PUBLIC VERSION

AMERICAN ELECTRIC POWER

BOUNDLESS ENERGY

American Electric Power
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May 1, 2019

Noelle J. Coates
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By Hand

The Honorable Joel H. Peck, Clerk
State Corporation Commission
Document Control Center
1300 East Main Street, First Floor
Richmond, Virginia 23219

Re: **In re: Appalachian Power Company's Integrated Resource Plan filing**
Case No. PUR-2019-00058

Dear Mr. Peck:

Pursuant to §§ 56-597 and 56-599 of the Code of Virginia, the Commission's Rules of Practice and Procedure, and the December 23, 2008 Order Establishing Guidelines for Developing Integrated Resource Plans, Case No. PUE-2008-00099, (IRP Guidelines), enclosed for filing, UNDER SEAL, are an original and fifteen copies of the 2019 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.

Copies of the public version of the filing have been sent to the Division of Consumer Counsel, Office of the Attorney General 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.
James G. Ritter, Esq.
Mr. William K. Castle

NOTICE TO THE PUBLIC OF
A FILING BY APPALACHIAN POWER COMPANY OF ITS
INTEGRATED RESOURCE PLAN
CASE NO. PUR-2019-00058

On May 1, 2019, 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 C of the Code, the Commission determines whether an IRP is reasonable and in the public interest.

APCo states that it serves approximately 956,000 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 2019 to 2033 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 and guidelines.

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. APCo states that, per the Commission's directive in its Final Order in APCo's 2017 IRP case (Case No. PUR-2017-00045), "APCo considered the effect of environmental rules and guidelines, which have the potential to add significant costs and present significant challenges to operations. This IRP considers 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, in the Commission's Final Orders in Case Nos. PUR-2017-00045 and PUR-2018-00051, the Commission directed APCo to include, in this and future IRPs, plans to implement the mandates contained in the Grid Transformation and Security Act, which became effective July 1, 2018. Accordingly, APCo considered the impact of the resource additions required by the Grid Transformation and Security Act, which include solar, energy storage, and energy efficiency. In addition, the Company's IRP takes into consideration the impacts of the federal Tax Cuts and Jobs Act of 2017.

The Commission entered an Order for Notice and Hearing in this case that, among other things, scheduled a public hearing at ____________________, in the Commission's second floor courtroom located in the Tyler Building, 1300 East Main Street, Richmond, Virginia 23219, to receive the testimony of public witnesses. Any person desiring to testify as a public witness should appear at this hearing location fifteen (15) minutes before the starting time of the hearing and contact the Commission's Bailiff. A public hearing will convene at 9:30 a.m. on ________, 2019, in the same location, to receive the testimony and evidence offered by the Company, respondents, and the Staff on the Company's Application.

The public version of the Company's IRP and the Commission's Order for Notice and Hearing are available for public inspection during regular business hours at each of the Company's business offices in the Commonwealth of Virginia. Copies also may be obtained by submitting a written request to counsel for the Company, Noelle J. Coates, Esquire, American Electric Power, 1051 East Cary Street, Suite 1100, Richmond, Virginia 23219. If acceptable to the requesting party, the Company may provide the documents by electronic means.

Copies of the public version of the IRP and other documents filed in this case are also available for interested persons to review in the Commission's Document Control Center, located on the first floor of the Tyler Building, 1300 East Main Street, Richmond, Virginia 23219, between the hours of 8:15 a.m. and 5 p.m., Monday through Friday, excluding holidays. Interested persons also may download unofficial copies from the Commission's website: http://www.scc.virginia.gov/case.

On or before ________, 2019, any interested person wishing to comment on the Company's IRP shall file written comments with Joel H. Peck, Clerk, State Corporation Commission, c/o Document Control Center, P.O. Box 2118, Richmond, Virginia 23218-2118. Any interested person desiring to file comments electronically may do so on or before ________, 2019, by following the instructions found on the Commission's website: http://www.scc.virginia.gov/case. Compact disks or any other form of electronic storage medium may not be filed with the comments. All such comments shall refer to Case No. PUR 2019-00058.

On or before _________, 2019 any person or entity may participate as a respondent in this proceeding by filing a notice of participation. If not filed electronically, an original and fifteen (15) copies of the notice of participation shall be submitted to the Clerk of the Commission at the address above. A copy of the notice of participation as a respondent also must be sent to counsel for the Company at the address set forth above. Pursuant to Rule 5 VAC 5-20-80 B, *Participation as a respondent,* of the Commission's Rules of Practice and Procedure ("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-2019-00058. For additional information about participation as a respondent, any person or entity should obtain a copy of the Commission's Order for Notice and Hearing.

All documents filed with the Office of the Clerk of the Commission in this docket may use both sides of the paper. In all other respects, 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 Commission's Rules of Practice may be viewed at http://www.scc.virginia.gov/case. A printed copy of the Commission's Rules of Practice and an official copy of the Commission's Order for Notice and Hearing in this proceeding may be obtained from the Clerk of the Commission at the address set forth above.

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-2019-00058

PUBLIC VERSION

May 1, 2019

Table of Contents

List of Figures

List of Tables

Executive Summary

This Integrated Resource Plan (IRP 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 commitment to specific resource additions or other courses of action, as the future is highly uncertain. Accordingly, this IRP and the action items described herein are subject to change as new information becomes available or as circumstances warrant.

This IRP addresses the mandates contained in Virginia's recently enacted Grid Transformation and Security Act, which became effective July 1, 2018 (the 2018 Virginia Act), 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 a 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, 2019-2033). 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 and guidelines, which have the potential to add significant costs and present significant challenges to operations. This IRP considers 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 timing and form future carbon regulation may take.

This 2019 IRP addresses the mandates included in the 2018 Virginia Act:

- The construction or acquisition by APCo of at least 200MW of utility-owned solar located in Virginia prior to 2028;
- In future EE-RAC proceedings, APCo is required to request Commission approval of $140 million in EE programs from July 2018 to July 2027; and
- As part of a five-year battery pilot program deemed to be in the public interest, APCo may invest in up to 10MWs of new battery storage installations.

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, and its two gas-steam units at Clinch River. The Company will also continue to operate its hydroelectric generators, including Smith Mountain Lake. The Company has a portfolio of 575MW of purchase power agreements consisting of five wind farms and one hydro-electric facility. During the planning period, contracts covering 455MW of that amount will expire. In addition, the Company has contracted for the output of the 15MW Depot solar facility in Rustburg, Va., which it expects will be available in 2021. Another consideration in this IRP is the increased adoption of distributed rooftop solar resources by APCo's customers. While APCo does not have control over where, and to what extent, such resources are deployed, it recognizes that distributed rooftop solar will reduce APCo's growth in capacity and energy requirements to some degree. From a capacity viewpoint, the 2020/2021 planning year is when PJM's new Capacity Performance construct will take full effect

The Commission's April 2, 2018 Order[1] denied APCo's request to acquire two additional Wind Facilities. The Company has consistently modeled resource additions with an eye towards minimizing both capacity and energy costs for its customers over the respective planning periods. The Commission's Wind Facilities Order, by focusing only on capacity "need", suggests that, given the current availability of short-term energy from the PJM market, unless APCo has a need for capacity under PJM requirements, APCo's IRPs should propose adding resources solely on the basis of meeting its capacity obligation. The Company notes that this Report indicates that APCo does not have a capacity need until 2027, and that its projected shortfall can be met with the addition of solar and energy efficiency resources consistent with the mandates of the 2018 Virginia Act and wind resources. In this IRP, the Company continues to model portfolios that not only add resources to meet its capacity obligation, but also provide zero variable cost energy to enhance rate stability and further diversify its generation portfolio.

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

- Adds at least 200MW of large-scale solar resources, consistent with directives in the 2018 Virginia Act.
- Continues to diversify APCo's mix of supply-side resources through the addition of battery storage, wind and large-scale solar;
- Incorporates demand-side resources, including but not limited to additional EE programs and Volt VAR Optimization (VVO) installations; and

[1] Final Order, *Application of Appalachian Power Co. For a rate adjustment clause pursuant to § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2017-00031, Doc. Con. Cen. No. 180410050 (April 2, 2018).

- Recognizes that residential and commercial customers will add distributed resources, primarily in the form of residential and commercial rooftop solar (i.e. Distributed Generation [DG]).

Key Changes from 2018 IRP

This IRP includes the following changes from the Company's 2018 IRP:

- Addresses the Commission's 2018 IRP order.
- Incorporates the most recent load forecast, which shows a reduced need for capacity additions over the forecast period, and a minimal change in energy needs.
- Incorporates the most recent fundamental forecast developed in the first quarter of 2019.
- Incorporates updated renewable cost information primarily based upon Bloomberg New Energy Finance's (BNEF) H2 2018 U.S. Renewable Energy Market Outlook and informed by the Company's 2019 Solar Request for Proposals (RFP).
- Discusses APCo's electric distribution grid transformation (EDGT), as defined by the 2018 Virginia Act, planning and implementation initiatives.

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. Through 2026, APCo has capacity resources to meet its forecasted internal demand. In 2027, APCo anticipates experiencing a slight capacity shortfall, 75MW, based upon its assumption regarding the retirement of Clinch River Units 1 and 2 in 2026, and the expiration of wind and hydro contracts totaling 455MWs (nameplate) of renewable generation, during the 2027-2030 timeframe. By 2033, APCo has a capacity deficit of approximately 200MW.

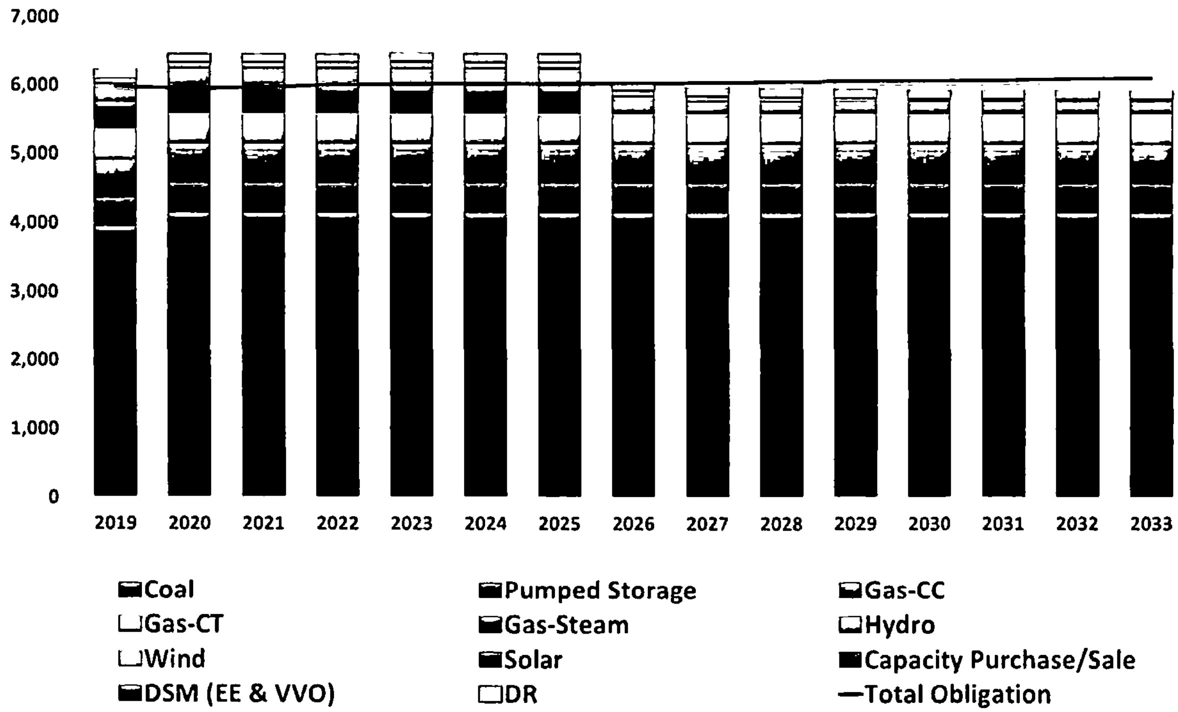

Figure ES - 1. APCo "Going-In" Position

Recognizing its modest capacity deficit position over the planning period, ~200MW in 2033, APCo considered the impact of the resource additions required by the 2018 Virginia Act and resources necessary to satisfy Virginia's voluntary Renewable Portfolio Standard (RPS) goals. These additions, which include solar, energy storage and energy efficiency resources, are expected to eliminate most of the capacity deficit through the planning period. The solar resources are assumed to provide PJM capacity equal to 51.1% of their nameplate rating (or 102MW for 200MW of nameplate solar). Energy storage will provide 10MW, and EE will provide approximately 20MW of planning capacity. Taking these resources into account, a resource plan that meets the 2018 Virginia Act would also be compliant with Virginia's voluntary RPS goals, if the plan adds 300MW of wind resources in 2023.

The resource additions required by the 2018 Virginia Act, and needed to meet Virginia's voluntary RPS goals, allow APCo to satisfy most of its PJM load obligations over the planning period. In addition to the required resource additions, the analysis shows that the addition of VVO and additional solar provide benefits to APCo's customers. Additionally, customer owned generation such as rooftop solar, will also improve APCo's capacity position.

APCo's energy requirements vary over the year with APCo customers using more energy in the winter months than APCo can supply with its own resources. Therefore, absent a directive from the Commission to the contrary, APCo will continue to consider the addition of cost-effective energy resources, including wind resources, to reduce its reliance on the volatile PJM energy market, particularly during the winter months.

To determine the appropriate timing of new resources, APCo used the *Plexos®* model to calculate the lowest cost resource addition portfolio under four pricing scenarios, (*i.e.* Base, Upper Band, No Carbon and Low No Carbon) also referred to as the Optimal Plan for a given commodity pricing scenario. APCo also considered the resource additions required to comply with the 2018 Virginia Act and Virginia's voluntary RPS goals. To arrive at the Preferred Plan, APCo considered a resource mix that included attributes of the various Optimal Plans, the 2018 Virginia Act and the RPS goals. APCo then calculated the cost of this Preferred Plan under the three long-term commodity price forecasts to ensure the plan was not significantly costlier under these different futures. The Preferred Plan is presented as an option that balances cost, including energy costs, and other factors, while meeting the 2018 Virginia Act mandates and voluntary RPS goals.

In summary, the Preferred Plan:

- Assumes the 15MW (nameplate) Depot solar facility is available by 2021;
- Adds 300MW (nameplate) of wind energy resources by 2023, but no additional wind before 2033;
- Adds 450MW (nameplate) of utility scale solar by 2028 and 1,500MW by 2033;
- By 2033, implements EE programs reducing energy requirements by 770GWh and summer capacity by 114MW by 2033;
- Adds 1 Tranche of VVO providing 17MW of summer capacity requirements and 67GWh of annual energy savings;

- Meets Virginia's Voluntary Renewable Portfolio Standard (RPS) goals through the planning period;
- Assumes APCo's customers add distributed generation (DG) (i.e. rooftop solar) capacity totaling over 82MW (nameplate) by 2033;
- Adds 10MW (nameplate) of battery storage resources in 2021;
- Continues operation throughout the planning period of APCo's facilities including the Amos Units 1-3 and Mountaineer Unit 1 coal-fired facilities, the Ceredo and Dresden natural gas facilities and operating hydro facilities. Maintains APCo's share of Ohio Valley Electric Company (OVEC) coal-fired facilities: Clifty Creek Units 1-6 and Kyger Creek Units 1-5;
- Retires the natural gas-steam Clinch River Units 1 and 2 in 2026; and
- Reflects the expiration of 455MWs of wind and hydro purchase power contracts during the 2027-2030 timeframe.

Table ES-1 provides a summary of the Preferred Plan, which resulted from analyses that gave consideration to optimization modeling under various load and commodity pricing

Table ES 1. Preferred Plan Cumulative Additions from 2019 to 2033

Preferred Plan		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Base - Compliant with SB-966 and RPS	Base/Intermediate															
	Peaking															
	Solar (Firm)					77	77	77	77	153	230	383	537	613	690	767
	Solar (Nameplate)					150	150	150	150	300	450	750	1,050	1,200	1,350	1,500
	Wind (Firm)					37	37	37	37	37	37	37	37	37	37	37
	Wind (Nameplate)					300	300	300	300	300	300	300	300	300	300	300
	Battery Storage			10	10	10	10	10	10	10	10	10	10	10	10	10
	Energy Efficiency (Degraded)				36	69	98	92	85	78	69	56	47	36	27	20
	Energy Efficiency (Non-Degraded)				36	72	108	114	120	126	132	137	138	140	127	114
	CHP															
	VVO		17	17	17	17	17	17	17	17	17	17	17	17	17	17
	Demand Response															
	Distr. Gen.					18	21	22	23	24	25	27	29	30	32	34
	Total Additions (Firm & Degraded)		17	27	63	228	260	255	249	319	388	530	676	743	813	884
Capacity Reserves Above PJM Requirement without New Additions		242	493	475	439	443	434	428	17	(75)	(104)	(128)	(150)	(164)	(183)	(196)
Capacity Reserves Above PJM Requirement with New Additions		242	510	502	518	671	693	683	266	244	285	401	526	580	630	688

Base/Intermediate=NGCC; Peaking=NGCT, AD; CHP=Combined Heat & Power; VVO=Volt VAR Optimization; DG=Distributed Generation scenarios, APCo's modeling of carbon emission regulations, the mandates of the 2018 Virginia Act, and Virginia's voluntary RPS goals.

Specific APCo capacity changes by resource type over the 15-year planning period associated with the Preferred Plan are shown in Figure ES - 2 and their relative impacts to APCo's annual energy position are shown in Figure ES-3 and Figure ES-4.

Figure ES-2 indicates that the Preferred Plan would increase APCo's reliance on solar, energy efficiency and wind generation over the planning period, while mostly maintaining its existing fleet of coal-, gas- and hydro-based generation with the exception of the assumed retirement of Clinch River gas plant.

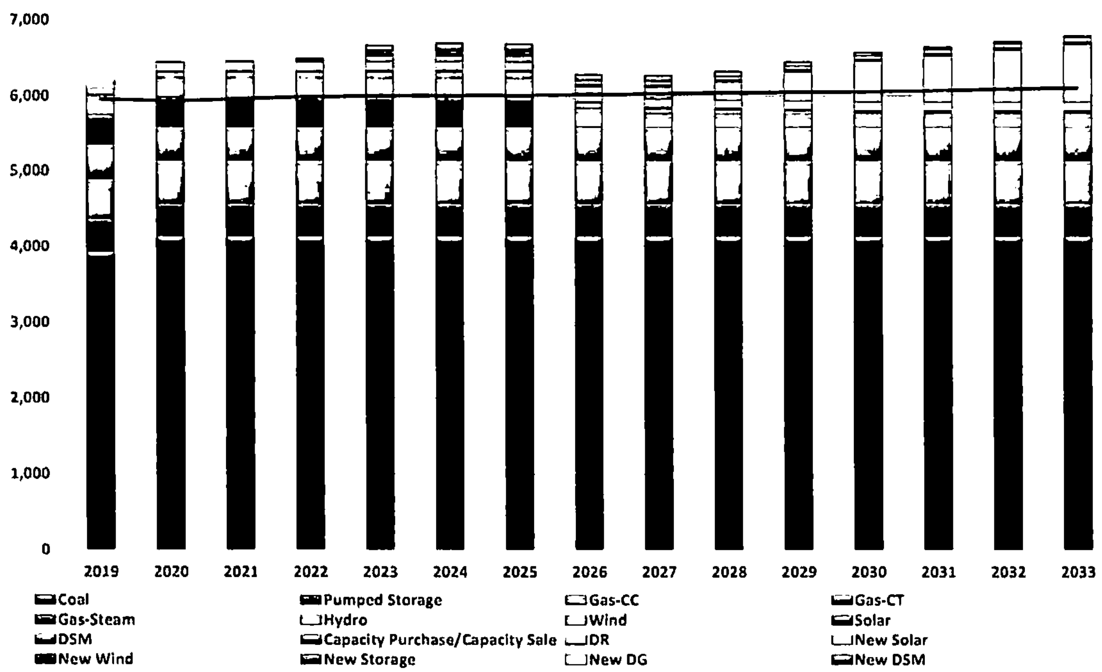

Figure ES - 2. APCo's Preferred Plan Annual Capacity Position (MW)

The capacity contribution from renewable resources is fairly modest due to their intermittent characteristic; however, those resources (particularly wind) provide a significant volume of energy. Wind resources were selected in all of the scenarios because they are a low cost energy resource.

Figure ES-3 and Figure ES-4 show annual changes in energy mix that result from the Preferred Plan over the planning period. APCo's energy output attributable to coal-fired generation shows a slight decrease over the period, while the energy output attributable to renewable generation (wind and solar) grows. Energy from these renewable resources, combined with EE and VVO energy savings reduce APCo's exposure to PJM energy, fuel and potential carbon emission prices.

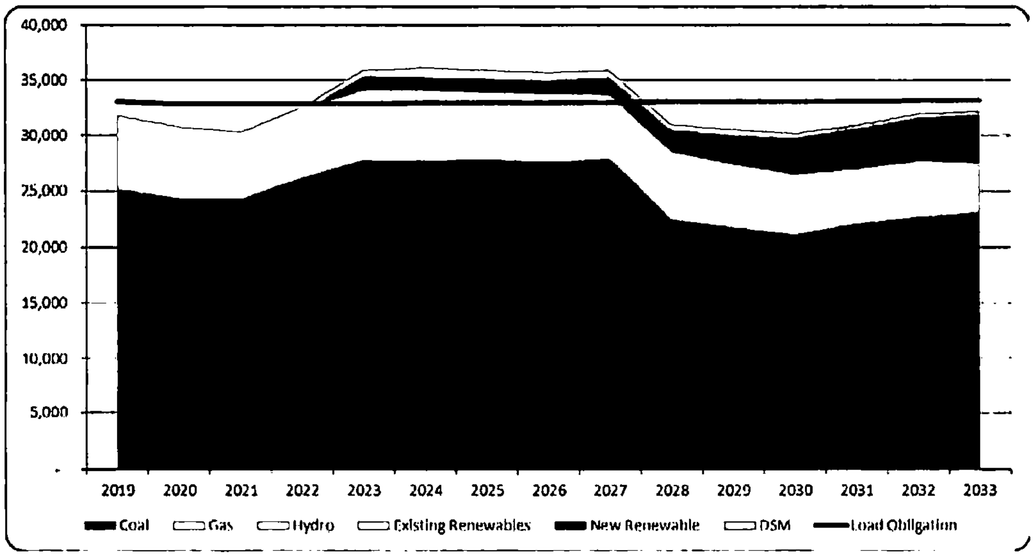

Figure ES - 4. APCo's Preferred Plan Annual Energy Position (GWh)

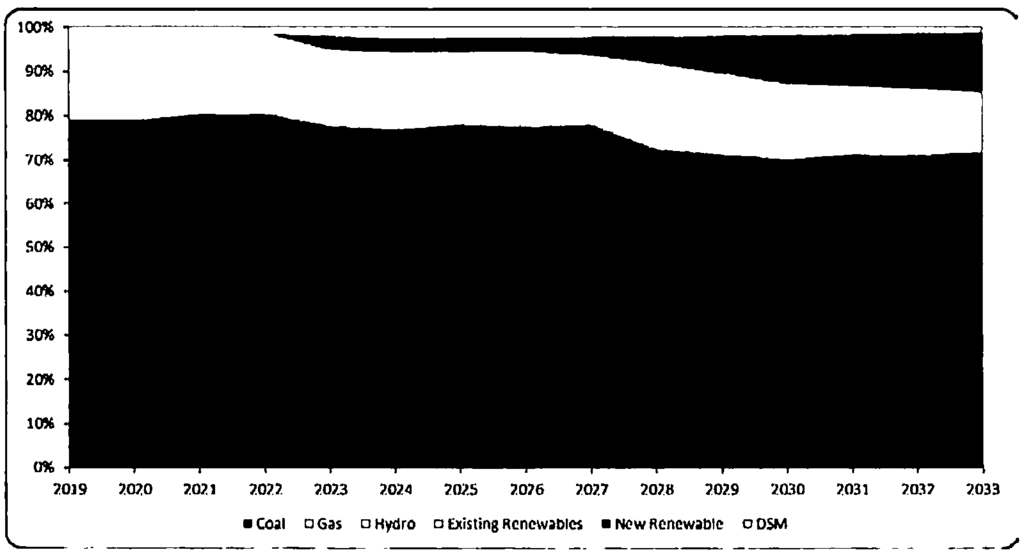

Figure ES - 3. APCo's Preferred Plan Percentage of Annual Energy by Supply Type (%)

Conclusion

This IRP presents various plans, including the Preferred Plan, that would provide adequate capacity resources at reasonable cost, through a combination of supply-side resources (exclusively renewable supply-side resources) and demand-side programs throughout the planning period.

The Preferred Plan includes incremental resources that will provide—in addition to the needed PJM installed capacity to achieve mandatory PJM (summer) peak demand requirements—modest amounts of additional energy to reduce the long-term exposure of the Company's customers to PJM energy markets.

Recognizing PJM's Capacity Performance construct, the portfolios discussed in this Report attribute limited capacity value for certain intermittent resources (solar and wind). It is possible that intermittent resources can be combined, or "coupled," and offered into the PJM market as Capacity Performance resources. The Company continues to investigate methods to maximize the utilization of its intermittent resource portfolio within that construct, which becomes effective in the 2020/2021 PJM planning year.

This IRP also addresses the 2018 Virginia Act mandates regarding solar, energy storage and energy efficiency; APCo's plans to satisfy Virginia's voluntary RPS goals throughout the planning period; and the effects of potential carbon emission regulations.

The resource portfolios developed herein reflect, to a large extent, assumptions that are subject to change; an IRP is simply a snapshot of the future at a given time. As noted previously, this IRP is not a commitment to specific resource additions or other courses of action. 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. Continue the evaluation of the Company's Solar RFP and determine if any projects will be brought forward for regulatory consideration.
2. Implement a battery pilot program with up to 10MW of energy storage.
3. Continue the planning and regulatory actions necessary to implement additional economic EE programs in Virginia and West Virginia, as well as programs that target low-income, disabled and elderly customers provided for in the 2018 Virginia Act.
4. Complete its deployment of AMI meters and associated infrastructure, add Distribution Automation Circuit Reconfiguration schemes to 60 circuits, widen certain distribution rights-of-way, and relocate or underground certain lines.
5. Plan to meet Virginia's Voluntary Renewable Portfolio Standard goals.
6. Continue to monitor market prices for renewable resources, particularly wind and solar, and if economically advantageous, or if needed to meet escalating voluntary RPS goals, pursue competitive solicitations that would include self-build or acquisition options.
7. Pursue opportunities to identify a suitable host facility for a CHP installation.
8. Monitor developments associated with PJM's Capacity Performance rule.
9. Monitor the status of, and participate in formulating any proposed carbon emissions regulations. Once established, assess the implications of such regulations on APCo's resource profile.
10. Be in a position to adjust this action plan and future IRPs to reflect changing circumstances.

1.0 Introduction

1.1 Overview

This Report presents the 2019 Integrated Resource Plan (IRP or Plan) for Appalachian Power Company (APCo or Company) 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 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 2019 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, 2019 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 Generation (DG);
- 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 beginning in 2028 as a surrogate for potential future 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 Resource Plan, which provides a road map to inform future resource decisions, including the following specific resource actions required by the 2018 Virginia Act:

- construct or acquire at least 200MW of solar power located in the Commonwealth by 2028;
- propose $140 million in Energy Efficiency programs over 10 years; and
- invest in a five-year battery pilot program of up to 10 MW.

1.3 Compliance with 2018 IRP Order

APCo's 2019 IRP addresses each of the requirements of the Commission's final order in the Company's 2018 IRP (the 2018 IRP Order), which include the following:

- 2018 IRP Order Requirement #1: Implement the mandates in the 2018 Virginia Act, including the mandate to propose $140 million in EE programs[2] APCo addressed this requirement in Section 5.2.2.3 and 5.3.

[2] Commonwealth of Virginia, State Corporation Commission, In re: Appalachian Power Company's Integrated Resource Plan filing, Case No. PUr-2018-00051, Final Order at 3 (December 18, 2019).

- 2018 IRP Order Requirement #2: Propose a least-cost plan to provide a benchmark against which to measure the costs of other alternative plans.[3] APCo addressed this requirement in Section 5.2.2 and 5.3.
- 2018 IRP Order Requirement #3: Model EE programs as reduction to load and as a supply resource.[4] APCo addressed this requirement in Section 5.3.1.
- 2018 IRP Order Requirement #4: Consider PJM peak load forecast.[5] APCo addressed this requirement in Section 5.2.2.2.

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

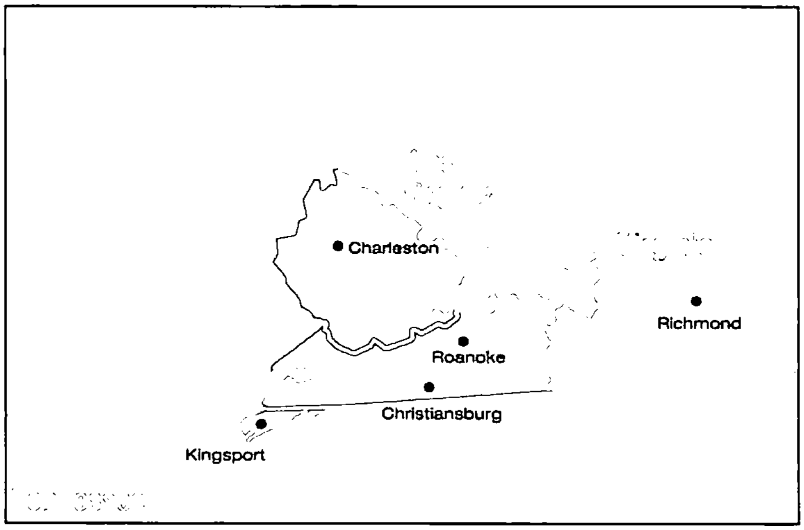

Figure 1. APCo Service Territory

[3] Id. at 3-4.

[4] Id. at 4

[5] Id. at 4.

approximately 532,000 and 424,000 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 2018 and winter 2018/19) actual APCo summer and winter peak demands were 5,618MW and 7,319MW, occurring on June 18, 2018 and January 21, 2019, respectively.

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 2018.[6] 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 (2019-2033)[7], APCo's service territory is expected to see population and non-farm employment growth 0.4% 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 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

[6] 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.

[7] 15 year forecast periods begin with the first full forecast year, 2019.

at a compounded annual growth rate (CAGR) of -0.3% per year. Finally, APCo's internal energy is expected to remain relatively flat and peak demand is expected to change at an average rate of -0.1% per year through 2033.

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 December 2017. Moody's Analytics projects moderate growth in the U.S. economy during the 2019-2033 forecast period, characterized by a 2.0% annual rise in real Gross Domestic Product (GDP), and moderate inflation, with the implicit GDP price deflator expected to rise by 2.0% per year. Industrial output, as measured by the Federal Reserve Board's (FRB) index of industrial production, is expected to grow at 1.6% per year during the same period. Moody's projects regional employment growth of 0.4% 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.

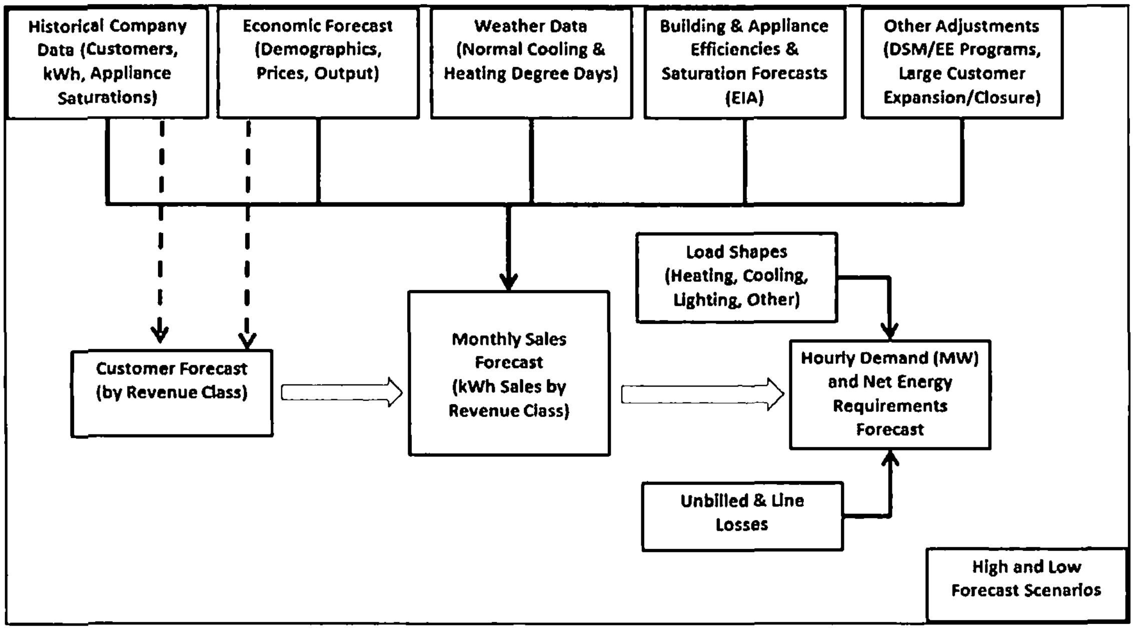

Figure 2. APCo Internal Energy Requirements and Peak Demand Forecasting Method

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 "2018 Annual Energy Outlook." The natural gas price model is based upon 1980-2017 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 "2018 Annual Energy Outlook." The estimation period for the model was 1998-2017.

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 December 2017. 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 December 2017.

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 December 2017.

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 2018 and 2019 are taken from the short-term process. Forecast values for 2020 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 2020 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 2015-2018 and on a forecast basis for the years 2019-2033. 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 2033.

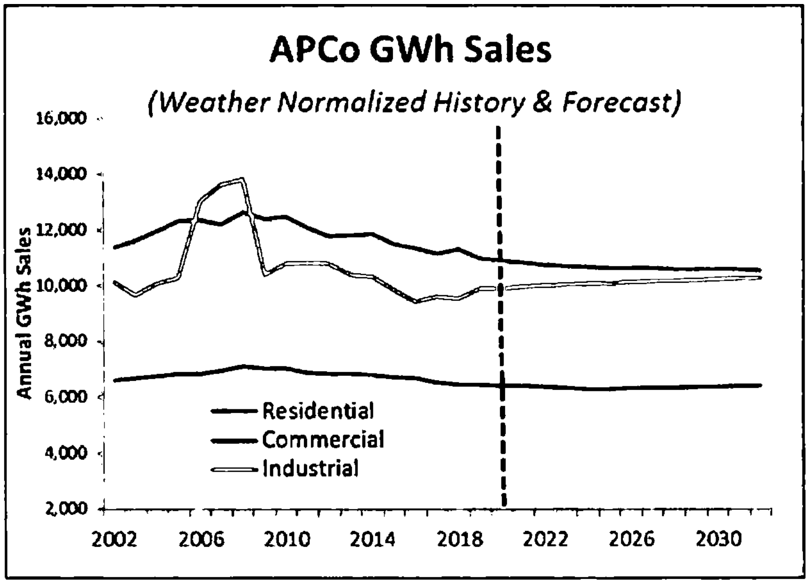

Figure 3. APCo GWh Retail Sales

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 2015-2018 and on a forecast basis for the years 2019-2033. 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 2033. 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.

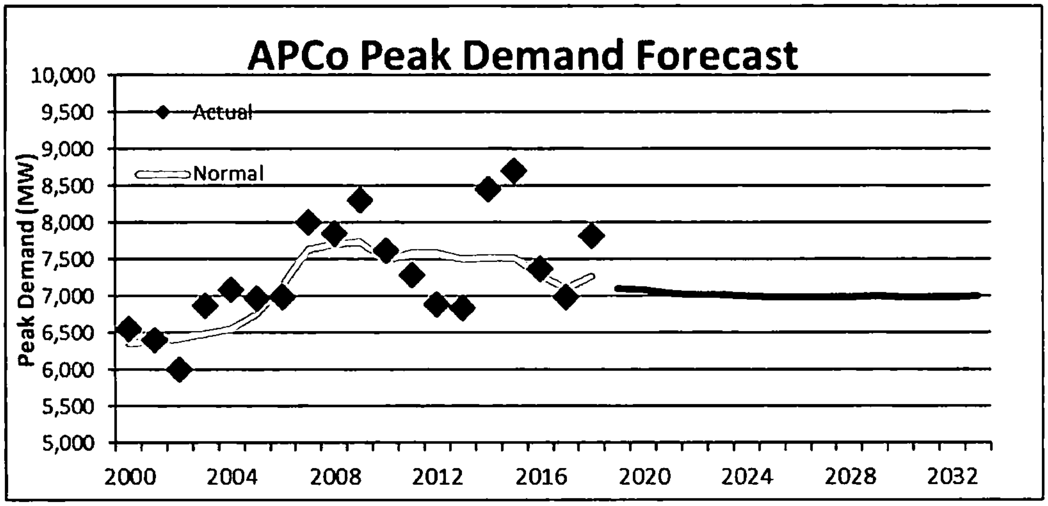

Figure 4. APCo Peak Demand Forecast

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 2025. 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 0.7% per year while the commercial class usage decreased by 0.5% per year. In the last decade shown (2011-2020) residential usage is projected to decline at a rate of 1.01% per year while the commercial usage decreases by an average of 0.9% per year. It is worth noting that the decline in residential and commercial usage accelerated between 2008 and 2018, with usage declining at average annual rates of 1.1% and 1.3% for residential and commercial sectors, respectively, over that period. For the forecast period 2020 through 2025, residential and commercial usage per customer are project to decline at average annual rates of 0.4% and 0.7%, respectively.

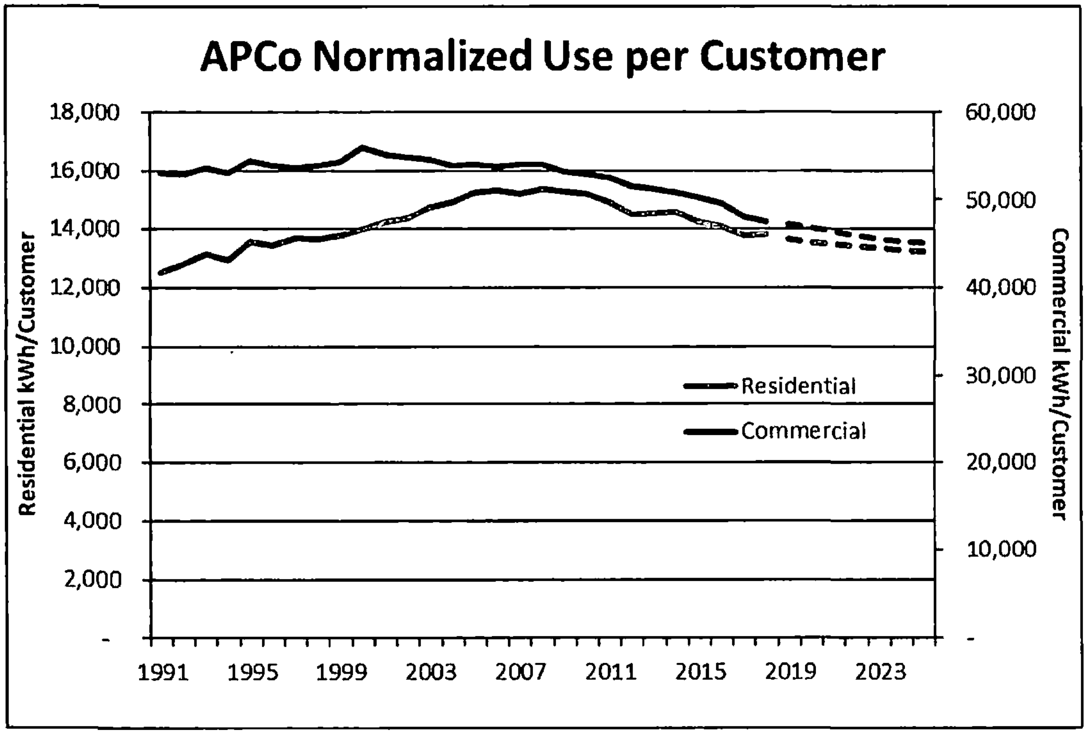

Figure 5. APCo Normalized Use per Customer (kWh)

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 11.6 in 2010 to nearly 13.6 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 clothes washers over the same period.

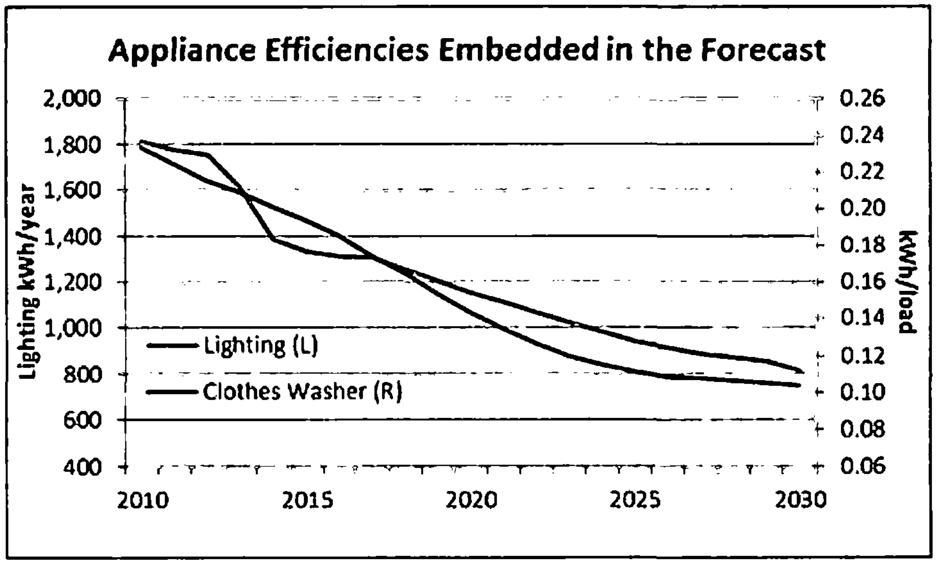

Figure 6. Projected Changes in Cooling Efficiencies, 2010-2030

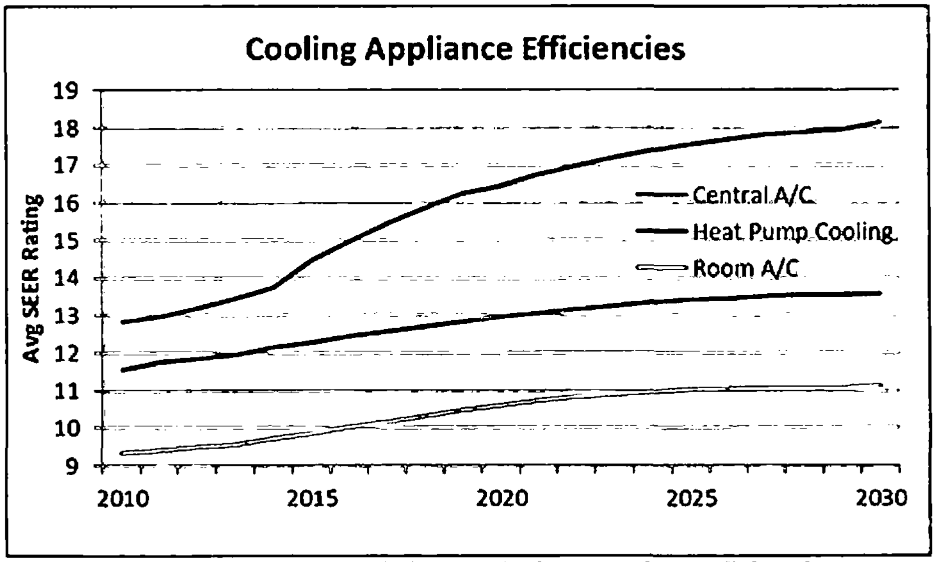

Figure 7. Projected Changes in Lighting & Clothes Washer Efficiencies, 2010-2030

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.

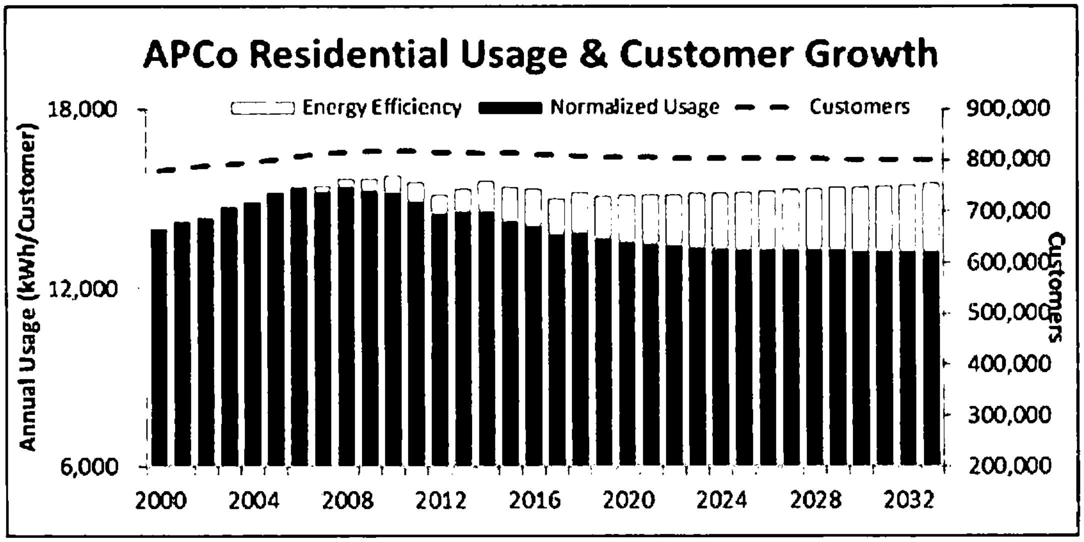

Figure 8. Residential Usage & Customer Growth, 2000-2033

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 uses assumptions from the DSM programs currently pending approval before the Commission. For the years beyond 2021, the IRP model selected optimal levels of economic EE, which may differ from the levels currently being implemented, based on projections of future market conditions. 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-9 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 306MW. However, these customers are expected to have 135MW and 153MW available for interruption at the time of the winter and summer peaks, respectively. An additional customer has 14MW 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 3.4.3.1.

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 2019 were typically taken from the short-term process. Forecast values for 2020 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 2020 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.

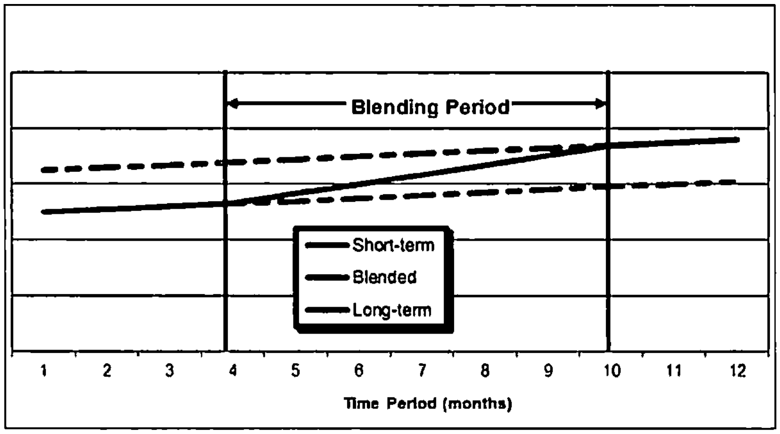

Figure 9. Load Forecast Blending Illustration

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.

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 2018 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, 2033, represent deviations of about 10.5% below and 8.4% 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.

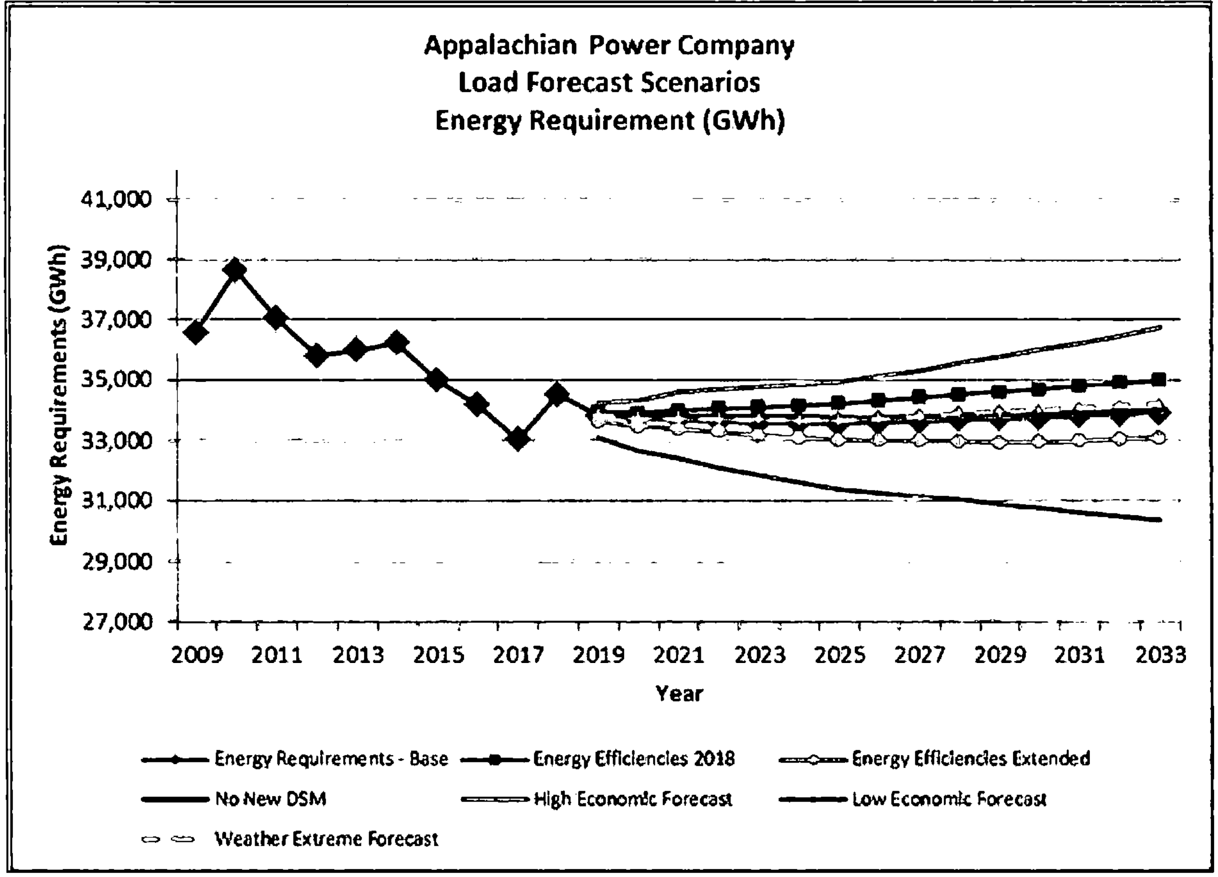

Figure 10. Load Forecast Scenarios

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 2018 scenario keeps energy efficiencies at 2018 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.

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 2019 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.

Part 2

2.9 Senate Bill 966, Energy Efficiency and Economic Development

In accordance with the final order on the APCo 2018 IRP and in compliance with SB 966, the Company has included, in this IRP, programs for energy conservation measures with a projected aggregate cost of no less than $140 million for the period July 1, 2018 through July 1, 2028. 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 Commission's directive. Section 4.4 discusses in detail the Company's process for selecting the additional energy conservation programs. Furthermore, as required by the 2018 APCo IRP final order, the Company also considered DSM as a reduction to load. The Company's discussion of this request is included in Section 5.3.1.

On December 1, 2018 and in compliance with SB 966, 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. Since 2012, the Company has supported 18 economic development projects in Virginia that created 2,071 direct jobs and customer investment of nearly $505 million. An analysis of these projects utilizing IMPLAN impact analysis tool, indicates that these jobs support an additional 2,669 jobs or making the total impact on the region of 4,740 jobs. 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, in addition to its currently available Rider RPR. 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 Company has implemented a number of new initiatives that intend to encourage job growth and retention in its Virginia service area. One of these initiatives is APCo's Economic Development Growth Enhancement (EDGE) program, which offers grants to nonprofit city, county, or regional economic development organizations for marketing and promotion, business retention and expansion, and programs that support site and building development. In 2018, EDGE awarded 12 grants totaling $148,000 to recipients in Virginia for various projects to enhance the economy of the Company's Virginia service area. In 2017, EDGE awarded the Martinsville-Henry County Economic Development Corporation a grant for the development of marketing materials for the Commonwealth Center for Advanced Training. The Company also promotes the development of new industrial properties through its Quality Sites Program. Through this program, the Company performs due diligence studies to assist growing businesses reduce overall site location risk and reduce costs associated with site development.

The Company can further encourage potential business expansions or new customer additions by employing its 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 1,000 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.

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 16.0 percent.[8] 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 ($EFOR_D$).[9] The PJM FPR is 8.95% for the 2019/2020 PJM planning year, and decreases to 8.87% for the remainder of the planning period, which ends with the 2033/2034 PJM planning year. Table 1 displays key parameters for APCo's current supply-side resources.

Table 1 identifies the current generating resources included in the Company's plan. Future

[8] Per Section 2.1.1 of PJM Manual 18: PJM Capacity Market (Effective: July 27, 2017). 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 26, 2015, which reflect PJM's Capacity Performance proposal, as currently interpreted by APCo.

[9] Per Section 2.1.4 of PJM Manual 18: PJM Capacity Market (Effective: July 27, 2017).
$FPR = (1 + IRM) * (1 - EFOR_D)$. Reserve Margin = FPR – 1.

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.

Table 1. APCo Generation Assets as of December, 2018

Unit Name	Location	Unit Type	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	75	
Ceredo 2	Ceredo, WV	Combustion Turbine	Gas	2001	75	
Ceredo 3	Ceredo, WV	Combustion Turbine	Gas	2001	75	
Ceredo 4	Ceredo, WV	Combustion Turbine	Gas	2001	75	
Ceredo 5	Ceredo, WV	Combustion Turbine	Gas	2001	75	
Ceredo 6	Ceredo, WV	Combustion Turbine	Gas	2001	75	
Clinch River 1	Carbo, VA	Steam	Gas	1958	225	
Clinch River 2	Carbo, VA	Steam	Gas	1958	230	
Dresden	Dresden, OH	Combined Cycle	Gas	2012	572	
Mountaineer 1	New Haven, WV	Steam	Coal	1980	1,336	
Buck 1 - 3	Ivanhoe, VA	Hydro	--	1912	9	
Byllesby 1 - 4	Byllesby, VA	Hydro	--	1912	22	
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	0	
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	--	1956	192	(B)
Kyger Creek	Cheshire, OH	Steam	--	1955	158	(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)
Balls Gap Battery	Milton, WV	Battery	--	2008	0 (3)	
					7,036	

(1) Commercial operation date.
(2) Peak net capability as of filing.
(3) Battery used for frequency regulation
(A) Units 1, 3 & 5 have pump-back capability, units 2 & 4 are generation only.
(B) Represents APCO's share of these units
(C) Represents capacity from Power Purchase Agreements (PPAs)

In regards to note 3 in Table 1 above, Balls Gap storage capability was not considered for capacity planning purposes in this IRP. Figure 11 below depicts APCo's current generation resources, their nameplate ratings and current age.

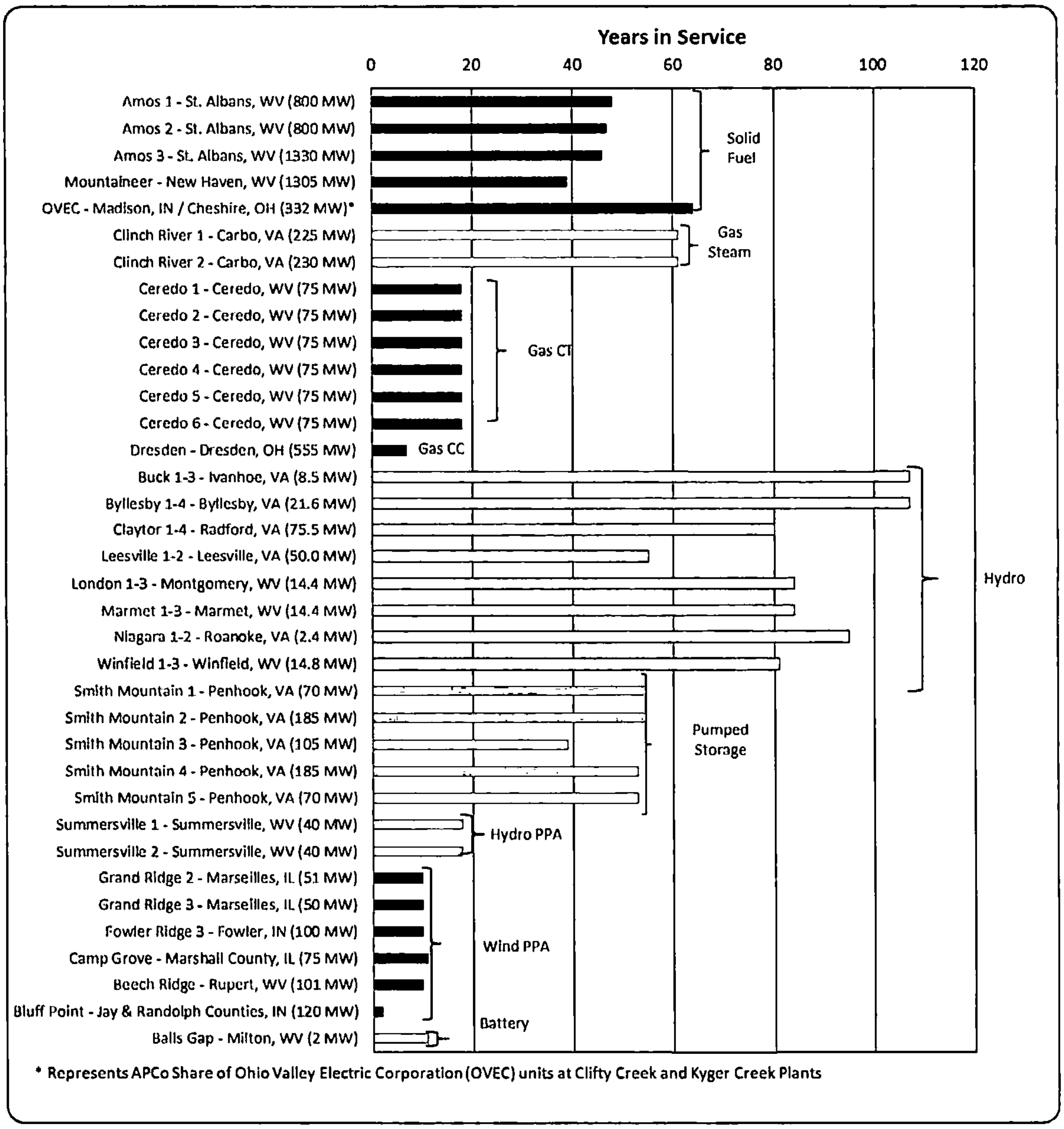

Figure 11 Current Resource Fleet (Owned & Contracted) with years in Service, as of April 1, 2019

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). The "Going-In" position includes the Depot solar resource 15MW (nameplate) in 2021.

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. The resulting PJM rule requires future capacity auctions to transition from current or "Base" capacity products to Capacity Performance products. 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. The rulemaking is effective with the 2020/2021 PJM planning year.

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 based on the assumptions made by the Company and 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 Requirements

The 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 continue to drive investments in AEP's existing generating units include: (a) periodic revisions to NAAQS and the development of SIPs 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 MATS, (d) implementation and review of CSAPR, a FIP designed to eliminate significant contributions from sources in upwind states to non-attainment or maintenance areas in downwind states and (e) the Federal EPA's regulation of greenhouse gas emissions from fossil fueled electric generating units under Section 111 of the CAA. 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

The Federal EPA issued new, more stringent NAAQS for PM in 2012 and ozone in 2015; the existing standards for NOx and SO_2 were retained after review by the Federal EPA in 2018 and 2019, respectively. Implementation of these standards is underway.

In 2016, the Federal EPA completed an integrated review plan for the 2012 PM standard. Work is currently underway on scientific, risk and policy assessments necessary to develop a proposed rule, which is anticipated in 2021.

The Federal EPA finalized non-attainment designations for the 2015 ozone standard in 2018. The Federal EPA has confirmed that for states included in the CSAPR program, there are no additional interstate transport obligations, as all areas of the country are expected to attain the 2008 ozone standard before 2023. Challenges to the 2015 ozone standard are pending in the U.S. Court of Appeals for the District of Columbia Circuit. In 2018, the Federal EPA proposed final requirements for implementing the 2015 ozone standard, which have also been challenged in the U.S. Court of Appeals for the District of Columbia Circuit.

3.3.3 Cross-State Air Pollution Rule (CSAPR)

In 2011, the Federal EPA issued CSAPR as a replacement for the Clean Air Interstate Rule, 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 SO_2 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.

Petitions to review the CSAPR were filed in the U.S. Court of Appeals for the District of Columbia Circuit. In 2015, the court found that the Federal EPA over-controlled the SO_2 and/or NOx budgets of 14 states. The court remanded the rule to the Federal EPA for revision consistent with the court's opinion while CSAPR remained in place.

In 2016, the Federal EPA issued a final rule to address the remand and to incorporate additional changes necessary to address the 2008 ozone standard. The final rule significantly reduced ozone season budgets in many states and discounted the value of banked CSAPR ozone season allowances beginning with the 2017 ozone season. The rule has been challenged in the courts and petitions for administrative reconsideration have been filed. APCo has been complying with the more stringent ozone season budgets while these petitions were pending.

APCO will rely on the installed SCR and FGD systems' respective emission reductions of NOx and SO_2, the use of allocated NOX and SO_2 emission allowances in conjunction with adjusted banked allowances, and the purchase of additional allowances as needed through the open market to comply with CSAPR Phase 2 and the CSAPR.

3.3.4 Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

In 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. 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 HAPs and dioxin/furans. Compliance was required within three years. Administrative extensions for up to one year at several units were obtained to facilitate the installation of controls or to avoid a serious reliability problem.

In 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied all of the petitions for review of the 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 Federal EPA to consider costs in determining whether to regulate emissions of HAPs from power plants. In 2016, the Federal 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 Federal EPA's determination were filed in the U.S. Court of Appeals for the District of Columbia Circuit. In 2018, the Federal 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 Federal 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 Federal EPA proposed to retain the current MATS standards without change. The comment period on this proposal closed in April 2019.

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 SO_2 emissions, which together achieve a co-benefit removal of mercury as well.

3.3.5 Carbon Dioxide (CO_2) Regulations, Including the Clean Power Plan (CPP) and the Affordable Clean Energy (ACE) Rule

In 2015, the Federal EPA published the final CO_2 emissions standards for new, modified and reconstructed fossil fuel-fired steam generating units and combustion turbines, and final guidelines for the development of state plans to regulate CO_2 emissions from existing sources, known as the Clean Power Plan (CPP).

The final rules were challenged in the courts. In 2016, the U.S. Supreme Court issued a stay on the final CPP, including all of the deadlines for submission of initial or final state plans, until a final decision is issued by the U.S. Court of Appeals for the District of Columbia Circuit and the U.S. Supreme Court considers any petition for review. In 2017, the President issued an Executive Order directing the Federal EPA to reconsider the CPP and the associated standards for new sources. The Federal EPA filed a motion to hold the challenges to the CPP in abeyance, and the cases are still pending.

In 2018, the Federal EPA proposed the Affordable Clean Energy (ACE) rule to replace the CPP with new emission guidelines for regulating CO_2 from existing sources. ACE would establish a framework for states to adopt standards of performance for utility boilers based on heat rate improvements for such boilers. In 2018, the Federal EPA filed a proposed rule revising the standards for new sources and determined that partial carbon capture and storage is not the best system of emission reduction because it is not available throughout the U.S. and is not cost-effective. APCo is actively monitoring these rulemaking activities.

For purposes of this Integrated Resource Plan, APCo has not directly attempted to model either the Clean Power Plan or Affordable Clean Energy rule as the former has been proposed for replacement and the latter still remains in proposal stage, leaving considerable uncertainty around actual standards and implementation, which is left to individual states. 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 April 2019, the Virginia Air Pollution Control Board (Board) approved rules that would require a thirty percent reduction in greenhouse gas emissions from electric generation facilities located within the Commonwealth (the GHG Regulations). The GHG Regulations, which establish a program similar to the Regional Greenhouse Gas Initiative (RGGI), set an initial statewide emission cap of 28 million tons. That cap is ratcheted down by three percent each year thereafter for a total emissions cap of 19.6 million tons by 2030. The regulation will go into effect in 2020 subject to final approval of the state budget.

APCo's preliminary analysis of the GHG Regulations, concludes that the impact of the GHG Regulations on APCo will likely be relatively insignificant. APCo only owns one affected facility in the Commonwealth, consisting of the two natural gas-steam units at Clinch River, and annual emissions from these units represent less than 2% of the overall Virginia emission budget established by the GHG Regulations. Furthermore, for purposes of this IRP, APCo assumed that the Clinch River units will retire in 2026, which limits the duration that the units will be subject to regulation.

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 2 and Table 3. 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 2. 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 3. 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 Rule

In 2015, the Federal EPA published a final rule to regulate the disposal and beneficial re-use of coal combustion residuals (CCR), including fly ash and bottom ash generated at coal-fired electric generating units and also FGD gypsum generated at some coal-fired plants. The rule applies to new and existing active CCR landfills and CCR surface impoundments at operating electric utility or independent power production facilities. The rule imposes construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria and additional groundwater monitoring requirements to be implemented on a schedule spanning an approximate four-year implementation period. In 2018, some of AEP's facilities were required to begin assessment monitoring programs to determine if unacceptable groundwater impacts will trigger future corrective measures. Based on additional groundwater data further studies to design and assess appropriate corrective measures will be undertaken at four facilities in accordance with the rule.

The final 2015 rule was challenged in the courts. In 2018, the U.S. Court of Appeals for the District of Columbia Circuit issued its decision vacating and remanding certain provisions of the 2015 rule. Remaining issues were dismissed. The provisions addressed by the court's decision, including changes to the provisions for unlined impoundments and legacy sites, will be the subject of further rulemaking consistent with the court's decision.

Prior to the court's decision, the Federal EPA issued a final rule that modifies certain compliance deadlines and other requirements in the rule. In December 2018, challengers filed a motion for partial stay or vacatur of the July 2018 rule. On the same day, the Federal EPA filed a motion for partial remand of the July 2018 rule. The court granted Federal EPA's motion, and further rulemaking to address the court's decisions is expected to be completed near the end of 2019.

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 CWA. Two cases have been accepted by the U.S. Supreme Court for further review of the scope of CWA jurisdiction. The Federal EPA has 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.

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. Based on the timing of the gas conversion for Units 1 and 2 at the Clinch River Plant, that landfill is not subject to the requirements of the final CCR Rule. However, the ash pond 1a/1b is, as an inactive surface impoundment captured by the rule.

3.3.9 Clean Water Act Regulations

In 2014, the Federal EPA issued a final rule setting forth standards for existing power plants that is intended to reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) 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 National Pollutant Discharge Elimination System permit as those permits are renewed. Facilities with existing closed cycle recirculating cooling systems, including the Amos, Clinch River, Dresden, and Mountaineer Plants, may not be required to make any technology changes. If additional capital investment is required, the magnitude is expected to be relatively small compared to the investment that could be needed if the plants were not equipped with cooling towers. Given that all of APCo's active units are already equipped with either natural draft, hyperbolic or forced draft mechanical cooling towers, and these units withdraw less than 125 million gallons of water per day, the anticipated impact of the 316(b) rule is assumed to be limited to the installation of flow monitoring equipment.

In 2015, the Federal EPA issued a final rule revising effluent limitation guidelines (ELG) for electricity generating facilities. The rule establishes limits on FGD wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater to be imposed as soon as possible after November 2018 and no later than December 2023. These requirements would be implemented through each facility's wastewater discharge permit. The rule has been challenged in the U.S. Court of Appeals for the Fifth Circuit. A final rule revising the compliance deadlines for FGD wastewater and bottom ash transport water to be no earlier than 2020 was issued in September 2017, and has been challenged in the courts. EPA is reconsidering the final standards for FGD wastewater and bottom ash transport water, and a proposed rule could be issued later in 2019.

To ensure compliance with the ELG Rule, APCo has determined that wastewater treatment projects may be necessary at its supercritical coal-fired units and these have been considered as part of the respective long-term unit evaluations. Both the Amos and Mountaineer Plants utilize wet bottom ash handling systems, while the Amos Plant operates a FGD wastewater treatment system without biological treatment. Initial estimates of the potential plant modifications and capital expenditures to comply with the ELG Rule are not expected to impact APCo's future resource decisions. Similar to the effect on CCR compliance mentioned above the existing dry fly ash handling systems and dry ash landfills, along with existing wastewater treatment plants for FGD blowdown at both the Amos and Mountaineer Plants position them well for compliance with the final ELG rulemaking. In 2015, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a final rule to clarify the scope of the regulatory definition of "waters of the United States" in light of recent U.S. Supreme Court cases. The final rule was challenged in several courts that have reached different conclusions about whether the 2015 rule should be implemented. In December 2018, the Federal EPA and the U.S. Army Corps of Engineers released a proposed rule revising the definition, which would replace the definition in the 2015 rule and could significantly alter the scope of certain CWA programs. The comment period for this proposal ended in April 2019.

3.4 APCo Current Demand-Side Programs

3.4.1 Background

DSM refers to, for the purposes of this IRP, utility programs, including tariffs, which encourage reduced energy consumption, either at times of peak consumption or throughout the day/year. Programs or tariffs that are designed to reduce consumption primarily at periods of peak consumption are demand response (DR) programs, while around-the-clock measures are typically categorized as energy efficiency (EE) programs. The distinction between DR and EE is important, as the solutions for accomplishing each objective are typically different, but not necessarily mutually exclusive.

Included in the load forecast discussed in Section 2.0 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 preparation of this IRP. 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. For the year 2019, the Company anticipates 178MW of peak DSM reduction (total company basis); consisting of 10.8MW and 167MW of "passive" EE and "active" DR activity, respectively.[10] For capacity planning purposes the Company anticipates "active" DR will be 108MW.

3.4.2 Impacts of Existing and Future Codes and Standards

The EISA requires, among other things, a phase-in of heightened lighting efficiency standards, appliance standards, and building codes. The increased standards will have a pronounced effect on energy consumption as explained in Section 2.6. Many of the standards already in place impact lighting. For instance, since 2013 and 2014 common residential incandescent lighting options have been phased out as have common commercial lighting fixtures. Given that "lighting" measures have comprised a large portion of utility-sponsored EE programs prior to the phase-out, this pre-established transition is already incorporated into the SAE long-term load forecast modeling previously described in Section 2.4.4 and may greatly affect the market potential of utility EE programs in the near and intermediate term. Table 4 and Table 5 depict the current schedule for the implementation of new EISA codes and standards.

[10] "Passive" demand reductions are achieved via "around-the-clock" *EE* program activity as well as voluntary price response programs; "Active" DR is centered on summer peak reduction initiatives, including interruptible contracts, tariffs, and direct load control programs.

Table 4. Forecasted View of Relevant Residential Energy Efficiency Code Improvements

Central AC	SEER 13; SEER 14 in South	
Room AC	EER 11.0	
Heat Pump	SEER 14.0/HSPF 8.0	
Water Heater (<=55 gallons)	EF 0.95	
Water Heater (>55 gallons)	Heat Pump Water Heater	
Screw-in/Pin Lamps	Advanced Incandescent (20 lumens/watt)	Advanced Incandescent (45 lumens/watt)
Linear Fluorescent	T8 (89 lumens/watt)	T8 (92.5 lumens/watt)
Refrigerator	25% more efficient	
Freezer	25% more efficient	
Clothes Washer	1.29 IMEF top loader	1.57 IMEF top loader
Clothes Dryer	3.73 Combined EF	
Furnace Fans	Conventional	40% more efficient

Table 5. Forecasted View of Relevant Non-Residential Energy Efficiency Code Improvements

Technology	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Chillers	2007 ASHRAE 90.1										
Roof Top Units	EER 11.0/11.2										
PTAC	EER 11.7		EER 11.9								
Heat Pump	EER 11.0/COP 3.3										
PTHP	EER 11.9/COP 3.3										
Ventilation	Constant Air Volume/Variable Air Volume										
Screw-in/Pin Lamps	Advanced Incandescent (20					Advanced Incandescent (45 lumens/watt					
Linear Fluorescent	T8 (89 lumens/watt)			T8 (92.5 lumens/watt)							
High Intensity Discharge	EPACT 2005		Metal Halide Ballast Improvement								
Water Heater	EF 0.97										
Walk-in Refrigerator/Freezer	EISA 2007		10-38% more efficient								
Reach-in Refrigerator/Freezer	EPACT 2005		40% more efficient								
Glass Door Display	EPACT 2005		12-28% more efficient								
Open Display Case	EPACT 2005		10-20% more efficient								
Ice maker	EPACT 2005			15% more efficient							
Pre-rinse Spray Valve	1.6 GPM				1.0 GPM						
Motors	EISA 2007	Expanded EISA 2007									

The impact of energy efficiency, including codes and standards, is expected to reduce residential load, commercial load, and industrial lighting load in total by over 5%, as shown in Figure 12.

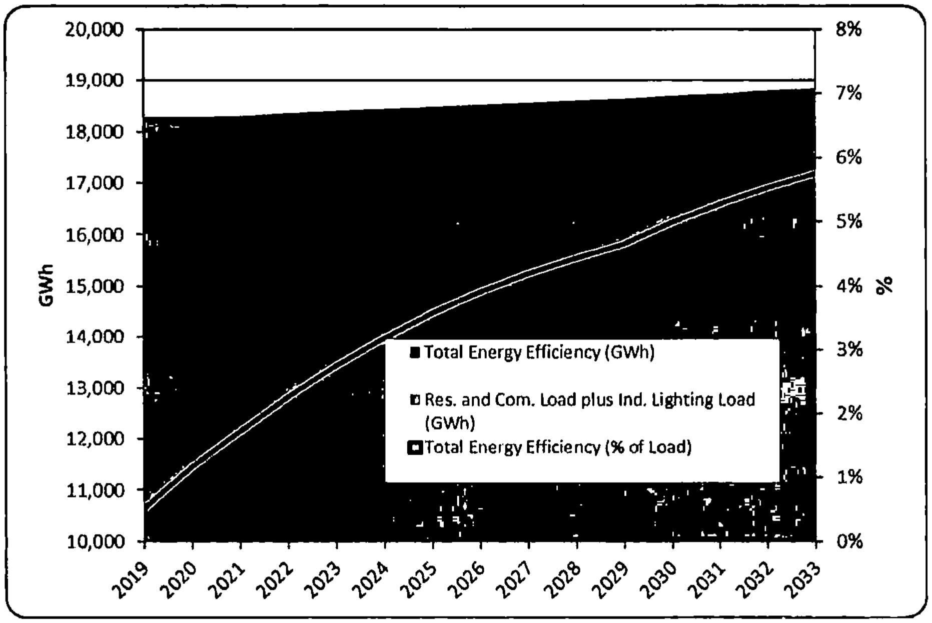

Figure 12. Total Energy Efficiency (GWh) Compared w/Total Residential & Commercial Load (GWh)

3.4.3 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.

As peak demand grows with the economy and population, new generating capacity must ultimately be built. To defer construction of new power plants, the amount of power consumed at the peak can be reduced. This can be addressed several ways:

- *Interruptible loads*. This refers to a contractual agreement between the utility and a large consumer of power, typically an industrial customer. In return for reduced rates, an industrial customer allows the utility to "interrupt" or reduce power consumption during peak periods, freeing up that capacity for use by other consumers.
- *Direct load control*. Very much like an (industrial) interruptible load, but accomplished with many more, smaller, individual loads. Commercial and residential customers, in exchange for monthly credits or payments, allow the energy manager to deactivate or cycle discrete appliances, typically air conditioners, hot water heaters, lighting banks, or pool pumps during periods of peak demand. These power interruptions can be accomplished through radio signals that activate switches or through a digital "smart" meter that allows activation of thermostats and other control devices.
- *Time-differentiated rates*. This offers customers different rates for power at different times during the year and even the day. During periods of peak demand, power would be relatively more expensive, encouraging conservation. Rates can be split into as few as two rates (peak and off-peak) to as often as 15-minute increments in what is known as "real-time pricing." Accomplishing real-time pricing requires digital (smart) metering.
- *EE measures*. If the appliances that are in use during peak periods use less energy to accomplish the same task, peak energy requirements will likewise be less.
- *Voltage Regulation*. Certain technologies, such as Conservation Voltage Reduction or Volt VAR optimization can be deployed that allow for improved monitoring of voltage throughout the distribution system. The ability to deliver electricity at design voltages improves the efficiency of many end use devices, resulting in less energy consumption.

What may not be apparent is that, with the exception of EE and voltage regulation measures, the remaining DR programs do not significantly reduce the amount of energy consumed by customers. Less energy may be consumed at the time of peak load, but that energy will be consumed at some point during the day. For example, if rates encourage customers to avoid running their clothes dryer at 4:00 P.M., then they will run it at some other point in the day. This is often referred to as load shifting.

3.4.3.1 Existing Levels of Demand Response (DR)

APCo currently has active DR programs totaling 167MW of peak DR capability. The majority of this DR is achieved through interruptible load agreements. A smaller portion is achieved through direct load control. In 2015 APCo launched a DR program for residential customers. Demand reduction is achieved by cycling customer air conditioning units on and off during periods of high demand in the summer. Each participating resident is compensated for this service with an end-of-season incentive payment. The current Virginia program is designed to allow approximately 2,300 residential customers to sign up each year, on average, through 2020. Each block of 2,300 customers is estimated to provide up to 2.9MW in demand savings. APCo's West Virginia jurisdiction has a similar program.

3.4.3.2 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

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- 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 programs that are currently approved or pending approval. APCo currently has EE programs in place in its Virginia and West Virginia service territories. Both states have approved EE programs. APCo forecasts EE measures will reduce peak demand in 2019 by 10.8MW and reduce 2019 energy consumption by 82GWh.

3.4.4 Distributed Generation (DG)

DG 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.

The economics of DG, particularly solar, continue to improve. Figure 13 charts the fairly rapid decline of expected installed solar costs, based on a combination of AEP market intelligence and the Bloomberg New Energy Finance's (BNEF) U.S. Renewable Energy Market Outlook forecast.

Prior to 2022, during the ITC phase out for residential systems, costs for residential customers are expected to decline rapidly. This decline, which is forecasted to bring residential costs down to commercial cost levels, is attributed to a shift from value-based pricing to cost-plus-margin pricing. Installers are expected to spend less on customer acquisition and less on customer specific solutions as they aim for the lowest cost installations possible.

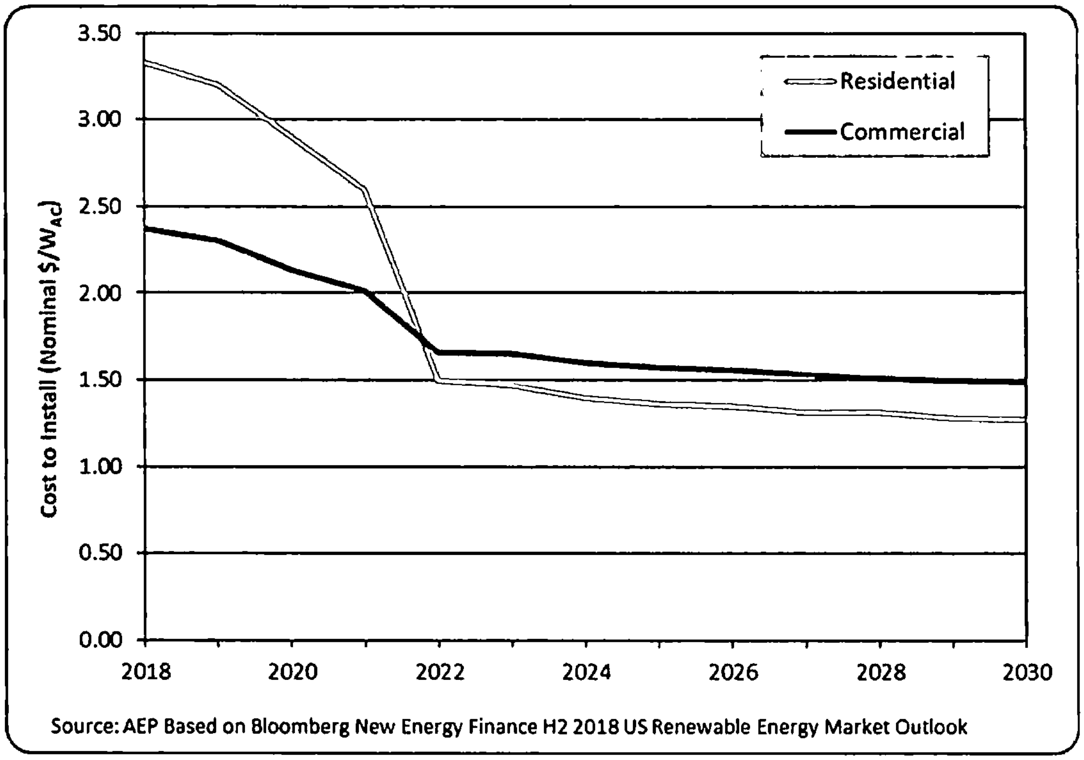

Figure 13. Residential & Commercial Forecasted Solar Installed Costs (Nominal W_{AC}$) for PJM

While the cost to install residential solar continues to decline, the economics of such an investment are not favorable for the customer for a number of years, given APCo's current rates. As Figure 14 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.

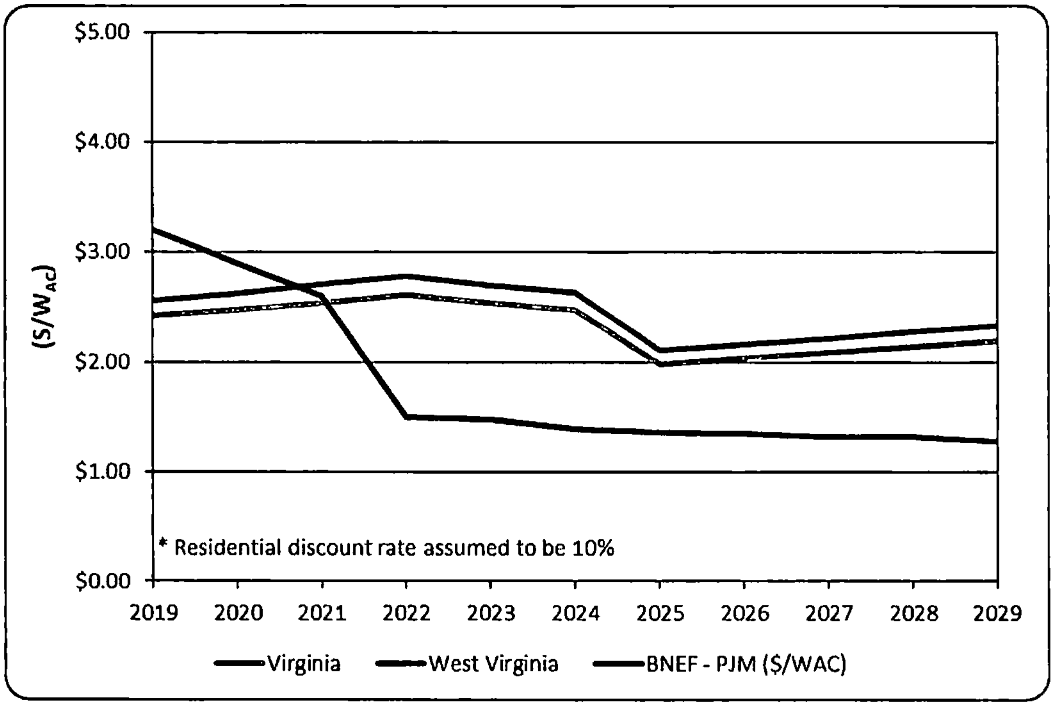

Figure 14. Distributed Solar Breakeven Costs for Residential Customers ($/$W_{AC}$)

A challenge of determining the value of a residential solar system is assigning an appropriate cost of capital or discount rate. Discount rates for residential investments vary dramatically and are based on each individual's financial situation. Figure 15 shows how the value of a residential customer's DG system can vary based on discount rate.

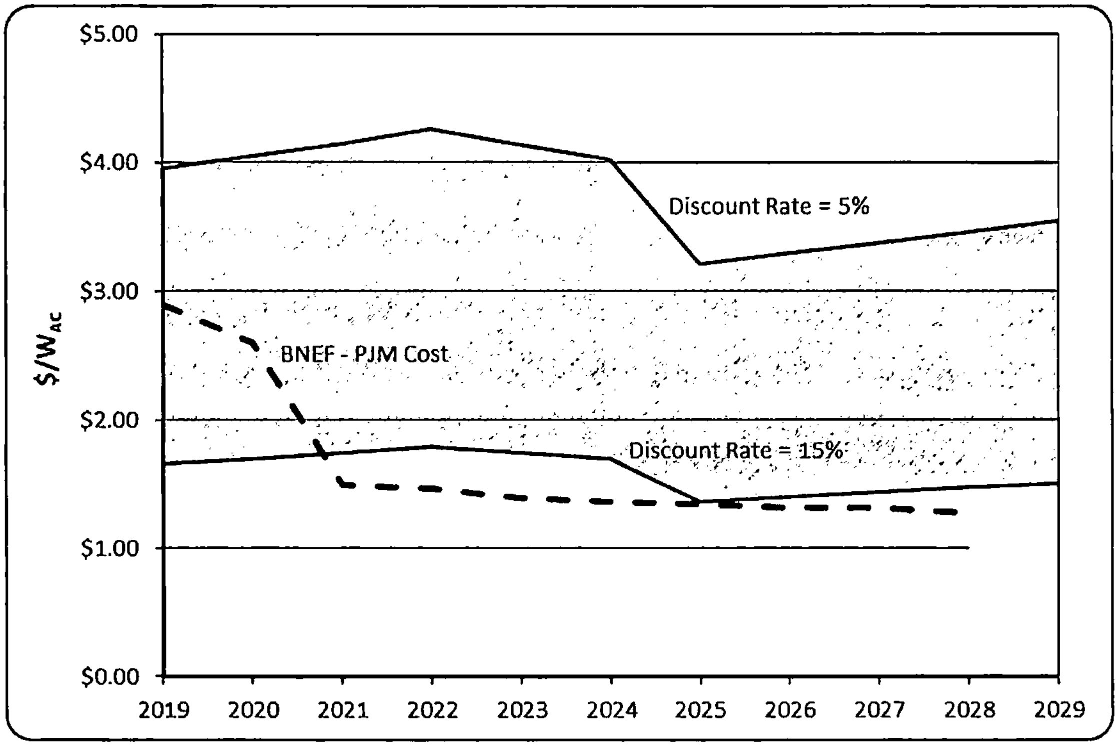

Figure 15. Range of Residential Distributed Solar Breakeven Values Based on Discount Rate

3.4.4.1 Existing Levels of Distributed Generation (DG)

At the end of 2018 APCo and its affiliate Kingsport Power have a total of 11.4MW of customer-installed DG consisting of 9.8MW in Virginia, 1.3MW in West Virginia and 0.3MW in Tennessee.

3.4.4.2 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. This is particularly true for solar generators during summer months when rooftop panels are able to generate close to their rated capacity for more hours of the day. Figure 16 below illustrates the average summer load profile for a representative customer with rooftop solar (blue line) and without rooftop solar (red line).

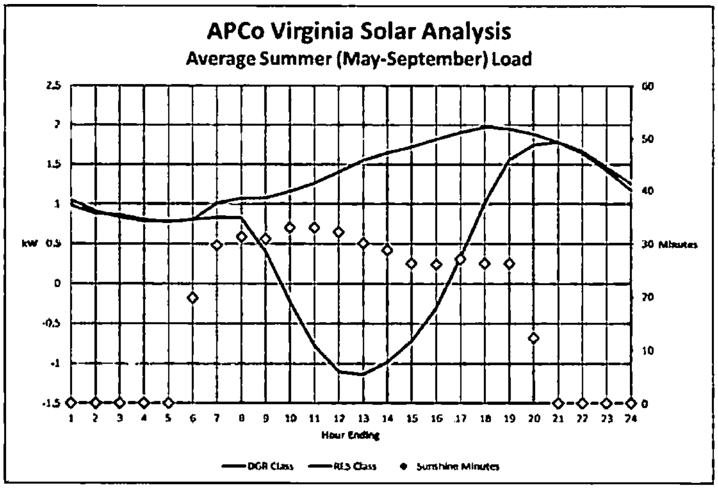

Figure 16. Summer Load Profile for Representative DG Customer with Rooftop Solar Installation

Figure 16 indicates that on average, during summer months, from approximately 9:30am until 5pm, a customer with rooftop solar would be supplying electricity to the grid, as evident by the negative load requirement. Figure 17 illustrates the average winter load profile for a representative customer with rooftop solar (blue line) and without rooftop solar (red line).

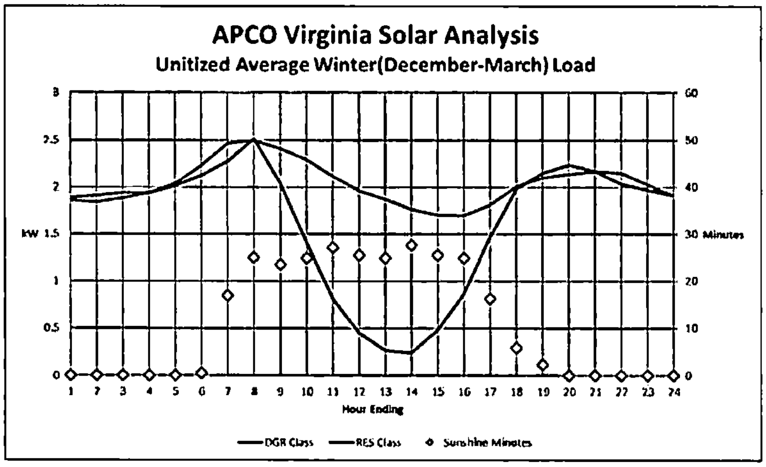

Figure 17. Winter Load Profile for Representative DG Customer with Rooftop Solar Installation

Figure 17 indicates that on average, during winter months, a customer with rooftop solar would not be supplying electricity to the grid. During periods when DG systems are generating they are offsetting the Company's total generation requirement, however the total offset is both difficult to quantify and plan for due to the variability of system output.

3.4.4.3 Impacts of Increased Levels of Distributed Generation (DG)

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 17, during these times of peak demand rooftop solar installations are providing little to no demand savings.

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

Currently, DG applicants in APCo's Virginia and West Virginia jurisdictions are required to fund any improvements needed to mitigate impacts to the operation and power quality of affected distribution stations and circuits. As DG penetration grows there is potential that the "next" applicant would be required to fund improvements that are a result of the aggregate impacts of previous DG customers because the incremental impact of the "next" customer now drives a need for improvements. This could lead to inequities among DG customers if necessary improvements are not planned appropriately.

3.4.5 Volt VAR Optimization (VVO)

An emerging technology known as VVO represents a form of voltage control that allows the grid to operate more efficiently. Depicted at a high-level in Figure 18, with VVO sensors and intelligent controllers monitor load flow characteristics and direct controls on capacitor and voltage regulating equipment to optimize power factor and voltage levels. Power factor is the ratio of real power to apparent power, and is a characteristic of electric power flow which is controlled to optimize power flow on an electric network. Power factor optimization also improves energy efficiency by reducing losses on the system. VVO enables Conservation Voltage Reduction (CVR) on a utility's system. CVR is a process by which the utility systematically reduces voltages in its distribution network, resulting in a proportional reduction of load on the network. Voltage optimization can allow a reduction of system voltage that still maintains minimum levels needed by customers, thereby allowing customers to use less energy without any changes in behavior or appliance efficiencies. Early results from limited rollouts in APCo's West Virginia service territory and other AEP operating companies indicate a range of 0.7% to 1.2% of energy demand reduction for each 1% voltage reduction is possible. Furthermore, in late 2016 APCo placed in service a VVO pilot on 3 circuits in West Virginia where approximately 3% energy and demand savings have been observed to-date.

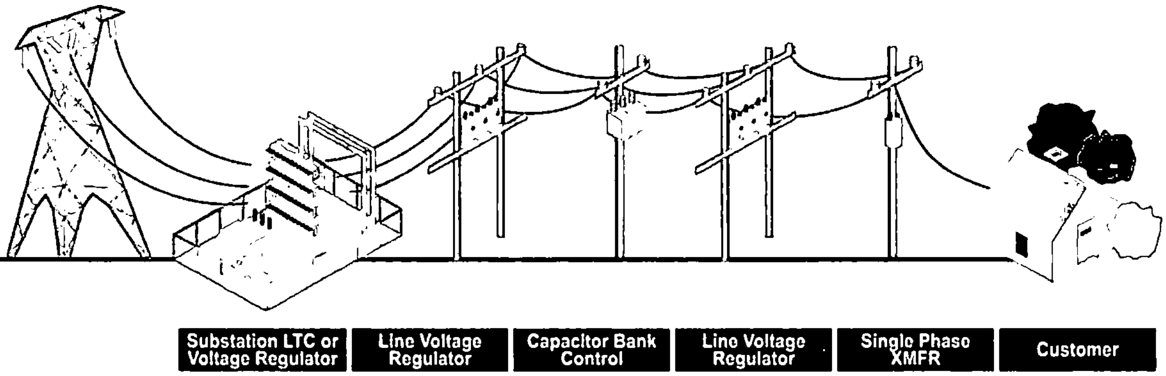

Figure 18. Volt VAR Optimization Schematic

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.

3.5 AEP-PJM Transmission

3.5.1 General Description

The AEP eastern transmission system (eastern zone) consists of the transmission facilities of the ten eastern AEP operating or Transmission companies (APCo, Ohio Power Company [OPCo], Indiana Michigan Power [I&M], Kentucky Power Company [KPCo], Wheeling Power Company [WPCo], Kingsport Power Company [KgPCo], AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, and AEP West Virginia Transmission Company). This portion of the transmission system is composed of approximately 14,800 miles of circuitry operating at or above 100kV. The eastern zone includes over 2,100 miles of 765kV transmission lines overlaying 3,500 miles of 345kV lines and over 8,900 miles of 138kV circuitry. This expansive system allows the economical and reliable delivery of electric power to approximately 21,660MW 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 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. 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. In addition, Extra High Voltage (EHV) transformer capacity has been increased at various stations across the eastern transmission system.

AEP's eastern transmission system assets are aging. Figure 19 below demonstrates the development of that Transmission Bulk Electric System. In order to maintain reliability, significant investments will have to be made in the rehabilitation of existing assets over the next decade.

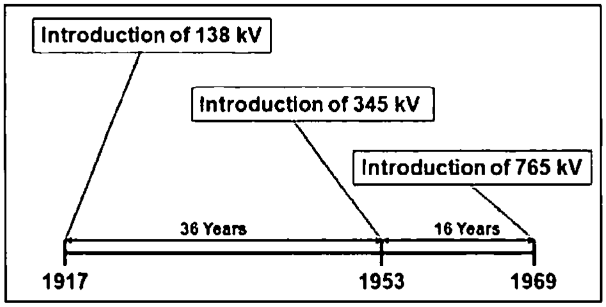

Figure 19. AEP Eastern Transmission System Development Milestones

Over the years, AEP, and now 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[11],

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

and based on executed agreements as of December 31[st], 2018). 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 System-East 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 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. By way of the RTEP, PJM will ensure that transmission expansion is developed for the entire RTO footprint via a single regional planning process, ensuring a consistent view of needs and expansion timing while minimizing expenditures. When the RTEP identifies system upgrade requirements, 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 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[12]. 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.

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.

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

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[13] load forecast for areas that may need to rely on external resources to meet their demands during an emergency condition.

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

[13] 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.

any projects that sign an interconnection agreement. The amount of this planned generation that will actually come to fruition 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 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 2019 FERC Form 715 Annual Transmission Planning and Evaluation Report. That filing also provides transmission maps, and pertinent information on power flow studies and an evaluation and continued adequacy assessment of AEP's eastern transmission system.

As the transmission planner for AEP and AEP subsidiaries in the east, 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.

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 West Virginia Transmission Company, Inc. (WV Transco) and Transource West Virginia, that have recently been completed or are presently underway in Virginia and West Virginia can be found below. 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. 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.

A brief summary of the major transmission projects in APCo's Virginia and West Virginia service territories for the 2018-2023 timeframe is provided below. Project information includes the project name and a brief description of the project scope.

Broadford Station Improvements: Three new 765 kV circuit breakers will be added to increase operational flexibility and reliability; six existing 138 kV circuit breakers will be replaced to address safety performance; and three new 138 kV circuit breakers will be added for greater operational flexibility and reliability.

Jacksons Ferry Station Improvements: Recently, various operational procedures had to be initiated to mitigate both high and low voltage conditions in the area around the Jacksons Ferry Station. APCo is installing a -450/+450 MVAR Static VAR Compensator (SVC). This is a PJM mandated/baseline project. In addition, an existing 765/500 kV transformer will be replaced; a new 765 kV circuit breaker will be added; and three existing 138 kV circuit breakers will be replaced.

Kanawha River Station Improvements: Replacement of the following assets at Kanawha Station will improve reliability, mitigate safety concerns, and/or allow for operational flexibility: three existing 345 kV circuit breakers; the existing Series Capacitor; and the existing 345/138 kV transformer.

Joshua Falls 138 kV Station Improvements: The Joshua Falls Improvement project includes building a new 138kV yard adjacent to the existing Joshua Falls 765 kV Station in Lynchburg, VA, which has been retired. This project will also establish a new connection from the 138 kV yard to the 765 kV yard and upgrade some line relays.

Reusens Station Improvements: The Reusens Station Improvement Project will replace three 138 kV circuit breakers, four 69 kV breakers, and two 138/34.5 kV transformers; install a new Drop In Control Module (DICM); and add three new 138 kV sectionalizing devices to improve overall reliability of the area.

Cloverdale Area Improvement Project: The Cloverdale Area Improvement Project will address reliability by replacing a 765/345 kV transformer, a 765 kV circuit breaker and two 345 kV current breakers; and adding two new 765 kV circuit breakers. In the 138 kV yard, the 138/69 kV transformer will be replaced and four new 138 kV breakers will be installed to improve reliability.

Opossum Synchronous Condenser Project: Two new smaller synchronous condensers at Opossum Creek Station will be installed and the existing single unit will be retired. Seven 138 kV breakers will be replaced and five new 138 kV breakers will be installed to add sectionalizing capability and thus improve overall reliability.

Cliffview Area Improvements: The major scope of work includes constructing a new double 138 kV circuit to a newly constructed 138 kV Cliffview Station. Upon completion of the work, the existing Wythe – Cliffview and Wythe – Byllesby 69 kV lines will be retired.

Sheridan Area Improvements: The Sheridan Area Improvements addresses necessary infrastructure improvements in Lincoln and Logan Counties in West Virginia as well as improvements related to looping long radial lines serving substantial load. The major scope of work includes constructing a new double circuit 138 kV line from the Midkiff 138 kV Station to a newly constructed Sheridan 138 kV Station. The Darrah – Sheridan 69 kV line will then be retired. Also, a new 138 kV line will be constructed from the Midkiff 138 kV Station to the Stone Branch 138 kV Station in order to provide a second feed to the approximately 40 MVA of load served out of Stone Branch. A new station at Chapmanville will be constructed in order to retire the Trace Fork Switching Station currently on the Hopkins – Logan 138 kV circuit. This new 138 kV Station will improve reliability of the 138 kV system in the area.

Leon – Ripley Conversion: The Leon – Ripley 69 kV conversion project addresses thermal violations for the loss of the Gavin – Meigs 69 kV line in conjunction with the Ripley – Ravenswood 69 kV line. In addition, this project will resolve voltage violations for the loss of the Leon – Ripley 69 kV line and the loss of the Gavin – Meigs 69 kV line. The major scope of work includes rebuilding the existing Leon – Ripley line and converting it to 138 kV, as well as building a new 138 kV Ripley Station.

Abingdon Area Improvements: The Abingdon Transmission Upgrades project will address planning criteria and asset renewal concerns associated with facilities in the Abingdon Area. The project will solve thermal and voltage criteria violations in the area by replacing the existing transformer at Meadowview with a larger bank and bringing the Broadford – Wolf Hills 138 kV circuit into Abingdon station. The project will allow for the retirement of the aging Abingdon – Hillman Highway 69 kV line by constructing a new 69 kV circuit between South Abingdon and Arrowhead stations.

Tri State Station Rehab Project: Tri-State Station is currently serving approximately 5,600 customers in the Huntington, West Virginia area with a projected load of approximately 34 MVA. The major scope of work, which will improve reliability, includes the replacement of two existing 345/138 kV transformers and a 345 kV circuit breaker, as well as the installation of four new 345 kV circuit breakers.

Huntington Area Improvements: The Huntington Area Improvement project addresses thermal violations on the 34.5 kV subtransmission network that supports the city of Huntington, WV. The major scope of work entails the construction of a new 138 kV line between Darrah and East Huntington Stations.

Nagel Gas Insulated System (GIS) Replacement. The proposed system will rebuild and replace the existing 500/138 kV GIS station yard as a conventional Air Insulated Station (AIS). In addition, a second 500/138 kV transformer will be installed at Nagel station in order to mitigate identified thermal criteria violations on the 34.5 kV subtransmission network.

Fieldale Synchronous Condenser 138kV: The Fieldale Synchronous Condenser was originally installed in 1974 and is one of only two facilities that provide dynamic voltage regulation and reactive compensation to the 138kV system around Roanoke. This project consists of installing two new -50/100 MVAr units at Fieldale Station that will replace the existing single -100/250 MVAr unit. In addition, several 138 kV and 69 kV breakers will be replaced. Five new 138 kV breakers will be installed to add sectionalizing capability and improve overall reliability.

Fayette County Area Transmission Improvements: To improve voltage, thermal, and reliability performance, the Fayette County Project entails constructing certain transmission facilities in the vicinity of Beckley and elsewhere in Fayette, Greenbrier and Raleigh Counties. Specifically the Fayette County Project includes: constructing new Beury Mountain and Brackens Creek Stations, constructing approximately twelve miles of 138kV transmission line between the new Beury Mountain and Brackens Creek Stations, constructing approximately two miles of new 138kV transmission line, rebuilding and upgrading approximately thirteen miles of existing 69kV transmission line to 138kV between the McClung and Brackens Creek Stations, and installing equipment at three existing stations.

Thorofare Project: This Transource West Virginia project addresses a Transmission Planning Criteria violation that is expected to occur in 2019 in the area northeast of Charleston, West Virginia. The major scope of work includes the addition of a new 138kV switching station (Linden Road Station) off First Energy's Powell Mountain – Goff Run 138kV transmission line and the construction of a new 138kV transmission line to connect the new Linden Road Station to APCo's existing Thorofare Creek switching station.

Bradley 46 kV Line Rebuild: This project was developed to address potential thermal and voltage planning criteria violations and replace assets nearing the end of their useful life. The scope of work includes rebuilding the Bradley – Scarbro 46 kV circuit.

Ravenswood Area Improvements: This project was developed to address potential thermal and voltage planning criteria violations and replacement of assets that are nearing the end of their useful life. The scope of work includes rebuilding the Ripley – Ravenswood 69 kV circuit and the Ravenswood – Racine 69 kV circuits.

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.[14] As it works to repair and/or replace aging distribution infrastructure, and lay

[14] 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.

the foundation for 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 impact 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. In addition, because the distribution grid transformation projects costs are assumed to be common in each portfolio, APCo did not consider associated incremental costs in the IRP modeling, and the costs are not included in this IRP.

3.6.1 Projects that "Enhance Electric Distribution Grid Reliability"

3.6.1.1 Vegetation Management

Vegetation management is the first building block to a modern grid. APCo has seen improvement in reliability statistics associated with circuits subject to enhanced vegetation management. [15]

Managing vegetation on APCo's distribution rights-of-way underpins its strategy for maintaining distribution system reliability, as vegetation-related momentary or sustained outages are among the biggest challenges to reliability. A distribution Right-of-Way (ROW) is 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 number 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 or

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[15] 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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disease. Native trees along the ROW can easily exceed sixty feet tall. If the tree is dead and decayed, a strong wind can break the tree causing it 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 2019 and 2020 to upgrade these circuits to full DACR. There are currently eight circuits with full DACR. Projects are planned to install DACR on sixty additional circuits in 2019 – 2023. 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.

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 DG 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.

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. In 2008, APCo installed a 2 MW NaS battery at the Balls Gap station, just south of Milton, West Virginia, which helped defer the construction of a new substation until 2017. During this period, the Balls Gap installation provided islanding functionality that allowed for service to up to 700 customers to be maintained for up to seven hours during an interruption in service. This battery also recently has been placed in the PJM market for frequency regulation.

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 is early in the evaluation process and expects to select at least one area in 2019 or 2020 for a demonstration project.

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. This alternative is evaluated for forecasted capacity projects.

As part of meeting the statutory requirement, the Company has included a 10MW storage project as part of its Preferred Plan.

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.

Part 3

4.0 Modeling 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 aims 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 sort through 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 needs and current available resources.[16] 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, *Plexos®* will return the optimal suite of proxy resources (portfolio) that meet the resource need. 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, weather-normalized commodity market forecast. It is not created to meet a specific regulatory need in a particular jurisdiction; rather, it is made available to AEPSC and all AEP operating companies after completion. It is referenced for purposes such as resource planning, capital improvement analyses, fixed asset impairment accounting, strategic planning and others. These projections cover the electricity market within the Eastern Interconnect (which includes PJM and the Southwest Power Pool), the Electric Reliability Council of Texas (ERCOT) and the Western Electricity Coordinating Council (WECC)). The Fundamentals Forecasts include: 1) monthly and annual regional power prices (in both nominal and real dollars); 2) prices for various qualities of Central Appalachian (CAPP), Northern Appalachian (NAPP), Illinois Basin (ILB), Powder River Basin (PRB), and Colorado coals; 3) monthly and annual locational natural gas prices, including the benchmark Henry Hub;

[16] *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.

4) nuclear fuel prices; 5) SO_2, NOx, and CO_2 values; 6) locational implied heat rates; 7) electric generation capacity values; 8) renewable energy subsidies; and 9) inflation factors, among others.

The primary tool used for the development of the North American long-term energy market pricing forecasts is the Aurora energy market simulation model. It 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 weather-normalized, long-term forecast of the market in which a utility operates.

The Aurora energy market simulation 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 energy market simulation model.

The Fundamentals Forecast is a long-term, weather-normalized energy market forecast and there is the credible modeling expectation that each forecast-year experiences 30-year average heating and cooling degree days. In fact, actual weather can deviate dramatically. The combination of both heating degree day departure from normal and above- or below-normal natural gas storage inventory levels are primary factors affecting any nearby deviation from a weather-normalized values. Warmer-than-normal winters result in reduced natural gas demand and materially depressed natural gas prices. Understandably, the Polar Vortex winter of 2013-2014 had the opposite effects. When comparing actual results to a weather normalized forecast, it is imperative to account for these impacts.

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. Although no exact forecast inputs from these sources of energy market research information are utilized, an in-depth assessment of this research information can yield, among other things, an indication of the supply, demand, and price relationship (price elasticity) over a period of time. This price elasticity, when applied to the Aurora-derived natural gas fuel consumption, yields a corresponding change in natural gas prices – which is recycled through the Aurora model iteratively until the change in natural gas fuel consumption for the electric generation sector is de minimis. Figure 20 illustrates that any changes in input assumptions must be iteratively processed through Aurora to determine a new merit order of dispatch. It is this new merit order of dispatch that takes into account the effect of operating conditions across North America and, in turn, ultimately determines zonal energy market prices.

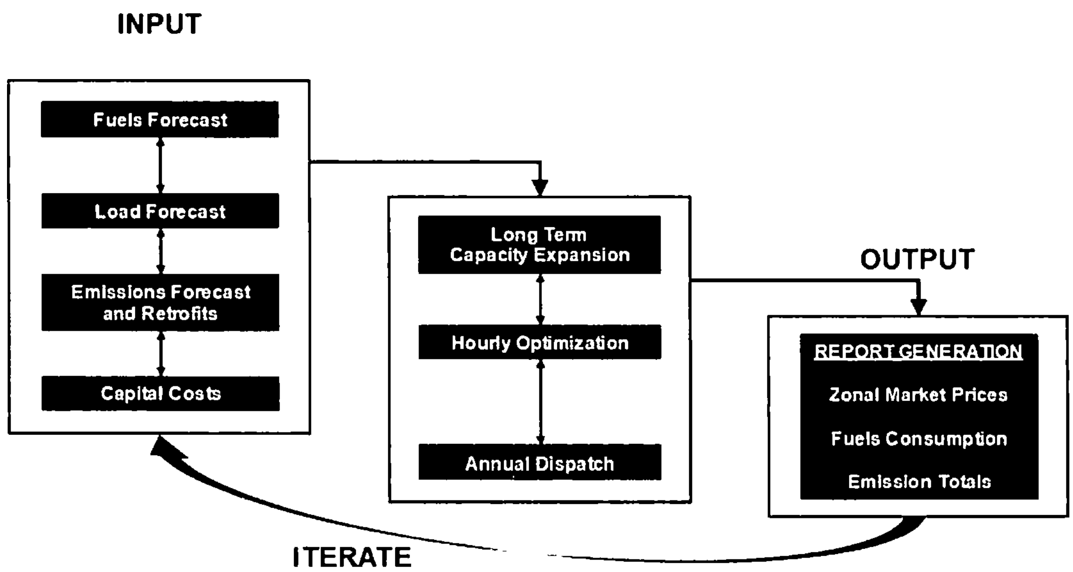

Figure 20. Long-term Power Price Forecast Process Flow

4.3.1 Commodity Pricing Scenarios

Five commodity pricing scenarios were developed to construct resource plans for APCo under various long-term pricing conditions. In this Report, the five distinct long-term commodity pricing scenarios that were developed are the Base Case, Lower Band, Upper Band, No Carbon and Lower Band No Carbon cases. The overall fundamentals forecasting effort was most recently completed in April of 2019. The associated cases were designed and generated to define a plausible range of outcomes surrounding the Base Case Fundamentals Forecast. The Lower and Upper Band forecasts consider lower and higher North American demand for electric generation and fuels and, consequently, lower and higher fuels prices. Nominally, fossil fuel prices vary one standard deviation above and below Base Case values. The Base No Carbon and Lower Band No Carbon cases assume there will be no regulations limiting CO_2 emissions throughout the entire forecast period. Renewable Energy Credits (REC) are assumed to be zero in the Fundamental Commodity price forecast; however, due to the unique characteristics of the Virginia voluntary Renewable Portfolio Standard (RPS) APCo has included an estimated forecast of REC values to be included in this IRP. This is discussed and shown in Section 5.2.1.

4.3.2 Forecasted Fundamental Parameters

Figure 21 through Figure 27 illustrate the forecasted fundamental parameters (fuel, energy, capacity and CO_2 emission prices) that were used in the long-term optimization modeling for this IRP.

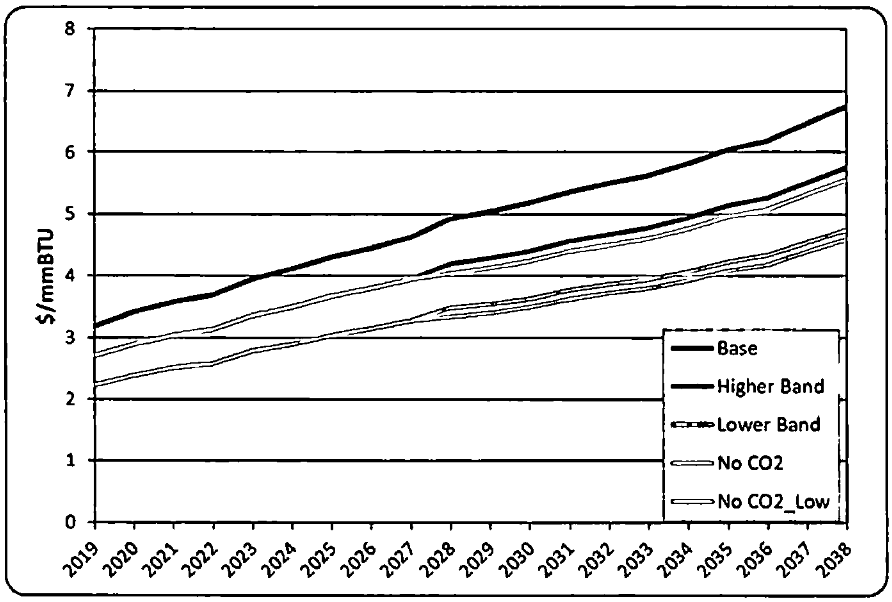

Figure 21. Dominion South Natural Gas Prices (Nominal $/mmBTU)

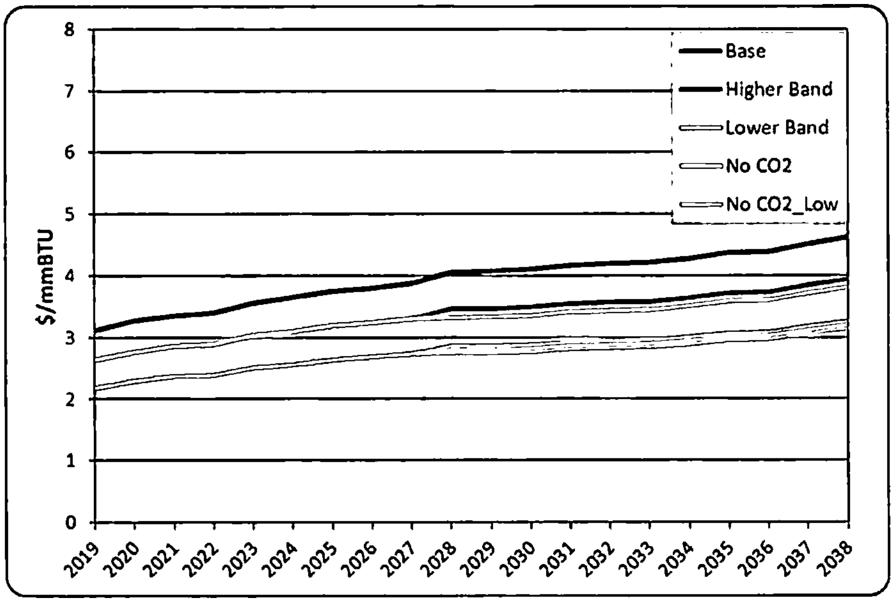

Figure 23. Dominion South Natural Gas Prices (Real $/mmBTU)

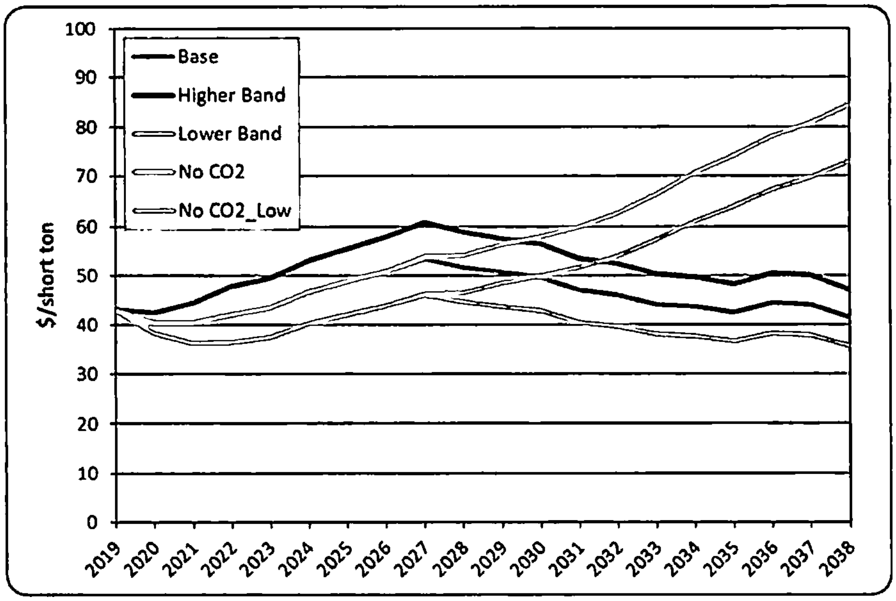

Figure 22. NAPP High Sulfur Coal Prices (Nominal $/ton, FOB origin)

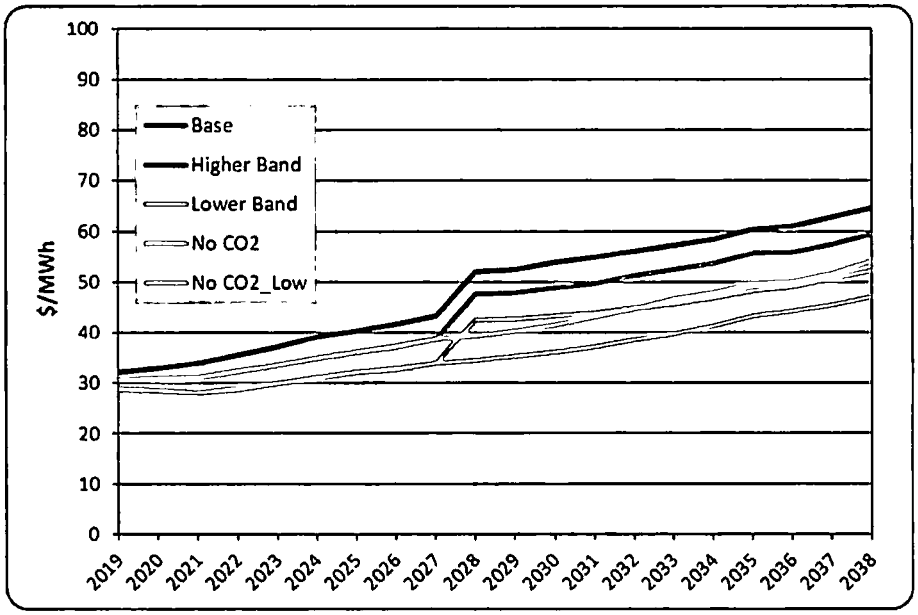

Figure 25.PJM On-Peak Energy Prices (Nominal $/MWh)

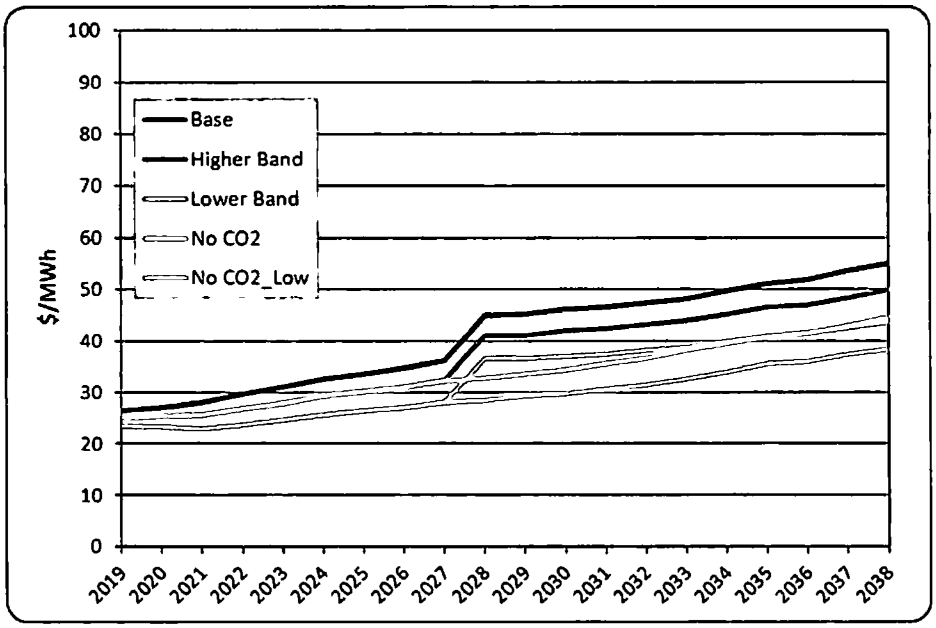

Figure 24. PJM Off-Peak Energy Prices (Nominal $/MWh)

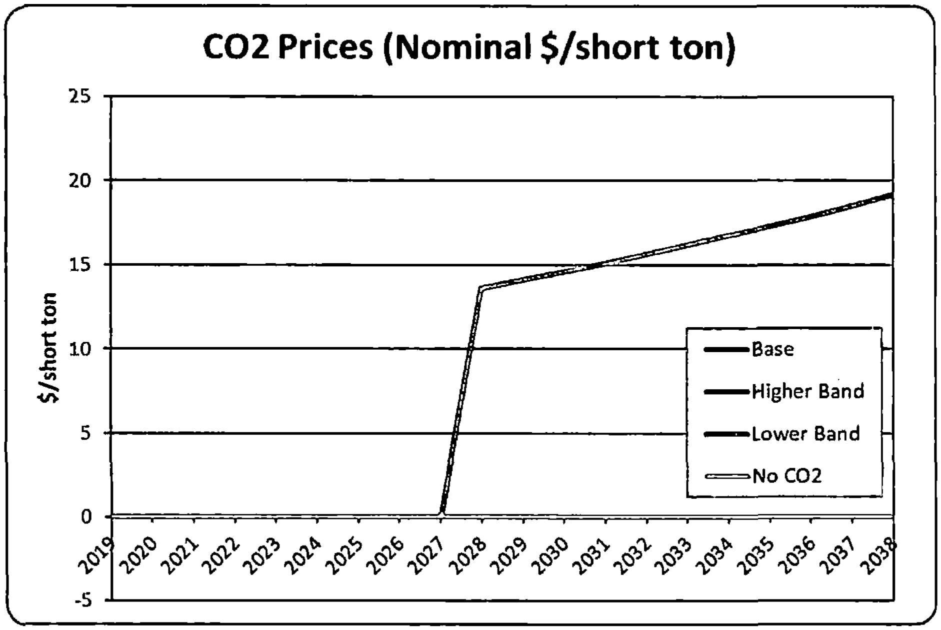

Figure 27. CO_2 Prices (Nominal $/short ton)

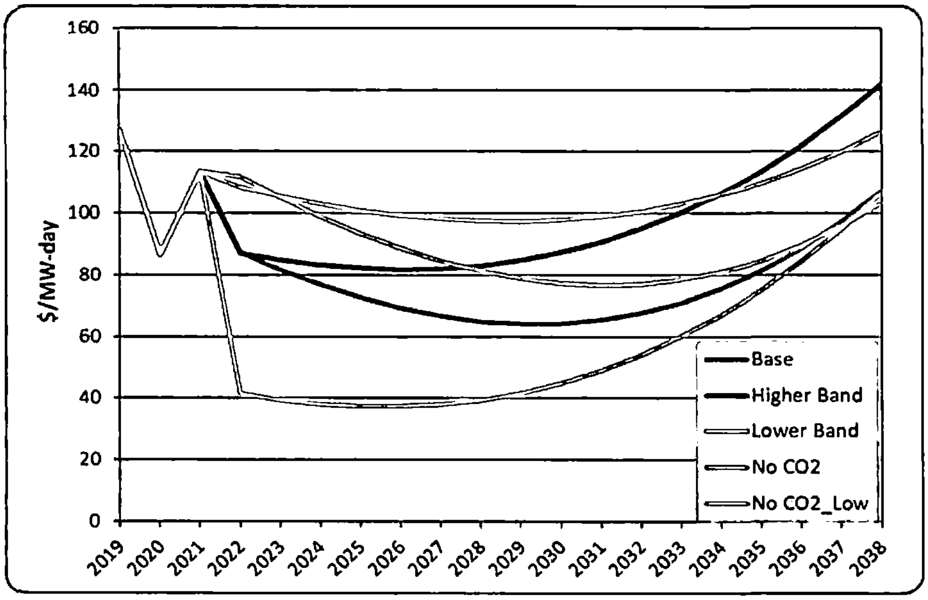

Figure 26. PJM Capacity Prices (Nominal $/MW-day)

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. 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 9 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 CHP, EE, DG, DR and VVO as resources, thereby considering such alternatives in the model on equal-footing with more traditional "supply-side" generation resource options. As required by the 2018 APCo IRP final order, the Company also considered DSM as a reduction to load. The Company's discussion of this request is included in Section 5.3.1.

4.4.3.1 Incremental Energy Efficiency (EE) Modeled

To determine the economic demand-side EE activity to be modeled that would be over-and-above existing EE program offerings in the load forecast, a determination was made as to the potential level and cost of such incremental EE activity as well as the ability to expand current programs. It was assumed that the incremental programs modeled would be effective in 2022. As a result of the 2018 Virginia Act, which provides that customers above 500kW of demand are not eligible for new EE programs, these Virginia customers were removed from the available EE potential and thus not modeled. Figure 28 and Figure 29 show the "going-in" make-up of projected end-usage in 2022 for APCo's residential and commercial sectors with lighting end-use also included for the industrial sector. Future incremental EE activity can further target these areas or address other end-uses.

The 2018 Virginia Act further requires that APCo propose $140 million of EE programs by 2028, and develop a long-term plan for EE measures in IRPs to accomplish the policy goals of reduction in customer bills, particularly for low-income, elderly, and disabled customers; reduction in emissions; and reduction in carbon intensity. This IRP includes plans that meet this requirement. These programs may consist of an expansion of the Company's current Low Income Weatherization program, additional low income-type programs, and/or programs designed to address energy efficiency in lower-income multi-family residences.

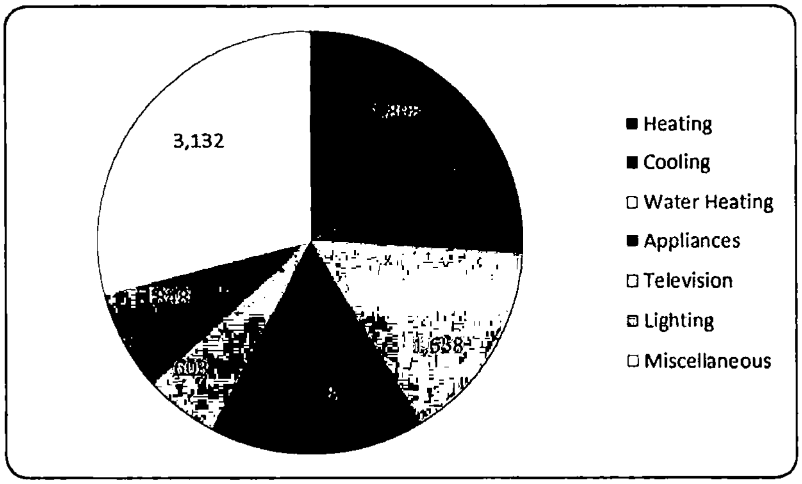

Figure 29. 2022 APCo Residential End Use (GWh)

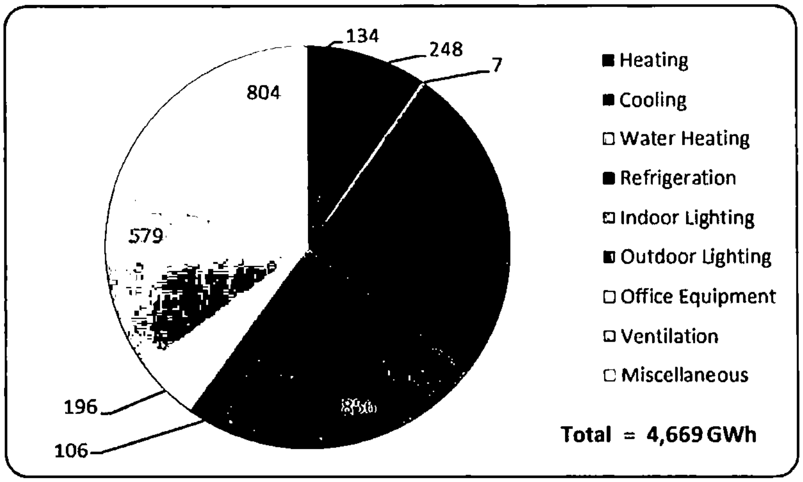

Figure 28. 2022 APCo Commercial End Use & Industrial Lighting End Use (GWh)

To determine which end-uses are targeted, and in what amounts, APCo looked at the previously-cited EPRI report and consulted its DSM team. 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 6 and Table 7, from the EPRI report, list the individual measure categories considered for both the residential and commercial sectors.

Table 7. Residential Sector Energy Efficiency (EE) Measure Categories

Central Air Conditioning	Programmable Thermostat	Storm Doors	Dishwashers
Air-Source Heat Pumps	Water Heating	External Shades	Clothes Washers
Ground-Source Heat Pumps	Faucet Aerators	Ceiling Insulation	Clothes Dryers
Room Air Conditioning	Pipe Insulation	Foundation Insulation	Refrigerators
Air Conditioning Maintenance	Low-Flow Showerheads	Duct Insulation	Freezers
Heat Pump Maintenance	Duct Repair	Wall Insulation	Cooking
Attic Fan	Dehumidifier	Windows	Televisions
Furnace Fans	Lighting – Linear Fluorescent	Reflective Roof	Personal Computers
Ceiling Fan	Lighting – Screw-in	Infiltration Control	Smart Plug Strips, Reduce Standby Wattage
Whole-House Fan	Enhanced Customer Bill Presentment		

Table 6. Commercial Sector Energy Efficiency (EE) Measure Categories

Heat Pumps	Water Heater	Energy-Efficient Motors	Lighting – Screw-in
Central Air Conditioning	Water Temperature Reset	Variable Speed Controls	Lighting – LED Street Lighting
Chiller	Computers	Programmable Thermostat	Anti-Sweat Heater Controls
Cool Roof	Servers	Duct Testing and Sealing	Floating Head Pressure Controls
Economizer	Displays	HVAC Retro-commissioning	Installation of Glass Doors
Energy Management System	Copiers Printers	Efficient Windows	High-Efficiency Vending Machine
Roof Insulation	Other Electronics	Lighting – Linear Fluorescent	Icemakers
Duct Insulation		Lighting – HID to LED	Reach-in Coolers and Freezers

From this information and recent APCo DSM activity, APCo has 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.

Bundle	Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2022-2024	Yearly Potential Savings (MWh) 2025-2029	Yearly Potential Savings (MWh) 2030-2040	Bundle Life
Thermal Shell - AP	$0.24	9,655	3,304	4,407	10
Thermal Shell - HAP	$0.36	44,966	22,921	11,014	10
Heating/Cooling - AP	$0.72	95,936	17,031	1,321	18
Heating/Cooling - HAP	$1.08	112,866	1,913	0	18
Water Heating - AP	$0.04	6,024	1,162	1,227	10
Water Heating - HAP	$0.05	27,887	11,925	4,325	10
Appliances - AP	$0.27	17,695	2,378	1,342	16
Appliances - HAP	$0.49	35,688	7,870	4,023	16
Lighting - AP	$0.03	28,221	0	0	30
Lighting - HAP	$0.05	49,685	2,176	350	30
Enhanced Customer Bill	$0.76	78,351	0	0	10

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

Bundle	Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2022-2024	Yearly Potential Savings (MWh) 2025-2029	Yearly Potential Savings (MWh) 2030-2040	Bundle Life
Heat Pump - AP	$12.72	8,098	875	0	15
Heat Pump - HAP	$19.09	9,527	147	0	15
HVAC Equipment - AP	$1.12	5,548	943	750	15
HVAC Equipment - HAP	$1.65	10,197	1,869	74	15
Indoor Screw-In Lighting - AP	$0.01	5,312	0	0	6
Indoor Screw-In Lighting - HAP	$0.02	7,835	0	0	6
Indoor HID/Fluor. Lighting - AP	$0.20	76,313	10,998	1,174	13
Indoor HID/Fluor. Lighting - HAP	$0.29	89,780	1,456	0	13
Outdoor Lighting - AP	$0.20	12,654	1,987	37	15
Outdoor Lighting - HAP	$0.30	14,887	246	0	15

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

As can be seen from the tables, each program has both AP and HAP characteristics. The development of these characteristics is based on the feedback from APCo's DSM team and the EPRI EE Potential report. The EPRI report further identifies Market Acceptance Ratios (MAR) and Program Implementation Factors (PIF) to apply to primary measure savings, as well as Application Factors for secondary measures. Secondary measures are not consumers of energy, but do influence the system that is consuming energy. The Residential Thermal Shell, Residential Water Heating and Commercial Cooling bundles—in both AP and HAP—include secondary measures. The MAR and PIF are utilized to develop the incremental AP program characteristics and the MAR only is used to develop the incremental HAP program characteristics.

Figure 30 shows the Levelized Cost of Electricity (LCOE) and potential energy savings in 2022 for each of the bundles offered into the model as a potential resource. To preserve a reasonable scale for illustrative purposes, the two bundles with the highest LCOE, Commercial Heat Pump AP and Commercial Heat Pump HAP, were omitted. Figure 30 provides a comparison of EE bundle cost versus potential savings. The model will determine if an EE bundle is beneficial to an optimization scenario. Each EE bundle is offered into the model as a stand-alone resource with its own unique cost and potential energy and demand savings. Should the model determine that a bundle is economical, that bundle will be included in the portfolio of optimized resources.

To develop appropriate EE offerings to propose for APCo's customers, APCo will consider the details of each EE bundle that was optimized by the Plexos model and included in the Plan Efforts to determine program attributes such as participant costs, penetration rates, and bill savings, prior to that point in time would be highly speculative and potentially inaccurate.

4.4.3.2 Volt VAR Optimization (VVO) Modeled

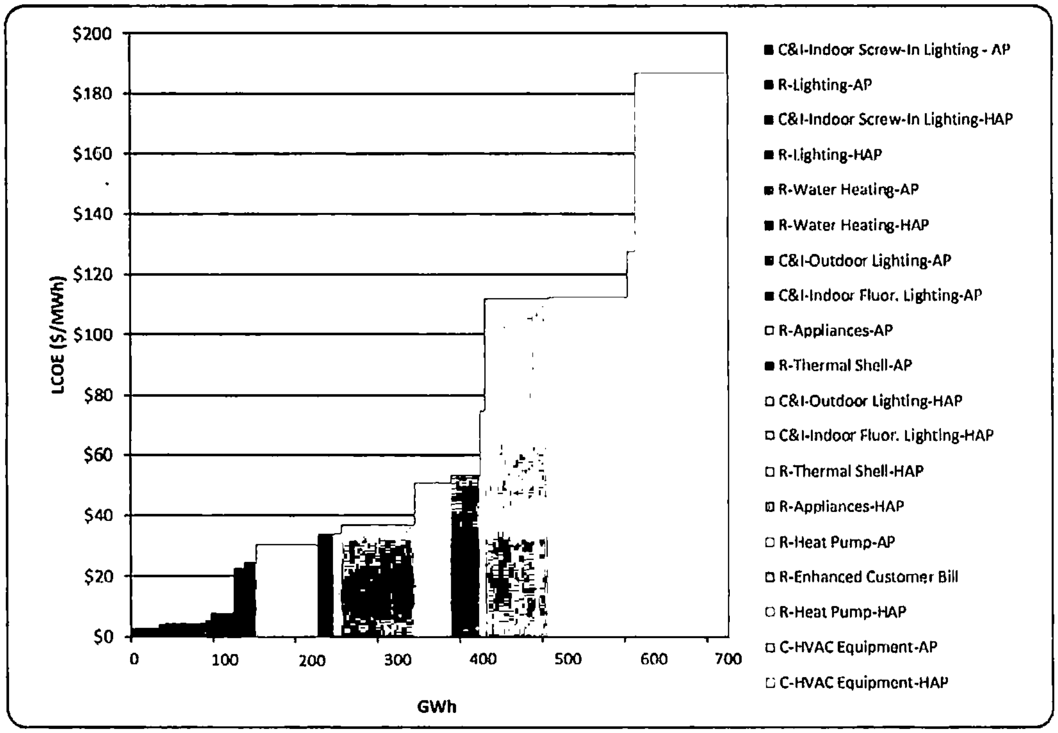

Figure 30. EE Bundle Levelized Cost vs. Potential Energy Savings for 2022

Potential future VVO circuits considered for modeling varied in relative cost and energy-reduction effectiveness. The circuits were grouped into 15 "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. The costs shown are in 2016 dollars.

Table 10. Volt VAR Optimization (VVO) Tranche Profiles

Tranche	No. of Circuits	Capital Investment	Annual O&M	Demand Reduction (kW)	Energy Reduction (MWh)
1	37	$12,358,000	$370,740	15,602	64,234
2	37	$12,358,000	$370,740	12,170	50,106
3	37	$12,358,000	$370,740	10,656	43,872
4	37	$12,358,000	$370,740	9,579	39,440
5	37	$12,358,000	$370,740	8,856	36,463
6	37	$12,358,000	$370,740	8,272	34,058
7	37	$12,358,000	$370,740	7,847	32,306
8	37	$12,358,000	$370,740	7,513	30,931
9	37	$12,358,000	$370,740	7,283	29,986
10	37	$12,358,000	$370,740	6,985	28,759
11	37	$12,358,000	$370,740	6,764	27,849
12	37	$12,358,000	$370,740	6,469	26,633
13	37	$12,358,000	$370,740	6,143	25,292
14	37	$12,358,000	$370,740	5,839	24,039
15	37	$12,358,000	$370,740	5,562	22,901

4.4.3.3 Demand Response (DR) Modeled

Incremental levels of DR were included in the IRP model. These resources, which are included in the model as a resource for the entire operating company, were modeled based on the Peak Reduction and Bring Your Own Thermostat (BYOT) programs, which reduces demand by either cycling the customer's air conditioner(s) or setting back the thermostat temperature. In the BYOT program, customers would own and self-install Wi-Fi enabled thermostats, which will communicate with APCo. Table 11, below, shows the DR resource offered into the model for residential customers. The model may select up to four units, each comprised of 3,000 customers, in any calendar year, beginning with 2022. Each unit has 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	3,000	8,370	123,820	$376,964	$694,599	$1,071,563	7

4.4.3.4 Distributed Generation (DG) Evaluation

DG resources were evaluated assuming a residential rooftop solar resource, as this is the primary distributed resource. To determine the level of customer penetration APCo referenced a forecast conducted by IHS Inc. on behalf of PJM[17]. This forecast considered the level of solar photovoltaic (PV) installations over the period of 2019-2034. The updated forecast utilized by PJM included the Net Energy Metering Reform scenario[18]. Figure 31 below depicts the forecast of DG resources in APCo over the planning period. To determine the level of DG penetration APCo created a forecast using existing levels of DG, as well as the incremental additions from PJM's forecast. This forecast is shown as the red line in Figure 31 below. The green line in Figure 31 utilizes the same forecast method but incorporates Virginia's state cap on net-metering, which is expected to affect the forecast beginning in 2022. The capped forecast (green line, or PJM Forecast w/VA Cap in Figure 31), is the level of DG resources included in this IRP. PJM's forecast issued in November 2018 represents a slightly lower level of DG penetration from the same forecast issued one year prior. APCo intends to closely monitor the levels of DG installed throughout its service territory to observe any potential divergence from the forecast shown above.

It is significant to note that rooftop solar does not represent the most economic means for APCo to add renewable generation as the cost of rooftop solar remains considerably higher than the cost of large-scale solar, the cost of which is discussed in Section 4.5.5.1.1.

[17] PJM solar forecast 2018: October 29, 2018. Available at https://pjm.com/-/media/committees-groups/subcommittees/las/20181127/20181127-item-06a-ihs-markit-pjm-solar-forecasts.ashx.

[18] Distributed Solar Generation Update, November 27, 2018. Available at https://pjm.com/-/media/committees-groups/subcommittees/las/20181127/20181127-item-06b-pjm-distributed-solar-generation-forecast.ashx and Distributed Solar Generation Forecast by Zone and State. Available at https://pjm.com/-/media/committees-groups/subcommittees/las/20181127/20181127-las-distributed-solar-generation-data.ashx.

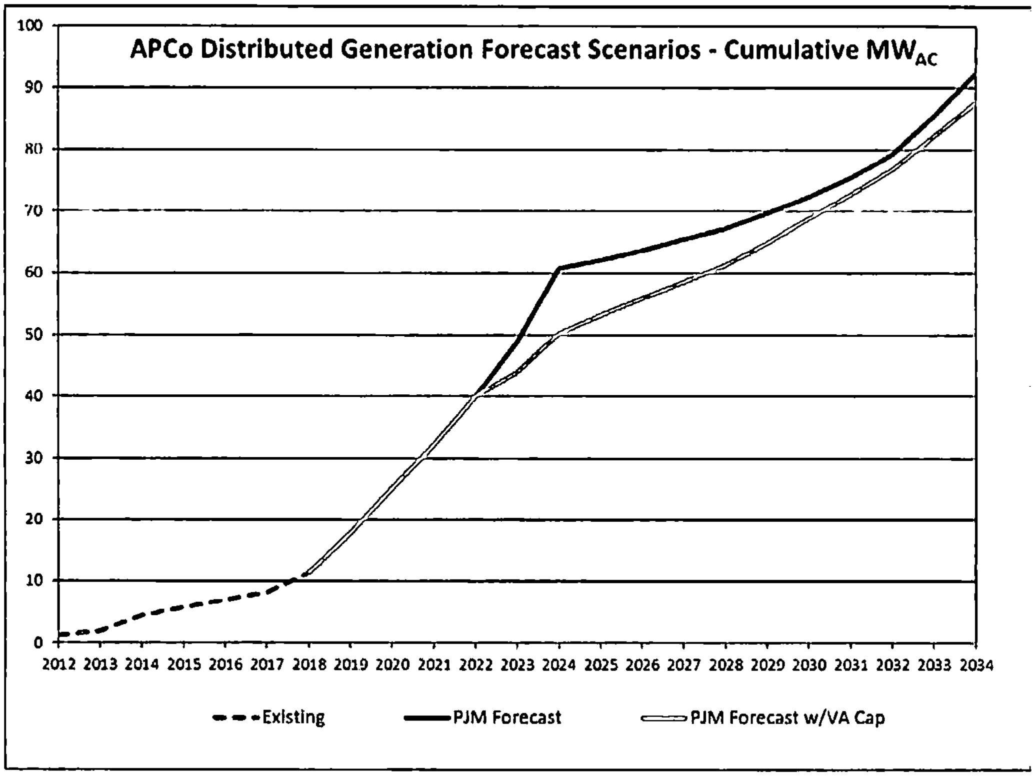

Figure 31. Cumulative Distributed Generation Additions/Projections for APCo

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.

4.4.3.6 Combined Heat and Power (CHP)

CHP (also known as Cogeneration) is a process where electricity is generated and the waste heat by-product is used for heating or other processes, raising the net thermal efficiency of the facility. To take advantage of the increased efficiency associated with CHP, the host must have a ready need for the heat that is otherwise potentially wasted in the generation of electricity.

APCo worked with AEP Generation Engineering to develop a generic CHP option. The CHP option developed is a 15MW facility utilizing a natural gas fired combustion turbine, Heat Recovery Steam Generator (HRSG) and SCR to control NO_X. A major assumption is that all of the steam is taken by the host and the efficiency of the modeled CHP resource is credited for the value of the steam provided to the host. The overnight installed cost is estimated to be $2,300/kW and the assumed modeled full load heat rate is approximately 4,800 Btu/kWh. Additionally, the assumed capacity factor was 90%.

4.5 Identify and Screen 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.

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

Natural gas base/intermediate and peaking generating technologies were considered in this IRP as well as large-scale solar and wind. 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 forty year levelized basis. The options were screened by comparing levelized annual busbar costs over a range of capacity factors.

In this evaluation, each type of technology is represented by a line showing the relationship between its total levelized annual cost per kW and an assumed annual capacity factor. The value at a capacity factor of zero represents the fixed costs, including carrying charges and fixed Operations and Maintenance (O&M) costs, which would be incurred even if the unit produced no energy. The slope of the line reflects variable costs, including fuel, emissions, and variable O&M, which increase in proportion to the energy produced.

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) (d) Std. ISO	Summer	Winter	Installed Cost (c,e) ($/kW)	Capacity Factor (%)	LCOE (f) ($/MWh)
Base Load						
Nuclear	1,610	1,560	1,690	8,500	80	178.2
Pulv. Coal with Carbon Capture (PRB)	540	520	570	9,500	75	221.1
Combined Cycle (1X1 "J" Class)	610	800	820	900	75	59.5
Combined Cycle (2X1 "J" Class)	1,230	1,600	1,640	700	75	55.3
Combined Cycle (2X1 "H" Class)	1,150	1,490	1,530	700	75	56.1
Peaking						
Combustion Turbine (2 - "E" Class) (g)	180	190	190	1,200	25	148.6
Combustion Turbine (2 - "F" Class, w/evap coolers) (g)	490	500	510	700	25	116.4
Aero-Derivative (2 - Small Machines) (g)	120	120	120	1,100	25	135.7
Recip Engine Farm	220	220	230	1,300	25	127.3
Battery	10	10	10	1,900	25	156.6

4.5.3 Base/Intermediate Alternatives

Coal and Nuclear base-load options were evaluated by APCo but were not included in the *Plexos®* resource optimization modeling analyses. For coal generation resources, environmental regulation (see Section 3.3) makes the construction of new coal plants economically impractical. New nuclear construction is also economically impractical since it would potentially require an investment of $8,500/kW or more.

Intermediate generating sources are typically expected to serve a load-following and cycling duty and effectively shield base-load units from that obligation. Historically, many generators relied on older, smaller, less-efficient/higher dispatch cost, subcritical coal-fired or gas-steam units to serve such load-following roles. Over the last several years, these units have improved ramp rates and regulation capability, and reduced downturn (minimum load capabilities). With the anticipated retirement of APCo's subcritical units, other generation dispatch alternatives and new generation will need to be considered to cost effectively meet these duty cycle's operating characteristics.

4.5.3.1 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. The Company did not develop estimates for a larger "3x1" combined cycle configuration based on its overall size relative to the Company's needs as well as very limited operating experience with this configuration.

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 Battery Storage

The modeling of Battery 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 Battery Storage resource that was modeled in this IRP is a Lithium-ion storage technology and it has a nameplate rating of 10MW and 40MWh, with a round trip efficiency of 83%. See Figure 32 for the forecasted installed cost of this resource. To develop this resource, AEP's Generation Engineering Services considered a wide range of sources including: the DOE/EPRI 2015 Electricity Storage Handbook in Collaboration with the National Rural Electric Cooperative Association (NRECA), EPRI, BNEF and battery storage equipment suppliers. The storage resource characteristics and cost were updated in early 2019.

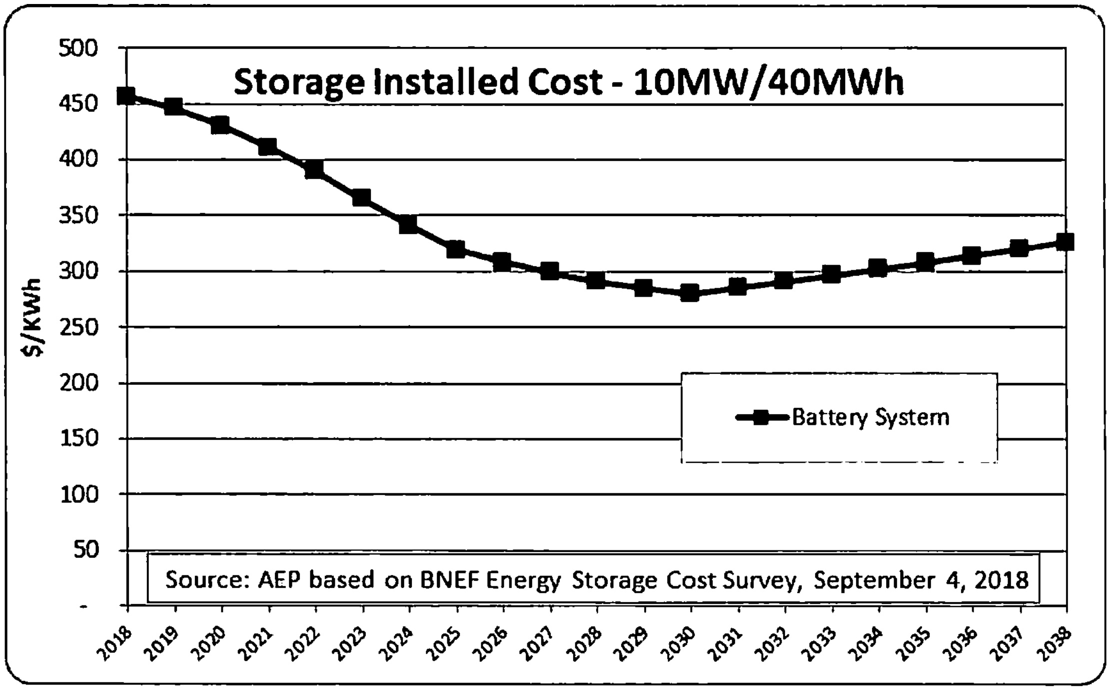

Figure 32. Energy Storage Installed Cost

4.5.5 Renewable Alternatives

Renewable generation alternatives use energy sources that are either naturally occurring (wind, solar, hydro or geothermal), or are sourced from a by-product or waste-product of another process (biomass or landfill gas). In the past, on a national level development of these resources has been driven primarily as the result of renewable portfolio requirements. That is not universally true now as advancements in both solar photovoltaics and wind turbine manufacturing have reduced both installed and ongoing costs.

At this time within the industry, renewable energy resources, because of their intermittent nature, provide more energy value than capacity value. For this IRP, the overall threshold for intermittent resource additions, 30% of APCo's energy demand for wind and 15% for solar. This assumes that the RTO and other key stakeholders will advance the understanding, forecasting and management of intermittent resources, ultimately supporting a higher penetration level and capacity planning values.

4.5.5.1 Solar

4.5.5.1.1 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.

The cost of large-, or utility-scale, solar projects has declined in recent years and is expected to continue to decline through 2023 (see Figure 33). This has been mostly a result of reduced panel prices that have resulted from manufacturing efficiencies spurred by accelerating penetration of solar energy in Europe, Japan, and California. With the trend firmly established, forecasts generally foresee declining nominal prices in the next decade as well, notwithstanding solar panel tariffs which from an IRP perspective are regarded as a short-term impact.

Large-scale solar plants require less lead time to build than fossil plants. There is no defined limit for how much utility solar can be built in a given time. However, in practice, solar facilities are not added without considering the timing impacts of obtaining siting and regulatory approval, for example.

Solar resources were made available in the *Plexos* model with some limits on the rate with which they could be chosen. In the IRP modeling, the assumption was made that large-scale solar resources were available in yearly quantities up to 300MWac[19] of nameplate capacity starting in 2022. A limit on solar capacity additions is needed because as solar costs continue to decrease relative to the market price of energy, there will come a point where the optimization model will theoretically pick an unlimited amount of solar resources, a nonsensical result. Additionally, this 300MWac annual threshold recognizes that there is a practical limit as to the number of sites that can be identified, permitted, constructed, and interconnected by APCo in a given year. For example, the land requirement to develop a 1MW solar plant is estimated to be 7 acres, implying that 700 acres of land would be required to develop 100MW of solar annually. Over the planning period the maximum threshold for solar resource additions was limited to approximately 15% of APCo's load obligation or 2,180MW. Certainly, as APCo gains experience with solar installations, this limit would likely be modified (for example, it may be lower earlier and greater later).

Solar resources were available in two tiers. The first year pricing was informed by the Company's recent Solar RFP. Tier 1 pricing is initial based on the pricing of the lowest 20% of the responses. Tier 2 pricing is initially based on all responses removing the highest pricing response. Both pricing tiers are adjusted annually based on the change in BNEF's utility scale solar installed cost through 2030 and then escalated at 1% annually. Both tiers of solar resources were available in blocks of 150MW, which is comprised of three 50MW installations and totals 300MW

[19] Manufacturers usually quote system performance in DC watts; however electric service from the utility is supplied in AC watts. An inverter converts the DC electrical current into AC electrical current. Depending on the inverter efficiency, the AC wattage may be anywhere from 80 to 95 percent of the DC wattage.

annually. Additionally, both tiers of solar resources were modeled with capacity factors of approximately 26%, which is representative of a tracking solar resource located in Roanoke, VA.

Figure 33 illustrates the projected large-scale solar pricing included in the IRP model. Both tiers account for Federal ITCs. The large-scale solar pricing used in this IRP reflects a normalized treatment of the ITC, as well as a four-year safe harbor factor in ITC pricing. This safe harbor factor allows projects to lock in ITC benefits four years prior to commercial operation, as long as construction has been commenced. The ITC benefit is included through 2030. At this point in time the 10% ITC benefit would become indiscernible from potential variations in forecasted prices. Solar resources are modeled with a 51.1% capacity credit, which is based on PJM's expected long-term performance of the resource.

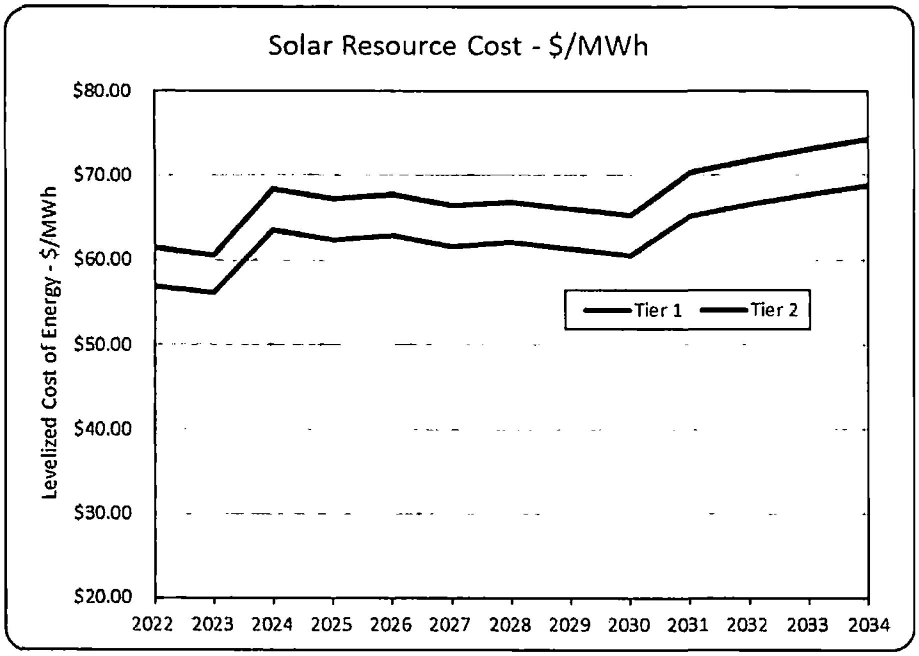

Figure 33. Large-Scale Solar Pricing Tiers

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4.5.5.1.2 Trends in Solar Energy Pricing

As mentioned above, solar energy prices have declined significantly in recent years as shown below in Figure 34. From 2010 to 2018 installation costs have declined by more than 60% for residential, commercial, and large-scale solar. Further, large-scale solar has been, and is projected to be, substantially lower in cost compared to other sectors, with large-scale installations costing 49% and 29% less than residential and commercial installations, respectively, based on 2019 costs.

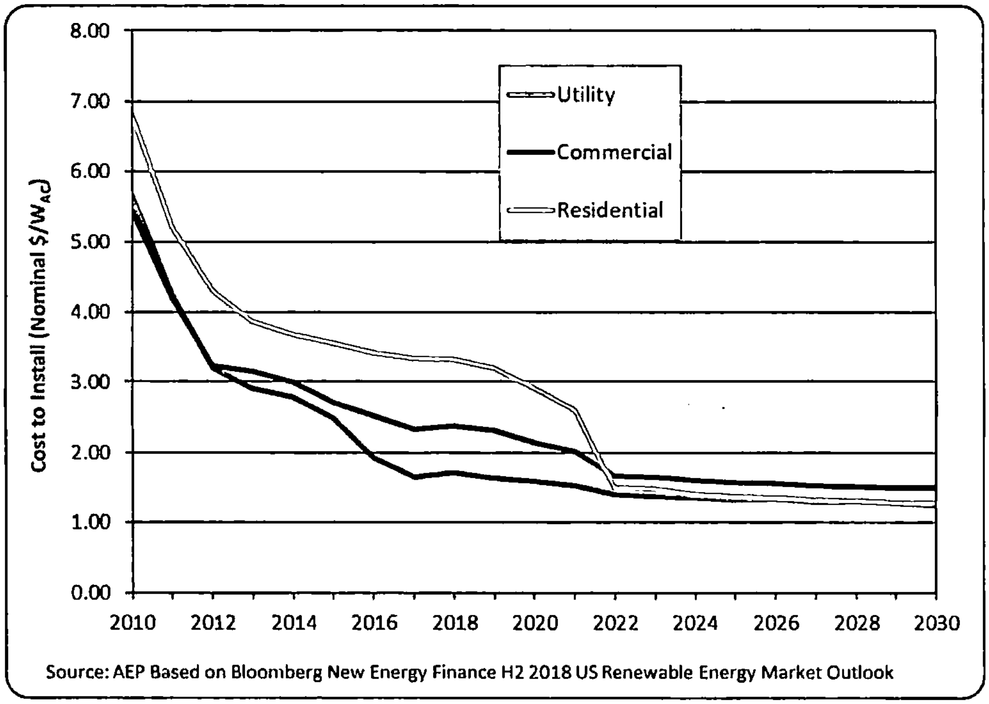


Figure 34. PJM Photovoltaic (PV) Installation Cost (Nominal $/W$_{AC}$) Trends, excluding Investment Tax Credit Benefits

4.5.5.2 Wind

Large-scale wind energy is generated by turbines ranging from 1.0 to 3.2MW. 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.

A variable source of power in most non-coastal locales, with capacity factors ranging from 30 percent (in the eastern portion of the U.S.) to over 50 percent (largely in more westerly portions of the U.S., including the Plains states), wind energy's life-cycle cost ($/MWh), excluding subsidies, is currently higher than the marginal (avoided) cost of energy, in spite of its negligible operating costs.

Another consideration with wind power is that its most critical factors (*i.e.*, wind speed and sustainability) are typically highest in more remote locations, which forces the electricity to be transmitted longer distances to load centers necessitating the build out of EHV transmission to optimally integrate large additions of wind into the grid.

For modeling purposes, wind resources are first made available to the model in 2023 (i.e., commercial operation date 12/31/22), due to the amount of time necessary to secure resources and obtain any necessary regulatory approvals. Figure 35 shows the LCOE prices of one wind resource tranches assumed for the IRP. The first tranche of wind resources, Tranche A, was modeled as a 150MW resource block with a 37% capacity factor load shape. The second tranche of wind resources, Tranche B, was modeled as a 150MW resource block with a 32% capacity factor load shape. Wind resources capacity credit for capacity planning purposes is based on PJM's analysis and is assumed to be 12.3% of nameplate[20]. The wind pricing reflects the value of Federal Production Tax Credits (PTCs). After 2020 tax credits reduce to 80%, 60% and 40% of their 2020 value in 2021, 2022, and 2023, respectively. These PTC values are based on developers taking advantage of the safe-harbor guidelines which provide up to a four-year delay in the effects of declining tax credits as long as adequate construction has commenced. Wind prices were developed based on the Bloomberg New Energy Finance H2 2018 U.S. Renewable Energy Market Outlook and market knowledge.

The amount of wind resources available beginning in 2023 was limited to 300MW nameplate annually through the remainder of the planning period. In total, wind resources were limited to 3,300MW nameplate over the planning period. The annual limit on wind additions is

[20] PJM "Effective Load Carrying Capability (ELCC) Analysis for Wind and Solar Resources", February 7, 2019.

based on APCo's ability to plan, manage and develop either the construction or the procurement of these resources. As with solar resource additions, as APCo gains experience with wind installations, this limit would likely be modified (for example, it may be lower earlier and greater

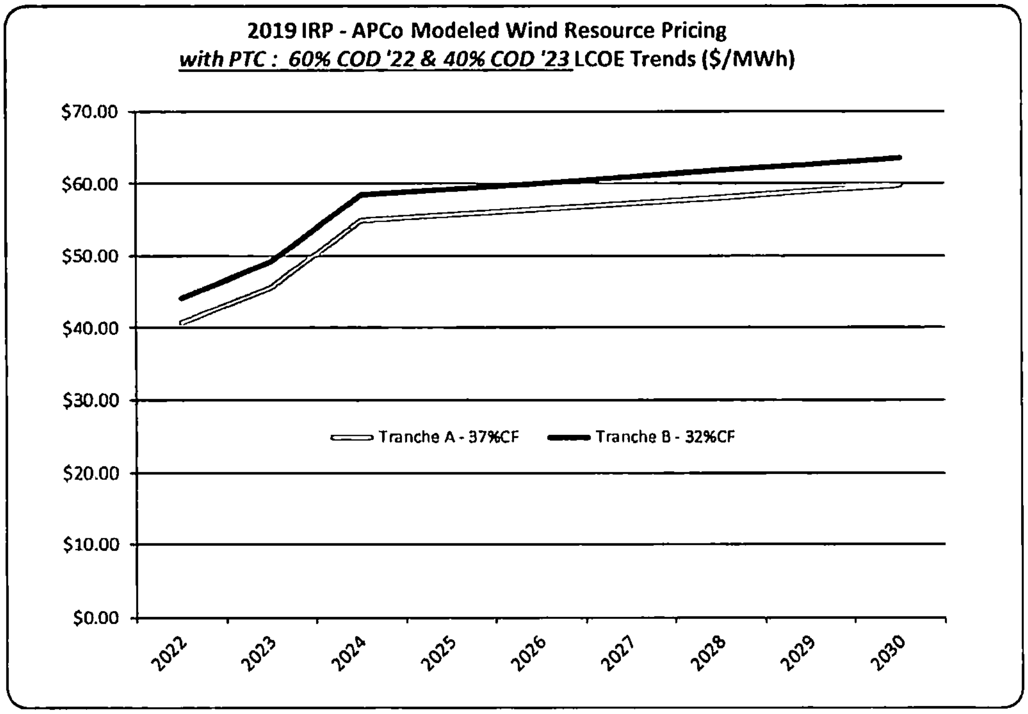


Figure 35. Levelized Cost of Electricity of Wind Resources (Nominal $/MWh)

later). This cap is based on the DOE's Wind Vision Report[21] which suggests from numerous transmission studies that transmission grids should be able to support 20% to 30% of intermittent resources in the 2020 to 2030 timeframe. The cap for APCo allows the model to select up to 30% of generation energy resources as wind-powered by 2033.

4.5.5.3 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

[21] *Wind Vision: A New Era for Wind Power in the United States* (2015). Retrieved from http://www1.eere.energy.gov/library/default.aspx?Page=12, Figure 1-5.

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.

4.5.5.4 Biomass

Biomass is a term that typically includes organic waste products (sawdust or other wood waste), organic crops (corn, switch grass, poplar trees, willow trees, etc.), or biogas produced from organic materials, as well as select other materials. Biomass costs will vary significantly depending upon the feedstock. Biomass is typically used in power generation to fuel a steam generator (boiler) that subsequently drives a steam turbine generator; similar to the same process of many traditional coal fired generation units. Some biomass generation facilities use biomass as the primary fuel, however, there are some existing coal-fired generating stations that will use biomass as a blend with the coal. Given these factors, plus the typical high cost and required feedstock supply and attendant long-term pricing issues, no incremental biomass resources were considered in this IRP.

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.

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.

4.6.2 Optimization of Other Demand-Side Resources

Customer-sited DG, specifically rooftop solar, was not modeled. Instead, reductions in energy use and peak demand were built into the load forecast based on the adoption rates. CHP was modeled as a high thermal efficiency NGCC facility.

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. 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.

APCo examined planned new resource deployments through the use of S&P Global Market Intelligence's dataset. Table 13 below shows new generating capacity within PJM which is scheduled to be in-service in 2019 or 2020.

Based upon a review of this market data, APCo has concluded it is reasonable to base IRP pricing assumptions for wind on the BNEF H2 2018 U.S. Renewable Energy Market Outlook report and solar on the Company's recent solar RFP and the BNEF H2 2018 U.S. Renewable Energy Market Outlook report. A complete description of the solar resource assumptions is in Section 4.5.5.1 and the wind resource assumptions are in Section 4.5.5.2. For the combined cycle assumptions, APCo is utilizing a 25% share of an advanced gas turbine technology, in a 2x1 configuration, with an estimated cost of $700/kW, and a full load heat rate of approximately 6,200 Btu/kWh High Heating Value, as shown in Exhibit B.

Regarding comparables or market alternatives associated with power purchase agreements, the Company continues to monitor this space; however, it has yet to find a source that provides pricing information on a comparable basis. Therefore, the Company for its "Market Alternatives" analysis is relying on the data from S&P Global Market Intelligence dataset for projected build cost, as discussed above.

Table 13. PJM Total New Generating Capacity and Cost by Type (Under Construction) – 2019 and 2020 In-Service Dates

Type of Capacity	Generating Capacity		Construction Cost (Est. Weighted)
	(MW)	(%)	($/kW)
Combined Cycle (CC)	***3,811***	***60.3%***	***1,070***
Renewables			
Wind	1,524	24.1%	2,064
Solar	909	14.4%	2,427
Total/Average	***2,433***	38.5%	***2,199***
Other			
Combustion Turbine	11	0.2%	950
Internal Combustion	65	1.0%	1,217
Storage	0	0.0%	NA
Total/Average	***76***	***1.2%***	***1,178***
Total PJM New Capacity)	**6,320**	**100.0%**	

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. By minimizing CPW the model will provide optimized portfolios with the lowest and most stable customer rates, while adhering to the Company's constraints. Low, stable rates benefit the entire region by attracting new commercial and industrial customers, and retaining/expanding existing load.

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 possible constraints:

- Minimum and maximum reserve margins;
- resource additions (i.e., maximum units built);
- age and lifetime of power generation facilities;
- retrofit dependencies (SCR and FGD combinations);
- 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.

5.1.1 Key Input Parameters

Two of the major underpinnings in this IRP are long-term forecasts of APCo's energy requirements and peak demand, as well as the price of various generation-related commodities, including energy, capacity, coal, natural gas and, potentially, CO_2/carbon. Both forecasts were created internally within AEP. The load forecast was created by the AEP Economic Forecasting organization, while the long-term commodity pricing forecast was created by the AEP Fundamental Analysis group. These groups have many years of experience forecasting APCo and AEP system-wide demand and energy requirements and fundamental pricing for both internal operational and regulatory purposes. Moreover, the Fundamental Analysis group constantly performs peer review by way of comparing and contrasting its commodity pricing projections versus "consensus" pricing on the part of outside forecasting entities such as IHS- Cambridge Energy Research Associates (CERA), Petroleum Industry Research Associates (PIRA) and the EIA.

Another input parameter of note is the PJM capacity reserve margin. The PJM capacity reserve margin, combined with APCo's forecasted demand, set the limit for the minimum capacity required to maintain service reliability within the region. Each of the scenarios modeled below are optimized while adhering to this constraint. This ensures that each of the scenarios considered will result in an acceptable amount of generation available to APCo customers.

With regard to environmental regulations, the estimated, potential impact of current and pending regulations was factored into the analyses of potential resource plans by adding incremental costs to comply.

Additional critical input parameters include the installed cost of replacement capacity alternative options, as well as the attendant operating costs associated with those options. This data came from the AEP Engineering Services organization.

5.2 *Plexos*® Optimization

5.2.1 Modeling Options and Constraints

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

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 2022 due to the anticipated period required to approve, site, engineer and construct, from:
  - A 50% share of two CT units consisting of "F" class turbines with evaporative coolers and dual fuel capability, rated at 500MW total at summer conditions.
  - AD units consisting of 2 aeroderivative turbines at 120MW total at summer conditions.
  - RICE units consisting of 12 reciprocating engines rated at 220MW total at summer conditions.
  - Battery Storage units available in 10MW blocks per year.
- *Intermediate-Baseload* capacity was modeled, effective in 2023 due to anticipated period required to approve, site, engineer and construct, from:
  - A 25% share of a NGCC (2x1 "J" class turbines with duct firing and evaporative inlet air cooling) facility, rated at 1,600MW at summer conditions. The 25% interest assumes APCo coordinates the addition of this resource with other parties.
- Wind resources were made available up to 300MW annually beginning in 2023 (commercial operation date 12/31/22). One 150MW unit of each Tranche A and B was available each year. Tranche A had a LCOE of $40.67/MWh, in 2022 with the PTC. Tranche B had a LCOE of $44.16/MWh, in 2022 with the PTC. Wind resources were assumed to have a PJM capacity value equal to 12.3% of nameplate rating.
- Large-scale solar resources were made available in two tiers, with up to 150MW

of each tier available each year beginning in 2022, for a total of up to 300MW annually. Initial costs for Tier 1 were approximately $56.94/MWh in 2022 with the ITC. Tier 2 has an initial cost of approximately $61.41/MWh in 2022 with the ITC. Solar resources were assumed to have a PJM capacity value equal to 51.1% of nameplate rating.

- DG, in the form of distributed solar resources, was embedded in amounts equal to a CAGR of 10.7% over the planning period.

- CHP resources were made available in 15MW (nameplate) blocks, with an overnight installed cost of $2,300/kW and assuming full host compensation for thermal energy for an effective full load heat rate of ~4,800 Btu/kWh.

- 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, Commercial, and Industrial measures considering cost and performance parameters for both HAP and AP categories. Industrial measures were limited to lighting. The Commercial and Industrial potential was reduced based on the 2018 Virginia Act.

- VVO was available in 15 tranches of varying installed costs and number of circuits/sizes ranging from a low of 5.6MW up to 15.6MW of demand savings potential.

- Renewable Energy Credits are included in all portfolios. The Company developed a forecasted value for PJM Tier 1 RECs over the planning period. The values used in this IRP are considered planning assumptions to assist in understanding the net cost of both solar and wind resources, especially given Virginia's RPS requirement to optimize RECs. Table 14 shows the net Tier 1 values modeled which includes two Tier 2 RECs purchased for each Tier 1 REC sold. The development of the REC forecasted value is based on the Company's knowledge and activity in trading RECs within the PJM markets.

Table 14. Modeled REC Prices – ($/MWh)

Year	PJM Tier 1 ($/MWh)	Virginia Compliant Tier 2 ($/MWh)	Modeled Net Tier 1 ($/MWh)
2019	6.50	0.50	6.00
2020	8.42	0.50	7.92
2021	9.79	0.50	9.29
2022	10.00	0.50	9.50
2023	10.21	0.50	9.71
2024	10.50	0.50	10.00
2025	13.36	0.50	12.86
2026	13.44	0.50	12.94
2027	13.53	0.50	13.03
2028	13.62	0.50	13.12
2029	13.71	0.50	13.21
2030	16.77	0.50	16.27
2031	16.88	0.50	16.38
2032	17.00	0.50	16.50
2033	17.00	0.50	16.50

5.2.2 Traditional Optimized Portfolios

The key decision to be made by APCo during the planning period is how to fill the resource need identified. Portfolios with various options addressing APCo's capacity and energy resource needs over time were optimized under various commodity price and load conditions. In order to bound APCo's resource selection across varying commodity price and load conditions seven traditional scenarios were initially analyzed for this IRP (see Table 15). The resource portfolios discussed below for these scenarios represent incremental resources which are in addition to those currently in-service.

Table 15. Traditional Scenarios

Type	Name	Commodity Pricing Conditions	Load Conditions
Commodity Pricing Scenarios	Base	Base	Base
	Upper Band	Upper Band	Base
	No Carbon	No Carbon	Base
	Low No Carbon	Low No Carbon	Base
Load Scenarios	Low Load	No Carbon	Low
	High Load	No Carbon	High
	PJM Load	No Carbon	PJM

5.2.2.1 Base, Upper Band, No Carbon and Low No Carbon Commodity Pricing Portfolios

Table 16 shows the capacity additions associated with the Base, Upper Band, No Carbon and Low No Carbon commodity pricing scenarios. Recall from Section 4.3 that the modeling associated with the Base and Upper Band scenarios assumed a CO_2 dispatch burden, or allowance value, equal to $13.61/short ton commencing in 2028 and escalating at 3% per annum thereafter on a nominal dollar basis. The No Carbon and Low No Carbon scenarios do not include a CO_2 dispatch burden and are the low cost optimized portfolios.

Table 16. Cumulative PJM Capacity Additions (MW) for Base, Upper Band, No Carbon Band & Low No Carbon Commodity Pricing Scenarios

Commodity Pricing Scenario		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Base	Base/Intermediate															
	Peaking															
	Solar (Firm)					77	77	77	77	153	230	383	537	613	690	767
	Solar (Nameplate)					150	150	150	150	300	450	750	1,050	1,200	1,350	1,500
	Wind (Firm)					37	37	37	37	37	37	37	37	37	37	37
	Wind (Nameplate)					300	300	300	300	300	300	300	300	300	300	300
	Battery Storage															
	Energy Efficiency (Degraded)				15	28	39	36	33	29	25	18	16	12	9	7
	Energy Efficiency (Non-Degraded)				15	29	44	47	50	53	57	59	60	62	53	44
	CHP															
	VVO		17	17	17	17	17	17	17	17	17	17	17	17	17	17
	Demand Response															
	Distr. Gen.					18	21	22	23	24	25	27	29	30	32	34
Upper Band	Base/Intermediate															
	Peaking															
	Solar (Firm)				77	153	153	230	307	383	460	613	767	843	920	996
	Solar (Nameplate)				150	300	300	450	600	750	900	1,200	1,500	1,650	1,800	1,950
	Wind (Firm)					37	37	37	37	37	37	37	37	37	37	37
	Wind (Nameplate)					300	300	300	300	300	300	300	300	300	300	300
	Battery Storage															
	Energy Efficiency (Degraded)				30	42	52	50	48	42	36	27	23	18	14	10
	Energy Efficiency (Non-Degraded)				30	45	60	65	70	74	77	79	80	82	73	64
	CHP															
	VVO		17	17	17	17	17	17	17	17	17	17	17	17	17	17
	Demand Response															
	Distr. Gen.					18	21	22	23	24	25	27	29	30	32	34
No Carbon	Base/Intermediate															
	Peaking															
	Solar (Firm)										26	102	179	256	332	409
	Solar (Nameplate)										50	200	350	500	650	800
	Wind (Firm)					37	37	37	37	37	37	37	37	37	37	37
	Wind (Nameplate)					300	300	300	300	300	300	300	300	300	300	300
	Battery Storage															
	Energy Efficiency (Degraded)				15	28	39	36	33	29	25	18	15	11	9	7
	Energy Efficiency (Non-Degraded)				15	29	44	47	50	53	57	59	60	61	53	43
	CHP															
	VVO															
	Demand Response															
	Distr. Gen.					18	21	22	23	24	25	27	29	30	32	34
Low No Carbon	Base/Intermediate															
	Peaking															
	Solar (Firm)										26	51	128	128	128	128
	Solar (Nameplate)										50	100	250	250	250	250
	Wind (Firm)					37	37	37	37	37	37	37	37	37	37	37
	Wind (Nameplate)					300	300	300	300	300	300	300	300	300	300	300
	Battery Storage															
	Energy Efficiency (Degraded)				15	28	39	36	33	29	25	18	15	11	9	7
	Energy Efficiency (Non-Degraded)				15	29	44	47	50	53	57	59	60	61	53	43
	CHP															
	VVO															
	Demand Response															
	Distr. Gen.					18	21	22	23	24	25	27	29	30	32	34

Base/Intermediate=NGCC; Peaking=NGCT, AD; VVO=Volt VAR Optimization; DG=Distributed Generation

All four portfolios include similar resource additions, such as:

- Wind resources of 300MW (nameplate) in 2023;

- Solar resources of 150MW (nameplate) beginning as early as 2022 and total solar resource additions ranging from 250MW to 1,950MW (nameplate) by 2033 depending on the commodity pricing scenario; and
- EE programs including VVO totaling ranging from 94MW to 57MW by 2028.

This analysis provides APCo information regarding optimum resource selection under various views of the future.

5.2.2.2 Load Sensitivity Scenario Portfolios

Table 17 shows the capacity additions associated with the Low Load, High Load and PJM Load sensitivity scenarios, using No Carbon commodity prices.

Table 17. Cumulative Capacity Additions (MW) for Low, High and PJM Load Sensitivity Scenarios with No Carbon Commodity Pricing

Load Sensitivities Under No Carbon Commodity Prices		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Low Load	Base/Intermediate															
	Peaking															
	Solar (Firm)												77	77	77	77
	Solar (Nameplate)												150	150	150	150
	Wind (Firm)					37	37	37	37	37	37	37	37	37	37	37
	Wind (Nameplate)					300	300	300	300	300	300	300	300	300	300	300
	Battery Storage															
	Energy Efficiency (Degraded)				15	28	39	36	33	29	25	18	15	11	9	7
	Energy Efficiency (Non-Degraded)				15	29	44	47	50	53	57	59	60	61	53	43
	CHP															
	VVO															
	Demand Response															
	Distr. Gen.					18	21	22	23	24	25	27	29	30	32	34
High Load	Base/Intermediate															
	Peaking															
	Solar (Firm)				26	102	102	102	179	256	332	409	511	588	664	741
	Solar (Nameplate)				50	200	200	200	350	500	650	800	1,000	1,150	1,300	1,450
	Wind (Firm)					37	37	37	37	37	37	37	37	37	37	37
	Wind (Nameplate)					300	300	300	300	300	300	300	300	300	300	300
	Battery Storage															
	Energy Efficiency (Degraded)				28	40	50	49	46	43	37	28	24	18	14	11
	Energy Efficiency (Non-Degraded)				28	43	57	63	68	73	77	79	80	81	73	63
	CHP															
	VVO		17	17	17	17	17	17	17	17	17	17	17	17	17	17
	Demand Response															
	Distr. Gen.					18	21	22	23	24	25	27	29	30	32	34
PJM Load	Base/Intermediate															
	Peaking															
	Solar (Firm)					77	77	77	128	204	281	358	511	588	664	741
	Solar (Nameplate)					150	150	150	250	400	550	700	1,000	1,150	1,300	1,450
	Wind (Firm)					37	37	37	37	37	37	37	37	37	37	37
	Wind (Nameplate)					300	300	300	300	300	300	300	300	300	300	300
	Battery Storage															
	Energy Efficiency (Degraded)				18	31	42	41	39	37	32	24	21	15	12	9
	Energy Efficiency (Non-Degraded)				18	33	48	53	58	63	67	69	70	71	63	53
	CHP															
	VVO		17	17	17	17	17	17	17	17	17	17	17	17	17	17
	Demand Response															
	Distr. Gen.					18	21	22	23	24	25	27	29	30	32	34

Base/Intermediate=NGCC; Peaking=NGCT, AD; CHP=Combined Heat & Power; VVO=Volt VAR Optimization; DG=Distributed Generation

Part 4

As expected, the overall capacity additions in the High Load scenario are naturally greater than those in the Low Load scenario, due to the higher load requirement. The High Load scenario calls for solar resources sooner and in greater amounts. The PJM Load scenario calls for slightly less resources than the High Load scenario. Both the High and PJM Load scenarios selected VVO, while the Low Load scenario did not select VVO.

5.2.2.3 Senate Bill 966 and Virginia Renewable Portfolio Standard Portfolios

The Company developed portfolios that considered the impacts of SB966 and Virginia's voluntary Renewable Portfolio Standard (RPS) under both a future with carbon and without carbon. Table 18 summarizes the scenarios considered.

Table 18. SB 966 and RPS Scenarios Considered

Type	Name	Commodity Pricing Conditions	Load Conditions
Commodity Pricing Scenarios	SB 966 Mandates & RPS	Base	Base
	SB 966 Mandates & RPS	No Carbon	Base
	SB 966 Mandates	Low No Carbon	Base
	SB 966 Mandates & RPS -Not Optimized (1)	No Carbon	Base
	SB 966 Mandates & RPS -Not Optimized (1)	Low No Carbon	Base

Note: (1) This Portfolio takes the optimized resources from the SB 966 under the Base commodity price conditions and Base load conditions and quantifies this portfolio cost under No Carbon commodity price conditions and Base load conditions.

The SB 966 Mandates scenarios also complied with the Virginia voluntary Renewable Portfolio Standard; therefore, Table 19 does not have separate capacity portfolios for SB 966 and RPS and the capacity portfolios for the "Not Optimized" scenarios under No Carbon and Low No Carbon because they are the same as the SB 966 Mandates and RPS optimized values.

Table 19. Cumulative Capacity Additions (MW) for SB 966 Scenarios

SB 966 and RPS Portfolios		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Base - Compliant with SB-966 and RPS	Base/Intermediate															
	Peaking															
	Solar (Firm)					77	77	77	77	153	230	383	537	613	690	767
	Solar (Nameplate)					150	150	150	150	300	450	750	1,050	1,200	1,350	1,500
	Wind (Firm)					37	37	37	37	37	37	37	37	37	37	37
	Wind (Nameplate)					300	300	300	300	300	300	300	300	300	300	300
	Battery Storage			10	10	10	10	10	10	10	10	10	10	10	10	10
	Energy Efficiency (Degraded)				36	69	98	92	85	78	69	56	47	36	27	20
	Energy Efficiency (Non-Degraded)				36	72	108	114	120	126	132	137	138	140	127	114
	CHP															
	VVO		17	17	17	17	17	17	17	17	17	17	17	17	17	17
	Demand Response															
	Distr. Gen.					18	21	22	23	24	25	27	29	30	32	34
No Carbon - Compliant with SB-966 and RPS	Base/Intermediate															
	Peaking															
	Solar (Firm)									26	102	102	179	256	332	409
	Solar (Nameplate)									50	200	200	350	500	650	800
	Wind (Firm)					37	37	37	37	37	37	37	37	37	37	37
	Wind (Nameplate)					300	300	300	300	300	300	300	300	300	300	300
	Battery Storage			10	10	10	10	10	10	10	10	10	10	10	10	10
	Energy Efficiency (Degraded)				39	69	95	89	81	74	65	50	42	31	23	17
	Energy Efficiency (Non-Degraded)				39	72	105	110	116	121	127	129	130	131	118	105
	CHP															
	VVO															
	Demand Response															
	Distr. Gen.					18	21	22	23	24	25	27	29	30	32	34
Low No Carbon - Compliant with SB-966 and RPS	Base/Intermediate															
	Peaking															
	Solar (Firm)									26	102	102	128	128	128	128
	Solar (Nameplate)									50	200	200	250	250	250	250
	Wind (Firm)					37	37	37	37	37	37	37	37	37	37	37
	Wind (Nameplate)					300	300	300	300	300	300	300	300	300	300	300
	Battery Storage			10	10	10	10	10	10	10	10	10	10	10	10	10
	Energy Efficiency (Degraded)				38	73	104	97	88	79	69	55	46	35	26	18
	Energy Efficiency (Non-Degraded)				38	76	114	120	125	129	134	139	140	141	128	115
	CHP															
	VVO															
	Demand Response															
	Distr. Gen.					18	21	22	23	24	25	27	29	30	32	34

All three SB 966 compliant portfolios shown in Table 19 include similar resource additions to their corresponding optimized resource additions shown in Table 16, as well as to each other such as:

- Wind resources of 300MW (nameplate) in 2023;
- Solar resources ranging from 250 to 1,500MW (nameplate) by 2033, depending on the commodity prices. In the Base commodity price future, solar resources are selected in 2023, whereas both the No Carbon and Low No Carbon scenarios

delay the addition of solar resources to 2027, which is one year earlier than the optimized results, in Table 16;

- EE programs, including VVO, totaling ranging from 149MW to 127MW by 2028. These amounts are significantly higher than the optimized levels in Table 16, due to the compliance with SB 966.

This analysis provides APCo information regarding how the resource selection varies from the optimum resource selection when portfolios are developed to comply with SB 966 and Virginia's voluntary RPS.

Because the optimal plans created for the various commodity price scenarios selected a significant volume of renewable resources and energy efficiency, APCo developed three alternative portfolios from those optimal plans that are compliant with both SB 966 and Virginia's voluntary RPS. The results of the analysis are shown in Table 20; the compliant portfolios are approximately $33M to $54M costlier than the corresponding optimal portfolios. In all scenarios, the cost difference between the compliant portfolios and the optimal portfolios is driven by: the addition of the battery in 2021 with an approximate $10M cost increase; and the addition of energy efficiency resources to achieve $140M of energy efficiency spending by 2028. In the no carbon scenarios, an additional cost difference is due to the need to accelerate utility solar for SB 966 compliance versus the corresponding optimal plan scenario.

Table 20. SB 966 Compliance Cost – ($000)

Pricing Scenario	Optimal Plan CPW ($000)	SB 966 Plan CPW ($000)	SB 966 Increased Cost ($000)
Base Plan	17,652,988	17,686,435	33,446
No Carbon	15,953,284	16,005,259	51,975
Low No Carbon	14,370,003	14,423,755	53,752

5.3 Preferred Plan

Each of the scenarios provides insight into a potential alternative mix of resources for the future. Given that the resource additions under the four commodity pricing scenarios offer comparable resource additions, APCo is using the Base commodity pricing scenario, with SB 966 compliant resources included as its Preferred Plan.

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.
- Complying with SB 966 and Virginia's voluntary RPS requirements.
- Meeting PJM capacity obligations if load growth is closer to PJM load growth assumptions.

The cumulative capacity additions associated with the Preferred Plan are shown below in Table 21.

Table 21. Cumulative Capacity Additions (MW) for Preferred Plan

Preferred Plan		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Base - Compliant with SB-966 and RPS	Base/Intermediate															
	Peaking															
	Solar (Firm)					77	77	77	77	153	230	383	537	613	690	767
	Solar (Nameplate)					150	150	150	150	300	450	750	1,050	1,200	1,350	1,500
	Wind (Firm)					37	37	37	37	37	37	37	37	37	37	37
	Wind (Nameplate)					300	300	300	300	300	300	300	300	300	300	300
	Battery Storage			10	10	10	10	10	10	10	10	10	10	10	10	10
	Energy Efficiency (Degraded)				36	69	98	92	85	78	69	56	47	36	27	20
	Energy Efficiency (Non-Degraded)				36	72	108	114	120	126	132	137	138	140	127	114
	CHP															
	VVO		17	17	17	17	17	17	17	17	17	17	17	17	17	17
	Demand Response															
	Distr. Gen.					18	21	22	23	24	25	27	29	30	32	34
	Total Additions (Firm & Degraded)		17	27	63	228	260	255	249	319	388	530	676	743	813	884

In conjunction with the Company's five-year action plan, the Preferred Plan offers APCo significant flexibility should future conditions differ considerably from the assumptions underpinning the Preferred Plan. For example, as EE programs are implemented, APCo will gain insight into customer acceptance and develop additional hard data as to the impact these programs have on load growth. This will assist APCo in determining whether to expand program offerings, change incentive levels for programs, or target specific customer classes for the best results. If current long-term renewable cost assumptions change, APCo could either accelerate or delay the installation of renewable generation facilities.

5.3.1 Demand-Side Resources

In the Preferred Plan, incremental EE resources were selected beginning in 2022 and throughout the remainder of the planning period. Economic savings are attributable to both Commercial/Industrial and Residential programs, with the majority coming from Residential programs. In 2028, the EE resources included in the Preferred Plan are expected to reduce energy usage by approximately 449GWhs. Table 22 shows the annual Energy Efficiency energy and capacity savings over the reporting period both as a "Supply" resource and as a "Load" modifier or demand savings. From the IRP modeling perspective, they are equivalent. The Company models incremental EE as a resource to allow the model to compare EE resource characteristics to other alternative resources. To provide the impact to load in Table 22, the Company applied the PJM Forecast Pool Requirement of 1.0887. The Company does not need to model this separately because they are equivalent to each other; whether modeled as a "Supply" capacity impact or as shown as a "Load" demand impact.

Table 22. EE Resources in the Preferred Plan on a Capacity basis and a Load basis

	Supply Level		Load Level			
Year	Energy GWh	Capacity MW	Energy GWh	Demand MW	Forecasted Pool Requirement MW	Total MW
2019	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0
2021	0.0	0.0	0.0	0.0	0.0	0.0
2022	241.0	35.9	241.0	33.0	2.9	35.9
2023	463.4	69.1	463.4	63.5	5.6	69.1
2024	661.0	98.3	661.0	90.3	8.0	98.3
2025	615.1	92.3	615.1	84.8	7.5	92.3
2026	562.9	85.2	562.9	78.2	6.9	85.2
2027	507.6	77.5	507.6	71.2	6.3	77.5
2028	448.7	69.1	448.7	63.5	5.6	69.1
2029	366.2	55.9	366.2	51.3	4.6	55.9
2030	305.2	47.3	305.2	43.5	3.9	47.3
2031	232.4	36.1	232.4	33.2	2.9	36.1
2032	171.1	27.0	171.1	24.8	2.2	27.0
2033	120.8	19.6	120.8	18.0	1.6	19.6

The amounts of EE resources included in the Preferred Plan to comply with SB 966 are based on the following assumptions: an estimated spend of approximately $38M from July 2018 through 2021; optimized EE spend of approximately $10M from 2022 to 2028, Virginia's share; and approximately $92M of EE spend from 2022 through 2028 to equal the SB 966 mandate of $140M spending on EE programs. The estimated annual cost to provide this level of EE resources in the Preferred Plan is shown below in Table 23.

Table 23. Preferred Plan – EE Annual Spend ($000)

Year	Spend ($000)
2019	-
2020	-
2021	-
2022	30,554
2023	31,167
2024	31,887
2025	4,121
2026	4,400
2027	4,461
2028	4,489
2029	4,624
2030	521
2031	539
2032	365
2033	348

As part of the Preferred Plan, one of the fifteen available VVO tranches is proposed. This results in a cumulative capacity reduction of 17MW by 2028. The VVO estimates are subject to future revision as more operational information is gained from the pilot installation as well as other tests that are currently underway throughout the AEP system.

DG (i.e. rooftop solar) resources were not modeled during the planning period. DG resources were added incrementally at a CAGR of 10.7% (based on nameplate capacity), resulting in a total of 34MW of PJM capacity credit (82MW nameplate) by 2033.

5.4 Risk Analysis

In addition to comparing the Preferred Plan to the optimized portfolios under a variety of pricing assumptions, the Preferred Plan and an alternative portfolio were also evaluated using a stochastic, or "Monte Carlo" modeling technique where input variables are randomly selected from a universe of possible values, given certain standard deviation constraints and correlative relationships. This offers an additional approach by which to "test" the Preferred Plan over a distributed range of certain key variables. The output is, in turn, a distribution of possible outcomes, providing insight as to the risk or probability of a higher cost (revenue requirement) relative to the expected outcome.

This study included multiple risk iteration runs performed over the study period with key price variables (risk factors) being subjected to this stochastic-based risk analysis. The results take the form of a distribution of possible revenue requirement outcomes for each plan. Table 24 and Table 25 shows the input variables or risk factors within this IRP stochastic analysis and the historical correlative relationships to each other. Table 24 shows the input variables before carbon regulation (2019 to 2027) and Table 25 shows the input variables details after carbon pricing.

Table 24. Risk Analysis Factors & Their Relationships, 2019-2027

2019 - 2027	Gas	Coal - Blended	Coal - High Sulfur	CO2	Market Prices
Gas	1.00	0.69	0.76	0.00	0.88
Coal - Blended		1.00	0.96	0.00	0.73
Coal - High Sulfur			1.00	0.00	0.79
CO2				0.00	0.00
Market Prices					1.00
Average Coefficient of Variation	15.4%	7.6%	8.2%	0.0%	10.1%

Table 25. Risk Analysis Factors & Their Relationships After Carbon Pricing, 2028-2038

2028 - 2038	Gas	Coal - Blended	Coal - High Sulfur	CO2	Market Prices
Gas	1.00	0.67	-0.71	0.83	0.58
Coal - Blended		1.00	-0.40	0.76	0.53
Coal - High Sulfur			1.00	-0.87	-0.58
CO2				1.00	0.67
Market Prices					1.00
Average Coefficient of Variation	16.2%	7.1%	11.6%	70.7%	17.1%

Comparing the Preferred Plan to an alternative portfolio which is significantly different provides a data point that may be used to evaluate the risk associated with the Preferred Plan. The Preferred Plan has a similar resource profile to other optimized plans, so there would be little difference in the risk profiles between such portfolios and the Preferred Plan, and therefore those portfolios were not included in the stochastic analysis. Instead, the least cost portfolio was compared against the Preferred Plan. The least cost portfolio for this IRP is the optimized Low No Carbon plan. This allows APCo to determine if the resources in the Preferred Plan introduce more risk than relying on the least cost plan. The range of values associated with the variable inputs is shown in Figure 36.

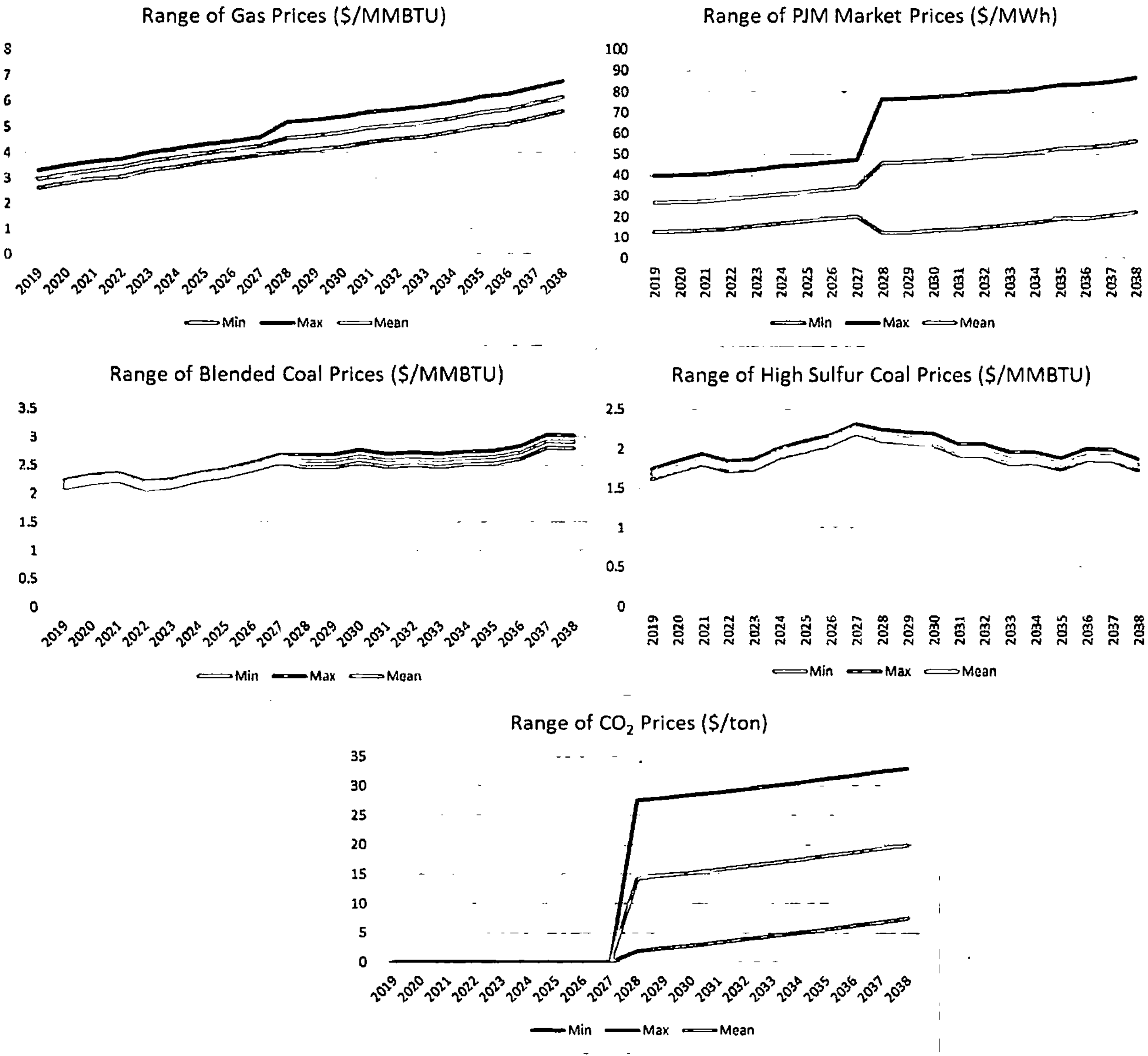


Figure 36. Range of Variable Inputs for Stochastic Analysis

5.4.1 Stochastic Modeling Process and Results

For each portfolio, the results of 100 random iterations are sorted from lowest cost to highest cost, with the differential between the median and higher percentile result from the multiple runs identified as Revenue Requirement at Risk (RRaR). For example, the 95th percentile is a level of required revenue sufficiently high that it will be exceeded, assuming the given plan is adopted, only five percent of the time. Thus, it is 95 percent likely that those higher-ends of revenue requirements would not be exceeded. The larger the RRaR, the greater the likelihood that customers could be subjected to higher costs relative to the portfolio's mean or expected cost. Conversely, there is equal likelihood that costs may be lower than the median value. These higher or lower costs are generally the result of the difference, or spread, between fuel prices and resultant PJM market energy prices. The greater that spread, the more "margin" is enjoyed by the Company and its customers.

Figure 37 illustrates the RRaR (expressed in terms of incremental cost over the 50th percentile).

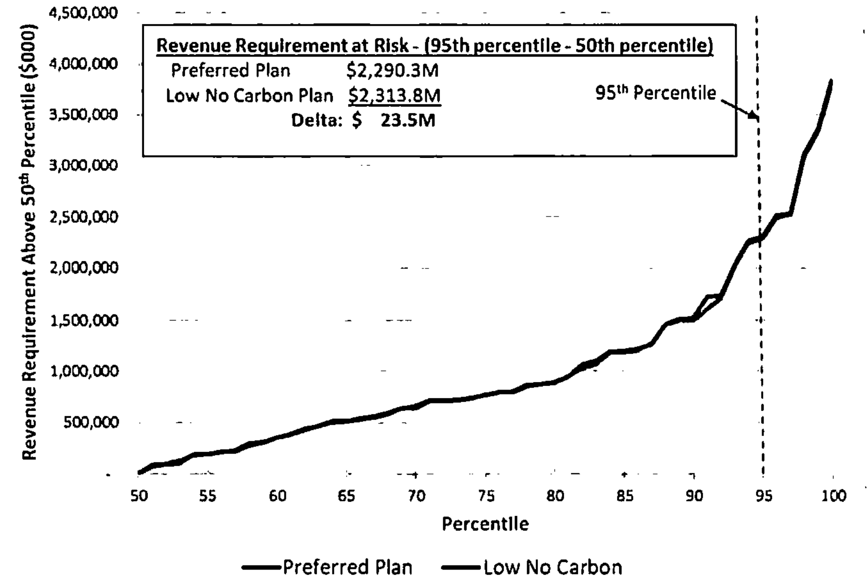


Figure 37. Revenue Requirement at Risk (RRaR) ($000) for Select Portfolios

The difference in RRaR between the two portfolios that were analyzed is relatively small over the 100 simulations, with the Preferred Plan being less risky by about $23.5M, which indicates that the additional resources, specifically solar, storage, energy efficiency and VVO in the Preferred Plan does not introduce additional risk.

Based on the risk modeling performed, it is reasonable to conclude that the inherent risk characteristics of the Preferred Plan, which includes a higher level of resources, is not significantly greater than a least cost portfolio. This suggests that the Preferred Plan represents a reasonable combination of expected costs and risk.

5.4.2 Preferred Portfolio Cost

Another method of determining whether the proposed plan is better for customers is to compare the cost of the Preferred Portfolio under varying futures or commodity price scenarios. To do this APCo fixed the Preferred Plan resources and applied both the No Carbon and Low No Carbon commodity price scenarios. As expected, when considering these different futures, the Preferred Plan is sub-optimal or more expensive than the optimal portfolio under both of these futures. Table 26 shows the incremental cost of the Preferred Plan under Base commodity pricing versus No Carbon and Low No Carbon pricing, as well as, the estimated levelized Residential annual bill impact of the Preferred Plan under either a No Carbon or Low No Carbon future.

Table 26. Comparison of Preferred Plan vs. Optimized Plans based on Cumulative Present Worth ($000), Incremental Cost ($000) and Levelized Annual Bill Impact ($)

Plan	Base CPW ($000)	No Carbon CPW ($000)	Low No Carbon CPW ($000)
Preferred Plan Portfolio	17,686,435	16,081,178	14,685,513
SB 966 & RPS Optimized	17,686,435	16,005,259	14,423,755
Cost Difference	-	75,919	261,759
Levelized Residential Annual Bill Impact ($)*	NA	2.13	5.87

* Assumes 12,000 kWh per year consumption

6.0 Conclusions and Five-Year Action Plan

6.1 Plan Summary

APCo used the modeling results to develop a Preferred Plan or "Plan". To arrive at the Preferred Plan, using Plexos®, APCo developed optimal portfolios based on four long-term commodity price forecasts, three load sensitivities and compliance with SB 966 and Virginia's voluntary RPS. The Preferred Plan balances cost and other factors such as risk and environmental regulatory considerations, to cost effectively meet APCo's demand and energy obligations. For APCo, the Preferred Plan is the optimized portfolio modeled under the base commodity pricing scenario and meeting the SB 966 mandates and RPS.

Table 27[22] provides a summary of the Preferred Plan throughout the planning period (2019-2033), which resulted from analysis of optimization modeling under the load and commodity pricing scenarios.

Table 27. Preferred Plan Cumulative Capacity Additions throughout Planning Period (2019-2033)

Preferred Plan		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Base - Compliant with SB-966 and RPS	Base/Intermediate															
	Peaking															
	Solar (Firm)					77	77	77	77	153	230	383	537	613	690	767
	Solar (Nameplate)					150	150	150	150	300	450	750	1,050	1,200	1,350	1,500
	Wind (Firm)					37	37	37	37	37	37	37	37	37	37	37
	Wind (Nameplate)					300	300	300	300	300	300	300	300	300	300	300
	Battery Storage			10	10	10	10	10	10	10	10	10	10	10	10	10
	Energy Efficiency (Degraded)				36	69	98	92	85	78	69	56	47	36	27	20
	Energy Efficiency (Non-Degraded)				36	72	108	114	120	126	132	137	138	140	127	114
	CHP															
	VVO		17	17	17	17	17	17	17	17	17	17	17	17	17	17
	Demand Response															
	Distr. Gen.					18	21	22	23	24	25	27	29	30	32	34
	Total Additions (Firm & Degraded)		17	27	63	228	260	255	249	319	388	530	676	743	813	884
Capacity Reserves Above PJM Requirement without New Additions		242	493	475	439	443	434	428	17	(75)	(104)	(128)	(150)	(164)	(183)	(196)
Capacity Reserves Above PJM Requirement with New Additions		242	510	502	518	671	693	683	266	244	285	401	526	580	630	688

Base/Intermediate=NGCC; Peaking=NGCT, AD; CHP=Combined Heat & Power; VVO=Volt VAR Optimization; DG=Distributed Generation

[22] Note: This IRP begins adding new demand-side resources such as energy efficiency in 2022 that are incremental to programs that are currently approved or pending approval. The programs that are currently approved or pending approval during the 2019-2021 timeframe are embedded in the Company's load forecast.

The IRP process is a continuous activity; assumptions and plans are reviewed as new information becomes available and modified as appropriate. Indeed, the resource portfolios developed herein reflect, to a large extent, assumptions that are subject to change; an IRP is simply a snapshot of the future at a given time. 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. Continue the evaluation of the Company's Solar RFP and determine if any projects will be brought forward for regulatory consideration.
2. Implement a battery pilot program with up to 10MW of energy storage.
3. Continue the planning and regulatory actions necessary to implement additional economic EE programs in Virginia and West Virginia, as well as programs that target low-income, disabled and elderly customers provided for in the 2018 Virginia Act.
4. Complete its deployment of AMI meters and associated infrastructure, add Distribution Automation Circuit Reconfiguration schemes to 60 circuits, widen certain distribution rights-of-way, and relocate or underground certain lines.
5. Plan to meet Virginia's Voluntary Renewable Portfolio Standard goals.
6. Continue to monitor market prices for renewable resources, particularly wind and solar, and if economically advantageous, or if needed to meet escalating voluntary RPS goals, pursue competitive solicitations that would include self-build or acquisition options.
7. Pursue opportunities to identify a suitable host facility for a CHP installation.
8. Monitor developments associated with PJM's Capacity Performance rule.

9. Monitor the status of, and participate in formulating any proposed carbon emissions regulations. Once established, assess the implications of such regulations on APCo's resource profile.

Appendix

Exhibit A Load Forecast Tables

Exhibit A-1

Appalachian Power Company
Annual Internal Energy Requirements and Growth Rates
2015-2033

Year	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Total Internal Energy Requirements	
	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth
Actual										
2015	11,495	---	6,721	---	9,866	---	6,890	---	34,972	---
2016	11,421	-0.6	6,751	0.4	9,410	-4.6	6,590	-4.4	34,171	-2.3
2017	10,701	-6.3	6,453	-4.4	9,603	2.1	6,288	-4.6	33,045	-3.3
2018	11,870	10.9	6,603	2.3	9,555	-0.5	6,487	3.2	34,515	4.4
Forecast										
2019	10,995	-7.4	6,457	-2.2	9,876	3.4	6,498	0.2	33,826	-2.0
2020	10,900	-0.9	6,417	-0.6	9,896	0.2	6,491	-0.1	33,704	-0.4
2021	10,816	-0.8	6,390	-0.4	9,961	0.7	6,515	0.4	33,682	-0.1
2022	10,765	-0.5	6,363	-0.4	9,996	0.4	6,511	-0.1	33,635	-0.1
2023	10,714	-0.5	6,324	-0.6	10,031	0.3	6,523	0.2	33,592	-0.1
2024	10,667	-0.4	6,290	-0.5	10,074	0.4	6,527	0.1	33,558	-0.1
2025	10,638	-0.3	6,288	0.0	10,095	0.2	6,521	-0.1	33,542	0.0
2026	10,621	-0.2	6,310	0.4	10,114	0.2	6,534	0.2	33,579	0.1
2027	10,617	0.0	6,329	0.3	10,143	0.3	6,540	0.1	33,630	0.2
2028	10,607	-0.1	6,338	0.1	10,179	0.4	6,562	0.3	33,686	0.2
2029	10,606	0.0	6,345	0.1	10,207	0.3	6,571	0.1	33,728	0.1
2030	10,588	-0.2	6,355	0.2	10,234	0.3	6,572	0.0	33,749	0.1
2031	10,580	-0.1	6,384	0.5	10,262	0.3	6,578	0.1	33,804	0.2
2032	10,561	-0.2	6,396	0.2	10,296	0.3	6,602	0.4	33,854	0.1
2033	10,554	-0.1	6,415	0.3	10,330	0.3	6,601	0.0	33,899	0.1
Average Annual Growth Rates										
2015-2018		1.1		-0.6		-1.1		-2.0		-0.4
2019-2033		-0.3		0.0		0.3		0.1		0.0

Exhibit A-2A

Appalachian Power Company-Virginia
Annual Internal Energy Requirements and Growth Rates
2014-2032

	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										
2015	6,138	---	3,199	---	5,356	---	3,241	---	17,934	---
2016	6,153	0.2	3,233	1.1	5,270	-1.6	3,191	-1.5	17,847	-0.5
2017	5,845	-5.0	3,102	-4.1	5,278	0.2	3,036	-4.9	17,261	-3.3
2018	6,474	10.8	3,176	2.4	5,293	0.3	3,113	2.5	18,056	4.6
Forecast										
2019	6,014	-7.1	3,103	-2.3	5,342	0.9	3,220	3.4	17,678	-2.1
2020	5,982	-0.5	3,082	-0.7	5,363	0.4	3,218	-0.1	17,644	-0.2
2021	5,953	-0.5	3,060	-0.7	5,385	0.4	3,230	0.4	17,627	-0.1
2022	5,939	-0.2	3,041	-0.6	5,397	0.2	3,227	-0.1	17,605	-0.1
2023	5,928	-0.2	3,020	-0.7	5,410	0.2	3,235	0.2	17,592	-0.1
2024	5,921	-0.1	3,003	-0.6	5,432	0.4	3,238	0.1	17,594	0.0
2025	5,921	0.0	3,000	-0.1	5,453	0.4	3,236	-0.1	17,610	0.1
2026	5,923	0.0	3,004	0.2	5,473	0.4	3,244	0.3	17,645	0.2
2027	5,930	0.1	3,010	0.2	5,497	0.4	3,249	0.1	17,686	0.2
2028	5,935	0.1	3,012	0.1	5,521	0.4	3,262	0.4	17,729	0.2
2029	5,945	0.2	3,015	0.1	5,541	0.4	3,267	0.2	17,768	0.2
2030	5,947	0.0	3,017	0.1	5,561	0.4	3,270	0.1	17,795	0.2
2031	5,954	0.1	3,026	0.3	5,581	0.4	3,275	0.1	17,836	0.2
2032	5,959	0.1	3,036	0.3	5,601	0.4	3,290	0.5	17,885	0.3
2033	5,970	0.2	3,048	0.4	5,621	0.4	3,292	0.1	17,931	0.3
Average Annual Growth Rates										
2014-2017		1.8		-0.2		-0.4		-1.3		0.2
2018-2032		-0.1		-0.1		0.4		0.2		0.1

Exhibit A-2B

Appalachian Power Company-West Virginia
Annual Internal Energy Requirements and Growth Rates
2015-2033

	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										
2015	5,357	---	3,522	---	4,510	---	1,503	---	14,892	---
2016	5,268	-1.7	3,518	-0.1	4,140	-8.2	1,302	-13.4	14,228	-4.5
2017	4,856	-7.8	3,351	-4.7	4,325	4.5	1,235	-5.1	13,766	-3.2
2018	5,396	11.1	3,427	2.3	4,262	-1.5	1,266	2.5	14,351	4.2
Forecast										
2019	4,982	-7.7	3,354	-2.1	4,534	6.4	1,201	-5.1	14,071	-2.0
2020	4,918	-1.3	3,335	-0.6	4,534	0.0	1,193	-0.7	13,979	-0.7
2021	4,864	-1.1	3,330	-0.1	4,576	0.9	1,196	0.3	13,966	-0.1
2022	4,825	-0.8	3,322	-0.3	4,600	0.5	1,188	-0.7	13,934	-0.2
2023	4,786	-0.8	3,304	-0.5	4,621	0.5	1,188	0.0	13,899	-0.3
2024	4,747	-0.8	3,286	-0.5	4,642	0.4	1,185	-0.3	13,860	-0.3
2025	4,717	-0.6	3,288	0.0	4,642	0.0	1,176	-0.8	13,823	-0.3
2026	4,698	-0.4	3,306	0.5	4,641	0.0	1,177	0.1	13,821	0.0
2027	4,687	-0.2	3,319	0.4	4,646	0.1	1,175	-0.1	13,827	0.0
2028	4,672	-0.3	3,326	0.2	4,658	0.3	1,180	0.4	13,836	0.1
2029	4,661	-0.2	3,330	0.1	4,666	0.2	1,179	-0.1	13,835	0.0
2030	4,641	-0.4	3,338	0.3	4,673	0.2	1,175	-0.3	13,827	-0.1
2031	4,626	-0.3	3,358	0.6	4,681	0.2	1,173	-0.2	13,838	0.1
2032	4,602	-0.5	3,360	0.1	4,695	0.3	1,179	0.5	13,836	0.0
2033	4,584	-0.4	3,367	0.2	4,709	0.3	1,172	-0.6	13,831	0.0
Average Annual Growth Rates										
2015-2018		0.2		-0.9		-1.9		-5.6		-1.2
2019-2033		-0.6		0.0		0.3		-0.2		-0.1

Exhibit A-3

Appalachian Power Company

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

2015-2033

	Summer Peak			Preceding Winter Peak			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
2015	06/23/15	5,744	---	02/20/15	8,708	---	8,708	---	34,972	---	45.7
2016	07/25/16	5,885	2.5	01/19/16	7,379	-15.3	7,379	-15.3	34,171	-2.3	52.9
2017	07/20/17	5,616	-4.6	01/09/17	6,984	-5.3	6,984	-5.3	33,045	-3.3	54.0
2018	06/18/18	5,618	0.0	01/02/18	7,816	11.9	7,816	11.9	34,515	4.4	50.4
Forecast											
2019		5,676	1.0		7,097	-9.2	7,097	-9.2	33,826	-2.0	54.3
2020		5,662	-0.2		7,084	-0.2	7,084	-0.2	33,704	-0.4	54.3
2021		5,662	0.0		7,044	-0.6	7,044	-0.6	33,682	-0.1	54.6
2022		5,660	0.0		7,028	-0.2	7,028	-0.2	33,635	-0.1	54.6
2023		5,658	0.0		7,016	-0.2	7,016	-0.2	33,592	-0.1	54.5
2024		5,660	0.0		7,005	-0.2	7,005	-0.2	33,558	-0.1	54.7
2025		5,663	0.1		6,995	-0.1	6,995	-0.1	33,542	0.0	54.7
2026		5,676	0.2		6,994	0.0	6,994	0.0	33,579	0.1	54.8
2027		5,688	0.2		6,996	0.0	6,996	0.0	33,630	0.2	54.7
2028		5,703	0.3		6,993	0.0	6,993	0.0	33,686	0.2	55.0
2029		5,710	0.1		6,998	0.1	6,998	0.1	33,728	0.1	55.0
2030		5,718	0.1		6,993	-0.1	6,993	-0.1	33,749	0.1	55.1
2031		5,733	0.3		6,996	0.0	6,996	0.0	33,804	0.2	55.2
2032		5,749	0.3		6,995	0.0	6,995	0.0	33,854	0.1	55.2
2033		5,760	0.2		6,999	0.1	6,999	0.1	33,899	0.1	55.3
Average Annual Growth Rates											
2015-2018			-0.7			-3.5		-3.5		-0.4	
2019-2033			0.1			-0.1		-0.1		0.0	

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
2019	81.8	10.9	13.2	52.8	6.5	8.2	29.0	4.4	5.0
2020	118.0	15.4	18.9	74.3	9.2	11.7	43.7	6.1	7.3
2021	147.4	19.0	23.8	91.8	11.5	14.6	55.6	7.5	9.2
2022	173.8	22.0	27.0	106.4	13.3	16.7	67.3	8.7	10.4
2023	203.5	25.2	29.7	118.5	14.7	17.9	85.0	10.5	11.8
2024	236.3	28.7	32.8	128.0	15.6	18.6	108.3	13.0	14.2
2025	232.3	27.6	31.7	123.9	14.8	17.8	108.4	12.7	14.0
2026	193.3	21.7	26.0	107.2	12.3	15.2	86.1	9.4	10.8
2027	163.4	18.0	22.2	93.8	10.6	13.3	69.5	7.4	8.8
2028	147.5	17.3	21.0	86.3	10.1	12.7	61.1	7.2	8.3
2029	144.6	18.5	21.7	85.4	10.6	12.9	59.2	7.9	8.8
2030	127.7	18.0	21.0	79.4	10.5	12.7	48.3	7.6	8.3
2031	96.4	15.9	19.1	68.5	9.7	12.2	27.9	6.2	6.9
2032	97.3	17.4	21.1	60.6	9.3	12.0	36.7	8.2	9.1
2033	102.7	19.6	24.5	56.1	9.3	12.6	46.6	10.3	12.0

*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

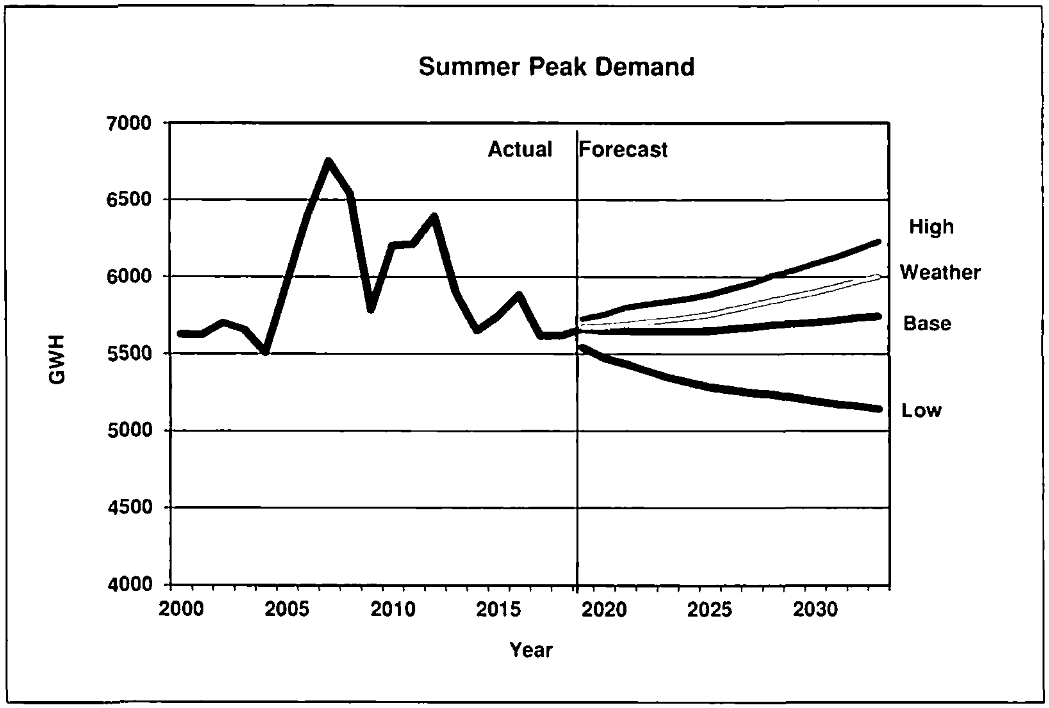
Exhibit A-7

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
2019	6,946	7,097	7,180	5,556	5,676	5,743	33,107	33,826	34,226
2020	6,868	7,084	7,218	5,489	5,662	5,769	32,673	33,704	34,339
2021	6,782	7,044	7,236	5,451	5,662	5,816	32,429	33,682	34,600
2022	6,710	7,028	7,248	5,404	5,660	5,837	32,114	33,635	34,687
2023	6,649	7,016	7,262	5,362	5,658	5,857	31,837	33,592	34,771
2024	6,597	7,005	7,273	5,330	5,660	5,876	31,602	33,558	34,842
2025	6,544	6,995	7,286	5,299	5,663	5,899	31,382	33,542	34,940
2026	6,508	6,994	7,315	5,281	5,676	5,937	31,244	33,579	35,122
2027	6,473	6,996	7,346	5,263	5,688	5,973	31,117	33,630	35,312
2028	6,441	6,993	7,387	5,253	5,703	6,024	31,027	33,686	35,583
2029	6,411	6,998	7,423	5,231	5,710	6,056	30,899	33,728	35,774
2030	6,372	6,993	7,466	5,210	5,718	6,105	30,752	33,749	36,033
2031	6,332	6,996	7,497	5,189	5,733	6,143	30,599	33,804	36,226
2032	6,300	6,995	7,535	5,177	5,749	6,193	30,489	33,854	36,469
2033	6,268	6,999	7,589	5,157	5,760	6,245	30,355	33,899	36,755
Average Annual Growth Rate % - 2018-2032									
	-0.7	-0.1	0.4	-0.5	0.1	0.6	-0.6	0.0	0.5

Exhibit A-8

Appalachian Power Company
Range of Forecasts and Weather Scenario



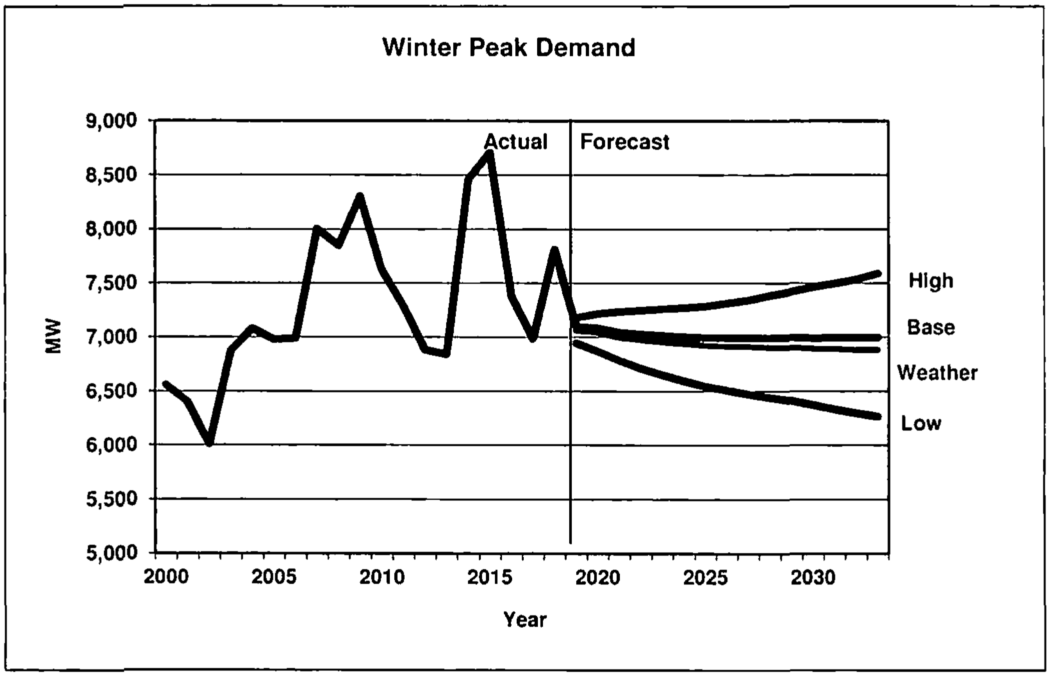


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Exhibit A-9

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
2019	5,470.1	5,470.1	5,583.3
2020	5,450.6	5,450.6	5,612.7
2021	5,474.6	5,474.6	5,661.9
2022	5,507.8	5,507.8	5,685.8
2023	5,532.8	5,514.0	5,707.6
2024	5,572.5	5,519.3	5,730.4
2025	5,597.4	5,521.5	5,751.6
2026	5,625.7	5,528.0	5,781.9
2027	5,660.6	5,536.6	5,813.6
2028	5,700.0	5,550.2	5,862.9
2029	5,738.4	5,557.7	5,894.9
2030	5,772.6	5,565.1	5,941.7
2031	5,796.8	5,577.4	5,976.9
2032	5,831.8	5,594.8	6,026.9
2033	5,865.2	5,607.2	6,079.5
2034	5,909.8	5,620.1	6,120.6

* PJM forecast is based on PJM's 2019 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

Appalachian Power Company
Forecasted DSM, Adjusted for IRP Modeling (1)

Year	Energy (MWh)	Total APCo Summer Peak (MW)	Winter Peak (MW)
2019	81,798	10.9	13.2
2020	118,011	15.4	18.9
2021	147,434	19.0	23.8
2022	124,358	16.1	20.9
2023	73,626	10.3	13.2
2024	48,061	6.8	8.9
2025	25,119	3.8	5.2
2026	16,193	2.4	3.5
2027	8,850	1.4	2.1
2028	3,073	0.5	0.9
2029	762	0.1	0.3
2030	-	-	-
2031	-	-	-
2032	-	-	-
2033	-	-	-

(1) DSM values shown here reflect the most recent information for APCo available at the time of the IRP. These values may differ from the DSM values shown in Exhibit A-4, which are the APCo DSM values at the time of the APCo load forecast.

Exhibit B Non-Renewable New Generation Technologies

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

Type	Capability (MW) (d) Std. ISO	Capability (MW) (d) Summer	Capability (MW) (d) Winter	Installed Cost (c,e) ($/kW)	Full Load Heat Rate (HHV,Btu/kWh)	Fuel Cost ($/MBtu)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Capacity Factor (%)	LCOE (f) ($/MWh)
Base Load										
Nuclear	1,610	1,560	1,690	8,500	10,500	0.94	3.99	168.33	80	178.2
Pulv. Coal with Carbon Capture (PRB)	540	520	570	9,500	12,500	2.42	4.37	104.12	75	221.1
Combined Cycle (1X1 "J" Class)	610	800	820	900	6,200	3.42	1.77	12.86	75	59.5
Combined Cycle (2X1 "J" Class)	1,230	1,600	1,640	700	6,200	3.42	1.55	10.65	75	55.3
Combined Cycle (2X1 "H" Class)	1,150	1,490	1,530	700	6,300	3.42	1.51	11.07	75	56.1
Peaking										
Combustion Turbine (2 - "E" Class) (g)	180	190	190	1,200	11,700	3.42	4.05	30.46	25	148.6
Combustion Turbine (2 - "F" Class, w/evap coolers) (g)	490	500	510	700	10,000	3.42	6.27	24.55	25	116.4
Aero-Derivative (2 - Small Machines) (g)	120	120	120	1,100	9,900	3.42	2.51	32.17	25	135.7
Recip Engine Farm	220	220	230	1,300	8,300	3.42	5.36	13.91	25	127.3
Battery	10	10	10	1,900	83% (h)	0.00	0.00	38.99	25	156.6

Notes:
(a) Installed cost, capability and heat rate numbers have been rounded
(b) All costs in 2019 dollars, except as noted.
(c) $/kW costs are based on summer capability
(d) All Capabilities are at 1,000 feet above sea level
(e) Total Plant Investment Cost w/AFUDC (AEP-East rate of 5.5%,site rating $/kW)
(f) Levelized cost of energy based on capacity factors shown in table
(g) Includes SCR environmental installation
(h) Denotes efficiency, (w/ power electronics)

Exhibit C Schedules

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View) Schedule 1

PEAK LOAD AND ENERGY FORECAST

	(ACTUAL)			(PROJECTED)														
1. Peak Load (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PJM Coincident Internal Load [4,5]	n/a	n/a	n/a	5,470	5,451	5,475	5,508	5,514	5,519	5,521	5,528	5,537	5,550	5,558	5,565	5,577	5,595	5,607
A. Summer																		
1. Base Forecast [1]	-	-	-	5,687	5,678	5,681	5,682	5,683	5,689	5,691	5,698	5,706	5,720	5,728	5,736	5,748	5,766	5,779
2. Conservation, Efficiency [2,6]	-	-	-	(11)	(15)	(19)	(22)	(25)	(29)	(28)	(22)	(18)	(17)	(19)	(18)	(16)	(17)	(20)
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	5,885	5,616	5,618	5,676	5,662	5,662	5,660	5,658	5,660	5,663	5,676	5,688	5,703	5,710	5,718	5,733	5,749	5,760
5. % Increase in Adjusted Load (from previous year)	2	(5)	0	1	(0)	(0)	(0)	(0)	0	0	0	0	0	0	0	0	0	0
B. Winter [3]																		
1. Base Forecast [1]	-	-	-	7,110	7,103	7,068	7,055	7,045	7,038	7,026	7,020	7,018	7,014	7,020	7,014	7,015	7,016	7,024
2. Conservation, Efficiency [2,6]	-	-	-	(13)	(19)	(24)	(27)	(30)	(33)	(32)	(26)	(22)	(21)	(22)	(21)	(19)	(21)	(25)
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	7,379	6,984	7,816	7,097	7,084	7,044	7,028	7,016	7,005	6,995	6,994	6,996	6,993	6,998	6,993	6,996	6,995	6,999
5. % Increase in Adjusted Load (from previous year)	(15)	(5)	12	(9)	(0)	(1)	(0)	(0)	(0)	(0)	(0)	0	(0)	0	(0)	0	(0)	0
2. Energy (GWh)																		
A. Base Forecast [1]	-	-	-	33,907	33,822	33,829	33,808	33,796	33,794	33,774	33,773	33,793	33,833	33,872	33,877	33,900	33,952	34,002
B. Conservation, Efficiency [2,6]	-	-	-	(82)	(118)	(147)	(174)	(204)	(236)	(232)	(193)	(163)	(147)	(145)	(128)	(96)	(97)	(103)
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	34,172	33,045	34,515	33,826	33,704	33,682	33,635	33,592	33,558	33,542	33,579	33,630	33,686	33,728	33,749	33,804	33,854	33,899
E. % Increase in Adjusted Energy (from previous year)	(2)	(3)	4	(2)	(0)	(0)	(0)	(0)	(0)	(0)	0	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) 2016 data refers to winter of 2015/2016, 2017 data refers to winter of 2016/2017, etc.
(4) Through 2022, 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) APCo is not an independent PJM member and therefore does not have actual PJM specific data.
(6) Tables reflect DSM levels consistent with 2018 Load Forecast and do not include DSM incremental to the forecast associated with Plexos IRP portfolios.
- = not available

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

GENERATION

	(ACTUAL)			(PROJECTED)														
I. SYSTEM OUTPUT(GWh)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
A. Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
B. Coal	22,121	21,040	18,695	23,730	22,984	22,922	24,708	26,322	26,191	26,322	26,000	26,367	21,217	20,512	19,977	20,954	21,560	21,958
C. Heavy Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Light Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E. Natural Gas	4,364	4,144	4,949	4,517	4,177	3,681	3,759	3,909	3,992	3,667	3,863	3,479	4,159	4,030	3,985	3,712	3,765	3,280
F. Hydro-Conventional[1]	848	716	959	825	863	861	860	860	861	860	860	769	641	641	641	641	641	641
G. Hydro-Pumped Storage & Battery	509	419	515	639	642	656	644	656	645	638	665	693	741	747	741	737	742	734
H. Renewable Resources[2]	967	965	1,296	1,336	1,340	1,371	1,436	2,696	2,714	2,710	2,714	3,066	3,242	3,654	4,032	4,220	4,590	4,928
I. Total Generation (sum of A through H)	28,809	27,285	26,414	31,047	30,005	29,490	31,408	34,443	34,403	34,198	34,103	34,373	30,000	29,584	29,377	30,265	31,298	31,541
J. Purchased and Interchange Received																		
1. Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Total DSM[5]	-	-	-	82	185	215	433	604	776	708	647	584	519	434	373	300	238	188
3. Other[3]	1,486	1,873	1,915	1,616	1,569	1,567	1,660	1,701	1,730	1,751	1,743	1,779	1,464	1,427	1,377	1,344	1,357	1,343
K. Pumping/Charging Energy	544	467	479	766	770	786	772	786	765	763	796	841	907	913	907	904	906	899
L. Net Market Purchase/(Sale)[4]	4,421	4,353	6,664	1,928	2,832	3,343	1,079	(2,168)	(2,350)	(2,119)	(1,925)	(2,101)	2,757	3,339	3,658	2,896	1,963	1,828
M. Total System Firm Energy Requirements	34,172	33,045	34,515	33,907	33,822	33,829	33,808	33,796	33,794	33,774	33,773	33,793	33,833	33,872	33,877	33,900	33,952	34,002

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 2016-2033.
(4) Includes net sales or purchases with other electric utilities 2016-2033.
(5) Includes Embedded EE, Incremental EE, and DG

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

GENERATION

	(ACTUAL)			(PROJECTED)														
III. SYSTEM OUTPUT MIX (%) [1]	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
A. Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
B. Coal	65	64	54	70	68	68	73	78	78	78	77	78	63	61	59	62	64	65
C. Heavy Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Light Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E. Natural Gas	13	13	14	13	12	11	11	12	12	11	11	10	12	12	12	11	11	10
F. Hydro-Conventional	2	2	3	2	3	3	3	3	3	3	3	2	2	2	2	2	2	2
G. Hydro-Pumped Storage	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
H. Renewable Resources	3	3	4	4	4	4	4	8	8	8	8	9	10	11	12	12	14	14
I. Total Generation (sum of A through H)	84	83	77	92	89	87	93	102	102	101	101	102	89	87	87	89	92	93
J. Purchased and Interchange Received																		
1. Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Total DSM [3]	-	-	-	0	1	1	1	2	2	2	2	2	2	1	1	1	1	1
3. Other	4	-	-	5	5	5	5	5	5	5	5	5	4	4	4	4	4	4
K. Energy for Pumping	-	-	-	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)	(3)
L. Other Sales	13	13	19	6	8	10	3	(6)	(7)	(6)	(6)	(6)	8	10	11	9	6	5
IV. SYSTEM LOAD FACTOR (%) [2]	53	54	50	55	54	55	55	55	55	55	55	55	55	55	55	55	55	55

(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)	(ACTUAL)[1] 2016	2017	2018	(PROJECTED) 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
1. Summer PJM Capacity (ICAP)[5]																		
A. Installed Dependable Capability[1,2]	7,016	6,997	6,967	7,035	7,035	7,035	7,035	7,035	7,035	7,035	6,580	6,488	6,476	6,460	6,446	6,446	6,446	6,446
B. Total Positive Interchange Commitments[3]	26	26	21	(6)	22	22	22	22	22	22	22	22	22	22	22	22	22	22
C. Capability in Cold Reserve Status	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Total Installed Capacity (ICAP)	7,042	7,023	6,988	7,029	7,057	7,057	7,057	7,057	7,057	7,057	6,602	6,510	6,498	6,482	6,468	6,468	6,468	6,468
E. Total Unforced Capacity UCAP[4]	6,573	6,573	6,506	6,091	6,320	6,320	6,320	6,320	6,320	6,320	5,918	5,835	5,823	5,807	5,793	5,793	5,793	5,793
2. Winter PJM Capacity (ICAP)[5,6]																		
A. Installed Net Dependable Capability[1,2]	7,016	6,997	6,967	7,035	7,035	7,035	7,035	7,035	7,035	7,035	6,580	6,488	6,476	6,460	6,446	6,446	6,446	6,446
B. Total Positive Interchange Commitments[3]	26	26	21	(6)	22	22	22	22	22	22	22	22	22	22	22	22	22	22
C. Capability in Cold Reserve Status	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Total Installed Capacity (ICAP)	7,042	7,023	6,988	7,029	7,057	7,057	7,057	7,057	7,057	7,057	6,602	6,510	6,498	6,482	6,468	6,468	6,468	6,468
F. $EFOR_D$				13.70	10.48	10.48	10.48	10.48	10.48	10.48	10.40	10.41	10.43	10.45	10.47	10.47	10.47	10.47
E. Total Unforced Capacity UCAP[4]	6,573	6,573	6,506	6,091	6,320	6,320	6,320	6,320	6,320	6,320	5,918	5,835	5,823	5,807	5,793	5,793	5,793	5,793

(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)	(ACTUAL)			(PROJECTED)														
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
1. Summer																		
A. Adjusted Summer Peak [1]	5,885	5,616	5,618	5,676	5,662	5,662	5,660	5,658	5,660	5,663	5,676	5,688	5,703	5,710	5,718	5,733	5,749	5,760
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	5,885	5,616	5,618	5,676	5,662	5,662	5,660	5,658	5,660	5,663	5,676	5,688	5,703	5,710	5,718	5,733	5,749	5,760
D. Percent Increase in Total Summer Peak	2	(5)	0	1	(0)	(0)	(0)	(0)	0	0	0	0	0	0	0	0	0	0
2. Winter [3]																		
A. Adjusted Winter Peak [1]	7,379	6,984	7,816	7,097	7,084	7,044	7,028	7,016	7,005	6,995	6,994	6,996	6,993	6,998	6,993	6,996	6,995	6,999
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	7,379	6,984	7,816	7,097	7,084	7,044	7,028	7,016	7,005	6,995	6,994	6,996	6,993	6,998	6,993	6,996	6,995	6,999
D. Percent Increase in Total Winter Peak	(15)	(5)	12	(9)	(0)	(1)	(0)	(0)	(0)	(0)	(0)	0	(0)	0	(0)	0	(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) 2016 data refer to winter of 2015/2016, 2017 data refer to winter of 2016/2017, 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	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
(Including Cold Reserve Capability) [1]																		
1. Summer Reserve Margin																		
A. MW (ICAP)	1,158	1,407	1,371	1,353	1,394	1,395	1,397	1,399	1,397	1,394	926	822	795	772	750	735	719	708
B. Percent of Load	19.7	25.1	24.4	23.8	24.6	24.6	24.7	24.7	24.7	24.6	16.3	14.5	13.9	13.5	13.1	12.8	12.5	12.3
2. Winter Reserve Margin [2]																		
A. MW (ICAP)	(337)	39	(827)	(68)	(27)	13	29	41	52	62	(392)	(485)	(495)	(517)	(525)	(528)	(527)	(531)
B. Percent of Load	(5)	1	(11)	(1)	(0)	0	0	1	1	1	(6)	(7)	(7)	(7)	(8)	(8)	(8)	(8)
II. Reserve Margin																		
(Excluding Cold Reserve Capability) [3]																		
1. Summer Reserve Margin																		
A. MW (ICAP)	1,158	1,407	1,371	1,353	1,394	1,395	1,397	1,399	1,397	1,394	926	822	795	772	750	735	719	708
B. Percent of Load	19.7	25.1	24.4	23.8	24.6	24.6	24.7	24.7	24.7	24.6	16.3	14.5	13.9	13.5	13.1	12.8	12.5	12.3
2. Winter Reserve Margin [2]																		
A. MW (ICAP)	(337)	39	(827)	(68)	(27)	13	29	41	52	62	(392)	(485)	(495)	(517)	(525)	(528)	(527)	(531)
B. Percent of Load	(5)	1	(11)	(1)	(0)	0	0	1	1	1	(6)	(7)	(7)	(7)	(8)	(8)	(8)	(8)
III. Annual Loss-of-Load Hours [4]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

(1) Calculated based on Total Net Capability for summer and winter.
(2) 2016 data refers to winter of 2015/2016, 2017 data refers to winter of 2016/2017, 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]	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
A. Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
B. Coal	4,576	4,576	4,576	4,616	4,616	4,616	4,616	4,616	4,616	4,616	4,616	4,616	4,616	4,616	4,616	4,616	4,616	4,616
C. Heavy Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Light Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E. Natural Gas	1,613	1,594	1,594	1,477	1,477	1,477	1,477	1,477	1,477	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022
F. Hydro-Conventional	281	281	281	281	281	281	281	281	281	281	281	201	201	201	201	201	201	201
G. Pumped/Battery Storage	615	615	585	585	585	595	595	595	595	595	595	595	595	595	595	595	595	595
H. Wind	376	376	495	495	495	495	495	795	795	795	795	795	795	520	420	420	420	420
I. Solar	-	-	-	0	0	15	15	165	165	165	165	315	465	765	1,065	1,215	1,365	1,515
J. Demand-Side [4]	-	-	-	117	116	116	152	214	242	234	227	219	211	199	192	182	175	170
K. Purchases	26	21	21	-6	22	22	22	22	22	22	22	22	22	22	22	22	22	22
L. Total (sum of A through K)	7,487	7,463	7,552	7,565	7,592	7,617	7,653	8,165	8,193	7,730	7,723	7,785	7,927	7,940	8,133	8,273	8,416	8,561
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	61.12	61.31	60.59	61.02	60.80	60.60	60.32	56.54	56.34	59.72	59.77	59.29	58.23	58.13	56.76	55.79	54.85	53.92
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	21.54	21.36	21.11	19.52	19.45	19.39	19.30	18.09	18.03	13.22	13.23	13.13	12.89	12.87	12.57	12.35	12.14	11.94
F. Hydro-Conventional	3.76	3.77	3.72	3.72	3.70	3.69	3.67	3.44	3.43	3.64	3.64	2.58	2.54	2.53	2.47	2.43	2.39	2.35
G. Pumped Storage	8.21	8.24	7.75	7.73	7.71	7.81	7.77	7.29	7.26	7.70	7.70	7.64	7.51	7.49	7.32	7.19	7.07	6.95
H. Wind	5.02	5.04	6.55	6.54	6.52	6.49	6.46	9.73	9.70	10.28	10.29	10.21	10.03	6.55	5.16	5.07	4.99	4.90
I. Solar	0.00	0.00	0.00	0.00	0.00	0.20	0.20	2.02	2.01	2.13	2.14	4.05	5.87	9.63	13.09	14.69	16.22	17.70
J. Demand-Side [4]	0.00	0.00	0.00	1.55	1.53	1.52	1.99	2.62	2.95	3.03	2.94	2.82	2.66	2.51	2.36	2.20	2.08	1.98
K. Purchases	0.35	0.28	0.28	-0.08	0.29	0.29	0.29	0.27	0.27	0.28	0.28	0.28	0.28	0.28	0.27	0.27	0.26	0.26

(1) 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.

COMPANY NAME: AEP SYSTEM - EAST ZONE

UNIT PERFORMANCE DATA

Equivalent Availability Factor (%) [1]

Schedule 8

CONFIDENTIAL

	(ACTUAL)			(PROJECTED)														
Unit Name	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Amos 1	[redacted]																	
Amos 2	[redacted]																	
Amos 3	[redacted]																	
Ceredo 1	[redacted]																	
Ceredo 2	[redacted]																	
Ceredo 3	[redacted]																	
Ceredo 4	[redacted]																	
Ceredo 5	[redacted]																	
Ceredo 6	[redacted]																	
Clinch River 1	[redacted]																	
Clinch River 2	[redacted]																	
Mountaineer 1	[redacted]																	
Dresden	[redacted]																	

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

-= not available

COMPANY NAME: AEP SYSTEM - EAST ZONE
UNIT PERFORMANCE DATA
Net Capacity Factor (%) [1]

Schedule 9
CONFIDENTIAL

	(ACTUAL)			(PROJECTED)														
Unit Name	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
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																		

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

COMPANY NAME: AEP SYSTEM - EAST ZONE
UNIT PERFORMANCE DATA
Average Heat Rate - (Btu/kWh) [1]

Schedule 10
CONFIDENTIAL

	(ACTUAL)			(PROJECTED)														
Unit Name	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Amos 1	[redacted]																	
Amos 2	[redacted]																	
Amos 3	[redacted]																	
Ceredo 1	[redacted]																	
Ceredo 2	[redacted]																	
Ceredo 3	[redacted]																	
Ceredo 4	[redacted]																	
Ceredo 5	[redacted]																	
Ceredo 6	[redacted]																	
Clinch River 1	[redacted]																	
Clinch River 2	[redacted]																	
Mountaineer 1	[redacted]																	
Dresden	[redacted]																	

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

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View)
RENEWABLE 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) 2016	(ACTUAL) 2017	(ACTUAL) 2018
Wind	Camp Grove	01/18/08	Purchase	20 years	75	12	202,649	207,331	193,068
	Fowler Ridge 3	02/27/09	Purchase	20 years	99	13	238,278	210,431	219,415
	Grand Ridge 2-3	12/21/09	Purchase	20 years	101	16	251,015	267,767	232,879
	Beech Ridge	06/01/10	Purchase	20 years	101	14	274,621	279,778	279,635
	Bluff Point	01/01/18	Purchase	20 years	120	24	-	-	370,974
	New	Varies	Owned	30 years	Varies	Varies			
Wind Subtotal					495	78	966,563	965,307	1,295,921
Solar	Distributed	-	-	-	-	-	-	-	-
	Depot	Dec/2020	Purchase	20 years	15	8	-	-	-
	New Large-Scale	Varies	-	30 years	Varies	Varies	-	-	-
Solar Subtotal					15	8	-	-	-
Total Renewables					510	86	966,563	965,307	1,295,921

Resource Type [1]	Unit Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
		(PROJECTED)														
Wind	Camp Grove	208,089	208,816	208,089	208,089	208,089	208,816	208,089	208,089	208,089	22,812	0	0	0	0	0
	Fowler Ridge 3	239,308	240,112	239,308	239,308	239,308	240,112	239,308	239,308	239,308	240,112	50,368	0	0	0	0
	Grand Ridge 2-3	256,129	257,040	256,129	256,129	256,129	257,040	256,129	256,129	256,129	257,040	191,324	0	0	0	0
	Beech Ridge	244,867	245,835	244,867	244,867	244,867	245,835	244,867	244,867	244,867	245,835	244,867	164,380	0	0	0
	Bluff Point	387,175	388,468	387,175	387,175	387,175	388,468	387,175	387,175	387,175	388,468	387,175	387,175	387,175	388,468	387,175
	New	0	0	0	0	906,529	908,949	906,529	906,529	906,529	908,949	906,529	906,529	906,529	908,949	906,529
Wind Subtotal		1,335,568	1,340,271	1,335,568	1,335,568	2,242,097	2,249,220	2,242,097	2,242,097	2,242,097	2,063,216	1,780,263	1,458,084	1,293,704	1,297,417	1,293,704
Solar	Distributed	0	0	0	64,703	71,173	81,198	85,731	90,584	95,436	99,061	105,142	111,612	118,082	125,044	132,641
	Depot	0	0	35,792	35,613	35,435	35,342	35,082	34,906	34,732	34,641	34,385	34,213	34,042	33,953	33,703
	New Large-Scale	0	0	0	0	346,825	348,222	346,825	346,825	693,650	1,044,665	1,734,124	2,427,774	2,774,599	3,133,998	3,468,248
Solar Subtotal		-	-	35,792	100,316	453,433	464,762	467,638	472,315	823,818	1,178,367	1,873,651	2,573,599	2,926,723	3,292,993	3,634,592
Total Renewables		1,335,568	1,340,271	1,371,360	1,435,884	2,695,530	2,713,982	2,709,735	2,714,412	3,065,915	3,241,583	3,653,914	4,081,683	4,220,427	4,590,410	4,928,296

(1) Per definition of 56-576 of the code of Virginia.
(2) Commercial operation date.
(3) Describe as Company built or purchase.
(4) State expected life of facility or duration of purchase contract.
(5) Net dependable capacity (summer).
- = not available

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

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

Program Type	Program Name	Date (3)	Life/ Duration (4)	Size (MW) (5)	(ACTUAL) (6) 2016	2017	2018	(PROJECTED) (6) 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
EE (1)	Current Programs	06/12/2016	10	19	34,566	54,681	43,297	81,798	118,011	147,434	124,358	73,626	48,061	25,119	16,193	8,850	3,073	762	-	-	-	-
EE (2)	Residential Lighting	01/01/2022	30	13.6				-	-	-	78,000	149,569	214,200	194,780	173,816	152,614	130,878	108,098	85,938	64,569	45,494	29,495
EE (2)	Residential Water Heating	01/01/2022	10	27.7				-	-	-	34,000	65,043	91,035	87,851	82,248	76,551	69,003	47,866	44,113	32,600	26,403	22,672
EE (2)	Residential Applicances	01/01/2022	16	6.9				-	-	-	18,000	34,373	49,300	46,370	43,795	40,556	36,777	31,800	26,768	20,733	15,250	10,523
EE (2)	Commercial/Ind. Lighting - Screw-In	01/01/2022	6	2.2				-	-	-	13,000	24,948	34,425	28,305	22,005	15,930	10,395	5,806	2,475	585	-	-
EE (2)	Commercial/Ind. Lighting - Fluorescent	01/01/2022	13	54.7				-	-	-	85,000	164,433	236,300	223,670	209,017	192,396	174,192	148,977	125,870	98,350	72,448	50,134
EE (2)	Commercial/Ind. Lighting - Outdoor	01/01/2022	15	8.5				-	-	-	13,000	25,083	35,700	34,130	32,066	29,544	27,423	23,686	20,046	15,570	11,496	7,974
EE (2)	VVO	01/01/2020	15	17.0				-	67,361	67,361	67,361	67,361	67,361	67,361	67,361	67,361	67,361	67,361	67,361	67,361	67,361	67,361
Subtotal				150	34,566	54,681	43,297	81,798	185,372	214,796	432,719	604,436	776,382	707,587	646,501	583,803	519,103	434,355	372,571	299,768	238,452	188,159
DR	PSEDR	06/12/2015	15	8		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	Interruptible	06/12/2015	15	13		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	ATOD	06/12/2015	15	78		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal				99	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Demand Side Management				249	34,566	54,681	43,297	81,798	185,372	214,796	432,719	604,436	776,382	707,587	646,501	583,803	519,103	434,355	372,571	299,768	238,452	188,159

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) Average life of measures that constitute programs.

5) Demand impacts for EE programs reflect 2033 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]

Unit Name	2016 (ACTUAL)	2017 (ACTUAL)	2018 (ACTUAL)	2019 (PROJECTED)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Amos 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amos 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amos 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ceredo 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clinch River 1 [3]	7	(12)	-	-	-	-	-	-	-	(225)	-	-	-	-	-	-	-	-
Clinch River 2 [3]	7	(7)	-	-	-	-	-	-	-	(230)	-	-	-	-	-	-	-	-
Mountaineer 1	-	-	-	31	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Buck 1 - 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Byllesby 1 - 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Claytor 1 - 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Leesville 1 - 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
London 1 - 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Marmet 1 - 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Niagara 1 - 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Winfield 1 - 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Smith Mountain 1	-	-	(4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Smith Mountain 2	-	-	(11)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Smith Mountain 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Smith Mountain 4	-	-	(11)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Smith Mountain 5	-	-	(4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dresden	-	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OVEC	-	-	-	24	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind & Solar	-	-	-	(5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-

(1) Reflects owned, active units. Combustion turbines, combined cycles and hydro plants reported as composite facilities.

(2) PJM capability as of filing. 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 2026.

COMPANY NAME: AEP SYSTEM - APCo

Schedule 14

UNIT PERFORMANCE DATA

Existing Owned Supply-Side Resources (MW) as of April 1, 2019 [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		75	
Ceredo 2	APCo	Ceredo, WV	Combustion Turbine	Gas	2001	86		75	
Ceredo 3	APCo	Ceredo, WV	Combustion Turbine	Gas	2001	86		75	
Ceredo 4	APCo	Ceredo, WV	Combustion Turbine	Gas	2001	86		75	
Ceredo 5	APCo	Ceredo, WV	Combustion Turbine	Gas	2001	86		75	
Ceredo 6	APCo	Ceredo, WV	Combustion Turbine	Gas	2001	86		75	
Clinch River 1	APCo	Carbo, VA	Steam	Gas	1958	230		225	
Clinch River 2	APCo	Carbo, VA	Steam	Gas	1958	235		230	
Dresden	APCo	Dresden, OH	Combined Cycle	Gas	2012	652		572	
Mountaineer 1	APCo	New Haven, WV	Steam	Coal - Bit.	1980	1,351		1,336	
Buck 1 - 3	APCo	Ivanhoe, VA	Hydro	--	1912	9		9	(A)
Byllesby 1 - 4	APCo	Byllesby, VA	Hydro	--	1912	22		22	(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)
						6,700		6,529	

Notes:

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

(2) Commercial operation date.

(3) Peak net dependable capability as of filing.

(A) Estimated summer net capability.

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

COMPANY NAME: AEP SYSTEM - APCo

UNIT PERFORMANCE DATA

Schedule 15

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]
Depot Solar	APCo	Campbell County, VA	Solar	Solar	Dec/2020	15	8
2023 APCo Solar	APCo	TBD	Solar	Solar	Jan/2023	150	77
2027 APCo Solar	APCo	TBD	Solar	Solar	Jan/2027	150	77
2028 APCo Solar	APCo	TBD	Solar	Solar	Jan/2028	150	77
2029 APCo Solar	APCo	TBD	Solar	Solar	Jan/2029	300	153
2030 APCo Solar	APCo	TBD	Solar	Solar	Jan/2030	300	153
2031 APCo Solar	APCo	TBD	Solar	Solar	Jan/2031	150	77
2032 APCo Solar	APCo	TBD	Solar	Solar	Jan/2032	150	77
2033 APCo Solar	APCo	TBD	Solar	Solar	Jan/2033	150	77
2023 APCo Wind	APCo	TBD	Wind	Wind	Jan/2023	300	37
2021 APCo Storage	APCo	TBD	Storage	NA	Jan/2021	10	10

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 are assumed to have a installed capacity rating of 12.3% of nameplate and solar is assumed to have 51%.

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View) Schedule 16

UTILITY CAPACITY POSITION (MW) [1]

	(ACTUAL) [2]			(PROJECTED)														
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Existing Capacity (ICAP)																		
Conventional	-	-	-	6,093	6,093	6,093	6,093	6,093	6,093	5,638	5,638	5,638	5,638	5,638	5,638	5,638	5,638	5,638
Wind				78	78	78	78	78	78	78	78	66	54	38	24	24	24	24
Hydro				866	866	866	866	866	866	866	866	786	786	786	786	786	786	786
Sales	-	-	-	(25)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	19	22	22	22	22	22	22	22	22	22	22	22	22	22	22
Total Existing Capacity	-	-	-	7,031	7,059	7,059	7,059	7,059	7,059	6,604	6,604	6,513	6,500	6,484	6,470	6,470	6,470	6,470
Planned Capacity Changes (ICAP)																		
Conventional	-	-	-	0	0	0	0	0	0	(455)	(455)	(455)	(455)	(455)	(455)	(455)	(455)	(455)
Wind				0	0	0	0	0	0	0	0	(12)	(24)	(40)	(54)	(54)	(54)	(54)
Hydro				0	0	0	0	0	0	0	0	(80)	(80)	(80)	(80)	(80)	(80)	(80)
Total Planned Capacity Changes	-	-	-	0	0	0	0	0	0	(455)	(455)	(547)	(559)	(575)	(589)	(589)	(589)	(589)
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	-	-	-	0	0	8	8	121	121	121	121	198	275	428	581	658	734	811
Battery Storage	-	-	-	0	0	10	10	10	10	10	10	10	10	10	10	10	10	10
Total Expected New Capacity	-	-	-	0	0	18	18	131	131	131	131	208	285	438	591	668	744	821
EFORd				13.70%	10.48%	10.48%	10.48%	10.48%	10.48%	10.48%	10.40%	10.41%	10.43%	10.45%	10.47%	10.47%	10.47%	10.47%
Unforced Availability (Factor)	-	-	-	13.70%	10.48%	10.48%	10.48%	10.48%	10.48%	10.48%	10.40%	10.41%	10.43%	10.45%	10.47%	10.47%	10.47%	10.47%
Net Generation Capacity (UCAP)	-	-	-	6,315	6,561	6,578	6,650	6,888	6,944	6,928	6,512	6,491	6,538	6,651	6,777	6,834	6,896	6,962
Existing DSM Reductions (ICAP) [3,5]																		
Demand response	-	-	-	117	99	99	99	99	99	99	99	99	99	99	99	99	99	99
Conservation/Efficiency	-	-	-	0	0	0	0	10	7	4	2	1	1	0	0	0	0	0
Total Existing DSM Reductions	-	-	-	117	99	99	99	109	106	103	102	100	100	99	99	99	99	99
Expected New DSM Reductions (ICAP) [3,5]																		
Demand Response	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Conservation/Efficiency/VVO (degraded)	-	-	-	0	17	17	53	86	115	109	102	95	86	73	64	53	44	37
Distributed Generation	-	-	-	0	0	0	0	18	21	22	23	24	25	27	29	30	32	34
Combined Heat and Power	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Expected New DSM Reductions	-	-	-	0	17	17	53	104	136	131	125	119	111	100	93	83	76	70
Total Demand-side Reductions (ICAP)	-	-	-	117	116	116	152	214	242	234	227	219	211	199	192	182	175	170
Net Generation & Demand-side (UCAP)	-	-	-	6,197	6,445	6,462	6,498	6,674	6,702	6,694	6,285	6,271	6,327	6,452	6,585	6,652	6,721	6,792
PJM Capacity Obligation (UCAP) [4]	-	-	-	5,960	5,936	5,959	5,996	6,003	6,009	6,011	6,018	6,028	6,043	6,051	6,059	6,072	6,091	6,105
Additional Obligation	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Obligation	-	-	-	5,960	5,936	5,959	5,996	6,003	6,009	6,011	6,018	6,028	6,043	6,051	6,059	6,072	6,091	6,105
Net Utility Capacity Position	-	-	-	238	509	504	502	671	693	683	266	244	285	401	526	580	630	688

(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 2022, 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 2018 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		
	2016	2017	2018	2019	2020	2021
I. New Traditional Generating Facilities	[redacted]					
a. Capital Investment (Exclusive of AFUDC)						
b. AFUDC						
c. Annual Total						
d. Cumulative Total						
II. New Renewable Generating Facilities[1]						
III. Other Facilities						
a. Existing Generation						
b. Transmission						
c. Distribution						
d. Energy conservation/efficiency & demand response						
e. gridSMART						
f. Other						
g. AFUDC						
h. Annual Total						
i. Cumulative Total						
IV. Total Construction Expenditures						
a. Annual Total						
b. Cumulative Total						
V. Percent of Funds for Total Construction Provided from External Financing						

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]														
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
I. Delivered Fuel Price (cents/MBtu)																		
a. Nuclear	[redacted]																	
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas																		
f. Renewable *																		
II. Primary Fuel Expenses (cents/kWh)																		
a. Nuclear																		
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas																		
f. Renewable *																		
g. Purchases Energy Charges only																		
h. Purchases Energy and Capacity Charges																		

* Per definition of 56-576 of the Code of Virginia.
(1) As consumed.

- =not available

Exhibit D Cross Reference Table

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, 5.3
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.	

Virginia - Integrated Resource Planning Guidelines Cross Reference Table | **Section/Page Reference**

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
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.	Executive Summary, Section 1.2, 3.2
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.	Section 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 3, 5, 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 the projected effects of incremental demand-side options on the forecasted annual energy and peak loads, and	Section 2; Schedule 1
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, 5; Schedules 13, 14

Virginia - Integrated Resource Planning Guidelines Cross Reference Table	Section/Page Reference
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

Virginia - Integrated Resource Planning Guidelines Cross Reference Table	Section/Page Reference
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	
Integrated resource plan shall consider options for maintaining and enhancing rate stability	Sections 1.3, 5.2.2.3, and 5.4.2
Integrated resource plan shall consider options for maintaining and enhancing energy independence	Sections 1.3, and 6.0
Integrated resource plan shall consider options for maintaining and enhancing economic development including retention and expansion of energy-intensive industries	Sections 1.3 and 2.8
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	Sections 5.2.2.1, 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	Section 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	Section 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 3.4.5
Include a detailed analysis of the load characteristics of net metering customers and the generation-related impacts of customer generation	Section 3.4.5
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.	

Virginia - Integrated Resource Planning Guidelines Cross Reference Table	Section/Page Reference
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 5.2.2.3, 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;	Executive Summary, Sections 1.3, 5.3, and 6
Request Commission approval of $140 million in EE programs over ten years, customers over	Executive Summary, Sections 1.3, 4.4.3.1, 5.3, and 6
Invest in up to 10MWs of new battery storage installations as part of a five-year battery pilot program; and	Executive Summary, Sections 1.3, 5.3, and 6
Systematically evaluate and consider proposing long-term electric distribution grid planning and proposed electric distribution grid transformation projects	Section 3.6
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.	Section 5.3
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.	Section 5.3
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 5.2.2.1, 5.3
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.	Section 5.3.1
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 5.2.2.2