EXHIBIT NO. ______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Long-Term	)	
Forecast Report of Ohio Power Company	)	
And Related Matters.	)	Case No. 18-501-EL-FOR

DIRECT TESTIMONY OF
JOHN F. TORPEY
ON BEHALF OF
OHIO POWER COMPANY

Filed: September 19, 2018

INDEX TO DIRECT TESTIMONY OF
JOHN F. TORPEY

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PERSONAL DATA

Q. STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John F. Torpey, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by the American Electric Power Service Corporation (AEPSC) as the Managing Director – Resource Planning and Operational Analysis. AEPSC supplies engineering, financing, accounting, planning, and advisory services to the eleven electric operating companies of the American Electric Power (AEP), including Ohio Power Company ("AEP Ohio " or "the Company").

Q. WOULD YOU PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Engineering from the Cooper Union for the Advancement of Science and Art (New York) in 1979 and a Master of Business Administration from Saint John's University (New York) in 1984. In addition, in 1995, I completed the American Electric Power System Management Development Program at the Ohio State University, and in 2000, I completed the Darden Partnership Program at the Darden Graduate School of Business Administration, University of Virginia.

In 1979, I was employed by AEPSC as a Design Engineer in the Structural Design Department. In 1985 I became the Project Controls Engineer for the Zimmer Conversion Project and then for the Gavin FGD Retrofit Project. I became Manager of the Controls Services Department in 1994 with responsibility for capital and expense budgeting, and maintenance outage planning for the AEP generating plants. I held various managerial positions in the AEPSC generation organization related to planning, budgeting, and cost control. In 2004, I became the Director of Corporate Budgeting in the Corporate Planning and Budgeting Department, and in 2007 became Director - Integrated Resource Planning. I assumed my current position in January 2018.

I am a Professional Engineer registered in the State of Ohio and a Certified Management Accountant. I have been an adjunct instructor at Franklin University (Ohio) since 2006 and have taught classes in the Accounting program and the Energy Management program.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR-RESOURCE PLANNING AND OPERATIONAL ANALYSIS?

A. I am primarily responsible for the supervision and administration of long-term generation resource planning and analysis for AEP. In such capacity, I coordinate the use of short and long-term generation production costing and other resource planning models used in the ultimate development of operating and capital budget forecasts for the Company and AEP. I regularly monitor actual performance and review the preparation of forecasted information for use in regulatory proceedings.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have testified or provided testimony on behalf of AEP Ohio affiliates Appalachian Power Company (APCo) and Wheeling Power Company before the Public Service Commission of West Virginia, and for APCo before the Virginia State Corporation Commission. I also testified on behalf of AEP Ohio affiliate Indiana Michigan Power Company before the Michigan Public Service and the Indiana Utility Regulatory Commissions.

<u>PURPOSE OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support AEP Ohio's 2018 Amended Long-Term Forecast Report (Amended LTFR) filing submitted contemporaneously with this testimony, including the integrated resource plan (IRP) and the supplemental load forecast report information. In addition, my testimony explains the methodology used by AEP Ohio to develop its assumptions for renewable resource costs and presents the economic benefits associated with the addition of renewable resources for AEP Ohio.

Q. WHAT PORTIONS OF THE AMENDED LRFT FILING ARE YOU SPONSORING?

A. I am supporting the following sections of the filing:

Exhibit JFT-1: Integrated Resource Plan (Ohio Adm, Code 4901:5-5-06) and Forecast Report Requirements for Electric Utilities (Ohio Adm, Code 4901:5-5-03).

IRP REQUIREMENTS

Q. WHAT ARE THE FILING REQUIREMENTS FOR AN IRP?

A. The Ohio Administrative Code 4901:5-5-06 delineates the requirements for an integrated resource plan (IRP). The rules require specific information for the Public Utilities Commission of Ohio to determine the reasonableness of the resource plan. Specifically, the rules require an analysis of anticipated technological changes that may be expected to influence traditional and alternative energy use and the use of energy efficiency and peak demand reduction programs, analysis of the availability and potential development of alternative energy resources, discussion of research and development efforts relating to alternative energy resources, and an analysis of the impact of environmental regulations on generating capacity, cost, and reliability. They also require a description of the existing generating system, analysis of need for additional electricity resource options, and analysis of an electric utility's projected mix of resource options, projected system reliability, and a demonstration of the cost-effectiveness and reasonableness of the plan.

Q. HAS AEP OHIO ADDRESSED THESE REQUIREMENTS?

A. Yes. AEPSC, through the Resource Planning and Operational Analysis group, provided AEP Ohio with the data and research necessary to prepare the IRP. Specifically, AEPSC provided 1) data and research for alternative and renewable energy technologies, 2) cost trends and projects for those technologies, 3) forecasts of peak load and energy consumption, and 4) forecasts of commodity prices, which were used to evaluate the economics of renewable resource additions.

<u>RENEWABLE PROJECT ANALYSIS</u>

Q. WHAT INFORMATION WAS USED TO DEVELOP RENEWABLE TECHNOLOGY COSTS?

A. The Resource Planning and Operational Analysis group used multiple sources of information as part of its analysis. These sources include the cost and production data received in AEP Ohio's recent 250 MW wind and 400 MW solar Request for Proposals (RFP) refreshed in early 2018, the 2016 DOE Wind Vision Report[1], and the U.S. Energy Information Administration's <u>Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook</u> (2018).[2]

Q. PLEASE SUMMARIZE THE ANALYSES PERFORMED FOR THE IRP.

A. The Company completed four separate analyses associated with the addition of large scale renewable energy projects in Ohio. The first analysis was prepared using data developed by the AEPSC Transmission Planning department and is explained in Company witness Ali's testimony. This analysis generally quantified the impact the short-listed renewable projects have on the PJM Locational Marginal Price (LMP), which is the price in dollars per megawatt hour ($/MWh) that AEP Ohio and other Load Serving Entities pay to PJM for energy from the PJM system for their customers ("PJM Impact"). The second analysis quantifies the specific net impact to AEP Ohio and its customers ("AEP Ohio Impact") from adding approximately 650 MW of generic renewable resources. This analysis calculated the change in the net present value or "NPV" of revenue requirements associated with adding generic wind and solar

[1] https://www.energy.gov/eere/wind/maps/wind-vision
[2] https://www.eia.gov/outlooks/aeo/electricity_generation.php

renewable energy projects. The third analysis calculated the break-even prices for wind and solar renewable energy purchase agreements (REPAs) that would result in a $0 NPV impact. The fourth analysis used a probabilistic simulation technique to evaluate the likelihood that AEP Ohio customers would benefit from the generic renewable energy projects.

Q. PLEASE SUMMARIZE THE RESULTS OF THESE FOUR ANALYSES.

A. The table below provides a summary of the four analyses performed. Note that each analyses results in a benefit to AEP Ohio customers.

AEP Ohio's Proposed Renewable Investment Benefit Summary

ANALYSIS	RESULT
PJM Impact	**Economic Benefit:** • LMP price reduction of $0.07/MWh, and • NPV savings of $31 million to AEP Ohio customers.
AEP Ohio Impact	**Economic Benefit:** • NPV benefit of $88 million from the 400 MW generic solar resources, and • NPV benefit of $54 million from the 250 MW generic wind resources.
Total Customer Benefit	PJM Benefit $31 M Solar Benefit $88 M Wind Benefit $54 M $173 M
Break-Even Analysis	Actual REPA costs lower than the REPA price noted below result in lower costs to AEP Ohio customers: • SOLAR: REPA costs below $56.82/MWh • WIND: REPA costs below $48.40/MWh
Probabilistic Simulation	• 100 % of the time solar projects result in a net benefit • 99.9% of the time wind projects show a net benefit.

Q. PLEASE DESCRIBE THE PJM IMPACT ANALYSIS.

A. For the PJM Impact analysis, the AEPSC Transmission Planning department utilized the PROMOD model to determine the impact of the addition of the AEP Ohio RFP short-listed wind and solar renewable energy projects on the PJM LMP at the AEP Hub in particular. Because renewable resources have little to no variable costs the energy they generate displaces generation resources with higher variable costs (*e.g.*, gas, coal). The net effect of displacing higher cost resources with lower cost resources is a reduction in the PJM LMP. Though there may be local or regional situations where this may not occur– in general, this is the net effect.

Q. PLEASE DESCRIBE THE AEP OHIO IMPACT ANALYSIS.

A. The AEP Ohio Impact analysis measures the change in net financial position (Revenue – Cost) of AEP Ohio by adding generic renewable generation resources. The generic renewable resources evaluated herein include 250 MW of wind REPAs and 400 MW of solar REPAs. The generic solar and wind resources were evaluated based upon their levelized "Net Cost of Energy." Net Cost of Energy compares the estimated contract cost of the renewable resource (REPA price) to the avoided cost of energy and capacity from the market. The equation below shows how Net Cost of Energy is calculated for a given year, where Avoided Cost of Energy and Avoided Cost of Capacity are forecasted values of energy and capacity available in PJM and discussed further below.

$$Net\ Cost\ of\ Energy\ \left(\frac{\$}{MWh}\right) = REPA\ Price\ \left(\frac{\$}{MWh}\right) - \left(\frac{Avoided\ Cost\ of\ Energy\ (\$) + Avoided\ Cost\ of\ Capacity\ (\$)}{Annual\ Generation\ (MWh)}\right)$$

Q. PLEASE EXPLAIN WHY LEVELIZED COSTS ARE USED IN YOUR ANALYSIS.

A. For each generic renewable resource, the annual Net Cost of Energy varies year to year due to the changes in forecast energy and capacity prices. In addition, wind and solar projects generate energy at different hours of the day, which influences the value of the avoided cost of energy. The wind and solar projects are also different sizes, making comparisons on a net present value basis impractical. To enable a meaningful comparison for the solar and wind projects, discounted annual values (in 2021 dollars) levelized over a 20-year period are calculated. The resulting levelized net cost of energy (LNCOE) in $/MWh provides a uniform basis suitable for comparing the relative value of different size projects and technologies.

Q. PLEASE DESCRIBE HOW THE AVOIDED COST OF ENERGY WAS CALCULATED FOR EACH GENERIC RENEWABLE RESOURCE.

A. The annual Avoided Cost of Energy was calculated for the generic wind and solar renewable energy projects by multiplying the expected output (MWh) of the renewable facility during each hour of the year by the corresponding forecast value of market energy ($/MWh) in PJM.

Data provided by responsive bidders to the Company's RFPs were the basis for expected hourly energy output values. Hourly market prices for energy are from the AEPSC Fundamental Analysis department's 2018 Fundamentals Forecast described by Company witness Bletzacker. In this analysis, the Avoided Cost of Energy is a benefit compared to buying from the PJM market. For example, if in a given hour, the cost of energy received through a REPA was $40/MWh, and the market price of energy was $45/MWh, AEP Ohio would realize an Avoided Cost of Energy of -$5/MWh.

Q. PLEASE DESCRIBE HOW AND WHY CAPACITY CREDIT WAS CONSIDERED IN YOUR ANALYSIS.

A. The generic wind resource assumption for a PJM capacity credit equals five percent of the nameplate rating of the site and the generic solar was given a capacity credit equal to 19% of the nameplate rating. In these analyses, the monetary value of capacity is viewed as a savings versus the market. Each MW of PJM capacity credit obtained through a REPA represents capacity that could be offered into the PJM capacity auction. The monetary value of capacity resources was calculated using the AEP Fundamental Analysis Department's 2018 Fundamentals Forecast. This forecast utilizes capacity values which have been established through the PJM Base Residual Auction through 2021, and then incorporates forecasted values for each subsequent year. Capacity credit is stated in dollars per megawatt-day. To determine the annual capacity credit value each site's PJM capacity credit was multiplied by 365 and then multiplied by the monetary value of capacity.

These capacity credits reflect the conservative capacity value AEP Ohio would place on intermittent resources under PJM's Capacity Performance requirement, which goes into full effect in June 2020. PJM publishes class average capacity values for wind and solar projects. The latest values, published June 1, 2017, were 17.6% for wind on flat terrain, 60% for solar with ground mounted tracking, and 38% for solar with "other than ground mounted" tracking.

Q. PLEASE DESCRIBE HOW YOUR ANALYSIS ADDRESSED RENEWABLE ENERGY PRODUCTION TAX CREDITS (PTCs).

A. The owner of the renewable energy facility will be entitled to any available tax credits and the value of these credits are factored into the generic renewable resource prices and the bids submitted in response to the RFPs. Renewable PTCs were not included as a direct benefit to AEP Ohio in the IRP analysis.

Q. DID YOUR ANALYSIS CONSIDER ANY VALUE OF RENEWABLE ENERGY CERTIFICATES (RECs)?

A. No. The analysis does not include REC values.

Q. PLEASE SUMMARIZE THE RESULTS OF THE PJM IMPACT ANALYSIS.

A. As described by Company witness Ali, the "PJM Impact" analyzed the effect on LMPs caused by the addition of renewable energy projects equivalent to the short-listed renewable projects would cause across the PJM footprint. The PJM footprint includes Ohio utilities that participate in the PJM energy markets, including AEP Ohio.

To calculate the LMP savings associated with adding renewable projects, the Resource Planning and Operational Analysis group started with the changes in LMPs for years 2021, 2024, and 2027 as calculated by Company witness Ali. The savings between 2021 and 2024, and between 2024 and 2027, were interpolated. The savings for 2028 and beyond were developed by applying the annual changes in the AEP 2018 Fundamental PJM energy price forecast for those future years. The result of this analysis (as shown on Table 3 of Exhibit JFT-1) shows a reduction in the cost of energy at the AEP load hub of $0.07/MWh on a levelized basis. In general, this savings would apply to any entity in PJM purchasing energy at this load hub. For example, by applying the hourly energy price savings to the hourly AEP Ohio load for the period 2021 through 2040, the Company calculated the NPV of the annual energy cost savings for the AEP Ohio load would be $31 million. This is in addition to the margin savings calculated in the "AEP Ohio Impact analysis."

Q. PLEASE SUMMARIZE THE RESULTS OF THE AEP OHIO IMPACT ANALYSIS.

The "AEP Ohio Impact" analysis shows that the 650 MW of generic renewable projects that go in service by 2021 will result in a reduction of costs relative to market (on an

NPV basis) over the life of the projects. Specifically, the NPV benefit from the 400 MW generic solar resources would be $88.0 million, and $54.0 million from the 250 MW generic wind resources, for a total benefit of $142 million. When combined with the "PJM Impact" savings, the total benefit to customers over the REPA period is approximately $173 million on an NPV basis. On a LNCOE basis, the solar projects result in a ($11.82)/MWh reduction in cost, and the wind project results in a ($8.40)/MWh reduction in cost (Table 4 and Table 5, respectively, of Exhibit JFT-1).

Q. PLEASE DESCRIBE THE BREAK-EVEN ANALYSIS PERFORMED BY THE COMPANY.

The Company performed a break-even analysis for both the generic wind and solar projects. For solar projects with operational characteristics similar to those in the generic solar case, a 400MW fixed price solar REPA at a cost of $56.82/MWh would result in $0 NPV, and $0/MWh LNCOE (Table 6 of Exhibit JFT-1). Likewise, for wind projects with operational characteristics similar to those in the generic wind case, a 250 MW fixed price wind REPA at a cost of $48.40/MWh results in $0 NPV, and $0/MWh LNCOE (Table 7 of Exhibit JFT-1). Therefore, REPAs with costs lower than these respective break-even values have the potential to lower AEP Ohio's costs.

Q. PLEASE DESCRIBE THE PROBABLISTIC SIMULATION ANALYSIS PERFORMED BY THE COMPANY.

A. To simulate the volatility of the PJM energy market, the Company prepared an analysis that takes into account the variability of market prices, in addition to the variability of the wind and solar project outputs. To perform this simulation, the Company looked at ten years of peak and off-peak monthly market price data in PJM to establish the standard deviation versus the average price. This historical data yields a standard deviation equal to 25 percent of the average annual energy price. Likewise, the Company looked at historical output data for wind farms under REPAs with AEP Ohio affiliates and deliverable to PJM. From this data, a standard deviation of seven percent of the annual output was calculated. Looking at historical solar project output data from the Wyandot Solar project yields a standard deviation of five percent of the annual output. Using these standard deviation values, the Company created a normal distribution of the annual avoided market energy prices and the annual projected wind/solar project output using random numbers (a Monte Carlo simulation). Performing this simulation 1,000 times and capturing the resulting 1,000 LNCOE values allowed for the construction of a graphic representation of the distribution of potential LNCOE outcomes. These simulations show that solar projects will result in a net benefit 100 percent of the time (Figure 4 of Exhibit JFT-1), and wind projects will realize a net benefit to customers 99.9 percent of the time (Figure 5 of Exhibit JFT-1).

Q. BASED ON THE ANALYSIS PERFORMED BY YOUR GROUP AND BY TRANSMISSION PLANNING, WHAT ARE YOUR CONCLUSIONS REGARDING THE ADDITION OF RENEWABLE ENERGY PROJECTS?

A. Adding solar and wind renewable energy projects will provide benefits for the customers of AEP Ohio, as well as for customers of other Ohio utilities that participate in the PJM energy market.

Q. DOES THIS ANALYSIS SUGGEST THAT ONLY UP TO APPROXIMATELY 650 MW OF RENEWABLE ENERGY PROJECTS WOULD BE BENEFICIAL TO AEP OHIO?

A. No. The analyses of generic renewable resources included in the IRP and discussed above were informed by cost and performance data included in proposals received by the Company for an RFP that totaled approximately 650 MW. If the Company solicits and receives an additional 250 MW or more of project proposals that result in costs less than the break-even values described above, with similar performance characteristics to the generic renewable projects, those additional projects would likely also benefit AEP Ohio’s customers.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

INTEGRATED RESOURCE PLANNING REPORT

AND

FORECAST REPORT REQUIREMENTS FOR ELECTRIC UTILITIES

TO THE

PUBLIC UTILITIES COMMISSION OF OHIO

CASE NO. 18-501-EL-FOR

September 19, 2018

INTEGRATED RESOURCE PLAN OF OHIO POWER COMPANY

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1 Executive Summary

The Public Utilities Commission of Ohio ("Commission") recognized in the ESP IV Order[1] that the Commission's PPA Rider Case Order (issued March 31, 2016 in Case No. 14-1693-EL-RDR, *et al.*) requires Ohio Power Company ("AEP Ohio" or the "Company") to propose renewable energy projects, and R.C. 4928.143(B)(2)(c) requires AEP Ohio to demonstrate need for electric generating facilities based on Company-submitted resource planning projections before the Commission will authorize recovery of the costs of those facilities. Consistent with the ESP IV Order, the purpose of the Company's 2018 LTFR Amendment filing is to demonstrate the need for at least 900 MW of renewable energy projects in Ohio.

AEP Ohio's Resource Plan ("Plan" or the "IRP") is the primary component of the 2018 LTFR Amendment Filing. Through the analyses documented in this IRP, the Company determined it was more cost-effective to meet a portion of it customer's future energy requirements by executing fixed price Renewable Energy Purchase Agreements (REPAs) for wind and solar consistent with the terms analyzed herein than to rely exclusively on the PJM market. Further, AEP Ohio's customers have expressed the desire for clean energy and a reduced carbon footprint, and the Plan would provide net economy-wide reduction in carbon emissions while creating manufacturing jobs in Ohio.

To develop the Plan, the Company completed four separate analyses associated with the addition of large scale renewable energy projects in Ohio. Each analysis concluded that the addition of renewable energy projects would be in the best interest of AEP Ohio's customers. The results are summarized in Table 3 of this report.

Renewable energy projects with characteristics similar to the generic projects modeled for this IRP would result in lower costs to customers over the project life cycles, provide a hedge against market volatility, and diversify the generation resources in Ohio that are bid into the PJM market. The total benefit to customers is expected to exceed $175 million (Table 3). Although the analyses performed were representative of the amount of generating capability requested in

[1] Case No. 16-1852-EL-SSO, *et al.*, Opinion and Order (Apr. 25, 2018).

AEP Ohio's RFP, as additional projects are identified with similar operating characteristics and costs below the break-even costs, AEP Ohio should consider those projects as well.

The purpose of this filing is to demonstrate the need for up to 900 MW of renewable energy projects in Ohio. AEP Ohio intends to prepare a separate filing requesting cost recovery for specific renewable resource project.

2 Introduction

This Report presents the 2018 IRP for AEP Ohio, including descriptions of assumptions, study parameters, and methodologies. The intent of the Plan is to dileneate AEP Ohio's long-term energy strategy in light of new technological advances in renewable power generation. A recent study performed by the Company suggests AEP Ohio customers support carbon free resources to meet their future power needs. As renewable energy costs continue their downward trend, the Company's future generation mix is expected to evolve with more emphasis on fixed pricing agreements that provide a hedge against volatile market prices. Investment in wind and solar generation are key drivers of economic growth in Ohio as new manufacturing jobs would be created as a result of the Company's Plan.

3 Narrative Discussion and Analysis of Resource Plan

3.1.1 Anticipated Technological Changes

American Electric Power Service Corporation (AEPSC) provides technical and administrative services to the operating subsidiaries of American Electric Power Company, Inc. (AEP), including Ohio Power Company ('AEP Ohio"). On behalf of AEP's operating subsidiaries, AEPSC continually tracks and monitors changes in the estimated cost and performance parameters for a wide array of generation technologies. Access to industry collaborative organizations such as the Electric Power Research Institute and the Edison Electric Institute, AEPSC's association with architect and engineering firms and original equipment manufacturers, and AEPSC's own experience and market intelligence, provides AEPSC with current estimates for the planning process. Table 1, below, summarizes current (non-renewable) technology performance parameter and cost data.

Table 1. New Generation Technology Options with Key Assumptions

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

Type	Capability (MW) (g)			Installed Cost (c,d)	Full Load Heat Rate	Fuel Cost (f)	Variable O&M	Fixed O&M	SO2	Emission Rates NOx	CO2	Capacity Factor	Overall Availability	LCOE (k)
	Std. ISO	Winter	Summer	($/kW)	(HHV,Btu/kWh)	($/MBtu)	($/MWh)	($/kW-yr)	(Lb/mmBtu)	(Lb/mmBtu)	(Lb/mmBtu)	(%)	(%)	($/MWh)
Base Load														
Nuclear	1,610	1,690	1,560	7,400	10,500	1.2	6.2	143.5	0.0000	0.000	0.0	90	94	171.7
Base Load (90% CO2 Capture New Unit)														
Pulv. Coal (Ultra-Supercritical) (PRB)	540	570	520	8,900	12,500	4.4	5.6	95.8	0.0650	0.050	21.3	85	90	244.0
Base / Intermediate														
Combined Cycle (1X1 "J" Class)	540	570	700	1,200	6,300	7.2	2.0	7.3	0.0007	0.007	117.1	60	89	87.2
Combined Cycle (2X1 "J" Class)	1,083	1,140	1,410	900	6,300	7.2	1.7	4.8	0.0007	0.007	117.1	60	89	78.7
Combined Cycle (2X1 "H" Class)	1,150	1,210	1,500	900	6,300	7.2	1.6	4.3	0.0007	0.007	117.1	60	89	75.9
Peaking														
Combustion Turbine (2 - "E" Class) (h)	182	190	190	1,200	11,700	7.2	3.9	9.4	0.0007	0.008	117.1	25	93	177.3
Combustion Turbine (2 - "F" Class, w/evap coolers) (h)	486	510	500	700	10,000	7.2	6.1	5.0	0.0007	0.008	117.1	25	93	139.3
Aero-Derivative (2 - Small Machines) (h,i)	120	120	130	1,400	9,700	7.2	2.4	36.9	0.0007	0.008	117.1	25	97	175.4
Recip Engines (12 - w/SCR, Natural Gas Only)	220	240	220	1,200	8,300	7.2	5.4	6.0	0.0007	0.008	117.1	25	98	148.0
Storage Battery (4 Hour-Lithium Ion)	10	10	10	2,200	87% (j)	--	--	142.3	--	--	--	25	99	275.0

Notes: (a) Installed cost, capability and heat rate numbers have been rounded
(b) All costs in 2018 dollars. Assume 2.17% escalation rate for 2018 and beyond
(c) $/kW costs are based on nominal capability
(d) Total Plant Investment Cost w/AFUDC (AEP-East rate of 5.5%,site rating $/kW)
(f) Levelized Fuel Cost (40-Yr. Period 2018-2057)
(g) All Capabilities are at 1,000 feet above sea level
(h) Includes Dual Fuel capability and SCR environmenttal installation
(i) Includes Black Start capability
(j) Denotes efficiency, (w/ power electronics)
(k) Levelized cost of energy based on assumed capacity factors shown in table

Vertically integrated utilities or independent power producers may add resources listed in Table 1 to meet capacity and energy needs, or to sell those attributes to load serving entities or PJM. While all of the options in Table 1 may provide capacity, energy and/or ancillary service products, the current expected market value for these products does not offset the fixed and carrying costs of acquiring the resource. Acquiring any of the options in Table 1 would result in increased costs to customers over the life of the asset. These assets are generally acquired by utilities to satisfy a capacity need.

3.1.2 Advances in Renewable Energy

Renewable generation alternatives use energy sources that are either naturally occurring (wind, solar, hydro or geothermal), or are sourced from a by-product or waste-product of another process (biomass or landfill gas). In the past, the driving forces behind renewable development were primarily voluntary or mandated renewable standards. Today, as advancements in both solar photovoltaics and wind turbine manufacturing have reduced both installed and ongoing costs, renewable resources are becoming increasingly economical, and many customers want clean energy at a reasonable cost.

Renewable generation resources are recognized more for their energy (MWh) value than capacity (MW) value because of their intermittent nature. Due to decreasing costs and currently available Federal tax credits, wind and solar projects have become economic resource options for utilities to consider (i.e., wind and solar resource additions may result in lower costs to customers over their lifecycle), particularly as an energy resource option.

3.1.3 Large Scale Solar and Wind

The two fundamental designs of large-scale solar power generation are concentrating and photovoltaics. Concentrated solar power systems generate solar power by using mirrors or lenses to concentrate a large area of sunlight, or solar thermal energy, onto a small area. This technology is more prevalent in western states (e.g. Arizona) where the solar resource and land availability is greater. Phototovoltaics (PV) are a traditional panel technology that is powered by solar cells. Solar panel tracking solutions are a more advanced technology for mounting photovoltaic panels and enable the panels to track the sun throughout the day versus a fixed tilt system that does not track the sun's path. The primary benefit of PV tracking systems is its ability to capture more energy from the sun, thereby maximizing output. A significant advantage of large-scale solar plants is that they require less lead time to build than fossil or nuclear plants and can be built in various sizes (e.g. 10 MW, 50 MW, 100 MW) versus commiting to a large central station plant size (e.g. 600 MW). There is no engineering defined limit on how much utility solar can be built in a given time, although there are practical constraints including siting, land acquisition, interconnection applications, permitting and equipment procurement and construction lead times.

Large-scale wind energy is generated by wind turbine generators, which generally range in size from 1.0 MW to 2.7 MW (and larger). Many wind turbines are grouped in rows or grids to develop a wind turbine power project, which requires only a single connection to the transmission system. Location of wind turbines at the proper site is particularly critical, as not only does the wind resource vary by geography, but also its proximity to a transmission system with available capacity. In addition to costs associated with interconnecting a wind project to the transmission system, other costs may include transmission system upgrades due to transmission congestion issues.

3.1.4 Battery Storage

Globally, energy storage has become increasingly popular. Further growth is expected as technologies are developed, production is ramped up, and effective business models and policies are developed. As battery and system component costs decline, energy storage will become an economical alternative to traditional power generation for certain applications, especially where energy costs are high or there is a shared benefit to the distribution system. In addition, energy storage will be able to supplement intermittent resources such as renewable generation.

3.1.5 Availability and Potential Development of Alternative Energy Resources

AEP Ohio remains committed to investing in intermittent renewable generation such as wind and solar resources. Responses to a recent Request for Proposals (RFP) yielded more than 1,500 MW of wind and solar projects in Ohio. The Company's intent to procure at least 900 MW of zero-fuel-cost renewable generation resources provides the means to satisfy AEP Ohio's customers' growing demand for in-state "green" energy.

3.1.6 Research, Development, and Demonstration Efforts Relating to Alternative Energy Resources

Flexibility in generation supply is important to manage the intermittency of renewable resources to maintain reliability of the grid. AEP Ohio supports a proactive policy to support research and technology development of lower carbon fossil fuel technologies, which would ensure the reliability and resiliency of the grid and improve carbon emissions.

3.1.7 Historical U.S. REPA Prices

Wind is a variable source of power with capacity factors ranging from 30 percent (in the eastern portion of the U.S.) to over 50 percent (largely in more westerly portions of the U.S., including the Plains states). A better understanding of wind resources and continued technology developments are leading trends in improved performance, increased reliability, and reduced cost of wind electricity. The U.S. Department of Energy's 2016 Wind Technologies Market Report stated that the average wind Renewable Energy Purchase Agreement (REPA) for the "Great Lakes" region of the nation had steadily trended down, with a 2015 average price executed around $40/MWh.

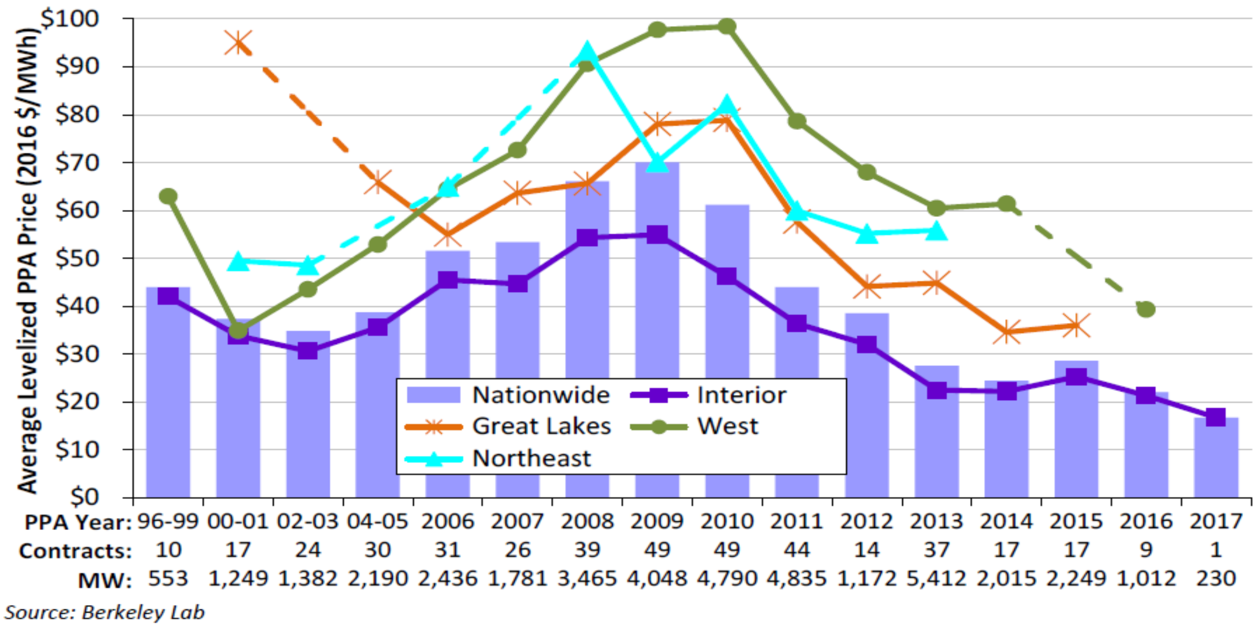

Figure 1. Historical Average of Wind REPA Prices
Source: 2016 Wind Technologies Market Report (Figure 49 on p. 70)

Solar energy prices have declined significantly in recent years as shown below in Figure 2. From 2010 to 2018, installation costs have declined by more than 50% for residential, commercial, and large-scale solar. Further, large-scale solar has been, and is projected to be, substantially lower in cost compared to other sectors, with large-scale installations costing 50% and 29% less than residential and commercial installations, respectively, based on 2018 costs.

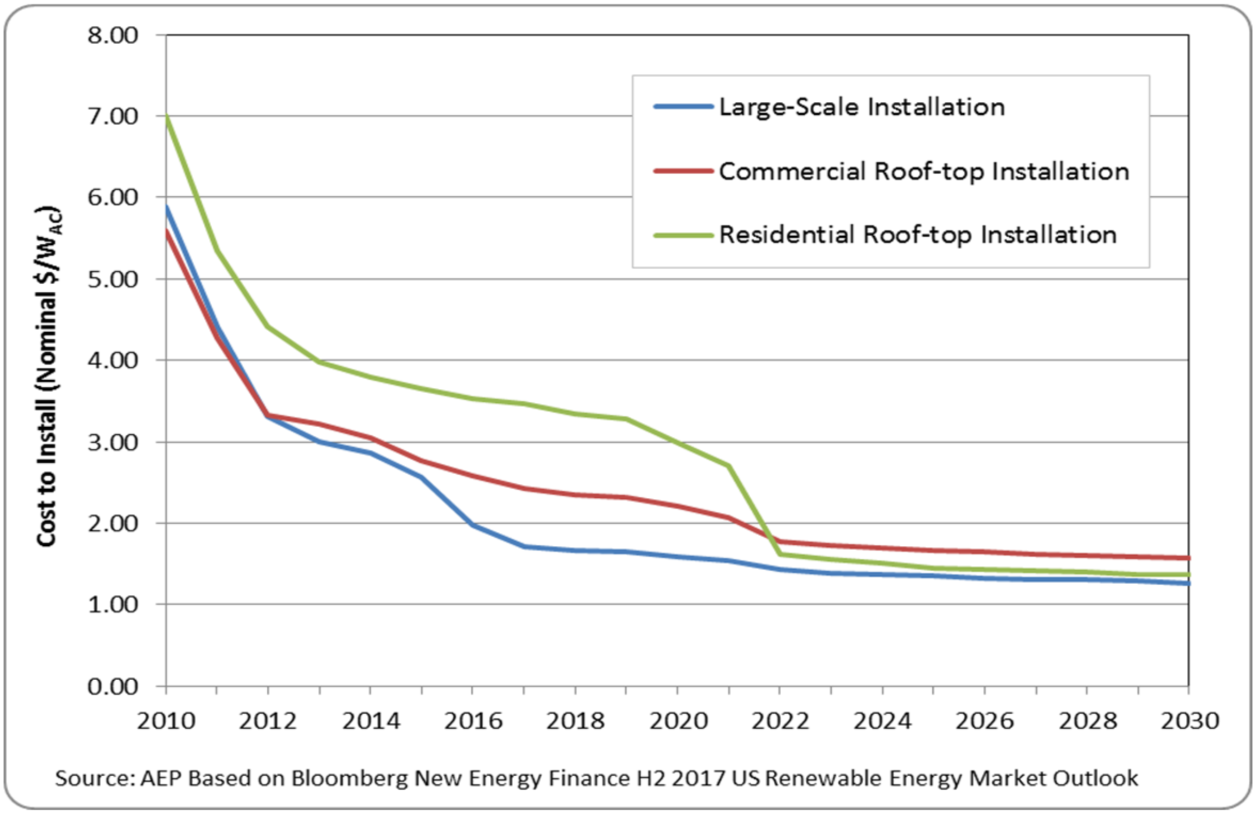

Figure 2. PJM Average Solar Photovoltaic (PV) Installation Cost (Nominal $/Watt AC) Trends

To support the flexibility of intermittent renewable resources, energy storage solutions are being considered. Lithium-ion battery storage is gaining momentum as electrification technologies mature and develop. A key benefit of battery storage is flexibility in response times to changes in frequency regulation. As battery technology advances, the Company envisions universal solar or wind projects that incorporate low-cost energy storage to minimize or smooth intermittency on the grid. AEPSC and AEP Ohio will continue to monitor battery storage technology developments. Figure 3 depicts the declining costs of battery storage technology.

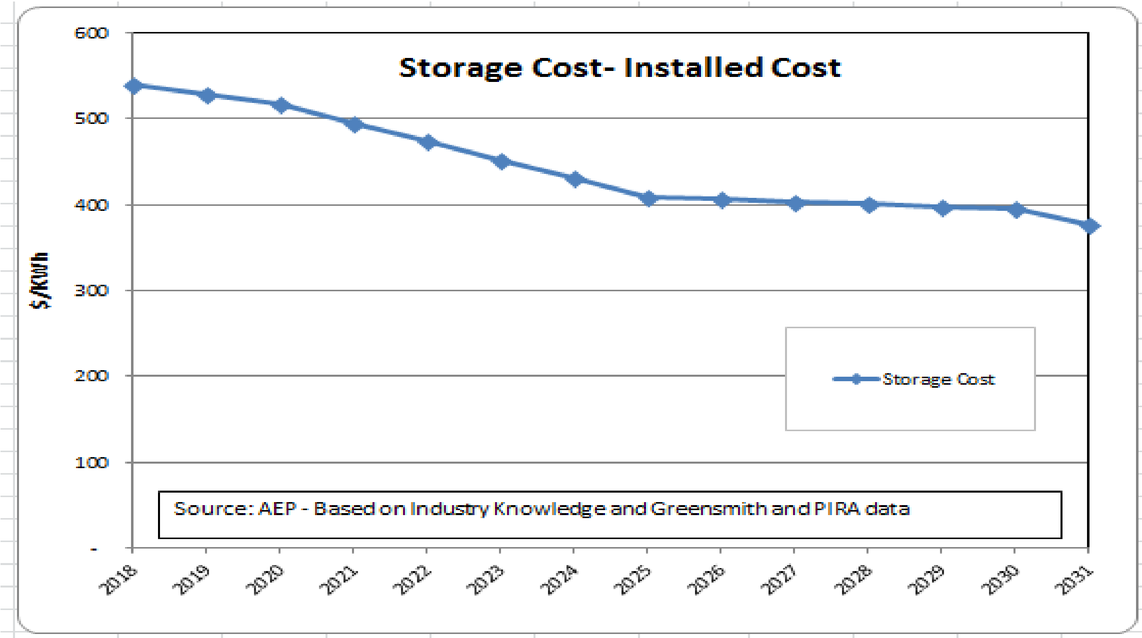

Figure 3. Storage Technology Costs

3.1.8 Impact of Environmental Regulations on Generating Capacity, Cost, and Reliability

Environmental requirements and renewable energy mandates at both the federal and state levels can impact the cost of energy and capacity. Those impacts are inherent in the 2018 Base fundamentals forecast of capacity and energy utilized in this report.

4 Existing Generating System Description

AEP Ohio is engaged in the transmission and distribution of electric power to approximately 1.5 million retail customers in Ohio. Following corporate separation of AEP Ohio's generation assets in December 2013, AEP Ohio purchases energy and capacity to serve its standard service customers [from PJM Interconnection LLC (PJM) a Regional Transmission Organization (RTO)]. PJM, as the Company's RTO, is responsible for maintaining electric system safety, reliability, and economic dispatch of its members. AEP Ohio is a Load Serving Entity (LSE) and purchases energy and capacity from PJM to serve its customers demand.

AEP Ohio has contractual entitlements to generation from the following facilities: Fowler Ridge II (100 MW wind); Timber Road (99 MW wind); Wyandot Solar (10 MW solar) and OVEC (437 MW coal). As of December 31, 2016, AEP Ohio had 1,582 employees. AEP Ohio is a member of PJM. AEP Ohio data is provided in Table 2.

Table 2. AEP Ohio 2017 Data

Residential Customers	**1,285,871**
Commercial Customers	**178,286**
Industrial Customers	**9,656**
Other Retail Customers	**2,680**
Total Retail Customers	**1,476,493**
PPA Capacity (MW)	**646**
• **% Coal**	**67.6%**
• **% Wind & Solar**	**32.4%**
Transmission Miles	**7,866**
Distribution Miles	**45,727**

5 Projected Generation Mix

Including renewable energy to the generation mix is becoming increasingly popular amongst electric utilities. The Company intends to pursue development of at least 900 MW of wind and solar projects in Ohio. This increased generation of electricity would provide a net economy-wide reduction in carbon emissions, as some fossil fuel use from other generation sources would be reduced. The addition of 900 MW of green energy would increase the Company's contracted renewable energy supply to approximately 6.1% from 1.3% of customer energy use.

6 Projected System Reliability, Projected System Adequacy, and Future Fuel Supply Adequacy

AEP Ohio is a member of PJM which is tasked to ensure the safety, reliability and security of the bulk electric power system. PJM has a mandatory capacity market. PJM allows an entity to either participate in a capacity auction (in which PJM functions to procure the capacity for the load obligation) or utilize the Fixed Resource Requirement (FRR) option in which the entity supplies its own capacity resource either through constructing the necessary capacity or through bilateral contracts (e.g. REPAs) with existing resources. The Reliability Assurance Agreement (RAA) sets forth the rules of participation in the PJM Capacity Market and also establishes capacity obligations of PJM Load Serving Entities (LSEs).

Given PJM's role and the Company's procurement of capacity through PJM's Base Residual Auction, rather than supplying its own capacity through Company-owned generation resources, the Company does not maintain projections regarding system reliability or system adequacy. Moreover, AEP Ohio's existing generation mix is entirely made up of REPAs. Thereby, AEP Ohio does not procure fuel supplies for its generating resources.

7 Demonstration of Cost-Effectiveness of Plan

To evaluate the economic benefits of procuring approximately 650 MW of generic Wind and Solar generation, the Company employed the Levelized Net Cost of Energy (LNCOE) metric. The Net Cost of Energy compares the estimated contract cost of the renewable resource (REPA price) and the avoided cost of energy and capacity from the market. The equation below shows how Net Cost of Energy is calculated for a given year, where Avoided Cost of Energy and Avoided Cost of Capacity are forecasted values of energy and capacity available in PJM and discussed further below.

Equation 1. Net Cost of Energy

$$Net\ Cost\ of\ Energy\ \left(\frac{\$}{MWh}\right) = REPA\ Price\ \left(\frac{\$}{MWh}\right) - \left(\frac{Avoided\ Cost\ of\ Energy\ (\$) + Avoided\ Cost\ of\ Capacity\ (\$)}{Annual\ Generation\ (MWh)}\right)$$

The generic solar and wind resources were evaluated based upon their levelized "Net Cost of Energy." In order to make a meaningful comparison of the REPA projects, the annual Net Cost of Energy values are discounted to a present value in terms of the base year, 2021, and then levelized over a 20-year period. The resulting levelized values (LNCOE) provide a uniform basis suitable for comparing the relative value of multiple bids. Key inputs to calculating LNCOE include the following:

- REPA price ($/MWh)
- Capacity Factor, which is an assumed utilization rate for each REPA project,
- PJM Energy Price ($/MWh), which is an hourly forecast of market energy prices,
- Capacity (MW), which is an assumption as to the firm capacity that each resource represents, and
- PJM Capacity Value ($/MW-day), which is a forecast of PJM capacity values. The Company utilized the 2018 Base Fundamentals Forecast as a proxy for PJM market prices.

The basis for the information used in the analysis of the net impact to AEP Ohio and its customers ("AEP Ohio Impact"), which is explained in the next section of this IRP, was informed by multiple sources including: the cost and production data received in AEP Ohio's recent 250 MW wind and 400 MW solar RFPs received in early 2018; the 2016 DOE Wind Vision Report; and the U.S. Energy Information Administration's Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook (2018). Data from these sources were used to develop generic wind and solar pricing and operational characteristics used in the IRP analysis. The AEP Ohio Impact analysis focused on the net financial position (Revenue – Cost) of AEP Ohio by adding generic renewable generation resources. In the Plan, the Company evaluated generic renewable resources consisting of 250 MW of wind and 400 MW of solar REPAs.

8 Methodology for Arriving at Plan

8.1.1 PJM LMP Impact Scenario

To develop the Plan, the Company completed four separate analyses associated with the addition of large scale renewable energy projects in Ohio. The first analysis was prepared using data developed by the AEPSC Transmission Planning department. This analysis generally quantified the impact of specific renewable projects on the PJM Locational Marginal Price (LMP), which is the price in dollars per megawatt hour ($/MWh) that AEP Ohio and other electric service providers pay to PJM for energy from the PJM system for their customers ("PJM Impact").

8.1.2 AEP Ohio Impact Scenario

The second analysis quantifies the specific net impact to AEP Ohio and its customers ("AEP Ohio Impact") from adding approximately 650 MW of generic renewable resources. This analysis calculated the change in the net present value or "NPV" of revenue requirements associated with adding generic wind and solar renewable energy projects.

8.1.3 Break Even Scenario

The third analysis calculated the break-even prices for wind and solar REPAs that would result in a $0 NPV impact.

8.1.4 Probabilistic Scenario

The fourth analysis used a probabilistic simulation technique to evaluate the likelihood that AEP Ohio customers would benefit from generic renewable energy projects. Each of these analyses concluded that the addition of renewable energy projects would be in the best interest of AEP Ohio's customers.

Table 3. AEP Ohio's Proposed Renewable Invesment Benefit Summary

ANALYSIS	RESULT
PJM LMP Impact	**Economic Benefit:** • LMP price reduction of $0.07/MWh, and • NPV savings of $31 million to AEP Ohio customers.
AEP Ohio Impact	**Economic Benefit:** • NPV benefit of $88 million from the 400 MW generic solar resources, and • NPV benefit of $54 million from the 250 MW generic wind resources.
Total Customer Benefit	PJM Benefit $31 M Solar Benefit $88 M Wind Benefit $54 M $173 M
Break-Even Analysis	Actual REPA costs lower than the REPA price noted below result in lower costs to AEP Ohio customers: • SOLAR: REPA costs below $56.82/MWh • WIND: REPA costs below $48.40/MWh
Probabilistic Simulation	• 100 % of the time solar projects result in a net benefit • 99.9% of the time wind projects show a net benefit.

8.1.5 Description of PJM LMP Impact Scenario

In the first analysis, to calculate the PJM Impact, there were two market simulation "Cases"- the Base Case and Generic REPA Case. The Base Case mimics the business as usual approach to meeting the future energy needs of the Company through PJM market purchases without a REPA. The REPA Case reflects the acquisition of REPAs for both Wind and Solar resources. To assess the LMP impact for all PJM customers buying energy in the AEP Zone, and specifically for AEP Ohio customers, the company employed the PROMOD –simulation tool that valued the Locational Marginal Price (LMP) impacts from adding approximately 600 MW of renewables into the PJM footprint. The difference between the "Cases" quantifies the savings realized through the REPA case relative to purchasing approximately 600 MW of generation from the PJM Market as represented by the base case. The PROMOD study suggests that as higher variable cost resources (e.g., gas, coal) are displaced by zero cost generation (e.g., wind, solar), LMPs would be reduced for AEP Ohio customers further supporting the need for renewable resources.

The result of this analysis as shown in Table 4 is a reduction in the cost of energy at the AEP load hub of $0.07/MWh on a levelized basis. In general, this savings would apply to any entity in PJM purchasing energy at this load hub. For example, by applying the hourly energy price savings (i.e., $0.07/MWh) to the hourly AEP Ohio load for the period 2021 through 2040, the Company calculated the NPV of the annual energy cost savings for AEP Ohio customers would be $31 million.

Table 4. PJM Impact Applied to AEP Ohio Load

AEP LMPs										
Base Load LMPs w/o Renewables					Combined Renewable Load LMPs					Change
Year	Present Value Factor	Load Cost ($Mil)	OPCo Load (GWh)	Load Energy Cost ($/MWh)	Year	Present Value Factor	Load Cost ($Mil)	OPCo Load (GWh)	Load Energy Cost ($/MWh)	Load Energy Cost ($/MWh)
2021	0.9217	$1,642	46,249	$35.51	2021	0.9217	$1,640	46,249	$35.46	-$0.05
2022	0.8495	$1,721	46,233	$37.23	2022	0.8495	$1,719	46,233	$37.19	-$0.04
2023	0.7829	$1,807	46,372	$38.97	2023	0.7829	$1,806	46,372	$38.94	-$0.03
2024	0.7216	$1,892	46,445	$40.74	2024	0.7216	$1,891	46,445	$40.72	-$0.02
2025	0.6650	$1,980	46,441	$42.63	2025	0.6650	$1,978	46,441	$42.59	-$0.03
2026	0.6129	$2,069	46,452	$44.55	2026	0.6129	$2,067	46,452	$44.50	-$0.05
2027	0.5649	$2,160	46,535	$46.41	2027	0.5649	$2,156	46,535	$46.34	-$0.07
2028	0.5207	$2,774	46,712	$59.38	2028	0.5207	$2,770	46,712	$59.30	-$0.08
2029	0.4799	$2,851	46,920	$60.76	2029	0.4799	$2,847	46,920	$60.68	-$0.09
2030	0.4423	$3,021	47,108	$64.13	2030	0.4423	$3,017	47,108	$64.04	-$0.09
2031	0.4076	$3,152	47,335	$66.58	2031	0.4076	$3,147	47,335	$66.49	-$0.09
2032	0.3757	$3,265	47,595	$68.60	2032	0.3757	$3,261	47,595	$68.51	-$0.10
2033	0.3463	$3,410	47,884	$71.21	2033	0.3463	$3,405	47,884	$71.11	-$0.10
2034	0.3191	$3,515	48,178	$72.97	2034	0.3191	$3,511	48,178	$72.87	-$0.10
2035	0.2941	$3,656	48,467	$75.44	2035	0.2941	$3,651	48,467	$75.33	-$0.11
2036	0.2711	$3,798	48,734	$77.93	2036	0.2711	$3,793	48,734	$77.82	-$0.11
2037	0.2499	$3,912	48,978	$79.87	2037	0.2499	$3,906	48,978	$79.75	-$0.11
2038	0.2303	$4,095	49,196	$83.24	2038	0.2303	$4,089	49,196	$83.12	-$0.12
2039	0.2122	$4,149	49,407	$83.97	2039	0.2122	$4,143	49,407	$83.85	-$0.12
2040	0.1956	$4,319	49,618	$87.04	2040	0.1956	$4,313	49,618	$86.92	-$0.12
NPV	9.4633	$24,274	445,395		NPV	9.4633	$24,244	445,395		
Levelized		$2,565	47,065	$54.50	Levelized		$2,562	47,065	$54.43	**-$0.07**
					NPV Change ($Mil)		($31)			

8.1.6 Description of AEP Ohio Impact Scenario

The following three analyses calculated the benefit of the wind and solar projects independently. The "AEP Ohio Impact" analysis shows that the 650 MW of generic renewable projects that go in service by 2021 will result in a reduction of costs to customers (on an NPV basis) over the term of the REPA. Specifically, the NPV benefit from the 400 MW generic solar resources would be $88.0 million (Table 5), and from the 250 MW generic wind resources would be $54.0 million (Table 6). On a LNCOE basis, the solar project results in a $11.82/MWh reduction in cost, and the wind project results in a $8.40/MWh reduction in cost.

Table 5. Generic Solar REPA Benefits

Net Cost of Energy
Generic Solar (400 MW)
2021 - 2040

A	B	C	D	E	F	G	H	I	J	K	L	M	N
		REPA Cost					Avoided Energy Cost		Avoided Capacity Cost				
Year	Present Value Factor	Capacity (Nameplate)	Solar Energy	Capacity Factor	Solar Energy Cost	Solar Total Cost	Solar Energy Priced at Market	Avoided Cost of Energy	Capacity Price	Solar Capacity Credit	Solar Capacity Credit Value	Total Change in Net Revenue Requirement	Net Cost of Energy
		(MW)	(GWh)	(%)	($/MWh)	($M)	($/MWh)	($M)	($/MW-Day)	(MW)	($M)	($M)	($/MWh)
2021	0.9217	400	813.9	23.2%	45.00	36.6	37.8	(30.8)	50.8	76.0	(1.4)	4.4	5.46
2022	0.8495	400	809.9	23.1%	45.00	36.4	39.2	(31.7)	30.1	76.0	(0.8)	3.9	4.77
2023	0.7829	400	805.8	23.0%	45.00	36.3	40.5	(32.7)	44.2	76.0	(1.2)	2.4	2.95
2024	0.7216	400	803.3	22.9%	45.00	36.2	41.8	(33.6)	58.7	76.0	(1.6)	0.9	1.18
2025	0.6650	400	797.8	22.8%	45.00	35.9	43.0	(34.3)	73.6	76.0	(2.0)	(0.5)	(0.60)
2026	0.6129	400	793.8	22.7%	45.00	35.7	44.0	(34.9)	88.9	76.0	(2.5)	(1.7)	(2.09)
2027	0.5649	400	789.8	22.5%	45.00	35.5	44.6	(35.2)	104.7	76.0	(2.9)	(2.6)	(3.29)
2028	0.5207	400	787.4	22.4%	45.00	35.4	55.6	(43.8)	120.9	76.0	(3.4)	(11.7)	(14.86)
2029	0.4799	400	781.9	22.3%	45.00	35.2	57.2	(44.7)	137.6	76.0	(3.8)	(13.3)	(17.04)
2030	0.4423	400	778.0	22.2%	45.00	35.0	60.7	(47.2)	154.8	76.0	(4.3)	(16.5)	(21.23)
2031	0.4076	400	774.1	22.1%	45.00	34.8	62.7	(48.6)	172.2	76.0	(4.8)	(18.5)	(23.90)
2032	0.3757	400	771.8	22.0%	45.00	34.7	64.9	(50.1)	190.1	76.0	(5.3)	(20.6)	(26.69)
2033	0.3463	400	766.4	21.9%	45.00	34.5	66.5	(51.0)	208.5	76.0	(5.8)	(22.3)	(29.09)
2034	0.3191	400	762.6	21.8%	45.00	34.3	68.1	(52.0)	227.3	76.0	(6.3)	(24.0)	(31.44)
2035	0.2941	400	758.8	21.7%	45.00	34.1	70.8	(53.7)	246.5	76.0	(6.8)	(26.4)	(34.83)
2036	0.2711	400	756.5	21.5%	45.00	34.0	72.2	(54.6)	266.3	76.0	(7.4)	(28.0)	(36.99)
2037	0.2499	400	751.2	21.4%	45.00	33.8	74.2	(55.7)	286.5	76.0	(7.9)	(29.9)	(39.78)
2038	0.2303	400	747.4	21.3%	45.00	33.6	78.0	(58.3)	307.1	76.0	(8.5)	(33.2)	(44.48)
2039	0.2122	400	743.7	21.2%	45.00	33.5	78.1	(58.1)	328.6	76.0	(9.1)	(33.7)	(45.34)
2040	0.1956	400	741.4	21.1%	45.00	33.4	80.7	(59.8)	350.6	76.0	(9.7)	(36.2)	(48.77)
Present Worth	9.4633					335.1		(389.2)			(33.9)	(88.0)	
Levelized			786.9	22.4%	45.00	35.4	52.3	(41.1)	129.0	76.0	(3.6)	(9.3)	(11.82)

Column Definitions:

B. Present valued to 2021 at 8.5% discount rate.
C. Total nameplate capacity of the REPA.
D. Total estimated energy output of the REPA.
E. Estimated annual capacity factor based on estimated energy, nameplate capacity and hours per year.
F. Projected annual total cost per MWh inclusive of return and ITC.
G. Projected annual total cost = D x F/1000.
H. Weighted average of hourly market price of energy displaced by hourly incremental REPA purchase.
I. Change in revenue requirement due to solar energy impact on market sales/purchases (Column D x Column H ÷ 1000).
J. Based on 2018 H2 AEP Fundamental Forecast - Base Case
K. Based on 5 percent (wind) or 19 per cent (solar) PJM Capacity Credit.
L. Column J x Column K x 365 ÷ 1,000,000. Adjusted for leap years
M. Total Change in Net Revenue Requirement is the sum of columns G, I, & L.
N. The net cost of energy for the REPA, Column O x 1000 ÷ Column D

Table 6. Wind Generic REPA Benefits

Net Cost of Energy
Generic Wind (250 MW)
2021 - 2040

A	B	C	D	E	F	G	H	I	J	K	L	M	N
		REPA Cost					Avoided Energy Cost		Avoided Capacity Cost				
Year	Present Value Factor	Capacity (Nameplate)	Wind Energy	Capacity Factor	Wind Energy Cost	Wind Total Cost	Wind Energy Priced at Market	Avoided Cost of Energy	Capacity Price	Wind Capacity Credit	Wind Capacity Credit Value	Total Change in Net Revenue Requirement	Net Cost of Energy
		(MW)	(GWh)	(%)	($/MWh)	($M)	($/MWh)	($M)	($/MW-Day)	(MW)	($M)	($M)	($/MWh)
2021	0.9217	250	678.9	31.0%	40.00	27.2	34.1	(23.2)	50.8	12.5	(0.2)	3.7	5.51
2022	0.8495	250	678.9	31.0%	40.00	27.2	35.2	(23.9)	30.1	12.5	(0.1)	3.2	4.65
2023	0.7829	250	678.9	31.0%	40.00	27.2	36.2	(24.6)	44.2	12.5	(0.2)	2.4	3.46
2024	0.7216	250	680.8	31.0%	40.00	27.2	37.5	(25.5)	58.7	12.5	(0.3)	1.4	2.11
2025	0.6650	250	678.9	31.0%	40.00	27.2	38.7	(26.3)	73.6	12.5	(0.3)	0.6	0.82
2026	0.6129	250	678.9	31.0%	40.00	27.2	39.0	(26.5)	88.9	12.5	(0.4)	0.3	0.40
2027	0.5649	250	678.9	31.0%	40.00	27.2	40.1	(27.2)	104.7	12.5	(0.5)	(0.5)	(0.77)
2028	0.5207	250	680.8	31.0%	40.00	27.2	50.9	(34.6)	120.9	12.5	(0.6)	(7.9)	(11.68)
2029	0.4799	250	678.9	31.0%	40.00	27.2	51.7	(35.1)	137.6	12.5	(0.6)	(8.6)	(12.61)
2030	0.4423	250	678.9	31.0%	40.00	27.2	54.8	(37.2)	154.8	12.5	(0.7)	(10.8)	(15.87)
2031	0.4076	250	678.9	31.0%	40.00	27.2	56.8	(38.6)	172.2	12.5	(0.8)	(12.2)	(18.00)
2032	0.3757	250	680.8	31.0%	40.00	27.2	58.2	(39.6)	190.1	12.5	(0.9)	(13.3)	(19.50)
2033	0.3463	250	678.9	31.0%	40.00	27.2	60.1	(40.8)	208.5	12.5	(1.0)	(14.6)	(21.54)
2034	0.3191	250	678.9	31.0%	40.00	27.2	61.9	(42.0)	227.3	12.5	(1.0)	(15.9)	(23.39)
2035	0.2941	250	678.9	31.0%	40.00	27.2	63.8	(43.3)	246.5	12.5	(1.1)	(17.3)	(25.50)
2036	0.2711	250	680.8	31.0%	40.00	27.2	66.4	(45.2)	266.3	12.5	(1.2)	(19.2)	(28.22)
2037	0.2499	250	678.9	31.0%	40.00	27.2	67.6	(45.9)	286.5	12.5	(1.3)	(20.0)	(29.51)
2038	0.2303	250	678.9	31.0%	40.00	27.2	70.4	(47.8)	307.1	12.5	(1.4)	(22.0)	(32.47)
2039	0.2122	250	678.9	31.0%	40.00	27.2	71.7	(48.7)	328.6	12.5	(1.5)	(23.0)	(33.94)
2040	0.1956	250	680.8	31.0%	40.00	27.2	74.1	(50.5)	350.6	12.5	(1.6)	(24.8)	(36.45)
Present Worth	9.4633					257.1		(305.6)			(5.6)	(54.0)	
Levelized			679.3	31.0%	40.00	27.2	47.5	(32.3)	129.0	12.5	(0.6)	(5.7)	(8.40)

Column Definitions:

B. Present valued to 2021 at 8.5% discount rate.
C. Total nameplate capacity of the REPA.
D. Total estimated energy output of the REPA.
E. Estimated annual capacity factor based on estimated energy, nameplate capacity and hours per year.
F. Projected annual total cost per MWh inclusive of return and ITC.
G. Projected annual total cost = D x F/1000.
H. Weighted average of hourly market price of energy displaced by hourly incremental REPA purchase.
I. Change in revenue requirement due to wind energy impact on market sales/purchases (Column D x Column H ÷ 1000).
J. Based on 2018 H2 AEP Fundamental Forecast - Base Case
K. Based on 5 percent (wind) or 19 per cent (solar) PJM Capacity Credit.
L. Column J x Column K x 365 ÷ 1,000,000. Adjusted for leap years
M. Total Change in Net Revenue Requirement is the sum of columns G, I, & L.
N. The net cost of energy for the REPA, Column O x 1000 ÷ Column D

8.1.7 Description of Break-Even Analysis

In the break-even analysis, a REPA price was derived that yielded a $0/MWh LNCOE price or $0 Net Present Value (NPV). For a 400 MW fixed price solar REPA with operational characteristics similar to those in the generic solar case, a price of $56.82/MWh would result in $0 NPV (and $0/MWh LNCOE) (Table 6). For wind projects with operational characteristics similar to those in the generic wind case, a 250 MW fixed price wind REPA at $48.40/MWh results in $0 NPV (and $0/MWh LNCOE) (Table 7). Therefore, REPAs with costs lower than these respective break-even prices are worth considering as future AEP Ohio resources.

Table 7. Break Even Solar Analysis

Net Cost of Energy
Generic Solar (400 MW)
2021 - 2040

A	B	C	D	E	F	G	H	I	J	K	L	M	N
		REPA Cost					Avoided Energy Cost		Avoided Capacity Cost				
Year	Present Value Factor	Capacity (Nameplate)	Solar Energy	Capacity Factor	Solar Energy Cost	Solar Total Cost	Solar Energy Priced at Market	Avoided Cost of Energy	Capacity Price	Solar Capacity Credit	Solar Capacity Credit Value	Total Change in Net Revenue Requirement	Net Cost of Energy
		(MW)	(GWh)	(%)	($/MWh)	($M)	($/MWh)	($M)	($/MW-Day)	(MW)	($M)	($M)	($/MWh)
2021	0.9217	400	813.9	23.2%	56.82	46.2	37.8	(30.8)	50.8	76.0	(1.4)	14.1	17.29
2022	0.8495	400	809.9	23.1%	56.82	46.0	39.2	(31.7)	30.1	76.0	(0.8)	13.4	16.59
2023	0.7829	400	805.8	23.0%	56.82	45.8	40.5	(32.7)	44.2	76.0	(1.2)	11.9	14.77
2024	0.7216	400	803.3	22.9%	56.82	45.6	41.8	(33.6)	58.7	76.0	(1.6)	10.4	13.00
2025	0.6650	400	797.8	22.8%	56.82	45.3	43.0	(34.3)	73.6	76.0	(2.0)	9.0	11.23
2026	0.6129	400	793.8	22.7%	56.82	45.1	44.0	(34.9)	88.9	76.0	(2.5)	7.7	9.73
2027	0.5649	400	789.8	22.5%	56.82	44.9	44.6	(35.2)	104.7	76.0	(2.9)	6.7	8.53
2028	0.5207	400	787.4	22.4%	56.82	44.7	55.6	(43.8)	120.9	76.0	(3.4)	(2.4)	(3.03)
2029	0.4799	400	781.9	22.3%	56.82	44.4	57.2	(44.7)	137.6	76.0	(3.8)	(4.1)	(5.22)
2030	0.4423	400	778.0	22.2%	56.82	44.2	60.7	(47.2)	154.8	76.0	(4.3)	(7.3)	(9.41)
2031	0.4076	400	774.1	22.1%	56.82	44.0	62.7	(48.6)	172.2	76.0	(4.8)	(9.4)	(12.08)
2032	0.3757	400	771.8	22.0%	56.82	43.9	64.9	(50.1)	190.1	76.0	(5.3)	(11.5)	(14.87)
2033	0.3463	400	766.4	21.9%	56.82	43.5	66.5	(51.0)	208.5	76.0	(5.8)	(13.2)	(17.27)
2034	0.3191	400	762.6	21.8%	56.82	43.3	68.1	(52.0)	227.3	76.0	(6.3)	(15.0)	(19.62)
2035	0.2941	400	758.8	21.7%	56.82	43.1	70.8	(53.7)	246.5	76.0	(6.8)	(17.5)	(23.01)
2036	0.2711	400	756.5	21.5%	56.82	43.0	72.2	(54.6)	266.3	76.0	(7.4)	(19.0)	(25.16)
2037	0.2499	400	751.2	21.4%	56.82	42.7	74.2	(55.7)	286.5	76.0	(7.9)	(21.0)	(27.95)
2038	0.2303	400	747.4	21.3%	56.82	42.5	78.0	(58.3)	307.1	76.0	(8.5)	(24.4)	(32.66)
2039	0.2122	400	743.7	21.2%	56.82	42.3	78.1	(58.1)	328.6	76.0	(9.1)	(24.9)	(33.52)
2040	0.1956	400	741.4	21.1%	56.82	42.1	80.7	(59.8)	350.6	76.0	(9.7)	(27.4)	(36.94)
Present Worth	9.4633					423.1		(389.2)			(33.9)	0.0	
Levelized			786.9	22.4%	56.82	44.7	52.3	(41.1)	129.0	76.0	(3.6)	0.0	0.00

Column Definitions:

B. Present valued to 2021 at 8.5% discount rate.
C. Total nameplate capacity of the REPA.
D. Total estimated energy output of the REPA.
E. Estimated annual capacity factor based on estimated energy, nameplate capacity and hours per year.
F. Projected annual total cost per MWh inclusive of return and ITC.
G. Projected annual total cost = D x F/1000.
H. Weighted average of hourly market price of energy displaced by hourly incremental REPA purchase.
I. Change in revenue requirement due to solar energy impact on market sales/purchases (Column D x Column H ÷ 1000).
J. Based on 2018 H2 AEP Fundamental Forecast - Base Case
K. Based on 5 percent (wind) or 19 per cent (solar) PJM Capacity Credit.
L. Column J x Column K x 365 ÷ 1,000,000. Adjusted for leap years
M. Total Change in Net Revenue Requirement is the sum of columns G, I, & L.
N. The net cost of energy for the REPA, Column O x 1000 ÷ Column D

Table 8. Break Even Wind Analysis

Net Cost of Energy
Break Even Generic Wind (250 MW)
2021 - 2040

A	B	C	D	E	F	G	H	I	J	K	L	M	N
		REPA Cost					Avoided Energy Cost		Avoided Capacity Cost				
Year	Present Value Factor	Capacity (Nameplate)	Wind Energy	Capacity Factor	Wind Energy Cost	Wind Total Cost	Wind Energy Priced at Market	Avoided Cost of Energy	Capacity Price	Wind Capacity Credit	Wind Capacity Credit Value	Total Change in Net Revenue Requirement	Net Cost of Energy
		(MW)	(GWh)	(%)	($/MWh)	($M)	($/MWh)	($M)	($/MW-Day)	(MW)	($M)	($M)	($/MWh)
2021	0.9217	250	678.9	31.0%	48.40	32.9	34.1	(23.2)	50.8	12.5	(0.2)	9.4	13.91
2022	0.8495	250	678.9	31.0%	48.40	32.9	35.2	(23.9)	30.1	12.5	(0.1)	8.9	13.05
2023	0.7829	250	678.9	31.0%	48.40	32.9	36.2	(24.6)	44.2	12.5	(0.2)	8.1	11.86
2024	0.7216	250	680.8	31.0%	48.40	33.0	37.5	(25.5)	58.7	12.5	(0.3)	7.2	10.51
2025	0.6650	250	678.9	31.0%	48.40	32.9	38.7	(26.3)	73.6	12.5	(0.3)	6.3	9.22
2026	0.6129	250	678.9	31.0%	48.40	32.9	39.0	(26.5)	88.9	12.5	(0.4)	6.0	8.80
2027	0.5649	250	678.9	31.0%	48.40	32.9	40.1	(27.2)	104.7	12.5	(0.5)	5.2	7.63
2028	0.5207	250	680.8	31.0%	48.40	33.0	50.9	(34.6)	120.9	12.5	(0.6)	(2.2)	(3.28)
2029	0.4799	250	678.9	31.0%	48.40	32.9	51.7	(35.1)	137.6	12.5	(0.6)	(2.9)	(4.21)
2030	0.4423	250	678.9	31.0%	48.40	32.9	54.8	(37.2)	154.8	12.5	(0.7)	(5.1)	(7.47)
2031	0.4076	250	678.9	31.0%	48.40	32.9	56.8	(38.6)	172.2	12.5	(0.8)	(6.5)	(9.60)
2032	0.3757	250	680.8	31.0%	48.40	33.0	58.2	(39.6)	190.1	12.5	(0.9)	(7.6)	(11.10)
2033	0.3463	250	678.9	31.0%	48.40	32.9	60.1	(40.8)	208.5	12.5	(1.0)	(8.9)	(13.14)
2034	0.3191	250	678.9	31.0%	48.40	32.9	61.9	(42.0)	227.3	12.5	(1.0)	(10.2)	(14.99)
2035	0.2941	250	678.9	31.0%	48.40	32.9	63.8	(43.3)	246.5	12.5	(1.1)	(11.6)	(17.10)
2036	0.2711	250	680.8	31.0%	48.40	33.0	66.4	(45.2)	266.3	12.5	(1.2)	(13.5)	(19.82)
2037	0.2499	250	678.9	31.0%	48.40	32.9	67.6	(45.9)	286.5	12.5	(1.3)	(14.3)	(21.11)
2038	0.2303	250	678.9	31.0%	48.40	32.9	70.4	(47.8)	307.1	12.5	(1.4)	(16.3)	(24.07)
2039	0.2122	250	678.9	31.0%	48.40	32.9	71.7	(48.7)	328.6	12.5	(1.5)	(17.3)	(25.54)
2040	0.1956	250	680.8	31.0%	48.40	33.0	74.1	(50.5)	350.6	12.5	(1.6)	(19.1)	(28.05)
Present Worth	9.4633					311.1		(305.6)			(5.6)	0.0	
Levelized			679.3	31.0%	48.40	32.9	47.5	(32.3)	129.0	12.5	(0.6)	0.0	0.00

Column Definitions:

B. Present valued to 2021 at 8.5% discount rate.
C. Total nameplate capacity of the REPA.
D. Total estimated energy output of the REPA.
E. Estimated annual capacity factor based on estimated energy, nameplate capacity and hours per year.
F. Projected annual total cost per MWh inclusive of return and ITC.
G. Projected annual total cost = D x F/1000.
H. Weighted average of hourly market price of energy displaced by hourly incremental REPA purchase.
I. Change in revenue requirement due to wind energy impact on market sales/purchases (Column D x Column H ÷ 1000).
J. Based on 2018 H2 AEP Fundamental Forecast - Base Case
K. Based on 5 percent (wind) or 19 per cent (solar) PJM Capacity Credit.
L. Column J x Column K x 365 ÷ 1,000,000. Adjusted for leap years
M. Total Change in Net Revenue Requirement is the sum of columns G, I, & L.
N. The net cost of energy for the REPA, Column O x 1000 ÷ Column D

8.1.8 Description of the Probablistic Scenario

The probabilistic simulation or "Risk Analysis" underscores the overall profitability of the Resource Plan under 1,000 possible LNCOE data points, highlighting the benefits to customers. Results suggest 100 % of the time, solar projects will realize a net benefit (Figure 4), and 99.9% of the time wind projects show a net benefit (Figure 5).

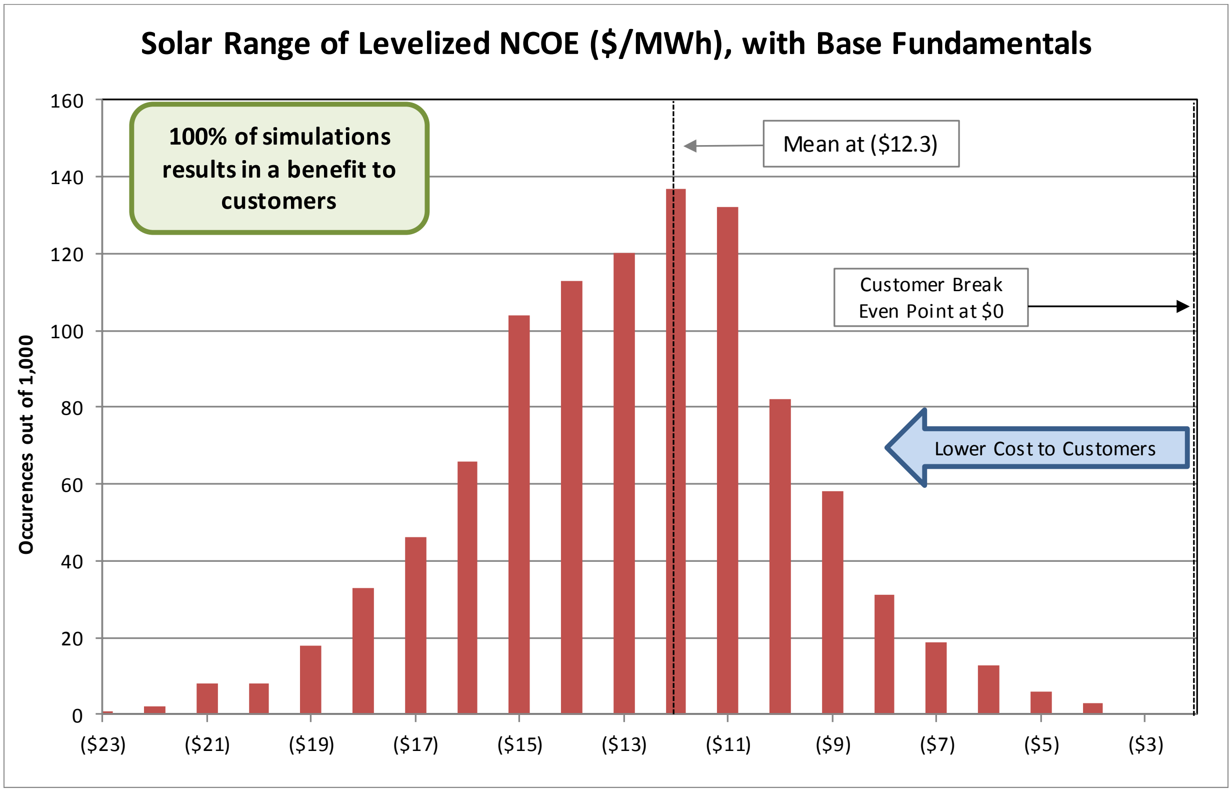

Figure 4. Probabilistic Simulation Results for Solar

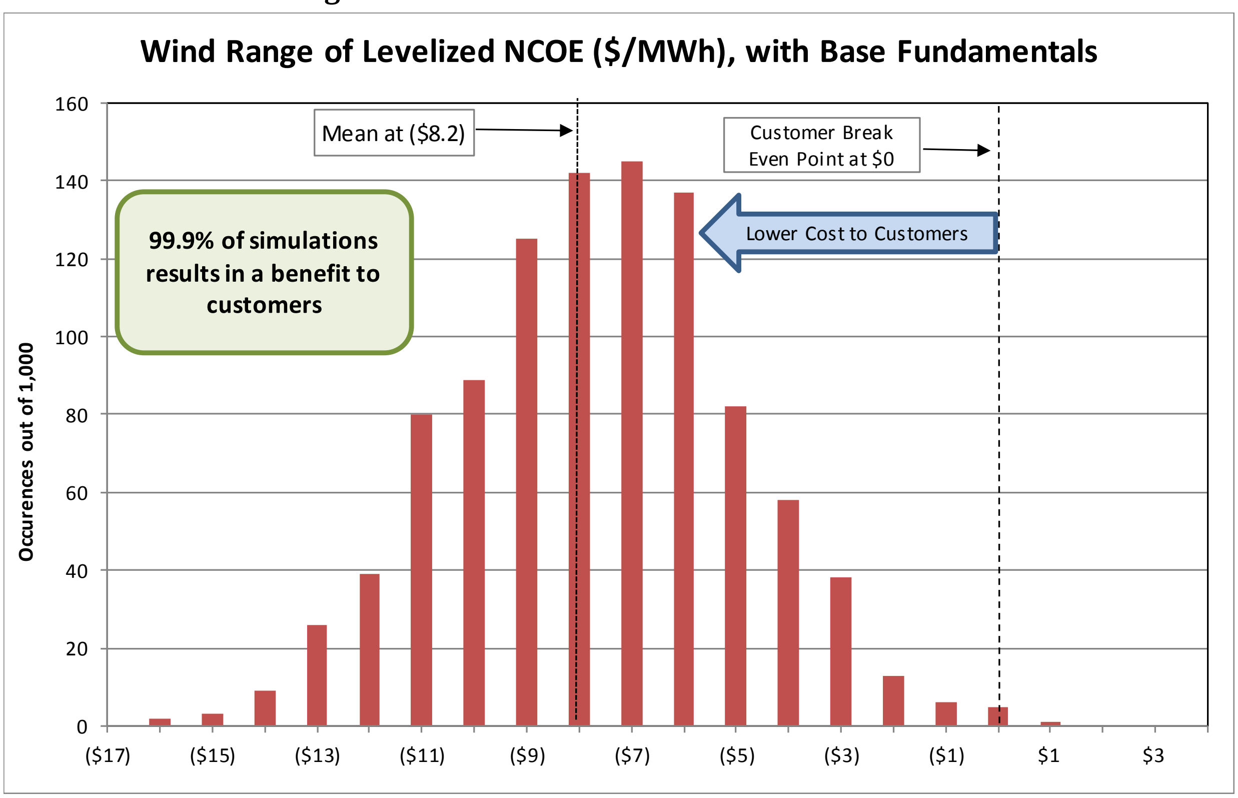

Figure 5. Probabilistic Simulation Results for Wind

Each of these four analyses show the benefit of adding renewable energy projects to AEP Ohio's resource portfolio. Renewable energy projects with characteristics similar to the generic projects modeled for this IRP would result in lower costs to customers over the project life cycles, provide a hedge against market volatility, and divesify AEP Ohio's resource mix. While the analyses performed were representative of the amount of capacity requested in AEP Ohio's RFP, additional projects are identified with similar operating characteristics and below the break-even costs, those projects should be considered by AEP Ohio as well.

9 Resource Forms

9.1.1 Long-Term Forcast Reports (LTFR)

On April 16, 2018 AEP Ohio submitted the Long-Term Forecast Reports (LTFR) forms pursuant to Section 4935.04 Ohio Revised Code.

10 Integrated Resource Plan Conclusion

Emission-free forms of generation continue to outpace investment in electricity from coal, gas, and nuclear power plants. The Company's resource planning analysis reflects the need to develop renewable generation in Ohio. The key findings of the study identified approximately $173 million in net benefits attributed to AEP Ohio customers through Renewable Energy Purchase Agreements. Producing clean energy in Ohio minimizes our reliance on out-of-state generation.

11 Load Forecast and Forecasting Methodology

11.1.1 Summary of AEP Ohio Load Forecast

The Ohio Power Company ("AEP Ohio" or the "Company") load forecast was developed by the American Electric Power Service Corporation (AEPSC) Economic Forecasting organization and completed in June 2017. 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 10 year period (2018-2028), AEP Ohio's service territory is expected to see population and non-farm employment growth of 0.4% and 0.8% per year, respectively. AEP Ohio is projected to see customer count growth of 0.2% per year over this period. Over the same forecast period, AEP Ohio's retail energy is projected to grow at 0.1% per year with stronger growth expected from the commercial and industrial classes (+0.3% and +0.2% per year, respectively) while the residential class experiences a slight decline over the forecast horizon. Finally, AEP Ohio's internal energy and peak demand are both expected to change at an average rate of -0.1% per year through 2028.

11.1.2 Forecast Assumptions

11.1.3 Economic Assumptions

The load forecasts for AEP Ohio and the other operating companies in the AEP System incorporate a forecast of U.S. and regional economic growth provided by Moody's Analytics. The load forecasts utilized Moody's Analytics economic forecast issued in November 2016. Moody's Analytics projects moderate growth in the U.S. economy during the 2018-2028 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 1.5% per year during the same period. Moody's projects employment growth of 0.8% per year during the forecast period and real regional income per-capita annual growth of 1.9% for the AEP Ohio service area.

11.1.4 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.

11.1.5 Specific Large Customer Assumptions

AEP Ohio'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.

11.1.6 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.

11.1.7 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.

11.1.8 Overview of Forecast Methodology

AEP Ohio'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.

AEP Ohio 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 AEP Ohio'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 1, below.

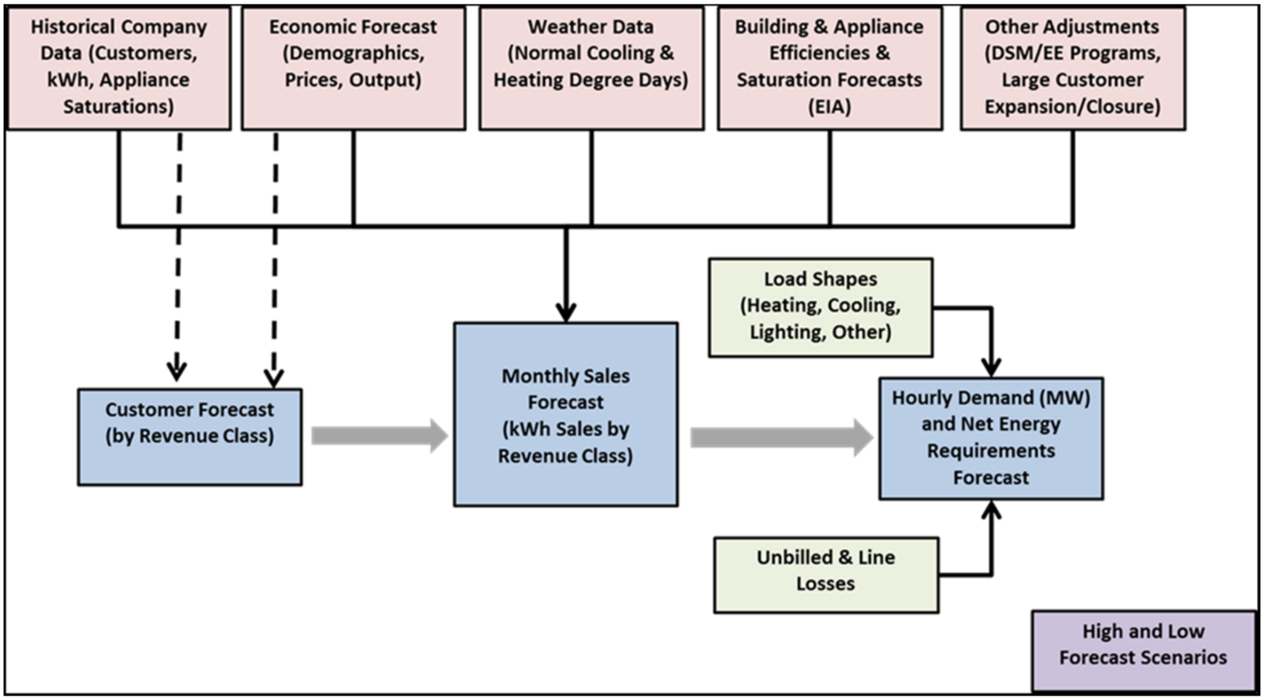

Figure 6. AEP Ohio Internal Energy Requirements and Peak Demand Forecasting Method

11.1.9 Detailed Explanation of Load Forecast

11.1.10 General

This section provides a more detailed description of the short-term and long-term models employed in producing the forecasts of AEP Ohio'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.

11.1.11 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 customer forecasting models are also monthly but extend for 30 years. The explanatory jurisdictional economic and demographic variables include gross regional product, employment, 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.

11.1.12 Short-term Forecasting Models

The goal of AEP Ohio'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 historical Columbus Southern Power and Ohio Power service areas of the Company. The estimation period for the short-term models was January 2007 through January 2017. There are models for residential, commercial, industrial, other retail, and wholesale sectors. The industrial models are comprised of 21 large industrial models and models for the remainder of the industrial sector. The wholesale forecast is developed using a model for the Ohio Edison load served by the Company.

11.1.13 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 AEP Ohio 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 1995-2016 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.

11.1.14 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 Company's historical Columbus Southern and Ohio Power service areas. These models are discussed below.

11.1.15 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 the 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 "2017 Annual Energy Outlook." The natural gas price model is based upon 1980-2016 historical data.

11.1.16 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 Northern 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 "2017 Annual Energy Outlook." The estimation period for the model was 1998-2016.

11.1.17 Residential Energy Sales

Residential energy sales for AEP Ohio 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 2017. It is important to note, as will be discussed later, that this modeling *has* incorporated the reductive effects of the EPAct, EISA, American Recovery and Reinvestment Act of 2009 (ARRA) and Energy Improvement and Extension Act of 2008 (EIEA2008) on the residential (and commercial) energy usage based on analysis by the EIA regarding appliance efficiency trends.

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

Separate residential SAE models are estimated for the Company's historical Columbus Southern and Ohio Power jurisdictions.

11.1.18 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.

11.1.19 Industrial Energy Sales

The Company's industrial energy is modeled by manufacturing sector, mine power sector and associated companies sectors.

11.1.20 Manufacturing Energy Sales

The Company uses some combination of the following economic and pricing explanatory variables: service area gross regional product manufacturing, Federal Reserve Board (FRB) industrial production indexes, service area industrial electricity prices and service area manufacturing employment. 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 historical Columbus Southern and Ohio Power jurisdictions. The last actual data point for the industrial energy sales models is January 2017.

11.1.21 Mine Power and Associated Companies Energy Sales

For its mine power energy sales models, the Company uses the following economic and pricing explanatory variables: 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. A mine power model is estimated for the Company's historical Ohio Power jurisdiction. The associated companies' sales are estimated for the Companies historical Columbus Southern and Ohio Power jurisdictions. The last actual data point for the industrial energy sales models is January 2017.

11.1.22 All Other Energy Sales

The forecast of other retail load relates energy sales to service area employment and binary variables. Wholesale energy sales are estimated based on recent activity by the customer.

11.1.23 Internal Energy Forecast

11.1.24 Blending Short and Long-Term Sales

Forecast values for 2017 and 2018 are taken from the short-term process. Forecast values for 2019 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 2019 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.

11.1.25 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.

11.1.26 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 AEP Ohio 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).

11.1.27 Load Forecast Results and Issues

11.1.28 Load Forecast

The Company's load forecast was provided on Forms FE-D1 through FE-D6 in Company's 2018 Long-Term Forecast Report to Public Utilities Commission of Ohio filed in this docket on April 16, 2018.

11.1.29 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.

12 Load Forecast Trends & Issues

12.1.1 Changing Usage Patterns

Over the past decade, there has been a significant change in the trend for electricity usage from prior decades. Below presents AEP Ohio's historical and forecasted residential and commercial usage per customer between 1991 and 2025. During the first decade shown (1991-2000), residential usage per customer grew at an average rate of 0.7% per year while the commercial usage also grew by 0.7% per year. Over the next decade (2001-2010), growth in residential usage growth was at 0.6% per year while the commercial class usage increased by 0.3% per year. In the last decade shown (2011-2020) residential usage is projected to decline at a rate of 1.0% per year while the commercial usage decreases by an average of 0.1% per year. It is worth noting that the decline in residential and commercial usage accelerated between 2008 and 2017, with usage declining at average annual rates of 0.9% and 0.6% for residential and commercial sectors, respectively, over that period.

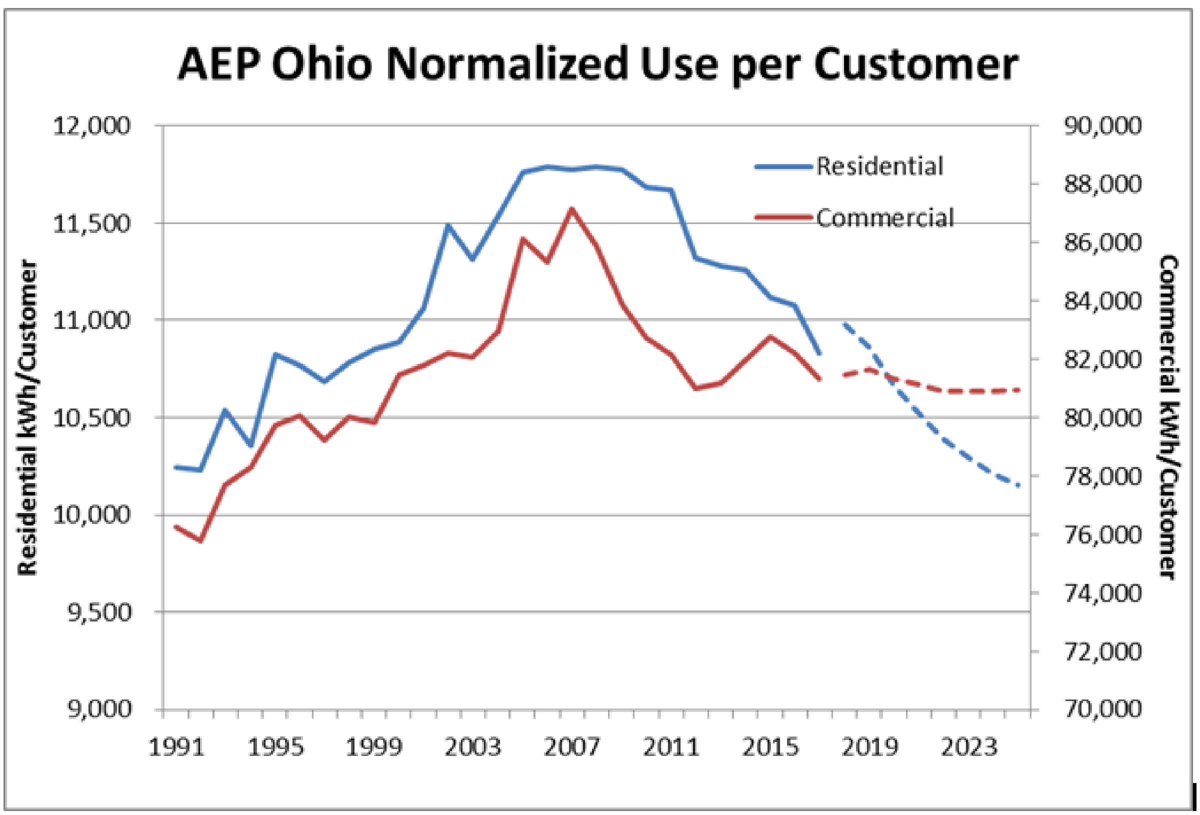

Figure 7. AEP Ohio Normalized Use Per Customer

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, 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 11.6 in 2010 to nearly 13.6 by 2030. The chart shows a similar trend in projected cooling efficiencies for heat pump cooling as well as room air conditioning units show similar improvements in the efficiencies of lighting and clothes washers over the same period.

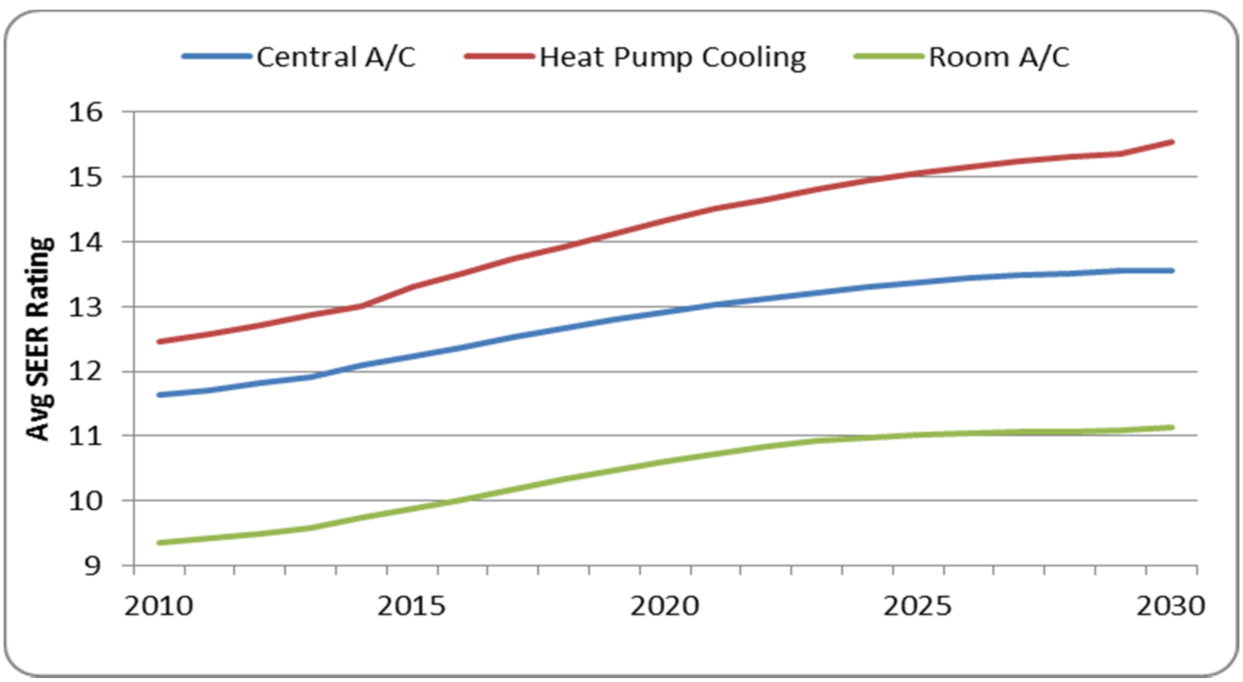

Figure 8. Projected Changes in Cooling Efficiencies, 2010-2030

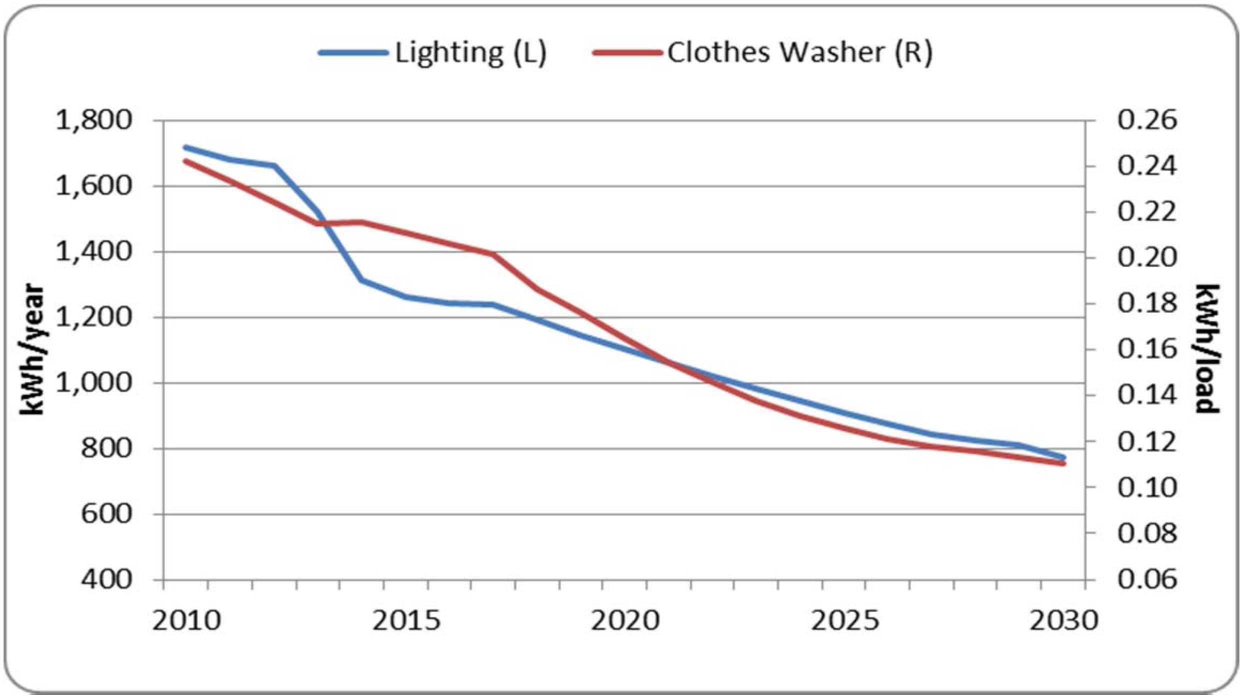

Figure 9. Projected Changes in Lighting and Clothes Washer Efficiencies, 2010-2030

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

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

For the near term horizon (through 2021), the load forecast uses assumptions from the latest commission approved DSM programs,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. Forms FE-D1 and FE-D3 provide the DSM/EE impacts incorporated in AEP Ohio’s load forecast provided in the Company’s 2018 Long-Term Forecast Report. Annual energy and seasonal peak demand impacts for the Company are provided on Form FE-D1 and FE-D3, respectively.

The commercial and industrial programs included in the DSM/EE forecast are Prescriptive Lighting, Custom Program, and New Construction. The residential programs in the DSM/EE forecast are Efficient Products Program, Appliance Recycling Program, Behavior Change, Retrofit, New Construction, E3Smart, and Community Assistance. Other DSM/EE efforts include Self Direct, Express Install, and Internal Facility/Other activities

12.1.3 Interruptible Load

The Company has one custome with 3MW available for interruption in emergency situations in Demand Response (DR) agreements. The load forecast does not reflect any load reductions for this customer. The commercial and industrial programs included in the DSM/EE forecast are Prescriptive Lighting, Custom Program, and New Construction. The residential programs in the DSM/EE forecast are Efficient Products Program, Appliance Recycling Program, Behavior Change, Retrofit, New Construction, E3Smart, and Community Assistance. Other DSM/EE efforts include Self Direct, Express Install, and Internal Facility/Other activities

12.1.4 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. The industrial forecast for the historical Ohio Power jurisdiction was blended and the remainder of the forecasts uses the long-term model results. In addition, the wholesale forecast utilizes the long-term model results.

In general, forecast values for the year 2018 were typically taken from the short-term process. Forecast values for 2019 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 2019 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 illustrates a hypothetical example of the blending process. However, in the final review of the blended forecast, there may be instances where the short-term and long-term forecasts diverge especially when the long-term forecast incorporates a structural shift in the economy that is not included in the short-term models. In these instances, professional judgment is used to develop the most reasonable forecast.

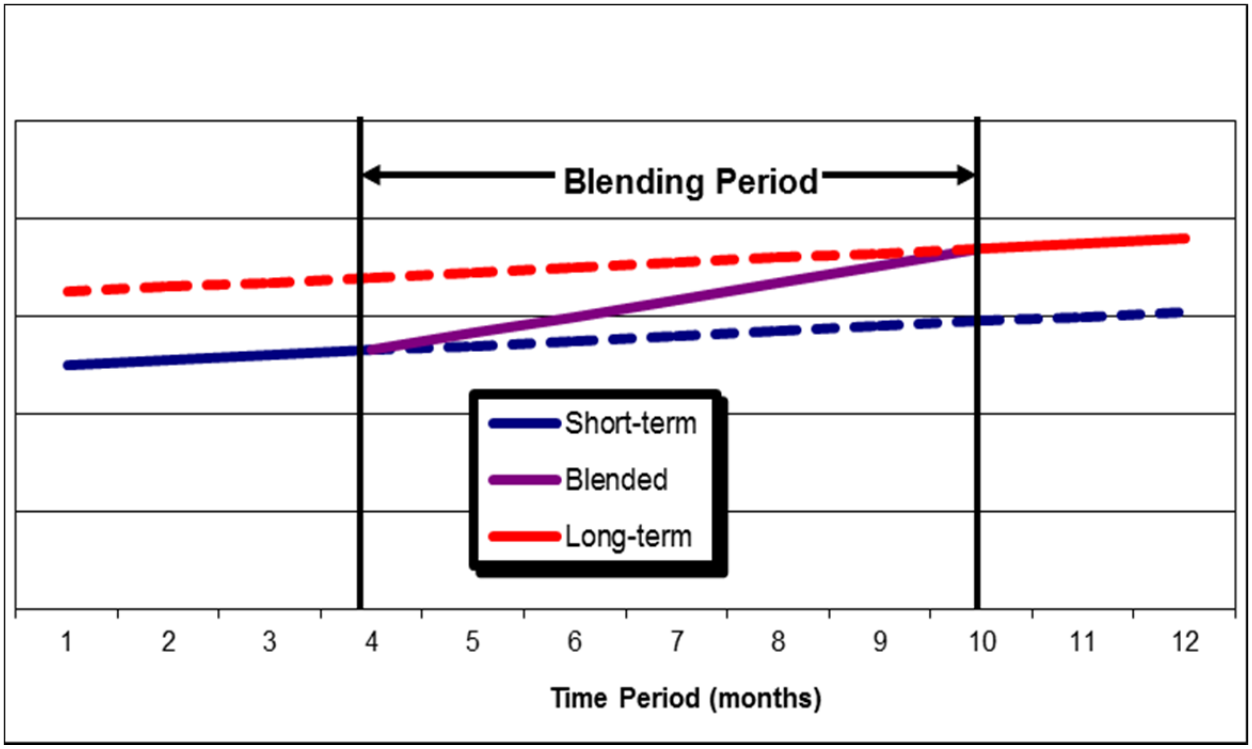

Figure 10. Load Forecast Blending Illustration

12.1.5 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.

12.1.6 Wholesale Customer Contracts

Company representatives are in continual contact with wholesale customer representatives about their contractual needs.

12.1.7 Customer Surveys

A residential customer survey was last conducted in the winter of 2016 in which data on end-use appliance penetration and end-use saturation rates were obtained. Beginning in 1980, in intervals of approximately three years, the Company has regularly surveyed residential customers to monitor customers' demographic characteristics, appliance ownership, penetration of new energy use products and services, and conservation efforts.

The Company has no proposed schedule for industrial and/or commercial customer surveys to obtain end-use information in the near future. AEP Ohio monitors its industrial and commercial (and residential) customer end-use consumption patterns through its ongoing load research program.

12.1.8 Price Elasticity

In every load forecast, AEP Ohio takes electricity price and the effects of its changes into consideration. This is true for the forecast included in this IRP. The following provides a discussion of the impacts of prices on electricity sales and how price is accounted for in the load forecast.

An understanding of the relationship between energy prices and energy consumption is fundamental to developing a forecast of electricity consumption. In theory, the effect of a change in the price of a good on the consumption of that good can be disaggregated into two effects, the "income" effect and the "substitution" effect. The income effect refers to the change in consumption of a good attributable to the change in real income incident to the change in the price of that good. For most goods, a decline in real income would induce a decline in consumption. The substitution effect refers to the change in the consumption of a good associated with the change in the price of that good relative to the prices of all other goods. The substitution effect is assumed to be negative in all cases; that is, a rise in the price of a good relative to other, substitute goods would induce a decline in consumption of the original good. Thus, if the price of electricity were to rise, the consumption of electricity would fall, all other things being equal. Part of the decline would be attributable to the income effect; consumers must make decisions on how to allocate their budget to purchase electricity services and other goods and services after the price of electricity rises. Part would be attributable to the substitution effect; consumers would substitute relatively cheaper fuels for electricity once its price had risen.

The magnitude of the effect of price changes on consumption differs over different time horizons. In the short-term, the effect of a rise in the price of electricity is severely constrained by the ability of consumers to substitute other fuels or to incorporate more electricity-efficient technology. (The fact that the Company's short-term energy consumption models do not include price as an explanatory variable is a reflection of the belief that this constraint is severe).

In the long-term, however, the constraints on substitution are lessened for a number of reasons. First, durable equipment stocks begin to reflect changes in relative energy prices by favoring the equipment using the fuel that was expected to be cheaper; second, heightened consumer interest in saving electricity, backed by willingness to pay for more efficiency, spurs development of conservation technology; third, existing technology, too expensive to implement commercially at previous levels of energy prices, becomes feasible at the new, higher energy prices; and fourth, normal turnover of electricity-using equipment contributes to a higher average level of energy efficiency.

For these reasons, energy price changes are expected to have an effect on long-term energy consumption levels. As a reflection of this belief, most of the Company's long-term forecasting models, including the residential, commercial, manufacturing and mine power energy sales models, incorporate the price of electricity as an explanatory variable. The residential Statistically Adjusted End-Use (SAE) Model uses price in development of explanatory variables. There are a variety of short- and long-run elasticities utilized in this analysis. In addition to electricity prices, the residential SAE model utilizes the price of natural gas and associated cross-price elasticities. Likewise, the commercial SAE model incorporates electricity price and an associated price elasticity to develop explanatory variables. Manufacturing and mine power have price as an explanatory variable. In these cases, the coefficient of the price variable provides a quantitative measure of the sensitivity of the forecast value to a change in price.

12.1.9 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 proarios are consistent with scenarios laid out in the EIA's 2017 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.

Graphical displays of the range of forecasts of internal energy requirements and summer peak demand for AEP Ohio are shown in Figures 6 and 7, respectively.

For AEP Ohio, the low-case and high-case energy and peak demand forecasts for the last forecast year, 2028, represent deviations of about 6.3% below and 5.1% above, respectively, the base-case forecast.

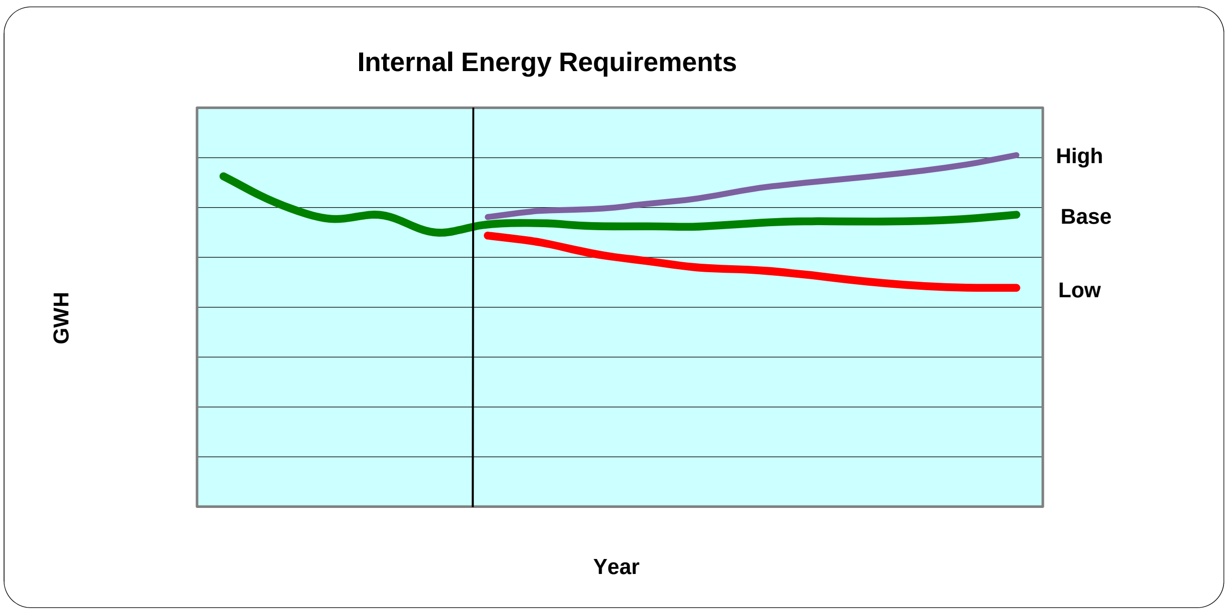

Figure 11. AEP Ohio Internal Energy Requirements Scnearios

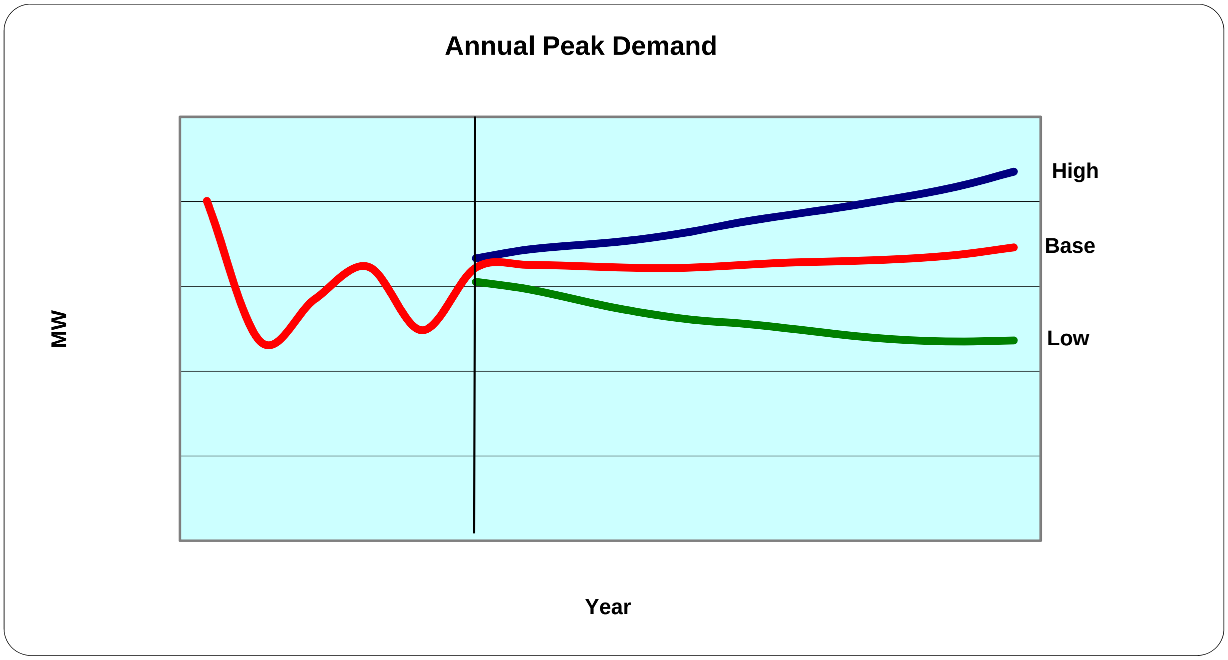

Figure 12. AEP Ohio Annual Peak Demand Scenarios

12.1.10 Distributed Generation

The Company monitors and evaluates the amount of distributed (or behind the meter) generation connected to its system. Currently, the Company has 1,551 customers with a total of 199 MW of generating capability. This total includes customers with 119 MW of combined heat and power (CHP), 12 MW of solar, 4 MW of energy storage, 1 MW fuel cell and 19 MW wind. The effects of past distributed generation are reflected in the Company's historical load and the trends of that activity is reflected in the load forecast. The Company monitors this activity for potential impacts on the load forecast.

13 Transmission Forecast

The AEP Ohio transmission forecast is for the load connected to the Company's transmission system. The core of the forecast is the Company internal load which is discussed in Load Forecast and Methodology section of this report (the Load Forecast section). This forecast is supplemented with forecasts for load serving entities on the Company's transmission system but not included in internal load. These entities include Buckeye Power, City of Bryan, City of Woodsfield, D.O.S.S. (cities of Dover, Orville, Shelby and St. Marys), Ohio Municipal Electric Group, City of Columbus, City of Jackson, City of Westerville and the Village of Glouster. The load for Wheeling Power Company (which is connected to Company's transmission system but is located outside of Ohio) is forecast with methods discussed in the Load Forecast section. The entities are forecast using econometric models with drivers in various combinations including service area commercial employment, service area commercial gross regional product, service area real personal income, service area population, service area employment, service area gross regional employment, and service area heating and cooling degree days. In addition, binary area variables are used to capture special events and monthly variations. The service area economic and demographic variables are from Moody’s Analytics. AEP Ohio’s transmission forecast was provided on Forms FE-T1 through FE-T3 in Company’s Long-Term Forecast Report to the Public Utilities Commission of Ohio (Case No. 18-501-EL-FOR).

CERTIFICATE OF SERVICE

In accordance with Rule 4901-1-05, Ohio Administrative Code, the PUCO's e-filing system will electronically serve notice of the filing of this document upon the following parties. In addition, I hereby certify that a service copy of the foregoing *Direct Testimony of John F. Torpey* was sent by, or on behalf of, the undersigned counsel to the following parties of record this 19th day of September, 2018.

/s/ Steven T. Nourse
Steven T. Nourse

campbell@whitt-sturtevant.com;
paul@carpenterlipps.com;
charris@spilmanlaw.com;
cmblend@aep.com;
cpirik@dickinsonwright.com;
Christopher.Miller@icemiller.com;
cmooney@ohiopartners.org;
dwilliamson@spilmanlaw.com;
dborchers@bricker.com;
ehewell@bricker.com;
egallon@porterwright.com;
Elizabeth.Watts@duke-energy.com;
EAkhbari@bricker.com;
fdarr@mwncmh.com;
Greg.Tillman@walmart.com;
glpetrucci@vorys.com;
ibatikov@vorys.com;
jkylercohn@BKLlawfirm.com;
Sechler@carpenterlipps.com;
joe.halso@sierraclub.org;
joliker@igsenergy.com;
Bojko@carpenterlipps.com;
kboehm@BKLlawfirm.com
Kurt.Helfrich@ThompsonHine.com;
lhawrot@spilmanlaw.com;
mfleisher@elpc.org;
callwein@keglerbrown.com
ckilgard@taftlaw.com;
chris@envlaw.com;
dstinson@bricker.com;
Cynthia.brady@exeloncorp.com
dparram@bricker.com

msmckenzie@aep.com;
mpritchard@mwncmh.com;
MWarnock@bricker.com;
Michael.Austin@ThompsonHine.com;
mkurtz@BKLlawfirm.com;
mnugent@igsenergy.com;
mjsettineri@vorys.com;
mdortch@kravitzllc.com;
mleppla@theoec.org;
glover@whitt-sturtevant.com;
rsahli@columbus.rr.com;
rdove@attorneydove.com;
robert.eubanks@ohioattorneygeneral.gov;
rkelter@elpc.org;
sasloan@aep.com;
sean.mcglone@ohiohospitals.org
ssheely@bricker.com;
Stephanie.Chmiel@ThompsonHine.com;
Stephen.Chriss@walmart.com;
stnourse@aep.com;
todonnell@dickinsonwright.com;
tony.mendoza@sierraclub.org;
tdougherty@theOEC.org;;
Werner.margard@ohioattorneygeneral.gov;
whitt@whitt-sturtevant.com;
William.michael@occ.ohio.gov;
Kristin.henry@sierraclub.org;
Larry.sauer@occ.ohio.gov;
laurie.williams@sierraclub.org;
msmckenzie@aep.com;
MWarnock@bricker.com;
msoules@earthjustice.org;

drinebolt@ohiopartners.org;
dboehm@BKLlawfirm.com;
evelyn.robinson@pjm.com;
gaunder@CarpenterLipps.com;
haydenm@firstenergycorp.com;
perko@carpenterlipps.com;
jeffrey.mayes@monitoringanalytics.com;
jlang@calfee.com;
jmcdermott@firstenergycorp.com;
Sechler@carpenterlipps.com;
Allison@carpenterlipps.com;
jsecrest@dickinsonwright.com
jvickers@elpc.org;
Katie.johnson@puc.state.oh.us;
msmalz@ohiopovertylaw.org
myurick@taftlaw.com
plee@oslsa.org;
glover@whitt-sturtevant.com;
sam@mwncmh.com;
schmidt@sppgrp.com;
sdismukes@eckertseamans.com
sechler@carpenterlipps.com
sfisk@earthjustice.org;
steven.beeler@ohioattorneygeneral.gov;
talexander@calfee.com;;
twilliams@snhslaw.com;
william.wright@ohioattorneygeneral.gov;
werner.margard@ohioattorneygeneral.gov

Attorney Examiners:
Sarah.Parrot@puc.state.oh.us;
Greta.See@puc.state.oh.us;