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April 29, 2016

The Honorable Joel H. Peck, Clerk
State Corporation Commission
Document Control Center
1300 East Main Street, First Floor
Richmond, Virginia 23218

Re: Commonwealth of Virginia, ex rel. State Corporation Commission
In re: Appalachian Power Company's Integrated Resource Plan pursuant to Virginia Code § 56-597 et seq., Case No. PUE-2016-00050

Dear Mr. Peck:

Pursuant to §§56-597 through 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 (15) copies of the 2016 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 herewith 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.

APCo suggests that the public notice be published on one occasion in newspapers of general circulation throughout the Company's service territory within Virginia and that a time interval of approximately four weeks each be used 1) from the date that the Commission enters a procedural order directing APCo to publish the notice until the publication deadline, and 2) from the notice publication date until the filing deadline for comments, notices of participation and requests for hearing.

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 recent amendments to § 56-599 of the Code (2015 Acts of Assembly, Chapt. 6).

Thank you for your assistance in this matter.

Sincerely,

John K. Byrum, Jr.

Enclosures

cc: William H. Chambliss, General Counsel

NOTICE TO THE PUBLIC OF
A FILING BY APPALACHIAN POWER COMPANY OF AN
INTEGRATED RESOURCE PLAN
CASE NO. PUE-2016-00050

On April 29, 2016, Appalachian Power Company (Appalachian 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 957,000 retail electric customers in Virginia, West Virginia, and Tennessee, and that the Company's combined service territory in these three states covers approximately 19,260 square miles.

APCo states that its IRP, based upon various assumptions, provides for adequate capacity resources, at reasonable cost, through a combination of supply-side resources, renewable supply and demand-side programs through the forecast period. According to the Company, the IRP encompasses the 15-year planning period from 2016 to 2030 and is based on the Company's current assumptions regarding customer load requirements, commodity price projections, supply side alternative costs, and demand side management program costs and analysis.

APCo states in its filing that the Company's IRP process attempts to strike a balance among various factors, including rate stability, energy independence, economic development, service reliability, and compliance options to minimize the effects on customer rates of pending implementation of state and federal environmental regulations. According to the Company, the resource planning process is becoming increasingly complex in light of technology advancement, changing energy supply pricing fundamentals, uncertainty of demand, end-use efficiency improvements and pending regulatory restrictions, including implementation of proposals to control greenhouse gases, particularly regulation by the United States Environmental Protection Agency ("EPA") to control carbon dioxide emissions from existing electric generation units under Section 111(d) of the Clean Air Act (Clean Power Plan or CPP).

The 2015 Session of the Virginia General Assembly enacted legislation ("2015 Amendments") that, among other things, amended the IRP statutes to require that IRPs evaluate 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 the most cost-effective means of complying with current and pending environmental regulations. The Company indicates that its IRP filing conforms to the requirements of the IRP statutes, as modified by the 2015 Amendments, as well as requirements enumerated by the Commission in its February 1, 2016 Final Order in Case No. PUE-2015-00036.

The Commission entered an Order for Notice and Hearing that, among other things, scheduled a public hearing on ___________, 2016, at ___:___a.m., in the Commission's second floor courtroom located in the Tyler Building, 1300 East Main Street, Richmond, Virginia 23219, to receive testimony from members of the public and evidence related to the IRP from the Company, any respondents, and the Commission's Staff. Any person desiring to testify as a public witness at this hearing should appear fifteen (15) minutes prior to the starting time of the hearing and contact the Commission's Bailiff. Individuals with disabilities who require an accommodation to participate in the hearing should contact the Commission at least seven (7) days before the scheduled hearing at 1-800-552-7945.

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, John K. Byrum, Jr., Esquire, Woods Rogers PLC, Riverfront Plaza, West Tower, 901 East Byrd Street, Suite 1550, 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 documents filed in this case also are 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.

Any person or entity may participate as a respondent in this proceeding by filing, on or before __________, 2016, a notice of participation. If not filed electronically, an original and fifteen (15) copies of the notice of participation shall be submitted to Joel H. Peck, Clerk, State Corporation Commission, c/o Document Control Center, P.O. Box 2118, Richmond, Virginia 23218-2118. 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, 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. All filings shall refer to Case No. PUE-2016-00050. 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.

On or before ________, 2016, each respondent may file with the Clerk of the Commission, and serve on the Commission's Staff, the Company, and all other respondents, any testimony and exhibits by which the respondent expects to establish its case, and each witness's testimony shall include a summary not to exceed one page. If not filed electronically, an original and fifteen (15) copies of such testimony and exhibits shall be submitted to the Clerk of the Commission at the address set forth above. Respondents also shall comply with the Commission's Rules of Practice and Procedure, including, but not limited to: 5 VAC 5 20 140, Filing and service; 5 VAC 5-20-150, Copies and format; and 5 VAC 5-20-240, Prepared testimony and exhibits. All filings shall refer to Case No. PUE-2016-00050.

On or before ________, 2016, any interested person wishing to comment on the Company's IRP shall file written comments on the IRP with the Clerk of the Commission at the address set forth above. Any interested person desiring to file comments electronically may do so on or before ________, 2016, by following the instructions on the Commission's website: http://www.scc.virginia.gov/case. Compact discs or any other form of electronic storage medium may not be filed with the comments. All such comments shall refer to Case No. PUE-2016-00050.

The Commission's Rules of Practice and Procedure may be viewed at http://www.scc.virginia.gov/case. A printed copy of the Commission's Rules of Practice and Procedure 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.

AEP APPALACHIAN POWER®

A unit of American Electric Power

INTEGRATED RESOURCE PLANNING REPORT TO THE COMMONWEALTH OF VIRGINIA STATE CORPORATION COMMISSION

PUE-2016-00050

PUBLIC VERSION

April 29, 2016

APPALACHIAN POWER

A unit of American Electric Power

INTEGRATED RESOURCE PLANNING REPORT

TO THE

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

April 29, 2016

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Executive Summary

This Integrated Resource Plan (IRP, Plan, or Report) is submitted by Appalachian Power Company (APCo or Company) based upon the best information available at the time of preparation. However, changes that impact this Plan can occur without notice. Therefore this Plan is not a commitment to specific resource additions or other courses of action, since the future is highly uncertain, particularly in light of current economic conditions, the movement towards increasing use of renewable generation and end-use efficiency, as well as current and future environmental regulations, including the U.S. Environmental Protection Agency's (EPA) Final Clean Power Plan (CPP).

In accordance with the Virginia State Corporation Commission's (Commission or SCC) February 1, 2016 Order in APCo's 2015 IRP case (2016 Final Order), and recognizing the many uncertainties, this IRP provides useful information to assess potential approaches for compliance with, and the possible costs and rate impacts of the CPP. The specific locations within this IRP filing, which respond to each bulleted requirement in the 2016 Final Order, appear both at the end of this Executive Summary, in Table ES-2, and in the Appendix as part of APCo's larger index (Exhibit D).

As in past IRP filings, APCo faced a number of other dynamic circumstances as it developed the assumptions and analyses outlined in this IRP. For example, on June 9, 2015, the Federal Energy Regulatory Commission (FERC) issued an order pertaining to PJM's proposed Capacity Performance construct, thereby providing guidance to PJM on its capacity market proposals. While this Report incorporates the Company's expectations regarding Capacity Performance, APCo will continue to evaluate the impact of the FERC order, as it takes effect June 1, 2016. Further, FERC allowed an exemption from the Capacity Performance rules for companies which utilize the Fixed Resource Requirement (FRR) (i.e. self-supply) alternative through 2018/19. APCo has elected the FRR alternative to fulfill its capacity obligations through 2019/20. Thus, this IRP and the action items described herein are subject to change as new information becomes available or as circumstances warrant.

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 period (in this filing, 2016-2030). This IRP has been developed using the Company's current long-term assumptions for:

- Customer load requirements – peak demand and energy;
- commodity prices – coal, natural gas, on-peak and off-peak power prices, capacity and emission prices;
- supply-side alternative costs – including fossil fuel and renewable generation resources; and
- demand-side program costs and impacts.

In addition, APCo considered the effect of environmental rules and guidelines, such as the CPP, which could add significant costs and present significant challenges to operations. The CPP is still being reviewed by the courts, and individual state plans to implement it may not be finalized –let alone approved - for a number of years. In preparing this Report, APCo has analyzed multiple scenarios, with differing commodity pricing conditions, as well as multiple internal load conditions. APCo has also conducted analyses which specifically address certain aspects of compliance with the CPP, per the 2016 Final Order.

To meet its customers' future 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) and combustion turbine (Ceredo) units, and two units at Clinch River, which were recently converted from coal to natural gas. 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 rule will take full effect, potentially limiting the capacity value of intermittent resources, such as run-of-river hydro, wind, solar, as well as pumped storage,[1] thereby creating a greater future need within APCo for additional capacity. Keeping these considerations in mind, APCo has developed an IRP that provides adequate supply and demand resources to meet peak load obligations for the next fifteen years. The key components of this Plan are for APCo to:

- Continue to diversify its mix of supply-side resources through the addition of cost-effective wind, large-scale solar, and natural gas-fired generation resources, as necessary;
- incorporate demand-side resources, including but not limited to additional Energy Efficiency (EE) programs and Volt VAR Optimization (VVO) installations; and
- recognize that residential and commercial customers will add distributed resources, primarily in the form of residential and commercial rooftop solar.

The Clean Power Plan (CPP) and APCo's Preliminary Modeling Assessment

On October 23, 2015, EPA published a final rule – the Clean Power Plan or CPP - in the *Federal Register* establishing carbon dioxide (CO_2) emission guidelines for existing fossil fueled electric generating units under Section 111(d) of the Clean Air Act. The CPP established interim and final uniform national emission standards for two subcategories of generating units: (1) fossil-fueled electric steam generating units; and (2) natural gas-fired combined-cycle units. EPA also determined equivalent state-specific CO_2 emission rate-based goals and mass-based goals. The interim goals decline over the period from 2022-2029, with final goals effective in 2030 and beyond.

The CPP requires states to develop plans to implement the national uniform CO_2 emission standards or state goals, and to submit a final state plan or a request for extension by September 6, 2016. Twenty-seven states, many utilities, coal producers, unions, national business

[1]The FERC's June 9, 2015 Capacity Performance Order indicates that there may be a further opportunity to aggregate the capacity value of some of these intermittent resources.

associations and other interested parties challenged the final rule, and sought to stay its implementation pending judicial review. Although the D.C. Circuit denied these motions for stay, on February 9, 2016, the U.S. Supreme Court granted the applications, staying implementation of the CPP during review by the D.C. Circuit and any subsequent petitions for review by the Supreme Court.

Despite the fact that the CPP has been stayed, The Governor of Virginia has announced that the Commonwealth will proceed with efforts to develop a state plan. Given this announcement, as well as the uncertainty of the outcome in the courts, APCo will continue to consider strategies to comply with the CPP and emerging state and/or federal compliance plans. Manifestly, such strategies will be strongly influenced by the resolution of the pending litigation and the development of various state plans. Particularly for multi-state utilities like APCo, it will be critical to leverage the investments in and operations of utility assets across multiple jurisdictions. APCo has used the model EPA rules to inform its preliminary examination of compliance options, but the final emission guidelines provide a wide range of program design options for the states. The choices states will make about whether to use a rate-based or mass-based compliance methodology, whether to allow interstate trading of compliance instruments, which activities or facilities will be eligible to receive credits or allowances, how such credits or allowances will be distributed, and many other issues will have a profound impact on the costs of compliance. Additionally, many states, including those in which APCo has operations or facilities, are deferring plan development while the stay remains in effect. At this time, there is limited information available about which options may be pursued by each of those states, if the CPP is ultimately implemented.

As the Commission directed in its 2016 Final Order, APCo performed preliminary analyses that addressed multiple potentially CPP-compliant plans. In order to establish a baseline, APCo also modeled another view assuming no CPP impact. As the Commission suggested, the suite of modeling performed was based on a host of assumptions that may or may not be applicable depending upon the ultimate outcome of the CPP. Given that, these analyses should be considered as quite preliminary, but informative, analyses that will certainly be subject to change over time.

The following initial observations can be drawn from these analyses:

- A CPP-compliant resource plan could result in incremental costs to APCo in the range of approximately $300 million to $600 million;
- there are likely no material cost differences between a "mass-based" or a "rate-based" compliance approach;
- an approach that assumes an interstate-market for trading of allowances (or emission reduction credits) appears preferable to APCo being essentially self-compliant as "an island," as the latter view could result in incremental costs to APCo of approximately $200 to $400 million; and
- a federal plan based upon the model rule could result in higher incremental costs, when compared to the presumed state plan, of up to $400 million.

Additional supporting information pertaining to these initial observations, as well as the Company's response to other requests for information and comments pertaining to the Commission's 2016 Final Order can be found in Section 5 of this Report and is cross-referenced at the end of this Executive Summary in Table ES-2.

Summary of APCo Resource Plan

APCo's total internal energy requirements are forecasted to increase at a compound average growth rate (CAGR) of 0.3% through 2030. APCo's peak internal demand is forecasted to increase at a CAGR of 0.3%, with annual peak demand expected to continue to occur in the winter season through 2030. Figure ES-1, below, shows APCo's "going-in" (i.e. *before* resource additions) capacity position over the planning period. Through 2019, APCo has capacity resources to meet its forecasted internal demand, but, in 2020 APCo is anticipated to experience a capacity shortfall based upon APCo's assumptions regarding the timing and parameters of

PJM's Capacity Performance rule, which is evident from the (slight) gap between the stacked bar of available resources and the black line representing APCo's load demand, plus PJM reserve margin requirements.

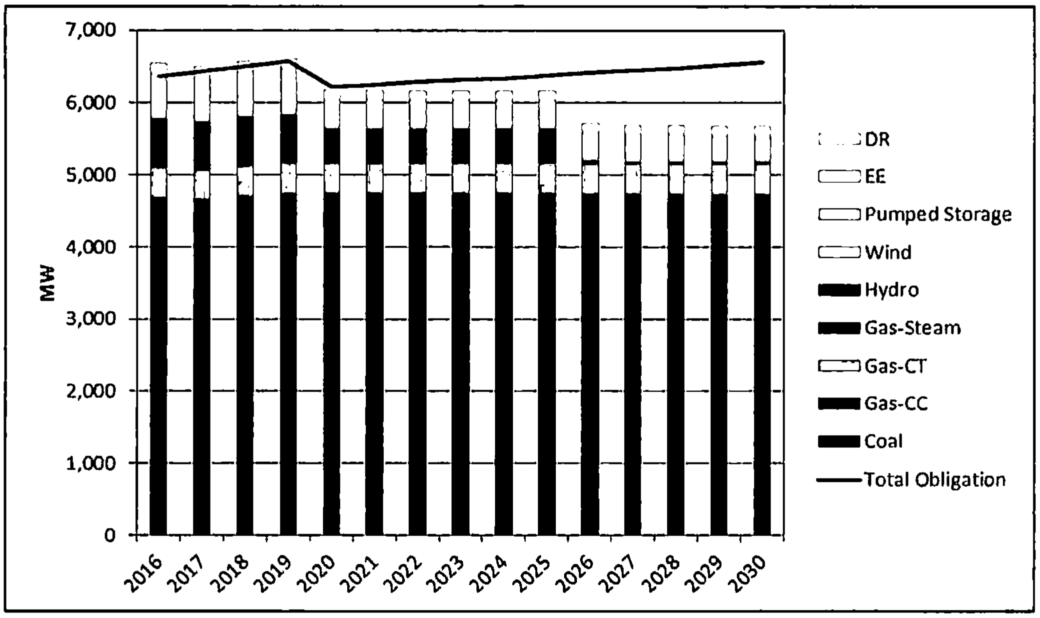

Figure ES-1. APCo "Going-In" PJM Capacity Position (MW)

To determine the appropriate level and mix of incremental supply-side and demand-side resources required to address the indicated going-in capacity deficiencies, APCo utilized the *Plexos®* Linear Program optimization model to develop least cost resource portfolios under a variety of pricing and load scenarios. Although the IRP planning period is limited to 15 years (through 2030), the *Plexos®* modeling was performed through the year 2035, so as to properly consider various cost-based "end-effects" for the resource alternatives being considered.

APCo used the results of the modeling to develop a "Hybrid Plan." To arrive at the Hybrid Plan composition, APCo developed *Plexos®*-derived, "optimum" portfolios under four long-term commodity price forecasts, and two "load sensitivity" forecasts. The Hybrid Plan is presented as an option that attempts to balance cost and other factors while meeting APCo's peak load obligations. In addition, this IRP considers existing and future environmental requirements, including those that may result from the CPP, and the practical limitations of customer self-generation.

In summary, the Hybrid Plan:

- Adds 20MW (nameplate) of large-scale solar energy by 2018, with subsequent additions throughout the planning period, for a total of 590MW (nameplate) by 2030;
- adds 300MW wind energy by 2018, followed by 150 to 300 MW additions throughout the planning period, for a total of 1800MW (nameplate) of wind over the 15-year planning period;
- implements customer and grid EE programs, including VVO, reducing energy requirements by 1,161GWh) and capacity requirements by 203MW by 2030;
- assumes APCo's customers add distributed generation (DG) (i.e. rooftop solar) capacity totaling over 60MW (nameplate) by 2030. (Note 1);
- adds 10MW (nameplate) of battery storage resources in 2025;
- assumes a host facility is identified such that a Combined Heat and Power (CHP) project can be implemented by 2020; and
- addresses expected PJM Capacity Performance rule impacts on APCo's capacity position beginning with the 2020/2021 PJM planning year. Among other things, it assumes that the rule may result in APCo:
    - reducing the level of Smith Mountain pumped storage PJM capacity contribution by approximately 200MW (from 585MW to 385MW);
    - reducing wind resources from prior PJM-recognized capacity levels (i.e. from 13% to 5% of nameplate capacity); and
    - reducing run-of-river hydro contributions to 25% of nameplate rating.
- Continues operation 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) solid-fuel facilities: Clifty Creek Units 1-6 and Kyger Creek Units 1-5; and
- retires natural gas-converted Clinch River Units 1 and 2 in 2026.

Note 1: APCo does not have control over the amount, location or timing of these additions.

Specific APCo capacity changes over the 15-year planning period associated with the Hybrid Plan are shown in Figure ES-2 and Figure ES-3, and their relative impacts to APCo's annual energy position are shown in Figure ES-4 and Figure ES-5.

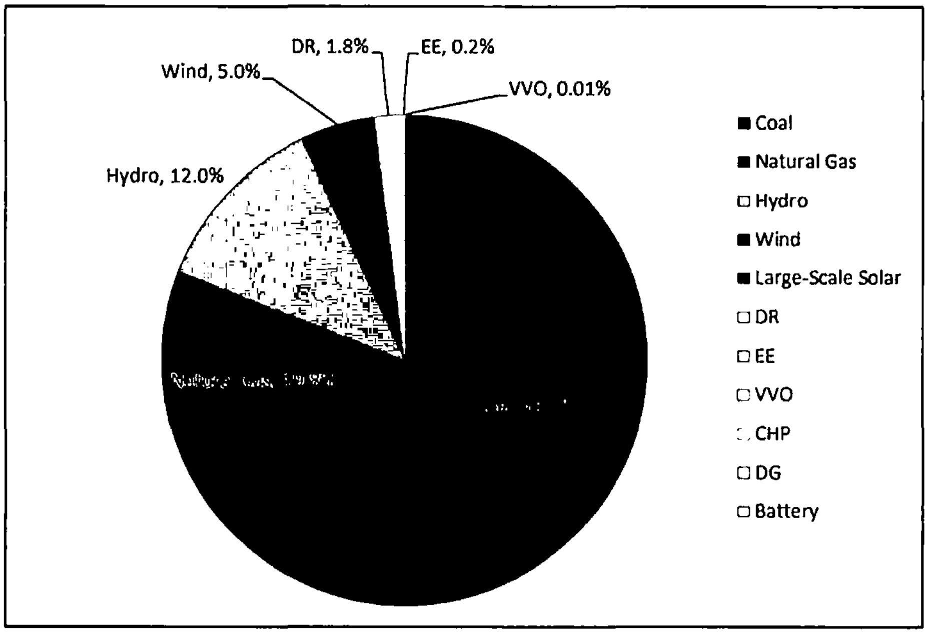

Figure ES-2. 2016 APCo Nameplate Capacity Mix

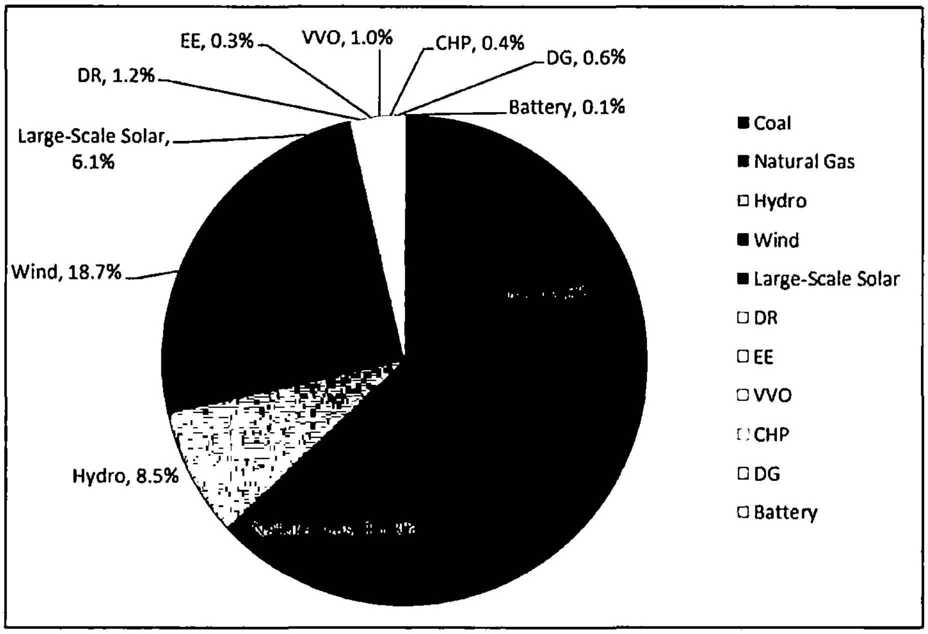

Figure ES-3. 2030 APCo Nameplate Capacity Mix

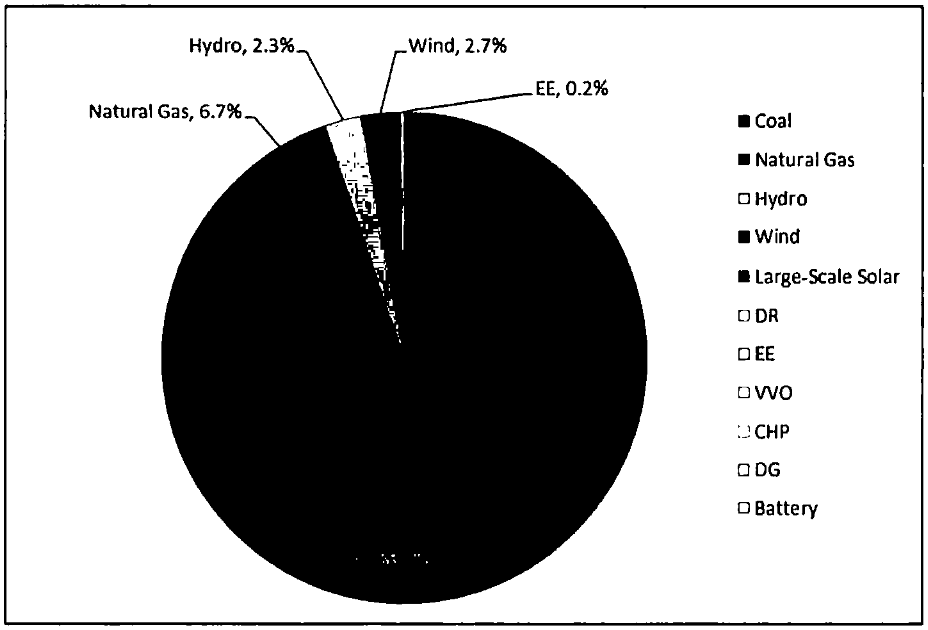

Figure ES-4. 2016 APCo Energy Mix

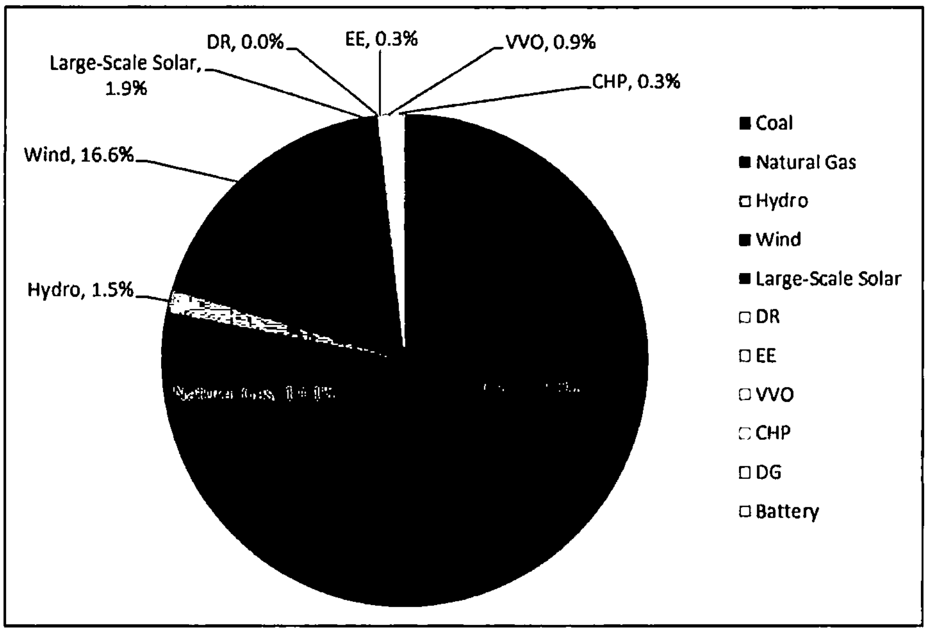

Figure ES-5. 2030 APCo Energy Mix

Figure ES-2 through Figure ES-5 indicate that this Hybrid Plan would reduce APCo's reliance on coal-based generation and increase reliance on demand-side and renewable resources, further diversifying the portfolio. Specifically, over the 15-year planning horizon the Company's nameplate capacity mix attributable to coal-fired assets would decline from 61.2% to 47.8%. Wind and solar assets climb from 5% to 24.8%, and demand-side resources (including EE, VVO, DG, Demand Response [DR], and CHP) increase from 2.0% to 3.5% over the planning period.

APCo's energy output attributable to coal-fired generation shows a substantial decrease from 88.0% to 59.0% over the period. The Hybrid Plan shows a significant increase in renewable energy (wind and solar), from 2.7% to 18.5%. Energy from these renewable resources, combined with EE and VVO energy savings reduce APCo's exposure to energy, fuel and potential carbon prices.

Figure ES-6 and Figure ES-7 show annual changes in capacity and energy mix, respectively, that result from the Hybrid Plan, relative to capacity and energy requirements. The capacity contribution from renewable resources is fairly modest due to the implications of PJM's Capacity Performance rule reducing the amount of credit for intermittent resources; however, those resources (particularly wind) provide a significant volume of energy. APCo's model selected those wind resources because they were lower cost than alternative resources. When comparing the capacity values in Figure ES-6 with those in Figure ES-2 and Figure ES-3, it is important to note that Figure ES-6 provides an analysis of PJM-recognized capacity, while Figure ES-2 and Figure ES-3 depict nameplate capacity.

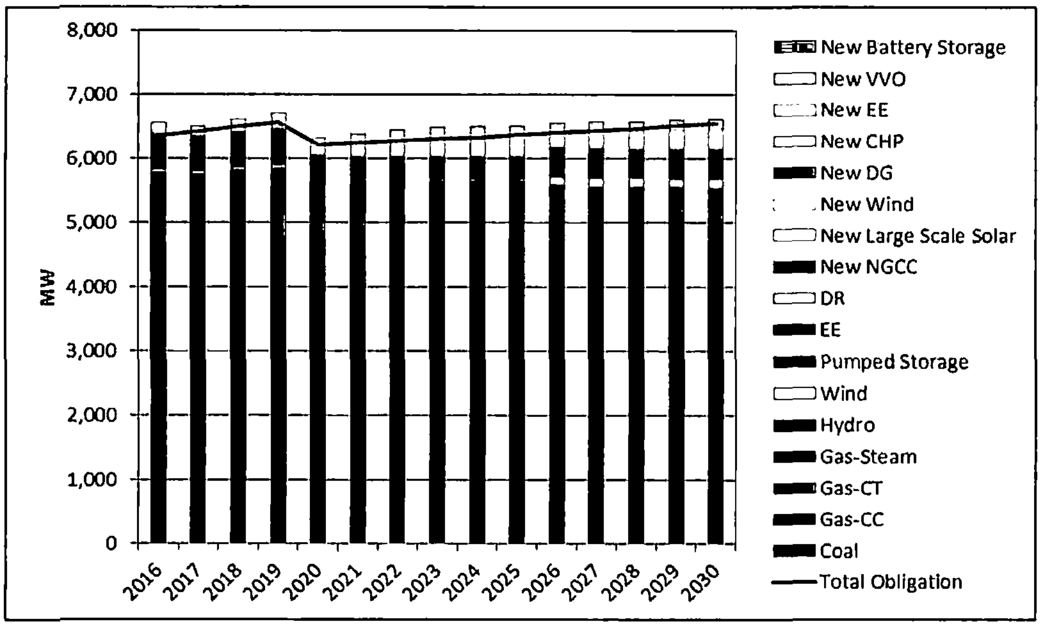

Figure ES-6. APCo Annual PJM Capacity Position (MW) According to Hybrid Plan

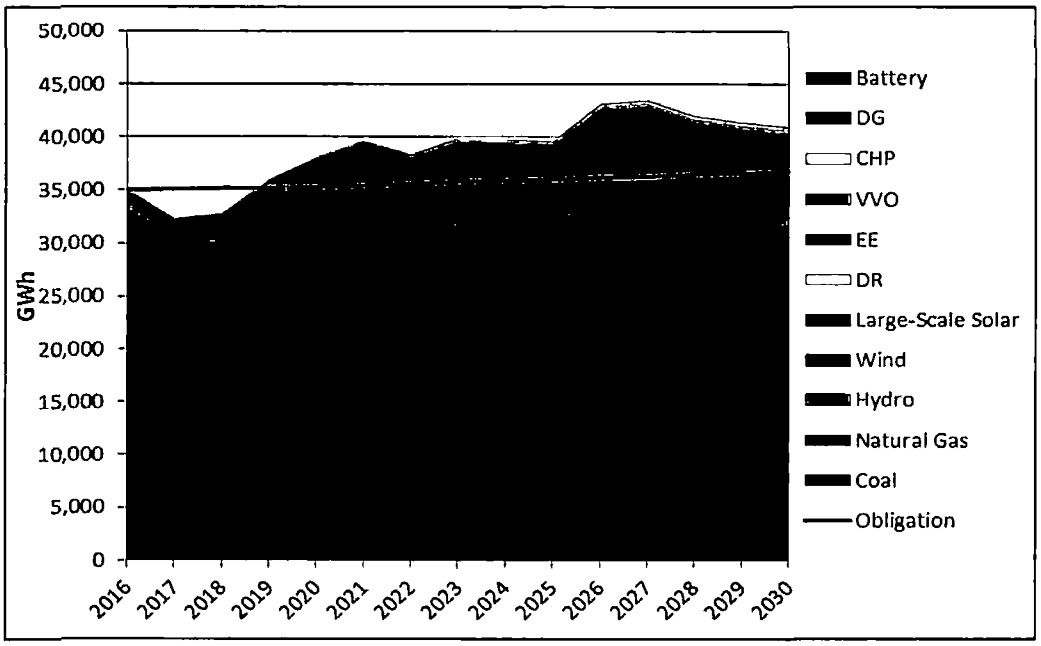

Figure ES-7. APCo Annual Energy Position (GWh) According to Hybrid Plan

Table ES-1 provides a summary of the Hybrid Plan, which resulted from analysis of optimization modeling under load and commodity pricing scenarios, giving consideration to APCo's CPP modeling:

Table ES-1. Hybrid Plan Cumulative Capacity Additions throughout Planning Period (2016-2030)

Appalachian Power Company
(Virginia Filing)
2016 Integrated Resource Plan
Cumulative Resource Changes

Hybrid Plan

MW		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)		(14)	(15)	(16)	(17)	(18)	(19)	(20)
		(Cumulative) Existing Fleet	(Cumulative) Existing Fleet	(Cumulative) Firm Capacity Resource ADDITIONS												(Cumul.) NET "RESOURCE CHANGE"[8]	Resulting APCo Reserves Above		(Cumulative) 'NAMEPLATE' ADDITIONS			
				New-Build		Energy Efficiency (EE)			VVO	DR	Wind[4]	Solar[5]		Battery[6]					Wind[4]	Solar[5]		Battery[6]
IRP Period	PJM Planning Year[1]	Unit Uprates & Derates	PJM Capacity Performance Impact (UCAP Reduction)	NG CHP	NG CC	"Embedded" Federal EE Regulations ("Non-DSM EE")[2]	Current DSM Programs[3]	New	New	Pre-Existing DR Programs[3]		Large Scale	Dis-tributed				PJM Minimum Reserve[9]	PJM Reserve Margin %		Large Scale	Dis-tributed	
Yr.		MW		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW		MW	MW		MW	MW	MW	
1	2016	14 [a]	-	-	-	397	20	-	1	142	-	-	5	-		179	212	4.4%	-	-	8	-
2	2017	14	-	-	-	424	47	-	1	142	-	-	3	-		207	159	1.6%	-	-	9	-
3	2018	14	-	-	-	448	63	-	1	142	15	8	4	-		245	125	2.1%	300	20	10	-
4	2019	50 [b]	-	-	-	470	71	37	1	142	30	19	5	-		354	190	2.7%	600	50	12	-
5	2020	50	(433) [c]	14	-	491	71	44	1	123	45	35	5	-		(43)	123	1.9%	900	150	15	-
6	2021	50	(433)	14	-	516	71	50	23	123	60	75	7	-		43	141	2.5%	1,200	200	17	-
7	2022	50	(433)	14	-	537	71	56	43	123	68	114	8	-		115	175	3.1%	1,350	300	21	-
8	2023	50	(433)	14	-	557	71	62	48	123	75	152	10	-		170	182	3.3%	1,500	400	25	-
9	2024	50	(433)	14	-	574	71	68	56	123	75	152	12	-		195	180	3.2%	1,500	400	30	-
10	2025	50	(433)	14	-	595	71	74	66	123	75	152	14	5		203	137	2.4%	1,500	400	35	10
11	2026	(422) [d]	(433)	14	472	612	71	80	82	123	75	152	17	5		227	147	2.5%	1,500	400	41	10
12	2027	(422)	(433)	14	472	628	71	86	97	123	75	187	19	5		255	123	2.1%	1,500	450	45	10
13	2028	(422)	(433)	14	472	640	71	92	97	123	75	195	19	5		290	112	2.0%	1,500	450	51	10
14	2029	(422)	(433)	14	472	655	71	98	97	123	83	205	21	5		324	84	1.5%	1,650	540	55	10
15	2030	(422)	(433)	14	472	669	71	106	97	123	90	224	23	5		351	69	1.2%	1,800	590	61	10
							177													651		
							'TOTAL Increm' Energy Efficiency													'TOTAL' Solar		

[1] PJM Planning Year is effective 6/1/XXXX.
[2] Represents estimated (post-2015) energy efficiency levels already 'embedded' into APCo's long-term load & peak demand forecast based on emergence of PROMULGATED federal efficiency standards (EPAct 2005; 2007 EISA, 2009 ARRA).
[3] Represents estimated contribution from current/known APCo DSM-EE and Demand Response (Interruptible, DLC/ELM) program activity through 2018; values are baselined from 2015
[4] Due to the intermittency of wind resources, APCo assumes 5% of nameplate MW rating are included for capacity resource determination purposes beyond 2020.
[5] Due to the intermittency of solar resources, Utility and Distributed Solar receive 38% of nameplate MW rating for capacity resource determination purposes.
[6] Due to the intermittency of battery/storage resources, APCo assumes 50% of nameplate MW rating for capacity resource determination purposes.

Changes to existing resources from June 1, 2015:
[a] Clinch River 1&2 Gas Conversion uprate
[b] Claytor hydro turbine upgrade.
[c] Assumed removal of 75% Run-of-River Hydro capacity as well as a portion of Smith Mt. Pumped Storage and (Existing) Wind capacity to achieve PJM 'Capacity Performance' criteria

[8] Includes changes in existing resources plus plan additions, excluding "embedded" EE and existing DR programs.
[9] PJM minimum criterion @16.5% as a function of peak demand effective with the 2019/20 PY (previously @ 15.7%).
[d] Clinch River 1&2 Gas Conversion unit retirement

1 6 0 4 4 0 8 7

Conclusion

This IRP, based upon various assumptions, provides adequate capacity resources at reasonable cost, through a combination of supply-side resources (including renewable supply-side resources) and demand-side programs throughout the forecast period.

Moreover, this IRP also addresses APCo's energy short position. The Hybrid Plan offers incremental resources that will provide—in addition to the needed PJM installed capacity to achieve mandatory PJM (summer) peak demand requirements—additional energy to reduce the long-term exposure of the Company's customers to PJM energy markets, which could be influenced by many external factors, including the impact of carbon regulation.

Recognizing PJM's new Capacity Performance construct, the portfolios discussed in this Report attribute limited capacity value for certain intermittent resources (solar, wind and run-of-river hydro). Additionally, the capacity contributions of APCo's Smith Mountain pumped storage facility were reduced to account for the Capacity Performance rule; however this reduction will continue to be assessed. It is possible that intermittent resources can be combined, or "coupled," and offered into the PJM market as Capacity Performance resources. Once the final PJM Capacity Performance tariffs are accepted, the Company will investigate methods to maximize the utilization of its intermittent resource portfolio within that construct. An example could be the additional coupling of run-of-river hydro, wind and solar resources in a manner that would mitigate potentially costly non-performance risk.

This IRP also addresses this Commission's specific 2016 IRP requirements as set forth in the 2016 Final Order. Each of the requirements has been examined and, despite the uncertainty surrounding the legal status of the CPP and various other uncertainties, the Company has made a good-faith effort to provide both appropriate responses to the Commission's inquiries and reasonable analyses under the circumstances.

The IRP process is a continuous activity; assumptions and plans are reviewed as new information becomes available and modified as appropriate. Indeed, the capacity and energy resource portfolios reported 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 is becoming increasingly complex when considering 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 planning and regulatory actions necessary to implement economic EE programs in Virginia and West Virginia.
2. Continue to monitor market prices for renewable resources, particularly wind and solar, and if economically advantageous, pursue competitive solicitations that would include self-build or acquisition options.
3. Pursue opportunities to identify a suitable host facility for a combined heat and power installation.
4. Monitor status of PJM's Capacity Performance rule; continue to evaluate the extent/level of Smith Mountain pumped storage to commit as part of future plan offerings as well as investigate opportunities to couple/hedge traditional hydro and renewable resources (wind and solar) as reasonable Capacity Performance products.
5. Monitor the status of, and participate in formulating, Virginia (as well as West Virginia, Ohio and Indiana) state plans pertaining to the CPP. Once established, perform specific assessments as to the implications of the CPP on APCo's resource profile. and
6. Be in a position to adjust this action plan and future IRPs to reflect changing circumstances.

Table ES-2. Location of 2016 Final Order Requirements in this IRP

Requirement	Location
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	Sections 3.3.8, 3.3.8.8, 5.2.3
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;	Section 5.2.3.4
Provide a detailed description of leakage and treatment of new units under differing compliance regimes;	Section 3.3.8.3
Examine the differing impacts of the Virginia-specific targets verses source subcategory-specific rates under an intensity-based approach;	Section 3.3.8.2
Examine the potential for early action emission rate credits/allowances that may be available for qualified renewable energy or demand-side energy efficiency measures;	Section 3.3.8.4
Examine the cost benefits of trading emissions allowances or emissions reductions credits, or acquiring renewable resources from inside and outside of Virginia;	Section 3.3.8.5
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	Section 3.3.8.6
Identify a long-term recommendation that reflects EPA's final version of the CPP	Section 3.3.8.7
Rate Design	
Analyze whether maintaining the existing rate structure is in the best interest of residential customers	Section 4.4.3.8
Evaluate options for variable pricing models that would incent customers to shift consumption away from peak times to reduce costs and emissions	Section 4.4.3.8
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

1.0 Introduction

1.1 Overview

This Report presents the 2016 Integrated Resource Plan (IRP, Plan, or Report) 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 ensure a reliable supply of power and energy to customers at the least reasonable cost.*

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:

- Determining capital expenditure requirements;
- rate case planning; and
- environmental compliance and other planning processes.

1.2 Integrated Resource Plan (IRP) Process

This Report covers the processes and assumptions required to develop an IRP for the Company. The IRP process for APCo includes the following components/steps:

- Description of the Company, the resource planning process in general, and the implications of current issues as they relate to resource planning;
- provide projected growth in demand and energy which serves as the underpinning of the Plan;
- identify and evaluate demand-side options such as Energy Efficiency (EE) measures, Demand Response (DR) and Distributed Generation (DG);
- identify current supply-side resources, including projected changes to those resources (*e.g.*, de-rates or retirements), and transmission system integration issues;
- identify and evaluate supply-side resource options; and

- perform resource modeling, including modeling for possible Clean Power Plan (CPP) effects, and use the results to develop various portfolios.

1.3 Introduction to APCo

APCo's customers consist of both retail and sales-for-resale (wholesale) customers located in the states of Virginia, West Virginia and Tennessee (see Figure 1). Currently, APCo serves approximately 957,000 retail customers in those states, including over 526,000 and 431,000 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 2015 and winter 2015/16) actual APCo summer and winter peak demands were significant at 5,627MW and 7,379MW, occurring on August 5th and January 19th, respectively.

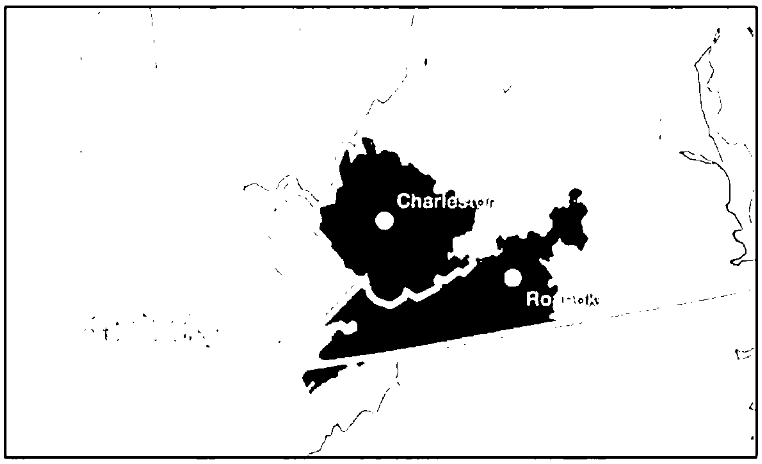

Figure 1. APCo Service Territory

This IRP is based upon the best available information at the time of preparation. However, changes that may impact this Plan can, and do, occur without notice. Therefore, this Plan is not a commitment to a specific course of action, since the future, is uncertain, particularly in light of current economic conditions, the movement towards increasing use of renewable generation and end-use efficiency, as well as regulations to control greenhouse gases.

The action items described herein are subject to change as new information becomes available or as circumstances warrant. This IRP report is being filed by May 1, 2016 in compliance with Virginia Senate Bill 1349. Senate Bill 1349 amended Section 56-599 of the Code of Virginia and required that electric utilities file an updated IRP by July 1, 2015, followed by annual updated IRPs due each year on May 1. Section 56-599 also required electric utilities to consider six factors in each IRP.

The first four factors to be considered relate to options (i.e. options for maintaining and enhancing rate stability; energy independence; economic development, including the retention and expansion of energy intensive industries; and, service reliability). The fifth and sixth factors relate to environmental regulations and require consideration of the effect of current and pending state and federal environmental regulations upon the continued operations of existing electric generation facilities or options for constructing new electric generation facilities; and, 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. As indicated throughout this Report, APCo's IRP process takes these requirements into account and attempts to strike a reasonable balance among these various factors.

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 2015.[2] The final 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 (2016-2030)[3], APCo's service territory is expected to see population and non-farm employment growth of 0.2% and 0.3% per year, respectively. Not surprisingly, APCo is projected to see customer count growth at a similar rate of 0.2% per year. Over the same forecast period, APCo's retail sales are projected to grow at 0.3% per year with stronger growth expected from the industrial class (+0.6% per year) while the residential class experiences a slight decline over the forecast horizon. Finally, APCo's internal energy and peak demand are expected to increase at an average rate of 0.3% and 0.3% per year, respectively, through 2030.

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.

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[2] The load forecasts (as well as the historical loads) presented in this Report 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.

[3] 15 year forecast periods begin with the first full forecast year, 2016.

The load forecasts utilized Moody's Analytics economic forecast issued in January 2015. Moody's Analytics projects moderate growth in the U.S. economy during the 2016-2030 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 2.1% per year. Industrial output, as measured by the Federal Reserve Board's (FRB) index of industrial production, is expected to grow at 1.4% per year during the same period. Moody's projected employment growth of 0.3% per year during the forecast period and real regional income per-capita annual growth of 1.3% 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.

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 Commission-approved programs at the time the load forecast is created to adjust the forecast for the impact of these programs.

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, below.

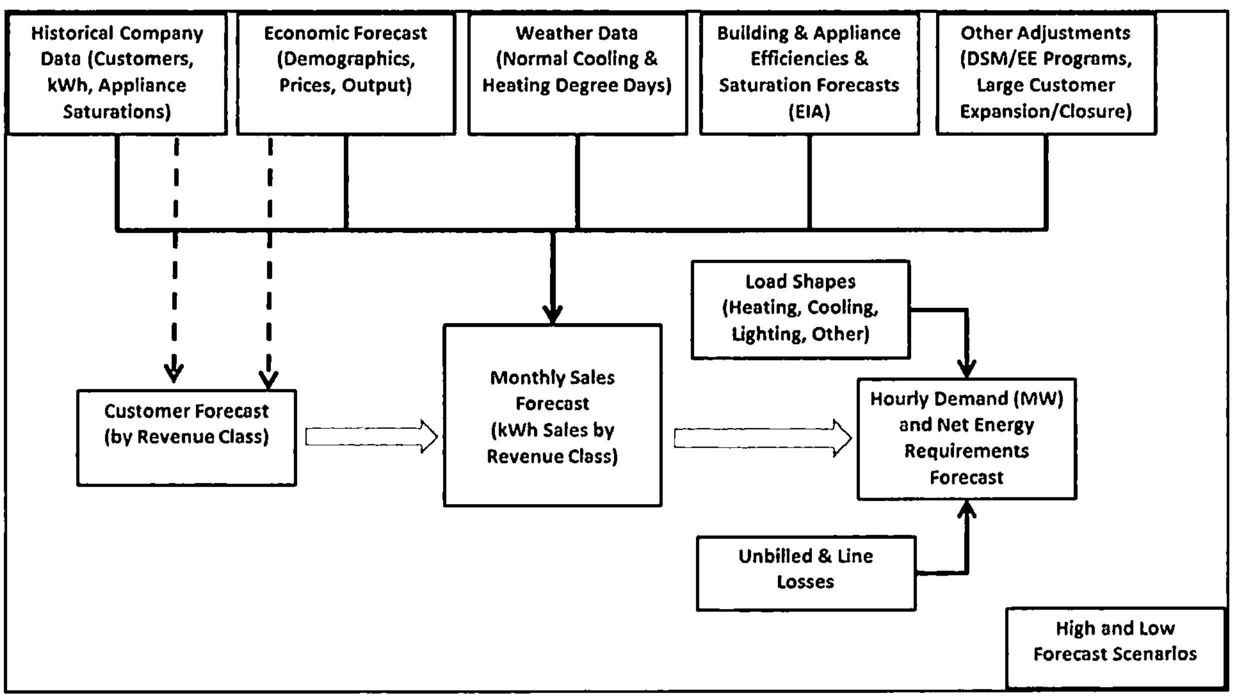

Figure 2. APCo Internal Energy Requirements and Peak Demand Forecasting Method

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 include gross regional product, employment, mortgage rate, population, real personal income and households are 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.

There are separate models for the Virginia and West Virginia jurisdictions of the Company. The estimation period for the short-term models was January 2005 through January 2015. There are models for residential, commercial, industrial, other retail, and wholesale sectors. The industrial models are comprised of 22 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 1995-2014 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 Models

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 Central Census region's sectoral prices, with the forecast being obtained from EIA's "2015 Annual Energy Outlook." The natural gas price model is based upon 1980-2014 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 "2015 Annual Energy Outlook." The estimation period for the model was 1998-2014.

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 East North 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 models are estimated using linear regression models. These monthly models are typically for the period January 1995 through January 2015. 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.

Separate residential SAE models are estimated for the Company's Virginia and West Virginia jurisdictions.

2.4.4.3 Commercial Energy Sales

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

2.4.4.4 Industrial Energy Sales

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

2.4.4.4.1 Manufacturing Energy Sales

The Company uses some combination of the following economic and pricing explanatory variables: service area gross regional product manufacturing, FRB industrial production indexes, service area industrial electricity prices and state industrial natural gas price. In addition binary variables for months are special occurrences and are incorporated into the models. Based on information from customer service engineers there may be load added or subtracted from the model results to reflect plant openings, closures or load adjustments. Separate models are estimated for the Company's Virginia and West Virginia jurisdictions. The last actual data point for the industrial energy sales models is January 2015.

2.4.4.4.2 Mine Power Energy Sales

For its mine power energy sales models, the Company uses some combination of the following economic and pricing explanatory variables: service area gross regional product mining, regional coal production, and service area mine power electricity prices. In addition binary variables for months are special occurrences and are incorporated into the models. Based on information from customer service engineers there may be load added or subtracted from the model results to reflect plant openings, closures or load adjustments. Separate models are estimated for the Company's Virginia and West Virginia jurisdictions. The last actual data point for the industrial energy sales models is January 2015.

2.4.4.5 All Other Energy Sales

The forecast of public-street and highway lighting relates energy sales to either service area employment or service area population and binary variables.

Wholesale energy sales are modeled relating energy sales to economic variables such as service area employment, energy prices, 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 modelled similarly to APCo's retail sales, with the exception that Kingsport Power does not have mine power energy sales.

2.4.5 Internal Energy Forecast

2.4.5.1 Blending Short and Long-Term Sales

Forecast values for 2015 and 2016 are taken from the short-term process. Forecast values for 2017 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 2017 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.

2.4.5.2 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.

2.4.6 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 2012-2015 and on a forecast basis for the years 2016-2030. 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.

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 2012-2015 and on a forecast basis for the years 2016-2030. The table also shows annual growth rates for both the historical and forecast periods.

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 3, below, presents APCo's historical and forecasted residential and commercial usage per customer between 1991 and 2020. During the first decade shown (1991-2000), residential usage per customer grew at an average rate of 1.3% 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 0.9% per year while the commercial class usage decreased by 0.3% per year. In the last decade shown (2011-2020) residential usage is projected to decline at a rate of 0.7% per year while the commercial usage decreases by an average of 0.3% per year. It is worth noting that the decline in residential and commercial usage accelerated between 2008 and 2014, with usage declining at average annual rates of 1.0% and 1.1% for residential and commercial sectors, respectively, over that period.

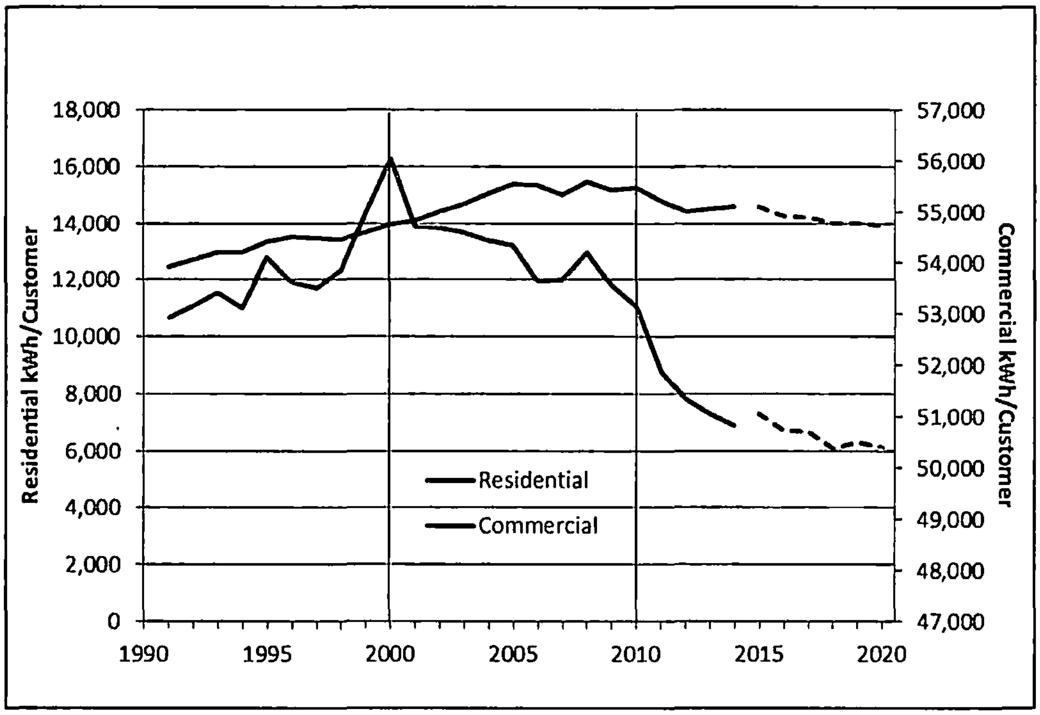

Figure 3. APCo Normalized Use per Customer (kWh)

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 4 below 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 13.1 in 2010 to over 13.9 by 2030. The chart shows a similar trend in projected cooling efficiencies for heat pump cooling as well as room air conditioning units. Figure 5 shows similar improvements in the efficiencies of lighting and clothes washers over the same period.

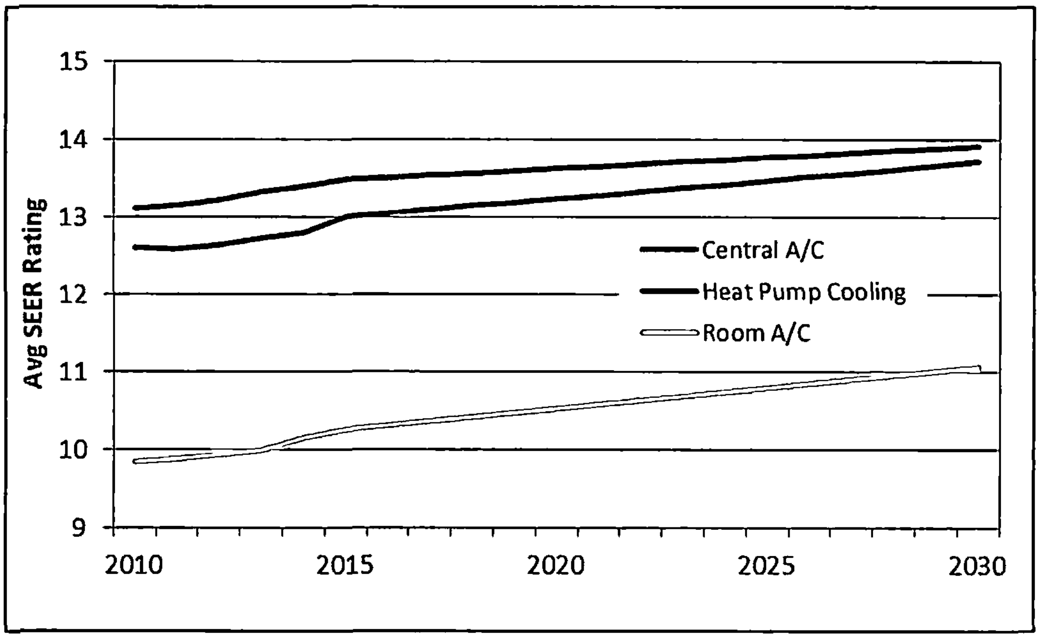

Figure 4. Projected Changes in Cooling Efficiencies, 2010-2030

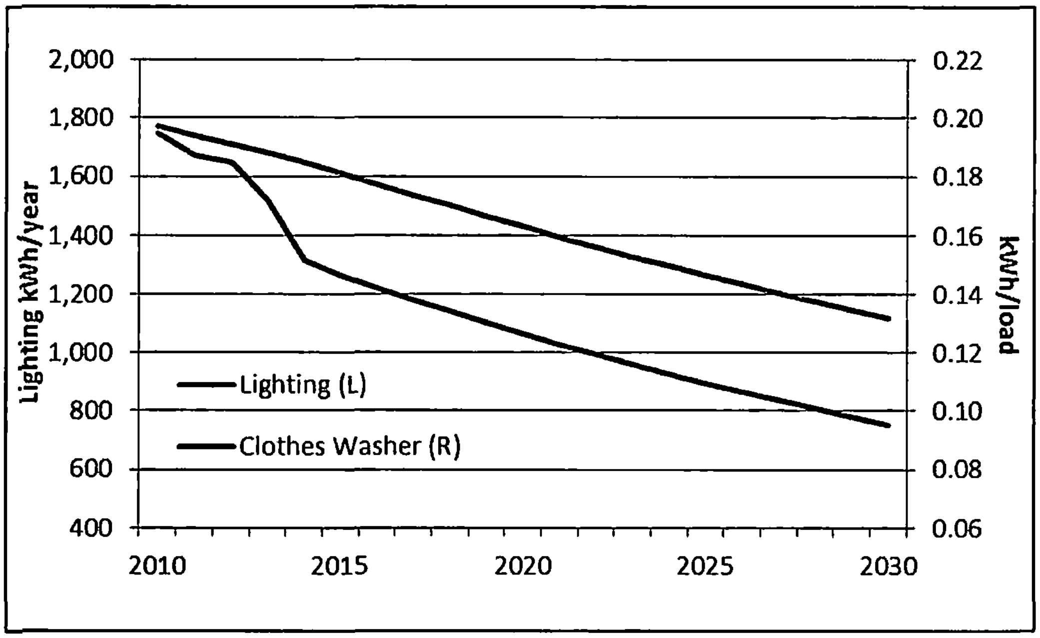

Figure 5. Projected Changes in Lighting and Clothes Washer Efficiencies, 2010-2030

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 2018), the load forecast uses assumptions from the latest commission approved DSM programs. For the years beyond 2018, 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 160MW and 193MW available for interruption at the time of the winter and summer peaks, respectively. An additional six customers have 44MW 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 2016 were typically taken from the short-term process. Forecast values for 2017 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 2017 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 6 illustrates a hypothetical example of the blending process (details of this illustration are shown in Exhibit A-6). owever, 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.

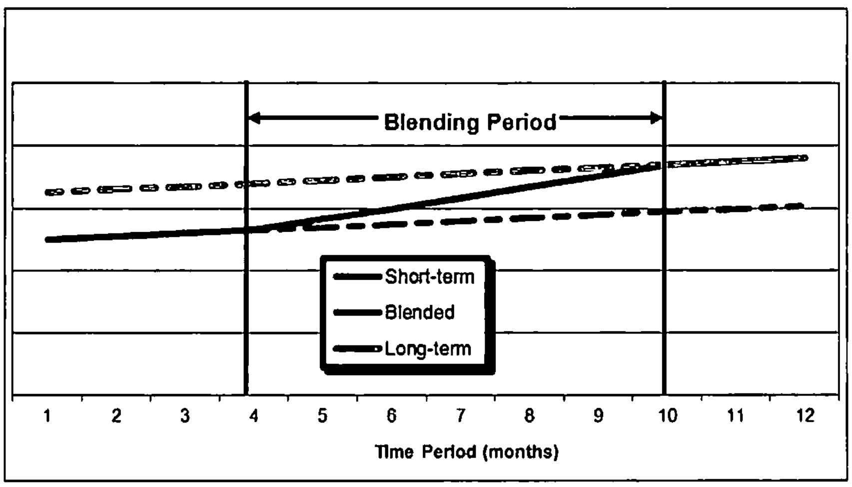

Figure 6. Load Forecast Blending Illustration

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 2015 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. Graphical displays of the range of forecasts of internal energy requirements and summer peak demand for APCo are shown in Exhibit A-8.

For APCo, the low-case and high-case energy and peak demand forecasts for the last forecast year, 2030, represent deviations of about 7.8% below and 8.0% above, respectively, the base-case forecast.

2.8 Economic Development

A requirement set forth by Senate Bill 1349 is that:

> "...the IRP shall consider options for maintaining and enhancing economic development including retention and expansion of energy-intensive industries."

This IRP sets forth portfolios to meet these and other needs 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.

2.8.1 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 will result in increased activity for local businesses and the creation of additional jobs. 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, for potential business expansions or new customer additions, can employ 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.

part 2

3.0 Resource Evaluation

3.1 Current Resources

An initial step in the IRP process is the demonstration of the capacity resource requirements. This "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 current PJM Installed Reserve Margin (IRM) of 15.7 percent, increasing to 16.5 percent by the 2019/2020 PJM planning year.[4] The ultimate reserve margin of 8.35 percent is determined from the PJM Forecast Pool Requirement (FPR) which considers the IRM and PJM's Pool-Wide Average Equivalent Demand Forced Outage Rate ($EFOR_D$) of 6.35 percent.[5]Table 1 displays key parameters for the generation resources currently owned by APCo.

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[4] Per Section 2.1.1 of PJM Manual 18: PJM Capacity Market (Effective: October 16, 2015). 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.

[5] Per Section 2.1.4 of PJM Manual 18: PJM Capacity Market (Effective: October 16, 2015). $FPR = (1 + IRM) * (1 - EFOR_D)$. Reserve Margin = FPR – 1.

Table 1. Current APCo-Owned Supply-Side Resources

Unit Name	Company	Location	Unit Type	Primary Fuel Type	C.O.D. [1]	Net Capability - MW [2] Winter		Summer	
Amos 1	APCo	St. Albans, WV	Steam	Coal	1971	800		800	
Amos 2	APCo	St. Albans, WV	Steam	Coal	1972	800		800	
Amos 3	APCo	St. Albans, WV	Steam	Coal	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	237		237	
Clinch River 2	APCo	Carbo, VA	Steam	Gas	1958	237		237	
Dresden	APCo	Dresden, OH	Combined Cycle	Gas	2012	613		555	
Mountaineer 1	APCo	New Haven, WV	Steam	Coal	1980	1,320		1,305	
Buck 1 - 3	APCo	Ivanhoe, VA	Hydro	--	1912	5		3	(A)
Byllesby 1 - 4	APCo	Byllesby, VA	Hydro	--	1912	8		4	(A)
Claytor 1 - 4	APCo	Radford, VA	Hydro	--	1939	28		15	(A)
Leesville 1 - 2	APCo	Leesville, VA	Hydro	--	1964	9		5	(A)
London 1 - 3	APCo	Montgomery, WV	Hydro	--	1935	12		7	(A)
Marmet 1 - 3	APCo	Marmet, WV	Hydro	--	1935	11		6	(A)
Niagara 1 - 2	APCO	Roanoke, VA	Hydro	--	1924	1		1	(A)
Reusens 1 - 5	APCo	Lynchburg, VA	Hydro	--	1903	0		0	(A)
Winfield 1 - 3	APCo	Winfield, WV	Hydro	--	1938	15		9	(A)
Smith Mountain 1	APCo	Penhook, VA	Pump. Stor.	--	1965	70	(B)	70	(B)
Smith Mountain 2	APCo	Penhook, VA	Pump. Stor.	--	1965	185	(B)	185	(B)
Smith Mountain 3	APCo	Penhook, VA	Pump. Stor.	--	1980	105	(B)	105	(B)
Smith Mountain 4	APCo	Penhook, VA	Pump. Stor.	--	1966	185	(B)	185	(B)
Smith Mountain 5	APCo	Penhook, VA	Pump. Stor.	--	1966	70	(B)	70	(B)
						6,558		6,379	

(1) Commercial operation date.
(2) 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.

Figure 7, below, depicts all generation sources employed to meet the APCo needs, along with their current age. The unit ratings are subject to change for the 2020/2021 PJM planning year based upon the Capacity Performance rule, discussed in the following section.

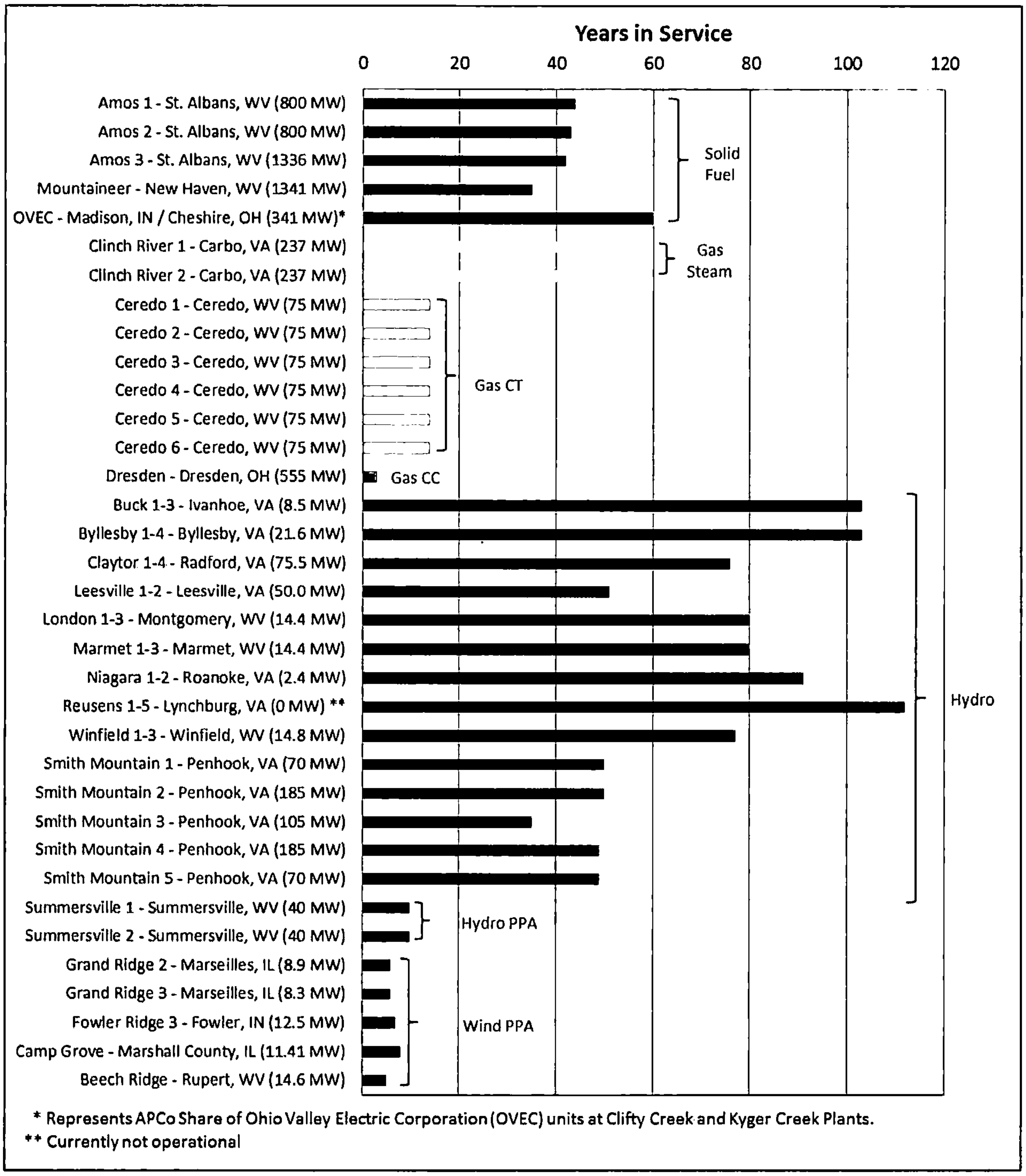

Figure 7. Current Resource Fleet (Owned and Contracted) with Years in Service

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).

3.2.1 PJM Capacity Performance Rule Implications

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.

This IRP incorporates the following assumptions for Capacity Performance values for certain gas-fired and intermittent resources, in order to address the Capacity Performance rulemaking effective with the 2020/2021 PJM planning year:

- Gas generation resources may require a firm natural gas supply or dual-fuel (gas/oil) capability to hedge against non-performance due to lack of firm gas supply;
- run-of-river hydro units valued at 25% of nameplate capacity rating;[6]
- pumped-storage hydro units, such as Smith Mountain, will be valued at approximately 2/3 of their nameplate capacity rating in recognition of their inability to generate at nameplate capacity on a continuous basis;[7]
- solar resources will be valued at 38% of nameplate capacity rating, consistent with current PJM criterion for new solar sources;
- wind resources will be valued at 5% of nameplate capacity rating, a reduction from current PJM criterion of 13.5 percent for new wind sources; and[8]

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[6] Run-of-river hydro "Capacity Performance" credit is assumed to be increased from the 2015 APCo Virginia IRP.

[7] Pumped-storage "Capacity Performance" credit is assumed to be increased from the 2015 APCo Virginia IRP.

[8] Wind resource "Capacity Performance" credit is assumed to be increased from the 2015 APCo Virginia IRP.

- DR resources will be reduced to 50% of currently planned levels. This reduction is in anticipation of current DR customers electing not to renew DR contracts due to uncertainty associated with penalties for non-performance. This assumption will be revisited in future IRP's as participation in the Company's proposed DR tariffs is realized.

This IRP assumes that during the 2020/2021 PJM planning year all capacity resources will need to be Capacity Performance products. It is possible that these resources can be combined, or "coupled", and offered into the PJM market as Capacity Performance resources. Once the final PJM Capacity Performance tariffs are approved and published, the Company will investigate methods to maximize the utilization of its current (and future) intermittent resource portfolio within that construct. An example could be the additional coupling of run-of-river hydro, pumped storage, wind and potential solar resources in a manner that would mitigate non-performance risk. The potential exists that an offer strategy could be formulated such that a portion of the over 200MW of run-of-river hydro generating capability, which is not currently recognized in APCo's ultimate Hybrid Plan as being Capacity Performance-eligible, could count as capacity in future PJM planning years. If that were to occur, then there is a reasonable prospect that the need for incremental capacity resources set forth in the various portfolios in this Report could be deferred further into the future.

3.3 Environmental Issues and Implications

3.3.1 Mercury and Air Toxics Standards (MATS)

The final Mercury and Air Toxics Standard (MATS) Rule became effective on April 16, 2012 and required compliance by April 16, 2015.[9] This rule regulates emissions of hazardous air pollutants from coal and oil-fired Electric Generating Units (EGUs). Hazardous air pollutants regulated by this rule are: 1) mercury; 2) certain non-mercury metals such as arsenic, lead,

[9] APCo received an extension through May 31, 2015 for Kanawha River Units 1&2, Sporn Units 1&3, Glen Lyn Units 5&6, and Clinch River Unit 3. An extension to April 16, 2016 was received for Clinch River Units 1&2.

cadmium and selenium; 3) certain acid gases, including Hydrochloric Acid (HCl); and 4) certain organic hazardous air pollutants. The MATS Rule establishes stringent emission rate limits for mercury, filterable Particulate Matter (PM) as a surrogate for all non-mercury toxic metals, and HCl as a surrogate for all acid gases. Alternative emission limits were also established for the individual non-mercury metals and for sulfur dioxide (SO_2) (alternate to HCl) for generating units that have operating Flue Gas Desulfurization (FGD) systems. The rule regulates organic hazardous air pollutants through work practice standards.

On November 25, 2014, the U.S. Supreme Court granted petitions to hear state and industry challenges against the EPA's MATS Rule to decide whether EPA unreasonably refused to consider costs in determining that it is appropriate to regulate hazardous air pollutants emitted by coal- and oil-fired EGUs. The Supreme Court determined on June 29, 2015, that EPA must consider costs when deciding whether it is "appropriate and necessary" to regulate emissions under MATS. The decision did not vacate the MATS rule, but remanded the rule to the D.C. Circuit Court for further proceedings. On December 15, 2015, the D.C. Circuit Court issued an order remanding the MATS rule to EPA without vacatur. EPA issued a proposed supplemental finding on December 1, 2015, and the Administrator signed a final notice on April 15, 2016, confirming her determination that it is appropriate and necessary to regulate hazardous air pollutants from EGUs through the MATS rule.

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 (NO_x) emissions and FGD systems for mitigation of SO_2 emissions, which together achieve a co-benefit removal of mercury as well. APCo's sub-critical units which could not meet all of the MATS requirements in their existing configuration are in the process of being refueled to natural gas-fired units (Clinch River Units 1 & 2) or were retired as of June 1, 2015 (Kanawha River Units 1 & 2, Glen Lyn Units 5 & 6, Clinch River Unit 3 and Sporn Units 1 & 3).

3.3.2 Cross-State Air Pollution Rule (CSAPR)

EPA developed the Cross-State Air Pollution Rule (CSAPR) to reduce the interstate transport of SO_2 and NO_x from 28 states in the eastern half of the country, including all APCo states, and to address associated concerns related to National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter. CSAPR was finalized in 2011 as a replacement for the Clean Air Interstate Rule (CAIR). Along with other requirements, the final CSAPR established state-specific annual emission "budgets" for SO_2 and annual and seasonal budgets for NO_x. Based on these budgets, each emitting unit within an affected state was allocated a specified number of NO_x and SO_2 allowances for the applicable compliance period, whether annual or ozone season. Allowance trading within states is allowed, as is trading between states, although on a significantly more limited basis.

Phase 1 of the CSAPR was originally intended to go into effect in January, 2012. The program was delayed as a result of complicated and lengthy litigation. That litigation has been resolved and EPA is required to reconsider the ozone season budgets for eleven states, and the SO_2 budgets for four states. Phase 1 ultimately went into effect in January, 2015, and the CSAPR Phase 2 emission budgets will be applicable beginning in 2017.

On December 3, 2015, EPA published a proposed rule to update the CSAPR to address the 2008 ozone national ambient air quality standard. The proposed rule included reduced NO_x ozone season (May through September) allowance budgets for the 23 covered states to become effective in 2017. Virginia, West Virginia, Ohio, and Indiana are among the states for which additional reductions are proposed. APCo owns or has an interest in generating facilities in each of these states. Comments on the proposed rule were accepted until February 1, 2016. AEP submitted comments identifying certain flaws in the agency's proposal and challenging the feasibility of achieving the proposed reductions by the ozone season in 2017.

The installed SCR and FGD systems' respective emission reductions of NO_x and SO_2 are anticipated to put APCo's remaining generating plants in the position of having excess CSAPR allowances when considering the original rule that took effect in 2015. The ultimate impact of the new proposal on APCo's forecasted allowance position cannot be determined at this time, but the Company will continue to monitor this proposal and include any anticipated impacts in future IRPs when it is practical to do so.

3.3.3 National Ambient Air Quality Standards (NAAQS)

The Clean Air Act (CAA) requires the EPA to establish and periodically review NAAQS designed to protect public health and welfare. Recently revised NAAQS include those for SO_2 (revised in 2010), fine particulate matter (revised in 2012), and ozone (revised in 2015). These revised NAAQS have not yet been fully implemented by the states and it is anticipated that state implementation plans may need to be updated to include any SO_2 and/or NO_x emission reductions necessary to demonstrate attainment with the revised NAAQS. The scope and timing of any potential emission reduction requirements associated with these NAAQS revisions is uncertain at this time.

3.3.4 Coal Combustion Residuals (CCR) Rule

EPA signed the final Coal Combustion Residuals (CCR) Rule on December 19, 2014. This rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act and became effective on October 19, 2015. The CCR Rule is an extensive rule applicable to new and existing CCR landfills and CCR surface impoundments. It contains requirements, with implementation schedules, for liner design criteria for new landfills, surface impoundment structural integrity requirements, CCR unit operating criteria, groundwater monitoring and corrective actions, closure and post-closure care, and recordkeeping, notification and internet posting obligations. EPA has not included a mandatory liner retrofit requirement for existing, unlined CCR surface impoundments, however operations must cease if groundwater monitoring data indicate there has been a release from the impoundment that exceeds applicable groundwater protection standards. While the necessary site-specific analyses to determine the requirements under the final CCR Rule are on-going, initial estimates of anticipated plant modifications and capital expenditures are factored into this IRP. It should be noted that APCo's Amos and Mountaineer Plants are already equipped with dry fly ash handling systems and dry ash landfills to meet current permit requirements, and that these projects also position the plants well for future compliance with the CCR rulemaking.

3.3.5 Effluent Limitations Guidelines

On September 30, 2015 EPA finalized a revision to the Effluent Limitation Guidelines and Standards (ELG Rule) for the Steam Electric Power Generating category. The ELG Rule requires more stringent controls on certain discharges from certain electric utility steam generating units or EGUs and sets technology-based limits for waste water discharges from power plants with a main focus on process water and wastewater from FGD, fly ash sluice water, bottom ash sluice water and landfill/pond leachate. Specifically, the ELG Rule will prohibit the discharge of fly ash and bottom ash transport water while also requiring the installation of physical/chemical/biological treatment for FGD wastewater to the prescribed units.

To ensure compliance with the ELG Rule, APCo has determined that wastewater treatment projects will 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 necessary 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.

3.3.6 Clean Water Act 316(b) Rule

EPA issued a final rule under Section 316(b) of the Clean Water Act on August 15, 2014, with an effective date of October 14, 2014, The rule affects all existing power plants withdrawing more than two million gallons of cooling water per day. The rule offers seven technology options to comply with a standard that addresses impingement of aquatic organisms on cooling water intake screens and requires site-specific studies to determine appropriate compliance measures to address entrainment of organisms in cooling water systems for those facilities withdrawing more than 125 million gallons per day. The overall goal of the rule is to decrease impacts on fish and other aquatic organisms from operation of cooling water intake systems. Additional requirements may be imposed as a result of consultation with other federal agencies to protect threatened and endangered species and their habitats.

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. This determination would be made by the applicable state environmental agency during the plants' next National Pollutant Discharge Elimination System (NPDES) permit renewal cycle. 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.

3.3.7 New Source Review Consent Decree

In December 2007, AEP companies entered into a settlement of outstanding litigation (Consent Decree) concerning New Source Review compliance. Pursuant to the terms of the settlement, AEP has completed environmental retrofit projects on its Eastern units, is 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. It is projected that these lowered caps will have little or no effect on the operation of APCo's electric generating facilities.

3.3.8 Carbon Dioxide (CO_2) Regulations, Including the Clean Power Plan (CPP)

On October 23, 2015, EPA published two final rules to regulate carbon dioxide (CO_2) emissions from fossil fuel-based electric generating units. EPA finalized New Source Performance Standards (NSPS) under Section 111(b) of the CAA that apply to new fossil units, as well as separate standards for modified or reconstructed existing fossil steam units. Separately, EPA finalized the CPP, which establishes CO_2 emission guidelines for existing fossil generation sources under Section 111(d) of the CAA. EPA also issued for public comment a proposed federal plan to implement the CPP if states fail to submit or do not develop an approvable state plan for compliance.

EPA finalized CO_2 NSPS for *new* sources at 1,400 pounds CO_2 per megawatt-hour gross (lb/MWh-g) for new coal units based on the agency's assumption that carbon capture and storage technology can be implemented. Reconstructed coal units have a limit of 1,800 or 2,000 lb/MWh-g based on the size of the unit. The NSPS for modified coal units is site-specific based on historical operations. For new and reconstructed Natural Gas Combined-Cycle (NGCC) units, the NSPS was finalized at 1,000 lb/MWh-g based on the use of efficient combustion turbine designs. No limit was proposed for modified NGCC or simple cycle units.

The CPP for *existing* sources establishes separate, uniform national CO_2 emission performance rates for fossil steam units (coal-, oil-, and gas-steam based units) and for stationary combustion turbines (which EPA defines as natural gas combined cycle units). The rates were established based on EPA's application of three building blocks as the Best System of Emission Reduction (BSER) for existing fossil generating units. Block 1 assumes efficiency improvements at existing coal units. Building Block 2 assumes the increased use of NGCC units that would displace coal-based generation. Building Block 3 entails the expansion of renewable energy sources that would displace generation from both coal and NGCC units. Excluded from the BSER process was consideration of nuclear energy, simple cycle gas turbines, and EE measures (originally proposed by EPA as Building Block 4), all of which had been included in the 2014 proposed rule.

From the national emission performance rates, EPA also developed equivalent state-specific emission rate goals and equivalent state-specific mass-based goals as alternatives for the interim period (2022-2029) and the final period (2030 and beyond). States may use the national emission performance rate, the interim and final emission rate goals, or the interim and final mass-based goals to develop their state plans. Otherwise, they may demonstrate that alternative goals are justified based on state-specific circumstances and seek EPA approval of such alternative goals through the state plan. For the states in which APCo-owned or purchased fossil generation reside, EPA's state-specific equivalent mass-based goals for the interim and final compliance periods are included in Table 2. Table 3 contains the equivalent rate-based goals for the same compliance periods.

Table 2. APCo State Mass-Based Clean Power Plan Goals

	Short Tons of CO_2				
	Annual Average Interim Goal - Step 1	Annual Average Interim Goal - Step 2	Annual Average Interim Goal - Step 3	Annual Average Interim Goal	Annual Average Final Goal
State	2022 - 2024	2025 - 2027	2028 - 2029	2022 - 2029	2030+
Indiana	92,010,787	83,700,336	78,901,574	85,617,065	76,113,835
Ohio	88,512,313	80,704,944	76,280,168	82,526,513	73,769,806
Virginia	31,290,209	28,990,999	27,898,475	29,580,072	27,433,111
West Virginia	62,557,024	56,762,771	53,352,666	58,083,089	51,325,342

Table 3. APCo State Rate-Based Clean Power Plan Goals

	lb/MWh CO_2 Emission Rate				
	Annual Average Interim Goal - Step 1	Annual Average Interim Goal - Step 2	Annual Average Interim Goal - Step 3	Annual Average Interim Goal	Annual Average Final Goal
State	**2022 - 2024**	**2025 - 2027**	**2028 - 2029**	**2022 - 2029**	**2030+**
Indiana	1,578	1,419	1,309	1,451	1,242
Ohio	1,501	1,353	1,252	1,383	1,190
Virginia	1,120	1,026	966	1,047	934
West Virginia	1,671	1,500	1,380	1,534	1,305

Note: As will be described later in this document, APCo has assumed a composite state approach when addressing the implications that the CPP could have across its existing fossil generation sources. For example, when determining the impacts of a (intensity) rate-based implementation approach, it was assumed that all resources, regardless of location, would utilize a rate-based approach. This was done for both consistency and to simplify the overall implications to the whole of APCo.

EPA delayed the start of the initial compliance period from 2020 in the proposed rule to 2022 in the final. States that decide to develop a state plan to implement the CPP have the option of developing a single state plan, a multi-state plan, or a "trading ready" plan that satisfies EPA's requirements for linking state plans to facilitate multi-state trading of emissions allowances among states that use a mass-based approach, or emission rate credits among states that use a rate-based approach. A final state plan or request for extension must be submitted to EPA by September 6, 2016. A two-year extension for submitting a final state plan is available if the state meets certain criteria.

All of the compliance deadlines in the CPP have been stayed by the U.S. Supreme Court. While Virginia has continued its stakeholder meetings and plan development activities, Ohio, Indiana, and West Virginia have not devoted significant state resources to CPP planning activities in light of the stay. APCo continues to analyze the available information and engage with the states and other stakeholders in an effort to understand the available program design options and their potential impacts on its operations.

3.3.8.1 The Proposed Federal Plan and Model Rules

On the same day that the CPP was published, EPA proposed model rules that states can use to develop "trading ready" plans based on either the state rate or mass goals, and that will provide a framework for the development of a federal plan if a state plan is either not submitted or is disapproved by EPA. These proposed rules can also be used as a backstop regulatory measure for a "state measures" plan that includes programs or activities beyond those that were included in the "BSER" EPA developed as a basis for the state plans and model rules. As proposed rules, which are subject to public notice and comment, there is the potential that key elements of the model rules or EPA's proposed approach to developing a federal plan could change significantly before they are finalized and implemented.

EPA intends to finalize model rules for both the rate-based state planning option and the mass-based state planning option. EPA has proposed the same two options for a federal plan, but EPA has indicated that it would prefer to finalize only one approach that would be applied to all states that become subject to a federal plan. This would allow interstate trading among all states that become subject to a federal plan, and other states that have adopted a trading ready plan based on the same compliance pathway (rate or mass).

However, there are several key distinctions between the proposed federal plan and state plan options which could potentially affect compliance decisions and customer costs. Under the rate-based federal plan, EPA would not allow for the use of EE measures to generate Emission Reduction Credits (ERCs). This could significantly reduce the supply of ERCs for a state subject to a federal plan. Also, under the mass-based federal plan, EPA would use an allowance allocation methodology based on historic generation that includes allowance set-asides to address leakage, including providing allowances to new renewable energy sources and natural gas combined cycle units that achieve utilization rates above 50 percent. While APCo has attempted to approximate the effect of such measures within this filing, many elements of the federal plan will remain uncertain and speculative until finalized.

3.3.8.2 Virginia-Specific Target Rates Versus Subcategory-Specific Rates

If Virginia elects to pursue a state plan approach that is based on a carbon intensity rate (i.e., pounds of CO_2 per MWh of electricity produced (lb./MWh)), there are several options for program design. As noted above, EPA has established uniform national emission rates for two sub-categories: (1) existing fossil steam units (any unit that fires coal, oil, or natural gas alone or in combination with other fuels to produce steam in a boiler which is then used to produce electricity); and (2) existing natural gas-fired combined cycle units. The interim rates for steam units must average 1,534 lb./MWh over the period from 2022-2029, and eventually decline to 1,305 lb./MWh in 2030 and thereafter. For gas combined cycle units the interim rate must average 832 lb./MWh during 2022-2029 and decline to 771 lb./MWh in 2030 and thereafter.

These emission rates cannot be achieved in practice by existing units. Existing units' emission rates vary significantly, but in 2012 were about 2,200 lb./MWh for coal steam units and about 900 lb./MWh for combined cycle units on a national basis. Accordingly, if CPP emission rates become enforceable obligations for each affected unit located within Virginia, then the owners and operators of each affected unit must collect a sufficient number of ERCs to demonstrate compliance on a unit-specific basis through the calculations provided in EPA's emission guidelines. Virginia can choose to participate in multi-state trading schemes for ERCs with states also utilizing a subcategory rate approach in order to allow unit owners and operators to take advantage of the benefits of a broader trading market.

Alternatively, EPA has calculated an emission rate target for Virginia, based upon the characteristics of the fleet of affected units operating in Virginia in 2012, and their contribution to the total amount of electricity generated by affected units in that year. During the interim period, Virginia's state-specific target begins at 1,120 lb./MWh and ends at 934 lb./MWh in 2030 and beyond. If the state-specific target rates are used as the basis for the CPP, owners and operators of affected units must still assure that in the aggregate, they possess sufficient ERCs to demonstrate compliance on a state-wide basis. However, use of a Virginia specific rate approach would restrict the potential for ERC trading to credits solely generated within Virginia.

APCo would expect that, given the multi-state operations of the utilities serving the majority of Virginia electricity customers, and the advantages of participating in a multi-state trading program, choosing a program design based on the subcategory-specific rates and allowing interstate trading of ERCs would provide the greatest benefits for Virginia customers. However, further analysis of these options and their impacts should be undertaken using a production cost model capable of analyzing multiple states and their potential plan structures before a firm commitment to a particular program design is made.

3.3.8.3 Leakage and Treatment of New Units

EPA requires states that elect to adopt a mass-based emission allowance program instead of the unit-specific emission rates or equivalent state-specific rate goals described in the emission guidelines to include measures to address what it terms "leakage." EPA describes the concept of "leakage" as follows:

> *"Where shifts in generation to unaffected fossil-fuel sources result in increased emissions, relative to what would have happened had generation shifts consistent with the BSER occurred."*

In general, EPA's modeling projects that if states adopt a mass-based allowance program instead of a rate-based program, new NGCC units will displace a larger portion of the generation from existing sources, and total sector emissions (that is, emissions from both new and existing sources) will be greater.

EPA provides two methods to address the "leakage" issue in a mass-based state plan. First, states can elect to include new units in the mass-based compliance program, and EPA has calculated a "new source complement" that provides additional allowances to accommodate the new sources. Alternatively, EPA has designed two allowance set-asides that would be withheld from general distribution and instead awarded to new renewable resources or existing NGCC units that operate at capacity factors above 50 percent. While the new source complement does permanently restrain growth in emissions from electric generating units, the set-asides may not have the same effect in individual states, particularly if the state participates in a broader regional or national trading system.

EPA's authority to regulate total sector emissions pursuant to a program developed under Section 111(d), which is particularly targeted at existing units, is questionable, and the methodology used by EPA to calculate the new source complement may not be sound and provides no flexibility for unanticipated changes. States are afforded an opportunity to demonstrate that "leakage" does not need to be addressed in their plans. AEP continues to work with its states to explore ways to make such a demonstration.

3.3.8.4 Potential for Early Action ERCs/Allowances

As part of the final emission guidelines, EPA proposed to include a Clean Energy Incentive Program (CEIP) as a mechanism to award up to an additional 300 million ERCs or allowances to certain types of projects that commence construction after the date for submittal of a final plan and operate during 2020 and 2021. For purposes of the federal plan that EPA would administer, only wind and solar renewable energy projects that produce revenue-quality metered electricity would be eligible. States can include broader categories of renewable resources in the plans they submit for EPA approval. EPA has also proposed to award ERCs or allowances to certain EE projects in low income communities, but the details of the program have not been fully developed.

The CEIP provides credit for a very narrow range of activities, and requires states to "match" the federal credits or allowances with ERCs or allowances that are "borrowed" from their state budgets. EPA has solicited comments on all aspects of the CEIP and may substantially change the program in its final model rules. Until there is some certainly regarding eligibility and the mechanics of applying for and receiving credit for early actions, it is not possible to quantify its impact.

3.3.8.5 Trading of Emissions Allowances or Emission Reduction Credits (ERCs) and Role of Renewable Resources

APCo currently owns two existing natural gas-fired steam generating units in Virginia, four existing coal-fired steam generating units in West Virginia, an existing NGCC facility in Ohio, and purchases energy from an existing coal-fired generating station in Ohio and an existing coal-fired generating facility in Indiana. APCo also owns existing hydroelectric facilities in Virginia and West Virginia, and purchases power from renewable energy facilities in West Virginia, Indiana and Illinois, but these facilities are not eligible to participate in any of the programs under the CPP.

Adoption of a regional or national trading system for allowances or ERCs by the states within which APCo is operating is likely to reduce the overall costs of compliance and allow for greater compliance flexibility. It may not be necessary to define a specific "region" in order to take advantage of the benefits of a trading program. EPA guidelines would allow states to trade freely with other states that choose the same fundamental program design (rate- or mass-based) and whose "currency" (allowances or ERCs) are generated and tracked through an EPA-administered or EPA–approved program as outlined in the model trading rules.

The benefits gained by participation in a broader market-based system result from the market's greater liquidity which allows for more efficient use of available compliance instruments. Interstate trading would also enable affected sources to take advantage of the best geographic locations available to generate renewable energy to either provide supplemental energy for Virginia customers under a mass-based program or generate ERCs to assist in compliance with a rate-based program. It is not possible to reach a firm conclusion about the most cost-effective approach for Virginia without more detailed information and better insight into the final framework of the CPP, and the approaches that other states are likely to take. However, prior analyses by various regional transmission organizations, including PJM Interconnection, LLC, the Midwest Independent System Operator (MISO), and the Southwest Power Pool, suggest that a multi-state trading program would be more cost-effective. Further analysis by these organizations may bring better focus to this issue.

It seems unlikely that a state-specific program with limited in-state trading would be the most cost-effective option for APCo customers under either a rate-based or mass-based approach. Broader markets generally produce more cost-effective reductions, and several of Virginia's utilities have operations in multiple states, so compliance planning and optimization of the most cost-effective compliance strategies across multiple jurisdictions would be facilitated by a more robust interstate trading program.

3.3.8.6 Other States' Compliance Planning Approaches

As of the date of this filing, Indiana, Ohio, and West Virginia have not determined specific compliance planning approaches. As a result of the stay issued by the U.S. Supreme Court, there are currently no additional compliance activities planned by these states until after judicial review is completed.

3.3.8.7 Long-Term Recommendations

Given the significant issues regarding EPA's authority to adopt and implement the CPP, the changes that might be made to the proposed federal plan and model rules based on comments received, and the limited state planning that has occurred, it is not possible to provide any long-term recommendations at this time. However, as explained later in this Report, the Hybrid Plan presented in this IRP is designed, in part, to preserve reasonable CPP implementation optionality, regardless of the rule's ultimate outcome, and, as a result, minimize attendant future cost exposures to the Company and its customers.

3.3.8.8 Potential Need for Changes in Virginia Law to Implement the CPP

Because no specific information about the potential structure of a state plan to implement the CPP is available, it is difficult to provide any comprehensive view of the changes that might be needed to Virginia law. Currently, the Air Pollution Control Board (the Board) has authority to develop and adopt regulations governing air pollutant emissions from stationary sources like power plants, but beyond regulating air emissions, the Board has no regulatory authority over the operation of existing electric generating units, nor any authority to require the construction or use of specific types of new generation, particularly non-emitting forms.

The General Assembly has given the Board limited authority to develop emissions trading programs in Code § 10.0-1322.3. The General Assembly authorized the Board to develop emissions trading programs solely for the purpose of achieving and maintaining the national ambient air quality standards (NAAQS) under Section 108 of the CAA. Such programs must result in net emissions reductions, create economic incentives for reducing air emissions, and allow for continued economic growth. In addition, for electric generating units specifically, such programs must foster competition and encourage the construction of new clean generating units. Specific requirements for new unit set-asides, offsets, trading with mobile sources, and consideration of allocations are also provided in the statute. Regulations adopted by the Board cannot prohibit trading of credits or allowances between private industries, provided that trades do not adversely impact Virginia air quality. Substantial additional authority would have to be granted to the Board by the General Assembly to fully implement the CPP.

Certain aspects of the CPP may also conflict with Virginia's integrated resource planning structure or other aspects of Virginia utility law and regulations. For example, Virginia's IRP authorizing statutes direct electric utilities to formulate a plan that "is most likely to provide the electric generation supply needed to meet the forecasted demand, net of any reductions from demand side programs, so that the utility will continue to provide reliable service at reasonable prices over the long term. " Va. Code § 56-598 2a. An IRP should also "reduc[e] load growth and peak demand growth through cost-effective demand reduction programs. " *Id.* at 1c. Moreover, the Commission's Integrated Resource Planning Guidelines ("Guidelines") direct that utilities provide detailed information on levelized busbar costs, annual revenue requirements or equivalent methodology for various supply-side and demand side options, Guidelines § F7, and engage in a "comprehensive analysis of all existing and new resource options . . . necessary to provide reliable electric utility service, at the lowest reasonable cost, over the planning period. " Guidelines at § C 2.

In anticipation of the CPP, the Virginia General Assembly enacted Senate Bill 1349, establishing the Virginia Transitional Rate Period. *See* Virginia Code §§ 56-585.1:1 (Transitional Rate Period: review of rates, terms and conditions for utility generation facilities); 56-599 (Integrated Resource Plan Required). The legislation directed the Commission to report to legislators annually on the projected cost and anticipated rate impacts of various CPP compliance options. Va. Code § 56-599 A; 56-585.1:1 F1-2. In order to fulfill these requirements, the Commission ordered electric utilities to provide in their 2016 IRPs "multiple plans that are each compliant with the Clean Power Plan, under both a mass-based approach and an intensity-based approach . . . ." *See, e.g.* In re: Appalachian Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597, *et seq*., Case No. PUE-2015-00036, Final Order entered February 1, 2016 at 4-5). It also ordered APCo to include in its IRP "a least-cost compliant plan where the Plexos model is allowed to choose the least-cost path given the emission constraints imposed by the Clean Power Plan." *Id.* at 4.

Assuming the CPP is implemented in its current form after review by the U.S. Supreme Court, APCo's least-cost compliant plan will depend not only on the choices made by Virginia regulators, but also on the choices made by regulators in other states. While Virginia could attempt to structure its CPP state plan submittal to allow for separate CPP compliance pathways for each regulated utility that represents a "least-cost compliant plan" based on the current integrated resource planning statutes and regulations, Virginia legislators may need to provide utilities with greater flexibility in formulating such plans, and to allow the Commission greater discretion in evaluating a CPP-compliant IRP. EPA's model rules contemplate a much different approach, where multiple states adopt "trading ready" programs that can interact with one another.

In addition, statutes and regulations governing the selection of individual resource options may need to be harmonized with whatever state or federal CPP compliance plan emerges, as well as with each other. Virginia utility law currently provides utilities with a menu of resource options with which to meet forecasted demand and ensure reliability of service. The CPP, on the other hand, sets broad emissions targets, but does not mandate the means by which individual utilities must achieve compliance. During Virginia's Transitional Rate Period retirement of an electric power generation facility is restricted pending CPP implementation. Va. Code § 56-585.1:1 E. The statute also creates incentives for construction or purchase of certain solar generation facilities located within the Commonwealth and establishes a statutorily-mandated, *prima facie* finding that such facilities are in the public interest regardless of whether they are located within the utility's service territory. Va. Code § 56-585.1:1 G. Other, non-solar new generation facilities remain subject to approval based on a finding that such facilities are "necessary to enable the public utility to furnish reasonably adequate service and facilities at reasonable and just rates." Va. Code § 56-234.3. Utility-sponsored DSM programs, on the other hand, are subject to approval according to a rigorous cost/benefit analysis. 20 VAC 5-304-20; 20 VAC 5-304-30. The legislature may need to consider the impact of these provisions on the practicality of implementing either a state or federal plan, and adjust the requirements for approval of potentially CPP-compliant resource options.

Based on all of the foregoing considerations, and others that have not yet been identified, the existing authorities granted to the Board and/or the Commission may not be sufficient to create an optimal state plan, or facilitate the implementation of a federal plan as envisioned by the CPP. However, obligations related to the development of a state plan have been stayed, and the federal plan has not yet been finalized, so it is not possible at this time to describe any necessary state law changes with specificity.

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 reduce consumption at the peak are DR programs, while around-the-clock measures are typically categorized as 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 previously approved in Virginia and West Virginia. 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 smart-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 2016, the Company anticipates 163MW of peak DR (total company basis); consisting of 21MW and 142MW of "passive" EE and "active" DR activity, respectively.[10] In 2020, when Capacity Performance is in effect, the Company anticipates "active" DR will be reduced to 123MW, as discussed in Section 3.2.1.

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. Many of the standards already in place impact lighting. For instance, beginning in 2013 and 2014 common residential incandescent lighting options have begun their phase out as have common commercial lighting fixtures. Given that "lighting" options have comprised a large portion of utility-sponsored EE programs over the past decade, 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

Technology	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
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 total energy efficiency, including codes and standards, is expected to reduce retail load by nearly 8%, as shown in Figure 8.

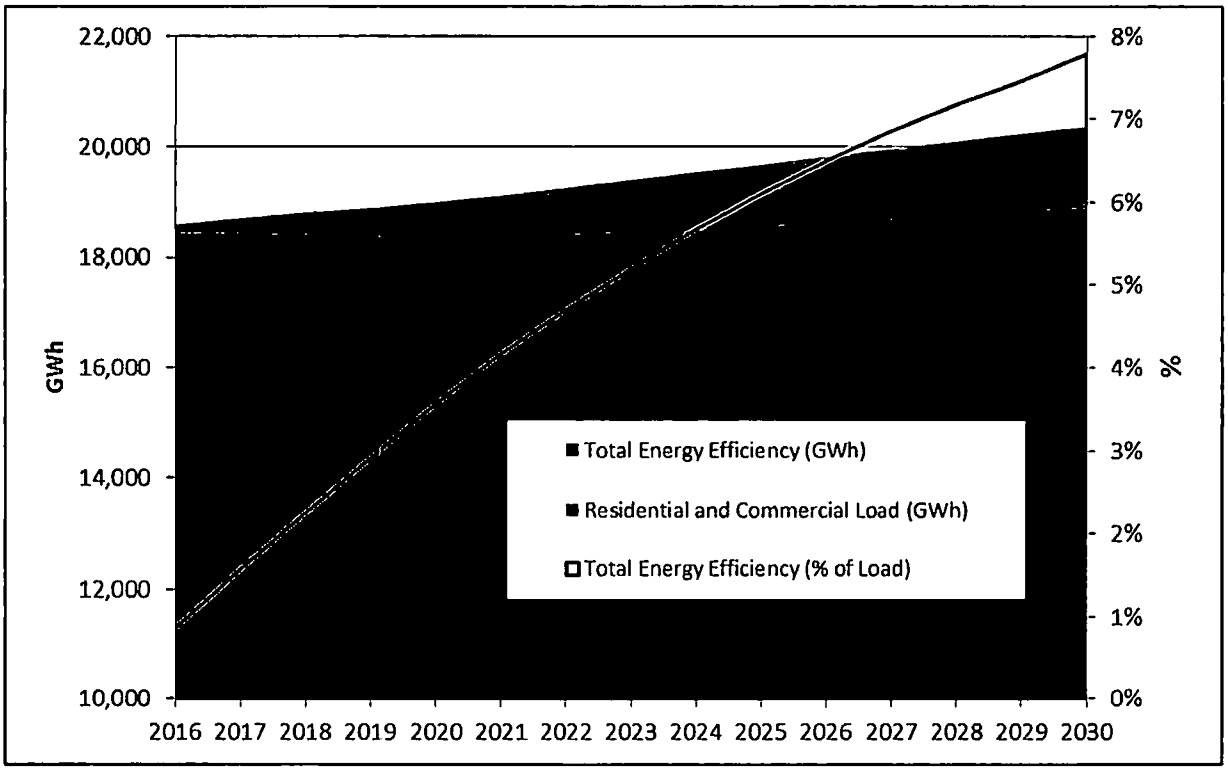

Figure 8. Total Energy Efficiency (GWh) Compared with Total Residential and Commercial Load (GWh)

3.4.3 Demand Response (DR)

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 electric heating by the majority of customers, as well as the normal use of other appliances and, commercial equipment, and (industrial) machinery. At other times during the day, and throughout the year, the use of power is less. In the context of capacity planning for PJM, it is the consumption of energy coincident with PJM's five highest summer peaks.

As peak demand grows with the economy and population, new 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 via both "active" and "passive" measures:

- *Interruptible loads (Active DR).* 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 (Active DR).* 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 (Active DR).* 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 (Passive DR).* 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 (Passive DR).* Certain technologies 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.; 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 Active Demand Response (DR)

APCo currently has active DR programs totaling 193MW 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 a credit to their bill. The current Virginia program is designed to allow 3,000 residential customers to sign up each year during 2015, 2016, and 2017. Each block of 3,000 customers is estimated to provide up to 2.7MW in demand savings. APCo's West Virginia jurisdiction has a similarly sized program.

3.4.4 Energy Efficiency (EE)

EE measures reduce bills and save money for customers billed on a per kilowatt-hour usage basis. The trade-off is the up-front investment in a building/appliance/equipment modification, upgrade, or new technology. If the consumer concludes that the new technology is a viable substitute and will pay him back in the form of reduced bills over an acceptable period, he 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, as summarized in Table 6, market barriers to EE may exist for the potential participant.

Table 6. Energy Efficiency Market Barriers

High First Costs	Energy-efficient equipment and services are often considered "high-end" products and can be more costly than standard products, even if they save consumers money in the long run.
High Information or Search Costs	It can take valuable time to research and locate energy efficient products or services.
Consumer Education	Consumers may not be aware of energy efficiency options or may not consider lifetime energy savings when comparing products.
Performance Uncertainties	Evaluating the claims and verifying the value of benefits to be paid in the future can be difficult.
Transaction Costs	Additional effort may be needed to contract for energy efficiency services or products.
Access to Financing	Lending industry has difficulty in factoring in future economic savings as available capital when evaluating credit-worthiness.
Split Incentives	The person investing in the energy efficiency measure may be different from those benefiting from the investment (e.g., rental property)
Product/Service unavailability	Energy-efficient products may not be available or stocked at the same levels as standard products.
Externalities	The environmental and other societal costs of operating less efficient products are not accounted for in product pricing or in future savings

Source: Eto, Goldman, and Nadel (1998): Eto, Prahl, and Schlegel (1996); and Golove and Eto (1996)

To overcome many of the participant barriers noted above, a portfolio of EE programs may often include several of the following elements:

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

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

Additionally, the speed with which programs can be rolled out also varies with the jurisdictional differences in stakeholder and regulatory review processes. The lead time can easily exceed a year for getting programs implemented or modified. This IRP begins adding new demand-side resources in 2019 that are incremental to currently approved programs.

3.4.4.1 Existing Levels of Energy Efficiency (EE)

APCo currently has DSM (i.e. EE) programs in place in its Virginia and West Virginia service territories. Both states have approved rate-design programs to promote EE programs. APCo has installed EE measures that reduced peak demand in 2016 by 11.9MW and reduced 2016 energy consumption by 79GWh.

3.4.5 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.

The economics of DG, particularly solar, continue to improve. Figure 9, below, 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) Installed Cost of Solar forecast. The costs shown in Figure 9 account for the Federal Investment Tax Credit (ITC) (30% through 2019, 26% through 2020, 22% through 2021, and 10% thereafter).

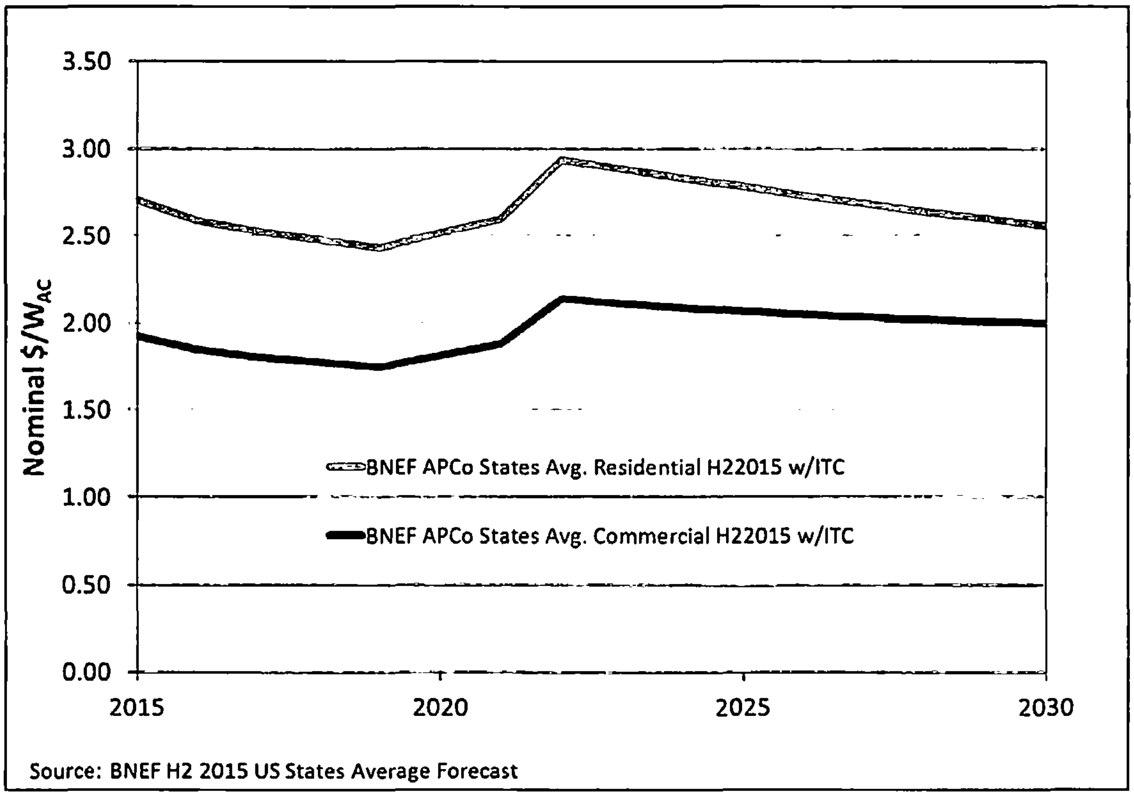

Figure 9. Residential and Commercial Forecasted Solar Installed Costs (Nominal $\$/W_{AC}$) for APCo States

While the cost to install residential solar continues to decline, the economics of such an investment are not favorable for the customer. Figure 10, below, illustrates, by APCo state jurisdictional residential sector, the equivalent value a customer would need to achieve, on a dollars per watt-AC ($\$/W_{AC}$) basis, in order to breakeven on their investment, assuming a 30 year life of the installed solar panels based on the customer's avoided retail rate. Also included is the average cost of solar residential installations in the U.S. Figure 10, below, 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.

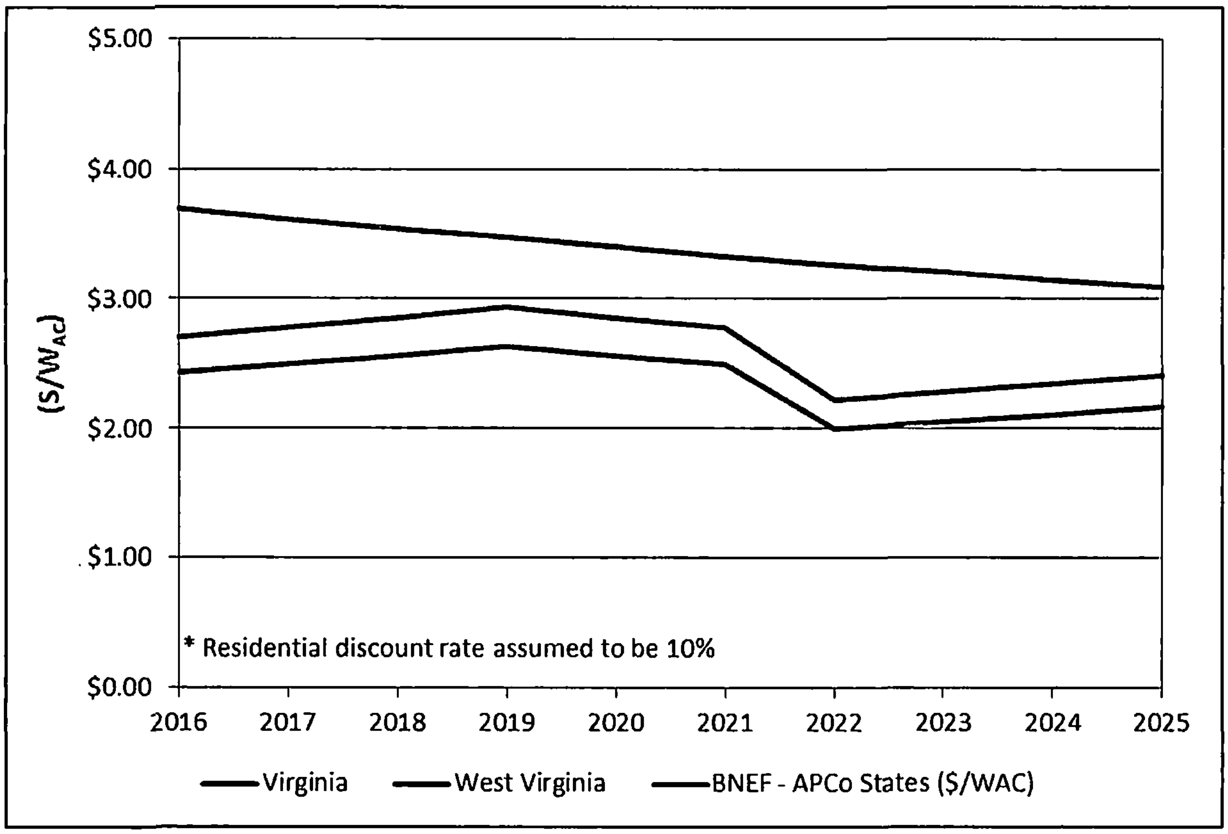

Figure 10. Distributed Solar Customer Breakeven Costs for Residential Customers ($\$/W_{AC}$)

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 11, below, shows how the value of a residential customer's DG system can vary based on discount rate.

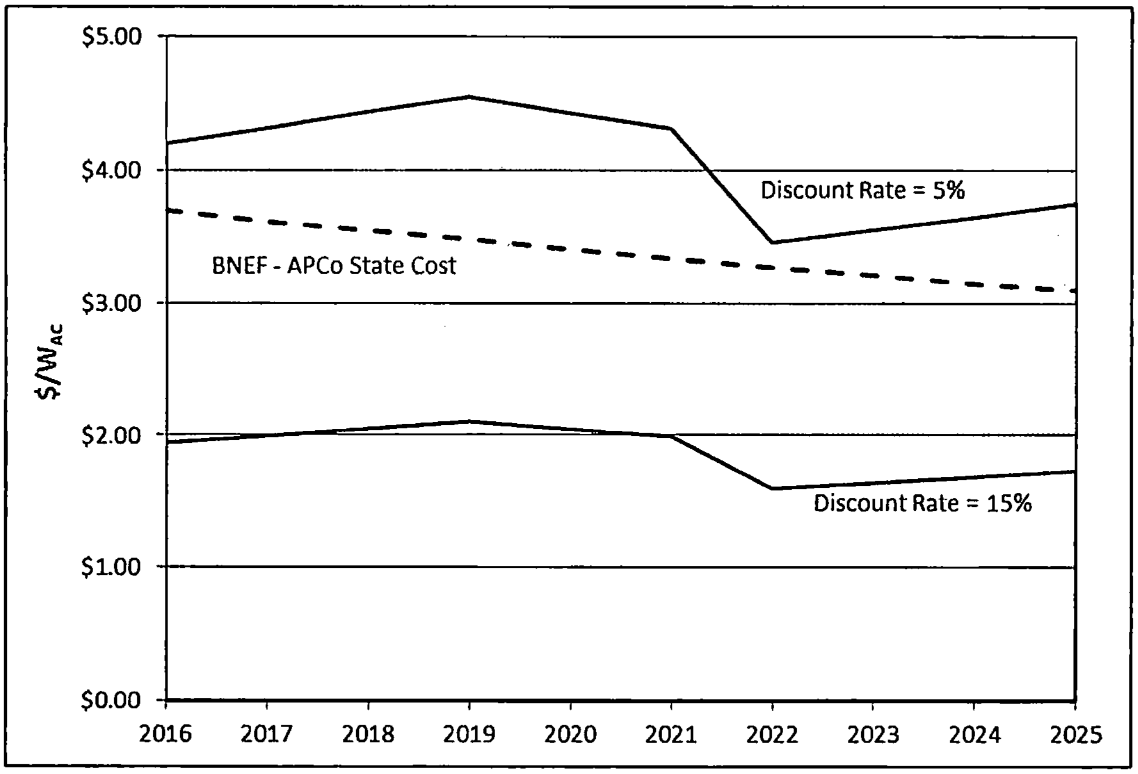

Figure 11. Range of Residential Distributed Solar Breakeven Values Based on Discount Rate

3.4.5.1 Existing Levels of Distributed Generation (DG)

APCo currently has a total of 5.6MW of DG installed throughout the service territory, consisting of 0.2MW in Tennessee, 4.7MW in Virginia, and 0.7MW in West Virginia.

3.4.5.2 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 12 below, illustrates the load profile for a representative net-metered customer with a rooftop solar installation.

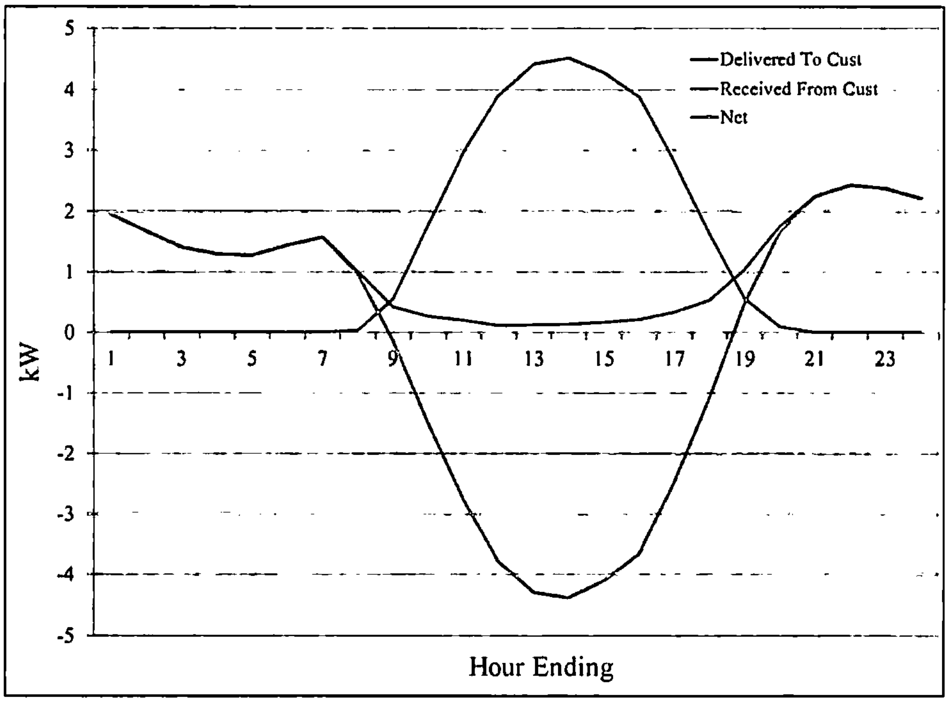

Figure 12. Summer Load Profile for Representative Net-Metered Customer with Rooftop Solar Installation

The green line in Figure 12 shows a negative net load for the customer from approximately 9am until 6pm. During these times the customer's system is 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.

During winter months the customer typically is not able to produce more electricity than they consume. Figure 13, below, illustrates the load profile for the same representative net-metered customer during the winter season.

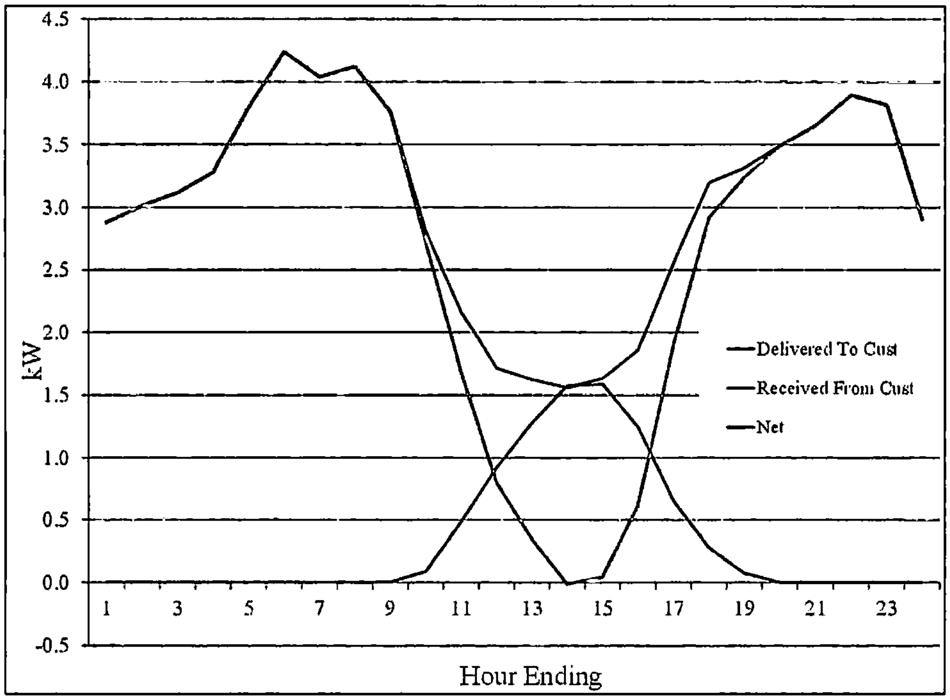

Figure 13. Winter Load Profile for Representative Net-Metered Customer with Rooftop Solar Installation

The green line in Figure 13 depicts the customer's net load. Because this net load is almost always positive the customer is rarely outputting to the electric grid during the winter season. Figure 13 also illustrates the lack of generation during hours of peak demand, as shown by the overlapping of the green and blue lines in the morning and evening.

3.4.5.3 Impacts of Increased Levels of Distributed Generation (DG)

As mentioned previously, rooftop solar installations allow a customer 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 true peak demand. As discussed in Section 2.0, APCo's overall peak demand generally occurs in the early morning on a winter day. During these times of peak demand rooftop solar installations are providing little to no demand savings. Figure 14 below, shows the electrical demand for an

APCo net-metered customer and a "traditional" APCo customer on a day representative of APCo's peak day.

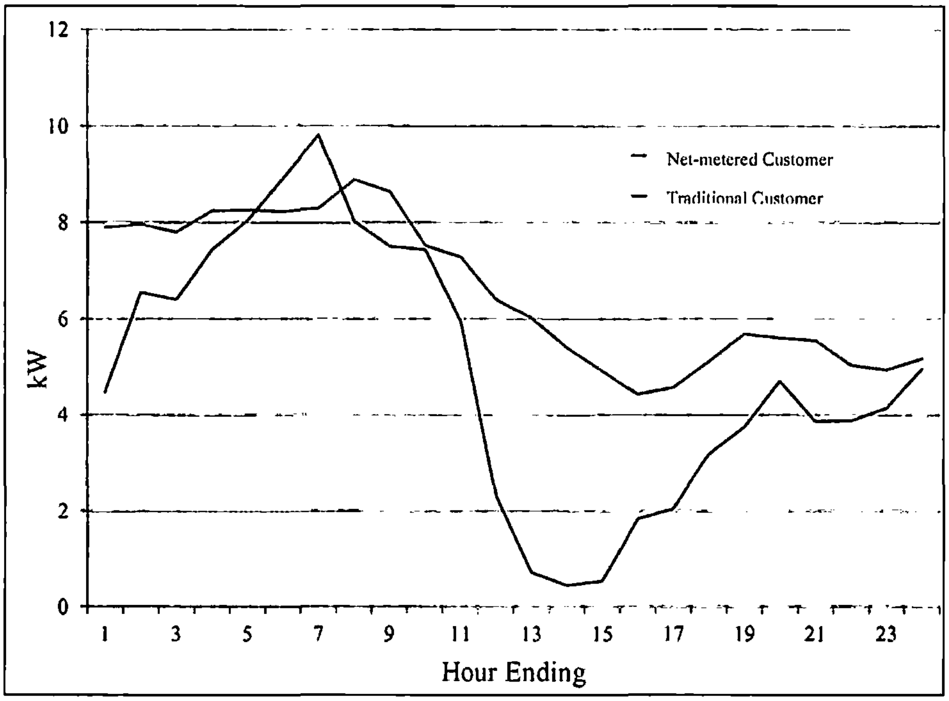

Figure 14. Electrical Demand of APCo Rooftop Solar Customer and Average "Traditional" Customer

Figure 14 demonstrates that both customers exhibit similar peak demands during the early morning hours which coincide with APCo's peak demand. The lack of peak demand savings in the winter months means that APCo must still plan to meet its overall demand absent any rooftop solar power. Therefore rooftop solar does not alleviate APCo's overall distribution and transmission requirements, as they relate to peak demand.

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.

3.4.6 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 15, 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 AEP affiliate operating companies indicate a range of 0.7% to 1.2% of energy demand reduction for each 1% voltage reduction is possible.

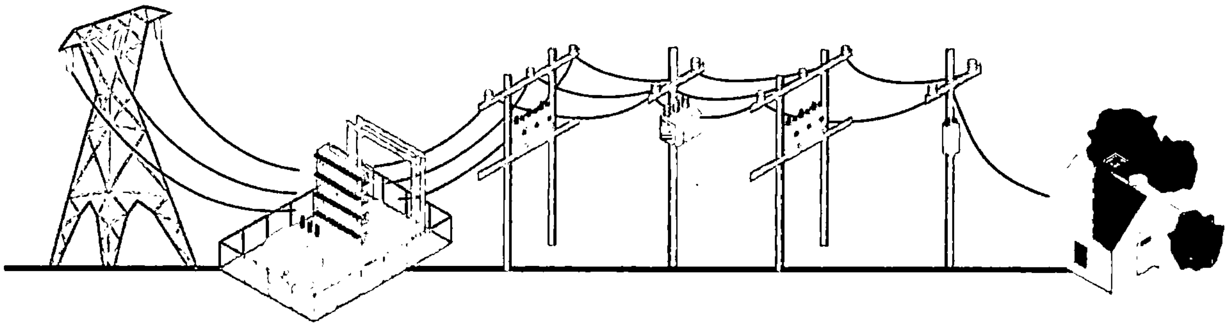

Figure 15. Volt VAR Optimization Schematic

While there is no "embedded" VVO load reduction impacts implicit in the base load forecast case, VVO has been modeled as a unique EE resource. The results of this modeling are discussed in Section 5.3.2.

3.5 AEP-PJM Transmission

3.5.1 General Description

The AEP eastern transmission system (eastern zone) consists of the transmission facilities of the six eastern AEP operating companies (APCo, Ohio Power Company [OPCo], Indiana Michigan Power [I&M], Kentucky Power Company [KPCo], Wheeling Power Company [WPCo], and Kingsport Power Company [KgPCo]). This portion of the transmission system is composed of approximately 15,000 miles of circuitry operating at or above 100kV. The eastern zone includes over 2,100 miles of 765kV transmission lines overlaying 3,800 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 24,200MW 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 enhancement to the AEP eastern transmission system over the last few 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 16 demonstrates the development of AEP's eastern 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.

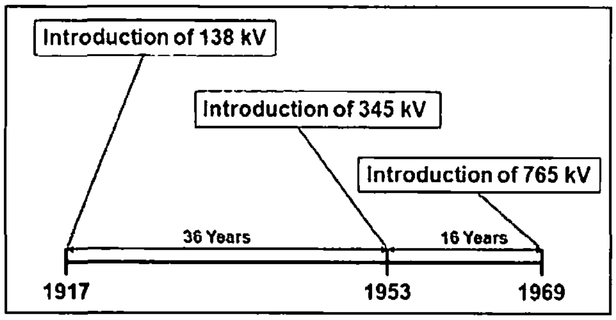

Figure 16. AEP Eastern Transmission System Development Milestones

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, in conjunction with PJM, has interconnection agreements in the AEP service territory with several merchant plant developers for approximately 1,000MW of additional generation to be connected to the eastern transmission system over the next several years. 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 MISO markets.

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, 1575 miles of 138kV, 631 miles of 69kV, 48 miles of 46kV and 92 miles of 34.5kV lines. APCo's West Virginia service territory includes approximately 382 miles of 765kV, 309 miles of 345kV, 1,179 miles of 138kV, 37 miles of 88kV, 349 miles of 69kV, 688 miles of 46kV, and 56 miles of 34.5kV lines.

The retirement of 13,000MW of generation in PJM, including 325MW at Glen Lynn in Virginia, coupled with the 800MW at Big Sandy in Kentucky, 400MW at Kanawha River, 630MW at Kammer, and 1050MW at Sporn in West Virginia, has created a need to develop transmission improvements within the APCo footprint. The retirement of these units requires deployment of improvements of the Virginia/West Virginia/Ohio/Kentucky infrastructure. There are three areas in particular that require transmission enhancements to maintain and allow sustainable reliable operation of the transmission network in the area encompassing APCo's Virginia and West Virginia service areas:

- **AEP-Dominion Interface** – The power flow patterns of the interface driven by generation availability, winter loading conditions, peak and off-peak load levels, will require significant transmission enhancements, additions of reactive support - both static and dynamic. The Cloverdale Station Improvements and re-conductor of the Cloverdale-Lexington 500kV line will address a majority of these issues in the near term. Additional major 765/138kV improvements like the Wythe Area Improvements will also address the mitigation of voltage problems which have been previously identified.
- **Megawatt Valley** — the Gavin/Amos/Mountaineer/Flatlick area currently has stability limitations and reliability issues during multiple transmission outages. Multiple overlapping transmission outages will require the reduction of generation levels in this area to ensure continued reliable transmission operation, although such conditions are expected to occur infrequently. Generation resource additions and retirements in the Gavin/Amos/Mountaineer/Flatlick area are influencing these stability constraints, requiring transmission enhancements–possibly including the construction of EHV lines and/or the addition of multiple large transformers– to more fully integrate the transmission facilities in this generation-rich area. Thermal constraints also need to be addressed.
- **The Kanawha Valley** — Power plant retirements in the Kanawha and Ohio River valleys have changed the way electric power flows on the electric transmission grid. To accommodate those changes and address additional issues identified by PJM, upgrades

are needed to the grid in West Virginia, with most of the work slated for the Kanawha Valley. The Kanawha Valley Area Transmission Reinforcement project, along with the Kammer Area Improvements will address these issues in the near term.

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[11]. 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.

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 reinforcements. Through this on-going process, AEP works

[11] http://www.aep.com/about/codeofconduct/OASIS/TransmissionStudies/GuideLines/AEP_East_FERC_715_2016_Final_Part_4.pdf

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[12] 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 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

[12] 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.

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 2016 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 affiliate AEP West Virginia Transmission Company, Inc. (WV Transco), 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 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 service territory for the 2015-2020 timeframe is provided below. Project information includes the project name and a brief description of the project scope.

Cloverdale Station Improvements: The upgrades are required in order to mitigate issues identified with transmission planning criteria, improve the reliability of the transmission system in the Roanoke, Virginia area and the interface capacity and operational performance between AEP and Dominion Virginia Power by eliminating congestion and reinforcing the existing network for future growth. In summary, the major scope of work includes establishing a new Cloverdale East 500kV station, installation of a new 765/500kV, 2250MVA transformer and replacement of two 500/345kV, 1500MVA transformers and associated circuit breakers.

Cloverdale-Lexington 500kV Re-Conductor: This project was developed in order to mitigate issues with planning criteria, address identified congestion issues, maintain adequate and reliable electrical service to the surrounding area, and to relieve the significant market congestion on the AEP-Dominion interface. The major scope of work includes re-conductoring 36 miles of the AEP owned portion of the Cloverdale-Lexington 500kV line in order to increase the thermal capability improving the reliability of the regional transmission system and operational performance.

Christiansburg Area Improvements: An analysis identified that during projected summer 2015 peak load conditions, a single contingency outage of the 138kV Merrimac Tap Line, Merrimac 138/69kV transformer, or the North Blacksburg 138/69kV transformer would overload the Midway-South Christiansburg 69kV sub-transmission circuit serving the Town of Christiansburg beyond its maximum allowable thermal limit, which could have jeopardized service to over 160MW of sub-transmission load. The major scope of work, which has been completed, included the construction of a 138kV line between the

Falling Branch and Merrimac Substations on the east side of Christiansburg establishing two-way service to the existing Vicker and Merrimac Substations, increasing transmission service reliability to the area. Also, a new 138/69kV transformer has been installed at Merrimac Substation to improve reliability and prevent thermal violations.

South Lynchburg Area Improvements: The South Lynchburg area has approximately 65MW of combined load served from Brush Tavern, George Street, and Lawyers Substations which are served radially by a transmission source. In order to provide adequate service reliability to these radially served substations, this project will provide two-way service by constructing approximately 4.0 miles of new 138kV line from Brush Tavern to a newly established 138/12kV distribution station (Lynbrook) and rebuilding the 69kV line to 138kV between South Lynchburg and Lawyers stations. The new Lynbrook station will replace the existing Lawyers station and will be located approximately 1 mile south of Lawyers station. George St. Station will be converted to 138kV by replacing the 69/12kV transformer with a 138/12kV 20MVA transformer. The new Lynbrook station will include a new 138/12kV 20MVA transformer. In addition, new 138kV breakers are being installed at New London, Brush Tavern and South Lynchburg stations, improving the reliability of the 138kV system.

Wythe Area Improvements: The Wythe Area Improvements project addresses transmission planning voltage deviation criteria violations in excess of 8%, improved the reliability of the existing transmission network in the Wytheville, VA area, and reinforced the electrical infrastructure for future growth. The major scope of work consists of constructing a 17 mile line from Jacksons Ferry to Progress Park and Wythe Substations. Also, a second 765/138kV transformer was installed at Jacksons Ferry. In summary, the project will mitigate planning voltage criteria issues, enhance operational performance and reliability to over 295MW of load, introduce a new source into the Wythe area and provide flexibility for routine maintenance of the transmission system.

<u>**Abingdon Area Improvements**</u>: The Abingdon Area Improvements addresses an overload on the Abingdon-Hillman Highway 69kV line and the Abingdon 138/69kV transformer due to the outage of the Meadowview 138/69kV transformer. The major scope of work includes construction of a new 138/69/12kV South Abingdon Station connected to the Broadford-Wolf Hills 138kV circuit via a new double circuit 138kV line. Also, a new 69kV line will be constructed between the new South Abingdon and Arrowhead Station, which will be built to 138kV standards.

<u>**Bland Area Improvements**</u>: The Bland Area Improvements addresses thermal criteria issues on the Tazewell-Buckhorn line in addition to voltage magnitude issues in the South Princeton area for the outage combination of Glen Lyn-Hinton 138kV and Jim Branch-Switchback 138kV lines. The major scope of work includes rebuilding the Wythe-South Bluefield 69kV to 138kV, re-routing the new line into Progress Park 138kV station, and replacing Bland 69kV station with Town Creek 138kV station.

<u>**Tazewell-Bearwallow 138kV**</u>: A comprehensive program to replace the aging 69kV sub-transmission system in Tazewell County, Virginia with a new 138kV transmission network includes rebuilding approximately 12.5 miles of the existing Tazewell-Bearwallow 69kV line, of which 7.8 miles is located in Virginia; the remaining line is located in McDowell County, West Virginia.

<u>**Richlands-Whitewood Rebuild**</u>: A new 8.0 mile 138kV line from Richlands to Whitewood is to be constructed in Tazewell and Buchanan Counties in addition to a new switchyard. This solution addresses thermal and voltage issues projected in 2017.

Other major transmission projects previously undertaken, or currently being performed by APCo, and/or WV Transco, are as follows:

Kanawha Valley Area Transmission Reinforcement Project: As addressed above, power plant retirements in the Kanawha and Ohio River valleys changed the way electric power flows on the electric transmission grid. To accommodate those changes and address additional issues identified by PJM, upgrades are needed to the grid in West Virginia, with most of the work slated for the Kanawha Valley. The upgrades include rebuilding existing transmission lines and upgrades to substations, such as the addition of a 450MVA 345/138kV transformer at the Kanawha River station, which has been completed. The bulk of the Kanawha Valley work will take place between APCo's Amos Plant and its Turner and Cabin Creek substations, with a key loop in the Cross Lanes area and another in the Kanawha City area. Additional work will be done to facilities that feed off the backbone transmission line that runs from Poca to Cabin Creek.

Fayette County Area Transmission Improvements: PJM has identified voltage, thermal, and reliability concerns in Fayette County, West Virginia and in the surrounding areas. 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.

McDowell Area Improvement Project: The McDowell Area Improvement Project will boost the electric transmission grid reliability in the region. The

McDowell Area Improvements Project will also provide southern West Virginia with an infrastructure capable of handling future economic growth. The project includes: removal of approximately 35 miles of existing 88kV transmission line, rebuilding and upgrading approximately 17 miles of an existing transmission line to 138kV, retirement of two substations, construction of three new substations, and upgrades at various existing substations.

Wyoming 765kV Reactor Addition: This project was developed in order to mitigate operational high voltage constraints identified on the APCo 765kV system during off peak time periods. The major scope of work includes the addition of a new 300 MVAR shunt reactor connected via a new 765kV circuit breaker at Wyoming station.

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 expansion plan that balances "least-cost" objectives with planning flexibility, asset mix considerations, adaptability to risk, and conformance with applicable NERC and RTO criteria. In addition, the planning effort must ultimately be in concert with anticipated long-term requirements established by the EPA-driven environmental compliance planning process. Resources selected through the modeling process are not locational specific.

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

In general, assumptions and plans are continually reviewed and modified as new information becomes available to ensure that market structures and governances, technical parameters, regulatory constructs, capacity supply, energy adequacy and operational reliability, and environmental mandate requirements are routinely reassessed to ensure optimal capacity resource planning.

Further impacting this process are a growing number of federal and state initiatives that address many issues relating to industry restructuring, customer choice, and reliability 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 establishment of the least-cost plan, with *cost* being more accurately described as *revenue requirement* under a traditional ratemaking construct.

That does not mean, however, that the best or optimal plan is the one with the absolute least cost over the planning horizon evaluated. Other factors–some more difficult to monetize than others–were considered in the determination of the Hybrid Plan. Sensitivity analyses were performed to understand the impact of addressing factors which may increase costs.

part 3

4.2 Methodology

The IRP process aims to address the long-term "gap" between resource needs and current resources. Given the various assets and resources that can satisfy this expected long-term gap, a tool is needed to sort through the myriad of potential combinations and return an optimum solution–or portfolio–subject to constraints. *Plexos®* is the primary modeling application, used by APCo and AEP for identifying and ranking portfolios that address the gap between needs and current available resources.[13] Given the cost and performance parameters around sets of potentially-available supply- and demand-side proxy resources 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 Fundamental Modeling Input Parameters

The AEP Fundamental Analysis group prepares the Long-Term North American Energy Market Forecast ("Fundamentals Forecast") with support from the proprietary AURORA^{xmp} Energy Market Model ("AURORA^{xmp}"). Similar to Plexos®, AURORA^{xmp} is a long-term fundamental production cost-based energy and capacity price forecasting tool developed by EPIS, Inc., that is driven by comprehensive, user-defined commodity input parameters. For example, nearer-term unit-specific fuel delivery and emission allowance price forecasts, based upon actual transactions, which are established by AEP Fundamental Analysis and AEP Fuel, Emissions and Logistics, are input into AURORA^{xmp}. Estimates of longer-term natural gas and coal pricing are provided by AEP Fundamental Analysis in conjunction with input received from

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[13] *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.

consultants, industry groups, trade press, governmental agencies, and others. Similarly, capital costs and performance parameters for various new-build generating options, by duty-type are vetted through AEP Engineering Services and incorporated into the tool. Other information specific to the thousands of generating units being modeled is researched from Velocity Suite, an on-line information database maintained by Ventyx, an ABB Company. This includes data such as unit capacity, heat rates, retirement dates and emission controls status. Finally, the model maintains and determines region-specific resource adequacy based on regional load estimates provided by AEP Economic Forecasting, as well as current regional reserve margin criterion. AEP uses AURORA^{xmp} to model long-term (market) energy and capacity prices for the entire U.S. eastern interconnect as well as Electric Reliability Council of Texas (ERCOT). The projection of a CO_2 pricing proxy is based on assumptions developed in conjunction with the AEP Strategic Policy Analysis organization. Figure 17 shows the Fundamentals process flow for solution of the long-term commodity forecast. The input assumptions are initially used to generate the output report. The output is used as feedback to change the base input assumptions. This iterative process is repeated until the output is congruent with the input assumptions (*e.g.*, level of natural gas consumption is suitable for the established price and all emission constraints are met).

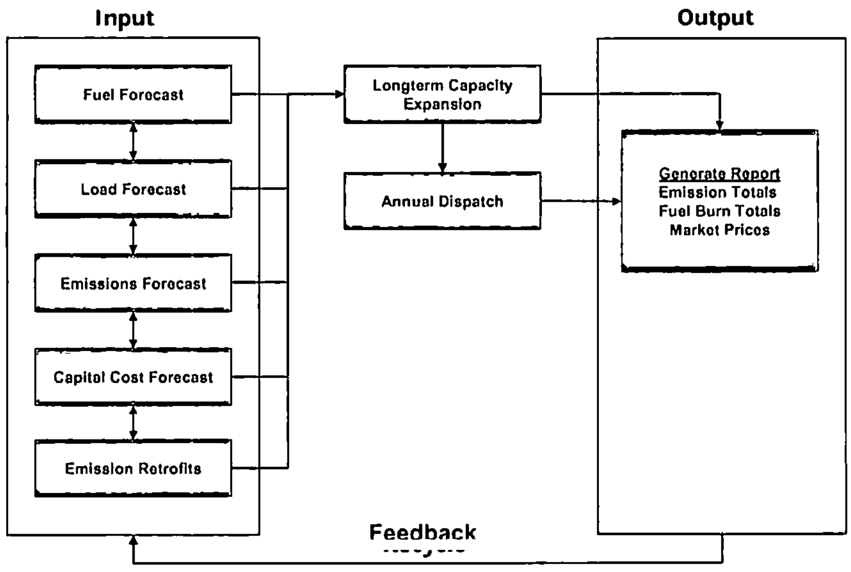


Figure 17. Long-term Power Price Forecast Process Flow

4.3.1 Commodity Pricing Scenarios

Four commodity pricing scenarios were developed by AEP Fundamental Analysis for APCo to enable Plexos® to construct resource plans under various long-term pricing conditions. In this Report, the four distinct long-term commodity pricing scenarios that were developed for Plexos® are the Mid, Low Band, High Band, and No Carbon scenarios. The overall fundamental forecasting effort was completed in July of 2015. Since the CPP was published in October 2015 in the *Federal Register*, AEP Fundamental Analysis has since performed additional modeling in order to provide a partial update to the Fundamentals Forecast. This update led to revised CO_2 and energy prices for the Mid, Low Band, and High Band scenarios. The purpose of the additional modeling was to determine the appropriate combination of CO_2 and energy prices which would provide for nationwide compliance with the CPP on a mass basis, as well as to better recognize the relative timing of the CPP based on the incorporation of interim targets in the years leading up to the final 2030 implemental date. These CO_2 values vary across the three scenarios and support the premise that CO_2 values are highly dependent upon fuel price assumptions – particularly natural gas. Each scenario is described below.

When comparing the following pricing scenarios with others throughout the industry it should be noted that AEP's commodity pricing forecasts account for the impacts of future events, such as proposed environmental regulations. This approach differs from the EIA's Annual Energy Outlook[14].

4.3.1.1 Emission Reduction Credit (ERC) Pricing

As indicated, for purpose of the CPP modeling performed by the Company, AEP Fundamental Analysis created a set of CO_2 allowance pricing scenarios predicated upon national compliance under a mass-based approach. This was done as a matter of modeling convenience

[14] From the Energy Information Administration's Annual Energy Outlook 2015 Preface: "The AEO2015 projections are based generally on federal, state, and local laws and regulations in effect as of the end of October 2014. The potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation that require implementing regulations or funds that have not been appropriated) are not reflected in the projections (for example, the proposed Clean Power Plan[3])". Available at http://www.eia.gov/forecasts/aeo/preface.cfm

given that a) the underlying AURORA^{xmp} (dispatch) modeling framework itself was more conducive to the use of a mass-based commodity approach and, b) there are greater uncertainties surrounding wide implementation approaches for an ERC or rate-based pricing scheme. This action, however, neither introduces nor presumes any bias toward a fundamental pricing basis for one CPP pricing approach (mass-based 'allowance') versus the other (rate-based 'ERC').

In fact, based on mass versus rate pricing approaches from other observed projections, overall mass versus rate pricing profiles were generally consistent. For this reason the Company assumed that, for the purpose of the Plexos optimization modeling exercise, a reasonable proxy for such a forecast of ERC pricing would be *equal to* the pricing point established for the mass-based approach. For example, a $10 per ton allowance price in a given year, would also be assumed to equal a $10 lb./MWh ERC price in that same year.

4.3.1.2 Mid Scenario

This scenario recognizes the following major assumptions:

- MATS Rule implementation beginning in 2015;
- relatively lower natural gas price due to the emergence of shale gas plays; and
- CO_2 emission pricing beginning in 2022

As mentioned above, the Mid, Low Band, and High Band scenarios include CO_2 pricing as a result of the assumed implementation of CO_2 reduction regulation. Also, the specific effects of the MATS Rule are modeled in the development of the long-term commodity forecast by retiring the smaller, older solid-fuel (i.e., coal and lignite) units which would not be economic to retrofit with emission control equipment. The retirement time frame modeled runs through 2017. Those remaining solid-fuel generating units will have some combination of controls necessary to comply with EPA rules. Incremental regional capacity and reserve requirements will largely be addressed with new natural gas plants. One effect of the expected retirements on the emission control retrofit scenario is an over-compliance of the CSAPR emission limits. This will drive the emission allowance prices for SO_2 and NO_x to zero by 2018 or 2019.

4.3.1.3 Low Band Scenario

This scenario is best viewed as a plausible lower natural gas/solid-fuel/energy price profile compared to the Mid scenario. In the near term, Low Band natural gas prices largely track Mid prices but, in the longer term, natural gas prices represent an even more significant infusion of shale gas. From a statistical perspective, this long-term pricing scenario is approximately one (negative) standard deviation (-1.0σ) from the Mid scenario and illustrates the effects of coal-to-gas substitution at plausibly lower gas prices. Like the Mid scenario, CO_2 pricing is assumed to start in 2022.

4.3.1.4 High Band Scenario

Alternatively, the High Band scenario offers a plausible, higher natural gas/solid-fuel/energy price profile compared to the Mid scenario. High Band natural gas prices reflect certain impediments to shale gas developments including stalled technological advances (drilling and completion techniques) and as yet unseen environmental costs. The pace of environmental regulation implementation is in line with the Mid and Low Band scenarios. Analogous to the Low Band scenario, this High Band view, from a statistical perspective, is approximately, one (positive) standard deviation ($+1.0\sigma$) from the Mid. Also, like the Mid and Low Band scenarios, CO_2 pricing is assumed to begin in 2022.

4.3.1.5 No Carbon Scenario

This scenario does not consider a price for CO_2 emissions. While also including the necessary correlative fuel price adjustments, it serves as a baseline to understand the impact on unit dispatch.

4.3.1.6 Forecasted Fundamental Parameters

Figure 18 through Figure 24 below illustrate the forecasted fundamental parameters included in this IRP.

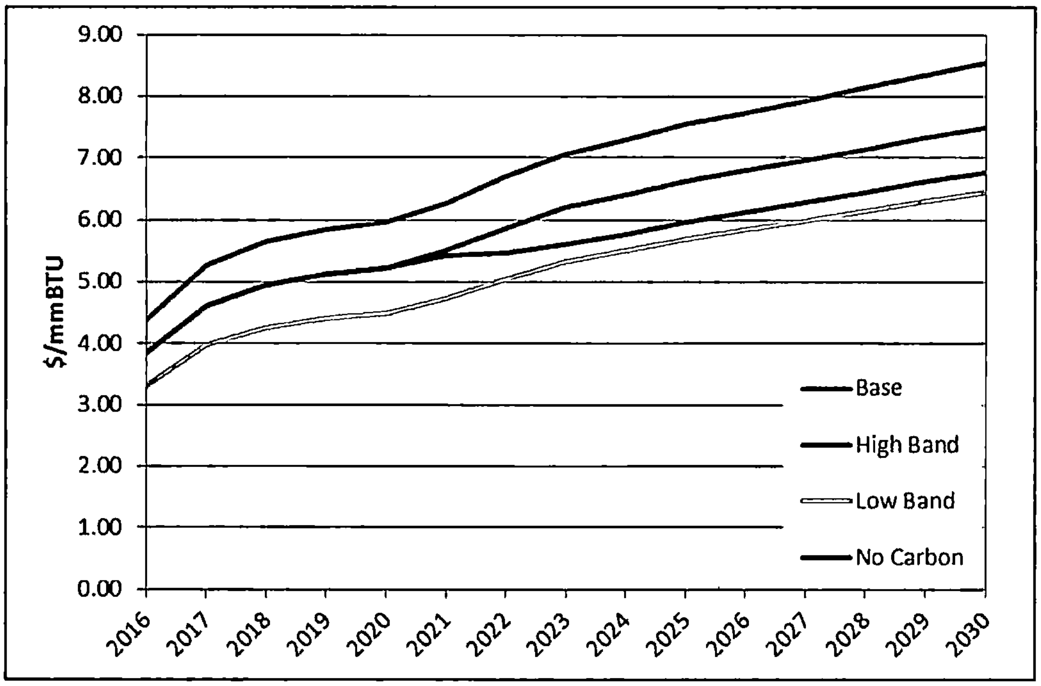


Figure 18. Dominion South Natural Gas Prices (Nominal $/mmBTU)

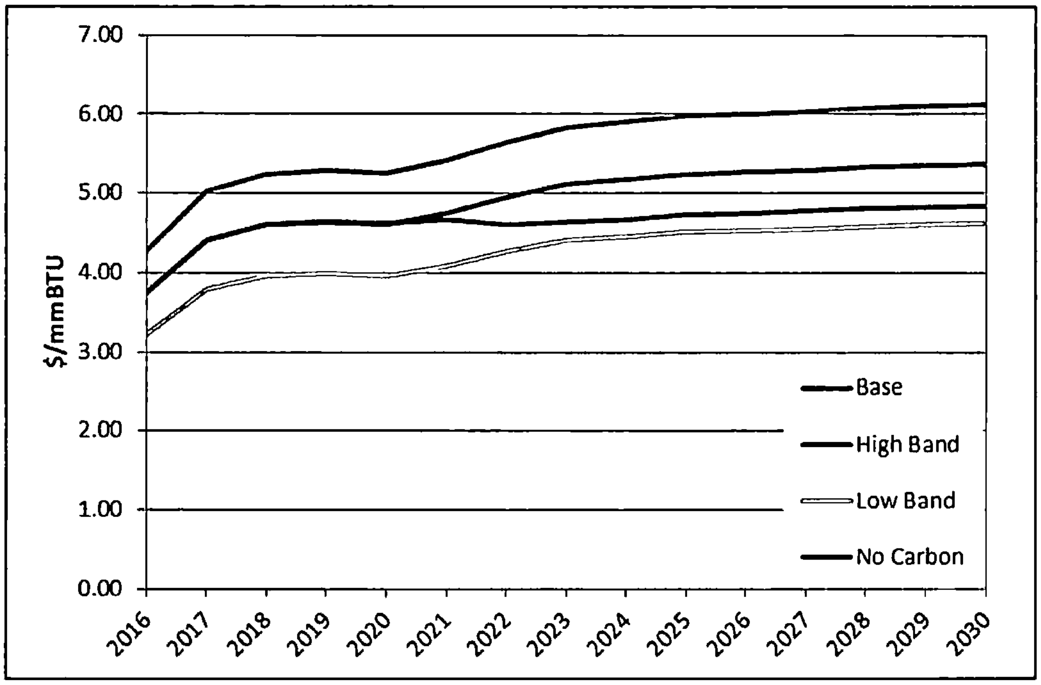


Figure 19. Dominion South Natural Gas Prices (2014 Real $/mmBTU)

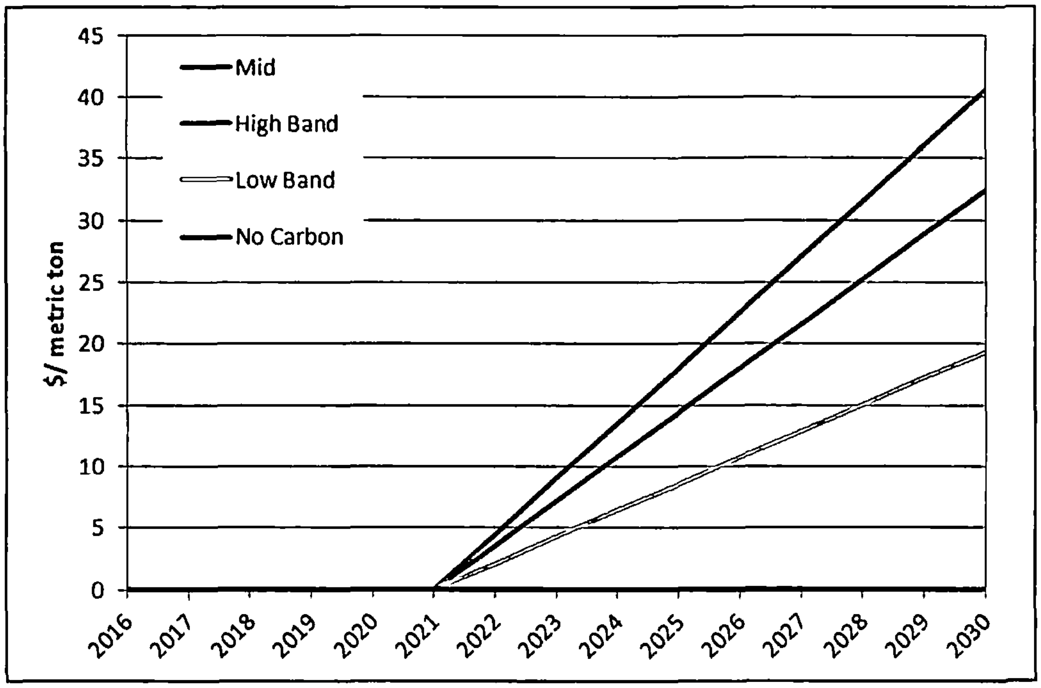


Figure 20. CO_2 Prices (Nominal $/metric ton)

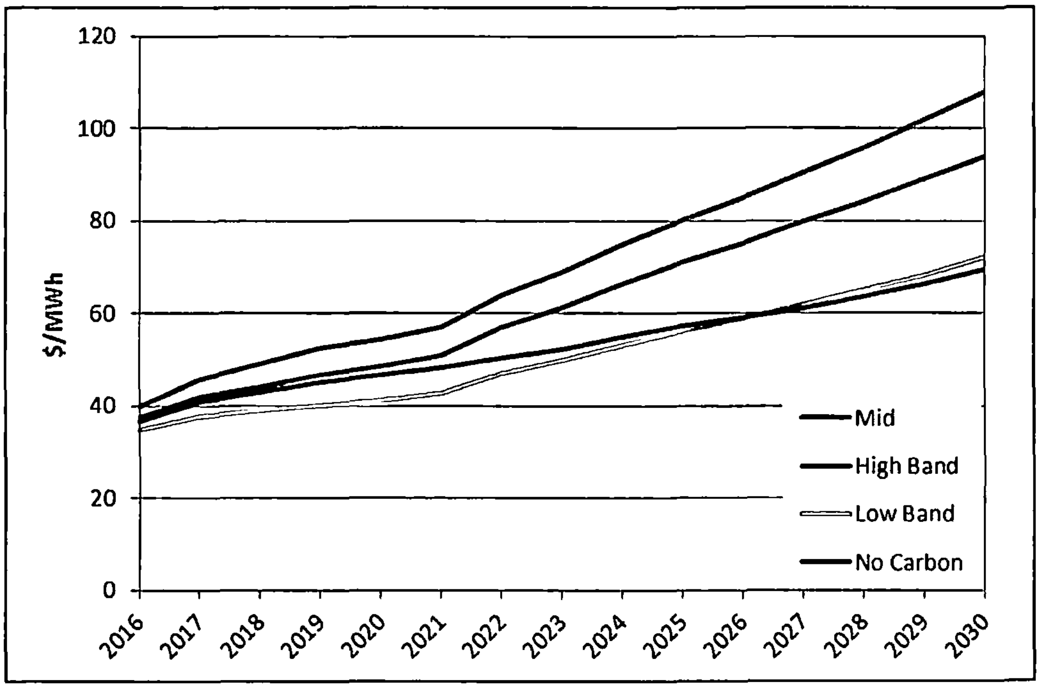


Figure 21. PJM On-Peak Energy Prices (Nominal $/MWh)

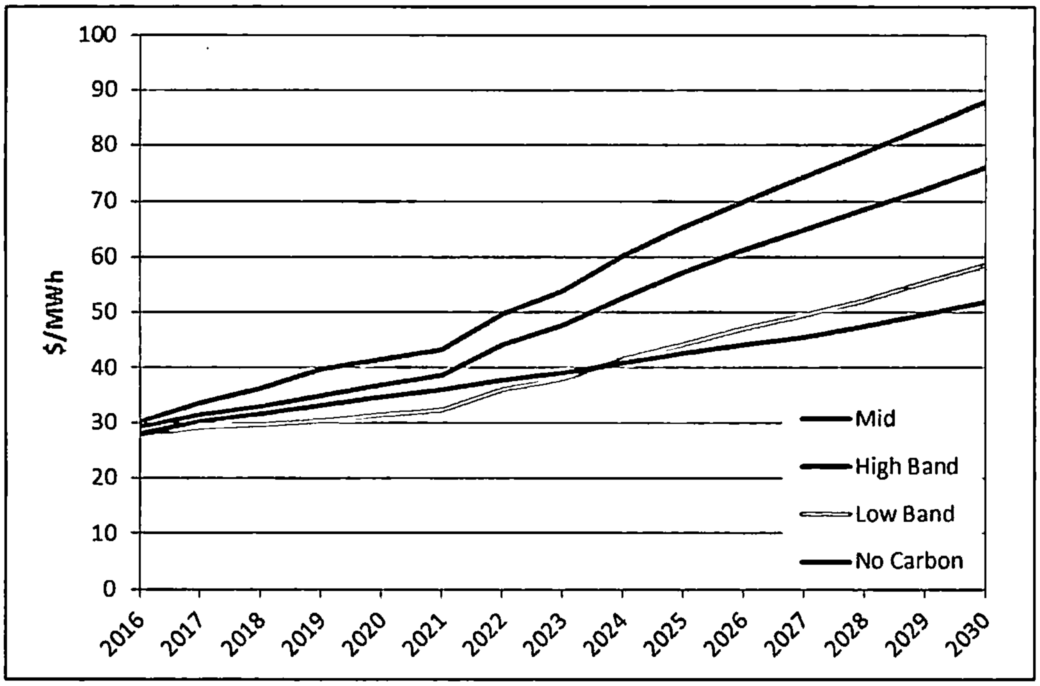


Figure 22. PJM Off-Peak Energy Prices (Nominal $/MWh)

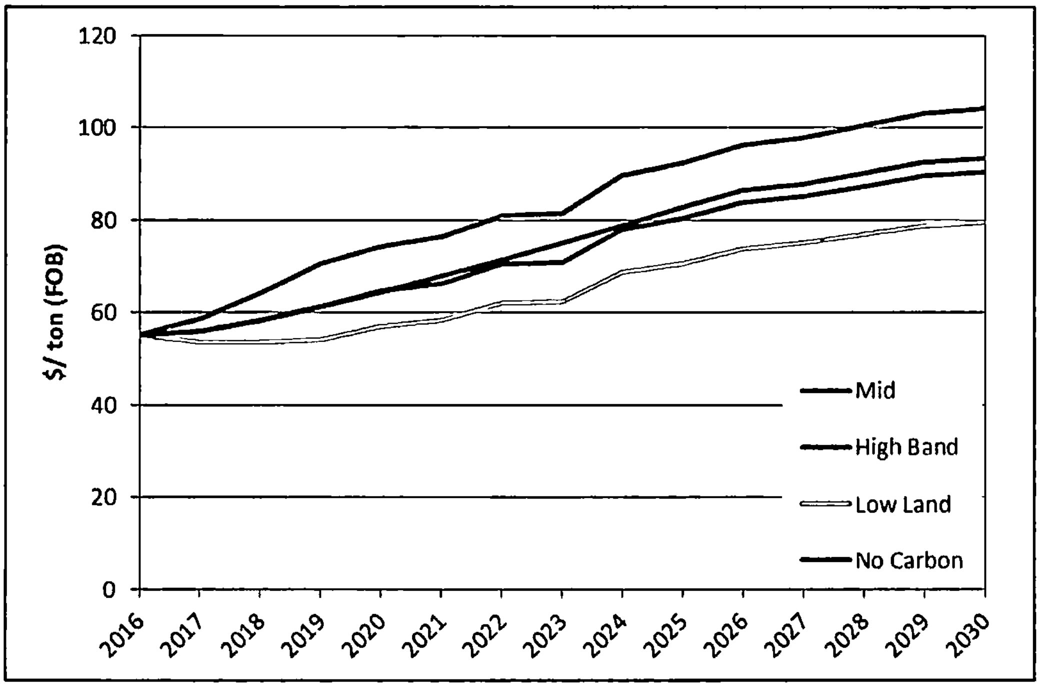


Figure 23. NAPP High Sulfur Coal Prices (Nominal $/ton, FOB)

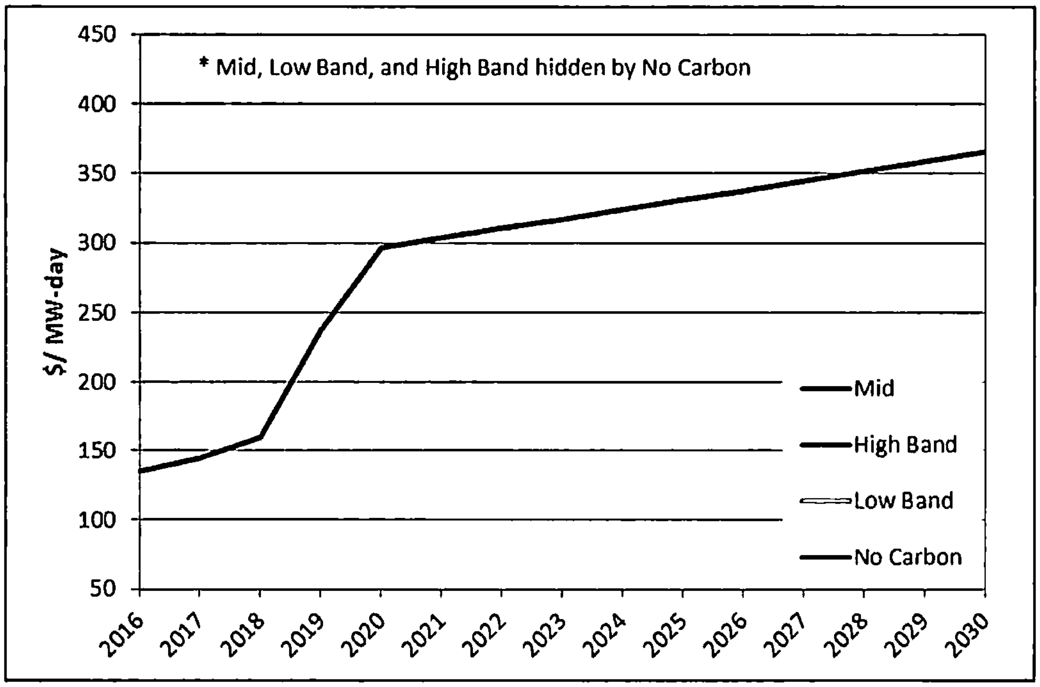


Figure 24. PJM Capacity Prices (Nominal $/MW-Day)

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 spheres: "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.

For APCo, the potential incremental DSM programs were developed and ultimately modeled based on 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. Industrial programs were not developed or modeled based on the rationale that industrial customers, by and large, will "self-invest" in EE measures based upon unique economic merit *irrespective* of the existence of utility-sponsored program activity.

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 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 and VVO as resources, thereby considering such alternatives in the model on equal-footing with more traditional "supply-side" generation resource options.

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. Figure 25 and Figure 26 show the "going-in" make-up of projected consumption in APCo's residential and commercial sectors in the year 2019. It was assumed that the incremental programs modeled would be effective in 2019, due to the time needed to develop specific program cost and measures and receive regulatory approval to implement such programs.

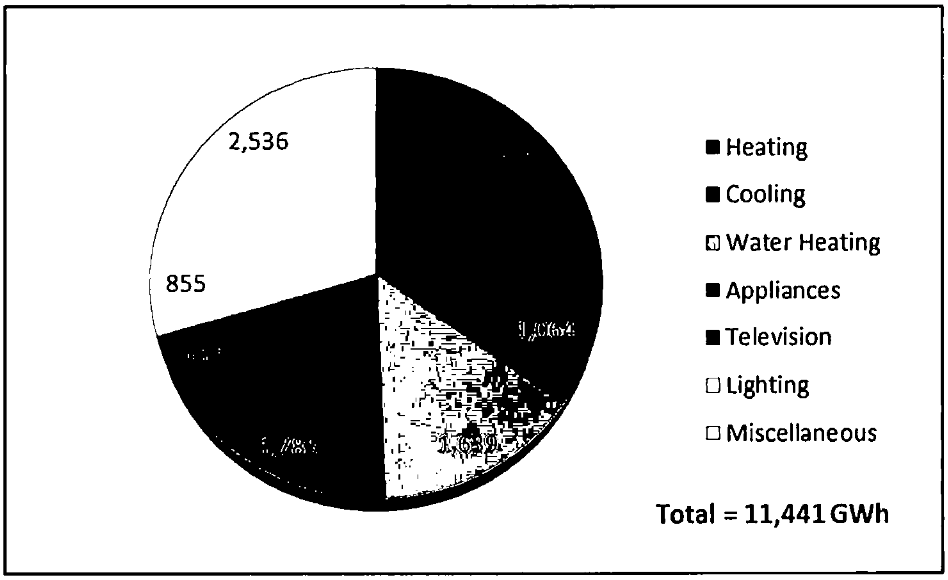


Figure 25. 2019 APCo Residential End-use (GWh)

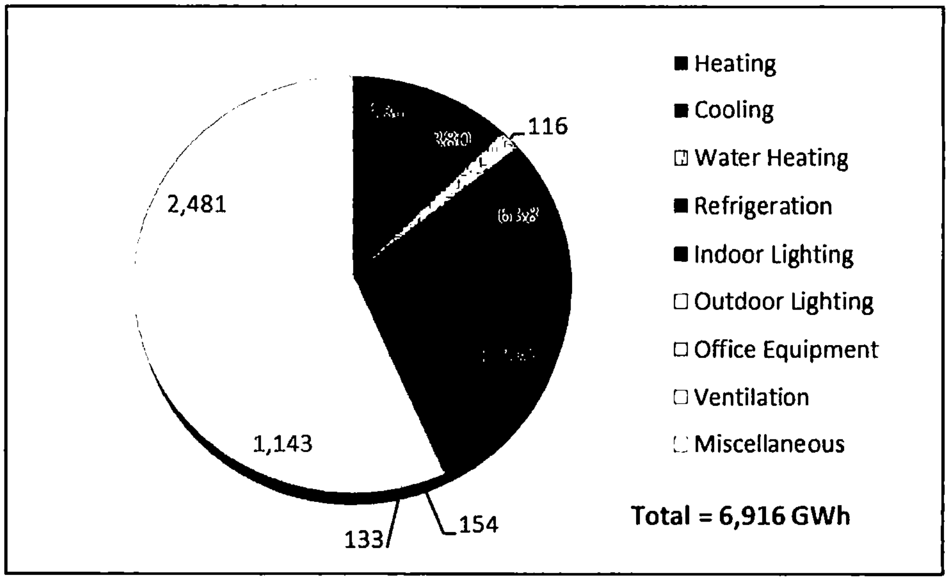


Figure 26. 2019 APCo Commercial End-use (GWh)

The current programs target certain end-uses in both sectors. Future incremental EE activity can further target those areas or address other end-uses. To determine which end-uses are targeted, and in what amounts, APCo looked at the previously-cited 2014 EPRI report. The EPRI report provides information on a multitude of current and anticipated end-use measures including measure costs, energy savings, market acceptance ratios and program implementation factors. APCo utilized this data to develop "bundles" of future EE activity for the demographics and weather-related impacts of its service territory. Table 7 and Table 8, 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 8. 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	Anti-Sweat Heater Controls
Chiller	Computers	Programmable Thermostat	Floating Head Pressure Controls
Cool Roof	Servers	Duct Testing and Sealing	Installation of Glass Doors
Economizer	Displays	HVAC Retro-commissioning	High-Efficiency Vending Machine
Energy Management System	Copiers Printers	Efficient Windows	Icemakers
Roof Insulation	Other Electronics	Lighting – Linear Fluorescent	Reach-in Coolers and Freezers
Duct Insulation			

What can be derived from the tables is that the 2014 EPRI report has taken a comprehensive approach to identifying available EE measures. From this information, APCo has developed proxy EE bundles for both residential and commercial customer classes to be modeled within *Plexos*®. These bundles are based on measure characteristics identified within the EPRI report and APCo customer usage.

Table 9 and Table 10 list the energy and cost profiles of EE resource "bundles" for the residential and commercial sectors, respectively.

Table 9. Incremental Demand-Side Residential Energy Efficiency (EE) Bundle Summary

Bundle	Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2019	Yearly Potential Savings (MWh) 2020-2024	Yearly Potential Savings (MWh) 2025-2029	Yearly Potential Savings (MWh) 2030-2040	Bundle Life
Thermal Shell - AP	$0.16	22,243	4,009	5,455	8,484	10
Thermal Shell - HAP	$0.24	129,815	30,932	35,054	18,098	10
Heat Pump - AP	$0.97	84,685	11,210	5,163	1,472	18
Heat Pump - HAP	$1.46	32,122	0	0	0	18
Water Heating - AP	$0.04	11,627	1,224	1,195	1,455	10
Water Heating - HAP	$0.05	67,469	12,884	11,846	4,872	10
Appliances - AP	$0.22	42,187	3,047	2,751	2,294	16
Appliances - HAP	$0.39	74,833	12,990	10,179	6,329	17
Lighting - AP	$0.08	155,107	1,172	0	0	30
Lighting - HAP	$0.12	166,025	24,485	1,853	332	30
Enhanced Customer Bill	$0.68	249,882	0	590	1,072	30

Table 10. Incremental Demand-Side Commercial Energy Efficiency (EE) Bundle Summary

Bundle	Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2019	Yearly Potential Savings (MWh) 2020-2024	Yearly Potential Savings (MWh) 2025-2029	Yearly Potential Savings (MWh) 2030-2040	Bundle Life
Heat Pump - AP	$3.29	67,930	5,089	5,896	0	15
Heat Pump - HAP	$4.94	25,766	3,296	630	0	15
HVAC Equipment - AP	$0.23	4,213	421	362	317	16
HVAC Equipment - HAP	$0.35	7,826	1,315	953	116	16
Indoor Screw-In Lighting - AP	$0.10	15,040	337	335	345	6
Indoor Screw-In Lighting - HAP	$0.15	9,336	1,588	1,306	301	6
Indoor Fluorescent Lighting - AP	$0.83	211,300	12,878	14,448	3,141	10
Indoor Fluorescent Lighting - HAP	$1.24	80,148	9,730	1,784	0	10

As can be seen from the tables, each program has both AP and HAP characteristics. The development of these characteristics is based on the 2014 EPRI EE Potential report that has been previously referenced. This 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 27 below shows the levelized cost of electricity and potential energy savings in 2018 for each of the bundles offered into the model as a potential resource. The total potential energy savings for EE programs in 2018 is 1,458GWh, 4% of APCo's total load, or 8% of APCo's total residential and commercial load.

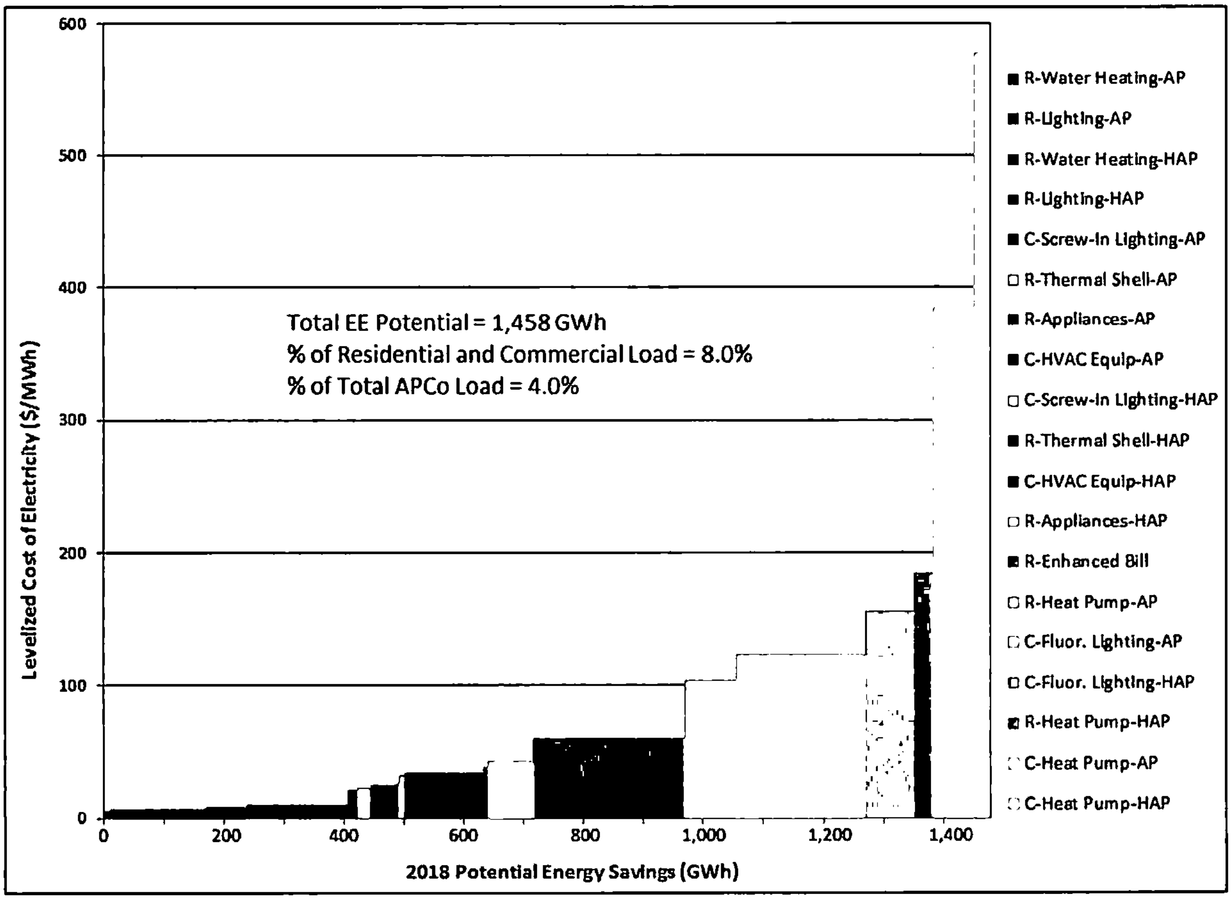


Figure 27. EE Bundle Levelized Cost vs. Potential Energy Savings for 2018

Each EE bundle is offered into the model as a stand-alone resource with its own unique cost and potential energy savings. Should the model determine that a bundle is economical, that bundle will be included in the portfolio of optimized resources. APCo will consider the details of which EE bundles were selected by the Plexos model, and included in the Hybrid Plan, to develop appropriate EE offerings to propose for APCo's customers in Virginia and West Virginia. 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

Potential future VVO circuits considered for modeling varied in relative cost and energy-reduction effectiveness. The circuits were grouped into 13 "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. Typically, a VVO tranche includes approximately 70-75 circuits. Table 11, details all of the tranches offered into the model and the respective cost and performance of each. The costs shown are in 2015 dollars.

Table 11. Volt VAR Optimization (VVO) Tranche Profiles

Tranche	No. of Circuits	Capital Investment	Annual O&M	Demand Reduction (kW)	Energy Reduction (MWh)
1	73	$24,309,000	$657,000	25,056	103,159
2	74	$24,642,000	$666,000	18,992	78,194
3	73	$24,309,000	$657,000	15,867	65,329
4	74	$24,642,000	$666,000	14,840	61,100
5	72	$23,976,000	$648,000	13,582	55,919
6	74	$24,642,000	$666,000	12,954	53,335
7	75	$24,975,000	$675,000	11,725	48,275
8	75	$24,975,000	$675,000	10,870	44,752
9	75	$24,975,000	$675,000	10,060	41,420
10	73	$24,309,000	$657,000	8,717	35,888
11	72	$23,976,000	$648,000	7,463	30,727
12	73	$24,309,000	$657,000	6,464	26,614
13	73	$24,309,000	$657,000	4,741	19,520

4.4.3.3 Demand Response (DR) Modeled

Incremental levels of DR were included in the IRP model. These resources were modeled based on the existing direct load control program for both Virginia and West Virginia which reduces demand by cycling customer air conditioners. Table 12 below, shows the blocks of DR resources which were offered into the model for residential and commercial customers. There is one block for residential customers, and one block for commercial customers. The model may select up to four blocks of each resource in any calendar year, beginning with 2019 and each block has a service life of seven years. For example, the model could select two blocks of residential DR in a given year which would consist of 6,000 customers. If the model were to select another block of residential DR in the following year there would be a total of 9,000 customers participating in the program.

Table 12. Incremental Demand Response (DR) Resource Blocks

Sector	Participants	Demand Savings (kW)	Energy Savings (kWh)	Installation Cost	Annual Cost	Total First Year Cost
Residential	3,000	2,700	120,000	$ 925,000	$ 263,000	$1,188,000
Commercial	500	450	43,750	$ 157,000	$ 44,500	$ 201,500

4.4.3.4 Distributed Generation (DG) Modeled

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[15]. This forecast considered the level of solar photovoltaic (PV) installations over the period of 2016-2031. The forecast included levels of large-scale solar PV, but did not consider state caps for net-metering which exist in Virginia and West Virginia. In order to understand the potential range of DG penetration APCo developed three forecasts which are illustrated below in Figure 28.

[15] Solar PV Capacity Addition Forecast for PJM States: 2016-2031. Available at http://www.pjm.com/~/media/committees-groups/subcommittees/las/20151130/20151130-item-04-ihs-pjm-solar-pv-forecast-presentation.ashx

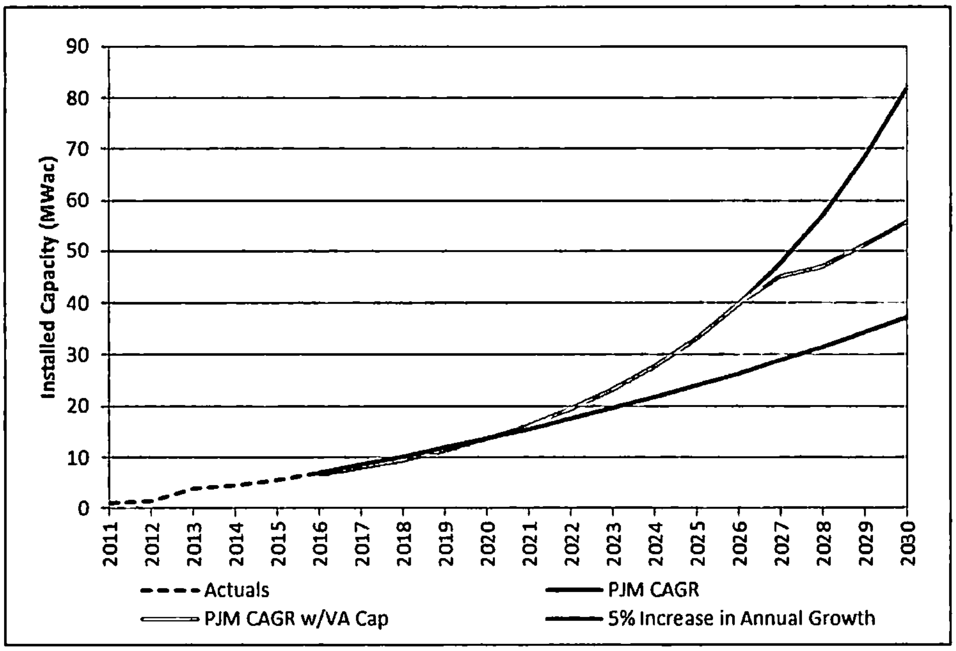


Figure 28. APCo Forecasted Distributed Generation Installed, or Nameplate, Capacity (DG), by Method

The first method utilizes a 5% increase in annual growth rate for each state – Tennessee, Virginia, and West Virginia. The second method uses the Compound Average Growth Rates (CAGRs) for each state based on the PJM forecast, as calculated from 2016-2031, while recognizing state caps on net-metered customers[16]. To account for the caps, the PJM CAGRs were applied until the caps were reached. Once a cap was reached, a 0.5% annual growth rate is applied to reflect the notion that some customers will install DG regardless of economics. The Virginia cap on net-metered customers is forecasted to be reached in 2027. The third method applies the PJM CAGRs for each state without any consideration for a state cap. West Virginia also has a cap on net-metered customers, however forecasted DG additions for West Virginia are below the cap level during this IRP's planning period. This IRP incorporates the second method which is depicted by the green line labeled "PJM CAGR w/VA Cap" in Figure 28 above.

[16] Net-metered rates for customers are capped at 1% and 3% of annual peak demand, for Virginia and West Virginia, respectively.

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.

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 $1,800/kW and the assumed modeled full load heat rate is approximately 4,800 Btu/kWh. Additionally, the assumed capacity factor was 90%.

4.4.3.7 Conservation

Conservation is a reduction in consumption of electricity accomplished solely through behavioral changes. It may be encouraged through several possible mechanisms and, in general, would provide the greatest benefit under a mass-based CPP-compliance approach. While the cost of a conservation program, particularly one effected through rate design changes, is minimal, there is nevertheless an impact on rates. To demonstrate this, a simplified example (shown below in Table 13) demonstrates a hypothetical revenue requirement comprised of fixed and variable costs. With a costless conservation program achieving 10% reduction in residential consumption, the revenue requirement would be reduced by a fraction of that amount, and residential rates would need to increase as a result, so that the utility has an opportunity to recover its fixed costs.

Table 13. Example of Effect of Conservation on Revenue Requirements

Rate Component	Before	After	Increase/ Decrease
Fuel and Purchased Power	$200	$180	-10.0%
Base Rates	$600	$600	0.0%
Revenue Requirement	$800	$780	-2.5%
kWh	7,000	6,300	-10.0%
Volumetric Rate ($/kWh)	0.114	0.124	8.3%

4.4.3.8 Rate Design

The Hybrid Plan presented in this IRP does not include components of rate design programs. Rate design changes warrant continued analysis. However, the characteristics of a service territory must be factored into any decision to pursue a path such as inclining block rates, as customers may not be able to adjust behavior. Further, rate design adjustments should be implemented via pilot programs so that the impacts on various customers are well-examined before full implementation across the service territory. The following section discusses the consideration which must be accounted for when considering various rate design programs.

4.4.3.8.1 Current Residential Rate Design

With regard to either base rates or rate adjustment clauses, APCo's current residential rate design recovers the applicable revenue requirement through one or both of these two mechanisms: a fixed customer service charge and a volumetric rate. The customer charge is designed to recover a portion of the costs attributable to serving distribution customers while the volumetric rate recovers all other costs as well as capacity and energy components. Because the revenue requirement is recovered primarily volumetrically, small changes in consumption have disproportionately large impacts upon customers' bills, and Company revenues.

It remains to be seen whether increasing the fixed component of a residential customer's bill, and decreasing the variable component of rates will discourage conservation or will merely disproportionately impact low-income customers. What is better known, however, is that increasing the fixed component of residential rates more accurately reflects the way costs are incurred and at the same time decreases the volatility of residential bills, particularly during the heating and cooling seasons.

The current rate structure does not provide customers with clear price signals. As is, the actual delivered price of energy cannot be distinguished from the portion of the rate associated with Company's infrastructure investments (fixed costs). If the goal of rate design is to manage customers' peak demands and reduce peak related costs, customers need to receive clearer price signals and education regarding the new price signals and how their consumption, and the timing of their consumption, affects demand and energy costs. APCo's current Virginia residential rate structure collects 93% of all revenues through a flat energy charge which includes all variable costs and most fixed costs.

Three-part rates (kWh energy charge, on peak kW demand charge and a basic service charge) would allow for cost-based billing of non-homogenous customers like the residential class within one rate schedule. A three-part rate system would provide customers with a greater level of detail and allow them to make consumption decisions based on more accurate price signals better correlated to actual costs (fixed versus variable) *i.e.*, they would be able to discern how much their monthly peak usage is costing them, and other customers, each month. With three-part rates, more accurate price signals and consumer education, customers would have the tools they need to make a conscious decision regarding the management of their monthly peaks and total kWh usage.

Additionally, three-part rates, and the advanced metering technology needed to facilitate three-part rates, would enable the Company to offer additional, innovative pricing structures that could be tailored to influence consumers' usage habits.

More elemental rate design can be a way of effecting changes in consumption behavior, which may be a strategy for CPP compliance, in much the same way as energy efficiency investments. Rate design changes must be revenue-neutral, meaning that if a certain tariff customer pays more as a result of a change in rate design, a different tariff class must pay less. It follows that, if a rate design change results in a conservation effect, aggregate rates must increase to enable the utility to collect its revenue requirement.

Two possible rate design changes that wouldn't necessitate advance metering investments are the imposition of inclining block rates or, alternatively, basic time-varying rates. Inclining block rates are rates that increase as customer consumption increases, typically in one or more steps, or "blocks". These rates are generally independent of the time of day or even the month that the consumption occurs. On the other hand, time-varying rates seek to loosely mimic the actual "real time" or marginal cost of production, providing customers with a more accurate "price signal" upon which to base consumption decisions.

4.4.3.8.2 Inclining Block Rates in Appalachian Power Company Service Territory

APCo's service territory is mountainous and rural, with approximately 17 customers per mile of distribution line. Natural gas service is not generally available, and as a result, a high percentage of customers heat their homes with electricity. This makes the use of block rates, if applied during the heating season, potentially problematic for a couple of reasons.

Customers who heat their homes electrically would be subject to higher rates as their consumption increases past a predetermined threshold. Residential bills are at their highest, in APCo's service territory, during the winter when consumption of electricity is not discretionary. Accordingly, in the event of a particularly cold month, customers would experience the "double-whammy" of increased consumption and increased rates. Correspondingly, it will be difficult for such customers to compensate for that impact by conserving energy during warmer months where consumption is less, as there are fewer opportunities to conserve and because such conservation would yield reduced benefits at lower rates.

Generally, therefore, if an inclining block rate is applied to APCo's service territory it may not substantially reduce consumption and would likely increase total annual bills for electric heating customers.

4.4.3.8.3 Budget Billing

Another aspect that can reduce the benefit of rate design changes is the availability of budget billing. By paying the same amount every month budget-billing customers are insulated from the impacts of conservation decisions, which may be further muddled by actual weather. Conservation in April may not manifest itself in bill savings for many months and may be eliminated altogether if unusual weather causes higher than budgeted usage.

4.4.3.8.4 Time-Variable Pricing Structures

Time-variable pricing structures can include:

- Time of Use (TOU) Rates – Typically applies different prices to large blocks of hours (6-12 hours) to encourage a shift in consumption from peak hours to off-peak hours.
- Real Time Pricing (RTP) – Applies different prices, often tied to a market index, to smaller increments of time, anywhere from 15 minutes to an hour. These rates encourage shifting consumption from peak times to off-peak times.
- Variable Peak Pricing (VPP) – This rate structure is a hybrid approach where blocks of time are designated as peak, as in a TOU rate, but the price for those blocks vary, as in a RTP rate.
- Critical Peak Pricing (CPP) – Implements high prices during a few periods or hours a year that correspond with system emergencies or time of very high market prices. This rate is designed to reduce consumption just during those periods.
- Critical Peak Rebates (CPR) – Similar to CPP, but rather than exposing customers to high prices, a payment is made to customers to reduce consumption.

These programs are all designed to shift consumption away from periods of higher demand and typically higher prices. Their effectiveness at reducing consumption is limited as there is a measurable "rebound effect" as loads are increased during off-peak hours.[17]

APCo's affiliate company, AEP Ohio, conducted an extensive pilot program of various rate designs from 2012-2013. Two TOU tariffs, "SMART Shift" and "SMART Shift Plus" had mixed results. During 2012, the TOU tariffs had lower consumption than standard residential tariff customers, but in 2013, during peak hours, consumption was lower during the first two hours of an event, but higher during the last two hours. After the peak period, time-of-day consumers' consumption was greater than that of flat rate consumers in both 2012-2013.

In terms of reducing CO_2 emissions, the AEP Ohio study concluded that differences in pollutant emission per kWh due to shifting load from peak to off-peak times are "insignificant" compared to total pollutant reductions that result from kWh reductions. Overall, reductions in consumption were measurable, but were not large.

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. The options assumed to be available for modeling analyses for APCo are presented in Table 14, below.

[17] http://energy.gov/sites/prod/files/DemandReductionsReport_Dec2012Final.pdf

When applicable, APCo may take advantage of economical 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 14, below, 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 14. New Generation Technology Options with Key Assumptions

Type	Capability	Emission Rates			Capacity Factor	Overall Availability
		SO_2	NO_x	CO_2		
	(MW)(a)	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	(%)	(%)
Base Load						
Nuclear	1610	0.0000	0.0000	0.0	90	94
Base Load (90% CO2 Capture New Unit)						
Pulv. Coal (Ultra-Supercritical) (PRB)	460	0.1200	0.0700	20.5	85	90
IGCC "F" Class (PRB)	530	0.0100	0.0600	20.5	85	88
Base / Intermediate (b)						
Combined Cycle (1X1 "F" Class)	380	0.0007	0.0090	116.0	60	89
Combined Cycle (1X1 "J" Class)	440	0.0007	0.0070	116.0	60	89
Combined Cycle (2X1 "J" Class)	910	0.0007	0.0070	116.0	60	89
Combined Cycle (2X1 "H" Class)	990	0.0007	0.0070	116.0	60	89
Peaking						
Combustion Turbine (2 - "E" Class) (b)	170	0.0007	0.0090	116.0	3	93
Combustion Turbine (2 - "F" Class, w/evap coolers) (b)	470	0.0007	0.0090	116.0	25	93
Aero-Derivative (1 - Large Machine)	100	0.0007	0.0110	116.0	30	95
Aero-Derivative (2 - Large Machines) (b)	200	0.0007	0.0070	116.0	25	95
Aero-Derivative (2 - Small Machines) (c)	90	0.0007	0.0930	116.0	25	96
Recip Engine Farm (3 Engines)	50	0.0007	0.0180	116.0	36	96
Battery Storage (Lithium-Ion)	10	-	-	-	10	94

Notes: (a) Capability at Standard ISO Conditions at 1,000 feet above sea level.
(b) Includes Dual Fuel capability and SCR environmenttal installation, except 3 Recip Engines Farm.
(c) Includes Dual Fuel capability.

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. The forecasted difference between APCo's load forecast and existing resources is such that a large, central generating station would not be required. In addition, for coal generation resources, the proposed EPA NSPS rulemaking effectively makes the construction of new coal plants environmentally/economically impractical due to the implicit requirement of Carbon Capture and Sequestration (CCS) technology. New nuclear construction is financially impractical since it would potentially require an investment of $6,000/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 retirement of APCo's subcritical units, other generation dispatch alternatives and new generation will need to be considered to cost effectively meet this 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 45-60% 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. NGCC plants may be designed with the capability of being "islanded" which would allow them, in concert with an associated diesel generator, to perform system restoration (Black Start) services. 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.

4.5.4 Peaking Alternatives

Peaking generating sources provide needed capacity during extreme 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 7EA frame machine requires 20 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 on the order of 20% 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 increase; 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.

Some of the better known AD vendors and their models include GE's LM series, Pratt & Whitney's FT8 packages, and the Rolls Royce Trent and Avon series of machines.[18]

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. Additionally, the fuel supply pressure required is in the range of 40 to 70 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.

[18] Turbomachinery International, Jan/Feb. 2009; Gas Turbine World; EPRI TAG.

The main North American suppliers for utility-scale natural gas-fired RE most recently have been Caterpillar and Wartsila[19].

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 30MWh, with a round trip efficiency of 87%. For Capacity Performance considerations the assumed PJM capacity rating that was modeled was 5MW. To develop this resource, Generation Engineering Services considered a wide range of sources including: the DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with the National Rural Electric Cooperative Association (NRECA), EPRI TAGWEB, BNEF and battery storage equipment suppliers.

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 recent past, 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.

[19] Technical Assessment Guide (TAG) Power Generation and Storage Technology Options, 2012; Electric Power Research Institute.

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 produce electricity on a smaller scale (typically 2kW to 20MW per installation) and can be distributed throughout the grid.

The cost of large-, or utility-scale, solar projects has declined in recent years and is expected to continue to decline (see Figure 29 below). 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.

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 in an unlimited fashion given siting and regulatory constraints.

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 100MWac[20] of nameplate capacity starting in 2018. 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. Additionally, this 100MWac 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. The land

[20] 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.

requirement to develop a 1MW solar plant is estimated to be in the 6 to 8 acres range, implying that 600 to 800 acres of land would be required to develop 100MW of solar annually. 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 tier was priced at 10% below BNEF forecast costs for utility solar. The reduced pricing is based on the average of bids received by I&M, an affiliate of APCo. Resources from this tier were available in blocks of 50MW, which is comprised of five 10MW installations. The second tier was priced at BNEF forecast costs for utility solar. Resources from this tranche were also available in 50MW blocks, again comprised of five 10MW installations. Figure 29 below illustrates the projected large-scale solar pricing included in the IRP model. Both tiers account for Federal ITCs, which were extended at the end of 2015.

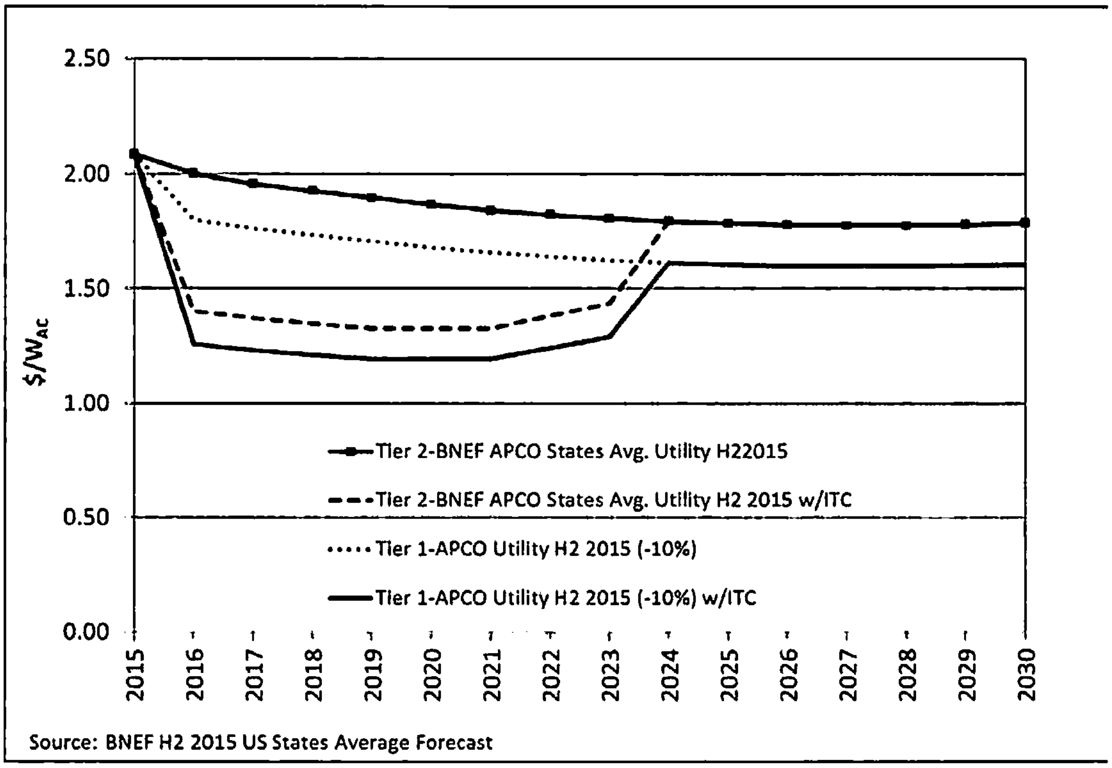
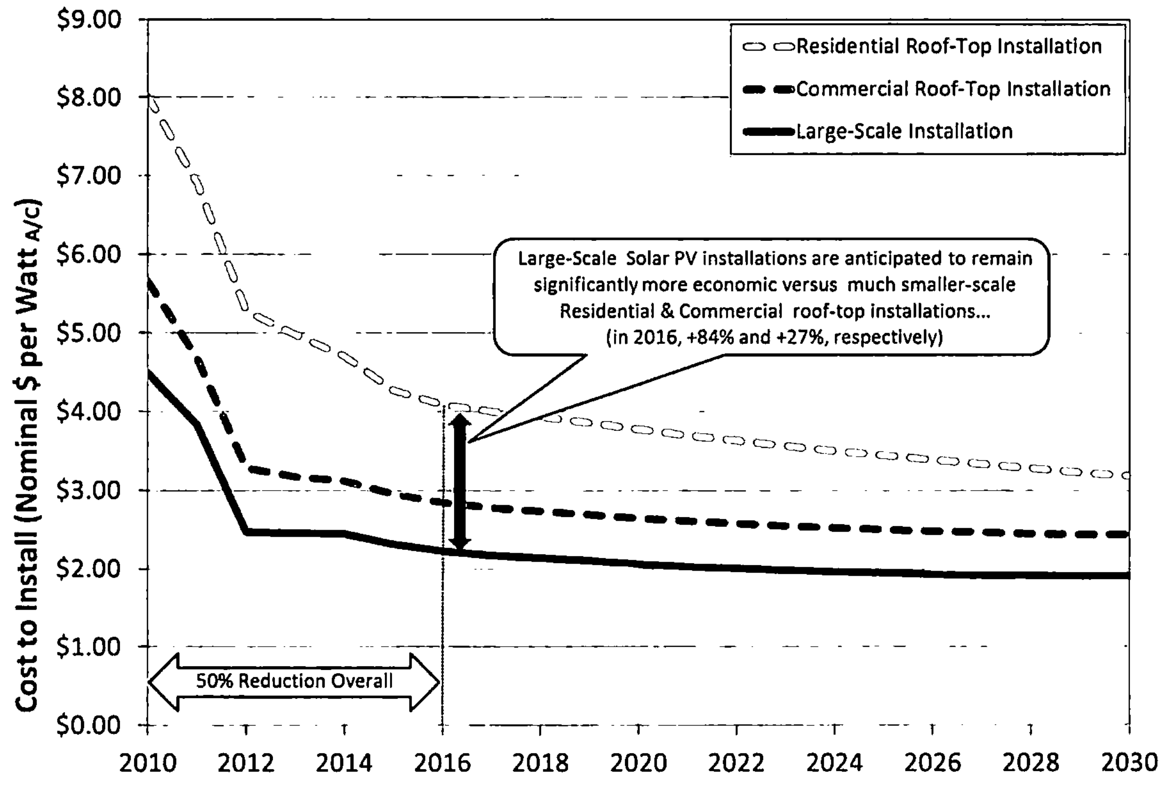


Figure 29. Large-Scale Solar Pricing Tiers with Investment Tax Credits

Solar resources' PJM capacity is less than its nameplate rating. This IRP assumes solar resources will have capacity valued at 38% of nameplate rating.

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 30. From 2010 to 2016 installation costs have declined by 50% 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 84% and 27% less than residential and commercial installations, respectively, based on 2016 costs.



Source: Bloomberg New Energy Forecast (BNEF) -- 'H2 2015 U.S. States Average' Forecast

Figure 30. U.S. Average Solar Photovoltaic (PV) Installation Cost (Nominal $/Watt$_{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 2.5MW. 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 very remote locations, which forces the electricity to be transmitted long 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 was considered under various 'blocks' or 'tranches' for each year. There are two tranches of wind with different pricing and performance characteristics. The wind resources are first made available to the model in 2018, due to the amount of time necessary to obtain approval for and secure resources. The first tranche of wind resources, Tranche A, was modeled as a 150MW resource with a Levelized Cost of Energy (LCOE) of $35/MWh in 2016 in nominal dollar. Prices are initially flat for a period of two years to reflect the fact that developers will likely take advantage of opportunities to lock in tax-advantaged pricing with a minimal investment in a project. Tranche A has a 38% capacity factor load shape. The second tranche of wind resources, Tranche B, was modeled as a 150MW resource with a LCOE of $40/MWh in 2016 in nominal dollars. Tranche B has a 35% capacity factor load shape. The pricing of both tranches reflect the full value of Federal Production Tax Credits (PTCs) in

2016, equal to $23/MWh. These tax credits reduce to 80%, 60% and 40% of their 2016 value in 2017, 2018, and 2019, respectively. Again, there is up to a two year delay in the effects of declining tax credits due to developers locking in preferred pricing projects. After expiration of the PTCs, pricing escalates at 1% and 1.5% annually for Tranche A and Tranche B, respectively. The 150MW block size is supported primarily by AEP Services Renewable Energy group and Table 15, which illustrates that recent Wind Requests for Proposals (RFPs) have been executed in the 135MW range. Both tranches were assigned a capacity value of 5% of nameplate rating based upon APCo's current evaluation of the PJM Capacity Performance rule. Wind prices were developed based on the U.S. DOE's Wind Vision Report and market knowledge.[21]Figure 31 , below, illustrates the two tranches of wind resources modeled and the relative LCOE for each tranche.

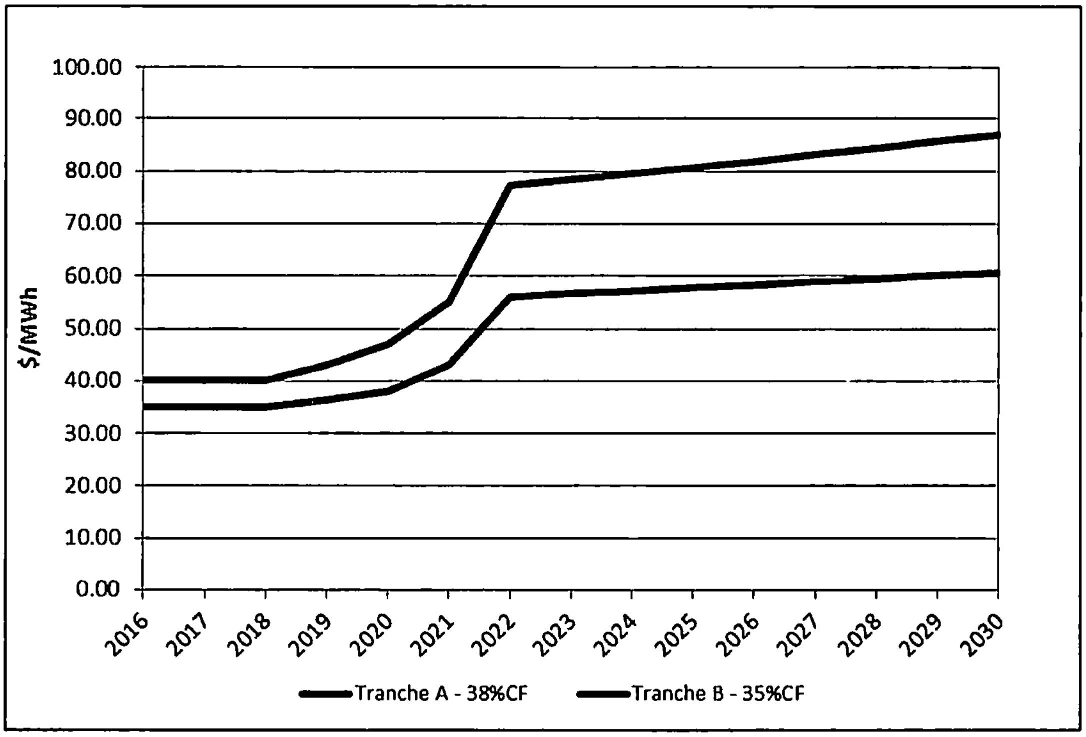


Figure 31. Levelized Cost of Electricity for Two Tranches of Wind Resources

[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=9

The expected magnitude of wind resources available per year was limited to 300MW nameplate; for the years 2018 through 2021 two blocks of Tranche A were available and post 2021 (one block of Tranche A and one block of Tranche B) with a limit of approximately 2,000MW nameplate over the planning period. This modification was made to recognize a potential limit to the availability of Tranche A resources within the PJM market. The annual limit on wind additions is 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 later). This cap is based on the DOE's Wind Vision Report[22] 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 capacity resources as wind-powered by 2035.

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 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, switchgrass, 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

[22] Specifically, Figure 1-5, p.12

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.

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 (see Table 9 and Table 10).

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 discussed in Section 4.4.3.4.

CHP was modeled as high thermal efficiency, NGCC facility, as described in Section 4.4.3.6.

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.

Table 15 below summarizes recent power purchase agreements by technology from 2011 through 2013 for the PJM region and data from a recent Virginia Electric and Power Company (DVP) filing, case PUE-2015-00104.

Table 15. PJM Wind and Solar PPA Contract Capacity and Prices, as of 2011-2013 Signing Dates

Type of Capacity	Count	Avg. Capacity (MW)	Avg. Offtake Price ($/MWh)	APCo Modeled 2016 Price ($/MWh)
Wind (1)				
Fixed	7	135	56	35
Escalating	3	122	45	
Solar (1)		No records	No records	
Solar (2)			72	87

(1) Bloomberg, "New Energy Finance FERC EQR," July 7, 2015

(2) Virginia Electric Power Company Case No. PUE-2015-00104, adjusted to a levelized value

This data set identifies key renewable technology that is being deployed and the magnitude and reported pricing within the PJM region. The data shows there is limited value to be gained from large-scale solar as this data set did not include any solar transactions. However, the data from the recent DVP filing suggest that, through an RFP, third party suppliers of solar resources can provide solar resource options in the $56/MWh range with 2.5% annual escalation for a 20 year term. This is equivalent to a $72/MWh levelized price and reflects the ITC benefit from a merchant perspective. The testimony also identifies DVP's total cost to build three solar facilities of $129.5 million with a total capacity value of 56 MW or $2,313/kW with AFUDC. As discussed in Section 4.5.5.1, APCo suggests modeling solar in two tranches: Tranche B is a lower cost owned facility with a net installed cost in 2016 of $1,260/kW and Tranche A is a slightly higher cost owned facility with a net installed cost in 2016 of $1,400/kW, both inclusive of the ITC value.

The data for wind farm activity through a PPA market assessment is higher than APCo's planned wind resource option cost, as shown in Figure 31. However, this difference is somewhat expected in that most experts believe the cost for wind resources will continue to decline, as the PPA data is from 2011 – 2013 and would not reflect future wind technology advancements. As APCo continues to evaluate the responses to its recent Wind RFP, additional information will be available to modify future wind resource costs and performance input assumptions.

Additionally, APCo examined planned new resource deployments through the use of SNL's dataset. Table 16 below shows new generating capacity within PJM which is scheduled to be in-service in 2016 or 2017.

Table 16. PJM Total New Generating Capacity and Cost by Type (Under Construction) – 2016 and 2017 In-Service Dates

Type of Capacity	Generating Capacity		Construction Cost (Est. Weighted)
	(MW)	(%)	($/kW)
Combined Cycle (CC)	9,415	90.4%	1,072
Renewables			
Wind	563	5.4%	1,940
Solar	155	1.5%	2,533
Total	718	6.9%	2,068
Hydro (Conventional)	145	1.4%	2,900
Steam Turbine (Waste)	100	1.0%	3,500
Internal Combustion			
Natural Gas	21	0.2%	1,500
Biomass	4	0.0%	3,300
Distillate Fuel Oil	6	0.1%	1,500
Landfill Gas	6	0.1%	3,300
Total	38	0.4%	1,994
Total PJM New Capacity)	**10,415**	**100.0%**	

Based upon a review of this market data and other available information, for purposes of this IRP, APCo has concluded it is reasonable to rely primarily on BNEF for the solar pricing assumptions, with some consideration of the information in the DVP filing; and on the DOE Wind Vision report as well as the results of APCo's Wind RFP for its longer-term and shorter-term wind pricing and performance assumptions, respectively. For the combined cycle assumptions, APCo is utilizing a 50% share of an advanced gas turbine technology, in a 2x1 configuration, with an estimated cost of $900/kW, and a full load heat rate of approximately 6,400 Btu/kWh High Heating Value, as shown in Exhibit B.

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.

Other input parameters of note are the PJM capacity reserve margin and the continued operation of the gas-converted Clinch River Units after their conversion to natural gas fuel. 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, and retiring units where it was not economical to comply. As a proxy for modeling the effect of, and a cost-effective means of complying with the CPP proposal, this IRP analyzed both mass-based and rate-based approaches, and for each of those approaches it considered market, stand-alone (island), and federal plan views.

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 2018 due to the anticipated period required to approve, site, engineer and construct, from:
  - CT units consisting of two "E" class turbines at 179MW total at summer conditions
  - CT units consisting of two "F" class turbines with evaporative coolers and dual fuel capability, rated at 477MW total at summer conditions.
  - AD units consisting of 2 GE LM 6000 turbines at 90MW total at summer conditions.
  - Battery Storage units available in 10MW blocks per year.
- *Intermediate-Baseload* capacity was modeled, effective in 2020 due to anticipated period required to approve, site, engineer and construct, from:

- 50% share of a NGCC (2x1 "H" class turbines with duct firing and evaporative inlet air cooling) facility, rated at 984MW at summer conditions. The 50% interest assumes APCo coordinates the addition of this resource with other parties.

- Wind resources were made available up to 300MW annually. From 2018 to 2021, two units (150MW/each) of Tranche A were available and post 2021 150MW each of Tranche A and Tranche B were available each year. Tranche A had a LCOE of $35/MWh, in 2016 with the PTC. Tranche B had a LCOE of $40/MWh, in 2016 with the PTC. Wind resources were assumed to have a PJM capacity value equal to 5% of nameplate rating.

- Large-scale solar resources were made available in two tranches, with up to 50MW of each tier available each year, for a total of up to 100MW annually. Initial costs for Tier 1 (discounted at 10% of published costs) were approximately $1,260/kW in 2016 with the ITC. Tier 2 has an initial cost of approximately $1,400/kW, with the ITC benefits. Solar resources were assumed to have a PJM capacity value equal to 38% of nameplate rating.

- DG, in the form of distributed solar resources, was embedded in amounts equal to a CAGR of 19.6% up until a defined cap on net-metered customers in Virginia was met in 2027. Virginia DG was increased at 0.5% annually through the remainder of the planning period while West Virginia continued to grow at the CAGR.

- CHP resources were made available in 15MW (nameplate) blocks, with an overnight installed cost of $1,800/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 19 unique "bundles" of Residential and Commercial measures considering cost and performance parameters for both HAP and AP categories.

- VVO was available in 13 tranches of varying installed costs and number of circuits/sizes ranging from a low of 4.7MW, up to 25MW of demand savings potential.

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 conditions. Six traditional scenarios were initially analyzed for this IRP, resulting in six unique portfolios (see

Table 17 below).

Table 17. Traditional Scenarios/Portfolios

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

5.2.2.1 No Carbon Commodity Pricing Portfolio

In the No Carbon scenario APCo would add NGCC generation in 2026. 1,800MW (nameplate) of wind generation would be added by the end of the planning period. APCo's portfolio would also include significant amounts of demand-side resources consisting of DR, VVO, EE and DG.

Table 18 below shows the results of the No Carbon scenario. The No Carbon portfolio demonstrates the resources which would be used to satisfy APCo's capacity and energy needs absent any restrictions due to carbon regulations and serves as the basis for comparing the cost associated with complying with any carbon regulations.

In the No Carbon scenario APCo would add NGCC generation in 2026. 1,800MW (nameplate) of wind generation would be added by the end of the planning period. APCo's portfolio would also include significant amounts of demand-side resources consisting of DR, VVO, EE and DG.

Table 18. Yearly Incremental PJM Capacity Additions (MW) and Energy Positions (GWh) for No Carbon Commodity Pricing Scenarios

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2030 Net Energy Position (GWh)	Avg Net Energy Position (GWh) (2016-2030)
No Carbon	Base/Intermediate											472	472	472	472	472	5,678	641
	Peaking																	
	Solar (Firm)					19	38	57	76	76	76	76	95	114	133	152		
	Solar (Nameplate)					50	100	150	200	200	200	200	250	300	350	400		
	Wind (Firm)			15	30	45	60	60	60	60	60	68	75	75	83	90		
	Wind (Nameplate)			300	600	900	1,200	1,200	1,200	1,200	1,200	1,350	1,500	1,500	1,650	1,800		
	Battery Storage																	
	Energy Efficiency				35	42	47	52	57	62	69	75	81	85	90	99		
	CHP																	
	VVO	1	1	1	1	1	28	28	28	28	48	48	66	82	97	97		
	Demand Response														10	23		
	DG	2.9	3.3	3.7	4.5	5.8	6.6	7.9	9.5	11.6	13.6	16.5	18.6	19.4	21.1	23.2		

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

5.2.2.2 Mid, Low Band, High Band Commodity Pricing Portfolios

Table 19 below shows the capacity additions associated with the Mid, Low Band, and High Band commodity pricing scenarios. Recall from Section 4.3.1 that each of these scenarios includes a unique set of prices for CO_2 emission allowances.

All three portfolios include similar resources additions, such as:

- NGCC generation (50% of a 2x1 plant) in 2026, coinciding with the retirement of the gas-fired Clinch River Units 1 and 2;
- 1,800MW (nameplate) of wind;
- 97MW of VVO resources;
- EE programs totaling 100MW or more by 2030

The Mid portfolio includes 640MW (nameplate) of large-scale solar by 2030. The Low Band and High band portfolios add 410MW and 750W (nameplate) of large-scale solar over the same period, respectively. These varying levels of large-scale solar are expected due to the changing relative value of renewable resources with respect to fuel prices.

All three portfolios results in APCo having a positive annual net energy position in the last year of the planning period, 2030.

Table 19. Yearly Incremental PJM Capacity Additions (MW) and Energy Positions (GWh) for Mid, Low Band and High Band Commodity Pricing Scenarios

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2030 Net Energy Position (GWh)	Avg Net Energy Position (GWh) (2016-2030)
Mid	Base/Intermediate											472	472	472	472	472	4,136	2,981
	Peaking																	
	Solar (Firm)				19	38	76	114	152	152	152	167	186	205	224	243		
	Solar (Nameplate)				50	100	200	300	400	400	400	440	490	540	590	640		
	Wind (Firm)			15	30	45	60	68	75	75	75	75	75	75	83	90		
	Wind (Nameplate)			300	600	900	1,200	1,350	1,500	1,500	1,500	1,500	1,500	1,500	1,650	1,800		
	Battery Storage																	
	Energy Efficiency				37	44	50	56	62	68	74	80	86	92	98	106		
	CHP																	
	VVO	1	1	1	1	1	28	48	48	48	66	82	82	97	97	97		
	Demand Response																	
	Distr. Gen.	2.9	3.3	3.7	4.5	5.8	6.6	7.9	9.5	11.6	13.6	16.5	18.6	19.4	21.1	23.2		
Low Band	Base/Intermediate											472	472	472	472	472	1,775	(403)
	Peaking																	
	Solar (Firm)					19	38	57	76	76	76	76	95	114	133	156		
	Solar (Nameplate)					50	100	150	200	200	200	200	250	300	350	410		
	Wind (Firm)			15	30	45	60	60	60	60	60	68	75	75	83	90		
	Wind (Nameplate)			300	600	900	1,200	1,200	1,200	1,200	1,200	1,350	1,500	1,500	1,650	1,800		
	Battery Storage																	
	Energy Efficiency				35	40	45	50	56	61	67	73	80	86	92	100		
	CHP																	
	VVO	1	1	1	1	1	28	28	28	28	48	48	66	82	97	97		
	Demand Response														7	18		
	Distr. Gen.	2.9	3.3	3.7	4.5	5.8	6.6	7.9	9.5	11.6	13.6	16.5	18.6	19.4	21.1	23.2		
High Band	Base/Intermediate											472	472	472	472	472	3,065	2,632
	Peaking																	
	Solar (Firm)			19	38	76	114	152	190	190	190	209	228	247	266	285		
	Solar (Nameplate)			50	100	200	300	400	500	500	500	550	600	650	700	750		
	Wind (Firm)			15	30	45	60	68	75	75	75	75	75	75	83	90		
	Wind (Nameplate)			300	600	900	1,200	1,200	1,200	1,200	1,200	1,350	1,500	1,500	1,650	1,800		
	Battery Storage																	
	Energy Efficiency				54	60	67	74	81	87	105	111	117	123	128	137		
	CHP																	
	VVO	1	1	1	1	1	28	48	66	82	97	97	97	97	97	97		
	Demand Response																	
	Distr. Gen.	2.9	3.3	3.7	4.5	5.8	6.6	7.9	9.5	11.6	13.6	16.5	18.6	19.4	21.1	23.2		

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

5.2.2.3 Load Sensitivity Scenario Portfolios

Table 20 below shows the capacity additions associated with the Low Load, and High Load sensitivity scenarios, using the Mid commodity pricing scenarios.

As expected, the overall capacity additions in the High Load scenario are naturally greater than those in the Low Load scenario. The High Load scenario calls for three installments of NGCC capacity (each as 50% of a 2x1 facility), as well as higher quantities of large-scale solar as compared to the Low Load scenario.

Table 20. Yearly Incremental PJM Capacity Additions (MW) and Energy Positions (GWh) for Low Load and High Load Sensitivity Scenarios

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2030 Net Energy Position (GWh)	Avg Net Energy Position (GWh) (2016-2030)
Low Load	Base/Intermediate											472	472	472	472	472	5,537	3,743
	Peaking																	
	Solar (Firm)																	
	Solar (Nameplate)																	
	Wind (Firm)			15	30	45	60	68	68	68	68	68	75	75	83	90		
	Wind (Nameplate)			300	600	900	1,200	1,350	1,350	1,350	1,350	1,350	1,500	1,500	1,650	1,800		
	Battery Storage																	
	Energy Efficiency				23	24	25	27	27	27	27	27	31	35	38	44		
	CHP																	
	VVO	1	1	1	1	1	1	1	1	1	1	1	1	1	28	28		
	Demand Response																	
	Distr. Gen.	2.9	3.3	3.7	4.5	5.8	6.6	7.9	9.5	11.6	13.6	16.5	18.6	19 4	21.1	23.2		
High Load	Base/Intermediate								472	472	472	945	945	945	1,417	1,417	8,359	3,828
	Peaking																	
	Solar (Firm)			19	38	68	106	144	144	144	144	144	144	144	144	144		
	Solar (Nameplate)			50	100	180	280	380	380	380	380	380	380	380	380	380		
	Wind (Firm)			15	30	45	60	68	75	75	75	75	75	75	83	90		
	Wind (Nameplate)			300	600	900	1,200	1,350	1,500	1,500	1,500	1,500	1,500	1,500	1,650	1,800		
	Battery Storage																	
	Energy Efficiency				58	73	88	104	110	116	122	128	133	139	145	152		
	CHP																	
	VVO	1	28	28	28	44	65	82	82	82	82	82	82	82	82	82		
	Demand Response																	
	Distr. Gen.	2.9	3.3	3.7	4.5	5.8	6.6	7.9	9.5	11.6	13.6	16.5	18.6	19.4	21.1	23.2		

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

5.2.3 Clean Power Plan (CPP) Scenarios

In February of 2016 the Commission issued its Final Order in APCo's 2015 IRP. In its Order the Commission required, among other things, that APCo:

> "*...model and provide multiple plans that are each compliant with the Clean Power Plan, under both a mass-based approach and an intensity-based approach*".

Modeling compliance with the CPP presents challenges. CPP compliance plans could be implemented at various levels (e.g. state-specific, regional, national, etc.) and currently the four states in which APCo owns (or purchases) fossil generation – Virginia, West Virginia, Ohio and Indiana – have not provided guidance on preference for a type of plan or design elements. Furthermore, the stay issued by the U.S. Supreme Court will likely delay the development of compliance plans and strategies. Without knowing the specific details of each state's compliance strategy, any modeling results should be viewed as indicative only, based on the need to incorporate numerous assumptions for what today are large unknowns in both policy choices and market outcomes. With this in mind, the following portfolios should be reviewed with careful understanding of the parameters under which they were modeled. Furthermore, given the speculative nature of the assumptions used and the scope of the study only covering APCo assets, it is premature to make substantive conclusions from this analysis as to prudent state compliance decisions.

For this IRP, mass-based and rate-based CPP compliance scenarios were considered. In a mass-based scenario, APCo is assumed to be allocated a specific number of CO_2 emission allowances each year (i.e. an amount of CO_2 mass) for each applicable state. APCo's generation is then monitored throughout the year to determine the total mass of CO_2 which has been emitted by their units in each state. Each ton of emissions requires one emission allowance for compliance purposes. In a rate-based scenario, APCo generates ERCs in MWh for eligible renewable energy and EE programs in each applicable state. APCo's generation is then monitored throughout the year to determine the amount of CO_2 emissions per MWh of generation. The ERCs are used to help demonstrate compliance by providing emission free MWhs in the rate calculation, which help to lower APCo's CO2 emission rate. More details on the four compliance methods considered in this IRP are as follows:

- **Mass-based - Island**

  APCo is constrained to comply with a total company total mass limit of CO_2 emissions absent access to additional emissions allowances from an external market. APCo's limit is determined by APCo's pro rata share of historical (2012),

part 4

state-specific emissions in each state which APCo has generating assets (Indiana, Ohio, Virginia, and West Virginia). The assumed emission limit, which would correspond to an allocation of allowances, is speculative in that states ultimately have authority over the allocation of allowances and could utilize a different methodology. Additionally, this scenario assumes that allowances would be fungible across the four states in which APCo has affected generation and that allocations are received in perpetuity. Table 21 below displays the assumed allowance allocations for APCo.

Table 21. APCo Assumed Annual Allowance Allocations

State	*2012 (Actual)*	2022-2024 Avg Annual (short tons)	2025-2027 Avg Annual (short tons)	2028-2029 Avg Annual (short tons)	2030+ Avg Annual (short tons)
Indiana	*1,019,000*	848,000	772,000	727,000	702,000
Ohio	*1,895,000*	1,638,000	1,493,000	1,411,000	1,365,000
Virginia	*1,016,000*	890,000	825,000	794,000	780,000
West Virginia	*23,354,000*	20,202,000	18,331,000	17,230,000	16,575,000
Total-APCo	*27,284,000*	**23,578,000**	**21,421,000**	**20,162,000**	**19,422,000**

- **Mass-based - Market**

APCo is constrained to comply with a total company mass limit of CO_2 emissions and is able to procure additional emissions allowances from an external market. Initial allowances are allocated in the same manner as the island approach above. Given that the Mass-based – Market CO_2 pricing and dispatch constraints were the same as those included in the Mid, Low Band, and High Band commodity pricing scenarios discussed above in Section 5.2.2.2, no additional scenarios were modeled.

- **Rate-based - Island**

APCo is constrained to comply with a total company rate-based limit of CO_2 emissions (lb./MWh), absent of access to ERC's from an external market. It was assumed that the ERCs generated by eligible renewables or EE would be fungible across the four states in which APCo has affected generation. Table 22 below shows the total company (i.e. state-composite) weighted ERC targets. The targets are based on the EPA's subcategory emissions rates for 'Fossil-Steam' and '(Existing) NGCC' resources (Table 23).

Table 22. APCo Assumed Annual (Weighted) Emission Rate Credit (ERC) Targets

	2012 (Actual)	2022-2024 (lb./Mwh)	2025-2027 (lb./Mwh)	2028-2029 (lb./Mwh)	2030+ (lb./Mwh)
Total-APCo	*1,961*	1567	1421	1314	1251

Table 23. Sub-Category Emission Rate Credit (ERC) Targets

Sub-Category	2022-2024 (lb./Mwh)	2025-2027 (lb./Mwh)	2028-2029 (lb./Mwh)	2030+ (lb./Mwh)
Fossil-Steam	1671	1500	1380	1305
NGCC	877	817	784	770

- **Rate-based - Market:**

APCo is constrained to comply with a total company rate-based limit of CO_2 emissions (lb./MWh), and is able to procure additional ERCs from an external market. Rate-based limits were determined in the same manner as the island approach discussed above.

In order to provide flexibility to meet CPP-related constraints, additional supply-side resource options were made available to the model during the optimization of the CPP scenarios described above. The options only affected APCo's large coal-fired units at the Amos and Mountaineer plants, and consisted of the following:

- Unit curtailments were considered as alternatives for Amos Units 1, 2 and 3 and Mountaineer Unit 1;
- co-firing on natural gas was considered for Amos Units 2 and 3; and
- the retirement of Amos Unit 1.

5.2.3.1 Clean Power Plan Mass-Based Scenario Portfolios

5.2.3.1.1 Mass-Based- Island

Table 24 below shows the capacity additions associated with the Mass-Based – Island CPP scenario. In order to meet APCo's CO_2 limits without an external market the optimized portfolio includes unit curtailments as well as co-firing. During the planning period Amos Units 1, 2 and 3 were curtailed to run at capacity factors as low as 45, 35, and 40%, respectively. Mountaineer Unit 1 was curtailed to run at a capacity factor as low as 50%. The portfolio also calls for Amos Unit 1 to be retired in 2026.

Table 24. Yearly Incremental PJM Capacity Additions (MW) and Energy Positions (GWh) for Mass-based – Island CPP Scenario

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2030 Net Energy Position (GWh)	Avg Net Energy Position (GWh) (2016-2030)
Mass Based - Island	Base/Intermediate											472	1,417	1,417	1,417	1,417	3,776	869
	Peaking																	
	Solar (Firm)					19	38	57	76	76	76	76	76	76	76	95		
	Solar (Nameplate)					50	100	150	200	200	200	200	200	200	200	250		
	Wind (Firm)			15	30	45	60	68	75	75	75	75	75	75	83	90		
	Wind (Nameplate)			300	600	900	1,200	1,350	1,500	1,500	1,500	1,500	1,500	1,500	1,650	1,800		
	Battery Storage																	
	Energy Efficiency				37	44	50	56	62	68	74	80	86	91	97	105		
	CHP																	
	VVO	1	1	1	1	1	28	48	48	48	66	82	82	82	82	82		
	Demand Response																	
	Distr. Gen.	2.9	3.3	3.7	4.5	5.8	6.6	7.9	9.5	11.6	13.6	16.5	18.6	19.4	21.1	23.2		

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

5.2.3.1.2 Mass-Based - Market

As mentioned above, the Mid, Low Band, and High Band commodity pricing portfolios represent compliance plans under a Mass-Based approach with access to allowances in an external market. Capacity additions associated with these portfolios are shown above in Table 19.

5.2.3.1.3 Clean Power Plan Mass-Based Portfolio CO_2 Emissions

Figure 32 below illustrates the emissions of CO_2 for each of the Mass-Based CPP scenario portfolios. The island approach forces the model to optimize the portfolio of resources such that CO_2 emissions stay below the Company limit. In the Mass-Based – Market scenarios each portfolio may emit more CO_2 than the initial limit due to the availability of additional allowances in an external market. The quantity of the additional allowances needed in each market plan is represented in Figure 32 as the distance between each market scenario trendline and the dashed black target line.

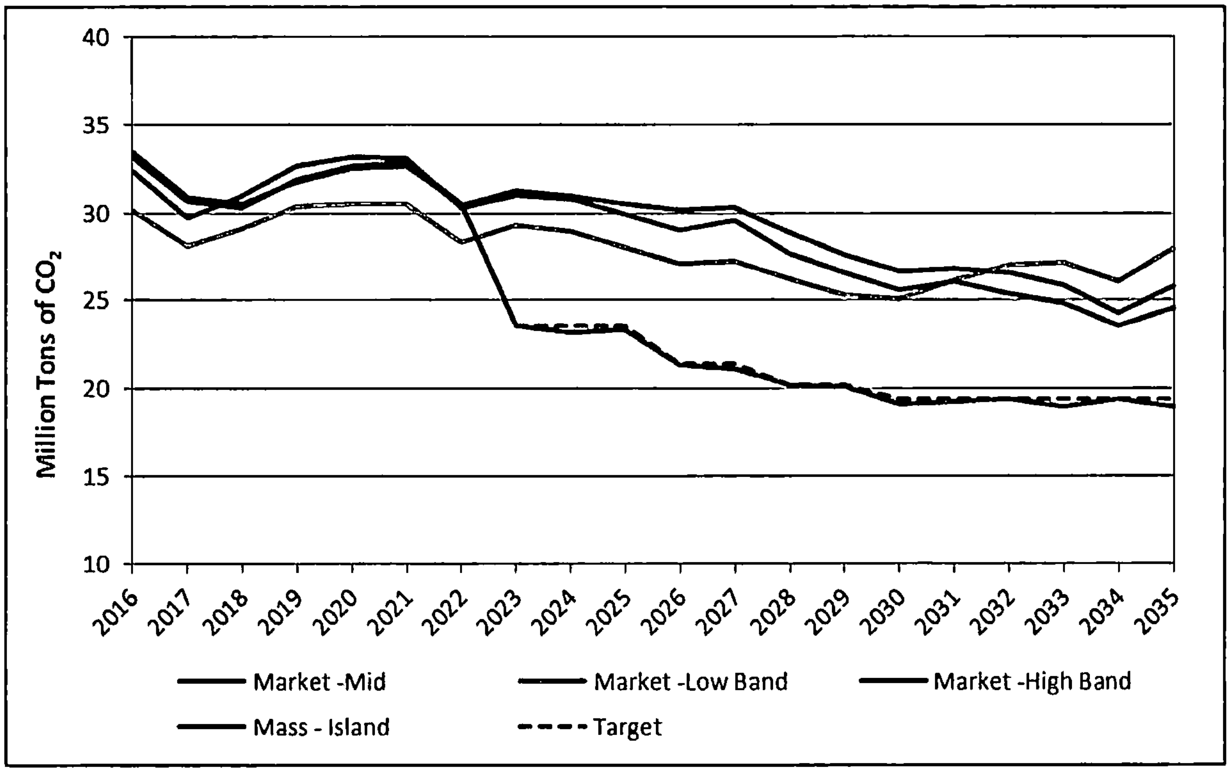


Figure 32. Mass-Based CPP Scenario Emissions (Million Tons of CO_2) vs. Target

5.2.3.2 Clean Power Plan Rate-Based Scenario Portfolios

5.2.3.2.1 Rate-Based - Island

Table 25 below shows the capacity additions associated with the Rate-Based – Island CPP scenario. The Rate-Based – Island plan calls for large amounts of large-scale solar generation, in addition to the large amounts of wind seen in all other plans. This portfolio further seeks to add additional carbon-free capacity resources with increased amounts of VVO (97MW). The Rate-Based – Island plan calls for the curtailment of coal-fired units with Amos Units 1 and

3 curtailed to run at capacity factors as low as 45, and 40%, respectively. Mountaineer Unit 1 was curtailed to run at a capacity factor as low at 50%. This portfolio calls for the retirement of Amos Unit 1 in 2025 and the conversion of Amos Unit 2 to a co-fired resources beginning in 2030.

Table 25. Yearly Incremental PJM Capacity Additions (MW) and Energy Positions (GWh) for Rate-based – Island CPP Scenario

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2030 Net Energy Position (GWh)	Avg Net Energy Position (GWh) (2016-2030)
Rate Based - Island	Base/Intermediate											472	945	945	945	945	1,379	1,955
	Peaking																	
	Solar (Firm)			34	72	110	148	186	224	243	277	315	350	384	422	460		
	Solar (Nameplate)			90	190	290	390	490	590	640	730	830	920	1,010	1,110	1,210		
	Wind (Firm)			15	30	45	60	68	75	75	75	75	75	75	83	90		
	Wind (Nameplate)			300	600	900	1,200	1,350	1,500	1,500	1,500	1,500	1,500	1,500	1,650	1,800		
	Battery Storage																	
	Energy Efficiency				43	50	56	63	70	76	93	102	110	115	121	129		
	CHP																	
	VVO	1	1	1	1	1	28	48	65	82	82	82	97	97	97	111		
	Demand Response																	
	Distr. Gen.	2.9	3.3	3.7	4.5	5.8	6.6	7.9	9.5	11.6	13.6	16.5	18.6	19.4	21.1	23.2		

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

5.2.3.2.2 Rate-Based - Market

Table 26 below shows the capacity additions associated with the Mass-Based – Market CPP scenario.

Table 26. Yearly Incremental PJM Capacity Additions (MW) and Energy Positions (GWh) for Rate-based – Market CPP Scenario

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2030 Net Energy Position (GWh)	Avg Net Energy Position (GWh) (2016-2030)
Rate Based - Market	Base/Intermediate											472	472	472	472	472	5,054	3,421
	Peaking																	
	Solar (Firm)			19	57	95	133	171	209	228	247	266	304	342	380	418		
	Solar (Nameplate)			50	150	250	350	450	550	600	650	700	800	900	1,000	1,100		
	Wind (Firm)			15	30	45	60	68	75	75	75	75	75	75	83	90		
	Wind (Nameplate)			300	600	900	1,200	1,350	1,500	1,500	1,500	1,500	1,500	1,500	1,650	1,800		
	Battery Storage																	
	Energy Efficiency				50	56	63	70	77	84	101	112	118	124	134	142		
	CHP																	
	VVO	1	1	1	1	1	28	48	66	82	97	97	111	111	111	111		
	Demand Response											2	2	2	2	2		
	Distr. Gen.	2.9	3.3	3.7	4.5	5.6	6.6	7.9	9.5	11.6	13.6	16.5	18.6	19.4	21.1	23.2		

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

The Rate-Based – Market plan calls for the addition of a NGCC resource (50% of a 2x1 facility) in 2026. No unit retirements, curtailments, or co-firing is incorporated into this plan.

Substantial amounts of carbon-free energy and capacity is included with the addition of 1,100MW (nameplate) of large-scale solar, on top of 1,800MW (nameplate) of wind resources.

5.2.3.2.3 Clean Power Plan Rate-Based Portfolio CO_2 Emissions

Figure 33 below illustrates the emission rates for each of the Rate-Based CPP scenario portfolios during select years. The island approach forces the model to optimize the portfolio of resources such that CO_2 emissions stay below the Company limit. In the Rate-Based – Market scenarios each portfolio may emit CO_2 at a higher rate than the initial limit due to the availability of additional ERCs from an external market. The quantity of the additional ERC's needed in each market plan is represented in Figure 33 as the difference between the "Pre-ERC Market Rate" column in blue and the "Target" rate shown in green.

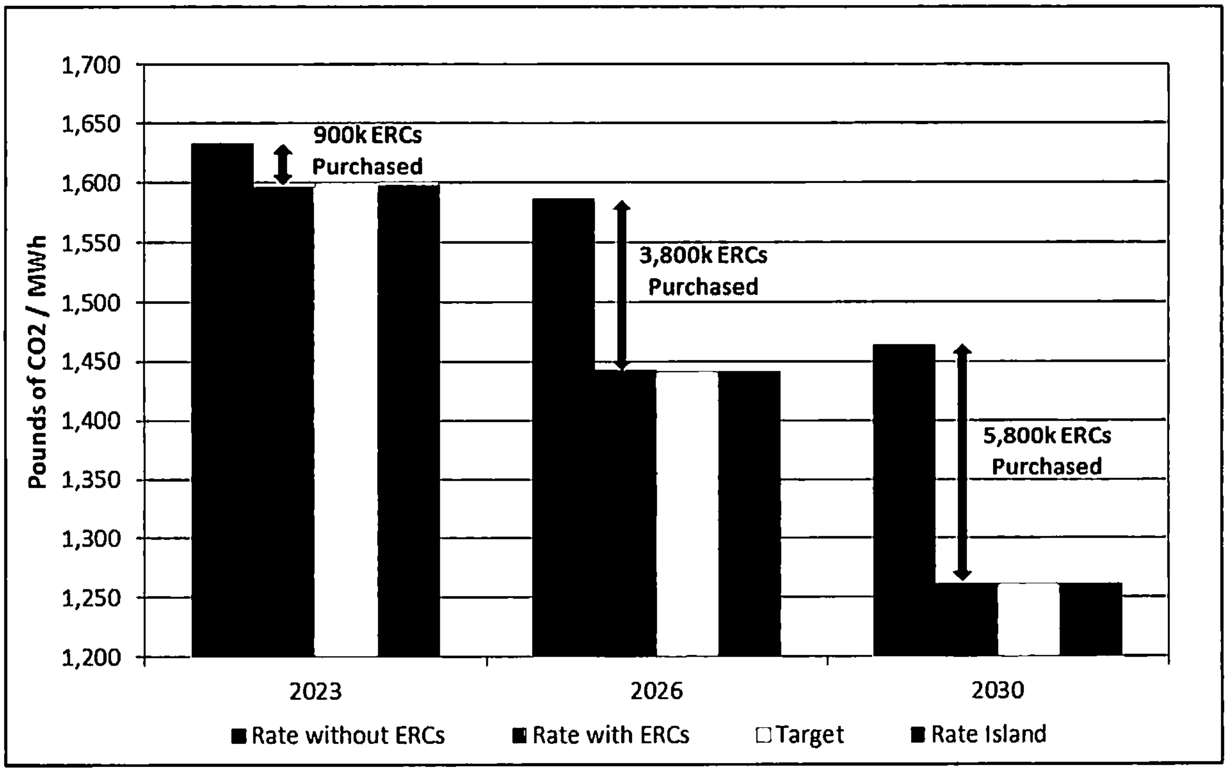


Figure 33. Rate-Based CPP Scenario Emissions (lbs. CO_2/MWh) vs. Target

5.2.3.3 Comparing Clean Power Plan Scenario Costs

The cost of the CPP compliant plans may be compared to the extent they were developed using the same commodity pricing scenario as shown below in Table 27. As the table shows, the market-based compliance strategies are less costly (i.e. have a lower CPW of costs) than the island-based strategies.

Further, the rate-based market strategy is a little less costly than the mass market strategy. Given the uncertainties and assumptions around the ultimate CPP state requirements that are inherent in this modeling, the level of differentiation between the mass and rate market plans is too small to be conclusive.

Table 27. Clean Power Plan Compliance Scenario Cost Comparison ($000)

CPP Scenario	Plan CPW	Cost Above Lowest Cost CPP Compliant Plan	Cost Above No Carbon Plan
Rate Target Market Plan	$23,885,814	Lowest Cost	$286,644
Rate Target Island Plan	$24,224,417	$338,603	$625,247
Mass Target Market Plan	$24,033,007	$147,193	$433,837
Mass Target Island Plan	$24,143,069	$257,255	$543,899
No Carbon Plan	$23,599,170		

5.2.3.4 Federal Implementation Plan Analyses

The proposed federal plans are market-based plans where either allowances (if mass-based) or ERCs (if rate-based) can be purchased on an open market. The federal plans are assumed to be more restrictive than what was assumed for the state market plans. For example, in the assumed mass-based federal plan, APCo's emission allowances will be reduced over time as EPA has proposed that retired units would not receive an allocation in perpetuity. For the federal rate-based plan, it is assumed that EE projects would not be eligible for generating ERCs. As a result of these differences between the assumed federal and state plans, additional allowances or ERCs would need to be purchased. To determine the cost of a plan that complies with the draft federal rules, APCo used the market-based portfolios described above as starting points, then adjusted the APCo target (mass or rate) in accordance with the proposed federal plan rules to determine the incremental allowances or ERCs that would need to be procured. The cost (i.e., CPW) of the state and federal mass-based and rate-based plans are shown below in Table 28. Note that the cost difference is much more significant with the mass-based plans.

Table 28. CPP Federal Plan Cost Comparison ($000)

CPP Scenario	Plan CPW	Cost Above State Plan	Cost Above No Carbon
Mass-Based Market - Federal	$24,434,109	$401,102	$834,939
Mass-Based Market - State	$24,033,007		
Rate-Based Market - Federal	$23,916,721	$30,907	$317,551
Rate-Based Market - State	$23,885,814		
No Carbon Plan	$23,599,170		

5.2.3.5 Rate Impacts of Clean Power Plan Scenarios

The Company evaluated the rate impacts of the various presumptive CPP compliant portfolios, which were requested by the SCC and are discussed in this Report, relative to a no-carbon scenario. To calculate the rate impact, total company costs from the Plexos model output were categorized as either energy or demand costs, multiplied by the Virginia jurisdictional factor to reflect only Virginia retail costs, and then divided by forecasted Virginia load, net of DSM reductions. Figure 34 below illustrates the incremental rate impacts of the CPP-compliant scenarios. The rate impacts are shown as an aggregate, energy-only rate for comparison purposes.

Under the two "Island" scenarios, the increase in retail rates shows the impacts of the early retirement of Amos 1, assuming the unit is then replaced with incremental NGCC capacity. The other drivers of the rate increase are costs associated with purchasing allowances or ERCs, for the market scenarios, incremental solar and DSM resources for the Rate-Based island scenario, and differences in fuel costs and load costs between a CPP compliant scenarios and a scenario where there is no CPP. The Rate-Based Market and Rate-Based Market Federal Plans offer lower costs in the mid-2020's due to larger relative additions of wind energy during that period. Wind is more attractive in the market scenarios due to higher assumed energy prices relative to the No Carbon scenario.

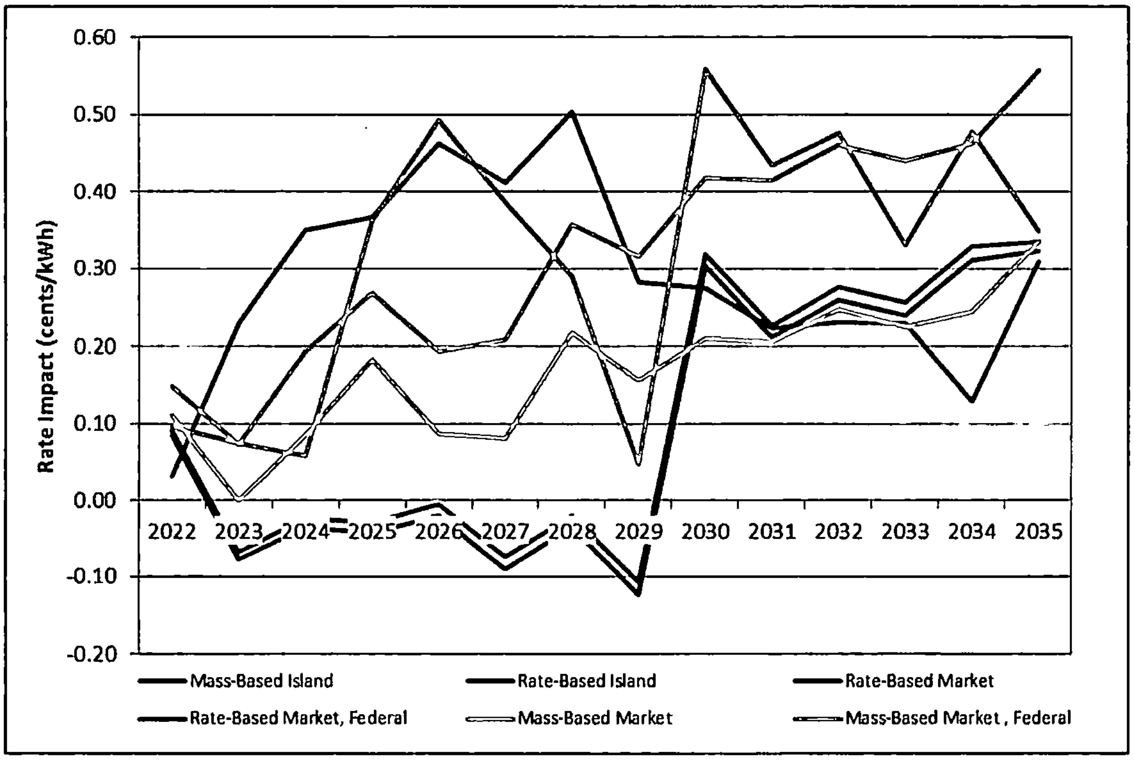


Figure 34. Rate Impacts (cents/kWh) of Clean Power Plan (CPP) Compliance Scenarios - shown as Incremental Change from No-Carbon Scenario.

Compared to current APCo Virginia residential rates, implementation of these CPP compliant plans could result in an approximate 0.3% to 1.7% increase in 2022; and in 2031, increases ranging from 2.3% to 2.5% for the Rate Market/Rate Market – Federal plans and the Mass Island/Mass Market plans, and 4.5% to 4.7% for the Mass Allowance Market Federal and the Rate Island plans. It is important to remember that these increases are *over and above* any incremental costs to implement the optimized No Carbon portfolio (i.e. are not representative increases from current rates), and are highly dependent upon both the assumptions used in the Company's modeling and the uncertainties surrounding the CPP, as discussed throughout this Report. These projected increases are likely to change as better information becomes available.

5.3 Hybrid Plan

Each of the scenarios analyzed provides insight into APCo's preferred potential mix of resources for the future. This mix is referred to as the Hybrid Plan. APCo's Hybrid Plan was developed based on certain considerations such as minimizing revenue requirement exposure (i.e., cost to customers) over the planning period while meeting capacity obligations, minimizing the Company's dependency on external energy and its corresponding risk of energy market price volatility, and adding and/or accelerating renewable energy resources (wind and solar) in a reasonably cost effective manner to secure potential optionality based on the prospects of a Clean Power Plan. As a result, while the Hybrid Plan has many of the same near term capacity additions as the No CO_2 portfolio, over the long term it mirrors the optimized Mid portfolio.

The incremental capacity additions associated with the Hybrid Plan are shown below in Table 29. Specifically, the Hybrid Plan incorporates the following changes from the optimized Mid and No CO_2 portfolios:

- Advancement of a portion of solar resources from 2019 to 2018. This will allow APCo to gain experience with smaller tranches of solar capacity before embarking on a larger build program.
- Addition of battery storage in 2025. While currently not an economic resource, battery storage may provide benefits which complement the additional renewable sources; and
- Addition of a CHP facility in 2020. This acknowledges that certain customers are interested in CHP initiatives and assumes a suitable host application is identified.

Table 29. Yearly Incremental PJM Capacity Additions (MW) and Energy Positions (GWh) for Hybrid Plan

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2030 Net Energy Position (GWh)	Avg Net Energy Position (GWh) (2016-2030)
Hybrid Plan	Base/Intermediate											472	472	472	472	472		
	Peaking																	
	Solar (Firm)			8	19	38	76	114	152	152	152	152	167	186	205	224		
	Solar (Nameplate)			20	50	100	200	300	400	400	400	400	440	490	540	590		
	Wind (Firm)			15	30	45	60	68	75	75	75	75	75	75	83	90		
	Wind (Nameplate)			300	600	900	1,200	1,350	1,500	1,500	1,500	1,500	1,500	1,500	1,650	1,800	4,170	3,052
	Battery Storage										5	5	5	5	5	5		
	Energy Efficiency				37	44	50	56	62	68	74	80	86	92	98	106		
	CHP					14	14	14	14	14	14	14	14	14	14	14		
	VVO	1	1	1	1	1	28	48	48	66	66	82	97	97	97	97		
	Demand Response																	
	Distr Gen	2.9	3.3	3.7	4.5	5.5	6.6	7.9	9.5	11.6	13.6	16.5	18.6	19.4	21.1	23.2		

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

A key facet of the Hybrid Plan is that it reduces APCo's need to purchase energy from the PJM market. APCo finds itself short on energy largely because the Company's load profile does not align with that of PJM. APCo experiences its greatest demand during the winter, and hence is a winter-peaking entity. PJM as a whole operates as a summer-peaking RTO. Therefore, when APCo meets its summer demand obligations—per PJM rules—it is not meeting its true peak demand obligations and ultimately the Company is short on energy during the winter months. The Hybrid Plan has the potential to minimize the consequences of APCo's energy position by adding renewable resources which can provide significant energy in both the summer and winter months. Similarly, the Plan also calls for DSM programs—EE and VVO—which reduce both demand and energy on a year-round basis.

The Hybrid Plan, in conjunction with the Company's five-year action plan, offers APCo significant flexibility should future conditions differ considerably from its assumptions. 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 ultimately increase, APCo could consider a more traditional new peaking capacity build, which has a relatively short lead time to implement. Changes to APCo's existing portfolio associated with this Hybrid Plan are described in greater detail in Section 6.0 of this Report.

5.3.1 Future CO_2 Emissions Trending – Hybrid Plan

The Hybrid Plan could be a CPP compliant plan under a Mass-Based Market approach. Figure 35 below shows how the Hybrid Plan's CO_2 emissions compare with the CPP targets on a mass basis. Again, the distance between the Hybrid Plan emission and the target emission lines represent CO_2 allowances which would need to be purchased from the market.

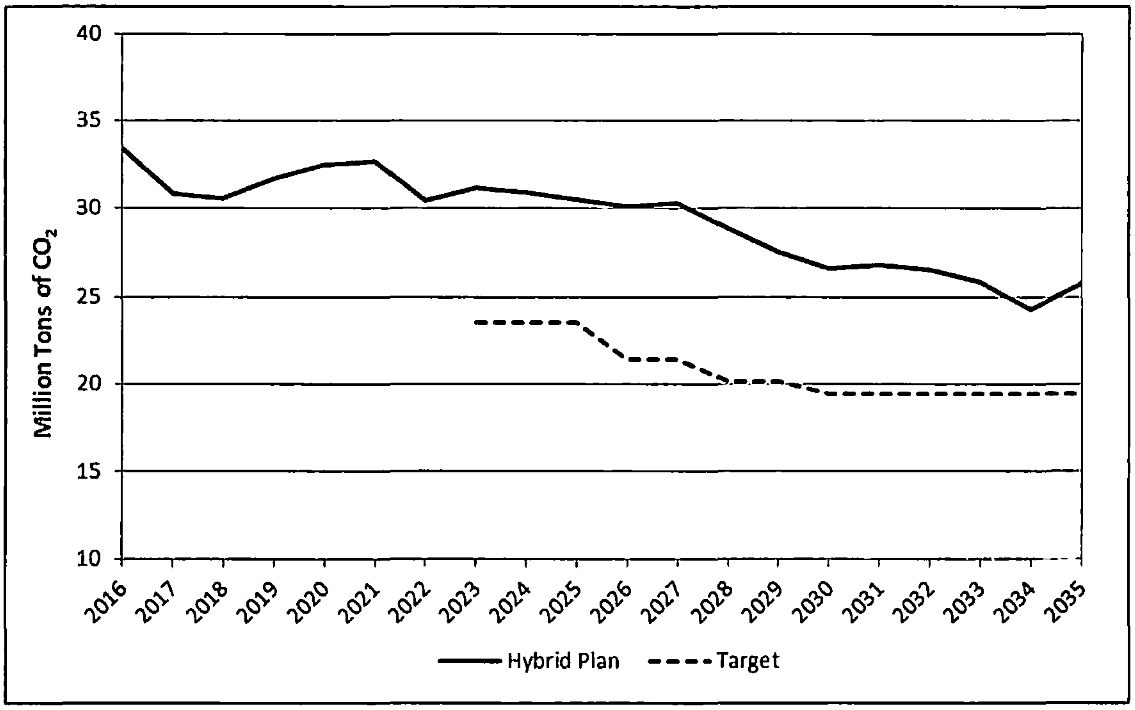


Figure 35. Mass-Based CO_2 Emissions (Million Tons of CO2) of Hybrid Plan vs. Target

5.3.2 Energy Efficiency (EE), Volt VAR Optimization (VVO) and Distributed Generation (DG)

In the Hybrid Plan, incremental EE resources were selected throughout the planning period. Economic savings are attributable to both Commercial and Residential programs, with the majority coming from Residential Lighting programs. By 2030, overall EE savings – consisting of Other Energy Efficiency, Existing DSM Programs, and Incremental DSM Programs – will provide a decrease in residential and commercial energy usage by nearly 8% (as shown in Figure 36). Existing DSM and Incremental DSM will provide a reduction in residential and commercial capacity by 106MW by 2030.

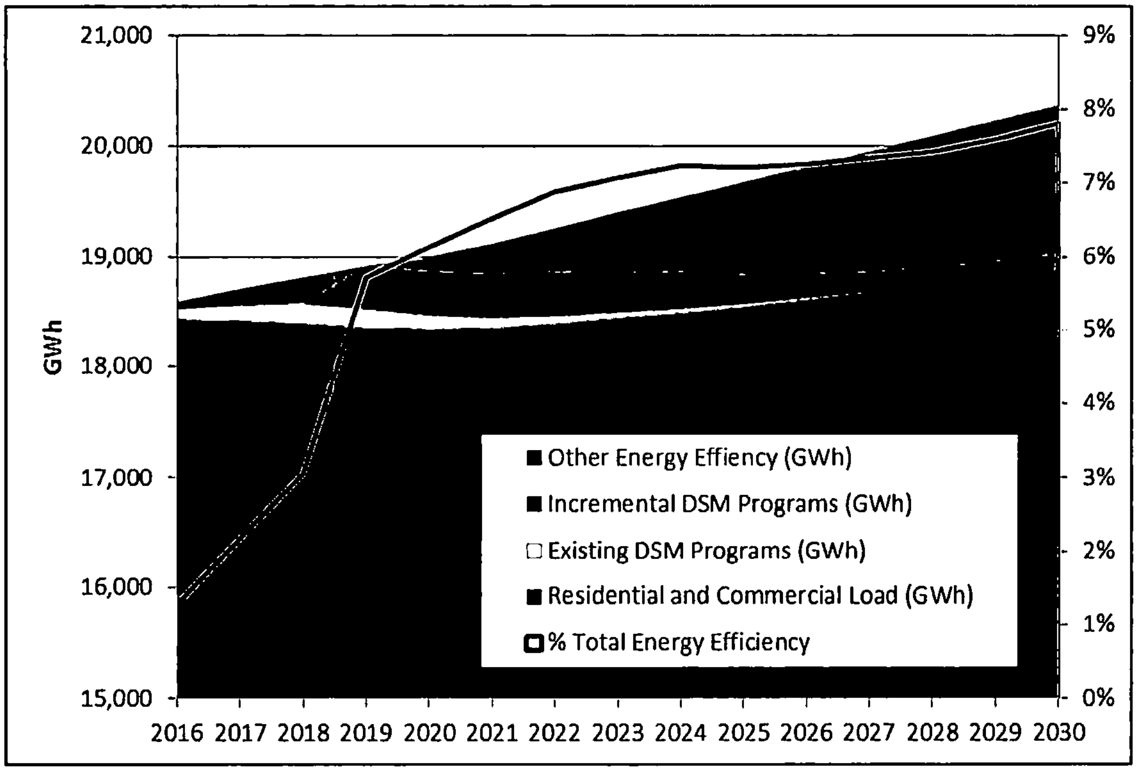


Figure 36. APCo Energy Efficiency Savings According to Hybrid Plan

As part of the Hybrid Plan, 5 of the 13 available VVO tranches were ultimately selected by the model. When coupled with APCo's existing pilot installation this results in a cumulative capacity reduction of 97MW by 2030. The first tranche of circuits in addition to the pilot program was added in 2021, and additional tranches were added in 2022, 2024, 2026, and 2027. 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 selected under any economic scenario during the planning period. DG resources were added incrementally at a CAGR of over 30% (based on nameplate capacity), resulting in a total of 23.2MW of PJM capacity credit (60.9MW nameplate) by 2030.

5.3.3 Comparing the Cost of the Hybrid Plan

When comparing plan costs it is important to remember that there are distinct differences between how the market-based rate and mass plan targets and subsequent optimized portfolios were developed and the inherent assumptions in each. For the mass plans, incremental carbon free energy that is introduced into the portfolio, whether through EE or additional renewable resources, does not, in and of itself, allow APCo to achieve its mass goal. The way APCo meets its goal in the mass-based strategy is through the reduction of CO_2 output from its affected sources – its existing fossil units, followed by the purchase of an allowance for each ton of CO_2 emitted in excess of its target. In a rate-based strategy, adding non-carbon energy sources in concert with reduced fossil unit output will contribute to APCo's rate reduction goals. As a result, carbon free resources have more value (and subsequently less net costs) in a rate-based strategy than in a mass-based strategy.

It is appropriate, therefore, to compare the Hybrid Plan, which was developed under the assumption of a mass-market strategy, to other mass-market plans. Table 30 below compares the CPW cost of the Hybrid plan to the optimized plans under the Low, Mid, High and No Carbon pricing scenarios. It also includes a calculation of the levelized cost difference for a customer using 1,000 kWh of energy per month, assuming that cost would apply over the entire study period. Note that the resource selection under the Hybrid Plan in the near term is similar to all the optimized plans, and therefore could be easily adjusted if the states in which APCo has affected units follow a rate based strategy, or if the CPP is further delayed. As shown in the table, the *annual* levelized bill impact associated with the Hybrid Plan is negligible.

Table 30. Comparison of Hybrid Plan vs. Optimized Plan based on Cumulative Present Worth ($000), Incremental Cost ($000), and Levelized Annual Bill Impact ($)

	Low Band	Mid	High Band	No Carbon
Optimized Plan	$22,993,078	$24,033,007	$25,543,607	$23,599,170
Hybrid Plan	$23,075,419	$24,042,506	$25,576,035	$23,672,058
Incremental Cost	$82,341	$9,499	$32,428	$72,888
Levelized Annual Bill Impact	$2.22	$0.26	$0.87	$1.96

The Hybrid Plan presented in this IRP is expected to provide adequate reliability over the planning period. By minimizing CPW, the Company's model produced optimized portfolios with the lowest and most stable rates for customers. Low stable rates benefit customers by attracting new commercial and industrial customers, and retaining and/or expanding existing load. A key aspect of the Hybrid Portfolio presented in this IRP is that it would reduce APCo's need to purchase energy from the PJM market, which enhances energy independence. Also, by including renewable and natural gas resources, the IRP should mitigate volatility in future fuel and purchase power costs.

5.4 Risk Analysis

In addition to comparing the Hybrid Plan to the optimized portfolios under a variety of pricing assumptions, the Hybrid Plan, Mass-Based Island and Rate-Based Island portfolios 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 Hybrid 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 four 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 31 shows the input variables or risk factors within this IRP stochastic analysis and the historical correlative relationships to each other.

Table 31. Risk Analysis Factors and Relationships

	Coal	Gas	Power	CO2
Coal	1	0.18	0.53	-0.98
Gas		1	0.47	0.96
Power			1	0.95
CO2				1
Standard Deviation	6.4%	19%	14.7%	43%

Comparing the Hybrid Plan to portfolios which exclude a large coal unit (both "Island" portfolios include the retirement of Amos 1 and replace it with NGCC capacity), or contain more renewable options, as in the Rate-Based Island portfolio, provides the Company with a range of resource profiles, and therefore different revenue requirements, than those in the Hybrid Plan. The Hybrid Plan has a similar resource profile to other "non-island" optimized plans, so there would be little difference in the risk profiles between the other portfolios (High Band, Low Band, Rate-Based Market) and the Hybrid Plan, and therefore those portfolios were not included in the stochastic analysis. The range of values associated with the variable inputs is shown in Figure 37.

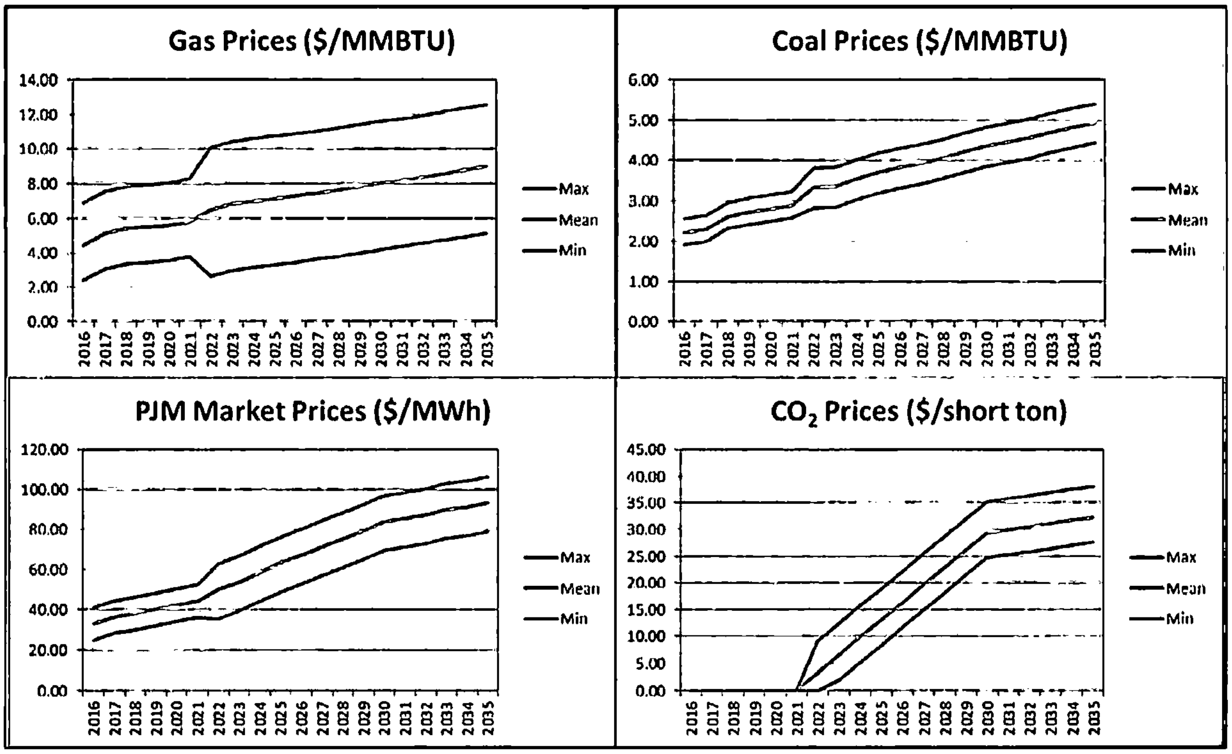


Figure 37. Range of Variable Inputs for Stochastic Analysis

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 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 38, below, illustrates the RRaR (expressed in terms of incremental cost over the 50th percentile).

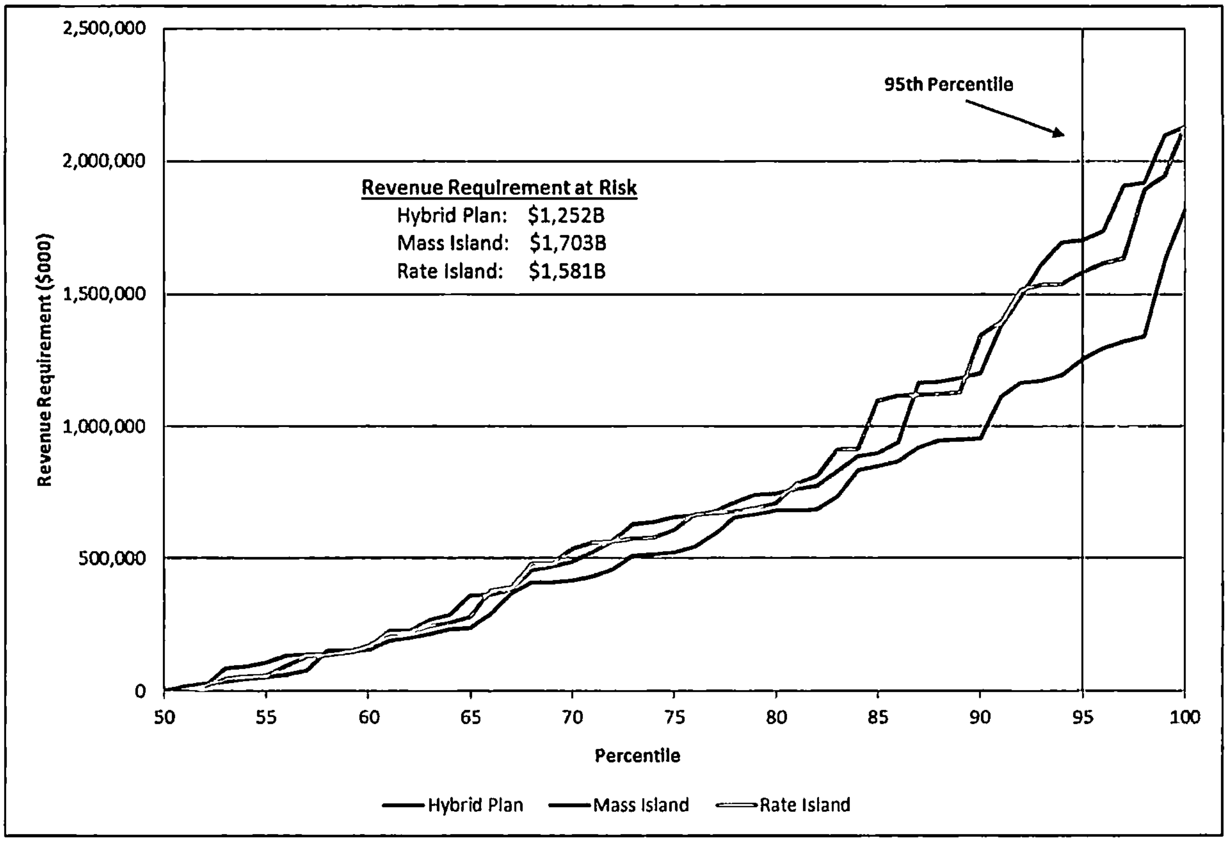


Figure 38. Revenue Requirement at Risk (RRaR) ($000) for Select Portfolios

The difference in RRaR between the portfolios that were analyzed is relatively small through the 70th percentile. At the tail end of the analysis (85th through 95th percentiles), the Rate Island and Mass Island portfolios show increased risk relative to the Hybrid Plan. The retirement of Amos 1 and additional natural gas generation in the Island portfolios relative to the Hybrid Plan, appears to introduce additional risk.

Based on the risk modeling performed, it is reasonable to conclude that the inherent risk characteristics of the Hybrid Plan is not as great as portfolios which retire a coal unit and replace it with additional NGCC resources. This suggests that the Hybrid Plan represents a more reasonable combination of expected costs and risk than those portfolios.

6.0 Conclusions

The optimization results and associated risk modeling of this IRP demonstrate that APCo, as a stand-alone entity in the PJM RTO, can serve customer needs over the prescribed planning period by continuing operation of its existing resources while adding NGCC generation, wind and solar renewables, and DSM resources, including EE measures and VVO. The Hybrid Plan attempts to balance cost, and the potential risk of a volatile energy market, while allowing APCo the flexibility to adapt to future changes.

The following are summary highlights of the Hybrid Plan:

- Adds 20MW (nameplate) of large-scale solar energy by 2018, with subsequent additions throughout the planning period, for a total of 590MW (nameplate) by 2030;
- adds 300MW wind energy by 2018, followed by 150 to 300 MW additions throughout the planning period, for a total of 1800MW (nameplate) of wind over the 15-year planning period;
- implements customer and grid EE programs, including VVO, reducing energy requirements by 1,161GWh) and capacity requirements by 203MW by 2030;
- assumes APCo's customers add DG (i.e. rooftop solar) capacity totaling over 60MW (nameplate) by 2030. (Note 1);
- adds 10MW (nameplate) of battery storage resources in 2025;
- assumes a host facility is identified such that a Combined Heat and Power (CHP) project can be implemented by 2020; and
- addresses expected PJM Capacity Performance rule impacts on APCo's capacity position beginning with the 2020/2021 PJM planning year. Among other things, it assumes that the rule may result in APCo:
    - reducing the level of Smith Mountain pumped storage PJM capacity contribution by approximately 200MW (from 585MW to 385MW);
    - reducing wind resources from prior PJM-recognized capacity levels (i.e. from 13% to 5% of nameplate capacity); and

- reducing run-of-river hydro contributions to 25% of nameplate rating.

- Continues operation 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) solid-fuel facilities: Clifty Creek Units 1-6 and Kyger Creek Units 1-5; and
- retires natural gas-converted Clinch River Units 1 and 2 in 2026.

Note 1: APCo does not have control over the amount, location or timing of these additions.

Specific APCo capacity position changes over the 15-year planning period associated with the Hybrid Plan are shown for 2016 and 2030, in Figure 39 and Figure 40, respectively.

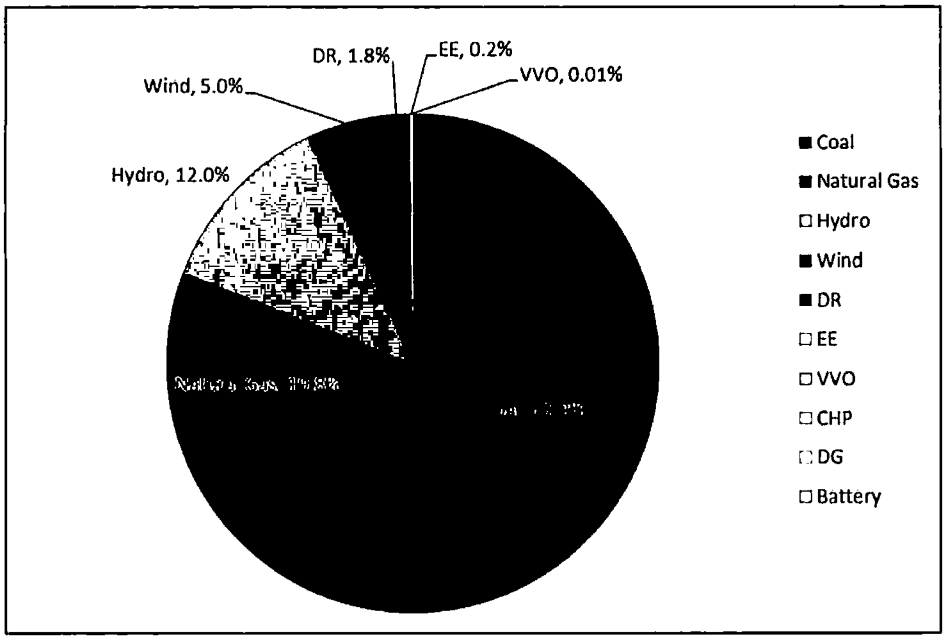


Figure 39. 2016 APCo Nameplate Capacity Mix

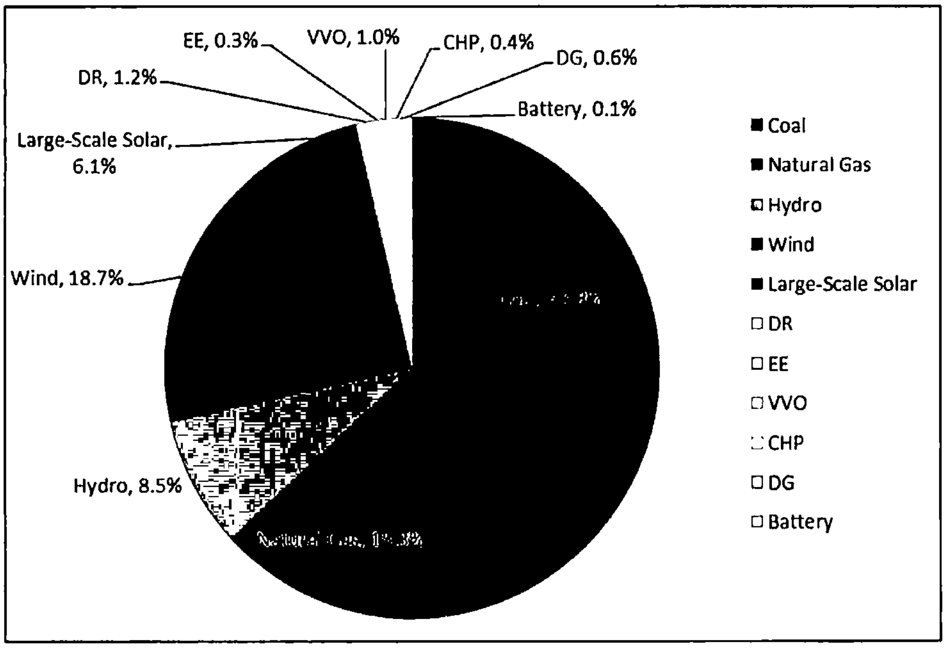


Figure 40. 2030 APCo Nameplate Capacity Mix

Specific APCo energy production changes over the 15-year planning period associated with the Hybrid Plan are shown for 2016 and 2030, in Figure 41 and Figure 42, respectively.

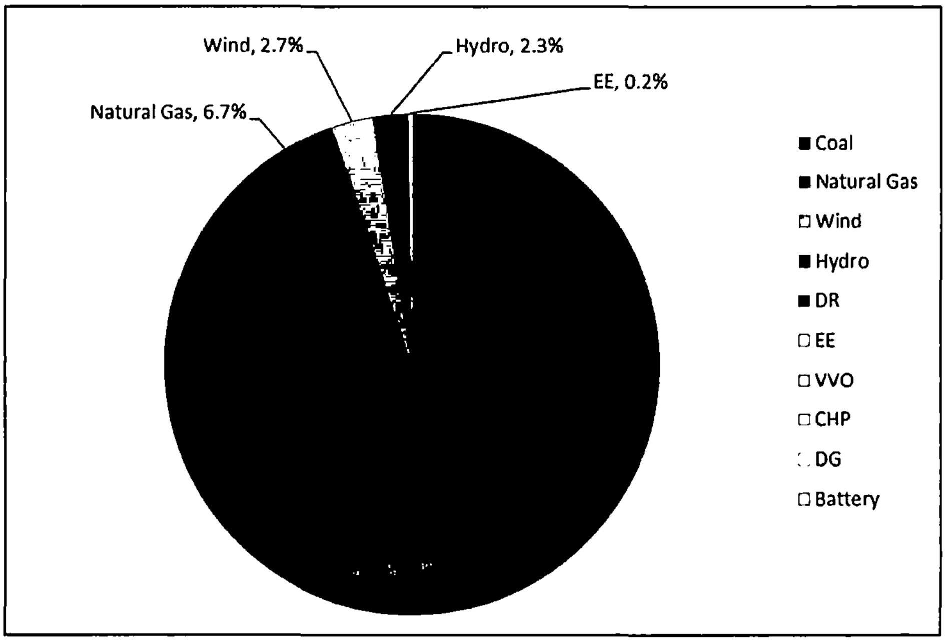


Figure 41. 2016 APCo Energy Mix

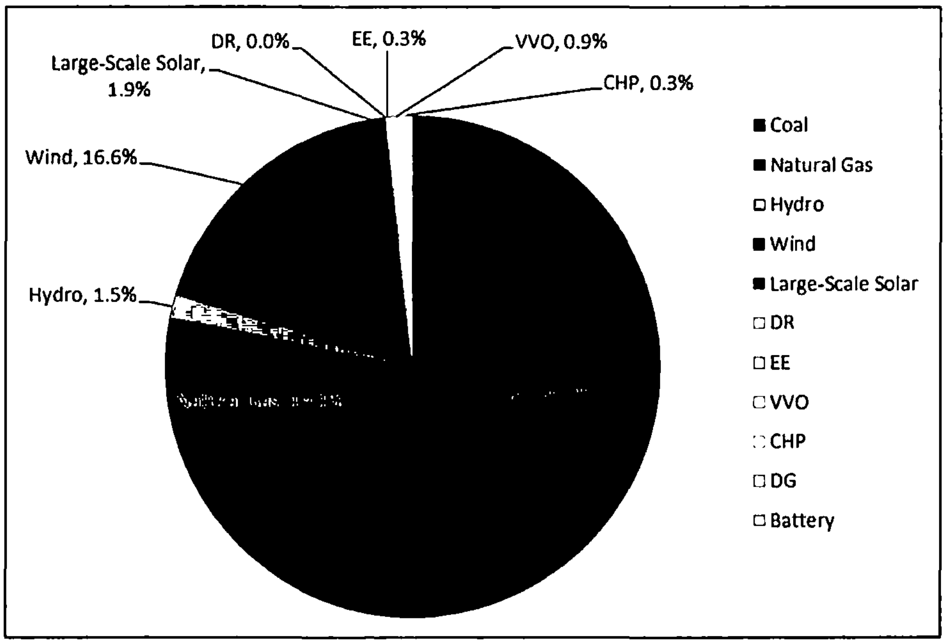


Figure 42. 2030 APCo Energy Mix

Figure 39 through Figure 42, above, indicate that this Hybrid Plan would reduce APCo's reliance on coal-based generation and increase reliance on demand-side and renewable resources, improving the diversity of the portfolio. Specifically, over the 15-year planning horizon the

Company's nameplate capacity mix attributable to coal-fired assets would decline from 61.2% to 47.8%. Renewable assets (wind and solar) climb from 5% to 24.8%, and demand-side resources (including EE, VVO, DG, DR, and CHP) increase from 2.0% to 3.5% over the planning period.

APCo's energy output attributable to coal-fired generation shows a substantial decrease from 88.0% to 59.0% over the period. The Hybrid Plan shows a significant increase in renewable energy (wind and solar), from 2.7% to 18.5%. Energy from these renewable resources, combined with EE and VVO energy savings serve to reduce APCo's exposure to energy, fuel and potential carbon prices.

Figure 43 and Figure 44 show the changes in capacity and energy position, respectively, on an annual basis, that result from the Hybrid Plan, relative to capacity and energy requirements. The capacity contribution from renewable resources is fairly modest due to the implications of PJM's Capacity Performance rule; however, those resources (particularly wind) provide a significant volume of energy. APCo's model selected those wind resources because they add more value (lowered APCo cost) than alternative resources.

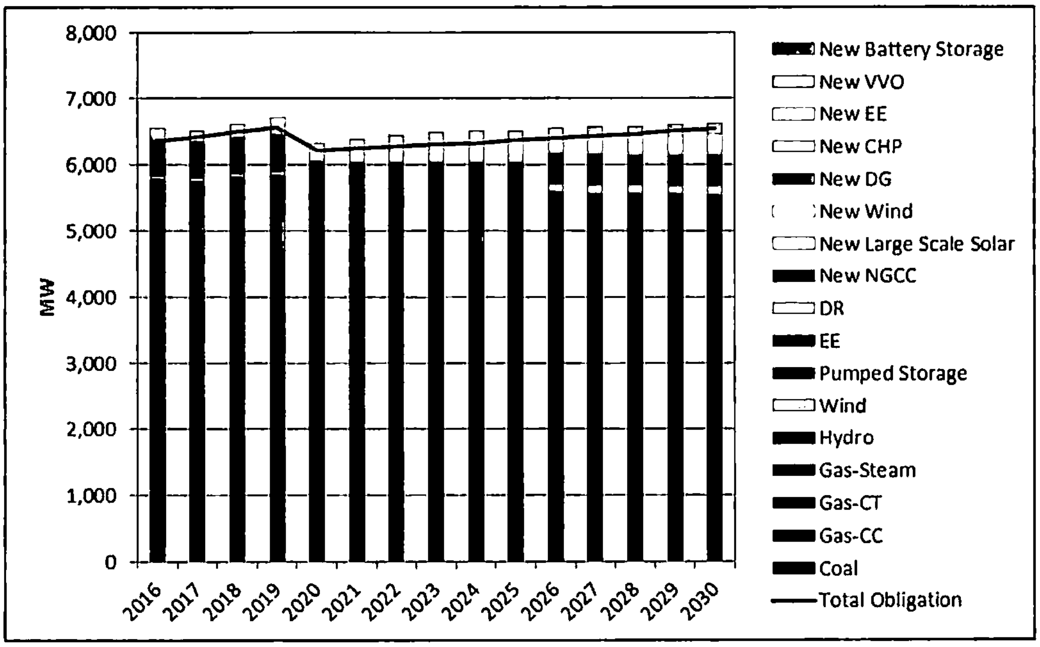


Figure 43. APCo Annual PJM Capacity Position (MW) According to Hybrid Plan

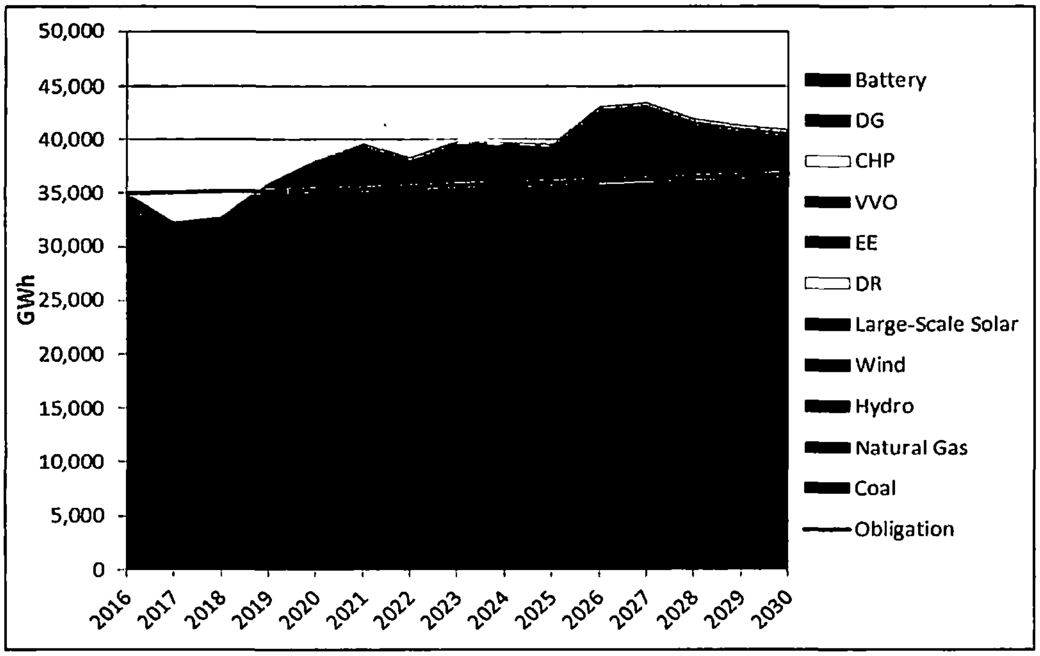


Figure 44. APCo Annual Energy Position (GWh) According to Hybrid Plan

Not only does the Hybrid Plan improve APCo's annual energy position, it also improves APCo's winter energy position. Although APCo is a winter peaking company, PJM stipulates that capacity requirements are set based on the PJM peak, which occurs in the summer. This has resulted in APCo being historically short on energy in the winter. Figure 45 illustrates APCo's modeled daily energy position throughout February of 2016. During this month APCo is short on energy for a total of 17 days, with the average energy shortage on those days being approximately 25,000MWh. Figure 46 shows APCo's improved daily energy position throughout the same month in 2030. In 2030 APCo is short for a total of nine days, with the average energy shortage on those days being approximately 15,000MWh. Energy production values shown in Figure 45 and Figure 46 incorporate random unit outages which are apparent in the sudden changes in output on subsequent days.

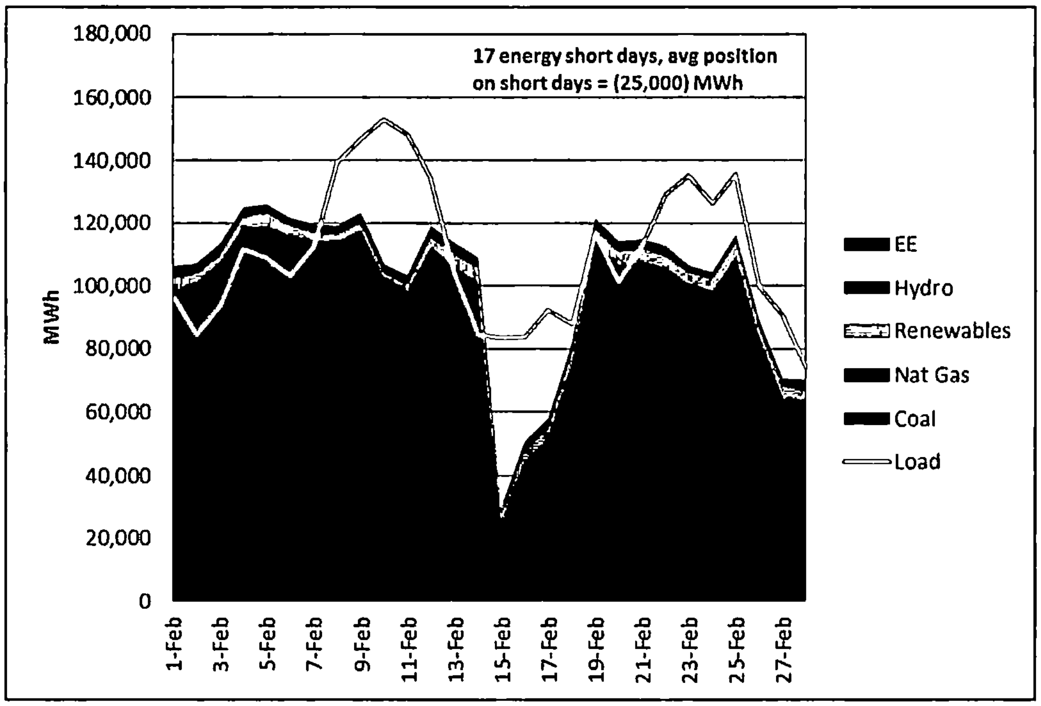


Figure 45. APCo Daily Energy Output and Requirement (MWh), February 2016

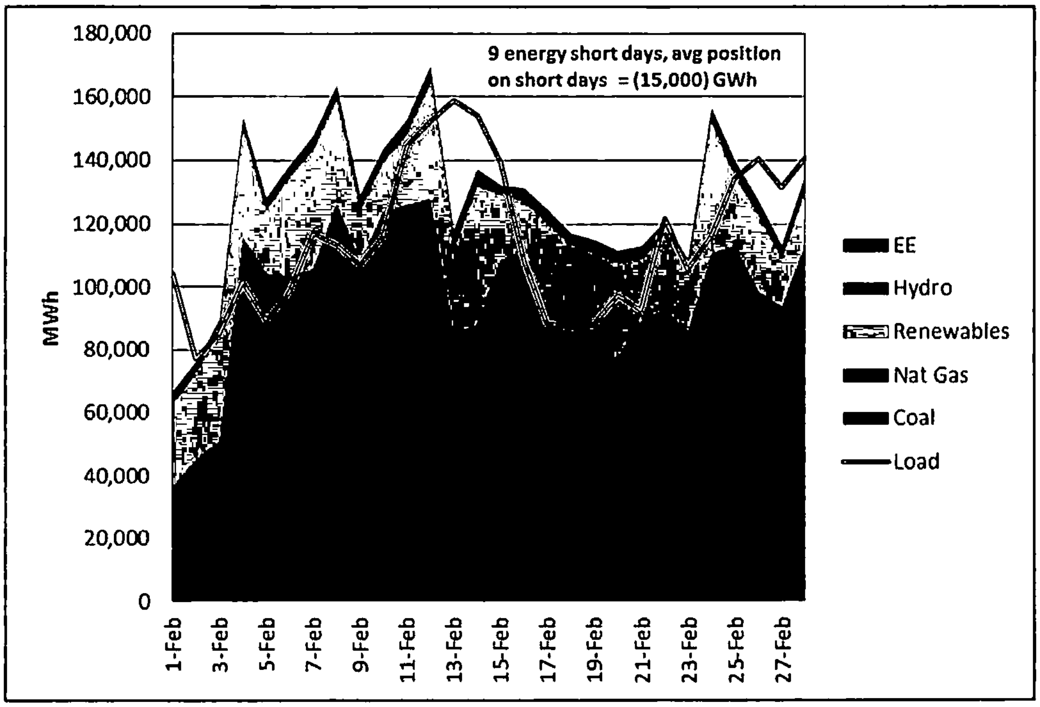


Figure 46. APCo Daily Energy Output and Requirement (MWh), February 2030

Recognizing the prospects of PJM's new Capacity Performance construct, the portfolios discussed in this Report attribute limited capacity value for certain intermittent resources (solar, wind and run-of-river hydro). Additionally, appropriate levels of APCo's Smith Mountain pumped storage facility were reduced to account for the Capacity Performance rule; however this reduction will continue to be assessed. It is possible that intermittent resources can be combined, or "coupled", and offered into the PJM market as Capacity Performance resources. Once the final PJM Capacity Performance tariffs are accepted, the Company will investigate methods to maximize the utilization of its current (and future) intermittent resource portfolio within that construct. An example could be the additional coupling of run-of-river hydro, wind and solar resources in a manner that would mitigate potentially costly non-performance risk.

Table 32 provides a summary of the Hybrid Plan which resulted from resource optimization modeling under the load and commodity pricing scenarios:

Table 32. Hybrid Plan Cumulative Capacity Additions throughout Planning Period (2016-2030)

Appachian Power Company
(Virginia Filing)
2016 Integrated Resource Plan
Cumulative Resource Changes

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)=(1)to(13), excl(5)	(15)	(16)	(17)	(18)	(19)	(20)
MW		(Cumulative) Existing Fleet	(Cumulative) Existing Fleet	(Cumulative) Firm Capacity Resource ADDITIONS											(Cumul.) NET 'RESOURCE' CHANGE[J]	Resulting APCo Reserves Above		(Cumulative) 'NAMEPLATE' ADDITIONS			
				New-Build		Energy Efficiency (EE)			VVO	DR	Wind[D]	Solar[E]		Battery[F]				Wind[D]	Solar[E]		Battery[F]
IRP Period	PJM Planning Year[A]	Unit Uprates & Derates	PJM Capacity Performance Impact (UCAP Reduction)	NG CHP	NG CC	'Embedded' Federal EE Regulations (Non-DSM EE)[B]	Current DSM Programs[C]	New	New	Pre-Existing DR Programs[C]		Large Scale	Dis-tributed			PJM Minimum Rqrmnt[K]	PJM Reserve Margin %		Large Scale	Dis-tributed	
Yr.		MW		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW		MW	MW	MW	
1	2016	14 [G]	-	-	-	*397*	20	-	1	142	-	-	3	-	179	212	4.4%	-	-	8	-
2	2017	14	-	-	-	*424*	47	-	1	142	-	-	3	-	207	107	1.8%	-	-	9	-
3	2018	14	-	-	-	*448*	63	-	1	142	15	8	4	-	246	125	2.1%	300	20	10	-
4	2019	50 [H]	-	-	-	*470*	71	37	1	142	30	19	5	-	354	160	2.7%	600	50	12	-
5	2020	50	(435) [I]	14	-	*491*	71	44	1	123	45	38	6	-	(45)	103	1.9%	900	100	15	-
6	2021	50	(435)	14	-	*516*	71	50	28	123	60	76	7	-	43	141	2.6%	1,200	200	17	-
7	2022	50	(435)	14	-	*537*	71	56	48	123	68	114	8	-	116	175	3.1%	1,350	300	21	-
8	2023	50	(435)	14	-	*557*	71	62	48	123	75	152	10	-	170	182	3.3%	1,500	400	25	-
9	2024	50	(435)	14	-	*574*	71	68	66	123	75	152	12	-	195	180	3.2%	1,500	400	30	-
10	2025	50	(435)	14	-	*595*	71	74	66	123	75	152	14	5	203	137	2.4%	1,500	400	36	10
11	2026	(424) [L]	(435)	14	472	*612*	71	80	82	123	75	152	17	5	227	147	2.6%	1,500	400	44	10
12	2027	(424)	(435)	14	472	*628*	71	86	97	123	75	167	19	5	265	123	2.1%	1,500	440	49	10
13	2028	(424)	(435)	14	472	*640*	71	92	97	123	75	186	19	5	290	112	2.0%	1,500	490	51	10
14	2029	(424)	(435)	14	472	*655*	71	98	97	123	83	205	21	5	324	84	1.5%	1,650	540	55	10
15	2030	(424)	(435)	14	472	*669*	71	106	97	123	90	224	23	5	361	69	1.2%	1,800	590	61	10
							177 'TOTAL Increm' Energy Efficiency												651 'TOTAL' Solar		

[A] PJM Planning Year is effective 6/1/XXXX.

[B] Represents estimated (post-2005) energy efficiency levels already 'embedded' into APCo's long-term load & peak demand forecast based on emergence of PRIOR-ESTABLISHED Federal efficiency standareds (EPAct 2005; 2007 EISA, 2009 ARRA).

[C] Represents estimated contribution from current/known APCo DSM-EE and Demand Response (Interruptible, DLC/ELM) program activity <u>through 2018</u>; values are baselined from 2015

[D] Due to the intermittency of wind resources, APCo assumes 5% of nameplate' MW rating are included for capacity resource determination purposes beyond 2020.

[E] Due to the intermittency of solar resources, Utility and Distributed Solar receive 38% of nameplate MW rating for capacity resource determination purposes.

[F] Due to the intermittency of battery/storage resources, APCo assumes 50% of nameplate MW rating for capacity resource determination purposes.

Changes to existing resources Post-June 1, 2015:

[G] Clinch River 1&2 Gas Conversion uprate

[H] Mountaineer turbine upgrade.

[I] Assumed removal of 75% Run-of-River Hydro capacity as well as a portion of Smith Mt. Pumped Storage and (Existing) Wind capacity to achieve PJM 'Capacity Performance' criteria

[J] <u>Includes changes in existing resources plus plan additions, excluding "embedded" EE and existing DR programs.</u>.

[K] PJM minimum criterion @16.5% as a function of peak demand effective with the 2019/20 PY (previously @ 15.7%).

[L] Clinch River 1&2 Gas Conversion unit retirement

This IRP, based upon various assumptions, provides adequate capacity resources at reasonable cost, through a combination of supply-side resources (including renewable supply-side resources) and demand-side programs throughout the forecast period.

Moreover, this IRP also addresses APCo's energy short position. The Hybrid Plan offers incremental resources that will provide—in addition to the needed PJM installed capacity to achieve mandatory PJM (summer) peak demand requirements—additional energy to reduce the long-term exposure of the Company's customers to PJM energy markets, which could be influenced by many external factors, including the impact of carbon regulation.

Recognizing PJM's new Capacity Performance construct, the portfolios discussed in this Report attribute limited capacity value for certain intermittent resources (solar, wind and run-of-river hydro). Additionally, the capacity contributions of APCo's Smith Mountain pumped storage facility were reduced to account for the Capacity Performance rule; however this reduction will continue to be assessed. It is possible that intermittent resources can be combined, or "coupled," and offered into the PJM market as Capacity Performance resources. Once the final PJM Capacity Performance tariffs are accepted, the Company will investigate methods to maximize the utilization of its intermittent resource portfolio within that construct. An example could be the additional coupling of run-of-river hydro, wind and solar resources in a manner that would mitigate potentially costly non-performance risk.

This IRP also addresses this Commission's specific 2016 IRP requirements as set forth in the 2016 Final Order. Each of the requirements has been examined and, despite the uncertainty surrounding the legal status of the CPP and various other uncertainties, the Company has made a good-faith effort to provide both appropriate responses to the Commission's inquiries and reasonable analyses under the circumstances.

The IRP process is a continuous activity; assumptions and plans are reviewed as new information becomes available and modified as appropriate. Indeed, the capacity and energy resource portfolios reported 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 is becoming increasingly complex when considering 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 planning and regulatory actions necessary to implement economic EE programs in Virginia and West Virginia.
2. Continue to monitor market prices for renewable resources, particularly wind and solar, and if economically advantageous, pursue competitive solicitations that would include self-build or acquisition options.
3. Pursue opportunities to identify a suitable host facility for a combined heat and power installation.
4. Monitor status of PJM's Capacity Performance rule; continue to evaluate the extent/level of Smith Mountain pumped storage to commit as part of future plan offerings as well as investigate opportunities to couple/hedge traditional hydro and renewable resources (wind and solar) as reasonable Capacity Performance products.
5. Monitor the status of, and participate in formulating, Virginia (as well as West Virginia, Ohio and Indiana) state plans pertaining to the CPP. Once established, perform specific assessments as to the implications of the CPP on APCo's resource profile. and
6. Be in a position to adjust this action plan and future IRPs to reflect changing circumstances.

This IRP presents various portfolios, including a Hybrid portfolio that, over the planning period would provide reliable electric utility service, at reasonable cost, through a combination of existing resources, natural gas generation, renewable energy and demand-side programs. The Five-Year Action Plan provides flexibility to allow APCo to choose appropriate actions as new information becomes available and circumstances warrant.

Appendix

Exhibit A **Load Forecast Tables**

Exhibit B **Non-Renewable New Generation Technologies**

Exhibit C **Schedules**

Exhibit D **Cross Reference Table**

Exhibit A Load Forecast Tables

Exhibit A-1
Appalachian Power Company
Annual Internal Energy Requirements and Growth Rates
2012-2030

Year	Residential Sales GWH	Residential Sales % Growth	Commercial Sales GWH	Commercial Sales % Growth	Industrial Sales GWH	Industrial Sales % Growth	Other Internal Sales GWH	Other Internal Sales % Growth	Total Internal Energy Requirements GWH	Total Internal Energy Requirements % Growth
Actual										
2012	11,395	---	6,794	---	10,778	---	6,847	---	35,813	---
2013	11,914	4.6	6,828	0.5	10,393	-3.6	6,855	0.1	35,990	0.5
2014	12,183	2.3	6,829	0.0	10,314	-0.8	6,904	0.7	36,230	0.7
2015	11,495	-5.6	6,721	-1.6	9,866	-4.3	6,890	-0.2	34,972	-3.5
Forecast										
2016	11,598	0.9	6,833	1.7	10,633	7.8	6,970	1.2	36,034	3.0
2017	11,547	-0.4	6,858	0.4	10,813	1.7	7,017	0.7	36,235	0.6
2018	11,410	-1.2	6,843	-0.2	10,856	0.4	7,179	2.3	36,287	0.1
2019	11,410	0.0	6,883	0.6	10,949	0.9	7,069	-1.5	36,312	0.1
2020	11,373	-0.3	6,894	0.1	11,023	0.7	7,083	0.2	36,372	0.2
2021	11,332	-0.4	6,908	0.2	11,086	0.6	7,133	0.7	36,459	0.2
2022	11,346	0.1	6,950	0.6	11,162	0.7	7,130	0.0	36,588	0.4
2023	11,356	0.1	6,986	0.5	11,237	0.7	7,162	0.4	36,740	0.4
2024	11,363	0.1	7,018	0.5	11,302	0.6	7,190	0.4	36,873	0.4
2025	11,385	0.2	7,054	0.5	11,354	0.5	7,205	0.2	36,997	0.3
2026	11,411	0.2	7,092	0.6	11,401	0.4	7,225	0.3	37,130	0.4
2027	11,439	0.2	7,130	0.5	11,449	0.4	7,250	0.3	37,267	0.4
2028	11,476	0.3	7,170	0.6	11,503	0.5	7,275	0.4	37,424	0.4
2029	11,515	0.3	7,208	0.5	11,558	0.5	7,305	0.4	37,585	0.4
2030	11,559	0.4	7,234	0.4	11,613	0.5	7,330	0.3	37,736	0.4
Average Annual Growth Rates										
2012-2015		0.3		-0.4		-2.9		0.2		-0.8
2016-2030		0.0		0.4		0.6		0.4		0.3

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Exhibit A-2a
Appalachian Power Company-Virginia
Annual Internal Energy Requirements and Growth Rates
2012-2030

	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										
2012	6,030	---	3,204	---	5,502	---	3,437	---	18,173	---
2013	6,297	4.4	3,208	0.1	5,474	-0.5	3,190	-7.2	18,170	0.0
2014	6,461	2.6	3,223	0.5	5,488	0.2	3,233	1.3	18,405	1.3
2015	6,138	-5.0	3,199	-0.7	5,356	-2.4	3,241	0.2	17,934	-2.6
Forecast										
2016	6,171	0.5	3,237	1.2	5,554	3.7	3,476	7.3	18,438	2.8
2017	6,152	-0.3	3,251	0.4	5,611	1.0	3,514	1.1	18,528	0.5
2018	6,093	-1.0	3,249	-0.1	5,638	0.5	3,599	2.4	18,579	0.3
2019	6,109	0.3	3,276	0.8	5,691	0.9	3,547	-1.5	18,623	0.2
2020	6,105	-0.1	3,289	0.4	5,728	0.7	3,558	0.3	18,680	0.3
2021	6,094	-0.2	3,301	0.4	5,759	0.5	3,587	0.8	18,741	0.3
2022	6,109	0.2	3,324	0.7	5,796	0.6	3,589	0.0	18,817	0.4
2023	6,124	0.2	3,344	0.6	5,832	0.6	3,606	0.5	18,905	0.5
2024	6,138	0.2	3,362	0.5	5,866	0.6	3,621	0.4	18,987	0.4
2025	6,158	0.3	3,381	0.6	5,898	0.5	3,629	0.2	19,066	0.4
2026	6,179	0.3	3,401	0.6	5,929	0.5	3,639	0.3	19,149	0.4
2027	6,202	0.4	3,421	0.6	5,961	0.5	3,652	0.4	19,236	0.5
2028	6,230	0.5	3,443	0.6	5,995	0.6	3,666	0.4	19,334	0.5
2029	6,258	0.5	3,464	0.6	6,028	0.5	3,681	0.4	19,432	0.5
2030	6,290	0.5	3,484	0.6	6,059	0.5	3,695	0.4	19,528	0.5
Average Annual Growth Rates										
2012-2015		0.6		-0.1		-0.9		-1.9		-0.4
2016-2030		0.1		0.5		0.6		0.4		0.4

Exhibit A-2b
Appalachian Power Company-West Virginia
Annual Internal Energy Requirements and Growth Rates
2012-2030

	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										
2012	5,365	---	3,590	---	5,276	---	1,303	---	15,532	---
2013	5,617	4.7	3,620	0.8	4,919	-6.8	1,556	19.5	15,712	1.2
2014	5,722	1.9	3,606	-0.4	4,826	-1.9	1,488	-4.4	15,643	-0.4
2015	5,357	-6.4	3,522	-2.3	4,510	-6.6	1,503	1.0	14,892	-4.8
Forecast										
2016	5,426	1.3	3,596	2.1	5,079	12.6	1,286	-14.4	15,388	3.3
2017	5,395	-0.6	3,607	0.3	5,202	2.4	1,292	0.4	15,496	0.7
2018	5,316	-1.5	3,594	-0.4	5,218	0.3	1,367	5.8	15,495	0.0
2019	5,302	-0.3	3,607	0.4	5,258	0.8	1,307	-4.4	15,474	-0.1
2020	5,268	-0.6	3,605	-0.1	5,295	0.7	1,308	0.1	15,475	0.0
2021	5,238	-0.6	3,607	0.1	5,327	0.6	1,324	1.3	15,496	0.1
2022	5,237	0.0	3,626	0.5	5,366	0.7	1,315	-0.7	15,543	0.3
2023	5,232	-0.1	3,642	0.4	5,405	0.7	1,321	0.5	15,601	0.4
2024	5,225	-0.1	3,656	0.4	5,436	0.6	1,327	0.5	15,644	0.3
2025	5,227	0.0	3,672	0.5	5,456	0.4	1,328	0.0	15,683	0.2
2026	5,232	0.1	3,691	0.5	5,472	0.3	1,330	0.2	15,726	0.3
2027	5,237	0.1	3,708	0.5	5,488	0.3	1,334	0.3	15,768	0.3
2028	5,246	0.2	3,727	0.5	5,508	0.4	1,338	0.2	15,819	0.3
2029	5,256	0.2	3,743	0.4	5,530	0.4	1,343	0.4	15,872	0.3
2030	5,269	0.2	3,750	0.2	5,554	0.4	1,346	0.2	15,919	0.3
Average Annual Growth Rates										
2012-2015		-0.1		-0.6		-5.1		4.9		-1.4
2016-2030		-0.2		0.3		0.6		0.3		0.2

Exhibit A-3
Appalachian Power Company
Seasonal and Annual Peak Internal Demands, Energy Requirements and Load Factor
2012-2030

	Summer Peak			Preceding Winter Peak			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
2012	06/29/12	6,391	---	01/04/12	6,881	---	6,881	---	35,813	---	59.3
2013	07/18/13	5,902	-7.6	01/23/13	6,839	-0.6	6,839	-0.6	35,990	0.5	60.1
2014	07/02/14	5,649	-4.3	01/30/14	8,460	23.7	8,460	23.7	36,230	0.7	48.9
2015	06/23/15	5,744	1.7	02/20/15	8,708	2.9	8,708	2.9	34,972	-3.5	45.8
Forecast											
2016		5,978	4.1		7,490	-14.0	7,379	-15.3	36,034	3.0	55.6
2017		6,026	0.8		7,529	0.5	7,529	2.0	36,235	0.6	54.9
2018		6,042	0.3		7,527	0.0	7,527	0.0	36,287	0.1	55.0
2019		6,053	0.2		7,515	-0.2	7,515	-0.2	36,312	0.1	55.2
2020		6,055	0.0		7,491	-0.3	7,491	-0.3	36,372	0.2	55.3
2021		6,091	0.6		7,527	0.5	7,527	0.5	36,459	0.2	55.3
2022		6,119	0.5		7,546	0.2	7,546	0.2	36,588	0.4	55.4
2023		6,152	0.5		7,566	0.3	7,566	0.3	36,740	0.4	55.4
2024		6,168	0.3		7,561	-0.1	7,561	-0.1	36,873	0.4	55.5
2025		6,212	0.7		7,606	0.6	7,606	0.6	36,997	0.3	55.5
2026		6,243	0.5		7,628	0.3	7,628	0.3	37,130	0.4	55.6
2027		6,274	0.5		7,649	0.3	7,649	0.3	37,267	0.4	55.6
2028		6,296	0.3		7,649	0.0	7,649	0.0	37,424	0.4	55.9
2029		6,345	0.8		7,699	0.7	7,699	0.7	37,585	0.4	55.7
2030		6,382	0.6		7,721	0.3	7,721	0.3	37,736	0.4	55.8

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
2016	62.6	9.2	12.1	3.5	0.5	1.3	59.2	8.7	10.8
2017	72.4	12.5	15.7	4.8	0.7	1.8	67.5	11.9	13.9
2018	90.0	15.7	19.6	5.3	0.7	2.0	84.8	14.9	17.6
2019	104.4	18.1	22.6	5.6	0.8	2.1	98.8	17.3	20.5
2020	116.8	19.8	24.8	5.8	0.8	2.1	110.9	18.9	22.7
2021	124.6	20.9	26.4	5.9	0.8	2.2	118.7	20.0	24.2
2022	130.3	21.7	27.6	6.0	0.9	2.2	124.3	20.8	25.4
2023	134.5	22.3	28.4	5.9	0.8	2.2	128.7	21.4	26.3
2024	136.6	22.5	28.6	5.5	0.8	2.0	131.1	21.7	26.5
2025	135.5	22.5	28.5	5.2	0.7	1.9	130.4	21.8	26.6
2026	135.4	22.5	28.4	5.0	0.7	1.8	130.4	21.8	26.6
2027	135.5	22.5	28.4	5.0	0.7	1.8	130.4	21.8	26.6
2028	135.5	22.5	28.3	5.0	0.7	1.8	130.5	21.7	26.5
2029	135.5	22.5	28.4	5.0	0.7	1.8	130.5	21.8	26.6
2030	135.5	22.5	28.4	5.0	0.7	1.8	130.5	21.8	26.6

*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	Blend
Other Retail	Long-Term	Long-Term

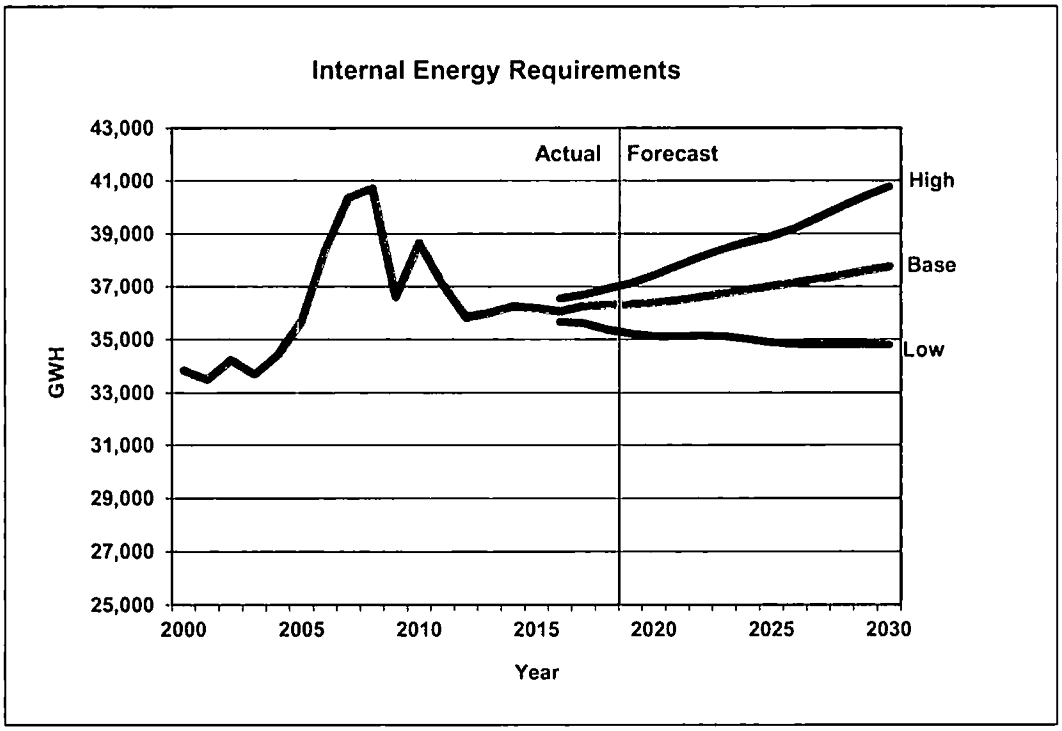
Exhibit A-6
Blending Illustration

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**
2016	7,410	7,490	7,595	5,914	5,978	6,062	35,648	36,034	36,540
2017	7,397	7,529	7,620	5,921	6,026	6,099	35,599	36,235	36,673
2018	7,337	7,527	7,655	5,889	6,042	6,144	35,369	36,287	36,901
2019	7,286	7,515	7,680	5,869	6,053	6,186	35,208	36,312	37,110
2020	7,232	7,491	7,707	5,846	6,055	6,230	35,118	36,372	37,424
2021	7,249	7,527	7,798	5,866	6,091	6,310	35,113	36,459	37,771
2022	7,248	7,546	7,860	5,878	6,119	6,374	35,144	36,588	38,111
2023	7,232	7,566	7,915	5,880	6,152	6,436	35,117	36,740	38,436
2024	7,179	7,561	7,931	5,856	6,168	6,470	35,010	36,873	38,679
2025	7,173	7,606	7,997	5,858	6,212	6,531	34,893	36,997	38,897
2026	7,152	7,628	8,053	5,854	6,243	6,591	34,813	37,130	39,201
2027	7,142	7,649	8,126	5,859	6,274	6,666	34,799	37,267	39,591
2028	7,113	7,649	8,177	5,855	6,296	6,731	34,801	37,424	40,006
2029	7,129	7,699	8,278	5,876	6,345	6,822	34,806	37,585	40,413
2030	7,119	7,721	8,342	5,884	6,382	6,894	34,791	37,736	40,768
Average Annual Growth Rate % - 2016-2025									
	-0.3	0.2	0.7	0.0	0.5	0.9	-0.2	0.3	0.8

Exhibit A-8
Appalachian Power Company
Range of Forecasts



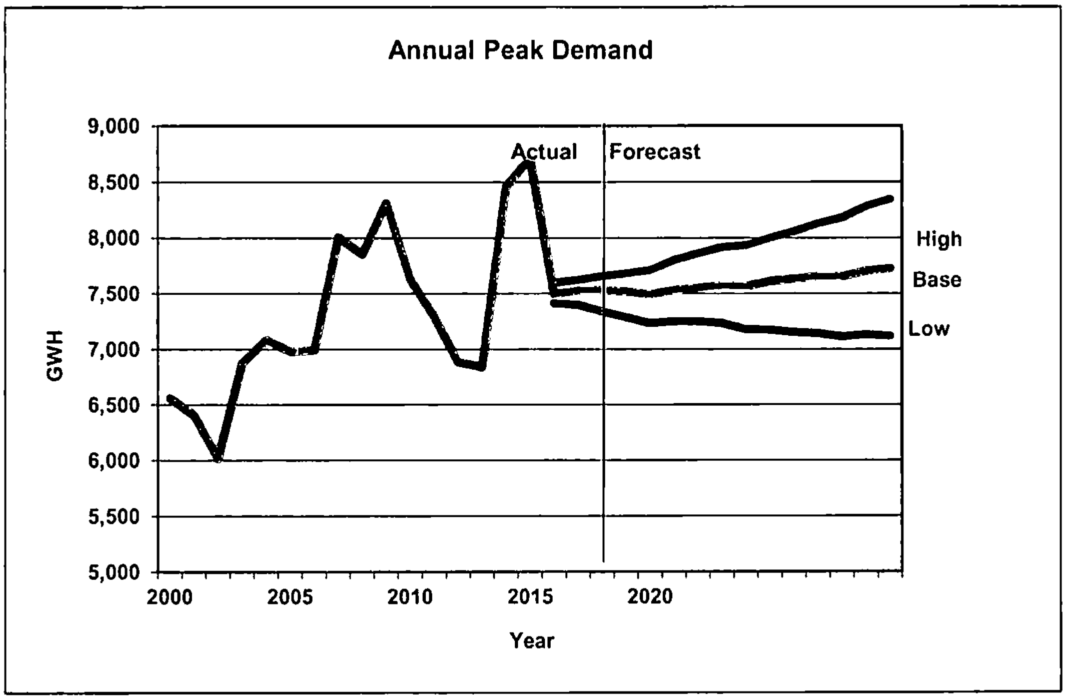


Exhibit A-9
Appalachian Power Company
Forecasted DSM, Adjusted for IRP Modeling [1]

Year	Virginia Energy (MWh)	Virginia Summer Peak (MW)	Virginia Winter Peak (MW)	West Virginia Energy (MWh)	West Virginia Summer Peak (MW)	West Virginia Winter Peak (MW)	Total APCo Energy (MWh)	Total APCo Summer Peak (MW)	Total APCo Winter Peak (MW)
2016	20,010	3.2	4.6	59,152	8.7	10.8	79,162	11.9	15.3
2017	53,305	8.7	11.5	67,548	11.9	13.9	120,853	20.5	25.4
2018	81,976	13.4	17.4	84,755	14.9	17.6	166,731	28.3	34.9
2019	89,194	14.7	18.9	75,194	13.3	16.4	164,388	28.0	35.3
2020	76,785	12.7	16.5	40,408	7.3	10.4	117,193	20.0	27.0
2021	63,999	10.7	14.2	20,872	3.8	6.1	84,871	14.5	20.3
2022	52,399	8.8	11.9	12,493	2.3	3.9	64,892	11.1	15.8
2023	42,076	7.1	9.7	6,175	1.1	2.0	48,251	8.2	11.7
2024	31,937	5.4	7.3	688	0.1	0.3	32,625	5.5	7.6
2025	21,296	3.6	4.8	-	-	-	21,296	3.6	4.8
2026	11,399	1.9	2.4	-	-	-	11,399	1.9	2.4
2027	4,387	0.7	0.9	-	-	-	4,387	0.7	0.9
2028	1,158	0.2	0.2	-	-	-	1,158	0.2	0.2
2029	367	0.1	0.1	-	-	-	367	0.1	0.1
2030	222	0.0	0.1	-	-	-	222	0.0	0.1

(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 overall APCo load forecast.

Exhibit B Non-Renewable New Generation Technologies

EXHIBIT B
AEP System-East Zone
Non-Renewable New Generation Technologies
Key Supply-Side Resource Option Assumptions (a)(b)(c)

Type	Capability (MW) (g) Std. ISO	Capability (MW) (g) Winter	Capability (MW) (g) Summer	Installed Cost (d) ($/kW)	Trans. Cost (e) ($/kW)	Full Load Heat Rate (HHV,Btu/kWh)	Fuel Cost (f) ($/MBtu)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Emission Rates SO2 (Lb/mmBtu)	Emission Rates NOx (Lb/mmBtu)	Emission Rates CO2 (Lb/mmBtu)	Capacity Factor (%)	Overall Availability (%)	LCOE (k) ($/MWh)
Base Load															
Nuclear	1,610	1,620	1,540	6,500	64	10,500	1.1	5.6	109.5	0.0000	0.000	0.0	90	94	160.5
Base Load (90% CO2 Capture New Unit)															
Pulv. Coal (Ultra-Supercritical) (PRB)	460	470	460	8,500	32	11,600	3.8	10.1	89.0	0.1185	0.070	20.5	85	90	258.5
IGCC "F" Class (PRB)	530	530	520	7,200	29	10,300	3.8	8.9	76.4	0.0128	0.057	20.5	85	88	224.9
Base / Intermediate (h)															
Combined Cycle (1X1 "F" Class)	376	400	430	1,400	60	6,600	7.6	3.1	16.1	0.0007	0.009	116.0	60	89	103.1
Combined Cycle (1X1 "J" Class)	435	450	430	1,200	60	6,500	7.6	3.0	14.8	0.0007	0.007	116.0	60	89	97.9
Combined Cycle (2X1 "J" Class)	912	940	910	900	60	6,400	7.6	2.2	8.7	0.0007	0.007	116.0	60	89	86.0
Combined Cycle (2X1 "H" Class)	990	1,020	980	900	60	6,400	7.6	2.2	8.4	0.0007	0.007	116.0	60	89	85.2
Peaking															
Combustion Turbine (2 - "E" Class) (b)	175	180	180	900	61	11,700	7.6	8.3	13.3	0.0007	0.009	116.0	25	93	179.9
Combustion Turbine (2 - "F" Class, w/evap coolers) (b)	466	480	480	600	61	10,000	7.6	1.4	7.3	0.0007	0.009	116.0	25	93	130.6
Aero-Derivative (1 - Large Machine)	100	110	100	1,500	59	9,100	7.6	4.3	20.9	0.0007	0.011	116.0	25	95	202.9
Aero-Derivative (2 - Large Machines) (b)	200	210	200	1,300	59	9,100	7.6	4.3	17.5	0.0007	0.007	116.0	25	95	183.9
Aero-Derivative (2 - Small Machines) (c)	90	100	90	1,300	60	9,700	7.6	3.3	11.6	0.0007	0.093	116.0	25	96	179.8
Recip Engine Farm (3 - Engines)	50	50	50	1,400	60	8,500	7.6	4.5	20.2	0.0007	0.018	116.0	25	96	181.9
Battery Storage (Lithium-Ion)	10	10	10	2,300	–	87% (j)	–	–	15.9	–	–	–	25	94	209.9

Notes: (a) Installed cost, capability and heat rate numbers have been rounded.
(b) All costs in 2016 dollars. Assume 2.14% escalation rate for 2016 and beyond.
(c) $/kW costs are based on nominal capability.
(d) Total Plant & Interconnection Cost w/AFUDC (AEP-East rate of 6.5%,site rating $/kW).
(e) Transmission Cost ($/kW,w/AFUDC).
(f) Levelized Fuel Cost (40-Yr. Period 2017-2056)
(g) All Capabilities are at 1,000 feet above sea level
(h) Includes Dual Fuel capability and SCR environmental installation,
(i) Includes Dual Fuel capability.
(j) Denotes efficiency, (w/ power electronics).
(k) Levelized cost of energy based on assumed capacity factors shown in table.

Exhibit C Schedules

EXHIBIT C

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

Schedule 1

PEAK LOAD AND ENERGY FORECAST

	(ACTUAL)			(PROJECTED)														
1. Peak Load (MW)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PJM Coincident Intertal Load [4,5]	n/a	n/a	n/a	5,809	5,905	5,973	6,032	5,715	5,749	5,777	5,808	5,823	5,864	5,894	5,923	5,944	5,990	6,024
A. Summer																		
1. Base Forecast [1]	-	-	-	5,987	6,039	6,058	6,071	6,075	6,112	6,141	6,174	6,191	6,234	6,265	6,296	6,318	6,368	6,405
2. Conservation, Efficiency [2,6]	-	-	-	(9)	(13)	(16)	(18)	(20)	(21)	(22)	(22)	(23)	(22)	(22)	(22)	(22)	(23)	(23)
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	5,902	5,649	5,744	5,978	6,026	6,042	6,053	6,055	6,091	6,119	6,152	6,168	6,212	6,243	6,274	6,296	6,345	6,382
5. % Increase in Adjusted Load (from previous year)	(8)	(4)	2	4	1	0	0	0	1	0	1	0	1	0	0	0	1	1
B. Winter [3]																		
1. Base Forecast [1]	-	-	-	7,391	7,545	7,547	7,538	7,515	7,553	7,573	7,594	7,589	7,634	7,656	7,677	7,677	7,727	7,750
2. Conservation, Efficiency [2,6]	-	-	-	(12)	(16)	(20)	(23)	(25)	(26)	(28)	(28)	(29)	(28)	(28)	(28)	(28)	(28)	(28)
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	6,839	8,460	8,708	7,379	7,529	7,527	7,515	7,491	7,527	7,546	7,566	7,561	7,606	7,628	7,649	7,649	7,699	7,721
5. % Increase in Adjusted Load (from previous year)	(1)	24	3	(15)	2	(0)	(0)	(0)	0	0	0	(0)	1	0	0	0	1	0
2. Energy (GWh)																		
A. Base Forecast [1]	-	-	-	36,096	36,307	36,377	36,417	36,489	36,583	36,718	36,875	37,009	37,133	37,266	37,403	37,560	37,720	37,871
B. Conservation, Efficiency [2,6]	-	-	-	(63)	(72)	(90)	(104)	(117)	(125)	(130)	(135)	(137)	(136)	(135)	(135)	(135)	(136)	(136)
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	35,990	36,230	34,972	36,034	36,235	36,287	36,312	36,372	36,459	36,588	36,740	36,873	36,997	37,130	37,267	37,424	37,585	37,736
E. % Increase in Adjusted Energy (from previous year)	0	1	(3)	3	1	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) 2013 data refer to winter of 2012/2013, 2014 data refer to winter of 2013/2014, etc.
(4) Through 2019, 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 June 2015 forecast and do not include DSM incremental to the forecast associated with Plexos portfolios.
-= not available

EXHIBIT C

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

GENERATION

	(ACTUAL)			(PROJECTED)														
I. SYSTEM OUTPUT(GWh)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
A. Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
B. Coal	17,660	24,760	23,511	29,227	26,984	26,716	28,125	28,756	28,971	26,493	27,246	26,809	26,235	25,707	25,896	24,363	23,032	22,178
C. Heavy Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Light Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E. Natural Gas	2,996	4,105	4,251	2,365	1,884	1,699	1,923	2,310	2,271	2,773	2,870	3,181	3,598	7,622	7,814	7,879	8,018	7,861
F. Hydro-Conventional[1]	934	713	811	824	824	765	824	825	824	824	824	825	824	824	732	605	605	605
G. Hydro-Pumped Storage	384	365	294	664	667	681	545	530	542	613	610	570	546	532	532	529	533	539
H. Renewable Resources[2]	887	1,004	1,024	942	939	1,973	3,026	4,124	5,292	5,971	6,649	6,664	6,649	6,649	6,721	6,822	7,399	7,988
I. Total Generation (sum of A through H)[3]	22,477	30,583	29,596	33,358	30,631	31,153	33,898	36,015	37,358	36,061	37,589	37,479	37,306	40,802	41,163	39,669	39,054	38,632
J. Purchased and Interchange Received																		
1. Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Total DSM[6]	-	-	-	78	89	108	518	546	665	753	733	778	719	745	774	745	739	737
3. Other[4]	25,362	1,710	1,303	1,673	1,685	1,656	1,689	1,697	1,727	1,681	1,691	1,687	1,698	1,699	1,697	1,693	1,693	1,699
K. Pumping Energy	(362)	(379)	(229)	801	807	827	632	611	628	729	725	667	635	615	614	608	615	624
L. Net Market Purchase/(Sale)[5]	(11,849)	3,937	4,073	988	3,902	3,461	311	(1,769)	(3,167)	(1,777)	(3,138)	(2,935)	(2,590)	(5,981)	(6,232)	(4,548)	(3,765)	(3,196)
M. Total System Firm Energy Requirements	35,990	36,230	34,972	36,096	36,307	36,377	36,417	36,489	36,583	36,718	36,875	37,009	37,133	37,266	37,403	37,560	37,720	37,871

II. ENERGY SUPPLIED BY:
COMPETITIVE SERVICE PROVIDERS

(1) Includes purchases from Summersville Hydro
(2) Includes purchases from Grand Ridge, Beech Ridge, Fowler Ridge and Camp Grove wind facilities
(3) Excludes Hydro Pumped Storage since the net of pump load energy and generation is accounted for in the load forecast
(4) Includes Pool purchases in 2013 as well as purchases from OVEC 2013-2030.
(5) Includes pool sales in 2013 as well as net sales or purchases with other electric utilities 2013-2030.
(6) Includes Embedded EE, Incremental EE, and DG

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EXHIBIT C

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

GENERATION

III. SYSTEM OUTPUT MIX (%) [1]	(ACTUAL) 2013	2014	2015	(PROJECTED) 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
A. Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
B. Coal	49	68	67	81	74	73	77	79	79	72	74	72	71	69	69	65	61	59
C. Heavy Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Light Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E. Natural Gas	8	11	12	7	5	5	5	6	6	8	8	9	10	20	21	21	21	21
F. Hydro-Conventional	3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
G. Hydro-Pumped Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
H. Renewable Resources	2	3	3	3	3	5	8	11	14	16	18	18	18	18	18	18	20	21
I. Total Generation (sum of A through H)	62	84	85	92	84	86	93	99	102	98	102	101	100	109	110	106	104	102
J. Purchased and Interchange Received																		
1. Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Total DSM [3]	-	-	-	0	0	0	1	1	2	2	2	2	2	2	2	2	2	2
3. Other	70	5	-	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4
K. Energy for Pumping	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
L. Other Sales	(33)	11	12	3	11	10	1	(5)	(9)	(5)	(9)	(8)	(7)	(16)	(17)	(12)	(10)	(8)
IV. SYSTEM LOAD FACTOR (%) [2]	62	48	47	56	55	55	55	55	55	56	56	56	56	56	56	56	56	56

(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
(4) Excludes Hydro Pumped Storage since the net of pump load energy and generation is accounted for in the load forecast

EXHIBIT C

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

POWER SUPPLY DATA[7]

I. CAPABILITY (MW)	(ACTUAL)[1] 2013	2014	2015	(PROJECTED) 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1. Summer PJM Capacity (ICAP)[5]																		
A. Installed Dependable Capability[1,2]	7,278	8,185	6,984	6,998	6,998	6,998	7,034	7,034	7,034	7,034	7,034	7,034	7,034	6,560	6,468	6,456	6,439	6,424
B. Total Positive Interchange Commitments[3]	(251)	4	25	26	26	26	26	4	4	4	4	4	4	4	4	4	4	4
C. Capability in Cold Reserve Status	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Total Installed Capacity (ICAP)	7,027	8,189	7,009	7,024	7,024	7,024	7,060	7,038	7,038	7,038	7,038	7,038	7,038	6,564	6,472	6,460	6,443	6,428
E. Total Unforced Capacity UCAP[4]	6,534	7,544	6,365	6,573	6,532	6,624	6,723	6,324	6,399	6,463	6,504	6,519	6,521	6,563	6,572	6,583	6,605	6,628
2. Winter PJM Capacity (ICAP)[5,6]																		
A. Installed Net Dependable Capability[1,2]	7,278	8,185	6,984	6,998	6,998	6,998	7,034	7,034	7,034	7,034	7,034	7,034	7,034	6,560	6,468	6,456	6,439	6,424
B. Total Positive Interchange Commitments 3	(251)	4	25	26	26	26	26	4	4	4	4	4	4	4	4	4	4	4
C. Capability in Cold Reserve Status	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Total Installed Capacity (ICAP)	7,027	8,189	7,009	7,024	7,024	7,024	7,060	7,038	7,038	7,038	7,038	7,038	7,038	6,564	6,472	6,460	6,443	6,428
E. Total Unforced Capacity UCAP[4]	6,534	7,544	6,365	6,573	6,532	6,624	6,723	6,324	6,399	6,463	6,504	6,519	6,521	6,563	6,572	6,583	6,605	6,628

(1) PJM Installed Capacity (ICAP) Rating
(2) Changes in unit capability are reflected on schedule 13
(3) Capacity sales/purchases, positive values are sales, negative values are purchases
(4) UCAP value includes the impacts of $EFOR_D$, and the impacts of DSM resources
(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

EXHIBIT C

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

POWER SUPPLY DATA (continued)[4]

II. LOAD (MW)	(ACTUAL) 2013	2014	2015	(PROJECTED) 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1. Summer																		
A. Adjusted Summer Peak[1]	6,200	6,214	6,391	5,978	6,026	6,042	6,053	6,055	6,091	6,119	6,152	6,168	6,212	6,243	6,274	6,296	6,345	6,382
B. Total Negative Power Commitments[2]	72	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C. Total Summer Peak	6,272	6,214	6,391	5,978	6,026	6,042	6,053	6,055	6,091	6,119	6,152	6,168	6,212	6,243	6,274	6,296	6,345	6,382
D. Percent Increase in Total Summer Peak	7	(1)	3	(6)	1	0	0	0	1	0	1	0	1	0	0	0	1	1
2. Winter[3]																		
A. Adjusted Winter Peak[1]	6,839	8,460	8,708	7,379	7,529	7,527	7,515	7,491	7,527	7,546	7,566	7,561	7,606	7,628	7,649	7,649	7,699	7,721
B. Total Negative Power Commitments[2]	79	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C. Total Winter Peak	6,918	8,460	8,708	7,379	7,529	7,527	7,515	7,491	7,527	7,546	7,566	7,561	7,606	7,628	7,649	7,649	7,699	7,721
D. Percent Increase in Total Winter Peak	(14)	22	3	(15)	2	(0)	(0)	(0)	0	0	0	(0)	1	0	0	0	1	0

(1) Peak after energy efficiency and demand-side programs, see Schedule 1.
(2) Includes firm commitments for the delivery of specified blocks of power (i.e., unit power, diversity exchange).
(3) 2013 data refers to winter of 2012/2013, 2014 data refers to winter of 2013/2014, etc.
(4) Values shown are exclusive of resource additions

EXHIBIT C

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

POWER SUPPLY DATA (continued)[5]

	(ACTUAL)			(PROJECTED)														
I. Reserve Margin	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
(Including Cold Reserve Capability) [1]																		
1. Summer Reserve Margin																		
A. MW	755	1,975	618	1,046	998	982	1,007	983	947	919	886	870	826	321	198	164	98	46
B. Percent of Load	12	32	10	17	17	16	17	16	16	15	14	14	13	5	3	3	2	1
2. Winter Reserve Margin [2]																		
A. MW	109	(271)	(1,699)	(355)	(505)	(503)	(455)	(453)	(489)	(508)	(528)	(523)	(568)	(1,064)	(1,177)	(1,189)	(1,256)	(1,293)
B. Percent of Load	2	(3)	(20)	(5)	(7)	(7)	(6)	(6)	(6)	(7)	(7)	(7)	(7)	(14)	(15)	(16)	(16)	(17)
II. Reserve Margin																		
(Excluding Cold Reserve Capability) [3]																		
1. Summer Reserve Margin																		
A. MW	755	1,975	618	1,046	998	982	1,007	983	947	919	886	870	826	321	198	164	98	46
B. Percent of Load	12	32	10	17	17	16	17	16	16	15	14	14	13	5	3	3	2	1
2. Winter Reserve Margin [2]																		
A. MW	109	(271)	(1,699)	(355)	(505)	(503)	(455)	(453)	(489)	(508)	(528)	(523)	(568)	(1,064)	(1,177)	(1,189)	(1,256)	(1,293)
B. Percent of Load	2	(3)	(20)	(5)	(7)	(7)	(6)	(6)	(6)	(7)	(7)	(7)	(7)	(14)	(15)	(16)	(16)	(17)
III. Annual Loss-of-Load Hours [4]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

(1) Calculated based on Total Net Capability for summer and winter.
(2) 2013 data refers to winter of 2012/2013, 2014 data refers to winter of 2013/2014, 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

EXHIBIT C

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

CAPACITY DATA

	(ACTUAL)			(PROJECTED)														
I. Nameplate Capacity (MW) [1]	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
A. Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
B. Coal	5,437	6,264	5,027	4,573	4,573	4,573	4,609	4,609	4,609	4,609	4,609	4,609	4,609	4,609	4,609	4,609	4,609	4,609
C. Heavy Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Light Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E. Natural Gas	1,124	1,005	1,005	1,479	1,479	1,479	1,479	1,493	1,493	1,493	1,493	1,493	1,493	1,511	1,511	1,511	1,511	1,511
F. Hydro-Conventional	117	277	281	281	281	281	281	281	281	281	281	281	281	281	201	201	201	201
G. Pumped Storage	586	586	615	615	615	615	615	615	615	615	615	615	615	615	615	615	615	615
H. Wind	376	376	376	376	376	676	976	1,276	1,576	1,726	1,876	1,876	1,876	1,876	1,801	1,701	1,751	1,800
I. Solar	-	-	-	-	-	20	50	100	200	300	400	400	400	400	440	490	540	590
J. Total (sum of A through H)	7,337	8,186	6,984	7,324	7,324	7,644	8,010	8,374	8,774	9,024	9,274	9,274	9,274	9,292	9,177	9,127	9,227	9,326
II. Installed Capacity Mix (%) [2]																		
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	74.10	76.52	71.98	62.44	62.44	59.82	57.54	55.04	52.53	51.07	49.70	49.70	49.70	49.60	50.22	50.50	49.95	49.42
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	15.32	12.28	14.39	20.19	20.19	19.35	18.46	17.83	17.02	16.54	16.10	16.10	16.10	16.26	16.47	16.56	16.38	16.20
F. Hydro-Conventional	1.59	3.38	4.02	3.84	3.84	3.68	3.51	3.36	3.20	3.11	3.03	3.03	3.03	3.02	2.19	2.20	2.18	2.16
G. Pumped Storage	7.99	7.16	8.81	8.40	8.40	8.05	7.68	7.34	7.01	6.82	6.63	6.63	6.63	6.62	6.70	6.74	6.67	6.59
H. Wind	5.12	4.59	5.38	5.13	5.13	8.84	12.18	15.24	17.96	19.13	20.23	20.23	20.23	20.19	19.63	18.64	18.98	19.30
I. Solar	0.00	0.00	0.00	0.00	0.00	0.26	0.62	1.19	2.28	3.32	4.31	4.31	4.31	4.30	4.79	5.37	5.85	6.33

(1) Installed capacities by fuel types for supply-side resources

(2) Each item in A-I of Section II. as a percent of line J above in Section I.

EXHIBIT C

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

Schedule 8
CONFIDENTIAL

	(ACTUAL)			(PROJECTED)														
Unit Name	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Amos 1																		
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																		
Clinch River 1 Gas Conversion																		
Clinch River 2 Gas Conversion																		
15 MW CHP																		
445 MW CC																		

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

-- = not available

EXHIBIT C

COMPANY NAME: AEP SYSTEM - EAST ZONE Schedule 9
UNIT PERFORMANCE DATA CONFIDENTIAL
Net Capacity Factor (%) [1]

	(ACTUAL)			(PROJECTED)														
Unit Name	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Amos 1																		
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																		
Clinch River 1 Gas Conversion																		
Clinch River 2 Gas Conversion																		
445 MW CC																		

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

EXHIBIT C

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

Schedule 10
~~CONFIDENTIAL~~

	(ACTUAL)			(PROJECTED)														
Unit Name	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Amos 1																		
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																		
Clinch River 1 Gas Conversion																		
Clinch River 2 Gas Conversion																		
445 MW CC																		

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

EXHIBIT C

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View) Schedule 11

RENEWABLE RESOURCES (MWh)

Resource Type [1]	Unit Name	C.O.D [2]	Build/ Purchase [3]	Life/ Duration [4]	Size (MW) Nameplate	NDC [5]	(ACTUAL) 2013	2014	2015	(PROJECTED) 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Wind	Camp Grove	Jan/2008	Purchase	20 years	75	13	178,254	209,727	222,278	210,667	209,956	209,956	209,956	210,667	209,956	209,956	209,956	210,667	209,956	209,956	209,956	17,556	-	-
	Fowler Ridge 3	Feb/2009	Purchase	20 years	100	22	243,185	243,629	262,350	246,204	245,566	245,566	245,566	246,204	245,566	245,566	245,566	246,204	245,566	245,566	245,566	246,204	40,928	-
	Grand Ridge 2	Dec/2009	Purchase	20 years	51	9	121,745	135,149	135,629	131,157	130,739	130,739	130,739	131,157	130,739	130,739	130,739	131,157	130,739	130,739	130,739	131,157	98,054	-
	Grand Ridge 3	Dec/2009	Purchase	20 years	50	8	117,093	130,303	127,697	127,299	126,893	126,893	126,893	127,299	126,893	126,893	126,893	127,299	126,893	126,893	126,893	127,299	105,744	-
	Beech Ridge	Jun/2010	Purchase	20 years	101	15	226,034	283,747	276,044	226,848	225,803	225,803	225,803	226,848	225,803	225,803	225,803	226,848	225,803	225,803	225,803	226,848	225,803	150,535
	New	Varies	-	20 years	Varies	Varies	-	-		-	-	998,640	1,997,280	3,001,755	3,994,560	4,493,880	4,993,200	5,002,925	4,993,200	4,993,200	4,993,200	5,002,925	5,492,520	5,991,840
Wind Subtotal					376	66	886,311	1,002,555	1,023,998	942,175	938,957	1,937,597	2,936,237	3,943,930	4,933,517	5,432,837	5,932,157	5,945,100	5,932,157	5,932,157	5,932,157	5,751,988	5,963,049	6,142,376
Solar	Distributed	-	-	-	-	-	-	-	-	12,576	14,341	16,133	19,719	25,152	28,682	34,059	41,230	50,305	59,156	71,704	80,667	84,440	91,422	100,385
	New Large-Scale	Varies	-	25 years	Varies	Varies	-	-	-	0	0	35,852	89,630	179,659	358,519	537,778	717,038	718,637	717,038	717,038	788,742	880,330	968,001	1,057,631
Solar Subtotal					-	-	-	-	-	12,576	14,341	51,985	109,348	204,811	387,200	571,838	758,267	768,941	776,193	788,742	869,408	964,770	1,059,423	1,158,016
Total Renewables					376	66	886,311	1,002,555	1,023,998	954,751	953,297	1,989,582	3,045,585	4,148,741	5,320,717	6,004,674	6,690,424	6,714,041	6,708,350	6,720,898	6,801,565	6,716,758	7,022,473	7,300,392

(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)(as of 6-1-2015).

- = not available

160440090

EXHIBIT C

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

Schedule 12

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

Program Type	Program Name	Date (3)	Life/ Duration (4)	Size (MW) (5)	(ACTUAL) (6) 2013	2014	2015	(PROJECTED) (6) 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
EE (1)	Current Programs	06/12/2015	10	71	55,254	49,227	39,196	79,162	120,853	166,731	164,388	117,193	84,871	64,892	48,251	32,625	21,296	11,399	4,387	1,158	367	222
EE (2)	Residential Lighting	01/01/2019	30	22				-	-	-	299,493	303,307	305,316	305,520	277,543	247,156	179,448	127,374	86,396	59,608	43,132	29,488
EE (2)	Residential Water Heating	01/01/2019	10	52				-	-	-	71,100	71,939	68,594	67,110	63,205	60,564	57,424	56,876	56,898	49,791	49,540	35,519
EE (2)	Residential Thermal Shell	01/01/2020	10	15				-	-	-	-	4,000	7,200	5,867	8,069	9,865	12,235	15,205	17,094	17,916	18,666	30,155
EE (2)	Residential Applicances	01/01/2020	16	8				-	-	-	-	3,000	5,598	8,670	8,000	7,330	8,830	9,918	10,643	11,460	12,848	18,128
EE (2)	Residential Enhanced Cust. Bill	01/01/2030	30	0				-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,000
EE (2)	Commercial Lighting	01/01/2019	6-10	7				-	-	-	21,600	19,602	16,510	13,871	12,325	11,012	9,078	7,724	7,278	5,478	5,596	3,183
EE (2)	Commercial Cooling	01/01/2025	16	2				-	-	-	-	-	-	-	-	-	1,000	1,866	2,601	2,400	2,199	1,749
EE (2)	VVO	01/01/2016	15	97				2,180	2,171	2,161	2,149	2,143	107,636	187,599	187,817	254,964	255,412	318,893	377,432	378,611	379,981	381,454
Subtotal				274	55,254	49,227	39,196	81,342	123,025	168,892	558,730	521,183	595,724	653,529	605,209	623,516	544,722	549,254	562,729	526,423	512,429	500,897
DR	PSEDR	06/12/2015	15	23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	Interruptible	06/12/2015	15	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	ATOD	06/12/2015	15	88	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal				123	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Demand Side Management				397	55,254	49,227	39,196	81,342	123,025	168,892	558,730	521,183	595,724	653,529	605,209	623,516	544,722	549,254	562,729	526,423	512,429	500,897

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 2030 undegraded value. Values are coincendent peak impacts. Demand impacts for DR programs are for PJM (summer) peak.

6) Energy values shown are degraded.

EXHIBIT C

COMPANY NAME: AEP SYSTEM - APCo

UNIT PERFORMANCE DATA[1]

Unit Size (MW) Uprate and Derate[2]

Schedule 13

CONFIDENTIAL

	(ACTUAL)			(PROJECTED)														
Unit Name	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Amos 1																		
Amos 2																		
Amos 3																		
Ceredo 1-6																		
Clinch River 1[3]																		
Clinch River 2[3]																		
Clinch River 3[4]																		
Glen Lyn 5[4]																		
Glen Lyn 6[4]																		
Kanawha River 1[4]																		
Kanawha River 2[4]																		
Mountaineer 1																		
Sporn 1[4]																		
Sporn 3[4]																		
Buck 1 - 3																		
Byllesby 1 - 4																		
Claytor 1 - 4																		
Leesville 1 - 2																		
London 1 - 3																		
Marmet 1 - 3																		
Niagara 1 - 2																		
Reusens 1 - 5																		
Winfield 1 - 3																		
Smith Mountain 1																		
Smith Mountain 2																		
Smith Mountain 3																		
Smith Mountain 4																		
Smith Mountain 5																		
Dresden																		

(1) Combustion turbines, combined cycles and hydro plants reported as composite facilities.
(2) Peak summer net dependable capability as of filing. Incremental Uprates shown as positive (+) and decremental Derates shown as negative (-).
(3) Inlcudes conversion from coal to natural gas fuel in 2016, unit retirement in 2026
(4) Reflects unit retirement

EXHIBIT C

COMPANY NAME: AEP SYSTEM - APCo Schedule 14

UNIT PERFORMANCE DATA [1]

Existing Supply Side Resources (MW) as of April 1, 2016

						Net Capability - MW [3]			
Unit Name	**Company**	**Location**	**Unit Type**	**Primary Fuel Type**	**C.O.D. [2]**	**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	237		237	
Clinch River 2	APCo	Carbo, VA	Steam	Gas	1958	237		237	
Dresden	APCo	Dresden, OH	Combined Cycle	Gas	2012	613		555	
Mountaineer 1	APCo	New Haven, WV	Steam	Coal - Bit.	1980	1,320		1,305	
Buck 1 - 3	APCo	Ivanhoe, VA	Hydro	--	1912	5		3	(A)
Byllesby 1 - 4	APCo	Byllesby, VA	Hydro	--	1912	8		4	(A)
Claytor 1 - 4	APCo	Radford, VA	Hydro	--	1939	28		15	(A)
Leesville 1 - 2	APCo	Leesville, VA	Hydro	--	1964	9		5	(A)
London 1 - 3	APCo	Montgomery, WV	Hydro	--	1935	12		7	(A)
Marmet 1 - 3	APCo	Marmet, WV	Hydro	--	1935	11		6	(A)
Niagara 1 - 2	APCO	Roanoke, VA	Hydro	--	1924	1		1	(A)
Reusens 1 - 5	APCo	Lynchburg, VA	Hydro	--	1903	0		0	(A)
Winfield 1 - 3	APCo	Winfield, WV	Hydro	--	1938	15		9	(A)
Smith Mountain 1	APCo	Penhook, VA	Pump. Stor.	--	1965	70	(B)	70	(B)
Smith Mountain 2	APCo	Penhook, VA	Pump. Stor.	--	1965	185	(B)	185	(B)
Smith Mountain 3	APCo	Penhook, VA	Pump. Stor.	--	1980	105	(B)	105	(B)
Smith Mountain 4	APCo	Penhook, VA	Pump. Stor.	--	1966	185	(B)	185	(B)
Smith Mountain 5	APCo	Penhook, VA	Pump. Stor.	--	1966	70	(B)	70	(B)
						6,558		6,379	

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.

EXHIBIT C

COMPANY NAME: AEP SYSTEM - APCo **Schedule 15**

UNIT PERFORMANCE DATA

Planned Supply Side Resources (MW) [1]

Unit Name	Company	Location	Unit Type	Primary Fuel Type	C.O.D. [2]	Nameplate Capacity [3]	Installed Capacity [4]
Clinch River 1 Gas Conversion	APCo	Carbo, VA	Gas Steam	Gas	Dec/2015	242	242
Clinch River 2 Gas Conversion	APCo	Carbo, VA	Gas Steam	Gas	May/2016	242	242
2026 APCo Gas	APCo	TBD	Combined Cycle	Gas	Jun/2026	494	492
2020 APCO CHP	APCO	TBD	Combined Heat and Power	Gas	Jun/2020	15	14
2018 APCo Solar	APCo	TBD	Solar	Solar	Jun/2018	20	8
2019 APCo Solar	APCo	TBD	Solar	Solar	Jun/2019	30	11
2020 APCo Solar	APCo	TBD	Solar	Solar	Jun/2020	50	19
2021 APCo Solar	APCo	TBD	Solar	Solar	Jun/2021	100	38
2022 APCo Solar	APCo	TBD	Solar	Solar	Jun/2022	100	38
2023 APCo Solar	APCo	TBD	Solar	Solar	Jun/2023	100	38
2027 APCo Solar	APCo	TBD	Solar	Solar	Jun/2027	40	15
2028 APCo Solar	APCo	TBD	Solar	Solar	Jun/2028	50	19
2029 APCo Solar	APCo	TBD	Solar	Solar	Jun/2029	50	19
2030 APCo Solar	APCo	TBD	Solar	Solar	Jun/2030	50	19
2018 APCo Wind	APCo	TBD	Wind	Wind	Jun/2018	300	15
2019 APCo Wind	APCo	TBD	Wind	Wind	Jun/2019	300	15
2020 APCo Wind	APCo	TBD	Wind	Wind	Jun/2020	300	15
2021 APCo Wind	APCo	TBD	Wind	Wind	Jun/2021	300	15
2022 APCo Wind	APCo	TBD	Wind	Wind	Jun/2022	150	8
2023 APCo Wind	APCo	TBD	Wind	Wind	Jun/2023	150	8
2029 APCo Wind	APCo	TBD	Wind	Wind	Jun/2029	150	8
2030 APCo Wind	APCo	TBD	Wind	Wind	Jun/2030	150	8

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 reating of 5% of nameplate and solar is assumed to have 38%.

EXHIBIT C

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

UTILITY CAPACITY POSITION (MW)[1]

	(ACTUAL)[2]			(PROJECTED)														
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Existing Capacity (ICAP)																		
Conventional	-	-	-	6,046	6,046	6,046	6,082	6,082	6,082	6,082	6,082	6,082	6,082	5,608	5,608	5,608	5,608	5,608
Renewable[7]	-	-	-	952	952	952	952	952	952	952	952	952	952	952	860	848	831	816
Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	26	26	26	26	4	4	4	4	4	4	4	4	4	4	4
Total Existing Capacity	-	-	-	7,024	7,024	7,024	7,060	7,038	7,038	7,038	7,038	7,038	7,038	6,564	6,472	6,460	6,443	6,428
Planned Capacity Changes (ICAP)																		
Conventional	-	-	-	0	0	0	36	36	36	36	36	36	36	(438)	(438)	(438)	(438)	(438)
Renewable	-	-	-	0	0	0	0	0	0	0	0	0	0	0	(92)	(104)	(121)	(136)
Total Planned Capacity Changes	-	-	-	0	0	0	36	36	36	36	36	36	36	(438)	(530)	(542)	(559)	(574)
Capacity Performance Changes (UCAP)	-	-	-	0	0	0	0	(557)	(557)	(557)	(557)	(557)	(557)	(557)	(495)	(487)	(475)	(465)
Expected New Capacity (UCAP)																		
Conventional	-	-	-	0	0	0	0	0	0	0	0	0	0	472	472	472	472	472
Renewable	-	-	-	0	0	23	49	83	136	182	227	227	227	227	242	261	288	314
Battery Storage	-	-	-	0	0	0	0	0	0	0	0	0	5	5	5	5	5	5
Total Expected New Capacity	-	-	-	0	0	23	49	83	136	182	227	227	232	704	719	738	765	791
Unforced Availability (Factor)	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Generation Capacity (UCAP)	-	-	-	6,427	6,386	6,478	6,539	5,996	6,049	6,095	6,140	6,140	6,145	6,172	6,163	6,179	6,200	6,221
Existing DSM Reductions (ICAP)[3,6]																		
Demand response	-	-	-	137	137	137	137	237	237	237	237	237	237	237	237	237	237	237
Conservation/Efficiency	-	-	-	12	21	28	28	20	15	11	8	6	4	2	1	0	0	0
Total Existing DSM Reductions	-	-	-	149	158	165	165	257	252	248	245	243	241	239	238	237	237	237
Expected New DSM Reductions (ICAP)[3,6]																		
Demand Response	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Conservation/Efficiency/VVO				1	1	1	38	45	78	84	110	134	140	162	183	189	195	203
Distributed Generation	-	-	-	3	3	4	5	6	7	8	10	12	14	17	19	19	21	23
Combined Heat and Power	-	-	-	0	0	0	0	14	14	14	14	14	14	14	14	14	14	14
Total Expected New DSM Reductions	-	-	-	4	4	5	42	59	87	109	108	125	125	142	158	155	156	158
Total Demand-side Reductions (ICAP)	-	-	-	153	162	170	207	316	339	357	353	368	366	381	396	392	393	395
Net Generation & Demand-side (UCAP)	-	-	-	6,574	6,532	6,625	6,723	6,322	6,398	6,462	6,502	6,517	6,520	6,562	6,568	6,580	6,602	6,625
PJM Capacity Obligation (UCAP)[4]	-	-	-	6,361	6,425	6,499	6,563	6,218	6,255	6,285	6,319	6,335	6,380	6,413	6,444	6,467	6,517	6,554
Additional Obligation	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Obligation	-	-	-	6,361	6,425	6,499	6,563	6,218	6,255	6,285	6,319	6,335	6,380	6,413	6,444	6,467	6,517	6,554
Net Utility Capacity Position[5]				212	107	125	160	103	141	175	182	180	137	147	123	112	84	69

(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 is delayed three years to represent its impact on actual load feeding through the PJM load forecast process.
(4) Through 2017, 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) Through 2017, reflects APCo's contribution as part of a 4-Company (through 2015) or 3-Company (through 2017) FRR entity.
(6) Tables reflect DSM levels consistent with July 2015 forecast and DSM incremental to the forecast associated with Plexos portfolios.
(7) Renewable represents conventional hydro, pumped storage, solar and wind

EXHIBIT C

Schedule 17
CONFIDENTIAL

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)

CONSTRUCTION FORECAST (Million Dollars)

	ACTUAL EXPENDITURES			PROJECTED EXPENDITURES		
	2013	2014	2015	2016	2017	2018
I. New Traditional Generating Facilities						
a. Capital Investment (Exclusive of AFUDC)						
b. AFUDC						
c. Annual Total						
d. Cumulative Total						
II. New Renewable Generating Facilities						
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						

050044091

EXHIBIT C

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

Schedule 18
CONFIDENTIAL

	(ACTUAL)			(PROJECTED)[1]														
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
I. Delivered Fuel Price (cents/MBtu)																		
a. Nuclear																		
b. Coal[2]																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas																		
f. Renewable *																		
II. Primary Fuel Expenses (cents/kWh)																		
a. Nuclear																		
b. Coal[2]																		
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.
(2) Includes APCo & OPCo deliveries to Sporn plant.
- =not available

Exhibit D Cross Reference Table

Exhibit D

Appalachian Power Company
For the 15 Year Forecast Period Beginning 2016

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. Integated 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
C.2. Option Analyses A comprehensive analysis of all existing and new resource options (supply- and demand-side), including costs, benefits, risks, uncertainties, reliabiltiy, 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.	See item C.2.a below
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.	Referenced throughout report

Exhibit D

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
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 5; 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; Schedule 1
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.	Sections 5; Schedule 15
F.2. Supply-side Resources The forecast shall provide data for its existing and planned electric generating facilities (including planned additions and retirements and rating changes, as well as firm purchase contracts, including cogeneration and small power production) and a narrative description of the driver(s) underlying such anticipated changes such as expected environmental compliance, carbon restrictions, technology enhancements, etc:	Sections 3; Schedules 13, 14

Exhibit D

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 6; 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.	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.	Secion 6; Schedule 16
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

Exhibit D

Virginia - Integrated Resource Planning Guidelines Cross Reference Table	Section/Page Reference
Required Schedules not Specifcally 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 govermental, 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, 5.2.3.3.1, and 5.3.3
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	Sections 3.3, 5 and 6
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	Sections 5 and 6
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	Sections 3.3.8, 3.3.8.8, 5.2.3
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;	Section 5.2.3.4
Provide a detailed description of leakage and treatment of new units under differing compliance regimes;	Section 3.3.8.3
Examine the differing impacts of the Virginia-specific targets verses source subcategory-specific rates under an intensity-based approach;	Section 3.3.8.2
Examine the potential for early action emission rate credits/allowances that may be available for qualified renewable energy or demand-side energy efficiency measures;	Section 3.3.8.4
Examine the cost benefits trading emissions allowances or emissions reductions credits, or acquiring renewable resources from inside and outside of Virginia;	Section 3.3.8.5
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	Section 3.3.8.6
Identify a long-term recommendation that reflects EPA's final version of the CPP	Section 3.3.8.7
Rate Design	
Analyze whether maintaining the existing rate structure is in the best interest of residential customers	Section 4.4.3.8
Evaluate options for variable pricing models that would incent customers to shift consumption away from peak times to reduce costs and emissions	Section 4.4.3.8
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