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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

160440087

APPALACHIAN POWER®

A unit of American Electric Power

INTEGRATED RESOURCE PLANNING REPORT

TO THE

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

April 29, 2016

Table of Contents

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List of Figures

List of Tables

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.

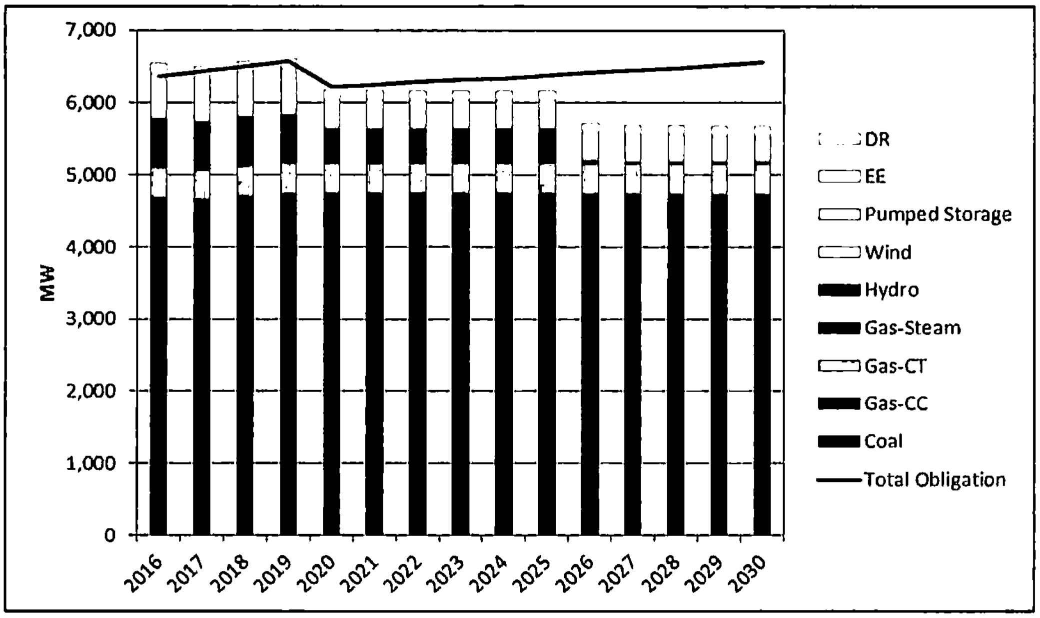

Figure ES-1. APCo "Going-In" PJM Capacity Position (MW)

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.

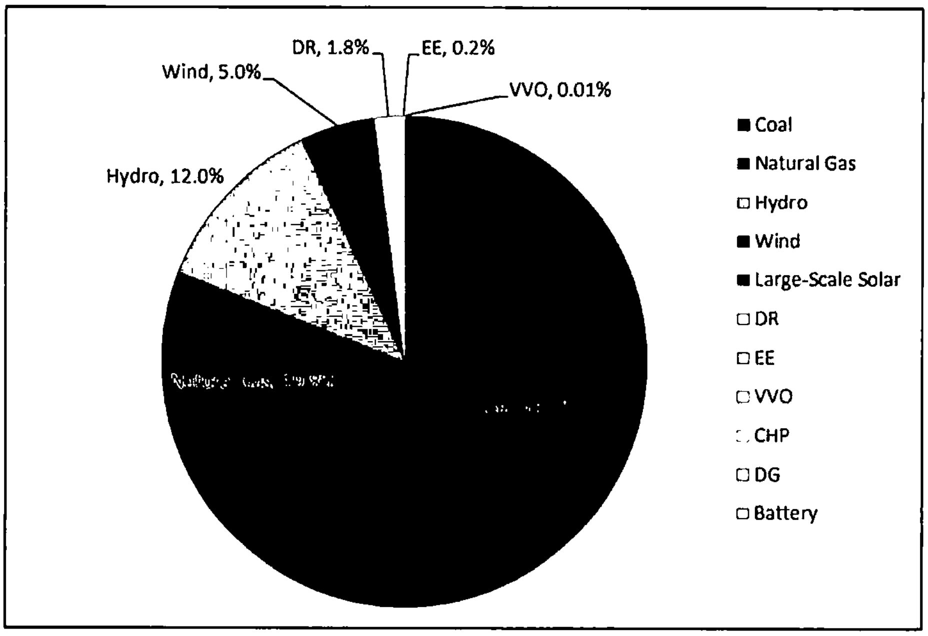

Figure ES-2. 2016 APCo Nameplate Capacity Mix

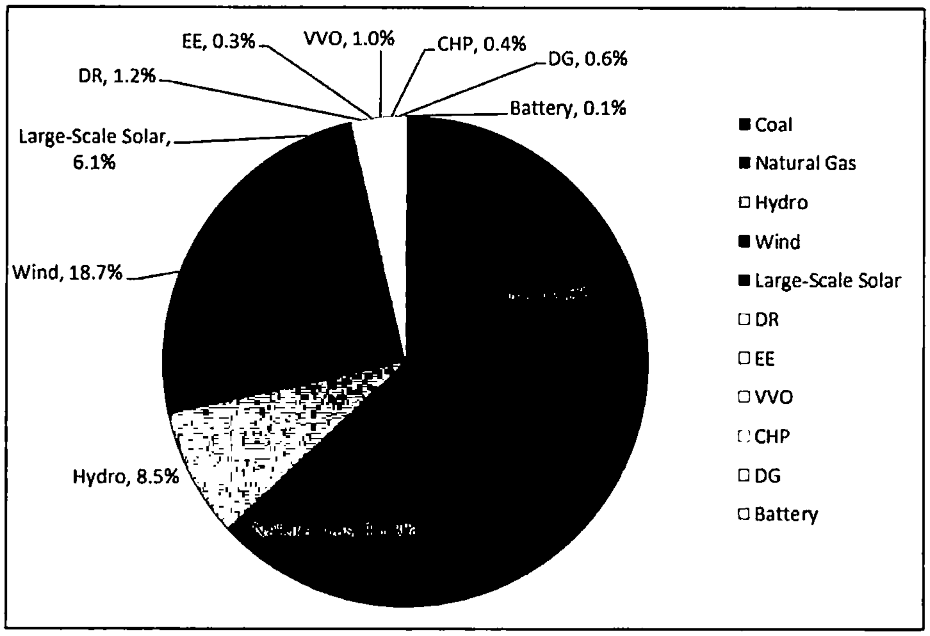

Figure ES-3. 2030 APCo Nameplate Capacity Mix

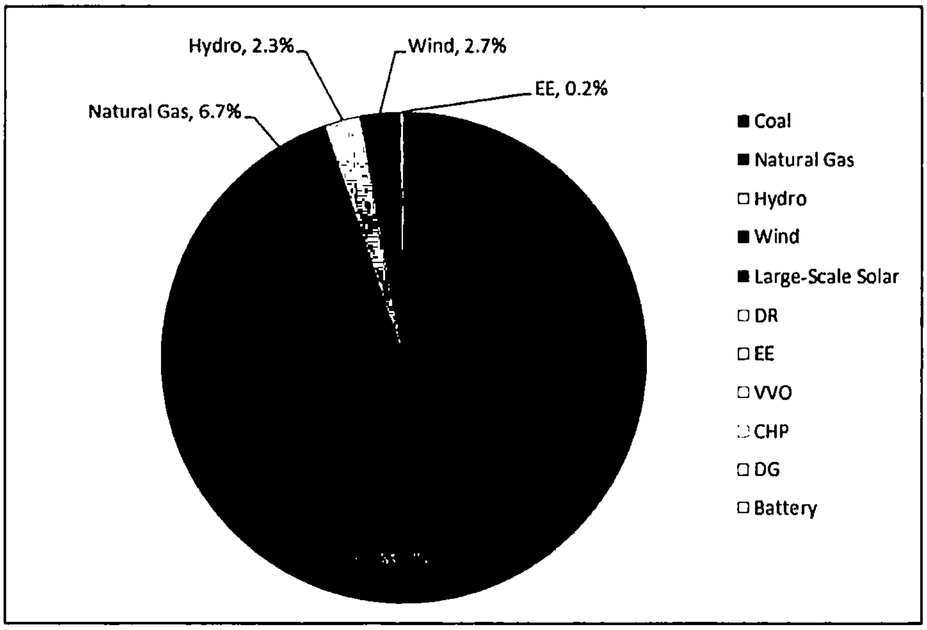

Figure ES-4. 2016 APCo Energy Mix

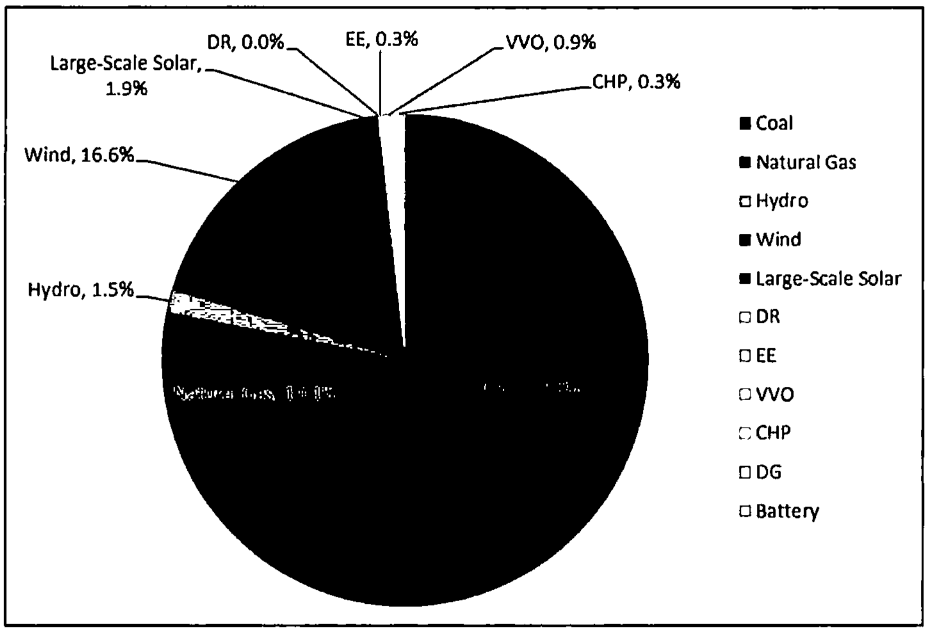

Figure ES-5. 2030 APCo Energy Mix

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.

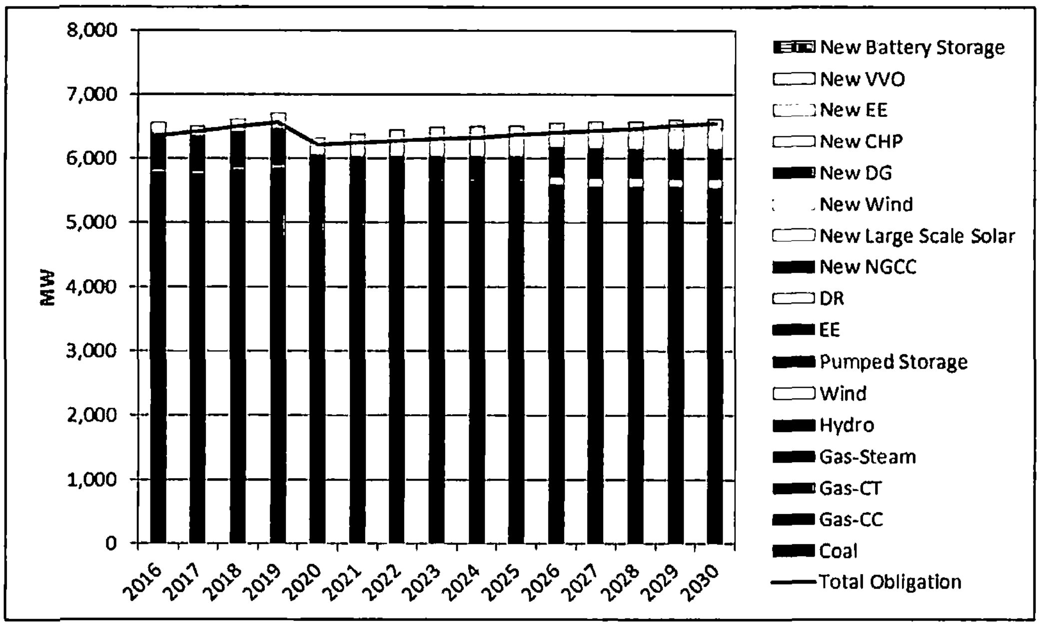

Figure ES-6. APCo Annual PJM Capacity Position (MW) According to Hybrid Plan

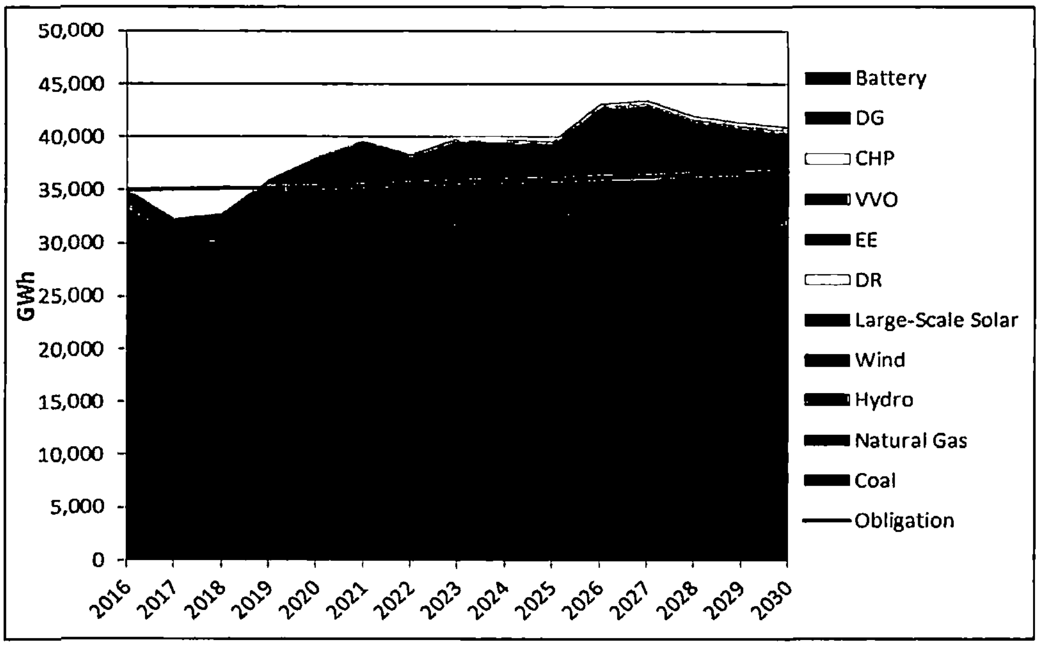

Figure ES-7. APCo Annual Energy Position (GWh) According to Hybrid Plan

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)

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

Hybrid Plan

IRP Period	PJM Planning Year[(a)]	(1) (Cumulative) Existing Fleet: Unit Uprates & Derates	(2) (Cumulative) Existing Fleet: PJM Capacity Performance Impact (UCAP Reduction)	(3) (Cumulative) Firm Capacity Resource ADDITIONS: New-Build: NG CHP	(4) New-Build: NG CC	(5) Energy Efficiency (EE): "Embedded" Federal EE Regulations (Non-DSM EE)[(b)]	(6) Energy Efficiency (EE): Current DSM Programs[(c)]	(7) Energy Efficiency (EE): New	(8) VVO: New	(9) DR: Pre-Existing DR Programs[(c)]	(10) Wind[(d)]	(11) Solar[(e)]: Large Scale	(12) Solar[(e)]: Dis-tributed	(13) Battery[(f)]	(14) (Cumul.) NET "RESOURCE CHANGE"[(g)]	(15) Resulting APCo Reserves Above PJM Minimum Reqmt[(h)]	(16) PJM Reserve Margin %	(17) (Cumulative) 'NAMEPLATE' ADDITIONS: Wind[(d)]	(18) Solar[(e)]: Large Scale	(19) Solar[(e)]: Dis-tributed	(20) Battery[(f)]
Yr.		MW		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW		MW	MW	MW	
1	2016	14 [(i)]	-	-	-	397	20	-	1	142	-	-	5	-	179	212	4.4%	-	-	8	-
2	2017	14	-	-	-	424	47	-	1	142	-	-	3	-	207	157	1.6%	-	-	9	-
3	2018	14	-	-	-	448	63	-	1	142	15	8	4	-	245	125	2.1%	300	20	10	-
4	2019	50 [(ii)]	-	-	-	470	71	37	1	142	30	19	5	-	354	190	2.7%	600	50	12	-
5	2020	50	(433) [(iii)]	14	-	491	71	44	1	123	45	38	5	-	(43)	123	1.9%	900	110	15	-
6	2021	50	(433)	14	-	516	71	50	23	123	60	76	7	-	43	141	2.5%	1,200	220	17	-
7	2022	50	(433)	14	-	537	71	56	43	123	58	114	6	-	115	175	3.1%	1,350	300	21	-
8	2023	50	(433)	14	-	557	71	62	43	123	73	152	10	-	170	182	3.3%	1,500	400	25	-
9	2024	50	(433)	14	-	574	71	56	56	123	75	152	12	-	195	180	3.2%	1,500	400	30	-
10	2025	50	(433)	14	-	595	71	74	68	123	75	152	14	5	203	137	2.4%	1,500	400	35	10
11	2026	(421) [(iv)]	(433)	14	472	612	71	80	82	123	75	152	17	5	227	147	2.5%	1,500	400	44	10
12	2027	(421)	(433)	14	472	628	71	86	97	123	75	167	19	5	255	123	2.1%	1,500	410	49	10
13	2028	(421)	(433)	14	472	640	71	92	97	123	75	185	19	5	290	112	2.0%	1,500	430	51	10
14	2029	(421)	(433)	14	472	655	71	98	97	123	83	205	21	5	324	61	1.5%	1,650	540	55	10
15	2030	(322)	(433)	14	472	669	71	106	97	123	90	224	23	5	351	69	1.2%	1,650	530	61	10

177 — 'TOTAL Increm' Energy Efficiency

651 — 'TOTAL' Solar

[(a)] PJM Planning Year is effective 6/1/XXXX.

[(b)] Represents estimated (post-2015) energy efficiency levels already 'embedded' into APCo's long-term load & peak demand forecast based on emergence of PROSPECTIVE Federal efficiency standards (EPAct 2005; 2007 EISA, 2009 ARRA).

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

[(d)] Due to the intermittency of wind resources, APCo assumes 5% of nameplate MW ratings 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 from June 1, 2015:
[(i)] Clinch River 1&2 Gas Conversion uprate
[(ii)] [illegible] turbine upgrade.
[(iii)] 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
[(iv)] Clinch River 1&2 Gas Conversion unit retirement

[(g)] Includes changes in existing resources plus plan additions, excluding "embedded" EE and existing DR programs.

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

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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.

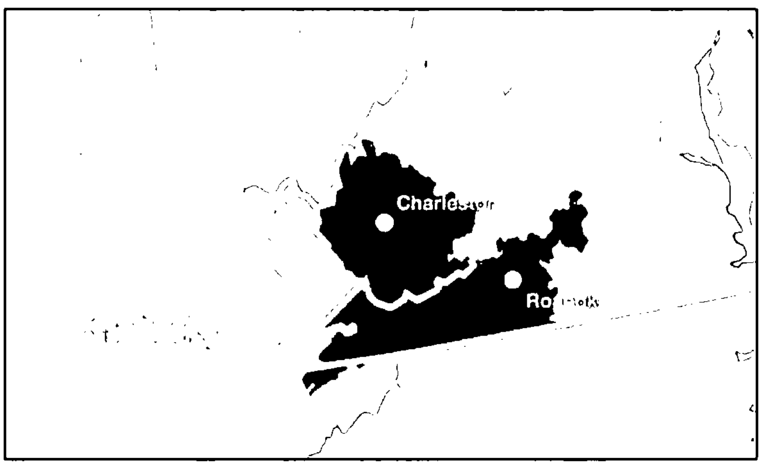

Figure 1. APCo Service Territory

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.

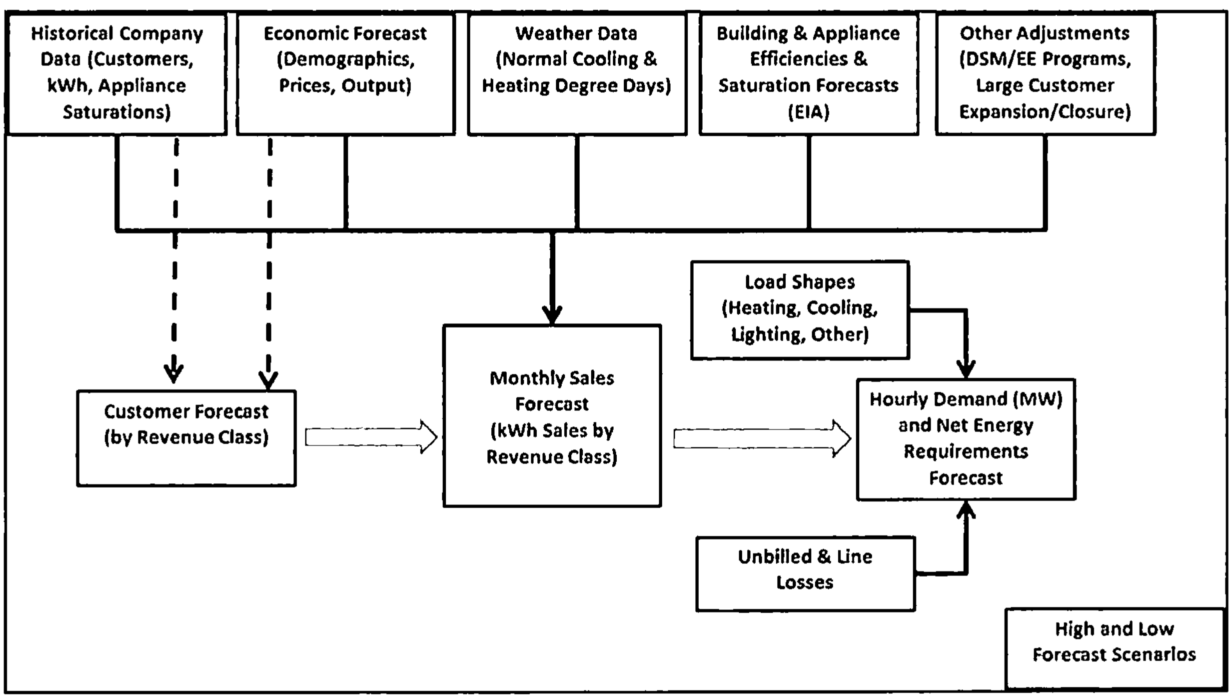

Figure 2. APCo Internal Energy Requirements and Peak Demand Forecasting Method

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.

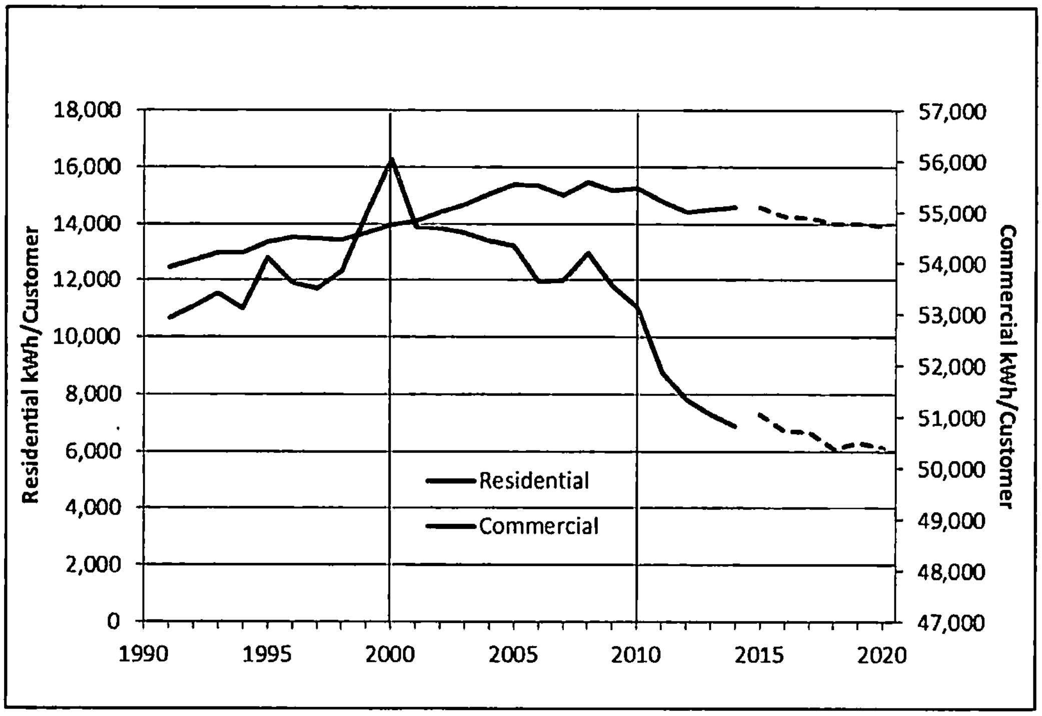

Figure 3. APCo Normalized Use per Customer (kWh)

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.

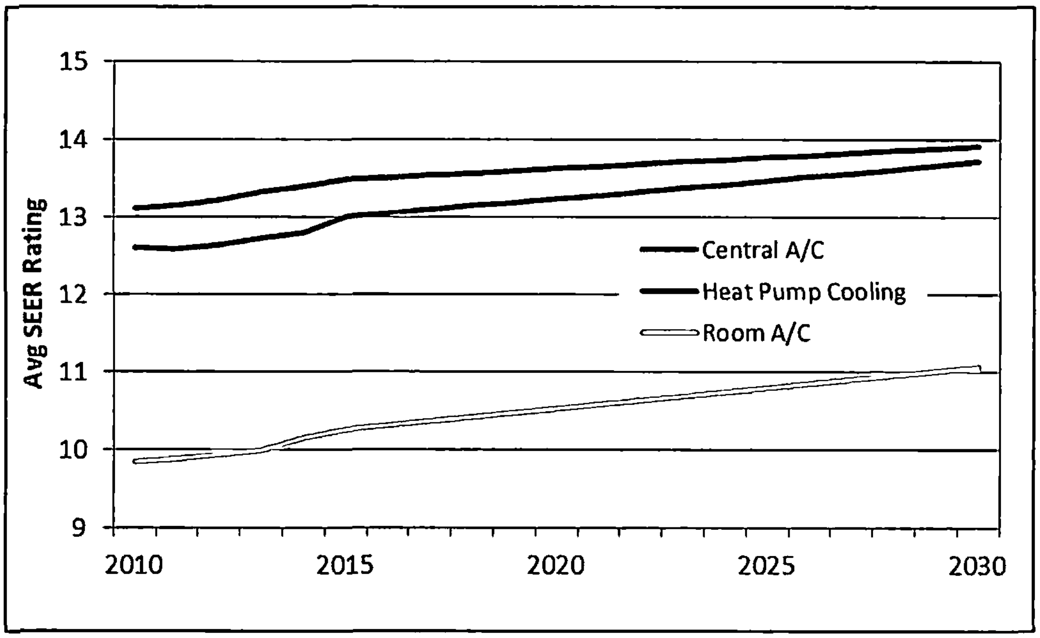

Figure 4. Projected Changes in Cooling Efficiencies, 2010-2030

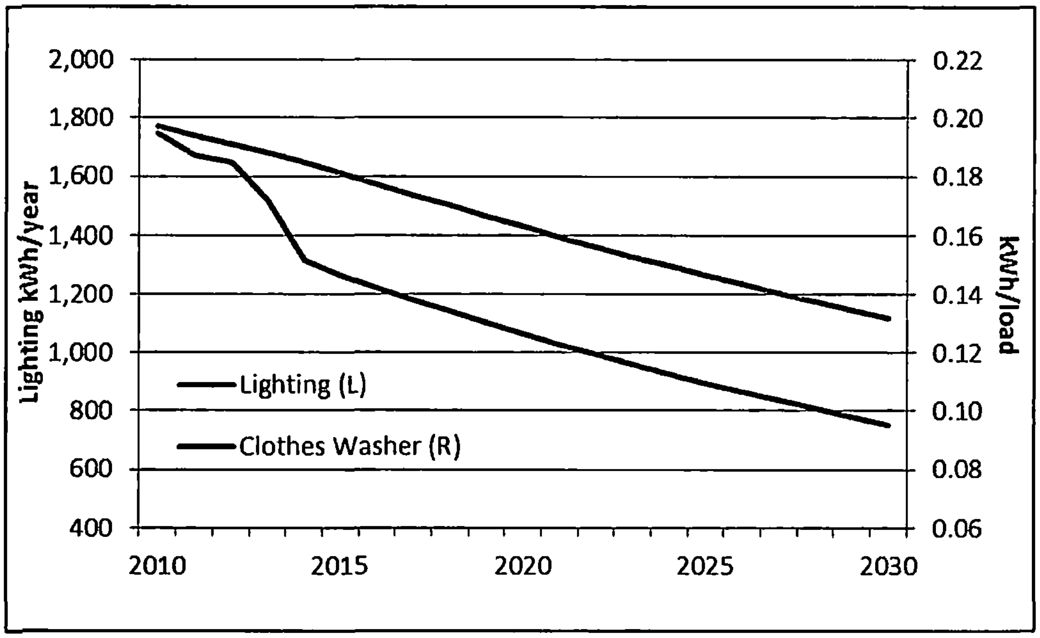

Figure 5. Projected Changes in Lighting and Clothes Washer Efficiencies, 2010-2030

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.

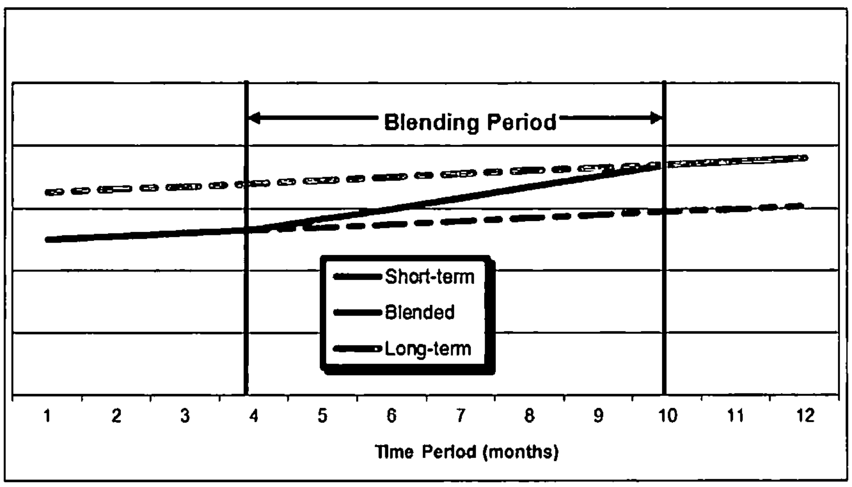

Figure 6. Load Forecast Blending Illustration

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.