BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 18-1875-EL-GRD
18-1876-EL-WVR
18-1877-EL-AAM

Distribution Modernization Plan

DIRECT TESTIMONY OF PATRICK N. AUGUSTINE

- ☐ MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION
- ☐ OPERATING INCOME
- ☐ RATE BASE
- ☐ ALLOCATIONS
- ☐ RATE OF RETURN
- ☐ RATES AND TARIFFS
- ■ OTHER

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

TABLE OF CONTENTS

I. INTRODUCTION 1
II. OVERVIEW OF THE PJM MARKET 3
III. MARKET MODELS OVERVIEW 4
IV. MAJOR MARKET INPUT ASSUMPTIONS 8
V. MAJOR FORECAST RESULTS 15
VI. CONCLUSION 19

Attachments:

PNA-1: Curriculum Vitae
PNA-2: PJM Market Report

I. INTRODUCTION

Q. Please state your name, professional position, business address, and for whom you are testifying.

A. My name is Patrick N. Augustine. I am a Principal in the Energy Practice at Charles River Associates ("CRA"). My business address is 1201 F Street, NW, Washington, DC 20004. I am testifying on behalf of The Dayton Power and Light Company ("DP&L").

Q. What is your educational and professional background?

A. I received a Bachelor of Arts degree from Harvard University and received a Master of Environmental Management degree from the Nicholas School of the Environment at Duke University. I have been employed by CRA since 2015 and have worked in the energy consulting industry for over twelve years. Prior to joining CRA, I worked at Pace Global Energy Services, now a Siemens business, for over nine years, performing the roles of analyst, project manager, and director. At CRA, in my role as Principal, I oversee the maintenance of the firm's power market modeling tools and processes, manage consulting assignments in the power and utilities sectors, and supervise junior staff in performing market, policy, and strategic analyses for our clients.

Q. Please describe CRA and the work you perform in more detail.

A. CRA is a consulting firm that offers economic, financial, and strategic expertise to support our clients in business decisions, regulatory and litigation proceedings, and market and policy analysis. My professional experience within CRA's energy practice has focused on power market analysis and utility resource planning work to support project developers, electric utilities, investors, and lenders in energy market forecasting, power asset valuation, and utility portfolio planning. This work involves energy market research and analysis and the use of market models, particularly those that simulate the competitive electric power markets.

Q. Have you previously testified before the Public Utilities Commission of Ohio ("Commission") or any other regulatory commission?

A. I have not previously testified before this Commission. However, I previously provided testimony and appeared before the Kentucky Public Service Commission with regard to an application for approval of an environmental compliance plan and associated cost recovery in Case No. 2012-00063. I also provided testimony on behalf of a power generating asset owner before the Michigan Public Service Commission in the course of a Certificate of Need proceeding in Case No. U-17429. I have also provided testimony before the Indiana Utility Regulatory Commission on behalf of the Northern Indiana Public Service Company regarding their 2018 Integrated Resource Plan and certain coal plant retirement decisions. This is an active proceeding in Cause No. 45159.

Q. What is the purpose of your testimony in this proceeding?

A. CRA has been retained by DP&L to provide a fundamentals-based market forecast of the PJM energy and capacity markets. My testimony describes the PJM market, the models that were used to produce these market price forecasts, the major assumptions associated with the analysis, and the key outputs and findings.

Q. What are the attachments and schedules for which you are responsible?

A. I am sponsoring all or part of the following items:

- PNA-1 – Curriculum Vitae
- PNA-2 – PJM Market Report

II. OVERVIEW OF THE PJM MARKET

Q. Please describe the PJM market.

A. The PJM Interconnection is the world's largest wholesale electricity market, coordinating the generation and delivery of power to over 60 million customers in 14 states, including Ohio. As an independent system operator ("ISO"), PJM is authorized by the Federal Energy Regulatory Commission to provide access to and manage the regional transmission grid and operate markets for energy, ancillary services, and capacity. The energy market is a competitive, bid-based wholesale market for electricity, which clears on a locational basis. In addition to the energy market, PJM operates a separate market for capacity, which compensates resources for their capacity or availability, rather than the energy that they produce. Section 2 of attachment PNA-2 provides a detailed overview of the PJM market structure and operations.

Q. Was attachment PNA-2 ("PJM Market Forecast Report") prepared by you or under your direction?

A. Yes, it was.

Q. Why are the PJM energy and capacity markets and the prices in those markets relevant to DP&L customer costs?

A. The energy, capacity and ancillary services needs of DP&L's Standard Service Offer ("SSO") customers are met through annual auctions administered by CRA and monitored by the Commission. Potential suppliers in these auctions bid to supply DP&L's SSO requirements over periods ranging from one to three years. Winning bidders in the auction are the suppliers that are willing to accept the lowest fixed price over the delivery period. These suppliers are paid a fixed dollar per Megawatt-hour ("MWh") payment by DP&L for each MWh of load supplied and are charged by PJM the energy and capacity market prices for their supplier share of the DP&L SSO load. Because bidders in the auction are charged by PJM consistent with PJM market prices, the auction's clearing prices are broadly reflective of overall PJM market conditions and market expectations. Higher forward energy prices and higher PJM capacity prices will lead directly to higher SSO auction clearing prices. Lower energy and capacity prices will yield lower SSO auction clearing prices. As to customers who have switched electricity providers, the same is true. The market prices for energy and capacity in PJM will affect the prices that competitive retail suppliers will offer them.

III. MARKET MODELS OVERVIEW

Q. Can you describe the general process you used to develop price forecasts for the PJM energy and capacity markets?

A. The forecasting exercise attempted to simulate the operations of the PJM energy and capacity markets through the use of market models. Prior to running the market models, key input assumptions were developed for the major drivers of energy and capacity prices. These input assumptions were based on public data sources, forecasts produced by PJM and other major government agencies, and fundamental economic analysis. The input assumptions often included projections for many years into the future, so that the market models could be run to produce forecasts of energy and capacity prices for a period out to 2040.

Q. Please describe the market models that you used in more detail.

A. My team and I at CRA deployed an integrated set of market models to develop long-term PJM price projections. The Aurora[1] model was used to generate energy prices, and an integrated proprietary capacity market model was used to generate capacity prices. Aurora is a chronological, hourly dispatch model that performs market-level production cost analysis. The model takes as inputs plant-level operational data, hourly demand expectations, and price inputs for fuel and emission prices, among other variable cost drivers. The model simulates the day-ahead market dispatch that is performed by system operators like PJM and solves for wholesale market prices as a function of the marginal cost of supply and the demand in any given modeled hour, while respecting transmission constraints on a zonal level. The hourly price forecast can be summarized on an annual and monthly basis and for the traditional on-peak and off-peak periods designated by PJM.

---

[1] Aurora is licensed by Energy Exemplar. For more information, see: https://energyexemplar.com/products/aurora-electric-modeling-forecasting-software/

The capacity market model simulates the capacity auctions within the Reliability Pricing Model ("RPM") with an explicit representation of the Variable Resource Requirement ("VRR") curve and simulated supply and demand-side resource offers based on assumptions regarding unit fixed costs and expected energy margins. The supply side plant-level offer forecasts are based directly on projections from the Aurora simulation of dispatch and economic performance in the energy market.

Q. Are these models broadly used in the power industry?

A. Yes, CRA regularly uses this modeling system to support consulting engagements on behalf of electric utilities, power developers, and investors to evaluate power market prices, power plant performance, and utility resource planning questions. Aurora is widely used throughout the industry, with approximately 100 companies or organizations currently licensing the software.

Q. Please describe the major inputs to the core Aurora dispatch model in more detail.

A. The Aurora model has four major types of inputs: (i) demand for electricity for each modeled region on an annual, monthly, and hourly level; (ii) a detailed representation of supply resources in the market, including parameters for capacity, heat rate or efficiency, emission rate, type of fuel or renewable power source, and other operational characteristics; (iii) key commodity price inputs that drive the marginal costs of generating resources like coal prices, natural gas prices, and emission prices; and (iv) a representation of transmission constraints between modeled zones.

Q. Please describe the major inputs to the capacity market model.

A. The capacity market model is directly connected with inputs and outputs from the Aurora model, and it ultimately evaluates the supply of capacity and the demand for capacity in the PJM market within the RPM framework. Therefore, the major inputs to the capacity market model include a representation of individual suppliers and their expected price offers to the market, which create a supply curve, and the parameters that define the VRR demand curve. The resource-level supply inputs are specified with a capacity in MW and an expected offer cost in dollars per kW-year (or dollars per MW-day). The demand inputs are specified according to the administratively-set parameters of the VRR curve, which include a net cost of new entry ("CONE") benchmark and specific adjustments to the CONE value based on planning reserve margin targets. The supply resources, which include generators and demand-side resources like energy efficiency and demand response, and the demand inputs are specified for each year of the forecast period.

Q. Please explain the integration between the Aurora dispatch model and the capacity market model in more detail.

A. The major inputs to the capacity market model are fully consistent with those used in the Aurora model. Consistent load growth assumptions are used in both models to develop demand projections over time, and plant-specific outputs from the Aurora model contribute to the supply data. In order to develop the expected offer costs in dollars per kW-year for the individual suppliers of capacity, the capacity model requires energy market performance data for each plant from Aurora.

IV. MAJOR MARKET INPUT ASSUMPTIONS

Q. Can you summarize which of the major input assumptions are the most important drivers of the energy and capacity price forecast?

A. While the power sector models deployed in this analysis are based on a large number of inputs, I have identified five major drivers that contribute most significantly to the energy and capacity price forecasts developed in my analysis. These include (i) the PJM electric load growth forecast, (ii) changes to the supply (including generation and demand-side resources) in PJM over time, (iii) the price of natural gas, (iv) the price associated with carbon dioxide ("carbon" or "CO_2") emissions, and (v) the CONE assumption used in the development of the parameters for the capacity market.

Q. When were the major assumptions developed for the forecast analysis?

A. All major assumptions were finalized as of October 11, 2018. It is likely that certain drivers of PJM power prices will change over time, including factors such as natural gas forward market prices, federal or state-level energy policy changes, and plant construction or retirement announcements, but all assumptions were current as of October 11, 2018.

Q. What load growth inputs were used in your analysis?

A. The analysis utilized PJM's 2018 load forecast.[2] PJM performs this forecast with econometric multiple regression models to estimate daily peak load for each PJM zone (the non-coincident peak), the zone's contribution to the daily system-wide peak (the coincident peak), and monthly net energy for load. PJM accounts for several variables, including historical weather patterns, economic and demographic activity, and end-use energy efficiency and behind-the-meter generation trends to determine its load forecast.[3] PJM produces 15-year (2018-2033) monthly forecasts of peak load and energy, assuming a range of weather conditions for each PJM zone and the entire system. My analysis utilized the weather-normal forecast. In that forecast, summer peak load growth for the PJM system is projected to average 0.4% per year over the next 10 years and 0.4% over the next 15 years. Net energy for load growth for all of PJM is projected to average 0.4% per year over the next ten-year period and 0.5% over the next 15-years. In order to estimate the load outlook beyond the 15-year forecast period, the analysis utilized the average annual growth in peak and net energy for load from the 2024 to 2032 time period. The annual peak and net energy for load estimates utilized in the PJM market forecast are presented in Appendix B of attachment PNA-2.

---

[2] PJM,"PJM Load Forecast Report- January 2018", 28 December 2017, < https://www.pjm.com/-/media/library/reports-notices/load-forecast/2018-load-forecast-report.ashx?la=en>.

[3] PJM. "Manual 19: Load Forecasting and Analysis." 25 October 2018 < https://www.pjm.com/-/media/documents/manuals/m19.ashx?la=en>.

Q. How do you evaluate potential future supply changes in the PJM market?

A. The evaluation of future supply in the PJM market involved two major steps: (i) the explicit incorporation of announced new capacity additions or retirements into the models; and (ii) an economic evaluation of likely future additions and retirements based on expected policy, the fixed costs associated with building new capacity or maintaining existing plants, and the expected revenues that such capacity is likely to achieve in the PJM markets.

Q. Can you provide more detail regarding the criteria for including announced new capacity additions and retirements in the analysis?

A. For new builds, all plants that are under construction or have cleared the PJM capacity market auction were considered as firm additions in the modeling. In addition, there are several plants that are in an advanced stage of development that are probability-weighted for inclusion in the modeling. For example, a 500 MW plant with a 50% probability weighting implies that 250 MW will be added to the model simulation. This allows for a reasonable accounting of future near-term additions, recognizing that only some of the currently proposed plants in an advanced stage of development will ultimately get built. For retirements, all plants that have announced a firm retirement date were retired in the model on their announced retirement date. For a listing of all announced new builds and retirements included in the analysis, see Appendices C and D of attachment PNA-2.

Q. Can you provide more detail regarding how you incorporated potential generic additions and retirements beyond the firm announcements over the 20-year forecast period?

A. Yes. The analysis assumed that state-level renewable portfolio standards ("RPS") throughout PJM are met over time with sufficient renewable additions. Beyond accounting for these policy requirements, the modeling assessment tracked the economic performance of new resource addition candidates and existing plants that are candidates for retirement. When assessing candidate plants for retirement, the analysis considered plant age, technology, and the ability of a plant to cover its fixed operating costs from the energy and capacity markets. For plant additions, when new resource options were able to cover the cost of new entry with expected energy and capacity revenues, new builds were incorporated in the modeling. Over time, the forecast incorporated cumulative generic capacity additions of about 27 GW of natural gas-fired resources, 14 GW of solar, 17 GW of wind and 4 GW of energy storage. On the retirement side, beyond announced retirements, the analysis projected that an additional 18 GW of coal, 1.7 GW of nuclear, and 1 GW of natural gas capacity will retire during the forecast period.

Q. What natural gas prices were used in the forecast assessment?

A. The near-term gas price outlook through 2019 was based on market forwards. Beyond that period, the analysis transitioned to the reference case natural gas forecast published in the U.S. Energy Information Administration's ("EIA") Annual Energy Outlook ("AEO") 2018. EIA's AEO provides modeled projections of domestic energy markets through 2050, and it includes cases with different assumptions regarding macroeconomic growth, world oil prices, technological progress, and energy policies.[4] My analysis utilized the reference case natural gas price outlook at Henry Hub, which rises gradually from \$3.69/MMBtu (in real 2017 dollars) in 2022 to \$4.50/MMBtu (in real 2017 dollars) in 2040. Local delivered prices for natural gas at various points throughout PJM were developed by analyzing historical and forward market basis between these points and the benchmark Henry Hub price. A table of the annual natural gas prices used in the analysis is presented in Appendix B of attachment PNA-2.

Q. Is there currently a price on carbon emissions in the PJM market?

A. There is not currently a price on carbon emissions throughout much of PJM, including Ohio. However, several states in the eastern part of PJM currently participate in or are in the process of joining the Regional Greenhouse Gas Initiative ("RGGI"). RGGI is a multi-state cap-and-trade program that incorporates several states in the Mid-Atlantic and Northeast regions of the United States. Power plants in participating states must surrender an allowance for each ton of carbon dioxide that they emit, and the allowances are priced based on supply and demand in the market. This carbon price currently influences power market prices in participating RGGI states, and to a lesser extent, the rest of PJM.

---

[4] U.S. EIA, "Annual Energy Outlook 2018", 6 February 2018, < https://www.eia.gov/outlooks/aeo/>

Q. Did your analysis incorporate a future carbon price for generators throughout all of PJM, including Ohio?

A. Yes, the market price forecast incorporated a price on carbon beginning in 2026. This is based on the expectation that a federal or broadly regional program is implemented by that time. The carbon price used in the forecast starts at around \$8 per short ton (in real 2017 dollars) in 2026, growing to around \$10 per ton (in real 2017 dollars) in 2030 and \$13 per ton (in real 2017 dollars) by 2040. A table of the annual carbon price values used in the analysis is presented in Appendix B of attachment PNA-2.

Q. How did you develop the carbon price assumptions?

A. CRA has conducted independent assessments of the required price on carbon to achieve emission reductions from the U.S. electric power sector in line with recent policy proposals. The carbon price incorporated in the analysis results in reductions of power sector CO_2 emissions by 2030 of around 22% relative to a 2012 baseline and 34% relative to a 2005 baseline. This level is in line with targets that were proposed in the U.S. Environmental Protection Agency's ("EPA") 2015 Clean Power Plan, which remains a reasonable benchmark for potential future policy.

The carbon prices used in this analysis are also reasonable when compared to recent estimates of the social cost of carbon that have been produced by the EPA under the last two administrations.[5] Although there is significant uncertainty around the social cost of carbon calculation, the market price for carbon used in the analysis falls well within the range of the social cost of carbon estimates produced by the EPA in recent years.

Q. How does this carbon price impact the power price forecast?

A. A price on carbon would raise the variable costs of operation for any plant that emits CO_2, regardless of whether the policy implemented a tax or instituted a cap-and-trade program with an allowance price. Thus, the carbon price raises the expected marginal cost of operation of any fossil-fired plant based on its emission rate per MWh. This will contribute to higher power prices whenever such units are expected to set the PJM market price.

Q. What assumptions did you use for the cost of new entry?

A. PJM undertakes a quadrennial review of the CONE parameters that are used in setting the demand curve for the RPM. My analysis used data from the latest CONE review, which was undertaken in April, 2018.[6] The review estimated CONE for combustion turbines and combined cycles using a bottom-up analysis of capital costs, project development costs, and annual fixed operation and maintenance costs.

---

[5] See EPA, "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis", August 2016, <https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf> and EPA, "Regulatory Impact Analysis for the Review of the Clean Power Plan: Proposal", October 2017, <https://www.epa.gov/sites/production/files/2017-10/documents/ria_proposed-cpp-repeal_2017-10.pdf>

[6] The Brattle Group, "PJM Cost of New Entry : Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date", 19 April 2018, < https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx>

V. MAJOR FORECAST RESULTS

Q. Please summarize the energy price forecast.

A. The energy price forecast is developed in constant 2017 dollars for PJM's DP&L zone and summarized for two distinct time periods, as designated by PJM: on-peak and off-peak. The on-peak period is an average of the expected energy prices from 7am through 11pm from Monday through Friday. The off-peak period is an average of the expected energy prices from 11pm through 7am during the five weekdays and all hours during Saturday and Sunday. CRA's energy market price forecast starts at around $38 per MWh for on-peak prices and $29 per MWh for off-peak prices in 2019. On-peak prices are expected to grow to over $45 per MWh by 2025, with off-peak prices rising to around $35 per MWh. Prices are projected to increase by around $4 to $5 per MWh in 2026 and then grow to around $55 per MWh for the on-peak period and $44 per MWh for the off-peak period by 2040. A table of annual forecast values is presented in Appendix A of attachment PNA-2.

Q. What are the drivers of the expected increase in real prices over the forecast time period?

A. The price forecast rises over time due to the expected increases in the key underlying drivers of the marginal cost of electricity production, namely the price of natural gas and the price of carbon. The expected load growth and the expected evolution of the generation mix in PJM over time are also important drivers. As discussed earlier, the expected retirement of a significant amount of uneconomic capacity and the expected entry of new natural gas and renewable resources influence the PJM supply mix considerably and impact expected clearing prices.

Q. Please summarize the capacity price forecast.

A. The capacity price forecast is developed in constant 2017 dollars per kW-year, or alternatively dollars per MW-day and not on a per MWh basis like energy prices. This is because the capacity price represents a fixed price that is paid to resources based on their available capacity and not based on how many MWh are generated. The forecast represents the expected system-wide clearing price for capacity across PJM. Although there can be zonal price separation across the system in PJM's RPM capacity auction, the DP&L zone is not expected to clear at a different price than the system-wide price during the forecast period. The capacity price for the calendar year 2019 is around $44 per kW-year or around $120 per MW-day. By 2025, the price is projected to be around $56 per kW-year or around $154 per MW-day. Over the long-term, between 2020 and 2030, the price is expected to average around $75 per kW-year or around $207 per MW-day. A table of annual forecast values is presented in Appendix A of attachment PNA-2.

Q. How does your forecast account for forward auctions that have already occurred?

A. The prices from forward auctions that have already occurred are explicitly incorporated into the forecast. The auctions occur in May for annual delivery starting on June 1 three years in the future. The latest BRA occurred in May, 2018 for capacity delivery for June 1, 2021 through May 31, 2022. Thus, the capacity price forecast includes actual cleared prices for the full years of 2019, 2020, and 2021, and a partial year of 2022. The latest auction price cleared at around $46 per kW-year (real 2017 dollars).[7] This is relatively close to the prices projected in the forecast for the next few auctions.

Q. What drives your forecast of capacity prices over the next ten years?

A. Recent dynamics in the PJM capacity market have been characterized by stagnant load growth and an influx of new combined cycle capacity additions. These factors have resulted in recent capacity clearing prices that have fluctuated between around $76 per MW-day (nominal dollars) and $165 per MW-day (nominal dollars) over the last four auctions, averaging around $110 per MW-day, or around $40 per kW-year. Although prices have moved up and down and individual bidding behavior in the auction is difficult to assess, the going-forward economics of existing coal and nuclear plants in the market have been a major driver of capacity pricing. In other words, under current market conditions, new natural gas-fired plants have been entering the market as a result of strong expected performance in the energy market, raising the regional reserve margin and resulting in capacity prices being set by existing plants. These plants generally require a fixed payment to cover the costs associated with their continued operations. The forecast expects that these dynamics persist in the near-term and that existing unit costs will continue to drive capacity pricing for the next several years. Through the 2020s, it is expected that the pace of new combined cycle additions will slow, as evidenced by a reduction in the amount of new combined cycle capacity that cleared in the last auction versus the previous three auctions, and a development queue that is

---

[7] The capacity auctions clear in nominal dollars, and the 2021-2022 auction cleared at $51 per kW-year (or $140 per MW-day). Using a 2.1% inflation rate, this value is equivalent to around $46 per kW-year in real 2017 dollars.

smaller than it has been in recent years. The reduction in new capacity additions is expected to place upward pressure on capacity prices. In addition, the introduction of a carbon price in the energy market in 2026 would be expected to negatively impact coal plant operations in the energy market, causing them to demand higher prices in the capacity market to remain in operation.

Q. What are the primary drivers of the long-term capacity price outlook?

A. By the late 2020s, the forecast expects that new natural gas-fired entry will require larger capacity payments than existing coal and nuclear plants, which are expected to see improved energy margins as a result of increasing natural gas prices. These new projects by the late 2020s are also expected to require larger capacity payments than new natural gas projects do today, as a result of the expectation for higher gas prices and more renewable capacity additions, both factors that reduce energy margins for gas plants. Thus, over the final ten to twelve years of the forecast, the prices are driven primarily by the expected net CONE for new natural gas-fired resource additions.

Q. Did CRA prepare an estimate of the social cost of carbon in this case?

A. Yes, CRA prepared an estimate of the social cost of carbon using public sources, which DP&L witness Hulsebosch uses in his testimony. In developing this estimate, CRA relied on recent social cost of carbon projections developed by the EPA in August 2016 and October 2017. In August 2016, the EPA's five percent discount rate scenario for the social cost of carbon started at $14.4 per short ton in 2018 (real 2017 dollars) and rose to

$25.2 per ton (real 2017 dollars) by 2040.[8] In October 2017, EPA revised its social cost of carbon estimate downwards and produced projections using three and seven percent discount rates. In order to approximate a projection that would be consistent with the five percent discount rate scenario from 2016, CRA took the average of the two October 2017 cases to arrive at an estimate of the social cost of carbon from the 2017 study of $3.6 per ton in 2018 (2017 dollars), rising to $6.0 per ton (2017 dollars) by 2040.[9] The difference in the two estimates reflect different methodologies and assumptions deployed by two different federal administrations. Rather than rely on one of the sources, it is reasonable to take the average of the two as representative of recent analysis on the topic. Under this approach, the social cost of carbon estimate developed by CRA grows from $9.0 per ton (2017 dollars) in 2018 to $15.6 per ton (2017 dollars) in 2040.

VI. CONCLUSION

Q. Does that conclude your pre-filed direct testimony at this time?

A. Yes.

1318739.1

[8] U.S. EPA, "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis - Under Executive Order 12866", August 2016, <https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf>. CRA utilized historical Consumer Price Index inflation data from the U.S. Department of Labor (Bureau of Labor Statistics) to inflate the estimate from 2007$ to 2017$.

[9] U.S. EPA, "Regulatory Impact Analysis for the Review of the Clean Power Plan: Proposal", October 2017, < https://www.epa.gov/sites/production/files/2017-10/documents/ria_proposed-cpp-repeal_2017-10.pdf>. CRA utilized historical Consumer Price Index inflation data from the U.S. Department of Labor (Bureau of Labor Statistics) to inflate the estimate from 2011$ to 2017$.

PNA-1

Patrick Augustine

Principal

MEM, Duke University, Nicholas School of the Environment

B.A. Environmental Science and Public Policy, Harvard University

Patrick Augustine is a Principal in CRA's Energy practice, with over a decade of experience in the electric industry, specializing in market analysis and strategy development within the utility and power market sectors. Mr. Augustine is experienced with power market dispatch systems and utility planning tools and has performed and managed power and environmental market assessments throughout North America in support of project developers, utilities, investors, and lenders in their development, financing, and planning efforts. He has worked for numerous electric utilities in support of their resource planning and strategy development activities and has extensive experience assessing and designing power market modeling techniques and processes.

Power Market Analysis

- Management of power market analysis to support investment and development efforts in PJM for a major infrastructure fund.
- Management of asset valuation for a portfolio of plants in PJM and ISO-NE.
- Management of an assessment of the near-term dispatch of 15 combined cycles in ERCOT, PJM, ISO-NE, CAISO, SPP, and WECC to support a potential transaction related to long-term service agreement value.
- Review of scarcity market value and dispatch stack positioning of two ERCOT assets on behalf of a private equity owner.
- Management of multiple PJM market advisory assignments on behalf of asset owners or investors.
- Review of combined cycle valuation in California, including energy and resource adequacy value over a range of potential market outcomes.
- Buy-side market advisory to evaluate investment in a transmission line between PJM and NYISO.
- Quarterly plant valuation analysis for a major power asset owner with capacity in California, ERCOT, PJM, and MISO markets.
- National risk-integrated project development screening for new combined cycle or natural gas peaking capacity for a major independent power producer.
- Analysis of the value of a combined cycle in Ontario after contract expiry in support of a potential acquisition.
- Sell-side stochastic valuation support for a Northeast power portfolio of nine mid-merit and peaking natural gas-fired power generating assets.
- Stochastic analysis of multiple ERCOT portfolios (gas, wind, coal, nuclear) to assess future performance of power generating assets in order to support lenders, investors, and utility asset owners.
- Power market assessments for portfolio of over 20 assets across eight market areas in the United States and Europe.
- Evaluation of the gaming potential of the United Kingdom power market reforms that introduce a capacity market, carbon price floor, and Feed-in Tariff structure.
- Support to a consortium of six Middle Eastern Gulf states in the determination of the level of

capacity required by each of its Member States in order to maintain system security. Development of unique modeling applications and risk-based simulations to assess Loss of Load events and establish reserve margin targets.

- Power market assessment in the NYISO region to support multiple wind, natural gas, and transmission assets.
- Power market assessment of the ISO-New England Maine market to support the financing of a portfolio of hydroelectric assets.
- Power market assessment of the PJM market to evaluate effects of a new Integrated Gasification Combined Cycle plant and to support financing of a natural gas-fired combined cycle project.
- Power market assessment of the Southwest Power Pool market to develop an integrated power market pricing forecast and project operational results for a gas-fired combined cycle unit.
- North American power market review to assist a major mining company in evaluating growth opportunities.
- International power market assessments for analyses in Alberta, Canada, Australia, Ukraine, Guatemala, and Colombia.

Utility Resource Planning and Advisory

- Management of all Integrated Resource Planning and generation strategy activities for a Midwestern investor owned utility. The IRP analysis included development of commodity price forecasts and stochastic and scenario-based uncertainty analysis to identify preferred portfolio options within a public stakeholder process.
- Management of a peer utility retail rate forecasting exercise, including evaluation of the generation portfolios of 16 Midwestern Investor Owned Utilities.
- Management of resource planning assignment for a Midwestern utility evaluating wind versus coal economics, including support for testimony filing in four states.
- Design of a risk-based framework for resource planning analysis for a Midwestern investor owned utility; lead role in strategic resource planning support for the utility, including at the senior executive level, over a seven-year period.
- Management of an integrated resource plan assignment for a California municipal utility, including analysis of local gas-fired repowering options, development of a renewable procurement strategy, assessment of distributed solar penetration, and analysis of loss of load risks.
- Assessment of the impacts of the draft Clean Power Plan on behalf of a consortium of four Arizona electric utilities.
- Management of a Clean Power Plan compliance analysis on behalf of a Colorado utility.
- Development of a long-term Risk Integrated Resource Plan (RIRP) for a Midwestern utility.
- Development of a national power market forecast and associated scenarios on behalf of a large Midwestern investor owned utility.
- Oversight in the development of Excel-based market analysis tools for a utility needing assistance in long-term planning analysis and short-term fuel procurement, budgeting, and off-system sales tracking.
- Development of a risk-based modeling approach and training the resource planning team in deploying the RIRP process for a major Southeastern investor owned utility.
- Resource and strategic planning for a Midwestern utility to evaluate retrofit economics for a

major coal plant in its fleet and to assess opportunities to develop natural gas-fired generation.

- RIRP development and stakeholder process participation for a California utility and a Texas utility examining resource planning decisions in the context of cost, risk, and environmental compliance objectives.
- Development of an RIRP analysis focused on different contract options for baseload, intermediate, peaking, and renewable power.
- RIRP for a California municipal utility to examine options for local generation upgrades, renewable contract opportunities, and coal plant displacement.

Environmental Market Analysis

- Development of SO_2 and NO_x allowance price forecasts to create plant-level environmental compliance strategies, and interpret results in the context of various regulatory regimes.
- Policy analysis and emission allowance price forecasting for CO_2 markets across a range of active or proposed state, regional, and federal carbon regulations.
- Plant-level analysis of all renewable energy resources eligible to bid into the New York State Energy Research and Development Authority's central procurement auction for renewable energy credits ("RECs").
- REC market analysis in the Midwest, California, and PJM to support wind asset transactions.

Expert Witness Testimony

- Testimony before the Indiana Utility Regulatory Commission on behalf of an electric utility related to its Integrated Resource Plan and certain coal plant retirement decisions – Cause No. 45159.
- Testimony on behalf of a power generating asset owner before the Michigan Public Service Commission in the course of a Certificate of Need proceeding – Case No. U-17429.
- Written testimony and appearance before the Kentucky Public Service Commission on behalf of an electric utility with regard to an application for approval of an environmental compliance plan and associated cost recovery – Case No. 2012-00063.

Professional History

- 2015 – Present *Principal*, Charles River Associates, Washington, DC.
- 2006 – 2015 *Executive Director*, Pace Global, a Siemens Business, Fairfax, VA. Previously held positions as Director, Project Manager, and Analyst.

PNA-2

CRA Charles River Associates

PJM Market Forecast Report

Prepared by:

Charles River Associates

1201 F St. NW, Suite 700

Washington, DC 20004

www.crai.com/energy

Date: December 21, 2018

Table of Contents

1. **Introduction and Summary** 1
 1.1. Introduction and Overview of Analysis 1
 1.2. Results Summary 1
  1.2.1. Energy Price Forecast 1
  1.2.1. Capacity Price Forecast 1

2. **PJM Market Overview** 3
 2.1. PJM Overview 3
 2.2. PJM Day-Ahead and Real-Time Energy Market 4
 2.3. PJM Ancillary Services Market 6
 2.4. PJM Capacity Market 6

3. **PJM Supply and Demand Fundamentals** 12
 3.1. Electricity Demand Projections 12
 3.2. Existing Supply 13
 3.3. Capacity Additions and Retirements 14
  3.3.1. New Capacity 14
  3.3.2. Retirements 18
 3.4. Projected Capacity and Generation Mix 19
  3.4.1. Reserve Margin Outlook 20

4. **Fuel Prices** 21

5. **Carbon Prices** 22

6. **Cost of New Entry** 23

Appendix A: Power Price Forecast Details 24

Appendix B: Detailed Market Driver Assumptions 25

Appendix C: PJM Detailed List of New Entrants 30

Appendix D: PJM Detailed List of Announced Retirements Included in Modeling 34

Appendix E: Power Market Modeling Methodology 37

Table of Exhibits

Exhibit 1: Dayton Zone Energy Price Forecast 2
Exhibit 2: PJM-RTO Annual Capacity Price Outlook 2
Exhibit 3: PJM Footprint and Zones 4
Exhibit 4: Historic Monthly Average PJM Day-Ahead LMP Prices 5
Exhibit 5: Timing of PJM Capacity Auctions 6
Exhibit 6: Locational Deliverability Areas within PJM 7
Exhibit 7: Load Zones in Each CONE Area in PJM 8
Exhibit 8: VRR Curve 9
Exhibit 9: Historical RPM Clearing Prices 11
Exhibit 10: PJM and Dayton Peak Demand Forecast (MW) 12
Exhibit 11: PJM and Dayton Net Energy for Load Forecast (GWh) 13
Exhibit 12: PJM RTO Capacity Mix, 2017 (% Breakdown) 14
Exhibit 13: PJM RTO Generation Mix, 2017 (% Breakdown) 14
Exhibit 14: PJM Firm Capacity Additions (Cumulative from 2018) 15
Exhibit 15: PJM RPS Requirements – Final Target by Year 16
Exhibit 16: PJM Renewable Generation Forecast 17
Exhibit 17: PJM Generic Capacity Additions (Cumulative from 2018) 17
Exhibit 18: PJM Firm Capacity Retirements (Cumulative from 2018) 18
Exhibit 19: PJM Economic Capacity Retirements (Cumulative from 2018) 19
Exhibit 20: Projected Capacity Mix in PJM 19
Exhibit 21: Projected Generation Mix in PJM 20
Exhibit 22: Projected PJM Reserve Margin 20
Exhibit 23: Natural Gas Price Outlook 21
Exhibit 24: U.S. National Carbon Price Outlook 22
Exhibit 25: Wholesale Energy and Capacity Price Forecast for Dayton Zone 24
Exhibit 26: Peak Load (MW) and Net Energy for Load (GWh) Projections 25
Exhibit 27: Natural Gas Price Forecast (2017$/MMBtu) 26
Exhibit 28: Coal Basin Price Forecast (2017$/MMBtu) 27
Exhibit 29: CO_2 Emission Price Forecast (2017$/ton) 28
Exhibit 30: PJM Levelized Cost of New Entry (CONE in 2017$/ICAP kW-yr) 29
Exhibit 31: Market Modeling Approach 37

1. Introduction and Summary

1.1. Introduction and Overview of Analysis

This report presents a summary of Charles River Associates' ("CRA") evaluation of the PJM electricity market for The Dayton Power and Light Company ("DP&L"). CRA developed energy and capacity price forecasts for the DP&L pricing zone in PJM for the 2019 to 2040 time period using an integrated set of market models. The price projections are summarized in this chapter, while the subsequent chapters of this report include the following:

- An overview of PJM's energy and capacity markets;
- A summary of long-term supply and demand fundamentals that influence the forecast;
- A discussion and documentation of key input price and cost assumptions for fuel prices, carbon prices, and cost of new entry estimates; and
- An appendix with detailed input assumptions and a summary of the market models that were used.

All figures in this report are presented in real 2017 dollars, unless otherwise stated. All conclusions and estimates set forth in this report reflect market conditions and information available as of October 11, 2018, when CRA finalized the underlying power market analysis.

1.2. Results Summary

1.2.1. Energy Price Forecast

CRA developed forecasts for wholesale energy prices for the on-peak and off-peak period for the DP&L (or "Dayton") zone in PJM.[1] On-peak prices in the Dayton zone are projected to rise from $38/MWh in 2019 to $55/MWh in 2040, and off-peak prices are expected to rise from $29/MWh to $44/MWh over the same time period. Exhibit 1 presents the annual forecast of on-peak and off-peak energy prices for the Dayton zone. Annual values are provided in Appendix A.

1.2.1. Capacity Price Forecast

CRA developed a forecast of capacity prices for the PJM system, which accounts for forward auctions that have already occurred[2] and a fundamental price projection for the long-term. Recently, the PJM capacity market has been characterized by stagnant load growth and an influx of new combined cycle additions, resulting in capacity clearing prices fluctuating between $76/MW-day (nominal dollars) and $165/MW-day (nominal dollars) over the last four auctions. The average over this period has been roughly $110/MW-day, or $40/kW-year

[1] The on-peak period is an average of the expected energy prices from 7am through 11pm from Monday through Friday. The off-peak period is an average of the expected energy prices from 11pm through 7am during the five weekdays and all hours during Saturday and Sunday.

[2] The PJM capacity market is a three-year forward auction, and clearing prices are known through May, 2022 as of the date of this report.

(nominal dollars). Expectations for strong energy market revenues for new natural gas fired combined cycles have resulted in a significant number of new capacity additions, which has raised reserve margin expectations across PJM and resulted in capacity prices being set by existing coal and nuclear plants (as opposed to new entrants). CRA expects these dynamics to persist in the near-term, resulting in capacity prices between $50/kW-yr and $60/kW-yr for the next few forward auctions.

Over time, it is expected that the pace of new combined cycle entry will slow, lowering reserve margins and driving capacity prices higher, especially as energy margins for existing coal-fired capacity decline with the introduction of a carbon price. These factors are projected to put upward pressure on capacity prices. Over the long-term, capacity prices are projected to align closely with CRA's calculation of the net cost of new entry for natural gas-fired capacity additions. Exhibit 2 summarizes the annual capacity price outlook, by calendar year. Annual values are provided in Appendix A.

Exhibit 1: Dayton Zone Energy Price Forecast

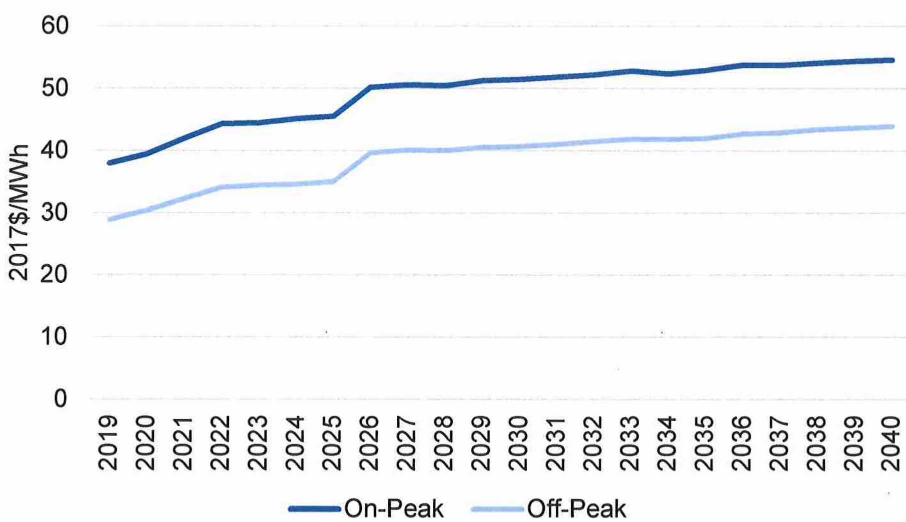
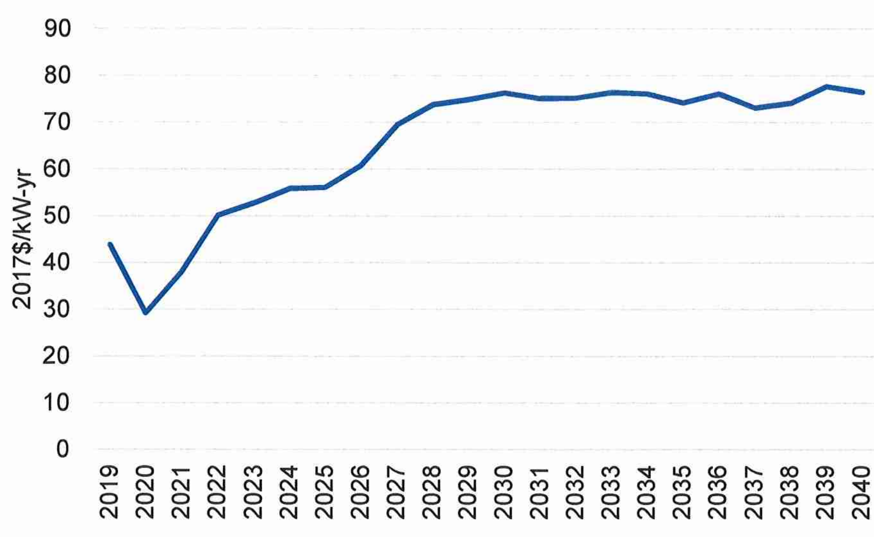


Exhibit 2: PJM-RTO Annual Capacity Price Outlook



2. PJM Market Overview

This section describes the PJM markets, providing an overview of the market's structure and a summary of the energy, ancillary services, and capacity markets.

2.1. PJM Overview

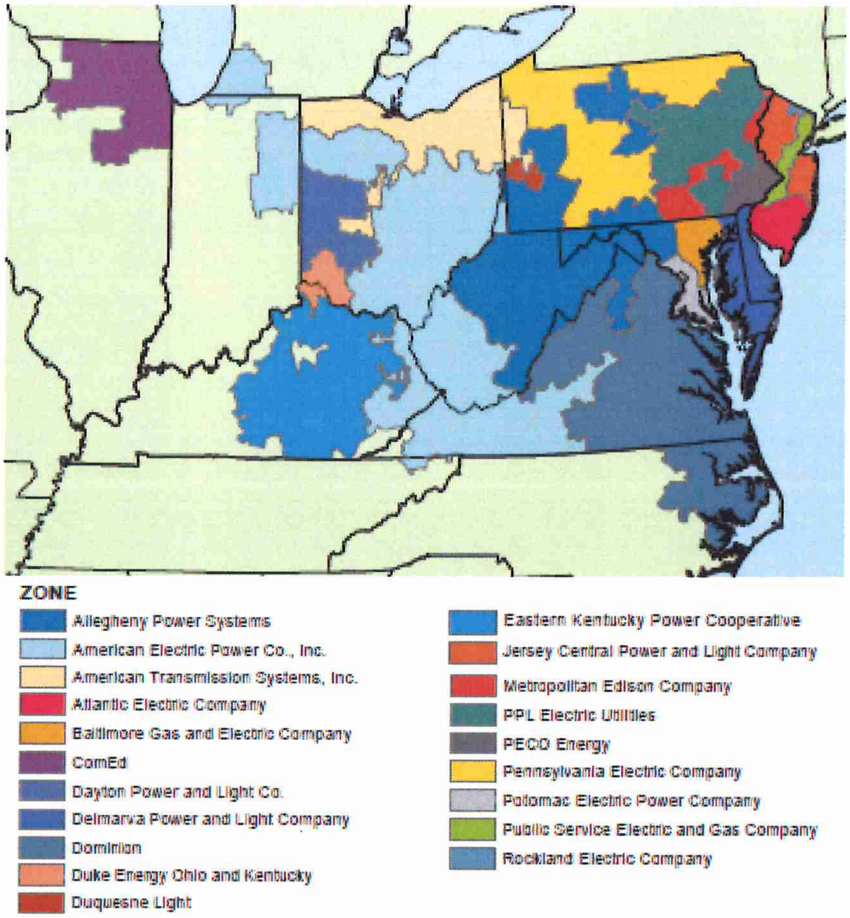
The PJM Interconnection is the world's largest wholesale electricity market, coordinating the generation and delivery of power to over 60 million customers to 14 states across the mid-Atlantic U.S. PJM was created in 1927, and in 1997 became the first Independent System Operator ("ISO") in the United States. Weather-normalized peak demand in PJM was 147.4 GW in the summer of 2018.[3] PJM has a diverse capacity mix, with coal, nuclear, and natural gas capacity supplying approximately equivalent quantities of energy on an annual basis in recent years. PJM currently operates markets for energy, ancillary services, and capacity. The bid-based market for balancing energy, based on locational marginal pricing ("LMP"), was initiated in 1998, followed by a day-ahead energy market in 2000. The current capacity market structure, known as the Reliability Pricing Model ("RPM"), has been in place since 2007.

The PJM footprint covers a broad geographic area, spanning the Mid-Atlantic region from Newark, New Jersey to North Carolina's Outer Banks and extending inland as far north as Chicago and as far south as the eastern portion of Kentucky. PJM is currently divided into twenty control zones, as shown in Exhibit 3. DP&L's service territory is within a single control zone, referred to as the DP&L or Dayton zone in this report.

PJM administers competitive markets for day-ahead and real-time energy, Financial Transmission Rights ("FTRs") markets, ancillary services, and a capacity market administered through the RPM forward market design. Load-serving entities ("LSEs") procure wholesale energy, ancillary services, and capacity through the PJM spot markets as well as through short- and long-term bilateral transactions that are accounted for by PJM, but the terms of which are negotiated outside the market construct.

3 PJM Interconnection Summer 2018 Weather Normalized RTO Coincident Peaks (MW). <https://www.pjm.com/-/media/planning/res-adeq/load-forecast/20181017-summer-2018-peaks-and-5cps.ashx?la=en>

Exhibit 3: PJM Footprint and Zones[4]



2.2. PJM Day-Ahead and Real-Time Energy Market

PJM began operating a bid-based competitive wholesale market in 1997 and, in 1998, implemented LMP pricing. Under LMP, congestion is managed economically by providing price signals at the nodal level for each location of the grid. LMPs reflect the production costs and incremental value associated with the supply of power at any given location, accounting for the impacts of both transmission congestion and line losses. Energy prices in PJM, therefore, reflect both the marginal cost of generation needed to meet system load, as well as the costs associated with congestion and losses on the transmission system.[5]

PJM operates its energy market with a two-settlement system, consisting of both day-ahead and real-time market clearing. In the day-ahead market, offers received from generators are cleared against day-ahead forecasted loads, producing schedules for unit commitment and expected dispatch. Based on the day-ahead dispatch, generation owners receive an hourly, day-ahead schedule for each generating unit and are paid the day-ahead price for all

[4] PJM. "Transmission Zones." <http://www.pjm.com/~/media/about-pjm/pjm-zones.ashx>.

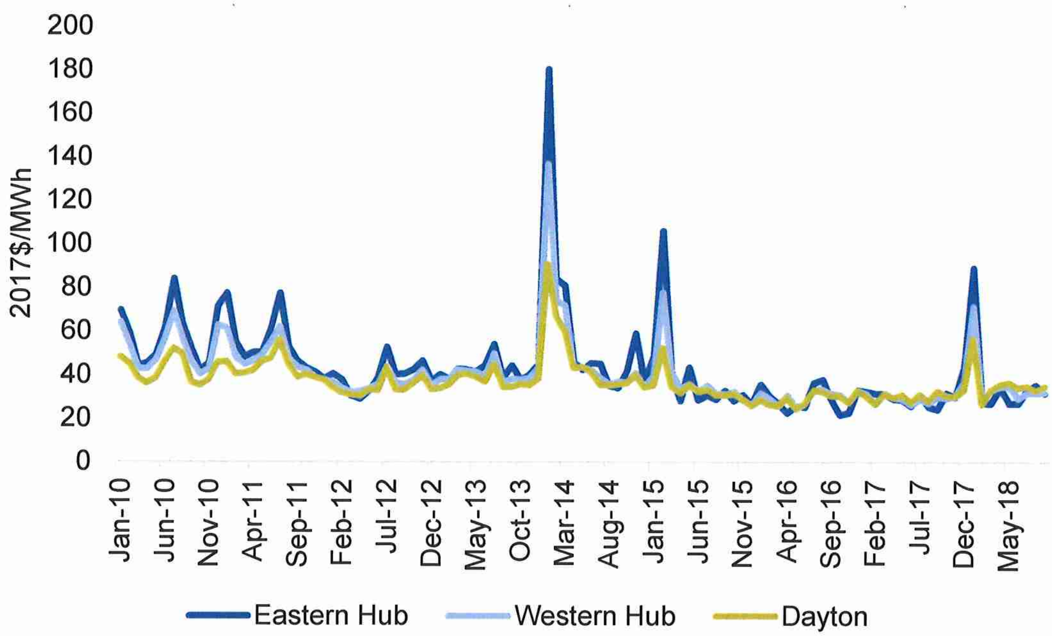
[5] PJM. "Manual 11: Energy & Ancillary Services Market Operations." Section 2: Overview of the PJM Energy Markets. 25 Aug 2016. <http://pjm.com/~/media/documents/manuals/m11.ashx>.

scheduled output from the units, in exchange for a financial commitment to supply energy at the specified location in real-time.[6]

PJM subsequently dispatches generation to meet actual real-time load, accounting for any real-time deviations from forecasted load and any real-time deviations from the day-ahead schedules of generators. The real-time dispatch is performed for 5-minute intervals, and LMPs are determined for each 5-minute interval. The values from the 5-minute dispatch are integrated back to hourly values for settlement purposes. Generators with day-ahead schedules are paid for their scheduled generation based on the day-ahead price, with any real-time deviations from the day-ahead schedule priced at the real-time LMP. Any other generators called only in real-time are paid the real-time price.[7]

Exhibit 4 shows the historic monthly average day-ahead energy prices at PJM's Eastern and Western Hubs and for the Dayton zone. The Dayton zonal price has historically tracked the Western Hub, with a slight discount being common for many years. However, recent prices in Dayton have been quite close to the Western Hub, with a premium evident in many months. The Dayton zone tends to be less susceptible than the Western and Eastern Hubs to large winter price spikes which are caused by spikes in the price of natural gas. This is largely due to the presence of significant coal generation in the Dayton region and surrounding zones, as well as access to lower-cost natural gas supplies in Dayton and the surrounding zones when compared to the constrained markets in the Northeast and Mid-Atlantic regions.

Exhibit 4: Historic Monthly Average PJM Day-Ahead LMP Prices



[6] PJM. "Manual 11: Energy & Ancillary Services Market Operations." Section 2: Overview of the PJM Energy Markets. 25 Aug 2016. <http://pjm.com/~/media/documents/manuals/m11.ashx>.

[7] PJM. "Manual 11: Energy & Ancillary Services Market Operations." Section 2: Overview of the PJM Energy Markets. 25 Aug 2016. <http://pjm.com/~/media/documents/manuals/m11.ashx>.

2.3. PJM Ancillary Services Market

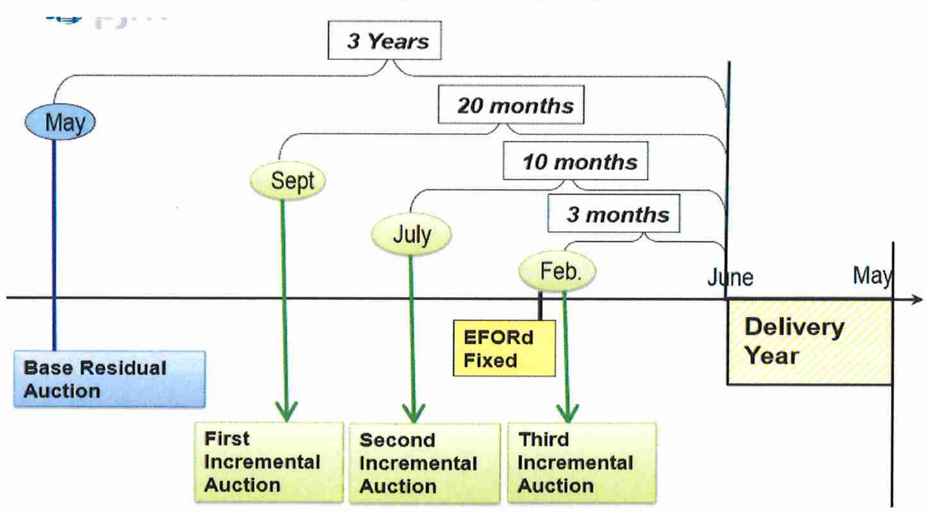
In addition to the energy market, PJM operates a market for ancillary services and coordinates the dispatch of generators to provide these services. Ancillary services in PJM include synchronous and non-synchronous operating reserves, regulation, reactive power support, and black start services. The supply and pricing of operating reserves and regulation are coordinated with the energy dispatch of generators through bid-based markets. Other ancillary services are procured contractually at tariff-based rates.[8]

2.4. PJM Capacity Market

In 2007, PJM launched the RPM capacity market, which provides long-term price signals and incentives for the development of new generation and/or load management products to meet PJM resource adequacy needs. RPM is a forward capacity market, structured around a mandatory Base Residual Auction ("BRA") that occurs approximately three years in advance of the planning year for which capacity is procured. RPM capacity is an annual product, in which suppliers have an obligation to make their capacity available during the entire Delivery Year, which runs from June 1 through the following May 31. PJM acts as a central buyer in these auctions, allocating costs of capacity purchases back to 19 LSEs in proportion to the allocation of peak load and resulting capacity purchase obligations.[9]

While most or all of the expected capacity obligations of LSEs will be met through the BRA, or through self-supply and bilateral transactions established in advance of the BRA, suppliers also have the opportunity to rebalance their positions through three incremental auctions. First, Second, and Third Incremental Auctions ("IA") are conducted twenty, ten, and three months prior to the Delivery Year. Exhibit 5 illustrates the timing of the PJM capacity auctions.

Exhibit 5: Timing of PJM Capacity Auctions[10]



[8] PJM. "Manual 11: Energy & Ancillary Services Market Operations." Section 1: Overview of Energy & Ancillary Services Market Operations. 25 August 2016. <http://pjm.com/~/media/documents/manuals/m11.ashx>.

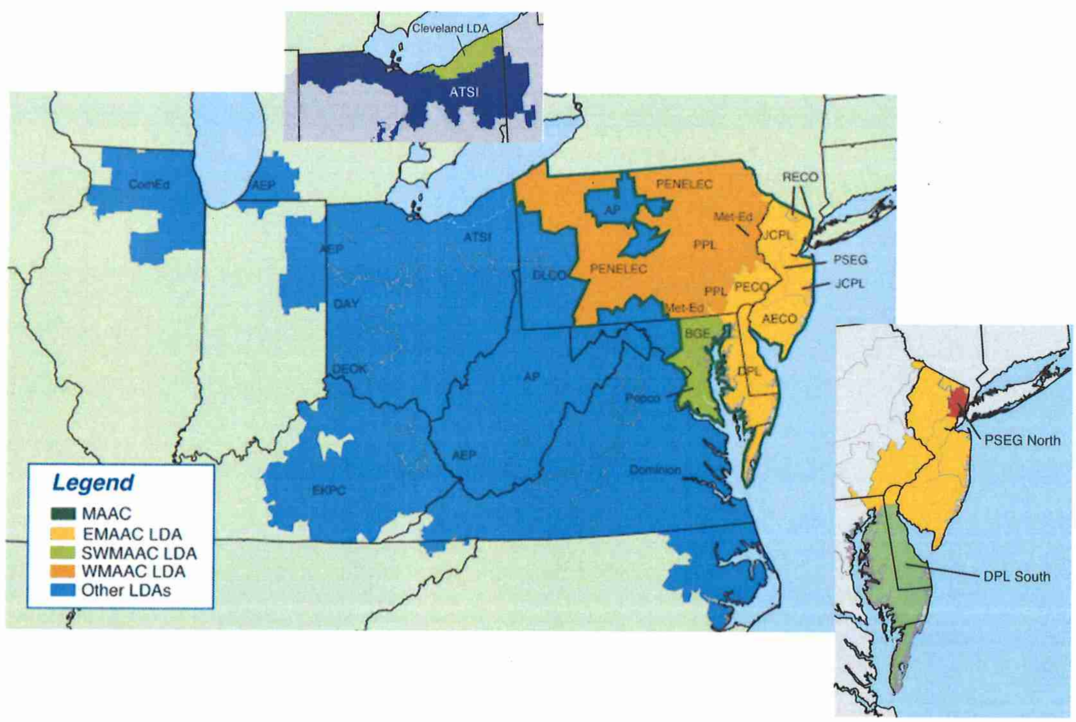
[9] PJM. "Manual 18: PJM Capacity Market." 28 July 2016. <http://pjm.com/~/media/documents/manuals/m18.ashx>.

[10] Keech, Adam, Director of Market Operations for PJM. "Energy Efficiency in RPM." 13 Jan 2015. <http://www.njcleanenergy.com/files/file/Committee%20Meeting%20Postings/ee/20150113%20-%20NJBPU%20Presentation%20-%20EE%20with%20stopgap%20slides.pdf>.

Though the transmission capacity between zones in the PJM system is considerable, there remain limitations on capacity import and export capability for some parts of the system. In recognition of this, RPM has been implemented as a locational market, with pricing regions called Locational Deliverability Areas ("LDAs").[11] PJM has separate reliability requirements for a number of LDAs, which may be nested within one another; for example, the PEPCO zone in Maryland and Washington, DC is in the larger SWMAAC zone, which is within the even larger MAAC zone, which is within the full Regional Transmission Operator ("RTO") zone. Exhibit 6 presents a map of all LDAs in PJM. The Dayton zone is located only in the RTO LDA.

An installed capacity requirement is determined for each LDA, which can be met through a combination of local resources and imports up to a specified transfer limit. Depending on transmission congestion and load pockets, an LDA will either clear with the RTO or break out at a higher price. In the most recent 2021/2022 delivery year auction, for instance, the RTO-wide price was $140.00/MW-day (nominal dollars), while numerous zones broke out at higher prices, including ComEd ($195.55/MW-day), EMAAC ($165.73/MW-day), PSEG ($204.29/MW-day), and BGE ($200.30/MW-day).[12]

Exhibit 6: Locational Deliverability Areas within PJM[13]



[11] Note: LDAs are not mutually exclusive pricing regions. Several LDAs (e.g., MAAC, EMAAC, SWMAAC) include other LDAs. A nested LDA can have a capacity price that is the same or greater the wider are LDA.

[12] PJM. *2021/2022 RPM Base Residual Auction Results.* 23 May 2018. <http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en >. Values in nominal dollars.

[13] Monitoring Analytics. "PJM State of the Market Report – 2016." Section 5. 11 Aug 2016. <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016.shtml>.

Market parameters are also set on a regional basis, reflecting differences in construction costs and market prices throughout the PJM footprint. Specifically, the Gross and Net Cost of New Entry ("CONE"), which affect the shape of the administratively-set demand curve, are calculated for each region. Exhibit 7 identifies the different load zones in each CONE Area.[14]

Exhibit 7: Load Zones in Each CONE Area in PJM[15]

Cone Area	LSEs
Cone Area 1	AE, DPL, JCPL, PECO, PSEG, RECO
Cone Area 2	BGE, PEPCO
Cone Area 3	AEP, APS, ComEd, Dayton, DLCo, ATSI, DEOK, EKPC, Dominion
Cone Area 4	METED, PENELEC, PPL

Multiple types of resources can offer supply in the RPM, including existing or planned generation, existing or planned load management products (demand response and energy efficiency), and planned qualifying transmission upgrades. Generating resources supply capacity on an unforced capacity ("UCAP") basis, which is equal to the nameplate installed capacity of the unit multiplied by one minus the equivalent forced outage rate ("EFORd") for the resource.[16] Load management resources are adjusted by an administratively-determined Demand Resource Factor ("DR Factor").[17]

Prices in the RPM market are set by the intersection of an offer curve, determined by the offers from resources available to supply capacity, and an administratively set "demand curve" called the Variable Resource Requirement ("VRR") curve. The price levels on the VRR curve are set based on PJM's estimates of Net CONE, equal to the all-in cost of building a new gas combustion turbine generating unit (or Gross CONE) less the expected energy and ancillary services earnings. Exhibit 8 shows the PJM VRR curve shape relative to the market parameters that are updated on an annual basis.[18] Section 6 contains a brief discussion of the CONE values that were used in CRA's market analysis.

---

[14] PJM. "Manual 18: PJM Capacity Market," page 24. 14 June 2016. <http://www.pjm.com/~/media/documents/manuals/m18.ashx>.

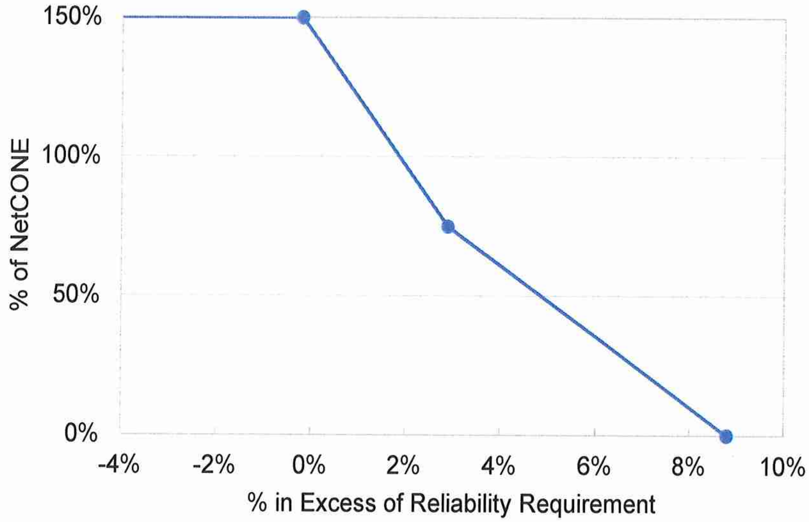
[15] PJM. "2021-2022 RPM Base Residual Auction Planning Parameters." 3 May 2018.

[16] In mathematical terms, UCAP = ICAP * (1-EFORd) * 100

[17] PJM. "Manual 18: PJM Capacity Market." 28 July 2016. <http://pjm.com/~/media/documents/manuals/m18.ashx>.

[18] PJM. "2021-2022 RPM Base Residual Auction Planning Parameters." 1 February 2018. < https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-rpm-bra-planning-parameters-report.ashx?la=en> and CRA analysis.

Exhibit 8: VRR Curve



The VRR curve is constructed such that, at PJM's target level of installed capacity, Net CONE is the expected pricing outcome. In other words, when new capacity is needed to meet PJM capacity requirements, the VRR curve is designed to return a price equal to CONE, net of earnings from the sale of energy and ancillary services that a new generator can be expected to earn. The PJM tariff specifies that the new reference unit used to set the demand curve is a combustion turbine ("CT") generating station, configured with one General Electric Frame 7HA turbine.[19]

When the quantity of capacity falls below the target level, the price will be above Net CONE, signaling a need for new entry; with surplus capacity, the price will fall below Net CONE, signaling that additional entry is not needed and potentially triggering the retirement of uneconomic capacity. However, the use of a sloped demand curve retains a price signal that indicates to market participants that even quantities of capacity in excess of the procurement target have some value to the system.

Capacity Performance

Following the 2013/2014 winter Polar Vortex event, PJM faced criticism that supply resources were compensated for providing capacity but they did not face sufficient incentives to actually provide firm capacity when needed. PJM subsequently developed the capacity performance ("CP") rules and an enhanced non-performance penalty structure. CP was implemented gradually after Federal Energy Regulatory Commission ("FERC" or "Commission") approval in 2015; capacity obligations were bifurcated between CP-type obligations and "base" type obligations through the 2019/2020 delivery years. From 2020/2021 onward, all cleared resources are subject to CP rules. Under CP, resources' performance is assessed during

[19] PJM. "Manual 18: PJM Capacity Market," page 24. 14 June 2016. <http://www.pjm.com/~/media/documents/manuals/m18.ashx>. Note that PJM is in the midst of its update of CONE parameters, but is still recommending that the reference unit be a General Electric Frame 7HA turbine. Revised parameters were filed with the Federal Energy Regulatory Commission on October 15, 2018. If accepted, the updated tariff will go into effect on January 17, 2019.

periods of system stress that meet certain criteria. Though the details are more complex, the ultimate effect is that resources that perform better than the pool average are eligible to receive bonus payments, while resources that underperform the pool average are subject to considerable penalties. CP is designed to create incentives for resources to provide capacity value when it is most needed, during peak periods. CP supplements the long-term price signal of capacity prices with short-term economic incentives designed not only to promote availability during periods of system stress, but also to incent resources to make efficient capital investments and business decisions to ensure that they are able to operate reliably when needed most. Such measures might include upgrades to increase reliability and decrease unscheduled outages, improved forward planning and coordination to optimize planned outages, and fuel and storage arrangements to ensure supplies are available even during disruptive events.

Owing to the expanded set of risk and opportunities, CP was expected to shift capacity offer behavior and have at least some effect on market outcomes. Before CP, non-performance penalties were very low and resources sought capacity sales revenue with very little downside risk.[20] This calculus has shifted under CP, as there are considerable risks for unreliable units and opportunities to recover large bonus payments with no risk for uncommitted resources during performance events. CRA's analysis expects that these risks and incentives should be taken into account in any resource's competitive offer, and that under the CP construct, each generation resource, in forming its offer strategy, should weigh the likelihood and magnitude of incurring CP penalties against the expected revenue from clearing the capacity auction. Resources should also account for the fact that cleared resources also have a smaller CP upside than energy-only units. Energy-only units face no penalty risk and may earn bonus payments for all output during performance events, rather than only for additional output beyond expected performance (the metric for committed resources).[21] This calculus is specific to each resource and each owner, but the net effect should be upward pressure on capacity market offers and price outcomes. A comparison of the pre- and post-CP supply curves offered in RPM auctions shows this directional shift in capacity market offers.[22]

Historical Capacity Prices and Recent Market Dynamics

A wide range of capacity clearing prices has been observed over the life of the RPM, driven by a combination of changes in market rules and key fundamental market drivers. Regulatory drivers include rules around transmission limits and import participation, standards for demand response and energy efficiency participation, and the recent implementation of CP. Fundamental drivers around the costs of new builds and the energy market performance of natural gas, coal, and nuclear plants in the face of changing fuel price dynamics and environmental regulations have also influenced market prices across the RTO and within specific LDAs. Exhibit 9 summarizes the clearing prices for the major LDAs since the 2015/2016 delivery year. The capacity price for the Dayton zone is equal to the PJM RTO price.

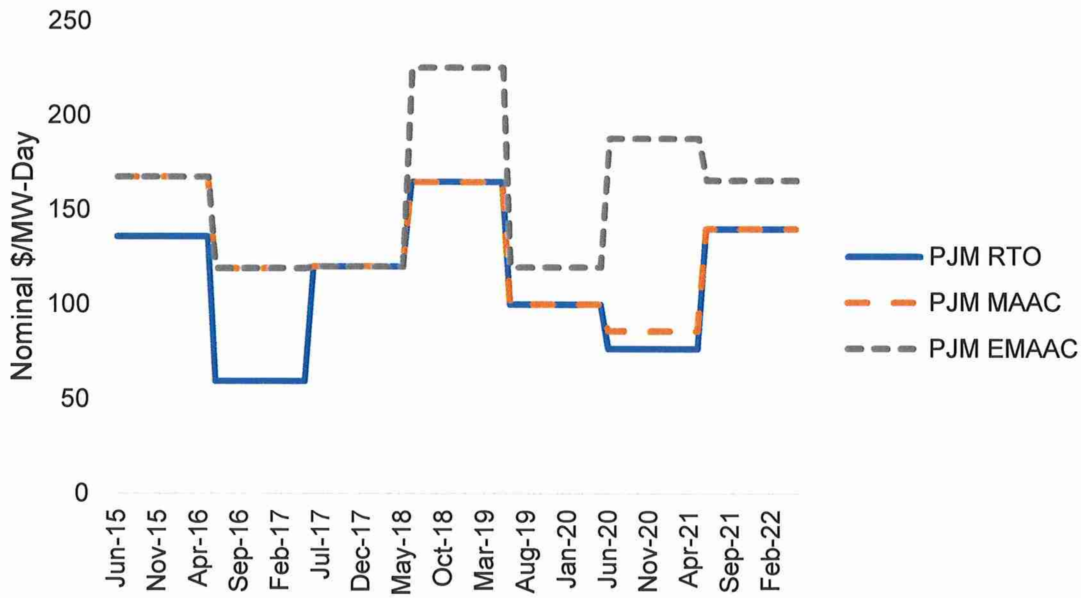
---

[20] *See, e.g., PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208, at P 47, *order on reh'g*, 152 FERC ¶ 61,064 (2015).

[21] This methodology has been presented by the PJM Market Monitor as the optimal competitive offer strategy. Prior to public flings in related dockets, CRA developed the methodology independently based on internal economic analysis.

[22] *The Brattle Group*. Fourth Review of PJM's Variable Resource Requirement Curve. April 19, 2018 at p 42.

Exhibit 9: Historical RPM Clearing Prices[23]



**Capacity Performance clearing prices shown for 2018/19 and 2019/20.*

The RTO price for delivery year 2021/2022 was $140.00/MW-day, up from $76.53/MW-day in 2020/2021. The higher clearing price can be ascribed to a combination of factors. On the demand curve side, there was downward pressure on prices from a reduction in peak load expectations, but also upward pressure from increases in net CONE across the RTO, largely driven by decreases in expectations for the energy and ancillary services offset. On the supply side, there were fewer new generation entrants and fewer announced retirements than had been observed in recent years, but considerable additional capacity offered by demand response and energy efficiency. PJM surmises that higher prices across the RTO were significantly driven by higher offer prices from supply resources, potentially reflecting ongoing bearish expectations about the promise of revenues from the energy and ancillary services markets.

The 2021/2022 BRA also saw a decline in new capacity and uprates to a level not seen since the 2014/2015 auction. Between the 2015/2016 auction and 2020/2021 auctions, uprates and new capacity generally exceeded 5,000 MW of additions per auction. However, the 2021/2022 auction only procured 893 MW of new generation and 508 MW of uprates. The majority of this addition came from the expansion of combined cycle units, with solar being the second largest source of new generation, followed by combustion turbines, and wind resources. Unlike prior auctions, there were not significant quantities of pre-cleared combined cycle units that offered but did not clear, which indicates that there may be a more limited backlog of new gas projects than has been present in past years.

[23] PJM. *Capacity Market (RPM) Base Residual and Capacity Performance Auction Results.* <http://www.pjm.com/markets-and-operations/rpm.aspx> and CRA analysis.

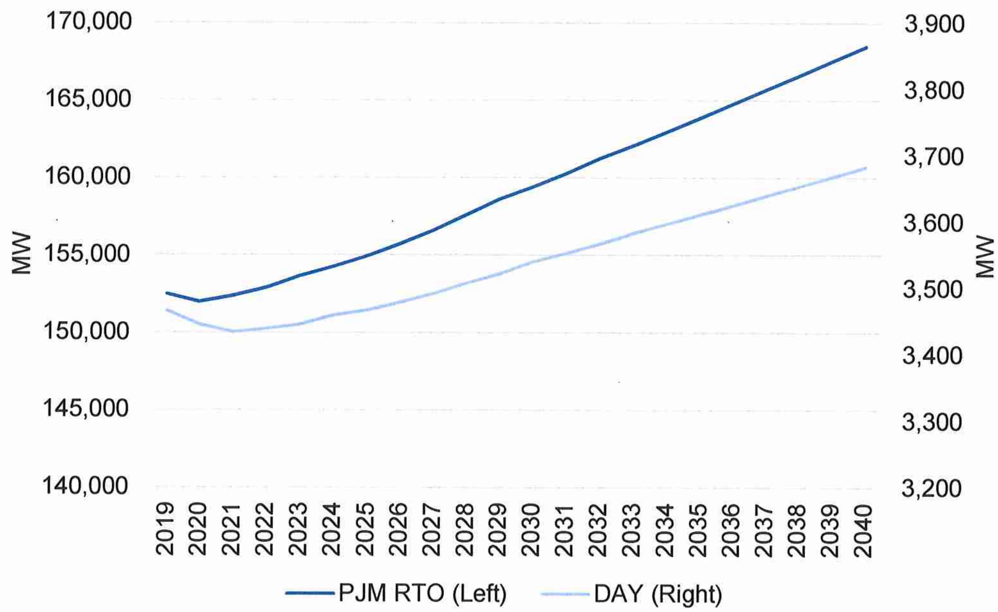
3. PJM Supply and Demand Fundamentals

The demand for and the supply of energy and capacity are important determinants of the price forecasts. The following sections provide an overview of demand growth expectations and current and future supply resources in PJM.

3.1. Electricity Demand Projections

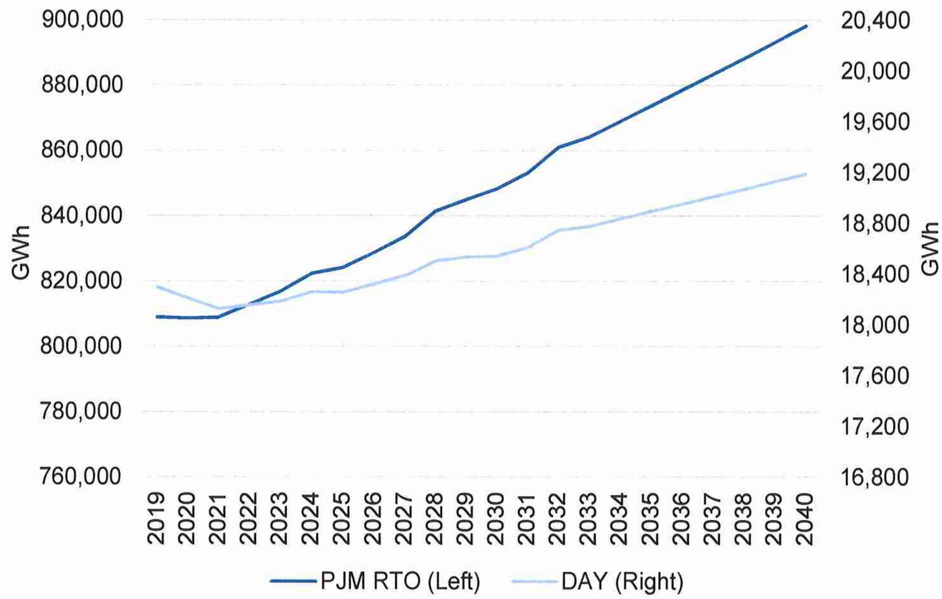
Load growth across much of PJM has been relatively flat in recent years due to relative weakness in underlying economic growth factors, but also increased penetration of energy efficiency and distributed energy resources. PJM's 2018 load forecast expects flat to declining load in the near-term, but a greater rate of growth over the long term. Exhibit 10 and Exhibit 11 summarize the peak demand and net energy for load outlook for all of PJM and the Dayton zone, respectively. These load forecasts have been used by CRA in its analysis. The compound annual growth rates for peak demand from 2019 to 2040 are 0.5% and 0.3% for the RTO and Dayton, respectively. The 2019-2040 growth rates for net energy for load are 0.5% and 0.2%, respectively.

Exhibit 10: PJM and Dayton Peak Demand Forecast (MW)[24]



24 PJM 2018 Load Forecast

Exhibit 11: PJM and Dayton Net Energy for Load Forecast (GWh)[25]



3.2. Existing Supply

PJM's generating fleet is diverse, with substantial amounts of nuclear, coal, natural gas, and renewable capacity. At the end of 2017, coal comprised 35 percent of the total capacity, natural gas accounted for 37 percent, and nuclear for 18 percent of the fleet.[26] In terms of generation, there has been a fairly even split between coal, nuclear and natural gas resources in recent years. Nuclear units have a higher share of electricity generation than capacity because they run at very high capacity factors, while the opposite holds true for many natural gas units. The capacity and generation mix for PJM is summarized in Exhibit 12 and Exhibit 13. In the Dayton and AEP zones (making up much of Ohio), coal comprises 48 percent of the summer installed capacity, with natural gas accounting for a further 34 percent of installed capacity. The remaining capacity is split approximately equally between renewable and nuclear resources.[27]

---

[25] PJM 2018 Load Forecast

[26] Monitoring Analytics. *State of the Market Report for PJM.* March 8, 2018. p 36.

[27] Energy Velocity Suite.

Exhibit 12: PJM RTO Capacity Mix, 2017 (% Breakdown)

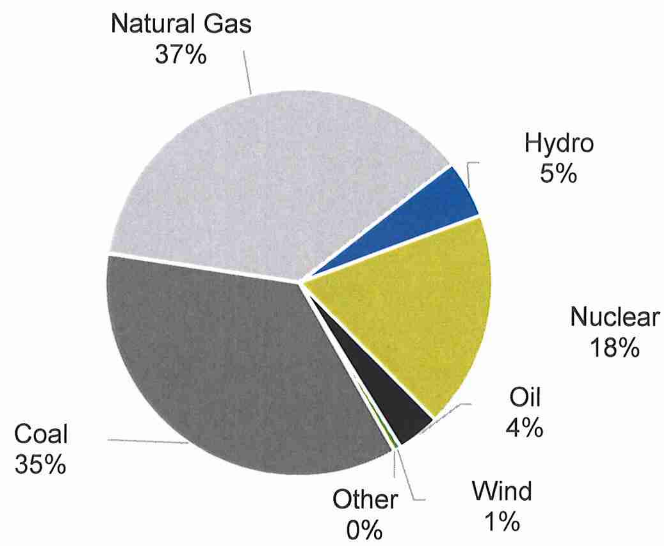
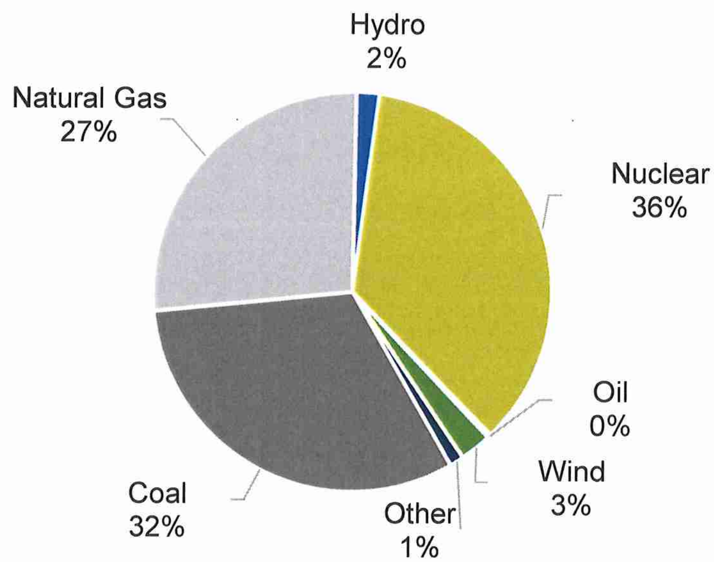


Exhibit 13: PJM RTO Generation Mix, 2017 (% Breakdown)

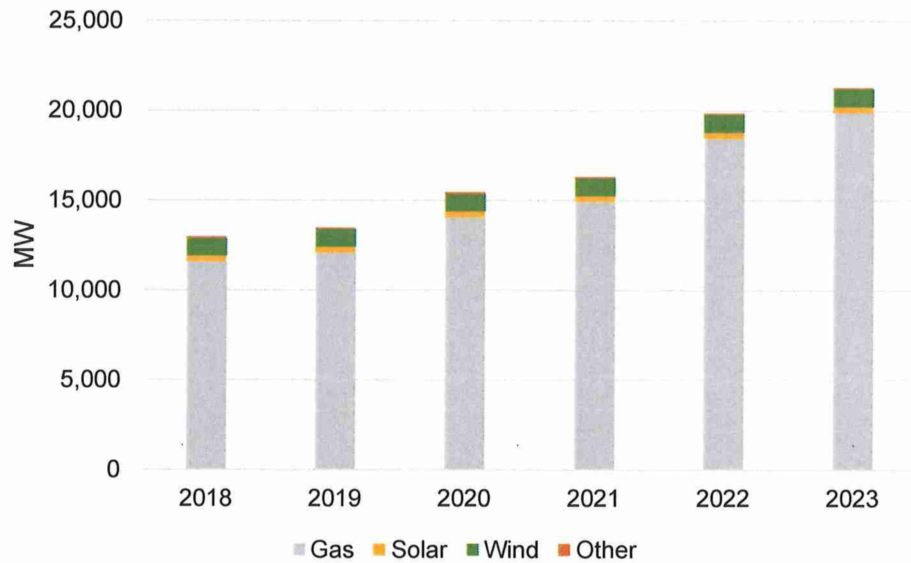


3.3. Capacity Additions and Retirements

3.3.1. New Capacity

CRA has assessed the proposed new units in PJM and has explicitly added high-probability unit additions in its analysis based on expected online dates. At present, there are a great number of generation projects in various stages of development that have applied for interconnection permits in PJM. Approximately 13 GW of natural gas capacity has or is expected to come online in 2018 alone, and between 2019 and 2020 the analysis expects another 2.5 GW of new natural gas capacity will be operational. Most of this capacity is state-of-the-art, high-efficiency combined-cycle plants taking advantage of abundant Marcellus shale production and very low gas prices. In addition, CRA has identified another nearly 4 GW of gas capacity at various stages of development that has some probability of entering into service in the 2021 to 2023 period. Beyond the natural gas-fired additions, PJM has approximately 1.3 GW of renewable energy under construction.[28] Exhibit 14 summarizes the probability-weighted modeled capacity additions included in the analysis. There is a significant number combined cycle additions throughout Ohio and Pennsylvania that aim to take advantage of low natural gas prices. Appendix C contains a list of all of the announced capacity included in the analysis with the relevant probability weightings.

Exhibit 14: PJM Firm Capacity Additions (Cumulative from 2018)[29]



Renewable Portfolio Standards

Renewable resources make up a growing part of the PJM capacity and generation mix. Many renewable resources were originally developed to satisfy the RPS standards established by a number of states over the last several years. In addition to general RPS standards that may be satisfied by any qualifying renewable technology, certain states have set technology-specific mandates for distributed solar, off-shore wind and batteries in their RPS targets.

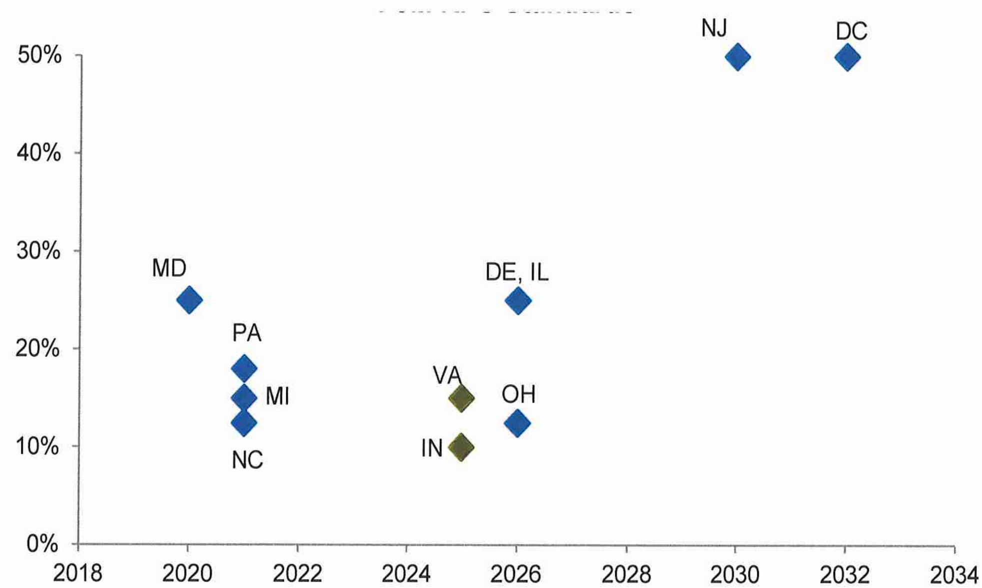
Relevant to the Dayton zone, Ohio has in place an "alternative portfolio standard" that requires load-serving entities to procure a volume of electricity from qualified renewable resources equal to 5.5 percent of total retail sales in 2019, ramping up to 12.5 percent of total retail sales by 2026. Of the 12.5 percent, at least 0.5 percent must come from solar

[28] Ibid.

[29] CRA Analysis.

resources (in 2026).[30] Exhibit 15 summarizes the RPS standards for relevant states in PJM as a percentage of total retail sales.

Exhibit 15: PJM RPS Requirements – Final Target by Year[31]



**Note: Green points for IN and VA represent non-binding voluntary targets.*

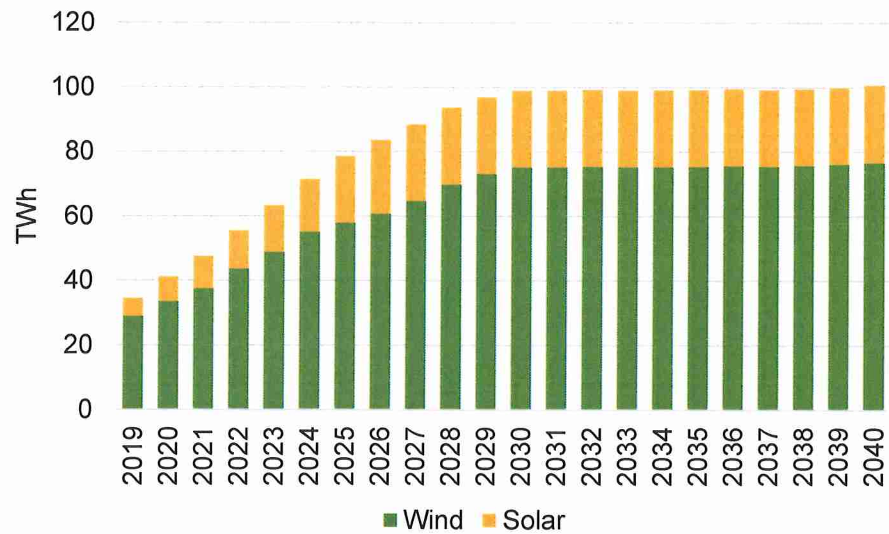
CRA's analysis explicitly incorporates the new renewable capacity that is required in order to achieve the state-level RPS requirements that exist across PJM, though individual states may rely on exports from other states within and outside of PJM to meet their RPS targets. In the long-term, the weighted RPS targets across the region (inclusive of states without RPS and not counting voluntary standards) would result in ten to twelve percent of PJM's energy to be supplied by renewables. By 2030, the sum of all PJM state-level renewable requirements implies that approximately 100 TWh of generation must come from renewable resources. CRA's forecast for wind and solar generation over time is shown in Exhibit 16.

---

30 NC Clean Energy Technology Center at NC State University. Database of State Incentives for Renewables & Efficiency (DSIRE).

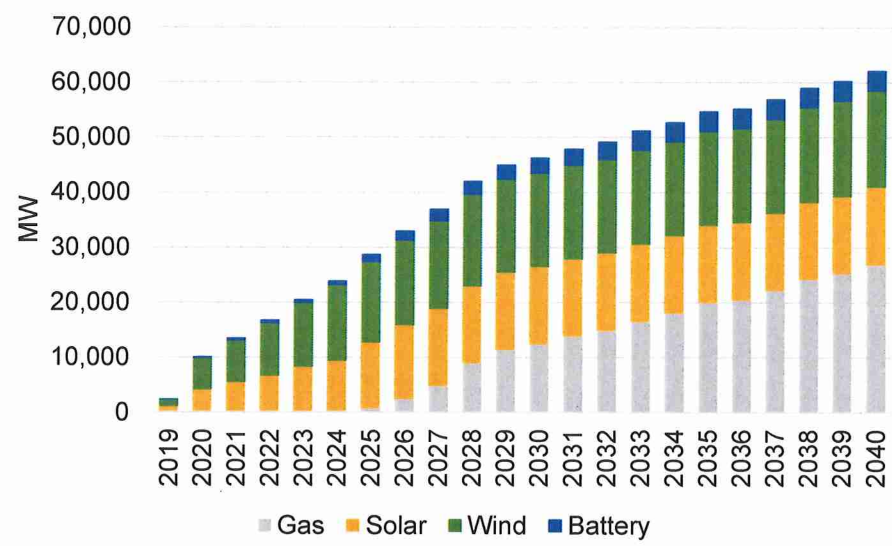
31 Ibid.

Exhibit 16: PJM Renewable Generation Forecast[32]



In addition to the new capacity needed to satisfy RPS requirements and the announced units expected to enter into service in the near term, CRA's market analysis adds generic capacity in response to economic signals that generally materialize when reserve margins fall and capacity prices or energy margins increase. The total cumulative capacity additions by year in CRA's assessment, including additions to meet the RPS requirements described above, are summarized in Exhibit 17.

Exhibit 17: PJM Generic Capacity Additions (Cumulative from 2018)[33]



32 CRA Analysis.

33 CRA analysis.

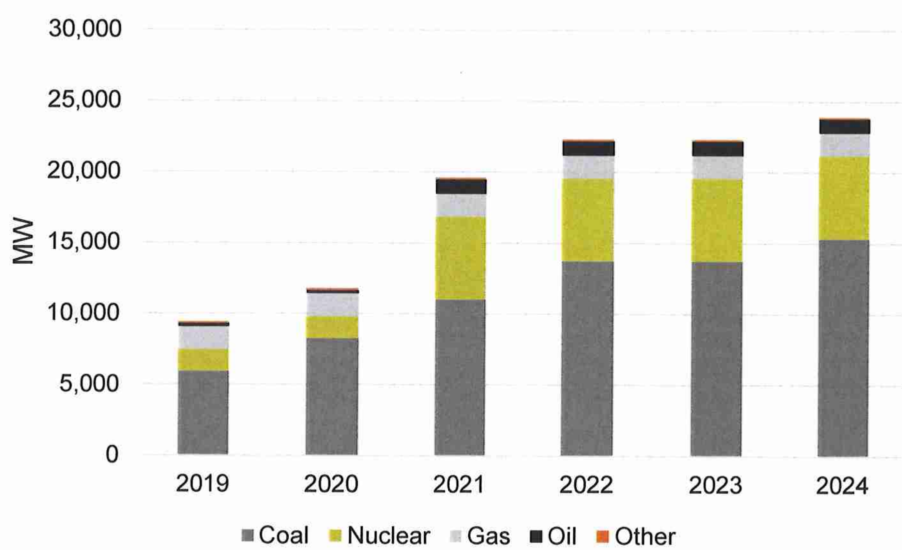
3.3.2. Retirements

Over time, capacity is also likely to exit the market as a result of economic conditions, age, or environmental regulations. Notably, a number of coal units have either retired in the last several years or announced a retirement date in the next few years due to regulations on mercury and air toxics, low natural gas prices, and age. Over 5 GW of coal capacity in PJM has retired since 2014, and over 8 GW of additional coal capacity in PJM has announced retirement between 2020 and 2022.

Beyond coal plant retirements, a significant number of nuclear units are at risk of early retirement. Many nuclear units reach the end of their current operating licenses during the 2030s and 2040s. To date, the US Nuclear Regulatory Commission has licensed nuclear plants for up to 60 years, but indicated that it will allow reactors to apply for additional 20-year license renewals. CRA has assumed that nuclear plants with multiple units will be allowed to extend their operations to 80 years and that single unit plants will shut down after 60 years.

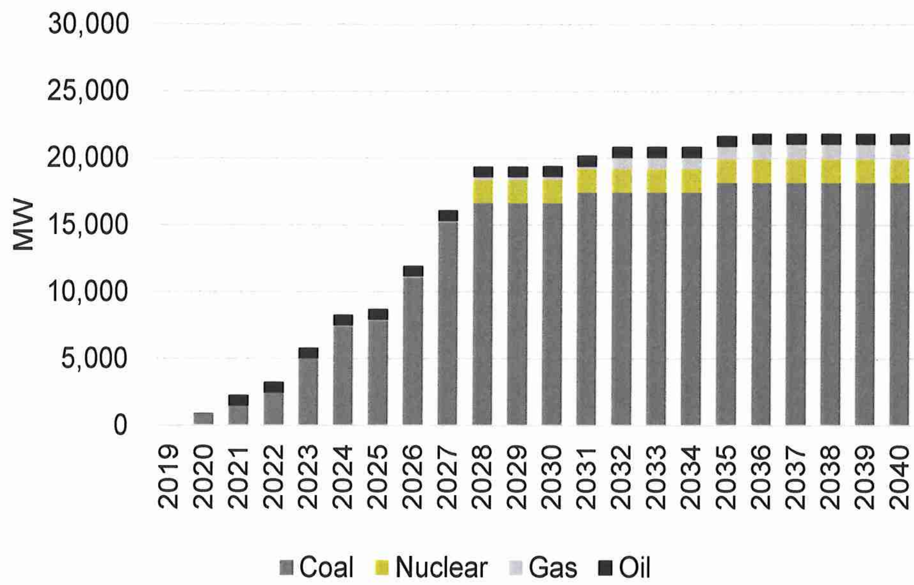
Apart from the issue of license renewal, several nuclear units have announced early retirements due to low economic performance in recent years. In 2016, Exelon announced plans to retire plants in Illinois, but state lawmakers provided support to these plants through zero emission credit subsidies. These plants are now expected to operate through 2028. More recently, in March 2018, First Energy Solutions announced its intention to close three nuclear units: Beaver Valley in Pennsylvania and Perry and Davis Besse in Ohio by mid-2021. These retirements are included in CRA's analysis. The cumulative expected firm capacity retirements, mostly made up of coal and nuclear units, are summarized in Exhibit 18, with specific units listed in Appendix D.

Exhibit 18: PJM Firm Capacity Retirements (Cumulative from 2018)



Beyond the near-term period, CRA's long-term analysis assesses the economic conditions and plant age of all existing capacity in PJM in order to project likely retirements over time. CRA expects that approximately 17 GW of additional coal capacity will retire between 2020 and 2030 as a result of weak energy and capacity margins and impending carbon emission restrictions, with an additional 1.5 GW retiring from 2031 to 2040. Exhibit 19 summarizes the economic retirements included in the analysis, which are dominated by coal-fired capacity.

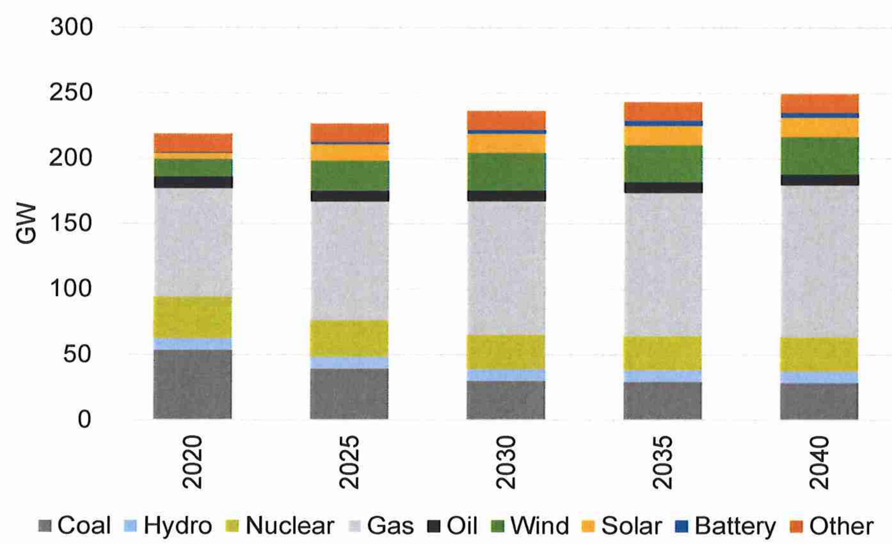
Exhibit 19: PJM Economic Capacity Retirements (Cumulative from 2018)



3.4. Projected Capacity and Generation Mix

Over the long-term, the capacity and generation mix in PJM is likely to evolve away from coal and towards natural gas and renewables. On a capacity basis, CRA expects installed coal capacity in PJM to decline from about one third of the total today to just over one fifth by 2036. The nuclear share is also likely to decline slightly as a result of retirements, while natural gas and renewable capacity shares are expected to increase. This is shown in Exhibit 20.

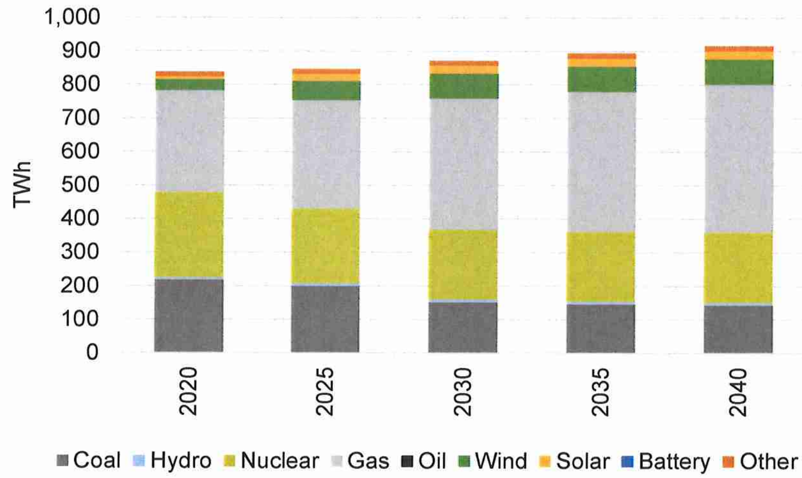
Exhibit 20: Projected Capacity Mix in PJM[34]



34 CRA Analysis. Note that the "Other" category includes demand response.

On a generation basis, total gas and renewable generation is likely to increase over time, while coal and nuclear generation is projected to decline. This is summarized in Exhibit 21.

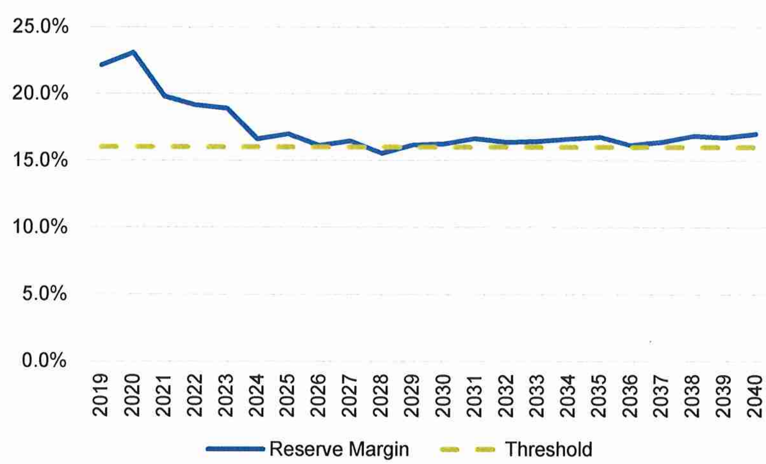
Exhibit 21: Projected Generation Mix in PJM[35]



3.4.1. Reserve Margin Outlook

Exhibit 22 summarizes CRA's reserve margin expectations over time for the entire PJM footprint. Near-term announced natural gas capacity additions are likely to keep reserve margins in the 20 percent range, but in the mid-2020s, the combination of economic retirements and load growth cause reserve margins to decline in the forecast. The long-term outlook expects PJM to meet a minimum reserve requirement around 16 percent. PJM's installed reserve margin requirement for the 2021/2022 delivery year was 15.8 percent.[36]

Exhibit 22: Projected PJM Reserve Margin[37]



[35] CRA Analysis. "Other" category includes demand response.

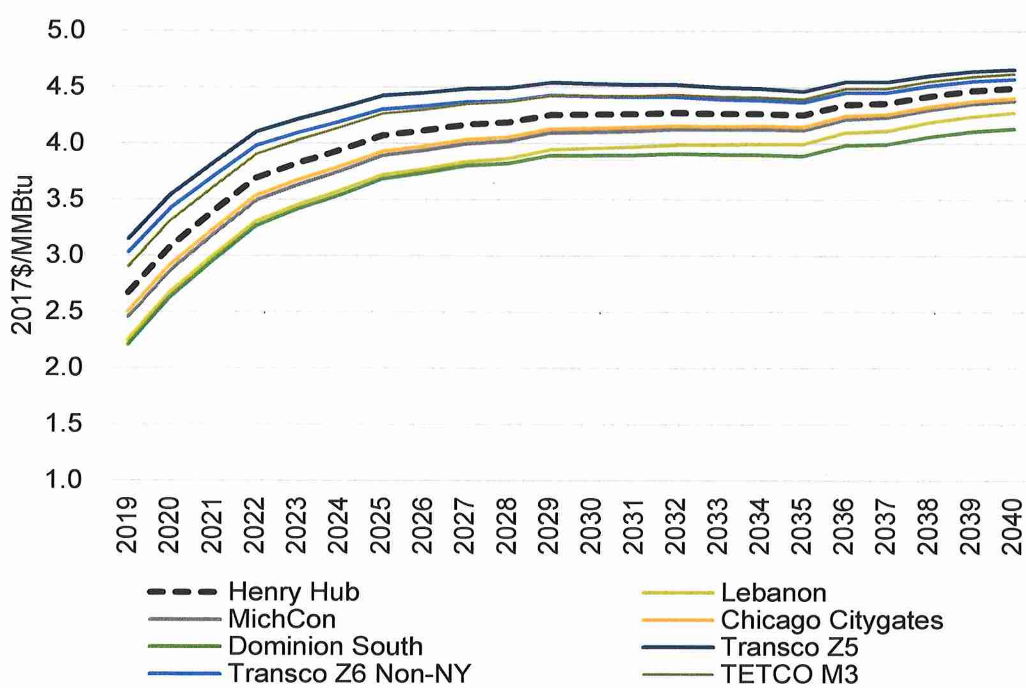
[36] PJM. "2021/2022 RPM Base Residual Auction Planning Parameters." 3 May 2018.

[37] CRA Analysis.

4. Fuel Prices

The natural gas prices for major hubs in PJM along with the Henry Hub benchmark that were used in CRA's analysis are summarized in Exhibit 23. The near-term natural gas price projections through 2019 were based on OTC Global Holdings forwards. Beyond that period, the analysis transitioned to the reference case natural gas forecast published in the U.S. Energy Information Administration's ("EIA") Annual Energy Outlook ("AEO") 2018. EIA's AEO provides modeled projections of domestic energy markets through 2050, and it includes cases with different assumptions regarding macroeconomic growth, world oil prices, technological progress, and energy policies. The analysis utilized the reference case natural gas price outlook at Henry Hub, which rises gradually from \$3.69/MMBtu in 2022 to \$4.50/MMBtu 2040. Local delivered prices for natural gas at various points throughout PJM were developed by analyzing historical and forward market basis between these points and the benchmark Henry Hub price.

Exhibit 23: Natural Gas Price Outlook[38]



CRA's analysis developed delivered coal prices for plants throughout PJM by combining basin level coal price forecasts for the major coal producing regions with transportation costs for each plant based on historical coal delivery data. The basin level coal price forecasts were developed by CRA, through an analysis of expected supply and demand for coal, along with production cost expectations for each producing region. The detailed coal price projections used in the analysis are presented in Exhibit 28 in the appendix.

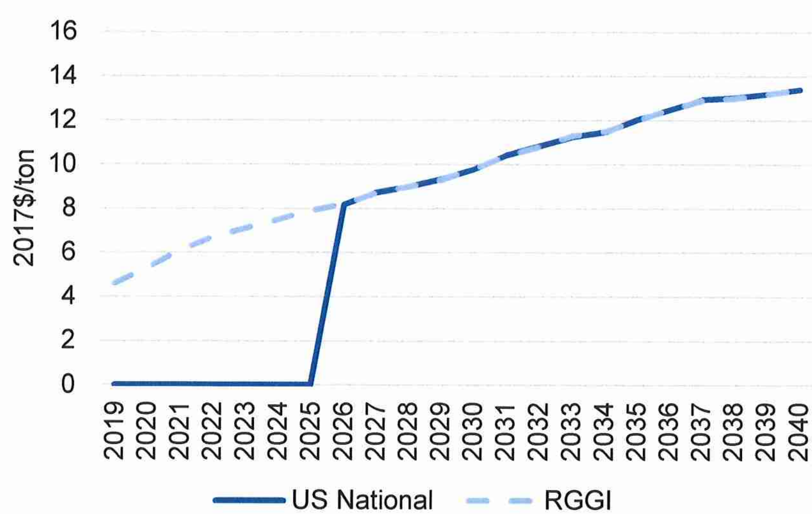
[38] AEO 2018 and CRA Analysis.

5. Carbon Prices

There is currently no national or PJM-wide program in place to limit carbon dioxide emissions or implement a price associated with them. However, several states within PJM participate in the Regional Greenhouse Gas Initiative ("RGGI"). The RGGI program is a joint effort by the states of New York, Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, Rhode Island, and Vermont, with New Jersey and Virginia due to join soon, to reduce greenhouse emissions from the power sector. The program is a cap-and-trade system, where most emission allowances are sold by the states through an auction program designed to support energy efficiency and clean energy programs. Power generators must then surrender an allowance for each associated ton of CO_2 emissions. The allowances can be traded and the price of an allowance raises the variable costs of generation for fossil-fired units throughout the states that participate.

In addition to a price on carbon for generators in RGGI states, CRA's analysis also includes a national carbon price, beginning at around $8/ton in 2026 and gradually rising to around $13/ton in 2040. This is shown in Exhibit 24. This price trajectory is informed by CRA's independent assessments of the price required on carbon to achieve emissions reductions from the U.S. electric power sector in line with recent policy proposals. The carbon price incorporated in the analysis results in reductions of power sector carbon emissions by 2030 of around 22 percent relative to a 2012 baseline and 34 percent relative to a 2005 baseline. This level is in line with targets that were proposed in the EPA's 2015 Clean Power Plan, which remains a reasonable benchmark for potential future policy. Note that prices for the Regional Greenhouse Gas Initiative ("RGGI") carbon market are included for states participating in that program through 2025. In 2026 and beyond, RGGI states are also assumed to face the national price. The appendix contains the values for the RGGI and national carbon prices over time.

Exhibit 24: U.S. National Carbon Price Outlook[39]



[39] CRA Analysis.

6. Cost of New Entry

The cost of new entry (or CONE) value used by PJM to establish the parameters of the VRR curve is an important driver of capacity pricing. This value is based on an assessment of the capital and fixed operating costs associated with a new plant entering the market, and it also represents the total annual revenue that a new generation resource would need to recover its capital investment and fixed costs over its economic life.

CRA has used PJM's CONE estimates to produce the capacity price forecast. PJM develops estimates of new unit costs for a simple-cycle combustion turbine ("CT") and combined cycle ("CC") gas unit on a quadrennial basis, with the latest update being produced in April, 2018.[40] The estimation process represents a bottom-up analysis of the capital and fixed operation and maintenance ("O&M") costs needed to build and operate the candidate plants.[41] The estimated costs are then annualized assuming a 20-year economic life and a suitable weighted–average cost of capital.[42]

As compared to the previous update in 2014, the latest CONE estimates are 22 to 28 percent lower for CTs and 40 to 41 percent lower for CCs. The major drivers for these decreases include greater economies of scale on larger combustion turbines, reduced federal income taxes and lower cost of capital outlook. The CONE values used in this analysis are summarized in the Appendix (Exhibit 30).

[40] PJM, Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date <http://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx>

[41] The capital costs required to build the plant include the engineering, procurement, and construction ("EPC") costs, project development, financing fees, gas and electric interconnection costs, and inventories. The annual fixed O&M costs include labor, materials, property taxes and insurance.

[42] An after-tax weighted-average cost of capital of 7.5 percent was assumed by PJM. This is equivalent to a return on equity of 12.8 percent, a 6.5 percent cost of debt, and a 65/35 debt-to-equity capital structure with an effective combined state and federal tax rate of 29.25 percent.

Appendix A: Power Price Forecast Details

Exhibit 25: Wholesale Energy and Capacity Price Forecast for Dayton Zone[43]

Year	*Energy Price Forecast (2017$/MWh)*		*Capacity Price Forecast (2017$/kW-yr)*
	On Peak	*Off Peak*	
2019	37.95	28.84	43.80
2020	39.41	30.37	29.20
2021	41.95	32.27	38.00
2022	44.28	34.09	50.10
2023	44.41	34.40	52.80
2024	45.11	34.64	55.80
2025	45.52	35.02	56.10
2026	50.18	39.63	60.80
2027	50.60	40.14	69.50
2028	50.44	40.00	73.80
2029	51.25	40.52	74.90
2030	51.48	40.67	76.30
2031	51.82	41.03	75.10
2032	52.21	41.45	75.20
2033	52.77	41.85	76.40
2034	52.32	41.78	76.10
2035	52.89	42.01	74.20
2036	53.78	42.69	76.10
2037	53.73	42.94	73.10
2038	54.11	43.39	74.10
2039	54.41	43.67	77.70
2040	54.57	43.95	76.50

43 Calendar year depicted. Highlighted cells represent already cleared PJM BRA prices on a calendar year basis.

Appendix B: Detailed Market Driver Assumptions

Exhibit 26: Peak Load (MW) and Net Energy for Load (GWh) Projections[44]

Peak Load (MW)

Year	PJM RTO	Dayton
2018	152,108	3,459
2019	152,479	3,466
2020	151,962	3,445
2021	152,363	3,434
2022	152,887	3,439
2023	153,632	3,445
2024	154,245	3,459
2025	154,941	3,467
2026	155,724	3,479
2027	156,605	3,492
2028	157,635	3,508
2029	158,624	3,522
2030	159,412	3,540
2031	160,294	3,553
2032	161,259	3,567
2033	162,095	3,583
2034	162,992	3,597
2035	163,893	3,611
2036	164,800	3,625
2037	165,711	3,640
2038	166,628	3,654
2039	167,549	3,668
2040	168,476	3,683

Net Energy For Load (GWh)

Year	PJM RTO	Dayton
2018	806,725	18,286
2019	809,000	18,294
2020	808,638	18,208
2021	808,882	18,126
2022	812,908	18,152
2023	816,817	18,183
2024	822,364	18,258
2025	824,140	18,254
2026	828,788	18,319
2027	833,712	18,387
2028	841,506	18,501
2029	845,058	18,533
2030	848,237	18,541
2031	853,245	18,608
2032	861,074	18,745
2033	864,236	18,776
2034	869,020	18,835
2035	873,831	18,893
2036	878,669	18,952
2037	883,533	19,011
2038	888,424	19,070
2039	893,343	19,130
2040	898,288	19,189

44 PJM 2018 Load Forecast from 2018-2033. CRA Analysis for 2034 and beyond.

Exhibit 27: Natural Gas Price Forecast (2017$/MMBtu)[45]

Year	Henry Hub	Lebanon	MichCon	Chicago Citygate	Domin-ion South	Transco Z5	Transco Z6 Non-NY	TETCO M3
2018	2.88	2.60	2.73	2.79	2.44	3.21	4.31	3.84
2019	2.67	2.25	2.45	2.50	2.21	3.15	3.03	2.90
2020	3.08	2.67	2.87	2.92	2.63	3.54	3.42	3.31
2021	3.40	3.00	3.19	3.24	2.96	3.83	3.71	3.62
2022	3.69	3.31	3.49	3.54	3.27	4.10	3.98	3.90
2023	3.83	3.45	3.63	3.68	3.42	4.22	4.10	4.03
2024	3.94	3.58	3.76	3.80	3.54	4.32	4.20	4.15
2025	4.07	3.72	3.89	3.93	3.68	4.42	4.30	4.26
2026	4.11	3.77	3.94	3.98	3.74	4.45	4.33	4.30
2027	4.17	3.84	4.00	4.03	3.80	4.49	4.37	4.35
2028	4.19	3.87	4.02	4.06	3.82	4.49	4.38	4.37
2029	4.26	3.94	4.09	4.13	3.89	4.54	4.43	4.43
2030	4.26	3.96	4.10	4.14	3.89	4.53	4.42	4.42
2031	4.26	3.97	4.11	4.14	3.90	4.52	4.41	4.42
2032	4.27	3.99	4.13	4.16	3.91	4.52	4.42	4.43
2033	4.27	3.99	4.12	4.15	3.90	4.50	4.40	4.42
2034	4.27	4.00	4.13	4.16	3.90	4.49	4.39	4.41
2035	4.25	3.99	4.12	4.15	3.89	4.46	4.37	4.40
2036	4.35	4.10	4.22	4.25	3.98	4.55	4.45	4.49
2037	4.36	4.12	4.23	4.26	3.99	4.55	4.46	4.49
2038	4.43	4.19	4.30	4.33	4.06	4.61	4.52	4.56
2039	4.47	4.24	4.35	4.38	4.11	4.64	4.56	4.60
2040	4.50	4.27	4.38	4.41	4.13	4.66	4.58	4.62

45 Henry Hub - OTCGH forwards for 2018 and 2019. 2020 and 2021 represent a blend of forwards and AEO 2018. AEO 2018 outlook for 2022 and beyond. All other hub pricing is informed by CRA's basis analysis.

Exhibit 28: Coal Basin Price Forecast (2017$/MMBtu)[46]

Year	Central Appala-chian	Northern Appala-chian	Illinois Basin	Powder River Basin	Rocky Moun-tain Ba-sin
2018	2.48	1.79	1.51	0.68	1.15
2019	2.36	1.70	1.48	0.68	1.14
2020	2.32	1.68	1.47	0.70	1.15
2021	2.29	1.66	1.47	0.71	1.17
2022	2.27	1.63	1.47	0.73	1.18
2023	2.23	1.62	1.47	0.74	1.21
2024	2.23	1.61	1.47	0.73	1.22
2025	2.24	1.59	1.47	0.73	1.22
2026	2.24	1.58	1.48	0.73	1.23
2027	2.24	1.57	1.49	0.73	1.25
2028	2.24	1.57	1.48	0.74	1.25
2029	2.24	1.57	1.48	0.74	1.26
2030	2.24	1.57	1.48	0.76	1.25
2031	2.24	1.57	1.48	0.76	1.25
2032	2.25	1.57	1.48	0.77	1.25
2033	2.25	1.57	1.48	0.77	1.26
2034	2.28	1.58	1.50	0.78	1.26
2035	2.30	1.59	1.51	0.78	1.27
2036	2.29	1.60	1.51	0.79	1.28
2037	2.29	1.61	1.51	0.79	1.28
2038	2.29	1.61	1.52	0.80	1.30
2039	2.30	1.62	1.53	0.80	1.30
2040	2.31	1.63	1.54	0.81	1.31

[46] CRA Analysis

Exhibit 29: CO_2 Emission Price Forecast (2017$/ton)[47]

Year	US National	RGGI
2018	0.0	4.2
2019	0.0	4.6
2020	0.0	5.3
2021	0.0	6.1
2022	0.0	6.7
2023	0.0	7.1
2024	0.0	7.5
2025	0.0	7.9
2026	8.2	8.2
2027	8.7	8.7
2028	9.0	9.0
2029	9.3	9.3
2030	9.8	9.8
2031	10.4	10.4
2032	10.8	10.8
2033	11.3	11.3
2034	11.5	11.5
2035	12.0	12.0
2036	12.5	12.5
2037	12.9	12.9
2038	13.0	13.0
2039	13.2	13.2
2040	13.4	13.4

[47] CRA Analysis

Exhibit 30: PJM Levelized Cost of New Entry (CONE in 2017$/ICAP kW-yr)[48]

ISO	Zone	Tech-nology	Gross CONE
PJM	RTO	CT	88.5
PJM	EMAAC	CT	95.9
PJM	RTO	CC	99.0
PJM	EMAAC	CC	104.6

[48] PJM, Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date <http://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx>

Appendix C: PJM Detailed List of New Entrants[49]

Plant Name	Unit	Plant State	Nameplate Capacity (MW)	PJM Zone Name	Online Date	Primary Fuel	Unit Status	Probability	Modeled Capacity (MW)
CPV St Charles	CC	Maryland	746	PEPCO	3/1/2017	NG	Operating	100%	746
Stonewall	CC1	Virginia	750	DOM	5/1/2017	NG	Operating	100%	750
Oregon Clean Energy Center (OH)	CC1	Ohio	869	ATSI	7/1/2017	NG	Operating	100%	869
Carroll County Energy Project	CC1	Ohio	700	AEP	12/1/2017	NG	Operating	100%	700
Doswell Peaking Unit	CT	Virginia	340	DOM	4/1/2018	NG	Operating	100%	340
Wildcat Point Generation Facility	CC1	Maryland	1,000	DPL	4/17/2018	NG	Operating	100%	1,000
Middletown Energy Center	CC1	Ohio	525	DEOK	4/30/2018	NG	Operating	100%	525
Keys Energy Center	CC1	Maryland	800	PEPCO	5/31/2018	NG	Operating	100%	800
PSEG Sewaren	CC	New Jersey	540	PSEG	6/1/2018	NG	Operating	100%	540
St Joseph Energy Center	CC	Indiana	670	IMPC	6/1/2018	NG	Operating	100%	670
Moxie Freedom Project	CC1	Pennsylvania	900	PPL	7/31/2018	NG	Under Const	100%	900
York 2 Energy Center	CC2	Pennsylvania	760	PECO	8/31/2018	NG	Under Const	100%	760
Lordstown	CC	Ohio	904	ATSI	9/1/2018	NG	Under Const	100%	904
Panda Sunbury / Hummel	CC	Pennsylvania	1,064	PPL	9/1/2018	NG	Testing	100%	1,064

49 Sources: Energy Velocity, SNL, CRA market research. Unit Capacity greater than 5 MW has been reported. Announced units are specifically hardcoded into the modeling system. The general criteria is that a unit must have secured financing and broken ground, achieving a status of "Site Prep," "Under Const," or "Testing." In addition, given the scale of CC development, plants that have cleared a Base Residual Auction are included, with probability weightings given to other speculative plants to reflect additional expected new builds in the coming capacity auction. It is assumed that Birdsboro, Hickory Run and CPV Fairview cleared the 2020/2021 Capacity Auction, and that Hill Top cleared the 2021/2022 Capacity Auction.

Invenergy Lackawanna	CC	Pennsylvania	1,480	PPL	12/1/2018	NG	Operating	100%	1,480
Tenaska Westmoreland	CC1	Pennsylvania	900	APS	12/1/2018	NG	Under Const	100%	900
Dom. Greensville	CC	Virginia	1,681	DOM	12/31/2018	NG	Under Const	100%	1,681
Birdsboro	CC1	Pennsylvania	485	PPL	5/1/2019	NG	Under Const	100%	485
Hickory Run	CC	Pennsylvania	998	ATSI	5/1/2020	NG	Under Const	100%	998
CPV Fairview	CC1	Pennsylvania	980	PENELEC	6/1/2020	NG	Under Const	100%	980
Hill Top Energy Center	CC	Pennsylvania	860	APS	6/1/2021	NG	Advanced Development	100%	860
Trumbull Energy Center	CC1	Ohio	940	ATSI	5/1/2022	NG	Early Devel-opment	50%	470
Emberclear Harrison Power Plant	CC	Ohio	1,080	ATSI	5/1/2022	NG	Early Devel-opment	50%	540
J-Power Jackson Genera-tion	CC	Illinois	1,222	COMED	5/1/2022	NG	Early Devel-opment	50%	611
Chickahominy	CC	Virginia	1,602	DOM	5/1/2022	NG	Early Devel-opment	50%	801
South Field Energy	CC	Ohio	1,132	ATSI	6/1/2022	NG	Early Devel-opment	100%	1,132
CPV Three Rivers Energy Center	CC	Illinois	1,100	COMED	1/1/2023	NG	Early Devel-opment	25%	275
West Deptford Expansion	CC	New Jersey	400	AE	1/1/2023	NG	Early Devel-opment	25%	100
APV Renaissance	CC1	Pennsylvania	1,140	APS	4/1/2023	NG	Early Devel-opment	20%	228
Calpine Garrison II	CC2	Delaware	450	DPL	6/1/2023	NG	Early Devel-opment	25%	113
Oregon Energy Center 2	CC1	Ohio	955	ATSI	6/1/2023	NG	Early Devel-opment	75%	716
Panda Mattawoman	CC	Maryland	990	PEPCO	6/1/2023	NG	Postponed	0%	0
Hog Creek Wind Farm	WT1 25	Ohio	50	AEP	1/11/2018	WND	Operating	100%	50
Merck Rahway Power Plant	GEN9A	New Jersey	5	PSEG	1/31/2018	OTH	Operating	100%	5
Phelps 158 Solar Farm LLC	PV1	North Caroli-na	5	DOM	2/1/2018	SUN	Operating	100%	5

Fort Meade	PV1	Maryland	9	BGE	2/26/2018	SUN	Operating	100%	9
Cove Point LNG Terminal Generation	ST1	Maryland	40	PEPCO	3/5/2018	WH	Operating	100%	40
Cove Point LNG Terminal Generation	ST2	Maryland	40	PEPCO	3/5/2018	WH	Operating	100%	40
Danville Solar	PV1	Virginia	6	AEP	3/29/2018	SUN	Operating	100%	6
Great Bay Energy Center	PV1	Maryland	57	DPL	3/31/2018	SUN	Operating	100%	57
DC DGS Solar Projects	PV1 35	District of Columbia	11	PEPCO	4/17/2018	SUN	Operating	100%	11
Kentuck Solar Project	PV1	Virginia	6	AEP	5/23/2018	SUN	Operating	100%	6
Raritan Solar 53 Highway	PV1	New Jersey	10	JCPL	5/31/2018	SUN	Operating	100%	10
New Road Solar	PV1	New Jersey	10	PSEG	7/17/2018	SUN	Operating	100%	10
Old Bridge Solar Farm	PV1	New Jersey	10	JCPL	8/7/2018	SUN	Operating	100%	10
Quakertown Solar Farm No 1	PV1	New Jersey	10	JCPL	9/30/2018	SUN	Under Const	100%	10
Sun Farm VI LLC	PV1	North Caroli-na	5	DOM	9/30/2018	SUN	Under Const	100%	5
Northwest Ohio Wind Ener-gy	WT1 40	Ohio	100	AEP	9/30/2018	WND	Under Const	100%	100
Dorchester County Solar 1 Project	PV1	Maryland	20	DPL	10/1/2018	SUN	Under Const	100%	20
Annapolis Renewable Ener-gy Park	PV1	Maryland	18	BGE	10/31/2018	SUN	Under Const	100%	18
Carl Friedrich Gauss Solar	PV1	North Caroli-na	10	DOM	10/31/2018	SUN	Testing	100%	10
Buckleberry	PV1	North Caroli-na	50	DOM	10/31/2018	SUN	Under Const	100%	50
Colice Hall Solar LLC	PV1	North Caroli-na	5	DOM	10/31/2018	SUN	Under Const	100%	5
Ashburn Corporate Center	ACC10	Virginia	15	DOM	10/31/2018	DSL	Under Const	100%	15
Springfield Solar Project	PV1	New Jersey	9	PSEG	11/1/2018	SUN	Under Const	100%	9
Mendota Hills LLC	WT29	Illinois	75	COMED	11/2/2018	WND	Under Const	100%	75

Walnut Ridge Wind Farm	WT1 114	Illinois	210	COMED	12/30/2018	WND	Under Const	100%	210
Hardin Wind Energy Center	WT129 329	Ohio	300	AEP	12/30/2018	WND	Under Const	100%	300
Meadow Lake Wind Farm	WT351 387	Indiana	200	AEP	12/31/2018	WND	Under Const	100%	200
Gateway Solar	PV1	Maryland	5	DPL	12/31/2018	SUN	Under Const	100%	5
Hamptons At Pohatcong Solar Farm	PV1	New Jersey	17	JCPL	12/31/2018	SUN	Under Const	100%	17
Franklin Township Solar Farm	PV1	New Jersey	15	JCPL	12/31/2018	SUN	Under Const	100%	15
Edenton Solar	PV1	North Caroli-na	10	DOM	12/31/2018	SUN	Under Const	100%	10
UVA Hollyfield Solar Facility	PV1	Virginia	17	DOM	12/31/2018	SUN	Under Const	100%	17
UVA Puller Solar	PV1	Virginia	15	DOM	12/31/2018	SUN	Under Const	100%	15
Beech Ridge Wind Farm (WV)	WT68 100	West Virginia	53	AEP	12/31/2018	WND	Under Const	100%	53
Advanced Solar Two Mile Desert Project	PV1	North Caroli-na	20	DOM	5/31/2019	SUN	Under Const	100%	20

Appendix D: PJM Detailed List of Announced Retirements Included in Modeling[50]

Plant Name	Unit	Plant State	Nameplate Capacity MW	PJM Zone Name	Retirement Date	Primary Fuel Code[51]
B L England	3	New Jersey	176.4	AECO	1/24/2018	RFO
Mallard Lake Electric	CC	Illinois	20	COMED	2/28/2018	LFG
Mecklenburg Cogeneration Facil	GEN1	Virginia	69.9	DOM	4/9/2018	BIT
Mecklenburg Cogeneration Facil	GEN2	Virginia	69.9	DOM	4/9/2018	BIT
Bellmeade	CC	Virginia	330	DOM	4/15/2018	NG
Bremo Bluff	3	Virginia	69	DOM	4/15/2018	NG
Bremo Bluff	4	Virginia	185.2	DOM	4/15/2018	NG
J M Stuart	2	Ohio	610.2	DAY	5/31/2018	BIT
Killen Station	2	Ohio	660.6	DAY	5/31/2018	BIT
J M Stuart	3	Ohio	610.2	DAY	5/31/2018	BIT
J M Stuart	4	Ohio	610.2	DAY	5/31/2018	BIT
Killen Station	GT1	Ohio	28.7	DAY	5/31/2018	DFO
C P Crane	1	Maryland	190.4	BGE	6/1/2018	BIT
C P Crane	2	Maryland	209.4	BGE	6/1/2018	BIT
Bayonne Cogeneration Plant	CC	New Jersey	191.6	PSEG	6/1/2018	NG
C P Crane	GT1	Maryland	16	BGE	6/1/2018	DFO

50 Sources: Energy Velocity Suite, SNL Financial, Dominion 2018 IRP, and CRA Analysis. IL nuclear plants are assumed to stay online until expiration of the IL ZEC program but retire thereafter (in 2028). Beaver Valley in PA is assumed to retire by the end of 2021/2022 deliverability year. CRA's forecast for units owned by Dominion is consistent with Plan B in the Dominion 2018 IRP (which assumes VA joins RGGI in 2020). Plants that were placed into cold reserve in 2018 for final retirement in 2021 are assumed to retire in 2018. As discussed in section 3.4.2, this appendix lists only those plants that have announced retirement. Other plants are retired, beginning in 2020, based on CRA's analysis of plant margins and age.

51 RFO = Residual Fuel Oil. LFG = Landfill Gas, BIT = Bituminous Coal, NG = Natural Gas, DFO = Distillate Fuel Oil, URA = Uranium, OT = Other, WC = Waste Coal; MSW = Municipal Solid Waste, SUB = Subbituminous Coal.

Sewaren	1	New Jersey	110.7	PSEG	6/6/2018	NG
Sewaren	2	New Jersey	107.5	PSEG	6/6/2018	NG
Sewaren	3	New Jersey	107.5	PSEG	6/6/2018	NG
Sewaren	4	New Jersey	126.5	PSEG	6/6/2018	NG
Pittsylvania	1,2	Virginia	83	DOM	8/1/2018	OT
Oyster Creek (NJ)	1	New Jersey	550	JCPL	9/30/2018	URA
Chesterfield	3	Virginia	112.5	DOM	12/1/2018	BIT
Chesterfield	4	Virginia	187.5	DOM	12/1/2018	BIT
Possum Point	3	Virginia	113.6	DOM	12/1/2018	NG
Possum Point	4	Virginia	239.3	DOM	12/1/2018	NG
Pleasants	2	West Virginia	684	APS	12/31/2018	BIT
Kline Township Cogeneration Facility	GEN1	Pennsylvania	59	PPL	12/31/2018	WC
Pleasants	1	West Virginia	684	APS	12/31/2018	BIT
Cogentrix of Richmond Inc	GEN1	Virginia	57.4	DOM	1/12/2019	BIT
Cogentrix of Richmond Inc	GEN2	Virginia	57.4	DOM	1/12/2019	BIT
Cogentrix of Richmond Inc	GEN3	Virginia	57.4	DOM	1/12/2019	BIT
Cogentrix of Richmond Inc	GEN4	Virginia	57.4	DOM	1/12/2019	BIT
Warren Energy Resource Co	NA	New Jersey	13.5	JCPL	1/30/2019	MSW
E W Brown	1	Kentucky	113.6	EKPC	2/28/2019	BIT
E W Brown	2	Kentucky	179.5	EKPC	2/28/2019	BIT
Cogentrix Hopewell	GEN1	Virginia	57.4	DOM	3/31/2019	BIT
Cogentrix Hopewell	GEN2	Virginia	57.4	DOM	3/31/2019	BIT
B L England	2	New Jersey	163.2	AECO	4/30/2019	BIT
Marcus Hook Refinery Cogeneration	GEN1	Pennsylvania	50.5	PECO	6/1/2019	NG
Yorktown	1	Virginia	187.5	DOM	6/1/2019	BIT
Yorktown	2	Virginia	187.5	DOM	6/1/2019	BIT
Three Mile Island	1	Pennsylvania	975.6	METED	9/30/2019	URA
W H Sammis	1	Ohio	190.4	ATSI	5/31/2020	BIT
W H Sammis	2	Ohio	190.4	ATSI	5/31/2020	BIT
W H Sammis	3	Ohio	190.4	ATSI	5/31/2020	BIT
W H Sammis	4	Ohio	190.4	ATSI	5/31/2020	BIT

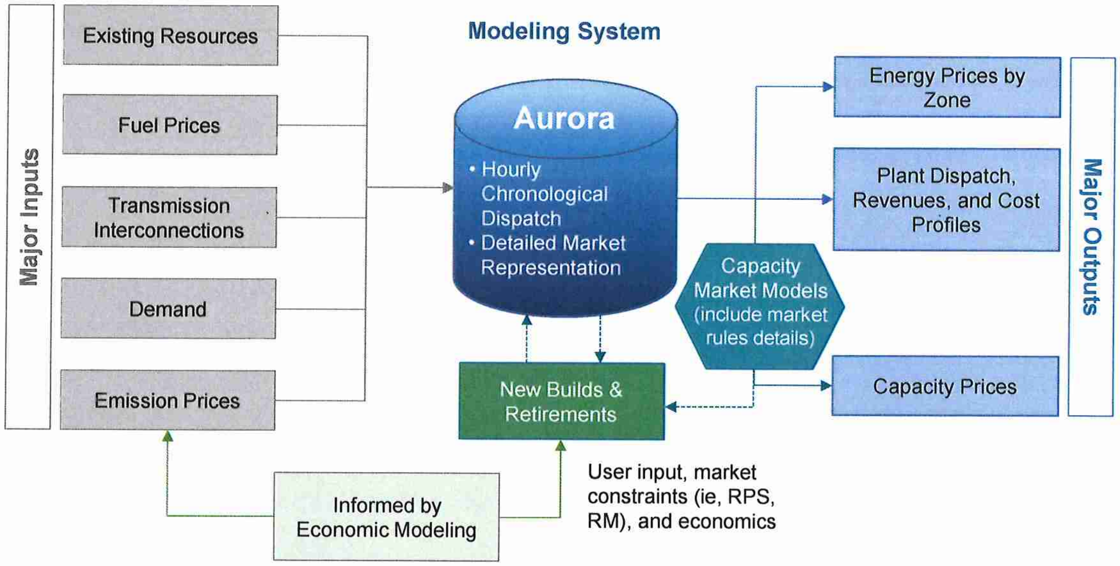
Herbert A Wagner	2	Maryland	136	BGE	6/1/2020	BIT
Colver Power Project	COLV	Pennsylvania	118	PENELEC	9/1/2020	WC
Beaver Valley	1	Pennsylvania	1011.23	DUQ	5/31/2021	URA
Conesville	4	Ohio	443.9	AEP	12/31/2020	BIT
Conesville	5	Ohio	443.9	AEP	12/31/2020	BIT
Conesville	6	Ohio	443.9	AEP	12/31/2020	BIT
Bruce Mansfield	1	Pennsylvania	913.7	ATSI	6/1/2021	BIT
Bruce Mansfield	2	Pennsylvania	913.7	ATSI	6/1/2021	BIT
Bruce Mansfield	3	Pennsylvania	913.7	ATSI	6/1/2021	BIT
Beaver Valley	2	Pennsylvania	1011.23	DUQ	10/31/2021	URA
Yorktown	3	Virginia	790	DOM	12/31/2021	DFO
W H Sammis	5	Ohio	334	ATSI	5/31/2022	BIT
W H Sammis	6	Ohio	680	ATSI	5/31/2022	BIT
W H Sammis	7	Ohio	680	ATSI	5/31/2022	BIT
Chesterfield	5	Virginia	359	DOM	12/31/2022	BIT
Chesterfield	6	Virginia	658	DOM	12/31/2022	BIT
Perry (OH)	1	Ohio	1,313	ATSI	5/31/2021	URA
Davis Besse	1	Ohio	970	ATSI	5/31/2021	URA
Clover	1	Virginia	336	DOM	12/31/2024	BIT
Clover	2	Virginia	670	DOM	12/31/2024	BIT
Will County	4	Illinois	598.4	COMED	12/31/2024	SUB

Appendix E: Power Market Modeling Methodology

CRA's power market modeling approach is outlined in detail in Exhibit 31. It is characterized by the following major elements:

- A chronological, hourly dispatch analysis performed in the Aurora[52] market modeling system, which takes into account all of the major market inputs and drivers documented in this report. In the development of the price forecasts, CRA evaluated the entire Eastern Interconnect in its dispatch modeling.
- Integrated new build and retirement logic that accounts for environmental constraints (emissions and RPS) and plant economics from energy and capacity value; and
- An integrated capacity price model that uses fundamental market drivers to project capacity value and is internally consistent with energy market dynamics and forecasts.

Exhibit 31: Market Modeling Approach



52 Aurora is licensed by Energy Exemplar. For more information, see: https://energyexemplar.com/products/aurora-electric-modeling-forecasting-software/