Public Service Commission of West Virginia

Electric Supply – Demand Forecast Report for 2017 – 2026

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Executive Summary

The major generation-owning electric utility systems in West Virginia have completed major acquisitions of generation in recent years. At the same time, several older generating facilities have been retired. Cancellation of long-standing capacity agreements with affiliates has occurred, which has contributed to the need for alternative capacity resources. Appalachian Power Company (APCo) and Wheeling Power Company (WPCo) will have marginally adequate capacity for summer requirements in the near future, but will have low reserve margins in the next several years and may have low winter reserve margins during the forecast period. Monongahela Power Company (MPC) and Potomac Edison (PE) also have adequate capacity for summer requirements in the near future, but reserve margins will gradually shrink, becoming negative during the forecast period.

If implemented, new EPA standards to limit carbon emissions from existing power plants will affect generation resources. As those standards are proposed, it is likely that generating utilities in West Virginia will need to modify existing generation to meet the EPA goals on both an interim and final basis. Because the timing and extent of rules implementing the EPA standard are unknown at this time, the impacts of any carbon limitations are not included in this report. The Presidential election in November 2016 will likely have a significant impact on the EPA, including how its standards may affect the electric utility and coal industries. West Virginia industries remain flexible when complying with current and future EPA standards, no matter what national policy evolves.

The general conclusions reached in preparing this report are:

- Expected growth in annual peak electric demand will average approximately 0.7% with higher near-term growth of nearly 4.4% for MPC.

- Because of PJM discounting a portion of Installed Capacity (ICAP), it is appropriate to use the reduced peak capacity value, referred to as Unforced Capacity (UCAP) assigned annually to each generation unit by PJM.

- PJM has received FERC approval of its Capacity Performance Rules. These rules affect both APCo and MPC. A major result of these rules is to reduce the capacity of solar, hydro and wind resources.

- Both APCo and MPC face declining reserve margins above their PJM UCAP that will require additions of capacity or reductions in demand during the forecast period.

General Discussion

The 64th Legislature (1979) directed the Public Service Commission of West Virginia (Commission) to report to the Legislature annually on the 10-year supply and demand balance for the electric utilities in West Virginia (W. Va. Code § 24-1-1(d)(3)). To prepare that report, the Commission Staff conducts an annual examination of long-term demand forecasts and resource plans of the major electric utilities in West Virginia. Staff evaluates the underlying assumptions and reasonableness of the forecasts and plans and prepares the annual *Electric Utilities Supply and Demand Forecast Report* required by the statute.

The four largest regulated electric utilities in West Virginia are APCo, WPCo, MPC and PE. APCo, WPCo and MPC are regulated electric distribution utilities that own generation facilities. APCo and WPCo are sister companies in American Electric Power (AEP). MPC and PE are sister companies in FirstEnergy (FE). These four electric utilities account for approximately 96% of West Virginia residential sales and 98% of West Virginia commercial and industrial sales. For purposes of this report, APCo and WPCo are paired, and a combined supply and demand forecast is prepared based on their combined resource plans and projected demand. MPC and the PE West Virginia operations are similarly paired. Reference to APCo includes the supply resources and load of WPCo, which operates only in West Virginia. Reference to MPC includes the load of the PE West Virginia operations.

Currently, there are five independent non-generation electric utilities in West Virginia that purchase power at wholesale and distribute that power to local residential, commercial and industrial customers at retail rates. Those are:

- Harrison Rural Electrification Association
- Black Diamond Power Company
- Craig-Botetourt Electric Cooperative
- New Martinsville Municipal Utilities
- Philippi Municipal Electric

These companies purchase their power supply requirements from various suppliers operating in the regional area served by PJM Interconnection (PJM).[1] They have historically relied on medium to long-term contracts with wholesale providers, but they can also consider the available energy and capacity in the PJM markets when planning their power supply requirements. The PJM organization manages the bulk-power transmission system and an extensive capacity and energy market. This market

[1] PJM Interconnection, LLC manages electricity energy and capacity markets and the transmission network covering a large portion of the Middle Atlantic and Midwest area. For a description of PJM Interconnection, see Appendix A.

has become the major source of power supply for many customers and load-serving entities in the PJM Region.

The *Electric Utilities Supply-Demand Forecast* is based primarily on a review of supply resources and load forecasts provided by AEP and FE. The AEP and FE information includes a capacity (supply) plan, also known as an integrated resource plan (IRP), that considers future demand requirements of customers and options for controlling or reducing demand. The plan then considers supply options to economically meet the future net demand requirements. The IRP includes projected equipment upgrades, re-rating of plants, retirement of internal generation resources, additional internal generation resources, demand side resources and purchased capacity, if needed. Commission Staff reviews the information and determines how the capacity resources compare to the projected loads and whether the expected supply is sufficient to meet peak loads while maintaining a reasonable reserve margin over the forecast period. These IRPs are updated periodically, accounting for economic and regulatory influences that may affect the utilities' operation.

Both APCo and MPC have retired several older coal-fired, sub-critical generating units. Both companies sought and received approval to acquire additional generation capacity of existing generating facilities in West Virginia. In 2013, the Commission issued decisions in cases involving both APCo and MPC with regard to approval of these transactions. A further proposal by WPCo to acquire an undivided 50% interest in the Mitchell Plant was approved by the Commission in December 2014.

In Case No. 12-1571-E-C, the Commission authorized MPC to sell its interest in the Pleasants generation plant and to acquire 100% ownership of the Harrison generating plant. The net result of this transaction increased the installed capacity of MPC by 1,476 megawatts (MW).

In Case No. 12-1655-E-PC, the Commission authorized APCo to acquire 100% ownership of Unit 3 at the John Amos generating plant. This acquisition increased the installed generation capacity of APCo by 867 MW.

The U.S. Environmental Protection Administration (EPA) released proposed rules for the reduction of carbon emissions from existing power plants in June 2014. The proposed rules set interim and final goals for each state. The West Virginia Department of Environmental Protection (WVDEP), with input from the West Virginia Division of Energy and Commission Staff, filed comments with the EPA on December 1, 2014.

On August 3, 2015, the EPA issued a pre-publication release of its final rule, which became effective when it was published in the *Federal Register* on October 23, 2015. The EPA has titled this rule its "Clean Power Plan." The final rule, as applied to West Virginia power plants, is more stringent than the proposed rule that was released in

2014. The 2014 proposal had set a final (2030) carbon dioxide emission rate limit of 1,620 tons per megawatt hour (MWh) of generation. The final rule sets the 2030 rate limit at 1,305 tons per MWh.

The final rule requires a four-step phase-in between 2022 and 2028. The interim steps and the rate limits for CO2 per MWh generated during the phase-in are: (2022-2024) 1,671 tons/MWh, (2025-2027) 1,500 tons/MWh, and (2028-2029) 1,380 tons/MWh. The average emission rate limit over the entire phase-in period is 1,534 tons. States may establish different interim period reductions as long as the aggregate steps meet the total interim period average limit of 1,534 tons per MWh.

The final rule also sets an alternative 2030 total tonnage carbon dioxide emission limit (mass limit) of 51.3 million tons for West Virginia. As with the emission rate limits, if the State pursues a tonnage limit goal, the step-down must begin in 2022 and the average limit over the full eight-year step-down period must be 58.1 million tons. The intermediate step-down mass limits are: (2022-2024) 62.6 million tons, (2025-2027) 56.8 million tons, and (2028-2029) 53.4 million tons.

The final rule provides for compliance through either plant specific, state specific or regional approaches. States are allowed to adopt an EPA model trading rule or write their own plan that includes trading with other states, with certain requirements and limitations. If emitters in some states are able to reduce carbon dioxide output below their maximum limits, then they may have carbon credits that can be purchased by other emitters in that state, or in other states, in lieu of those purchasers of credits reducing their physical output of carbon. Such a trading approach would require state plans that provide for carbon credit trading, either intrastate, interstate or both.

All West Virginia power plants emitted a combined 72.3 million tons of carbon dioxide in 2012. To achieve the final mass limit of 51.3 million tons in 2030, the West Virginia plants must reduce carbon output or acquire carbon emissions credits, if allowed by a state plan, by a total of 21 million tons: a 29% reduction from the 2012 output. Of the 72.3 million tons of emissions in 2012, West Virginia utility companies accounted for 52 million tons, or 72%. Non-utility, PURPA-qualified wholesale generators that contract to sell their plant output to a West Virginia utility output 1.7 million tons. The balance of the emissions came from generators that do not serve retail customers in West Virginia.

HB 2004, passed by the West Virginia Legislature in 2015, required the DEP report to the Legislature regarding the feasibility of the State's compliance with the EPA Clean Power Plan. If the DEP determined that compliance is feasible, it must then submit a proposed state plan for consideration by the Legislature. The DEP initiated a study of the final Clean Power Plan and completed its initial report to the Legislature on April 20, 2016. In that report, the DEP noted:

> In the final rule, EPA established an initial deadline of September 6, 2016, for submission of a state plan. However, on February 9, 2016, the United States Supreme Court granted a stay of the rule. As a result, all deadlines in the EPA rule are delayed during the pendency of the lawsuits challenging the rule. If these lawsuits result in the 111(d) rule being vacated by the courts, there will be no deadline. Should the rule be upheld, the WVDEP expects that EPA be required to extend the regulatory deadlines contained in the rules to allow an amount of time for action following the conclusion of litigation that is comparable to what would have been allowed in the absence of litigation and a stay. Although the WVDEP shares the belief of those challenging the rule that it is unlawful, the WVDEP cannot predict with certainty either the outcome of the litigation or when that outcome will be final. Accordingly, the WVDEP cannot predict when an EPA deadline will fall or whether there will even be an EPA deadline under this rule. (Feasibility Report, West Virginia Department of Environmental Protection, April 20, 2016, pp 10 – 11.)

In addition to the uncertainty of the feasibility of compliance, which is addressed in the DEP report, there have been lawsuits filed to block or slowdown the Clean Power Plan as issued by the EPA. It has been reported that it has become the most heavily litigated environmental regulation ever issued. Twenty-seven states and a number of industry groups have filed more than 15 separate cases against the rules. West Virginia has been joined by 23 other states in one case.[2] Oklahoma, North Dakota and Mississippi have filed individual lawsuits. Challenges have been filed by trade associations, utilities, coal companies, mining interests and other business sectors. Eighteen states and several municipal entities have announced that they will support the Clean Power Plan and defend the EPA in court. The lawsuits are currently consolidated in the U.S. Court of Appeals for the District of Columbia Circuit. The United States Supreme Court has stayed the implementation of the EPA Rule during the pendency of litigation before the DC Circuit and the Supreme Court.

If implemented, the EPA Clean Power Plan could affect the supply and cost of electricity available to West Virginia utilities. If a state plan is ultimately required, the final timing and outcome of legal challenges and the timing and provisions of a West Virginia plan for compliance are not certain. It would be premature to estimate or model, at this time, how the Clean Power Plan might affect the future supplies of electricity in West Virginia. Given the uncertainty of the timing and outcome of the Clean Power Plan, no assumptions regarding its impact on West Virginia's electricity supply or demand are made in this report.

PJM incurs its peak capacity requirements in the summer, and plans its capacity resources accordingly. Both APCo and MPC have been winter peaking companies.

[2] Alabama, Arizona, Arkansas, Colorado, Florida, Georgia, Indiana, Kansas, Kentucky, Louisiana, Michigan, Missouri, Montana, Nebraska, New Jersey, North Carolina, Ohio, South Carolina, South Dakota, Utah, Wisconsin and Wyoming joined the lawsuit filed by West Virginia and Texas.

Historically, the ability of those companies to meet their internal peak, whenever that occurred, has been the focus of capacity adequacy planning. Because of the availability of energy from the PJM market and the PJM assignment of capacity obligations based on summer peaks, the Commission now evaluates the APCo and MPC supply and demand during the summer months. For the forecast period of summer 2017 through 2026:

- Expected growth in annual peak electric demand will decline an average approximately 0.2% for APCo. Growth in MPC annual peak electric demand is expected to be higher due to natural gas production, processing and transportation activities in the MPC service territory. The MPC annual growth is projected to be around 4.4% through 2020, and then drop to around 0.7% in 2021.

- Utility-owned (internal) generation installed capacity plus existing installed capacity available through purchased power contracts will be greater than customer demand.

- PJM discounts Installed Capacity (ICAP) to reflect the probability of outages of generation units, based on prior unit performance that PJM uses to assign an Equivalent Forced Outage Rate (EFOR) to each generation unit. The reduced peak capacity value assigned to each generation unit is referred to as UCAP.

- The Commission forecast of electricity supply has historically focused on the ICAP of APCo and MPC. Because of changes taking place in PJM definitions of reliable capacity resources and more stringent requirements being placed on generation resources operating in the PJM market, this report reflects the reduced UCAP values that the utilities must use for PJM planning purposes.

- Because UCAP reflects lower values than ICAP, there is a level of built-in reserve margin reflected in the difference between UCAP and projected peak customer demand. This built-in reserve margin for fossil fuel-fired generation changes annually and generally ranges between 8% and 12%, depending on the PJM determination of historical EFOR.

- PJM has recently changed its Capacity Performance Rules, requiring a greater level of reliability of capacity resources. These changes in the Capacity Performance Rules will affect both APCo and MPC. One of the major changes is a further discounting of capacity from solar, hydro and wind resources. The decrement between ICAP and UCAP of these resources will increase during the forecast period of this report. APCo has a greater level of solar, hydro and wind resources in its capacity, so it will be affected more than MPC by the PJM

Capacity Performance changes. Most significantly for both APCo and MPC, the UCAP of hydro generation, including pump storage generation, will be reduced significantly in 2020.

- Based on existing capacity resources, both APCo and MPC face declining PJM cushions above their UCAP obligations and each will require additions of capacity or reductions in demand during the forecast period.

American Electric Power

Appalachian Power Company and Wheeling Power Company

APCo is the largest AEP subsidiary in terms of population served, number of customers and area of service territory of the operating companies that comprise the AEP East System (AEP East). The APCo service territory covers southern West Virginia and adjacent portions of Virginia. WPCo owns generation facilities as well as transmission and distribution facilities providing service in Marshall and Ohio Counties in the Northern Panhandle of West Virginia. For rate regulation purposes in West Virginia, all operating costs, including power supply costs, of APCo and WPCo are combined and shared among APCo and WPCo customers.

APCo's current internal supply sources include coal-fired steam plants, natural gas-fired plants employing either solely combustion turbine technology or combined combustion turbine and steam technology (combined cycle), hydroelectric facilities and purchased power contracts. The APCo purchased power contracts presently include hydro and wind capacity. Potential future changes in APCo supply sources include capacity and energy supplies from renewable energy sources.

In June 2015, due to the company's inability to economically comply with new environmental standards, the Kanawha River Plant, the APCo units at the Phillip Sporn Plant, Glen Lyn Units 5 and 6 and Clinch River Unit 3 were retired.

APCo is continuing operations at Clinch River Units 1 and 2 after converting the units' steam generators from coal to natural gas fuel sources. Clinch River Units 1 and 2 are expected to continue operating as gas-fired generating units throughout the forecast period. APCo evaluated the conversion of the Kanawha River Plant to natural gas and reported that such conversion was not an economical option. This Commission however, urged APCo to preserve the equipment necessary for a natural gas conversion of the plant for a four-year period, given the present economic and political uncertainties.

APCo has historically reached its annual peak demands during the winter months. Historically, the Commission has projected the APCo supply and demand balances at the time of the annual winter peaks. Because PJM peaks in the summer, for PJM planning purposes the adequacy of APCo capacity is measured during the summer months and the supply/demand data used in this report reflect summer peaks. Thus, it is likely that projected reserve margins in any year, over the reserve margins already built into PJM UCAP values, will be less in the winter when APCo reaches its internal peaks. Because of the availability of capacity from the PJM market, any additional capacity required during APCo's winter peaking should be available from the PJM market.

Projected capacity of APCo/WPCo reflects significant derating of some "intermittent" resources in 2020 due to the new Capacity Performance rules of PJM. Run-of-river hydro capacity is reduced to a value of zero. Pumped-storage hydro unit capacity is reduced by approximately 33%. Wind resource capacity value is reduced to 5% of nameplate rating, as compared to the current PJM value of 13.5%. These assumptions are based on a current understanding of the PJM Capacity Performance rules, but may change when the PJM tariffs relating to Capacity Performance are finalized.

Gradual additions to APCo/WPCo capacity resources are reflected in the *Electric Utilities Supply/Demand Forecast Report*. These are not firm commitments for capacity additions, but reflect types and amounts of additions that are under consideration by APCo. The projected additions to capacity resources have not significantly changed since the *2015 Electric Utilities Supply/Demand Forecast Report* and are summarized to include:

- Beginning in 2020: Reduction of Smith Mountain pumped storage capacity by approximately 200 MW, reduction of all run-of-river hydro from the available UCAP by 25%, and reduction in PJM-allowed capacity levels for wind resources from 13.5% to 5% of nameplate capacity.[3]

- Additions of 20 MW of utility-owned, large-scale solar capacity beginning in 2018, with subsequent additions totaling 590 MW by 2030.

- Additions of 300 MW (nameplate rating) of wind capacity in 2018, with additional wind capacity being added through 2025 totaling 1,800 MW.

- Increased efficiency of distribution facilities.

- Increased use of battery storage resources.

[3] These reductions are not an actual reduction in installed capacity, but reflect reduced values of the installed capacity after considering PJM rules.

- Increased energy efficiency projects at the end-user level.
- Increases in customer-owned distributed solar capacity.

A summary of the combined projected capacity supply and demand (at PJM UCAP level) for APCo and WPCo are represented in the following table. Projections for UCAP capacity calculated by PJM in 2016 were not available at the time of this report. Therefore, the UCAP capacity values are based on the PJM 2015 calculated assignments. These calculations incorporate unit operating data over a three-year rolling average, reflecting minimal changes from year to year.

Appalachian Power Company / Wheeling Power Company Projected Supply and Demand - 2017 through 2026 (1) Based on Summer Internal Load and PJM UCAP Obligations and Capacity								
Year	APCo	WPCo	APCo / WPCo					
	Internal Load Plus Reserves	Internal Load Plus Reserves	Total Internal Load Plus Reserves	UCAP Capacity (2)			Reserve Margin in Additional to Margins Already Built Into UCAP Values	
				APCo	WPCo	APCo+WPCo		
	MW	MW	MW	MW	MW	MW	MW	Percent
2017	6,283	518	6,801	6,386	690	7,076	275	3.9%
2018	6,357	522	6,879	6,455	690	7,145	266	3.7%
2019	6,421	495	6,916	6,490	690	7,180	264	3.7%
2020	5,951	496	6,447	5,927	690	6,617	170	2.6%
2021	5,994	499	6,493	5,927	690	6,617	124	1.9%
2022	6,028	501	6,529	5,927	690	6,617	88	1.3%
2023	6,065	504	6,569	5,927	690	6,617	48	0.7%
2024	6,085	506	6,591	5,927	690	6,617	26	0.4%
2025	6,131	509	6,640	5,927	690	6,617	(23)	-0.3%
2026	6,166	511	6,677	5,927	690	6,617	(60)	-0.9%

Notes:

(1) Includes APCo total company (WV and VA) UCAP capacity resources and UCAP load obligations.

(2) Includes APCo-owned generation and long-term power contracts and WPCo-owned generation. (Based on Integrated Resource Plan (IRP), January 1, 2016.)

FirstEnergy Corporation

Monongahela Power Company and Potomac Edison Company

Monongahela Power Company (MPC) and The Potomac Edison Company (PE) are regulated subsidiaries of FirstEnergy Corp. (FE). The long-term assessment of supply and demand includes the total current and future capacity resources owned or contracted by MPC and the total load (demand) for the combined FE service territory in West Virginia.

MPC's current internal supply sources include coal-fired steam plants and purchased power contracts. The purchased power contracts include coal and gob-fired generation and both run-of-river and pump storage hydro generation. Potential future changes in the MPC supply sources include acquisition of additional generating capacity and additional purchases from the PJM market.

Like APCo, MPC has historically reached its annual peak demands during the winter months. Because PJM peaks in the summer, for PJM planning purposes, the adequacy of MPC capacity is measured during the summer months. Although on a stand-alone basis it would be normal to project the MPC supply and demand balances at the time of the annual winter peaks, for purposes of this report, the Commission is using the summer demand levels that are used for PJM planning purposes. It is likely that projected reserve margins will be less or projected deficits will be greater in the winter when MPC reaches its internal peaks. If MPC requires more capacity at the time of its internal winter peak, that capacity may be available from the PJM market.

Projected capacity of MPC reflects significant derating of its share of the Bath County pumped-storage capacity beginning in 2020. This decrease is based on a current understanding of the PJM Capacity Performance rules, but may change when the PJM tariffs relating to Capacity Performance are finalized.

A summary of the MPC projected capacity supply and demand for the forecast period is reflected below. The MPC data reflects a gradual decline in the calculated reserve margin in addition to the margins already built into the PJM UCAP values, reaching a deficit capacity during the forecast period. Absent significant changes in actual values from the projections, at some point during the forecast period MPC will have to consider adding new capacity. MPC has indicated that it believes its declining reserves should be offset by the purchase of additional coal-fired capacity from an existing source in the near future. Because of uncertainty about the amount and timing of that addition or any other additions to the MPC UCAP capacity, capacity additions above existing resources have not been reflected in the following table. Projections for UCAP capacity calculated by PJM in 2016 were not available at the time of this report. Therefore, the UCAP capacity values are based on the PJM 2015 calculated assignments.

These calculations incorporate unit operating data over a three year rolling average reflecting minimal changes from year to year.

Monongahela Power Company/Potomac Edison Company Projected Supply and Demand - 2017 - 2026 (1) Based on Summer Internal Load and PJM UCAP Obligations and Capacity				
Year	**MPC and PE West Virginia**			
	Total Internal Load UCAP Obligation	**UCAP Capacity (2)**	**Reserve Margin in Addition to Margins Already Built-Into UCAP Values**	
	MW	**MW**	**MW**	**Percent**
2017	2,743	3,357	614	22.4%
2018	2,899	3,357	458	15.8%
2019	2,968	3,357	389	13.1%
2020	3,119	3,118	-1	0.0%
2021	3,279	3,118	-161	-4.9%
2022	3,322	3,118	-204	-6.1%
2023	3,344	3,118	-226	-6.8%
2024	3,365	3,118	-247	-7.3%
2025	3,385	3,118	-267	-7.9%
2026	3,404	-	-	-

Notes:

(1) Includes MPC total company UCAP capacity resources and summer peak UCAP load obligations plus PE West Virginia summer peak UCAP load obligations.

(2) Includes MPC-owned generation and long-term power contracts. (Based on 2015 PJM projections; 2026 data not available.)

PJM Interconnection LLC

PJM Interconnection (PJM) is a regional transmission organization that operates the transmission grid delivering power in all or parts of Illinois, Michigan, Indiana, Ohio, Kentucky, Tennessee, North Carolina, Virginia, West Virginia, Maryland, the District of Columbia, Pennsylvania, Delaware and New Jersey. The PJM grid is made up of the major transmission facilities owned by a large number of integrated electric utilities, transmission companies spun off from former integrated electric utilities and new transmission companies. These transmission owners have turned over the operation of their interconnected transmission lines to PJM. As the grid operator, PJM conducts ongoing long-term regional planning that projects load within the system. Based on overall load levels, geographic locations and the ability of the transmission lines to move energy within the grid, PJM evaluates potential grid transmission bottlenecks and reliability issues. The end result of the evaluation and planning process is the identification of transmission upgrades and construction necessary to ensure reliably delivered power now and over the long-term planning horizon. PJM notifies the transmission owners of the need for system upgrades. The transmission owners are then responsible for implementing the necessary upgrades.

PJM also operates a competitive wholesale electricity energy market within the region served by the transmission facilities under its control. Generation providers can bid their production volumes and prices for delivery into the market on the next day, and load-serving entities bid their load requirements and prices they are willing to pay the market on the next day (day-ahead market). PJM matches generation and load requirements on a regional basis where it determines the price at which power will enter the market. The market price for power can vary based on location and time of day. In addition, PJM manages a real-time power market to price power necessary to serve hourly supply and demand fluctuations from the day-ahead market commitments.

PJM also operates a capacity market. The capacity market is based on the PJM long-term Reliability Pricing Model (RPM). Along with capacity buyers and sellers, the RPM takes into consideration the continued use of self-supply and bilateral contracts by load-serving entities electing to generate their own energy requirements. The capacity auctions obtain the remaining capacity that is needed after market participants have committed the resources they will supply themselves or provide through contracts. PJM receives bids for long-term capacity from suppliers. This bidding process develops the prices that will be paid for future capacity.