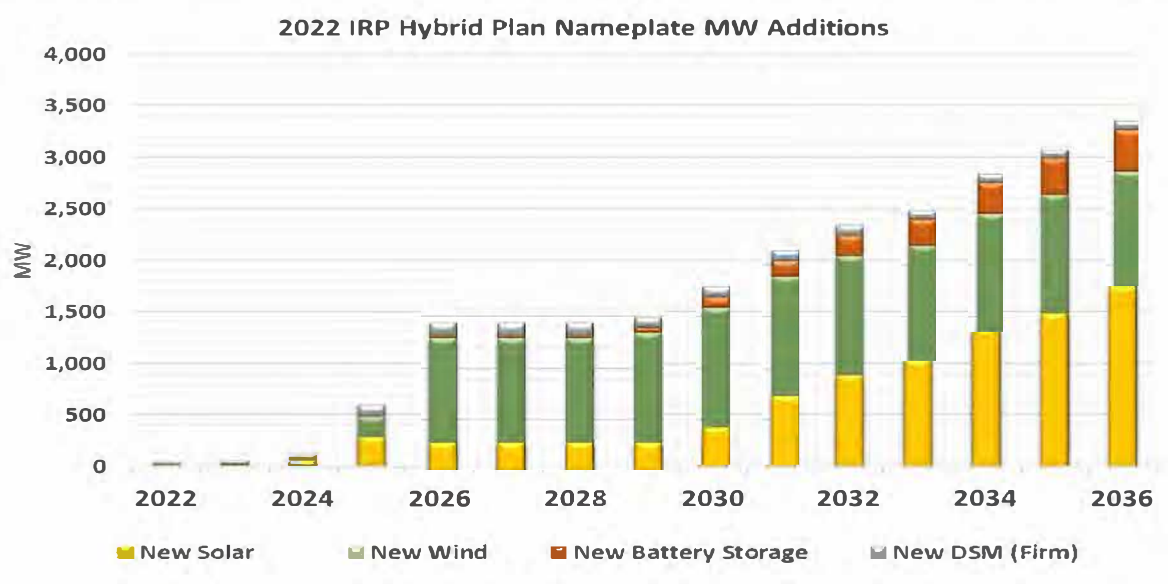


Figure 22. Hybrid Plan Nameplate Cumulative Capacity Additions

The Hybrid Plan includes a similar mix of supply-side resources to the Base Portfolio, Case A, but allows for an earlier addition of wind resources to take advantage of PTC's available through December 2025 for 2026 resources as informed by Case I, Increased Technology Costs Portfolio. Furthermore, the Hybrid Plan adds storage resources more uniformly across the reporting period compared to the Base Plan. Finally, the Hybrid plan, informed by Case H, Base+15 w/NG and Clinch River Extension, assumed the extension of the Clinch River plant through the reporting period to help assess potential future alternative retirement dates and provides further annual insights to consider various extension periods.

In the Hybrid Plan, incremental DSM resources including DR, EE and DER resources are included through the reporting period. Distributed Generation resources were included with a capacity credit of 83MW by 2036.

Incremental EE resources were included beginning in 2022 with energy savings consistent with the Company's 2022-2026 DSM plan that complies with the VCEA requirements and bundles available for economic selection beginning in 2027. Economic savings in compliance with the VCEA requirements and are shown in Figure 23 are associated with both Residential and Commercial programs with more savings attributed to the Commercial programs.

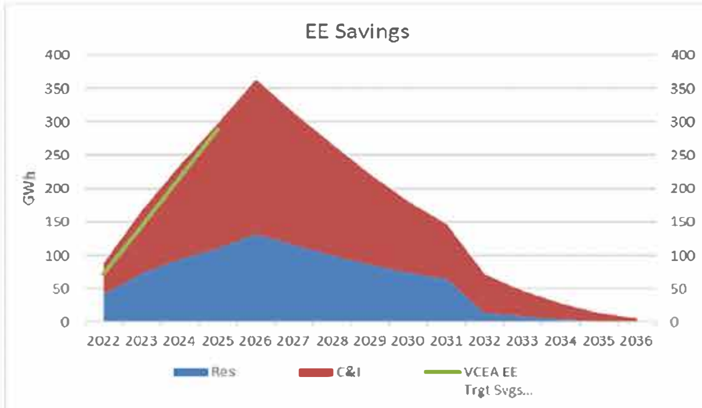


Figure 23. Hybrid Plan EE Savings

The Hybrid Plan includes resources that comply with the VCEA requirements while also providing flexibility in resource additions if market resources become available. The Company expects to procure materially all resources through an annual RFP process, whether through acquisition or contracts for energy, capacity, and environmental attributes. Through the RFP's, the Company will have the opportunity to moderate its actual resource additions with the potential to adjust the amount of wind and solar resources based on market availability as well as the inclusion of PPA resources along with owned resources.

The cost analysis of the Hybrid plan shown in Table 23 illustrates a more favorable plan relative to the Base Plan without natural gas resources (Case A). Table 23 also compares the Base Plan with natural gas resources allowed under the RGGI only commodity pricing scenario (Case J). This particular comparison provides some insight to the potential costs if a national carbon tax, or alternative carbon burden, does get introduced in 2028 as modeled.

Table 23. Hybrid Plan Revenue Requirement Comparison

	Base Plan (Case A) $M	Hybrid Plan $M	Base w/NG, RGGI Only (Case J) $M
Utility NPV 2022-2027	$4,837	$4,816	$4,836
Utility NPV 2028-2036	$6,566	$6,463	$5,665
Utility NPV 2037-2051	$7,646	$7,567	$6,646
NPV of End Effects beyond 2051	$5,290	$5,244	$4,368
TOTAL Utility Cost, Net Present Value	$24,340	$24,091	$21,515

While the Company will meet its capacity obligation, the national transition to more intermittent and renewable resources will impact the Company's anticipated energy output from its fossil-fueled fleet. The Company will maintain appropriate capacity reserves and the Hybrid Plan includes resources to support the energy targets set forth in the VCEA for the Company to Virginia customers. However, energy delivered to APCo's non-Virginia customers is expected to be purchased from the market and from fossil resources as shown in Figure 24.

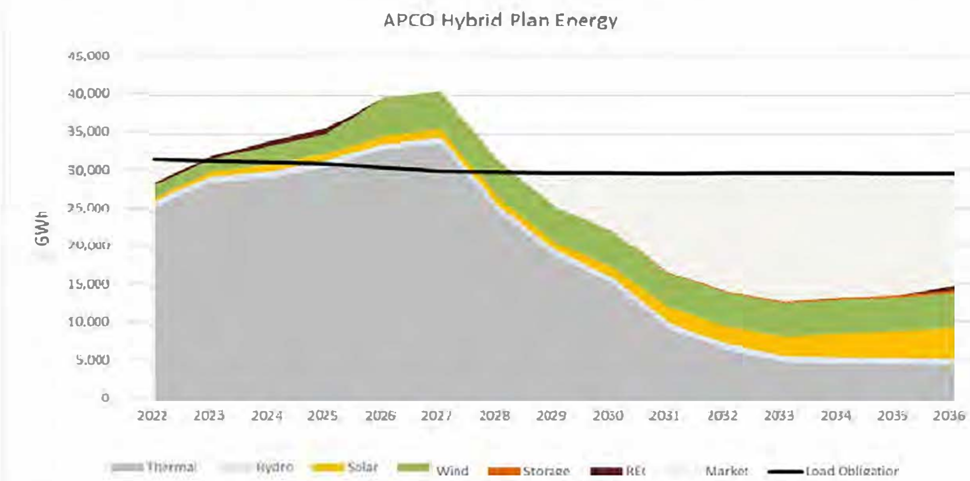


Figure 24. APCo Hybrid Plan Energy

With the plan indicating a reliance on market energy after 2028 when the modeling assumes a national carbon tax or alternative carbon burden begins, the Company will still have the flexible thermal generation resources to provide reliability services to PJM. This also is aligned to a recent PJM whitepaper related to the current energy transition indicating in part, "Today, thermal resources supply essential reliability services. Until a different technology can provide a reliable substitute at scale, an adequate supply of thermal resources will be needed to maintain grid stability." [15]

5.4 Risk Analysis

A method of determining the risk of a plan for customers is to compare the cost of a Portfolio under varying futures or commodity price scenarios. For this, APCo fixed the Hybrid Plan resources and analyzed the performance under both the High and Low commodity price scenarios. When considering these different futures, the Hybrid Plan exhibits a high side risk cost through 2027 of approximately 0.7% above the base commodity pricing scenario while exhibiting nearly a 3% benefit to customers under a low commodity pricing scenario. The effects on the high side risk vs low side benefits to customers is more balanced after 2028 when a carbon burden is assumed to begin in the modeling as shown in Table 24.

[15] https://pjm.com/-/media/committees-groups/committees/mrc/2021/20211215/20211215-item-09-energy-transition-in-pjm-whitepaper.ashx

Table 24. Hybrid Plan Cost Risk Based on Commodity Price Variability

	Hybrid Plan Low RGGI+15 $M	Hybrid Plan RGGI+15 $M	Hybrid Plan High RGGI+15 $M	Low RGGI+15 Benefit	High RGGI+15 Risk
Utility NPV 2022-2027	$4,672	$4,816	$4,852	3.0%	-0.7%
Utility NPV 2028-2036	$6,002	$6,463	$6,872	7.1%	-6.3%
Utility NPV 2037-2051	$7,159	$7,567	$7,970	5.4%	-5.3%
NPV of End Effects beyond 2051	$4,914	$5,244	$5,499		
TOTAL Utility Cost, Net Present Value	$22,747	$24,091	$25,193	5.6%	-4.6%

5.5 Rate Impact Analysis

In addition to the portfolio risk assessment discussed, the Company also estimated a retail customer rate impact analysis assuming a typical residential customer using 1,000 kWh/month, for each of the first 5 years of the IRP. In this analysis, the Company used a traditional, non-levelized, calculation of the annual cost of service and the change in revenue requirement for the period of 2022-2026. The Company compared the Hybrid Plan with Case H, Base+15 w/NG and Clinch River Extension which was the least cost portfolio over 30 years.

The estimated rate impacts for the Hybrid plan relative to the least cost plan, Case H, for a typical residential customer are the same through 2025 as shown in Table 25 and Table 26. In 2026, however, the Hybrid plan adds more wind (in service December 2025 to take advantage of available PTC's that will continue for 10 years), resulting in a $0.70 higher estimated monthly cost for that calendar year for 2026.

Table 25. Hybrid Plan Estimated Monthly Rate Impacts

Hybrid Plan Estimated Monthly Rate Impacts - Residential Rate Schedule

	2021	2022	2023	2024	2025	2026
Residential Customer Gross [1000 kWh]	$ 138.94	$ 138.94	$ 138.94	$ 145.61	$ 161.00	$ 176.46
Offsets		0.15	(0.08)	(5.26)	(15.17)	(26.24)
Net Impact	$ 138.94	139.09	138.87	140.35	145.83	150.22
% increase (cumulative)		0%	0%	1%	5%	8%

Table 26. Case H, Base+15 w/NG and Clinch River Extension Estimated Monthly Rate Impacts

Case H Estimated Monthly Rate Impacts - Residential Rate Schedule

	2021	2022	2023	2024	2025	2026
Residential Customer Gross [1000 kWh]	$ 138.94	$ 138.94	$ 138.94	$ 145.61	$ 161.00	$ 171.44
Offsets		0.15	(0.07)	(5.25)	(15.17)	(21.92)
Net Impact	$ 138.94	139.09	138.87	140.36	145.84	149.52
% increase (cumulative)		0%	0%	1%	5%	8%

6.0 Conclusions and Five-Year Action Plan

6.1 Plan Summary

The Hybrid Plan provides an optimized selection of resources that balances the Company's obligations for capacity and renewable energy requirements under the VCEA law while also meeting ongoing PJM reliability and capacity obligations. Figure 25 illustrates the Company's firm capacity position with new resources from the Hybrid Plan included as well as the extension of the Clinch River plant through the reporting period.

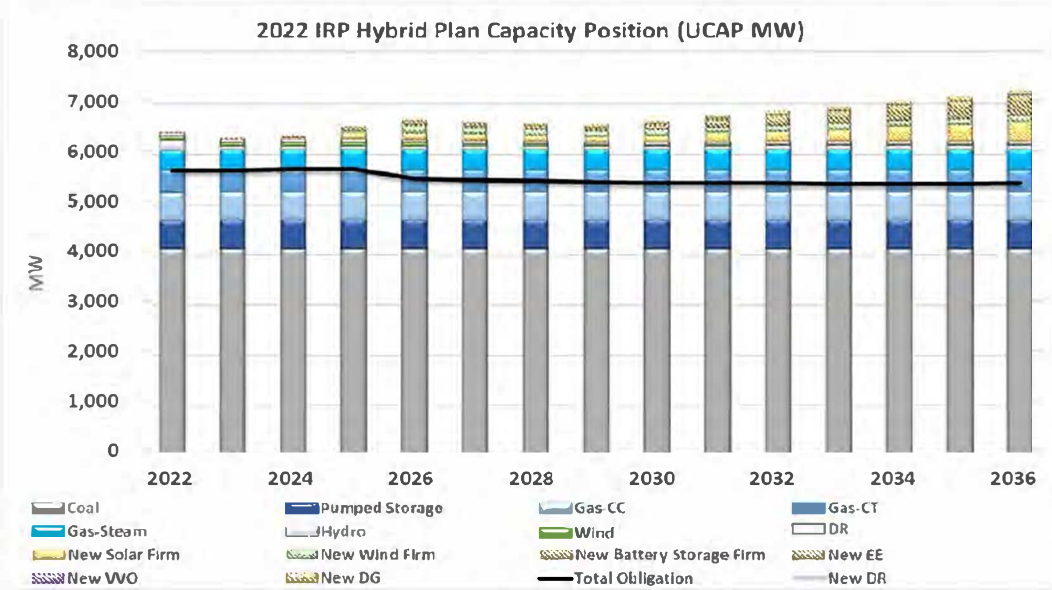


Figure 25. APCo Capacity Position with Hybrid Plan Additions

New resources over the reporting period, 2022-2036), include a mix of supply and demand-side resources including Utility Owned and PPA Wind and Solar resources as well as storage resources. A summary of the resource additions over the reporting period is shown in Figure 26.

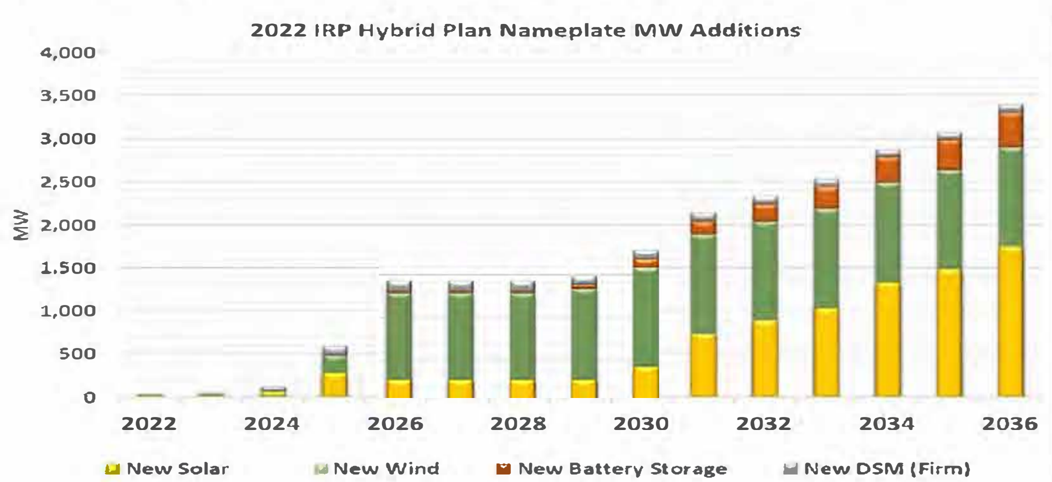


Figure 26. Hybrid Plan Nameplate Cumulative Capacity Additions

The Company expects to procure materially all resources through an annual RFP process, whether through acquisition or contracts for energy, capacity, and environmental attributes. Through the RFPs, the Company will have the opportunity to moderate its actual resource additions with the potential to adjust the amount of wind and solar resources based on market availability as well as the inclusion of PPA resources along with owned resources.

The IRP process is a continuous activity; assumptions and plans are reviewed as new information becomes available and modified as appropriate. As noted previously, this IRP is not a commitment to specific resource additions or other courses of action, as the future is highly uncertain. The resource planning process continues to be complex, especially with regard to such things as pending regulatory restrictions, technology advancement, changing energy supply pricing fundamentals, uncertainty of demand and end-use efficiency improvements. These complexities exacerbate the need for flexibility and adaptability in any ongoing planning activity and resource planning process. To that end, APCo intends to pursue the following five-year action plan:

1. Issue annual RFPs in compliance with VCEA requirements.
2. Seek competitive offers for energy storage in support of non-wires alternatives and storage requirements.
3. Utilize 100% of the Company's hydro resources for VCEA compliance beginning in 2025 through intra-Company transactions at market value.
4. Monitor federal and state regulatory developments related to continued operation of the Amos and Mountaineer plants
5. Evaluate the benefits and viability for the continued operation of the Clinch River plant
6. Monitor developments in REC markets to evaluate RECs as a compliance option

7.0 Unit Retirement Analysis

As a component of a settlement entered into on September 11, 2020 in Virginia State Corporation Commission Case No. PUR-2020-00015, the Company entered into a stipulation with the Sierra Club requiring a unit-by-unit retirement analysis to be performed for the Amos and Mountaineer coal units. That stipulation required that analysis to be filed with this 2022 IRP. The requirements of that analysis, per Article 3 of that stipulation are as follows:

Appalachian Power Company agrees that its 2022 Integrated Resource Plan will include robust unit-by-unit retirement analyses for the Amos and Mountaineer coal units. Those retirement analyses will:

a) be performed on a capacity expansion and dispatch model (e.g., PLEXOS);
b) reflect all costs and benefits associated with near- and mid-term retirement dates—including, for example, sustaining capital expenditures and anticipated environmental expenditures;
c) consider all available resources as potential replacements for retired capacity or for services needed by the system in the absence of retired units;
d) evaluate the units under reasonable, alternative commodity price (e.g., natural gas, greenhouse gas emissions) forecasts;
e) reflect costs of replacement resources that are informed by recent requests for proposals; and
f) be performed in 2021 or 2022, so as to reflect the most up-to-date information.

Subsequent to the adoption of the Sierra Club stipulation, on August 14, 2021, the Public Service Commission of West Virginia in case No. 20-1040-E-CN, granted approvals of certain environmental investments required for compliance with the EPA's Coal Combustion Residuals (CCR) and Effluent Limitation Guidelines (ELG) rules. The order states that the compliance investments were to be made for the purpose of keeping the plants open and generating electricity through 2040. As a result the Company is assuming for planning purposes that the units will operate through 2040.

None of the four units will retire by "near or mid-term" dates, but the Company prepared an analysis in April of 2022 as if they will, containing all of the Sierra Club stipulation requirements. All of the modeling was performed on a total company basis. A summary of the unit analyses performed using the Plexos model as part of this study is shown in Table 27 In compliance with stipulation 3(b), the Company elected to define "near and mid-term retirement dates" as 2028 and 2034. The 2028 date aligns with the date the units would have needed to retire had the decision to make the ELG compliance investments not been made. The 2034 date for the mid-term cases is the midpoint between 2028 and 2040.

Per stipulation Article 3(c), the Company prepared scenarios making all of the same types of resources available, including natural gas-fired resources, that were available in the IRP portfolios presented in this report. Article 3(d) required multiple commodity scenarios. For this requirement the Company ran two scenarios. The first assumed the RGGI carbon emission requirements remained in place, with Virginia as a member, along with an assumed $15/ton national carbon tax imposed in 2028. The second assumed the RGGI carbon rules were in effect, without the additional national carbon tax. Regarding Article 3(e), wind and solar resource costs were aligned with APCo's 2021 RFP.

A summary of the unit analyses performed as part of this study is shown in Table 27.

Table 27. Amos and Mountaineer Retirement Portfolios

Group	Case	Portfolio Name	Commodity Pricing Conditions	Load Forecast Assumptions
Unit Retirement Portfolios	K	Base w/ Nat. Gas, w/o AM1* 2028	RGGI + $15CO2	Base
	L	Base w/ Nat. Gas, w/o AM1* 2034	RGGI + $15CO2	Base
	M	Base w/ Nat. Gas, w/o AM1* 2028	RGGI	Base
	N	Base w/ Nat. Gas, w/o AM3 2028	RGGI + $15CO2	Base
	O	Base w/ Nat. Gas, w/o AM3 2034	RGGI + $15CO2	Base
	P	Base w/ Nat. Gas, w/o AM3 2028	RGGI	Base
	Q	Base w/ Nat. Gas, w/o MT 2028	RGGI + $15CO2	Base
	R	Base w/ Nat. Gas, w/o MT 2034	RGGI + $15CO2	Base
	S	Base w/ Nat. Gas, w/o MT 2028	RGGI	Base

* Analysis for AM1 retirement assumed the same as if AM2 retirement

7.1 Retirement Analysis Assumptions

The stipulation required a unit-by-unit analysis. All of the scenarios were prepared with only one of the four units retiring, in order to isolate the impacts of retiring one unit. As was done with the portfolios presented throughout this IRP, the 30 year NPV of the revenue requirements of each scenario was calculated. All of the scenarios were VCEA compliant, meaning that all of the physical resources or REC purchases required by the VCEA were included in the scenarios. For this analysis, Amos 1 and 2 are both 800 MW units that burn the same coal blends, have similar heat rates, and incur similar levels of O&M and Capital to operate. As a result, separate scenarios were not prepared for Amos 1 and 2 and the Amos 1 retirement scenarios are a proxy for Amos 2 retirement scenarios.

Retiring any of the units would allow customers to avoid paying for ongoing O&M and capital expense after the retirement date. An estimate of that savings has been included in each scenario. In the Mountaineer retirement scenarios, 100% of ongoing O&M and Capital was eliminated beginning in the first year post-retirement. Mountaineer is a single unit plant. In the case of the three unit Amos plant, shutting down one unit would not result in elimination of a full MW-weighted share of the total plant's O&M expense. Much of the O&M would still be needed to operate remaining two units. For this analysis, it was assumed that 50% of the fixed O&M for the retiring unit was eliminated starting the year after the retirement year, creating a savings versus cases when that unit continued to operate.

In the event a unit retires, any undepreciated net book value remaining as of the retirement date would need to be collected from customers after retirement. The earlier a unit retires, the larger the unrecovered balance will be, absent a corresponding increase in depreciation rates. In order to capture this difference across cases, a projection of the amount of the December 31, 2021 net book value which will be unrecovered was prepared for each unit for all years through 2040. Unrecovered balances, if any, were assumed to be recovered over the first three years post-retirement. This projection of net book value was prepared using depreciation rates currently in effect in Virginia. For Amos those rates are based on full recovery of existing investment in 2032 for units 1 and 2, and by 2033 for unit 3. This resulted in an unrecovered balance as of 2028, but no uncovered balance in the 2034 retirement cases. Mountaineer's depreciation rates are based on recovery by 2040, and thus there was unrecovered balance recovery to add to both the 2028 and 2034 retirement cases. In addition, the analysis assumed that all ongoing capital expense from 2022 onward would be fully recovered by the assumed retirement date through levelized carrying charges rates which increase through time.

7.2 Retirement Analysis Results

The conclusion reached by the analysis was obtained by computing the 30 year net present value of the revenue requirement of each retirement scenario, and then computing a difference versus the Base Portfolio with NG (Case G), which has all four units operating through 2040. A similar comparison was performed for the 2028 Retirement Portfolios modeled with the RGGI Only commodity scenario, comparing the results to Case J. This summary is shown in Table 28. A negative number means that an early unit retirement is projected to cost more than keeping the unit operating. All nine of the single unit retirement scenarios resulted in higher costs. This robust analysis indicates that continuing to operate each of the four units through 2040 will be beneficial for customers.

Table 28. NPV of Revenue Requirements – Amos and Mountaineer Unit Retirement Analysis

	NPV Revenue Requirement Incremental Savings / (Cost) of unit retirement	
	RGGI + $15/ton CO2 tax	RGGI Only CO2
All four units 2040 Retirement		
Amos 1 or 2 2028 Retirement	($137)	($145)
Amos 3 2028 Retirement	($339)	($354)
Mountaineer 2028 Retirement	($458)	($547)
Amos 1 or 2 2034 Retirement	($25)	
Amos 3 2034 Retirement	($91)	
Mountaineer 2034 Retirement	($117)	

Appendix

Exhibit A	Load Forecast Tables
Exhibit B	Non-Renewable New Generation Technologies
Exhibit C	Schedules
Exhibit D	Cross Reference Table
Exhibit E	Fundamentals
Exhibit F	REC Purchases
Exhibit G	Transmission Project Details

Exhibit A: Load Forecast Tables

Exhibit A-1

Appalachian Power Company Annual Internal Energy Requirements and Growth Rates 2018-2036										
	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Total Internal Energy Requirements	
Year	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth
Actual										
2018	11,871	---	6,581	---	9,576	---	6,535	---	34,563	---
2019	11,253	-5.2	6,364	-3.3	9,546	-0.3	6,198	-5.2	33,362	-3.5
2020	10,915	-3.0	5,887	-7.5	8,873	-7.0	5,744	-7.3	31,420	-5.8
2021	11,207	2.7	5,949	1.1	8,879	0.1	5,829	1.5	31,864	1.4
Forecast										
2022	11,006	-1.8	5,952	0.0	9,187	3.5	5,973	2.5	32,118	0.8
2023	10,908	-0.9	5,934	-0.3	9,139	-0.5	5,975	0.0	31,955	-0.5
2024	10,838	-0.6	5,936	0.0	9,062	-0.8	5,969	-0.1	31,805	-0.5
2025	10,782	-0.5	5,946	0.2	9,030	-0.4	5,950	-0.3	31,707	-0.3
2026	10,711	-0.7	5,932	-0.2	9,043	0.1	5,567	-6.4	31,252	-1.4
2027	10,669	-0.4	5,930	0.0	9,076	0.4	5,091	-8.5	30,766	-1.6
2028	10,630	-0.4	5,917	-0.2	9,115	0.4	4,980	-2.2	30,642	-0.4
2029	10,594	-0.3	5,906	-0.2	9,138	0.3	4,831	-3.0	30,468	-0.6
2030	10,547	-0.4	5,887	-0.3	9,155	0.2	4,823	-0.2	30,412	-0.2
2031	10,508	-0.4	5,871	-0.3	9,170	0.2	4,822	0.0	30,371	-0.1
2032	10,465	-0.4	5,856	-0.3	9,176	0.1	4,836	0.3	30,334	-0.1
2033	10,438	-0.3	5,848	-0.1	9,183	0.1	4,830	-0.1	30,300	-0.1
2034	10,401	-0.4	5,839	-0.2	9,190	0.1	4,847	0.4	30,277	-0.1
2035	10,373	-0.3	5,837	0.0	9,199	0.1	4,846	0.0	30,255	-0.1
2036	10,346	-0.3	5,836	0.0	9,207	0.1	4,846	0.0	30,235	-0.1
Average Annual Growth Rates										
2018-2021		-1.9		-3.3		-2.5		-3.7		-2.7
2022-2036		-0.4		-0.1		0.0		-1.5		-0.4

Exhibit A-2a

Appalachian Power Company-Virginia
Annual Internal Energy Requirements and Growth Rates
2018-2036

	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Total Internal Energy Requirements	
Year	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth
Actual										
2018	6,474	---	3,164	---	5,305	---	3,140	---	18,083	---
2019	6,194	-4.3	3,064	-3.2	5,194	-2.1	3,085	-1.8	17,537	-3.0
2020	6,027	-2.7	2,837	-7.4	4,958	-4.5	2,922	-5.3	16,744	-4.5
2021	6,245	3.6	2,871	1.2	5,014	1.1	3,065	4.9	17,195	2.7
Forecast										
2022	6,210	-0.6	2,876	0.2	5,110	1.9	3,165	3.3	17,361	1.0
2023	6,184	-0.4	2,869	-0.2	5,116	0.1	3,174	0.3	17,344	-0.1
2024	6,166	-0.3	2,879	0.3	5,107	-0.2	3,174	0.0	17,327	-0.1
2025	6,155	-0.2	2,892	0.5	5,110	0.1	3,167	-0.2	17,325	0.0
2026	6,132	-0.4	2,891	0.0	5,112	0.0	2,811	-11.2	16,947	-2.2
2027	6,124	-0.1	2,894	0.1	5,129	0.3	2,363	-16.0	16,510	-2.6
2028	6,118	-0.1	2,890	-0.1	5,149	0.4	2,243	-5.0	16,400	-0.7
2029	6,115	0.0	2,888	-0.1	5,164	0.3	2,092	-6.7	16,259	-0.9
2030	6,105	-0.2	2,879	-0.3	5,179	0.3	2,089	-0.1	16,252	0.0
2031	6,098	-0.1	2,873	-0.2	5,192	0.3	2,090	0.0	16,253	0.0
2032	6,090	-0.1	2,867	-0.2	5,200	0.2	2,100	0.5	16,257	0.0
2033	6,093	0.1	2,866	-0.1	5,209	0.2	2,096	-0.2	16,264	0.0
2034	6,090	-0.1	2,864	-0.1	5,215	0.1	2,106	0.5	16,275	0.1
2035	6,091	0.0	2,868	0.1	5,224	0.2	2,106	0.0	16,289	0.1
2036	6,094	0.0	2,872	0.1	5,231	0.1	2,107	0.0	16,303	0.1
Average Annual Growth Rates										
2018-2021		-1.2		-3.2		-1.9		-0.8		-1.7
2022-2036		-0.1		0.0		0.2		-2.9		-0.4

Exhibit A-2b

Appalachian Power Company-West Virginia
Annual Internal Energy Requirements and Growth Rates
2018-2036

	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Total Internal Energy Requirements	
Year	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth
Actual										
2018	5,396	---	3,417	---	4,271	---	1,287	---	14,373	---
2019	5,059	-6.2	3,300	-3.4	4,352	1.9	1,127	-12.4	13,839	-3.7
2020	4,888	-3.4	3,050	-7.6	3,915	-10.0	1,123	-0.4	12,976	-6.2
2021	4,961	1.5	3,079	0.9	3,865	-1.3	1,081	-3.7	12,986	0.1
Forecast										
2022	4,796	-3.3	3,076	-0.1	4,077	5.5	1,111	2.8	13,060	0.6
2023	4,724	-1.5	3,064	-0.4	4,022	-1.4	1,101	-0.9	12,911	-1.1
2024	4,672	-1.1	3,057	-0.2	3,954	-1.7	1,088	-1.2	12,772	-1.1
2025	4,626	-1.0	3,054	-0.1	3,919	-0.9	1,070	-1.7	12,669	-0.8
2026	4,579	-1.0	3,041	-0.4	3,931	0.3	1,037	-3.0	12,587	-0.6
2027	4,545	-0.7	3,035	-0.2	3,947	0.4	1,006	-3.0	12,533	-0.4
2028	4,513	-0.7	3,026	-0.3	3,966	0.5	1,009	0.3	12,513	-0.2
2029	4,479	-0.7	3,018	-0.3	3,974	0.2	1,005	-0.4	12,476	-0.3
2030	4,442	-0.8	3,008	-0.3	3,977	0.1	996	-0.8	12,423	-0.4
2031	4,410	-0.7	2,999	-0.3	3,977	0.0	991	-0.5	12,377	-0.4
2032	4,376	-0.8	2,989	-0.3	3,975	0.0	993	0.1	12,333	-0.4
2033	4,345	-0.7	2,983	-0.2	3,975	0.0	984	-0.9	12,286	-0.4
2034	4,311	-0.8	2,974	-0.3	3,975	0.0	986	0.2	12,247	-0.3
2035	4,282	-0.7	2,970	-0.2	3,975	0.0	978	-0.7	12,205	-0.3
2036	4,252	-0.7	2,965	-0.2	3,976	0.0	972	-0.6	12,165	-0.3
Average Annual Growth Rates										
2018-2021		-2.8		-3.4		-3.3		-5.7		-3.3
2022-2036		-0.9		-0.3		-0.2		-0.9		-0.5

Exhibit A-3

Appalachian Power Company

Seasonal and Annual Peak Internal Demands, Energy Requirements and Load Factor

2018-2036

	Summer Peak			Preceding Winter Peak			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
2018	06/18/18	5,618	---	01/02/18	7,816	---	7,816	---	34,563	---	50.3
2019	09/11/19	5,537	-1.4	01/21/19	7,319	-6.4	7,319	-6.4	33,362	-3.5	52.0
2020	07/20/20	5,502	-0.6	01/22/20	6,523	-10.9	6,523	-10.9	31,420	-5.8	55.0
2021	08/25/21	5,363	-2.5	02/08/21	5,977	-8.4	5,977	-8.4	31,864	1.4	60.9
Forecast											
2022		5,381	0.3		6,987	16.9	6,987	16.9	32,118	0.8	52.3
2023		5,353	-0.5		6,918	-1.0	6,918	-1.0	31,955	-0.5	52.7
2024		5,316	-0.7		6,855	-0.9	6,855	-0.9	31,805	-0.5	53.0
2025		5,315	0.0		6,853	0.0	6,853	0.0	31,707	-0.3	52.8
2026		5,178	-2.6		6,830	-0.3	6,830	-0.3	31,252	-1.4	52.1
2027		5,148	-0.6		6,682	-2.2	6,682	-2.2	30,766	-1.6	52.6
2028		5,137	-0.2		6,597	-1.3	6,597	-1.3	30,642	-0.4	53.0
2029		5,114	-0.4		6,546	-0.8	6,546	-0.8	30,468	-0.6	53.1
2030		5,108	-0.1		6,524	-0.3	6,524	-0.3	30,412	-0.2	53.1
2031		5,104	-0.1		6,510	-0.2	6,510	-0.2	30,371	-0.1	53.3
2032		5,100	-0.1		6,467	-0.7	6,467	-0.7	30,334	-0.1	53.5
2033		5,098	-0.1		6,479	0.2	6,479	0.2	30,300	-0.1	53.4
2034		5,095	-0.1		6,441	-0.6	6,441	-0.6	30,277	-0.1	53.7
2035		5,094	0.0		6,430	-0.2	6,430	-0.2	30,255	-0.1	53.7
2036		5,109	0.3		6,422	-0.1	6,422	-0.1	30,235	-0.1	53.7
Average Annual Growth Rates											
2018-2021			-1.5			-8.6		-8.6		-2.7	
2022-2036			-0.4			-0.6		-0.6		-0.4	

Exhibit A-4

Appalachian Power and Virginia and West Virginia Jurisdictions
DSM/Energy Efficiency Included in Load Forecast
Energy (GWh) and Coincident Peak Demand (MW)

	APCo DSM/EE			APCo - Viginia DSM/EE			APCo - West Virginia DSM/EE		
Year	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand
2022	46.0	8.0	8.9	44.0	7.5	8.4	1.9	0.4	0.5
2023	53.3	9.6	11.0	45.5	7.9	9.2	7.8	1.8	1.8
2024	61.0	11.4	13.3	46.7	8.2	9.9	14.3	3.3	3.3
2025	71.9	13.9	16.3	49.3	8.7	11.0	22.6	5.2	5.3
2026	88.6	17.2	20.5	53.7	9.5	12.5	34.9	7.7	8.0
2027	79.4	15.9	18.8	47.4	8.5	11.4	32.0	7.4	7.4
2028	61.8	12.1	14.8	38.7	7.0	9.2	23.2	5.1	5.6
2029	46.6	9.1	11.0	30.0	5.5	7.0	16.6	3.7	4.0
2030	32.0	6.3	7.4	21.7	4.0	4.9	10.3	2.3	2.5
2031	18.9	3.6	4.3	14.6	2.7	3.3	4.3	1.0	1.0
2032	8.5	1.5	1.9	8.5	1.5	1.9	0.0	0.0	0.0
2033	3.2	0.6	0.7	3.2	0.6	0.7	0.0	0.0	0.0
2034	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2035	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2036	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

*Demand coincident with Company's seasonal peak demand.

Exhibit A-5

Appalachian Power Company
Short-Term Load Forecast
Blended Forecast vs. Long-Term Model Results

Class	Virginia	West Virginia
Residential	Long-Term	Long-Term
Commercial	Long-Term	Long-Term
Industrial	Long-Term	Long-Term
Other Retail	Long-Term	Long-Term

Exhibit A-6

Blending Illustration

Month	Short-term Forecast	Weight	Long-term Forecast	Weight	Blended Forecast
1	1,000	100%	1,150	0%	1,000
2	1,010	100%	1,160	0%	1,010
3	1,020	100%	1,170	0%	1,020
4	1,030	100%	1,180	0%	1,030
5	1,040	83%	1,190	17%	1,065
6	1,050	67%	1,200	33%	1,100
7	1,060	50%	1,210	50%	1,135
8	1,070	33%	1,220	67%	1,170
9	1,080	17%	1,230	83%	1,205
10	1,090	0%	1,240	100%	1,240
11	1,100	0%	1,250	100%	1,250
12	1,110	0%	1,260	100%	1,260

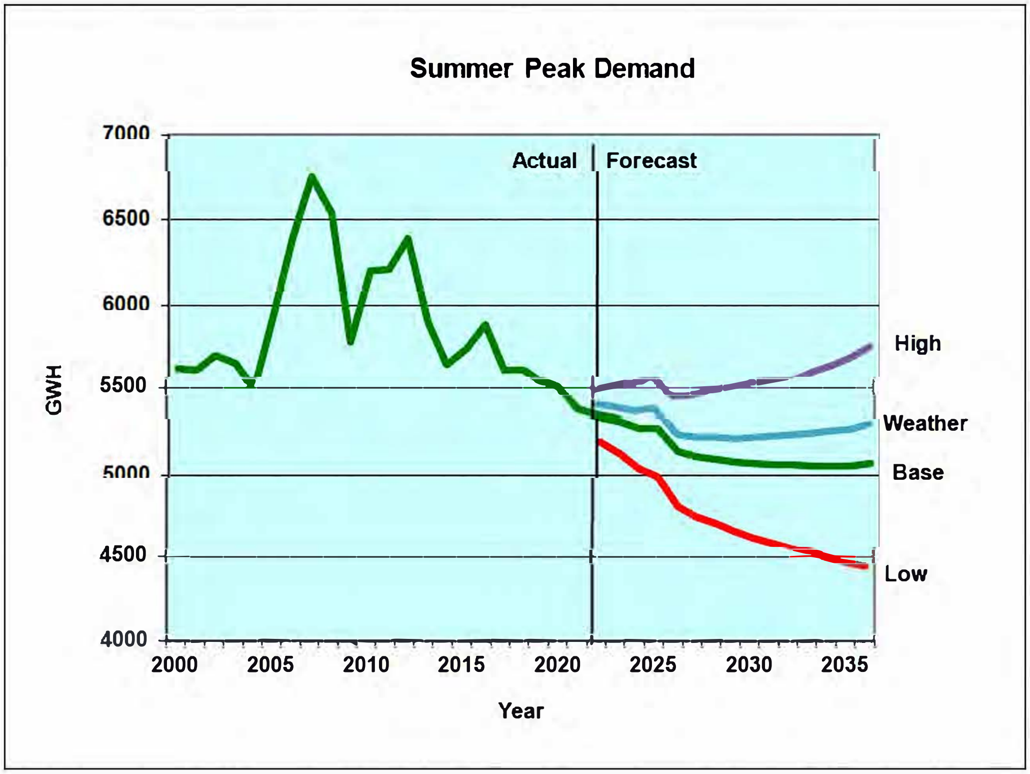
Exhibit A-7

Appalachian Power Company
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements

	Winter Peak Internal Demands (MW)			Summer Peak Internal Demands (MW)			Internal Energy Requirements (GWH)		
Year	Low Case	Base Case	High Case	Low Case	Base Case	High Case	Low Case	Base Case	High Case
2022	6,756	6,943	7,129	5,194	5,339	5,482	30,944	31,804	32,655
2023	6,631	6,874	7,139	5,123	5,311	5,515	30,520	31,641	32,859
2024	6,508	6,813	7,135	5,038	5,274	5,523	30,084	31,491	32,978
2025	6,439	6,810	7,176	4,986	5,273	5,556	29,683	31,393	33,078
2026	6,360	6,787	7,193	4,812	5,135	5,442	28,989	30,937	32,786
2027	6,176	6,638	7,081	4,751	5,106	5,447	28,331	30,451	32,482
2028	6,069	6,555	7,050	4,717	5,094	5,479	28,078	30,325	32,618
2029	5,984	6,502	7,045	4,667	5,071	5,494	27,750	30,151	32,668
2030	5,923	6,480	7,059	4,629	5,065	5,518	27,506	30,094	32,785
2031	5,868	6,466	7,071	4,594	5,062	5,536	27,273	30,052	32,867
2032	5,800	6,424	7,060	4,566	5,057	5,558	27,097	30,015	32,986
2033	5,774	6,435	7,136	4,535	5,055	5,605	26,901	29,981	33,247
2034	5,692	6,397	7,148	4,495	5,052	5,645	26,656	29,958	33,475
2035	5,638	6,386	7,196	4,460	5,051	5,692	26,429	29,935	33,731
2036	5,589	6,379	7,249	4,438	5,066	5,756	26,211	29,915	33,993
Average Annual Growth Rate % - 2018-2032									
	-1.3	-0.6	0.1	-1.1	-0.4	0.3	-1.2	-0.4	0.3

Exhibit A-8

Appalachian Power Company
Range of Forecasts and Weather Scenario



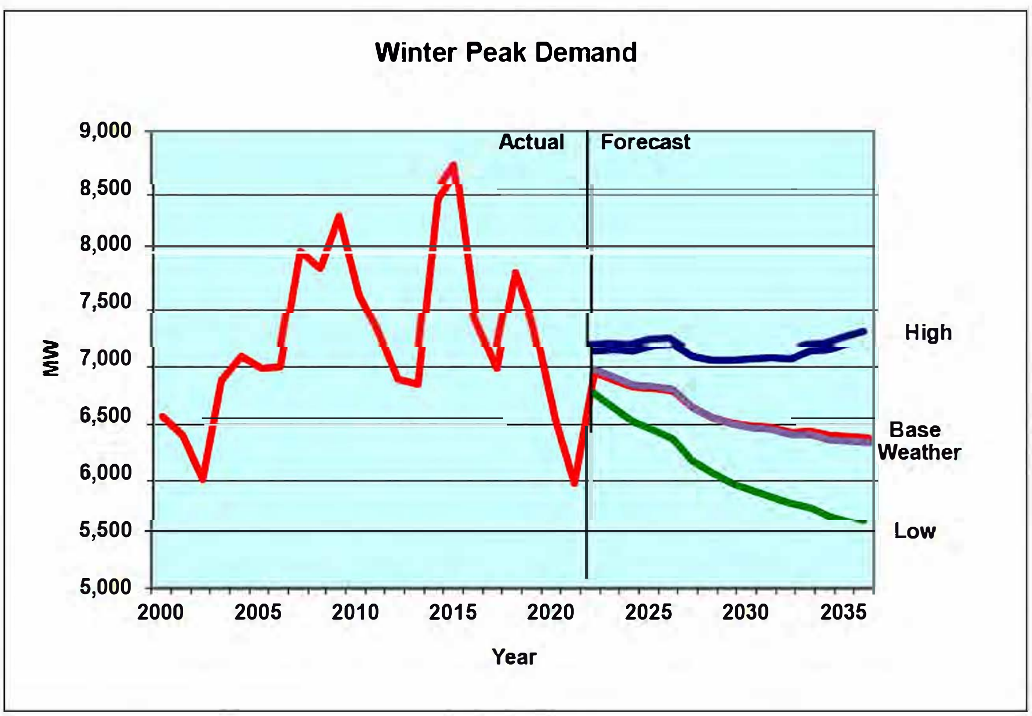


Exhibit A-9

Appalachian Power Company
Forecast Summer Peak Demand (MW) Coincident with PJM RTO
PJM, APCo IRP and APCo High Economic Scenario Forecasts

Year	APCo Portion of PJM Forecast* of AEP Zone	APCo Typical IRP Forecast** Coincident with PJM RTO	APCo High Forecast Coincident with PJM RTO
2022	5,513.8	5,513.8	5,661.4
2023	5,546.2	5,546.2	5,759.8
2024	5,571.4	5,571.4	5,834.6
2025	5,579.4	5,202.3	5,481.6
2026	5,467.0	5,071.3	5,374.3
2027	5,430.8	5,041.5	5,377.8
2028	5,416.4	5,026.5	5,406.4
2029	5,432.2	5,001.1	5,418.4
2030	5,446.7	4,992.2	5,438.5
2031	5,451.8	4,986.5	5,453.5
2032	5,476.2	4,980.6	5,473.6
2033	5,494.8	4,977.1	5,519.2
2034	5,500.6	4,973.7	5,557.6
2035	5,504.2	4,973.3	5,603.8
2036	5,505.6	4,987.2	5,666.9

* PJM forecast is based on PJM's 2021 Load Forecast.

* * APCo typically uses the PJM coincident forecast through the most recent Base Residual Auciton period, which is usally the first four years of the forecast.

Exhibit A-10

Forecasted DSM, Adjusted for IRP Modeling

	APCo Total		
Year	Energy (MWh)	Summer Peak (MW)	Winter Peak (MW)
2021	26,416	4.5	5.0
2022	35,157	6.1	6.5
2023	19,037	3.4	3.6
2024	2,731	0.8	0.6
2025	1,250	0.4	0.3
2026	991	0.3	0.3
2027	730	0.3	0.2
2028	475	0.2	0.1
2029	232	0.1	0.1
2030	8	0.0	0.0
2031	-	-	-

AEP System
New Generation Technologies
Key Supply-Side Resource Option Assumptions (a)(b)(c)(d)

Type	Capability (MW) (e) Std. ISO	Summer	Winter	Installed Cost (d,f) ($/kW)	Full Load Heat Rate (HHV,Btu/kWh)	Fuel Cost ($/MBtu)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Emission Rates SO2 (Lb/mmBtu)	NOx (Lb/mmBtu)	CO2 (Lb/mmBtu)	Capacity Factor (%)	LCOE (g) ($/MWh)
Base Load													
SMALL MODULAR REACTOR NUCLEAR POWER PLANT, 600 MW	600	600	600	7,300	10,000	0.96	3.18	100.91	0.000	0.000	0.0	90	129.0
ULTRA-SUPERCRITICAL COAL WITH 90% CO2 CAPTURE 650 MW	650	630	690	7,200	12,500	1.97	11.52	62.56	0.013	0.057	20.5	75	170.8
COMB TURBINE H CLASS, COMB-CYCLE SINGLE SHAFT W/90% CO2 CAPTURE, 430 MW	380	370	390	2,500	7,100	2.89	6.13	28.96	0.001	0.008	11.7	75	84.2
COMB TURBINE H CLASS, 1100-MW COMBINED CYCLE	1,030	1,010	1,070	1,100	6,400	2.59	1.96	11.82	0.001	0.008	117.1	75	55.6
COMB TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT, 430 MW	420	410	440	1,200	6,400	2.59	2.68	14.80	0.001	0.008	117.1	75	58.9
Peaking													
COMB TURBINE F CLASS, 240-MW SIMPLE CYCLE	230	230	250	800	9,900	2.89	0.63	7.35	0.001	0.008	117.1	25	95.0
COMB TURBINES AERODERIVATIVE, 100-MW SIMPLE CYCLE	110	100	110	1,300	9,100	2.89	4.93	17.11	0.001	0.008	117.1	25	128.4
INTERNAL COMBUSTION ENGINES, 20 MW	20	20	20	2,100	8,300	2.89	5.37	36.90	0.000	0.020	117.0	25	173.9
Intermittent													
BATTERY ENERGY STORAGE SYSTEM, 50 MW / 200 MWH	50	50	50	1,470				21.70				25	157.0
ONSHORE WIND, LARGE PLANT FOOTPRINT, 200 MW(h)	200	200	200	1,540				24.00				35	41.2
SOLAR PHOTOVOLTAIC, 150 MWAC(i)	150	150	150	1,380				10.33				22	55.6
SOLAR PHOTOVOLTAIC WITH BATTERY ENERGY STORAGE SYSTEM 150 MWx200 MWh (i)	150	150	150	1,890				31.53				20	97.6

Notes: (a) Costs and performance data informed by EIA report Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies (Feb 2020)
(b) Installed cost, capability and heat rate numbers have been rounded
(c) All Base Load and Peaking costs in 2021 dollars, except as noted. Costs adjustments made based on EIA report Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2020 (Region 11-PJMW)
(d) $/kW costs are based on summer capability
(e) All Capabilities adjusted by the Performance Adjustment Factors defined in the reference report (a)
(f) Total Plant Investment Cost w/AFUDC (AEP rate of 6.41%, site rating $/kW)
(g) Levelized cost of energy based on capacity factors shown in table
(h) System in service (COD) 2022, Costs shown in 2025$, informed by Bloomberg New Energy Finance's (BNEF) 2H 2020 U.S. Renewable Energy Market Outlook
(i) System in service (COD) 2022, Costs shown in 2025$, Tier 1, informed by 2021 Renewable RFP

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View)																		Schedule 1
PEAK LOAD AND ENERGY FORECAST																		
	(ACTUAL)			(PROJECTED)														
1. Peak Load (MW)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PJM Coincident Internal Load [4,5]	5,476	5,355	5,237	5,207	5,212	5,240	5,239	5,071	5,041	5,026	5,001	4,992	4,986	4,981	4,977	4,974	4,973	4,997
A. Summer																		
1. Base Forecast [1]	-	-	-	5,389	5,363	5,327	5,329	5,195	5,164	5,149	5,123	5,114	5,108	5,102	5,098	5,095	5,094	5,109
2. Conservation, Efficiency [2,6]	-	-	-	(0)	(3)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	0	0	0
3. Demand-side and Response [2,6]	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4. Adjusted Load	5,537	5,502	5,363	5,383	5,360	5,327	5,329	5,195	5,164	5,149	5,123	5,114	5,108	5,102	5,098	5,095	5,094	5,109
5. % Increase in Adjusted Load (from previous year)	(1)	(1)	(3)	0	(0)	(1)	0	(3)	(1)	(0)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	0
B. Winter [3]																		
1. Base Forecast [1]	-	-	-	6,996	6,929	6,868	6,870	6,851	6,701	6,611	6,557	6,531	6,514	6,469	6,480	6,441	6,430	6,422
2. Conservation, Efficiency [2,6]	-	-	-	(9)	(11)	(13)	(16)	(20)	(19)	(15)	(11)	(7)	(4)	(2)	(1)	0	0	0
3. Demand-side and Response [2,6]	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4. Adjusted Load	7,319	6,523	5,977	6,987	6,918	6,855	6,853	6,830	6,682	6,597	6,546	6,524	6,510	6,467	6,479	6,441	6,430	6,422
5. % Increase in Adjusted Load (from previous year)	(6)	(11)	(8)	17	(1)	(1)	(0)	(0)	(2)	(1)	(1)	(0)	(0)	(1)	0	(1)	(0)	(0)
2. Energy (GWh)																		
A. Base Forecast [1]	-	-	-	31,804	31,641	31,491	31,393	30,937	30,451	30,325	30,151	30,094	30,053	30,015	29,981	29,956	29,935	29,915
B. Conservation, Efficiency [2,6]	-	-	-	(35)	(19)	(3)	(1)	(1)	(1)	(0)	(0)	(0)	0	0	0	0	0	0
C. Demand-side and Response [2,6]	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D. Adjusted Energy	33,362	31,420	31,864	31,769	31,622	31,488	31,392	30,936	30,450	30,325	30,151	30,094	30,053	30,015	29,981	29,956	29,935	29,915
E. % Increase in Adjusted Energy (from previous year)	(3)	(6)	1	(0)	(0)	(0)	(0)	(1)	(2)	(0)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)

(1) Reflects the impact of past and on-going conservation and load management and approved or proposed new programs.
(2) Estimated aggregate impact of projected expanded demand-side management and energy efficiency programs.
(3) 2019 data refers to winter of 2018/2019, 2020 data refers to winter of 2019/2020, etc.
(4) Through 2024, the values shown represent an estimate of APCo's share of the final and forecasted PJM load that is the basis for AEP's capacity obligation.
The remaining years represent an estimate of APCo's share of the internal AEP forecast that has been adjusted to the PJM peak.
(5) While APCo load is included in the AEP four company total for FRR planning, APCo and the LSE in its service territory load can be determined in the manner used to determine the AEP FRR obligation. Such load is provided in this response.
(6) Tables reflect DSM levels consistent with 2021 load forecast and do not include DSM increments to the forecast associated with Plexos IRP portfolios.
- = not available

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View) — Schedule 2

GENERATION

I. SYSTEM OUTPUT (GWh)	2019 (ACTUAL)	2020 (ACTUAL)	2021 (ACTUAL)	2022 (PROJECTED)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
A. Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
B. Coal	18,051	15,728	19,146	19,534	22,967	23,549	25,086	27,126	27,974	19,543	14,736	10,335	4,797	1,954	822	524	390	285
C. Heavy Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Light Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E. Natural Gas	5,162	4,997	4,565	5,013	4,894	4,836	4,513	4,557	4,457	4,682	3,700	4,587	4,330	4,429	4,036	4,166	4,274	4,222
F. Hydro-Conventional[1]	769	1,066	742	973	993	994	993	973	881	754	754	754	754	754	754	754	754	754
G. Hydro-Pumped Storage & Battery																		
1. Hydro-Pumped Storage	427	577	404	333	316	325	300	308	283	298	274	266	258	249	224	205	174	176
2. Standalone Battery - LT Additions	-	-	-	0	0	0	0	33	32	35	67	124	167	188	210	236	289	334
H. Renewable Resources[2]	1,323	1,301	1,237	1,699	1,738	2,385	3,534	5,293	5,299	5,134	4,996	5,298	5,765	6,104	6,399	7,030	7,350	8,714
I. Total Generation (sum of A through H)	25,733	23,669	26,094	27,551	30,908	32,089	34,427	38,289	38,928	30,446	24,527	21,365	16,070	13,678	12,445	12,915	13,230	14,485
J. Purchased and Interchange Received																		
1. Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Total DSM[5]	-	-	-	88	166	234	298	363	314	266	221	181	147	71	47	27	13	5
3. Other[3]	1,853	1,442	1,579	1717	1708	1725	1890	2101	2146	1473	1407	1296	1195	1123	1096	1069	1043	1066
K. Pumping/Charging Energy	421	506	437	354	329	345	304	315	280	297	265	253	239	224	189	158	111	113
L. Net Market Purchase/(Sale)[4]	6,198	6,814	4,629	2,801	(811)	(2,212)	(4,918)	(9,501)	(10,656)	(1,562)	4,262	7,506	12,881	15,367	16,582	16,106	15,760	14,472
M. Total System Firm Energy Requirements	33,362	31,420	31,864	31,804	31,641	31,491	31,393	30,937	30,451	30,325	30,151	30,094	30,053	30,015	29,981	29,958	29,935	29,915

II. ENERGY SUPPLIED BY:
COMPETITIVE SERVICE PROVIDERS

(1) Includes purchases from Summersville Hydro
(2) Includes owned and purchased renewable energy.
(3) Includes purchases from OVEC 2019-2036.
(4) Includes net sales or purchases with other electric utilities 2019-2036.
(5) Includes Incremental EE

APPALACHIAN POWER

An AEP Company

BOUNDLESS ENERGY

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View) — Schedule 3

GENERATION

	(ACTUAL)			(PROJECTED)														
III. SYSTEM OUTPUT MIX (%) [1]	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
A. Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
B. Coal	54	50	60	61	73	75	80	88	92	64	49	34	16	7	3	2	1	1
C. Heavy Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Light Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E. Natural Gas	15	16	14	16	15	15	14	15	15	15	12	15	14	15	13	14	14	14
F. Hydro-Conventional	2	3	2	3	3	3	3	3	3	2	2	3	3	3	3	3	3	3
G. Hydro-Pumped Storage																		
1. Hydro-Pumped Storage	1	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2. Standalone Battery - LT Additions	-	-	-	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1
H. Renewable Resources	4	4	4	5	5	8	11	17	17	17	17	18	19	20	21	23	25	29
I. Total Generation (sum of A through H)	77	75	82	87	98	102	110	124	128	100	81	71	53	46	42	43	44	48
J. Purchased and Interchange Received																		
1. Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Total OSM [3]	-	-	-	0	1	1	1	1	1	1	1	1	0	0	0	0	0	0
3. Other	6	-	-	5	5	5	6	7	7	5	5	4	4	4	4	4	3	4
K. Energy for Pumping	(1)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(0)
L. Other Sales	19	22	15	9	(3)	(7)	(16)	(31)	(35)	(5)	14	25	43	51	55	54	53	48
IV. SYSTEM LOAD FACTOR (%) [2]	52	55	61	52	52	52	52	52	52	52	53	53	53	53	53	53	53	53

(1) Expressed as a percent of Total System Firm Energy Requirements (Schedule 2, line M).
(2) Based on Total System Firm Energy Requirements (internal load) and annual peak demand.
(3) Includes Embedded EE, Incremental EE, and DG

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View) — Schedule 4

POWER SUPPLY DATA[7]

I. CAPABILITY (MW)	2019 (ACTUAL)[1]	2020	2021	2022 (PROJECTED)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
1. Summer PJM Capacity (ICAP)[5]																		
A. Installed Dependable Capability[1,2]	6,938	6,936	6,937	6,945	6,766	6,766	6,767	6,764	6,747	6,733	6,720	6,714	6,719	6,723	6,723	6,723	6,723	6,723
B. Total Positive Interchange Commitments[3]	19	17	17	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
C. Capability in Cold Reserve Status	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Total Installed Capacity (ICAP)	6,957	6,952	6,954	6,963	6,784	6,784	6,785	6,782	6,764	6,751	6,738	6,732	6,736	6,741	6,741	6,741	6,741	6,741
E. Total Unforced Capacity UCAP[4]	6,091	6,348	6,108	6,200	6,134	6,145	6,082	5,866	5,847	5,838	5,823	5,822	5,829	5,834	5,832	5,831	5,831	5,837
2. Winter PJM Capacity (ICAP)[5,6]																		
A. Installed Net Dependable Capability[1,2]	6,938	6,936	6,937	6,945	6,766	6,766	6,767	6,764	6,747	6,733	6,720	6,714	6,719	6,723	6,723	6,723	6,723	6,723
B. Total Positive Interchange Commitments[3]	19	17	17	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
C. Capability in Cold Reserve Status	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Total Installed Capacity (ICAP)	6,957	6,952	6,954	6,963	6,784	6,784	6,785	6,782	6,764	6,751	6,738	6,732	6,736	6,741	6,741	6,741	6,741	6,741
F. $EFOR_D$				8.32%	7.79%	7.79%	7.79%	7.79%	7.81%	7.83%	7.84%	7.85%	7.84%	7.84%	7.84%	7.84%	7.84%	7.84%
E. Total Unforced Capacity UCAP[4]	6,091	6,348	6,108	6,200	6,134	6,145	6,082	5,866	5,847	5,838	5,823	5,822	5,829	5,834	5,832	5,831	5,831	5,837

(1) PJM Installed Capacity (ICAP) Rating, includes OVEC entitlement
(2) Changes in unit capability are reflected on schedule 13
(3) Capacity sales/purchases, positive values are purchases, negative values are sales
(4) UCAP value; includes EE, VVO, and DR
(5) Value represent PJM planning year 20XX/20XX+1
(6) Difference in Summer and Winter capacity ratings is negligible
(7) Values shown are exclusive of resource additions

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View) Schedule 5

POWER SUPPLY DATA (continued)[4]

II. LOAD (MW)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	(ACTUAL)			(PROJECTED)														
1. Summer																		
A. Adjusted Summer Peak[1]	5,537	5,502	5,363	5,383	5,360	5,327	5,329	5,195	5,164	5,149	5,123	5,114	5,108	5,102	5,098	5,095	5,094	5,109
B. Total Negative Power Commitments[2]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C. Total Summer Peak	5,537	5,502	5,363	5,383	5,360	5,327	5,329	5,195	5,164	5,149	5,123	5,114	5,108	5,102	5,098	5,095	5,094	5,109
D. Percent Increasein Total Summer Peak	(1)	(1)	(3)	0	(0)	(1)	0	(3)	(1)	(0)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	0
2. Winter[3]																		
A. Adjusted Winter Peak[1]	7,319	6,523	5,977	6,987	6,918	6,855	6,853	6,830	6,682	6,597	6,546	6,524	6,510	6,467	6,479	6,441	6,430	6,422
B. Total Negative Power Commitments[2]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C. Total Winter Peak	7,319	6,523	5,977	6,987	6,918	6,855	6,853	6,830	6,682	6,597	6,546	6,524	6,510	6,467	6,479	6,441	6,430	6,422
D. Percent Increasein Total Winter Peak	(6)	(11)	(8)	17	(1)	(1)	(0)	(0)	(2)	(1)	(1)	(0)	(0)	(1)	0	(1)	(0)	(0)

(1) Peak after energy efficiency and demand-side programs, see Schedule 1; does not reflect new IRP EE/DR programs.
(2) Includes firm commitments for the delivery of specified blocks of power (i.e., unit power, diversity exchange).
(3) 2019 data refer to winter of 2018/2019, 2020 data refer to winter of 2019/2020, etc.
(4) Values shown are exclusive of resource additions

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View) — Schedule 6

POWER SUPPLY DATA (continued)[5]

	(ACTUAL)			(PROJECTED)														
I. Reserve Margin	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
(Including Cold Reserve Capability)[1]																		
1 - Summer Reserve Margin																		
A. MW (ICAP)	1,420	1,450	1,591	1,579	1,424	1,457	1,456	1,587	1,600	1,602	1,615	1,618	1,628	1,639	1,643	1,646	1,647	1,632
B. Percent of Load	25.6	26.4	29.7	29.3	26.6	27.4	27.3	30.6	31.0	31.1	31.5	31.6	31.9	32.1	32.2	32.3	32.3	32.0
2. Winter Reserve Margin[2]																		
A. MW (ICAP)	(362)	430	977	(24)	(134)	(71)	(69)	(49)	82	154	192	208	227	274	262	300	311	319
B. Percent of Load	(5)	7	16	(0)	(2)	(1)	(1)	(1)	1	2	3	3	3	4	4	5	5	5
II. Reserve Margin																		
(Excluding Cold Reserve Capability)[3]																		
1. Summer Reserve Margin																		
A. MW (ICAP)	1,420	1,450	1,591	1,579	1,424	1,457	1,456	1,587	1,600	1,602	1,615	1,618	1,628	1,639	1,643	1,646	1,647	1,632
B. Percent of Load	25.6	26.4	29.7	29.3	26.6	27.4	27.3	30.6	31.0	31.1	31.5	31.6	31.9	32.1	32.2	32.3	32.3	32.0
2. Winter Reserve Margin[2]																		
A. MW (ICAP)	(362)	430	977	(24)	(134)	(71)	(69)	(49)	82	154	192	208	227	274	262	300	311	319
B. Percent of Load	(5)	7	16	(0)	(2)	(1)	(1)	(1)	1	2	3	3	3	4	4	5	5	5
III. Annual Loss-of-Load Hours[4]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

(1) Calculated based on Total Net Capability for summer and winter.
(2) 2019 data refers to winter of 2018/2019, 2020 data refers to winter of 2019/2020, etc.
(3) Same as footnote 1 above less capability in cold reserve.
(4) The loss of load calculation is carried out by PJM and reserve targets are set with the intention of maintaining a loss of load expectation of no more than 1 day in 10 years.
(5) Values shown are exclusive of resource additions
- = not available

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View) Schedule 7

CAPACITY DATA

	(ACTUAL)			(PROJECTED)														
I. Nameplate Capacity (MW) [1,3]	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
A. Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
B. Coal	4,585	4,568	4,568	4,568	4,568	4,568.1	4,568	4,568	4,568	4,568	4,568	4,568	4,568	4,568	4,568	4,568	4,568	4,568
C. Heavy Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Light Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E. Natural Gas	1,460	1,475	1,477	1,479	1,479	1,479.4	1,479	1,479	1,479	1,479	1,479	1,479	1,479	1,479	1,479	1,479	1,479	1,479
F. Hydro-Conventional	281	281	281	281	281	281	281	281	201	201	201	201	201	201	201	201	201	201
G. Pumped/Battery Storage	585	585	585	585	585	585	585	610	610	610	635	685	735	785	835	885	935	985
H. Wind	495	495	495	495	495	495	699	1,499	1,424	1,325	1,274	1,274	1,274	1,274	1,274	1,274	1,274	1,274
I. Solar	-	-	-	15	15	65	285	285	285	285	285	435	735	885	1,035	1,335	1,485	1,785
J. Demand-Side [4]	-	-	-	98	119	132	188	206	201	195	175	173	167	160	152	149	148	140
K. Purchases	19	17	17	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
L. Total(sum of A through K)	7 425	7 421	7422	7 540	7560	7623	8 103	8 946	8 786	8681	8 636	8 833	9 177	9370	9 562	9 909	10 108	10450
II. Installed Capacity Mix (%) [2,3]																		
A. Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
B. Coal	61.75	61.56	61.55	60.59	60.43	59.93	56.37	51.06	51.99	52.62	52.90	51.72	49.78	48.75	47.78	46.10	45.19	43.71
C. Heavy Fuel Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
D. Light Fuel Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
E. Natural Gas	19.66	19.88	19.89	19.62	19.57	19.41	18.26	16.54	16.84	17.04	17.13	16.75	16.12	15.79	15.47	14.93	14.64	14.16
F. Hydro-Conventional	3.79	3.79	3.79	3.73	3.72	3.69	3.47	3.14	2.29	2.32	2.33	2.28	2.19	2.15	2.10	2.03	1.99	1.93
G. Pumped Storage	7.88	7.88	7.88	7.76	7.74	7.67	7.22	6.82	6.94	7.03	7.35	7.76	8.01	8.38	8.73	8.93	9.25	9.43
H. Wind	6.67	6.67	6.67	6.56	6.54	6.49	8.62	16.75	16.20	15.26	14.76	14.42	13.88	13.59	13.32	12.85	12.60	12.19
I. Solar	0.00	0.00	0.00	0.20	0.20	0.85	3.52	3.19	3.24	3.28	3.30	4.92	8.01	9.45	10.82	13.47	14.69	17.08
J. Demand-Side [4]	0.00	0.00	0.00	1.31	1.57	1.73	2.32	2.31	2.29	2.25	2.03	1.95	1.82	1.70	1.59	1.50	1.46	1.34
K. Purchases	0.25	0.22	0.23	0.23	0.23	0.23	0.22	0.20	0.20	0.20	0.20	0.20	0.19	0.19	0.19	0.18	0.18	0.17

(1) Summer Nameplate capacities by fuel types for supply-side resources
(2) Each item in lines A-K of Section II. as a percent of line L above in Section I.
(3) Reflects resource additions of the Preferred Plan
(4) Includes EE, VVO, DR, and DG Resources. Actual DSM is embedded in actual demand.

APPALACHIAN POWER
An AEP Company
BOUNDLESS ENERGY

COMPANY NAME: AEP SYSTEM - EAST ZONE

Schedule 8

UNIT PERFORMANCE DATA

CONFIDENTIAL

Equivalent Availability Factor (%) [1]

	(ACTUAL)			(PROJECTED)																	
Unit Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Amos 1	[redacted]																	
Amos 2																		
Amos 3																		
Ceredo 1																		
Ceredo 2																		
Ceredo 3																		
Ceredo 4																		
Ceredo 5																		
Ceredo 6																		
Clinch River 1																		
Clinch River 2																		
Mountaineer 1																		
Dresden (2)																		

(1) Does not inlcude renewable generation, or power purchases.

(2) Dresden Duct Burner not included.

-= not available

COMPANY NAME: AEP SYSTEM - EAST ZONE

Schedule 9

UNIT PERFORMANCE DATA

CONFIDENTIAL

Net Capacity Factor (%) [1]

Unit Name	2019 (ACTUAL)	2020 (ACTUAL)	2021 (ACTUAL)	2022 (PROJECTED)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Amos 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Amos 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-
Amos 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-
Ceredo 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-
Ceredo 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-
Ceredo 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-
Ceredo 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-
Ceredo 5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-
Ceredo 6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-
Clinch River 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Clinch River 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mountaineer 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dresden	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

(1) Does not inlcude renewable generation, or power purchases

(2) Dresden Duct Burner not included.

- = not available

COMPANY NAME: AEP SYSTEM - EAST ZONE

Schedule 10

UNIT PERFORMANCE DATA

CONFIDENTIAL

Average Heat Rate - (Btu/kWh)[1]

	(ACTUAL)			(PROJECTED)														
Unit Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Amos 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			
Amos 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Amos 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-
Ceredo 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-
Ceredo 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-
Ceredo 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-
Ceredo 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-
Ceredo 5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-
Ceredo 6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-
Clinch River 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
Clinch River 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
Mountaineer 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dresden	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

(1) Does not inlcude renewable generation, or power purchases

(2) Dresden Duct Burner not included.

- = not available

APPALACHIAN POWER

OMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View)

Schedule 11

ENEWABLE RESOURCES (MWh)

Resource Type[1]	Unit Name	C.O.D[2]	Build/ Purchase[3]	Life/ Duration[4]	Size (MW) Nameplate	Size (MW) NDC[5]	(ACTUAL) 019	(ACTUAL) 2020	(ACTUAL) 2021
ind	Camp Grove	01/18/08	Purchase	0 years	75	13	209,557	193,099	200,662
	Fowler Ridge 3	02/27/09	Purchase	0 years	99	13	241,329	220,299	175,796
	Grand Ridge 2-3	12/21/09	Purchase	0 years	101	16	253,484	238,068	226,301
	Beech Ridge	06/01/10	Purchase	0 years	101	15	230,745	278,788	253,730
	Bluff Point	01/01/18	Purchase	0 years	120	24	388,279	370,849	380,595
	Top Hat	01/01/25	Owned	0 years	204	31			
	New[7]	Varies	Both	5 years	950	Varies			
ind Subtotal					1,649	111	1,323,394	1,301,102	1,237,084
Solar	istributed	-	-	-	-	173	-	-	-
	edington	10/1/2023	Owned	5 years	50	27			
	epot[6]	06/01/22	Purchase	0 years	15	8	-	-	-
	irefly	07/01/24	Owned	5 years	150	77			
	lorsepen	01/01/25	Purchase	0 years	20	10			
	un Valley	01/01/25	Purchase	0 years	50	26			
	ew large-Scale[7]	Varies	Both	0 years	3,147	Varies	-	-	-
lar Subtotal					3,432	320	-	-	-
REC									
Total Renewables					5,081	30	1,323,394	1,301,102	1,237,084

Unit Name	2022	2023	2024	2025	2026	2027	028	2029
Camp Grove	206,962	206,962	207,679	206,962	206,962	206,962	22,416	0
Fowler Ridge 3	237,833	237,833	238,637	237,833	237,833	237,833	238,637	49,596
Grand Ridge 2-3	254,236	254,236	255,121	254,236	254,236	254,236	255,121	189,788
Beech Ridge	246,850	246,850	247,797	246,850	246,850	246,850	247,797	246,850
Bluff Point	381,344	381,344	382,706	381,344	381,344	381,344	382,706	381,344
Top Hat	0	0	0	759,800	759,800	759,800	762,434	759,800
New[7]	0	0	0	0	,455,835	2,455,835	2,465,785	2,609,325
ind Subtotal	,327,226	1,327,226	,331,940	2,087,026	,542,861	4,542,861	4,374,896	4,236,704
istributed	0	0	0	64,703	71,173	81,198	85,731	90,584
edington	0	4,840	157,149	155,983	155,203	154,427	154,029	152,886
epot[6]	20,951	5,613	35,520	35,258	35,082	34,906	34,815	34,558
irefly	0	0	157,195	131,084	129,429	127,782	126,994	124,512
lorsepen	0	0	0	43,444	43,227	43,011	42,908	42,582
un Valley	0	0	0	116,169	115,588	115,010	114,702	113,863
ew large-Scale[7]	0	0	0	0	0	0	0	0
lar Subtotal	20,951	0,453	149,863	146,640	149,701	156,333	159,179	158,985
REC	350,400	350,400	702,720	700,800	0	0	0	0
Total Renewables	1,698,577	1,738,079	2,384,523	,534,466	5,292,562	5,299,194	5,134,075	4,995,688

Unit Name	2030	2031	2032	2033	2034	2035	2036
Camp Grove	0	0	0	0	0	0	0
Fowler Ridge 3	0	0	0	0	0	0	0
Grand Ridge 2-3	0	0	0	0	0	0	0
Beech Ridge	166,395	0	0	0	0	0	0
Bluff Point	381,344	381,344	382,706	381,344	381,344	381,344	382,706
Top Hat	759,800	759,800	762,434	759,800	759,800	759,800	762,434
New[7]	2,916,304	2,916,304	,928,120	,916,304	,916,304	2,916,304	2,928,120
ind Subtotal	4,223,844	4,057,448	,073,260	,057,448	,057,448	4,057,448	4,073,260
istributed	95,436	99,061	105,142	111,612	118,082	125,044	132,641
edington	152,122	151,361	150,971	149,852	149,102	148,357	147,975
epot[6]	34,385	34,213	34,124	33,872	33,703	33,534	33,446
irefly	322,889	321,275	320,503	318,070	316,480	314,897	314,141
lorsepen	42,369	42,157	42,056	41,736	41,528	41,320	41,222
un Valley	113,293	112,727	112,425	111,602	111,044	110,489	110,194
ew large-Scale[7]	313,948	946,338	,265,828	,574,722	,202,431	2,518,524	3,158,396
lar Subtotal	1,074,442	1,707,132	,031,050	,341,467	,972,370	3,292,166	3,938,014
REC	0	0	0	0	0	0	702,720
Total Renewables	5,298,286	5,764,580	6,104,309	6,398,915	7,029,818	7,349,614	8,713,994

) Per definition of 56-576 of the code of Virginia.
) Commercial operation date.
) Describe as Company built or purchase.
) State expected life of facility or duration of purchase contract.
) Net dependable capacity (for summer 2022).
) Not modeled as a behind the meter resource.
) LT Additions
= not available

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View) Schedule 12

Energy Efficiency/Conservation/Demand Side Management/Demand Response (MWh)

Program Type	Program Name	Date (3)	Life/ Duration (4)	Size (MW) (5)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
						(ACTUAL) (6)									(PROJECTED) (6)							
EE (1)	Current Programs	6/12/2019	10	6	23,982	29,188	26,416	35,157	19,037	2,731	1,250	991	730	475	232	8	-	-	-	-	-	-
EE (1)	Residential	1/1/2022	10	62				42,000	72,590	93,490	110,963	131,949	115,506	99,855	85,752	73,821	64,569	12,960	8,181	4,455	1,863	405
EE (2)	Commerical	1/1/2022	14	13				46,000	93,449	140,505	186,813	230,649	198,098	165,755	134,840	106,937	82,055	58,068	38,358	22,732	11,530	4,794
EE (2)	WO	1/1/2036	15	5.9				-	-	-	-	-	-	-	-	-	-	-	-	-	-	24,105
Subtotal				86	23,982	29,188	26,416	123,157	185,076	236,726	299,026	363,589	314,334	266,085	220,823	180,766	146,624	71,028	46,539	27,187	13,393	29,304
DR	PSEDR	06/12/2021	15	7		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	Interruptible	06/12/2021	15	29		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	ATOD	06/12/2021	15	20		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal				55	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Demand Side Management				142	23,982	29,188	26,416	123,157	185,076	236,726	299,026	363,589	314,334	266,085	220,823	180,766	146,624	71,028	46,539	27,187	13,393	29,304

Notes:

(1) Current Program Descriptions

C&I Rebates - Program includes lighting, motor, and refrigeration measures

Residential Low & Moderate Income - Program includes insulation, thermostat, duct sealing, CFL, low flow fixtures, and water heater blanket measures

Residential Rebates - Primarily CFL, also Energy Star appliance measures

Residential Whole House - Program primarily includes CFL, low flow, with some insulation, thermostat, duct sealing, and A/C measures

PSEDR - Peak Shaving and Emergency Demand Response

Interruptible - Special contracts

ATOD Pricing - Tariff, tiered pricing

(2) Incremental Proxy EE Programs modeled in the IRP.

(3) Date indicates year program starts.

(4) Weighted Average life of measures that constitute programs.

(5) Demand impacts for EE programs reflect 2036 undegraded value. Values are coincendent peak impacts. Demand impacts for DR programs are for PJM (summer) peak.

(6) Energy values shown are degraded.

COMPANY NAME: AEP SYSTEM - APCo | Schedule 13

UNIT PERFORMANCE DATA[1]

Unit Size (MW) Uprate and Derate[2]

	(ACTUAL)			(PROJECTED)															
Unit Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Amos 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amos 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amos 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ceredo 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clinch River 1[3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clinch River 2[3]	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mountaineer 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Buck 1 - 3	-	-	-	-	(0.9)	-	-	-	-	-	-	-	-	-	-	-	-	-
Byllesby 1 - 4	-	-	-	-	(2.4)	-	-	-	-	-	-	-	-	-	-	-	-	-
Claytor 1 - 4	-	-	-	-	(43.6)	0.6	0.6	0.6	0.6	0.6	-	-	-	-	-	-	-	-
Leesville 1 - 2	-	-	-	-	(28.5)	0.4	0.4	0.4	0.4	0.4	-	-	-	-	-	-	-	-
London 1 - 3	-	-	-	-	(3.8)	0.1	0.1	0.1	0.1	0.1	-	-	-	-	-	-	-	-
Marmet 1 - 3	-	-	-	-	(3.4)	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-
Niagara 1 - 2	-	-	-	-	(0.3)	-	-	-	-	-	-	-	-	-	-	-	-	-
Winfield 1 - 3	-	-	-	-	(5.7)	0.1	0.1	0.1	0.1	0.1	-	-	-	-	-	-	-	-
Smith Mountain 1	-	-	-	-	-	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	-	-	-	-	-	-	-	-
Smith Mountain 2	-	-	-	-	-	(2.4)	(2.5)	(2.4)	(2.5)	(2.4)	-	-	-	-	-	-	-	-
Smith Mountain 3	-	-	-	-	-	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	-	-	-	-	-	-	-	-
Smith Mountain 4	-	-	-	-	-	(2.4)	(2.5)	(2.4)	(2.5)	(2.4)	-	-	-	-	-	-	-	-
Smith Mountain 5	-	-	-	-	-	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	-	-	-	-	-	-	-	-
Dresden	-	15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OVEC	-	(17)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind & Solar	-	-	-	8	(5)	(5)	(5)	(5)	(14)	(15)	(11)	(11)	-	-	-	-	-	-

(1) Reflects owned, ~~active units~~. Combustion turbines, combined cycles and hydro plants reported as composite facilities. Hydro, Wind and Solar changes reflect changes in PJM ELCC %.

(2) PJM capability as of filing. Value represent PJM planning year 20XX/20XX+1. Incremental Uprates shown as positive + and decremental Derates shown as negative (-).

(3) Includes conversion from coal to natural gas fuel in 2016, unit retirement in 12/2025.

COMPANY NAME: AEP SYSTEM - APCo — Schedule 14

UNIT PERFORMANCE DATA

Existing Owned Supply-Side Resources (MW) as of April 1, 2022 [1]

Unit Name	Company	Location	Unit Type	Primary Fuel Type	C.O.D. [2]	Net Capability - MW [3] Winter		Summer	
Amos 1	APCo	St. Albans, WV	Steam	Coal - Bit.	1971	800		800	
Amos 2	APCo	St. Albans, WV	Steam	Coal - Bit.	1972	800		800	
Amos 3	APCo	St. Albans, WV	Steam	Coal - Bit.	1973	1,330		1,330	
Ceredo 1	APCo	Ceredo, WV	Combustion Turbine	Gas	2001	86		76	
Ceredo 2	APCo	Ceredo, WV	Combustion Turbine	Gas	2001	86		76	
Ceredo 3	APCo	Ceredo, WV	Combustion Turbine	Gas	2001	86		76	
Ceredo 4	APCo	Ceredo, WV	Combustion Turbine	Gas	2001	86		76	
Ceredo 5	APCo	Ceredo, WV	Combustion Turbine	Gas	2001	86		75	
Ceredo 6	APCo	Ceredo, WV	Combustion Turbine	Gas	2001	86		76	
Clinch River 1	APCo	Carbo, VA	Steam	Gas	1958	230		225	
Clinch River 2	APCo	Carbo, VA	Steam	Gas	1958	235		232	
Dresden	APCo	Dresden, OH	Combined Cycle	Gas	2012	665		570	
Mountaineer 1	APCo	New Haven, WV	Steam	Coal - Bit.	1980	1,320		1,305	
Buck 1 - 3	APCo	Ivanhoe, VA	Hydro	--	1912	11		11	(A)
Byllesby 1 - 4	APCo	Byllesby, VA	Hydro	--	1912	19		19	(A)
Claytor 1 - 4	APCo	Radford, VA	Hydro	--	1939	75		75	(A)
Leesville 1 - 2	APCo	Leesville, VA	Hydro	--	1964	50		50	(A)
London 1 - 3	APCo	Montgomery, WV	Hydro	--	1935	14		14	(A)
Marmet 1 - 3	APCo	Marmet, WV	Hydro	--	1935	14		14	(A)
Niagara 1 - 2	APCO	Roanoke, VA	Hydro	--	1924	2		2	(A)
Winfield 1 - 3	APCo	Winfield, WV	Hydro	--	1938	15		15	(A)
Smith Mountain 1	APCo	Penhook, VA	Pump. Stor.	--	1965	65	(B)	65	(B)
Smith Mountain 2	APCo	Penhook, VA	Pump. Stor.	--	1965	175	(B)	175	(B)
Smith Mountain 3	APCo	Penhook, VA	Pump. Stor.	--	1980	105	(B)	105	(B)
Smith Mountain 4	APCo	Penhook, VA	Pump. Stor.	--	1966	175	(B)	175	(B)
Smith Mountain 5	APCo	Penhook, VA	Pump. Stor.	--	1966	65	(B)	65	(B)
Depot Solar(4)	APCo	Campbell County, VA	Solar	--	2022	15		15	
						6,697		6,516	

Notes:

(1) Power Purchase Agreements (PPAs) are not included.

(2) Commercial operation date.

(3) Peak net dependable capability as of filing.

(A) Nameplate.

(B) Units 1, 3 & 5 have pump-back capability, units 2 & 4 are generation only.

(4) Modeling reflects Depot Solar coming in at the end of 2021, however, recent project updates indicate the project will come online in April 2022. Not modeled as a behind the meter resource.

COMPANY NAME: AEP SYSTEM - APCo							Schedule 15
UNIT PERFORMANCE DATA							
Planned Supply Side Resources (MW) [1]							
Unit Name	Company	Location	Unit Type	Primary Fuel Type	C.O.D. [2]	Nameplate Capacity [3]	Installed Capacity [4]
Top Hat	APCo	Illinois	Wind	n/a	Jan/2025	204	31
Bedington	APCo	West Virginia	Solar	n/a	Oct/2023	50	27
Depot	APCo	Virginia	Solar	n/a	Jun/2022	15	8
Firefly	APCo	Virginia	Solar	n/a	Jul/2024	150	77
Horsepen	APCo	Virginia	Solar	n/a	Jan/2025	20	10
Sun Valley	APCo	Virginia	Solar	n/a	Jan/2025	50	26
APCo Solar 2030	APCo	Virginia	Solar	n/a	Dec/2029	150	48
APCOo Solar 2031	APCo	Virginia	Solar	n/a	Dec/2030	300	81
APCOo Solar 2032	APCo	Virginia	Solar	n/a	Dec/2031	150	33
APCOo Solar 2033	APCo	Virginia	Solar	n/a	Dec/2032	150	33
APCOo Solar 2034	APCo	Virginia	Solar	n/a	Dec/2033	300	66
APCOo Solar 2035	APCo	Virginia	Solar	n/a	Dec/2034	150	33
APCOo Solar 2036	APCo	Virginia	Solar	n/a	Dec/2035	300	66
APCo Wind 2026	APCo	Virginia	Wind	n/a	Dec/2025	800	112
APCo Wind 2029	APCo	Virginia	Wind	n/a	Dec/2028	50	6
APCo Wind 2030	APCo	Virginia	Wind	n/a	Dec/2029	100	11
APCo Storage 2026	APCo	Virginia	Storage	n/a	Jan/2026	25	19
APCo Storage 2029	APCo	Virginia	Storage	n/a	Jan/2029	25	20
APCo Storage 2030	APCo	Virginia	Storage	n/a	Jan/2030	50	45
APCo Storage 2031	APCo	Virginia	Storage	n/a	Jan/2031	50	49
APCo Storage 2032	APCo	Virginia	Storage	n/a	Jan/2032	50	50
APCo Storage 2033	APCo	Virginia	Storage	n/a	Jan/2033	50	50
APCo Storage 2034	APCo	Virginia	Storage	n/a	Jan/2034	50	50
APCo Storage 2035	APCo	Virginia	Storage	n/a	Jan/2035	50	50
APCo Storage 2036	APCo	Virginia	Storage	n/a	Jan/2036	50	50

Notes:

(1) In view of the current economic conditions, potential federal and state requirement for renewable energy and energy efficiency, and the potential for federal CO_2 legislation the timing of future generation resource additions are highly uncertain.

(2) Commercial operation date.

(3) Standard ISO rating at 1000' elevation

(4) Net Dependable Rating of unit as determined in accordance with PJM's Rules and Procedures.
Wind Resources and Solar Resources are assumed to have a installed capacity rating of PJM'S ELCC % of nameplate.

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo) (Stand Alone View)																		Schedule 16
UTILITY CAPACITY POSITION (MW) [1]																		
	(ACTUAL) [2]			(PROJECTED)														
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Existing Capacity (ICAP)																		
Conventional	-	-	-	6,048	6,048	6,047.5	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048
Wind				80	70	69.7	67	62	50	38	25	19	17	19	19	19	19	19
Hydro				817	650	649.6	653	655	650	648	648	648	655	658	658	658	658	658
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Total Existing Capacity	-	-	-	6,962.6	6,784.5	6,784.5	6,785.2	6,782.2	6,764.9	6,751.5	6,738.3	6,732.0	6,736.8	6,741.6	6,741.6	6,741.6	6,741.6	6,741.6
Planned Capacity Changes (ICAP)																		
Conventional	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind				0	(10)	(10)	(13)	(18)	(30)	(42)	(55)	(61)	(63)	(61)	(61)	(61)	(61)	(61)
Hydro				0	(168)	(168)	(164)	(163)	(168)	(169)	(169)	(169)	(163)	(160)	(160)	(160)	(160)	(160)
Solar	-	-	-	0	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
Battery Storage																		
Total Planned Capacity Changes	-	-	-	0	(178)	(178)	(177)	(180)	(198)	(211)	(224)	(231)	(226)	(221)	(221)	(221)	(221)	(221)
Capacity Performance Changes (UCAP)	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Expected New Capacity (UCAP)																		
Conventional	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewable	-	-	-	8	8	35	176	275	256	234	221	266	314	322	355	421	454	520
Battery Storage	-	-	-	0	0	0	0	19	18	19	40	89	147	200	250	300	350	400
Total Expected New Capacity	-	-	-	8	8	35	176	293	274	254	261	355	461	522	605	721	804	920
EFORd				8.32%	7.79%	7.79%	7.79%	7.79%	7.81%	7.83%	7.84%	7.83%	7.84%	7.84%	7.84%	7.84%	7.84%	7.84%
Unforced Availability (Factor)	-	-	-	8.32%	7.79%	7.79%	7.79%	7.79%	7.81%	7.83%	7.84%	7.83%	7.84%	7.84%	7.84%	7.84%	7.84%	7.84%
Net Generation Capacity (UCAP)	-	-	-	6,297	6,387	6,451	6,641	6,579	6,531	6,489	6,442	6,528	6,630	6,681	6,746	6,854	6,935	7,042
Existing DSM Reductions (ICAP) [3,5]																		
Demand response	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Conservation/Efficiency	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Behind the Meter Resources				22	26	26	35	32	30	27	25	22	19	15	15	15	15	6
Total Existing DSM Reductions	-	-	-	72	77	77	86	83	81	78	76	72	69	66	66	66	66	56
Expected New DSM Reductions (ICAP) [3,4]																		
Demand Response	-	-	-	8	8	8	8	12	12	12	4	4	4	4	0	0	0	0
Conservation/Efficiency/VVO (degraded)	-	-	-	18	34	47	59	71	62	53	36	29	22	16	10	6	3	1
Distributed Generation	-	-	-	0	0	0	35	40	46	52	59	67	72	74	76	77	79	83
Combined Heat and Power	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Expected New DSM Reductions	-	-	-	26	42	55	102	123	120	117	99	100	98	94	86	83	82	84
Total Demand-side Reductions (ICAP)	-	-	-	98	119	132	188	206	201	195	175	173	167	160	152	149	148	140
Net Generation & Demand-side (UCAP)	-	-	-	6,199	6,268	6,319	6,453	6,373	6,330	6,294	6,267	6,356	6,463	6,521	6,594	6,706	6,788	6,901
PJM Capacity Obligation (UCAP) [4]	-	-	-	5,679	5,682	5,708	5,707	5,525	5,492	5,476	5,448	5,439	5,432	5,426	5,422	5,418	5,418	5,433
Additional Obligation	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Obligation	-	-	-	5,679	5,682	5,708	5,707	5,525	5,492	5,476	5,448	5,439	5,432	5,426	5,422	5,418	5,418	5,433
Net Utility Capacity Position	-	-	-	520	587	611	745	848	838	818	818	917	1,030	1,095	1,172	1,288	1,370	1,468

(1) Net dependable installed capability during peak season (summer); unit capabilities are classified by primary fuel type.
(2) Not Applicable - APCo is not an independent PJM member and therefore does not have actual PJM specific data.
(3) The impact of new conservation, efficiency and distributed generation is delayed four years to represent its impact on actual load feeding through the PJM load forecast process.
(4) Through 2024, the values shown represent an estimate of APCo's share of the final and forecasted PJM load that is the basis for AEP's capacity obligation.
The remaining years represent an estimate of APCo's share of the internal AEP forecast that has been adjusted to the PJM peak.
(5) Tables reflect DSM levels consistent with June 2021 forecast and DSM incremental to the forecast associated with Plexos portfolios.
(6) Renewable represents conventional hydro, pumped storage, solar and wind.

Schedule 17

CONFIDENTIAL

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)

CONSTRUCTION FORECAST (Million Dollars)

	ACTUAL EXPENDITURES			PROJECTED EXPENDITURES		
	2019	2020	2021	2022	2023	2024
I. New Traditional Generating Facilities						
a. Capital Investment (Exclusive of AFUDC)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
b. AFUDC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
c. Annual Total	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
d. Cumulative Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-
II. New Renewable Generating Facilities[1]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted] Other Facilities						
a. Existing Generation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
b. Transmission	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
c. Distribution	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
d. Energy conservation/efficiency & demand response	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
e. gridSMART	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
f. Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
g. AFUDC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
h. Annual Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
i. Cumulative Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
IV. Total Construction Expenditures						
a. Annual Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
b. Cumulative Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
V. Percent of Funds for Total Construction Provided from External Financing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

1 APCo has signed contracts to purchase renewable energy under power purchase agreements with third parties.

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View) | Schedule 18

FUEL DATA | CONFIDENTIAL

	(ACTUAL)			(PROJECTED)[1]														
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
I. Delivered Fuel Price (cents/MBtu)																		
a. Nuclear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
b. Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
c. Heavy Fuel Oil	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
d. Light Fuel Oil (2)	[redacted]																	
e. Natural Gas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
f. Renewable *	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
II. Primary Fuel Expenses (cents/kWh)																		
a. Nuclear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
b. Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
c. Heavy Fuel Oil				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
d. Light Fuel Oil	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
e. Natural Gas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
f. Renewable *	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		-
g. Purchases (3) Energy Charges only	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
h. Purchases (3) Energy and Capacity Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

* Per definition of 56-576 of the Code of Virginia.

(1) As consumed.

(2) Projected Light Fuel Oil values are within Coal and Natural Gas projected values.

(3) Includes existing PPAs.

- =not available

Exhibit D: Cross Reference Table

For the 15 Year Forecast Period Beginning 2022

Virginia - Integrated Resource Planning Guidelines Cross Reference Table	Section/Page Reference
A. Purpose The purpose of these guidelines is to implement the provisions of §§ 56-597, 56-598 and 56-599 of the Code of Virginia with respect to integrated resource planning ("IRP") by the electric utilities in the Commonwealth. In order to understand the basis for the utility's plan, the IRP filing shall include a narrative summary detailing the underlying assumptions reflected in its forecast as further described in the guidelines. To better follow the utility's planning process, the narrative shall include a description of the utility's rationale for the selection of any particular generation addition or demand-side management program to fulfill its forecasted need. Such description should include the utility's evaluation of its purchase options and cost/benefit analyses for each resource option to confirm and justify each resource option it has chosen.	
Such narrative shall also describe the planning process including timelines and appropriate reviews and/or approvals of the utility's plan. For members of PJM Interconnection, LLC ("PJM"), the narrative should describe how the IRP incorporates the PJM planning and implementation processes and how it will satisfy PJM load obligations.	
These guidelines also include sample schedules to supplement this narrative discussion and assist the utilities in developing a tabulation of the utility's forecast for at least a 15-year period and identify the projected supply-side or demand-side resource additions and solutions to adequately and reliably meet the electricity needs of the Commonwealth. This tabulation shall also indicate the projected effects of demand response and energy efficiency programs and activities on forecasted annual energy and peak loads for the same period. These guidelines also direct that all IRP filings include information to comparably evaluate various supply-side technologies and demand-side programs and technologies on an equivalent basis as more fully described below in Section F (7). The Commission may revise or supplement the sample schedules as needed or warranted.	
B. Applicability These guidelines are applicable to all investor-owned utilities responsible for procurement of any or all of its individual power supply resources.	
C. Integrated Resource Plan Each utility shall develop and keep current an integrated resource plan, which incorporates, at a minimum, the following:	
C.1. Forecast A three-year historical record and a 15-year forecast of the utility's native load requirements, the utility's PJM load obligations if appropriate, and other system capacity or firm energy obligations for each peak season along with the supply-side (including owned/leased generation capacity and firm purchased power arrangements) and demand-side resources expected to satisfy those loads, and the reserve margin thus produced.	Schedule 1, Exhibits A-1, A-2A, A-2B, A- 3, Section 5.3
C.2. Option Analyses A comprehensive analysis of all existing and new resource options (supply- and demand-side), including costs, benefits, risks, uncertainties, reliability, and customer acceptance where appropriate, considered and chosen by the utility for satisfaction of native load requirements and other system obligations necessary to provide reliable electric utility service, at the lowest reasonable cost, over the planning period.	Sections 5.3, 5.4

C.2.a. Purchased Power Assess the potential costs and benefits of purchasing power from wholesale power suppliers and power marketers to supply it with needed capacity and describe in detail any decision to purchase electricity from the wholesale power market.	Sections 4.7, 5.4
C.2.b. Supply-side Energy Resources Assess the potential costs and benefits of reasonably available traditional and alternative supply-side energy resource options, including, but not limited to technologies such as, nuclear, pulverized coal, clean coal, circulating fluidized bed, wood, combined cycle, integrated gasification combined cycle, and combustion turbine, as well as renewable energy resources such as those derived from sunlight, wind, falling water, sustainable biomass, energy from waste, municipal solid waste, wave motion, tides, and geothermal power.	Section 4.5, Exhibit B
C.2.c. Demand-side Options Assess the potential costs and benefits of programs that promote demand-side management. For purposes of these guidelines, peak reduction and demand response programs and energy efficiency and conservation programs will collectively be referred to as demand-side options.	Section 4.4
C.2.d. Evaluation of Resource Options Analyze potential resource options and combinations of resource options to serve system needs, taking into account the sensitivity of its analysis to variations in future estimates of peak load, energy requirements, and other significant assumptions, including, but not limited to, the risks associated with wholesale markets, fuel costs, construction or implementation costs, transmission and distribution costs, environmental impacts and compliance costs.	Sections 5.2, 5.3
C.3. Data Availability To the extent the information requested is not currently available or is not applicable, the utility will clearly note and explain this in the appropriate location in the plan, narrative, or schedule.	

D. Narrative Summary Each utility shall provide a narrative summary detailing the major trends, events, and/or conditions reflected in the forecasted data submitted in response to these guidelines. Examples of items which should be highlighted in the summary include:	Sections 1, 2, 3
D.1. Discussion regarding the forecasted peak load obligation and energy requirements. PJM members should also discuss the relationship of the utility's expected non-coincident peak and its expected PJM related load obligations.	Section 2.5
D.2. Discussion regarding company goals and plans in response to directives of Chapters 23 and 24 of Title 56 of the Code of Virginia, including compliance with energy efficiency, energy conservation, demand-side and response programs, and the provision of electricity from renewable energy resources.	Sections 3.4, Section 4
D.3. Discussion regarding the complete planning process, including timelines, assumptions, reviews, approvals, etc., of the company's plans. For PJM members, the discussion should also describe how the IRP integrates into the complete planning process of PJM.	Section 3, 5, 6; Schedules 8, 9, 10 and 13
D.4. Discussion of the critical input assumptions to determine the load forecast and expected changes in load growth including factors such as energy conservation, efficiency, load management, demand response, variations in customer class sizes, expected levels of economic activity, variations in fuel prices and appliance inventories, etc.	Section 2
D.5. Discussion regarding cost/benefit analyses and the results of such factors on this plan, including the methodology used to consider equal or comparable treatment afforded both the demand-side options and supply-side resources.	Sections 4, 5

D.6. Planned changes in operating characteristics such as unit retirements, unit uprates or derates, changes in unit availabilities, changes in capacity resource mix, changes in fuel supplies or transport, emissions compliance, unit performance, etc.	Section 6; Schedules 8, 9, 10 and 13
D.7. Discussion regarding the effectiveness of the utility's IRP to meet its load obligations with supply-side and demand-side resources to enable the utility to provide reliable service at reasonable prices over the long term.	Section 5
E. Filing By September 1, 2009, and every two years thereafter, each utility shall file with the Commission its then current integrated resource plan, which shall include all information required by these guidelines for the ensuing 15-year planning period along with the prior three-year historical period. The process and analyses shall be described in a narrative discussion and the results presented in tabular format using an EXCEL spreadsheet format, similar to the attached sample schedules, and be provided in both printed and electronic media. For those utilities that operate as part of a multi-state integrated power system, the schedules should be submitted for both the individual company and the generation planning pool of which the utility is a member. The top line stating the company name should indicate that the data reflects the individual utility company or the total system. For partial ownership of any facility, please provide the percent ownership and footnote accordingly.	
Each filing shall include a five-year action plan that discusses those specific actions currently being taken by the utility to implement the options or activities chosen as appropriate per the IRP.	Executive Summary, Section 6
If a utility considers certain information in its IRP to be proprietary or confidential, the utility may so designate, file separately and request such treatment in accordance with the Commission's Rules of Practice and Procedures.	Confidential Schedules will be labeled as such and will be included in a separate Confidential Supplement
Additionally, by September 1 of each year in which a plan is not required, each utility shall file a narrative summary describing any significant event necessitating a major revision to the most recently filed IRP, including adjustments to the type and size of resources identified. If the utility provides a total system IRP in another jurisdiction by September 1 of the year in which a plan is not required, filing the total system IRP from the other jurisdiction will suffice for purposes of this section.	
As § 56-599 E requires the giving of notice and an opportunity to be heard, each utility shall also include a copy of its proposed notice to be used to afford such an opportunity.	
F. Contents of the Filing The IRP shall include the following data:	
F.1. Forecast of Load The forecast shall include descriptions of the methods, models, and assumptions used by the utility to prepare its forecasts of its loads, requirements associated with the utility's PJM load obligation (MW) if appropriate, the utility's peak load (MW) and energy sales (MWh) and the variables used in the models and shall include, at a minimum, the following:	Section 2; Schedule 1
F.1.a. The most recent three-year history and 15-year forecast of energy sales (kWh) by each customer class,	Section 2; Exhibits A-1, A-2A, A-2B
F.1.b. The most recent three-year history and 15-year forecast of the utility's peak load and the expected load obligation to satisfy PJM's coincident peak forecast if appropriate, and the utility's coincident peak load and associated non-coincident peak loads for summer and winter seasons of each year (prior to any DSM), annual energy forecasts, and resultant reserve margins. During the forecast period, the tabulation shall also indicate	Section 2; Schedule 1

the projected effects of incremental demand-side options on the forecasted annual energy and peak loads, and	
F.1.c. Where future resources are required, a description and associated characteristics of the option that the utility proposes to use to address the forecasted need.	Section 5; Schedule 15
F.2. Supply-side Resources The forecast shall provide data for its existing and planned electric generating facilities (including planned additions and retirements and rating changes, as well as firm purchase contracts, including cogeneration and small power production) and a narrative description of the driver(s) underlying such anticipated changes such as expected environmental compliance, carbon restrictions, technology enhancements, etc.:	Sections 3; Schedules 13, 14

F.2.a. Existing Generation. For existing units in service:	
i. Type of fuel(s) used;	Schedule 14
ii. Type of unit (e.g., base, intermediate, or peaking);	Schedule 14
iii. Location of each existing unit;	Schedule 14
iv. Commercial Operation Date;	Schedule 14
v. Size (nameplate, dependable operating capacity, and expected capacity value to meet load obligation (MW));	Schedules 13 and 14
vi. Units to be placed in reserve shutdown or retired from service with expected date of shutdown or retirement and an economic analysis supporting the planned retirement or shutdown dates;	Schedules 13 and 14
vii. Units with specific plans for life extension, refurbishment, fuel conversion, modification or upgrading. The reporting utility shall also provide the expected (or actual) date removed from service, expected return to service date, capacity rating upon return to service, a general description of work to be performed as well as an economic analysis supporting such plans for existing units;	Schedules 13 and 14
viii. Major capital improvements such as the addition of scrubbers, shall be evaluated through the IRP analysis to assess whether such improvements are cost justified when compared to other alternatives, including retirement and replacement of such resources; and	Section 3
ix. Other changes to existing generating units that are expected to increase or decrease generation capability of such units.	Schedule 14
F.2.b. Assessment of Supply-side Resources. Include the current overall assessment of existing and potential traditional and alternative supply-side energy resources, including a descriptive summary of each analysis performed or used by the utility in the assessment. The utility shall also provide general information on any changes to the methods and assumptions used in the assessment since its most recent IRP or annual report.	Sections 3.1, 3.2, and 4.5
F.2.b.i. For the currently operational or potential future supply-side energy resources included, provide information on the capacity and energy available or projected to be available from the resource and associated costs. The utility shall also provide this information for any actual or potential supply-side energy resources that have been discontinued from its plan since its last biennial report and the reasons for that discontinuance.	Schedules 9, 13 and 15

F.2.b.ii. For supply-side energy resources evaluated but rejected, a description of the resource; the potential capacity and energy associated with the resource; estimated costs and the reasons for the rejection of the resource.	Section 5
F.2.c. Planned Generation Additions. A list of planned generation additions, the rationale as to why each listed generation addition was selected, and a 15-year projection of the following for each listed addition:	Section 5.3 ; Schedule 15
i. Type of conventional or alternative facility and fuel(s) used;	Schedule 15
ii. Type of unit (e.g. baseload, intermediate, peaking);	Schedule 15
iii. Location of each planned unit, including description of locational benefits identified by PJM and/or the utility;	Schedule 15
iv. Expected Commercial Operation Date;	Schedule 15
v. Size (nameplate, dependable operating capacity, and expected capacity value to meet load obligation (MW));	Schedule 15
vi. Summaries of the analyses supporting such new generation additions, including its type of fuel and designation as base, intermediate, or peaking capacity.	Section 5.3, Schedule 15
vii. Estimated cost of planned unit additions to compare with demand-side options.	Schedule 15
F.2.d. Non-Utility Generation. A separate list of all non-utility electric generating facilities included in the IRP, including customer-owned and stand-by generating facilities. This list shall include the facility name, location, primary fuel type, and contractual capacity (including any contract dispatch conditions or limitations), and the contractual start and expiration dates. The utility shall also indicate which facilities are included in their total supply of resources.	Schedule 11
F.3. Capacity Position Provide a narrative discussion and tabulation reflecting the capacity position of the utility in relation to satisfying PJM' s load obligation, similar to Schedule 16 of the attached schedules.	Executive Summary, Section 6
F.4. Wholesale Contracts for the Purchase and Sale of Power A list of firm wholesale purchased power and sales contracts reflected in the plan, including the primary fuel type, designation as base, intermediate, or peaking capacity, contract capacity, location, commencement and expiration dates, and volume.	Schedule 11
F.5. Demand-side Options Provide the results of its overall assessment of existing and potential demand-side option programs, including a descriptive summary of each analysis performed or used by the utility in its assessment and any changes to the methods and assumptions employed since its last IRP. Such descriptive summary, and corresponding schedules, shall clearly identify the total impact of each DSM program.	Section 4.4; Schedules 12 and 16
F.6. Evaluation of Resource Options Provide a description and a summary of the results of the utility's analyses of potential resource options and combinations of resource options performed by it pursuant to these guidelines to determine its integrated resource plan. IRP filings should identify and include forecasted transmission interconnection and enhancement costs associated with specific resources evaluated in conjunction with the analysis of resource options.	Sections 5 and 6
F.7. Comparative Costs of Options Provide detailed information on levelized busbar costs, annual revenue requirements or equivalent methodology for various supply-side options and demand-side options to permit comparison of such resources on equitable footing. Such data should be tabulated and at a minimum, reflect the resource's heat rate, variable and fixed operating maintenance costs, expected service. life, overnight construction costs, fixed charged rate, and the basis of escalation for each component.	Section 4, Exhibit B
§ 56-598. (Effective until October 1, 2021) Contents of integrated resource plans.	
An IRP should:	

1. Integrate, over the planning period, the electric utility's forecast of demand for electric generation supply with recommended plans to meet that forecasted demand and assure adequate and sufficient reliability of service, including:	Section 5
a. Generating electricity from generation facilities that it currently operates or intends to construct or purchase;	
b. Purchasing electricity from affiliates and third parties;	
c. Reducing load growth and peak demand growth through cost-effective demand reduction programs; and	
d. Utilizing energy storage facilities to help meet forecasted demand and assure adequate and sufficient reliability of service;	
2. Identify a portfolio of electric generation supply resources, including purchased and self-generated electric power, that:	Sections 5&6
a. Consistent with § 56-585.1, is most likely to provide the electric generation supply needed to meet the forecasted demand, net of any reductions from demand side programs, so that the utility will continue to provide reliable service at reasonable prices over the long term; and	
b. Will consider low cost energy/capacity available from short-term or spot market transactions, consistent with a reasonable assessment of risk with respect to both price and generation supply availability over the term of the plan;	
3. Reflect a diversity of electric generation supply and cost-effective demand reduction contracts and services so as to reduce the risks associated with an over-reliance on any particular fuel or type of generation demand and supply resources and be consistent with the Commonwealth's energy policies as set forth in § 67-101.1; and	
4. Include such additional information as the Commission requests pertaining to how the electric utility intends to meets its obligation to provide electric generation service for use by its retail customers over the planning period.	
§ 56-599. (Effective until October 1, 2021) Integrated resource plan required.	
A. Each electric utility shall file an updated integrated resource plan by July 1, 2015. Thereafter, each electric utility shall file an updated integrated resource plan by May 1, in each year immediately preceding the year the utility is subject to a triennial review filing. A copy of each integrated resource plan shall be provided to the Chairman of the House Committee on Labor and Commerce, the Chairman of the Senate Committee on Commerce and Labor, and to the Chairman of the Commission on Electric Utility Regulation. All updated integrated resource plans shall comply with the provisions of any relevant order of the Commission establishing guidelines for the format and contents of updated and revised integrated resource plans. Each integrated resource plan shall consider options for maintaining and enhancing rate stability, energy independence, economic development including retention and expansion of energy-intensive industries, and service reliability.	
B. In preparing an integrated resource plan, each electric utility shall systematically evaluate and may propose:	Sections 5&6
1. Entering into short-term and long-term electric power purchase contracts;	
2. Owning and operating electric power generation facilities;	
3. Building new generation facilities;	
4. Relying on purchases from the short term or spot markets;	
5. Making investments in demand-side resources, including energy efficiency and demand-side management services;	

6. Taking such other actions, as the Commission may approve, to diversify its generation supply portfolio and ensure that the electric utility is able to implement an approved plan;	
7. The methods by which the electric utility proposes to acquire the supply and demand resources identified in its proposed integrated resource plan;	
8. The effect of current and pending state and federal environmental regulations upon the continued operation of existing electric generation facilities or options for construction of new electric generation facilities;	
9. The most cost effective means of complying with current and pending state and federal environmental regulations, including compliance options to minimize effects on customer rates of such regulations;	
10. Long-term electric distribution grid planning and proposed electric distribution grid transformation projects;	
11. Developing a long-term plan for energy efficiency measures to accomplish policy goals of reduction in customer bills, particularly for low-income, elderly, and disabled customers; reduction in emissions; and reduction in carbon intensity; and	
12. Developing a long-term plan to integrate new energy storage facilities into existing generation and distribution assets to assist with grid transformation.	
C. As part of preparing any integrated resource plan pursuant to this section, each utility shall conduct a facility retirement study for owned facilities located in the Commonwealth that emit carbon dioxide as a byproduct of combusting fuel and shall include the study results in its integrated resource plan. Upon filing the integrated resource plan with the Commission, the utility shall contemporaneously disclose the study results…"	Section 5.2.3

Required Schedules not Specifically Addressed Above	Schedules 2, 3, 4, 5, 6, 7,17 and 18
Chapter 476 of the 2008 Virginia Acts of Assembly ("Senate Bill 311")	
2. That as part of its 2009 integrated resource plan developed pursuant to this act, each electric utility shall assess governmental, nonprofit, and utility programs in its service territory to assist low income residential customers with energy costs and shall examine, in cooperation with relevant governmental, nonprofit, and private sector stakeholders, options for making any needed changes to such programs.	
2015 Virginia Acts of Assembly ("Senate Bill 1349) *	
Provide a copy of integrated resource plan to the Chairmen of the House and Senate Committees on Commerce and Labor and to the Chairman of the Commission on Electric Utility Regulation	**APCO team**
Integrated resource plan shall consider options for maintaining and enhancing rate stability	Sections 1.2, 5.2, and 5.5
Integrated resource plan shall consider options for maintaining and enhancing energy independence	Sections 5 and 6
Integrated resource plan shall consider options for maintaining and enhancing economic development including retention and expansion of energy-intensive industries	Section 2.10
Integrated resource plan shall consider options for maintaining and enhancing service reliability	Sections 5 and 6
The effect of current and pending state and federal environmental regulations upon the continued operation of existing electric generation facilities or options for construction of new electric generation facilities	Section 3.3

The most cost effective means of complying with current and pending state and federal environmental regulations, including compliance options to minimize effects on customer rates of such regulations	Section 5
-	
Final Order from 2015 Virginia IRP (Case No. PUE-2015-00036)	
Clean Power Plan	
Model and provide an optimal (least-cost, base plan) for meeting the electricity needs of its service territory over the IRP planning timeframes	Section 5.3
Model and provide multiple plans compliant with the CPP under a mass-based approach and an intensity-based approach (including a least-cost compliant plan where the Plexos model is allowed to choose the least-cost path given emission constraints imposed by the CPP), providing a detailed analysis of the impacts of each (in terms of total cost, including capital, programmatic and financing costs) as well as the impact on rates and identification of whether any aspect of the plan would require a change in existing Virginia law	
Analyze the final federal implementation plan (should the final federal plan be published by May 1, 2016 or, if not, analyzing any proposed federal plan), providing a detailed analysis of the impact of a federal plan in terms of all costs, as well as the impact on rates and identification of whether any aspect of the federal plan would require a change in existing Virginia law;	
Provide a detailed description of leakage and treatment of new units under differing compliance regimes;	
Examine the differing impacts of the Virginia-specific targets verses source subcategory-specific rates under an intensity-based approach;	
Examine the potential for early action emission rate credits/allowances that may be available for qualified renewable energy or demand-side energy efficiency measures;	
Examine the cost benefits of trading emissions allowances or emissions reductions credits, or acquiring renewable resources from inside and outside of Virginia;	
Provide a detailed discussion of the development of state compliance plans in Indiana, Ohio, and West Virginia, as well as the potential for differing compliance approaches in each and how such differing approaches may impact APCo's ability to comply with the CPP	
Identify a long-term recommendation that reflects EPA's final version of the CPP	
Rate Design	
Analyze whether maintaining the existing rate structure is in the best interest of residential customers	Commission's Order for 2016 IRP provided respite of these requirements
Evaluate options for variable pricing models that would incent customers to shift consumption away from peak times to reduce costs and emissions	
Market Alternatives	
Include a detailed analysis of market alternatives, especially third-party purchases, that may provide long-term price stability and which includes wind and solar resources	Sections 4.5, 4.7
Examine wind and solar purchases at prices (including prices available through long-term purchase power agreements) and in quantities that are seen in the market at the time that the Company prepares its IRP filings	Sections 4.5, 4.7
Solar Photovoltaic Generation	
Examine the impact of higher levels of distributed generation and identify any barriers to increased reliance by the Company on solar voltaic generation	Section 3.4.3

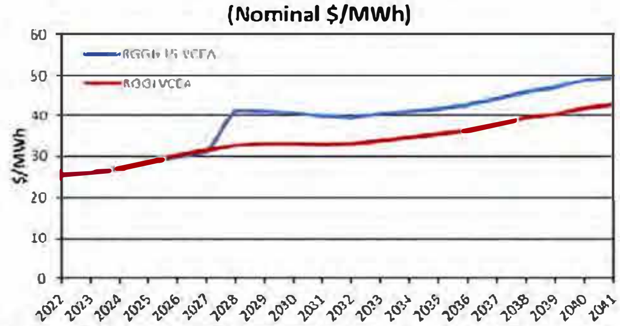
Include a detailed analysis of the load characteristics of net metering customers and the generation-related impacts of customer generation	Section 3.4.3
In future IRPs, APCo shall inlcude an index that identifies the specific location(s) within the IRP that complies with each bulleted requirement in this Final Order	Appendix Exhibit D
_	
Final Order from 2016 Virginia IRP (Case No. PUE-2016-00050)	
For next year's IRP filing, we direct the Company to model and present scenarios similar to those included in the current IRP, updating the data and assumptions as appropriate. These scenarios shall include, at a minimum, the following: (1) Least-cost base plan (non-compliant with the CPP); (2) Least-cost CPP-compliant intensity-based plan (regional and island approaches10); (3) Least-cost CPP-compliant mass-based plan (regional and island approaches); (4) Federal implementation plan; and (5) Company-preferred plan, if any.	
Continue to comply with our prior directives to provide detailed analysis of market alternatives of all types.	
_	
Final Order from 2017 Virginia IRP (Case No. PUR-2017-00045)	
APCo's future IRPs, beginning with the IRP due to be filed on May 1, 2018, shall include detailed plans to implement the mandates contained in that legislation, as well as plans that comply with all other legal requirements. This includes, for example, the utility's least-cost plan along with plans compliant with proposed federal carbon-control regulations, which are required in accordance with the provisions of both Code § 56-585.1:1 F 1, and Code § 56-599 B 9 (requiring an IRP to include "the most cost effective means of complying with current and pending state and federal environmental regulations, including compliance options to minimize effects on customer rates of such regulations").	Section 5.2, 5.3, 6
Senate Bill 966 ("Grid Transformation and Security Act" or "The 2018 Virginia Act")	
Construct or acquire at least 200MW of utility-owned solar;	VCEA Compliant Plan
Request Commission approval of $140 million in EE programs over ten years, customers over	VCEA Compliant Plan
Invest in up to 10MWs of new battery storage installations as part of a five-year battery pilot program; and	Section 3.6.3
Systematically evaluate and consider proposing long-term electric distribution grid planning and proposed electric distribution grid transformation projects	Section 3.6.3
Develop a long-term plan for EE measures to accomplish policy goals of reduction in customer bills, particularly for low-income, elderly, and disabled customers; reduction in emissions; and reduction in carbon intensity.	VCEA Compliant Plan
Final Order from 2018 Virginia IRP (Case No. PUR-2018-00051)	
Include in its next IRP detailed plans to implement the mandates contained in Senate Bill 966, including but not limited to the statute's mandate that APCo develop a proposed program of energy conservation measures of no less than an aggregate amount of $140 million for the period beginning July 1,2018, and ending July 1, 2028.	VCEA Compliant Plan
For purposes of its least-cost plan the Company shall not include any costs associated with carbon control regulations, nor force the modeling to select any resource, nor exclude any reasonable resource.	Section 5

Model the $140 million in energy efficiency programs that are mandated in Enactment Clause 15 of Senate Bill 966. These energy efficiency programs shall be modeled both as a reduction to load and as a supply resource.	VCEA Compliant Plan
We further direct APCo to include in all future IRPs modeling that includes, but need not be limited to, the AEP Zone PJM coincident peak load forecast produced by PJM Interconnection, LLC, scaled down to the APCo load serving entity level.	Section 2.8
Final Order from 2019 Virginia IRP (CASE NO. PUR-2019-00058)	
In future IRPs, the Company shall calculate the incremental cost impacts of any grid transformation project mandates it believes are applicable as contained in Senate Bill 966, including a comparison to the identified least-cost plan.	Section 3.5
Company shall quantify all known or anticipated costs of carbon abatement under Executive Directive 11 (VA joining RGGI) in future IRPs	Section 3.3
APCo must model the following in its next IRP: o 30% renewable by 2030 o 75% renewable by 2040 o 100% renewable by 2050 o Any legislative mandate before the date of APCo's next IRP submission o All with costs compared to a least-cost plan with engineering analysis of reliability effects on customers	Modeling requirements changed by June 16, 2021 Order in Case No. PUR-2019-00058
APCo should continue to refine the specific assumptions and sensitivity adjustments used in its gas price forecasting	Section 4.3
Modeling the average capacity performance of APCo's Company-owned fleet, using VA specific data, is more appropriate than the Company's proposal. The Company can do otherwise, but an average is the baseline and all else are sensitivities.	Section 4.5, Section 5
APCo is directed to provide its best estimate of customer bill impacts for the least-cost plan and preferred plans in future IRPs. Company should provide the incremental impact of these plans to the bill of a typical residential customer using 1,000 kWh/month, for each of the first 5 years for he IRP.	Section 5.5
Additional requirements: o Make wind or solar PPAs available options for modeling o Include all known or anticipated costs of future transmission projects o Model solar coupled with battery storage as a capacity resource option o Model solar resources using the performance of current and similarly-situated technology o Utilize updated battery costs o Describe modeling of future interconnection costs for wind and solar o Work with Staff on Company's REC price forecast methodology, and provide sensitivities o Exclude carbon costs in least-cost plan	Section 4.5, Section 5
May 25, 2021, Commission Staff ("Staff) filed a motion to amend and supplement APCo's Future IRP Filing Requirements.	

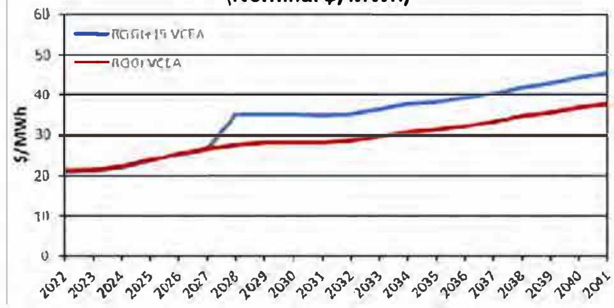
Requested the Commission to direct APCo, in its May 1, 2022 IRP filing, to contemplate and fully account for the directives set forth in the Virginia Clean Economy Act ("VCEA"),3 the Clean Energy and Community Flood and Preparedness Act,4 and the Virginia Environmental Justice Act,5 and to: • Model the VCEA's mandatory renewable energy portfolio standard ("RPS") program requirements, as set forth in Code § 56-585.5 C, in lieu of the 2019 IRP Final Order requirement to model a "30% renewable power by 2030" plan, a "75% renewable power by 2040" plan, and a "100% renewable power by 2050" plan; • Model the annual energy savings targets set forth in Code § 56-596.2 B 1 that APCo must achieve between 2022 and 2025 through the implementation of energy efficiency programs and measures; • Model reasonable energy efficiency targets after 2025; • Model the impacts of carbon regulations as required by the Regional Greenhouse Gas Initiative and incorporate the mandatory Code § 56-585.5 C RPS program requirements as part of the Company's least-cost plan; • Update its forecasts of future commodity prices to reflect the passage of the VCEA; • Address electric system reliability impacts of the VCEA's renewable energy resource mandates; • Address the Company's plans related to banking renewable energy certificates; and • Address environmental justice.	Section 1.6, Section 4.3, Section 5.5
2020 Triennial Review Stipulation in Case No. PUR-2020-00015	
Appalachian Power Company agrees that its 2022 Integrated Resource Plan will include robust unit-by-unit retirement analyses for the Amos and Mountaineer coal units. Those retirement analyses will: (a) be performed on a capacity expansion and dispatch model (e.g., PLEXOS); (b) reflect all costs and benefits associated with near- and mid-term retirement dates—including, for example, sustaining capital expenditures and anticipated environmental expenditures; (c) consider all available resources as potential replacements for retired capacity or for services needed by the system in the absence of retired units; (d) evaluate the units under reasonable, alternative commodity price (e.g., natural gas, greenhouse gas emissions) forecasts; (e) reflect costs of replacement resources that are informed by recent requests for proposals; and (f) be performed in 2021 or 2022, so as to reflect the most up-to-date information.	Section 7

Exhibit E: Fundamentals

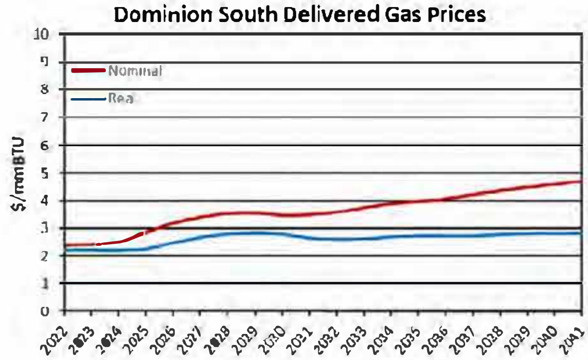
PJM AEP On Peak Energy Prices - (Nominal $/MWh)



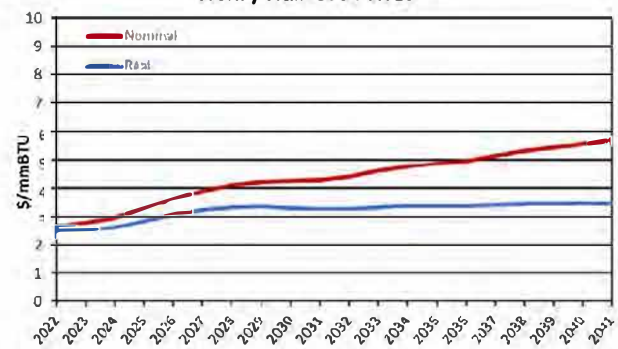
PJM AEP Off-Peak Energy Prices - (Nominal $/MWh)



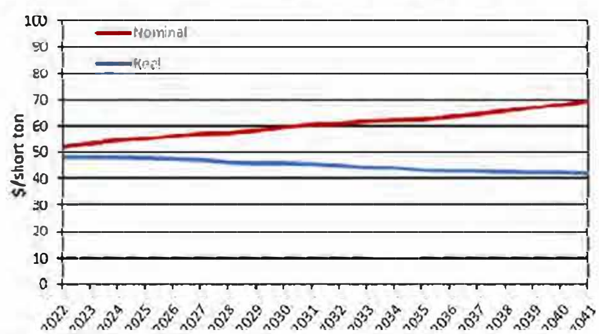
Dominion South Delivered Gas Prices



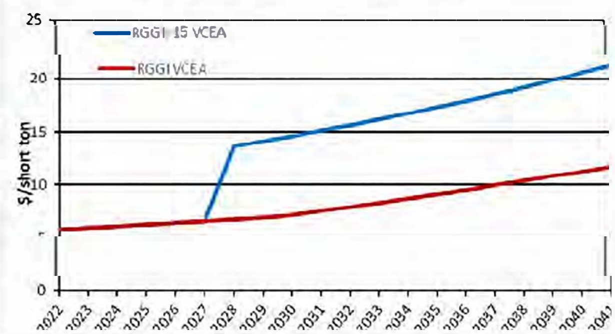
Henry Hub Gas Prices



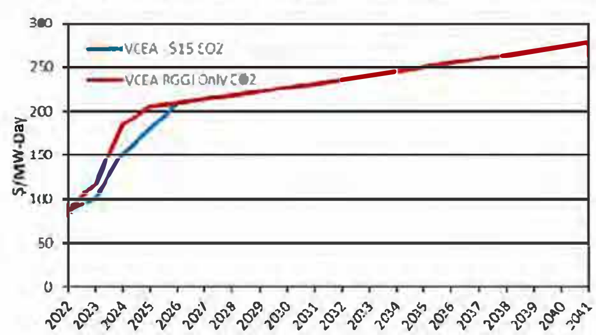
NAPP Coal Prices - ($/ton, FOB Origin)



CO2 Prices (Nominal $/short ton)



PJM AEP Capacity Prices (Nominal $/MW-day)



PRB 8800 Coal Prices - ($/Ton, FOB Origin)

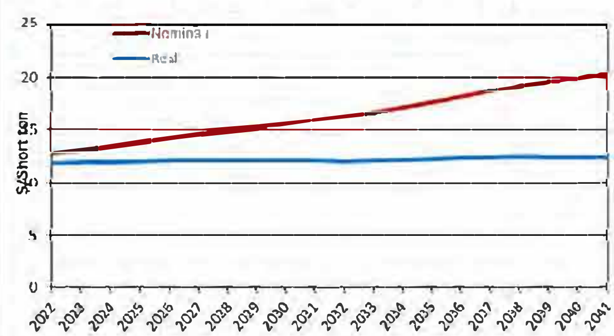


Exhibit F: **REC Purchases,**

Exhibit F-1: Base Commodity Portfolios

	VCEA Energy Requirement GWh	BASE RGGI +$15CO2	BASE RGGI ONLY	HIGH RGGI +$15CO2	LOW RGGI +$15CO2	BASE RGGI +$15CO2 Low REC $	BASE RGGI +$15CO2 High REC $	HYBRID PLAN Base RGGI +$15 CO2 Clinch River ext
2022	1,051	350	350	350	350	350	350	350
2023	1,200	350	350	350	350	350	350	350
2024	1,499	701	701	701	701	701	701	701
2025	2,100	701	701	701	701	701	701	701
2026	2,546	0	0	0	0	0	0	0
2027	2,999	0	0	0	0	350	0	0
2028	3,601	0	0	0	0	0	0	0
2029	4,055	0	0	0	0	0	0	0
2030	4,505	0	0	0	0	0	0	0
2031	4,956	0	0	0	0	0	0	0
2032	5,406	0	0	0	0	0	0	0
2033	5,861	0	0	0	0	0	0	0
2034	6,314	0	0	0	0	0	0	0
2035	6,772	0	0	0	0	0	0	0
2036	7,985	701	701	0	701	701	350	701
2037	7,994	350	350	0	350	350	0	350
2038	8,608	350	701	350	701	350	350	350
2039	9,219	0	0	0	0	0	0	0
2040	9,829	0	0	0	0	0	0	0
2041	10,301	0	0	0	0	0	0	0
2042	10,761	350	350	350	350	350	350	350
2043	11,227	701	701	701	701	701	701	701
2044	11,694	1,402	1,402	1,051	1,402	1,402	1,402	1,402
2045	12,171	1,752	1,752	1,752	1,752	1,752	1,752	1,752
2046	12,798	2,453	2,453	2,453	2,453	2,453	2,453	2,453
2047	13,427	3,154	3,154	3,154	3,154	3,154	3,154	3,154
2048	14,053	3,504	3,504	3,504	3,504	3,504	3,504	3,504
2049	14,695	4,205	4,205	4,205	4,205	4,205	4,205	4,205
2050	15,325	4,906	4,906	4,906	4,906	4,906	4,906	4,906
2051	15,349	5,256	5,256	5,256	5,256	5,256	5,256	5,256

Exhibit F-2: Alternative Portfolio REC Purchases

	VCEA Energy Requirement GWh	Increased Technology Cost Case	Base RGGI +$15 CO2 w NG Options	Base RGGI Only w NG Options	Base RGGI +$15 CO2 w NG Options Clinch River ext
2022	1,051	350	350	350	350
2023	1,200	350	350	350	350
2024	1,499	701	701	701	701
2025	2,100	701	701	701	701
2026	2,546	0	0	0	0
2027	2,999	0	0	0	0
2028	3,601	0	0	0	0
2029	4,055	0	0	0	0
2030	4,505	0	0	0	0
2031	4,956	0	0	0	0
2032	5,406	0	0	0	0
2033	5,861	0	0	0	0
2034	6,314	0	0	0	0
2035	6,772	350	0	0	0
2036	7,985	1,051	350	701	350
2037	7,994	350	0	350	0
2038	8,608	350	350	350	350
2039	9,219	350	350	350	350
2040	9,829	0	350	0	350
2041	10,301	0	0	0	0
2042	10,761	350	350	350	350
2043	11,227	701	1,051	701	1,051
2044	11,694	1,402	1,402	1,402	1,402
2045	12,171	1,752	1,752	1,752	1,752
2046	12,798	2,453	2,453	2,453	2,453
2047	13,427	2,803	3,154	3,154	3,154
2048	14,053	3,504	3,504	3,504	3,504
2049	14,695	4,205	4,205	4,205	4,205
2050	15,325	4,906	4,906	4,906	4,906
2051	15,349	4,906	5,256	5,256	5,256

Exhibit G: Transmission Projects

Description	Location	Projected In-Service Date	PJM RTEP Cost Estimate ($M)	PJM ID
Broadford Station Upgrades	VA	In-Service	$102.00	s1462
Glenmary Station	VA	In-service	$5.10	s2252
Ravenswood Area Improvements	WV	In-Service	$66.14	b3040
Boone-Ward Hallow 46 kV Rebuild	WV	In-Service	$32.47	s1501
Wyoming Station Upgrades	WV	In-Service	$53.00	s1580
Skin Fork Area Improvements	WV	In-Service	$13.7(Baseline)* $4.4 (Supplemental)*	b2883 s2611
Boone Area Improvements	WV	In-Service	87.95*	b2603
Racine Improvements	WV	In-Service	$17.50	s2166
Galax Area Improvements	VA	2/11/2022	$10.20	s2214
Carbondale-Tower 117 Rebuild	WV	3/31/2022	$25.95	s1509
Baileysville-Bolt Rebuild	WV	4/30/2022	$78.41	s1497
Huff Creek Station	WV	5/19/2022	$6.60	s1997
Lakin-Racine 69 kV Rebuild	WV	6/1/2022	$23.9(Baseline) $33.4 (Supplemental)	b3094 s2166
Chemical Station	WV	10/17/2022	$35.30	s2348
Fieldale-Dan River 138 kV Rebuild	VA	10/31/2022	$32.20	s2190
Dearington-Peakland 69 kV Rebuild	VA	11/1/2022	$12.70	s1291
Hernshaw Area Improvements	WV	4/1/2023	$31.80	s2225
Trap Hill Project	WV	5/31/2023	$34.30	s2144
Carbondale-Kincaid 46 kV Rebuild	WV	6/1/2023	$43.30	s2177
Hancock Station Upgrades	VA	6/2/2023	$30.00	s1598
Fort Robison-Hill Project	TN	7/1/2023	$46.80	s2408
Kincaid Area Improvements	WV	9/1/2023	$72.00	S2430
Nitro Station	WV	11/8/2023	$38.50	s2165
Kenna Project	WV	11/17/2023	$61.70	s2178
Sheridan Area Improvements	WV	12/8/2023	$88.10	s1377
Saltville-Kingsport Project	VA	5/1/2024	$107.10	s2250
Mount Heron-Coal Creek 69 kV Rebuild	VA	6/7/2024	$40.18	b3333
Abingdon Area Improvements	VA	7/1/2024	$98.66	s2444
Clifford-Scottsville Area Improvements	VA	4/22/2025	$85 (Baseline) $51.9 (Supplemental)	b3208 s2000 s2438

				s2439
Cabin Creek-Kelly Creek 46 kV Rebuild	WV	5/1/2025	$17.90	b3280
Jubal Early - Independence 69kV Install	VA	6/1/2025	$42.7M	s1851
East Huntington-North Proctorville 138 kV	WV	6/1/2025	$10.40	b3282
Saltville Project	VA	7/1/2025	$0.72 (Baseline)$75.61 (Supplemental)	b3278.1 s2572
Lakin-Point Pleasant 69 kV Rebuild	WV	10/31/2025	$13.50	b3284
Becco Area Improvements	WV	3/1/2026	$65.80	b3348
Fries - Point Lookout Rebuild	VA	3/1/2026	$33M	s2574
Joshua Falls Station Upgrades	VA	10/31/2026	$40.70	s1668
Bancroft-Milton 69 kV Rebuild	WV	11/1/2026	$56.73	b3347
Speedway Project	VA	12/1/2026	$55.40	s2226
Midway - South Christiansburg Line Rebuild	VA	6/1/2027	$17.5M	**
Stuart Area Improvements	VA	10/31/2027	$292.60	s2179
Reusens-Roanoke 138 kV Rebuild	VA	10/31/2028	$177.60	s2469

*Cost estimate has been revised due to change in scope and/or increases in cost. These figures have been reported to PJM and will be available when submissions are updated on their website.

**Need submitted to PJM.